Clean Energy Transmission Working Group

Report to the Legislature

December 2023

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Letter From the Chairs

Massachusetts Secretary of Energy and Environmental Affairs (EEA) Rebecca Tepper would like to acknowledge the following people for their volunteer service on the Clean Energy Transmission Working Group (CETWG) and assistance in preparing this report.

[Thank you to non-members who contributed, e.g., Jenner & Block]

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Acroynms

AC	alternating current
AI	artificial intelligence
AMI	advanced metering infrastructure
ANOPR	advanced notice of proposed rulemaking
ARI	active resource integration
ASO	affected system operator
BIL	Bipartisan Infrastructure Law
CCRIS	Cape Cod Resource Integration Study
CECP	Clean Energy and Climate Plan
CEISP	Commission on Energy Infrastructure Siting and Permitting
CETWG	Clean Energy Transmission Working Group
CIP	Capital Investment Project
DC	direct current
DER	distributed energy resources
DERMS	Distributed Energy Resource Management Systems
DG	distributed generation
DLR	dynamic line rating
DOE	Department of Energy
DOER	Department of Energy Resources
DPU	Department of Public Utilities
EDC	electric distribution companies
EEA	Energy and Environmental Affairs
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EOED	Executive Office of Economic Development
EPS	electric power system
ESMP	Electric Sector Modernization Plans
ETU	Elective Transmission Upgrades
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GDO	Grid Deployment Office
GET	Grid Enhancing Technologies
GHG	greenhouse gas
GRIP	Grid Resilience and Innovation Partnerships
HVDC	high voltage direct current
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act

ISO-NE	Independent Service Operator New England
kV	kilovolt
LRTP	long-range transmission plan
MassCEC	Massachusetts Clean Energy Center
MassDEP	Massachusetts Department of Environmental Protection
MEPA	Massachusetts Environmental Policy Act
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MMBtu	million British thermal units
MOWIP	Modular Offshore Wind Integration Plan
MVP	multi-value planning
MW	megawatts
NECEC	New England Clean Energy Connect
NERC	North American Electricity Reliability Corporation
NESCOE	New England States Committee on Electricity
NIETC	national interest electric transmission corridor
NJ BPU	New Jersey Bureau of Public Utilities
NOPR	Notice of Proposed Rulemaking
NPCC	Northeast Power Coordinating Council
NPCC	Northeast Power Coordinating Council
NYES	New York Energy Solution
OATT	open access transmission tariff
PFC	power flow controllers
PNNL	Pacific Northwest National Laboratory
POI	point of interconnection
PV	photovoltaic
QW	gigawatt
RTOs	Regional Transmission Operators
SEMA	Southeast Massachusetts
SPP	Southwest Power Pool
TFP	Transmission Facilitation Program
TO	transmission operator
TSED	Transmission Siting and Economic Development
VSC	voltage source converters
WPI	Worcester Polytechnic Institute
ZBA	Zoning Board of Appeal

1. Background

Massachusetts is moving aggressively to meet statutory requirements to reduce carbon emissions from the electric, heating, and transportation sectors by 2050 and to increase renewable energy resources.[1] Other New England states have similar requirements and goals.[2] These requirements are prompting an historic transition to the electric power grid, prioritizing clean resources such as wind and solar photovoltaic (PV) generation and leading to increased electrification of the heating and transportation sectors. Over the next several decades, electrification is expected to increase overall consumer demand for electricity, drive changes in usage patterns[3], and increase the need for transmission to move electricity from new generation resources to the consumer. As the electric grid evolves toward renewable and variable or intermittent resources, and consumers rely more on electricity for generation, transportation and heating and cooling, ensuring a robust transmission system to meet these new demands will be increasingly important.[4]

Legislative Mandate for the Clean Energy Transmission Working Group

1.1.1. Section 71 of the 2022 Climate Act Requirements

The Clean Energy Transmission Working Group (CETWG) was established as part of the requirements of Chapter 179, §71 of the Acts of 2022, "An Act Driving Clean Energy and Offshore Wind" (the Climate Law) to assess and report to the general court on any necessary transmission infrastructure upgrades that may be required to support the deployment of clean energy projects that may interconnect into the Commonwealth for the benefit of residents of the Commonwealth and the region, including but not limited to offshore wind projects.

The CETWG's scope includes the following:

- Consider both in-state transmission upgrades as well as regional transmission upgrades that may be necessary to accommodate the Commonwealth's clean energy requirements.
- Provide recommendations on actions or initiatives that may be undertaken by Independent Service Operator of New England (ISO-NE), the Federal Energy Regulatory Commission (FERC), and other regional and state-level entities that may be helpful or necessary to funding, securing, or approving such upgrades.
- Include a cost-benefit analysis to identify regulatory and legal challenges associated with obtaining and streamlining tariff approvals to accommodate increased clean energy penetration across New England.

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[1] In December 2022, the Executive Office of Energy and Environmental Affairs (EOEEA) released the 2050 Clean Energy and Climate Plan (CECP), detailing how the state plans to meet its statutory requirements to achieve Net Zero greenhouse gas emissions by 2050. The plan sets sector-specific emissions limits which equal the required gross greenhouse gas emissions reductions of at least 85 percent below 1990 levels and proposes carbon sequestration goals to supplement reductions and meet the 2050 net-zero requirement.

[2] The five New England states with emission reduction requirements or goals are Connecticut, Maine, Massachusetts, Rhode Island, and Vermont.

3 To include changes in seasonal and daily shifts in peak demand.

4 The ISO-New England 2023 Regional System Plan, page 15, "the power grid of the future looks radically different from the power grid of the past, and immense resource and transmission buildouts, along with flexible loads and modifications to our grid planning processes, are required to meet the changed needs."

- Assess and review cost-allocation measures adopted in other jurisdictions that aim to spread transmission upgrade costs equitably among ratepayers and developers across the states and regions.
- Give special attention to the need to equitably allocate costs to, and share costs with, benefitted populations outside the Commonwealth, and include policy recommendations that may be needed to equitably recover such costs.

The Climate Law requires the CETWG to submit a final report, along with any recommendations for legislative and regulatory actions at the state, regional, and federal level, no later than December 31, 2023, to the clerks of the House of Representatives and the Senate and the chairs of the Joint Committee on Telecommunications, Utilities and Energy.

1.1.2. Clean Energy Transmission Working Group membership

CETWG membership is specified in the Climate Law and comprises seventeen (17) members, or their designees, appointed by the Governor and representing a wide array of organizations and interests. The Chairman of the Department of Public Utilities (DPU) and the Commissioner of Department of Energy Resources (DOER) chair the CETWG, which is supported by DPU and DOER staff. Members do not receive compensation for their services and serve until completion of the final report with recommendations is issued. The members include the following representatives:

- Chair of the Department of Public Utilities
- Commissioner of the Department of Energy Resources
- Attorney General
- 2 co-chairs of the Joint Committee on Telecommunications, Utilities, and Energy
- 6 appointees of the Governor from the following organizations and associations:
    - American Society of Civil Engineers
    - Associated Industries of Massachusetts, Inc.
    - Massachusetts Taxpayers Foundation, Inc.
    - National Consumer Law Center
    - The Acadia Center
    - Northeast Clean Energy Council, Inc.
- 6 additional appointees of the Governor, representing:
    - Representative or consultant to the offshore wind industry
    - Representative or consultant to the solar energy industry
    - Economist with knowledge of the electricity transmission, distribution, generation, and power supply
    - Representative of municipal interests or a regional public entity
    - 2 representatives of investor-owned utilities in the Commonwealth

Public Meetings

1.1.3. Schedule

The CETWG conducted a total of nine public meetings between July and December 2023. Meetings were held virtually via Zoom and advance notice provided to the public.

Meeting Dates and Presentations

- July 28th: Introduction to ISO-New England System Planning
- August 25th: ISO-NE's 2050 Transmission Study
- September 22nd: Offshore Wind Transmission
- October 13th: Distribution System Planning and Operations
- November 3rd: Jurisdictional Authority and Cost Allocation
- November 17th: Interconnection and FERC Order 2023, Clean Energy Sitting and Permitting, and Review Draft CETWG Report Conclusions and Recommendations
- December 6th: Review of Draft CETWG Report
- December 15th: Review of 2nd Draft CETWG Report
- December 21st: Final Report Vote

1.1.4. Public comments and participation

Meetings of the CETWG provided an opportunity for public comment and written comments were accepted throughout the process of meeting and developing this report. Written public comments are summarized in a brief appendix and posted to the CETWG website. In addition, interested parties were encouraged to register for notifications of meetings via a CETWG list service and meeting materials and presentations were made available via the CETWG website for review.

2. Jurisdiction Authority

Federal/FERC

FERC is an independent federal agency within the Department of Energy (DOE) that regulates the interstate transmission of electricity, natural gas, and oil. FERC was created in 1977 by the Department of Energy Organization Act and replaced its predecessor agency known as the Federal Power Commission. As an independent agency, FERC's decisions are not reviewable by the DOE, although they are subject to judicial review in the U.S. courts of appeals.

Below is an overview of FERC's jurisdiction over electricity transmission, particularly with respect to the setting of rates, system planning and interconnection, siting of facilities, and maintaining reliability.

2.1.1. Transmission rates

The Federal Power Act of 1935 (FPA) gave FERC's predecessor, the Federal Power Commission, jurisdiction over the transmission of electricity, and the sale of electric energy at wholesale, in interstate commerce. In short, FERC has exclusive authority over sales for resale of electricity that cross state lines, as well the transmission of electricity across state lines.

In *New York v. FERC*, the Supreme Court affirmed the FPA's "clear and specific grant of jurisdiction" to FERC over the regulation of electric transmission in interstate commerce. 535 U.S. 1, 22 (2002). This statutory grant extends to FERC's review of public utility transmission owners' tariffs filed under FPA Section 205, as well as over FERC's power under FPA Section 206 to fix any rate, charge, or classification demanded, observed, charged, or collected for transmission by such utilities (including the FERC's remedial authority over "any rule, regulation, practice, or contract affecting such rate, charge, or classification"). FERC plays an essentially passive and reactive role under Section 205, as those filings are driven by the filing utility. By contrast, FERC can take on a proactive role under Section 206, which empowers it to modify existing rates either upon a complaint or upon its own initiative.

FERC's actions in these areas may impact consumer bills, but it is the state public utility commissions that determines retail rates (*i.e.*, the rates individual consumers pay each month on their electricity bills). States have authority over sales of electricity to consumers within their state, as well as intra-state transmission (also called distribution) of electricity.

2.1.2. Transmission planning and interconnection

FERC also affirmed and clarified its jurisdiction over transmission planning and interconnection of facilities to the bulk transmission system through a series of orders dating back to 1990s. In 1996, FERC issued its historic Order No. 888, which restructured interstate transmission of electricity from a contract-based service to a common carrier-type service and provided for open access. In 1999, FERC issued Order No. 2000, which promoted the creation of regional transmission organizations (RTOs) to provide nondiscriminatory open access to transmission. Order No. 2000 defined the minimum characteristics of an RTO as: (1) independence from market participants; (2) appropriate scope and regional configuration; (3) possession of operational authority for all transmission facilities under RTO control; and (4) exclusive authority to maintain short-term reliability of the grid.

Then, in 2005, Congress amended the FPA to specifically authorize FERC to act "in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities." In 2007, FERC issued Order No. 890, requiring all public utility transmission providers' local transmission planning processes to satisfy nine transmission planning principles: (1) coordination; (2) openness; (3) transparency; (4) information exchange; (5) comparability; (6) dispute resolution; (7) regional participation; (8) economic planning studies; and (9) cost allocation for new projects.

Building on this, in 2011, FERC issued another transmission planning order (Order No. 1000) requiring each transmission owning and operating public utility to participate in regional transmission planning that satisfies specific planning principles designed to prevent undue discrimination and preference in transmission service, and that produces a regional transmission plan. Each planning process must have a method for allocating *ex ante* among beneficiaries the costs of new transmission facilities in the regional transmission plan, and the method must satisfy six regional cost allocation principles—including "cost causation," under which "[t]he cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."

In 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) to reform regional transmission planning and cost allocation, which is still pending at FERC. One goal of this Proposed Rule is to ensure more proactive and forward-looking planning of future transmission needs while also affording regions and states sufficient flexibility in developing appropriate methods for allocating the costs of meeting those transmission needs.

2.1.3. Federal role in transmission siting

The Energy Policy Act of 2005 established a limited federal role for the siting of transmission facilities by adding Section 216 to the FPA, authorizing the Commission to issue permits to construct transmission facilities, under certain circumstances, including when a state denies or fails to act on a siting application within one year. See section 8.1 for more information about FERC's limited transmission siting authority.

2.1.4. Transmission reliability

After the 2003 Northeast Blackout, Congress gave FERC broad authority over the reliability of the high voltage (99 kilovolt (kV)+) transmission system, also called the bulk power system. FPA Section 215 directs FERC to adopt and enforce mandatory reliability standards. Under this regime, the North American Electricity Reliability Corporation (NERC) develops the standards and proposes them to FERC; FERC then gets to review and approve. NERC, in turn, delegates authority to eight regional entities to monitor and enforce compliance of those reliability standards. The entity that covers New England, the Northeast Power Coordinating Council (NPCC), is thus authorized within its region to enhance reliability by, among other things, engaging in assessments of reliability, creating region-specific standards, and monitoring the compliance of users, owners, and operators within the region.

State Authorities

States and local governments have authority over the siting and construction of transmission lines. They also have authority over the electric distribution system, including rate regulation, siting and construction of distribution facilities, and interconnection of facilities to the distribution system. The legislature directs statutory and regulatory changes, including to the distribution system, siting, and electric generation procurement. The legislature also drives the need for transmission through legislative changes, such as decarbonization requirements leading to greater electrification that, in turn, increases load and potential need for new transmission. In addition, state- initiated and led procurements for renewable generating resources can have implications for transmission needs and reliability impacts.

In Massachusetts, the DPU is the state's regulatory agency that can promulgate policies, including clean energy policies, that impact the grid. The Siting Division of the DPU has authority to, among other things, issue licenses to construct and operate transmission lines and permit the taking of land (or issuance of easements) for necessary energy facilities. Separately, the Energy Facilities Siting Board (EFSB), an independent state board, reviews proposed large energy facilities, including electric transmission lines. EFSB approval is required prior to the commencement of construction of any EFSB-jurisdictional facility in the Commonwealth, and no State agency may issue a construction permit for any such facility unless EFSB has approved the petition to construct the facility.

The Massachusetts DOER develops and implements policies that include maximizing procurement and deployment of clean energy resources and improving the cost of such resources relative to fossil fuel generation. For example, DOER plays a key role in supporting Massachusetts' procurement of offshore wind generation. Massachusetts' current procurement goals target a total of 5,600 megawatts (MW) from clean energy and offshore wind. The original legislation, the 2016 Energy Diversity Act, required a total of 1,600 MW of offshore wind by 2027. That target was increased several times in ensuing years. Recent legislation (H. 5060, enacted Aug. 2022) provides that DOER may competitively solicit and procure proposals for offshore wind energy transmission to support wind energy generation projects. Under the Act, DOER may coordinate with other state agencies and other New England states to develop a solicitation to best meet the needs of the growing offshore wind industry while maintaining reliability. DOER must consider the total amount of transmission needed to maintain reliability, avoid unnecessary costs to upgrade the existing transmission grid, achieve the Commonwealth's offshore wind and decarbonization goals, and benefit consumers and the environment. Proposals can include upgrades to the existing grid, extending the grid closer to offshore wind locations, and interconnecting offshore substations. The Act also directed DOER to prepare a study on the benefits and costs of requiring electric distribution companies to conduct additional solicitations and procurements for up to 1,600 megawatts (MW) of additional offshore wind. DOER published its Offshore Wind Study in May 2019, recommending that Massachusetts distribution companies proceed with solicitations to secure an additional 1,600 MW of offshore wind generation.

3. Transmission Planning

Bulk Power System

3.1.1. ISO-NE transmission planning

The New England transmission system has been carefully maintained and expanded for decades to move power efficiently from various sources to the region's load centers. To manage the varying amounts and sources of generation to serve the load needed for New England customers, the transmission system requires thoughtful and in-depth short- and long-term planning. With the growing amount of new, clean energy generation across the Commonwealth and region, it is essential that all stakeholders involved work together to ensure system reliability and expand the grid to meet rapidly evolving needs.

Transmission facilities across the Commonwealth are owned and operated primarily by National Grid and Eversource Energy, and to a lesser extent by several other utilities, including many of the Commonwealth's municipal light plants. These facilities operate at voltages levels between 69 kV and 345 kV. They are part of a much larger interconnected electric grid which extends from the Canadian Maritime Provinces to the Midwest United States. The entire grid is designed, operated, and maintained to ensure compliance with mandatory NERC reliability standards. Within New England, the grid is also designed to comply with mandatory standards and criteria from the NPCC, ISO-NE, as well as transmission planning and design criteria specific to individual transmission owners. These standards and criteria continue to evolve to ensure that the transmission system can continue to operate reliably in the face of growing load, changing generation sources, and increasing severe weather.

ISO-NE conducts regional transmission planning in New England pursuant to Attachment K of its open access transmission tariff (OATT) and generally considers projects based on reliability, market efficiency, or public policy needs. The ISO-NE planning process for reliability needs begins with a reliability assessment study of a particular sub-area of the New England transmission system, called a "Needs Assessment." These studies identify system needs (i.e. potential overloads, instability, etc.), considering forecasted loads and known changes to the generation fleet over a ten-year horizon. When a system reliability problem is identified from a needs assessment, ISO-NE works with transmission owners to develop a portfolio of transmission upgrades to resolve the transmission reliability needs or, in some cases, uses the competitive transmission development process to solicit transmission solutions from qualified transmission developers.

The transmission system solution options are then further evaluated to determine, among other things, their feasibility of construction, potential for environmental impacts, estimated costs, longevity, and operational differences. When analysis of the options is complete, ISO-NE recommends a proposed transmission solution.

The transmission owners use similar approaches to periodically assess their portions of the bulk power transmission system for compliance with reliability planning standards and criteria. These assessments overlap, to some extent, with the assessments that ISO-NE performs. They also include additional planning criteria specific to each transmission owner, and assessments of transmission needs arising from upgrades or changes on the distribution system. For example, load growth or the addition of generation connected to the distribution system may require expansion of existing substations or the addition of new substations, both of which often require upgrades to the transmission system. These projects would be identified by the transmission owners and coordinated with regional planning processes that ISO-NE oversees.

Incumbent transmission owners plan local projects in New England, typically radial expansion of a network or lower voltage level transmission facilities. These do not require ISO-NE formal review or approval. The transmission owners also have ongoing obligations to maintain or replace their existing facilities – many of which are at least 50 years old and in some cases over 100 years old. Because of this, the transmission owners frequently engage in asset condition-related upgrades. These projects can range from targeted replacements of individual components of a transmission facility – such as transmission line structures – to the complete reconstruction of a particular facility. For projects with estimated costs greater than $5 million, the transmission owners provide notice through presentations to ISO-NE's Planning Advisory Committee. Transmission owners are in the process of implementing reforms to these procedures in response to a NESCOE request. Asset condition projects are not subject to the regional planning process, but costs are generally allocated on a pro rata basis across the region. In many cases, asset condition projects add capacity to the transmission system as an ancillary benefit, which can help integrate new clean energy resources.

ISO-NE's tariff also includes planning processes that can be used to identify transmission upgrades that provide primarily economic benefits (i.e. lower wholesale power costs) or meet public policy requirements or goals identified by one or more New England states. For transmission planning driven by public policy-related needs, there are several mechanisms that ISO-NE can employ:

- Longer-Term Transmission Planning Process: Under a new process that FERC approved last year, the ISO-NE's regional system planning process authorizes ISO-NE to conduct longer-term transmission studies that may extend beyond a ten-year planning horizon. While the ISO conducts the longer-term transmission studies, it relies on the states to determine the range of scenarios, including drivers, inputs, assumptions, and timeframes to be used in these studies.

- Order 1000 Process: Since 2017, ISO-NE has initiated a process every three-years required under its tariff that provides an opportunity for regional study and potential evaluation and selection of public policy-driven transmission. This process, which covers the ten-year planning horizon, includes a role for the states in confirming that public policy requirements drive transmission needs and a role for ISO-NE is analyzing transmission needs and determining whether to select solutions.

- Elective Transmission Upgrades (ETU) offers the opportunity to submit a request for ISO-NE to study a proposed transmission upgrade. The requestor pays for the ISO-NE study and is ultimately responsible for the cost of building the project and any identified system upgrades. Once the ETU transmission project is built, it becomes part of the New England transmission network. This process is nearly identical to the interconnection process for new generation in ISO-NE. The New England Clean Energy Connect (NECEC) project is an example of a public policy project that ISO-NE studied as an ETU.

To date, these processes have been used infrequently and have not resulted in any regional transmission upgrades, although ISO-NE is currently in the process of developing tariff language for the longer-term transmission planning process that would allow states to operationalize study results through an ISO-NE led procurement.

3.1.2. Interregional needs in New England

3.1.2.1. Need for greater network connectivity

The transmission system is an essential component of the transition to a clean energy future and a resilient transmission network is of increasing importance to the nation's economic, energy security, and overall well-being. The electric grid is confronting ongoing challenges stemming from aging infrastructure, insufficient transmission capacity, and a growing population of variable generation sources. As such, in response to the President's Bipartisan Infrastructure Law (BIL) also known as IIJA, a National Transmission Needs Study[5] (Needs Study) was recently completed by the DOE, to better understand these challenges at a national level by identifying and quantifying interregional needs under different levels of clean energy policy achievement. Additionally, the DOE (in collaboration with Pacific Northwest National Laboratory (PNNL)) is currently conducting a National Transmission Planning Study[6] to understand the value of building interregional transmission to meet these identified needs.

Independent of regional differences to how areas are operated, the Needs Study delved into publicly available data and more than 50 other industry reports from the past five years that assess existing and anticipated needs given varying factors such as electricity demand, public policy, and market conditions.

3.1.2.2. Economic indicators for more flexible interregional connections

There are regional differences in electricity prices. Extraordinary conditions and high-value periods significantly influence the value of transmission, with 50% of the transmission congestion value originating from just 5% of the hours. An examination of new generation and energy storage resources awaiting interconnection agreements across various regions suggests a shift towards greater use of wind, solar, and battery storage technologies in the generation mix. A review of recent power systems studies underscores the historical and expected drivers, advantages, and obstacles associated with expanding the nation's electric transmission network. Collectively, these studies underscore an urgent need to expand electric transmission, driven by the imperatives of enhancing grid reliability, resilience, and resource adequacy, facilitating the integration of renewable resources and access to clean energy, reducing the energy burden, supporting electrification efforts, and alleviating congestion and curtailment.

3.1.2.3. Benefits of interregional transmission

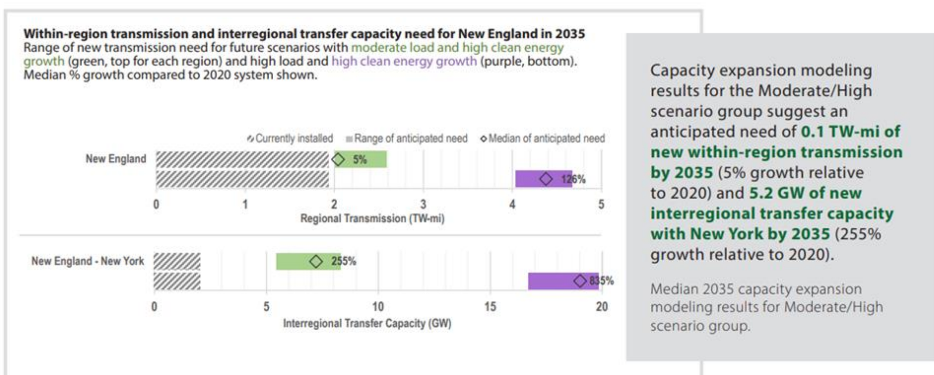
Interregional transmission investments will bolster system resilience by granting access to diverse generation resources in different climatic zones, a crucial factor as climate change leads to more frequent extreme weather events that can disrupt the power system. Equitable investments in areas with higher cumulative burdens may also mitigate existing disadvantages and enhance the benefits for communities that face elevated energy burdens, prolonged outages, and heightened environmental risks. Additionally, alongside shifts in electricity supply, regional objectives and legislative actions pertaining to heating and transportation are poised to reshape the way electricity is consumed across the country in the coming decade and beyond. The electrification of heating and transportation will substantially increase total demand on the national grid and reshape daily electrical system demand patterns.

5 National Transmission Needs Study (energy.gov)
6 National Transmission Planning Study | Department of Energy

The Needs Study assessed anticipated future transmission and transfer capacity needs for various scenarios within the power sector across three different future years. According to the results of capacity expansion models, the most substantial growth in transmission capacity will be required in the Texas, Mountain, Southeast, Midwest, and Plains regions. However, most significant increase in interregional transfer capacity will occur between the Plains and Midwest, between the Midwest and the Mid-Atlantic, and between New York and New England, with notable growth in connections between these three interconnections. For the towns and communities in Massachusetts, this study output is a strong signal that action needs to occur now, to position the Commonwealth to achieve this enhanced transfer capacity when it is most needed.

3.1.2.4. Key findings in DOE study

The DOE Study shows an urgent demand exists for additional electric transmission infrastructure in nearly all regions across the United States to enhance reliability and resilience. In New England, the ISO-NE 2023 Energy Shortfall Study supports this concern. Specifically, more hydro power imports into the region by existing and new circuits could reinforce the overall resiliency of the region. The DOE Study found interregional needs between New York and New England grow significantly under all examined scenarios. (see image below from the Needs Study results). It is worth emphasizing the timing of the need, considering an interregional transmission solution could take upwards of 10 years to implement, meaning New England, working with New York, should consider upgrades in the near term to keep pace with needs.



The most significant advantages stem from increasing interregional transmission. Historically, the most substantial advantages in augmenting interregional transfer capacity have been observed along the interconnection boundaries, but the needs both continue to grow and evolve. With specific mentions in the Study on the future benefit of enhanced New York to New England transfers, the starting point to prudently act upon this goal is to assess all of the existing circuits that make up this transfer. This may allow the region and states the visibility to see what circuits making up these transfers may need to be rebuilt in the future, and if capacity could be significantly increased through an insignificant scope addition to these projects. The same approach could be taken for transfers coming in and out of Boston from the North and South.

It is worth noting that over time these needs will evolve along with the significant change in power demand and generation profiles. The transformation toward cleaner energy sources, evolving regional demands, and the escalating frequency of extreme weather events all necessitate adjustments in the future power grid. Substantial transmission expansion is imperative by 2030 in many regions across the US. The same applies to interregional transmission expansion, with a significant demand for new interregional transmission between nearly all regions by 2040.

Progress is being made to explore expanding ties between regions in the Northeast. Earlier this year, Massachusetts led a bipartisan request to DOE from all six New England states, New York, and New Jersey to form a multi-state collaborative to work with our federal partners on opportunities to develop electric transmission infrastructure to enhance our interregional connections, including the potential build-out of an offshore wind network.[7] This is the first time this kind of federal-multi state collaboration has been implemented. Since the initial request, two additional states in the Mid-Atlantic, Maryland and Delaware, joined this effort. DOE convened the first in person meeting of the collaborative in November 2023. The collaborative is working to develop an actionable scope of work covering short, medium, and long-term activities.

Distribution System

3.1.3. Defining the distribution system

The distribution electric network encompasses the intricate network of power lines, utility poles, substations, and associated equipment that acts as the final link in the journey of supplying electrical energy from the transmission system to end-users. Traditionally the system bridged the gap between the high voltage transmission system and end users, by efficiently conveying power to homes, businesses, and other establishments.

In contrast to the high-voltage transmission system, the distribution system operates at lower voltages and is responsible for transporting electricity from transmission substations over shorter distances to a multitude of endpoints within a designated geographic area, be it a neighborhood or a city. Substations are crucial elements in the distribution system; they house transformers that allow power to be stepped down from a transmission voltage to a lower distribution voltage so it can safely serve the residents in a particular locality. Transformers also allow voltage to step up from low to higher voltage if there is a surplus of DERs in an area that results in exports to the transmission system. To enable the smooth bidirectional flow of power between transmission and distribution, the transformers and accompanying primary electrical equipment within substations must possess sufficient capacity, which is why the electric distribution companies' (EDCs) current Electric Sector Modernization Plans (ESMPs) consider many expanded or new substations. These substation buildouts will play a pivotal role in enhancing network capability, ensuring that customers continue to get their evolving power needs served safely and reliably.

3.1.4. Current state of the distribution system

The distribution system within the Commonwealth has been experiencing a systematic change in recent years in how it operates. While in the past load growth has been more predictable, and generation was primarily large, centralized, and fossil-fueled, the landscape is rapidly changing. This includes the successful adoption of distributed solar power, and the increased deployment of energy storage solutions, which have both contributed to the positive, and drastic shift in generation profiles throughout the State. This growth can be attributed to proactive State policies and initiatives, resulting in the distribution networks within Massachusetts becoming some of the most densely connected systems for distributed energy resources (DER) in the entire country.

[7] https://www.mass.gov/doc/interregional-transmission-letter/download.

3.1.5. Comprehensive planning approach

In recognition of these changes, it has been necessary to re-examine what it means to effectively plan for the distribution system of the future. With this considered, the distribution companies have implemented more rigorous processes aimed at better comprehending the localized conditions within the diverse regions in the Commonwealth, concurrently assessing the projected continued DER adoptions and electrification needs well into the future. This approach is focused on better encompassing asset condition needs, tracking significant DER adoption trends, anticipating demand growth, and addressing the specific, evolving needs of customers. While the distribution networks have made significant strides in optimizing the value derived from current assets through asset management and planning practices, the distribution companies have raised concerns that infrastructure is now approaching a critical juncture. They have concluded that the existing network's capacity is coming close to becoming fully utilized, and in response to the demands of the clean energy transition, there is a pressing need for investment to enhance capacity, and flexibility for customers.

3.1.6. Future focus for system optimization and flexibility

As part of the growing electrification of the State, the distribution system will be driven by the need to accommodate substantial new load from a number of sources, including transportation and heating. An essential element in fostering an affordable transition to clean energy is promoting the efficient utilization of the network, in conjunction with the creation of more capacity in the appropriate areas. Enhanced flexibility minimizes the need for excess system capacity and, in turn, lessens costs for customers. Technologies like Distributed Energy Resource Management Systems (DERMS), including active resource integration (ARI), could help facilitate the efficient expansion of the system. The integration of technologies such as advanced metering infrastructure (AMI), combined with dynamic price signals, would actively engage customers in managing their demand and encouraging the efficient use of the system infrastructure.

Moving to a more comprehensive, longer term distribution planning approach is key to achieving our clean energy transition. Such a process should ensure that infrastructure is robust enough for the more complex load profiles of the future.

ISO-NE 2050 Transmission Study

In 2020, the New England states through the New England States Committee on Electricity (NESCOE), released a Vision Statement for a clean reliable and affordable power grid.[8] The Vision Statement calls for changes in three key areas of the regional energy system: wholesale market design, transmission planning, and governance. With respect to transmission planning, the states asked ISO New England (ISO-NE) to implement a longer-term, repeatable regional transmission planning effort that would provide a high-level transmission system plan to meet the needs of the New England states' energy transition with participation and input by State officials. In addition, NESCOE asked ISO-NE to develop a process whereby states can operationalize study results (e.g., competitive solicitations).

In 2021, ISO-NE began work on the 2050 Transmission Study, the first such longer-term study.[9] The 2050 Transmission Study is designed to inform states, stakeholders, and the region of possible future transmission needs. It is important to note that the study is a high-level transmission analysis and not an

[8] https://nescoe.com/resource-center/vision-stmt-oct2020/#:~:text=October%202020%20–%20The%20New%20England,system%3A%20Wholesale%20Electricity%20Market%20Design
[9] ISO-NE also revised its tariff to establish this process. These changes were approved by FERC in 2022.

exhaustive analysis of the transmission needs that may need to be addressed in the future. Rather, the 2050 Transmission Study provides directional results that can help inform plans for and decisions around future investment needed to meet the region's clean energy needs.

3.1.7. Scope, assumptions, state input

The 2050 Transmission Study is a high-level transmission study that considers both summer and winter peaks for the years 2035, 2040, and 2050. The objective of the study is to identify the amount, type, and high-level cost estimates of transmission infrastructure that would be needed to meet state energy policies while satisfying reliability criteria. The assumptions for the study were provided by NESCOE and represent a scenario that is compliant with greenhouse gas (GHG) emission limits scenario that reflects the region's energy and environmental laws. The demand (load) forecast and expected resource mix are based on the All Options Pathway in Massachusetts' Deep Decarbonization Roadmap report, published in December 2020.[10]

The assumed loads in the 2050 Transmission Study are significantly higher than any loads seen to date in New England, driven by the electrification of the heating and transportation sectors (see Figure 1). The highest load modeled was the 2050 winter evening peak of approximately 57 gigawatts (GW). For comparison, the highest load observed to date on the New England system was the 2006 summer peak of just over 28 GW, and the highest winter load observed to date was the January 2004 peak of just below 23 GW.[11]

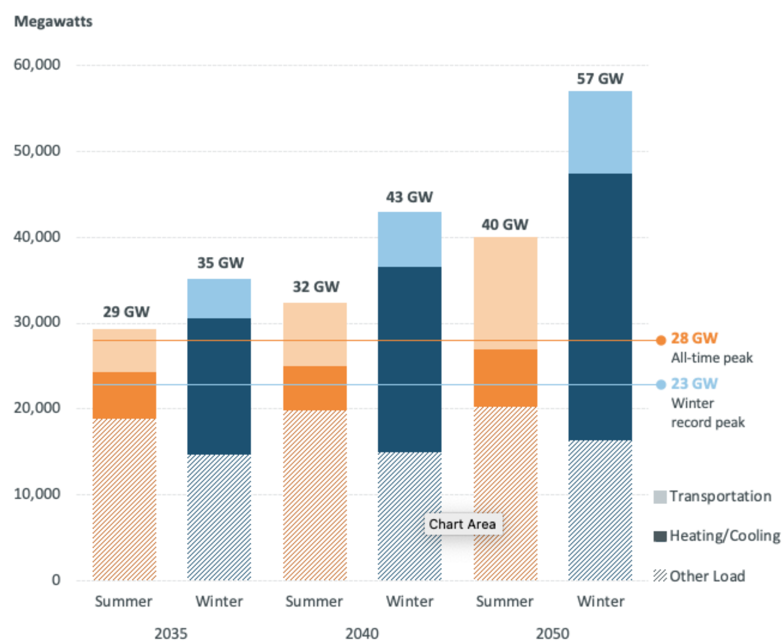


Figure 1: ISO-NE 2050 Transmission Study Peak Load Forecast

The 2050 Transmission Study assumes these loads are served by a generation fleet that differs significantly from today's resource mix. All coal, oil, diesel, and municipal solid waste-fueled generation, as well as a portion of today's natural-gas-fueled generation, was assumed retired by 2035. The remainder of today's natural-gas-fueled generation, as well as biomass, nuclear, hydroelectric, and renewable

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[10] https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download
[11] Draft 2050 Transmission Report at 11.

generators, were assumed to remain operational through 2050. New clean resources, such as wind, solar, battery storage, and increased imports from neighboring power systems in New York and Québec replace the retired generation and serve the increases in load.

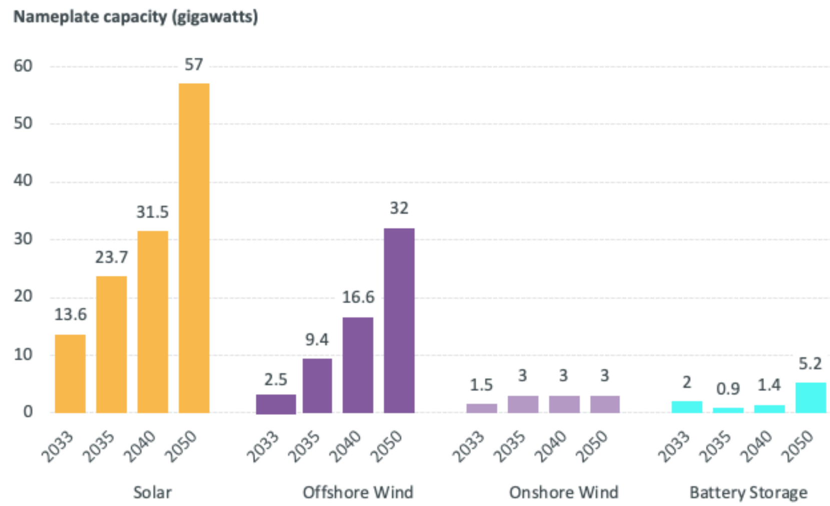

Figure 2: ISO-NE 2050 Transmission Study Resource Mix

3.1.8. Findings

The 2050 Transmission Study identified a series of transmission concerns that would need to be addressed to reliably serve the forecast load in 2050. In response to feedback from NESCOE and other stakeholders, ISO-NE identified the most commonly observed, or "high likelihood," transmission concerns. The high-likelihood concerns identified by ISO-NE are those that are relatively insensitive to specific assumptions; that is, they are likely to occur even if the assumptions used in the study do not unfold exactly as predicted. Where possible, ISO-NE grouped the high-likelihood concerns when they occurred in a similar region and could be resolved by a common solution set. ISO-NE identified 4 such groupings:

- **North-South:** a variety of overloads occurred at the transmission interfaces that connect Maine and New Hampshire to northeastern Massachusetts.
- **Boston Import:** In most scenarios, the current paths to import power into Boston were unable to support increasing load due to high load and low assumed generation in the area.
- **Northwestern Vermont Import:** in the winter, the current paths to import power into northwestern Vermont (Burlington area) were unable to support the increasing load with assumed low generation.
- **Southwest Connecticut Import:** there are currently two high voltage paths connecting Southwest Connecticut to the rest of the New England system, which were unable to support the needed power flow as the load increased.

In addition to the groupings above, ISO-NE identified numerous other isolated high-likelihood concerns as well as many concerns that were not considered high-likelihood. The latter are mainly related to serving the highest load level considered in the study (57 GW winter peak).

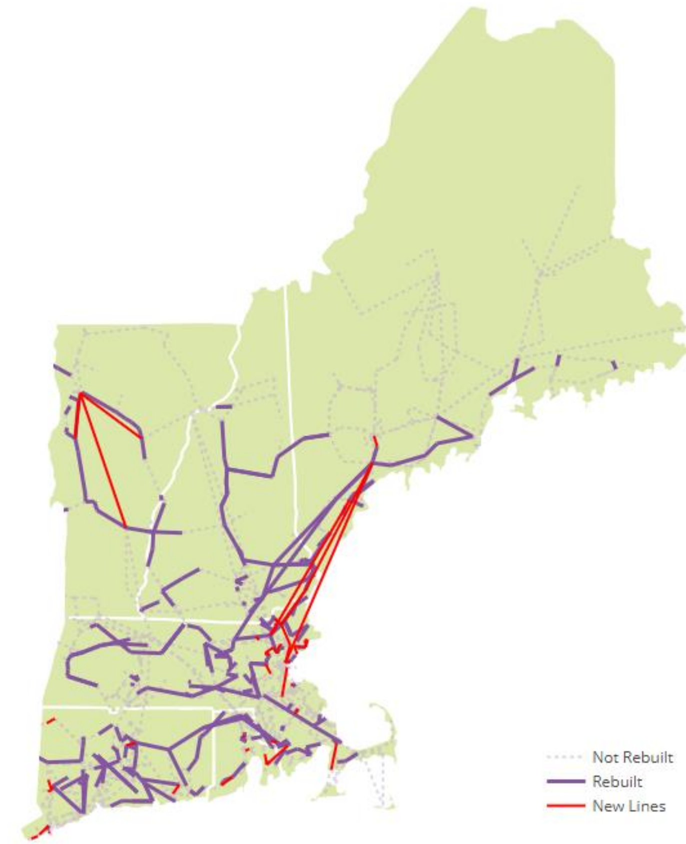

Figure 3: ISO-NE 2050 Transmission Study Solutions Map

As part of the study, ISO-NE developed conceptual solutions for all identified concerns and corresponding cost estimates. Generally, the solutions comprised both new transmission lines as well as the rebuilding of existing transmission lines. For the key groupings of high-likelihood concerns, ISO-NE explored one or more conceptual approaches to resolve the identified concerns and noted tradeoffs between the various approaches. For example, ISO-NE identified four possible approaches, or roadmaps, to resolve the North-South/Boston Imports (which were grouped together since solutions were heavily dependent on one another). These roadmaps were developed to provide a variety of examples of how these concerns might be mitigated. The 2050 Transmission Study does not recommend any particular roadmap over another; each includes advantages and disadvantages.

3.1.9. Next steps

3.1.9.1. Cost estimates and key findings

The identified upgrades are useful for providing an order-of-magnitude estimate of future transmission system costs. These estimated costs are intended to inform consumers, industry stakeholders, and policy makers of the costs inherent in maintaining reliable transmission service through the clean energy transition.

Table 1: ISO-NE 2050 Transmission Study Cost Estimates

Year/Load Level	Maximum Load Served (MW)	Total Cost Range
2035	35,000	$6-9 Billion
2040	43,000	$11-13 Billion
2050 (51 GW winter peak)	51,000	$16-17 Billion
2050 (57 GW winter peak)	57,000	$23-26 Billion

ISO-NE estimates that it could cost up to $26 billion to resolve the transmission concerns identified in the 2050 Transmission Study. It is important to note that this estimate reflects costs to solve the high-level concerns identified in the 2050 Transmission Study, which are only part of the total required investment. More detailed transmission analysis may uncover additional needed investments. In addition, the 2050 Transmission Study does not consider potential distribution system upgrades. ISO-NE notes that significant upgrades to the distribution system will be needed to accommodate the 2050 peak load studied.

The investment will be spread out between now and 2050, so the total cost of $16-$17 billion to serve a 51 GW winter peak load is approximately $0.62-$0.65 billion per year. Similarly, the total cost of $23-$26 billion to serve a 57 GW winter peak load results in average spending of approximately $0.88-$1.00 billion per year. For context, total transmission spending between 2002 and 2023 totaled $15.3 billion, or an average of approximately $0.73 billion per year.

The 2050 Transmission Study resulted in several high-level observations around transmission-related challenges the future grid may face as a result of the clean energy transition.

- **Reducing peak load significantly reduces transmission cost.** The assumptions initially provided by NESCOE included an assumed 2050 winter peak load of 57 GW. The study explored how a lower peak load in 2050 might impact transmission needs and costs by also studying at 51 GW 2050 winter peak load. The 2050 Transmission Study found that increases in load result in significantly higher transmission costs as load levels increase. The cost to serve 51 GW of load is $16-$17 billion, while the cost to serve 57 GW of load is $23-$26 billion. Limiting load growth could be achieved through more aggressive demand response, energy efficiency, and peak shaving programs. Limiting load growth could also be achieved by using some stored fuel for heating on the coldest days. For example, moving from 57 GW to 51 GW of peak load could represent ~80% heating electrification while still maintaining 100% transportation electrification.

- **Targeting and prioritizing high likelihood concerns is highly effective.** While the 2050 Transmission Study is a high-level analysis, the results can be used to identify which areas of the transmission system are most likely to be constrained in the future. The 2050 Transmission Study found that "projects that address these high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates."[12]

[12] Draft 2050 Transmission Report at 17.

- **Incremental upgrades can be made as opportunities arise.** Many of the transmission concerns found in the 2050 Transmission Study can be addressed by rebuilding existing transmission lines rather than building new lines in new locations. Taking advantage of line rebuilds could minimize costs as well as be less environmentally disruptive. Rebuilds can generally be achieved in a shorter timeframe than new transmission lines, which would allow the region to postpone investment decisions until more information is available. The 2050 Transmission Study found that upgrading the capacity of lines as the opportunity arises, or "right-sizing" asset condition projects[13] when they occur, could be a financially prudent way for New England to reliably serve increased peak loads. Discussion on how to "right-size" transmission investment will occur at ISO-NE's public stakeholder forum, the Planning Advisory Committee. NESCOE has requested that the region first make progress on reforms to improve the transparency, predictability, and cost discipline of asset condition projects as a prerequisite to a right-sizing approach.[14]
- **Generator locations matter.** The specific location of generators can have a significant impact on the needed transmission upgrades. In general, locating generation close to large load centers, such as cities, can reduce the strain on the transmission system.
- **Transformer capacity is crucial.** Transformers "step down" power from higher to lower voltages. The 2050 Transmission Study found that as load increases, higher voltage lines become more important. In turn, the power transferred on the higher voltage lines must eventually be stepped down to lower voltages on the way to the distribution system. A significant number of additional transformers will be needed to support load growth. Transformers typically are expensive, however, and require a long lead time (1-2 years). The 2050 Transmission Study found that "due to the long lead times and the large number of transformers needed, it may be prudent to start ordering transformers ahead of time and determining their exact locations later on."[15]

3.1.9.2. Final report

The draft 2050 Transmission Study was published on November 1, 2023, with a 30-day public comment period. ISO-NE will finalize the study after reviewing the comments received and updating the report as needed.

3.1.9.3. Phase 2 tariff change

As noted above, in 2020, the New England states, through NESCOE, requested that in addition to a longer-term, repeatable transmission planning process, ISO-NE establish a process by which the states can operationalize the study results. ISO-NE began stakeholder discussions on this second-phase of the longer-term transmission study process in October 2023. The proposed process, which reflects NESCOE input, would allow NESCOE to identify transmission concerns to address, followed by a solicitation that ISO-NE would administer. The proposal contemplates that costs for projects selected through the solicitation would be allocated across the region on a load share basis. Discussions on this proposal will continue into 2024, and are expected to become effective in mid-2024, depending on approval.

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[13] In New England, asset condition projects are identified by transmission owners when equipment exceeds its useful life. Draft 2050 Transmission Report at 17.
[14] https://nescoe.com/resource-center/asset-condition-process-improvements-next-steps/
[15] Draft 2050 Transmission Report at 20

4. Cost Allocation

Overview of Transmission Costs and Benefits

In Order No. 1000, FERC mandated the adoption of cost allocation methods in planning regions. It also directed that cost allocation methods focus on aligning costs with benefits by identifying the beneficiaries of proposed regional transmission facilities and imposing those costs on them. However, FERC did not adopt a universal or comprehensive definition of "benefits" and "beneficiaries." Recognizing inherent difficulty and controversy of cost allocation decisions, FERC allowed regional planning entities flexibility if they complied with six regional cost allocation principles identified by FERC. Among other principles, costs are to be allocated in a manner *at least roughly commensurate* with estimated benefits (Principle 1), and a planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional plan (Principle 6).

After FERC's Order No. 1000, public utility transmission providers in each planning region adopted varying cost allocation methods to comply with that Order's cost allocation principles. The most common methods to allocate costs have treated reliability needs, economic needs, and public policy requirements separately. But some [transmission providers?] have identified benefits across a portfolio of transmission facilities rather than on a facility-by-facility basis.

In 2021, FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) presenting potential reforms to improve the regional transmission planning and cost allocation processes, among other things. In the ANOPR, FERC expressed a concern that regional transmission planning and cost allocation processes may not be sufficiently forward-looking to meet transmission needs driven by changes in the resource mix and demand. FERC was concerned that planners and policy makers may not be considering the full range of benefits that transmission investments can provide, understating the expected value of such projects and how these values change over time.

Following the ANOPR, as referenced earlier, in 2022 FERC issued its NOPR to reform regional transmission planning and cost allocation. One goal of the NOPR was to afford regions and states sufficient flexibility in developing appropriate methods for allocating the costs of meeting long-term transmission needs. The NOPR proposed greater state involvement in determining cost allocation, while also preserving the Order No. 1000 cost allocation principles. The cost allocation would either be negotiated in advance and applied to all or some set of transmission facilities that are (1) identified as part of long-term regional transmission planning, (2) negotiated on a case-by-case basis after transmission facilities are identified (the State Agreement approach), or (3) a combination of these methods. Under a State Agreement approach, the relevant state entities must voluntarily agree to a cost allocation method. The NOPR remains pending at FERC.

ISO-NE Cost Allocation

4.1.1. Reliability projects and economic projects

Pursuant to Schedule 12 of ISO-NE's tariff, costs for Regional Benefit Upgrades (which includes Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades) are shared by consumers across the region, on the principle that all consumers benefit when the reliability and efficiency of the regional network is improved. More specifically, costs for Regional Benefit Upgrades are allocated on a load-ratio basis – *i.e.*, based on the amount of electricity demand in each state.

4.1.2. Public policy projects

The default cost allocation methodology for public policy projects is that 70% of the costs are shared by consumers throughout the region on a load-ratio basis, and 30% of the costs are allocated to each state in direct proportion of the state's share of the public policy planning need that gives rise to the projects. Elective Transmission Projects, funded 100% by the project developer, provide another means for pursuing state policy goals. For example, the NECEC project was developed as a result of the Commonwealth's 2016 Energy Diversity Act and recovers most of its costs from ratepayers of the Massachusetts utilities holding long-term contracts for transmission service on the NECEC line.

4.1.3. Local transmission projects

As noted above, incumbent transmission owners plan local projects in New England, typically radial expansion of a network or lower voltage level transmission facilities. These do not require formal review or approval by ISO-NE. Costs of these projects are allocated locally, to the transmission customer causing the need for the project.

Review of cost allocation measures in other jurisdictions

Several RTOs use other cost sharing models, such as portfolio-based allocation methods instead of a project-by-project approach.

4.1.3.1. SPP Highway-Byway

Under the Southwest Power Pool's (SPP) Highway-Byway approach, the costs of facilities are allocated differently based on the voltage level. The costs of those facilities operating at 300 kV and above will be allocated 100 percent across the SPP region on a postage stamp basis. The costs of facilities operating above 100 kV and below 300 kV will be allocated one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located. The costs of facilities operating at or below 100 kV will be allocated 100 percent to the zone in which the facilities are located.

For 100-300kV facilities, SPP recently proposed to establish a process to allocate 100 percent of the costs of these facilities on a regionwide basis. While FERC initially accepted the proposal, on rehearing it reversed that conclusion and found that SPP had not met its burden under Section 205 of the FPA to show that the proposed process will result in just and reasonable, and not unduly discriminatory or preferential, outcomes. FERC found that SPP's proposal, even as modified on compliance, gave the SPP board too much discretion in allocating the costs of Byway facilities.

4.1.3.2. MISO MVP

Through a multi-value planning (MVP) approach, the Midcontinent Independent System Operator (MISO) evaluates a wider range of multiple possible benefits from regional transmission solutions, rather than more narrow standard approaches of placing projects into reliability, economic, or public policy siloes. Through this multi-value approach, MISO has collectively—with its stakeholders, including the Organization of MISO States—assessed multiple benefits of proposed facilities together and compared those benefits to the costs. MISO considers a broad range of benefits, including fuel and congestion cost savings, avoided local investment, decarbonization, and avoided risk of blackouts. And it compares these benefits to the costs on a portfolio-wide basis to determine net benefits to the region, and to broadly allocate the costs of the transmission to those that benefit.

Building on the MVP approach, MISO has undertaken a new approach—the Long-Term Regional Transmission Plan—which focuses on the MISO Midwest region. This portfolio-based approach, evaluating networked facilities that can provide benefits across the MISO Midwest footprint, has helped secure broad political support from all states. That support was critical for securing buy-in from each state to broadly allocate the cost of such transmission projects across the region. As a result of this work, the first tranche of long-range transmission plan (LRTP) projects approved by the MISO board consists of 18 different regional transmission facilities, spanning nine states in MISO Midwest. These projects are designed to facilitate an expected retirement of 58 GW of existing generation resources (including 39 GW of aging coal generation) and support the integration of 90 GW of new generation, including 56 GW of wind and solar generation. MISO estimates that the $10.3 billion cost of the LRTP portfolio will generate between $37 billion and $69 billion in total benefits for the region, primarily through reduced fuel costs, reduced transmission congestion (which forces dispatch of higher cost generators), avoided investment in less efficient local facilities, and decarbonization.

4.1.3.3. PJM State Agreement Approach

FERC has approved PJM's State Agreement Approach to transmission planning. Under this approach, states may jointly or individually agree voluntarily to share in the allocation of costs of a proposed transmission expansion or enhancement that addresses state public policy requirements identified or accepted by the state(s) in the region—so long as they agree to pay all the costs of the project. 174 FERC ¶ 61,090. The expansion or enhancement project would be reflected in the PJM Regional Transmission Expansion Plan as either a supplemental project or a state public policy project.

New Jersey was the first state in the PJM region to use the State Agreement Approach when the New Jersey Bureau of Public Utilities (NJ BPU) issued an order requesting PJM to open a competitive proposal window to solicit proposals to expand the PJM transmission system to provide for the deliverability and interconnection of 7,500 MW of offshore wind into the state by 2035. PJM explained in its proposal that, because the State Agreement Approach is a flexible mechanism, as opposed to a prescriptive process, there is no pro forma service agreement that a state must use to identify and develop a project that will effectuate its public policy requirements. Under PJM's proposal, as accepted by FERC, PJM would develop recommendations for project proposals and New Jersey would subsequently file with FERC identifying the public policy projects, the chosen developers, and the cost allocation method for the projects.

5. Offshore Wind Transmission

Offshore Wind Opportunities in Massachusetts

The current approach to offshore wind transmission planning involves offshore wind developers taking interconnection and delivery risk by making informed approximations on where they can import the most amount of clean energy at the lowest cost and least disruption to the surrounding communities. The cost to connect the submarine cables of an offshore wind farm to an onshore substation is only one contributor to the overall cost of the project, however. s. The availability of land near a coastal landing point to expand a substation, construct a converter station, or site a new transmission circuit leading out of the area has proven to be very challenging and can lead to high costs for onshore facilities. The offshore wind developers may not have information on a lot of these factors, and the utilities owning the facilities with which they will connect may be unable to offer any meaningful help until a potential interconnection customer has selected a desired point of interconnection and entered the interconnection queue. As each subsequent state RFP is released, the low-cost options for onshore interconnection sites for individual offshore wind farms are quickly dwindling, and onshore interconnection and grid upgrade costs and associated uncertainties are rapidly increasing.

For these reasons, Massachusetts and the New England region are at a critical juncture, where the experiences of the past may successfully inform a better way of achieving the interconnection of the region's approximately 9 GW of existing offshore wind commitments. Targeted upgrades of the onshore network to facilitate delivery of offshore wind from proactively planned points of interconnections can provide substantial benefits, regardless of whether future offshore wind developers use radial lines or connect to multi-plant collector lines. In any scenario, the points of interconnection need to be maximized for imported power capacity, dependability, and resilience, considering environmental and community impacts. A more collaborative and proactive planning process considering how to integrate future clean energy resources onshore and offshore will allow the region to evaluate the most cost-effective and flexible options for the region and its electricity customers—ones that can also be expanded readily as the energy transition progresses. In addition, this planning effort and the resulting implementation plans could be effectively coordinated with ongoing transmission work in these areas so efficiencies can be gained where appropriate.

Massachusetts customers and the broader New England region have made large investments in the transmission network over the last decade and should expect not just a safe and reliable system, but a network that can cost-effectively integrate large volumes of clean power in a timely fashion. Now is the time to identify, and reinforce or enhance, the existing onshore grid infrastructure to make that possible. In doing so, the Commonwealth has an opportunity to leverage the existing capability of the transmission network in the State and help de-risk offshore wind projects looking to connect.

With an ever-changing set of circumstances, offshore wind developers must consider the right delivery approaches for their projects, as outlined in a recent report issued by the Brattle Group.[16] Below is a list of some of the prevailing approaches, based on an assumption of four offshore wind farms.

- Radial Tie Lines: This would be where all four wind farms connect into different and respective substations onshore and are not connected offshore.
- Backbone Offshore Grid: This where all four offshore windfarms are connected with each other, but only two of them (e.g., the most northern and most southern windfarm) are connected to onshore substations.
- Meshed Generation Ties: A combination of the radial line and backbone approach, with each wind farm connected to an individual substation on land, but all of the wind farms connected with each other. It is possible to connect radial tie lines into a meshed offshore grid at some point in the future, if the radial tie lines are built with "mesh ready" (or "network ready") offshore substations (as New York and New Jersey have mandated in their recent OSW procurements).
- Offshore Collector Station. This is where a large offshore platform, or energy island, is built and all four wind farms connect into the "collector" substation at that offshore platform. Only one set of submarine cables then go from this platform to a single beachhead, connecting to one or more existing onshore substations.
- Onshore Collector Station: Same as the radial tie line approach, except all of the windfarms connect directly into a single collector substation on shore.

[16] U.S. Offshore Wind Transmission: Holistic Planning and Challenges

Of the above examples, the radial tie line approach is the more prevalent approach today, as it has appeared to present the lowest level of risk and complexity for developers to date. It should also be noted that while a meshed and backbone approach may offer more system flexibility and reduced congestion, it is more challenging to define these benefits at this point, and these approaches also increase the costs of the offshore transmission facilities. The fact that facilities and benefits would be shared between multiple projects and multiple states also adds complexity to such meshed, backbone, and collector station solutions.

Offshore Wind Industry Assessments

There have been several studies of offshore wind grid interconnections for New England and the east coast of the U.S. These studies have yielded some prevailing principles as they approach the challenge in the context of offshore wind goals of up to 85 GW along the U.S. Atlantic coast, connected together and tied into the mainland at preferred points of interconnection. There is some common logic to the core initial steps that need to be taken, to best position for the magnitude of successful integration that is targeted.

5.1.1. Central strategic themes

5.1.1.1. Benefits of an offshore backbone:

Efficiently integrating 85 GW of offshore wind would require an ultra-high capacity offshore transmission network that could also efficiently enable long-distance, interregional energy transfer. Consistent with a modelling project the National Offshore Wind Research and Development Consortium (NOWRDC) has sponsored, a team of experts from Tufts University, Iowa State, and Clemson University have developed three separate models to evaluate and illustrate this future state. The coordinated expansion models varied in size, including a 93,520-bus model, a 722-bus model, and 176-bus grid model. All three models were developed specifically to evaluate East Coast offshore wind, and together serve a full suite of capabilities from detailed evaluation of points of interconnection (“POIs”) to expansion planning horizons out to 2050.

5.1.1.2. Design standards

To ensure future models for high levels of connectivity and benefit, it is critical that the early offshore wind transmission system be designed as modular and expandable with clear standards. For these reasons, theneed for standardization is apparent:

- Voltage: Should the offshore grid be planned for 525 kV or 325 kV?
- Direct current (DC) versus alternating current (AC): While DC transmission solutions for offshore wind can be more costly, the control and quality achievable far outweighs AC. This is especially the case over longer distances and where fewer cables and narrower rights of way are desired. There is also discussion regarding whether a bi-pole high-voltage DC (HVDC) line design is a better approach than a mono-pole HVDC design.
- Offshore platform capacity: A standard design—likely HVDC—is important to optimize for feasible offshore platforms and submarine cables.
- Converter Type: Should Voltage Source Converters (VSC), as a more modern HVDC technology, be the preferred choice for all developers?

- Market Flexibility and Interregional Connections: With a backbone or meshed offshore transmission network, there would be the capability for delivering offshore wind generation to different power markets. This interregional sharing of electricity and grid services is intended to allow for a least-cost, reliable, and resilient decarbonization of the nation's electric systems.

Areas of Immediate Focus

5.1.2. Interconnection points

Common to all studies, despite the offshore configuration employed, optimizing points of interconnection (POIs) is as critical as, if not more critical than, all other offshore wind transmission considerations. If there is an uninformed developer landscape or communities that have not been consulted (or do not want offshore wind), this can become a key impediment to any otherwise strong offshore wind project. The location of offshore wind generation connections to the onshore grid will also determine how expensive the necessary onshore upgrades will be. Some POIs may be more distant from offshore wind plants (and thus require longer, more expensive offshore cables to reach the POIs), but require substantially fewer and less expensive onshore upgrades. The objective should be to determine which POIs offer solutions with the lowest total costs and the least environmental and community impacts.

5.1.3. Technology standardization and advances

Realizing the benefit of an offshore wind network requires that individual offshore wind transmission solutions are standardized so they can be integrated in the future. There is also HVDC equipment that needs continued work and assessment. For example, a networked HVDC transmission solutions will require DC circuit breakers that are not yet fully available commercially. More work needs to be performed to improve what is currently available, diversifying supplier options in the market, and building out a United States HVDC supply chain that can bring down costs.

5.1.4. Supply chain and services

With so much interest in HVDC as it relates to offshore wind, the supply of HVDC equipment is significantly backlogged worldwide. If the "right" plan comes along too late, all the manufacturing slots will be taken for the rest of the decade. Additionally, services such as the availability of specialized ships needed to install equipment are an issue, as New York experienced earlier in 2023.

Review of Industry Studies and Offshore Wind Activities in Massachusetts

ISO-NE has performed several assessments of the capability of the existing transmission system to interconnect and deliver increasing quantities of offshore wind. The first was the Offshore Wind Integration component of the 2019 economic studies, which was finalized in early 2020 (ISO-NE 2019 Economic Study: Offshore Wind Integration- June 30, 2020)

This study was undertaken by ISO-NE at the request of NESCOE. It sought to examine the potential wholesale market and transmission impacts of adding up to 8,000 MW of offshore wind resources to the New England transmission system by 2030. It found that 5,800 MW of offshore wind could be added to points across southern New England (Pilgrim & Brayton Point-MA, Kent County-RI, & Montville-CT) without significant upgrades to the onshore transmission network.

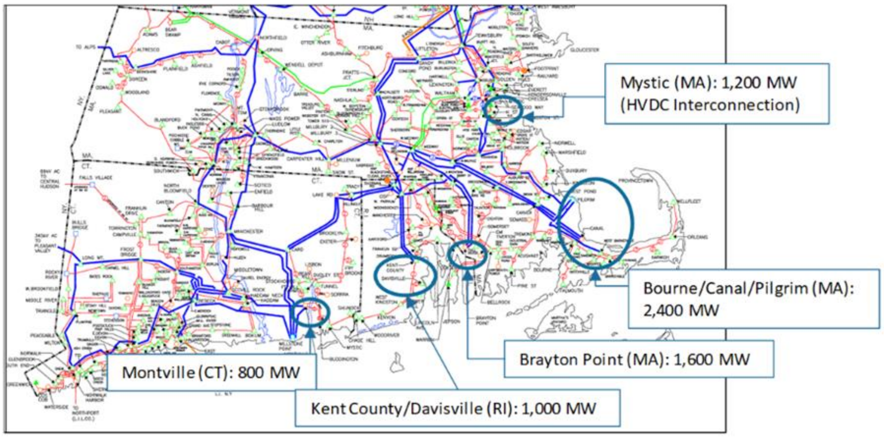

Figure 6-13: Anticipated injection capabilities without major transmission reinforcements.

Figure 4: Anticipated injection capabilities with major transmission reinforcements. Source: ??

Beyond the 5,800 MWs identified as "Low Hanging Fruit," two alternative transmissions approaches were studied to reach the 8,000 MWs requested by NESCOE. These approaches were:

- Continued interconnection of offshore wind on the southern coast of New England combined with onshore upgrades, or
- HVDC submarine cables that would travel further offshore to collection centers, then inject more directly into large load centers like Boston (Mystic-MA).

The study highlighted that beyond ~5,800 MW, there is a tradeoff regarding larger investments to either the onshore transmission network or additional offshore transmission, with each potential approach worthy of further consideration. It estimated the incremental transmission costs to be approximately $1B or more for the incremental 1,200 MWs of offshore wind under either configuration and actual AC upgrade costs were highly location specific. The study was high-level, and further analysis of potential onshore points of interconnection would be needed to determine the potential costs more precisely.

The second study is the multi-phase Cape Cod Resource Integration Study (CCRIS), which is being conducted by ISO-NE to identify potential transmission and associated system upgrades required for the interconnection of certain proposed offshore wind farms to Cape Cod. The Phase 1 study results, completed in July 2021, showed that a new 345 kV line between West Barnstable and Bourne substations would be required to interconnect 1,200 MWs in either the Falmouth or West Barnstable areas. An initial estimate of ~$335 M was provided for the identified transmission and associated upgrades. Phase 2 of the study is ongoing. At this time, it is not clear what impact the changes to ISO-NE interconnection process required by FERC Order No. 2023 will have on the completion of the study.

Two other studies have examined different configurations for the interconnection of offshore wind along the New England coastline.

After the Massachusetts DOER-Offshore Wind Study in May 2019, the Massachusetts DOER considered whether a separate solicitation should occur for independent transmission, prior to the Commonwealth conducting additional solicitations for offshore wind generation. If the DOER had elected to proceed with an independent solicitation for transmission, the solicitation would have likely occurred in 2020 or 2021. After receiving comments from utilities, offshore wind developers, independent transmission developers, and other parties, the DOER elected not to conduct a separate solicitation for independent transmission. The decision was based, in part, on the additional risk than a separate solicitation would add to the Commonwealth's offshore wind procurements.

The final relevant study, Offshore Wind in New England: The Benefits of a Better Planned Grid - May 2020, was commissioned by Anbaric, an independent transmission developer, and performed by the Brattle Group. Two different approaches were evaluated both quantitatively and qualitatively in this study:

- Current Approach- Offshore wind developers include project specific transmission as part of their bid(s)
- "Planned" Approach Alternative- Transmission is developed independently, and in advance of, future offshore wind generation.

The study concluded that a planned approach will likely lower onshore upgrade costs and risk for both offshore transmission and generation. It would require significant coordination between the New England states and ISO-NE.

Federal Funding Opportunities

IIJA, passed by Congress in 2021, and the Inflation Reduction Act (IRA), passed by Congress in 2022, include billions of dollars in loans, grants, and other forms of financial assistance to support transmission infrastructure.

5.1.5. Infrastructure Investment and Jobs Act

Through the IIJA, the DOE's Grid Deployment Office (GDO) is administering a $10.5 billion Grid Resilience and Innovation Partnerships (GRIP) Program[17] to enhance grid flexibility and improve the resilience of the power system against growing threats of extreme weather and climate change. The GRIP Program includes three funding mechanisms:

- **Grid Resilience Utility and Industry Grants ($2.5 billion)**: Support the modernization of the electric grid to reduce impacts due to extreme weather and natural disasters. Electric grid operators, electricity storage operators, electricity generators, transmission owners and operators, distribution providers and fuel suppliers are eligible to apply.
- **Smart Grid Grants ($3 billion)**: Aim to increase the flexibility, efficiency, and reliability of the electric power system, with particular focus on increasing capacity of the transmission system, preventing faults that may lead to wildfires or other system disturbances, integrating renewable energy at the transmission and distribution levels, and facilitating the integration of increasing electrified vehicles, buildings, and other grid-edge devices. Eligible applicants include institutions of higher education, for-profit entities, non-profit entities, and state and local governmental entities, and tribal nations.
- **Grid Innovation Program ($5 billion)**: Supports projects that use innovative approaches to transmission, storage, and distribution infrastructure to enhance grid resilience and reliability. Projects selected under this program can include interregional transmission projects, investments that accelerate interconnection of clean energy generation, and utilization of distribution grid assets to provide backup power and reduce transmission requirements.

[17] [1] https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

Eligible entities include states (individual or combined), tribes and territories, local governments, and public utility commissions.

- In addition to the GRIP Program, DOE's GDO has developed a $2.5 billion **Transmission Facilitation Program**[18] (TFP) that will help build out new interregional transmission lines across the country. The TFP, administered through the Building a Better Grid Initiative, is a revolving fund program that will provide federal support to overcome the financial hurdles in the development of large-scale new transmission lines and upgrading existing transmission.

Under the TFP, DOE is authorized to borrow up to $2.5 billion through three financing tools:

- Capacity contracts with eligible projects where DOE would serve as an "anchor customer" to buy up to 50% of planned line rating for up to 40 years and to sell the contract to recover costs
- Loans from DOE
- DOE participation in public-private partnerships within a national interest electric transmission corridor (NIETC) and necessary to accommodate an increase in electricity demand across more than one state or transmission planning region

5.1.6. Inflation Reduction Act[19]

Through the IRA, DOE's GDO has approximately $3 billion in financing and facilitation tools to support the buildout of transmission lines across the country. The Grid Deployment Office is administering the following IRA financing and facilitation programs.

- **Transmission Facility Financing**: Provides $2 billion in direct loan authority for facility financing. This program is currently under development and more information will be available in the coming months.
- **Grants to Facilitate the Siting of Interstate Electricity Transmission Lines -** Transmission Siting and Economic Development (TSED) Grants: Provide $760 million in grants to siting authorities to facilitate the siting and permitting of interstate and offshore electricity transmission lines and provide economic development grants to communities affected by interstate and offshore transmission lines.
- **Interregional and Offshore Wind Electricity Transmission Planning, Modeling and Analysis**: Provides $100 million in funding for offshore wind and interregional transmission analyses and convenings.

In May 2023, the Massachusetts DOER submitted an application to DOE seeking up to $250 million in funding through the Grid Innovation Program for a project focused on onshore transmission upgrades and infrastructure, including key POIs to integrate offshore wind.[20] While DOE did not select the project for funding through the first round of the program, the identification of regionally beneficial POIs highlighted the potential for proactively planned onshore transmission upgrades to lower consumer costs by reducing uncertainties for developers and accelerating the integration of offshore wind resources through grid-ready interconnections.

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[18] https://www.energy.gov/gdo/transmission-facilitation-program
[19] https://www.energy.gov/gdo/inflation-reduction-act
20 https://www.mass.gov/news/healey-driscoll-administration-to-compete-for-up-to-250-million-in-federal-grants-for-clean-energy-infrastructure

DOER is already preparing for the second round of Grid Innovation Program funding by working with other New England states to solicit innovative project design concepts for possible submission to DOE.[21] Full applications by states, tribes and territories, local governments, and public utility commissions are due by April 17, 2024.[22]

Policy and Regulatory Initiatives and Coordination

The last several years have seen a great deal of collaboration among the New England states in pursuit of innovative and proactive approaches to transmission planning. As penetration of renewable energy and long-term load forecasts continues to grow, a clear need arose to optimize the integration of renewable energy resources, and offshore wind in particular.

In the fall of 2022, the New England States began the Regional Transmission Initiative to seek comments on how to best integrate further onshore and offshore renewable energy into the New England grid in a reliable, efficient and cost-effective manner. This included requesting specific feedback on the feasibility of a Modular Offshore Wind Integration Plan (MOWIP) and a solicitation for project concept papers from utilities and independent transmission developers for submission to the US DOE for funding in early 2023. DOE responded favorably to several of the concept papers, and several states submitted full applications for grants to DOE in May 2023 (including Massachusetts, as discussed above).

In October 2023, Massachusetts, Rhode Island, and Connecticut agreed to coordinate their combined offshore wind RFPs for up to 6,800 MWs of new resources. It is hoped that these efforts could lead to multi-state proposals which provide greater cost savings and regional benefits than the individual states might receive in their individual procurements.

Other State & Regional Planning and Policy Documents

5.1.7. Massachusetts Clean Energy and Climate Plan for 2025 and 2030

Massachusetts has ambitious clean energy requirements, and offshore wind development is an anchor resource in achieving our clean energy transition. According to the Massachusetts Clean Energy and Climate Plan (CECP) for 2025 and 2030, offshore wind is expected to be the primary source of electricity for a decarbonized energy system. Offshore wind buildout will require regional and interregional collaboration to successfully integrate generation facilities to the electric grid.

The CECP identifies a pathway for the electric sector to achieve decarbonization goals, which require the electric sector to decrease its GHG emissions by more than 53% by 2025 and 70% by 2030.Many other Northeast states have published plans or roadmaps to achieve their climate goals.

5.1.8. Maine Offshore Wind Roadmap

Maine's Offshore Wind Roadmap is a strategic economic development plan for the offshore wind industry in Maine that maximizes benefits to Maine citizens, ensures compatibility with the Maine coastal heritage, and minimizes the impacts on ocean-based industries and environment.

New England will need an estimated 3 GW to 11 GW of offshore wind capacity by 2050 in the Gulf of Maine to meet both climate goals and projected demand for clean energy. In 2019, Maine passed legislation to require 80% of electricity consumed in Maine to be generated from renewable sources by

21 https://newenglandenergyvision.com/new-england-states-transmission-initiative/
22 https://www.grants.gov/search-results-detail/350971

2030, with a goal of 100% by 2050 and GHG emission reduction requirements of 45% below 1990 levels by 2030 and 80% by 2050.

Transmission planning is an essential piece of the puzzle when discussing OSW build out. Planning and coordination are necessary to ensure that future development of OSW resources is done efficiently while balancing other factors. This includes long-term planning strategies and identifying POIs considering existing capacity, distance to future OSW leases, and environmental impacts. Maine has proposed actions such as coordination among stakeholders to meet state policy goals, continuing engagement with ISO-NE to discuss market administration and regional planning, prioritizing existing POIs with robust transmission infrastructure, and continuing efforts such as the New England Regional Transmission Initiative.

5.1.9. ·Rhode Island Road to 100% Renewable Electricity

In January 2020, Rhode Island Governor Gina Raimondo signed Executive Order 20-01, setting a first-in-the-nation goal to meet 100% decarbonization in the State by 2030. In December 2020 the state issued "Rhode Island Road to 100% Renewable Electricity" to detail an approach to achieve 100% decarbonization by the end of this decade, with offshore wind one of the resources outlined as a significant contributor in meeting this goal. The report also described two areas of potential exploration when considering integrated grin planning in the state - analyzing transmission and distribution system needs for multiple scenarios with 100% renewable electricity to identify potential grid challenges and development opportunities and exploring how to enhance grid visibility and forecasting. Rhode Island also emphasizes the importance of regional collaboration throughout the report, indicating that this is necessary to remove barriers to distributed energy resource deployment with competing policy interests.

6. Interconnection and Order 2023

Because new resources, including energy storage facilities, can affect the performance of the electric system, they must be studied prior to interconnection to avoid adverse impacts on the reliability of the grid, such as an overload, voltage deviation outside of an acceptable range, or potential instability. If these studies identify an adverse impact to reliability, the affected transmission and/or distribution system owners must perform system upgrades or modifications before the generator can interconnect. The specific study process depends on whether a generator is seeking to interconnect to the transmission system under the FERC-jurisdictional interconnection process administered by ISO-NE, or state-jurisdictional interconnection processes administered by the transmission and distribution utilities.

ISO-NE Process

Interconnection process reform has become a focus for FERC, ISO-NE, and RTOs across the country because of large backlogs of projects in the interconnection queue waiting to be studied and high volumes of projects are dropping out of studies at various stages of the process. The diagram below, from a recent DOE presentation, shows a summary of the current interconnection study process.

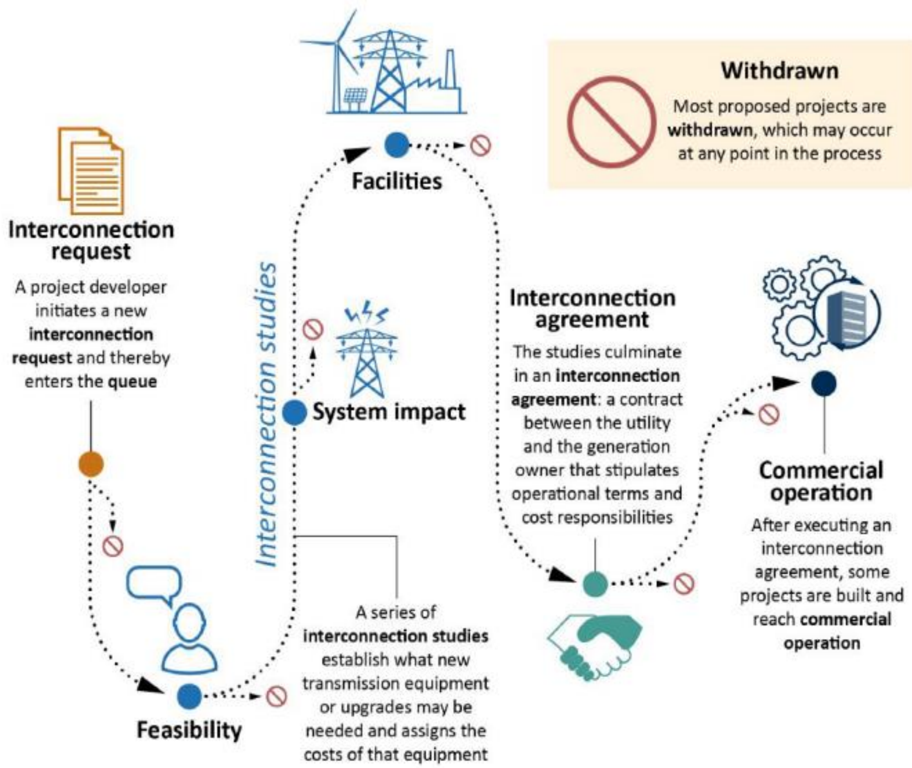

Figure 5: Department of Energy: Interconnection Study Process

While ISO-NE's interconnection queue is not as long as many others in the country, it too has seen significant delays in the time necessary to complete studies. With over 30,000 MW of proposed projects in its queue, ISO-NE shares the same challenge that many other RTOs face. Indeed, it is not just that studies take years to complete. The interest in developing clean energy has grown over the years, creating the need for many more studies, and more complex studies, than have historically been conducted. Studies are labor intensive, complicated, and rely on a workforce challenged by engineering shortages.

In ISO-NE, projects have primarily been studied "serially," meaning one after another. Under FERC regulations established two decades ago, project developers bear the costs of the upgrades needed to connect to the grid, including upgrades at the point of interconnection and upgrades elsewhere on the system, called network upgrades. This is because spare injection headroom has been exhausted and new, regional headroom has not been planned and constructed. If a single project seeking interconnection triggers costly upgrades - beyond the normal costs of building interconnection facilities, which already cost millions of dollars - the project may become nonviable and be canceled. Because the issue on the grid has not been resolved, it is likely that it will appear again for the next project that is studied, causing that project to be canceled, and the cycle continues. This is often referred to as queue collapse.

FERC Commissioner Alison Clements recently highlighted the impact of the broken study process:

> *"Ultimately, the dysfunction of the interconnection process harms consumers. It prevents low-cost generation from coming online that could have reduced the cost of electricity, and it harms reliability. Several of the nation's largest grid operators have*

stated that they could face resource adequacy problems if new resource entry does not occur rapidly enough to match the pace of resource retirements."

At the core of this issue is a misalignment of need with process. The country needs proactive transmission planning processes in order to integrate cost-effectively the thousands of needed new projects on the grid and maintain reliability. Currently, these transmission planning processes largely do not exist (see report section 3.3.2 for a description of the transmission planning processes in New England). This relegates identifying and funding major network upgrades to the interconnection process, which is not designed for this. Broad network upgrade costs are often too substantial for any individual project to fund. Many liken it to charging the first car on the onramp the entire cost of widening the highway. It is also inefficient, as one-by-one upgrades in unanticipated locations are not as cost-effective as holistic expansion plans.

However, while transmission planning reform gets to the root cause of the interconnection challenge, there are certainly process improvements that can speed up study processes and timelines. Those will be discussed in section 4.4.

Distribution System Process

Similar to the transmission interconnection process, distribution utilities within the Commonwealth have historically used a first-in, first-out (queued) approach to processing interconnection requests from DERs. The costs of system upgrades necessary to interconnect a particular distributed generation (DG) system would be assigned to the applicant. Queue backlogs have emerged in recent years due to a large influx of applications, many of them queued for the same substations.

Under several dockets[23], the Department of Public Utilities developed a framework to perform group studies at saturated substations to develop more comprehensive solutions and allow distribution utilities to propose and obtain approval for alternative cost allocation proposals. As a result of these dockets, Eversource and National Grid have performed numerous of group studies involving multiple substations and project owners and proposed cost allocation methodologies to share the costs for common system modifications between beneficiaries. Several group studies and associated cost allocation mechanisms are currently pending before the Department.

In Massachusetts, because of significant DG deployment, additional studies have been required for the interconnection of most projects 1 MW or greater since 2019. When the interconnection of a DG facility to a distribution electric power system (EPS) has the potential to adversely affect a neighboring EPS (distribution or transmission), a study of potential adverse impacts on that neighboring system is required by ISO-NE.[24] These Affected System Operator (ASO) studies can take 12-18 months (sequentially or concurrently with a distribution impact study) and the necessity of these studies are likely to continue indefinitely as all substations have reached DG "saturation."[25] As these studies are joint studies; the ASO and ISO-NE determine the procedural details and timing, including whether and when

[23] Massachusetts DPU dockets 17-164, 19-55, 20-75, and 20-75-B

[24] Pursuant to the Section I.3.9 Process outlined in the ISO-NE Tariff ("Affected System Operator ("ASO") Study"). Under ISO-NE Planning Procedure No. 5-1 regarding ISO-NE's review of such changes, a Proposed Plan Application is required for new or increased generation greater than five MW; ISO-NE reserves the right to require a Proposed Plan Application for new or increased generation greater than one MW and less than five MW.

[25] The Massachusetts Department of Public Utilities set rules concerning ASO studies in Order on Affected Operating Studies, D.P.U. 19-55-C (2020).

an ASO study is necessary. The Distribution Companies are responsible for coordinating with the ASO and ISO-NE and communicating with interconnecting customers and the state public utility commission.

To ensure efficient processing of DG and utility scale interconnections, it is necessary to align infrastructure upgrades at the distribution and transmission level. In light of FERC Order 2023, ISO-NE is in the process of providing clarification on the interaction between the DG ASO and ISO-NE interconnection queues. Following ISO-NE's implementation of Order 2023, an opportunity should be provided for regional stakeholder engagement on ASO study best practices.

Interconnection Improvements

As described in section 3.1, FERC has jurisdiction over interconnection applications in the ISO-NE queue and recently initiated a NOPR focused on making improvements to the transmission planning, cost allocation and interconnection processes. FERC Order 2023[26] mandates a variety of changes to the interconnection process, with the expectation these will speed up interconnection queues across regional RTOs and improve the timeliness of interconnection projects.

. The most important changes included in Order 2023 are as follows:

- Studies conducted in groups called clusters and shared network upgrade costs amongst projects.
- Fixed, predictable and (hopefully) faster timelines.
- Higher barriers to entry like site control and deposits to reduce volumes of "speculative" projects.
- Penalties for Transmission Owners and RTO/ISOs if they don't meet study deadlines.
- Evaluations of alternative technologies that could avoid costly upgrades.
- Flexibility for projects that add storage.
- Study methodology improvements for battery storage.

ISO-NE is in the process of developing its compliance rules, which will be submitted to FERC in 2024. The plans for these changes, as well as amendments and proposals from stakeholders, can primarily be found on the ISO-NE Transmission Committee website. [27]

The changes mandated by Order 2023, while beneficial to the overall interconnection process, leave certain challenges partially or completely unresolved. This provides an opportunity for ISO-NE to go beyond compliance with the basic rules outlined in Order 2023. Advanced Energy United recently

[26] See: https://www.ferc.gov/media/e-1-order-2023-rm22-14-000. Although the mechanics of the interconnection process will be substantially different after Order No. 2023 is implemented, many aspects of the process will remain the same. Complex technical studies will still need to be performed by ISO-NE and the transmission owners, and the transmission owners will still need to design, permit, and construct transmission upgrades as needed to ensure that reliability of the transmission system is maintained.
[27] https://www.iso-ne.com/committees/transmission/transmission-committee

published a whitepaper that articulated priorities for ISO-NE New England's Order 2023 compliance as well as reforms beyond the order. [28]

For example, it is important to note that entering the study process continues to be the only way for a project to determine its costs to interconnect. Order 2023 requires the use of heat maps and certain levels of data disclosure for interconnection customers, but because of the opaque nature of the studies and the unpredictability of costs, high volumes of "speculative" projects may continue to enter the queue, essentially on fact-finding missions, which in turn creates more work for RTOs and transmission operators (TOs). Improvements to data transparency and cost certainty for interconnection customers remain areas in need of more attention.

In addition, study processes remain slow and laborious. Even with improvements, ISO-NE estimates its queue entry and initial study phase (not including necessary re-studies) will take almost a year.[29] Process automation, Artificial Intelligence (AI), improved and streamlined models, staff additions, and other innovations to improve timelines and accuracy are areas for additional process improvements to assist in speeding study times.

Costly and delayed construction timelines will also be a challenge. Assuming the region is able to process many more studies, and interconnection customers accept the associated costs, network upgrades associated with those projects need to be built in an efficient and timely manner. Across the country multi-year backlogs for network upgrade construction projects and escalating costs due to inflationary pressures are emerging issues. ISO-NE, with its smaller market and less crowded queue, has an opportunity to lead on this issue before these issues become further entrenched.

Finally, to ensure efficient processing of DG and utility scale interconnections, it is necessary to align infrastructure upgrades at the distribution and transmission level. In light of Order 2023, ISO-NE is in the process of providing clarification on the interaction between the DG ASO and ISO-NE interconnection queues.

In addition to FERC Order 2023, the Department of Energy has released a draft roadmap[30] to improve interconnection processes, focusing on increasing data access and transparency, improving process and timing, promoting economic efficiency, and maintaining a reliable grid.

To address these issues, many RTOs around the country have established forums to discuss and implement needed interconnection improvements on an ongoing basis (i.e., a continuous improvement approach).

7. Grid Enhancing Technologies

Introduction and Definition

Grid Enhancing Technologies (GETs) are hardware and software tools that increase the capacity, efficiency, and/or safety of the electric transmission system. These optimization technologies, including dynamic line ratings (DLRs), advanced power flow controllers (PFCs), and topology optimization are

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[29] https://www.iso-ne.com/static-assets/documents/100004/a03b_2023_10_17_tc_order2023_proposed_compliance_overview.pdf
[29] https://www.iso-ne.com/static-assets/documents/100004/a03b_2023_10_17_tc_order2023_proposed_compliance_overview.pdf
[30] https://www.energy.gov/eere/articles/doe-releases-draft-roadmap-improve-interconnection-clean-energy-resources-nations

utilized on existing and new transmission infrastructure to give operators more situational awareness, flexibility, and control over the grid. As the nation's grid becomes increasingly congested and capacity constrained, GETs can reduce congestion costs and increase reliability and resilience by providing several system benefits, including situational awareness and alerting capability to enable safer real-time operations, asset health monitoring information to support asset replacement deferral while longer-term solutions are implemented, and increased grid resilience.

GETs can be utilized in a transmission loading order approach where optimization of the grid (via the utilization of low-cost tools such as GETs) is considered first, then grid reinforcement, and then grid expansion. This is a sequential way to create an expanded, flexible, dynamic grid with customer affordability as a guiding principle. Such transmission planning loading order principles have been used internationally: Germany's NOVA principle emphasizes "grid optimization first, then grid strengthening before any further grid expansion."[31]

7.1.1. Dynamic line ratings

DLRs use sensing devices and algorithms to collect ambient weather data and information about the overhead conductors to calculate the maximum amount of capacity a transmission line can safely carry, also called ampacity. More accurate consideration of ambient conditions allows operators to utilize the true thermal limits of the line more safely. Use of real time and forecasted DLRs often yields greater capacity than using static line ratings, which do not account for real-time ambient conditions and rely on very conservative assumptions, and thus provides an opportunity to safely use the existing transmission system more efficiently.[32]

An example of DLR creating critical grid capacity in Massachusetts came from a two-year pilot conducted by National Grid that aimed to verify the DLR system's performance and ability to accurately and safely maximize the utilization of existing transmission line capacity for optimized operations and enable clean and affordable energy delivery to customers.[33] Recorded DLR data showed the following results:

- DLR exceeds the Static Rating for 94% to 97% of the time.
- Mean (average) increase of 31% in line capacity above Ambient-Adjusted Ratings (AAR).
- Mean (average) increase of 47% in line's capacity above Static Rating.

7.1.2. Power Flow Control

Power flow control technologies actively balance the flow on transmission lines by pushing or pulling power from one line to another. The hardware can intelligently raise or lower the impedance, or the opposition to current, in real time to ensure that power is delivered on lines that have the capacity to carry it. Advanced power flow control expands on this function with enhancements such as faster and more flexible deployment options, easy scaling to meet the size of the need, and ability to relocate when needed elsewhere on the grid.[34]

[31] https://www.transnetbw.com/en/world-of-energy/nova-principle
[32] https://www.energy.gov/sites/default/files/2023-10/National_Transmission_Needs_Study_2023.pdf
[33] https://cigre-usnc.org/wp-content/uploads/2021/11/An-Empirical-Analysis-of-the-Operational-Efficiencies-and-Risks-Associated-with-Line-Rating-Methodologies.pdf
[34] https://watt-transmission.org/

7.1.3. Topology optimization

Transmission topology optimization software models the grid's network and power flow conditions to identify ways to reroute power flow around congested or overloaded transmission elements. These "reconfigurations" are implemented by switching on or off existing high voltage circuit breakers. By more evenly distributing flow over the network, topology optimization increases the transfer capacity of the grid.[35]

Use and Sequence of GETs

Historically, utilities, system operators, and regulators assumed the transmission grid was essentially “fixed” in capacity and configuration. However, use of GETs challenges this assumption as the capabilities of the grid varies based on things like ambient weather conditions, wind speed, and overall utilization of the network. The evolution of transmission planning practices to include GETs is critical as transmission related costs are expected to rise considerably in the next several decades. As noted in the ISO-NE 2050 transmission study, transmission costs could rise to as high as $23-$26 billion in a fully decarbonized future[36] as the state and region plans for scenarios with higher electrification, offshore wind integration, and renewable energy deployment. As the Commonwealth and region continue to develop transmission expansion strategies to address decarbonization goals, optimizing the use of GETs will be a critical tool in rightsizing transmission and reducing impacts to the consumer.

Grid enhancing technologies have been broadly deployed in Europe[37] to increase grid infrastructure by unlocking additional capacity on the existing transmission system. These technologies also complement transmission build outs by enhancing the utility of transmission infrastructure instead of eliminating or replacing it.

The operational flexibility provided by GETs is also valuable in the context of addressing extreme weather events and enhancing grid resilience. For example, during the 2018 “bomb cyclone” when a 13-day cold snap between December 25, 2017 and January 8, 2018 constrained a large portion of the Northeast U.S. grid.[38] During this extreme event, which featured higher loads triggered by colder weather, ISO-NE issued an abnormal conditions alert to address both the weather and supply concerns. ISO-NE also increased their transmission line ratings (made possible by the cold conditions, which helped to improve thermal transfer capability), including the scheduling limits on the AC ties into New York (from 1,400 MW to 1,600 MW), which helped avoid large congestion costs and maintained system reliability.

A recent DOE report highlighting the ratepayer impact of GETs identified six key indicators for GETs value[39]:

- Wind and Solar Share
- Renewable Curtailment

[35] https://watt-transmission.org/
[36] https://www.iso-ne.com/system-planning/transmission-planning/longer-term-transmission-studies
[37] See ENTSO-E Technopedia pages for DLR and APFC, and IRENA Innovation Landscape Brief on DLR for examples of worldwide deployments.
[38] See ISO-NE, https://www.iso-ne.com/static-assets/documents/2018/01/20180112_cold_weather_ops_npc.pdf, Jan 16, 2018
[39] https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf

- Transmission Congestion
- Price Differentials
- Proposed Transmission
- Proposed Renewables

A recent study highlighted three locations within ISO-NE as potentially well-suited for GETs based on the interconnection queue and 2030 Resource Plan, including a key offshore wind interconnection point in Southeast Massachusetts (SEMA).[40] The study identified DLRs and Advanced Power Flow Control deployments in the SEMA region to support reliability and reduce production costs under a modeled 2030 resource mix with over 50% renewable energy. Optimal deployment of the two technologies reduced renewable curtailment at the interconnection point by more than half, with the technologies paying for themselves in less than one year.

The Brattle Group also conducted a GETs study which modeled an optimal deployment of GETs using the Southwest Power Pool system in Kansas and Oklahoma and projects in the interconnection queue with signed interconnection agreements. They investigated how much new generation could economically interconnect if GETs unlocked additional capacity on the grid. Without GETs, 2,580 MW of wind and solar generation could interconnect in the next five years. With GETs, twice as much new generation (5,250 MW) could interconnect. In this study. GETs deployments would have one-time installation costs of $90 million, with annual production cost savings of $175 million.[41]

As noted in these studies, GETs play a key role in the integration of clean energy to the grid and at various stages of transmission expansion.[42]

Before: Before construction, GETs can reduce congestion by 40% or more.

The benefits of GETs start before traditional transmission projects are developed. Planning for and building new transmission typically takes five to ten years or longer. Many GETs can be installed in under a year to alleviate congestion and help integrate more resources before the new transmission projects are put in place. GETs are scalable and their deployments are reversible—unlike other capital heavy investments, they can be removed (and relocated) if the need is no longer there. The portability, scalability, reversibility, and comparatively smaller investment size of GETs provide flexibility to address transmission issues before new transmission is built. This option is particularly effective when there is uncertainty about the future, for example with the pace of load growth, or changes in flow patterns. In addition, GETs that provide immediate solutions to existing grid issues could allow more time to develop traditional transmission solutions, and simultaneously delay capital investments.

During: During construction, outages can be avoided or ameliorated, with similar reductions in congestion costs of 40% or more.

The complementary benefits of GETs continue during the construction of traditional transmission solutions by reducing the impact of outages or avoiding outages entirely. Installing GETs as the solution (in particular, DLR and Topology Control) often does not require transmission outages, or only require a

[40] Assessing the Value of Grid Enhancing Technologies: Modeling, Analysis, and Business Justification; Idaho National Laboratory – Jake Gentle, Alex Abboud, Megan Culler, Chris Sticht; Telos Energy - Sean Morash, Andrew Siler, Leonard Kapiloff, Derek Stenclik, Matthew Richwine. June 1, 2023. INL/MIS-23-71254

[41] https://watt-transmission.org/unlocking-the-queue/

[42] https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

shorter outage. When the preferred solution is to build new (or reconductor existing) transmission, GETs could help alleviate the impact of transmission outages needed for upgrading existing lines and interconnecting the new line(s) into the existing grid.

After: And after construction, utilization on new lines can increase by 16%, improving the Benefit to Cost ratio of the new lines.

GETs can further help increase the value of new traditional transmission projects after they are put in service. For example, GETs can increase the utilization of the existing system [which will include the newly added line(s)], hence increasing the Benefit to Cost ratio of any given transmission project. This could allow for more transmission projects to pass the selection threshold (the Benefit to Cost ratio is one of the key metrics used), potentially increasing the number of validated transmission projects. Previous analysis of the Southwest Power Pool ("SPP") system has shown that GETs will increase the utilization level of existing 345 kV lines by 16%. GETs can also be deployed after the fact to mitigate unanticipated consequences triggered by the new line(s). For example, if energizing the new line(s) results in unintended congestion, such as those on the underlying lower voltage lines, GETs could be quickly deployed to address it. Finally, GETs can contribute to system resiliency under extreme conditions as they provide means for situational awareness and operational remedies.

Furthermore, monitoring newly constructed transmission lines provides value for multiple aspects of the asset across its lifecycle. DLR provider LineVision offers an advanced non-contact overhead line monitoring system and it was installed on NY Transco's recently energized New York Energy Solution (NYES) electric transmission project, a 54-mile modernization of a 1930's-era transmission corridor with new modern, storm-resilient monopoles and several new and improved electric substations to relieve congestion and facilitate the flow of clean energy to homes and businesses in furtherance of New York State's carbon reduction goals. The use of this technology uniquely allows the operators monitoring NYES to track all phases of power with a single monitoring system that accomplishes dynamic line ratings and greater visibility of the asset's behavior.[43]

8. Siting and Permitting

Federal, state, and local authorities all play a role in siting and permitting electric transmission facilities. This section provides an overview of existing transmission siting and permitting authorities and processes.

Federal

As noted in Section 2.1, the Federal Power Act grants FERC jurisdiction over rates and terms of service for transmission of electric energy in interstate commerce but does not grant FERC authority over siting of transmission facilities, except for the limited backstop siting authority in Section 216. Thus, electric transmission facility siting and permitting largely rests with the states.

The Energy Policy Act of 2005 added section 216 to the FPA that provides for a limited federal role in transmission siting. Section 216 authorizes FERC to issue permits to construct transmission facilities under certain limited circumstances (i.e., FERC's "backstop" siting authority):

[43] https://www.linevisioninc.com/news/linevision-new-york-transco-collaborate-on-efficiency-resilience-health-of-new-clean-energy-transmission-line-in-the-hudson-valley

- FERC's authority is limited to facilities sited in DOE-designated NIETCs. NIETCs are geographic areas DOE determines have a need for transmission facilities to resolve electric transmission capacity constraints or congestion that adversely affects consumers.
- FERC may issue permits if: (1) a state lacks the authority to approve the siting of the proposed facilities or consider the interstate benefits; (2) the applicant does not qualify to apply in a state because the applicant does not serve end-use customers in the state; or (3) a state that has authority withheld its approval for more than one year or has conditioned its approval such that the proposed project will not significantly reduce congestion or is not economically feasible.
- FERC must find that the proposed facilities: (1) will be used for the transmission of electricity in interstate commerce; (2) are consistent with the public interest; (3) will significantly reduce transmission congestion in interstate commerce and benefit consumers; (4) are consistent with sound national energy policy and will enhance energy independence; and (5) will maximize, to the extent reasonable and economical, the transmission capabilities of existing towers or structures.[44]

Since section 216's enactment, federal court decisions have hindered DOE's ability to designate NIETCs and there have been no backstop siting applications filed with FERC. In 2021 Congress amended section 216 through the Infrastructure Investment and Jobs Act to address the court decisions. As amended, section 216 expanded the circumstances under which DOE may designate a NIETC to include geographic areas expected to experience transmission capacity constraints or congestion that adversely affects consumers. Section 216 as amended further clarifies that FERC has authority to issue permits in circumstances where a state has denied approval of an application.

In response to this amendment, in December 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) in to revise its existing backstop siting regulations.[45] A final rule on FERC's backstop siting NOPR is pending.

In addition to FERC's backstop siting authority, the U.S. Environmental Protection Agency, Bureau of Ocean Energy Management (off-shore wind facilities beyond 3-mile state nautical boundary), Army Corps of Engineers, U.S. Fish and Wildlife Service, and Federal Aviation Administration have specific authorities applicable to permitting electric transmission facilities.

State

This section explores the role of energy facilities siting, in general, and for transmission facilities in particular, by the Massachusetts DPU and the Massachusetts EFSB.

8.1.1. Dual siting responsibilities of the DPU and EFSB

The Commonwealth has two state agencies involved in energy facilities siting: the DPU and the EFSB. As described below, siting complexities and challenges exist within each agency's own siting processes, as well as in coordination between these two agencies. For the general public, the dual nature

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44 Section 216 authorizes a permit holder, if unable to reach agreement with a property owner, to use eminent domain to acquire the necessary right-of-way for the construction of the permitted transmission facilities.
45 Federal Register :: Applications for Permits To Site Interstate Electric Transmission Facilities.

of siting jurisdiction at the DPU and the EFSB (and other aspects of siting proceedings) can make it challenging to understand and participate fully in the process.

A brief history of energy facilities siting in Massachusetts may help explain the respective roles of DPU siting functions and the EFSB. For much of the past century, and until the creation of the EFSB, the DPU led the Commonwealth's involvement with siting-related functions for energy facilities including: (1) the grant of zoning exemptions to "public service corporations" for the construction and operation of energy facilities; (2) eminent domain and survey authority for electric transmission and natural gas pipelines; (3) approval for construction and operation of electric transmission lines; and (4) grants of location for electric transmission lines. The DPU continues to have primary jurisdictional authority in these areas.

Amid rising environmental concerns in the late 1960s and early 1970s regarding the development of new power plants and other large energy infrastructure – and increasing difficulties of then-vertically integrated utilities in securing permits for such facilities, the Legislature convened the Massachusetts Electric Power Plant Siting Commission to explore potential solutions. This led to the creation of the Energy Facilities Siting Council in 1974 ("EFSC," now EFSB) with responsibilities to review and approve not only the siting of electric power plants, but also natural gas and oil pipelines, large oil and natural gas storage facilities, and electric transmission facilities. The legislature also provided the Siting Council with extraordinary authority to issue or modify other state and local permits, if previously EFSC-approved facilities were unreasonably denied or delayed necessary state or local permits, or subject to onerous permit conditions. The legislature also exempted the Siting Council from most aspects of the Massachusetts Environmental Policy Act (MEPA) to avoid duplication of review and potential delay.

A state government reorganization in 1992 relocated the EFSB staff to the DPU in the newly established Siting Division and rebranded the EFSC as the EFSB. As part of the legislative reorganization, the EFSB shed some of its functions to other divisions of the DPU (such as natural gas long-range supply planning) and the DPU Chair was given the authority to assign DPU siting matters to the Siting Board for adjudication if a project encompassed both agencies' siting jurisdictions. Other than these and other administrative changes, the EFSB and DPU siting authorities remained largely intact and were not consolidated. In 2008, pursuant to the Green Communities Act, the DPU and EFSB, were relocated to a new Secretariat, the Executive Office of Energy and Environmental Affairs (EEA). As EEA agencies, both the EFSB and the DPU became subject to the EEA Environmental Justice Policy.[46]

8.1.2. What is the EFSB?

The EFSB is an independent nine-member board chaired by the Secretary of EEA, which includes the following officials (or designees): commissioners of the DPU (two), Massachusetts Department of Environmental Protection (MassDEP), and DOER; the Secretary of the Executive Office of Economic Development (EOED); and three public members (with energy, environmental, and labor expertise, respectively). The Siting Board's statutory purpose is to review proposed energy facilities to ensure a reliable energy supply, with a minimum impact on the environment, at the lowest possible cost. Statutory authority of the Siting Board is specified in G.L. c. 164, §§ 69G – 69S; Regulatory authority in 980 CMR 1.00 - 12.00. The DPU Siting Division is staff to the EFSB and the DPU Commission. Staff adjudicates cases and prepares tentative decisions and orders for review by the EFSB and DPU Commission.

46 Confirmed in the Brockton Power Company SJC decision, 469 Mass. 196 (2014).

Table 2: EFSB Siting Actions

EFSB Siting Actions
Approval to Construct (12-month proceeding) – this is the central adjudicatory function of the EFSB sought by applicants seeking to build and operate jurisdictional energy facilities. EFSB approval is required before any other state construction permits may be issued. G.L. c. 164, §§ 69J-69J$^1/_2$.
Action by Consent (ABC) – a mechanism to issue an EFSB decision, except a final decision in an adjudicatory matter. To become effective, an ABC must be signed by all Board members. 980 CMR 2.07.
Determination of Jurisdiction (four-month proceeding) – upon request, a proceeding to determine if the EFSB has jurisdiction over a particular facility. 980 CMR 2.09.
Advisory Rulings (60 days to accept request for Advisory Ruling) – written non-binding ruling regarding the applicability of an EFSB statute or regulation. 980 CMR 2.08.
Certificate of Environmental Impact and Public Interest (six-month proceeding) – Pursuant to G.L. c. 164, § 69K-69O½, the Siting Board may also issue a Certificate of Environmental Impact and Public Interest to any applicant that proposes to construct or operate a generation facility or to any electric, gas, or oil company that proposes to construct or operate jurisdictional facilities in Massachusetts. Such a Certificate, if granted, has the legal effect of providing all state and local permits that are required for construction and operation of the facility, as requested by the applicant.

8.1.3. EFSB jurisdictional facilities

G.L. c. 164, § 69G gives the Siting Board jurisdiction over the following types of proposed new energy facilities, which the Siting Board may approve, approve with conditions, or deny:

Electric generating facilities - any generating unit designed for or capable of operating at a gross capacity of 100 megawatts or more, including associated buildings, ancillary facilities, and transmission and pipeline interconnections that are not otherwise subject to the Siting Board's jurisdiction.

Electric transmission lines - new lines that have either: (1) a design rating of 69 kV or more and which is one mile or more in length on a new transmission corridor; or (2) a design rating of 115 kV or more which is 10 miles or more in length on an existing transmission corridor, except reconductoring (i.e., replacing the cables that carry or "conduct" the electric current) or rebuilding at the same voltage; (3) an ancillary structure (such as a new or modified substation), which is an integral part of the operation of any transmission line subject to the Siting Board's jurisdiction.

Gas manufacture or storage - a unit, including associated buildings and structures, designed for or capable of the manufacture or storage of gas, except: (1) a unit with a total gas storage capacity of less than 25,000 gallons and also with a manufacturing capability of less than 2,000 million British thermal units (MMBtu) per day; (2) a unit whose primary purpose is research, development or demonstration of technology and whose sale of gas, if any, is incidental to that primary purpose; or (3) a landfill or sewage treatment plant.

Gas transmission pipeline – a new pipeline with a normal operating pressure in excess of 100 pounds per square inch gauge, which is greater than one mile in length, except restructuring, rebuilding, or relaying of existing gas pipelines of the same capacity.

Oil storage facility - a new unit exceeding 500,000 barrels (21 million gallons) or an oil pipeline greater than one mile in length, except restructuring, rebuilding, or relaying of existing pipelines of the same capacity.

8.1.4. DPU jurisdictional facility siting and related functions

Electric Transmission Lines – The DPU has no jurisdictional thresholds for voltage or line length specified in statute or regulations. (G.L. c. 164, § 72). G.L. c. 164, § 72 requires electric companies to obtain Department approval prior to the construction or significant alteration of existing lines (e.g., increased voltage or increased structure heights) but not reconductoring and equivalent pole replacements. To receive such approval, the electric company must show that the proposed project is needed and that it serves "the public convenience and is consistent with the public interest." Each transmission facility submitted for Siting Board approval under c. 164, § 69J also requires G.L. c. 164, § 72 approval by the Department, administered by the Siting Board in consolidated proceedings. Given the lack of clearly defined physical thresholds for § 72 transmission facilities, the DPU is frequently asked for informal determinations of whether proposed transmission projects, particularly refurbishments of existing lines, require such reviews.

Eminent Domain (G.L. c. 164, §§ 72 & 75C) and Survey Authorization (G.L. c. 164, §§ 72A & 75D) for electric and gas companies, respectively. The Siting Division adjudicates petitions by electric and natural gas companies for the right to exercise the power of eminent domain to meet their public service obligations. To grant eminent domain, the DPU must determine that the project is necessary for the purpose alleged, will serve the public convenience, and is consistent with the public interest.

Zoning Exemptions for "Land and Structures" – The DPU may grant exemptions from local zoning ordinances or by-laws. G.L. c. 40A, § 3 applies to "public service corporations." DPU must find that "exemptions are required" and the "present or proposed use of the land or structure is reasonably necessary for the convenience or welfare of the public."

Grant of Location for transmission lines – Where a grant of location has been refused, the Department may provide grant a location for the transmission line if it deems the location necessary for the public convenience and in the public interest. G.L. c. 166, § 28.

The DPU exercises its jurisdictional authority through Orders issued by its three-member commission. In some cases, Siting Division staff may determine informally that proposed reconstruction/rebuilding of existing transmission lines does not trigger Section 72 jurisdiction (or EFSB jurisdiction).

8.1.5. EFSB/DPU adjudicatory process

The Siting Board's regulations detail how its review of jurisdictional facilities is conducted. See 980 CMR 1.00-12.00. The Siting Board conducts its review of jurisdictional facilities in adjudicatory proceedings under G.L. c. 30A. 980 CMR 2.02(3). Siting Board review commences with Notice and a public comment hearing in one or more of the affected cities or towns. 980 CMR 1.04. The purpose of the public comment hearing is to provide information on a proposed project and to afford members of the general public an opportunity to comment on a proposed facility. 980 CMR 1.04. The Siting Board accepts both oral and written comment on a proposed project and allows intervention and limited participation in a proceeding. 980 CMR 1.04, 1.05. The Siting Board establishes an evidentiary record relating to a proposed project through review of an applicant's petition, pre-filed testimony from the parties, discovery, and cross examination at evidentiary hearings. 980 CMR 1.06.

The Siting Board makes its decisions in a public meeting consistent with Open Meeting Law. 980 CMR 1.08, 2.04, 2.06. After the record is complete and parties submit briefing, Siting Board staff draft a Tentative Decision and issue it to the parties for written comment. The Tentative Decision is also made available to the public. 980 CMR 1.08, 2.06. The Siting Board accepts oral comment, deliberates, and votes at a public meeting. 980 CMR 2.04. After voting, the Siting Board directs staff to issue a Final Decision approving, rejecting, or approving with conditions the proposed project. 980 CMR 1.08, 2.04. The Siting Board's adjudicatory decisions are subject to judicial review at the Supreme Judicial Court. G.L. c. 164, § 69P; G.L. c. 25, § 5.

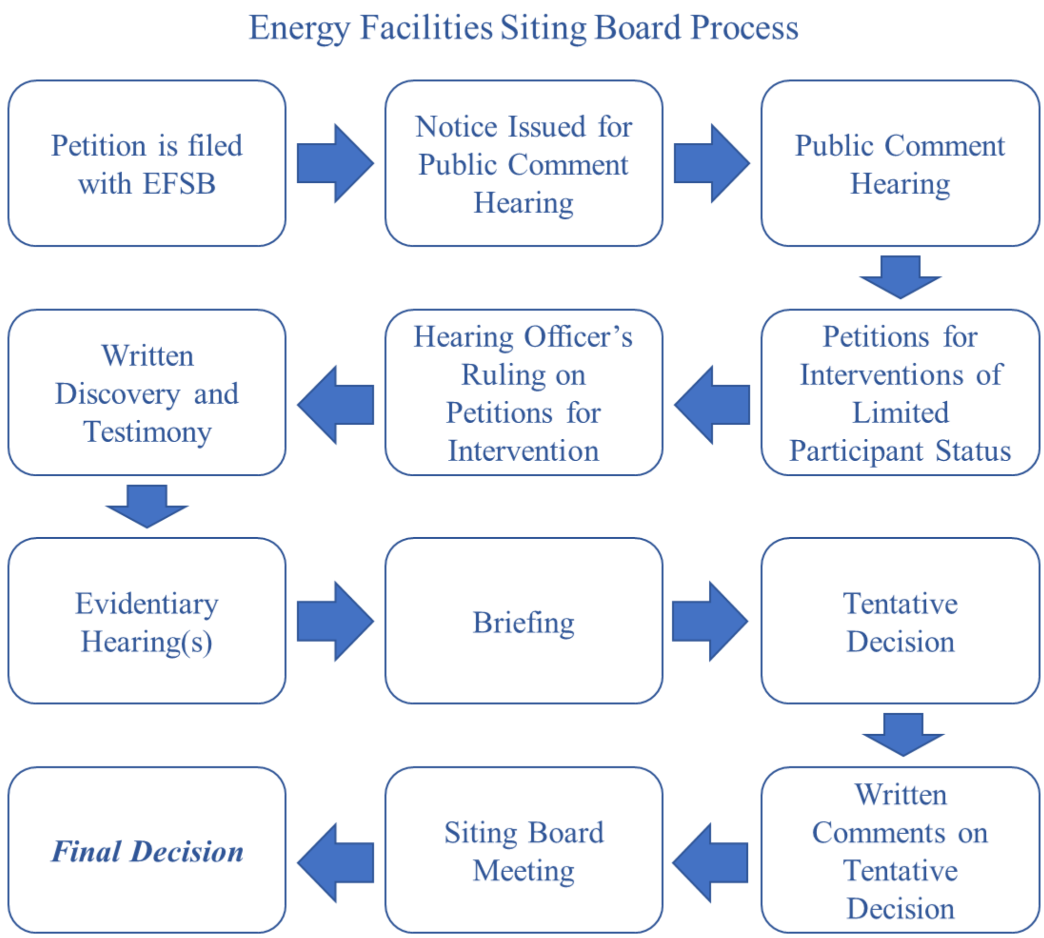

Figure 6: EFSP Process

8.1.6. Areas of EFSB/DPU review for electric transmission projects

Petitions seeking EFSB's approval of electric transmission line proposals must have the following elements by statute (G.L. c. 164, § 69J):

1. A description of the facility, site and surrounding areas;
2. An analysis of the need for the facility, within and/or outside the Commonwealth;
3. A description of alternatives to the facility, such as other methods of transmitting or storing energy, other site locations, other sources of electrical power, or a reduction of requirements through load management;

4. A description of the environmental impacts of the facility, such as land use impact, water resource impact, air quality impact, solid waste impact, radiation impact, and noise impact.

The Siting Board is required by G.L. c. 164, § 69J to approve a petition to construct if it determines that:

1. All information relating to current activities, environmental impacts, facilities agreements and energy policies as adopted by the commonwealth is substantially accurate and complete;
2. Projections of the demand for electric power, or gas requirements and of the capacities for existing and proposed facilities are based on substantially accurate historical information and reasonable statistical projection methods and include an adequate consideration of conservation and load management;
3. Plans for expansion and construction of the applicant's new facilities are consistent with current health, environmental protection, and resource use and development policies as adopted by the commonwealth and are consistent with the policies to provide a necessary energy supply for the commonwealth with a minimum impact on the environment at lowest possible cost.

The Siting Board does not have regulations specific to its review of petitions to construct electric transmission lines, although the statute makes this option available.[47] Based on statutory requirements and case precedent, the Siting Board has included the following key topics in its review of electric transmission lines:

- Need (in statute)
- Site and routing alternatives (in statute)
- Non-transmission alternatives (such as distributed generation, storage, and energy efficiency) (in statute)
- Cost of proposed project, alternative routes, and non-transmission alternatives
- Land use impact (in statute)
- Water resource impact (in statute)
- Air quality impact (in statute)
- Solid waste impacts (in statute)
- Magnetic field impacts (called "radiation impact" in statute)
- Noise impact (in statute)
- Visual impacts
- Historical/cultural resource
- Flora/fauna/habitat impacts
- Traffic impacts

47 "The board shall be empowered to issue and revise filing guidelines after public notice and a period for comment. A minimum of data shall be required by these guidelines from the applicant for review concerning land use impact, water resource impact, air quality impact, solid waste impact, radiation impact and noise impact." G.L. c. 164, § 69J

- Safety
- Hazardous waste
- Environmental Justice (pursuant to 2021 EEA Environmental Justice Policy and An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy. St. 2021, c. 8 ("Roadmap Act"), and when applicable, MEPA EJ Protocols)
- Public convenience and welfare (where zoning exemptions are requested pursuant to G.L. c. 40A, §3)
- Potential property value impacts48

In cases involving a Certificate (pursuant to G.L. c. 164, §§ 69K - 69O and 980 CMR §§ 6.00) in which an applicant requests that the Siting Board issue all necessary state and local permits for a previously EFSB-approved project, the applicant must also demonstrate:

- It meets at least one of six grounds (such as undue delay or burdensome conditions imposed by other state and local permit agencies)
- Need for the facility
- Compatibility of the facility with environmental protection, public health, and public safety
- The extent to which construction and operation of the facility will fail to conform with existing state and local laws, ordinances, bylaws, rules and regulations and reasonableness of exemptions thereunder, if any, consistent with the implementation of the energy policies contained in the Siting statute to provide a reliable energy supply for the commonwealth with a minimum impact on the environment at the lowest possible cost
- The public interest, convenience and necessity requiring construction and operation of the facility

8.1.7. Other permitting agencies

In addition to the siting jurisdiction by the EFSB and DPU, there are numerous other state and local agencies that may have specified areas of permit and approval authority and oversight for proposed electric transmission facilities. These include:

Massachusetts Environmental Policy Act - Disclosure of environmental impacts and consideration of feasible measures to minimize or avoid them. The Siting Board is exempt from the requirements of MEPA by statute. G.L. c. 164, § 69I.[49] However, DPU-jurisdictional siting matters (such as transmission lines under G.L. c. 164, § 72, and zoning exemptions under G.L. c. 40A, § 3) have no such exemption, and, when referred by the DPU to the Siting Board for consolidated review with related Siting Board petitions, remain subject to MEPA.

Massachusetts Dept. of Environmental Protection - Air Plan Review – use of best available technology to reduce emissions; Water-related permits – discharge; stormwater; water withdrawal; tidelands (chap. 91); Hazardous wastes and spill prevention plans

48 Property values impacts fall outside the scope of the Siting Board's review of transmission lines under G.L. c. 164, § 69J, but may be relevant to DPU review authority under G.L. c. 164, §72 and G.L. c. 40A, §3. See Eversource Energy, EFSB 17-02/D.P.U. 17-82/17-83, at 221 (2019).

49 Despite this statutory exemption, MEPA review is typically conducted in parallel with, and broadly informs the Siting Board's proceedings, which is a fundamental purpose of MEPA with respect to state permitting agencies. See 301 CMR 11.00 et seq.

Local Agencies - Conservation Commission; Zoning Board and Zoning Board of Appeal (ZBA); Building Department; Planning Board; Department of Public Works; Electrical Inspector; Health Department, others

Other - Massachusetts Historical Commission; Natural Heritage and Endangered Species Program; Coastal Zone Management; State Fire Marshal (fuel/ammonia storage); Massachusetts Legislature (Article 97 public lands)

Growing Portfolio of Clean Energy Projects

There are several discernable trends that point toward a sustained increase in workloads for DPU/EFSB Siting activity in the foreseeable future.

- Offshore wind development requires long, high-voltage transmission lines that run beneath state waters and onshore to points of interconnection on the New England grid as well as new or modified substations and switching stations. In addition, new or upgraded transmission lines elsewhere on the grid will be needed to enable offshore wind power to flow freely on the grid, without congestion or bottlenecks;

- Battery energy storage systems or other energy storage technologies may require new or modified substations, switching stations, and transmission lines to interconnect to the New England grid;

- DPU Capital Investment Project (CIP) Provisional Program: The DPU is investigating how to improve distributed energy resource planning to further the Commonwealth's progress towards achieving net-zero greenhouse gas emissions. Currently, a distributed generation facility whose interconnection triggers an upgrade of the electric power system must pay for the full cost of that upgrade. These upgrades can be expensive and require extensive system planning and time to construct. The DPU is reviewing significant customer-funded upgrades to transmission and distribution systems to facilitate interconnection of distributed generation resources;

- Electric Sector Modernization Plans (established by "An Act Driving Clean Energy and Offshore Wind" – 2022) will include both distribution and transmission system investments, such as substations and transmission lines that may be needed for electrification and resiliency;

- Asset Condition Replacements. Replacement of many old, oil-filled underground cables, and related work may trigger DPU/EFSB siting jurisdiction in some cases;

- ISO-NE recommended reliability-based transmission investments.

9. Recommendations

This CETWG offers the following recommendations designed to enhance the process of planning, developing, siting, and operating existing and new transmission facilities to support the Commonwealth's transition to a clean energy future.

9.1. Transmission Planning

- The Commonwealth should support regional and interregional efforts to create more holistic, proactive, and forward-looking transmission planning processes. This includes: (i) continuing to work with ISO-NE, transmission-owning utilities (TOs), and other New England states to develop and implement a new longer-term transmission planning process with a state-led option to operationalize study results through a regional transmission procurement that would allocate costs equitably to beneficiaries across the region, (ii) advocating to FERC to support transmission planning and cost allocation reforms reflecting such a holistic, proactive, and forward-looking transmission planning process, (iii) continuing to pursue reforms with TOs and regional partners such as ISO-NE and NESCOE to establish procedures for identifying upgrades to already existing infrastructure as solutions to near- and longer-term transmission needs, (iv) implementing mechanisms to optimize the grid, such as deploying grid enhancing technologies (GETs) to reduce costs and prioritizing multi-value transmission, and (v) continuing to advocate for cost discipline and transparency in connection with transmission development.

- To the extent new onshore transmission lines are needed, the Commonwealth should encourage the co-location of transmission infrastructure within state-owned or state-controlled properties and corridors, such as highway and railroad rights-of-way. The legislature should consult with relevant agencies (such as Massachusetts Department of Transportation and the Massachusetts Bay Transit Authority) and consider allocating additional resources to these agencies or granting additional statutory authority to support the Commonwealth's clean energy transition. This aligns with federal guidance on leveraging alternative uses of highway rights-of-way.[50]

- Consider directing EDCs and TOs to work with ISO-NE to identify local transmission upgrades necessary to meet statewide climate goals and associated cost allocation mechanisms to formalize the treatment of rate recovery of proactive local transmission upgrades. EDCs and TOs should complete this task by a specific date and submit a progress report to ISO-NE, EEA, DOER and DPU, and upgrades should include those needed to implement the ESMPs.

- The procurement of long-lead time bulk power system equipment risks delaying the Commonwealth's and the region's progress on constructing beneficial transmission. The Legislature should consider developing a program for identifying and procuring key pieces of transmission-related equipment, including the appropriate roles for ISO-NE and the Massachusetts DPU in such a process.

- The Commonwealth should support a regional analysis of GETs, informed by experience to-date with the implementation of FERC Order 881.

- Amend Section 70 of Chapter 179 of the Acts of 2022 to enable DOER to competitively solicit and select proposals for transmission to deliver clean energy generation to help achieve the Commonwealth's clean energy requirements, beyond existing authority to solicit and select transmission related solely to offshore wind.

[50] See 2021 Memorandum from the US DOT Federal Highway Administration available at https://www.fhwa.dot.gov/real_estate/right-of-way/corridor_management/alternative_uses_guidance.cfm.

9.2. Interconnection

- Encourage ISO-NE to establish a forum to continuously explore interconnection process improvements beyond initial Order 2023 compliance. Such as forum should promote broad participation, including from ISO-NE, state officials, utilities, developers of transmission-interconnected and distributed generation, and the public.

- Establish a working group, chaired by DOER and DPU, to facilitate stakeholder collaboration on regional best practices for Distributed Generation (DG) Affected System Operator (ASO) studies. The results of this working group would inform the ISO-NE stakeholder engagement process on DG ASO studies following compliance with Order 2023.

- While interconnection customers have long had the right to register objections and identify deficiencies in a transmission provider's identification of network upgrades in interconnection studies, steps should be taken within ISO-NE to provide renewable developers with ways to identify GETs solutions both in the interconnection process and to address constraints that may be leading to curtailments of existing projects. An example can be found in the Southwest Power Pool (SPP) where a renewable developer filed Revision Request 589 - Sponsor Upgrade: Dynamic Line Ratings[51]. The request proposes amendments to tariffs and operating criteria to affirm a process to evaluate the efficacy of a submitted DLR solution in reducing congestion on a specific flow gate. Specifically, a TO would have to identify limiting elements and their ratings and determine if installation of DLR equipment would be effective in reducing congestion on that Flow Gate.

- By using GETs, including DLR, to lower generator interconnection costs and shorten timelines, Massachusetts consumers stand to benefit through lower electricity costs. While FERC's Order 2023 on generator interconnection requires evaluation of certain grid enhancing/advanced transmission technologies, ISO-NE can go beyond what FERC established in Order 2023 and formally evaluate DLR alongside the GETs technologies so that the market can realize its benefits in all contexts where the technology is reasonably applied.[52] System operators and transmission owners should take steps to integrate GETs in interconnection processes, including by taking the following actions[53]:

    - System operators and utilities should consider GETs, including DLR, as a valid mitigation alternative in interconnection studies.

    - They should develop procedures to include GETs and document those in business practice manuals.

    - There should be detailed reporting on the evaluation of GETs in interconnection studies (including the basis for rejection.)

    - System operators and utilities should work with GETs vendors to develop the models to be used in interconnection studies.

[51] https://www.spp.org/spp-documents-filings/?id=21069
[52] https://blog.advancedenergyunited.org/articles/daymark-isone-interconnection-2023
[53] https://watt-transmission.org/grid-enhancing-technologies-in-generator-interconnection/

    - System operators and utilities should update their software to include the GETs models.

9.3. Offshore Wind Transmission

- The Commonwealth should evaluate the offshore wind procurement process as part of a strategic offshore wind plan, considering the recent procurement experiences along the east coast. This should target lowering total customer costs and de-risking offshore wind procurement events by reducing the cost of entry for developers. This could include separating land-based transmission upgrades from offshore wind development, and setting clear standards for offshore transmission projects that enable a modular and expandable multi-terminal HVDC offshore grid.

- The Commonwealth should work with other New England states, ISO-NE, and transmission-owning companies to initiate a regional analysis to determine the optimal locations for the interconnection of offshore wind. The analysis should include options to interconnect offshore wind resources that: (i) minimizes costs and needed upgrades to deliver power to load centers and meet future load growth, (ii) enables the ability to interconnect other new clean energy resources, and (iii) minimizes environmental and community impact.

9.4. Workforce Development

- Currently, power system engineers are in high demand across the country, as well as other economic and technical specialties. To expedite the interconnection of clean energy resources, and the development of the necessary transmission infrastructure, the Commonwealth should support workforce development efforts to increase the number of engineers and technical staff within relevant agencies to ensure review of state and local siting and permitting applications in a prudent and expeditious manner. Massachusetts state agencies and the Massachusetts Clean Energy Center (MassCEC) could work with universities that have existing engineering programs, such as Worcester Polytechnic Institute, to expand and enhance those programs and link them to internships and onsite training at ISO-NE and local clean energy companies. The Massachusetts legislature should consider directing the CEC to explore the possibility of such a program and allocate funding to ensure its success. Additional collaborations between Worcester Polytechnic Institute (WPI), Massachusetts Institute of Technology (MIT) and other universities could be established to pilot the use of AI and automation for study models and process management.

9.5. Siting and Permitting

- Existing authorities and processes applicable to siting and permitting of electric transmission in the Commonwealth pose multiple challenges to the timely development of new or upgraded transmission infrastructure. Some of the key areas of concern with the DPU/EFSB siting process include:
    - The time required to obtain final orders and decisions, which can greatly exceed the 12-month timeline described in the EFSB's statute (G.L. c. 164, § 69J);[54]

[54] The Supreme Judicial Court has construed such language to be directory in nature. Box Pond Ass'n v. EFSB, 435 Mass 408, 415, n.7 (2001).

  - The cost and complexity involved in siting cases for both applicants and other parties;
  - Frequent appeals of DPU/EFSB orders and decisions and the cost and delay this may entail;
  - Outdated statutes and regulations, and other areas where regulations would be helpful, but do not exist;
  - Concerns by environmental and community groups about barriers to participation in the adjudicatory process, and whether their concerns are adequately addressed in final orders and decisions;
  - Environmental Justice (and language access) as both a procedural and substantive issue;
  - Staffing of the DPU/EFSB Siting Division, and whether it is adequate;
  - Areas of duplication in permitting and siting review among multiple agencies;
  - A perception of insufficient outreach, community engagement, and consultation with stakeholders and residents prior to development of project proposals and submission for siting approval;
  - The dual role of the DPU and the EFSB as siting agencies and the additional procedural and substantive complexities that result; and
  - The composition of the EFSB Board, and whether new members are necessary to reflect additional stakeholder interests.

- Pursuant to Executive Order 620, Governor Healey established the Commission on Energy Infrastructure Siting and Permitting (CEISP). The CEISP's mandate is to advise the Governor on: (1) accelerating the responsible deployment of clean energy infrastructure through siting and permitting reform in a manner consistent with applicable legal requirements and the Clean Energy and Climate Plan; (2) facilitating community input into the siting and permitting of clean energy infrastructure; and (3) ensuring that the benefits of the clean energy transition are shared equitably among all residents of the Commonwealth. Executive Order 620 specifically tasks the CEISP with developing recommendations for reform of electric transmission facilities siting and permitting: *"The CEISP shall review and assess existing statutes, regulations, and administrative processes and make recommendations to the Governor concerning the reform of state and local permitting and siting processes for energy related infrastructure, including, for example, options to accelerate the deployment of clean energy generation and electric distribution and transmission infrastructure while ensuring that communities have adequate input into the siting and permitting processes for said infrastructure."*[55] The CEISP must produce a report conveying its recommendations to the Governor by March 31, 2024.

- The CETWG acknowledges the CEISP's mandate to advise the Governor on energy siting and permitting reforms to support the Commonwealth's need for clean energy infrastructure,

[55] Recommendations may include suggestions for administrative, regulatory, and legislative changes to existing laws and procedures.

including reforms specifically addressing siting and permitting of electric transmission. In carrying out this mandate, the CETWG recommends that the CEISP consider the conclusions regarding siting and permitting challenges to electric transmission infrastructure addressed in this report.

9.6. Other

- The 2050 Transmission Study resulted in several high-level observations around transmission-related challenges the future grid may face as a result of the clean energy transition. The CETWG acknowledges these key takeaways and supports the Commonwealth's continued engagement with regional partners on these issues, some of which are captured in the recommendations above.
    - **Reducing peak load significantly reduces transmission cost.** The assumptions initially provided by NESCOE included an assumed 2050 winter peak load of 57 GW. The study explored how a lower peak load in 2050 might impact transmission needs and costs by also studying at 51 GW 2050 winter peak load. The 2050 Transmission Study found that increases in load result in significantly higher transmission costs as load levels increase. The cost to serve 51 GW of load is $16-$17 billion, while the cost to serve 57 GW of load is $23-$26 billion. Limiting load growth could be achieved through more aggressive demand response, energy efficiency, and peak shaving programs. Limiting load growth could also be achieved by using some stored fuel for heating on the coldest days. For example, moving from 57 GW to 51 GW of peak load could represent ~80% heating electrification while still maintaining 100% transportation electrification.
    - **Targeting and prioritizing high likelihood concerns is highly effective.** While the 2050 Transmission Study is a high-level analysis, the results can be used to identify which areas of the transmission system are most likely to be constrained in the future. The 2050 Transmission Study found that "projects that address these high-likelihood concerns are likely to bring the greatest benefit for a wide range of possible future conditions as the clean energy transition accelerates."[56]
    - **Incremental upgrades can be made as opportunities arise.** Many of the transmission concerns found in the 2050 Transmission Study can be addressed by rebuilding existing transmission lines rather than building new lines in new locations. Taking advantage of line rebuilds could minimize costs as well as be less environmentally disruptive. Rebuilds can generally be achieved in a shorter timeframe than new transmission lines, which would allow the region to hold off on investment decisions until more information is available. The 2050 Transmission Study found that upgrading the capacity of lines as the opportunity arises, or "right-sizing" asset condition projects[57] when they occur, could be a financially prudent way for New England to reliably serve increased peak loads. Discussion on how to "right-size" transmission investment will occur at ISO-NE's public stakeholder forum, the Planning Advisory Committee. NESCOE has requested that the region first make progress on reforms to improve the

[56] Draft 2050 Transmission Report at 17.
[57] In New England, asset condition projects are identified by transmission owners when equipment exceeds its useful life. Draft 2050 Transmission Report at 17.

transparency, predictability, and cost discipline of asset condition projects as a prerequisite to a right-sizing approach.[58]

- **Generator locations matter.** The specific location of generators can have a significant impact on the needed transmission upgrades. In general, locating generation close to large load centers, such as cities, can reduce the strain on the transmission system.

- **Transformer capacity is crucial.** Transformers "step down" power from higher to lower voltages. The 2050 Transmission Study found that as load increases, higher voltage lines become more important. In turn, the power transferred on the higher voltage lines must eventually "step down" to lower voltages on the way to the distribution system. A significant number of additional transformers will be needed to support load growth. However, transformers typically are expensive and require a long lead time (1-2 years). The 2050 Transmission Study found that "due to the long lead times and the large number of transformers needed, it may be prudent to start ordering transformers ahead of time and determining their exact locations later on."[59]

[58] https://nescoe.com/resource-center/asset-condition-process-improvements-next-steps/
[59] Draft 2050 Transmission Report at 20