Subject: Release of a Strategic Action Plan on State-Led Interregional Transmission Priorities

As representatives of the States of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Jersey, New York, Rhode Island, and Vermont, we are pleased to share the attached Strategic Action Plan on Interregional Transmission prepared by the Northeast States Collaborative on Interregional Transmission.

The Action Plan identifies gaps in today's interregional transmission planning processes and recommends actions that States can take to improve grid reliability, support economic growth, and reduce costs for consumers across the Northeast.

We look forward to working with the federal government, regional grid operators, utilities, ratepayer advocates, and other stakeholders on how best to secure the benefits of robust interregional transmission planning for our citizens.

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Commissioner, Department of Energy and Environmental Protection
On behalf of Connecticut

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Strategic Action Plan

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APRIL 28, 2025

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NOTICE AND DISCLAIMER

The authors would like to thank the sponsor team members and several reviewers for helpful comments and discussions. However, all results and any errors are the responsibility of the authors.

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Executive Summary

The *Northeast States Collaborative on Interregional Transmission* ("Collaborative") consists of nine Mid-Atlantic and Northeast states—CT, DE, MA, ME, MD, NJ, NY, RI, and VT— and provides a forum for coordinating state efforts to improve transmission system planning across the regions. Since its formation, the Collaborative has engaged relevant federal agencies and organizations with technical expertise to identify and assess shared areas of focus for interregional transmission cooperation.

This Strategic Action Plan ("Plan") is intended to help advance the Collaborative's work by focusing its efforts over the near-term (the next year) and mid-term (the next several years).

Over the next year, the Plan identifies priority actions for the Collaborative to pursue to promote the consideration and potential development of interregional transmission projects, with the ultimate objective of providing reliability benefits and cost savings to the regions' electricity consumers. These efforts are likely to require coordinated requests for transmission solutions, project designs, and benefit calculations. During this near-term period, the Plan further identifies equipment standardization and interoperability efforts that can form the basis for future cost-effective grid expansions, including laying the groundwork for a future potential offshore network that can enable additional economic and reliability benefits to consumers.

Over the next few years (i.e., by the end of 2027), the Plan proposes to remove additional regulatory and technical barriers to the efficient deployment of offshore wind generation and interregional transmission. These mid-term efforts focus on identifying candidate interregional transmission projects, exploring necessary wholesale transmission planning tariff reforms, facilitating the future transition of generator tie-lines to network facilities, and adopting intertie optimization and other means to address seam-related inefficiencies.

I. Near-Term Action Plan

A. Address Current Gaps in Interregional Transmission Initiatives

Among the specified goals of the Collaborative's founding Memorandum of Understanding ("MOU") is to cooperate in the planning and development of robust interregional transmission infrastructure.[1] Currently, Federal Energy Regulatory Commission ("FERC" or "Commission") Order Nos. 1000 and 1920 on transmission planning and cost allocation only require limited interregional coordination and project selection procedures.[2] In practice, the existing structure has created a "triple hurdle," requiring potential interregional projects to be approved separately by each planning region (the first two "hurdles," one in each region) and again in a joint interregional evaluation (the third "hurdle").[3] Given the timing misalignment of regional planning cycles across regions, divergent benefit calculations, and absence of a clear interregional needs identification process, potentially beneficial interregional projects are not identified or meaningfully considered in the ongoing development of regional plans. This means the existing interregional coordination processes are unlikely to lead to the planning of beneficial interregional transmission projects.

A number of recent transmission studies have shown the significant value of interregional transmission.[4] Unfortunately, these studies do not translate into actionable projects for a number of reasons, including that the existing interregional coordination processes fall short of being able to address the identified interregional needs and realize the associated benefits.[5]

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1 Northeast Collaborative on Interregional Transmission, Memorandum of Understanding (July 9, 2024) at 2.

2 For a summary of Order 1920's enhanced interregional coordination requirements, see FERC, Explainer on the Transmission Planning and Cost Allocation Final Rule.

3 See, e.g., 168 FERC ¶ 61,018 at P 19 (2019) (discussing the so-called "triple hurdle").

4 We summarize the full suite of recent interregional transmission studies addressing Northeastern U.S. transmission needs in Appendix A.

5 For example, see:

PNNL, Planning and Development Pathways to Interregional Transmission | Report (January 16, 2025)

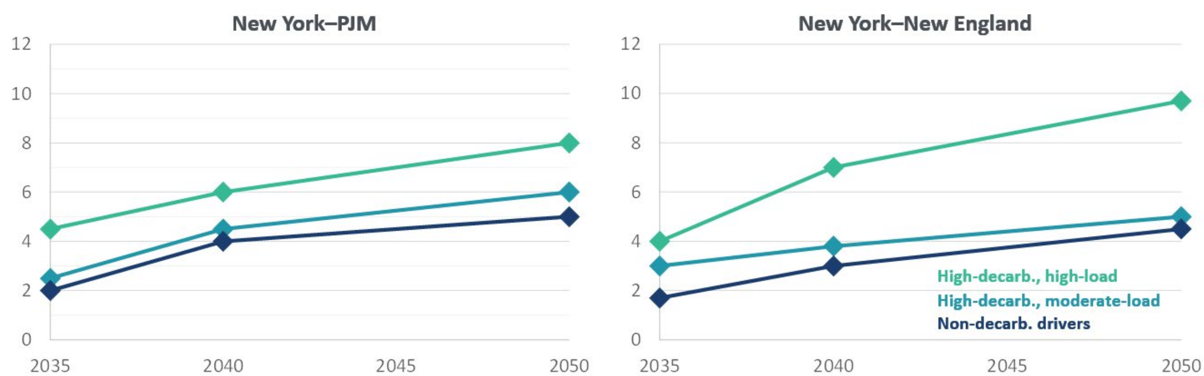
Brattle Economists Author Report on the Benefits of Expanding Interregional Transmission (November 2021);

NREL, Barriers and Opportunities to Realize the System Value of Interregional Transmission (June 2024);

Continued on next page

Even studies focused on limited decarbonization futures show that the value of interregional transmission steadily increases over time with continued load growth anticipated prior to 2040. Sourced from these various studies, Figure 1 summarizes our estimated range of “low-regrets” interregional transmission expansion needs, including separate estimates of transmission needs in low-decarbonization scenarios, low-load scenarios, and high-decarbonization scenarios with moderate- and high-load growth. By 2035, we estimate that adding 2 GW of additional transfer capability between New York and PJM would be a low-regrets expansion (before considering the value of transmission for decarbonization), with a similar 1.7 GW incremental low-regret need between New York and New England prior to considering decarbonization-related benefits. By 2040, these low-regret needs grow to 4 GW between PJM and New York and to 3 GW between New York and New England (again, before accounting for decarbonization targets). Assuming decarbonization targets are met, beneficial transmission additions by 2040 are much larger: 4.5–6 GW between New York and PJM, and between 4–7 GW between New York and New England.

FIGURE 1: ESTIMATED RANGE OF LOW-REGRETS TRANSMISSION EXPANSION NEEDS (GW)



Source: Appendix A.

Thus, while numerous studies document the benefits of interregional transmission and regional planning processes succeed at enabling transmission development, there are a number of gaps and barriers that have prevented the development of beneficial interregional transmission projects. No process currently exists for groups of states spanning different transmission planning regions to take the various steps necessary to identify, evaluate, select, and agree to share the cost of beneficial interregional transmission projects so they can be developed. Members of the Collaborative have referred to the absence of such a process as “the missing

NARUC, Collaborative Enhancements to Unlock Interregional Transmission (June 2024);
Brattle, The Need for Intertie Optimization (October 2023); and
Intertie Optimization: Efficient Use of Interregional Transmission (April 2024 Update).

middle." This part of the action plan is meant to address this "missing middle"—to identify beneficial interregional transmission expansion opportunities and make them actionable through existing regional planning processes.

To address this missing middle will require structuring and pursuing efforts to identify candidate interregional transmission projects, undertake the necessary benefit-to-cost calculations, and agree on cost allocation for any project(s) ultimately selected. To do so, we recommend two discrete action items for the Collaborative to pursue in the near term: (1) identify beneficial projects and propose them to ISOs/RTOs, and (2) develop cost allocation for these projects.

INTERREGIONAL CANDIDATE PROJECT IDENTIFICATION

Given the lack of an ISO-led process for identifying beneficial interregional transmission projects, the Collaborative should initiate a series of coordinated steps to identify and pursue such projects. Building from the consolidated identification of needs described above, the Collaborative should develop and issue a Request for Information ("RFI") for project designs that could meet the low-regrets interregional transmission needs identified in previous studies. The RFI would encourage the (if needed, confidential) submission of project ideas on either the PJM-NYISO or NYISO-ISO-NE interregional seam, allowing for both offshore and onshore transmission solutions as well as solutions that are synergistic with the regions' need to create the grid capacity necessary to integrate clean-energy resources, such as offshore wind generation. In particular, the RFI's scope would focus on "low-hanging fruit" project development opportunities to identify the most cost-effective projects with near-term benefits and feasible implementation plans, including any projects that may have already accomplished some of the necessary initial development milestones or interregional transmission expansion opportunities that simultaneously address the refurbishment needs of aging existing transmission assets.

In developing the RFI, the Collaborative should request that the RTOs/ISOs serve as technical advisers, given the ultimate need to integrate any identified interregional project with the RTOs/ISOs and their regional transmission plans. Working with the RTOs/ISOs would enable the Collaborative to jointly discuss the Collaborative's desire to prioritize use of grid enhancing technologies ("GETs"), advanced conductors, aging infrastructure upsizing opportunities, and other opportunities to maximize use of the existing grid or reduce ratepayer or community impacts. If possible, the RFI should be sequenced to take advantage of potential funding opportunities. The North American Electric Reliability Corporation ("NERC") may be able to serve a similar technical advisor role, given its recent identification of interregional transmission solutions as necessary to ensure a reliable electric grid.

Once RFI submissions are received, the Collaborative would be able to conduct an initial assessment of each project, and—together with the RTOs/ISOs—invite those projects demonstrating the most beneficial expansion opportunities to present their concepts in detail. This may involve the Interregional Planning Stakeholder Advisory Committee ("IPSAC") for PJM/NY/NE and Joint ISO/RTO Planning Council ("JIPC").[6] Following consideration of any feedback received, and taking into account ongoing activities within the RTOs/ISOs, the Collaborative could then consider a formal request to the JIPC to evaluate one or more of the identified projects from a multi-value perspective that meets the Collaborative's objectives. While a similar process might be utilized in future procurements to connect "network-ready" offshore platforms, it is currently unlikely that such offshore solutions will provide the highest-value projects for Collaborative consideration now—given that such links would not be feasible in the near-term, after network-ready offshore transmission facilities are identified, designed, and completed.

On a parallel path, and as discussed further below in II.A, the Collaborative should consult with FERC and RTOs/ISOs on tariff changes needed to propose and advance projects for more detailed evaluation and potential selection in the respective regional transmission plans.

These RFI-related consultations will have to consider staffing limitations at the RTOs/ISOs. To enable sufficient support in the mid-term time horizon, the Collaborative should consider coordinated work plan requests to the respective RTOs/ISOs, so the effort can be undertaken efficiently, and they can mobilize the necessary resources to support the interregional planning and engagement.

INTERREGIONAL ALLOCATION OF PROJECT COSTS

As a fundamental element of ultimately pursuing beneficial interregional transmission projects, states across three Northeastern market regions will need to agree on a framework for identifying benefits and sharing the costs of any interregional investments. The Brattle Group authors of this report have previously proposed flexible cost allocation frameworks and principles for interregional transmission projects that could form the starting point for a

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6 See, e.g., Northeastern ISO/RTO Coordinated Planning Protocol at § 2.1, noting the JIPC's responsibilities to include "facilitating the review by multi-state entities, regional state committees, state, provincial, or other similarly situated entities, of new interregional transmission facility additions."

Collaborative-supported cost allocation approach.[7] As summarized in these reports, a successful cost allocation framework will need to be (1) sufficiently flexible to accommodate projects that address different types of interregional needs (e.g., reliability, economic, and public policy projects) across different types of neighboring regions and entities; and (2) specific enough to be implementable by the RTOs/ISOs without being overly restrictive and formulaic. To achieve this balance, cost allocation agreements should include guidelines or illustrations of how benefit metrics would be applied to achieve cost allocation outcomes that are roughly commensurate with (often different types of) benefits received by the regions and each region's states.

We propose to work with the Collaborative to develop a strawman of a cost allocation framework. To supplement that framework, the Collaborative could consider issuing an open invitation for comments and/or alternative cost allocation structures for interregional transmission investments. This invitation would ask commenters to reference FERC precedent on interregional cost allocation, regional cost sharing models (e.g., MISO MVP, ISO-NE Longer - Term Transmission Planning, SPP highway-byway), and other innovative approaches. Once the concepts have been received, the Collaborative could consider convening a technical conference to further explore leading concepts. Based on this discussion and subsequent evaluation, the collaborative may finalize guidelines or develop model tariff rules on interregional transmission cost allocation.

The existing interregional allocation methodologies rely on the "avoided costs of the respective regional projects the interregional solution would replace."[8] Provisions within the various Joint Operating Agreements ("JOA") indicate that additional coordination and FERC approvals would be required to use an alternate allocation methodology under existing Order 1000 interregional processes.[9] However, states should not feel limited by currently-existing processes or allocation methodologies, particularly in light of the Commission's 2021 policy statement encouraging state-led funding mechanisms for transmission needs not met under Order 1000 planning

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7 Pfeifenberger, Spokas, Hagerty, Tsoukalis, A Roadmap to Improved Interregional Transmission Planning (November 30, 2021) at Section V ("Establishing a Flexible Interregional Cost Allocation Framework"). See also RENEW Northeast, A Transmission Blueprint for New England (May 25, 2022) at Section IV ("Cost Allocation").

8 See 2023 Northeast Coordinated System Plan at 2, n. 16, citing "the pertinent portions of the July 10, 2013, filings in FERC Docket Nos. ER13-1926 (PJM Transmission Owners); ER13-1942 (NYISO Transmission Owners); and ER13-1960 (ISO-NE Transmission Owners)."

9 See PJM/NYISO JOA at § 35.10.3; See also 2023 Northeast Coordinated System Plan at 2 ("Both regional planning processes must first select an interregional transmission project for it to receive cost allocation under the interregional cost allocation process").

processes.[10] A Collaborative agreement on cost allocation could pave the way for consideration of projects beyond existing planning processes, benefit calculations, and allocation frameworks to ultimately support the development of necessary interregional transmission.

B. Support Development of Uniform HVDC Design Standards with DOE Consortia

Despite the pace at which technologies continue to develop to support offshore wind generation, the various types of equipment utilized across projects, states, and regions remains non-standardized. These variations extend to the generator export cable used to interconnect the offshore wind plant to the onshore transmission grid. Notably, technological advancements in much of Europe have created a de-facto transmission standard with the ability to transmit up to 2,000 MW through a single set of cables—utilizing 525 kV HVDC transmission technologies in a “bi-pole” configuration that, during a cable outage, can continue to operate as a single “pole” capable of transmitting 1,000 MW.

Currently, ISO-NE and NYISO (as part of the Northeast Power Coordination Council, “NPCC”) do not permit the 525kV bi-pole HVDC technology to deliver 2,000 MW from offshore wind facilities based on caps on each region’s Most Severe Single Contingency (“MSSC”) assuming the entire bi-pole transmissions system would be lost. As an initial step, the Collaborative has already engaged with the three planning regions and the JIPC to evaluate the circumstances under which the MSSC level could be raised to 2,000 MW (or, alternatively, allow the maximum interconnection of OSW projects using HVDC transmission to be based on a 1,000 MW single-pole failure of the converter, as being more representative of expected performance). The Collaborative is further engaging the grid operators and NPCC on the NERC planning criteria applicable in the NPCC regions, including the methods used by the RTOs/ISOs in evaluating “single contingency (P1/P3)” and “multiple-contingency (P7)” planning criteria for single-pole failures and full bi-pole failures of bi-pole HVDC lines. We also note eastern RTOs/ISOs may need to more seriously consider remedial action schemes (“RAS”),[11] as more widely used by other system operators such as in California or Europe, as a way to address MSSC concerns

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[10] See J. DeLosa III, J. Pfeifenberger, Pathways to Coordination (October 2024) at 23-25, citing State Voluntary Agreements to Plan and Pay for Transmission Facilities, 175 FERC ¶ 61,225 (2021).

[11] Remedial Action Schemes have been defined by NERC as “a scheme designed to detect predetermined system conditions and automatically take corrective actions that may include, but are not limited to, curtailing or tripping generation or other sources, curtailing or tripping load, or reconfiguring a system,” see NERC, Remedial Action Scheme Definition Development (June 2014) at 3.

associated with the full (P7) failure of a 2,000 MW 525 kV bi-pole system. Continuing this technical effort would assist the RTOs/ISOs in adopting technical and operational standards that account for the full range of expected performance of HVDC facilities, including within various operating, planning, and interconnection studies.

In parallel, the DOE has created a recent funding opportunity to assist the Collaborative in developing technical standards associated with future development and use of the latest interoperable HVDC equipment that would be enabled by revisions to how the MSSC is defined.[12] This effort will fund a consortium to develop recommendations for technology standardization for OSW HVDC projects for use by the industry to ensure that future HVDC facilities are capable of being networked with each other, enabling the potential for future beneficial connections between offshore collector platforms in multiple states and regions. The Consortium should incorporate feedback from RTO/ISOs into development of its recommendations, and engage with ongoing two-way discussions with the Collaborative, ultimately enabling the regions to reflect expected performance capability of modern bi-pole HVDC lines and the AC substations where they are connected to the existing grid.

Once these efforts conclude, the states and regions should be able to agree on a common network-ready HVDC standard, such that different large HVDC-based cables, including those used for offshore wind plants or large interregional connections could be networked (i.e., connected with each other) into an offshore grid that reinforces the existing onshore grid and provides expanded regional or interregional transfer capabilities. This technology standardization effort may also build on the New York and New Jersey proposals to utilize AC transmission technology that is able to connect different types of HVDC export cables.[13]

C. Assess Opportunities to Align and Optimize State Offshore Wind and Transmission Procurements

To procure offshore wind generation resources, each state carries slightly different statutory and regulatory requirements that result in customized procurement frameworks. In the near-term, the Collaborative should consider, working in close coordination with relevant agencies within each state, identifying “best practice” contract language for offshore wind generation

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12 Connectwerx Opportunity: PO-CWX-004-GDO.

13 See, e.g., NYSERDA, Meshed Ready Technical Requirements; NJBPU Fourth OSW Solicitation Guidance Document at attachment 10.

and transmission procurements. For example, coordinated best practices may ensure that transmission options can be considered in state OSW procurements, such that bid evaluations of each state can consider the value of potential future regional and interregional networking options for individual wind facilities' export cables.

More broadly, areas of potential alignment in state procurements could include:

1. Incorporating a "network-ready" ("mesh-ready") standard for export cables (e.g., similar to the New York and New Jersey mesh-ready standards noted earlier);
2. Creating the option to convert export cables into open access transmission facilities in the future (should they become networked);
3. Developing bid evaluation criteria to reflect the value of proposals that offer regional/interregional transmission solutions (including attributing value associated with landing points and lease areas that could facilitate networking the individual export cables);
4. Combining state procurements into multi-state efforts (such as the recent joint MA, RI, CT procurement) to achieve the scale needed for cost-effective transmission solutions; and
5. Preserving contracting flexibility and coordinating timing of OSW targets to accommodate in-service dates that would avoid supply-chain bottlenecks (and achieve more cost-effective outcomes).

Given the highly specific nature of each state's solicitation requirements, ongoing coordination would be required to implement elements of "best practices" in the states' procurement and bid evaluation processes.

D. Develop Interregional Coordination Principles for Order 1920 Compliance Filings

In May of 2024, FERC approved Order 1920 requiring regions to develop a long-term planning process that identifies and assesses projects in response to overlapping drivers of system change across a 20-year time horizon.[14] As part of the Order, which was recently confirmed through Order 1920-A, the Commission requires regions to identify and jointly evaluate proposed interregional transmission facilities that can address regional needs within the long-term plans that will have to be prepared under Order 1920. In addition, the Order requires

[14] Order 1920, 187 FERC ¶ 61,068 (2024).

transmission providers to make publicly available a suite of information related to this interregional coordination process, including the results of cost-benefit evaluations of proposed interregional facilities. Depending on implementation strategies of various regions, these requirements have the potential to partially address the current lack of meaningful interregional planning and coordination processes.[15] The Commission has also recently clarified that compliance filings for interregional coordination are due in August of 2025 (pending extensions for state agreement processes).[16]

Given this abbreviated timeline, the Collaborative should work in the near term to develop a set of interregional planning principles for regions to incorporate when developing and implementing their Order 1920 interregional coordination provisions. Namely, the Collaborative should propose to develop the process under which entities (such as states) could propose interregional projects to address transmission needs more effectively. Such a process should not be limited to RTO-identified regional (or interregional) transmission needs but would instead allow proposers to explain the needs that their project would address, which may differ across regions. The principles should explain that the needs underlying future interregional projects are not limited to only the needs identified in the new Order 1920 long-term planning processes, or in existing Order 1000 regional plans. Further, the proposed process should not be limited to interregional projects that are proposed in each region simultaneously, as long-term planning cycles between regions may never fully coincide. Instead, when projects are submitted to one region, that region should be made responsible for coordinating with the relevant neighbor(s).

When evaluating benefits for the proposed interregional projects, the compliance filings should specify that all benefits be considered (cost savings from additional energy transactions, resource adequacy and resilience benefits, avoided regional transmission projects, etc.) that the regions may be able to obtain from new interregional transmission. These benefits should not be limited to the least-common denominator subset of different benefits estimated by <u>each</u> region but instead should consider <u>all</u> benefits considered by either one of the neighboring regions. The benefit assessment should also recognize that a specific interregional transmission project may provide very different sets of benefits to the neighboring regions (e.g., while one region may disproportionally benefit from resource adequacy savings and improved extreme-whether resilience, the other region may see a reduced cost of meeting public policy needs).

[15] See J. Pfeifenberger, Order 1920 Compliance: An Opportunity to Improve Transmission Planning beyond Mandates (October 22, 2024).

[16] Order 1920-A, 189 FERC ¶ 61,126 at P 915 (2024).

E. Support Reducing Seams-Related Inefficiencies

A number of studies have documented that existing interregional transmission facilities are poorly utilized and that RTOs/ISOs often do not recognize in their planning efforts the value that interregional transmission provides in terms of energy trading, resource adequacy, or grid resilience.[17] As a result, the RTOs/ISOs' own analyses may attribute little value to expanding interregional transmission while numerous industry studies—conducted by NERC, DOE, NREL, MIT, Princeton, and others—document significant value from such interregional transmission in the Northeastern U.S. and elsewhere.[18]

For example, while NYISO and ISO-NE recognize the resource adequacy value of uncommitted interregional transmission capacity, PJM attributes little resource adequacy value to the existing interregional transmission capacity and no resource adequacy value to new interregional transmission. Analyses by market monitors and others have also repeatedly shown inefficiencies in the current methods of scheduling and pricing electricity trades between regions in real-time.[19] Flows between PJM and New York were inconsistent with price differentials during 40% of the year, including 40% of hours with price differences greater than $10/MWh.[20] These inefficiencies increase customer costs and reduce the benefits of interregional facilities, with the current barriers to interregional trade reducing available value by an estimated 20-30%.[21] Other studies have similarly estimated a significant benefit to resolving these inefficiencies.[22]

Resolving these seam-related inefficiencies will prove key to ultimately realizing the benefits of interregional transmission projects identified by the Collaborative. Fortunately, relevant experience with attributing resource adequacy value already exists, and implementation

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17 J. Pfeifenberger, N. C. Bay et al., The Need for Intertie Optimization (October 2023); NREL, Barriers and Opportunities to Realize the System Value of Interregional Transmission (June 2024); and NARUC, Collaborative Enhancements to Unlock Interregional Transmission (June 2024).

18 See *Strategic Action Plan, Phase 1: Study Synthesis of Transmission Needs*, Brattle Group presentation to the Collaborative, (December 2024) attached as Appendix A.

19 See, for example, J. Pfeifenberger, N. C. Bay, et al., The Need for Intertie Optimization (October 2023) at 4.

20 Ibid.

21 Id. at 26-27.

22 Id. at 5 ("In 2010, for example, Potomac Economics estimated that optimizing existing interties between MISO, PJM, NYISO, ISO-NE, and Canadian system operators would conservatively yield between $160– 300 million in annual cost savings. In 2011, NYISO and ISO New England estimated that customer benefits from intertie optimization would be $789 million over five years").

frameworks for intertie optimization have been developed that resolve inefficiencies and enable customers to realize the value associated with interregional trades in real-time.[23]

Although identified interregional projects are likely to include the capability to materially reduce inefficiencies by enabling transfers over broader geographic areas, seams inefficiencies (and associated regulatory hurdles) ultimately limit the benefits realized by customers. Given the interregional scope of the Collaborative, the group is well-positioned to engage jointly with the regions (including through the IPSAC) to encourage the reduction of seam-related planning barriers, such as the recognition of resource adequacy and resilience value of interregional transmission in transmission planning or the implementation of intertie optimization in the RTOs'/ISOs' real-time operations. To ensure that the benefits of proposed interregional projects are accurately reflected (and ultimately realized by customers), this effort should proceed in parallel with the identification of candidate interregional projects by the Collaborative.

II. Mid-Term Action Plan

A. Explore Need for Tariff Revisions Based on Lessons Learned

Given the near-term efforts of the Collaborative to resolve the "missing middle" planning gap, including identifying high-net-benefit projects, the potential need may arise for new (or revised) tariff rules to enable the joint selection, pursuit, funding, and allocation of future potential interregional transmission projects. Although provisions already exist for joint interregional project selection within the JOAs, as described above, it is unlikely that the projects identified in the near term by the Collaborative would be responsive to a single regional "need," or be feasible under the existing RTO/ISO cost allocation approaches. Even if a project responded to a stated interregional need, under the status quo, the project would need to also be found to address discrete regional needs in each individual RTO/ISO planning process, which proceed on inconsistent timelines. This process overlooks opportunities for

[23] See Id. at 9, citing NYISO, ISO New England, Inter-Regional Interchange Scheduling (IRIS) Analysis and Options (January 5, 2011) and at 16-18 discussing European flow-based market coupling. See also J. Pfeifenberger, Intertie Optimization: Efficient Use of Interregional Transmission (Update) (April 12, 2024) at 3-4.

mutually beneficial interregional transmission facilities beyond addressing individual regional needs, which gives rise to the missing middle planning gap described above.

In preparation for moving forward with candidate interregional projects once they have been identified through a near-term project identification process (e.g., projects proposed in response to an RFI process discussed above or proactively identified by utilities or the ISOs/RTOs), the Collaborative should work with the RTOs/ISOs to develop the necessary revisions to their market rules (if any) to enable the evaluation and selection of identified beneficial interregional projects. These revisions would also implement the Collaborative's preferred cost allocation for the specific interregional project. Given the limited scope of existing interregional benefit calculations and otherwise disparate benefit metrics used to evaluate transmission projects in each region, the proposed market rule changes may need to specify the Collaborative's preferred benefit metrics and project selection criteria. Projects that satisfy the selection criteria could then be eligible for cost allocation under the framework identified by the Collaborative through the near-term Action Plan.

B. Explore the Creation of a Buying Pool for Transmission Equipment

As an additional step towards standardizing equipment utilized in future interregional transmission and offshore wind procurements, the Collaborative is exploring the creation of a multi-state buying pool for standardized HVDC and other transmission equipment. While implementation of this effort would be likely more effective following development of uniform HVDC equipment and operational standards, the underlying approach should be explored further by the Collaborative in the near term.

Such a buying pool would serve as a centralized mechanism for coordinated bulk orders of HVDC equipment (including potentially HVDC submarine cable) that, once deliverable by the manufacturers, can then be utilized by state-selected offshore wind facilities. This approach is similar to efforts in Europe that enabled multiple grid operators to procure large quantities of HVDC equipment well in advance of specific identified needs, providing more competitive pricing, improved delivery timing, and a powerful signal to build up the necessary HVDC supply chain.[24] A similar framework has also been recommended by the National Infrastructure

[24] See J. Pfeifenberger, L. Bai et al., The Operational and Market Benefits of HVDC to System Operators (September 2023) at § V.

Advisory Council to address the ongoing shortage of traditional HVAC equipment.[25] Lessons learned by the Collaborative in exploring this concept for HVDC equipment initially could help identify legal, regulatory, or practical issues that would also be relevant to any bulk purchasing efforts for traditional HVAC transmission equipment that is subject to supply-chain challenges.

As an initial step, the Collaborative should conduct the legal and market research necessary to determine the preferred structure and necessary scope of such a buying pool. Notable outstanding questions include: 1) what is the minimum buy-in to make suppliers willing to participate; 2) what are the off-ramps for changes in state policy or schedule; 3) how much money would have to be put "at risk;" 4) which technical criteria must be determined in advance; and 5) how to account for technological evolution? In addition to Collaborative-led legal and market research, discussions with experts from other regions with existing equipment buying pools should be undertaken to provide necessary insights.

As a further research item, the Collaborative will also need to explore the potential methods under which states (and/or successful awardees) can draw equipment from a potential future buying pool. This task is likely to require material effort given the different procurement requirements and regulatory frameworks of each Collaborative member state.

C. Enable the Transition From Generator Export Lines To Network Transmission Facilities

Individual offshore wind generators' radial export lines may eventually become transmission facilities of a future networked offshore grid. However, these facilities currently are procured and operated under a regulatory framework that is not suited for the type of networked operations associated with an offshore network grid. Similarly, state offshore wind procurements do not (or not consistently) specify and enable a future transition of the export cables to open-access network transmission facilities. As a part of future networked transmission systems, facilities currently operated by generation developers as generator lead-lines would be also networked with onshore transmission facilities, which would impose a new

[25] National Infrastructure Advisory Council, Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Grid (June 2024) at § 5.3 ("encouraging long-term contracts/customer commitments between transformer suppliers and the sectors driving demand"); § 5.4 ("establishing a strategic reserve of transformers, with the U.S. government as the buyer of last resort). Notably, an additional recommendation of the report is to "standardize transformer design and reduce complexity," § 5.5.

set of responsibilities for the offshore wind developer as a transmission owner subject to open access standards.

To enable this transition, the Collaborative should identify the necessary contractual and regulatory frameworks that could be adapted by Northeastern RTOs to create networked offshore grids. This will likely require mechanisms to preserve existing rights while making unused transmission capability available for system use—like the California ISO's recently FERC-approved "Subscriber PTO" model, which compensates the owner of the transmission facility (in this case, the OSW generator who funded the tie-line through state contracts) for any use of the facility beyond subscriber contracts, while enabling beneficial transfers on available capacity to reduce customer costs.[26] The RTOs should also be engaged to ensure ultimate feasibility and efficient operations of such offshore transmission frameworks.

From a regulatory perspective, the Collaborative could lead a series of discussions with FERC Staff to consult on the application of open access precedent throughout the process. Alongside these federal efforts, the Collaborative may find value in addressing the associated legal, tax, and implementation issues across the various states. Such support would assist states in determining the steps necessary for such a transition given applicable state laws, regulations, and past procurements. Considering these various inputs, the Collaborative ultimately should develop a regulatory and contract framework for adoption by the RTOs and by various states, including through a potential § 205 filing to secure FERC approval.

[26] For a summary of the CAISO's Subscriber PTO framework, see J. Pfeifenberger, N. C. Bay, et al., The Need for Intertie Optimization (October 2023) at 13-16.

Appendix A: Action Plan, Phase 1: Study Synthesis of Transmission Needs

Strategic Action Plan, Phase 1:
Study Synthesis of Transmission Needs

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February 2025

Brattle

Key Takeaways from Review of Studies

Interregional transmission between NYISO and both ISO-NE and PJM is highly valuable in the near- and long-term, and low-regrets expansion opportunities should be pursued

- Cost-effective expansions between these regions are identified in numerous studies
  - Studies consistently demonstrate benefits of added interregional transmission capability: lower production cost and congestion relief; resilience, capacity and ancillary service benefits; and supporting decarbonization policies
  - The near-term need for transmission is evident **even when decarbonization is not a constraint**: low-regrets interregional transmission expansion is **beneficial purely from a reliability and economic perspective**
- We identify a **low-regrets need of 2 GW between NY and PJM and 1.7 GW between NY and New England**
- In the long-term, the exact magnitude of interregional transfer capability needs are still quite uncertain for both interregional seams and depend on progress on decarbonization as well as load growth beyond 2035 needs
- Studies also highlighted the long-term need for expansion between the **Northeast and Canada**
  - **5 GW between Quebec and both New England and New York by 2050 is low-regrets**
- **Realizing the value of interregional transmission identified in these studies requires overcoming key barriers,** particularly introducing intertie optimization (see Appendix slides for further discussion) and fully accounting for the resource adequacy and resiliency value of existing and new intertie capacity

New York – PJM: Significant transmission expansion between is valuable in the near-term

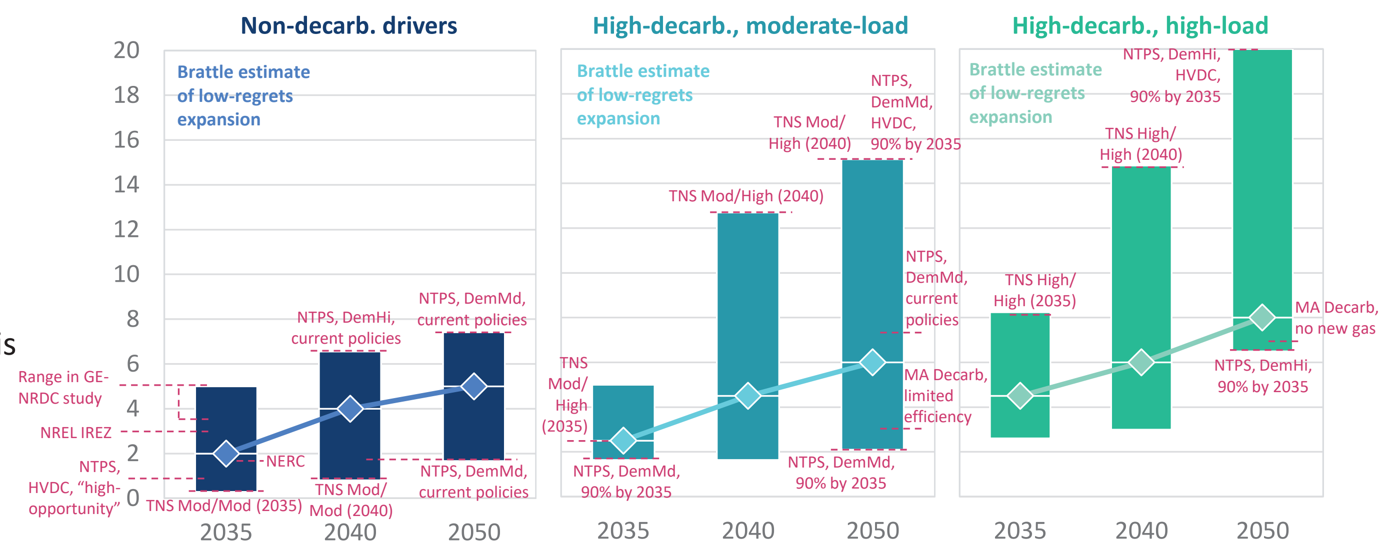
Based on multiple independent studies, we estimate that at least **2 GW** additional transfer capability between **New York and PJM by 2035 is low-regrets**, even without considering the value of transmission for decarbonization

- Represents low end of range from all studies, and central value of studies that did not consider decarbonization as the driver for transmission development

At least **4 GW by 2040 is likely low-regrets**, but needs may be significantly higher in high-decarbonization futures (up to 12–15 GW)

- Building in **flexibility and expandability** is likely efficient given the potential for much larger long-term needs
- Our low-regrets estimates for high-decarb. futures range from **4.5–6 GW in 2040** to **6–8 GW in 2050**
  - Datacenter and electrification demand in PJM makes high-load scenarios more likely

Estimated Range of NY–PJM Transmission Needs (GW)



Notes: Ranges above cover transfer capability needs reported in the DOE 2023 Transmission Needs study (TNS, summarizing multiple studies), DOE National Transmission Planning Study (NTPS), GE-NRDC study, MA Decarbonization Pathways study, LBNL study, NREL IREZ study, and NERC ITCS study. These ranges exclude scenarios deemed unrealistic, such scenarios with zero transmission expansion between NY and PJM in the MA Decarb Study. Annotations indicate noteworthy scenarios from these studies. NTPS results are from "AC" expansion scenarios unless denoted otherwise.

New York – New England: Interregional upgrades across the interface presents low-regrets, near-term opportunities

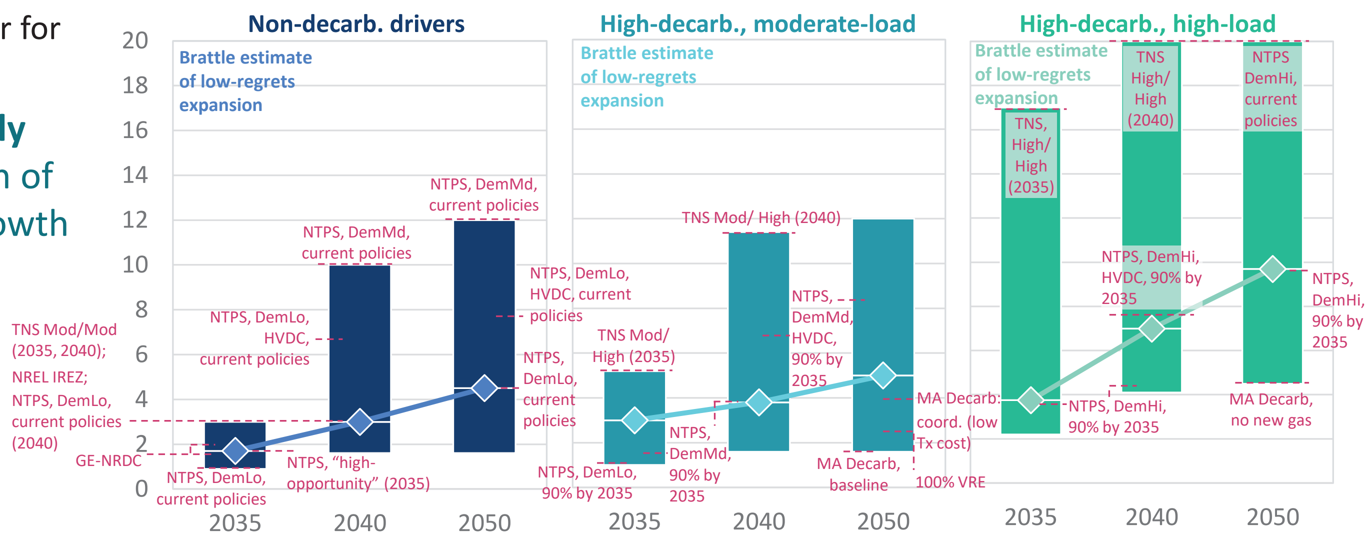
Based on multiple independent studies, we estimate that at least **1.7 GW** additional transfer capability between **NY and New England by 2035 is low-regrets**, even without considering the value of transmission for decarbonization.

- Similarly represents low end of range across studies and central estimate of studies that did not consider decarbonization as the driver for transmission development

Long-term (2040–2050) needs are highly uncertain; depend on scale and location of renewables adoption as well as load growth

- **3 GW by 2040 is low-regrets**, but may be conservative given decarbonization ambitions of both regions
  - Our low-regrets estimates for high-decarbonization scenarios conservatively skew towards the bottom of each range given the uncertainty amongst projects
- Option value for increased transfer capability is particularly valuable, given potentially high interregional needs

Estimated Range of New England–NY Transmission Needs (GW)



Notes: "Non-decarb. drivers" refers to scenarios where decarbonization was not a driver/constraint for the analysis. Ranges above cover transfer capability needs reported in the DOE 2023 Transmission Needs study (TNS, summarizing multiple studies), DOE National Transmission Planning Study (NTPS), GE-NRDC study, MA Decarbonization Pathways study, and NREL IREZ study. These ranges exclude scenarios deemed unrealistic, such as low-electrification and low-offshore wind scenarios in the MA Decarb. study which report low transmission needs due to new nuclear capacity in NY and CT. Annotations indicate noteworthy scenarios from these studies. NTPS results are from "AC" expansion scenarios unless denoted otherwise.

Canada: Significant expansion between the Northeast and Quebec is valuable long-term, and near-term for reliability in New York

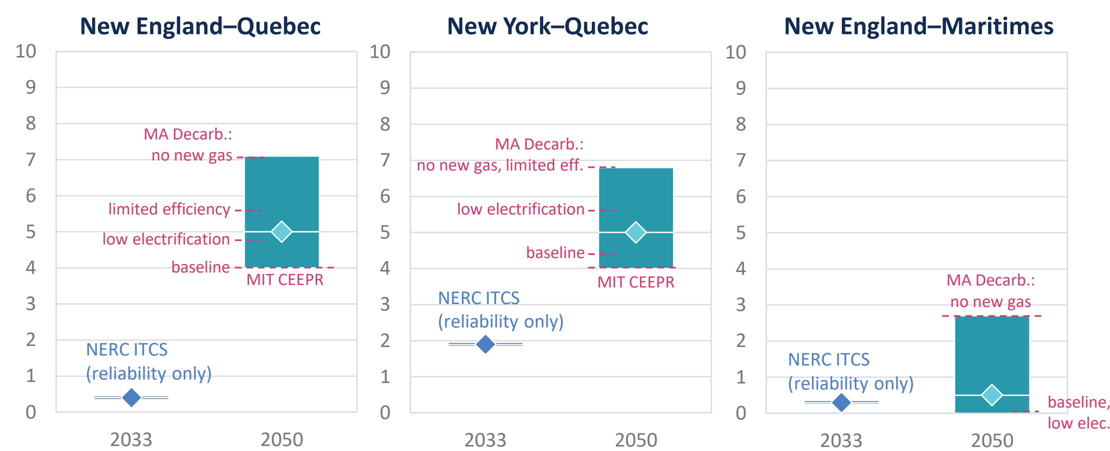
Based on multiple independent studies, we estimate that at least **5 GW** additional transfer capability **by 2050** between both **New England and Quebec** and **New York and Quebec is low-regrets**. When just considering reliability benefits, **1.9 GW between New York and Quebec by 2033 is low-regrets**.

- While fewer studies considered transmission expansion to Canada, long-term (2050) studies show consistent value in significant expansion between Quebec and both New England and New York.
  - Needs are greater (up to 7 GW) in higher renewables/low thermal generation futures.
  - Value is derived from operating lines **bidirectionally** to balance Northeast renewables.
- The MA Decarbonization Pathways study found a moderate need between **New England–New Brunswick** between 0–0.8 GW by 2050, scaling to 2.7 GW in a future with no new gas generation.

NERC study demonstrates near-term reliability need

- **0.4 GW between NE–QC, 1.9 GW between NY–QC, 0.3 GW between NE–Maritimes**
- These figures consider resource adequacy only, and are therefore **conservative estimates that do not consider economic or public policy benefits of further expansion.**

Estimated Range of Northeast–Canada Transmission Needs (GW)



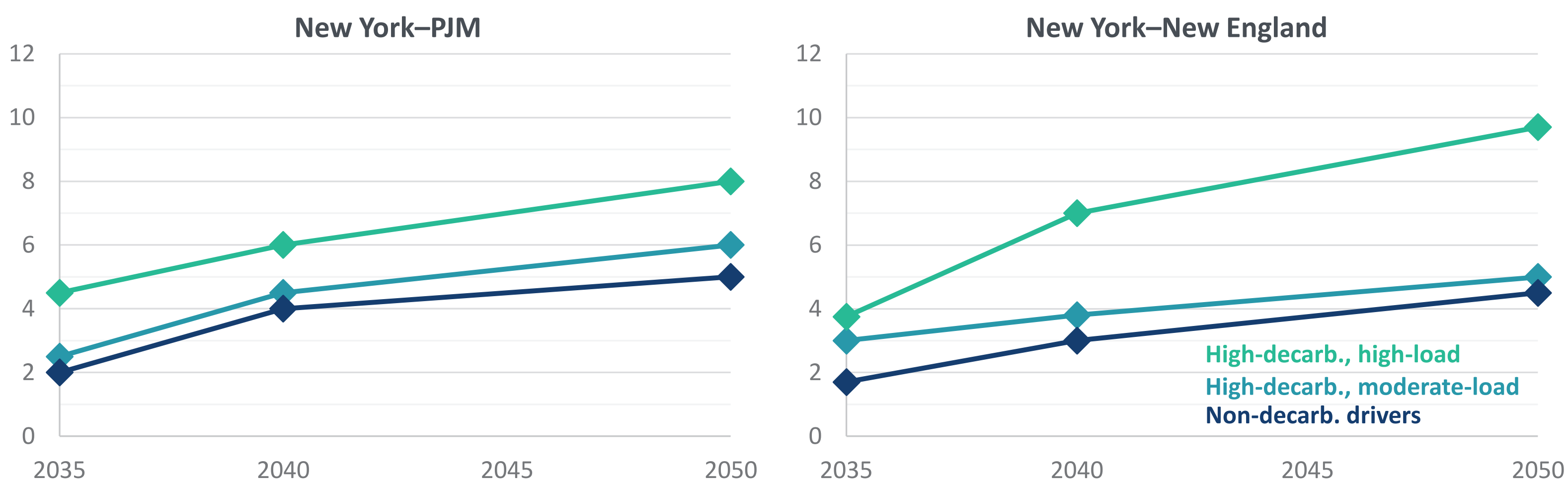
Notes: Ranges above cover transfer capability needs reported in the NERC ITCS (2033 only), the MIT CEEPR study (2050 only) and the MA Decarbonization Pathways study (2050 only). Annotations indicate noteworthy scenarios from these studies.

Summary: "Low-Regrets" Interregional Transmission Expansion

Based on our review of multiple independent transmission studies across several possible decarbonization and load growth scenarios, we believe the following transmission expansions to be low-regrets:

- **New York–PJM:** 2–4.5 GW by 2035, 4–6 GW by 2040, 5–8 GW by 2050
- **New York–New England:** 1.7–3.7 GW by 2035, 3–7 GW by 2040, 4.5–9.7 GW by 2050
- **Northeast–Canada (not pictured):** 1.9 GW NY–QC by 2033; 5 GW NE–QC and 5 GW NY–QC by 2050

Estimated Range of *Low-Regrets* Transmission Expansion Needs (GW)



Summary of Relevant Interregional Transmission Studies

Summary of Studies Reviewed

Study	Years analyzed	Considerations/assumptions	Findings
1. DOE 2023 Transmission Needs Study	2030, 2035, 2040	Review of 300 scenarios and sensitivities from 6 independent national transmission studies. Almost all have decarbonization constraints (in addition to BAU scenarios)	Range of transmission needs: **NY-New England:** 2035: 2.8–17 GW; 2040: 2.9–21.4 GW **NY-PJM:** 2035: 0.29–8.24 GW; 2040: 0.81–12.7 GW Excludes values from the moderate load growth/moderate clean energy cases, which represent business-as-usual scenarios without the IIJA and IRA and are "an unlikely representation of future power sector need."
2. DOE National Transmission Planning Study	2035, 2040, 2050	Conducted zonal capacity expansion & resource adequacy modelling through 2050 under 96 scenarios covering different transmission frameworks (AC, P2P HVDC & meshed HVDC), decarbonization assumptions, load growth assumptions, and 15 sensitivity cases	**NY-New England:** 1.7–2.9 GW by 2035, 3.8–6.7 GW by 2040 in central case **NY-PJM:** ~1 GW by 2040 for AC, but much higher in HVDC futures
3. DOE Atlantic OSW Transmission Study	2050	Optimized offshore transmission cables for five difference transmission topologies, and modeled production cost benefits as well as grid reliability, resource adequacy, power flow, grid strength and contingency analysis.	Interregional topology resulted in a **total of 14 GW of offshore transmission** between Atlantic states, with a **benefit-cost ratio of 2.9** ($2.4 billion/yr in production cost and resource adequacy benefits) [granular results on transfer capability needs between individual regions not provided].
4. GE-NRDC Study	2035	Uses nodal model to optimize transmission buildout by 2035 and estimate resilience benefits under severe weather events as well as production cost and capacity savings.	$12 billion in net present value from 87 GW interregional transmission (2 GW between NY-NE, 5 GW between NY-PJM), including $1 billion in resilience benefits from single 2035 polar vortex event.
5. MA Decarb Pathways Study	2050	Models 8 pathways to net zero for MA, including detailed capacity expansion modeling	**NY-New England:** 0.5–4.5 GW (1.6–4.5 GW when focusing on most realistic scenarios) **NY-PJM:** 1.5–7 GW (Caveat: PJM was not explicitly modeled as its own zone but a boundary condition for New York) **QC-NY:** 3.8–6.8 GW **QC-New England:** 4.1–7.1 GW **New England-Maritimes:** 0–2.7 GW (0–0.8 GW when focusing on most realistic scenarios)

Summary of Studies Reviewed (cont'd)

Study	Years analyzed	Considerations/assumptions	Findings
6. LBNL Analyses	2012–2023	Estimates congestion value (production cost savings) of expanding interregional transmission using historical data (2012-2023) on nodal marginal prices. Does not estimate transfer capability needs in GW.	**NY-New England:** documents historical energy market value of $137–189 million/yr per GW of transmission **NY-PJM:** documents historical energy market value of $149–156 million/yr per GW of transmission
7. NREL IREZ	2022	Models energy cost savings of transmission corridor from Midwest wind to Eastern part of the Interconnection	3 GW expansions from PJM to New York and New York to New England increases energy cost savings of transmission corridor by $118 million/yr and $28 million/yr, respectively (incremental costs: $27 million/yr and $21 million/yr, respectively)
8. MIT CEEPR	2050	Modeled power system cost savings associated with 4 GW transmission expansions for Quebec-New York and Quebec-New England. Analysis was constrained to meet OSW targets.	**QC-New England:** 4 GW provides power system cost savings of $1,121 million/yr (13%) **QC-NY:** 4 GW provides power system cost savings of $913 million/yr (13%) Value is generated by utilizing the transmission bidirectionally to balance Northeast renewables, avoiding firming costs
9. NERC ITCS	2033	Identifies "prudent" interregional transmission additions needed to maintain reliability—does not include any additional transmission justifiable based on economic and public policy benefits	**NY-New England:** 0 GW (this is unlikely once considering economic and public policy benefits) **NY-PJM:** 1.8 GW to alleviate significant resource deficiencies in New York **QC-New England:** 400 MW **QC-NY:** 1.9 GW **New England-Maritimes:** 300 MW

Note on Existing Interregional Transfer Capability

- In additional to transmission expansion needs, **we found that there were a range of values reported across different studies for how much interregional transfer capability exists today**.
- Namely, the DOE Transmission Needs Study, DOE National Transmission Planning Study (NTPS), and NERC Interregional Transfer Capability Study report different existing transfer capabilities at the New York–New England and New York–PJM interfaces.
- Different assumptions on existing capability partially explain differences in additional transfer capability needs.
  - e.g. DOE NTPS assumes greater existing transfer capability between New York and PJM than the Transmission Needs Study, and as a result finds less expansion is needed at that interface.

	DOE Transmission Needs Study	DOE NTPS	NERC ITCS
New York <> New England	2,030 MW	3,500 MW	Summer: >1,303 / <1,660 MW Winter: >2,432 / <1,359 MW
New York <> PJM	2,000 MW	6,600 MW	Summer: >913 / <1,356 MW Winter: >4,019 / <4,814 MW

Sources: DOE NTP Study Team letter, December 17, 2024; NERC ITCS Phase 1 results.

1. DOE National Transmission Needs Study (2023)

Takeaway

By **2035**, interregional transmission needs between New York–New England and New York–Mid-Atlantic will likely exceed **5 GW** and **2.4 GW**, respectively. By **2040**, these needs could grow to **11 GW** and **15 GW**

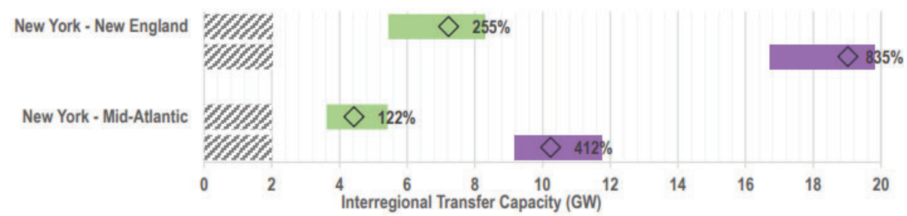
- Summarizes results from six national capacity expansion studies on interregional transmission expansion needs for 2030, 2035 and 2040 to achieve decarbonization
- In **2035** additional transfer capability requirements will be between **5.19–17.0 GW** for New York–New England and **2.43–8.24 GW** for New York–Mid-Atlantic
  - By **2040**, 11.4–21.4 GW and 12.7–14.8 GW, respectively
  - Dependent on load growth and clean energy penetration assumptions
    - We exclude values from the moderate load growth/moderate clean energy cases, which represent business-as-usual scenarios without the IIJA and IRA and are "an unlikely representation of future power sector need."

Gap

Expanding transmission between NY and PJM and New England is **low-regrets**; potential for **"low-hanging" interregional projects** that are cost effective but highly valuable

Within-region transmission and interregional transfer capacity need for New York in 2035

Range of new transmission need for future scenarios with moderate load and high clean energy growth (green, top for each region) and high load and high clean energy growth (purple, bottom). Median % growth compared to 2020 system shown.



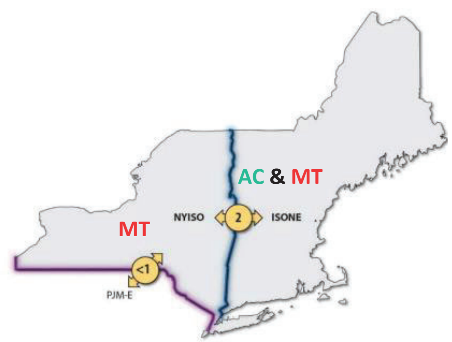
Regional Pair	2020 GW	Scenario Group	New in 2030		New in 2035		New in 2040	
			GW	% Growth	GW	% Growth	GW	% Growth
Mid-Atlantic – New York	2.00	Mod/Mod	0.00	0.0%	0.29	14.7%	0.81	40.6%
Mid-Atlantic – New York	2.00	Mod/High	0.00	0.0%	2.43	122%	14.8	742%
Mid-Atlantic – New York	2.00	High/High	2.03	102%	8.24	412%	12.7	634%
New England – New York	2.03	Mod/Mod	1.46	71.7%	2.84	140%	2.90	142%
New England – New York	2.03	Mod/High	1.53	75.1%	5.19	255%	11.4	559%
New England – New York	2.03	High/High	3.96	195%	17.0	835%	21.4	1050%

Source: DOE National Transmission Needs Study

2. DOE National Transmission Planning Study (2024)

Takeaway: At least **2 GW** of NY–ISO-NE transmission is likely needed by **2035**, increasing to nearly **5 GW** by **2040**. Significant expansion between NY–PJM and within New England is necessary by 2040. Results in net savings of **$56 billion, $54 billion** and **$33 billion by 2050** for ISO-NE, NYISO and PJM, respectively. HVDC buildout has higher value.

- Conducted zonal capacity expansion & resource adequacy modelling through 2050 under 96 scenarios covering:
  - Transmission frameworks (AC, P2P HVDC & meshed HVDC)
  - Policy assumptions (current policies; 90% power sector decarbonization by 2035; and 100% by 2035 [disregarded in this summary])
  - Low, medium and high demand futures
  - 15 sensitivity cases
  - Does not consider interchange or transmission expansion with Canada (international imports/exports set exogenously)
- "High-opportunity interfaces" for **2035**: Conservative estimates based on central scenario (see figure)
  - **1.7 GW** between **NYISO–ISO-NE**, **0.9 GW** between **NYISO–PJM** in the "meshed HVDC" scenario
  - However, needs increase significantly by 2040, and are sensitive to demand scenarios and transmission framework (see next slide)
- Central expansion scenario generates net cost savings through 2050. HVDC futures increase cost savings
  - ISO-NE: $56 billion (19%), up to $62 billion (21%) with HVDC
  - NYISO: $54 billion (16%), up to $63 billion (19%) with HVDC
  - PJM: $33 billion (2%), up to $75 billion (5%) with HVDC
  - Costs allocated amongst regions using "adjusted production cost" based on zonal marginal prices



NYISO & ISONE

AC Framework

Interface Capacity (GW)

REGION	EXISTING	25TH	50TH	75TH
		Percentile of New Capacity		
NYISO, ISONE	3.5	**1.7**	1.8	2.5
NYISO, PJM-E	6.6	**0**	0	0

MT Framework

Interface Capacity (GW)

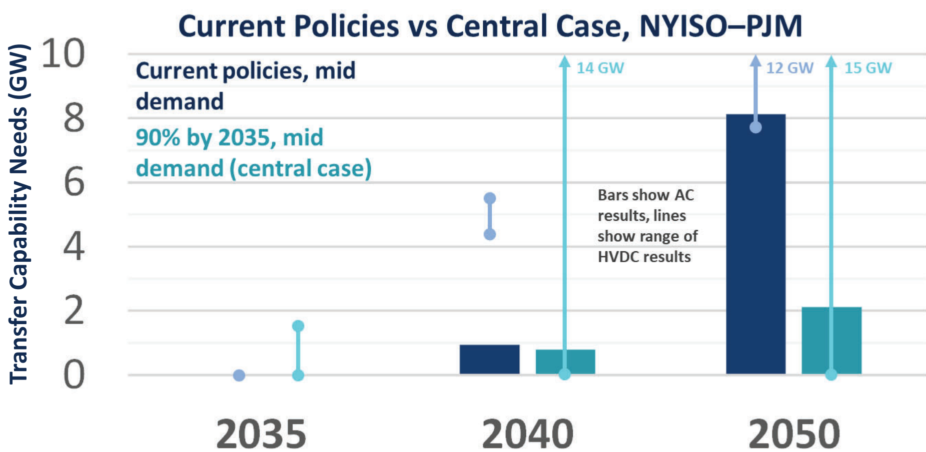
REGION	EXISTING	25TH	50TH	75TH
		Percentile of New Capacity		
NYISO, ISONE	3.5	**1.6**	2.2	2.9
NYISO, PJM-E	6.6	**0.9**	2.4	3.7

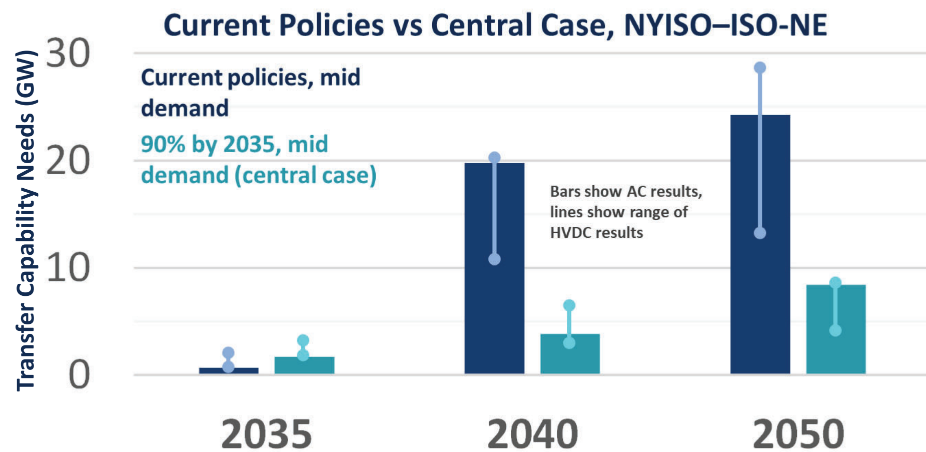
Source: DOE National Transmission Planning Study

2. DOE National Transmission Planning Study (2024) (cont'd)

Transmission needs increase by 2040, but vary greatly

- **NYISO–ISO-NE**: from 1.7–2.9 GW by 2035 to **3.8–6.7 GW by 2040** in central case
  - Under current policies, 2040 needs are much higher (11–21 GW)
- **NYISO–PJM: to ~1 GW by 2040** for AC scenario, but much higher in HVDC scenario
  - Low end of HVDC range represents point-to-point HVDC, whereas high end reflects multiterminal future



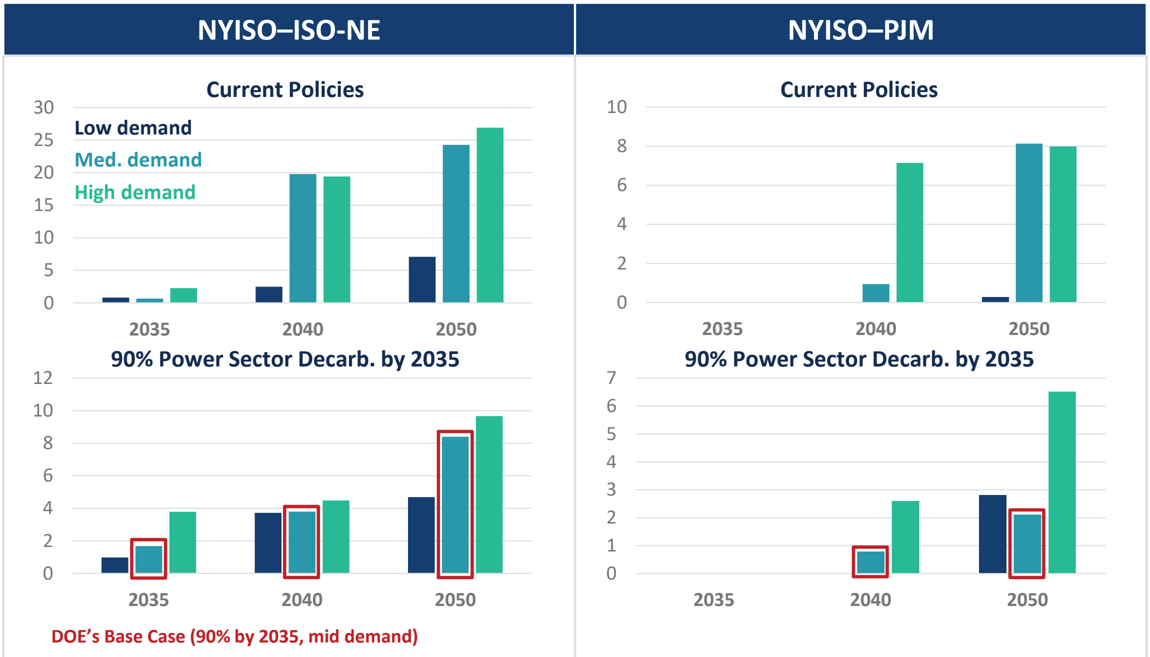


2. DOE National Transmission Planning Study (2024) (cont'd)

Load Assumptions Significantly Affect Interregional Transfer Capability Additions

- High demand increases transmission needs, particularly between NYISO–PJM (1 GW to 7 GW from mid to high demand)
- Even under low load and moderate decarbonization assumptions, nearly 4 GW is needed between NYISO–ISO-NE by 2040

Transfer Capability Needs (GW), AC Framework



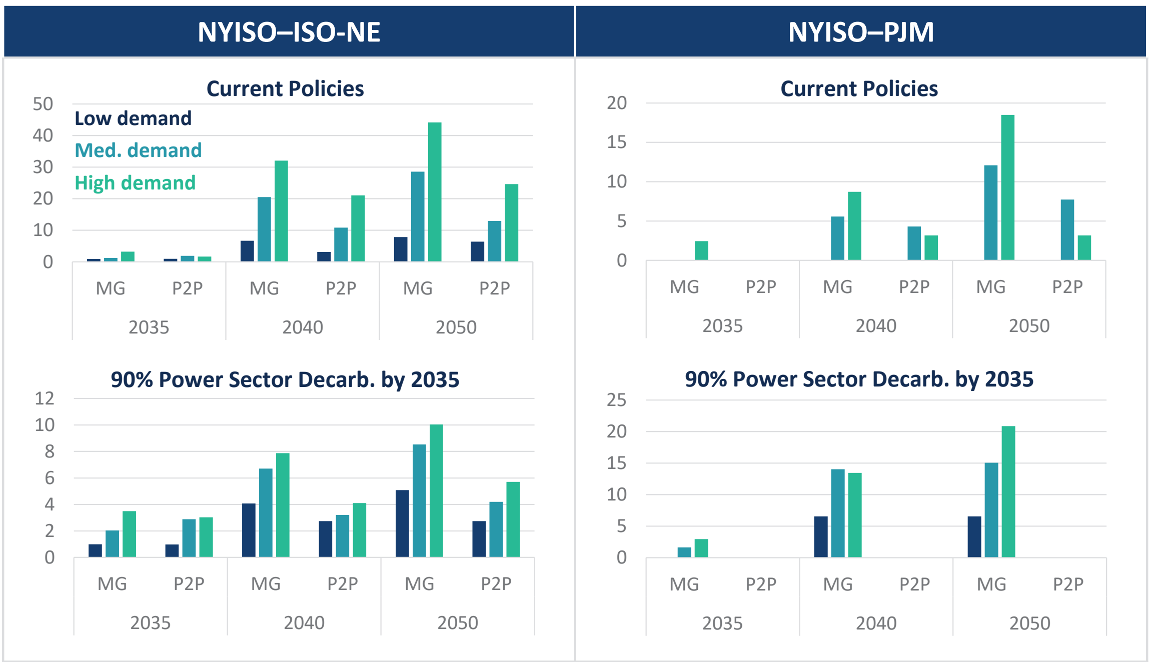
Note: All results assume an early phaseout of IRA tax credits in 2032.

2. DOE National Transmission Planning Study (2024) (cont'd)

HVDC Futures See Greater Variation in Transfer Capability Needs

- While NYISO–ISO-NE needs are similar to AC case, large differences in NYISO–PJM buildout
- Multiterminal HVDC sees significant buildout between NYISO–PJM by 2040, even under low load growth

Transfer Capability Needs (GW), HVDC Frameworks



Note: MG = multiterminal, P2P = point-to-point. All results assume an early phaseout of IRA tax credits in 2032.

3. DOE Atlantic Offshore Wind Transmission Study (2024)

Takeaway

Proactive, coordinated **interregional transmission planning is urgently needed** to integrate Atlantic OSW, and **networking offshore transmission generates that benefits significantly outweigh the costs**

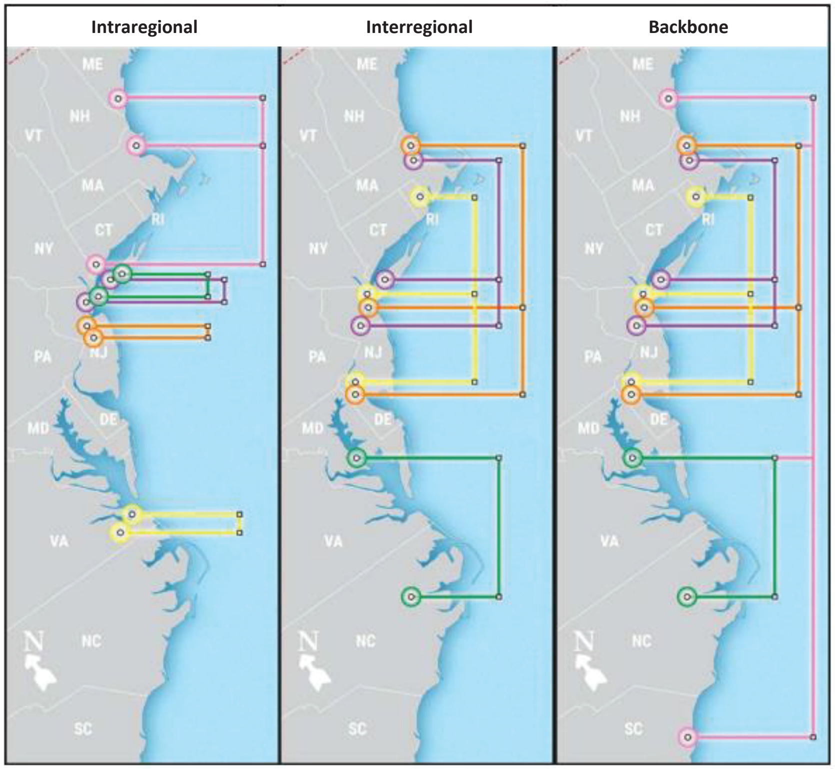
- Considered several transmission configurations to integrate **85 GW** of OSW: radial (reference case, directly from onshore to offshore), intraregional, interregional, inter-intra, and backbone
- **By 2050, benefits of interlinking offshore transmission outweigh costs by more than 2 to 1** across all configurations, with **interregional configurations offering the highest value-to-cost ratio**
  - Arise from reduced curtailment and generation costs, and increased reliability

Table ES-3. Annual Offshore Transmission Costs and Benefits of the Networked Topologies (Compared to Radial) in 2050

Topology	Annual Offshore Networking Costs ($ million)	Annual Gross Benefit ($ million)	Net Annual Value ($ million) [Benefits - Costs]	Benefit-to-Cost Ratio [Benefits/Costs]
Intraregional	260	590	330	2.3
Interregional	840	2,400	1,560	2.9
Inter-Intra	1,090	2,850	1,760	2.6
Backbone	1,470	3,940	2,470	2.7

Note: Costs in this table represent the additional annualized capital costs and operations and maintenance costs of the networked topologies compared to the radial topology. Benefits represent the 2050 annual production cost and resource adequacy value in the networked topologies compared to the radial topology.

Source: Atlantic Offshore Wind Transmission Study



3. DOE Atlantic Offshore Wind Transmission Study (2024) (cont'd)

Takeaway

Proactive, coordinated **interregional transmission planning is urgently needed** to integrate Atlantic OSW, and **networking offshore transmission generates that benefits significantly outweigh the costs**

- Interregional offshore transmission generates **significant resource adequacy value** by displacing generation investment
  - This contributes substantially to total value of offshore transmission
  - Accrues in winter-peaking conditions in colder, electrified regions like PJM, NYISO, and ISO-NE
- AOSWTS did not answer the question of <u>when</u> building offshore transmission is cost-effective (benefits were only evaluated for 2050)

Gap

Resource adequacy value must be appropriately captured within **benefit assessment methodologies**

Gap

HVDC technology standards will be required to enable a phased rollout of interregional offshore transmission

Gap

Standards to for design of meshed offshore facilities **("mesh-ready standards")** required to overcome barriers to offshore networking

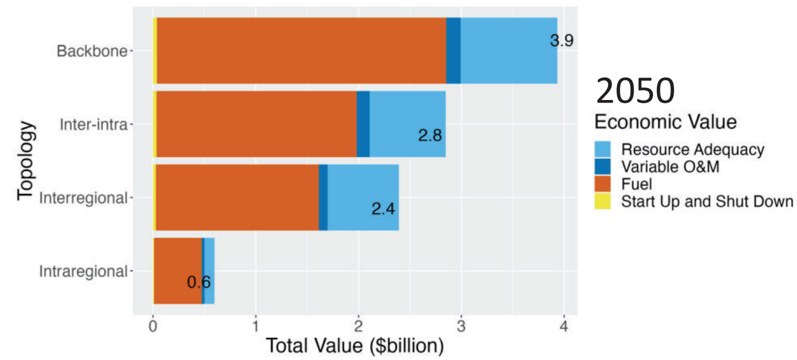


Table ES-1. Equivalent Firm Capacity Result

Topology	Quantity of Offshore Interlink Transmission Built (megawatts [MW])	Equivalent Firm Capacity (Potential Displaced Generation) (MW)
Intraregional	7,600	565–664
Interregional	14,000	4,062–4,726
Inter-Intra	21,600	4,453–5,000
Backbone	20,000	5,859–6,250
Intraregional	7,600	565–664

Source: Atlantic Offshore Wind Transmission Study

4. GE & NRDC: Benefits of Interregional Transmission Capacity (2022)

Takeaway

Expanding interregional transfer capability on Eastern Interconnect provides **significant resilience benefits** against major weather events, in addition to capacity and production cost savings

Resilience benefits

- **76 GW** of additional interregional transmission on Eastern Interconnect (~**1.3 GW** between ISO-NE and NYISO and **~5 GW** between NYISO and PJM) protects against simulated major weather events in **2035**, with **resilience benefits of $0.875–1 billion**
  - Summer heat wave: 27 GW (~0.7 GW ISO-NE to NYISO, ~5 GW NYISO to PJM) avoids loss of load equivalent to **$875 million**
  - Winter polar vortex: 65 GW (~1.3 GW ISO-NE to NYISO) avoids loss of load to ~2 million customers, equivalent to **$1 billion** of resilience benefits
- Assumes 28 GW of OSW by 2035 and 39 GW by 2040

Production cost and capacity savings

- Buildout would result in 20 GW of **capacity savings worth $2 billion/yr** and **ancillary service savings of $50 million/yr**
- Optimizing buildout to enable access to lower cost generation would build 54 GW of new interregional transmission (**~2 GW** ISO-NE–NYISO, **~3.5 GW** NYISO–PJM) and generate production cost savings of **$3 billion/yr in 2035** and **$4 billion/yr in 2040**

Altogether, 87 GW of additional interregional transmission (**~2 GW** ISO-NE–NYISO, **~5 GW** NYISO–PJM) would generate **$12 billion in net benefits**

Gap

Consistent benefit assessment frameworks are necessary for resilience benefits of interregional transmission to be correctly valued

Source: Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity

5. MA Decarbonization Pathways Roadmap (2020)

Takeaway

Significant interregional transmission expansion, particularly New England–New York and both New England and New York to Quebec, is **required to integrate OSW** and reach **net-zero** economy-wide by **2050** at lowest cost

Offshore wind is pivotal to MA's decarbonization roadmap

- At least 15 GW installed in MA across all scenarios where OSW isn't limited

Integration of OSW requires significant new transmission capacity

  - **1.7–4.5 GW** between New England and New York (excluding low OSW and low load growth cases)
  - **1.5–7 GW** between NY–PJM in aggressive decarb., high load scenarios
    - Caveat: PJM was not explicitly modeled as its own zone but a boundary condition for New York
  - **4.1–7.1 GW** and **3.8–6.8 GW** between QC–New England and QC–NY, respectively
    - Operated **bidirectionally** in all cases
  - **0–2.7 GW** between New England and New Brunswick.

- Enhancing interregional coordination on transmission planning was found to reduce overall system costs and result in greater interregional buildout
  - However, study did not evaluate processes required to achieve improved interregional coordination, but rather simply represented it through a lower transmission cost

Table 8. Cumulative transmission build 2020-2050 by pathway. The 17 modeled transmission paths are assumed to be symmetrical, meaning that 3.7 GW from New Hampshire to Massachusetts also implies operational capability of 3.7 GW from Massachusetts to New Hampshire.

Zone from	Zone to	no thermal	coordination regional	efficiency limited	primary 100% renewable	all options	breakthrough der	pipeline gas	constrained offshore wind
Connecticut	Rhode Island	0.5	0.9	1.3	1.6	0.3	0.3	0	0
Massachusetts	Connecticut	1.5	0.1	0	0.2	0	0	0	0
Massachusetts	Rhode Island	0.5	0	0	0	0	0	0	0
Rest of US	New York	7	6	3	1.5	0	0	0	0
New Brunswick	Maine	2.7	0.5	0.1	0.8	0	0	0	0.1
New Hampshire	Maine	3	1.8	1.2	1.5	1	0.9	0.9	0
New Hampshire	Massachusetts	3.7	2	1.6	0.2	0.6	1.3	0	0
New York	Connecticut	1.5	1	0.8	0.8	0.6	0.5	0.5	0.5
New York	Massachusetts	2.6	2.5	1.5	1.5	1	1.2	0	0
New York	Vermont	0.4	0.4	0	0	0	0	0	0
Quebec	Maine	2	1.2	1.1	0.9	0.6	0.6	0.6	0.9
Quebec	Massachusetts	4.3	4.8	3.7	3.3	2.7	2.8	3.1	3.9
Quebec	New Brunswick	0	0	0	0	0	0	0	0
Quebec	New York	6.8	6.8	6.8	4.7	4.4	4.2	5.6	3.8
Quebec	Vermont	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8
Vermont	Massachusetts	0	0	0	0	0	0	0	0
Vermont	New Hampshire	0	0	0	0	0	0	0	0
	Sum	37.3	28.7	21.9	17.8	12	12.6	11.5	10

Gap

Expanding transmission **between New England and New York is low-regrets**; indicates potential for **"low-hanging" interregional projects** that are cost effective but highly valuable

Source: Energy Pathways to Deep Decarbonization – A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study

6. LBNL: Empirical Estimates of Transmission Value (2022)

Takeaway

Expanding **New England–New York** and **New York–PJM** transfer capability could generate **$137–400 million per GW of transfer capability** and **$149–313 million per GW**, respectively, in energy trading value alone

Energy trading value / production cost savings:

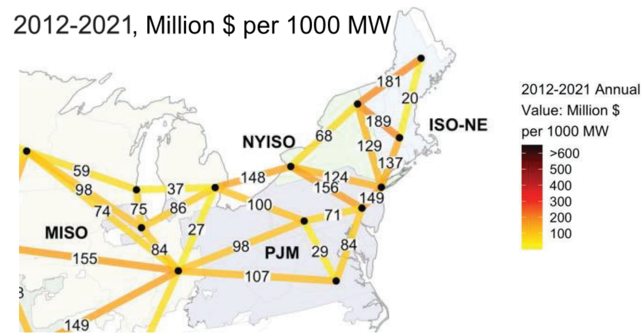
- Expanding interregional transmission capacity between ISO-NE–NYISO and NYISO–PJM would have generated **$137–189 million/yr per GW** and **$149–156 million/yr per GW** of trading value alone on average, respectively, between 2012 and 2021
- 2022 Update: ISO-NE–NYISO $211–400 million/yr, NYISO–PJM $219-313 million/yr
- Interregional transmission is more valuable than regional

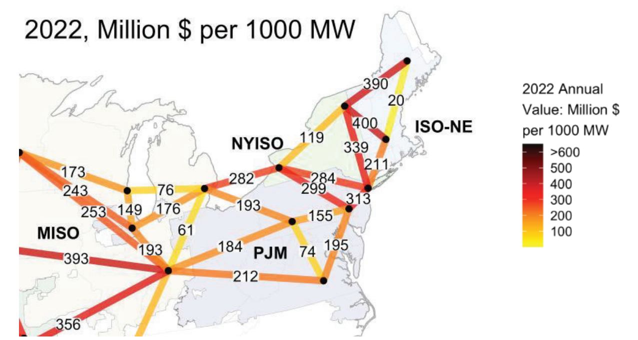
Resilience benefits:

- Not explicitly modelled, but **40–80%** of congestion value arises from **top 5%** of hours due to extreme conditions
- Winter storm Elliott (Dec 22–31 2022, ~2.5% of the year) made up **8–10%** and **12–13%** of the total 2022 value of expanding transmission between **ISO-NE–NYISO** and **NYISO–PJM**, respectively

Gap

Realizing congestion value of interregional transmission requires RTOs to implement effective **intertie optimization**





Source: Empirical Estimates of Transmission Value using Locational Marginal Prices
The Latest Market Data Show that the Potential Savings of New Electric Transmission was Higher Last Year than at Any Point in the Last Decade
Transmission Value in 2023

7. NREL Interregional Renewable Energy Zones Study (2024)

Takeaway

Interregional transmission corridor along Eastern Interconnect generates **significant energy cost savings** even without considering integration of Northeastern OSW resources

- Companion study to DOE's National Transmission Planning Study
- Extending Iowa–DC transmission corridor to New York City and Boston with **3 GW** of transfer capability increases annual energy cost savings from $740 to $886 million while only increasing transmission revenue requirement from $296 to $344 million
  - Incremental benefit: **$146 million/yr**; Incremental cost: $48 million/yr; Benefit-cost ratio of incremental expansion: **3.04**
  - Total benefit-cost ratio of transmission corridor from Iowa to Boston: 2.58
- Did not investigate cost savings of integrating OSW – would provide additional energy cost savings

Destinations
- Washington to New York to Boston
- Chicago/Milwaukee
- Indianapolis

	Washington, DC	New York	Boston
Energy cost savings[a] ($millions)	$740 *$994 with solar[d]*	$858	$886
Annual revenue requirement for transmission[b] ($millions)	$296 *$521 with solar[d]*	$323	$344
Benefit/cost ratio (energy savings only)	2.50 *1.91 with solar[d]*	2.66	2.58
Expected unserved energy (IREZ vs. local renewables)[c]	Worse *Better with solar[d]*	Similar	Similar
3 GW as % of 2022 peak (included load zones)	9% (PJM: PEPCO, BGE, Dominion)	9% (all NYISO)	12% (all ISO-NE)

Source: Interregional Renewable Energy Zones

Gap

Expanding transmission between PJM, New York and New England is low-regrets; potential for **"low-hanging" interregional projects** that are cost effective but highly valuable

8. MIT-CEEPR QC Hydro & Northeast Decarbonization (2020)

Takeaway

Expanding interregional transmission by **4 GW** between both **Quebec and New England** and **Quebec and New York** would **reduce net system costs in 2050** under a range of decarbonization scenarios

- **Quebec–New England:** increasing transfer capability by **4 GW** reduces power system costs (accounting for costs of transmission expansion) by **$913 million/yr** (13%) and **$2,387 million/yr** (24%) under 99% and 100% decarbonization scenarios, respectively
- **Quebec–New York:** increasing transfer capability by **4 GW** reduces power system costs by **$1,121 million/yr** (13%) and **$3,057 million/yr** (23%), respectively
- Value is generated by utilizing the transmission **bidirectionally** to balance Northeast renewables, avoiding firming costs
  - While the 4 GW increase was a model input (not reflective of max possible transmission value), this figure is in line with the low end of the ranges of transmission needs between Quebec and both New England and New York in the MA Decarbonization Pathways Roadmap, which reports 4.1–7.1 GW and 3.8–6.7 GW, respectively, by 2050
- Analysis was constrained to meet the OSW targets of each state
- Economic benefits remain robust under a range of sensitivities, including limited nuclear/carbon capture and sequestration as well as high load growth scenarios

Gap

Bidirectional operation of transmission to Quebec requires significant improvements in **intertie optimization**

Source: Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower

9. NERC Interregional Transfer Capability Study (ITCS) (2024)

Takeaway

Significant transmission expansion between **NY–PJM** and from **Quebec to New England and NY** is required in the **next 10 years** to maintain reliability. **Larger additions are likely justifiable when considering economic benefits.**

- Identifies "prudent" interregional transmission additions needed to maintain reliability
  - **Considers resource adequacy only and does not include assessment of economic or public policy benefits:** Transmission expansion results therefore represent only the lower bound of what would be valuable at each interface

New York–PJM transmission expansion is justifiable on a reliability basis alone

- **1.8 GW by 2033** to alleviate significant resource deficiencies in New York

Expansion to Quebec improves resource adequacy in both New England and NY

- **1.9 GW by 2033** between NY–QC (Champlain Hudson Power Express to provide 1.2 GW)
- **400 MW by 2033** between New England–QC (and 300 MW to Maritimes)
  - New England Clean Energy Connect likely to address a significant portion of this need

Prudent additions are based on 2033 resource mix and other study assumptions

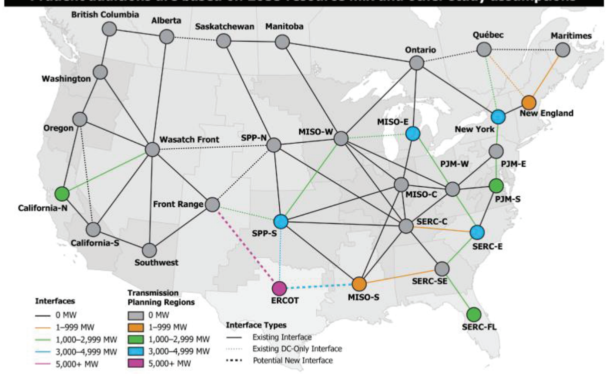


Figure ES.2: Prudent Additions to Transfer Capability

Table ES.1: Recommended Prudent Additions Detail

Transmission Planning Region	Weather Years (WY) / Events	Resource Deficiency Hours	Maximum Deficiency (MW)	Additional Transfer Capability (MW)	Interface Additions (MW)
New York	WY2023 Heat Wave and seven other events	52	3,729	3,700	PJM-E (1,800) Québec (1,900)
New England	WY2012 Heat Wave and two other events	5	984	700	Québec (400) Maritimes (300)

Gap

Consistent **benefit assessment frameworks covering economic, resiliency and public policy benefits**—not solely reliability—are essential to identify valuable transmission expansion opportunities and minimize risk of undersizing

Source: Interregional Transfer Capability Study (ITCS) - Recommendations for Prudent Additions to Transfer Capability (Part 2) and Recommendations to Meet and Maintain Transfer Capability (Part 3)

Appendix: The Need to Address Inefficiencies Across Market Seams

Five Sources of Inefficiencies Created by Market Seams

Seams between RTOs will generally be more efficient than seams between non-market regions that rely entirely on bilateral trades. Nevertheless, significant seams-related inefficiencies exist between RTO markets:

1. **Interregional transmission planning** is ineffective
2. **Generator interconnection** delays and cost uncertainty created by affected system impact studies (and effectiveness coordination through means such as the SPP-MISO JTIQ, reducing costs by 50%)
3. **Resource adequacy** value of interties (often not considered in RTO's resource adequacy evaluations) and barriers to capacity trades (often created by RTOs' restrictive capacity import requirements and incompatible resource accreditations)
4. **Loop flow management** inefficiencies through market-to-market coordinated flowgates (with shares of firm flow entitlements) under the existing JOAs
5. **Inefficient trading** across contract-path market seams and the need for intertie optimization
   - **This is the focus of these appendix slides**

Note

This content is in part based on:

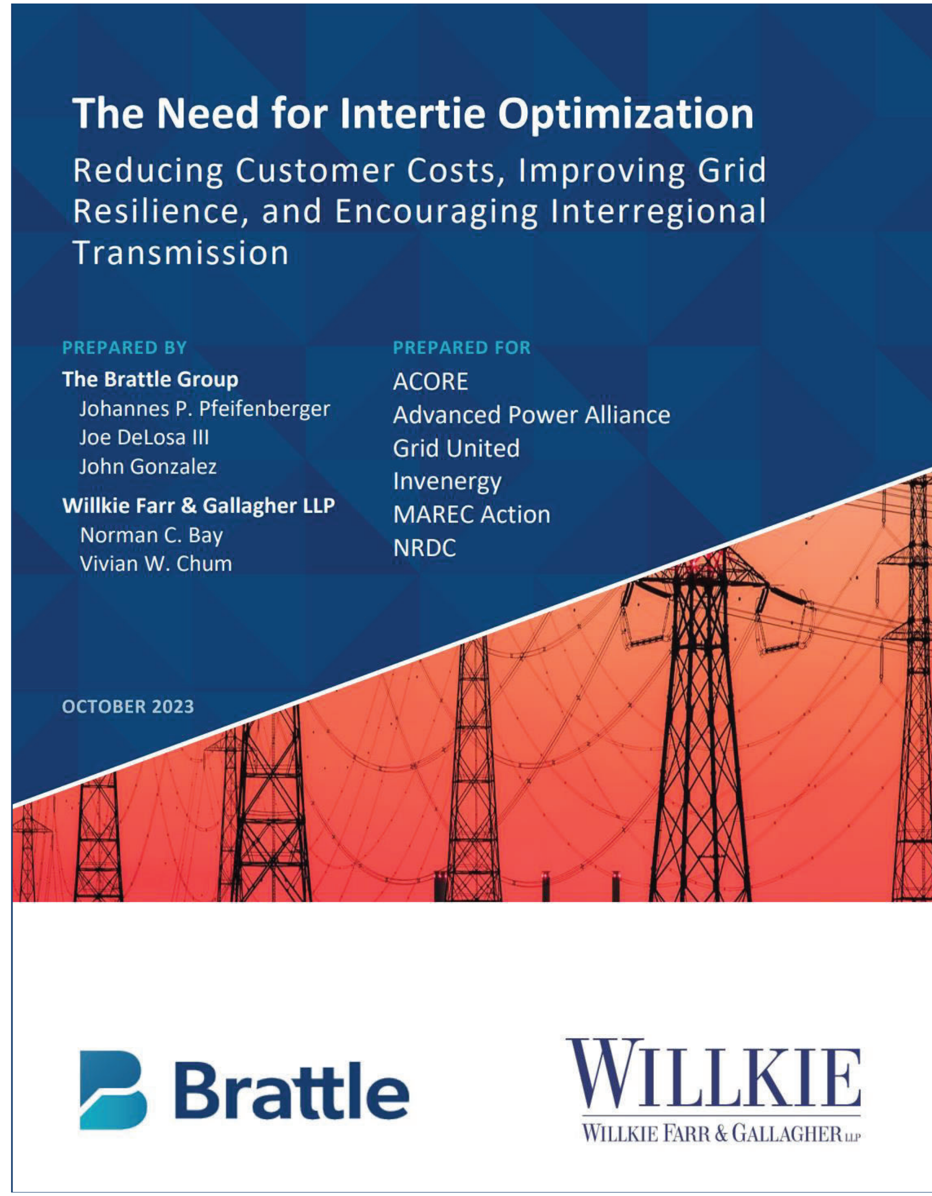
The Need for Intertie Optimization, prepared for ACORE, Advanced Power Alliance, Grid United, Invenergy, MAREC, and NRDC, October 2023

Intertie Optimization FAQs and Implementation Principles, February 2024

Intertie Optimization: Efficient Use of Interregional Transmission (Update), presented to OPSI, April 12, 2024

Market Benefits and Seams: Options and Implications, presented to CREPC-WIRAB, April 24, 2024.

Various State of Market, LBNL, and NREL reports
(as cited in the slides)



The Need for Intertie Optimization

Reducing Customer Costs, Improving Grid Resilience, and Encouraging Interregional Transmission

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NREL Report: Barriers and Opportunities to Realize the System Value of Interregional Transmission (June 2024)

NREL recommends reforms to "significantly enhance the value of interregional transmission and deliver additional within-region benefits":

Common Actions
- Develop a framework for resource adequacy sharing among regions
- Support joint studies to identify transfer needs during extreme events and develop operational procedures to mitigate issues
- Evaluate internal transmission system ability to accommodate large power transfers as the underlying generation mix changes

Nonmarket and Hybrid Actions
- Implement coordinated scheduling and operations platforms or consolidation
- Pursue joint congestion management programs and reevaluate qualified paths for congestion management
- Develop consistent methods to calculate available transfer capacity
- Update processes to prioritize system reliability in scheduling market and wheeling transactions

Market Actions
- Eliminate fees and improve price forecasting for coordinated transaction scheduling or move toward intertie optimization
- Update corridor flow limits, automate procedures, and align assumptions for congestion management programs
- Revise interface pricing methods and validate interregional transactions
- Integrate operational control of merchant HVDC lines with regional market operations

Transformative Actions
- Conduct long-range, nationwide interregional transmission planning
- Implement interconnection-wide intertie optimization
- Establish a national system operator and planner to coordinate national network planning, scheduling, and resource adequacy functions

- Recognize resource-adequacy and resilience value of interregional transmission
- Improved coordination and joint congestion management
- De-pancaking
- Improved intertie pricing
- **"Move toward intertie optimization"**
- Interregional planning
- Interconnection-wide optimization

NARUC Report: Collaborative Enhancements to Unlock Interregional Transmission (June 2024)

Recommends reforms improve planning, permitting, and operational utilization of interregional transmission, including intertie optimization:

	Solutions				Areas of State and Federal Engagement	
Planning	Coordinated Interregional Planning	Planning Methods Harmonization	Model and Data Harmonization		Involvement in Planning Encourage Interregional Collaboration	Issue Guidelines for Interreg. Planning Funding/Support, Potential Federal Planning Authority
Permitting	State Transmission Authorities	Host Community Benefits	Planning Need Determination Acceptance for Permitting	Multi-State Evidentiary Record	Communicate Tx Needs to Developers/ Planners Streamline Permitting	Funding/Training for State Staff Federal Backstop Authority
Operations	Reduce Transaction Charge Impacts	Reduce Advanced-Time Scheduling Requirements	Develop Optimized Interregional Scheduling Mechanism	Improve Preparation for Resiliency	Engage with System Operators to Encourage Improvements in Tx Utilization	Analytical Guidance Technical Forums to Improve Tx Utilization

Source: https://pubs.naruc.org/pub/BACDBB9D-02BF-0090-0109-B51B36B74439

NARUC
National Association of Regulatory Utility Commissioners

Promising Initiative: SPP's Inter-Market Optimization Framework

- SPP staff has been exploring an Inter-Market Optimization Framework to improve the efficiency of transfers between SPP and its neighbors, resulting in increased economic benefits for SPP's market participants
- On October 16, 2024, SPP's Strategic Planning Committee (SPC) endorsed that staff's work on this concept be prioritized within the "Optimized Seams" objectives of SPP's strategic planning roadmap
- SPP's proposed next steps:
  - Further evaluate potential value of adding this feature to the market design
  - Prioritize inter-market optimization within the Optimized Seams strategic opportunity
  - Develop policy proposals to address challenges identified

Source: SPP Documents & Filings – SPC Meeting Materials, Oct 8, 2024