U.S. DEPARTMENT OF
ENERGY

Office of
ENERGY EFFICIENCY &
RENEWABLE ENERGY

Atlantic Offshore Wind Transmission Study

MARCH 2024

Disclaimer

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Acknowledgments

Members of the Atlantic Offshore Wind Transmission Study technical review committee—which included experts representing various system operators; utilities; industry organizations; tribal nations; state and federal agencies; nongovernmental organizations; and others—helped guide the study assumptions, data, and methodologies to address relevant questions. Although the committee members helped review the report, it might not reflect the specific views or interpretations of specific members of the committee or their institutions. The authors would like to thank everyone who attended committee meetings or provided guidance during the study process, including those who provided specific comments on this report.

The authors would also like to thank Jian Fu, Cindy Bothwell, Jocelyn Brown-Saracino, Melissa Pauley, Hannah Taylor, Colette Fletcher-Hoppe, and Alissa Baker (U.S. Department of Energy [DOE]) for support and guidance throughout the project. Sheri Anstedt (National Renewable Energy Laboratory [NREL]) and Liz Hartman (DOE) helped with many iterations of edits. Jaquelin Cochran, Kendra Ryan, Venkatesh Venkataramanan, and Mark Ruth (NREL) all provided valuable comments and review. Trieu Mai, Randika Wijekoon, Walt Musial (NREL), Jim McCalley (Iowa State University), and Eric Hines (Tufts University) provided insights, analysis, and guidance.

This report was prepared by NREL and Pacific Northwest National Laboratory for the U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy Wind Energy Technologies Office.

List of Acronyms

AC	alternating current
AOSWTS	Atlantic Offshore Wind Transmission Study
ASSET	Automated System-wide Strength Evaluation Tool
BAU	business as usual
BOEM	Bureau of Ocean Energy Management
Btu	British thermal unit
DC	direct current
DCAT	Dynamic Contingency Analysis Tool
DCCB	direct-current circuit breaker
DOE	U.S. Department of Energy
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
GW	gigawatt
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
IBR	inverter-based resource
ISO	independent system operator
ISO-NE	Independent System Operator New England
kV	kilovolt
m	meter
MISO	Midcontinent Independent System Operator
MMC	modular multilevel converter
MMWG	Multiregional Modeling Working Group
MT-HVDC	multiterminal high-voltage direct current
MW	megawatt
NASCA	North American Submarine Cable Association
NERC	North American Electric Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
OCS	Outer Continental Shelf
OSWIT	Offshore Wind Integration Tool
PCM	production cost model/modeling
POI	points of interconnection
PNNL	Pacific Northwest National Laboratory
PRAS	Probabilistic Resource Adequacy Suite
p.u.	per unit
PV	photovoltaics
ReEDS	Regional Energy Deployment System
reV	Renewable Energy Potential
RTO	regional transmission operator
SAD	South Atlantic Division
SCR	short-circuit ratio
SERTP	Southeastern Regional Transmission Planning

SPP	Southwest Power Pool
TRC	technical review committee
TWh	terawatt-hour
USACE	U.S. Army Corps of Engineers
USCG	U.S. Coast Guard

Executive Summary

Offshore wind energy continues to grow in the U.S. Atlantic. In 2023, there were 41 gigawatts (GW) in East Coast project pipelines (Musial et al. 2023),[1] driven partly by state-level policies that incentivize offshore wind development. The Biden-Harris administration has set a national goal of deploying 30 GW of offshore wind energy by 2030 (The White House 2021), which would unlock a pathway to 110 GW or more by 2050. Ensuring adequate, equitable, affordable, and timely transmission access for offshore wind energy is critical to achieving state- and national-level goals.

The Atlantic Offshore Wind Transmission Study (AOSWTS) is part of the U.S. Department of Energy's (DOE) efforts to understand and facilitate the transmission of electricity from wind in the Atlantic Ocean. It was informed by the *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis* (Bothwell et al. 2021) and the convening workshops hosted in 2022–2023 by DOE and the U.S. Department of the Interior's Bureau of Ocean Energy Management. The study results help to inform *An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region* (Baker et al. 2024). DOE's Wind Energy Technologies Office funded AOSWTS.

The AOSWTS identifies and evaluates pathways to enable offshore wind energy deployment in the Atlantic Ocean through coordinated offshore transmission solutions in the near term (by 2030) and long term (by 2050). The study fills gaps in prior analyses by providing a multiregional planning perspective that evaluates offshore wind generation development with transmission planning. It incorporates environmental, ocean co-use, and other siting considerations into defining potential offshore transmission routes. The study also compares different multiregional offshore transmission topologies and their associated costs (using potential cable routes) and benefits (in terms of production cost[2] savings and enhanced resource adequacy).[3] In addition, the AOSWTS analyzes reliability impacts from a multiregional perspective.

The study provides guidance for policymakers and transmission stakeholders on possible outcomes resulting from a proactive, coordinated, and interregional approach to transmission planning for offshore wind energy development in the Atlantic. While this study presents possibilities, additional work following system operator methods and procedures can help build on this analysis.

[1] https://www.energy.gov/sites/default/files/2023-08/offshore-wind-market-report-2023-edition-data.xlsx, data collected by May 31, 2023

[2] Production costs are the operational costs of producing electricity, including fuel, operations and maintenance, and startup costs.

[3] Resource adequacy is the ability of a power system to generate electricity to meet demand with sufficiently low risk of needing emergency measures. Resource adequacy is one part of reliability.

Study Methods

With input from a technical review committee, the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory designed the AOSWTS to address important questions about transmission infrastructure to advance offshore wind energy development and the impact on regional and interregional electricity delivery costs. The study includes:

- Analysis of offshore substation and cable costs for five different offshore transmission topologies. These topologies comprise different layouts of cables that interlink between offshore wind platforms to form an offshore network (see Figure ES-1). The reference configuration is the radial topology, in which there are no interlinking cables, and each offshore platform connects directly to an onshore location.
- Development and use of a tool and datasets that incorporate 26 environmental siting layers to determine and optimize potential offshore cable routes considering economics and ocean co-uses.
- Evaluation of the production cost benefits using more than a dozen sensitivities on a 2050 low-carbon grid with 85 GW of offshore wind capacity from Maine through South Carolina.
- Grid reliability modeling, including resource adequacy, power flow, grid strength, and contingency analysis.
- Identification of a potential transmission expansion sequence that achieves benefits, considers near-term plans for deployment, and optimizes long-term transmission planning consistent with technology trends for offshore transmission.

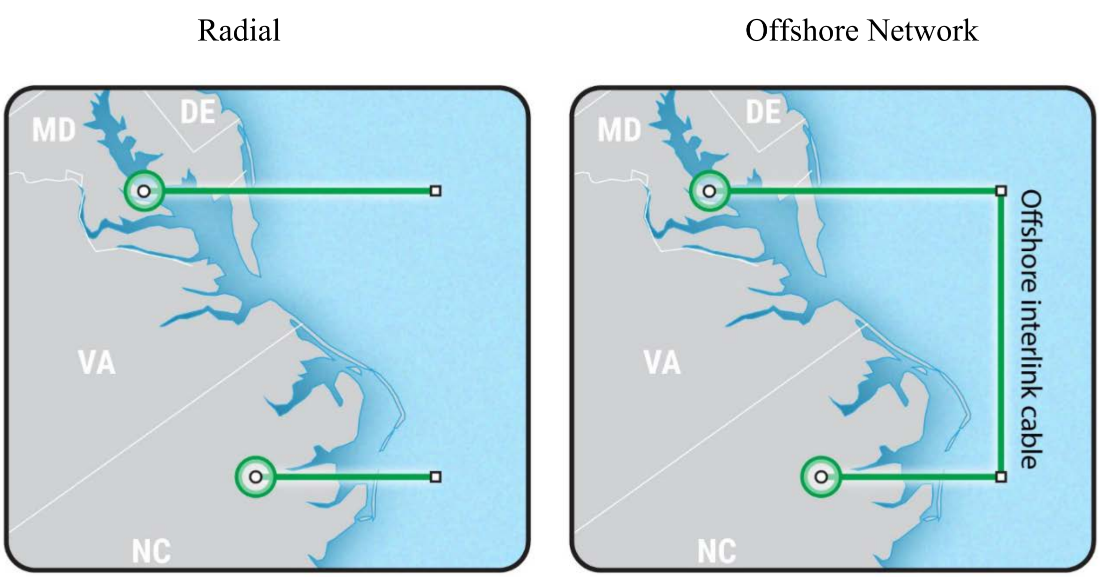

Figure ES-1. Diagram of radial (left) vs. networked (right) offshore transmission. ***Figure by NREL***

The analysis for this study focuses on the offshore space between Maine and South Carolina and the onshore grid in those states (plus Vermont and Pennsylvania due to proximity). The entire Eastern Interconnection grid is considered in the capacity expansion, resource adequacy, production cost, and reliability modeling.

Key Findings

Offshore wind energy development provides a unique opportunity to add transmission capacity offshore that provides value to the electric grid. Key findings of the study include:

- Offshore wind energy is projected to be a key part of achieving a low-carbon future for Atlantic states.
- Offshore transmission can be planned while considering ocean co-uses and environmental constraints.
- Benefits of networking offshore transmission come from reduced curtailment, reduced usage of higher-cost generators, and contributions to reliability.
- Offshore transmission networks contribute to grid reliability by enabling resource adequacy and helping manage the unexpected loss of grid components (contingencies).
- Benefits of offshore transmission networking outweigh the costs, often by a ratio of 2 to 1 or more. Offshore networks with interregional interlinks provide the highest value.
- Building offshore transmission in phases can help reduce development risk, but early implementation of high-voltage direct current (HVDC) technology standards is essential for future interoperability.

Offshore wind energy is projected to be a key part of achieving a low-carbon future for Atlantic states.

The electricity sector uses capacity expansion models to simulate and analyze the future expansion of generation and transmission capacity to meet expected loads. NREL's Regional Energy Deployment System capacity expansion model develops business-as-usual (BAU) and low-carbon (95% carbon-dioxide reduction from 2005 levels) generation capacity scenarios through 2050. The BAU scenario expands land-based wind energy, solar photovoltaics, and energy storage. The low-carbon scenario constructs 85 GW of offshore wind in the Atlantic, along with significant capacity expansion of land-based wind, solar photovoltaics, energy storage, hydrogen combustion turbines, and natural gas with carbon capture and sequestration in 2050. Electricity demand is significantly higher in the low-carbon scenario because of electrification of end uses like space heating to decarbonize these applications. This scenario is used to compare the cost, benefits, and reliability impacts of the various transmission topologies with significant long-term offshore wind energy development.

All 2050 topology analyses leverage the low-carbon scenario and include approximately 27 GW of offshore wind injection into the service area of the Independent System Operator of New England (ISO-NE) from Maine to Connecticut, 19 GW into the New York Independent System Operator (NYISO), 26 GW into the PJM Interconnection (PJM) area from New Jersey to Virginia and North Carolina (PJM-Atlantic), and 13 GW into the SERC Reliability Corporation (SERC) that serves North and South Carolina (SERC-Carolinas). Interlink cables that connect platforms between these regions are considered interregional.

Figure ES-2 shows the fractions of generation from energy sources in different regions in 2050, resulting from the capacity expansion modeling. Capacity expansion modeling results in 2050 show a transition to different mixes of low-carbon generation resources across Atlantic regions. The share of generation from offshore wind increases at a higher latitude: the northern three regions have more than 20% of electricity generation from offshore wind, and ISO-NE's offshore wind generation share is the largest with more than 40%.

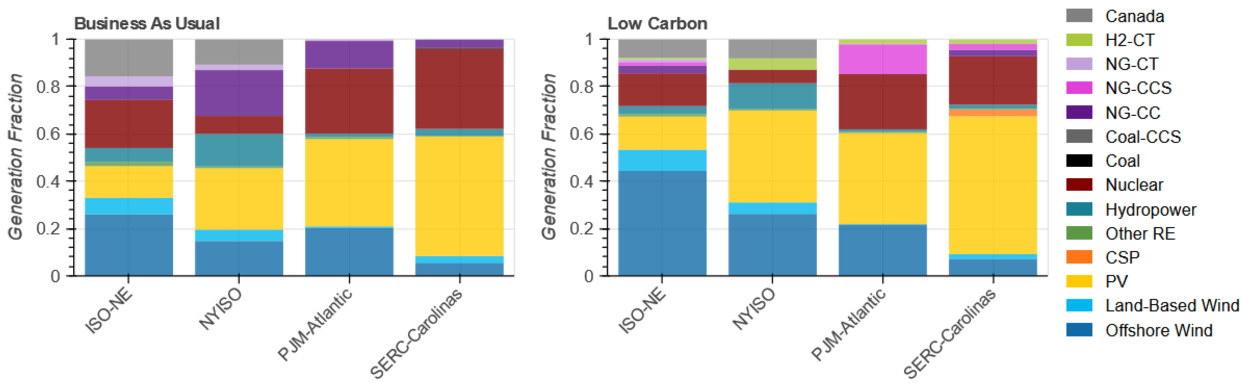

Figure ES-2. 2050 electricity generation fractions from capacity expansion modeling. ***Figure by NREL***

Note: H2-CT = hydrogen combustion turbine; NG-CT = natural-gas combustion turbine; NG-CCS = natural-gas combined cycle with carbon capture and sequestration NG-CC = natural-gas combined cycle; Coal-CCS = coal with carbon capture and sequestration; Other RE = other renewable energy, including biopower and geothermal; CSP = concentrating solar power; PV = photovoltaics. PJM-Atlantic includes the states of PJM that touch the Atlantic Ocean, SERC-Carolinas includes most of North and South Carolina. The electricity demand is significantly larger in the low-carbon scenario due to electrification.

Offshore transmission can be planned while considering ocean co-uses and environmental constraints.

The project team developed the AOSWTS' offshore transmission, including export cables and interlinks, by considering routes' potential to reduce environmental impacts and promote ocean co-uses (other uses of the ocean, such as shipping, fishing, military operations, and so on). The team identified hypothetical cable routes based on 26 data layers, including shipping, military, conservation, sand borrow and placement (for erosion management), and other considerations.

While this was not a comprehensive siting study, the analysis identifies potentially feasible corridors within the co-use and environmental constraints.

The team developed cable routes by balancing between maximizing the quality of the wind resource and minimizing the length of the potential export cable route to suitable points of interconnection (POIs) within the previously mentioned co-use and environmental constraints. These routes and POIs are not intended to be a prescription or suggestion for precise locations, but provide a useful suite of POIs for further analysis.

Offshore wind energy development provides a unique opportunity to add transmission capacity offshore to provide value to the grid.

Because the grid in the Atlantic regions is heavily congested in a high-demand, high-renewable 2050 future, offshore transmission infrastructure can be leveraged by interlinking platforms to reduce overall system costs. In modeled estimates using the radial topology in 2050, price differences between suitable POIs for offshore wind averaged over $100/megawatt-hour. This price difference is higher than the average wholesale electricity prices in recent years in some Atlantic market regions. High price differences indicate that offshore transmission with interlinking platforms can consistently flow power from lower- to higher-price regions to benefit electricity consumers by reducing the costs of generating electricity.

In addition to the foundational radial topology, the AOSWTS team evaluated four networked topologies: intraregional, interregional, inter-intra, and backbone, as described here. A simplified representation of three topologies is shown in Figure ES-3, and additional images of these topologies can be found in Section 4.

- The radial topology comprises connections from offshore substations to the onshore grid, with no interlinking between offshore platforms (see Figure ES-1). This topology (and its associated export cables) is the basis for all other topologies and is the status quo today for offshore wind generation development in the U.S. Atlantic.
- The intraregional topology focuses on connections within regions that could complement (and come before) interregional solutions.
- The interregional topology is specifically designed to leverage opportunities to connect diverse regions by interlinking offshore platforms.
- The inter-intra topology combines the interlinks in the interregional and intraregional topologies.
- The backbone topology starts with the interregional build and includes an additional cable that spans the studied portion of the Atlantic Seaboard, from Maine through South Carolina.

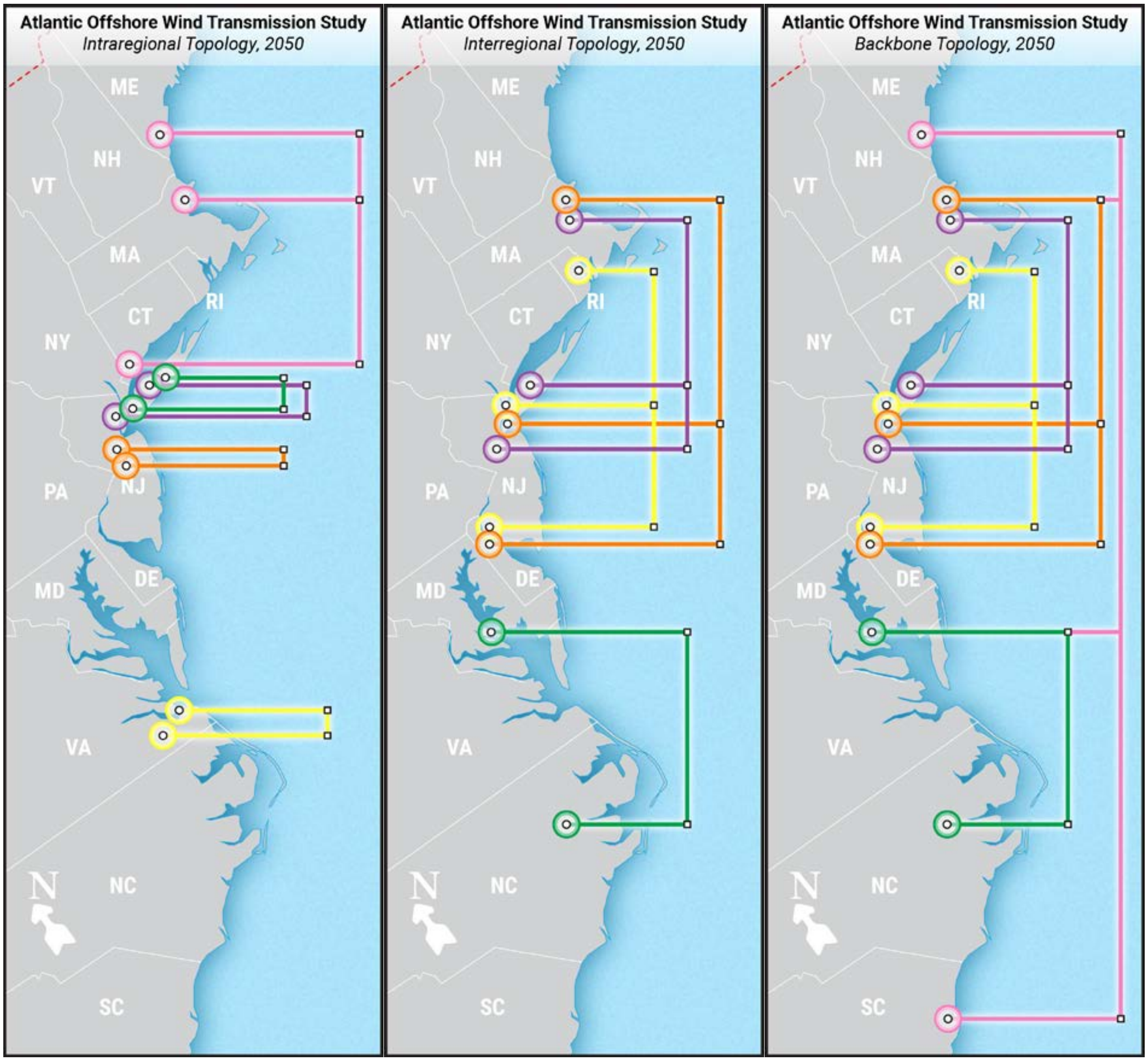

Figure ES-3. Intraregional, interregional, and backbone topologies. ***Illustration by Billy Roberts, NREL***

Note: The inter-intra topology combines the interlinks in the interregional and intraregional topologies, and thus is not shown here.

The interregional transmission expansion, with seven new cables interlinking 11 platforms and providing 14 GW of interregional capacity, is shown in Figure ES-4. Interconnecting offshore wind substations creates networked offshore transmission systems that can be used by multiple offshore and onshore generation resources. The study did not consider any networked topologies that "overbuild" the export cables to enable additional power flows even when the offshore wind is generating at full capacity. All interregional interlinks are 525-kilovolt HVDC technology, whereas the intraregional interlinks are assumed to be 525-kilovolt HVDC in New England, and high-voltage alternating current elsewhere.

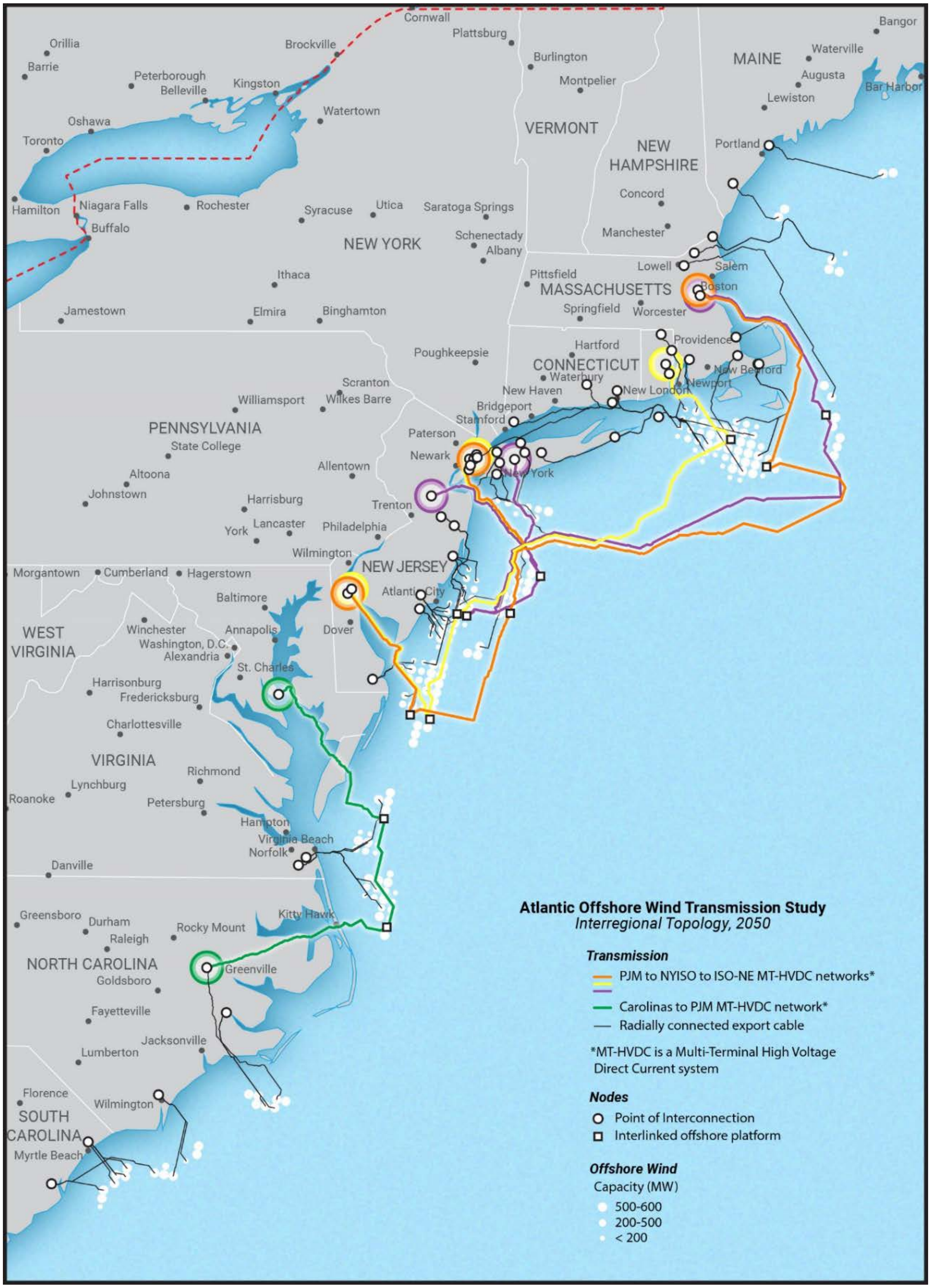

Figure ES-4. The 2050 interregional topology with modeled cable routes. ***Illustration by Billy Roberts, NREL***

Benefits of networking offshore transmission come from reduced curtailment, reduced usage of higher-cost generators, and contributions to reliability.

Figure ES-5 shows the total economic value in 2050 for each interlinked transmission topology compared to the radial topology, and the breakdown of the value by category. Most of the benefits are production cost savings (which include fuel, operations and maintenance [O&M], and startup and shutdown costs).

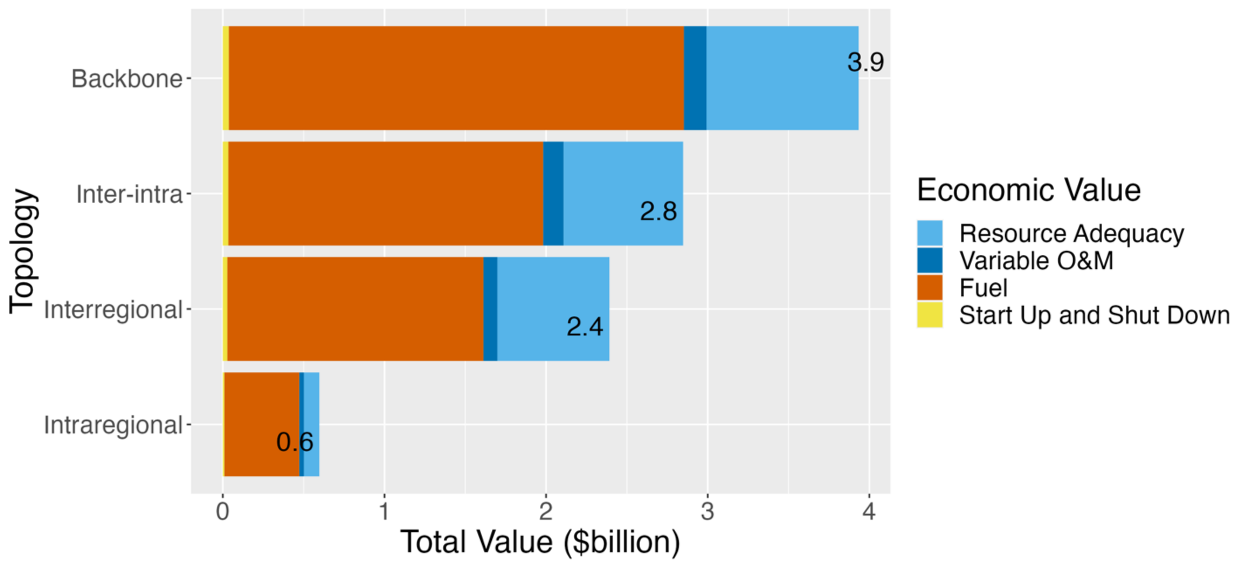

Figure ES-5. Grid benefits from interlinked offshore transmission in 2050. ***Figure by NREL***

In addition to economic benefits, AOSWTS modeling showed that flows on all interlinks go both directions every season, reducing overall generation costs and curtailment of offshore wind. The average utilization rate on each line is 50%–60% of the available capacity. Offshore wind curtailment is 1–2 percentage points lower when offshore wind generation is interconnected with interregional interlinks compared with the radial topology.

Offshore transmission networks contribute to grid reliability by enabling resource adequacy and helping manage the unexpected loss of grid components (contingencies).

Resource Adequacy

Improved connection between geographically diverse generation resources using offshore transmission can displace generation investment. Resource adequacy value in 2050 accrues during winter-peaking conditions in colder, electrified Atlantic regions like PJM, NYISO, and ISO-NE when additional transmission capacity can be used to flow power from adjacent regions.

Results on the quantity of displaced equivalent firm capacity[4] built in those regions from offshore interlinks are in Table ES-1.

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

Other Aspects of Reliability

The team conducted a high-level assessment of the potential impacts of offshore wind energy and related offshore transmission infrastructure on system reliability. This effort does not represent a comprehensive system reliability analysis for 30 GW of offshore wind in 2030 and 85 GW of offshore wind in 2050, but rather indicates some of the challenges and opportunities for offshore wind transmission. Conclusions from the reliability analysis include the following:

- Grid strength analysis of 30 GW of offshore wind capacity in 2030 shows that 14 of 24 considered POIs experience weak grid strength conditions. This does not mean the evaluated POIs are infeasible but indicates further studies (and possibly additional investment) are needed to ensure stable and reliable operation of the offshore wind power plant (or any inverter-based resource) under weak grid conditions.
- Dynamic and AC contingency analyses for 30 GW of offshore wind in 2030 do not indicate any widespread issues with maintaining reliability.
- A case study contingency analysis of the interregional topology in 2050 indicates potential benefits of interlinked offshore network topologies to system reliability by enabling mutual support between the onshore and offshore networks during contingency events.
- Developing 85 GW of Atlantic offshore wind capacity may expose the power system to additional resilience risks resulting from extreme weather events occurring in the ocean and at the landing point. To enable improved planning for resilient offshore wind energy

[4] Equivalent firm capacity results can be interpreted as the quantity of perfect (100% available) generation capacity built (e.g., in megawatts) that can be displaced by resource (e.g., offshore transmission) investment while achieving the same level of systemwide resource adequacy.

integration, the team developed datasets and methods to translate extreme weather events into simulations for both steady-state and dynamic analyses.

Benefits of offshore transmission networking outweigh the costs, often by a ratio of 2 to 1 or more. Offshore networks with interregional interlinks provide the highest value.

Table ES-2 shows the capital costs of offshore transmission infrastructure (including platform costs, circuit breakers, export cables, and interlink cables) in each topology. The total cost for each networked topology also includes $96.3 billion in capital costs for the radial topology that connects the offshore wind generation to the onshore grid. The onshore grid was assumed to be identical when comparing the topologies.

Table ES-2. Offshore Transmission Capital Costs

Topology	Total Cost	Additional Costs Vs. Radial
Radial	$96.3 billion	Not applicable
Intraregional	$99.9 billion	$3.6 billion
Interregional	$107.7 billion	$11.4 billion
Inter-Intra	$111.2 billion	$14.9 billion
Backbone	$116.3 billion	$20.0 billion

Note: These numbers are total capital costs, not annualized costs. All values are in 2021 U.S. dollars.

Table ES-3 presents the annual costs, benefits, net value, and benefit-to-cost ratios for each interlinked topology (compared to the radial topology) in 2050. All networked topologies studied have more benefits than costs of adding transmission interlinks when compared to the radial topology. Offshore networks with interregional interlinks provide the most value as quantified in benefit-to-cost ratios and total net value. Investment in offshore wind energy development—including HVDC converter stations, export cables, platforms, and grid interconnection costs—can be leveraged by interlinking between the platforms. The benefits of offshore networking persist when mixing interregional and intraregional interlinks, along with some radial connections.

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.

The cost-and-benefit analysis shows the net value for the portfolio of offshore transmission investments identified in the AOSWTS rather than evaluating individual projects or transmission corridors. The economic benefits of interlinked offshore transmission are based on avoided system costs for each transmission scenario compared to the radial topology. These savings include avoided production costs and avoided costs to meet resource adequacy requirements.

The team conducted additional analysis to test various assumptions, including cable capacity, fuel prices, onshore transmission expansion, and the way the offshore network is operated. Benefit-to-cost ratios were positive for the interregional offshore network topology in all variations. Adding high-voltage east-west land-based transmission in the mid-Atlantic region (PJM) provides the largest increase in value. Limiting offshore cable maximum flows to 1,200 megawatts (consistent with current system limitations) offers the largest decrease in value. This additional analysis helps provide confidence in the study results. However, uncertainty in the evolution of the grid means that further study is needed by transmission planners to understand evolving conditions and to build on the data, tools, and methodologies developed in this study. Sections 5 and 6 describe these scenarios in more detail.

Building the offshore transmission in phases can help reduce development risk, but early implementation of HVDC technology standards is essential for future interoperability.

The AOSWTS assumes a planning trajectory that considers interoperable, multiterminal HVDC technology available for offshore transmission starting in the mid-2030s. Offshore wind energy development planned for operation by 2030 does not include multiterminal HVDC readiness. These assumptions are consistent with current offshore wind project procurements and their timelines (Pfeifenberger et al. 2023b). The studied interregional and backbone topologies require multiterminal HVDC technology to be available and implemented on offshore platforms (which would need to be designed for potential future interlinking) by 2035.

The study team considered a possible phased approach for offshore transmission development. This order of offshore transmission, shown in Figure ES-6, is based on interlinking projects as they are developed and available to interlink, with more favorable projects developed earlier, considering wind resource, cable distance, and state targets. This phasing of offshore transmission development can use infrastructure development capabilities efficiently but requires a consistent HVDC technology standard to enable multiterminal, multivendor interoperability. Defining a common interoperability standard before HVDC is deployed in topologies like the interregional scenario will be critical to meeting the development timelines and achieving the benefits quantified in this study.

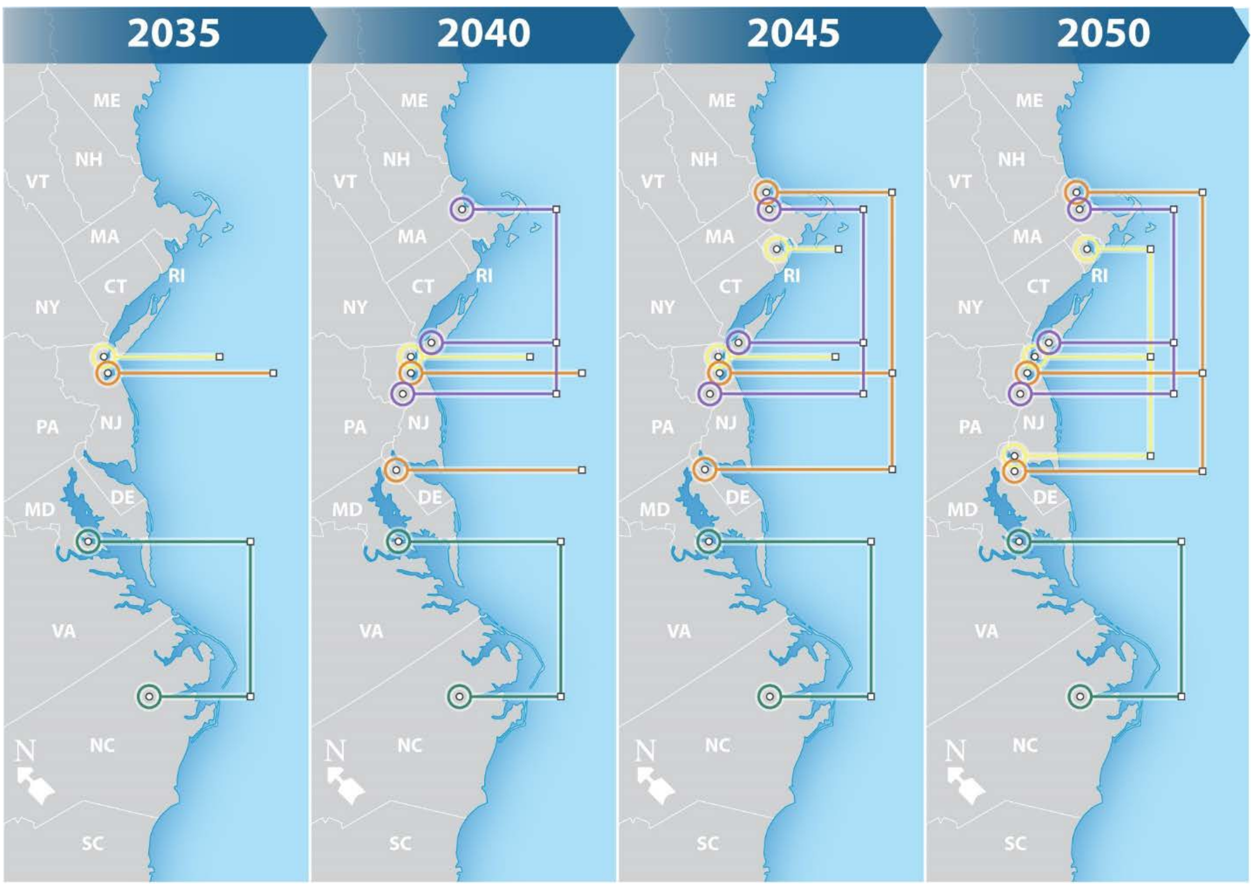

Figure ES-6. Potential build timeline of the interregional topology. ***Illustration by Billy Roberts and Al Hicks, NREL***

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1 Introduction

1.1 Overview

Offshore wind energy continues to grow in the U.S. Atlantic. In 2023, there were 41 gigawatts (GW) in East Coast project pipelines (Musial et al. 2023), driven partly by state-level policies that incentivize offshore wind development. The Biden-Harris administration has set a national goal of deploying 30 GW of offshore wind energy by 2030 (The White House 2021), which would unlock a pathway to 110 GW or more by 2050. Ensuring adequate, equitable, affordable, and timely transmission access for offshore wind energy is critical to achieving state- and national-level goals.

The Atlantic Offshore Wind Transmission Study (AOSWTS) was launched by the U.S. Department of Energy (DOE) Wind Energy Technologies Office to identify and evaluate multiple pathways to achieving these offshore wind deployment goals through various transmission solutions along the U.S. Atlantic Coast in the near term (by 2030) and long term (by 2050). These pathways include various combinations of electricity supply and demand while supporting grid reliability and resilience and environmental and siting constraints associated with ocean co-use. The study fills identified gaps by providing a multiregional planning perspective; coordinating offshore wind generation with transmission planning; connecting various planning aspects in a comprehensive way, such as landing points, transmission cable routing, and points of interconnection (POIs); and evaluating grid reliability and resilience from a multiregional perspective.

The study also compares different offshore transmission technologies and topologies and quantifies the benefits and costs of each. The study's findings are valuable for decision makers, stakeholders, and the overall offshore wind energy industry, as well as the research community, as they offer feasible solutions, data, and models that can inform transmission planning processes and help meet the ambitious goals for offshore wind energy.

1.2 Broader Context

In a parallel effort to this study, DOE and the Bureau of Ocean Energy Management (BOEM), in consultation with Federal Energy Regulatory Commission (FERC), hosted a series of nine Atlantic offshore wind transmission convening workshops and a Tribal nation dialogue from April 2022 through March 2023 (Gange and Baker 2023). Decisionmakers invited to the workshops included Tribal nations, federal agencies, state agencies, regional transmission operators (RTOs)/independent system operators (ISOs), electric reliability organizations, consumer advocates, and existing BOEM leaseholders. There was also an opportunity for public input. The purpose of these workshops was to identify a planned approach for Atlantic offshore wind transmission and interconnection to achieve state goals and the Biden administration's goal of 30 GW of offshore wind capacity by 2030 and to facilitate offshore wind energy development beyond the 2030 goal. Workshops were organized around three tracks: technical planning and development; economics and policy; and siting and permitting. The contents of the workshops were partially informed by the preliminary findings of the AOSWTS. At the end of the workshop series, DOE released *An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region* (Baker et al. 2024).

Prior to commencing the AOSWTS, DOE conducted the *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis* (Bothwell et al. 2021). This report summarized the recent and ongoing offshore wind transmission analyses along the U.S. Atlantic Coast, with content from publicly available transmission studies from states, the offshore wind energy industry, RTOs and ISOs, and other grid stakeholders. Additionally, it contains a gaps analysis examining what is needed to achieve offshore wind energy development goals.

The following recent state developments have occurred since the *Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis* (Bothwell et al. 2021):

- In 2022, the New York State Public Service Commission mandated that future offshore wind energy project proposals have a “meshed ready” interconnection to allow for array cables between adjacent offshore wind plants and possess the performance, interface, controls, and functional and physical requirements for transmitting alternating current (AC) power to other meshed-ready plants (New York State 2022; NYSERDA 2022).
- The New Jersey Board of Public Utilities and PJM are collaborating to competitively solicit (in two rounds, using PJM’s State Agreement Approach) coordinated offshore wind transmission proposals to help support 11,000 megawatts (MW) of offshore wind generation in New Jersey by 2040 (New Jersey Board of Public Utilities 2023). New Jersey’s third offshore wind energy solicitation includes “Attachment 11: Offshore Transmission Network Preparation Requirements” (New Jersey Board of Public Utilities 2022), which mandates that all project proposals be offshore-transmission-network-ready, which is based on the ability to leverage technology that is not available now but will be in the future.
- Independent System Operator-New England’s (ISO-NE’s) *2050 Transmission Study* outlines potential costs and solutions to support reliability (ISO-NE 2023b), including a roadmap for incorporating offshore wind energy into the New England grid while maintaining reliability, assessing costs, and addressing environmental and regulatory aspects of this transition.
- The PJM *Offshore Wind Transmission Study: Phase 1 Results* is a comprehensive analysis of offshore wind energy considering state renewable portfolio standard targets to meet renewable energy goals. It focuses on grid reliability and determining the needed onshore grid reinforcements to deliver 14,268 MW of offshore wind energy in PJM’s region (PJM 2021).

- The *North Carolina Offshore Wind Cost-Benefit Analysis* (Southeastern Wind Coalition 2022; North Carolina Department of Environmental Quality n.d.) evaluates proposals and projects in different stages of development along the North Carolina coast to meet the state's goal of developing 2.8 GW of offshore wind energy by 2030 and 8.0 GW by 2040.

In addition, ISO-NE, New York Independent System Operator (NYISO), and PJM continue to evaluate different offshore wind scenarios as part of their ongoing planning studies.

There are numerous studies and projects involving offshore wind energy and transmission worldwide, and therefore too many to list here. However, in this study, the authors strived to include the most recent data and expert knowledge base from the global offshore wind community.

1.3 Technical Review Committee

A technical review committee (TRC) was created comprising technical experts from the following:

- BOEM
- National Oceanic and Atmospheric Administration (NOAA)
- FERC
- U.S. Army Corp of Engineers (USACE)
- U.S. Coast Guard (USCG)
- U.S. Department of Defense
- Federal Communications Commission (FCC)
- U.S. Fish and Wildlife Service
- Tribal nations
- State agencies
- Atlantic Coast ISOs and RTOs (PJM, NYISO, ISO-NE)
- Utilities
- Environmental nongovernmental organizations
- Developers of transmission and offshore wind plants
- Offshore wind and power system consultancies
- Universities
- Fisheries management and ocean councils

- Original equipment manufacturers
- Electric reliability organizations
- Trade organizations.

TRC members provided feedback and input throughout the study on the modeling framework; models; data; scenarios; environmental and siting sensitivities for potential cable routing; POIs; transmission topologies; and transmission technologies (e.g., performance and expected date of commercial availability and projected costs). Interim results were reported to the TRC and reviewed on an ongoing basis.

TRC members provided valuable information on the details of high-voltage alternating current (HVAC) and high-voltage direct current (HVDC) transmission technology. The members also gave important feedback on transmission planning, AC power flow analysis (including contingency analysis and grid strength), and environmental and siting issues. A total of 12 TRC meetings (and many smaller meetings with subsets of the TRC) with 210 participants were held between December 2021 and November 2023.

1.4 Study Scope and Objectives

With input from the TRC, the National Renewable Energy Laboratory (NREL) and Pacific Northwest National Laboratory (PNNL) designed the AOSWTS to address important questions about transmission infrastructure to advance offshore wind energy development and the impact on regional and interregional energy delivery costs. The study includes:

- Analysis of offshore substation and cable costs for five different offshore transmission topologies. These topologies comprise different layouts of cables that interlink between offshore wind platforms to form an offshore network (see Figure 1). The configuration we use as a reference is the radial topology, in which there are no interlinking cables, and each offshore platform connects directly to an onshore location.
- Development and use of a tool and datasets that incorporate 26 siting layers to determine and optimize offshore cable routes considering economics and ocean co-uses.
- Evaluation of the production cost benefits using more than a dozen sensitivities on a 2050 low-carbon grid with 85 GW of offshore wind capacity from Maine through South Carolina.
- Grid reliability modeling, including resource adequacy, power flow, grid strength, and contingency analysis.
- Identification of a potential transmission expansion sequence that achieves benefits, considers near-term plans for deployment, and optimizes long-term transmission planning consistent with technology trends for offshore transmission.

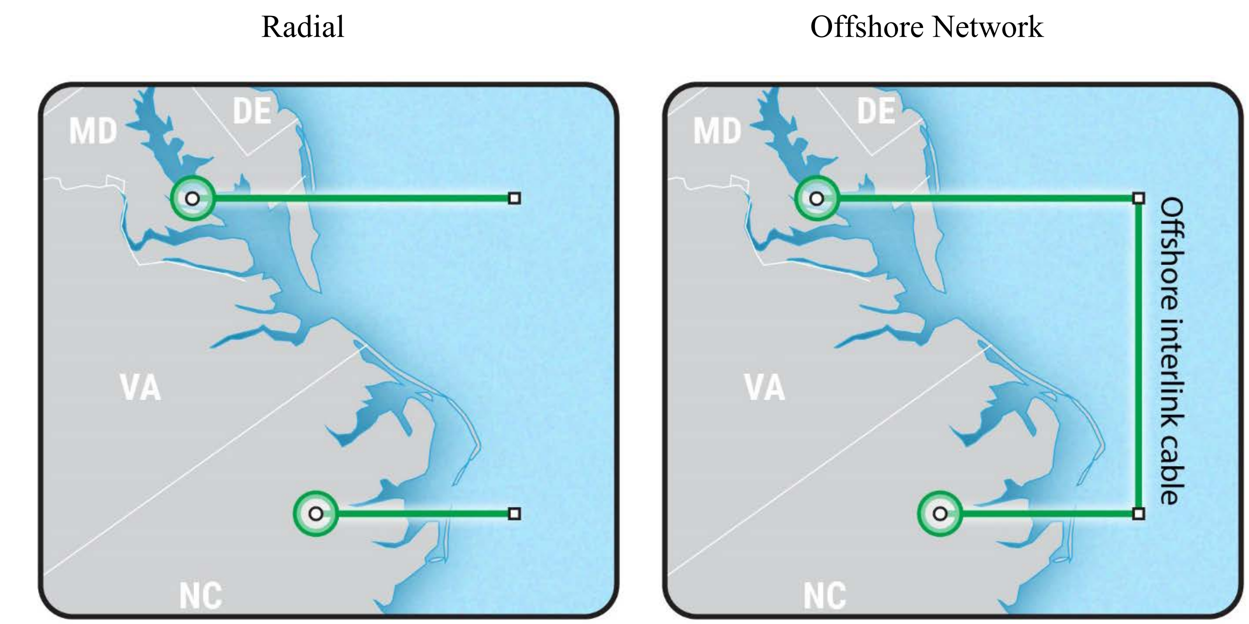

Figure 1. Diagram of radial (left) vs. networked (right) offshore transmission. ***Illustration by NREL***

The study evaluates multiple pathways for deployment and coordination of offshore wind energy and transmission across the Atlantic Coast. The AOSWTS is designed to:

- Identify scenarios and pathways to deploying offshore wind energy with various transmission topologies (such as radial lines, backbones, or a meshed network) and the build-out of the transmission in U.S. Atlantic waters from 2030 through 2050.
- Analyze impacts, such as economic, wind curtailment, and reliability, of multiple offshore wind energy and transmission scenarios.
- Characterize and compare transmission technologies for the different scenarios, as well as cost and benefit trade-offs for HVAC and HVDC technologies.
- Evaluate operational, environmental, reliability, and resilience considerations of various transmission topologies.
- Collect data and develop models and tools that are readily usable by industry for conducting analyses and future studies.

The AOSWTS is not at the same level of detail as an interconnection study that would be conducted by an ISO/RTO as part of their detailed transmission planning. It is also not a detailed siting or routing study. Instead, it provides a valuation of illustrative, interregional offshore networked topologies, but not precise transmission build prescriptions. Figure 2 summarizes some of the key elements of the study while delineating what it is and what it is not.

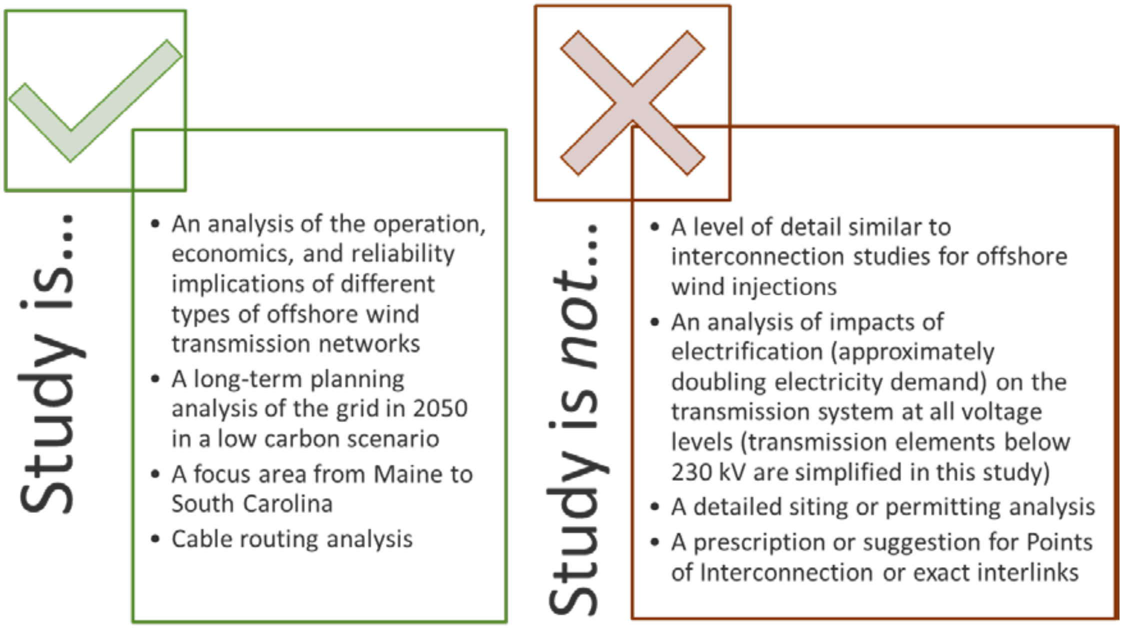

Figure 2. Overview of what the AOSWTS is and what it is not. ***Figure by NREL***

The AOSWTS provides an analysis of the operation, economics, and reliability implications of different types of offshore wind transmission networks that are described in depth in the following sections:

- **Section 2: Capacity expansion through 2050**. To provide context for the offshore wind transmission topologies being studied, we conducted a capacity expansion analysis among all fuel types to determine future generation, in addition to the 85 GW of offshore wind capacity that was included. The primary goal of this effort was to create a scenario of onshore generation capacity through 2050 that could be evaluated with a variety of assumptions about offshore wind transmission.
- **Section 3: Environmental considerations and siting**. We incorporated environmental and siting considerations into the study's development of offshore wind transmission topologies for 2030 and 2050. These considerations included the siting of hypothetical transmission cables from offshore wind power plants through the coastal zone (close to onshore) to the POIs onshore, and therefore included both offshore and onshore siting considerations.
- **Section 4: Transmission topologies**. This section discusses the development of offshore transmission topologies, which involved: developing cable siting methods that considered offshore transmission costs and technologies starting with a radial connection as a baseline, evaluating candidate POIs onshore, assessing different methods for path routing and geospatial data analysis, and studying related transmission parameters that characterize both HVAC and HVDC transmission systems.

- **Section 5: Production cost and resource adequacy**. The production cost and resource adequacy analysis quantifies how offshore transmission topologies add value to the bulk electric power system in the eastern United States. Production cost modeling evaluates how the hourly output of generation resources changes with the different offshore transmission topologies. Resource adequacy analysis quantifies how generation resources can be shared across geographies to reduce the risk of insufficient electricity supply when additional transmission topologies are made available.
- **Section 6: Economic analysis**. The economic analysis identifies and evaluates the quantifiable benefits associated with transmission investments identified in the previous two sections. We used replicable and scalable methods to allocate economic benefits and transmission costs among transmission planning regions.
- **Section 7: Reliability**. The reliability analysis, in addition to the resource adequacy analysis discussed earlier, included analyzing 2030 and 2050 AC power flow and contingency analysis results for the offshore transmission topologies using results from the production cost modeling, including assessing the grid strength at select candidate POIs. This task also included analyzing the protection and HVDC breaker needs for the offshore multiterminal HVDC transmission networks considered in some of the 2050 transmission topologies.
- **Appendices**. Additional technical details are provided in the appendices as noted in the individual sections.

2 Capacity Expansion Through 2050

To provide context for the offshore wind transmission topologies being studied, we started with a generation and transmission capacity expansion analysis using NREL's Regional Energy Deployment System (ReEDS) model (Ho et al. 2021). ReEDS optimizes the evolution of the grid over time, including generation and transmission. The primary goal of this effort was to create scenarios of onshore generation capacity through 2050 that could be evaluated with a variety of assumptions about offshore wind transmission. Section 2.2 describes the ReEDS model in more detail. The scenarios considered, as well as the methodology and results of these scenarios, are described in this section.

2.1 Scenarios

We created the following two trajectories through 2050 for analysis:

- A business-as-usual (BAU) scenario that represents existing grid-relevant policies and planning (e.g., legislated state carbon targets and the Inflation Reduction Act of 2022)
- A low-carbon scenario that represents a future with deep decarbonization of the electric sector and increased load from additional electrification of transportation, heating, and other sectors.

These two scenarios help explore the range of plausible futures for offshore-wind-energy-focused analysis.

All scenarios modeled include the following key assumptions:

- **Offshore wind energy costs and performance**. Annual Technology Baseline 2022 Moderate costs, which include the 30% investment tax credit through 2050, as per the Inflation Reduction Act
- **Other technology costs**. Annual Technology Baseline 2022 Moderate projections for all generation and storage technologies
- **Fuel prices**. All scenarios use the Annual Energy Outlook 2022 reference case for natural gas, coal, and uranium prices

- **Limited-access renewable energy siting**. Limited-access siting regimes for land-based wind and utility photovoltaics;[5] open access siting regime for offshore wind energy, but does not consider wind in the Great Lakes
- **Limited interregional transmission**. New transmission only allowed within (not between) FERC Order 1000 planning regions for the capacity expansion modeling. Some of the offshore transmission topologies described later do span planning regions, as it could be easier to build this type of interregional transmission.[6] Offshore designs that include Canada were not considered for this study.
- **Technology availability**. No nuclear small-modular reactors, or carbon-dioxide removal technologies such as direct air capture
- **Existing policies**. Relevant existing policies are considered, such as existing federal tax credit policies including the Inflation Reduction Act,[7] state renewable portfolio standards as of September 2022,[8] 30 GW of offshore wind by 2030, the Regional Greenhouse Gas Initiative, Cross-State Air Pollution Rule nitric oxide limits, and state-level battery capacity legislated mandates as of September 2022. Combined, these assumptions lead to significantly lower carbon emissions, even without additional carbon constraints.
- **Other assumptions**. Unless otherwise noted, assumptions are consistent with those used in the *2022 Standard Scenarios Report: A U.S. Electricity Sector Outlook* (Gagnon et al. 2022).

We defined the scenarios using two main factors: assumed electricity demand and national carbon emissions policy. Table 1 describes the demand and carbon assumptions for the two scenarios.

[5] These limited siting regimes make it more challenging to site land-based wind energy and utility photovoltaics, especially in population-dense areas. Siting regimes are from the 2021 wind supply curve versions (https://www.nrel.gov/gis/wind-supply-curves.html). See Lopez et al. (2021; 2023), and Zuckerman et al. (2023) for offshore-wind-specific details.
[6] The AOSWTS focuses on capacity expansion scenarios that do not include major interregional transmission to consider scenarios where challenges to onshore siting and permitting prevent these large builds. See the National Governors Association *Transmission Siting and Permitting* for more information on these challenges. See Section 5.2.2 for more detail on a sensitivity where a significant interregional path expansion was considered.
[7] See the *2022 Standard Scenarios Report: A U.S. Electricity Sector Outlook* (Gagnon et al. 2022) regarding the implementation and implications of the Inflation Reduction Act for the Regional Energy Deployment System model.
[8] Includes renewable targets for Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Delaware, Maryland, North Carolina, and Virginia. See the Lawrence Berkeley National Laboratory's Renewables Portfolio Standards Resources for more details.

Table 1. Scenario Definitions

	Business as Usual	Low Carbon
Demand	Minimal electrification, based on the U.S. Energy Information Administration Annual Energy Outlook 2021 Reference Case[9]; considers existing state regulations[10]; 1.0% load growth per year	Higher electrification, 2.4% energy demand growth per year on average; represents some electrification of transportation, space heating, and other sectors; significant impact on demand profile[11]
Carbon Emissions Policy	No national carbon emissions policy; only existing state and regional policies	80% reduction by 2035 (from 2005 levels) and 95% by 2050; existing state and regional policies are considered (and relevant when they are more stringent)
Atlantic Offshore Wind	30 GW by 2030	30 GW by 2030; 85 GW by 2050

For the low-carbon scenario, we evaluated 85 GW of offshore wind energy in the Atlantic, between South Carolina and Maine. We selected the 85 GW based on preliminary runs with similar assumptions to the low-carbon scenario, and on the Atlantic wind generation capacity developed in the "core" scenario from Beiter et al. (2023). In our preliminary runs and Beiter et al.'s core scenario, we projected approximately 85 GW in the Atlantic based on the economics and constraints in the capacity expansion model. Beiter et al. performed a scenario analysis and found that increased challenges and limitations to major interregional onshore transmission development was one of the key drivers behind increased development of offshore wind. The low-carbon scenario, with 85 GW offshore wind, is used in subsequent analyses for studying offshore topologies in detail. It is possible that some of the offshore network topologies studied may impact the optimal mix of resources in a region, however, we did not consider this potential benefit because we wanted more direct comparisons between the topologies.

Figure 3 shows the electricity demand growth in the scenarios in the contiguous United States (for context) and Atlantic states.[12] Note the substantial growth in the low-carbon scenario compared to today as well as the BAU.

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[9] For context, the Annual Energy Outlook Reference Case considers about 7% of the light-duty vehicle fleet to be electric in 2050.
[10] For New York, the business-as-usual assumptions for demand and emissions are consistent with the reference scenario of the Climate Action Council Draft Scoping Plan. The low-carbon scenario considers full achievement of this plan for New York in 2050. The full achievement was modeled as a zero-carbon constraint for generation in state and a constraint on net imports greater than or equal to zero.
[11] Demand profiles were from a preliminary version of the *United States Annual Decarbonization Perspective 2022*.
[12] For the purposes of this study, Atlantic states considered include South Carolina through Maine, including Pennsylvania and Vermont (due to proximity and grid connectivity).

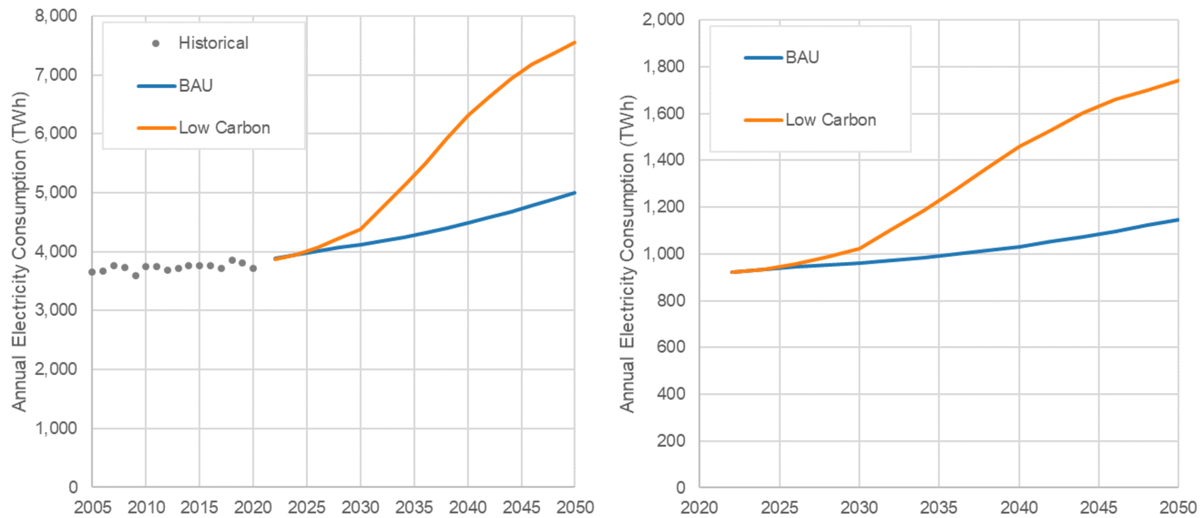


Figure 3. Assumed annual electricity demand by scenario in the contiguous United States (left) and Atlantic states (right). ***Figure by NREL.***

Note: TWh = terawatt-hour(s)

Figure 4 shows the emissions trajectories from the two scenarios in the contiguous United States and Atlantic states. Tax credits drive significant emissions reductions in both cases, although the low-carbon scenario continues to see carbon reductions beyond 2035.

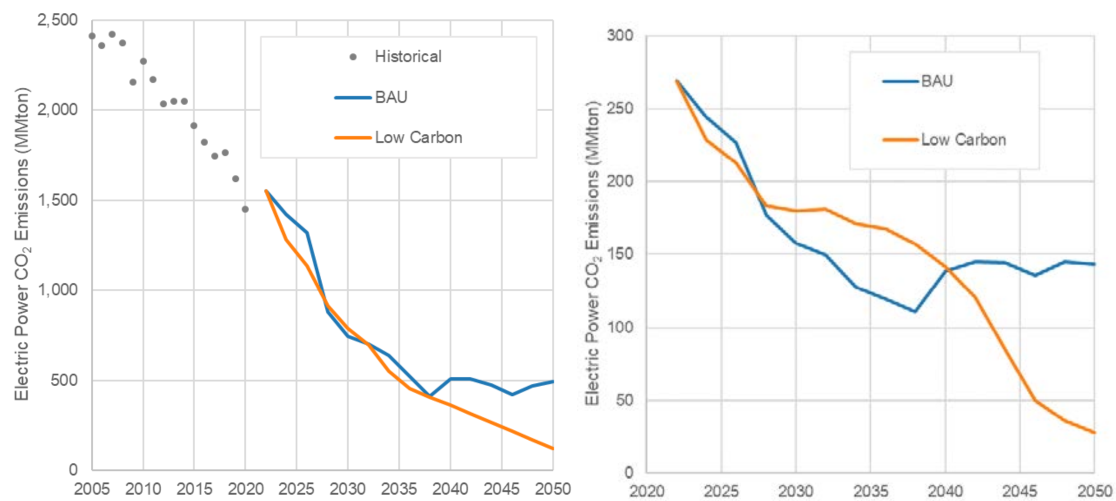


Figure 4. Electric power carbon-dioxide (CO_2) emissions by scenario in the contiguous United States (left) and Atlantic states (right). ***Figure by NREL.***

Note: MMton = million metric tons

2.2 Regional Energy Deployment System Model

To provide an electricity system context for the transmission topologies explored in this study, we simulated expanding the electricity sector of the contiguous United States with the ReEDS model (Ho et al. 2021). ReEDS optimizes the expansion and operation of the electricity system, including electricity generation technologies, storage, and transmission, to meet regional electricity demand projections, reserve margins, operating reserves, and policy requirements. In addition to the offshore-wind-energy-specific work cited in this section, the model has been used for many recent large, policy-relevant grid studies, including studying 100% renewable grids (Denholm et al. 2022), the Inflation Reduction Act (Steinberg et al. 2023), and the *Storage Futures Study: Key Learnings for the Coming Decades* (Blair et al. 2022). There are several relevant limitations of the ReEDS model for this application. The model considers a systemwide optimization rather than representing specific market actors, and the transmission networks are simplified (see following paragraphs). For a more comprehensive list of limitations, see Ho et al. (2021).

In this study, we configured ReEDS to optimize the electricity system build-out in 2-year increments through 2050. We used an hourly submodule between the model steps to calculate curtailment and contribution to peak demand from wind, solar, and storage technologies, and then incorporated those factors into the capacity expansion and dispatch optimization.

ReEDS models 134 balancing areas,[13] and most technologies and transmission corridors are represented at this regional level. However, for this study, wind was represented at a much greater resolution, with 33,082 land-based wind energy sites and 7,628 offshore wind energy sites[14] explicitly represented in the model. Note that we did not use the resulting ReEDS transmission expansions when developing the offshore transmission topologies in Section 4.6, as they were based on a nodal model of the grid (with 92,000 nodes) and we conducted additional analysis to enhance the placement of the offshore wind sites and points of interconnection.

These scenarios also included transmission build-out restrictions beyond those in the default ReEDS model. In the capacity expansion modeling, new land-based transmission was disallowed between FERC Order 1000 planning regions and any neighbors (including Canada), which for our Atlantic focus region are NYISO, ISO-NE, PJM, and Southeastern Regional Transmission Planning (SERTP), as described in Section 2.1. Assumptions for the more detailed transmission models are presented in Section 5. We did not perform a detailed fuel infrastructure and delivery analysis for new fuels (e.g., hydrogen) or existing (e.g., natural gas) for this study.

[13] Zones in the transmission modeling for ReEDS. Supply and demand must balance in these zones.
[14] We did not consider offshore wind energy in the Great Lakes or Gulf of Mexico in these scenarios to focus on the Atlantic region.

2.3 ReEDS Capacity Expansion Results

We executed the BAU and low-carbon scenarios in the ReEDS model. The low-carbon scenario results in significant capacity expansion of land-based wind, solar, storage, hydrogen combustion turbines, and natural gas with carbon capture and sequestration. The BAU scenario reveals significant expansion of land-based wind, solar, and storage, but limited offshore wind at approximately 40 GW (Figure 5 and Figure 6). Because offshore wind transmission is our topic for this study, the analysis using more detailed models in subsequent sections focuses on the low-carbon scenario with 85 GW of offshore wind energy.

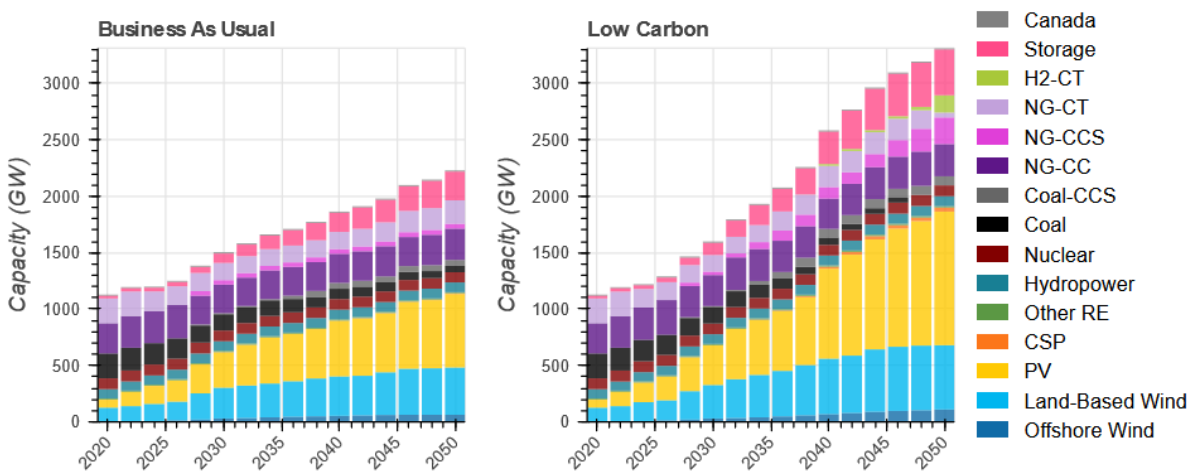


Figure 5. ReEDS electricity generation capacity by technology in the contiguous United States. ***Figure by NREL.***

Note: H2-CT = hydrogen combustion turbine; NG-CT = natural-gas combustion turbine; NG-CC = natural-gas combined cycle; NG-CCS = natural-gas combined cycle with carbon capture and sequestration; Coal-CCS = coal with carbon capture and sequestration; Other RE = other renewable energy, including biopower and geothermal; CSP = concentrating solar power; PV = photovoltaics. Canada refers to import capacity from Canada. Storage includes batteries and pumped storage hydropower.

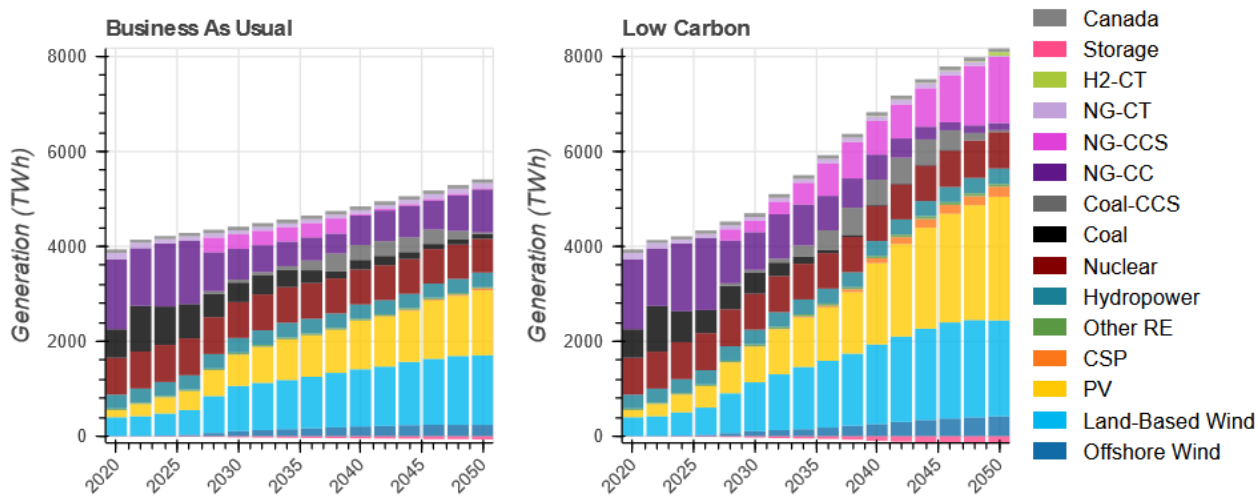


Figure 6. ReEDS electricity generation by technology in the contiguous United States. ***Figure by NREL***

Note: Net generation storage is negative due to efficiency losses.

While offshore wind is a small fraction of the national electricity generation in both scenarios, it is a significant fraction of generation in ISO-NE, NYISO, and PJM-Atlantic[15] by 2050, especially in the low-carbon scenario, for which offshore wind energy is 44% of generation in ISO-NE, 26% in NYISO, and 22% in PJM-Atlantic (Figure 7 shows 2030; Figure 8 shows 2050). As mentioned in the Section 2.1, these scenarios included transmission restrictions between ISOs. However, we did not develop the specific ReEDS transmission build-out for the production cost modeling, so that more detailed methods could be used for the nodal transmission expansion (see Section 5.1).

[15] Note that only states that border the Atlantic Ocean in PJM are shown here (as PJM Atlantic).

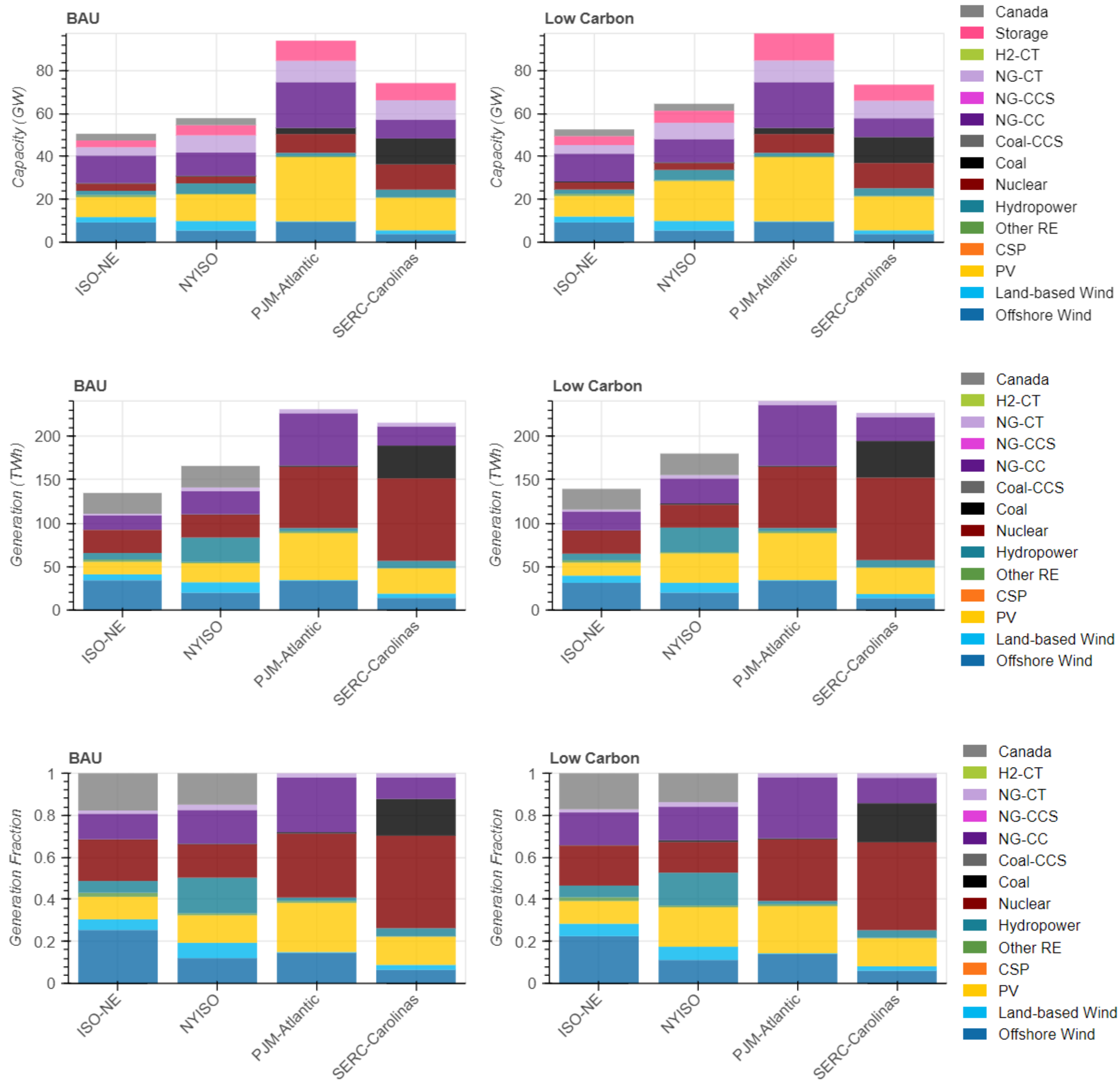


Figure 7. ReEDS 2030 installed electricity capacity (top), generation (middle), and generation fraction (bottom) by technology in Atlantic regions of interest. ***Figure by NREL***

Note: PJM-Atlantic refers to the states within PJM that border the Atlantic Ocean.

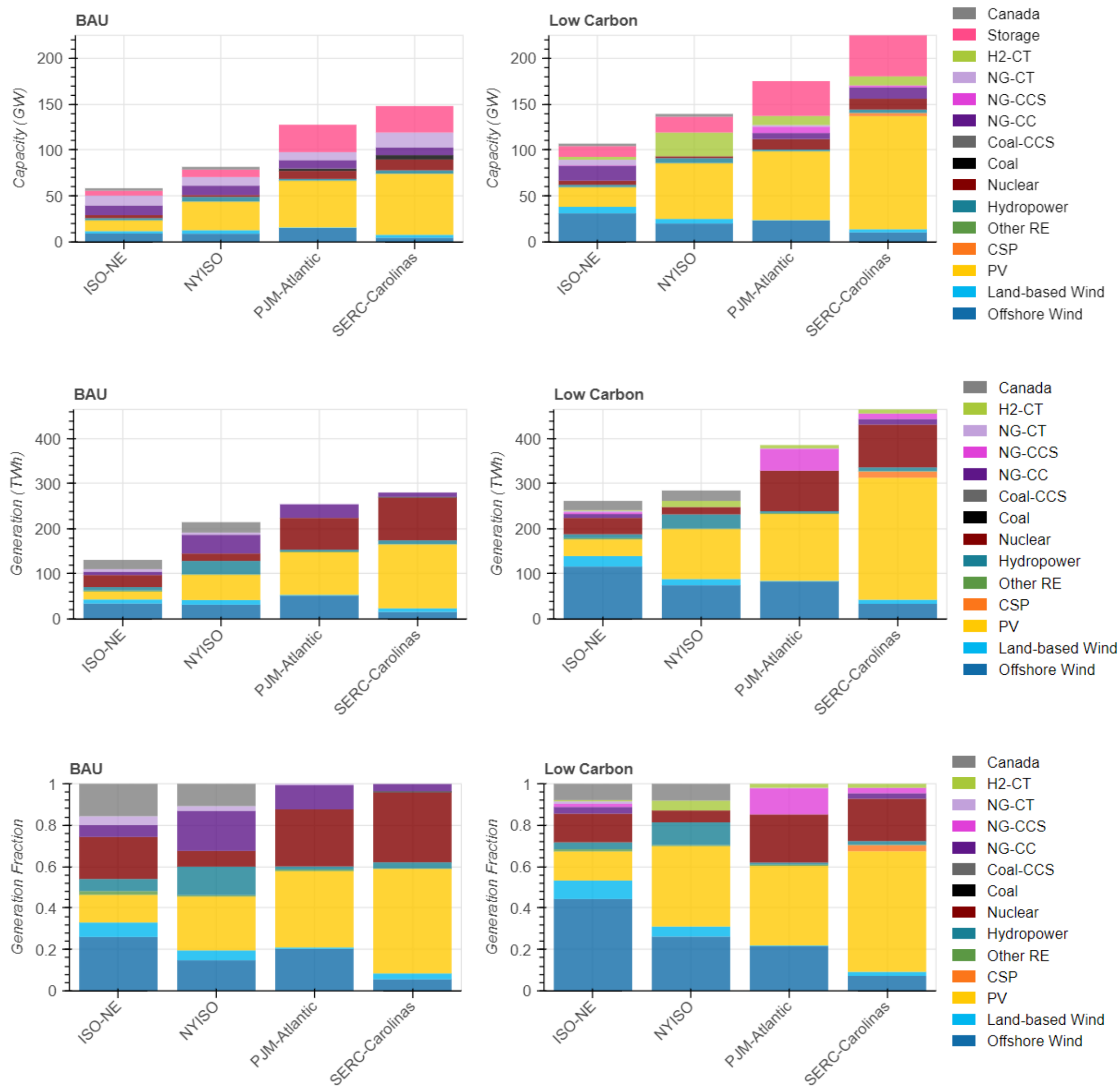


Figure 8. ReEDS 2050 installed electricity capacity (top), generation (middle), and generation fraction (bottom) by technology in Atlantic regions of interest. ***Figure by NREL***

Note: PJM-Atlantic refers to the states within PJM that border the Atlantic Ocean.

2.4 Discussion

Although offshore wind energy comprises a small fraction of total electricity generation in the contiguous United States, 85 GW of installed offshore wind represents a significant fraction of generation in the Atlantic regions. The other technologies that have significant capacity and/or generation in the Atlantic regions are solar PV, nuclear, natural-gas combined cycle (NG-CC), storage, and natural-gas combustion turbine (H2-CT). The primary goal of the ReEDS analysis was to provide an electricity system generation capacity expansion and load growth context for further, more-detailed study of the transmission topologies required to support projected growth of Atlantic offshore wind energy in the low-carbon scenario in 2050. Other onshore generation and transmission builds are possible and could impact some outcomes; we explore some of those options in Section 5.2.2.1.

In Section 5, we use the onshore generation fleet build-out from the ReEDS low-carbon scenario to conduct more detailed analysis of offshore wind and the operation of the supporting transmission topologies.

3 Environmental and Siting

3.1 Background, Scope, and Process

This section describes how we incorporated environmental and siting considerations into the study's development of offshore wind transmission topologies for 2030 and 2050. The scope included siting hypothetical transmission cables from offshore wind plants through the coastal zone to the POIs onshore, and thereby included both offshore and onshore siting considerations. The scope did not include siting interarray cables.

Drawing on the mitigation hierarchy (e.g., Arlidge et al. 2018), this study sought to avoid and minimize interactions between transmission routing/grid integration and sensitive environmental areas, as well as areas of ocean co-use. Our team identified the major offshore and coastal resources that could potentially affect siting of the long-term transmission scenarios and learned more about Atlantic areas that are relatively unconstrained. We also sought to use the best-available existing or emerging geospatial data layers and ensure that appropriate stakeholders were engaged to discuss responsible siting of transmission routing. The study was informed by existing information on potential environmental effects to marine life and habitat from offshore cables (e.g., New York State Energy Research and Development Authority [NYSERDA] 2021a) and existing methodological guidance for assessing cable burial risk (e.g., Carbon Trust 2015).

We recognized regional ocean data portals as an important data source for the study. Prior to this study, we obtained siting layers from several ocean data portals as inputs to NREL's Renewable Energy Potential (reV) model (Maclaurin et al. 2021) to calculate offshore wind energy capacity, generation, and cost based on intersection with grid infrastructure and ocean-use characteristics (Zuckerman et al. 2023). Note that this previous study was associated with siting offshore wind plants rather than transmission. Examples of regional ocean data portals that were reviewed to identify siting layers for potential use in this study included the BOEM-NOAA MarineCadastre, Northeast Ocean Data Portal, and NOAA Office for Coastal Management's Digital Coast.

Not all of the datasets considered were used in the analysis. For example, we did not include current fisheries information given the long-term nature of the scenarios analyzed for this study (through 2050). Specifically, given the impacts of climate change and other factors, there is a high degree of uncertainty around long-term species distributions and associated areas of prime fishing. In addition, information related to hard bottom and other key habitats was not included and should be considered for updating future studies, such as for project-specific analysis. Beyond the national marine sanctuaries included in this study, other types of marine-protected areas should be considered as potential siting constraints in future work. For the data that were within scope, see Section 3.3 for the list of sources used.

3.2 Stakeholder Engagement

The environmental and siting considerations for this study were updated based on feedback from external experts on the TRC and other stakeholders. This feedback was not part of a formal regulatory process or proceeding and was separate from any current or future federal National Environmental Policy Act reviews and associated consultations, including for specific offshore wind transmission projects. We sought individual expert guidance and input in support of this DOE-funded study and did not seek any group position or consensus. Environmental and siting considerations were discussed with TRC members in seven meetings held during 2021 and 2022. Ad hoc follow-up meetings (several, in some cases) were also held with the NYSERDA cable corridor constraints analysis team, BOEM, USACE, New England Fishery Management Council, NOAA (National Marine Fisheries Service and National Centers for Coastal Ocean Science), U.S. Navy, FCC, North American Submarine Cable Association (NASCA), U.S. Fish & Wildlife Service, the University of Rhode Island, and the Massachusetts Board of Underwater Archaeological Resources. Written comments were received from The Nature Conservancy and USCG.

We gathered TRC feedback on priority existing and emerging siting topics, available geospatial layers, and incorporating data layers into the analyses. Some of the information gathered from the TRC and stakeholders directly informed the siting data layers used in this study, as well as the level of constraint assigned to each layer, whereas other information was collected and described in this document (see Section 3.3).

We developed an initial set of offshore data layers for TRC review and feedback, including those related to seafloor geology, conservation, regulatory areas, shipping and channels, and physical structures. Regarding the constraints criteria, several layers were highlighted to obtain TRC input and determine whether to force inclusion or exclusion, or apply friction to a particular layer in the reV model. Friction is in relative terms for this analysis and uses a scale from 1 (low friction) to 10 (high friction), in which higher frictions are avoided during cable route design more than lower frictions (or no friction). For example, a 0° seafloor slope has less friction than a 15° seafloor slope, due to the relative ease of laying cables on smaller slopes. Friction levels were based on combining TRC feedback and the study team's understanding of technology constraints, such as those related to cable laying and water depth in the region.

3.3 Siting Data Sources and Data Layers

Based on TRC and stakeholder feedback, we determined a final set of environmental and siting data layers for use in this study and incorporated them into the reV model. We acknowledge that this is not a comprehensive list of all possible siting layers but rather provides the most critical layers selected based on relevance to the study scope and the time available for subject matter expert input. The final NYSERDA *Offshore Wind Cable Corridor Constraints Assessment* report was also completed while this study was being conducted and was consulted for identifying types of constraints (WSP USA 2023). The offshore portion of our study included a set of 26 siting data layers (organized by theme), along with their constraint criteria and buffers, if applicable (Table 2). BOEM provided the best-available information for sand and gravel borrow areas[16] and placement areas, as well as access to a confidential shipwrecks database. USACE provided information on the national federal channel framework. USCG provided the Consolidated Port Approaches and International Entry and Departure Transit Areas Port Access Route Studies, with associated constraints for shipping safety fairways and fairway anchorages (Stone 2022). Note that newer USCG data have become available since the modeling for this study was completed and can be found at USCG's Navigation Center's web app for the Port Access Route Studies' routing measure layers. In addition, for the navigation fairway layers, future studies should consider the traffic separation scheme extensions and precautionary areas as constraints. Future studies should also consider updates or alternate datasets for slope and sediment.

Table 2. Offshore Data Layers Used in the Study

Theme	Name	Data Source Obtained From	Description	Constraint Type
Seafloor Geology	Water depth	General Bathymetric Chart of the Oceans (British Oceanographic Data Centre 2022)	Gridded bathymetry data identifies potential deeper areas that would require dynamic cables	Friction (Rank 2 for water deeper than 200 meters [m])
	Underwater slope	calculated	NREL calculated underwater slope based on bathymetry (above).	Friction (Rank 1 for 0–10° slope; Rank 5 for 11-15° slope); exclude (>15° slope)
	Seafloor sediment	U.S. Geological Survey (1985)	Continental Margin Mapping Program identifies the sediment grainsize distribution for the United States East Coast Continental Margin.	Friction (Rank 5 for gravel-sand, gravel); exclude (bedrock)
Conservation	Marine national monuments	NOAA (2021a; 2021b) Marine Protected Areas inventory	Similar to national marine sanctuaries, marine national monuments are designated to protect areas of the marine environment.	Exclude

[16] A borrow area is where sand or gravel is sourced for placement elsewhere.

Theme	Name	Data Source Obtained From	Description	Constraint Type
	National marine sanctuaries	NOAA (2021a; 2021b) Marine Protected Areas inventory	National marine sanctuaries are areas of special national significance designated as such by NOAA and intended to protect important marine ecosystems around the nation.	Exclude
	Atlantic canyons	BOEM (2021) Atlantic cadastral data	BOEM 2019-2024 Outer Continental Shelf (OCS) oil and gas leasing draft proposed program exclusion option areas – Atlantic Region; the exclusion option areas for the 2019-2024 draft proposed program are areas that the Secretary of the Interior included for additional analysis and consideration, including an "Atlantic canyon area," which is considered potentially sensitive habitat.	Exclude
	Artificial reefs	NOAA (2021c) National Marine Fisheries Service	An artificial reef is a human-made underwater structure, typically built to promote marine life in areas with a generally featureless bottom. This dataset was derived from multiple state websites.	Exclude
Regulatory	Offshore wind planning areas	BOEM-NOAA (2021) Marine Cadastre	Wind planning areas represent up to seven different types of announcements within the U.S. Federal Register that can be used to show the status of an area being considered for wind energy development.	Force inclusion
	Offshore wind energy leases	BOEM-NOAA (2021) Marine Cadastre	This data layer contains blocks that have been leased by a company with intent to build a wind energy facility.	Force inclusion
	OCS sand resources	BOEM (2022) Marine Minerals Information System	This layer contains delineations of sand resource areas on the OCS and (if available) nearshore areas.	Exclude

Theme	Name	Data Source Obtained From	Description	Constraint Type
	OCS sand and gravel borrow areas	BOEM (2022) Marine Minerals Information System	This layer represents federal OCS sand and gravel borrow areas (BOEM Marine Minerals Lease Areas)	Exclude
	USACE South Atlantic Division (SAD) sand sources/borrow areas	USACE (2022a)	This is a product of the SAD Sand Availability and Needs Determination Study conducted by USACE. For the SAD region (North Carolina-Mississippi), it is a more comprehensive version of the BOEM Marine Minerals Information System sand resource layer, as it includes many more areas in state waters.	Exclude
	USACE borrow areas	USACE (2022b)	This layer contains all USACE borrow areas in state and federal waters nationwide. Note that the North Atlantic Division does not have a product equivalent to the one listed earlier for SAD, so this is being used.	Exclude
	USACE placement areas	USACE (2022b)	This layer contains all USACE placement areas in state and federal waters nationwide. Note that some of these placement areas are also used as borrow areas, and their status and frequency of use are subject to change.	Exclude
	Danger zones and restricted areas	BOEM-NOAA (2021) Marine Cadastre	These data represent areas outlined by the Code of Federal Regulations and the raster navigational charts. Water used for target practice, bombing, rocket firing, or other especially hazardous operations.	Exclude
	Ocean disposal sites	U.S. Environmental Protection Agency (2023)	The Environmental Protection Agency is responsible for designating and managing ocean dumping sites under the Marine	Exclude

Theme	Name	Data Source Obtained From	Description	Constraint Type
			Protection, Research and Sanctuaries Act. All but one of the currently designated ocean sites are for disposing dredged material permitted or authorized under the act.	
Shipping and Navigation	Shipping lanes	BOEM-NOAA (2021) Marine Cadastre	Shipping zones delineate activities and regulations for marine vessel traffic.	Friction (Rank 5)
	National federal channel framework	USACE (2022c)	The National Channel Framework database provides information about congressionally authorized navigation channels maintained by USACE.	Friction (Rank 7)
	Shipping safety fairway	Stone (2022)	A lane or corridor in which no artificial island or fixed structure, whether temporary or permanent, will be permitted. Temporary underwater obstacles may be permitted under certain conditions.	Friction (Rank 7)
	Fairway anchorages	Stone (2022)	An anchorage area contiguous to and associated with a fairway, in which fixed structures may be permitted within certain spacing limitations.	Exclude
Physical Structures	Natural-gas pipelines	Homeland Infrastructure Foundation-Level Data (2021)	Natural-gas trunk lines both on and offshore; note: there are no oil pipelines in the Atlantic regions	Friction (Rank 5)
	Submarine cable areas	BOEM-NOAA (2021) Marine Cadastre	These data depict the occurrence of submarine cables in and around U.S. navigable waters.	Friction (Rank 2)
	Military ship shock boxes	BOEM-NOAA (2021) Marine Cadastre	Military ship shock boxes are locations, which are not considered military ranges, where ship shock trials (explosives are detonated underwater against surface ships) can be conducted by Naval Sea	Exclude

Theme	Name	Data Source Obtained From	Description	Constraint Type
			System Command on new classes of Navy ships.	
	Unexploded ordnance locations	BOEM-NOAA (2021) Marine Cadastre	Unexploded ordnances are explosive weapons (e.g., bombs, bullets, shells, grenades, mines) that did not explode when they were employed and still pose a risk of detonation.	Exclude
	Automated Wreck and Obstruction Information System	NOAA (2021d)	The Automated Wreck and Obstruction Information System contains information on more than 10,000 submerged wrecks and obstructions in the coastal waters of the United States.	Exclude with a 100-m buffer
	Atlantic Shipwrecks Database (confidential)	BOEM (personal communication in 2022)	This database provides an inventory of federal and private data sources developed as part of a BOEM-funded study to inform the bureau's environmental review of proposed renewable energy development on the Atlantic OCS.	Exclude with a 100-m buffer

The maps for subregions across the study area in Figures 8 through 11 illustrate the variable spatial extent of the different siting layers and their role in the cable routing analysis. For purposes of illustration, individual layers were grouped into the following categories and represented as a single compiled layer:

- **Sand Borrow and Placement**. Includes USACE placement areas, USACE SAD sand borrow areas, USACE other sand borrow areas, and BOEM Outer Continental Shelf (OCS) sand and gravel borrow areas and sand resources
- **Shipping and Navigation**. Includes shipping lanes, USCG fairway anchorages, USCG shipping safety fairways, and federal channels
- **Conservation**. Includes Atlantic canyons, artificial reefs, marine national monuments, and national marine sanctuaries
- **Military**. Includes military ship shock boxes, unexploded ordnances, danger zones, and restricted areas.

Note that the data layer groupings in Figures 9 through 12 comprise individual data layers that have varying levels of friction and exclusion. Figure 13 illustrates the entire study area (Maine to South Carolina) and the combined frictions and exclusions for all siting layers.

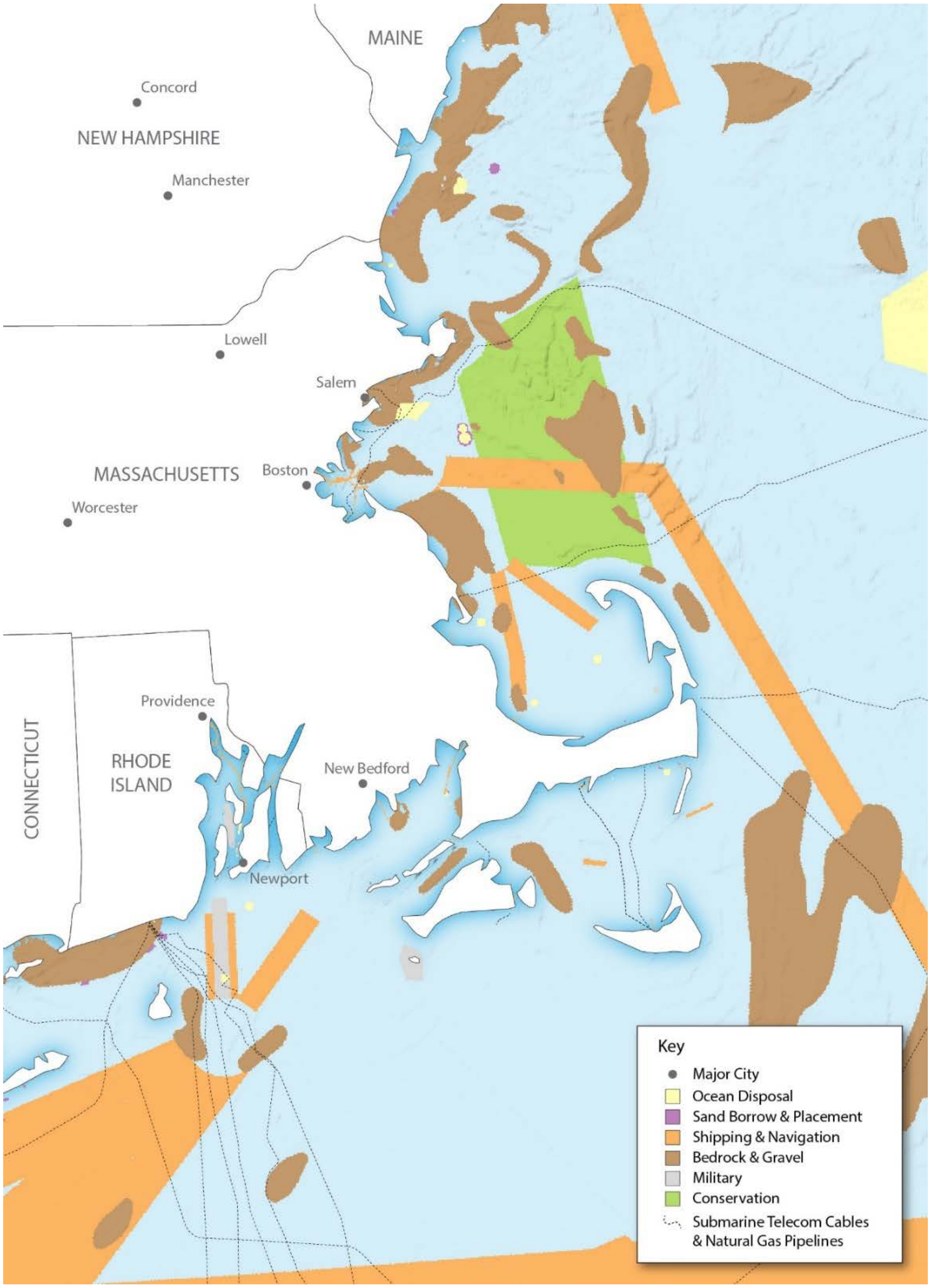


Figure 9. New England subregion siting constraints. ***Illustration by Billy Roberts, NREL.***

Note: Varying levels of friction and exclusion are applied to each layer; layers with forced inclusion are not shown here.

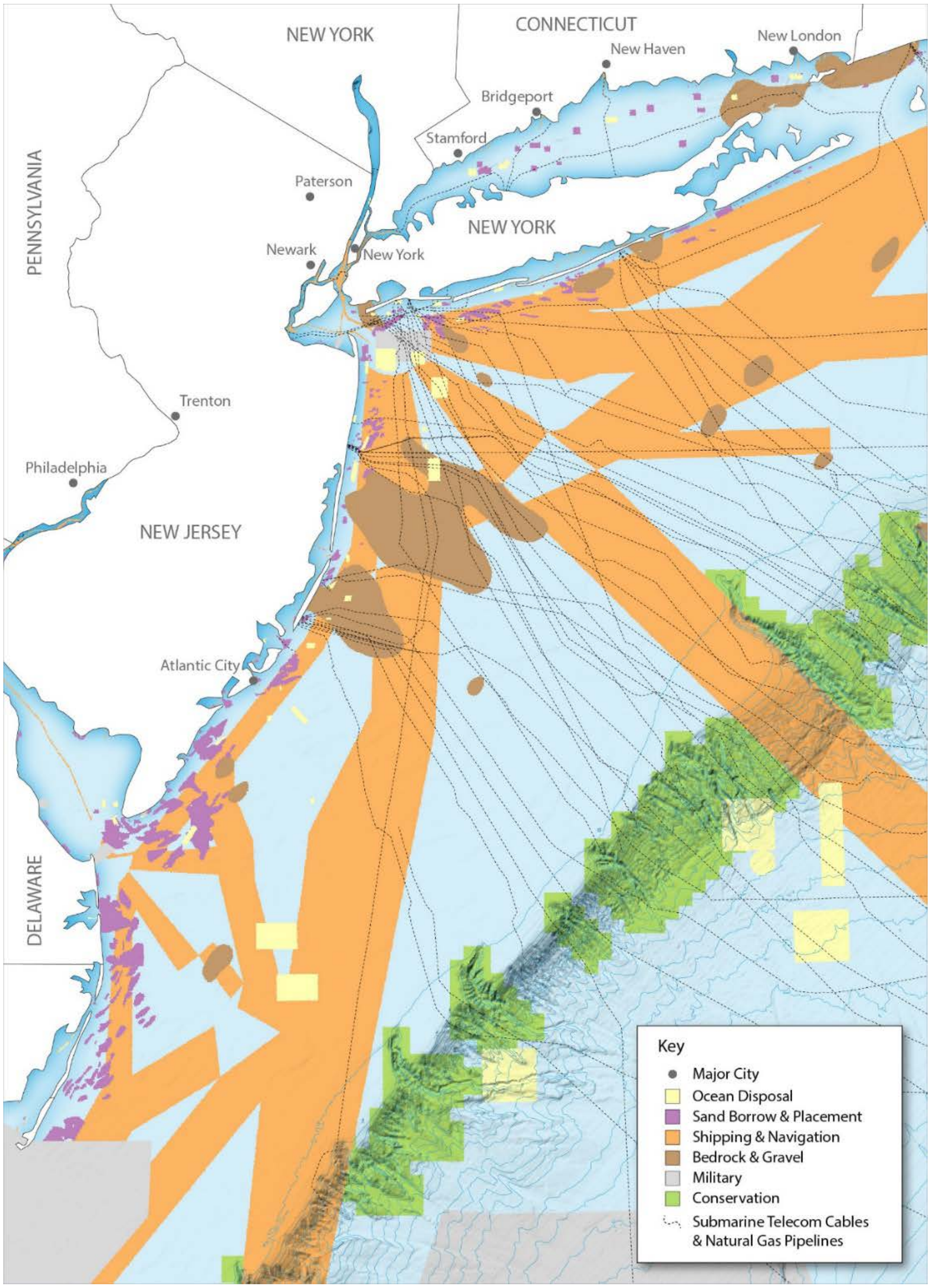


Figure 10. New York/New Jersey Bight subregion siting constraints. ***Illustration by Billy Roberts, NREL*****.**

Note: Varying levels of friction and exclusion are applied to each layer; layers with forced inclusion are not shown here.

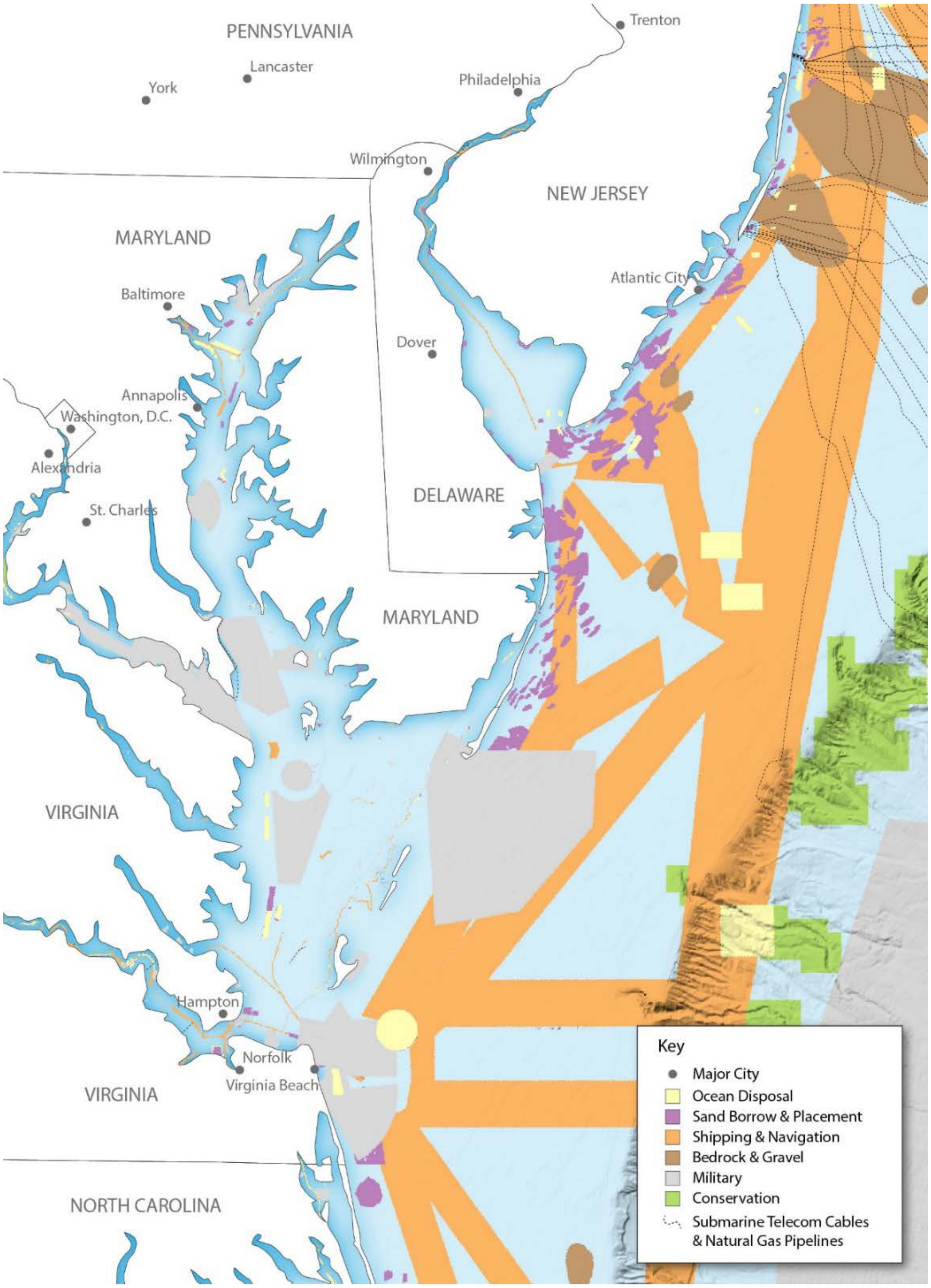


Figure 11. Central Atlantic subregion siting constraints. ***Illustration by Billy Roberts, NREL*****.**

Note: Varying levels of friction and exclusion are applied to each layer; layers with forced inclusion are not shown here.

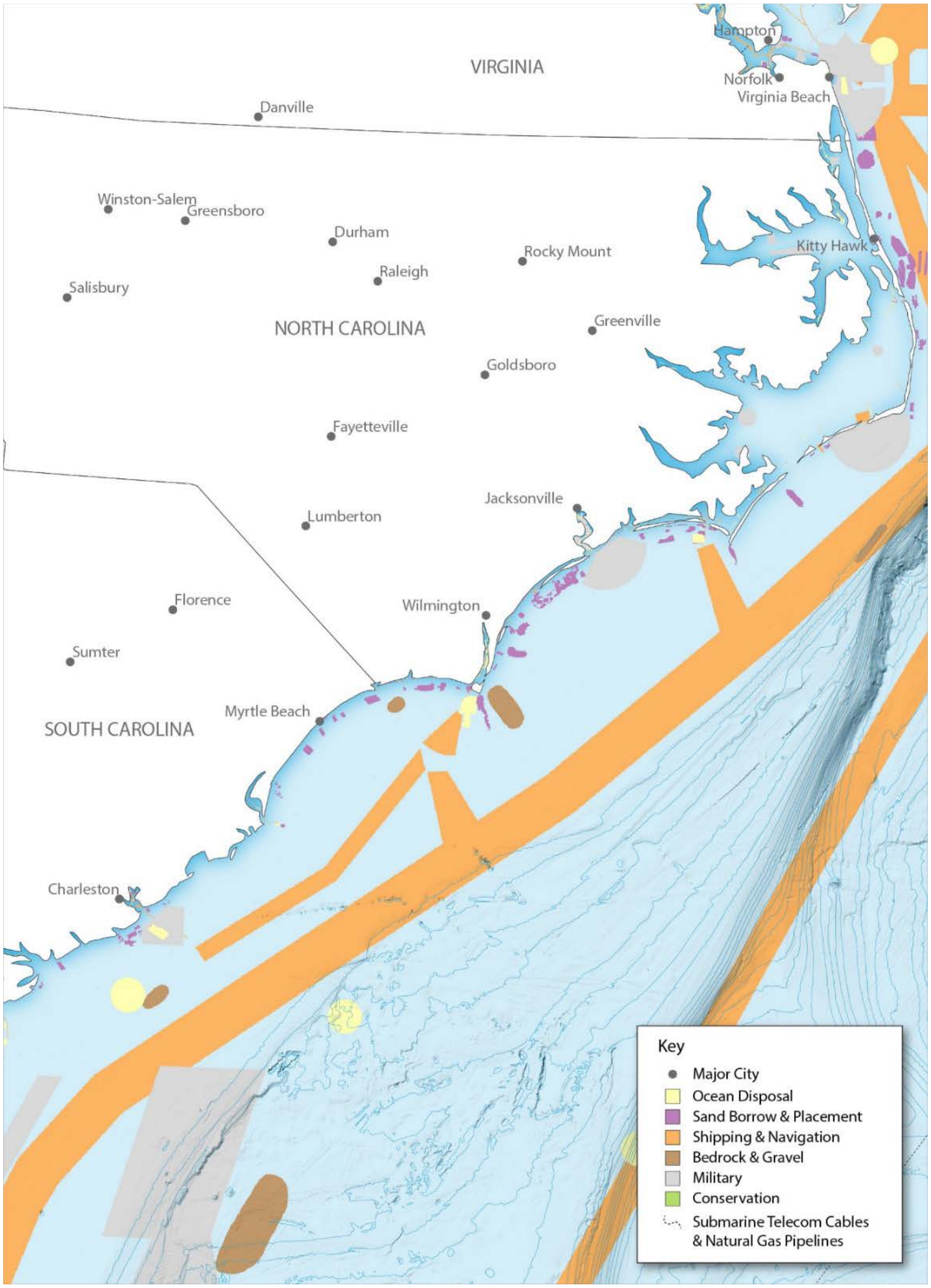


Figure 12. Carolinas subregion siting constraints. ***Illustration by Billy Roberts, NREL.***

Note: Varying levels of friction and exclusion are applied to each layer; layers with forced inclusion are not shown here.

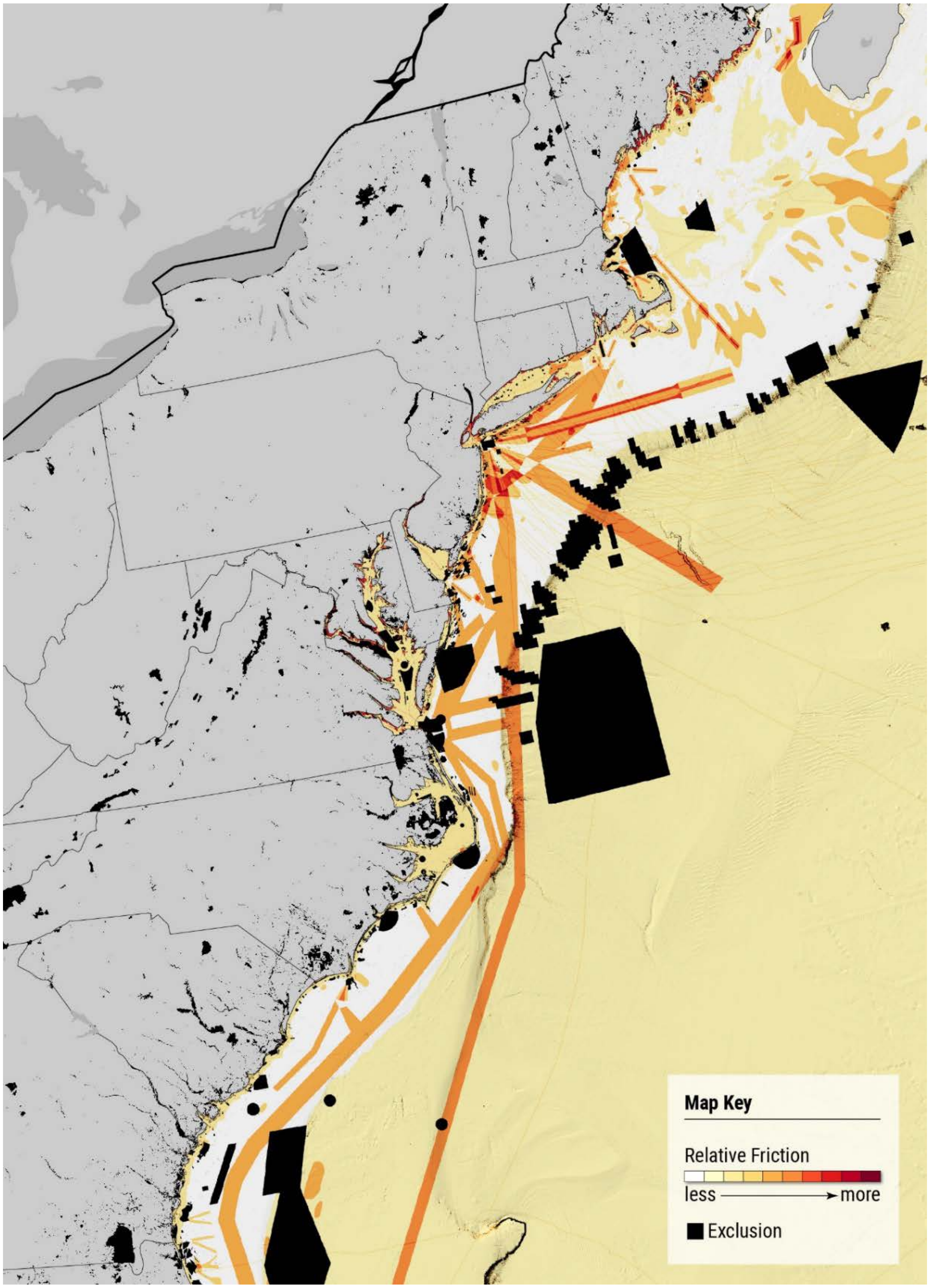


Figure 13. Frictions and exclusions. ***Illustration by Billy Roberts, NREL***

In addition to the offshore area, the onshore area for routing cables to the POIs was also considered within the study's scope. The onshore area included an extensive set of considerations and associated constraints that were determined through a previous study (Lopez et al. 2021). Onshore siting considerations included competing land use and associated infrastructure, site topography, siting ordinances, and protected areas. These onshore spatial exclusions either identified land already occupied by another physical feature or represented possible challenges associated with social, ecological, and wildlife considerations, or legal or jurisdictional restrictions that would impede transmission lines. In total, the modeling included 17 onshore exclusion types (with nearly 100 associated constraints). Examples of exclusion types include urban areas, land use, slope, U.S. Bureau of Land Management Areas of Critical Environmental Concern, federal lands, airports, roads, railroads, and building structures.

We used all offshore and onshore siting data layers in the transmission path routing assessment for this study, which looked at all possible route combinations as informed by these siting constraints. For more information on path routing methodology and results, see Section 4.1.

3.4 Summary of Best Practices and Guidance

This section summarizes recommended best practices and guidance related to offshore wind transmission siting that stakeholders shared during project discussions, and which either directly or indirectly informed siting constraints used in the study or simply provided useful context. The following is not an exhaustive list of documents available, but rather information that was brought to the study team's attention by the TRC and other stakeholders. Offshore wind transmission planning should continue to be informed by these types of documents and any future guidance that becomes available.

3.4.1 NYSERDA Studies

The study was informed by existing information, including from past NYSERDA studies, on potential environmental effects to marine life and habitat from offshore cables. A NYSERDA study on offshore wind submarine cabling provided helpful background information (NYSERDA 2021a), as summarized here. For example, seabed alterations can be caused by the equipment used for route preparation and cable installation, with potential impacts to reefs, shellfish beds, and seagrass beds. Cable installation activities can also resuspend chemical pollutants and sediments, with potential effects of the latter on photosynthesizing species, such as plankton and seagrasses. Noise may also be produced by physical installation and dredging, potentially causing short-term avoidance of the area by marine life. Electrical cables in the marine environment also add electromagnetic fields within a very small range of detectability from the cable, with the potential to displace recreational and/or commercial fishing if the target species avoids the cables. However, sheathing and burying the cables substantially reduces the levels of magnetic and induced electric fields in seawater.

NYSERDA's *Offshore Wind Cable Corridor Constraints Assessment* also provided context for this study (NYSERDA 2021b). The report identified offshore approach area, landfall, and overland area considerations. Offshore approach area considerations included marine geology;

marine commercial and recreational uses; navigation and vessel traffic; aquatic biological resources and sensitive habitats; sediment and water quality; cultural resources; and coastal habitats. Landfall and overland area considerations included sediment, soil types, and steep slopes; coastal resources; terrestrial biological resources; wetlands, surface waters, and water quality; areas of contamination; cultural resources; land use; and environmental justice/disadvantaged communities. Many of the considerations were identified in previous methodological guidance for cable burial risk assessments (e.g., Carbon Trust 2015).

3.4.2 Federal Communications Commission

The FCC is an independent agency that regulates interstate and international communications by radio, television, wire, satellite, and cable in all 50 states, the District of Columbia, and U.S. territories. The FCC has relevant documents that are based on the work of its advisory committee, the Communications Security, Reliability, and Interoperability Council. The council has a working group on submarine cable resiliency that published a final report on clustering cables and cable landings (Communications Security, Reliability, and Interoperability Council 2016). Furthermore, another working group focused on submarine cable routing and landing and published a final report on protecting submarine cables through spatial separation (Communications Security, Reliability, and Interoperability Council 2014). The FCC issues and renews cable licenses.

3.4.3 International Cable Protection Committee

The International Cable Protection Committee developed guidance documents for coordinating the submarine telecommunication industry and other industries, such as offshore wind (International Cable Protection Committee 2023). A subset of those recommendations that are most relevant are highlighted here. The first recommendation promotes best industry practice by facilitating good working relationships between seabed users. The second recommendation assists cable owners and those planning submarine cable systems that cross or are near existing in-service cables. The third recommendation identifies criteria to be applied to proposed crossings of submarine cables and/or pipelines. Other recommendations address coordination procedures for repair operations near active cable systems, actions for effective cable protection (after installation), construction in the vicinity of active cables, and the proximity of offshore renewable wind energy installations and submarine cable infrastructure.

3.4.4 European Subsea Cables Association

The European Subsea Cables Association’s Guideline 06, along with the International Cable Protection Committee’s recommendation 13-2C, addresses the proximity of offshore renewable wind energy installations and submarine cable infrastructure in national waters (European Subsea Cables Association 2016). These guidelines were developed in collaboration with the renewable energy industry. European Subsea Cables Association Guideline 06 provides guidance on developing projects that require proximity agreements between offshore wind power plant projects and subsea cable projects in the United Kingdom.

3.4.5 North American Submarine Cable Association

NASCA was formed in 2000 as a nonprofit organization of companies that own, install, or maintain submarine telecommunications cables in the waters of North America. The association serves as a forum to provide and exchange information on technical, legal, and policy issues, including standards and procedures for government approval of new submarine telecommunications cable installations; working relationships with other marine industries; and public education about such cables. In 2013, NASCA endorsed the adoption and application of European Subsea Cables Association Guideline 06, "Proximity of Wind Farms," by the U.S. regulatory agencies responsible for offshore renewable energy projects, including wind, tidal, and wave projects. Data portals that contain locations of telecommunications cables in U.S. waters do not address cables under development; therefore, NASCA recommends that offshore wind energy parties interested in identifying planned cable routes contact NASCA as a first step. NASCA has submitted comments to BOEM requesting that they address the concerns of submarine telecommunications owners, operators, and maintenance providers in developing and implementing BOEM's proposals for renewable energy projects on the OCS, including requests associated with commercial wind energy leasing (e.g., NASCA 2022).

3.4.6 International Council on Large Electric Systems

Established in 1921 in Paris, France, the International Council on Large Electric Systems is a global community committed to the collaborative development and sharing of end-to-end power system expertise. Study subcommittee B1 deals with insulated power cable systems, including AC and DC cable systems for power transmission, distribution and generation connections on land and in submarine applications associated with microgrids, and the integration of distributed resources. The council published information on offshore generation cable connections (International Council on Large Electric Systems 2015) and installation of submarine power cables (International Council on Large Electric Systems 2022) and has a forthcoming publication on the environmental impact of decommissioning underground and submarine power cables.

3.4.7 Paleocultural Landscapes

Paleocultural landscapes (paleolandforms) are places that show evidence of human interaction with the physical environment and were raised as a consideration for the laying of new offshore wind transmission cables by the TRC. While no datasets were available for use in this study, information on past research is discussed here.

A collaboration between BOEM, the University of Rhode Island's Graduate School of Oceanography, Rhode Island Coastal Resource Management Council, and Narragansett Indian Tribal Historic Preservation Office completed a 6-year study in 2020 to improve the methods used to locate, identify, understand, and protect ancient sites, now submerged, where Indigenous people once lived on the OCS (King et al. 2020; Robinson et al. 2020). The study concluded that successful consultation between governments requires respectful communication; trusting and mutually beneficial relationships; and shared capacity among parties. It was recommended that, before disturbance, areas considered for federal offshore wind energy activities should be characterized in the following ways: perform a desktop study to yield a geospatial synthesis of existing geoarchaeological information; review sea-level-rise models and creation of paleo-shoreline reconstructions; create a detailed reconstruction of the subsurface stratigraphy; and on a regional scale, create a paleoenvironmental reconstruction for the time period of hypothesized habitation and assess the paleo-cultural sensitivity of preserved paleo landscapes.

The study also recommended the following three areas that could benefit from best practices for which immediate action could be taken (King et al. 2020):

1. Develop a standardized methodology for identifying areas of paleo-landscape preservation in submerged environments, instead of attempting to use predictive models to simply locate areas with the highest potential for containing submerged archaeological sites.

2. Increase the capacity of Tribal communities, agencies, and academic researchers to collaborate in a mutually respectful and beneficial manner.

3. Build personal relationships among individual members of the Tribal, agency, and research groups.

3.4.8 Southeast Conservation Adaptation Strategy

The Southeast Conservation Adaptation Strategy is an initiative that spans from the Caribbean to the southern United States, whose vision is a connected network of lands and waters that support thriving fish and wildlife populations and improved quality of life for residents. Partners include federal and state agencies and nongovernmental organizations. The Southeast Conservation Adaptation Strategy produces the "Southeast Conservation Blueprint," which is a spatial plan to achieve the initiative's vision. The blueprint identifies high-priority areas based on many natural and cultural resource indicators representing terrestrial, freshwater, and marine ecosystems. It is available as a resource that could be helpful for informing future offshore wind energy and transmission planning efforts.

4 Transmission Topologies

To determine the offshore transmission topologies to study in detail, we began by making a radial topology that connects all offshore platforms to onshore POIs via an export cable. In the radial topology, there are no interlinks between offshore platforms to exchange power. The export cables were assumed to be HVDC if the distance to the POI was more than 45 miles or HVAC if shorter. This cutoff is based on early versions of the cost analysis, described in Section 4.3. We selected candidate POIs by reviewing previous studies (e.g., Vijayan 2021, PJM 2021, DNV-GL 2021, North Carolina Transmission Planning Collaborative 2021, and others) and discussions with the TRC. We then used the path routing methodology to create hypothetical routes (informed by the siting layers in Section 3.3) between each candidate POI and all potential offshore wind locations. We optimized the selection of 85 GW[17] by comparing between all potential combinations of offshore wind, routes, and candidate POIs (see details later in this section). This process created our radial topology. It—and its wind turbine locations, selected POIs, and export cable connections—are the basis for all additional topologies that include interlinks between offshore platforms.

When we initiated the study, we considered comparing our topologies to a counterfactual, or reference case, that included smaller projects and more radial cables. However, the U.S. industry has generally moved beyond these types of projects to larger ones for procurements (Musial et al. 2023). Recent solicitations in New York[18] and New Jersey[19] mandate using HVDC in most circumstances, and the New England Energy Visions Transmission Initiative is based on it (New England Energy Vision n.d.). Because these projects are generally larger than 1 GW and use the full capacity of an HVDC cable already, it made sense to assume that the radial topology, with large projects, is the reference for the more interlinked topologies.

We then performed initial production cost modeling (see Section 5 for methods) to help inform several manual topology designs in consultation with the TRC. To maximize benefit and minimize costs, we looked for potential connections between nodes that had significant energy price differences,[20] but relatively small cable distances where possible. Using this philosophy, we created the following five core offshore transmission topologies (plus several more alternative topologies discussed in Section 5.2.2). The radial topology aside, these topologies include various types of networking with interlink cables:

[17] Although we did not specifically enforce state targets in the algorithm, state mandates were reached or exceeded in the 2050 result.

[18] https://www.nyserda.ny.gov/All-Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2022-Solicitation

[19] https://www.nj.gov/bpu/pdf/boardorders/2023/20230306/8D%20ORDER%20OSW%20Third%20Solicitation.pdf

[20] These price differences can be driven by diverse generation resources and load and weather patterns.

- **Radial**. Planned connections from offshore substations to the onshore grid; no interlinking platforms
- **Intraregional**. Within-region connections that could complement (and come before) interregional solutions
- **Interregional**. Specifically designed to take advantage of opportunities to connect diverse transmission planning regions by interlinking offshore platforms
- **Inter-intra**. Combines the interregional and intraregional topologies; its intent for study is to determine if the benefits of the two approaches are additive
- **Backbone**. A larger, longer version of interregional build that uses multiple cables to connect platforms connected to POIs in the bookend states for the study—South Carolina and Maine.

We assumed that by 2030, only HVAC lines and 320-kilovolt (kV) monopole HVDC technologies would be used, and single-source contingency limits (between 1,200 and 1,400 MW, depending on the region) would limit single export cables. After 2030 and the first 30 GW installed, we also considered 525-kV bipole HVDC technology, with potential multiterminal solutions noted earlier. This approach assumes alternative solutions to reliability concerns regarding increased single-source contingency limits will be implemented, as the regions are beginning a study of potential solutions now.[21] More discussion on the transmission technologies is provided in Section 4.3.

4.1 Path Routing and Geospatial Data Analysis

For developing both radial and other topologies, all connections (POI to offshore platform, or offshore platform to offshore platform) are assumed to be connected by cables running on routes that use the path routing methodology as described in this section. The goal of the path routing analysis is to understand the approximate cable distances that may be needed to connect certain points, identify cable siting challenges, and select offshore wind locations that are consistent with these siting challenges. This effort was not intended to be an analysis for permitting or detailed project siting. An actual project would need to do project-specific, detailed geophysical studies and surveys.

The path routing method that we used seeks to find the path with the fewest challenges between any two points, on or offshore, using the exclusions and frictions described in Section 3.3. This is the route that minimizes the friction multiplied by the distance for every segment along the path. For example, a 2-mile distance at friction level two is equivalent to a 1-mile distance at friction level four. Each siting layer is applied to every 90-meter (m) resolution grid cell. To find the path

[21] See ISO-NE's request to study increasing the minimum loss of source limit to 2 GW.

with the fewest challenges (also referred to as a "minimum cost path"), we used the Dijkstra (1959) algorithm.[22]

We then used the methods described in Section 4.2 to determine which of the combinations of POIs and offshore wind locations would offer the optimal combination to produce the 85-GW low-carbon scenario in 2050. This detailed siting exercise replaces the initial siting done by ReEDS, so that POI connections and selections can be more precise. We applied the path routing to every combination of candidate POI and every candidate offshore wind energy site within approximately 540 kilometers as an input to that analysis.

Candidate offshore wind locations and their associated wind resource were considered based on siting selection and methods described in Beiter et al. (2023). Many generation siting layers are the same as those used for the friction and exclusions in the cable routing for this study (see Section 3.3). The wind resource is based on wind speed data from the Wind Integration National Dataset Toolkit for 2007–2013, with the power output produced using the reV model and the methods and assumptions from the NREL Standard Scenarios 2022 (Gagnon et al. 2022) and Annual Technology Baseline 2022 for the moderate technology assumptions (15-MW wind turbines with a 150-m hub height).

4.2 Points of Interconnection and Methodology

As noted earlier, the radial topology (and the associated wind plants and POIs) is included in all the topologies. To develop the 2050 radial topology, we used the following categories of information:

- Candidate POIs, location, and suitability for injection (including information from PJM [2021], ISO-NE [2021], DNV-GL [2021] for New York POIs, North Carolina Transmission Planning Collaborative (2021), and stakeholder discussions for considering "new" POIs). These sources were also used to estimate many of the maximum injections at POIs.
- Offshore wind resource quality, costs, availability, and location (from NREL's Annual Technology Baseline n.d.)
- Path route between the two and associated cable costs (described in this section).

We performed a simple optimization to minimize the total approximate levelized cost of energy based on capital costs from these three categories. The cost minimization is intended to represent the trade-offs between resource quality, POI quality (including capacity limitations and a proxy for upgrade costs), and total cable distance between the two. The optimization candidates comprise every possible connection between a candidate POI and a potential location for

[22] Implemented via the scikit-image Python package, which is publicly available at https://scikit-image.org/.

offshore wind energy. Existing lease areas were assumed to be developed. For additional information and a list of POIs considered, see Appendix E.

Cost estimates for this comparison are not intended to represent the total cost of interconnection, generation, and transmission for any given location. Similarly, the POIs are not recommendations from the study team, but are intended to make a credible case for testing the value of different transmission topologies. Further study by grid stakeholders (e.g., by system operators and developers and relevant state energy agencies) will be necessary to select the best combinations of POIs and offshore wind energy areas. See Appendix E for more details. Table 3 shows the selected POIs. These injections total approximately 27 GW physically interconnected in ISO-NE, 19 GW in NYISO, 26 in PJM, and 13 GW in the Carolinas.

Table 3. Points of Interconnection and Total Megawatt Injection in All Topologies (2050)

ISO-NE		NYISO		PJM		SERC-Carolinas	
Name	MW	Name	MW	Name	MW	Name	MW
Barnstable, Massachusetts (MA)	830	Astoria, New York (NY)	1,230	BL England, New Jersey (NJ)	430	Georgetown, South Carolina (SC)	2,400
Block Island, Rhode Island (RI)	30	Barrett, NY	1,350	Calvert Cliffs, Maryland	2,000	Greenville, North Carolina (NC)	2,850
Bourne, MA	1,200	East Garden City, NY	2,000	Cardiff, NJ	1,500	Myrtle Beach, SC	2,400
Brayton Point, MA	2,330	East Hampton, NY	140	Deans, NJ	3,100	New Bern, NC	3,200
Haddam Neck, Connecticut (CT)	1,200	Farragut East, NY	1,310	Fentress, Virginia (VA)	5,200	Sutton North, NC	2,200
Davisville, RI	720	Farragut West, NY	1,310	Hope Creek, NJ	2,000		
K Street, MA	2,000	Gowanus, NY	820	Indian River, Delaware	1,600		
Kent County, RI	1,870	Holbrook, NY	1,050	Landstown, VA	2,600		
Maguire Road, Maine (ME)	1,200	Mott Haven, NY	2,000	Larrabee, NJ	1,300		
Manchester St, RI	1,200	Northport/ Pilgrim, NY	1,500	Oyster Creek, NJ	820		
Millstone, CT	1,200	Rainey, NY	2,000	Salem, NJ	2,000		

ISO-NE		NYISO		PJM		SERC-Carolinas	
Name	MW	Name	MW	Name	MW	Name	MW
Montville, CT	800	Ruland Rd, NY	2,000	Smithburg/ Atlantic, NJ	3,600		
Mystic, MA	1,990	Shore Rd, NY	1,310				
Norwalk, CT	1,200						
Pilgrim, MA	1,830						
Seabrook, New Hampshire	660						
Tewksbury, MA	1,770						
Ward Hill, MA	1,200						
West Barnstable, MA	840						
West Farnum, RI	1,200						
Yarmouth, ME	1,200						

Note: Salem, Hope Creek, Calvert Cliffs, Millstone, and Seabrook are injections near existing nuclear units. If these units retire after existing permits expire, they could be good injection points with minimal upgrades. If the licenses are extended again, grid upgrades or injections nearby on the network may be necessary. Longer export cables at these injections would add less than 1% to the total radial costs described in the following section.

4.3 Transmission Costs

This section compares different transmission topologies to better understand the additional resources required to build a low-carbon, reliable grid offshore. The results are not intended for specific project planning because of the high variability of specific project characteristics.

This analysis uses a combination of Offshore Renewables Balance-of-system and Installation Tool modeling (Nunemaker et al. 2020) and subcontracted work with DNV-GL to reach a complete system cost for each topology.

We derived all cost data provided in this section and Section 4.6 from a subcontract with DNV-GL unless stated otherwise. We developed unit costs with as recent data as possible, and adjusted data sourced from literature to account for inflation. Ongoing inflation and commodity price changes due to varying market conditions add some uncertainty.

4.4 Radial Topology Cost Assumptions

The radial topology includes all the connections from the wind power plant locations to the onshore POIs. All radial connections are one of three technology types: HVAC (220 kV), HVDC monopole (320 kV), or HVDC bipole (525 kV). The distance of the offshore wind plant to shore and the size of the plant determine which technology is the most suitable for each radial connection. HVAC systems have lower substation costs than HVDC systems; however, the carrying capacity of each line is significantly lower, meaning large projects require multiple cables to deliver the same power. There are costs to additional lines beyond the monetary ones. Environmental impacts increase with the number of lines installed; therefore, HVAC implementations lead to more environmental impacts than a similar project using HVDC.

To determine which export system technology was most suitable for each radial connection, we developed cost metrics for the three cable types. We then split the cost of export systems into six categories: cable materials, offshore substation materials, cable installation, offshore substation installation, onshore substation costs, and risk contingency.

The cable material cost includes the cost of the cables themselves. The total length of cable required depends on the carrying capacity of the cable and the distance from the wind power plant to the POI. The carrying capacity and cost per mile of each export system technology are included in Table 4. The listed carrying capacities represent the nominal rating of the line assuming uniform resistivity.

Table 4. Export Cable Unit Costs

Cable	Carrying Capacity (MW)	$ Million per Mile
220-kV HVAC	315	2.06
320-kV HVDC Monopole	1,200	2.67
525-kV HVDC Bipole	2,000	4.57

Offshore substation costs are driven by the cost of transformers, electrical components to protect the export cables, and the substructure and platform required to safely support the mass of all necessary components. The material costs do not include installation as that is added separately. The components required, and thus the platform and substructure size, differ between HVAC and HVDC technologies. The platform size required for HVDC systems is larger than that of HVAC systems due to the mass and footprint of the AC/DC converters. There are additional ancillary costs associated with offshore substations that include communications systems, backup generators, workspace costs, and more. The unit costs for all substation components are included in Table 5 and Table 6. All costs reported in this section are based on recent expectations and do not fully account for ongoing supply chain developments, inflation, or equipment costs. While these factors could influence costs significantly, long-term trends in equipment costs are difficult to predict given the rapid growth of global offshore wind energy markets.

Table 5. HVAC Offshore Substation Unit Costs

Cable	$ Million
Transformer	2.87
Shunt Reactor	0.14/mile
Switchgear	4.0
Platform	107.3
Ancillary Systems	6.0

Table 6. HVDC Offshore Substation Unit Costs

Device	Monopole	Bipole
	$ million	$ million
Converter	127	296
Platform	294	476

Export cable installation costs depend primarily on the day rate of the required vessels, the time required for installation, and the port fees associated with installation time. As a result, we determined the cost rate of installation per mile of installed line. These costs were developed with TRC feedback and align with DNV estimates. For this analysis, we do not account for the cost differences due to varying seabed conditions. The installation cost rates are included in Table 7.

Table 7. Export Cable Installation Rates

Cable	$ Million/Mile
220-kV HVAC	1.3
320-kV HVDC Monopole	1.6
525-kV HVDC Bipole	2.7

Onshore costs of transmission are the most challenging to model because of various existing infrastructure onshore. While offshore electrical infrastructure can be designed largely independent of location, the onshore connections depend on available capacity at the POIs. The following results use a minimum cost of interconnection, including the hardware required to connect a transmission line to an existing substation, to estimate an onshore substation cost. The unit costs include the major electrical components and estimated onshore construction cost. Table 8 and Table 9 show the cost rates of these onshore components.

Table 8. HVAC Onshore Substation Unit Costs

Device	$ Million
Switchgear	9.33
Shunt Reactor	39.96
Transformer	2.87
Construction	5.00

Table 9. HVDC Onshore Substation Unit Costs

Device	Monopole ($ million)	Bipole ($ million)
Converter	157	350
Construction	87.3	100

Both the HVAC and HVDC designs include a risk contingency adder to account for unforeseen challenges in design and installation. Although cost uncertainties are lower for more mature technologies, we add 8% of the total capital costs (in addition to the costs presented earlier) to all technologies to incorporate risk and contingencies (e.g., DNV-GL 2021).

Given all the unit costs reported, we developed cost metrics to compare the three technologies. Different project sizes were chosen for each configuration to avoid unused capacity and explore the ones that are the most efficient. We chose the project size to use all available capacity for each technology. The 220-kV HVAC cable configuration used a project size of 900 MW, which requires three cables and one substation, all at maximum carrying capacity. The HVDC cable configurations each used the maximum carrying capacity of the cable—1,200 MW and 2,000 MW for the 320-kV monopole and 525-kV bipole, respectively—and thus requiring one set of cables and one substation each.

We explored three cable lengths in Figure 14 to show the relative benefit of HVDC for longer cable lengths. Using these generalized cost assumptions, HVAC costs are lower for a 20 mile cable route, but HVDC costs are more economical at 50 miles and beyond. HVAC export systems have a lower carrying capacity per cable, thus requiring more cables, driving up the total cable material and installation cost as cable length increases. Because of losses in long HVAC lines, the shunt reactor cost will increase with cable length as additional reactive power compensation is needed. The total per-megawatt cost for each of the HVDC technologies is similar, with 525-kV bipole systems being slightly more expensive across all cable lengths.

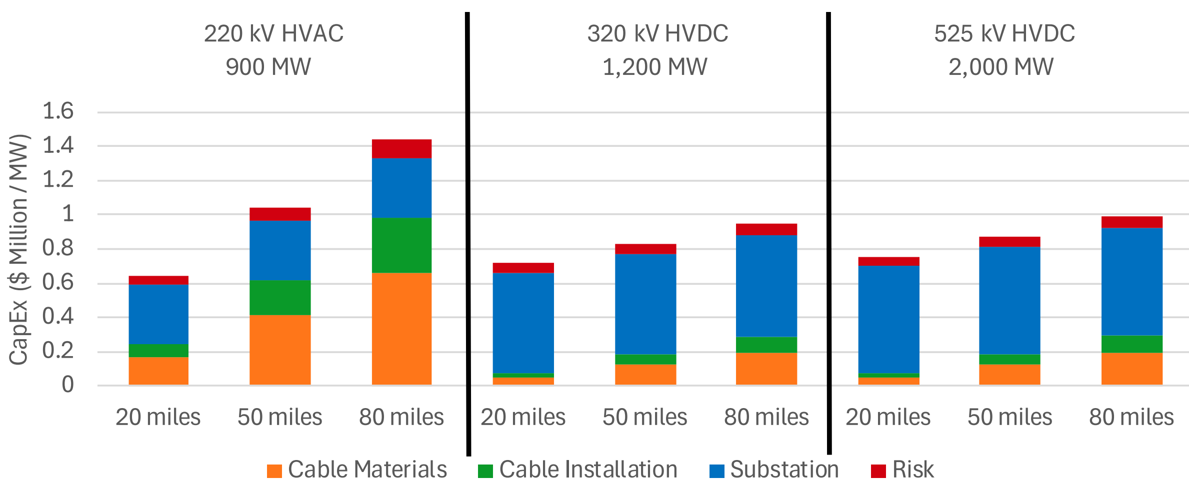


Figure 14. Optimized capacity cost metrics. ***Figure by NREL***

Note: CapEx = capital expenditures; OSS = offshore substation; mi = miles

The cable cost metrics in Figure 14 informed the cable selection for the radial topology. Cables of all three types were used in the radial topology depending on the distance of the wind plant from shore and the plant capacity. The radial topology was used as the base of each of the following interlinked topologies, which include the interregional, intraregional, inter-intra, and backbone.

4.4.1 Interlinked Topology Cost Assumptions

The additional costs required for HVDC interlinks include direct-current circuit breakers (DCCBs), breaker platforms, and interlink cables. HVAC interlinks comprise a meshing cost (including the shunt reactors for compensation) and the cable cost. The meshing unit cost was derived from the expected mesh-ready costs required to meet the NYSERDA mesh-ready requirements (Pfeifenberger et al. 2021).

For multiterminal HVDC networks, the number and placement of the DCCBs and platforms influence the system costs. The DCCB cost estimate used in this study assumes a current rating of 16 kilo-amps (kA) and falls within a reasonable range of uncertainty given the emerging market as provided by DNV. Figure 15 shows the placement of DCCBs in a representative six-terminal network.

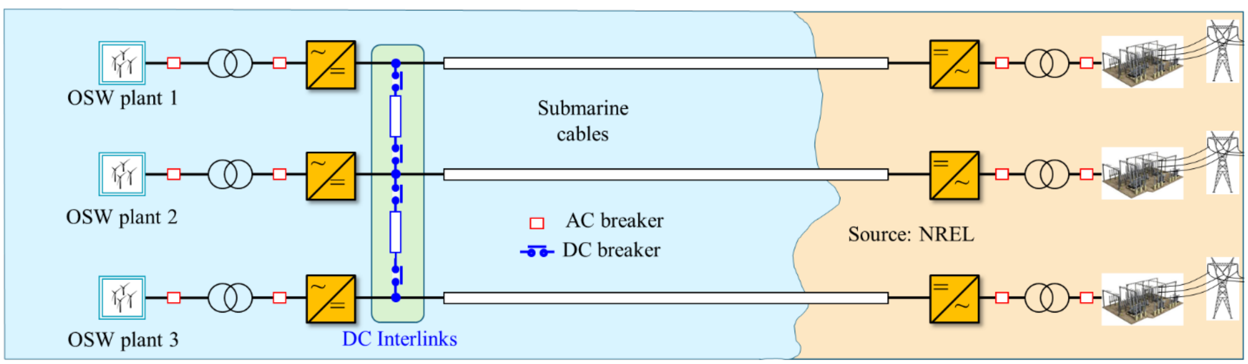


Figure 15. Multiterminal HVDC network. ***Figure by NREL.***

Note: OSW = offshore wind

Circuit breakers are required on the end of each pole in the network, meaning the end nodes on the network have two DCCBs, whereas the middle node has four DCCBs. This configuration also means the platform at the middle node is larger and has higher costs because it must support twice the number of DCCBs. The assumed DCCB and platform unit costs are included in Table 10. All DC interlink cables are 525 kV.

Table 10. Interlink Unit Costs

Component	$ Million
DCCB	25
End Platform	75
Middle Platform	95
AC Meshing	45

4.5 Radial Topology for 2050

The build-out resulting from the path routing and route selection analysis described earlier for 85 GW is shown in Figure 16. The development of wind generation goes beyond the existing lease areas today. The white bubbles in the ocean represent areas with wind turbine development. The black outlined circles onshore represent POIs, whereas the black cables represent the cables connecting them. Subsequent maps will highlight the additional transmission topologies in different colors.

Figure 16. Radial topology for 2050 (85 GW of offshore wind). ***Illustration by Billy Roberts, NREL***

4.6 Interlinked Topologies for 85 GW in 2050

4.6.1 Interlinked Topology Design

After designing the radial topology and performing initial production cost modeling (see Section 5), we designed several different topologies for comparison. The intraregional, interregional, inter-intra, and backbone topologies all extend the radial topology by including interlinks between offshore platforms. Collectively, these four interlinked topologies characterize possible future trajectories for offshore transmission builds to support reliable, low-cost operation of the bulk power system in the Atlantic portion of the Eastern Interconnection. In each topology, the interlinks can be used for arbitrage, curtailment mitigation, and reliability (e.g., resource adequacy or redirecting power during export cable outage). These topologies with offshore interlinks are also referred to as interlinked or networked topologies.

Offshore transmission build-out in each of these topologies considers feasibility of cable routing, cost of cable routing, and benefits of the transmission build. Each of the four interlinked topologies is designed to consider these objectives, primarily by reducing cable lengths where feasible, given that greater cable length increases costs; and building interlinks to connect POIs with large annual average price differences as an indicator of value. As was the case with POI selection, interlinking cables chosen for the four topologies are not recommendations. Instead, build-outs characterize future trajectories while considering the difficulties, costs, and relative value of pursuing the selected interlink build-out.

Cable length between linked platforms is an important driver of interlink cost (see Section 4.6.2). Cable lengths are constrained by path routing feasibility and topology definition. For example, the intraregional topology is defined to only include cables that connect offshore platforms with radials to POIs in the same Atlantic region (e.g., both in ISO-NE). Cables in the interregional topology all connect two adjacent Atlantic regions (e.g., ISO-NE to NYISO). The inter-intra topology combines the two topologies without modifying them. The backbone builds three additional cables connecting a platform in each of the four regions in addition to including the interregional topology build. There are seven linking intraregional and seven linking interregional cables, each with a default rating of 2,000 MW and assuming 525-kV multiterminal HVDC.[23]

Cables should generally interconnect the POIs with the highest price differentials between them where possible, subject to topology definition. Because of restrictions around cable routing, distance between prospectively connectable platforms, different sizes of onshore POIs (see Table 3), and additional engineering judgement, cables do not strictly connect the POIs with the highest price differences. However, connection choices, particularly for interregional builds, are guided by the information in Figure 17. For the interregional multiterminal networks, we also tried to

[23] This technology was assumed for multiterminal HVDC for consistency with efforts in Europe to procure multiterminal offshore wind energy systems.

connect ISO-NE all the way to PJM in a multiterminal network, so power could flow longer distances without going onshore and back offshore. An interregional topology that did not make this last assumption was explored in the sensitivity analysis in Section 5.2.2.1.

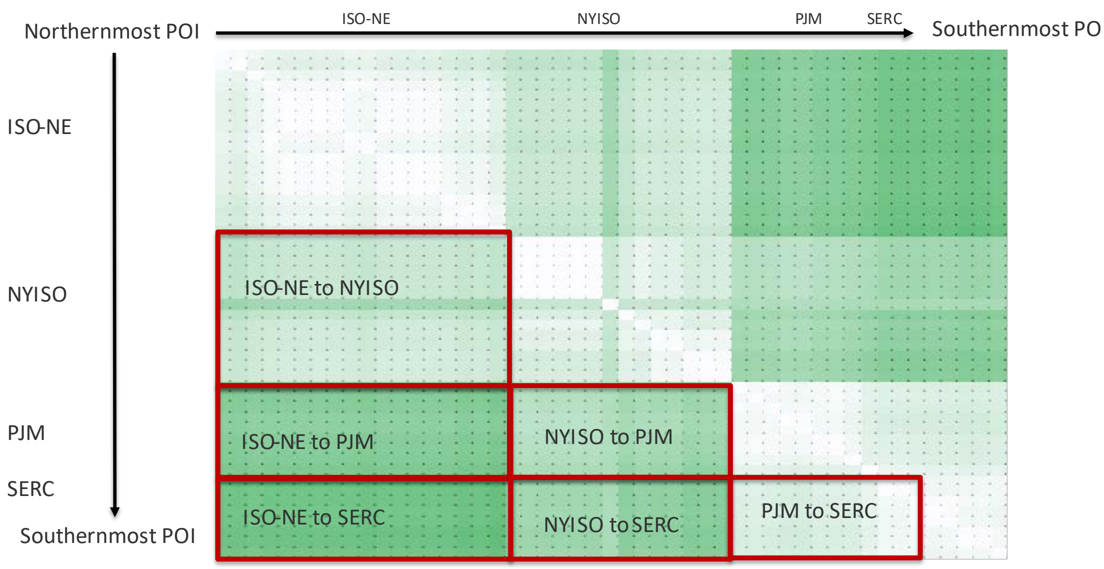


Figure 17. Grid of average absolute hourly price difference between POIs in the 2050 radial PLEXOS run. ***Figure by NREL.***

Note: Red boxes group and label interregional POI pairings. Dark green colors represent price differences of approximately $130/megawatt-hour on average between ISO-NE and SERC.

As shown in Figure 17, price differences[24] between POIs in the radial topology are highest between regions. Using this information along with distance and implied cost information, we selected the platforms that connect to the POIs in Table 11 for inclusion in the four topologies.

[24] Price differences were based on early production cost modeling for the project, as described in Section 5.

Table 11. Interlinks by Scenario

Platform 1		Platform 2		Interlink Scenario (Grey Is Included, Red Is Not)			
POI Name	**Region**	**POI Name**	**Region**	**Intraregional**	**Interregional**	**Inter-Intra**	**Backbone**
Landstown	PJM	Fentress	PJM				
Mystic	ISO-NE	Tewksbury	ISO-NE				
Norwalk	ISO-NE	Mystic	ISO-NE				
Pilgrim	NYISO	Farragut	NYISO				
Shore Rd	NYISO	West 49th	NYISO				
Smithburg	PJM	Deans	PJM				
Tewksbury	ISO-NE	Maguire	ISO-NE				
Greenville	SERC	Calvert Cliffs	PJM				
Kent County	ISO-NE	Mott Haven	NYISO				
K Street	ISO-NE	Ruland Rd	NYISO				
Mott Haven	NYISO	Hope Creek	PJM				
Mystic	ISO-NE	Rainey	NYISO				
Rainey	NYISO	Salem	PJM				
Ruland Rd	NYISO	Deans	PJM				
Georgetown	SERC	Calvert Cliffs	PJM				
Calvert Cliffs	PJM	Mystic	ISO-NE				
Mystic	ISO-NE	Maguire	ISO-NE				

The interregional, intraregional, and backbone topologies are shown in Figure 18 through Figure 20. Figure 21 shows a stylized version of the interlinks for easier understanding of the interregional and backbone topologies.

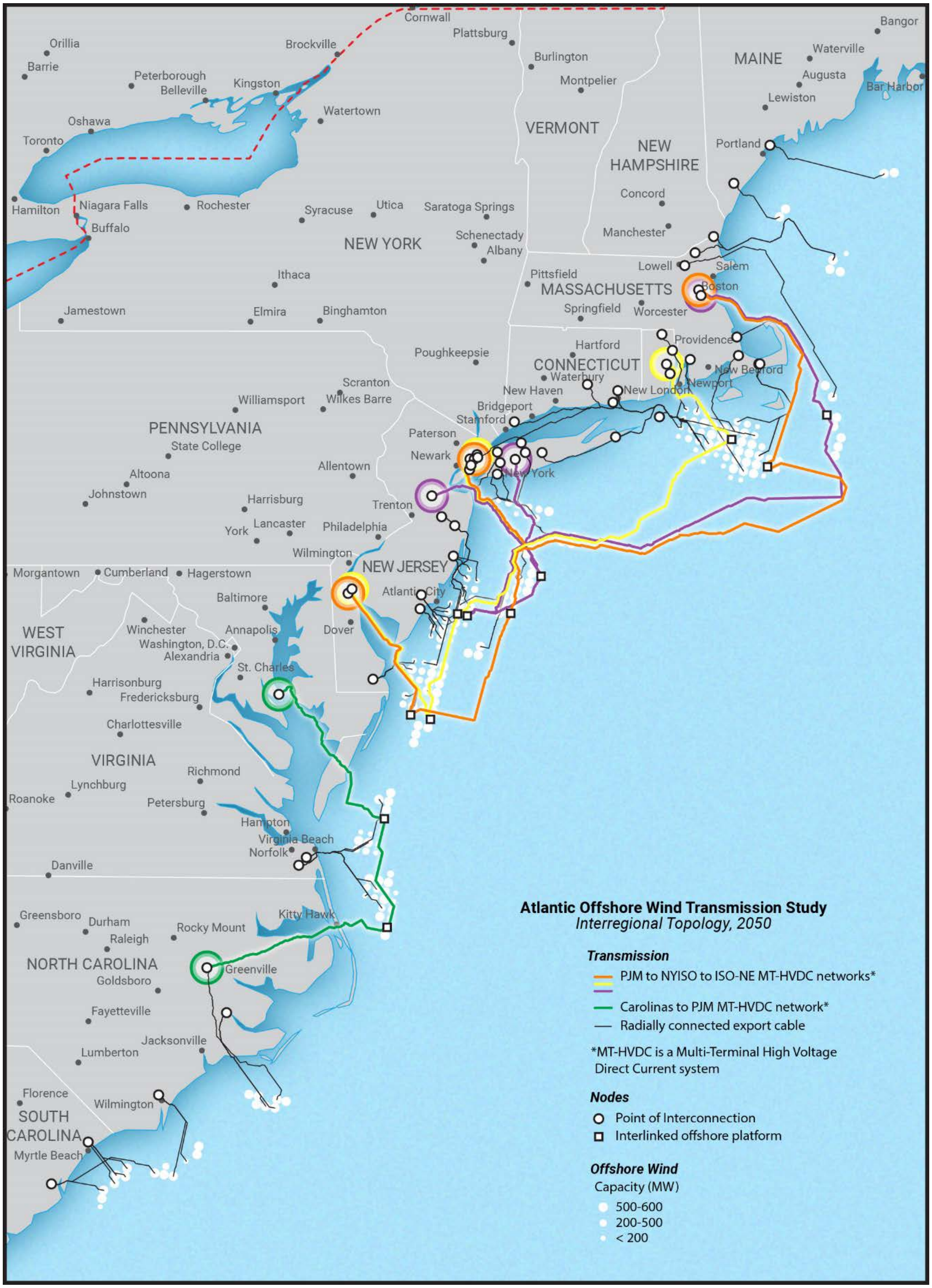


Figure 18. Interregional topology geographic path-routed map (2050, 85 GW). ***Illustration by Billy Roberts, NREL***

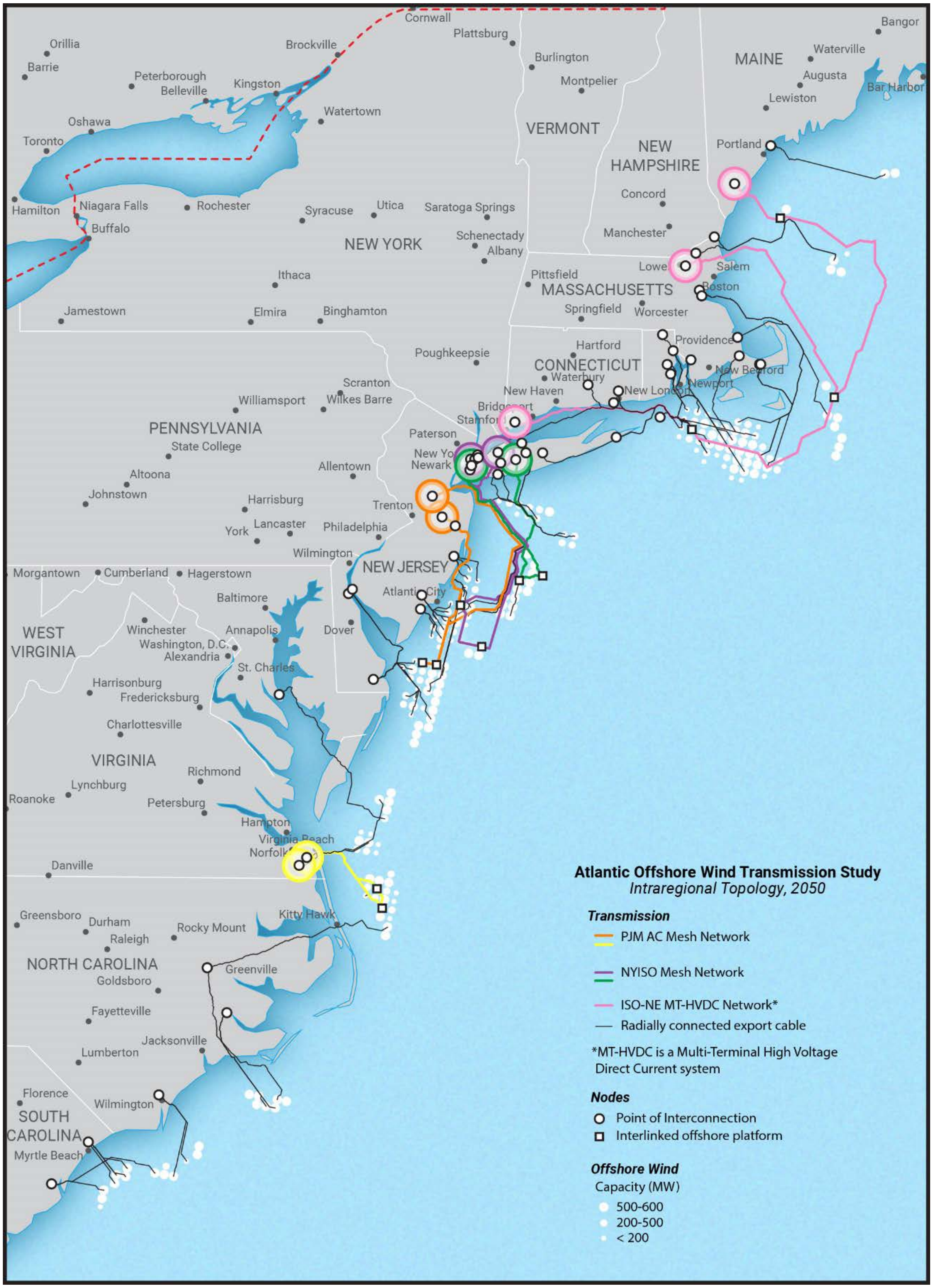


Figure 19. Intraregional topology path-routed map (2050, 85 GW). *Illustration by Billy Roberts, NREL*

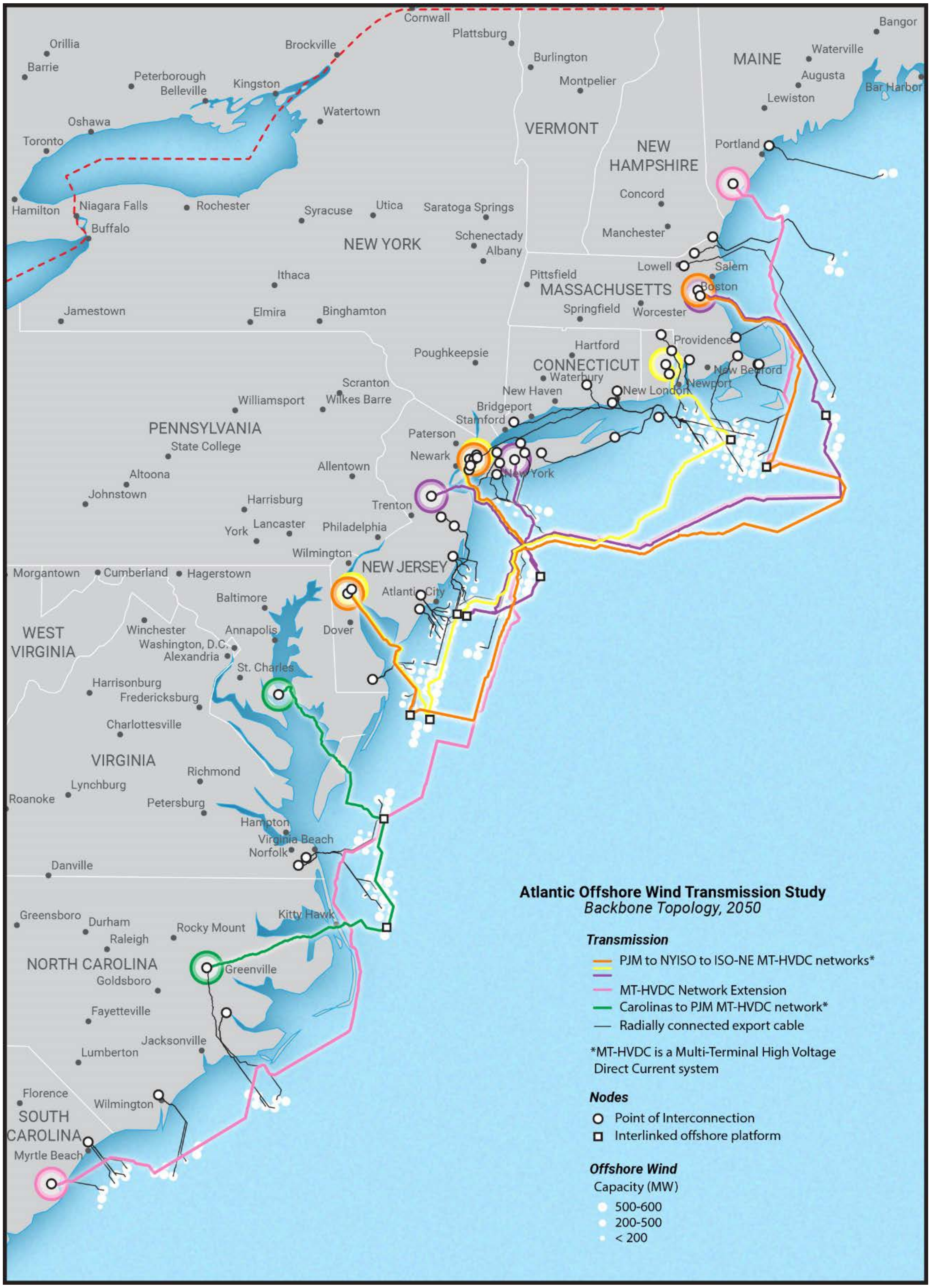


Figure 20. Backbone topology path-routed map (2050, 85 GW). *Illustration by Billy Roberts, NREL*

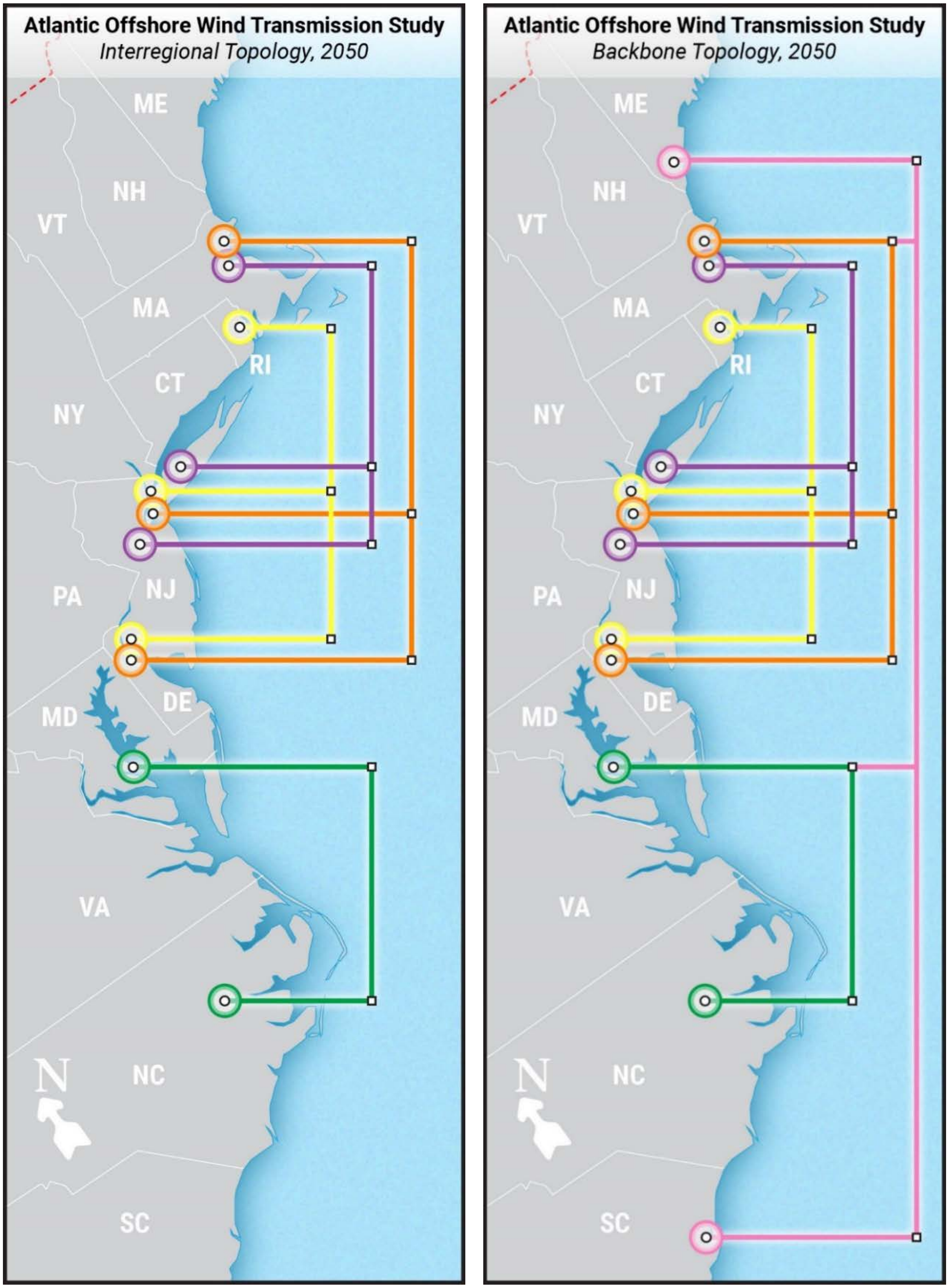


Figure 21. Map of the connectivity for the interlinked topologies in the interregional (left) and backbone (right) topologies (path-routed versions in previous figures, both for 2050, 85 GW of offshore wind energy).
Illustration by Billy Roberts, NREL

4.6.2 Transmission Costs of the Five Topologies

The total costs of the five topologies are included in Table 12. We calculated the radial topology cost using export system specifications provided by the path-routing task. The total cost of each interlink adder was calculated using the unit costs provided earlier and the topology specifications determined in the path-routing analysis. The costs in this section assume all installation occurs in a single stage, or with prebuilds that minimize retrofits. If implementations required retrofitting of existing infrastructure, additional costs would be incurred.

The cable cost comprises most of the cost in every case as shown in Figure 22. The platform and DCCB costs each account for less than 10% of the total cost in every interlink adder case. The AC meshing costs comprise 9% of the intraregional cost but only 2% of the inter-intra topology cost. All costs in the interlink topologies include installation and the risk adder.

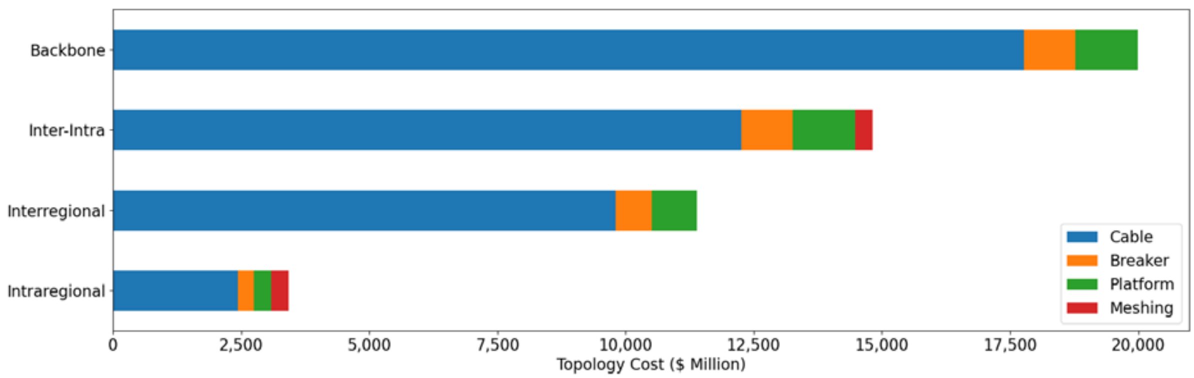


Figure 22. Interlink adder cost breakdown (85 GW installed offshore wind energy). ***Figure by NREL***

As mentioned previously, each topology builds on the radial case, so Table 12 includes the interlink adder cost for each interlink case and the total topology. The interlink costs are a relatively small percentage of the radial export system that is constructed in every case. Even in the highest cost case—the backbone—the interlink costs comprise only 17% of the total topology cost. The benefits of these interlinked topologies are explored in Section 6.

Table 12. Topology Total Costs (85 GW Installed Offshore Wind Energy)

Topology	Interlink Adder ($ billion)	Total Cost ($ billion)
Radial	--	96.3
Intraregional	3.6	99.9
Interregional	11.4	107.7
Inter-Intra	14.9	111.2
Backbone	20.0	116.3

5 Production Cost and Resource Adequacy

Production cost and resource adequacy analysis quantifies how offshore transmission topologies listed in Section 4.6 add value to the bulk electric power system in the eastern United States. Modeling results show offshore transmission builds provide the most value when they enable additional interregional power flow, particularly during times when low-cost generation in one region can be used to displace high-cost generation in another. Additional transmission build has generally additive value in explored scenarios and retains value under a range of key sensitivities in 2050 scenarios with high shares of renewable generation and load growth. Transmission builds also reduce generation curtailment of the 85-GW build-out of Atlantic offshore wind generation capacity.

Production cost modeling evaluates how the hourly utilization generation resources changes with the different offshore transmission topologies. Resource adequacy analysis quantifies how generation resources can be shared across regions to reduce the risk of insufficient electricity supply when additional transmission topologies are made available. Together, production cost and resource adequacy analysis allow us to evaluate the energy-related and capacity-related value, respectively, of offshore transmission build alternatives. Additional details on modeling tools used to conduct the analysis are included in Appendix A.

5.1 Production Cost Scenarios and Data

The aim of production cost scenarios is to provide sufficient detail on transmission and generation resource operations in the Eastern Interconnection on a realistic, envisioned future electric grid to value offshore transmission builds. Because this value is contingent on the Eastern Interconnection's transmission network design and locations of loads and generation resources, modeling proceeds from adding transmission-focused detail to future scenarios developed in Section 2. We begin from the same envisioned 2050 power system based primarily on the ReEDS low-carbon scenario. Production cost scenarios use 2012 weather and additional onshore transmission system expansion to the 2031 Eastern Interconnection multimodel working group data (Appendix D) to integrate a highly decarbonized generation mix. Additional transmission expansion and unit-level generator operating characteristics and locations are added to the zonal capacity expansion model to create a more refined nodal model. Production cost scenarios differ in offshore transmission topology, offshore transmission operational limits, and fuel price assumptions.

All production cost scenarios have the same 85-GW offshore wind build in 2050. Site-level offshore wind generation profiles are aggregated to their connected POI (see Section 4.2 for details on POI selection). We expand onshore transmission to conduct realistic production cost modeling with greatly increased electricity load and share of variable generation in the Atlantic regions. An explanation of the process of selecting transmission lines for expansion is in Appendix D.

To connect offshore wind in production cost modeling, we associated each POI with an offshore platform to which offshore wind generators are connected. Radial lines between the onshore POI and offshore platform are sized to ensure full deliverability and assumed to have a 2% forced outage rate, which is similar to values for related transmission configurations in other recent studies (DNV-GL 2021; Pfeifenberger et al. 2023b) and consistent with engineering estimates for similar technology (TenneT 2019). Additional topology-specific offshore transmission builds, where applicable, link offshore platforms and are assumed to have a 2% forced outage rate.

The 2050 fuel price assumptions common to all scenarios (except low and high hydrogen price sensitivity) are in Table 13. Fuel prices are consistent with ReEDS modeling (Section 2) and with NREL's 2022 Standard Scenarios (Gagnon et al. 2022), including costs reflecting the low-carbon scenario emissions constraint. Fuel prices are reported in real 2021$.

Table 13. 2050 Fuel Price Assumptions

Category	2050 Price ($/million British thermal units)
Biomass	2.30
Coal-CCS	7.38
Natural Gas	29.00
Natural Gas-CCS	5.60
Nuclear	0.82

The 2012 weather year is used in all production cost scenarios; additional weather years are incorporated in resource adequacy modeling (Section 5.4). The 2012 weather year is used for consistency with capacity expansion planning in ReEDS (Section 2) and recent NREL grid integration work (Brinkman et al. 2021; Bloom et al. 2022). In the Atlantic in 2012 there was relatively mild winter weather and below-average offshore wind generation compared to other weather years. Figure 23 provides a comparison of 2012 offshore wind production to other available weather years (see also Maclaurin et al. 2021). Milder winter weather results in lower peak loads in electrified, winter-peaking Atlantic regions (Figure 24) than in most other weather years with available time-synchronized generation and load data (2007–2013).

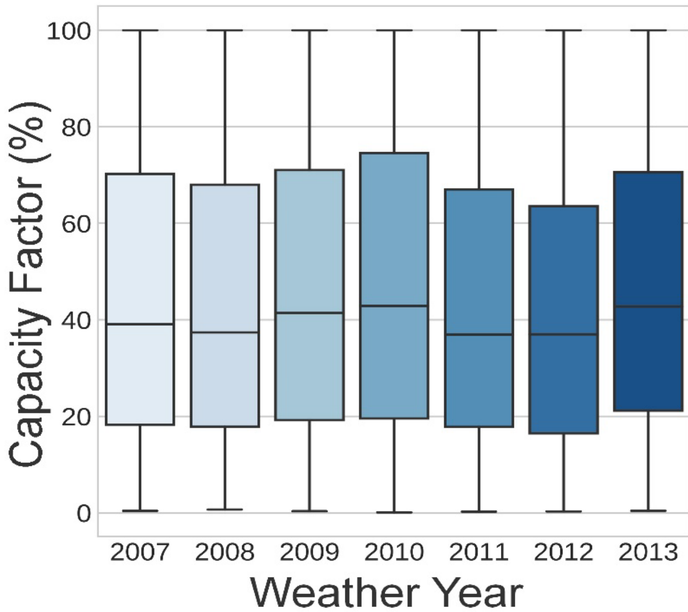


Figure 23. Offshore wind hourly capacity factor distribution for aggregation of sites comprising a 85-GW build by weather year. ***Figure by NREL.***

Note: The black line is the median hourly capacity factor; blue boxes show the interquartile range.

Electrification in the low-carbon ReEDS scenario (see Section 2) includes significant electrification of space heating that is consistent with previous NREL research on future electricity demand trajectories (Mai et al. 2018). Electrification causes the three Atlantic-adjacent independent system operators' (e.g., PJM, NYISO, ISO-NE) systems to transition to peaking in the winter for 2012 weather, whereas SERTP peaks in the summer.

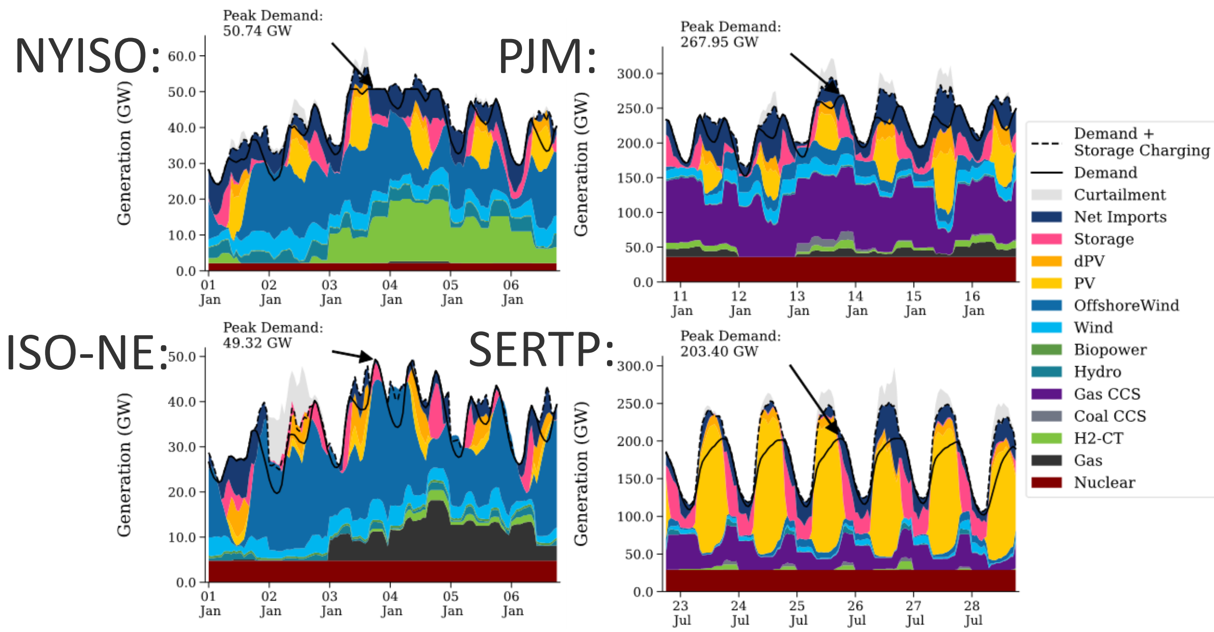


Figure 24. Peak demand and radial scenario generation for Atlantic regions with offshore wind POIs during the 2012 weather year with 2050 electricity system infrastructure. ***Figure by NREL*.**

Note: dPV = distributed photovoltaics; PV = photovoltaics; H2-CT = hydrogen combustion turbine

5.2 Production Cost Results

Production cost scenario results presented in this section cover the radial reference topology and four interlinked offshore topologies (intraregional, interregional, inter-intra, and backbone) introduced in Section 4 (see Table 11) and seven additional sensitivities. The four offshore topologies are referred to as interlinked topologies. Sensitivities are all variations on the four interlinked topologies and the radial topology and, because they do not introduce new interlinks, are referred to as sensitivity scenarios. Unless otherwise specified, the radial topology (no offshore interlinks) is the reference scenario.

5.2.1 Interlinked Topology Production Cost Results

Table 14 details the production cost savings in the Eastern Interconnection and offshore wind curtailment relative to the radial reference scenario. Results in Table 14 and throughout this section are single-year, 2050 savings. Offshore wind curtailment values likewise reflect 2050 results. Production costs reflect the cost of producing electricity but not investment in building electricity generation and transmission infrastructure. Dollar values are in real 2021 U.S. dollars.

Table 14. 2050 Production Cost Results (U.S. Eastern Interconnection, 2050 Build-Out With 2012 Weather).
Note: Curtailment values are plotted in Appendix A.

Topology	Description	Annual Savings vs. Radial ($ million) in 2050[25]	Offshore Wind Curtailment (terawatt-hour/%)
Radial	Baseline	-	22.2 [7.2%]
Intraregional	Interlinked topologies as described in Section 4.6	502	22.0 [7.1%]
Interregional		1,699	18.5 [6.0%]
Inter-Intra		2,108	17.6 [5.7%]
Backbone		2,993	15.4 [5.0%]

Additional transmission capacity reduces production costs primarily by substituting lower-cost generators for higher-cost ones. For offshore transmission cables, this substitution happens via two mechanisms:

- **Increased deliverability of offshore wind generation**. Lower-cost wind generation that might otherwise be curtailed if the only deliverable to its onshore POI can instead be delivered via offshore transmission to an alternative POI. Offshore wind curtailments are reduced with increasing offshore transmission build (Table 14).
- **Increased use of lower-cost onshore generation**. Offshore transmission build increases the ability to substitute less-expensive existing generators with ones that are more expensive by using newly enabled transmission paths.

The combined effect of these mechanisms is captured in the annual generation change, shown for the interregional topology compared to the reference radial topology in Figure 25. Annual generation changes for each of the four Atlantic regions with offshore wind POIs (e.g., PJM, ISO-NE, NYISO, SERTP) for the interregional topology are in Appendix A.

[25] Total production costs in the radial topology are $89.3 million, so production cost savings range from 0.6%–3.3% of total production costs.

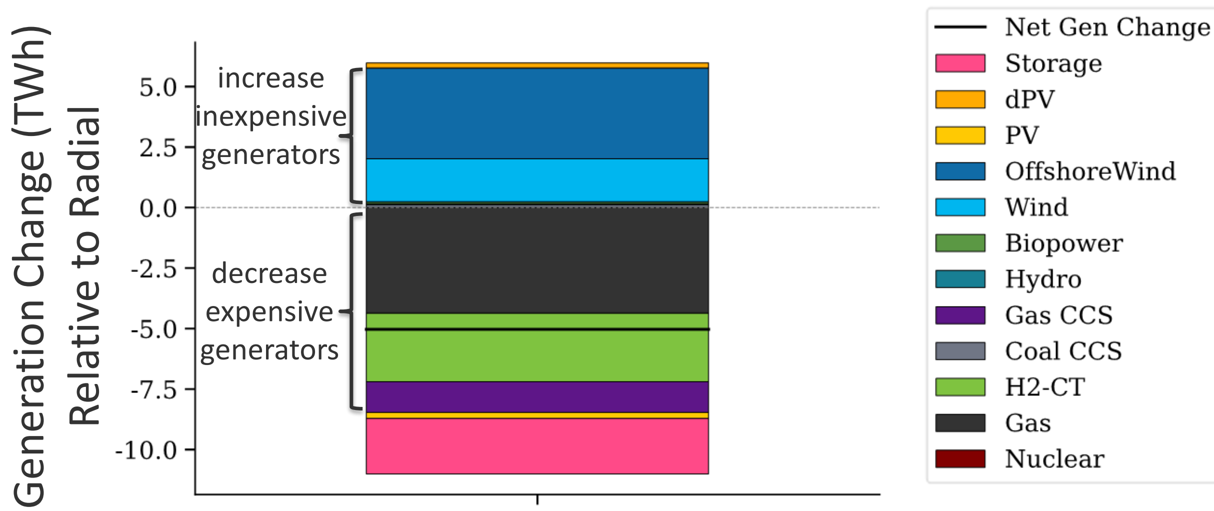


Figure 25. Annual total generation change (TWh) in the interlinked interregional topology compared to the reference radial topology. ***Figure by NREL***

Annual generation changes result from hourly changes to generation mix due to the ability to flow power on the offshore transmission network. The interregional offshore interlinks are highly used, with flows occurring during most hours (Figure 26).

High interlink use can result from bidirectional flows or increased unidirectional flow from a lower- to a higher-priced region. Unidirectional flows can make implementation more challenging because value flows from generators in one region to consumers in another. Figure 26 shows that flows are bidirectional for the interregional interlinks, indicating shared operational value for additional connections between Atlantic regions. A version of Figure 26 that plots duration curves is included in Appendix A.

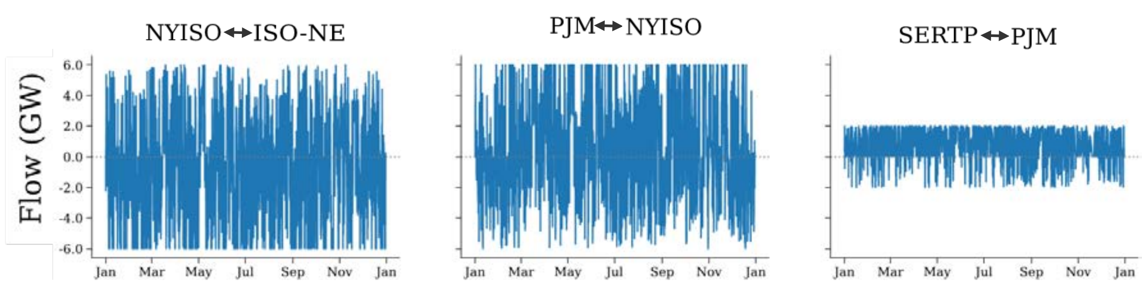


Figure 26. Hourly flows on interlinked interregional transmission lines in the interregional topology. ***Figure by NREL***

Note: PJM to ISO-NE and PJM to NYISO flows comprise three different interregional lines.

Flows occur and create value throughout the year, but the highest value times for interregional offshore flows are typically those with low offshore wind generation (Figure 27). Days with high load or load net of renewable generation (Atlantic regions only) also have higher production cost savings on average, though largely because days with high load net of renewable generation are correlated with low offshore wind days (see Figure A-3 in Appendix A). This correlation between low offshore wind generation and increasing network value is observed primarily because low offshore wind generation times are, by definition, when the most power can flow on an offshore network not otherwise constrained by delivering wind generation. Flows on the interregional offshore lines themselves decrease with increasing availability of offshore wind generation (Figure 27), which congests lines needed to flow power to onshore POIs.

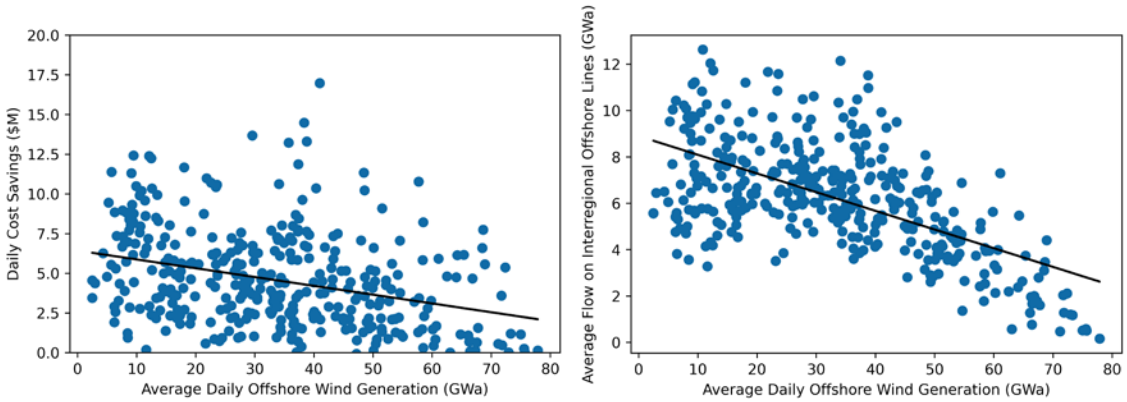


Figure 27. Production cost difference savings in the interregional vs. radial topology for each of the 365 modeled days in the 2050 Eastern Interconnection (left), and average daily flow (both directions positive) (right) on the seven 2-GW (14 GW total) interlinked interregional lines shown in Figure 26. *Figure by NREL*.

Note: GWa = average gigawatts

5.2.2 Sensitivity Scenarios and Results

We conducted a sensitivity analysis to evaluate the benefits of interlinked offshore transmission for a range of uncertainties. The seven sensitivities comprising this analysis fall generally into three categories: topology (Section 5.2.2.1), operational (Section 5.2.2.2), and fuel prices (Section 5.2.2.3). Fuel price sensitivities and the onshore extension sensitivity make changes to the onshore power system assumptions. In these sensitivities, a comparison to the radial reference scenario is no longer appropriate, because, for example, changes to fuel prices also affect production costs in the reference scenario. We ran three additional references scenarios for comparison with the fuel price and onshore extension sensitivities. All other sensitivities use the radial topology as a reference scenario comparison. The sensitivities are designed to explore the impact of different key uncertainties on offshore transmission value. They are not designed to holistically capture a full range of future system conditions or uncertainties.

The sensitivity scenarios are described in Sections 5.2.2.1-5.2.2.3. Table 15 summarizes the seven sensitivity scenarios and resulting change in system savings compared to the radial reference scenario.

5.2.2.1 Alternative Offshore and Onshore Topology Sensitivities

Sensitivities include three alternative transmission topology designs for the offshore (modified backbone, inter short distance) and onshore (onshore extension) Eastern Interconnection network. The alternative onshore (onshore extension) network affects the production costs of the whole system, so we ran a radial scenario with the same adjustments and used it as the comparison scenario.

The purpose of these scenarios is to investigate whether significant changes in topologies impact our overall conclusions about the value of an offshore network. The three alternative sensitivities include:

- **Modified backbone.** The interlinked backbone topology is modified to reduce the length of the backbone and bring more power up from the southern portion of the Atlantic study area. Modifications are also informed by POI price differences (see Section 4.6.1) observed in the radial and backbone topology results. The three southern POIs are incorporated into the three northern offshore networks instead of a new, parallel network that runs the entire length of the coast.
- **Inter short distance.** We reconfigured the seven interregional lines to decrease the average line length while still linking POIs in adjacent market regions with large price differences. The inter short distance sensitivity is motivated by results in Section 4.6.2 showing that interlinked offshore transmission builds are largely (65%–90% in interlinked topologies) made up of cable costs, with some of those costs a function of cable line miles.
- **Onshore extension.** This sensitivity increases the connection between the 765-kV transmission system in noncoastal PJM and PJM's Atlantic Coast offshore wind POIs by adding two lines. These two additional lines enable higher utilization of lower-cost generation in the western PJM and the Midcontinent Independent System Operator (MISO) to serve load in Eastern PJM. When the interregional offshore build is added to the onshore extension, higher use of low-cost generation (e.g., renewables and combined cycle with carbon capture and sequestration) can serve more load in the Atlantic regions.

Additionally, the modified backbone and inter short distance scenarios are not included in Section 6.3.2 because the costs and benefits of the build are not studied in detail. The modified backbone sensitivity is motivated by the potential to reduce the number of cable line miles in an Atlantic-spanning build with attention to linking potentially high-value POIs based on large observed price differences. Production cost savings for the modified backbone are higher than for the backbone ($3.3 billion vs. $3.0 billion compared to the radial topology); so, if it is feasible to route at a similar or lower cost given the reduced line miles, there is potential for alternative backbone topologies to offer similar net benefits.

Production cost savings for the inter short distance sensitivity are lower than the interlinked interregional topology ($1.2 billion vs. $1.7 billion), but net benefits and the benefit-to-cost ratio could increase if the sizable reduction in line miles of offshore cables linking platforms significantly reduces costs while retaining many of the savings from increased interregional transmission capacity.[26]

5.2.2.2 Additional Operational Constraint Sensitivities

We conducted two operational constraint sensitivity analyses to help distinguish between the value associated with changing operational rules from the current practice for application to operating offshore transmission networks in the future. Both sensitivities make modifications to the interlinked interregional topology. Because both sensitivities modify only the offshore interlinks, they are compared to the radial topology in Table 15. The two operational constraint sensitivities include:

- **Cable limit.** The offshore transmission network is sized to be 1.2 GW instead of 2 GW for consistency with existing rating limits on the loss of a single transmission line or generator (single-source contingency). Currently, Atlantic system operators are beginning to consider raising the limit from 1.2 GW to 2 GW (ISO-NE 2023a). This sensitivity uses the same interregional build as the interlinked interregional topology; its change from 2 GW to 1.2 GW for all seven interregional lines is the only adjustment.[27] Comparing this sensitivity ($1.4 billion savings compared to the radial topology) to the interlinked interregional topology with the 2-GW limit ($1.7 billion savings) highlights the additional value of increasing present-day 1.2-GW contingency limits in the context of offshore transmission.
- **Limit radials.** Lines between offshore platforms and onshore POIs are constrained to only allow unidirectional flow from offshore to onshore. The unidirectional offshore to onshore flow constraint highlights the portion of the offshore network value associated with increased deliverability of offshore wind energy by disallowing value from trading power between POIs. The limit radials sensitivity approximately halves production cost savings compared to the interlinked interregional topology ($1.0 billion vs. $1.7 billion). This result indicates that both delivering offshore wind (still allowed) and increased use of lower-cost onshore generation (disallowed by unidirectional offshore to onshore flows) provide significant sources of value for interlinked offshore transmission builds.

[26] One of the philosophies of the interregional topology was that long-distance flows could be accomplished on the offshore multiterminal network without bringing the power onshore. The inter short distance sensitivity does not make this assumption. For flows to go from PJM to ISO-NE, for example, it would have to go via a New York platform, through the New York onshore grid, and then back offshore. Our models are not tuned to confirm the feasibility of using the local onshore network in this manner, so we did not calculate benefit-to-cost ratios.
[27] In practice, single-source contingency limits would have other planning and cost impacts beyond resizing interregional transmission capacity, including downsizing the export cables. For simplicity in comparing value the studied scenario makes no further adjustments.

5.2.2.3 Fuel Price Change Sensitivities

We include two fuel price sensitivities for hydrogen-fired generation to highlight the effect of uncertainty on the delivered price of high-cost fuels for power generation into the future. In both high- and low-hydrogen price sensitivities, we used production cost modeling to run an additional radial scenario with the change in fuel price to compare the change in value of the interregional offshore network because of a change in hydrogen prices.

We conduct the sensitivities on a specific high-cost fuel, hydrogen, because it plays a critical role in ensuring reliability in a highly decarbonized power system in ReEDS but relies on commercializing technology (e.g., electrolyzers) at an uncertain cost in the future. Fuel price sensitivity scenarios include:

- **Low-hydrogen price**. Delivered hydrogen for power generation is assumed $10/million British thermal units (Btu) instead of the $20/million Btu in the four interlinked topologies. A $10/million Btu price for hydrogen is consistent with DOE's Hydrogen Shot target of $1/kg (DOE n.d.). However, both the low- and high-hydrogen price sensitivities are meant to illustrate a range of directional outcomes, not assign likelihood to cost trajectories for future hydrogen prices.
- **High-hydrogen price**. Delivered hydrogen for power generation is assumed $30/million Btu instead of the $20/million Btu in the four interlinked topologies.

Production cost savings come from displacing higher- with lower-cost generation. Higher hydrogen prices increase the value of displacing hydrogen generation. Lower hydrogen prices have the opposite effect. Savings results (Table 15) for the interregional topology compared to the radial topology show an increase as the cost of hydrogen increases: the lowest savings are $1.5 billion for the low-hydrogen price, then $1.7 billion at the reference $20/million Btu price, and finally $2.1 billion for the high-hydrogen price. Savings assume the same build-out of generation capacity in all compared sensitivities, including hydrogen price sensitivities. While this is generally informative for changes to offshore transmission topologies, persistently low or high hydrogen prices should be expected to influence Eastern-Interconnection-wide generation capacity build-out and therefore savings in ways these sensitivities do not capture.

5.2.2.4 Summary of Sensitivity Scenarios

Table 15 summarizes the results of the sensitivity scenarios described in this section.

Table 15. Sensitivity Scenario Descriptions and Savings.
Note: All sensitivities use the interregional build except the two alternative offshore topologies.

Scenario	Category	Description	Comparison Scenario[28]	2050 Savings vs. Comparison Scenario ($ million) (vs. Core Interregional Topology)[29]
Interregional	Interlinked	For comparison	Radial	1,700 (not applicable)
Modified Backbone	Alternative offshore topology	Shorter cables in backbone	Radial	3,300 (+1,600)
Inter Short Distance	Alternative offshore topology	Connect only very close platforms with large price differences	Radial	1,200 (-500)
Onshore Extension	Alternative onshore topology	Increase connections between Atlantic Coast and 765-kV network in PJM	Onshore extension (radial)	2,600 (+900)
Cable Limit	Additional operational constraint	Interregional offshore cables 1.2 GW instead of 2 GW	Radial	1,400 (-300)
Limit Radials	Additional operational constraint	Offshore lines only deliver power from offshore to onshore, same interregional build as interlinked interregional	Radial	1,000 (-700)
Low Hydrogen	Fuel price change	Hydrogen $10/million Btu	Low hydrogen (radial)	1,500 (-200)
High Hydrogen	Fuel price change	Hydrogen $30/million Btu	High hydrogen (radial)	2,100 (+400)

[28] Comparisons for the onshore extension and low and high hydrogen prices require running an additional radial sensitivity to create a counterfactual against which the added value of the interregional build can be isolated. This means 10 sensitivity scenarios are run to create the seven comparisons.
[29] Total production costs in the radial topology are $89.3 million, so production cost savings range from 1.1% (limit radials, interregional topology) to 3.7% (modified backbone alternative topology) of total production costs compared to the radial topology counterfactual.

5.3 Summary of Production Cost Findings

Production cost modeling results in a few general conclusions (see Section 6.5 for more detailed economic analysis conclusions):

- Benefits persist with different mixes of regional offshore topologies.
- Transmission between two or more of the four transmission regions (e.g., SERTP, PJM, ISO-NE, NYISO) creates more value than additional transmission links within one of the four regions.
- Offshore transmission creates value by displacing higher-cost generation (e.g., hydrogen) with lower-cost generation (e.g., land-based wind). As a result, the use of lower-cost generation increases.
- Value comes from increased deliverability (reduced curtailment) of low-cost offshore wind generation and increased utilization of low(er) cost onshore generation now deliverable via increased transmission capacity from the offshore network to a larger geography.
- Scenarios with higher differences in generation costs (e.g., higher hydrogen prices) show more value for transmission than scenarios with lower differences in generation costs (e.g., lower hydrogen prices).

5.4 Resource Adequacy Methodology

Offshore transmission helps ensure sufficient electricity supply when it enables available generation resources in one location to export and better serve electricity demand in another (importing) location. If this happens during times when the importing location would otherwise be short of generation resources, the transmission can add value by displacing the build of additional generation capacity in planning while ensuring a consistent level of resource adequacy.

Resource adequacy modeling evaluates the contribution of the interlinked offshore transmission topologies to ensuring sufficient electricity supply for bulk power system operation during all hours of the year. Our analysis uses PRAS. The four interlinked topologies are again evaluated compared to the radial reference scenario for the 85 GW of offshore wind build and the same underlying ReEDS low-carbon generation expansion scenario (Section 2). Sensitivity scenarios are not evaluated for resource adequacy. Electricity infrastructure is again envisioned and analyzed in a single future year, 2050, but resource adequacy modeling incorporates a wider range of load, weather, and generator outage conditions than production cost modeling when evaluating electricity supply sufficiency. Additionally, we use resource adequacy modeling to estimate the offshore transmission builds' ability to displace generation capacity build ("capacity value”). Capacity value is used along with the operational production cost value estimates (Section 5.2.1) to conduct economic analysis (Section 6.3.1).

Using PRAS for resource adequacy modeling enables probabilistic, interscenario comparisons of many more generator and transmission outage and weather scenarios than in production cost modeling. Resource adequacy modeling uses 7 weather years (2007–2013) to evaluate the equivalent firm capacity contribution of offshore transmission topologies on the envisioned 2050 power system. Equivalent firm capacity results can be interpreted as the quantity of hypothetical perfect generation capacity build (in megawatts) that can be displaced by the offshore transmission investment while achieving the same level of systemwide resource adequacy. Using 7 weather years of data better captures the effect of a range of possible weather conditions (Figure 22) on resource adequacy. Eastern Interconnection load in additional weather years is the same as what was used for capacity accreditation in the 2050 low-carbon scenario in ReEDS (Section 2). As shown in Table 16, the 2012 weather year used for production cost modeling has relatively lower Atlantic ISO region winter peak loads because of mild winter weather. Including additional weather years enables PRAS to evaluate events with higher load and lower renewable generation availability during winter weather in 2007 and 2009.

Table 16. 2050 Winter Peak Load (GW) for Three Atlantic ISO Regions by Weather Year

Region	2007	2008	2009	2010	2011	2012
Peak Load in GW						
PJM	301.8	295.8	312.5	291.0	287.1	267.9
ISO-NE	56.2	55.5	55.5	52.0	57.3	49.3
NYISO	61.3	58.1	61.5	57.8	56.6	50.7
PJM	301.8	295.8	312.5	291.0	287.1	267.9

PRAS’ consideration of time-synchronized variable generation and load across all included weather years enables a 2050 evaluation of the resource adequacy contribution of variable resources like offshore wind. Figure 28 shows how offshore wind generation varies in its average availability throughout the year. Offshore wind capacity factors are generally higher during the early winter morning hours, which present the most loss-of-load risk in the 2050 PJM, ISO-NE, and NYISO winter-peaking systems in this analysis, indicating a higher capacity credit than a summer-peaking system (Jorgenson et al. 2021). Capacity factors are not capacity value and are not a substitute for more detailed evaluation of offshore wind’s availability during times of high stress that may not be well-captured by averages in Figure 28. The estimated capacity value of the 85 GW of offshore wind in the radial configuration is 25 GW from the ReEDS model results. In the low-carbon scenario, wind, solar, and batteries contribute approximately half of the resource adequacy contribution to peak demand in the Atlantic regions. The other half comes from fossil-fuel, nuclear, hydrogen, and hydropower resources.

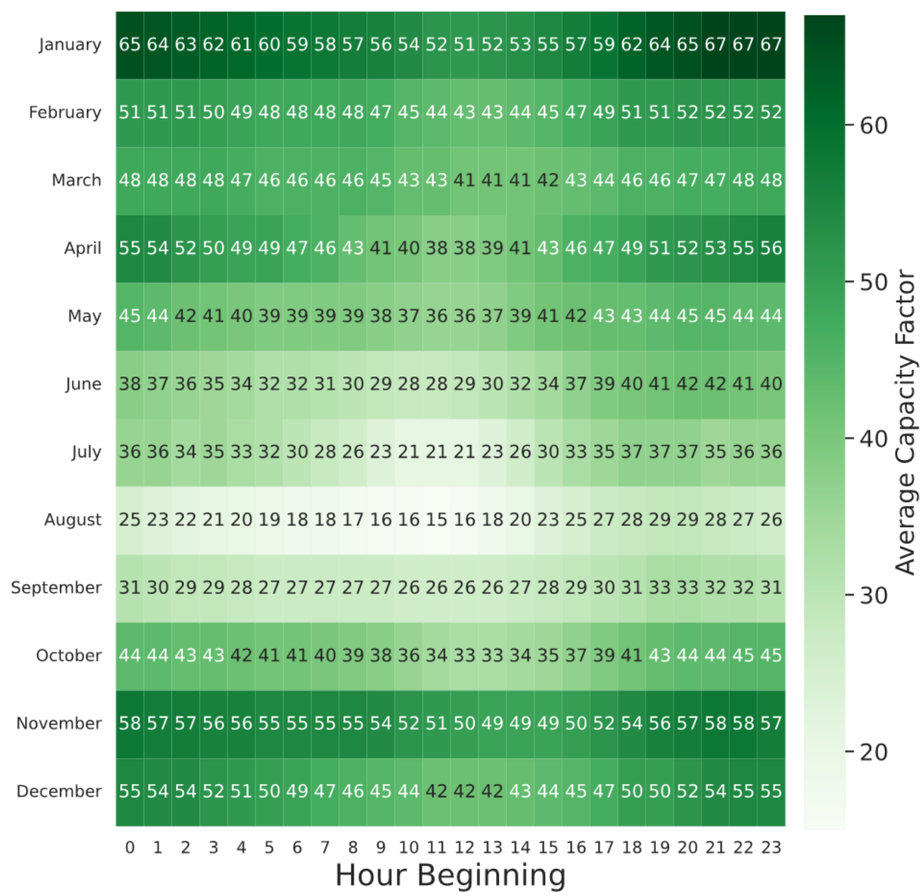


Figure 28. Month-hour average capacity factors (%) for all offshore wind generation (85 GW) in the 2012 weather year. ***Figure by NREL***

To best evaluate the resource adequacy contribution of offshore transmission, we add small increments to electricity load to all zones in the three winter-peaking regions with offshore wind POIs—PJM, ISO-NE, and NYISO—until each region is at approximately the target electricity supply insufficiency of 0.1 events/year loss-of-load expectation[30] and less than 10 parts per million normalized expected unserved energy (nEUE) (Figure 29) in the interregional topology. Transmission capacity linking zones in PRAS are consistent with the interlinked transmission topology described in Section 5.1. Adjustments to load are common in similar evaluations (MISO 2022b, 2023) to compare the marginal reliability contribution of different resources at the target long-run level of resource adequacy. A 0.1 event-days/year loss-of-load-expectation target is used because of its common application in present-day planning (Garrido 2021; MISO 2022b). Single-digit (1-10, or 0.0001%-0.001%) parts per million nEUE is generally consistent with the 0.1 loss-of-load expectation target for the northeastern United States (de Mijolla 2023) and offers a resource adequacy metric alternative that considers both event magnitude (in energy units),

[30] Loss-of-load expectation is defined as "the expected (average) count of periods experiencing shortfall over the study period… expressed in terms of event-periods (e.g., event-hours per year, event-days per year)" (Stephen 2021).

normalizes for power system size, and is used by the North American Electric Reliability Corporation (Newell et al. 2020). SERTP is not further adjusted after no loss of load is observed in the summer-peaking SERTP region (Figure 24) during coincident Atlantic winter high-risk time periods. We do not separately adjust summer peak loads from the winter adjustments in favor of preserving time and geographic consistency in evaluating Atlanticwide electricity supply insufficiency risk. Figure 29 shows the impact of the topologies on nEUE after the adjustments.

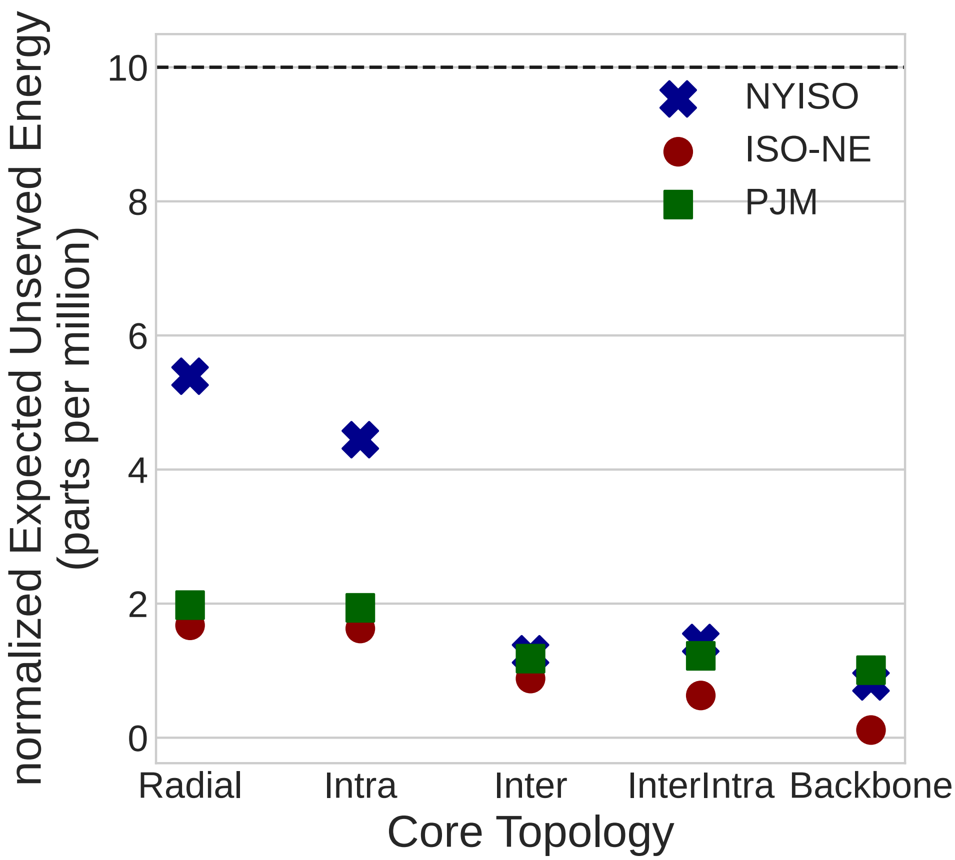


Figure 29. Normalized expected unserved energy (nEUE) by Atlantic region for the radial reference scenario and four interlinked offshore topologies after adjustments. ***Figure by NREL***

Note: Intra is the intraregional topology and inter is the interregional topology. Inter-intra has both the intraregional and interregional topologies. PJM includes only Atlantic regions.

5.5 Resource Adequacy Results

Resource adequacy results calculate the equivalent firm capacity in capacity units of each of the four interlinked topologies. Results reflect the generation capacity build that can be displaced by adding the offshore network, not the generation capacity build displaced by the offshore wind itself (included in all scenarios). Table 17 shows the quantity of perfect generation capacity that can be avoided by each interlinked topology build while achieving the same resource adequacy as the radial topology with that capacity. We include the scenario's total quantity of offshore transmission capacity (in megawatts) for comparison in Table 17 to give a sense of what fraction of the total nameplate transmission build can be used to deliver resource adequacy value.[31]

Table 17. Equivalent Firm Capacity Result Ranges for the Offshore Transmission Build in Interlinked Topologies in PRAS

Interlinked Topology	Total Quantity of Offshore Interlink Transmission Built (MW)[32]	Equivalent Firm Capacity Range Result for Offshore Transmission (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

Ranges of equivalent firm capacity for each interlinked offshore transmission topology can then be monetized using a geographically and temporally applicable estimate of the marginal value of firm capacity in the economic analysis (Section 6.3.1). Monetizing equivalent firm capacity values reflects an assumption of Atlanticwide resource adequacy planning and contributions in 2050 and may not be consistent with current capacity accreditation rules. Interregional lines have capacity value in our multiregion resource adequacy modeling because they enable generation resources to simultaneously contribute to adequacy in more than one planning region. Transmission resource adequacy value should therefore be interpreted as resulting from its complementarity with geographically diverse generation resources in operations, not an independent property of the transmission itself. Current resource adequacy accreditation practice will differ when modeling planning areas as a single region or prescribing limits on the ability of external resources to contribute to resource adequacy in multiple planning regions by using transmission.

Offshore transmission contributes to resource adequacy because it can flow power from zones with additional generation to zones with more demand than generation. Hours with generation shortfall typically occur on our system for some Atlantic-adjacent zones during peak or near-peak load winter hours. In the interregional topology, 85 hours during the 7 weather years (2007-2013) evaluated on the 2050 power system risk having insufficient generation to meet load. All resource adequacy events occur during either January 2007 or January 2009 weather. When the

[31] Generator resource adequacy contribution values are often reported as a fraction of nameplate; for example, effective load-carrying capability is commonly reported as power quantity and fraction of a generator or a generator type's nameplate capacity.
[32] Counts each line between a platform individually. So, for example, the backbone adder is three linked 2-GW cables, counted as 6 GW total.

interregional connections are added, they can leverage geographic diversity in resources and load to flow power from onshore areas with excess generation to those with generation shortfall. In the interregional topology, this most clearly occurs for the line between SERTP and PJM: because SERTP is not winter-peaking and has excess generation, the line can be highly used to flow power to winter-peaking parts of PJM. Average flow values for all seven interregional lines during the 85 loss of load hours are shown in Table 18.

Table 18. Average Flows on Interregional Lines During Nonzero Loss of Load Probability Hours.
Note: Positive values are from/to directional flows; negative values are to/from directional flows.

Topology	Line From Region	Line to Zone (Region)	Line Capacity (MW)	Average Flow During Resource Adequacy Hours (MW)
Inter	SERTP (North Carolina)	PJM (Maryland)	2,000	1,366
	NY Zone K	PJM (New Jersey)	2,000	106
	ISO-NE (Massachusetts)	New York Zone K	2,000	955
	ISO-NE (Rhode Island)	New York Zone J	2,000	135
	ISO-NE (Massachusetts)	New York Zone J	2,000	1,051
	New York Zone J	PJM (New Jersey)	2,000	554
	New York Zone J	PJM (New Jersey)	2,000	-1,313

The ability to flow additional power between regions on new transmission during these hours can displace generation capacity build. Transmission's contribution to resource adequacy comes from increasing use of existing resources, thereby displacing build of generation resources in multiple locations to ensure sufficient electricity supply. Equivalent firm capacity estimates quantify how much generation capacity could be displaced by offshore transmission, thereby enabling higher use of existing, geographically diverse generation resources while planning to the same target level of long-run system electricity supply adequacy. Appropriately monetized equivalent firm capacity values are additive to operational value estimates. While not strictly a substitute for capacity expansion modeling, particularly for large changes to power system condition or cost assumptions, the analytical approach of coupling resource adequacy and production cost modeling scenario analysis to estimate marginal capacity and production cost value is commonly employed when it enables additional modeling detail (Hawaiian Electric Company 2023) and forward-looking scenario analysis (ISO-NE 2022; PJM 2018).

5.6 Summary of Resource Adequacy Findings

- Interlinked offshore transmission networks contribute to resource adequacy.

- Interlinked offshore transmission contributes to resource adequacy during periods of high load and low renewable generation availability by increasing use of geographically diverse generation resources.
- Interlinked offshore transmission adds more resource adequacy value when it links regions with different timing of high load and low renewable generation availability (e.g., SERTP and PJM).
- Resource adequacy value is additive with production cost value, which allows for adding when estimating benefits in Section 6.

6 Economic Analysis

The production cost analysis shows significant operational benefits of coordinated offshore transmission planning, especially across regions that are geographically diverse and exhibit complementary system characteristics. Other analysis has shown benefits of coordinated planning and management of regional and interregional offshore transmission infrastructure to reduce system costs and enable greater use of finite points of interconnection to deliver offshore wind energy generation (FERC 2022; Pfeifenberger et. al. 2023a). However, failure to capture the full benefits of candidate transmission projects and disagreements over how to allocate project costs among network users can impact valuable transmission projects (Chang et al. 2013). The widespread nature of transmission benefits creates challenges in estimating project benefits and how they accrue to different network users. Furthermore, the application of cost-benefit analysis is inconsistent between regions. As a result, this inconsistency complicates the ability to allocate project costs among network users, which is a process that is already highly contentious.[33]

To overcome these challenges, this economic analysis is designed to 1) determine and evaluate quantifiable benefits associated with transmission investments identified in the AOSWTS, 2) demonstrate replicable and scalable methods to allocate economic benefits of transmission among transmission planning regions, and 3) compare methods for allocating costs of the offshore topologies among planning regions.

6.1 Economic Benefits of Offshore Transmission

The analytical approach developed to identify and evaluate transmission benefits was designed to reflect ongoing transmission planning reforms under consideration by FERC (2022) and the level of analysis used for AOSWTS planning and operational studies. The following sections outline the overall approach and applications to the study scenarios, with the five key framing decisions presented in Figure 30.

[33] See submitted comments to FERC Notice of Proposed Rulemaking on transmission planning and cost allocation (Docket RM21-17); https://elibrary.ferc.gov/eLibrary/.

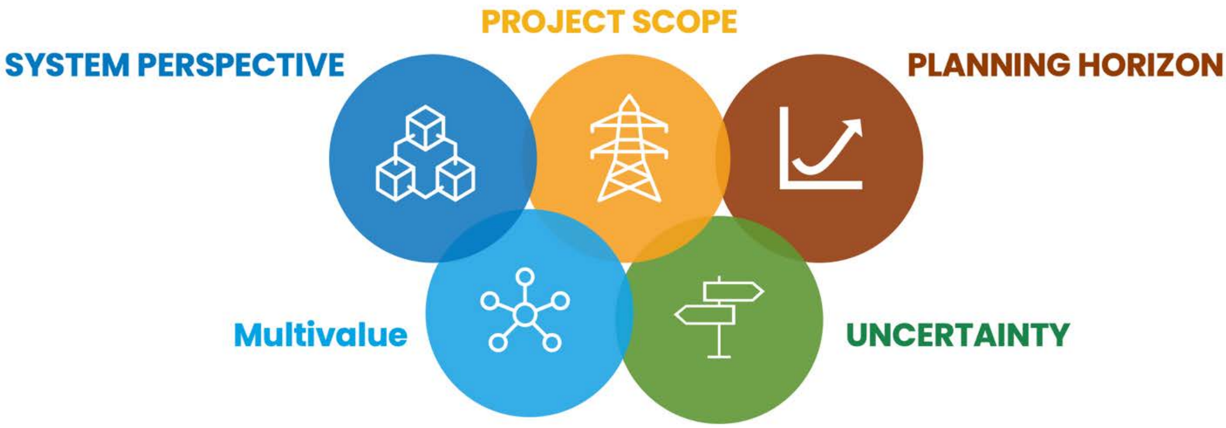


Figure 30. Study approach to evaluate and quantify transmission benefits. *Illustration by NREL*

6.1.1 Multivalue

This analysis considers a broad range of transmission benefits including reduced operating costs and benefits of sharing generation across interregional transmission to meet resource adequacy requirements. Historically, production cost savings have been the primary metric for valuing transmission investments. The multivalue approach addresses two issues:

- It will better capture the full range of potential benefits that transmission can provide, which may vary over time and across geographic regions.
- As the share of zero-marginal-cost resources increases, transmission will play an important role in distributing low-cost power across greater spatial areas and contribute to meeting reliability and policy goals.

FERC has expressed the need to expand the range of benefits for transmission valuations and some regions, such as MISO, have already implemented multivalue transmission planning (MISO 2022a).

6.1.2 System Perspective

The AOSWTS evaluates transmission investments and operations across the entire Eastern Interconnection. This analysis evaluates the value of offshore transmission across the entire system as well as to a given region (e.g., ISO-NE, NYISO, PJM, and SERTP). We do not seek to disaggregate the benefits experienced by different types of network users within each region (e.g., generators, consumers). In addition, we make no assumptions about how transmission cost recovery is allocated within a region or among customer classes. Section 6.4 evaluates different cost allocation approaches among regions.

6.1.3 Project Scope

This analysis evaluates the net benefits for the portfolio of offshore transmission investments identified in AOSWTS scenarios rather than evaluating individual projects or transmission corridors. This approach reflects planning processes in place, such as MISO's multivalue project process that evaluates bundles of projects**.** It also aligns with the AOSWTS approach, whereby transmission investments and system operations are optimized on a multiregion scale. To isolate the impact of specific types of transmission development, we compare a reference scenario with alternative "change" cases that represent different types of offshore transmission development, in line with the interlinked AOSWTS topologies.

6.1.4 Planning Horizon

We are considering a 20+ year planning horizon, simulating system investments and operations in 2050. The analysis is focused on the 2050 operational year and does not include the interim years to 2050 to inform how the benefits of transmission change over time as the underlying power system changes.

6.1.5 Uncertainty

The benefit valuation captures a range of possible future outcomes, drawing from the broad set of AOSWTS scenarios to provide insights on robust offshore transmission investment options. These include macroeconomic drivers such as hydrogen prices as well as a range of system states such as different weather conditions. This analysis focuses primarily on scenario-based comparisons to capture uncertainty in system operations across a range of system futures and probabilistic analysis of resource adequacy to assess transmission value under uncertainty for the 2050 operating year.

6.2 Benefit Identification

FERC put forth in its Notice of Proposed Rulemaking a list of potential benefits that planners may seek to include in their assessments, with regional institutions responsible for the overall selection of which benefits to include and how to quantify them (FERC 2022). For practical purposes, the benefits proposed by FERC and others in transmission planning literature need to be prioritized and a smaller subset implemented as part of the transmission planning process.[34] Identifying which benefits to evaluate early on is important to critically evaluate which ones are the most important or likely most pronounced for the projects under consideration. For this analysis, we identified three categories of transmission benefits (Figure 31) that were common across the literature, the FERC Notice of Proposed Rulemaking, and regional planning processes for valuation, as well as consistent with the modeling approach designed for this study.

[34] For more discussion on benefit selection, see Stenclik and Deyoe (2022).

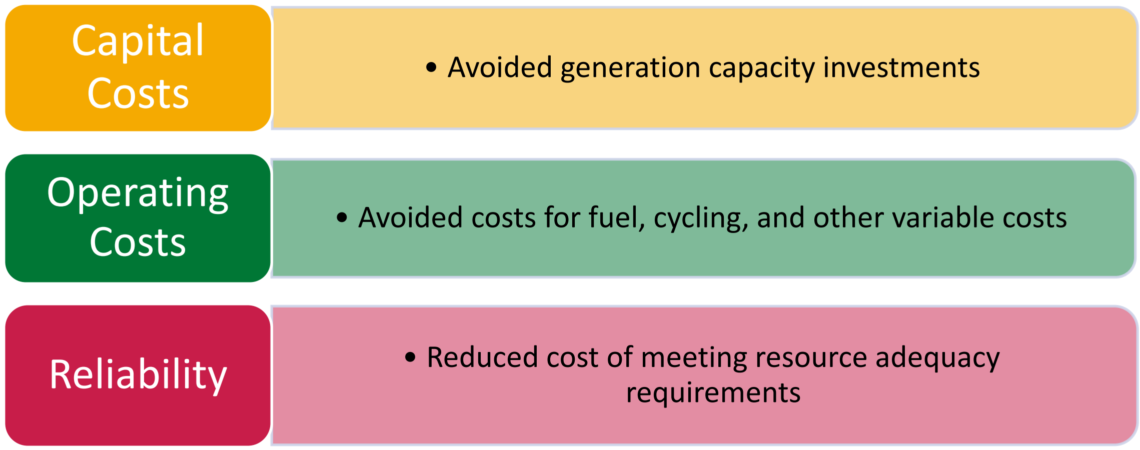


Figure 31. Transmission benefits identified for valuation. ***Illustration by NREL***

Note: Many benefits are correlated and not mutually exclusive.

While Figure 31 shows each type of benefit as separate, many are not mutually exclusive. For example, transmission investments that reduce the cost of meeting resource adequacy requirements may also reduce capital investments needed to meet those requirements.

Therefore, the multivalue approach demonstrated in this analysis will not necessarily quantify each type of benefit individually but, rather, seek to quantify as many benefits as possible without double counting.[35] The focus for this analysis is on offshore transmission benefits but the methods can also be used to quantify key benefits for any transmission project.

6.3 Benefit Evaluation

To evaluate the benefits of an offshore transmission network, we used the production cost and resource adequacy modeling tools.

For this analysis, the radial topology serves as the reference case against which the alternative transmission topologies and sensitivities were evaluated.

6.3.1 Systemwide Economic Benefits

The economic benefits of interlinked offshore transmission are based on avoided system costs compared to the radial topology. These savings include avoided production costs and avoided costs to meet resource adequacy requirements. Figure 32 shows the total economic value for the

[35] While this analysis seeks to quantify a range of benefits, it does not capture all of the possibilities that transmission investments can provide. Other benefits not quantified could include avoided generation and transmission investments due to access to lower-cost resources, reduced costs for meeting ancillary service requirements, reduced loss-of-load probability, reduced severity and duration of outages, reduced redispatch costs due to weather and load uncertainty, and improved postcontingency performance. Further analysis could be used to evaluate and quantify these benefits.

Eastern Interconnection for each interlinked transmission topology compared to the radial topology.

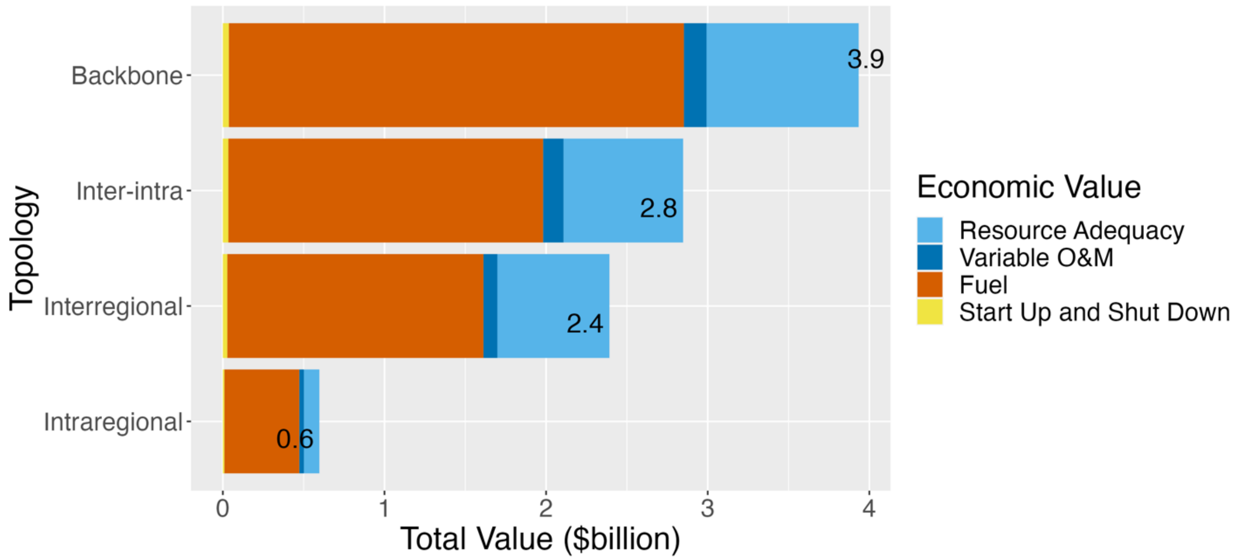


Figure 32. Annual systemwide savings compared to the radial topology. ***Figure by NREL.***

Note: O&M = operations and maintenance

In the radial topology, total production costs reach $89 billion in 2050 for the 2012 weather year (2021$). As more offshore links are added between transmission planning regions, total production costs decrease, falling to $86 billion in the backbone topology, representing a 4% cost decline. Avoided fuel costs account for more than 90% of production cost savings across all scenarios. Reduced start-up and shut-down costs associated with unit cycling are the smallest source of quantified savings.

Resource adequacy value is derived from the ability of transmission to provide equivalent firm capacity, potentially reducing the need for generation capacity investments to meet the same level of system reliability. Based on the analysis presented in Section 5.5, offshore transmission can provide 600–6,100 MW of equivalent firm capacity in 2050.[36] This capacity translates to $96–$940 million (2021$) in annualized avoided generation investment costs for the 2050 operating year.

Table 19 summarizes the total value by category for each interlinked topology.

[36] For more details on the input assumptions and calculations used for the resource adequacy valuation, see Appendix A.

Table 19. Economic Value of Interlinked Transmission Topologies for Modeled Year 2050 ($ million)

Economic Value	Intraregional	Interregional	Inter-intra	Backbone
Resource Adequacy	100	690	740	940
Variable Operations and Maintenance	30	90	130	140
Fuel	460	1,590	1,950	2,820
Start Up and Shut Down	10	30	30	40
Total	**600**	**2,400**	**2,850**	**3,940**

The savings presented in Table 19 do not include the estimated cost of building the offshore transmission network presented in Section 4.6. Identifying high-value transmission options requires considering both costs and benefits. Table 20 presents the annualized net value and benefit-to-cost ratio results for each interlinked topology.[37]

Table 20. Net Transmission Value Considering Transmission Capital Costs

Topology	Net Annual Value ($ million)	Benefit-to-Cost Ratio
Intraregional	330	2.3
Interregional	1,560	2.9
Inter-intra	1,760	2.6
Backbone	2,470	2.7

Across all topologies, the net savings are positive and the benefit-to-cost ratio exceeds 2.0, indicating the value of each topology exceeds the estimated investment cost. The results in Table 20 also indicate the highest value comes from scenarios with interregional offshore transmission additions. The interregional and backbone topologies achieve the highest benefit-to-cost ratios of 2.9 and 2.7, respectively. These values are based on a snapshot of systemwide savings in 2050 when the final offshore network is fully developed; further analysis is needed to evaluate the systemwide savings for interim years as the underlying power system is changing.

6.3.2 Sensitivity Analysis of Economic Results

To understand the drivers of transmission value and test the robustness of these results, this study also considers several sensitivities. These sensitivities, summarized in Section 5.2.2, evaluate the impact of transmission topology design, network operations, and technology prices and costs on

[37] The annualized transmission costs are calculated based on the equivalent annual cost assuming a 40-year asset life, 5% discount rate, and capital recovery factor of 0.06 for capital costs and an annual fixed operations and maintenance cost of 1.5% of the upfront capital cost.

the systemwide economic value of the offshore network. This analysis is conducted only with the production cost model and does not include potential impacts on the resource adequacy value of the network. In addition to the sensitivities tested with the production cost model, we analyzed a further sensitivity related to uncertainty on the cost of the offshore transmission network. We evaluate a low- and high-transmission scenario to quantify the impact of a 10% decrease or increase, respectively, in the capital cost of the network.[38]

Figure 33 compares the net annual value for the interregional topology and alternative sensitivities. The net annual value captures the annual production cost savings minus the annualized estimated cost of transmission for the interregional topology.

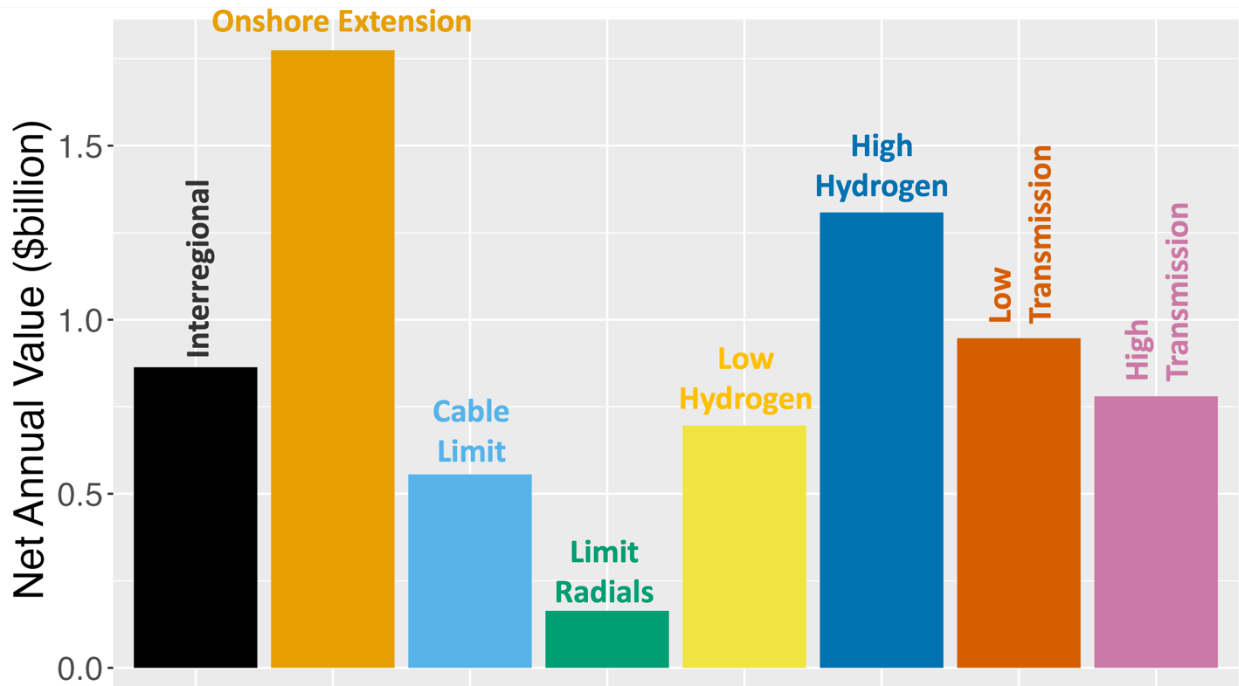


Figure 33. Sensitivity analysis of net annual value for the interregional topology, considering production costs only. ***Figure by NREL***

The largest value increase of the offshore network comes from a scenario with greater onshore interconnections, investigated here through onshore extensions to connect the Atlantic Coast to the 765-kV network in western PJM. The additional $900 million in annual savings comes from greater use of low-cost renewable generation located in western PJM reaching the offshore grid to be distributed along with offshore wind and reach electricity load in major demand centers along the coast. This result indicates that onshore transmission expansion can complement the

38 This range is intended to demonstrate the sensitivity of net savings to the cost of the network and does not reflect an evaluation of the actual uncertainty bounds on the offshore network costs.

development of the offshore network to maximize the use of onshore and offshore renewable energy generation.

Reducing the transfer capacity of the offshore cables from 2 GW to 1.2 GW (cable limit) results in a 36% decrease in net annual value. This result suggests that increasing the size of the offshore cables and the associated single-source contingency limit to achieve a higher transfer limit can significantly increase interregional value and cost savings. Constraining power flows to one-directional flows from offshore to onshore (limit radials) has the largest negative impact on transmission value, reducing net annual savings by 81%. This result illustrates that a key driver for interregional transmission value is the ability to facilitate greater power exchanges between regions even during times of low offshore wind generation.

The value of interregional transmission is sensitive to assumed prices for hydrogen in 2050, with its value increasing as hydrogen prices increase (high hydrogen) and decreasing with low hydrogen prices (low hydrogen) because the networked transmission allows regions to exchange power and reduce the use of high-cost generation, like hydrogen. The value of transmission is less sensitive to the assumed cost of transmission, with a 10% increase in transmission investment cost (high transmission), resulting in a 10% decrease in the annual net value of transmission and vice versa.

Figure 34 shows the interregional topology sensitivities in terms of benefit-to-cost ratio. Across almost all sensitivities, the benefit-to-cost ratio exceeds 1.25 (red dotted line), which is the maximum threshold suggested in FERC Order 1000 to determine if transmission facilities have significant net benefits to be included in a regional transmission plan (FERC 2011). While the limit radials scenario does not meet the 1.25 threshold, it does have a benefit-to-cost ratio of 1.2, indicating the production cost benefits from increased use of offshore wind resources accessing the interregional transmission network exceed the transmission investment costs. These results indicate that the value of interregional offshore transmission is resilient against a range of future uncertainties as to how the network is designed and system costs and prices evolve.

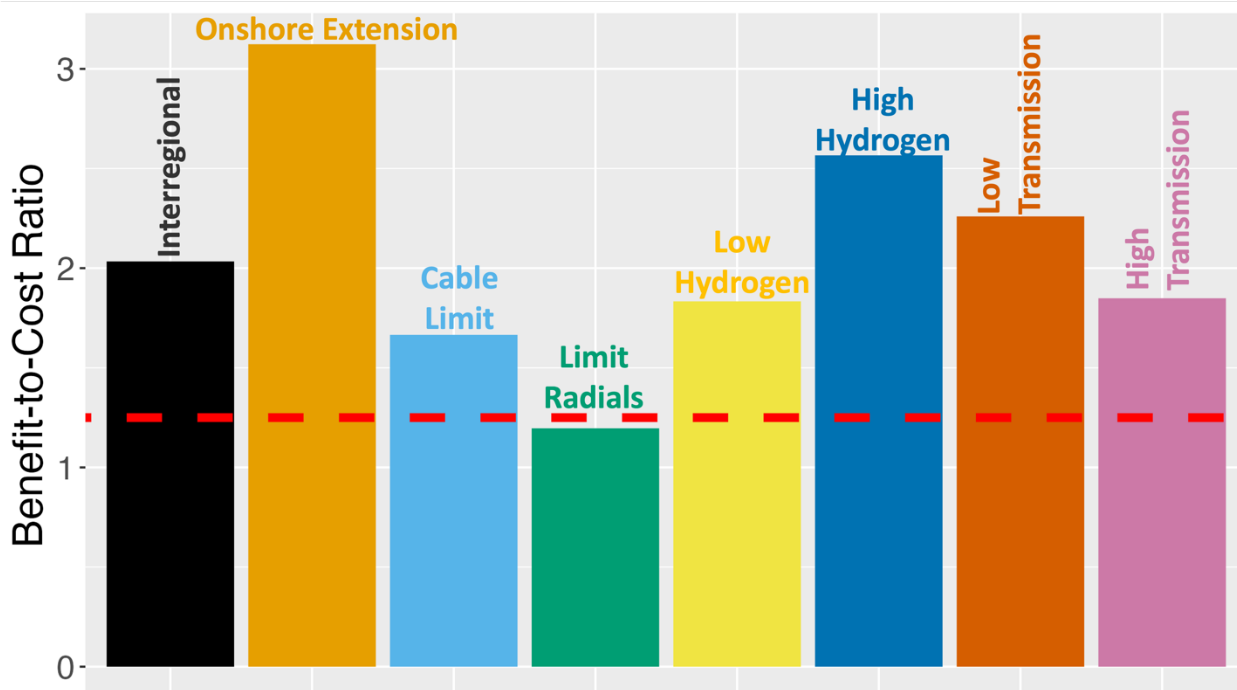


Figure 34. Sensitivity analysis of the benefit-to-cost ratio for the interregional topology, considering production costs only. ***Figure by NREL.***

Note: The red dashed line indicates the 1.25 benefit-to-cost ratio.

6.3.3 Benefit Disaggregation

While the systemwide value of each transmission planning topology could be high, the value to each transmission planning region varies. Further, when evaluating the benefit distribution among regions, further consideration is needed to capture the transmission benefits of interregional trade to each region. To evaluate these benefits, we used the adjusted production cost metric.[39] This metric is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission upgrade. Figure 35 shows the annual savings for each interlinked topology realized by each transmission planning region compared to the radial topology. While net benefits for the entire system are positive, total savings across individual regions vary significantly.

[39] See Appendix B for more details on the methods used to calculate the adjusted production cost.

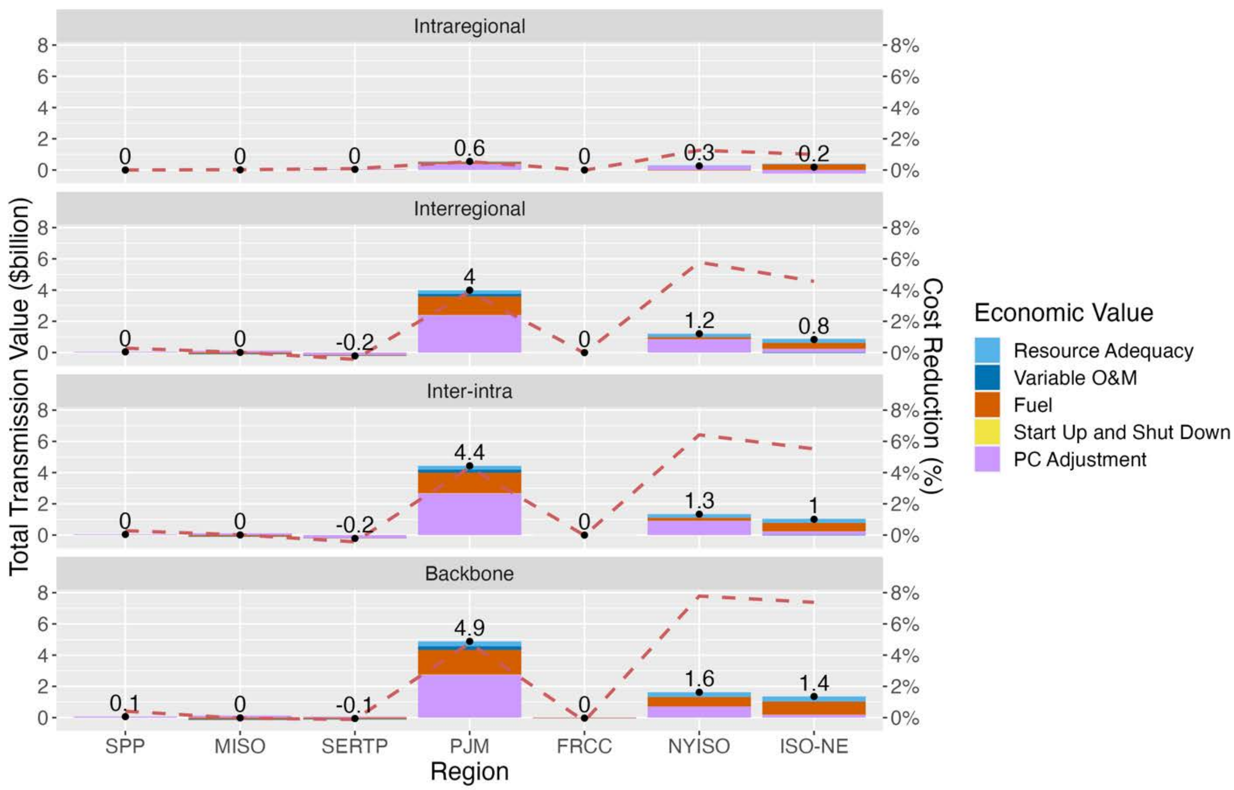


Figure 35. Transmission value by region for each interlinked offshore topology in absolute $ billion of avoided production costs and as a percentage of total costs for each region. ***Figure by NREL.***

Note: PC adjustment = production cost adjustment; FRCC = Florida Reliability Coordinating Council. See Appendix B for more details. Dotted line is the cost reduction (%) as a share of total costs in each region.

Among planning regions, the value of offshore transmission accrues almost exclusively in PJM, NYISO, and ISO-NE, where most offshore wind POIs are located. Regions that can displace high-cost generation with low-cost offshore wind generation or imports from neighboring regions, such as PJM, see the largest savings across all scenarios. As a share of total costs, NYISO and ISO-NE see the largest savings, with annual costs falling by more than 7% in each region in the backbone topology. Other regions benefit through greater use of their most efficient or lower-cost units for local consumption and export to neighboring regions using new interregional lines. By contrast, MISO, Southwest Power Pool, and regions in the southeast see little to no value of networked offshore transmission. These regions have fewer opportunities for cost reductions because they have lower use of high-cost generators that could be displaced and fewer points of interconnection to facilitate power trade with other regions.

Similar to systemwide savings, the regional value of transmission is sensitive to the transmission topology design, network operations, and technology prices and costs. Figure 36 shows the range of total adjusted production cost savings across all interregional sensitivities by region.

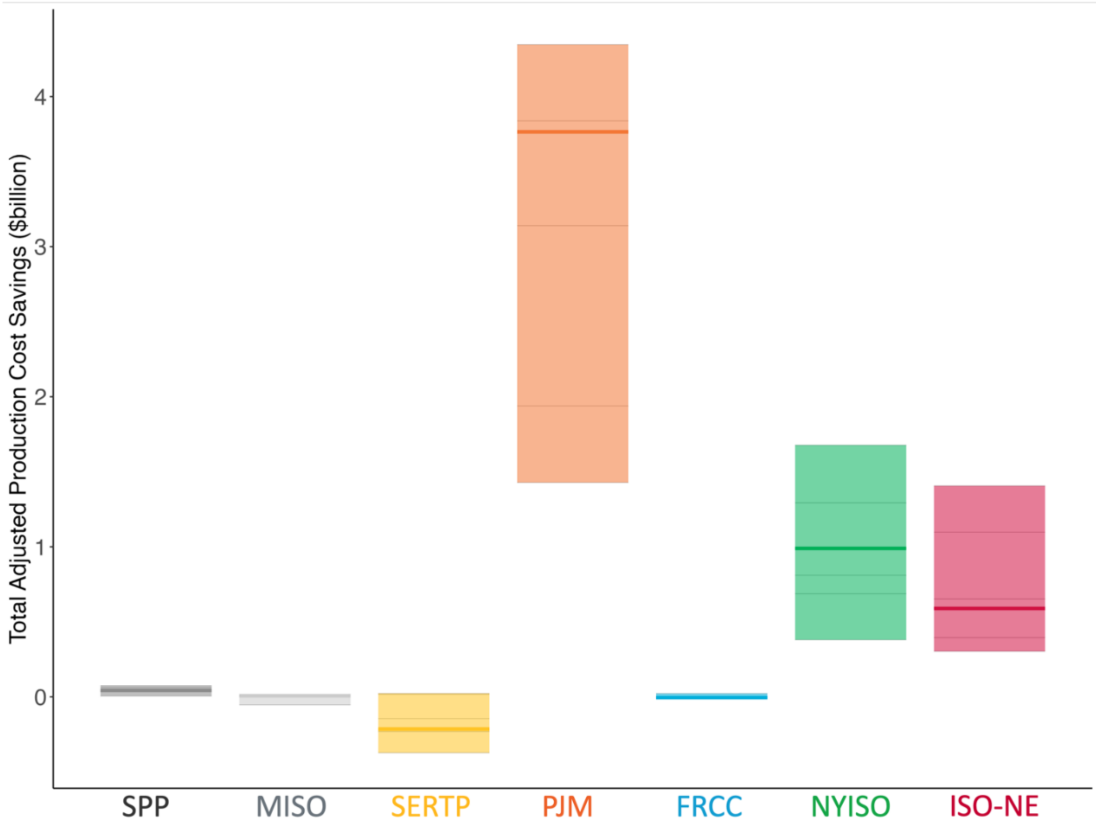


Figure 36. Total adjusted production cost savings by region in absolute $ billion for the interregional topology (bold line) and interregional sensitivities. ***Figure by NREL.***

Note: SPP = Southwest Power Pool

Across all sensitivities, the largest changes in transmission value occur in regions such as PJM, NYISO, and ISO-NE, where most offshore POIs are located. Across these regions, the highest transmission value occurs in scenarios with high hydrogen prices because the networked transmission allows regions to exchange power and reduce the use of high-cost generation, like hydrogen. In NYISO and ISO-NE, the value of transmission increases in sensitivities with greater connectedness between regions (onshore extension) and decreases in sensitivities that limit the use of the offshore network to facilitate power flows between regions (limit radials and cable limit). By contrast, as net exporters, PJM and SERTP have increased transmission value in scenarios with lower interconnectedness or constrained power flows among regions.

How are benefits disaggregated by region?

Production costs incurred within nodes are aggregated to their respective planning regions. The resource adequacy value is disaggregated among regions with shortfall risk that can be reduced by offshore transmission builds. The adjusted production cost metric is used to account for changes in the purchase costs to meet regional load and generator revenues. See Appendix A and Appendix B for more details.

6.4 Cost Allocation Methods for Offshore Transmission Network

Transmission cost allocation involves assigning the costs of a new or existing transmission facility among network users. There is no consensus on which cost allocation method is the most suitable and regional markets have adopted a wide range of approaches. The demonstrated methods for evaluating and disaggregating transmission benefits can contribute to negotiations around cost allocation and cross subsidization for interregional projects. Ultimately, these decisions are made through local regulatory processes and must be integrated with existing rate structures. To help bridge the gap between the AOSWTS analysis and local regulatory processes, this section demonstrates the impact of different cost allocation methods on the cost obligation among regions and provides an evaluation framework by which different approaches could be compared. The purpose is to inform future cost allocation negotiations, not attempt to recommend a specific method or allocation.

6.4.1 Framing Assumptions and Evaluation Criteria

Figure 37 summarizes the framing assumptions for the cost allocation evaluations.

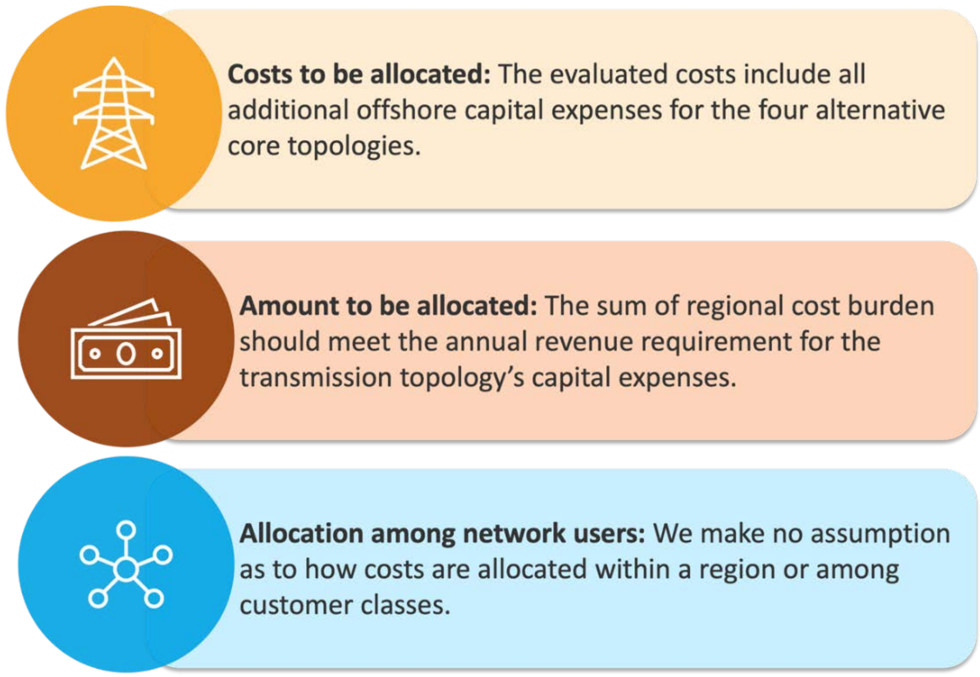


Figure 37. Framing assumptions for cost allocation evaluations. ***Illustration by NREL***

This evaluation only allocates the capital costs for the four interlinked offshore transmission topologies. We do not attempt to estimate or allocate costs associated with the radial topology, as these investments are common across all scenarios. Second, the allocation will cover the full annualized cost of each topology. In practice, for lines that are built and not fully used for the initial years, it could make sense to only allocate a fraction of the project's cost and then distribute the remaining portion among all network users initially. For simplicity and demonstration purposes, we fully allocate all network costs. Third, costs are only allocated among transmission planning regions and no assumptions were made as to how each region's cost responsibility is allocated among network users within that region.

There is no single scheme for cost allocation that is both technically and economically sound and easy to implement in a real system. In the United States, each pair or group of regions negotiate their own cost-sharing agreements, subject to FERC approval, resulting in a range of potential cost sharing solutions.[40] The effectiveness of any cost allocation scheme will depend on its adherence to basic regulatory principles, technical and economic soundness, and its compatibility with the institutional design and capabilities of the region. Therefore, any well-designed method should:

- Recover the full cost of the network
- Allocate costs in proportion to benefits

[40] See FERC Notice of Proposed Rulemaking on transmission planning and cost allocation (Docket RM21-17) for ongoing efforts to improve cost allocation for certain types of transmission.

- Avoid interfering with interregional trade
- Separate cost allocation from commercial transactions
- Use a technically sound method to approximate network benefits
- Be feasible to implement in a real system (Rivier et al. 2013).

To identify what method or combination of methods is the best option for networked offshore wind transmission, we applied multiple cost allocation methods to the offshore topologies and compare their performance using these six criteria.

6.4.2 Cost Allocation Methods

There are a wide variety of cost allocation methods that have been implemented or proposed for new transmission investments. This study evaluates four options that capture diverse approaches and the resulting trade-offs in outcomes and complexity required for each approach. Table 21 summarizes the cost allocation methods selected for comparison.[41]

[41] For more details on each method, see Appendix C.

Table 21. Description of Cost Allocation Methods Evaluated for Comparison

Method	Description
Beneficiary Pays	Costs are allocated based on estimated production cost and resource adequacy benefits that each region obtains with the added transmission
Postage Stamp	Costs are allocated in proportion to coincident peak withdrawals from the network
Modified Postage Stamp	Costs are allocated in proportion to coincident peak withdrawals from the network; regions with no estimated production cost or resource adequacy benefit have no allocated costs
Load Imbalance	Costs are allocated based on changes in annual load imbalance (net imports and exports) with the added transmission

6.4.3 Comparison of Allocated Costs Under Each Method

Figure 38 shows the allocated costs by region for each transmission topology and method.

Figure 38. Comparison of regional cost responsibility for each transmission topology and cost allocation methods. ***Figure by NREL***

The comparison in Figure 38 shows significant variation in cost responsibility among regions depending on the cost allocation method applied. To compare each method, Table 22 shows an evaluation in terms of six regulatory principles for cost allocation.

Table 22. Evaluation of Cost Allocation Methods

Method	Cost Recovery	Beneficiary Pays	Does Not Distort Trade	Nontransaction-Based	Techni-cally Sound	Feasible to Implement
Beneficiary Pays	✓	✓	✓	✓	✓	??
Postage Stamp	✓	X	✓	✓	X	✓
Modified Postage Stamp	✓	X	✓	✓	X	✓
Load Imbalance	✓	X	X	✓	X	✓

The beneficiary pays method is conceptually sound but could be difficult to implement because of a lack of consensus as to which benefits to quantify, and the methods used to quantify the benefits. Evaluating production cost and resource adequacy benefits used in this study demonstrates that avoided fuel costs, changes in generator revenue and purchase costs, and resource adequacy value among regions are important to capture. Changes in start-up and shut-down costs or variable operations and maintenance costs had limited impact on overall transmission value.

The postage stamp method is a useful proxy for well-developed networks that do not require locational signals. However, in the context of an offshore network where some regions are more highly impacted than others due to the location and relative number of points of interconnection with the new network investments, this method may not capture the actual value that different regions derive from the network. Specifically, the cost burden may exceed the value of transmission for regions with high coincident peak demand (i.e., SPP, MISO), regardless of the value each region gets from the network. The modified postage stamp method provides some adjustment for this by restricting the regions with allocated costs to those with some positive benefit based on model results. It still tends to disproportionately allocate costs to regions with high coincident peak demand compared to that region's estimated benefits. As the share of renewables increases, the need for new transmission may be driven less by peak demand and more by other periods of the year, such as net peak demand of low renewable generation. Further modifications to the postage stamp method could be developed to better capture system conditions that may drive the need for more transmission.

The load imbalance method uses a simple approximation to estimate network use as a proxy for benefits. However, this approach can only capture changes in load net of all within-region generation for each region with the new transmission additions and not how each region benefits from the network. For example, ISO-NE has no cost burden for most topologies with the load imbalance method, even though this region benefits from access to lower-cost generation from offshore wind power plants and neighboring regions. Importantly, this approach could distort interregional power trade because it incentivizes regions to minimize their annual load imbalance (and resulting cost burden).

6.5 Summary and Key Findings

Coordinated planning and operation of regional and interregional offshore transmission infrastructure can provide a range of benefits in the form of reduced operating costs and resource adequacy value. This effort demonstrates how systemwide modeling can be used to identify the value of transmission portfolios for different regions and contributes to negotiations around cost responsibility for networked offshore transmission investments.

The following insights from this analysis can help inform transmission planning processes and decisions that may increase the ability to achieve state and national policy targets for offshore wind energy deployment, system reliability, and cost-effectiveness:

- Investments in an offshore transmission network can provide significant production cost and resource adequacy value through increased intra and interregional power exchanges and greater use of low-cost generation resources, including offshore wind. The benefit-to-cost ratio for all interlinked topologies ranges from 2.3–2.9. The greatest benefits are derived from increased interregional connections.
- Technical or operational restrictions on the offshore network related to cable sizing and the direction of power flows can significantly reduce the value of the offshore network by limiting the use of the network for interregional power exchanges.
- The benefit-to-cost ratio of interregional offshore connections exceeds 1.25 across a range of sensitivities. Even under restricted scenarios that limit the use of the network for interregional power trade, the benefit-to-cost ratio exceeds 1.2. Onshore extensions that improve connectivity between the western PJM grid and load centers on the East Coast can further increase the value of interregional transmission, achieving a benefit-to-cost ratio greater than 3.
- Networked Atlantic offshore transmission is valuable to a small number of transmission planning regions in the Eastern Interconnection. These regions—PJM, NYISO, and ISO-NE—benefit from reduced costs to meet regional load and resource adequacy requirements.
- For systemwide analysis, operating costs comprise variable operations and maintenance, fuel, and start-up and shut down. These metrics are sufficient to evaluate the change in operating costs for the entire system, however, when evaluating the benefit distribution

among regions, a further consideration is needed to capture the transmission benefits of interregional trade to each region.

- There is no single best method for allocating transmission costs among regions that is easy to implement in a real system. However, any feasible method must seek to allocate costs in proportion to benefits based on a technically sound method for approximating benefits and fully recovering the cost of the network. Methods that interfere with interregional trade could significantly reduce the value of the interregional network.

7 Reliability Analysis

7.1 Introduction and Objectives

The reliability analysis of the AOSWTS assesses the grids presented in Section 4 for their operability and reliability with increased levels of offshore wind energy. The evaluation was largely conducted by simulating the steady-state and dynamic behavior of the Eastern Interconnection, with an emphasis on the transmission grids close to the offshore wind injection points, in normal and under contingency conditions.

Figure 39 presents the reliability and resilience analysis framework, as well as the underlying simulation models, employed in this study. This framework is used to assess the reliability of target years 2030 and 2050, evaluate different offshore transmission topologies from the reliability standpoint, screen the candidate POIs according to grid strength metrics, and investigate the functional requirements and behaviors of protection schemes of offshore HVDC grids.

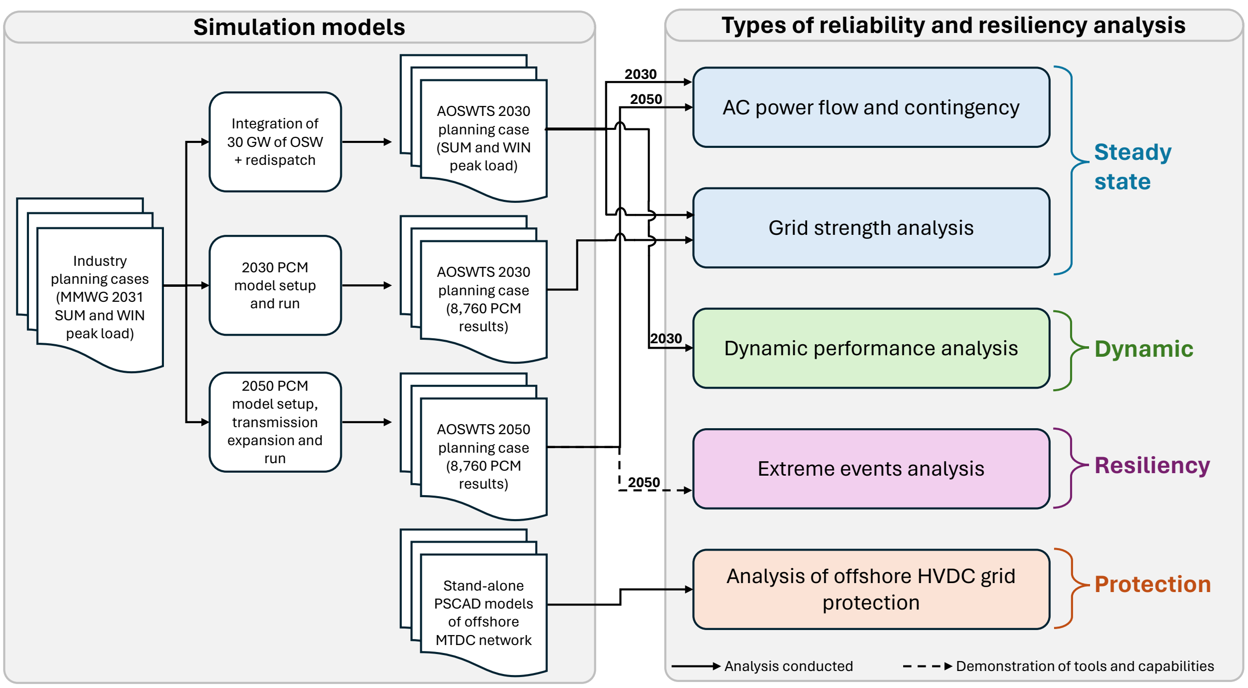


Figure 39. Reliability and resilience analysis framework and simulation models employed in this study.[42]
Figure by NREL.

Note: MMWG = Multiregional Modeling Working Group; SUM = summer; WIN = winter; PCM = production cost model; OSW = offshore wind; PSCAD = Power Systems Computer Aided Design; MTDC = multiterminal HVDC

[42] The different simulation models used in this study, including the industry planning cases, are described in Section 7.2.

Note that the analyses performed in this study do not constitute a comprehensive system reliability assessment (e.g., only the North American Electric Reliability Corporation [NERC] technology performance level-001 standard is considered). Several key elements of a comprehensive reliability assessment were not considered in this study; some of these limitations include, but are not limited to:

- This study primarily focused on voltage levels at 230 kV and above
- Only a limited number of operating conditions were assessed
- A limited number of dynamic incidents were investigated
- A reduced set of system planning and performance criteria were monitored (e.g., mainly voltage limits, branch flow limits, and instability detection).

7.2 Simulation Model Development

The base power flow and dynamic models of the Eastern Interconnection grid correspond to the ones developed by the Eastern Interconnection Reliability Assessment Group's Multiregional Modeling Working Group (MMWG). The MMWG develops a series of power flow and dynamic cases on an annual basis for selected target years and seasons within the planning horizon. Each case reflects the latest available data, at the time of submittal, regarding forecasted load at each node or bus on the interconnected system; the branches (lines and transformers) linking buses; the generating units available to supply the load; and the patterns of generation and interchange determined by economics and maintenance within the constraints of available capacity (Eastern Interconnection Reliability Assessment Group 2021). These cases include various updates obtained from ISOs and RTOs that were required to meet system requirements.

The MMWG planning cases used in this study are[43]:

- Target year 2031, 2021 series, summer peak load
- Target year 2031, 2021 series, winter peak load.

Sections 7.2.1 and 7.2.2 present the changes made to the base simulation models to reflect the AOSWTS planning cases for 2030 and 2050 target years.

7.2.1 2030 Network Topology (Onshore and Offshore)

The AOSWTS 2030 planning case for steady-state and dynamic analyses were derived from the industry planning cases shown in Figure 40.

[43] These cases are also called "industry planning cases" within the context of this study.

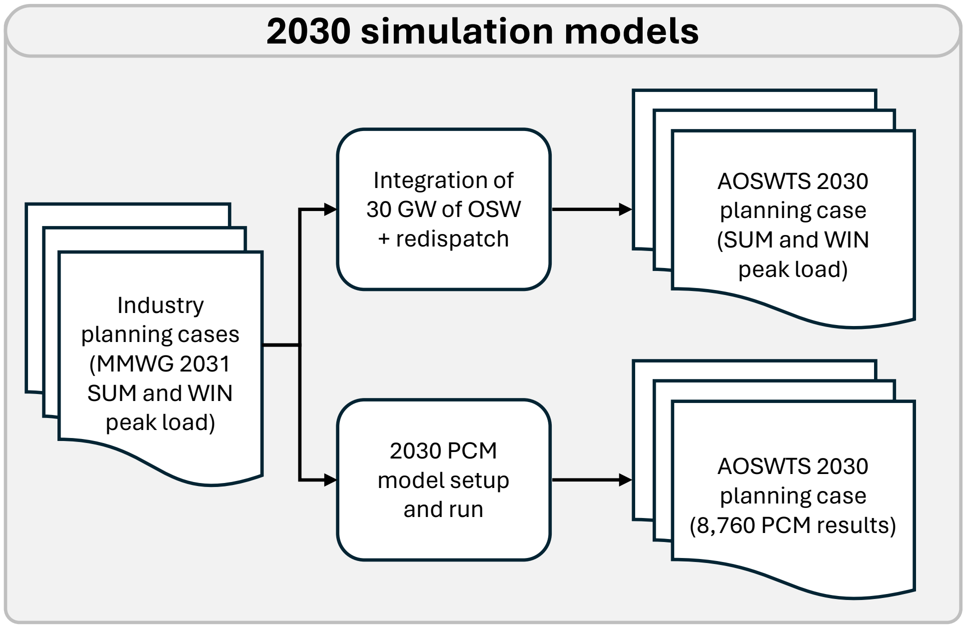


Figure 40. 2030 simulation models for reliability analysis. *Figure by NREL*

There are two sets of simulation AOSWTS 2030 planning cases used in this study:

- **Set 1.** This set is derived from the industry planning cases by adding new generators representing the offshore wind power plants added to the system at the selected POIs (see Section 4.2 for more information) and turning down generation in selected areas[44] to compensate for the additional injections from the new offshore wind plants.
- **Set 2.** A network topology derived from the industry planning case and generator, load, HVDC, and phase-shifter transformer set points derived from the nodal production cost model results.

Set 1 is used for AC power flow, AC contingency analysis, grid strength analysis, and dynamic performance assessment. Set 2 is used for grid strength analysis.

The offshore network topology considered for the AOSWTS 2030 planning case setup is the radial one (see Section 4 for more information).

7.2.2 2050 Network Topology (Onshore and Offshore)

We obtained the AOSWTS 2050 planning case for steady-state analyses by applying the following modifications to the original industry planning case:

[44] Generation redispatch is performed within each area where new offshore wind power plants are being integrated. The power injections from these new plants in a given area are compensated by reducing generation dispatch at other units within the same balancing authority area so that the load and generation balance of the areas are preserved.

- Addition of new generators representing the offshore wind plants added to the system at the selected POIs (see Section 4.5 for more information)
- Addition of new generators representing the onshore generation expansion plan derived from the capacity expansion and production cost modeling tasks, as described in Section 5.1
- Adjustments to system load to match the load values used in the capacity expansion and production cost modeling tasks, as described in Section 5.1
- Addition of models for new transmission elements resulting from the onshore transmission expansion planning performed in the production cost modeling task and detailed in Appendix D
- Addition of new shunt compensators based on reactive power planning to compensate the reactive power losses and improve the system voltage, as described in Appendix I.

7.3 Methodology

This section describes the methodology employed for each part of the reliability analysis framework presented in Figure 39.

7.3.1 Steady-State Analyses

We employed the following types of steady-state analysis in this study:

- AC power flow analysis (2030 and 2050)
- AC contingency analysis (2030 and 2050)
- Grid strength analysis (2030).

Details on the methodology employed for each of the analyses are presented in the following subsections.

7.3.1.1 AC power flow and contingency analysis

The objective of the AC power flow analysis is to ensure that the system can operate within predefined normal operating voltage and branch loading limits. It is also a prerequisite for the AC contingency analysis.

We performed AC power flow analysis for the 2030 and 2050 target years using different approaches, as follows:

- Year 2030
  - Starting from the converged AC power flow cases from the industry planning case

- Integrating the 30 GW of offshore wind achieved by using the Offshore Wind Integration Tool (OSWIT), which is detailed in Appendix L, and developed by PNNL to:
  - Create new generators at the selected POIs with an aggregated representation of the different offshore wind plants
  - Generation that was not offshore wind was turned down to accommodate the addition of 30 GW of offshore wind injections without changing system load, using the following merit order (baseload/must-run units were not turned down):
    - Peaker: gas turbines, internal combustion engine
    - Steam-fuel oil/coal/natural gas
    - Combined cycle.
- Producing convergent AC power flow cases by updating the switched shunt status and adjusting the voltage profile by updating the switched shunt status.

- Year 2050
  - Starting from nodal PCM results (see Section 5 for more details)
  - Selecting relevant operating conditions that have a significant amount of offshore wind injections from the nodal PCM results
  - Updating generator, load, HVDC, and phase-shifter transformer set points on the power flow model from the selected PCM results
  - Using PNNL's C-PAGE tool to produce convergent AC power flow cases, including reactive power compensation design.

The objective of the AC contingency analysis is to ensure that the system can operate within predefined voltage and branch loading limits under different types of contingencies. Table 23 presents a summary of the contingencies used in this study.[45]

Table 23. Contingency List for Steady-State Contingency Analysis

ISO	Number of Contingencies	NERC Category (NERC 2020, 2004)
ISO-NE	2,700	P1, P2, P7
NYISO	9,351	P1, P2, P3, P7
PJM	12,077	P1, P2, P3, P7

The analyses focused on the 230-kV-and-above voltage levels. We did not monitor network behavior at lower voltage levels.

[45] The full sets of contingencies were provided by ISO-NE, NYISO, and PJM as input for the study.

The steady-state performance criteria used in this study are summarized as follows[46]:

- Bus voltage magnitude limits:
  - Normal operation: 0.95–1.05 per unit (p.u.)
  - Under contingency:
    - ISO-NE: 0.95–1.05 p.u.
    - NYISO: 0.9–1.1 p.u.
    - PJM: 0.97–1.1 p.u. (500 kV only) and 0.92–1.05 p.u. (excluding 500 kV)
- Steady-state thermal ratings[47]:
  - Normal operation: 100% of rate A
  - Under contingency: 100% of rate B.

Depending on ISO requirements, the monitoring limit for special lines and zones may vary; in the AOSWTS study, we implemented those special monitoring limits for particular lines/buses/zones.

7.3.1.2 Grid strength analysis

The objective of this analysis is to screen offshore wind POI candidates based on system strength. The results can be used to inform system planners of the possible need for more in-depth reliability analyses for integrating offshore wind energy at weak POIs.

Grid strength describes a system's ability to maintain a stable voltage with changing grid conditions and disturbances. Strong grids provide a stiff voltage reference for various grid devices to maintain their synchronization with the grid. However, weak grids can pose challenges, particularly for connecting inverter-based resources (IBRs). These challenges are because of their asynchronous behavior, which may cause inverters to separate from the system when they are needed to further support grid stability. IBRs rely on an adequate grid strength (relative to the size of the resource) for synchronizing power electronics. While these issues alone do not pose a reliability risk, existing control and protection paradigms need to be adapted to accommodate these changing characteristics from the generation fleet.

In this study, we evaluated the grid strength at the POIs of the offshore wind power plants by using the short-circuit ratio (SCR) metric. The SCR metric is defined as the ratio between the short-circuit apparent power (SCMVA) from a three-phase-to-ground fault at a given location in the power system to the rating of the IBR connected to that location, as follows:

[46] Note: The monitoring limit for special lines and zones might be different depending on ISO requirements.
[47] Rates A and B as defined in the industry planning case power flow models.

$$SCR_{POI} = \frac{SCMVA_{POI}}{P_{nom,IBR}} \tag{1}$$

where:

- SCR_{POI} is the short-circuit ratio at the POI
- $SCMVA_{POI}$ is the short-circuit power (MVA) level at the POI without the fault current contribution of the IBR connected to the studied POI
- $P_{nom,IBR}$ is the nominal active power rating of the IBR connected at the studied POI.[48]

A low SCR area (“weak system”) indicates high sensitivity of voltage (magnitude and phase angle) to changes in power injection. High SCR (“stiff”) systems have a low sensitivity and are predominantly unaffected by changes in power injection. Table 24 presents the grid strength classification based on the SCR metric employed in the study.

Table 24. Grid Strength Classification

Grid Strength Classification	SCR Value[49]
Weak	SCR ≤ 3
Moderate	3 < SCR ≤ 5
Strong	SCR > 5

Although the SCR metric is the most appropriate to use when considering connecting a single IBR to the bulk power system, it is employed in this study as a valuable screening metric within the context of a long-term planning study for integrating offshore wind energy. In this study, SCR_{POI} is computed for all studied offshore wind plant POIs (see Table 28). The SCR_{POI} is determined by computing the minimum short-circuit current levels at the POI busbars while ignoring the short-circuit current contribution of the neighboring offshore wind plants (conservative approach). We compared the short-circuit currents according to the International Electrotechnical Commission 60909-0:2016 standard (“Short-circuit currents in three-phase AC systems – Part 0: Calculation of currents”).

During this study, NREL developed the Automated System-wide Strength Evaluation Tool (ASSET) to analyze grid strength in terms of SCR for large grid models with multiple POIs in a scalable manner. The tool also identifies the top two branches wherein disconnections will cause the largest reductions in system strength, thereby constructing critical N-1/N-2 contingencies corresponding to each POI. SCR metrics were computed in normal operating conditions (N-0), as well as under single

48 Refer to Table 28 for more information on the studied POIs and the nominal active power injection considered at each of the POIs.
49 This classification considers the points of interconnection SCR value to be the minimum SCR between all analyzed operating conditions (generation dispatch/load) and network topology (N-0, N-1, N-2).

(N-1) and double (N-2) contingencies. Quantification of system strength under contingency conditions is of the utmost importance to ensure that the offshore wind plants and the offshore transmission systems are capable of sustaining grid operations during standard contingency events.

More details on the tools and methods used in this study to compute the short-circuit metrics are given in Appendix H, where ASSET is described.

7.3.2 Dynamic Performance Analysis

This analysis assesses the dynamic behavior of the system against the selected contingencies summarized in Table 25[50] and focuses on the 2030 target year.

Table 25. Contingency List for Dynamic Performance Analysis

ISO	Number of Different Contingencies	NERC Category (NERC 2020, 2004)
ISO-NE	6	P1
NYISO	20	P1, P7
PJM	56	P1, P2, P7

The simulations were performed using PNNL's Dynamic Contingency Analysis Tool (DCAT) (Samaan et al. 2015)[51] developed to realistically model cascading-outage processes in the power grid. It uses a hybrid dynamic and steady-state approach to simulate the cascading-outage process, which includes both fast dynamic and slower events.

The dynamic performance criteria used in this study are for the new postcontingency steady state summarized as follows:

- Maximum frequency error in the postcontingency steady state: 0.03 hertz (NERC [2020, 2004])
- System stability criteria: maximum machine speed deviation in postcontingency steady state: 0.1% (Samaan et al. 2015).

7.3.3 Protection of Offshore HVDC Grids

The analysis of offshore HVDC grid protection focuses on evaluating the fault behavior and protection requirements of the offshore multiterminal HVDC (MT-HVDC) transmission topologies considered in this study. The primary objective of the analysis is to evaluate the feasibility of protecting the offshore MT-HVDC network so that a minimum number of export

[50] The full sets of contingencies were provided by ISO-NE, NYISO, and PJM as input for the study.

cables are lost during a contingency in the offshore DC network to minimize the impact on the onshore grid.

We developed detailed electromagnetic transient simulation models of MT-HVDC networks for this analysis including modular multilevel converter (MMC) HVDC converter stations, submarine cables, and control architectures. These models and simulations were decoupled from the steady-state and dynamic performance analyses described in the previous sections.

7.4 Selection of Relevant Operating Conditions

Performing system reliability analysis in a context of high variable renewable energy deployment (including offshore wind) requires analyzing a greater number of system operating conditions. The underlying reason is the variable nature of these sources, resulting in a much wider diversity of system operating conditions than in systems that are comprised mainly of conventional generation. This large number of operating conditions requires carefully selecting the relevant subset for each type of system characteristic to be analyzed. Further criteria and details on the selected operating conditions are as follows.

7.4.1 AC Power Flow and Contingency Analysis

Figure 41 presents the selected operating conditions for the AC power flow and contingency analyses. The analyses for the 2030 target year were performed on variations of the original industry planning cases while the analyses for the 2050 target year were performed on the network topology and operating conditions derived from the AOSWTS 2050 planning case defined in Section 5.

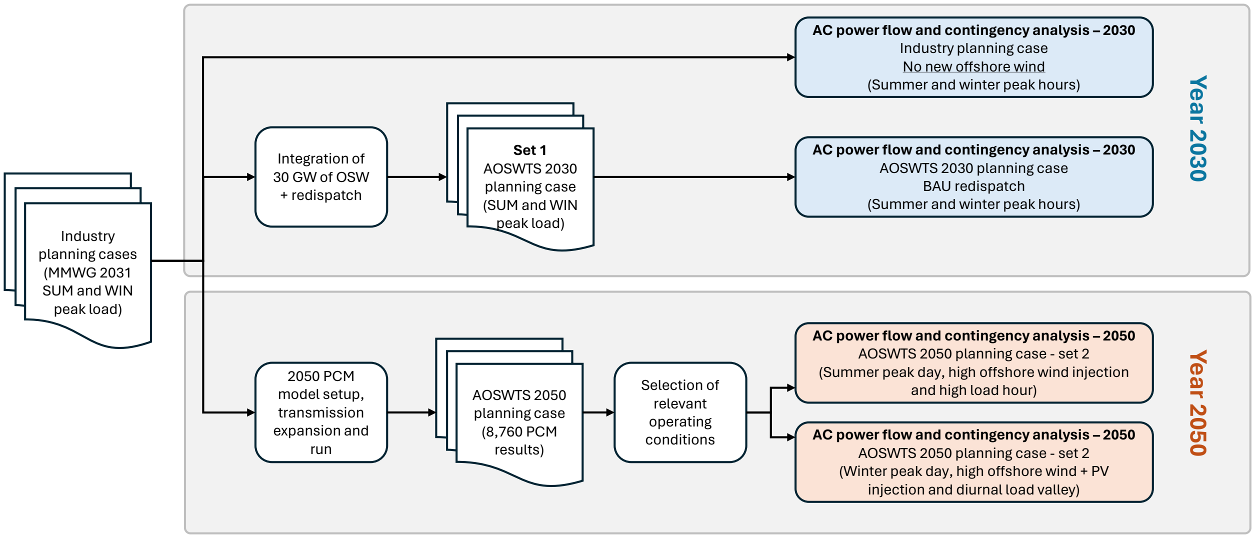


Figure 41. Overview of selected operating conditions[52] for AC power flow and contingency analysis. ***Figure by NREL***

We performed grid strength analysis for a wide range of system operating conditions aimed at capturing the variability of the system strength metrics with respect to changes in generation dispatch and load.

System operating conditions relevant for grid strength analysis were selected from the hourly production cost modeling (PCM) results for three different typical days: summer peak, winter peak, and spring off-peak. We conducted this analysis for 72 different system operating conditions (3 x 24 hours). See Section 7.5.1.3. for more details.

7.4.2 Dynamic Performance Analysis

We conducted the dynamic performance analysis only for the 2030 target year. Figure 42 shows the selected operating conditions for this analysis. The analyses were performed on variations of the original industry planning case for winter and summer peak hours.

[52] For PCM-based 2050 conditions, the renewable injections came from the 2012 meteorological year hours representing those conditions.

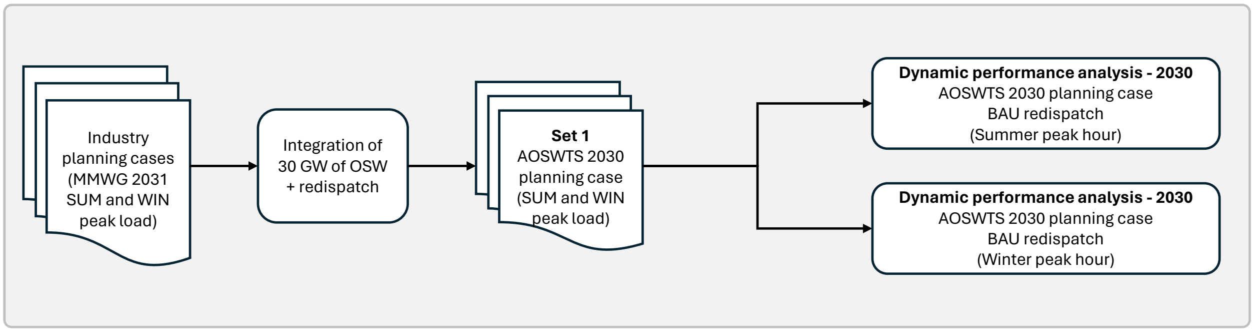


Figure 42. Overview of selected operating conditions for dynamic performance analysis. ***Figure by NREL***

7.5 Simulation Results

This section presents the results of the different reliability analyses within the framework introduced in Section 7.1.

7.5.1 Steady-State Analyses

This section presents the results of the AC power flow, AC contingency, and grid strength analyses. Notably, a subsection is included in which the potential benefits of offshore MTDC network topologies to system performance under contingencies are explored.

7.5.1.1 AC power flow and contingency analysis

We conducted the AC power flow and contingency analysis for both 2030 and 2050 target years, using the network topologies and operating conditions described in Section 7.2 and 7.4, respectively.

Year 2030

The 2030 analyses were performed for both the original industry planning cases and the AOSWTS planning cases.[53] The reason was to identify the potential impacts (positive and negative) of offshore wind energy integration on the system's steady-state performance. The analyses focused on the high-voltage transmission networks (230 kV and above) of ISO-NE, NYISO, PJM, and the Southeast.

We observed the following from the different simulation results for the limited number of contingencies and conditions studied:

- ISO-NE

[53] The industry planning case was modified to integrate 30 GW of offshore wind energy at select POIs.

- Normal operating conditions (N-0): No overloads or violation of voltage limits were observed in N-0 in both the summer and winter peak load cases, with or without offshore wind.
- Contingencies include:
  - Undervoltage issues: No structural[54] violations of lower-voltage limits were observed for the different contingencies simulated across the studied power flow cases.
  - Overvoltage issues: No structural violations of upper-voltage limits were observed for the different contingencies simulated across the studied power flow cases.
  - Branch overload issues: No structural violations of branch loading limits were observed for the different contingencies simulated across the studied power flow cases.

- NYISO
  - Normal operating conditions (N-0): No overloads or violation of voltage limits were observed in N-0 in both the summer and winter peak load cases, with or without offshore wind. It must be emphasized that the 345-kV network is operated close to the upper-voltage limit in the N-0 state for the cases with offshore wind energy.
  - Contingencies include:
    - Undervoltage issues:18 different buses present violations to the lower-voltage limit in the postcontingency state for a small subset of the simulated contingencies in the cases with offshore wind energy. However, a thorough analysis of the results indicates that the identified issues are not structural and can be managed by an improved voltage profile in the precontingency state.
    - Overvoltage issues: 50 different buses present violations to the upper-voltage limit in the postcontingency state for a small subset of the simulated contingencies in the cases with offshore wind energy. However, a thorough analysis of the results indicates that the identified issues are not structural and can be managed by an improved voltage profile in the precontingency state.
    - Branch overload issues: 12 transmission lines that do not show postcontingency overload issues in the cases without offshore wind present overloads in the postcontingency state for a small subset of the simulated contingencies in the cases with offshore wind. However, a thorough analysis of the results indicates that the identified issues are not structural and can be managed by an improved voltage profile in the precontingency state to reduce reactive power flows across the high-

[54] In this study, a structural issue is defined as a violation of system planning criteria across all operating conditions, across multiple contingencies, or having postcontingency violations on a significant number of network elements not directly close to the element under contingency. In other words, issues that are persistent and not adequately solvable using operational measures such as local generation redispatch or voltage profile management.

voltage lines, and a slightly different generation redispatch strategy when integrating the offshore wind injections into the original planning case aiming at reducing the network stress around the offshore wind POIs.

- PJM
    - Normal operating conditions (N-0): No overloads or violation of voltage limits are observed in N-0 in both the summer and winter peak load cases, with or without offshore wind. It must be emphasized that several parts of the high-voltage network are operated close to the lower-voltage limit in the N-0 state for the cases with offshore wind.
    - Contingencies include:
        - Undervoltage issues: 115 different buses present violations to the lower-voltage limit in the postcontingency state for a small subset of the simulated contingencies in the cases with offshore wind. However, a thorough analysis of the results indicates that the identified issues are not structural and can be managed by an improved voltage profile in the precontingency state.
        - Overvoltage issues: 23 different buses present violations to the upper-voltage limit in the postcontingency state for a small subset of the simulated contingencies in the cases with offshore wind. However, a thorough analysis of the results indicates that the identified issues are not structural and can be managed by an improved voltage profile in the precontingency state.
        - Branch overload issues: 21 transmission lines that do not show postcontingency overload issues in the cases without offshore wind present overloads in the postcontingency state for a small subset of the simulated contingencies in the cases with offshore wind. However, a thorough analysis of the results indicates that the identified issues are not structural. The issues can be managed by an improved voltage profile in the precontingency state to reduce reactive power flows across high-voltage lines and a slightly different generation redispatch strategy when integrating the offshore wind injections into the original planning case aiming at reducing the network stress around the offshore wind POIs.
        - About 2% of the simulated contingencies failed to converge. Further investigations are required on that small subset of contingencies, but the initial analyses indicate that those are not the result of integrating offshore wind in the PJM area.
- Southeast (Carolinas)
    - Normal operating conditions (N-0): No overloads or violation of voltage limits are observed in N-0 in both the summer and winter peak load cases, with or without offshore wind.
    - Contingencies include:

- Undervoltage issues: No structural violations of lower-voltage limits are observed for the different contingencies simulated across the studied power flow cases.
- Overvoltage issues: No structural violations of upper-voltage limits are observed for the different contingencies simulated across the studied power flow cases.
- Branch overload issues: No structural violations of branch loading limits are observed for the different contingencies simulated across the studied power flow cases.

7.5.1.2 Assessment of potential benefits of offshore MTDC network configurations to system performance under contingencies

In this section, the potential reliability benefits of offshore MTDC network configurations to system performance under onshore and offshore contingencies are assessed from a steady-state system performance perspective. We conducted this assessment for the 2050 AOSWTS planning case. The selected base operating condition for this analysis is the 2050 summer peak day, high offshore wind injection, and high load hour. The analysis is focused on the ISO-NE and NYISO high-voltage networks and is aimed at demonstrating the potential for how the MTDC network could help manage onshore congestion and contingencies and vice-versa. This is not a comprehensive analysis of multiple operating conditions and contingencies.

The MTDC interregional offshore network topology considered for these analyses is shown in Figure 43. It is a subset of the interregional MTDC network topology studied in Section 5 and 6, focusing on the ISO-NE and NYISO systems.

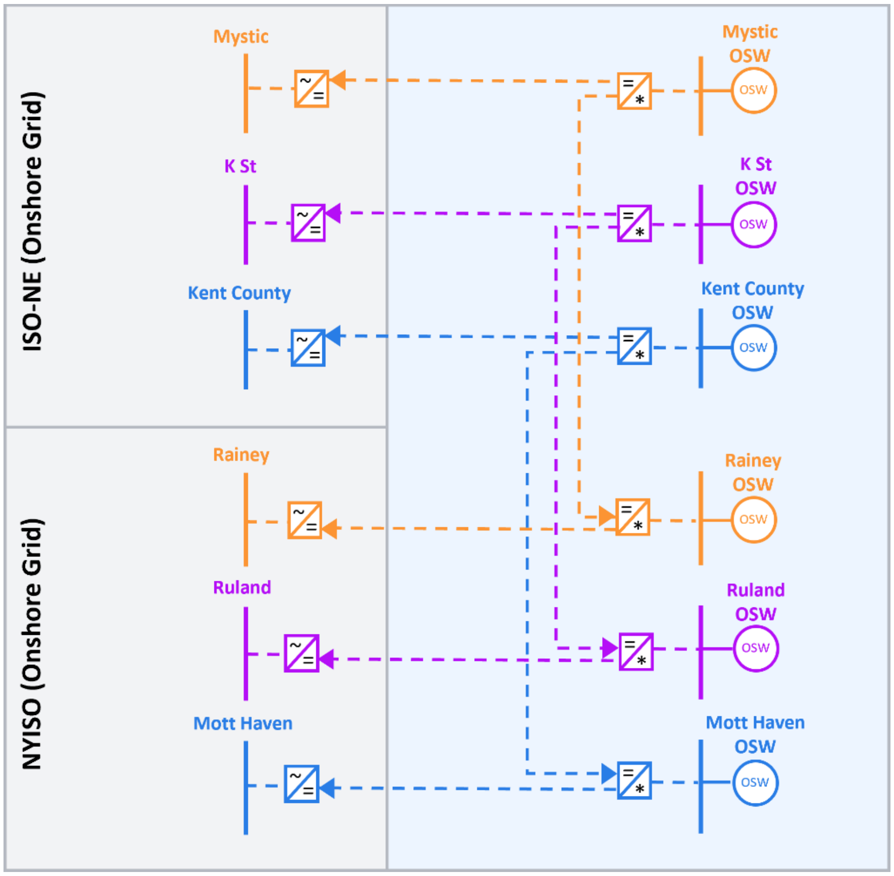


Figure 43. Studied MTDC network topology for assessing the potential benefits of offshore MTDC network configurations to system performance under contingencies. *Figure by NREL*

Table 26. Selected Contingencies for the MTDC Interregional Offshore Network Study

Category	Initial Condition	Event	Location	Case
P1[55]	Normal system	Loss of onshore transmission circuit	Onshore (Massachusetts area)	1
P7	Normal system	Loss of an offshore interlink bipole	Offshore (ISO-NE to NYISO)	1 and 2

Table 26 lists the simulated onshore and offshore contingencies. This analysis is performed for two different operating conditions that include power exchanges between ISO-NE and NYISO, as follows:

- **Case 1.** Power exchanges between ISO-NE and NYISO almost exclusively through the onshore HVAC network

[55] Suggested by ISO-NE.

- **Case 2.** Power exchanges between ISO-NE and NYISO through both the onshore HVAC network and offshore DC interlinks.

Case 1

Figure 44 shows the precontingency power flows (lossless representation) across the offshore MTDC network and the onshore power exchange between ISO-NE and NYISO for Case 1. The power flow solution is obtained by employing the sequential AC-DC power flow solution algorithm implemented by PNNL and detailed in Appendix J.

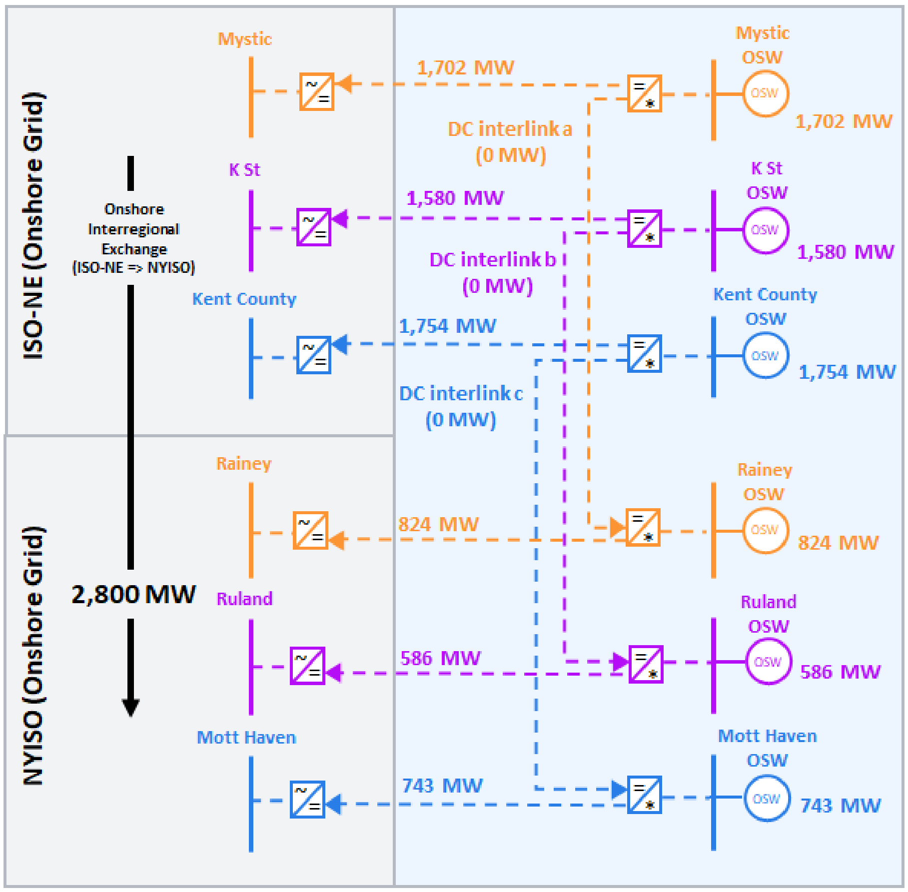


Figure 44. Offshore MTDC network power flows – Case 1 (precontingency). ***Figure by PNNL***

The simulation results for one of the P1 contingencies studied for the ISO-NE system indicates that one transmission line in the Massachusetts area gets overloaded (118% of Rate B, 52% of Rate C) in postcontingency, whereas the loading of the same line in precontingency was about 50%. To investigate if the overloading on this AC line can be alleviated by rescheduling the DC power injections at the onshore MTDC terminals in the postcontingency state, the offshore wind injection into the ISO-NE area is reduced by redirecting part of those injections (1,200 MW) to the NYISO area via the offshore DC interlinks without leading to offshore wind generation curtailment.[56]

The impact on the AC system (based on the AC line rate B rating) using the proposed approach is provided in Table 27. Additionally, it was observed that the loading on the considered critical AC line is 88% after the DC redispatch, which clearly shows that there has not been any overloading observed on the line after using the proposed DC redispatch methodology. The postcontingency and post-DC-redispatch power flows (lossless representation) across the offshore MTDC network and the onshore power exchange between ISO-NE and NYISO for Case 1 are shown in Figure 45.

Table 27. Evidence of Alleviating the Overloading of the Critical AC Line After Considering the DC Redispatch for the MTDC Topology (Case 1)

	Before Contingency	P1 Contingency (Before DC Redispatch)	P1 Contingency (After DC Redispatch)
Critical AC Line Flow	50%	118%	88%

[56] The results from this specific analysis, including the postcontingency corrective actions, are only valid because New England was exporting power to New York through the onshore system. For tie-line flows in the opposite direction (NYISO to ISO-NE), additional analyses are required to determine the postcontingency performance of the system and the possible corrective actions that may be needed.

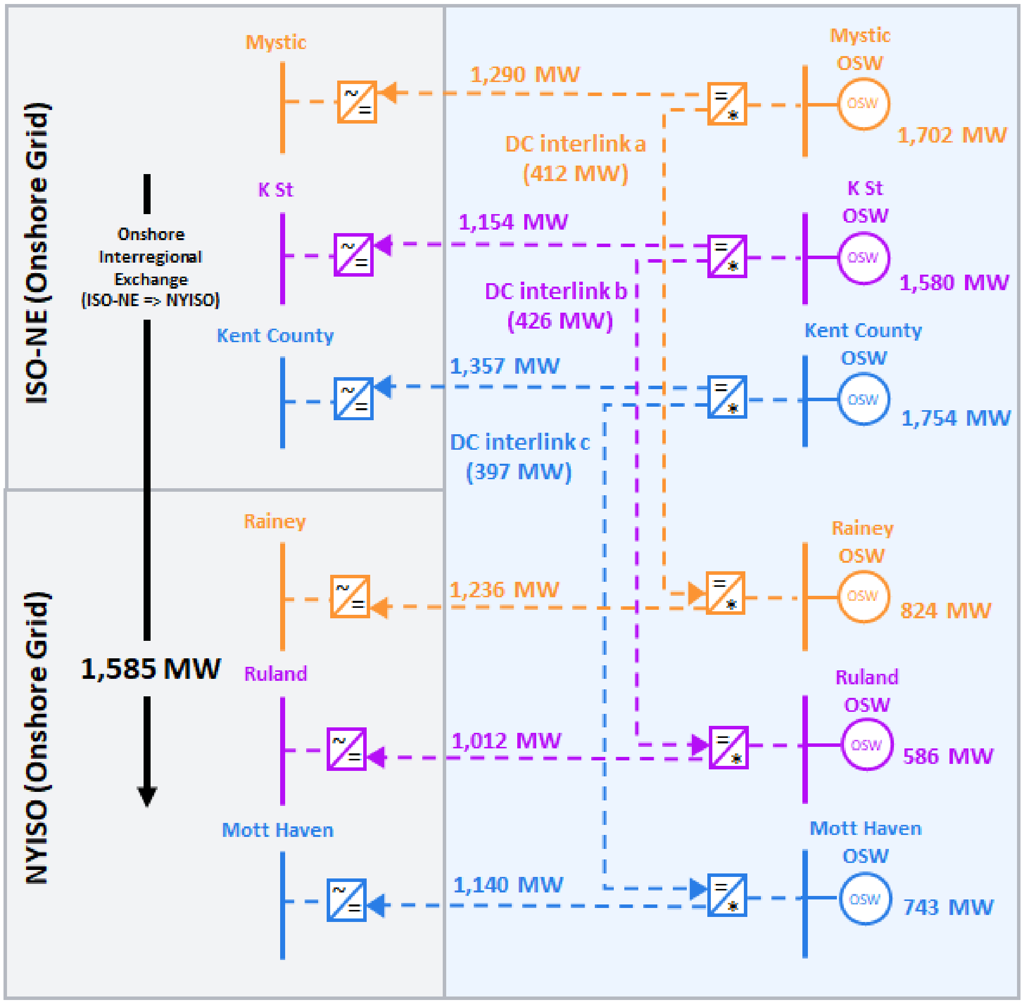


Figure 45. Offshore MTDC network power flows – Case 1 (postcontingency, postredispatch). *Figure by PNNL*

Case 2

Figure 46 shows the precontingency power flows (lossless representation) across the offshore MTDC network and the onshore power exchange between ISO-NE and NYISO for Case 2. In this case, the 1,300-MW ISO-NE to NYISO power exchange is via the onshore network, whereas 1,500 MW are exchanged through the offshore interties (3 x 500 MW). The power flow solution is obtained by employing the sequential AC-DC power flow solution algorithm implemented by PNNL and detailed in Appendix J.

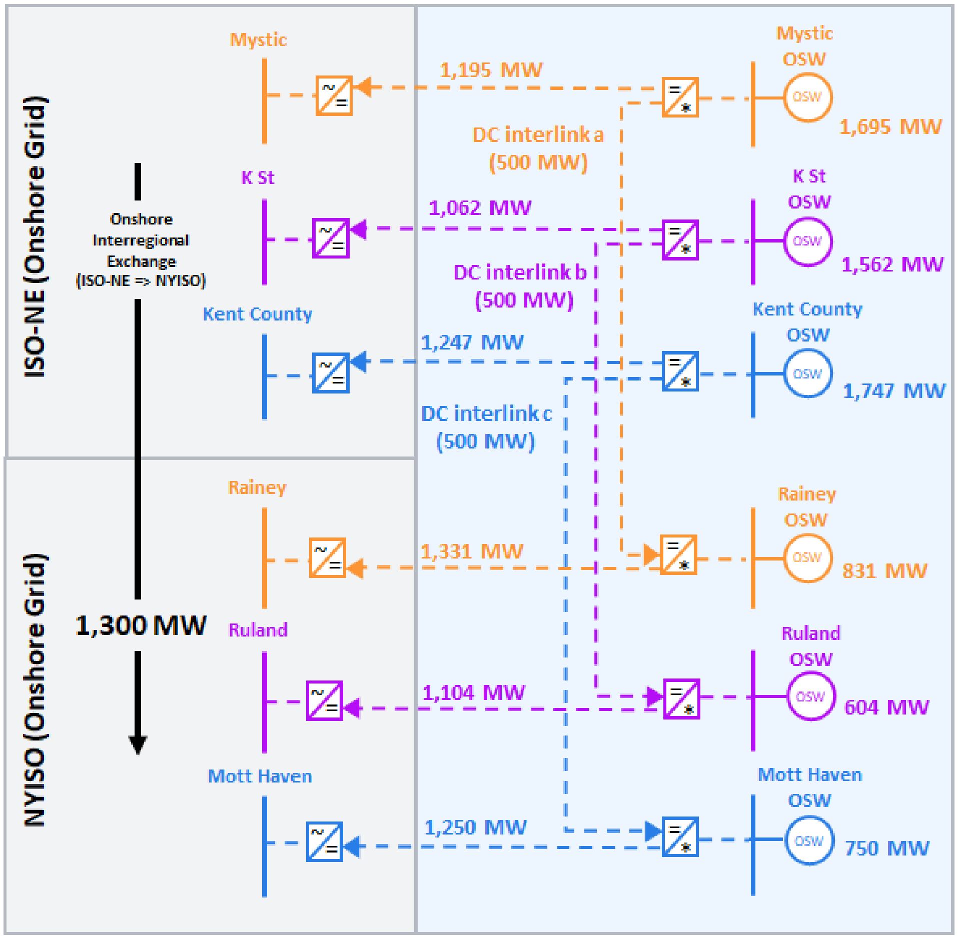


Figure 46. Offshore MTDC network power flows – Case 2 (precontingency). *Figure by PNNL*

Three different contingencies are considered in this analysis; defined as follows:

- Case 2, contingency "a": P7 contingency (bipole outage) of the DC interlink "a"
- Case 2, contingency "b": P7 contingency (bipole outage) of the DC interlink "b"
- Case 2, contingency "c": P7 contingency (bipole outage) of the DC interlink "c."

Case 2, Contingency “a”

The simulation outcomes for one specific contingency in the offshore MTDC interlink (specifically, tripping of offshore interlink between Rainy and Mystic) reveal that the loss of the 500-MW offshore interlink will result in an additional 456 MW of power being transmitted through onshore AC interties. Following this contingency, two 345-kV transmission lines in the New York City area exhibit overloads. The overloads could potentially be managed through the dispatch systems in the precontingency state, a different generation dispatch state, or precontingency or postcontingency redispatch on the MTDC network. The lossless representation of postcontingency power flows across the offshore MTDC network and the onshore power exchange between ISO-NE and NYISO for Case 2 are shown in Figure 47.

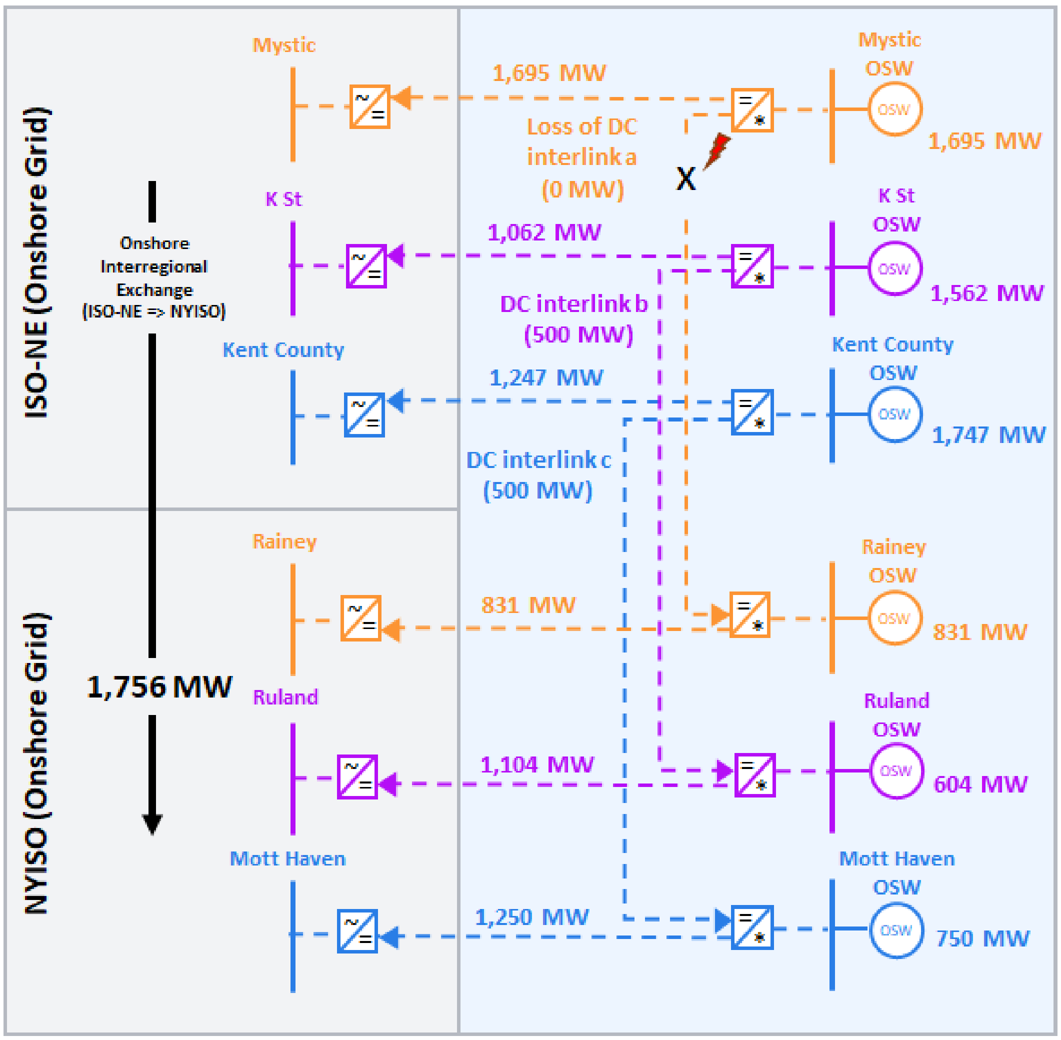


Figure 47. Offshore MTDC network power flows – Case 2, contingency “a” (postcontingency). *Figure by PNNL*

Case 2, Contingency "b"

The Case 2, contingency "b" (tripping of offshore interlink between K St and Ruland) results in an additional 473 MW of power being transmitted through AC interties. This contingency resulted in no overloads.

The lossless representation of postcontingency power flows across the offshore MTDC network and the onshore power exchange between ISO-NE and NYISO for Case 2, contingency "b" is provided in Figure 48.

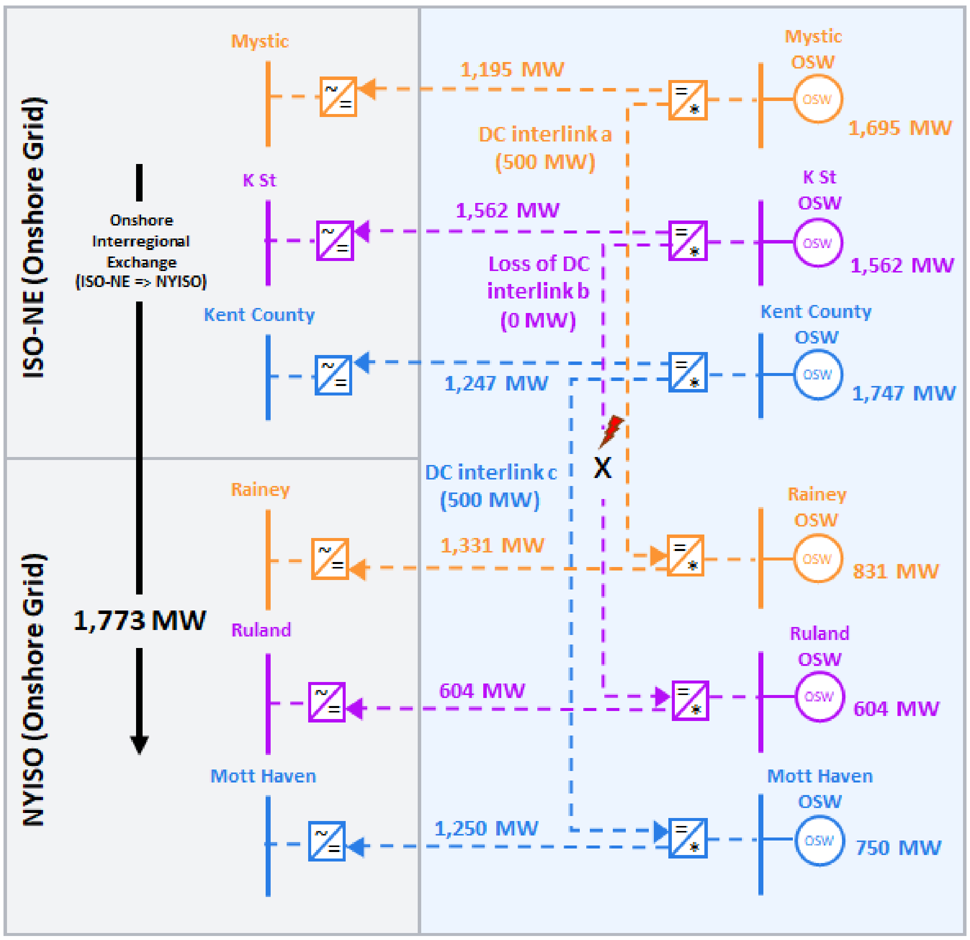


Figure 48. Offshore MTDC network power flows - Case 2, contingency "b" (postcontingency). *Figure by PNNL*

Case 2, Contingency "c"

For Case 2, contingency "c" (tripping of offshore interlink between Kent County and Mott Haven) results in an additional 455 MW of power being transmitted through AC interties. This contingency resulted in no overloads.

The lossless representation of postcontingency power flows across the offshore MTDC network and the onshore power exchange between ISO-NE and NYISO for Case 2, contingency "c" is provided in Figure 49.

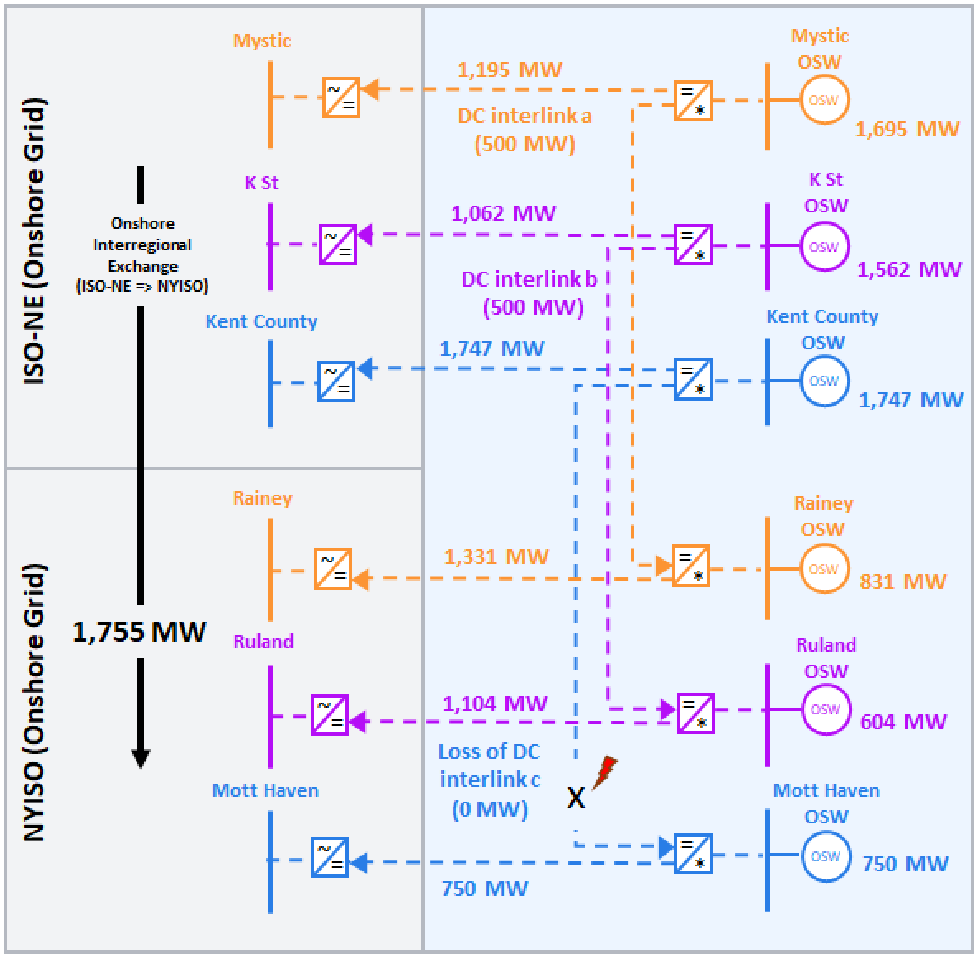


Figure 49. Offshore MTDC network power flows - Case 2, contingency "c" (postcontingency). ***Figure by PNNL***

7.5.1.3 Grid strength analysis

This section presents the results of the grid strength analysis following the methodology described in Section 7.3.1.2 and using ASSET, which is described in Appendix H. This analysis focused on the 30 GW of installed offshore wind capacity in the 2030 scenario only. Table 28 presents the list of studied POIs and the associated offshore wind installed capacity.[57]

[57] The list of studied POIs and related maximum injection capacity corresponds to about 36 GW of offshore wind capacity at select POIs (higher than the 30 GW for the studied scenario). The reason for having more POIs and offshore wind capacity than the studied 30-GW-by-2030 scenario is because we used the grid strength analysis to help identify the more suitable POIs for the studied scenario (30 GW by 2030), and some POIs studied had a higher capacity than the 30-GW scenario.

Table 28. List of Studied POIs and Associated Offshore Wind Installed Capacity.

Note: See Appendix E for additional information on selecting candidate POIs.

POI	State	Maximum Injection [MW]
Gowanus 345 kV	New York (NY)	816
Astoria 138 kV	NY	1,230
Farragut East 345 kV	NY	1,310
Farragut West 345 kV	NY	1,310
W. 49th 345 kV	NY	1,310
East Hampton 69 kV	NY	139
Holbrook 138 kV	NY	1,050
Barrett 138 kV	NY	1,350
Indian River 230 kV	Delaware	1,568
Fentress 500 kV	Virginia (VA)	5,200
Landstown 230 kV	VA	2,600
Oyster Creek 230 kV	New Jersey (NJ)	816
BL England 138 kV	NJ	432
Larrabee 230 kV	NJ	1,300
Smithburg 500 kV	NJ	2,400
Atlantic 230 kV	NJ	1,200
Cardiff 230 kV	NJ	1,500
Ward Hill 345 kV	Massachusetts (MA)	1,200
New Bourne 345 kV	MA	1,200
West Barnstable 345 kV	MA	838

We split the grid strength analysis into two parts, according to the studied system configuration, as depicted in Figure 50.

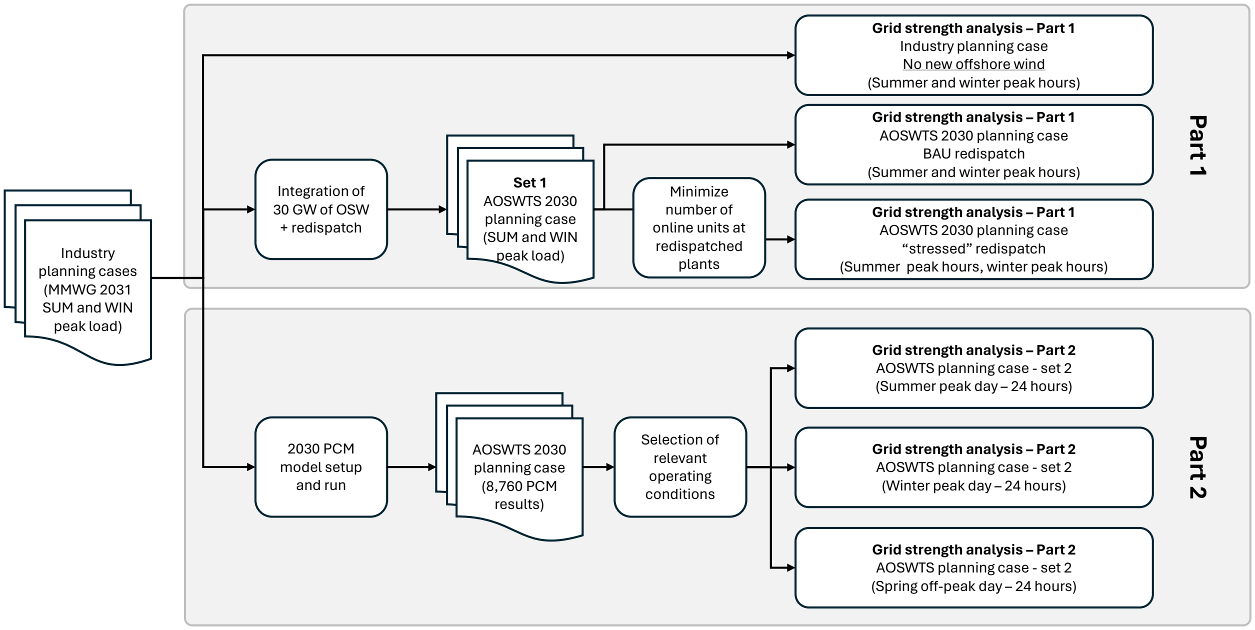


Figure 50. Selected grid topologies and operating conditions for the system strength analysis. ***Figure by NREL***

The selection of planning cases and operating conditions is intended to capture a wide range of grid conditions, aiming to provide a more robust quantification of system strength at the selected POIs. More details on the selected grid topologies and operating conditions for system strength analysis are presented in the following subsections.

7.5.1.3.1 Part 1

This subsection presents the grid strength analysis results from Part 1 of this analysis, which was conducted for three different generation dispatch conditions, as shown in Figure 51.

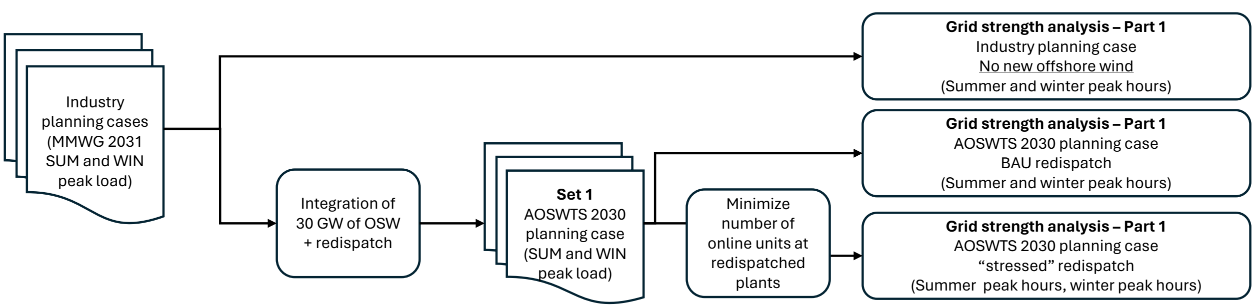


Figure 51. Selected operating conditions for Part 1 of the system strength analysis. ***Figure by NREL***

Studied cases include:

- Summer and winter peak load, without additional offshore wind; original industry planning cases, without additional offshore wind

- Summer and winter peak load, with additional offshore wind, BAU redispatch– AOSWTS 2030 planning cases (Set 1); dispatch of other conventional units is modified (reduced) to compensate for the additional offshore wind injections
- Summer and winter peak load, with additional offshore, "stress" redispatch– AOSWTS 2030 planning cases (Set 1); dispatch of other conventional units is modified (reduced) to compensate for the additional offshore wind injections while minimizing the number of online units at the redispatched power plants.

Results of the Part 1 grid strength analysis are shown in Figure 52. Of the 24 studied POIs, 9 can be classified as "strong," 3 as "moderate," and 12 as "weak." Results show that contingencies have a major impact on the POI strength (in N-0, only 2 POIs are classified as "weak" while 17 are classified as "strong"). It must also be emphasized that the Fentress POI is weak even in the case without offshore wind.[58] Detailed SCR calculation results for Part 1 are presented in Appendix F.

[58] This is explained by the topology of the network around the Fentress POI, making the grid strength under N-1 or N-2 conditions significantly lower than in N-0.

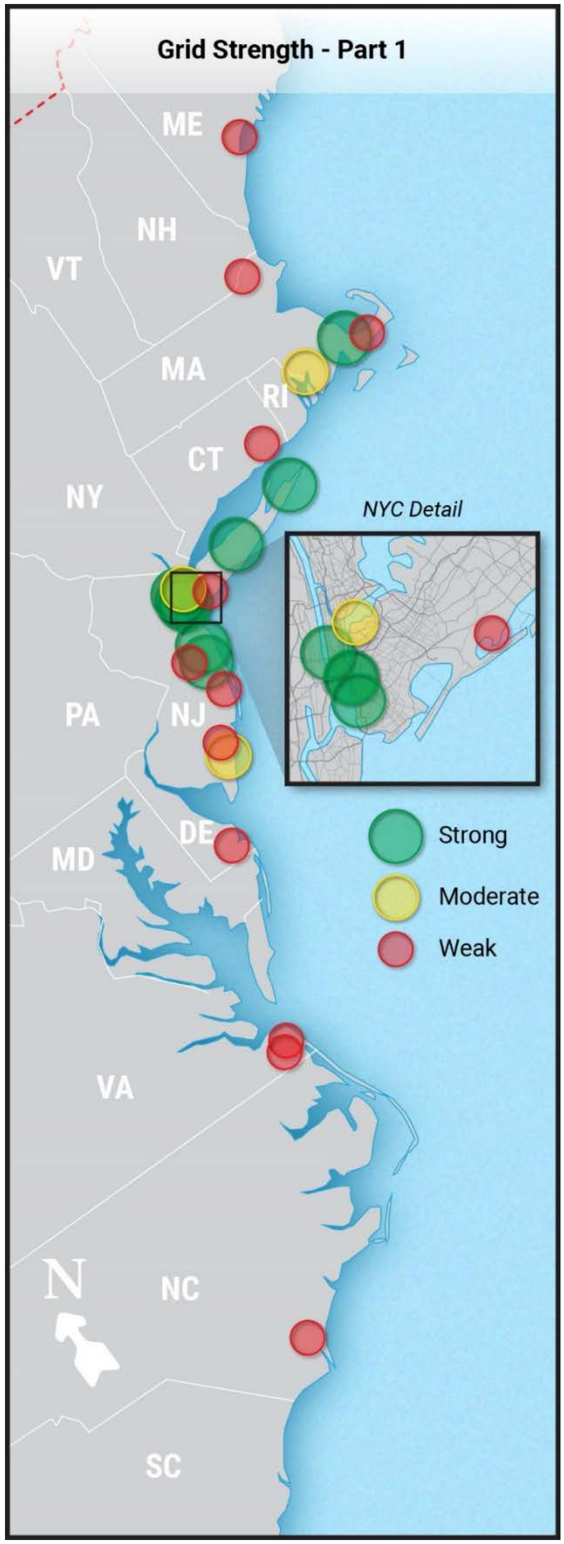


Figure 52. Classification of POI strength (Part 1 grid strength results). *Figure by NREL*

Part 1 of the grid strength analysis focuses on characterizing the POI strength for two specific operating conditions: summer and winter peak load. It is known that peak load conditions tend to present higher SCR values due to the fact of higher dispatch of synchronous machine-based units during those high load conditions. However, characterizing POI strength should consider a broader range of operating conditions so that the conclusions made from this screening exercise are robust enough to inform the subsequent stages of the grid analysis process.

This subsection presents the grid strength analysis results for Part 2 of this work, wherein the 2030 AOSWTS planning case grid configuration (30 GW of offshore wind installed capacity) is considered. System operating conditions were selected from the nodal production cost modeling results for three different typical days: summer peak, winter peak, and spring off peak. We conducted this analysis for 72 different generation dispatch conditions (3 x 24 hours) and compared them to two operating conditions in Part 1, as depicted in Figure 53.

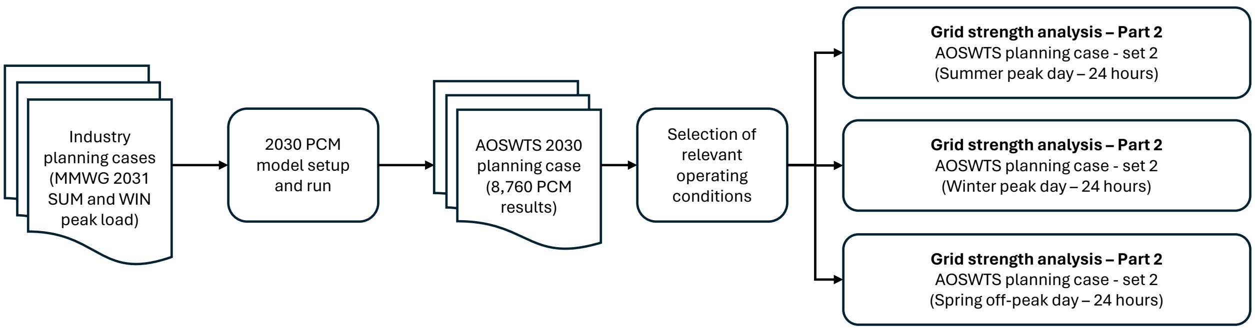


Figure 53. Selected operating conditions for Part 2 of the system strength analysis. ***Figure by NREL***

Results of the Part 2 grid strength analysis are shown in Figure 54. Of the 24 studied POIs, 5 can be classified as "strong," 5 as "moderate," and 14 as "weak." Results show that contingencies have a major impact on the POI strength (in N-0, only 2 POIs are classified as "weak" while 17 are classified as "strong").

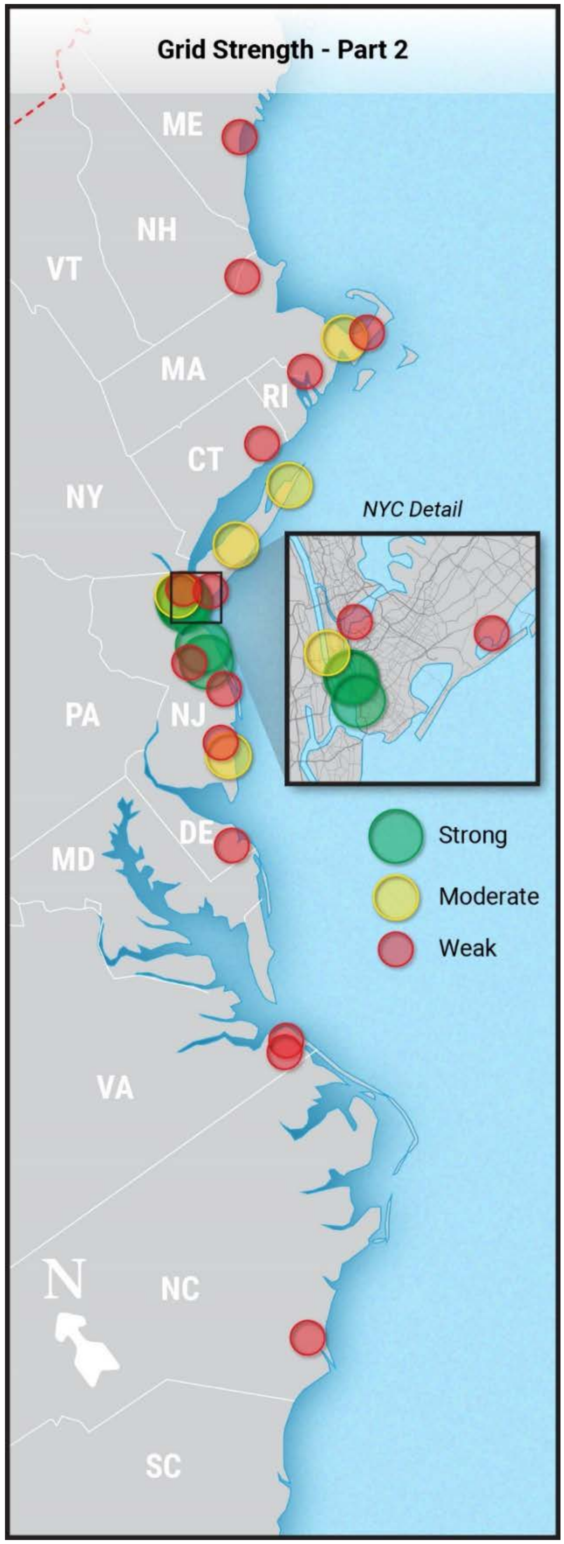


Figure 54. Classification of POI strength (Part 2 grid strength results). *Figure by NREL*

Figure 55 shows the SCR in N-0 at the selected POIs as a function of the operating conditions (generation dispatch) for the selected summer peak, winter peak, and spring off-peak days (against the Eastern-Interconnection-wide generation dispatch stack). Some of the selected POIs are more sensitive to the generation dispatch conditions than others (higher variability depending on the dispatch stack). The POIs most sensitive to operating conditions (larger SCR variations) are the ones closer to peaking thermal units (dispatched at high load conditions only) and therefore present higher SCR values at times when those units are operating.

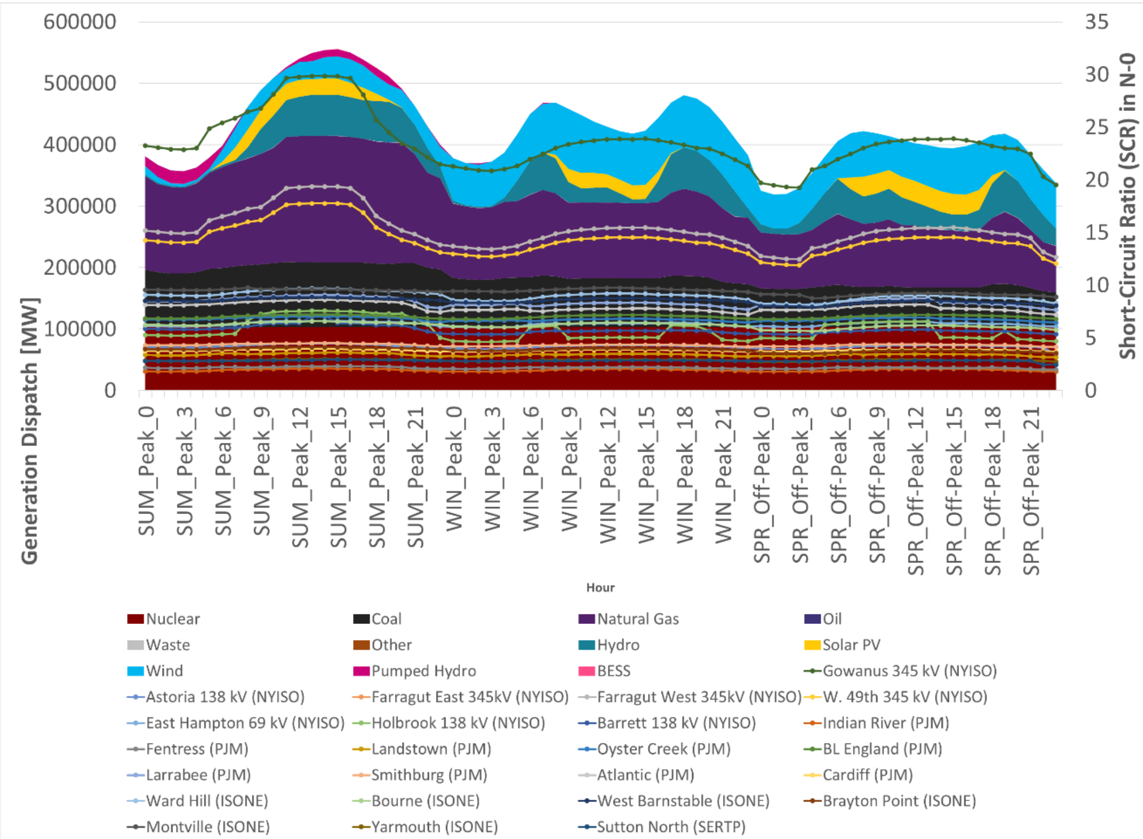


Figure 55. SCR at selected POIs in the N-0 condition vs. the generation dispatch stack (Eastern-Interconnection-wide).[59] ***Figure by NREL***

Although operating conditions (generation dispatch) impact POI strength, those impacts are lower when compared to the impact of contingencies on POI strength.

Detailed SCR calculation results for Part 2 are presented in Appendix G.

7.5.2 Dynamic Performance Analysis

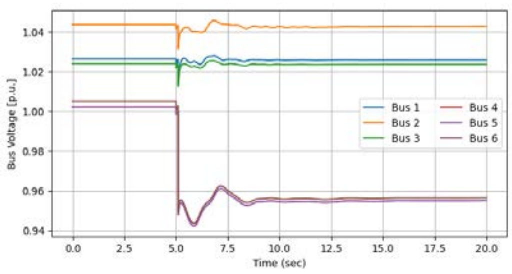
We conducted the dynamic performance analysis for the 2030 target year only, using the network topology and operating conditions described in Section 7.2 and 7.4, respectively.

[59] The x-axis labels in this plot are defined using the following convention: SUM_Peak_0 represents summer peak day, hour 0 of the chronological 24-hour dispatch for that given day.

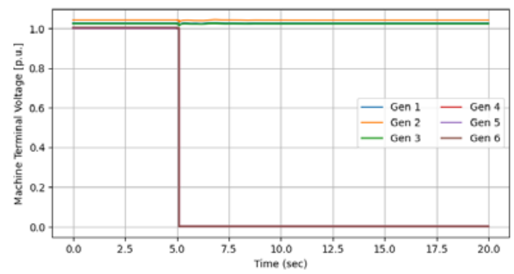
The system dynamic analytics were carried out by DCAT. The significant execution steps of DCAT include identifying contingencies, determining control actions, assessing system stability, evaluating the transient response, remedial action scheme planning, and corrective action analysis. The DCAT results can provide a comprehensive understanding of system behavior during the contingencies while assisting in operator training and emergency preparedness.

We studied six different 345-kV P1 circuit contingencies around offshore wind POIs suggested by ISO-NE that are relevant to the New England area. Using generic dynamic models to represent the offshore wind systems, one contingency showed an unacceptable result related to the addition of offshore wind, and this is because the machine speed deviations for several generators were greater than 0.1% at the end of dynamic simulation (Agrawal, Etingov, and Huang 2021). This contingency was a 345-kV line crossing the Maine-New Hampshire interface. This outcome is because the dynamic models associated with these machines could not give enough frequency response in a postfault steady state, causing machine speeds to further vary from their prefault speeds. When they become available, updated machine-specific dynamic models may give suitable governor controls to mitigate this issue.

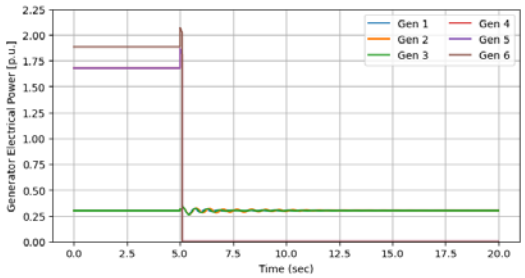
For demonstration, one of the P1 contingencies is introduced at t = 5 seconds (s) and simulation runs until dynamic simulation reaches a steady state. In this test, dynamic simulation reaches a steady state at t = 20 s. This contingency resulted in a total of three tripping actions with a total generation loss of 525 MW and no-load loss. Simulation results are provided in Figure 56. Generators 1–3 in the charts are selected randomly from the population of affected generators during the contingency. Generators 4–6 have tripped during the contingency.



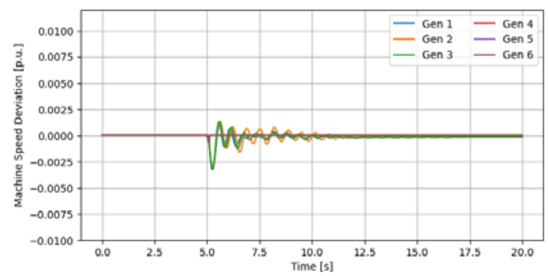
(a.) Bus voltage



(b.) Machine terminal voltage



(c.) Machine electrical power



(d.) Machine speed deviation

Figure 56. The offshore wind system response for one of the NERC P1 branch contingency runs by DCAT.
Figures by PNNL

After the dynamic simulation, no control conditions that could trigger special protection systems and remedial action schemes were observed. No line overloads were observed above 100% of rate B, but some voltage violations were observed in the offshore wind Eastern Interconnection system that required relative corrective actions to mitigate those violations. Therefore, DCAT employed operator actions in the postcontingency to alleviate voltage violations. Figure 57 shows the bus voltage profiles in precontingency (base case), postcontingency (after dynamic simulation), and after corrective action. After applying the corrective actions, system voltages were within the voltage limits.

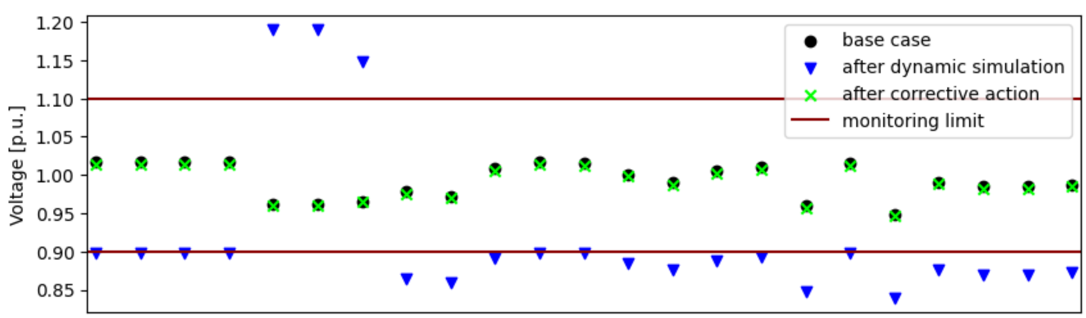


Figure 57. Voltage profile for Eastern Interconnection buses that exceeded the limit in postcontingency.
Figure by PNNL

7.5.3 Protection of Offshore HVDC Grids

The performance of the offshore MT-HVDC transmission during a fault in the DC network is primarily governed by the following three factors as shown in Figure 58:

1. The fault behavior and control of the DC network, particularly of the onshore and offshore MMC-HVDC converter stations
2. The performance of the fault detection systems depending on the protection relays used for detection faults
3. The performance of the protection equipment, such as fault current limiting DC reactors (DCRs) and DCCBs to reduce fault current levels and isolate faulted sections of the DC network.

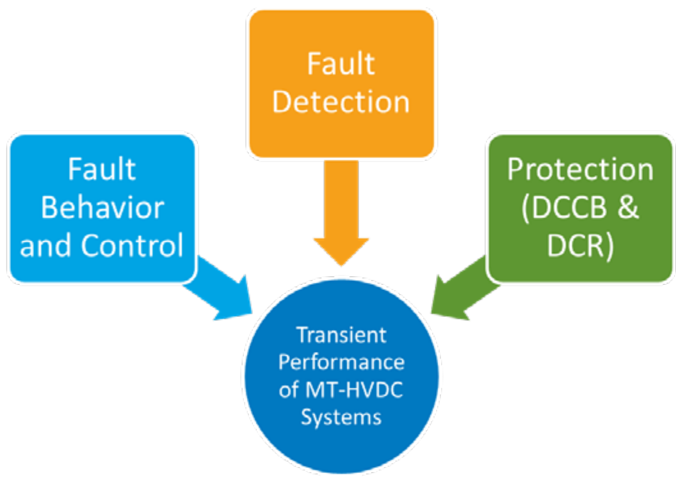


Figure 58. Factors governing the transient performance of offshore MT-HVDC transmission during faults in the DC network. ***Figure by NREL***

This preliminary analysis evaluates the fault behavior and protection requirements of offshore MT-HVDC transmission topologies. The primary objective of this analysis was to evaluate the feasibility of protecting an offshore MT-HVDC network so that the minimum number of export cables will be lost during a contingency in the DC network and the stability impact of the onshore grid will be minimized. We developed detailed electromagnetic transient simulation models of MT-HVDC networks for this analysis including MMC-HVDC converter stations, submarine cables, and control architectures.

Figure 59 shows a four-terminal HVDC offshore transmission topology simulated in PSCAD using detailed electromagnetic transient models for evaluating the fault behavior and protection needs of offshore HVDC networks. The HVDC network was simulated using 320-kV/1,200-MW symmetric monopole technology. The quantitative results will be different for the 525-kV bipole technology; however, the high-level conclusions on the driving factors that influence the behavior of offshore HVDC networks apply to both monopole and bipole technologies. Note that although the driving factors that influence the behavior of HVDC networks with both monopole and bipole technologies are similar, the bipole configuration can offer additional performance by being able to operate at half capacity in the event of a fault in the DC network. Because the objective of this analysis was to evaluate protection needs and the speed and rating of HVDC breakers, we did not include the HVDC breakers in the simulated models. This approach demonstrates the behavior of each HVDC converter during different types of faults without the HVDC breakers and it can help identify points in which an HVDC converter might enter a blocking mode due to the overcurrent of its semiconductor switches.

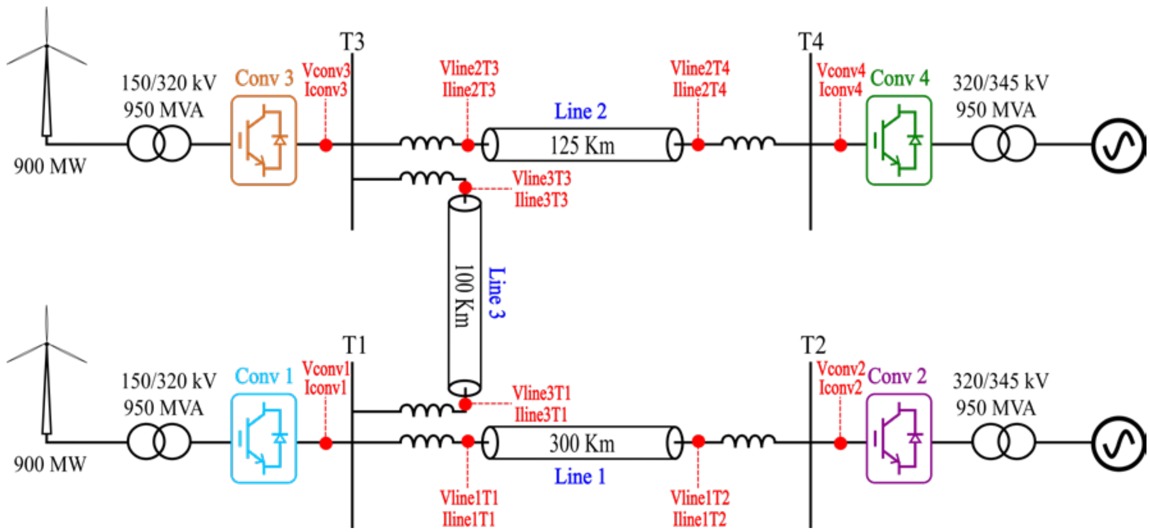


Figure 59. A four-terminal HVDC offshore transmission network based on 320-kV/1,200-MW symmetrical monopole technology. ***Figure by NREL***

Figure 60 shows the response of an offshore HVDC converter (Conv1 in Figure 58) during a pole-to-pole fault on the export cable of the offshore converter for different fault locations. The response is shown by plotting the HVDC converter pole-to-ground voltage and the positive pole output current. The fault location is defined in terms of the distance from the submarine export cable of the fault from the offshore HVDC converter.

As shown in Figure 60, the worst voltage drop occurs when the fault is 30 kilometers away from the offshore converter station. Also, the fault current hits the overcurrent limit of insulated gate bipolar transistors (IGBTs) inside the HVDC converter fastest when the fault is 30 kilometers away from the converter station. This outcome indicates that the worst-case fault location on a cable, as indicated by the rate of rise of fault current in IGBTs inside an HVDC converter station, is not necessarily near the converter stations. Multiple electromagnetic transient simulations are required to identify the worst-case fault location for determining the required speed of protection equipment such as DC circuit breakers required for protecting the offshore HVDC converters. Similar electromagnetic transient simulation-based studies were performed to evaluate different aspects of the fault behavior of offshore MT-HVDC networks. The key findings are summarized at the end of this section.

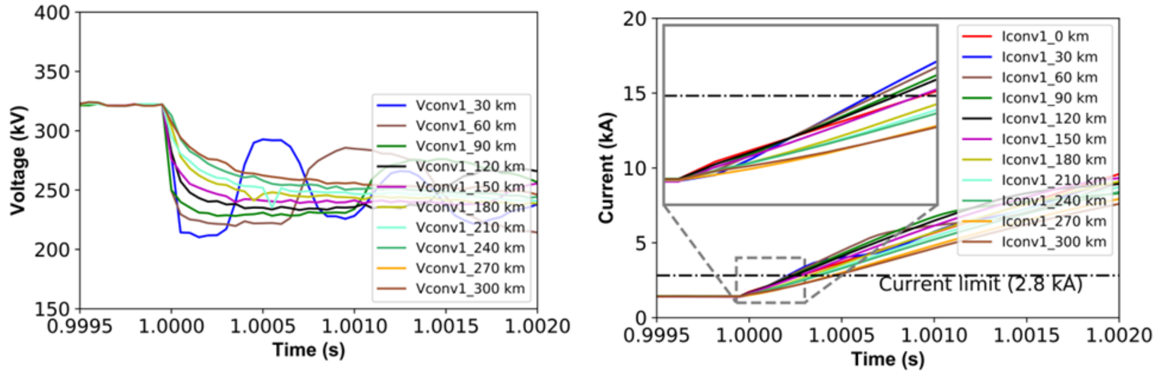


Figure 60. Positive pole to ground voltage (left) and positive pole output current (right) of an offshore HVDC converter (conv) for fault at different distances from the converter station on its export cable. ***Figures by NREL***

7.6 Consideration of Power System Resilience for Offshore Wind Integration

The deployment of offshore wind energy has the potential to increase the exposure of electricity systems to severe weather-related events in the ocean space that previously did not represent a challenge. This possibility requires that system planners and operators consider these new challenges in their system planning and operation processes. In the U.S. East Coast, diverse types of severe weather phenomena (e.g., hurricanes, Nor'easters, blizzards, tropical storms, and heat waves) could impact the system resilience under the presence of high levels of offshore wind energy.

To support system planners and operators in assessing extreme events on power system resilience, PNNL developed and continues to improve the Electrical Grid Resilience and Assessment System (EGRASS) tool (Elizondo et al. 2020). EGRASS was demonstrated in the AOSWTS to showcase how the tool can assess the impacts of extreme weather events on offshore wind plants and onshore transmission systems.

This demonstration involved simulating the impact of a fictitious hurricane event on the 2050 grid configuration (summer peak condition). These simulation results do not represent a realistic scenario and therefore should be seen as a demonstration of the tools and methods only.

For this demonstration, EGRASS was applied to the Eastern Interconnection in an event like Hurricane Sandy.

The following are the assumptions for this case study:

- Hurricane Sandy is assumed to be a Category 2 hurricane instead of Category 1 to assess the impacts if the original hurricane was more severe; the same hurricane path was used from the National Hurricane Center 6-hour storm data.

- EGRASS produces contingencies for damages to only transmission-level assets. Load losses resulting from damages to the distribution system from the hurricane are not reflected in the results of this case study.
- Transmission line failures in EGRASS are associated only with the tower fragilities because of wind gust intensity and the accuracy of the tower mapping. The tower mapping refers to the association between the geographical lines and the expected towers that comprise it with the lines in the power systems model.
- Out of the 25,556 transmission towers in the area, only 6,112 are available in the mapping from the geographical line towers to the power system line model, resulting in fewer contingencies than expected.
- It was assumed that the system is compliant with N-1 security.
- If the system separates into islands, a steady-state simulation was conducted for each island.
- In an unstable island or system, a complete load loss was assumed.

Figure 61 presents an overview of the simulated case to demonstrate the proposed methodology and tools for resilience analysis. The expected time interval between each step of offshore wind generator loss is 5–6 hours, but this may vary depending on the severity of the hurricane events.

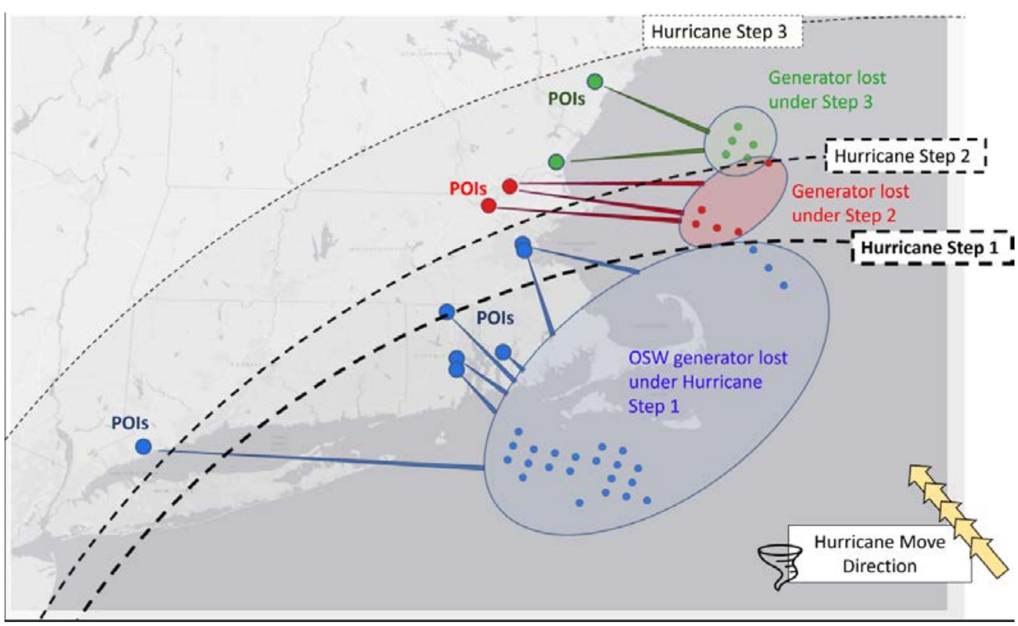


Figure 61. Overview of the demonstration case for the resilience analysis. ***Figure by PNNL***

More details on the tool capabilities and simulation results are presented in Appendix K. Based on limited sample simulations, the Easten Interconnection reached a stable state after multiple hurricane events. However, no definitive conclusion should be derived from the case study results presented here and in Appendix K.

7.7 Summary and Key Findings

A preliminary set of analyses to investigate the potential impacts of offshore wind on system reliability was conducted. These analyses also include a high-level assessment of the potential impacts and benefits of offshore wind and related offshore transmission infrastructure to system reliability.

The analyses performed in this study do not constitute a comprehensive system reliability assessment. Several key elements of that kind of assessment were not considered. Some of these limitations include, but are not limited to:

- This study primarily focused on voltage levels at 230 kV and above
- Only a limited number of operating conditions were assessed
- A limited number of dynamic incidents, of only some types, were investigated
- A reduced set of system planning and performance criteria were monitored (e.g., mainly voltage limits, branch flow limits, and instability detection).

7.7.1 AC Power Flow and Contingency Analysis

AC power flow and contingency analysis results indicate that:

- In the 2030 system configuration, the already planned grid configuration should be able to handle the studied 30 GW of offshore wind injections without incurring widespread reliability issues or requiring additional structural changes to the system.
- In the 2050 system configuration, several network expansion and reinforcement projects are required to ensure reliable operation of the grid to integrate the studied 85 GW of offshore wind injections and load growth. These reinforcements were designed using the production cost and DC power flow modeling methods described in Section 5 and Appendix D.

Contingency analysis for the 2050 grid configuration indicates potential benefits of interlinked offshore network topologies to system reliability by enabling mutual support between the onshore and offshore networks during contingency events. For contingency events at onshore transmission elements, offshore interlinks may be able to provide controllable transmission resources to alleviate potential onshore network overloads and/or voltage dips under some system conditions. For contingency events at the interlinked offshore network, increased interregional transmission capacity (onshore and offshore) may be able to provide the required transmission reliability margins to allow the system to ride through offshore contingencies at radial export links or interties.

7.7.2 Grid Strength Analysis

The analyses and results presented in this section were used to assess the selected offshore wind POI candidates from a system strength point of view using the SCR as a screening metric. The results from this screening analysis are then used to inform system planners of the possible need for more in-depth analyses for integrating offshore wind at weak POIs.

Figure 62 compares the POI strength classification derived from Part 1 and 2 of this analysis.

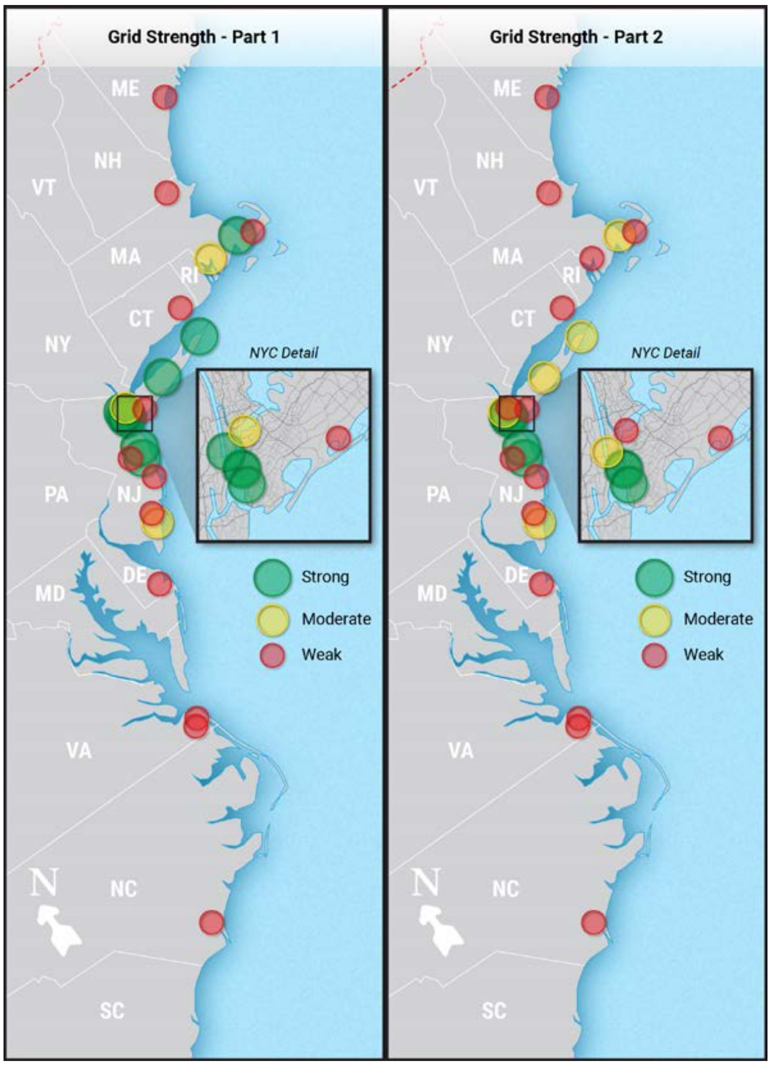


Figure 62. Part 1 vs. Part 2 POI strength classification. *Figure by NREL*

The following key findings are derived from these analyses:

- Of the 24 studied POIs, 5 can be classified as "strong," 5 as "moderate," and 14 as "weak" for the 2030 30-GW offshore wind grid configuration.
- A POI classified as "weak" does not mean that it is infeasible. The low POI strength is rather an indication that additional studies (and possibly additional equipment) are needed to ensure stable and reliable operation of the offshore wind power plant (or any inverter-based resource) under weak grid conditions.
- Contingencies have a major impact on POI strength, leading in some cases to some POIs being classified as weak in the postcontingency condition, whereas the POI was classified as strong or moderate in the precontingency condition.
- Operating conditions (generation dispatch) also impact POI strength, but to a lower extent when compared to contingencies.
- POI strength assessment should consider a wide range of plausible operating conditions, as well as the required sets of contingencies so that the POI strength is properly characterized to inform downstream engineering analysis to ensure reliable operation of offshore wind power plants.

7.7.3 Dynamic Performance Analysis

Dynamic performance analysis results for the 2030 system configuration indicate no structural stability issues related to/induced by integrating offshore wind. However, it must be emphasized that the dynamic performance analyses performed in this study do not constitute a thorough system stability analysis and that more detailed studies are required, including the use of electromagnetic transient and/or hybrid root-mean-square-electromagnetic transient models to assess system stability and dynamic performance in the areas of offshore wind injections at weak POIs.

7.7.4 Protection of Offshore HVDC Grids

The major takeaways of this ongoing analysis are as follows:

- The protection system components, such as DC reactors and DC circuit breakers, can be optimized to reduce the overall cost of the MT-HVDC networks and minimize the number of export cables that will experience outage during a DC network fault.
- The worst-case fault location on a submarine cable (export or interlink) in terms of the rate of rise of fault current in the IGBT modules of an HVDC converter is not necessarily near the HVDC converter station. Fault currents at the HVDC converter station might rise faster if the fault is located a moderate distance away from it, as compared to a fault closer to the station. This faster rise in fault current can result in lower time available for

protecting the converter before it goes into blocking mode due to the overcurrent of the IGBT modules. Hence, a series of electromagnetic transient studies need to be conducted to pinpoint the worst-case fault location and the highest rate of rise of fault current expected in IGBT modules in the converter station during a DC network fault. The project team is developing an automated tool to use with electromagnetic transient models of MT-HVDC networks to find out worst-case fault locations.

- DCRs can be designed to reduce the rate of rise of fault currents at converter stations to increase the required DCCB operation time. The sizing of the DCRs and DCCBs can be co-optimized to meet the DC network protection objectives, thereby minimizing the cost of the protection system.
- With existing DCCB technology, it is possible to avoid an outage of healthy export cables during a fault on an export cable, resulting in the outage of only one export cable. However, during a fault on an interlink between two offshore HVDC converter stations, it is difficult to protect the two export cables at the ends of the interlink, resulting in the loss of two export cables. This is because a fault on an interlink travels to the two offshore converter stations at the end of the interlink in just a few milliseconds. The operation time of existing HVDC circuit breakers (in operation and prototypes) ranges from 2 or 3 milliseconds to 10 milliseconds depending on the technology used for the breaker. Faster DCCB technologies and advanced control methods that improve resilience of HVDC converters during faults (Huang, Shah, and Vanfretti 2023) will be required to protect export cables at the end of an interlink.
- New control methods are being explored by the project team to reduce the rate of rise of fault currents at the HVDC converter stations during faults in the DC network to minimize the number of converter stations that enter blocking mode following a fault. Control methods to reduce the converter station recovery time after the converter block are also being explored.

DOE's Wind Energy Technologies Office is supporting several new projects through Funding Opportunity Announcement 2828 to better understand the transient performance of offshore MT-HVDC transmission networks during faults and develop new control and protection technologies to reduce disruption and outage time during faults in offshore transmission networks.[60]

[60] For more details on the Funding Opportunity Announcement, visit: https://www.energy.gov/eere/wind/articles/doe-wind-energy-technologies-office-selects-15-projects-totaling-27-million.

8 Conclusions

The study fills identified gaps in offshore transmission planning along the Atlantic Seaboard by providing a multiregional planning perspective and coordinating offshore wind generation with transmission planning. We studied a suite of topologies and assumptions to estimate costs and benefits.

Offshore wind energy development provides a unique opportunity to add transmission capacity offshore that provides value to the electric grid. Key findings of the study include the following:

- Offshore wind is projected to be a key part of achieving a low-carbon future for Atlantic states.
- Offshore transmission can be planned while considering ocean co-uses and environmental constraints.
- Benefits of networking offshore transmission come from reduced curtailment, reduced usage of higher-cost generators, and contributions to reliability.
- Offshore transmission networks contribute to grid reliability by enabling resource adequacy and helping manage the unexpected loss of grid components (contingencies).
- Benefits of offshore transmission networking outweigh the costs, often by a ratio of 2 to 1 or more. Offshore networks with interregional interlinks provide the highest value.
- Building offshore transmission in phases can help reduce development risk, but early implementation of HVDC technology standards is essential for future interoperability.

The AOSWTS assumes a planning trajectory that considers interoperable multiterminal HVDC technology available for offshore transmission starting in the mid-2030s. Offshore wind energy development planned for operation by 2030 does not include multiterminal HVDC readiness (consistent with Marshall et al. 2020). These assumptions are consistent with current offshore wind project procurements and their timelines (Pfeifenberger et al. 2023b). The studied interregional and backbone topologies require multiterminal HVDC technology to be available and implemented on offshore platforms (which would need to be designed for potential future interlinking) by 2035. While this study specifically looks at 30 GW in 2030 and 85 GW in 2050 in the Atlantic, the general findings should apply to slightly different timelines and scenarios.

The study team considered a possible phasing of offshore transmission development. This development order of offshore transmission, shown in Figure 63, is based on interlinking projects as they are developed and available to interlink, with more favorable projects developed earlier, considering wind resource, cable distance, and state targets. This phasing of offshore transmission development can use infrastructure development capabilities efficiently but requires a consistent HVDC technology standard to enable multiterminal, multivendor interoperability.

Defining a common interoperability standard before HVDC is deployed in topologies like the interregional scenario will be critical to meeting the development timelines and achieving the benefits quantified in this study.

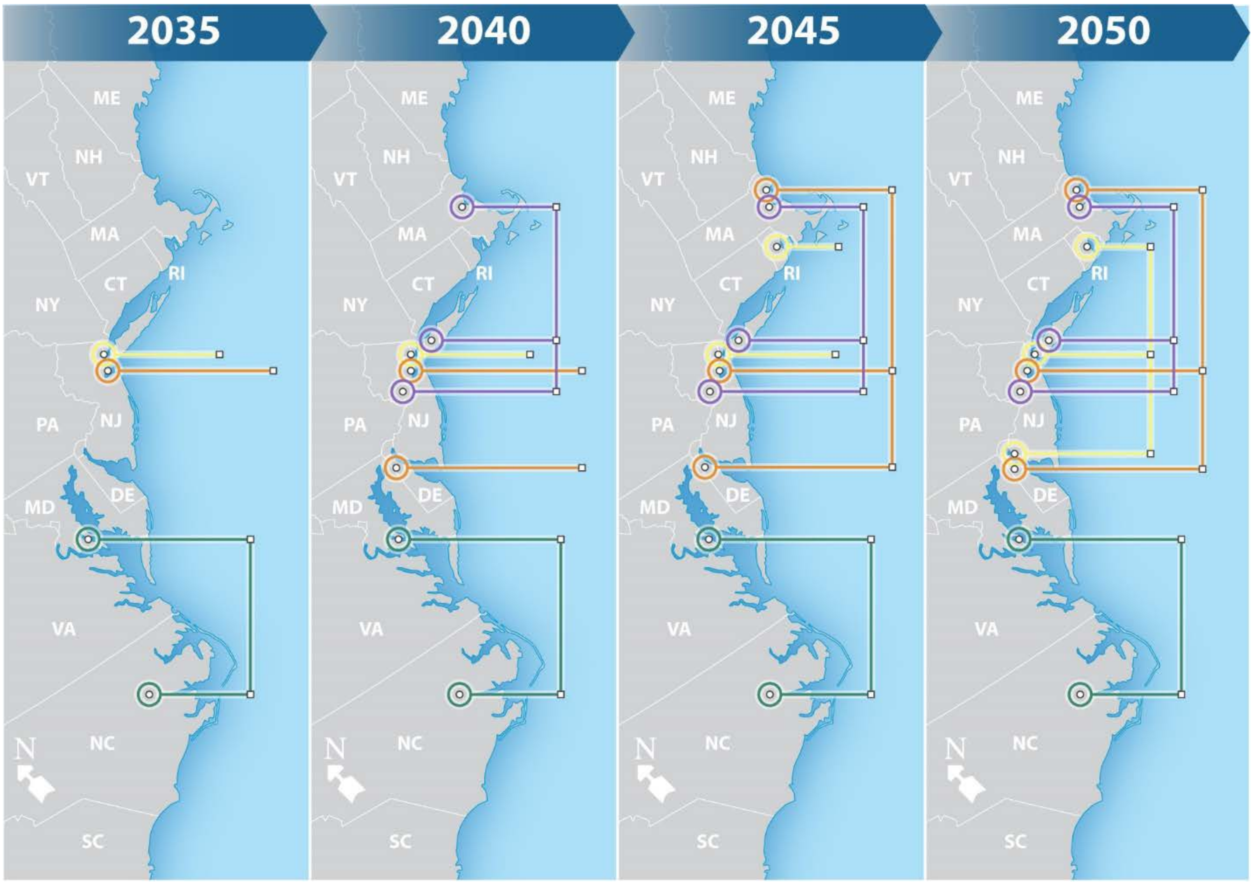


Figure 63. Potential build timeline of the interregional topology. ***Figure by Billy Roberts and Al Hicks, NREL***

The study provides a guide for policymakers and transmission stakeholders on possible outcomes resulting from a proactive, coordinated, and interregional approach to transmission planning for offshore wind energy development in the Atlantic. While this study presents possibilities, additional work applying system operator methods and procedures can build on this analysis.

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Appendix A. Production Cost and Resource Adequacy Modeling Details

We conducted production cost analysis using the commercial software PLEXOS (Version 9.0r9 solved using Gurobi Version 9.5.1). Resource adequacy analysis uses the National Renewable Energy Laboratory's (NREL's) open-source Probabilistic Resource Adequacy Suite (PRAS, Version 0.6). This appendix describes in more detail how these analyses were conducted.

Additional Detail on Production Cost Modeling

Production cost modeling scenarios using PLEXOS must be configured to run at a nodal spatial and hourly temporal resolution on an envisioned 2050 Eastern Interconnection. To enable this analysis, we began from a nodal resolution representation of the Eastern Interconnection from the 2031 Multiregional Modeling Working Group (MMWG) core scenario. Generation expansion and retirements applicable in 2050 are taken from the Regional Energy Deployment System (ReEDS) low-carbon scenario in Section 2 and assigned to nodes using NREL's nodal ReEDS2PLEXOS translation software. ReEDS2PLEXOS also subsets ReEDS' contiguous U.S. results to only the Eastern Interconnection. Variable generation profiles for each selected solar and wind site come from NREL's Renewable Energy Potential (reV) model variable generation profiles for the applicable weather year (only 2012 in production cost modeling). In all production cost scenarios, PLEXOS is configured to run a mixed integer program (1% optimality gap) for each modeled day at an hourly resolution in the short-term scheduling.

The 2050 load data from ReEDS is available for 2007–2013 weather years (see Section 2.2) at ReEDS' United-States-wide 134 balancing area zonal resolution. We developed translation software to map load from the ReEDS low-carbon scenario data and zonal resolution to nodes within the MMWG regions.

Transmission expansion is needed to avoid costly and result-distorting infeasibilities and violations in production cost modeling of the Atlantic in nodal detail on the envisioned 2050 system with the low-carbon ReEDS build-out. The expansion selection process itself is described in more detail in Appendix D. Transmission expansion begins from the MMWG representation of the Eastern Interconnection with approximately 92,000 buses and more than 100,000 alternating current (AC) lines and transformers. Transmission limits are enforced in PLEXOS based on North American Electric Reliability Corporation flowgate inclusion and lines between MMWG subregions. Final production cost runs simplify non-Atlantic study regions for computational reasons; in particular, we retain full transmission detail only for Atlantic regions.[61] Large non-Atlantic transmission regions like the Midcontinent Independent System

[61] Regions with retained nodal detail are multimodel working group regions 101 (Independent System Operator-New England), 102 (New York Independent System Operator), 105-106 (New Brunswick and Nova Scotia) 201,

Operator and Southwest Power Pool have each of their MMWG zones represented, but transmission detail within those regions is not included in production cost modeling.

Curtailment values for all 85 gigawatts (GW) of offshore wind build in the radial and interlinked topologies shown in Table 14 are also plotted in Figure A-1.

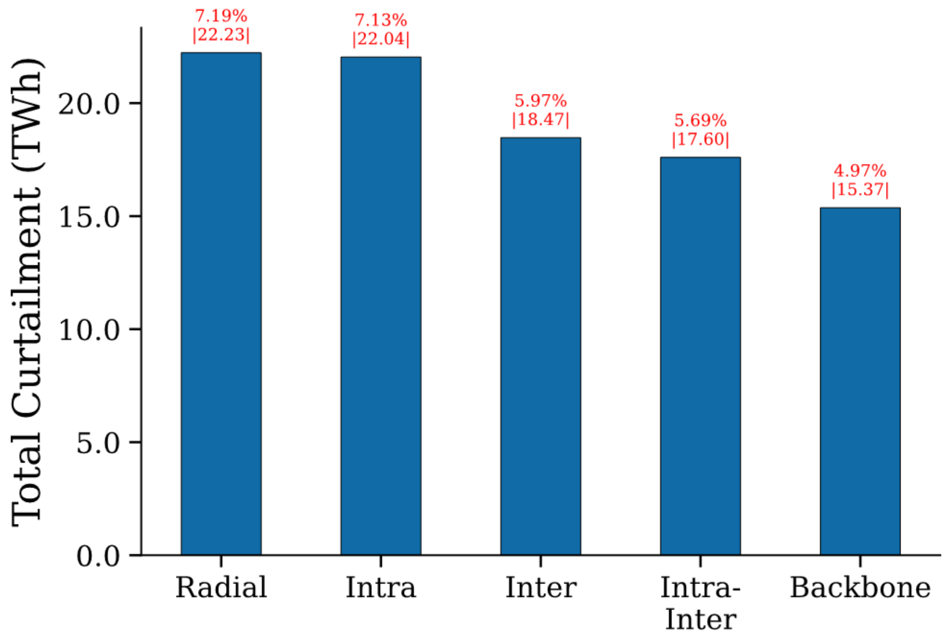


Figure A-1. Total offshore wind curtailment in radial and interlinked topologies. ***Figure by NREL.***

Notes: TWh = terawatt-hour. Intra is intraregional topology and Inter is interregional topology. Inter-intra has both the intraregional and interregional topologies.

Annual generation changes in the interlinked interregional topology compared to the radial topology for the entire Eastern Interconnection are shown in Figure 24. Figure A-2 shows generation changes for the interregional topology compared to the radial topology broken down by the four Atlantic-adjacent regions with offshore wind points of interconnection (POIs).

202, 205, 206, 209, 212, 215, 222, 225-238, 320, 345 (PJM), 330, 340-344 and 346 (Southeastern Regional Transmission Planning).

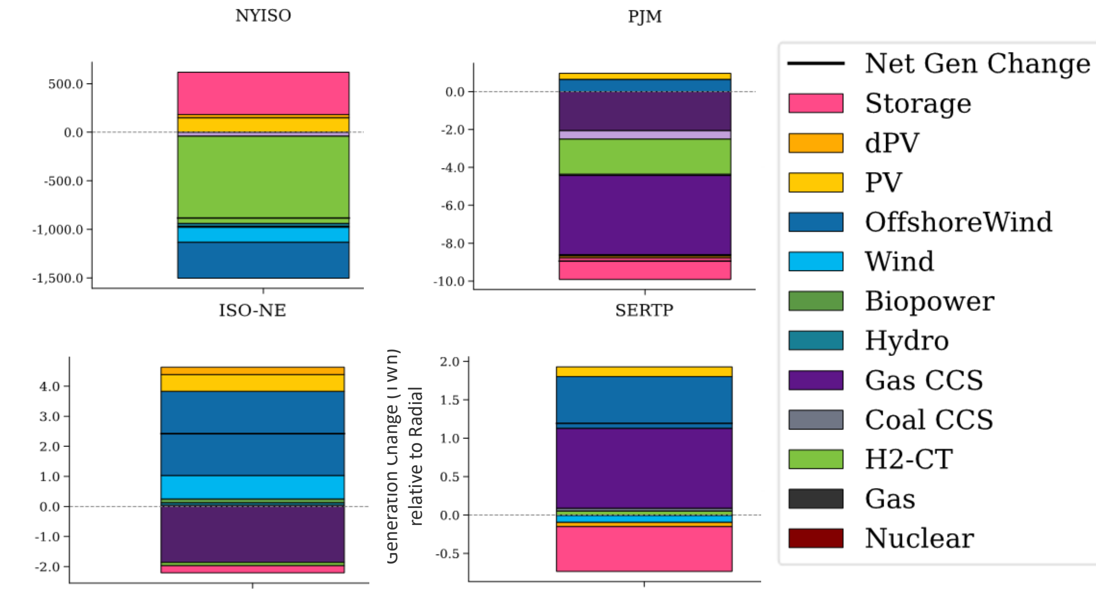


Figure A-2. Annual generation change in the interregional scenario for four Atlantic-adjacent regions with offshore wind POIs. ***Figure by NREL.***

Note: dPV = distributed photovoltaics; Gas CCS = gas with carbon capture and sequestration; Coal CCS = coal with carbon capture and sequestration; H2-CT = hydrogen combustion turbine; NYISO = New York Independent System Operator; ISO-NE = Independent System Operator New England; SERTP = Southeastern Regional Transmission Planning

Figure A-3 shows the duration curve of simultaneous use of all seven 2-GW interregional lines, whereas Figure 26 shows hourly flows between regions on those lines. Figure A-3 is the same data as Figure 26, but plotted as a duration curve.

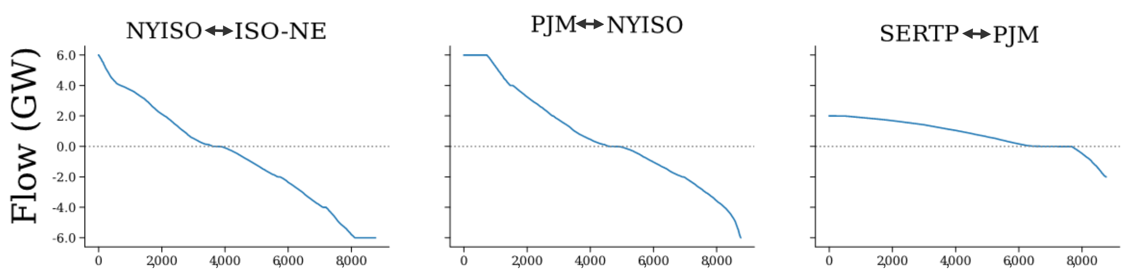


Figure A-3. Duration curve (each panel ranked in descending order independently 0-8,759 by flow) of interregional flows on offshore interregional lines. ***Figure by NREL***

Note: Positive values are south to north; negative values are north to south.

Figure 27 shows correlations between daily average offshore wind generation as well as daily production cost savings and average flow on the seven 2-GW offshore interregional lines. Figure A-4 provides additional detail on the correlation between load and net load (figures only include load and net load in Atlantic regions with offshore wind POIs: ISO-NE, NYISO, PJM, and

SERTP). Both Atlantic load and net load show low correlation with savings; and, as indicated in Figure 27, correlation between net load and savings is driven by the correlation between offshore wind generation itself and net load (i.e., net load is generally higher when offshore wind generation is lower because offshore wind is part of variable generation).

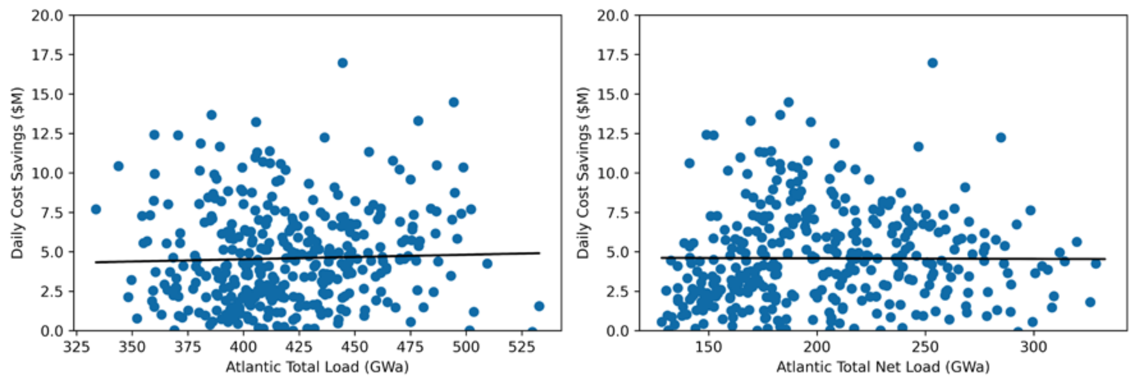


Figure A-4. (Left) Correlation between daily production cost savings for interregional topology and total load in the four Atlantic regions with offshore POIs. (Right) Correlation between daily production cost savings for the interregional topology and total net load (net of all variable generation, including offshore wind itself) in the four Atlantic regions with offshore POIs. ***Figure by NREL***

Note: GWa = average gigawatts

Additional Detail on Resource Adequacy Modeling

Resource adequacy modeling requires re-translating our nodal production cost modeling representation of the Eastern Interconnection in PLEXOS into PRAS' zonal format while retaining representation of the studied interzonal offshore transmission build. Translation from PLEXOS to PRAS uses NREL's open-source PLEXOS2PRAS software. PRAS' zonal representation of the power system and reliability-focused approach to operational dispatch simplify transmission representation and operations compared to PLEXOS. In exchange, PRAS can evaluate the reliability of many more generator and interregional transmission outage scenarios and weather years of time-synchronized variable generation and load data using sequential Monte Carlo analysis with less computational cost than PLEXOS. To better evaluate the value of offshore transmission in a zonal model, we augmented the PLEXOS2PRAS translation by representing each offshore wind platform as its own zone ("platform zone"), with a radial line to the onshore zone. We also disaggregate single MMWG regions representing all of ISO-NE and NYISO into their constituent load zones as currently implemented by the respective system operators. To enable the disaggregation of single ISO-NE and NYISO MMWG regions, we mapped each node in ISO-NE and NYISO to existing load zones; load is then re-allocated from the single MMWG region to load zones based on nodal load participation factors. Applicable offshore transmission builds connect platform zones. This approach sufficiently represents a zonal system wherein the reliability contribution offshore transmission can be evaluated.

Quantitative evaluation of the reliability contribution of a generation or transmission resource in PRAS requires choosing both a reliability and capacity credit metric. We use loss-of-load expectation as the primary reliability metric to maximize consistency with current planning practices in Atlantic region system operators. We additionally report normalized expected unserved energy because its use of energy units (e.g., normalized megawatt-hours) instead of events can be more consistently defined across power systems and considers loss-of-load magnitude (de Mijolla 2023). We used the equivalent firm capacity metric to report the resource adequacy benefit of transmission. Equivalent firm capacity differs from the commonly reported alternative, effective load-carrying capability, in that it is a measure of how much generation capacity build (rather than additional quantity of load) can be displaced while achieving the same level of reliability by an evaluated resource.

In our analysis, the evaluated resource is alternative offshore transmission builds with interlinks between platform zones. Our resource adequacy model, PRAS, requires the user to specify which zones should have a share of total firm capacity added until the reference radial scenario (no interlinked offshore topology built) is at equal reliability to the offshore transmission-augmented system. In the core analysis, we added firm capacity equally (i.e., one-third each) to the highest unserved energy zone in PJM, ISO-NE, and NYISO. For our purposes, this means we added firm capacity to PJM's Baltimore Gas & Electric, ISO-NE's Massachusetts National Grid, and NYISO's -K (Long Island) zones until the reference radial topology had equal reliability to each of the four interlinked topologies.

Final PRAS evaluations were run for 25 seeded, random sequential Monte Carlo samples of the 7 (2007-2013) weather years for each of the four interlinked topologies. PRAS reports results (Table 17) in lower and upper bound ranges based on its statistical approach to evaluating uncertainty in capacity credit with a finite number of samples.[62]

Offshore transmission builds with interlinks have nonzero equivalent firm capacity because they can flow additional power between zones with excess generation and those with generation shortfall during times of high load and/or low generation availability. Section 5.4 provides more detail on how PRAS utilizes additional offshore transmission in the interregional topology to reduce modeled unserved energy. PRAS line utilization is averaged across 25 samples; samples reflect random (but seeded for consistency across topologies) sequential Monte Carlo draws of outage realizations for generators with forced outage and mean time to recovery parameters. Generators with forced outrage rates are listed in Table A-1. Mean time to recovery is 24 hours

[62] For more detail, see the Probabilistic Resource Adequacy Suite v0.6 Model Documentation (Stephen 2021).

for all generators. Additional information on how PRAS conducts its sequential Monte Carlo and dispatches resources to minimize reliability risk is available in Stephen (2021).

Table A-1. Forced Outage Rate Assumptions by Generator Type Groups.

Note: ReEDS generators are new builds selected in capacity expansion (Section 2). MMWG generators are preexisting generator types in the MMWG dataset. Some categories of MMWG generators are mostly or fully retired by 2050.

Generator Type	Source	Forced Outage Rate (%)
Battery	ReEDS	2
Hydrogen Combustion Turbine (H2-CT) and Hydrogen Combined Cycle (H2-CC)	ReEDS	5
Coal Steam Turbine, Combustion Turbine, and Waste Coal	MMWG	4.29
Distillate Fuel Oil Combustion Turbine (Combustion Turbine) and Residual Fuel Oil Combustion Turbine	MMWG	4.19
Natural-Gas Combustion Turbine	MMWG	4.19
Natural-Gas Steam Turbine, Residual Fuel Oil Steam Turbine	MMWG	3.28
Other Steam Turbine	MMWG	3.63
Municipal Waste	MMWG	3.09
Nuclear	MMWG	4
Nuclear	ReEDS	3
Biopower	ReEDS	9
Gas Combined Cycle, Combustion Turbine, Oil-Gas-Steam, Gas Combined Cycle With Carbon Capture and Sequestration	ReEDS	5
Pumped Hydropower	ReEDS	4
Coal Carbon Capture and Sequestration	ReEDS	8

We used equivalent firm capacity estimates from PRAS along with capacity costs to estimate value in Section 6.3.1. We report these values as additive to production cost savings with two caveats: (1) we do not re-run capacity expansion to precisely determine the interaction of reduced capacity build-out on the production cost merit order, primarily because of the lack of resolution to enable this method in our capacity expansion model, ReEDS, and (2) current regional capacity accreditation practices may not assign value to interregional transmission in planning. Therefore, reported values are modeled results and actual value is contingent on the evolution of future planning practices. The primary reason for not re-running ReEDS is that it does not endogenously model intraregional transmission. Because offshore networks do not necessarily cross ReEDS zones, there is no straightforward way to incorporate new zones (i.e., offshore zones) in the model. The employed method of combining production cost and resource adequacy modeling to enable higher resolution study of marginal capacity additions is consistent with deployment of these tools in other studies and planning processes (Hawaiian Electric Company 2023). Current accreditation practices typically assign capacity credits to generation, not transmission, and make assumptions about deliverability from regions external to the planning region. Some interregional planning processes like the nascent Western Resource Adequacy Program exist and there is no theoretical barrier to considering transmission's value in planning when it contributes to system resource adequacy.

Equivalent firm capacity ranges reported in the main text (Table 17) use 25 Monte Carlo draws for PRAS simulations. Reported ranges reflect both uncertainty from the parameterized number of draws and a range of tunings to approximately 0.1 loss-of-load expectation and single-digit normalized expected unserved energy (Figure 28). To monetize the megawatt values of equivalent firm capacity that transmission can provide, we calculated the annualized cost of new entry for marginal generation capacity at that location. The net cost of new entry at different locations is the shadow price of the capacity constraint in 2050 from the capacity expansion model, ReEDS. The resource adequacy value is equal to the mean equivalent firm capacity (from PRAS) times the annualized cost of new entry (from the capacity expansion model). Table A-2 summarizes the inputs and calculated resource adequacy value for each region and transmission topology.

Table A-2. Resource Adequacy Value of Transmission by Region and Transmission Scenario

Topology	Region	Mean Equivalent Firm Capacity (megawatts [MW])	Annualized Cost of New Entry ($/MW)	Resource Adequacy Value ($ million)
Intraregional	ISO-NE	205	167,000	34
	NYISO	205	146,000	30
	PJM	205	154,000	32
Interregional	ISO-NE	1,483	167,000	248
	NYISO	1,483	146,000	217
	PJM	1,487	154,000	228
Inter-Intra	ISO-NE	1,582	167,000	264
	NYISO	1,582	146,000	231
	PJM	1,587	154,000	244
Backbone	ISO-NE	2,014	167,000	337
	NYISO	2,014	146,000	294
	PJM	2,020	154,000	310

Appendix B. Adjusted Production Cost

As interregional transmission enables more coordinated operation of low-cost generation resources, the distribution of operating costs within each region changes. For systemwide analysis, operating costs comprise variable operations and maintenance, fuel, and start-up and shutdown. These metrics are sufficient to evaluate the change in operating costs for the entire system but, when evaluating the benefit distribution among regions, a further consideration is needed to capture the transmission benefits of interregional trade to each region. To evaluate these benefits, we use the adjusted production cost (APC) metric. The APC is the difference in total production costs adjusted for import costs and export revenues with and without a proposed transmission upgrade. This metric is used among independent system operators/regional transmission operators in the United States for transmission valuation and cost allocation including Southwest Power Pool, Midcontinent Independent System Operator, and PJM and is defined as follows:

$$\text{APC} = \text{Production Cost} + \text{Purchase Costs} - \text{Generator Revenue}$$

where

Purchase Costs = (Hourly Consumer Load + Storage Charging + Imports) * Locational Marginal Price

Generator Revenue = Hourly Generation * Locational Marginal Price

A key benefit of the APC when trying to disaggregate transmission benefits is that it does not strictly rely on the physical location where costs are incurred to estimate costs and benefits. As an example, a new transmission upgrade may enable the development of low-cost generation capacity in one region (Region A) that can serve additional load in a neighboring region (Region B). Strictly looking at where costs are occurring, the new transmission line will increase capital and operating costs in Region A because it is building more capacity and generating more. By contrast, capital and operating costs will decrease in Region B because it is building less capacity and relying on imports to meet its load. However, Region A is also benefiting from increased sales of power to its neighbors. In addition, Region B is not getting these imports for free; it incurs some cost to purchase imported energy. By including an adjustment for import costs and export revenues, the APC can capture these benefits.

Although the Atlantic Offshore Wind Transmission Study is not designed to calculate locational marginal prices, the nodal production cost models do output hourly prices for each node along with hourly load, storage charging, import, and generation data. Figure B-1 shows the production cost adjustment (change in purchase cost – generator revenue) added to the transmission value for each region and topology.

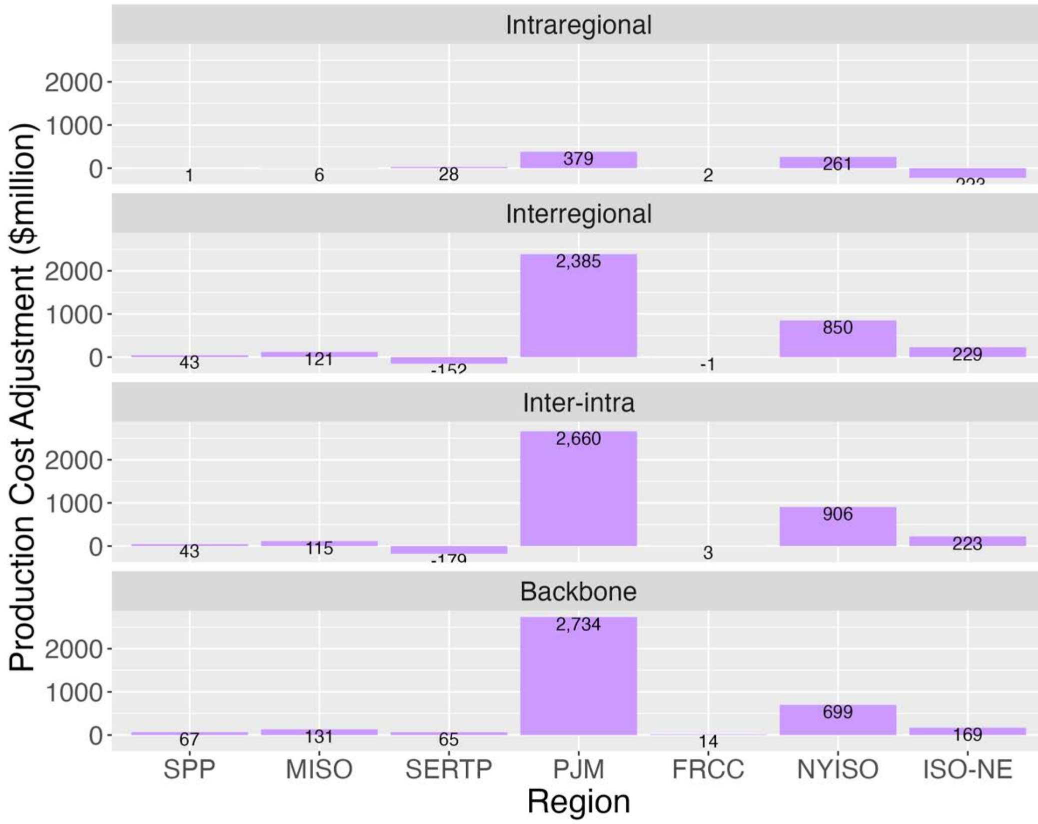


Figure B-1. Production cost adjustment for each transmission planning region and network topology ($ million). ***Figure by NREL***

Note: SPP = Southwest Power Pool; MISO = Midcontinent Independent System Operator; SERTP = Southeastern Regional Transmission Planning; FRCC = Florida Reliability Coordinating Council; NYISO = New York Independent System Operator; ISO-NE = Independent System Operator New England

Appendix C. Review of Cost Allocation Methods

This appendix reviews the methods that could be implemented under the proposed regulatory principles for interregional transmission charges. It is intended to highlight a variety of approaches for comparison and is not intended to be a comprehensive review of all methods that exist or have been proposed.

Beneficiary Pays

Beneficiary pays is a simple concept that is difficult to implement in practice. It attempts to directly allocate network costs to agents in proportion to the benefits they receive from the network. This approach is the best method conceptually and is attractive because it has dimensions of fairness and equity. Under this method, the net benefit for each network user is calculated as the difference in benefits with and without the line. The most basic application of beneficiary pays only considers changes in revenues over operating costs for generators and changes in the cost of purchasing electricity for consumers. However, the calculation could be expanded to include a range of other potential benefits that transmission investments could provide.

While transmission costs are usually well-defined, benefits are more difficult to quantify. The challenge is that some benefits (e.g., production cost savings and reduced transmission energy losses) are relatively straightforward to measure but others (e.g., increased market liquidity and reliability during extreme weather events) are difficult to measure and quantify. Furthermore, the nature and magnitude of benefits may change over the lifetime of the line. Despite these difficulties, beneficiary pays continues to be adopted and implemented in other markets. In the United States, Federal Energy Regulatory Commission Order 1000 states that transmission costs "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 benefits." Order 1000 was purposefully designed to be broad, allowing local markets to develop their own cost allocation methods. As a result, implementing the "beneficiary pays" principle varies among local markets in the United States.

Considering the difficulty of defining and measuring the various benefits of transmission lines, many cost allocation methods use network utilization as a proxy for benefits. Under this approach, network agents that use the network more would pay a higher transmission charge. In practice, it is not possible to directly measure how much each market agent uses the network. This usage must be inferred based on values that can be measured, namely, the quantities injected or withdrawn at each node and how much power flows over each line. The remaining cost allocation methods all rely on various techniques to approximate network usage as a measure of network benefits.

Postage Stamp

The postage stamp method charges all users a flat rate based on the total amount (megawatts [MW] or megawatt-hours) injected or withdrawn from the network. The method is easy to implement and does not require detailed data or sophisticated modeling. In addition to its simplicity, it can be argued that it could be useful in cases where the distribution of benefits is likely to vary considerably over the lifetime of the transmission facility. It could also be appropriate for well-developed grids that do not need reinforcements and therefore do not need to send locational signals to potential investors. The postage stamp method is used widely in the local systems in the United States and individual European countries.

The major shortcoming of the postage stamp method is that the charges do not reflect actual network conditions or send locational signals. A generator located in a highly congested area is charged the same rate as one that does not contribute to network congestion. Furthermore, agents whose injections or withdrawals only impact flows across a limited number of adjacent lines could be charged the same as agents whose activities impact flows across the entire regional network. As a result, the charges may not reflect actual network usage.

Modified Postage Stamp

The modified postage stamp method is an alternative version of the postage stamp method that only allocates costs among regions that derive some positive value from the transmission additions. This modified approach was designed for this study because of the nonuniform and highly concentrated way in which the offshore network only benefited three transmission planning regions, leaving all other regions of the Eastern Interconnection with little to no benefit. After identifying which regions are eligible for cost allocation based on evaluated benefits, the modified postage stamp method allocates costs in proportion to the coincident withdrawals from the network—similar to the postage stamp method.

Load Imbalance

The load imbalance method is based on the premise that regions should pay based on the use that they make of the interregional network. Rather than track activity from individual network users, the load imbalance method uses aggregate regional data on load and generation to calculate the total use that agents within a given region make of outside networks. Because supply and demand must be balanced at all times, a region must necessarily be importing or exporting power during any period where regional consumption does not match generation. Each region is then charged in proportion to the change in load imbalance with and without the offshore network.

In practice, the load imbalance method may not fully capture actual network use within and outside a given service area. It assumes internal networks are sufficiently developed such that if 1 MW enters one border of Region A and 1 MW exits another border, the power must have been transferred through that region. In fact, there may be no physical links between the entry and exit points and it is the load and generators within Region A that are consuming and producing 1 MW at different points of the network. The method also sends no locational signals to individual network agents regarding their benefits from the network because all network activity is aggregated at the national level.

Appendix D. Onshore Transmission Expansion

After completing the radial topology, we performed a simple production cost model (PCM) and direct current (DC) power-flow-based transmission expansion. The goal of this modeling was to produce a future 2050 grid at a nodal resolution that represents a reasonable future well enough to assess the value of various offshore topologies. To do this, we started with the translation described in Section 5.1 for the generators. We ran the PCM for several peak days, allowing violations on lines to happen for a cost of $1,000/megawatt-hour in the model. We added parallel circuits for the lines that had violations and iterated this process until the violations were gone. The enforcement of line limits in the production cost model was focused on between-region (Multiregional Modeling Working Group region) lines and lines that were enforced in Brinkman et al. (2021), informed by North American Electric Reliability Corporation Flowgates. We followed a similar process using DC power flow analysis in PSS/E after the PLEXOS modeling to expand the lines that were not independently constrained in the PCM (including lower-voltage lines and some of the Tennessee Valley Authority network). Figure D-1 shows the outcome of this process.

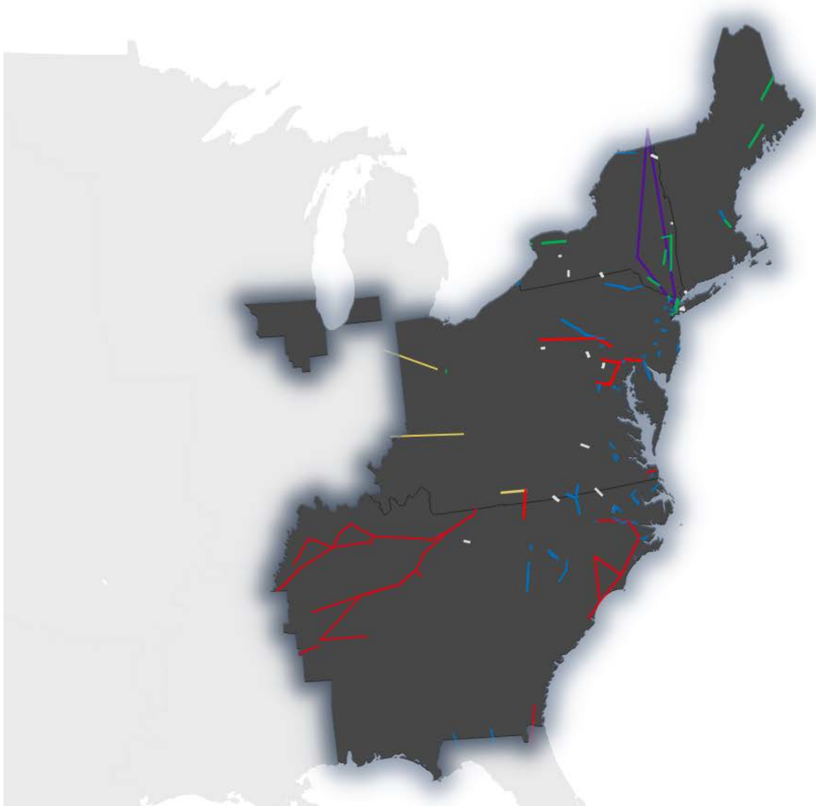


Figure D-1. Expanded transmission lines, beyond the Multiregional Modeling Working Group 2031 case.
Figure by NREL

This process does not replace more sophisticated interconnection and interregional transmission planning processes implemented by system operators, including considering N-1 contingency conditions. Instead, it provides a basis for analyzing the offshore wind energy network for PCM and reliability analysis.

Appendix E. Candidate Points of Interconnection

Table E-1 shows the information for each candidate points of interconnection (POI) that was considered in the study. The "cost category" represents the approximate cost to inject at that POI based on previous studies or suggestions for inclusion from stakeholders. We developed POIs assumed for 2030 using published information, lease areas, and discussions with the technical review committee. These 2030 POIs are labeled not applicable (N/A) for the cost category, because they were required to be included in the optimization and there is no cost consideration. The 2030 POIs were determined as likely by the project team, in consultation with existing project documentation and stakeholders. Limits come from sources, including PJM (2021), Independent System Operator New England (2021), DNV-GL (2021), New York State Energy Research and Development Authority, North Carolina Transmission Planning Collaborative (2021), and stakeholder discussions. Most POI costs are estimated from McCalley et al. (2022). North Carolina POI costs are categorized by North Carolina Transmission Planning Collaborative cost estimates. Maine POIs north of the South of Surowiec interface were categorized as high based on discussion with stakeholders on the cost of upgrading this interface. We preselected New York POIs to land the approximately 20 gigawatts simulated in the low-carbon scenario (and are all listed as "low" cost).

Table E-1. POI Candidate Information

POI	State	Megawatt Injection Limit	Cost Category
Gowanus	New York (NY)	816	N/A
Astoria	NY	1,230	N/A
Farragut East	NY	1,310	N/A
Farragut West	NY	1,310	N/A
W. 49th St	NY	1,310	N/A
Mott Haven	NY	2,000	Low
Rainey	NY	2,000	Low
East Hampton	NY	139	N/A
Holbrook	NY	1,050	N/A
Barrett	NY	1,350	N/A
Ruland Rd	NY	2,000	Low
East Garden City	NY	2,000	Low
Northport/ Newbridge	NY	2,000	Low

POI	State	Megawatt Injection Limit	Cost Category
Shore Rd	NY	1,310	Low
Pilgrim (NY)	NY	1,310	Low
Indian River	Delaware	1,600	N/A
Fentress	Virginia (VA)	5,200	N/A
Landstown	VA	2,600	N/A
Oyster Creek	New Jersey (NJ)	816	N/A
BL England	NJ	432	N/A
Larrabee	NJ	1,300	N/A
Deans	NJ	3,100	Low
Smithburg	NJ	3,600	N/A
Cardiff	NJ	1,500	N/A
Ward Hill	Massachusetts (MA)	1,200	Low
Tewksbury	MA	1,770	Low
Salem Harbor	MA	1,200	Medium
Mystic	MA	2,000	Low
K Street	MA	2,000	Low
Pilgrim (MA)	MA	1,830	Low
Bourne	MA	1,200	N/A
West Barnstable	MA	838	N/A
Barnstable	MA	832	N/A
Falmouth	MA	1,200	High
Brayton Point	MA	2,330	N/A
Davisville	Rhode Island (RI)	724	N/A
Manchester St	RI	1,200	Low
West Farnum	RI	1,200	Low
Kent County	RI	1,870	Low
Block Island	RI	29	N/A
Montville	Connecticut (CT)	1,200	N/A
Norwalk	CT	1,200	Low

POI	State	Megawatt Injection Limit	Cost Category
Seabrook	New Hampshire (NH)	1,200	Low
Newington	NH	387	Low
Orrington	Maine (ME)	1,200	High
Maine Yankee	ME	1,200	High
Surowiec	ME	1,200	High
Yarmouth	ME	2,200	Medium
Maguire Road	ME	1,200	Low
New Bern	North Carolina (NC)	3,200	Medium
Greenville	NC	3,500	Medium
Sutton North	NC	2,200	N/A
Myrtle Beach	South Carolina (SC)	2,400	Medium
Georgetown	SC	2,400	Low
Charleston	SC	2,400	High
Calvert Cliffs	Maryland	2,000	Low
Hope Creek	NJ	2,000	Low
Salem	NJ	2,000	Low
Haddam Neck	CT	1,200	Low
Vermont Yankee	Vermont	1,200	Low
Millstone	CT	1,200	Low

Note: Cost categories represent the $/megawatt cost of upgrading the system to deliver an injection at that node. It is a proxy for interconnection costs. Low represents values below $100 million per gigawatt, medium represents values through $500 million per gigawatt, and high represents values more than $500 million per gigawatt. Injections that are assumed for 2030 have N/A in this column because they are assumed to be built in the optimization.

Appendix F. Detailed Short-Circuit-Ratio Calculation Results (Part 1)

Part 1 short-circuit-ratio results for normal (N-0) and under single (N-1) and double (N-2) contingencies for the summer peak load cases are presented in Table F-1. Points of interconnection (POI) names:

- Highlighted in red indicate that the given POI presents a short-circuit ratio (SCR) below 3 in at least one of the studied grid conditions and is therefore classified as “weak”
- Highlighted in orange indicate that the given POI presents SCR above 3 and below 5 in at least one of the studied grid conditions and is therefore classified as “moderate”
- Highlighted in green indicate that the given POI presents SCR above 5 in all studied grid conditions and is therefore classified as “strong.”

Table F-1. Grid Strength Analysis Results – Part 1 (Raw Data) – Summer Peak Load

POI Name	State	Offshore Wind Installed Capacity (megawatts [MW])	Base Case			Offshore Wind + Redispatch			Offshore Wind + Redispatch + Minimize Number of Online Units		
			SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)
Gowanus 345 kilovolts (kV)	New York (NY)	816	40	37.9	37.7	39.5	37.2	13.8	36.6	34.8	13.6
Astoria 138 kV	NY	1,230	8	6.8	5.6	8	6.9	5.6	8	6.9	5.6
Farragut East 345 kV	NY	1,310	26.2	25.8	25.8	26	25.7	18.6	23.8	23.5	18.5
Farragut West 345 kV	NY	1,310	26.2	25.8	20.3	26	25.7	20.4	23.8	23.5	19.6
W. 49th 345 kV	NY	1,310	23.1	20.7	5.4	23	20.6	5.4	21.4	19.4	5.4
East Hampton 69 kV	NY	139	8.9	5.8	5.8	8.9	5.8	5.8	8.8	5.7	5.7
Holbrook 138 kV	NY	1,050	9.6	7.6	7.5	9.6	7.6	7.5	8.5	6.9	6.7
Barrett 138 kV	NY	1,350	8.4	7.4	3.7	8.2	7.3	3.7	7.6	6.7	3.2
Indian River	Delaware	1,568	3.4	2.7	2.6	3.4	2.7	2.6	3.3	2.7	2.6

POI Name	State	Offshore Wind Installed Capacity (megawatts [MW])	Base Case			Offshore Wind + Redispatch			Offshore Wind + Redispatch + Minimize Number of Online Units		
			SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)
Fentress	Virginia (VA)	5,200	2.5	1	1	2.5	1	1	2.5	1	1
Landstown	VA	2,600	3.8	3.2	2.1	3.8	3.3	2.1	3.8	3.2	2.1
Oyster Creek	New Jersey (NJ)	816	7.8	6.3	2.1	7.8	6.3	2.1	7.4	6.1	2.1
BL England	NJ	432	8.1	6.8	5.7	8.1	6.8	5.7	8.1	6.8	5.7
Larrabee	NJ	1,300	10.9	9.3	8.8	11	9.4	8.9	9.8	8.2	7.8
Smithburg	NJ	2,400	4.7	1.5	1.5	4.7	1.5	1.5	4.6	1.5	1.5
Atlantic	NJ	1,200	9.8	8.4	7.8	10	8.5	6.8	9.2	7.9	7.2
Cardiff	NJ	1,500	4.3	3.1	2.2	4.3	3.1	2.2	4.3	3.1	2.1
Ward Hill	Massachusetts (MA)	1,200	10.9	6.2	2.1	11	6.2	2.1	10.8	6.2	2.1
Bourne	MA	1,200	9.3	7.4	5.6	10.6	7.8	5.8	10.5	7.6	5.7
West Barnstable	MA	838	11	9.4	2.4	12.1	10.2	2.4	12	9.5	8.5
Brayton Point	MA	2,330	5.1	5	4.2	5.2	5.1	4.3	5	4.9	4.1
Montville	Connecticut	1,200	10.8	5.8	1.4	10.9	5.8	1.4	10.5	5.7	1.4

POI Name	State	Offshore Wind Installed Capacity (megawatts [MW])	Base Case			Offshore Wind + Redispatch			Offshore Wind + Redispatch + Minimize Number of Online Units		
			SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)
Yarmouth	Maine	2200	3.1	2.2	1.9	3.1	2.2	1.9	3.1	2.2	1.9
Sutton North	North Carolina	2,200	3.3	2.5	1.5	3.3	2.5	1.5	2.6	1.8	0.7

Part 1 short-circuit ratio results for normal (N-0) and under single (N-1) and double (N-2) contingencies for the winter peak load cases are presented in Table F-2.

From the 24 studied POIs, 9 can be classified as “strong,” 3 as “moderate,” and 12 as “weak.” Results show that contingencies have a major impact on the POI strength (in N-0, only 2 POIs are classified as “weak” while 17 are classified as “strong”). Notably, the Fentress POI is weak even in the case without offshore wind.

Table F-2. Grid Strength Analysis Results - Part 1 (Raw Data) – Winter Peak Load

POI Name	State	Offshore Wind Installed Capacity [MW]	Base Case			Offshore Wind + Redispatch			Offshore Wind + Redispatch + Minimize Number of Online Units		
			SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)
Gowanus 345 kV	NY	816	19.9	19.0	11.3	19.6	18.7	11.1	18.7	17.9	10.7
Astoria 138 kV	NY	1,230	6.6	5.5	4.4	6.6	5.4	4.4	5.2	4.0	3.1
Farragut East 345 kV	NY	1,310	26.1	25.7	23.4	26.0	25.6	23.3	23.0	22.6	20.6
Farragut West 345 kV	NY	1,310	26.1	25.7	23.4	26.0	25.6	23.3	23.0	22.6	20.6
W. 49th 345 kV	NY	1,310	24.7	23.4	17.2	24.6	23.3	17.0	22.0	21.0	16.0
East Hampton 69 kV	NY	139	7.4	5.3	5.3	7.5	5.3	5.3	7.3	5.2	5.2
Holbrook 138 kV	NY	1,050	7.3	6.2	6.1	7.4	6.3	6.1	6.1	5.3	5.1
Barrett 138 kV	NY	1,350	6.9	6.2	3.3	6.8	6.2	3.3	6.1	5.5	2.8
Indian River	DE	1,568	3.4	2.8	2.6	3.4	2.8	2.6	3.4	2.8	2.6
Fentress	VA	5,200	2.5	1.0	1.0	2.5	1.0	1.0	2.4	1.0	1.0
Landstown	VA	2,600	3.8	3.2	2.0	3.8	3.2	2.0	3.7	3.2	2.0
Oyster Creek	NJ	816	7.5	6.1	2.0	7.5	6.1	2.0	7.1	5.8	1.9
BL England	NJ	432	7.2	6.3	3.4	7.2	6.3	3.4	7.2	6.2	3.4
Larrabee	NJ	1,300	10.3	8.8	8.3	10.4	8.9	8.4	9.2	7.7	7.2

POI Name	State	Offshore Wind Installed Capacity [MW]	Base Case			Offshore Wind + Redispatch			Offshore Wind + Redispatch + Minimize Number of Online Units		
			SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)	SCR (N-0)	SCR (N-1)	SCR (N-2)
Smithburg	NJ	2,400	4.6	1.5	1.5	4.6	1.5	1.5	4.5	1.5	1.5
Atlantic	NJ	1,200	9.3	7.9	7.3	9.3	8.0	7.4	8.6	7.5	6.8
Cardiff	NJ	1,500	4.0	2.9	2.0	4.1	2.9	2.0	4.0	2.9	2.0
Ward Hill	MA	1,200	10.7	6.1	2.0	10.7	6.1	2.0	10.6	6.1	2.0
Bourne	MA	1,200	9.3	7.4	5.6	9.5	7.5	5.7	9.2	7.4	5.5
West Barnstable	MA	838	11.0	9.4	2.4	11.1	9.5	2.4	10.9	9.3	2.4
Brayton Point	MA	2,330	5.2	5.1	4.2	5.3	5.2	4.4	5.1	5.1	4.3
Montville	CT	1,200	10.7	5.7	1.3	10.7	5.7	1.3	10.6	5.7	1.3
Yarmouth	ME	2,200	3.1	2.2	1.9	3.1	2.2	1.9	3.1	2.2	1.9
Sutton North	NC	2,200	3.3	2.5	1.5	3.3	2.5	1.5	2.6	1.8	0.7

Appendix G. Detailed Short-Circuit-Ratio Calculation Results (Part 2)

Table G-1 presents the statistics of the Part 2 short-circuit-ratio (SCR) results (maximum, minimum, and average SCR values from the 24 hours of each typical day). The results show that 14 points of interconnection (POIs) present "weak" characteristics in at least one of the 72 studied operating conditions. Despite different SCR values for each operating condition, results show that the operating condition has no major impact in terms of changing the classification of a given POI (i.e., a weak POI remains weak across most, if not all, studied operating conditions). However, when looking at the impact of contingencies, they have a major effect on the POI strength (in N-0, only four POIs are classified as "weak).

Table G-1. Grid Strength Analysis Part 2 Summary of Results

POI_name	State	N-0									N-1									N-2								
		SUM_Day_Average	SUM_Day_Min	SUM_Day_Max	WIN_Day_Average	WIN_Day_Min	WIN_Day_Max	SPR_Day_Average	SPR_Day_Min	SPR_Day_Max	SUM_Day_Average	SUM_Day_Min	SUM_Day_Max	WIN_Day_Average	WIN_Day_Min	WIN_Day_Max	SPR_Day_Average	SPR_Day_Min	SPR_Day_Max	SUM_Day_Average	SUM_Day_Min	SUM_Day_Max	WIN_Day_Average	WIN_Day_Min	WIN_Day_Max	SPR_Day_Average	SPR_Day_Min	SPR_Day_Max
Gowanus 345 kV	NY	25.8	21.5	29.9	22.6	20.8	23.9	22.2	19.3	23.9	24.7	20.7	28.6	21.8	20.2	23.0	21.4	18.5	23.0	17.1	8.4	26.8	19.3	10.5	22.9	18.2	8.9	22.9
Astoria 138 kV	NY	4.2	4.0	4.4	4.1	4.0	4.3	4.1	3.4	4.3	3.1	2.9	3.3	3.0	2.9	3.1	3.0	2.3	3.1	2.2	2.0	2.3	2.2	2.0	2.3	2.1	1.5	2.3
Farragut East 345kV	NY	16.8	13.8	19.4	14.6	13.4	15.5	14.3	12.4	15.5	16.6	13.7	19.2	14.5	13.3	15.4	14.2	12.4	15.4	15.2	11.8	19.1	13.1	11.5	15.2	12.9	11.2	15.3
Farragut West 345kV	NY	16.8	13.8	19.4	14.6	13.4	15.5	14.3	12.4	15.5	16.6	13.7	19.2	14.5	13.3	15.4	14.2	12.4	15.4	14.5	11.1	18.1	12.9	10.6	15.4	12.5	10.6	15.4
W. 49th 345 kV	NY	15.6	13.1	17.8	13.8	12.7	14.6	13.6	11.9	14.6	14.5	12.4	16.4	13.0	12.0	13.7	12.8	11.3	13.7	5.0	4.8	5.1	4.9	4.7	5.0	4.9	4.7	5.0
East Hampton 69 kV	NY	6.4	6.1	6.6	6.2	6.0	6.4	6.3	6.0	6.5	4.2	4.1	4.4	4.2	4.1	4.3	4.2	4.1	4.3	4.2	4.1	4.3	4.2	4.0	4.3	4.2	4.0	4.3
Holbrook 138 kV	NY	6.5	5.0	7.6	5.2	4.6	6.2	5.5	4.7	6.6	5.6	4.3	6.5	4.6	4.1	5.6	4.8	4.1	5.8	5.3	4.1	6.2	4.3	3.8	5.3	4.6	3.9	5.6
Barrett 138 kV	NY	6.1	5.4	7.1	5.5	5.3	5.7	5.6	5.3	5.8	5.4	4.8	6.3	4.9	4.7	5.1	4.9	4.7	5.1	2.2	2.1	2.9	2.1	2.0	2.1	2.1	2.1	2.1
Indian River	DE	1.9	1.8	2.1	1.9	1.8	2.1	1.9	1.8	2.1	1.5	1.4	1.6	1.5	1.4	1.6	1.5	1.4	1.6	1.2	1.1	1.4	1.3	1.1	1.4	1.2	1.1	1.4
Fentress	VA	2.2	2.0	2.3	2.1	2.0	2.2	2.1	2.0	2.2	0.9	0.9	1.0	0.9	0.9	1.0	0.9	0.9	1.0	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9
Landstown	VA	3.5	3.2	3.6	3.4	3.2	3.5	3.4	3.1	3.5	3.0	2.8	3.1	2.9	2.8	3.0	2.9	2.7	3.0	1.9	1.8	2.0	1.9	1.8	2.0	1.9	1.8	1.9
Oyster Creek	NJ	6.9	6.5	7.0	6.7	6.4	6.8	6.7	6.4	6.9	5.7	5.4	5.8	5.6	5.4	5.7	5.6	5.4	5.7	1.9	1.8	1.9	1.9	1.8	1.9	1.9	1.8	1.9
BL England	NJ	7.0	6.8	7.2	7.0	6.8	7.2	7.0	6.8	7.2	6.1	5.9	6.3	6.1	5.9	6.2	6.1	5.9	6.2	3.3	3.2	3.4	3.3	3.2	3.4	3.3	3.2	3.4
Larrabee	NJ	8.7	7.8	9.1	8.1	7.7	8.3	8.3	7.6	8.7	7.2	6.4	7.5	6.7	6.2	6.8	6.8	6.2	7.2	6.8	6.0	7.1	6.3	5.9	6.4	6.4	5.9	6.8
Smithburg	NJ	4.4	4.2	4.5	4.3	4.1	4.3	4.3	4.1	4.4	1.5	1.4	1.5	1.4	1.4	1.5	1.4	1.4	1.5	1.5	1.4	1.5	1.4	1.4	1.4	1.4	1.4	1.5
Atlantic	NJ	8.3	7.4	8.6	7.6	7.2	7.8	7.8	7.2	8.2	7.2	6.4	7.5	6.7	6.3	6.8	6.8	6.3	7.1	6.5	5.8	6.8	6.0	5.6	6.1	6.1	5.6	6.4
Cardiff	NJ	3.8	3.7	3.9	3.8	3.7	3.9	3.8	3.7	3.9	2.8	2.7	2.8	2.7	2.6	2.8	2.7	2.6	2.8	1.9	1.8	2.0	1.9	1.8	2.0	1.9	1.8	2.0
Ward Hill	MA	9.3	9.0	9.7	8.9	8.5	9.2	8.6	8.1	9.0	5.6	5.4	5.7	5.4	5.2	5.5	5.3	5.1	5.4	1.9	1.8	1.9	1.7	1.7	1.8	1.7	1.7	1.8
Bourne	MA	6.4	6.2	6.6	6.2	6.0	6.4	5.9	5.6	6.2	5.5	5.4	5.7	5.4	5.2	5.6	5.2	5.0	5.4	4.5	4.4	4.6	4.4	4.3	4.5	4.2	4.1	4.3
West Barnstable	MA	8.7	8.5	8.9	8.5	8.3	8.8	8.2	7.9	8.5	7.5	7.3	7.6	7.3	7.2	7.5	7.1	6.9	7.3	1.4	1.4	1.5	1.4	1.4	1.5	1.4	1.4	1.5
Brayton Point	MA	4.0	3.9	4.1	3.9	3.8	4.0	3.7	3.5	3.8	2.9	2.9	3.0	2.9	2.8	2.9	3.0	2.7	3.7	2.9	2.8	2.9	2.8	2.8	2.9	2.8	2.6	3.2
Montville	CT	9.5	9.3	9.8	9.5	9.4	9.7	9.1	8.8	9.2	5.2	5.1	5.3	5.2	5.1	5.3	5.0	4.8	5.1	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
Yarmouth	ME	2.9	2.8	3.0	2.9	2.8	2.9	2.8	2.7	2.9	2.1	2.0	2.1	2.1	2.0	2.1	2.1	2.0	2.1	1.9	1.8	1.9	1.9	1.8	1.9	1.9	1.8	1.9
Sutton North	NC	2.8	2.8	2.9	2.8	2.8	2.9	2.8	2.4	2.8	2.1	2.1	2.1	2.1	2.1	2.1	2.1	1.7	2.1	1.1	1.0	1.1	1.0	1.0	1.1	1.0	0.7	1.0

The following figures show the SCR in N-0 condition at the selected POIs as a function of the operating conditions (generation dispatch) for the selected summer peak, winter peak, and spring off-peak days (against the area-specific generation dispatch stack).

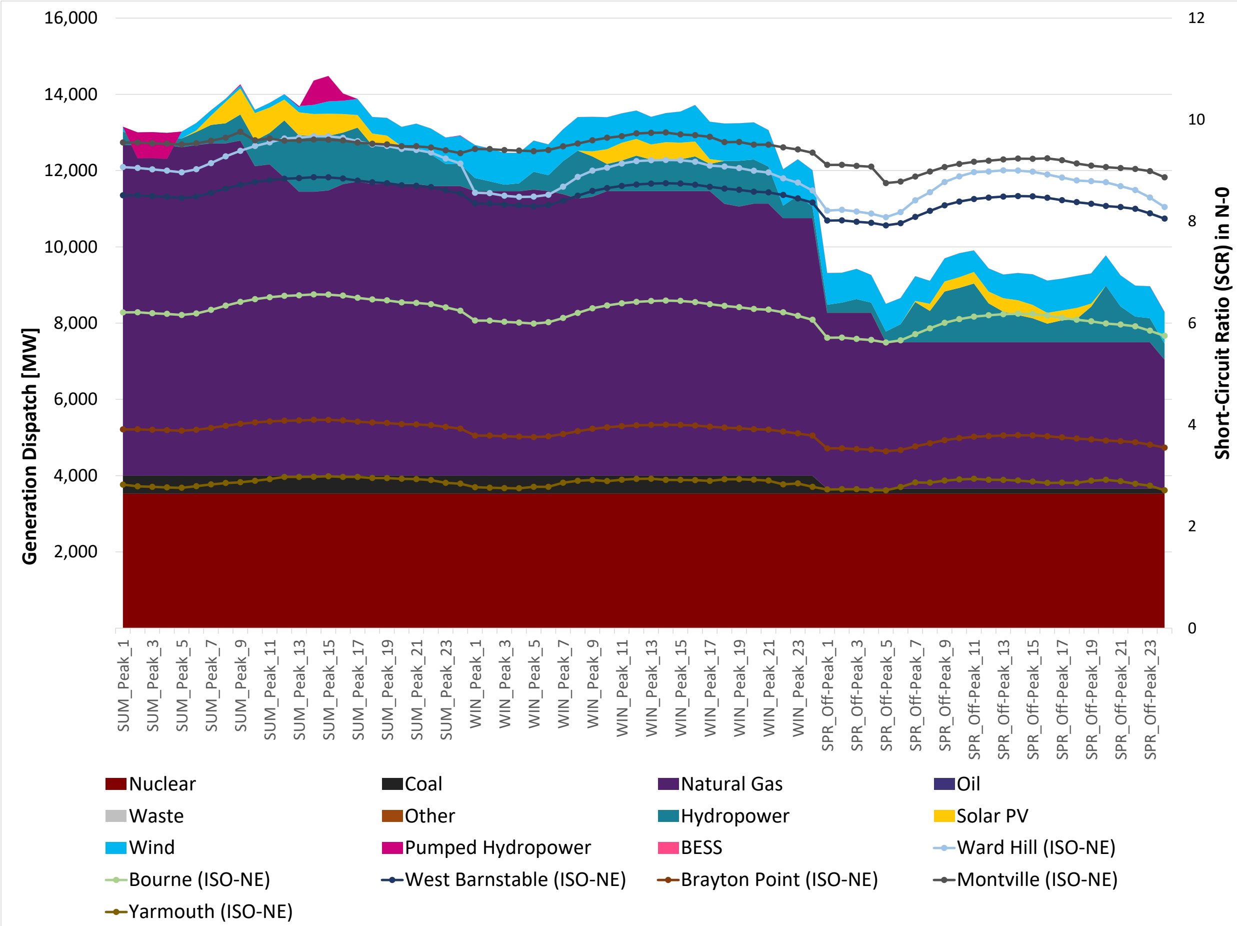


Figure G-1. SCR at selected POIs in the N-0 condition vs. generation dispatch stack (Independent System Operator New England [ISO-NE]). ***Figure by NREL.***

Note: MW = megawatts; BESS = Battery Energy Storage System; PV = photovoltaics

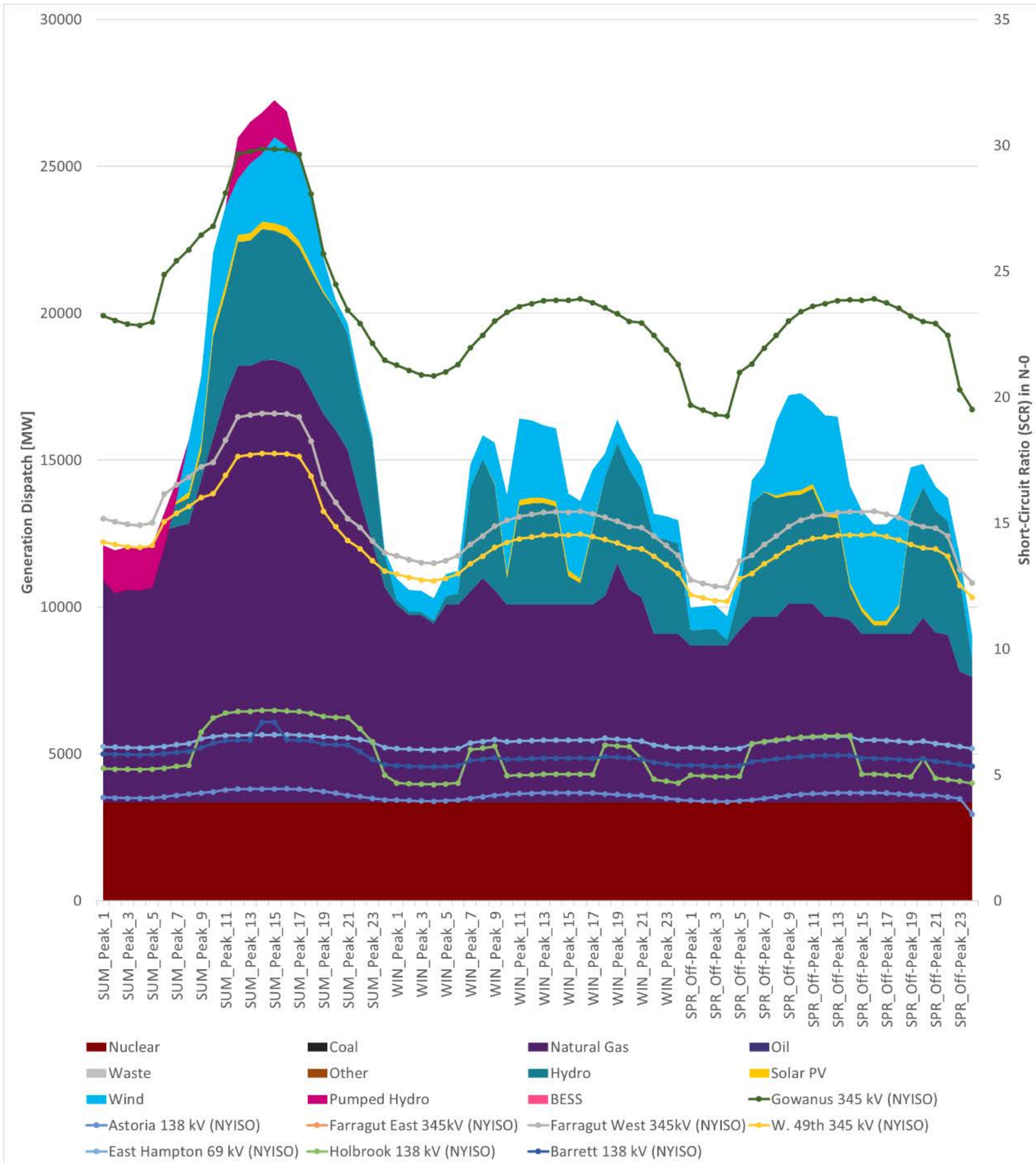


Figure G-2. SCR at selected POIs in the N-0 condition vs. generation dispatch stack (New York Independent System Operator [NYISO]). ***Figure by NREL***

Note: kV = kilovolt

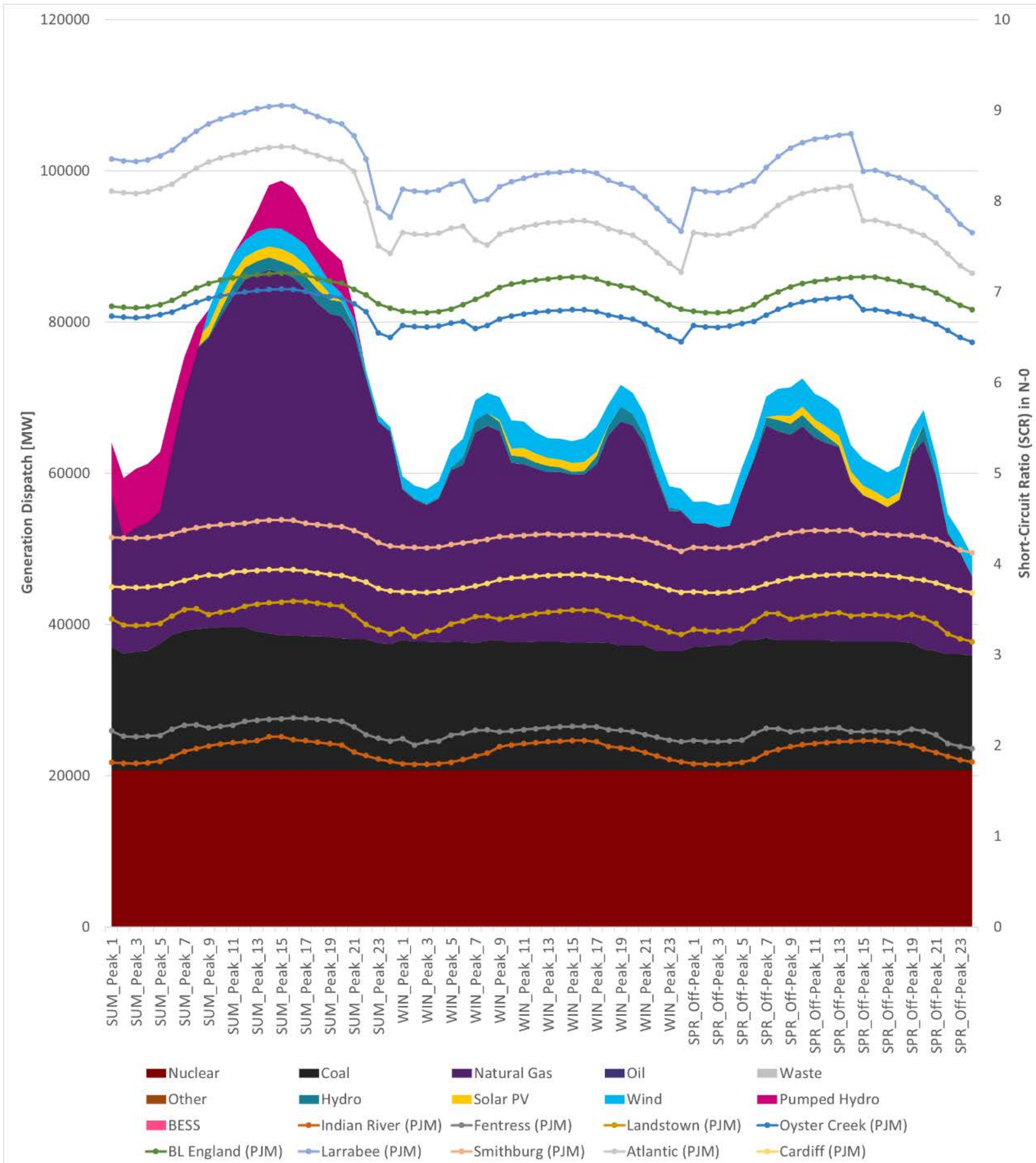


Figure G-3. SCR at selected POIs in the N-0 condition vs. generation dispatch stack (PJM). ***Figure by NREL***

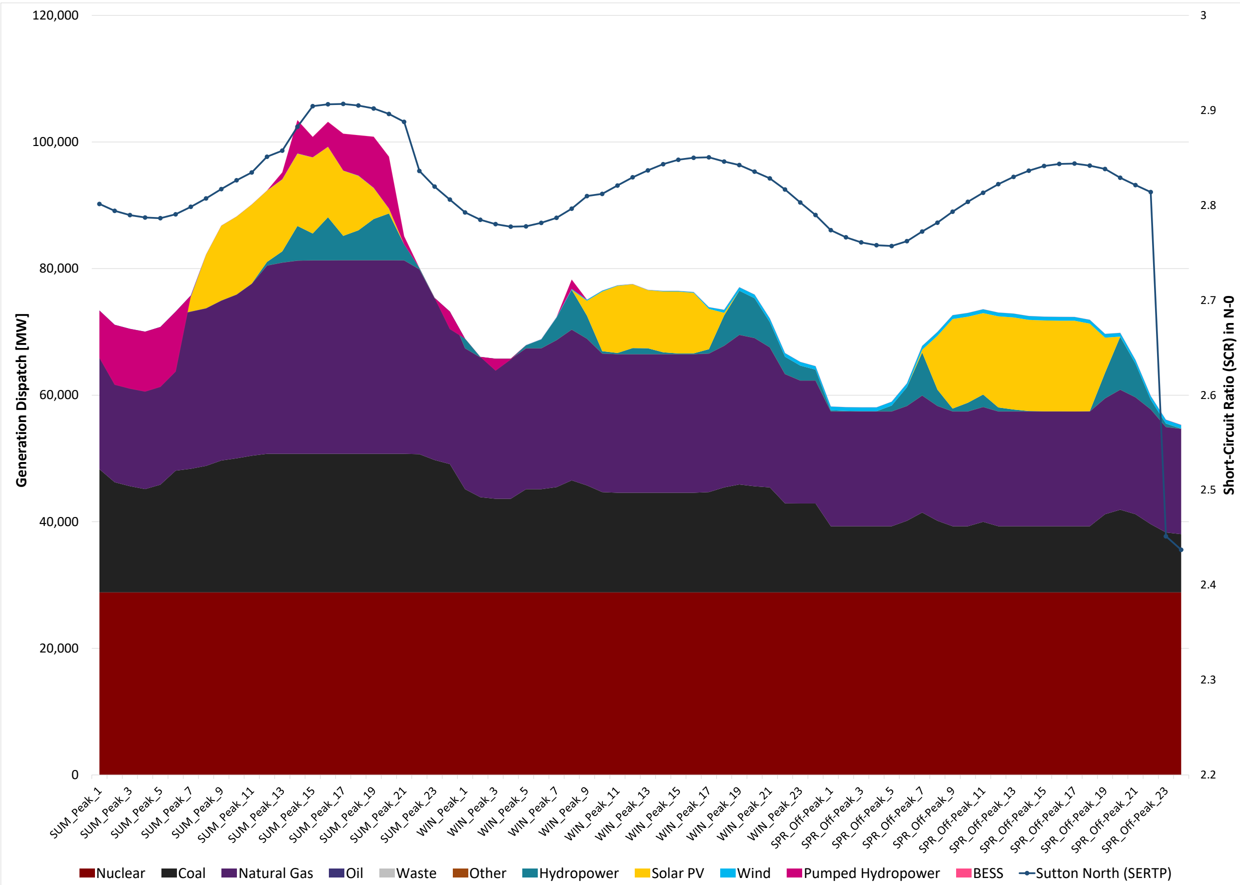


Figure G-4. SCR at selected POIs in the N-0 condition vs. generation dispatch stack (Southeastern Regional Transmission Planning [SERTP]). ***Figure by NREL***

Appendix H. Automated System-Wide Strength Evaluation Tool

The National Renewable Energy Laboratory's Automated System-wide Strength Evaluation Tool (ASSET), shown in Figure H-1, was developed to examine and assess large-scale systems for multiple system operating conditions under credible contingencies, as well as their impacts on system strength. ASSET was developed in Python by leveraging the PSS/E Python Application Programming Interface for calculating short-circuit current (SCC), which is shown in Figure H-2. More details about the tool and its key steps are provided in this appendix.

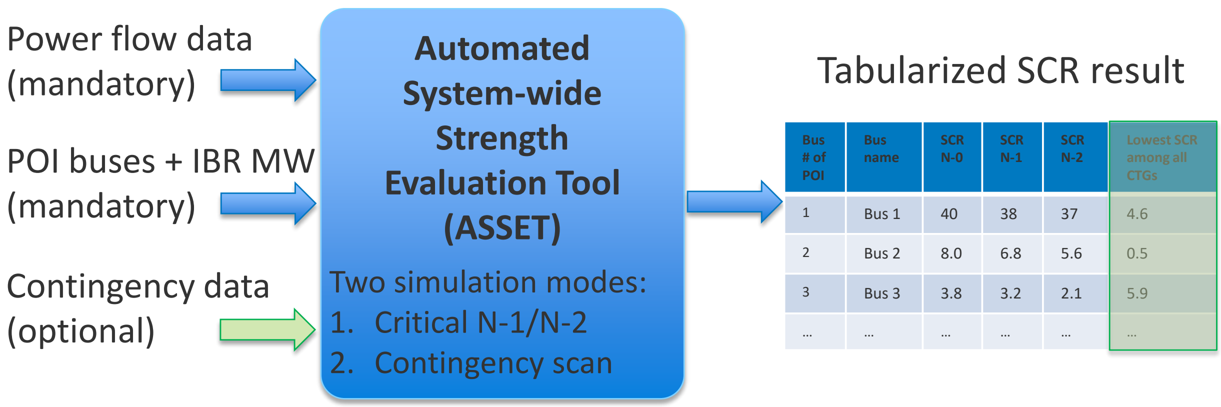


Figure H-1. The ASSET tool inputs and outputs. ***Figure by NREL***

Note: POI = points of interconnection; IBR MW = megawatt of inverter-based resource; SCR = short-circuit ratio

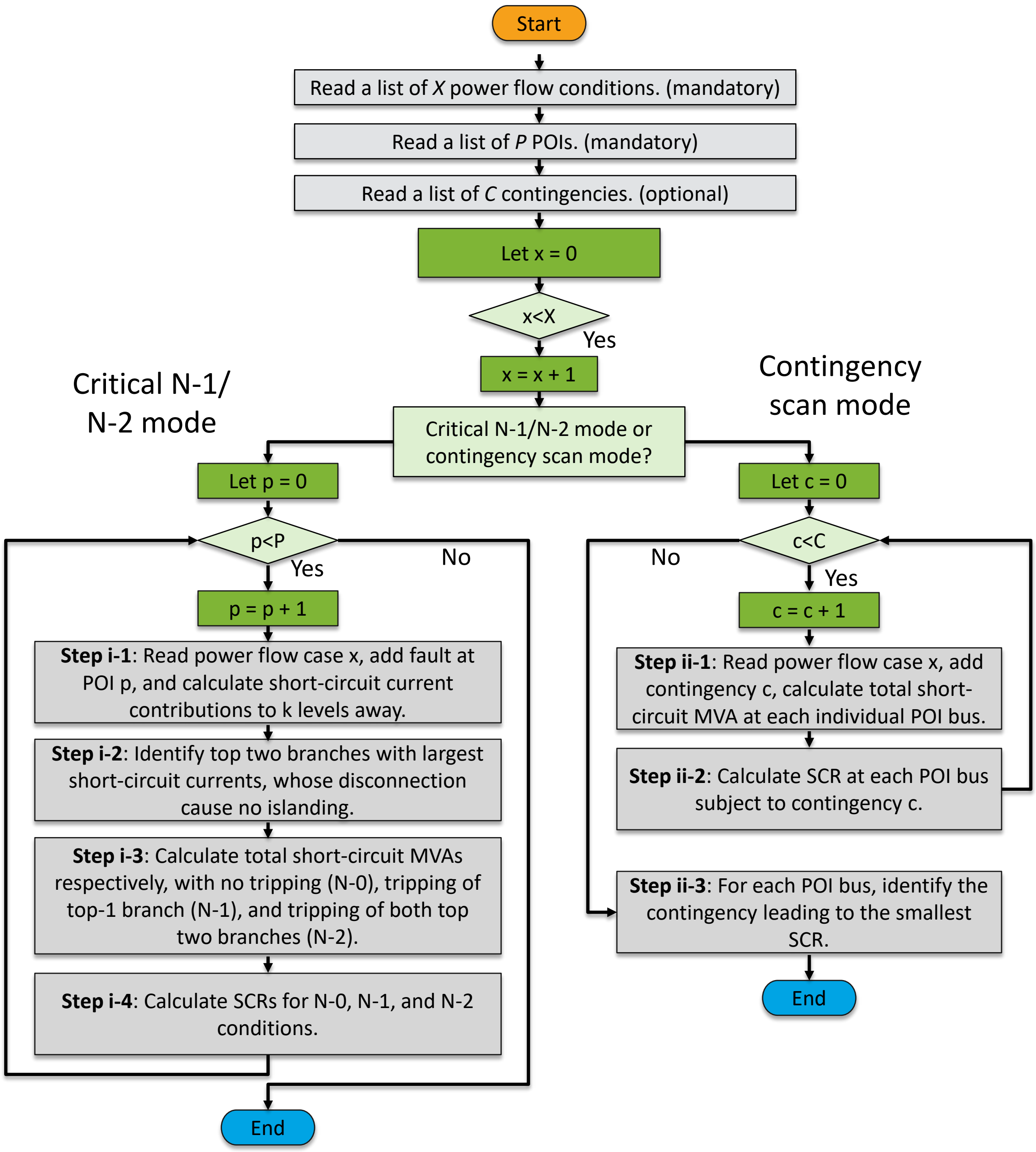


Figure H-2. Flowchart for implementing the ASSET toolbox. ***Figure by NREL***

Note: MVA = megavolt ampere

Input Requirement

There are two types of mandatory input files and one optional input file. Mandatory input files include the power flow data file(s) and the POI data file. Each power flow data file represents a different loading/dispatch condition, wherein the power flow does not need to be solved because the short-circuit current calculation does not require a converged power flow. The POI data file contains a list of POI buses and the total megawatt capacity of connected inverter-based resources for each POI bus. The optional input file contains the contingency data, which are required when the contingency scan mode is selected in ASSET.

Simulation Mode

ASSET has two simulation modes: the critical N-1/N-2 mode and the contingency scan mode. For each POI bus, the critical N-1/N-2 mode aims to identify the top two branches in which disconnections are most likely to cause the largest reductions in system strength without leading to an islanding condition. Figure H-3 gives an example of identifying the top two branches, wherein the fault is added to bus 7 and the largest SCC occurs on line 6-7. However, disconnecting line 6-7 causes an islanding condition. Thus, it is skipped to avoid islanding conditions, whereas lines 2-4 and 4-6 are identified as being the most critical contingencies. Once the top two branches carrying the largest SCCs are identified, the ASSET tool will calculate SCR for normal operation (N-0), and the critical N-1 and N-2 conditions. It should be noted that the critical branches identified by ASSET can differ from those used for the real-time contingency analysis applied in North American Electric Reliability Corporation's TOP-001-3 standard. The contingency scan mode calculates the SCR of each POI under each of the given contingencies, which further could identify the most critical contingency from the list that causes the largest reduction in system strength. Note that each POI bus may have a different critical contingency.

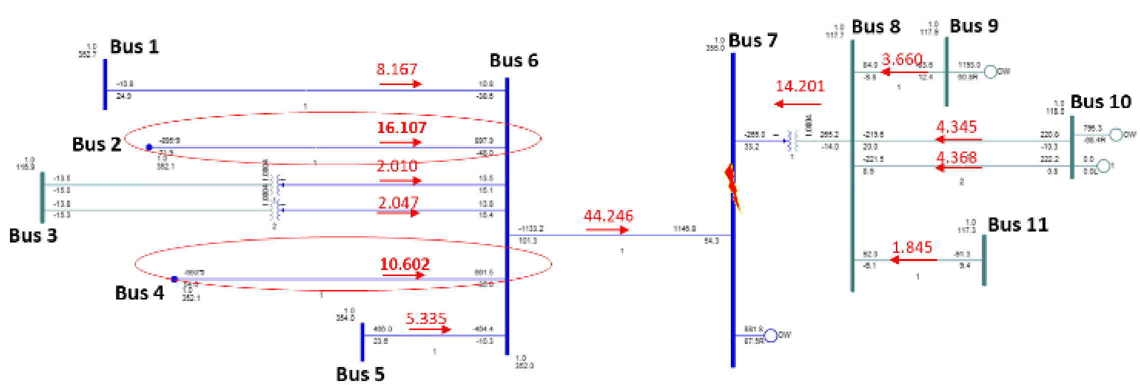


Figure H-3. Example of SCCs on the network and top two branches carrying the largest SCCs. ***Figure by NREL***

Short-Circuit Current Calculation

We adopted the International Electrotechnical Commission 60909-0:2016 standard to calculate the short-circuit currents and short-circuit MVAs in PSS/E. In addition, we used default PSS/E settings, applied the three-phase fault, and used the initial symmetrical short-circuit current I_k'' to calculate the SCR. To identify the top two critical branches, I_k'' contributions over the network were observed to k levels away from the fault at the POI bus. In all numerical studies in this analysis, k takes 10.

Appendix I. Alternating Current Power Flow Preparation (C-PAGE and Reactive Power Planning)

This appendix introduces Pacific Northwest National Laboratory's (PNNL's) Chronological AC Power Flow Automated Generation (C-PAGE) tool and the methodology implemented for reactive power planning to set up the short-term and long-term study cases.

C-PAGE Tool

The conversion from a production cost model (PCM) to a power flow model was accomplished through the direct current (DC) to alternating current (AC) conversion function within C-PAGE (Vyakaranam et al. 2021). C-PAGE is designed to programmatically automate the chronological AC case preparation for the bulk interconnection system, such as the Western Electricity Coordinating Council, the Eastern Interconnection, and the Texas Electric Reliability Council.

Process of DC-to-AC Conversion

The approach of the conversion of DC power flow from PCM findings to an AC-converged power flow case begins with Step 1 in Figure I-1, which updates the new PCM result to an AC-converged power flow case received from the previous time step.

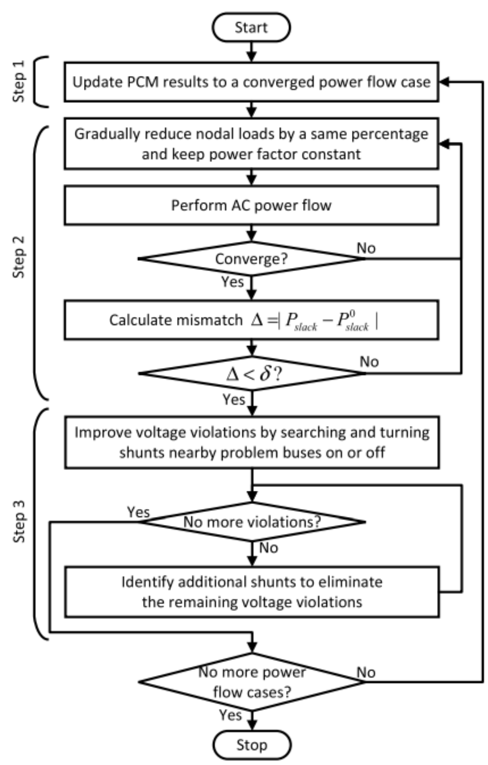


Figure I-1. Diagram for converting a DC-converged power flow case from PCM results to an AC-converged power flow case. ***Figure by PNNL***

The reasoning is because the loading circumstances of two consecutive power flow instances are frequently close to each other, therefore the voltage of the AC-converged power flow case in the prior time step is a useful starting point for solving power flow in the new power flow case. Losses were not considered in the PCM model in this study.

Since PCM employs DC power flow, total generation equals total load in the new power flow condition. In this approach, we assumed that the dispatch of all generation units, including the unit at the slack bus, is fixed, as in PCM results. As a result, nodal loads must be lowered to account for transmission losses when converting DC to AC power flow scenarios. As a result, nodal loads are repeatedly lowered in step 2 of the technique before AC power flow is initiated. If the power flow does not converge, the load is reduced even more.

If the power flow converges, the resulting real power generation at the slack bus is compared to the original value in the PCM result and the load is modified to keep the slack near the PCM. Following the achievement of an AC-converged power flow situation, the focus switches to optimizing the bus voltage profile. Improving voltage after establishing AC convergence is critical, because a good voltage profile at one time step has a direct impact on the potential of achieving AC convergence in following time steps. As a result, in step 3, all bus voltages are inspected for voltage violations.

Reactive Power Planning

To achieve reliability requirements under a wide range of practical contingencies, transmission planners must account for a sufficient supply of reactive power. An important dependability service for the bulk power system is reactive power balancing, considering transmission lines, generators, capacitors, and loads. The system voltage behavior is closely associated with reactive power in a particular region. Therefore, maintaining voltage within an acceptable operation range is always crucial. The block diagram shown in Figure I-2 provides a solution for the system reactive power planning.

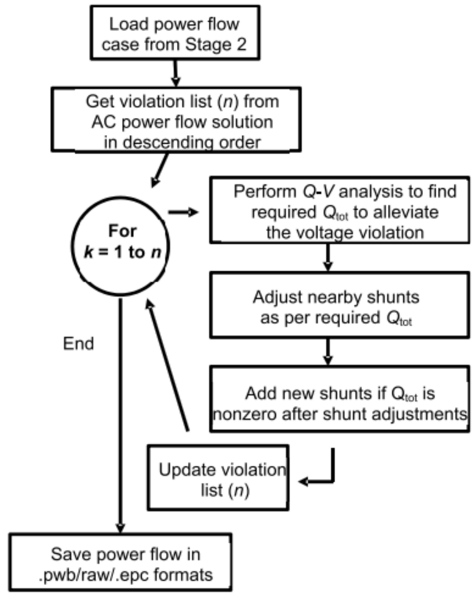


Figure I-2. Improving the system regional voltage by reactive power planning. ***Figure by PNNL***

Enhancing the system voltage is an essential prerequisite for achieving convergence in the AC power flow case during chronological case creation. In C-PAGE, improving voltage is accomplished by devising methods for conducting Q-V analysis, revealing the sensitivity and volatility of bus voltages in response to reactive power injections or absorptions. As depicted in Figure I-2, the approach involves systematically elevating the voltage profile while employing suitable reactive support devices.

Appendix J. The AC-DC Power Flow Algorithm and MTDC Redispatch Strategy

AC-DC Power Flow Algorithm

The existing PSS/E version lacks the capability to independently solve the direct current (DC) power flow for a multiterminal high-voltage direct current (MTDC) network. As a solution, a custom-built, parallel computing-oriented alternating current (AC)-DC power flow algorithm has been developed using Python and used in this study. The algorithm of solving AC-DC power flow considering the offshore wind MTDC configurations is shown in Figure J-1.

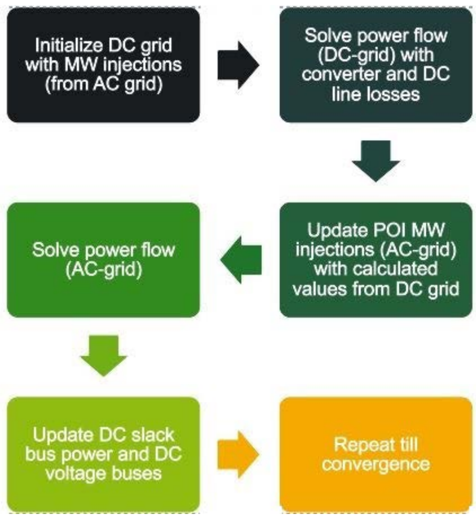


Figure J-1. The AC-DC power flow algorithm used to obtain the power flow solutions. ***Figure by the Pacific Northwest National Laboratory.***

Note: MW = megawatt(s)

This procedure involves concurrently solving AC and DC power flows, aiming for a fully integrated DC-grid (representing the MTDC system) with the AC bulk power grid. The procedure is initiated by calculating the initial power injected/absorbed at each point of interconnection (POI). Using the AC grid voltages and power injection at the AC grid side. We applied the Newton-Raphson method as a core root-finding algorithm to solve the power flow of the DC grid. Voltage and currents at the converter side are computed based on the voltage source conversion HVDC multiterminal model (Renedo et al. 2017). The computed values account for the DC losses, resulting in updated DC slack power injection. Subsequentially, the computed DC slack power is used to update the AC power flow solution. This iterative process continues until the mismatch between the slack bus and its corresponding AC bus is eliminated.

MTDC Redispatch Strategy

To mitigate the transformer overloading resulting from the P1 contingency outlined in Section 7.5.1.2, we implemented the MTDC redispatch strategy, as follows.

The total net flow (around 1,200 MW) into the Independent System Operator New England (ISO-NE) area from the offshore generation was reduced by redirecting its flow into the New York Independent System Operator (NYISO) via its MTDC onshore terminals without any wind curtailment. This action was taken in response to the analyzed N-1 AC contingency, which had already caused congestion on the AC lines in the vicinity of the onshore MTDC terminals within the ISO-NE area. By decreasing power injections into the ISO-NE onshore MTDC terminals and redirecting them through the NYISO interconnecting AC lines (less impacted), the goal to alleviate the flow on the already overloaded AC lines in the ISO-NE area was achieved. It is worth noting that the total change in 1,200 MW of net flow was redispatched to each MTDC terminal and the exact amount depended on the location. For example, suppose the onshore MTDC terminal is in NYISO. In that case, more than 400 MW of the original injection was redispatched, and vice versa for the DC redispatch at the onshore terminals at ISO-NE. The wind generation is also assumed to be the same even after the DC redispatch.

It should be noted that the DC redispatch action considered here has been based on the contingency event conducted in this work. For a different contingency event, more DC redispatch strategies need to be thoroughly investigated to obtain the full benefits from the proposed approach.

The impact on the AC system using the proposed approach is presented in Table J-1.

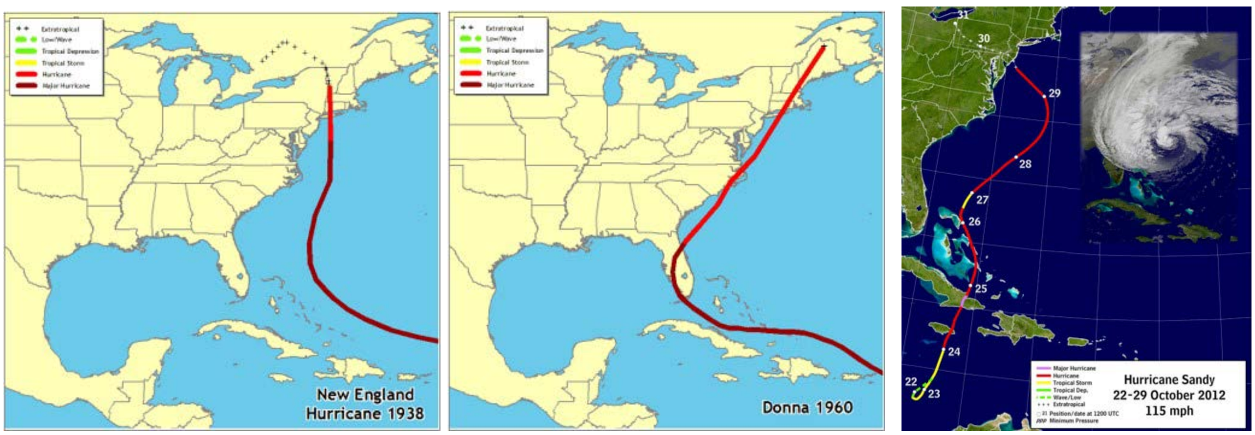
Table J-1. Evidence of Alleviation of Overloading on the Studied AC Line After Utilizing the DC Redispatch for the Considered MTDC Topology

MTDC Configuration	Before Contingency	P1-2 Contingency (Before DC Redispatch)	P1-2 Contingency (After DC Redispatch)
Identified Critical AC Line Flow (Based on Rating B)	50%	118%	88% ⬇

Table J-1 clearly shows that after the AC contingency, the ISO-NE area's identified AC critical line flow is overloaded. However, using the proposed DC redispatch, the overloading in this line has been eliminated.

Appendix K. The Electrical Grid Resilience and Assessment System

Hurricanes can result in strong winds, heavy rainfall, and storm surges, leading to power outages, flooding, and other damage. Offshore wind generation infrastructure can both be affected by and provide support during these events. Figure K-1 illustrates the path and intensity of three hurricanes that have impacted the U.S. East Coast.



(a) New England Hurricane (1938) (b) Hurricane Donna (1960) (c) Hurricane Sandy (2012)

Figure K-1. Path and intensity of three hurricanes that have impacted the U.S. East Coast. ***Figures from the National Hurricane Center, National Oceanic and Atmospheric Administration***

To facilitate the enhancement of grid resilience, the Pacific Northwest National Laboratory (PNNL) developed the Electrical Grid Resilience and Assessment System (EGRASS). The results from the EGRASS temporal sequence model were combined with the geographic information system (GIS) asset mappings to obtain a list of PSS®E assets with their corresponding failure probabilities and time stamps at which they are affected by the extreme weather events. Next, we applied the Monte Carlo method to generate "n" sets of contingencies based on the probabilities of asset failure. The resulting sets of failed assets for each Monte Carlo sampling were then grouped into different Dynamic Contingency Analysis Tool (DCAT) files based on their time stamps, resulting in "n" groupings of contingency files, with each grouping containing a file for each hour.

Appendix J illustrates the models, data, and process to set up EGRASS and study grid resilience impacts using a hurricane as a representative extreme weather event. Sample results are presented based on one of the Atlantic Offshore Wind Transmission Study simulation models established in Section 7.1.

Power System Grid Impact From Hurricanes To Consider

Wind turbines are designed to generate electricity by harnessing the kinetic energy of the wind. The behavior of a wind turbine depends on its design and the local wind characteristics. The three key wind speeds that determine the behavior of a wind turbine are illustrated in Figure K-2, being the cut-in wind speed, rated wind speed, and cut-off wind speed. The cut-in wind speed ($v_{\text{cut in}}$) is the minimum wind speed required for a wind turbine to start generating electrical power. At wind speeds below the cut-in speed, the wind turbine blades are stationary, and the generator is not producing any power. The rated wind speed (v_{rated}) is the wind speed at which the wind turbine generates its rated/maximum power output. At this speed, the turbine's blades are designed to produce maximum power while avoiding excessive mechanical stress on the turbine. The cut-off wind speed ($v_{\text{cut off}}$) is the maximum wind speed at which the wind turbine will shut down to avoid damage. At wind speeds above the cut-off speed, the turbine's blades will automatically pitch or feather to reduce their surface area and shut down completely to prevent damage to the turbine components (Sohoni et al. 2016).

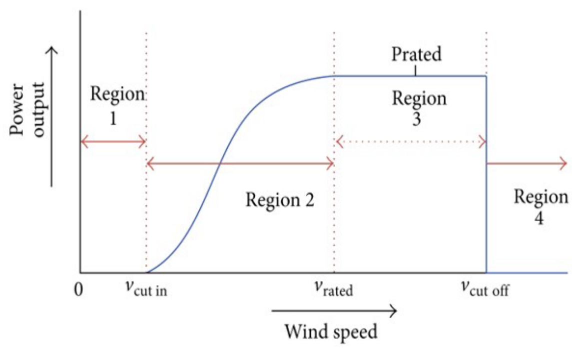


Figure K-2. Typical wind turbine electric power output in relation to a steady wind speed. *Image from Sohoni et al. (2016)*

In summary, wind turbines have a range of wind speeds over which they can operate effectively. The cut-in wind speed is the minimum speed required for the turbine to start generating power, the rated wind speed is the speed at which the turbine produces its maximum power output, and the cut-off wind speed is the maximum speed at which the turbine will shut down to avoid damage.

EGRASS: From Extreme Weather to Grid Resilience Analysis

Figure K-3 shows the EGRASS user interface that can translate extreme weather events into grid contingencies, as well as use the weather intensity data, location, and fragility of assets as inputs. The weather parameter is dependent on the time and geospatial location and the assets are dependent on their geospatial location. Figure K-3 presents an example, and shows the path of Hurricane Maria over Puerto Rico. In addition, it uses data from the National Oceanic and Atmospheric Administration's National Hurricane Center as the weather input. The intensity of the weather parameters on the location of assets was used to assess the impact of the event.

Converting the weather intensity parameters to asset impacts uses the fragility of the asset in relation to the intensity of the weather parameters.

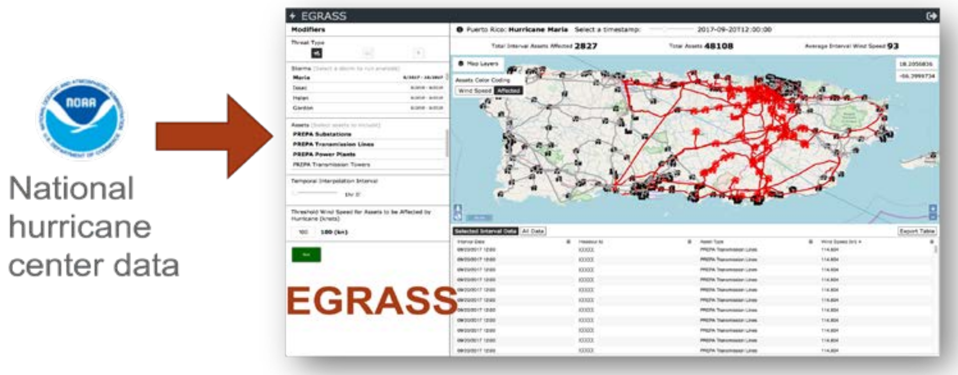


Figure K-3. EGRASS user interface. *Figure by PNNL*

Translating a Hurricane Event to Grid Resilience Analysis

Fragility Modeling of Power Systems Infrastructure

Fragility curves are essential for quantifying the vulnerability of structural assets to different levels of loading. These curves establish the relationship between the loading on an asset and the conditional probability of failure of the element given that loading. Fragility curves are statistical models that depict the likelihood of failure of a structural element at different levels of loading. The curves provide a graphical representation of the vulnerability of an element to specific loading conditions, typically mechanical loading or mechanical stresses. The fragility curves are developed by analyzing data from experiments, simulations, or historical records to establish the relationship between the loading and probability of failure. These curves are widely used in risk assessment and decision-making processes related to structural assets.

The key components of fragility curves include the loading parameter, probability of failure, and fragility function. The loading parameter refers to the variable that represents the level of loading on the structural element, such as the intensity of an earthquake, the wind speed, or the weight of a load. The probability of failure is the conditional probability that the element will fail given a specific level of loading. The fragility function is the mathematical representation of the relationship between the loading parameter and probability of failure.

Fragility curves have a wide range of applications in the field of structural engineering and risk assessment. They are commonly used to evaluate the performance of structural assets under different loading scenarios, such as earthquakes, windstorms, floods, or other extreme events. Additionally, fragility curves can be used to evaluate the effectiveness of retrofitting or repair measures to enhance the resilience of structural assets. Figure K-4 illustrates the typical shape of a fragility curve.

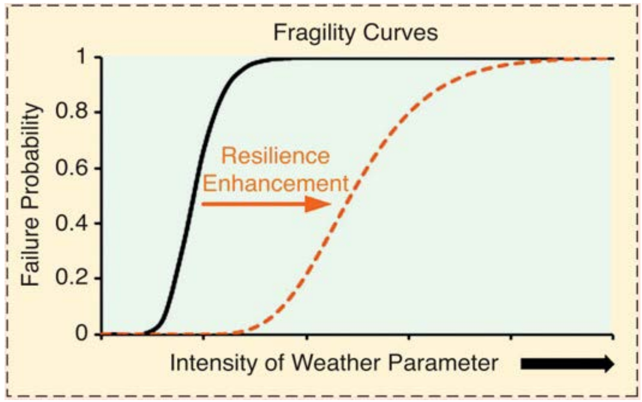


Figure K-4. Typical shape of a fragility curve. ***Image from Panteli and Mancarella (2015)***

Transmission Line Design and Fragility

The failure of transmission lines due to extreme events such as hurricanes has been a persistent problem for power systems. In particular, the wind speed during these events has been identified as a major cause of transmission line failure. Due to the vast geographical distance covered by transmission lines, the wind speed can easily render the entire connection out of service. In essence, only one component of the transmission line is required to fail for the transmission line to be out of service.

The design of transmission lines considers the vulnerability of their components to wind speed (American Society of Civil Engineers and Structural Engineering Institute 2009). The components are presented in Figure K-5. The overhead lines are of utmost importance during extreme events as their failure puts critical mechanical demands on the failure-containing capabilities of the support structures. On the other hand, insulators have larger mechanical loading than cables, whereas the foundation has the tower as the mechanical loading. By design, transmission towers are expected to fail before other components to prevent greater damage to the transmission line.

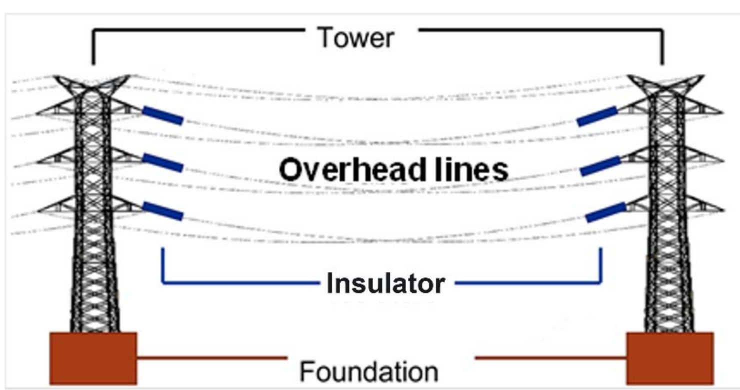


Figure K-5. Transmission line mechanical loading designed for failure containment. ***Image adapted from Xue et al. (2020)***

While wind-hardening measures are effective in protecting transmission lines from the high winds associated with severe weather events such as hurricanes, it is important to recognize that these measures may not provide complete protection from all potential hazards. Falling trees and flying debris are examples of hazards that are not addressed by wind-hardening measures and can still cause damage to transmission lines during severe weather events. To protect against these hazards, additional measures such as vegetation management and debris removal should be considered. Vegetation management can include trimming or removing trees and other vegetation near transmission lines to prevent them from falling onto the lines during severe weather events. Debris removal involves identifying and removing debris that could become airborne during severe weather events and cause damage to transmission lines. While wind-hardening measures are important, it is essential to consider the full range of potential hazards that can impact transmission lines during severe weather events and develop a comprehensive plan to address those hazards.

Transmission Line Structure Wind Failure Methods

Quanta Technology (2009) examines the economic feasibility of implementing utility infrastructure upgrades and storm-hardening programs. The report specifically focuses on the failure rate models for transmission tower infrastructure. The failure rate model discussed is based on historical data analysis and involves analyzing past failure incidents of transmission towers and using statistical methods to estimate the failure rates. The report provides details on the data collection process, data analysis techniques, and the resulting failure rate estimates. This information helps provide a better understanding of the historical performance of transmission tower infrastructure and can guide decision-making regarding maintenance and upgrades. It highlights the importance of understanding failure rates to make informed decisions regarding infrastructure upgrades and storm-hardening programs.

The two tower failure rate models from Quanta Technology (2009) were used by Watson and Etemadi (2020) and Bereta dos Reis et al. (2022). The models are for towers designed under the wind loading of 105 and 130 miles per hour (mph). The failure rate models are converted to failure probability and presented in Figure K-6. As expected, the towers designed for 130 mph wind loading are more resilient to wind gust intensity than the ones designed for 105 mph.

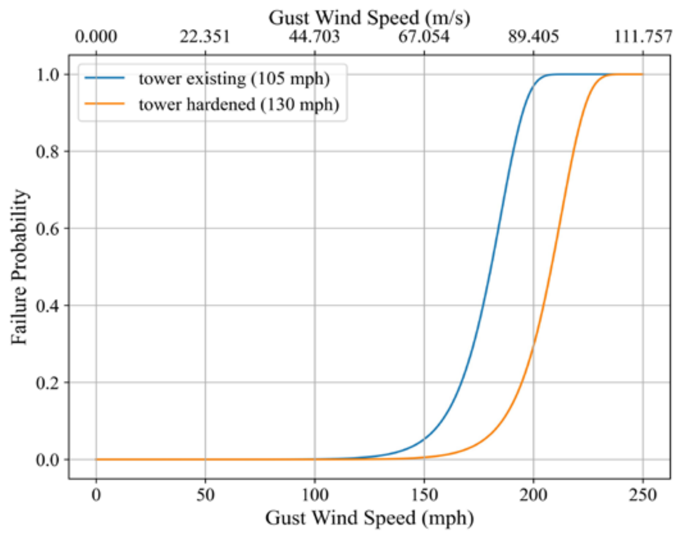


Figure K-6. The fragility curve for the towers designed for 105 and 130 mph wind loading. ***Figure by PNNL.***

Note: m/s = meters per second

Tower Fragility Depends on Wind Gust

Tower failure due to wind refers to instances where the structural integrity of the tower is compromised as a result of strong wind conditions, specifically wind gusts. In this context, a wind gust refers to a sudden, short-lived increase in wind speed over a brief period of time, typically lasting around 3 seconds. During a wind gust, the wind speed rapidly accelerates and can exert significant forces on the tower structure. These forces can cause bending, twisting, or even outright collapse of the tower if it is unable to withstand the applied loads. Wind gusts are often associated with turbulent atmospheric conditions, such as during severe storms or high-wind events. To assess the failure risk of towers to wind, it is important to consider the gust wind speed, which represents the maximum wind speed experienced during a gust event. The gust wind speed is typically measured and reported as a 3-second average value, providing a snapshot of the peak wind intensity.

The wind gust a tower structure is subjected to depends on the surrounding terrain characteristics. Cécé et al. (2021) focuses on modeling extreme wind gusts experienced during the landfall of Hurricane Irma in 2017 on small mountainous islands in the Lesser Antilles. Figure K-7 illustrates the computed wind gust speed-up factor (ratio of local wind speed to nearby areas) in complex terrain. Further information on calculating wind speed-ups in complex terrain is presented in Miller and Davenport (1998).

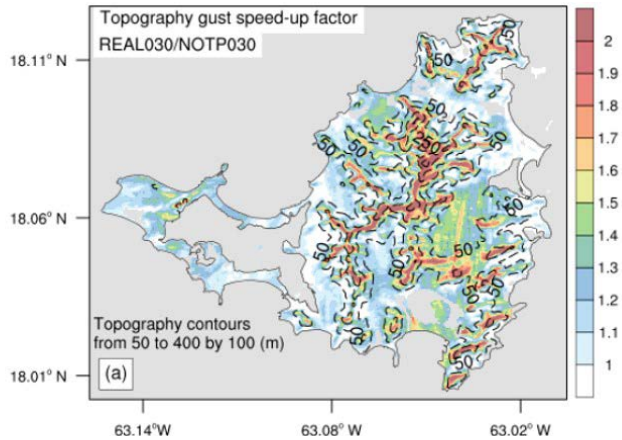


Figure K-7. Effects of Saint Martin Island terrain on the wind gust speed-up factor. ***Image from Cécé et al. (2021)***

Transmission Line Tower Population

The available GIS information for the Eastern Interconnection lacks tower-specific details but offers line path information. An average span based on the nominal voltage is estimated to compensate for this limitation. The average span from transmission line environmental impact reports is presented in Table K-1. However, it is essential to note that various factors, including tower height, terrain elevation, and crossings, influence tower spacing. This simplistic approach of using average span serves as a preliminary approximation, recognizing that a more comprehensive analysis is required to fully account for the impact of these multiple factors on tower spacing.

Wind Turbines

Wind generation in wind turbines can be estimated by considering the wind speed at the hub or rotor height. The available wind speed at 10 m/s ground level can be converted to the hub height speed as presented in Macdonald (2000) using the logarithmic wind profile equation (Eq. K-1), where z_0 is the roughness length, z_{ref} is the reference height, U_{ref} is the wind speed at z_{ref}, z is the new height, and $U(z)$ is the wind speed at height z.

$$U(z) = U_{ref} \frac{\ln(\frac{z}{z_0})}{\ln(\frac{z_{ref}}{z_0})} \qquad \text{(K-1)}$$

Typically, a 10-minute average wind speed is used for this purpose, as it provides a representative value for wind conditions during that time interval. The turbine-specific wind models consider the wind speed at the hub height, which is crucial for accurately predicting the power output of the wind turbine. When it comes to estimating wind plant generation, it has been observed that using turbine-specific wind models yields better approximations compared to equivalent wind plant models (Wan et al. 2010). This is because turbine-specific models account for the individual characteristics and performance of each turbine in the wind plant, resulting in more accurate predictions of the overall behavior.

The wind turbine classes, which vary in terms of their size and design, have a significant impact on several factors. These factors include the cut-in wind speed (v_{cutin}), rated wind speed (v_{rated}), and cut-off wind speed (v_{cutoff}), shown in Figure K-2. These parameters define the wind speed ranges at which the wind turbine starts generating power, operates at its maximum capacity, and stops generating power, respectively.

Modeling Assumptions

Hurricane Sandy was selected to demonstrate EGRASS' modeling setup for grid resilience evaluation. To model the wind field, data from the National Hurricane Center regarding the storm's intensity and track were used. These data are typically provided at 6-hour intervals and include information on the storm's center and wind speeds in available swaths.

Transmission Tower Data and Assumptions

The selected span is to be used in generating the synthetic GIS tower population on the transmission lines. The selected span based on the nominal voltages is presented in Table K-1, from available information in Table K-2. This table presents the span used for creating the synthetic towers. The nominal voltage ranges were used to classify the transmission lines to the nearest nominal voltage value available, or at and above 500-kilovolt nominal values. Using the selected transmission tower spacing, the in-land transmission lines affected by Hurricane Sandy 2012 wind swath of 64 knots were created and resulted in 25,556 towers. The synthetic towers were all assumed to have the same fragility curve of a tower design for 105-mph wind loading. Fragility curves can be calibrated using utility data, as presented in Bereta dos Reis et al. (2022). A simplification of gust speed-up factor of 1.287 was used so that all towers have the same terrain roughness of 0.05 meters as assumed by Quanta Technology (2009).

Table K-1. Selected Tower Span for Transmission Lines Based on the Nominal Voltage

Nominal Voltage (kilovolts [kV])	Selected Span (meters [m])
500 and Above	450
345 Range	365
230 Range	250
138 Range	205
69 Range	150

Table K-2. Available Span Information for Existing Transmission Line Projects

Nominal Voltage (kV)	Citation	Available Span (m)
765	Baker (2006)	450
500	ALTALINK (2006)	350–400
500	PT Perusahaan Listrik Negara (Persero) (2012)	450
345	Los Alamos (2000)	365.76
230	UNS Electric (2020)	213.36–274.32
138	Stantec (2017a)	180–210
138	Western Area Power Authority (2011)	182.88–213.36
138	Stantec (2015)	180–213
69	Cooperative Energy Environmental Affairs (2022)	213.36
69	Stantec (2017b)	100–200

Offshore Wind Generation Data and Assumptions

The specific information regarding every offshore wind turbine is not available. Table K-3 presents a summary of the wind turbine characteristics from Gaertner et al (2020). For all the considered offshore wind turbines, the values for v_{cutin}, v_{rated}, and v_{cutoff} were assumed to be 3.5, 11, and 25 m/s, respectively. The hub height was made by assigning the height from a uniform random sample having a lower bound of 119 m and an upper bound of 150 m. The assumptions considered include the wind turbine data presented in Table K-3. The studied East Coast Offshore wind capacity is 85 GW. Wind field modeling plays a pivotal role in evaluating the potential consequences of storms on offshore sites. In particular, the focus of this study was on towers that are situated at or above the specified wind speed cut-off threshold, denoted as v_{cutoff}. To assess the capacity available during storm events, we utilized the 30-knot wind swath data for Hurricane Sandy in 2012. By employing this dataset, we can accurately determined the time when the wind speeds surpassed the predefined threshold, allowing us to evaluate the available capacity during a storm event.

Table K-3. Parameters for the Technical University of Denmark 10-MW Turbine and International Energy Agency Wind 15-MW Turbine

	Technical University of Denmark (Lower Bound)	International Energy Agency (Upper Bound)
Hub Height (m)	119	150
$V_{cut\ in}$ (m/s)	4	3
V_{rated} (m/s)	11.4	10.59
$V_{cut\ off}$ (m/s)	25	25
Power Rating (MW)	10	15

Transmission Tower

Hurricane Sandy inland was expected to have a small impact on the tower's infrastructure given the intensity of the event. The procedure for evaluating the expected amount of tower damage includes first converting the wind speed at every tower to gust wind speed. Next, we must compute the probability of failure for all the affected towers; and third, evaluate the results. Figure K-8 illustrates the path of Hurricane Sandy and the tower structures affected by it. As presented in the legend, the color represents the intensity of the wind speed the towers are subjected to during the event. The wind speed does not include the wind gust gain. Table K-4 presents the number of expected tower failures for Hurricane Sandy. Given the small intensity of the event, a gain was given to the wind speed to consider what would have occurred if the event had been more intense. Please note the gain given directly on the towers' wind speed does not change the assumptions presented in Section 7.6. Thus, the swath remains unchanged in its dimensions. Stronger events would likely affect a larger area, with many areas needed to estimate tower damage. Hurricane events of varying intensities are anticipated to exhibit distinct footprints. For instance, hurricane-force winds can span distances ranging from 25 to 150 miles, whereas the reach of tropical-storm-force winds can extend up to 300 miles from the storm's center, especially for large hurricanes. However, assessing the wind gain above 1 solely based on the precise footprint of Hurricane Sandy is likely to result in an underestimation of the affected area and, consequently, the extent of damage.

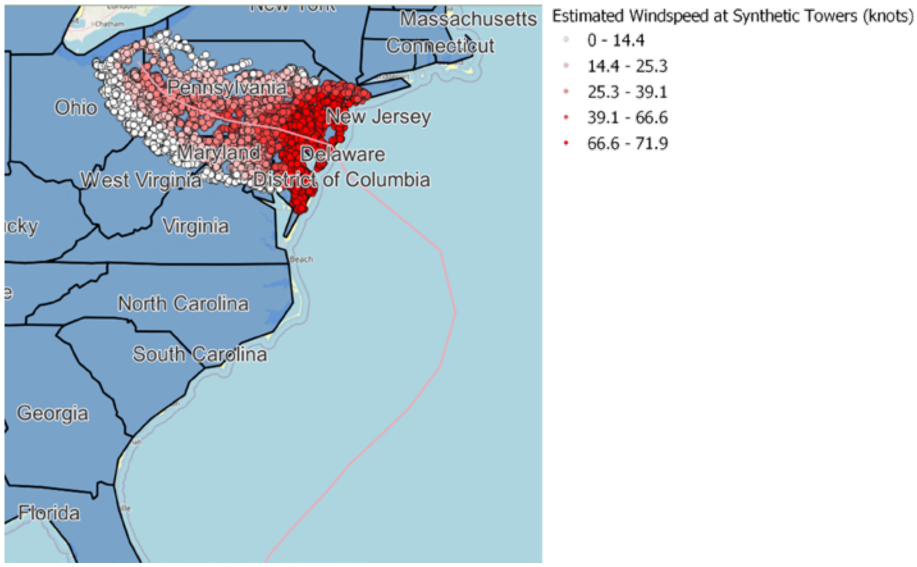


Figure K-8. Intensity of Hurricane Sandy 2012 on the power system transmission towers. ***Figure by PNNL***

Table K-4. Expected Number of Tower Failures for Hurricane Sandy 2012

Wind Gain	Expected Number of Tower Failures	Maximum Wind Gust (mph)	Hurricane Category
1.0	7.44	106.5	1
1.2	39.13	127.8	2
1.4	205.25	149.1	3
1.6	1033.34	170.4	4

Offshore Wind Generation

Hurricane Sandy 2012 had an expected small impact on transmission towers as presented in Section 7.6. The offshore wind turbine wind speed of interest is the cut-off wind speed, which is lower than the wind speed for tower wind damage. Figure K-9 presents the location of the offshore wind turbines on the East Coast affected by the event. As shown, the impacted area for a lower swath is much larger than the one considered for the tower damage.

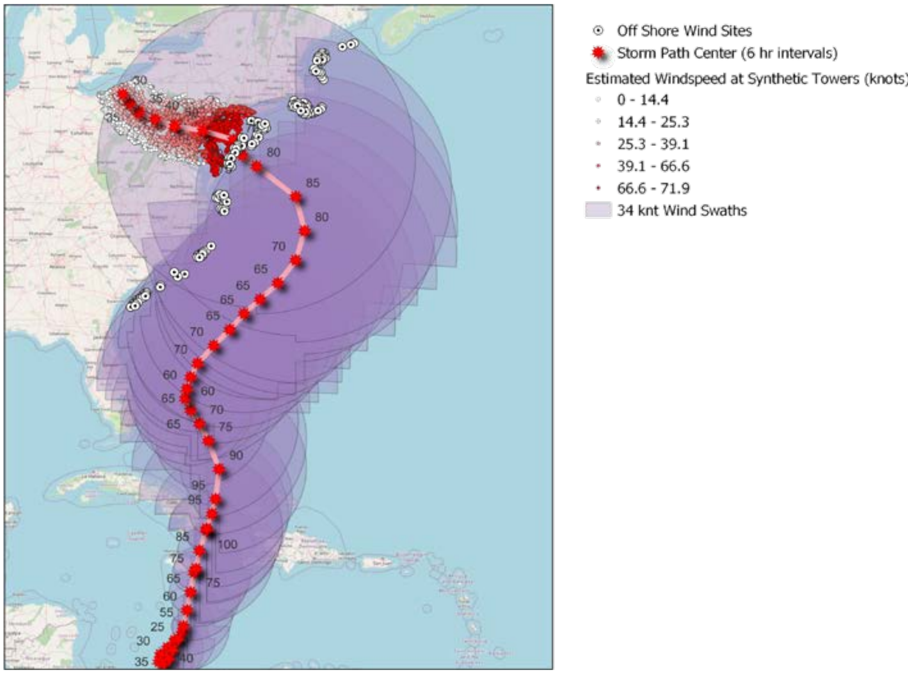


Figure K-9. Intensity of Hurricane Sandy 2012 on the power system transmission towers and offshore wind turbines. ***Figure by PNNL***

The procedure for evaluating the impact on offshore wind turbines is (1)converting the wind speed at every offshore wind turbine to wind speed at the hub height, (2) evaluating the wind speed in relation to the cut-off wind speed, and (3) evaluating the results.

The offshore wind turbine population within the hurricane swath has hub-height wind speeds above the cut-off wind speed, with a total impact capacity of 85 gigawatts (GW). However, the capacity loss does not occur simultaneously.

Figure K-10 expands on the duration and distribution of the start and end hour. It considers the start reference hour as “2012-10-26 18:00:00” and the end hour as “2012-10-30 00:00:00” (i.e., start hour + 78 hours). Most of the offshore wind turbines affected have the same end hour. The duration and start hour at or above the cut-off wind speed have a significant range. The mean duration at or above the cut-off wind speed is around 20 hours. The mean start hour at or above cut-off wind speed is around hour 60.

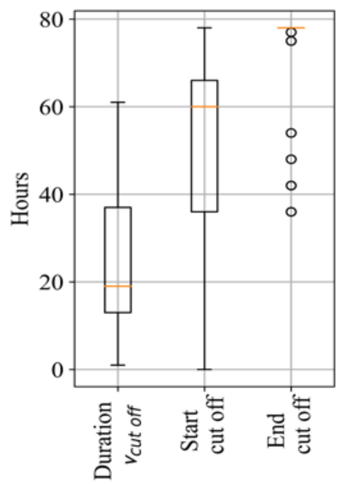


Figure K-10. Duration and distribution of start and end hours of the affected wind turbine by Hurricane Sandy 2012. ***Figure by PNNL***

Mapping the Offshore Wind Plants to Power Flow

For the dynamic analysis of such a system in a hurricane event, it is crucial to identify the wind turbine outages, along with the outages of other onshore assets. This identification requires establishing a mapping between the available geographical locations of the offshore wind turbines, their onshore POI, and the available power flow case information. This process is important because often, the offshore wind transmission is not modeled in the power flow data, and the wind turbines are directly modeled as a lumped unit on their respective POI bus representation in power flow.

Quasi-Steady State Simulation and Results

In this study, a demonstration study was conducted using quasi-steady state simulations, leveraging EGRASS' hurricane contingency, to evaluate the system performance. This section presents an illustrative sample result of the ISO-NE system derived from the Atlantic Offshore Wind Transmission Study 2050 summer planning case. The criteria of violation considered in this study include the following:

- Voltage limit (nominal voltage >= 230 kV)
- Overload limits: 100% of rate B
- The base case violations are not considered
- The operational actions for maintaining the system integrity have been considered.

The simulated hurricane unfolded in three steps, as depicted in Section 7.6, leading to a cumulative loss of 11 offshore wind generators totaling 6.5 GW. The anticipated time span between each time step of the analysis is approximately 5–6 hours. Figure K-11 shows the system branch loading under the normal condition before the hurricane approaches the study area.

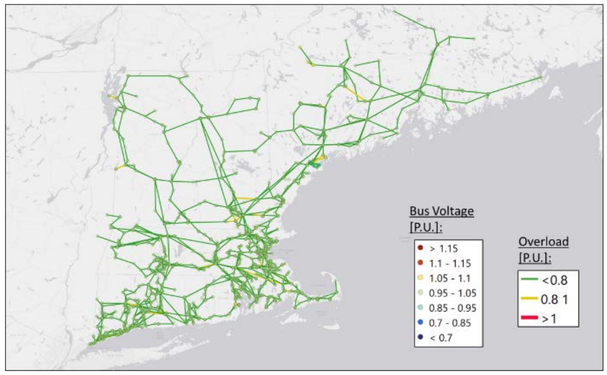


Figure K-11. 2050 summer ISO-NE AC power flow base case map. ***Image by PNNL***

The loss of offshore wind generators during the first step of hurricane leads to several overloads due to the pseudo automatic governor control response and the generation redispatch. The outcomes are shown in Figure K-12.

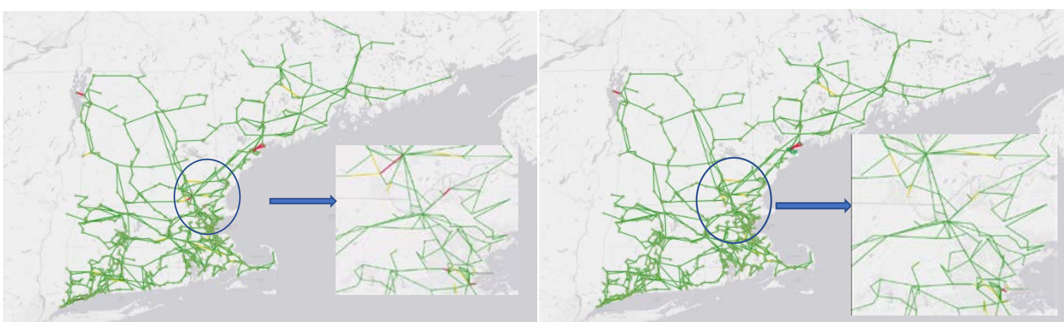


Figure K-12. (Left) hurricane step 1 result – the beginning of one generator outage; (right) system flow at the end of hurricane step 1 with a loss of seven generators. ***Image from PNNL***

The available generations from central and northeast ISO-NE are transmitted to the southern shoreline in Connecticut to compensate the loss of power generation. With operator actions, some overload issues can be resolved during redispatch, which ensures the system can meet the convergency at the end of hurricane step 1. During step 1, a total of 3.5 GW offshore wind electricity generation is lost.

Likewise, Figure K-13 illustrates the system branch loading following nine generator outages and with a cumulative loss of 5.2 GW of offshore wind generation in step 2, and provides insight into the system status after experiencing 11 generator outages and a loss of 6.5 GW of offshore wind generation after step 3.

The result of cumulative generation loss for this simulation is based on a specific assumption (i.e., if a generator is lost during any hurricane step, it remains offline, and no recovery mechanism is considered in this study). Despite those unfavorable assumptions, the system remains intact in this demonstration study.

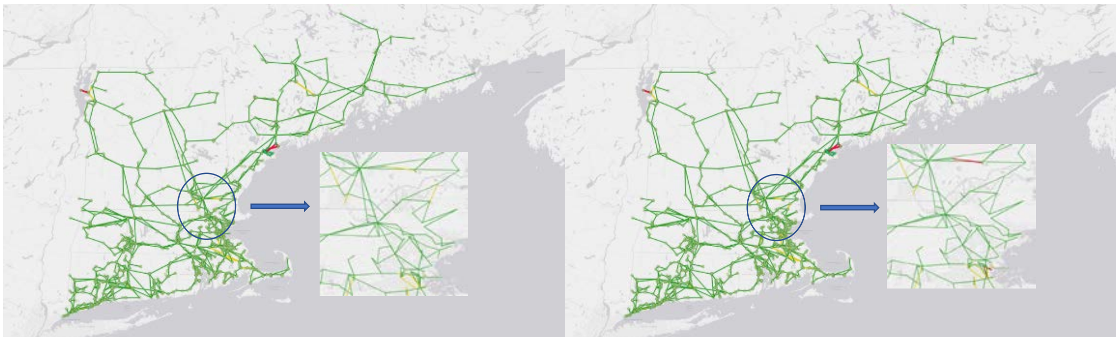


Figure K-13. Hurricane Step 2 result – after loss of 9 generators (left). Hurricane Step 3 result – after loss of 11 generators (right). ***Image by PNNL***

This alternating current hurricane quasi-steady state study demonstrates the process of identifying offshore wind plant contingencies in the EGRASS hurricane extreme weather event and assessing their impact based on Hurricane Sandy simulation. EGRASS' visual aids offer insights into how hurricanes affect systems integrated with offshore wind energy and help provide an understanding of the dispatch and system flow condition, potentially enhancing transmission capacity expansion for the future system.

Dynamic Simulation and Results

In this work, Monte-Carlo-sampled hurricane scenarios in a contingency file format were prepared by EGRASS that feed into DCAT for hurricane dynamic simulation. DCAT identifies the contingency events, simulation duration, and steps from the input contingency files and executes dynamic simulation by the contingency files accordingly. DCAT runs the transient stability simulation to observe the system's response to hurricane contingencies and monitor key variables such as synchronous generator shaft/synchronous speeds. During the simulation, DCAT determines appropriate control actions to mitigate the effects of contingencies and optimize the operations by simulating the response of various control schemes, such as tripping events.

After the DCAT analysis is complete, the results are pushed to a database server, including branch data, bus data, generator data, load data, status data, combined contingency records, corrective action information, and control action data. Meanwhile, the results are available for review by an executable DCAT visualization tool.

DCAT Results for Monte Carlo Simulation

Dynamic simulation offers a comprehensive analysis that provides insights into the transient behavior of generators and system responses, in contrast to quasi- or steady-state simulations. This section discusses more details about DCAT capabilities by presenting the Monte-Carlo-sampled contingency set, including system stability assessment, control actions, transient response evaluation, and special protection scheme. The dynamic models employed in this study have been tailored for the short-term future system. Hence, the results presented next are derived from simulations based on 2030 power flow cases.

Identifying the contingencies

DCAT runs the Hurricane Sandy Monte Carlo contingencies in compliant with a specified contingency file format that was translated from hurricane data using EGRASS. The contingency set Hurricane Sandy Monte Carlo-2 comprises two distinct hurricane steps, as outlined in Table K-5.

Table K-5. Monte-Carlo-Sampled Hurricane Sandy Contingency Input for Dynamic Contingency Analysis

Hurricane Step	Event Start Time (seconds)	State	Area
1	0	New Jersey	Jersey City Power and Light
1	5	New Jersey	Jersey City Power and Light
1	13	New Jersey	Jersey City Power and Light
2	29	New Jersey	Jersey City Power and Light
2	34	Maryland	Delmarva Power and Light

The hurricane step 1 contingency file involves three instances of branch tripping events, signifying the progression of the hurricane across the Jersey City Power and Light region within the initial 30 seconds. In step 2, the hurricane tripping events spread to the Delmarva Power and Light region. Based on the probability of transmission failure, this Hurricane Sandy Monte-Carlo simulation infers that three of the line tripping events were taken on the hurricane path. There are four impacted transmission lines from New Jersey, one of the East Coast states that was the most heavily affected by Hurricane Sandy, and one impacted line in Maryland.

System Stability Assessment and Control Actions

The DCAT performs the transient stability simulation to observe the system's response to the given hurricane contingencies and monitor key variables such as synchronous generator shaft/ synchronous speeds.

The Hurricane Sandy Monte Carlo simulation that EGRASS prepared contains two hurricane stages and a total of five branch-tripping events in 58 seconds. DCAT evaluates the hurricane scenario by including the maximum rotor speed deviation (i.e., if the system stands over the contingencies, reaches a steady state, and remains within acceptable limits, the system can be considered stable). To differentiate between the major impacts and the normal or lightly affected elements, principal component analysis (PCA) is adopted for data processing. The PCA results are illustrated in Figure K-14. This capability aids in identifying genuine stability issues and presenting realistic dynamic simulation outcomes.

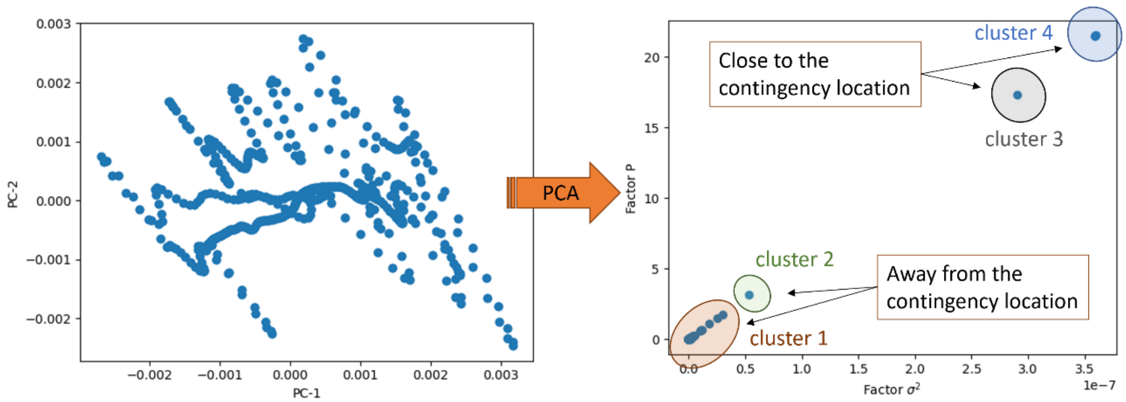
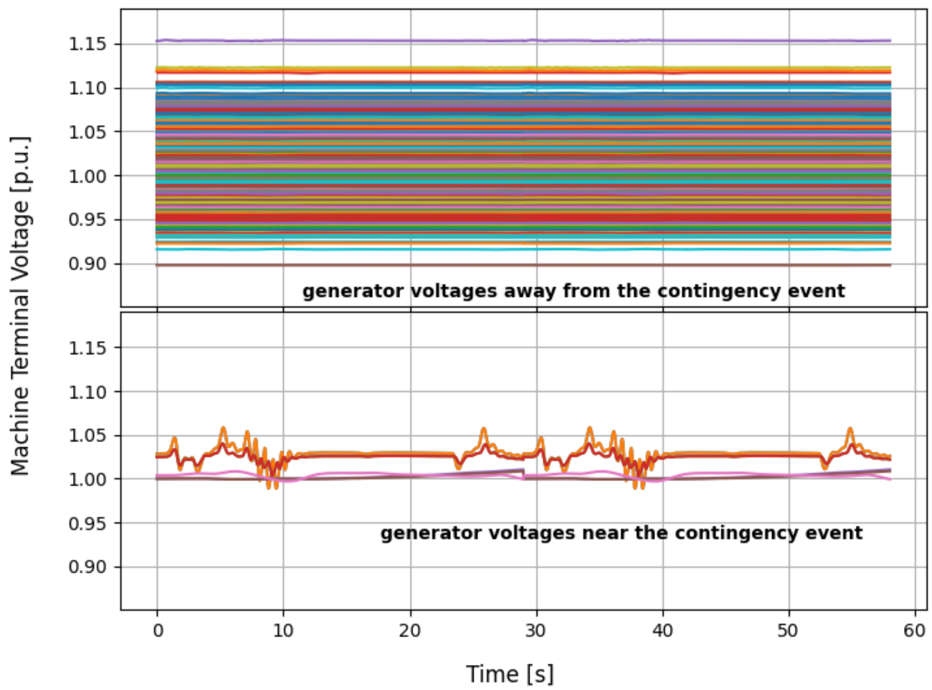


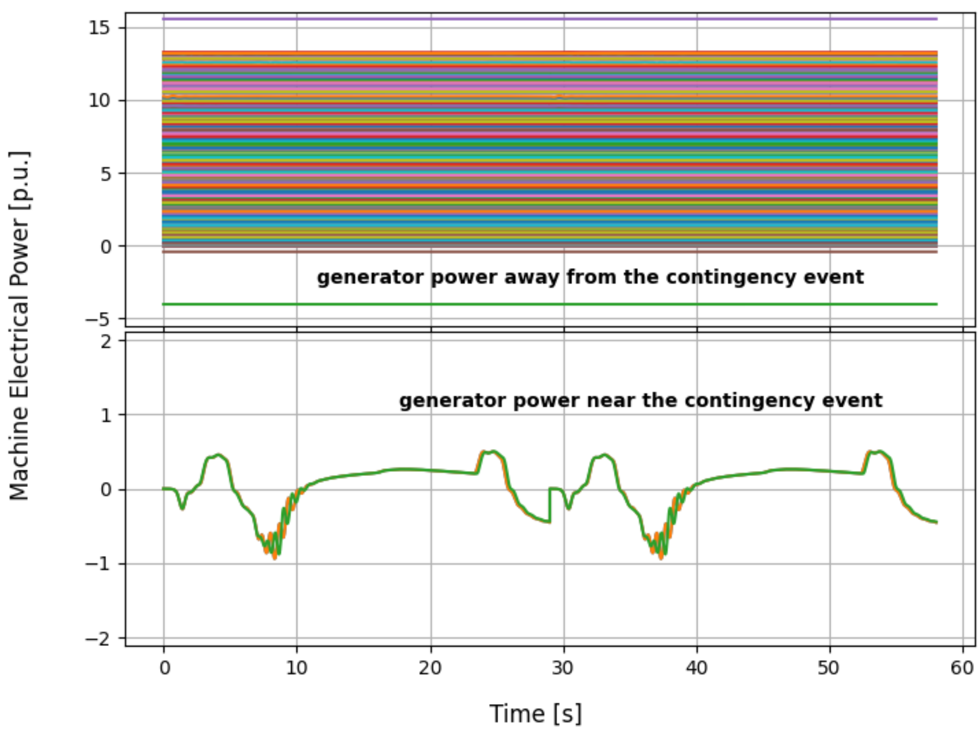
Figure K-14. Applied PCA to obtain the principal spatial-temporal features of the system responses during the contingency. ***Figure by PNNL***

In the simulations, the Eastern Interconnection under the two-stage hurricane contingency scenario reached a steady state approximately 60 seconds following the occurrence of the second hurricane-induced cascading branch tripping event.

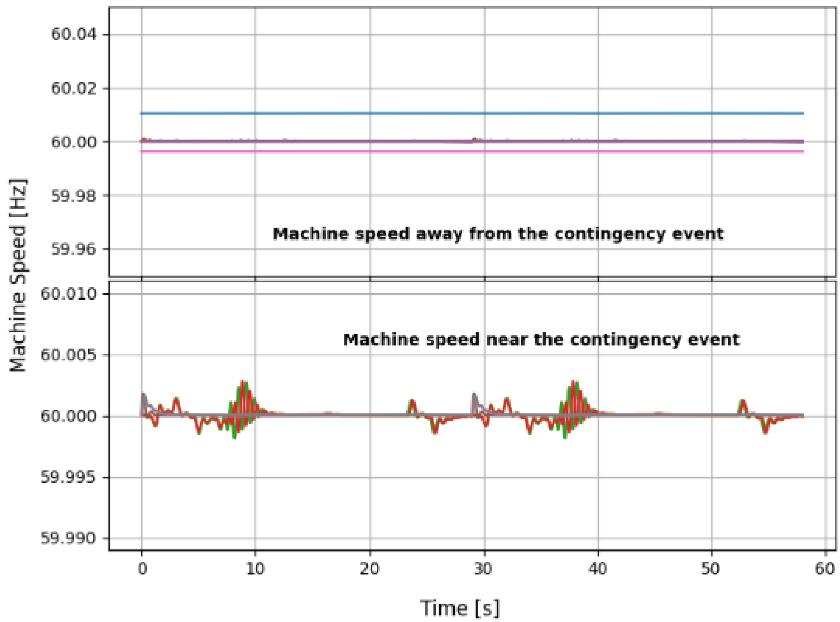
The system response regarding the Hurricane Sandy Monte Carlo simulation is shown in Figure K-15.



(a) Machine Terminal Voltage



(b) Machine Electrical Power



(c) Machine Speed Deviation

Figure K-15. The system responses under hurricane Monte Carlo simulation, with PCA identifying significantly impacted machines out of 10,000 generators. ***Image by PNNL*****.**

Note: p.u. = per unit; Hz = hertz

The maximum generator speed deviation was 0.00041 p.u. at the end of hurricane step 1. Ten synchronous generators out of 10,000 were slightly affected. At the end of hurricane step 2, the maximum generator deviation of the system was 0.002188 p.u. The generator speed deviations are shown in Figure K-16.

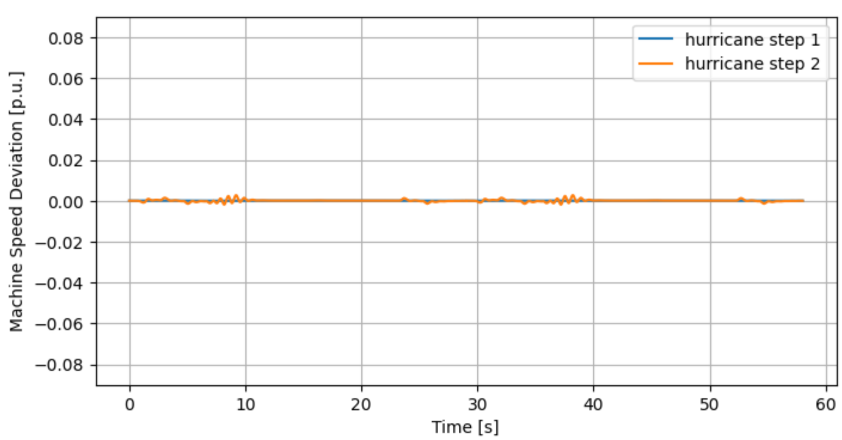


Figure K-16. The maximum machine speed deviations during the hurricane step 1 and step 2. ***Image by PNNL***

Note: While the system reached a stable state for the specific example, no definitive conclusion should be derived from this demonstration.

Appendix L. Offshore Wind Integration Tool

Obtaining a converged alternating current power flow case that accommodates the desired amount of offshore wind generation appropriately is essential for offshore wind reliability planning studies. The Offshore Wind Integration Tool (OSWIT) incorporates various advanced techniques and functionalities that are designed to interconnect offshore wind and set up reliability studies. The tool also helps identify the locations of the alternate nearby substation that are electrically more appealing for offshore wind energy injections. Figure L-1 provides an overview of OSWIT.

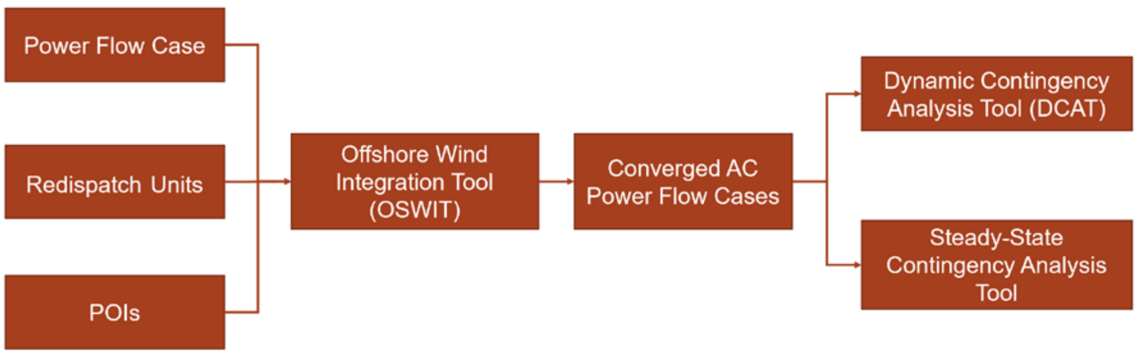


Figure L-1. A flow diagram of the Offshore Wind Integration Tool (OSWIT). ***Figure by PNNL.***

Note: POIs = points of interconnection; AC = alternating current

Base Case Preparation

The base case preparation algorithm is an iterative approach that incrementally increases the offshore wind injections at the points of interconnection (POIs) while simultaneously decreasing the same amount of offshore wind injection from the generators that are to be redispatched. However, it is important to select the redispatched generators appropriately. The redispatched units are the units in which scheduled generation is reduced as the offshore wind generation injection increases, such that the total load and generation in the system is balanced appropriately.

The overall methodology for base case preparation: once the redispatch generators are identified then the base case preparation for offshore wind generation injection can be initialized. Figure L-2 presents the iterative approach used to obtain the converged ACPF case with offshore wind injections at the desired POIs. As shown in the figure, the megawatts at the offshore POIs are incremented using a constant step and the redispatch generation units' scheduled generation is adjusted to accommodate (reduce the real power set points) the additional offshore wind generation injections. After redispatching the units, the ACPF is solved and a check is performed for total offshore megawatt target. If the total target is reached, then the process exits; otherwise, the process of redispatching units by incrementing the offshore wind injections POIs continues.

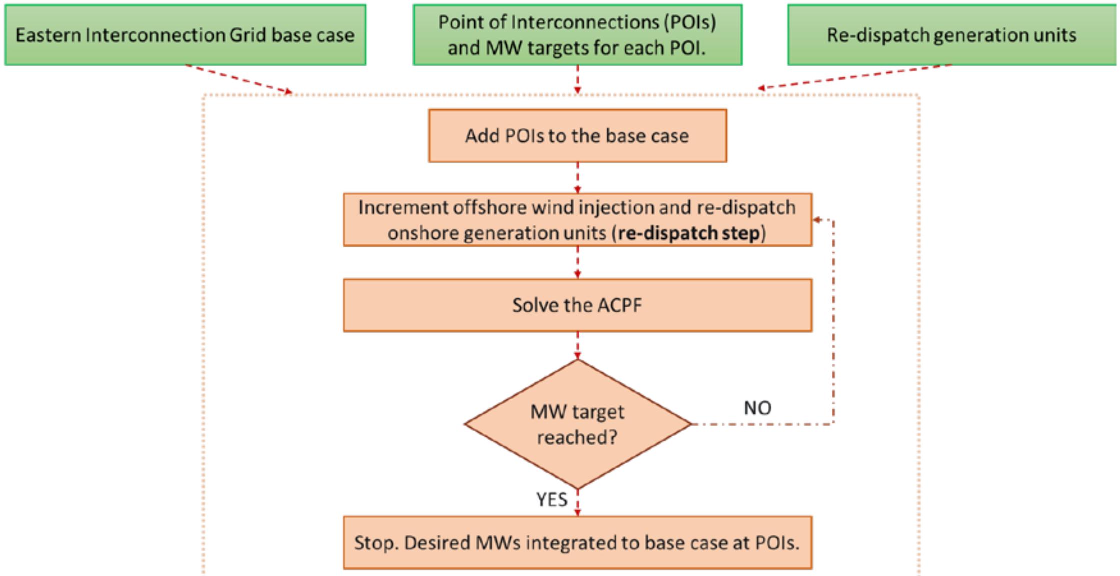


Figure L-2. The flow of the overall methodology of base case preparation with offshore wind injections at POIs. ***Figure by PNNL***

As shown in Figure L-3, the redispatch step is executed for every increment in the offshore megawatt value during the base case preparation process. This process allows for the generation and load ratio to remain the same as the original base case. This step takes the information of redispatch units and target megawatts that need to be redispatched. If the initial redispatch of the units does not result in their minimum capacity violation, then the process exits. Otherwise, the units whose minimum capacity are violated are set to their minimum capacity limit and the excess megawatts are redispatched with the other units whose minimum capacity are not violated until the target megawatts are re-dispatched successfully.

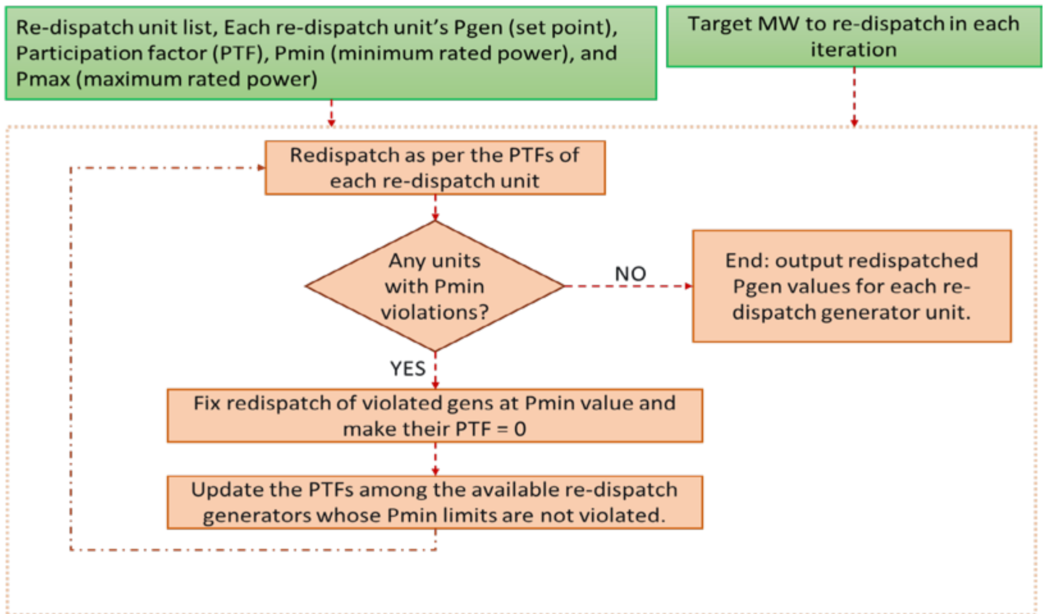


Figure L-3. Flow chart for the redispatch step that reduces the onshore generation unit's set points and increases the offshore POIs set points. ***Figure by PNNL***

Points of Interconnection Selection for Offshore Wind Generation

The methodology for determining better points of interconnection is presented in Figure L-4.

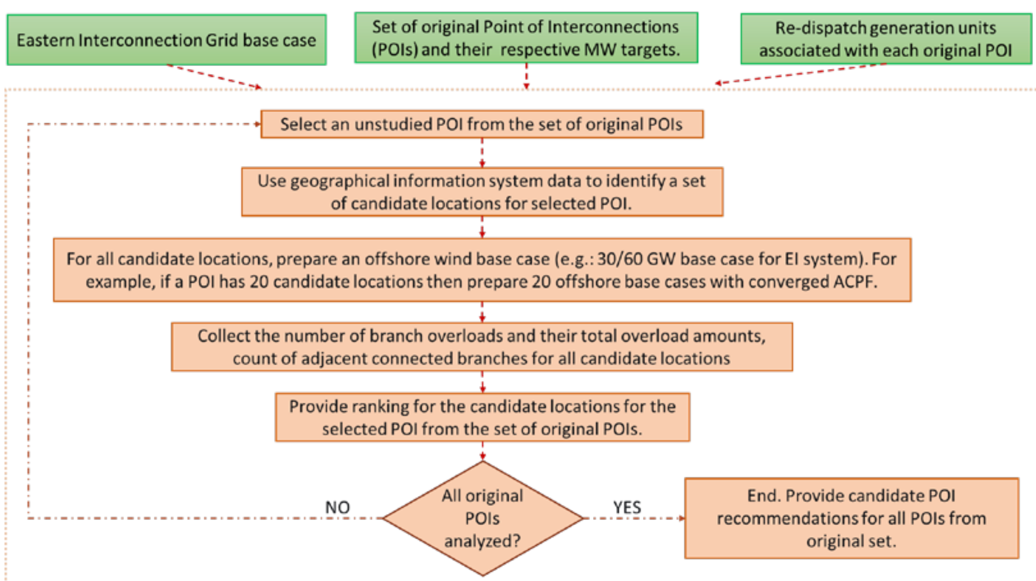


Figure L-4. Methodology for determining better points of interconnection. ***Figure by PNNL***

This process involves the following steps:

1. Select one POI from the original POI locations. The objective is to rank the candidate locations/POIs that could be a replacement for the selected original POI.

2. Use the geographical information system to identify the set of candidate locations that are within a certain distance from the selected original POI.
3. After obtaining the base case with ACPF convergence that accommodates the offshore wind generation, information such as transmission line overloads (at different kilovolt levels), the amount of overload amount for overloaded branches, and count of adjacent branches connected to the candidate POI location are extracted. The count of adjacent branches is one such parameter that can also help identify connectivity of selected candidate POI with the rest of the area in the power grid.
4. After extracting the desired information from the previous step for all candidate POI locations, they are ranked as follows:
   - The ranking of the candidate POI locations is primarily made by comparing the total count of overloads in the system for different candidate POI locations. This is shown in Figure L-5 and it can be observed that Wakefield has fewer overloaded branches than the original POI K Street. Figure L-6 presents the ranking of the candidate POIs. This entire process is repeated to rank all candidates for each one of the POIs from the original set initially identified by the independent system operators.
   - If all candidate POI locations have the same number of overloads, then the next step involves comparing the total overloaded amount and the electrical connectivity of the candidate POIs with its neighbors.

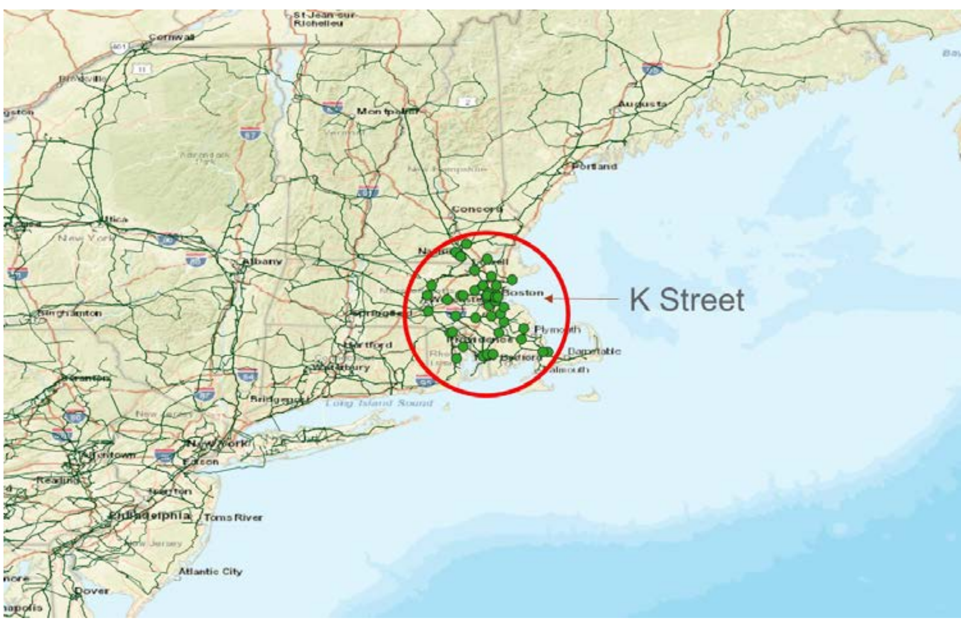


Figure L-5. Identification of candidate locations based on specific distance from the selected original POI location (K Street). ***Figure by PNNL***

Figure L-6. Location of K Street and other candidate POI locations (Wakefield and Woburn). *Figure by PNNL*

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Atlantic Offshore Wind Transmission Study

DOE/GO-102024-6116 · March 2024

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