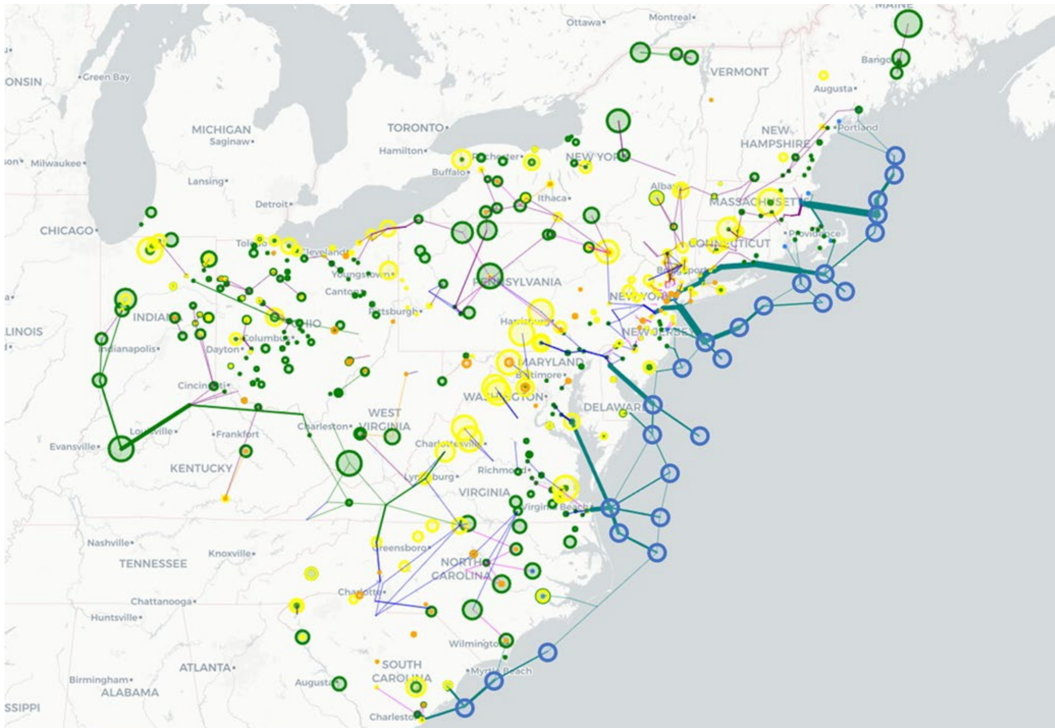

Offshore Wind Transmission Expansion Planning for the U.S. Atlantic Coast

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OffShore Power Research & Education Collaborative

Offshore Wind Transmission Expansion Planning for the U.S. Atlantic Coast

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Preface, Acknowledgements, and Disclaimer

This report, developed during the spring of 2025, concludes our team's efforts over the past six years to prototype a system of models, methods, and processes that can be used for what we call "responsive analysis" for offshore wind transmission expansion planning. Anecdotally, our experience has been that when questions are posed about the power system, it can take months and even years to commission a study, which is eventually reported out in a static document, preventing further iterations from proceeding based on new questions that may arise as a result of the analysis and/or changing conditions in the real world. The suite of models and results presented herein introduce less stringent, but still sufficiently accurate, methods for resource planning that we hope can facilitate practical discussions between planners and decision makers by making analysis results readily available in response to questions across all scales from a single substation to multiple regions.

The development of these models was funded under the National Offshore Wind Research and Development Consortium (NOWRDC) Grant #110: *Transmission Expansion Planning Models for Offshore Wind Energy*, as well as supplemental funds provided by the Massachusetts Clean Energy Center (MassCEC). We gratefully acknowledge the support of NOWRDC and MassCEC in the development of this present work, and we specifically acknowledge Mel Schultz at NOWRDC and Nils Bolgen at MassCEC, whose professionalism, collegiality, and support made the success of this work possible. We developed this project during the same timeframe as the U.S. Department of Energy's (DOE) Atlantic Offshore Wind Transmission Study executed by NREL and PNNL and published in 2024.[1] As our work progressed, we met monthly with our colleagues at NREL and we are grateful to NREL, PNNL, and the DOE for their engagement. While this study is not formally connected to the DOE study, the two studies were conceived and advanced as complementary to one another. We would like to acknowledge the role that Fara Courtney played early in the Tufts Offshore Wind Program, encouraging Eric in particular to pay closer attention to transmission. The views and results expressed in this report are our own and do not represent viewpoints or positions of NOWRDC, MassCEC, DOE, NREL, PNNL, or our reviewers, whom we acknowledge on the following page.

Eric Hines and Barbara Kates-Garnick
Tufts University, May 2025

James McCalley
Iowa State University, May 2025

[1] NREL. 2024. Atlantic Offshore Wind Transmission Study. March. www.nrel.gov/wind/atlantic-offshore-wind-transmission-study.html Accessed on January 11, 2025.

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Abstract

Results from a suite of models, methods, and processes developed for offshore wind (OSW) transmission planning on the U.S. Atlantic Coast identify necessary offshore and onshore transmission investments to accommodate OSW capacity levels ranging from 0 to 600 gigawatts (GW). For each capacity level, an integrated offshore/onshore grid design is developed that includes Points of Interconnection (POIs) and onshore transmission expansions. As onshore resources such as wind and solar become more constrained, more OSW becomes necessary to balance the system. At 250 GW of OSW, prevailing power flows to coastal load centers are found to experience a large-scale reversal from western onshore resources to eastern offshore resources, resulting in a case that minimizes the need for onshore transmission expansions.

Executive Summary

Results from a suite of models, methods, and processes developed for offshore wind (OSW) transmission planning on the U.S. Atlantic Coast identify necessary offshore and onshore transmission investments to accommodate OSW capacity levels ranging from 0 to 600 gigawatts (GW). For each capacity level, an integrated offshore/onshore grid design is developed that includes Points of Interconnection (POIs) and onshore transmission expansions. As onshore resources such as wind and solar become more constrained, more OSW becomes necessary to balance the system. At 250 GW of OSW, prevailing power flows to coastal load centers are found to experience a large-scale reversal from western onshore resources to eastern offshore resources, resulting in a case that minimizes the need for onshore transmission expansions.

Key Objectives

- Identify necessary offshore and onshore transmission investments to accommodate offshore wind (OSW) capacity levels ranging from 0 to 600 gigawatts (GW) in U.S. Atlantic Coast waters by 2051.
- Develop an integrated offshore/onshore grid design, including Points of Interconnection (POIs) and onshore transmission expansions.
- Evaluate economic, technical, and environmental trade-offs in integrating large-scale offshore wind into the U.S. power grid.
- Assess the potential for multiregional, high-capacity transmission backbones that together form a Macrogrid,[2] and explore the role that OSW growth could play in the development of this Macrogrid.

Methodology

Recognizing the need to work simultaneously at vastly different scales that range from a single point of interconnection (POI)[3] to the entire United States, the study leverages three primary models which together create a framework for RA:

1. Model 1 is a commercial grade 90,059-bus model that can be used to evaluate the cost of expanding the grid at specific POI locations under N-1 contingency conditions for a single case—Summer Peak 2031.

[2] A Macrogrid can be understood as an electricity transmission superhighway that quickly and efficiently transmits electricity between regions. A basic U.S. Macrogrid might consist of three N-S and three E-W interlinked high capacity power HVDC power corridors that can transmit approximately 30 GW. See Appendix C. See also McCalley, J. and Zhang, Q. 2020. Macro Grids in the Mainstream: An International Survey of Plans and Progress. Sponsored by Americans for a Clean Energy Grid as part of the Macro Grid Initiative. November 18. https://cleanenergygrid.org/macro-grids-mainstream/. Accessed on February 17, 2025.

[3] A point of interconnection (POI) is an onshore substation into which an offshore grid delivers power.

2. Model 2 is an 843-bus model that uses a Coordinated Expansion Planning (CEP) optimizer, without consideration of N-1 contingency analysis, to simulate investment decisions and transmission expansions considering four seasons with four time-blocks each plus summer peak over a range of years from 2031 to 2051.
3. Model 3 is an approximately 169-bus model that assesses the economic benefits of a national Macrogrid for connecting an Atlantic offshore wind transmission backbone with the broader U.S. grid.

This report focuses primarily on Model 2 and its results, but it includes discussions of Model 1 (described in Appendix B) and Model 3 (described in Appendix C) where appropriate either to independently validate Model 2 or to provide more detail and perspective on Model 2 results.

Findings and Key Insights[4]

1. Transmission Planning for Offshore Wind Growth[5]
    - OSW expansion will require a mix of offshore multi-terminal high-voltage direct current (MT-HVDC) transmission lines, onshore grid reinforcements, POI expansions, and coastal landing points or "beachheads."
    - At under 100 GW OSW, five disconnected offshore grid subregions emerge, requiring separate transmission investments. See Figure 3-1.
    - At 200-600 GW OSW, interconnections strengthen between these subregions even without N-1 constraints. These subregions eventually form a continuous offshore transmission corridor from Maine to the Carolinas. See Figure 3-1.
    - The 250 GW OSW level is identified as an optimal point where onshore transmission investment is minimized because the power flows become "balanced" with OSW effectively serving East Coast load centers. See Figure 3-2 and Figure 3-3.
2. POI Selection and Offshore Grid Design
    - The study identifies 14 major POIs whose capacities would need to exceed 2 GW, and 36 reasonable candidate POIs, with major hubs in ISONE, NYISO, PJM, and Duke Energy territories. See Table 3-3 and Figure 3-8.[6]

[4] These findings are restricted to and qualified by the models discussed herein. They do not include N-1, N-1-1, or N-2 contingency evaluations.

[5] For a European perspective on this subject, refer to Entsoe. 2025. Offshore Network Development Plans. https://www.entsoe.eu/outlooks/offshore-hub/tyndp-ondp/. Accessed on May 6, 2025. Within these plans, Multi-terminal HVDC solutions make more sense and become more affordable with OSW build-outs in the 100s of GW. The projection for Europe is 496 GW of offshore renewable generation capacity by 2050.

[6] POI siting constraints were not a major consideration in this power-systems-based analysis. In this project, the authors focused on the electric power system as an entity unto itself, with the goal of identifying and understanding emergent behaviors of this system. The authors acknowledge that permitting and siting are absolutely critical to building out the real world power system, and accept these considerations as critical to future work on this subject.

- The Deans (PJM), Salem (PJM), Landstown (PJM), and Calvert Cliffs (PJM) substations are among the most attractive POIs, forming 10+ GW points of entry into the PJM 500 kV network for OSW build-outs of 250-600 GW. See Table F-3 to Table F-7.
- The need for remedial action schemes (RAS) or improved fault protection is highlighted for handling high-capacity (> 2,000 MW) injections at select POIs.[7]

3. Generation Portfolio and CO_2 Reduction Goals
   - Together with onshore wind and solar, OSW replaces fossil-fuel generation, ensuring compliance with 90% CO_2 reduction by 2051.
   - The study confirms that OSW is a necessary and affordable means of achieving deep decarbonization on the U.S. Atlantic Coast. This is consistent with the results of the DOE's Atlantic Offshore Wind Transmission Study (AOSWTS).[8] With winter and spring seasonal capacity factors in excess of 50% and close proximity to coastal load centers, recommended OSW generation capacities of range from 186 to 384 GW depending on onshore development constraints. See Figure 3-7.
   - Higher OSW levels reduce the demand for onshore wind while demands for solar power remain relatively consistent. Onshore wind declines more than solar at higher OSW levels as offshore wind has higher capacity factors and closer proximity to load centers. See Figure 3-5 and Figure 3-6.
4. Macrogrid and Offshore Wind Synergies. (See Appendix C)
   - A national HVDC Macrogrid can enable Atlantic OSW integration as a critical factor in the national energy mix, enabling high-capacity energy transfer and reducing reliance on localized generation.[9]
   - Without a Macrogrid, higher OSW levels require costly onshore grid reinforcements to transfer the offshore wind energy further inland.
   - Macrogrid investments can pay for themselves by displacing over $80B of storage and fuel costs and further reducing onshore AC grid reinforcements by more than $80B for

[7] Members of the review panel or this report brought up questions on how different regions treat extreme contingencies, and the fact that RAS are not popular with many Eastern RTOs such as ISO-NE. This discussion is beyond the scope of this report, but the authors agree that the discussion of RAS within the Eastern interconnect (EIC) will require discussions across regions from the RTOs in the East, to the Midwest, to the West, where RAS are more common and have been successfully deployed.

[8] US DOE. 2024. Atlantic Offshore Wind Transmission Study. DOE/GO-102024-6116. March. https://www.nrel.gov/docs/fy24osti/88003.pdf. Accessed on May 6, 2025.

[9] The HVDC Macrogrid as imagined here, while more than an order of magnitude larger than the "Roadmaps" currently contemplated by ISO-NE in its 2050 transmission study, is consistent with current thinking in ISO-NE regarding the potential for near-term build-outs of point-to-point offshore HVDC lines to address "North-South/Boston Import" challenges. See "Section 4: Roadmaps and Representative Transmission Solutions" in ISO-NE. 2024. 2050 Transmission Study. February 12. https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf. Accessed on May 6, 2025.

OSW build-outs in excess of 250 GW. The development of such infrastructure must be grounded in joint benefit and joint cost allocation principles that acknowledge state authority.

Conclusions and Policy Implications

- 250 GW OSW is a key investment threshold, balancing land-based AC transmission expansion costs and OSW benefits. See Figure 3-2 and Figure 3-3.
- Offshore wind growth will require strong regulatory coordination, particularly in transmission planning and permitting. Historical examples, such as the Northwest-Southwest Intertie project of 1964, which advanced a basic design to bring stakeholders to the table and provide a basis for further discussion, could be helpful in informing a path forward on these fronts.[10]
- The offshore grid (OSG) could become the stimulus for developing a world-leading multi-terminal HVDC (MT-HVDC) supply chain in the U.S. and first leg of a future U.S. Macrogrid.
- A Macrogrid is a cost-effective complement to OSW, reducing the need for onshore AC transmission upgrades and local storage, as well as safeguarding against regional weather phenomena and fossil fuel price volatility.
- Future research should refine offshore grid protection strategies, through N-1 analysis and remedial action schemes (RAS), and explore further integration of energy storage solutions.

This study provides a roadmap for meeting the projected growth of electricity demands on the Atlantic Coast for approximately 20% of total U.S. electricity load. Offshore wind offers reliable and secure domestic energy that can be locally sourced and delivered directly to coastal load centers with cost-effective upgrades to the existing electricity grid. These upgrades have the potential to leverage the reversal of today's prevailing West-to-East power flows, provided that states and regions can work together to address the system as a cohesive whole rather than a fractured collection of individual projects.

[10] Refer to the thesis of Joshua Binus. 2008. Bonneville Power Administration and the Creation of the Pacific Intertie, 1958-1964. Dissertations and Theses. Portland State University. Paper 1724. https://doi.org/10.15760/etd.1723. https://pdxscholar.library.pdx.edu/open_access_etds/1724/. Accessed on May 6, 2025.

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1 Introduction

Legislation enacted by multiple states along the Atlantic Coast since 2016[11] demonstrates that offshore wind (OSW) is a renewable energy resource of choice for this region of the United States. As a result, there have been many studies to assess the potential for and impact of large-scale Atlantic Coast OSW resources, but few have considered levels beyond 100 GW. For example, the U.S. Department of Energy's March 2024 Atlantic Offshore Wind Transmission Study (AOSWTS) considered 30 GW in 2030 and 85 GW in 2050.[12] In this study, we have intentionally focused on significantly higher OSW levels to provide a view of the infrastructure necessary to accommodate levels of up to 600 GW, far in excess of the Biden-Harris Administration's previous goal of 110 GW[13] and the current collective goals of the coastal states. Even at 600 GW, Atlantic offshore wind would only account for approximately 20% of the total U.S. nameplate electricity generation capacity[14] necessary to complete the overall energy transition to renewable energy resources. Nevertheless, this 20% is extremely important to the region and to the nation because it has the potential to:

1. Deliver reliable, secure, locally-sourced power to the most populous cities on the U.S. Atlantic Coast;
2. Illustrate the essential technical and sociopolitical elements needed for a larger, nation-wide energy transition that brings with it a unique opportunity to advance U.S. innovation and manufacturing; and
3. Produce the first leg of the multiregional, high-capacity multi-terminal HVDC (MT-HVDC) transmission grid – the Macrogrid – to support the U.S. transition to a globally competitive producer of renewable energy.

The objective of the work described in this report is to identify offshore and onshore transmission investments to facilitate levels of Atlantic Coast offshore wind ranging from 0 to 600 GW. Specifically, we intend to develop an offshore transmission reference design, together with points of interconnection (POIs) and onshore transmission expansions, that evolves through time as

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[11] Atlantic Coast state legislation related to offshore wind includes Massachusetts (H4568, 2016), New York (A. 8429, 2019), Connecticut (HB 7156, 2019, S.B. 385, 2024), Virginia (HB 1526, 2021), Maine (L.D. 336, 2021, L.D. 1895, 2023), New Jersey (S. 3926, 2021), Massachusetts (H. 4524, 2022), New Hampshire (SB 268, 2022), South Carolina (H.J.R. 4831, 2022), and Maryland (SB781, 2023), with over 45 GW of offshore wind procurement mandates.

[12] US DOE. 2024. Atlantic Offshore Wind Transmission Study. DOE/GO-102024-6116. March. https://www.nrel.gov/docs/fy24osti/88003.pdf. Accessed on February 17, 2025.

[13] US DOE. 2023. DOE Releases Strategy to Accelerate and Expand Domestic Offshore Wind Deployment. March 29. https://www.energy.gov/articles/doe-releases-strategy-accelerate-and-expand-domestic-offshore-wind-deployment. Accessed on October 2, 2024.

[14] For the region studied, 600 GW of OSW in the year 2051 reference case accounts for approximately 49.9% of the total nameplate power generation capacity (1,201 GW) and 65.8% (1,656 TWh) of the total annual electricity generation (2,516 TWh).

Atlantic Coast OSW grows to these larger levels. Because these magnitudes represent nonnegligible percentages of the nation's generating capacity, the offshore transmission, POIs, and onshore transmission expansions will affect and be affected by the extent to which high-capacity multiregional transmission is developed in the U.S.; we also desire to illuminate these interdependencies.

In the remainder of this introductory chapter, we review key studies and moments in Section 1.1 that serve as critical references for this current work, we establish in Section 1.2 terminology that will be heavily used in this report. In Section 1.3, we provide perspectives central to the analysis and conclusions of the work described in this report. Section 1.4 describes the organization of the report.

1.1 Background

The study, or the NOWRDC study, reported here was independently funded by the National Offshore Wind Research and Development Consortium (NOWRDC).[15] It commenced formally in 2021, about the same time as the AOSWTS started. Both studies were the first of their kind to explore large-scale OSW power injections on the Atlantic Coast with a special focus on interregional power flows and economic benefits enabled through an offshore transmission backbone. AOSWTS worked forward from the present moment, incorporating currently planned OSW projects and their specific points of interconnection (POIs) within a framework that aimed to accomplish the Biden-Harris Administration's OSW goals of 30 GW by 2030 and 110 GW by 2050.[16]

Complementary to that, the NOWRDC study began at 2050 and worked backwards, developing a Coordinated Expansion Planning (CEP) Framework (Model 2) that could explore offshore wind generation capacities not only at 30 GW and 110 GW but also well in excess of 110 GW. In order to simplify this CEP Framework, the NOWRDC study assumed a clean slate, explicitly ignoring existing transmission projects,[17] and opting instead for a carefully designed network of POIs, beachheads, and energy islands as introduced in the next section. Therefore, the goal of this study was to explore the tendency of an evolving OSW build-out to require a transmission backbone topology once certain levels of generation were reached.

The idea of an Atlantic offshore transmission backbone dates back more than 15 years to the Atlantic Wind Connection, which was proposed by Google and Good Energies to carry up to 6

[15] https://nationaloffshorewind.org/projects/transmission-expansion-planning-models-for-offshore-wind-energy/
[16] While the DOE goal for the US was 110 GW by 2050, the AOSWTS team had set 85 GW as the 2050 target for the U.S. Atlantic Coast.
[17] In the context of OSW generation build-outs of 250 GW or greater, existing projects up to the first 30 GW could be considered small and would therefore have a negligible impact on the eventual larger build-out.

GW of power between New York and Virginia.[18,19] This project coincided with the New Jersey Offshore Wind Energy Development Act (OWEDA), which had detailed a few months earlier how "An entity seeking to construct an offshore wind project shall submit an application to the board [of public utilities] for approval by the board [of public utilities] as a qualified offshore wind project."[20] Around this same time, NREL was exploring large-scale wind build-outs to service the Eastern Interconnect (EIC) that included up to 79.1 GW of offshore wind,[21] but which focused primarily on economic analysis and did not consider an offshore transmission backbone from a power systems perspective. By 2014, DOE had published a study estimating that 54 GW of offshore wind may provide up to $7.68 Bn of national savings in annual production costs.[22] This study described the potential for offshore MT-HVDC and introduced a potential "offshore backbone system" for PJM similar in appearance to the Atlantic Wind Connection with just over 7 GW of capacity.

With the early 2015 loss of the Cape Wind power purchase agreement (PPA)[23] and the 2016 advent of the first utility-scale OSW legislation in Massachusetts,[24,25] requiring the procurement of 1600 MW of OSW by 2027, new capacity expansion and transmission studies began to emerge at a regional level. By 2018, new Massachusetts legislation[26] had required the Massachusetts Department of Energy Resources (DOER) to study the need for OSW procurements beyond 1600 and authorized the DOER to direct utilities to engage in independent transmission procurements.

[18] Wald, M.L. 2010. Offshore Wind Power Line Wins Backing. New York Times. October 12. https://www.nytimes.com/2010/10/12/science/earth/12wind.html. Accessed on February 17, 2024.
[19] Buigues, G., Valverde, V., Etxegarai, A., Eguía, P. and Torres, E. 2017. Present and future multiterminal HVDC systems: current status and forthcoming developments. In Proc. Int. Conf. Renewable Energies Power Quality (Vol. 1, No. 15, pp. 83-88). April.
[20] State of New Jersey, Senate, No. 2036. 2010. An Act concerning the development of offshore wind projects. Introduced June 10. Signed into Law in August. https://pub.njleg.state.nj.us/Bills/2010/S2500/2036_R2.PDF. Accessed on May 5, 2025. See also https://dep.nj.gov/offshorewind/about/. Accessed on May 5, 2025.
[21] NREL. 2011. Eastern Wind Integration and Transmission Study. Prepared for NREL by: EnerNex Corporation, Knoxville, Tennessee. Subcontract No. AAM-8-88513-01. February. https://www.nrel.gov/docs/fy11osti/47086.pdf. Accessed on February 17, 2025.
[22] ABB, Inc. 2014. National Offshore Wind Energy Grid Interconnection Study, Final Technical Report. DOE Award No. EE-0005365. https://www.osti.gov/servlets/purl/1148347/. Accessed on February 17, 2025.
[23] Lacey, S. 2015. Cape Wind Loses Power Contracts, Becomes Victim of Class Warfare. greentechmedia. January 07. https://www.greentechmedia.com/articles/read/cape-wind-becomes-victim-of-class-warfare. Accessed on February 17, 2025.
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[26] An Act To Advance Clean Energy. 2018. Massachusetts General Court. Chapter 227. August 9. https://malegislature.gov/Laws/SessionLaws/Acts/2018/Chapter227. Accessed on February 17, 2025.

The DOER released its study in May 2019,[27,28] and recommended both the pursuit of additional OSW procurements and a technical conference to discuss the possibility of independent transmission procurement.

Also in 2019, The New York State Energy Research and Development Authority (NYSERDA) released its report on the results from New York's Round 1 OSW solicitation,[29] and The Brattle Group estimated that a balanced portfolio resource mix in New England would contain 43 GW of OSW, 107 GW of solar, 28 GW of storage, and 31 GW of gas,[30] placing OSW build-out numbers in the public sphere that were higher and longer term than previously contemplated. By January 2020, NREL joined the focus on a regional approach with its report contemplating the impacts of OSW on both the ISO-NE and NYISO power systems at 2024 injection levels of 2 GW and 7 GW[31]. This report was followed quickly by the publication in March of 2020 by Brattle's "NYISO Grid in Transition Study"[32] which discussed impacts on the NYISO transmission system through a 5-zone "pipe and bubble" model. Contemporaneous with these U.S. studies, the European PROMOTioN project published its "Optimal Scenario for the Development of a Future European Offshore Grid."[33]

In the spring semester of 2020 the primary authors of this report (Hines and Kates-Garnick) had convened a joint seminar between the School of Engineering and the Fletcher School at Tufts University entitled "CEE-293: Power Systems and Markets" which focused on responding to the MA-DOER's requests for public comment on the possibility of an independent transmission

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27 MA-DOER. 2019. Offshore Wind Study. With support from Levitan & Associates. May. https://www.mass.gov/doc/offshore-wind-study/download. Accessed on February 17, 2025.

28 Judson, J., MA-DOER Commissioner. 2019. Letter to the Joint Senate/House Joint Telecommunication, Utilities and Energy (TUE) Committee on the DOER's OSW Study. May 31. https://www.mass.gov/doc/offshore-wind-study-committee-letter-may-2019/download. Accessed on February 17, 2025.

29 NYSERDA. 2019. Launching New York's Offshore Wind Industry: Phase 1 Report. Report Number 19-41. October. https://docslib.org/download/7563888/launching-new-yorks-offshore-wind-industry-phase-1-report. Accessed on February 17, 2025.

30 Weiss, J. and Hagerty, J.M. 2019. Achieving 80% GHG Reduction in New England by 2050: Why the region needs to keep its foot on the clean energy accelerator. Prepared by for the Brattle Group for the Coalition for Community SOLAR ACCESS. September. https://www.brattle.com/wp-content/uploads/2021/05/17233_achieving_80_percent_ghg_reduction_in_new_england_by_20150_september_2019.pdf. Accessed on February 17, 2025.

31 Beiter, Philipp, Jessica Lau, Joshua Novacheck, Qing Yu, Gord Stephen, Jennie Jorgenson, Walter Musial, and Eric Lantz. 2020. The Potential Impact of Offshore Wind Energy on a Future Power System in the U.S. Northeast. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-74191. nrel.gov./docs/fy20osti/74191.pdf. Accessed on February 17, 2025.

32 Lueken, R., Newell, S.A., Weiss, J., Moraski, J. and Ross, S. 2020. NYISO Grid in Transition Study. Presented to NYISO ICAO/MIWG/PRLWG Stakeholders. The Brattle Group. March 30. https://www.nyiso.com/documents/20142/11593028/2020.03.30%20Stakeholder%20Meeting%20Deck%20Brattle%20FOR%20POSTING.pdf/06562da7-ee27-cece-57f0-afd7d688121a. Accessed on February 17, 2025.

33 PROMOTioN. 2020. D12.2-Optimal Scenario for the Development of a Future European Offshore Grid. PROgress on Meshed HVDC Offshore TransmissIOn Networks. Work Package 12. Responsible partner: TenneT TSO B.IV. http://www.promotion-offshore.net/news_events/news/detail/optimal-scenarios-for-the-future-european-offshore-grid/. Accessed on February 17, 2025.

solicitation. The seminar participants submitted first-round comments on February 18, 2020,[34] attended the technical conference on March 3, 2020,[35] and submitted second-round comments on April 21, 2020[36] making the point that an independent transmission procurement in Massachusetts should be focused on approximately 12,000 MW of transmission capacity covering the entire Offshore MA-RI Wind Energy Areas (WEAs) rather than the 1,600 MW identified as a generation target. The reason for this was that by 2020, 1,600 MW was no longer considered a large number for OSW procurements, and it was reasonable to contemplate a single OSW developer developing 1600 MW of transmission capacity for their own projects. In May 2020, Brattle and Anbaric released a report estimating the need for 40 GW of OSW in New England, and advocating for planned offshore transmission, citing examples of successful planned transmission including "Texas (CREZ), California (Tehachapi Wind), MISO (Regional Multi-Value Projects), and several European countries," and estimating $1B savings in onshore transmission upgrades through Anbaric's southern New England OceanGrid.[37] On June 13, 2020, we recommended that it was time to re-think the scale of OSW and to imagine up to 300 GW by 2050. This build-out could be stimulated by a post-Covid-19 stimulus package[38] that could set in motion the construction of a "modern offshore/onshore transmission system."[39]

Our recommendation about scale, however, was out of step with the then prevailing concern in Massachusetts with the 1600 MW procurement number. ISO-NE's "Offshore Wind Integration" study, published on June 30, 2020, identified 5800 MW of Southern New England OSW interconnection capacity "without significant upgrades,"[40] and further reinforced the Massachusetts' near-term focus of OSW procurements and available POI capacity. Within this context, independent transmission procurement did not make sense. Within this context, the MA-

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[34] MA-DOER. 2020. Offshore Wind Transmission Stakeholder Comments (2-19-20). https://www.mass.gov/doc/offshore-wind-transmission-stakeholder-comments-2-19-20. Accessed on February 17, 2025.

[35] MA-DOER. 2020. https://www.mass.gov/info-details/offshore-wind-study; https://www.mass.gov/doc/agenda-massachusetts-offshore-wind-transmission-technical-conference. Accessed on February 15, 2025.

[36] MA-DOER. 2020. https://www.mass.gov/doc/offshore-wind-comments-transmission-second-round-comments-04-22-20/download. Accessed on February 17, 2025.

[37] Pfeifenberger, J., Newell, S. and Graf, W. 2020. Offshore Transmission in New England: The Benefits of a Better Planned Grid. Prepared for Anbaric by The Brattle Group. May. https://www.brattle.com/wp-content/uploads/2021/05/18939_offshore_transmission_in_new_england_-the_benefits_of_a_better-planned_grid_brattle.pdf. Accessed on February 17, 20205.

[38] The primary authors gratefully acknowledge our collaboration during the high pandemic of early summer 2020 with Ed Krapels, Kevin Knobloch, and Chris Greely of Anbaric and Juergen Weiss of the Brattle Group to estimate realistic 2030 and 2050 U.S. OSW build-outs, imagine post-Covid-19 stimulus plans, and conceptualize a high-capacity Atlantic offshore-onshore transmission system that could deliver hundreds of GW of power to coastal load centers, and make the point that ports for supporting the U.S. offshore wind build-out were often co-located with key beachheads and points of interconnection.

[39] Hines, E. 2020. New transmission infrastructure needed for offshore wind. Opinion. Commonwealth Magazine. June 13. https://commonwealthbeacon.org/opinion/new-transmission-infrastructure-needed-for-offshore-wind/. Accessed on February 17, 2025.

[40] ISO-NE. 2020. 2019 Economic Study: Offshore Wind Integration. June 30.

DOER reasonably recommended to the Massachusetts Senate/House Joint Committee on Telecommunication, Utilities and Energy (TUE) not to pursue independent OSW transmission procurement for 1600 MW of OSW.[41] As a result, independent OSW procurements were not discussed publicly in Massachusetts for the next several years. Nevertheless, national momentum was gathering, and by the end of Summer 2020 a new series of discussions began to emerge on large-scale offshore wind transmission.

While an exhaustive discussion of the public documents that followed the Summer of 2020 is beyond the scope of this section and could fill an entire report, the remainder of this section highlights some of the important studies that have bridged between regional and national thinking as well as between today and 2050 with respect to the prospect of offshore transmission infrastructure.

By summer 2020, New Jersey had expressed interest in "gathering information on the various approaches for future offshore wind transmission," through its June 26 Docket No. QO20060463,[42] and Anbaric had commissioned Brattle to develop "Offshore Wind Transmission: An Analysis of Options for New York"[43] in order to describe options for how New York could integrate its 9 GW OSW procurement into the NYISO grid. The Tufts seminar participants from the spring continued to work together to submit comments to New Jersey, attended the Friday, August 7, 2020 meeting with the NJ-BPU, associated with Docket No. QO20060463 and hosted by Levitan & Associates. We submitted formal comments to New Jersey on August 28, 2020.[44] A few days later, Maryland issued its Generation Interconnection System Impact Study Report.[45] By October 2020, both the Business Network for Offshore Wind[46] (BNOW, now Oceantic) and the

[41] Woodcock, P., MA-DOER Commissioner. 2020. Letter to the Joint Senate/House Joint Telecommunication, Utilities and Energy (TUE) Committee on the Offshore Wind Energy Transmission. July 28. https://www.mass.gov/doc/offshore-wind-transmission-letter-07-28-20/download . Accessed on February 17, 2025.
[42] NJ-BPU. 2020. New Jersey Offshore Wind Transmission. Docket No. QO20060463. June 26. https://www.publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109297. Accessed on February 17, 2025.
[43] Pfeifenberger, J., Newell, S., Graf, W. and Spokas, K. 2020. Offshore Wind Transmission: An Analysis of Options for New York. Prepared for Anbaric by The Brattle Group. August. https://www.brattle.com/wp-content/uploads/2021/05/19744_offshore_wind_transmission_-_an_analysis_of_options_for_new_york.pdf. Accessed on February 17, 2025. See Also Appendix B of this report: "Study of Transmission Alternatives to Interconnect 9000 MW of Offshore Wind Generation in New York." Pterra Consulting. Pterra Report R161-20.
[44] Tufts Power Systems and Markets Research Group. 2020. Comments to NJ-BPU. August 28. https://createsolutions.tufts.edu/wp-content/uploads/2020/09/2020-08-28_NJ-BPU-Response-Tufts-Power-Systems-and-Markets.pdf. Accessed on February 17, 2025.
[45] Maryland-PSC. 2020. Generation Interconnection System Impact Study Report. Prepared by Axum Energy Ventures, LLC. August 31. https://www.psc.state.md.us/wp-content/uploads/MD-OSW-Analyses-2-3-1__-8-31-2020_FINAL.pdf. Accessed on February 17, 2025.
[46] Burke, B., Goggin, M. and Gramlich, R. 2020. Offshore Wind Transmission White Paper. Business Network for Offshore Wind. October. https://oceantic.org/wp-content/uploads/2021/06/GT-White-Paper-030121.pdf. Accessed on February 17, 2025.

New England States Committee on Electricity[47] (NESCOE) had issued vision documents on OSW transmission, and advanced at the 2020 fall meeting

the Modular Offshore Wind Integration Plan (MOWIP) explicitly contemplating a multi-terminal HVDC offshore wind grid. A coalition of The Regulatory Assistance Project, Raab Associates, Ltd., and The Transition Accelerator submitted "A Collaborative for Greater Coordination and Integration Among the Electric Grids of Eastern Canada and the Northeastern United States" to the Northeast Electrification and Decarbonization Alliance.[48] ISO-NE had announced a "Notice of Initiation of the Cape Cod Resource Integration Study," responding to over 3700 MW of interconnection queue requests on Cape Cod.[49] The Federal Energy Regulatory Commission (FERC) convened an offshore wind transmission technical conference[50] to which the Tufts seminar participants submitted comments.[51] The Tufts seminar participants eventually summarized their comments to Massachusetts, New Jersey, and FERC in their report OSPRE-2021-01.[52]

In November 2020, Energy+Environmental Economics and the Energy Futures Initiative released their report "Net-Zero New England: Ensuring Economic Reliability in a Low-Carbon Future,"[53] and five New England Governors issued a joint statement committing to work together to modernize New England's wholesale electricity markets for the energy transition.[54] Also in

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[47] NESCOE. 2020. New England States Vision Statement for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid. October 16. https://nescoe.com/resource-center/vision-stmt-oct2020/. Accessed on February 17, 2025.

[48] NEDA. 2020. A Collaborative for Greater Coordination and Integration Among the Electric Grids of Eastern Canada and the Northeastern United States. Submitted to the Northeast Electrification and Decarbonization Alliance (NEDA) by the Regulatory Assistance Project, Raab Associates, Ltd., and the Transmission Accelerator. October 5. https://transitionaccelerator.ca/wp-content/uploads/2020/10/NEDA-Assessment-Report-October-2020-2.pdf. Accessed on February 17, 2025.

[49] McBride, A. 2020. Notice of Initiation of the Cape Cod Resource Integration Study. ISO-NE Planning Advisory Committee. October 21. https://www.iso-ne.com/static-assets/documents/2020/10/a6_initiation_of_the_cape_cod_resource_integration_study.pdf. Accessed on February 17, 2025.

[50] FERC. 2020. Staff-Led Technical Conference on Offshore Wind Integration in RTOs/ISOs. Docket No. AD20-18-000. October 27. https://www.ferc.gov/news-events/events/technical-conference-regarding-offshore-wind-integration-rtosisos-10272020. Accessed on February 17, 2025.

[51] Tufts Power Systems and Markets Research Group. 2020. Comments to FERC on Docket No. AD20-18-000. October 26. https://createsolutions.tufts.edu/wp-content/uploads/2020/10/2020-10-26_FERC-TuftsPowerSystemsandMarkets.pdf. Accessed on February 17, 2025.

[52] Smith, K., Lenney, S., Marsden, O., Kates-Garnick, B., Stanković and Hines, E. 2021. Offshore Wind Transmission and Grid Interconnection across U.S. Northeast Markets. OSPRE-2021-01. Tufts University Digital Library. February 6. https://doi.org/10.60965/0vjh-5w79. Accessed on February 18, 2025.

[53] E3 and Energy Futures Initiative. 2020. Net-Zero New England: Ensuring Electric Reliability in a Low-Carbon Future. November. https://www.ethree.com/wp-content/uploads/2020/11/E3-EFI_Report-New-England-Reliability-Under-Deep-Decarbonization_Full-Report_November_2020.pdf. Accessed on February 17, 2025.

[54] Baker, C. (MA), Lamont, N. (CT), Mills, J. (ME), Raimondo, G. (RI), and Scott, P. (VT). 2020. New England's Regional Wholesale Electricity Markets and Organizational Structures Must Evolve for 21st Century Clean Energy Future. October 14. https://portal.ct.gov/-/media/office-of-the-governor/news/20201015-electricity-system-reform-joint-governors-statement.pdf. Accessed on February 17, 2025.

November, the New Jersey Board of Public Utilities (NJ-BPU) formally requested "that PJM interconnection, LLC ("PJM") incorporate the State's offshore wind goals into the PJM transmission planning process, via the "State Agreement Approach" ("SAA"),"[55] marking the first time that a state formally engaged in an independent offshore wind transmission procurement process.

Also in November 2020, Dr. McCalley, the lead author on this present report from Iowa State, published "Macro Grids in the Mainstream: An International Survey of Plans and Progress,"[56] which pictured an Atlantic offshore transmission backbone as the only realistic means to build the eastern most North-South leg of a U.S. Macrogrid. This report and its timing in November of 2020 represents the initial confluence of national thinking on Macrogrids with Atlantic Coast engagement on the offshore-onshore grid system required for OSW grid integration. The authors of this present report (McCalley of ISU and Hines of Tufts) had come together from these two different perspectives to submit their proposal to NOWRDC for this work on October 19, 2020.

Within a year, by fall of 2021, PJM had received offshore wind transmission proposals under the NJ-SAA[57] and released its "Offshore Wind Transmission Study: Phase 1 Results,"[58] Brattle had published "A Roadmap to Improved Interregional Transmission Planning,"[59] the U.S. DOE had published "Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis,"[60] ISO-NE had launched its "2050 Transmission Study,"[61] and both the AOSWTS team and our team had commenced work and begun collaborating.

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[55] NJ-BPU. 2020. In the Matter of Offshore Wind Transmission. Docket No. QO20100630. November 18. https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468. Accessed on February 17, 2025.

[56] McCalley, J. and Zhang, Q. 2020. Macro Grids in the Mainstream: An International Survey of Plans and Progress. Sponsored by Americans for a Clean Energy Grid as part of the Macro Grid Initiative. November 18. https://cleanenergygrid.org/macro-grids-mainstream/. Accessed on February 17, 2025.

[57] NJ-BPU. 2021. State Agreement Approach, Process Guidance Document. September 24. https://www.nj.gov/bpu/pdf/ofrp/SAA%20Process%20Overview.pdf. Accessed on February 17, 2025.

[58] PJM. 2021. Offshore Wind Transmission Study: Phase 1 Results. October 19. https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx. Accessed on February 17, 2025.

[59] Pfeifenberger, J.P., Spokas, K., Hagerty, J.M. and Tsoukalis, J. 2021. A Roadmap to Improved Interregional Transmission Planning. Prepared by the Brattle Group for the Natural Resources Defense Council. November 30. https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf. Accessed on February 17, 2025.

[60] Bothwell, Cynthia, Melinda Marquis, Jessica Lau, Jian Fu, Liz Hartman. 2021. Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis. U.S. Department of Energy Office of Energy Efficiency and Renewable Energy. October. https://www.energy.gov/sites/default/files/2021 10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf. Accessed on February 17, 2025.

[61] Vijayan, P. 2021. 2050 Transmission Study: Preliminary Assumptions and Methodology for the 2050 Transmission Study Scope of Work. Revision 2. ISO New England. November 17. https://www.iso-ne.com/static-assets/documents/2021/12/draft_2050_transmission_planning_study_scope_of_work_for_pac_rev2_redline.pdf. Accessed on February 17, 2025.

In April 2022, the NOWRDC team developed a simple graphic, shown in Figure 1, that reflected the goals of the NOWRDC project. Framing the essential engineering problem as the development of key POIs for high landing capacities that could allow states, RTOs, and utilities to work together to focus on the most important Atlantic Coast POIs. This would ensure the prioritization of reliability, security, resilience and environmental impact both for key landing points and for the transmission backbone.

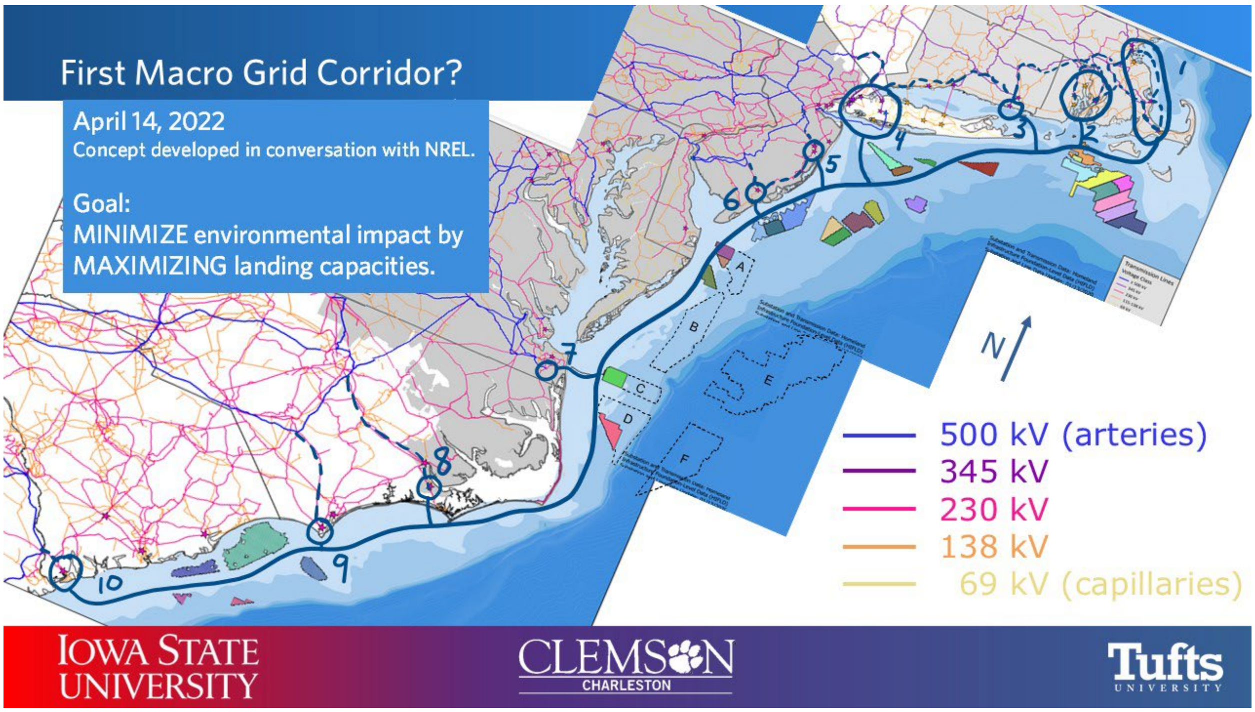

Figure 1-1. April 14, 2022 sketch of an Atlantic Offshore Wind Transmission backbone.

Later that year, in fall 2022, the NJ -BPU released its "Evaluation Report" for the SAA,[62] and recommended the Larrabee Tri-Collector Solution.[63] The SAA has since become a leading industry standard for offshore wind transmission procurement. Central to the chosen SAA solution was the bundling of 3,742 MW of power from shore to the Larrabee Collector Station[64] to distribute to three existing POIs: Larrabee, Smithburg, and Atlantic. This bundling of nearly 5 GW

[62] NJ-BPU. 2022. New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report. Prepared by the Brattle Group for the NJ-BPU. October 26. https://www.brattle.com/wp-content/uploads/2022/10/New-Jersey-State-Agreement-Approach-for-Offshore-Wind-Transmission-Evaluation-Report.pdf. Accessed on February 17, 2025.

[63] NJ-BPU. 2022. In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey. Docket No. QO20100630. October 26. https://www.nj.gov/bpu/pdf/boardorders/2022/20221026/8A%20ORDER%20State%20Agreement%20Approach.pdf. Accessed on February 17, 2025.

[64] A separate 1148 MW was reserved at Smithburg for a developer who had anticipated developing an interconnection outside of the NJ-SAA project.

of power in the context of eventually bringing up to 11 GW of power to shore demonstrated a change in thinking from project-based transmission procurements under single source contingency limit (SSCL)[65] to a modern offshore-onshore transmission infrastructure featuring high-capacity power corridors. As discussed in Appendix C of this present report, the eventual level of a full offshore transmission backbone and Macrogrid servicing a 90% decarbonized U.S. energy system will require MT-HVDC power corridors with capacities on the order of 30 GW.

In January 2023, Brattle released "The Benefit and Urgency of Planned Offshore Transmission,"[66] which listed 2050 goals of 150-197 GW of OSW from "state and regional studies," 224-458 GW of OSW from national studies, and 96-137 GW projected for the Atlantic Coast. This report made twelve recommendations for advancing offshore transmission including policy, economic, regulatory, and technology recommendations including an immediate recommendation to "[i]dentify and empower multi-state decision-making bodies,… [i]dentify feasible, cost-effective POIs,…" and "[d]evelop network-ready standards." Also in January 2023, the six New England states filed the Joint State Implementation Project (JSIP) Concept Paper with DOE for funding under the 2021 Bipartisan Infrastructure Law.[67] The JSIP expressly advanced an MT-HVDC OSW grid, was approved for future application for funding, and is possibly the only MT-HVDC concept paper that was approved by DOE. By June of 2023, top state energy officials had written to former DOE Grid Deployment Office (GDO) Director Maria Robinson to request her assistance in forming a "Northeast States Collaborative on Interregional Transmission," and the leaders of NYISO, ISO-NE, and PJM had also written to Director Robinson to pledge their support for such an initiative.[68] This collaborative is now housed at the Johns Hopkins University and is facilitated by Abe Silverman.[69]

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[65] The current SSL in New England is 1.2 GW, with discussions underway to move the SSL up to 2 GW.

[66] Pfeifenberger, J.P., Delosa III, J., Bai, L., Plet, C., Peacock, C. and Nelson, R. 2023. The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals. Prepared by the Brattle Group and DNV for the National Resources Defense Council, GridLab, the Clean Air Task Force, the American Clean Power Association, and the American Council on Renewable Energy. January 24. https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf. Accessed on February 18, 2025.

[67] Snook, R., Tremblay, E., Troy, J., and Bradbury, K. 2023. Join State Innovation Partnership for Offshore Wind. Concept Paper submitted to the U.S. DOE. January 13. https://newenglandenergyvision.com/new-england-states-transmission-initiative/. Accessed on May 6, 2025.

[68] Tepper, R. (MA), Dykes, K. (CT), Burgess, D. (ME), Tierney, J.E. (VT), Harris, D.M. (NY), Fiordaliso, J.L. (NJ), Kearns, C. (RI) and Chicoine, J. (NH). 2023. Letter to DOE Grid Deployment Office Director Maria Robinson requesting help in forming a "Northeast States Collaborative on Interregional Transmission." June 16; Dewey, R. (NYISO), Asthana, M. (PJM) and van Welie, G. (ISO-NE). 2023. Letter to Director Robinson. June 27. https://www.iso-ne.com/static-assets/documents/2023/06/northeast_collaborative_doe_june_letters_combined.pdf. Accessed on February 18, 2025.

[69] https://energyinstitute.jhu.edu/northeast-states-collaborative-on-interregional-transmission/. Accessed on February 18, 2025.

In September 2023, DOE published its interim DRAFT of an "Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region."[70] In December 2023 the Massachusetts DOER, the Executive Office of Energy and Environmental Affairs, and the DPU delivered their report to the Legislature by the "Clean Energy Transmission Working Group,"[71] and ISO-NE published its "2050 Transmission Study"[72] both of which marked a new level of engagement in New England on the energy transition at scale and the future of offshore wind transmission.

Ending with the publication of the AOSWTS in March 2024, this background section has provided context for this present report and its goals, which are distinct from and complementary to the powerful stream of publications, decisions, and engagements that the authors have monitored since the beginning of this research project. While this section has not provided an exhaustive list of publications and actions during this time, it has highlighted those which had the greatest impact on our work and which we archived as they were issued over these past five years. We hope that this narrative helps the reader understand the emergence of offshore transmission over the past 5 years as a major policy, technology, and investment consideration for the U.S. Atlantic States. We also hope that it clarifies the need for power systems analysis and coordinated expansion planning at the scale of both the entire Atlantic Coast and the entire country in order to realize the full benefits of a modern electricity grid.

1.2 Terminology

The system of procurement considered in this report for large OSW buildouts (from 30 to 600 GW) should be understood in a context of "beachheads" and "energy islands." A beachhead is the shoreline location for a cable landing from which an HVDC cable proceeds to a land-based substation or "point of interconnection" (POI) within the existing land-based AC transmission grid. We call this connection from beachhead to POI a "reach circuit" and we assume that all reach circuits and land-based upgrades will be accomplished under the authority and collaboration of existing states, RTOs, and utilities with the assistance of independent transmission developers according to facility siting requirements. An energy island may be an offshore platform, or a literal island, where power is accumulated from multiple offshore generators and bundled into high-

[70] U.S. DOE and BOEM. 2023. An Action Plan for Offshore Wind Transmission Development in the U.S. Atlantic Region. Interim DRAFT published September 2023. Final Publication Pending Completion of the Atlantic Offshore Wind Transmission Study. Final Version Published March 2024 https://www.energy.gov/sites/default/files/2024-04/Atlantic_Offshore_Wind_Transmission_Plan_Report_v16_RELEASE_508C.pdf. Accessed on February 18, 2025.

[71] MA-DOER, EoEEA and DPU. 2023. Clean Energy Transmission Working Group: Report to the Legislature. December. https://www.mass.gov/doc/clean-energy-transmission-working-group-final-report/download. Accessed on February 18, 2025.

[72] ISO-NE. 2024. 2050 Transmission Study. February 12. https://www.iso-ne.com/static-assets/documents/100008/2024_02_14_pac_2050_transmission_study_final.pdf. Accessed on February 18, 2025.

capacity subsea 525 kV HVDC transmission corridors ranging from 2 to 30 GW[73] before being transmitted to the beachhead. Within this report, we refer to the U.S. Atlantic offshore wind build-out simply as the "offshore wind build-out," and when we refer to offshore wind (OSW), we mean OSW in the exclusive economic zone (EEZ) located off the U.S. Atlantic Coast.

1.3 Guiding perspectives

There are two overarching and guiding perspectives taken in this work. The first relates to the models used to develop the design, which are optimization-based. The second relates to the nature of the offshore transmission design; we assume that it could require some level of backbone transmission interconnecting some or all of the regions along the East Coast. We describe these two perspectives below:

1. _Models used_: There are three models used in this work. Models 2 and 3 are both linear programs that we call coordinated expansion planning (CEP) optimizers. CEP determines location, size, and technology type for generation and transmission investments. It does this by minimizing generation and transmission investment costs, generation retirement costs, and generation production costs [74] over time. CEP is applied using two different system representations. The first of these, the centerpiece of this work, uses an 843-bus reduced equivalent representation of the eastern part of the US Eastern Interconnection (see Figure 2-2). We refer to the CEP with this 843-bus system representation of the eastern part of the Eastern Interconnection as Model 2. A second application of CEP enables exploring East Coast OSW outside the immediate East Coast region; it uses a 169-bus representation of the Eastern and Western Grids in North America, with and without representation of a multi-regional high capacity overlay we call the Macrogrid. We refer to this second application of CEP with its 169-bus North American grid representation as Model 3 (see Figure C-1). A third and final model uses a 90,059-bus representation of the Eastern Interconnection[75] (see Figure B-5); it does not use CEP but rather automates evaluation of onshore investment costs, including effects of N-1 contingencies, at selected POIs to identify least-cost POIs for a given offshore

[73] The authors recognize that 30 GW is an exceptionally high number in the context of today's understanding of electric power corridor capacities. Such a corridor would require a whole new approach to electricity transmission permitting, regulation, and operations. Such a corridor is the basis for thinking about a Macrogrid, which we estimate to require approximately three N-S and three E-W 30 GW HVDC power corridors, as discussed in Appendix C.
[74] Production costs include, for new and existing resources, fixed and variable operating and maintenance costs, fuel cost and operational reserve cost (regulation up/down and contingency reserve). Constraints imposed include: power balance at each node; "DC" angle constraints across each existing line; upper and lower limits on generation dispatch and line flows; lower limits on available up/down regulation reserves and available contingency reserves; upper limits on up/down regulation (contingency) reserves by the unit's 1-minute (10-minute) ramp rate; capacity in excess of the 115% of peak (all units contributed to the planning reserve according to each units capacity value which, for wind and solar, vary locationally but are independent of renewable penetration); and the definition of the particular transmission design being studied.
[75] Refer to Appendix B.

injection level; we refer to the ability the 90,059-bus system representation and this assessment approach as Model 1.

2. *Offshore transmission design*: We have developed Model 2 so that, given a designated level of OSW capacity and a set of offshore grid (OSG) candidate segments, it designs the OSG in terms of identifying capacities of the various OSG candidate segments. We have provided candidate segments from major OSW locations (energy islands)[76] to specified onshore beachheads, and from those beachheads to the nearest onshore POIs. We have also provided candidate segments between adjacent energy islands, and it is the presence of these inter-island candidate segments that enable Model 2 to consider economic benefits of backbone transmission, either in its entirety from Maine to the Carolinas or in terms of portions of this corridor.[77] All possible candidate segments are shown in black in Figure 2-2.

1.4 Report organization

This report is organized as follows. Chapter 2 describes Model 2 and its application in performing offshore grid segment selection. Chapter 3 provides analysis results. Chapter 4 provides conclusions and future work. Appendix A describes the model reduction process for Model 2. Appendices B and C provide detailed descriptions of Models 1 and 3, respectively, which are used to provide some of the results in Chapter 3. Appendices D and E list the selected beachheads and POIs used as inputs for Model 2. Appendix F presents detailed results of the POIs selected by Model 2 under varying levels of OSW investments. Appendix G contains the mathematical formulation of CEP, while Appendix H provides a comprehensive list of references used in this report.

[76] In this report, we use the term "energy island" to designate a high-capacity offshore substation capable of serving as a node in an MT-HVDC offshore grid with double-digit GW capacity. The actual construction of such an island, whether of fill, concrete, or steel, is immaterial compared to its role in functioning as node in the offshore grid. Energy islands would be constructed independently of OSW farms and would allow OSW developers to plug into an offshore grid rather than having to land onshore at a beachhead and connect into a POI. For more discussion on energy islands, refer to Energistyrelsen. 2025. Denmark's Energy Islands. https://ens.dk/en/energy-sources/offshore-wind-power/denmarks-energy-islands. Accessed on May 6, 2025.

[77] We expect that such OSG transmission would be built as a ±525 kV multiterminal HVDC system with DC breakers and voltage source converters consistent with the TenneT 2-GW standard described at www.tennet.eu/about-tennet/innovations/2gw-program (accessed October 2, 2024).

2 Model 2: Development of CEP and application to offshore grid design

This chapter describes Model 2, which refers to the software application together with the onshore and offshore representation of the grid to which the software is applied. The software application is a coordinated expansion planning (CEP) optimizer developed explicitly for this offshore wind project based on previous research and development in expansion planning software by the ISU team.[78,79] CEP assesses conditions associated with a sequence of operating conditions spanning 20 years to identify transmission and generation investments necessary to minimize the total investment and operational costs to adequately supply the demand over all the modeled conditions. In what follows, Section 2.1 describes the CEP optimizer. Section 2.2 summarizes the data and data processing used to represent the existing and possible onshore and offshore resources and transmission systems. Section 2.3 describes our offshore grid design method. Section 2.4 summarizes the codes used to perform all processing, design, and analysis tasks in this project.

2.1 Description of coordinated expansion planning (CEP) optimizer

In Section 2.1.1, we describe the CEP optimizer in terms of its optimization formulation. Section 2.1.2 describes solution settings.

2.1.1 Optimization formulation

Model 2 uses the CEP optimizer, a software application developed by the ISU team that enables coordinated resource and transmission expansion planning exercises that adhere closely to the actual topology and power systems behavior of the grid.[80] The objective of CEP is to identify, through the solution of an optimization problem, investments (i.e., expansions) in new generation and new transmission, and retirements in existing generation, given a set of assumptions and constraints, to minimize the net present value (NPV) of all investment and operating costs over the planning horizon. The set of assumptions includes projections on technology costs and electric loads. The set of constraints includes OSW capacity targets and carbon emission reduction requirements.

[78] A. Bloom et al.. 2022. "The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study." in IEEE Transactions on Power Systems, vol. 37, no. 3, pp. 1760-1769. May. doi: 10.1109/TPWRS.2021.3115092

[79] A. Figueroa-Acevedo, et al.. 2020. “Design and Valuation of High-Capacity HVDC Macrogrid Transmission for the Continental US.” January. doi: 10.1109/TPWRS.2020.2970865. IEEE Transactions on Power Systems.

[80] The CEP approach assesses DC power flow on a high-fidelity reduced grid and thus provides insights into actual power flow and transmission grid behavior. This approach is distinguished from a more common “copper plate” approach or a “pipe and bubble” approach, both of which provide less accurate approximations of the actual transmission system and focus mainly on capacity build-outs. The CEP approach to co-optimized capacity build-outs and transmission expansion is the basis for the name “coordinated” expansion planning.

The CEP is performed for a planning horizon of 20 years, from 2031 to 2051. Five years, called investment years, are selected for which the model is allowed to make investments; these years are 2031, 2036, 2041, 2046, and 2051. Non-investment years (e.g., 2032, 2033, 2034, 2035), called operational years, are modeled and their operational costs computed and included in the objective function. A conceptual illustration of the CEP optimizer is provided in Figure 2-1.

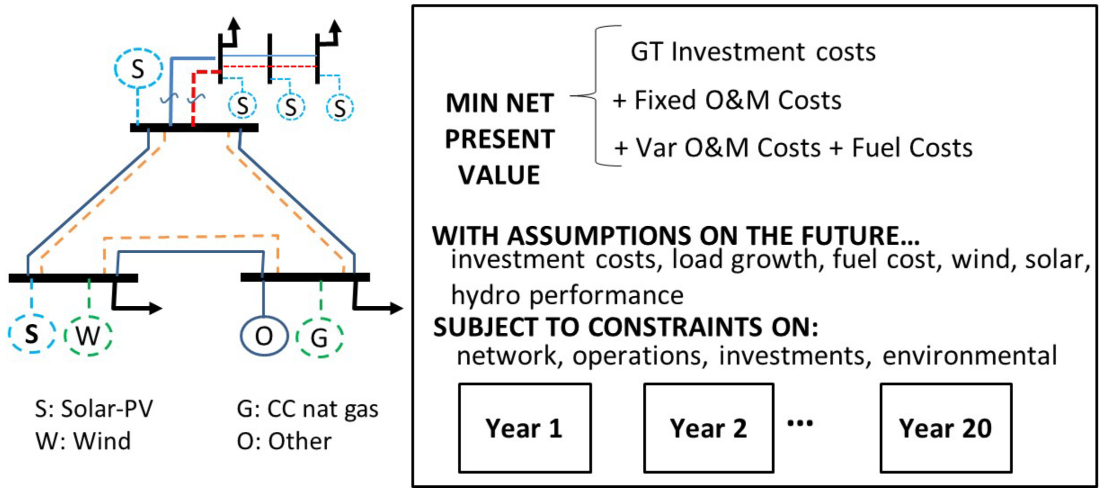

Figure 2-1: Illustration of CEP formulation.

In each year (investment year and operating year), 17 "operating blocks" are modeled. Each operating block reflects a network subject to a specified load. One of the 17 operating blocks represents a single hour corresponding to the year's peak load condition. The other 16 operating blocks are divided into four sets, one set for each of the four seasons (fall, winter, spring, summer). Each seasonal set is comprised of four operating conditions selected to represent a certain time of the day (11 pm to 6 am, 7 am to 1 pm, 2 pm to 6 pm, 7 pm to 10 pm) under the assumption that every day of that season is identical; the costs incurred for each hour of each season is multiplied by the number of such hours in that season. A high-level expression of this problem is provided below (a detailed analytic formulation is provided in Appendix G).

Minimize:

NPV{Cost of new generation resources
+ Cost of retiring generation resources
+ Cost of transmission expansion}

Subject to:

A. For each operating block:
   1. For each node:

a. Total nodal generation capacity is updated to be existing+invested-retired;
b. Minimum and maximum limits are imposed on generation resources;
c. Generation output is computed as capacity × capacity factor for the technology, season, and hour; and
d. Power balance is enforced (generation-load=flows out of node).

2. For each AC branch (line or transformer), flows are computed according to Kirchhoff's voltage law under the "DC-Power Flow" approximation, given by $f_{ij} = \frac{\theta_i - \theta_j}{x_{ij}}$ where θ_i and θ_j are the voltage phasor angles at the branch terminals and x_{ij} is the branch's impedance.
3. For each AC branch and DC line, flows are constrained to be no more than the continuous flow limit, computed as original flow limit + the sum of each year's transmission investments.

B. For each investment period:
   a. System CO_2 emission reduction must meet a specified target value for each investment period. This value is uniformly increasing to the last year of 2051 where it is required that CO_2 reduction be *P*% of a fixed CO_2 emission level characteristic of 2031 CO_2 emission levels.[81] Unless otherwise stated, *P*=90%.
   b. Each node is subject to generation investment limits. (see Figure 2-2 and Figure 2-3)
      i. For onshore nodes, these limits are provided for both wind and solar, specified according to the investment caps described in Section 2.2.4.1.
      ii. Offshore nodes are understood as "energy islands" where power is aggregated from multiple OSW farms before being transmitted to shore. For each offshore energy island, total OSW investment must equal a specified level divided by the number of energy islands. This constraint is enforced to ensure that the model invests the desired amount of OSW. Given there are up to 25 energy islands in our model, per energy island investment targets for OSW levels 100-600 GW are shown in Table 2-1. This approach provides that OSW growth is distributed uniformly among the 25 energy islands up and down the East Coast. Although uniform growth distribution will most certainly not be accurate for lower growth levels, i.e., levels of 50-100 GW), it is reasonable for higher growth levels, i.e., levels of 200-600 GW.

[81] The reference CO2 emissions level was chosen based on emissions in 2031, but it was a fixed value, i.e., it did not depend on 2031 investments. This is important because making emission reductions dependent on what the model computed to be 2031 emissions de-incentivized 2031 investments that would reduce 2031 emissions.

c. For each peak hour, a planning reserve margin (PRM) constraint is imposed that requires the total system accredited capacity must exceed 115% of the hour's load.[82]

Table 2-1: OSW investment levels with corresponding energy island maximum capacities.

Total OSW Investment (GW)	Investment per Energy Island (GW)
100	4
200	8
300	12
400	16
500	20
600	24

2.1.2 Optimization solution

The problem is formulated in the General Algebraic Modeling System (GAMS) and solved using the Gorubi solver. There are two main dimensions to solving the CEP: solver settings and data scaling.

- Solver settings: Gurobi software offers a range of settings to customize the solver's behavior. Gurobi uses a Barrier approach to solve the model. We also use 12 CPUs and allow the solver to use pre-solve to reduce the size of optimization problem and improve its numerical stability. We force the solver to aggressively scale the model to ensure numerical stability.
- Data scaling: CEP models work at the intersection of economic and physical power system data. Therefore, a large range of data is represented in CEP models. The range of coefficients present in the optimization models is an important factor in ensuring the numerical stability of the solution process. Although the solver can handle many of the numerical issues that are inherent to this problem, it is important that the user also is cognizant of these issues and scales the variables and constraints accordingly. To achieve numerical stability, several constraints and variables are scaled, and the range of the coefficient matrix is reduced from 1e+14 to 1e+5.

2.2 CEP data and processing

There are four main data requirements for developing the system representation used in our CEP. These data requirements are network data as described in Section 2.2.1, load data and operational

[82] During some of our initial runs of the model, we found that it chose to build OSW (because it was hard-constrained to do so) and contributed to the PRM without building the transmission to connect it. This was clearly an unacceptable feature. To address this, we require that OSW capacity is included in the PRM calculation by using its peak period generation values. This ensures OSW cannot contribute capacity without generating during the peak period, and it cannot generate during the peak period without being connected.

block development as described in Section 2.2.2, cost data as described in Section 2.2.3, renewable energy data as described in Section 2.2.4, and other data as described in Section 2.2.5.

2.2.1 Network data and processing

We used the network from a 90,059-bus power flow model of the Eastern Interconnection to initiate the study. However, the CEP optimizer is computationally intractable for such a large network; as a result, we had to reduce the network. Although network reduction is a relatively well established technique for power flow analysis, in this work we are performing it for expansion planning optimization, and as a result, we had to extend standard network reduction methods. The process we developed for reducing the network, together with the extensions that we made for doing so to an expansion planning model, are provided in Appendix A. The application of the reduction process resulted in an 843-bus expansion planning model of the eastern part of the Eastern Interconnection (EIC).

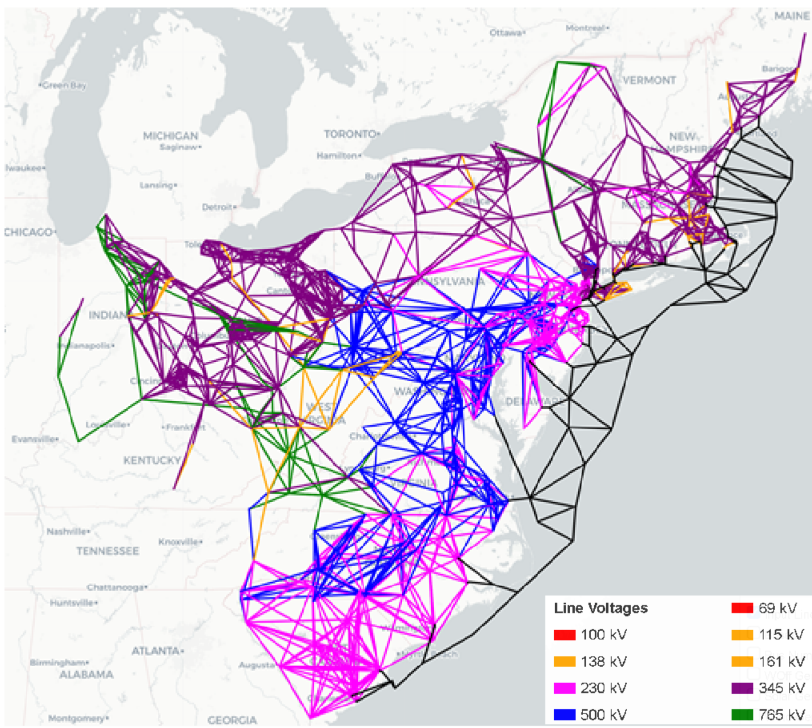

Figure 2-2: Reduced 843-bus network with offshore grid template.

This network is illustrated in Figure 2-2, and represents approximately 283 GW of generation capacity and 243 GW of load in 2031. This 243 GW of load represents approximately 36% of EIC load and 20% of the entire U.S. in 2031 as estimated by FERC-715 and the U.S. energy information administration.[83,84] Also shown in the figure is the "offshore grid template," which will be further described in Section 2.3.

2.2.2 Load data and operational block development

Load data was obtained from FERC form 714 for peak load data and FERC form 715 (Year 2020, projected to 2031) for 8760-hourly load data, also used in the power flow model. The loads were distributed to each bus in the reduced model using load distribution factors calculated during the model reduction process. The load was then 'blocked' into operating blocks to characterize the load in a way that balances computational speed with modeling fidelity. CEP models a production simulation internally to ensure that the investment decisions can satisfy the network constraints such as load balance, generation dispatch limitations, and line flow limitations. However, modeling the network for all operational conditions will render the CEP model intractable. Therefore, we group similar operational conditions in a year into one operational condition (or block).

We represent each year (8760 hours) with 17 blocks. Sixteen of those blocks each represent approximately 360-840 hours per year; one block represents just one hour. Each season is represented by four blocks and each block represents four to eight hours of a day. Four blocks per season are chosen for four seasons (winter, spring, summer, fall), and each of the four blocks in each season represents six hours per day (11 pm to 6 am, 7 am to 1 pm, 2 pm to 6 pm, 7 pm to 10 pm). The four seasons modeled were: (i) Winter: December, January, and February; (ii) Spring: March, April, and May; (iii) Summer: June, July, and August and (iv) Fall: September, October, and November. The 17th block for each year is added to represent the 1-hour peak load condition for the year.

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[83] FERC-715 estimates EIC load in 2031 as 673,043 MW. https://www.ferc.gov/industries-data/electric/electric-industry-forms/form-no-715-annual-transmission-planning-and-evaluation-report. FERC-715 also reports EIC load for 2021 as 643,309 MW. The 10-year growth rate from 2021 to 2031 can therefore be calculated as 673,043/643,309 = 1.0462, which is a low growth rate compared to the 4% annual growth rate assumed in this study between 2031 and 2051. Considering the entire U.S., the U.S. energy information administration (eia) reports 1,145,856 MW for 2021 Summer electricity generation capacity. https://www.eia.gov/electricity/data/eia860/. Assuming the FERC-715 4.62% growth rate between 2021 and 2031 for the EIC, this would imply 1,198,715 MW Summer 2031 capacity for the U.S.

[84] For a European perspective that outlines the latest version of TYNDP, please refer to Entsoe. 2025. A European-wide vision for the future of our power network. https://tyndp.entsoe.eu/explore. Accessed on May 6, 2025.

2.2.3 Cost data

The sources of cost data for generation and transmission are described in the following two subsections.[85]

2.2.3.1 Cost data for transmission and substation expansion

There are four types of branches in the reduced system:

Onshore line cost as function of distances: We obtained transmission expansion cost per MW-mile for each voltage class as described in Section B.1.3, and also shown in Table 2-2.

1. The expansion cost of onshore AC transmission lines is computed as a product of the cost per MW-mile for the line's voltage class and the length of the transmission line. Transmission line length was computed using locations of the terminating substations. The location of each substation was identified using publicly available data.

2. *Onshore transformers*: If a branch in the reduced network connects two buses with different voltage levels, and if it needs to be expanded, we add the cost of transformer expansion to the cost of the line expansion. Transformer expansion costs used are provided in Appendix B, Section B.1.3; this data is also shown in Table 2-3.

3. *Reach circuit transmission lines*: Reach circuits are lines connecting beachheads and POIs. Reach circuits are assumed to be ±525 kV, 2 GW underground HVDC lines,[86] and the cost we use, 15 M$/mile,[87] reflects this expensive installation method. If a POI is connected to a beachhead through another POI, the transmission line between the two POIs is assumed to be a reach circuit, i.e., it is assumed to be a ±525 kV, 2 GW underground HVDC cable with 15 M$/mile cost.

[85] For a European perspective, the Danish Energy Agency is working on a technology costs catalogue for OSW and transmission. Refer to Energistyrelsen. 2025. Technology Data for Generation of Electricity and District Heating. https://ens.dk/en/analyses-and-statistics/technology-data-generation-electricity-and-district-heating. Accessed on May 6, 2025. It would be helpful to develop such a national catalogue for the U.S. that could account for different costs within different regions of the country.

[86] J. Enslin and M, Nazir, "Transmission Expansion Planning Models for Offshore Wind Energy," Sept., 2023.

[87] This cost was used following discussion between project participants and the project advisory board. The authors recognize that other studies have selected other $/mile values for onshore and offshore cables ranging between $5 M/mile, $18 M/mile, $38 M/mile, and even $51 M/mile. We have chosen to work with numbers for our study that seemed to satisfy several members of our project advisory board in 2022, whose membership included both industry and government representatives. Future work should explore the effects of these costs parametrically.

4. *Offshore transmission lines*: The offshore transmission lines are DC lines, and their costs are calculated at 10 M$/mile for a ±525 kV, 2 GW[88] submarine cable.[89] This cost per mile (for submarine HVDC) is less than that used for reach circuit cost per mile (for underground HVDC) because we assume that the expense for obtaining onshore right-of-way will outweigh the added expense for submarine installation.

Table 2-2: Cost of upgrades for onshore transmission lines based on voltage level.[90]

kV	M$/(MW-mi)
34.5	0.4
69.0	0.21
100.0	0.10365
115.0	0.1125
138.0	0.096
161.0	0.064
230.0	0.0408
345.0	0.00840
500.0	0.00500
735.0	0.00412
765.0	0.00312

Table 2-3: Cost of power transformer expansions.

ID	ratio *nv1:nv2*	Cost ($/MVA)
1	69/115	4139
2	69/138	4581
3	69/161	4822
4	69/230	5348
5	69/345	6566
6	69/500	8468
7	69/765	11914
8	115/138	4581
9	115/161	4822
10	115/230	5348
11	115/345	6241
12	115/500	7659
13	115/765	9802
14	138/161	6241

ID	ratio *nv1:nv2*	Cost ($/MVA)
15	138/230	5348
16	138/345	6241
17	138/500	7659
18	138/765	9802
19	161/230	5631
20	161/345	6566
21	161/500	8058
22	161/765	9802
23	230/345	6566
24	230/500	8058
25	230/765	9802
26	345/500	8466
27	345/765	10286
28	500/765	11347

[88] Note that 2-GW in a single cable exceeds the allowable cable capacities of the regions studied. Adopting this TenneT 2-GW standard would require new rules for cable design and permitting.
[89] ISO-NE, 2050 Transmission Study, Final Results and Estimated Costs, https://www.iso-ne.com/static-assets/documents/100004/a05_2023_10_19_pspc_2050_study_pac.pdf, Accessed on Feb. 10, 2025
[90] Refer to Appendix B.1.3 for more information on the values in this table.

When expanding POI substations, we include the cost of expanding the AC substations as described in Appendix B, Section B.1.3; the \$/MW expansion costs are also shown in Table 2-4.[91]

Table 2-4: AC substation upgrade costs for each voltage level.

Voltage Level (kV)	M\$/MW
13.8	0.1008
34.5	0.1008
46	0.1008
69	0.1008
115	0.0575
138	0.051
161	0.0371
230	0.0259
345	0.0122
500	0.008
735	0.0078
765	0.0074

2.2.3.2 Generation operation and investment data

Generation data include investment costs of each technology as well as fixed and variable operation and maintenance costs. These data were obtained from NREL's 2022 Annual Technology Baseline (ATB).[92] All other cost data used in Model 2 were converted to 2022 dollars to be compatible with the cost data from NREL's 2022 ATB. This made it convenient to express all Model 2 net present worth values using an initial year of 2022.[93]

2.2.4 Investment caps and wind/solar production levels in operating blocks

There are two additional types of generation data required by CEP. The first is investment caps at each bus, for onshore and offshore, as described in Section 2.2.4.1. The second is power outputs of wind/solar in each of the 17 operating blocks of each year, as described in Section 2.2.4.2.

[91] Substation costs were included approximately by raising the transmission line \$0.15 M/MW for each end, which totals \$300 M for each end per 2 GW converter. Substation costs were handled similarly in Model 3. Model 1 accounted for substation cost explicitly, something easily done in Model 1 since it is not a linear program.

[92] National Renewable Energy Laboratory (NREL), "2022 Annual Technology Baseline," 2022, National Renewable Energy Laboratory. https://atb.nrel.gov/.

[93] Given all investments were made from 2031-2051 (9-29 years after 2022), the present worth calculation is $\text{PresentWorth}(2022)=\Sigma_{k=9,29}\,(Ck_{2022})\times[1/(1+i_R)^k]$, where Ck is the cost in 2022 dollars of investments made in year k, and i_R is the real discount rate. The alternative to this (not used) is to express present worth as of 2031, the start of the investment period; if this were done, the calculation is $\text{PresentWorth}(2031)=\Sigma_{k=0,20}(Ck_{2022}\times(1+e)^9)\times[1/(1+i_R)^k]$, where the first term $Ck_{2022}\times(1+e)^9$ is inflating the 2022 values from NREL's ATB to 2031 values. Understood in their context, both approaches are correct; however, the second approach results in considerably higher numerical values due to the effect of inflating the 2022 values to 2031 and due to the avoidance of the 9-year delay in discounting.

2.2.4.1 Investment caps

Depending on the location of each substation, the potential for expanding wind and solar resources varies. There are several factors affecting the potential of wind and solar ranging from availability of natural resources to local ordinances and land availability. NREL publishes "supply curves"[94] for wind and solar where they specify potential for wind and solar in 11.5 km by 11.5 km area areas for the entire US. These supply curves are collectively referred to as the "onshore renewable build-out cap" and are provided for different scenarios that include: open access, reference access, and limited access supply curves:

- **The Open Access** supply curve data "only applies land area exclusions based on physical constraints (e.g., wetlands, building footprints) or for protected lands."
- **The Reference Access** supply curve data applies a wider range of exclusions,
- **The Limited Access** supply curve data "applies the most restrictive land area exclusions, capturing potential increased setback requirements and difficulties deploying on federally managed lands."

We enabled user-selection of any of these three supply curve scenarios in our CEP model by translating the information provided per geographical square (i.e., each 11.5 km by 11.5 km area) to the buses represented in our reduced model. To accomplish this, the distance between each bus and each square's centroid is calculated. Then, each square is assigned to its closest bus. The potential of renewable energy at each bus is then computed as the sum over all squares assigned to that bus of each square's potential, first for wind, and then for solar.

The capacity of wind and the capacity of solar are each capped at 12 GW for each bus; doing so avoids results where investments are made at a bus that cannot be supported with realistic transmission investments within the network. These bus caps, when applied to values obtained from processing the supply curves, result in, for limited, reference, and open access supply curves, upper bounds on onshore wind of 513.0, 1031.8, and 1773.9 GW, respectively, and on solar of 2671.3, 4367.9, and 5317.1 GW, respectively.

We limit investment in both major natural gas generation technologies (combined cycle and combustion turbines) to only buses where they already exist, with each of these two technologies having an upper bound on investment of 3 GW. This results in a maximum investment limit over the entire study area in all three scenarios for combined cycle plants of 639 GW and for combustion turbines of 213 GW. To gain perspective, we provide these results in the context of the existing levels of each generation technology, as shown in Table 2-5.

[94] NREL (National Renewable Energy Laboratory). 2021, Available: www.nrel.gov/gis/wind-supply-curves.html and https://www.nrel.gov/docs/fy24osti/87843.pdf.

Table 2-5: Onshore existing capacity, with wind, solar & gas investment limits for each onshore build-out cap scenario: Open, Reference, and Limited Access.

Technology	2031 Existing (GW)	Supply Curve Scenario (GW)		
		Open	Reference	Limited
Biomass	1.7	-	-	-
Combined Cycle	90.6	639	639	639
Coal	48.7	-	-	-
Other Natural Gas	36.6	213	213	213
Hydro	8.8	-	-	-
Nuclear	60.6	-	-	-
Oil	2.2	-	-	-
PS	8.8	-	-	-
Solar	8.5	5,317	4,368	2,671
Wind	17.1	1,774	1,032	513
Total	284	7,943	6,252	4,132

2.2.4.2 Wind and solar outputs for each operating block

Whereas the previous section addresses the maximum wind and solar investment that can be made at each bus, this section addresses the maximum power production in each operating block of the wind and solar that exists (sum of initial year plus any investments up to the given year) at each bus. This maximum power production is the value of the wind or solar output at the given time and season if the corresponding resource (wind speed or solar irradiance) equals the expected value of the resource over all hours represented by the operating block.[95] To accomplish this, hourly or sub-hourly onshore wind, solar, and offshore wind profiles over a year are needed. We satisfy this need using NOAA's 2020 HRRR dataset[96] which provides 15-minute wind and solar profiles over a year. The wind profiles are converted to per-unit output power of wind power plants using wind turbine power curves. The type of power curve used for this conversion is chosen to correspond to the wind technology used in the existing wind farm closest to the bus in question as determined from analysis of the 2022 EIA 860 Form.[97] Per-unit solar output is computed using NREL's System Advisory Model.

Once the wind and solar per-unit outputs over the entire year are obtained, the 15-minute outputs corresponding to each block are extracted and averaged. These values become the maximum per-

[95] The load blocks in this study were created by grouping the load based on the time of the day to create a set of blocks that are "sequential." In previous work, the research team has considered the effects of wind/solar in creating load blocks by grouping net-load instead of load. It is possible to run CEP using any number of load blocks, but compute-time limits the number to 15-20 per year. Here, the maximum number of load blocks we used was four for one day in each season, plus the annual load peak.
[96] Available: https://rapidrefresh.noaa.gov/hrrr/
[97] Available: https://www.eia.gov/electricity/data/eia860/.

unit outputs for the block. With minimum outputs of zero, and with an assigned cost of zero, the CEP treats the wind and solar generation outputs as free variables (subject to their minimum and maximum limits), and the model uses them to minimize the total system cost expended by the thermal plants. This means that, if there were no curtailments due to transmission congestion, all wind and solar would be operated at their maximum, which is the value set by the block's expected value of the resource.[98] Of course, transmission curtailments do occur, and so actual wind and solar output at some buses can be constrained by the model to levels below their maximums.

2.2.5 Other data

Various assumptions were modeled in the dataset, including a real discount rate of 5.4%[99], consistent with that assumed in the NREL ATB 2022. Fuel prices were taken from the EIA. A 4% per year load growth rate[100] was applied to hourly load levels before the yearly blocks were created. Seasonal demands were assumed to grow at consistent rates, which means that the expected transition in the Northeast from summer peaking to winter peaking, due to the electrification of heating, was not captured in these analyses. A constraint for step-by-step carbon reduction with the goal of 90% carbon reduction[101] in the last year of expansion (compared to the first year) was imposed. No constraints were imposed related to ancillary service reserves.

2.3 Offshore grid design

The offshore grid design for high OSW levels is challenging because, unlike most of today's transmission planning problems, it requires the actual siting and interconnection of a large number of new GW-scale offshore substations, also known as energy islands. The following three overarching design principles guide our work:

1. **High OSW levels and grid evolution**: We desire to identify the evolution of the OSG as the OSW levels grow from the current level of almost 0 GW to 600 GW. The 600 GW level was

[98] The point that this paragraph is making is that the model can "spill" some of the wind/solar energy to avoid transmission investments. If there were no transmission capacities (copper plate model), the optimizer would prefer to use all of the generated wind/solar energy since they are "free energy." However, in this model transmission line investments are enforced and, therefore, the optimizer may choose to not use the energy produced by wind/solar generators.

[99] Our choice of discount rate was influenced not only by what NREL 2022 ATB suggested but also by a review of the general literature. For example, as indicated in the Synapse Energy Economics 2023 report "Application of Discount Rates for Assessing Cost-effectiveness of Utility Risk Related Investments," (see https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/safety-policy-division/meeting-documents/discount-rates-and-risk-modeling_synapse_101123.pdf). Real discount rates used recently by investor-owned electric utilities range between 5-8%. Real discount rates used by publicly owned electric utilities are lower.

[100] This load growth rate was chosen as a round number that approximately doubles electricity demand over the 20-year period from 2031 to 2051. This is calculated as $(1.04)^{20} = 2.19$.

[101] This was the highest round number level for carbon reduction that could be specified and still ensure convergence of Model 2.

chosen as an upper bound because it extends what has been thought to be realistic in terms of the offshore wind energy capacity that is available in the region depicted in Figure 2-3.

2. **OSG Template**: We develop the OSG template (OSGT) comprised of an over-prescribed set of zero-capacity offshore lines, with some of those lines connected to the onshore grid; these lines are candidate lines for the OSG. These lines specify pathways that are available to be used by the model but are not required to be used by the model as it selects where and at what capacity to connect offshore energy islands both with beachheads and with other offshore energy islands.

3. **Economic design**: The CEP "fills the OSGT" by identifying

   - capacities of the energy islands (offshore wind nodes);
   - capacities of candidate lines in the OSGT; and
   - onshore generation and transmission expansions necessary to accommodate a target OSW level while minimizing investment cost plus operating cost over the 20-year planning horizon.

Of the above principles, the second and third require significant engineering design. The CEP optimizer and its data are described in Section 2.1 and 2.2, respectively. In this section, we focus on design principle #2: development of the OSGT. Specifically, we identify a set of practical design guidelines to which we adhere in developing the OSGT. We present these guidelines in two sets: one on node selection and one on link selection. These guidelines are as follows:

A. **Approach/criteria for selecting node locations**:

   1. *Energy island locations*: These are chosen based on proximity to offshore wind lease areas and proximity to attractive candidate beachheads. A total of 25 energy islands were modeled in our OSGT design. While it is unrealistic to consider these 25 energy islands sufficient to handle more than 200-300 GW (8-12 GW per energy island), the same energy island configuration is used all the way up to 600 GW (24 GW per energy island) for the sake of consistency in this theoretical study.[102]

   2. *Candidate beachhead locations*: These are chosen based on proximity to offshore wind lease areas, proximity to attractive candidate POIs, and the need to avoid locations

[102] In this study, the authors are primarily concerned with electricity injections into the existing land-based HVAC grid and the notion of how and when offshore HVDC connections might come together to form an offshore transmission backbone. For the purposes of exploration, this study ramps up offshore wind nameplate capacities to exceptionally high levels such as 600 GW without fully considering the exact placement of the implied OSW resources.

having potential for adverse environmental or socially disruptive impacts. A total of 51 beachhead locations were modeled in our OSGT design.

3. *Candidate POIs*: These are chosen based on proximity to attractive beachheads[103] (or to waterways), electrical capacity to interconnect offshore wind energy with the onshore loads, and ability to acquire land for converter stations. A total of 57 POIs were modeled in our OSGT design.

B. **Approach/criteria for selecting candidate links between nodes (i.e., OSGT links)**:

1. *Completely connected N-S path*: There is a completely connected path from New England to the Carolinas.

2. *Reliability-motivated loops*: Some parts of the backbone have parallel N-S paths that are observed as OSGT loops; these parallel N-S paths result from the reliability-motivated design criteria that each energy island is connected by more than one route to both the backbone and the beachheads in order to satisfy an N-1 contingency. While this study does not specifically explore N-1, the authors have attempted to create a baseline candidate OSGT topology that could support future N-1 and other contingency analyses.

3. *Special conditions*:

   a. <u>Multi-POI reach circuits</u>: In most cases, the OSGT connects each beachhead to a single POI, but it is possible that one beachhead is used to connect to additional POIs through a radial HVDC underground line. We call this a multi-POI reach circuit. Multi-POI reach circuits occur where beachhead availability is limited and/or where the distance between two candidate POIs is very short. There are three such situations in the current OSGT: (i) New Jersey, POIs Larabee, Smithburg; (ii) New Jersey, POIs Salem and Hope Creek; (iii) Virginia, POIs Fentress and Landstown.

   b. <u>Use of waterways</u>: OSGT includes submarine routes along rivers and waterways where possible, to minimize the need for onshore transmission routes given related difficulties associated with obtaining rights-of-way and related public resistance. The specifics of environmental permitting for these waterways was not considered.

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[103] In this study specifically, a beachhead is attractive for its proximity to a key POI. In the real world, beachheads are likely to be evaluated for their ability to be permitted, to achieve social acceptance, and to allow for practical and economical pathways to key POIs.

Several assumptions were made in applying the above OSGT design guidelines. These assumptions:

i. *Routing restrictions*: Restrictions on routing lines, due to environmental, military, or fishing industry, are not considered.

ii. *Single source contingency limitations (SSCL)*: SSCLs on POI capacities are not enforced. Today's SSCLs used in the grids of the systems along the US Atlantic Coast can be less than 2 GW and so enforcing them would result in a significantly larger number of beachheads and POIs. Here, in the Model 2 work, we have not limited POI capacities. It will be important as follow-on work to either show that high SSCLs can be addressed through deploying remedial action schemes (RAS) and/or to refine the design with SSCLs imposed (see footnote 123in Appendix B for further discussion of this issue).[104] There is no doubt that analyses through Model 2 would arrive a different set of results if strict SSCLs were imposed.

iii. *Protection from electrical faults*: The protection of the offshore grid is a tradeoff between reliability and cost. There are two extremes: the design for highest cost and highest reliability would deploy DC circuit breakers to enable removal of only the faulted line; the design for least cost and lowest reliability would assume the DC grid is a single protection zone, using AC breakers to remove the entire DC grid for a fault anywhere on it. Because DC circuit breakers are at least an order of magnitude more expensive than AC circuit breakers, a design between these two extremes is attractive, where the DC grid is divided into a limited number of protection zones and protected by a combination of both AC and DC circuit breakers. We assumed no additional cost for protection equipment in all results provided in this report; however, the nature of the protection design could influence the resulting OSG design. This is a topic for additional modeling work and design. Some additional discussion on this issue is provided in an earlier report. [105]

[104] The Joint ISO/RTO Planning Committee (JIPC), consisting of PJM, NYISO, and ISO-NE were requested by ISO-NE on March 27, 2023 to raising the SSCL for New England from 1,200 MW to 2,000 MW. https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/postings/joint-iso-rto-planning-committee-loss-of-source-limit.pdf. Accessed on May 5, 2025.

[105] Johan Enslin and Moazzam Nazir, "Transmission Expansion Planning Models for Offshore Wind Energy," Task Report for Task 4.2, Sept., 2022.

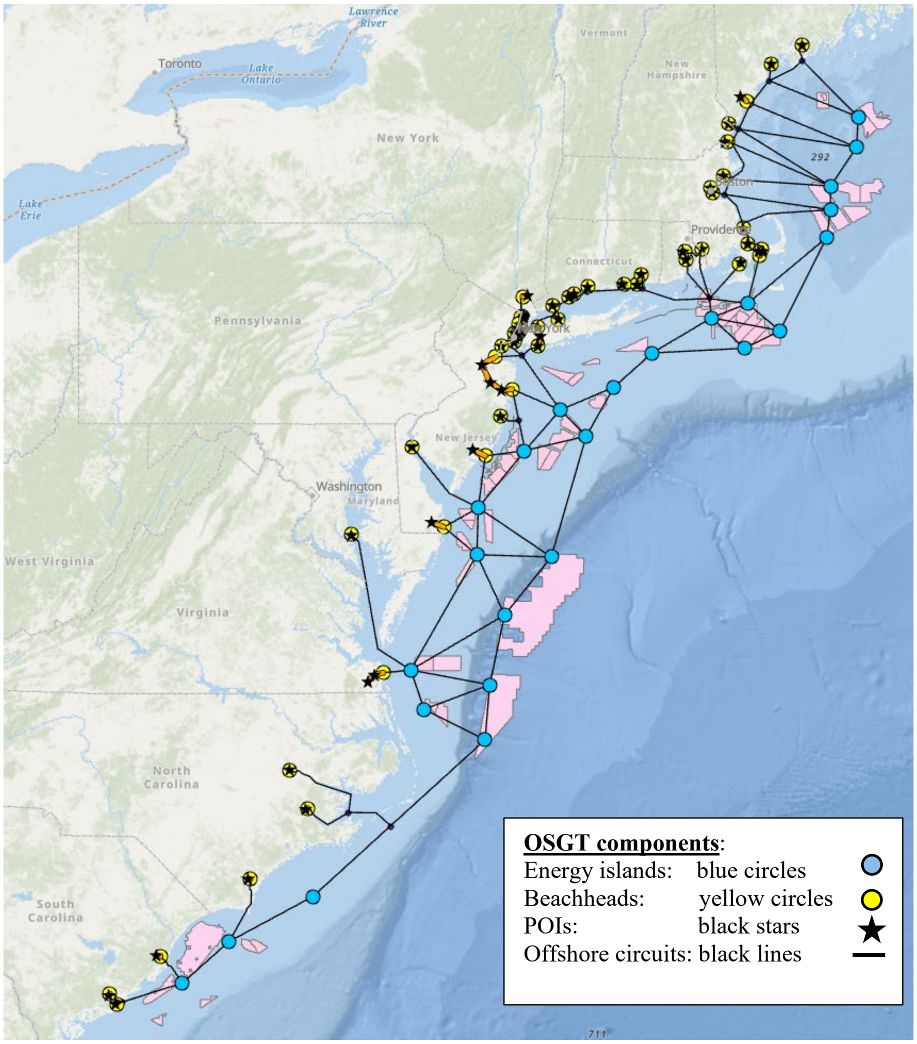

Figure 2-3: Offshore grid template (OSGT).

The results of applying the OSGT guidelines under the stipulated assumptions to develop the OSGT template are illustrated in Figure 2-3. In this figure, the pink areas offshore are wind energy lease areas and planning areas, blue circles are energy islands, yellow circles are beachheads, black stars are POIs, and potential offshore HVDC circuits are black lines.

2.4 Model 2 software used in this project

Several software applications were developed and used to complete this project, highlighting the diverse range of tools and data employed in power system planning for offshore wind. These applications are summarized in Table 2-6. This diversity in tools underscores the need for a comprehensive, unified platform that can integrate these requirements and tools, streamlining the power system planning process and enhancing efficiency.

Table 2-6: List of software used in developing and solving Model 2.

Name	Language/Software	Functionality
Retained Bus Selection	Python	Selects retained buses
Reduction	Matlab (Matpower)	Performs network reduction using Ward's method
Weather Data	Python	Reads the weather data from the HRRR datasets for the calculation of capacity factors
Wind Output	Python	Converts wind speed data to output power
Solar Output	System Advisory Model	Converts solar irradiance data to output power
Capacity Mapping	Python	Maps the capacities of onshore wind and solar to the retained buses and calculates their capacity factors
Equivalent Line Capacity	Julia	Estimates the capacity of equivalent branches in the reduced network
CEP	GAMS	Models the capacity expansion
Postprocessing	Python	Postprocessing and visualization of CEP results
Visualization	JavaScript/HTML	Visualizes flows of transmission lines on a map to show direction of the flows
OSG Design	ArcGIS	Used to overlay different layers for the design of OSG

3 Results of Model 2 analysis

In this chapter, we describe OSG design results obtained from Model 2. Model 2 is run for the reference scenario of onshore wind and solar investible capacity (see Section 2.2.4.1 for description of the three possible investment cap scenarios). As described in the report's introduction (Section 1), the objective of the work is to identify offshore and onshore transmission investments to facilitate much higher levels of East coast OSW levels than have been studied previously. To this end, we assess target OSW levels from 100 to 600 GW in increments of 100 GW. We also run Model 2 for a target OSW level of 0 GW, but with no OSW, under the reference scenario of investment caps and the constraint of 90% CO_2 emission reduction, the production level is insufficient to satisfy the demand (suggesting that a low carbon future may be difficult to realize without any OSW). This was addressed by loosening the CO_2 emission reduction constraint from 90% to 85% CO_2 reduction level.

As explained in Chapter 2, the use of Model 2 consists of, for a targeted 2051 OSW level, applying a CEP to the OSG template (an OSG topology of zero-capacity lines) to identify OSW locations and OSG line capacities together with onshore generation and transmission expansion. The CEP's objective function in making these identifications is to minimize net present worth of investment costs plus operational costs over the 2031-2051 planning period. The only investible technologies for generators are onshore wind and solar, offshore wind, and natural gas-fueled combined cycle and combustion turbines. Candidate investment locations for onshore wind and solar are determined by the data obtained from NREL's supply curves. The natural-gas combined cycle units can only be invested in locations for which such technology already exists.[106]

Although the capacity of OSW invested in each year is hard-constrained, there are two constraints of significant influence in driving *use* (energy production) of that OSW, and as a result of that use, its interconnection to shore. The first requires that CO_2 emission levels be reduced by 90% in 2051 relative to the emissions in 2031; this constraint motivates use of OSW because OSW generation produces no CO_2 emissions. The second is the planning reserve margin (PRM) constraint, which requires total system capacity to exceed 115% of the annual peak (appropriate capacity credits were applied for each technology). This motivates use of OSW in the peak period because OSW has a higher capacity credit than onshore wind.

This chapter is organized as follows: Section 3.1 provides high-level results of the 100-600 GW CEP analysis in terms of OSG design and onshore transmission investments and Section 3.2 presents results from one of those cases in more detail.

3.1 Analysis of necessary investments for 2051 OSW levels of 0-600 GW

The CEP result varies as a function of final year OSW level. By "CEP result," we mean the OSW levels in the energy islands, the OSG transmission capacities between the energy islands and beachheads, the transmission capacities between beachheads and POIs, the locations, amounts, and technologies of onshore generation retirements and investments, the onshore transmission expansions, and the investment years in which the related changes take place. In this section, we study the cumulative final investments in the last year of the planning horizon (2051) as a function of OSW levels, from 0 to 600 GW in increments of 100 GW. Here, we are not exploring the evolution through time to these higher levels (we do that in Section 3.2); rather, we are exploring the cumulative changes necessary to reach these different OSW levels in the final year of 2051. Throughout this section, it is important to remember that a constraint is imposed requiring a 90%

[106] The models take approximately 20 minutes to run each on one of the servers in the Department of Electrical Engineering at Iowa State University. Each of these servers has 256 MB of memory and is equipped with 36 CPUs; the model is allowed to only use 12 CPUs. Each CPU is of type Intel(R) Xeon(R) Gold 6354 CPU @ 3.00GHz. The planning horizon is from years 2031 to 2051, with operational costs accounted for in every year but investments allowed only in years 2031, 2036, 2041, 2046, and 2051.

CO_2 reduction from 2031 to 2051. This means that most existing fossil-fueled generation must be retired and replaced by solar, onshore wind, and offshore wind, and a small amount of gas combined cycle.

3.1.1 Analysis of transmission investments

The cumulative 2051 onshore and offshore transmission investments for each level of offshore wind investments are shown in Figure 3-1.

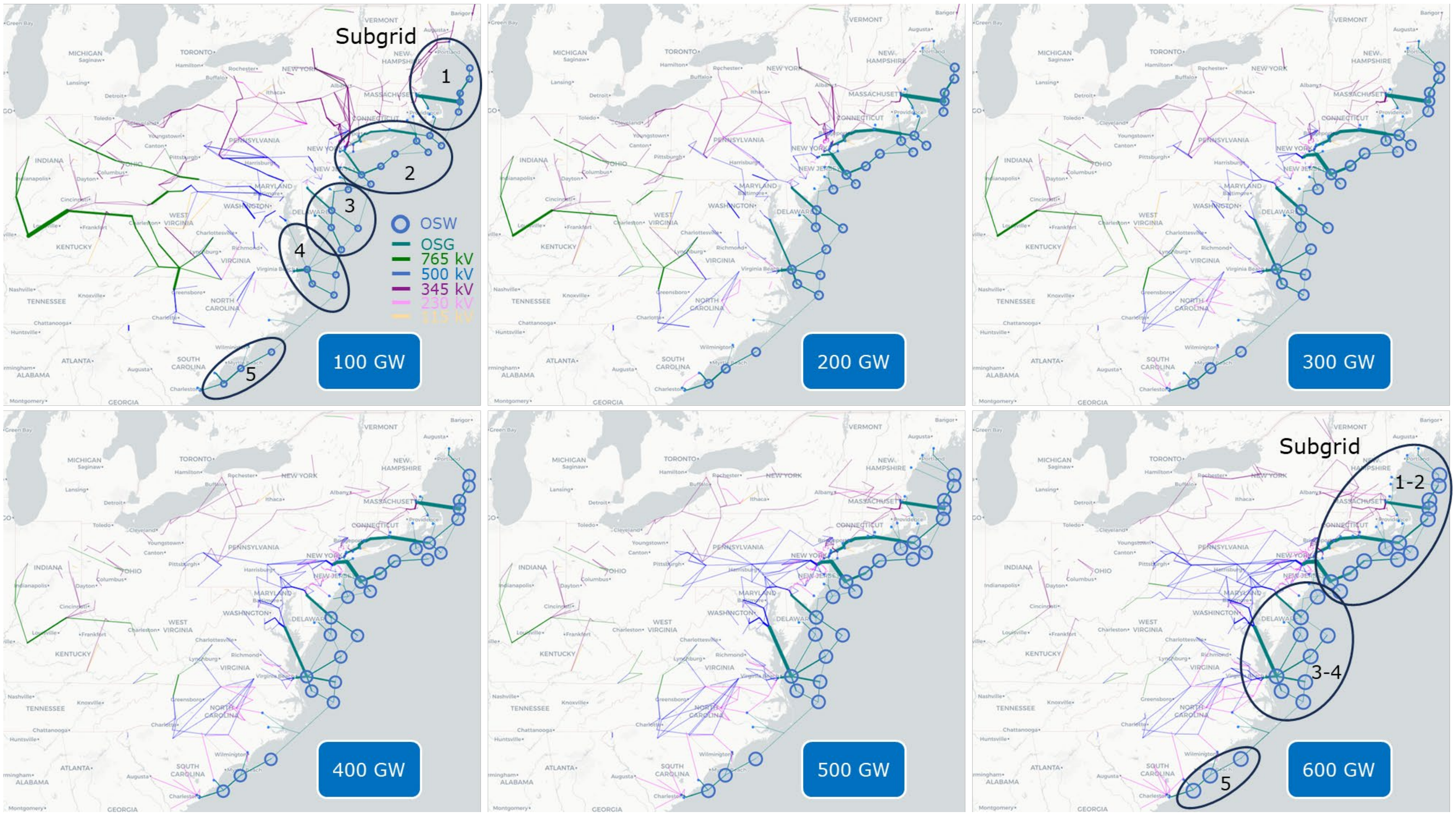

Figure 3-1: Onshore & offshore transmission investments for OSW wind levels of 100-600 GW in final year 2051

The following observations are made based on visual inspection of these maps.

- *Offshore grid*: At the 100 GW level, the OSG is established as five disconnected or very lightly connected subgrids.[107] These are, from North to South: Subgrid 1 from Maine to Boston; Subgrid 2 encircling Long Island; Subgrid 3 from New Jersey to Delaware; Subgrid 4 – a loop off the coast at Virginia Beach with a segment extending up the Chesapeake Bay; and Subgrid 5 – a radial "Carolina" leg from north of Wilmington extending southward to Charleston. These subgrids are clearly visible on the 100 GW OSW map in Figure 3-1. From 200-600 GW of 2051 OSW, two pairs of these subgrids become more heavily interconnected, and so we see only three subgrids: Subgrid 1-2, Subgrid 3-4, and Subgrid 5, as illustrated on the 600 GW map. It is clear from these maps that there is *onshore intersubgrid transmission* built between Subgrid 1-2 and Subgrid 3-4, and between Subgrid 3-4 and Subgrid 5, in parallel to the light *offshore intersubgrid transmission*. The implication of this is that, for high OSW levels, the optimizer sees value in developing transmission for a full Maine-to-Carolina interconnected grid (with most of it offshore but some of it onshore). It would be of interest to further explore the OSG topology and related onshore and offshore intersubgrid transmission with modeling capability to reflect OSG N-1 contingency constraints; it is likely that doing so will increase onshore and offshore intersubgrid transmission.
- *Onshore Western transmission*: For the lowest level of OSW (100 GW), the transmission investment in the Western region (close to Chicago, in Pennsylvania, and in upstate New York) is significant. This indicates that, for the reference investment cap scenarios modeled here, meeting the 90% CO_2 reduction constraint without Atlantic Coast OSW requires the import of Midwestern wind. This Western region transmission presence diminishes as OSW levels increase from 200 to 600 GW and Midwestern onshore wind is replaced with OSW.
- *Onshore Eastern transmission*: For the lower levels of OSW (100-200 GW), the transmission investment around the Eastern load centers of Boston, New York, Philadelphia, Baltimore, Washington, D.C., Richmond, Norfolk/Virginia Beach, Wilmington, and Charleston are modest, as the OSW injections east of these load centers tend to counter the prevailing flows from the west, essentially freeing transmission capacity as eastward flows decrease. As OSW levels increase beyond 300 GW, this effect diminishes, and what were declining eastward flows begin to increase westward to meet loads further inland. At the same time transmission around load centers becomes congested. Both effects motivate increasing onshore transmission investments for the 300-600 GW OSW levels.

[107] The absence of N-1 and other contingency analysis in this work implies that the connections between subgrids are weaker here than they would actually need to be. The need for redundancy is a primary driver in the design and build-out of an offshore transmission backbone with appropriate RAS. Understanding the impacts of contingency planning on the offshore grid is critical to future work on this subject.

The last two bullets indicate that onshore transmission investment at first declines with OSW levels (due to the Onshore Western transmission effect) and then increases with OSW (due to the Onshore Eastern transmission effect); these two effects taken together suggest that, as OSW increases from 0[108] GW to 600 GW, there should be a value of OSW level that minimizes onshore transmission investment. To check this, we have plotted onshore transmission investment cost against OSW level, as OSW increases from 0 GW to 600 GW. This plot is illustrated in Figure 3-2, which shows that the minimum occurs at an OSW level of 250 GW (although we accept this for our purposes here, we recognize that the actual minimum might be somewhat less than or somewhat more than 250 GW). This is very useful information, since building additional onshore transmission on the Atlantic Coast is challenging, given its population density and related public resistance.

As a check on this last result, that onshore transmission investment is minimized at an OSW level of 250 GW, we developed the same plot – of onshore transmission cost vs OSW level – but using a different model, which we call Model 3. This model is fully described in Section C.3.1 of Appendix C; here, we duplicate the relevant figure, which is Figure 3-3. This figure shows two curves of onshore transmission costs as a function of OSW level, one without the Macrogrid modeled, and another with the Macrogrid modeled. The higher curve corresponds to Model 2 (because it does not model a Macrogrid); it shows a minimum onshore transmission cost at an OSW level of 250 GW, in exact agreement with the 250 GW minimum identified by the Model 2 work. The fact that these two models (which differ significantly in terms of the source and dimension of the represented network) gives such a similar result, provides strong supporting evidence for the result. Although the Model 3 curve with the Macrogrid represented does not show a minimum (the dashed curves are extrapolations and do not represent actual results), the fact that it shows onshore transmission cost decreasing with OSW levels is intuitively pleasing, since the Macrogrid tends to relieve onshore transmission. We suspect that the Model 3 curve with the Macrogrid will show a minimum if it is extended to larger levels of OSW.

As an ancillary comment in this subsection, it is significant that Figure 3-3 indicates the presence of the Macrogrid reduces the cost of East coast onshore transmission by $45B at 200 GW and by $80B at 300 GW. This is strong evidence of the coupling between an offshore backbone grid and the Macrogrid, and that Macrogrid development, costing in the range of $150B, could pay for itself at the higher levels of OSW.

[108] We note that in the case of no offshore wind, there is not enough energy from onshore wind and solar to satisfy the demand and the 90% emission reduction constraint. Therefore, the emission reduction requirement is lowered to 85%.

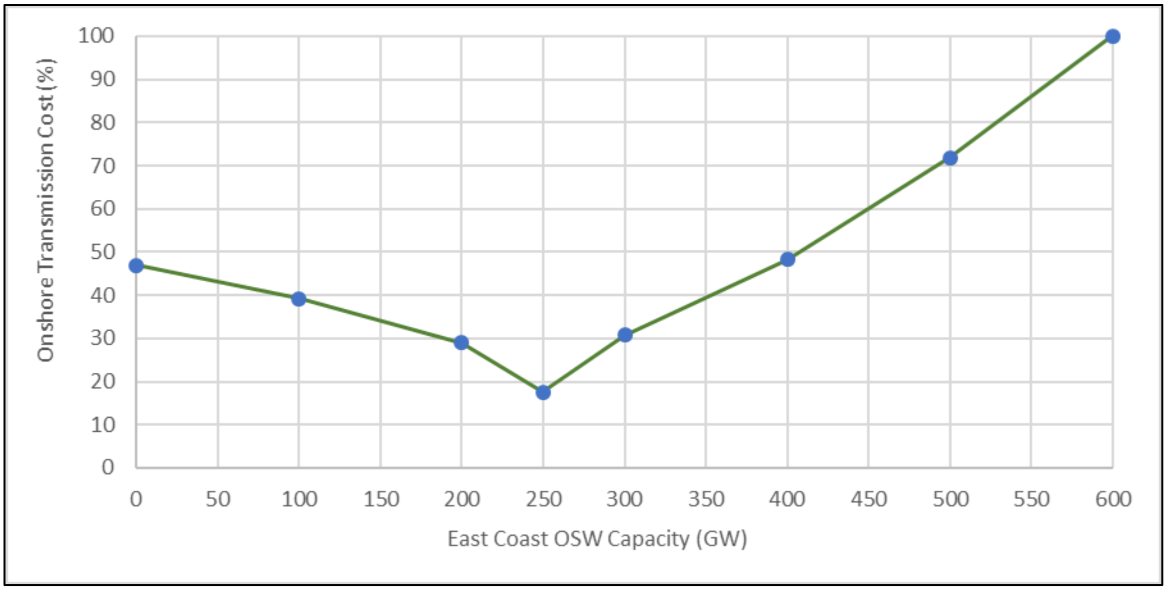

Figure 3-2: Model 2, Onshore transmission investment cost vs offshore wind power capacity build-out (GW).

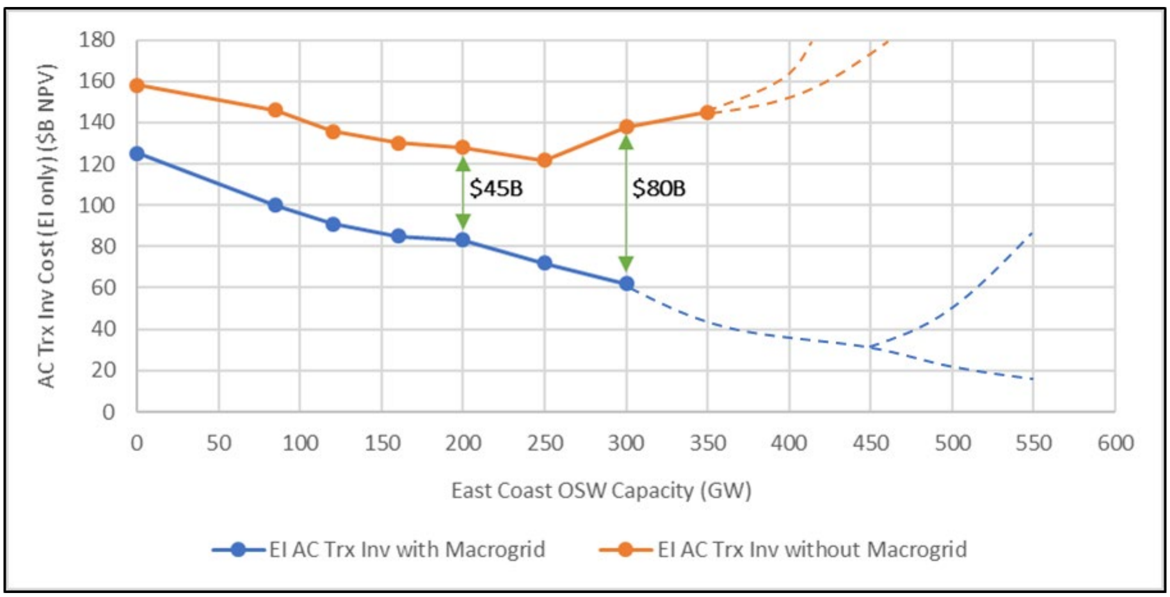

Figure 3-3: Model 3, Plot of East Coast OSW power capacity build-out (GW) vs. AC upgrades required in the Eastern Interconnect (EI), with and without the Macrogrid.

3.1.2 Analysis of generation investments for reference investment cap scenario

The cumulative onshore and offshore generation added, through 2051, for each level of offshore wind investments, from 100 to 600 GW, are shown in Figure 3-4. These maps differ from those of Figure 3-1 in that here, we also show the onshore wind and solar generation investments. As was the case for the map of Figure 3-1, the maps of Figure 3-4 are not evolutionary; rather, they show the added generation in 2051 for the stated 2051 target OSW level. The following observations are made based on visual inspection of these maps.

- *Onshore generation reduces*: The maps indicate that onshore generation reduces as the target OSW level in 2051 increases from 100 to 600 GW.
- *Onshore wind reduces more than solar*: The maps indicate that onshore wind (green) reduces more sharply than solar (yellow) as the target OSW level in 2051 increases from 100 to 600 GW.

To check these observations, we developed Figure 3-5, which shows variation in total solar capacity and total onshore wind capacity as a function of OSW levels from 100-600 GW. This plot confirms that the need to build both solar capacity and onshore wind capacity reduce as OSW levels increase. As observed in the map of Figure 3-4 and as indicated in the second bullet above, the need to build onshore wind reduces more than solar. Whereas the required build-out of onshore wind reduces by about 870 GW, the required solar build-out reduces by only 250 GW. One reason for this is that solar capacity factors have lower locational variation than onshore wind in the Northeast and can be sited closer to load, thus reducing the required transmission upgrades. Another reason is that the daily and seasonal variations in solar capacity are complementary both to onshore and offshore wind capacities. This tends to maintain solar capacity and reduce onshore wind as OSW levels increase. However, because we have not represented storage in Model 2, the system must maintain a certain amount of wind to supply nighttime loads, when solar is unavailable. This implies that the total onshore and offshore wind capacity levels should remain relatively constant as OSW levels increase, an implication that is supported by the lower plot in Figure 3-6. There is small, but nonnegligible (~280 GW) reduction in total onshore and offshore wind capacity levels as OSW levels increase; this is because OSW has higher capacity factors than onshore wind. This effect is amplified in the top plot of Figure 3-6, which shows an even steeper decline in capacity for total onshore wind plus offshore wind plus solar capacity; this amplified effect is because OSW produces more energy per installed nameplate capacity due to larger wind resource availability. This phenomenon is quantified as a "capacity factor" which is calculated as the energy produced over a given time period divided by the project nameplate power generation capacity. OSW has significantly higher capacity factors than land-based wind and solar for the region in question. For instance, for the Reference Case 250 GW OSW build-out, the annual energy production, capacity build-outs, and average annual capacity factors for Solar, Wind, and Offshore Wind are listed in Table 3-1 and calculated according to Equation 1.

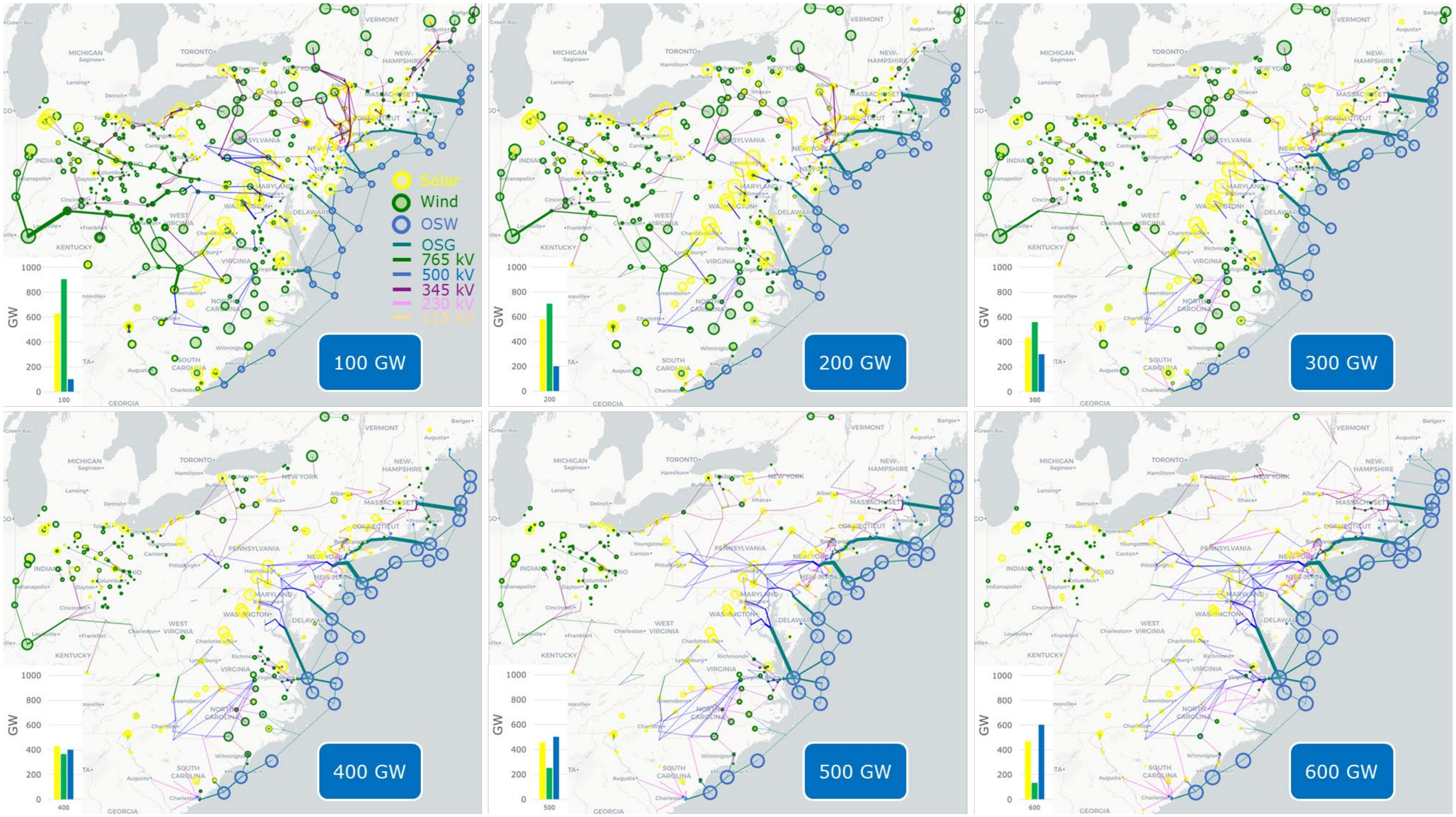

Figure 3-4: Onshore & offshore added generation for OSW build-out levels of 100-600 GW in final year 2051.

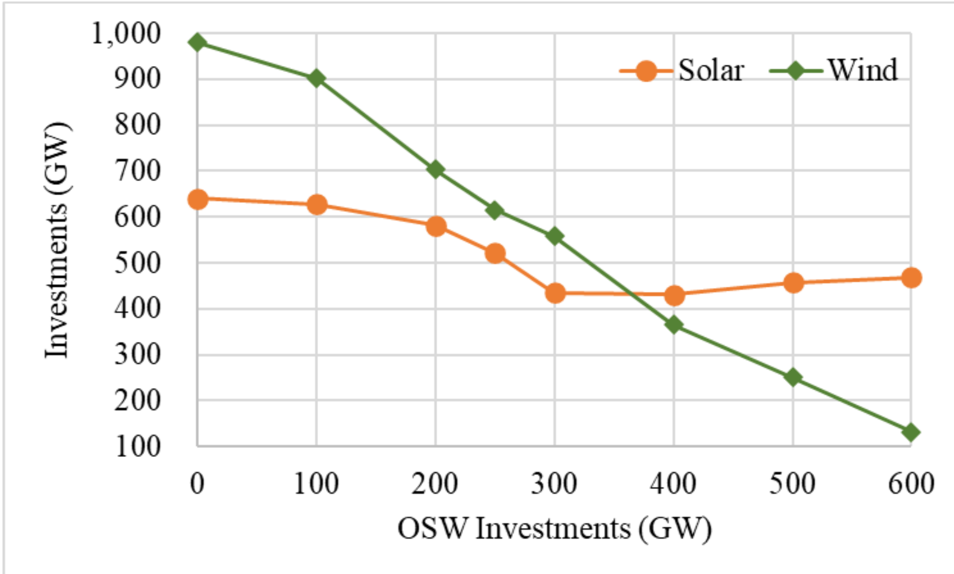

Figure 3-5: Onshore wind and solar in 2051 as OSW build-out levels increase from 0-600 GW.

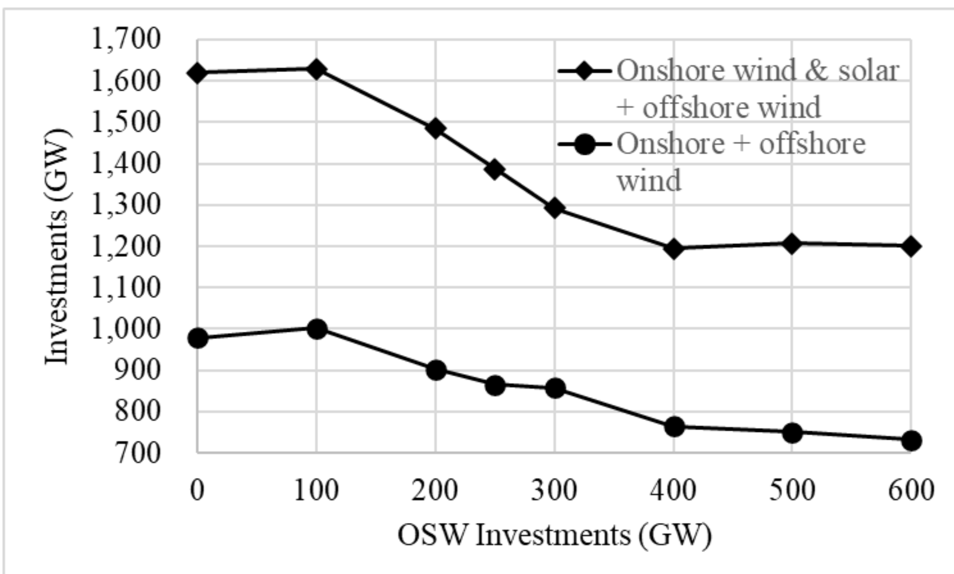

Figure 3-6: Solar, onshore and offshore wind capacities in 2051 as OSW build-out levels increase.

3.1.3 Analysis of generation investments for three onshore build-out cap scenarios

All analysis in this report, outside of this subsection, is based on the assumption that the onshore wind and solar capacity limit is characterized by the "reference scenario" (see Section 2.2.4.1). In reality, there is some uncertainty on what the onshore wind and solar capacity limits are; relative to the reference onshore build-out cap scenario, this uncertainty is characterized by the "limited" and "open access" scenarios. This fact motivates the following question: *how much OSW should be built under each capacity limit scenario to achieve 90% CO2 reduction*?

We modeled each of the three capacity limit scenarios in our model. In contrast to all work described so far in this report, we allowed the model to choose the OSW level, i.e., we did not impose constraints to force the model to build a certain specific OSW level. The result of this analysis is that in the open access scenario, 186 GW of OSW should be built; in the reference scenario, 286 GW of OSW should be built; and in the limited scenario, 384 GW of OSW should be built.

Amounts of required OSW build-out for each of these three scenarios increase with decreasing onshore wind and solar build-out levels as indicated by Figure 3-7 below. It is observed that the utility-scale solar investments stay almost the same across the scenarios (there is an abundance of solar potential in all three scenarios, but the need to serve nighttime loads inhibit its growth in favor of onshore or offshore wind). When onshore renewable siting is more constrained, as it is in the "limited" scenario, the need for OSW investments increases and OSW becomes competitive with otherwise less expensive onshore resources. In other words, as the onshore locations with higher capacity factors and affordable transmission routes are taken, OSW becomes comparatively more affordable.

The question arises whether the OSW is developed because the solution would be infeasible otherwise, or because the OSW is economically attractive. In considering this question, we focus on only the reference scenario, because we have used that scenario to perform other analyses in this report. Specifically, we consider the reference case reported in Section 3.1.2, where we constrained the case to build exactly 100 GW. We refer to this case as the "targeted" reference case, in contrast to the "unconstrained" reference case described here where a 286 GW OSW build-out is required. Besides the constraints imposed in the targeted case, all other conditions in the two cases are exactly the same. The implication of the 100 GW OSW in the targeted case is that it is feasible to have less than 286 GW of OSW. This means that in the 100 GW targeted case, there must be another 186 GW OSW that is more economically attractive than any onshore resource. Some reasons why there is another 186 GW of OSW that is more economically attractive than any onshore resource include:

- gas is unavailable because of the need to satisfy the 90% CO2 reduction requirement;
- solar is unavailable because of the need to supply nighttime load; and

- it is possible to add more onshore wind (there are wind sites remaining), but these sites have low-capacity factors and high transmission build cost (e.g., they are in the mountains and farther away from load).

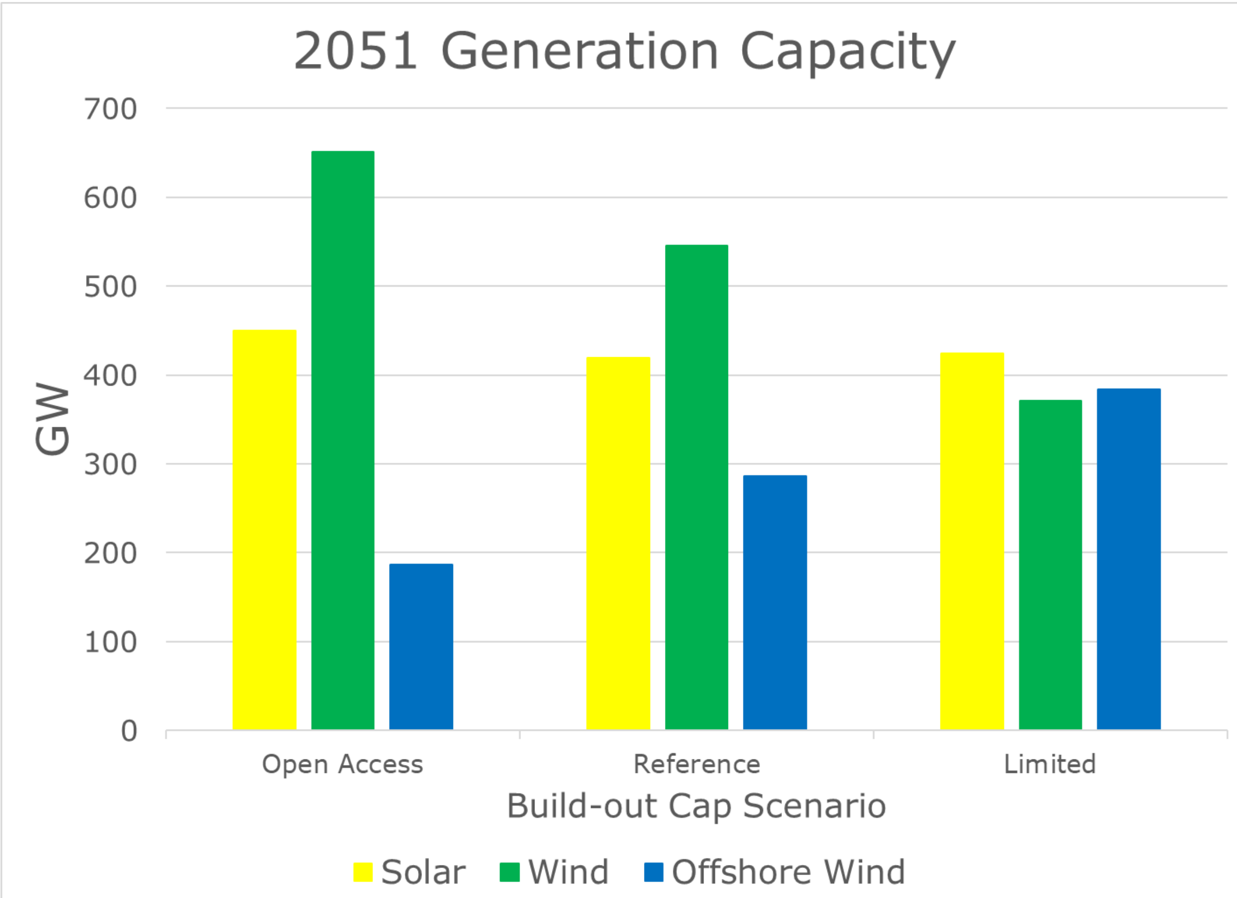

Figure 3-7: Power generation build-out levels across different onshore renewable build-out cap scenarios.

3.2 Results of the 250 GW case

In Section 3.1, we saw that a case with 250 GW of OSW investment is at or close to the minimum onshore transmission investment cost. Thus, 250 GW is an attractive and credible OSW target that stretches current thinking on what is achievable. Therefore, in this section, we choose a 2051 OSW level of 250 GW to assess in more detail. Specifically, we provide information on the breakdown of capacity and peak energy in Section 3.2.1, the POI selection in Section 3.2.2, and in Section 3.2.3 the time-evolution from 2031 to 2051 of the system that results in an OSW level of 250 GW in 2051.

3.2.1 Breakdown of capacity and peak energy

Table 3-1 lists 2051 power generation capacities (GW), their corresponding annual energy outputs (TWh) used, and average annual capacity factors (ACF) calculated as

Equation 1

$$ACF = \frac{(TWh)(1000\ GW/TW)}{(GW)(8760\ hrs/y)}$$

Offshore wind is shown in blue as OSW. Land-based wind is shown in green. Solar is shown in orange. These are followed by nuclear, hydro, "Other," and combined cycle (CC) natural gas plants. The technology "Other" is comprised of coal power plants (32 GW), other natural gas technologies such as steam turbines (36.6 GW), and other technologies such as oil-fired (2.17) units, biomass (1.7 GW), legacy pumped storage and storage (8.7 GW).

Table 3-1: Power and energy resource mix for the case of 250 GW OSW in 2051.

Resource	GW	% Cap	TWh	% Energy	ACF
OSW	**250**	15.0%	744	24.9%	0.340
Wind	615	36.8%	981	32.8%	0.182
Solar	521	31.2%	671	22.4%	0.147
Nuclear	61	3.6%	294	9.8%	0.550
Hydro	9	0.5%	28	0.9%	0.355
Other	81	4.9%	93	3.1%	0.131
CC	133	8.0%	180	6.0%	0.156
Total	**1,670**		**2,991**		

Table 3-2: Energy resource mix at Peak for 4-5pm EST on July 9.

Resource	GWh	% Energy
OSW	42	7.9%
Wind	20	3.7%
Solar	367	68.7%
Nuclear	44	8.2%
Hydro	2	0.4%
Other	8	1.5%
CC	51	9.6%
Total	**534**	

In 2051, the peak load of the system occurs at 4pm EST on July 9. Table 3-2 shows the energy resource mix at this moment in time. This result is not consistent with the expectation that the Northeast will transition to winter-peaking by 2051 due to the electrification of the heating sector.[109] The result, therefore, reflects the fact that Model 2 has assumed consistent 4% annual load growth without any change to the electricity demands of different seasons or peak conditions. Based on this analysis, the wind output at this hour is not significant and the solar output contributes to 69% of the total produced energy. Although most of the energy is being produced by solar, offshore wind, combined cycle natural gas, and nuclear power plants contribute the main portion of the remaining required energy. Under winter-peaking conditions in the Northeast, one would expect to see higher annual and peak utilization of OSW, which has higher capacity factors during the winter months than during the summer months.

3.2.2 POI selection

Appendix E identifies candidate POIs used for Model 2 analysis. The theoretical capabilities of these substations provide a realistic and illustrative representation of what it would take to build out large-scale OSW in coordination with a Macrogrid.

Table 3-3: Selected POIs and their capacity for 250 GW OSW in year 2051[110]

POI	ISO	Capacity (GW)	POI	ISO	Capacity (GW)
DEANS	PJM	12.24	SHORE RD	NYISO	1.51
SALEM	PJM	11.97	W BARNSTABLE	ISONE	1.43
6LANDSTN	PJM	11.78	BARRETT1	NYISO	1.42
CLVT CLF	PJM	9.26	FARRAGUT WES	NYISO	1.32
MYSTIC MA	ISONE	6.97	GOWANUS	NYISO	1.31
K STREET 3_R	ISONE	6.97	MILLSTONE	ISONE	1.23
RAINEY WEST	NYISO	5.02	MAINE YANKEE	ISONE	1.13
6WINYAH	DUKE	4.98	6SUTTON230 T	DUKE	0.94
28LARRABEE	PJM	4.24	SALEM HARBOR	ISONE	0.62
NRTHPRT1	NYISO	4.00	MONTVILE_364	ISONE	0.49
GOTHLS	NYISO	3.75	6NEW BERN WE	DUKE	0.42
6CHURCH2!	DUKE	3.38	NORWALK HRBR	ISONE	0.24
PILGRIM	ISONE	3.03	BRAYTN POINT	ISONE	0.14
INDRIV 4	PJM	2.86	YARMOUTH	ISONE	0.13
3JAMES I	DUKE	1.80	DAVISVIL90_T	ISONE	0.10
28OYSTER C	PJM	1.74	CANAL	ISONE	0.09
ASTORIA W-N	NYISO	1.73	MOTT HAVEN	NYISO	0.08
CARDIFF	PJM	1.62	ACADEMY	NYISO	0.04

[109] According to our project advisory board, New England utilities anticipate that the peak will shift from summer to winter as early at the 2030s. While beyond the scope of this report, more accurate models of load growth and seasonal peaking should be priorities for future analyses that leverage CEP and Model 2.

[110] It is not clear to the authors why some of these POIs have numbers in front of their names. These substation names have been taken directly from the original data used to compile Model 2.

For the 250 GW OSW case, the model chooses 32 out of the 57 candidate POIs to inject power from the OSW into the onshore grid. The chosen POIs are listed in Table 3-3 and shown geographically on the map of Figure 3-8. Table F-1 through Table F-7 in Appendix F show POI capacities for OSW injections ranging from 100 GW to 600 GW.

The top 14 highest capacity POIs selected, all of which are above 2 GW and add up to 90.5 GW (36% of the 250 GW OSW nameplate capacity), are identified by name in Figure 3-8. Comments on POI selection follow:

- *POI total capacity*: Although 250 GW of OSW is modeled, the CEP builds only 110 GW of POI capacity, or 44% of the total nameplate capacity. The implication of this is that the maximum OSW generation condition that we have modeled injects 110 GW of power into the onshore system. Although geographical diversity will ensure that a 250 GW power injection will never occur, it is also certain that OSW generation conditions higher than 110 GW will occur. We have not captured such higher generation conditions because of temporal averaging, i.e., the OSW capacity factors we have used represent 6-hour blocks and are therefore averaged over 6 hours. Thus, the highest wind speeds in those 6-hour blocks are "averaged-out." The implication is that, with the given design (beachhead, POI, and transmission capacities), curtailment will be necessary under some OSW conditions. An improvement to our model would adjust POI capacity based on the economics of curtailment vs. investment.
- *POI locations*: The POI capacity is distributed up and down the Atlantic Coast, with 51% in the PJM area, 21% in the ISONE area, 18% in the NYISO area, and 10% in the Duke Energy area. From Figure 3-8, the heavy POI capacity in PJM is observed at Deans, Salem, Landstown, and Calvert Cliffs, with other high-capacity POIs at Mystic and K Street in ISONE, at Rainey West in NYISO, and at Winyah in Duke.
- *Concentration of key power corridors:* These POI capacities confirm that the selection of key power corridors is not only possible but also desirable from a power flow point of view. This conclusion supports the original goals of this project as expressed in Figure 1-1: *to minimize environmental impact by maximizing power flows at key landings and POIs*. This conclusion places additional emphasis on the need to think through OSW transmission from an interregional perspective and to identify the most important POIs for investment and upgrade. It also raises the importance of reliability analysis for N-1 and other contingencies where a major power corridor is assumed to be compromised.

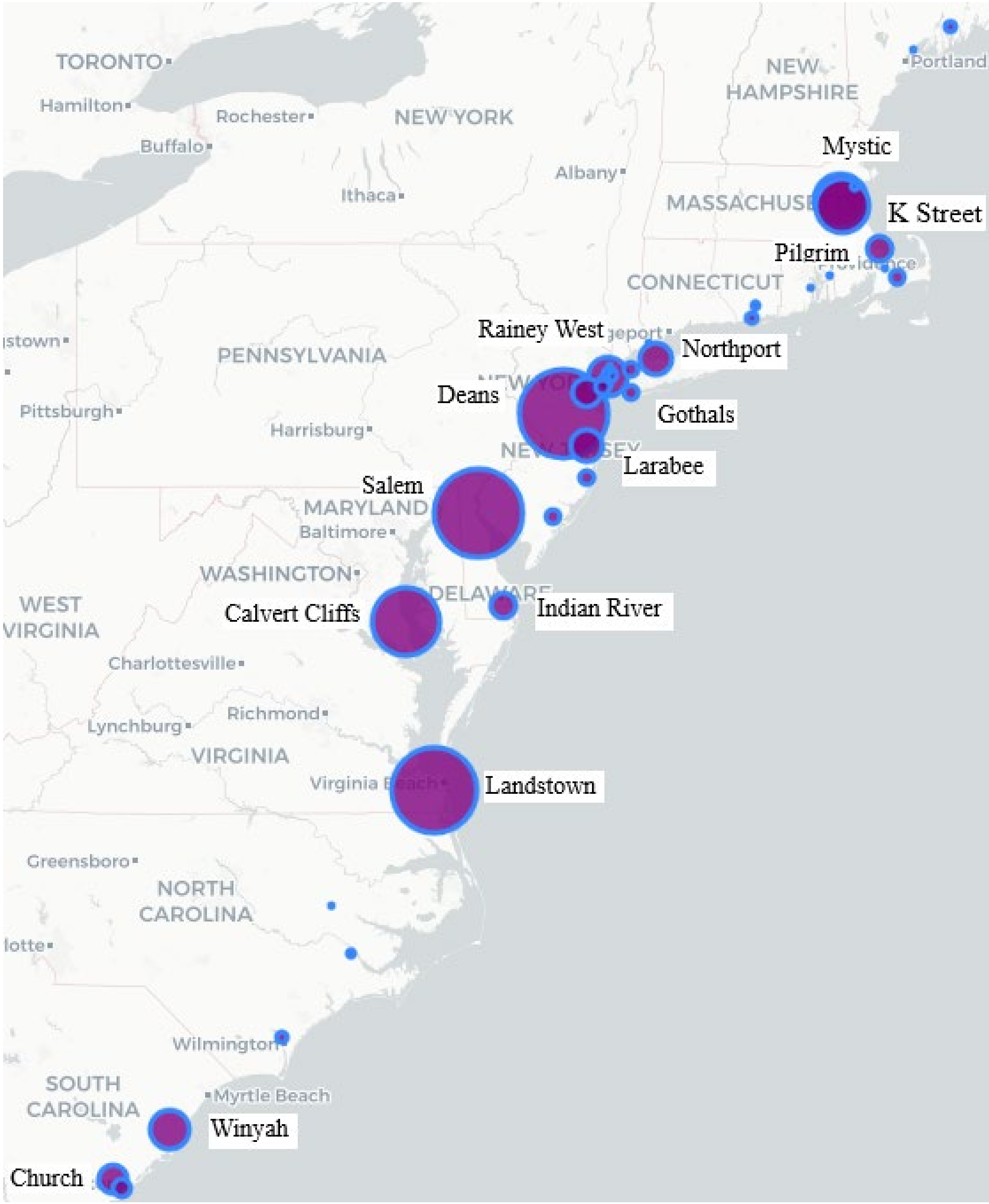

Figure 3-8: Map of POIs at 250 GW OSW investments. Larger circles refer to larger OSW injections, for which numerical values are provided in Table 3-1.

3.2.3 Evolution through time of grid investments

The evolution through time of the onshore and offshore transmission investments for the 250 GW OSW case is shown in Figure 3-9. The evolution is a “controlled” one in that it uses constraints to impose that OSW capacity increases by 50 GW every fifth year. Whereas each of the maps of Figure 3-1 are final year (2051) for a specific target OSW design, the maps of Figure 3-9 show a temporal evolution. Similar to the 100 GW map of Figure 3-1, the 50 GW OSW map in Figure 3-10 tends to organize around five subgrids, and similar to the 300-600 GW maps of Figure 3-1, the 250 GW map shows that offshore transmission merges two pair of these, resulting in three subgrids, each of which are internally well connected. Although the interconnections between the three subgrids are light, as in the 300-600 GW maps of Figure 3-1, these light offshore inter-subgroup interconnections tend to be compensated by parallel onshore transmission investments, forming a continuous transmission path along the Atlantic Coast.

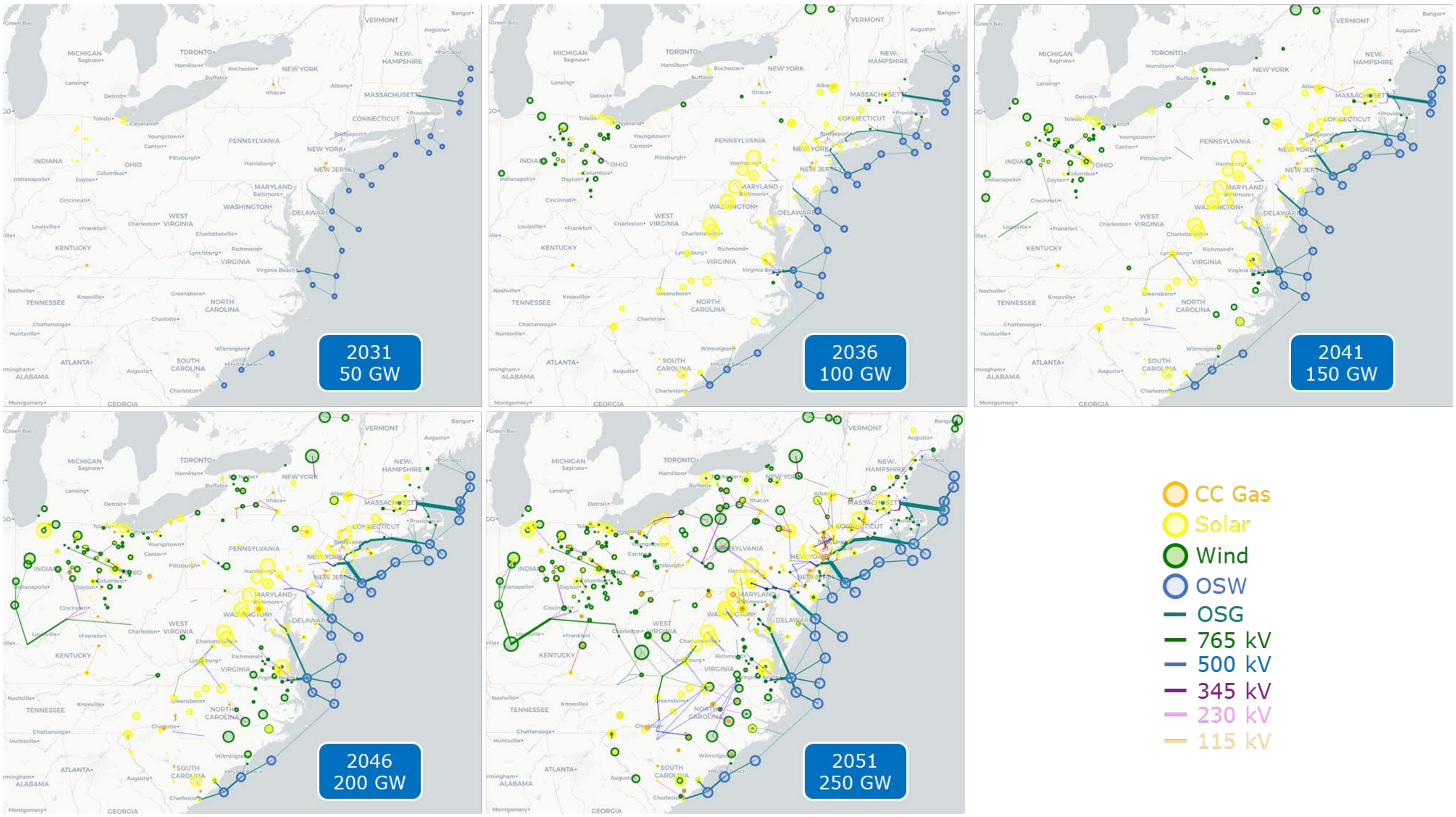

Figure 3-9: Evolution of onshore and offshore generation and transmission investments for 250 GW offshore investment by 2051.

4 Conclusions and further work

The project highlights the role of offshore wind in the U.S. Atlantic Coast and provides insights related to the necessary investments for both offshore and onshore generation and transmission, focusing particularly on OSW levels ranging from 100 to 600 GW. Conclusions from this project are provided in Section 4.1. Further work is described in Section 4.2.

4.1 Conclusions

The following conclusions are based on the work completed within this project.

1. **Design method**: We have created a design approach for identifying effective, reliable, and cost-efficient onshore and offshore designs for any targeted OSW level. This design method includes the development of an offshore grid template to specify possible grid topologies and then deployment of a coordinated expansion planning (CEP) optimizer to identify link capacities as well as onshore generation and transmission expansion. Two constraints are particularly important in this design procedure:
    a. *CO_2 reduction constraint*: All modeling in this report requires reaching, by 2051, a CO_2 reduction of 90% relative to a 2031 reference level.
    b. *Planning reserve margin (PRM) constraint*: In each year, the total model generating capacity is required to be 115% of the annual peak load.
2. **Maine to Carolinas Transmission and OSW Integration:** A robust transmission corridor from Maine to the Carolinas emerges as an optimal strategy to integrate higher OSW capacities while ensuring reliability and economic efficiency. This approach leverages regional energy exchange for lower values of offshore wind investments and interregional energy exchange for higher values of offshore wind. Some features of particular significance include:
    a. *Subgrid organization*: Although the model develops an interconnected north-to-south backbone transmission corridor from Maine to the Carolinas, there are five main subgrids for 100-200 GW of OSW that transition to three main subgrids for 300-600 GW of OSW.
    b. *Onshore and offshore*: Although some sections of the offshore north-to-south corridor are weakly connected (and thus the identification of subgrids), the model also builds onshore north-to-south transmission that is parallel to those weakly connected offshore sections. This observation confirms that the model is seeing economic benefit for building a north-to-south transmission corridor that is strong for the entire length of the Maine-to-Carolinas coast.

   c. *Macrogrid integration*: An Atlantic Coast offshore grid to support OSW would integrate into a Macrogrid design as the eastern leg of a multiregional high-capacity North American transmission system.
3. **Onshore Transmission Investments:** The analysis identifies two significant ways of reducing onshore transmission investment and thereby mitigating the sociopolitical difficulties of building onshore transmission on the population-dense East Coast.
   a. *Targeting 250 GW OSW*: A pivotal threshold at 250 GW of OSW capacity is identified, where onshore transmission investment requirements are minimized. Below this level, significant investments are needed to transfer energy from onshore generation to coastal load centers.[111] Above 250 GW, additional investments facilitate the inland distribution of OSW-generated energy, reducing reliance on onshore wind from the Midwest.
   b. *Macrogrid influence*: Macrogrid development for higher OSW levels tends to "lift up" onto the Macrogrid traditional loadings on the AC transmission system, essentially freeing up AC transmission capacity. Although Macrogrid transmission must be built to capture this benefit, the savings in cost and sociopolitical difficulties of building a few high-capacity transmission lines (Macrogrid) greatly outweigh that of a large number of expansions on the AC transmission system.
4. **POI Selection and Offshore Grid Design:** We found that the design procedure consistently selects POIs located near major load centers, emphasizing their importance for cost-effective OSW energy interconnection. Some features of particular importance include:
   a. *36 POIs*: Although 36 POIs were selected, 14 of them exceeded 2 GW in capacity. POIs within the PJM region are of highest capacity; fairly high-capacity POIs are also needed in the regions of ISONE, NYISO, and Duke.
   b. Single source contingency limit (SSCL): Many of the POIs have capacity that exceeds the current SSCL of their region. Imposing these SSCLs on all POIs would result in in more beachheads and shore landing points. It is therefore important to weigh the social and environmental consequences of more landings versus higher-capacity power corridors. Allowing for high-capacity POIs implies that SSCL problems must be addressed via engineering solutions. We think this is doable via deployment of remedial action schemes (RAS) to add system flexibility and allow for a suite of alternative solutions to potential faults. RAS are a technology that has been heavily used for many decades in the Western Interconnection of North America.

[111] There is an opportunity here to study the 2050 transmission expansion needs of a given RTO with and without 250 GW of OSW. Understanding the upgrades required for both scenarios could be helpful in setting priorities for early investments in land-based transmission expansion.

5. **Generation technology portfolio:** The 90% CO_2 reduction constraint limited the generation portfolio to mainly onshore wind, offshore wind, and solar. Increasing OSW levels results in diminished onshore wind and solar, with total wind and solar capacity declining due to the higher capacity factors typical of offshore wind. As OSW levels increase, solar declines less than onshore wind because solar can be placed closer to load and requires less onshore transmission. Total onshore and offshore wind tends to stay relatively constant as OSW levels increase, to satisfy nighttime loads. The model indicates reaching the CO_2 reduction level by 2051 using regional resources is infeasible without some OSW. Specifically, reaching the 90% CO_2 reduction level will require between 186 GW and 384 GW of OSW, depending on onshore wind and solar build-out caps, a range that conveniently includes the 250 GW OSW level that minimizes onshore transmission investment (see conclusion #3 above). Other (untested) solutions could include the deployment of nuclear energy, large-scale storage, or other renewable resources that are not yet as affordable at scale as solar, wind, and offshore wind.

4.2 Further work

There are significant analysis and design efforts that are needed before Atlantic offshore wind can be built at the scale considered in this project. We think there are areas of particular interest that deserve attention in the near term. These areas are summarized below.

1. **Single source contingency limits (SSCL)**: Studies should be conducted to determine the viability of remedial action schemes (RAS) for relieving consequences of losing POIs that are operating at capacities exceeding today's SSCLs. Such studies would be done using a dynamic analysis tool such as PSS\E's DSA application. The RAS would operate within milliseconds of POI interruption, taking control action to relieve the flows injected from the offshore grid into the onshore grid through alternative POIs, and shedding load on the onshore side to relieve the resulting underfrequency condition in the AC system. It is likely that such a RAS will benefit from automated control action taken through the HVDC converter stations. It will be helpful to understand the history of RAS in the Northeast (where it is less common and accepted) compared to the Midwest and the West, where it is has been deployed with considerable success.
2. **Offshore grid N-1 contingency modeling**: This would require the addition of model constraints imposed on offshore flows due to outages of offshore branches. These constraints would be written accounting for pre-contingency flow on all DC grid branches and estimates of additional loading on those branches resulting from of outage of one branch. It is expected that such modeling would increase capacities of the offshore north-to-south links and diminish the tendency of the OSG to be subdivided. Such contingency modeling and its coordination with the practices and standards of RTOs and utilities is critical for the development of credible

offshore-onshore MT-HVDC grid topologies and realistic approaches to their incremental build-out.

3. **Effect of storage and incorporation of other technologies**: We have not modeled storage in our CEP studies. It is useful to extend our CEP model to include both short-duration battery storage as well as longer-duration hydrogen storage with fuel cells. Doing so should occur simultaneously with improved modeling of ancillary service requirements. It is expected that doing so will result in increased presence of both solar (because nighttime demand will not require so much wind) and offshore wind (because offshore wind has a smaller effect on increasing netload variability which drives the need for ancillary services). Additional studies should be conducted to consider the effect of new technologies on OSW. Two such new technologies that should be considered are carbon capture and new nuclear.
4. **HVDC technology standardization**: While the TenneT 2 GW standard with 525 kV cables and voltage source converters (VSC) has emerged as an effective shorthand for MT-HVDC technology standardization, the development of clearly defined national standards will be critical to bridging between the longer-term ideas advanced in this report and the near-term needs to develop offshore grid elements and connections that are modular and expandable. Europe has advanced MT-HVDC technology and standards through projects such as PROMOTioN[112] and InterOPERA.[113] In the U.S., ARPA-E has developed the "DC-GRIDS" program[114] and the DOE has been working the DNV to develop HVDC standards for the U.S.[115] Working together, the U.S. and Europe could set standards for MT-HVDC technology that could enable coordination across projects and robust supply chain development. Critical to the adoption of MT-HVDC technology as well as the successful integration of RAS, the increase of SSCLs, and the development of robust contingency planning (from Items 1 and 2 above), will be the development of large-scale HVDC demonstration projects that can explore and test the limits of these new systems before they are deployed widely as critical features of the future grid.
5. **Responsive analysis**: Results from a new suite of models, methods, and processes developed for offshore wind transmission expansion planning on the U.S. Atlantic Coast demonstrate the potential for a new approach to "responsive analysis" wherein one can envision the possibility

[112] PROMOTioN. 2024. Progress on Meshed HVDC Offshore Transmission Networks. https://www.promotion-offshore.net/. Accessed on January 27, 2024.
[113] InterOPERA. 2025. https://interopera.eu/. Accessed on May 6, 2025.
[114] ARPA-E. 2024. DC-GRIDS: Disruptive DC Converters for Grid Resilient Infrastructure to Deliver Sustainable Energy. https://arpa-e.energy.gov/programs-and-initiatives/view-all-programs/dc-grids. Accessed on May 6, 2025.
[115] DNV. 2024. Robust performance standards for HVDC transmission systems needed for deployment success-DNV study. https://www.dnv.com/news/robust-performance-standards-for-hvdc-transmission-systems-needed-for-deployment-success-dnv-study/. Accessed on May 6, 2025; and RTO Insider. 2024. Study: HVDC Needs Standards to Take off in U.S. to Aid Offshore Wind. September 9. https://www.rtoinsider.com/86814-study-hvdc-needs-standards-take-off-us/. Accessed on May 6, 2025.

of quickly and accurately "round-tripping"[116] between conversations with planners and decision-makers about transmission expansion and the power systems analyses implied within these conversations. The concept of responsive analysis overlaps significantly with existing design charrette methodologies used in multidisciplinary infrastructure and urban planning. Our main objective in using this term is to position responsive analysis as a power-systems specific adaptation of the charette process that can open pathways for future power systems planning to benefit from proven participatory design methods and allow for broader cross-sectoral engagement.[117]

Traditional transmission studies are slow, static, and region specific, often failing to adapt to the evolving interregional needs that present themselves in the context of the energy transition. The responsive analysis methodology enables iterative, rapid assessments of large-scale electricity generation and transmission capacity expansion needs to inform decision-making, ensuring both technical rigor and real-time responsiveness. The results introduced in this report represent over 200 iterations wherein constraints such as grid topology, load growth, CO_2 reductions, availability of onshore versus offshore resources, seasonality, resource availability and price, discount factors, optimization algorithms, and graphical and numerical representations were explored by the research team in an effort to set a standard for future responsive analysis engagements with decision-makers. While the authors feel that in contemplating a complete energy transition for the region in question, the models and methods presented herein represent a helpful step forward in terms of modern power systems planning, it is important to acknowledge that this academic exercise is only a step and much work remains.[118]

[116] In this context, the phrase "round-trip" speaks to the need for multiple analyses to support a specific conversation between engineers and decision makers. For instance, the conversation may begin in Meeting #1 with a question, "which of three candidate POIs can we most economically upgrade to a total capacity of 4,000 MW?" The first analysis, or Iteration #1, would investigate this question and return to Meeting #2 with cost estimates for the three POIs. At Meeting #2, in the discussion of the results, a new question might arise, "what is the additional cost of going to 6,000 MW, and at what point does the marginal cost of an additional MW of capacity become significantly greater?" Iteration #2 would then investigate this question in preparation for Meeting #3. This fluid movement between meetings and iterations of analysis is known as "round-tripping," which describes the efficient back-and-forth between a deliberative, human-centered process, and a technically rigorous, analytical process. The ability to "round-trip" quickly and easily is key to enabling the process we are calling "Responsive Analysis." Our reviewers have emphasized that responsive analysis is most effective as an "education[al] tool in the early phases of a decision process, where options are open and the objective is to get a common understanding of solutions and challenges both among different stakeholders and inside organizations." We agree with this assessment and consider the importance of responsive analysis to be mostly helpful in the contemplation of GW-scale build-outs of and changes to the future offshore and onshore transmission systems.

[117] We acknowledge our reviewers for their recommendation to position responsive analysis in this way. This description is a direct transcription of reviewer comments.

[118] As an academic exercise, this report explicitly acknowledges gaps between the world modeled and discussed herein and the real world of actual OSW build-out timelines; policy, legal, and siting constraints; and reliability planning. As

Responsive analysis is a method to bring stakeholders into the process of design and development of Atlantic Coast OSW and the transmission system it requires. This is important because insights that emerge from the complex engineering design effort behind offshore transmission directly affect the social, political, and environmental (SPE) impacts of such a system. Conversely, SPE considerations must inform the framing and evaluation of such engineering efforts. There have been few opportunities to engage in real-time conversation between power systems engineering and SPE. The need for major infrastructure investments in an offshore grid combined with new models and tools developed in this work offers a new opportunity for socio-technical engagement that can support high-quality decision making. Future work requires the prototyping of responsive analysis through multiple small-group discussions with a variety of decision-makers and stakeholders from states, RTOs, utilities, developers, communities, and other relevant entities. The tools and methods described in this report could serve as the technical basis for responsive feedback loops to questions that emerge from these discussions. Based on this prototyping exercise, a responsive analysis process could be developed and deployed by multiple teams on a larger scale. This process would ultimately need to incorporate reliability planning criteria to the extent that it affects a proper understanding of the future offshore grid and its offshore-onshore build-out and can be discussed outside of CEII constraints before being incorporated into more detailed planning exercises. Understanding and clearly delineating the lines between public information and sensitive CEII information will be important to making the planning process both intelligible and acceptable to all stakeholders.

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discussed in the Introduction, this report was created as a companion to the DOE's Atlantic Offshore Wind Transmission Study (AOSWTS). In particular, the levels of OSW discussed in this report are extremely high and questions of procurement, siting, and construction of hundreds of GW of OSW are beyond the scope of this report. In order to imagine a complete energy transition, the report assumes a blank slate in terms of the development of ultra-high capacity power corridors and single source contingency limits. The report does not address N-1 contingencies or other reliability concerns, and this particular approach to analysis has yet to be tested in the real world with RTOs, utilities, states, communities, and other decision makers. The authors feel that the value of this report is in the introduction of new tools that can help the power systems community move closer to responsive analysis and the more ready contemplation of the relationships between near-term and long-term goals for power systems planning.

Appendix A Model reduction

A.1 Model reduction process

The four main steps in developing the 843-bus reduced model for coordinated expansion planning (CEP) analysis, as illustrated by Figure A-1. The procedure outlined here aims to achieve computational tractability by creating a model with a reduced network representation while maintaining sufficient fidelity to the full-model representation. The process begins with Kron reduction (Step 1), which generates the admittance matrix for the reduced network of the internal system and produces the load fraction matrix to distribute loads from eliminated buses to retained buses. The internal system refers to the part of the interconnection where the study and analysis will be conducted. Step 2 involves developing a reduced representation of the external system and interconnecting that external system with the reduced internal system. Step 3 relocates generation from eliminated buses to nearby retained buses, and Step 4 includes wind and solar resource characterization by location, ensuring that both existing and future renewable generation is accurately represented in the CEP model.

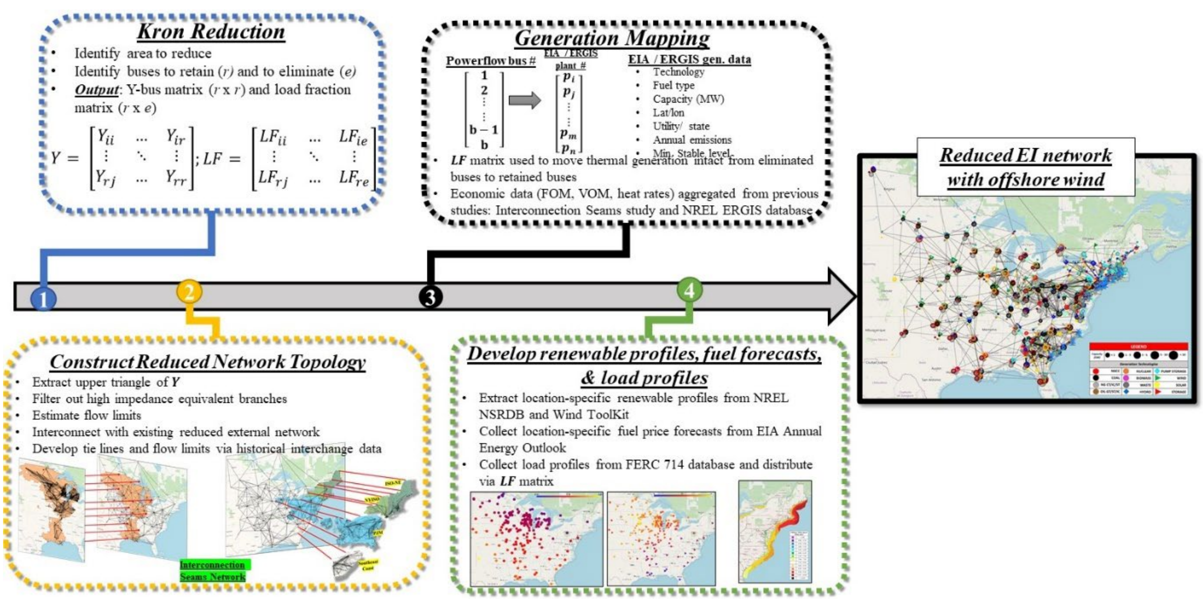

Figure A-1: Overview of CEP modeling steps

The Kron reduction of the network originates from the nodal current-voltage relation of the full network, where the buses are partitioned into buses to be retained (R) and buses to be eliminated (E), according to

$$\begin{bmatrix} I_R \\ I_E \end{bmatrix} = \begin{bmatrix} Y_{RR} & Y_{RE} \\ Y_{ER} & Y_{EE} \end{bmatrix} \begin{bmatrix} V_R \\ V_E \end{bmatrix} \qquad \text{(A-1)}$$

where Y_{RR} is the $n_r \times n_r$ admittance matrix of the retained buses, Y_{EE} is the $n_e \times n_e$ admittance matrix of the buses to be eliminated, Y_{RE} is the $n_r \times n_e$ matrix of admittances for connections between retained buses and buses to be eliminated, and $Y_{ER}=Y_{RE}^T$. I_R and I_E are nodal current injections into retained and eliminated buses, respectively, and V_R and V_E are nodal voltages at retained and eliminated buses, respectively. Upon elimination, we obtain (via the Gaussian elimination procedure)

$$I_R = Y_{RE} Y_{EE}^{-1} I_E = \left[Y_{RR} - Y_{RE} Y_{EE}^{-1} Y_{ER} \right] V_R \qquad \text{(A-2)}$$

If we define the reduced Y-bus matrix as

$$Y'_{RR} = Y_{RR} - Y_{RE} Y_{EE}^{-1} Y_{ER} \qquad \text{(A-3)}$$

and the change in retained bus current injections as

$$I'_E = Y_{RE} Y_{EE}^{-1} I_E \qquad \text{(A-4)}$$

Then, we have the nodal current and voltage relation of the reduced network given by

$$I_R - I'_E = Y'_{RR} V_R \qquad \text{(A-5)}$$

where the current injections on the left are the current injections of the reduced equivalent network, and Y'_{RR} is the admittance matrix of the reduced equivalent network. It is also useful to recognize that the pre-multiplying matrix product $Y_{RE}Y_{EE}^{-1}$ of (A-3) and (A-4) is referred to as the load fraction matrix. We have implemented this procedure in Matlab.

Following Kron reduction of the internal system (this includes ISO-NE, NYISO, PJM, and Duke/South Carolina), the reduced network is then constructed. There are two parts to the external network – External 1: the western part of the EI; and External 2: the Eastern Canadian system (Quebec and Ontario). There are 427 tie-lines between the internal system and External 1, and 42 between the internal system and External 2. The tie-lines between the reduced network and External 1 and 2 are represented by injections/withdrawals at the terminal buses of the tie-lines indicating incoming or outgoing flows.

Following the Kron reduction and tie-line modeling, the generation mapping step is performed to relocate generation resources from eliminated buses to retained buses, a step which preserves the individual identity of each existing generator (thermal, hydro, wind, or solar). The approach taken in the last step of Figure A-1, developing renewable and load profiles, is addressed in a later section of this document.

A.2 Validating the reduced CEP model – creating a reduced power flow model

We create a reduced power flow model as an intermediate step in the process of creating a reduced CEP model. Our motivation for creating the power flow model is related to the validation of the CEP. The power flow model, as we implement for use in a commercial solver such as PSS/E, is not used within CEP, but the underlying nodal balance and line flow equations are. Therefore, we used the power flow model as an intermediate step in validating the CEP model. The value of doing so is associated with the ability to perform direct comparison between reduced and full models to ensure that the reduced model captures the important features of the full model.

The model from which the reduction procedure was applied was a full model of the Eastern Interconnection, having 90,059 buses, 10,596 generating units, 83,487 lines, and 26,970 transformers; it represents a 2031 “90/10”[119] heavy summer loading condition. The reduced model has 843 buses, 558 generating units, and 2876 lines, of which 988 are two-winding transformers (three-winding transformers were eliminated). Transformer taps were fixed, and, to avoid voltage problems, generator reactive power limits were very large. The reduced model has the same total load as the full model, but the full model losses were added to that load since circuit resistances in the reduced model are neglected. The reduced model was solved using the PSS/E power flow program; the case solved from a flat start in 20 iterations. The topology of the resulting reduced network model is illustrated in Figure A-2.

[119] A 90/10 power flow case is one in which there is a 90% chance that the load of the given year (in this case, 2031) will not exceed the load represented in the power flow case.

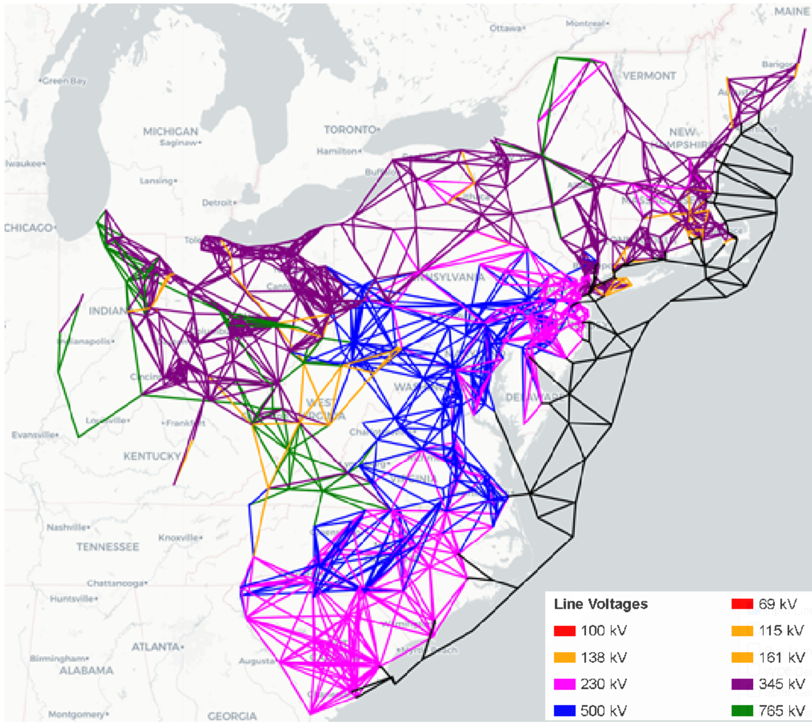

Figure A-2: Reduced network with offshore grid design

A.3 Special features developed for CEP model reduction

A.3.1 Retained Buses

Certain criteria are developed to choose retained buses. The items below summarize these criteria.

1. *Retaining non-generator buses*: We established criteria for retaining non-generator buses. These criteria are as follows:

    - <u>kV level</u>: The nominal voltage of the bus must be 345 kV or greater.
    - <u>Deliverability</u>: Deliverability must exceed 500 MW. The deliverability of a bus is the sum of normal ratings (BASEA) of all circuits connected to that bus less the normal rating of the circuit having the highest normal rating.
    - <u>Connectivity</u>: There must be at least three circuits terminating at the bus. This criterion ensures that buses with low connectivity are not retained, a feature which tends to avoid density (many non-zero fills) in the Y-bus of the reduced model.

2. *Retaining generator buses*: We retain the high-side buses connected to generator buses having in excess of 100 MW of capacity. High-side buses are retained because doing so always results in elimination of the low-side bus, whereas retaining the low-side bus does not always result

in elimination of the high-side bus. Applying this for generation in excess of 100 MW means that large generators retain their electrical position in the network; eliminating a generator bus means that it is moved (heuristically) to the electrically closest retained bus, an action which we have found introduces inaccuracy into the reduced model.

3. *Retaining circuits*: There are two reasons for retaining a circuit: (i) because it is a tie to the external system, and (ii) to use its flow as a basis of comparison between full and reduced model to assess accuracy of the reduced model. Retaining buses does not necessarily retain a circuit. An illustrating example is the retention of two buses unconnected in the full model – since they are not originally connected, their retention cannot result in the retention of a circuit. However, even when two buses are connected in the full model, it is possible, even likely, that retention of those two buses will not retain the line in its original form. The effect that causes this is referred to as “folding,” where the circuit to be retained has a parallel path in the network, and the parallel path is effectively “folded” into the circuit terminated by the two retained buses, causing the resulting circuit in the reduced model to have lower impedance and higher capacity than the targeted circuit in the full model, although it is terminated by the same two buses. Figure A-3 illustrates this situation. To avoid the “folding” influence, it is necessary to retain at least one bus in each parallel path. In the example of Figure A-3, this could be done by retaining either buses *m1* and *m2*, or buses *n1* and *n2*, or any combination of a bus in the upper parallel path with a bus in the lower parallel path. One issue here is that it can be difficult to know whether a targeted line has a parallel path that is not inherently addressed by the retention of some bus (according to the criteria stated in #1 above); a solution to this is, for any targeted retained circuit, retain all buses directly connected to one of its terminal buses.

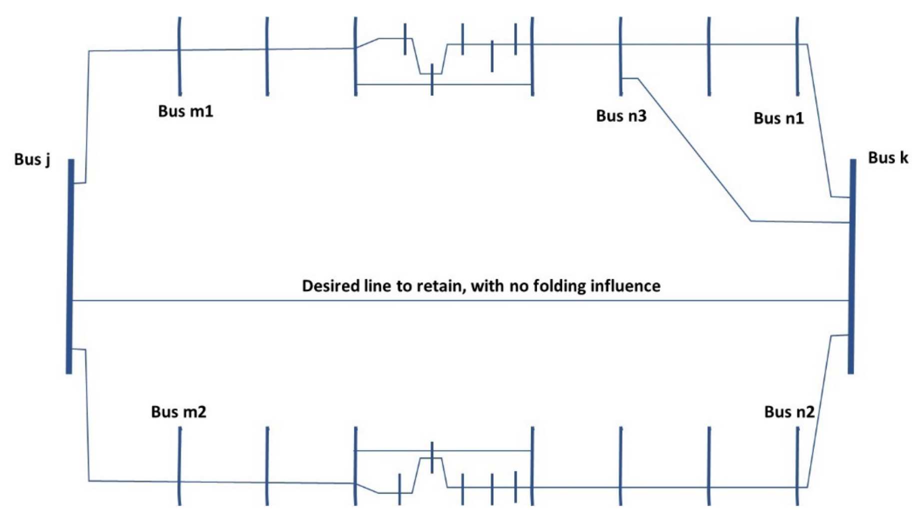

Figure A-3: Illustration of folding influence when retaining circuits

4. *Phase angle regulators (PARs)*: A PAR modifies the phase angle across a transmission line to increase or decrease the power flow across it. PARs are present in the ISO-NE, NYISO, and

PJM regions. We retain circuits containing PARs, together with their phase angle regulating capability, if the circuit has nominal voltage 345 kV or higher; otherwise, we treat the circuit as a standard line or transformer (without the phase angle regulating capability), and unless its terminating buses are retained for some other reason (per 1, 2, or 3 above), it is eliminated in the Kron reduction procedure.

5. *Points of Interconnections*: These buses are identified as the potential points where the offshore wind connects to the onshore grid. These buses are always retained.

A.3.2 External System Representation

Addressing the external system: Figure A-4 illustrates the relation between the internal system (in our case, it is the Atlantic Coast) and the external system. In our case, the external system is the portion of the Eastern Interconnection in the west we call External 1, and the Canadian system, Quebec and Ontario, in the north, External 2. There are 427 tie-lines between the internal system and External 1, and 42 tie-lines between the internal system and External 2.

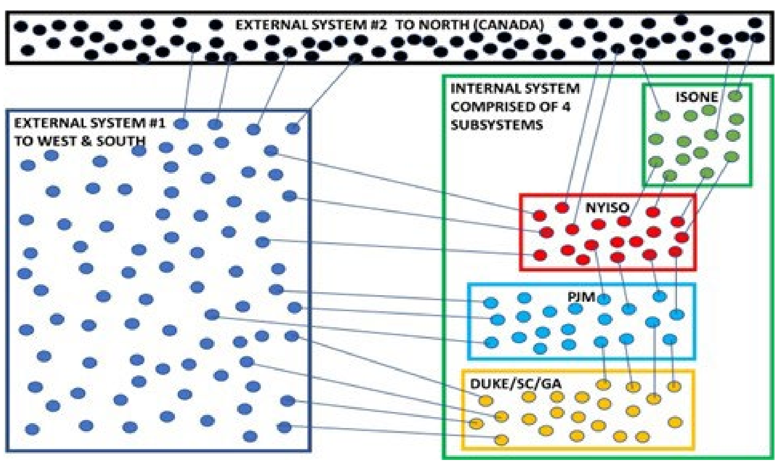

Figure A-4: External and internal systems, and subsystems

The external system can be handled using one of three approaches; in all three approaches, the boundary buses (buses terminating tie lines, i.e., lines connecting external and internal systems) are retained. In Approach 1, the external system is reduced using Kron. In Approach 2, transfer capacity between selected external areas is computed (using, for example, a commercial tool such as TARA), and an external reduced network is derived accordingly; this is similar to what was done in the Interconnections Seam Study.[120,121] In Approach 3, injections are modeled on the boundary buses corresponding to the external side of each tie line equal to the flow in the original model. Approaches 1 and 2 hold promise regarding modeling the impedance of the path seen by the internal network looking into the external network, an effect that influences flows when conditions change from the base conditions; however, in both of these approaches, external generation must be heuristically located, and doing so can result in inaccuracy related to the flows injected into the internal model, thus affecting the accuracy of flows in the base condition. Approach 3's weakness and strength are the complement of those of Approaches 1 and 2; whereas Approach 3 fails entirely to approximate the impedance of the path seen by the internal network looking into the external network and therefore may exhibit inaccuracy under changes from the base conditions, it captures with very high accuracy the base conditions since the injections into the internal network of the reduced model are identical to what they were in the full model. We have used Approach 3 for this work. For future work, however, we are considering Approach 2 where we will identify impedances of the equivalent lines via a tuning procedure.

A.3.3 Validation of reduced model

It is desirable to assess the fidelity of the final CEP model produced. This is difficult, however, because doing so requires running a CEP on the full model (90,059 buses in this case) and then comparing CEP results using the reduced model with CEP results using the full model. However, running CEP on the full model is not computationally feasible; indeed, this is the motivating reason for producing a reduced model. However, it is possible to make a full/reduced-model comparison at the intermediate step of obtaining a reduced power flow, which is what we do. In this section, we provide two forms of validation. In Subsection A.3.4, we compare load and generation by region. We also compare, for a set of retained lines, the MW flows in the full model with the MW flows in the reduced model.

A.3.4 Data Validation

In this section, we assess the extent to which the reduced-bus power flow model represents the full power flow model. We do this by comparing the load and generation of the reduced-bus model to the load and generation of the full model, a comparison that indicates reasonable fidelity between reduced-bus and full models.

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[120] A. Bloom, J. Novacheck, G. Brinkman, J. McCalley, A. L. Figueroa-Acevedo, A. Jahanbani-Ardakani, H. Nosair, A. Venkatraman, J. Caspary, D. Osborn and J. Lau, "The Value of Increased HVDC Capacity Between Eastern and Western U.S. Grids: The Interconnections Seam Study," *IEEE Transactions on Power Systems, doi: 10.1109/TPWRS.2021.3115092,* 2021.

[121] A. L. Figueroa Acevedo, A. Jahanbani-Ardakani, H. Nosair, A. Venkatraman, J. D. McCalley, A. Bloom, D. Osborn, J. Caspary, J. Okullo, J. Bakke, and H. Scribner, "Design and valuation of high-capacity HVDC Macro Grid transmission for the continental US," IEEE Transactions on Power Systems, 2020.

Here, we compare peak load and generation of the reduced model to load and generation of the full model, in total, and by region for the year 2031. Table A-1 shows load and generation of each region in the reduced model closely matches that of the full system. The main difference lies in the fact that circuit resistance was zeroed in the reduced-bus model and so it was a lossless system. To compensate, we added the losses identified in the full model, 8,037 MW, to the external load of the reduced-bus model. The fact that total generation in the reduced model is the same as total generation in the full model is an indication that losses were appropriately added into the reduced model load. There is some difference between each region's generation; this is due to the fact that the heuristic movement of generators less than 100 MW caused some generation close to the regional boundaries to move from one region to another region.

Table A-1: Comparison of full model to reduced model in terms of load and generation.

REGION	LOAD (MW)		GENERATION (MW)	
	Reduced Model	Full Model	Reduced Model	Full Model
ISO-NE	24,546	24,061	22,118	22,773
NYISO	30,423	28,533	34,360	33,514
PJM	169,860	165,576	167,987	168,678
SC	10,855	10,186	10,804	11,960
Duke	37,949	37,240	38,364	36,708
losses		8,037		
Sum	273,633	265,596	273,633	273,633

A.3.5 Retained line flows

Table A-2 provides a list of 57 retained lines showing the MW flow in the reduced model, P_{red}, the MW flow in full model, P_{full}, and the error $\Delta P=|P_{red}-P_{full}|$. All of these circuits were AC, were located in the internal areas, and were of nominal voltage 345 kV or above. Observations related to this table follow.

Table A-2: List of retained lines, ordered from least error to most (all P values in MW)

Cct#	From Bus	To Bus	Pred	Pfull	ΔP	Cct#	From Bus	To Bus	Pred	Pfull	ΔP
1	120812	120830	-176.4	-207.3	30.9	30	240069	240074	-860.0	-857.5	2.5
2	120821	120830	-351.1	-290.8	60.3	31	240281	240282	-23.7	-18.6	5.1
3	126298	126299	605.9	640.7	34.8	32	240282	240283	1.6	-4.8	6.4
4	136155	147830	-170.3	-171.8	1.5	33	240283	240284	-14.1	-18.2	4.0
5	147839	148789	-21.0	49.5	70.5	34	241901	241902	-850.0	-849.1	0.9
6	200301	200302	-791.2	-790.0	1.2	35	241927	241928	-345.4	-331.3	14.1
7	200568	200918	-13.3	2.4	15.7	36	241928	241929	-32.2	-30.7	1.6
8	200579	200818	-32.5	-24.5	8.1	37	241929	241930	-260.1	-253.2	6.9
9	200710	200726	-20.3	-25.5	5.3	38	242544	242545	-319.6	-225.5	94.1
10	200819	200918	-101.5	-63.1	38.4	39	242855	242856	-335.1	-276.3	58.9
11	204529	205904	-31.0	-30.8	0.2	40	242855	242857	-335.1	-276.3	58.9
12	204693	205903	-523.6	-512.3	11.3	41	243319	270198	-16.8	-16.8	0.1
13	206305	206403	-1161.2	-1133.0	28.2	42	243537	243538	-633.5	-580.2	53.4
14	212340	212397	765.0	762.4	2.6	43	243918	244130	-715.9	-714.9	1.0
15	217151	217162	693.1	690.2	2.9	44	245491	246177	148.4	144.1	4.3
16	227000	227001	-15.6	-14.9	0.8	45	245491	246177	148.4	144.1	4.3
17	227008	227009	5.3	-27.6	32.9	46	249582	249583	-525.6	-524.0	1.6
18	227013	227014	12.2	14.9	2.7	47	253310	253311	-150.5	-149.3	1.1
19	232129	233924	-56.3	-55.6	0.7	48	270107	270108	-9.2	-9.2	0.0
20	235212	235617	-3.0	-1.1	1.9	49	270193	270194	-747.3	-744.6	2.7
21	235427	237014	-19.4	-19.3	0.0	50	312717	312733	-259.4	-236.0	23.5
22	238542	238543	-29.7	-20.4	9.3	51	313859	315609	-799.8	-798.9	0.9
23	238543	238544	-139.0	-112.3	26.7	52	313892	316120	-20.9	-20.8	0.1
24	238665	238666	26.7	19.8	6.9	53	313899	316017	-38.7	-38.6	0.1
25	238685	241921	58.3	51.1	7.2	54	314524	316100	-32.0	-31.9	0.0
26	238685	241922	54.9	59.0	4.1	55	316105	316110	30.4	30.2	0.1
27	238685	241923	104.7	96.4	8.3	56	316172	316176	-28.2	-28.0	0.2
28	238685	241924	158.0	150.9	7.1	57	316206	316207	-28.8	-28.8	0.0
29	238685	241925	93.8	79.2	14.6						

One observes from Table 4-2 that the error is less than 100 MW for all circuits. This is reasonable performance considering the reduction is from 90,059 buses to 843 buses; in addition, accuracy of flows within 100 MW will satisfy the fidelity required by this project, where we are designing grids having GW-scale corridors. The distribution of flow errors is shown in Figure A-5.

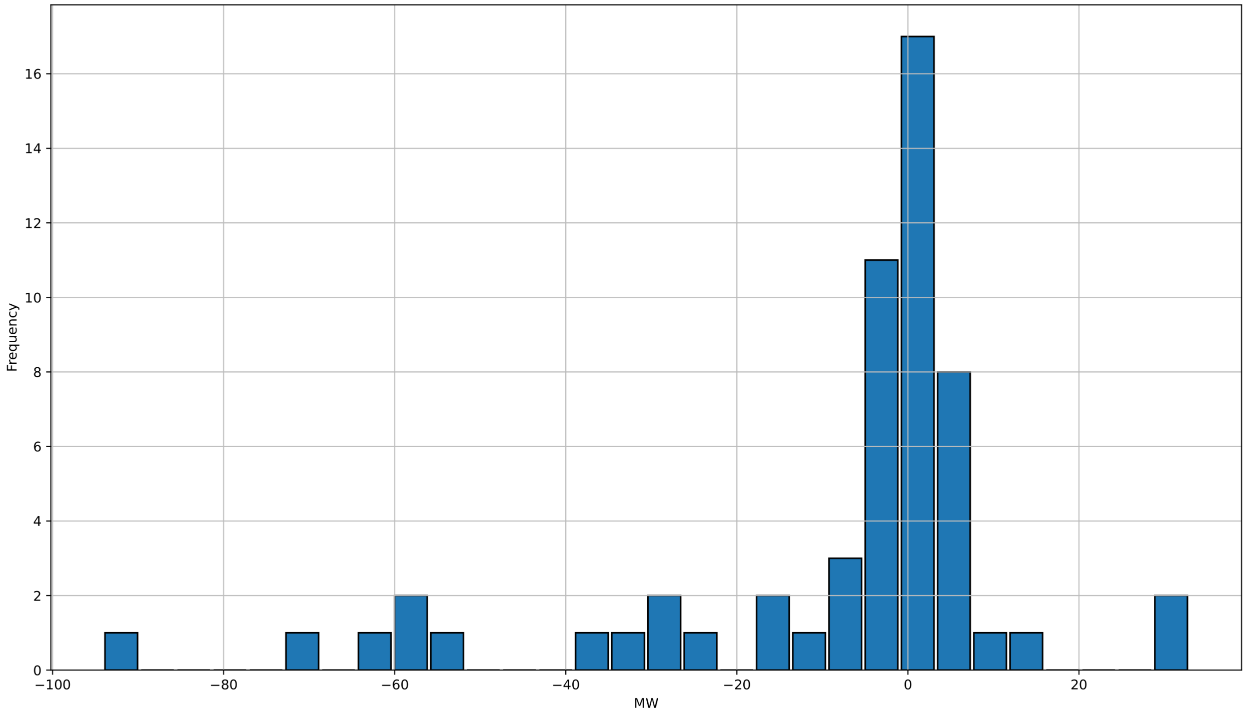


Figure A-5: Distribution of flow errors

Appendix B Description of Model 1 for POI identification

Model 1 uses two software applications collectively referred to as TARA/POIA. TARA stands for Transmission Adequacy & Reliability Assessment, a commercial-grade power flow solver marketed by the company PowerGem. POIA stands for "Points of Interconnection Assessment," a Matlab software developed within this project that processes TARA output. The objective of the TARA/POIA application is, given an offshore wind capacity target, to identify a set of onshore substations and capacities to bring the offshore wind energy to shore such that the expansion cost of the onshore transmission system is low. The strength of the TARA/POIA application is that it performs its objective for any size of a grid, i.e., it can be used effectively for grids having typical sizes common in the industry. We have used it to assess potential POIs on the U.S. Atlantic Coast using a typically-sized model for the Eastern Interconnection; the model has 90,059 buses. The ability to handle such model sizes is indeed a strength of Model 1; another strength is assessing onshore grid expansion needs while accounting for N-1 contingencies. One weakness of Model 1 is that it only considers a single loading condition for the onshore system; thus, its POI identification and capacity solution may not be robust to other loading conditions since they would have different power flow patterns in the transmission network and different expansion needs. A second weakness of Model 1 is that it uses a heuristic procedure to solve its optimization problem and so does not find optimal solutions, although it does find *good* solutions.

In the process of identifying low-cost POI sets for a given target offshore wind level, Model 1 computes a dollar per MW cost estimate for each candidate POI. This estimate includes the cost of the HVDC reach circuit from the offshore grid to the POI, the cost of the POI substation expansion (including the converter), and the cost of necessary onshore AC transmission expansions. We expect that these computed POI costs per MW from Model 1 should show consistency with the amount of injection identified at each POI by Model 2. That is, where Model 1 shows POIs with low cost per MW, we expect Model 2 to show high capacity; where Model 1 shows POIs with high cost per MW, we expect Model 2 to show low capacity. Our goal in this appendix is to assess this consistency or lack thereof.

Section 7.1 summarizes modeling features for Model 1 and Section 7.2 summarizes results of analysis on the Eastern Interconnection using Model 1.

B.1 Model 1 problem statement and modeling features

Section 2.1.1 formally states the problem addressed by Model 1. Section 2.1.2 summarizes the solution approach implemented in TARA/POIA. Section 2.1.3 describes salient modeling features.

B.1.1 Problem statement

The general form of the Model 1 problem is given below.

$$min\, C = \sum_i k_i C_i(\underline{p}, \underline{\Delta p_r}) \qquad \text{(A-1)}$$

subject to

$$\sum_i k_i p_i + \sum_j \Delta p_{rj} = 0 \qquad \text{(A-2a)}$$

$$\sum_i k_i p_i = P_{offshore} \qquad \text{(A-2b)}$$

$$\underline{P}(\underline{p}, \underline{\Delta p_r}) = \underline{g_c}(\underline{\theta_c}) \;,\; c{=}0,1,2,\ldots,N_C \qquad \text{(A-2c)}$$

$$\sum_i k_i \leq K \qquad \text{(A-2d)}$$

k_i are binary $\forall i$

where C is the total expansion cost (reach circuit cost, substation/converter station expansion cost, and onshore AC transmission expansion cost), C_i represents the onshore expansion cost associated with POI #i, k_i are binary "selector" variables (0, 1) that select POI #i or not; p_i are capacities (treated as injections) of POI #i; $\underline{\Delta p_r}$ is the vector of dispatch changes for onshore power delivery buses (, i.e., Δp_{rj} is the change in onshore power delivery bus j (OPDB – these are generator buses for which generation is reduced to compensate for the offshore injection at the POI) to compensate for non-zero values of POI injection p_i; $\underline{P}$ is the vector of injections at every bus, $\underline{\theta_j}$ is the vector of bus angles corresponding to contingency c (c=0 is normal condition), and $g_c(\underline{\theta_c})$ are the power flow equations for contingency c.

Equation (A-2a) expresses that the change in capacities (injections) at POIs must be compensated by changes in OPDBs; (A-2b) requires POI capacities must equal the total desired offshore capacity; (A-2c) represents the linearized power flow equations for the normal condition (c=0) and for c=1,2…,N_c contingency conditions; and (A-2d) imposes that up to K POIs may be selected. Some explanatory and clarifying comments follow.

1. Equation (A-2a) may appear to be contained by (A-2c) since (A-2a) imposes power balance and (A-2c) represents the linearized power flow equations (which also impose power balance), However, whereas (A-2c) imposes power balance in the <u>*system*</u>, (A-2a) imposes power balance <u>*between POIs and OPDBs*</u>.
2. Referring to the cost (objective) function (A-1), the individual terms in the summation are the products of the selector variable k_i and the cost function for POI #i, $C_i(\underline{p}, \underline{\Delta p}_r)$. We make the following comments about the cost function for POI #i:

a. It represents the onshore transmission expansion costs which includes the cost of AC onshore transmission expansion (line, transformer, and substation, including converter which is assumed to be located at the POI; and the cost of the reach circuit (circuit from beachhead to the POI).
b. We view *capacity* of a POI and its *injection* as synonymous; the reason is that we perform all POI evaluation assuming that its injection is maximum, i.e., that its injection equals its capacity.
c. A cost C_i for a particular POI i is a function of its own capacity p_i (which is an element of the vector $\underline{p}$). In addition, C_i also depends on other POI capacities as indicated by other elements in the vector $\underline{p}$, and on the redispatch of the onshore power delivery buses as indicated by the vector $\underline{\Delta p_r}$.
d. The dependence of C_i on other POI capacities (injections) and on the redispatch vector occurs because (A-2c) uses values of other POI capacities and values of redispatch vector to determine power flows in the network; when any one of these values change, the power flows change. And it is the power flows that determine the expansion costs for each POI. This implies that the cost functions change with different values of $\underline{p}$; therefore, the cost function of a POI depends on POIs that have been chosen before it and on whether any other POIs are chosen with it. This means that the cost functions used to obtain the optimization solution depend on that solution.
e. In general, the dependence of C_i on $\underline{p}$ and $\underline{\Delta p_r}$ occurs because, through eqs. (A-2a) and (A-2c), changes in any of the elements in these vectors cause changes in the flows on all lines in the network, and these flows determine the expansion costs which are one of the two components to C_i (the other one being the reach circuit cost – see Section B.1.3). For example, if an OPDB in Δp_r reaches a lower limit, then it stops participating in the redispatch, and this could cause what were increasing flows on an overloaded circuit to decrease, resulting in a non-convex cost function.
f. The dependence of C_i on $\underline{p}$ and $\underline{\Delta p_r}$ means that cost functions for each POI change as POIs and their injection levels are selected. This means that all POI cost functions C_i (and thus the best POI to supply the last increment of that capacity) depend on how the first increment of that capacity was supplied, e.g., whether the first increment of that capacity was supplied by, for example, POI #1 and POI #2, or POI #1 and POI #3, since flows in the network will change depending on which of these two was selected.

The significance of the above comments is that this is a challenging optimization problem to solve. It is non-convex not only because it is a mixed integer program but also because of the dependence of the cost function on the solution. As a result, we have not yet tried to apply standard integer optimization solvers to solve this problem. To ensure that we can obtain a reasonable solution to the problem, we have developed and applied a heuristic solution approach, as described in Subsection B.1.2.

B.1.2 Solution approach

Figure B-1 illustrates key concepts used in describing Model 1, including the offshore transmission system (thick black offshore lines), beachheads (blue dots), existing substations (white and black dots), candidate POIs (white dots), reach circuits (dashed lines connecting beachheads to candidate POIs), onshore transmission (thin black lines), expanded onshore transmission to accommodate higher POI capacity levels (yellow lines), and OPDBs (represented in the figure by power plants at a substation).

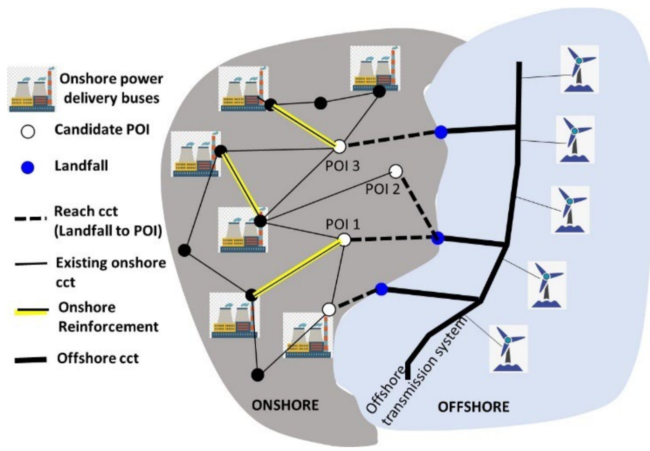


Figure B-1: Illustration of key concepts underlying Model 1

The heuristic solution approach to solving the problem specified in eqs. (A-1) and (A-2a, A-2b, A-2c, and A-2d) is given as follows:

0. j=1; power flow condition j=1 is represented by the power flow model without any POIs (zero OSW injection).
1. Use TARA/POIA to evaluate average costs for all POIs using power flow condition j, and construct the minimum average cost curve (MACC).[122] The MACC is given by the ratio of
    - onshore transmission expansion costs to

[122] In step (1), the evaluation of the average costs for all POIs using power flow condition j, is implemented using the Transfer Limit (TrLim) functionality within the commercial-grade power flow solver called Transmission Adequacy and Reliability Assessment (TARA), together with post-processing code implemented explicitly for this purpose, called Point of Interconnection Assessment (POIA). TARA/TrLim computes the power transfer distribution factors (PTDFs) for each POI injection, with withdrawals at the OPDBs, under both normal and all N-1 contingency conditions. Then, for the range of MW injections considered (e.g., 0 to 5000 MW in 100 MW intervals), POIA identifies overloads and necessary circuit expansions to eliminate those overloads and the cost of these expansions. Finally, at each 100 MW interval, POIA identifies the POI having the minimum average cost.

- capacity;

The MACC expresses the minimum average cost, \$M/MW, as a function of POI capacity.

2. Choose the POI with the minimum average cost. Which POI has the minimum average cost for a given iteration varies, depending on capacity. This dependency is observed in Figure B-2, which shows the Minimum Average Cost Curve (MACC) for iteration #1 in the NYISO region. For example, the plot shows that 200 MW of POI capacity is desired, the least-cost POI is the East Hampton 69 kV substation; if 1000 MW of POI capacity is desired, the least-cost POI is the Farragut West 345 kV substation.

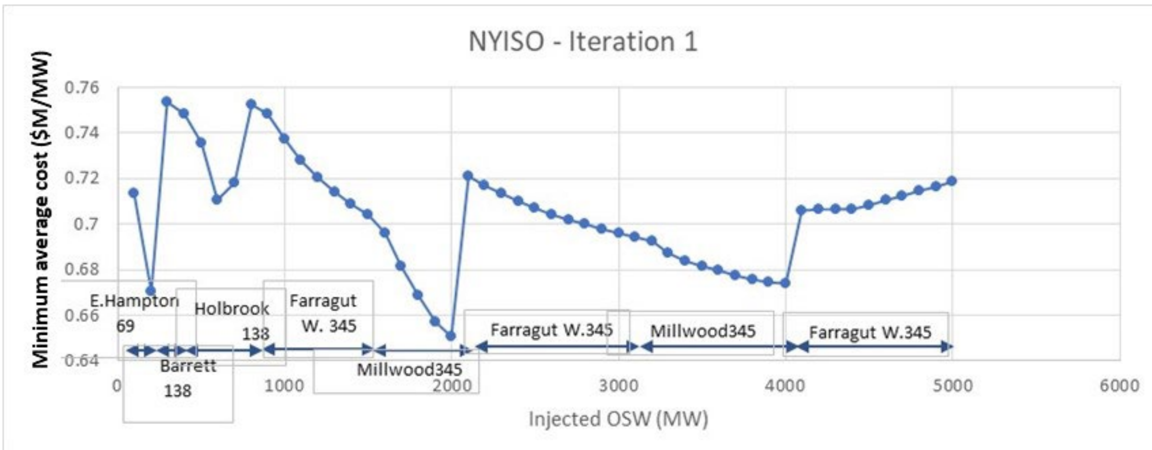


Figure B-2: MACC for iteration 1, NYISO region

Thus, the MACC enables selection of the POI and associated capacity offering the least average cost of the range of capacity values covered by the MACC. From Figure B-2, the best selection is the Millwood 345 kV bus with a POI capacity of 2000 MW for POI #1, since it has the lowest average cost over the range of capacity values assessed in this iteration. But another option is to select the Millwood 345 kV bus at a 4000 MW capacity since its average cost is low and its selection will reduce the number of iterations.[123] Such decisions within the method must be made manually by the analyst.

3. If the regional capacity ($P_{offshore}$, in eq. (2b)) need is met, then stop; else, modify power flow condition j by (i) setting the selected POI injection to the capacity level p and (ii) applying

[123] The single source contingency limit (SSCL) for most East Coast regions is less than 2000 MW and so, without reconsideration, would prevent designs having POI capacities of 2000 MW or more. However, it is possible to extend SSCL; we believe 6000 MW limits can be reached. There are two approaches for use in extending SSCL to 6000 MW. First, the "rule of 3" should be applied in POI selection and offshore transmission design where there should be at least two additional paths to which the power injected through a designated POI into the onshore system should be able to flow upon outage of that designated POI. Second, it should be possible to implement fast remedial action schemes and automatic control action following loss of a given POI. This remedial action would typically include tripping or ramp-down of some offshore generation. It may also include deployment of onshore devices which contribute to stabilizing the onshore network; such devices might include, for example, switched shunt capacitors or dynamic var resources. Good references related to remedial action schemes and automatic control action include (1) J. McCalley, et al., "System protection schemes: limitations, risks, and management," Final Project Report, Dec. 2010. [Online]. Available: https://pserc.wisc.edu/wp-content/uploads/sites/755/2018/08/S-35_Final-Report_Dec-2010.pdf; and (2) P.-A. Löf, "New Principles for System Protection Schemes in Electric Power Networks," Bulk Power System Dynamics and Control V, August 26-31, 2001, Onomichi, Japan.

necessary transmission reinforcements (decreasing impedance and increasing RATEA and RATEB limits for overloaded circuits). This new condition is denoted j+1.

4. $j \leftarrow j$+1 and go to step (1).

Figure B-3 illustrates the process for the first 2 iterations applied in identifying POIs for the NYISO region.

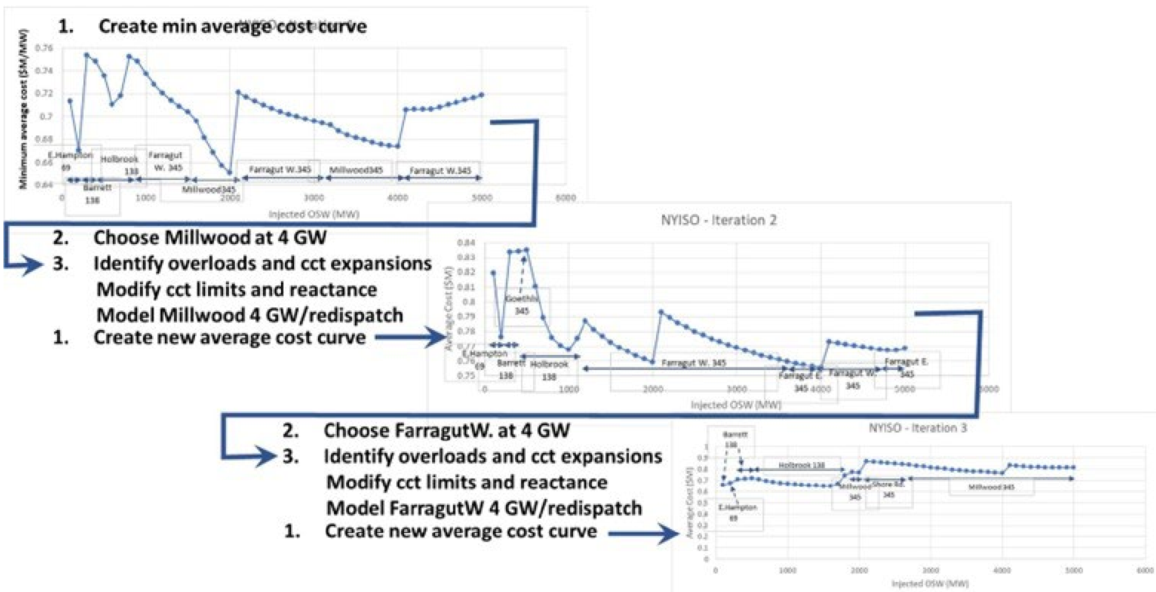


Figure B-3: Illustration of two iterations of the heuristic optimization procedure

B.1.3 Modeling features

Some important modeling features for Model 1 are summarized in what follows:

1. Reach circuit model: As illustrated in Figure B-1, the reach circuit connects the beachhead location with the POI. The reach circuit is assumed to be an underground HVDC bipole line. The cost of the first 2 GW of reach circuit capacity is assumed to be \$15M/mile (2/3 is fixed cost; and 1/3 is variable and a function of capacity); the cost of additional 2 GW lines is \$11.25M/mile (using the same fixed/variable splits), where the lower value is assumed to reflect the diminished cost for obtaining the right-of-way for the additional circuits.
2. MACC behavior: The MACC of Figure B-2 includes several discontinuities; these discontinuities are caused by two influences. First, as observed in the portion of the plot between 0 and 2000MW, the minimum-cost POI can change from one bus to another bus as capacity is increased, a feature that results from one or more circuits exceeding their normal or emergency limit and thus requiring expansion. Injection at different POIs sees such expansion

costs at different capacity levels and for different circuits, each having different loading increases, different voltage levels, and different lengths and thus different costs per unit of injected POI power. Second, the reach circuit model causes discontinuities at multiples of 2 GW because the ±525kV DC lines are assumed to have 2 GW capacities.

3. AC expansion costs: There are three types of AC expansion costs used within the TARA/POIA application.
    a. The first AC expansion cost type is the cost of expanding AC transmission lines and AC substations, as indicated in Table B-1. Transmission line expansion costs, in \$M/MW-mile and given in Column E of Table B-1 were obtained as
        - The Column C values of \$M/miles, which are three times the corresponding estimates made in the 2022 Transmission Cost Estimation Guide developed by the Midcontinent Independent System Operator (MISO),[124] represent the cost of rebuilding and reconductoring (for 69-230 kV lines) or just reconductoring (for 345-765 kV lines) to obtain an additional capacity (as indicated in Column D of Table 2-1, which are 1/4 of the line capacity of 765, 500, and 345 kV circuits, and 1/2 of the line capacity for 230, 161, 138, 115, and 69 kV circuits).[125] The original MISO \$M/miles figures were multiplied by a factor of three to roughly account for the typically higher line expansion costs incurred on the East Coast relative to the Midwest.
        - The Column C values in \$M/miles were divided by the Column D MW values of additional capacity, in MW, assumed to be obtainable, resulting in the Column E figures of \$/MW-mile.
    b. The second AC expansion cost type is substation expansion costs (to accommodate, as a POI, the additional injection from a reach circuit) in \$M/MW and given in column F of Table B-1. These values were also obtained from the MISO 2022 Transmission Cost Estimation Guide, representing the cost of handling additional capacity assuming a breaker-and-a-half substation configuration with 6 positions (3 incoming circuits and 3 outgoing circuits). It is assumed that AC substation expansion would not require much additional land and so no adjustment was made in applying the MISO data for East Coast application.[126]
    c. The third AC expansion cost type is the cost of expanding power transformers, as indicated in Table B-2. These costs were also obtained from the MISO 2022

[124] MISO, "Transmission Cost Estimation Guide for MTEP 22," April, 2022, https://cdn.misoenergy.org/20220208%20PSC%20Item%2005c%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP22_Draft622733.pdf.

[125] The reason for the difference (1/4 vs 1/2) is to remain consistent with the assumption made in the MISO document that 765, 500, 345 kV transmission may only be reconductored (but not rebuilt), whereas the other (lower voltage) lines can be both reconductored and rebuilt.

[126] For any given transmission line, there is an upper bound to how much capacity can be added to the line without adding right-of-way. In our TARA/POIA assessment, we do not account for such upper bounds. As a result, our cost estimates should be viewed as being reasonable indicators of relative cost between POIs, but not necessarily accurate indicators of absolute cost.

Transmission Cost Estimation Guide. It was assumed that transformer expansion costs (generally performed through the addition of another transformer with little or no additional land needed), would not require adjustment in applying MISO data for East Coast application.

Table B-1: AC transmission reinforcement and AC substation expansion costs

Column A Nominal voltage (kV)	Column B Assumed (short-line) capacity for each kV-level (MW)	Column C Estimated East-Coast Cost of Rebuild & reconductor or just Reconductor ($M/mile)	Column D Assumed max amt of capacity from the rebuild and/or recoductoring (MW)	Column E Cost per MW-Mile used in Studies ($M/MW-mile)	Column F Cost per MW for expanding AC Substation ($M/MW)
765	4000	3.12	1000	0.00312	0.0074
735	3000	3.09	750	0.00412	0.0078
500	1800	2.25	450	0.005	0.008
345	800	1.68	200	0.0084	0.0122
230	250	5.1	125	0.0408	0.0259
161	150	4.8	75	0.064	0.0371
138	100	4.8	50	0.096	0.051
115	80	4.5	40	0.1125	0.0575
69	40	4.2	20	0.21	0.1008

Table B-2: Cost of power transformer expansion

ID	ratio *nv1:nv2*	Cost ($/MVA)
1	69/115	4139
2	69/138	4581
3	69/161	4822
4	69/230	5348
5	69/345	6566
6	69/500	8468
7	69/765	11914
8	115/138	4581
9	115/161	4822
10	115/230	5348
11	115/345	6241
12	115/500	7659
13	115/765	9802
14	138/161	6241

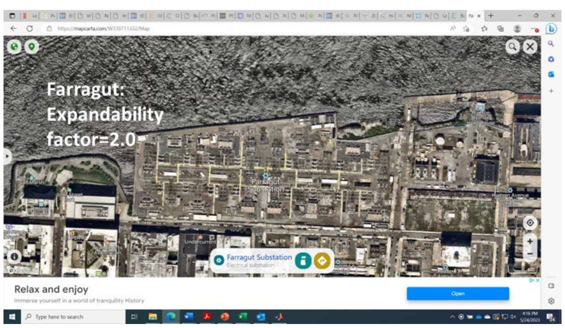
ID	ratio *nv1:nv2*	Cost ($/MVA)
15	138/230	5348
16	138/345	6241
17	138/500	7659
18	138/765	9802
19	161/230	5631
20	161/345	6566
21	161/500	8058
22	161/765	9802
23	230/345	6566
24	230/500	8058
25	230/765	9802
26	345/500	8466
27	345/765	10286
28	500/765	11347

4. DC expansion cost: There are two types of DC expansion cost.
   a. The first is the reach circuit cost; our model for that is described in comment 1 above.
   b. The second is the DC converter station cost. Because we felt there to be significant uncertainty in converter cost, we assumed a base converter station cost of $SE_{dc,base}$=\$0.3M/MW, based on a review of converter costs provided in the literature, summarized in Table B-3. From Table B-3, it is observed that converter cost estimates range from \$0.078M/MW to \$0.230M/MW for line compensated converters (LCC) and

$0.282M/MW for voltage source converters (VSC); our choice of $0.3M/MW is just above the high end of this range. In addition, we scale the base cost by multiplying it by a “substation expandability factor” for substation *i*, (SEF_i) where $1 \leq SEF_i \leq 2$. Expandability factors for 83 candidate POIs were estimated by satellite imagery, where visual inspection was used to estimate difficulty and related cost impact of siting a converter station at a particular candidate POI. Satellite images and corresponding SEF estimates are given for two substations in Figure B-4 to illustrate this estimation process.

Table B-3: Summary of literature sources providing DC converter cost estimates[127]

Source	Year of source	MW capacity	kV Level	Cost	$Cost/MW
EIPCC/PJM (LCC)	2013	3500	500	$275M	78,570
WECC/Black&Veatch (LCC)	2014	3000	500	$460M	153,330
IEA-ETSAP (LCC)	2014	1000		$230M	230,000
MISO (LCC)	2022	2000	500	$435M	217,500
Brattel/NYSERDA (LCC)	2022	1300		$260M	200,000
MISO (VSC)	2022	2000	500	$563M	281,500



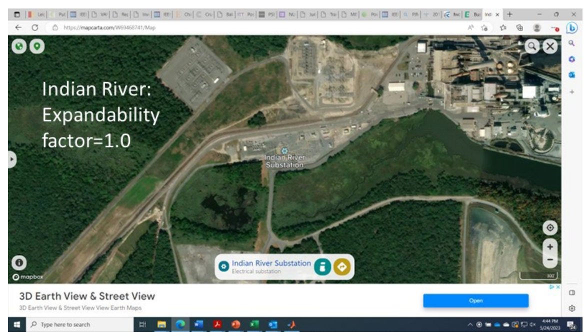


Figure B-4: Illustration for two substations of satellite imagery used to estimate expandability factors (SEFs)

Accounting for comments 3b, 3c, and 4 above, all related to substation expansion, we summarize by expressing the total onshore expansion cost for an injection of *P* MW into POI #*i* as

$$TotC_i(P) = ExpC_i(P) + RCC_{li}(P) + SEC_i(P) \qquad (A-3)$$

where $ExpC_i(P)$ is the expansion cost for onshore AC branches (lines and transformers), $RCC_{li}(P)$ is the expansion cost for the reach circuit connecting beachhead *l* to POI *i*, and $SEC_i(P)$ is the

[127] According to our reviewers: There is additional HVDC converter cost information available as part of the data submitted to PJM as part of the New Jersey OSW State Agreement Approach (NJ OSW SAA), and that these data may be found at https://www.pjm.com/planning/competitive-planning-process/redacted-proposals under the **2020/2021 NJ OSW SAA Window**. These data should be useful, although we recognize that these data are for symmetric monopole systems, whereas we have assumed bipolar systems in this study,

expansion cost for the substation equipment at POI i. This latter term, $SEC_i(P)$, has two components, DC converter cost and AC substation expansion cost, expressed as:

$$SEC_i(P) = \left(SEF_i \times SE_{dc\_base} + SE_{ac_{base,i}}\right) \times P \qquad (A-4)$$

where SEF_i is the substation expandability factor as described in comment 4 above, SE_{dc_base} is the base expansion cost necessary to develop the DC converter station, in \$/MW, and $SE_{ac\_base,i}$ is the cost necessary to expand the AC substation to accommodate the additional injection from the reach circuit into POI i. The expandability factor is applied to the DC base cost because development of the DC converter station will require additional land. The expandability factor is not applied to the AC base cost because, as indicated in comment 3b above, it is assumed that AC substation expansion does not require much or any additional land.

B.2 Summary of results and observations

There are three efforts documented in this section using model 1. The first identifies the least cost POIs to accommodate 33 GW of East Coast OSW, as presented in Subsection B.2.1. The second identifies the least cost POIs to accommodate 76 GW of East Coast OSW, as presented in Subsection B.2.2. The third compares POI results from Model 2 (as presented in Chapter 2) with POI results obtained with Model 1 (as described in this chapter).

The Model 1 analysis for both the 33 GW and the 76 GW OSW levels were done to identify the best POIs based only on the cost of onshore transmission expansion needs (including both line/transformer expansion as well as reach circuit). With the exception of land cost for DC converter stations (see item 4b in Subsection B.1.3), no effort was made to account for differentiating POI selection, as functions of cost influenced by social, political, or environmental factors. For example, our analysis indicates that the Millstone 345 kV substation along the coast of Connecticut is the least-cost POI candidate in the ISO-NE region; however our analysis does not account for the fact that this substation is located at a nuclear power plant for which restrictions on nuclear plant operation and waste fuel storage may make this site very expensive or even not viable for use as a POI, i.e., this issue was not accounted for in the analysis reported in this appendix.

B.2.1 33 GW East Coast POI assessment

Analysis was performed to identify POIs for a 33 GW OSW level. The results of that work, in terms of POI identities, POI capacities, and associated costs are summarized in Table B-4.

Table B-4: Results of POI assessment for 33 GW offshore wind level

POI_name	POI Bus #	State	Capacity (MW) of TARA/POIA Solution	Reach Cct Distance (miles)	Expansion Cost ($M) of TARA/POIA Solution	Reach Cct Cost of TARA/POIA Solution ($M)	Total Cost of TARA/POIA solution ($M)
ISO-NE RESULTS							
Millstone 345	119194	CT	4000	1	160.04	30	190.04
Seabrook 345	104127	NH	2000	5	77.55	75	152.55
TOTAL ISO-NE			6000		237.59	105	342.59
NYISO RESULTS							
Farragut East 345	126645	NY	4000	10	99.72	262.5	362.22
Farragut West 345	126644	NY	4000	10	12.38	262.5	274.88
East Hampton 69	129868	NY	200	1	1.15	10.5	11.65
Barrett 138	129202	NY	800	1	0	12	12
TOTAL NYISO			9000		113.25	547.5	660.75
PJM RESULTS							
Larrabee 230	206294	NJ	4000	10	330.08	262.5	592.58
Smithburg 500	200017	NJ	4000	20	46.36	525	571.36
Cardiff 230	227900	NJ	2000	12	26.66	180	205.66
Indian River 230	232006	DE	2000	10	207.75	150	357.74
Fentress 500	314909	VA	2000	17	84.67	255	339.67
Landstown 230	314481	VA	2000	8	14.71	120	134.71
TOTAL PJM			16000		710.23	1492.5	2201.72
SOUTH RESULTS							
Winyah 230		SC	2000	10	18.75	150	
TOTAL SOUTH			2000		18.75	150	168.76
TOTAL EAST COAST			33000		1079.82	2295	3373.82

An important observation can be made based from Table B-4, in relation to cost components. Reference to the bottom row of Table B-5 indicates the two cost components of interconnecting 33GW of OSW (exclusive of wind turbine cost and offshore transmission cost) are the expansion (or reinforcement) costs in the blue column and the reach circuit cost in the green column. These costs are $1079.82M (or $1.079B) and $2295M (or $2.295B), respectively. This indicates that reach circuit cost, double that of expansion cost, is the dominant cost, an indication that may initially motivate interest to select POIs that are closer to shore than those selected here. However, the expansion costs are as low as they are because of the careful selection of POIs. Although one may be able to reduce reach circuit cost by using an alternative POI, it will likely be at the expense of increased expansion costs.

B.2.2 76 GW East Coast POI assessment

Analysis was performed to identify POIs for a 76 GW OSW level. The results of that work, in terms of POI identities, POI capacities, and associated costs are summarized in Table B-5 and Figure B-5, from which some important observations can be made, as follows:

1. *Why 76 GW?* Model 1 uses an iterative process based on DC power flow to identify transmission expansion. Each iteration is initiated with an AC power flow solution. As the program progresses through iterations, it identifies necessary network expansions to accommodate the desired POI injection, and it models those changes in the next iteration in the power flow data. As POI injections increase, so do power flow changes to each AC power flow case. The AC power flow changes thus become larger with each iteration, inhibiting the nonlinear Newton-Raphson solution method used in AC power flow solvers. In addition,

voltages modeled in the AC solver become more stressed, and since expansions are identified via a DC solution, no additional voltage support is included. As a result, Model 1 results were limited to 76GW. Additional iterations to achieve higher OSW levels would perform the automated least-cost POI search to occur over established intermediate solved AC power flow cases (with human-decision overseeing deployment of voltage support measures in each case), e.g., for increments of OSW levels at 75 GW, 100 GW, 125 GW, …, etc.

2. *Impact of heuristic optimization*: Table B-5, which illustrates the choice of POI and POI capacity at each iteration of the TARA/POIA heuristic optimization solution procedure, shows that in general, the average cost per MW increases with each iteration as the model selects the least-cost POI in each iteration. However, there are some exceptions that result from the heuristic process of selection where previous iterations reduce expansion needs for subsequent POIs, a situation that occurs when a previous iteration tends to unload one or more transmission paths in the system. This can be seen in the cost decreases in ISO-NE between iterations 1 and 2, in NYISO between iterations 4 and 5, and in PJM between iterations 6 and 7.
3. *Total cost and capacity with regional breakdown*: The total capacity of 76 GW incurs onshore transmission expansion cost, including reach circuit cost, of $50B, which is a $0.66M/MW per unit cost. This should be considered as a lower bound because we have not represented expansion limits on lines and transformers, and their representation would increase expansion cost. In addition, it is significant to observe the per-unit costs by region, which are $0.504M/MW in ISO-NE, $0.601M/MW in PJM, $0.783M/MW in South, and $0.821 in NYISO. The fact that PJM has a relatively low per-unit cost but at 30 GW the highest capacity allocation is an indication that OSW injection into the PJM region is attractive, a feature made possible through the relatively low-expansion cost for the 500 kV POIs at Smithburg, Deans, and Fentress, and also for the 230 kV POIs at Larabee and Landstown.

Table B-5: Results of POI assessment for 76 GW offshore wind level, by iteration

Iteration	Solution		Avg. Cost	Total Cost
ISO-NE	**20GW**			
1	Millstone 345	4 GW	$0.479M/MW	
2	Woburn 345	4 GW	$0.469M/MW	
3	Carver 345	4 GW	$0.497M/MW	
4	Maguire Rd. 345	4 GW	$0.503M/MW	
5	Card St. 345	4 GW	$0.572M/MW	
	Regional Total		**$0.504M/MW**	**$10.1B**
NYISO	**20GW**			
1	Millwood 345	4 GW	$0.674M/MW	
2	Farragut W.	4 GW	$0.766M/MW	
3	Millwood 345	2 GW	$0.772M/MW	
4	Shore Rd. 345	4 GW	$0.897M/MW	
5	Holbrook 138	2 GW	$0.855M/MW	
6	Farragut E. 345	4 GW	$0.955M/MW	
	Regional Total		**$0.821M/MW**	**$16.4B**
PJM	**30GW**			
1	Smithburg 500	4 GW	$0.441M/MW	
2	Larabee 230	4 GW	$0.441M/MW	
3	Landstn 230	4 GW	$0.496M/MW	
4	Deans 500	4 GW	$0.574M/MW	
5	Fentress 500	4 GW	$0.615M/MW	
6	Cardiff 230	4 GW	$0.747M/MW	
7	Indian River 230	2 GW	$0.593M/MW	
8	Smithburg 500	2 GW	$0.860M/MW	
9	Deans 500	2 GW	$0.935M/MW	
	Regional Total		**$0.601M/MW**	**$18.0B**
South	**6GW**			
1	Winyah 230	4 GW	$0.576M/MW	
2	Sutton 230	2 GW	$1.198M/MW	
	Regional Total		**$0.783M/MW**	**$4.7B**
EAST COAST			**$0.66M/MW**	**$50B**

4. *Geographical view*: Whereas Table B-5 identifies, for each region, the POIs selected in order of the iterations performed by the heuristic optimization procedure, Figure B-5 identifies the POIs by geographic location, in order of north to south. The POI numbering used in the table of Figure B-5 corresponds to the numbering in the map of Figure B-5.

POI	kV	State	Capacity (MW)
ISO-NE			
1 Maguire Road	345	ME	4000
2 Woburn	345	MA	4000
3 Carver	345	MA	4000
4 Card Street	345	CT	4000
5 Millstone	345	CT	4000
Total			**20000**
NYISO			
6 Holbrook	138	NY	2000
7 Shore Road	345	NY	4000
8 Millwood	345	NY	6000
9 Farragut East	345	NY	4000
10 Farragut West	345	NY	4000
Total			**20000**
PJM			
11 Deans	500	NJ	6000
12 Smithburg	500	NJ	6000
13 Larrabee	230	NJ	4000
14 Cardiff	230	NJ	4000
15 Indian River	230	DE	2000
16 Landstown	230	VA	4000
17 Fentress	500	VA	4000
Total			**30000**
South			
18 Sutton	230	NC	2000
19 Winyah	230	SC	4000
Total			**6000**
EAST COAST			**76000**

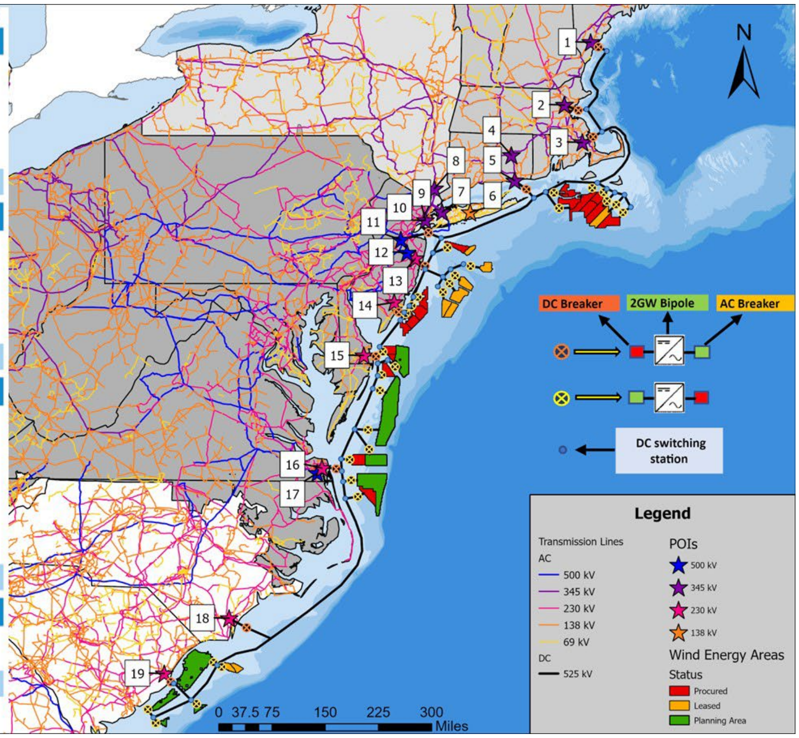


Figure B-5: Results of POI assessment for 76 GW offshore wind level, by location

B.2.3 Comparing Model 1 and Model 2 POI results

In the results presented in Chapter 2, POI "strength" (or attractiveness) is characterized by the capacity identified for them via flows from OSW to the onshore loads. This characterization is in units of MW. In the work reported here (Appendix B), POI "strength" is characterized by total expansion cost, in units of $k/MW. Although Model 1 and Model 2 are quite different in the method used to arrive at these characterizations, we expect to see some consistency in the results. To assess these, we show the strength of each POI, by region (ISO-NE, NYISO, PJM, and SOUTH), on a plot of Model 2-derived capacity (MW) vs Model 1-derived $k/MW. We expect POIs that have high capacity in Model 2 to also have low cost in Model 1; i.e., their "strength" indication should be consistent. Thus, we expect that POI plots to exhibit an inverse relationship, as illustrated in Figure B-6.

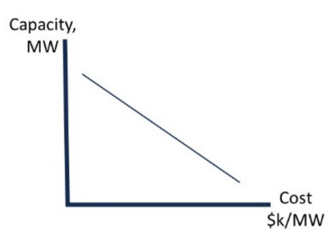


Figure B-6: Expected relationship between Model 2 capacity and Model 1 cost

The plots are shown for ISO-NE in Figure B-7, for NYISO in Figure B-8, for PJM in Figure B-9, and for SOUTH in Figure B-10. Comments on these plots follow their presentation.

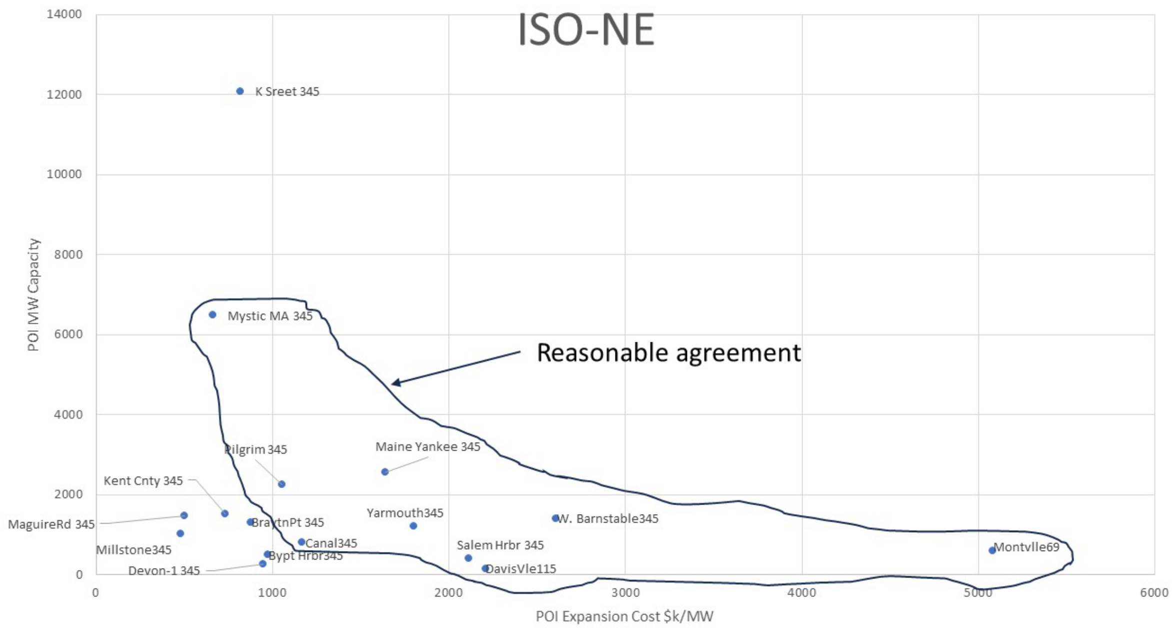


Figure B-7: ISO-NE POI Comparison of Model 2 Capacities (MW) vs Model 1 Expansion Cost ($k/MW)

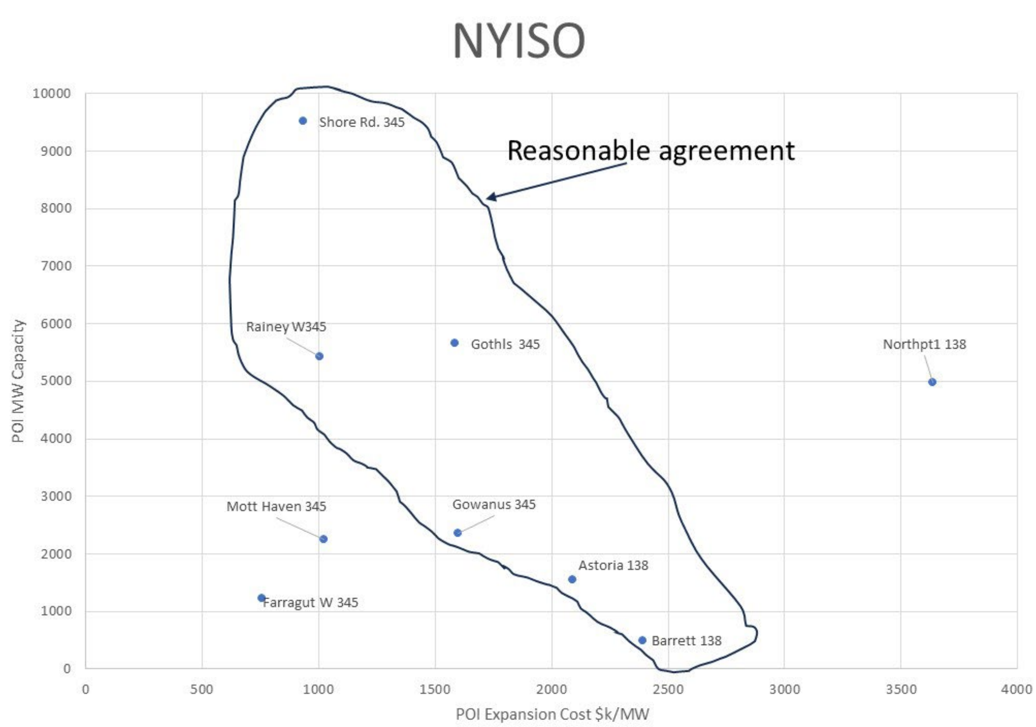


Figure B-8: NYISO POI Comparison of Model 2 Capacities (MW) vs Model 1 Expansion Cost ($k/MW)

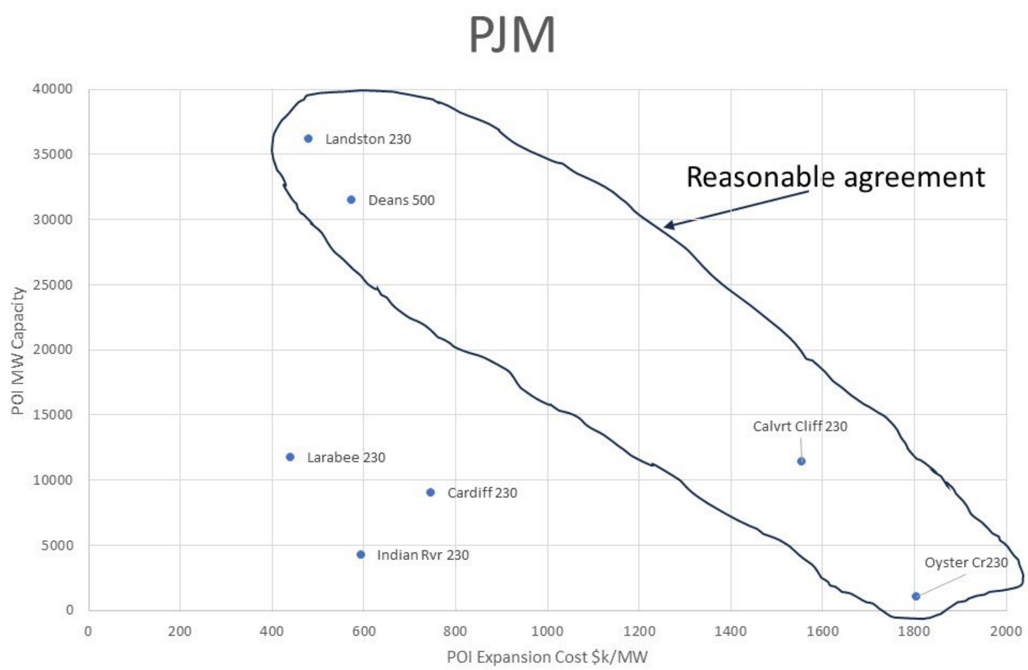


Figure B-9: PJM POI Comparison of Model 2 Capacities (MW) vs Model 1 Expansion Cost ($k/MW)

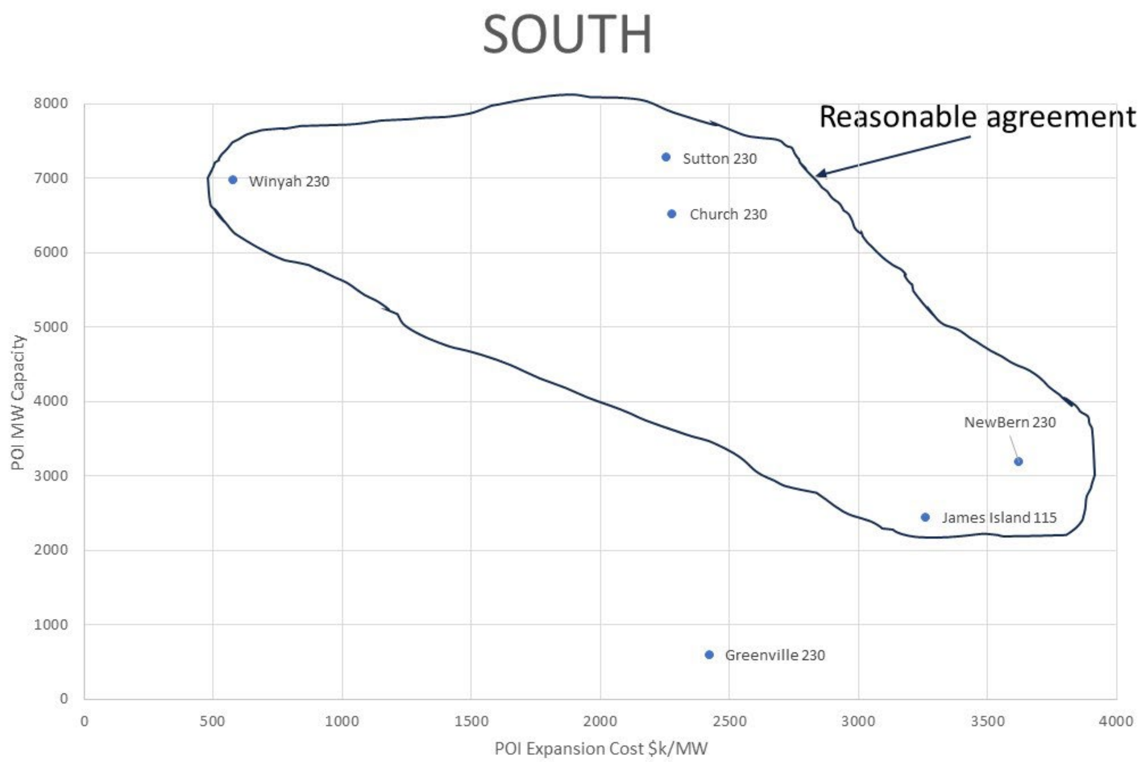


Figure B-10: SOUTH POI Comparison of Model 2 Capacities (MW) vs Model 1 Expansion Cost ($k/MW)

In each plot (for each region), we observe a number of POIs that reflect consistency in the Model 1/Model 2 results, as indicated by the encircled POIs of each plot. This consistency is indicated by the form of the encircled POIs which show the inverse relationship of Figure B-6[128]. In addition, each plot shows some POIs outside the circles; these POIs indicate inconsistency between the two models.

The method of characterizing POI strength (attractiveness), as performed using the two models, is quite different. In Table B-6, we summarize 11 differences between the two characterizations. Of these, we believe that the first six (highlighted) are most significant, with #1 and #2 being the main advantage of Model 1, and #3-#6 being the main advantage of Model 2. Given these differences, we view that consistencies between the results of the two models (either a positive indication from the two models or a negative indication from the two models) offer strong evidence that the indicated level of POI attractiveness is correct. On the other hand, when a given POI is

[128] We have not yet developed a quantitative evaluation of "consistency" because, as we explored these models, we were mainly interested in whether they would, as different as they are in terms of network representation and analysis method, would provide a general consistency. We believe the analysis of this section suggests they have. Additional work is needed to explore a more quantitative evaluation of their mutual strengths and weaknesses.

characterized inconsistently by the two models, then exploration of the reasons, guided by the differences summarized in Table B-6, offers opportunity to better understand the advantages and disadvantages of the two models, and/or to understand unique features of the POI.

Table B-6: Summary of differences between POI characterization by Model 1 & POI characterization by Model 2

#	POI Investment Cost $/kW from Model 1	POI Capacity from Model 2
1	More granular "exact" model, 90,059 buses	Less granular, reduced equivalent model, 843 buses
2	All N-1 contingencies represented	No contingencies represented
3	Only one loading condition represented	Multiple loading conditions represented
4	Cost reflects condition of only one offshore wind level	Capacity reflects trajectory of offshore wind growth
5	Lower offshore wind represented (76GW injected)	Higher offshore wind represented (250 GW injected)
6	Heuristic optimization used (only one POI at a time)	Formal optimization used
7	No onshore gen growth allowed	Zero-CO2 onshore gen growth allowed
8	Onshore fossil gen reduced to compensate OSW growth	Onshore fossil gen reduced to reach 90% of 2031 CO2 emissions
9	Assessed one region at a time	Assessed all regions simultaneously
10	Represented parallel paths outside 4 regions	Did not represent parallel paths outside 4 regions
11	Variation in substation expansion cost based on location	No variation in substation expansion cost

For example, from Figure B-9, we observe that the POI at the Larrabee 230 kV substation, at about $420k/MW, exhibits the lowest expansion cost of any PJM POI (per Model 1), but its capacity at the highest injection of a 600 GW OSW level is, at about 12 GW (per Model 2). This capacity is roughly the same as the POI at Calvert Cliffs 230 kV, a POI that has a much higher cost (per Model 1) at about $1550k/MW. In addition, the Larrabee 230 kV substation, at its 12 GW capacity, has a much lower POI capacity than the POIs at Deans 500 kV and Landstown 230 kV, both of which have POI capacities well above 30 GW; yet, Deans 500 kV and Landstown 230 kV have expansion costs slightly higher than that of Larrabee 230 kV. Investigation into the Model 1 results indicates that the $420k/MW expansion cost of the Larrabee substation was identified for an 8 GW level of OSW received at PJM POIs. Checking the Larrabee expansion cost for higher levels of OSW received at PJM POIs indicates the Larrabee cost increases significantly, e.g., at a 32 GW OSW received at PJM POIs, the Larrabee cost is $1664k/MW, approximately the same as that identified for Calvert Cliffs.

B.3 Concluding observations

At this point in time, Model 1 and Model 2 have their own strengths and weaknesses. Although we have made significant progress in this project with respect to designing an offshore grid, identifying POIs, and identifying associated onshore expansion, we believe there is substantive value to advancing this work beyond its current state. There are two ways to move forward, described in what follows.

<u>*Option A, enhance Model 2:*</u> Here, we aim to address the weaknesses of Model 2 so that Model 1 is no longer necessary. The most important features of model 1 that model 2 does not have are (i) network granularity; and (ii) representation of contingencies. The challenge associated with enhancing Model 2 so that it has these features is computational; can the necessary enhancements be made while maintaining Model 2 solve times less than 3-4 hours? We think the most important Model 2 changes necessary to facilitate this goal is to adopt decomposition together with linear factors. The adoption of decomposition avoids increased model dimensionality by employing an iterative solution approach. In this approach, the model is divided into N_p investment periods, where, at each iteration, each investment period is solved independent of the others (allowing low solve times for higher dimensional models). Following an iteration, constraints are tightened to force smoother transitions between investment periods in the next iteration. The formulation for each investment period utilizes linear factors instead of angles, thus decreasing the number of decision variables. Contingencies are modeled by adding equations for designated outage/monitored branch combinations. Identification of these outage/monitored branch combinations are made between iterations to limit the additional equations.

<u>*Option B, enhance and integrate Models 1 and 2*</u>: Although this option does not limit any enhancements that might be made to Model 2 (indeed, this option may include those enhancements described in Option A, especially if those Option A enhancements do not achieve sufficiently low compute times for the desired higher level of modeling granularity and the desired contingency representation), the focus is on continuing to benefit from the capabilities of TARA in terms of computational speed, modeling granularity, and representation of contingencies. There are two significant changes necessary.

- First, the TARA/POIA software is modified so that it searches over combinations of POIs rather than searching over one POI at a time. In the problem statement of Section B.1.1, this means that, in equation (A-2d), our solution approach needs to admit values of K (number of POIs) for which K>1. Assuming we solve the problem one region at a time, then it would be good to have the capability of doing so for up to K=10. To implement this, we would modify the TARA/POIA software so that it performs exhaustive searches among all possible combinations of POI injection levels. Computational intensity can be relieved by choosing larger "deltas" between tested values of POI injection levels. For example, we could relieve computation by testing at 500 MW increments, or even 1000 MW increments, instead of 100 MW increments as we have done heretofore.
- Second, Model 1 and Model 2 would be integrated so that Model 2 passes loading conditions and investments (both generation and transmission investments) to Model 1, and Model 1

implements them before identifying the next set of POIs. Then, Model 1 returns the identified POIs to Model 2, and Model 2 utilizes them in a second iteration.

Appendix C Model 3: Macrogrid

With large offshore wind farms in several stages of planning and commissioning off the U.S. Atlantic Coast coupled with unprecedented investments in renewable electricity generation resources onshore, there is significant value in building High Voltage Direct Current (HVDC) transmission in the form of a national Macrogrid. This Macrogrid will serve as an ultra-high capacity interregional transmission highway, enabling efficient long-distance energy transfer. It is an ideal complement to the clean energy transition, enabling multi-regional sharing of electric energy and grid services to achieve least-cost reliable and resilient decarbonization of the nation's electric systems.

This section outlines how the presence of an HVDC Macrogrid, in conjunction with offshore wind and onshore renewable resources, can complement and stimulate the clean energy transition. Modeling features and assumptions particular to Model 3 are described in section C.1. Results illustrating two cases (85 GW and 200 GW East Coast offshore wind) with the Macrogrid are presented in section C.2. Observations and takeaways, including benefits of an HVDC Macrogrid in conjunction with offshore wind, are outlined in section C.3.

C.1 Modeling features

This section describes the modeling features for Model 3, including CEP as applied to Model 3, modeling assumptions, characterization of offshore wind for the study and Macrogrid topology design.

C.1.1 Introduction

The need for building a high capacity, interregional HVDC Macrogrid stems from anticipated load growth and the need to modernize the existing U.S. electricity transmission system. Cross-seam transmission between the Eastern and Western interconnections has garnered significant interest in the recent past, emerging as a cost-effective technological solution to mitigate carbon emissions, and enhance grid reliability and resilience. Preliminary studies indicate that augmenting capacity between the interconnections can provide economic benefit while reducing the need for localized, expensive generation resources for planning reserve requirements, since capacity is then available from other regions through the Macrogrid. Some of these studies are summarized in this section.

At the Midcontinent Independent System Operator (MISO), Dale Osborn et al.[129] developed an HVDC overlay covering a large part of the contiguous U.S. The HVDC Macrogrid overlay, with 15 GW of transfer capability between the Western Interconnection and Eastern Interconnection,

[129] D. Osborn, Midcontinent Independent System Operator, "HVDC for DOE", September 2016, Available: https://www.energy.gov/sites/prod/files/2016/10/f33/2_HVDC%20Panel%20-%20Dale%20Osborn%2C%20MISO.pdf

prioritized annual load diversity and capacity sharing assumptions for planning reserve margin compliance. Additionally, Li and McCalley, in 2015, created a high-fidelity transmission-planning model to investigate hybrid HVDC/HVAC transmission designs for the contiguous U.S., determining that approximately 10 GW of new seam transmission would be necessary to accommodate 800 GW of inland wind and 200 GW of solar by 2050.[130]

One of the most important studies in recent times is the Interconnections Seam Study, funded by the U.S. Department of Energy and spearheaded by NREL, bringing together national labs, academia and industry to evaluate four different transmission scenarios to increase interregional transmission capacity.[121] One of the designs with a high benefit to cost ratio was a version of the HVDC Macrogrid with 8 GW/segment, although the design of the Macrogrid was such that its scope was limited within the eastern interconnection, with large parts of the EI with large population centers not served by the Macrogrid. The study did not consider offshore wind either. However, it was a milestone in terms of starting a conversation about the idea of a national HVDC Macrogrid and its significant benefits.

The Energy Systems Integration Group (ESIG) published another study with an alternate VSC-based HVDC Macrogrid design in order to support high carbon reduction goals. Conceptualized by a team of experts across industry, academia and national labs, ESIG said the Macrogrid would be a "largescale and fundamental change to the North American power system" such that "its planning, design and operations will require developing new procedures, approaches and tools."[131]

More recently, the Department of Energy published the National Transmission Needs Study, which emphasized that today's grid cannot adequately support 21st century challenges, such as large-scale electrification, especially in transportation and buildings, and the clean energy transition, while ensuring resilience against an increasing number of extreme weather events. The study showed that there is a pressing need for additional transmission infrastructure to improve reliability and resilience. It concluded that increasing interregional transmission resulted in the largest benefits.[132]

This present study builds on previous studies to explore how the HVDC Macrogrid interacts with OSW from a nation-wide perspective. It does not seek to accurately site offshore transmission infrastructure or evaluate points of interconnection, since Model 2 is better equipped to study those aspects. Model 3 focuses on introducing the HVDC Macrogrid as part of a high renewable future, including Atlantic Coast offshore wind. It seeks to compare and contrast a future without the Macrogrid and a future in which the Macrogrid plays an important role in interregional cross-seam

[130] Li, Y. & McCalley, J. D., 2015, "Design of a High Capacity Inter-Regional Transmission Overlay for the US", *IEEE Transactions on Power Systems,* January, 30(1), pp. 513-521.
[131] Energy Systems Integration Group, February 2022, "Design Study Requirements for a U.S. Macrogrid."
[132] U.S. Department of Energy, October 2023, "National Transmission Needs Study."

transmission, to leverage natural load diversity caused by time zones in the United States. The following sub-sections illustrate the assumptions and results of this study.

C.1.2 CEP as applied to Macrogrid studies

The Coordinated Expansion Planning (CEP) model co-optimizes both generation and transmission within the same model, employing linear programming (LP) optimization techniques. Its primary objective is to identify optimal future investments in generation and transmission infrastructure within a power system. The overarching goal is to minimize the net present value, encompassing both the cost of these investments and the operational expenses of the power system over a specified decision horizon. The decision horizon typically spans 10-30 years, subject to variability based on the study's objectives.

Co-optimization is defined as the concurrent identification of two or more interrelated classes of investment decisions within a single optimization strategy. In the context of this project, these investment classes encompass decisions related to building both generation and transmission infrastructure. Given that the decision to construct generation at a specific location influences the decision to build or expand transmission at that location during a particular time period, co-optimization is expected to be as effective as, or superior to, sequential optimization. Co-optimization proves particularly beneficial when applied in vertically integrated utilities to ascertain lower-cost combined generation and transmission expansion plans, departing from the traditional planning approach.

Coordinated planning involves a strategic tradeoff between investing in generation and transmission infrastructure based on specific criteria. In some instances, constructing more economical generation sources farther away from the load, along with the required transmission, proves economically preferable to building costlier generation sources closer to the load. Alternatively, investments in transmission infrastructure may not necessitate concurrent investments in new generation. Given that transmission infrastructure is considerably more cost-effective to build than generation facilities, it offers substantial value in terms of cost savings. Co-optimization, in such cases, identifies the most optimal solution, emphasizing cost-effectiveness.

The Coordinated Generation and Transmission Expansion Planning (CGT-PLAN) software, developed by researchers in Dr. McCalley's research group at ISU, facilitates the identification of multi-year generation and transmission investment decisions. These decisions aim to meet demand and reserve requirements while minimizing the net present value of long-term investment plus operational costs. The formulation of CGT-PLAN can be succinctly represented as follows:

Minimize: *Net Present Value {Gen. and Tr. Investment costs + Fixed O&M costs*

+ Variable O&M costs + Fuel costs + Environmental costs}

Subject to: *Operational generation, transmission and policy constraints*

The transmission expansion planning problem, employing "DC" (or linearized) power flow equations, is typically framed as a mixed integer nonlinear program (MINLP). However, the incorporation of a "disjunctive" representation for power flow equations affected by transmission candidates converts the problem into a mixed integer linear program (MILP). An alternative formulation treats the transmission expansion problem as a 'transportation' model, neglecting the impedance of transmission lines and simplifying the problem to an LP. Although this simplification improves computation time to solve the expansion planning problem, it also reduces modeling fidelity.

To address this trade-off, a 'hybrid' transmission model is employed, combining the DC power flow representation for existing circuits with the transportation model for candidate circuits. This approach preserves the fidelity of the original system topology while simultaneously reducing computational burden and time, as the formulation becomes an LP, avoiding the more complex MILP formulation.

C.1.3 Modeling assumptions

The formulation of the CEP optimization problem requires assumptions, typically derived from input data, to characterize future conditions. These assumptions encompass aspects such as the temporal evolution of technology and investment costs, fuel prices, load growth, and technical specifications such as heat rates and capacity factors for generation resources.

Hourly data for generation, hydro, and load corresponding to the year 2024 were procured from NREL. A load growth rate of 2.5% per year[133] was used to characterize the increase in demand due to widespread electrification. Existing generators were constrained by their capacity factor in terms of energy limitations and by their forced outage rate in terms of capacity constraints. The parameters for investment cost, operational cost, and maturation rates of potential generation technologies were sourced from NREL's 2023 Annual Technology Baseline.[134]

For the Western Interconnection (WI), Ward reduction was employed to create a reduced network equivalent of a 2026 power flow case obtained from the Transmission Expansion Planning Policy

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[133] Note that the load growth assumed for the Model 2 CEP study was 4% per year between 2031-2051.
[134] NREL (National Renewable Energy Laboratory). 2023. "2023 Annual Technology Baseline." Golden, CO: National Renewable Energy Laboratory. https://atb.nrel.gov/.

Committee (TEPPC) of the Western Electricity Coordinating Council (WECC).[135] A total of 101 buses, including 7 buses for modeling existing back-to-back (B2B) DC ties to the Eastern Interconnection (EI), were selected and preserved to retain key paths in the WECC region as defined in the notes for the TEPPC 2026 power flow case. The fractional mapping of eliminated buses, obtained through Ward reduction, was utilized to redistribute load in fractions, with the highest fraction selected for relocating generation to maintain the identity of individual generation units. This model reduction was originally performed for the Interconnection Seams Study.

The Eastern Interconnection (EI) model, developed by MISO engineers,[136] incorporated a total of 68 buses, including 7 buses for modeling existing B2B DC ties to the WI. MISO utilized the Transmission Adequacy and Reliability Assessment (TARA) software to calculate transfer limits between connected buses under N-1 conditions. Equivalent impedances for all lines within the EI were estimated based on knowledge of voltage levels connecting each pair of regions, distance, and transfer limits. For this study, the reduced transmission topology and capacity were left unchanged, but generation capacity at some EI nodes were updated to reflect more recent generator data. Figure C-1 illustrates the 169-bus representative model of the onshore Eastern + Western Interconnection grid used in this study.

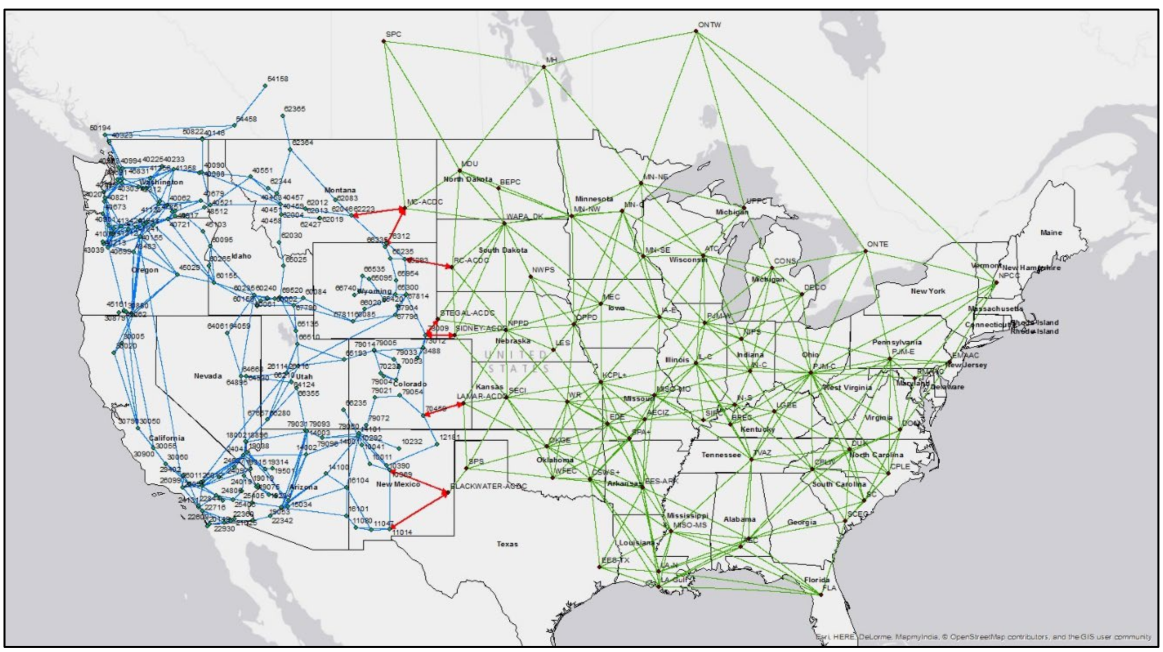

Figure C-1. Illustration of 169 bus EI + WI reduced model

[135] Western Electric Coordinating Council, System Adequacy Planning - Datasets, 2016. Available: www.wecc.biz/SystemAdequacy Planning/Pages/Datasets.aspx.

[136] A. Figueroa-Acevedo, et al., "Design and Valuation of High-Capacity HVDC Macrogrid Transmission for the Continental US,", doi: 10.1109/TPWRS.2020.2970865. IEEE Transactions on Power Systems.

Interregional transmission candidate lines were assumed to be overhead, encompassing high-voltage AC and HVDC technologies. Fuel prices for natural gas, oil, and coal aligned with forecasted values in the EIA's Annual Energy Outlook 2023. A 5.7% per year real discount rate with 2% per year inflation was assumed based on a review of government documents and previous studies.[137,138,139]

A crucial aspect of CEP modeling lies particularly in how load, wind, and solar elements are represented, utilizing an hourly "unit commitment" representation, capturing the chronological sequence of 8760 distinct hourly operating conditions each year. While this approach offers a highly detailed operational representation, it necessitates integer variables and significantly inflates the problem size, making the resulting CEP computationally intractable. To strike a balance between computational efficiency and modeling fidelity, the 8760 different operating conditions for each year are condensed into a much smaller number of load blocks.

Each block, representing a single operating condition, is chosen to encompass multiple hours. To capture the daily variations in wind, solar and load, all the time series were synchronized to a common time reference (Eastern Standard Time was used in this study). Operating blocks, each representing a multi-hour operating condition indicative of multiple but similar 1-hour operating conditions, were developed. In this CEP model (and also in Model 2), these operating conditions need not be sequential and typically do not occur sequentially.[140] Although we do capture within this approach required operational features characterized by the word "flexibility" (e.g., regulation and ramping reserves), modeling sequential operating conditions within a CEP enhances the fidelity of this capture. However, such modeling significantly increases CEP computational cost, and we elected not to do so in Model 3.

A total of 19 blocks were created to represent each year, with two kinds of operating blocks - a 5-block representation of a typical 24-hour period for 3 defined seasons, which we refer to as energy blocks, and an additional 4 blocks to represent the peak load of four different reserve sharing groups (RSGs) in the model, referred to as peak blocks. Each energy block was characterized by

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137 OMB Circular A-94, Appendix C, Rev. Nov., 2015, "Discount rates for cost-effectiveness, lease purchase and related analyses." Available: www.whitehouse.gov/omb/circulars_a094/a94_appx-c.

138 A. Figueroa-Acevedo, "Opportunities and Benefits for Increasing Transmission Capacity Between the US Eastern and Western Interconnections," Ph.D. Dissertation, Iowa State University, 2017.

139 Note, these assumptions differ slightly from the Model 2 analysis, which was completed after the Model 3 analysis had been completed. Model 3 was primarily developed under a separate project, but the NOWRDC team made substantial efforts to incorporate Model 3 results into this work and explicitly created the OSW part of the Model 3 analysis for comparison with Models 2 and 1. While not exactly apples-to-apples, we think these analyses are close enough to one another in their assumptions to form the basis for effective and interesting comparisons.

140 Here we include a comment from one of our reviewers: "There has been research to the contrary. CEP done without capturing the need for fast ramps develops inefficient portfolio. CEP is not just about the least cost capacity and energy; the capacity has to have the right operational characteristics for the system. Perhaps consider adding to future work."

the average load, wind and solar production levels over the hours it represented, along with a capacity addition above net-load to consider operating reserve products such as regulation up, regulation down, and contingency.[141] To capture the annual variation of wind, solar and load, three seasons were defined: winter (November, December, January, February), summer (May, June, July, August), and shoulder (March, April, September, October), resulting in a total of 15 energy blocks. Additionally, four 1-hour duration blocks were established to represent conditions throughout the model corresponding to the actual peak load of each of four reserve sharing groups (RSGs), defined based on time zones. A 15% planning reserve margin (PRM) above peak was mandated for each peak-load block.[142] With 15 energy blocks and 4 peak blocks, this model represents 19 operating conditions per year.

Although the blocking process is based on load and initially performed on the load data, the same blocks are then used to characterize the solar and wind capacity factor data to create multiple distinct operating conditions, each consisting of load, solar and wind. This ensures that the modeled wind and solar data is successfully integrated into CEP.

C.1.4 Offshore wind characterization

Offshore wind profiles can be characterized at varying levels of modeling fidelity, using wind speed data from NREL's Wind Toolkit Offshore Mid Atlantic Wind Data, produced in the year 2020 using Weather Research and Forecasting (WRF) numerical weather prediction model.[143,144,145] Hourly data is available at various hub heights over a span of 21 years, and this data is aggregated using the blocking process described previously to capture long-term energy production trends for each operating condition.

Since the reduced model offshore nodes signify one entire project area, geographic latitude/longitudes for 10 wind sites are identified within each project area and offshore wind speed data at 140m is obtained from the Wind Toolkit for each site. The data is then processed to obtain normalized power production curves at each site using turbine power curves for representative 15 MW offshore wind turbines.

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[141] This is a balance between computational tractability and fidelity of the model. The model also has a peak operational block.

[142] Capacity credit was used to calculate the credited generation to enforce PRM.

[143] Draxl, C., B.M. Hodge, A. Clifton, and J. McCaa. 2015. Overview and Meteorological Validation of the Wind Integration National Dataset Toolkit (Technical Report, NREL/TP-5000-61740). Golden, CO: National Renewable Energy Laboratory.

[144] Draxl, C., B.M. Hodge, A. Clifton, and J. McCaa. 2015. "The Wind Integration National Dataset (WIND) Toolkit." Applied Energy 151: 355366.

[145] King, J., A. Clifton, and B.M. Hodge. 2014. Validation of Power Output for the WIND Toolkit (Technical Report, NREL/TP-5D00-61714). Golden, CO: National Renewable Energy Laboratory.

C.1.5 Macrogrid topology

The United States, being the third largest country in the world by land area, has immense potential in terms of renewable energy resources throughout the contiguous US. A quick glance at the wind and solar resource map shows wind-rich areas, mainly in the Midwest going North-South, and solar-rich areas in the southern third of the country going East-West. The mainland's coastline, with a combined length of almost 5000 miles, has significant offshore wind potential. However, with coastal areas of the US accounting for 40% of the nation's population contained within less than 10% of the mainland's land mass, the clean energy transition necessitates large-scale transmission buildout throughout the country, connecting renewable energy-rich regions with population centers across the country.

Herein lies the motivation for a national HVDC Macrogrid, illustrated in Figure C-2, since it is well understood that existing transmission infrastructure will not be able to meet the needs of a largely electrified future, where load growth occurs due to widespread electrification in transportation, industry and residential electric use, moving away from fossil fuels. Expanding the current AC system in small increments, although possible, would forego benefits associated with a high capacity HVDC Macrogrid and make load growth and grid modernization more difficult to achieve, since changing the basic nature of operation of AC grids is a challenge, especially in relation to long-distance energy transfer.

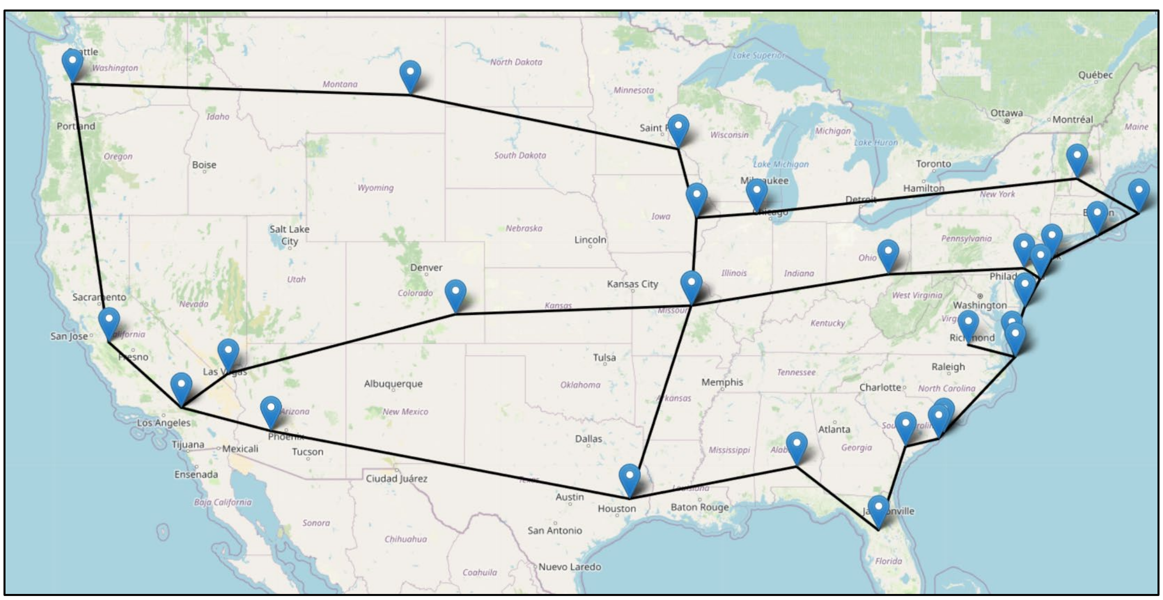

Figure C-2. HVDC Macrogrid schematic

The black lines in Figure 5.2 represent Macrogrid segments. Blue markers represent potential interconnections with the underlying AC system, or in the case of offshore nodes, collection points for OSW.

The HVDC Macrogrid on which this study is based on was conceptualized by a team at MISO, and further studied by teams comprised of national labs, industry representatives and universities as part of the Interconnection Seams Study. The study comprised of Line Commutated Converter (LCC)-based HVDC lines crossing the EI-WI seam, with limited coverage east of the Midwest, except for segments going into Florida in the south. A re-imagined version of the MISO design was developed for this study, replacing LCC with Voltage Source Converter (VSC)-based HVDC and extending the Macrogrid eastward, including offshore HVDC segments to incorporate the capability of planning for a future generation resource mix with various levels of offshore wind resources.[146] This topology connects renewable resource-rich areas with load centers, and is also well positioned to transport electricity from base-load power plants, with the location, capacity and investment timing of both generation and transmission co-optimized within CEP.

The Macrogrid consists of 31 segments, with the rule of 3 applied in the east-west direction[123]. All onshore segments of the Macrogrid are thus constrained to be of equal capacity, such that they see equal growth throughout the planning horizon to satisfy the rule of 3, i.e. having three parallel paths of equal capacity, such that they can be operated in an economically attractive way while still satisfying N-1 reliability criteria. The constraint is not applied to offshore segments since offshore transmission infrastructure is expensive, and enforcing equal capacity on all offshore segments would prevent the optimizer from fully utilizing the value of offshore HVDC. For these offshore segments, the alternative to the rule of 3 would be to use remedial action schemes. The comparison between the two approaches, in terms of reliability, complexity and economics, needs further attention.

Off the Carolinas coastline, a choice existed between building segments of the Macrogrid onshore or offshore and the latter was preferred, with the assumption that the additional cost of building offshore transmission would be justified, given permitting and regulatory hurdles of building onshore.

The offshore segments were not required to be equal capacity constrained, given the high investment cost of submarine transmission lines. The approach was thus to right-size these lines, as opposed to over-investing to match the onshore segments. For some segments, both onshore and offshore, a distance multiplier of 1.15 has been used to account for practical considerations of

[146] VSC's ability to provide voltage support, control reactive power and operate in multi-terminal DC (MTDC) configurations makes it ideal for the Macrogrid, as well as for supporting connections to weaker AC grids. Within the Macrogrid, strategically positioned multi-terminal VSC-HVDC networks can also enhance flexibility and augment grid resilience.

transmission line routing, since all transmission lines are drawn as straight schematic lines in the model. Similarly, transmission cost multipliers have also been used to account for terrain and regional cost variations. For example, building transmission through densely populated areas of the East Coast will be significantly more expensive than building transmission through the sparsely populated Midwest.

The offshore segments are designed to collect offshore wind energy from Bureau of Ocean Energy Management (BOEM) planned and approved lease areas off the Atlantic coast, extending all the way from Maine down to South Carolina, forming an HVDC 'backbone'. The offshore grid interconnects with the onshore grid at points of interconnection (POIs). However, being applied to a highly reduced model of the electric grid in Model 3, the locations of these POIs should not be considered as recommendations, since heavy reduction of the onshore transmission system (performed to make the problem computationally tractable) prevents the model from representing beachheads and POIs in detail. Identifying particular POIs requires more in-depth analysis of the East Coast electric system, such as the studies in Appendix B and Chapter 3 of this report. Even though POIs in this study are modeled in an aggregated manner, the general results are still relevant in relation to the other two studies presented in this report.

C.2 Results

The overarching question this section attempts to address is the following – With a goal of introducing various levels of East Coast offshore wind, and with the transition towards reducing carbon emissions from electric power generation, how does an HVDC Macrogrid transmission overlay benefit the future US electric system?

The results assume the following:

- Investments are allowed only in onshore wind, offshore wind, solar and natural gas-fired generation. No new investments are allowed in hydro and nuclear.
- Onshore segments of the Macrogrid are equal capacity constrained. This is done from a reliability perspective to enforce the rule of 3 such that the Macrogrid is self-contingent if built using at least 3 equal capacity parallel lines.
- Offshore Macrogrid segments are not equal capacity constrained.
- No emissions reduction or clean energy targets are set, instead allowing the model to make economic choices that drive investments, other than in offshore wind.
- The model is required to invest in offshore wind by including constraints requiring a certain level of offshore wind investment within a specified investment period. If this constraint is

not included, the model chooses not to build offshore wind, owing to its high capital cost, compared to onshore wind and solar.[147]

- No carbon pricing mechanisms are implemented in these results.
- The Macrogrid is designed using VSC-based HVDC, unless otherwise specified.
- Planning horizon is assumed to be 2024-2050 for all cases.

C.2.1 85 GW East Coast OSW

This design for 85 GW offshore wind on the East Coast is comprised of 30 segments – 20 onshore equal capacity constrained interregional HVDC lines and 10 offshore or partially offshore/submarine HVDC lines.

Offshore nodes are located by referencing BOEM lease areas. The eastern north-south leg of the Macrogrid, from New England and New York down to Florida, can be considered to be an HVDC backbone, connecting densely populated load centers to offshore wind along the East Coast. Offshore wind generation investments are spread out over the planning horizon, with 20 GW invested in 2030, 25 GW in 2035, 25 GW in 2040 and the remaining 15 GW in 2045, to get to a total 85 GW by 2050.

C.2.2 200 GW East Coast OSW

This design for 200 GW offshore wind on the East Coast is comprised of 31 segments – 19 onshore equal capacity constrained interregional HVDC lines and 12 offshore or partially offshore/submarine HVDC lines, illustrated in Figure C-2.

Although very similar to the 85 GW design, a slightly modified northeastern design is considered here to allow access to additional offshore wind generation capacity off the New England coastline. This design also prefers an all-offshore north-south corridor, similar to the 85 GW design. To get to 200 GW offshore wind on the East Coast, turbine spacing was slightly reduced compared to the 85 GW case to accommodate a greater number of turbines within the BOEM lease areas.

Offshore wind generation investments are spread out over the planning horizon, with 30 GW invested in 2030, 30 GW in 2035, 40 GW in 2040, 50 GW in 2045 and the remaining 50 GW in 2050, to get to a total 200 GW by 2050.

[147] Model 3 includes an HVDC Macrogrid overlay spanning the lower 48 states, which Model 2 does not study. The Macrogrid provides a high capacity transmission pathway across the country, so Model 3 has access to inexpensive onshore wind and solar in the Midwest and the South/Southwest. This reduces incentive to build comparatively expensive offshore wind generation and transmission off the Atlantic coast, thus requiring constraints to build a certain level of offshore wind within every investment period.

C.2.3 Comparison of 85 GW and 200 GW OSW Results

Results for both 85 GW and 200 GW OSW on the East Coast, with the Macrogrid, are presented and compared in this section. Figure C-3 shows economic investment results for both scenarios. Figure C-4 illustrates the generation resource capacity mix in 2050 for the 85 GW OSW scenario, whereas Figure C-5 illustrates the same for the 200 GW OSW scenario. The results are presented for both the EI and WI together.

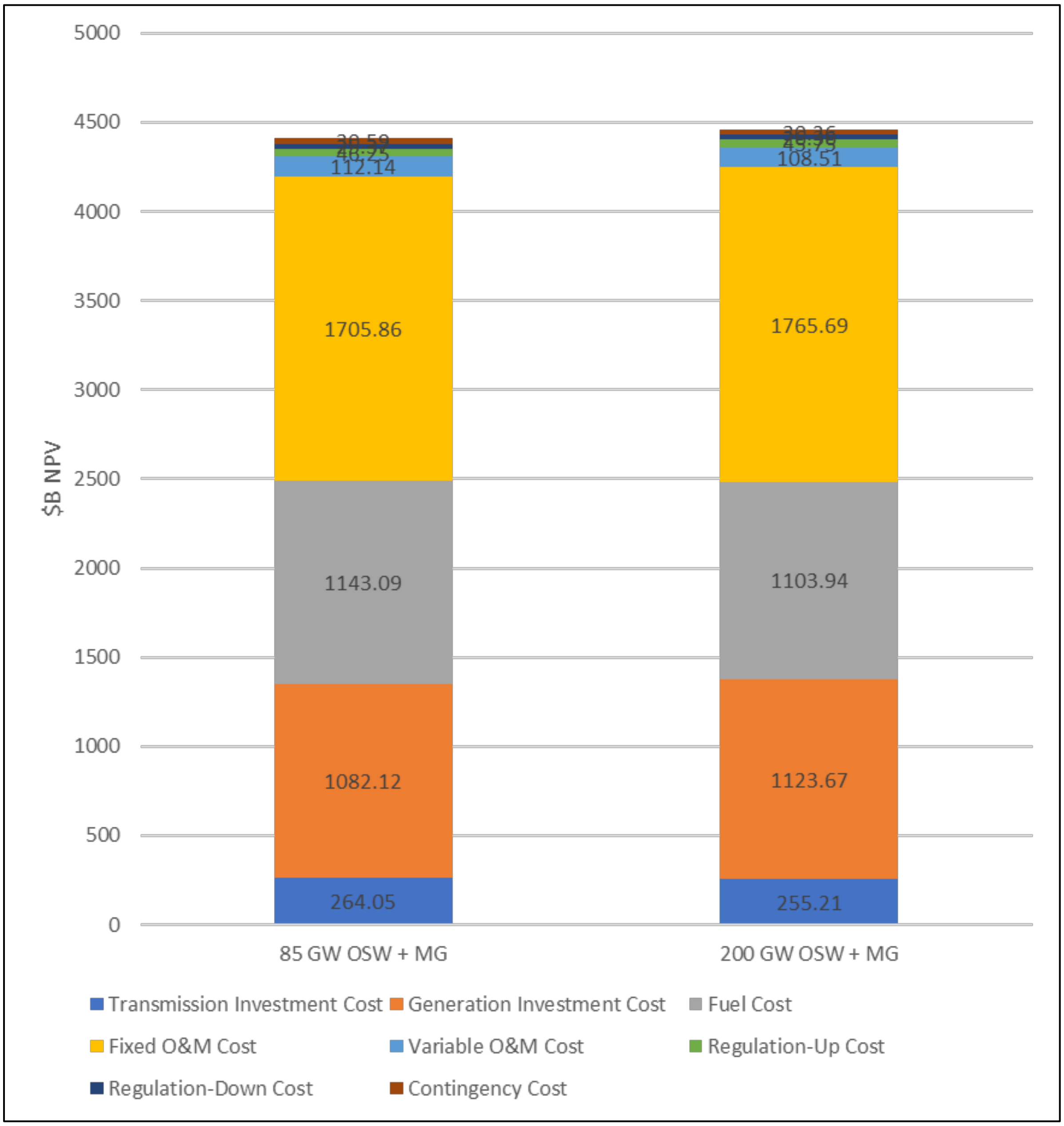

Figure C-3. Economic investments and cost results

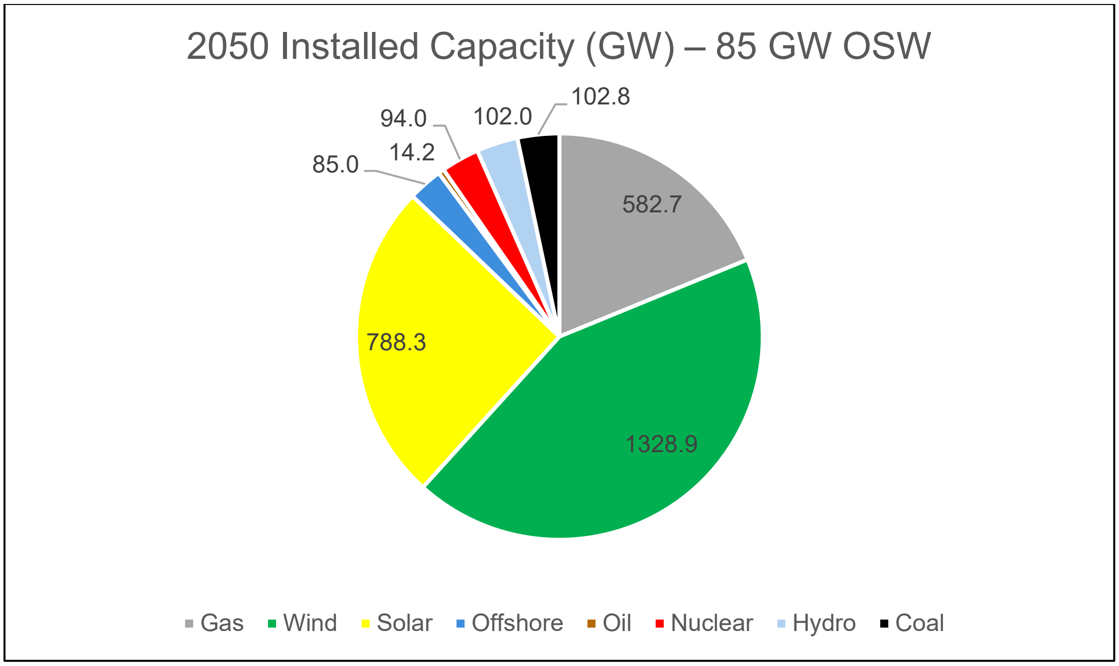

Figure C-4. 2050 generation resource capacity mix with 85 GW OSW

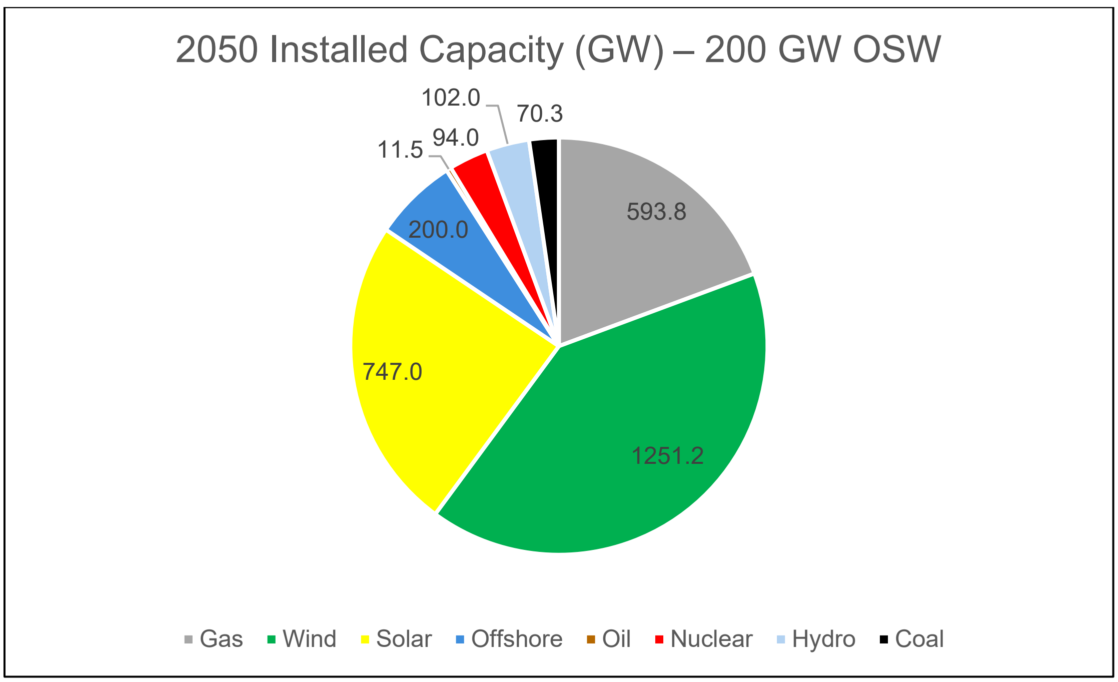

Figure C-5. 2050 generation capacity resource mix with 200 GW OSW

Overall transmission needs reduce in the 200 GW scenario compared to the 85 GW scenario, owing to the presence of a large amount of high-quality, inexpensive (once built) localized offshore wind resource close to large load centers on the Atlantic Coast, reducing the need for investment in transmission infrastructure to move energy from generation resources in the Midwest and South to the Atlantic Coast. Transmission infrastructure is utilized to handle this influx of OSW from the East, albeit in the opposite direction to existing line flows, thus diminishing the need for building more transmission in the 200 GW OSW scenario compared to the 85 GW scenario. This is particularly significant closer to the coast, since some AC transmission paths may be difficult to expand given the population density. Similarly, the Macrogrid also sees a reduction in onshore segment capacity, from 32 GW/segment in the 85 GW OSW scenario to 30 GW/segment in the 200 GW OSW scenario.

Generation investment costs go up for the 200 GW OSW scenario, since offshore wind generation has a high capital cost per GW compared to onshore wind/solar. Fixed O&M (operation and maintenance) costs also go up for the same reason, due to higher fixed costs for offshore wind. Fuel costs reduce in the 200 GW OSW scenario, due to better quality renewable generation resources in the mix and lower utilization of fossil fuel-fired generation, which exist in the resource mix primarily to meet operational and planning reserve requirements, mostly in the form of natural gas combined cycle generators.

In both scenarios, between 216 to 249 GW of mostly coal, oil and natural gas-fired generation is retired over the planning horizon. The model retires these generators owing to their high operational costs and associated fuel costs compared to other resources with lower costs available in the resource mix, or for investment. The decision to retire a generator is primarily dictated by economics. As long as the net present value of the generator is greater than the operational costs, or if the generator helps with maintaining reliability by contributing to regional operational and planning reserve requirements, the generator is kept in-service. Typically, older coal and gas fired generation meet the retirement criteria and are hence retired in favor of generators that are cheaper to operate, such as wind and solar.

Both scenarios result in close to 3200 GW of installed generation capacity in 2050, producing ~9000 TWh of energy, with similar levels of clean energy (from non-carbon emitting resources including nuclear and hydro) produced – 90.3% clean energy in 2050 in the 85 GW OSW scenario, and 91.3% clean energy in the 200 GW OSW scenario. These clean energy levels in 2050 are achieved without the need for incentivizing the model to invest in carbon-free generation resources. Additionally, the ~3200 GW of installed capacity in 2050 also satisfies planning reserve margin requirements for each region.

C.3 Observations and Summary

This section presents observations and takeaways from the study, with respect to discussing the benefits of a national HVDC Macrogrid and its interaction with OSW.

C.3.1 Macrogrid reduces AC transmission needs with increased OSW

Figure C-6 shows a plot with Atlantic Coast OSW capacity plotted on the X-axis vs. AC transmission investment cost in the Eastern Interconnection plotted on the Y-axis. Two curves are presented – the orange curve shows AC transmission investment in the EI without the Macrogrid modeled (i.e. only AC transmission expansion is allowed). The blue curve shows AC transmission investment in the EI with the Macrogrid modeled, thus allowing for investments in the HVDC Macrogrid and in the underlying AC transmission.

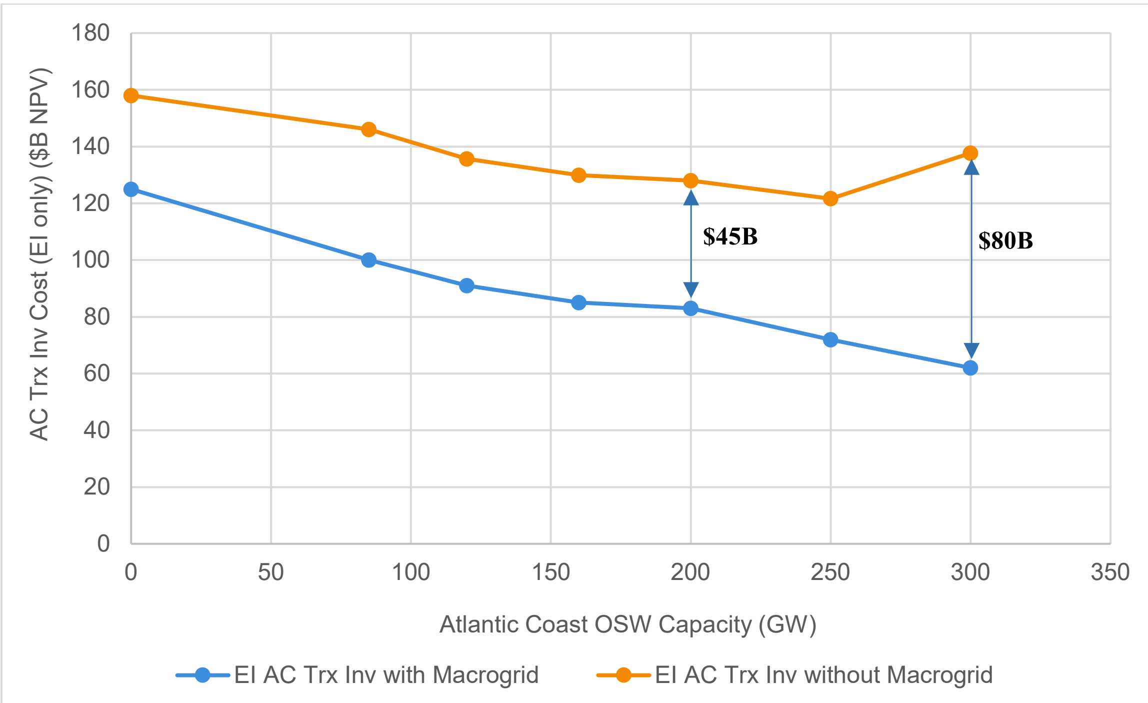

Figure C-6. Plot of Atlantic Coast OSW capacity vs. AC upgrades required in EI, with and without the Macrogrid

Both curves show a decline in AC transmission needs in the EI until 250 GW OSW. This can be attributed to a diminished requirement to move energy from the wind-rich Midwest and solar-rich South towards large load centers close to the northeast portion of the Atlantic Coast. The presence of OSW causes flows in the opposite direction to prevailing flows, causing transmission expansion to decline with increasing OSW levels for both curves. This phenomenon continues until the point where flows on these lines completely turn around, moving away from the load centers at 300 GW OSW, for the case without the Macrogrid, whereas the case with the Macrogrid continues to see a decline in underlying AC transmission investments even beyond 250 GW.

The case with the Macrogrid shows a clear reduction in AC transmission investments compared to the case without the Macrogrid, with a ~$45B difference between the two cases at OSW levels of 85 GW and above, until 250 GW. This is a direct result of the Macrogrid offloading the underlying AC system by providing a high-capacity transmission highway around the country. However, at 300 GW OSW, the two curves diverge and the difference between the two cases increases to $80B, with this difference expected to grow further at higher levels of OSW.

To illustrate the benefit of building the Macrogrid in conjunction with OSW, consider an example of 160 GW OSW with and without the Macrogrid, shown in Table C-1. Compared to the case without the Macrogrid, EI-only AC transmission investment costs are lower by ~$45B with the Macrogrid present. Fuel costs are lower by ~$83B (over the course of the planning horizon) because the Macrogrid displaces carbon-emitting, expensive, local generation such as natural gas-fired generators. The case without the Macrogrid also invests ~$66B more in building these localized natural gas-fired units compared to the case with the Macrogrid. Overall, these differences total ~$194B, which is sufficient to build the Macrogrid and reap its benefits, especially since building AC transmission in and around large population centers on the East Coast is both complicated and costly.

Table C-1. 160 GW East Coast OSW with and without the Macrogrid

	160 GW OSW without Macrogrid	160 GW OSW with Macrogrid	Delta Δ
EI-only AC Trx Cost	$129.7B	$84.9B	$44.8B
EI-only Fuel Cost	$825.2B	$742.5B	$82.7B
EI-only Natural Gas-fired Generation Investment Cost	$66B excess investment compared to case with Macrogrid	-	$66B
Difference between results with and without the Macrogrid			**$193.5B**

C.3.2 Benefits of a national HVDC Macrogrid

The motivation behind an HVDC Macrogrid is to lower the cost of the clean energy transition, while leveraging load and resource diversity such that the ability to provide energy, capacity and ancillary services across the country exists without the need to build more expensive, localized generation which may contribute to carbon emissions. The following bullets illustrate the benefits of a national HVDC Macrogrid:

- Circumvents congestion in the underlying AC transmission system by "flying over" transmission bottlenecks. This is especially relevant close to the Atlantic Coast where transmission systems are constrained, and hence injecting high levels of OSW may require a large-scale upgrade of the underlying AC transmission infrastructure in the absence of a Macrogrid.

- Enables efficient, controllable, high-capacity transfer of clean energy from remote generation resources (both onshore and offshore) to load centers.
- Allows long-distance movement of electricity with limited right-of-way requirements.
- Improves deliverability for highly attractive renewable resources.
- Reduces the need for onshore AC transmission upgrades, compared to a scenario in which the Macrogrid is not built.
- Enables sharing of energy, capacity and grid services across regions, and not just between neighboring areas.
- Counteracts the inability of a region to satisfy its own planning reserve margin due to the presence of large amounts of variable generation, via interregional capacity sharing.
- Provides increased operational reserves in a region via interregional reserve sharing capabilities.
- Boosts resilience against extreme events by providing a more effective and less costly mitigation strategy.
- Supports the stability of the grid due to the use of highly controllable inverter-based resources in VSC-based HVDC.

C.3.3 Summary

This study demonstrates that a national HVDC Macrogrid gives impetus to the clean energy transition by providing an interregional, high capacity and controllable transmission super highway across the country, connecting remote but high value renewable energy resources with load centers. The goal of introducing a significant amount of offshore wind on the Atlantic Coast, between 85 and 200 GW by 2050, is locally significant closer to the Atlantic Coast, but nationally a sliver of the total expected generation fleet with an installed capacity of ~3200 GW in 2050, producing ~9000 TWh of energy. However, the study found that the Macrogrid reduces the need for AC transmission investments in the EI with an increase in Atlantic Coast OSW levels, leading to economic and operational benefits. At 30 GW/segment onshore, flows on the Macrogrid will be orders of magnitude higher than flows seen in the present grid, and new systems of operating, regulating and administering the grid may be required to make the switch to a decarbonized electric system more efficient.

Appendix D Beachheads

This appendix lists all the beachheads used as landing points of OSGs.

Table D-1: Beachheads

Name	State	Latitude	Longitude	Name	State	Latitude	Longitude
MaineYankee	ME	43.952	-69.692	Millwood	NY	41.177	-73.876
Yarmouth	ME	43.75	-70.156	Sprainbrook	NY	40.959	-73.895
Barnstable	MA	41.71	-70.294	MottHaven	NY	40.805	-73.902
Barnstable	MA	41.635	-70.334	Dunwoodie	NY	40.938	-73.903
Canal	MA	41.771	-70.512	Astoria	NY	40.79	-73.912
MaguireRd	ME	43.342	-70.525	Academy	NY	40.865	-73.934
Pilgrim	MA	41.94	-70.617	RaineyEW	NY	40.763	-73.944
Falmouth	MA	41.539	-70.634	Farragut	NY	40.706	-73.984
Newington	NH	43.101	-70.79	W49thSt	NY	40.767	-73.998
Seabrook	NH	42.894	-70.81	Gowanus	NY	40.662	-74.004
SalemHarbor	MA	42.526	-70.875	Larrabee	NJ	40.122	-74.03
KStreet	MA	42.34	-71.039	Goethals	NY	40.616	-74.195
Mystic	MA	42.393	-71.069	OysterCreek	NJ	39.814	-74.208
BraytonPoint	MA	41.708	-71.195	Deans	NJ	40.492	-74.281
Davisville	RI	41.584	-71.429	Cardiff	NJ	39.353	-74.435
KentCounty	RI	41.681	-71.448	IndianRiver	DE	38.587	-75.059
Montville	CT	41.429	-72.101	SalemHopeCreek	NJ	39.461	-75.532
Millstone	CT	41.313	-72.16	Landstown	VA	36.796	-75.961
BOKUM	CT	41.32	-72.35	CalvertCliffs	MD	38.436	-76.44
East Shore	CT	41.288	-72.905	NewBern	NC	35.151	-77.084
EastDevon	CT	41.228	-73.109	Greenville	NC	35.616	-77.367
Bridgeport	CT	41.173	-73.184	Sutton	NC	34.28	-77.952
Northport	NY	40.924	-73.344	Winyah	SC	33.314	-79.291
Norwalk	CT	41.073	-73.411	James	SC	32.719	-79.953
ShoreRoad	NY	40.829	-73.648	Church	SC	32.839	-80.061
Barrett	NY	40.618	-73.648				

Appendix E Input POIs

In this Appendix, the list of all POIs that have been considered for injection of offshore wind is shown in Table E-1.

Table E-1: List of POIs

POI Name	Latitude	Longitude	POI Name	Latitude	Longitude
MAINE YANKEE	43.954	-69.695	MOTT HAVEN	40.808	-73.907
YARMOUTH	43.751	-70.155	ASTORIA W-N	40.788	-73.909
BARNSTABLE	41.686	-70.285	ACADEMY	40.86	-73.919
W BARNSTABLE	41.686	-70.35	RAINEY WEST	40.763	-73.943
CANAL	41.769	-70.51	RAINEY EAST	40.763	-73.943
FALMOUTH 115	41.564	-70.611	FARRAGUT WES	40.705	-73.984
MAGUIRE ROAD	43.397	-70.617	FARRAGUT EAS	40.705	-73.984
PILGRIM	41.907	-70.629	W 49 ST	40.766	-73.996
NEWINGTON	43.098	-70.792	GOWANUS	40.662	-74.003
SEABROOK	42.899	-70.849	28LARRABEE	40.114	-74.192
SALEM HARBOR	42.525	-70.878	GOTHLS	40.617	-74.195
K STREET 3_R	42.34	-71.039	28OYSTER C	39.814	-74.209
MYSTIC MA	42.393	-71.068	SMITHBRG	40.201	-74.361
BRAYTN POINT	41.712	-71.194	DEANS	40.406	-74.485
DAVISVIL90_T	41.593	-71.435	CARDIFF	39.428	-74.621
KENT COUNTY	41.683	-71.479	OCEANCTY	38.334	-75.088
MONTVILLE	41.43	-72.1	INDRIV 4	38.586	-75.239
MILLSTONE	41.311	-72.168	SALEM	39.463	-75.533
BOKUM	41.461	-72.477	Hope Creek	39.468	-75.534
EAST SHORE	41.288	-72.904	6LANDSTN	36.771	-76.092
DEVON	41.228	-73.099	8FENTRES	36.69	-76.19
BRPT HRBR 5	41.172	-73.185	CLVRT CLIFF2	38.432	-76.446
NRTHPRT1	40.924	-73.341	6NEW BERN WE	35.141	-77.123
NORWALK HARBOR	41.127	-73.429	6GREENVILE S	35.625	-77.366
SHORE RD	40.828	-73.647	6SUTTON230 T	34.283	-77.985
BARRETT1	40.618	-73.648	6WINYAH	33.332	-79.357
MILLWOOD	41.192	-73.801	3JAMES I	32.723	-79.967
SPRAINBROOK	40.958	-73.856	6CHURCH2!	32.831	-80.07
DUNWOODIE	40.938	-73.86			

Appendix F List of selected POIs for each case

Table F-1: Selected POIs for 100 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
6LANDSTN	PJM	6.26	**MILLSTONE**	ISONE	0.96
SALEM	PJM	4.00	**6CHURCH2!**	DUKE	0.89
MYSTIC MA	ISONE	3.53	**ASTORIA W-N**	NYISO	0.60
K STREET 3_R	ISONE	3.48	**CLVT CLF**	PJM	0.56
28LARRABEE	PJM	3.40	**3JAMES I**	DUKE	0.55
6WINYAH	DUKE	3.11	**BARRETT1**	NYISO	0.51
PILGRIM	ISONE	2.56	**NORWALK HRBR**	ISONE	0.31
INDRIV 4	PJM	2.48	**6SUTTON230 T**	DUKE	0.24
NRTHPRT1	NYISO	2.30	**RAINEY WEST**	NYISO	0.24
CARDIFF	PJM	2.27	**BRAYTN POINT**	ISONE	0.22
GOWANUS	NYISO	1.89	**CANAL**	ISONE	0.13
SHORE RD	NYISO	1.87	**FARRAGUT WES**	NYISO	0.09
GOTHLS	NYISO	1.67	**6NEW BERN WE**	DUKE	0.07
28OYSTER C	PJM	1.48	**DAVISVIL90_T**	ISONE	0.05
W BARNSTABLE	ISONE	1.46	**MAINE YANKEE**	ISONE	0.02

Table F-2: Selected POIs for 200 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
6LANDSTN	PJM	10.66	**3JAMES I**	DUKE	1.62
SALEM	PJM	9.02	**W BARNSTABLE**	ISONE	1.38
DEANS	PJM	8.12	**BARRETT1**	NYISO	1.26
MYSTIC MA	ISONE	6.51	**ASTORIA W-N**	NYISO	1.23
K STREET 3_R	ISONE	6.00	**CANAL**	ISONE	1.07
CLVT CLF	PJM	5.99	**MILLSTONE**	ISONE	0.92
6WINYAH	DUKE	4.85	**MAINE YANKEE**	ISONE	0.81
28LARRABEE	PJM	3.84	**SALEM HARBOR**	ISONE	0.69
RAINEY WEST	NYISO	3.48	**FARRAGUT WES**	NYISO	0.65
NRTHPRT1	NYISO	3.4	**MONTVILE_364**	ISONE	0.39
GOTHLS	NYISO	2.94	**6SUTTON230 T**	DUKE	0.3
INDRIV 4	PJM	2.65	**NORWALK HRBR**	ISONE	0.24
6CHURCH2!	DUKE	2.56	**BRAYTN POINT**	ISONE	0.22
PILGRIM	ISONE	2.07	**6NEW BERN WE**	DUKE	0.16
CARDIFF	PJM	1.93	**ACADEMY**	NYISO	0.06
SHORE RD	NYISO	1.77	**YARMOUTH**	ISONE	0.06
28OYSTER C	PJM	1.68	**MOTT HAVEN**	NYISO	0.05
GOWANUS	NYISO	1.66			

Table F-3: Selected POIs for 250 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
DEANS	PJM	12.24	**SHORE RD**	NYISO	1.51
SALEM	PJM	11.97	**W BARNSTABLE**	ISONE	1.43
6LANDSTN	PJM	11.78	**BARRETT1**	NYISO	1.42
CLVT CLF	PJM	9.26	**FARRAGUT WES**	NYISO	1.32
MYSTIC MA	ISONE	6.97	**GOWANUS**	NYISO	1.31
K STREET 3_R	ISONE	6.97	**MILLSTONE**	ISONE	1.23
RAINEY WEST	NYISO	5.02	**MAINE YANKEE**	ISONE	1.13
6WINYAH	DUKE	4.98	**6SUTTON230 T**	DUKE	0.94
28LARRABEE	PJM	4.24	**SALEM HARBOR**	ISONE	0.62
NRTHPRT1	NYISO	4.00	**MONTVILE_364**	ISONE	0.49
GOTHLS	NYISO	3.75	**6NEW BERN WE**	DUKE	0.42
6CHURCH2!	DUKE	3.38	**NORWALK HRBR**	ISONE	0.24
PILGRIM	ISONE	3.03	**BRAYTN POINT**	ISONE	0.14
INDRIV 4	PJM	2.86	**YARMOUTH**	ISONE	0.13
3JAMES I	DUKE	1.8	**DAVISVIL90_T**	ISONE	0.1
28OYSTER C	PJM	1.74	**CANAL**	ISONE	0.09
ASTORIA W-N	NYISO	1.73	**MOTT HAVEN**	NYISO	0.08
CARDIFF	PJM	1.62	**ACADEMY**	NYISO	0.04

Table F-4: Selected POIs for 300 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
DEANS	PJM	15.83	**ASTORIA W-N**	NYISO	1.92
SALEM	PJM	14.55	**MILLSTONE**	ISONE	1.92
6LANDSTN	PJM	13.71	**3JAMES I**	DUKE	1.89
CLVT CLF	PJM	11.18	**28OYSTER C**	PJM	1.7
K STREET 3_R	ISONE	9.21	**BARRETT1**	NYISO	1.57
MYSTIC MA	ISONE	7.71	**GOWANUS**	NYISO	1.55
RAINEY WEST	NYISO	6.36	**MOTT HAVEN**	NYISO	1.23
6WINYAH	DUKE	5.00	**SHORE RD**	NYISO	1.16
28LARRABEE	PJM	4.2	**6SUTTON230 T**	DUKE	1.14
NRTHPRT1	NYISO	4.01	**W BARNSTABLE**	ISONE	0.8
6CHURCH2!	DUKE	3.9	**MONTVILE_364**	ISONE	0.44
PILGRIM	ISONE	3.36	**FARRAGUT WES**	NYISO	0.39
GOTHLS	NYISO	3.18	**6NEW BERN WE**	DUKE	0.33
INDRIV 4	PJM	2.97	**SALEM HARBOR**	ISONE	0.27
MAINE YANKEE	ISONE	2.81	**BRAYTN POINT**	ISONE	0.14
CARDIFF	PJM	1.94	**NORWALK HRBR**	ISONE	0.1

Table F-5: Selected POIs for 400 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
DEANS	PJM	25.92	**3JAMES I**	DUKE	2.24
CLVT CLF	PJM	20.62	**SALEM HARBOR**	ISONE	2.17
SALEM	PJM	18.44	**BARRETT1**	NYISO	2.15
6LANDSTN	PJM	15.54	**6SUTTON230 T**	DUKE	2.13
K STREET 3_R	ISONE	12.27	**ASTORIA W-N**	NYISO	2.00
MYSTIC MA	ISONE	9.49	**28OYSTER C**	PJM	1.84
RAINEY WEST	NYISO	7.40	**FARRAGUT WES**	NYISO	1.77
6CHURCH2!	DUKE	5.79	**MOTT HAVEN**	NYISO	1.48
6WINYAH	DUKE	5.46	**MILLSTONE**	ISONE	1.37
MAINE YANKEE	ISONE	4.62	**GOWANUS**	NYISO	1.27
NRTHPRT1	NYISO	4.29	**MONTVILE_364**	ISONE	0.93
28LARRABEE	PJM	4.05	**6NEW BERN WE**	DUKE	0.68
SHORE RD	NYISO	3.79	**BRPT HRBR 5**	ISONE	0.66
GOTHLS	NYISO	3.71	**W BARNSTABLE**	ISONE	0.42
PILGRIM	ISONE	3.47	**6GREENVILE S**	DUKE	0.12
INDRIV 4	PJM	2.89	**BRAYTN POINT**	ISONE	0.03
CARDIFF	PJM	2.40			

Table F-6: Selected POIs for 500 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
DEANS	PJM	33.46	**MOTT HAVEN**	NYISO	2.01
CLVT CLF	PJM	31.66	**ASTORIA W-N**	NYISO	1.99
6LANDSTN	PJM	18.81	**28OYSTER C**	PJM	1.77
SALEM	PJM	18.42	**GOWANUS**	NYISO	1.48
K STREET 3_R	ISONE	13.86	**BARRETT1**	NYISO	1.45
MYSTIC MA	ISONE	10.04	**FARRAGUT WES**	NYISO	1.08
SHORE RD	NYISO	9.77	**MILLSTONE**	ISONE	0.94
RAINEY WEST	NYISO	8.14	**MONTVILE_364**	ISONE	0.79
6CHURCH2!	DUKE	6.50	**6NEW BERN WE**	DUKE	0.77
6WINYAH	DUKE	5.76	**BRPT HRBR 5**	ISONE	0.46
MAINE YANKEE	ISONE	4.69	**6GREENVILE S**	DUKE	0.40
NRTHPRT1	NYISO	4.03	**MAGUIRE ROAD**	ISONE	0.38
PILGRIM	ISONE	3.92	**BOKUM**	ISONE	0.38
INDRIV 4	PJM	3.75	**ACADEMY**	NYISO	0.36
6SUTTON230 T	DUKE	3.32	**YARMOUTH**	ISONE	0.22
GOTHLS	NYISO	3.29	**NORWALK HRBR**	ISONE	0.18
28LARRABEE	PJM	3.17	**W BARNSTABLE**	ISONE	0.15
3JAMES I	DUKE	2.44	**DAVISVIL90_T**	ISONE	0.04
CARDIFF	PJM	2.37	**BRAYTN POINT**	ISONE	0.02
SALEM HARBOR	ISONE	2.03			

Table F-7: Selected POIs for 600 GW of OSW investment

POI	ISO	Investment (GW)	POI	ISO	Investment (GW)
DEANS	PJM	41.76	**6GREENVILE S**	DUKE	1.98
CLVT CLF	PJM	35.86	**SALEM HARBOR**	ISONE	1.86
6LANDSTN	PJM	25.93	**MOTT HAVEN**	NYISO	1.69
SALEM	PJM	18.70	**28OYSTER C**	PJM	1.60
K STREET 3_R	ISONE	15.37	**GOWANUS**	NYISO	1.46
SHORE RD	NYISO	13.06	**FARRAGUT WES**	NYISO	1.27
MYSTIC MA	ISONE	11.05	**BARRETT1**	NYISO	1.23
RAINEY WEST	NYISO	7.42	**YARMOUTH**	ISONE	1.20
6CHURCH2!	DUKE	7.09	**MILLSTONE**	ISONE	1.14
6WINYAH	DUKE	6.06	**NEWINGTON**	ISONE	1.04
MAINE YANKEE	ISONE	4.69	**BRPT HRBR 5**	ISONE	0.67
6SUTTON230 T	DUKE	4.62	**BOKUM**	ISONE	0.45
NRTHPRT1	NYISO	4.28	**MONTVILE_364**	ISONE	0.30
GOTHLS	NYISO	3.95	**NORWALK HRBR**	ISONE	0.10
INDRIV 4	PJM	3.79	**W BARNSTABLE**	ISONE	0.07
PILGRIM	ISONE	3.62	**CANAL**	ISONE	0.05
28LARRABEE	PJM	3.07	**DAVISVIL90_T**	ISONE	0.05
3JAMES I	DUKE	2.54	**E SHORE_TAP**	ISONE	0.04
6NEW BERN WE	DUKE	2.35	**BRAYTN POINT**	ISONE	0.04
CARDIFF	PJM	2.26	**SEABROOK**	ISONE	0.03
ASTORIA W-N	NYISO	2.14			

Appendix G CEP Analytical Formulation

Below is the mathematical representation of the CEP problem used in this project.

$$\text{Minimize} \quad FOMC + VOMC + FUELC + CC^{\text{inv}} + FC^{\text{inv}} \tag{G-1}$$

$$C_{g(b,t),y} = C^{\text{init}}_{g(b,t)} + \sum_{y' \le y} \left(C^{\text{inv}}_{g(b,t),y'} - C^{\text{ret}}_{g(b,t),y'} \right), \quad \forall g(b,t), y, t \in T^{\text{inv}} \tag{G-2}$$

$$\sum_{g} C^{\text{inv}}_{g_{b,t}} \le C^{\text{MAX INV}}_{g_{b,t}}, \quad \forall g \tag{G-3}$$

$$CC^{\text{inv}} = \sum_{t} \sum_{y}^{Y} \eta_y c^{\text{inv}}_t C^{\text{inv}}_{g(b,t),y} \tag{G-4}$$

$$\sum_{g_{b,t'}} C_{g_{b,t'},y} \times CapCdt'_t + \sum_{g_{b,t''}} C^{disp}_{g_{b,t''},y,bl} \ge PRM \times \sum_{b} d^{peak}_{b,y},$$

$$bl = \text{peak}, t'' \in t^{\text{OSW}}, t' \in t^{\text{Onshore}} \tag{G-5}$$

$$F^{\ell_{i,j}}_{y,bl} = \frac{\theta_{i,y,bl} - \theta_{j,y,bl}}{x_{ij}} \times S_{base} \tag{G-6}$$

$$-F^{\max}_{\ell_{i,j}} - F^{\text{inv}}_{\ell_{i,j}} \le F^{\ell_{i,j}}_{y,bl} \le F^{\max}_{\ell_{i,j}} + F^{\text{inv}}_{\ell_{i,j}} \tag{G-7}$$

$$FC^{\text{inv}} = \sum_{y}^{Y} \sum_{\ell} \eta_y f^{\text{inv}}_{\ell} F^{\text{inv}}_{\ell,y} \tag{G-8}$$

$$C^{\text{disp}}_{g_{b,t},y,bl} \le C_{g(b,t),y'}, \quad \forall t \notin T \tag{G-9}$$

$$C^{\text{disp}}_{g_{b,t},y,bl} \le CapFac_{g(b,t),bl} \times C_{g(b,t),y'}, \quad \forall t \notin T \tag{G-10}$$

$$\sum_{g} C^{\text{disp}}_{g_{i,t}} + \sum_{j} F^{\ell_{j,i}}_{y,bl} - \sum_{j} F^{\ell_{i,j}}_{y,bl} = d_{i,y,bl}, \quad \forall t \notin T \tag{G-11}$$

$$\sum_{bl} \sum_{g} (C^{\text{disp}}_{g_{b,t},y,bl} \times HR_t \times CE_t \times T_{bl}) \le ER_y \times \sum_{bl} \sum_{g} (C^{\text{disp}}_{g_{b,t},y',bl} \times HR_t \tag{G-12}$$

$$\times CE_t \times T_{bl}), \tag{G-13}$$

$$FOMC = \sum_{g} \sum_{y \in Y} \eta_y c_t^{\mathrm{fom}} \times C_{g_{(b,t)},y} \quad \text{(G-14)}$$

$$VOMC = \sum_{g} \sum_{y \in Y} \eta_y c_t^{\mathrm{vom}} \times C_{g_{(b,t)},y}^{\mathrm{disp}} \times T_{bl} \quad \text{(G-15)}$$

$$FUELC = \sum_{g} \sum_{y \in Y} \eta_y c_t^{\mathrm{fuel}} \times C_{g_{(b,t)},y}^{\mathrm{disp}} \times HR_t \times T_{bl}. \quad \text{(G-16)}$$

Each variable and parameter are explained below:

bl	block.
b	bus.
t	technology.
y	year.
Y	set of years.
T^{inv}	set of investible technologies.
FOMC	Total fixed O&M cost for all generations ($).
VOMC	Total variable O&M cost for all generations ($).
FUELC	Total fuel cost for all generations ($).
$\mathrm{CC}^{\mathrm{inv}}$	Total investment cost for all generations ($).
$\mathrm{FC}^{\mathrm{inv}}$	Total investment cost for all transmission lines ($).
$C_{g_{(b,t)},y}$	Total generation capacity of technology t at bus b at year y (MW).
$C_{g_{(b,t)}}^{init}$	Initial generation capacity of technology t at bus b (MW).
$C_{g_{(b,t)},y}^{inv}$	Generation capacity investment of technology t at bus b at year y (MW).
$C_{g_{(b,t)},y}^{ret}$	Generation capacity of retirement of technology t at bus b at year y (MW).
$C_{g_{(b,t)}}^{\mathrm{MAX\ INV}}$	Maximum investible capacity for generation technology t (MW).
η_y	real discount factor at year y (dimensionless).
c_t^{inv}	Investment cost for generation technology t ($/MW).

$F^{\ell_{i,j}}_{y,bl}$	Power flow on transmission line ℓ from bus i to bus j at year y block bl (MW).
$\theta_{i,y,bl}$	Voltage angle at bus i at year y block bl (radians).
x_{ij}	Reactance of transmission line between bus i and bus j (p.u.).
S_{base}	Base power (MVA).
$F^{\max}_{\ell_{i,j}}$	Maximum power flow capacity of transmission line ℓ from bus i to bus j (MW).
$F^{\text{inv}}_{\ell_{i,j}}$	Investment in transmission line ℓ from bus i to bus j (MW).
f^{inv}_{ℓ}	Investment cost for transmission line ℓ (\$/MW).
$C^{\text{disp}}_{g_{b,t},y,bl}$	Dispatched generation capacity of technology t at bus b at year y block bl (MW).
$d_{i,y,bl}$	Demand at node i and year y block bl (MW).
$d^{\text{peak}}_{b,y}$	Peak demand at bus b and year y (MW).
HR_t	Heat rate of technology t (MMBtu/MWh).
CE_t	Carbon emission of technology t (tons/MWh).
T_{bl}	Number of hours in block bl.
ER_y	Emission reduction of year y (tons/MMBtu).
PRM	Planning reserve margin (dimensionless).
$CapCdt_t$	Capacity credit of technology t (dimensionless).
c^{fom}_t	Fixed O&M cost for generation technology t (\$/MW).
c^{vom}_t	Variable O&M cost for generation technology t (\$/MWh).
c^{fuel}_t	Fuel cost for generation technology t (\$/MMBtu).

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