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SUBMITTED VIA E-TARIFF

July 22, 2024

Debbie-Anne A. Reese
Acting Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: Mid-Atlantic Offshore Development, LLC
Formula Rate Tariff Filing
Docket No. ER24-2564-000

Dear Acting Secretary Reese:

Pursuant to section 205 of the Federal Power Act ("FPA"),[1] Part 35 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") regulations,[2] and Order No. 679,[3] Mid-Atlantic Offshore Development, LLC ("MAOD") hereby submits its proposed formula rate template ("Template") and implementation protocols ("Protocols") (together, "Formula Rate") to: (1) calculate and recover MAOD's Annual Transmission Revenue Requirement ("ATRR") for MAOD's transmission facilities located within the PJM Interconnection, L.L.C.[4] ("PJM") region; and (2) provide the procedures for stakeholders to review and comment upon (and, if necessary, challenge) MAOD's ATRR. MAOD's

[1] 16 U.S.C. § 824d (2012).

[2] 18 C.F.R. §§ 35.2, 35.12, 35.13, 35.35 (2024).

[3] *Promoting Transmission Investment through Pricing Reform*, "Order No. 679," FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, "Order No. 679-A," FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[4] Pursuant to Order No. 714, this filing is submitted by PJM Interconnection, L.L.C. ("PJM") on behalf of MAOD as part of an XML filing package that conforms with the Commission's regulations. *See Electronic Tariff Filings*, "Order No. 714," FERC Stats. & Regs. ¶ 31,276 (2008). PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Open Access Transmission Tariff ("PJM Tariff"). Thus, MAOD has requested PJM submit this Attachment H-35 Formula Rate tariff in the eTariff system as part of PJM's electronic Intra PJM Tariff.

proposed Template includes a proposed return on equity ("ROE") and depreciation rates. MAOD is not proposing a transmission revenue requirement at this time.

As detailed below, in coordination with PJM, MAOD was selected by the New Jersey Board of Public Utilities ("NJBPU") to construct, own, operate, and maintain a transmission substation designated as the "Larrabee Collector Station" and acquire adjacent land to accommodate up to four high-voltage direct current ("HVDC") converter stations, which will be used to interconnect New Jersey offshore wind generation to the PJM transmission system (collectively, the "Project"). The Project is a central component of the Larrabee Tri-Collector Solution, which is, primarily, a combined MAOD-owned and Jersey Central Power & Light Company-owned ("JCP&L") onshore transmission delivery solution selected by the NJBPU to interconnect New Jersey offshore wind projects to onshore points of interconnection ("POI") within the PJM transmission system.[5] This selection was made based on the results of a competitive solicitation process that NJBPU and PJM jointly implemented from April 2021 through October 2022 pursuant to the PJM Regional Transmission Expansion Plan ("RTEP") process and the PJM State Agreement Approach Process ("SAA Process") under the PJM Operating Agreement ("PJM OA").[6]

On August 21, 2023, PJM and MAOD executed a Designated Entity Agreement ("DEA"), which expressly requires MAOD to construct the Project and have it reach commercial operation by December 31, 2027 ("COD").[7] Upon COD, the Project will become subject to PJM's operational control under the PJM Open Access Transmission Tariff ("PJM Tariff") and MAOD will become a transmission-owning member of PJM.

As explained herein, MAOD respectfully requests that the Commission grant the following authorizations with respect to MAOD's proposed Formula Rate:

First, MAOD requests that the Commission accept MAOD's proposed Formula Rate (including MAOD's proposed Protocols) to be effective September 21, 2024, which is sixty-one (61) days after the date of this filing.

Second, MAOD requests that the Commission expressly confirm that the Order No. 679 transmission rate incentives already approved for the Project (in an order issued February 15, 2024 ("Incentives Order")[8]) also apply to an additional NJBPU mandated scope change for the Project that was approved by the PJM Board for inclusion in the RTEP after MAOD

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[5] *See In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey,* Order on the State Agreement Approach SAA Proposals, Docket No. QO20100630, at 59-63, App. A (Oct. 26, 2022) ("NJBPU Oct. 2022 Order"). A copy of the NJBPU Oct. 2022 Order is provided as Exhibit No. MAOD-3.

[6] *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 20-24, 59-64, 66-67.

[7] *See* Exhibit No. MAOD-1, Direct Testimony of Christopher Sternhagen ("Sternhagen Testimony"), at Q9, Q32 (citing Exhibit No. MAOD-9, "Designated Entity Agreement between PJM Interconnection, L.L.C. and Mid-Atlantic Offshore Development, LLC, PJM RTEP Projects b3737.22 & b3737.60: New Jersey SAA – Larrabee Collector Station (LCS)" (Aug. 21, 2023) ("PJM-MAOD DEA")).

[8] *See Mid-Atlantic Offshore Dev., LLC*, 186 FERC ¶ 61,116 (2024) ("Incentives Order").

made its filing with the Commission to request such incentives.[9] Specifically, the Commission granted MAOD the following Order No. 679 incentives for the Project in the Incentives Order: (1) Regulatory Asset Incentive; (2) Abandoned Plant Incentive; (3) Hypothetical Capital Structure Incentive; and (4) Regional Transmission Organization ("RTO") Participation Incentive.[10] After MAOD filed for approval of those incentives, the NJBPU and PJM approved a change of scope for the Project through its RTEP, referred to as the "Interconnection Work." On February 28, 2024, the PJM Board approved this work as part of the Project and for inclusion in the RTEP,[11] and thus MAOD believes that the incentives granted to the Project also apply to the Interconnection Work. Out of an abundance of caution, however, MAOD respectfully requests that the Commission expressly confirm the transmission rate incentives approved for the Project also apply to the Interconnection Work. Further, MAOD requests that the Commission expressly confirm that the four granted transmission rate incentives will also apply to future changes to the scope of the Project approved by the NJBPU and PJM in the coordinated SAA Process and RTEP process, as long as those changes do not materially alter the basis of the Commission's grant of the original incentives.[12]

I. BACKGROUND

A. Description of MAOD and Related Entities

MAOD is a non-incumbent, transmission-only company whose only business is to develop, own, maintain, and operate transmission facilities in New Jersey, within the RTO area operated by PJM. MAOD is a Delaware limited liability company that is a joint venture between EDF-RE Offshore Development, LLC ("EDFR") and Shell New Energies US, LLC ("Shell New Energies"). EDFR and Shell New Energies each own a 50 percent interest in MAOD.

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[9] *See In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey,* "Order Approving State Agreement Approach Project Scope Modifications and Addressing Scope-Related Cost Estimate Adjustments," Docket No. QO20100630, at 5, 9-10 (June 29, 2023), available at https://nj.gov/bpu/pdf/boardorders/2023/20230629/8B%20ORDER%20SAA%20Project%20Scope%20Changes.pdf (approving MAOD's change of scope and cost increases for interconnection work, pre-build infrastructure study and refinement of cost estimates) ("June 29, 2023, NJBPU Order"). A copy of the June 29, 2023, NJBPU Order is attached as Exhibit No. MAOD-10. *See also* PJM Interconnection, L.L.C., "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, PJM Staff White Paper," at 8, 11 (Feb. 2024), available at https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240206/20240206-pjm-teac-board-whitepaper-feburary-2024.ashx ("PJM February 2024 White Paper") (stating that on February 28, 2024, the PJM Board approved the prebuild extension work (referred to herein as the "Interconnection Work") in PJM project number b3737.22). A copy of the PJM February 2024 White Paper is provided as Exhibit No. MAOD-13.

[10] *See* Incentives Order, at PP 1-2, 34-48. *See also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q39-Q40.

[11] *See* Exhibit No. MAOD-13, PJM February 2024 White Paper, at 8, 11.

[12] *Pioneer Transmission, LLC*, 130 FERC ¶ 61,044, P21 (2010). *See also Green Power Express LP*, 135 FERC ¶ 61,141, P 22 (2011).

EDFR's ultimate parent is Électricité de France S.A., one of the world's largest electricity generators. Shell New Energies is an affiliate of Shell Oil Company US, which is a subsidiary of Shell plc.

B. Description of the Project

As explained in the Direct Testimony of Christopher Sternhagen, Director – MAOD Development ("Sternhagen Testimony"),[13] the Project includes an alternating current ("AC") 230/500 kilovolt ("kV") substation designated as the Larrabee Collector Station and adjacent land required to interconnect up to four future HVDC converter stations. The Project will be constructed adjacent to JCP&L's existing Larrabee substation located in Howell Township, Monmouth County, New Jersey ("JCP&L Larrabee Substation"). Once completed, the Project will accommodate up to four future HVDC circuits that will deliver future generation from New Jersey offshore wind generators.[14]

The Larrabee Tri-Collector Solution is, in aggregate, the combined and inter-related series of transmission facilities selected by the NJBPU to interconnect New Jersey offshore wind generation projects to onshore POI within the PJM-operated transmission system pursuant to PJM's SAA Process set forth in Rate Schedule 49 of the PJM Tariff.[15] As explained above, the Project will comprise a portion of the Larrabee Tri-Collector Solution. JCP&L will also own a significant portion of the Larrabee Tri-Collector Solution.[16]

MAOD's development of the Project is subject to the DEA executed with PJM. Per the DEA, the Project's required COD is December 31, 2027. Moreover, pursuant to the DEA,

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[13] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q2.

[14] *See id*. at Q34-Q35, Q37.

[15] *See id*. at Q23-Q24 (citing PJM Interconnection, L.L.C., Rate Schedules, Rate Schedule FERC No. 49, "Amended and Restated State Agreement Approach Agreement By and Among PJM Interconnection, L.L.C. and New Jersey Board of Public Utilities," Docket No. ER23-775-000 (filed Jan. 5, 2023) (hereinafter, "PJM Rate Sched. 49, Amended SAA Agreement"); Appendix A – NJBPU OSW Solicitation Schedule (0.0.0); Appendix B – Reliability Analysis (0.0.0); Appendix C – Description of SAA Project Selected by the NJBPU (0.0.0); Appendix D – SAA Capability (0.0.0)). A copy of PJM Rate Schedule 49, Amended SAA Agreement is provided as Exhibit No. MAOD-4.

[16] The JCP&L facilities included as part of the Larrabee Tri-Collector Solution include, among other things, the facilities necessary to transmit power from the Larrabee Collector Station to three existing JCP&L points of interconnection on the PJM Transmission System, which are the Smithburg 500 kV substation in Freehold Township, Monmouth County, New Jersey ("JCP&L Smithburg Substation"), JCP&L Larrabee Substation, and Atlantic 230 KV substation in Colts Neck Township, Monmouth County, New Jersey ("JCP&L Atlantic Substation"). A map of the MAOD and JCP&L components of the Larrabee Tri-Collector Solution is provided in Exhibit No. MAOD-2 [CUI//CEII]. The Larrabee Tri-Collector Solution also includes various onshore upgrades being developed and constructed by Atlantic City Electric Company, Baltimore Gas and Electric Company, LS Power Grid Mid-Atlantic, LLC, PECO Energy Company, Public Service Electric & Gas Company, and Transource Energy, LLC. *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 64, Appendix A.

MAOD is required to construct the Project based on certain project financing and development milestones.[17]

The Project is MAOD's first (and currently only) transmission project in development and requires a significant upfront investment, at a current estimated capital cost of approximately $217 million.[18]

C. Description of PJM Regional Transmission Planning Process and the State Agreement Approach Process

As explained in the Sternhagen Testimony, pursuant to its RTEP, PJM determines a plan to enhance and expand the transmission system in the PJM region to meet demand for firm transmission service and support competition.[19] Among other things, as outlined in the PJM OA, PJM's RTEP governs the process by which PJM prepares a "baseline" reliability analysis and identifies needed transmission enhancements five years into the future, and project enhancements likely to be needed over the next fifteen years.[20] PJM's RTEP process develops a single plan to address transmission needs on the "on the bases of (i) maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner, (ii) supporting competition in the PJM Region, (iii) striving to maintain and enhance the market efficiency and operational performance of wholesale electric service markets and (iv) considering federal and state Public Policy Requirements."[21] PJM has explained that, "[f]undamentally, the Baseline reliability analysis underlies all [RTEP] planning analyses and recommendations."[22]

In 2013, to better accommodate state public policy needs in the RTEP, PJM established its SAA,[23] which is a mechanism in the PJM OA[24] through which one or more authorized state governmental entities, individually or jointly, may agree to be solely cost-

[17] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q32. *See also* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order; Exhibit No. MAOD-9, PJM-MAOD DEA, at Schedule C.

[18] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q31, Q41.

[19] *See id*. at Q17 (citing PJM OA, Schedule 6, § 1.1).

[20] *See id*. at Q17 (citing PJM Manual 14B, PJM Region Transmission Planning Process § 2.1.2, at 32 (Rev. 55 effective Dec. 20, 2023), available at: https://www.pjm.com/-/media/documents/manuals/m14b.ashx (hereinafter cited as "PJM Manual 14B").

[21] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q17 (citing PJM OA, Schedule 6, § 1.4(a)).

[22] *See id*. (citing PJM Manual 14B, § 2.1, at 30).

[23] *See PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214, P 142 (2013), *order on reh'g and compliance,* 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance,* 150 FERC ¶ 61,038, *order on reh'g and compliance,* 151 FERC ¶ 61,250 (2015); PJM OA, Schedule 6, §§ 1.5, 1.5.9; *see also* PJM Interconnection, L.L.C., Intra-PJM Tariffs, Open Access Transmission Tariff ("Tariff"), Schedule 12, § (b)(xii)(B) ("Public Policy Projects"), and Schedule 12 – Appendix C ("State Agreement Public Policy Projects Constructed Pursuant to the State Agreement Approach").

[24] PJM OA, Schedule 6, § 1.5.9.

allocated for a proposed transmission expansion or enhancement that addresses state public policy requirements.[25]

Importantly, SAA transmission expansions or enhancements may not be selected in the RTEP for purposes of regional cost allocation.[26] All costs related to transmission expansions or enhancements identified pursuant to the SAA are to be recovered from customers in a state or group of states that agree to be responsible for the project.[27] This means that all costs associated with the Project will be recovered from New Jersey ratepayers.

D. Description of PJM and NJBPU SAA Study Agreement and Competitive Solicitation Process

As detailed in the Sternhagen Testimony, New Jersey became the first state to request that PJM open a competitive bidding process to solicit transmission proposals to expand the state's transmission system to satisfy its offshore wind goals.[28] To implement the competitive solicitation, PJM and the NJBPU entered into a study agreement, which was filed on December 18, 2020 in Docket No. ER21-689-000, and accepted by the Commission on February 16, 2021.[29] The SAA Study Agreement required PJM to: (i) perform planning studies to identify system improvements to interconnect and to provide for the deliverability of New Jersey's planned offshore wind generation at specific POI to the transmission system; and (ii) open a competitive proposal window to solicit transmission solutions for the deliverability of New Jersey's planned offshore wind generation.[30] The SAA Study Agreement established that transmission projects identified as part of the SAA process would be included in PJM's 2020-2021 RTEP cycle and used as inputs in the development of the RTEP and generation interconnection studies.[31]

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[25] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q17 (citing *PJM,* 142 FERC ¶ 61,214, at P 142 ("PJM's State Agreement Approach supplements, but does not conflict or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000 …")).

[26] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q17 (citing *PJM,* 147 FERC ¶ 61,128, at P 92; *PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024, P 2, *reh'g denied*, 179 FERC ¶ 62,131 (2022)).

[27] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q17 (citing PJM OA, Schedule 6, § 1.5.9(a)). *See also PJM,* 147 FERC ¶ 61,128, at P 92; *PJM,* 179 FERC ¶ 61,024, at P 2.

[28] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q18 (citing *In the Matter of Offshore Wind Transmission,* Order, NJBPU Docket No. QO20100630, at 7 (Nov. 18, 2020)); State of New Jersey, 2019 Energy Master Plan, Pathway to 2050 (2019), available at https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf; Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 10-11.

[29] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q19 (citing *PJM Interconnection, L.L.C.,* 174 FERC ¶ 61,090 (2021) ("SAA Study Agreement Order"); PJM Service Agreements Tariff, PJM SA No. 5890, PJM SA No. 5890 among PJM and NJBPU (0.0.0) ("PJM-NJBPU SAA Study Agreement")).

[30] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q19 (citing SAA Study Agreement Order, 174 FERC ¶ 61,090, at P 12).

[31] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q19 (citing *PJM Interconnection, L.L.C.,* "New Jersey State Agreement Approach Agreement, Rate Schedule FERC No. 49," Docket No. ER22-902-000, Transmittal Letter, at 10 (filed Jan. 27, 2022) ("PJM Jan. 2022 Filing")).

On April 15, 2021, consistent with the SAA Study Agreement, PJM opened a competitive window to solicit transmission proposals to interconnect 7,500 MW of offshore wind generation off the cost of New Jersey to the PJM Transmission System by 2035.[32] The PJM competitive window closed on September 17, 2021.[33]

PJM received eighty proposals during the competitive solicitation window, including MAOD's three related sets of proposals.[34] Mr. Sternhagen explains the details of MAOD's proposals and PJM's evaluation of submissions into the competitive solicitation.[35]

E. Description of the PJM-NJBPU SAA Agreement and Selection of Transmission Projects

As detailed in the Sternhagen Testimony, PJM and the NJBPU entered into a State Agreement Approach Agreement, which PJM filed with the Commission on January 27, 2022, in Docket No. ER22-902-000, and which was accepted by the Commission on April 14, 2022 ("SAA Agreement").[36] The SAA Agreement established processes for the review and selection of specific transmission projects submitted to New Jersey's offshore wind competitive solicitation.[37] As Mr. Sternhagen explains further, the SAA Agreement required PJM to review submissions into the competitive solicitation and to develop recommendations for potential winning bidders through its RTEP. The NJBPU subsequently would decide whether to sponsor one or more of PJM's recommended transmission projects.[38] Following the NJBPU's notification to PJM of the NJBPU's selection and sponsorship of an SAA Project, PJM would follow its RTEP process to determine the specific "designated entity" that would construct, own, and operate the SAA Project.[39]

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[32] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q20 (citing PJM RTEP – 2021 SAA Proposal Window To Support NJ OSW, at 1 (Apr. 15, 2021), available at https://www.pjm.com/planning/competitive-planning-process, Closed Windows 2021, 2021 SAA Proposal Window to Support NJ OSW, zip file "Without Analytical Files V9, non-CEII update 9.24.2021," file named "Option 1a Problem Statement For 2021 SAA Window to Support NJ OSW"; *PJM*, 179 FERC ¶ 61,024, at P 5; Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 10, 20).

[33] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q20 (citing PJM website at https://www.pjm.com/planning/competitive-planning-process, Closed Windows 2021, 2021 SAA Proposal Window to Support NJ OSW (showing competitive window "close 9.17.2021"); *PJM,* 179 FERC ¶ 61,024, at P 5).

[34] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q20-Q21.

[35] *See id*. at Q20-Q21.

[36] *See id*. at Q22. The Commission accepted the SAA Agreement, effective April 15, 2022. *PJM,* 179 FERC ¶ 61,024, at PP 1, 40, and ordering paragraph.

[37] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q22 (citing *PJM*, 179 FERC ¶ 61,024, at P 6).

[38] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q22 (citing *PJM*, 179 FERC ¶ 61,024, at PP 6-7).

[39] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q22 (citing *PJM*, 179 FERC ¶ 61,024, at P 8 (footnote omitted); SAA Agreement, §§ 4.1, 4.2).

The competitive solicitation resulted in eighty project proposals being submitted for coordinated review by PJM and the NJBPU. PJM's review was documented in six reports provided to PJM stakeholders, which described the scope of reliability, economic and congestion relief, financial, and constructability parameters that PJM considered for potential inclusion in the RTEP. The coordinated review process identified fifty-two projects as potential new public policy baseline projects for the NJBPU to contemplate for its selection, three of which were MAOD's proposals. Four finalists were ultimately selected by the NJBPU, including one of MAOD's proposals, identified as Proposal 551.[40]

On October 26, 2022, the NJBPU combined aspects of MAOD's Proposal 551 with two JCP&L Proposals (JCP&L Proposal 17 and JCP&L Proposal 453) to create the core components of what the NJBPU defined as the Larrabee Tri-Collector Solution, which the NJBPU then selected as its preferred transmission solution to accommodate delivery of New Jersey offshore wind generation.[41] In the NJBPU October 2022 Order, the NJBPU explained that, when compared to other "baseline" alternatives evaluated by PJM and considered by the NJBPU, the "analysis reveals the Larrabee Tri-Collector Solution features benefits across the stated SAA evaluation criteria, and is the strongest … single corridor solution when compared to [other proposals]."[42] With respect to the Project, the NJBPU stated:

> The predominant portion of the Larrabee Tri-Collector Solution is a new substation adjacent to the existing JCP&L Larrabee substation (the "Larrabee Collector Station"). MAOD proposes to construct the AC portion of the new Larrabee Collector Station to accommodate three future HVDC circuits. The proposal also includes sufficient land for the future installation of up to four DC converter stations…. The HVDC cables delivering the output of future [offshore wind] generators will interconnect at this new Larrabee Collector Station.[43]

With respect to the JCP&L facilities, the NJBPU stated:

> The [Larrabee Tri-Collector Solution] includes a "tri-collector" that distributes up to 4,890 MW from the Larrabee Collector Station to three existing [points of interconnection] on PJM's grid (the Smithburg 500 kV substation ("Smithburg"), the Larrabee 230 kV substation ("Larrabee"), and the Atlantic 230 kV substation ("Atlantic")), utilizing JCP&L's existing transmission [Rights of Way ("ROWs")]. To provide a complete [onshore delivery] solution, [NJBPU] Staff recommends that the [NJBPU] select

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[40] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q23.

[41] *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 59-60; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

[42] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 60; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

[43] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 60; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

> MAOD's Larrabee Collector Station in combination with JCP&L's tri-collector proposal.[44]

The NJBPU explained that the combination of MAOD's and JCP&L's proposals "leverages JCP&L's existing ROW's to create a single point for connecting [offshore wind] projects and maximizes use of available headroom at existing POI, while offering a single corridor solution preferred by [the NJBPU] Staff."[45] Finally, the NJBPU explained that the use of its competitive and SAA processes will result in approximately $900 million in savings for New Jersey ratepayers.[46]

Per the NJBPU October 2022 Order, the Larrabee Tri-Collector Solution (and consequently, also the Project) is subject to further modification by order of the NJBPU and/or under the PJM RTEP Process.[47] As explained in Section III, when awarding the Larrabee Tri-Collector Solution, the NJBPU also recognized that updates to PJM RTEP projects are common and that the Larrabee Tri-Collector Solution (and, consequently, the Project) may evolve as New Jersey's offshore wind initiatives evolve.[48]

After being selected by the NJBPU, PJM included the projects comprising the Larrabee Tri-Collector Solution (including the Project) as baseline reliability projects in the 2022 RTEP.[49] On January 5, 2023, in Docket No. ER23-775-000, PJM filed an executed Amended and Restated State Agreement Approach Agreement ("Amended SAA Agreement") between PJM and the NJBPU, which was revised to include a list of the specific projects selected in PJM's 2020-2021 RTEP and by the NJBPU, including the Project.[50] The Amended SAA Agreement was accepted on March 6, 2023.[51] The Project is identified as RTEP Project No. b3737.22 in Appendix C to the Amended SAA Agreement.[52]

As Mr. Sternhagen explains, on June 29, 2023, the NJBPU issued an order approving the performance (and cost recovery) of a "Prebuild study" by MAOD and implementing a change of the scope of work in the Project to include additional facilities referred to as the

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[44] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 60; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

[45] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 60-61; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

[46] *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 61 & n.93; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

[47] *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 61-62; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24.

[48] *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 62.

[49] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q25.

[50] *See id.* (citing Exhibit No. MAOD-4, PJM Rate Sched. 49, Amended SAA Agreement, App. C).

[51] *PJM Interconnection, L.L.C.,* Docket No. ER23-775-000, unpublished letter order (Mar. 6, 2023).

[52] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q25 (citing Exhibit No. MAOD-4, PJM Rate Sched. 49, Amended SAA Agreement, App. C; Exhibit No. MAOD-5, PJM 2022 RTEP Report, at 70).

"Interconnection Work."[53] The details of the Prebuild Study and Interconnection Work are described in the Sternhagen Testimony.[54]

F. Order No. 679 Transmission Rate Incentives Granted to MAOD

In the February 15, 2024, Incentives Order, the Commission granted MAOD's September 21, 2023, request, as supplemented on November 22, 2023, in Docket No. EL23-101-000, to implement the following Order No. 679 transmission rate incentives for the Project: (1) Regulatory Asset Incentive; (2) Abandoned Plant Incentive; (3) Hypothetical Capital Structure Incentive; and (4) RTO Participation Incentive.[55] As explained below, MAOD requests that the Commission expressly confirm that these incentives apply to the Interconnection Work and will also apply to future changes to the scope of the Project approved by the NJBPU and PJM in the coordinated SAA Process and RTEP process, as long as those changes do not materially alter the basis of the Commission's grant of the original incentives.

II. PROPOSED FORMULA RATE

MAOD files the attached Formula Rate and requests that it be accepted for filing effective September 21, 2024, which is sixty-one (61) days after the date of this filing. The Formula Rate will be used to determine the ATRR for MAOD.

The proposed Formula Rate is described in the Direct Testimony of William ("Bill") R. Davis, Assistant Vice President, Concentric Energy Advisors, Inc. ("Davis Testimony").[56] Components used by Mr. Davis in developing the Formula Rate are described in the Direct Testimony of Joshua C. Nowak, Vice President, Concentric Energy Advisors, Inc. ("Nowak Testimony"),[57] and Direct Testimony of Larry E. Kennedy, Senior Vice President, Concentric Energy Advisors, Inc. ("Kennedy Testimony").[58]

The Commission "encourage[s] public utilities to explore the benefits of filing transmission-related formula rates."[59] The proposed Formula Rate is consistent with Commission-approved ratemaking methodologies and contains sufficient specificity to

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[53] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q27 (citing Exhibit No. MAOD-10, June 29, 2023, NJBPU Order, at 5, 9-10).

[54] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q26-Q28.

[55] *See* Incentives Order, at PP 1-2, 34-48; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q46.

[56] *See* Exhibit No. MAOD-21, Direct Testimony of William ("Bill") R. Davis ("Davis Testimony").

[57] *See* Exhibit No. MAOD-16, Direct Testimony of Joshua C. Nowak ("Nowak Testimony").

[58] *See* Exhibit No. MAOD-18, Direct Testimony of Larry E. Kennedy ("Kennedy Testimony").

[59] Order No. 679, at P 386. *See also Allegheny Power Sys. Operating Cos.,* 111 FERC ¶ 61,308, P 51 (2005).

operate without discretion in its implementation.[60] The Formula Rate is just and reasonable and should be accepted for filing.

MAOD has not proposed an ATRR in this filing.

A. Formula Rate Design

As detailed in the Davis Testimony, the proposed Formula Rate is forward-looking, and is similar to formula rates the Commission recently has accepted for other competitive transmission developers, including those in the PJM region.[61] Mr. Davis explains that MAOD's proposed Formula Rate will consist of three components: (1) MAOD's statement of its ATRR (Attachment H-35 to the PJM Tariff) ("ATRR Statement"); (2) the Formula Rate Template (Attachment H-35A to the PJM Tariff); and (3) the Protocols (Attachment-H-35B to the PJM Tariff).[62] Mr. Davis explains that the proposed Formula Rate is just and reasonable because it will: (1) allow MAOD to collect a revenue requirement that reflects its operating and capital costs during the rate period; (2) provide greater certainty for cost recovery of capital expenditures needed to construct transmission infrastructure; and (3) ensure that transmission customers pay only the costs incurred to serve them over the life of the Project.[63]

Mr. Davis explains that the proposed ATRR Statement will allow PJM to determine the charges to MAOD's customers for the use of MAOD facilities in providing transmission service within PJM.[64] Mr. Davis describes the four Order No. 679 transmission rate incentives that the Commission granted MAOD for the Project, and how they are (or will be) incorporated into the proposed ATRR Statement.[65]

Mr. Davis explains that MAOD proposes to use a forward-looking Rate Formula Template, which includes a true-up for historical actuals (once available) and a forecast to

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[60] *See, e.g., NextEra Energy Transmission MidAtlantic, LLC,* 161 FERC ¶ 61,141 (2017), *order on settlement*, 164 FERC ¶ 61,042 (2018); *Kanstar Transmission, LLC,* 152 FERC ¶ 61,209 (2015); *PJM Interconnection, LLC and Transource W. Va., LLC,* 152 FERC ¶ 61,180 (2015); *Transource Kan., LLC,* 151 FERC ¶ 61,010 (2015); *Xcel Energy Sw.t Transmission Co., LLC,* 149 FERC ¶ 61,182 (2014); *Xcel Energy Transmission Dev. Co., LLC,* 149 FERC ¶ 61,181 (2014); *Transource Wis., LLC,* 149 FERC ¶ 61,180 (2014); *Am. Transmission Co., LLC,* 97 FERC ¶ 61,339 (2001).

[61] *See* Exhibit No. MAOD-21, Davis Testimony, at Q9. *See also NextEra,* 161 FERC ¶ 61,141 at P 13; *Transource W. Va, LLC,* 152 FERC ¶ 61,180.

[62] *See* Exhibit No. MAOD-21, Davis Testimony, at Q8.

[63] *See id*. at Q9.

[64] *See id*. at Q13.

[65] Exhibit No. MAOD-21, Davis Testimony, at Q11. Mr. Davis explains that MAOD is proposing to defer its rate case expense in a regulatory asset and recover those costs over a three-year period once the Project is in-service. *See id.* at Q7.

estimate MAOD's ATRR for the upcoming rate year.[66] Mr. Davis describes how MAOD's annual projected net revenue requirement will be determined, and how MAOD's rate base and overall rate of return will be calculated under the proposed Formula Rate Template.[67] Mr. Davis also details each of the nine Attachments of MAOD's proposed Formula Rate Template as well as supporting workpapers.[68]

B. Protocols

As described in the Davis Testimony, MAOD submits proposed Protocols for populating and updating its Formula Rate Template.[69] The Protocols are transparent, are consistent with the Commission's guidance on protocols for forward-looking formula rates, and are consistent with the formula rate protocols accepted by the Commission for other utilities in PJM.[70]

Mr. Davis explains that the Protocols describe the procedures that MAOD will follow when calculating and posting its projected and actual annual net revenue requirement. Mr. Davis also explains that MAOD's customers and other interested parties may review and challenge each of these calculations through procedures specified in the Protocols.[71] Finally, Mr. Davis provides an overview of the schedule of the Annual True-up filing process and related Annual True-up and Annual Projected Rate Meetings once the Project is in service.[72]

C. Return on Equity

As described in the Nowak Testimony, MAOD's ROE and proxy cost of debt are just and reasonable. Mr. Nowak describes the three financial models he used to determine his ROE recommendation. Using the Two-Step Discounted Cash Flow model ("DCF"), the Capital Asset Pricing Model ("CAPM"), and the Bond Yield Plus Risk Premium model ("Risk Premium"), Mr. Nowak produced a zone of reasonableness of 9.76% to 11.10% and

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[66] *See id*. at Q15. *See also* MAOD's proposed Formula Rate Template, provided as Exhibit No. MAOD-20, Attachment H-XX.

[67] *See* Exhibit No. MAOD-21, Davis Testimony, at Q15.

[68] *See id*. at Q16-Q24.

[69] *See id*. at Q25.

[70] *See, e.g., Mid-Atlantic Interstate Transmission, LLC*, 158 FERC ¶ 62,185 (2017), *order accepting settlement sub. nom PJM Interconnection, L.L.C. and Mid-Atlantic Interstate Transmission,* 163 FERC ¶ 61,131 (2018); *PJM Interconnection, L.L.C.,* 155 FERC ¶ 61,097 (2016); *NextEra Energy Transmission West, LLC,* 154 FERC ¶ 61,009 (2015); *PJM Interconnection, L.L.C.,* 152 FERC ¶ 61,180 (2015).

[71] *See* Exhibit No. MAOD-21, Davis Testimony, at Q25.

[72] *See id*. at Q26.

a proxy group median of 10.26%.[73] After including a 50 basis point adder for MAOD's membership in PJM, Mr. Nowak recommends an ROE of 10.76%.[74]

Beyond analytical models and their resulting calculations, Mr. Nowak points to the significance of expected economic and financial market conditions when determining a reasonable ROE.[75] After a confluence of factors led to high inflation rates, the Federal Reserve tightened its monetary policies, producing higher interest rates.[76] According to Mr. Nowak, these circumstances reinforce the importance of considering the results of multiple analytical models.[77]

Mr. Nowak's modeling used a proxy group of 30 electric utilities with investment-grade credit ratings.[78] Mr. Nowak's DCF analysis gave 80 percent weight to earnings growth estimates for the proxy group and 20 percent weight to gross domestic product ("GDP") growth estimates.[79] The DCF analysis produced a lower bound of 7.54% and an upper bound of 14.38%.[80]

For his CAPM analysis, Mr. Nowak followed the Commission's methodology in calculating the market risk premium using companies comprising the S&P 500, excluding non-dividend paying companies and companies with growth rates outside a range of zero percent to twenty percent.[81] Mr. Nowak explains how excluding companies not paying dividends may bias the results of his CAPM. Nonetheless, Mr. Nowak applied the Commission's preferred approach.[82] The CAPM analysis produced a lower bound of 9.79% and an upper bound of 12.95%.[83]

Mr. Nowak's Risk Premium analysis compares FERC-authorized ROEs for electric transmission utilities and the Moody's Baa Utility Bond Index Yield at the time of his analysis.[84] Mr. Nowak found, in general, that the risk premium increases as bond yields decrease, and vice versa.[85] Using the 6-month average yield on Moody's Baa Utility Index,

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[73] *See* Exhibit No. MAOD-16, Direct Testimony of Joshua C. Nowak ("Nowak Testimony"), at Q6.

[74] *See* Exhibit No. MAOD-16, Nowak Testimony, at Q6.

[75] *See id*. at Q9.

[76] *See id*. at Q11-Q12.

[77] *See id.* at Q16.

[78] *See id.* at Q19.

[79] *See id*. at Q25.

[80] *See id*. at Q27.

[81] *See id*. at Q28.

[82] *See id*. at Q32.

[83] *See id.* at Q34.

[84] *See id*. at Q35.

[85] *See id.* at Q36.

Mr. Nowak calculated a yield of 6.08% and a risk premium of 4.40% to produce an ROE of 10.48%.[86]

The zone of reasonableness using all three methods was 9.76% to 11.10% with a median of 10.26%.[87] With some uncertainty about continued use of the Risk Premium approach, Mr. Nowak's zone of reasonableness using only the DCF and CAPM models yielded a zone of reasonableness of 9.81% to 10.99% with a median of 10.15%.[88] Relying primarily on the three model approach, which includes the Risk Premium approach and with a 50 basis point adder for MAOD's PJM membership, Mr. Nowak's proposed ROE is 10.76%.[89]

Mr. Nowak explains that MAOD's 50 percent debt and 50 percent equity hypothetical capital structure will properly balance MAOD's need for capital at reasonable costs with the interests of New Jersey customers who will pay MAOD's cost of service in their utility rates.[90] Prior to construction financing, the Proxy Debt Rate will be priced at the 3-month Secured Overnight Financing Rate plus 200 basis points – based on a credit spread estimate from a leading project finance bank.[91] As of May 1, 2024, the Proxy Debt Rate would be 7.3190%.[92] Once debt financing is obtained (initially construction financing and then, prior to COD, long term debt financing), actual debt rates associated with the debt financings will be used for MAOD's cost of debt.

D. Capital Structure and Financing

In the Sternhagen Testimony, Mr. Sternhagen describes the combination of risks associated with MAOD's Project that support a base ROE of 10.26%. As a new company that does not own transmission assets (or any other assets apart from land) or have established credit history or credit ratings, MAOD will finance the Project without supporting revenues until the completed project is placed into service.[93] Consequently, the proposed Formula Rate (with MAOD's transmission rate incentives incorporated therein) will aid MAOD as it pursues project financing.

For equity financing, MAOD used equity investments from its parent companies to initiate the Project and plans to continue to use investments from its parent companies for

[86] *See id*. at Q36.

[87] *See id*. at Q38.

[88] *See id*. at Q38.

[89] *See id*. at Q39.

[90] *See id*. at Q40-41.

[91] *See id*. at Q47.

[92] *See id*. at Q47. MAOD's hypothetical capital structure will only apply until the Project reaches COD at which point MAOD's actual capital structure will apply.

[93] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q39, Q44.

additional equity financing.[94] After the Project starts producing revenue, MAOD plans to use retained earnings and additional paid-in-capital from its parent companies to support ongoing investments while maintaining the target equity ratio under the proposed capital structure.[95] MAOD does not currently plan to solicit additional equity investors.

Following Commission acceptance of the proposed Formula Rate, MAOD will finance construction spending and short-term working capital requirements with a construction loan arrangement. As the Project gets closer to COD, MAOD plans to obtain long-term debt financing from institutional capital markets or commercial lenders.[96]

To secure this debt financing on more favorable terms, Mr. Sternhagen explains that MAOD plans to build an investment grade credit profile.[97] MAOD's proposed capital structure, depreciation rates, ROE, and formula rate recovery should combine to yield investment grade financial metrics.[98] Preserving the 50% equity structure would facilitate MAOD's management of its financing costs.

Mr. Nowak explains that he assumed an initial debt rate for MAOD equal to the three-month Secured Overnight Financing Rate plus 200 basis points, based on guidance from MAOD's financial advisors who reviewed recent, comparable project finance transactions.[99] This Proxy Debt Rate would apply until replaced by the cost of Construction Debt financing, which would be superseded by the cost of longer-term debt financing as the Project approaches commercial operation.[100]

Mr. Nowak explains that MAOD's 10.76% proposed cost of equity is the product of a 10.26% base ROE and a 50 basis point RTO membership adder for participation in PJM.[101] This ROE will help mitigate the investment risks associated with a non-incumbent transmission company with no financial history or revenue-producing assets.[102]

E. Depreciation

The Kennedy Testimony supports the depreciation rates applied to the MAOD ATRR. Mr. Kennedy explains that, in developing the appropriate depreciation rates, he utilized four depreciation methodologies: (1) average service life, (2) forecast retirement dispersion curves (Iowa curve), (3) consideration of any economic or other constraints to the

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[94] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q40.

[95] *See id.* at Q40.

[96] *See id.* at Q41.

[97] *See id.* at Q42.

[98] *See id.* at Q45.

[99] *See* Exhibit No. MAOD-16, Nowak Testimony, at Q47.

[100] *See* Exhibit No. MAOD-16, Nowak Testimony, at Q47.

[101] *See id.* at Q39, Q48.

[102] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q45.

recovery of investment, and (4) consideration of the estimated cost of retirement (i.e., net salvage costs).[103] Mr. Kennedy states that he determined average service life, retirement dispersion estimates, and net salvage estimates based on his review of currently approved depreciation parameters through peer analysis.[104] Mr. Kennedy explains that his selection of appropriate peers is based on: (1) a selection of electric transmission systems recently constructed in the United States and Canada,[105] and (2) depreciation studies that have included electric transmission assets owned and operated by utilities in various U.S. jurisdictions.[106]

Mr. Kennedy explains that the results of his peer analysis show that the range of service life estimates was relatively narrow, allowing him to select an average service life estimate within the peer range for each asset account.[107] To develop the average service life estimates, Mr. Kennedy explains that for some accounts he based the estimated service life of MAOD's assets on the weighted average of each component that MAOD expects to track separately, utilizing both peer analysis and expert judgement.[108] To develop the net salvage estimates, Mr. Kennedy based his estimates on the lower end of the range of estimates from his peer analysis because there is insufficient removal data available given that MAOD's assets will be newly constructed.[109]

Mr. Kennedy explains that MAOD should be permitted to collect net salvage, principally because: (1) if collection is delayed, customers could be charged for plant from which they did not receive service and, as a result of the delay in recovery, also could result in higher future revenue requirements related to net salvage, and (2) FERC's Uniform System of Accounts requires that depreciation be recognized through accrual accounting (i.e., the service value of an asset must be accrued during the life of the asset).[110] Mr. Kennedy also explains that he did not include any Asset Retirement Obligation in the depreciation recommendations.[111]

Finally, Mr. Kennedy states that the calculation of the depreciation rates provided in Exhibit No. MAOD-20 was based on the straight-line method, the Average Life Group

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[103] *See* Exhibit No. MAOD-18, Direct Testimony of Larry Kennedy ("Kennedy Testimony"), at Q14. The results of Mr. Kennedy's analysis are provided in Exhibit No. MAOD-17, which includes the appropriate depreciation rates for each account.

[104] *See* Exhibit No. MAOD-18, Kennedy Testimony, at Q15.

[105] *See id.* at Q15.

[106] *See id.* at Q15.

[107] *See id.* at Q15. A summary of the peer review is provided in Exhibit No. MAOD-19.

[108] *See* Exhibit No. MAOD-18, Kennedy Testimony, at Q17.

[109] *See id.* at Q18.

[110] *See id.* at Q21.

[111] *See id.* at Q22.

procedure, and applied on a whole life basis.[112] Mr. Kennedy indicates that the stated values will be used in the Formula Rate until changed pursuant to a FPA section 205 or section 206 filing.[113]

III. REQUEST TO EXTEND ORDER NO. 679 INCENTIVES TO INCLUDE MODIFICATIONS TO THE PROJECT ORDERED BY THE NJBPU AND APPROVED BY PJM FOR INCLUSION IN THE RTEP

A. Application of the Incentives to Interconnection Work Added to the Project in the RTEP Process

On September 21, 2023, as supplemented on November 22, 2023, MAOD filed with the Commission a petition for declaratory order ("MAOD PDO") requesting authorization for (1) Regulatory Asset Incentive; (2) Abandoned Plant Incentive; (3) Hypothetical Capital Structure Incentive; and (4) RTO Participation Incentive.[114] MAOD sought these incentives for the Project as approved by both the NJBPU and PJM for inclusion in the RTEP. The Commission granted these incentives for the Project in the Incentives Order.[115]

As explained in the Sternhagen Testimony, in its October 26, 2022 order selecting the Project (as part of the Larrabee Tri-Collector Solution), the NJBPU acknowledged that "[u]pdates to approved PJM RTEP projects are typical."[116] The NJBPU indicated that the Larrabee Tri-Collector Solution (and consequently, also the Project) would be subject to further modification by order of the NJBPU and/or under the PJM RTEP process,[117] and that "[a]llowing for the modification of the [NJBPU] Order in the future to reflect significant updates will ensure that the specific configuration of the awarded SAA facilities remains optimal and beneficial to ratepayers over time."[118]

On June 29, 2023, the NJBPU indeed issued a subsequent order directing MAOD to include additional facilities in the Project, referred to as the "Interconnection Work."[119] Citing cost-effectiveness, the NJBPU directed MAOD to construct two sets of facilities: (1)

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[112] *See id.* at Q23.

[113] *See id.* at Q24.

[114] *See Petition for Declaratory Order of Mid-Atlantic Offshore Development, LLC for Authorization to Utilize Incentive Rate Treatment and Request for Expedited Consideration*, Docket No. EL23-101-000 (filed September 21, 2023).

[115] *See* Incentives Order, at PP 1-2, 34-48

[116] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24 (citing Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 62).

[117] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24 (citing Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 61-61).

[118] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q24 (citing Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 62).

[119] *See* Exhibit No. MAOD-10, June 29, 2023, NJBPU Order, at 3-4; *see also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q28.

the civil works necessary to connect the Prebuild Infrastructure to each HVDC converter station area, and (2) the AC collector lines necessary to interconnect the HVDC converters to the Project's substation facilities. At an estimated cost of $23 million,[120] the NJBPU awarded this work to MAOD as a "modification and expansion of MAOD's designated scope of work."[121] This additional work is described in more detail in the Sternhagen Testimony.[122]

In Order No. 679, the Commission stated that "[i]f an applicant obtains a declaratory order and the proposal changes from the facts on which the declaratory order was issued, the applicant may seek another declaratory order or wait to seek approval of the changes in the subsequent section 205 filing."[123] However, the Commission has also stated that some project changes "will not necessarily alter the basis upon which the Commission granted transmission incentives."[124] PJM approved the Interconnection Work for inclusion in the RTEP on February 28, 2024.[125] Therefore, this change could not have been described in the MAOD PDO. These facilities, however, are integral to the Project and the rationale for applying these incentives to the expanded scope of the Project are the same as those already approved by the Commission in the Incentives Order for the Project. The costs of the Interconnection Work should be subject to the same benefits resulting from the incentives granted to the Project by the Commission.

MAOD does not believe that this expansion of the scope of the Project materially changes the facts upon which the Incentives Order granting incentives for the Project were based, and that it does not alter the basis upon which those incentives were granted. Hence, MAOD believes that the incentives granted to the Project also apply to the Interconnection Work. Out of an abundance of caution, however, MAOD requests that the Commission expressly confirm that the four transmission rate incentives already approved for the Project extend to the Interconnection Work. As explained in the Sternhagen Testimony, even with the inclusion of the Interconnection Work, the requested incentives are narrowly tailored to

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[120] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q28 (citing Exhibit No. MAOD-10, June 29, 2023, NJBPU Order, at 5).

[121] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q28 (quoting Exhibit No. MAOD-10, June 29, 2023, NJBPU Order, at 9).

[122] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q28.

[123] Order No. 679, at P 78.

[124] *Pioneer Transmission, LLC*, 130 FERC ¶ 61,044, at P 21. *See also Green Power Express LP*, 135 FERC ¶ 61,141, at P 22.

[125] *See* PJM Interconnection, L.L.C., "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, PJM Staff White Paper," at 8, 11 (Feb. 2024), available at https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240206/20240206-pjm-teac-board-whitepaper-feburary-2024.ashx ("PJM February 2024 White Paper") (stating that on February 28, 2024, the PJM Board approved the prebuild extension work (referred to herein as the "Interconnection Work") in PJM project number b3737.22). A copy of the PJM February 2024 White Paper is provided in Exhibit No. MAOD-13.

mitigate the specific risks faced by the Project.[126] Each of the requested incentives is discussed briefly below, and in more detail in the Sternhagen Testimony.[127]

As recognized in the Incentives Order, the Regulatory Asset Incentive will allow MAOD to mitigate the pre-commercial operation risks of financing, developing, and constructing the Project. Specifically, MAOD faces considerable challenges in developing the Project, particularly as a non-incumbent transmission developer, for which the Project represents a significant investment of both human resources and funds, and in particular given that MAOD does not have existing rates through which it could recover development costs that are normally expensed.[128] The ability to book Project-related costs into a Regulatory Asset prior to MAOD's ATRR being filed and allocated under the PJM Tariff will provide up-front regulatory certainty, improve coverage ratios used by lenders and rating agencies to determine credit quality, and reduce interest expense.[129] Because this mitigation of risks will beneficially impact MAOD's credit risk for potential financing entities, the Regulatory Asset Incentive will benefit ratepayers.[130] As explained in the Sternhagen Testimony, the Interconnection Work is integrated into the Project and, therefore, MAOD faces the same risks as a non-incumbent transmission developer relative to the Interconnection Work as the overall Project. The costs of the Interconnection Work therefore should receive the benefit of the Regulatory Asset Incentive.[131]

As recognized in the Incentives Order, the Abandoned Plant Incentive will allow MAOD to mitigate the permitting, regulatory, "project on project," and political risks that the Project faces.[132] The grant of the Abandoned Plant Incentive to the Project provides assurances to financing entities that they can be repaid if the Project is abandoned for reasons outside of MAOD's control, and will support not only financing entities' willingness to commit funds, but also their ability to offer beneficial financing terms, which will benefit

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[126] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q47.

[127] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q48-Q51. If the Commission does not agree that the four granted incentives already apply to the Interconnection Work, MAOD respectfully requests that the Commission exercise its authority to grant these incentives for the Interconnection Work pursuant to FPA section 205 based on the explanations in this transmittal letter and supporting testimony. *See, e.g., GridLiance Heartland LLC,* 166 FERC ¶ 61,067, P 40 (2019); *PJM Interconnection, LLC*, 155 FERC ¶ 61,097, at P 175; *Midwest Power Transmission Ark., LLC*, 152 FERC ¶ 61,210, PP 14, 17, 20 (2015); *Kanstar Transmission, LLC*, 152 FERC ¶ 61,209, at PP 17, 22, 28, 85; *Transource Kan., LLC*, 151 FERC ¶ 61,010, at P 15; *Xcel Energy Sw. Transmission Co., LLC*, 149 FERC ¶ 61,182, at P 22.

[128] *See* Incentives Order, at PP 34-38. *See also* Exhibit No. MAOD-1, Sternhagen Testimony, at Q48.

[129] *See Promoting Transmission Investments Through Pricing Reform,* 141 FERC ¶ 61,129, P 13 (2012) ("2012 Policy Statement"); *DCR Transmission LLC,* 153 FERC ¶ 61,295, at P 35; *RITELine Ill., LLC, et al.,* 137 FERC ¶ 61,039, P 96 (2011) (citing *Green Power Express, LP,* 127 FERC ¶ 61,031, P 60 (2009); *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281, P 84 (2009)).

[130] *See RITELine Ill., LLC, et al.,* 137 FERC ¶ 61,039, at P 96 (citing *Green Power Express,* 127 FERC ¶ 61,031, at P 60; *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281, at P 84).

[131] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q48.

[132] *See* Incentives Order, at PP 39-43.

ratepayers. As explained in the Sternhagen Testimony, the risks that justify the application of the Abandoned Plant Incentive to the Project are equally applicable to the Interconnection Work. The costs of the Interconnection Work therefore should receive the benefit of the Abandoned Plant Incentive.[133]

As recognized in the Incentives Order, the Hypothetical Capital Structure Incentive will allow MAOD to mitigate financing risks for the Project associated with its status as a non-incumbent transmission provider that does not yet have the established capital structure of an incumbent utility. MAOD will require significant borrowings, as well as equity capital contributions, as development and construction of the Project progresses. MAOD's precise debt-to-equity ratio during the construction period consequently will fluctuate as new borrowings are made and equity is invested, and will also be affected by negotiations with lenders. The Hypothetical Capital Structure Incentive provides assurance to potential investors, helping with the challenge of raising capital during the development process when actual capital structures can fluctuate.[134] As explained by Mr. Sternhagen, as a part of the Project as a whole, MAOD faces the same risk with respect to the costs of the Interconnection Work. The costs of the Interconnection Work therefore should receive the benefit of the Hypothetical Capital Structure Incentive. As with the Project overall, MAOD confirms that this incentive will only apply until the Project reaches COD.[135]

Once the Project is placed into service, MAOD will become a Transmission Owner member of PJM, with all the responsibilities and obligations of such a member. Hence, in the Incentives Order, the Commission conditionally granted the RTO Participation Incentive for MAOD's participation in PJM.[136] As the Interconnection Work is integrated into the Project and a part of the PJM system, the RTO Participation Incentive also should apply to the costs associated with the Interconnection Work.[137]

As explained in the MAOD PDO and in the Sternhagen Testimony, the incentives that have been requested by MAOD are meant to mitigate MAOD's development risk, particularly as a non-incumbent transmission developer developing its first transmission project. The total package of incentives, as a whole granted to the Project in the Incentives Order, is narrowly tailored to address the well-recognized risks associated with transmission development (including, in this case, as part of the SAA Process). These risks apply equally to the Interconnection Work because these facilities are integrated parts of the Project. Therefore, for all of the reasons set forth in MAOD's PDO for the larger project and as explained in the Sternhagen Testimony, a nexus exists between the requested incentives and

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[133] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q49.

[134] *See* Incentives Order, at PP 44-46.

[135] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q50.

[136] *See* Incentives Order, at PP 47-48.

[137] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q51.

the risks and challenges of the Interconnection Work.[138] MAOD's requested incentives therefore also should apply to the Interconnection Work.

B. Application of the Incentives to Future Changes to the Project's Scope

As stated above, the NJBPU is actively pursuing an aggressive offshore wind development program, and MAOD expects that, as part of the Larrabee Tri-Collector Solution, the Project may further evolve as the NJBPU coordinates with PJM and the NJBPU potentially revises its onshore transmission plans pursuant to the SAA Process and the PJM RTEP.

Therefore, MAOD respectfully requests that the Commission expressly clarify that the four incentives already approved for the Project – (1) Regulatory Asset Incentive; (2) Abandoned Plant Incentive; (3) Hypothetical Capital Structure Incentive; and (4) RTO Participation Incentive – will also apply to future NJBPU-approved and RTEP-approved changes in scope for the Project, so long as such scope changes do not materially alter the basis – whether in the Incentives Order or in this proceeding – of the Commission's grant of the incentives.[139] This request is being made out of an abundance of caution to preclude MAOD from being required continually to amend its requested incentives as the Project changes based on NJBPU requirements that are coordinated with PJM through the SAA Process for inclusion in the RTEP.[140]

IV. PROPOSED EFFECTIVE DATE

MAOD requests that the Commission accept the MAOD Formula Rate to become effective on September 21, 2024, which is sixty-one (61) days after the date of this filing. The elements of this filing are consistent with Commission policy and are fully supported by

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[138] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q47.

[139] For example, the four autotransformers at the Larrabee Collector Station need to be resized to accommodate reactive power requirements, at an estimated cost of $800,000. The NJBPU approved this change in its March 20, 2024, order. The PJM Transmission Expansion Advisory Committee ("TEAC") included this change in its April 2, 2024, Reliability Analysis Update and, from MAOD's understanding, is recommending its approval to the PJM Board. The PJM Board is expected to approve the inclusion of this work in the RTEP under the Project's existing RTEP number b3737.22 at its August 2024 meeting. The scope of this change will not materially alter the basis upon which the Commission granted MAOD's requested incentives. *See Incentive Order; see also In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey,* "Order on the State Agreement Approach (SAA) – Project Scope Modifications and Cost Adjustments," Docket No. QO20100630 (Mar. 20, 2024), available at https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468 (then select Document Title 3-20-24-8D) (NJBPU order approving modified transformer sizing from 450 MVA to 480 MVA and increased cost thereof) ("March 20, 2024, NJBPU Order"). A copy of the March 20, 2024, NJBPU Order is provided in Exhibit No. MAOD-12; s*ee also* PJM Interconnection, L.L.C., presentation to Transmission Expansion Advisory Committee ("TEAC"), "Reliability Analysis Update," at slide 10 (Apr. 2, 2024) (stating the Amended Scope for b3737.22 as "Increase Sizing of Autotransformers: Increase sizing of four single phase 500/230 kV autotransformers at LCS from 450 MVA to 480 MVA to meet reactive power requirements").

[140] MAOD recognizes that, per Order No. 679, it will be required to file with the Commission for approval of incentive rate treatment for any future changes to the Project that may alter the basis upon which the Commission previously granted transmission incentives.

the testimony and associated exhibits included as part of this filing. In the event the Commission finds that a hearing is necessary, MAOD requests that the Commission suspend the filing for a nominal period of only one day so that the Formula Rate can go into effect on the requested effective date.

V. REQUESTED WAIVERS

The populated Formula Rate Template provided in Exhibit No. MAOD-23 contains abbreviated cost support for the projections in lieu of the full Statements AA through BL otherwise required under section 35.13 of the regulations. An attestation from Christopher Sternhagen, Director – MAOD Development, of MAOD, in satisfaction of the requirements of 18 C.F.R. § 35.13, is included in Exhibit No. MAOD-25. The abbreviated statements and the testimony submitted as exhibits to this filing provide ample support for the reasonableness of the proposed Formula Rate. To the extent that MAOD's proposed Formula Rate approach may require waivers of sections 35.12 and 35.13 of the Commission's regulations, MAOD respectfully requests such waivers, including waiver of the full Period I – Period II data requirements and waiver of the requirements in section 35.13(a)(s)(iv) to determine if and the extent to which a proposed change constitutes a rate increase based on Period I – Period II rates and billing determinants.

VI. REQUEST FOR CONFIDENTIAL TREATMENT

In accordance with section 388.113 of the Commission's regulations,[141] MAOD respectfully requests confidential treatment of page 3 of Exhibit No. MAOD-2 (CUI//CEII) because it contains Critical Energy/Electric Infrastructure Information ("CEII"). This information should be treated as CEII as of the date of this filing and extending for the maximum allowable five-year period.[142]

MAOD respectfully requests CEII treatment for page 3 of Exhibit No. MAOD-2 (CUI//CEII) because it includes detailed design information of MAOD's planned physical transmission facilities, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of such matters.[143] MAOD understands that the Commission will notify it prior to any contemplated disclosure of the CEII Information.[144] MOAD submits as Exhibit No. MAOD-26 to this filing a form of Protective Agreement, as required by section 388.113 of the Commission's regulations.[145]

As required by section 388.113 of the Commission's regulations, the public version of Exhibit No. MOAD-2 does not include the CEII Information and is labelled "PUBLIC VERSION – CRITICAL ENERGY/ELECTRIC INFRASTRUCTURE INFORMATION HAS BEEN REMOVED." MAOD also is submitting a non-public version of Exhibit No.

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[141] 18 C.F.R. § 388.113.

[142] *See* 18 C.F.R. §§ 388.113(d)(1)(i), 388.113(e)(1).

[143] *See* 18 C.F.R. § 388.113(c)(3).

[144] *See* 18 C.F.R. § 388.113(d)(1)(vi).

[145] See 18 C.F.R. § 388.113.

MAOD-2 (CUI//CEII) which includes the CEII Information and is labelled "CUI//CEII – NON-PUBLIC VERSION – CONTAINS CRITICAL ENERGY/ELECTRIC INFRASTRUCTURE INFORMATION – DO NOT RELEASE PURSUANT TO 18 C.F.R. § 388.113."

VII. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[146] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: https://www.pjm.com/library/filing-order as with a specific link to the newly filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[147] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.[148]

VIII. CORRESPONDENCE AND COMMUNICATIONS

All service of pleadings, orders, correspondence, and communications regarding this filing should be made to the following persons, and their names and addresses placed on the official service list for this docket.[149]

Chris Sternhagen
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[146] *See* 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

[147] PJM already maintains, updates, and regularly uses e-mail lists for all PJM members and affected state commissions.

[148] *See* Order No. 714.

[149] MAOD requests waiver of Rule 2010 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.2010, to permit more than two representatives to be included on the official service list for this docket.

IX. CONTENTS OF THIS FILING

As required by section 35.13(b)(1) of the Commission's regulations,[150] MAOD submits the following are included in this filing:

1. This transmittal letter;
2. Exhibit No. MAOD-1: Direct Testimony of Christopher Sternhagen;
3. Exhibit No. MAOD-2: Maps of Larrabee Tri-Collector Solution and of the Project, and a schematic of the Project [Public and Non-Public (CUI/CEII) versions];
4. Exhibit No. MAOD-3: October 26, 2022, NJBPU Order;
5. Exhibit No. MAOD-4: PJM Rate Schedule 49, Amended SAA Agreement;
6. Exhibit No. MAOD-5: PJM 2022 RTEP Report (March 1, 2023);
7. Exhibit No. MAOD-6: PJM Reliability Analysis Report (Nov. 4, 2022 version);
8. Exhibit No. MAOD-7: PJM Summary Report (Nov. 15, 2022);
9. Exhibit No. MAOD-8: PJM May 9, 2023 TEAC Presentation;
10. Exhibit No. MAOD-9: PJM-MAOD DEA;
11. Exhibit No. MAOD-10: June 29, 2023, NJBPU Order;
12. Exhibit No. MAOD-11: PJM July 2023 White Paper;
13. Exhibit No. MAOD-12: March 20, 2024, NJBPU Order;
14. Exhibit No. MAOD-13: PJM February 2024 White Paper;
15. Exhibit No. MAOD-14: PJM March 12, 2024, Letter;
16. Exhibit No. MAOD-15: November 17, 2023, NJBPU Order;
17. Exhibit No. MAOD-16: Direct Testimony of Joshua C. Nowak;
18. Exhibit No. MAOD-17: Return on Equity Exhibits;
19. Exhibit No. MAOD-18: Direct Testimony of Larry E. Kennedy;

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[150] 18 C.F.R. § 35.13(b)(1).

20. Exhibit No. MAOD-19: Summary of Average Service Life Estimates of Peer Electric Transmission Plant;

21. Exhibit No. MAOD-20: Summary of Proposed Electric Transmission Depreciation Rates;

22. Exhibit No. MAOD-21: Direct Testimony of William ("Bill") R. Davis;

23. Exhibit No. MAOD-22: MAOD ATRR Statement (Att. H-35);

24. Exhibit No. MAOD-23: MAOD Formula Rate Templates (Att. H-35A);

25. Exhibit No. MAOD-24: MAOD Formula Rate Protocols (Att. H-35B);

26. Workpapers of William ("Bill") R. Davis;

27. Exhibit No. MAOD-25: Attestation pursuant to section 35.13(d)(6);

28. Exhibit No. MAOD-26: Form of Protective Agreement.

X. CONCLUSION

For the reasons set forth above, MAOD respectfully requests that the Commission accept for filing the proposed Formula Rate filed herewith to be effective as of September 21, 2024, which is sixty-one (61) days after the date of this filing. MAOD also respectfully requests that the Commission issue an order extending MAOD's transmission rate incentive treatments to the Interconnection Work and to future NJBPU and RTEP-approved expansions of the Project.

Respectfully submitted,

/s/Joseph C. Hall
Joseph C. Hall
Roxane E. Maywalt
Alex Goldberg
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Attachments

Exhibit No. MAOD-1
Mid-Atlantic Offshore Development, LLC
Direct Testimony of Christopher Sternhagen

Exhibit No. MAOD-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	))	**Docket No. ER24-___-000**

DIRECT TESTIMONY OF
CHRISTOPHER STERNHAGEN

ON BEHALF OF
MID-ATLANTIC OFFSHORE DEVELOPMENT, LLC

July 18, 2024

TABLE OF CONTENTS

Exhibit No. MAOD-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	))	**Docket No. ER24-___-000**

DIRECT TESTIMONY OF
CHRISTOPHER STERNHAGEN

I. INTRODUCTION AND EXPERIENCE

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Christopher Sternhagen. My business address is 15445 Innovation Dr., San Diego, CA 92128.

Q2. WITH WHAT ENTITY ARE YOU EMPLOYED AND IN WHAT POSITION?

A2. I am employed by EDF-Renewables, which is an indirect owner of Mid-Atlantic Offshore Development, LLC ("MAOD" or "Company"). My title is Director – MAOD Development.

Q3. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A3. I am testifying on behalf of MAOD.

Q4. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, PROFESSIONAL QUALIFICATIONS, AND BUSINESS EXPERIENCE.

A4. I have a Bachelor of Science in Electrical Engineering Technology from South Dakota State University. I have over fifteen years of experience in utility scale renewable project development, having led the development of more than 2.5 gigawatts ("GW") of operating electricity generating assets and more than 4 GW of pipeline project assets.

Q5. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A5. I am responsible for oversight and execution of MAOD's functions including development, technical, commercial, finance, and regulatory. I manage the governance processes required for MAOD to execute project development. In this capacity, I lead and coordinate MAOD's project development activities and commercial work streams.

Q6. HAVE YOU PREVIOUSLY FILED TESTIMONY BEFORE A REGULATORY BODY?

A6. I have testified before the North Dakota Public Service Commission on multiple occasions in support of applications for Certificates of Site Compatibility. Additionally, I have supported numerous Certificate of Need and Large Wind Energy Conversion System applications submitted to the Minnesota Public Utilities Commission. In those dockets, however, I did not provide written direct testimony.

II. <u>SUMMARY AND PURPOSE OF TESTIMONY</u>

Q7. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A7. The purpose of my testimony is to:

1. provide an overview of MAOD's Federal Power Act Section 205 filing in this proceeding;
2. describe MAOD and its selection by the New Jersey Board of Public Utilities ("NJBPU") pursuant to the PJM Interconnection, L.L.C. ("PJM") Regional Transmission Expansion Plan ("RTEP") and State Agreement Approach Process ("SAA Process") to construct, finance, own, operate, and maintain a 230/500 kV transmission substation, related facilities and land for installation of future high voltage direct current converter stations (the "Project"). As explained below, the

Project is part of the larger proposed "Larrabee Tri-Collector Solution," which, in relevant part, predominantly is a combined MAOD and Jersey Central Power & Light Company-owned ("JCP&L") onshore transmission delivery solution selected by the NJBPU to interconnect New Jersey offshore wind projects to onshore points of interconnection ("POI") within the PJM transmission system;

3. describe PJM's and the NJBPU's coordinated RTEP and SAA Process to arrive at the current Project;

4. describe how the Project will be integrated into the existing PJM transmission system through three interconnections with JCP&L;

5. describe MAOD's plans for project financing; and

6. describe the Order No. 679[1] transmission rate incentives previously granted by the Commission to the Project[2] and the reasons why those incentives should extend to

[1] *Promoting Transmission Investment through Pricing Reform,* "Order No. 679," FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g,* "Order No. 679-A," FERC Stats. & Regs. ¶ 31,236, *order on reh'g,* 119 FERC ¶ 61,062 (2007).

[2] *See Mid-Atlantic Offshore Dev., LLC*, 186 FERC ¶ 61,116 (2024) ("Incentives Order"). In the Incentives Order, the Commission granted MAOD the following Order No. 679 incentives for the Project as the Project existed when it submitted its Petition for Declaratory Order ("PDO") on September 21, 2023 in Docket No. EL23-101-000: (1) Regulatory Asset Incentive; (2) Abandoned Plant Incentive; (3) Hypothetical Capital Structure Incentive; and (4) RTO Participation Incentive. *Mid-Atlantic Offshore Development, LLC,* "Petition for Declaratory Order of Mid-Atlantic Offshore Development, LLC for Authorization to Utilize Incentive Rate Treatment and Request for Expedited Consideration," Docket No. EL23-101-000 (filed Sep. 21, 2023, supplemented Nov. 22, 2023).

the "Interconnection Work" (as defined below), as well as other upgrades that have been or are approved in the future by the NJBPU[3] and PJM[4] as a part of the Project.

Q8. WHAT ROLE DOES MAOD HAVE IN THE PROJECT?

A8. MAOD will construct, finance, own, operate, and maintain the Project.

Q9. WHEN DO YOU ANTICIPATE THE PROJECT WILL GO INTO SERVICE?

A9. The expected commercial operation date ("COD") for the Project is December 31, 2027.

Q10. PLEASE PROVIDE A GENERAL TIMELINE FOR THE CONSTRUCTION OF THE PROJECT.

A10. MAOD anticipates starting construction activities in the fourth quarter of 2025, achieving substantial completion in the second quarter of 2027, and, as stated above, reaching COD on December 31, 2027.

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[3] *In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey,* "Order Approving State Agreement Approach Project Scope Modifications and Addressing Scope-Related Cost Estimate Adjustments," Docket No. QO20100630 (June 29, 2023), available at https://nj.gov/bpu/pdf/boardorders/2023/20230629/8B%20ORDER%20SAA%20Project%20Scope%20Changes.pdf (NJBPU order approving MAOD's change of scope and cost increases for Interconnection Work, Prebuild Infrastructure study and refinement of cost estimates) ("June 29, 2023, NJBPU Order"). A copy of the June 29, 2023, NJBPU Order is attached as Exhibit No. MAOD-10. *See also In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey,* "Order on the State Agreement Approach (SAA) – Project Scope Modifications and Cost Adjustments," Docket No. QO20100630 (Mar. 20, 2024), available at https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468 (then select Document Title 3-20-24-8D) (NJBPU order approving modified transformer sizing from 450 MVA to 480 MVA and increased cost thereof) ("March 20, 2024, NJBPU Order"). A copy of the March 20, 2024, NJBPU Order is attached as Exhibit No. MAOD-12.

[4] *See* PJM Interconnection, L.L.C., "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, PJM Staff White Paper," at 8, 11 (Feb. 2024), available at https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240206/20240206-pjm-teac-board-whitepaper-feburary-2024.ashx ("PJM February 2024 White Paper") (stating that on February 28, 2024, the PJM Board approved the prebuild extension work (referred to herein as the Interconnection Work) in PJM project number b3737.22). A copy of the PJM February 2024 White Paper is attached as Exhibit No. MAOD-13. *See also* PJM Interconnection, L.L.C., presentation to Transmission Expansion Advisory Committee ("TEAC"), "Reliability Analysis Update," at slide 10 (Apr. 2, 2024) (stating the Amended Scope for b3737.22 as "Increase Sizing of Autotransformers: Increase sizing of four single phase 500/230 kV autotransformers at LCS from 450 MVA to 480 MVA to meet reactive power requirements").

Q11. HAS MAOD BEGUN DEVELOPMENT OF THE PROJECT?

A11. Absolutely. The projected timeline for procuring certain required equipment is comparatively short because of exceptionally long lead times associated with the equipment necessary to construct the Project. MAOD expects to complete procurement of long lead time items, such as breakers and autotransformers, in the first half of 2024. MAOD also has acquired the land for the Project.

Q12. OTHER THAN YOUR DIRECT TESTIMONY, ARE YOU SPONSORING ANY EXHIBITS?

A12. Yes. I am including as exhibits to my testimony the following:

1. Exhibit No. MAOD-2: Maps of the Larrabee Tri-Collector Solution and of the Project and a schematic diagram of the Project [CUI/CEII].
2. Exhibit No. MAOD-3: October 26, 2022, NJBPU Order.
3. Exhibit No. MAOD-4: PJM Rate Schedule 49, Amended SAA Agreement.
4. Exhibit No. MAOD-5: PJM 2022 RTEP Report (March 1, 2023).
5. Exhibit No. MAOD-6: PJM Reliability Analysis Report (Nov. 4, 2022 version).
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10. Exhibit No. MAOD-11: PJM July 2023 White Paper.
11. Exhibit No. MAOD-12: March 20, 2024, NJBPU Order.
12. Exhibit No. MAOD-13: PJM February 2024 White Paper.
13. Exhibit No. MAOD-14: PJM March 12, 2024 Letter.
14. Exhibit No. MAOD-15: November 17, 2023, NJBPU Order.

III. OVERVIEW OF FILING

Q13. WHAT IS THE PURPOSE OF THIS FILING?

A13. MAOD is seeking Federal Energy Regulatory Commission ("Commission") acceptance of a proposed formula rate template and formula rate protocols (collectively, the "Formula Rate"). The Formula Rate is based on and consistent with previously approved PJM formula rates and protocols. MAOD has proposed a return on equity ("ROE"), a proxy cost of debt to be used until construction debt financing is obtained, and depreciation rates for its Formula Rate. The formula rate template will be used to calculate MAOD's annual transmission revenue requirement ("ATRR"); and the protocols will provide the procedures for stakeholders to review and comment upon (and, if necessary, challenge) MAOD's ATRR. MAOD has not proposed cost inputs for its Formula Rate at this time. In addition, MAOD requests that the Commission confirm that the Order No. 679 transmission incentives granted in the Incentives Order also apply to additional facilities (the Interconnection Work, described below) that were added to the Project based on the June 29, 2023, NJBPU Order and subsequently approved by the PJM Board for inclusion in the RTEP on February 28, 2024.[5] PJM's approval of these facilities for inclusion in the RTEP occurred after MAOD filed its September 21, 2023 Petition for Declaratory Order, as supplemented on November 22, 2023, in Docket No. EL23-101-000 ("MAOD PDO").[6] Finally, MAOD requests that the Commission confirm that the four granted incentives will

[5] *See* Exhibit No. MAOD-13, PJM February 2024 White Paper, at 8, 11; *see also* PJM Interconnection, L.L.C. letter to MAOD, at 1 and Att. B (Mar. 12, 2024) (stating that the PJM Board of Managers approved as part of the PJM RTEP change in scope of MAOD Project b3737.22 as: "Additional scope includes prebuild extension work, and three sets of AC collector lines from the LCS to the offshore wind converter station area.") ("PJM March 12, 2024, Letter"). A copy of the PJM March 12, 2024, Letter is attached as Exhibit No. MAOD-14.

[6] *See* Exhibit No. MAOD-13, PJM February 2024 White Paper, at 8, 11; Exhibit No. MAOD-14, PJM March 12, 2024, Letter at 1, Att. B; *see also* Incentives Order, at P 2; Exhibit No. MAOD-10, June 29, 2023, NJBPU Order.

also apply to future changes to the scope of the Project approved by the NJBPU and PJM in the coordinated SAA Process and RTEP process, as long as those changes are not inconsistent with the Commission's basis for granting the original incentives.

Q14. WHAT OTHER WITNESSES ARE SUBMITTING TESTIMONY IN SUPPORT OF THIS FILING?

A14. In addition to my testimony, the following Direct Testimony is being submitted in support of this filing:

1. Direct Testimony of Joshua C. Nowak, Vice President, Concentric Energy Advisors, Inc., supporting MAOD's proposed 10.76 percent ROE and a proxy cost of debt to be used in the time period preceding MAOD's acquisition of construction debt financing ("Nowak Testimony") (see Exhibit Nos. MAOD-16 and MAOD-17);

2. Direct Testimony of Larry E. Kennedy, Senior Vice President, Concentric Energy Advisors, Inc., supporting the proposed depreciation rates to be applied in the development of MAOD's ATRR (see Exhibit Nos. MAOD-18 through MAOD-20); and

3. Direct Testimony of William ("Bill") R. Davis, Assistant Vice President, Concentric Energy Advisors, Inc., describing the features of MAOD's proposed Formula Rate Template, and explaining why MAOD's proposal is just and reasonable. In addition, Mr. Davis's testimony describes MAOD's proposed Formula Rate Protocols, which set out the procedures for populating and updating MAOD's Formula Rate Template similar to other protocols filed and accepted by the Commission (see Exhibit Nos. MAOD-21 through MAOD-24).

IV. DESCRIPTION OF THE COMPANY

Q15. PLEASE DESCRIBE MAOD.

A15. MAOD is a non-incumbent transmission developer whose only business is to develop, construct, own, operate, and maintain transmission facilities in the regional transmission organization ("RTO") area operated by PJM. MAOD is a Delaware limited liability company that is a joint venture between EDF-RE Offshore Development, LLC ("EDFR") and Shell New Energies US, LLC ("Shell New Energies"). EDFR and Shell New Energies each own a 50 percent interest in MAOD.

EDFR's ultimate parent is Électricité de France S.A., one of the world's largest electricity generators. Shell New Energies is an affiliate of Shell Oil Company US, which is a subsidiary of Shell plc.

Q16. WHAT ARE THE BENEFITS OF MAOD AS A TRANSMISSION-ONLY COMPANY FOCUSED ON THE PROJECT?

A16. MAOD is a transmission-only company (*i.e.,* a "Transco"). MAOD is focused on developing the Project in a cost-effective manner and owning, operating, and maintaining the Project when it goes into commercial operation. The Project was selected through the NJBPU's and PJM's closely coordinated SAA Process (as described below) and has been approved by PJM as a baseline reliability project pursuant to the RTEP. MAOD has the ability to structure and separately finance the Project with appropriate resources for a project of this risk profile.

V. THE PROJECT AND THE NJBPU / PJM SAA PROCESS

Q17. PLEASE GENERALLY DESCRIBE THE BACKGROUND OF THE PJM RTEP AND SAA PROCESSES.

A17. Pursuant to its RTEP, PJM determines a plan to enhance and expand the transmission system in the PJM region to meet demand for firm transmission service and support competition.[7] Among other things, PJM's RTEP identifies needed transmission enhancements five years into the future, and project enhancements likely to be needed over the next fifteen years.[8] The PJM Operating Agreement ("OA") outlines PJM's "baseline" reliability analysis, stating:

> This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the [PJM] Office of Interconnection to prepare a plan for the enhancement and expansion of the Transmission Facilities in order to meet the demands for firm transmission service, and to support competition, in the PJM Region. The Regional Transmission Expansion Plan (also referred to as 'RTEP') to be developed shall enable the transmission needs in the PJM Region to be met on a reliable, economic and environmentally acceptable basis.[9]
>
> ***
>
> The Regional Transmission Expansion Plan shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of (i) maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner, (ii) supporting competition in the PJM Region, (iii) striving to maintain and enhance the market efficiency and operational performance of wholesale electric service markets and (iv) considering federal and state Public Policy Requirements.[10]

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[7] *See* PJM OA, Schedule 6, § 1.1.

[8] PJM Manual 14B, PJM Region Transmission Planning Process § 2.1.2, at p. 32 (Rev. 55 effective December 20, 2023), available at https://www.pjm.com/-/media/documents/manuals/m14b.ashx (hereinafter cited as "PJM Manual 14B"); *see also* "Regional Transmission Expansion Planning," PJM Learning Center website, Three Priorities, Planning for the Future, at https://learn.pjm.com/three- priorities/planning-for-the-future/rtep.

[9] PJM OA, Schedule 6, § 1.1.

[10] PJM OA, Schedule 6, § 1.4(a).

> The Regional Transmission Expansion Plan shall reflect, consistent with the requirements of this Schedule 6, transmission enhancements and expansions; load forecasts; and capacity forecasts, including expected generation additions and retirements, demand response, and reductions in demand from energy efficiency and price responsive demand for at least the ensuing ten years.[11]

PJM has explained that, "[f]undamentally, the Baseline reliability analysis underlies all [RTEP] planning analyses and recommendations."[12]

In 2013, to better accommodate state-specific public policy needs into the RTEP, PJM established its SAA Process.[13] PJM's SAA Process is a mechanism in the PJM OA[14] through which one or more state governmental entities, authorized by their respective states, individually or jointly, may agree to be solely cost-allocated for a proposed

[11] PJM OA, Schedule 6, § 1.4(b).

[12] PJM Manual 14B, § 2.1, at 30. *See also* Exhibit No. MAOD-6, PJM, "Reliability Analysis Report, PJM RTEP – 2021 SAA Proposal Window to Support NJ OSW" (Sep. 19, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/nj-osw-reliabilityanalysis- report-september-final.ashx, *revised* (Nov. 4, 2022), https://www.pjm.com/-/media/committeesgroups/ committees/teac/2022/20221104-special/informational-only---njosw-reliability-analysis-report.ashx ("PJM Reliability Analysis Report"), at 9, 11, which states, in pertinent part:

> The annual RTEP process consists of a baseline reliability review, analysis to identify the transmission needs associated with both generation interconnection and merchant transmission, review of conditions experienced in real time operations, inter-regional reliability analysis, and many other special studies. The RTEP incorporates the unique needs identified by in-depth thermal, stability, short circuit, and voltage reliability analysis. …
>
> The RTEP assesses the needs of the system, at peak load for year one, two, three[,] four and year 5 in the near term and over the longer term (up to 15 years) to identify baseline transmission enhancements that require more time to implement. … [PJM's assessment] establish[es] a starting point or 'baseline' from which the need and responsibility for enhancements can be determined.

[13] *See PJM Interconnection, L.L.C.,* 142 FERC ¶ 61,214, P 142 (2013), *order on reh'g and compliance,* 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance,* 150 FERC ¶ 61,038, *order on reh'g and compliance,* 151 FERC ¶ 61,250 (2015); PJM OA, Schedule 6, §§ 1.5, 1.5.9; *see also* PJM Interconnection, L.L.C., Intra-PJM Tariffs, Open Access Transmission Tariff ("Tariff"), Schedule 12, § (b)(xii)(B) ("Public Policy Projects"), and Schedule 12 – Appendix C ("State Agreement Public Policy Projects Constructed Pursuant to the State Agreement Approach").

[14] PJM OA, Schedule 6, § 1.5.9.

transmission expansion or enhancement that addresses state public policy requirements.[15] Under the SAA Process, a proposed transmission expansion or enhancement that addresses state public policy requirements may be included in PJM's RTEP, as either a Supplemental Project or a state public policy project.[16] Thus, the SAA allows PJM's RTEP process to incorporate a request from one or more states for PJM to develop or to review transmission facilities that would assist the states in implementing their public policy goals, such as facilitating the development of offshore wind generation.[17]

Importantly, SAA transmission expansions or enhancements may not be selected in the RTEP for purposes of regional cost allocation.[18] All costs related to a state public policy project or a project identified pursuant to the SAA are to be recovered from customers in the state or group of states that agree to be responsible for the project.[19] In this case, this means that all costs associated with the Project will be recovered from New Jersey ratepayers.

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[15] *See PJM,* 142 FERC ¶ 61,214, at P 142 ("PJM's State Agreement Approach supplements, but does not conflict or otherwise replace, PJM's process to consider transmission needs driven by public policy requirements as required by Order No. 1000 …").

[16] PJM OA, Schedule 6, § 1.5.9(a); PJM Manual 14B, § 2.1 (in pertinent part, stating: "PJM's annual 15-year planning review now yields a regional plan that encompasses the following: … Public Policy Requirements [sic] based elements via State Agreement Approach"). *See also PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024, P 2, *reh'g denied*, 179 FERC ¶ 62,131 (2022).

[17] *See PJM Interconnection, L.L.C.,* "New Jersey State Agreement Approach Agreement, Rate Schedule FERC No. 49," Docket No. ER22-902-000, Transmittal Letter, at 1-2 (filed Jan. 27, 2022) ("PJM Jan. 2022 Filing").

[18] *PJM,* 147 FERC ¶ 61,128, at P 92 (emphasis added); *PJM,* 179 FERC ¶ 61,024, at P 2 (emphasis added).

[19] PJM OA, Schedule 6, § 1.5.9(a). *See also PJM,* 147 FERC ¶ 61,128, at P 92; *PJM,* 179 FERC ¶ 61,024, at P 2. In its June 17, 2021, policy statement, FERC encouraged arrangements that allow for voluntary agreements such as those permitted by PJM's State Agreement Approach. *See State Voluntary Agreements to Plan & Pay for Transmission Facilities,* Policy Statement, 175 FERC ¶ 61,225 (2021).

Q18. HOW HAS NEW JERSEY USED COMPETITIVE SOLICITATIONS AND THE PJM SAA PROCESS TO IDENTIFY TRANSMISSION SOLUTIONS FOR OFFSHORE WIND GENERATION?

A18. On January 31, 2018, New Jersey Governor Philip Murphy signed Executive Order 8,[20] which directed the NJBPU to fully implement the New Jersey legislature's August 19, 2010 Offshore Wind Economic Development Act[21] and "begin the process of moving the State toward a goal of 3,500 MW of [offshore wind] by 2030."[22] On November 19, 2019, Governor Murphy more than doubled the state's offshore wind goal "to promote and realize the development of wind energy off the coast of New Jersey to meet a goal of 7,500 megawatts of offshore wind energy generation by the year 2035."[23] In January 2020, through various initiatives promulgated by different New Jersey administrative agencies, Governor Murphy implemented New Jersey's "Energy Master Plan" to expand the state's transmission system to accommodate New Jersey's proposed buildout of 7,500 MW of offshore wind generation by 2035.[24]

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[20] New Jersey Gov. Philip D. Murphy, Exec. Order No. 8, "An Order Mandating the BPU, the DEP, and Any Other New Jersey State Agency with Responsibilities Arising under the Offshore Wind Economic Development Act to Take all Necessary Actions to Implement the Act" (Jan. 31, 2018), 50 N.J.R. 887(a) (Feb. 20, 2018).

[21] *See* N.J.S.A. 48:3-87 *et seq.* The Offshore Wind Economic Development Act defined the Offshore Wind Renewable Energy Certificate ("OREC") (*see* N.J.A.C. 14:8-6.1) and directed the NJBPU to establish an OREC program to support at least 3,500 MW of offshore wind generation by 2035. *See id.*

[22] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 10 (citing Exec. Order No. 8; remainder of footnote omitted).

[23] *Id.* (quoting New Jersey Gov. Philip D. Murphy Exec. Order No. 92, "An Order Rescinding Paragraph 1 of Executive Order No. 8" (Nov. 19, 2019), 51 N.J.R. 1817(b) (Dec. 16, 2019)).

[24] State of New Jersey, 2019 Energy Master Plan, Pathway to 2050 (2019), available at https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf. Governor Murphy recently expanded New Jersey's offshore wind generation goal to be 11,000 MW by 2040. *See* New Jersey Gov. Philip D. Murphy, Exec. Order No. 307, "An Order Increasing Offshore Wind Goals to 11,000 MW by 2040," at 6 (Sep. 21, 2022), 54 N.J.R. 1945(a) (Oct. 17, 2022).

On November 18, 2020, through an order issued by the NJBPU, New Jersey became the first state to request that PJM, pursuant to the SAA Process, open a competitive bidding process to solicit transmission proposals to expand the state's transmission system to satisfy New Jersey's offshore wind goals.[25] As a consequence of the NJBPU's order, on December 18, 2020, in Docket No. ER21-689-000, PJM filed with FERC a study agreement to implement the NJBPU's requested competitive solicitation ("PJM-NJBPU SAA Study Agreement").[26]

Q19. PLEASE DESCRIBE THE PJM-NJBPU SAA STUDY AGREEMENT.

A19. On February 16, 2021, the Commission accepted the PJM-NJBPU SAA Study Agreement.[27] The PJM-NJBPU SAA Study Agreement established that facilities identified as part of the NJBPU's SAA process would be included in PJM's 2020-2021 RTEP cycle and used by PJM as inputs in the development of the RTEP and generation interconnection studies.[28] The PJM-NJBPU SAA Study Agreement specifies that: (1) PJM will perform planning studies to identify system improvements to interconnect and provide for the deliverability of New Jersey's planned offshore wind generation at specific POI to the transmission system; and (2) PJM will open a competitive proposal window to solicit transmission solutions for the deliverability of New Jersey's planned offshore wind

[25] *See In the Matter of Offshore Wind Transmission,* Order, NJBPU Docket No. QO20100630, at 7 (Nov. 18, 2020); *see also* State of New Jersey, 2019 Energy Master Plan, Pathway to 2050 (2019), available at https://nj.gov/emp/docs/pdf/2020_NJBPU_EMP.pdf; Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 10-11.

[26] *See PJM Interconnection, L.L.C., "*New Jersey State Agreement Approach Study Agreement, SA No. 5890," Docket No. ER21-689-000, at 3, 7 (filed Dec. 18, 2020) ("PJM Dec. 2020 Filing").

[27] *PJM Interconnection, L.L.C.,* 174 FERC ¶ 61,090 (2021) ("SAA Study Agreement Order"); PJM Service Agreements Tariff, PJM SA No. 5890, PJM SA No. 5890 among PJM and NJBPU (0.0.0) ("PJM-NJBPU SAA Study Agreement"); *see also PJM,* 179 FERC ¶ 61,024, at P 4.

[28] *See* PJM Jan. 2022 Filing, at 10 (citing PJM Dec. 2020 Filing).

generation.[29] When accepting the PJM-NJBPU SAA Study Agreement, the Commission explained that the agreement "memorializes the [NJBPU's] formal request that PJM incorporate New Jersey's public policy of deploying 7,500 MW of offshore wind generation by 2035 via the [SAA Process] and provides transparency to stakeholders regarding the process milestones and inclusion of [NJBPU's] requested transmission in the 2020-2021 RTEP cycle."[30]

Q20. PLEASE DESCRIBE THE PJM COMPETITIVE SOLICITATION WINDOW.

A20. On April 15, 2021, PJM opened a window to solicit transmission proposals consistent with the PJM-NJBPU SAA Study Agreement. This solicitation sought transmission solutions to interconnect 7,500 MW of offshore wind generation off the coast of New Jersey by 2035.[31] The solicitation requested three general categories of proposals (called "Options").

- Option 1 proposals were to focus on upgrades to existing onshore facilities (Option 1a) or the construction of new onshore facilities (Option 1b) to accommodate the delivery of offshore wind generation to onshore POI.
- Option 2 proposals were to focus on potential extension of the New Jersey transmission system offshore, including, among other things, potential high voltage direct current ("HVDC") circuits that could accommodate delivery from offshore wind generation and then deliver power to identified onshore

[29] SAA Study Agreement Order, 174 FERC ¶ 61,090, at P 12.

[30] *Id.* at P 13.

[31] PJM RTEP – 2021 SAA Proposal Window To Support NJ OSW, at 1 (Apr. 15, 2021), available at https://www.pjm.com/planning/competitive-planning-process, Closed Windows 2021, 2021 SAA Proposal Window to Support NJ OSW, zip file "Without Analytical Files V9, non-CEII update 9.24.2021," file named "Option 1a Problem Statement For 2021 SAA Window to Support NJ OSW." *See also PJM*, 179 FERC ¶ 61,024, at P 5; Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 10, 20.

delivery points.

- Option 3 proposals were to focus on offshore "backbone" transmission solutions that would deliver to potential Option 2 solutions, which, in turn, would deliver power to onshore delivery points.[32]

The PJM solicitation window closed on September 17, 2021.[33] On September 17, 2021, MAOD submitted three related proposals to the solicitation process.

Q21. WHAT WAS THE RESULT OF THE SOLICITATION PROCESS?

A21. A total of eighty proposals, including MAOD's proposals, were submitted to PJM during the competitive solicitation window. MAOD submitted three Option 2 proposals to develop HVDC circuits to accommodate delivery of power from multiple offshore generation facilities to a common substation utilizing a common right of way. Among other potential benefits, MAOD's Option 2 proposals were designed to maximize cost efficiencies and to limit the environmental impacts of constructing transmission facilities to bring offshore wind generation onshore. MAOD's Option 2 proposals included plans to sequence increasing levels of onshore delivery of offshore wind generation. One of these Option 2 Proposals (MAOD Proposal 551) included MAOD's proposed new 230/500 kV substation at Larrabee, which was designed to serve as the common alternating current

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[32] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 42-54. *See also See PJM Interconnection, L.L.C.,* "Amended and Restated New Jersey State Agreement Approach Agreement, Rate Schedule FERC No. 49," Docket No. ER23-775-000 (filed Jan. 5, 2023) (hereinafter "PJM Rate Sched. 49 Amended SAA Agreement"), at App. A – NJBPU Offshore Wind Solicitation Schedule. A copy of the PJM Rate Sched. 49, Amended SAA Agreement is provided as Exhibit No. MAOD-4.

[33] *See* PJM website at https://www.pjm.com/planning/competitive-planning-process, Closed Windows 2021, 2021 SAA Proposal Window to Support NJ OSW (showing competitive window "close 9.17.2021"); *see also PJM,* 179 FERC ¶ 61,024, at P 5.

("AC") injection point for offshore wind generation facilities at existing points in the JCP&L transmission system.[34]

Specifically, MAOD's Option 2 proposals complimented the Option 1 proposals submitted by JCP&L to allow the MAOD Option 2 facilities to serve as a common injection point for offshore wind generation to the existing JCP&L transmission system at three existing substations:

- JCP&L's Smithburg 500 kV substation in Freehold Township, Monmouth County, New Jersey ("JCP&L Smithburg Substation");
- JCP&L's Larrabee Substation in Howell Township, Monmouth County, New Jersey ("JCP&L Larrabee Substation"); and
- JCP&L's Atlantic 230 kV substation in Colts Neck Township, Monmouth County, New Jersey ("JCP&L Atlantic Substation").

These three substations are currently subject to PJM's operational control and planning under the PJM Tariff.

Q22. PLEASE DESCRIBE THE PJM-NJBPU SAA AGREEMENT.

A22. On January 27, 2022, pursuant to the PJM OA, Schedule 6, section 1.5.9, PJM filed an executed State Agreement Approach Agreement between PJM and NJBPU, designated as PJM Rate Schedule FERC No. 49 ("SAA Agreement").[35] The SAA Agreement

[34] Specifically, JCP&L submitted several Option 1 proposals to upgrade and to construct onshore facilities. In particular, JCP&L submitted Option 1a (Proposal 17) and Option 1b (Proposal 453) proposals to, among other things, upgrade existing facilities and increase capacity at (and around) potential points of interconnection at the JCP&L Smithburg Substation, JCP&L Larrabee Substation, and JCP&L Atlantic Substation, which would allow for interconnection of the Larrabee Collector Station to the transmission system. PJM has posted summaries of MAOD's Proposal 551 and JCP&L's Proposals 17 and 453 at the following links: https://www.pjm.com/planning/competitive-planning-process/redacted-proposals, and https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221104-special/informational-only---njosw-map-book.ashx. *See also* Exhibit No. MAOD-4, PJM Rate Sched. 49, Amended SAA Agreement, at App. C.

[35] *See* PJM Jan. 2022 Filing; *see also* Exhibit No. MAOD-4, PJM Rate Sched. 49, Amended SAA Agreement.

established processes for the review and selection of specific transmission projects submitted to New Jersey's offshore wind competitive solicitation for review.[36] FERC accepted the SAA Agreement, effective April 15, 2022.[37]

The SAA Agreement required PJM to review submissions into the solicitation and to develop recommendations for potential winning bidders through its RTEP.[38]

The SAA Agreement also provided that the NJBPU subsequently would decide whether to sponsor one or more of PJM's recommended transmission projects.[39] The SAA Agreement obligates NJBPU to provide notice to PJM for any projects that NJBPU decides to sponsor ("SAA Project"), as well as to submit to the PJM Transmission Owners Agreement Administrative Committee ("TOA-AC") a proposed allocation of SAA Project costs to New Jersey customers for the TOA-AC's consideration and filing with FERC.[40] Following the NJBPU's notification to PJM of the NJBPU's selection and sponsorship of an SAA Project, PJM follows its RTEP process under PJM OA, Schedule 6, sections 1.5.8 and 1.5.9 to determine the specific "designated entity" (such as MAOD, as described below) to construct, own, operate, and maintain the SAA Project.[41]

Further, the SAA Agreement provides that PJM will "track the construction progress of the SAA Project consistent with the development schedule and construction

[36] *PJM,* 179 FERC ¶ 61,024, at P 6.

[37] *See id.* at PP 1, 40, ordering paragraph.

[38] *Id.* at PP 6-7.

[39] *Id.*.

[40] *Id.* (citing SAA Agreement §§ 5.1, 5.4).

[41] *Id.* at P 8 (footnote omitted); *see also* SAA Agreement, §§ 4.1, 4.2.

milestones detailed in a designated entity agreement."[42] PJM also is required to provide construction progress reports to the NJBPU on a quarterly basis.[43]

In August 2022, PJM filed additional tariff revisions to incorporate a new Schedule 12 – Appendix C, setting forth provisions for "State Agreement Public Policy Projects Constructed Pursuant to the State Agreement Approach."[44] The new Schedule 12 – Appendix C[45] assigns cost responsibility for projects selected pursuant to the SAA for inclusion in the PJM RTEP in accordance with the PJM OA[46] and PJM Tariff.[47]

Q23. PLEASE DISCUSS PJM'S REVIEW OF THE SUBMISSIONS UNDER THE COMPETITIVE SOLICITATION AND NJBPU'S AWARD TO MAOD.

A23. PJM's review of the eighty project proposals submitted into the PJM and NJBPU competitive solicitation window was documented in six reports provided to PJM stakeholders, which described the scope of the reliability, economic, financial, and constructability parameters PJM considered.[48] PJM reviewed these eighty projects for

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[42] *PJM,* 179 FERC ¶ 61,024, at P 8.

[43] *Id.*

[44] *See PJM Interconnection, L.L.C.,* "Proposed Schedule 12 – Appendix C to the PJM Interconnection, L.L.C. Open Access Transmission Tariff," Docket No. ER22-2690-000 (filed Aug. 19, 2022) ("PJM Tariff Schedule 12 – Appendix C Filing"); *PJM Interconnection, L.L.C.,* 181 FERC ¶ 61,178 (2022) (order accepting PJM's Tariff revisions in Docket No. ER22-2690-000).

[45] PJM Tariff Schedule 12 – Appendix C Filing, Transmittal Letter at 2.

[46] PJM OA, Schedule 6, § 1.5.9.

[47] PJM Tariff Schedule 12, § (b)(xii)(B).

[48] These six reports are:

(1) Exhibit No. MAOD-6, PJM Reliability Analysis Report;

(2) PJM, "Financial Analysis Report, 2021 SAA Proposal Window to Support NJ OSW" (Sep. 19, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/nj-osw-financial-analysis- report-september-final.ashx;

(3) PJM, "Economic Analysis Report, PJM RTEP – 2021 SAA Proposal Window to Support NJ OSW" (Sep. 19, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/nj-osw-economic- analysis-report-september-final.ashx;

purposes of reliability and congestion relief for potential inclusion in the RTEP.[49] The coordinated review process implemented by PJM and the NJBPU identified fifty-two projects as potential new public policy baseline projects for the NJBPU to contemplate for its selection, three of which were MAOD's Option 2 proposals (including Proposal 551).[50] Four "finalists" were identified and ultimately selected by the NJBPU. In relevant part, MAOD's Proposal 551 was such a finalist and studied as "Scenario 18a" by PJM.[51]

Q24. DID NJBPU SELECT THE LARRABEE TRI-COLLECTOR SOLUTION (AND THE PROJECT)?

A24. Yes. On October 26, 2022, consistent with the SAA Agreement, the NJBPU combined aspects of MAOD's Proposal 551, JCP&L's Proposal 17, and JCP&L's Proposal 453 as the major components of what the NJBPU defined as the "Larrabee Tri-Collector

(4) PJM, "Constructability Report: Option 1a Proposals, 2021 SAA Proposal Window to Support NJ OSW" (Sep. 19, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/nj-osw-constructability-reports-for-option-1a-proposals-september-final.ashx;

(5) PJM, "Constructability Report: Option 1b Proposals, 2021 SAA Proposal Window to Support NJ OSW" (Sep. 19, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/nj-osw-constructability-reports-for-option-1b-proposals-september-final.ashx;

(6) PJM, "Constructability Report: Option 2 & 3 Proposals, 2021 SAA Proposal Window to Support NJ OSW" (Sep. 19, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20220906/nj-osw-constructability-report-for-option-2-and-3-proposals-september-final.ashx.

[49] *See* Exhibit No. MAOD-6, PJM Reliability Analysis Report, at 4-7, 9-11, 20-23. *See also* PJM Baseline Reliability Assessment, 2022-2037 Period, at 14-15, 70, 110-117 (Mar. 1, 2023), ("PJM 2022 RTEP Report"), available at https://www.pjm.com/-/media/planning/rtep-dev/baseline-reports/2022-rtep-baseline-assessment.ashx. A copy of the PJM 2022 RTEP Report is provided as Exhibit No. MAOD-5.

[50] *See* Exhibit No. MAOD-6, PJM Reliability Analysis Report, at 5-6, 20-21, 46-47 (discussing MAOD Proposal 551 as part of "finalist" Scenario 18a).

[51] PJM, "Summary Report for the NJBPU Selected Project, 2021 SAA Proposal Window to Support NJ OSW," at 4-5, 8, 14-18 (Nov. 15, 2022), https://www.pjm.com/-/media/committees-groups/committees/teac/2022/20221104-special/nj-osw-saa-summary-report.ashx ("PJM Summary Report"). The PJM Summary Report is provided as Exhibit No. MAOD-7.

Solution," which the NJPBU then selected as its preferred transmission solution to accommodate delivery of New Jersey offshore wind generation.[52]

Specifically, to create the Larrabee Tri-Collector Solution, the NJBPU combined: (1) the onshore 230/500kV substation portions of MAOD's Proposal 551, with (2) the Option 1a component of JCP&L Proposal 17 and Option 1b component of JCP&L Proposal 453 to upgrade existing facilities and to construct new collector facilities to increase transmission capacity into and around the JCP&L Smithburg Substation, the JCP&L Larrabee Substation, and the JCP&L Atlantic Substation. These core facilities of the Larrabee Tri-Collector Solution are supported by other onshore upgrades and facilities around the JCP&L service territory and central New Jersey to be constructed by Atlantic City Electric Company, Baltimore Gas and Electric Company, LS Power Grid Mid-Atlantic, LLC, PECO Energy Company, Public Service Electric & Gas Company, and Transource Energy, LLC.[53]

The aggregate set of combined transmission facilities composing the Larrabee Tri-Collector Solution allows offshore wind power injected at the Larrabee Collector Station to be transmitted to the JCP&L Smithburg Substation, the JCP&L Larrabee Substation, and the JCP&L Atlantic Substation, and then flowed to the surrounding transmission system.

[52] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 59-60. The NJBPU also selected other proposals from among the 52 recommended by PJM following its RTEP analyses. *See id.* at 2, 64.

[53] *See* Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 64, App. A. At least a portion of those Option 1a projects include facilities at the Pennsylvania-Maryland border. *See id.* *See also* Exhibit No. MAOD-5, PJM 2022 RTEP Report, at 110-117.

When selecting the Larrabee Tri-Collector Solution, the NJBPU explained that the Larrabee Tri-Collector Solution "best meet[s] the goals of the SAA and will result in a more efficient and cost-effective means of meeting the State's [offshore wind] goals at this time…."[54] The NJBPU explained that when compared to other "baseline" alternatives considered by the NJBPU, "analysis reveals the Larrabee Tri-Collector Solution features benefits across the stated SAA evaluation criteria, and is the strongest … single corridor solution when compared to [other proposals]."[55] With respect to the Project, the NJBPU stated:

> The predominant portion of the Larrabee Tri-Collector Solution is a new substation adjacent to the existing JCP&L Larrabee substation (the "Larrabee Collector Station"). MAOD proposes to construct the AC portion of the new Larrabee Collector Station to accommodate three future HVDC circuits. The proposal also includes sufficient land for the future installation of up to four DC converter stations…. The HVDC cables delivering the output of future [offshore wind] generators will interconnect at this new Larrabee Collector Station.[56]

With respect to the JCP&L facilities, the NJBPU stated:

> The [Larrabee Tri-Collector Solution] includes a 'tri-collector' that distributes up to 4,890 MW from the Larrabee Collector Station to three existing POI on PJM's grid (the Smithburg 500 kV substation ("Smithburg"), the Larrabee 230 kV substation ("Larrabee"), and the Atlantic 230 kV substation ("Atlantic")), utilizing JCP&L's existing transmission [Rights of Way ("ROWs")]. To provide a complete [onshore delivery] solution, [NJBPU] Staff recommends that the [NJBPU] select MAOD's Larrabee Collector Station in combination with JCP&L's tri-collector proposal.[57]

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[54] Exhibit No. MAOD-3, NJBPU Oct. 2022 Order, at 59.

[55] *Id.* at 59-60.

[56] *Id.* at 60.

[57] *Id.*

The NJBPU explained that the combination of MAOD's proposal and JCP&L's proposals "leverages JCP&L's existing ROWs *to create a single point for connecting [offshore wind] projects and maximizes use of available headroom at existing POIs, while offering a single corridor solution* preferred by [NJBPU] Staff."[58]

Finally, the NJBPU explained that the use of its competitive and SAA processes will result in approximately $900 million in savings for New Jersey ratepayers.[59] These savings comprise two elements: (1) the Larrabee Tri-Collector Solution costs $630 million less than other potential baseline upgrades evaluated under the 2020-2021 RTEP that may otherwise be constructed to interconnect New Jersey offshore wind; and (2) the selection of the Larrabee Tri-Collector Solution reduces the amount of cabling necessary to deliver the offshore wind energy to the onshore delivery points, resulting in an additional $288 million in potential savings compared to other modeled scenarios evaluated in PJM's baseline assessment.[60] The NJBPU also explained that offshore wind generators will benefit greatly from the Larrabee Tri-Collector Solution because it minimizes cost and delay uncertainty for transmitting power onshore, thereby encouraging development of their offshore wind generation projects.[61]

Per the NJBPU October 2022 Order, the Larrabee Tri-Collector Solution (and consequently, the Project) is subject to further modification by order of the NJBPU and/or

[58] *Id.* at 60-61 (emphasis added).

[59] *Id.* at 61 & n.93.

[60] *Id.* at 61 (footnote omitted).

[61] *Id.* at 61.

under the PJM RTEP process.[62] The NJBPU explained that "[u]pdates to approved PJM RTEP projects are typical. Allowing for the modification of the [NJBPU] Order in the future to reflect significant updates will ensure that the specific configuration of the awarded SAA facilities remains optimal and beneficial to ratepayers over time."[63]

Q25. HAVE PJM AND THE NJBPU COORDINATED TO INCLUDE THE PROJECT IN THE RTEP?

A25. Yes. On December 6, 2022, the PJM Board of Managers ("PJM Board") approved the inclusion of the facilities comprising the Larrabee Tri-Collector Solution (including the Project) as baseline reliability projects for purposes of the 2022 RTEP.[64]

On January 5, 2023, PJM filed an executed Amended and Restated State Agreement Approach Agreement ("Amended SAA Agreement") between PJM and the NJBPU, which was revised to include a list of the specific projects selected in PJM's 2020-2021 RTEP and by the NJBPU, including the Project.[65] The Project is identified in Appendix C to the Amended SAA Agreement and identified as RTEP Project No. b3737.22.[66] The Commission accepted the Amended SAA Agreement on March 6, 2023.[67]

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[62] *Id.* at 61-62.

[63] *Id.* at 62.

[64] PJM Board of Managers, Minutes of December 6, 2022 Board Meeting, at 6 (Dec. 6, 2022), available at https://www.pjm.com/-/media/about-pjm/who-we-are/board-meetings/2022/20221205/20221206-minutes.ashx ("PJM Board Meeting Minutes").

[65] *See PJM Interconnection, L.L.C.,* "Amended and Restated New Jersey State Agreement Approach Agreement, Rate Schedule FERC No. 49," Docket No. ER23-775-000 (filed Jan. 5, 2023) (hereinafter "PJM Rate Sched. 49 Amended SAA Agreement"). A copy of the PJM Rate Sched. 49, Amended SAA Agreement is provided as Exhibit No. MAOD-4.

[66] *See* Exhibit No. MAOD-4, PJM Rate Sched. 49, Amended SAA Agreement, App. C. *See also* Exhibit No. MAOD-5, PJM 2022 RTEP Report, at 70.

[67] *PJM Interconnection, L.L.C.,* Docket No. ER23-775-000, unpublished letter order (Mar. 6, 2023).

Also, on January 5, 2023, PJM filed proposed revisions to its Tariff Schedule 12 – Appendix A and Schedule 12 – Appendix C to incorporate cost responsibility for sixty-five baseline upgrades, including fifty-two projects submitted to PJM during the SAA competitive solicitation window and included within the updated RTEP approved by the PJM Board on December 6, 2022.[68]

Q26. HAVE THERE BEEN ANY CHANGES TO THE SCOPE OF MAOD'S PROJECT AND/OR HAS MAOD BEEN AWARDED ADDITIONAL PROJECTS?

A26. Yes. The Project's scope has been revised to: (1) include additional facilities referred to as the Interconnection Work; and (2) resize the autotransformers required for the Project. MAOD also was requested to perform an additional project, a "Prebuild study," by the NJBPU for which MAOD also will seek cost recovery.

Q27. PLEASE DESCRIBE THE PREBUILD STUDY.

A27. In mid-2023, the NJBPU requested that MAOD perform a "Prebuild study." This was a "desktop" study of "Prebuild Infrastructure" alternatives. Specifically, the NJBPU has been evaluating different solutions for the civil works necessary to accommodate the generation tie lines that will connect offshore generation facilities to the Larrabee Tri-Collector Solution. The aggregate set of civil works starting from the onshore landing point and stretching on land toward the Larrabee Tri-Collector Solution is referred to by the NJBPU as the Prebuild Infrastructure. This infrastructure includes, among other things, duct banks

[68] *See PJM Interconnection, L.L.C.,* "Revisions to Incorporate Cost Responsibility Assignments for Regional Transmission Expansion Plan Baseline Upgrades," Docket No. ER23-779-000, at 1, n.3 (filed Jan. 5, 2023) (explaining that PJM's tariff revisions were filed "to incorporate cost responsibility assignments for 65 baseline upgrades in the recent update to the Regional Transmission Expansion Plan ('RTEP') approved by the PJM Board of Managers ('PJM Board') on December 6, 2022."); *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER23-779-000 (unpublished) (issued Apr. 4, 2023); *see also* PJM Board Meeting Minutes, at 6.

and access cable vaults. The NJBPU originally sought Prebuild Infrastructure solutions in its initial 2021 request for proposals ("RFP") but, after evaluating proposals in that RFP, deferred consideration of a prebuild-related award to its more recent Third Solicitation for offshore wind generation. The Third Solicitation was opened in March 2023.[69] To assist the NJBPU in its analysis of potential Pre-Build solutions, the NJBPU requested that MAOD perform the Prebuild Study. The NJBPU subsequently approved the Prebuild Study as an addition to the Project in the NJBPU June 29, 2023, NJBPU Order.[70]

PJM assigned RTEP Project No. b3737.60 to the Prebuild Study.[71] Project No. b3737.60 was recommended by the PJM Transmission Expansion Advisory Committee

[69] *See In the Matter of the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC),* Order Opening the Application Window for the Third Offshore Wind Solicitation, NJBPU Docket No. QO22080481 (Mar. 6, 2023), available at https://www.nj.gov/bpu/pdf/boardorders/2023/20230306/8D%20ORDER%20OSW%20Third%20Solicitation.pdf. As explained below, on January 24, 2024, the NJBPU awarded 3,742 MW of offshore wind capacity to the winning bidders of its Third Solicitation. *See In the Matter of the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC),* "Order Approving Attentive Energy Two 1342 MW Project as a Qualified Offshore Wind Project," New Jersey Board of Public Utilities Docket No. QO22080481, at 21 (Jan. 24, 2024), available at https://www.nj.gov/bpu/pdf/boardorders/2024/20240124/8A%20ORDER%20Solicitation%203%20Attentive.pdf; *In the Matter of the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC),* "Order Approving Leading Light Wind 2400 MW Project as a Qualified Offshore Wind Project," New Jersey Board of Public Utilities Docket No. QO22080481, at 21 (Jan. 24, 2024).

[70] *See In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey,* "Order Approving State Agreement Approach Project Scope Modifications and Addressing Scope-Related Cost Estimate Adjustments," NJBPU Docket No. QO20100630, at 5, 9-10 (Jun. 29, 2023), available at https://nj.gov/bpu/pdf/boardorders/2023/20230629/8B%20ORDER%20SAA%20Project%20Scope%20Changes.pdf (approving MAOD's change of scope and cost increases for interconnection work, pre-build infrastructure study and refinement of cost estimates) ("June 29, 2023, NJBPU Order"). A copy of the June 29, 2023, NJBPU Order is attached as Exhibit No. MAOD-10.

[71] *See* Exhibit No. MAOD-4, PJM Rate Sched. 49, Amended SAA Agreement, at App. C – Description of SAA Projects Selected by the NJBPU.

("TEAC") for PJM Board approval during their May 9, 2023 meeting.[72] The PJM Board approved RTEP Project No. b3737.60 at its July 12, 2023 meeting.[73]

The Third Solicitation closed in August 2023. Based on its review of the Third Solicitation bids,[74] in its November 17, 2023 order the NJBPU opened a competitive process focused exclusively on proposed Prebuild Infrastructure solutions.[75] This bidding process closed on April 3, 2024.[76] As of the time of this filing, it is MAOD's understanding that the NJBPU is in the process of evaluating the April 3, 2024 Prebuild Infrastructure bids.

Q28. PLEASE DESCRIBE THE INTERCONNECTION WORK.

A28. In the June 29, 2023 Order, the NJBPU determined that it would be more cost effective for MAOD to construct two sets of facilities that will be located on the Larrabee Collector Station property: (1) the civil works necessary to connect the Prebuild Infrastructure to the

[72] *See* Exhibit No. MAOD-8, PJM May 9 TEAC Presentation, at 9, 15.

[73] *See* PJM Interconnection, "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board, PJM Staff White Paper July 2023," at 1, 5, 9 (July 2023), available at https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230711/20230711-pjm-teac-board-whitepaper-july-2023-public.ashx ("PJM July 2023 White Paper") (noting that on July 12, 2023, the PJM Board approved, among other things, changes to previously approved projects in the RTEP, including the scope and cost increases for MAOD's State Agreement Approach (SAA) project, as summarized in this white paper). A copy of the PJM July 2023 White Paper is attached as Exhibit No. MAOD-11. *See also* PJM Appendix, "July 2023 Board TEAC Review," line 19 (RTEP Project No. b3737.60) (Jun. 6, 2023), available at https://www.pjm.com/committees-and-groups/committees/teac under the TEAC Meeting Materials for June 6, 2023 meeting, Excel document name "Appendix – July 2023 Board TEAC Review."

[74] *See In the Matter of the Opening of a Solicitation for a Transmission Infrastructure Project to Support New Jersey's Offshore Wind Public Policy,* "Order Initiating a Prebuild Infrastructure Solution," NJBPU Docket No. QO23100719 (Nov. 17, 2023) ("November 17, 2023, NJBPU Order"). A copy of the NJBPU November 17, 2023 Order is attached hereto as Exhibit No. MAOD-15. *See also In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC),* NJBPU Docket No. QO22080481 (Oct. 25, 2023) ("October 25, 2023, NJBPU Order").

[75] *See* Exhibit No. MAOD-15, November 17, 2023, NJBPU Order, at 8.

[76] *See* Exhibit No. MAOD-15, November 17, 2023, NJBPU Order, at 8.

generator's HVDC converter station areas, and (2) the AC transmission lines interconnecting the generators' HVDC converters to the Project's Larrabee Collector Station.[77] These two sets of facilities are referred to by the NJBPU as the Interconnection Work for the Project. This Interconnection Work is comprised of the following:[78]

- The un-energized infrastructure from the end of the Prebuild Infrastructure to the direct current ("DC") converter stations ("Prebuild Extension Work"). More specifically, this work includes the engineering, procurement, and construction of civil work to accommodate four (4) HVDC circuits from the Prebuild Point of Demarcation to each individual generator's DC converter station area within the MAOD parcel awarded under the SAA; and

- The alternating current ("AC") collector lines that run from the generator's DC converter station area to the Larrabee Collector Station's AC interface ("AC Collector Lines Work"). More specifically, this work includes the engineering, procurement, and construction of civil works for three (3) separate trenches to accommodate AC collector lines and three (3) sets of AC collector lines that will connect each Generator Converter Station Area's AC interface to the Larrabee Collector Station. The three (3) sets of AC collector lines will consist of a total of 12 230 kilovolt ("kV") AC circuits.

The NJBPU ordered that MAOD should be awarded the Interconnection Work as a part of a "modification and expansion of MAOD's designated scope of work."[79] The estimated cost of the Interconnection Work is $23 million.[80] This Interconnection Work was reviewed by the TEAC on January 9, 2024[81] and approved by the PJM Board on February

[77] *See* Exhibit No. MAOD-10, June 29, 2023, NJBPU Order, at 3-5, 9.

[78] Exhibit No. MAOD-10, June 29, 2023, NJBPU Order, at 3-4.

[79] *Id*. at 9.

[80] *Id*. at 5.

[81] *See* PJM Interconnection, L.L.C., presentation to Transmission Expansion Advisory Committee ("TEAC"), "Reliability Analysis Update," at slide 31 (Jan. 9, 2024), available at https://www.pjm.com/-/media/committees-groups/committees/teac/2024/20240109/20240109-item-12---reliability-analysis-update.ashx (describing Amended Scope for MAOD's project b3737.22 to add Prebuild Extension Work and AC Collector Lines (also described herein

28, 2024.[82] The TEAC and PJM Board included the Interconnection Work under the umbrella of the Project's existing RTEP number b3737.22.[83]

Q29. WERE ANY ADDITIONAL CHANGES MADE TO THE PROJECT?

A29. Yes. The four single phase 500/230 kV autotransformers at the Larrabee Collector Station need to be resized from 450 MVA to 480 MVA to accommodate reactive power requirements. The estimated cost of the autotransformer resizing is $800,000. The NJBPU approved this change in its March 20, 2024 order.[84] The PJM Transmission Expansion Advisory Committee ("TEAC") included this change in its April 2, 2024, Reliability Analysis Update.[85] MAOD expects PJM Board approval for inclusion of this work in the RTEP in August 2024 under the umbrella of the Project's existing RTEP number b3737.22.

Q31. WHAT ARE THE ESTIMATED COSTS OF THE PROJECT AT THIS TIME?

A31. The Project's current estimated capital costs are approximately $217,090,000 and reflect: (1) $193 million of costs for the Larrabee Collector Station and the adjacent land, the additional $23 million in Interconnection Work, and the $800,000 cost of resizing of the

at Interconnection Work) at a total estimated cost increase of $23 million) ("PJM January 9, 2024 TEAC Presentation"). *See also* Exhibit No. MAOD-14, PJM February 2024 White Paper, at 8, 11 (same).

[82] *See* Exhibit No. MAOD-14, PJM February 2024 White Paper, at 8, 11.

[83] *See* PJM January 9, 2024 TEAC Presentation, at slide 31.

[84] *See* Exhibit No. MAOD-12, March 20, 2024, NJBPU Order (NJBPU order approving modified transformer sizing from 450 MVA to 480 MVA and increased cost thereof).

[85] *See* PJM Interconnection, L.L.C., "Reliability Analysis Update," presentation to Transmission Expansion Advisory Committee ("TEAC"), at slide 10 (Apr. 2, 2024) (stating the Amended Scope for b3737.22 as "Increase Sizing of Autotransformers: Increase sizing of four single phase 500/230 kV autotransformers at LCS from 450 MVA to 480 MVA to meet reactive power requirements").

autotransformers (collectively, RTEP Project No. b3737.22); and (2) $290,000 for the Prebuild study (RTEP Project No. b3737.60).

Q32. HAS MAOD ENTERED INTO A DESIGNATED ENTITY AGREEMENT WITH PJM FOR THE PROJECT?

A32. Yes. On August 21, 2023, PJM and MAOD executed a Designated Entity Agreement ("DEA") largely based on PJM's *pro forma* DEA in PJM's Tariff.[86] The DEA expressly requires MAOD to construct the Project based on certain project financing and development milestones, including a COD of December 31, 2027.[87]

Q33. HAS MAOD ENTERED INTO ANY TRANSMISSION INTERCONNECTION AGREEMENTS?

A33. No, as of the date of this testimony MAOD has not entered into any transmission interconnection agreements. However, MAOD has entered into an Interconnection Coordination Agreement with JCP&L to coordinate their interconnection. PJM is also a party to the Interconnection Coordination Agreement. Prior to going into service MAOD expects to enter into a Transmission to Transmission Interconnection Agreement with JCP&L. MAOD also expects to enter into Interconnection Service Agreements with multiple offshore wind generating facilities, as applicable. Finally, MAOD will be executing the PJM Consolidated Transmission Owners Agreement to transfer operational control of the Project (and planning authority relative to the Project) to PJM.

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[86] Exhibit No. MAOD-9, "Designated Entity Agreement between PJM Interconnection, L.L.C. and Mid-Atlantic Offshore Development, LLC, PJM RTEP Projects b3737.22 & b3737.60: New Jersey SAA – Larrabee Collector Station (LCS)" (Aug. 21, 2023) ("PJM-MAOD DEA"). *See also* Exhibit No. MAOD-14, PJM March 12, 2024, Letter, at 1, Att. B (expanding the scope of PJM RTEP Project b3737.22 under the PJM-MAOD DEA).

[87] Exhibit No. MAOD-9, PJM-MAOD DEA, at Sched. C.

VI. INTEGRATION OF THE PROJECT INTO THE EXISTING TRANSMISSION SYSTEM

Q34. CAN YOU PROVIDE A DETAILED DESCRIPTION OF THE TRANSMISSION FACILITIES COMPRISING THE PROJECT ONCE IT IS COMPLETE?

A34. Yes. The Project, as currently approved, consists of the Larrabee Collector Station which, as I explained above, will be an AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A, and four single phase 500/230 kV autotransformers to step up the voltage of one circuit for connection to the JCP&L Smithburg Substation. The other two circuits within the Larrabee Collector Station will be connected to the JCP&L Larrabee Substation and the JCP&L Atlantic Substation. As also stated above, the Project also includes land adjacent to the Larrabee Collector Station, on which MAOD will perform some site work to prepare it for offshore wind generators to construct four future DC to AC converter stations for interconnection of DC circuits from offshore wind generation. The Project will also include the Interconnection Work (as described above).

Please see Exhibit No. MAOD-2. Exhibit No. MAOD-2 contains maps that show the Project and its relationship to existing JCP&L substation facilities. Exhibit No. MAOD-2 also includes a schematic diagram of the Project, its internal configuration and the "Point of Demarcation" with the Prebuild Infrastructure.

Q35. HOW IS THE PROJECT GOING TO FACILITATE INTERCONNECTION OF NEW JERSEY OFFSHORE WIND GENERATION?

A35. As part of the Larrabee Tri-Collector Solution and pursuant to the PJM Tariff, the Project will serve as a common point of interconnection for future New Jersey offshore wind generation facilities to the PJM transmission system through the Project's interconnections with the JCP&L Smithburg Substation (at 500 kV), the JCP&L Larrabee Substation (at 230 kV), and the JCP&L Atlantic Substation (at 230 kV). In coordination with PJM, the NJBPU has assigned specific capacity on the MAOD and JCP&L facilities to winning bidders of the NJBPU's Third Solicitation process for offshore generation developers.[88]

PJM will have operational control of the Project and the Project will be included in PJM's transmission planning models. Importantly, PJM will facilitate generator interconnection for New Jersey offshore wind projects and other projects that may seek to interconnect to the Project.

Q36. PLEASE DESCRIBE THE PROJECT'S INTERCONNECTIONS WITH JCP&L'S LARRABEE SUBSTATION, JCP&L's ATLANTIC SUBSTATION, AND JCP&L'S SMITHBURG SUBSTATION, AND THE RELIABILITY BENEFITS SUCH INTERCONNECTIONS CAN PROVIDE.

A36. As stated above, the Project is located on a plot that is adjacent to the JCP&L Larrabee Substation in Howell Township, New Jersey. The Project will interconnect with JCP&L's Larrabee Substation through an approximately 550-yard long 230 kV circuit.

JCP&L's Atlantic Substation is located approximately 15 miles from the Project in Colts Neck Township, Monmouth County, New Jersey. The JCP&L Atlantic Substation will interconnect to the Project through a 230 kV circuit.

[88] The NJBPU announced the Third Solicitation winning bidders on January 24, 2024. *See In the Matter of the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC),* "Order Approving Attentive Energy Two 1342 MW Project as a Qualified Offshore Wind Project," NJBPU Docket No. QO22080481, at 21 (Jan. 24, 2024), available at https://www.nj.gov/bpu/pdf/boardorders/2024/20240124/8A%20ORDER%20Solicitation%203%20Attentive.pdf; *See In the Matter of the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC),* "Order Approving Leading Light Wind 2400 MW Project as a Qualified Offshore Wind Project," NJBPU Docket No. QO22080481, at 21 (Jan. 24, 2024).

JCP&L's Smithburg Substation is located approximately 16 miles from the Project in Freehold Township, Monmouth County, New Jersey. The JCP&L Smithburg Substation will interconnect to the Project through a 500 kV circuit.[89]

JCP&L is responsible for constructing the circuits that will run between its Larrabee, Atlantic, and Smithburg substations and the Project. MAOD and JCP&L currently are coordinating these transmission-to-transmission interconnections and plan to energize all three interconnections as they become available. Under the currently anticipated schedule, the interconnections to the Larrabee Substation and Smithburg Substation will be completed in late 2027 and the interconnection to the Atlantic Substation will be completed in Spring 2030. As soon as any of the circuits are complete, however, the Project will be integrated into the JCP&L/PJM system and turned over to the operational control of PJM.

From a reliability and grid operations standpoint, the circuits that JCP&L will construct from MAOD's Larrabee Collector Station to JCP&L's Larrabee Substation, JCP&L's Atlantic Substation, and JCP&L's Smithburg Substation can be utilized as parallel or alternative paths for a number of existing nearby JCP&L 230 kV and 500 kV circuits (*e.g.,* JCP&L's Larrabee to Atlantic 230 kV, Larrabee to Oceanview 230 kV, and Larrabee to Smithburg 230 kV circuits).[90] Thus, through its various interconnections, the Project will create an operational redundancy that will provide PJM with additional

[89] I note that the Project's interconnection to the JCP&L Larrabee Substation will solely be on JCP&L or MAOD property and therefore, will require no new rights-of-way. The interconnections to JCP&L's Atlantic Substation and JCP&L's Smithburg Substation also will be constructed on JCP&L's existing rights-of-way. Therefore, the Project site is optimally located, as it eliminates rights-of-way acquisition risks and no new rights-of-way acquisition costs will be required to connect to these substations.

[90] *See* Exhibit No. MAOD-2 [CUI/CEII].

operational flexibility to address potential real-time reliability and congestion issues it may face in the southern New Jersey section of the PJM-operated transmission system. During its real-time operation, PJM will determine when to utilize the Project's circuits to provide the needed parallel path(s) to aid reliability and congestion contingencies.

Q37. WHAT OTHER RELIABILITY BENEFITS AND CONGESTION BENEFITS WILL THE PROJECT FACILITATE FOR THE LOCAL TRANSMISSION SYSTEM AND PJM TRANSMISSION SYSTEM?

A37. The unique design of the Project will allow for increased reliability and congestion benefits because it will allow PJM to switch the Project into different configurations, resulting in different flows on the network that can maximize both reliability and congestion management, as appropriate. The design of the Project will allow its "bus breakers" in the breaker-and-a-half scheme normally to be open to allow each individual HVDC converter station to be isolated on a specific dedicated line. Each of the lines leaving the Project will deliver the energy to a separate JCP&L substation, allowing maximum energy injections to the system when required.

However, the Project's design will allow PJM, under appropriate, studied conditions, to "toggle" the Project's various combinations of bus and tie breakers in order to reconfigure the Project's substation facilities and allow generators and/or lines to be tied together in different combinations. This will result in the Project being able to redirect power flow to the different interconnected JCP&L substation facilities, thereby maximizing PJM's ability to manage both reliability and congestion as system conditions change. The Project's design also will reduce the potential need for curtailment of interconnected offshore generation if certain transmission facilities are forced out, or are on a scheduled outage for maintenance, by allowing PJM to reconfigure the operation of the substation to allow the maximum amount of generation to be delivered on the remaining facilities.

Q38. WHAT IS THE LAND ADJACENT TO THE SUBSTATION AND WHAT WILL IT BE USED FOR?

A38. The Project includes 60 acres divided into four parcels where four HVDC converter stations will be located.[91] These stations will convert DC power delivered by offshore wind generation facilities that interconnect to the Project through generation tie line facilities (that will use the Prebuild Infrastructure and Prebuild Extension Work described above) to AC power that will be flowed through the Project to its points of interconnection with JCP&L.

VII. <u>PROJECT FINANCING</u>

Q39. AS A TRANSMISSION-ONLY COMPANY THAT DOES NOT YET OWN ANY TRANSMISSION ASSETS, DOES MAOD FACE FINANCING RISKS?

A39. Yes. MAOD currently does not own any transmission assets (or any other assets apart from land) and does not have any financial history, credit history, or established credit ratings. MAOD will be required to finance the siting, permitting, development, and construction of the Project without supporting revenues until the completed project is placed into service. Consequently, MAOD faces a scope and level of funding and financial risks that are not faced by traditional utilities. MAOD's business plan, capital structure, authorized ROE, and cost-recovery mechanisms will form the primary basis upon which

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[91] To accommodate the scope of the Project, MAOD was able to acquire an approximately 100-acre property adjacent to JCP&L's Larrabee Substation. Approximately sixty acres of the property will be used for the purposes of the Larrabee Collector Station and the four parcels that will be used by offshore wind generators to locate their HVDC converter stations. Another approximately ten acres will accommodate the corridors for the Interconnection Work. The remaining approximately thirty acres represent environmentally sensitive areas and required setbacks.

investors and lenders will evaluate the Company. Securing Commission approval of the Formula Rate, with MAOD's approved rate incentives, is a key part of MAOD's plan to mitigate investor concerns about MAOD being a new entrant with very limited financial history. The terms of the proposed Formula Rate and the related transmission incentives will have a significant impact on the financial terms MAOD will be able to obtain from prospective lenders or other investors.

Q40. HOW WILL MAOD OBTAIN EQUITY FINANCING FOR THE PROJECT?

A40. MAOD currently anticipates funding its initial development of the Project using paid-in-capital (i.e., equity investments) from its parent companies. Once MAOD is collecting a revenue stream from the Project, MAOD will use a combination of retained earnings and additional paid-in-capital from its parent companies to fund its ongoing investments and to maintain the equity balance necessary to achieve its target equity ratio. MAOD does not plan to sell equity interests in the Company at this time. However, if it chooses to do so, MAOD's status as a corporate entity separate from its parent companies' other activities should simplify the process of bringing additional equity investors into this transmission-only line of business.

Q41. HOW WILL MAOD OBTAIN DEBT FINANCING FOR THE PROJECT?

A41. Based on the Commission's approval of MAOD's Order No. 679 transmission incentives and assuming the Commission's acceptance of MAOD's Formula Rate, MAOD plans to put in place a construction loan agreement to provide financing for project-related construction expenditures and short-term working capital requirements. MAOD currently anticipates that this construction financing will occur in the later part of 2025, but this date may change. When the Project nears its commercial operation date ("COD") and permanent financing can be utilized, MAOD plans to access long-term debt financing in either the institutional capital markets or via long-term commercial bank financing.

Q42. HOW DOES MAOD EXPECT TO RAISE CAPITAL AT A REASONABLE COST?

A42. MAOD is working with Credit Agricole Corporate and Investment Bank ("CACIB"), as Financial Advisor, to develop an appropriate project financing structure for the Project based on MAOD's predictable ATRR. The Project will be financed on a single-asset project finance basis and lenders will initially be exposed to construction risk until the Project is placed in service. Although there will be construction risk, MAOD is targeting a credit profile that is within the guidelines set forth by nationally recognized rating agencies for "investment grade" credit ratings based on the stable cash flow profile of the ATRR. An "investment grade" credit profile will allow MAOD to raise debt to build the Project at an attractive, low cost of debt.

Based on discussions with CACIB, MAOD envisions financing the Project in a manner that minimizes the total financing costs of the Project. The finance plan is a traditional two-stage financing process, where a construction loan is put in place to finance the Project during construction, and then once the Project is placed in service, long-term financing will be issued to refinance the construction debt.

The construction loan is expected to be provided by commercial banks, who are familiar with financing construction projects. During the construction period, waivers and amendments to the financing documents may be required. For example, an amendment to the construction loan credit agreement may be required based on a post-financial close change in the construction schedule. Typically, commercial banks are more flexible, and able to respond faster, to these waiver and amendment requests than institutional investors, which makes construction loans an attractive financing vehicle. Additionally, construction loans are typically structured to allow for more frequent draw-downs to fund project costs based on the construction schedule, relative to institutional debt which is typically fully funded at the issuance date. The tailored draw-down schedule available under construction loans minimizes the interest expense during construction and reduces overall project costs, which should offset any additional financing costs incurred as a result of a subsequent refinancing of the construction loan.

Construction loans in the U.S. market are typically issued for a maximum of seven to ten years, although the underlying amortization profile assumes a longer repayment period (in the case of MAOD, a thirty-year amortization period). Therefore, once the Project is placed in service, MAOD plans to refinance the construction loan with a term loan or with a U.S. Private Placement ("USPP") bond. Both the U.S. project finance loan market (term loan market) and the U.S. institutional market are familiar with single-asset utility financings. Therefore, MAOD will have the ability (and the flexibility) to evaluate both markets at the time of refinancing in order to select the most efficient source of capital.

VIII. SUPPORT FOR THE RECOMMENDED COST OF DEBT AND EQUITY

Q43. WHAT COST OF DEBT IS MAOD REQUESTING IN ITS FORMULA RATE?

A43. For the period before MAOD's construction loan financing (the "Construction Debt") is obtained, the estimated interest cost (the "Proxy Debt Rate") is shown on Attachment 9 to the Formula Rate Template. This rate reflects the assumption that the initial debt will be priced at the three-month Term Secured Overnight Financing Rate ("SOFR") plus 200 basis points. This assumption is based on guidance from CACIB. In developing the Proxy Debt

Rate, CACIB reviewed recent, comparable project finance transactions in the utility, transmission, and power sectors, with comparable risk profiles, to best approximate the cost of debt that commercial banks would require if lending to the Project today. The estimated credit spread of 200 basis points is based on the expectation that MAOD will not have a credit rating when it secures its initial construction financing for the Project. However, CACIB concluded that MAOD's expected financing structure is in line with commercial bank expectations to finance the construction of a single-asset, rate-regulated transmission project. The Proxy Debt Rate will be used in the Formula Rate until the Construction Debt is placed, at which point the actual cost of the Construction Debt financing will be reflected in the Formula Rate. At or near the time of COD, MAOD expects to refinance the construction loan with longer-term debt financing, which would then be reflected as the actual cost of debt in the Formula Rate Template.

Q44. WHAT COST OF EQUITY IS MAOD REQUESTING IN ITS FORMULA RATES?

A44. As discussed in the Nowak Testimony, MAOD is requesting Commission authorization to use a base ROE of 10.26%. As discussed above, and consistent with the Incentives Order, MAOD also is requesting a 50 basis point RTO membership adder given MAOD's membership in PJM. MAOD thus is requesting a total ROE of 10.76% in its Formula Rate, which, as Mr. Nowak explains, is within the range of reasonableness and consistent with Commission policy.

Q45. WHY IS IT IMPORTANT THAT MAOD BE GRANTED THE REQUESTED ROE?

A45. The requested ROE represents the return that is commensurate with the risk that MAOD's equity investors bear. Without an adequate return, it will be challenging for MAOD to attract the equity capital that will be required to build, own, and maintain regionally planned transmission projects like the Project. MAOD is a joint venture between EDFR and Shell New Energies and competes with other projects held by EDFR and Shell New Energies to attract capital. Further, EDFR and Shell New Energies compete for capital with other entities in the broader capital market, including the rate-regulated utilities included in Mr. Nowak's proxy group. While MAOD is targeting a credit profile that will support an investment grade credit rating, it is a non-incumbent transmission company that does not have a financial history, nor does it currently have transmission assets that are producing a revenue stream. As discussed above, MAOD is in the process of developing and constructing the Project, which requires its lenders and investors to accept a higher level of development and construction risk than is typical of the proxy group. Therefore, it is critical to provide MAOD with an ROE that adequately addresses these risks and provides MAOD with the ability to attract and retain equity capital.

IX. ORDER NO. 679 TRANSMISSION RATE INCENTIVES

Q46. HAS THE COMMISSION GRANTED RATE INCENTIVES TO MAOD FOR THE PROJECT?

A46. Yes. In the Incentives Order, the Commission granted MAOD the following Order No. 679 incentives for the Project: (i) Regulatory Asset Incentive; (ii) Abandoned Plant Incentive; (iii) Hypothetical Capital Structure Incentive; and (iv) RTO Participation Incentive.[92] The Incentives Order was based on MAOD's Petition for Declaratory Order filed on September

[92] *See* Incentives Order, at PP 1-2, 34-48.

21, 2023, in Docket No. EL23-101-000, as supplemented on November 22, 2023 (the "MAOD PDO").[93]

Q47. DOES MAOD REQUEST APPLICATION OF THE SAME FOUR INCENTIVES TO THE INTERCONNECTION WORK?

A47. Yes. MAOD expects that the Project will evolve as the NJBPU's offshore wind plans evolve and the NJBPU contemplates further revisions to the Larrabee Tri-Collector Solution. The NJBPU's decision to grant the Interconnection Work to MAOD is such an example.

The Interconnection Work was approved by the NJBPU in the June 29, 2023 Order but was not approved by the PJM Board for inclusion into the RTEP until February 28, 2024,[94] which was after the MAOD PDO was filed with the Commission. However, the Interconnection Work should receive the same incentive treatment as that granted in the Incentives Order. Like the rest of the Project, the Interconnection Work was approved under the process used by the NJBPU and PJM pursuant to the PJM RTEP, SAA Study Agreement and Amended SAA Agreement.[95] Indeed, as a reflection of its integration into the larger project, PJM included the Interconnection Work as part of RTEP Project b3737.22 when approving the Interconnection Work as part of the RTEP. Therefore, the Interconnection Work qualifies for the "rebuttable presumption" under Order No. 679.[96]

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[93] *See Mid-Atlantic Offshore Development, LLC,* "Petition for Declaratory Order," Docket No. EL23-101-000 (filed Sep. 21, 2023; supplemented Nov. 22, 2023) ("MAOD PDO").

[94] *See* Exhibit No. MOAD-PJM February 2024 White Paper, at 8, 11; *see also* Exhibit No. MAOD-14, PJM March 12, 2024, Letter, at 1, Att. B (stating that the PJM Board of Managers approved as part of the PJM RTEP change in scope of MAOD Project b3737.22 to include the Interconnection Work).

[95] *See id. See also* Exhibit No. MAOD-10, June 29, 2023, NJBPU Order.

[96] *See* Incentives Order, at PP 23-24.

Moreover, from my understanding, the Commission has explained that an applicant seeking rate incentives must demonstrate a "nexus" between the incentives requested and the proposed investment, including showing that the requested incentives address project-specific risks and challenges.[97] The nexus test is met when an applicant demonstrates that the total package of incentives requested are "tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project."[98]

In this case, as recognized in the Incentives Order, the incentives that have been granted to the Project, particularly the Regulatory Asset Incentive and the Hypothetical Capital Structure Incentive, are meant to mitigate MAOD's development risk as a non-incumbent transmission developer developing its first transmission project.[99] The total package of incentives, as a whole, were (and remain) tailored to address the well-established risks the Commission has recognized are associated with transmission development (including, in this case, as part of the SAA Process). These risks apply equally to the Interconnection Work because these facilities are integrated parts of the Project. Therefore, for all of the reasons set forth in the MAOD's PDO for the larger project and recognized in the Incentives Order,[100] a nexus exists between requested incentives and the risks and challenges of the Interconnection Work.

[97] Order No. 679-A, at P 27. *See also* 18 C.F.R. § 35.35(d) (2024) ("The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that the *total* package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that resulting rates are just and reasonable."). *See* MAOD PDO, at 25, 29-40; Incentives Order, at PP 49-50.

[98] 18 C.F.R. § 35.35(d); *San Diego Gas & Elec. Co. v. FERC,* 913 F.3d 127, 133 (D.C. Cir. 2019); *Ameren Servs. Co.,* 135 FERC ¶ 61,142, P 35 (2011) (quoting Order No. 679-A, at P 40).

[99] *See* Incentives Order, at PP 36, 46.

[100] *See* Incentives Order, at PP 49-50.

MAOD understands that the Commission's grant of incentives is flexible and accommodates changes in project scope that do not alter the basis of the Commission's grant of incentives. As explained above, the Interconnection Work is integrated into the Project. Out of an abundance of caution, however, MAOD is seeking express Commission confirmation of the extension of its requested incentives to the Interconnection Work.

Regulatory Asset Incentive

Q48. WHAT IS THE BASIS FOR MAOD'S REQUEST FOR THE APPLICATION OF THE REGULATORY ASSET INCENTIVE TO THE INTERCONNECTION WORK?

A48. As recognized in the Incentives Order,[101] the Regulatory Asset Incentive will allow MAOD to mitigate the pre-commercial operation risks of financing, developing, and constructing the Project. Specifically, MAOD faces considerable challenges in developing the Project, particularly as a non-incumbent transmission developer, for which the Project represents a significant investment of both human resources and funds. When developing the Project, MAOD expended (and will continue to expend) pre-commercial costs for items such as complicated design and engineering plans, cost estimates, identification of development challenges, and other items. All of these development challenges and costs apply equally to the Interconnection Work.

Because the Project is MAOD's first transmission project, MAOD does not have facilities in operation, is not yet charging rates under a tariff, and thus, cannot expense these costs as a current expense and recover them through existing rates. Assuming these costs meet the regulatory thresholds for reasonableness and prudency (which will be determined

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[101] *See* Incentives Order, at PP 36-37.

in a subsequent FPA section 205 proceeding), the Regulatory Asset Incentive allows MAOD to mitigate the risks related to these costs and provides certainty that they can be recovered once MAOD's rates are initiated.[102]

The ability to book the pre-commercial costs described above into a Regulatory Asset prior to MAOD's ATRR being filed and allocated under the PJM Tariff will provide up-front regulatory certainty, improve coverage ratios used by lenders and rating agencies to determine credit quality, and reduce interest expense.[103] Because this mitigation of risks will beneficially impact MAOD's credit risk for potential financing entities, the Regulatory Asset Incentive will benefit ratepayers.[104]

Consistent with the justification of the Regulatory Asset Incentive to the overall Project, MAOD is requesting that the Commission confirm that MAOD's Regulatory Asset Incentive applies to the Interconnection Work. As with the Project overall, MAOD seeks authorization to amortize Interconnection Work-related costs in its regulatory asset over five years, beginning when the Project becomes operational and costs are assessed to customers. Additionally, as with the Project overall, MAOD requests permission to accrue carrying charges on the regulatory asset balances beginning on the effective date of Commission

[102] *See, e.g., LS Power Grid Cal., LLC,* 171 FERC ¶ 61,222, PP 21-23 (2020); *DCR Transmission LLC,* 153 FERC ¶ 61,295, P 35 (2015); *RITELine Ill., LLC, et al.,* 137 FERC ¶ 61,039, P 96 (2011) (citing *Green Power Express LP,* 127 FERC ¶ 61,031, P 60 (2009); *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281, P 84 (2009)).

[103] *See Promoting Transmission Investments Through Pricing Reform,* 141 FERC ¶ 61,129, P 13 (2012) ("2012 Policy Statement") ; *DCR Transmission LLC,* 153 FERC ¶ 61,295, at P 35; *RITELine Ill., LLC, et al.,* 137 FERC ¶ 61,039, at P 96 (citing *Green Power Express,* 127 FERC ¶ 61,031, at P 60; *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281, at P 84).

[104] *See RITELine Ill., LLC, et al.,* 137 FERC ¶ 61,039, at P 96 (citing *Green Power Express,* 127 FERC ¶ 61,031, at P 60; *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281, at P 84).

approval of the Regulatory Asset Incentive until the regulatory assets are included in rate base.

<u>Abandoned Plant Incentive</u>

Q49. WHAT IS THE BASIS FOR MAOD'S REQUEST FOR THE APPLICATION OF THE ABANDONED PLANT INCENTIVE TO THE INTERCONNECTION WORK?

A49. The Interconnection Work faces the same regulatory, permitting, and project on project risks (as well as political risks) as the overall Project and therefore should be subject to the Abandoned Plant Incentive granted in the Incentives Order.[105]

As explained in the MAOD PDO, numerous New Jersey state and local (Township of Howell, New Jersey) permits are required for the Project. These state and local permits are as set forth below in Table 1:[106]

[105] *See* Incentives Order, at PP 39-43.

[106] *See* MAOD PDO, at 31-33.

Table 1 **Potential Permit / Authorization Requirements for Parcel Site Development**	
Potential Permit / Authorization	Agency
Freshwater Wetlands Individual Permit*	New Jersey Department of Environmental Protection (NJDEP) Division of Land Resource Protection
Flood Hazard Area Individual Permit*	NJDEP Division of Land Resource Protection
Water Quality Certificate*	NJDEP Division of Land Resource Protection
NJPDES 5G3 Stormwater General Construction Permit	NJDEP Division of Water Quality, Bureau of Stormwater Permitting
NJDEP Water Use / Temporary Dewatering Permit	NJDEP Division of Water Supply & Geoscience
Soil Erosion and Sediment Control Plan Permit	New Jersey Natural Resources Conservation Program, Freehold Soil Conservation District
Howell Township Major Site Plan Approval	Township of Howell, Department of Community Development & Land Use
Howell Township Tree Removal Permit	Township of Howell, Department of Community Development & Land Use

*These permits would only be required if freshwater wetlands and/or flood plains are impacted as a result of the parcel site development.

Furthermore, as part of the Larrabee Tri-Collector Solution and New Jersey's overall PJM SAA Process to facilitate the reliable and cost-effective interconnection of New Jersey's offshore wind generation facilities, the Project is one of an aggregate compilation of approximately $1 billion of transmission facilities that are being developed contemporaneously to advance New Jersey's goals for advancement of offshore wind generation.[107] These projects include the SAA transmission projects awarded by the NJBPU to a total of seven other awardees[108] (exclusive of MAOD), as well as the wind generation projects that are being developed offshore.

MAOD is confident that the Project can and will be constructed; however, given the broad and varied scope of potentially related transmission facility upgrades, there are significant risks and challenges outside of the scope of MAOD's Project and outside of MAOD's control. In addition to political risks (discussed below), the Project has "project-on-project" risks as part of the aggregate set of transmission facilities comprising the Larrabee Tri-Collector Solution. In particular, as I stated above, the Project will interconnect to the PJM transmission system through interconnections with three JCP&L substations; therefore, the Project may be impacted by risks associated with JCP&L's projects that are outside of MAOD's control.[109] As recognized by the Commission when granting the Abandoned Plant Incentive to JCP&L and other parties building facilities as part of the

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[107] *See* Exhibit No. MAOD-3, October 26, 2022, NJBPU Order, at 61 (stating that the total cost for onshore upgrades for the full Larrabee Tri-Collector Solution is $1.08 billion); *see also* MAOD PDO, at 2-3, n.8 (summarizing the various entities involved in constructing other elements of the Larrabee Tri-Collector Solution).

[108] As stated above the other companies, in addition to MAOD and JCP&L, selected by the NJBPU to construct various onshore upgrades as part of the Larrabee Tri-Collector Solution are Atlantic City Electric Company, Baltimore Gas and Electric Company, LS Power Grid Mid-Atlantic, LLC, PECO Energy Company, Public Service Electric & Gas Company, and Transource Energy, LLC.

[109] As stated above, the Project will interconnect to the PJM transmission system through three existing JCP&L substations: (1) the Smithburg 500 kV substation in Freehold Township, Monmouth County, New Jersey; (2) the JCP&L Larrabee Substation; and (3) the Atlantic 230 KV substation in Colts Neck Township, Monmouth County, New Jersey. Risks impacting these JCP&L projects are beyond MAOD's control but may impact the Project. *See* Exhibit No. MAOD-5, PJM 2022 RTEP Report, at 66-75. *See Jersey Cent. Power & Light Co.,* 184 FERC ¶ 61,108, P 40 (2023) (granting JCP&L the Abandoned Plant Incentive based on JCP&L's description of its regulatory and permitting risks, including the risks resulting from participation in the NJBPU SAA Process); *see also Transource Pa., LLC,* 184 FERC ¶ 61,091, P 45 (2023) ("Transource notes that the Project is part of the first set of transmission projects ever pursued under the PJM State Agreement Approach. As such, . . . there remains regulatory risk at the federal level that the Project could be canceled or not constructed for reasons beyond its control.").

Larrabee Tri-Collector Solution, these risks and challenges include permitting and regulatory risks.[110]

Further, New Jersey's commitment to offshore wind generation and the different SAA projects being developed to facilitate interconnection of such wind generation projects could change with political executive leadership (or legislative level leadership) in New Jersey. This potentially could result in an alteration or cancellation of the Project.

As recognized in the Incentives Order, the Abandoned Plant Incentive will provide assurances to financing entities that they can be repaid if the Project is abandoned for reasons outside of MAOD's control, and will support not only financing entities' willingness to commit funds, but also their ability to offer beneficial financing terms, which will benefit ratepayers.

Existing environmental, regulatory, and project-on-project risks are beyond MAOD's control and could lead to the abandonment of the Project. All of these risks apply equally to the Interconnection Work because it is integrated into the Project. From my understanding, MAOD's request for the Abandoned Plant Incentive for the Project (and, per this filing, as extended to the Interconnection Work) is consistent with recent Commission precedent granting the Abandoned Plant Incentive to other parties building facilities as part of the Larrabee Tri-Collector Solution.[111] Therefore, consistent with the justification of the

[110] *See, e.g.*, *Jersey Cent. Power & Light Co.,* 184 FERC ¶ 61,108, at P 40; *Silver Run Elec., LLC,* 184 FERC ¶ 61,092, P 30 (2023); *Transource Pa., LLC,* 184 FERC ¶ 61,091, at P 51.

[111] In addition to the Incentives Order (at PP 39-43), the Commission granted the Abandoned Plant Incentive, individually, to three other entities chosen by the NJBPU to construct other transmission facilities as part of the Larrabee Tri-Collector Solution based on its analysis of the regulatory and permitting risks faced by those projects. *See Transource Pa., LLC,* 184 FERC ¶ 61,091, at P 51; *Silver Run Elec., LLC,* 184 FERC ¶ 61,092, at P 30; *Jersey Cent. Power & Light Co.,* 184 FERC ¶ 61,108, at PP 2, 40.

Abandoned Plant Incentive overall, MAOD requests the Commission expressly confirm that its Abandoned Plant Incentive extends to costs associated with the Interconnection Work to offset its development risks.

<u>Hypothetical Capital Structure Incentive</u>

Q50. WHAT IS THE BASIS FOR THE REQUEST FOR THE APPLICATION OF THE HYPOTHETICAL CAPITAL STRUCTURE INCENTIVE TO THE INTERCONNECTION WORK?

A50. As recognized in the Incentives Order, the Hypothetical Capital Structure Incentive allows MAOD to mitigate financing risks for the Project resulting from its status as a non-incumbent transmission provider that does not yet have the established capital structure of an incumbent utility.[112] As part of the Project as a whole, the Interconnection Work faces this same risk.

As explained in the MAOD PDO, MAOD faces risks in developing the Project as a non-incumbent transmission provider without a business history or debt repayment history, including the financial challenges faced by the Project. For example, MAOD's capital structure will fluctuate as the Project is developed and debt financing is initially obtained, and then incrementally increased over the course of development and construction. To mitigate the financing risks associated with a fluctuating capital structure and, in turn, enhance MAOD's creditworthiness for potential investors, MAOD requested the Hypothetical Capital Structure Incentive with the objective to secure improved financing terms and benefit ratepayers.[113] The Commission has explained that a

[112] *See* Incentives Order, at PP 44-46.

[113] *See id.* at PP 44-45. *See, e.g., LS Power Grid Cal., LLC*, 171 FERC ¶ 61,222, at PP 29-30; *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, P 68 (2008), *reh'g denied*, 150 FERC ¶ 61,224 (2015); *Potomac-Appalachian Transmission*

hypothetical capital structure "can be an effective tool available to public utilities to foster transmission investment in appropriate circumstances."[114] The Commission has allowed hypothetical capital structures for transmission developers to facilitate "improved access to capital markets for transmission investment and . . . its use for specific projects when shown to be necessary for project financing, among other things."[115]

MAOD will require significant borrowings, as well as equity capital contributions, as development and construction of the Project progresses. MAOD's precise debt-to-equity ratio during the construction period consequently will fluctuate as new borrowings are made and equity is invested, and will also be affected by negotiations with lenders. The hypothetical capital structure provides assurance to potential investors, helping with the challenge of raising capital during the development process when actual capital structures can fluctuate.

Therefore, consistent with the justification of the Hypothetical Capital Structure Incentive for the Project overall, MAOD requests the Commission expressly confirm that its hypothetical capital structure of 50 percent debt and 50 percent equity extends to costs associated with the Interconnection Work to offset its development risks. MAOD only

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Highline, L.L.C., 122 FERC ¶ 61,188, P 55 (2008), *order on reh'g and settlement agreement*, 133 FERC ¶ 61,152 (2010) ("*PATH*").

[114] Order No. 679, at P 131; *see* Order No. 679-A, at P 93; *see also* 18 C.F.R. § 35.35(d)(1)(iv).

[115] Order No. 679, at P 131 (footnote omitted); *see also Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, at P 68 (the Commission explained that use of a stable debt-to-equity ratio for ratemaking purposes during construction provides certainty and improves access to capital); *PATH*, 122 FERC ¶ 61,188, at P 55 (the Commission explained that the use of a hypothetical capital structure during construction "will result in lower debt costs for the company, while also permitting it to vary its financing vehicles to the needs of the construction process, including such issues as timing of expenditures, regulatory developments, and changes in financial market conditions."); *PATH*, 122 FERC ¶ 61,188, at P 55 (citing *Trans-Allegheny Interstate Line Co.,* 119 FERC ¶ 61,219, PP 74-76 (2007) (The Commission also found the hypothetical capital structure approach during the construction period is a "pragmatic approach to address . . . fluctuating capital structure" at the outset of a project's development)).

seeks the Hypothetical Capital Structure Incentive through the Project's development and construction phases, and not beyond the Project's commercial operation date. MAOD's requested 50 percent debt and 50 percent equity hypothetical capital structure should allow MAOD to achieve reasonable costs of capital, which will inure to the benefit of PJM customers in New Jersey who will pay the cost of service in their utility rates. From my understanding, the requested hypothetical capital structure is also consistent with those allowed by the Commission for other transmission development projects.[116]

RTO Participation Incentive

Q51. WHAT IS THE BASIS FOR THE REQUEST FOR THE APPLICATION OF THE RTO PARTICIPATION INCENTIVE TO THE INTERCONNECTION WORK?

A51. In Order No. 679, the Commission determined that it will approve return on equity ("ROE") incentives "for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization."[117] The Commission has explained that this RTO Participation Incentive provides an important incentive for newly established transmission developers to participate in an RTO[118] and that the RTO Participation Incentive recognizes the benefits that flow from RTO membership, including

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[116] *See MidAmerican Cent. Cal. Transco, LLC*, 147 FERC ¶ 61,179, P 6 (2014) (52% equity and 48% debt); *Xcel Energy Sw. Transmission Co., LLC*, 149 FERC ¶ 61,182, P 5 (2014); *Xcel Energy Transmission Dev. Co., LLC*, 149 FERC ¶ 61,181, P 5 (2014) (55% equity and 45% debt); *Midwest Indep. Transmission Sys. Operator, Inc*., 141 FERC ¶ 61,121, P 51 (2012) (56% equity and 44% debt); *Transource Mo., LLC*, 141 FERC ¶ 61,075, P 66 (2012) (60% equity and 40% debt); *Green Power Express LP,* 127 FERC ¶ 61,031, at P 72 (60% equity and 40% debt); *Primary Power, LLC*, 131 FERC ¶ 61,015, P 141 (2010) (60% equity and 40% debt); *Atl. Grid Operations A LLC, et al.,* 135 FERC ¶ 61,144, P 121 (2011) (60% equity and 40% debt). *Compare Midcontinent Indep. Sys. Operator, Inc.*, 182 FERC ¶ 61,039, PP 21, 25 (2023) (50% equity and 50% debt); *PJM Interconnection, LLC and Ne. Transmission Dev., L.L.C*., 155 FERC ¶ 61,097, PP 50-52 (2016), *order on reh'g*, 158 FERC ¶ 61,060, P 4 (2017) (50% equity and 50% debt); *DCR Transmission, L.L.C*., 153 FERC ¶ 61,295, at P 45 (50% equity and 50% debt)).

[117] Order No. 679, at P 326; Order No. 679-A, at P 86; 18 C.F.R. § 35.35(e).

[118] *See, e.g., Midcontinent Indep. Sys. Operator, Inc.,* 150 FERC ¶ 61,004, P 42 (2015).

that RTOs "provide a platform for regional planning and cost allocation associated with transmission expansion and planning…."[119] The Commission has determined that the "basis for the incentive is a recognition of the benefits that flow from membership in such organizations, and the fact that continuing membership is generally voluntary."[120]

As recognized in the Incentives Order, MAOD will become a Transmission Owner member of PJM, and transfer operational control of the Project to PJM once it is constructed and placed into service.[121] The Interconnection Work is included in the Project that will be turned over to PJM's operational control. Therefore, while the RTO Participation Incentive applies to MAOD's ROE and the ROE applies to all of MAOD's facilities, MAOD nevertheless requests that the Commission confirm that the RTO Participation Incentive also applies to the costs associated with the Interconnection Work.[122]

Q52. IS THE TOTAL PACKAGE OF INCENTIVES NARROWLY TAILORED TO MITIGATE THE RISKS FACED BY THE PROJECT, INCLUDING THE INTERCONNECTION WORK?

A52. Yes. In line with the Commission's determination in the Incentives Order,[123] MAOD's requested incentives for the Project, to now expressly include the Interconnection Work, are narrowly tailored to best mitigate the immediate and future risks faced by the Project as a whole. Each requested incentive uniquely mitigates a particular risk (or set of risks)

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[119] Order No. 679-A, at P 87.

[120] Order No. 679, at P 331.

[121] *See* Incentives Order, at PP 47-48.

[122] *See* Order No. 679, at PP 326-27; Order No. 679-A, at P 86; *see also* 18 C.F.R. § 35.35(e).

[123] *See* Incentives Order, at PP 49-50.

faced by the Project, while the total package provides a balance between risk mitigation and ratepayer interests.

Given MAOD's status as a new transmission developer, the requested Regulatory Asset Incentive will mitigate the risk associated with recovery of pre-commercial costs, subject to future regulatory review in a FPA section 205 proceeding for reasonableness and prudency. In addition to up-front regulatory certainty, this incentive can provide financing benefits, including reduced interest expense and improved coverage ratios.

The Commission has stated that the Hypothetical Capital Structure Incentive mitigates risks associated with a fluctuating capital structure during development and construction of transmission facilities and supports beneficial project financing (which ultimately inures to the benefit of ratepayers).[124] This incentive will improve MAOD's access to capital markets and help mitigate the uncertainties that potential financing entities will consider in their financing decisions, improving the terms of financing offered. This incentive is especially helpful in the case of new transmission developers, such as MAOD, that are seeking project financing for their first transmission project. As explained above, the capital structures for MAOD, like other similarly situated entities, will fluctuate over the various stages of development, and establishing a hypothetical capital structure through a rate incentive provides financing benefits that ultimately benefit consumers.

The Commission has recognized that the Abandoned Plant Incentive addresses project-specific risks that could lead to abandonment of the project for reasons outside the control of the transmission developer, particularly regulatory and permitting risks. The

[124] Order No. 679, at P 131.

Project, including the Interconnection Work, has many and varied regulatory and permitting risks, as well as the additional risks – specifically, project-on-project and policy risks – resulting from the Project's status as one of many SAA Process-awarded transmission projects being contemporaneously developed as part of the Larrabee Tri-Collector Solution. Because the Abandoned Plant Incentive is intended to mitigate the risk of abandonment of the Project, including the Interconnection Work, inclusive of mitigating regulatory and permitting risks, the Abandoned Plant Incentive also provides a unique risk mitigation in comparison with other incentives sought by MAOD.

Finally, the Commission has explained that the RTO Participation Incentive recognizes the benefits that flow from RTO membership, including benefits resulting from regional transmission planning and cost allocation.[125] This includes the transmission planning efficiencies that result from increased participation in PJM.[126] For the reasons stated above, the total package of incentives applied to the Project, as it now includes the Interconnection Work, are narrowly tailored to mitigate the Project's risks.

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[125] *See* Order No. 679, at P 331; Order No. 679-A, at P 86.

[126] *See, e.g., NextEra Energy Transmission Sw., LLC*, 178 FERC ¶ 61,082, P 19 (2022) (in granting Abandoned Plant Incentive, FERC stated: "we find that the total package of incentives, including the previously granted incentives [which were Regulatory Asset Incentive, Hypothetical Capital Structure Incentive, and RTO Participation Incentive], is reasonable, because it addresses the risks and challenges associating [sic] with development of the Project" (footnote omitted)); *NextEra Energy Transmission Sw., LLC*, 161 FERC ¶ 61,139, PP 30, 35, 41 (2017) (granting of the Regulatory Asset Incentive, Hypothetical Capital Structure Incentive and RTO Adder incentive facilitates competition and participation of non-incumbent transmission developers); *DCR Transmission, LLC*, 153 FERC ¶ 61,295, at PP 11, 16, 29 (finding that DCR Transmission demonstrated that "its total package of requested incentives [consisting of the Regulatory Asset Incentive, Hypothetical Capital Structure, RTO Adder and Abandoned Plant was] tailored to address the demonstrable risks or challenges faced by DCR Transmission, including construction, regulatory, and financial challenges arising during the pre-construction and construction phases of the Delaney Project").

Q53. DOES MAOD REQUEST THAT ITS TRANSMISSION INCENTIVES APPROVED BY FERC IN THE INCENTIVES ORDER SHOULD CONTINUE TO APPLY AS THE PROJECT EVOLVES?

A53. Yes. MAOD requests that the Commission confirm that all of the transmission incentives already approved for the Project will apply to NJBPU-approved and RTEP-approved changes in scope for the Project on a going forward basis, provided the changes do not materially change the facts upon which the order granting incentives was based. MAOD recognizes, however, that certain changes of scope may alter the basis of the Commission's grant of incentives to the Project. In that case, MAOD would make a filing with the Commission seeking additional incentive treatment.

X. CONCLUSION

Q54. DOES THIS CONCLUDE YOUR TESTIMONY?

A54. Yes.

Exhibit No. MAOD-1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)	
	)	**Docket No. ER24-___-000**
	)	

VERIFICATION

I, Christopher Sternhagen, declare that I am the author of the foregoing testimony, that the facts set forth herein are true and correct to the best of my knowledge, information, and belief, and that if asked the same questions contained therein, my answers would be the same.

Christopher Sternhagen

Dated: 7/18/2024

Subscribed and sworn to before me, a Notary Public, this 18th day of July, 2024.

Notary

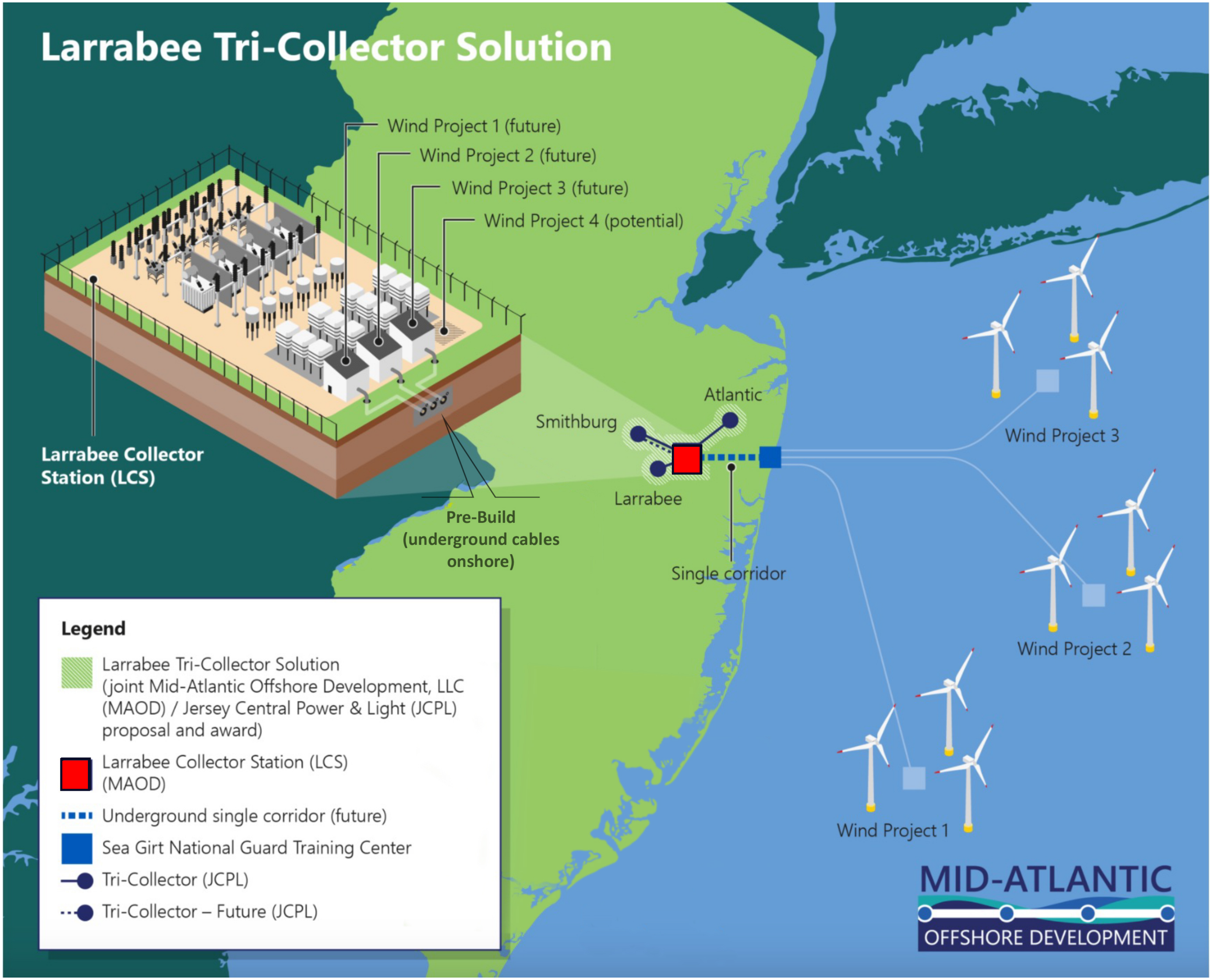
My commission expires: 5/28/2028

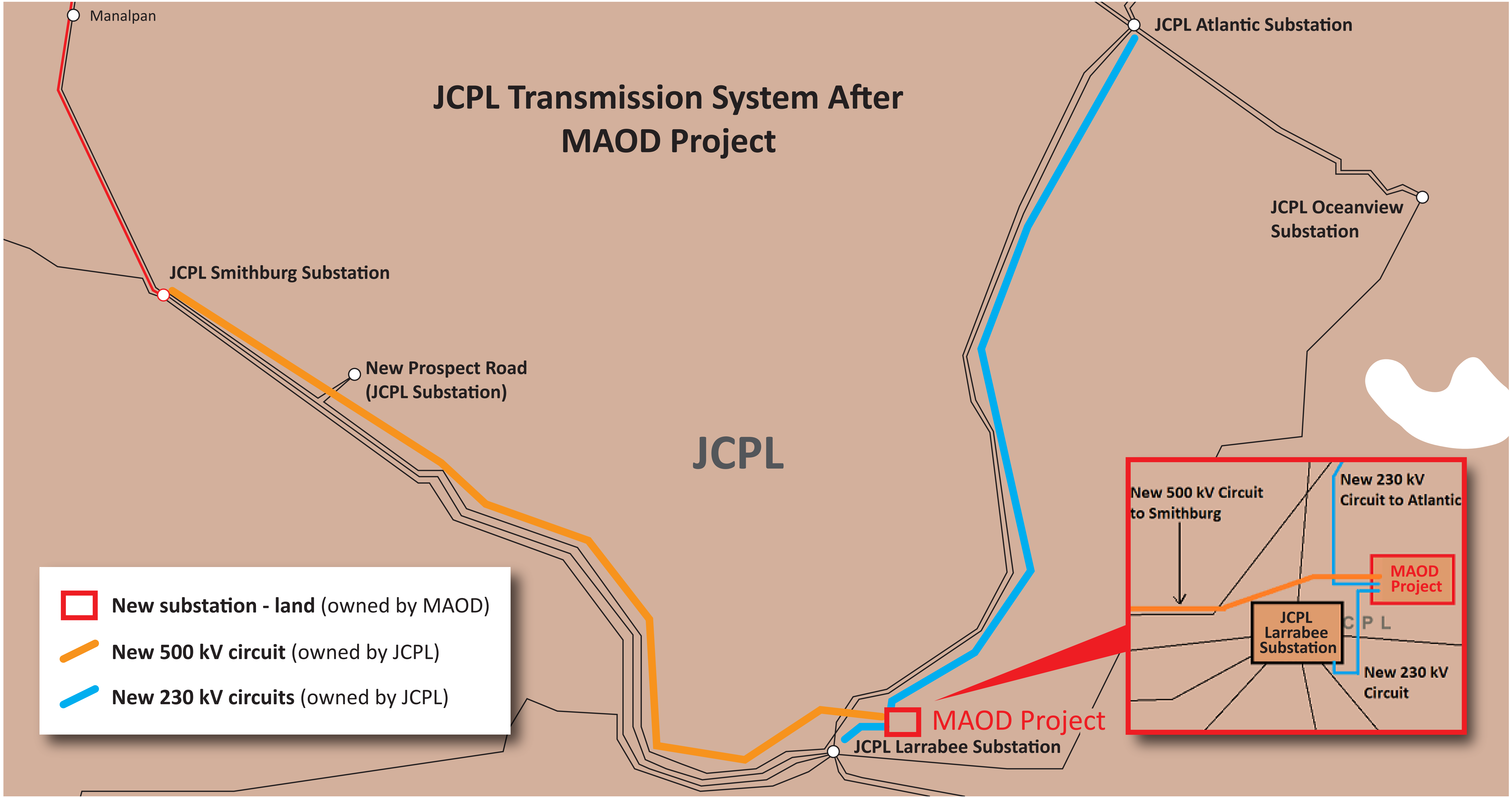
NOTARY PUBLIC STATE OF TEXAS
CATHERINE SPENCE
Notary ID #4231566
My Commission Expires
May 28, 2028

CUI//PUBLIC
CRITICAL ENERGY/ELECTRIC INFRASTRUCTURE INFORMATION REMOVED

Exhibit No. MAOD-2
Mid-Atlantic Offshore Development, LLC Maps

New Jersey Offshore Wind Transmission Solution: Larrabee Tri-Collector Solution





JCPL Transmission System After
MAOD Project
Manalpan
JCPL Atlantic Substation
JCPL Oceanview
Substation
JCPL Smithburg Substation
New Prospect Road
(JCPL Substation)
JCPL
New 500 kV Circuit
to Smithburg
New 230 kV
Circuit to Atlantic
MAOD
Project
JCPL
Larrabee
Substation
C P L
New 230 kV
Circuit
MAOD Project
JCPL Larrabee Substation
New substation - land (owned by MAOD)
New 500 kV circuit (owned by JCPL)
New 230 kV circuits (owned by JCPL)

CUI//CEII NON-PUBLIC INFORMATION REMOVED

Exhibit No. MAOD-3
Mid-Atlantic Offshore Development, LLC
October 26, 2022, NJBPU Order

Agenda Date: 10/26/2022
Agenda Item: 8A

STATE OF NEW JERSEY

Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY	)))))	ORDER ON THE STATE AGREEMENT APPROACH SAA PROPOSALS DOCKET NO. QO20100630

Parties of Record:
Brian O. Lipman, Esq., Director, New Jersey Division of Rate Counsel
Suzanne Glatz, PJM Interconnection LLC
Stephen Tutor, Jersey Central Power & Light Company
Michael Donnelly, Atlantic City Electric Company
Matthew Virant, Mid-Atlantic Offshore Development, LLC
Eric Hayes, LS Power Grid Mid-Atlantic, LLC
Shadab Ali, PPL Electric Utilities
Jodi Moskowitz, Public Service Electric and Gas Company,
Maria J. Malguarnera, Transource Energy, LLC

New Jersey took a monumental step on November 18, 2020, becoming the first state to integrate its offshore wind ("OSW") transmission objectives with the regional grid's planning and development process. To position the State to reach Governor Phil Murphy's ambitious OSW goals, the New Jersey Board of Public Utilities ("Board") formally requested inclusion of its OSW public policy into PJM's regional transmission expansion analysis through the State Agreement Approach ("SAA"). In response to the SAA solicitation, transmission developers submitted 80 unique, competitive, ready-to-build designs seeking to integrate New Jersey's OSW resources into the PJM system.

By this Order, the Board awards a series of projects to construct the on-shore transmission facilities necessary to successfully deliver offshore wind to New Jersey customers. The awards include a variety of projects needed to strengthen the regional and near-shore transmission grids, including the identification of a preferred point of interconnection ("POI") for future offshore wind projects off the coast of New Jersey. The Board finds that this "transmission-first" approach to offshore wind, undertaken in partnership with its regional grid operator, PJM Interconnection LLC ("PJM"), will lower costs, reduce the chance of delays in offshore wind projects, and minimize community and environmental impacts.

The Board selects Mid-Atlantic Offshore Development, LLC's ("MAOD") and Jersey Central Power & Light Company's ("JCP&L") jointly submitted Larrabee Tri-Collector Solution[1] ("Larrabee Tri-Collector Solution") for New Jersey's inaugural OSW coordinated transmission solution under PJM's SAA. In addition, the Board selects a number of projects that will upgrade the PJM system to accommodate New Jersey's OSW goals. After a thorough evaluation, the Larrabee Tri-Collector Solution and upgrades to the larger PJM transmission grid were determined to best meet New Jersey's stated SAA goals of reducing community disruption, environmental impacts, and customer costs, while minimizing risks. Ultimately, the Larrabee Tri-Collector Solution results in an innovative transmission solution, creating a single onshore POI while leveraging existing rights of ways, an outcome that would not have been possible without coordinated planning and a competitive solicitation.

The savings New Jersey ratepayers realize from the selection of these transmission projects are estimated to be over $900 million. In addition, the scope of the Larrabee Tri-Collector Solution was tailored to maximize federal tax incentives moving forward, preserving an additional $2.2 billion of ratepayer benefits. The awarded projects also position the State to seek direct federal funding for future expansions of the OSW transmission grid, including the potential to award a full OSW backbone in connection with the Board's future OSW solicitations, and preserves preferable interconnection locations and transmission corridors for future use.

The Board and its Staff ("Staff") will continue their efforts to ensure OSW energy can be brought to New Jersey customers as cost efficiently as possible, while reducing environmental and community impacts and maintaining safe and reliable electric service. First, this Order authorizes Staff to incorporate and, if appropriate, require, in the Board's next OSW generation solicitation, any additional facilities required to enable coordinated and impact-reducing access to the Larrabee Tri-Collector Solution. Second, the Board directs Staff to begin a second round of coordinated transmission planning to meet the newly announced 11,000 megawatts ("MW") OSW target, potentially including a new SAA solicitation to ensure that both the onshore and offshore transmission systems are ready to meet the full scope of New Jersey's OSW objectives. Combined with today's award, this Order marks the continued efforts of New Jersey that lead the nation in OSW development and comes on the heels of Governor Murphy's recent announcement to increase the State's OSW goal to 11,000 MW of OSW energy generation by 2040.

[1] For an in-depth discussion of MAOD and JCP&L's jointly submitted Larrabee Tri-Collector Solution, <u>see infra</u>, "Recommended SAA Solution: Larrabee Tri-Collector Solution."

Table of Contents:

Select Terms & Acronyms

Atlantic Shores Offshore Wind Project 1, LLC ("Atlantic Shores 1" or "ASOW 1"), a joint venture between EDF Renewables Offshore Development, LLC and Shell New Energies US, LLC, which plans to construct a 1,510 MW OSW project awarded by the Board on June 30, 2021.

Baseline Scenario, the transmission facilities that would be necessary to achieve New Jersey's 7,500 MW OSW energy goal in the absence of the SAA solicitation.

Bureau of Ocean Energy Management ("BOEM"), the federal agency which manages the development and permitting of the United States' offshore energy and mineral resources, including the OSW lease areas.

Cable Route, the pathway a transmission cable(s) will follow or use from the OSW project to the Point of Interconnection onto the regional electric grid.

Cable Vaults, physically-separate underground vaults (accessible through manhole covers), located at certain distances (such as every 2,000 feet) along the Cable Route, to allow each OSW generator to install and maintain its own transmission cables without impacting other OSW generators' transmission cables.

Capacity Interconnection Rights ("CIRs"), the rights to input generation as a capacity resource into the transmission system at the point of interconnection where the facility connects to the PJM transmission system.

Coordinated Transmission Corridor, the planning and consolidation of construction efforts to support more than one OSW generation project in a single onshore transmission Cable Route.

Corridor, the Cable Route from the landfall location on the shoreline to the point of interconnection into the regional electric grid.

Designated Entity Agreement ("DEA"), a *pro forma* agreement under the PJM Tariff that is entered into, as required under Schedule 6 of PJM's Operating Agreement, between PJM and the developer designated to construct and own and/or finance a transmission project included in the RTEP.[2]

Duct Banks, the concrete structure between Cable Vaults that house the necessary number of physically-separate conduits (empty pipes) in which transmission cables can be installed (pulled through, from one point to another).

Energy Master Plan ("EMP"), the State's plan that sets forth a strategic vision for the production, distribution, consumption, and conservation of energy in New Jersey. The State's energy policy reflects the full scope of New Jersey's current energy sector, creating new jobs, industries, and

[2] While use of the DEA is not required under PJM's SAA process, at the request of the Board, PJM has elected to follow its competitive solicitation procedures including use of a DEA for those greenfield portions of SAA Solutions.

workforce development as the state expands its green economy, providing exciting new opportunities for New Jersey's residents and business community.

Executive Order No. 307 ("EO 307"), the Executive Order Governor Murphy issued on September 22, 2022 that increased New Jersey's goal for OSW energy generation from 7,500 MW by 2035 to 11,000 MW by 2040. This Executive Order further directs the Board to study the feasibility of further increasing the OSW goal.

Executive Order No. 8 ("EO 8"), the Executive Order Governor Murphy issued on January 31, 2018, directing the Board and all State agencies with responsibility under OWEDA to "take all necessary action" to fully implement OWEDA and begin the process of moving New Jersey towards a goal of 3,500 MW of OSW energy generation by the year 2030.

Executive Order No. 92 ("EO 92"), the Executive Order Governor Murphy issued on November 19, 2019, that increased the State's OSW goal for OSW energy generation from 3,500 MW by 2030 to 7,500 MW by 2035.

Federal Energy Regulatory Commission ("FERC"), the federal agency with jurisdiction over wholesale sales and interstate transmission of electric energy, including a mandate to guarantee just and reasonable rates for these services. FERC exercises regulatory jurisdiction over PJM.

First Solicitation (or "Solicitation 1"), the Board's first OSW generation solicitation for Offshore Wind Energy Certificates held in 2018-2019.

High Voltage Alternating Current ("HVAC").

High Voltage Direct Current ("HVDC").

Interconnection Service Agreement ("ISA"), an agreement between PJM, an electric generator, and all impacted transmission owners that details developer cost responsibility and confers rights necessary for PJM market participation.

Investment Tax Credits ("ITC"), a federal investment tax credit (currently 30% of eligible project costs) that is provided under the Internal Revenue Code on eligible property, available for renewable energy projects, including any OSW generation projects that commence construction prior to December 31, 2025.

Megawatt ("MW"), the equivalent of 1,000 kilowatts, or 1 million watts. This measurement is used for purposes of quantifying the electric output of a power plant.

Network Upgrade, upgrades to existing PJM Grid facilities, similar in scope to Option 1a system upgrades, but identified through the PJM interconnection queue study process for individual generators.

New Jersey Board of Public Utilities ("Board" or "BPU").

New Jersey Department of Environmental Protection ("DEP").

New Jersey Department of Military and Veterans Affairs ("DMAVA").

New Jersey Division of Rate Counsel ("Rate Counsel").

New Jersey Offshore Wind Strategic Plan ("Strategic Plan").

New Jersey Pinelands Commission ("Pinelands Commission").

Ocean Wind I, LLC ("Ocean Wind I"), the joint venture between Ørsted and PSEG Renewable Generation, LLC, which plans to construct an 1,100 MW OSW project awarded by the Board on June 21, 2019.

Ocean Wind II, LLC ("Ocean Wind II"), a subsidiary of Ørsted, which plans to construct a 1,148 MW OSW project awarded by the Board on June 30, 2021.

Offshore Wind ("OSW").

Offshore Wind Economic Development Act ("OWEDA"), N.J.S.A.48:3-87.1 et seq.

Offshore Wind Renewable Energy Certificate ("OREC"), as defined in N.J.A.C. 14:8-6.1, a certificate issued by the Board or its designee, representing the environmental attributes of one megawatt hour of electric generation from a qualified offshore wind project.

Option 1, SAA proposals for system upgrades to the existing PJM Grid and for new onshore transmission facilities to extend the PJM Grid toward the New Jersey shoreline.

Option 1a, SAA proposals for system upgrades and additions to the existing PJM Grid required as a result of PJM's study of the planned injections of SAA-related OSW generation at proposed POIs.

Option 1b, SAA proposals for any additional onshore transmission facilities that would extend the PJM Grid to more efficiently enable the coordinated connection of offshore transmission facilities.

Option 1b+, SAA proposals including all elements of Option 1b (except the electrical cable), land for HVDC converter stations, the Duct Banks, and access Cable Vaults to enable access to a coordinated Point of Interconnection.

Option 2, SAA proposals for new transmission facilities from the onshore transmission facilities to the OSW Projects in available BOEM OSW lease areas.

Option 3, SAA proposals for transmission links between the offshore substations of Option 2 transmission facilities or OSW wind farms.

PJM Grid, the high voltage transmission system operated by PJM Interconnection, LLC, covering New Jersey and all or part of 13 other states and the District of Columbia.

PJM Interconnection, LLC ("PJM"), the regional transmission organization that coordinates the dispatch of wholesale electricity and the operation of the bulk electric system in all or parts of thirteen states and the District of Columbia, including New Jersey.

PJM Regional Transmission Expansion Plan ("RTEP"), the PJM process to identify and address changes to the bulk electric grid in the PJM territory, including to maintain future reliability and economic performance.

PJM Transmission Owner ("TO"), an entity that owns or leases, with rights equivalent to ownership, transmission facilities and is a signatory to the PJM Transmission Owners Agreement. TOs must adhere to applicable technical requirements and standards.

Point of Interconnection ("POI"), a specific location where an OSW Project seeks interconnection to the PJM Grid.

Prebuild Infrastructure, the Duct Banks and Cable Vaults associated with the Prebuild.

Prebuild, a concept that would require a single OSW generator to construct the necessary Duct Banks and access Cable Vaults for its own OSW project as well as the additional OSW projects needed to fully utilize the SAA Capability at the selected POI. For clarity, the Prebuild involves only the necessary infrastructure (Duct Banks and Cable Vaults) to house the transmission cables, but not the cables themselves.

SAA Agreement, PJM Rate Schedule 49, approved by FERC in 179 FERC ¶ 61,024 (2021).

SAA Capability, as set out in the FERC-approved PJM Rate Schedule 49 § 1.2, all transmission capability created by approved SAA Solutions as studied by PJM, including the capability to integrate resources injecting energy up to their maximum facility output, capability which may become CIRs through the PJM interconnection process, and any other capability as consistent with studies performed by PJM for the SAA.

SAA Developer, any developer whose SAA project is selected herein and is listed in Appendix A.

SAA Proposal (or "SAA Bid"), a specific proposal for an SAA Option 1a, Option 1b, Option 2, or Option 3 facility, submitted by a qualified entity, along with all supporting documents provided to the Board and PJM, including, but not limited to, any initial bid documents or other submissions, all responses to clarifying questions, any additional documents submitted or official statements made to PJM, and all subsequent communication between the SAA Developer and the Board and/or Staff.

SAA Scenario, the specific combination of POIs and SAA Proposals specified by the Board and analyzed by PJM.

SAA Solution, a package of separate SAA Proposals that, when combined, provides SAA Capability associated with the related SAA Scenario.

SAA Study Agreement, an executed agreement, between the Board and PJM, and approved by FERC in 174 FERC ¶ 61,090 (2021) that sets out PJM's ability to use its existing competitive solicitation process to implement the SAA, and sets out milestones and obligations on both PJM and the Board.

Second Solicitation (or "Solicitation 2"), the Board's second OSW generation solicitation for ORECs, held in 2020-2021.

Shore Crossing, the specific part of the Cable Route which brings the transmission cables from the ocean onto land at the New Jersey shoreline.

State Agreement Approach ("SAA"), as set out in PJM's Operating Agreement, Section 1.5.9(a) of Schedule 6, the authorization of states, to select and include transmission facilities in the RTEP to solve public policy needs identified by each of those states, and to voluntary accept allocation of all associated costs.

Third Solicitation (or "Solicitation 3"), the Board's future OSW generation solicitation scheduled to be held in 2023.

Transmission Corridor, the onshore Cable Route used by one or multiple OSW generators between the landfall location on the shoreline, including the Shore Crossing, to the POI into the PJM Grid.

Transmission System Upgrade Cost ("TSUC"), the costs for construction of necessary upgrades, as identified by PJM, assigned to OSW generators to enable interconnection of the OSW project to the transmission system. As set forth in the terms and conditions of the Board's Orders approving Atlantic Shores 1 and Ocean Wind II, the TSUC mechanism allows Qualified Offshore Wind Projects to share some portion of their downside Network Upgrade cost risk with New Jersey ratepayers.

Violation, a violation of the minimum planning standards monitored by PJM throughout the transmission planning process, as described in Section 1.5 of PJM Manual 14b.

BY THE BOARD:

<u>Background and History of New Jersey's Offshore Wind Industry</u>

New Jersey's Offshore Wind Regulatory Landscape & Public Policy

On August 19, 2010, OWEDA was signed into New Jersey law.[3] OWEDA directed the Board to establish a program for ORECs to support at least 1,100 MW of OSW generation capacity from Qualified Offshore Wind Projects.[4]

Within his first of month of taking office, on January 31, 2018, Governor Phil Murphy signed EO 8, which directed the Board to fully implement OWEDA and begin the process of moving the State toward a goal of 3,500 MW of OSW by 2030.[5] To achieve these goals, EO 8 also directed the Board to develop and implement a Strategic Plan to examine the critical components of OSW development.

On November 19, 2019, Governor Murphy more than doubled the State's OSW goal when he signed EO 92.[6] EO 92 directed the Board to take "all necessary actions to implement OWEDA in order to promote and realize the development of wind energy off the coast of New Jersey to meet a goal of 7,500 megawatts of offshore wind energy generation by the year 2035."

The 2019 EMP recommends expanding New Jersey's electric grid to accommodate New Jersey's 7,500 MW of OSW by 2035. The EMP explains how "planned transmission to accommodate the State's OSW goals provides the opportunity to decrease ratepayer costs and optimize the delivery of OSW generation into the State's transmission system."[7] The EMP further states that "[c]oordinating transmission from multiple projects may lead to considerable ratepayer savings, better environmental outcomes, better grid stability, and may significantly reduce permitting risk."[8] The EMP directs that the Board "should endeavor to collaborate with PJM to ensure that transmission planning and interconnection rules accommodate [OSW] resources."[9] The EMP also recognizes that transmission must be planned and that the Board must exercise its regulatory authority to "actively engage in transmission planning."[10] The same week that Governor Murphy

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[3] <u>See</u> N.J.S.A. 48:3-87 <u>et</u> <u>seq</u>.

[4] OWEDA defines an OREC as representing the environmental attributes of one MWh of electric generation from an OSW project. For each MWh delivered to the transmission grid, an OSW project will be credited with one OREC.

[5] <u>See</u> EO 8. In 2018, the Legislature also directed the Board to establish an OREC program to support "at least 3,500 MW" of OSW generation by 2035. <u>See</u> OWEDA, <u>supra</u> note 4.

[6] EO 92.

[7] EMP, Goal 2.2.1 at 117.

[8] <u>Id.</u>

[9] <u>Id.</u>

[10] <u>Id.</u>; EMP, Goal 5.2.1 at 182.

issued the EMP, he also signed legislation authorizing the Board to conduct one or more competitive solicitations for open access OSW transmission facilities.[11]

In 2020, the Board, in close coordination with other State agencies, issued the Strategic Plan.[12] The Strategic Plan found that "[i]nvestments in planning and infrastructure are necessary to build the transmission infrastructure and regional markets needed for offshore wind energy to support a clean energy future."[13] Specifically, the Strategic Plan recommends that meeting New Jersey's 7,500 MW OSW goal requires "[c]ollaborat[ing] with PJM, as set forth in the EMP, to assure transmission infrastructure accommodates renewable energy such as offshore wind."[14] The Strategic Plan also recommends "[w]ork[ing] with PJM and local utilities to develop a grid transmission study to integrate 7,500 MW of offshore wind energy by 2035."[15]

On September 21, 2022, Governor Murphy signed EO 307, increasing the OSW goal to 11,000 MW by 2040.[16]

New Jersey's Offshore Wind Generation Solicitations

With the clear directives from the State Legislature and the Governor, and after having adopted rules creating the OREC, on September 17, 2018, the Board issued its First Solicitation. This solicitation sought a target of 1,100 MW of OSW capacity and invited interested OSW generators to submit competitive bids for what was, at the time, the nation's largest OSW solicitation.

At the close of the First Solicitation, the Board received a total of fourteen project bids from three OSW generators, as follows: (i) Atlantic Shores 1; (ii) Boardwalk Wind, sponsored wholly by Equinor Wind US, LLC; and (iii) Ocean Wind I.[17]

After a six month review and evaluation process, the Board awarded ORECs for 1,100 MW of OSW capacity to the Ocean Wind I project on June 21, 2019.[18]

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[11] N.J.S.A. 48:3-87.1(e).

[12] See Strategic Plan at https://www.nj.gov/bpu/pdf/Final_NJ_OWSP_9-9-20.pdf.

[13] Strategic Plan at 77 (Sept. 9, 2020).

[14] Id. at 78.

[15] Id.

[16] EO 307 (2022).

[17] In the Matter of the Board of Public Utilities Offshore Wind Solicitation for 1,100 MW—Evaluation of the Offshore Wind Applications, BPU Docket No. QO18121289, Order dated June 21, 2019 ("June 21, 2019 Order").

[18] Id.

In September 2020, the Board issued its Second Solicitation with a desired target of 1,200 MW to 2,400 MW of OSW capacity.[19] At the close of the Second Solicitation window, the Board received a total of six project bids from two OSW generators as follows: (i) Atlantic Shores 1 and (ii) Ocean Wind II.[20] By two Board Orders, each dated June 30, 2021, the Board awarded a total of 2,658 MW of OSW capacity to two projects, Atlantic Shores 1 for 1,509.6 MW and Ocean Wind II for 1,148 MW.[21] Collectively, under the First Solicitation and under the Second Solicitation, the BPU has awarded a total of three OSW projects for a total of 3,758 MW.

The remaining OSW capacity that is needed to meet Governor Murphy's goal of 11,000 MW of OSW by 2040 is expected to be procured through additional OSW generation project solicitations. The below SAA solicitation schedule was designed to support the 7,500 MW OSW goal in effect at the time the SAA solicitation was issued. This schedule will be updated to account for the new goal set by EO 307.

Solicitation	Capacity Target (MW)	Capacity Awarded (MW)	Issue Date	Award Date	Estimated COD
1	1,100	1,100	Q3 2018	Q2 2019	2024-25
2	1,200 - 2,400	2,658	Q3 2020	Q2 2021	2027-29
3	1,200		Q1 2023	Q4 2023	2030
4	1,200		Q2 2024	Q1 2025	2031
5	1,342		Q2 2026	Q1 2027	2033
6+	3,500		To be determined		
Total	11,000				

As discussed further below, the Board expects to work with PJM to design a second SAA solicitation to support 11,000 MW of OSW by 2040, as recently set forth in EO 307, which may include transmission facilities to support future solicitations and may include both onshore and offshore facilities.

Coordinated Transmission Approach to Support New Jersey's Offshore Wind

New Jersey is positioning itself as a world leader in promoting OSW development, with a goal of 11,000 MW of OSW generation capacity by 2040. To effectuate this goal, New Jersey plans to hold a series of OSW solicitations every 18-months to 2-years scheduled between now and 2026 to meet the 7,500 MW goal, with additional solicitations to be added to achieve the 11,000 MW goal.

[19] In the Matter of the Opening of Offshore Wind Renewable Energy Certificate (OREC) Application Window for 1,200 to 2,400 Megawatts of Offshore Wind Capacity in Furtherance of Executive Order No. 8 and Executive Order No. 92, BPU Docket No. QO20080555, Order dated September 9, 2020.

[20] In the Matter of the Board of Public Utilities Offshore Wind Solicitation 2 for 1,200 to 2,400 MW – Ocean Wind II, LLC, BPU Docket No. QO21050825, Order dated June 30, 2021 ("Ocean Wind II June 2021 Order"), at 14.

[21] Id.; In the Matter of the Board of Public Utilities Offshore Wind Solicitation 2 for 1,200 to 2,400 MW – Atlantic Shores Offshore Wind Project 1, LLC, BPU Docket No. QO21050824, Order dated June 30, 2021 ("Atlantic Shores 1 June 2021 Order").

As with any new energy resource, the necessary transmission infrastructure required to support delivering the energy to customers must also be developed. Transmission infrastructure plays the critical role of delivering power, including clean OSW power, to the consumers who need it. Transmission is therefore an essential element, not only for the success of OSW in the State, but also in achieving the State's carbon emissions reduction goals necessary to mitigate climate change.

In New Jersey, the majority of the State's electric transmission infrastructure, or the "grid," runs through central or western New Jersey. Historically, this enabled siting of the State's electric generators close to the majority of the State's electricity needs, while enabling lower-voltage connections to New Jersey's less populated coastline. Further, transmission planning over the last century (at least in PJM) has generally assumed predominantly west-to-east flows of power.[22] As a consequence, the near-shore electric transmission grid in New Jersey is typically less robust than reinforced inland areas, with facilities not designed to facilitate power flows westward from the shoreline. Indeed, New Jersey's 500 kilovolt ("kV") transmission backbone generally runs in a north-south line, about 40 miles inland from the shoreline. While some bulk transmission substations of different voltages are located closer to or further away from the New Jersey coast, the existing transmission network is currently not designed to accommodate the energy injections at its eastern most edge associated with a large amount of OSW. With 11,000 MW of new OSW energy scheduled to be delivered to New Jersey over the next several decades, the State and PJM must now evaluate efficient pathways for the existing grid to successfully accommodate these additional injections.

Under the First Solicitation and the Second Solicitation, all projects, including each of the three approved projects, proposed a *bundled* approach to generation and transmission—that is, each project would individually develop and construct its own transmission facilities to bring electricity onshore from its own OSW turbines. Under this paradigm, the costs of the facilities needed to interconnect the project from the ocean to the POI are included in the OREC price. By utilizing a coordinated transmission approach where some or all of the transmission infrastructure is built by transmission developers (in this case under the SAA) and the electricity generation infrastructure is built by OSW generators, development responsibility is *unbundled*.

While the bundled approach, where each OSW project brings its own transmission onshore, is typically simpler for OSW generators, it can result in inefficient expansion of the transmission grid. For example, upgrading a transmission facility to meet the needs of one wind farm, without considering the needs of subsequent wind farms, can result in multiple and inefficient upgrades to related pieces of infrastructure. Further, the bundled approach creates a situation where there are multiple transmission cables from multiple OSW projects in the ocean reaching the shore.

[22] See PJM Grid of the Future, PJM's Regional Planning Perspective, at 15 ("The injection of thousands of megawatts from offshore wind will fundamentally change how power flows over the transmission grid in the Northeast and mid-Atlantic. Generation will now be located closer to load centers along the I-95 corridor; this area of the grid was originally served mainly by west-to-east power flow from large mine-mouth coal generating stations in western Pennsylvania and beyond and, later, shale natural gas-fired plants in central Pennsylvania. This unfolding scenario will drive the need for new transmission assets and system configurations to maximize power delivery to onshore load.").

Without advance planning, these landfall locations are unlikely to occur in the same place. They are also less likely to occur in a particular location that is optimal to the State as a whole, since each project will select a location that optimizes their particular project. Thus, without a coordinated landfall location, each OSW generator is likely to use at least one unique Transmission Corridor to access their individually-selected POI, which increases local community impacts. To illustrate, the three currently awarded OSW projects propose to use a total of seven HVAC cables and one HVDC cable that would travel from their respective OSW farms and land on-shore at four different points on the State's coastline. These cables, once making landfall, would then use four Transmission Corridors to travel to four different POIs in the State.[23] If the Board were to maintain the non-coordinated, bundled approach to procuring OSW transmission and OWS generation, future solicitations could result in more than a dozen cables connecting future OSW farms to the coastline at six to ten different POIs to support the delivery of the first 7,500 MW of OSW-generated energy. The State's new goal of 11,000 MW of OSW generation capacity would naturally increase these numbers of cables, landfall locations, Transmission Corridors, and POIs.

Stakeholder Input

To examine the range of commercial, technical, environmental, and operational advantages and disadvantages of OSW transmission options, Staff conducted extensive stakeholder outreach.

On November 12, 2019, Staff held an OSW transmission Technical Conference ("Technical Conference") to solicit input from stakeholders on transmission considerations and solutions. The Technical Conference included four panels of stakeholders to explore the following issues/questions:

- How other jurisdictions connected geographically remote generation through shared transmission facilities;
- Possible frameworks for building open access OSW transmission facilities;
- Technical considerations for offshore transmission facilities; and
- Cost responsibility, risk-sharing, and business model considerations associated with open access OSW transmission solutions.

Several stakeholders at the Technical Conference noted that a planned transmission solution could potentially minimize the environmental footprint of bringing power ashore, particularly by coordinating the number of times transmission facilities would need to cross environmentally-sensitive beach and ocean habitats. Stakeholders also noted the benefits of coordinated transmission upgrades in facilitating the delivery of the power into the PJM system. However,

[23] The Ocean Wind I project proposed to deliver 1,100 MW by three HVAC cables to two different substations; the Ocean Wind II project proposed to deliver 1,148 MW by three HVAC cables to one substation; and the Atlantic Shores 1 project proposed to deliver 1,500 MW by four HVAC cables to one substation.

others highlighted the potential risks associated with requiring OSW generation resources to depend on third parties to construct open access transmission facilities and, in particular, how this dependency posed certain commercial risks to OSW generators.

In March 2020, the Board retained Levitan & Associates, Inc. ("LAI") to prepare an OSW transmission study ("Transmission Study"). In order to inform the study, on June 26, 2020, the Board issued a Notice of Information Gathering (Docket No. QO20060463) on OSW transmission options. Approximately 80 representatives from 54 entities provided information. In addition, LAI conducted nine virtual interviews with multiple groups of stakeholders interested in OSW transmission, including generation and transmission developers, utilities, environmental groups, and commercial and recreational fishing representatives to ensure broad participation.

LAI completed the Transmission Study in December 2020, and concluded that a coordinated transmission approach would provide significant benefits. The Transmission Study included the following findings and observations:

1. Any coordinated transmission approach would have to be a regulated PJM asset because the merchant model[24] is not financeable;

2. In order to select an offshore transmission option, New Jersey will have to balance cost, performance, environmental impacts, ratepayer risk, and other unique factors;

3. The Board has the authority to authorize any coordinated transmission approach through PJM's SAA procurement process;

4. The SAA procurement process would attract enough qualified transmission developers to the bidding process to assure a competitive process and thus a cost-effective coordinated transmission design;

5. Any coordinated transmission project developed separately from OSW generation would impose project-on-project risks[25]; and

6. PJM's existing SAA procurement process offers a defined but untested path forward that is likely a better means than the bundled approach to achieve Governor Murphy's 7,500 MW OSW by 2035, by reducing costs, minimizing permitting, reducing construction delays, and reducing environmental impacts.

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[24] The merchant model in this context refers to transmission developers building OSW transmission assets and recovering their costs through commercial contracts with OSW generators who would use the assets.

[25] Project-on-project" risk in the context of OSW transmission and generation is the risk that one component—either the transmission or the generation— would be completed and ready to serve its purpose while the other component would not be ready at the time it is needed or scheduled, resulting in adverse financial impacts to one or both project components that have to be properly apportioned. For example, if the generation component was completed on schedule, but the transmission component was delayed, the generation component would not be able to interconnect. Put differently, "project-on-project" risk exists when the completion of independent projects depend on each other.

Potential Benefits of Coordinated Transmission

Informed by this analysis, Staff identified several potential benefits of coordinated transmission, summarized below. While these potential benefits are encouraging, Staff sought procurement options that would provide ready-to-build transmission options to evaluate the likelihood of any specific solution providing these benefits. Rigorous evaluation of submitted transmission options, discussed further below, is required to evaluate the presence and strength of these benefits to any particular OSW generation project.

Cost Savings

A key finding of Staff's analysis is that a proactively planned transmission system to accommodate new OSW generation saves ratepayers billions of dollars, compared to the costs of upgrading the transmission grid on a piecemeal basis.[26] A separate transmission solicitation invites a broad pool of regional transmission developers to compete and innovate to provide optimal solutions to specifically-identified transmission needs. In addition, proactively procuring the system upgrades required for a larger amount of OSW (e.g. 7,500 MW as part of this process and potentially up to 11,000 MW in the future) "ahead-of-time" enables identification of needed system upgrades that can be solved by proposals designed specifically for that purpose, enabling significant cost savings. In contrast, the bundled approach would separately identify the system upgrades for each approved OSW generation project, individually, foregoing efficiencies enabled through coordinated procurements.

Beyond the anticipated direct cost savings, unbundling transmission costs from the OREC funding mechanism for OSW generators provides the potential for additional benefits.

By removing the development and construction of some or all of the transmission assets and associated costs from the OSW generators' responsibility, and relying on transmission developers to design and construct those assets, New Jersey will see a decrease in OREC prices for OSW generation. Transmission costs associated with transmission developer projects would be removed from the OREC price and instead be included in the transmission portion of the ratepayer bill, alongside other transmission investments intended to prepare the grid for changing system conditions. Additional cost savings are likely to result from unbundling because OSW generators typically increase their bids (sometimes called "risk premiums") to account for the uncertainty in how much transmission upgrades will cost and how long they will take to implement. Potential impacts on project schedule from outside factors, such as scheduling and approvals at PJM and FERC, would also be removed from the OREC. How much of the costs will be removed from OREC prices will depend on the scope of unbundled transmission facilities procured, and the certainty that the projects will be available to the OSW generators when needed.

[26] Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Comments of the Board of Public Utilities at 6-7, FERC Docket No. RM21-17 (Aug. 17, 2022) (citing PJM Interconnection, Offshore Wind Transmission Study: Phase 1 Results 18-20 (2021); Brandon W. Burke, Michael Goggin, & Rob Gramlich, Offshore Wind Transmission White Paper 14 (2020)).

While the Board anticipates OREC prices to be significantly reduced as a result of utilizing a coordinated transmission approach, not all of the OREC price reduction directly results in savings to New Jersey's ratepayers. A portion of the OREC price decrease is simply a transfer of cost recovery from the OREC funding mechanism to transmission rates, which the TOs file and FERC approves, similar to the process used to recover costs of other RTEP transmission projects. Even though some of the costs are in fact transferred from OREC to FERC-regulated transmission rates, Staff's analysis shows substantial net savings to ratepayers resulting from a coordinated transmission approach, as detailed further below.

Additionally, while current federal tax policy favors generator ownership of offshore transmission facilities, all other things being equal, the U.S. Department of Energy ("DOE") is in the process of setting up additional programs that may be available to provide financial support for offshore wind transmission facilities that are not currently available. Thus, as offshore wind transmission technology matures and federal tax policy shifts, Staff anticipates that its analysis of future offshore facilities may yield even more positive savings.

Reducing Environmental Impact

Developing new transmission infrastructure in a coordinated manner can reduce the adverse impacts on the environment inherent in all new transmission projects. As noted in the EMP, a coordinated transmission approach may substantially improve environmental outcomes by reducing the number of new transmission facilities necessary to interconnect OSW, and may significantly reduce the time and cost needed for permits. As highlighted above, a bundled approach would require a substantial number of unique construction efforts, which could cause environmental impact to a range of communities and municipalities throughout the State. In general, project development is improved when environmental impacts to communities are reduced. This benefit is maximized if impacts can be limited to a single construction effort along the fewest possible Transmission Corridors, instead of multiple construction efforts that may otherwise be necessary to connect to an advantageous POI.

A coordinated approach affords the opportunity to reduce the number of landfall points by developing one or more designated Transmission Corridors that would be utilized by multiple OSW generation projects. Developing a Coordinated Transmission Corridor that can accommodate more than one OSW project and would be permitted and developed in a single construction effort, can reduce the number of regulatory siting proceedings and minimize disruption to communities along that Transmission Corridor. The competitive and advanced nature of a coordinated transmission solicitation provides an opportunity for transmission development experts to propose various cost-effective solutions that minimize environmental disruption, and allows the assessment of these solutions' relative merits and limitations with respect to environmental and permitting concerns. Unbundling OSW transmission and generation further enables New Jersey to leverage the extensive and specific expertise of each type of developer – generation and transmission. Transmission developers have extensive experience obtaining the necessary approvals - federal, state and local - to implement the large-scale transmission projects that the State needs to reliably and efficiently deliver on its OSW goals.

Reducing Schedule and Regulatory Risk

Under the bundled approach, design and construction of the transmission components are part of the PJM interconnection queue process, and are planned to occur at a specific point in the overall project's schedule, generally years after the development of the generation component begins. Any delays in the PJM interconnection process are not easily accommodated due to the complexity of developing the OSW project as a whole and the interdependence of both the generation and transmission components' schedules. In fact, recently, PJM's interconnection process has been slowed as the regional operator is flooded with many new interconnection requests.

By contrast, unbundled transmission projects are designed prior to the start of the generation project schedule, so that the transmission component is completed and is ready when needed by the generation project. This reduces the overall risk associated with a bundled OSW project schedule. These anticipated benefits are particularly robust for *onshore* system upgrades, which must be constructed in either the bundled or unbundled scenario, and are often a long lead-time item for connecting an OSW project to the grid.

Reducing the Number of Onshore Corridors

To enable the beneficial environmental and community outcomes described above, coordinated solutions should seek to minimize the number of landfall points and onshore Transmission Corridors utilized to deliver the maximum amount of OSW.

Each landing point and Transmission Corridor involves careful planning, coordination, and construction efforts including Rights of Way ("ROW") disturbance that may take place over several years. It also requires installation of underground Duct Banks and access Cable Vaults to accommodate HVAC or HVDC electric transmission cables.

As highlighted above, a bundled approach would require a substantial number of unique construction efforts, which could impact a range of communities and municipalities throughout the State. In general, project development is improved when impacts to communities are reduced. This benefit is maximized if impacts can be limited to a single construction effort along the fewest possible Transmission Corridors, instead of multiple construction efforts that may otherwise be necessary to connect to an advantageous POI.

Aside from the environmental impact benefits described above, a reduced number of Transmission Corridors also lays the foundation for future growth of OSW goals, including the newly-mandated 11,000 MW of OSW through EO 307. In particular, using a single Transmission Corridor enables other potentially suitable POIs to remain available for future efforts above and beyond current goals.

Therefore, there are tremendous benefits of limiting the number of landfall points and Transmission Corridors by having common, or consolidated, Cable Routes that can serve multiple OSW projects. Limiting the number of Transmission Corridors will limit design risks and can reduce the overall disturbance to both communities and the environment.

Transmission Procurement Options

OWEDA authorizes the Board to conduct transmission-only solicitations for open access OSW transmission facilities designed to deliver OSW electricity.[27] Having outlined the substantial potential benefits of an unbundled, coordinated transmission approach, the Board sought an avenue to procure the widest range of potential options, with the highest degree of ratepayer protections, at the lowest reasonable cost, and determined that incorporating the States' offshore wind transmission goals into the PJM regional planning process represented the best way of moving forward. The PJM tariff allowed for a New Jersey-initiated Transmission Project solicitation through the PJM SAA.

New Jersey-Initiated Transmission Solicitation & the PJM SAA Process

A New Jersey-initiated Transmission Project solicitation requires close coordination between the State, PJM, and transmission-owning utilities both inside and outside of New Jersey. OWEDA specifically allows the Board to identify its transmission needs and conduct a competitive solicitation similar to the OSW generation solicitations, but aimed at achieving the State's transmission-related OSW goals. Any competitive solicitation includes development of a Transmission Project solicitation guidance document, receipt and evaluation of responses to the solicitation, and the Board award of Transmission Projects.

In New Jersey and other Mid-Atlantic states, the transmission planning process is based on a detailed set of FERC-approved rules, implemented by PJM. Therefore, any new transmission facilities need to be conducted in close coordination with PJM, and particularly with the PJM RTEP[28] process. These rules determine how and when to expand and enhance the regional grid and also outline a highly competitive, robust procurement structure to select certain Transmission Projects, specifically those focused on transmission expansion. The annual RTEP identifies the needed transmission enhancements five years into the future, and it projects enhancements likely to be needed over the next fifteen years.[29] RTEP considers changes to grid demand profiles and the availability of power generation facilities.

In order to better accommodate state public policy needs into the regular RTEP cycle, PJM created the SAA to better enable states to incorporate their policy goals into the RTEP and to utilize PJM's competitive transmission solicitation process. The SAA is an optional mechanism enabling pathways for states to pursue their public policy objectives, under the condition that the state or states agree to voluntarily assume responsibility for all costs of the Transmission Project

[27] N.J.S.A. 48:3-87.1(e) ("Notwithstanding any provision of P.L.2010, c. 57 (C.48:3-87.1 et al.) to the contrary, the Board may conduct one or more competitive solicitations for open access offshore wind transmission facilities designed to facilitate the collection of offshore wind energy from qualified offshore wind projects or its delivery to the electric transmission system in this State.").

[28] See PJM Manual 14B.

[29] For more information, see PJM's Learning Center website, https://learn.pjm.com/three-priorities/planning-for-the-future.

selected through the SAA.[30] The PJM Operating Agreement specifies that a state can follow a process, first used under the Board's request described below, to identify and select a public policy project.[31]

New Jersey's SAA

By Order dated November 18, 2020 ("November 2020 Order"), the Board formally requested that PJM incorporate New Jersey's OSW goals into the PJM RTEP transmission planning process via the SAA.[32]

New Jersey's SAA Process

Prior to the issuance of the November 2020 Order, Staff engaged PJM for approximately six months in collaborative scoping discussions to determine the optimal pathway to achieve the State's then-current OSW goal of 7,500 MW. This effort included a two-phased approach to identifying grid injection locations and corresponding MW amounts in New Jersey to support the State's offshore wind targets through 2035. These efforts allowed identification of default violations (or "problems" with the bulk electric grid) needed to develop a competitive solicitation process. PJM's Phase 1 work commenced in April 2020 and entailed a screening analysis of over 100 potential in-state POIs to identify those most capable of supporting the State's OSW goals.

PJM's Phase 1 analysis[33] was based on standard linear first contingency transfer capability analyses using 2025 RTEP base cases for summer, winter, and light load conditions. PJM's Phase 1 work assumed that Ocean Wind I would install its own transmission cables to the two POIs identified in Ocean Wind I's bid, and that Ocean Wind I would not otherwise be part of an SAA Solution. PJM's Phase 1 results included desktop-level cost estimates for onshore Cable Routes from Shore Crossings to the POIs studied, using generic cost-per-mile values for overhead lines and underground cables. PJM also performed a single generator deliverability analysis to determine required transmission system upgrades and their costs. PJM's Phase 1 results identified a suite of potential POIs capable of enabling New Jersey's 7,500 MW goal.

In order to narrow the identified POIs into a single default case necessary for a potential SAA solicitation, Staff selected three scenarios of multiple POIs, deemed preferred from PJM's Phase 1 analysis, for further study.[34] These Phase 2 studies provided sufficient information for Staff to

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[30] See PJM Operating Agreement, Schedule 6, Section 1.5.9(a); PJM Tariff, Schedule 12(b)(xii)(B).

[31] PJM Operating Agreement, Schedule 6, Section 1.5.9(a); PJM Tariff, Schedule 12(b)(xii)(B).

[32] In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated November 18, 2020 ("November 2020 Order").

[33] The analysis, not public, is summarized here to show how it informed the Board's early decisions in the SAA process.

[34] Staff determined that any coordinated transmission approach would need to support the full 7,500 MW goal, therefore POIs supporting just 3,500 MW were not selected for further study.

recommend that the Board initiate the SAA process, and enabled identification of violations that would be necessary for PJM to initiate a competitive transmission solicitation under its approved RTEP processes.

Based on these screening analyses, prior stakeholder input, Staff evaluation, and the potential benefits of coordinated transmission for OSW, the Board issued the November 2020 Order, formally setting out the transmission needs of the State to reach its OSW goals to be addressed by a competitive solicitation through the SAA. The November 2020 Order explained the potential benefits of coordinated transmission, as outlined above, identifying key benefits of "more efficient or cost effective transmission solutions," reduction to "risks of permitting and construction delays," and "minimiz[ing] environmental impacts associated with [onshore] and potentially offshore upgrades."[35] The Board also referenced stakeholder-identified benefits, namely "minimiz[ing] the environmental footprint of bringing power ashore, particularly by coordinating the number of times transmission facilities would need to cross environmentally sensitive beach and ocean habitats."[36] The Board was also focused on limiting downside ratepayer and developer risks identified by stakeholders, encouraging transmission developers to address the "transfer of commercial risk between transmission and [generation] developers…prior to [the Board] approving a final coordinated transmission solution."[37]

On December 18, 2020, PJM submitted to FERC an executed SAA Study Agreement ("Study Agreement") between PJM and the Board to begin implementing the SAA.[38] The Study Agreement provides, for the first time, a framework for PJM to utilize its existing competitive solicitation process to receive proposals in response to the Board's SAA request.[39] PJM's existing solicitation process is designed to be integrated with regular RTEP cycles, and is the central forum for specialized transmission developers to submit transmission project proposals in the PJM footprint. As described further below, Staff would then work with PJM to review and evaluate the submissions received, and the Board would select which, if any, projects to sponsor under the SAA.[40] The Study Agreement also established a set of milestones and timelines for PJM and the Board.

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[35] November 2020 Order, supra note 33 at 5.

[36] Id. at 2.

[37] Id. at 5, 8 ("Finally, the Board is cognizant of the concerns raised by some stakeholders that a coordinated transmission approach may increase commercial risk on OSW generators by making projects dependent on transmission facilities constructed by third-parties. While the Board continues to see the benefits of exploring a coordinated offshore wind transmission option more fully, the Board notes that it will weigh heavily proposals from transmission developers that utilize the voluntary protections laid out in the SAA to limit down-side risk to New Jersey consumers and to reduce project-on-project risk for [OSW] generation [project] developers.").

[38] PJM Interconnection, L.L.C., 174 FERC ¶ 61,090 (2021).

[39] Id. at 5; see also PJM Service Agreement No. 5980 at section 2a (citing PJM Operating Agreement, Schedule 6, section 1.5.8(c)).

[40] Id. at 6.

On February 16, 2021, FERC accepted the Study Agreement between PJM and the Board.[41] Based on this approval, PJM was authorized to implement its existing competitive RTEP procurement process to enable New Jersey's SAA and effectuate New Jersey's public policy goals.

On February 26, 2021, Staff held a second technical conference ("Supplemental Technical Conference") to address certain issues referenced in the Board's November 2020 Order.[42] The Supplemental Technical Conference included three panels focused on the following topics:

1. Pre-commercial operation delays, mismatch of construction schedules;
2. Curtailment risk; and
3. Post-commercial operational risk.

Written comments on the topics discussed at the Supplemental Technical Conference were also accepted through March 12, 2021. Information from the Supplemental Technical Conference and written comments informed the design of the SAA solicitation.

The SAA competitive proposal window opened in April 2021 and closed in September 2021. Staff developed and released the SAA Process Guidance Document to provide more detail on the evaluation process and timeline. Namely, this document outlined the process behind the multi-month evaluation in which Staff and PJM reviewed all SAA transmission project proposals to determine which, if any, are best suited for New Jersey's needs and represent the best value for New Jersey consumers.

In January 2022, PJM filed Rate Schedule 49 at FERC, setting out the SAA Agreement between the Board and PJM.[43] The provisions of the SAA Agreement are intended to provide assurances to the Board that New Jersey's selected policy resources, expected to be primarily OSW resources, can efficiently utilize the SAA investment funded in-full by New Jersey ratepayers. The SAA Agreement sets out PJM's ongoing obligation to preserve the transmission capability created by selected SAA projects for the purpose of enabling New Jersey's OSW generation procurements—referred to as "SAA Capability."[44] The SAA Agreement provides a process by

[41] PJM Interconnection, L.L.C., 174 FERC ¶ 61,090 (2021).

[42] In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Notice dated January 26, 2021.

[43] PJM Interconnection, L.L.C., 179 FERC ¶ 61,024 (2022).

[44] SAA Agreement at § 6.2(c) ("The SAA Capability will be based, modeled and reserved in a manner (i) consistent with PJM's reliability criteria, study assumptions, and modeling processes for offshore wind turbines as detailed in PJM Manuals, and (ii) as described and identified in any subsequent FERC filings, as well as in Appendix B herein (citing PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at Appendix).") SAA Capability is defined as "all transmission capability created by a SAA Project(s), including but not limited to the capability to integrate resources injecting energy up to the Maximum Facility Output ("MFO"), capability which may become CIRs through the PJM interconnection process, and any other capability or rights under the PJM Tariff, and consistent with the reliability study

which the Board assigns the SAA Capability to OSW generators selected in future generation solicitations.[45] This assignment of SAA Capability must occur within two years of any OSW generator award, and could occur at the time of the award itself.[46] Lastly, the SAA Agreement established that the Board would later work with PJM and stakeholders to develop a cost allocation methodology and file it for approval at FERC, described further below.[47] FERC approved the SAA Agreement on April 14, 2022.[48]

In March and April 2022, Staff convened a series of four stakeholder meetings to solicit input from stakeholders to help inform Staff's evaluation of the SAA proposals.[49] The stakeholder meetings focused on the following topics:

1. General description of SAA goals and evaluation process, and review of applications;
2. Integration with OSW generation projects;
3. Environmental and permitting issues; and
4. Ratepayer protections and cost controls.

Following the stakeholder meetings, the Board received written comments from stakeholders including OSW generators, transmission developers, Rate Counsel, other organizations, and members of the public. The commenters generally supported the SAA process. Amongst the comments received, Rate Counsel stated that "the strong response during PJM's competitive proposal window, coupled with a variety of bid types and offers, supports our long-held position that competitive processes can be successful in leading to the most economical, efficient, and environmentally sound energy solutions."[50]

On April 27, 2022, the Board issued a Notice requesting additional information.[51]

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criteria applied to the evaluation of a SAA Project(s) as set forth in Paragraph 6 [of the SAA Agreement]." See SAA Agreement at § 1.2.

[45] SAA Agreement at § 5.3 ("Following the NJ BPU's selection to assign SAA Capability to an OSW generator, the NJ BPU shall provide written notification to the selected OSW generator of the type and amount of SAA Capability to be assigned to the OSW generator ("NJ BPU Notification"). The NJ BPU Notification shall advise the OSW generator of its responsibility to submit an OSW generator Notification to PJM prior to commencement by PJM of the OSW generator's System Impact Study.").

[46] SAA Agreement at § 6.2(d)(i). The key attributes of the Board's NJ BPU Notification are: Amount of SAA Capability to be awarded (nameplate MW, or nameplate MW and capacity MW); Location of SAA Capability (POI); Obligation of Awardee to notify PJM of SAA Capability award.

[47] Id. at 13-14.

[48] Id.

[49] In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Revised Notice dated March 7, 2022.

[50] Rate Counsel Comments dated April 29, 2022 at 3.

[51] In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Notice dated April 27, 2022.

On July 18, 2022, PJM held a special session of its Transmission Expansion Advisory Committee to update PJM stakeholders on the progress of the SAA solicitation window. PJM summarized its reliability, economic, constructability, financial, and legal analyses of the SAA Proposals, and allowed stakeholders to provide input into its analysis.

Throughout the SAA process, Staff relied upon input from several entities, most notably its consultant – The Brattle Group ("Brattle"),[52] PJM, Rate Counsel, and DEP. Staff also engaged the Pinelands Commission and DMAVA to assess potential constructability and permitting issues associated with projects that proposed to utilize property under their control or jurisdiction. Reports and analysis from these entities are provided under this docket on the Board's public document search tool.[53]

Cost Allocation Methodology

As described above, the SAA requires New Jersey customers to bear the cost of any SAA Transmission Project under a FERC-approved cost allocation agreed to by the State. FERC accepted the SAA Agreement established the process by which the Board would work with PJM to propose a cost allocation methodology for FERC approval. All costs for a selected SAA project must be allocated to New Jersey customers alone.[54]

On June 10, 2022, Staff presented its proposed cost-allocation methodology to the PJM Transmission Owner's Agreement Advisory Committee ("TOA-AC") for consideration. The Board proposed to allocate costs to New Jersey customers on a pro-rata basis. On August 19, 2022, after their consultation period with the PJM membership, the TOs filed the proposed cost allocation at FERC.[55] Under FERC and PJM rules, the TOs retain the sole authority to file all cost-allocation mechanisms at FERC. [56]

SAA Solicitation

The November 2020 Order directed PJM to plan for injections of power into four POIs on the PJM system between 2028 and 2035, based on the preliminary screening studies PJM performed, as described above.[57] The four injection locations and associated capacity were: (i) 900 MW at the Cardiff 230 kV substation in southern New Jersey; (ii) 1,200 MW at the Larrabee 230 kV substation in central New Jersey; (iii) 1,200 MW at the Smithburg 500 kV substation in central New Jersey; and (iv) 3,100 MW at the Deans 500 kV substation in northern New Jersey. However, the Board also required that the SAA solicitation allow transmission developers to

[52] Brattle assembled an SAA evaluation team that, in addition to Brattle consultants, also included Steven Herling (former Vice President of planning at PJM), Mark C. Kalpin (Partner with Holland & Knight), and environmental permitting consultants led by Douglass Sullivan (Senior Associate with Dewberry).

[53] State of New Jersey Board of Public Utilities, Public Document Search, located at https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468.

[54] PJM Interconnection, LLC.,179 FERC ¶ 61,024, 40-41.

[55] PJM Interconnection, LLC, FERC Docket No. ER22-2690 (Aug. 19, 2022).

[56] Id. at 5, 25.

[57] *See* November 2020 Order, supra note 33.

propose alternate POIs if they could enable development of the State's OSW industry in a lower-cost or more-efficient fashion.

As a result of the Second Solicitation in June 2021, default injection locations and amounts were revised to account for the Ocean Wind II and ASOW 1 projects. Following the Second Solicitation awards, PJM revised its modeling to a new set of defaults, including 1,510 MW at the Cardiff 230 kV substation accounting for ASOW 1, and 1,148 MW at the Smithburg 500 kV substation accounting for Ocean Wind II. The remaining 3,742 MW were divided between 1,200 MW at the Larrabee 230 kV substation, with the remaining 2,542 at the Deans 500 kV substation. To ensure identification of all necessary facilities to enable seamless interconnection of future facilities, PJM's model included injections from already-awarded projects, as discussed further below.

Throughout this Order, reference is made to 7,500 MW, 6,400 MW and 3,742 MW of capacity to support the SAA and the State's OSW goals. For clarity, these numbers were calculated as follows:

- 7,500 MW reflects the total original amount of desired OSW capacity as set forth in EO 92;
- 6,400 MW reflects the remaining desired OSW capacity after the Ocean Wind I 1,100 MW project was awarded by the Board; and
- 3,742 MW reflects the remaining desired OSW capacity after the Ocean Wind II 1,148 MW project and ASOW 1 1,510 MW project was awarded by the Board.

Additionally, the November 2020 Order declared that any transmission project(s) the Board selected through the SAA solicitation would be a "state public policy project" and that all costs of any Board-selected transmission project(s) would be recoverable from New Jersey customers, in accordance to a FERC-accepted cost allocation.[58] The November 2020 Order also directed that any state or private entity wishing to utilize any SAA selected project, would be expected to bear a fair share of any development and operating costs.[59] The November 2020 Order further declared that the SAA was not intended to impact the first OSW award to Ocean Wind I, nor would the SAA process alter any guidance issued to bidders in the Board's Second Solicitation.

Under the SAA, the Board decides which, if any, of the transmission projects received through the SAA solicitation proceed to construction and may also decide to terminate the SAA process, or select no transmission projects, if those decisions are in the best interest of the State.

The November 2020 Order authorized PJM to include three "options" in a future RTEP solicitation window. The term "option" refers to the expected component parts of an OSW transmission solution. It is not intended to indicate that the options are necessarily exclusive or inclusive of one another.

[58] November 2020 Order, supra note 33 at 8.

[59] Id.

Option 1, including Option 1a and Option 1b

Option 1 projects are those that would upgrade the onshore portions of the PJM regional transmission system to accommodate the increased power flows from the OSW generation projects. Included within the overall Option 1 universe are Options 1a and 1b. Option 1a involves upgrades to the PJM bulk system, while Option 1b typically involves onshore transmission facilities that would extend the PJM Grid to more efficiently enable the coordinated connection of offshore transmission facilities.

Prior to the SAA solicitation, PJM and Staff further subdivided the Option 1 upgrades into separate classifications. Option 1a projects reflect system upgrades to existing onshore transmission facilities required as a result of PJM's study of the planned injections of OSW generation at proposed POIs. Option 1b projects represent any additional onshore transmission facilities that would extend the onshore PJM Grid to more efficiently enable the coordinated connection of offshore transmission facilities. If an "Option 1 only" solution is selected through the SAA, each generator would be responsible to build the necessary transmission facilities, including offshore substations, onshore and offshore converter stations if employing HVDC cables, and offshore and onshore transmission cables to interconnect at the SAA POI.

Expected benefits of Option 1a and Option 1b projects included:

- Cost effective system upgrades. By identifying and constructing onshore upgrades needed for the planned OSW injection at one time, rather than implementing such upgrades on an OSW generation project by OSW generation project basis – over years – costs, engineering needs, and environmental risks would all be minimized.

- A streamlined interconnection pathway for future OSW generation projects. Under Option 1, onshore upgrades are identified prior to the selection of future OSW generation projects to ensure that power injection into a POI can meet reliability standards. Therefore, subsequent generation developers will have more certainty regarding the cost and schedule for onshore upgrades as a result of these advanced construction efforts.

Option 2

Option 2 projects would have transmission developers design and construct offshore transmission facilities, including substations, converter stations if needed, and electric transmission cables to connect one or more OSW generation projects to an onshore POI enabled by either an Option 1a or an "Option 1a + Option 1b" solution. Under an Option 2 proposal, OSW generators would be responsible for collecting the energy from each turbine and connecting to the Option 2 offshore substation.

Expected benefits of Option 2 projects included:

- Minimizing the number of offshore and onshore cables. Connecting multiple OSW generation projects to a single offshore substation reduces the number of Shore Crossings and offshore and onshore cable routes.

- Offshore cable and substation infrastructure would have a dedicated team focused on transmission development. An Option 2 project would enable Transmission developers and OSW generators to focus on the work in which they have the most expertise.

Option 3

Option 3 projects would connect offshore substations to each other, in order to directly interconnect, or network, multiple offshore wind projects, which could improve reliability and market outcomes for OSW generators and ratepayers. Option 3 projects have been referred to as an "offshore backbone."

Expected benefits of Option 3 projects included:

- Improved reliability and availability of OSW deliverability to onshore POIs.

- Improved access to transmission facilities by future OSW Generation Projects, and market efficiency benefits associated with linking the selected OSW generation projects.

SAA Proposals Received

At the close of the SAA application window, PJM received 80 proposed projects from 13 different applicants - four incumbent TOs, eight independent transmission developers, and one partnership between an independent transmission developer and an incumbent TO. The proposals represented a mixture of conventional as well as creative, novel, and competitive solutions to respond to New Jersey's OSW transmission challenge.[60]

The 13 applicants were:

1. Anbaric Development Partners, LLC ("Anbaric");
2. Atlantic City Electric Company ("ACE");
3. Atlantic Power Transmission, a Blackstone Infrastructure Partners portfolio company ("APT");
4. Con Edison Transmission, Inc. ("ConEdison");
5. Jersey Central Power & Light Company ("JCP&L");
6. LS Power Grid Mid-Atlantic, LLC ("LS Power");
7. Mid-Atlantic Offshore Development, LLC, a joint venture of EDF Renewables North America and Shell New Energies US, LLC ("MAOD");
8. NextEra Energy Transmission MidAtlantic Holdings, LLC ("NextEra");
9. Outerbridge New Jersey, LLC, a subsidiary of Rise Light & Power, LLC ("RILPOW");
10. PPL Electric Utilities ("PPL");

[60] Due to the volume and detail of the proposals, each proposal is not summarized in detail in today's Order. PJM has released six individual reports detailing all aspects of each submitted proposal (Economic Analysis, Financial Analysis, Reliability, Option 1a constructability, Option 1b/2 constructability, and Option 3 constructability).

11. PSE&G Renewable Transmission LLC and Ørsted N.A. Transmission Holding, LLC ("Coastal Wind Link");
12. Public Service Electric & Gas Company ("PSE&G"); and
13. Transource Energy, LLC ("Transource").

Of the 80 project proposals received, there were 27 Option 1a solutions, 11 Option 1b solutions, 34 Option 2 solutions, and 8 Option 3 solutions.

Evaluation Framework and Approach

Baseline Scenario

As explained in the November 2020 Order, the Board would not select an SAA Solution unless it would likely result in a "more efficient and cost-effective means of meeting the state's offshore wind goals and decreasing the chance of delays."[61] Therefore, the first step in the evaluation process is a robust comparison of the proposed SAA Solution against the status quo. To facilitate this comparison, Staff and Brattle developed the baseline scenario ("Baseline Scenario" or "Baseline").

Generally, the Baseline Scenario included estimated costs and processes associated with the bundled procurement of all offshore and onshore transmission facilities, constructed by an OSW generator, necessary to interconnect up to 7,500 MW of OSW to the transmission and distribution system in the absence of any SAA Solutions. In the Baseline Scenario, this bundled onshore and offshore transmission procurement and development will continue on a project-specific basis until the 7,500 MW goal is met. Each future OSW generator the Board selects would arrange for interconnection of its individual project to the PJM Grid and develop the transmission facilities necessary to connect its project to the existing system. PJM would then identify the system upgrades needed to interconnect each project through its generation interconnection request process.[62] In sum, under the Baseline, each OSW generator would design only the transmission facilities necessary for its project to meet its specific needs, including the transmission technology selected (for example HVAC vs. HVDC), the necessary ratings of the facilities, and the location for Shore Crossing, POI, and onshore and offshore Cable Routes. All of these transmission facilities would be procured in a bundled manner with their generation facilities.

The full costs of building and operating the onshore and offshore transmission facilities would be recovered through the fixed-price OREC payments at the price proposed by the winning OSW generators and approved by the Board, with a true-up mechanism described below for system upgrade costs. The approved OREC prices, so far, have not included the full ratepayers' final share of the PJM TSUCs, but they do include an estimate. When actual upgrade costs are known, the OREC price will be trued-up to account for the TSUC cost-sharing proposed by the OSW generator and accepted by the Board, which results in a partial sharing of these costs with New

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[61] November 2020 Order, supra note 33 at 8.

[62] When identified through the PJM interconnection queue for an Individual project request, system upgrades are also referred to as Network Upgrades.

Jersey ratepayers.[63] In addition, under the Baseline, it is anticipated that OSW generators will be able to receive a 30% ITC on the OSW generator-owned transmission facilities necessary to deliver the generation to the interconnection point on the PJM Grid.

The first step in the development of the Baseline Scenario is to identify the full set of transmission facilities needed to enable New Jersey's 7,500 MW of OSW by 2035. Under the Board's previous OSW solicitations, the three awarded projects were presumed to use this Baseline approach to develop the necessary transmission upgrades to support their individual projects, totaling 3,758 MW, as follows:

1. Ocean Wind I - 1,100 MW, interconnected at the BL England and Oyster Creek POIs;
2. Ocean Wind II - 1,148 MW, interconnected at the Smithburg POI; and
3. Atlantic Shores 1 - 1,510 MW, interconnected at Cardiff POI.

The Baseline Scenario assumes that OSW generation projects that are selected in the Board's future generation solicitations will interconnect at specific POIs. Following the Second Solicitation, the Baseline assumes 2,542 MW will be interconnected at Deans, and 1,200 MW will be interconnected at Larrabee. To achieve these injections, the Baseline assumes all necessary transmission components of three additional OSW generators will use HVDC technology.

The next step was to estimate costs for the PJM system upgrades necessary to support the interconnection of future OSW projects. PJM system upgrade costs were identified by reviewing required Network Upgrades of current generation interconnection requests (following the completion of Solicitation 1 and Solicitation 2), supplemented with system upgrade cost information for non-PJM interconnection queue facilities identified by PJM through SAA reliability studies. Staff and Brattle reviewed publicly-available PJM interconnection queue data to identify the active projects that could be selected to satisfy the necessary OSW injections, and, accounting for supplemental expected system upgrade cost information, averaged the Network Upgrade costs from the referenced studies.

Next, the full set of facilities required to interconnect OSW generators to the POI, assumed under the Baseline, needed to be identified. Staff and Brattle assumed that each future generator would fill a single HVDC export cable, consistent with the size of the recently procured New Jersey OSW projects (1,100 MW to 1,510 MW). Offshore converter station platforms for each future generator were assumed to be located at the edge of the applicable BOEM OSW lease area, at the point closest to the POI. To identify the cost of these necessary facilities, Staff and Brattle estimated the costs of onshore and offshore Baseline transmission facilities based on a survey of public reports and market data, including information from the National Renewable Energy Laboratory, Offshore Renewables Balance-of-System and Installation Tool ("NREL ORBIT"), NYSERDA 2021 Power Grid Study[64], PJM construction cost estimates, and other public studies.

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[63] As an example, TSUC provisions are provided and explained in Ocean Wind II June 2021 Order, supra note 21 at 27, 16; Atlantic Shores 1 June 2021 Order, supra note 22 at 27, 16.

[64] New York State, New York Power Grid Study, https://www.nyserda.ny.gov/About/Publications/Research-and-Development-Technical-Reports/Electric-Power-Transmission-and-Distribution-Reports/Electric-Power-Transmission-and-Distribution-Reports---Archive/New-York-Power-Grid-Study.

The total estimated onshore and offshore transmission-related capital cost of the Baseline Scenario is approximately $8.9 billion (2021 dollars) for 6,400 MW of offshore wind. This does not include the costs for the 1,100 MW Ocean Wind 1 facility.

The $8.9 billion Baseline capital cost estimate does not account for the 30% federal ITC, which is available for most of the transmission-related portions of OSW projects, provided those portions are constructed as part of the OSW project. Based on the cost estimates and the assumption that projects will be able to qualify for the ITC for all facilities—generation and transmission other than onshore system upgrades—the Baseline cost estimate is reduced by approximately $2.2 billon (2021 dollars), resulting in an estimated Baseline cost of $6.7 billion net of ITC.

When comparing SAA projects to the Baseline, cost is only one factor. Other factors that make SAA projects more or less favorable compared to the Baseline are described below.

Factors that make the SAA projects potentially superior against the baseline include the following:

- First, the PJM interconnection queue reform process will likely extend the expected queue completion date of near-term projects under the Baseline Scenario. Any new OSW projects entering the PJM interconnection queue (based on the currently proposed reforms by PJM) would not likely be able to complete their interconnection process until mid-2027.[65] This is a significant disadvantage of the Baseline Scenario versus selecting system upgrades through the SAA (i.e., Option 1a solutions), which could enable construction efforts for the necessary PJM system upgrades to begin upon PJM Board approval of the SAA Projects awarded in today's Order. Some OSW generators have consistently raised schedule delays due to PJM queue reform as a cause of concern.

- Second, in the Baseline Scenario, OSW generators will size their transmission facilities only to meet their specific needs, foregoing the opportunity to take advantage of coordinated planning, economies of scale, and reduced environmental and community impacts (e.g., through means such as the development of POIs and common Transmission Corridors that can serve multiple OSW projects).

- Third, because each generator would build their own transmission facilities in the Baseline Scenario, each OSW project would require a separate onshore Transmission Corridor to reach the existing PJM Grid. To achieve 6,400 MW[66] of OSW generation in the Baseline Scenario, it is estimated that five such corridors would be required, including the two corridors for the Second Solicitation projects and three additional corridors for projects awarded in future solicitations. Each of these corridors would involve large-scale construction efforts taking place over several years and would require installation of underground access Cable Vaults and Duct Banks to facilitate installation and operation of export cables.

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[65] *See* PJM Interconnection Queue Reform, presented to PJM Interconnection Process Reform Task Force (March 11, 2022).

[66] This excludes the 1,100 MW awarded to Ocean Wind I during the First Solicitation.

- Lastly, in the Baseline Scenario, each OSW project using HVDC technology would need to obtain a plot of land comprising several acres, reasonably close to the POI, in order to construct the needed onshore converter station. This could lead to only specific parties being able to obtain land near desirable POIs, which would place later entrants into the OSW market at a disadvantage and at risk for not being able to obtain the land sought.

Factors that make the Baseline Scenario potentially attractive include:

- OSW generators will select the optimal technologies (such as HVDC cables) specific to their projects at the time their projects are being developed. Since offshore transmission facilities selected through the SAA would rely solely on the technologies that SAA bidders propose (reflecting technologies and costs as of 2022), the Baseline Scenario offers the opportunity to flexibly take advantage of future technological advances.

- The Baseline Scenario requires OSW generators to recover the transmission-related costs through fixed-price OREC payments (with pre-defined escalation over time), beginning only once the OSW project is interconnected and delivering energy to the PJM Grid. In contrast, costs of SAA facilities are recovered through PJM's tariff as soon as the SAA facilities are placed in service and under the terms of any particular transmission developer's cost control mechanism.

- Lastly, Baseline Scenario will result in OSW generators building and operating their own offshore transmission and onshore interconnection facilities, minimizing the potential project-on-project risks during the construction phase and aligning operational and maintenance incentives. Relying on a separate entity to construct and operate the SAA transmission elements creates two types of project-on-project risks not present in the Baseline Scenario: (1) transmission facilities do not reach commercial operation dates in time (as early as 2028) to align with the testing, commissioning, and in service dates of the OSW generators; and (ii) the operations, outages, and repairs (if any) of SAA transmission facilities may not be optimized to allow project owners to achieve the highest value for their generation.

The attributes of the Baseline Scenario described above establish a measure against which to compare the proposed SAA Solutions. This enables the critical initial phase of evaluation - the determination of the appropriate scope of facilities (i.e. which options) to be procured through the SAA. Prior to a direct comparison of any SAA Proposals against one another, the evaluation must first compare each scenario created by the SAA proposals against the Baseline, in an effort to identify the appropriate combination of transmission facilities and procurement methods that maximize benefits to New Jersey ratepayers. The Baseline Scenario approximates a future without the SAA. Because there are many moving parts and evolving variables in OSW generation and transmission, the Baseline Scenario is necessarily an estimate. Using the Baseline Scenario, the Board can assess whether the proposed SAA Solution will, or will not improve upon the Baseline.

Evaluation Criteria

Based on the November 2020 Order, Staff set out detailed evaluation criteria in the SAA solicitation window overview document published by PJM.[67] This document contained guidance to interested bidders on the overall New Jersey ratepayer impact and risk perspective Staff would apply in its evaluation of SAA proposals. These published evaluation criteria were:

- **PJM system reliability –** ability to provide a solution to the needs defined in the problem statements, additional needs identified by the proposing entities, or the needs associated with alternative POIs and to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC, and local TOs), including the solution's ability to (a) resolve identified PJM reliability violations and satisfy any applicable criteria that may impact the performance measurement of the project, even if it was not explicitly stated as part of the original problem statement; and (b) reduce the need for must-run generation and special operating procedures, extreme weather outages and weather-related multiple unforced outages, reduced probability of common mode outages due to electrical and non-electrical causes, islanding, power quality degradation.

- **Project constructability** – extent to which the proposal identifies, addresses, and mitigates (through technical studies and documentation of experience with similar solutions elsewhere) the financing, constructability, execution, technology, environmental, and permitting challenges of the proposed solution, including the need for construction- or other-related outages on related transmission facilities.

- **Project costs –** total cost of proposed solutions and individual elements (partial solutions); quality of proposed innovative cost control approaches (such as phased-in development of project segments, capped project costs or capped revenue requirements, and cost recovery for excess or unused capacity) or levelized cost recovery options (such as trended original costs, which may improve the intergenerational equity of cost recovery); financial commitments regarding rate of return, specific provisions to protect against cost overruns, or other comparable provisions designed to control costs.

- **Project risk mitigation** – ability of the proposed solution to mitigate environmental, permitting, financing, constructability, timing, project-on-project (including the use of financial assurance mechanisms, guaranteed in-service dates or financial commitments contingent on meeting targeted commercial online dates, and delay damage payment provisions), and any other risks that could increase costs, reduce value, or delay the development and delivery of OSW generation for New Jersey.

- **Environmental benefits** – ability of the proposed solution to minimize potential environmental impacts; minimize impacts to marine, nearshore, and onshore habitats, listed species, cultural resources, air (emissions) including potential benefits, water quality, noise, aesthetics, tourism, and navigation; minimize impacts related to fisheries resources and the fishing community and industry.

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[67] PJM Competitive Planning Webpage, 2021 NJ OSW Proposal Overview, at 7-8, https://www.pjm.com/planning/competitive-planning-process.

- **Permitting plan** – ability of the proposed solution to minimize permitting risks, including plan for and likelihood of achieving all State and Federal necessary regulatory agency approvals, permits, or other authorizations; likelihood of meeting projected commercial operation dates, operation and maintenance plans, site control or ability to achieve site control, constructability, project longevity, and project schedule.

- **Quality of proposal and developer experience –** quality of project documentation and proposal description, discussion of commitments and benefits, and supporting analyses and benefits quantifications (including documentation of assumptions and analyses, if any); documentation of developer experience relevant to the successful implementation of the proposed solution.

- **Flexibility, modularity, and option value of solutions** – ability of project proposals to achieve efficient outcomes through combinations of solutions for Option 1a, Option 1b, Option 2 and Option 3 needs, or ways in which proposed solutions, or portions of proposed solutions, can be combined, integrated, and sequenced to more cost effectively achieve the State's overall public policy and risk mitigation objectives; ability of the proposed solution to accommodate future increases in OSW generation above current plans; innovative solutions that yield a transmission investment schedule that is optimally aligned with the planned schedule of OSW Generation Project procurements.

- **Market value of offshore wind generation –** ability of the proposed solution to maximize the energy, capacity and Renewable Energy Credit ("REC") values of OSW energy generation delivered to the chosen POIs, including mitigation of curtailment risks, and the level and sustainability of PJM capacity, congestion, or other rights created by the proposed solution that increase the delivered value of the OSW generation or otherwise reduce the total cost of the proposal.

- **Additional New Jersey benefits –** ability of proposed solutions and associated upgrades to provide additional onshore-grid-related benefits, resolve PJM market congestion, and/or otherwise reduce or avoid PJM-related costs and improve PJM market performance; this includes (a) energy market benefits, including energy deliverability of offshore wind production or curtailment, production cost savings, or other benefits; (b) identification of benefits to the transmission system, including synergies with transmission solutions from already-ongoing procurements, opportunistic replacement of aging transmission infrastructure, the creation of valuable transmission-related rights, and other transmission cost savings; (c) capacity market benefits (including Capacity Emergency Transfer Limit ("CETL") increases), improve resiliency/redundancy, avoid future costs (such as future reliability upgrades or aging facilities replacements); and (d) other benefits, including state energy sufficiency, improvements in local transmission and distribution outage statistics, reduced utilization of aging infrastructure, improvements in local resiliency.

The criteria provide a way by which Staff could consider the optimal SAA Solution. Neither the Board nor Staff provided any relative weighting of any of these evaluation criteria, enabling Staff to weigh criteria in their recommendation as was deemed appropriate throughout the proposal review process. The Board retained flexibility to consider each criteria apart from one another, or collectively. No single criteria was dispositive. This flexibility was appropriate, due to the first-ever nature of this SAA solicitation, with a large degree of uncertainty related to the nature of proposals that would be received through the solicitation. However, by explaining the criteria in detail, the applicants were provided with a series of goals that would be reflected in an optimal SAA Solution.

To facilitate its review, Staff and Brattle combined the ten criteria into five high-level metrics and associated sub-metrics, described below.

Reliability & Other Transmission Benefits

Regarding reliability, Staff and PJM evaluated whether the proposed SAA transmission facilities will best utilize the existing transmission system and provide the necessary new facilities to support 7,500 MW of offshore wind. PJM studied the impacts of various injection scenarios for new generation facilities on its system to ensure that the grid could accommodate the OSW injections while maintaining system reliability. PJM identified where on its system the injections of OSW energy would cause reliability criteria violations and identified the transmission upgrades necessary to resolve those violations. Based on these analyses and specified upgrades, all SAA Scenarios considered will meet PJM's reliability criteria once the identified system upgrades are completed.

PJM's reliability analysis included its generator deliverability procedures, which is its primary reliability test used in generator interconnection studies to identify reliability violations caused by new OSW generators. By itself, this reliability analysis typically identifies the majority, if not all, of the upgrades needed to reliably interconnect new generation to the PJM system. As part of PJM's reliability analysis, PJM evaluated the Option 1a proposals that were in direct competition with one another, having been designed to solve similar violations. PJM provided performance scores for each of the competitive Option 1a proposals that informed Staff's recommendation. Option 1a proposals that were preferred on the basis of performance and cost were utilized to solve similar violations when they arose across PJM's modeling of different SAA Scenarios.

In addition to PJM's reliability analysis, Staff examined a suite of other transmission benefits and potential impacts, including whether SAA proposals effectively utilized available POIs. New Jersey has a limited number of attractive POIs on the grid to interconnect new, OSW generation. An "attractive" POI may include a variety of considerations, such as availability of excess headroom, location, availability of surrounding land, permitting challenges, and community considerations. In addition, Staff also analyzed whether SAA proposals would ensure healthy competition in future generation solicitations. Ensuring any SAA Solution promotes healthy competition among future OSW generators remains a key element in evaluating the proposals. SAA Solutions that supported competition in future OSW generation solicitations were preferred to those that may stifle competition.

Staff also considered the local economic benefits to New Jersey in its evaluation. Construction of new transmission facilities can provide significant employment and economic benefits to New Jersey as a whole and to local communities within the State. Staff evaluated whether potential

SAA developers proposed and guaranteed ways in which their proposed projects would maximize benefits to New Jersey's economy. SAA proposals that provided higher guaranteed benefits to the State were preferred.

With each proposal, Staff also considered the ability to support a future OSW transmission "backbone." An offshore network, one in which the offshore substations of OSW farms are electrically connected to one another in the ocean, provide potential benefits to New Jersey and the PJM system. These benefits include reducing curtailments of OSW resources, improving system reliability, reducing congestion on the grid, improving OSW availability, and increasing capacity import limits on the onshore system. However, to achieve these benefits, offshore substations and their platforms needed to be designed with the ability to operate in a networked fashion, linked with neighboring offshore substations. Staff evaluated whether the design of the proposed offshore substation was able to facilitate a future "Option 3" offshore backbone network. SAA Solutions that provided the best opportunity to do so were preferred relative to those that would have a limited ability to do so, or no ability at all.

Lastly, Staff examined the operational risks of each SAA bid. Offshore transmission facilities, especially those that are not interconnected to other offshore transmission facilities, can create outage risks for OSW generators if the transmission facilities are disconnected. Staff evaluated whether the SAA proposals provided incentives for maintaining transmission operability in alignment with the needs and incentives of OSW generators. SAA proposals that mitigate outage risks for OSW generators were preferred over those that did not propose an approach or incentives to do so.

Net Ratepayer Cost Impacts

By utilizing the SAA, New Jersey has the unique opportunity to identify the most cost-effective transmission approach by comparing the total costs of any selected SAA Solution against what would otherwise be needed to enable 7,500 MW of OSW generation. For each SAA Scenario, Staff assessed the expected total ratepayer cost of all necessary OSW-related transmission facilities, the quality of the cost containment provisions proposed by applicants, the proposed cost recovery profile, the PJM energy and capacity market benefits of selecting alternative POIs, and the timing of the cost impacts on ratepayers.

Cost containment mechanisms associated with SAA proposals can limit the risk to ratepayers of cost overruns for transmission projects by creating incentives to complete the proposed projects at the estimated costs. Brattle and PJM conducted a legal review of the strength of submitted cost controls, categorized by their effectiveness, and compared the submissions against the ratepayer cost protections that New Jersey would expect to obtain in its generation procurements (through fixed OREC prices). Staff evaluated the quality of the cost containment mechanisms each bidder proposed by (i) analyzing the scope of the cost cap, if any, on Option 2 facilities, (ii) identifying exclusions and penalties for failing to meet identified commitments, and (iii) reviewing the legal language proposed to enforce the cap in the DEA. SAA proposals that limit the risk of cost overruns to New Jersey ratepayers were preferred to those with weaker or no cost control mechanisms. The final cost allocation, including any cost containment or other commitments would be memorialized as part of the FERC approval process and any authorized costs would flow through to New Jersey ratepayers, as required by the SAA process.

One potential issue that impacted the analysis is that the costs of transmission upgrades are "front-loaded," meaning that ratepayers may see the costs of any transmission costs in their rates before offshore wind facilities begin generating power. Further, under traditional ratemaking, the costs associated with a new transmission project start higher in the early years of project's existence, declining over time as the transmission investments are depreciated. On the other hand, a fixed-price payment structure spread out over 20 years—as utilized to recover transmission costs in the Baseline Scenario—distributes total costs equally over time through the OREC schedule. Thus, one consequence of utilizing the PJM transmission planning process is that ratepayers see greater costs in the near term for any selected SAA project, yet those costs would decrease over time. To reduce potential near-term rate impacts, SAA Scenarios with lower near-term costs to ratepayers were preferred to those with more front-loaded cost recovery mechanisms.

Another factor that was taken into consideration was the impact of different SAA Solutions on the revenues that future OSW generation projects would expect to earn in PJM's markets. Under the OREC structure, any additional revenues earned in the PJM markets are credited to New Jersey customers. PJM identified that using certain POIs could provide additional efficiency benefits in PJM's energy and capacity markets that thus reduce the net costs of generation to New Jersey ratepayers. SAA Scenarios with higher OSW generation market values (energy and capacity) and lower load payments were preferred, as these items would ultimately offset a portion of the SAA transmission costs.

Staff evaluated the ratepayer cost impacts of the SAA Scenarios in terms of their total installed capital costs and their total (annualized) ratepayer costs. The total installed capital costs include all costs incurred to construct the transmission facilities. These installed costs were then compared on a $/kW basis to normalize for the differing amount of OSW generation enabled by each proposal. In addition, New Jersey ratepayer costs were calculated in terms of $/MWh of enabled OSW to estimate what ratepayers would have to pay for the transmission portions of OSW generation in their utility bills over the assumed life of the facilities.

Independently, PJM and its financial consultant assessed the effectiveness of SAA Proposals' cost containment mechanisms and the lifetime costs to ratepayers, including the total costs of the facilities to ratepayers and OSW generation cost savings. PJM also performed energy market simulations to evaluate the economic performance of selected OSW Scenarios, as well as evaluating the impact of various SAA Scenarios on capacity market parameters, including the CETL. Staff and Brattle reviewed these reports and used their contents to inform their analysis and the evaluation process described above.

Rate Counsel also assisted Staff in evaluating the ratepayer impacts of the SAA proposals. Rate Counsel provided Staff its independent feedback on the ratepayer costs, which Staff closely considered and incorporated into its final analysis.

Schedule Compatibility

Due to the need for transmission facilities to be built in time for OSW generators to construct, test, commission, and operate their facilities, it is important that the transmission facilities are available by the time the generator needs them. During the Board's stakeholder meetings regarding the SAA process, OSW generators indicated that project-on-project risk due to a misalignment in the timing of generation and transmission infrastructure is their primary concern with the SAA approach. In fact, the Baseline Scenario (i.e., all OSW-related transmission facilities are constructed by the OSW generator) creates the least project-on-project risk, as the same entity is responsible for coordinating all development of new onshore and offshore facilities related to an individual OSW project (with the exception of required upgrades to existing grid infrastructure).

Staff assessed how well the proposed transmission development schedules aligned with the generation solicitation schedule, and a potential acceleration of the solicitation schedule Staff gave preference to SAA bids with proposed in-service dates of at least 12 months before the generation procurement schedule, and those SAA bids that included flexibility to work with generation developers to ensure schedule alignment.

Additionally, the Baseline Scenario aligns incentives to achieve this coordination, by withholding OREC payments until electricity from an OSW project is flowing to the grid in New Jersey. In its Order instructing PJM to begin the SAA solicitation, the Board emphasized that, "[w]hile the Board continues to see the benefits of exploring a coordinated offshore wind transmission option more fully, the Board notes that it will weigh heavily proposals from Transmission Developers that utilize the voluntary protections laid out in the SAA process to limit down-side risk to New Jersey consumers and to reduce project-on-project risk for [OSW] generation [project] developers."[68] As such, SAA proposals that provided an approach for reducing project-on-project risk were preferred to those that did not.

Schedule commitments can limit the risk of schedule delays by creating incentivizes or guarantees to complete the proposed projects on schedule. Staff evaluated whether the commitments proposed by the SAA developers were likely to provide assurance that the proposed schedule will be achieved to allow OSW generators to meet their placed in service dates in a manner that is comparable with, or better than, the timeline assurances the Baseline Scenario establishes. SAA proposals with stronger commitments that limit the risk of schedule delays were preferred to those with no or weaker commitments.

Environmental Impacts

Development of transmission lines requires careful consideration of the potential environmental impacts of the construction and operation of these facilities, especially when these facilities are located near environmentally sensitive resources along coastlines and waterways. Staff, Brattle, PJM, and DEP completed an extensive analysis of the potential environmental impacts of the proposed SAA facilities and the permitting process necessary to build these facilities. Each proposal was evaluated both for its impacts on environmental resources as well as the risks associated with receiving the necessary permits to construct the facilities. More generally, SAA proposals were also evaluated based on the number of Transmission Corridors they would create, because of the substantial impact this determination alone has on the ability of proposals to minimize environmental and community impacts.

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[68] November 2020 Order, supra note 33 at 9.

In partnership with Staff, DEP reviewed the pertinent application materials and evaluated each unique proposal as it related to potential environmental impacts and permit feasibility, based on a number of environmental considerations. This analysis included review of the following: wetlands; streams and waterbodies; threatened and endangered species; fisheries; marine and terrestrial habitats; cultural and historic resources; impacts on environmental justice communities; Green Acres-encumbered parklands; and State-owned lands, among other categories. Each proposal was assessed an overall risk level, ranging from low to high. The risk levels were assigned based on the information provided in the SAA bid and any responses to applicable clarifying questions. DEP did not that because it is early in the proposed project development process, in many cases, sufficient details necessary for a comprehensive environmental assessment were lacking. Thus, the overall risk level assigned in this preliminary review did not necessarily reflect all aspects that determine the actual viability of a project from an environmental and permitting aspect. Due to the relatively early stage of project development of proposals submitted through the SAA, certain elements of the assessment remained subject to future revision, based on evolving developments through the project's life-cycle.

DEP recommended that the Board award projects that minimize the number of cables coming onshore in New Jersey, while also meeting PJM's reliability requirements and the State of New Jersey's transmission needs. DEP further recommended that Cable Routes be sited within existing roads, corridors, and ROWs; avoid Shore Crossings and Cable Routes through back bays and sensitive coastal areas to the greatest extent possible; reduce new impacts to Green Acres-encumbered parkland and State-owned lands, all to the greatest extent possible, while ultimately minimizing the number of radial lines associated with OSW farms.[69] In addition, DEP recommended special consideration be given to applications that avoid impacts to natural resources, minimize impacts where avoidance is not possible, and propose appropriate measures to mitigate impacts when necessary.

In addition to the proposal-specific review, Staff's evaluation also considered the number of Transmission Corridors necessary in each SAA Scenario to achieve the overall New Jersey OSW goal. As described above, having fewer Transmission Corridors provides a number of significant benefits, including potentially greater cost savings, reduced environmental impacts, and fewer community disruptions. Critically, guaranteeing fewer Transmission Corridors through a coordinated transmission approach is the only way to guarantee the wide range of environmental and community benefits outlined above. Although operational risks may exist in having consolidated transmission corridors, SAA proposals enabling achievement of OSW goals with fewer corridors were preferred, due to the substantial benefits enumerated above.

Constructability

To assess whether the transmission facilities could be constructed as designed, Staff, PJM, and DEP evaluated each proposal's design. Many factors contribute to the potential constructability of a proposal, including, but not limited to, supply chain plans, schedule, technology selection,

[69] Radial lines provide a single pathway from power to travel from a generator to a POI, as opposed to networked facilities, which provide multiple pathways for the power to travel.

developer experience, environmental and permitting challenges, ROWs, and risk mitigation measures.

PJM closely evaluated the proposals and utilized an analysis similar to that of their typical RTEP process. This analysis included reviewing the PJM Proposal Submittal Template (including project description, value proposition to New Jersey, cost control measures, and risk mitigation measures), the Board's Supplemental Offshore Wind Transmission Proposals Data Collection Form, project diagrams and schedules, and the technical analysis files and documentation. PJM's review also included evaluation of project scope, complexity and constructability factors that impact the project cost and/or schedule, including but not limited to ROW acquisition, land acquisition, siting and permitting requirements, project complexity, project coordination complexity, outage coordination, and project schedule.

In addition to including PJM's constructability analysis into its evaluation, Staff and Brattle also closely examined whether the developer had previously built facilities similar to those proposed. A particular emphasis was given to the experience the proposing entities had developing offshore Transmission Projects if they submitted an Option 2 or Option 3 proposal.

Due to the importance of gaining access to the necessary ROW and land to host converter stations near POIs, Staff closely considered the degree to which proposals made use of existing or previously obtained ROW and site control for their proposed facilities. As described above, a coordinated transmission approach requires land for transmission facilities and any associated work OSW generators require for their projects, depending on the scope of the coordinated facilities described in each proposal. Proposals that have already obtained ROW and site control were preferred.

DMAVA staff reviewed proposals that indicated plans to have transmission cables make landfall at the National Guard Training Center ("NGTC") at Sea Girt. DMAVA, who administers the NGTC, assessed potential impacts of SAA Proposals to the grounds and operational mission of this facility. DMAVA staff's review indicates that placing underground infrastructure related to OSW transmission on NGTC grounds is supportable, provided that a number of conditions are met. Those conditions include: (i) Cable Routes that avoid impacts to onsite wetlands; (ii) a construction laydown area that does not disrupt NGTC's activities; (iii) the work to install the transmission infrastructure occurs during a period that would not adversely impact either NGTC's mission or endangered species that are seasonally present at NGTC; (iv) the entity seeking to utilize NGTC as a landfall location endeavors to minimize the number of times heavy construction is required (i.e., seeks to do trenching and earthwork only once); and (v) a long-term easement and a temporary construction easement package must be submitted, processed, and finalized before construction can commence. DMAVA staff's assessment indicated that proposals that contemplate significant above-grade structures and use of an appreciable portion of NGTC's footprint would be disruptive and problematic due to such infrastructure competing with military training site areas and activities on such areas that are routinely conducted at the site. It is important to note that while DMAVA administers the NGTC, the decision to utilize the grounds for any transmission purpose rests with the New Jersey Statehouse Commission.

Previously Awarded OSW Projects

The November 2020 Order noted that the Ocean Wind I project, awarded through the First Solicitation, would not be impacted by the SAA solicitation. When the Board awarded projects in its Second Solicitation—Ocean Wind II and ASOW 1 (collectively, "the Second Solicitation Projects")—it noted that "*interconnection efficiencies for the* [Second Solicitation] *Project may exist as a result of a selected SAA project*..." (emphasis added),[70] and left open the possibility for the Second Solicitation Projects to utilize an SAA Solution, should the use of the facilities envisioned under the SAA process be in the best interest of New Jersey ratepayers.[71]

In both Orders relating to the Second Solicitation Projects, the Board further noted:

> For any deviation from the interconnection plan approved in this Order, including for use of any SAA transmission capability, a mutually acceptable revision to this Order will be required. Prior to the determination by the Board that use of SAA transmission capability is in the best interests of New Jersey ratepayers, [the Second Solicitation Project] will need to pursue its PJM transmission interconnection plan, and will be required to recognize the reasonableness of including such out-of-pocket costs in any mutually acceptable revision to this Order.[72]

More specifically, Staff was instructed that if the determination is made that the utilization of any SAA Solution(s) would increase the benefits to ratepayers and the residents of New Jersey, and would not negatively impact the OSW project, Staff should initiate discussions with each of the Second Solicitation Projects regarding a potential change to its interconnection plan, including the return of any interconnection cost savings to ratepayers in the form of a reduced OREC price.

While not determinative in itself, one additional consideration in Staff's review of potential SAA Solutions was how well the proposed SAA Solution might work with the Second Solicitation Projects. A key element of this review is the effect of the PJM interconnection queue reform process. All new generators, including OSW projects, must complete PJM's interconnection queue process. On June 14, 2022, PJM filed revisions to its tariffed interconnection process, proposing to restructure its queue process. The proposed PJM interconnection queue reform rules are currently pending before FERC.

If accepted, the proposed queue reforms are expected to result in significant improvements in the timely processing of interconnection requests over the long-term. However, the proposed queue reforms are expected to impact the two Second Solicitation Projects differently because PJM assigns OSW generation projects into "queue cycles" based on when the OSW generation project submitted to PJM its request for interconnection to PJM. Thus, while ASOW 1's earlier queue position is expected to complete the interconnection process and receive its ISAs in late 2022, the Ocean Wind II project which has a later queue position is not expected to receive its ISA until

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[70] Atlantic Shores 1 June 2021 Order, supra note 22 at 23; Ocean Wind II June 2021 Order, supra note 21 at 23.

[71] Atlantic Shores 1 June 2021 Order, supra note 22 at 23; Ocean Wind II June 2021 Order, supra note 21 at 23.

[72] Atlantic Shores 1 June 2021 Order, supra note 22 at 24; Ocean Wind II June 2021 Order, supra note 21 at 24.

the latter part of 2026, assuming FERC accepts the proposed queue reforms. Thus, any necessary Network Upgrades needed to interconnect the Ocean Wind II project are unlikely to begin until the latter part of 2026, absent incorporating Ocean Wind II into the SAA process.

The RTEP process has different drivers and separate rules which may result in completion of system upgrades more expeditiously than through the PJM generation interconnection process. While the RTEP planning process and interconnection study queue are coordinated and integrated into a single RTEP, the RTEP process is not constrained by the interconnection study queue and therefore allows for a more expeditious path to building out the PJM system to meet the needs of New Jersey's OSW.

Because of the currently projected timing of the studies for the AG2 PJM interconnection queue position[73] under PJM's proposed transition timing under the proposed interconnection reform rules, Ocean Wind II may significantly benefit from utilizing an SAA Solution rather relying solely on the interconnection process to identify the needed transmission system upgrades. Further, because Ocean Wind II is at an early stage in PJM's interconnection process, the Ocean Wind II project would be able to request and apply SAA Capability to its existing PJM queue position under the terms of the SAA Agreement.[74] This has beneficial timing implications.

The Board and the State of New Jersey are interested in seeing Ocean Wind II and all other projects fully developed and delivering clean energy to New Jersey's grid within the timeframe proposed in its application. The Board explicitly contemplated potential interconnection efficiencies of this type in approving Ocean Wind II. Thus, Staff evaluated the benefits of SAA Solutions that could potentially accommodate the Ocean Wind II project and alleviate the delay concerns related to Ocean Wind II's current queue position, in light of PJM's ongoing interconnection queue reforms and transition timing associated with such reforms.

ASOW 1 has a clear path toward completing the interconnection queue ahead of PJM's proposed reforms, with an ISA expected later in 2022. However, since the SAA Scenarios that PJM studied included all of the targeted 7,500 MW except for the projects that already had executed ISAs as of November 2020, ASOW 1's capacity of 1,510 MW at Cardiff was included in all SAA Scenarios. PJM has provided guidance on how the ASOW 1 interconnection could be impacted by the SAA project.

PJM provided that if the selected SAA projects obviate the need for identified Network Upgrades or reduced scope for ASOW 1, then ASOW 1 would not be required to build and fund those upgrades projects in their ISA and PJM will reconcile costs as appropriate. PJM also noted that there should be no change to the selected SAA projects unless ASOW 1 requires additional system capability in addition to what is provided by the selected SAA projects.

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[73] "[PJM interconnection] Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time ... Queue AG2 opened on October 1, 2020 and closed on March 31, 2021..." Independent Market Monitor, State of the Market Report 2021 at: 625, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec12.pdf.

[74] See SAA Agreement, sections 4.3 (a), 5.3, 6.2(d)(i).

It is important to recognize that PJM's guidance suggests that the SAA projects, even when not explicitly creating capability for ASOW 1 to utilize in its interconnection study,[75] could impact the actual upgrades needed for interconnection of the ASOW 1 project.[76] Because the SAA project is not yet PJM Board-approved as an RTEP baseline project, the extent of the changes to the Network Upgrades that will be assigned to ASOW 1 cannot be determined at this time. However, PJM has affirmed that it will update its analysis following PJM Board approval to ensure that only the needed transmission upgrades are included in the RTEP and affected ISAs to accommodate the SAA Capability and the queue project interconnection requirements. It is possible that with an SAA project in place, ASOW 1's 1,510 MW injection at Cardiff may be able to rely upon more cost-effective SAA system upgrades in lieu of those identified in its ISA. Because PJM cannot perform a study that integrates the ASOW 1 ISA with approved SAA projects until SAA projects are approved and ASOW 1's ISA is executed, Staff requests flexibility from the Board to continue to closely monitor this integration process and make further recommendations as Staff deems appropriate. This will ensure facilities are built efficiently and costs are not duplicated. ASOW 1 should not see an increase in its costs as a result of the SAA.

<u>Evaluation Results</u>

The evaluation results of the SAA proposals discussed herein are the combined analyses and findings completed by PJM, Brattle, DEP, Rate Counsel, and other relevant State agencies. Staff relied on the following to support its recommendation herein[77]:

- All application materials submitted by all SAA bidders, including Clarifying Question responses;
- Brattle's evaluation report;
- PJM reports;
- DMAVA's memos;
- Rate Counsel's memo;
- DEP's memo; and
- The Pinelands Commission's memo

Staff initially compared the attributes of the four categories of SAA procurement – Option 1a, Option 1b, Option 2, and Option 3 – against the attributes of the Baseline Scenario described above. This comparative evaluation enabled Staff to initially recommend the appropriate scope and attributes of attractive SAA proposals. On the basis of this initial recommendation, Staff identified specific proposals that satisfy these scope and attribute criteria, to be compared against

[75] ASOW 1 project System Impact studies were completed in February 2020.

[76] The costs may be removed if a Baseline project obviates the need for Network Upgrades, but the Baseline upgrades will need to be listed as Contingent Facilities in the ISA. The OSW generator will not be permitted to go in-service without the upgrades unless an interim deliverability study demonstrates the unit is deliverable. If any Network Upgrades are obviated by a Baseline project, then all affected ISAs that benefit from the same upgrades would be updated.

[77] The following materials were critical in informing Staff's recommendation herein. These materials are located on the Board's Public Document Search, under Docket No. QO20100630, https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468.

one another for final recommendation to the Board. This evaluation framework is supported by the need for a feasible process to sort through a wide range of transmission facilities submitted that were not direct competitors against other project proposals. In addition, this initial recommendation, which will identify attributes of favorable SAA Scenarios, is necessary to ensure that the appropriate scope of SAA facilities are recommended for Board approval, as compared to the Baseline Scenario.

Export cable technology: HVAC vs HVDC

During the evaluation, Staff and Brattle considered the implications of HVAC and HVDC technology for the connections from the offshore facilities to the onshore grid. The evaluation concluded that HVDC technology is preferable to HVAC technology for the following reasons:

1. Fewer physical cables are needed in the case of HVDC technology, resulting in less impact to the environment and communities, and potentially enabling more capacity to utilize the same Transmission Corridor.
2. HVDC cables can be economically employed over longer distances, and result in fewer line losses, which creates a more even playing field for bidders into future New Jersey OSW solicitations given the distances to most of the BOEM OSW lease areas in the New York Bight.
3. Technology trends inside and outside the U.S. indicate a move towards HVDC technology for larger OSW farms.
4. Other states in the region have made a definitive choice for HVDC technology.

The choice for HVDC requires the construction of converter stations both offshore and onshore. The onshore converter stations will typically be located within a reasonably close distance from the POI, and have a footprint of several acres each. Current HVDC technology requires that the offshore and onshore converter stations need to be compatible, which usually means that they each need to be procured from the same supplier.

A decision with respect to POIs and onshore infrastructure upgrades is necessarily dependent both on whether the Board elects to include offshore options in its SAA decision, as well as on the location of any selected POIs. Thus, the evaluation process entailed a review of the merits of the offshore proposals compared to the Baseline before a determination could be made on the suite of potential onshore solutions. In addition, since all developers submitting Option 3 proposals indicated that they were contingent on the selection of that developer’s relevant Option 2 proposal, and because certain Option 2 proposals also required the selection of associated Option 1b proposals, the evaluation of Option 2 proposals informed the decision-making with respect to all other categories of proposals. Therefore, the analysis of Option 2 proposals is presented first.

Option 2

An Option 2 solution would extend the PJM Grid into the ocean, providing a potential interconnection location for OSW generators that is relatively close to the turbines. When it initiated the SAA solicitation, the Board desired an Option 2 solution that would reduce the number of Shore Crossings to support 7,500 MW of offshore wind. To enable this outcome, offshore collector stations would need to be designed to collect electricity from more than one OSW farm, and bring the electricity from these projects collectively onshore to associated POIs. However, at the conclusion of Staff's analysis, it was determined that none of the Option 2 proposals offer sufficient benefits to the State to garner Staff's recommendation, and do not improve upon the baseline Scenario. This conclusion rests on the following evaluations.

i. Technological Limitations

The Option 2 proposals submitted provided for individual offshore substations that could collect between 1,200 - 1,500 MW of capacity. Many OSW farms currently being developed, as well as the Ocean Wind I project and the Second Solicitation Projects that the Board has already awarded, are in the same range of capacity as the current substation limits of between 1,200 – 1,500 MW. Staff expects that future OSW generation projects will be comparable in size to the existing projects. Therefore, the SAA bidders' Option 2 designs as proposed would predominantly connect a *single* OSW project to each particular offshore substation and export cable, rather than connect multiple OSW farms.

From the Board's perspective, an important benefit of an Option 2 solution is to reduce the number of export cables required to accommodate future OSW projects, thereby reducing offshore Transmission Corridors and required landfall locations. Because the offshore substations in the Option 2 proposals submitted can only accommodate a maximum of 1,500 MW, or only a single OSW farm project at a time, the Option 2 proposals did not reduce the number of cables to interconnect each OSW generation facility.

However, the Board expects that HVDC technology will advance significantly over the next few years and that a future SAA solicitation provides an opportunity for the technology to mature. For example, it is expected that within the near future, capacity ratings for individual HVDC systems will significantly increase and may very well allow for a single collector station to accommodate multiple offshore wind farms of the size expected to be bid. Further, any future offshore transmission solution must be able to meet the full scope of New Jersey's 11,000 MW OSW goal, potentially enabling an even larger offshore wind grid in the future, as well as potentially accessing federal funding opportunities that are not currently available, but may be available for a future coordinated transmission initiative.

ii. Costs to New Jersey

In order to enable appropriate comparison of the cost of Option 2 solutions against the Baseline Scenario, Staff and Brattle, together with PJM, developed SAA Scenarios. For each SAA Scenario, Staff and Brattle developed cost estimates for the complete set of new transmission facilities needed to integrate 6,400 MW of OSW generation, including the transmission facilities from the OSW generation facilities to the proposed SAA facilities, depending on the specific facilities included in each SAA Proposal. Without this combination of facilities into full SAA

Scenarios, it would be challenging to directly compare the costs of different Option 2 facilities, each of which enables varying amounts of OSW generation in varying configurations.[78]

Notably, transmission-only projects do not currently qualify for the ITC, which provides a federal tax credit for capital investments in renewable energy projects, including OSW. As noted above, Congress established a 30% ITC for any OSW generation project that commences construction by December 31, 2025. If OSW generators construct the transmission necessary to bring their respective projects onshore, costs for these systems, having been part of the project's capital investments, are eligible for the 30% ITC. However, stand-alone transmission projects, including Option 2 proposals, would not have access to the ITC.

Another factor that Staff considered is that the cost containment mechanisms in SAA proposals are weaker than the cost containment provided in OREC awards—which is considered best-in-class in terms of ratepayer protections. ORECs are only awarded once an OSW project begins generating electricity. Further, awards specify a fixed price with exclusions limited only to increases in Network Upgrade costs. Many of the cost commitments of SAA proposals included only soft cost caps that reduced the allowed return on equity, or that contained significant exclusions—all of which would leave additional risk with New Jersey ratepayers compared to the Baseline Scenario with transmission costs recovered through ORECs. Accordingly, no cost containment proposals submitted support a Staff recommendation in favor of Option 2 facilities to be procured through the SAA.

While the Board was hopeful that Option 2 proposals would nonetheless be cost preferred even without receiving the ITC, unfortunately, the Board did not receive such applications in the SAA solicitation process. Staff remains optimistic that the costs of coordinated transmission will continue to decrease, which could open the door to a procurement of Option 2 facilities through a future SAA solicitation. In addition, a revision to the ITC that enables independently-developed OSW transmission facilities to qualify for this tax credit, and/or additional sources of federal funding, would materially improve the comparative cost-effectiveness of independent transmission solutions.

iii. Locational Implications of the Proposed Offshore Wind Platforms

Under an Option 2 solution, offshore substations would collect the electricity from the wind farms constructed by OSW generators who received awards in New Jersey's OSW solicitations. In their SAA proposals, some developers proposed pre-specified fixed locations for the offshore wind substations ("fixed" locations), while others offered to finalize locations of the offshore substations following the selection of the OSW generation projects through the State's solicitation process ("flexible" locations). Both of these approaches provide distinct benefits and challenges.

One substantial benefit of the flexible substation location approach is that it optimizes the location of the offshore platforms close to OSW generators. While the flexibility of this approach is

[78] As discussed further below, SAA Scenarios also set out POI and injection amounts, enabling PJM to identify the appropriate Option 1a Network Upgrades to ensure reliability after accounting for the SAA Scenario injections.

attractive, it also presents a potentially considerable delay risk. Rather than immediately starting the necessary processes, the transmission developer could not finalize permitting and construction plans until after the Board awards the OSW generation project. This results in a delay commensurate with the State's procurement schedule for offshore wind.

One of the sought-after benefits of any SAA Solution is the substantial timing advantage, achieved by pre-building transmission facilities to accommodate future OSW generation. A solution using flexible locations for OSW platforms that could not be pursued until after generation facilities are selected fails to achieve this timing advantage. For this reason, a flexible location offshore substation design, initiated upon award of OSW generation bids, significantly increases project-on-project risk associated with delivering OSW generation, as discussed further below.

Alternatively, pre-specified, fixed locations for the OSW substations that could begin permitting immediately present their own set of challenges. Fixed locations for OSW substations could hinder competition in future generation solicitations, as compared to the Baseline Scenario. The Board would have to determine the pre-specified, fixed locations, which would provide significant advantages to nearby offshore wind projects over more distant projects, as having these fixed locations would increase the distance of offshore cables to the substations from the BOEM OSW lease areas more distant from the substation. This could provide significant disadvantages for some OSW generators in competing with others in future OSW solicitations.

A related challenge to the fixed approach is the likely need to build additional offshore platforms when compared against the Baseline. Inter-array cables are generally designed at lower voltage and therefore limited in their maximum length. Therefore, unless the Option 2 offshore substation is located near, or within, an offshore wind project, the project would need to build an additional offshore platform within its lease area in order to interconnect the individual wind turbines. The collector station in the wind farm would then connect to the offshore substation built by the transmission developer at the pre-specified fixed location. As compared with the Baseline approach, where each OSW generator would require only one offshore substation (per 1,200 MW - 1,500 MW) to interconnect its wind turbines, the need for additional offshore platforms and substations could increase the total cost of each OSW project by $200 - $300 million.

iv. Schedule Guarantees & Project on Project Risk

The unbundling of OSW transmission and generation responsibilities raises coordination challenges and increases project-on-project risk. While all potential SAA Solutions carry a degree of project-on-project risk, OSW generators widely indicated that Option 2 projects would present the largest increase in risk relative to the Baseline Scenario. The November 2020 Order required Staff to fully evaluate this issue, and recommend solutions that mitigated the Board's concerns about ratepayer exposure to downside project-on-project risks.

If an Option 2 SAA Solution were pursued, OSW generators would no longer control the development, and thus timing, of their project's transmission solution. Since an electrical connection is necessary to construct and test the wind turbines, OSW generators have a substantial interest in whether the offshore transmission solution is complete in time for the OSW project to be tested and commissioned to meet the project schedule. In comparison, the Baseline OREC mechanism includes (by design) a mechanism for incentivizing timely project completion, by withholding project revenues until the project delivers energy to the New Jersey transmission system.

Since New Jersey's OREC payment mechanism allows payments only when the OSW generation project delivers electricity to the grid, any generator will be acutely concerned about ensuring the necessary transmission infrastructure is fully in place by the time their offshore wind project is constructed and ready to generate electricity.

While certain SAA Option 2 bidders did submit schedule commitments and financial penalties for completion delays, no SAA bidder submitted innovative risk sharing proposals that would insulate New Jersey ratepayers from the risk of OSW generation facilities being stranded due to a delay in completing the necessary transmission facilities, particularly compared to the Baseline. Without an appropriate risk-sharing mechanism, the SAA transmission developer's incentive to complete the transmission projects on time is significantly weaker than the generator's incentive under the Baseline. The high level of permitting, logistical, and supply-chain challenges associated with achieving on-time development of offshore transmission facilities further elevates the project-on-project risk.

In addition to scheduling concerns, operational concerns exist when an entity other than the OSW generator is responsible for constructing the transmission solution. In an Option 2 scenario, OSW generators would be fully reliant on the transmission developer to ensure availability of the necessary transmission facilities; without these transmission facilities, the generator cannot deliver their output to the grid and earn revenues. None of the SAA bidders proposed an incentive structure that would tie cost recovery of the transmission facilities to the operational performance of these facilities. While transmission facilities tend to be highly reliable, selecting Option 2 facilities through the SAA creates additional risks for OSW generators due to the misalignment of incentives between OSW generators and the SAA transmission developer. While SAA facility developers face few consequences if their facilities are unavailable or not repaired expeditiously, poor operational performance would be disproportionally consequential for OSW generation projects and New Jersey ratepayers, who would not receive the contracted OSW generation.

v. Summary of Comparison of Option 2 Proposals with the Baseline Scenario

In evaluating these proposals against the Baseline Scenario, Staff concluded that the Option 2 proposals submitted provided limited additional benefits and a higher degree of risk, compared to similar transmission facilities constructed by OSW generators.

Staff recognizes that there are benefits that would come with selection of an Option 2 solution that would not be realized with an Option 1-only solution. These benefits include:

1. Consolidation of offshore cable corridors, including Shore Crossings, and potentially onshore Cable Routes. A consolidation leads to fewer environmental impacts, disturbances to communities, permitting risks, and improved utilization of the POIs on the existing PJM Grid.

2. Inclusion of land that will be required to build the onshore HVDC converter stations into the SAA Solution. As discussed earlier, the footprint of HVDC converter stations is not

trivial, and the Board's selection of specific POIs to which future OSW generation projects will be required to connect, could lead to a land rush for suitable parcels close to the POI.

Currently, these benefits do not override the downside project-on-project risk, operational, technological, and timing attributes outlined above to support a Staff recommendation to procure Option 2 transmission facilities. Further, the proposed Option 2 facilities do not appear to provide cost advantages compared to this baseline, at this time. However, as part of the SAA evaluation, Staff analyzed whether some of the other SAA proposals could enable the main identified benefits of Option 2 as part of the SAA, as discussed further below.

In sum, while all of the Option 2 proposals achieved PJM's reliability criteria and some of the proposals included the capability to integrate into an offshore network, the comparison against the Baseline Scenario make the Option 2 proposals undesirable at this time.

Option 3

Option 3 proposals received were dependent on the selection of Option 2 proposals. Therefore, the Option 3 transmission interlinks could only be evaluated together with their corresponding Option 2 segments. If the Option 3 interlinks had provided substantial value, such benefits could have influenced the evaluation of Option 2 facilities. This was not the case.

i. Reliability Benefits

Staff and PJM's analysis determined that Option 3 links will provide some reliability benefit by providing alternative paths to deliver offshore generation if an Option 2 transmission facility is temporarily made unavailable under certain operational configurations. As part of a full package analysis, the benefits of Option 3 proposals were evaluated and included in the incremental costs, ability for future growth, and the net benefits. However, given the determination that an Option 2 is not desirable at this time, there is no basis for an Option 3 procurement at this time, based on the proposals received.

Three SAA bidders proposed Option 3 transmission facilities through the SAA process for the Board's consideration. The HVDC links proposed by two of the developers for their respective, proposed Option 3 facilities do not feature the technical design and operational capability that would allow these links to be controlled and optimized in order to capture any future market efficiency benefits for New Jersey ratepayers. Rather, these links would be "normally-open," unable to create a controllable offshore network—unless additional equipment (such as HVDC circuit breakers) would be added in the future at substantial additional costs. The bidder who submitted an HVAC configuration similarly assumes HVAC cables that are only on "standby" during normal operations and could only be used with significant operational restrictions during outages of some of the interconnected Option 2 facilities. While such Option 3 links will have some value even if used only as backup links to mitigate Option 2 outages and improve the reliability of OSW deliveries to shore, bidders have not provided analyses showing that the backup function would be of sufficient value to justify procuring Option 3 transmission links at this point.

ii. Energy and Capacity Market benefits

PJM's analysis concluded that the Option 3 proposals failed to provide meaningful energy and capacity market benefits, which, under the OREC construct, would be passed on to ratepayers. The PJM simulations of future market conditions suggest that that there will be only minor differences in wholesale energy market and capacity market benefits, insufficient to support a recommendation of Option 3 proposals.

iii. Constructability, Technology and Cost

PJM's constructability review determined that all proposed Option 3 projects were potentially feasible and are reasonably capable of being constructed in an offshore environment, provided that proper design and construction methods are used.[79] However, PJM noted several concerns regarding proposed HVDC ties as interlinks between offshore platforms. Since HVDC circuit breaker technology for the voltages and systems contained in the proposals is still in early development by HVDC suppliers, none of the HVDC interlink cables can be switched while energized. This limits reconfiguration of offshore transmission systems to only times when the entire system can be de-energized. This will require curtailment of all OSW generation prior to full de-energization and coordinated startup between the transmission system and available OSW generators. Further, it appears that HVDC breakers will require their own offshore platform due to the size and configuration of the equipment involved which would further increase the cost of the interlinked system when this technology becomes available. Lastly, PJM's evaluation noted that regional system operators are not yet ready for meshed offshore grids in terms of regulatory (planning, open access) frameworks and market integration.

Rate Counsel also noted that Option 3 projects contain significant additional costs relative to Option 1a and 1b proposals, and therefore would not be in ratepayers' interest.

Summary of Comparison of Option 3 Proposals with the Baseline Scenario

When initiating the SAA, the Board was hopeful an Option 3 scenario may be the right solution for New Jersey. However, the Option 3 proposals as bid do not provide benefits to the State that are commensurate with the high costs and do not improve on the Baseline Scenario. Staff remains committed to exploring the option of a full ocean grid as the industry and technology matures. The new 11,000 MW goal announcement provides the opportunity for this exploration and, potentially, future SAAs to support the increased goal. The future option value to build Option 3 facilities can be facilitated by requesting "mesh-ready" offshore substation designs in future OSW solicitations, as other states have done.[80] It is likely that future regulatory developments,

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[79] PJM Constructability Report: Option 2&3 Proposals 2021 SAA Proposal Window to Support NJ OSW at 59, 97, 160.

[80] *See* NYSERDA, "2022 Offshore Wind Solicitation," https://www.nyserda.ny.gov/offshore-wind-2022-solicitation. For its 2022 solicitation, NYSERDA required the use of HVDC transmission links to shore, which have lower right-of-way requirements, lower environment impacts than HVAC cables, and are a precondition for controllable offshore grids. With engineering support and stakeholder input, NYSERDA also developed technical standards for mesh-ready offshore substations that can accommodate at least

including development of tax policy and potential federal funding streams, will continue to enable and enhance the attractiveness of facilities required for a network offshore grid. Perhaps in the future, federal funding and tax policies will apply to transmission-only projects that support OSW growth.

Option 1

Having concluded that neither an Option 2 nor an Option 3 scenario should be included in Staff's recommendation to the Board, Staff examined the Option 1 proposals, which include all transmission upgrades and new facilities that are fully onshore. The proposals were separated into Option 1a proposals, which included system upgrades to existing onshore facilities, and Option 1b proposals, which build out new onshore transmission connection facilities, including upgrades from the default or alternative POIs up to, and including, new onshore substations. After comparison of the attributes of these SAA Bids with the Baseline, Staff analysis demonstrates substantial benefits of Option 1a solutions. Option 1b solutions are also advantageous, and additional design considerations, outlined below, enable Option 1b procurements to provide many benefits of Option 2 outlined above. This analysis and comparison informed Staff's recommendations of the SAA facilities to be procured through the SAA, reflected in the Favorable SAA Scenarios used in Staff's final recommendation below.

Option 1a

Through a close collaborative process, PJM, Brattle, and Staff selected and analyzed Option 1a Network Upgrade solutions to address PJM-identified reliability needs for each identified SAA Scenario, utilizing the following process.

First, PJM's reliability analysis identified the specific violations associated with the amounts and locations of injections associated with each SAA Scenario. Second, where only one SAA bid was available for a necessary grid upgrade identified in PJM's reliability analysis, that Option 1a solution was selected as the preferred bid.[81] Third, where no SAA bid was available for a necessary Option 1a solution that could resolve an identified reliability violation, PJM requested a solution (including a cost estimate) from the incumbent TO, which was applied as the preferred bid. Lastly, in cases where more than one SAA bid was available to resolve a reliability violation, Staff and Brattle worked with PJM to select the lowest-cost Option 1a bid that (i) provided a complete solution, (ii) was acceptable to PJM from a technological and operational perspective, and (iii) did not raise any significant constructability or permitting issues.

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two HVAC cable links between neighboring wind farms, capable of at least 400 MW per link. The incremental cost of procuring such mesh-ready offshore platforms is estimated to add less than 1% to the total cost of OSW generating plants. *See* discussion of "Mesh Network Optionality" and "HVDC Transmission" in NYPSC, Order on Power Grid Study Recommendations, CASE 20-E-0197 et al., January 20, 2022 at 9–15. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b23F0F463-A059-4CFC-9134-4535F660611F%7d. See also id.

[81] PJM Reliability Analysis Report, 2021 SAA Proposal Window to Support NJ OSW, September 19, 2022 at 8.

Brattle estimated that procuring Option 1a upgrades through the SAA will reduce costs to New Jersey ratepayers by an average of about $1.1 billion, compared to the Baseline Scenario, for the injection of 6,400 MW. Without the SAA, the PJM system upgrades identified through PJM's conventional interconnection process (i.e. Network Upgrades) are estimated to cost approximately $1.5 billion. Through the SAA, the Board can obtain similar injection rights at an estimated cost of $271 million to $863 million (with an average of $445 million), depending on the POIs and injection levels selected. The large cost reduction for PJM system upgrades is attributable to utilizing a coordinated and proactive planning approach that simultaneously creates the necessary SAA Capability for all of New Jersey's OSW generation up to 7,500 MW and identifies the most attractive Option 1a upgrades through the SAA solicitation process.

Based on the results of these reliability and cost analyses, along with the attributes of Option 1a proposals explained below, procuring the PJM network system upgrades necessary to allow OSW generators to interconnect at selected POIs through the SAA provides clear cost-savings benefits to New Jersey ratepayers. In addition to these substantial cost savings, Staff found numerous additional benefits of procuring Option 1a facilities through the SAA when compared against the Baseline Scenario.

First, completing a full range of interconnection studies in advance of selecting the OSW generation projects greatly reduces the cost and timing uncertainty inherent in PJM's conventional interconnection process. Timing benefits exist by allowing work to begin on needed Option 1a system upgrade facilities at the time PJM's Board approves the SAA-awarded facilities, as opposed to construction of generator-specific Network Upgrades which would be not begin development until the completion of the OSW generators' queue process. This timing changes the critical path milestone for network system upgrade facilities—under the Baseline Scenario, construction of Network Upgrades cannot begin until after the completion of the generator's queue process, whereas under the SAA, the same transmission upgrades can be developed simultaneously with the generator's progression through the queue.

Second, with the selection of Option 1a facilities through the SAA, the Board can identify its preferred POIs and enable SAA Scenarios that most effectively utilize the available SAA Capability of these POIs. In the Baseline Scenario, each generator will propose to interconnect at a POI that best suits their individual project, which may result in inefficient utilization of POIs from a state-wide perspective, including the potential for stranded headroom or the construction of multiple transmission facilities or Transmission Corridors to access the same POI.

Third, selecting Option 1a upgrades through the SAA process will likely increase competition in future OSW generation solicitations. Procuring the Network Upgrades prior to these solicitations will reduce some of the complexity and uncertainty associated with developing OSW generation bids, since obtaining POIs through the conventional PJM interconnection process is associated with significantly higher cost and timing uncertainties. The reduced POI- and interconnection-related risks and cost uncertainty should decrease the cost of OSW procurements by reducing complexity and network-upgrade related cost and timing risk.

Fourth, the incumbent PJM TO will build most of the Option 1a system upgrades selected through the SAA process. These TOs, as per general business practice, have not proposed specific cost-control mechanisms.[82] The level of uncertainty inherent in the cost of these upgrades is evaluated to be similar both across the available Option 1a solutions, and with respect to the uncertainty in cost estimates that OSW generators would face for system upgrades triggered through PJM's conventional generation interconnection process. Cost uncertainty is, therefore, neither improved nor worsened by procuring Option 1a facilities through the SAA. However, several independent transmission developers have proposed cost control mechanisms for a subset of the selected Option 1a upgrades (for example, those upgrades needed on the Pennsylvania-Maryland border[83]) that provide a degree of cost control benefit relative to upgrades that PJM would identify under the conventional interconnection process. Further, in utilizing PJM's competitive SAA process, the Board could identify the widest range of available alternatives, and select the most cost-effective Option 1a upgrades. This optionality is unavailable to OSW generators requiring Network Upgrades under the Baseline Scenario.

Fifth, none of the Option 1a proposals submitted into the SAA solicitation (including those requested by PJM from the incumbent TOs to address SAA-related needs not addressed by SAA bidders) provided schedule commitments. However, due to the structure of advanced procurement of transmission facilities as part of the SAA, in contrast to the Baseline's timing of Network Upgrade procurement at the completion of the OSW generator's PJM queue process, delivery of coordinated onshore system upgrades selected through the SAA would provide timing benefits including reduced schedule risk relative to the Baseline Scenario.

Sixth, selecting Option 1a facilities through the SAA reduces the total number of upgrades necessary to interconnect OSW generation projects and thus the net environmental impacts and permitting challenges associated with Option 1a upgrades required to achieve the injection 7,500 MW of OSW. These benefits are enabled by evaluating the suite of violations associated with the full 7,500 MW of injection (6,400 MW of SAA Capability) simultaneously, as opposed to in-sequence under the Baseline.

Seventh, selecting POIs and their associated PJM transmission system upgrades through the SAA is a necessary first step in reducing the number of Transmission Corridors needed to deliver OSW generation to the available POIs. Procuring all necessary onshore transmission facilities in a coordinated manner allows for an outcome where fewer Transmission Corridors are required to accommodate the interconnection of several OSW generators. The reduced number of Transmission Corridors, as well as simultaneous construction of all major onshore facilities necessary to accommodate transmission needs, will reduce the impacts of onshore transmission construction on New Jersey communities. The procurement of Option 1a facilities alone are insufficient, but is a necessary prerequisite to reducing the number of Transmission Corridors.

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[82] Under the PJM Operating Agreement, any construction to be performed on facilities owned by an incumbent TO shall be performed by that TO. See 172 FERC ¶ 61,136 (2020) at 84-85.

[83] Upgrades to facilities outside of New Jersey will be required and recommended under today's Order. These facilities were identified by PJM as necessary to integrate 7,500 MW of OSW, with or without the SAA. These facilities are required to enable the full injection capability of the OSW generators modeled in SAA Scenarios, and will not be critical path milestones preventing testing or initial operation of OSW generators.

In sum, Staff's evaluation demonstrates that procuring Option 1a solutions through the SAA reduces cost and schedule risk to OSW generators by allowing earlier initiation of required upgrades on the PJM system. Further, procuring Option 1a facilities provides the Board with the ability to specify POIs and injection amounts that can most fully utilize the capability of the existing grid and enable the reduction of environmental and community impacts. As discussed further below, ensuring the benefits of reduced community impacts requires additional coordination beyond procurement of Option 1a facilities. However, selection of the necessary Option 1a facilities is a necessary prerequisite to enabling any additional scope of procurement that would then capture these benefits.

Option 1b

Four SAA bidders initially submitted Option 1b-only proposals. Several other bidders provided Option 1b proposals within and as part of their Option 2 proposals.

Through clarifying questions, Staff confirmed whether such transmission developers would be willing to construct the Option 1b-only portion of their Option 2 proposals, including the onshore HVAC components of their solutions and the acquisition of the land adjacent to such components, with sufficient space for future HVDC converter stations, similar to the Option 1b only proposals.

Some developers were amendable to scaling back their Option 2 proposals to construct just the Option 1b elements, including the AC portion of the proposed substation and the acquisition of the adjacent land for the future HVDC converters. Others indicated that this change would not be a good fit for their business model. Still others proposed modifications to the Option 1b-portion of their Option 2 proposals. Notably, some provided a scaled-back version of their Option 2 proposal, but also included the underground Duct Banks and access Cable Vaults between the coordinated POI and the shoreline (landfall site) to house the electric transmission cables of two or more future OSW projects, but without installing the associated electric transmission cables. This approach would allow for a reduced number of Cable Routes and construction efforts. Staff referred to these solutions as "Option 1b+", and more specifically, the prebuilding of Duct Banks and access Cable Vaults that future awarded OSW projects would use was referred to as the "Prebuild Infrastructure." To clarify, the Option 1b+ proposals included the Option 1b upgrades, as well as the Prebuild Infrastructure—the Duct Banks and access Cable Vaults.

In total, 28 Option 1b/1b+ proposals were evaluated. In reviewing the applications and PJM's analysis, Staff made several findings regarding the Option 1b/1b+ proposals.

First, many Option 1b proposals are cost competitive compared to the Baseline. Notably, the Option 1b proposals allow OSW generators to apply the ITC to a larger range of total cost, as compared to an Option 2 proposal.[84]

Second, the selection of Option 1b facilities enables the POI utilization benefits described above

[84] Further, while a few of the Option 2 proposals were proposed at a cost competitive level, the larger construction commitment for Option 2 increases the risk of cost overruns compared to an Option 1b solution. As noted below, the strongest cost containment mechanism is the OREC.

by coordinating not only the injections at the POI, but also the access to the POI through common Transmission Corridors. The design and scope of specific Option 1b facilities still weigh heavily on the degree of POI utilization benefits available, with facilities that extend POIs closer to shore increasing these benefits. The maximum capacity of Option 1b proposals also indicates the level of reduced community impacts ascribable to each proposal. For instance, the largest Option 1b solutions can reduce the number of onshore Transmission Corridors required to achieve the remaining 3,742 MW of OSW to achieve 7,500 MW from three Transmission Corridors in the Baseline Scenario, to either one or two Transmission Corridors, depending on the size of the Option 1b facility. Option 1b facilities that could reduce the number of Transmission Corridors to one were preferred, in order to avoid the environmental and community impacts of an additional Transmission Corridor.

Third, selecting Option 1b upgrades through the SAA process will likely increase competition in future OSW generation solicitations by providing a single "plug" for OSW generators to attach their own facilities. Any coordinated Transmission Corridor also reduces permitting and land acquisition requirements associated with an OSW generator's construction of necessary onshore transmission facilities. Further, benefits to competition are expected based on the access provided by Option 1b proposals to land near the POIs for locating HVDC converter stations. Procuring Option 1b proposals that offer sufficient space for this construction encourages robust competition, particularly from offshore leaseholders who may not have already secured land near POIs.

Fourth, similar to Option 2 facilities, the cost containment mechanisms in Option 1b proposals are weaker than the cost containment provided in OREC contracts with OSW generators —which is considered best-in-class. The OREC-approving Board Orders specify a fixed price with exclusions limited only to increases in Network Upgrade costs. In contrast, many of the cost commitments of SAA proposals included only soft cost caps that reduced the allowed return on equity or contained significant exclusions—all of which would leave additional risk with New Jersey ratepayers compared to the Baseline Scenario with OREC cost recovery. This observation supports Staff's recommendation to procure only the coordinated facilities required to enable the substantial reduction in environmental and community impacts associated with coordinated Transmission Corridors.[85]

Fifth, the proposed schedules for developing Option 1b facilities closely track the specified OSW solicitation dates, with online dates 12-18 months or more prior to the anticipated in-service dates for OSW generation (to allow for power back-feeds for turbine testing). In addition, PJM evaluated each delivery date, including providing an independent estimate of critical path milestones of each project, confirming that the proposed schedule for most Option 1b proposals is feasible.

No SAA bidder submitted innovative risk sharing proposals that would insulate ratepayers or OSW generators from the risk of OSW generation facilities being stranded due to a delay in completing the necessary transmission facilities. In contrast, the entire revenue stream of an OSW generator is contingent upon successful completion of transmission facilities. Staff's observations support

[85] Note, the decision of whether to procure these Coordinated Transmission Corridor facilities through the SAA will be discussed further below.

utilizing the Baseline OREC procurement mechanism to the extent possible to enable coordinated Transmission Corridors, which allows for the benefits of coordination while minimizing project-on-project risk, as discussed further below.

Staff Recommendation

As discussed herein, the SAA process has enabled the State to incorporate its public policy requirements within a competitive Transmission Project solicitation. As a result of the Board's decision to participate in the SAA process, Staff was afforded the ability to evaluate 80 proposals designed to enable New Jersey to achieve its goal of integrating 7,500 MW of OSW generation by 2035. Staff considered a multitude of factors in its evaluation as described above. As such, Staff believes that its recommendation in this matter, as further discussed below, will enable New Jersey to pursue its OSW goals while minimizing any potential adverse impacts to customers and the State.

Favorable SAA Scenarios

When issuing the SAA solicitation, the Board was optimistic that it would receive proposals that would allow the State to realize many of the potential benefits set forth herein of a coordinated transmission approach. Critical to the Board's decision in pursing the SAA was the ability to select an SAA project (or not select any project at all) that best suits New Jersey's goals while providing a "more efficient and cost-effective means of meeting the State's OSW goals and decreasing the chance of delays."[86] As such, in evaluating the SAA proposals, Staff not only evaluated the proposals against one another, but also against the Baseline Scenario and against achieving the State's overarching SAA goals. For example, a submitted SAA Proposal that does not uphold the desired goals or is found to be inferior to the Baseline Scenario, regardless of the proposal's strength and merit against other submitted proposals, would nonetheless not be selected at this time.

As previously set forth, the Option 2 proposals, while innovative, involved additional risks which outweigh the potential benefits relative to the Baseline Scenario. Some of the challenges included the technological limitations of the offshore substations, the high costs, the ineligibility for the ITC, the locational implications related to the offshore substations, and the high project-on-project risks. As such, Staff recommends that, at this time, an Option 2 solution is not in the best interest of the State. The Option 3 proposals, because they are contingent upon the selection of the associated Option 2 proposals, and because of other considerations discussed above, were also deemed not advisable at this time.

As outlined above, the results of PJM's reliability analysis and Staff's consultant's analysis, showed that many of the Option 1a proposals provided substantial cost savings while reducing the time and uncertainty of the upgrades to existing facilities for OSW generation projects developed through the conventional PJM interconnection queue process. In total, analysis conducted during the evaluation process indicates that the Option 1a proposals would save New Jersey ratepayers about $1.1 billion dollars compared to the Baseline.

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[86] November 2020 Order, supra note 33 at 8.

Similarly, as outlined above, Staff found significant potential benefits of procuring Option 1b proposals that build out the onshore transmission facilities to enable the interconnection of future OSW projects at the selected POIs created by PJM through SAA-procured Option 1a system upgrades.

In total, there were 28 Option 1b proposals. This includes those proposals initially submitted as Option 1b, as well as the 1b portions of Option 2 proposals that provide similar capabilities and that bidders have confirmed they are willing to construct. These proposals were evaluated against the overarching SAA goals, the Baseline Scenario and the SAA criteria. Staff found that several of the Option 1b proposals were superior to the Baseline Scenario and achieved many of the desired goals of a coordinated transmission approach.

One initial consideration in evaluating the Option 1b solutions was how many potential corridors the proposal included. Option 1b solutions provide an opportunity to reduce the number of additional future onshore corridors required to achieve the 7,500 MW from three Transmission Corridors in the Baseline Scenario to either one or two. Some of the Option 1b proposals that included one Transmission Corridor included smaller injection capacities and would therefore need to be paired with another proposal in order for the Board to achieve the full desired capacity of 6,400 MW, resulting in two corridors. A single corridor allows all the remaining OSW generators required to meet New Jersey's 7,500 MW goal to access the same single POI (or single location created through the SAA to access multiple POIs), enabled through a combination of Option 1a and (depending on the SAA Scenario) Option 1b solutions. A two-corridor solution would entail two POIs and OSW generators would be directed to connect to one or the other POI.

Staff's analysis found that a single Transmission Corridor solution (a "single corridor solution") has the potential to offer substantial permitting efficiency for that singular right of way rather than two Transmission Corridors (a "two-corridor solution") which would require two distinct permitting processes. A two-corridor solution, however, mitigates risk if one of the Transmission Corridors face permitting delays or challenges. Perhaps most importantly in the comparison of one- or two-corridor solutions, is that a single corridor solution has the potential to coordinate shore-crossings (even if multiple cables are needed to make landfall in one coordinated location), and best minimizes community disruptions and environmental impacts. A single corridor solution also better captures economies of scale by reducing the number of installation events. This results in significant benefits, particularly to New Jersey's shores, coastal communities, and communities along proposed Transmission Corridors. DEP also noted that, "[a] single corridor to bring cables to shore would be most beneficial, as long as the corridor location is well planned."[87] Ultimately, Staff found that an SAA Solution that provided for a single Transmission Corridor was preferred.

The full complement of potential benefits of an Option 1b single corridor solution are only conferred if the single corridor solutions involve a single route and single coordinated installation event. In the absence of this type of coordinated approach to interconnection with Option 1b facilities, awarded OSW generators would still need to build the remaining onshore infrastructure

[87] DEP "State Agreement Approach – OSW Transmission- NJDEP Environmental Review" Memo to Staff, October 7, 2022 at 2.

for their own transmission cables from the landing point at the shore to reach the Option 1b facilities (e.g., a new collector station). This could result in three or more different Cable Routes from the shore to the Option 1b facilities (one for each future OSW generator) or a single Cable Route which all awarded OSW generators would utilize but would nonetheless result in three separate construction efforts occurring approximately every two years, magnifying environmental impacts and community disruption in the Transmission Corridor.

There are two approaches to achieving the full complement of potential benefits of an Option 1b single corridor solution. Both approaches entail procuring the land for the converter stations and the Prebuild Infrastructure (the Duct Banks and Cable Vaults). The Prebuild Infrastructure could either be procured through the Board's Third Solicitation or through the SAA if the Board awards an SAA Proposal which includes the Prebuild Infrastructure.

These procurement options have distinct benefits and risks, even for procuring the same set of facilities. Staff examined which approach—through the SAA or through the Third Solicitation—was best.

Procuring the Prebuild Infrastructure through the SAA enables the use of the existing PJM regulatory structure for procurement of facilities, instead of having to create such a framework for the OSW solicitation. In addition, procuring the Prebuild Infrastructure through the SAA has the benefit of allowing for construction activities for the Prebuild Infrastructure to commence upon SAA award, as opposed to the Third Solicitation award, about 12 months later. While this could have considerable timing advantages, these advantages are not determinative because, when procured through the Third Solicitation, the Prebuild Infrastructure is a part of the critical path milestones for the OSW generator constructing the Prebuild Infrastructure, who retains a strong incentive to complete its transmission solution to receive ORECs. Procuring the Prebuild Infrastructure through the Third Solicitation therefore is likely to improve project-on-project coordination and reduce project-on-project risks by aligning incentives for the OSW generator(s) selected in the Third Solicitation with the construction effort of prebuilding the necessary facilities.

While there are benefits for obtaining the Prebuild Infrastructure through the SAA using the Option 1b+ proposals, some drawbacks and risks exist. Acquiring this infrastructure through the SAA would require the voluntary waiver of the right enjoyed by PJM TOs to build new transmission on their right of way or upgrade existing facilities (to allow OSW generators to utilize the prebuilt infrastructure for their cables). It would also result in less favorable cost-control mechanisms compared to procuring the facilities through OREC awards. Additionally, the Prebuild Infrastructure, if built as part of a transmission-only project, would not currently qualify for the ITC.[88]

In contrast, waiting to obtain the Prebuild Infrastructure through the Third Solicitation allows the OSW generator who constructs the Prebuild Infrastructure to propose mutually agreeable contractual terms for the use of underground facilities by future developers. This approach also

[88] Note several caveats: (a) Cable Vaults and Duct Banks account for only a small portion of total OSW costs ($300-400 million) and (b) OSW generators may be unable to offer a fixed-cost OREC bid for the portion of their bids covering the Cable Vaults and Duct Banks.

takes advantage of the more-beneficial cost control mechanism included in the OREC provisions. As described above, procuring the Prebuild Infrastructure through the OREC process also aligns incentives of the OSW generator. Lastly, it provides greater opportunity for OSW generators to propose contractual structures and co-ownership arrangements under which transmission developers could utilize the ITC for the cost of constructing the necessary Cable Vaults and Duct Banks.[89]

In considering all of the factors regarding whether to obtain the Prebuild Infrastructure through the SAA or the Third Solicitation, Staff found that for the reasons stated above, the Prebuild Infrastructure to support a single corridor solution is best constructed by a future OSW generator at this time. Additional details on the procurement of the Prebuild Infrastructure through the Third Solicitation are provided later in this Order.

Three Option 1b SAA Solutions proposed onshore HVAC substations and related onshore transmission facilities to accommodate the HVDC cables and converter stations that would reduce the number of additional onshore corridors required to achieve the 7,500 MW goal by 2035 (that is, the remaining 3,742 MW) from three Transmission Corridors in the Baseline Scenario to one corridor. These proposals include two Option 1b proposals and one Option 1b+ proposal equipped with the onshore HVAC collector substation and a proposal to provide land for OSW generators to construct their HVDC converters. These SAA Solutions for the remaining 3,742 MW of SAA Capability include both proposals initially submitted as Option 1b proposals as well as the 1b portions of Option 2 proposals that provide similar capabilities (and that bidders have confirmed they are willing to construct).[90]

The costs of the Option 1b single corridor solution proposals varied. Some had relatively low capital costs. However, Staff found that although the proposals themselves were lower cost, the OSW generator costs to utilize that solution would be higher, increasing the total cost to New Jersey ratepayers. In the Option 1b proposals which were more expensive, the OSW generator costs to utilize that solution were lower. In looking at the total costs to New Jersey ratepayers, the individual costs of the SAA proposals were not determinative.

A more determinative criteria was the environmental and permitting impact of the Option 1b single corridor solution proposals. Staff, in coordination with DEP, evaluated the environmental impacts, the permitability and the community impacts of these proposals. Proposals which limited these concerns and challenges were preferred.

Of the three Option 1b single corridor solutions, two had significant potential siting concerns associated with their preferred locations, which were identified during the environmental and

[89] Note, however, that value of the federal tax credit for Duct Banks and Cable Vaults is limited due to Cable Vaults and Duct Banks accounting for only a relatively small share of total costs. The value of the tax credit, estimated at approximately 1% of total OSW generation costs, is expected to be smaller than the savings form Prebuilding Cable Vaults and Duct Banks for multiple OSW generators.

[90] Other Option 1b or Option 2 bidders either did not propose solutions that allowed for multiple cables to be installed in a single corridor or were unwilling to scale back their Option 2 proposals to only the onshore components.

constructability reviews. As noted above, proposals with a robust plan for securing the required land and related permits were preferred.

Finally, Staff also considered the preferred location of the single corridor solution. The Option 1b proposals included POIs across the State—northern, central and southern POIs. PJM reliability analysis found that larger injections in the southern POIs resulted in costly reliability violations. Staff found that northern POIs could benefit northern BOEM OSW lease areas over the more distant southern lease areas, which may reduce competition in future OSW solicitations. Staff also determined that the cost for future OSW generators to interconnect to a northern New Jersey POI were substantially more than if they were to interconnect to a central or southern POI due to the longer Cable Routes needed to reach the northern POIs. Only two of the three single corridor Option 1b solutions proposed central POIs. DEP noted that, "[t]he DEP's Marine Resource Administration prefers shorter offshore cable routes and would recommend co-location of cables when possible."[91]

Staff prefers SAA Scenarios which meet the following specific criteria anticipated to maximize benefits and minimize risks to New Jersey ratepayers: (1) create a single collector substation with space to house the onshore converter stations of OSW generators, (2) reduce the number of necessary onshore Transmission Corridors to reduce environmental and community impacts, and (3) increase competition in future OSW solicitations by providing all OSW generation bidders equal access to the necessary land near the selected POIs.

In sum, Staff's evaluation demonstrates that procuring certain Option 1b facilities through the SAA reduces the number of POIs, reduces cost, has the potential to reduce environmental disruptions and mitigate community impact, and increases competition. Staff, therefore, recommends that the Board award a combination of an Option 1b proposal and Option 1a proposals to support the creation of 6,400 MW of SAA Capability to enable achievement of the State's OSW goals. In determining precisely which Option 1a proposals to select, Staff examined which combination of Option 1a proposals that most uphold the State's SAA goals set forth in the criteria, including, but not limited to, desired POIs, capacity injection amounts, reduced environmental disturbances and permitting challenges, reduced community impacts, and the ability for OSW generators to utilize those upgrades. The Option 1a upgrades that best meet the State's goals are those that support the preferred Option 1b solution.

Recommended SAA Solution: Larrabee Tri-Collector Solution

In considering all the application materials, PJM's analysis, DEP's evaluation, DMAVA's input, Rate Counsel's review and Brattle's analysis, Staff determined that certain elements of the jointly developed MAOD/JCP&L proposal, detailed below, best meet the goals of the SAA and will result in a more efficient and cost-effective means of meeting the State's OSW goals at this time. Staff determined that Option 1b proposals with the associated Option 1a upgrades, which together enable a single corridor solution with a POI in central New Jersey, and do not include the Prebuild Infrastructure of the Option 1b+ facilities, provide the most advantageous structure at this time.

[91] DEP "State Agreement Approach – OSW Transmission- NJDEP Environmental Review" Memo to Staff, October 7, 2022 at 3.

When compared against the Baseline Scenario, analysis reveals the Larrabee Tri-Collector Solution features benefits across the stated SAA evaluation criteria, and is the strongest Option 1b single corridor solution when compared to others.

The recommended SAA Solution has several “names” across the reviewers’ evaluations, so for clarity, Staff identifies this solution as the “Larrabee Tri-Collector Solution” or “MAOD-JCP&L Option 1b Solution,” which includes elements of the JCP&L Option 1b proposal as well as scaled-down elements of MAOD’s Option 2 proposal, and the necessary Option 1a upgrades to create the SAA Capability associated with the SAA Scenario evaluating the Larrabee Tri-Collector Solution. The full list of projects associated with the Larrabee Tri-Collector Solution is listed in Appendix A.

The predominant portion of the Larrabee Tri-Collector Solution is a new substation adjacent to the existing JCP&L Larrabee substation (the “Larrabee Collector Station”). MAOD proposes to construct the AC portion of the new Larrabee Collector Station to accommodate three future HVDC circuits. The proposal also includes sufficient land for the future installation of up to four DC converter stations;this parcel of land for the converter station(s) is indicated as being in the process of being acquired.[92] The HVDC cables delivering the output of future OSW generators will interconnect at this new Larrabee Collector Station. Selection of the Larrabee Tri-Collector Solution and associated Option 1a upgrades will enable the 6,400 MW of SAA Capability required to efficiently satisfy New Jersey’s OSW goal pursued under the SAA.

Board Staff will work with MAOD and PJM to ensure future OSW generators have adequate and equal access to the land that will be used for the DC converter stations. This will ensure robust competition is maintained – upholding open-acess transmission principles – throughout future OSW solicitations. To facilitate a transparent process, MAOD should enter into a formal agreement with each OSW generator awarded SAA Capability by the Board, to set forth the basic terms and conditions to access the land necessary to construct the DC converters, including construction as well as operations and maintenance (“O&M”) throughout the operating life of the equipment. Staff and PJM should be active in these discussions, as appropriate. Staff expects that these principles should be defined in the DEA filed at FERC (the DEA process is explained in the Looking Forward section below), but Staff is willing to work with MAOD and PJM to explore other avenues to accomplish these principles. Staff will work to ensure MAOD is appropriately compensated for the use of these lands.

The MAOD-JCP&L Option 1b Solution includes a “tri-collector” that distributes up to 4,890 MW from the Larrabee Collector Station to three existing POIs on PJM’s grid (the Smithburg 500 kV substation (“Smithburg”), the Larrabee 230 kV substation (“Larrabee”), and the Atlantic 230 kV substation (“Atlantic”)), utilizing JCP&L’s existing transmission ROWs. To provide a complete Option 1b solution, Staff recommends that the Board select MAOD’s Larrabee Collector Station in combination with JCP&L’s tri-collector proposal.

The MAOD-JCP&L Option 1b solution was originally intended to connect three 1,200 MW HVDC systems built by MAOD, but PJM indicates that the ratings of the equipment in the AC substation

[92] PJM Constructability Report: Option 2 & 3 Proposals 2021 SAA Proposal Window to Support NJ OSW at 44.

can handle up to 4,530 MW of future injections from DC converter stations, and thus provide a single corridor solution for the remaining 3,742 MW of SAA Capability (after accounting for the First Solicitation and Second Solicitation). This approach leverages JCP&L's existing ROWs to create a single point for connecting OSW projects and maximizes use of available headroom at existing POIs, while offering a single corridor solution preferred by Staff. Creating the SAA Capability also requires additional Option 1a Network Upgrades, as discussed further below.

Whether procured through the SAA or through the OSW solicitations, transmission upgrades are necessary to inject 7,500 MW of OSW onto the grid. The driving question then becomes which approach is more cost effective, results in fewer environmental and community disturbances, and provides the greatest benefit to New Jersey ratepayers. Staff's analysis found that procuring the necessary transmission upgrades through the SAA by selecting the Larrabee Tri-Collector Solution provides the best approach.

The MAOD-JCP&L Option 1b Solution is estimated to cost $504 million. The necessary Option 1a upgrades PJM identified are estimated to cost an additional $575 million. Therefore, the total cost for the onshore Option 1 upgrades for the full Larrabee Tri-Collector Solution is $1.08 billion, or $1.03 per month for the average residential customer.

By procuring the Larrabee Tri-Collector Solution through the SAA, it is estimated that ratepayers will realize approximately $900 million in savings compared to procuring these transmission upgrades through the Baseline Scenario.

The savings are comprised of two elements. First, the Larrabee Tri-Collector Solution costs $630 million less than the comparable onshore upgrades required under the Baseline Scenario. Under the Baseline Scenario, onshore Option 1 upgrades are estimated to be $1.71 billion, compared to the $1.08 billon cost of the Larrabee Tri-Collector Solution. Second, the selection of the Larrabee Tri-Collector Solution reduces the amount of cabling necessary to deliver the OSW energy to the grid, resulting in an additional $288 million in savings compared against the Baseline.[93]

In addition, the scope of the Larrabee Tri-Collector solution was tailored to maximize federal tax incentives by increasing the share of upgrades eligible to receive the Investment Tax Credit. The difference between receiving and not receiving the Investment Tax Credit could be as much as $2.2 billion. The Larrabee Tri-Collector's receiving the Investment Tax Credit would provide additional ratepayer benefits. In addition to the significant cost savings, there are substantial environmental and permitting benefits, as well as reduced community impacts this solution provides. OSW generators will also benefit greatly from this recommended solution, as it minimizes cost and delay uncertainty, ensuring a clearer path forward for developing their OSW projects.

MAOD designed the Larrabee Collector Station to operate during normal conditions with each transmission circuit electrically separate, feeding the output of one OSW generation project into one of the three HVAC cables of the Larrabee Tri-Collector Solution. This design provides a single collector station for three OSW generators to physically connect their DC converter stations

[93] $630 million savings plus $288 million savings equals the estimated total $900 million in savings.

to the grid, but then keeps those injections electrically separate and connected to three separate POIs.

The SAA Capability associated with the Larrabee Tri-Collector Solution, including the necessary Option 1a Network Upgrades, is specific to each POI based on PJM's SAA study assumptions. Namely, aside from the projects awarded in the Second Solicitation, the Larrabee Tri-Collector Solution provides 1,200 MW of SAA Capability each at the Larrabee and Atlantic substations, and an additional 1,342 MW of SAA Capability at the Smithburg substation. PJM's analysis suggests that this provides an excellent platform for accessing additional headroom on the PJM system with modest additional upgrades in the future. Thus, Staff anticipates that future OSW generators utilizing SAA Capability will have the flexibility to tailor the size of their projects by interconnecting at one or more of these points of interconnection. Future OSW generators may also explore selective additional upgrades to take advantage of the excess transmission system headroom at these locations.

While Staff found proposals that comprise the Larrabee Tri-Collector Solution are in the best interest of New Jersey ratepayers in accordance with the evaluation criteria, transmission development is a long-term process materializing over many years with a degree of uncertainty. In addition, uncertainties in the development of OSW farms could trigger the need for changes. Accordingly, Staff recommends that the Board retain the flexibility to issue further Board Orders in this docket should significant revisions to the scope, configuration or cost of awarded projects be required to optimize the use of the SAA Solution.

Updates to approved PJM RTEP projects are typical. Allowing for the modification of this Board Order in the future to reflect significant updates will ensure that the specific configuration of the awarded SAA facilities remain optimal and beneficial to ratepayers over time. In the interest of administrative efficiency, Staff also recommends the Board delegate routine project review and oversight, including updates or revisions to projects that do not entail significant changes to the scope, configuration or cost, to Staff and/or PJM as appropriate. Staff anticipates ongoing work with PJM to identify additional flexibility or other configurations that would increase the benefits of the Larrabee Tri-Collector Solution to New Jersey ratepayers.

The environmental review rated this project as "moderate" risk.[94] The potential for the project to intersect Green Acres encumbered lands, cultural resources, and wetlands were the primary concerns raised by DEP. However, based on the information provided in the application, it is anticipated that the proposed work is primarily within existing right of way routes and substation properties. PJM also noted that "given that the project uses pre-disturbed ROW, the impacts are expected to be minimal."[95] JCP&L indicated that New Jersey Historic Preservation Office concurrence would be pursued, as applicable, with respect to cultural resources. Finally, with respect to Green Acres encumbered lands, JCP&L stated in their response to a clarifying question posed by Staff: "No Green Acres impact is anticipated based on the current scope of this proposal."

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[94] The environmental review was the collective evaluation of DEP, Staff, Brattle and PJM.

[95] PJM's NJOSW Constructability Report for Option 1b Proposals September Final at 20.

Notably, compared against other Option 1b single corridor proposals that utilize a central New Jersey POI, the Larrabee Tri-Collector Solution provides the least environmental, permitting, and community impact risks. These risks are critical in the evaluation as they can pose significant cost and delay overruns, as well as jeopardize the project altogether.

Additionally, PJM favorably noted that, overall, the MAOD portion of the Tri-Collector Solution system uses technology that is currently commercially available and has examples in service at several other locations.[96]

For the JCP&L portion of the Tri-Collector Solution, PJM noted the project is constructible as proposed and compatible with the land uses crossed. Since much of the construction will occur in JPC&L's existing transmission line ROW, conflicts with land use are expected to be minimal. PJM also noted that it does not anticipate any adverse effects to the economic wellbeing of any "Special Urban Areas" which are areas the New Jersey Department of Community Affairs defines as municipalities in urban aid legislation qualified to receive State aid to enable them to maintain and upgrade municipal services and offset local property taxes. Further, this portion of the Tri-Collector Solution is not located on any State protected land such as the Hackensack Meadowlands District or the Pinelands Protection Area.

While the Larrabee Tri-Collector Solution does not provide an SAA Shore Crossing solution, the Option 2 portion of the MAOD proposal identified the NGTC facility at Sea Girt as the preferred shore crossing point.

Staff engaged DMAVA to examine the impact of utilizing the Sea Girt NGTC as the anticipated landing point for OSW generators to access the new Larrabee Collector Station. DMAVA stated that the "concept of placing underground infrastructure on the [Sea Girt NGTC] grounds is supportable" provided future considerations are made to avoid significant disruptions to their mission critical operations.[97] DMAVA considered the impacts from both the construction efforts as well as any permanent infrastructure that was proposed to be located on the property. DMAVA was unsupportive of bids that proposed substantial new above-ground infrastructure on the property, which would compete with the military training site areas and would therefore not be conducive to support activities routinely conducted at the site.

To enable the 6,400 MW of SAA Capability associated with the Larrabee Tri-Collector Solution (including the SAA Capability associated with the awarded Second Solicitation projects), necessary Option 1a upgrades must be procured, based on PJM's analysis of this specific suite of injections. As outlined above, Option 1a upgrades through the SAA result in tremendous cost savings, reduced risk, and the ability to pre-specify POIs and injection amounts for OSW generators which reduces environmental and community impacts.

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[96] PJM Constructability Report: Option 2 & 3 Proposals 2021 SAA Proposal Window to Support NJ OSW at 19-36, 47.

[97] Jill Ann Priar, State Deputy CFMO, Sea Girt National Guard Training Facility, DMAVA Review of BPU proposals for wind generated power distribution lines proposed to traverse the Sea Girt National Guard Training Center Mid-Atlantic Offshore Development (MAOD), September 1, 2022 at 1.

In its SAA Reliability Analysis Report[98], PJM recommended the following Option 1a proposals to support the Larrabee Tri-Collector Solution based on their costs, reliability benefits, and constructability. As set out in PJM's report, these selected Option 1a proposals were chosen from competing proposals seeking to resolve similar violations. In addition to these selections, other projects were selected as needed to enable the Larrabee Tri-Collector Solution, as set out in Attachment A:

- PSE&G's Proposal 180 components 180.1, 180.2 (Brunswick to Deans and Deans subprojects), 180.5, and 108.6 (Windsor to Clarksville subproject);
- LS Power's Proposal 229 (additional Hope Creek-Silver Run 230 kV submarine cable plus upgrade);
- Atlantic City Electric's Proposal 127.10 (Reconductor Richmond-Waneeta 230 kV); and
- Transource's Proposal 63 (North Delta A).

Staff agrees with PJM's recommended selections, set out above, in the SAA Reliability Analysis Report, and in Attachment A. PJM may work with JCP&L and MAOD to evaluate and finalize the planned transmission builds. If there are any material changes to the Option 1a solutions or selection of the Option 1b solution, the Board will make an update in this docket to notify stakeholders.

The components identified by PJM of PSE&G's Proposal 180, LS Power's Proposal 229, and Atlantic City Electric Proposal 127.10 resolve the identified reliability violations; their estimated proposal costs are lower than any of the alternative options, none of which proposed cost containment mechanisms; the anticipated in service dates are sufficient to support generation facilities selected through the OSW solicitation process; all three of the proposals were assigned a "moderate" permitting and environmental impact risk level with no significant concerns identified; and ultimately, PJM found that these proposals were constructible as proposed.

Transource's Proposal 63 included upgrades to resolve the identified reliability violations and "provide the largest reduction in the loading on the Peach Bottom-Conastone 500 kV circuit than any other proposal with a comparable cost," which PJM identifies as the "most challenging and costly of the reliability violations identified for the PA-MD Border Cluster to resolve."[99] In addition, in sensitivity analysis without the Transource 9A project (a project that had been approved as a market efficiency project by PJM, but whose permit application was rejected by the Pennsylvania Public Utilities Commission), this proposal "proved to be the more robust and cost-effective solution once again and was deemed to be the most likely proposal to mitigate the need for further

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[98] PJM's NJOSW Reliability Analysis Report, 2021 SAA Proposal Window to Support NJ OSW, September 19, 2022. The proposals' names and identifying numbers (i.e. "Atlantic City Electric's Proposal 127.10") were created by PJM to identity the specific proposal across of all PJM's analysis; Board Staff references those proposal numbers here for consistency. More information on the specific proposal can be find in PJM's Reliably Analysis Report.

[99] Id. at 18.

upgrades."[100] PJM found that the online date of 2025 is sufficient to support generation facilities selected through the OSW solicitation process. The proposal was assigned a "moderate" permitting and environmental impact risk level with no significant concerns identified. PJM found that this proposal was constructible as proposed.[101]

Prebuilding Shore Crossing Infrastructure and Onshore Cable Routes

Upon review of the different options, including the Baseline Scenario, a key potential benefit of the SAA was found to be that it offers the opportunity to consolidate the number of Shore Crossings and onshore Cable Routes from future projects to interconnect to the grid, so as to limit community disruptions, permitting risks, environmental impacts, delay risks, cost overrun risks and associated OREC risk premiums. DEP also noted that, "[t]hrough a planned transmission approach, and particularly a single corridor, the overall reduction in environmental impacts, permitting, and time, applied to multiple future projects has significant benefits from DEP's perspective."[102]

Staff recognizes that by selecting an Option 1b-only SAA Solution (along with applicable Option 1a projects) that provides for a single location for future interconnections, each OSW generator utilizing that SAA Solution will still need to build the necessary electric transmission cables and infrastructure to carry future New Jersey OSW generation projects from the ocean to the POI. Future OSW generators utilizing the SAA could each propose different landing points and/or different routes from their landing points to the Option 1b Larrabee Collector Station, resulting in multiple routes within the same Transmission Corridor to be constructed at separate times. Even if the future projects use the same landing point and the same onshore route, if they are permitted and constructed at different times, many of the risks and adverse impacts identified above would still exist.

In evaluating how to minimize these risks, Staff identified a solution that, when coupled with the Option 1b and associated Option 1a projects, would result in a single Shore Crossing and a single onshore route to the POI, all of which would be permitted and constructed at the same time for use by future OSW generation projects up to the 7,500 MW goal of this SAA.

This concept, referred to as the "Prebuild," would require a single OSW generator, selected in Solicitation 3, to construct the necessary Duct Banks and associated access Cable Vaults for its own project as well as the additional OSW projects needed to fully utilize the SAA Capability at the selected POI. If more than one project is selected in the Third Solicitation, the Board would specify which awardee would be responsible for constructing the Prebuild Infrastructure, based on schedule, design, cost and other factors. The developer that constructs the Prebuild would utilize one of the Duct Banks/Cable Vaults they are constructing, leaving additional sets of Cable

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[100] Id.

[101] PJM SAA Constructability 1a Report at 120-121. Note that there is regulatory uncertainty surrounding approvals of Certificates of Public Convenience and Necessity needed from Pennsylvania Public Utility Commissions and Maryland Public Service Commissions for these projects.

[102] DEP "State Agreement Approach – OSW Transmission- NJDEP Environmental Review" Memo to Staff, October 7, 2022 at 2.

Vaults and Duct Banks for use by OSW projects awarded in Solicitation 3 and/or subsequent solicitations. Developers of future OSW projects would then install their cables through the prebuilt Duct Banks utilizing the prebuilt Cable Vaults, with little additional disruptions to the shore or the onshore route resulting in minimal further disruption to communities and a reduction in the risks and potential adverse environmental impacts identified above. For clarity, the Prebuild involves only the necessary infrastructure (Duct Banks and Cable Vaults) to house the electric transmission cables, but not the cables themselves or the related converter stations.

The Board recognizes that the Prebuild would be constructed outside of this SAA award. However, the concept, the infrastructure, and the resulting benefits support the selection of an Option 1b proposal at this time. Staff will pursue the Prebuild concept more fully in the Third Solicitation process, and intends to solicit input from stakeholders and the public on issues related to design, construction, operations and maintenance, how the Prebuild developer will be compensated, insurance, risk management, safety and other relevant considerations.

Looking Forward

PJM will undertake the following activities to effectuate the selected SAA projects selected by the Board and subsequently approved by the PJM Board. PJM will include the elements of the Larrabee Tri-Collector Solution approved in today's Order into the RTEP as baseline public policy projects upon the approval of the PJM Board. This will ensure all future transmission planning conducted by PJM considers the SAA projects and the OSW it was built to support, including the 6,400 MW of created SAA Capability. Also, after the Board identifies and selects the SAA projects, PJM will work with the Board to finalize the details to be included in a DEA,[103] including incorporation of the additional language the Board has identified in this Order. Consistent with its current practice, PJM will negotiate the terms of the DEA with the entities approved by the Board to construct and own and/or finance the system upgrades.

The DEA itself will include the obligations and the commitments the developers made to the Board and PJM when they submitted their proposal to PJM and in their responses to subsequent clarifying questions. If a DEA contains nonconforming provisions, PJM will file the DEA with FERC for approval; if conforming, PJM will report the DEA in its Electric Quarterly Report. Regardless whether conforming or non-conforming, all DEA(s) will be posted on the PJM website.

The projects selected herein by the Board, as PJM baseline public policy RTEP projects, will be included in PJM's RTEP, to be acted upon by the PJM Board in December 2022. By incorporating these projects into the RTEP, the SAA projects are akin to other RTEP projects. For example, if a project included in the RTEP impacts a project identified through the SAA, PJM could determine that an enhancement to the SAA project is needed.

[103] The DEA is a *pro forma* agreement under the PJM Tariff that is entered into, as required under Schedule 6 of PJM's Operating Agreement, between PJM and the developer designated to construct and own and/or finance a transmission project included in the RTEP. While use of the DEA is not required under PJM's SAA process, at the request of the Board PJM has elected to follow its competitive solicitation procedures including use of a DEA for those greenfield portions of the selected SAA Solution.

The SAA Agreement contains provisions governing the assignment of the SAA Capability to individual public-policy resources selected by the Board.[104] In awarding SAA Capability to OSW generators, the Board must include the amount (nameplate MW), location (POI), and type (resource type) of the SAA Capability, and direct the OSW generator to submit this award to PJM. Although not required, Staff recommends that the Board notes the PJM queue position that will be used by the OSW generator or selected public policy resource to accept the assignment of SAA Capability.[105] Any award of SAA Capability must occur within two years after the OSW generator is selected through a New Jersey OSW solicitation.[106] In addition, SAA Capability must be awarded prior to the date the OSW generator executes its System Impact Study Agreement.[107] To ensure full and efficient use of SAA Capability for New Jersey ratepayers funding the project, careful consideration of the details of transferring, using, and assigning SAA Capability to each generator selected by New Jersey to receive SAA Capability will be required. These details will vary depending on the specifics of the awarded OSW generator, including its PJM interconnection queue position.

OSW generation applicants are expected, although not required, to have a PJM queue position included with their generation application for future OSW solicitations. PJM queue positions should align with the POIs and timeframes associated with the upgrades awarded through the SAA. The Board would expect to award SAA Capability in the Order approving the OSW generation project, pursuant to the process described above. Additionally, existing OSW projects that have already been awarded may petition the Board to use SAA Capability and address how they would hold ratepayers harmless by adjusting their initial OREC recovery mechanism with the goal of putting ratepayers in the financial position they would have been but for the use of the SAA Capability. In either scenario, the OSW generator then must include the Board's SAA Capability award to their PJM queue position ahead of System Impact Study Agreement execution.

Looking further forward, Staff notes the expansion of New Jersey's OSW goals as an exciting development further securing New Jersey's leadership position in the burgeoning OSW industry. However, similar to the initial 7,500 MW OSW goal addressed in today's Order, additional challenges are anticipated in efficiently and cost-effectively delivering the incremental 3,500 MW of OSW required to reach the 11,000 MW OSW goal specified in EO 307. These challenges are similar to the animating factors underlying this SAA process, set forth in detail above. Based on these anticipated challenges, and the robust developer response and creative proposals received through this SAA process, Staff recommends that the Board initiate the necessary preliminary steps to pursue a second SAA process, with the goal of providing an efficient, coordinated transmission approach to reach 11,000 MW and beyond, while minimizing cost to New Jersey ratepayers. Staff also notes that it may be beneficial, prior to initiation of the second SAA, to review with other states, both inside and outside the PJM region, the potential for jointly undertaking an offshore wind planning process and incorporating those larger needs, into this

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[104] SAA Agreement at Section 6.2(d).

[105] Id. at Section 6.2(d)(i) ("...such OSW generator and or NJ BPU-selected Public Policy Resource shall have a position in the PJM New Service Queue at the time of such assignment.").

[106] Id. at Section 6.2(d)(i).

[107] Id. at Section 4.3(a).

future SAA. While such a multi-state process may present additional complexities, it is also likely to reduce costs to ratepayers, by identifying even more robust regional solutions by considering a wider range of public policy needs, and by enabling the sharing of costs with other states who participate in the SAA process.

Currently Awarded Offshore Wind Projects

The Ocean Wind II project presents the most straightforward case for reaching agreement on assigning SAA Capability to the project, due to its primary PJM queue position, AG2--055 with interconnection at Smithburg.[108] In addition to this existing queue position, the Board's award to Ocean Wind II contemplated alternate POIs through the SAA process, should these alternates provide lower-cost or lower-risk solutions.[109] Any revision to the approved Ocean Wind II interconnection plan as approved by the Board would require a mutually acceptable revision to the interconnection plan.[110] Revisions to the interconnection plan would also likely require updates to the approved TSUC mechanism included in the Second Solicitation Order, which originally contemplated OSW generators bearing interconnection costs in full up to a certain amount.[111]

The processing of PJM's interconnection queue is currently on hold due to proposed revisions to PJM's interconnection process, which will keep all AG2 queue positions, including Ocean Wind II's, in the pre-study phase well into 2024.[112] Under the terms of the SAA Agreement, the Board will be able to assign SAA Capability to the Ocean Wind II project during the pendency of this pre-study interconnection phase. Some complexities arise when determining the most efficient interconnection *location* for the Ocean Wind II project. PJM informed Staff and its consultant that any shift in queue position away from the Deans or Smithburg POIs (as reflected in Ocean Wind II's initial interconnection request) could have significant negative schedule ramifications. Without any grant of SAA Capability, Ocean Wind II is currently pursuing its submitted and approved interconnection plan at Smithburg.[113]

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[108] June 21, 2019 Order, supra note 18 at 23-24 ("…OW2 noted its intent to change the OW2 Project's primary POI from Deans to Smithburg") (internal citations omitted).

[109] Id. at 24 ("Despite the existing interconnection plan, the Board leaves open the potential for the Ocean Wind II Project to utilize newly developed SAA transmission capability. The Board encourages maximum utilization of shared offshore wind facilities, to the extent that the use of those facilities is in the best interest of New Jersey ratepayers, be delivering the OW2 Project in a lower-cost or lower-risk fashion.").

[110] Id. at 25 ("For any deviation from the interconnection plan approved in this order, including for use of any SAA transmission capability, a mutually acceptable revision to this Order will be required.").

[111] Id. at 16, 27; Atlantic Shores 1 June 2021 Order, supra note 22 at 16, 27.

[112] PJM IRPSTF at Figure 9 (Transition Cycle #2). https://www.pjm.com/directory/etariff/FercDockets/6726/20220614-er22-2110-000.pdf FERC Docket No. ER22-2110.

[113] June 21, 2019 Order, supra note 18,_at 25 ("Prior to any determination by the Board that use of SAA transmission capability is in the best interests of New Jersey ratepayers, OW2 will need to pursue its PJM transmission interconnection plan…").

Despite Ocean Wind II's position in the PJM interconnection queue, other aspects of the SAA Agreement suggest that swift action toward assigning SAA Capability to Ocean Wind II may be in the best interests of New Jersey ratepayers and the Ocean Wind II project. Specifically, the SAA Agreement limits the Board's ability to assign SAA Capability to within two years after the OSW generation award.[114] As both the Ocean Wind II and Atlantic Shores 1 projects were selected by the Board on June 30, 2021, the ability for SAA Capability assignment expires in June of 2023 for these 2 projects, eight months after today's Order awarding SAA facilities.[115] To enable the appropriate revisions to the TSUC mechanism, adherence to tight schedule deadlines will be needed to ensure a final award of SAA Capability can occur within the required timeframe.

The Atlantic Shores 1 project suggests a more intricate process for utilizing SAA Capability. In all SAA Scenarios, Atlantic Shores 1 will inject 1,510 MW at Cardiff, because the project has advanced in the PJM interconnection queue, having already submitted its SIS study agreement[116]. Per the SAA Agreement, this queue progression currently disqualifies the Atlantic Shores 1 project from receiving a direct assignment of SAA Capability. Accordingly, Staff and Brattle worked with PJM to ensure Atlantic Shores 1's approved interconnection plan (1,510 MW at Cardiff) can be accomplished in a cost-effective manner considering any SAA outcome.

Specifically, there needs to be a reconciliation between Atlantic Shores 1's three anticipated ISAs, which will provide injection rights for the ASOW 1 project's 1,510 MW at Cardiff (Atlantic Shores 1 retains three PJM interconnection queue positions that together make up 1,510 MW), and the SAA, which also modeled 1,510 MW at Cardiff. This inclusion was required in the PJM reliability studies to ensure that coordinated solutions could enable the full suite of New Jersey public policy requirements, even with Atlantic Shores 1 pursuing its own interconnection plan. PJM has indicated that, if any Option 1a system upgrades selected through the SAA process obviate the need for Network Upgrades identified in ASOW 1's interconnection study, Atlantic Shores 1's obligation under its ISAs would be reduced—including issuing a scope change to the Atlantic Shores 1 ISAs as necessary—to ensure that Network Upgrades previously identified but no longer required are removed from the project's obligation.[117] This process allows Atlantic Shores 1 to retain its interconnection plan as approved by the Board,[118] including the benefit of its advanced queue positions, while also allowing all parties to benefit from the lower-cost interconnection opportunities created through the proactive SAA process.

The same injection amount for the Atlantic Shores 1 project interconnection study was included in the SAA studies and therefore reconciliation is necessary to ensure only the needed facilities will be built and no unnecessary duplication of transmission facilities. In order to reconcile the

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[114] SAA Agreement at § 6.2(d)(i) ("SAA Capability shall be assigned initially by the NJ BPU to an OSW Generator or NJ BPU-selected Public Policy Resource no later than two (2) years from the actual Solicitation Award Date under a NJ BPU OSW Solicitation….").

[115] See June 21, 2019 Order, supra note 18.

[116] See PJM Manual 14A, Section 5.2, available at https://www.pjm.com/-/media/documents/manuals/m14a.ashx.

[117] PJM Confidential April 13, 2022 response to BPU Staff/Brattle questions, at 1.

[118] Atlantic Shores 1 June 2021 Order, supra note 22.

two processes with each other, the SAA Capability available for the Board to assignmay be adjusted upon the conclusion of the integration of the Atlantic Shores 1 ISAs with the approved SAA facilities, to ensure SAA Capability representing ASOW 1 is not used twice. This will still ensure the remaining 3,742 MW of SAA Capability remains for future OSW projects. As explained above, because PJM cannot produce a fulsome study of the integration of the ASOW 1 ISA with the approved SAA projects prior to both an SAA approval and ASOW's ISA execution, Staff recommends that the Board retain flexibility to take additional action on the basis of the reconciliation process explained herein.

Findings and Discussion

Based on the review of PJM, Brattle, DEP, Rate Counsel, and DMAVA's evaluation and analysis of the SAA bid proposals and analysis, and based on Staff's resulting recommendation described above, the Board **HEREBY FINDS** that the Larrabee Tri-Collector Solution is the most desirable SAA Solution at this time, and thus, **HEREBY APPROVES** the elements of Larrabee Tri-Collector Solution, and the associated Option 1a facilities to enable 6,400 MW of SAA Capability, as detailed in Appendix A, and further detailed by PJM in its update to the approved SAA Agreement.[119] PJM may work with JCP&L and MAOD to evaluate and finalize the planned transmission builds. If there are any material changes to the Option 1a solutions or selection of the Option 1b solution, the Board will make an update in this docket to notify stakeholders.

The Board agrees with Staff's recommendation that an Option 1b proposal represents the best option for New Jersey ratepayers at this time after carefully weighing all of the various benefits and potential risks. To coordinate on an ongoing basis to ensure active consultation and conflict resolution in accord with the Board's commitment to generators' equal access to the relevant SAA project(s), JCP&L and MAOD are **HEREBY DIRECTED** to coordinate with Staff and OSW generators (or other Board-selected Public Policy Resources as set forth in the SAA Agreement) on awarded SAA Capability.

Additionally, to enable the efficient allocation and distribution of the necessary land to support future HVDC converter stations, to be constructed and maintained by the OSW generators selected by the Board in future solicitations at the site of the Larrabee Tri-Collector Solution, MAOD is **HEREBY DIRECTED** to coordinate with Staff and generators awarded ORECs to ensure each generator has adequate and equal access to such land as is reasonably necessary to develop their individual projects according to the generator's project schedule. The Board **HEREBY DIRECTS** all parties to act in good faith and to ensure that each party is provided the necessary time and information to develop their respective projects as awarded by the Board. To facilitate a transparent process, Staff, MAOD, and PJM should develop a process so that a formal agreement with each OSW generator awarded SAA Capability by the Board has equal and adequate access to the land necessary to construct the DC converters, including construction as well as operations and maintenance ("O&M") throughout the operating life of the equipment. The Board expects Staff, MAOD, and PJM to set forth these terms in a DEA filed at FERC, but is open to the parties developing a separate process. Further, because the costs of the Larrabee Tri-Collector Solution will be recovered through the approved SAA cost-allocation methodology, Staff

[119] See SAA Agreement at Section 3.0.

and MAOD should ensure that any monies involved in a land-transfer, land-lease, or other land-use transaction best protects ratepayers from unnecessary or duplicative costs. The Board recognizes that eventually, up to four OSW generators may be required to construct their HVDC converter stations on this land.

As such, the Board **HEREBY** **DIRECTS** MAOD to ensure all such future OSW generators that are awarded SAA Capability selected by the Board are provided equal and adequate access to the land to construct and maintain their respective projects, without hindering another OSW generators' ability to do the same. The Board encourages MAOD to engage with Staff in the interim to design pro-forma site layouts that would ensure access to up to four HVDC converters at the site. Since the costs of the Larrabee Tri-Collector Solution will be recovered through the approved SAA cost-allocation methodology, MAOD must ensure no unnecessary or duplicative costs are borne by ratepayers for any land-use transaction. MAOD shall work with Staff and PJM to ensure these principles are memorialized in a DEA or other agreement. For any monies involved in such a transaction, MAOD is **HEREBY** **DIRECTED** to either credit these revenues against the revenue requirements of the Larrabee Tri-Collector Solution through the SAA cost allocation or use another mechanism to avoid the double recovery of costs. MAOD is **HEREBY** **DIRECTED** to submit the details of any transaction to Staff 90 days before any exchange occurs. Staff shall review and, if appropriate and able, provide its approval to MAOD for any transaction related to the use of the land.

The Board recognizes that the development of transmission projects requires years of planning and coordination. Further, even after construction, ongoing O&M could require occasional changes to the projects. Since the components of the Larrabee Tri-Collector Solution are critical to support New Jersey's OSW goals and resulting projects that seek to utilize the Larrabee Tri-Collector Solution, the Board has a unique interest in ensuring all projects that comprise the Larrabee Tri-Collector Solution, and the associated Option 1a facilities, are developed in accordance with the proposed timelines. To ensure the Board remains fully informed on a regular basis, the Board **HEREBY** **DIRECTS** JCP&L and MAOD to provide, in addition to the reports required in Appendix B: Terms and Conditions to this Order, quarterly progress reports on the projects awarded herein under the Larrabee Tri-Collector Solution until these facilities are placed in-service. These quarterly progress reports shall include, but are not limited to, updates on construction activities, community engagement, all PJM and FERC filings and updates, schedule updates and notification of delays. These reports may take the form of quarterly meetings. Every year, within 90 days following the anniversary of this Order, JCP&L and MAOD shall submit written reports on their projects. Staff may, at its discretion, request additional pertinent information or more frequent updates.

In order to assist in developing the specifications for the Third Solicitation, MAOD, and if deemed appropriate by Staff, any other SAA Developer awarded herein, is **HEREBY** **DIRECTED** to:

1) Meet with Staff within seven calendar days of the effective date of this Order to discuss the parameters and requirements related to the interconnection of future OSW generators, including, but not limited to, the technical requirements and limitations, land access and use, and O&M plans, and the construction and operations of future converter stations that may be constructed on the site;

2) Provide in a timely manner all the necessary information to Staff that may be needed to develop the Third Solicitation;
3) Provide in a timely manner all the necessary information to potential OSW generators seeking to develop applications for any of New Jersey's OSW solicitations;
4) Ensure any OSW generator seeking to develop an application(s) for any of New Jersey's OSW solicitations shall have equal and adequate access to the information needed to develop an OREC application.
5) Provide in a timely manner all the necessary information to any existing OSW generator previously awarded in New Jersey's OSW solicitations which may be utilizing any of the facilities awarded herein.

In order to ensure the timely delivery of information to OSW generators seeking to develop an application(s) for New Jersey's Third Solicitation, the Board **HEREBY AUTHORIZES** Staff to hold a technical conference, if Staff deems appropriate, with MAOD and any other SAA transmission developer awarded herein, to provide guidance and clarity on the specifications necessary to interconnect to the projects awarded herein.

The Board **HEREBY DIRECTS** JCP&L and MAOD to submit annual reports on the projects awarded herein under the Larrabee Tri-Collector Solution after CODs of the respective projects. These reports shall be submitted within 90 days following the anniversary of the project's CODs, until such date that the SAA Capability will be fully utilized, or Staff deems these reports no longer necessary. The annual reports shall include relevant O&M developments and any engagement updates with offshore wind developers utilizing the Larrabee Tri-Collector Solution. Staff may, at its discretion, request additional information from the project as it deems necessary.

The Board is committed to ensuring that the Larrabee Tri-Collector Solution awarded herein is developed according to the proposed schedules in order to support the OSW generation projects. Hence the Board **HEREBY DIRECTS** all projects awarded herein as specified in Appendix A under the Larrabee Tri-Collector Solution to notify the Board of any estimated delay longer than three months. Such notification shall be in writing and be submitted to the Board no more than 30 days after discovering such delay exists or may exist. The Board retains the right to share this information with all impacted OSW generators.

The Board **HEREBY DIRECTS** Ocean Wind II and Staff to enter into good faith negotiations to determine whether, and under what conditions, Ocean Wind II may petition the Board to utilize SAA Capability that will become available under the SAA Solution. Should all parties to the June 30, 2021 Order agree that Ocean Wind II shall utilize SAA Capability, all necessary agreements, including modification to the OREC schedule and other requirements contained in the June 30, 2021 Order, must be fully executed such that the Board can assign the SAA Capability no later than two years after the solicitation award date, or before June 30, 2023, in accordance with the PJM SAA Agreement.

The Board **HEREBY DIRECTS** Atlantic Shores 1 and Staff to jointly evaluate the effects of the Board's SAA decision on the planned interconnection of this project, including its costs, and develop a mutually acceptable recommendation for reconciliation of such effects.

The Board finds that future revisions to the awarded projects herein under the Larrabee Tri-Collector Solution may be required depending on changed circumstances unknowable as of the time of award. The Board accepts Staff's recommendation and **HEREBY RETAINS THE RIGHT** to enter further orders in this docket as deemed necessary to reflect significant updates to the scope, configuration and/or cost of projects on the basis of any future changed circumstances. In addition, should PJM or Staff identify routine changes to elements of any awarded projects that would increase the benefits to New Jersey ratepayers, the Board **HEREBY AUTHORIZES** Staff to review and accept these revisions, and notify PJM of the same.

All developers of the approved projects herein ("SAA Developer") must **HEREBY COMPLY** with the terms of this Order, all the relevant terms in the SAA Agreement, and all terms within any applicable DEA with PJM. The terms and conditions specified in Appendix B: Terms and Conditions to this Order, shall apply to all approved SAA Developers and projects. These terms, as appropriate, may be filed with FERC under a DEA.

The Board has reviewed the impacts related to the number of Transmission Corridors. The community disruptions, the environmental impacts, the permitting challenges, the costs and the high risk of delays increase with each Transmission Corridor. As such, the Board **HEREBY FINDS** that there are great benefits in limiting the number of Transmission Corridors for OSW projects. The Board appreciates the novel and innovative approach set forth in Staff's recommended Prebuild concept. As such, the Board **HEREBY DIRECTS** Staff to require the Prebuild concept in the Third Solicitation.

Finally, the Board continues to recognize the potential benefits of a full offshore wind backbone and continues to see the creation of such a grid as a key future area of interest, particularly as additional sources of federal funding become available through the recently enacted Inflation Reduction Act and other measures. The Board **HEREBY DIRECTS** Staff to begin necessary preliminary steps to support a future SAA process, to enable the transmission of New Jersey's new goal of 11,000 MW of OSW energy generation to occur in a coordinated manner, for the benefit of ratepayers. Further given the regional interest in offshore wind, the Board **HEREBY DIRECTS** Staff to continue its engagement with other states, regional grid operators, and other interested stakeholders about how to further advance New Jersey's transmission-first approach to offshore wind.

The effective date of this Order is November 5, 2022.

DATED: October 26, 2022

BOARD OF PUBLIC UTILITIES
BY:

JOSEPH L. FIORDALISO
PRESIDENT

MARY-ANNA HOLDEN
COMMISSIONER

DIANNE SOLOMON
COMMISSIONER

ROBERT M. GORDON
COMMISSIONER

DR. ZENON CHRISTODOULOU
COMMISSIONER

ATTEST:

CARMEN D. DIAZ
ACTING SECRETARY

Appendix A: Selected Projects

This Board Order approves the following projects under PJM's 2021 SAA Proposal Window to Support New Jersey's OSW public policy and as described in the PJM analysis reports,[120] for review and approval by the PJM Board as baseline public policy projects included in PJM's RTEP, under the terms and conditions set forth in Appendix B:

PJM's Proposal IDs	Components	Estimated In-Service Date (ISD)	Estimated Cost ($MM)
ACE			
Proposal ID 127	The following components of Proposal 127:	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	
	10. Rebuild the underground portion of Reconductor Richmond –– Waneeta 230 kV (1098SN/1247SE, 1150WN/1299WE MVA)		$16.00
	1. Upgrade Cardiff- – Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation (377SN/478SE, 451WN/478WE MVA)		$0.10
	3. Upgrade Cardiff- – New Freedom 230 kV by modifying the existing relay settings (650SN/804SE, 748WN/906WE MVA)		$0.30
	2. Upgrade Lewis No. 2- – Lewis No. 1 138 kV by replacing bus tie with 2000 A circuit breaker (478SN/478SE, 478WN/478WE MVA)		$0.50
MAOD			
Proposal ID 551	Construct the AC switchyard portion of MAOD proposal 551, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000A and four single phase 500/230 kV 450MVA autotransformers to step up the voltage for connection to the Smithburg substation. AC switchyard design and site preparation shall be suitable for expansion to a 230 kV 4 X 230 kV breaker and a half substation and seven single phase 500/230 kV 450 MVA autotransformers to step up voltage for connection of two circuits to Smithburg substation.	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	$121.00

[120] As discussed in the body of this Order, PJM prepared six comprehensive analysis reports of the proposals submitted in the window. The PJM analysis reports collectively make up a comprehensive evaluation of the proposals, which were studied either individually or in combinations indicated as SAA Scenarios. The reports consist of a reliability analysis report, an economic report, a financial analysis report and constructability analysis reports for options 2/3, 1a, and 1b. The PJM analysis reports were posted on September 19, 2022 on the PJM's TEAC page under the September 6, 2022 meeting date.

	Procure land adjacent to the MAOD AC switchyard, which is a portion of the MAOD proposal 551, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four (4) individual converters to accommodate circuits with equivalent rating of 1400MVA at 400 kV. MAOD will commit to work with NJBPU and Staff, PJM, the relevant transmission owners, and all future developers to lease or otherwise make land access available for construction of converters by those future developers to support the integration of OSW generators to achieve the OSW goals of New Jersey	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	MAOD will perform further assessments to improve its refinement of the estimate and scope of work as requested by the NJBPU.
JCP&L			
Proposal ID 453	The following components of Proposal 453:		
	1. Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	6/1/2030	$31.47
	2. Freneau Substation - Update relay settings	6/1/2030	$0.03
	3. Smithburg Substation - Update relay settings	6/1/2030	$0.03
	4. Oceanview Substation - Update relay settings	6/1/2030	$0.04
	5. Red Bank Substation - Update relay settings	6/1/2030	$0.04
	6. South River Substation - Update relay settings	6/1/2030	$0.03
	7. Larrabee Substation - Update relay settings	6/1/2030	$0.03
	8. Atlantic Substation - Install line terminal	6/1/2030	$4.95
	9. Larrabee Substation - Reconfigure substation	6/1/2029	$4.24
	10. Larrabee substation: 230 kV equipment for direct connection	6/1/2029	$4.77
	11. Lakewood Gen Substation - Update relay settings	6/1/2029	$0.03
	12. G1021 (Atlantic-Smithburg) 230 kV	6/1/2030	$9.68
	13. R1032 (Atlantic-Larrabee) 230 kV	6/1/2030	$14.50
	14. New Larrabee Converter-Atlantic 230 kV	6/1/2030	$17.07
	15. Larrabee-Oceanview 230 kV	6/1/2030	$6.00
	16. B54 Larrabee-South Lockwood 34.5 kV Line Transfer	6/1/2029	$0.31
	17. Larrabee Converter-Larrabee 230 kV New Line	6/1/2029	$7.52
	18. Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	12/31/2027	$150.35
	24. G1021 Atlantic-Smithburg 230 kV	12/31/2027	$62.85
	27. Smithburg Substation 500 kV Expansion	12/31/2027	$5.81

	28. Larrabee Substation	6/1/2030	$0.86
	29. Smithburg Substation 500 kV 3 Brk Ring	12/31/2027	$62.44
Proposal ID 17	The following components of Proposal ID 17: Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line - Smithburg-East Windsor 500 kV (3678SN/4541SE, 4262WN/5503WE MVA) - Deans-Smithburg 500 kV (3215SN/3998SE, 3890WN/4334WE MVA)	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	
	4. East Windsor-Smithburg 500kV Line		$104.21
	5. East Windsor-Smithburg 230kV Line		$37.80
	6. East Windsor Substation		$32.10
	7. T5020 Smithburg-Deans 500kV		$13.24
	8. K137 Windsor-Twin Rivers-Wyckoff Street 34.5kV		$6.20
	9. X752 Jerseyville-Smithburg 34.5kV		$4.58
	10. B158 Gravel Hill Smithburg 34.5kV		$4.23
	11. Smithburg 230 kV Substation		$4.12
	18. Add third Smithburg 500/230 kV (1034SN/1287SE, 1036WN/1451WE MVA)		$13.40
	16. Rebuild approximately 0.8 miles of the D1018 Reconductor Clarksville-Lawrence 230 kV line between Lawrence substation (PSEG) and structure No. 63 (1140SN/1387SE, 1342WN/1495WE MVA)		$19.00
	19. Reconductor Kilmer I- – Lake Nelson I 230 kV (1136SN/1311SE, 1139WN/1379WE MVA)		$4.42
PJM Identified Upgrades	Proposal Email 12/30/21: Additional reconductoring required for Lake Nelson I- 1 – Middlesex I 230 kV (1114SN/1285SE, 1116WN/1352WE MVA)	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	$3.30
	Proposal Email 2/24/22: Rebuild Larrabee- – Smithburg #1 230 kV (1136SN/1311SE, 1139WN/1379WE MVA)		$52.00
	Proposal Email 2/11/22: Reconductor small section of Raritan River- – Kilmer 1I 230 kV (n6201) (1156SN/1334SE, 1158WN/1403WE MVA)		$0.20
	Proposal Email 2/11/22: Replace substation conductor at Kilmer & reconductor Raritan River- – Kilmer W 230 kV (n6202) (1156SN/1334SE, 1158WN/1403WE MVA)		$25.88
	Proposal Email 2/11/22: Reconductor Red Oak A- – Raritan River 230 kV (n6203) (1156SN/1334SE, 1158WN/1403WE MVA)		$11.05

	Proposal Email 2/11/22: Reconductor Red Oak B- – Raritan River 230 kV (n6204) (1156SN/1334SE, 1158WN/1403WE MVA)		$3.90
LS Power			
Proposal ID 229	One additional Hope Creek- – Silver Run 230 kV submarine cable (1364SN/1614SE, 1364WN/1614WE MVA) and rerate plus upgrade line:	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	
	1. Transmission Line Upgrade		$60.20
	2. Silver Run Substation Upgrade		$1.00
PSE&G			
Proposal ID 180	The following components of Proposal ID 180:	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	
	3. Linden Subproject (IP)		$16.36
	4. Linden Subproject (OP)		$8.56
	5. Upgrade Lake Nelson W-Middlesex W-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230kV (Lake Nelson W-Greenbrook W 230 kV: 934SN/1080SE, 999WN/1143WE MVA)(OP)		$4.28
	6. Upgrade Lake Nelson W-Middlesex W-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230kV (Lake Nelson W-Greenbrook W 230 kV: 934SN/1080SE, 999WN/1143WE MVA) (IP)		$1.49
	7. Bergen Subproject		$5.53
PJM Identified Upgrades	Proposal PPT 3/11/22: Upgrade inside plant equipment at Lake Nelson I 230 kV (Kilmer I-Lake Nelson I 230 kV: 1378SN/1625SE, 1475WN/1723WE MVA)	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	$3.80
	Proposal PPT 2/4/22: Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230kV (Kilmer W-Lake Nelson W 230 kV: 934SN/1080SE, 999WN/1143WE MVA)		$0.16
	Proposal PPT 2/4/22: Upgrade Lake Nelson W-Middlesex W-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230kV (Lake Nelson W-Greenbrook W 230 kV: 934SN/1080SE, 999WN/1143WE MVA)		$0.12
PPL			
Proposal ID 330	The following components of Proposal ID 330:	ISD to be aligned with NJBPU solicitation	
	1. Reconductor Gilbert-Springfield 230 kV		$0.38

		schedule and related JCP&L Proposal 453 project work	
Transource			
Proposal ID 63	North Delta Option A:	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	
	1. Graceton Station Upgrade		$1.55
	2. North Delta Station		$76.27
	3. Tline Upgrade – Graceton – Cooper - Peach Bottom		$28.74
	4. Tline Upgrade – North Delta – Cooper Cut-in Lines		$1.56
	5. Tline Upgrade – Peach Bottom - Delta Cut-in Lines		$1.56
PECO			
PJM Identified Upgrades	Replace 4 Peach Bottom 500 kV breakers	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	$5.6

BGE			
PJM Identified Upgrades	Upgrade one Conastone 230 kV breaker	ISD to be aligned with NJBPU solicitation schedule and related JCP&L Proposal 453 project work	$1.3

Appendix B: Terms and Conditions

The following terms and conditions will apply to all projects selected under the SAA.

1. For any greenfield portion of a selected project, or to reflect any other commitments associated with a selected project, the SAA Developer shall execute a DEA with PJM that (i) memorializes the design, construction and operation of the project, (ii) fully incorporate the commitments made by the SAA Developer regarding its SAA Proposal, as set forth in Schedule E of the SAA Developer's proposal, and (iii) is consistent with the form and substance reasonably acceptable to PJM and the Board. As a condition of the DEA, the SAA Developer shall not be permitted to amend, modify or terminate (or cause the termination of) the DEA without prior written consent of the Board.
2. Prior to making any filings with PJM under the DEA, the PJM Operating Agreement or the PJM Open Access Transmission Tariff (collectively, the "PJM Governing Documents"), or otherwise, the SAA Developer shall provide a draft of such filing to the Board Secretary and the Deputy Director of the Division of Clean Energy for review and comment, and shall use reasonable efforts to incorporate into such filing any comments received from the Board and/or Staff.
3. The SAA Developer shall provide to Staff a copy of all correspondence submitted by the SAA Developer to PJM, or received by the SAA Developer from PJM, promptly upon such submittal or receipt.
4. Prior to making any filings with FERC pursuant to the DEA, the PJM Governing Documents, the Federal Power Act, or otherwise, the SAA Developer shall provide a draft of such filing to the Board Secretary and the Deputy Director of the Division of Clean Energy for review and comment, and shall use reasonable efforts to incorporate into such filing any comments received from the Board and/or Staff.
5. Unless otherwise agreed to by the Board in writing, all formula rate and similar filings by the SAA Developer with the FERC pursuant to Section 205 or Section 206 of the Federal Power Act shall fully conform to commitments made by the SAA Developer in its SAA Proposal, the DEA, and the requirements of this Order.
6. The SAA Developer shall provide regular, quarterly status reports in writing to the Board. The reports shall contain, but not be limited to, updates and information regarding: (a) current permitting and land acquisition status of the project; (b) current engineering and construction status of the project; (c) project completion percentage, including milestone completion; (d) current target project and phase completion date(s); and (e) cost expenditures to date, including any associated overhead and fringe benefits related costs and revised projected cost estimates for completion of the project.
7. The SAA Developer shall design, construct, operate and maintain the project, as set forth in Appendix A, in accordance with: (a) the provisions of this Order; (b) all applicable laws, regulations, ordinances and permits (collectively, "Applicable Law"); (c) the DEA; (d) the PJM Governing Documents; (e) the Federal Power Act; (f) applicable reliability principles, guidelines, and standards of the Applicable Regional Reliability Council and the North American Electric Reliability Corporation ("NERC"); and (g) Good Utility Practice (as defined in the DEA). The SAA Developer shall promptly notify the Board of any actual, alleged or anticipated failure to comply with the foregoing requirements.
8. The SAA Developer shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance

with Applicable Laws associated with the Project, including but not limited to obtaining all necessary permits, siting, and other regulatory approvals. The Board in its discretion or as set forth in this Order may, but shall have no responsibility to, supervise or ensure compliance or adequacy of same.

9. The SAA Developer may not modify the Project without prior written consent of Board Staff under the terms of this Order, including but not limited to, modifications necessary to obtain siting approval or necessary permits, which consent shall not be unreasonably withheld, conditioned, or delayed.
10. The SAA Developer shall construct and place into service the Project in accordance with the schedule of milestones set forth in its SAA Proposal. In the event The SAA Developer, despite the exercise of due diligence, fails to meet, or reasonably believes it may fail to meet, any milestones required to meet the delivery timeline set forth in its SAA Proposal, the SAA Developer shall promptly notify the Board and submit a revised Development Schedule that (a) identifies to the remedial measures to be implemented by the SAA Developer to mitigate the delay (or expected delay), and (b) contains revised milestones showing the Project in full operation no later than the Required Project In-Service Date pursuant to SAA Developer's SAA Proposal.
11. The SAA Developer shall seek and obtain all required government authority authorizations or approvals as soon as reasonably practicable.
12. Upon reasonable notice, the Board shall have the right to inspect the project for the purposes of assessing the progress of the project and satisfaction of milestones. Such inspection shall not be deemed as review or approval by the Board of any design or construction practices or standards used by the SAA Developer.
13. The SAA Developer shall, as directed by the Board, perform or permit the engineering and construction necessary to accommodate the interconnection of generation or other facilities that have been identified and selected by the Board in accordance with PJM Rate Schedule FERC No. 49 (State Agreement Approach Agreement) ("Rate Schedule 49") (such facilities, a "Public Policy Project"). Except in accordance with the foregoing or as otherwise may be set forth in a final order issued by the FERC, the SAA Developer shall not allow the interconnection of any other generation, transmission or other facilities to the project.
14. The SAA Developer will construct, operate and maintain its project in accordance with all submissions made to the Board and/or PJM in the pendency of this SAA solicitation. In connection with the foregoing, the SAA Developer's construction, operation and maintenance of the Project, including recovery of prudently incurred costs associated therewith, shall be subject to the provisions of the DEA, the PJM Governing Documents, and Sections 205 and 206 of the Federal Power Act.
15. The SAA Developer may not assign, in whole or in part, its rights and obligations under this Order except with the prior written consent of the Board.
16. The SAA Developer shall pass through to New Jersey ratepayers all federal investment tax credit benefits and accelerated depreciation benefits that are received by the project or the SAA Developer under the Internal Revenue Code.
17. The SAA Developer shall use reasonable efforts to pursue funding opportunities from the DOE and other governmental sources, and shall pass through to New Jersey ratepayers all funding and economic benefits it receives from any such funding.
18. The Board shall not be liable to the SAA Developer, any third-party, or any other person for any claims, losses or damages arising or resulting from any acts or omissions

associated in any way with performance under this Order. The SAA Developer shall at all times indemnify, defend, and save the Board and its members, officers and employees harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third-parties, arising out of or resulting from the SAA Developer's acts or omissions associated with the performance of its obligations under this Order.

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY

DOCKET NO. QO20100630

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Exhibit No. MAOD-4
Mid-Atlantic Offshore Development, LLC
PJM Rate Schedule 49, Amended SAA Agreement

PJM Interconnection, L.L.C.,Rate Schedules
Filing Category: Normal Filing Date: 01/05/2023
FERC Docket: ER23-00775-000 FERC Action: Accept
FERC Order: Delegated Letter Order Order Date: 03/06/2023
Effective Date: 03/07/2023 Status: Effective
Rate Schedule FERC No. 49, State Agreement Approach Agreement between PJM and NJ BPU (1.0.0)

AMENDED AND RESTATED

STATE AGREEMENT APPROACH AGREEMENT

By and Among

PJM Interconnection, L.L.C.

And

New Jersey Board of Public Utilities

This Amended and Restated State Agreement Approach Agreement ("Agreement") is entered into by and between PJM Interconnection, L.L.C. ("PJM"), the Regional Transmission Organization for the PJM Region (hereinafter "Transmission Provider" or "PJM") and the New Jersey Board of Public Utilities ("NJ BPU"), duly authorized to act on behalf of the State of New Jersey (each referred to herein individually as a "Party" and collectively as the "Parties").

WITNESSETH

WHEREAS, this Agreement is entered into in accordance with the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), Schedule 6, section 1.5.9;

WHEREAS, the New Jersey Legislature has authorized the NJ BPU as the state governmental entity to conduct one or more competitive solicitations for open access offshore wind transmission facilities pursuant to N.J.S.A. 48:3-87.1(e);

WHEREAS, in furtherance of this authority and the state of New Jersey's State Public Policy Objectives or Public Policy Requirements (collectively referred to herein as, "Public Policy Goals"), PJM and the NJ BPU entered into the State Agreement Approach Study Agreement among PJM Interconnection, L.L.C. and the New Jersey Board of Public Utilities, Original Service Agreement No. 5980, effective November 18, 2020, and filed with, and accepted by, the Federal Energy Regulatory Commission ("Commission" or "FERC") in FERC Docket No. ER21-689-000 ("SAA Study Agreement");

WHEREAS, PJM, as the Transmission Provider of the PJM Region, is responsible for the development of the regional transmission expansion plan ("RTEP"). As such, PJM implemented the terms and conditions associated with the NJ BPU's request that PJM, through its State Agreement Approach ("SAA") process, open a competitive proposal window under

Operating Agreement, Schedule 6, section 1.5.8(c) to: (i) solicit project proposals to identify system improvements and new offshore facilities to interconnect and provide for the deliverability of up to 7,500 megawatts ("MW") of offshore wind by 2035 ("SAA Request"); and (ii) evaluate and develop recommendations from the project proposals submitted through the competitive proposal window by proposers for consideration by the NJ BPU and/or its staff in deciding whether to sponsor one or more projects (each, a "SAA Project(s)") that address the state of New Jersey's Public Policy Goals;

WHEREAS, on October 26, 2022, the NJ BPU issued an order in NJ BPU Docket No. QO20100630, in which the NJ BPU selected a SAA Project to sponsor, which SAA Project is comprised of a series of projects to construct on-shore transmission facilities necessary to accommodate the delivery of offshore wind generation to New Jersey customers ("SAA Project Selection Order");

WHEREAS, on December 2, 2022, FERC issued an order in FERC Docket No. ER22-2690-000 and -001 accepting PJM Open Access Transmission Tariff ("Tariff"), Schedule 12 – Appendix C, section (1), which sets forth the cost allocation methodology for SAA Projects selected by the NJ BPU ("SAA Project Cost Allocation Order"); and

WHEREAS, this Agreement amends Rate Schedule FERC No. 49, which was filed with and accepted by FERC in Docket No. ER22-902-000 by Order dated April 14, 2022, to reflect revisions necessitated by the issuances of the SAA Project Selection Order and the SAA Project Cost Allocation Order.

NOW THEREFORE, in consideration of and subject to the mutual covenants contained herein, the Parties agree as follows:

This Agreement sets forth the manner in which SAA Capability (as defined below) created by a SAA Project(s) will: (i) be allocated to generators that enter PJM's New Services Queue and are selected by the NJ BPU through its offshore wind solicitations ("OSW Solicitations") (each such generator an "OSW Generator"); and (ii) thereafter be evaluated by PJM during an OSW Generator's System Impact Study, in accordance with Tariff, Part VI, in defining such OSW Generator's Capacity Interconnection Rights ("CIRs").

This Agreement herein, further details how the SAA Capability will be preserved by PJM for public policy use by the NJ BPU on behalf of New Jersey customers through PJM's tariffed transmission planning and generation interconnection processes, including granting of rights, if eligible, for any incremental transmission capability created by a SAA Project(s), as provided for under the PJM Tariff, for the benefit of New Jersey's customers.

This Agreement sets forth the process by which subsequent users (other than OSW Generators or other Public Policy Resources (as defined below)) of any portion of a SAA Project(s) will equitably share in the costs of a SAA Project(s).

1.0 Definitions.

1.1 Capitalized terms used and defined in this Agreement shall have the meaning given them under the Agreement. Capitalized terms used and not defined in this Agreement but defined in other provisions of the Tariff, Operating Agreement or Reliability Assurance Agreement (collectively, "Governing Documents") shall have the meaning given them under those provisions. Capitalized terms used in this Agreement that are not defined herein or elsewhere in the Governing Documents shall have the meanings customarily attributed to such terms by the electric utility industry operating within PJM.

1.2 For the purposes of this Agreement, the term "SAA Capability" shall mean all transmission capability created by a SAA Project(s), including but not limited to the capability to integrate resources injecting energy up to the Maximum Facility Output ("MFO"), capability which may become CIRs through the PJM interconnection process, and any other capability or rights under the PJM Tariff, and consistent with the reliability study criteria applied to the evaluation of a SAA Project(s) as set forth in Paragraph 6 below. For the avoidance of doubt, SAA Capability shall also include any incremental transmission capability that is created by a SAA Project(s) and is determined to provide Incremental Auction Revenue Rights ("IARRs") or Incremental Capacity Transfer Rights ("ICTRs") associated with Incremental Rights-Eligible Required Transmission Enhancements, pursuant to Tariff, Schedule 12-A.

2.0 **Offshore Wind Solicitation Schedule.** The NJ BPU's current offshore wind solicitation schedule ("Solicitation Schedule") is set forth in Appendix A to this Agreement. The NJ BPU will use due diligence to assign SAA Capability to OSW Generators selected by the NJ BPU under the Solicitation Schedule. The NJ BPU may propose changes to the Solicitation Schedule or select other types of resources to facilitate New Jersey's Public Policy Goals (such resources, "Public Policy Resources"), in addition to (or in combination with) OSW Generators, pursuant to the processes set forth below. Any assignment of SAA Capability must be consistent with PJM's tariffed generation processes for such other resource.

3.0 **Description of a SAA Project Selected by the NJ BPU.** Appendix C to this Agreement includes project-specific information about each component of the SAA Project selected by the NJ BPU in the SAA Project Selection Order.

4.0 **PJM's Obligations and Milestones.**

4.1 **Notifying the Entity Designated to Construct, Own, Operate and Maintain a SAA Project.** Following the NJ BPU's notification to PJM of its decision to select and sponsor a SAA Project(s) and commit New Jersey customers to be responsible for the allocation of all costs related to such SAA Project(s), PJM will follow its processes set forth in Operating Agreement, Schedule 6, sections 1.5.8 and 1.5.9 specific to the selection and notification of the entity or entities (incumbent transmission owner or non-incumbent transmission developer) to be designated to construct, own, operate and maintain the NJ BPU-selected SAA Project(s) ("SAA Designated Entity").

4.2 **Tracking Construction of a SAA Project.** PJM will track the SAA Designated Entity's construction progress with respect to a SAA Project consistent with the Development Schedule and associated construction milestones detailed in a Designated Entity Agreement, and PJM Manual 14C. PJM will provide construction progress reports to the NJ BPU on a quarterly basis.

4.3 **Interconnection Study Process for OSW Generators Selected by the NJ BPU through the OSW Solicitation.**

(a) Upon the NJ BPU's selection of an OSW Generator, the OSW Generator must notify and present to PJM documentation provided to the OSW Generator by the NJ BPU informing PJM of the amount and type of SAA Capability that the NJ BPU proposes be assigned to the OSW Generator at one or several points of injection associated with a SAA Project(s) ("OSW Generator Notification"). Such OSW Generator Notification must be received on or before the date the Interconnection Customer executes the System Impact Study Agreement associated with its Generation Interconnection Request.

(b) PJM will commence the OSW Generator's respective System Impact Study utilizing the SAA Capability assigned to the OSW Generator through the OSW Solicitation, consistent with Paragraph 6.2 below, and any existing system capability (headroom) associated with the OSW Generator's Queue Position.

(c) Following the completion of the System Impact Study for the selected OSW Generator, PJM will notify the NJ BPU of the actual amount of SAA Capability that will remain for future assignments by the NJ BPU ("SAA Capability Pool").

(d) Each OSW Generator must proceed through the PJM interconnection study process and execute an Interconnection Service Agreement to be awarded CIRs.

(e) Should an OSW Generator fail to execute an Interconnection Service Agreement, withdraw prior to achieving commercial operation, or have its assignment of SAA Capability rescinded prior to execution of an Interconnection Service Agreement, PJM shall terminate the OSW Generator's Interconnection Request and revise the amount of SAA Capability in the SAA Capability Pool to include such rescinded amount, subject to the terms contained in Paragraph 6.2 below.

5.0 NJ BPU's Obligations and Milestones.

5.1 NJ BPU Must Notify PJM of the NJ BPU's Decision to Sponsor a SAA Project(s). Following PJM's evaluation of the project proposals submitted through the proposal window, and subsequent project recommendations submitted to the NJ BPU and/or its staff for consideration in deciding whether or not to sponsor a SAA Project(s), the NJ BPU must notify PJM whether it wishes to sponsor a SAA Project(s) and, if so, which SAA Project(s) it will commit New Jersey customers to be responsible for the allocation of costs associated with a SAA Project(s).

5.2 NJ BPU OSW Generation Solicitations. NJ BPU will use reasonable efforts to conduct its future OSW Solicitations (Nos. 3 through 5) pursuant to the Solicitation Schedule set forth in Appendix A, and to thereafter select and designate OSW Generators for an assignment of SAA Capability, provided that the NJ BPU may propose changes to (i) the Solicitation Schedule set forth in Appendix A as provided for in Paragraph 10, or (ii) add other types of Public Policy Resources as provided for in Paragraph 6.2(e), of this Agreement. Any assignment of such SAA Capability to other types of Public Policy Resources shall be evaluated by PJM consistent with the provisions of this Agreement and PJM's tariffed generation interconnection processes for such other resources.

5.3 NJ BPU Notification to Selected OSW Generators. Following the NJ BPU's election to assign SAA Capability to an OSW Generator, the NJ BPU shall provide written notification to the selected OSW Generator of the type and amount of SAA Capability to be been assigned to the OSW Generator ("NJ BPU Notification"). The NJ BPU Notification shall advise the OSW Generator of its responsibility to submit an OSW Generator Notification to PJM prior to commencement by PJM of the OSW Generator's System Impact Study.

5.4 Cost Allocation. Costs of the SAA Project shall be assigned consistent with the methodology set forth in Tariff, Schedule 12 – Appendix C as accepted by FERC in the SAA Project Cost Allocation Order.

6.0 Rights Associated with a SAA Project.

6.1 Priority Reservation of SAA Capability Initially Assigned to OSW Generators. The NJ BPU shall have the right to assign the SAA Capability created by a SAA Project(s) to OSW Generators and NJ BPU-selected Public Policy Resources that enter PJM's New Services Queue and are selected by NJ BPU to serve customers in New Jersey and effectuate New Jersey's Public Policy Goals. The initial assignment of SAA Capability to a specific OSW Generator(s) and NJ BPU-selected Public Policy Resources will be conducted pursuant to Paragraph 6.2(d)(i). The NJ BPU shall have and maintain priority rights to assign SAA Capability created by a SAA Project(s) to OSW Generators and NJ BPU-selected Public Policy Resources, subject to Paragraphs 5.2, 6.2(d)(i), 6.2(e), 6.2(f) and 10 of this Agreement. Any SAA Capability that is not allocated in conformance with such provisions may be made available by PJM to entities other than OSW Generators and NJ BPU-selected Public Policy Resources, consistent with Paragraphs 6.2(g) and 10 herein.

6.2 Award of SAA Capability, including CIRs.

(a) Points of Injection. The completion of all Transmission System upgrades and new facilities associated with a SAA Project(s) will create additional SAA Capability on the PJM onshore and offshore Transmission System to facilitate the injection and delivery of energy and other services by OSW Generators consistent with New Jersey's Public Policy Goals. Upon the selection by the NJ BPU of one or more SAA Project(s), PJM shall promptly notify NJ BPU of amount and type of SAA Capability that is associated with such SAA Project(s), and which thereafter can be assigned to OSW Generators. The points and amounts of injection associated with the SAA Project are set forth in Appendix D to this Agreement.

(b) Deliverability. OSW Generators assigned SAA Capability will not be guaranteed full deliverability (or an award of CIRs by PJM) until the completion of the applicable SAA Project(s) (and, if appropriate, any additional Network Upgrades that are required by the OSW Generator's Interconnection Service Agreement, as well as demonstration of Initial Commercial Operation consistent with Appendix 2, section 1.2 of the OSW Generator's Interconnection Service Agreement).

(c) SAA Study Assumptions. The SAA Capability will be based, modeled and reserved in a manner (i) consistent with PJM's reliability criteria, study assumptions, and modeling processes for offshore wind turbines as detailed in PJM Manuals, and (ii) as described and identified in any subsequent FERC filings, as well as in Appendix B herein (PJM RTEP - 2021 NJ Offshore Wind SAA Transmission Proposal Window Overview – Appendix: Reliability Analysis to Support 2021 NJ Offshore Wind SAA Transmission Proposal Window) to the PJM RTEP – 2021 NJ Offshore Wind SAA Transmission Proposal Overview Document.

(d) Granting of SAA Capability to an OSW Generator.

(i) SAA Capability shall be assigned initially by the NJ BPU to an OSW Generator or NJ BPU-selected Public Policy Resource no later than two (2) years from the actual Solicitation Award Date under a NJ BPU OSW Solicitation, provided that such OSW Generator and or NJ BPU-selected Public Policy Resource shall have a position in the PJM New Service Queue at the time of such assignment. SAA Capability assigned to OSW Generators and NJ BPU-selected Public Policy Resources will be included in such entity's System Impact Study conducted by PJM consistent with Paragraph 4.3 of this Agreement. All SAA Capability must initially be assigned by the NJ BPU to OSW Generators and NJ

BPU-selected Public Policy Resources no later than two (2) years from the last Solicitation Award Date set forth in the Solicitation Schedule in Appendix A herein, subject to Paragraphs 5.2 and 10 of this Agreement. Any SAA Capability not assigned within such timeframe by the NJ BPU to OSW Generators and other NJ BPU-selected Public Policy Resources shall be released for use by entities other than OSW Generators and NJ BPU-selected Public Policy Resources, subject to the cost sharing provisions set forth in Paragraph 6.2(g) below.

(ii) The amount of CIRs (expressed in MW) granted by PJM to an OSW Generator will: (1) be based on the type and amount of SAA Capability assigned by the NJ BPU to the OSW Generator; (2) be determined by PJM using (a) the applicable RTEP base case used to study the individual Interconnection Requests along with the stated points and amounts of injection for any approved SAA Project(s), as verified by PJM, (b) the SAA Study Assumptions set forth in Paragraph 6.2(c) above; and (c) the actual point of interconnection proposed by the OSW Generator in its System Impact Study; and (3) take into account any existing system headroom associated with the OSW Generator's Queue Position.

(e) Project Eligibility for Assignment of SAA Capability. Should New Jersey choose to assign some or all SAA Capability created by a SAA Project(s) to Public Policy Resources other than OSW Generators, NJ BPU will notify PJM of the Public Policy Resource(s) to which NJ BPU proposes to assign such SAA Capability. Any assignment of such SAA Capability to other types of Public Policy Resources shall be evaluated by PJM consistent with the provisions of this Agreement, PJM's tariffed generation interconnection processes for such other resources, and PJM Manuals, including but not limited to PJM Manual 14G, section 4.4.

(f) Reassignment of SAA Capability. In the event an OSW Generator's or other Public Policy Resource's Queue Position is terminated or withdrawn prior to the achievement of commercial operation, all SAA Capability assigned to such OSW Generator or other Public Policy Resource shall revert back to the SAA Capability Pool and be available for further assignment by NJ BPU for a period of two (2) years from the date on which the OSW Generator or NJ BPU-selected Public Policy Resource submits its notice of withdrawal or termination, but no later than eight (8) years from the last Solicitation Award Date, subject to Paragraphs 5.2 and 10 of this Agreement.

(g) Use of SAA Project(s) by Entities Other than OSW Generators or other NJ BPU-Selected Public Policy Resources. The SAA Project(s) shall be controlled by PJM and subject to PJM's open access policies consistent with this Agreement; provided, however, that for a period from the date on which the PJM Board of Managers approves a SAA Project(s) for inclusion in the RTEP through twenty (20) years from the last Solicitation Award Date, subject to Paragraphs 5.2 and 10 of this Agreement, PJM shall allocate to any future user of a SAA Project(s) (other than an OSW Generator or NJ BPU-Selected Public Policy Resource) a *pro rata* share of the total costs of a SAA Project(s) that are attributable to those portions of any Transmission Facilities that extend the existing PJM Transmission System, such as offshore Transmission Facilities or onshore Transmission Facilities that transmit power generated offshore to any point of injection identified in Paragraph 6.2(a) above (as may be modified). Such future users may include, but shall not be limited to, the developer or any user of any offshore wind transmission "backbone" or "network" that extends a SAA Project(s) to additional states, neighboring regions or ISO/RTOs, use by hydrokinetic, offshore wind, other generators not selected by the NJ BPU as Public Policy Resources, or any other comparable user of the transmission that would interconnect to facilities that would not exist in the absence of the SAA Project(s). The specific process for allocating such costs to future users shall be memorialized in a future filing with the FERC.

7.0 Modification or Termination of a SAA Project(s).

7.1 Project Modification. PJM may modify a SAA Project with concurrence from the NJ BPU in the event such modifications result in a more efficient or cost effective solution to meet New Jersey's Public Policy Goals.

7.2 Project Cancelation. PJM may cancel a SAA Project(s) or any transmission upgrades associated with a SAA Project(s), with concurrence from the NJ BPU, in the event PJM determines the transmission upgrade(s) is no longer needed to resolve identified system needs or New Jersey's Public Policy Goals.

7.3 Project Infeasibility. In the event PJM reasonably determines that a SAA Project(s) is infeasible (e.g., due to permitting, siting, or other conditions), PJM will advise NJ BPU of the reasons why PJM has determined a SAA Project(s) is infeasible and of PJM's decision to terminate such SAA Project(s) or, in the alternative, provide other options available to NJ BPU to achieve New Jersey's Public Policy Goals.

7.4 Nothing in this Paragraph 7 is intended to supersede or alter the terms of the Operating Agreement, Schedule 6, section 1.5.8 (k).

8.0 Effective Date. This Agreement shall be effective as of April 15, 2022, subject to acceptance by FERC, or on such other date as specified by the FERC ("Effective Date").

9.0 Modification or Termination of this Agreement.

9.1 Modification of the SAA Agreement. The Parties may mutually agree to modify, amend or supplement this Agreement by a written instrument duly executed by the Parties. An amendment to the Agreement shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations.

9.2 Termination of the SAA Agreement.

(a) Mutual Consent. This Agreement may be terminated as of the date on which the Parties mutually agree to terminate this Agreement.

(b) In the event the SAA Study Agreement is terminated because either Party fails to satisfy a milestone date set forth in Schedule C of the SAA Study Agreement and fails to cure such breach/default as provided for under the SAA Study Agreement, this Agreement shall terminate, and NJ BPU shall withdraw its SAA Request within 45 days of the State Agreement Approach Study Agreement's termination date.

(c) NJ BPU may unilaterally terminate this Agreement upon providing PJM no less than 45 days prior written notice. Upon approval by the PJM Board of Managers and inclusion of a SAA Project in the RTEP, construction costs incurred at the time of termination may be subject to cost recovery from New Jersey customers pursuant to the terms of a FERC-accepted filed rate. Consistent with the PJM Tariff, the NJ BPU shall be responsible for additional RTEP upgrades based on subsequent projects in the New Services Queue that are reliant on a SAA Project(s).

(d) FERC Approval. Notwithstanding any other provision of this Agreement, no termination hereunder shall become effective until PJM and/or the NJ BPU have complied with all laws and regulations applicable to such termination, including the filing with the FERC of a notice of termination of this Agreement and acceptance of such notice for filing by the FERC.

(e) Notwithstanding the foregoing, in the event that this Agreement is terminated subsequent to the construction of a SAA Project(s) and the creation of SAA Capability, the provisions of this Agreement shall survive and continue in full force and effect after termination to the extent necessary with respect to such existing SAA Projects and existing SAA Capability.

10.0 Solicitation Schedule Delays. In the event the Solicitation Schedule included herein as Appendix A is modified or delayed, NJ BPU shall promptly notify PJM, provide an explanation for the schedule change, and submit a proposed Solicitation Schedule that will complete the solicitations within a reasonable time period. Such modifications or delays must be agreed to by PJM, which approval may not be unreasonably withheld. In the event PJM determines that the revised Solicitation Schedule materially deviates from the Solicitation Schedule set forth in Appendix A in a manner that may adversely impact the New Services Queue, PJM and NJ BPU shall meet to agree upon a solution. If the Parties cannot reach such a solution, they may seek to utilize dispute resolution processes pursuant to PJM Governing Documents or FERC's dispute resolution service processes. In the event the Parties are unable to reach agreement, PJM reserves the right to promptly seek approval from FERC pursuant to FPA section 205 to release the remaining SAA Capability, subject to the provisions of Paragraph 6.2(g) herein.

11.0 Conflicts with PJM Governing Documents. In the event of any conflicts or inconsistencies between the terms and conditions of this Agreement and any terms or conditions set forth in the PJM Tariff or Operating Agreement, the terms and conditions set forth in the PJM Tariff and Operating Agreement shall control.

12.0 Notice. Any notice, demand, or request required or permitted to be given by any Party to another and any instrument required or permitted to be tendered or delivered by any Party in writing to another may be so given, tendered, or delivered by a recognized national courier or by depositing the same with the United States Postal Service, with postage prepaid for delivery by certified or registered mail addressed to the Party, or by personal delivery to the Party, at the address specified below. Such notices, if agreed to by the Parties, may be made via electronic means, with e-mail confirmation of delivery.

Transmission Provider

Vice President – Planning
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403-2497
custsvc@pjm.com

With a copy to PJM's General Counsel (Chris.OHara@pjm.com)

NJ BPU

NJ BPU
Chief Counsel
New Jersey Board of Public Utilities
44 South Clinton Ave.
Trenton, NJ 08625
abe.silverman@bpu.nj.gov

13.0 No Waiver. No waiver by either Party of one or more defaults by the other in performance of any of the provisions of this Agreement shall operate or be construed as a waiver of any other or further default or defaults, whether of a like or different character.

14.0 Assignment of SAA Agreement. This Agreement may not be assigned without the express written consent of PJM, which consent may be withheld in its sole discretion.

15.0 Incorporation of PJM Tariff and Operating Agreement. All portions of the Tariff and Operating Agreement, as they may be amended from time to time, pertinent to the subject matter of this Agreement and not otherwise made a part hereof are hereby incorporated herein and made a part hereof.

16.0 Breach.

16.1 Notice of Breach. A Party not in breach shall give written notice of an event of breach to the breaching Party. Such notice shall set forth, in reasonable detail, the nature of the breach, and where known and applicable, the steps necessary to cure such breach.

16.2 Cure of Breach or Termination Pursuant to Breach. The breaching Party may reach agreement with the Party not in breach to timely cure the breach within thirty (30) days from the receipt of such written notice of breach. In the event the Parties are unable to agree on a timely cure period, the Party not in breach reserves the right to promptly seek remedy from FERC.

17.0 Governing Law, Regulatory Authority and Rules. The validity, interpretation, and enforcement of this Agreement and each of its provisions shall be governed by the FPA and federal law, and where not in conflict with federal law, the laws of the State of Delaware. The FERC is the exclusive forum for actions arising out of or relating to this Agreement.

18.0 No Third-Party Beneficiaries. Except as otherwise provided herein, this Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties.

19.0 Multiple Counterparts. This Agreement may be executed in two or more counterparts, each of which is deemed an original but all of which constitute one and the same instrument.

20.0 No Partnership. This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

21.0 Severability. If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

22.0 Reservation of Rights. Nothing in this Agreement shall be construed as affecting or limiting in any way the rights of any Party under FPA sections 205 or 206 and the FERC's rules and regulations.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials. By each individual signing below each represents to the other that they are duly authorized to sign on behalf of that Party and have actual and/or apparent authority to bind the respective Party to this Agreement.

Transmission Provider:

By:	*_/s/ Kenneth Seiler_*	Vice President, Planning, PJM	January 5, 2023
	Name	Title	Date

Printed name of signer: Kenneth Seiler

NJ BPU: (on behalf of the NJ BPU and the staff of the NJ BPU)

By:	*/s/ Joseph Fiordaliso*	President, NJ BPU	January 5, 2023
	Name	Title	Date

Printed name of signer: Joseph Fiordaliso

Rate Schedules – SAA Agreement –Rate Schedule FERC No. 49

PJM Interconnection, L.L.C.,Rate Schedules
Filing Category: Normal Filing Date: 01/27/2022
FERC Docket: ER22-00902-000 FERC Action: Accept
FERC Order: 179 FERC ¶ 61,024 Order Date: 04/14/2022
Effective Date: 04/15/2022 Status: Effective
SAA Agreement, Appendix A, SAA Agreement, Appendix A - NJ BPU OSW Solicitation Schedule (0.0.0)

APPENDIX A

NJ BPU Offshore Wind Solicitation Schedule

Solicitation	Capability Target (MW)	Capability Awarded	Issue Date	Submittal Date	Solicitation Award Date	Estimated Commercial Operation Date
1	1,100*	1,100	Q3 2018	Q4 2018	Q2 2019	2024-25
2	1,200**	2,658	Q3 2020	Q4 2020	Q2 2021	2027-29
3	1,200	N/A	Q3 2022	Q4 2022	Q2 2023	2030
4	1,200	N/A	Q2 2024	Q3 2024	Q1 2025	2031
5	1,342	N/A	Q2 2026	Q3 2026	Q1 2027	2033

** Solicitation 1: Incorporates the injection of a combined total of 1,100 MW at the Oyster Creek 230 kV substation and the BL England 138 kV substation, and is not part of the NJ SAA Process.*

***Solicitation 2 was awarded on June 30, 2021, with a total capability of 2,658 MW. Nothing shall limit the ability of the NJ BPU, upon reasonable prior notice to PJM, to assign a portion of the SAA Capability created by a SAA Project to an OSW Generator selected by NJ BPU under Solicitation 2.*

PJM Interconnection, L.L.C.,Rate Schedules
Filing Category: Normal Filing Date: 01/27/2022
FERC Docket: ER22-00902-000 FERC Action: Accept
FERC Order: 179 FERC ¶ 61,024 Order Date: 04/14/2022
Effective Date: 04/15/2022 Status: Effective
SAA Agreement, Appendix B, SAA Agreement, Appendix B - Reliability Analysis (0.0.0)

APPENDIX B

APPENDIX: RELIABILITY ANALYSIS TO SUPPORT 2021 NJ OFFSHORE WIND SAA TRANSMISSION PROPOSAL WINDOW

Scope: 2028 Summer Reliability Analysis; 2028 Winter Reliability Analysis; 2028 Light Load Reliability Analysis; 2035 Long-Term Deliverability Analysis

PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC, and Local Transmission Owner criteria).

Criterion Applied by PJM for this Proposal Window

- 2028 Summer Baseline Thermal and Voltage N-1 Contingency Analysis
- 2028 Summer Generator Deliverability and Common Mode Reliability Analysis
- 2028 Summer Load Deliverability Thermal and Voltage Analysis
- 2028 Summer N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- 2028 Winter Baseline Thermal and Voltage N-1 Contingency Analysis
- 2028 Winter Generator Deliverability and Common Mode Reliability Analysis
- 2028 Winter Load Deliverability Thermal and Voltage Analysis
- 2028 Winter N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- 2028 Light Load Baseline Thermal and Voltage N-1 Contingency Analysis
- 2028 Light Load Generator Deliverability and Common Mode Reliability Analysis
- 2028 FERC Form 715 Analysis
- 2035 Long-Term Deliverability Analysis
- 2025 Stability Analysis
- 2025 Short Circuit Analysis

Terminology for Proposal Windows

Through the analyses listed above, PJM has compiled a list of criteria violations unique to the set of injection locations and amounts identified for the Public Policy Projects identified in the SAA Proposal Window Overview document. This will be referred to as the default set of POIs. The violations and the impacted facilities are identified by a table of flowgates. Descriptions of the column headings are provided below. Different analyses often use different column headings.

Typical thermal analysis column headings:

Column Heading	Title	Description
FG #	Flowgate Number	A sequential numbering of the identified potential violations
Fr Bus	From Bus Number	PSSE model bus number corresponding to one end of line identified as a potential violation
Fr Name	From Bus Name	PSSE model bus name corresponding to one end of line identified as a potential violation
To Bus	To Bus Number	PSSE model bus number corresponding to other end of line identified as a potential violation
To Name	To Bus Name	PSSE model bus name corresponding to other end of line identified as a potential violation
Monitored Facility	Monitored Facility	The circuit on which a potential violation is occurring
Base Rate (MVA)	Base Rate (MVA)	Normal Facility Rating (Rate A)
% Overload	Percentage Overload	Percentage above corresponding Facility Rating
CKT	Circuit ID	Circuit number of identified potential violation
KVs	Kilovolt level (A/B)	Kilovolt level of both sides of potential violation, if A does not equal B, potential violation is a transformer
Areas	Area Numbers (A/B)	Area numbers of both ends of potential violation (A=From Bus Area Number, B=To Bus Area Number) If A does not equal B, potential violation is a tie line
Rating	Facility Rating	Applicable thermal rating (MVA) of facility
DC Ld(%)	Direct Current Loading percentage	Percentage above Facility Rating determined from DC testing
AC Ld(%)	Alternating Current Loading percentage	Percentage above Facility Rating determined from AC testing
Cont Type	Contingency Type	Contingency categorization (e.g., Single, Bus, Line_FB, Tower)
Cont Name	Contingency Name	Contingency name as identified in associated contingency file or embedded in the spreadsheet
Contingency	Contingency	Contingency description
Violation Date	Violation Date	Date on which violation is expected to occur
Analysis Case	Analysis Case	Case title to use in replicating analysis

Typical voltage analysis column headings:

Column Heading	Title	Description
FG #	Flowgate Number	A sequential numbering of the identified potential violations
Bus #	Bus Number	PSSE model bus number corresponding to bus identified as a potential violation
KVs	Kilovolt level	Kilovolt level of bus identified as potential violation
Area	Area Number	Area number of bus identified as potential violation
ContVolt	Contingency Voltage (P.U.)	Per Unit Voltage at identified bus after contingency is applied
BaseVolt	Basecase Voltage (P.U.)	Per Unit Voltage at identified bus before contingency is applied
Low Limit	Low Voltage Limit(P.U.)	Threshold of Per Unit Low voltage, if ContVolt is under this limit, a potential violation is identified
Upper Limit	High Voltage Limit(P.U.)	Threshold of Per Unit High voltage, if ContVolt is over this limit, a potential violation is identified
Cont Type	Contingency Type	Contingency categorization (e.g., Single, Bus, Line_FB, Tower)
Vdrop (%)	Voltage drop	The percentage that the voltage has dropped as a result of the contingency
Contingency	Contingency	Contingency name as identified in associated contingency file
Contingency 1	First Contingency	N-1 (first) contingency identified
Contingency 2	Second Contingency	N-1-1 (second) contingency identified in N-1-1 analysis

Proposal Window Exclusion Definitions

The following definitions explain the basis for excluding flowgates from the competitive planning process and designating projects to the incumbent Transmission Owner.

Flowgates excluded from competition will include the underlined language in the comment field.

- Below 200kV Exclusion: Due to the lower voltage level of the identified violations, these reliability violations are excluded from the competitive proposal window process. As a result, the local Transmission Owner will be the Designated Entity. Refer to Operating Agreement, Schedule 6 § 1.5.8(n).
- Substation Equipment Exclusion: For reliability violations on existing transmission substation equipment, these reliability violations are excluded from the competitive proposal window process. As a result, the local Transmission Owner will be the Designated Entity. Refer Operating Agreement, Schedule 6 § 1.5.8(p).

Analysis Procedure

Participants are expected to develop solutions to all applicable criteria violations and perform analysis to validate that the solutions remove these violations. The competitive planning process is documented in PJM Manual 14F, which is available here: http://www.pjm.com/-/media/documents/manuals/m14f.ashx

Proposed solutions must also meet Transmission Owner Planning Criteria which is available here: http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

The table below provides the base case dispatch and ramping limits to be applied for the New Jersey Offshore Wind units. This table supplements the base case dispatch and ramping limits specified in PJM Manual 14B, which is available here: https://pjm.com/-/media/documents/manuals/m14b.ashx

Generator Deliverability Requirements For New Jersey Offshore Wind Units

Season	Contingency Type	Base Case Dispatch*	Ramping Limit*
Summer	Single	30%**	30%**
Winter	Single	60%	80%
Light Load	Single	60%	80%
Summer	Common Mode	30%**	100%
Winter	Common Mode	60%	100%
Light Load	Common Mode	60%	80%

* Expressed as % of Maximum Facility Output (MFO)

** In order to reflect awarded solicitations the 30% value will be modified as follows. For Solicitation 1 both BL England and Oyster Creek will be studied at 28.1%. For Solicitation 2 at Cardiff will be studied at 18.2% and Smithburg will be studied at 28.5%.

Although PJM does its best to provide complete and accurate results, changes to the list of violations under consideration are possible. That is, flowgates may be added or removed from consideration in the proposal window. PJM works with Transmission Owners, Generation Owners, neighboring TOs and other affected parties to verify the quality of the analysis. PJM endeavors to minimize such changes and will clearly communicate any changes to the participants.

PJM regularly updates the system model to reflect changes to the transmission system. Analyses are performed to verify that violations continue to be valid, no new violations have appeared and proposed solutions still address the targeted violation(s).

PJM shall determine the more efficient or cost-effective enhancements or expansions for any violation in consultation with the BPU to consider state preferences.

WHAT PJM PROVIDES:

The information listed below is provided to allow replication of PJM analyses. Some of these data are designated Critical Energy Infrastructure Information (CEII) and must be handled consistent with PJM's CEII request process at Competitive Planning Process page on the PJM website:

1. 2028 Power Flow Base Cases (summer, winter and light load). Identifies one or more system configurations to which planning criteria are applied. The default NJ OSW POIs will be included and dispatched in the

models at their expected seasonal capacity factor.   These are the same power flow cases that were used to derive the flowgate violations posted for this window.

2. Generator Deliverability Workbooks corresponding to the 2028 Power Flow Base Cases.
3. TARA Generation Deliverability options files.
4. Contingency Files: Contains all contingency types (single, bus, tower, line w/ stuck breaker).
5. Subsystem Files: Identifies all subsystem zones to be considered in analysis.
6. Monitor Files: Identify specific ranges of facilities by area and kV level to be considered in analysis.
7. Facility Ratings: (if different from those included in the base cases)
8. Violations List: Lists all criteria violations with power flow results and additional technical notes (flowgates). The results indicate the case(s) to which the criteria violations apply. Note that the criteria violations supplied are for the particular set of injection amounts and locations specified in the overall project description.
9. Short Circuit Base Case. This case reflects the 2025 RTEP base case and will not include models for the NJ OSW.
10. Stability Base Case: This case reflects the 2025 RTEP summer and light load stability models and will not include models for the NJ OSW.
11. TO Criteria Setting Files. Lists settings used for short circuit analysis for each specific TO.
12. Load Forecast Through 2035: To be used for 2035 Long-Term Deliverability Analysis.
13. 2028 Load Deliverability Analytical Files: Analytical files for multiple modelled LDAs in the Mid-Atlantic Region without the NJ OSW are provided.   Additional files for the EMAAC and MAAC LDAs with the default NJ OSW POIs are also provided
14. 2028 Market Efficiency Analytical & Supporting Files

Document Revision History

4/15/2021 - V1 - Original Problem Statement posted to the PJM Competitive Planning Process webpage: https://www.pjm.com/planning/competitive-planning-process.aspx.

7/30/2021 – V2 - Problem Statement update to account for award of Solicitation #2 on June 30, 2021 posted to the PJM Competitive Planning Process webpage: https://www.pjm.com/planning/competitive-planning-process.aspx.

8/31/2021 – V3 - Problem Statement update to account for updated Solicitation schedule announced by NJBPU: https://www.njcleanenergy.com/renewable-energy/programs/nj-offshore-wind/solicitations.

PJM Interconnection, L.L.C.,Rate Schedules
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Effective Date: 03/07/2023 Status: Effective
SAA Agreement, Appendix C, SAA Agreement, Appendix C - Description of SAA Project (0.0.0)

Appendix C

Description of SAA Project Selected by the NJBPU

RTEP project b3737, including all associated sub-projects, by multiple designated entities, represents the SAA project selected by the NJBPU. Details of the RTEP project b3737 are provided in the following tables.

Designated Entity: FirstEnergy (JCP&L)					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**
b3737.1	Larrabee Substation - Reconfigure substation	Reconfigure Larrabee substation to include new 230 kV Circuit Breaker: Install (1) 230kV circuit breakers Install (2) 230kV breaker disconnect switches Install (1) lot of bus, fittings, insulators, and bus supports Relay & Control Modify relay settings for 230kV southwest bus diff Modify relay settings for 230kV northeast bus diff Modify relay settings for 230kV K2011 line to Lakewood Install (1) breaker control panel	N/A	$4.24	6/1/2029

b3737.2	Larrabee substation: 230 kV equipment for direct connection	Install (1) 230kV circuit breakers, (2) 230kV breaker disconnect switches, (1) 230kV motor operated line disconnect switch, (1) 230kV H frame dead end structure, (3) 230kV CVTs for generator line terminal, (3) 230kV surge arresters, (1) pre-fabricated line relaying panel for the generator line terminal, and (1) breaker control panels	N/A	$4.77	6/1/2029
b3737.3	Lakewood Gen Substation - Update relay settings	Lakewood Gen Substation - Modify relay settings on the K2011 Larrabee line	N/A	$0.03	6/1/2029
b3737.4	B54 Larrabee-South Lockwood 34.5 kV Line Transfer	B54 Larrabee-South Lockwood 34.5kV Line Transfer: Remove (1) 34.5kV single circuit wood monopole tangent structure and (3) 34.5kV post insulators, and transfer the existing conductor and shield wire onto a newly built 85' 230kV deadend monopole structure	N/A	$0.31	6/1/2029
b3737.5	Larrabee Collector Station-Larrabee 230 kV New Line	Install (1) new 230kV line from Larrabee Collector Station to the Larrabee Substation. Project involves building a new 230kV line from the Larrabee Collector Station to the Larrabee Substation as a single circuit line on self-supporting steel structures with drilled shaft foundations. New line is expected to cross under a new Larrabee Collector Station-Smithburg 500kV line and over multiple 34.5kV lines east of the existing Larrabee Substation. Conductor will be double bundled 2312 kcmil 76/19 ACSR "Thrasher" with SFPOC SFSJ-J-6641 48 Fiber OPGW - 0.3 Circuit Miles	1418/1739/1610/2062	$7.52	6/1/2029

b3737.6	Larrabee Collector Station-Smithburg No. 1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line.	New Larrabee Collector Station-Smithburg No. 1 500 kV line to be built double circuit to accommodate a 500 kV line and a 230 kV line. Assuming the line will parallel existing lattice towers for the D2004/H2008 lines, the following double circuit 500kV/230kV steel monopoles on drilled shaft foundations will be required: (56) Steel Tangents Single circuit 500kV steel structures on drilled shaft foundations: (15) Steel Monopole Deadends, (3) Steel 2-pole H-frame Deadend crossing structures. Conductor will be Double Bundled 2493 kcmil 54/37 ACAR – 12.2 Circuit Miles	3678/4541/4262/5503	$150.35	12/31/2027
b3737.7	Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500kV/230kV line	Project involves rebuilding the G1021 Atlantic-Smithburg 230kV line between the Larrabee and Smithburg Substations as a double circuit 500kV/230kV line on self-supporting steel monopole structures with drilled shaft foundations. Conductor will be 1590 kcmil 45/7 ACSR "Lapwing"– 12.2 Circuit Miles	709/869/805/1031	$62.85	12/31/2027
b3737.8	Smithburg substation 500 kV expansion to 4 breaker ring	Rebuild the Smithburg 500 kV and 230 KV Substations. Remove 500kV GIS yard and rebuild as an open air 4 breaker ring bus for Offshore Wind Generation Interconnection. Remove 230kV GIS yard and rebuild as an open air yard. Remove 34.5kV yard and rebuild in new location.	N/A	$68.25	12/31/2027

b3737.9	Larrabee Substation upgrades	At Larrabee Substation, rewire 230kV breakers B96 and B93 CT wiring and associated CCVTs from Oceanview line relaying to R-1032 Atlantic line relaying. Rewire 230kV breakers B60 and B63 CT wiring and associated CCVTs from R-1032 Atlantic line relaying to Oceanview line relaying Relay setting changes for 230kV Oceanview and R-1032 Atlantic lines	N/A	$0.86	6/1/2030
b3737.10	Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	Convert Atlantic 230 kV substation to a double-breaker double-bus configuration and install a new 230 kV line terminal & substation exit for the interconnection of 1200 MW of wind generation.	N/A	$31.47	6/1/2030
b3737.11	Freneau Substation - Update relay settings on the Atlantic 230 kV line	At Freneau Substation, modify relay settings on the Atlantic 230 kV Line.	N/A	$0.03	6/1/2030
b3737.12	Smithburg Substation - Update relay settings on the Atlantic 230 kV line	At Smithburg Substation, modify relay settings on the Atlantic 230 kV Line.	N/A	$0.03	6/1/2030
b3737.13	Oceanview Substation - Update relay settings on the Atlantic 230 kV lines	At Oceanview Substation, modify relay settings on the Atlantic 230 kV lines.	N/A	$0.04	6/1/2030
b3737.14	Red Bank Substation - Update relay settings on the Atlantic 230 kV lines	At Red Bank Substation, modify relay settings on the Atlantic 230 kV lines.	N/A	$0.04	6/1/2030

b3737.15	South River Substation - Update relay settings on the Atlantic 230 kV line	At South River Substation, modify relay settings on the Atlantic 230 kV Line.	N/A	$0.03	6/1/2030
b3737.16	Larrabee Substation - Update relay settings on the Atlantic 230 kV line	At Larrabee Substation, modify relay settings on the Atlantic 230 kV Line.	N/A	$0.03	6/1/2030
b3737.17	Atlantic Substation - Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector Station	Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind converter substation. Install (2) 230kV circuit breakers, (4) 230kV disconnect switches, (1) 230kV line disconnect switch, (3) 230kV surge arresters, (3) 230kV CVTs, (1) 230kV dead end structure, (1) lot bus, insulators, steel supports, fittings, and conductor. Install (1) prewired relaying panels for OSW Generator 1. Install (2) prewired breaker control panel.	N/A	$4.95	6/1/2030

b3737.18	G1021 (Atlantic-Smithburg) 230 kV upgrade	Project involves relocating the circuit to a new bay position to be installed south of the existing bay at Atlantic Substation. Additionally, the project includes modifying existing tubular steel monopole structures in the 7.9 miles south of Atlantic Substation to support the G1021 (Atlantic-Smithburg) 230kV circuit on the west side of the structures. Tangent structures will need to have new braced post insulator assemblies installed (two on the west side of the structure in the middle and bottom phase positions. Angle/Deadend structures will need to have arms installed in the middle and bottom phase positions along with insulator assemblies. New 1590 kcmil 45/7 ACSR conductor pulled in for these two phases.	1356/1626/1610/1858	$9.68	6/1/2030
b3737.19	R1032 (Atlantic-Larrabee) 230 kV upgrade	Project includes modifying existing steel pole structures currently supporting the G1021 (Atlantic-Smithburg) 230kV circuit to accommodate new conductor for the R1032 (Atlantic-Larrabee) 230kV circuit on the east side of the steel pole structures for approximately 7.9 miles to Structure 15179. Tangent structures will need to have new braced post insulator assemblies installed in the bottom phase position on the west side of the structures. Angle/Deadend structures will need to have arms installed in the bottom phase positions along with insulator assemblies. The existing1590 kcmil 45/7 ACSR conductor currently installed in the upper and middle phase positions for the G1021 (Atlantic-Smithburg) 230kV circuit will need to be replaced with new 1590 kcmil 42/19	1104/1273/1106/1390	$14.50	6/1/2030

		ACSS/TW/HS285 wire. New 1590 kcmil 42/19 ACSS/TW/HS285 wire will be installed for the bottom phase on the east side as well.			
b3737.20	New Larrabee Collector Station-Atlantic 230 kV line	Description of Work Project involves adding a 230kV circuit between Atlantic Substation and new Larrabee Collector Station. The new line will be conductored with bundled 636 ACSS 26/7 “Grosbeak” on the east side of the existing structures starting at Structure 15207 located just outside of Larrabee Substation and will continue north to Atlantic Substation, approximately 11.6 miles.	1260/1447/1259/1523	$17.07	6/1/2030
b3737.21	Larrabee-Ocean view 230 kV line upgrade	Project involves modifying structures in the first 3.7 miles north of Larrabee substation so that the Larrabee-Oceanview circuit can be supported on the west side of the eastern 230kV steel poles. A new braced post insulator assembly will be installed for the bottom phase on the west side of the tangent structures and new deadend assemblies will be installed on the angle/deadend structures between Structure 15207 and Structure 63. New 1590 kcmil 42/19 ACSS/TW/HS285 conductor will be strung in this bottom phase position, which will match the existing conductor that is currently used for the R1032 (Atlantic-Larrabee) 230kV circuit.	1104/1273/1106/1339	$6.00	6/1/2030
b3737.27	Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence	Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence) 230kV Line between Lawrence Substation (PSEG) and Structure #63 with double bundled 1590 kcmil 45/7 ACSR "Lapwing”.	1140/1387/1342/1495	$11.45	6/1/2029

	substation (PSEG) and structure No. 63				
b3737.28	Reconductor Kilmer I-Lake Nelson I 230 kV	Reconductor the Lake Nelson-Kilmer Line Section of the Lake Nelson Raritan River No. 1 230kV Line with 1590 ACSS 54/19, 2 Circuit Miles	1136/1311/1139/1379	$4.42	6/1/2029
b3737.29	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line	Project includes the following scope: Rebuild six-wired East Windsor-Smithburg E2005 230 kV to double circuit East Windsor-Smithburg 500kV (Double Bundled 2493 kcmil 54/37 ACAR, and East Windsor-Smithburg 230kV Line (Double Bundled 1590 kcmil 45/7 ACSR “Lapwing”), 9.15 Circuit Miles. East Windsor and Smithburg Substation Upgrades T5020 Smithburg-Deans 500kV relocation to new bay position at Smithburg Convert 1050 feet of K137 Windsor-Twin Rivers-Wyckoff Street 34.5kV, X752 Jerseyville-Smithburg 34.5kV, B158 Gravel Hill Smithburg 34.5kV overhead lines to underground to accommodate East Windsor-Smithburg DCT 500/230 kV line.	3678/4541/4262/5503	$206.48	6/1/2029
b3737.30	Add third Smithburg 500/230 kV transformer	At Smithburg, Install 500 kV breaker position for new transformer Install a new 500/230 kV transformer. Add a new string on the 230 kV breaker-and-a-half station at Smithburg Substation for a position for the new 500/230 kV	1034/1287/1036/1451	$13.40	12/31/2027

		transformer			
b3737.31	Additional reconductoring required for Lake Nelson 1 – Middlesex 230 kV	Additional reconductoring required for Lake Nelson 1 – Middlesex 230 kV to achieve 1114/1285/1116/1352 SN/SE/WN/WE MVA Ratings	1114/1285/1116/1352	$3.30	6/1/2029
b3737.32	Rebuild D2004 Larrabee-Smithburg No1 230kV	Project involves rebuilding the D2004 Larrabee-Smithburg No1 230kV line between the Larrabee and Smithburg Substations as a double circuit 500kV/230kV line on self-supporting steel monopole structures with drilled shaft foundations. The rebuilt structures will parallel the other 500kV/230kV line. Entire length of the line is to be rebuilt. Conductor will be 1590 kcmil 45/7 ACSR "Lapwing"– 12.2 Circuit Miles	709/869/805/1031	$44.77	12/31/2027
b3737.33	Reconductor Red Oak A – Raritan River 230 kV	Reconductor Red Oak A – Raritan River 230 kV to achieve 1156/1334/1158/1403 SN/SE/WN/WE MVA Ratings	1156/1334/1158/1403	$11.05	6/1/2029
b3737.34	Reconductor Red Oak B – Raritan River 230 kV	Reconductor Red Oak B – Raritan River 230 kV to achieve 1156/1334/1158/1403 SN/SE/WN/WE MVA Ratings	1156/1334/1158/1403	$3.90	6/1/2029
b3737.35	Reconductor small section of Raritan River - Kilmer I 230 kV	Reconductor small section of Raritan River - Kilmer I 230 kV to achieve 1156/1334/1158/1403 SN/SE/WN/WE MVA Ratings	1156/1334/1158/1403	$0.20	6/1/2029
b3737.36	Replace substation conductor at Kilmer & reconductor	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV to achieve 1156/1334/1158/1403	1156/1334/1158/1403	$25.88	6/1/2029

	Raritan River – Kilmer W 230 kV	SN/SE/WN/WE MVA Ratings			
b3737.40	Windsor to Clarksville subproject: Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV.	Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV. Wreck and rebuild one suspension tower outside Clarksville Station to carry the new twin bundle conductor spans into the station A-Frame. Wreck and rebuild (if required) an existing structure outside of Windsor to carry the new twin bundle conductor span (Double Bundled 1590 kcmil 45/7 ACSR "Lapwing"), 1.3 Circuit Miles	1356/1626/1610/1858	$4.28	6/1/2029

Designated Entity: Mid-Atlantic Offshore Development (MAOD)					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**
b3737.22	Construct the Larrabee Collector Station (LCS) AC switchyard, procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation.	Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A, and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to	N/A	$121.1	12/31/2027

		accommodate circuits with equivalent rating of 1400 MVA at 400 kV.			

Designated Entity: Transource					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**
b3737.47	Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high side and five low side breakers in ring bus configuration).	"Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers. Nine 63 kA breakers (four high side and five low side breakers in ring bus configuration): 4 – 4000A 500kV 63kA Breakers with associated switches 5 – 5000A 230kV 63KA Breakers with associated switches 6 – 500kV CCVT's on the Incoming Peach Bottom and Delta Power Plant Lines. 9 – 230kV CCVT's on the Tie-Lines – (Cooper, Graceton # 1, Graceton # 2) 1 - Drop In Control Module (DICM)"	North Delta 500/230 kV Transformers: 1500/1875/1875/2025	$76.27	6/1/2029

Designated Entity: Exelon (AEC)					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**

b3737.23	Rebuild the underground portion of Richmond-Waneeta 230 kV.	Increase the ratings of the Richmond-Waneeta 230 kV line by rebuilding the underground portion of the line. The length of the line that will be rebuilt is 0.95 miles. Adequate space exists for installation of new duct banks. New conductor will be 5000 kcmil XLPE.	1098/1247/1150/1299	$16.00	6/1/2029
b3737.24	Upgrade Cardiff-Lewis #2 138 kV by replacing 1590 kcmil strand bus inside Lewis substation.	Upgrade summer ratings of the Cardiff-Lewis #2 138 kV line by replacing 1590 kcmil strand bus inside Lewis substation.	377/478/451/478	$0.10	4/30/2028
b3737.25	Upgrade Lewis No. 2-Lewis No. 1 138 kV by replacing its bus tie with 2000 A circuit breaker.	Upgrade summer ratings of the Lewis No. 2-Lewis No. 1 138 kV line by replacing its bus tie with 2000 A circuit breaker.	478/478/478/478	$0.50	4/30/2028
b3737.26	Upgrade Cardiff-New Freedom 230 kV by modifying existing relay setting to increase relay limit.	Upgrade Cardiff-New Freedom 230 kV line by modifying existing relay setting to increase relay limit.	650/804/748/906	$0.30	4/30/2028

Designated Entity: Exelon (BGE)					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**

b3737.46	Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station	Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station	N/A	$1.55	6/1/2029
b3737.52	Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA.	Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA circuit breaker	N/A	$1.30	6/1/2029

Designated Entity: Exelon (PECO)					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**
b3737.48	Build a new North Delta-Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper-Graceton 230 kV line to double circuit.	Retire existing single circuit line from Cooper - Graceton 230 kV, to accommodate new double circuit line from North Delta to Graceton in the same route. Rebuild 6.07 miles as double circuit 230kV AC transmission line between the existing Graceton Station and the proposed North Delta Station. The double circuit line will be constructed using 2 - 1590 kcmil (54/19 Strand) ACSS “Falcon” conductors.	North Delta-Graceton 230 kV No.1 & 2: 1295/1863/1642/2077	$28.74	6/1/2029

b3737.49	Bring the Cooper-Graceton 230 kV line "in and out" of North Delta by constructing a new double-circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines.	Bring the Cooper-Graceton 230 kV line "in and out" of North Delta by constructing a new double-circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines.	Cooper - North Delta 230 kV: 463/578/521/639	$1.56	6/1/2029
b3737.50	Bring the Peach Bottom-Delta Power Plant 500 kV line "in and out" of North Delta by constructing a new Peach Bottom-North Delta 500 kV (0.3 miles) cut-in and cut-out lines.	Bring the Peach Bottom-Delta Power Plant 500 kV line "in and out" of North Delta by constructing a new Peach Bottom-North Delta 500 kV (0.3 miles) cut-in and cut-out lines.	Peach Bottom-North Delta 500 kV & North Delta-Delta Power Plant 500 kV: 2338/2931/3062/3480	$1.56	6/1/2029
b3737.51	Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA.	Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA circuit breakers.	N/A	$5.60	6/1/2029

Designated Entity: PSEG					
PJM Baseline Upgrade ID	**Description of Projects**	**Scopes of Work**	**Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)**	**Cost Estimate ($M)**	**Required In-Service Date**

b3737.38	Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV Switching station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV.	Install a new 345/230 kV transformer at the Linden 345 kV Switching station Install new 230kV strain bus connecting Linden 230kV yard to Linden 345kV yard through the new transformer. Relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV.	New Linden 345/230 kV transformer: 913/1080/999/1143	$24.92	12/31/2027
b3737.39	Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work.	Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work.	N/A	$5.53	12/31/2027
b3737.41	Windsor to Clarksville subproject: Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV as necessary to create a paired conductor path between Clarksville and JCPL East Windsor Switch 230 kV.	Windsor to Clarksville subproject: Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV as necessary to create a paired conductor path between Clarksville and JCPL East Windsor Switch 230 kV.	N/A	$1.49	6/1/2029
b3737.42	Upgrade inside plant equipment at Lake Nelson I 230 kV.	Upgrade inside plant equipment at Lake Nelson I 230 kV.	1378/1625/1475/1723	$3.80	6/1/2029

b3737.43	Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.	Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.	934/1080/999/1143	$0.16	6/1/2029
b3737.44	Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.	Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.	934/1080/999/1143	$0.12	6/1/2029

Designated Entity: LS Power (Silver Run Electric)

PJM Baseline Upgrade ID	Description of Projects	Scopes of Work	Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)	Cost Estimate ($M)	Required In-Service Date
b3737.37	Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line.	The transmission line upgrade will consist of adding an additional submarine cable to each phase of the existing Silver Run - Hope Creek 2300kV line. The upgrade includes two (2) new transition structures used to tie into the existing overhead line. The Silver Run - Hope Creek line will then be re-rated to operate at a higher conductor temperature. The Silver Run Substation Upgrade will consist of upgrading the line terminal equipment to 5,000 amps.	Hope Creek-Silver Run 230 kV: 1364/1614/1364/1614	$61.20	6/1/2029

Designated Entity: PPL Electric Utilities (PPL EU)

PJM Baseline Upgrade ID	Description of Projects	Scopes of Work	Required Ratings Summer Normal/ Summer Emerg/ Winter Normal/ Winter Emerg (MVA)	Cost Estimate ($M)	Required In-Service Date
b3737.45	PPL EU	Reconductor 0.33 miles of PPL's portion of the Gilbert-Springfield 230 kV line.	Gilbert-Springfield 230 kV: 830/954/939/1087	$0.38	6/1/2030

Notes:

- Detailed Construction milestones will be included in each designated entity Designated Energy Agreement (DEA Schedule C). These DEAs will be filed with FERC upon execution.
- Terms and Conditions for the SAA projects are similarly included in each designated entity's Designated Energy Agreement (DEA Schedule E).
- Cost responsibility for the SAA Projects shall be assigned consistent with the methodology set forth in Tariff, Schedule 12 – Appendix C.

PJM Interconnection, L.L.C.,Rate Schedules
Filing Category: Normal Filing Date: 01/05/2023
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SAA Agreement, Appendix D, SAA Agreement, Appendix D - SAA Capability (0.0.0)

Appendix D

SAA Capability

The SAA Project, RTEP project b3737, including all associated sub-projects, will result in creating SAA Capability as follows:

Point of Interconnection and Associated Injected Amounts

Location	State	Transmission Owner	SAA Capability MW	MFO MW	MW Energy	MW Capacity
Larrabee Collector station 230 kV – Larrabee	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Atlantic	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Smithburg	NJ	MAOD	1,342	1,342	1,342	402.6
Smithburg 500 kV	NJ	JCPL	1,148	1,148	1,148	327

The SAA Capability will be used for the sole purpose of conducting PJM interconnection studies, subject to the terms of Paragraph 4.3 of this Agreement.

Exhibit No. MAOD-5
Mid-Atlantic Offshore Development, LLC
PJM 2022 RTEP Report (March 1, 2023)

PJM Baseline Reliability Assessment 2022 – 2037 Period:TPL-001-5.1

PJM

March 1, 2023

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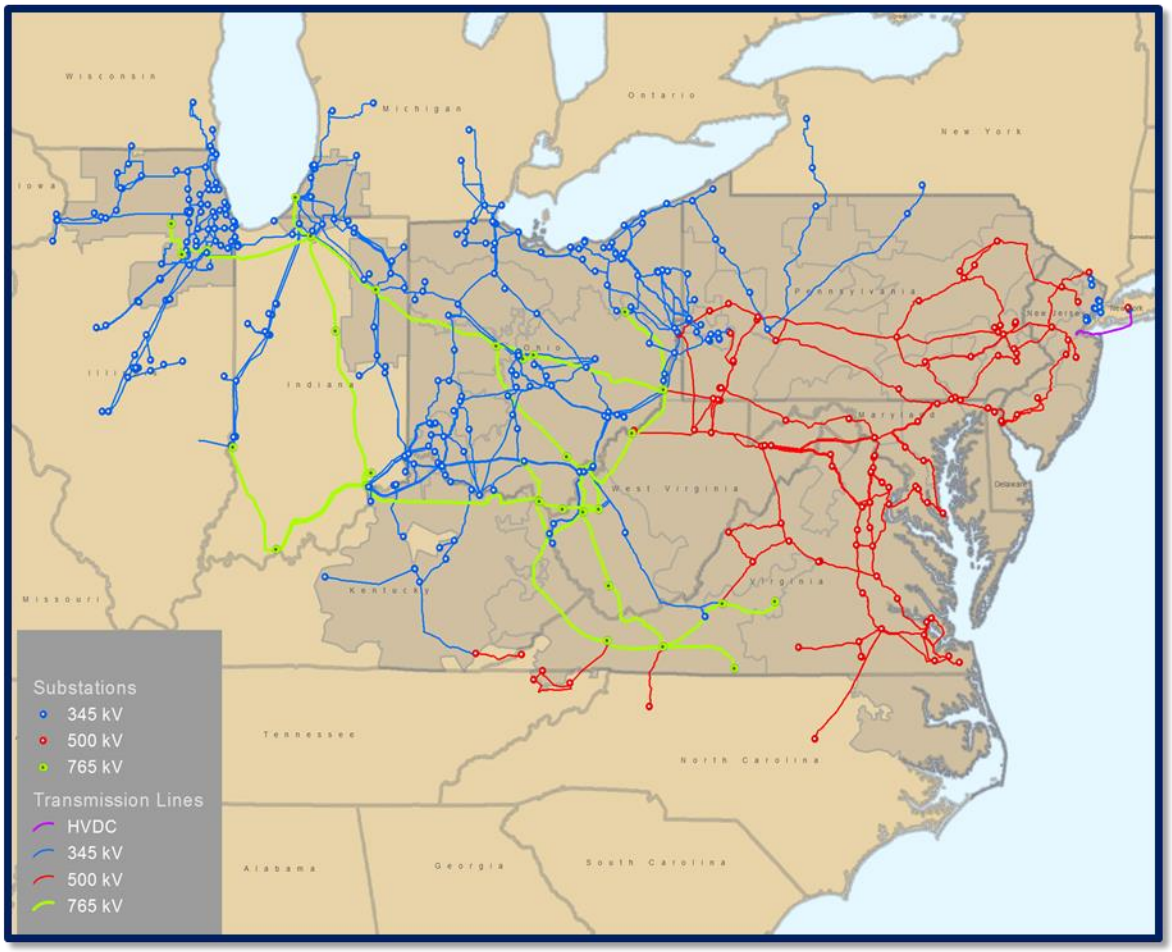
Contents

Introduction

The PJM system covers more than 369,000 square miles in 13 states and the District of Columbia. Serving approximately 65 million people, the PJM system includes major U.S. load centers from the western border of Illinois to the Atlantic coast including the metropolitan areas of Baltimore, Chicago, Cleveland, Columbus, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond, and Washington D.C. PJM dispatches more than 180,000 megawatts of generation capacity over more than 84,000 miles of transmission lines – a system that serves nearly 21 percent of the U.S. economy. The PJM system is electrically continuous and consists of multiple electrical service territories. PJM's Bulk Electric System (BES) includes a robust network of 765kV, 500kV, 345kV, 230kV, 161kV, 138kV, and 115kV facilities. The map below depicts the PJM service territory footprint overlaid with PJM high voltage lines operated at 345 kV and above.



Map 1. Existing PJM 345 kV, 500 kV, and 765 kV Network

As a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO), one of PJM's core functions encompasses regional transmission planning. PJM is also a North American Electric Reliability Corporation (NERC) registered Reliability Coordinator, Planning Coordinator, and Transmission Planner. PJM's annual planning process is known as the PJM Regional Transmission Expansion Plan (RTEP). The RTEP process is established in the PJM Operating Agreement – Schedule 6 – Regional Transmission Expansion Planning Protocol. The RTEP processes and procedures are described in detail in the PJM Regional Transmission Planning Process Manuals. PJM Manual 14B – PJM Region Transmission Planning process contains the process used to complete the annual baseline reliability assessment.

PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission upgrades and enhancements that are required to preserve the reliability of the transmission system. The PJM system is planned such that it can be operated to applicable System Operating Limits (SOL) while supplying projected customer demands and projected firm transmission service over a range of forecast system demands under contingency conditions that have a reasonable probability of occurrence. PJM reliability planning encompasses a comprehensive series of detailed analyses that ensure reliability and compliance under the most stringent of the applicable NERC, Regional Entity (RFC or SERC as applicable), PJM, and local criteria. To accomplish this each year, a baseline assessment is completed for applicable facilities over the near term (1-5 years) and longer term (years 6-15). All Bulk Electric System (BES) facilities are included in the RTEP baseline assessment process as required by NERC Standards.

PJM is registered with the North American Electric Reliability Corporation (NERC) as the Reliability Coordinator (RC), Interchange Authority (IA), Transmission Operator (TOP), Balancing Authority (BA), Planning Coordinator (PC), Transmission Planner (TP), Transmission Service Provider (TSP), and Resource Planner (RP). There are multiple transmission zones within PJM. Table 1 lists individual transmission zones in the PJM footprint. A few smaller PJM transmission owners are modeled within another larger PJM transmission area and are not explicitly listed on this table. A few examples of this are Neptune Regional Transmission System LLC, Linden VFT LLC, and Essential Power/Rock Springs.

AP	Allegheny Power System, Inc.
AE	Atlantic Electric
AEP	American Electric Power Co., Inc.
ATSI	American Transmission Systems, Inc.
BG&E	Baltimore Gas & Electric Co.
CE	Commonwealth Energy System
DAY	Dayton Power and Light Co
DEO&K	Duke Energy Ohio and Kentucky
DLCO	Duquesne Light Co
DP&L	Delmarva Power and Light Co
EKPC	Eastern Kentucky Power Cooperative
ITCI	ITC Interconnection
JCP&L	Jersey Central Power and Light
METED	Metropolitan Edison Co
OVEC	Ohio Valley Electric Corporation
PECO	PECO Energy Co.
PENELEC	Pennsylvania Electric Co
PEPCO	Potomac Electric Power Co.
PPL	PPL Electric Utilities
PSE&G	Public Service Electric and Gas Company
RECO	Rockland Electric Company
UGI	UGI Utilities Inc.
DVP	Virginia Power (Dominion)

Table 1. **PJM area Transmission Zones**

PJM is interconnected with neighboring systems and has over 100 BES transmission ties to these adjacent systems. Table 2 lists PJM's neighboring systems and associated entities. PJM coordinates planning analyses with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems are studied as part of PJMs RTEP process.

ALTE	Alliant Gas and Electric – East
ALTW	Alliant Gas and Electric – West
AMIL	Ameren Illinois
AMMO	Ameren Missouri
BREC	Big Rivers Electric Corporation
CPLE	Carolina Power and Light Company - East
CPLW	Carolina Power and Light Company - West
DEI	Duke Energy Indiana
DUKE	Duke Energy Carolinas
IPL	Indianapolis Power and Light Company
ITCT	International Transmission Company
LAGN	Louisiana Generating Company
LGEE	LGE Energy
LIPA	Long Island Power Authority
MEC	MidAmerican Energy
METC	Michigan Electric Transmission Co.
National Grid	National Grid
NIPS	Northern Indiana Public Service Company
NYISO	New York ISO
OMU	Owensboro Municipal Utilities
ORU	Orange & Rockland
SMT	Brookfield/Smoky Mountain Hydropower LLC
SIGE	Southern Indiana Gas & Electric Company
TVA	Tennessee Valley Authority
WEC	Wisconsin Electric Power Company

Table 2. **PJM Neighboring Systems**

The PJM RTEP process requires that cost responsibility for facility enhancements be established. In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities, a 'baseline' assessment of system adequacy and security is necessary. The purpose of this assessment is threefold:

1. To identify areas where the system as planned under previous assessments does not meet the applicable reliability criteria and standards as a result of load increases on the system or changes to methodologies associated with the analyses.
2. To develop and recommend facility expansion plans which will bring areas where the system does not meet performance requirements specified in an applicable standard into compliance. These plans include cost estimates and required in-service dates.
3. To establish what will be included as baseline costs in the allocation of the costs of expansion for those generation and merchant transmission projects proposing to connect to the PJM system.

The system as planned is evaluated for its compliance with all applicable reliability standards to accommodate the forecast demand, committed resources, and commitments for firm transmission services for a specified time frame. Areas that are found to not meet applicable reliability criteria are identified and enhancement plans are developed to achieve compliance within an identified timeframe. The lead time necessary to implement the system enhancement is considered as part of the overall plan. In addition, the status and progress of each upgrade is tracked closely to ensure that the required in-service dates are met.

The 'baseline' assessment and the resulting expansion plans serve as the base system for the conduct of Interconnection Feasibility Studies and System Impact Studies associated with new generation, merchant transmission and long term firm transmission service. The interconnection process is described by Manual 14A: Generation and Transmission Interconnection Process. This report details the results of the 'baseline' assessment from 2022 through 2037 for the PJM footprint.

Executive Summary

PJM is responsible for the development of a Regional Transmission Expansion Plan (RTEP) for the PJM system that will meet the needs of the region in a reliable, economic and environmentally acceptable manner. As further described in following portions of this assessment, the PJM RTEP combines a broad set of analysis into a single plan. The annual RTEP process consists of a baseline reliability review, analysis to identify the transmission needs associated with both generation interconnection and merchant transmission, review of conditions experienced in real time operations, inter-regional reliability analysis, and many other special studies. The RTEP incorporates the unique needs identified by in-depth thermal, stability, short circuit, and voltage reliability analysis. PJM ensures a robust and comprehensive annual RTEP by incorporating all of these diverse needs into a single plan.

The annual RTEP planning assessment includes a comprehensive review of PJM Bulk Electric System (BES) facilities as required by NERC standard TPL-001-5.1. PJM maintains a series of power flow, short circuit and stability cases that represent a range of critical system conditions for a range of forecast demand levels and study years. The annual RTEP baseline analysis performs the following tests at a minimum to ensure NERC TPL compliance:

1) Thermal Analysis
    a) Normal system (all facilities in service), single, and multiple contingency analysis as required by NERC TPL-001-5.1
    b) Generation deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
    c) Common mode outage procedure analysis, as described in PJM Manual 14B Section 2 RTEP Process
    d) Load deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
    e) N-1-1 analysis
    f) Light Load Reliability Analysis
    g) Winter Reliability Analysis
    h) 15 Year Analysis
    i) Transfer Limit Analysis
2) Short Circuit fault duty analysis
3) Voltage Analysis
    a) Voltage limit testing, including voltage magnitude and voltage drop monitoring for many of the test methods listed above for the thermal analysis
    b) Voltage collapse, including non-convergent events
    c) PV analysis, including Transfer Limits
4) Stability Analysis
    a) Transient stability (short and long term)
    b) Small signal stability (oscillations)
    c) Voltage Stability
    d) Nuclear Plant Interface Requirements (NPIR)

PJM also studies, requests for new generation, merchant transmission, and long term firm transmission service. The process for studying these requests is described in PJM Manual 14A. In Calendar year 2022, PJM completed 594 system impact studies to accommodate new generation, merchant transmission, and long term firm transmission service. The 2022 RTEP includes any upgrades associated with the queue projects that are required to maintain the reliability of the PJM system.

1) New Services Queue Analysis
   a) Generation interconnection
   b) Merchant transmission
   c) Yearly long term firm transmission service

Information related to the generation, merchant transmission, and yearly long term firm transmission service request queues can be found on the PJM website at the following link.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Information that is posted on the PJM website includes the status of the New Services Queues, as well as the technical study reports. The technical reports include the feasibility, impact, and facility study reports. PJM agreements such as interconnection service agreements (ISA) and interconnection construction service agreements (CSA) are also posted on the website.

PJM coordinates inter-regional activities with neighboring systems pursuant to PJM's Tariff and interregional agreements. PJM annually participates in a wide range of inter-regional groups and committees. Several significant efforts in 2022 are listed below.

1) Inter-regional planning groups
   a) Independent System Operator / Regional Transmission Organization (ISO/RTO) Council (IRC)
   b) Eastern Interconnection Planning Collaborative (EIPC): Planning Coordinators of the Eastern Interconnection
      i) DOE National Transmission Study
      ii) Workshops on Transmission Planning for High Penetration of Renewable Resources
      iii) Workshops on Minimum Interregional Transfer Capability approach
   c) Joint Operating Agreement with New York ISO (NYISO) and Joint Operating Agreement with Mid-Continent ISO (MISO)
      i) Joint ISO/RTO Planning Committee (JIPC) activities pursuant to the PJM/NYISO/ISO-NE Northeast Planning Coordination Protocol
         (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability Interconnection Queue and Market Efficiency Analysis
      ii) Joint RTO Planning Committee (JRPC) activities pursuant to the MISO/PJM Joint Operating Agreement
         (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability and Market Efficiency Analysis
   d) Southeastern Regional Transmission Planning: (SERTP)

    i) Joint Operating Agreement with Duke Energy Progress (DEP)
    ii) Joint Operating Agreement with Tennessee Valley Authority (TVA)
  e) Joint Reliability Coordination Agreement between PJM and TVA
  f) North Carolina Transmission Planning Collaborative (NCTPC) planning and data sharing agreement
2) North American Electric Reliability Corporation (NERC) and Eastern Interconnection Reliability Assessment Group (ERAG) related activities
    i) SERC Reliability Corporation and associated committees and working groups
    ii) RFC Reliability Corporation and associated committees and working groups

PJM Planning also coordinates with PJM Operations to review operational performance issues. In addition, sensitivity studies may be requested by stakeholders. Examples of these studies include:

Additional Studies

- Investigation of Susquehanna N-1-1 oscillation issue (PPL)
- Investigation of Calvert Cliffs N-1-1 oscillation issue (BGE)
- Peach Bottom event analysis (PECO)
- Conowingo damping issue verification (PECO)

The RTEP assesses the needs of the system, at peak load for year one, two, three four and year 5 in the near term and over the longer term (up to 15 years) to identify baseline transmission enhancements that require more time to implement. Additionally, PJM evaluates an off peak load seasonal assessment for year 5 PJM also is responsible for recommending the assignment of any transmission expansion costs to the appropriate parties. In order to carry out these responsibilities, it is necessary to establish a starting point or 'baseline' from which the need and responsibility for enhancements can be determined.

As the NERC registered Planning Coordinator, PJM is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems for both the near term and longer term. The planned network upgrades required by the RTEP serve as a central repository for the BES related reliability plans of the individual PJM transmission owners. By integrating the individual plans into a single plan, the RTEP is able to provide a robust reliability plan for the PJM Bulk Electric System.

In order to establish the long term plan, PJM has defined the fifteen (15) year period from 2022 through 2037 as the 2022 "baseline" planning period. This assessment is inclusive of the previous years' baseline assessments, models, and required upgrades. As such, the existing system plus any planned modifications to the transmission system including reactive resources that are scheduled to be in service prior to the 2027 summer peak period were chosen as the base system for the near-term assessment. This ensures the system as planned remains compliant with reliability standards. Appendix A represents a snapshot of all upgrades identified in RTEP evaluations prior to 2022. These identified upgrades, when added to the previously existing system, function as the base system for future

models. In addition, assessments for delivery years prior to 2027 were updated with current assumptions to validate the on-going need for identified upgrades and to ensure continued compliance with reliability criteria.
For the 2022 RTEP cycle, PJM has studied 22 generator deactivation notifications resulting in over 4,400 MW of existing generation deactivating in 2022 or some point in the near term planning horizon. In order to establish a model which accurately included all expected generation retirements, PJM performed many sets of analysis to study the effects of these generation retirements on the system. Baseline transmission upgrades were identified as a result of these deactivations. The upgrades resulting from the deactivations were examined in the basecase before approving new RTEP upgrades for any of the standard RTEP analysis for the 2022 RTEP cycle. The scope of the deactivation notification analysis was significant and included a review of system impacts in years 2022 through 2027. The scope and results of the generation deactivation analysis is discussed in subsequent sections of this report.

All new generation and merchant transmission projects that executed an Interconnection Service Agreement were also included in this baseline system along with any associated transmission enhancements as identified in the System Impact Studies associated with those requests. Queued generation, merchant transmission, and firm transmission service is studied and subsequently included in the basecase for the New Services Queue studies. The process for these studies is detailed in PJM manual 14A. PJM manual 14B attachments A-I describe the analysis that is performed to ensure the reliability of new generation, merchant transmission, and firm transmission service. Any supplemental transmission enhancements independent of those associated with new generation or merchant transmission projects were also included. All firm transmission service currently committed for the period was represented.

PJM has conducted a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria. The applicable reliability planning criteria are listed below:

- NERC Planning Standards
  http://www.nerc.com/pa/Stand/Pages/default.aspx
- RFC Reliability Standards
  https://rfirst.org/ProgramAreas/Standards/Regional/Pages/Regional.aspx
- SERC Reliability Corporation
  http://www.serc1.org/Application/HomePageView.aspx
- PJM Reliability Planning Criteria as contained in PJM Regional Transmission Planning Process Manuals http://www.pjm.com/library/manuals.aspx
- Transmission Owner Reliability Planning Criteria as filed in their respective FERC Form 715 filing http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

In completing this assessment, PJM has documented all conditions where the system did not meet applicable reliability criteria and identified the system reinforcements required to bring the system into compliance along with estimated cost and lead-time to implement them.

Those areas that were found to not meet applicable reliability standards establish the need for reinforcement in those areas independent of any future interconnection projects not included in the baseline analysis. The resulting system with the identified reinforcements to bring the system into compliance, is anticipated to be used in evaluating the impact of the projects in queues AF1 and AF2 that qualify and elect to proceed with the system impact studies. The extent to which reinforcements identified in the baseline assessment are advanced, deferred, modified or eliminated will be used in determining cost responsibility for the final plans in the RTEP.

It should be recognized that the reinforcements identified in this baseline analysis may be modified, advanced, deferred or eliminated as a result of future system assumptions. Future assumptions include generation projects, merchant transmission projects, generation retirements, or transmission service being added to or removed from the system. The development of the RTEP for PJM is an ongoing process, which includes the conduct of system impact studies and development of plans to accommodate the new interconnection projects. Upon completion of the system impact studies some projects may elect not to proceed. When it is determined which projects will commit to proceed, PJM develops a new baseline RTEP to meet the needs of the region, including the accommodation of all new projects committed to connect, during the next 5 year period.

Key Findings

Inclusive of the baseline upgrades identified in the Results Section of this assessment, PJM assesses its system as being compliant with the thermal, reactive, short circuit, and stability requirements of all applicable standards including NERC Standard TPL-001-5.1 for both the near term and longer term. The results section of this assessment includes all planned upgrades needed to meet the performance requirements of Table 1 in each respective TPL standard throughout the planning horizon.

The reinforcements identified as part of the 2022 RTEP that are required to achieve compliance having an estimated cost of at least $5 million are described below. The required in-service date of these upgrades is also included. A complete list of projects along with detailed descriptions of the conditions that are driving the need for them, are described in the Results section and Appendix A of this report. PJM staff from the Infrastructure Coordination group coordinates with the transmission owners and generation or merchant transmission developers to monitor project schedules for implementation of these reinforcements and coordinate any required outage activities to ensure these reinforcements are completed by their required in-service dates. The cost estimates below are based on those provided by the responsible entities and discussed at the monthly Transmission Expansion Advisory Committee (TEAC) meetings during the calendar year.

PJM MID ATLANTIC

AEC

- Rebuild the underground portion of Richmond-Waneeta 230 kV. - 6/1/2029 - $16.00M

BGE

- Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild which is 2.16 miles. - 6/1/2029 - $9.92M
- Rebuild 1.4 miles of existing single circuit 230 kV tower line between BGE's Graceton substation to the Brunner Island PPL tie-line at the MD/PA state line to double circuit steel pole line with one (1) circuit installed to uprate 2303 circuit - 6/1/2027 - $8.40M
- Reconductor two (2) 230 kV circuits from Conastone to Northwest #2 - 6/1/2027 - $37.76M

DPL

- Rebuild the New Church - Piney Grove 138 kV line - 6/1/2027 - $63.00M

JCPL

- Add third Smithburg 500/230 kV transformer. - 12/31/2027 - $13.40M
- Atlantic 230 kV substation – Convert to double-breaker double-bus. - 6/1/2030 - $31.47M
- Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line. - 6/1/2029 - $206.48M
- G1021 (Atlantic-Smithburg) 230 kV upgrade. - 6/1/2030 - $9.68M
- Larrabee Collector station-Larrabee 230 kV new line. - 6/1/2029 - $7.52M

- Larrabee Collector station-Smithburg No. 1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line. - 12/31/2027 - $150.35M
- Larrabee-Oceanview 230 kV line upgrade. - 6/1/2030 - $6.00M
- New Larrabee Collector station-Atlantic 230 kV line. - 6/1/2030 - $17.07M
- R1032 (Atlantic-Larrabee) 230 kV upgrade. - 6/1/2030 - $14.50M
- Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63. - 6/1/2029 - $11.45M
- Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line. - 12/31/2027 - $62.85M
- Rebuild Larrabee-Smithburg No. 1 230 kV. - 12/31/2027 - $44.77M
- Reconductor Red Oak A-Raritan River 230 kV. - 6/1/2029 - $11.05M
- Replace substation conductor at Kilmer and reconductor Raritan River-Kilmer W 230 kV. - 6/1/2029 - $25.88M
- Smithburg substation 500 kV expansion to 4-breaker ring. - 12/31/2027 - $68.25M

LS POWER

- Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line. - 6/1/2029 - $61.20M

MAOD

- Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. - 12/31/2027 - $121.10M

ME

- Install a new Allen four breaker ring bus switchyard near the existing MetEd Allen substation on adjacent property presently owned by FirstEnergy. Terminate the Round Top-Allen and the Allen-PPGI (PPG Industries) 115 kV lines into the new switchyard. - 6/1/2026 - $6.41M
- Install second TMI 500/230kV Transformer with additional 500 and 230 bus expansions - 6/1/2027 - $30.19M
- Rebuild/Reconductor the Germantown - Lincoln 115 kV Line. Approximately 7.6 miles. Upgrade limiting terminal equipment at Lincoln, Germantown and Straban - 6/1/2027 - $17.36M

PECO

- Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for PECO's portion of the line rebuild which is 4.1 miles. - 6/1/2029 - $18.82M
- Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA. - 6/1/2029 - $5.60M

PENELEC

- At Maclane tap: Construct a new three breaker ring bus to tie into the Warrior Ridge - Belleville

46 kV D line and the 1LK line - 6/1/2027 - $10.09M

Replace the Shawville 230/115/17.2 kV transformer with a new Shawville 230/115 kV transformer and associated facilities. Replace the plant's No. 2B 115/17.2 kV transformer with a larger 230/17.2 kV transformer. - 6/1/2026 - $8.78M

- Purchase one 80 MVAR 345 kV spare reactor, to be located at the Mainesburg station. - 12/1/2022 - $6.44M
- Rebuild 6.4 miles of the Roxbury - Shade Gap 115 kV line from Roxbury to the AE1-071 115 kV ring bus with single circuit 115 kV construction - 6/1/2027 - $15.03M
- Rebuild 7.2 miles of the Shade Gap - AE1-071 115 kV line section of the Roxbury - Shade Gap 115 kV line - 6/1/2027 - $17.43M

PPL

- At the existing PPL Williams Grove substation, install a new 300 MVA 230/115 kV transformer. - 6/1/2026 - $6.30M
- Construct a new ~3.4 mile 115 kV single circuit transmission line from Williams Grove to Allen substation. - 6/1/2026 - $5.11M
- Reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another. - 6/1/2027 - $10.70M

PSEG

- Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work. - 12/31/2027 - $5.53M
- Construct a new 69kV line from 14th Street to Harts Lane - 6/1/2027 - $34.40M
- Construct a third 69kV supply line from Totowa substation to the customer's substation - 1/1/2025 - $8.20M
- Convert existing Medford 69kV Straight bus to Seven breaker ring bus, construct a new 69kV line from Medford to the Mount Holly station, and install a capacitor bank at Medford - 6/1/2027 - $78.70M
- Convert Locust Street 69kV from a Straight Bus to a Ring Bus. - 6/1/2027 - $30.00M
- Convert Maple Shade 69kV from a Straight Bus to a Ring Bus - 6/1/2027 - $33.90M
- Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV Switching station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV. - 12/31/2027 - $24.92M
- Replace existing 230/138 kV Athenia No. 220-1 transformer. - 6/1/2026 - $13.04M
- Replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard - 6/1/2026 - $13.36M

Transource

- Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high side and five low side breakers in ring bus configuration). - 6/1/2029 - $76.27M

PJM WEST

AEP

- Hayes 138 kV: Build a new 4-138 kV circuit breaker ring bus. The following cost includes the new station construction, property purchase, metering, station fiber and the College Corner –Randolph 138 kV line connection. - 6/1/2027 - $7.44M
- Rebuild ~16.7 mi Dorton – Breaks 46kV line to 69kV - 12/1/2027 - $58.52M
- Rebuild the 1.8 mile 69kV T-line between Summerhill and Willow Grove Switch. Replace 4/0 ACSR conductor with 556 ACSR. - 6/1/2027 - $5.10M
- Rebuild the existing Darrah-Barnett 69 kV line, approximately 2.8 miles and replace a riser at Darrah station. - 12/1/2027 - $6.98M
- Rebuild the George Washington – Kammer 138 kV circuit, except for 0.1-mile of previously-upgraded T-line outside each terminal station (6.7 miles of total upgrade scope). Remove the existing 6-wired steel lattice towers and supplement the right-of-way as needed. - 6/1/2027 - $18.30M
- Replace the Jug Street 138kV breakers M, N, BC, BF, BD, BE, D, H, J, L, BG, BH, BJ, BK with 80KA breakers - 6/1/2024 - $14.00M
- Retire ~17.2 mi Cedar Creek – Elwood 46kV circuit. - 12/1/2027 - $11.15M
- Terminate the existing Broadford – Wolf Hills #1 138 kV line into Abingdon 138 kV Station. This line currently bypasses the existing Abingdon 138 kV Station; Install two new 138 kV circuit breakers on each new line exit towards Broadford and towards Wolf Hills #1; Install one new 138 kV circuit breaker on line exit towards South Abingdon for standard bus sectionalizing - 6/1/2027 - $8.48M

APS

- Reconductor 27.3 miles of the Messick Road - Morgan 138 kV Line from 556 ACSR to 954 ACSR. At Messick Road Substation: Replace 138 kV wave trap, circuit breaker, CT's, disconnect switch, and substation conductor and upgrade relaying. At Morgan Substation: Upgrade Relaying – 6/1/2027 - $49.23M
  Install two new 500 kV breakers on the existing open SVC string to create a new bay position. Relocate & Reterminate facilities as necessary to move the 500 kV SVC into the new bay position and Install a 500 kV breaker on the 500/138 kV #3 transformer. Upgrade relaying at Black Oak substation. - 6/1/2027 - $17.37M
- Scope Change: During 2027 RTEP analysis, it was determined that the topology change caused the new AA2-161 to Charleroi line to be overloaded. The new overload is conductor limited and the cost to upgrade 12.8 miles is $32 M. As a result, the cost-effective solution is to alternatively reconductor Yukon to AA2-161 ckt 1 & 2 while maintaining the existing topology. The cost to upgrade is $10.64 M Expand the future AA2-161 138 kV six (6) breaker ring bus into an eleven (11) breaker substation with a breaker-and-a-half layout by constructing five (5) additional breakers and expanding the bus. Loop the Yukon - Charleroi #2 138 kV line into the future AA2-161 substation. Relocate terminals as necessary at AA2-161. Upgrade terminal equipment (wavetrap, substation conductor) and relays at Yukon,

Huntingdon, Springdale, Charleroi, and the AA2-161 substation. - 6/1/2026 - $10.64M

ATSI

- Rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 kcmil 26/7 ACSR. - 6/1/2027 - $10.40M
- Rebuild the Abbe-Johnson #2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. Replace three disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe. Replace one disconnect switch (A159) and line drops and revise relay settings at Johnson. Replace two MOAB disconnect switches (A4 & A5), one disconnect switch (D9), and line drops at Redman. - 6/1/2027 - $10.90M

Dayton

- New Westville – West Manchester 138kV Line: Construct a new approximate 11-mile single circuit 138kV line from New Westville to the Lewisburg tap off 6656. Convert a portion of 6656 West Manchester – Garage Rd 69kV line between West Manchester - Lewisburg to 138kV operation (circuit is built to 138kV). This will utilize part of the line already built to 138kV and will take place of the 3302 that currently feeds New Westville. The 3302 line will be retired as part of this project. - 6/1/2027 - $16.00M
- West Manchester Substation: The West Manchester Substation will be expanded to a double bus double breaker design where AES Ohio will install one 138kV circuit breaker, a 138/69kV transformer, and eight new 69kV circuit breakers. These improvements will improve help improve a non-standard bus arrangement where there is only one bus tie today and will improve the switching arrangement for the West Sonora Delivery Point. - 6/1/2027 - $9.90M

DL

- Install a series reactor on Cheswick-Springdale 138 kV line - 12/31/2024 - $9.00M
- Transmission Line Rearrangement:
  · Replacement of four structures and reconductor DLCO portion of Plum-Springdale 138 kV line.
  · Associated communication and relay setting changes at Plum and Cheswick. - 12/31/2024 - $15.00M

EKPC

- Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR. - 12/1/2026 - $8.50M
- Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR. - 12/1/2026 - $8.50M

PJM South

Dominion

- Reconductor approximately 10.5 miles of 115kV line #23 segment from Oak Ridge to AC2-079 Tap to minimum emergency ratings of 393 MVA Summer / 412 MVA Winter. - 6/1/2027 - $23.50M

Objective and Scope

The objectives of this assessment were as follows:

- **a)** To identify system reinforcements as required to ensure compliance with NERC standards TPL-001-5.1.
- **b)** To identify areas where the system as planned for the near term period 2022 through 2027 would not meet applicable reliability standards.
- **c)** To develop and recommend preliminary facility expansion plans, including cost estimates and required in service dates, to ensure all areas meet applicable reliability criteria.
- **d)** To identify areas where the system as planned for the longer term period 2028 through 2037 that would not meet applicable reliability criteria, and where appropriate, develop expansion plans. These plans include required in service dates of the facilities needed to bring those areas into compliance. This longer term planning is in consideration of larger scope projects that may require long lead time to implement.
- **e)** To establish what will be included as baseline expansion costs for the allocation of the costs of expansion for those projects included in New Services Queues.

The scope of this assessment included analysis for the period 2022 through 2037 to ensure the system would meet all applicable reliability planning criteria. These assessments include baseline thermal, baseline voltage, thermal and voltage Load Deliverability, generation deliverability, and baseline stability analysis. The baseline thermal and voltage analysis encompasses an exhaustive analysis of all BES facilities for compliance with NERC P0 – P7 (TPL-001-5.1) events. In addition, consistent with NERC standard TPL-001-5.1, a number of extreme events as defined in Table 1 of TPL-001-5.1 were evaluated for risk and consequences to the system. Results of this study are not documented in this report due to their sensitive nature, and can be found in the 2022 Extreme Event Report.

The PJM Load Deliverability testing methods are described in Manual 14B, section 2. The tests ensure that an area of the transmission system that is experiencing higher than normal load levels (90/10) with higher than normal internal generation unavailability has the transmission capability to import energy to meet the transmission system reliability criteria. The generation deliverability testing ensures sufficient transmission capability so that generation can be ramped to full output so that excess energy can be exported to an area that is experiencing a capacity deficiency. PJM also performed a stability analysis consistent with NERC and local transmission owner criteria to ensure the system is stable for critical system conditions including fault conditions that include multi-phase faults and faults with delayed clearing and light load conditions.

Analytical testing is performed annually on a range of study years and system conditions to satisfy NERC standards. Every year analysis is performed on the 5 year out case, while the other nearer term cases (years 0 through 4) are retooled to be studied for specific projects as changes to system conditions warrant. Additional analysis is also performed for the longer term to identify marginal conditions that may require long lead time solutions. Currently as part of the RTEP a year 7 or year 8 case is studied in detail as part of the annual RTEP. During the 2022 RTEP, a year 7 (2028 study year) was studied.

PJM Generator Deliverability testing, which simulates higher than normal generation availability in an area, is performed at 50/50 load levels. PJM Load Deliverability testing, which is performed on 27 Locational Deliverability Areas (LDA's) within PJM's footprint, simulates an internal generation deficiency within the LDA (which simulates higher than expected forced outage conditions) being tested with the area at 90/10 load levels. Single and multiple contingency analyses were also performed on a shoulder peak case as described in subsequent sections of this document.

The combination of these tests includes simulation of various system conditions over a range of forecast system demands and generation availability scenarios that simulate planned and forced outage conditions. This analysis is performed for both the near term and longer term.

The continued need for the system reinforcements previously identified in prior RTEP Baseline Assessment Reports and the queue A through AE2 System Impact Studies associated with projects that have executed an Interconnection Service Agreement were evaluated. Any previously identified reinforcements that are no longer required were documented and removed from the list of RTEP Reinforcements. PJM adjusts required in-service dates based on updated forecasts that can affect the modeling of the system conditions. In the event that changing system conditions delay the need for a baseline upgrade beyond the 5 year planning horizon, PJM will re-evaluate the need for that upgrade. When evaluating the continued need for previous reinforcements, analysis is performed to test for system performance associated with all applicable reliability criteria including that specified under all event categories listed in Table 1 of TPL-001-5.1.

Analysis methodology

PJM completed a robust series of analysis over a broad spectrum of system conditions encompassing a range of study years and forecast demand levels. The following sections detail the assumptions of the modeling and analysis. The analysis sub-sections are grouped by the analysis type. The modeling assumptions of the 2027 cases and analysis are discussed in detail. The modeling assumptions for the retool cases are not discussed in detail but followed the same procedure as the 2027 case, which can be found in PJM Manual 14B, Attachment H The modeling assumptions of all of the cases follow the procedure in PJM Manual 14B, Attachment B. All study year cases model all normal (NERC TPL P0) operating procedures in place. PJM Manual 3 – Transmission Operations contains all PJM operating procedures that are applicable to PJM planning studies.

<table>
<tr><th>Analysis Type</th><th>NERC Contingency Category from Table 1 of TPL Standard</th><th>Applicable Limits Monitored</th><th>Monitored Elements</th><th>Contingencies Considered</th></tr>
<tr><td>Normal System (no contingency)</td><td>P0</td><td rowspan="7">All System Operating Limits, including the most limiting thermal, voltage limit (magnitude and deviation), voltage collapse</td><td rowspan="9">All BES & select lower voltage facilities, all ties to neighboring systems regardless of voltage</td><td rowspan="9">Normal system, All BES & select lower voltage facilities. N-1-1 considers all possible combinations of single contingencies</td></tr>
<tr><td>Single Contingency</td><td>P1, P2</td></tr>
<tr><td>Multiple Contingency</td><td>P3, P4, P5, P6, P7</td></tr>
<tr><td>Load Deliverability</td><td>P1</td></tr>
<tr><td>Light Load Reliability Analysis</td><td>P0, P1, P2, P4, P5, P7</td></tr>
<tr><td>Winter Reliability Analysis</td><td>P0, P1, P2, P3, P4, P5, P6, P7</td></tr>
<tr><td>N-1-1 Analysis</td><td>P3, P6</td></tr>
<tr><td>Generation Deliverability</td><td>P1</td><td rowspan="2">thermal, voltage collapse</td></tr>
<tr><td>Common Mode Outage Procedure</td><td>P2, P4, P7</td></tr>
</table>

Table 3. **Analysis Type Summary**

Modeling Assumptions & Critical System Conditions

PJM selected a range of forecast demand levels for the year 2027.

- 2027 90/10 Summer Peak
- 2027 50/50 Summer Peak
- 2027 Light Load Reliability Analysis (50% of 50/50 Summer Peak)
- 2027 Winter Reliability Analysis

In addition to the analysis of the 2027 system, as part of this assessment, PJM also performed analysis of multiple critical system conditions in the near term and longer term planning horizons. The assessments of the critical system conditions within these study years will be discussed in subsequent sections of this document.

The load forecast from the 2027 PJM Load Forecast Report was used and can be found on the PJM website at the following address:

https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx

The 2027 summer peak analysis used the 2027 summer model from the 2021 series MMWG (Multiregional Model Working Group) case. The model was updated according to the procedures in PJM Manual 14B, Attachment H. The case build is a collaborative process that involves PJM, PJM transmission owners, and neighboring entities. The case was reviewed with all PJM transmission owners to ensure that all existing and planned facilities were modeled. All future transmission upgrades with a required in-service date up to and including June 1, 2027 were modeled as in service. The list of future upgrades along with a schedule for implementation is contained in Appendix A.

All existing generation was modeled in the base case. Future generation that had an executed Interconnection Service Agreement (ISA) was modeled along with any upgrades required to maintain the reliability of the PJM system including the future generation. Future merchant transmission facilities that had an executed Interconnection Service Agreement (FSA) were modeled along with any upgrades required to maintain the reliability of the PJM system including the future merchant transmission. Information regarding all of these projects can be found on the PJM website at the address below.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Adequate Reactive Power resources were included in the base model to ensure system voltage performance. Some of the reactive power resources modeled are existing and in-service equipment while some are planned with a future implementation date. A list of the planned reactive upgrades along with a schedule for implementation is contained in Appendix A. Table 4 below is a summary of the reactive power resources included in the 2027 case (note these are in addition to the reactive power associated with the generation noted above).

2027			
Area Name	Static	Dynamic	Total
AE	945	450	1395
AEP	14142	650	14792
AP	5817	1765	7582
BGE	9522	0	9522
CE	9798	1800	11598
DAY	1108	0	1108
DEO&K	842	0	842
DLCO	-110	0	-110
DP&L	1579	375	1954
DVP	10888	1750	12638
EKPC	1335	0	1335
FE	7229	1614	8843
JCPL	4762	40	4802
METED	1233	500	1733
PECO	5974	600	6574
PENELEC	2731	674	3405
PEPCO	1305	0	1305
PJM*	0	0	0
PPL	3259	0	3259
PSEG	7073	0	7073
RECO	0	0	0
UGI	66	0	66
Grand Total	89497	10218	99715

Table 4. **Reactive Power Resources in base case Static MVAR: Capacitor Banks, Switched Shunts; Dynamic MVAR: SVCs, Synchronous Condensers, and Dynamic Switched Shunts.**

The interchange targets in Table 5 below represents the net sum of all existing and planned yearly long-term firm transmission service commitments between PJM and neighboring systems for the 2027 summer period. A 2027, 2021 Series, MMWG case was used as a starting point for the modeling, all PJM firm transactions were included in the RTEP base case modeling. The base dispatch is set as defined in PJM Manual 14B, Attachment B.

2027 RTEP Interchange		
Source	**Sink**	**Total (MW)**
PJM	NYISO	817
PJM	LGEE	-481
PJM	DEI	-156
PJM	WEC	94
PJM	LAGN	-100
PJM	CPLE	105
PJM	DUK	-100
PJM	TVA	400
PJM	EEI	0
PJM	AMIL	-884
PJM	OMUA	0
PJM	MEC	454
PJM	SMT	-285
Total		-136

Table 5. **Net Yearly Long Term Firm Interchange**

In all cases, where the physical design of connections or breaker arrangements resulted in the outage of more than the faulted facility when the fault was cleared, the additional facilities were also outaged in the load flow. That is, the breaker arrangements and system topology are used to develop and maintain the contingency files. For example, if a transformer is tapped off a line without a breaker, both the line and transformer were outaged as a single contingency event.

In addition, approved operating procedures were utilized as applicable. These operating procedures include the use of control devices such as Phase Angle Regulators (PARs) to manage flows on the system. Also, the expected operation of Remedial Action Schemes (RAS) were modeled and additionally tested where applicable. A complete listing of applicable remedial action schemes and operating procedures can be found in the Transmission Operation Manual (M-03) at the following link:

https://www.pjm.com/library/manuals.aspx

Contingencies Considered

The thermal and voltage analysis used a set of contingencies as required by NERC TPL standards. PJM's rationale was to define and select a comprehensive set that includes every possible BES contingency. Every possible single and multiple contingency loss of PJM BES elements as described in Table 1 of NERC TPL-001-5.1 was defined in contingency files and included in the assessment. No single or multiple BES contingencies were excluded from this assessment. The contingency set also included an inclusive set of single contingencies of non-BES elements that are modeled in the base case. A set of multiple facility contingencies involving non-BES facilities was included in the contingency set. A complete set of multiple facility contingencies involving non-BES facilities was not included in the contingency set given that issues on non-BES facilities are not expected to propagate to the BES system.

Contingency analysis takes into account the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. This includes tripping of generators and transmission elements when protection equipment may exceed its performance capabilities.

In addition to the contingencies studied within PJM's footprint, analysis includes contingencies located in areas outside of PJM's footprint. PJM worked with its neighboring ISO's and RTO's to identify off-system contingencies that could affect PJM's system. All contingencies identified by these entities have been included in PJM's RTEP analysis.

- Over 14,000 Single contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- Over 18,000 Multiple Facility Contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- The N-1-1 analysis considers every possible combination of single contingencies, a total of over 190,000,000 combinations.

PJM's 2022 analysis focused on contingencies as defined by TPL-001-5.1 Table 1 – Steady State & Stability Performance Planning Events.

The new TPL-001-5.1 P5 contingency definition replaces failure of a non-redundant relay in TPL-001-4 with failure of a non-redundant component of a protection system. For the purposes of TPL-001-5.1, non-redundant components of a protection system are as follows:

- A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides comparable Normal Clearing times;
- A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (an exception is a single communications system that is both monitored and reported at a Control Center);
- A single station dc supply associated with protective functions required for Normal Clearing (an exception is a single station dc supply that is both monitored and reported at a Control Center for both low voltage and open circuit);

- A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

PJM worked with its Transmission Owners to identify new P5 contingencies that incorporated single points of failure within their respective protection systems. All contingencies identified by the Transmission Owners have been included in PJM's RTEP analysis.

- Over 3,700 new P5 contingencies were defined.

Planned Outages in the Transmission Planning Horizon

Although there are situations in which outages are planned and scheduled more than 12 months in advance, more often outages are submitted no more than one year in advance of the planned outage. Most maintenance plans are developed, and therefore the associated outages are planned with less lead time. In cases where outages are scheduled less than one year out, the lead time makes it impractical for inclusion in planning studies under the TPL timeframe. Outages planned with a lead time of less than one year are evaluated by PJM Operations.

PJM performed analysis as per TPL-001-5.1 of known outages in the planning horizon by utilizing a documented technical rationale for their selection. For the steady state portion (Requirement 2.1.4), analysis consisted of studying outages of 5 days or greater and on facilities 230 kV and above as reported through PJM's outage coordination software (eDART). For the stability portion (Requirement 2.4.4), analysis consisted of studying outages within eDART that also had the 'stability' or 'TSA Stability Study' flag set which identifies stability-related facilities. Results of the analysis are documented in the "**2022 RTEP Assessment of Planned Maintenance Outages in the Planning Horizon TPL-001-5.1**" report. The report was sent to PJM Operations for review and situational awareness.

Spare Equipment

In instances where an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), PJM studies the impact of this possible unavailability on system performance. Annually, PJM solicits input from its Transmission Owners to identify long lead time equipment for subsequent study. Steady State analysis (Requirement 2.1.5) is conducted for the P0, P1 and P2 categories and stability analysis (Requirement 2.4.5) is conducted for the P1 and P2 categories defined in Table 1 of TPL-001-5.1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. Results of the analysis are documented in the "**2022 RTEP Assessment of Spare Equipment Strategy in the Planning Horizon TPL-001-5.1**" report.

Monitored Facilities

All cases used for this assessment model all PJM Bulk Electric System facilities. The specific facilities monitored for each analysis is described in detail in subsequent sections of this document. PJM also monitored every tie line to neighboring systems regardless of voltage. Over 20,000 individually modeled BES facilities are monitored in the analysis that supports this assessment. In addition to all BES elements, PJM monitors lower voltage, non-BES, facilities that are monitored by PJM operations. As part of the 2022 RTEP, PJM expanded its monitored facility list to include BES facilities in the MISO footprint. PJM also completed several joint studies of neighboring systems as described in the scope contained in the Executive Summary above.

Analysis of Near-Term

As part of the near-term assessment, PJM evaluated a range of critical system conditions. The range of system conditions included thermal and voltage analysis of a 2027 90/10 summer peak scenario, thermal and voltage analysis of a 2027 50/50 summer peak scenario, and thermal and voltage analysis of a light load scenario. The thermal analysis included applicable thermal limit checking. The voltage limit analysis included checking applicable voltage magnitude and voltage drop limits. PV analysis is an important part of the RTEP analysis and is performed for selected scenarios. The methodology for selecting the PV scenarios is discussed in a subsequent section of this document.

Analysis is performed for planning events listed in Table 1 of TPL-001-5.1 to ensure that all performance requirements are met, or upgrades to the system are implemented to address required performance issues.

The forecast demand level, analysis type, and mapping to TPL standards are summarized in tables in this section. In addition, a summary of the analysis type, contingencies considered, monitored elements, and monitored limits are summarized in the Analysis Methodology Section. Stability tests are detailed in a subsequent section of this document.

Normal System (All Facilities in Service) Analysis

The 2027 90/10 summer peak, 50/50 summer peak, light load and shoulder peak cases were evaluated for system performance under normal conditions. These models use data consistent with information provided in MOD-032 and MOD-033 standards. The normal system analysis as defined in P0 on Table 1 of NERC TPL-001-5 does not include a contingency event. Rather, all facilities are assumed to be in-service. Every BES facility and select lower voltage facilities in PJM were monitored for thermal limits, voltage limits, and voltage stability. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Single Contingency Analysis

The 2027 50/50 summer peak, 90/10 summer peak and light load cases were evaluated for system performance following the loss of a single element. The single elements included all of the P1 and P2 events defined on Table 1 of NERC TPL-001-5.1. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage collapse. Additionally select off-system contingencies which may affect PJM's system were included in the single contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Contingency Analysis

The 2027 50/50 summer peak and light load cases were evaluated for system performance following the loss of two or more (multiple) elements. The multiple elements included all common mode events defined in Table 1 of NERC TPL-001-5.1. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage stability. Additionally select off-system contingencies which may affect PJM's system were included in the Common Mode contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

N-1-1 Analysis

The purpose of the N-1-1 analysis is to determine if all monitored facilities can be operated within normal thermal and voltage limits after an actual N-1 contingency and within the applicable emergency thermal and voltage limits after an additional simulated contingency. The 2027 50/50 summer peak was evaluated for system performance following a single contingency, followed by manual system adjustments, followed by another single contingency. The N-1-1 analysis monitored all BES facilities. The set of single contingencies that was used to compile the contingency pairs included all single contingencies in PJM regardless of voltage, all PJM tie lines regardless of voltage, and selected contingencies in neighboring systems. The contingency pairs that were considered included every possible combination of single contingencies, a total of over 376,000,000 combinations. The N-1-1 analysis also analyzed the contingency pairs in both possible orders to assess every combination and order of event. Reinforcements were developed for areas where the system failed to meet the applicable normal rating after the first contingency or the applicable emergency rating after the second contingency.

The N-1-1 analysis also assessed applicable voltage magnitude and voltage drop limits. For voltage magnitude and voltage drop testing, PJM screened for potential voltage violations. Voltage violations include exceeding the normal low voltage limit after the first contingency, emergency low limit after the second contingency, or exceeding the emergency voltage drop limit after the second contingency. Reinforcements were developed for areas where voltage violations were identified.

Deliverability Analysis

The 2027 base case was also used to analyze the capability of PJM's transmission system, including all PJM BES elements. To maintain reliability in a competitive capacity market, a resource must be deliverable to the overall network. PJM has developed the Load Deliverability and Generator Deliverability test methods for evaluating the adequacy of network capability for each of these deliverability requirements. Common mode outage analysis uses a procedure similar to Generator Deliverability to assess the impact of P2, P4 and P7 contingencies, as defined in PJM Manual 14B, Addendum 2.

A broad range of critical system conditions are established and analyzed through the deliverability test methods. The Generator Deliverability test establishes a critical stressed generation dispatch for every flowgate (monitored element and contingency pair) that could potentially be overloaded by the test. For every monitored facility, a critical stressed dispatch is created for all normal (all facilities in service) and single contingency conditions that could potentially overload the facility. This method results in the analysis of a large number of critical system conditions.

The load deliverability test procedure evaluates multiple critical system conditions though the evaluation of 27 individual stressed Locational Deliverability Areas, one thermal and one voltage case, for each of the defined Locational Deliverability Areas (LDA's) resulting in a minimum of 54 cases. The Locational Deliverability Areas are defined in Manual 14B – Attachment C. The load deliverability cases model stressed 90/10 summer peak loads in the LDA under study in each of the cases. A Capacity Emergency Transfer Objective (CETO) is identified. The CETO is the amount of energy an LDA will need to be able to import so that the area is not expected to have a loss of load event more frequently than one event in 25 years. A Capacity Emergency Transfer Limit (CETL) is calculated for each LDA (i.e. 54 cases) to determine the energy that can be imported into the area under test. In each case, the CETL ("the limit") is compared to the target Capacity Emergency Transfer Objective (CETO). Through this method, a large number of critical system conditions are also developed as part of the Load Deliverability Analysis. The system is planned to ensure that each of the LDAs meet the CETO at a minimum. System reinforcements were developed for any condition where the calculated import capability into any LDA would not meet the CETO.

Generator Deliverability Analysis

The PJM Generation Deliverability procedure was used to determine if the PJM transmission system, including all PJM BES elements, was adequate to deliver all PJM capacity resources to the network. Generator Deliverability analysis is performed to ensure that capacity resources within a given electrical area will, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes the Generator Deliverability procedure to study the normal system and single contingencies under a stressed generation dispatch. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The Generator Deliverability procedure is defined in PJM Manual 14B Attachment C.

PJM performed the Generator Deliverability test on the 2027 50/50 summer peak model. The Generator Deliverability test examined system performance under normal and single contingency conditions. The contingency set included a complete set of single contingencies as defined by P1 and P2.1 in Table 1 of TPL-001-5.1.

The 2027 generator deliverability analysis tested a large number of critical system conditions. Every facility was monitored for applicable thermal limits for both the normal system and following the loss of every possible contingency. This process considers every one of the 19,000+ possible single contingencies for each monitored facility. As described in PJM Manual 14B, Attachment C a stressed dispatch was also developed and applied to each potentially overloaded flowgate to determine if an overload could be simulated. Through the method of applying a stressed dispatch to every possible single flowgate, the Generator Deliverability test identifies a large number of critical system conditions.

Reinforcements were developed for areas where the system failed to meet thermal limits or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Outage Analysis

Common mode outage analysis procedures are similar to the generation deliverability analysis procedure; however this analysis focuses specifically on the loss of multiple elements. The common mode outage analysis studies all events listed as P2, P4 and P7 under a stressed generation dispatch. Over 15,000 multiple contingency events were analyzed. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The common mode outage procedure is defined in Addendum 2 of PJM Manual 14B.

Reinforcements were developed for areas where the system failed to meet thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

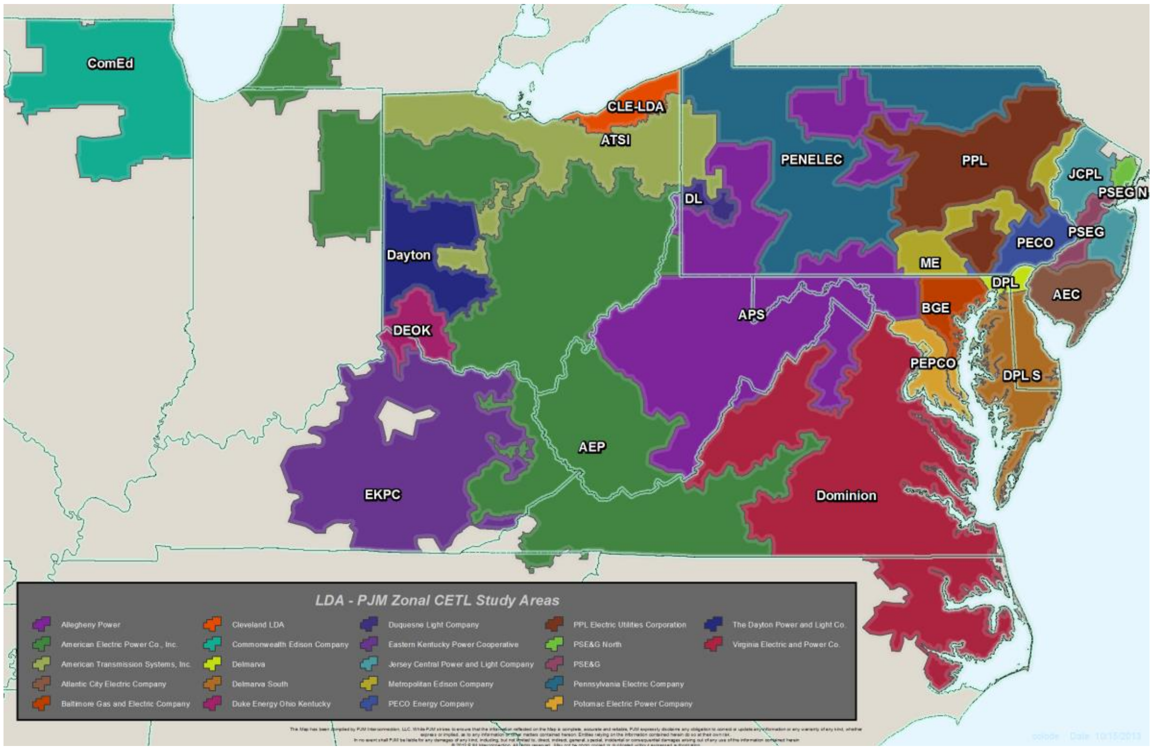
Load Deliverability Analysis

The Load Deliverability test procedures were used to determine if the Capacity Emergency Transfer Limit (CETL) for each of the various electrical areas of PJM is greater than each respective area's Capacity Emergency Transfer Objective (CETO).

There are currently 27 Locational Deliverability areas defined in PJM. The electrical areas within each of the 27 Locational Deliverability areas are described in table 6 and Map 2.

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM WEST	APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, Cleveland, OVEC
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTH	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
ComEd	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	Eastern Kentucky Power Cooperative
Cleveland	Cleveland Area

Table 6. **PJM Locational Deliverability Areas (LDA)**



Map 2. PJM Load Deliverability Areas

The 2027 Load Deliverability test used the 2027 summer peak base case as a starting point. From that starting point, 27 individual thermal Load Deliverability cases were built following the Load Deliverability thermal procedure as defined in PJM Manual 14B Attachment C. In addition, 27 individual voltage Load Deliverability cases were built following the Load Deliverability voltage procedure defined in PJM Manual 14B, Attachment C. This process developed one thermal and one voltage study case for each of the 27 Locational Deliverability Areas (LDA) resulting in 54 cases. These studies cover critical system conditions with load levels in the cases set to a 90/10 summer peak for the respective LDA under study and a 50/50 summer load level for all other areas. Modeling of specific system conditions such as load, reactive resources, and phase angle regulator settings were modeled as specified in PJM Manual 14B, Attachment G for the Load Deliverability tests. Manual 14B, Attachment C also specifies a procedure to dispatch generation in both the area assumed to be under a capacity emergency and the areas assumed not to be under a capacity emergency.

Capacity emergency transfer objectives (CETO's) for each of the 27 LDA's were used to set the target net interchange for the LDA under study in each of the thermal and voltage cases.

A thermal Load Deliverability study was then performed on each of the 27 thermal Load Deliverability cases. The thermal Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Reinforcements were developed for areas where the system failed to meet thermal limits. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

A voltage Load Deliverability study was then performed on each of the 27 voltage Load Deliverability cases. The voltage Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Critical system conditions were analyzed and reinforcements were developed for areas where the system failed to meet voltage magnitude limits, voltage drop limits, or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Light Load Reliability Analysis

PJM also performed a year 2027 light load reliability analysis. The 50% of 50/50 summer peak demand level was chosen as being representative of a stressed light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level. In addition to the generation dispatch, the Light Load Reliability Analysis procedure also requires that PJM set interchanges within PJM and neighboring regions to their historical values.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The flowgates ultimately used in the light load reliability analysis were determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis included single and multiple contingencies, with the exception of the N-1-1criteria. Normal system conditions (P0) were also studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list were monitored.

Winter Reliability Analysis

PJM also performed a year 2027 winter reliability analysis. This analysis included Generator Deliverability Studies, as well as Load Deliverability studies using a 2027 RTEP case with winter loadings and winter transmission line ratings. PJM focused these studies on Locational Deliverability Areas which had a Winter Loss of Load Expectation greater than 50%.

Voltage Stability

PV analysis was used to study a set of contingencies from the 2027 Load Deliverability voltage studies that were very severe or non-convergent. A set of single contingencies was selected for further study in the PV analysis. The methodology used to select the contingencies was to choose 500 kV or above contingencies that did not converge in a Load Deliverability voltage test. Also, contingencies that created a severe voltage drop or severe low magnitude violation on the BES were selected.

A PV analysis was then run on each of the selected contingencies. The analysis monitored all PJM facilities while simulating a transfer from all PJM generation outside the CETO area to all generation inside the CETO area where the contingency was identified. Typical to a PV analysis, the transfer was backed off until each contingency solved, and was then incrementally increased until a voltage collapse was simulated.

Retool Analysis of the Near-Term 2022-2027

Retool analysis is analysis that is performed during the current assessment to verify analysis that was performed in previous assessment. The retool analysis of the near-term was performed to verify the RTEP for the near-term due to forecasted changes in system conditions. Due to the recent overall net decrease in the projected load forecast for the PJM system, the retool work performed by PJM was a significant part of the 2022 RTEP. The retool analysis of the near-term included Generator Deliverability, Load Deliverability, common mode outage, and N-1-1 analysis. The methodologies for each of these analyses was performed as described in the detailed 2027 method descriptions in previous sections of this document. Through this approach, an extensive set of critical system conditions were analyzed. The conditions studies are summarized below.

Cases and contingency files for each year under study were updated in coordination with the Transmission Owners to reflect the most recent planned and existing facilities. The updated 2022 PJM load forecast was used to determine the load in the individual cases. The modeling updates included a review of the modeling of existing and planned facilities.

The retool analysis performed as part of the 2022 RTEP included the following groups of analysis. This analysis was in addition to the work performed as part of the near term and long term assessments required by the TPL standards. As a result of the significant generation deactivation notifications received throughout 2022, PJM performed a significant reliability review of years 2022 through 2027. As part of the 2022 RTEP, PJM performed system wide assessment of normal system, single contingency, multiple contingency, N-1-1, generator deliverability and load deliverability testing for year 2022 through 2027 summer peak models as needed for the widespread generation deactivations. PJM completed studies and developed system reinforcements related to generation deactivation requests for each year in the near-term in addition to the specific retool efforts outlined below. System enhancements, including an implementation schedule, were developed for every system performance issue that was identified as a result of the generation deactivation notifications. The system enhancements required as a result of the generation deactivations are described in more detail in the results section of this report. In addition to deactivation related retool studies PJM continually validates that previously identified system enhancements are still necessary.

2024 Retool

- B2003 verification (PSEG)

2025 Retool

- S2152 scope change (AEP)
- S2770 scope change (AEP)
- S2584 scope change (AEP)
- S1666 scope change (AEP)

2027 Retool

- Generation Updates Retool including New ISA, Withdrawn, Deactivation (Multiple TOs)

15 Year Planning and Analysis of the Longer-Term System

The purpose of the long term review is to simulate system trends to identify problems which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation of a reinforcement project in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon. The detailed description of the 15 year planning process is described in PJM Manual 14B.

The 2022 RTEP also included a review of the fifteen year planning horizon through 2037. The analyses conducted as part of the review included normal system, single, and multiple (tower) contingency analysis of the 2027 50/50 Summer Peak case as summarized in Table 7. Following the 15 year procedure, the calculated loading on every flowgate was then scaled by a factor consistent with the forecasted load growth to determine a facility loading in years 2028 through 2037 (years 6 through 15). Both the Generator Deliverability and Load Deliverability procedures were used to establish the critical system conditions under which the system was evaluated.

<table>
<tr><th>Analysis Type</th><th>Monitored Flowgates</th><th>Contingencies Considered</th><th>Years Considered</th></tr>
<tr><td>Load Deliverability</td><td rowspan="2">Any BES element loaded at 75% or greater in the 2027 analysis</td><td>normal system, single, double circuit tower line</td><td rowspan="2">2028 through 2037</td></tr>
<tr><td>Generation Deliverability</td><td>normal system, single</td></tr>
</table>

Table 7. **15 Year Planning Analysis**

Load forecasts for the years 2027 through 2037 from the 2021 PJM Load Forecast Report were used to generate load growth scaling factors for each of the highest loaded flowgates in each year. The DC scaling factors were then used to calculate a loading for each flowgate for each year 2028 through 2037.

Analysis of the Longer-Term System

PJM evaluated a 2028 (year 8) 50/50 Summer Peak case. One purpose of this evaluation was to identify any thermal or voltage reliability criteria violations in year 2028 that would require a longer term lead time to resolve. The evaluation of the 2028 Summer Peak case did not identify any reliability criteria violations that would require a longer lead time solution. In addition, this targeted analysis of 2028 summer conditions was benchmarked for consistency to the 2028 results from the 15 year analysis procedure.

Verification of Planned Reinforcements

Analysis was performed to verify that all planned reinforcements that were identified as part of the 2022 RTEP and all previously identified reinforcements acceptably resolved all criteria violations throughout the planning horizon. Analysis was also performed to verify that no new potential criteria violations were created as a result of implementing the required system reinforcements.

New Services Queue Analysis

Analysis for customer requests in the New Services Queue was performed for several different types of New Service Requests: Generator interconnection, long term firm transmission service, ARR requests, and Merchant transmission requests. The reliability of the requests is determined through two separate technical studies, the feasibility study and system impact study.

The feasibility study is the first study that is performed and is an initial look at the effect of the New Service Request on the transmission system. This study includes generator deliverability analysis that is performed on a summer peak load case to analyze the normal system and all single and multiple contingencies (Excluding N-1-1). Additionally Short Circuit analysis is performed.

If a developer elects to move forward and executes a System Impact Study Agreement PJM performs a more detailed study of the impact of the proposed request. The system impact study includes thermal analysis (AC Generator Deliverability) of the normal system and all single and multiple contingencies (Excluding N-1-1) as well as short circuit and stability assessments. Additionally, and as required based on the type of request made, load deliverability analysis may also be performed.

As part of the system impact study process, steady state voltage studies are performed for all interconnection projects. The steady state voltage studies included a check of the applicable voltage magnitude limits under normal and contingency conditions. The voltage of every BES facility was monitored. The contingencies included in the steady state voltage analysis included all multiple contingencies except N-1-1contingencies.

Specific results of interconnection studies can be found at:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Short Circuit Assessment

PJM conducts short circuit analysis annually to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and transmission facilities in service which could impact the study area. Short circuit analysis is performed consistent with the following industry standards:

1) ANSI/IEEE 551-2006 —IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems
   a) This standard is used to provide short circuit current information for breakers and power system equipment used to sense and interrupt fault currents.
2) ANSI/IEEE C37.04-1999 —IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers

   a) This standard is used to establish the rating structure for circuit breakers and equipment associated with breakers.
3) ANSI/IEEE C37.010-1999 —IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Symmetrical Current Basis taking into consideration reclosing duration, X/R ratio differences, temperature conditions, etc.
4) ANSI/IEEE C37.5-1979 —IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Total Current Basis.

Each of these standards is used jointly with transmission owners' methodologies as a basis to calculate fault currents on all BES breakers. By using these standards, single phase to ground and three phase fault currents are calculated and compared to the breaker interrupting capability, provided by the transmission owners, for each BES breaker within the PJM footprint. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation. All breakers are used in specific short circuit cases which help to identify the cause and year breakers are likely to become overdutied.

Short circuit cases are built consistent with a 2 year planning representation and a 5 year planning representation. The 2 year planning case consists of the current system in addition to all facilities planned to be in-service within the next year. The 5 year planning case uses the 2 year planning case as its base model and it is updated to include all system upgrades, generation projects, and merchant transmission projects planned to be in-service within 5 years. The 5 year planning case is similar to the 5 year PJM RTEP load flow basecase.

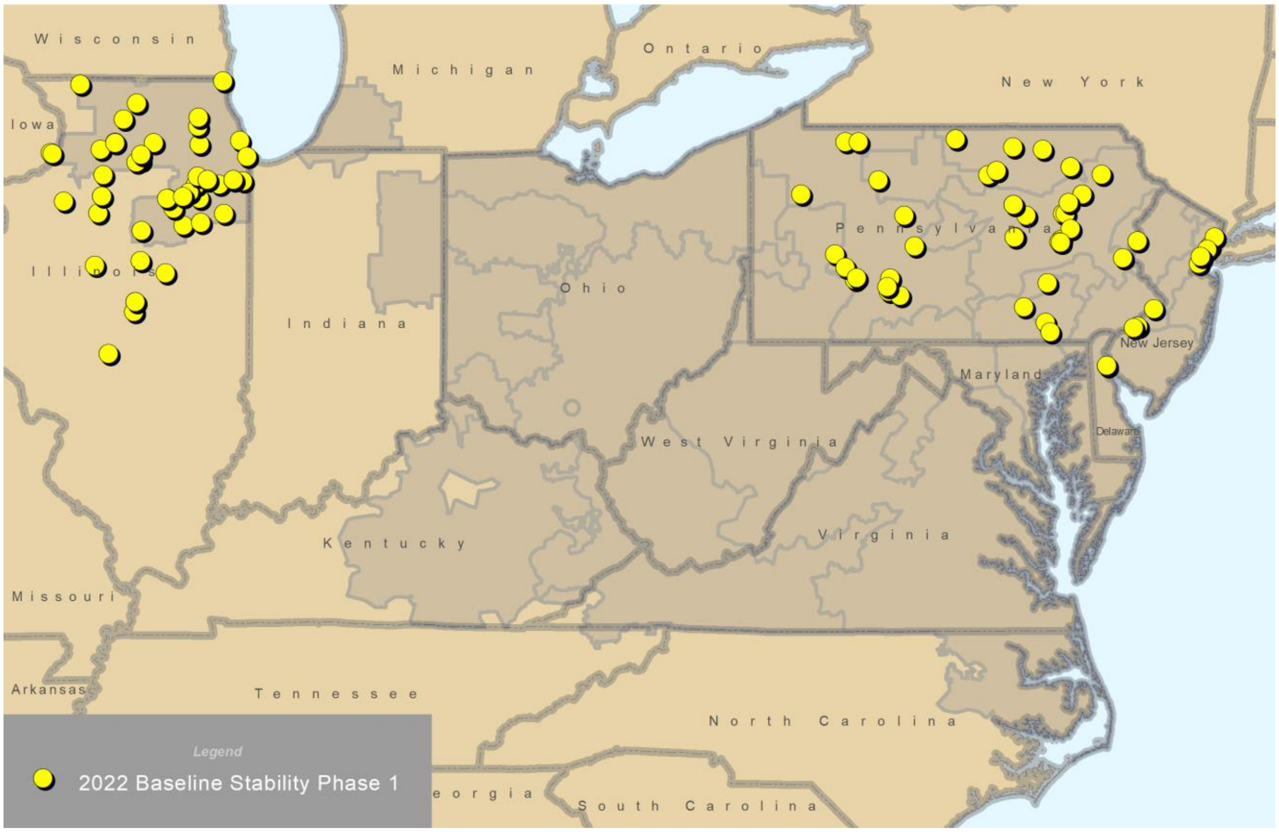
Once an overdutied breaker is confirmed breaker replacement and reinforcements along with cost estimates are determined. Breaker replacements and reinforcements, along with a schedule for implementation, were presented at monthly TEAC stakeholder meetings and are contained in the results section of this document.

Stability Assessment

PJM performs multiple tiers of analysis to ensure the system will remain stable and have satisfactory dynamic performance for disturbances that are consistent with Table 1 of the NERC TPL-001-5.1 standards. Collectively, the studies performed assess system dynamic performance over a wide range of load levels. Whenever system dynamic performance does not meet criteria, appropriate reinforcements are incorporated in the system plans and design. These measures include the installation of PSS (Power System Stabilizer), Excitation system refinements, dynamic or static reactive supports for wind generation plants, relaying and breaker configuration modifications.

Stability Studies	2022 RTEP
Annual baseline stability analysis of 1/3 of existing stations	100
New Services Queue stability analysis	119
Total	**219**

Table 8. **Number of Generation Stations Studied for Stability as Part of the 2022 RTEP**


Wisconsin
Michigan
Ontario
New York
Iowa
Illinois
Indiana
Ohio
Pennsylvania
New Jersey
Maryland
Delaware
West Virginia
Virginia
Kentucky
Missouri
Arkansas
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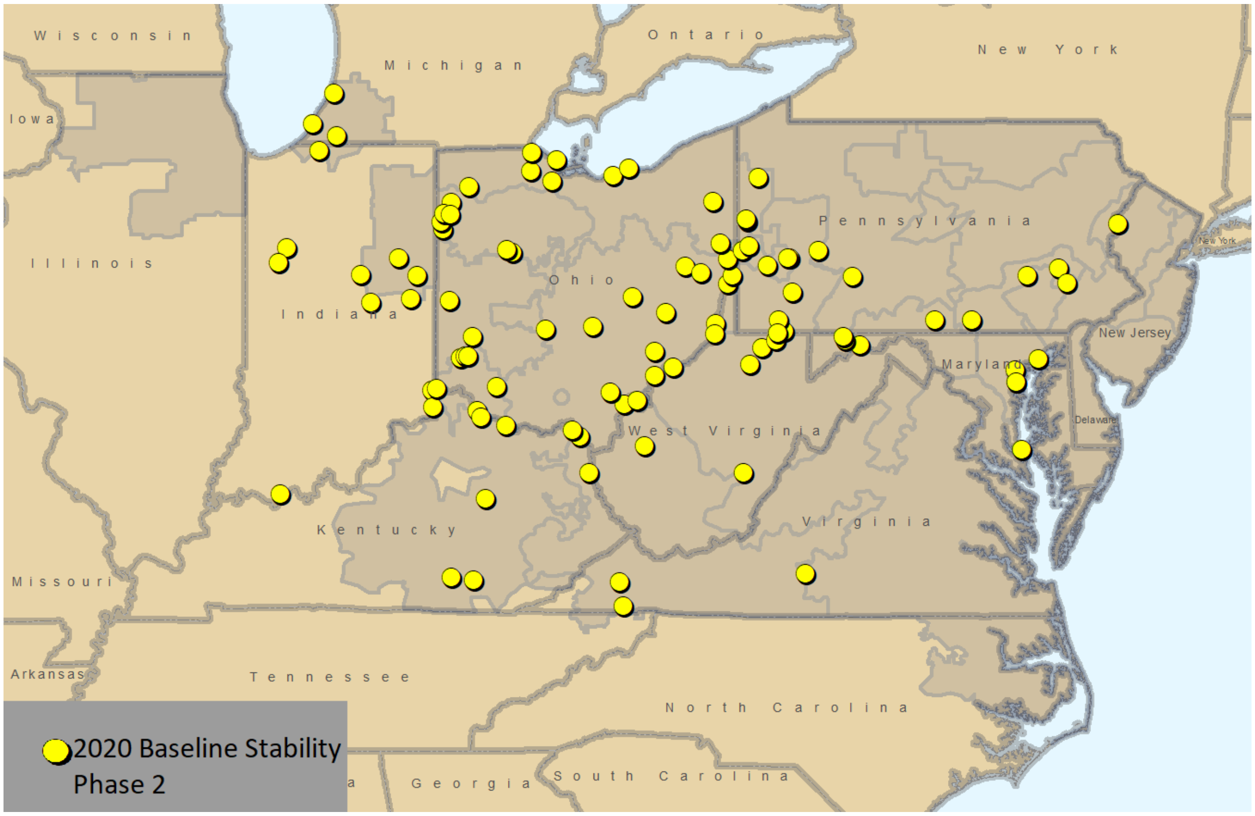
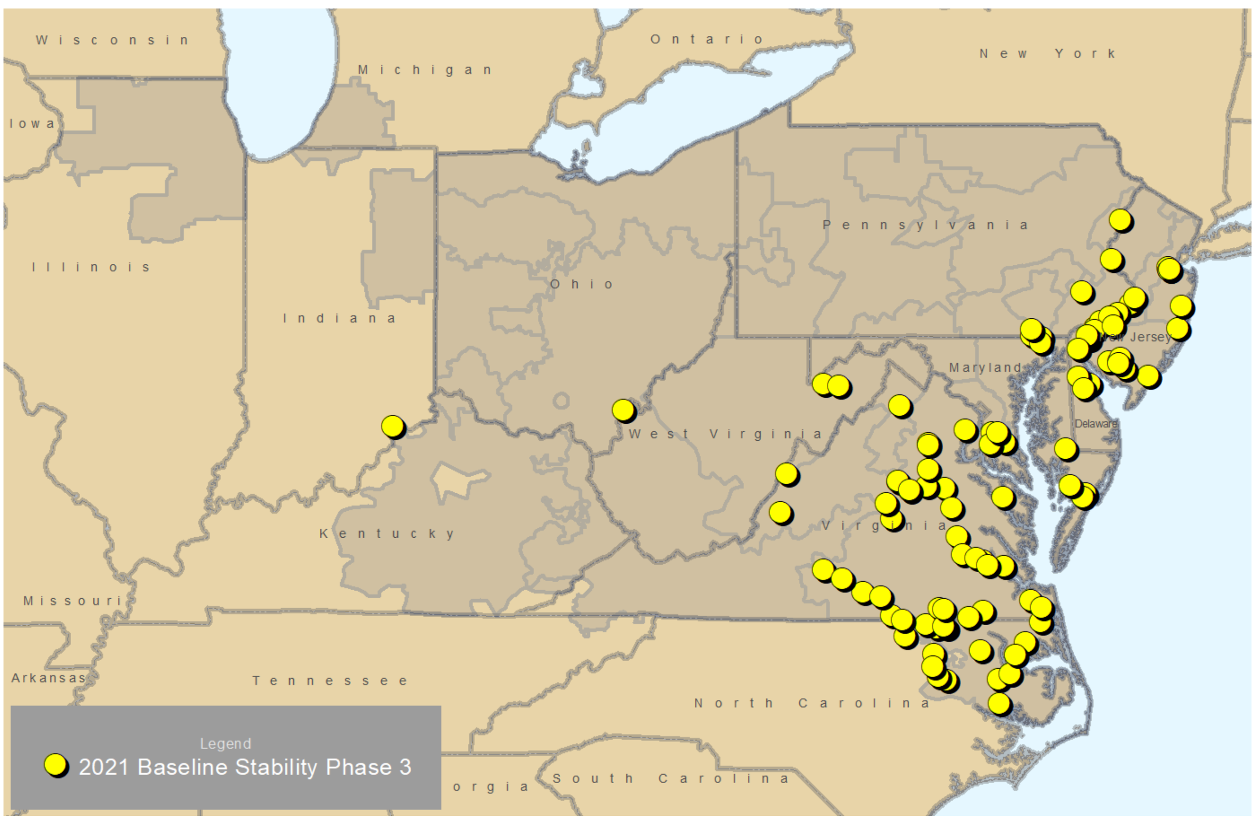
North Carolina
South Carolina
Georgia
Legend
2022 Baseline Stability Phase 1





Map 3. Three-Year Baseline Stability Cycle

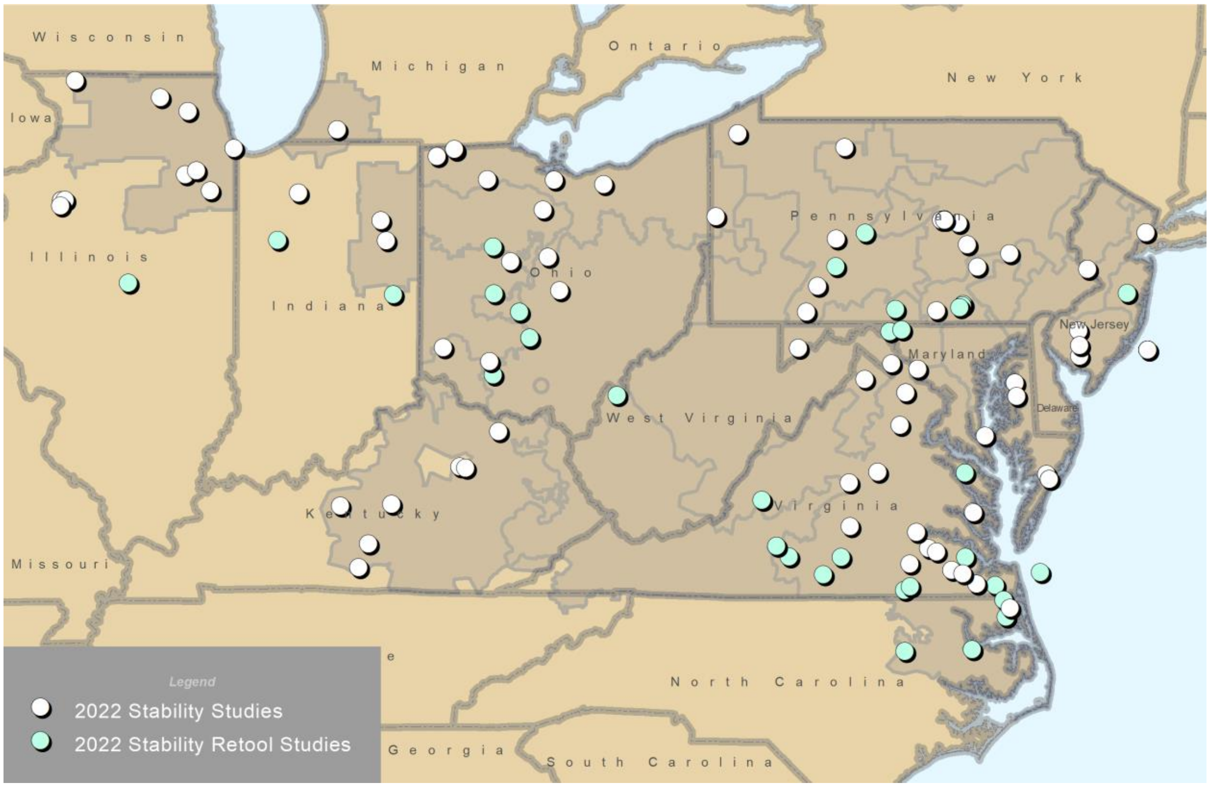
Good engineering practices as related to ensuring adequate system dynamic performance for the Bulk Electric System starts with proper base case models. PJM uses full ERAG MMWG models as a starting point for the dynamic stability analysis. All known transmission system as well as generation model changes available from approved system plans are incorporated. Step response simulations are conducted to detect and correct any modeling errors. Case initialization results are carefully analyzed to make sure that all the initial conditions are satisfactory. A 20 second no fault simulation is performed to ensure proper parameters are used in the models.

As part of the 2022 RTEP, several tiers of system stability analysis were performed. The first tier of this analysis includes PJM's annual comprehensive transient stability assessment of generating stations in the system. The annual analysis is performed for one third of the PJM footprint each year.

The annual baseline analysis includes an evaluation of the system under light load conditions as well as peak load conditions. PJM's rationale for choosing a light load case is that the light load system conditions are found to be the most challenging and severe from a transient stability perspective. The analysis also includes an evaluation of the system under summer peak loading (50/50) conditions.

PJM incorporates dynamic load models in peak load stability study to consider the behaviors of dynamic loads including induction motor loads. Various contingencies near load centers and generation stations are studied to ensure PJM system meets dynamic voltage recovery criteria as well as transient stability and damping criteria. In addition PJM evaluates the impact of dynamic load models on the system performance under a stressed power transfer condition across PJM eastern interface.

All PJM stability studies start by testing the system for a major transmission line switching operation. This examines the system under system normal conditions, as specified in TPL-001-5.1. The system response is verified by monitoring generating unit angle curves over a 20 second time frame. This test also provides the information to verify that all dynamic parameters are correctly initiating and responding properly. The stability test procedure includes a simulation of all applicable disturbances on all outlets of generating plants for multiple contingency (P3-P7) conditions. Additionally, all existing Remedial Action Schemes and their controlling actions are evaluated to ensure their effectiveness. A visual depiction of the coverage of the three latest baseline stability study cycles is shown in Map 3 above.



Map 4. Locations of proposed generation studied for stability in 2022

A second tier of PJM's stability assessment includes stability analysis for all proposed generator interconnections that exceed 20 MWs. New generator interconnections represent a significant modification to the system that could affect stability. In 2022 as part of the generation interconnection process, PJM completed transient stability analysis for 119 proposed generator interconnections within the PJM footprint. The locations of these proposed generators are shown in Map 4. In this analysis P0, P1, P2, P3, P4, P5, P6 and P7 conditions were analyzed for disturbances on all generating plant outlets as well as on transmission lines at a minimum, one bus away and more than one bus away from the point of interconnection if warranted by the system topology. In general, the analysis associated with proposed generation additions identifies any potential transient stability concerns among the generators electrically close to the portion of the system being modified. The proposed generation interconnections span all transmission system voltage levels and are widespread throughout PJM's footprint. Hence, the resulting stability analysis covers broad sections of PJM's Bulk Electric System. Solutions to the identified problems are developed and implemented prior to the proposed generation being placed in service.

As depicted in Map 4, the locations of the proposed generation additions are dispersed throughout the PJM footprint. In addition to monitoring the stability of the proposed generation, existing generation within several layers of the interconnection bus are also monitored. The transient stability analysis that is run for proposed generation interconnections not only ensures that the proposed unit will remain stable but also ensures that the transient stability of existing generation at nearby buses will not be compromised. It is important to note that the relative queue position is respected for this analysis, so that potential transient stability concerns are identified for the proposed unit and nearby existing generation. This ensures that violations will be allocated to the correct project based on queue order. The results of this analysis and any required upgrades or other mitigation measures needed, are identified in the System Impact Study for each New Service Request and are posted on the PJM web at the following address:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

A third tier of PJM's stability analysis includes ad-hoc studies that were performed in 2022 and occur annually to support PJM operations.

The transient stability analysis performed by PJM is done with forward looking cases representing the system as planned in future years. Given the continued load growth within the PJM footprint and the on-going transmission system reinforcements that are identified as part of the regional transmission expansion plan, the transient stability of the system is expected to continue to improve.

As a result of PJM integrating each of these tiers of stability assessment, PJM has ensured its compliance to all applicable standards including the assessments required by Table 1 of the NERC TPL-001-5.1 standard.

Based on PJM's knowledge and evaluation of current and forecasted system conditions, stability related upgrades would not require a lead time during the longer-term (year 6 and beyond) time frame, therefore stability analysis is not performed beyond 5 years out.

N-1-1 Stability Assessment

N-1-1 stability study for 75 plants was performed in 2022 RTEP. Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. PJM will continue to conduct N-1-1 stability study for selected plants on a rotating basis.

Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. No transient stability issues and damping violations were identified during the study.

NPIR Plant Specific Stability & Voltage Assessment

PJM has a total of 17 plants that fit the criteria for NPIR stability study. All 17 of those plants were studied as part of the 2022 RTEP. PJM will continue to study these 17 plants annually as part of future RTEPs. RAS or specific operation guidelines were implemented if necessary. Also, several nuclear plant NPIR studies were performed to verify and validate 2022 new dynamic models per TOs request.

In addition to the NPIR stability studied, PJM also performed NPIR voltage studies. As part of the 2022 RTEP, all 17 PJM nuclear plants were studied to ensure these plants comply with voltage monitoring criteria. Voltage magnitude and voltage drop were monitored under selected contingencies. Study results have been sent to NGOs.

Results of 2022 RTEP

The results of the baseline assessment for the 2022 – 2037 periods are presented below. This report, containing all corrective reinforcements, is provided to applicable regional entities annually in compliance with TPL-001-5.1. All of the upgrades below were presented to the TEAC stakeholder committee at one of the monthly TEAC stakeholder meetings in 2022.

PJM found the following areas of the PJM system to not meet reliability criteria during the assessment of the 2022 – 2037 study periods. These baseline upgrades were all identified as part of the 2022 RTEP. The list of required upgrades contains a summary of the system deficiencies and the associated action needed to achieve required system performance. This includes deficiencies identified in multiple sensitivity studies. The expected required in-service date of each upgrade is also included. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. System enhancements and corrective action plans are reviewed in subsequent annual studies for continued validity and implementation status of identified system facilities and operating procedures. Additionally, results include all recommended upgrades where short circuit analysis shows that existing breakers exceed their equipment rating.

In areas of the PJM system that did not meet reliability criteria under the revised P5 planning event, PJM will be working with its Transmission Owners on the identification of Corrective Action Plans (CAPs) to remediate the violations. Corrective reinforcements can include among other things the elimination of non-redundancy and/or inclusion of monitoring and reporting at a Control Center where applicable. The TPL-001-5 Implementation Plan provides an additional 24-month period for the development of CAPs (7/1/2025) following the effective date of the standard (7/1/2023). Upgrades identified and established in previous RTEP cycles are detailed in Appendix A.

The most up to date information concerning in-service dates and schedule for implementation can be found at the following link: https://www.pjm.com/planning/project-construction.aspx. With the exception of the baseline upgrades noted below, all other areas of the system were found to meet applicable reliability criteria.

1) Baseline Upgrade b3130.11

- Overview of Reliability Problem
    - Criteria Violation: Five Atlantic 34.5 kV breakers (BK1A, BK1B, BK3A and BK3B) overdutied
    - Criteria Test: Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Replace four Atlantic 34.5 kV breakers (BK1A, BK1B, BK3A and BK3B) with 63kA rated breakers and associated equipment
    - Upgrade In-Service Date: 9/30/2023
    - Estimated Upgrade Cost: $3.50M
    - Construction Responsibility: JCPL

2) Baseline Upgrade b3130.12

- Overview of Reliability Problem

- Criteria Violation: Six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) overduties
- Criteria Test: Short Circuit

- Overview of Reliability Solution
  - Description of Upgrade: Replace six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $4.20M
  - Construction Responsibility: JCPL

3) Baseline Upgrade b3350.1

- Overview of Reliability Problem
  - Criteria Violation: Bellefonte 69kV breakers JJ, C, I, AB, Z and G are overdutied.
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace overdutied 69 kV breakers C, G, I, Z, AB and JJ in place. The new 69 kV breakers to be rated at 3000 A 40 kA breakers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: AEP

4) Baseline Upgrade b3350.2

- Overview of Reliability Problem
  - Criteria Violation: Bellefonte 69kV breakers JJ, C, I, AB, Z and G are overdutied.
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade remote end relaying at Point Pleasant, Coalton and South Point 69 kV substations.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

5) Baseline Upgrade b3354

- Overview of Reliability Problem
  - Criteria Violation: 40 kV circuit breakers '42' and '43' at Bexley station are exceeding their maximum fault interuption rating (132% and 138%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breakers '42' and '43' at Bexley station with 3000 A, 40 kA 69 kV breakers (operated at 40 kV), slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023

- Estimated Upgrade Cost: $1.00M
- Construction Responsibility: AEP

6) Baseline Upgrade b3355

- Overview of Reliability Problem
  - Criteria Violation: 34.5 kV circuit breakers 'A' and 'B' at South Side Lima station are exceeding their maximum fault interuption rating (106% and 112%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breakers 'A' and 'B' at South Side Lima station with 1200 A, 25 kA 34.5 kV breakers, slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.75M
  - Construction Responsibility: AEP

7) Baseline Upgrade b3356

- Overview of Reliability Problem
  - Criteria Violation: 69 kV circuit breaker 'H' at West End Fostoria station is exceeding its maximum fault interuption rating (102%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breaker 'H' at West End Fostoria station with 3000 A, 40 kA 69 kV breaker, slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: AEP

8) Baseline Upgrade b3357

- Overview of Reliability Problem
  - Criteria Violation: 69 kV circuit breakers 'C', 'E', and 'L' at Natrium station are exceeding their maximum fault interuption rating (104% , 110%,and 104%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breakers 'C', 'E,' and 'L' at Natrium station with 3000 A, 40 kA 69 kV breakers, slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $1.50M
  - Construction Responsibility: AEP

9) Baseline Upgrade b3701

- Overview of Reliability Problem
  - Criteria Violation: Congestion
  - Criteria Test: Market Efficiency

- Overview of Reliability Solution
  - Description of Upgrade: Replace terminal equipment on the French's Mill-Junction JST1 138 kV line.
  - Upgrade In-Service Date: 11/1/2022
  - Estimated Upgrade Cost: $0.77M
  - Construction Responsibility: APS

10) Baseline Upgrade b3703

- Overview of Reliability Problem
  - Criteria Violation: Load loss for the loss of the two source to West Windsor
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a third 69 kV supply line from Penns Neck substation to the West Windsor substation.
  - Upgrade In-Service Date: 1/1/2023
  - Estimated Upgrade Cost: $1.05M
  - Construction Responsibility: PSEG

11) Baseline Upgrade b3704

- Overview of Reliability Problem
  - Criteria Violation: Transformer End of Life
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $13.36M
  - Construction Responsibility: PSEG

12) Baseline Upgrade b3705

- Overview of Reliability Problem
  - Criteria Violation: Transformer End of Life
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Replace existing 230/138 kV Athenia No. 220-1 transformer.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $13.04M
  - Construction Responsibility: PSEG

13) Baseline Upgrade b3706

- Overview of Reliability Problem
    - Criteria Violation: Transformer End of Life
    - Criteria Test:
- Overview of Reliability Solution
    - Description of Upgrade: Replace Fair Lawn 230/138kV transformer No. 220-1 with an existing O&M system spare at Burlington.
    - Upgrade In-Service Date: 6/1/2026
    - Estimated Upgrade Cost: $4.45M
    - Construction Responsibility: PSEG

14) Baseline Upgrade b3707.1

- Overview of Reliability Problem
    - Criteria Violation: Thermal Violation
    - Criteria Test:
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor approximately 0.57mi of 115kV Line #1021 from Harmony Village to Greys Point with 768 ACSS to achieve a summer emergency rating of 237MVA. The current conductor is 477 ACSR.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $1.89M
    - Construction Responsibility: Dominion

15) Baseline Upgrade b3707.2

- Overview of Reliability Problem
    - Criteria Violation: Thermal Violation
    - Criteria Test:
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor approximately 0.97mi of 115 kV Line #65 from Rappahanock to White Stone with 768 ACSS to achieve a summer emergency rating of 237MVA. The current conductor is 477 ACSR.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $1.89M
    - Construction Responsibility: Dominion

16) Baseline Upgrade b3708

- Overview of Reliability Problem
    - Criteria Violation: Light Load Overlplad on the Shawville 230/115/17.2 kV transformer #2A
    - Criteria Test: Generation Deliverability and N-1
- Overview of Reliability Solution

- Description of Upgrade: Replace the Shawville 230/115/17.2 kV transformer with a new Shawville 230/115 kV transformer and associated facilities. Replace the plant's No. 2B 115/17.2 kV transformer with a larger 230/17.2 kV transformer.
- Upgrade In-Service Date: 6/1/2026
- Estimated Upgrade Cost: $8.78M
- Construction Responsibility: PENELEC

17) Baseline Upgrade b3709

- Overview of Reliability Problem
  - Criteria Violation: Summer Shade-West Columbia 69 kV line section is overloaded
  - Criteria Test: Winter N-1, EKPC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Summer Shade-West Columbia 69 kV 0.19 miles of 266 conductor double circuit to 556 conductor.
  - Upgrade In-Service Date: 12/1/2025
  - Estimated Upgrade Cost: $0.19M
  - Construction Responsibility: EKPC

18) Baseline Upgrade b3710

- Overview of Reliability Problem
  - Criteria Violation: AA2-161 to Yukon two 138 kV lines
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Scope Change: During 2027 RTEP analysis, it was determined that the topology change caused the new AA2-161 to Charleroi line to be overloaded. The new overload is conductor limited and the cost to upgrade 12.8 miles is $32 M. As a result, the cost-effective solution is to alternatively reconductor Yukon to AA2-161 ckt 1 & 2 while maintaining the existing topology. The cost to upgrade is $10.64 M Expand the future AA2-161 138 kV six (6) breaker ring bus into an eleven (11) breaker substation with a breaker-and-a-half layout by constructing five (5) additional breakers and expanding the bus. Loop the Yukon - Charleroi #2 138 kV line into the future AA2-161 substation. Relocate terminals as necessary at AA2-161. Upgrade terminal equipment (wavetrap, substation conductor) and relays at Yukon, Huntingdon, Springdale, Charleroi, and the AA2-161 substation.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $10.64M
  - Construction Responsibility: APS

19) Baseline Upgrade b3711

- Overview of Reliability Problem
  - Criteria Violation: The Dresden 345/138 kV No. 81 transformer is overloaded
  - Criteria Test: Winter Generation Deliverability
- Overview of Reliability Solution

- Description of Upgrade: Install 345 kV bus tie 5-20 circuit breaker in the ring at Dresden station in series with existing bus tie 5-6.
- Upgrade In-Service Date: 12/1/2026
- Estimated Upgrade Cost: $4.26M
- Construction Responsibility: ComEd

20) Baseline Upgrade b3712

- Overview of Reliability Problem
  - Criteria Violation: Low voltage at Broughtentown, Tommy Gooch and Highland 69 kV
  - Criteria Test: Winter N-1, EKPC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Install a 28 MVAR cap bank at Liberty Junction 69 kV.
  - Upgrade In-Service Date: 12/1/2022
  - Estimated Upgrade Cost: $0.54M
  - Construction Responsibility: EKPC

21) Baseline Upgrade b3713

- Overview of Reliability Problem
  - Criteria Violation: Not Specified
  - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
  - Description of Upgrade: • Disconnect and remove five 138 kV bus tie lines and associated equipment from the Avon Lake Substation to the plant (800-B Bank, 8-AV-T Generator, 5-AV-T, 6-AV-T, and 7-AV-T).
    • Disconnect and remove one 345 kV bus tie line and associated equipment from the Avon substation to the plant (Unit 9).
    • Adjust relay settings at Avon Lake, Avon and Avondale substations.
    • Removal/rerouting of fiber to the plant and install new fiber between the 345 kV and 138 kV yards for the Q4-AV-BUS relaying.
    • Remove SCADA RTU, communications and associated equipment from plant.
  - Upgrade In-Service Date: 4/28/2023
  - Estimated Upgrade Cost: $2.50M
  - Construction Responsibility: ATSI

22) Baseline Upgrade b3714

- Overview of Reliability Problem
  - Criteria Violation: Overload Beaver to Hayes 345KV Line
  - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
  - Description of Upgrade: • Replace (4) 345 kV disconnect switches (D74, D92, D93, & D116) with 3000 A disconnect switches at Beaver.
    • Replace dual 954 45/7 ACSR SCCIR conductors between 5” pipe and WT with new, which meets or exceeds ratings of SN: 1542 MVA, SSTE: 1878 MVA at Beaver.
    • Replace 3000 SAC TL drop and 3000 SAC SCCIR between 954 ACSR and 5” bus

with new, which meets or exceeds ratings of SN: 1542 MVA, SSTE: 1878 MVA at Beaver.
• Upgrade BDD relays at breaker B-88 and B-115 at Beaver.
• Relay settings changes at Hayes.

- Upgrade In-Service Date: 6/1/2023
- Estimated Upgrade Cost: $2.10M
- Construction Responsibility: ATSI

23) Baseline Upgrade b3715.1

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: N2-SVM8, N2-SVM9, N2-SVM10, N2-SVM11, N2-SVM12, N2-SVM13, N2-SVM16, N2-SVM17, N2-SVM18, N2-SVM19, N2-SVM26, N2-SVM27, N2-SVD1, N2-SVD2, N2-SVD3, N2-SVD4, N2-SVD5, N2-SVD6, N2-SVD7, N2-SVD8, N2-SVD9, N2-SVD10, N2-SVD11, N2-SVD12, N2-SVD15, N2-SVD16
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: At the existing PPL Williams Grove substation, install a new 300 MVA 230/115 kV transformer.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $6.30M
  - Construction Responsibility: PPL

24) Baseline Upgrade b3715.2

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: N2-SVM8, N2-SVM9, N2-SVM10, N2-SVM11, N2-SVM12, N2-SVM13, N2-SVM16, N2-SVM17, N2-SVM18, N2-SVM19, N2-SVM26, N2-SVM27, N2-SVD1, N2-SVD2, N2-SVD3, N2-SVD4, N2-SVD5, N2-SVD6, N2-SVD7, N2-SVD8, N2-SVD9, N2-SVD10, N2-SVD11, N2-SVD12, N2-SVD15, N2-SVD16
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new ~3.4 mile 115 kV single circuit transmission line from Williams Grove to Allen substation.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $5.11M
  - Construction Responsibility: PPL

25) Baseline Upgrade b3715.3

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: N2-SVM8, N2-SVM9, N2-SVM10, N2-SVM11, N2-SVM12, N2-SVM13, N2-SVM16, N2-SVM17, N2-SVM18, N2-SVM19, N2-SVM26, N2-SVM27, N2-SVD1, N2-SVD2, N2-SVD3, N2-SVD4, N2-SVD5, N2-SVD6, N2-SVD7, N2-SVD8, N2-SVD9, N2-SVD10, N2-SVD11, N2-SVD12, N2-SVD15, N2-SVD16
  - Criteria Test: N-1-1
- Overview of Reliability Solution

- Description of Upgrade: Install a new Allen four breaker ring bus switchyard near the existing MetEd Allen substation on adjacent property presently owned by FirstEnergy. Terminate the Round Top-Allen and the Allen-PPGI (PPG Industries) 115 kV lines into the new switchyard.
- Upgrade In-Service Date: 6/1/2026
- Estimated Upgrade Cost: $6.41M
- Construction Responsibility: ME

26) Baseline Upgrade b3716

- Overview of Reliability Problem
  - Criteria Violation: Load loss for the loss of the two source to the Customer
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a third 69kV supply line from Totowa substation to the customer's substation
  - Upgrade In-Service Date: 1/1/2025
  - Estimated Upgrade Cost: $8.20M
  - Construction Responsibility: PSEG

27) Baseline Upgrade b3717.1

- Overview of Reliability Problem
  - Criteria Violation: Overload Collier - Erwin #1 and #2 138KV Lines, Forbes - Oakland 138KV Line, Carson - Oakland 138KV Line
  - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution
  - Description of Upgrade: Install a series reactor on Cheswick-Springdale 138 kV line
  - Upgrade In-Service Date: 12/31/2024
  - Estimated Upgrade Cost: $9.00M
  - Construction Responsibility: DL

28) Baseline Upgrade b3717.2

- Overview of Reliability Problem
  - Criteria Violation: Overload Collier - Erwin #1 and #2 138KV Lines, Forbes - Oakland 138KV Line, Carson - Oakland 138KV Line
  - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution
  - Description of Upgrade: Transmission Line Rearrangement:
    · Replacement of four structures and reconductor DLCO portion of Plum-Springdale 138 kV line.
    · Associated communication and relay setting changes at Plum and Cheswick.
  - Upgrade In-Service Date: 12/31/2024
  - Estimated Upgrade Cost: $15.00M

- Construction Responsibility: DL

29) Baseline Upgrade b3718.1

- Overview of Reliability Problem
  - Criteria Violation: Multiple overloads in the Data Center Alley area
  - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Install one 500/230kV 1440MVA transformer at a new substation called Wishing Star. Cut and extend 500 kV Line #546 (Brambleton-Mosby) and 500 kV Line #590 (Brambleton-Mosby) to the proposed Wishing Star substation. Lines to terminate in a 500 kV breaker and a half configuration.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

30) Baseline Upgrade b3718.10

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #9349 (Sojourner-Mars)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~1.61 miles of 230 kV line #9349 (Sojourner-Mars) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

31) Baseline Upgrade b3718.11

- Overview of Reliability Problem
  - Criteria Violation: Overduty Breakers
  - Criteria Test: GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade 4-500 kV breakers (total) to 63kA on either end of 500 kV Line #502 (Loudoun-Mosby)
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

32) Baseline Upgrade b3718.12

- Overview of Reliability Problem
  - Criteria Violation: Overduty Breakers
  - Criteria Test: GenDeliv Summer 2025
- Overview of Reliability Solution

- Description of Upgrade: Upgrade 4-500 kV breakers (total) to 63 kA on either end of 500 kV Line #584 (Loudoun-Mosby)
- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: Dominion

33) Baseline Upgrade b3718.13

- Overview of Reliability Problem
    - Criteria Violation: >300 MW load loss
    - Criteria Test: N-1-1 Summer 2025
- Overview of Reliability Solution
    - Description of Upgrade: Cut and loop 230 kV Line #2079 (Sterling Park-Dranesville) into Davis Drive substation and install two GIS 230 kV breakers.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

34) Baseline Upgrade b3718.14

- Overview of Reliability Problem
    - Criteria Violation: Multiple overloads in the Data Center Alley area
    - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
    - Description of Upgrade: Construct a new 230 kV transmission line for ~3.5 miles along with substation upgrades at Wishing Star and Mars. New right-of-way will be needed and will share same structures with the 500 kV line. New conductor to have a minimum summer normal rating of 1573 MVA.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

35) Baseline Upgrade b3718.2

- Overview of Reliability Problem
    - Criteria Violation: Multiple overloads in the Data Center Alley area
    - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
    - Description of Upgrade: Install one 500/230 kV 1440 MVA transformer at a new substation called Mars near Dulles International Airport.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

36) Baseline Upgrade b3718.3

- Overview of Reliability Problem
  - Criteria Violation: Multiple overloads in the Data Center Alley area
  - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 500 kV transmission line for ~ 3.5 miles along with substation upgrades at Wishing Star and Mars. New right-of-way will be needed and will share same structures with the line. New conductor to have a minimum summer normal rating of 4357 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

37) Baseline Upgrade b3718.4

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2214 (Buttermilk-Roundtable)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~0.62 miles of 230 kV line #2214 (Buttermilk-Roundtable) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

38) Baseline Upgrade b3718.5

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2031 (Enterprise-Greenway-Roundtable)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~1.52 miles of 230 kV line #2031 (Enterprise-Greenway-Roundtable) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

39) Baseline Upgrade b3718.6

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2186 (Enterprise-Shellhorn)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~0.64 miles of 230 kV line #2186 (Enterprise-Shellhorn) to achieve a summer rating of 1574 MVA.

- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: Dominion

40) Baseline Upgrade b3718.7

- Overview of Reliability Problem
    - Criteria Violation: Overload of 230 kV line #2188 (Lockridge-Greenway-Shellhorn)
    - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor ~2.17 miles of 230 kV line #2188 (Lockridge-Greenway-Shellhorn) to achieve a summer rating of 1574 MVA.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

41) Baseline Upgrade b3718.8

- Overview of Reliability Problem
    - Criteria Violation: Overload of 230 kV line #2223 (Lockridge-Roundtable)
    - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor ~0.84 miles of 230 kV line #2223 (Lockridge-Roundtable) to achieve a summer rating of 1574 MVA.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

42) Baseline Upgrade b3718.9

- Overview of Reliability Problem
    - Criteria Violation: Overload of 230 kV line #2218 (Sojourner-Runway-Shellhorn)
    - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor ~3.98 miles of 230 kV line #2218 (Sojourner-Runway-Shellhorn) to achieve a summer rating of 1574 MVA.
    - Upgrade In-Service Date: 6/1/2025
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

43) Baseline Upgrade b3719

- Overview of Reliability Problem
    - Criteria Violation: Spare equipment for Bergen series reactors (R and M), and short circuit issue on the Bergen bypass switches
    - Criteria Test: Spare equipment

- Overview of Reliability Solution
  - Description of Upgrade: Replace the two existing 1200A Bergen 138 kV Circuit Switchers with two (2) 138 kV Disconnect Switches to achieve a minimum summer normal device rating of 298 MVA and a minimum summer emergency rating of 454 MVA.
  - Upgrade In-Service Date: 12/31/2022
  - Estimated Upgrade Cost: $1.20M
  - Construction Responsibility: PSEG

44) Baseline Upgrade b3720

- Overview of Reliability Problem
  - Criteria Violation: The Abbe-Johnson 69 kV Line overload to 102.6% of its 92MVA/SE for P2-1 Contingecy, opening the Abbe-Johnson #1 69 kV Line breaker B-177 at Johnson
  - Criteria Test: Baseline Analysis
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Abbe-Johnson #2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. Replace three disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe. Replace one disconnect switch (A159) and line drops and revise relay settings at Johnson. Replace two MOAB disconnect switches (A4 & A5), one disconnect switch (D9), and line drops at Redman.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.90M
  - Construction Responsibility: ATSI

45) Baseline Upgrade b3721

- Overview of Reliability Problem
  - Criteria Violation: The Avery-Hayes 138 kV line overloads to 103.65% of its 282MVA/SE rating for P7 Contingecy, Outage of the Beaver-Hayes & Beaver-AD1-103 345 kV Lines
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 kcmil 26/7 ACSR.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.40M
  - Construction Responsibility: ATSI

46) Baseline Upgrade b3722

- Overview of Reliability Problem
  - Criteria Violation: the Darrah – Barnett 69 kV line is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the existing Darrah-Barnett 69 kV line, approximately

2.8 miles and replace a riser at Darrah station.

- Upgrade In-Service Date: 12/1/2027
- Estimated Upgrade Cost: $6.98M
- Construction Responsibility: AEP

47) Baseline Upgrade b3723

- Overview of Reliability Problem
  - Criteria Violation: the George Washington-Kammer 138 kV line is overloaded
  - Criteria Test: Summer Gen Deliv
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the George Washington – Kammer 138 kV circuit, except for 0.1-mile of previously-upgraded T-line outside each terminal station (6.7 miles of total upgrade scope). Remove the existing 6-wired steel lattice towers and supplement the right-of-way as needed.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $18.30M
  - Construction Responsibility: AEP

48) Baseline Upgrade b3724

- Overview of Reliability Problem
  - Criteria Violation: overload of Cloverdale-Ingersoll Rand-Monterey Avenue 69 kV line sections
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Install 138 kV circuit switcher on the high-side of Transformer #2 at Roanoke station (previously proposed as a portion of s2469.7, posted in 2021 AEP local plan).
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.10M
  - Construction Responsibility: AEP

49) Baseline Upgrade b3725

- Overview of Reliability Problem
  - Criteria Violation: The Elwood-Goodings Grove 345 kV line is overloaded
  - Criteria Test: Winter Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace the 1600A bus disconnect switch at Goodings Grove on L11622 Elwood-Goodings Grove 345 kV.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: ComEd

50) Baseline Upgrade b3726

- Overview of Reliability Problem
  - Criteria Violation: Voltage Drop violations at Black Oak 500 kV substation
  - Criteria Test: N-1-1 Summer and Winter
- Overview of Reliability Solution
  - Description of Upgrade: Install two new 500 kV breakers on the existing open SVC string to create a new bay position. Relocate & Reterminate facilities as necessary to move the 500 kV SVC into the new bay position and Install a 500 kV breaker on the 500/138 kV #3 transformer. Upgrade relaying at Black Oak substation.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $17.37M
  - Construction Responsibility: APS

51) Baseline Upgrade b3727

- Overview of Reliability Problem
  - Criteria Violation: The Fawkes-Duncannon Lane Tap 69 kV line (LGEE-EKPC tie line) is overloaded
  - Criteria Test: Winter N-1, EKPC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $8.50M
  - Construction Responsibility: EKPC

52) Baseline Upgrade b3728.1

- Overview of Reliability Problem
  - Criteria Violation: Overload on Peach Bottom - Conastone 500 kV for several contingencies
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade two Breaker bushings on the 500 kV Line 5012 (Conastone-Peach Bottom) at Conastone substation.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: BGE

53) Baseline Upgrade b3728.2

- Overview of Reliability Problem
  - Criteria Violation: Overload on Peach Bottom - Conastone 500 kV for several contingencies
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution

- Description of Upgrade: Replace 4 meters and bus work inside Peach Bottom substation on the 500 kV Line 5012 (Conastone-Peach Bottom).
- Upgrade In-Service Date: 12/1/2027
- Estimated Upgrade Cost: $3.80M
- Construction Responsibility: PECO

54) Baseline Upgrade b3729

- Overview of Reliability Problem
  - Criteria Violation: Overload Conowingo – Colora 230 kV kV circuit
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: To increase the Maximum Operating Temperature of DPL Circuit 22088 (Colora-Conowingo 230 kV), install cable shunts on each phase, on each side of four (4) dead-end structures and replace existing insulator bells.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.26M
  - Construction Responsibility: DPL

55) Baseline Upgrade b3730

- Overview of Reliability Problem
  - Criteria Violation: Overload on Lackawanna 500/230 kV transformer # T3
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.70M
  - Construction Responsibility: PPL

56) Baseline Upgrade b3731

- Overview of Reliability Problem
  - Criteria Violation: 40 kV circuit breaker 'J' at McComb station was identified as being overdutied.
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Replace 40kV breaker J at McComb station with a new 3000A 40kA breaker
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: AEP

57) Baseline Upgrade b3732

- Overview of Reliability Problem
    - Criteria Violation: e, low voltage and voltage-drop violations on the 34.5kV system between North Coshocton, Newcomerstown, and West New Philly stations, including Allegheny Pipe, East Coshocton, Gen Tire, Isleta, Morgan Run, North Coshocton, Newcomerstown, W Lafayette, Copper head 34.5kV buses
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
    - Description of Upgrade: Install a 6 MVAR, 34.5kV cap bank at Morgan Run station
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.37M
    - Construction Responsibility: AEP

58) Baseline Upgrade b3733

- Overview of Reliability Problem
    - Criteria Violation: The Summerhill-Willow Grove Switch 69kV line segment is overloaded
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the 1.8 mile 69kV T-line between Summerhill and Willow Grove Switch. Replace 4/0 ACSR conductor with 556 ACSR.
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $5.10M
    - Construction Responsibility: AEP

59) Baseline Upgrade b3734

- Overview of Reliability Problem
    - Criteria Violation: voltage-drop violations at Rarden switch, Otway station, Tick Ridge station, and Rarden station 69kV buses
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
    - Description of Upgrade: Install a 7.7 MVAR, 69kV cap bank at both Otway station and Rosemount station
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $1.73M
    - Construction Responsibility: AEP

60) Baseline Upgrade b3735

- Overview of Reliability Problem
    - Criteria Violation: Thermal overload on theArrowhead - Hillman Highway 69 kV line; Voltage Mag and Voltage Drop Violations at Arrowhead, Damascus,Hillman and South Abington 69kV buses
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution

- Description of Upgrade: Terminate the existing Broadford – Wolf Hills #1 138 kV line into Abingdon 138 kV Station. This line currently bypasses the existing Abingdon 138 kV Station; Install two new 138 kV circuit breakers on each new line exit towards Broadford and towards Wolf Hills #1; Install one new 138 kV circuit breaker on line exit towards South Abingdon for standard bus sectionalizing
- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $8.48M
- Construction Responsibility: AEP

61) Baseline Upgrade b3736.1

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Establish 69kV bus and new 69 kV line CB at Dorton substation.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $1.13M
  - Construction Responsibility: AEP

62) Baseline Upgrade b3736.10

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Henry Clay S.S Retirement:
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.30M
  - Construction Responsibility: AEP

63) Baseline Upgrade b3736.11

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Cedar Creek substation work
  - Upgrade In-Service Date: 12/1/2027

- Estimated Upgrade Cost: $0.44M
- Construction Responsibility: AEP

64) Baseline Upgrade b3736.12

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Breaks substation retire 46kV equipment:
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.25M
  - Construction Responsibility: AEP

65) Baseline Upgrade b3736.13

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire Pike 29 SS and Rob Fork SS
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.42M
  - Construction Responsibility: AEP

66) Baseline Upgrade b3736.14

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Serve Pike 29 and Rob Fork customers from nearby 34kV Distribution sources.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

67) Baseline Upgrade b3736.15

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses

  - (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Poor Bottom substation install
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

68) Baseline Upgrade b3736.16

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Henry Clay 46kV substation retirement
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

69) Baseline Upgrade b3736.17

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: New Draffin 69kV substation install
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

70) Baseline Upgrade b3736.18

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Draffin 46kV substation retirement
  - Upgrade In-Service Date: 12/1/2027

- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: AEP

71) Baseline Upgrade b3736.2

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: At Breaks substation, reuse 72kV breaker A as the new 69kV line breaker.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.71M
  - Construction Responsibility: AEP

72) Baseline Upgrade b3736.3

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild ~16.7 mi Dorton – Breaks 46kV line to 69kV
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $58.52M
  - Construction Responsibility: AEP

73) Baseline Upgrade b3736.4

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire ~17.2 mi Cedar Creek – Elwood 46kV circuit.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $11.15M
  - Construction Responsibility: AEP

74) Baseline Upgrade b3736.5

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses

(along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
- Criteria Test: AEP 715 critiera

- Overview of Reliability Solution
  - Description of Upgrade: Retire ~ 6.2 mi Henry Clay – Elwood 46kV line section.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $4.30M
  - Construction Responsibility: AEP

75) Baseline Upgrade b3736.6

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire Henry Clay 46 kV substation and replace with Poor Bottom 69 kV station. Install a new 0.7 mi double circuit extension to Poor Bottom 69kV.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $3.42M
  - Construction Responsibility: AEP

76) Baseline Upgrade b3736.7

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire Draffin substation and replace with a new substation. Install a new 0.25 mi double circuit extension to New Draffin substation.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $2.01M
  - Construction Responsibility: AEP

77) Baseline Upgrade b3736.8

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution

- Description of Upgrade: Remote End work at Jenkins substation
- Upgrade In-Service Date: 12/1/2027
- Estimated Upgrade Cost: $0.03M
- Construction Responsibility: AEP

78) Baseline Upgrade b3736.9

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Provide Transition fiber to Dorton, Breaks, Poor Bottom, Jenkins and New Draffin substations
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.41M
  - Construction Responsibility: AEP

79) Baseline Upgrade b3737.1

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation – Reconfigure substation.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $4.24M
  - Construction Responsibility: JCPL

80) Baseline Upgrade b3737.10

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Atlantic 230 kV substation – Convert to double-breaker double-bus.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $31.47M
  - Construction Responsibility: JCPL

81) Baseline Upgrade b3737.11

- Overview of Reliability Problem

    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: Freneau substation – Update relay settings on the Atlantic 230 kV line.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.03M
    - Construction Responsibility: JCPL

82) Baseline Upgrade b3737.12

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: Smithburg substation – Update relay settings on the Atlantic 230 kV line.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.03M
    - Construction Responsibility: JCPL

83) Baseline Upgrade b3737.13

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: Oceanview substation – Update relay settings on the Atlantic 230 kV lines.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.04M
    - Construction Responsibility: JCPL

84) Baseline Upgrade b3737.14

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: Red Bank substation – Update relay settings on the Atlantic 230 kV lines.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.04M
    - Construction Responsibility: JCPL

85) Baseline Upgrade b3737.15

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: South River substation – Update relay settings on the Atlantic 230 kV line.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.03M
    - Construction Responsibility: JCPL

86) Baseline Upgrade b3737.16

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: Larrabee substation – Update relay settings on the Atlantic 230 kV line.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.03M
    - Construction Responsibility: JCPL

87) Baseline Upgrade b3737.17

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: Atlantic substation – Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector station.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $4.95M
    - Construction Responsibility: JCPL

88) Baseline Upgrade b3737.18

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: G1021 (Atlantic-Smithburg) 230 kV upgrade.

- Upgrade In-Service Date: 6/1/2030
- Estimated Upgrade Cost: $9.68M
- Construction Responsibility: JCPL

89) Baseline Upgrade b3737.19

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: R1032 (Atlantic-Larrabee) 230 kV upgrade.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $14.50M
  - Construction Responsibility: JCPL

90) Baseline Upgrade b3737.2

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation – 230 kV equipment for direct connection.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $4.77M
  - Construction Responsibility: JCPL

91) Baseline Upgrade b3737.20

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: New Larrabee Collector station-Atlantic 230 kV line.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $17.07M
  - Construction Responsibility: JCPL

92) Baseline Upgrade b3737.21

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee-Oceanview 230 kV line upgrade.

- Upgrade In-Service Date: 6/1/2030
- Estimated Upgrade Cost: $6.00M
- Construction Responsibility: JCPL

93) Baseline Upgrade b3737.22

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $121.10M
  - Construction Responsibility: MAOD

94) Baseline Upgrade b3737.23

- Overview of Reliability Problem
  - Criteria Violation: The Richmond-Waneeta 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the underground portion of Richmond-Waneeta 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $16.00M
  - Construction Responsibility: AEC

95) Baseline Upgrade b3737.24

- Overview of Reliability Problem
  - Criteria Violation: The Cardiff-Lewis 138 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Cardiff-Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation.
  - Upgrade In-Service Date: 4/30/2028
  - Estimated Upgrade Cost: $0.10M
  - Construction Responsibility: AEC

96) Baseline Upgrade b3737.25

- Overview of Reliability Problem
    - Criteria Violation: The Lewis No. 2-Lewis No. 1 138 kV line is overloaded
    - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade Lewis No. 2-Lewis No. 1 138 kV by replacing its bus tie with 2000 A circuit breaker.
    - Upgrade In-Service Date: 4/30/2028
    - Estimated Upgrade Cost: $0.50M
    - Construction Responsibility: AEC

97) Baseline Upgrade b3737.26

- Overview of Reliability Problem
    - Criteria Violation: The Cardiff-New Freedom 230 kV line is overloaded
    - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade Cardiff-New Freedom 230 kV by modifying existing relay setting to increase relay limit.
    - Upgrade In-Service Date: 4/30/2028
    - Estimated Upgrade Cost: $0.30M
    - Construction Responsibility: AEC

98) Baseline Upgrade b3737.27

- Overview of Reliability Problem
    - Criteria Violation: The Clarksville-Lawrence 230 kV line is overloaded
    - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63.
    - Upgrade In-Service Date: 6/1/2029
    - Estimated Upgrade Cost: $11.45M
    - Construction Responsibility: JCPL

99) Baseline Upgrade b3737.28

- Overview of Reliability Problem
    - Criteria Violation: The Kilmer I-Lake Nelson I 230 kV line is overloaded
    - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor Kilmer I-Lake Nelson I 230 kV.
    - Upgrade In-Service Date: 6/1/2029

- Estimated Upgrade Cost: $4.42M
- Construction Responsibility: JCPL

100) Baseline Upgrade b3737.29

- Overview of Reliability Problem
  - Criteria Violation: Smithburg-Windsor 230 kV, Smithburg-Deans 500 kV lines and Smithburg 500/230 kV No. 2 transformer are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $206.48M
  - Construction Responsibility: JCPL

101) Baseline Upgrade b3737.3

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Lakewood Generator substation – Update relay settings on the Larrabee 230 kV line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: JCPL

102) Baseline Upgrade b3737.30

- Overview of Reliability Problem
  - Criteria Violation: The Smithburg 500/230 kV No. 1 transformer is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Add third Smithburg 500/230 kV transformer.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $13.40M
  - Construction Responsibility: JCPL

103) Baseline Upgrade b3737.31

- Overview of Reliability Problem
  - Criteria Violation: The Lake Nelson I-Middlesex 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution

- Description of Upgrade: Additional reconductoring required for Lake Nelson I-Middlesex 230 kV.
- Upgrade In-Service Date: 6/1/2029
- Estimated Upgrade Cost: $3.30M
- Construction Responsibility: JCPL

104) Baseline Upgrade b3737.32

- Overview of Reliability Problem
  - Criteria Violation: The Larrabee-Smithburg No. 1 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Larrabee-Smithburg No. 1 230 kV.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $44.77M
  - Construction Responsibility: JCPL

105) Baseline Upgrade b3737.33

- Overview of Reliability Problem
  - Criteria Violation: The Red Oak A-Raritan River 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor Red Oak A-Raritan River 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $11.05M
  - Construction Responsibility: JCPL

106) Baseline Upgrade b3737.34

- Overview of Reliability Problem
  - Criteria Violation: The Red Oak B-Raritan River 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor Red Oak B-Raritan River 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $3.90M
  - Construction Responsibility: JCPL

107) Baseline Upgrade b3737.35

- Overview of Reliability Problem
  - Criteria Violation: The Raritan River-Kilmer I 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability

- Overview of Reliability Solution
  - Description of Upgrade: Reconductor small section of Raritan River-Kilmer I 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.20M
  - Construction Responsibility: JCPL

108) Baseline Upgrade b3737.36

- Overview of Reliability Problem
  - Criteria Violation: The Raritan River-Kilmer W 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace substation conductor at Kilmer and reconductor Raritan River-Kilmer W 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $25.88M
  - Construction Responsibility: JCPL

109) Baseline Upgrade b3737.37

- Overview of Reliability Problem
  - Criteria Violation: The Hope Creek-LS Power Cable Ease 230 kV No. 1 and No. 2 and LS Power Cable East-LS Power Silver Run 230 kV lines are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $61.20M
  - Construction Responsibility: LS POWER

110) Baseline Upgrade b3737.38

- Overview of Reliability Problem
  - Criteria Violation: The Linden-Tosco 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV Switching station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $24.92M
  - Construction Responsibility: PSEG

111) Baseline Upgrade b3737.39

- Overview of Reliability Problem
    - Criteria Violation: The Linden-Tosco 230 kV line is overloaded
    - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work.
    - Upgrade In-Service Date: 12/31/2027
    - Estimated Upgrade Cost: $5.53M
    - Construction Responsibility: PSEG

112) Baseline Upgrade b3737.4

- Overview of Reliability Problem
    - Criteria Violation: N/A
    - Criteria Test: N/A
- Overview of Reliability Solution
    - Description of Upgrade: B54 Larrabee-South Lockwood 34.5 kV line transfer.
    - Upgrade In-Service Date: 6/1/2029
    - Estimated Upgrade Cost: $0.31M
    - Construction Responsibility: JCPL

113) Baseline Upgrade b3737.40

- Overview of Reliability Problem
    - Criteria Violation: The Windsor-Clarksville 230 kV line is overloaded
    - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Windsor to Clarksville subproject: Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV.
    - Upgrade In-Service Date: 6/1/2029
    - Estimated Upgrade Cost: $4.28M
    - Construction Responsibility: JCPL

114) Baseline Upgrade b3737.41

- Overview of Reliability Problem
    - Criteria Violation: The Windsor-Clarksville 230 kV line is overloaded
    - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
    - Description of Upgrade: Windsor to Clarksville subproject: Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV as necessary to create a paired

conductor path between Clarksville and JCPL East Windsor Switch 230 kV.
- Upgrade In-Service Date: 6/1/2029
- Estimated Upgrade Cost: $1.49M
- Construction Responsibility: PSEG

115) Baseline Upgrade b3737.42

- Overview of Reliability Problem
  - Criteria Violation: The Kilmer-Lake Nelson I 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade inside plant equipment at Lake Nelson I 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $3.80M
  - Construction Responsibility: PSEG

116) Baseline Upgrade b3737.43

- Overview of Reliability Problem
  - Criteria Violation: The Kilmer-Lake Nelson W 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.16M
  - Construction Responsibility: PSEG

117) Baseline Upgrade b3737.44

- Overview of Reliability Problem
  - Criteria Violation: The Lake Nelson-Middlesex-Greenbrook W 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.12M
  - Construction Responsibility: PSEG

118) Baseline Upgrade b3737.45

- Overview of Reliability Problem
  - Criteria Violation: The Gilbert-Springfield 230 kV line is overloaded

    - Criteria Test: Winter Generator Deiverability
  - Overview of Reliability Solution
    - Description of Upgrade: Reconductor 0.33 miles of PPL's portion of the Gilbert-Springfield 230 kV line.
    - Upgrade In-Service Date: 6/1/2030
    - Estimated Upgrade Cost: $0.38M
    - Construction Responsibility: PPL

119) Baseline Upgrade b3737.46

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.55M
  - Construction Responsibility: BGE

120) Baseline Upgrade b3737.47

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high side and five low side breakers in ring bus configuration).
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $76.27M
  - Construction Responsibility: Transource

121) Baseline Upgrade b3737.48

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Build a new North Delta-Graceton 230 kV line by rebuilding

6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for PECO's portion of the line rebuild which is 4.1 miles.
- Upgrade In-Service Date: 6/1/2029
- Estimated Upgrade Cost: $18.82M
- Construction Responsibility: PECO

122) Baseline Upgrade b3737.49

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Bring the Cooper-Graceton 230 kV line “in and out” of North Delta by constructing a new double-circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.56M
  - Construction Responsibility: PECO

123) Baseline Upgrade b3737.5

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee Collector station-Larrabee 230 kV new line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $7.52M
  - Construction Responsibility: JCPL

124) Baseline Upgrade b3737.50

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Bring the Peach Bottom-Delta Power Plant 500 kV line “in and out” of North Delta by constructing a new Peach Bottom-North Delta 500 kV (0.3 miles) cut-in and cut-out lines.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.56M

- Construction Responsibility: PECO

125) Baseline Upgrade b3737.51

- Overview of Reliability Problem
  - Criteria Violation: Four Peach Bottom circuit breakers "205", "235", "225" and "255" are overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $5.60M
  - Construction Responsibility: PECO

126) Baseline Upgrade b3737.52

- Overview of Reliability Problem
  - Criteria Violation: One Conastone circuit breakers "B4" is overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.30M
  - Construction Responsibility: BGE

127) Baseline Upgrade b3737.56

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild which is 2.16 miles.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $9.92M
  - Construction Responsibility: BGE

128) Baseline Upgrade b3737.6

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A

- Overview of Reliability Solution
  - Description of Upgrade: Larrabee Collector station-Smithburg No. 1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $150.35M
  - Construction Responsibility: JCPL

129) Baseline Upgrade b3737.7

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $62.85M
  - Construction Responsibility: JCPL

130) Baseline Upgrade b3737.8

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Smithburg substation 500 kV expansion to 4-breaker ring.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $68.25M
  - Construction Responsibility: JCPL

131) Baseline Upgrade b3737.9

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation upgrades.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.86M
  - Construction Responsibility: JCPL

132) Baseline Upgrade b3738

- Overview of Reliability Problem

    - Criteria Violation: Charleroi - Dry Run
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Charleroi - Dry Run 138 kV Line: Replace Limiting Terminal Equipment
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.38M
    - Construction Responsibility: APS

133) Baseline Upgrade b3739

- Overview of Reliability Problem
    - Criteria Violation: Dry Run - Mitchell
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Dry Run - Mitchell 138 kV Line: Replace Limiting Terminal Equipment
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.40M
    - Construction Responsibility: APS

134) Baseline Upgrade b3740

- Overview of Reliability Problem
    - Criteria Violation: Glen Falls - Bridgeport
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Glen Falls - Bridgeport 138 kV Line: Replace Limiting Terminal Equipment
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $1.88M
    - Construction Responsibility: APS

135) Baseline Upgrade b3741

- Overview of Reliability Problem
    - Criteria Violation: Yukon - Charleroi 1
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Yukon - Charleroi No.1 138 kV Line: Replace Limiting Terminal Equipment
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.70M
    - Construction Responsibility: APS

136) Baseline Upgrade b3742

- Overview of Reliability Problem
  - Criteria Violation: Yukon - Charleroi 2
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Yukon - Charleroi No.2 138 kV Line: Replace Limiting Terminal Equipment
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.45M
  - Construction Responsibility: APS

137) Baseline Upgrade b3743

- Overview of Reliability Problem
  - Criteria Violation: Cherry Run - Harmony Jct Tap
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: At Bedington Substation: Replace substation conductor, wavetrap, CT's and upgrade relaying
At Cherry Run Substation: Replace substation conductor, wavetrap, CT's, disconnect switches, circuit breaker and upgrade relaying
At Marlowe: Replace substation conductor, wavetrap, CT's and upgrade relaying.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $4.66M
  - Construction Responsibility: APS

138) Baseline Upgrade b3744

- Overview of Reliability Problem
  - Criteria Violation: Shanor - Krendale
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace one span of 1272 ACSR from Krendale substation to structure 35 (~630 ft)
Replace one span of 1272 ACSR from Shanor Manor to structure 21 (~148 ft)
Replace 1272 ACSR risers at Krendale & Shanor Manor Substations
Replace 1272 ACSR Substation Conductor at Krendale Substation
Replace relaying at Krendale Substation
Revise Relay Settings at Butler & Shanor Manor Substations.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.75M
  - Construction Responsibility: APS

139) Baseline Upgrade b3745

- Overview of Reliability Problem
    - Criteria Violation: Carbon Center Substation
    - Criteria Test: Baseline
- Overview of Reliability Solution
    - Description of Upgrade: Carbon Center Substation - Install Redundant Relaying
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.57M
    - Construction Responsibility: APS

140) Baseline Upgrade b3746

- Overview of Reliability Problem
    - Criteria Violation: Meadow Brook Substation
    - Criteria Test: Baseline
- Overview of Reliability Solution
    - Description of Upgrade: Meadow Brook Substation - Install Redundant Relaying
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.21M
    - Construction Responsibility: APS

141) Baseline Upgrade b3747

- Overview of Reliability Problem
    - Criteria Violation: Bedington Substation
    - Criteria Test: Baseline
- Overview of Reliability Solution
    - Description of Upgrade: Bedington Substation - Install Redundant Relaying
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.28M
    - Construction Responsibility: APS

142) Baseline Upgrade b3748

- Overview of Reliability Problem
    - Criteria Violation: The Jefferson – Clifty 345KV line is overload
    - Criteria Test: Summer Gen Deliv
- Overview of Reliability Solution
    - Description of Upgrade: Replace four Clifty Creek 345 kV 3000A switches with 5000 A 345 kV switches.
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.85M
    - Construction Responsibility: AEP

143) Baseline Upgrade b3749

- Overview of Reliability Problem
    - Criteria Violation: Overload on New Church – Piney 138 kV circuit
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the New Church - Piney Grove 138 kV line
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $63.00M
    - Construction Responsibility: DPL

144) Baseline Upgrade b3750

- Overview of Reliability Problem
    - Criteria Violation: Overload on the Seward – Florence 115 kV
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Upgrade Seward Terminal Equipment of the Seward-Blairsville 115 kV Line to increase the line rating such that the Transmission Line conductor is the limiting component.
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.43M
    - Construction Responsibility: PENELEC

145) Baseline Upgrade b3751

- Overview of Reliability Problem
    - Criteria Violation: Overload on Roxbury to the AE1-071 115 kV
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild 6.4 miles of the Roxbury - Shade Gap 115 kV line from Roxbury to the AE1-071 115 kV ring bus with single circuit 115 kV construction
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $15.03M
    - Construction Responsibility: PENELEC

146) Baseline Upgrade b3752

- Overview of Reliability Problem
    - Criteria Violation: Overload on Shade Gap - AE1-071 115 kV
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild 7.2 miles of the Shade Gap - AE1-071 115 kV line section of the Roxbury - Shade Gap 115 kV line

- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $17.43M
- Construction Responsibility: PENELEC

147) Baseline Upgrade b3753

- Overview of Reliability Problem
  - Criteria Violation: Overload on the Tyrone North 115 /46 kV transformer #1
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Tyrone North 115 /46 kV transformer with a new standard 75 MVA top rated bank and upgrade the entire terminal to minimum 100 MVA capability for both SN and SE rating
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $2.82M
  - Construction Responsibility: PENELEC

148) Baseline Upgrade b3754

- Overview of Reliability Problem
  - Criteria Violation: Low voltage violation in the Belleville 46 kV vicinity
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: At Maclane tap: Construct a new three breaker ring bus to tie into the Warrior Ridge - Belleville 46 kV D line and the 1LK line
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.09M
  - Construction Responsibility: PENELEC

149) Baseline Upgrade b3755

- Overview of Reliability Problem
  - Criteria Violation: Low voltage and voltage drop violation at Locust 69 kV station
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Convert Locust Street 69kV from a Straight Bus to a Ring Bus.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $30.00M
  - Construction Responsibility: PSEG

150) Baseline Upgrade b3756

- Overview of Reliability Problem
  - Criteria Violation: Voltage drop violation at Maple Shade 69 kV
  - Criteria Test: FERC Form 715

- Overview of Reliability Solution
    - Description of Upgrade: Convert Maple Shade 69kV from a Straight Bus to a Ring Bus
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $33.90M
    - Construction Responsibility: PSEG

151) Baseline Upgrade b3757

- Overview of Reliability Problem
    - Criteria Violation: Voltage drop violation at Medford and South Hampton 69 kV stations
    - Criteria Test: FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Convert existing Medford 69kV Straight bus to Seven breaker ring bus, construct a new 69kV line from Medford to the Mount Holly station, and install a capacitor bank at Medford
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $78.70M
    - Construction Responsibility: PSEG

152) Baseline Upgrade b3758

- Overview of Reliability Problem
    - Criteria Violation: Voltage drop violation at Harts Lane station
    - Criteria Test: FERC Form 715
- Overview of Reliability Solution
    - Description of Upgrade: Construct a new 69kV line from 14th Street to Harts Lane
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $34.40M
    - Construction Responsibility: PSEG

153) Baseline Upgrade b3759

- Overview of Reliability Problem
    - Criteria Violation: Overload of 115kV Line #23 from Oak Ridge - AC2-079
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Reconductor approximately 10.5 miles of 115kV Line #23 segment from Oak Ridge to AC2-079 Tap to minimum emergency ratings of 393 MVA Summer / 412 MVA Winter
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $23.50M
    - Construction Responsibility: Dominion

154) Baseline Upgrade b3760

- Overview of Reliability Problem
  - Criteria Violation: Interregional TMEP Analysis
  - Criteria Test: 2022 CSP Study
- Overview of Reliability Solution
  - Description of Upgrade: At Powerton Sub, replace most limiting facility 800A wave trap with 2000A wave trap on the Powerton-Towerline 138kV line terminal
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.20M
  - Construction Responsibility: ComEd

155) Baseline Upgrade b3761

- Overview of Reliability Problem
  - Criteria Violation: Carbon Center to Elko
  - Criteria Test: Baseline
- Overview of Reliability Solution
  - Description of Upgrade: Install 138 kV Breaker on the Ridgway 138/46 kV #2 Transformer
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.10M
  - Construction Responsibility: APS

156) Baseline Upgrade b3762

- Overview of Reliability Problem
  - Criteria Violation: The Fawkes-Duncannon Lane Tap 69 kV line (LGEE-EKPC tie line) is overloaded
  - Criteria Test: EKPC 715 Criteria, N-1
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $8.50M
  - Construction Responsibility: EKPC

157) Baseline Upgrade b3763

- Overview of Reliability Problem
  - Criteria Violation: Jug Street 138kV breakers M, N,BC,BF, BD, BE,D, H, J, L, BG, BH, BJ, BK are overdutied.
  - Criteria Test: short circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Jug Street 138kV breakers M, N, BC, BF, BD, BE, D, H, J, L, BG, BH, BJ, BK with 80KA breakers

- Upgrade In-Service Date: 6/1/2024
- Estimated Upgrade Cost: $14.00M
- Construction Responsibility: AEP

158) Baseline Upgrade b3764

- Overview of Reliability Problem
  - Criteria Violation: Hyatt 138kV breakers AB1 and AD1 are overdutied.
  - Criteria Test: short circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Hyatt 138kV breakers AB1 and AD1 with 63kA breakers
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: AEP

159) Baseline Upgrade b3765

- Overview of Reliability Problem
  - Criteria Violation: High voltage at Mainesburg
  - Criteria Test: Spare Equipment
- Overview of Reliability Solution
  - Description of Upgrade: Purchase one 80 MVAR 345 kV spare reactor, to be located at the Mainesburg station.
  - Upgrade In-Service Date: 12/1/2022
  - Estimated Upgrade Cost: $6.44M
  - Construction Responsibility: PENELEC

160) Baseline Upgrade b3766.1

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: Hayes – New Westville 138 kV line: Build ~0.19 miles of 138 kV line to the Indiana/ Ohio State line to connect to AES's line portion of the Hayes – New Westville 138 kV line with the conductor size 795 ACSR26/7 Drake. The following cost includes the line construction and ROW.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.38M
  - Construction Responsibility: AEP

161) Baseline Upgrade b3766.2

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload

- Criteria Test: Summer/Winter Gen deliv

- Overview of Reliability Solution
  - Description of Upgrade: Hayes – Hodgin 138 kV line: Build ~0.05 miles of 138 kV line with the conductor size 795 ACSR26/7 Drake. The following cost includes the line construction, ROW, and fiber.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.22M
  - Construction Responsibility: AEP

162) Baseline Upgrade b3766.3

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: Hayes 138 kV: Build a new 4-138 kV circuit breaker ring bus. The following cost includes the new station construction, property purchase, metering, station fiber and the College Corner –Randolph 138 kV line connection.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $7.44M
  - Construction Responsibility: AEP

163) Baseline Upgrade b3766.4

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: New Westville – AEP Hodgin 138kV Line: Construct a 138kV 1.86-mile single circuit transmission line. This transmission line will help loop the radial load served at New Westville as part of the overall effort to improve reliability in this area. Also, it provides a source to feed New Westville load while the 138kV tie built back into the AES Ohio system
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $3.70M
  - Construction Responsibility: Dayton

164) Baseline Upgrade b3766.5

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: New Westville – West Manchester 138kV Line: Construct a new approximate 11-mile single circuit 138kV line from New Westville to the Lewisburg tap off 6656. Convert a portion of 6656 West Manchester – Garage Rd 69kV line

between West Manchester - Lewisburg to 138kV operation (circuit is built to 138kV). This will utilize part of the line already built to 138kV and will take place of the 3302 that currently feeds New Westville. The 3302 line will be retired as part of this project.

- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $16.00M
- Construction Responsibility: Dayton

165) Baseline Upgrade b3766.6

- Overview of Reliability Problem
    - Criteria Violation: the College Corner – Collinsville 138KV line is overload
    - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
    - Description of Upgrade: West Manchester Substation: The West Manchester Substation will be expanded to a double bus double breaker design where AES Ohio will install one 138kV circuit breaker, a 138/69kV transformer, and eight new 69kV circuit breakers. These improvements will improve help improve a non-standard bus arrangement where there is only one bus tie today and will improve the switching arrangement for the West Sonora Delivery Point.
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $9.90M
    - Construction Responsibility: Dayton

166) Baseline Upgrade b3768

- Overview of Reliability Problem
    - Criteria Violation: Overload on Germantown - Straban - Lincoln 115 kV
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild/Reconductor the Germantown - Lincoln 115 kV Line. Approximately 7.6 miles. Upgrade limiting terminal equipment at Lincoln, Germantown and Straban
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $17.36M
    - Construction Responsibility: ME

167) Baseline Upgrade b3769

- Overview of Reliability Problem
    - Criteria Violation: Overload on TMI 500/230 kV transformer
    - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
    - Description of Upgrade: Install second TMI 500/230kV Transformer with additional 500 and 230 bus expansions
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $30.19M

- Construction Responsibility: ME

168) Baseline Upgrade b3770

- Overview of Reliability Problem
  - Criteria Violation: Overload on Graceton - Brunner Island 230 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild 1.4 miles of existing single circuit 230 kV tower line between BGE's Graceton substation to the Brunner Island PPL tie-line at the MD/PA state line to double circuit steel pole line with one (1) circuit installed to uprate 2303 circuit
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $8.40M
  - Construction Responsibility: BGE

169) Baseline Upgrade b3771

- Overview of Reliability Problem
  - Criteria Violation: Overload on Conastone - North West 230 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor two (2) 230 kV circuits from Conastone to Northwest #2
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $37.76M
  - Construction Responsibility: BGE

170) Baseline Upgrade b3772

- Overview of Reliability Problem
  - Criteria Violation: Overload on Messick Rd - Morgan 238 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor 27.3 miles of the Messick Road - Morgan 138 kV Line from 556 ACSR to 954 ACSR. At Messick Road Substation: Replace 138 kV wave trap, circuit breaker, CT's, disconnect switch, and substation conductor and upgrade relaying. At Morgan Substation: Upgrade Relaying
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $49.23M
  - Construction Responsibility: APS

171) Baseline Upgrade b3773

- Overview of Reliability Problem

- Criteria Violation: Low voltage in the McConnellsburg 138kV vicinity
- Criteria Test: N-1-1

- Overview of Reliability Solution
  - Description of Upgrade: McConnellsburg 138 kV Susbtation: Install 33 MVAR switched capacitor, 138 kV Breaker, and associated relaying
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $3.05M
  - Construction Responsibility: APS

172) Baseline Upgrade b3774

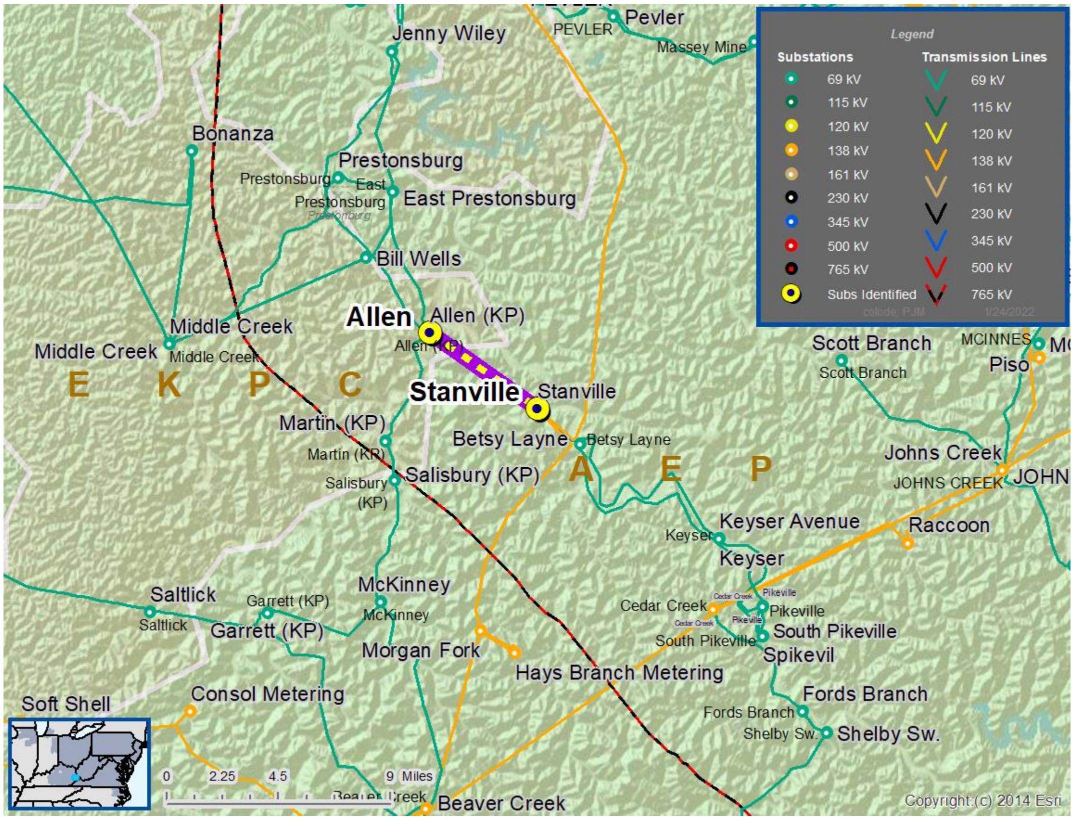
- Overview of Reliability Problem
  - Criteria Violation: Overload on Brunner Island - Yorkanna 230 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade terminal equipment at Brunner Island (on the Brunner Island - Yorkana 230 kV circuit)
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $2.50M
  - Construction Responsibility: PPL

Baseline Project b3353: Allen 46 kV Station Rebuild Baseline Conversion

AEP Transmission Zone

In the 2026 RTEP winter case, the Stanville-Allen 46 kV line section is overloaded for multiple N-1 outage combination.

Map 1. **b3353: Allen 46 kV Area**



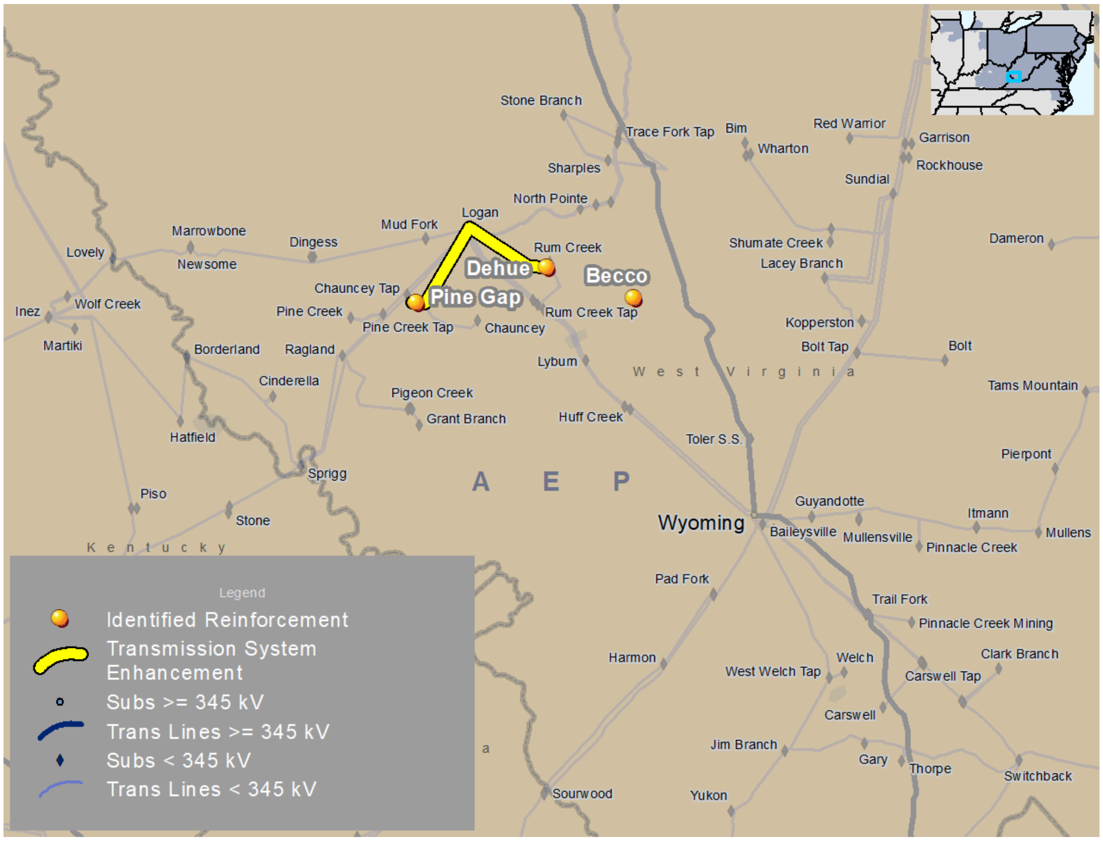
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is an existing supplemental project that has been converted to a baseline. The supplemental project scope, slated to be in service by the end of 2023, addresses the severe flooding issue and obsolete equipment at the existing Allen station. The supplemental project was converted to a baseline as it addresses both the supplemental needs identified through the M-3 process and the identified reliability needs in the 2026 RTEP winter case. The proposed conversion of the supplemental project to a baseline does not add any cost to the RTEP. The solution is to rebuild the Allen 46 kV station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7-foot concrete platforms and a control house raised by a 10-foot platform to mitigate flooding concerns. Five 69 kV 3000 A 40 kA circuit breakers in a ring bus (operated at 46 kV) configuration will be installed with a 13.2 MVAR capacitor bank. The existing Allen station will be retired. A 0.20 mile segment of the Allen-East Prestonsburg 46 kV line will be relocated to the new station. The new McKinney-Allen line extension will extend around the south and east sides of the existing Allen station to the new Allen station being built in the clear. A short segment of new single circuit 69 kV line and a short segment of new double circuit 69 kV line (both operated at 46 kV) will be added to the line to tie into the new Allen station bays. A segment of the Stanville-Allen line will also have to be relocated to the new station. A 0.25 mile segment of the existing Allen-Prestonsburg single circuit will be relocated, and the relocated line segment will require construction of one custom self-supporting double circuit dead-end structure and single circuit suspension structure. A short segment of new double circuit 69 kV line (energized at 46 kV) will be added to tie into the new Allen station bays, which will carry Allen-Prestonsburg and Allen-East Prestonsburg 46 kV lines. A temporary 0.15 mile section double circuit line will be constructed to keep both lines energized during construction. Remote end work will also be required at Prestonsburg, Stanville and McKinney 46 kV stations. The estimated cost for this project is $16 million, with a required in-service date of December 2026. The projected in-service date is December 2023, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3348: Dehue Area Improvements

AEP Transmission Zone

In the 2026 RTEP light load case, the Becco-Slagle, Dehue-Pine Gap and Dehue-Slagle 46 kV lines are overloaded for an N-1 outage combination. There are also low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane, Latrobe, Becco, Slagle and Dehue 46 kV buses for an N-1 outage combination.

Map 2. **b3348: Dehue Area**



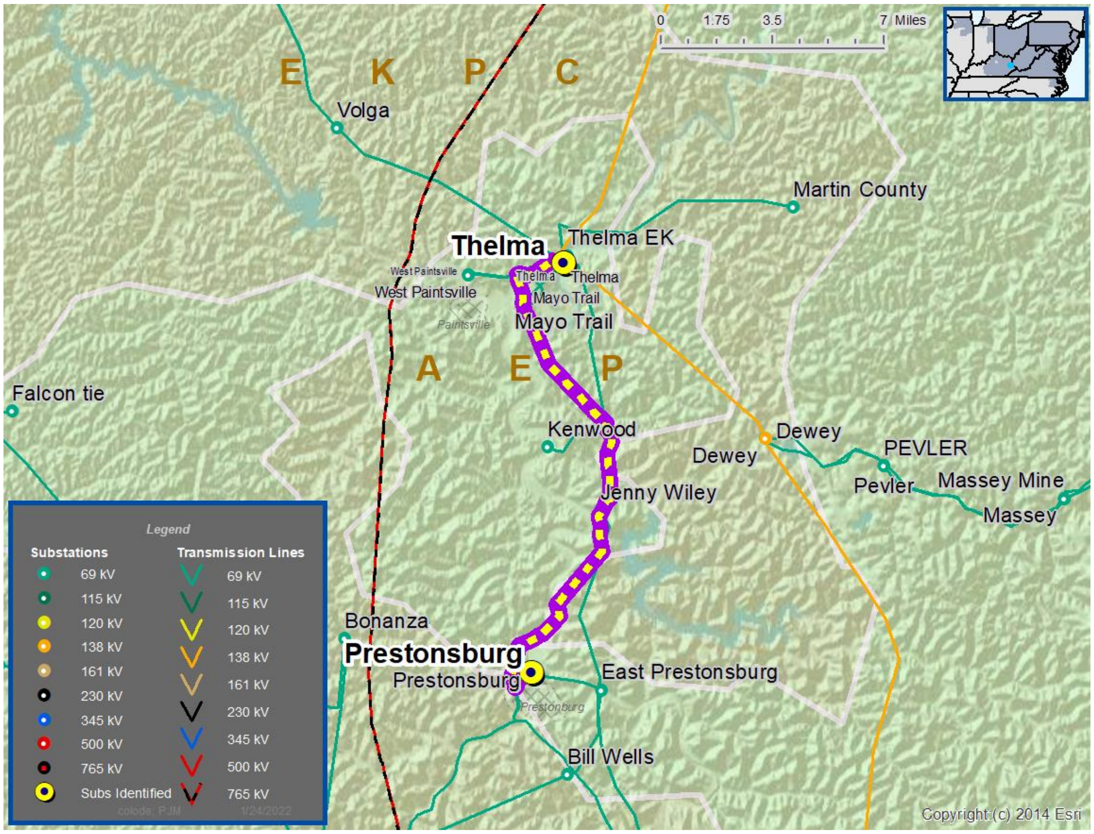
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to construct a new 138 kV Tin Branch single bus station to replace Pine Gap station, consisting of a 138 kV box bay with a distribution transformer and 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Sprigg stations), and distribution will have one 12 kV feed. The project installs two 138 kV circuit breakers on the line exits and a 138 kV circuit switcher for the new transformer. A new 138/46/12 kV Argyle station will be constructed to replace the Dehue station, with a 138 kV ring bus using a breaker-and-a-half configuration, an autotransformer (46 kV feed) and a distribution transformer (12 kV distribution bay). Two 138 kV lines will feed the Argyle station (from Logan and Wyoming stations), and there will also be a 46 kV feed from this station to Becco station (distribution will have two 12 kV feeds). The project retires the Dehue station in its entirety, and brings the Logan-Sprigg No. 2 138 kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138 kV line. The Logan-Wyoming No. 1 138 kV circuit will be brought in and out of the new Argyle substation. Double circuit T3 series lattice towers will be used along with 795,000 cm ACSR 26/7 conductor. One shield wire will be conventional 7 No. 8 ALUMOWELD, and one shield wire will be optical ground wire (OPGW). Approximately 10 miles of the 46 kV line between Becco and the new Argyle substation will be rebuilt, and approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey substation will be retired. Relay settings need to be adjusted due to new line terminations and retirements at Logan, Wyoming, Sprigg, Becco and Chauncey substations. The estimated cost for this project is $65.8 million, with a required in-service of November 2026. The projected in-service date is June 2026, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3361: Prestonsburg-Thelma 46 kV Rebuild

AEP Transmission Zone

In the 2026 RTEP winter case, there are voltage magnitude and voltage drop violations at Mckinney, Salsbury, Allen, East Prestonsburg, Prestonsburg, Middle Creek and Kenwood 46 kV buses for multiple N-1 outage combinations.

Map 3. **b3361: Prestonsburg-Thelma 46 kV**



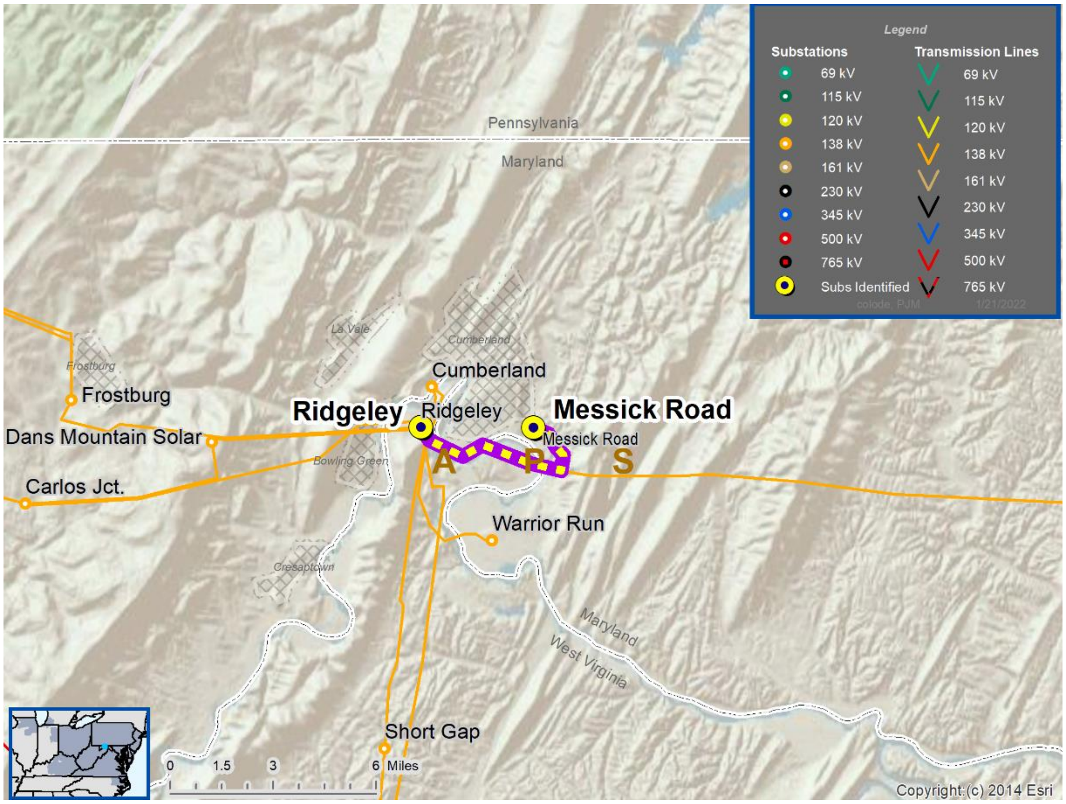
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, addresses both the identified reliability needs and a supplemental need identified through the M-3 process. There are equipment condition issues with structures that make up the Prestonsburg-Thelma 46 kV line. These conditions include damaged/rotted poles, guy wires and cross arms. The majority of this line utilizes 1960s wood structures and 336.4 ACSR conductor. The solution is to rebuild the Prestonsburg-Thelma 46 kV line (approximately 14 miles) and retire Jenny Wiley 46 kV switching station. The estimated cost for this project is $33.01 million, with a required in-service date of December 2026. The projected in-service date is October 2025, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3683: Messick Road-Ridgeley 138 kV Upgrades

APS Transmission Zone

In the 2026 RTEP summer case, the Messick Road-Ridgeley 138 kV line is overloaded for multiple N-2 outage combinations.

Map 4. **b3683: Messick Road-Ridgeley 138 kV**



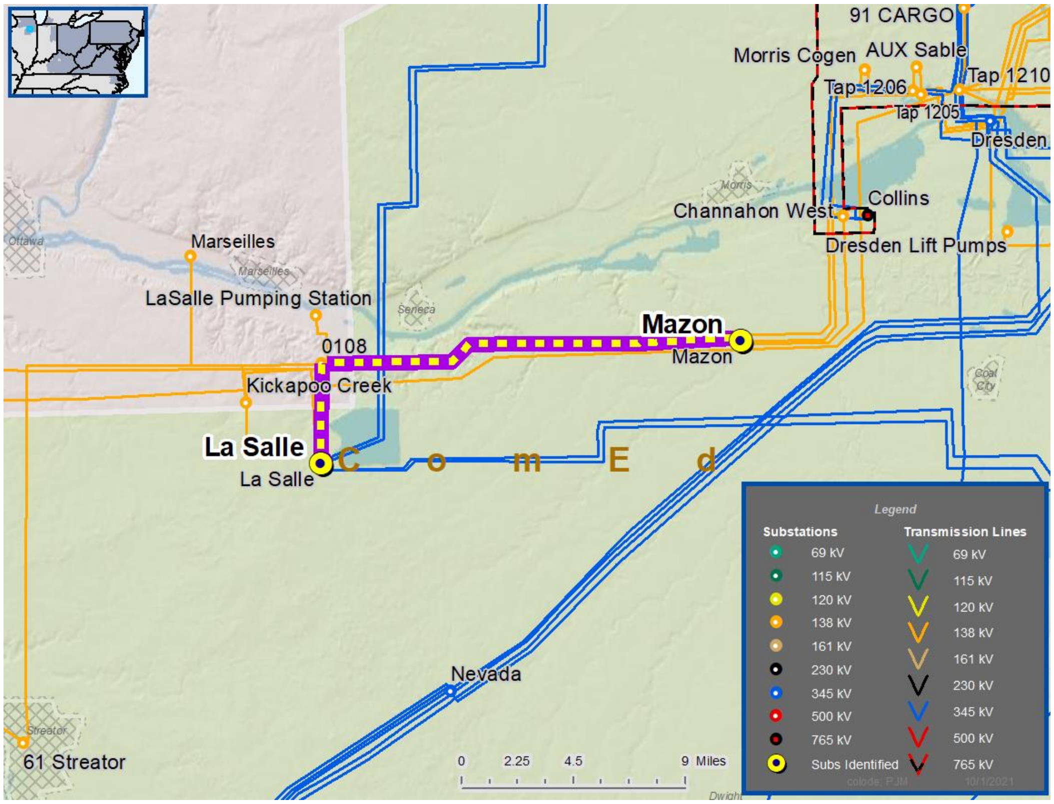
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to reconductor the existing 556.5 ACSR line segments on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR. The remote end equipment for the Messick Road-Ridgeley WC4 138 kV line will also be replaced. The estimated cost for this project is $11.2 million, with a required and projected in-service date of June 2026. The local transmission owner, APS, will be designated to complete this work.

Baseline Project b3677: LaSalle-Mazon 138 kV Rebuild

ComEd Transmission Zone

In the 2026 RTEP light load case, the LaSalle-Mazon 138 kV line is overloaded for an N-2 outage.

Map 5. **b3677: LaSalle-Mazon 138 kV**



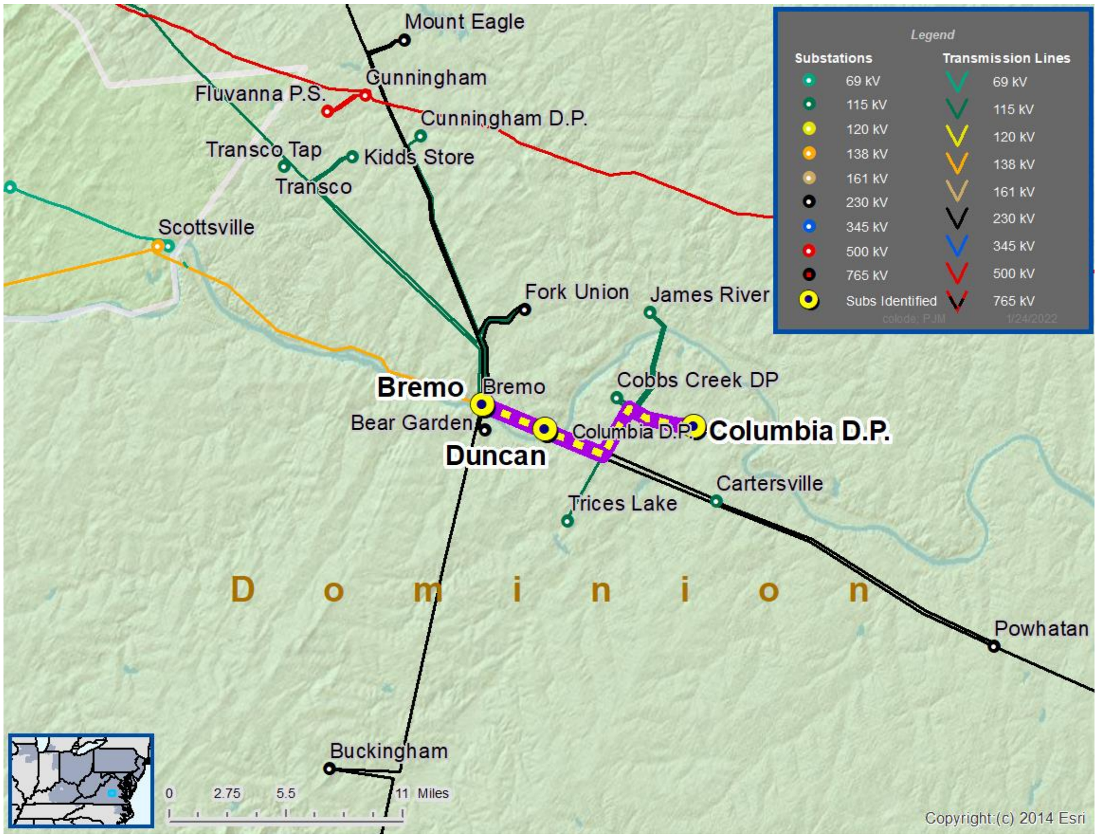
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to rebuild a 13 mile section of 138 kV line 0108 between LaSalle and Mazon with 1113 ACSR or higher rated conductor. The estimated cost for this project is $42.06 million, with a required in-service date of November 2026. The projected in-service date is December 2024, and the local transmission owner, ComEd, will be designated to complete this work.

Baseline Project b3686: Bremo-Columbia D.P. 115 kV Switching Station

Dominion Transmission Zone

In the 2026 RTEP winter case, the Bremo-Columbia D.P. 115 kV line (No. 4) is a radial transmission line and exceeds the 700 MW-Mile threshold under Dominion's FERC 715 Planning Criteria.

Map 6. **b3686: Bremo-Columbia D.P. 115 kV**



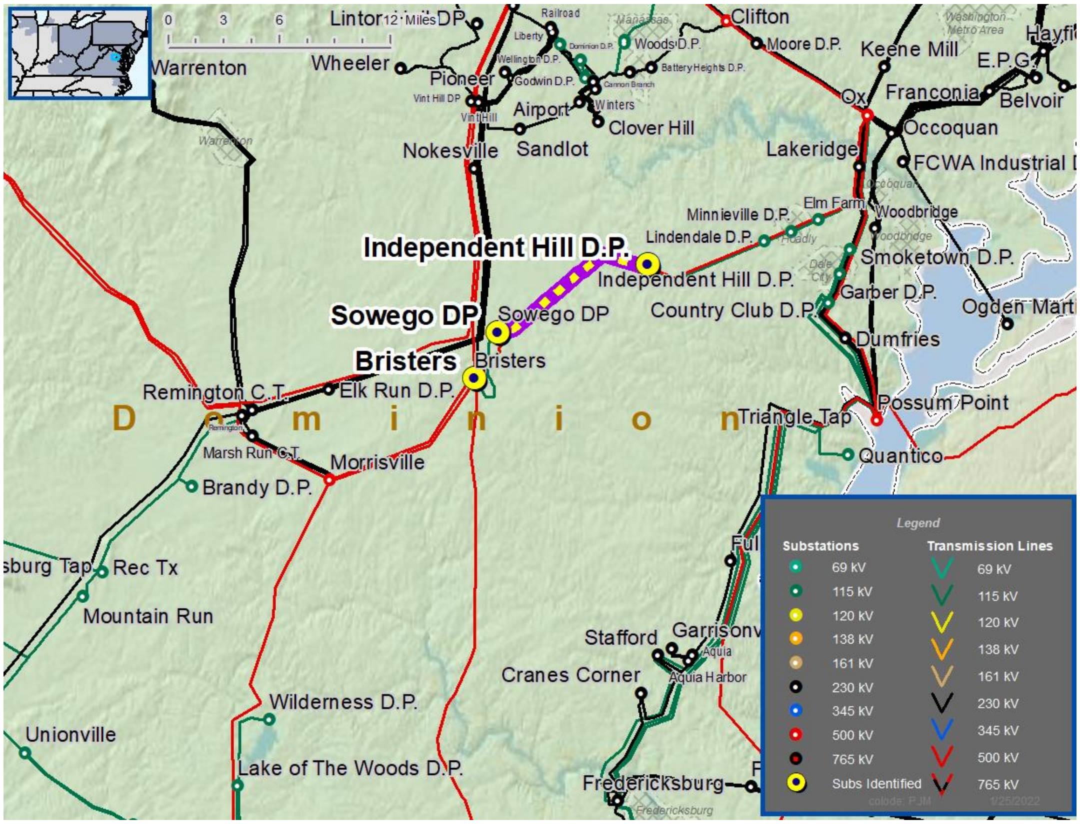
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to purchase land close to the bifurcation point of line No. 4 (where the line is split into two sections) and build a new 115 kV switching station called Duncan Store 115 kV. The new switching station will require space for an ultimate transmission interconnection consisting of a 115 kV six-breaker ring bus (with three breakers installed initially). The estimated cost for this project is $16 million, with a required and projected in-service date of December 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3687: Bristers-Minnieville D.P. 115 kV Rebuild

Dominion Transmission Zone

In the 2026 RTEP summer case, the Bristers 230/115 kV transformer is overloaded for an N-1 outage under the generator deliverability study and for Dominion's Stress Case (FERC 715 Planning Criteria). The 115 kV line No. 183 (Sowego-Independent Hill segment) is overloaded for N-1 and N-2 outages, along with multiple N-1 outage combinations under PJM reliability studies and Dominion's Stress Case.

Map 7. **b3687: Bristers-Minnieville D.P. 115 kV Area**



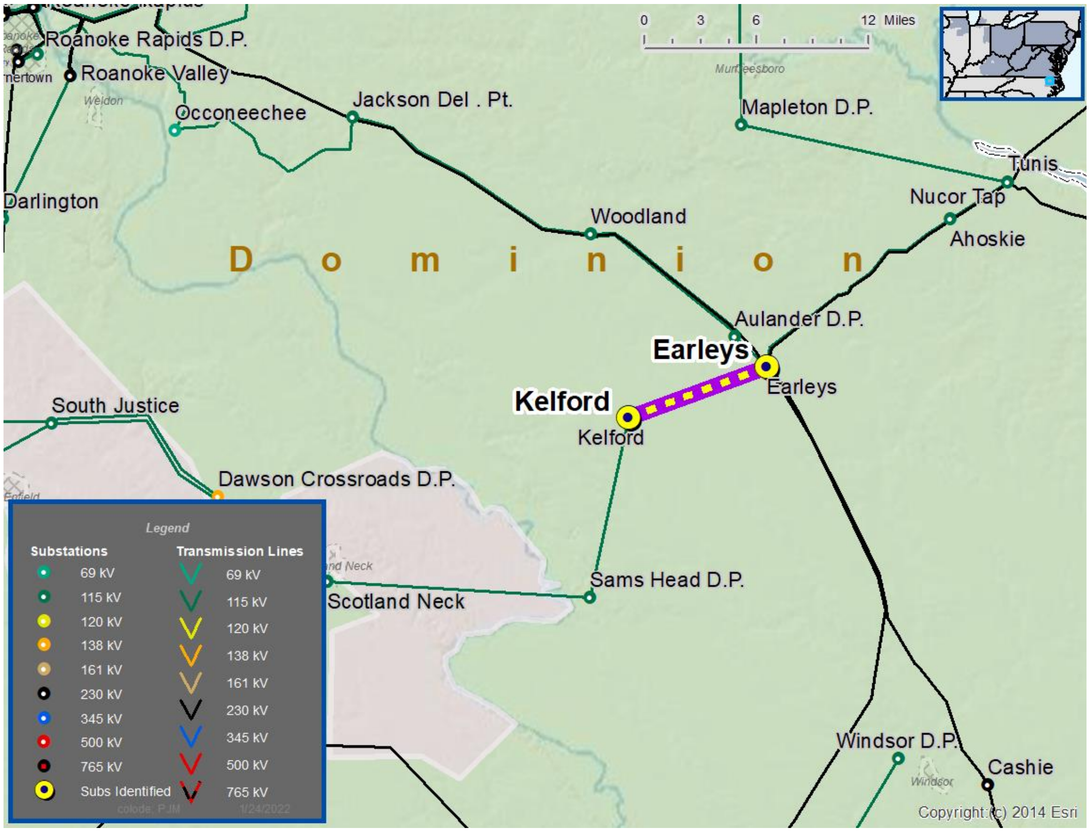
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to rebuild of the approximately 15.1-mile-long line segment between Bristers and Minnieville D.P. with 2-768 ACSS and 4000 A supporting equipment from Bristers to Ox to allow for future 230 kV capability of 115 kV line No. 183 (Sowego-Independent Hill segment). The estimated cost for this project is $30 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3684: Earleys-Kelford 115 kV Rebuild

Dominion Transmission Zone

In the 2026 RTEP summer case, the 115 kV line No. 126 segment from Earleys to Kelford is overloaded for an N-2 outage.

Map 8. **b3684: Earleys-Kelford 115 kV**



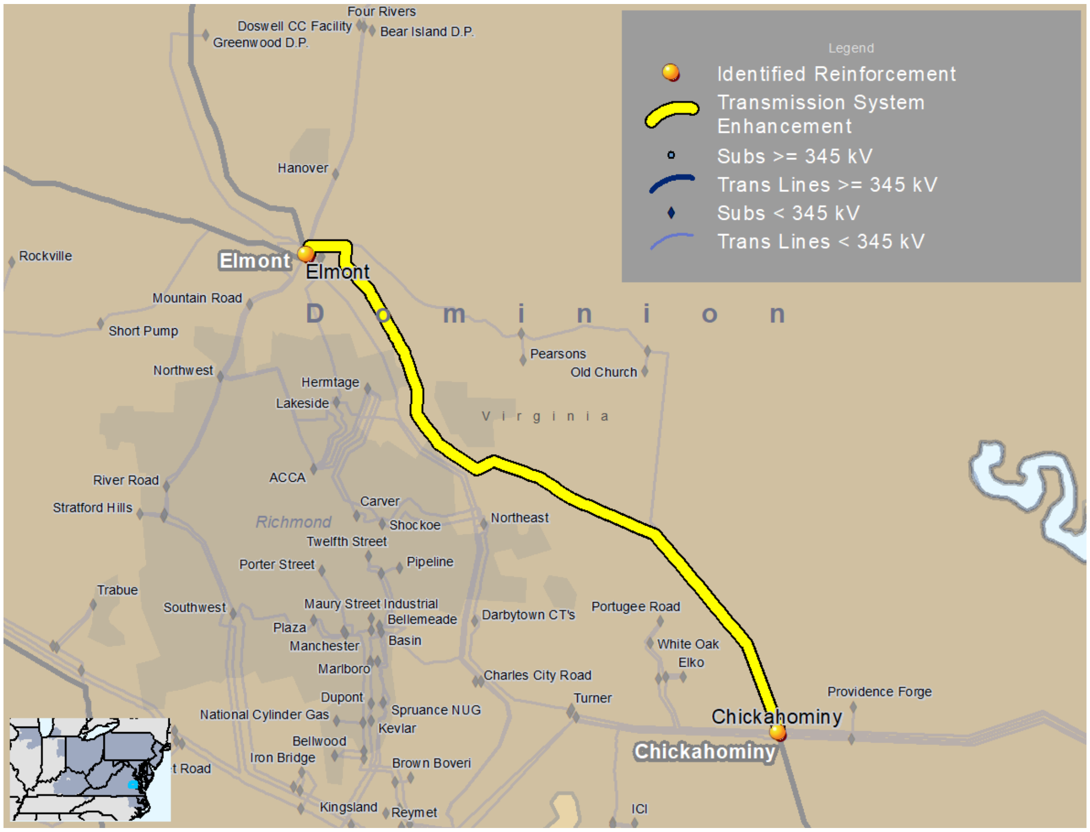
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to rebuild 12.4 miles of 115 kV line No. 126 segment from Earleys to Kelford line with a summer emergency rating of 262 MVA and replace structures as needed to support the new conductor. The breaker switch 13668 at Earleys will also be upgraded from 1200 A to 2000 A. The estimated cost for this project is $18.75 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3692: Elmont-Chickahominy 500 kV Rebuild

Dominion Transmission Zone

The Elmont-Chickahominy 500 kV line (No. 557) was constructed in 1971 with 2500 ACAR conductor and 5-series Corten towers that need to be rebuilt to current standards based on Dominion's End-of-Life Criteria.

Map 9. **b3692: Elmont-Chickahominy 500 kV**



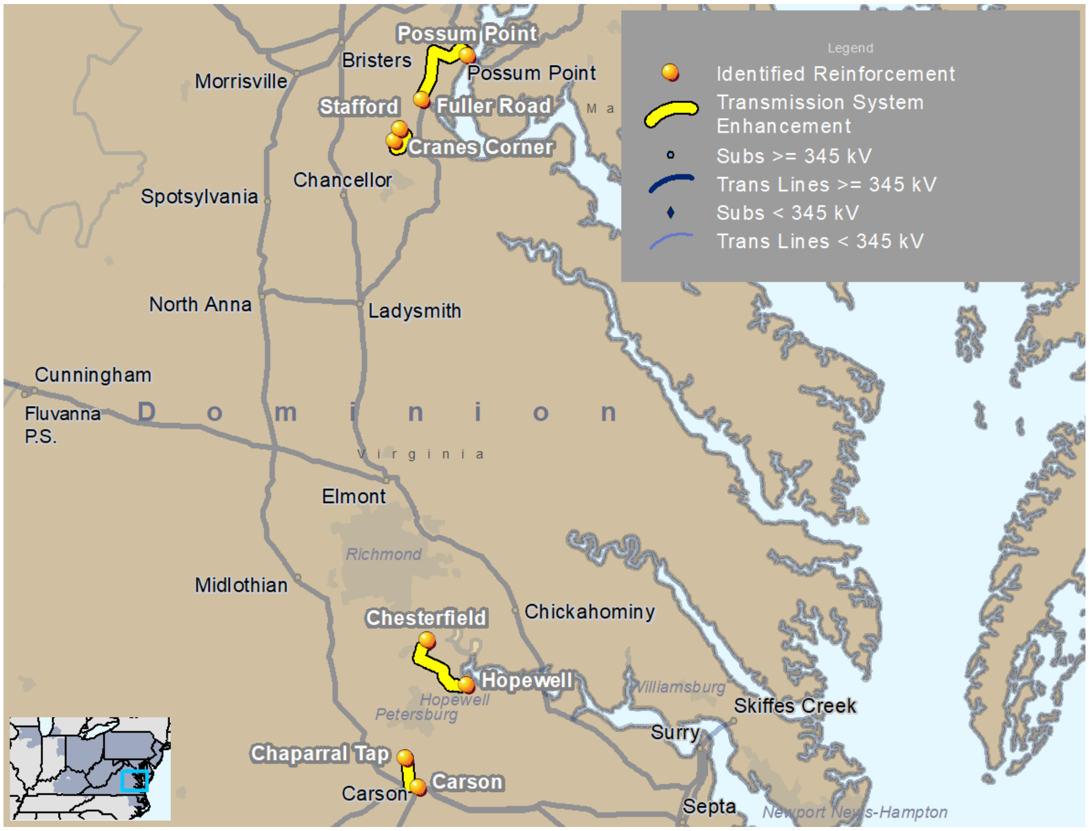
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to rebuild approximately 27.7 miles of 500 kV transmission line from Elmont to Chickahominy with current 500 kV standards construction practices to achieve a summer rating of 4330 MVA. The estimated cost for this project is $58.16 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3694: Fredericksburg/Carson/Hopewell Area Improvements

Dominion Transmission Zone

In the 2026 RTEP summer case, in the Fredericksburg area, the Cranes Corner-Stafford 230 kV line (No. 2104) is overloaded for an N-1 and N-2 outage as well as under Dominion stress case criteria, and there is load loss of 307 MW for N-1 outage combinations. In the Carson area, the Carson 500/230 kV transformer No. 2 is overloaded for an N-2 outage, and the Carson-Chaparral 230 kV line (No. 249) is overloaded for an N-1 outage. In the Hopewell area, the Chesterfield-Hopewell 230 kV line (No. 211) is overloaded for an N-1 outage, and the Chesterfield-Hopewell 230 kV line (No. 228) is overloaded for an N-1 and N-2 outage.

Map 10. **b3694: Fredericksburg/Carson/Hopewell Area Improvements**



The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is a comprehensive project that addresses all three areas.

In the Fredericksburg area, the project will convert 115 kV line No. 29 (Aquia Harbor-Possum Point) to 230 kV (extended line No. 2104) and swap line No. 2104 (Cranes Corner-Stafford 230 kV) and converted line No. 29 at Aquia Harbor backbone termination. The project will also upgrade terminal equipment at Possum Point, Aquia Harbor and Fredericksburg 230 kV. The project will add a new breaker at the Fredericksburg 230 kV bay and reconfigure 230 kV line terminations. Approximately 7.6 miles of 230 kV line No. 2104 (Cranes Corner-Stafford) and approximately 0.34 miles of 230 kV line No. 2104 (Stafford-Aquia Harbor) will be reconductored/rebuilt to achieve a summer rating of 1047 MVA (terminal equipment at Cranes Corner will be upgraded to not limit the new conductor rating). The project will upgrade the wave trap and line leads at 230 kV line No. 2090 Ladysmith CT terminal to achieve 4000 A rating. The Fuller Road substation will be upgraded to feed the Quantico substation via a 115 kV radial line, and a four-breaker ring will be installed to break 230 kV line No. 252 into two new lines: 1) No. 252 between Aquia Harbor to Fuller Road, and 2) No. 9282 between Fuller Road and Possum Point. A 230/115 kV transformer will also be installed, which will serve Quantico substation.

In the Carson area, the project will energize the in-service spare 500/230 kV Carson No. 1 transformer, and partially wreck and rebuild 10.34 miles of 230 kV line No. 249 (Carson-Locks) to achieve a minimum summer emergency rating of 1047 MVA (terminal equipment at Carson and Locks will be upgraded to not limit the new conductor rating). The project includes the wreck and rebuild of 5.4 miles of 115 kV line No. 100 (Locks-Harrowgate) to achieve a minimum summer emergency rating of 393 MVA (terminal equipment at Locks and Harrowgate will be upgraded to not limit the new conductor rating), and will perform line No. 100 Chesterfield terminal relay work.

In the Hopewell area, the project will reconductor approximately 2.9 miles each of 230 kV lines No. 211 (Chesterfield-Hopewell) and No. 228 (Chesterfield-Hopewell) to achieve a minimum summer emergency rating of 1046 MVA (equipment at Chesterfield and Hopewell substations will be upgraded to not limit ratings on lines No. 211 and No. 228).

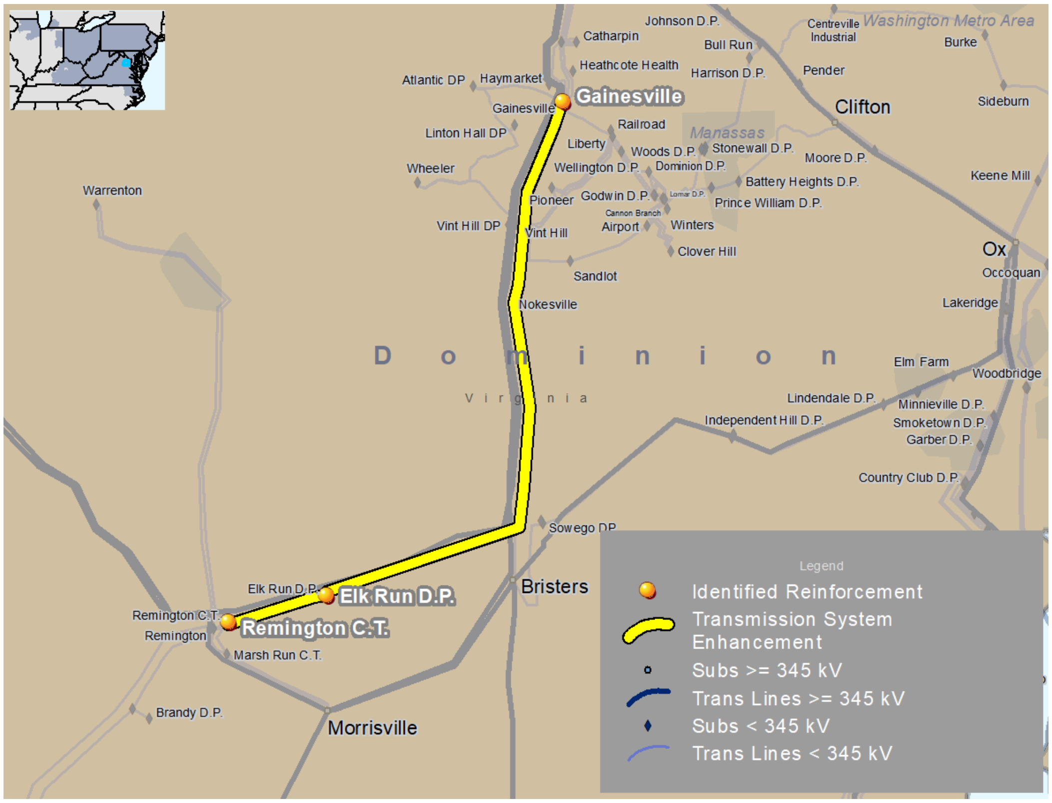
The total estimated cost for this project is $93.41 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3689: Remington CT-Gainesville 230 kV Reconductor

Dominion Transmission Zone

In the 2026 RTEP summer case, the Remington CT-Gainesville 230 kV line (No. 2114) is overloaded for multiple N-1 and N-2 outages.

Map 11. **b3689: Remington CT-Gainesville 230 kV**



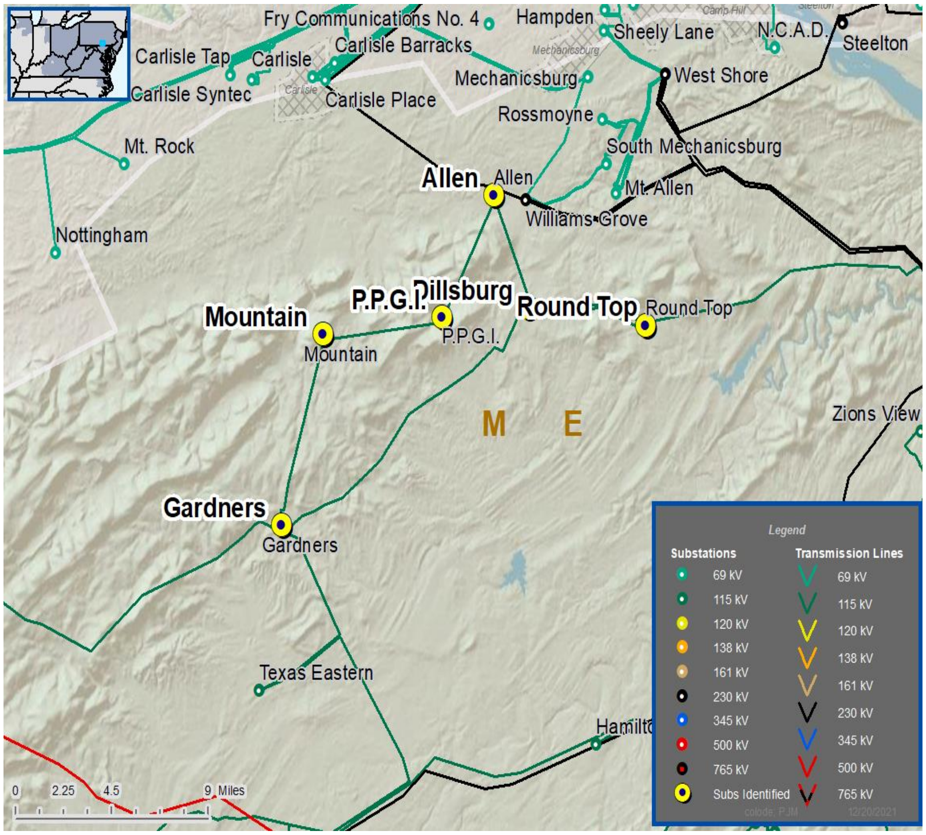
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to reconductor approximately 24.42 miles of Remington CT-Elk Run-Gainesville 230 kV line (No. 2114) to achieve a summer rating of 1574 MVA (by fully reconductoring the line and upgrading the wave trap and substation conductor at Remington CT and Gainesville 230 kV). The project will replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 4000 A 80 kA breakers and associated equipment, including breaker leads as necessary, to address breaker duty issues identified in short circuit analysis. The estimated cost for this project is $30.68 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3715: Allen 115 kV Area Improvements

ME Transmission Zone

In the 2026 RTEP summer case, there are voltage magnitude and voltage drop violations at several 115 kV stations in the Allen vicinity for multiple N-1 outage combinations.

Map 12. **b3715: Allen 115 kV Area**



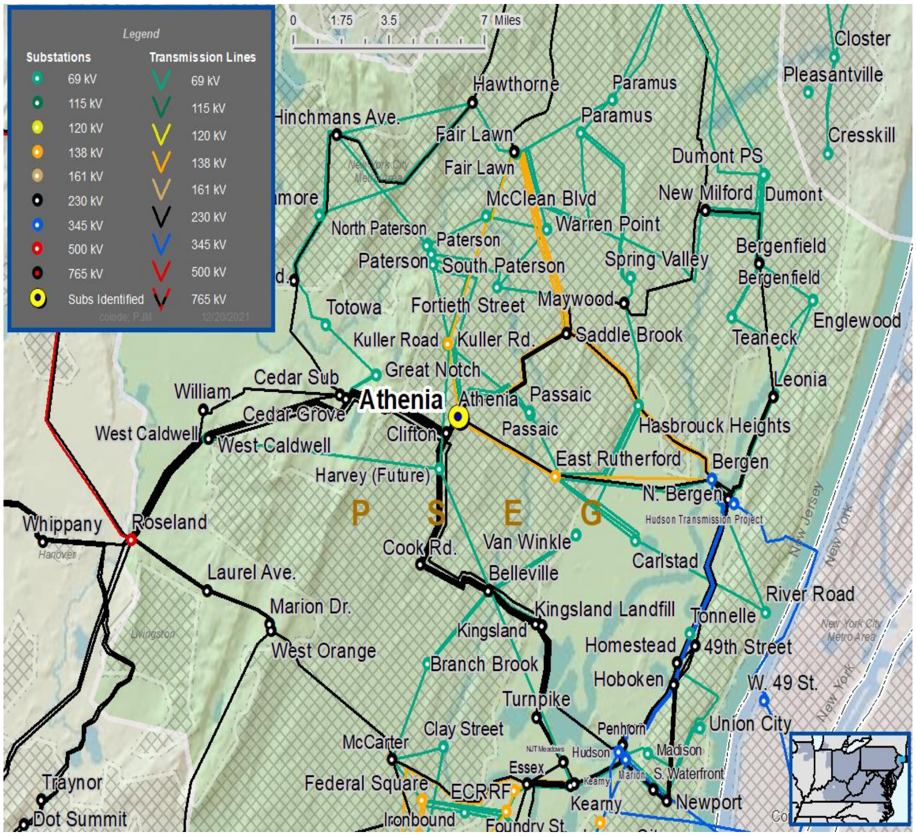
The recommended solution, which was solicited through the 2021 Window 1, is to install a new 300 MVA 230/115 kV transformer at the existing PPL Williams Grove substation and construct a new 3.4 mile 115 kV single-circuit transmission line from Williams Grove to Allen substation. A new four breaker ring bus switchyard will be installed at Allen, near the existing ME Allen substation on adjacent property presently owned by FirstEnergy. The Round Top-Allen and Allen-PPGI (P.P.G. Industries) 115 kV lines will terminate into the new switchyard. The estimated cost for this project is $17.82 million, with a required and projected in-service date of June 2026. The local transmission owners, ME and PPL, will be designated to complete this work.

Baseline Project b3705: Athenia 230/138 kV Transformer Replacement

PSEG Transmission Zone

Per PSEG's FERC 715 planning criteria evaluation, the Athenia 230/138 kV transformer No. 220-1 was identified for replacement based on equipment performance, condition assessment and system needs. The No. 220-1 transformer at Athenia has been heavily gassing for many years and has been de-gassed multiple times due to high levels of combustible gas in the main tank.

Map 13. **b3705: Athenia 230/138 kV**



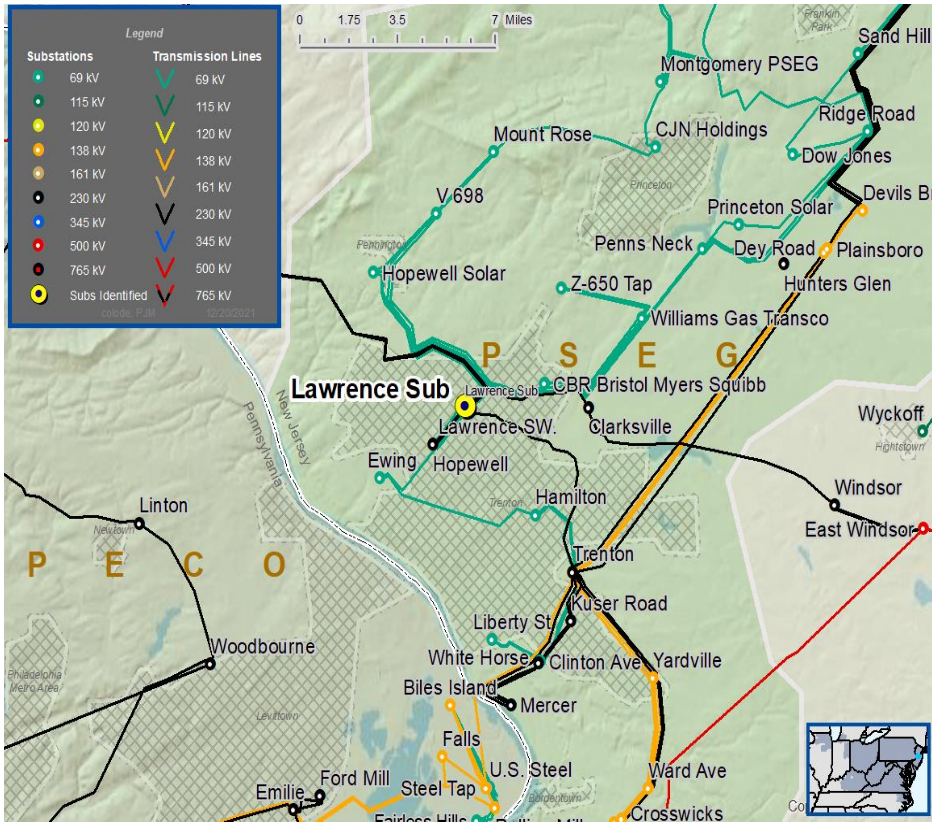
The recommended solution, which was solicited through the 2021 Window 3, is to replace the existing Athenia 230/138 kV transformer No. 220-1. The estimated cost for this project is $13.04 million, with a required and projected in-service date of June 2026. The local transmission owner, PSEG, will be designated to complete this work.

Baseline Project b3704: Lawrence 230/69 kV Transformer Replacement

PSEG Transmission Zone

Per PSEG's FERC 715 planning criteria evaluation, the Lawrence 230/69 kV transformer No. 220-4 was identified for replacement based on equipment performance, condition assessment and system needs.

Map 14. **b3704: Lawrence 230/69 kV**



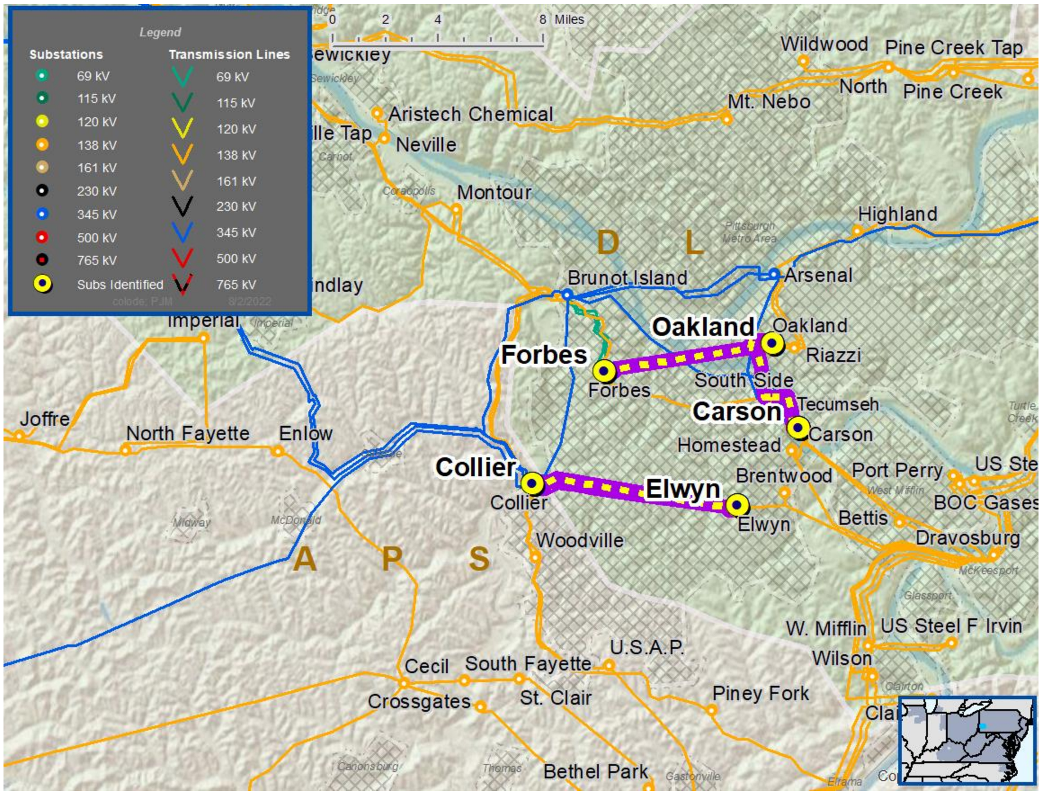
The recommended solution, which was solicited through the 2021 Window 3, is to replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger-capacity transformer with Load Tap Changer (LTC) and new dead tank circuit breaker. A new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment will be installed to complete the bay within the Lawrence 230 kV switchyard. The estimated cost for this project is $13.36 million, with a required and projected in-service date of June 2026. The local transmission owner, PSEG, will be designated to complete this work.

Baseline Project b3717: Cheswick 1 Deactivation Reinforcements

DL Transmission Zone

Cheswick 1 deactivated in March 2022; however, additional overloads were identified in the 2023 RTEP summer case. The Collier-Elwyn No. 1 and No. 2, Forbes-Oakland, and Carson-Oakland 138 kV transmission lines are overloaded for multiple N-1 outage combinations.

Map 15. **b3717: Cheswick 1 Deactivation**



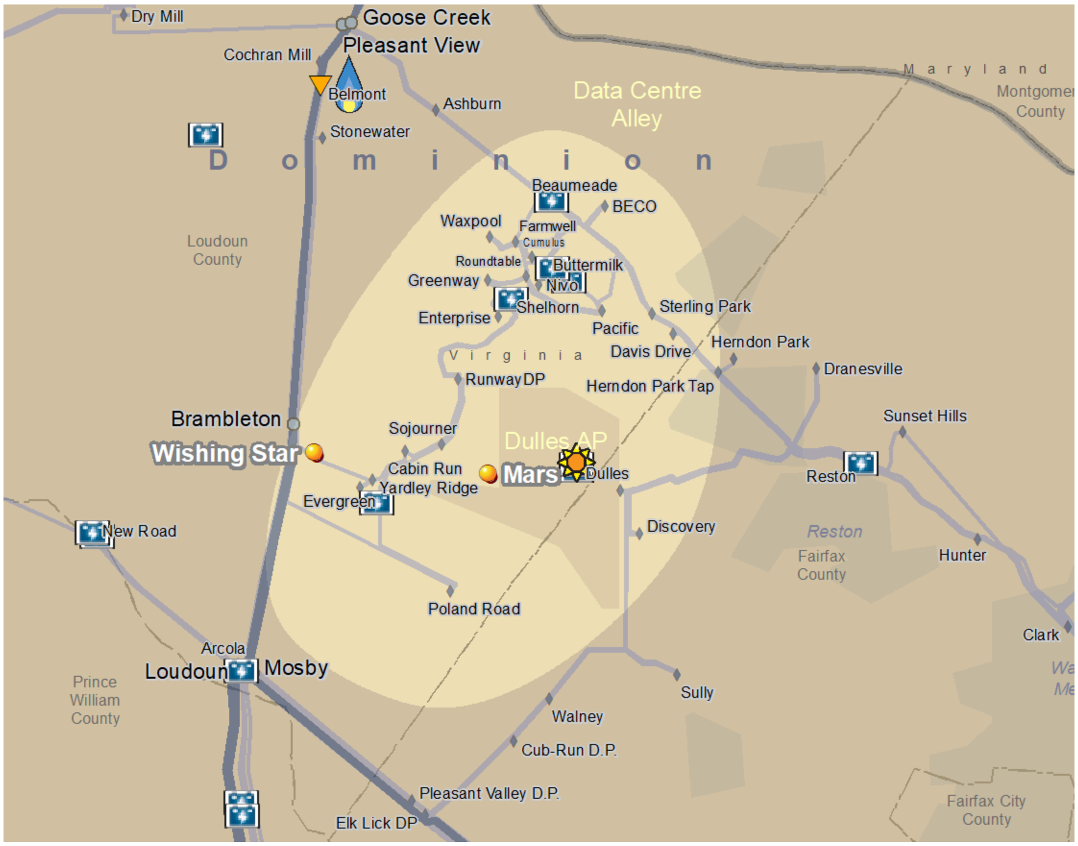
The recommended solution is to install a series reactor on Cheswick-Springdale 138 kV line, replace four structures and reconductor Duquesne Light Company's portion of Plum-Springdale 138 kV line. Associated communication and relay setting changes are also needed at Plum and Cheswick. The estimated cost for this project is $24 million, with a projected in-service date of December 2024. This project is identified as immediate need, and operating measures have been identified to mitigate reliability impacts in the interim. The local transmission owner, DL, will be designated to complete this work.

Baseline Project b3718: Data Center Alley Improvements

Dominion Transmission Zone

The Dominion zone has been experiencing load growth in the Data Center Alley area around Dulles airport. Forecasted data center additions for the 2022 Load Forecast provided by Dominion and NOVEC were noticeably higher than in the prior year. Due to the highly concentrated load growth in the Data Center Alley Area, numerous reliability violations (thermal overloads and load loss) were observed in the 2024 and 2025 time frames despite planned supplemental and baseline upgrades.

Map 16. **b3718 – Data Center Alley**



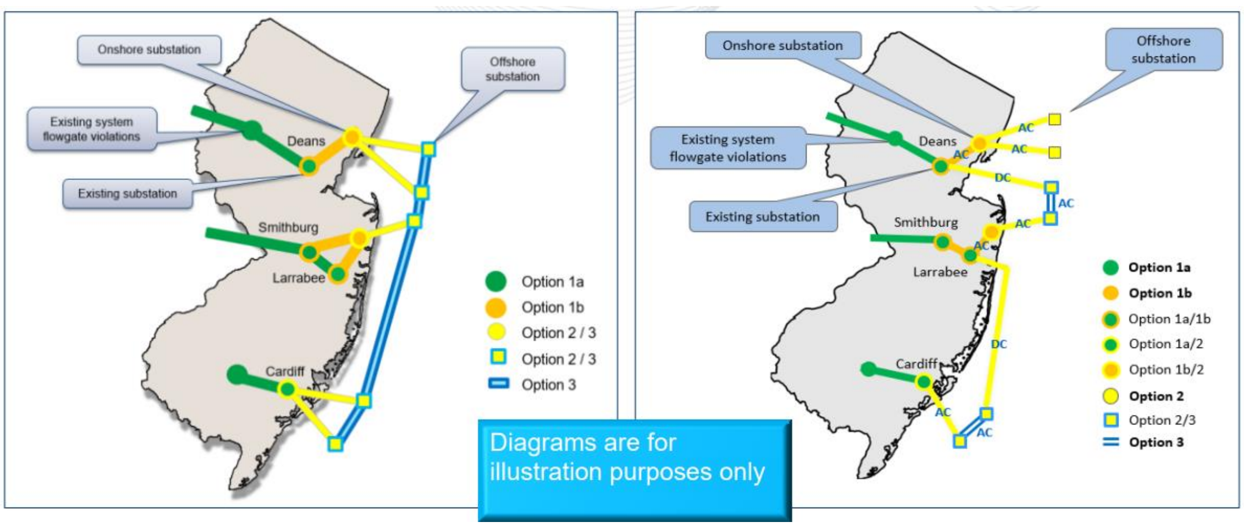
The recommended solution is to build a new 500/230 kV substation called Wishing Star near Brambleton substation and install one 500/230 kV 1440 MVA transformer at the substation. A new 500/230 kV substation called Mars will be built near Dulles International Airport, and one 500/230 kV 1440 MVA transformer will be installed at the substation. The 500 kV line No. 546 (Brambleton-Mosby) and 500 kV line No. 590 (Brambleton-Mosby) will be cut and extended to the proposed Wishing Star substation, and lines will terminate in a 500 kV breaker and a half configuration. The project will reconductor the approximate mileage of the following lines: 0.62 miles of 230 kV line No. 2214 (Buttermilk-Roundtable), 1.52 miles of 230 kV line No. 2031 (Enterprise-Greenway-Roundtable), 0.64 miles of 230 kV line No. 2186 (Enterprise-Shellhorn), 2.17 miles of 230 kV line No. 2188 (Lockridge-Greenway-Shellhorn), 0.84 miles of 230 kV line No. 2223 (Lockridge-Roundtable), 3.98 miles of 230 kV line No. 2218 (Sojourner-Runway-Shellhorn), and 1.61 miles of 230 kV line No. 9349 (Sojourner-Mars). The project will also upgrade four 500 kV breakers to 63 kA on either end of 500 kV line No. 584 (Loudoun-Mosby circuit No. 1) and four 500 kV breakers to 63 kA on either end of 500 kV line No. 502 (Loudoun-Mosby circuit No. 2), cut and loop the 230 kV line No. 2079 (Sterling Park-Dranesville) into the Davis Drive substation and install two GIS 230 kV breakers. The estimated cost for this project is $627.62 million. This project is identified as immediate need, with a required and projected in-service date of June 2025. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3737: NJ SAA Project

AE, BGE, JCPL, PECO, PPL & PSEG Transmission Zones

As part of the 2021 State Agreement Approach (SAA) Proposal Window to support New Jersey offshore wind, PJM received proposals to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind. The proposals were categorized into four options according to the function and location of the proposal. Altogether, PJM received a diverse set of 80 proposals.

- **Option 1a proposals:** Onshore transmission upgrades to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC and local Transmission Owner criteria)
- **Option 1b proposals:** Onshore new transmission connection facilities
- **Option 2 proposals:** Offshore new transmission connection facilities
- **Option 3 proposals:** Offshore new transmission network facilities



Concepts depicted are for illustration purposes only.
Details of new lines and facilities are to be provided by sponsors in proposals to meet objectives of this solicitation.

Figure 1. Potential Options for the NJ Offshore Wind Transmission Solution

PJM worked with the NJ BPU to create offshore wind injection scenarios involving various combinations of the submitted Option 1b and Option 2 proposals. Each scenario contained the awarded solicitation No. 1 for 1,100 MW and solicitation No. 2 for 2,658 MW. While the scope for the submission of proposals did not allow alternative point of injections (POIs) for solicitation No. 1, it did allow alternative POIs for solicitation No. 2. As a result, each scenario contained identical considerations for solicitation No. 1, and the scenario creation focused on selecting combinations of submitted Option 1b and Option 2 proposals that together enable the transmission system to reliably deliver approximately 6,400 MW of additional offshore wind.

After the comprehensive reliability analysis and all other evaluations were complete, the NJ BPU selected Scenario 18a as the SAA Project. Scenario 18a uses JCPL Option 1b proposals 453.1–18, 24, 26–29 to interconnect 3,742 MW of offshore wind to central New Jersey, including 1,200 MW to Larrabee 230 kV, 1,200 MW to Atlantic 230 kV and 1,342 MW to Smithburg 500 kV. It also uses a portion of Mid-Atlantic Offshore Development (MAOD) proposal 551 to construct the Larrabee 230 kV AC Collector station and procure land adjacent to the MAOD AC switchyard for future HVDC converters.

The interconnection of the remaining 1,148 MW of solicitation No. 2 (Ocean Wind 2) offshore wind, 1,510 MW of solicitation No. 2 (Atlantic Shores 1) offshore wind, and the interconnection of the entire 1,100 MW of solicitation No. 1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

JCPL Option 1b proposal 453.1–18, 24, 26–29 involves the following components:

- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct new approximately 11.6-mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

- MAOD proposal 551 (partial) involves constructing the Larrabee 230 kV AC Collector station and procuring land adjacent to the MAOD AC switchyard for future HVDC converters. The below tables show a summary of costs by option components and the SAA Capability created by the selected SAA project:

Table 1. Scenario 18 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)

18a	6,400	3,742	JCPL, MAOD	453.1-18,24,27-29	$428	551 (partial)	$121	$515	$1,064

Table 2. Point of Interconnection & Associated Injected Amounts

Location	State	Transmission Owner	SAA Capability	MFO	MW Energy	MW Capacity
Larrabee Collector station 230 kV – Larrabee	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Atlantic	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Smithburg	NJ	MAOD	1,342	1,342	1,342	402.6
Smithburg 500 kV	NJ	JCPL	1,148	1,148	1,148	327

The tables below show the Option 1b, 2 and 1a component cost estimates:

Table 3. Scenario 18a Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	453.1	Atlantic 230 kV substation – Convert to double-breaker double-bus	$31.47
	453.2	Freneau substation – Update relay settings	$0.03
	453.3	Smithburg substation – Update relay settings	$0.03
	453.4	Oceanview substation – Update relay settings	$0.04
	453.5	Red Bank substation – Update relay settings	$0.04
	453.6	South River substation – Update relay settings	$0.03
	453.7	Larrabee substation – Update relay settings	$0.03
	453.8	Atlantic substation – Install line terminal	$4.95
	453.9	Larrabee substation – Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen substation – Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230 kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230 kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230 kV	$17.07
	453.15	Larrabee-Oceanview 230 kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5 kV line transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV new line	$7.52

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
	453.18	Larrabee Converter-Smithburg No. 1 500 kV line (new asset)	$150.35
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.26	D2004 Larrabee-Smithburg No1 230 kV	$44.77
	453.27	Smithburg substation 500 kV expansion	$5.81
	453.28	Larrabee substation	$0.86
	453.29	Smithburg substation 500 kV 3-breaker ring	$62.44
Total			**$427.82**

Table 4. Scenario 18a Option 2 Component Cost Estimates

Component Descriptions	In-Service Date (ISD)	Cost ($M)
MAOD		
Proposal ID 551		
Construct the AC switchyard portion of MAOD proposal 551, composed of a 230 kV 3 x breaker-and-a-half substation with a nominal current rating of 4000A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. AC switchyard design and site preparation shall be suitable for expansion to a 230 kV 4 X 230 kV breaker-and-a-half substation and seven single phase 500/230 kV 450 MVA autotransformers to step up voltage for connection of two circuits to Smithburg substation.	ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work	**$121.10** *Note:* *This cost represents a partial scope of MAOD proposal #551.* *It excludes other owners' costs, permitting, commercial and financial fees, and will require further evaluation to refine the estimate.*
Procure land adjacent to the MAOD AC switchyard, which is a portion of the MAOD proposal 551, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. MAOD will commit to work with NJBPU and staff, PJM, the relevant transmission owners, and all future developers to lease or otherwise make land access available for construction of converters by those developers to support the integration of OSW generators to achieve the OSW goals of New Jersey.	ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work	

Table 5. Scenario 18a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.4–17.11	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.	**$206.48**

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	**$13.40**
PPL	330	Reconductor Gilbert-Springfield 230 kV	**$0.38**
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	**$11.45**
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	**$3.80**
JCPL	17.19	Reconductor Kilmer I-Lake Nelson I 230 kV	**$4.42**
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	**$0.16**
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	**$3.30**
PSEG	180.3, 180.4, 180.7	Linden & Bergen subprojects	**$30.45**
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	**$0.12**
JCPL	Email 2/11/2022	Reconductor small section of Raritan River-Kilmer I 230 kV (n6201)	**$0.20**
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River-Kilmer W 230 kV (n6202)	**$25.88**
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	**$11.05**
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	**$3.90**
AE	127.10	Reconductor Richmond-Waneeta 230 kV	**$16.00**
PSEG	180.5, 180.6	Windsor to Clarksville subproject	**$5.77**
AE	127.1	Upgrade Cardiff-Lewis 138 kV	**$0.10**
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	**$0.30**

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	**$0.50**
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	**$61.20**
Transource	63	North Delta Option A	**$109.68**
PECO	Incumbent TO	Replace four Peach Bottom 500 kV breakers	**$5.60**
BGE	Incumbent TO	Upgrade one Conastone 230 kV breaker	**$1.30**
TOTAL			**$515.44**

The total estimated cost for this project is $1,064.36 million, with various required in-service dates ranging from December 2027 through June 2030 to align with New Jersey's solicitation schedule. The designated entities that proposed the projects and the local transmission owners, AE, BGE, JCPL, LS Power, MAOD, PECO, PPL, PSEG and Transource, will be designated to complete this work.

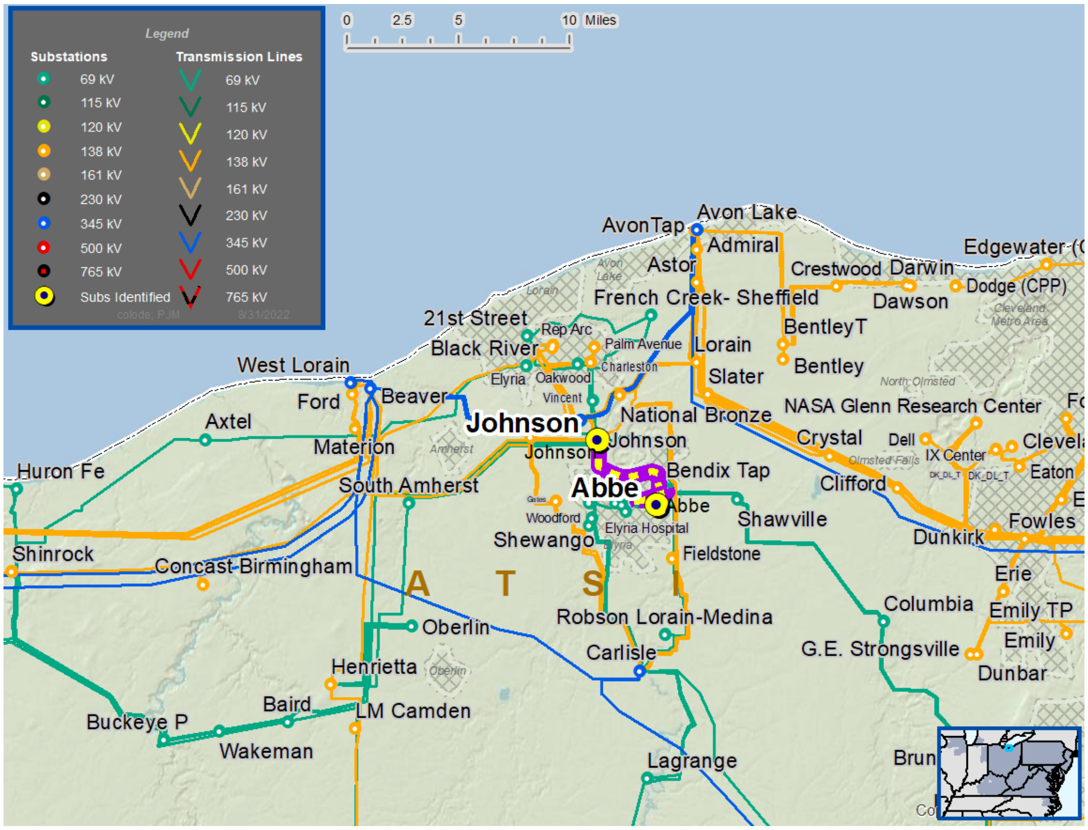
For additional details regarding the NJ SAA project, please refer to the Nov. 4, 2022, special TEAC presentation and the reports posted with the meeting materials: https://pjm.com/committees-and-groups/committees/teac.aspx

Baseline Project b3720: Abbe-Johnson 69 kV Rebuild

ATSI Transmission Zone

In the 2027 RTEP summer case, the Abbe-Johnson 69 kV line is overloaded for an N-1 outage combination. The flow gate was posted as part of 2022 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 17. b3720 – Abbe-Johnson 69 kV



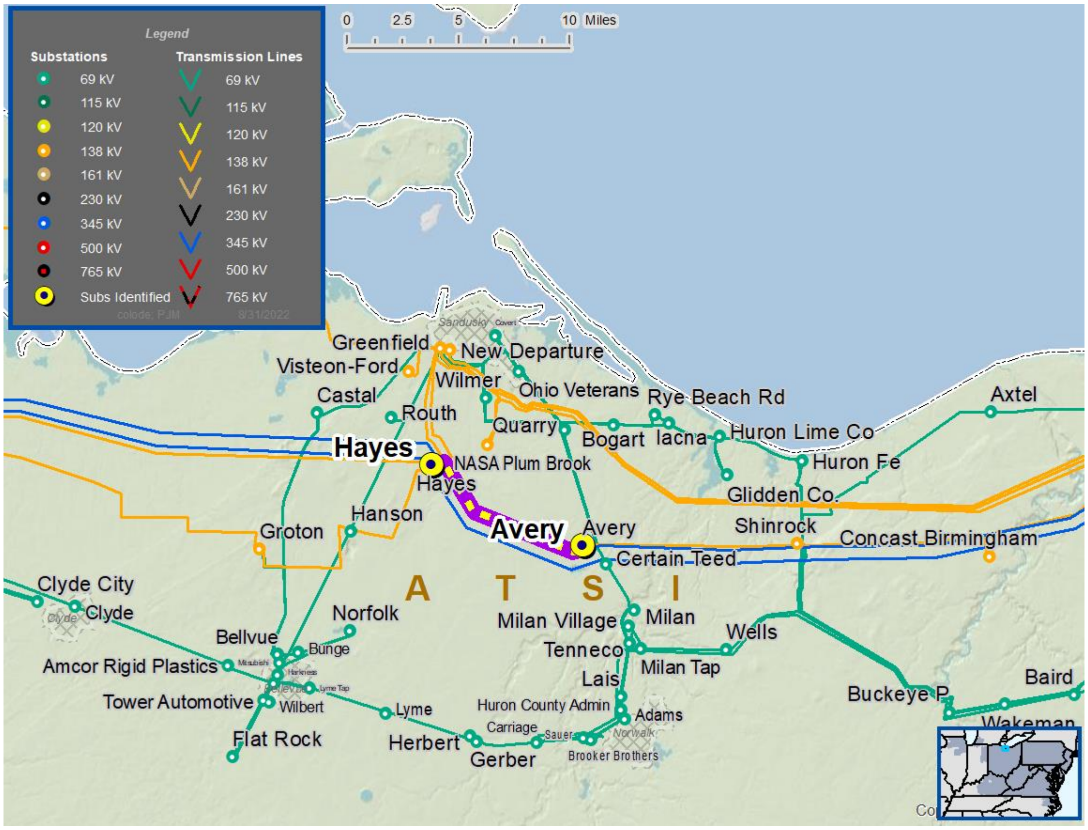
The recommended solution is to rebuild the Abbe-Johnson No. 2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. The project will also replace three disconnect switches (A17, D15 and D16), replace line drops and revise relay settings at Abbe substation; replace one disconnect switch (A159), replace line drops and revise relay settings at Johnson substation; and replace two motor-operated airbreak disconnect switches (A4 & A5), one disconnect switch (D9) and line drops at Redman substation. The estimated cost for this project is $10.9 million. This project has a required in-service date of June 2027 and a projected in-service date of June 2026. The local transmission owner, ATSI, will be designated to complete this work.

Baseline Project b3721: Avery-Hayes 138 kV Rebuild and Reconductor

ATSI Transmission Zone

In the 2027 RTEP summer case, the Avery-Hayes 138 kV line is overloaded for an N-2 outage. The flow gate was posted as part of 2022 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 18. **b3721 – Avery-Hayes 138 kV**



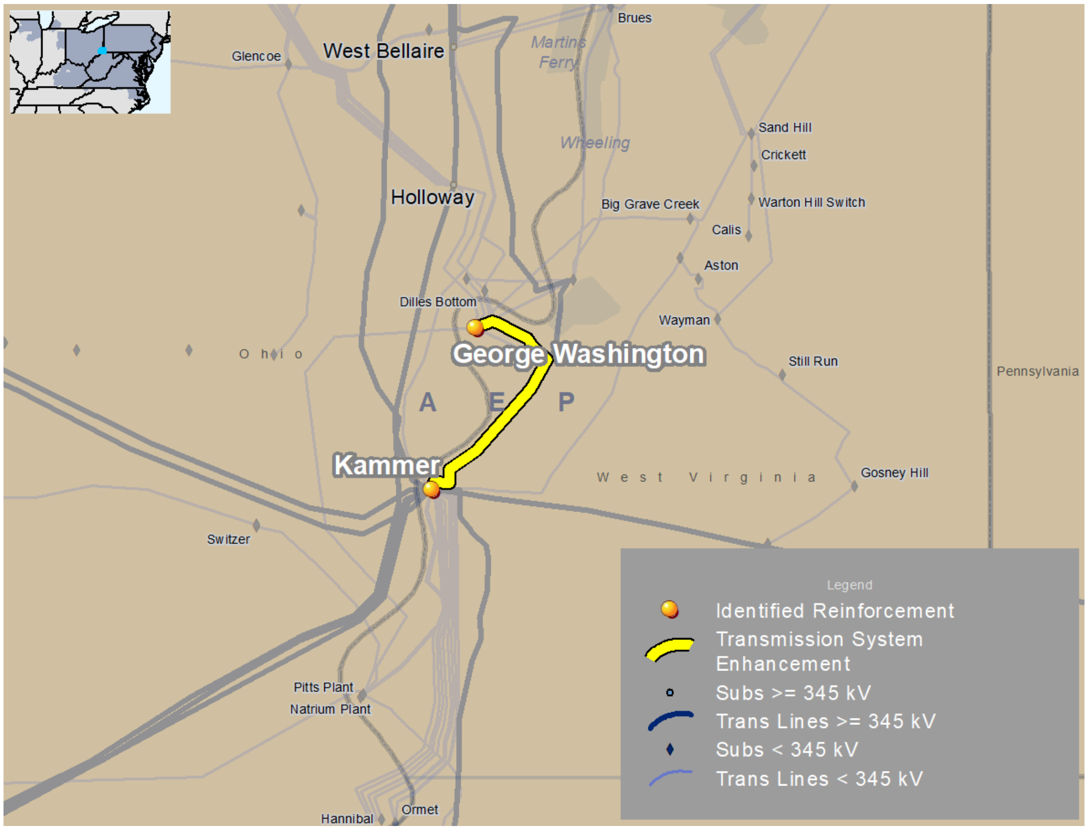
The recommended solution is to rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 kcmil 26/7 ACSR. The estimated cost for this project is $10.4 million, with a required and projected in-service date of June 2027. The local transmission owner, ATSI, will be designated to complete this work.

Baseline Project b3723: George Washington-Kammer 138 kV Rebuild

AEP Transmission Zone

In the 2027 RTEP summer case, the George Washington-Kammer 138 kV line is overloaded for an N-2 outage. The flow gate was posted as part of 2022 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 19. **b3723 – George Washington-Kammer 138 kV**



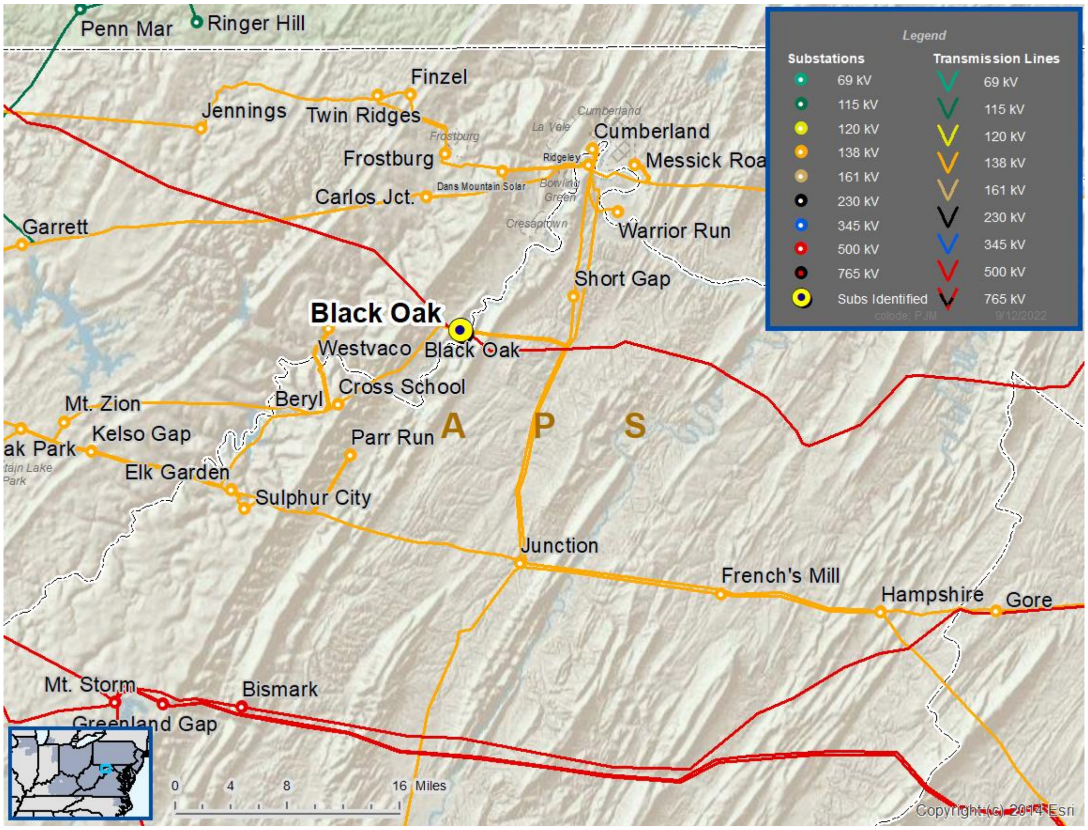
The recommended solution is to rebuild the George Washington-Kammer 138 kV line (6.7 miles of total upgrade scope). The project will also remove the existing six-wired steel lattice towers and supplement the right-of-way as needed. The estimated cost for this project is $18.3 million. This project has a required in-service date of June 2027 and a projected in-service date of June 2024. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3726: Black Oak 500 kV Substation Improvements

APS Transmission Zone

In the 2027 RTEP summer and winter case, there are several voltage drop violations at the Black Oak 500 kV substation for N-1 outage combinations. The flow gates were posted as part of 2022 RTEP Window 1, and PJM received one proposal to address the flow gates.

Map 20. **b3726 – Black Oak 500 kV**



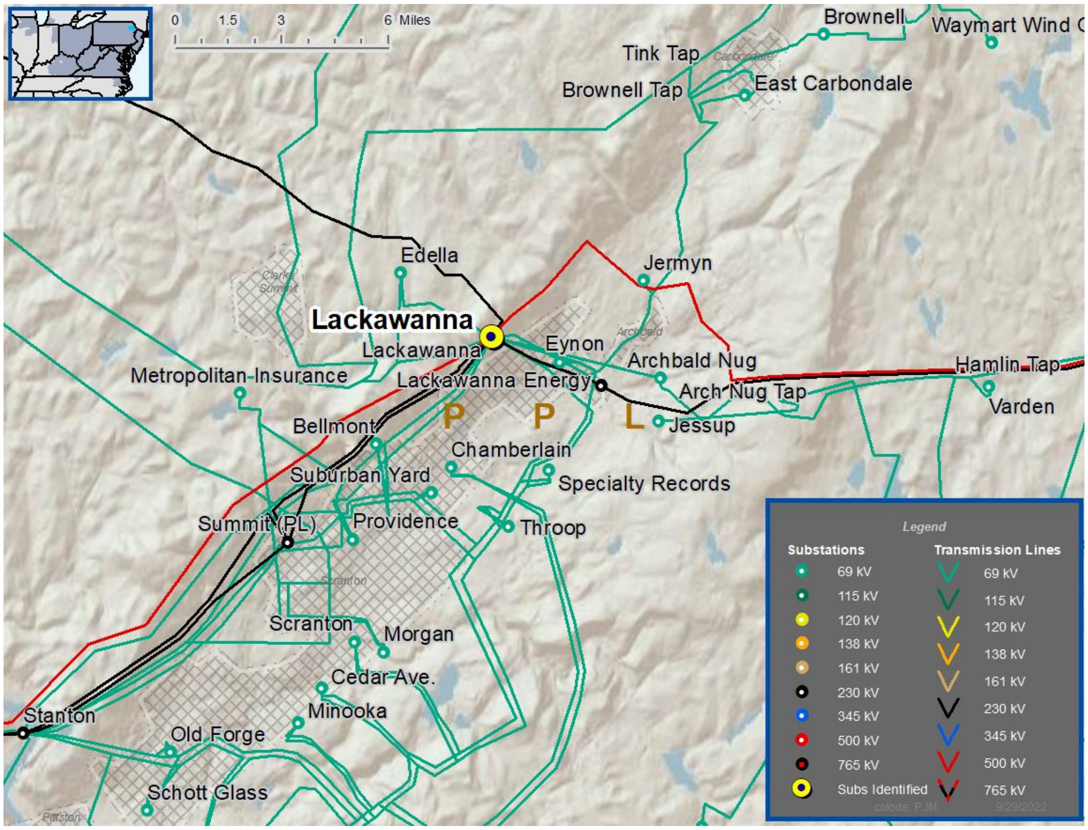
The recommended solution is to install two new 500 kV 50 kA breakers on the existing open SVC string to create a new bay position, and relocate and reterminate facilities as necessary to move the 500 kV SVC into the new bay position. The project will also install a 500 kV 50 kA breaker on the 500/138 kV No. 3 transformer, and upgrade relaying at Black Oak substation. The estimated cost for this project is $17.37 million, with a required and projected in-service date of June 2027. The local transmission owner, APS, will be designated to complete this work.

Baseline Project b3730: Lackawanna 500/230 kV Transformer Improvements

PPL Transmission Zone

In the 2027 RTEP summer case, the Lackawanna No. T3 transformer is overloaded for an N-2 outage. The flow gate was posted as part of 2022 RTEP Window 1, and PJM received three proposals to address the flow gate.

Map 21. **b3730 – Lackawanna 500/230 kV**



The recommended solution is to reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another. The estimated cost for this project is $10.7 million. This project has a required in-service date of June 2027 and a projected in-service date of January 2026. The local transmission owner, PPL, will be designated to complete this work.

Appendix A - Previously Identified RTEP Baseline Upgrades

Appendix A contains all currently required baseline upgrades that were identified in previous RTEP assessments. This appendix also contains expected required in-service dates for facilities. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. The continuing need for these required system facilities was evaluated as part of the 2022 RTEP assessment and will be evaluated in future RTEP assessments. This list of upgrades represents a snapshot of all required planned facilities in the RTEP as of 12/31/2022.

1) Baseline Upgrade b0866
   - Replace Chalk Point 230 kV breaker (6C) with 80 Ka breaker - 6/1/2012 - $2.00M
2) Baseline Upgrade b1270
   - Reconductor Bath - Trebein 138kV - 6/1/2015 - $1.30M
3) Baseline Upgrade b1273
   - Add 2nd Bath 345/138kV Xfr - 6/1/2015 - $7.00M
4) Baseline Upgrade b1274
   - Add 2nd Trebein 138/69kV Xfr - 6/1/2015 - $5.30M
5) Baseline Upgrade b1275
   - Add 2nd W. Milton 138/69kV Xfr - 6/1/2015 - $8.80M
6) Baseline Upgrade b1276
   - Add 2nd W. Milton 345/138 Xfr - 6/1/2015 - $5.50M
7) Baseline Upgrade b1570
   - Add a 345/69 kV transformer at Dayton's Peoria 345 kV bus - 6/1/2014 - $16.00M
8) Baseline Upgrade b1570.1
   - Add/reconductor Peoria - Darby 69 kV line - 6/1/2014 - $0.00M
9) Baseline Upgrade b1570.2
   - Add / reconductor Peoria - Union REA 69 kV line - 6/1/2014 - $0.00M
10) Baseline Upgrade b1570.3
   - Reconductor Union REA - Honda MT 69 kV line - 6/1/2014 - $0.00M
11) Baseline Upgrade b1572
   - Construct a new 138 kV line from West Milton to Eldean - 6/1/2014 - $16.00M
12) Baseline Upgrade b1696
   - Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV - 5/1/2016 - $159.00M
13) Baseline Upgrade b1696.2
   - Replace the Idylwood 230 kV '209712' breaker with 50 kA breaker - 6/1/2017 - $0.35M

14) Baseline Upgrade b2003

- Construct a Whippany to Montville 230 kV line (6.4 miles) - 6/1/2015 - $80.60M

15) Baseline Upgrade b2220

- Install two 115 kV breakers at Chestnut Hill and remove sag limitations on the Pumphrey - Frederick Rd 115 kV circuits 110527 and 110528 to obtain a 125 deg. Celsius rating (161/210 MVA) - 6/1/2017 - $14.00M

16) Baseline Upgrade b2257

- Rebuild the Pokagon - Corey 69 kV line as a double circuit 138 kV line with one side at 69 kV and the other side as an express circuit between Pokagon and Corey stations - 6/1/2017 - $84.70M

17) Baseline Upgrade b2361

- Construct a 230kV UG line approx. 4.5 miles from Idylwood to Tysons. Tysons Substation will be rebuilt, within its existing footprint, with a 6-breaker ring bus using GIS equipment. - 6/1/2017 - $210.00M

18) Baseline Upgrade b2436.90

- Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades - 6/1/2015 - $40.21M

19) Baseline Upgrade b2443.6

- Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed. - 6/1/2026 - $23.08M

20) Baseline Upgrade b2555

- Updated scope: Reconductor 0.3 miles of Tiltonsville-Windsor 138 kV into Tiltonsville station with 795 ACSS; string the vacant side of the 3.8 mile middle section using 556 ACSR and operate in a six wire configuration; rebuild the 0.9 mile section crossing from Ohio into the Windsor station in West Virginia, using 795 ACSS. - 6/1/2019 - $2.00M

21) Baseline Upgrade b2597

- Rebuild approximately 1 mi. section of Dragoon-Virgil Street 34.5 kV line between Dragoon and Dodge Tap switch and replace Dodge switch MOAB to increase thermal capability of Dragoon-Dodge Tap branch - 6/1/2019 - $2.15M

22) Baseline Upgrade b2598

- Rebuild approximately 1 mile section of the Kline-Virgil Street 34.5 kV line between Kline and Virgil Street tap. Replace MOAB switches at Beiger, risers at Kline, switches and bus at Virgil Street. - 6/1/2019 - $1.69M

23) Baseline Upgrade b2604.1

- Remove approximately 11.32 miles of the 69 kV line between Millbrook Park and Franklin Furnace. - 6/1/2019 - $1.13M

24) Baseline Upgrade b2604.10

- Build a new station (Althea) with a 138/69 kV, 90 MVA transformer. The 138 kV side will have a single 2000 A 40 kA circuit breaker and the 69 kV side will be a 2000 A 40 kA three breaker ring bus. - 6/1/2019 - $11.07M

25) Baseline Upgrade b2604.11

- Remote end work at Hanging Rock, East Wheelersburg and North Haverhill 138 kV. - 6/1/2019 - $0.06M

26) Baseline Upgrade b2604.2

- At Millbrook Park station, add a new 138/69 kV transformer #2 (90 MVA) with 3000 A 40 kA breakers on the high and low side. Replace the 600 A MOAB Switch and add a 3000 A circuit switcher on the high side of transformer #1. - 6/1/2019 - $3.05M

27) Baseline Upgrade b2604.3

- Replace Sciotoville 69 kV station with a new 138/12 kV in-out station (Cottrell) with 2000A line MOABs facing Millbrook Park and East Wheelersburg 138 kV. - 6/1/2019 - $1.40M

28) Baseline Upgrade b2604.4

- Tie Cottrell switch into the Millbrook Park-East Wheelersburg 138 kV circuit by constructing 0.50 miles of line using 795 ACSR 26/7 Drake (SE 359 MVA). - 6/1/2019 - $1.96M

29) Baseline Upgrade b2604.5

- Install a new 2000 A 3-way POP Switch outside of Texas Eastern 138 kV substation (Sadiq Switch). - 6/1/2019 - $1.08M

30) Baseline Upgrade b2604.6

- Replace the Wheelersburg 69 kV station with a new 138/12 kV in-out station (Sweetgum) with a 3000 A 40 kA breaker facing Sadiq Switch and a 2000 A 138 kV MOAB facing Althea. - 6/1/2019 - $2.16M

31) Baseline Upgrade b2604.7

- Build approximately 1.4 miles of new 138 kV line using 795 ACSR 26/7 Drake (SE 359 MVA) between the new Sadiq Switch and the new Sweetgum 138 kV stations. - 6/1/2019 - $3.41M

32) Baseline Upgrade b2604.8

- Remove the existing 69 kV Hayport Road Switch. - 6/1/2019 - $0.10M

33) Baseline Upgrade b2604.9

- Rebuild approximately 2.3 miles along existing ROW from Sweetgum to the Hayport Rd switch 69 kV location as 138 kV single circuit and rebuild approximately 2.0 miles from the Hayport Road switch to Althea 69 kV with double circuit 138 kV construction, one side operated at 69 kV to continue service to K.O. Wheelersburg, using 795 ACSR 26/7 Drake (SE 359 MVA). - 6/1/2019 - $10.76M

34) Baseline Upgrade b2633

- Artificial Island Solution - 4/1/2019 - $0.00M

35) Baseline Upgrade b2633.91

- Implement changes to the tap settings for the two Salem units' step up transformers - 4/1/2019 - $0.01M

36) Baseline Upgrade b2633.92

- Implement changes to the tap settings for the Hope Creek unit's step up transformers - 4/1/2019 - $0.01M

37) Baseline Upgrade b2668.1

- Replace the bus/risers at Dequine 345 kV station - 6/1/2020 - $2.30M

38) Baseline Upgrade b2708

- Replace the Oceanview 230/34.5 kV transformer #1 - 6/1/2020 - $4.07M

39) Baseline Upgrade b2743.1

- Tap the Conemaugh - Hunterstown 500 kV line & create new Rice 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $43.10M

40) Baseline Upgrade b2743.2

- Tie in new Rice substation to Conemaugh-Hunterstown 500 kV - 6/1/2020 - $14.60M

41) Baseline Upgrade b2743.3

- Upgrade terminal equipment at Conemaugh 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.35M

42) Baseline Upgrade b2743.4

- Upgrade terminal equipment at Hunterstown 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.20M

43) Baseline Upgrade b2743.5

- Build new 230 kV double circuit line between Rice and Ringgold 230 kV, operated as a single circuit. - 6/1/2020 - $93.40M

44) Baseline Upgrade b2743.6

- Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme - 6/1/2020 - $7.87M

45) Baseline Upgrade b2743.6.1

- Replace the two Ringgold 230/138 kV transformers - 6/1/2020 - $6.26M

46) Baseline Upgrade b2743.7

- Rebuild/Reconductor the Ringgold - Catoctin 138 kV circuit and upgrade terminal equipment on both ends - 6/1/2020 - $47.22M

47) Baseline Upgrade b2743.8

- Replace Ringgold Substation 138 kV breakers '138 BUS TIE' and 'RCM0' with 40 kA breakers - 6/1/2020 - $0.71M

48) Baseline Upgrade b2752.1

- Tap the Peach Bottom – TMI 500 kV line & create new Furnace Run 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $39.80M

49) Baseline Upgrade b2752.2

- Tie in new Furnace Run substation to Peach Bottom-TMI 500 kV - 6/1/2020 - $10.50M

50) Baseline Upgrade b2752.3

- Upgrade terminal equipment and required relay communication at Peach Bottom 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $1.70M

51) Baseline Upgrade b2752.4

- Upgrade terminal equipment and required relay communication at TMI 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $2.00M

52) Baseline Upgrade b2752.5

- Build new 230 kV double circuit line between Furnace Run and Conastone 230 kV, operated as a single circuit. - 6/1/2020 - $51.12M

53) Baseline Upgrade b2752.6

- Conastone 230 kV substation tie-in work (install a new circuit breaker at Conastone 230 kV and upgrade any required terminal equipment to terminate the new circuit) - 6/1/2020 - $6.14M

54) Baseline Upgrade b2752.7

- Reconductor/Rebuild the two Conastone - Northwest 230 kV lines and upgrade terminal equipment on both ends - 6/1/2020 - $52.14M

55) Baseline Upgrade b2752.8

- Replace the Conastone 230kV '2322 B5' breaker with a 63kA breaker - 6/1/2020 - $1.51M

56) Baseline Upgrade b2752.9

- Replace the Conastone 230kV '2322 B6' breaker with a 63kA breaker - 6/1/2020 - $1.51M

57) Baseline Upgrade b2753.7

- Retire line sections (Dilles Bottom - Bellaire and Moundsville - Dilles Bottom 69 kV lines) south of First Energy 138 kV line corridor, near “Point A”. Tie George Washington - Moundsville 69 kV circuit to George Washington - West Bellaire 69 kV circuit. - 5/31/2020 - $5.52M

58) Baseline Upgrade b2759

- Rebuild Line #550 Mt. Storm – Valley 500kV - 6/1/2016 - $476.00M

59) Baseline Upgrade b2760

- Perform a Sag Study of the Saltville - Tazewell 138 kV line to increase the thermal rating of the line - 6/1/2021 - $0.10M

60) Baseline Upgrade b2765

- Upgrade bus conductor at Gardners 115 kV substation; Upgrade bus conductor and adjust CT ratios at Carlisle Pike 115 kV - 6/1/2021 - $1.20M

61) Baseline Upgrade b2791

- Rebuild Tiffin-Howard, new transformer at Chatfield - 6/1/2021 - $20.39M

62) Baseline Upgrade b2791.3

- New 138/69kV transformer with 138kV & 69kV protection at Chatfield station. - 6/1/2021 - $0.00M

63) Baseline Upgrade b2791.4

- New 138kV & 69kV protection at existing Chatfield transformer. - 6/1/2021 - $2.50M

64) Baseline Upgrade b2793

- Energize the spare Fremont Center 138/69 kV 130 MVA transformer #3. Reduces overloaded facilities to 46% loading. - 6/1/2021 - $1.30M

65) Baseline Upgrade b2891

- Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area. - 6/1/2021 - $13.40M

66) Baseline Upgrade b2914

- Rebuild Tharp Tap-KU Elizabethtown 69kV line section to 795 MCM (2.11 miles). - 12/1/2024 - $1.22M

67) Baseline Upgrade b2932

- Replace terminal equipment at Tanners Creek on Tanners Creek Dearborn 345 kV line. - 6/1/2021 - $1.50M

68) Baseline Upgrade b2933

- Third Source for Springfield Rd. and Stanley Terrace Stations - 6/1/2018 - $0.00M

69) Baseline Upgrade b2933.31

- Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Front Street - Springfield) - 6/1/2018 - $39.66M

70) Baseline Upgrade b2935

- Third Supply for Runnemede 69kV and Woodbury 69kV - 6/1/2018 - $90.60M

71) Baseline Upgrade b2935.1

- Build a new 230/69 kV switching substation at Hilltop utilizing the PSE&G property and the K-2237 230 kV line. - 6/1/2018 - $0.00M

72) Baseline Upgrade b2935.2

- Build a new line between Hilltop and Woodbury 69 kV providing the 3rd supply - 6/1/2018 - $0.00M

73) Baseline Upgrade b2938

- Perform a sag mitigations on the Broadford – Wolf Hills 138kV circuit to allow the line to operate to a higher maximum temperature. - 6/1/2022 - $2.60M

74) Baseline Upgrade b2940

- Upgrade the distance relay on the Wayne Co – Wayne Co KY 161kV line to increase the line winter rating would be 167/167 - 12/1/2022 - $0.00M

75) Baseline Upgrade b2945.1

- Rebuild the BL England – Middle Tap 138kV line to 2000A on double circuited steel poles and new foundations - 6/1/2022 - $52.20M

76) Baseline Upgrade b2945.2

- Re-conductor BL England – Merion 138kV (1.9miles) line - 6/1/2022 - $3.73M

77) Baseline Upgrade b2945.3

- Re-conductor Merion – Corson 138kV (8miles) line - 6/1/2022 - $8.36M

78) Baseline Upgrade b2946

- Convert existing Preston 69 kV Substation to DPL's current design standard of a 3-breaker ring bus. - 6/1/2022 - $6.67M

79) Baseline Upgrade b2947.1

- Upgrade terminal equipment at DPL's Naamans Substation (Darley-Naamans 69 kV) - 6/1/2022 - $0.38M

80) Baseline Upgrade b2950

- Upgrade limiting 115 kV switches on the 115 kV side of the 230/115 kV Northwood substation and adjust setting on limiting ZR relay - 6/1/2022 - $0.25M

81) Baseline Upgrade b2970

- Ringgold - Catoctin Solution - 6/1/2020 - $0.00M

82) Baseline Upgrade b2970.1

- Install two new 230 kV positions at Ringgold for 230/138 kV transformers. - 6/1/2020 - $3.20M

83) Baseline Upgrade b2970.2

- Install new 230 kV position for the Catoctin 230 kV line at Ringgold. - 6/1/2020 - $1.60M

84) Baseline Upgrade b2970.3

- Install one new 230 kV breaker at Catoctin substation. - 6/1/2020 - $7.60M

85) Baseline Upgrade b2970.4

- Install new 230 / 138 kV transformer at Catoctin substation. Convert Ringgold-Catoctin 138 kV Line to 230 kV operation. - 6/1/2020 - $0.90M

86) Baseline Upgrade b2970.5

- Convert Garfield 138/12.5 kV substation to 230/12.5 kV - 6/1/2020 - $2.20M

87) Baseline Upgrade b2981

- Rebuild 115 kV Line No.29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV) - 12/31/2022 - $19.24M

88) Baseline Upgrade b2986.1

- Roseland-Branchburg 230kV corridor rebuild - 6/1/2018 - $0.00M

89) Baseline Upgrade b2986.11

- Roseland-Branchburg 230kV corridor rebuild (Roseland - Readington) - 6/1/2018 - $292.18M

90) Baseline Upgrade b2986.12

- Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) - 6/1/2018 - $55.29M

91) Baseline Upgrade b2986.2

- Branchburg-Pleasant Valley 230kV corridor rebuild - 6/1/2018 - $0.00M

92) Baseline Upgrade b2986.22

- Branchburg-Pleasant Valley 230kV corridor rebuild (East Flemington - Pleasant Valley) - 6/1/2018 - $108.12M

93) Baseline Upgrade b2986.23

- Branchburg-Pleasant Valley 230kV corridor rebuild (Pleasant Valley - Rocktown) - 6/1/2018 - $21.73M

94) Baseline Upgrade b2986.24

- Branchburg-Pleasant Valley 230kV corridor rebuild (the PSEG portion of Rocktown - Buckingham) - 6/1/2018 - $9.18M

95) Baseline Upgrade b2987

- Install a 30 MVAR capacitor bank at DPL's Cool Springs 69 kV Substation. The capacitor bank would be installed in two separate 15 MVAR stages allowing DPL operational flexibility - 6/1/2022 - $3.65M

96) Baseline Upgrade b3005

- Reconductor 3.1 mile 556 ACSR portion of Cabot to Butler 138 kV with 556 ACSS and upgrade terminal equipment. 3.1 miles of line will be reconductored for this project. The total length of the line is 7.75 miles. - 6/1/2021 - $5.88M

97) Baseline Upgrade b3007.1

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - AP portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Social Hall, meters, relays, bus conductor, a wavetrap, circuit breaker and disconnects will be replaced. - 6/1/2021 - $4.42M

98) Baseline Upgrade b3007.2

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - PENELEC portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Blairsville East, the wave trap and breaker disconnects will be replaced. - 6/1/2021 - $7.00M

99) Baseline Upgrade b3010

- Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wavetrap, and meter will be replaced. At Cabot, a wavetrap and bus conductor will be replaced. - 6/1/2021 - $0.78M

100) Baseline Upgrade b3011.1

- Construct new Route 51 substation and connect 10 138 kV lines to new substation - 6/1/2021 - $36.34M

101) Baseline Upgrade b3011.6

- Upgrade remote end relays for Yukon –Allenport – Iron Bridge 138 kV line - 6/1/2021 - $1.97M

102) Baseline Upgrade b3012.1

- Construct two new 138 kV ties with the single structure from APS's new substation to DUQ's new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase. - 6/1/2021 - $23.10M

103) Baseline Upgrade b3012.3

- Construct a new Elrama - Route 51 138 kV No.3 line: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at APS Route 51 substation. - 6/1/2020 - $18.10M

104) Baseline Upgrade b3013

- Reconductor Vasco Tap to Edgewater Tap 138 kV line. 4.4 miles. The new conductor will be 336 ACSS replacing the existing 336 ACSR conductor. - 6/1/2021 - $5.88M

105) Baseline Upgrade b3014

- Replace the existing Shelocta 230/115 kV transformer and construct a 230 kV ring bus - 6/1/2021 - $7.35M

106) Baseline Upgrade b3015.8

- Upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line - 6/1/2021 - $2.00M

107) Baseline Upgrade b3017.1

- Rebuild Glade to Warren 230 kV line with hi-temp conductor and substation terminal upgrades. 11.53 miles. New conductor will be 1033 ACSS. Existing conductor is 1033 ACSR. - 6/1/2021 - $42.40M

108) Baseline Upgrade b3017.2

- Glade substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

109) Baseline Upgrade b3017.3

- Warren substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

110) Baseline Upgrade b3019.1

- Update the nameplate for Morrisville 500 kV breaker "H1T594" to be 50 kA - 6/1/2018 - $0.00M

111) Baseline Upgrade b3019.2

- Update the nameplate for Morrisville 500 kV breaker "H1T545" to be 50 kA - 6/1/2018 - $0.00M

112) Baseline Upgrade b3020

- Rebuild 500kV Line #574 Ladysmith to Elmont - 26.2 miles long - 6/1/2018 - $91.32M

113) Baseline Upgrade b3021

- Rebuild 500kV Line #581 Ladysmith to Chancellor - 15.2 miles long - 6/1/2018 - $44.38M

114) Baseline Upgrade b3023

- Replace West Wharton 115kV breakers 'G943A' and 'G943B' with 40kA breakers - 6/1/2020 - $0.50M

115) Baseline Upgrade b3025

- Construct two (2) new 69/13kV stations in the Doremus area and relocate the Doremus load to the new stations - 6/1/2018 - $96.60M

116) Baseline Upgrade b3025.2

- Install a new 69/13 kV station (area of 19th Ave) with a ring bus configuration - 6/1/2018 - $0.00M

117) Baseline Upgrade b3025.3

- Construct a 69kV network between Stanley Terrace, Springfield Road, McCarter, Federal Square, and the two new stations (Vauxhall & area of 19th Ave) - 6/1/2018 - $0.00M

118) Baseline Upgrade b3029

- Install 69 kV underground transmission line from Harings Corner Station terminating at Closter Station (about 3 miles). - 5/31/2020 - $22.00M

119) Baseline Upgrade b3029.1

- Reconfigure Closter Station to accommodate the UG transmission line from Harings Corner Station - 5/31/2020 - $0.00M

120) Baseline Upgrade b3029.2

- Loop in the existing 751 Line (Sparkill - Cresskill 69 kV) into Closter 69 kV station - 5/31/2020 - $0.00M

121) Baseline Upgrade b3031

- Transfer load off of the Leroy Center-Mayfield Q2 138 kV line by reconfiguring the Pawnee Substation primary source, via the existing switches, from the Leroy Center-Mayfield Q2 138 kV line to the Leroy Center-Mayfield Q1 138 kV line. - 6/1/2021 - $0.10M

122) Baseline Upgrade b3033

- Ottawa-Lakeview 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $20.00M

123) Baseline Upgrade b3034

- Lakeview-Greenfield 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $4.80M

124) Baseline Upgrade b3037

- Upgrades at the Natrium substation - 6/1/2023 - $1.10M

125) Baseline Upgrade b3039

- Line Swaps at Muskingum 138 kV Station - 12/1/2023 - $0.10M

126) Baseline Upgrade b3041

- Peach Bottom - Furnace Run 500kV Terminal Equipment - 6/1/2021 - $3.50M

127) Baseline Upgrade b3042

- Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal - 6/1/2023 - $0.05M

128) Baseline Upgrade b3050

- Install redundant relay to Port Union 138 kV Bus#2 - 6/1/2023 - $0.39M

129) Baseline Upgrade b3053

- Upgrade terminal equipment on Gibson - Petersburg 345kV - 10/29/2018 - $4.30M

130) Baseline Upgrade b3054

- Install a battery storage device at Grasonville Substation * Rebuild Wye Mills - Stevensville 69 kV Line * Construct a new 69 kV line from Wye Mills to Grasonville. - 12/1/2023 - $0.00M

131) Baseline Upgrade b3055

- Install spare 230/69 kV transformer at Davis Substation - 6/1/2023 - $0.54M

132) Baseline Upgrade b3056

- Partial Rebuild 230 kV Line #2113 Waller to Lightfoot - 6/1/2018 - $9.00M

133) Baseline Upgrade b3057

- Rebuild 6.1 miles of Waller-Skiffess Creek 230 kV Line (#2154) between Waller and Kings Mill to current standards with a minimum summer emergency rating of 1047 MVA utilizing single circuit steel structures. Remove this 6.1 mile section of Line #58 between Waller and Kings Mill. Rebuild the 1.6 miles of Line #2154 and #19 between Kings Mill and Skiffes Creek to current standards with a minimum summer emergency rating of 1047 MVA at 230 kV for Line #2154 and 261 MVA at 115 kV for Line #19, utilizing double circuit steel structures. - 6/1/2018 - $18.36M

134) Baseline Upgrade b3058

- Partial Rebuild of 230 kV lines between Clifton and Johnson DP (#265, #200 and #2051) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2018 - $11.50M

135) Baseline Upgrade b3064.3

- Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork – Elrama 138 kV line and Bethel Park – Elrama 138 kV line. - 6/1/2021 - $0.60M

136) Baseline Upgrade b3066

- Reconductor the Cranberry - Jackson 138 kV line (2.1 miles), reconductor 138 kV bus at Cranberryand replace 138 kv line switches at Jackson - 6/1/2022 - $2.90M

137) Baseline Upgrade b3067

- Reconductor the Jackson - Maple 138 kV line (4.7 miles), replace line switches at Jackson 138 kV and replace the line traps and relays at Maple 138 kV - 6/1/2022 - $7.10M

138) Baseline Upgrade b3068

- Reconductor the Yukon - Westraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Westraver 138 kV - 6/1/2022 - $2.50M

139) Baseline Upgrade b3069

- Reconductor the Westraver - Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV - 6/1/2022 - $7.50M

140) Baseline Upgrade b3070

- Reconductor the Yukon - Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV - 6/1/2022 - $10.00M

141) Baseline Upgrade b3071

- Reconductor the Yukon - Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

142) Baseline Upgrade b3072

- Reconductor the Yukon - Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

143) Baseline Upgrade b3073

- Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor - 6/1/2022 - $2.10M

144) Baseline Upgrade b3074

- Replace Substation conductor on the 345/138 kV transformer at Armstrong substation - 6/1/2022 - $0.10M

145) Baseline Upgrade b3075

- Replace substation conductor and 138 kV circuit breaker on the #1 transformer (500/138 kV) at Cabot substation - 6/1/2022 - $0.30M

146) Baseline Upgrade b3076

- Reconductor the Edgewater - Loyalhanna 138 kV line (0.67 miles) - 6/1/2022 - $2.00M

147) Baseline Upgrade b3077

- Reconductor the Franklin Pike - Wayne 115 kV line (6.78 miles) - 6/1/2022 - $11.40M

148) Baseline Upgrade b3078

- Reconductor 138 kV bus and replace the line trap, relays at Morgan Street. Reconductor 138 kV bus at Venango Junction - 6/1/2022 - $1.00M

149) Baseline Upgrade b3079

- Replace the Wylie Ridge 500/345 kV transformer #7 - 6/1/2022 - $6.37M

150) Baseline Upgrade b3080

- Reconductor 138 kV bus at Seneca - 6/1/2022 - $0.07M

151) Baseline Upgrade b3081

- Replace 138 kV breaker and substation conductor at Krendale - 6/1/2022 - $0.30M

152) Baseline Upgrade b3082

- Construct a 4-breaker 115 kV ring bus at Franklin Pike - 6/1/2022 - $8.00M

153) Baseline Upgrade b3083

- Replace substation conductor at Butler (138 kV) Replace substation conductor and line trap at Karns City (138 kV) - 6/1/2022 - $0.20M

154) Baseline Upgrade b3085

- Reconductor Kammer - George Washington 138 kV line (~0.08 miles). Replace the wave trap at Kammer 138 kV. - 6/1/2022 - $0.50M

155) Baseline Upgrade b3086.2

- Rebuild New Liberty – North Baltimore 34 kV Line Str's 1-11 (0.5 miles), utilizing 795 26/7 ACSR conductor - 6/1/2022 - $1.80M

156) Baseline Upgrade b3086.4

- North Findlay Station: Install a 138 kV 3000 A 63 kA line breaker and low side 34.5 kV 2000 A 40 kA breaker, high side 138 kV circuit switcher on T1 - 6/1/2022 - $1.70M

157) Baseline Upgrade b3087.1

- Construct a new greenfield station to the west (~1.5 mi.) of the existing Fords Branch Station potentially in/near the new Kentucky Enterprise Industrial Park. . This new station will consist of 4 -138 kV breaker ring bus and two 30 MVA 138/34.5 kV transformers. The existing Fords Branch Station will be retired. - 12/1/2018 - $3.40M

158) Baseline Upgrade b3087.2

- Construct approximately 5 miles of new double circuit 138 kV line in order to loop the new Fords Branch station into the existing Beaver Creek – Cedar Creek 138 kV circuit. - 12/1/2018 - $19.90M

159) Baseline Upgrade b3087.3

- Remote end work will be required at Cedar Creek Station. - 12/1/2018 - $0.50M

160) Baseline Upgrade b3087.4

- Install 28.8MVar switching shunt at the new Fords Branch substation - 12/1/2023 - $0.50M

161) Baseline Upgrade b3089

- Rebuild 230kV Line #224 between Lanexa and Northern Neck utilizing double circuit structures to current 230kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA. - 6/1/2018 - $112.22M

162) Baseline Upgrade b3090

- Convert the OH portion (approx. 1500 Feet) of 230 kV Lines #248 & #2023 to UG and convert Glebe substation to GIS. - 1/1/2021 - $202.00M

163) Baseline Upgrade b3094

- Move 69 kV 12.0 MVAR capacitor bank from Greenbriar to Bullitt Co 69kV substation - 6/1/2018 - $0.40M

164) Baseline Upgrade b3095

- Rebuild Lakin – Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 12/1/2022 - $23.90M

165) Baseline Upgrade b3096

- Rebuild 230 kV line No.2063 (Clifton – Ox) and part of 230 kV line No.2164 (Clifton – Keene Mill) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2019 - $19.00M

166) Baseline Upgrade b3098

- Rebuild 9.8 miles of 115kV Line #141 between Balcony Falls and Skimmer and 3.8 miles of 115kV Line #28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA. - 6/1/2019 - $30.90M

167) Baseline Upgrade b3098.1

- Rebuild Balcony Falls Substation - 6/1/2019 - $9.00M

168) Baseline Upgrade b3099

- Install a 138 kV 3000A 40 kA circuit switcher on the high side of the existing 138/34.5 kV transformer #5 and a 138 kV 3000A 40 kA circuit switcher transformer #7 at Holston station - 6/1/2022 - $0.70M

169) Baseline Upgrade b3100

- Relocate 138 kV circuit breaker W between 138 kV bus #1 extension and bus #2 at Chemical station. Install a new 138 kV circuit breaker between bus #1 and bus #1 extension. - 12/1/2022 - $0.70M

170) Baseline Upgrade b3101

- Rebuild the 1/0 Cu. conductor sections (~1.5 miles) of the Fort Robinson - Moccasin Gap 69 kV line section (~5 miles) utilizing 556 ACSR conductor and upgrade existing relay trip limit (WN/WE: 63 MVA , line limited by remaining conductor sections). - 12/1/2023 - $3.00M

171) Baseline Upgrade b3104

- Perform a sag study on the Polaris - Westerville 138 kV line (~ 3.6 miles) to increase the Summer Emergency rating to 310 MVA. - 6/1/2020 - $0.50M

172) Baseline Upgrade b3108.2

- Install 100 MVAR reactor at Sugarcreek 138 kV substation - 6/1/2019 - $5.00M

173) Baseline Upgrade b3108.3

- Install 100 MVAR reactor at Hutchings 138 kV substation - 6/1/2019 - $5.00M

174) Baseline Upgrade b3114

- Rebuild the 18.6 mile section of 115kV Line #81 which includes 1.7 miles of double circuit Line #81 with 230kV Line #2056 and 1.3 miles of double circuit Line #81 with 230kV Line #239. This segment of Line #81 will be rebuilt to current standards with a minimum rating of 261 MVA. This segment of Line #239 will be rebuilt to current standards with a minimum rating of 1046 MVA. Line #2056 rating will not change. - 6/1/2019 - $27.10M

175) Baseline Upgrade b3115

- Provide new station service to control building from 230 kV bus (served from plant facilities presently). - 9/30/2019 - $1.50M

176) Baseline Upgrade b3116

- Replace existing Mullens 138/46 kV 30 MVA transformer No.4 and associated protective equipment with a new 138/46 kV 90 MVA transformer and associated protective equipment. Install required high side transformer protection by replacing the existing ground switch MOAB with a new 138 kV high side circuit breaker. - 12/1/2022 - $4.00M

177) Baseline Upgrade b3118.3

- Perform 138 kV remote end work at Bellefonte station. - 6/1/2022 - $0.50M

178) Baseline Upgrade b3119.1

- Rebuild the Jay – Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station - 6/1/2022 - $38.10M

179) Baseline Upgrade b3119.2

- Install three (3) 69 kV breakers to create the "U" string and add a low side breaker on the Jay transformer 2 - 6/1/2022 - $3.40M

180) Baseline Upgrade b3119.3

- Install two (2) 69 kV breakers at North Portland station to complete the ring and allow for the new line. - 6/1/2022 - $1.90M

181) Baseline Upgrade b3121

- Rebuild Clubhouse-Lakeview 230 kV Line #254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1047 MVA. - 6/1/2019 - $25.50M

182) Baseline Upgrade b3122

- Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV Line #2181 and Line #2058 with double circuit steel structures using double circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA. - 6/1/2019 - $13.00M

183) Baseline Upgrade b3123

- At Sammis 345 kV station: Install a new control building in the switchyard, construct a new station access road, install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes - 6/1/2022 - $8.00M

184) Baseline Upgrade b3124

- Separate metering, station power, and communication at Bruce Mansfield 345 kV station - 12/31/2020 - $0.93M

185) Baseline Upgrade b3125

- At Davis Bessie 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes - 5/31/2020 - $1.80M

186) Baseline Upgrade b3126

- At Perry 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and construct a new station access road - 6/1/2021 - $0.60M

187) Baseline Upgrade b3130

- Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), Rebuild/Reconductor two 34.5 kV circuits (total of 5.5 miles) and install a 2nd 115/34.5 kV transformer (Werner) - 6/1/2016 - $223.00M

188) Baseline Upgrade b3130.1

- Construct a new 34.5 kV circuit from Oceanview to Allenhurst 34.5 kV (3.9 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

189) Baseline Upgrade b3130.10

- Install 2nd 115-34.5 kV Transformer at Werner Substation - (replaces B1690) - 6/1/2016 - $0.00M

190) Baseline Upgrade b3130.2

- Construct a new 34.5 kV circuit from Atlantic to Red Bank 34.5 kV (10.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

191) Baseline Upgrade b3130.3

- Construct a new 34.5 kV circuit from Freneau to Taylor Lane 34.5 kV (10.7 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

192) Baseline Upgrade b3130.4

- Construct a new 34.5 kV circuit from Keyport to Belford 34.5 kV (5.6 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

193) Baseline Upgrade b3130.5

- Construct a new 34.5 kV circuit from Red Bank to Belford 34.5 kV (5.7 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

194) Baseline Upgrade b3130.6

- Construct a new 34.5 kV circuit from Werner to Clark Street (7.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

195) Baseline Upgrade b3130.7

- Construct a new 34.5 kV circuit from Atlantic to Freneau (13.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

196) Baseline Upgrade b3130.8

- Rebuild/Reconductor the Atlantic to Camp Woods Switch Point (3.5 Miles) 34.5 kV circuit - (replaces B1690) - 6/1/2016 - $0.00M

197) Baseline Upgrade b3130.9

- Rebuild/Reconductor the Allenhurst to Elberon (2.0 Miles) 34.5 kV circuit - (replaces B1690) - 6/1/2016 - $0.00M

198) Baseline Upgrade b3131

- At East Lima and Haviland.The Haviland – East Lima 138kV line is overloaded for multiple contingencies in winter generator deliverability test and basecase analysis test. 138 kV stations, replace line relays and wavetrap on the East Lima-Haviland 138 kV facility.In addition, replace 500 MCM Cu Risers and Bus conductors at Haviland 138 kV - 12/1/2024 - $1.35M

199) Baseline Upgrade b3131.1

- Rebuild approximately 12.3 miles of remaining Lark conductor on the double circuit line between Haviland and East Lima with 1033 54/7 ACSR conductor. - 12/1/2024 - $25.90M

200) Baseline Upgrade b3133

- Move the existing Botkins 69 kV capacitor from the Sidney-Botkins side of the existing breaker at Botkins to the Botkins-Jackson Center side. This will keep the capacitor in-service for the loss of Sidney-Botkins. This reduces the voltage drop to less than 3% and also resolves the overload on the Blue Jacket Tap-Huntsville 69 kV line. - 6/1/2024 - $0.20M

201) Baseline Upgrade b3134

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview substation (21 miles) and create a line terminal at Belle Haven delivery point (three-breaker ring bus) - 6/1/2019 - $22.00M

202) Baseline Upgrade b3134.1

- Reconfigure the Belle Haven 69 kV bus to three-breaker ring bus and create a line terminal for the new 69 kV circuit to Bayview - 6/1/2019 - $0.00M

203) Baseline Upgrade b3134.2

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview Substation (21 miles) - 6/1/2019 - $0.00M

204) Baseline Upgrade b3136

- Replace bus conductor at Smith 115 kV substation - 6/1/2024 - $0.24M

205) Baseline Upgrade b3137

- Rebuild 20 miles of the East Towanda - North Meshoppen 115 kV line - 6/1/2024 - $58.60M

206) Baseline Upgrade b3138

- Move 2 MVA load from the Roxborough to Bala substation. Adjust the tap setting on the Master 138/69 kV transformer No.2 - 6/1/2024 - $0.01M

207) Baseline Upgrade b3142

- Rebuild Michigan City-Trail Creek - Bosserman 138 kV (10.7 mi) - 1/1/2023 - $33.26M

208) Baseline Upgrade b3143.1

- Reconductor the Silverside – Darley 69 kV circuit - 6/1/2024 - $1.39M

209) Baseline Upgrade b3143.2

- Reconductor the Darley – Naamans 69 kV circuit - 6/1/2024 - $2.09M

210) Baseline Upgrade b3143.3

- Replace three (3) existing 1200 A disconnect switches with 2000 A disconnect switches and install three (3) new 2000 A disconnect switches at Silverside 69 kV station - 6/1/2024 - $0.48M

211) Baseline Upgrade b3143.4

- Replace two (2) 1200 A disconnect switches with 2000 A disconnect switches, replace existing 954 ACSR and 500 SDCU stranded bus with (2) 954 ACSR stranded bus. Reconfigure four (4) CTs from 1200 A to 2000 A and install two (2) new 2000 A disconnect switches, new (2) 954 ACSR stranded bus at Naamans 69 kV station - 6/1/2024 - $0.60M

212) Baseline Upgrade b3143.5

- Replace four (4) 1200 A disconnect switches with 2000 A disconnect switces. Replace existing 954 ACSR and 1272 MCM AL stranded bus with (2) 954 ACSR stranded bus. Reconfigure eight (8) CTs from 1200 A to 2000 A and install Four (4) new 2000 A (310 MVA SE / 351 MVA WE) disconnect switches, new (2) 954 ACSR (331 MVA SE / 369 MVA WE) stranded bus at Darley 69 kV station - 6/1/2024 - $0.95M

213) Baseline Upgrade b3144

- Upgrade bus conductor and relay panels Jackson Road – Nanty Glo 46 kV SJN line - 6/1/2024 - $1.50M

214) Baseline Upgrade b3144.1

- Upgrade line relaying and substation conductor on the 46 kV Nanty Glo line exit at Jackson Road substation - 6/1/2024 - $0.00M

215) Baseline Upgrade b3144.2

- Upgrade line relaying and substation conductor on the 46 kV Jackson Road line exit at Nanty Glo substation - 6/1/2024 - $0.00M

216) Baseline Upgrade b3149

- Rebuild the 2.3 mile Decatur – South Decatur 69 kV line using 556 ACSR in order to alleviate the overloads. - 6/1/2024 - $9.30M

217) Baseline Upgrade b3150

- Rebuild Ferguson 69/12 kV station in the clear as the 138/12 kV Bear station and connect it to a ~1 mile double circuit 138 kV extension from the Aviation – Ellison Rd 138 kV line to remove the load from the 69 kV line. - 6/1/2024 - $6.40M

218) Baseline Upgrade b3151.1

- Rebuild the ~30 mile Gateway – Wallen 34.5 kV circuit as the ~27 mile Gateway – Wallen 69 kV circuit. - 6/1/2024 - $43.30M

219) Baseline Upgrade b3151.10

- Rebuild the 2.5 mile Columbia – Gateway 69 kV line. - 6/1/2024 - $6.20M

220) Baseline Upgrade b3151.11

- Rebuild Columbia station in the clear as a 138/69 kV station with two (2) 138/69 kV transformers and 4-breaker ring buses on the high and low side. Station will reuse 69 kV breakers “J” & “K” and 138 kV breaker “D”. - 6/1/2024 - $15.00M

221) Baseline Upgrade b3151.12

- Rebuild the 13 mile Columbia – Richland 69 kV line. - 6/1/2024 - $29.30M

222) Baseline Upgrade b3151.13

- Rebuild the 0.5 mile Whitley – Columbia City No.1 line as 69 kV. - 6/1/2024 - $1.00M

223) Baseline Upgrade b3151.14

- Rebuild the 0.5 mile Whitley – Columbia City No.2 line as 69 kV. - 6/1/2024 - $0.70M

224) Baseline Upgrade b3151.15

- Rebuild the 0.6 mile double circuit section of the Rob Park – South Hicksville / Rob Park – Diebold Road as 69 kV - 6/1/2024 - $1.00M

225) Baseline Upgrade b3151.2

- Retire the ~3 miles Columbia – Whitley 34.5 kV line. - 6/1/2024 - $0.50M

226) Baseline Upgrade b3151.3

- At Gateway station, remove all 34.5 kV equipment and install one (1) 69 kV circuit breaker for the new Whitley line entrance. - 6/1/2024 - $1.00M

227) Baseline Upgrade b3151.4

- Rebuild Whitley as a 69 kV station with two (2) line and one (1) bus tie circuit breakers. - 6/1/2024 - $4.20M

228) Baseline Upgrade b3151.5

- Replace the Union 34.5 kV switch with a 69 kV switch structure. - 6/1/2024 - $0.60M

229) Baseline Upgrade b3151.6

- Replace the Eel River 34.5 kV switch with a 69 kV switch structure. - 6/1/2024 - $0.60M

230) Baseline Upgrade b3151.7

- Install a 69 kV Bobay switch at Woodland Station. - 6/1/2024 - $0.60M

231) Baseline Upgrade b3151.8

- Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two (2) line circuit breakers, one (1) bus tie circuit breaker and a 14.4 MVAR cap bank - 6/1/2024 - $8.70M

232) Baseline Upgrade b3151.9

- Remove 34.5 kV circuit breaker "AD" at Wallen station. - 6/1/2024 - $0.30M

233) Baseline Upgrade b3152

- Reconductor the 8.4 mile section of the Leroy Center - Mayfield Q1 line between Leroy Center and Pawnee Tap to achieve a rating of at least 160 MVA / 192 MVA (SN/SE). - 6/1/2022 - $14.10M

234) Baseline Upgrade b3154

- Install one (1) 13.2 MVAR 46 kV capacitor at the Logan substation - 6/1/2024 - $1.70M

235) Baseline Upgrade b3155

- Rebuild approximately 12 miles of Wye Mills - Stevensville line to achieve needed ampacity - 12/1/2023 - $23.60M

236) Baseline Upgrade b3156

- Replace line relaying and fault detector on the Wylie Ridge terminal at Smith 138 kV Substation - 6/1/2022 - $0.85M

237) Baseline Upgrade b3157

- Replace line relaying and fault detector relaying at Messick Rd. and Morgan 138 kV substations; Replace wave trap at Morgan 138 kV substation - 12/1/2024 - $0.23M

238) Baseline Upgrade b3159

- Build a new 138/69 kV substation. Install one (1) 138 kV circuit breaker, one (1) 138/69 kV 130 MVA transformer, three (3) 69 kV circuit breakers. Build a 0.15 mile 138 kV 795 ACSR transmission line between the FE Brim 138/69 kV substation and the newly proposed AMPT substation (three steel poles). Loop the Bowling Green Sub No.5 – Bowling Green Sub No.2 69 kV lines in and out of the newly established substation. Complete the remote end terminal work at BG substations #2 and #5 to accommodate the new substation. - 6/1/2024 - $10.10M

239) Baseline Upgrade b3160.1

- Construct a ~2.4 mile double circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network. - 6/1/2024 - $6.00M

240) Baseline Upgrade b3160.2

- Retire the ~2.5 mile 34.5 kV Niles – Simplicity Tap line. - 6/1/2024 - $1.20M

241) Baseline Upgrade b3160.3

- Retire the ~4.6 mile Lakehead 69 kV Tap - 6/1/2024 - $1.40M

242) Baseline Upgrade b3160.4

- Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB - 6/1/2024 - $4.00M

243) Baseline Upgrade b3160.5

- Rebuild the ~1.2 mile Buchanan South 69 kV Radial Tap using 795 ACSR - 6/1/2024 - $3.00M

244) Baseline Upgrade b3160.6

- Rebuild the ~8.4 mile 69 kV Pletcher – Buchanan Hydro line as the ~9 mile Pletcher – Buchanan South 69 kV line using 795 ACSR. - 6/1/2024 - $20.00M

245) Baseline Upgrade b3160.7

- Install a PoP switch at Buchanan South station with 2 line Moabs. - 6/1/2024 - $0.60M

246) Baseline Upgrade b3161.1

- Install two, 2000 Amp, 115kV line switches. Extend Reymet fence and bus to allow installation of risers to Line #53 (Chesterfield-Kevlar 115 kV). - 6/1/2024 - $3.00M

247) Baseline Upgrade b3162

- Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV (Line #2199) will be cut and connected to the new station. Remington-Mt. Run 115 kV (Line #70) and Mt. Run-Oak Green 115 kV (Line #2) will also be cut and connected to the new station. - 6/1/2024 - $22.00M

248) Baseline Upgrade b3208

- Retire approximately 38 miles of the 44 mile Clifford-Scottsville 46 kV circuit. Build new 138 kV “in and out” to two new Distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Construct new 138 kV lines from Joshua Falls-Riverville (~10 mi.) and Riverville-Gladstone (~5 mi.). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen – Monroe 69 kV (~4 mi.) - 12/1/2022 - $85.00M

249) Baseline Upgrade b3209

- Rebuild the 10.5 mile Berne – South Decatur 69 kV line using 556 ACSR in order to alleviate the overload and address a deteriorating asset. - 6/1/2022 - $16.60M

250) Baseline Upgrade b3211

- Rebuild the 1.3 mile section of 500 kV Line No.569 (Loudoun - Morrisville) with single-circuit 500 kV structures at the current 500 kV standard. This will increase the rating of the line to 3424 MVA. - 6/1/2019 - $4.50M

251) Baseline Upgrade b3213

- Install 2nd Chickahominy 500/230 kV transformerRelocate the Chickahominy – Elmont 500kV line #557 to terminate in a new bay at Chickahominy substation and relocate the Chesterfield – Lanexa 115kV line #92 to allow for the expansion of the Chickahominy substation • Add three new 500 kV breakers with 50kA interrupting rating and associated equipment - 6/1/2023 - $22.00M

252) Baseline Upgrade b3214

- Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi - 6/1/2022 - $24.50M

253) Baseline Upgrade b3214.1

- Reconductor the Yukon – Smithton 138 kV Line. Upgrade terminal equipmet at Yukon and replace line relaying at Michell and Charleroi. - 6/1/2022 - $24.50M

254) Baseline Upgrade b3214.2

- Reconductor the Smithton – Shepler Hill Jct 138 kV Line - 6/1/2022 - $0.00M

255) Baseline Upgrade b3218

- At Oak Mound 138 kV substation, replace the 138 kV bus tie and Waldo Run #2 breakers with 40 kA, 3000 amp units. Install CTs as 2000/5 MR. - - $0.00M

256) Baseline Upgrade b3221

- Replace terminal equipment (bus conductor) on the 230 kV side of the Steel City 500/230 kV transformer #1 - 6/1/2025 - $0.09M

257) Baseline Upgrade b3222

- Install one (1) 7.2 MVAR fixed cap bank on the Lock Haven-Reno 69 kV line and one (1) 7.2 MVAR fixed cap bank on the Lock Haven-Flemington 69 kV line near the Flemington 69/12kV substation. - 6/1/2025 - $1.90M

258) Baseline Upgrade b3223.1

- Install a 2nd 230kV circuit with a minimum summer emergency rating of 1047 MVA between Lanexa and Northern Neck Substations. The 2nd circuit will utilize the vacant arms on the double-circuit structures that are being installed on the Line #224 (Lanexa-Northern Neck) End-of-Life rebuild project (b3089). - 6/1/2023 - $14.00M

259) Baseline Upgrade b3223.2

- Expand the Northern Neck terminal from a 230kV, 4-breaker ring bus to a 6-breaker ring bus.

- 6/1/2023 - $5.00M

260) Baseline Upgrade b3223.3

- Expand the Lanexa terminal from a 6-breaker ring bus to a breaker-and-a-half arrangement. - 6/1/2023 - $4.00M

261) Baseline Upgrade b3224

- Replace a disconnect switch and reconductor a short span of Mt. Pleasant - Middletown Tap line - 6/1/2025 - $0.43M

262) Baseline Upgrade b3226

- Add 10 MVAR 69 kV capacitor bank at Swainton substation - 6/1/2025 - $2.90M

263) Baseline Upgrade b3227

- Rebuild the Corson-Court 69 kV line to achieve ratings equivalent to 795 ACSR conductor or better - 6/1/2025 - $13.20M

264) Baseline Upgrade b3228

- Replace two relays at Center Substation to increase ratings on the 110552 circuit - 6/1/2025 - $0.03M

265) Baseline Upgrade b3230

- At Enon Substation install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switcher. - 6/1/2025 - $1.84M

266) Baseline Upgrade b3231

- Replace the existing No. 2 cap bank breaker at Huntingdon substation with a new breaker with higher interrupting capability. - 6/1/2025 - $0.80M

267) Baseline Upgrade b3232

- Replace the existing Williamsburg, ALH (Hollidaysburg) and bus section breaker at the Altoona substation with a new breaker with higher interrupting capability. - 6/1/2025 - $1.70M

268) Baseline Upgrade b3233

- Install one 34 MVAR 115 kV shunt reactor and breaker. Install one 115 kV circuit breaker to expand the substation to a 4 breaker ring bus. - 6/1/2025 - $4.90M

269) Baseline Upgrade b3234

- Extend both the east and west 138 kV buses at Pine substation, and install one 138 kV breaker, associated disconnect switches, and one 100 MVAR reactor. - 6/1/2025 - $3.80M

270) Baseline Upgrade b3235

- Extend 138 kV bus work to the west of Tangy substation for the addition of the 100 MVAR reactor bay and one 138 kV 40 kA circuit breaker. - 6/1/2025 - $3.70M

271) Baseline Upgrade b3236

- Extend the 138 kV Bus by adding two new breakers and associated equipment and install a 75 MVAR Reactor - 6/1/2025 - $4.50M

272) Baseline Upgrade b3237

- Install two 46 kV 6.12 MVAR capacitors effective at Mt Union. - 6/1/2025 - $4.00M

273) Baseline Upgrade b3238

- Replace (7) overdutied 34.5 kV breakers with 50 kA rated equipment at the Whippany substation. - 6/1/2025 - $5.10M

274) Baseline Upgrade b3239

- Replace (14) overdutied 34.5 kV breakers with 63 kA rated equipment. - 6/1/2025 - $8.50M

275) Baseline Upgrade b3240

- Upgrade Cherry Run and Morgan terminals to make the Transmission Line the limiting component.

  Morgan: Wave Trap

  Cherry Run: Substation conductor, relays, CT - 6/1/2024 - $1.10M

276) Baseline Upgrade b3241

- Install 138 kV, 36 MVAR capacitor and a 5 uF reactor protected by a 138 kV capacitor switcher. Install a breaker on the 138 kV Junction terminal. Install a 138 kV 3.5 uF reactor on the existing Hardy 138 kV capacitor. - 6/1/2025 - $2.85M

277) Baseline Upgrade b3242

- Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker breaker-and-a-half layout and add two 36 MVAR capacitors with capacitor switchers. - 6/1/2025 - $13.30M

278) Baseline Upgrade b3243

- Replace risers at Bass 34.5kV station - 6/1/2025 - $0.10M

279) Baseline Upgrade b3244

- Rebuild approximately 9 miles of the Rob Park - Harlan 69 kV line - 6/1/2025 - $20.90M

280) Baseline Upgrade b3245

- Construct a new breaker-and-a-half substation near Tiffany substation. All transmission assets and lines will be relocated to the new substation. The two distribution transformers will be fed via two dedication 115 kV feeds to the existing Tiffany substation. - 6/1/2025 - $23.20M

281) Baseline Upgrade b3246.1

- Convert 115 kV Line #172 Liberty-Lomar and 115 kV Line #197 Cannon Branch-Lomar to 230 kV to provide a new 230 kV source between Cannon Branch and Liberty. The majority of 115 kV Line #172 Liberty-Lomar and Line #197 Cannon Branch-Lomar is adequate for 230 kV operation. Lines to have a summer rating of 1047 MVA/1047 MVA (SN/SE) - 6/1/2023 - $8.00M

282) Baseline Upgrade b3246.2

- Perform substation work for the 115 kV to 230 kV Line conversion at Liberty, Wellington, Godwin, Pioneer, Sandlot and Cannon Branch. - 6/1/2023 - $20.00M

283) Baseline Upgrade b3246.3

- Extend 230kV Line #2011 Cannon Branch – Clifton to Winters Branch by removing the existing Line #2011 termination at Cannon Branch and extending the line to Brickyard creating 230kV Line #2011 Brickyard-Clifton. Extend a new 230kV line between Brickyard and Winters Branch with a summer rating of 1572MVA/1572MVA (SN/SE) - 6/1/2023 - $10.29M

284) Baseline Upgrade b3246.4

- Perform substation work at Cannon Branch, Brickyard and Winters Branch for the 230kV Line #2011 extension. - 6/1/2023 - $1.41M

285) Baseline Upgrade b3246.5

- Replace the Gainesville 230kV 40kA breaker "216192" with a 50kA breaker. - 6/1/2023 - $0.50M

286) Baseline Upgrade b3247

- Replace 13 towers with galvanized steel towers on Doubs - Goose Creek 500 kV. Reconductor 3 mile section with 3-1351.5 ACSR 45/7. Upgrade line terminal equipment at Goose Creek substation to support the 500 kV line rebuild. - 6/1/2025 - $7.60M

287) Baseline Upgrade b3248

- Install a low side 69 kV circuit breaker at Albion 138/69 kV transformer 1 - 6/1/2025 - $0.40M

288) Baseline Upgrade b3249

- Rebuild the Chatfield-Melmore 138kV line (~ 10 miles) to 1033 ACSR conductor. - 6/1/2025 - $27.20M

289) Baseline Upgrade b3253

- Install a 3000A 40 kA 138 kV breaker on high side of 138/69 kV transformer #5 at Millbrook Park station. The transformer and associated bus protection will be upgraded accordingly. - 6/1/2025 - $0.63M

290) Baseline Upgrade b3255

- Upgrade 795 AAC risers at Sand Hill 138 kV station towards Cricket Switch with 1272 AAC - 6/1/2025 - $0.04M

291) Baseline Upgrade b3257

- Replace two spans of 336.4 26/7 ACSR on Twin Branch-AM General #2 34.5 kV circuit - 6/1/2025 - $0.14M

292) Baseline Upgrade b3258

- Install a 3000A 63 kA 138 kV breaker on high side of 138/69 kV transformer #2 at Wagenhals station. The transformer and associated bus protection will be upgraded accordingly. - 6/1/2025 - $1.10M

293) Baseline Upgrade b3259

- At West Millersburg station, replace the 138 kV MOAB on the West Millersburg - Wooster 138 kV line with a 3000A 40 kA breaker. - 6/1/2025 - $0.68M

294) Baseline Upgrade b3262

- Install a second 115kV 33.67MVar cap bank at Harrisonburg substation along with a 115kV breaker. - 12/1/2025 - $1.25M

295) Baseline Upgrade b3264

- Install 115kV breaker at Stuarts Draft station and sectionalize 115kV Line#117 into two 115kV lines. - 6/1/2025 - $5.00M

296) Baseline Upgrade b3265

- Implement slow circulation on existing underground 138 kV high pressure fluid filled (HPFF) cable between Arsenal and Riazzi substations. - 6/1/2025 - $2.40M

297) Baseline Upgrade b3267

- Rebuild the 4/0 ACSR Norwood-Shopville 69 kV line section using 556 ACSR/TW. - 12/1/2021 - $3.75M

298) Baseline Upgrade b3268

- Build a switching station at the junction of 115kV line #39 and 115kV line #91 with a 115kV capacitor bank. The switching station will built with 230kV structures but will operate at 115kV. - 12/1/2025 - $3.00M

299) Baseline Upgrade b3269

- At West New Philadelphia station, add a high side 138 kV breaker on the 138/69 kV transformer #2 along with a 138 kV breaker on the line towards Newcomerstown. - 6/1/2025 - $2.02M

300) Baseline Upgrade b3270

- Install 1.7 miles of 795 ASCR 138kV conductor along the other side of Dragoon Tap 138 kV line, which is currently double circuit tower with one position open. Additionally, install a 2nd 138/34.5 kV transformer at Dragoon, install a high side circuit switcher on the current transformer at Dragoon Station, and install 2-138 kV line breakers on the Dragoon-Jackson 138 kV and Dragoon-Twin Branch 138 kV lines. - 6/1/2025 - $4.89M

301) Baseline Upgrade b3270.1

- Replace Dragoon 34.5 kV Breakers "B", "C" and "D" with 40 kA breakers. - 6/1/2025 - $2.00M

302) Baseline Upgrade b3271

- Install a 138 kV circuit breaker at Fremont station on line towards Fremont Center and install a 9.6 MVAR 69 kV capacitor bank at Bloom Road station. - 6/1/2025 - $1.76M

303) Baseline Upgrade b3272

- Install two 138 kV circuit switchers on the high side of 138/34.5 kV transformers #1 & #2 at Rockhill station. - 6/1/2025 - $1.47M

304) Baseline Upgrade b3273.1

- Rebuild and convert the existing 17.6 miles East Leipsic-New Liberty 34.5 kV circuit to 138 kV using 795 ACSR - 6/1/2025 - $31.35M

305) Baseline Upgrade b3273.2

- Convert the existing 34.5 kV equipment to 138 kV and expanded the existing McComb station to the north and east to allow for new equipment to be installed. Install two new 138 kV box bays to allow for line positions and two new 138/12 kV transformers. - 6/1/2025 - $0.87M

306) Baseline Upgrade b3273.3

- Expand the existing East Leipsic 138 kV station to the north to allow for another 138 kV line exit to be installed. The new line exit will involve installing a new 138 kV circuit breaker, disconnect switches and new dead end structure along with extending existing 138 kV bus work. - 6/1/2025 - $1.30M

307) Baseline Upgrade b3273.4

- Add one 138 kV circuit breaker and disconnect switches in order to add an additional line position at New Liberty 138 kV station. Install line relaying potential devices and retire the 34.5 kV breaker F. - 6/1/2025 - $0.90M

308) Baseline Upgrade b3274

- Rebuild approximately 8.9 miles of 69 kV line between Newcomerstown and Salt Fork Switch with 556 ACSR conductor. - 6/1/2025 - $15.89M

309) Baseline Upgrade b3275.1

- Rebuild Kammer Station-Cresaps Switch 69 kV, approximately 0.5 miles. - 6/1/2025 - $0.93M

310) Baseline Upgrade b3275.2

- Rebuild Cresaps Switch-McElroy Station 69 kV, approximately 0.67 miles. - 6/1/2025 - $1.25M

311) Baseline Upgrade b3275.3

- Replace a single span of 4/0 ACSR from Moundsville-Natrium str 93L to Carbon Tap switch 69kV located between Colombia Carbon and Conner Run stations. Remainder of line is 336 ACSR. - 6/1/2025 - $0.01M

312) Baseline Upgrade b3275.4

- Rebuild from Colombia Carbon to Columbia Carbon Tap str 93N 69 kV, approximately 0.72 miles. The remainder of the line between Colombia Carbon Tap structure 93N and Natrium station is 336 ACSR and will remain. - 6/1/2025 - $1.08M

313) Baseline Upgrade b3275.5

- Replace the Cresaps 69 kV 3-Way Phase-Over-Phase Switch and structure with a new 1200 A 3-Way Switch and Steel Pole. - 6/1/2025 - $0.71M

314) Baseline Upgrade b3275.6

- Replace 477 MCM Alum bus and risers at McElroy 69 kV station. - 6/1/2025 - $0.33M

315) Baseline Upgrade b3275.7

- Replace Natrium 138 kV bus existing between CB-BT1 and along the 138 kV Main Bus # 1 dropping to CBH1 from the 500MCM conductors to a 1272 KCM AAC conductor. Replace the dead end clamp and strain insulators. - 6/1/2025 - $0.29M

316) Baseline Upgrade b3276.1

- Rebuild the 2/0 Copper section of the Lancaster-South Lancaster 69 kV line, approximately 2.9 miles of the 3.2 mile total length with 556 ACSR conductor. The remaining section has 336 ACSR conductor. - 6/1/2025 - $5.37M

317) Baseline Upgrade b3276.2

- Rebuild the 1/0 Copper section of the line between Lancaster Junction and Ralston station 69 kV, approximately 2.3 miles of the 3.1 mile total length. - 6/1/2025 - $4.58M

318) Baseline Upgrade b3276.3

- Rebuild the 2/0 Copper portion of the line between East Lancaster Tap and Lancaster 69 kV, approximately 0.81 miles. - 6/1/2025 - $1.20M

319) Baseline Upgrade b3277

- Replace the existing East Akron 138 kV breaker B-22 with 3000A continuous, 40 KA momentary current interrupting rating circuit breaker. - 6/1/2021 - $0.55M

320) Baseline Upgrade b3278.1

- Saltville Station: Replace H.S. MOAB Switches on the high side of the 138/69/34.5 kV T1 with a H.S. Circuit Switcher. - 12/1/2025 - $0.72M

321) Baseline Upgrade b3278.2

- Meadowview Station: Replace existing 138/69/34.5 kV transformer T2 with a new 130 MVA 138/69/13 kV transformer. - 12/1/2025 - $3.14M

322) Baseline Upgrade b3278.3

- Saltville Station: Install two 138 kV breakers and bus diff protection - 12/1/2025 - $0.36M

323) Baseline Upgrade b3279

- Install a new 138 kV, 21.6 MVAR cap bank and circuit switcher at Apple Grove Station. - 6/1/2025 - $1.00M

324) Baseline Upgrade b3280

- Rebuild the existing Cabin Creek - Kelly Creek 46 kV line (to structure 366-44), approximately 4.4 miles. This section is double circuit with the existing Cabin Creek - London 46 kV line so a double circuit rebuild would be required. - 6/1/2025 - $17.90M

325) Baseline Upgrade b3281

- Install 138 kV circuit switcher on the 138/69 kV transformer #1 and 138/34.5 kV transformer #2 at Dewey. Install 138 kV 2000 A 40 kA breaker on Stanville line at Dewey 138 kV substation. - 12/1/2025 - $1.40M

326) Baseline Upgrade b3282.1

- Install a second 138 kV circuit utilizing 795 ACSR conductor on the open position of the existing double circuit towers from East Huntington-North Proctorville. Remove the existing 34.5 kV line from East Huntington-North Chesapeake and rebuild this section to 138 kV served from a new PoP switch off the new East Huntington-North Proctorville 138 kV #2 line. - 6/1/2025 - $7.10M

327) Baseline Upgrade b3282.2

- Install a 138 kV 40 kA circuit breaker at North Proctorville. - 6/1/2025 - $1.40M

328) Baseline Upgrade b3282.3

- Install a 138 kV 40 kA circuit breaker at East Huntington. - 6/1/2025 - $1.10M

329) Baseline Upgrade b3282.4

- Convert the existing 34/12 kV North Chesapeake to a 138/12 kV station. - 6/1/2025 - $0.80M

330) Baseline Upgrade b3283

- Replace the existing Inez 138/69 kV 50 MVA autotransformer with a 138/69 kV 90 MVA autotransformer. - 12/1/2025 - $2.96M

331) Baseline Upgrade b3284

- Rebuild ~5.44 miles of 69 kV line from Lock Lane to Point Pleasant. - 6/1/2025 - $13.50M

332) Baseline Upgrade b3285

- Replace the Meigs 69 kV 4/0 Cu station riser towards Gavin and rebuild the section of the Meigs – Hemlock 69 kV circuit from Meigs to approximately structure #40 (~4 miles) replacing the line conductor 4/0 ACSR with the line conductor size 556.5 ACSR. - 6/1/2025 - $12.14M

333) Baseline Upgrade b3287

- Upgrade 69 kV risers at Moundsville station towards George Washington. - 6/1/2025 - $0.05M

334) Baseline Upgrade b3288.1

- Construct ~ 2.75 mi Orinoco - Stone 69 kV transmission line in the clear between Orinoco station and Stone station. - 12/1/2025 - $9.23M

335) Baseline Upgrade b3288.2

- Construct ~ 3.25 mi Orinoco – New Camp 69 kV transmission line in the clear between Orinoco station and New Camp station. - 12/1/2025 - $9.95M

336) Baseline Upgrade b3288.3

- At Stone substation, circuit breaker A to remain in place and be utilized as T1 low side breaker, circuit breaker B to remain in place and be utilized as new Hatfield (via Orinoco and New Camp) 69 kV line breaker. Add new 69 kV circuit breaker E for Coleman Line exit. - 12/1/2025 - $0.66M

337) Baseline Upgrade b3288.4

- Reconfigure the New Camp 69 kV tap which includes access road improvements/installation, temporary wire and permanent wire work along with dead end structures installation. - 12/1/2025 - $0.45M

338) Baseline Upgrade b3288.5

- At New Camp substation, rebuild the 69 kV bus, add 69 kV MOAB W and replace the 69 kV ground switch Z1 with a 69 kV circuit switcher on the New Camp transformer. - 12/1/2025 - $1.18M

339) Baseline Upgrade b3289.1

- Roanoke Station: Install high-side circuit switcher on 138/69/12 kV T5 - 6/1/2025 - $1.10M

340) Baseline Upgrade b3289.2

- Huntington Court Station: Install high-side circuit switcher on 138/69/34.5 kV T1 - 6/1/2025 - $1.42M

341) Baseline Upgrade b3290.1

- Build 9.4 miles of single circuit 69 kV line from Roselms to near East Ottoville 69 kV Switch. - 6/1/2025 - $13.70M

342) Baseline Upgrade b3290.2

- Rebuild 7.5 miles of double circuit 69kV line between East Ottoville Switch and Kalida Station (combining with the new Roselms to Kalida 69 kV circuit). - 6/1/2025 - $23.60M

343) Baseline Upgrade b3290.3

- At Roselms Switch, install a new three way 69kV, 1200 A phase-over-phase switch, with sectionalizing capability. - 6/1/2025 - $0.60M

344) Baseline Upgrade b3290.4

- At Kalida 69 kV station, terminate the new line from Roselms Switch. Move the CS XT2 from high side of T2 to the high side of T1. Remove existing T2 transformer. - 6/1/2025 - $1.00M

345) Baseline Upgrade b3291

- Replace the Russ St. 34.5 kV Switch - 6/1/2025 - $1.50M

346) Baseline Upgrade b3292

- Replace existing 69 kV capacitor bank at Stuart Station with a 17.2 MVAr capacitor bank - 12/1/2025 - $0.00M

347) Baseline Upgrade b3293

- Replace 2/0 Cu entrance span conductor on the South Upper Sandusky 69 kV line and 4/0 Cu Risers/Bus conductors on the Forest line at Upper Sandusky 69 kV station. - 6/1/2025 - $0.54M

348) Baseline Upgrade b3294

- Replace existing 69 kV disconnect switches for circuit breaker "C" at Walnut Avenue station - 6/1/2025 - $0.00M

349) Baseline Upgrade b3295

- Grundy 34.5 kV: Install a 34.5 kV 9.6 MVAR cap bank - 6/1/2025 - $0.80M

350) Baseline Upgrade b3296

- Rebuild the overloaded portion of the Concord-Whitaker 34.5 kV line (1.13 miles). Rebuild is double circuit and will utilize 795 ACSR conductor. - 6/1/2025 - $2.80M

351) Baseline Upgrade b3297.1

- Rebuild 4.23 miles of 69 kV line between Sawmill and Lazelle station, using 795 ACSR 26/7 conductor. - 6/1/2025 - $12.00M

352) Baseline Upgrade b3297.2

- Rebuild 1.94 miles of 69 kV line between Westerville and Genoa stations, using 795 ACSR 26/7 conductor. - 6/1/2025 - $5.90M

353) Baseline Upgrade b3297.3

- Replace risers and switchers at Lazelle, Westerville, and Genoa 69 kV stations. Upgrade associated relaying accordingly. - 6/1/2025 - $1.90M

354) Baseline Upgrade b3298

- Rebuild 0.8 miles of double circuit 69 kV line between South Toronto and West Toronto. Replace 219 kcmil ACSR with 556 ACSR. - 6/1/2025 - $2.83M

355) Baseline Upgrade b3298.1

- Replace the 69 kV breaker D at South Toronto station with 40 kA breaker. - 6/1/2025 - $0.70M

356) Baseline Upgrade b3299

- Rebuild 0.2 mile of the West End Fostoria - Lumberjack Switch 69 kV line with 556 ACSR (Dove) conductors. Replace jumpers on West End Fostoria line at Lumberjack Switch. - 6/1/2025 - $0.47M

357) Baseline Upgrade b3300

- Reconductor 230kV Line #2172 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $2.32M

358) Baseline Upgrade b3301

- Reconductor 230kV Line #2210 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $2.26M

359) Baseline Upgrade b3302

- Reconductor 230kV Line #2213 from Cabin Run to Yardley Ridge along with upgrading the line leads at Yardley to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $1.75M

360) Baseline Upgrade b3303.1

- Extend a new single circuit 230KV line (#9250) from Farmwell Substation to Nimbus Substation. - 6/1/2025 - $5.65M

361) Baseline Upgrade b3303.2

- Remove Beaumeade 230kV Line #2152 line switch. - 6/1/2025 - $0.05M

362) Baseline Upgrade b3304

- Midlothian Area 300 MW Load Drop Relief Area Improvements - 6/1/2025 - $6.22M

363) Baseline Upgrade b3304.1

- Cut 230kV Line #2066 at Trabue junction - 6/1/2025 - $0.00M

364) Baseline Upgrade b3304.2

- Reconductor idle 230kV Line #242 (radial from Midlothian to Trabue junction) to allow a minimum summer rating of 1047 MVA and connect to the section of 230kV Line #2066 between Trabue junction and Winterpock; re-number 230kV Line #242 structures to #2066; -

6/1/2025 - $0.00M

365) Baseline Upgrade b3304.3

- Use the section of idle 115kV Line #153, between Midlothian and Trabue junction to connect to the section of (former) 230kV Line #2066 between Trabue junction and Trabue to create new Midlothian-Trabue lines with new line numbers #2218 and #2219 - 6/1/2025 - $0.00M

366) Baseline Upgrade b3304.4

- Create new line terminations at Midlothian for the new Midlothian-Trabue lines. - 6/1/2025 - $0.00M

367) Baseline Upgrade b3305

- Replace Pumphrey 230/115kV transformer - 6/1/2025 - $4.69M

368) Baseline Upgrade b3306

- Install a second 125 MVAR 345 kV shunt reactor and associated equipment at Pierce Brook Substation. Install a 345 kV breaker on the high side of the #1 345/230 kV transformer - 6/1/2025 - $8.08M

369) Baseline Upgrade b3307

- Rebuild Fleming station in the clear; Replace 138/69kV Fleming Transformer #1 with 138/69 kV 130 MVA transformer with high side 138 kV CB; Install a 5 breaker 69 kV ring bus on the low side of the transformer, replace 69 kV circuit switcher AA, replace 69/12kV transformer #3 with 69/12 kV 30 MVA transformer, replace 12 kV CB A and D. Retire existing Fleming substation. - 12/1/2025 - $21.10M

370) Baseline Upgrade b3308

- Reconductor and rebuild 1 span of T-line on the Fort Steuben-Sunset Blvd 69 kV branch with 556 ACSR. - 6/1/2025 - $0.73M

371) Baseline Upgrade b3309

- Rebuild 1.75 miles of the Greenlawn - East Tiffin line section of the Carrothers - Greenlawn 69 kV circuit containing 133 ACSR conductor with 556 ACSR conductor. Upgrade relaying as required. - 6/1/2025 - $3.45M

372) Baseline Upgrade b3310.1

- Rebuild 10.5 miles of the Howard-Willard 69 kV line utilizing 556 ACSR conductor. - 6/1/2025 - $19.00M

373) Baseline Upgrade b3310.2

- Upgrade relaying at Howard 69 kV station. - 6/1/2025 - $0.23M

374) Baseline Upgrade b3310.3

- Upgrade relaying at Willard 69 kV station. - 6/1/2025 - $0.23M

375) Baseline Upgrade b3311

- Install a 120.75 kV 79.4 MVAR capacitor bank at Yorkana 115 kV - 5/31/2022 - $2.20M

376) Baseline Upgrade b3312

- Rebuild approximately 4.0 miles of existing 69 kV line between West Mount Vernon and Mount Vernon stations. Replace the existing 138/69 kV transformer at West Mount Vernon with a larger 90 MVA unit along with existing 69 kV breaker 'C'. - 6/1/2025 - $12.93M

377) Baseline Upgrade b3313

- Add 40 kA circuit breakers on the low and high side of East Lima 138/69 kV Transformer - 6/1/2025 - $1.20M

378) Baseline Upgrade b3314.1

- Install a new 138/69 kV 130 MVA transformer and associated protection at Elliot station. - 6/1/2025 - $3.00M

379) Baseline Upgrade b3314.2

- Perform work at Strouds Run station to retire 138/69/13 kV 33.6 MVA transformer #1 and install a dedicated 138/13 KV distribution transformer. - 6/1/2025 - $0.00M

380) Baseline Upgrade b3315

- Upgrade Relaying on Mark Center-South Hicksville 69 kV line and replace Mark Center cap bank with a 7.7 MVAR unit. - 6/1/2025 - $1.25M

381) Baseline Upgrade b3316

- Greene Substation - replace 138 kV 40 kA breaker GJ-138C with a 63 kA breaker - 6/1/2025 - $0.28M

382) Baseline Upgrade b3319

- Add forced cooling to increase the normal rating of the Brunot Island-Carson (302) 345 kV High Pressure Fluid Filled (HPFF) underground cable circuit - 6/1/2022 - $22.00M

383) Baseline Upgrade b3321

- Rebuild Cranes Corner-Stafford 230 kV line - 6/1/2022 - $20.20M

384) Baseline Upgrade b3324

- Replace the bus section at Olive - 6/1/2022 - $0.10M

385) Baseline Upgrade b3325

- Reconductor the Charleroi-Union 138 kV line and upgrade terminal equipment at Charleroi - 6/1/2022 - $11.00M

386) Baseline Upgrade b3326

- Rebuild the 13707 Vienna-Nelson 138 kV line - 6/1/2022 - $43.50M

387) Baseline Upgrade b3327

- Upgrade the disconnect switch (6784-L1) at Kent - 6/1/2022 - $0.25M

388) Baseline Upgrade b3328

- Upgrade the disconnect switch (13710-L1) and CT at Vienna - 6/1/2022 - $0.25M

389) Baseline Upgrade b3329

- Rerate the 13773 Farmview-Milford 138 kV line - 6/1/2022 - $0.20M

390) Baseline Upgrade b3330

- Rerate the 13774 Farmview-S. Harrington 138 kV line - 6/1/2022 - $0.25M

391) Baseline Upgrade b3331

- Upgrade bus conductor and relay at Seaford 138 kV - 6/1/2022 - $0.50M

392) Baseline Upgrade b3332

- Rerate the 23076 Steel-Milford 230 kV line - 6/1/2022 - $0.60M

393) Baseline Upgrade b3333.1

- Rebuild Skeggs Branch substation in the clear as Coronado substation. Establish New 138 kV and 69 kV Buses. Install 138/69 kV 130 MVA transformer, 138 kV circuit switcher and 69 kV breaker. Retire Existing Skeggs Branch substation. - 6/1/2023 - $6.32M

394) Baseline Upgrade b3333.10

- At Whetstone Branch substation, Replace 69KV 600A 2 Way POP Switch with 69KV 1200A 2 Way POP Switch. Remove 69KV to Skeggs Branch (Switch "22" POP). - 6/1/2023 - $0.57M

395) Baseline Upgrade b3333.11

- At Garden Creek substation, remove 69 kV Richlands (via Coal Creek) line (Circuit Breaker F and disconnect switches) and update relay settings. - 6/1/2023 - $0.14M

396) Baseline Upgrade b3333.12

- Remote end work at Clinch River substation - 6/1/2023 - $0.08M

397) Baseline Upgrade b3333.13

- Remote end work at Clinchfield substation. - 6/1/2023 - $0.08M

398) Baseline Upgrade b3333.2

- New ~1.2 mi 138kV extension to new Skeggs Branch substation location. - 6/1/2023 - $4.62M

399) Baseline Upgrade b3333.3

- Install 46.1 MVAR Cap bank at Whitewood substation along with a 138 kV breaker. - 6/1/2023 - $1.05M

400) Baseline Upgrade b3333.4

- Rebuild ~9 mi 69kV line from new Skeggs branch station to Coal Creek 69kV line. 6-wire the short double circuit section between Whetstone Branch and Str. 340-28 to convert the line to single circuit. Retire Garden Creek to Whetstone Branch 69kV line section. - 6/1/2023 - $26.25M

401) Baseline Upgrade b3333.5

- Retire Knox Creek SS. - 6/1/2023 - $0.06M

402) Baseline Upgrade b3333.6

- Retire Horn Mountain SS. This will be served directly from 69kV bus at New Skeggs branch Substation. - 6/1/2023 - $0.05M

403) Baseline Upgrade b3333.7

- At Clell SS, replace two 600A POP Switches and Poles with single 2 Way 1200A POP Switch and Pole. - 6/1/2023 - $0.34M

404) Baseline Upgrade b3333.8

- At Permac, replace 600A Switch and structure with 2 Way 1200A POP Pole Switch and pole. - 6/1/2023 - $0.31M

405) Baseline Upgrade b3333.9

- At Marvin SS, replace 600 A Switch and structure with 2 Way 1200 A POP Pole Switch and pole. - 6/1/2023 - $0.31M

406) Baseline Upgrade b3334

- Rebuild the section of Miami Fort-Hebron Tab 138 kV - 6/1/2022 - $44.30M

407) Baseline Upgrade b3335

- Reconductor a 0.76 mile portion of the Croydon-Burlington 230 kV line - 6/1/2022 - $0.79M

408) Baseline Upgrade b3337

- Replace the one (1) Hyatt 138 kV breaker “AB1(101N)” with 3000 A, 63 kA interrupting breaker. - 6/1/2026 - $0.48M

409) Baseline Upgrade b3338

- Replace the two (2) Kenny 138 kV breakers, “102” (SC-3) and “106” (SC-4), each with a 3000 A, 63 kA interrupting breaker. - 6/1/2026 - $0.76M

410) Baseline Upgrade b3339

- Replace the one (1) Canal 138 kV breaker “3” with 3000 A, 63 kA breaker. - 6/1/2026 - $0.48M

411) Baseline Upgrade b3341.1

- Marysville Substation: Install two 69 kV 16.6 MVAR cap banks; Install five 69 kV circuit breakers; Upgrade station relaying; Replace 600 A wave trap on the Marysville-Kings Creek 69 kV (6660) circuit - 6/1/2026 - $2.43M

412) Baseline Upgrade b3341.2

- Darby Substation: Upgrade remote end relaying at Darby 69 kV substation - 6/1/2026 - $0.25M

413) Baseline Upgrade b3341.3

- Kings Creek: Upgrade remote end relaying at Kings Creek 69 kV substation - 6/1/2026 - $0.25M

414) Baseline Upgrade b3342

- Replace the 2156 ACSR & 2874 ACSR bus and risers with 2-bundled 2156 ACSR at Muskingum River 345 kV station to address loading issues on Muskingum-Waterford 345 kV line. - 6/1/2026 - $0.53M

415) Baseline Upgrade b3343

- Rebuild approximately 0.3 miles of overloaded 69 kV line between Albion-Philips Switch and Philips Switch-Brimfield Switch with 556 ACSR conductor. - 6/1/2026 - $0.61M

416) Baseline Upgrade b3344.1

- Install two (2) 138 kV circuit breakers in the M and N strings in the breaker-and-a half configuration in West Kingsport station 138 kV yard to allow the Clinch River-Moreland Dr. 138 kV to cut in the West Kingsport station - 11/1/2026 - $1.85M

417) Baseline Upgrade b3344.2

- Upgrade remote end relaying at Riverport 138 kV station due to the line cut in at West Kingsport station - 11/1/2026 - $0.25M

418) Baseline Upgrade b3345.1

- Rebuild ~4.2 miles of overloaded sections of the 69 kV line between Salt Fork Switch and Leatherwood Switch with 556 ACSR. - 6/1/2026 - $9.06M

419) Baseline Upgrade b3345.2

- Update relay settings at Broom Road station. - 6/1/2026 - $0.04M

420) Baseline Upgrade b3346.1

- Rebuild approximately 3.5 miles of overloaded 69 kV line between North Delphos-East Delphos-Elida Road switch. This includes approximately 1.1 miles of double circuit line that makes up a portion of the North Delphos-South Delphos 69 kV line and the North Delphos-East Delphos 69 kV line. Approximately 2.4 miles of single circuit line will also be rebuilt between the double circuit portion to East Delphos station and from East Delphos to Elida

Road Switch. - 6/1/2026 - $8.43M

421) Baseline Upgrade b3346.2

- Replace the line entrance spans at South Delphos to eliminate the overloaded 4/0 Copper and 4/0 ACSR conductor. - 6/1/2026 - $0.44M

422) Baseline Upgrade b3347.1

- Rebuild approximately 20 miles of line between Bancroft and Milton stations with 556 ACSR conductor - 11/1/2026 - $56.55M

423) Baseline Upgrade b3347.2

- Replace the jumpers around Hurrican switch with 556 ACSR - 11/1/2026 - $0.01M

424) Baseline Upgrade b3347.3

- Replace the jumpers around Teays switch with 556 ACSR - 11/1/2026 - $0.01M

425) Baseline Upgrade b3347.4

- Winfield Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild - 11/1/2026 - $0.05M

426) Baseline Upgrade b3347.5

- Bancroft Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild - 11/1/2026 - $0.03M

427) Baseline Upgrade b3347.6

- Milton Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild. - 11/1/2026 - $0.03M

428) Baseline Upgrade b3347.7

- Putnam Village Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild - 11/1/2026 - $0.05M

429) Baseline Upgrade b3348.1

- Construct a 138 kV single bus station (Tin Branch) consisting of a 138 kV box bay with a distribution transformer and 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Sprigg stations), and distribution will have one 12 kV feed. Install two 138 kV circuit breakers on the line exits. Install 138 kV circuit switcher for the new transformer. - 11/1/2026 - $5.58M

430) Baseline Upgrade b3348.2

- Construct a new 138/46/12 kV Argyle station to replace Dehue station. Install a 138 kV ring bus using a breaker-and-a-half configuration, with an autotransformer with a 46 kV feed and a distribution transformer with a 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Wyoming stations). There will also be a 46 kV feed from this station to Becco station. Distribution will have two 12 kV feeds. Retire Dehue station in its entirety. - 11/1/2026 - $10.00M

431) Baseline Upgrade b3348.3

- Bring the Logan-Sprigg #2 138 kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138 kV line. Double circuit T3 series lattice towers will be used along with 795,000 cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD, and one shield wire will be OPGW. - 11/1/2026 - $8.58M

432) Baseline Upgrade b3348.4

- Logan-Wyoming No. 1 circuit in and out of the proposed Argyle station. Double circuit T3 series lattice towers will be used along with 795,000 cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD, and one shield wire will be OPGW. - 11/1/2026 - $7.70M

433) Baseline Upgrade b3348.5

- Rebuild approximately 10 miles of 46 kV line between Becco and the new Argyle substation. Retire approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey station. - 11/1/2026 - $33.71M

434) Baseline Upgrade b3348.6

- Adjust relay settings due to new line terminations and retirements at Logan, Wyoming, Sprigg, Becco and Chauncey stations. - 11/1/2026 - $0.23M

435) Baseline Upgrade b3349

- Replace Bellefonte 69 kV risers on the section between Bellefonte TR #3 and 69 kV Bus #2. - 6/1/2026 - $0.54M

436) Baseline Upgrade b3351

- Replace the 69 kV in-line switches at Monterey 69 kV substation. - 6/1/2026 - $0.00M

437) Baseline Upgrade b3352

- Replace MOAB W, MOAB Y, line and bus side jumpers of both W and Y at 47th Street 69 kV station. Upgrade the 69 kV strain bus between MOABs W and Y to 795 KCM AAC. Change the connectors on the tap to MOAB X1 to accommodate the larger 795 KCM AAC. - 6/1/2026 - $0.00M

438) Baseline Upgrade b3353.1

- Allen substation: Rebuild Allen station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7' concrete platforms and control house raised by a 10' platform to mitigate flooding concerns. Install five 69 kV 3000A 40 kA circuit breakers in a ring bus (operated at 46 kV) configuration with a 13.2 MVAR capacitor bank. Existing Allen station will be retired (does not include the distribution cost). Distribution scope of work: Install 69/46 kV-12 kV 20 MVA transformer along with 2-12 kV breakers on 7' concrete platforms (conversion of S2405.1). - 12/1/2026 - $10.55M

439) Baseline Upgrade b3353.2

- Allen-East Prestonsburg: A 0.20 mile segment of this 46 kV line will be relocated to the new station (SN/SE/WN/WE: 53/61/67/73MVA). (Conversion of S2405.2) - 12/1/2026 - $0.33M

440) Baseline Upgrade b3353.3

- McKinney-Allen: The new line extension will walk around the south and east sides of the existing Allen station to the new Allen station being built in the clear. A short segment of new single circuit 69 kV line and a short segment of new double circuit 69 kV line (both operated at 46 kV) will be added to the line to tie into the new Allen station bays. (Conversion of S2405.3) - 12/1/2026 - $1.95M

441) Baseline Upgrade b3353.4

- Stanville-Allen: A segment of this line will have to be relocated to the new station (SN/SE/WN/WE: 50/50/63/63MVA). (Conversion of S2405.4) - 12/1/2026 - $0.17M

442) Baseline Upgrade b3353.5

- Allen-Prestonsburg: 0.25 mile segment of this existing single circuit will be relocated. The relocated line segment will require construction of one custom self-supporting double circuit dead-end structure and single circuit suspension structure. A short segment of new double circuit 69 kV line (energized at 46 kV) will be added to tie into the new Allen station bays, which will carry Allen-Prestonsburg 46 kV and Allen-East Prestonsburg 46 kV lines. A temporary 0.15 mile section double circuit line will be constructed to keep Allen-Prestonsburg and Allen-East Prestonsburg 46 kV lines energized during construction. (Conversion of S2405.5) - 12/1/2026 - $2.66M

443) Baseline Upgrade b3353.6

- Remote end work will be required at Prestonsburg, Stanville and McKinney stations. (Conversion of S2405.6) - 12/1/2026 - $0.34M

444) Baseline Upgrade b3358

- Install a 69 kV 11.5 MVAR capacitor at Biers Run station. - 6/1/2026 - $0.85M

445) Baseline Upgrade b3359

- Rebuild approximately 2.3 miles of the existing North Van Wert Sw-Van Wert 69 kV line utilizing 556 ACSR conductor. - 6/1/2026 - $6.20M

446) Baseline Upgrade b3360

- Replace Thelma Transformer #1 with a 138/69/46 kV 130/130/90 MVA transformer and replace 46 kV risers and relaying toward Kenwood substation. Existing TR#1 to be used as spare. - 12/1/2026 - $3.54M

447) Baseline Upgrade b3361

- Rebuild Prestonsburg-Thelma 46 kV circuit, approximately 14 miles. Retire Jenny Wiley SS. - 12/1/2026 - $33.01M

448) Baseline Upgrade b3362

- Rebuild approximately 3.1 miles of the overloaded conductor on the existing Oertels Corner-North Portsmouth 69 kV line utilizing 556 ACSR. - 6/1/2026 - $8.00M

449) Baseline Upgrade b3370

- Upgrade terminal equipment on the Loretto - Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor - 6/1/2026 - $0.80M

450) Baseline Upgrade b3371

- Rebuild approx. 3.6 miles of 875 (N. Boyertown - W. Boyertown). Upgrade terminal equipment (circuit breaker, disconnect switches, substation conductor) and relays at N. Boyertown and W. Boyertown substation - 6/1/2026 - $8.79M

451) Baseline Upgrade b3372

- East Towanda – North Meshoppen 115 kV Line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS - 6/1/2026 - $6.66M

452) Baseline Upgrade b3373

- Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line - 6/1/2026 - $0.30M

453) Baseline Upgrade b3374

- Replace Five Atlantic 34.5 kV breakers (J36, BK1A, BK1B, BK3A and BK3B) with 63kA rated breakers and associated equipment - 6/1/2026 - $3.50M

454) Baseline Upgrade b3375

- Replace Six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment.. - 6/1/2026 - $4.20M

455) Baseline Upgrade b3376

- Replace One Freneau 34.5 kV breaker (BK6) with 63 kA rated breakers and associated equipment - 6/1/2026 - $0.70M

456) Baseline Upgrade b3664

- Juniata: Replace the limiting 230 kV T2 transformer leads, bay conductor and bus conductor with double bundle 1590 ACSR. Replace the limiting 1200 A MODs on the Bus tie breaker with 3000 A MODs - 6/1/2026 - $0.68M

457) Baseline Upgrade b3665

- Replace several pieces of 1033.5 AAC substation conductor at East Towanda 230 kV Substation (on East Towanda-Canyon 230 kV Line terminal) - 6/1/2026 - $0.41M

458) Baseline Upgrade b3666

- Marshall 230 kV Substation: Install dual reactors and expand existing ring bus - 6/1/2026 - $5.83M

459) Baseline Upgrade b3667

- Pierce Brook Substation: Install second 230/115 kV transformer - 6/1/2026 - $5.07M

460) Baseline Upgrade b3668

- Upgrade Windy Edge 115 kV substation conductor to increase ratings of the Windy Edge-Chesco Park 110501 circuit. - 6/1/2026 - $0.50M

461) Baseline Upgrade b3669.1

- Replace terminal equipment (stranded bus, disconnect switch and circuit breaker) at Church substation (Townsend-Church 138 kV). - 12/1/2026 - $1.00M

462) Baseline Upgrade b3669.2

- Replace terminal equipment (circuit breaker) at Townsend substation (Townsend-Church 138 kV). - 12/1/2026 - $0.45M

463) Baseline Upgrade b3670

- Upgrade terminal equipment on the Loretto-Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor. - 6/1/2026 - $0.80M

464) Baseline Upgrade b3672

- East Towanda-North Meshoppen 115 kV line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS. - 6/1/2026 - $6.66M

465) Baseline Upgrade b3673

- Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line. - 6/1/2026 - $0.30M

466) Baseline Upgrade b3677

- Rebuild a 13 mile section of 138 kV line 0108 between LaSalle and Mazon with 1113 ACSR or higher rated conductor. The 13 mile portion of line 7713 from Oglesby (future Corbin) to Mazon that shares double circuit towers with line 0108 will also be reconductored due to the rebuild. - 11/1/2026 - $42.06M

467) Baseline Upgrade b3678

- Expand Galion 138 kV substation; Install 100 MVAR reactor, associated breaker and relaying. - 11/1/2026 - $5.74M

468) Baseline Upgrade b3679

- Replace West Fremont 138/69 kV TR2 with a transformer having additional high-side taps. - 11/1/2026 - $6.44M

469) Baseline Upgrade b3680

- At Sanborn, replace limiting substation conductors on Ashtabula 138 kV exit to make transmission line conductor the limiting element. - 6/1/2026 - $0.30M

470) Baseline Upgrade b3681

- Upgrade the Shingletown #82 230-46 kV transformer circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays. - 6/1/2026 - $1.66M

471) Baseline Upgrade b3682

- Install a second 345/138 kV transformer at Hayes, 448 MVA nameplate rating. Add one 345 kV circuit breaker (3000A) to provide transformer high-side connection between breaker B-18 and the new breaker. Connect the new transformer low side to the 138 kV bus. Add one 138 kV circuit breaker (3000A) at Hayes 138 kV substation between B-42 and the new breaker. Relocate the existing 138 kV No. 1 capacitor bank between B-42 and the new breaker. Protection per FE standard. - 6/1/2026 - $7.59M

472) Baseline Upgrade b3683

- Reconductor the existing 556.5 ACSR line segments (3.49 miles) on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the Messick Road-Ridgeley WC4 138 kV line. The total length of the line is 5.02 miles. - 6/1/2026 - $11.20M

473) Baseline Upgrade b3684

- Rebuild 12.4 miles of 115 line #126 segment from Earleys to Kelford with a summer emergency rating of 262 MVA. Replace structures as needed to support the new conductor. Upgrade breaker switch 13668 at Earleys from 1200 A to 2000 A. - 6/1/2026 - $18.75M

474) Baseline Upgrade b3685

- Install a 33 MVAR cap bank at Cloud 115 kV bus along with a 115 kV breaker. Add 115 kV circuit breaker for 115 kV line #38. - 6/1/2026 - $1.50M

475) Baseline Upgrade b3686

- Purchase land close to the bifurcation point of 115 kV line #4 (where the line is split into two sections) and build a new 115 kV switching station called Duncan Store. The new switching station will require space for an ultimate transmission interconnection consisting of a 115 kV six-breaker ring bus (with three breakers installed initially). - 12/1/2026 - $16.00M

476) Baseline Upgrade b3687

- Rebuild approximately 15.1-mile-long line segment between 115 kV line #183 Bristers and Minnieville D.P. with 2-768 ACSS and 4000 A supporting equipment from Bristers to Ox to allow for future 230 kV capability of 115 kV line #183. The continuous summer normal rating will be 523 MVA from Ox-Minnieville. The continuous summer normal rating will be 786 MVA from Minnieville-Bristers. - 6/1/2026 - $30.00M

477) Baseline Upgrade b3688

- Replace the 4/0 SDCU stranded bus with 954 ACSR and a 600 A disconnect switch with a 1200 A disconnect switch on the 6716 line terminal inside Todd substation (on the Preston-Todd 69 kV circuit). - 6/1/2026 - $0.75M

478) Baseline Upgrade b3689.1

- Reconductor approximately 24.42 miles of 230 kV line #2114 Remington CT-Elk Run-

Gainesville to achieve a summer rating of 1574 MVA by fully reconductoring the line and upgrading the wave trap and substation conductor at Remington CT and Gainesville. - 6/1/2026 - $28.99M

479) Baseline Upgrade b3689.2

- Replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 4000A 80 kA breakers and associated equipment including breaker leads as necessary to address breaker duty issues identified in short circuit analysis. - 6/1/2026 - $1.69M

480) Baseline Upgrade b3690

- Reconductor approximately 1.07 miles of 230 kV line #2008 segment from Cub Run-Walney to achieve a summer rating of 1574 MVA. Replace line switch 200826 with a 4000A switch. - 6/1/2026 - $2.03M

481) Baseline Upgrade b3692

- Rebuild approximately 27.7 miles of 500 kV transmission line from Elmont to Chickahominy with current 500 kV standards construction practices to achieve a summer rating of 4330 MVA. - 6/1/2026 - $58.16M

482) Baseline Upgrade b3693

- Expand substation and install approximately 294 MVAR cap bank at 500 kV Lexington substation along with a 500 kV breaker. Adjust the tap positions associated with the two 230/69 kV transformers at Harrisonburg to neutral position and lock them. - 11/1/2026 - $5.86M

483) Baseline Upgrade b3694.1

- Convert line #29 Aquia Harbor to Possum Point to 230 kV (Extended line #2104) and swap line #2104 and converted line #29 at Aquia Harbor backbone termination. Upgrade terminal equipment at Possum Point to terminate converted line 29 (now extended line #2104). (Line #29 from Fredericksburg to Aquia Harbor is being rebuilt under baseline b2981 to 230kV standards.) - 6/1/2026 - $9.39M

484) Baseline Upgrade b3694.10

- Reconductor approximately 2.9 miles of 230 kV line #211 Chesterfield-Hopewell to achieve a minimum summer emergency rating of 1046 MVA. - 6/1/2026 - $4.91M

485) Baseline Upgrade b3694.11

- Reconductor approximately 2.9 miles of 230 kV line #228 Chesterfield-Hopewell to achieve a minimum summer emergency rating of 1046 MVA. - 6/1/2026 - $4.91M

486) Baseline Upgrade b3694.12

- Upgrade equipment at Chesterfield substation to not limit ratings on lines 211 and 228. - 6/1/2026 - $0.76M

487) Baseline Upgrade b3694.13

- Upgrade equipment at Hopewell substation to not limit ratings on lines 211 and 228. - 6/1/2026 - $1.71M

488) Baseline Upgrade b3694.2

- Upgrade Aquia Harbor terminal equipment to not limit 230 kV line #9281 conductor rating. - 6/1/2026 - $0.63M

489) Baseline Upgrade b3694.3

- Upgrade Fredericksburg terminal equipment by rearranging 230 kV bus configuration to terminate converted line 29 (now becoming 9281). The project will add a new breaker at the 230 kV bay and reconfigure line termination of 230 kV lines #2157, #2090 and #2083. - 6/1/2026 - $2.73M

490) Baseline Upgrade b3694.4

- Reconductor/rebuild approximately 7.6 miles of 230 kV line #2104 Cranes Corner-Stafford to achieve a summer rating of 1047 MVA(1). Reconductor/rebuild approximately 0.34 miles of 230 kV line #2104 Stafford-Aquia Harbor to achieve a summer rating of 1047 MVA. Upgrade terminal equipment at Cranes Corner to not limit the new conductor rating. - 6/1/2026 - $19.60M

491) Baseline Upgrade b3694.5

- Upgrade wave trap and line leads at 230 kV line #2090 Ladysmith CT terminal to achieve 4000A rating. - 6/1/2026 - $0.15M

492) Baseline Upgrade b3694.6

- Upgrade Fuller Road substation to feed Quantico substation via 115 kV radial line. Install four-breaker ring and break 230 kV line #252 into two new lines: 1) #252 between Aquia Harbor to Fuller Road and 2) #9282 between Fuller Road and Possum Point. Install a 230/115 kV transformer which will serve Quantico substation. - 6/1/2026 - $24.16M

493) Baseline Upgrade b3694.7

- Energize in-service spare 500/230 kV Carson Tx#1. - 6/1/2026 - $0.00M

494) Baseline Upgrade b3694.8

- Partial wreck and rebuild 10.34 miles of 230 kV line #249 Carson-Locks to achieve a minimum summer emergency rating of 1047 MVA. Upgrade terminal equipment at Carson and Locks to not limit the new conductor rating. - 6/1/2026 - $22.01M

495) Baseline Upgrade b3694.9

- Wreck and rebuild 5.4 miles of 115 kV line #100 Locks-Harrowgate to achieve a minimum summer emergency rating of 393 MVA. Upgrade terminal equipment at Locks and Harrowgate to not limit the new conductor rating and perform line #100 Chesterfield terminal relay work. - 6/1/2026 - $9.10M

496) Baseline Upgrade b3697

- Replace station conductor and metering inside Whitpain and Plymouth substations to increase the ratings of the 220-13/220-14 Whitpain-Plymouth 230 kV line facilities. - 6/1/2025 - $0.62M

497) Baseline Upgrade b3698

- Reconductor the 14.2 miles of the existing Juniata-Cumberland 230 kV line with 1272 ACSS/TW HS285 "Pheasant" conductor. - 12/31/2023 - $8.99M

498) Baseline Upgrade b3702

- Install one 13.5 Ohm series reactor to control the power flow on the 230 kV line #2054 from Charlottesville substation to Proffit Rd 230 kV line. - 6/1/2023 - $11.38M

Revision History:

Version: 1

Date: 3/1/2023

Approver: Sami Abdulsalam, Manager Transmission Planning

Version: 2

Date: 6/1/2023

Updates for TPL-001-5 Compliance:

P5 contingencies

Planning Outages

Spare Equipment

Approver: Sami Abdulsalam, Manager Transmission Planning

Exhibit No. MAOD-6
Mid-Atlantic Offshore Development, LLC
PJM Reliability Analysis Report (Nov. 4, 2022 version)

Reliability Analysis Report

2021 SAA Proposal Window to Support NJ OSW

September 19, 2022
Revised November 4, 2022

For Public Use

The information contained herein is based on information provided in project proposals submitted to PJM by third parties through its 2021 SAA Proposal Window. PJM analyzed such information for the purpose of identifying potential solutions for NJBPU's consideration as contemplated under the SAA Agreement, FERC Rate Schedule No. 49. Any decision made using this information should be based upon independent review and analysis, and shall not form the basis of any claim against PJM.

Contents

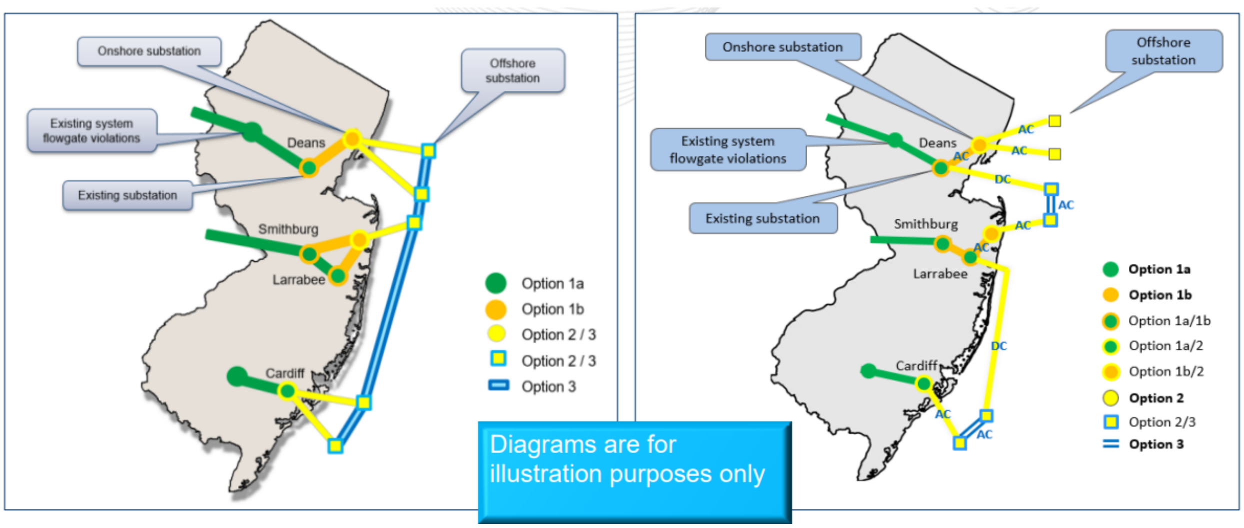
NJ SAA PROPOSAL WINDOW RELIABILITY ANALYSIS

Background

As part of the 2021 State Agreement Approach (SAA) Proposal Window to support New Jersey offshore wind, PJM received proposals to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind. The proposals were categorized into four options according to the function and location of the proposal. Altogether, PJM received a diverse set of 80 proposals.

- Option 1a proposals: Onshore transmission upgrades to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC and Local Transmission Owner criteria)
- Option 1b proposals: Onshore new transmission connection facilities
- Option 2 proposals: Offshore new transmission connection facilities
- Option 3 proposals: Offshore new transmission network facilities

Figure 1. Potential Options for the NJ Offshore Wind Transmission Solution (Concepts depicted are for illustration purposes only; details of new lines and facilities are to be provided by sponsors in proposals to meet objectives of this solicitation.)



Offshore Wind Scenarios

PJM worked with the NJ BPU to create offshore wind injection scenarios involving various combinations of the submitted Option 1b and Option 2 proposals. Each scenario contains the awarded solicitation #1 for 1,100 MW and solicitation #2 for 2,658 MW. While the scope for the submission of proposals did not allow alternative point of injections (POIs) for solicitation #1, it did allow alternative POIs for solicitation #2. As a result, each scenario contains identical considerations for solicitation #1, and the scenario creation focused on selecting combinations of submitted Option 1b and Option 2 proposals that together enable the transmission system to reliably deliver approximately 6,400 MW of additional offshore wind.

Table 1 and Table 2 illustrate the POI locations and MW injection amounts for each scenario considered. Appendix B to this report provides a detailed description of each scenario.

Table 1. POI Onshore Scenarios – Option 1b Only

						Alt POI	Default POI	Alt POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI
Scenario ID	**Total (MW)**	**Proposing Entities**	**Option 1b Proposal IDs**	**Option 2 Proposal IDs**	**Excess Capacity (MW)**	**New Freedom 500 kV (MW)**	**Cardiff 230 kV (MW)**	**Half Acre 500 kV (MW)**	**Lighthouse 500 kV (MW)**	**Smithburg 500 kV (MW)**	**Atlantic 230 kV (MW)**	**Larrabee 230 kV (MW)**	**Werner 230 kV (MW)**
2a	6258	AE, JCPL	797 929.9 453.1-18,24,28-29	None	0		1510 1148			1200	1200	1200	
3	6458	AE, RILPOW, JCPL	797 127.8,9 490 376 453.9-11,16-17	None	200	1148	1510	2200				1200	400
12	6400	CNTLM	781	None	1110		1510		4890				
13	6400	CNTLM	629	None	710		1510		4890				
14	6400	RILPOW, JCPL	490 171 453.18-27,29	None	710		1510	2400		1690			800
18	6400	JCPL	453	None	0		1510			2490	1200	1200	
18a	6400	JCPL, MAOD	453.1-18,24,27-29	551 (partial)	0		1510			1342 1148	1200	1200	

Note 1: All POI Scenarios include Solicitation #1 (1,100 MW), which has been subtracted from the total MW.
Note 2: All MW assumed to be injected at the offshore platform for Option 2 proposals.
Note 3: Excess capacity represents additional transmission capability to the POI beyond the amounts being studied.
Note 4: Transmission interconnection facilities for POI MWs in black font are assumed to be supplied outside this SAA window.

LEGEND

Alt POI = Alternative POI

Table 2. POI Onshore/Offshore Scenarios – Option 1b/2

						Alt POI	Default POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI	Alt POI
Scenario ID	**Total (MW)**	**Proposing Entities**	**Option 1b Proposal IDs**	**Option 2 Proposal IDs**	**Excess Capacity (MW)**	**Reega 230 kV (MW)**	**Cardiff 230 kV (MW)**	**Fresh Ponds 500 kV (MW)**	**Deans 500 kV (MW)**	**Lighthouse 500 kV (MW)**	**Smithburg 500 kV (MW)**	**Atlantic 230 kV (MW)**	**Larrabee 230 kV (MW)**	**Neptune 230 kV (MW)**	**Sewaren 230 kV (MW)**
1.1	6310	COEDTR, ANBARD	None	990 574 831	400		1510		2400		1200		1200		
1.2	6310	COEDTR, PSEGRT	None	990 613	0		1510		1200		1200 1148		1200		
1.2a	6400	COEDTR, ANBARD	None	990 574	58		1510		1342		1200 1148		1200		
1.2b	6400	COEDTR, ATLPWR	None	990 210 172	1058		1510		1342		1200 1148		1200		
1.2c	6400	JCPL MAOD, ANBARD	453.9-11, 16-18, 24, 29	431 574	58		1510		1342		1200 1148		1200		
2c	6258	AE, JCPL, MAOD	797 929.9 453.1-18,24,28-29	551	0		1510 1148				1200	1200	1200		
4	6010	NEETMH	None	461 27	0		1510	3000						1500	
4a	6400	NEETMH	None	461 27	758		1510	2242			1148			1500	
5	6310	JCPL, MAOD	453	321	0		1510				2400	1200	1200		
6	6400	CNTLM	781	594	110		1510			4890					
7	6400	CNTLM	629	594	110		1510			4890					

Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Alt POI Reega 230 kV (MW)	Default POI Cardiff 230 kV (MW)	Alt POI Fresh Ponds 500 kV (MW)	Default POI Deans 500 kV (MW)	Alt POI Lighthouse 500 kV (MW)	Default POI Smithburg 500 kV (MW)	Alt POI Atlantic 230 kV (MW)	Default POI Larrabee 230 kV (MW)	Alt POI Neptune 230 kV (MW)	Alt POI Sewaren 230 kV (MW)
10	6400	ANDBARD	None	882 841 921 131	258		1510		2290				1200		1400
11	6399	PSEGRT	None	683	459		1510		1247		1148		1247		1247
15	6400	NEETMH	None	250	1110		1510	4890							
16	6400	NEETMH	None	604 860	758	2658		3742							
16a	6400	NEETMH	None	860	758		1510	3742			1148				
17	6400	ATLPWR, NEETMH	None	210 172 15	510		1510		1890					3000	
19	6258	ATLPWR	None	210 172 769	0		1510		3600		1148				
20	6400	NEETMH	None	298 461	158		1510	1342			1148			2400	
20a	6400	NEETMH, ANBARD	None	298 574	58		1510		1342		1148			2400	
20b	6400	NEETMH, ATLPWR	None	298 210 172	1058		1510		1342		1148			2400	

Note 1: All POI Scenarios include Solicitation #1 (1,100 MW), which has been subtracted from the total MW.
Note 2: All MW assumed to be injected at the offshore platform for Option 2 proposals.
Note 3: Excess capacity represents additional transmission capability to the POI beyond the amounts being studied.
Note 4: Transmission interconnection facilities for POI MWs in black font are assumed to be supplied outside this SAA window.

LEGEND
Alt POI = Alternative POI

Reliability Analysis Screening

The purpose of the initial reliability analysis screening was to identify the relative magnitude of the onshore upgrade requirements for each scenario and to support the development of a comparative framework for the scenarios under evaluation that considered both the offshore and onshore transmission needs. A final comprehensive reliability analysis and performance evaluation will be performed for the final selected scenario or finalist scenarios.

PJM performed initial reliability analysis screening of these scenarios using PJM's generator deliverability procedures. While generator deliverability analysis is only one of the reliability tests that will need to be examined prior to approving the winning proposals, this analysis is the primary reliability test used in PJM's generator interconnection studies to identify reliability violations caused by new generators and, by itself, typically identifies the majority, if not all, of the upgrades needed to reliably interconnect new generation to the PJM system.

Summer, winter and light power flow models were developed for each scenario for the year 2028 without including any Option 1a proposals. Single and common mode contingencies were examined to identify the reliability violations caused by the offshore wind scenarios.

Once the reliability violations without any Option 1a proposals were identified, PJM consulted with the NJ BPU to select an initial single set of Option 1a proposals from among the competitive Option 1a proposal clusters, described in the next section of this report, to evaluate further.

Each offshore wind scenario resulted in a unique set of onshore reliability violations. A number of the reliability violations were identified as a result of alternate POIs submitted by proposers that the submitted Option 1a proposals did not address. PJM consulted with the affected Transmission Owner(s) (TOs) to identify the appropriate upgrades and provide the associated cost estimates to address the newly identified reliability violations.

Once a complete set of onshore upgrades for a scenario was identified, PJM added the upgrades to the scenario power flow models and ran another generator deliverability analysis to ensure the selected set of upgrades resolved all identified reliability violations and did not cause any additional reliability violations.

Reliability Solutions

PJM received 27 Option 1a proposals as part of this window. A number of the Option 1a proposals addressed similar sets of reliability violations and were grouped into one of three competitive proposal clusters in order to compare the proposals:

- PA/MD Border Proposal Cluster
- Central NJ Proposal Cluster
- Southern NJ Proposal Cluster

The remaining Option 1a proposals each addressed a unique set of reliability violations and were analyzed to demonstrate that they met PJM standards for an acceptable reliability solution and were selected as part of the set of reliability solutions used for scenario evaluations.

The proposals for addressing the Option 1a violations included both conventional transmission solutions, such as rebuild or reconductoring of an existing transmission line as well as installation of power flow controlling devices. While power flow controlling devices can be a solution that mitigates certain violations, such solutions do not increase transmission capability on the system and require additional active control in operations. Where there are acceptable conventional solutions and where the additional transmission capacity offered by conventional solutions are extensive compared to cost savings of adopting power flow control devices, PJM will generally prioritize consideration of the conventional solutions. Power flow controlling devices, such as phase angle regulators and SmartWire devices, were proposed in this window. Such devices are generally not preferred solutions but may be considered when there is no other transmission solution within an order of magnitude cost of the power flow controlling device.

For any upgrades to an existing transmission facility, only incumbent TOs can be designated to upgrade existing facilities. For these TO upgrades, PJM contacted the incumbent TO to request a reliability solution and a corresponding project cost estimate.

Option 1a Proposals Selected To Resolve Scenario Reliability Violations

Option 1a Competitive Proposal Clusters

Tables 3 to 8 show the Option 1a competitive proposal clusters as well as PJM's review summary of the proposal performance using the default scenario. The initial set of Option 1a proposals that were selected to resolve scenario reliability violations involved:

- Proposal 63 from the PA-MD Border Cluster
- Proposals 180.1, 180.2, 180.5 and 180.6 from the Central NJ Cluster
- Proposals 127.10 and 229 from the Southern NJ Border Cluster

This initial selection was based on the cost and performance summaries provided in Tables 3 through 8. Reasons for not selecting other Option 1a proposals are provided in Tables 9 through 13.

Table 3. PA-MD Border Cluster Option 1a Proposals

Proposal ID	Entity	Proposal Name	Cost($M)
203	CNTLM	Broad Creek - Robinson Run	104
11	NEETMH	Wiley 1	202
982	NEETMH	Wiley 2	182
587	NEETMH	Wiley 3	96
345	Transource	Peach Bottom - Conastone	104
63	Transource	North Delta A	110
296	Transource	North Delta B	87
127	AE	Peach Bottom - Conastone	201

Table 4. PA-MD Border Cluster Option 1a Proposal Performance

			Option 1a Proposals							
Overloaded Facility	Rating (MVA)	Base	203	11*	982*	587	345	63	296	127
Peach Bottom - Conastone 500 kV	3700	127%	96%	109%	114%	96%	96%	86%	93%	84%
Peach Bottom - Furnace Run 500 kV	4323	102%	78%	77%	78%	77%	53%	78%	79%	96%
Furnace Run 500/230 kV 1 & 2	1348	116%	90%	92%	90%	90%	60%	90%	91%	< 100%
Furnace Run - Conastone 230 kV 1 & 2	1534	101%	78%	80%	78%	78%	51%	78%	79%	< 100%

*** Project taps Peach Bottom - Conastone 500 kV and section connected to Peach Bottom is overloaded**

Table 5. Central NJ Option 1a Proposals

IDs	Entity	Brief Description	Cost ($M)
44.1	NEETMH	Reconductor Deans-Brunswick 230 kV	$4.68
180.1, 180.2	PSEG	Brunswick to Deans & Deans Subprojects	$50.54
103	CNTLM	New Old York 500/230 kV substation	$75.60
17.14, 17.15	JCPL	Upgrade Windsor-Clarksville 230 kV	$4.00
180.5, 180.6	PSEG	Windsor to Clarksville Subproject	$5.77

Table 6. Central NJ Cluster Option 1a Proposal Performance Summary

IDs	Overloaded Facilities	Performance
44.1	Deans-Brunswick 230 kV	Lowers loading to 81%
180.1, 180.2	Deans-Brunswick 230 kV	Lower loading to 91%
103	Deans-Brunswick 230 kV Windsor-Clarksville 230 kV Clarksville-Lawrence 230 kV	Lowers loading to 88% Lowers loading to 78% Lowers loading to 65%
17.14, 17.15	Windsor-Clarksville 230 kV	Lowers loading to 63%
180.5, 180.6	Windsor-Clarksville 230 kV	Lowers loading to 49%

Table 7. Southern NJ Border Cluster Option 1a Proposals

IDs	Entity	Brief Description	Cost ($M)
127.10	AE	Reconductor Richmond-Waneeta 230 kV	$16.00
229	CNTLM	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
894	PSEG	One additional Hope Creek-Silver Run 230 kV submarine cable	$71.92
419	Transource	New Bridgeport-Claymont 230 kV DE river crossing	$193.07

Table 8. Southern NJ Border Cluster Option 1a Proposal Performance Summary

IDs	Overloaded Facilities	Performance
127.10	Richmond-Waneeta 230 kV	Lowers loading to 72%
229	Hope Creek-LS Power Cable East 230 kV 1 & 2 LS Power Cable East-LS Power Silver Run 230 kV	Lowers loading to 78% Lowers loading to 78%
894	Hope Creek-LS Power Cable East 230 kV 1 & 2 LS Power Cable East-LS Power Silver Run 230 kV	Lowers loading to 63% Still overloaded at 107%
419	Hope Creek-LS Power Cable East 230 kV 1 & 2 LS Power Cable East-LS Power Silver Run 230 kV Richmond-Waneeta 230 kV	Lowers loading to 91% Lowers loading to 97% Lowers loading to 84% Causes new overload on Bridgeport-Mickleton 230 kV

Option 1a Proposals Not In Competitive Proposal Clusters

Many Option 1a proposals were not part of one of the competitive proposal clusters but were selected to resolve reliability violations identified in one or more scenarios. Also, reliability violations were identified in many of the scenarios where there was no Option 1a proposal to address the issue. For these reliability violations PJM contacted the incumbent Transmission Owner and requested solutions for the onshore upgrades. All of the Option 1a proposals and incumbent Transmission Owner onshore upgrades selected for each scenario are shown in Appendix B.

Option 1a Proposals Not Selected To Resolve Scenario Reliability Violations

Tables provided below summarize the complete list of Option 1a proposals that were submitted yet not selected to resolve the initial set of reliability violations identified for any of the scenarios. These tables provide the project description, basic project information and the rationale for determination of why the solution was not selected for inclusion as a reliability solution in any of the injection scenarios.

Table 9. Option 1a Proposals Not Selected In Central New Jersey

Location: Central New Jersey							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	**IDs**	**Description**	**Cost ($M)**	**Circuits**	**TO**	**Reason For Not Selecting**	**Selected Proposal IDs**
JCPL	17.17	Upgrade Hopewell-Lawrence 230 kV	**$3.13**	Hopewell-Lawrence 230 kV	JCPL	No reliability violation identified by PJM	
NEETMH	44.1	Reconductor Deans-Brunswick 230 kV	**$4.68**	Deans-Brunswick 230 kV	PSEG	Reconductor estimate too low (~$72M)	180.1, 180.2
CNTLM	103	New Old York 500/230 kV substation	**$75.60**	Deans-Brunswick 230 kV		More cost effective solution exists	
				Windsor-Clarksville 230 kV Clarksville-Lawrence 230 kV	JCPL/ PSEG		
JCPL	17.14, 17.15	Upgrade Windsor-Clarksville 230 kV	**$4.00**	Windsor-Clarksville 230 kV		More cost effective solution exists	180.5, 180.6
NEETMH	331.6	Reconductor Windsor-Clarksville 230 kV	**$10.09**				
	158.1	Reconductor Gilbert-Springfield 230 kV	**$15.53**	Gilbert-Springfield 230 kV	JCPL/ PPL	Incumbent TO has more cost effective solution	330
	331.1, 331.11, 331.12	Build new Atlantic-Smithburg 230 kV	**$81.04**	Atlantic-Smithburg 230 kV	JCPL	Incumbent TO has more cost effective solution	Oceanview-Smithburg Upgrades
	331.2, 331.3	Reconductor Larrabee-Smithburg 230 kV 1 & 2	**$30.56**	Larrabee-Smithburg 230 kV 1 & 2			
	331.4, 331.5	Reconductor Atlantic-Smithburg 230 kV	**$32.38**	Atlantic-Smithburg 230 kV			
	331.15, 331.16	New Larrabee-Oceanview 230 kV	**$61.97**	Larrabee-Oceanview 230 kV			

Location: Central New Jersey							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	IDs	Description	Cost ($M)	Circuits	TO	Reason For Not Selecting	Selected Proposal IDs
NEETMH	520.1, 520.4, 520.5	New Atlantic-Oceanview 230 kV; loop in existing Larrabee-Oceanview 230 kV into Atlantic 230 kV	**$21.98**	Atlantic-Oceanview 230 kV	PSEG/ JCPL		
	331.7	Reconductor Raritan River-Kilmer 230 kV	**$7.91**	Raritan River-Kilmer 230 kV		More extensive work required than reconductor	South River - Greenbrook Upgrades
NEETMH	331.13, 331.14	Add PAR Red Oak-Raritan River 230 kV 1 & 2	**$30.00**	South River-Red Oak A 230 kV Red Oak A-Raritan River 230 kV Red Oak B-Raritan River 230 kV Raritan River-Kilmer I 230 kV Raritan River-Kilmer W 230 kV Kilmer-Lk Nelson I 230 kV Kilmer-Lk Nelson W 230 kV Lk Nelson-Middlesex I 230 kV Lk Nelson-Middlesex W 230 kV Middlesex I-Bridegwater 230 kV Middlesex W-Greenbk 230 kV		PARs are not preferred when conventional transmission solutions are available	
NEETMH	331.8, 331.9	Reconductor Windsor-East Windsor 230 kV 1 & 2	**$6.86**	Windsor-East Windsor 230 kV 1 & 2	JCPL	No reliability violation identified by PJM	
	331.10	Reconductor Smithburg-East Windsor 230 kV	**$5.00**	Smithburg-East Windsor 230 kV		Substation equipment (not conductor) is limit	Rebuild Smithburg and East Windsor 230 kV substations
	878.7	Eliminate contingencies that derate Smithburg-East Windsor 230 kV winter rating	**$5.00**				

Location: Central New Jersey							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	IDs	Description	Cost ($M)	Circuits	TO	Reason For Not Selecting	Selected Proposal IDs
JCPL	17.4, 17.5, 17.6	New Smithburg-East Windsor 500 kV line	**$237.00**				
NEETMH	651.5	Increase Deans 500/230 kV #3 rating	**$8.36**	Deans 500/230 kV #3	PSEG	No reliability violation identified by PJM	
	651.6	Put Smithburg 500/230 kV spare transformer in service	**$11.51**	Smithburg 500/230 kV 1 & 2	JCPL	Not required for NEETMH proposals; putting spare transformer into service would eliminate the spare	17.18
	793.3, 793.4	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	**$10.00**	Oyster Creek-Manitou 230 kV 1 & 2		Incumbent TO has proposed same solution	17.1, 17.2, 17.3, 17.12, 17.13, 17.21

Table 10. Option 1a Proposals Not Selected Near The Southern New Jersey Border

Location: Southern New Jersey Border							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	IDs	Description	Cost ($M)	Circuits	TO	Reason For Not Selecting	Selected Proposal IDs
NEETMH	158.2	Reconductor Richmond-Waneeta 230 kV	**$4.15**	Richmond-Waneeta 230 kV	PECO	Incumbent TO has proposed same solution	127.10
AE	734.7	Install Smart Wire on Richmond-Waneeta 230 kV	**$4.70**			Flow control devices are not preferred when conventional transmission solutions are available	
NEETMH	158.2	Reconductor Richmond-Waneeta 230 kV	**$4.15**	Richmond-Waneeta 230 kV	PECO	Incumbent TO proposed same solution	127.10
	158.3	Red Lion 500 kV substation upgrade	**$5.00**	Red Lion 500/230 kV #2	DPL	No reliability violation identified by PJM	
	11.11, 11.12	Add two PARs at Hope Creek 230 kV	**$30.00**	Hope Creek-LS Power Cable East 230 kV 1 & 2 LS Power Cable East-LS Power Silver Run 230 kV	PSEG/ SRE SRE	PARs are not preferred when conventional transmission solutions are available	229
PSEG	894	One additional Hope Creek-Silver Run 230 kV submarine cable	**$71.92**			More cost effective solution provided by incumbent TO	
Transource	419	New Bridgeport-Claymont 230 kV DE river crossing	**$193.07**	Hope Creek-LS Power Cable East 230 kV 1 & 2 LS Power Cable East-LS Power Silver Run 230 kV Richmond-Waneeta 230 kV		Does not resolve all reliability issues targeted and more cost effective solution exists	

Table 11. Option 1a Proposals Not Selected In Southern New Jersey

Location: Southern New Jersey							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	IDs	Description	Cost ($M)	Circuits	TO	Reason For Not Selecting	Selected Proposal IDs
AE	127.9	Rebuild Cardiff-New Freedom 230 kV as DCTL	**$154.96**	Cardiff-New Freedom 230 kV	PSEG/ AE	More cost effective solution exists, TO Upgrade	127.3 Reconductor Cardiff-New Freedom 230 kV
NEETMH	158.2	Reconductor Richmond-Waneeta 230 kV	**$4.15**	Richmond-Waneeta 230 kV	PECO	Incumbent TO proposed same solution, TO Upgrade	127.10
	158.3	Red Lion 500 kV substation upgrade	**$5.00**	Red Lion 500/230 kV #2	DPL	No reliability violation identified by PJM	
	793.1, 793.2	Reconductor Cardiff-Lewis 138 kV 1 & 2	**$10.27**	Cardiff-Lewis 138 kV	AE	Incumbent TO proposed simpler solution, TO Upgrade	127.1
	793.5, 793.6	Add PAR on New Freedom-Hilltop 230 kV at New Freedom	**$25.00**	New Freedom-Hilltop 230 kV	PSEG	No reliability violation identified by PJM	
	793.8	Replace Cardiff 230/138 kV	**$10.00**	Cardiff 230/138 kV	AE	Incumbent TO proposed simpler solution, TO Upgrade	Upgrade Cardiff 230/138 kV Transformer
	793.9	Replace Cardiff 230/69 kV	**$10.00**	Cardiff 230/138 kV		Incumbent TO proposed simpler solution, TO Upgrade	
	793.7, 793.10	Add PAR on Cardiff-Cedar 230 kV at Cardiff	**$19.03**	Cardiff-Cedar 230 kV		No reliability violation identified by PJM	

Table 12. Option 1a Proposals Not Selected In Northern New Jersey

Location: Northern New Jersey							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	IDs	Description	Cost ($M)	Circuits	TO	Reason For Not Selecting	Selected Proposal IDs
NEETMH	44.2, 44.3	New Aldene PAR Upgrade Bergen 138 kV bus section	**$18.00**	Linden-Tosco 230 kV Tosco-Linden VFT 230 kV Aldene-Springfield Rd 230 kV Aldene-Stanley Terrace 230 kV	PSEG	PARs are not preferred when conventional transmission solutions are available	180.3, 180.4, 180.7
	651.4	Reconductor Pierson Ave H-Metuchen 230 kV	**$1.00**	Pierson Ave H-Metuchen 230 kV		Upgrade insufficient to resolve identified overloads, TO Upgrade	Uprate the Metuchen-Pierson Ave-Meadow Rd-Brunswick 230 kV line to carry two conductors per phase

Table 13. Option 1a Proposals Not Selected Near The Pennsylvania-Maryland Border

Location: PA-MD Border							
Option 1a Proposals				Overloaded Facilities Addressed			
Proposing Entity	IDs	Description	Cost ($M)	Circuits	TO	Reason For Not Selecting	Selected Proposal IDs
NEETMH	11.1-11.10	1A-Wiley1	**$202.06**	Peach Bottom-Conastone 500 kV Peach Bottom-Furnace Run 500 kV Furnace Run 500/230 kV Transformers 1 & 2 Furnace Run-Conastone 230 kV 1 & 2	PECO/ BGE PECO/ Transource Transource Transource/ BGE	Proposal 63 was initially selected because it has the most favorable relationship between cost and performance than any of the other Option 1a proposals. In particular, it provided the largest reduction in the loading on the Peach Bottom-Conastone 500 kV circuit than any other proposal with a comparable cost. The Peach Bottom-Conastone 500 kV circuit is expected to be the most challenging and costly of the reliability violations identified for the PA-MD Border Cluster to resolve. Subsequently, sensitivity analysis was performed for each of the proposals in this cluster without the 9a project and proposal 63 proved to be the more robust and cost effective solution once again and was deemed to be the most likely proposal to mitigate the need for further upgrades.	63
	982.1-982.10	1A-Wiley2	**$181.92**				
	587.1-587.5	1A-Wiley3	**$96.44**				
AE	127.4-127.6, 127.11	Reconductor Peach Bottom-Conastone 500 kV	**$87.97**				
	127.7	Reconductor Peach Bottom-Furnace Run 500 kV	**$23.00**				
AE	None	Replace Furnace Run 500/230 kV Transformers 1 & 2	**$50.00**				
AE	None	Reconductor Furnace Run-Conastone 230 kV 1 & 2	**$40.00**				
CNTLM	203	Broad Creek to Robinson Run Project	**$104.18**				
Transource	296	North Delta Option B	**$87.02**				
	345.1-345.3	Second Peach Bottom-Conastone 500 kV	**$104.29**				

Summary of Initial Reliability Screening Analysis Results

The tables below provide the cost estimates for the Option 1b, Option 2 and Option 1a proposals selected for each scenario. Note that the Option 1a cost estimates include both the selected Option 1a proposals and any incumbent Transmission Owner identified onshore upgrades required to resolve reliability violations for the scenario that were not resolved by a submitted Option 1a proposal.

The State Agreement Approach (SAA) MW are the POI injections associated with an Option 1b or Option 2 proposal, i.e., the sum of the POI MW for the scenario in Tables 1 and 2 that are not in black font.

Table 14. POI Onshore Scenarios – Option 1b Only

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
2a	6258	4748	AE, JCPL	797 929.9 453.1-18,24,28-29	$233 $70 $377	None	$0	$856	$1,536	$0.32
3	6458	4948	AE, RILPOW, JCPL	797 127.8,9 490 376 453.9-11,16-17	$233 $225 $1,732 $68 $17	None	$0	$385	$2,660	$0.54
12	6400	4890	CNTLM	781	$1,772	None	$0	$271	$2,043	$0.42
13	6400	4890	CNTLM	629	$1,568	None	$0	$283	$1,851	$0.38
14	6400	4890	RILPOW, JCPL	490 171 453.18-27,29	$1,732 $109 $519	None	$0	$422	$2,782	$0.57
18 *(finalist)*	6400	4890	JCPL	453	$620	None	$0	$567	$1,187	$0.24
18a *(finalist)*	6400	4890	JCPL, MAOD	453.1-18,24,27-29	$383	551 (partial)	$121	$567	$1,071	$0.29

Table 15. POI Onshore/Offshore Scenarios – Option 1b/2

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.1	6310	4800	COEDTR, ANBARD	None	$0	990 574 831	$2,747 $1,810 $1,877	$327	$6,761	$1.41
1.2	6310	3652	COEDTR, PSEGRT	None	$0	990 613	$3,317 $2,151	$352	$5,820	$1.59
1.2a	6400	3742	COEDTR, ANBARD	None	$0	990 574	$2,747 $1,810	$352	$4,909	$1.31
1.2b	6400	3742	COEDTR, ATLPWR	None	$0	990 210 172	$2,747 $2,024 $1,601	$352	$5,823	$1.56
1.2c *(finalist)*	6400	3742	JCPL, MAOD, ANBARD	453.9-11,16-18,24,29	$293	431 574	$2,957 $1,810	$381	$5,441	$1.45
2c	6258	4748	AE, JCPL, MAOD	797 929.9 453.1-18,24,28-29	$233 $70 $377	551	$4,411	$670	$5,761	$1.21
4	6010	4500	NEETMH	None	$0	461 27	$3,608 $1,477	$390	$5,475	$1.22
4a	6400	3742	NEETMH	None	$0	461 27	$3,608 $1,477	$387	$5,461	$1.46
5	6310	4800	JCPL, MAOD	453	$620	321	$5,726	$561	$6,907	$1.44
6	6400	4890	CNTLM	781	$1,772	594	$2,460	$271	$4,503	$0.92
7	6400	4890	CNTLM	629	$1,568	594	$2,460	$283	$4,311	$0.88

Table 16. POI Onshore/Offshore Scenarios – Option 1b/2

Scenario ID	Total (MW)	\SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
10	6400	4890	ANDBARD	None	$0	882 841 921 131	$1,776 $1,794 $1,545 $1,648	$406	$7,169	$1.47
11	6399	3741	PSEGRT	None	$0	683	$7,181	$402	$7,583	$2.03
15	6400	4890	NEETMH	None	$0	250	$7,029	$311	$7,340	$1.50
16	6400	6400	NEETMH	None	$0	604 860	$2,943 $5,285	$519	$8,747	$1.37
16a ***(finalist)***	6400	3742	NEETMH	None	$0	860	$5,285	$327	$5,612	$1.50
17	6400	4890	ATLPWR, NEETMH	None	$0	210 172 15	$2,024 $1,601 $3,023	$772	$7,420	$1.52
19	6258	3600	ATLPWR	None	$0	210 172 769	$2,024 $1,601 $1,478	$324	$5,427	$1.51
20	6400	3742	NEETMH	None	$0	298 461	$2,662 $3,608	$586	$6,856	$1.83
20a	6400	3742	NEETMH, ANBARD	None	$0	298 574	$2,662 $1,810	$578	$5,050	$1.35
20b	6400	3742	NEETMH, ATLPWR	None	$0	298 210 172	$2,662 $2,024 $1,601	$578	$6,865	$1.83

Final Reliability Analysis

The completion of the initial reliability analysis screening and identification of an initial set of onshore upgrades for each scenario was necessary to provide NJ BPU with a comparative framework of preliminary transmission cost estimates for the scenarios under evaluation that considers both the offshore and onshore transmission needs. The NJ BPU used this information to select four scenarios for a final, comprehensive reliability evaluation that included both a further review of the competitive Option 1a proposal clusters as necessary as well as a full set of reliability studies. The four finalist scenarios were:

- Scenario 1.2c
- Scenario 16a
- Scenario 18
- Scenario 18a

Comprehensive Reliability Analysis

A complete list of the reliability criteria that was applied by PJM during the final evaluation of proposals in this proposal window – along with the associated analytical procedures, study material and the terminology used to define the criteria violations – is described in Appendix A in this report.

This comprehensive reliability analysis identified five overdutied breakers for each of the four finalist scenarios. A description of the required breaker upgrades and cost estimate is provided in Table 17 below. Tables 14 through 16 contain these additional breaker costs in the cost estimates developed for the four finalist scenarios.

Table 17. Additional Reliability Upgrades Identified During Comprehensive Reliability Analysis

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
PECO	Incumbent TO	Replace 4 Peach Bottom 500 kV breakers	$5.60
BGE	Incumbent TO	Upgrade one Conastone 230 kV breaker	$1.30
TOTAL			**$6.90**

After the comprehensive reliability analysis and all other evaluations were complete, the NJ BPU selected Scenario 18a as the State Agreement Approach Project.

APPENDIX A: SCOPE OF FINAL RELIABILITY ANALYSIS

PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC and Local Transmission Owner criteria).

Criterion Applied by PJM for This Proposal Window

- 2028 Summer Baseline Thermal and Voltage N-1 Contingency Analysis
- 2028 Summer Generator Deliverability and Common Mode Reliability Analysis
- 2028 Summer Load Deliverability Thermal and Voltage Analysis
- 2028 Summer N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- 2028 Winter Baseline Thermal and Voltage N-1 Contingency Analysis
- 2028 Winter Generator Deliverability and Common Mode Reliability Analysis
- 2028 Winter Load Deliverability Thermal and Voltage Analysis
- 2028 Winter N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- 2028 Light Load Baseline Thermal and Voltage N-1 Contingency Analysis
- 2028 Light Load Generator Deliverability and Common Mode Reliability Analysis
- 2028 FERC Form 715 Analysis
- 2035 Long-Term Deliverability Analysis
- 2025 Stability Analysis
- 2025 Short Circuit Analysis

APPENDIX B: OFFSHORE WIND SCENARIO DESCRIPTIONS

Option 1b Only Scenarios

Scenario 2a

Scenario 2a Description

Scenario 2a uses AE Option 1b proposals 797 and 929.9 to interconnect 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind to Cardiff 230 kV. Scenario 2a also uses JCPL Option 1b proposals 453.1-18, 24, 28-29 to interconnect 1,200 MW offshore wind to Larrabee 230 kV, 1,200 MW offshore wind to Atlantic 230 kV and 1,200 MW offshore wind to Smithburg 500 kV. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) are assumed to be the responsibility of the offshore wind developers.

AE Option 1b proposals 797 and 929.9 involve building a new transition vault connecting 275 kV offshore cables and 275 kV onshore cables, building new 275 kV transmission lines between the transition vault and new 275-230 kV substation near Cardiff, building a new 275-230 kV substation near Cardiff connected to existing substation at Cardiff, and rebuilding the Cardiff substation to accommodate a breaker-and-a-half bus design. A normally open breaker at Cardiff 230 kV in AE proposal 929.9 needs to be normally closed to avoid stability problems identified by bypassing Cardiff 230 kV and directly connecting either to Orchard 230 kV or New Freedom 230 kV. The stability issues appear under critical contingencies as high-frequency oscillations on the offshore wind turbines themselves and, to a lesser degree, on surrounding generators. AE Option 1b proposals 929.10 and 929.12 create a second Cardiff-Orchard 230 kV line and a second Orchard 500/230 kV transformer.

JCPL Option 1b proposals 453.1-18, 24, 28-29 involve the following components:

- Rebuild the D2004 Larrabee-Smithburg #1 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal, and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct a new ~11.6 mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

JCPL proposed a new Smithburg-East Windsor 500 kV line as Option 1a proposals 17.4-11 to complement its Option 1b proposal 453, but PJM determined that this would not be required to support the 3,600 MW injection into central New Jersey as part of this scenario.

Table 18. Scenario 2a Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b	Option 1b	Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
2a	6258	4748	AE, JCPL	797 929.9 453.1-18,24,28-29	$233 $70 $377	None	$0	$856	$1,536	$0.32

Table 19. Scenario 2a POI Summary

						Default POI	Default POI	Alt POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)
2a	6258	AE, JCPL	797 929.9 453.1-18,24,28-29	None	0	1510 1148	1200	1200	1200

Table 20. Scenario 2a Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
AE	797.1 797.2	Build new substation at Cardiff near existing substation at Cardiff Build new 275 kV transmission lines from transition vault to new Cardiff substation	$232.71
	929.9	Rebuild Cardiff substation to accommodate a breaker and a half bus design	$70.10
JCPL	453.1	Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	$31.47
	453.2	Freneau Substation - Update relay settings	$0.03
	453.3	Smithburg Substation - Update relay settings	$0.03
	453.4	Oceanview Substation - Update relay settings	$0.04
	453.5	Red Bank Substation - Update relay settings	$0.04
	453.6	South River Substation - Update relay settings	$0.03
	453.7	Larrabee Substation - Update relay settings	$0.03
	453.8	Atlantic Substation - Install line terminal	$4.95

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230kV	$17.07
	453.15	Larrabee-Oceanview 230kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230kV New Line	$7.52
	453.18	Larrabee Converter-Smithburg No1 500kV Line (New Asset)	$150.35
	453.24	G1021 Atlantic-Smithburg 230kV	$62.85
	453.28	Larrabee Substation	$0.86
	453.28	Smithburg Substation 500 kV 3 Brk Ring	$62.44
Total			**$680.06**

Table 21. Scenario 2a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
AE	929.10, 929.12	Second Cardiff-Orchard 230 kV Second Orchard 500/230 kV	$197.52
Transource	63	North Delta Option A	$109.68
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV	$0.20
	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV	$25.88
	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV	$11.05
	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
Exelon	Email 5/13/2022	Reconductor Cardiff-New Freedom 230 kV	$40.00
	Email 5/13/2022	Cardiff transformer replacements	$8.00
	Email 5/13/2022	Rebuild Cardiff-Lewis #1 138 kV	$20.00
	Email 5/13/2022	Reconductor Cardiff-Lewis #2 138 kV	$7.00
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
PSEG	Email 2/22/2022	Build a new ~10 mile 230 kV UG line from Beaver Brook - Camden	$186.00
Total			**$855.92**

Scenario 3

Scenario 3 Description

Scenario 3 uses AE Option 1b proposals 797, 127.8 and 127.9 to interconnect 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind to New Freedom 230 kV, Rise Light & Power Option 1b proposal 490 to interconnect 2,200 MW offshore wind to a new Half Acre 500 kV substation, Rise Light & Power Option 1b proposal 376 to interconnect 400 MW offshore wind to Werner 230 kV, and JCPL Option 1b proposals 453.9-11, 16-17 to interconnect 1,200 MW offshore wind to Larrabee 230 kV. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) are assumed to be the responsibility of the offshore wind developers.

AE Option 1b proposals 797, 127.8 and 127.9 involve building a new transition vault connecting 275 kV offshore cables and 275 kV onshore cables, building new 275 kV transmission lines between the transition vault and new 275-230 kV substation near Cardiff, building a new 275-230 kV substation near Cardiff connected to existing substation at Cardiff, rebuilding the Cardiff substation to accommodate a breaker-and-a-half bus design, and rebuilding the Cardiff-New Freedom 230 kV line. A normally open breaker at Cardiff 230 kV in AE proposal 127.8 needs to be normally closed to avoid stability problems identified by bypassing Cardiff 230 kV and directly connecting either to Orchard 230 kV or New Freedom 230 kV. The stability issues appear under critical contingencies as high-frequency oscillations on the offshore wind turbines themselves and to a lesser degree on surrounding generators. However, note that this scenario does not consider closing this normally open breaker, and if this scenario is selected for further review, then additional upgrades may be required to support closing the proposed normally open breaker at Cardiff.

Rise Light & Power's Option 1b proposal 490 involves relocating and rebuilding the existing Werner substation as a gas-insulated substation (GIS) on the existing parcel to make room for two 320 kV HVDC converters. An underground HVDC cable system consisting of two 1,200 MW cables will connect the Werner site to a new Half Acre 500 kV substation to be looped into the existing Deans-East Windsor 500 kV line (only up to a 2,200 MW loading level was studied as part of this scenario). The new Half Acre 500 kV substation will contain two 320 kV HVDC converters connected to a new AC switching station.

Rise Light & Power's Option 1b proposal 376 involves construction of a new Werner 275 kV AIS substation to interconnect 400 MW offshore wind to the new Werner 230 kV substation in their Option 1b proposal 490.

JCPL Option 1b proposals 453.9-11, 16-17 involve the following components:

- Expand the Larrabee 230 kV substation to interconnect the offshore wind generation
- Construct approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station and supporting work

Table 22. Scenario 3 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
3	6458	4948	AE, RILPOW, JCPL	797 127.8,9 490 376 453.9-11,16-17	$233 $225 $1,732 $68 $17	None	$0	$385	$2,660	$0.54

Table 23. Scenario 3 POI Summary

						Alt POI	Default POI	Alt POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	New Freedom 500 kV (MW)	Cardiff 230 kV (MW)	Half Acre 500 kV (MW)	Larrabee 230 kV (MW)	Werner 230 kV (MW)
3	6458	AE, RILPOW, JCPL	797 127.8,9 490 376 453.9-11,16-17	None	200	1148	1510	2200	1200	400

Table 24. Scenario 3 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
AE	797.1	Build new substation at Cardiff near existing substation at Cardiff	$97.66
	797.2	Build new 275 kV transmission lines from transition vault to new Cardiff substation	$135.05
	127.8	Rebuild Cardiff substation	$70.10
	127.9	Rebuild the Cardiff-New Freedom 230 kV line	$154.66
RILPOW	490.1	Outerbridge Onshore Collector Station #1	$53.23
	490.2	Outerbridge Onshore Collector Station #2	$44.67
	490.3	Outerbridge HVDC Converter Station #1	$284.51
	490.4	Outerbridge HVDC Converter Station #2	$281.25
	490.5	HVDC Transmission Line #1	$334.46
	490.6	HVDC Transmission Line #2	$86.52
	490.7	Inland HVDC Converter Station #1	$285.09
	490.8	Inland HVDC Converter Station #2	$283.26
	490.9	Inland Switching Station	$28.90
	490.10	East Windsor-Deans Transmission Line	$10.63
	490.11	Werner Substation	$39.50
	376.1	Outerbridge Collector Station	$67.85
JCPL	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.16	B54 Larrabee-South Lockwood 34.5kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230kV New Line	$7.52
TOTAL			$2,274.22

Table 25. Scenario 3 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
JCPL	Email 4/19/2022	Reconductor Werner-Raritan River 115 kV	$4.40*
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
Total			**$384.5**

*Reflects per mile type cost estimate, and will be updated with Transmission Owner estimates once available. Per mile estimates came from Eastern Interconnection Planning Collaborative (EIPC) and are used in PJM renewable integration studies to estimate transmission costs.

Scenario 12

Scenario 12 Description

Scenario 12 uses LS Power's Option 1b proposal 781 to construct a new Lighthouse 500/345 kV AC substation at the shoreline to interconnect 4,890 MW of offshore wind, including 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind. An underground 500 kV cable system connects the Lighthouse substation to three new onshore 500 kV substations: Crossroads, Gateway and Wells Landing. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

The new Lighthouse 500/345 kV substation has terminals to connect up to 15 345 kV submarine cables and convert them to 500 kV with four 500/345 kV transformers. The new Crossroads 500/230 kV substation connects two new 500 kV underground circuits from the Lighthouse substation to two 500/230 kV transformers for connection to the existing Larrabee 230 kV substation. The new Gateway 500 kV substation connects four new underground 500 kV cables from the Lighthouse substation to the existing Deans to East Windsor 500 kV transmission line. The new Wells Landing 500/230 kV substation connects two new underground 500 kV cables from the new Gateway 500 kV substation to the existing Trenton to Brunswick 230 kV transmission lines via two 500/230 kV transformers.

The proposal involves several thousand MVARs of reactors and a Statcom to compensate for the cable charging.

- Lighthouse 500/345 kV: Shunt reactors and dynamic compensation will be specified once offshore wind locations are determined.
- Crossroads 500 kV: 2x150 MVAR shunt reactors
- Mid-point reactive compensation along the Lighthouse-Gateway 500 kV UG cable: 8x215 MVAR shunt reactors
- Gateway 500 kV: 4x215 MVAR shunt reactors and a +/- 450 MVAR Statcom
- Wells Landing 500 kV: 2x150 MVAR shunt reactors

Table 26. Scenario 12 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
12	6400	4890	CNTLM	781	$1,772	None	$0	$271	$2,043	$0.42

Table 27. Scenario 12 POI Summary

						Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Lighthouse 500 kV (MW)
12	6400	CNTLM	781	None	110	1510	4890

Table 28. Scenario 12 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
CNTLM	781.1	Lighthouse Substation	$198.50
	781.2	Gateway Substation	$109.84
	781.3	Lighthouse - Gateway 500kV Transmission Line #1	$246.20
	781.4	Well's Landing Substation	$59.25
	781.5	Crossroads Substation	$38.82
	781.6	Lighthouse - Crossroads 500kV Transmission Line #1	$90.27
	781.7	Gateway - Well's Landing 500kV Transmission Line Circuit #1	$72.79
	781.8	Gilbert - Springfield - Terminal Equipment Upgrades	$0.10
	781.9	Trenton - Devils Brook 230kV Transmission Interconnection	$0.67
	781.10	Trenton - Hunters Glen 230kV Transmission Interconnection	$0.67
	781.11	Deans - East Windsor 500kV Transmission Interconnection	$1.28
	781.12	Midpoint Reactor Station	$42.67
	781.13	Larrabee - Substation Interconnection	$7.45
	781.14	Lighthouse - Gateway 500kV Transmission Line #2	$246.20
	781.15	Lighthouse - Gateway 500kV Transmission Line #3	$247.07
	781.16	Lighthouse - Gateway 500kV Transmission Line #4	$247.07
	781.17	Gateway - Well's Landing 500kV Transmission Line #2	$72.79
	781.18	Lighthouse - Crossroads 500kV Transmission Line #2	$90.27
Total			**$1,771.90**

Table 29. Scenario 12 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			**$270.61**

Scenario 13

Scenario 13 Description

Scenario 13 uses LS Power's Option 1b proposal 629 to construct a new Lighthouse 500/345 kV AC substation at the shoreline to interconnect 4,890 MW of offshore wind, including 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind. An underground 500 kV cable system connects the Lighthouse substation to a new Crossroads 500 kV substation near the existing Larrabee 230 kV substation and then connects Crossroads 500 kV substation to both the existing Smithburg 500 kV substation and to a new Gardenview 500 kV substation through two new 500 kV overhead circuits. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

The new Lighthouse 500/345 kV substation has terminals to connect up to 15 345 kV submarine cables and convert them to 500 kV with four 500/345 kV transformers. The new Crossroads 500/230 kV substation will connect new underground 500 kV cables from the Lighthouse substation to the existing Larrabee substation through a new 500/230 kV transformer. The new Crossroads substation will also connect to the existing Smithburg 500 kV substation through a new overhead 500 kV transmission line and to the new Gardenview 500 substation through separate new overhead 500 kV transmission line. Reactive support for the underground cables is provided by a shunt reactor for each underground cable. Dynamic reactive support and short circuit support to ensure system stability and system optimization are provided by multiple synchronous condensers. The new Gardenview substation is a new gas-insulated 500 kV switchyard located adjacent to East Windsor substation. The substation will replace the existing East Windsor 500 kV switchyard. Old York substation is a new gas-insulated 500/230 kV substation that will connect the East Windsor (Gardenview) to New Freedom 500 kV transmission line with the existing Burlington to Trenton 230 kV transmission lines via two transformers.

Table 30. Scenario 13 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
13	6400	4890	CNTLM	629	$1,568	None	$0	$283	$1,851	$0.38

Table 31. Scenario 13 POI Summary

						Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Lighthouse 500 kV (MW)
13	6400	CNTLM	629	None	110	1510	4890

Table 32. Scenario 13 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
CNTLM	629.1	Lighthouse - Crossroads 500 kV Transmission Line #1	$96.59
	629.2	Lighthouse 500 kV Substation	$194.59
	629.3	Crossroads 500 kV Substation	$309.63
	629.4	Larrabee 230 kV Upgrades	$8.57
	629.5	Smithburg 500 kV Bus Expansion	$45.75
	629.6	Crossroads - Garden View 500 kV Transmission Line	$125.96
	629.7	Deans - Smithburg 500 kV Transmission Line Uprate	$110.79
	629.8	Old York 500/230 kV Substation	$73.10
	629.9	Lighthouse - Crossroads 500 kV Transmission Line #2	$96.59
	629.10	Lighthouse - Crossroads 500 kV Transmission Line #3	$96.61
	629.11	Gardenview 500 kV Substation	$38.25
	629.12	Smithburg - Crossroads 500 kV Transmission Line	$73.17
	629.13	Deans - Substation Interconnection	$12.93
	629.14	Lighthouse - Crossroads 500 kV Transmission Line #4	$96.61
	629.15	Lighthouse - Crossroads 500 kV Transmission Line #5	$94.49
	629.16	Lighthouse - Crossroads 500 kV Transmission Line #6	$94.49
Total			**$1,568.11**

Table 33. Scenario 13 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.7	Upgrade Smithburg-Deans 500 kV	$13.24
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
Total			**$283.47**

Scenario 14

Scenario 14 Description

Scenario 14 uses Rise Light & Power Option 1b proposal 490 to interconnect 2,400 MW offshore wind to a new Half Acre 500 kV substation, Rise Light & Power Option 1b proposal 171 to interconnect 800 MW offshore wind to Werner 230 kV, and JCPL Option 1b proposals 453.18-27, 29 to interconnect 1,690 MW offshore wind, including 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind, to Smithburg 230 kV. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

Rise Light & Power's Option 1b proposal 490 involves relocating and rebuilding the existing Werner substation as a GIS on the existing parcel to make room for two 320 kV HVDC converters. An underground 320 kV HVDC cable system will connect the Werner site to a new Half Acre 500 kV substation to be looped into the existing Deans-East Windsor 500 kV line. The new Half Acre 500 kV substation will contain two 320 kV HVDC converters connected to a new AC switching station.

Rise Light & Power's Option 1b proposal 171 involves construction of a new Werner 275 kV AIS substation to interconnect 800 MW offshore wind to the new Werner 230 kV substation in their Option 1b proposal 490.

JCPL Option 1b proposals 453.18-27, 29 involve several components:

- Rebuild the D2004 Larrabee-Smithburg #1 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection

Table 34. Scenario 14 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
14	6400	4890	RILPOW, JCPL	490 171 453.18-27,29	$1,732 $109 $519	None	$0	$492	$2,852	$0.58

Table 35. Scenario 14 POI Summary

						Default POI	Alt POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Half Acre 500 kV (MW)	Smithburg 500 kV (MW)	Werner 230 kV (MW)
14	6400	RILPOW, JCPL	490 171 453.18-27,29	None	710	1510	2400	1690	800

Table 36. Scenario 14 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
RILPOW	490.1	Outerbridge Onshore Collector Station #1	$53.23
	490.2	Outerbridge Onshore Collector Station #2	$44.67
	490.3	Outerbridge HVDC Converter Station #1	$284.51
	490.4	Outerbridge HVDC Converter Station #2	$281.25
	490.5	HVDC Transmission Line #1	$334.46
	490.6	HVDC Transmission Line #2	$86.52
	490.7	Inland HVDC Converter Station #1	$285.09
	490.8	Inland HVDC Converter Station #2	$283.26
	490.9	Inland Switching Station	$28.90
	490.10	East Windsor-Deans Transmission Line	$10.63
	490.11	Werner Substation	$39.50
	171.1	Outerbridge Collector Station	$108.66
JCPL	453.18	Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	$150.35
	453.19	Larrabee Converter-Smithburg No2 500 kV Line (New Asset)	$111.71
	453.20	B1042 Cookstown-Larrabee 230 kV	$39.79
	453.21	L220 Hyson-Larrabee 34.5 kV	$13.57
	453.22	K219 Hyson-Larrabee 34.5 kV	$10.33
	453.23	E83 Line 115kV (NIS)	$8.47
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.25	H2008 Larrabee Smithburg No2 230 kV	$8.47
	453.26	D2004 Larrabee-Smithburg No1 230 kV	$44.77
	453.27	Smithburg Substation 500 kV Expansion	$5.81
	453.29	Smithburg Substation 500 kV 3 Brk Ring	$62.44
Total			$2,359.24

Table 37. Scenario 14 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 9/23/2022	Rebuild the Werner-Freneau 69 kV not-in-service lines (8.5 miles) to 230 kV operation. Expand Werner 230 kV substation to a 230 kV three breaker ring bus. Expand Freneau substation to a 12 breaker-and-a-half station.	$85.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
Total			$492.09

Scenario 18

Scenario 18 Description

Scenario 18 uses JCPL Option 1b proposal 453 to interconnect 4,890 MW of offshore wind to central New Jersey, including 1,200 MW to Larrabee 230 kV, 1,200 MW to Atlantic 230 kV and 2,490 MW to Smithburg 500 kV, which accounts for the 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

JCPL Option 1b proposal 453 involves the following components:

- Rebuild the D2004 Larrabee-Smithburg #1 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct new ~11.6 mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

Table 38. Scenario 18 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
18	6400	4890	JCPL	453	$620	None	$0	$561	$1,181	$0.24

Table 39. Scenario 18 POI Summary

						Default POI	Default POI	Alt POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)
18	6400	JCPL	453	None	0	1510	2490	1200	1200

Table 40. Scenario 18 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	453.1	Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	$31.47
	453.2	Freneau Substation - Update relay settings	$0.03
	453.3	Smithburg Substation - Update relay settings	$0.03
	453.4	Oceanview Substation - Update relay settings	$0.04
	453.5	Red Bank Substation - Update relay settings	$0.04
	453.6	South River Substation - Update relay settings	$0.03
	453.7	Larrabee Substation - Update relay settings	$0.03
	453.8	Atlantic Substation - Install line terminal	$4.95
	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230 kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230 kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230 kV	$17.07
	453.15	Larrabee-Oceanview 230 kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5 kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV New Line	$7.52
	453.18	Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	$150.35
	453.19	Larrabee Converter-Smithburg No2 500 kV Line (New Asset)	$111.71
	453.20	B1042 Cookstown-Larrabee 230 kV	$39.79
	453.21	L220 Hyson-Larrabee 34.5 kV	$13.57
	453.22	K219 Hyson-Larrabee 34.5 kV	$10.33
	453.23	E83 Line 115 kV (NIS)	$8.47
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.25	H2008 Larrabee Smithburg No2 230 kV	$8.47
	453.26	D2004 Larrabee-Smithburg No1 230 kV	$44.77
	453.27	Smithburg Substation 500 kV Expansion	$5.81
	453.28	Larrabee Substation	$0.86
	453.29	Smithburg Substation 500 kV 3 Brk Ring	$62.44
Total			$620.16

Table 41. Scenario 18 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.4-17.11	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.	$206.50
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer I-Lake Nelson I 230 kV	$4.42
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
PECO	Incumbent TO	Replace four Peach Bottom 500 kV breakers	$5.60
BGE	Incumbent TO	Upgrade one Conastone 230 kV breaker	$1.30
TOTAL			**$567.45**

Scenario 18a

Scenario 18a Description

Scenario 18a uses JCPL Option 1b proposals 453.1-18,24,27-29 to interconnect 3,742 MW of offshore wind to central New Jersey, including 1,200 MW to Larrabee 230 kV, 1,200 MW to Atlantic 230 kV and 1,342 MW to Smithburg 500 kV. It also uses a portion of MAOD proposal 551 to construct the Larrabee 230 kV AC Collector Station and procure land adjacent to the MAOD AC switchyard for future HVDC converters.

The interconnection of the remaining 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind, 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

JCPL Option 1b proposal 453.1-18,24,27-29 involves the following components:

- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct new ~11.6 mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

MAOD proposal 551 (partial) involves constructing the Larrabee 230 kV AC Collector Station and procuring land adjacent to the MAOD AC switchyard for future HVDC converters.

Table 42. Scenario 18 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
18a	6400	3,742	JCPL, MAOD	453.1-18,24,27-29	$383	551 (partial)	$121	$567	$1,071	$0.29

Table 43. Scenario 18 POI Summary

						Default POI	Default POI	Alt POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)

18a	6400	JCPL, MAOD	453.1-18,24,27-29	551 (partial)	0	1510	1,342 1,148	1200	1200

Table 44. Scenario 18a Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	453.1	Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	$31.47
	453.2	Freneau Substation - Update relay settings	$0.03
	453.3	Smithburg Substation - Update relay settings	$0.03
	453.4	Oceanview Substation - Update relay settings	$0.04
	453.5	Red Bank Substation - Update relay settings	$0.04
	453.6	South River Substation - Update relay settings	$0.03
	453.7	Larrabee Substation - Update relay settings	$0.03
	453.8	Atlantic Substation - Install line terminal	$4.95
	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230 kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230 kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230 kV	$17.07
	453.15	Larrabee-Oceanview 230 kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5 kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV New Line	$7.52
	453.18	Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	$150.35
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.27	Smithburg Substation 500 kV Expansion	$5.81
	453.28	Larrabee Substation	$0.86
	453.29	Smithburg Substation 500 kV 3 Brk Ring	$62.44
Total			**$383.05**

Table 45. Scenario 18a Option 2 Component Cost Estimates

	Component Descriptions	In-Service Date (ISD)	Cost ($M)
MAOD			

<table>
<tr>
<td rowspan="2">Proposal ID 551</td>
<td>Construct the AC switchyard portion of MAOD proposal 551, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000A and four single phase 500/230 kV 450MVA autotransformers to step up the voltage for connection to the Smithburg substation. AC switchyard design and site preparation shall be suitable for expansion to a 230 kV 4 X 230 kV breaker and a half substation and seven single phase 500/230 kV 450 MVA autotransformers to step up voltage for connection of two circuits to Smithburg substation.</td>
<td>ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work</td>
<td rowspan="2">$121.10
Note: This cost represents a partial scope of MAOD proposal #551. It excludes other owners costs, permitting, commercial and financial fees, and will require further evaluation to refine the estimate.</td>
</tr>
<tr>
<td>Procure land adjacent to the MAOD AC switchyard, which is a portion of the MAOD proposal 551, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of 4 individual converters to accommodate circuits with equivalent rating of 1400MVA at 400 kV. MAOD will commit to work with NJBPU and Staff, PJM, the relevant transmission owners, and all future developers to lease or otherwise make land access available for construction of converters by those developers to support the integration of OSW generators to achieve the OSW goals of New Jersey</td>
<td>ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work</td>
</tr>
</table>

Table 47. Scenario 18a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.4-17.11	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.	$206.50
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer I-Lake Nelson I 230 kV	$4.42
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
PECO	Incumbent TO	Replace four Peach Bottom 500 kV breakers	$5.60
BGE	Incumbent TO	Upgrade one Conastone 230 kV breaker	$1.30
TOTAL			**$567.45**

Option 1b/2 Scenarios

Scenario 1.1

Scenario 1.1 Description

Scenario 1.1 uses ConEd Option 2 proposal 990 to interconnect 1,200 MW of offshore wind, which includes 1,148 MW of solicitation #2 (Ocean Wind 2), to Smithburg 500 kV and 1,200 MW to Larrabee 230 kV. Scenario 1.1 also uses Anbaric Option 2 proposals 574 and 831 to interconnect 2,400 MW of offshore wind to Deans 500 kV. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

ConEd Option 2 proposal 990 involves the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems
- One new onshore 320 kV converter station at Smithburg 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Smithburg
- One new onshore 320 kV converter station at Larrabee 230 kV with 320/230 kV transformation and a short 230 kV underground connection to Larrabee

Anbaric Option 2 proposals 574 and 831 involve the following components:

- Two new offshore 400 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,400 MW submarine and underground cable systems (only up to a 2,400 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- Two new onshore 400 kV converter stations at Deans 500 kV with 400/500 kV transformation and a short 500 kV underground connection to Deans

Table 48. Scenario 1.1 Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.1	6310	4800	COEDTR, ANBARD	None	$0	990 574 831	$2,747 $1,810 $1,877	$327	$6,761	$1.41

Table 49. Scenario 1.1 POI Summary

					Excess	Default POI	Default POI	Default POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Larrabee 230 kV (MW)
1.1	6310	COEDTR, ANBARD	None	990 574 831	400	1510	2400	1200	1200

Table 50. Scenario 1.1 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
COEDTR	990.1	New Offshore Converter Station	$754.13
	990.2	New Offshore Line to Landfall	$171.24
	990.3	New Underground Transmission Line	$235.11
	990.4	New Onshore Converter Station	$306.39
	990.5	New Offshore Converter Station	$717.49
	990.6	New Offshore Line to Landfall	$162.92
	990.7	New Underground Line	$108.40
	990.8	Onshore Converter Station	$291.50
ANBARD	574.1	Upgrade/Expansion of 500 kV Deans Substation	$11.20
	574.2	400 kV HVDC Submarine Cable	$360.16
	574.3	400 kV HVDC Underground Cable	$175.43
	574.4	500 kV HVAC Underground Cable	$10.06
	574.5	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore wind energy area - OWF Interface Transformer # 1	$859.98
	574.6	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - OWF Interface Transformer # 2	$0.00
	574.7	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - Offshore Converter Station	$0.00
	574.8	New Onshore Converter Station - Onshore Converter Station	$393.40
	574.8	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
	831.1	Upgrade/Expansion of 500 kV Deans Substation	$11.17
	831.2	400 kV HVDC Submarine Cable	$429.62
	831.3	400 kV HVDC Underground Cable	$175.06
	831.4	500 kV HVAC Underground Cable	$10.03
	831.5	Offshore Substation Platform (OSP) at Hudson South 2 (“HS2”) offshore wind energy area - OWF Interface Transformer # 1	$858.10
	831.6	Offshore Substation Platform (OSP) at Hudson South 2 (“HS2”) offshore wind energy area - OWF Interface Transformer # 2	$0.00
	831.7	Offshore Substation Platform (OSP) at Hudson South 2 (“HS2”) offshore wind energy area - Offshore Converter Station	$0.00
	831.8	New Onshore Converter Station - Onshore Converter Station	$392.59
	831.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
Total			$6,433.99

Table 51. Scenario 1.1 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
Total			$327.21

Scenario 1.2

Scenario 1.2 Description

Scenario 1.2 uses ConEd Option 2 proposal 990 to interconnect 1,200 MW of offshore wind to Smithburg 500 kV and 1,200 MW to Deans 500 kV. Scenario 1.2 also uses PSEGRT Option 2 proposals 613 to interconnect 1,200 MW of offshore wind to Larrabee 230 kV. The interconnection of the 2,658 MW of solicitation #2 (Ocean Wind 2 and Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

ConEd Option 2 proposal 990 involves the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems
- One new onshore 320 kV converter station at Smithburg 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Smithburg
- One new onshore 320 kV converter station at Deans 500 kV with 320/500 kV transformation and a 500 kV underground connection to Deans

PSEGRT Option 2 proposal 613 involves the following components:

- One new offshore 320 kV converter station with 320/275 kV transformation to interconnect the offshore wind
- One new 320 kV HVDC, 1,200 MW submarine and underground cable system
- One new onshore 320 kV converter station at Larrabee 230 kV with 320/500 kV transformation and 500 kV underground connection to Larrabee 230 kV
- Upgrade/expansion of Larrabee 230 kV substation; include 500 kV positions and 500/230 kV transformation

Table 52. Scenario 1.2 Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.2	6310	3652	COEDTR, PSEGRT	None	$0	990 613	$3,317 $2,151	$352	$5,820	$1.59

Table 53. Scenario 1.2 POI Summary

					Excess	Default POI	Default POI	Default POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Larrabee 230 kV (MW)
1.2	6310	COEDTR, PSEGRT	None	990 613	0	1510	1200	1200 1148	1200

Table 54. Scenario 1.2 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
COEDTR	990.1	New Offshore Converter Station	$754.13
	990.2	New Offshore Line to Landfall	$171.24
	990.3	New Underground Transmission Line (to Smithburg 500 kV)	$235.11
	990.4	New Onshore Converter Station	$306.39
	990.5	New Offshore Converter Station	$717.49
	990.6	New Offshore Line to Landfall	$162.92
	990.7	New Underground Line (to Larrabee 230 kV)	$108.40
	990.8	Onshore Converter Station	$291.50
	990	Adder For Connection At Deans	$570.00
PSEGRT	613.1	L1 320 kV Larrabee POI Upgrade	$46.61
	613.2	L2 320 kV Larrabee AC Tie Line	$62.73
	613.3	L3 320 kV Larrabee Onshore Converter	$461.21
	613.4	L4 320 kV Larrabee Offshore/Onshore HVDC Cable	$583.45
	613.5	L5 320 kV Larrabee Offshore Converter	$996.79
Total			$5,467.97

Table 55. Scenario 1.2 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			**$352.41**

Scenario 1.2a

Scenario 1.2a Description

Scenario 1.2a uses ConEd Option 2 proposal 990 to interconnect 1,200 MW of offshore wind to Smithburg 500 kV and 1,200 MW to Larrabee 230 kV. Scenario 1.2a also uses Anbaric Option 2 proposals 574 to interconnect 1,342 MW of offshore wind to Deans 500 kV. The interconnection of the 2,658 MW of solicitation #2 (Ocean Wind 2 and Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

ConEd Option 2 proposal 990 involves the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems
- One new onshore 320 kV converter station at Smithburg 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Smithburg
- One new onshore 320 kV converter station at Larrabee 230 kV with 320/230 kV transformation and a short 230 kV underground connection to Larrabee

Anbaric Option 2 proposals 574 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,400 MW submarine and underground cable system (only up to a 1,342 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- One new onshore 400 kV converter station at Deans 500 kV with 400/500 kV transformation and a short 500 kV underground connection to Deans

Table 56. Scenario 1.2a Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.2a	6400	3742	COEDTR, ANBARD	None	$0	990 574	$2,747 $1,810	$352	$4,909	$1.31

Table 57. Scenario 1.2a POI Summary

						Default POI	Default POI	Default POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Larrabee 230 kV (MW)
1.2a	6400	COEDTR, ANBARD	None	990 574	58	1510	1342	1200 1148	1200

Table 58. Scenario 1.2a Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
COEDTR	990.1	New Offshore Converter Station	$754.13
COEDTR	990.2	New Offshore Line to Landfall	$171.24
COEDTR	990.3	New Underground Transmission Line	$235.11
COEDTR	990.4	New Onshore Converter Station	$306.39
COEDTR	990.5	New Offshore Converter Station	$717.49
COEDTR	990.6	New Offshore Line to Landfall	$162.92
COEDTR	990.7	New Underground Line	$108.40
COEDTR	990.8	Onshore Converter Station	$291.50
ANBARD	574.1	Upgrade/Expansion of 500 kV Deans Substation	$11.20
ANBARD	574.2	400 kV HVDC Submarine Cable	$360.16
ANBARD	574.3	400 kV HVDC Underground Cable	$175.43
ANBARD	574.4	500 kV HVAC Underground Cable	$10.06
ANBARD	574.5	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore wind energy area - OWF Interface Transformer # 1	$859.98
ANBARD	574.6	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - OWF Interface Transformer # 2	$0.00
ANBARD	574.7	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - Offshore Converter Station	$0.00
ANBARD	574.8	New Onshore Converter Station - Onshore Converter Station	$393.40
ANBARD	574.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
Total			**$4,557**

Table 59. Scenario 1.2a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
TOTAL			**$352.41**

Scenario 1.2b

Scenario 1.2b Description

Scenario 1.2b uses ConEd Option 2 proposal 990 to interconnect 1,200 MW of offshore wind to Smithburg 500 kV and 1,200 MW to Larrabee 230 kV. Scenario 1.2b also uses Atlantic Power Transmission Option 2 proposals 210 and 172 to interconnect 1,342 MW of offshore wind to Deans 500 kV. The interconnection of the 2,658 MW of solicitation #2 (Ocean Wind 2 and Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

ConEd Option 2 proposal 990 involves the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems
- One new onshore 320 kV converter station at Smithburg 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Smithburg
- One new onshore 320 kV converter station at Larrabee 230 kV with 320/230 kV transformation and a short 230 kV underground connection to Larrabee

Atlantic Power Transmission Option 2 proposals 210 and 172 involve the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems (only up to a 1,342 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- One new onshore 320 kV converter station at Deans 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Deans

Table 60. Scenario 1.2b Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.2b	6400	3742	COEDTR, ATLPWR	None	$0	990 210 172	$2,747 $2,024 $1,601	$352	$6,724	$1.77

Table 61. Scenario 1.2b POI Summary

						Default POI	Default POI	Default POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Larrabee 230 kV (MW)
1.2b	6400	COEDTR, ATLPWR	None	990 210 172	1058	1510	1342	1200 1148	1200

Table 62. Scenario 1.2b Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
COEDTR	990.1	New Offshore Converter Station	$754.13
COEDTR	990.2	New Offshore Line to Landfall	$171.24
COEDTR	990.3	New Underground Transmission Line	$235.11
COEDTR	990.4	New Onshore Converter Station	$306.39
COEDTR	990.5	New Offshore Converter Station	$717.49
COEDTR	990.6	New Offshore Line to Landfall	$162.92
COEDTR	990.7	New Underground Line	$108.40
COEDTR	990.8	Onshore Converter Station	$291.50
ATLPWR	210.1	Offshore 1235MW Converter Station and Supporting Platform	$948.19
ATLPWR	210.2	Submarine Section of 1200 MW HVDC Transmission Line	$416.15
ATLPWR	210.3	Onshore Section of 1200 MW HVDC Transmission Line	$236.96
ATLPWR	210.4	Onshore 1200 MW Converter Station	$408.90
ATLPWR	210.5	500 kV AC underground transmission line	$14.29
ATLPWR	210.6	Expansion of 500 kV switching area at Deans substation	$0.00
ATLPWR	172.1	Submarine Section of 1200 MW HVDC Transmission Line	$347.07
ATLPWR	172.2	Onshore Section of 1200 MW HVDC Transmission Line	$142.93
ATLPWR	172.3	Onshore 1200 MW Converter Station	$331.47
ATLPWR	172.4	500 kV AC underground transmission line	$11.53
ATLPWR	172.5	Expansion of 500 kV switching area at Deans substation	$0.00
ATLPWR	172.6	Offshore 1235 MW Converter Station and Supporting Platform	$768.36
Total			**$6,373.03**

Table 63. Scenario 1.2b Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
TOTAL			**$352.41**

Scenario 1.2c

Scenario 1.2c Description

Scenario 1.2c uses JCPL Option 1b proposal 453.9-11, 16-18, 24, 29 and MAOD Option 2 proposal 431 to interconnect 1,200 MW of offshore wind to Smithburg 500 kV and 1,200 MW to Larrabee 230 kV. It also uses Anbaric Option 2 proposal 574 to interconnect 1,342 MW of offshore wind to Deans 500 kV. The interconnection of the 2,658 MW of solicitation #2 (Ocean Wind 2 and Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

JCPL Option 1b proposal 453.9-11, 16-18, 24, 29 involves the following components:

- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station

MAOD Option 2 proposal 431 involves the following components:

- Two 320 kV offshore converter stations including:
    - 320/66 kV transformation to interconnect the offshore wind
    - Normally open 320 kV HVDC interlinks between platforms
- Two 320 kV HVDC, 1,200 MW submarine and underground cable systems
- Two 320 kV onshore converter stations at the Larrabee 230 kV station

Anbaric Option 2 proposal 574 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,400 MW submarine and underground cable system (only up to a 1,342 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- One new onshore 400 kV converter station at Deans 500 kV with 400/500 kV transformation and a short 500 kV underground connection to Deans

Table 64. Scenario 1.2c Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.2c	6400	3742	JCPL MAOD, ANBARD	453.9-11,16-18,24,29	$293	431 574	$2,957 $1,810	$381	$5,441	$1.45

Table 65. Scenario 1.2c POI Summary

						Default POI	Default POI	Default POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Larrabee 230 kV (MW)
1.2c	6400	JCPL MAOD, ANBARD	453.9-11,16-18,24,29	431 574	58	1510	1342	1200 1148	1200

Table 66. Scenario 1.2c Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.16	B54 Larrabee-South Lockwood 34.5 kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV New Line	$7.52
	453.18	Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	$150.35
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.29	Smithburg Substation 500 kV 3 Brk Ring	$62.44
Total			$293

Table 67. Scenario 1.2c Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
MAOD	431	1. HVDC Circuit 1	$1,597.12
	431	2. HVDC Circuit 2	$1,359.74
ANBARD	574.1	Upgrade/Expansion of 500 kV Deans Substation	$11.20
ANBARD	574.2	400 kV HVDC Submarine Cable	$360.16
ANBARD	574.3	400 kV HVDC Underground Cable	$175.43
ANBARD	574.4	500 kV HVAC Underground Cable	$10.06
ANBARD	574.5	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore wind energy area - OWF Interface Transformer # 1	$859.98
ANBARD	574.6	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - OWF Interface Transformer # 2	$0.00
ANBARD	574.7	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - Offshore Converter Station	$0.00
ANBARD	574.8	New Onshore Converter Station - Onshore Converter Station	$393.40
ANBARD	574.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
Total			**$4,767**

Table 68. Scenario 1.2c Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
JCPL	Incumbent TO	Swap generator lead line and 500/230 kV tranformer No. 4 positions	$5.00
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Incumbent TO	"Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.1	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	Incumbent TO	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	"Reconductor Kilmer-Lake Nelson ""I"" 230 kV	$4.42
PSEG	Incumbent TO	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Incumbent TO	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
JCPL	Incumbent TO	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PECO	Incumbent TO	Replace 4 Peach Bottom 500 kV breakers	$5.60
BGE	Incumbent TO	Upgrade one Conastone 230 kV breaker	$1.30
TOTAL			**$381**

Scenario 2c

Scenario 2c Description

Scenario 2c uses AE Option 1b proposals 797 and 929.9 to interconnect 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind to Cardiff 230 kV and JCPL Option 1b proposals 453.1-18, 24, 28-29 to interconnect 1,200 MW offshore wind to Larrabee 230 kV, 1,200 MW offshore wind to Atlantic 230 kV and 1,200 MW offshore wind to Smithburg 500 kV. Scenario 2c also used MAOD Option 2 proposal 551 to link 3,600 MW of offshore wind to the JCPL Option 1b proposal. The interconnection of the Ocean Wind 2 project to the AE Option 1b proposal, the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1), and the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) are assumed to be the responsibility of the offshore wind developers.

AE Option 1b proposals 797 and 929.9 involve the following components:

- Build a new transition vault connecting 275 kV offshore cables and 275 kV on shore cables
- Build a new 275 kV transmission line between the transition vault and new 275-230 kV substation near Cardiff
- Build a new 275-230 kV substation near Cardiff connected to existing substation at Cardiff
- Rebuild the Cardiff substation to accommodate a breaker-and-a-half bus design. A normally open breaker at Cardiff 230 kV in AE proposal 929.9 needs to be normally closed to avoid stability problems identified by bypassing Cardiff 230 kV and directly connecting either to Orchard 230 kV or New Freedom 230 kV. The stability issues appear under critical contingencies as high-frequency oscillations on the offshore wind turbines themselves and to a lesser degree on surrounding generators. Note that AE Option 1a/1b proposals 929.10 and 929.12 create a second Cardiff-Orchard 230 kV line and a second Orchard 500/230 kV transformer.

JCPL Option 1b proposals 453.1-18, 24, 28-29 involve the following components:

- Rebuild the D2004 Larrabee-Smithburg #1 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct a new ~11.6 mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

JCPL proposed a new Smithburg-East Windsor 500 kV line as Option 1a proposals 17.4-11 to complement its Option 1b proposal 453, but PJM determined that this would not be required to support the 3,600 MW injection into central New Jersey as part of this scenario.

MAOD Option 2 proposal 551 involves the following components:

- Three 320 kV offshore converter stations including:
  - 320/66 kV transformation to interconnect the offshore wind
  - Normally open 320 kV HVDC interlinks between platforms
  - Three 320 kV HVDC, 1,200 MW submarine and underground cable systems
  - Three 320 kV onshore converter stations at the Larrabee 230 kV station

Table 69. Scenario 2c Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
2c	6258	4748	AE, JCPL, MAOD	797 929.9 453.1-18,24,28-29	$233 $70 $377	551	$4,411	$670	$5,761	$1.21

Table 70. Scenario 2c POI Summary

						Default POI	Default POI	Alt POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)
2c	6258	AE, JCPL, MAOD	797 929.9 453.1-18,24,28-29	551	0	1510 1148	1200	1200	1200

Table 71. Scenario 2c Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
AE	797.1	Build new substation at Cardiff near existing substation at Cardiff	$97.66
	797.2	Build new 275 kV transmission lines from transition vault to new Cardiff substation	$135.05
	929.9	Rebuild Cardiff substation to accommodate a breaker and a half bus design	$70.10
JCPL	453.1	Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	$31.47
	453.2	Freneau Substation - Update relay settings	$0.03
	453.3	Smithburg Substation - Update relay settings	$0.03
	453.4	Oceanview Substation - Update relay settings	$0.04
	453.5	Red Bank Substation - Update relay settings	$0.04
	453.6	South River Substation - Update relay settings	$0.03
	453.7	Larrabee Substation - Update relay settings	$0.03
	453.8	Atlantic Substation - Install line terminal	$4.95
	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230 kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230 kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230 kV	$17.07
	453.15	Larrabee-Oceanview 230 kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5 kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV New Line	$7.52
	453.18	Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	$150.35
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.28	Larrabee Substation	$0.86
	453.29	Smithburg Substation 500 kV 3 Brk Ring	$62.44
Total			**$680.06**

Table 72. Scenario 2c Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
MAOD	551	1. HVDC Circuit 1	$1,674.46
	551	2. HVDC Circuit 2	$1,349.89
	551	3. HVDC Circuit 3	$1,386.63
Total			**$4,410.99**

Table 73. Scenario 2c Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
AE	929.10, 929.12	Second Cardiff-Orchard 230 kV Second Orchard 500/230 kV	$197.52
Transource	63	North Delta Option A	$109.68
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
Exelon	Email 5/13/2022	Reconductor Cardiff-New Freedom 230 kV	$40.00
Exelon	Email 5/13/2022	Cardiff transformer replacements	$8.00
Exelon	Email 5/13/2022	Rebuild Cardiff-Lewis #1 138 kV	$20.00
Exelon	Email 5/13/2022	Reconductor Cardiff-Lewis #2 138 kV	$7.00
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			**$669.92**

Scenario 4

Scenario 4 Description

Scenario 4 uses NextEra Mid-Atlantic Option 2 proposal 461 to interconnect 3,000 MW offshore wind to a new Fresh Ponds 500 kV substation. Scenario 4 also uses NextEra Mid-Atlantic Option 2 proposal 27 to interconnect 1,500 MW offshore wind, which includes 1,148 MW of solicitation #2 (Ocean Wind 2), to a new Neptune 230 kV substation. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

NextEra Mid-Atlantic Option 2 proposal 461 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,500 MW submarine and underground cable systems
- A new Fresh Ponds 500 kV substation looping in existing 500 kV lines from Deans to Windsor and Deans to Smithburg
- Two new onshore 400 kV converter stations at Fresh Ponds 500 kV with 400/500 kV transformation

NextEra Mid-Atlantic Option 2 proposal 27 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,500 MW submarine and underground cable system
- A new Neptune 230 kV substation looping in existing 230 kV lines from Atlantic to Oceanview and Larrabee to Oceanview
- One new onshore 400 kV converter station at Neptune 230 kV with 400/230 kV transformation

Table 74. Scenario 4 Cost Summary

Scenario	Total	SAA	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
ID	(MW)	(MW)		Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
4	6010	4500	NEETMH	None	$0	461 27	$3,608 $1,477	$390	$5,475	$1.22

Table 75. Scenario 4 POI Summary

						Default POI	Alt POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Fresh Ponds 500 kV (MW)	Neptune 230 kV (MW)
4	6010	NEETMH	None	461 27	0	1510	3000	1500

Table 76. Scenario 4 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	461.1	Offshore Platform A	$787.56
	461.2	Offshore Platform B	$787.56
	461.3	Offshore Platform A – Raritan Bay Waterfront Park Landing HVDC	$425.24
	461.4	Offshore Platform B – Raritan Bay Waterfront Park Landing HVDC	$453.02
	461.5	Raritan Bay Waterfront Park Landing – Fresh Ponds Converter Station HVDC	$575.79
	461.6	Fresh Ponds Converter Station	$562.33
	461.7	Loop in and existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500 kV OH line to Fresh Ponds 500kV AIS substation	$3.00
	461.8	Loop in existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 AIS substation and use existing conductors	$3.00
	461.9	Loop in existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation and use existing conductors	$8.00
	461.10	Loop in existing Deans - E. Winsdor 500 kV OH line to Fresh Ponds 500 kV AIS substation and use existing conductors	$3.00
	27.1	Offshore Platform A –Asbury Park Landing HVDC	$255.77
	27.2	Asbury Park Landing – Neptune Converter Station HVDC	$109.17
	27.3	Neptune Converter Station	$301.54
	27.4	Offshore Platform A	$800.39
	27.5	Loop in existing Atlantic - Oceanview 230 kV OH line circuit X at Neptune 230 kV substation	$2.00
	27.6	Loop in existing Atlantic - Oceanview 230 kV OH line circuit Y at Neptune 230 kV substation	$2.00
	27.7	Loop in existing Atlantic - Oceanview 230 kV OH line circuit Y at NEETMA proposed Neptune substation	$2.00
	27.8	Loop in existing Atlantic - Oceanview 230 kV OH line circuit X at NEETMA proposed Neptune 230 kV substation	$2.00
	27.9	Reterminate the Oceanview termination of the existing Larrabee-Oceanview 230 kV line into NEETMA proposed Neptune 230 kV substation and loop-in the line at Atlantic resulting in a line configuration that goes from Larrabee - Atlantic - Neptune	$2.00
Total			**$5,085.38**

Table 77. Scenario 4 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
JCPL	Email	Upgrade to address Fresh Pond-Deans 500 kV: The reconductor component of Fresh Pond-Deans 500 kV in NEETMH proposal 461 ($5 M) is subtracted from JCPL proposal component 17.7 Deans - Smithburg 500 kV Terminal Upgrade ($13.24 M)	$8.24
Total			**$389.61**

Scenario 4a

Scenario 4a Description

Scenario 4a uses NextEra Mid-Atlantic Option 2 proposal 461 to interconnect 2,242 MW offshore wind to a new Fresh Ponds 500 kV substation. Scenario 4 also uses NextEra Mid-Atlantic Option 2 proposal 27 to interconnect 1,500 MW offshore wind, which includes 1,148 MW of solicitation #2 (Ocean Wind 2), to a new Neptune 230 kV substation. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

NextEra Mid-Atlantic Option 2 proposal 461 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 2,242 MW loading level was studied as part of this scenario)
- A new Fresh Ponds 500 kV substation looping in existing 500 kV lines from Deans to Windsor and Deans to Smithburg
- Two new onshore 400 kV converter stations at Fresh Ponds 500 kV with 400/500 kV transformation

NextEra Mid-Atlantic Option 2 proposal 27 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,500 MW submarine and underground cable system
- A new Neptune 230 kV substation looping in existing 230 kV lines from Atlantic to Oceanview and Larrabee to Oceanview
- One new onshore 400 kV converter station at Neptune 230 kV with 400/230 kV transformation

Table 78. Updated Scenario 4a Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
4a	6400	3742	NEETMH	None	$0	461 27	$3,608 $1,477	$387	$5,461	$1.46

Table 79. Scenario 4a POI Summary

						Default POI	Alt POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Fresh Ponds 500 kV (MW)	Smithburg 500 kV (MW)	Neptune 230 kV (MW)
4a	6400	NEETMH	None	461 27	758	1510	2242	1148	1500

Table 80. Scenario 4a Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	461.1	Offshore Platform A	$787.56
	461.2	Offshore Platform B	$787.56
	461.3	Offshore Platform A – Raritan Bay Waterfront Park Landing HVDC	$425.24
	461.4	Offshore Platform B – Raritan Bay Waterfront Park Landing HVDC	$453.02
	461.5	Raritan Bay Waterfront Park Landing – Fresh Ponds Converter Station HVDC	$575.79
	461.6	Fresh Ponds Converter Station	$562.33
	461.7	Loop in and existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500 kV OH line to Fresh Ponds 500kV AIS substation	$3.00
	461.8	Loop in existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 AIS substation and use existing conductors	$3.00
	461.9	Loop in existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation and use existing conductors	$8.00
	461.10	Loop in existing Deans - E. Winsdor 500 kV OH line to Fresh Ponds 500 kV AIS substation and use existing conductors	$3.00
	27.1	Offshore Platform A –Asbury Park Landing HVDC	$255.77
	27.2	Asbury Park Landing – Neptune Converter Station HVDC	$109.17
	27.3	Neptune Converter Station	$301.54
	27.4	Offshore Platform A	$800.39
	27.5	Loop in existing Atlantic - Oceanview 230 kV OH line circuit X at Neptune 230 kV substation	$2.00
	27.6	Loop in existing Atlantic - Oceanview 230 kV OH line circuit Y at Neptune 230 kV substation	$2.00
	27.7	Loop in existing Atlantic - Oceanview 230 kV OH line circuit Y at NEETMA proposed Neptune substation	$2.00
	27.8	Loop in existing Atlantic - Oceanview 230 kV OH line circuit X at NEETMA proposed Neptune 230 kV substation	$2.00
	27.8	Reterminate the Oceanview termination of the existing Larrabee-Oceanview 230 kV line into NEETMA proposed Neptune 230 kV substation and loop-in the line at Atlantic resulting in a line configuration that goes from Larrabee - Atlantic - Neptune	$2.00
Total			$5,085.38

Table 81. Scenario 4a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
JCPL	Email	Upgrade to address Fresh Pond-Deans 500 kV: The reconductor component of Fresh Pond-Deans 500 kV in NEETMH proposal 461 ($5 M) is subtracted from JCPL proposal component 17.7 Deans - Smithburg 500 kV Terminal Upgrade ($13.24 M)	$8.24
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
Total			$386.86

Scenario 5

Scenario 5 Description

Scenario 5 uses JCPL Option 1b proposal 453 to interconnect 1,200 MW offshore wind to Larrabee 230 kV, 1,200 MW offshore wind to Atlantic 230 kV and 2,490 MW offshore wind to Smithburg 500 kV, which accounts for the 1,148 MW of solicitation #2 (Ocean Wind 2). Scenario 5 also used MAOD Option 2 proposal 321 to link 4,800 MW of offshore wind to the JCPL Option 1b proposal. The interconnection of the 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

JCPL Option 1b proposals 453 involves the following components:

- Rebuild the D2004 Larrabee-Smithburg #1 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct new ~11.6 mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

MAOD Option 2 proposal 321 involves the following components:

- Four 320 kV offshore converter stations including:
    - 320/66 kV transformation to interconnect the offshore wind
    - Normally open 320 kV HVDC interlinks between platforms
- Four 320 kV HVDC, 1,200 MW submarine and underground cable systems
- Four 320 kV onshore converter stations at the Larrabee 230 kV station

Table 82. Scenario 5 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
5	6310	4800	JCPL, MAOD	453	$620	321	$5,726	$561	$6,907	$1.44

Table 83. Scenario 5 POI Summary

						Default POI	Default POI	Alt POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Smithburg 500 kV (MW)	Atlantic 230 kV (MW)	Larrabee 230 kV (MW)
5	6310	JCPL, MAOD	453	321	0	1510	2400	1200	1200

Table 84. Scenario 5 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	453.1	Atlantic 230 kV Substation - Convert to Double-Breaker Double-Bus	$31.47
	453.2	Freneau Substation - Update relay settings	$0.03
	453.3	Smithburg Substation - Update relay settings	$0.03
	453.4	Oceanview Substation - Update relay settings	$0.04
	453.5	Red Bank Substation - Update relay settings	$0.04
	453.6	South River Substation - Update relay settings	$0.03
	453.7	Larrabee Substation - Update relay settings	$0.03
	453.8	Atlantic Substation - Install line terminal	$4.95
	453.9	Larrabee Substation - Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen Substation - Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230 kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230 kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230 kV	$17.07
	453.15	Larrabee-Oceanview 230 kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5 kV Line Transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV New Line	$7.52
	453.18	Larrabee Converter-Smithburg No1 500 kV Line (New Asset)	$150.35
	453.19	Larrabee Converter-Smithburg No2 500 kV Line (New Asset)	$111.71
	453.20	B1042 Cookstown-Larrabee 230 kV	$39.79
	453.21	L220 Hyson-Larrabee 34.5 kV	$13.57
	453.22	K219 Hyson-Larrabee 34.5 kV	$10.33
	453.23	E83 Line 115 kV (NIS)	$8.47
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.25	H2008 Larrabee Smithburg No2 230 kV	$8.47
	453.26	D2004 Larrabee-Smithburg No1 230 kV	$44.77
	453.27	Smithburg Substation 500 kV Expansion	$5.81
	453.28	Larrabee Substation	$0.86
	453.28	Smithburg Substation 500 kv 3 Brk Ring	$62.44
Total			$620.16

Table 85. Scenario 5 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
MAOD	321.1	HVDC Circuit 1	$1,683.92
	321.2	HVDC Circuit 2	$1,326.71
	321.3	HVDC Circuit 3	$1,322.03
	321.4	HVDC Circuit 4	$1,393.77
Total			$5,726.43

Table 86. Scenario 5 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.4-17.11	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.	$206.50
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer I-Lake Nelson I 230 kV	$4.42
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
Total			**$560.55**

Scenario 6

Scenario 6 Description

Scenario 6 uses LS Power's Option 1b proposal 781 to construct a new Lighthouse 500/345 kV AC substation at the shoreline to interconnect 4,890 MW of offshore wind, including 1,148 MW of solicitation #2 (Ocean Wind 2). An underground 500 kV cable system connects the Lighthouse substation to three new onshore 500 kV substations: Crossroads, Gateway and Wells Landing. Scenario 6 also uses LS Power Option 2 proposal 594 to link 4,890 MW of offshore wind to the LS Power Option 1b proposal. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

The new Lighthouse 500/345 kV substation has terminals to connect up to 15 345 kV submarine cables and convert them to 500 kV with four 500/345 kV transformers. The new Crossroads 500/230 kV substation connects two new 500 kV underground circuits from the Lighthouse substation to two 500/230 kV transformers for connection to the existing Larrabee 230 kV substation. The new Gateway 500 kV substation connects four new underground 500 kV cables from the Lighthouse substation to the existing Deans to East Windsor 500 kV transmission line. The new Wells Landing 500/230 kV substation connects two new underground 500 kV cables from the new Gateway 500 kV substation to the existing Trenton to Brunswick 230 kV transmission lines via two 500/230 kV transformers.

The Option 1b proposal involves several thousand MVARs of reactors and a Statcom to compensate for the cable charging.

- Lighthouse 500/345 kV: Shunt reactors and dynamic compensation will be specified once offshore wind locations are determined.
- Crossroads 500 kV: 2x150 MVAR shunt reactors
- Mid-point reactive compensation along the Lighthouse-Gateway 500 kV UG cable: 8x215 MVAR shunt reactors
- Gateway 500 kV: 4x215 MVAR shunt reactors and a +/- 450 MVAR Statcom
- Wells Landing 500 kV: 2x150 MVAR shunt reactors

LS Power Option 2 proposal 594 for this scenario involves the following components:

- Two new 345 kV offshore AC stations
- Ten 345 kV AC submarine cable systems from the offshore 345 kV stations to the new Lighthouse 500 kV station (note that this is an expansion option involving two additional cables in addition to the proposed 8-cable system)

Table 87. Scenario 6 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
6	6400	4890	CNTLM	781	$1,772	594	$2,460	$271	$4,503	$0.92

Table 88. Scenario 6 POI Summary

						Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Lighthouse 500 kV (MW)
6	6400	CNTLM	781	594	110	1510	4890

Table 89. Scenario 6 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
CNTLM	781.1	Lighthouse Substation	$198.50
	781.2	Gateway Substation	$109.84
	781.3	Lighthouse - Gateway 500 kV Transmission Line #1	$246.20
	781.4	Well's Landing Substation	$59.25
	781.5	Crossroads Substation	$38.82
	781.6	Lighthouse - Crossroads 500 kV Transmission Line #1	$90.27
	781.7	Gateway - Well's Landing 500 kV Transmission Line Circuit #1	$72.79
	781.9	Trenton - Devils Brook 230 kV Transmission Interconnection	$0.67
	781.10	Trenton - Hunters Glen 230 kV Transmission Interconnection	$0.67
	781.11	Deans - East Windsor 500 kV Transmission Interconnection	$1.28
	781.12	Midpoint Reactor Station	$42.67
	781.13	Larrabee - Substation Interconnection	$7.45
	781.14	Lighthouse - Gateway 500 kV Transmission Line #2	$246.20
	781.15	Lighthouse - Gateway 500 kV Transmission Line #3	$247.07
	781.16	Lighthouse - Gateway 500 kV Transmission Line #4	$247.07
	781.17	Gateway - Well's Landing 500 kV Transmission Line #2	$72.79
	781.18	Lighthouse - Crossroads 500 kV Transmission Line #2	$90.27
Total			$1,771.80

Table 90. Scenario 6 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
CNTLTM	594.1	Prosperity Substation	$410.31
	594.2	Revolution Substation	$410.31
	594.3	Prosperity - Lighthouse 345 kV Transmission Line #1	$127.14
	594.4	Revolution - Lighthouse 345 kV Transmission Line #1	$132.17
	594.5	Lighthouse Substation	$110.50
	594.6	Prosperity - Lighthouse 345 kV Transmission Line #2	$127.14
	594.7	Prosperity - Lighthouse 345 kV Transmission Line #3	$127.14
	594.8	Prosperity - Lighthouse 345 kV Transmission Line #4	$127.14
	594.9	Revolution - Lighthouse 345 kV Transmission Line #2	$132.17
	594.10	Revolution - Lighthouse 345 kV Transmission Line #3	$132.17
	594.11	Revolution - Lighthouse 345 kV Transmission Line #4	$132.17
	594	Two additional 345 kV cables	$491.66
Total			$2,460.00

Table 91. Scenario 6 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			$270.61

Scenario 7

Scenario 7 Description

Scenario 7 uses LS Power's Option 1b proposal 629 to construct a new Lighthouse 500/345 kV AC substation at the shoreline to interconnect 4,890 MW of offshore wind, including 1,148 MW of solicitation #2 (Ocean Wind 2). An underground 500 kV cable system connects the Lighthouse substation to a new Crossroads 500 kV substation near the existing Larrabee 230 kV substation and then connects Crossroads 500 kV substation to both the existing Smithburg 500 kV substation and to a new Gardenview 500 kV substation through two new 500 kV overhead circuits. Scenario 7 also uses LS Power Option 2 proposal 594 to link 4,890 MW of offshore wind to the LS Power Option 1b proposal. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

The new Lighthouse 500/345 kV substation has terminals to connect up to 15 345 kV submarine cables and convert them to 500 kV with four 500/345 kV transformers. The new Crossroads 500/230 kV substation will connect new underground 500 kV cables from the Lighthouse substation to the existing Larrabee substation through a new 500/230 kV transformer. The new Crossroads substation will also connect to the existing Smithburg 500 kV substation through a new overhead 500 kV transmission line, and to the new Gardenview 500 substation through a separate new overhead 500 kV transmission line. Reactive support for the underground cables is provided by a shunt reactor for each underground cable. Dynamic reactive support and short circuit support to ensure system stability, and system optimization is provided by multiple synchronous condensers. The new Gardenview substation is a new gas-insulated 500 kV switchyard located adjacent to East Windsor substation. The substation will replace the existing East Windsor 500 kV switchyard. Old York substation is a new gas-insulated 500/230 kV substation that will connect the East Windsor (Gardenview) to New Freedom 500 kV transmission line with the existing Burlington to Trenton 230 kV transmission lines via two transformers.

LS Power Option 2 proposal 594 for this scenario involves the following components:

- Two new 345 kV offshore AC stations
- Ten 345 kV AC submarine cable systems from the offshore 345 kV stations to the new Lighthouse 500 kV station (note that this is an expansion option involving two additional cables in addition to the proposed 8-cable system)

Table 92. Scenario 7 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
7	6400	4890	CNTLM	629	$1,568	594	$2,460	$283	$4,311	$0.88

Table 93. Scenario 7 POI Summary

						Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Lighthouse 500 kV (MW)
7	**6400**	**CNTLM**	**629**	**594**	**110**	**1510**	**4890**

Table 94. Scenario 7 Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
CNTLM	629.1	Lighthouse - Crossroads 500 kV Transmission Line #1	$96.59
	629.2	Lighthouse 500 kV Substation	$194.59
	629.3	Crossroads 500 kV Substation	$309.63
	629.4	Larrabee 230 kV Upgrades	$8.57
	629.5	Smithburg 500 kV Bus Expansion	$45.75
	629.6	Crossroads - Garden View 500 kV Transmission Line	$125.96
	629.7	Deans - Smithburg 500 kV Transmission Line Uprate	$110.79
	629.8	Old York 500/230 kV Substation	$73.10
	629.9	Lighthouse - Crossroads 500 kV Transmission Line #2	$96.59
	629.10	Lighthouse - Crossroads 500 kV Transmission Line #3	$96.61
	629.11	Gardenview 500 kV Substation	$38.25
	629.12	Smithburg - Crossroads 500 kV Transmission Line	$73.17
	629.13	Deans - Substation Interconnection	$12.93
	629.14	Lighthouse - Crossroads 500 kV Transmission Line #4	$96.61
	629.15	Lighthouse - Crossroads 500 kV Transmission Line #5	$94.49
	629.16	Lighthouse - Crossroads 500 kV Transmission Line #6	$94.49
Total			$1,568.11

Table 95. Scenario 7 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
CNTLTM	594.1	Prosperity Substation	$410.31
	594.2	Revolution Substation	$410.31
	594.3	Prosperity - Lighthouse 345 kV Transmission Line #1	$127.14
	594.4	Revolution - Lighthouse 345 kV Transmission Line #1	$132.17
	594.5	Lighthouse Substation	$110.50
	594.6	Prosperity - Lighthouse 345 kV Transmission Line #2	$127.14
	594.7	Prosperity - Lighthouse 345 kV Transmission Line #3	$127.14
	594.8	Prosperity - Lighthouse 345 kV Transmission Line #4	$127.14
	594.9	Revolution - Lighthouse 345 kV Transmission Line #2	$132.17
	594.10	Revolution - Lighthouse 345 kV Transmission Line #3	$132.17
	594.11	Revolution - Lighthouse 345 kV Transmission Line #4	$132.17
	594	Two additional 345 kV cables	$491.66
Total			$2,460.00

Table 96. Scenario 7 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.7	Upgrade Smithburg-Deans 500 kV	$13.24
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
Total			$283.47

Scenario 10

Scenario 10 Description

Scenario 10 uses Anbaric Option 2 proposals 882, 841, 921 and 131 to interconnect 2,290 MW offshore wind to Deans 500 kV, which accounts for the 1,148 MW of solicitation #2 (Ocean Wind 2); 1,200 MW to Larrabee 230 kV and 1,400 MW to Sewaren 230 kV. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

Anbaric Option 2 proposal 882 involves the following components:

- One new offshore 320 kV converter station with 320/66 kV transformation to interconnect the offshore wind
- One new 320 kV HVDC, 1,148 MW submarine and underground cable system
- Upgrade/expansion of Deans 500 kV substation
- One new onshore 320 kV converter station at Deans 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Deans

Anbaric Option 2 proposal 841 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,400 MW submarine and underground cable system (only up to a 2,142 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- One new onshore 400 kV converter station at Deans 500 kV with 400/500 kV transformation and a short 500 kV underground connection to Deans

Anbaric Option 2 proposal 921 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,200 MW submarine and underground cable system
- Upgrade/expansion of Larrabee 230 kV substation
- One new onshore 400 kV converter station at Larrabee 230 kV and a short 230 kV underground connection to Larrabee

Anbaric Option 2 proposal 131 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,400 MW submarine and underground cable system
- Upgrade/expansion of Sewaren 230 kV substation
- One new onshore 400 kV converter station at Sewaren 230 kV and a short 230 kV underground connection to Sewaren

Table 97. Scenario 10 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
10	6400	4890	ANDBARD	None	$0	882 841 921 131	$1,776 $1,794 $1,545 $1,648	$406	$7,169	$1.47

Table 98. Scenario 10 POI Summary

						Default POI	Default POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Larrabee 230 kV (MW)	Sewaren 230 kV (MW)
10	6400	ANDBARD	None	882 841 921 131	510	1510	2290	1200	1400

Table 99. Scenario 10 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
ANBARD	882.1	Upgrade/Expansion of 500 kV Deans Substation	$11.21
	882.2	320 kV HVDC Submarine Cable	$506.93
	882.3	320 kV HVDC Underground Cable	$158.55
	882.4	500 kV HVAC Underground Cable	$10.07
	882.5	Offshore Substation Platform (OSP) at Ocean Wind 2 (“OW2”) offshore wind farm - OWF Interface Transformer # 1	$734.79
	882.6	Offshore Substation Platform (OSP) at Ocean Wind 2 (“OW2”) offshore wind farm - OWF Interface Transformer # 2	$0.00
	882.7	Offshore Substation Platform (OSP) at Ocean Wind 2 (“OW2”) offshore wind farm - Offshore Converter Station	$0.00
	882.8	New Onshore Converter Station - Onshore Converter Station	$353.98
	882.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
	841.1	Upgrade/Expansion of 500 kV Deans Substation	$11.21
	841.2	400 kV HVDC Submarine Cable	$350.55
	841.3	400 kV HVDC Underground Cable	$167.92
	841.4	500 kV HVAC Underground Cable	$10.06
	841.5	Offshore Substation Platform (OSP) at Hudson South 1 (“HS1”) offshore wind lease area - OWF Interface Transformer # 1	$860.47
	841.6	Offshore Substation Platform (OSP) at Hudson South 1 (“HS1”) offshore wind lease area - OWF Interface Transformer # 2	$0.00
	841.7	Offshore Substation Platform (OSP) at Hudson South 1 (“HS1”) offshore wind lease area - Offshore Converter Station	$0.00
	841.8	New Onshore Converter Station - Onshore Converter Station at Deans	$393.62
	841.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
	921.1	Upgrade/Expansion of the 230 kV Larrabee Substation	$4.55
	921.2	400 kV HVDC Submarine Cable	$266.79
	921.3	400 kV HVDC Underground Cable	$85.21
	921.4	230 kV AC Underground Cable	$9.42
	921.5	Offshore Substation Platform (OSP) at Atlantic Shores 2 (“AS2") offshore wind lease area - OWF Interface Transformer # 1	$836.33
	921.6	Offshore Substation Platform (OSP) at Atlantic Shores 2 (“AS2") offshore wind lease area - OWF Interface Transformer # 2	$0.00
	921.7	Offshore Substation Platform (OSP) at Atlantic Shores 2 (“AS2") offshore wind lease area - Offshore Converter Station	$0.00
	921.8	New Onshore Converter Station - Onshore Converter Station at Larrabee	$342.98
	921.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
ANBARD	131.1	Upgrade/Expansion of the 230 kV Sewaren Substation	$4.19
	131.2	400 kV HVDC Submarine Cable	$383.58
	131.3	400 kV HVDC Submarine Cable Extension	$17.10
	131.4	230 kV HVAC Underground Cable	$21.12
	131.5	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3") offshore wind lease area - OWF Interface Transformer # 1	$851.00
	131.6	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3") offshore wind lease area - OWF Interface Transformer # 2	$0.00
	131.7	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3") offshore wind lease area - Offshore Converter Station	$0.00
	131.8	New Onshore Converter Station - Onshore Converter Station at Sewaren	$371.30
	131.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
Total			$6,762.90

Table 100. Scenario 10 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Transource	63	North Delta Option A	$109.68
PSEG	N/A	Reconductor Sewaren-Minue Street R-Linden 230 kV	$19.40
PSEG	N/A	Reconductor the Metuchen-New Dover-Fanwood 230kV	$22.80
PSEG	N/A	Reconductor the Fanwood-Front Street 230kV	$3.10
PSEG	N/A	Uprate the Metuchen-Pierson Ave-Meadow Rd-Brunswick 230 kV line to carry two conductors per phase	$35.20
PSEG	Email 7/27/2022	Reconductor the Metuchen -Pierson Ave_S 230kV line (approximately 0.38 miles in length) with 1590 ACSS	$0.9

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
PSEG	Email 7/27/2022	Upgrade the overhead line connecting the Linden 345/230 kV transformer with Linden 230 kV yard (approximately 0.31 miles in length) with 1033 ACSS conductor	$3.2
TOTAL			**$405.75**

Scenario 11

Scenario 11 Description

Scenario 11 uses PSEGRT Option 2 proposal 683 to interconnect 1,247 MW offshore wind to Deans 500 kV, 1,247 MW to Larrabee 230 kV and 1,247 MW to Sewaren 230 kV. The interconnection of the 2,658 MW of solicitation #2 (Atlantic Shores 1 and Ocean Wind 2) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

PSEGRT Option 2 proposal 683 involves the following components:

- Three new offshore 400 kV converter stations interlinked with 275 kV submarine cables and 400/275 kV transformation to interconnect the offshore wind
- Three new 400 kV HVDC, 1,400 MW submarine and underground cable systems (only up to a 1,247 MW loading level was studied on each of these cable systems as part of this scenario)
- Upgrade/expansion of Deans 500 kV, Larrabee 230 kV and Sewaren 230 kV substations
- One new onshore 400 kV converter station at Deans 500 kV with 400/500 kV transformation and a short 500 kV underground connection to Deans
- One new onshore 400 kV converter station at Larrabee 230 kV with 400/500 kV transformation and 500 kV underground connection to Larrabee 230 kV
- Upgrade/expansion of Larrabee 230 kV substation; include 500 kV positions and 500/230 kV transformation
- One new onshore 400 kV converter station at Sewaren 230 kV with 400/230 kV transformation and a short 230 kV underground connection to Sewaren

Table 101. Scenario 11 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
11	6399	3741	PSEGRT	None	$0	683	$7,181	$402	$7,583	$2.03

Table 102. Scenario 11 POI Summary

						Default POI	Default POI	Default POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Larrabee 230 kV (MW)	Sewaren 230 kV (MW)
11	6399	PSEGRT	None	683	459	1510	1247	1148	1247	1247

Table 103. Scenario 11 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
PSEGRT	683.1	S1 400 kV Sewaren POI Upgrades	$18.07
	683.2	S2 400 kV Sewaren AC Tie Line	$0.65
	683.3	S3 400 kV Sewaren Onshore Converter	$423.93
	683.4	S4 400 kV Sewaren Offshore/Onshore HVDC Cable	$754.46
	683.5	S5 400 kV Sewaren Offshore Converter	$1,133.24
	683.6	L1 400 kV Larrabee POI Upgrade	$46.61
	683.7	L2 400 kV Larrabee AC Tie Line	$58.40
	683.8	L3 400 kV Larrabee Onshore Converter	$453.75
	683.9	L4 400 kV Larrabee Offshore/Onshore HVDC Cable	$522.04
	683.10	L5 400k V Larrabee Offshore Converter	$1,165.16
	683.11	D1 Deans POI Upgrade	$18.07
	683.12	D2 Deans AC Tie Line	$43.67
	683.13	D3 Deans Onshore Converter	$449.27
	683.14	D4 Deans Offshore/Onshore HVDC Cable	$870.75
	683.15	D5 Deans Offshore Converter	$1,110.15
	683.16	Interlink SDL Sewaren/Deans/Larrabee (HS-21 to HS-22)	$18.63
	683.17	Interlink SDL Sewaren/Deans/Larrabee (HS-22 to HS-12)	$42.85
	683.18	Interlink SDL Sewaren/Deans/Larrabee (HS-12 to HS-21)	$50.92
Total			$7,180.60

Table 104. Scenario 11 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
PSEG	Email 4/8/2022	Reconductor the Sewaren-MinueSt-Linden 230 kV line	$19.40
JCPL	17.20	Upgrade Lake Nelson I-Middlesex 230 kV	$0.67
PSEG	Email 4/8/2022	Reconductor the Metuchen -New Dover -Fanwood 230kV line	$22.80
PSEG	Email 4/8/2022	Uprate the Metuchen -Pierson Ave-Meadow Rd-Brunswick 230 kV line to carry two conductors per phase	$35.20
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
PSEG	Email 7/27/2022	Upgrade the overhead line connecting the Linden 345/230 kV transformer with Linden 230 kV yard (approximately 0.31 miles in length) with 1033 ACSS conductor	$3.20
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
Total			**$402.42**

Scenario 15

Scenario 15 Description

Scenario 15 uses NextEra Mid-Atlantic Option 2 proposal 250 to interconnect 4,890 MW offshore wind to a new Fresh Ponds 500 kV substation, which includes 1,148 MW of solicitation #2 (Ocean Wind 2) offshore wind, to a new Neptune 230 kV substation. The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

NextEra Mid-Atlantic Option 2 proposal 250 involves the following components:

- Four new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Four new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 4,890 MW loading level was studied as part of this scenario)
- A new Fresh Ponds 500 kV substation looping in existing 500 kV lines from Deans to Windsor and Deans to Smithburg
- Four new onshore 400 kV converter stations at Fresh Ponds 500 kV with 400/500 kV transformation

Table 105. Scenario 15 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
15	6400	4890	NEETMH	None	$0	250	$7,029	$311	$7,340	$1.50

Table 106. Scenario 15 POI Summary

						Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Fresh Ponds 500 kV (MW)
15	6400	NEETMH	None	250	1110	1510	4890

Table 107. Scenario 15 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	250.1	Offshore Platform A	$729.65
	250.2	Offshore Platform B	$729.64
	250.3	Offshore Platform C	$729.64
	250.4	Offshore Platform D	$729.64
	250.5	Fresh Ponds Converter Station	$1,069.29
	250.6	Offshore Platform A – Raritan Bay Waterfront Park Landing HVDC	$423.99
	250.7	Offshore Platform B – Raritan Bay Waterfront Park Landing HVDC	$451.69
	250.8	Offshore Platform C – Raritan Bay Waterfront Park Landing HVDC	$505.50
	250.9	Offshore Platform D – Raritan Bay Waterfront Park Landing HVDC	$669.28
	250.10	Raritan Bay Waterfront Park Landing – Fresh Ponds Converter Station HVDC	$968.21
	250.11	Loop in and reconductor existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500kV AIS substation	$8.00
	250.12	Loop in and reconductor existing Deans -Smithburg 500 kV OH line to Fresh Ponds 500 kV AIS substation	$8.00
	250.13	Loop in existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation and use existing conductors	$3.00
	250.14	Loop in existing Deans - E. Winsdor 500 kV OH line to Fresh Ponds 500 kV AIS substation and use existing conductors	$3.00
Total			**$7,028.54**

Table 108. Scenario 15 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			$310.54

Scenario 16

Scenario 16 Description

Scenario 16 uses NextEra Mid-Atlantic Option 2 proposal 604 to interconnect the entire solicitation #2 2,658 MW offshore wind to a new Reega 230 kV substation near the existing Cardiff 230 kV substation. Scenario 16 also uses NextEra Mid-Atlantic Option 2 proposal 860 to interconnect 3,472 MW offshore wind to a new Fresh Ponds 500 kV substation. The interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind is assumed to be the responsibility of the offshore wind developers.

NextEra Mid-Atlantic Option 2 proposal 604 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,510 MW submarine and underground cable system
- One new 400 kV HVDC, 1,200 MW submarine and underground cable system (only up to a 1,148 MW loading level was studied as part of this scenario)
- Rebuild existing Cardiff to New Freedom 230 kV line and add second Cardiff to New Freedom 230 kV line
- A new Reega 230 kV substation next to the Cardiff 230 kV substation and loop in the two 230 kV lines from Cardiff to New Freedom
- Two new onshore 400 kV converter stations at Reega 230 kV with 400/230 kV transformation

NextEra Mid-Atlantic Option 2 proposal 860 involves the following components:

- Three new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Three new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 3,742 MW loading level was studied as part of this scenario)
- A new Fresh Ponds 500 kV substation next to the Deans 500 kV substation and loop in existing 500 kV lines from Deans to Windsor and Deans to Smithburg
- Three new onshore 400 kV converter stations at Fresh Ponds 500 kV with 400/500 kV transformation

Table 109. Scenario 16 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
16	6400	6400	NEETMH	None	$0	604 860	$2,943 $5,285	$519	$8,747	$1.37

Table 110. Scenario 16 POI Summary

						Alt POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Reega 230 kV (MW)	Fresh Ponds 500 kV (MW)
16	6400	NEETMH	None	604 860	758	2658	3742

Table 111. Scenario 16 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	604.1	Offshore Platform E	$808.27
	604.2	Offshore Platform F	$676.96
	604.3	Reega Converter Station	$524.31
	604.4	Offshore Platform E – Absecon Bay Landing HVDC	$126.79
	604.5	Offshore Platform F – Absecon Bay Landing HVDC	$119.25
	604.6	Absecon Bay Landing -Reega Converter Station HVDC	$524.09
	604.7	Remove and replace existing New Freedom- Cardiff 230 kV OH line and loop-in at NEETMA proposed Reega 230 kV substation, upgrade line section Reega - New Freedom	$77.17
	604.8	Build one new single circuit New Freedom - NEETMA proposed Reega 230 kV OH line in same ROW parallel to proposed rebuild of 230kV existing circuit	$77.17
	604.9	Remove and replace existing New Freedom - Cardiff 230 kV OH line and loop-in at NEETMA proposed Reega 230 kV sub, upgrade the line section Reega-Cardiff	$4.67
	604.10	Build one new single circuit Cardiff - NEETMA proposed Reega 230 kV OH line in same ROW parallel to proposed rebuild of 230kV existing circuit	$4.67
	860.1	Offshore Platform A – Raritan Bay Waterfront Park Landing HVDC	$424.81
	860.2	Offshore Platform B – Raritan Bay Waterfront Park Landing HVDC	$452.28
	860.3	Offshore Platform C – Raritan Bay Waterfront Park Landing HVDC	$506.16
	860.4	Raritan Bay Waterfront Park Landing – Fresh Ponds Converter Station HVDC	$776.31
	860.5	Offshore Platform A	$762.52
	860.6	Offshore Platform B	$762.51
	860.7	Offshore Platform C	$762.51
	860.8	Fresh Ponds Converter Station	$815.99
	860.9	Loop in and reconductor existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation	$3.00
	860.10	Loop in and reconductor existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 kV AIS substation	$8.00
	860.11	Loop in existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation and use existing conductors	$3.00
	860.12	Loop in existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 kV AIS substation and use existing conductors	$8.00
Total			$8,228.46

Table 112. Scenario 16 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2 Note: The upgrade will be required to remedy the set rating adjustments, and it is assumed that the cost to remove the set rating adjustments is minimal compared to overall cost.	$52.00
Exelon	Email 5/13/2022	Cardiff transformer replacement	$4.00
Exelon	Email 5/13/2022	Reconductor Cardiff-Lewis #2 138 kV	$7.00
PSEG	Email 2/22/2022	Build a new ~10 mile 230 kV UG line from Beaver Brook - Camden	$186.00
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
Transource	63	North Delta Option A	$109.68
JCPL	Email	Replace substation terminal conductors at Lakewood and Larrabee to bring the facility rating up to the line conductor (Lakewood - Larrabee 230 kV)	$1.50
Total			$518.87

Scenario 16a

Scenario 16a Description

Scenario 16a uses NextEra Mid-Atlantic Option 2 proposal 860 to interconnect 3,472 MW offshore wind to a new Fresh Ponds 500 kV substation. The interconnection of the 2,658 MW of solicitation #2 (Atlantic Shores 1 and Ocean Wind 2) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

NextEra Mid-Atlantic Option 2 proposal 860 involves the following components:

- Three new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Three new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 3,742 MW loading level was studied as part of this scenario)
- A new Fresh Ponds 500 kV substation next to the Deans 500 kV substation and loop in existing 500 kV lines from Deans to Windsor and Deans to Smithburg
- Three new onshore 400 kV converter stations at Fresh Ponds 500 kV with 400/500 kV transformation

Table 113. Scenario 16a Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
16a	6400	3742	NEETMH	None	$0	860	$5,285	$327	$5,612	$1.50

Table 114. Scenario 16a POI Summary

						Default POI	Alt POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Fresh Ponds 500 kV (MW)	Smithburg 500 kV (MW)
16a	6400	NEETMH	None	860	758	1510	3742	1148

Table 115. Scenario 16a Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	860.1	Offshore Platform A – Raritan Bay Waterfront Park Landing HVDC	$424.81
	860.2	Offshore Platform B – Raritan Bay Waterfront Park Landing HVDC	$452.28
	860.3	Offshore Platform C – Raritan Bay Waterfront Park Landing HVDC	$506.16
	860.4	Raritan Bay Waterfront Park Landing – Fresh Ponds Converter Station HVDC	$776.31
	860.5	Offshore Platform A	$762.52
	860.6	Offshore Platform B	$762.51
	860.7	Offshore Platform C	$762.51
	860.8	Fresh Ponds Converter Station	$815.99
	860.9	Loop in and reconductor existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation	$3.00
	860.10	Loop in and reconductor existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 kV AIS substation	$8.00
	860.11	Loop in existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation and use existing conductors	$3.00
	860.12	Loop in existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 kV AIS substation and use existing conductors	$8.00
Total			$5,285.11

Table 116. Scenario 16a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			$326.54

Scenario 17

Scenario 17 Description

Scenario 17 uses Atlantic Power Transmission Option 2 proposals 172 and 210 to interconnect 1,890 MW offshore wind to Deans 500 kV. Scenario 17 also uses NextEra Mid-Atlantic Option 2 proposal 15 to interconnect 3,000 MW offshore wind at a new Neptune 230 kV substation, which accounts for the 1,148 MW of solicitation #2 (Ocean Wind 2). The interconnection of the remaining 1,510 MW of solicitation #2 (Atlantic Shores 1) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

Atlantic Power Transmission Option 2 proposals 172 and 210 involve the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems (only up to a 1,890 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- Two new onshore 320 kV converter stations at Deans 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Deans

NextEra Mid-Atlantic Option 2 proposal 15 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,500 MW submarine and underground cable systems
- New Neptune 230 kV substation that loops in existing 230 kV lines from Atlantic to Oceanview and Larrabee to Oceanview
- Two new onshore 400 kV converter stations at Neptune 230 kV with 400/230 kV transformation and a short 230 kV underground connection to Neptune

Table 117. Scenario 17 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
17	6400	4890	ATLPWR, NEETMH	None	$0	210 172 15	$2,024 $1,601 $3,023	$772	$7,420	$1.52

Table 118. Scenario 17 POI Summary

						Default POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Neptune 230 kV (MW)
17	6400	ATLPWR, NEETMH	None	210 172 15	510	1510	1890	3000

Table 119. Scenario 17 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
ATLPWR	210.1	Offshore 1235 MW Converter Station and Supporting Platform	$948.19
	210.2	Submarine Section of 1200 MW HVDC Transmission Line	$416.15
	210.3	Onshore Section of 1200 MW HVDC Transmission Line	$236.96
	210.4	Onshore 1200 MW Converter Station	$408.90
	210.5	500 kV AC underground transmission line	$14.29
	210.6	Expansion of 500 kV switching area at Deans substation	$0.00
	172.1	Submarine Section of 1200MW HVDC Transmission Line	$347.07
	172.2	Onshore Section of 1200 MW HVDC Transmission Line	$142.93
	172.3	Onshore 1200 MW Converter Station	$331.47
	172.4	500 kV AC underground transmission line	$11.53
	172.5	Expansion of 500 kV switching area at Deans substation	$0.00
	172.6	Offshore 1235 MW Converter Station and Supporting Platform	$768.36
NEETMH	15.1	Offshore Platform A –Asbury Park Landing HVDC	$275.61
	15.2	Offshore Platform B –Asbury Park Landing HVDC	$303.07
	15.3	Asbury Park Landing – Neptune Converter Station HVDC	$153.92

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	15.4	Offshore Platform A	$784.42
	15.5	Offshore Platform B	$784.42
	15.6	Neptune Converter Station	$681.05
	15.7	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic to Neptune	$6.21
	15.8	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic to Neptune	$6.19
	15.9	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview	$2.00
	15.10	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the circuit section from Neptune - Oceanview 230 kV OH line circuit -Y	$2.00
	15.11	Reconductor and reterminate existing Larrabee - Oceanview 230 kV OH line	$23.83
Total			**$6,648.57**

Table 120. Scenario 17 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 5/17/2022	Rebuild Smithburg and East Windsor 230 kV substations	$75.00
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
JCPL	Email 4/15/2022	Reconductor/Rebuild Atlantic-New Prospect 230 kV to 1590 ACSS	$92.00
JCPL	Email 4/15/2022	Reconductor/Rebuild Larrabee-Smithburg 230 kV ckt 2 to 1590 ACSS	$88.00
NEETMH	331.15, 331.16	New Larrabee-Oceanview 230 kV	$61.97
JCPL	Email 4/15/2022	Rebuild Raritan River - Kilmer I 230 kV to double 1590 ACSS (biring the rating up to PSEG limit at Kilmer)	$69.00
JCPL	Email 4/15/2022	Reconductor/Rebuild New Prospect-Smithburg 230 kV to 1590 ACSS	$32.00
JCPL	Email 4/15/2022	Reconductor/Rebuild S River-Red Oak A 230 kV to 1590 ACSS	$6.00
N/A	N/A	Rebuild Kilmer-Lake Nelson "I" 230 kV	$6.53*
Total			**$772.06**

*Reflects per mile type cost estimate, and will be updated with Transmission Owner estimates once available. Per mile estimates came from Eastern Interconnection Planning Collaborative (EIPC) and are used in PJM renewable integration studies to estimate transmission costs.

Scenario 19

Scenario 19 Description

Scenario 19 uses Atlantic Power Transmission Option 2 proposals 172, 210 and 769 to interconnect 3,600 MW offshore wind to Deans 500 kV. The interconnection of the 2,658 MW of solicitation #2 (Atlantic Shores 1 and Ocean Wind 2) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

Atlantic Power Transmission Option 2 proposals 172, 210 and 769 involve the following components:

- Three new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Three new 320 kV HVDC, 1,200 MW submarine and underground cable systems
- Upgrade/expansion of Deans 500 kV substation
- Three new onshore 320 kV converter stations at Deans 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Deans

Table 121. Scenario 19 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
19	6258	3600	ATLPWR	None	$0	210 172 769	$2,024 $1,601 $1,478	$324	$5,427	$1.51

Table 122. Scenario 19 POI Summary

						Default POI	Default POI	Default POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)
19	6258	ATLPWR	None	210 172 769	0	1510	3600	1148

Table 123. Scenario 19 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
ATLPWR	210.1	Offshore 1235 MW Converter Station and Supporting Platform	$948.19
	210.2	Submarine Section of 1200 MW HVDC Transmission Line	$416.15
	210.3	Onshore Section of 1200 MW HVDC Transmission Line	$236.96
	210.4	Onshore 1200 MW Converter Station	$408.90
	210.5	500 kV AC underground transmission line	$14.29
	210.6	Expansion of 500 kV switching area at Deans substation	$0.00
	172.1	Submarine Section of 1200 MW HVDC Transmission Line	$347.07
	172.2	Onshore Section of 1200 MW HVDC Transmission Line	$142.93
	172.3	Onshore 1200MW Converter Station	$331.47
	172.4	500 kV AC underground transmission line	$11.53
	172.5	Expansion of 500 kV switching area at Deans substation	$0.00
	172.6	Offshore 1235 MW Converter Station and Supporting Platform	$768.36
	769.1	Offshore 1235 MW Converter Station and Supporting Platform	$691.11
	769.2	Submarine Section of 1200 MW HVDC Transmission Line	$322.37
	769.3	Onshore Section of 1200 MW HVDC Transmission Line	$131.97
	769.4	Onshore 1200 MW Converter Station	$322.67
	769.5	500 kV AC underground transmission line	$10.35
	769.6	Expansion of 500 kV switching area at Deans substation	$0.00
Total			$5,104.30

Table 124. Scenario 19 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	$13.40
Transource	63	North Delta Option A	$109.68
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	180.1, 180.2	Brunswick to Deans & Deans Subprojects	$50.54
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
Total			$323.94

Scenario 20

Scenario 20 Description

Scenario 20 uses NextEra Mid-Atlantic Option 2 proposal 461 to interconnect 1,342 MW offshore wind to a new Fresh Ponds 500 kV substation. Scenario 20 also uses NextEra Mid-Atlantic Option 2 proposal 298 to interconnect 2,400 MW offshore wind at a new Neptune 230 kV substation. The interconnection of the 2,658 MW of solicitation #2 (Atlantic Shores 1 and Ocean Wind 2) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

NextEra Mid-Atlantic Option 2 proposal 461 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,500 MW submarine and underground cable system (only up to a 1,342 MW loading level was studied as part of this scenario)
- A new Fresh Ponds 500 kV substation next to the Deans 500 kV substation and loop in existing 500 kV lines from Deans to Windsor and Deans to Smithburg
- One new onshore 400 kV converter station at Fresh Ponds 500 kV with 400/500 kV transformation

NextEra Mid-Atlantic Option 2 proposal 298 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 2,400 MW loading level was studied as part of this scenario)
- New Neptune 230 kV substation that loops in existing 230 kV lines from Atlantic to Oceanview and Larrabee to Oceanview
- Two new onshore 400 kV converter stations at Neptune 230 kV with 400/230 kV transformation and a short 230 kV underground connection to Neptune

Table 125. Scenario 20 Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
20	6400	3742	NEETMH	None	$0	298 461	$2,662 $3,608	$586	$6,856	$1.83

Table 126. Scenario 20 POI Summary

						Default POI	Alt POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Fresh Ponds 500 kV (MW)	Smithburg 500 kV (MW)	Neptune 230 kV (MW)
20	6400	NEETMH	None	298 461	758	1510	1342	1148	2400

Table 127. Scenario 20 Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	298.1	Offshore Platform A –Asbury Park Landing HVDC	$278.20
	298.2	Offshore Platform B –Asbury Park Landing HVDC	$289.06
	298.3	Asbury Park Landing – Neptune Converter Station HVDC	$153.92
	298.4	Offshore Platform A	$662.04
	298.5	Offshore Platform B	$662.03
	298.6	Neptune Converter Station	$578.72
	298.7	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic-Neptune	$6.19
	298.8	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic-Neptune	$6.19
	298.9	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview 230 kV OH line Circuit -X	$2.00
	298.10	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview 230 kV OH line Circuit -Y	$2.00
	298.11	Reterminate and Reconductor existing Larrabee - Oceanview 230 kV OH circuit	$21.58
	461.1	Offshore Platform A	$787.56
	461.2	Offshore Platform B	$787.56
	461.3	Offshore Platform A – Raritan Bay Waterfront Park Landing HVDC	$425.24
	461.4	Offshore Platform B – Raritan Bay Waterfront Park Landing HVDC	$453.02
	461.5	Raritan Bay Waterfront Park Landing – Fresh Ponds Converter Station HVDC	$575.79
	461.6	Fresh Ponds Converter Station	$562.33
	461.7	Loop in and existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500 kV OH line to Fresh Ponds 500kV AIS substation	$3.00
	461.8	Loop in existing Deans - E. Windsor 500 kV OH line to Fresh Ponds 500 AIS substation and use existing conductors	$3.00
	461.9	Loop in existing Deans - Smithburg 500 kV OH line to Fresh Ponds 500kV AIS substation and use existing conductors	$8.00
	461.10	Loop in existing Deans - E. Winsdor 500 kV OH line to Fresh Ponds 500 kV AIS substation and use existing conductors	$3.00
Total			$6,270.43

Table 128. Scenario 20 Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	Email 4/15/2022	Reconductor/Rebuild Atlantic-New Prospect 230 kV to 1590 ACSS	$92.00
JCPL	Email 4/15/2022	Reconductor/Rebuild Larrabee-Smithburg 230 kV ckt 2 to 1590 ACSS	$88.00
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
JCPL	Email	Upgrade to address Fresh Pond-Deans 500 kV: The reconductor component of Fresh Pond-Deans 500 kV in NEETMH proposal 461 ($5 M) is subtracted from JCPL proposal component 17.7 Deans - Smithburg 500 kV Terminal Upgrade ($13.24 M)	$8.24
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
Total			**$586.42**

Scenario 20a

Scenario 20a Description

Scenario 20a uses Anbaric Option 2 proposal 574 to interconnect 1,342 MW of offshore wind to Deans 500 kV. Scenario 20a also uses NextEra Mid-Atlantic Option 2 proposal 298 to interconnect 2,400 MW offshore wind at a new Neptune 230 kV substation. The interconnection of the 2,658 MW of solicitation #2 (Atlantic Shores 1 and Ocean Wind 2) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

Anbaric Option 2 proposal 574 involves the following components:

- One new offshore 400 kV converter station with 400/66 kV transformation to interconnect the offshore wind
- One new 400 kV HVDC, 1,400 MW submarine and underground cable system (only up to a 1,342 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- One new onshore 400 kV converter station at Deans 500 kV with 400/500 kV transformation and a short 500 kV underground connection to Deans

NextEra Mid-Atlantic Option 2 proposal 298 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 2,400 MW loading level was studied as part of this scenario)
- New Neptune 230 kV substation that loops in existing 230 kV lines from Atlantic to Oceanview and Larrabee to Oceanview
- Two new onshore 400 kV converter stations at Neptune 230 kV with 400/230 kV transformation and a short 230 kV underground connection to Neptune

Table 129. Scenario 20a Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
20a	6400	3742	NEETMH, ANBARD	None	$0	298 574	$2,662 $1,810	$578	$5,050	$1.35

Table 130. Scenario 20a POI Summary

						Default POI	Default POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Neptune 230 kV (MW)
20a	6400	NEETMH, ANBARD	None	298 574	58	1510	1342	1148	2400

Table 131. Scenario 20a Option 2 Component C2ost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	298.1	Offshore Platform A –Asbury Park Landing HVDC	$278.20
	298.2	Offshore Platform B –Asbury Park Landing HVDC	$289.06
	298.3	Asbury Park Landing – Neptune Converter Station HVDC	$153.92
	298.4	Offshore Platform A	$662.04
	298.5	Offshore Platform B	$662.03
	298.6	Neptune Converter Station	$578.72
	298.7	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic-Neptune	$6.19
	298.8	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic-Neptune	$6.19
	298.9	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview 230 kV OH line Circuit -X	$2.00
	298.10	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview 230 kV OH line Circuit -Y	$2.00
	298.11	Reterminate and Reconductor existing Larrabee - Oceanview 230 kV OH circuit	$21.58
ANBARD	574.1	Upgrade/Expansion of 500 kV Deans Substation	$11.20
	574.2	400 kV HVDC Submarine Cable	$360.16
	574.3	400 kV HVDC Underground Cable	$175.43
	574.4	500 kV HVAC Underground Cable	$10.06
	574.5	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore wind energy area - OWF Interface Transformer # 1	$859.98
	574.6	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - OWF Interface Transformer # 2	$0.00
	574.7	Offshore Substation Platform (OSP) at Atlantic Shores 3 (“AS3”) offshore energy area - Offshore Converter Station	$0.00
	574.8	New Onshore Converter Station - Onshore Converter Station	$393.40
	574.9	New Onshore Converter Station - Onshore Grid Interface Transformer	$0.00
Total			**$4,472.16**

Table 132. Scenario 20a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	Email 4/15/2022	Reconductor/Rebuild Atlantic-New Prospect 230 kV to 1590 ACSS	$92.00
JCPL	Email 4/15/2022	Reconductor/Rebuild Larrabee-Smithburg 230 kV ckt 2 to 1590 ACSS	$88.00
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
JCPL	Email 2/11/2022	Reconductor small section of Raritan River - Kilmer I 230 kV (n6201)	$0.20
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
Total			**$578.18**

Scenario 20b

Scenario 20b Description

Scenario 20b uses Atlantic Power Transmission Option 2 proposals 172 and 210 to interconnect 1,342 MW offshore wind to Deans 500 kV. Scenario 20b also uses NextEra Mid-Atlantic Option 2 proposal 298 to interconnect 2,400 MW offshore wind at a new Neptune 230 kV substation. The interconnection of the 2,658 MW of solicitation #2 (Atlantic Shores 1 and Ocean Wind 2) offshore wind as well as the interconnection of the entire 1,100 MW of solicitation #1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

Atlantic Power Transmission Option 2 proposals 172 and 210 involve the following components:

- Two new offshore 320 kV converter stations with 320/66 kV transformation to interconnect the offshore wind
- Two new 320 kV HVDC, 1,200 MW submarine and underground cable systems (only up to a 1,342 MW loading level was studied as part of this scenario)
- Upgrade/expansion of Deans 500 kV substation
- Two new onshore 320 kV converter stations at Deans 500 kV with 320/500 kV transformation and a short 500 kV underground connection to Deans

NextEra Mid-Atlantic Option 2 proposal 298 involves the following components:

- Two new offshore 400 kV converter stations with 400/66 kV transformation to interconnect the offshore wind
- Two new 400 kV HVDC, 1,500 MW submarine and underground cable systems (only up to a 2,400 MW loading level was studied as part of this scenario)
- New Neptune 230 kV substation that loops in existing 230 kV lines from Atlantic to Oceanview and Larrabee to Oceanview
- Two new onshore 400 kV converter stations at Neptune 230 kV with 400/230 kV transformation and a short 230 kV underground connection to Neptune

Table 133. Scenario 20b Cost Summary

				Option 1b		Option 2		Option 1a	TOTAL	
Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
20b	6400	3742	NEETMH, ATLPWR	None	$0	298 210 172	$2,662 $2,024 $1,601	$578	$6,865	$1.83

Table 134. Scenario 20b POI Summary

						Default POI	Default POI	Default POI	Alt POI
Scenario ID	Total (MW)	Proposing Entities	Option 1b Proposal IDs	Option 2 Proposal IDs	Excess Capacity (MW)	Cardiff 230 kV (MW)	Deans 500 kV (MW)	Smithburg 500 kV (MW)	Neptune 230 kV (MW)
20b	**6400**	**NEETMH, ATLPWR**	**None**	**298 210 172**	**1058**	**1510**	**1342**	**1148**	**2400**

Table 135. Scenario 20b Option 2 Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
NEETMH	298.1	Offshore Platform A –Asbury Park Landing HVDC	$278.20
	298.2	Offshore Platform B –Asbury Park Landing HVDC	$289.06
	298.3	Asbury Park Landing – Neptune Converter Station HVDC	$153.92
	298.4	Offshore Platform A	$662.04
	298.5	Offshore Platform B	$662.03
	298.6	Neptune Converter Station	$578.72
	298.7	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic-Neptune	$6.19
	298.8	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Atlantic-Neptune	$6.19
	298.9	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit X at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview 230 kV OH line Circuit -X	$2.00
	298.10	Loop in existing Atlantic - Oceanview 230 kV OH line Circuit Y at NEETMA proposed Neptune 230 kV substation and reconductor the line section from Neptune - Oceanview 230 kV OH line Circuit -Y	$2.00
	298.11	Reterminate and Reconductor existing Larrabee - Oceanview 230 kV OH circuit	$21.58
ATLPWR	210.1	Offshore 1235 MW Converter Station and Supporting Platform	$948.19
	210.2	Submarine Section of 1200 MW HVDC Transmission Line	$416.15
	210.3	Onshore Section of 1200 MW HVDC Transmission Line	$236.96
	210.4	Onshore 1200MW Converter Station	$408.90
	210.5	500 kV AC underground transmission line	$14.29
	210.6	Expansion of 500 kV switching area at Deans substation	$0.00
	172.1	Submarine Section of 1200 MW HVDC Transmission Line	$347.07
	172.2	Onshore Section of 1200 MW HVDC Transmission Line	$142.93
	172.3	Onshore 1200 MW Converter Station	$331.47
	172.4	500 kV AC underground transmission line	$11.53
	172.5	Expansion of 500 kV switching area at Deans substation	$0.00
	172.6	Offshore 1235 MW Converter Station and Supporting Platform	$768.36
Total			$6,287.78

Table 136. Scenario 20b Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Brief Proposal Description	Proposal Cost ($M)
Transource	63	North Delta Option A	$109.68
PPL	330	Reconductor Gilbert-Springfield 230 kV	$0.38
JCPL	Email 4/15/2022	Reconductor/Rebuild Atlantic-New Prospect 230 kV to 1590 ACSS	$92.00
JCPL	Email 4/15/2022	Reconductor/Rebuild Larrabee-Smithburg 230 kV ckt 2 to 1590 ACSS	$88.00
JCPL	17.1, 17.2, 17.3, 17.12, 17.13, 17.21	Upgrade Oyster Creek-Manitou 230 kV 1 & 2	$52.00
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JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River – Kilmer W 230 kV (n6202)	$25.88
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	$11.05
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	$3.90
PSEG	180.5, 180.6	Windsor to Clarksville Subproject	$5.77
AE	127.10	Reconductor Richmond-Waneeta 230 kV	$16.00
PSEG	180.3, 180.4, 180.7	Linden & Bergen Subprojects	$30.45
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	$3.80
JCPL	17.19	Reconductor Kilmer-Lake Nelson "I" 230 kV	$4.42
JCPL	Email 2/24/2022	Reconductor 2 miles of Kilmer W-Lake Nelson W 230 kV	$5.53
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	$0.16
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	$3.30
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	$0.12
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	$11.45
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	$0.30
AE	127.1	Upgrade Cardiff-Lewis 138 kV	$0.10
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	$0.50
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	$61.20
JCPL	Email 2/24/2022	Rebuild Larrabee-Smithburg #1 230 kV	$52.00
Total			**$578.18**

Document Revision History

9/19/2022 - V1: original version posted

11/04/2022 – V2: Table 36 - Scenario 14 Option 1a Component Cost Estimates updated to reflect latest information received from TO for Werner and Raritan River area reinforcement. Updated to include four finalist scenarios, the final reliability results and the SAA Project selection by NJ BPU.

Exhibit No. MAOD-7
Mid-Atlantic Offshore Development, LLC
PJM Summary Report (Nov. 15, 2022)

Summary Report for the NJBPU Selected Project

2021 SAA Proposal Window to Support NJ OSW

November 15, 2022

For Public Use

The information contained herein is based on information provided in project proposals submitted to PJM by third parties through its 2021 SAA Proposal Window. PJM analyzed such information for the purpose of identifying potential solutions for the NJBPU's consideration as contemplated under the SAA Agreement, FERC Rate Schedule No. 49. Any decision made using this information should be based upon independent review and analysis, and shall not form the basis of any claim against PJM.

Contents

EXECUTIVE SUMMARY

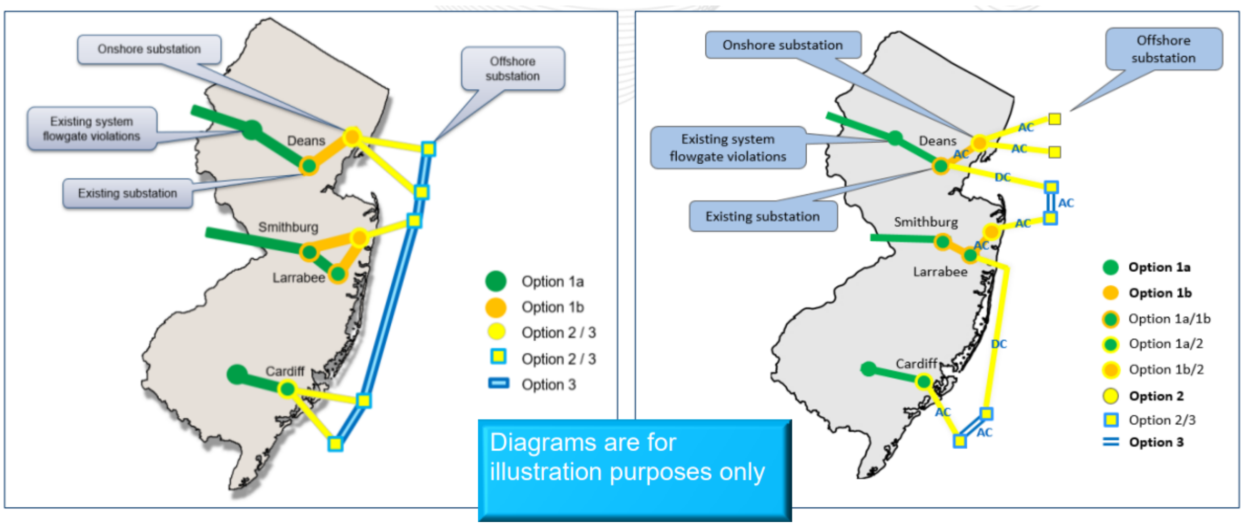
Background

On Nov. 18, 2020, the New Jersey Board of Public Utilities (NJBPU) issued an order formally requesting that PJM open a competitive proposal window to solicit project proposals to identify a transmission project that addresses the state's public policy goals for 7,500 MW of offshore wind (OSW) by 2035.

Working with the NJBPU, PJM opened its first public policy window in April 2021 and closed it in September 2021. As part of the 2021 State Agreement Approach (SAA) Proposal Window to support New Jersey offshore wind, PJM received proposals to meet the state's goal of interconnecting up to 7,500 MW of offshore wind by 2035. The proposals were categorized into four options according to the function and location of the proposal (see **Figure 1**). Altogether, PJM received a diverse set of 80 proposals.

- **Option 1a proposals:** Onshore transmission upgrades to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, ReliabilityFirst and local transmission owner criteria)
- **Option 1b proposals:** Onshore new transmission connection facilities
- **Option 2 proposals:** Offshore new transmission connection facilities
- **Option 3 proposals:** Offshore new transmission network facilities

Figure 1. Potential Options for the New Jersey Offshore Wind Transmission Solution



Concepts depicted are for illustration purposes only.
Details of new lines and facilities are to be provided by sponsors in proposals to meet objectives of this solicitation.

Objective

The objective of the PJM analysis was to evaluate the technical performance of the submitted proposals to ensure that they satisfy PJM reliability requirements and New Jersey's public policy requirements to achieve 7,500 MW of offshore wind by 2035. The findings of each body of analysis were provided to the NJBPU for its consideration and as input to its independent evaluation of the proposals and decision on which project, if any, it would select.

Overview of Evaluation Approach

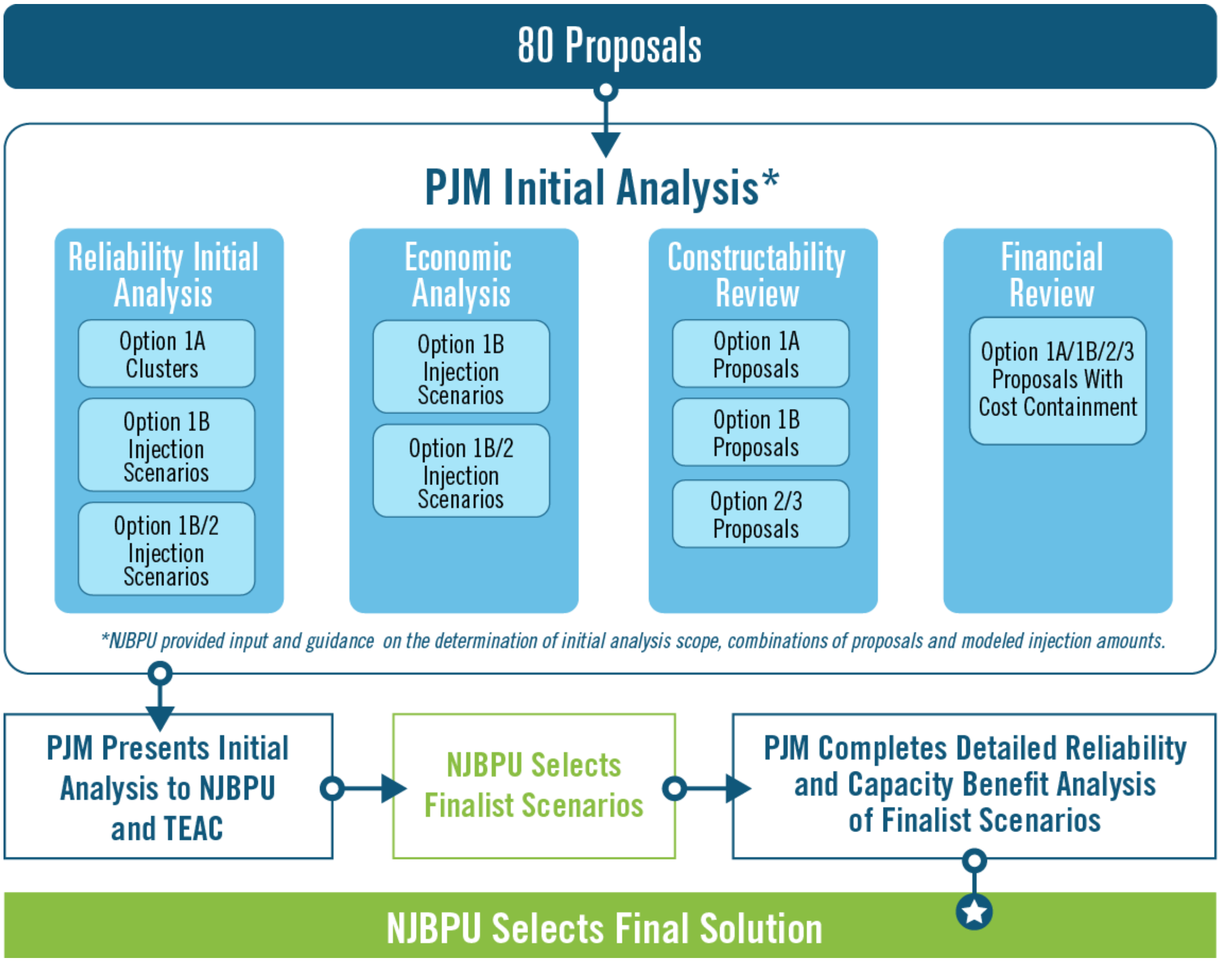
Following the submittal of proposals in a competitive planning solicitation, PJM performs technical analysis as needed to assess the performance of proposed solutions to meet the identified system need(s). As described in PJM Manual 14F, the approach to technical analysis typically involves an initial screening followed by a more detailed analysis phase as may be required to evaluate solutions in a window with multiple competitive proposals and/or complex system needs. For a window driven by public policy, where the project selection is by the sponsoring state, PJM and the NJBPU jointly determined the analysis that PJM would perform to assess the performance of the proposals, which would then be shared with the NJBPU as an input into their independent evaluation and decision to pursue project selection. The analysis included reliability, economic, constructability, financial and legal review.

The evaluation of the proposals in the 2021 New Jersey OSW SAA competitive window presented a number of unique challenges in the approach to analysis. The requirements as specified by the NJBPU and as posted by PJM permitted proposing entities to submit solutions to address any one or more of the posted options. The window requirements also permitted and invited these entities to offer solutions for different injection amounts that varied from the OSW target amount, as well as alternative points of injection (POIs) that might differ from those identified as the default POI. The window was further complicated by the incorporation of the outcome of New Jersey's second offshore wind generation procurement, which was concluded during PJM's open window.

In response to PJM competitive transmission solicitation, PJM received 80 proposals from 13 different entities for onshore upgrades, onshore greenfield facilities to extend the grid to the shore, offshore transmission proposals to extend the grid to access OSW lease areas and offshore backbone transmission to intertie future OSW platforms.

In a cooperative effort, PJM performed its initial analysis of the proposals as depicted in **Figure 2**. The NJBPU provided its input and guidance to the initial analysis scope, which informed the combinations of proposals and modeled injection amounts. Additionally, the NJBPU separately convened several public meetings for stakeholder input on various topics concerning the development of transmission for offshore wind. This information was also made available to PJM in its analysis.

Figure 2. Evaluation Process Overview



In order to perform the range of analysis, PJM grouped the project proposals into three main groups for conducting the initial analysis:

1. **Option 1a proposals:** Proposals to resolve identified violations of the existing facilities due to injections at the default POIs
2. **Option 1b-only proposals:** Proposals to extend the existing grid toward the shore to accommodate future interconnection of offshore wind projects to be constructed at a future time
3. **Option 1b/2/3 proposals:** Proposals to extend the transmission grid to offshore platforms such that future OSW generator developers could interconnect their projects to the platforms

The initial reliability screening analysis of the proposals was performed for the purpose of determining what upgrades would be needed to the existing system in combination with Option 1b/2 proposals to satisfy both reliability criteria and the OSW requirements. The analysis consisted of a range of injection scenarios to consider the various proposed POIs and concepts offered by each of the proposing entities. Each injection scenario incorporated the consideration of NJBPU solicitation #2 projects. Given the number of proposals and associated scenarios, it was impractical to perform the full complement of reliability tests for all of the scenarios. For this initial reliability analysis, the scope of the technical studies was limited to those tests that were deemed mostly likely to stress the system and provide a reasonable test of proposed Option 1a onshore system upgrades. The balance of complete reliability analysis was conducted for the four finalist scenarios selected by the NJBPU.

Similar to the reliability analysis, economic analysis was performed for the injection scenarios that included projections of energy market and capacity market benefits. The scope of the economic analysis was developed jointly with the NJBPU for the purpose of identifying potential economic benefits that might differentiate the performance of the transmission proposals.

The energy market benefits simulations were performed in conjunction with the initial reliability analysis and consisted of estimated load locational marginal prices (LMPs) and gross load payments for Load Serving Entities, generation LMPs and energy market value of New Jersey's OSW generation, simulated OSW unit energy and curtailments of New Jersey's OSW generation to the state's estimated emissions.

The capacity market benefits simulations were conducted for the three finalists' scenarios (scenarios 18 and 18a are equivalent for market analysis simulations) and consisted of simulating capacity market prices for the four New Jersey load zones (Atlantic City Electric, Jersey Central Power & Light, Public Service Electric & Gas Company, Rockland Electric) and adjacent load zones (Baltimore Gas & Electric, PECO).

Detailed constructability evaluation of all Option 1a, 1b and 2/3 proposals was performed in parallel with the initial screening analysis to assess the feasibility of constructing the proposed solutions. The detailed constructability analysis consisted of an in-depth review of the project scope, project cost, project complexity and constructability factors that could impact the cost and/or schedule, including ability to acquire rights-of-way and land, ability to site and permit the project, equipment technical feasibility, and the overall project schedule.

Detailed financial analysis of the proposals that included a cost commitment was performed during the initial analysis. The financial analysis consisted of simulating the cost of the project over the lifetime under a base scenario as well as several stress scenarios. The lifetime cost was calculated as the net present value revenue requirement (NPVRR) for the projects based on the proposed financial parameters and a representative cost of service revenue model. The NPVRR was then calculated for several scenarios that included variations of return on equity, capital cost, debt cost, equity percentage, and operation and maintenance costs. The purpose of the scenario simulations was to test the overall effectiveness of the proposed cost commitments.

In conjunction with the financial analysis, PJM performed a legal review of the cost commitment language that consisted of a qualitative assessment of the risks associated with the cost commitment provisions. The assessment considered such factors that might lead to delays in finalizing of the Designated Entity Agreement (DEA) or potential risks to acceptance of filed DEA and subsequent rate filing.

After completion of the initial analysis work, PJM presented its findings to the NJBPU and to PJM's Transmission Expansion Advisory Committee (TEAC) on July 18, 2022. The findings of the initial analysis are detailed in separate reports and are posted with TEAC materials.

The NJBPU then selected four finalist scenarios for the balance of reliability analysis, and PJM provided the results of the final comprehensive reliability analysis to the NJBPU. The NJBPU completed its independent evaluation of the proposals and selected the project, inclusive of all necessary components, that it will sponsor as a public policy project.

New Jersey's Selected Project

On Oct. 26, 2022, the NJBPU issued an order notifying PJM of its selection of the transmission project, inclusive of all components, that it will sponsor to achieve its stated public policy goals of injecting 7,500 MW of offshore wind into New Jersey by 2035.

The NJBPU has selected the solution identified as the "Larrabee Tri-Collector Solution" or "MAOD-JCP&L Option 1b Solution," which includes elements of the Jersey Central Power & Light (JCP&L) Option 1b proposal, as well as scaled-down elements of Mid-Atlantic Offshore Development's (MAOD's) Option 2 proposal, and the necessary Option 1a upgrades to create the SAA Capability[1] associated with the SAA scenario evaluating the Larrabee Tri-Collector Solution. The total cost for the selected solution is estimated to be $1.08 billion.

The primary component of the MAOD portion of Larrabee Tri-Collector Solution is a new substation to be constructed adjacent to the existing JCP&L Larrabee 230 kV substation, which is identified as the Larrabee Collector station (LCS). MAOD will construct the alternating current (AC) portion of the new Larrabee Collector station to accommodate three future high-voltage direct current (HVDC) circuits, which would be constructed by the future OSW generator developers. The proposal also includes sufficient land for the future installation of up to four DC converter stations. The HVDC cables delivering the output of future OSW generators will interconnect at the new Larrabee Collector station.

The JCP&L Option 1b (proposal #453) portion of the Larrabee Tri-Collector Solution includes transmission upgrades to the grid to create three paths from the LCS to the three points of injection: Larrabee 230 kV, Atlantic 230 kV and Smithburg 500 kV.

The primary components include:

- Smithburg substation 500 kV expansion to a four-breaker ring
- Atlantic 230 kV substation conversion to double-breaker double-bus
- New Larrabee Collector station-Smithburg No. 1 500 kV line
- G1021 Atlantic-Smithburg 230 kV line rebuild between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line
- D2004 Larrabee-Smithburg 230kV rebuild to 1590 ACSS
- New Larrabee Collector station-Atlantic 230 kV line
- New Larrabee Collector station-Larrabee 230 kV line

[1] SAA Capability has the meaning set forth in Paragraph 1 of the State Agreement Approach Agreement by and among PJM Interconnection, L.L.C. and New Jersey Board of Public Utilities, designated as Rate Schedule FERC No. 49, as filed at and accepted by FERC in Docket No. ER22-902-000. *See PJM Interconnection, L.L.C.,* 179 FERC ¶ 61,024 (2022), *reh'g denied* 179 FERC ¶ 62,131 (2022). Specifically, SAA Capability is defined to include:

> all transmission capability created by a SAA Project(s), including but not limited to the capability to integrate resources injecting energy up to the Maximum Facility Output ("MFO"), capability which may become CIRs through the PJM interconnection process, and any other capability or rights under the PJM Tariff, and consistent with the reliability study criteria applied to the evaluation of a SAA Project(s) as set forth in Paragraph 6 below. For the avoidance of doubt, SAA Capability shall also include any incremental transmission capability that is created by a SAA Project(s) and is determined to provide Incremental Auction Revenue Rights ("IARRs") or Incremental Capacity Transfer Rights ("ICTRs") associated with Incremental Rights-Eligible Required Transmission Enhancements, pursuant to Tariff, Schedule 12-A.

The selected solution also requires a number of Option 1a upgrades to reinforce the existing grid to accommodate the OSW injections. The primary components include:

- Rebuild the underground portion of Richmond-Waneeta 230 kV.
- Rebuild Clarksville-Lawrence 230 kV.
- Reconductor Kilmer I-Lake Nelson I 230 kV.
- Rebuild Larrabee-Smithburg No. 1 230 kV.
- Reconductor Red Oak A-Raritan River 230 kV (b3737.33).
- Reconductor Red Oak B-Raritan River 230 kV (b3737.34).
- Reconductor small section of Raritan River-Kilmer I 230 kV (b3737.35).
- Add a third set of submarine cables for the Silver Run-Hope Creek 230 kV line.
- Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV switching station and relocate the Linden-Tosco 230 kV line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV.
- Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers.
- Build a new North Delta-Graceton 230 kV line by rebuilding 6.07 miles of the existing Cooper-Graceton 230 kV line. Upgrade to Graceton-Cooper 230 kV.

The complete list of components that make up the Larrabee Tri-Collector Solution are provided in **Appendix** A: Summary of Larrabee Tri-Collector Solution**A**.

SAA Capability

The selected SAA project will result in creating SAA Capability as follows:

Table 1. Point of Interconnection & Associated Injected Amounts

Location	State	Transmission Owner	SAA Capability	MFO	MW Energy	MW Capacity
Larrabee Collector station 230 kV – Larrabee	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Atlantic	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Smithburg	NJ	MAOD	1,342	1,342	1,342	402.6
Smithburg 500 kV	NJ	JCPL	1,148	1,148	1,148	327

OVERVIEW OF PROPOSALS

Of the 80 project proposals received from the 13 applicants, there were 27 Option 1a solutions, 11 Option 1b solutions, 34 Option 2 solutions, and eight Option 3 solutions. The proposals represented a mixture of competitive onshore and offshore transmission solutions to support New Jersey's offshore wind needs.

In addition to the competitive proposals submitted in the window, transmission upgrades were provided by the incumbent Transmission Owners (TOs) to address new violations that were identified as a result of the reliability analysis and were not previously identified as part of the posted problem statement for the default points of injection.

Summary level project information and a geographical map for each of the 80 project proposals as well as the transmission upgrades provided by the incumbent TOs are provided in the 2021 NJ OSW SAA Window Map Book.

Option 1a Proposals

PJM received 27 Option 1a proposals as part of this window. A number of the Option 1a proposals addressed similar sets of reliability violations and were grouped into one of three competitive proposal clusters in order to compare the proposals:

- Pennsylvania/Maryland Border Proposal Cluster
- Central New Jersey Proposal Cluster
- Southern New Jersey Proposal Cluster

The remaining Option 1a proposals each addressed a unique set of reliability violations and were analyzed to demonstrate that they met PJM standards for an acceptable reliability solution and were selected as part of the set of reliability solutions used for scenario evaluations.

The proposals for addressing the Option 1a violations included both conventional transmission solutions, such as the rebuild or reconductoring of an existing transmission line as well as installation of power flow controlling devices. While power flow controlling devices can be a solution that mitigates certain violations, such solutions do not increase transmission capability on the system and require additional active control in operations. Where there are acceptable conventional solutions and where the additional transmission capacity offered by conventional solutions are extensive compared to cost savings of adopting power flow control devices, PJM will generally prioritize consideration of the conventional solutions. Power flow controlling devices, such as phase angle regulators and SmartWire devices, were proposed in this window. Such devices are generally not preferred solutions but may be considered when there is no other transmission solution within an order of magnitude cost of the power flow controlling device.

For any upgrades to an existing transmission facility, only incumbent TOs can be designated. For these TO upgrades, PJM contacted the incumbent TO to request a reliability solution and a corresponding project cost estimate.

Tables 3 through 9 in the Reliability Analysis Report provide a brief description, location and cost estimate of each of the 27 Option 1a proposals.

Option 1b Only Proposals

PJM received 11 Option 1b proposals, submitted by four entities in this window. Each of these proposals represented onshore-only projects with all necessary upgrades and/or greenfield solutions for transferring the offshore wind generation from new onshore substations to default or alternative POIs.

The Option 1b proposals are summarized in the following table.

Table 2. Option 1b Proposals

PJM Proposal ID	Proposing Entity	Proposal Cost Estimate	Project Description
797	Atlantic City Electric Company	**$233 M**	Onshore 275 kV AC system that facilitates 1,200 MW of offshore wind injection into Cardiff via new transition vault near shore at Great Egg Harbor
453	Jersey Central Power & Light Company	**$620 M**	Onshore 230/500 kV AC systems and expansions to existing JCPL stations to enable offshore wind injections of 2,490 MW at Smithburg, 1,200 MW at Larrabee, and 1,200 MW at Atlantic via new onshore Larrabee Collector AC substation to be constructed by MAOD
72	LS Power Grid Mid-Atlantic, LLC	**$1.601 B**	Five onshore HVAC scenarios to accommodate offshore wind injections of up to 6,000 MW via new Lighthouse shore AC substation
294	LS Power Grid Mid-Atlantic, LLC	**$1.545 B**	
627	LS Power Grid Mid-Atlantic, LLC	**$1.474 B**	
629	LS Power Grid Mid-Atlantic, LLC	**$1.568 B**	
781	LS Power Grid Mid-Atlantic, LLC	**$1.772 B**	
171	Rise Light & Power/Outerbridge Renewable Connector	**$109 M**	One or two onshore HVDC systems to enable offshore wind injections of 1,200/2,400 MW via Outerbridge shore AC station at Werner to new Half Acre HVDC converter station that ties into Deans-E. Windsor 500 kV; two options to directly inject an additional 400/800 MW of offshore wind at Werner 230 kV AC substation
376	Rise Light & Power/Outerbridge Renewable Connector	**$67 M**	
490	Rise Light & Power/Outerbridge Renewable Connector	**$1.732 B**	
582	Rise Light & Power/Outerbridge Renewable Connector	**$1.035 B**	

Additional details on these Option 1b proposals can be found in the NJ OSW Constructability Reports for Option 1b proposals.

Option 2 and 3 Proposals

PJM received 34 Option 2 proposals, submitted by seven entities in this window. Each of these proposals included new offshore substation(s), and all necessary greenfield solutions connecting the new offshore substation to an onshore substation proposed as part of an Option 1b project, or to a default or alternative point of injection (POI) where onshore substations are not needed.

The Option 2 proposals are summarized in the following table.

Table 3. Option 2 Proposals

PJM Proposal ID	Proposing Entity	Proposal Cost Estimate	Project Description
131	Anbaric Development Partners, LLC	**$1.648 B**	Twelve offshore scenarios for injecting offshore wind into Deans, Sewaren and Larrabee POIs, using single 1,200, 1,400, or 1,510 MW HVDC systems
145	Anbaric Development Partners, LLC	**$1.905 B**	
183	Anbaric Development Partners, LLC	**$1.682 B**	
285	Anbaric Development Partners, LLC	**$1.580 B**	
568	Anbaric Development Partners, LLC	**$1.978 B**	
574	Anbaric Development Partners, LLC	**$1.810 B**	
802	Anbaric Development Partners, LLC	**$1.715 B**	
831	Anbaric Development Partners, LLC	**$1.877 B**	
841	Anbaric Development Partners, LLC	**$1.794 B**	
882	Anbaric Development Partners, LLC	**$1.776 B**	
921	Anbaric Development Partners, LLC	**$1.545 B**	
944	Anbaric Development Partners, LLC	**$1.748 B**	
172	Atlantic Power Transmission LLC	**$1.601 B**	Offshore scenarios to inject up to 3,600 MW offshore wind into Deans POI using one, two or three 1,200 MW HVDC systems
210	Atlantic Power Transmission LLC	**$2.024 B**	
769	Atlantic Power Transmission LLC	**$1.478 B**	
990	Con Edison Transmission	**$2.747 B**	Offshore scenarios to inject 2,400 MW offshore wind into Deans, Larrabee or Smithburg POIs using two 1,200 MW HVDC systems
594	LS Power Grid Mid-Atlantic, LLC	**$1.968 B**	Offshore scenario to inject 4,000 MW offshore wind into new Lighthouse shore station using eight 345 kV HVAC cables
321	Mid-Atlantic Offshore Development	**$5.726 B**	Three offshore scenarios for up to 4,800 MW offshore wind injections into Smithburg, Atlantic and Larrabee via new Larrabee Collector AC substation, using two, three or four 1,200 MW HVDC systems (works with JCP&L Option 1b onshore project)
431	Mid-Atlantic Offshore Development	**$2.957 B**	
551	Mid-Atlantic Offshore Development	**$4.411 B**	
15	NextEra (NEETMH)	**$3.023 B**	Offshore scenarios for varying MW levels of offshore wind injections into Oceanview (up to 3,000 MW), Deans (up to 6,000 MW), and Cardiff (2,700 MW) via new Neptune, Fresh Ponds and Reega onshore
27	NextEra (NEETMH)	**$1.477 B**	
250	NextEra (NEETMH)	**$7.029 B**	

PJM Proposal ID	Proposing Entity	Proposal Cost Estimate	Project Description
298	NextEra (NEETMH)	**$2.662 B**	Converter stations, using combinations of 1,200 and 1,500 MW HVDC systems
461	NextEra (NEETMH)	**$3.608 B**	
604	NextEra (NEETMH)	**$2.943 B**	
860	NextEra (NEETMH)	**$5.285 B**	
208	PSEG/Orsted	**$4.719 B**	Seven offshore scenarios for varying MW levels (up to 4,200 MW) of offshore wind injections into Sewaren, Larrabee and Deans POIs, using combinations of 1,200 and 1,400 MW HVDC systems
214	PSEG/Orsted	**$2.445 B**	
230	PSEG/Orsted	**$2.328 B**	
397	PSEG/Orsted	**$2.295 B**	
613	PSEG/Orsted	**$2.151 B**	
683	PSEG/Orsted	**$7.181 B**	
871	PSEG/Orsted	**$4.843 B**	

PJM received eight Option 3 proposals, submitted by two entities in this window. Each of these involved greenfield transmission solutions connecting the new offshore substations (platforms) proposed as part of an Option 2 project.

The Option 3 proposals are summarized in the following table.

Table 4. Option 3 Proposals

PJM Proposal ID	Proposing Entity	Proposal Cost Estimate	Project Description
137	Anbaric Development Partners, LLC	**$60 M**	Seven 400 kV 700 MW HVDC cable links between offshore substation platforms proposed in Anbaric Option 2 solutions
243	Anbaric Development Partners, LLC	**$96 M**	
248	Anbaric Development Partners, LLC	**$80 M**	
428	Anbaric Development Partners, LLC	**$81 M**	
748	Anbaric Development Partners, LLC	**$67 M**	
889	Anbaric Development Partners, LLC	**$72 M**	
896	Anbaric Development Partners, LLC	**$65 M**	
359	NextEra Energy Transmission MidAtlantic Holdings, LLC	**$739 M**	Four 230 kV 800 MW AC cable links between the six offshore substation platforms proposed in NEETMH Option 2 solutions

In addition to the eight Option 3 proposals listed above, a number of entities also included Option 3 offshore links as part of their Option 2 proposals. This was the case for the Con Edison Transmission, Mid-Atlantic Offshore Development and PSEG/Orsted Option 2 proposals.

Additional details on the Option 2 and 3 proposals can be found in the NJ OSW Constructability Reports for Option 2 and 3 Proposals.

RELIABILITY ANALYSIS

Approach Overview

PJM first performed an initial reliability analysis screening of 28 offshore wind scenarios using PJM's generator deliverability procedures. Generator deliverability analysis is the primary reliability test used in PJM's generator interconnection studies to identify reliability violations caused by new generators and, by itself, typically identifies the majority, if not all, of the upgrades needed to reliably interconnect new generation to the PJM system. As part of the generator deliverability analysis, summer, winter and light power flow models were developed for each scenario for the year 2028 without including any Option 1a proposals. Single- and common-mode contingencies were examined to identify the reliability violations caused by the offshore wind scenarios.

Once the reliability violations without any Option 1a proposals were identified, PJM consulted with the NJBPU to select an initial single set of Option 1a proposals from among the competitive Option 1a proposal clusters, described above, to evaluate further.

Each offshore wind scenario resulted in a unique set of onshore reliability violations. A number of the reliability violations were identified as a result of alternate POIs submitted by proposers that the submitted Option 1a proposals did not address. PJM consulted with the affected TOs to identify the appropriate upgrades and provide the associated cost estimates to address the newly identified reliability violations.

After this initial reliability analysis screening, the NJBPU selected four scenarios for PJM to investigate more rigorously. PJM performed a comprehensive reliability analysis on these four finalist scenarios, as discussed further below, to ensure the final transmission buildout satisfied all PJM reliability criteria.

Offshore Wind Injection Scenarios

PJM worked with the NJBPU to create 28 offshore wind-injection scenarios involving various combinations of the submitted Option 1b and Option 2 proposals. Each scenario contains the awarded solicitation #1 for 1,100 MW and solicitation #2 for 2,658 MW. While the scope for the submission of proposals did not allow alternative POIs for solicitation #1, it did allow alternative POIs for solicitation #2. As a result, each scenario contains identical considerations for solicitation #1, and the scenario creation focused on selecting combinations of submitted Option 1b and Option 2 proposals that together enable the transmission system to reliably deliver approximately 6,400 MW of additional offshore wind. Table 55 and 6 illustrate the POI locations and megawatt injection amounts for each scenario considered. Appendix B of the Reliability Analysis report provides a detailed description of each scenario.

Table 5. POI Onshore Scenarios – Option 1b Only

						Alt POI	Default POI	Alt POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI
Scenario ID	**Total (MW)**	**Proposing Entities**	**Option 1b Proposal IDs**	**Option 2 Proposal IDs**	**Excess Capacity (MW)**	**New Freedom 500 kV (MW)**	**Cardiff 230 kV (MW)**	**Half Acre 500 kV (MW)**	**Lighthouse 500 kV (MW)**	**Smithburg 500 kV (MW)**	**Atlantic 230 kV (MW)**	**Larrabee 230 kV (MW)**	**Werner 230 kV (MW)**
2a	6,258	AE, JCPL	797 929.9 453.1-18,24,28-29	None	0		1,510 1,148			1,200	1,200	1,200	
3	6,458	AE, RILPOW, JCPL	797 127.8,9 490 376 453.9-11,16-17	None	200	1148	1,510	2,200				1,200	400
12	6,400	CNTLM	781	None	1110		1,510		4,890				
13	6,400	CNTLM	629	None	710		1,510		4,890				
14	6,400	RILPOW, JCPL	490 171 453.18-27,29	None	710		1,510	2,400		1,690			800
18	6,400	JCPL	453	None	0		1,510			2,490	1,200	1,200	
18a	6,400	JCPL, MAOD	453.1-18,24,26-29	551 (partial)	0		1,510			1,342 1,148	1,200	1,200	

Note 1: All POI Scenarios include Solicitation #1 (1,100 MW), which has been subtracted from the total MW.
Note 2: All MW assumed to be injected at the offshore platform for Option 2 proposals.
Note 3: Excess capacity represents additional transmission capability to the POI beyond the amounts being studied.
Note 4: Transmission interconnection facilities for POI MWs in black font are assumed to be supplied outside this SAA window.

LEGEND

Alt POI = Alternative POI

Table 6. POI Onshore/Offshore Scenarios – Option 1b/2

						Alt POI	Default POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI	Alt POI
Scenario ID	**Total (MW)**	**Proposing Entities**	**Option 1b Proposal IDs**	**Option 2 Proposal IDs**	**Excess Capacity (MW)**	**Reega 230 kV (MW)**	**Cardiff 230 kV (MW)**	**Fresh Ponds 500 kV (MW)**	**Deans 500 kV (MW)**	**Lighthouse 500 kV (MW)**	**Smithburg 500 kV (MW)**	**Atlantic 230 kV (MW)**	**Larrabee 230 kV (MW)**	**Neptune 230 kV (MW)**	**Sewaren 230 kV (MW)**
1.1	6,310	COEDTR, ANBARD	None	990 574 831	400		1,510		2,400		1,200		1,200		
1.2	6,310	COEDTR, PSEGRT	None	990 613	0		1,510		1,200		1,200 1,148		1,200		
1.2a	6,400	COEDTR, ANBARD	None	990 574	58		1,510		1,342		1,200 1,148		1,200		
1.2b	6,400	COEDTR, ATLPWR	None	990 210 172	1058		1,510		1,342		1,200 1,148		1,200		
1.2c	6,400	JCPL MAOD, ANBARD	453.9-11, 16-18,24,29	431 574	58		1,510		1,342		1,200 1,148		1,200		
2c	6,258	AE, JCPL, MAOD	797 929.9 453.1-18,24,28-29	551	0		1,510 1,148				1,200	1,200	1,200		
4	6,010	NEETMH	None	461 27	0		1,510	3,000						1,500	
4a	6,400	NEETMH	None	461 27	758		1,510	2,242			1,148			1,500	
5	6,310	JCPL, MAOD	453	321	0		1,510				2,400	1,200	1,200		
6	6,400	CNTLM	781	594	110		1,510			4,890					
7	6,400	CNTLM	629	594	110		1,510			4,890					
10	6,400	ANDBARD	None	882 841	258		1,510		2,290				1,200		1,400

						Alt POI	Default POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI	Default POI	Alt POI	Alt POI
Scenario ID	**Total (MW)**	**Proposing Entities**	**Option 1b Proposal IDs**	**Option 2 Proposal IDs**	**Excess Capacity (MW)**	**Reega 230 kV (MW)**	**Cardiff 230 kV (MW)**	**Fresh Ponds 500 kV (MW)**	**Deans 500 kV (MW)**	**Lighthouse 500 kV (MW)**	**Smithburg 500 kV (MW)**	**Atlantic 230 kV (MW)**	**Larrabee 230 kV (MW)**	**Neptune 230 kV (MW)**	**Sewaren 230 kV (MW)**
				921 131											
11	6,399	PSEGRT	None	683	459		1,510		1,247		1,148		1,247		1,247
15	6,400	NEETMH	None	250	1,110		1,510	4,890							
16	6,400	NEETMH	None	604 860	758	2,658		3,742							
16a	6,400	NEETMH	None	860	758		1,510	3,742			1,148				
17	6,400	ATLPWR, NEETMH	None	210 172 15	510		1,510		1,890					3,000	
19	6,258	ATLPWR	None	210 172 769	0		1,510		3,600		1,148				
20	6,400	NEETMH	None	298 461	158		1,510	1,342			1,148			2,400	
20a	6,400	NEETMH, ANBARD	None	298 574	58		1,510		1,342		1,148			2,400	
20b	6,400	NEETMH, ATLPWR	None	298 210 172	1,058		1,510		1,342		1,148			2,400	

Note 1: All POI Scenarios include Solicitation #1 (1,100 MW), which has been subtracted from the total MW.
Note 2: All MW assumed to be injected at the offshore platform for Option 2 proposals.
Note 3: Excess capacity represents additional transmission capability to the POI beyond the amounts being studied.
Note 4: Transmission interconnection facilities for POI MWs in black font are assumed to be supplied outside this SAA window.

LEGEND
Alt POI = Alternative POI

Initial Reliability Analysis

Table 7 through **Table 9** below summarize the cost estimates for the Option 1b, Option 2 and Option 1a proposals selected for each scenario. Note that the Option 1a cost estimates include both the selected Option 1a proposals and any incumbent TO-identified onshore upgrades required to resolve reliability violations for the scenario that were not resolved by a submitted Option 1a proposal.

The SAA megawatts are the POI injections associated with an Option 1b or Option 2 proposal, i.e., the sum of the POI megawatts for the scenario in **Table 5** and **Table 6** that are not in black font.

Table 7. POI Onshore Scenarios – Option 1b Only

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
2a	6,258	4,748	AE, JCPL	797 929.9 453.1-18,24,28-29	$233 $70 $377	None	$0	$856	$1,536	$0.32
3	6,458	4,948	AE, RILPOW, JCPL	797 127.8,9 490 376 453.9-11,16-17	$233 $225 $1,732 $68 $17	None	$0	$385	$2,660	$0.54
12	6,400	4,890	CNTLM	781	$1,772	None	$0	$271	$2,043	$0.42
13	6,400	4,890	CNTLM	629	$1,568	None	$0	$283	$1,851	$0.38
14	6,400	4,890	RILPOW, JCPL	490 171 453.18-27,29	$1,732 $109 $519	None	$0	$422	$2,782	$0.57
18 *(finalist)*	6,400	4,890	JCPL	453	$620	None	$0	$515	$1,135	$0.23
18a *(finalist)**	6,400	3,742	JCPL, MAOD	453.1-18,24,26-29	$428	551 (partial)	$121	$515	$1,064	$0.28

* Costs updated to reflect latest information included in the Nov. 4 TEAC presentation. The correction reflects moving Larrabee-Smithburg 230 kV rebuild from Option 1a components into Option 1b components, as it is component 26 of Proposal #453.

Table 8. POI Onshore/Offshore Scenarios – Option 1b/2

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
1.1	6,310	4,800	COEDTR, ANBARD	None	$0	990 574 831	$2,747 $1,810 $1,877	$327	$6,761	$1.41
1.2	6,310	3,652	COEDTR, PSEGRT	None	$0	990 613	$3,317 $2,151	$352	$5,820	$1.59
1.2a	6,400	3,742	COEDTR, ANBARD	None	$0	990 574	$2,747 $1,810	$352	$4,909	$1.31
1.2b	6,400	3,742	COEDTR, ATLPWR	None	$0	990 210 172	$2,747 $2,024 $1,601	$352	$5,823	$1.56
1.2c *(finalist)*	6,400	3,742	JCPL, MAOD, ANBARD	453.9-11,16-18,24,29	$293	431 574	$2,957 $1,810	$381	$5,441	$1.45
2c	6,258	4,748	AE, JCPL, MAOD	797 929.9 453.1-18,24,28-29	$233 $70 $377	551	$4,411	$670	$5,761	$1.21
4	6,010	4,500	NEETMH	None	$0	461 27	$3,608 $1,477	$390	$5,475	$1.22
4a	6,400	3,742	NEETMH	None	$0	461 27	$3,608 $1,477	$387	$5,461	$1.46
5	6,310	4,800	JCPL, MAOD	453	$620	321	$5,726	$561	$6,907	$1.44
6	6,400	4,890	CNTLM	781	$1,772	594	$2,460	$271	$4,503	$0.92
7	6,400	4,890	CNTLM	629	$1,568	594	$2,460	$283	$4,311	$0.88

Table 9. POI Onshore/Offshore Scenarios – Option 1b/2

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL	
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M/SAA MW)
10	6,400	4,890	ANDBARD	None	$0	882 841 921 131	$1,776 $1,794 $1,545 $1,648	$406	$7,169	$1.47
11	6,399	3,741	PSEGRT	None	$0	683	$7,181	$402	$7,583	$2.03
15	6,400	4,890	NEETMH	None	$0	250	$7,029	$311	$7,340	$1.50
16	6,400	6,400	NEETMH	None	$0	604 860	$2,943 $5,285	$519	$8,747	$1.37
16a ***(finalist)***	6,400	3,742	NEETMH	None	$0	860	$5,285	$327	$5,612	$1.50
17	6,400	4,890	ATLPWR, NEETMH	None	$0	210 172 15	$2,024 $1,601 $3,023	$772	$7,420	$1.52
19	6,258	3,600	ATLPWR	None	$0	210 172 769	$2,024 $1,601 $1,478	$324	$5,427	$1.51
20	6,400	3,742	NEETMH	None	$0	298 461	$2,662 $3,608	$586	$6,856	$1.83
20a	6,400	3,742	NEETMH, ANBARD	None	$0	298 574	$2,662 $1,810	$578	$5,050	$1.35
20b	6,400	3,742	NEETMH, ATLPWR	None	$0	298 210 172	$2,662 $2,024 $1,601	$578	$6,865	$1.83

Finalist Scenarios

The completion of the initial reliability analysis screening and identification of an initial set of onshore upgrades for each scenario was necessary to provide the NJBPU with a comparative framework of preliminary transmission cost estimates for the scenarios under evaluation that consider both the offshore and onshore transmission needs. The NJBPU used this information to select four scenarios for a final, comprehensive reliability evaluation that included both a further review of the competitive Option 1a proposal clusters as necessary and a full set of reliability studies. The four finalist scenarios were

- Scenario 1.2c
- Scenario 16a
- Scenario 18
- Scenario 18a

PJM performed a comprehensive reliability analysis on these four finalist scenarios, as discussed further below, to ensure the final transmission buildout satisfied all PJM reliability criteria.

Balance of Reliability Analysis for Finalist Scenarios

A complete list of the reliability criteria that was applied by PJM during the final evaluation of proposals in this proposal window – along with the associated analytical procedures, study material and terminology used to define the criteria violations – is described in Appendix A of the Reliability Analysis Report.

This comprehensive reliability analysis only identified an additional five over-dutied breakers for each of the four finalist scenarios. Tables 3 through 5 contain these additional breaker costs in the cost estimates developed for the four finalist scenarios.

SAA Project Selection

After the comprehensive reliability analysis and all other evaluations were complete, the NJBPU selected Scenario 18a as the State Agreement Approach Project. The description, required in-service date and cost estimate for each of the components of Scenario 18a, which is called the Larrabee Tri-Collector Solution, is provided in the Appendix to this report.

ECONOMIC ANALYSIS

Overview of Economic Analysis Approach

As part of the initial screening, PJM undertook 2028 energy market simulations for the New Jersey Offshore Wind Study to estimate the impact of selected OSW scenarios on key New Jersey market metrics.

The PJM energy market analysis utilized a production cost simulation tool, PROMOD by Hitachi Energy, which incorporates extensive electric market modeling details. The PROMOD “base case” used by PJM as the starting point for this analysis included the best available topology (2025 RTEP) and the forecast 2028 market conditions as used for the PJM 2020/21 Long-Term Window.

PJM created a "Scenario" by adding the combination of a selected transmission package along with the corresponding OSW generation injection it supported.

Summary of Energy Market Findings

There are some differences between the four finalist scenarios, but they may not be, at a high level, significant. The largest difference in New Jersey load payments between the finalist scenarios is 0.29%. The largest difference in POI annual average LMP is 2.73%.

Scenarios 1.2c and 16a result in offshore wind curtailment. The highest scenario annual curtailment is 70,991 MWh, or 0.31% of total annual generation. Scenarios 18 and 18a have no wind curtailment.

Detailed energy market simulation outputs for the completed scenarios can be found in the NJ OSW Economic Analysis Report posted at the Nov. 4, 2022, TEAC meeting.

Summary of Capacity Market Findings

The Capacity Market Operations Team executed seven different Base Residual Auction scenario runs for this study. The base scenario assumed that no offshore wind or transmission upgrades would be constructed and resulted in an estimated 2028/2029 total capacity cost for the key Locational Deliverability Areas of $1.01 billion. The remaining six auction runs all included 7,500 MW (installed capacity) of installed offshore wind units, and each of the three scenarios was run with transmission upgrades completed and then again without those same upgrades. The average total capacity cost for scenarios run without upgrades was $626 million, while the average cost with transmission upgrades was $612.3 million.

CONSTRUCTABILITY EVALUATION

Overview of Approach

PJM reviewed the information submitted by the proposing entities for each proposal, which included the following:

- Completed PJM Proposal Submittal Template (including project description, value proposition to New Jersey and cost control and risk mitigation measures)
- Completed BPU Supplemental Offshore Wind Transmission Proposals Data Collection Form – consisting of supplemental information related to proposals, including: a narrative description of the proposed project(s) and options; documentation of the projected benefits in terms of design, flexibility, ratepayer costs, and environmental impacts; an identification of major risks of (such as delay or noncompletion risks, including the project-on-project risks created by the interdependence of the proposed project(s) and those of other transmission and offshore wind projects); strategies to limit risks to New Jersey customers; and cost recovery and containment provisions

- Project diagrams and schedules
- Technical analysis files and documentation

With the submitted information, PJM and its consultants conducted a detailed review of each project, using the following approach for evaluation of the projects:

1. Environmental (Regulatory) Analysis: Examine each project utilizing available public-sector data, aerial photographs, and internet-based real estate records to determine if the project is feasible and to identify potential regulatory permitting risks. The following is a list of the subtasks that are performed as part of this task:
    a) Conduct a desktop review to identify significant barriers that might add additional risk to the project and determine whether the proposed project area (a Study Area that is defined for each project) can support the economical construction of the electric transmission and/or substation facilities.
    b) Identify those permits and agency consultations that are complex and require long lead times that could potentially significantly impact the project in-service date. Specifically, evaluate federal and state authorizations required for potential impacts to sensitive environmental resources, such as wetlands; rivers and streams; coastal zone management areas; critical habitats; wildlife refuges; conservation land; and rare, threatened and endangered species. The assessment will result in a preliminary list of potential siting issues and permits that could impact cost and/or schedule including estimated agency review times.
    c) Identify potential high-level risks and items that may require protracted permitting time frames or that may raise serious issues during the permitting process.
2. Transmission Line Analysis: Review of transmission line modifications proposed based on desktop reviews investigating routing, conductor size and length, rights-of-way (ROW) and easements, structures, and construction required.
3. Substation Analysis: Review of substation modifications proposed based on industry practices to estimate the equipment, bus and general layout required.
4. Construction Schedule: Prepare a preliminary project schedule for each project. The project schedule will be broken into four project phases: engineering; siting and major permit acquisition; long-lead equipment procurement; and construction and commissioning. Any significant risks to the project schedule will be discussed.
5. Cost Review: Prepare preliminary estimate for each project based on engineering expertise and the most recent material and equipment costs. Costs will be broken into eight categories, as required: materials and equipment; engineering and design; construction and commissioning; permitting/routing/siting; ROW/land acquisition; construction management; company overheads and other miscellaneous costs; and project contingency. Prepare a summary of the cost-estimating technique and assumptions used for the costs.

Summary of Findings

Detailed findings from PJM's constructability reviews are provided in the following constructability reports, categorized by the NJ OSW problem statements they address (Options), have been publicly posted on the PJM Transmission Expansion Advisory Committee (TEAC) meeting page.

- Constructability Report: Option 1a Proposals 2021 SAA Proposal Window to Support NJ OSW
- Constructability Report: Option 1b Proposals 2021 SAA Proposal Window to Support NJ OSW
- Constructability Report: Option 2 & 3 Proposals 2021 SAA Proposal Window to Support NJ OSW

Each report provides the constructability findings for each reviewed proposal, which includes results from environmental and regulatory analysis, transmission line analysis, substation analysis, and cost and construction schedule reviews.

From the reviews, all 80 NJ OSW SAA proposals were found to be constructible as proposed and remained under consideration by the NJBPU for potential selection. Key takeaways from the constructability evaluations were incorporated into PJM's constructability risk assessments, which were provided to the NJBPU to take into consideration in its independent evaluation. Please see Appendix B of each NJ OSW Constructability Report for constructability matrices summarizing PJM's risk assessments of the projects.

NJBPU Selected Project

On Oct. 26, 2022, the NJBPU issued an order selecting the "Larrabee Tri-Collector Solution" or "MAOD-JCP&L Option 1b Solution," which includes elements of the Jersey Central Power & Light (JCP&L) Option 1b proposal as well as scaled-down elements of Mid-Atlantic Offshore Development's (MAOD's) Option 2 proposal, and the necessary Option 1a upgrades to create the SAA Capability associated with the SAA scenario evaluating the Larrabee Tri-Collector Solution.

The Larrabee Tri-Collector Solution comprises elements of the original Option 1a, Option 1b and Option 2 NJ OSW SAA proposals, for which PJM performed constructability evaluations, with results as summarized in the previous section.

The main elements of the Larrabee Tri-Collector Solution are discussed below.

1. **Larrabee Tri-Collector Station (LCS) – Mid-Atlantic Offshore Development (MAOD):**

   - This component represents a scaled-down version of MAOD Proposal #551, which is an Option 2 proposal for three HVDC systems that includes three new offshore platforms, three HVDC submarine and underground cable segments, a new onshore converter station for three HVDC systems, and a new 500/230 kV onshore AC substation, both located at a new site adjacent to JCP&L's existing Larrabee substation. In the scaled-down version selected, only the 500/230 kV onshore AC substation is included for construction by MAOD, along with procurement of sufficient land, and site preparation for future installation of an onshore converter station that accommodates up to four HVDC systems. HVDC cables delivering the output of future OSW generators will interconnect at the new Larrabee Collector station.
   - During the evaluation process, the NJBPU requested answers to Clarifying Questions submitted to MAOD, JCP&L and other proposing entities. Responses to these questions, which were provided to the NJBPU and PJM for review, provided clarifications on the ability of the proposing entities to construct scaled-down versions of the original proposals submitted to the NJ OSW SAA window that better aligned with the NJBPU's final selection criteria as laid out in the NJBPU order.

- The original scope of MAOD Option 2 Proposal #551 was estimated to cost $4.411 billion, with the bulk of the cost attributed to offshore HVDC transmission components. In comparison, the reduced scope in the scaled-down version of Proposal #551 results in a significantly lower revised cost estimate of $121.1 million, which excludes other owners costs, permitting, commercial and financial fees that will require further evaluation and refinement by MAOD. This revised cost estimate was provided in MAOD's responses to the NJBPU Clarifying Questions.

2. Transmission Upgrades From LCS to Larrabee, Atlantic and Smithburg – JCP&L:

- The JCP&L Option 1b (Proposal #453) portion of the Larrabee Tri-Collector Solution includes transmission upgrades to the grid to create three paths from the LCS to the three points of injection: Larrabee 230 kV, Atlantic 230 kV and Smithburg 500 kV. The specific components of the Proposal #453 selected include components 1–18, 24 and 26–29, with components 27 and 29 combined into a single scope for a Smithburg 500 kV four-breaker ring bus. A key difference between the original scope and the NJBPU selected scope of Proposal #453 is the exclusion of a second Larrabee Collector station to Smithburg 500 kV line.
- The original scope of JCP&L Option 1b Proposal #453 was estimated to cost $620 million. In comparison, the reduced scope in the selected version of Proposal #453 results in a lower revised cost estimate of $427.82 million.

FINANCIAL EVALUATION

Overview of Analysis Approach

Altogether, PJM received a diverse set of 80 proposals submitted by 13 different entities, and each proposal was reviewed for completeness and consistency of cost information. Ultimately, 36 proposals were selected for a more detailed cost analysis and are representative of the solutions being offered by the participating entities. PJM engaged an expert financial consultant for the financial evaluation of the selected proposals, which included a comparative evaluation of the proposals' net present value revenue requirements (NPVRRs) under base case and other scenarios. The results obtained are intended to illustrate the lifetime costs to ratepayers for the proposals and the effectiveness of their cost containment mechanisms.

Each proposal received by PJM was accompanied by a number of supporting documents, all of which PJM reviewed in detail. The key documents relevant to the financial analysis included:

- PJM Competitive Planner Proposal Form – This document contains general information about the proposal, including project title, proposal ID number, a brief project description and key dates (construction start, capital spend start and in-service).
- BPU Supplemental Document – The BPU supplemental document collects more in-depth data necessary to evaluate the proposal. The key section most relevant to the financial analysis is the Proposal Costs, Containment Provisions and Cost Recovery section. This section contains a detailed characterization of the cost containment mechanisms, project costs and key assumptions for the revenue requirement (such as ROE, capital structure, book life and tax assumptions).

- Project Financial Information Schedule – Developers completed the financial information schedule for each proposed project. The financial information schedule depicts annual capital spend by project element.
- Revenue Requirement Schedule – Developers completed the revenue requirement schedule for each proposed project. The revenue requirement schedule depicts the estimated annual revenue requirement for the project over its life. We used a consistent revenue requirement modeling process, described later in this report, to ensure comparability. However, the proposer's revenue requirement models were used to obtain model inputs, such as operations and maintenance (O&M), property taxes and working capital, if not provided elsewhere in their submitted proposal documents.

Additional documents submitted by some proposers included:

- Cost Containment Document – Developers proposing projects with cost-capping mechanisms submitted a separate document describing their cost containment in detail in addition to mentioning them in their BPU Supplemental Document.
- Project Schedule – Some developers submitted documents with more detailed construction schedules than what they provided in the BPU Supplemental document or the project Financial Information Schedule.

Using the above information, a common template covering all proposals was created to ensure consistency in the revenue requirement modeling and comparisons across proposals. The most important sections in this common template are:

- General Information – Consists of the project description and project components from the Proposal Form, as well as key dates (i.e., construction start, capital spend start and in-service date)
- Capital Costs – Contains proposer estimates for total capital expenditures as well as some checks for consistency between the various proposer documents
- Cost Containment – Contains various binary indicators based on whether the overall project and certain components are capped, dollar amounts for those caps, further descriptions of the capping mechanisms and separate cost containment summaries. Key cost containment information such as the project components and elements were included as well.
- Financial Inputs & Assumptions – Contains information about the proposal's capital structure, tax assumptions, depreciation schedule and O&M
- Interdependency – Describes any issues, benefits or requirements related to modularity and pairing with other proposals
- Risks & Mitigations – Describes any uncertainties in timeline or other disruptions in the project that arise from major risks, with special attention included to any impacts on cost projections

With the common template developed, PJM and its consultants then conducted a detailed cost analysis for the 36 modeled projects using the following key steps:

- Revenue Requirement Modeling – A comparison of project cost estimates was performed, and for a more detailed cost analysis, a revenue requirement model was developed to allow comparison of the lifetime cost to ratepayers for the 36 modeled proposals. The analysis model calculates a bottom-up revenue requirement for each of the solutions utilizing the bidders' cost and financial assumptions, as well as a number of standardized model inputs. The NPVRR represents the discounted total cost of the proposed project over its lifetime.

- Review of Cost Containment Mechanisms – An evaluation of the various cost containment mechanisms offered by bidders was also performed. Particularly, for high-cost Option 1B and 2 proposals, a well-capped proposal could considerably lower-cost overrun risks, while a poorly capped or uncapped proposal could result in millions or even billions of extra ratepayer dollars over the lifetime of the project if actual project costs are higher than proposed.
- Scenario Analysis – In addition to the base case NPVRR comparison for the modeled proposals, PJM also modeled six scenarios that alter one or multiple model inputs. Five of the scenarios alter a single variable (setting the return on equity to 12%, increasing the cost of debt to 6%, increasing project costs by 25%, increasing O&M by 50%, and setting the capital structure at 50% debt and 50% equity). A sixth, referred to as "downside," combines the impacts of the five single variable scenarios. The use of the scenarios provided insight into the impact of potential cost increases as well as the effectiveness of the proposed cost containment mechanisms.

Summary of Findings

Detailed results from PJM and its consultant's financial analysis are provided in the Financial Analysis report, which has been publicly posted on the PJM Transmission Expansion Advisory Committee (TEAC) meeting page.

As detailed in Results & Key Observations section of the report, PJM compared base case and scenario NPVRR results for each option group, namely, Option 1A, Option 1B, Option 1B/2, and Option 3, to best provide like-for-like project cost-of-service comparisons. For each proposal, PJM measured the percentage and dollar increase in each of the six scenarios compared to the base case NPVRR, then compared the total cost of each scenario across the option group. While the percentage increase serves as a good indicator of the effectiveness of various cost caps, the dollar increase measure provides a more holistic picture that factors in the proposals' different base cost levels. Well-capped proposals may result in a higher dollar increase in certain scenarios due to their high base costs, whereas the opposite could be true for uncapped, lower base cost proposals. It was also noted that the number of different capping mechanisms does not necessarily increase overall effectiveness of cost containment.

The Financial Analysis was not intended to declare winners or losers, but rather to provide useful information about the expected cost impacts over time, and the related impact on customer rates, as well as the ability of the proposals' cost containment mechanisms to mitigate unexpected increases in costs.

Legal Review of Cost Containment Provisions

In addition to the Financial Analysis, PJM also performed a qualitative assessment of the risks associated with the cost commitment provisions submitted by the eight developers from a legal perspective. In performing the qualitative assessment, PJM reviewed the legal language submitted by the developers to determine:

- Whether any aspect of the language could lead to a delay in the negotiation of a Designated Entity Agreement (DEA), including, for instance, whether the developer submitted proposed legal language for inclusion in Schedule E of a DEA, and, if so, whether the proposal included any unclear or ambiguous language, or that would otherwise make the developer's commitment under the cost commitment language less firm;
- Potential risks associated with third-party challenges when the DEA is filed at FERC; and
- Potential risks associated with third-party challenges when the proposed cost of service rate is filed at FERC. Proposals that included clear legal language including firm commitments with respect to costs, ROE and capital structure tended to be considered low risk, whereas proposals that did not include legal language, or that did not include firm commitments with respect to costs, ROE and capital structure, tended to be considered medium risk.

Appendix C of the Financial Analysis report includes: (i) a summary of the cost commitment language included in the developers' proposals; (ii) issues that could, in PJM's view, lead to potential DEA negotiation delays or third-party challenges; and (iii) PJM's qualitative assessment of the relative risk related to DEA negotiation delays or third-party challenges.

APPENDIX A: SUMMARY OF LARRABEE TRI-COLLECTOR SOLUTION

Proposal IDs	Components	In-Service Date (ISD)	Cost ($M)
	ACE		
Proposal ID 127	The following components of Proposal 127		
	10. Rebuild the underground portion of Reconductor Richmond-Waneeta 230 kV (1098SN/1247SE, 1150WN/1299WE MVA)	6/1/2029	$16.00
	1. Upgrade Cardiff-Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation (377SN/478SE, 451WN/478WE MVA)	4/30/2028	$0.10
	3. Upgrade Cardiff-New Freedom 230 kV by modifying the existing relay settings (650SN/804SE, 748WN/906WE MVA)	4/30/2028	$0.30
	2. Upgrade Lewis No. 2-Lewis No. 1 138 kV by replacing bus tie with 2000A circuit breaker (478SN/478SE, 478WN/478WE MVA)	4/30/2028	$0.50
	MAOD		
Proposal ID 551	Construct the AC switchyard portion of MAOD Proposal 551, composed of a 230 kV 3 x breaker-and-a-half substation with a nominal current rating of 4000A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. AC switchyard design and site preparation shall be suitable for expansion to a 230 kV 4 X 230 kV breaker-and-a-half substation and seven single phase 500/230 kV 450 MVA autotransformers to step up voltage for connection of two circuits to Smithburg substation.	ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work	$121.10 Note: This cost represents a partial scope of MAOD proposal #551. It excludes other owners' costs, permitting, commercial and financial fees, and will require further evaluation to refine the estimate.
	Procure land adjacent to the MAOD AC switchyard, which is a portion of the MAOD Proposal 551, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. MAOD will commit to work with NJBPU and staff, PJM, the relevant transmission owners, and all future developers to lease or otherwise make land access available for construction of converters by those future developers to support the integration of OSW generators to achieve the OSW goals of New Jersey.	ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work	
	JCP&L		
Proposal ID 453	The following components of Proposal 453:		
	1. Atlantic 230 kV substation – Convert to double-breaker double-bus	6/1/2030	$31.47
	2. Freneau substation – Update relay settings	6/1/2030	$0.03
	3. Smithburg substation – Update relay settings	6/1/2030	$0.03
	4. Oceanview substation – Update relay settings	6/1/2030	$0.04
	5. Red Bank substation – Update relay settings	6/1/2030	$0.04

Proposal IDs	Components	In-Service Date (ISD)	Cost ($M)
	6. South River substation – Update relay settings	6/1/2030	$0.03
	7. Larrabee substation – Update relay settings	6/1/2030	$0.03
	8. Atlantic substation – Install line terminal	6/1/2030	$4.95
	9. Larrabee substation – Reconfigure substation	6/1/2029	$4.24
	10. Larrabee substation: 230 kV equipment for direct connection	6/1/2029	$4.77
	11. Lakewood Gen substation – Update relay settings	6/1/2029	$0.03
	12. G1021 (Atlantic-Smithburg) 230 kV	6/1/2030	$9.68
	13. R1032 (Atlantic-Larrabee) 230 kV	6/1/2030	$14.50
	14. New Larrabee Converter-Atlantic 230 kV	6/1/2030	$17.07
	15. Larrabee-Oceanview 230 kV	6/1/2030	$6.00
	16. B54 Larrabee-South Lockwood 34.5 kV line transfer	6/1/2029	$0.31
	17. Larrabee Converter-Larrabee 230 kV new line	6/1/2029	$7.52
	18. Larrabee Converter-Smithburg No. 1 500 kV line (new asset)	12/31/2027	$150.35
	24. G1021 Atlantic-Smithburg 230 kV	12/31/2027	$62.85
	26. D2004 Larrabee-Smithburg No1 230 kV	12/31/2027	$44.77
	27. Smithburg substation 500 kV expansion	12/31/2027	$5.81
	28. Larrabee substation	6/1/2030	$0.86
	29. Smithburg substation 500 kV 3 breaker ring	12/31/2027	$62.44
Proposal ID 17	The following components of Proposal 17: Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line - Smithburg-East Windsor 500 kV (3678SN/4541SE, 4262WN/5503WE MVA) - Deans-Smithburg 500 kV (3215SN/3998SE, 3890WN/4334WE MVA)		
	4. East Windsor-Smithburg 500 kV line	12/31/2028	$104.21
	5. East Windsor-Smithburg 230 kV line	12/31/2028	$37.80
	6. East Windsor substation	12/31/2028	$32.10
	7. T5020 Smithburg-Deans 500 kV	12/31/2028	$13.24
	8. K137 Windsor-Twin Rivers-Wyckoff Street 34.5 kV	12/31/2028	$6.20
	9. X752 Jerseyville-Smithburg 34.5 kV	12/31/2028	$4.58
	10. B158 Gravel Hill Smithburg 34.5 kV	12/31/2028	$4.23
	11. Smithburg 230 kV substation	12/31/2028	$4.12
	18. Add third Smithburg 500/230 kV (1034SN/1287SE, 1036WN/1451WE MVA)	12/31/2027	$13.40

Proposal IDs	Components	In-Service Date (ISD)	Cost ($M)
	16. D1018 (Clarksville-Lawrence) 230kV: Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence) 230kV Line between Lawrence Substation (PSEG) and Structure #63 with double bundled 1590 kcmil 45/7 ACSR.	12/31/2029	$11.45
	19. Reconductor Kilmer I-Lake Nelson I 230 kV (1136SN/1311SE, 1139WN/1379WE MVA)	12/31/2029	$4.42
PJM Identified Upgrades	Proposal Email 12/30/21: Additional reconductoring required for Lake Nelson I- 1 – Middlesex I 230 kV (1114SN/1285SE, 1116WN/1352WE MVA)	6/1/2029	$3.30
	Proposal Email 2/11/22: Reconductor small section of Raritan River-Kilmer 1I 230 kV (n6201) (1156SN/1334SE, 1158WN/1403WE MVA)	6/1/2029	$0.20
	Proposal Email 2/11/22: Replace substation conductor at Kilmer & reconductor Raritan River-Kilmer W 230 kV (n6202) (1156SN/1334SE, 1158WN/1403WE MVA)	6/1/2029	$25.88
	Proposal Email 2/11/22: Reconductor Red Oak A-Raritan River 230 kV (n6203) (1156SN/1334SE, 1158WN/1403WE MVA)	6/1/2029	$11.05
	Proposal Email 2/11/22: Reconductor Red Oak B-Raritan River 230 kV (n6204) (1156SN/1334SE, 1158WN/1403WE MVA)	6/1/2029	$3.90
LS Power			
Proposal ID 229	One additional Hope Creek-Silver Run 230 kV submarine cable (1364SN/1614SE, 1364WN/1614WE MVA) and rerate plus upgrade line:	5/1/2028	
	1. Transmission line upgrade		$60.20
	2. Silver Run substation upgrade		$1.00
PSE&G			
Proposal ID 180	The following components of Proposal 180:	6/1/2029	
	3. Linden subproject (IP)		$16.36
	4. Linden subproject (OP)		$8.56
	5. Upgrade Lake Nelson W-Middlesex W-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV (Lake Nelson W-Greenbrook W 230 kV: 934SN/1080SE, 999WN/1143WE MVA)(OP)	6/1/2029	$4.28
	6. Upgrade Lake Nelson W-Middlesex W-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV (Lake Nelson W-Greenbrook W 230 kV: 934SN/1080SE, 999WN/1143WE MVA) (IP)		$1.49
	7. Bergen Subproject		$5.53
PJM Identified	Proposal PPT 3/11/22: Upgrade inside plant equipment at Lake Nelson I 230 kV (Kilmer I-Lake Nelson I 230 kV: 1378SN/1625SE, 1475WN/1723WE MVA)	6/1/2029	$3.80

Proposal IDs	Components	In-Service Date (ISD)	Cost ($M)
Upgrades	Proposal PPT 2/4/22: Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV (Kilmer W-Lake Nelson W 230 kV: 934SN/1080SE, 999WN/1143WE MVA)		$0.16
	Proposal PPT 2/4/22: Upgrade Lake Nelson W-Middlesex W-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV (Lake Nelson W-Greenbrook W 230 kV: 934SN/1080SE, 999WN/1143WE MVA)		$0.12
PPL			
Proposal ID 330	The following components of Proposal 330:	6/1/2029	
	1. Reconductor Gilbert-Springfield 230 kV		$0.38
Transource			
Proposal ID 63	North Delta Option A:	12/31/2028	
	1. Graceton station upgrade		$1.55
	2. North Delta station		$76.27
	3. Tline upgrade – Graceton-Cooper-Peach Bottom		$28.74
	4. Tline upgrade – North Delta-Cooper Cut-in Lines		$1.56
	5. Tline upgrade – Peach Bottom-Delta Cut-in Lines		$1.56
Peco			
PJM Identified Upgrades	Replace four 63 kA circuit breakers “205,” “235,” “225” and “255” at Peach Bottom 500 kV with 80 kA breakers	12/31/2028	$5.60
BGE			
PJM Identified Upgrades	Replace one 63 kA circuit breaker “B4” at Conastone 230 kV with 80 kA breaker	12/31/2028	$1.3

Document Revision History

11/15/2022 - V1: original version posted

Exhibit No. MAOD-8
Mid-Atlantic Offshore Development, LLC
PJM May 9, 2023 TEAC Presentation

Reliability Analysis Update

Sami Abdulsalam, Senior Manager

Transmission Expansion Advisory Committee
May 9, 2023

- On April 26, 2023, the NJBPU notified PJM of its public policy requirements for offshore wind and has requested that PJM open a competitive proposal window to solicit onshore and offshore project proposals that address New Jersey's public policy needs.
- The order contains more information about this request.
- The NJBPU requests PJM to plan for injections of power into the Deans[1] 500 kV substation on the PJM system between 2032 and 2040 as summarized below.
- As of the date of the order, this information will be reflected in the PJM planning process.

Location	State	Transmission Owner	MW MFO	MW Energy	MW Capacity	Notification Date	Requested In-Service Date
Deans 500 kV	NJ	PSEG	3,500[2]	3,500[2]	3,356.50[2]	4.26.2023	2032-2040

Notes: (1) Alternative cost-effective POI proposals while meeting NJ State Policy goal will be invited through solicitation. (2) Transmission proposals will be solicited for up to 3500 MWs of capability.

M-3 Process

Baseline Reliability Projects

M-3 Process Solutions Meeting Study File Submittal Requirements

- M-3 Process - Transmission Owner created process approved by the FERC
  - Described in PJM Transmission Owners Attachment M-3 Process Guidelines v0.2 Section 3.2.3 "Review of Potential Solutions"
  - Presented at a TO Hosted PC Special Session August 28, 2018

- Solution Meeting – submittal requirements **15 days** prior to meeting

	Activity	Timing	Day	Who	How
1	Send Solutions Meeting slides and, for proposed solution, modeling information (contingency files, IDEV, etc.) to PJM	15 days before Solutions Meeting	-15	TOs and Stakeholders	E-mail to PJM
2	Finalizes Solutions Meeting slides (i.e., adds diagrams, etc.)	Upon receipt of slides, prior to posting date	>-10	PJM	Revises supplied slides
3	Post Solutions Meeting slides	10 days before Solutions Meeting	-10	PJM	Web posting of meeting materials
4	Solutions Meeting		0	All	

- Short Circuit files are considered modeling information

Changes to Existing Projects

Baseline Reliability Projects

- **Scope Clarification (administrative update):**
  - A portion of the Windsor to Clarksville Subproject b3737.40 scope was modified to reconductor one span (0.1 mile) of the C1017 (Clarksville-Windsor) 230 kV in lieu of creating a paired conductor path between Clarksville and Windsor.
  - A portion of the Windsor to Clarksville Subproject b3737.41 (Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV) previously included both PSEG and JCPL scope of work. This sub-ID was broken up into 2 sub-IDs to reflect both TOs' scope of work (PSEG scope remains with .41 sub-ID, while JCPL scope was transferred to new .59 sub-ID).
  - The b3737.48 scope of work to build a new North Delta-Graceton 230 kV line by rebuilding the existing Cooper-Graceton 230 kV line to double circuit previously included both PECO and BGE scope of work. This sub-ID was broken up into 2 sub-IDs to reflect both TOs' scope of work (PECO scope remains with .48 sub-ID, while BGE scope was transferred to new .56 sub-ID).

- **JCPL Zone Updates:**
  - Additional Project Scope:
    - Remove the existing E83 Line 115 kV (not in-service) to accommodate the new 500kV/230kV lines (approximately 7.7 miles) **(b3737.53)** - $8.47M
    - Remove the existing H2008 Larrabee-Smithburg No. 2 230 kV to accommodate the new 500kV/230kV lines **(b3737.54)** - $8.47 M
    - Middlesex Substation 230kV - Replace the 2000A Circuit Switcher at Middlesex Switch point for the Lake Nelson I1023 230kV exit **(b3737.55)** - $0.53 M
  - Updated Project Costs:
    - Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line (b3737.27) cost increase from $11.45 M to $14.58 M
    - Reconductor Red Oak A-Raritan River 230 kV (b3737.33) cost increase from $11.05 M to $12.53 M
    - Reconductor small section of Raritan River-Kilmer I 230 kV (b3737.35) cost increase from $0.2 M to $27.3 M

- **PSEG Zone Updates:**
  - Cost to Install the new 345/230 kV transformer at Linden 345 kV, and relocate Linden-Tosco 230 kV (b3737.38) has increased from $24.92M to $35.30M.
  - Cost to upgrade inside plant equipment at Lake Nelson I 230 kV (b3737.42) has increased from $3.80M to $4.80M.
  - Cost to upgrade Kilmer W – Lake Nelson W 230 kV (b3737.43) has increased from $0.16M to $0.57M.
  - Cost to upgrade Lake Nelson – Middlesex – Greenbrook W 230 kV (b3737.44) has increased from $0.12M to $0.58M.
- **PECO Zone Updates:**
  - PECO's project scope to replace four 63 kA circuit breakers "205", "235", "225" and "255" at Peach Bottom 500 kV with 80 kA (b3737.51) is no longer needed due to a case correction, resulting in a total project decrease of $5.6 M.

NJ SAA Project Updates

- **MAOD's Project Updates:**
  - Costs to construct the Larrabee Collector Station AC switchyard, and procure and prepare land adjacent to the AC switchyard (b3737.22) have increased from $121.1 M to $193.3 M. Includes costs that were explicitly excluded from MAOD's original estimate, that are required for the project.
  - Additional cost and scope for MAOD Pre-build Infrastructure evaluation study
    - Pre-build Infrastructure scope is intended so that either an Offshore wind developer, or other entity selected by NJBPU, construct the necessary duct banks and access cable vaults for other Offshore wind generators, to fully utilize the Larrabee Tri-Collector Solution.
    - The NJBPU approved that MAOD perform a Pre-build Infrastructure evaluation study in alignment with requirements in Attachment 10 of the NJBPU Solicitation Guidance Document (SGD).
    - The deliverables for this study will be a desktop study, updated cable routes and cross-section diagrams, detailed scope, schedule and cost estimates for the pre-build infrastructure.
    - Study cost estimate is $290K, and targeted for completion by June 2, 2023.
- **NJ SAA Project Total Cost Increase:** $1,064.36 M → $1,191.70 M

Appendix

Baseline Reliability Projects

JCPL Transmission Zone: Baseline NJ SAA Project

Assumption Reference: 2020 RTEP assumption

Model Used for Analysis: 2021 SAA Proposal Window cases

Proposal Window Exclusion: None

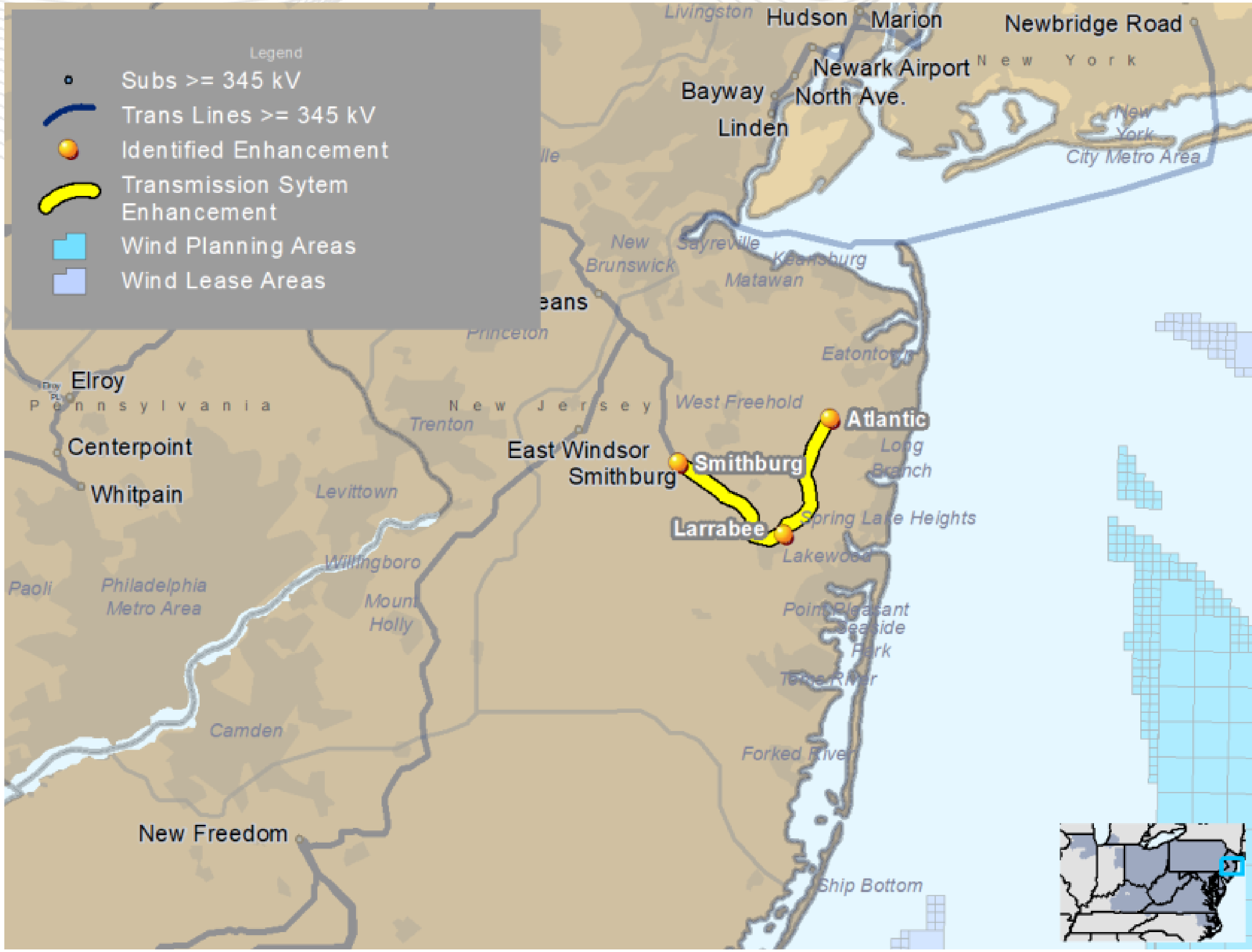
Problem Statement:

PJM solicited project proposals to build the necessary transmission to meet New Jersey's goal to facilitate the delivery of a total of 6,400 MW of offshore wind.

Recommended Solution: Option 1b – Proposal 453 (Partial)

- Larrabee Substation - Reconfigure substation (b3737.1) - $4.24
- Larrabee Substation - 230 kV equipment for direct connection (b3737.2) - $4.77 M
- Lakewood Generator Substation - Update relay settings on the Larrabee 230 kV line (b3737.3) - $0.03 M
- B54 Larrabee-South Lockwood 34.5 kV line transfer (b3737.4) - $0.31 M
- Larrabee Collector Station-Larrabee 230 kV new line (b3737.5) - $7.52 M

Required IS Date (b3737.1-.5): 6/1/2029



JCPL Transmission Zone: Baseline NJ SAA Project

Assumption Reference: 2020 RTEP assumption

Model Used for Analysis: 2021 SAA Proposal Window cases

Proposal Window Exclusion: None

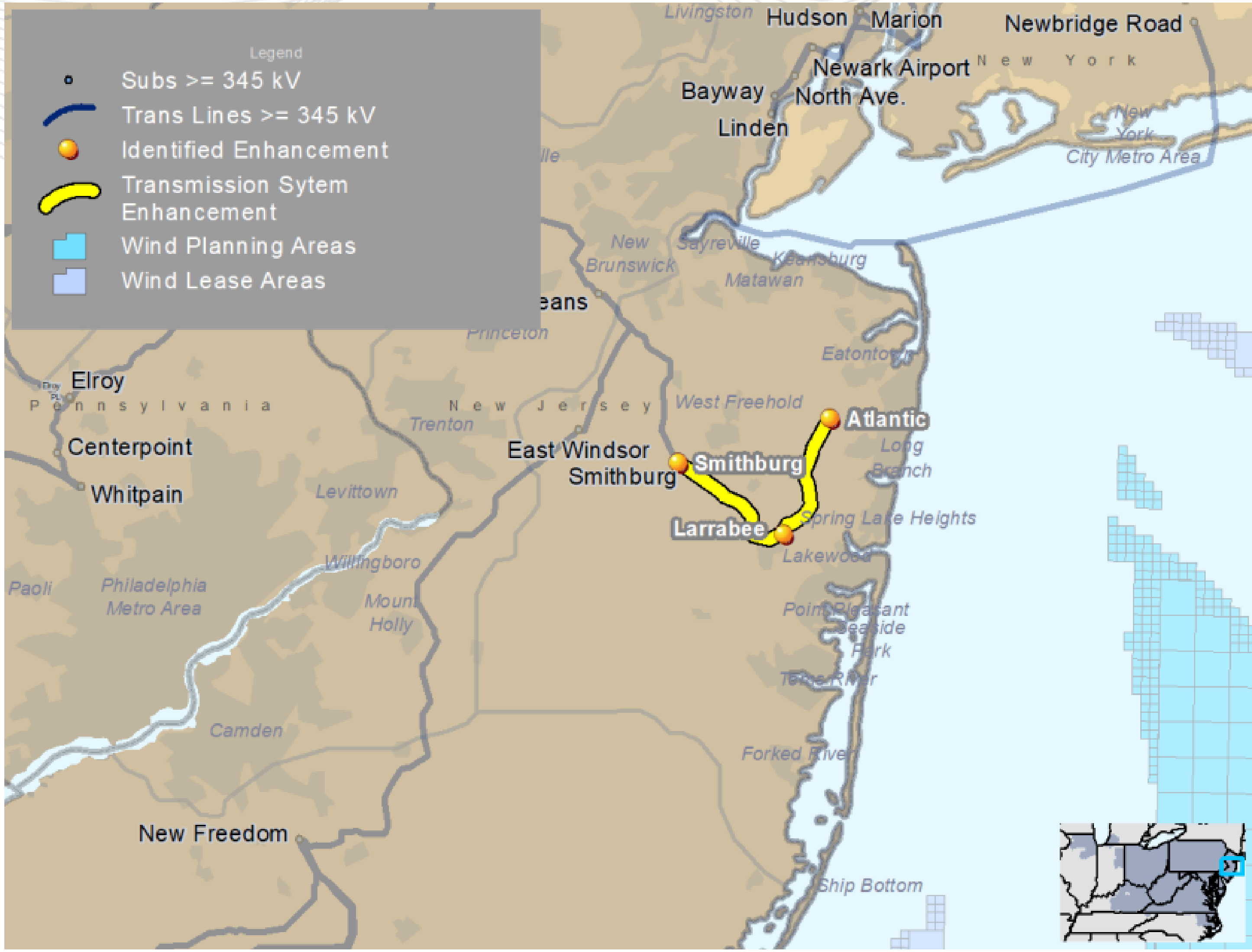
Problem Statement:

PJM solicited project proposals to build the necessary transmission to meet New Jersey's goal to facilitate the delivery of a total of 6,400 MW of offshore wind.

Recommended Solution: Option 1b – Proposal 453 (Partial)

- Larrabee Collector Station-Smithburg No. 1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line. (b3737.6) - $150.35 M
- Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500kV/230kV line (b3737.7) - $62.85 M
- Smithburg substation 500 kV expansion to 4 breaker ring (b3737.8) - $68.25 M
- Rebuild Larrabee-Smithburg No. 1 230 kV (b3737.32) - $44.77 M
- Remove the existing E83 Line 115 kV (not in-service) to accommodate the new 500kV/230kV lines (approximately 7.7 miles) **(b3737.53)** - $8.47M
- Remove the existing H2008 Larrabee-Smithburg No. 2 230 kV to accommodate the new 500kV/230kV lines **(b3737.54)** - $8.47 M

Required IS Date (b3737.6-.8 & .32): 12/31/2027



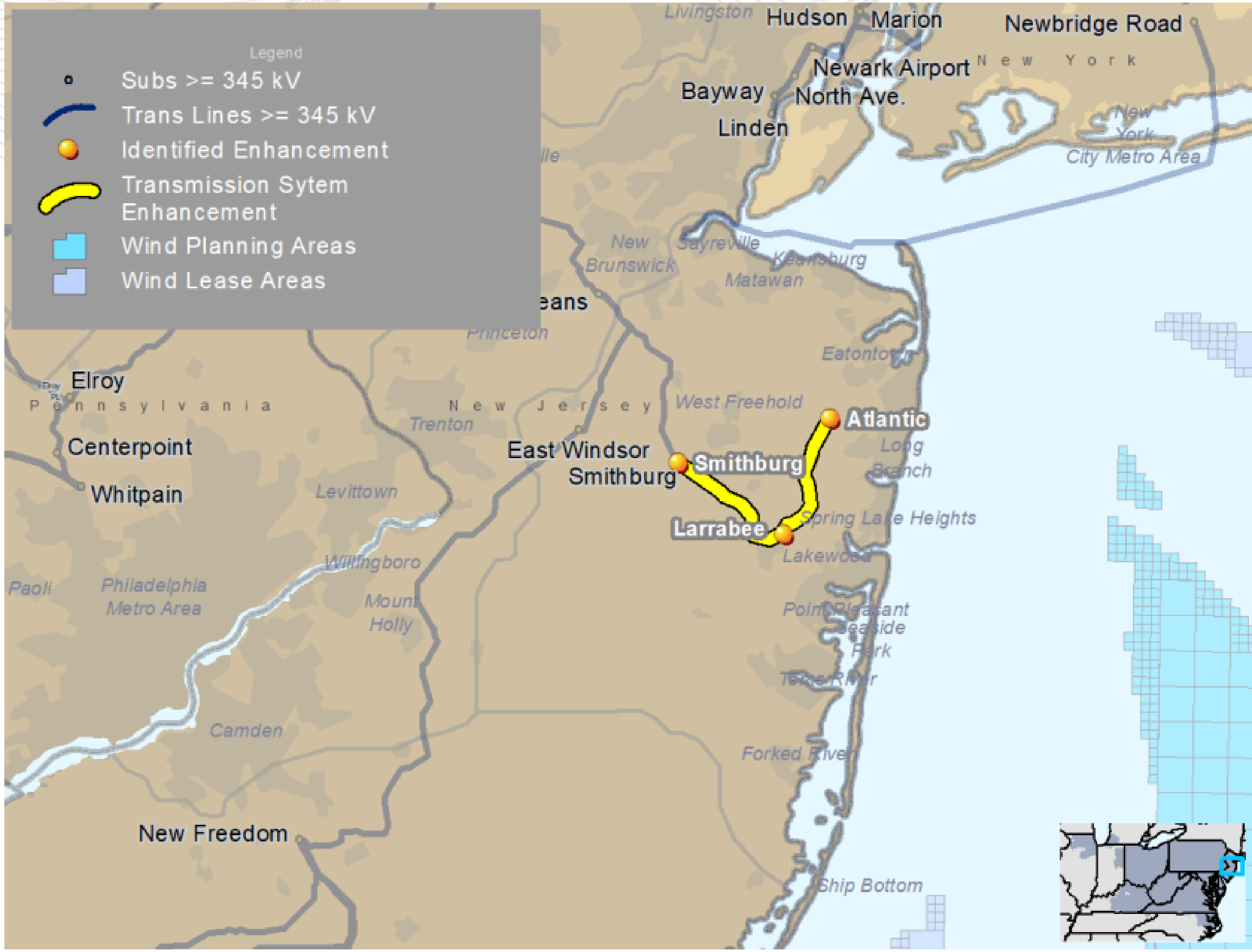
JCPL Transmission Zone: Baseline NJ SAA Project

Recommended Solution (cont.): Option 1b – Proposal 453 (Partial)

- Larrabee substation upgrades (b3737.9) - $0.86 M
- Atlantic 230 kV Substation - Convert to double-breaker double-bus (b3737.10) - $31.47 M
- Freneau Substation - Update relay settings on the Atlantic 230 kV line (b3737.11) - $0.03 M
- Smithburg Substation - Update relay settings on the Atlantic 230 kV line (b3737.12) - $0.03 M
- Oceanview Substation - Update relay settings on the Atlantic 230 kV lines (b3737.13) - $0.04 M
- Red Bank Substation - Update relay settings on the Atlantic 230 kV lines (b3737.14) - $0.04 M
- South River Substation - Update relay settings on the Atlantic 230 kV line (b3737.15) - $0.03 M
- Larrabee Substation - Update relay settings on the Atlantic 230 kV line (b3737.16) - $0.03 M
- Atlantic Substation - Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector Station (b3737.17) - $4.95 M
- G1021 (Atlantic-Smithburg) 230 kV upgrade (b3737.18) - $9.68 M
- R1032 (Atlantic-Larrabee) 230 kV upgrade (b3737.19) - $14.5 M
- New Larrabee Collector Station-Atlantic 230 kV line (b3737.20) - $17.07 M
- Larrabee-Oceanview 230 kV line upgrade (b3737.21) - $6 M

Required IS Date (b3737.9-.21): 6/1/2030

Estimated Cost (b3737.1-.21 & .32 & .53-.54): ~~$427.82 M~~ $444.76 M



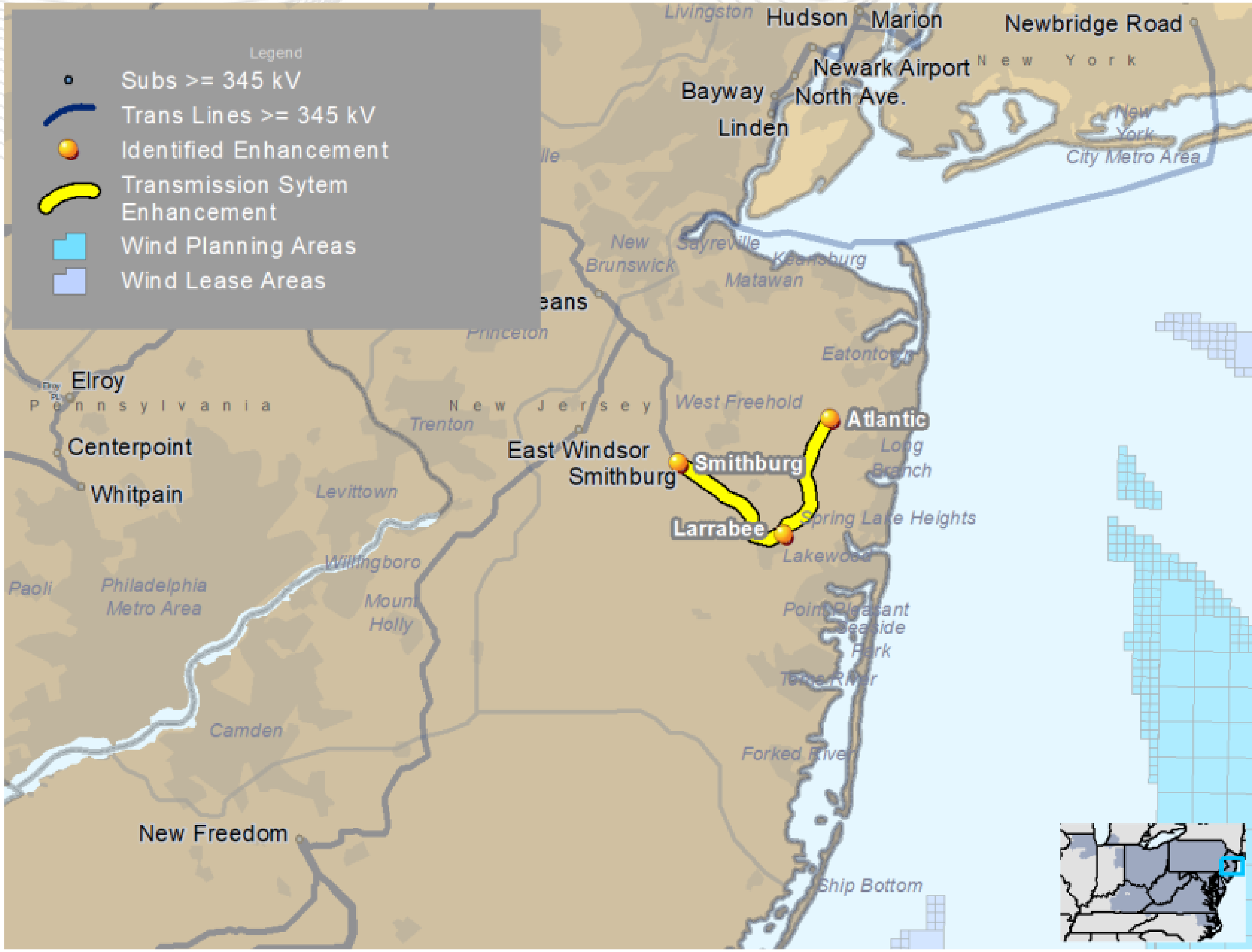
JCPL Transmission Zone: Baseline NJ SAA Project

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Larrabee-Smithburg No. 1 230 kV	650/817/785/943
Larrabee-Smithburg No. 2 230 kV	678/813/805/929
Atlantic-Larrabee 230 kV	913/1147/1116/1352
Larrabee-Oceanview 230 kV	709/869/805/1031
Larrabee-Smithburg No. 1 230 kV	650/817/785/943

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Larrabee-Smithburg 230 kV	709/869/805/1031
Atlantic-Larrabee 230 kV	1104/1273/1106/1390
Larrabee-Oceanview 230 kV	1104/1273/1106/1339
Larrabee-Smithburg No. 1 230 kV	1136/1311/1139/1379
Larrabee Collector-Atlantic 230 kV	1260/1447/1259/1523
Larrabee Collector-Larrabee 230 kV	1418/1739/1610/2062
Larrabee Collector-Smithburg No. 1 500 kV	3678/4541/4262/5503



MAOD in JCPL Transmission Zone: Baseline NJ SAA Project

Recommended Solution (cont.): Option 2 – Proposals 551 (Partial)

- Construct the Larrabee Collector Station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation.
- Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of 4 individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. (b3737.22)

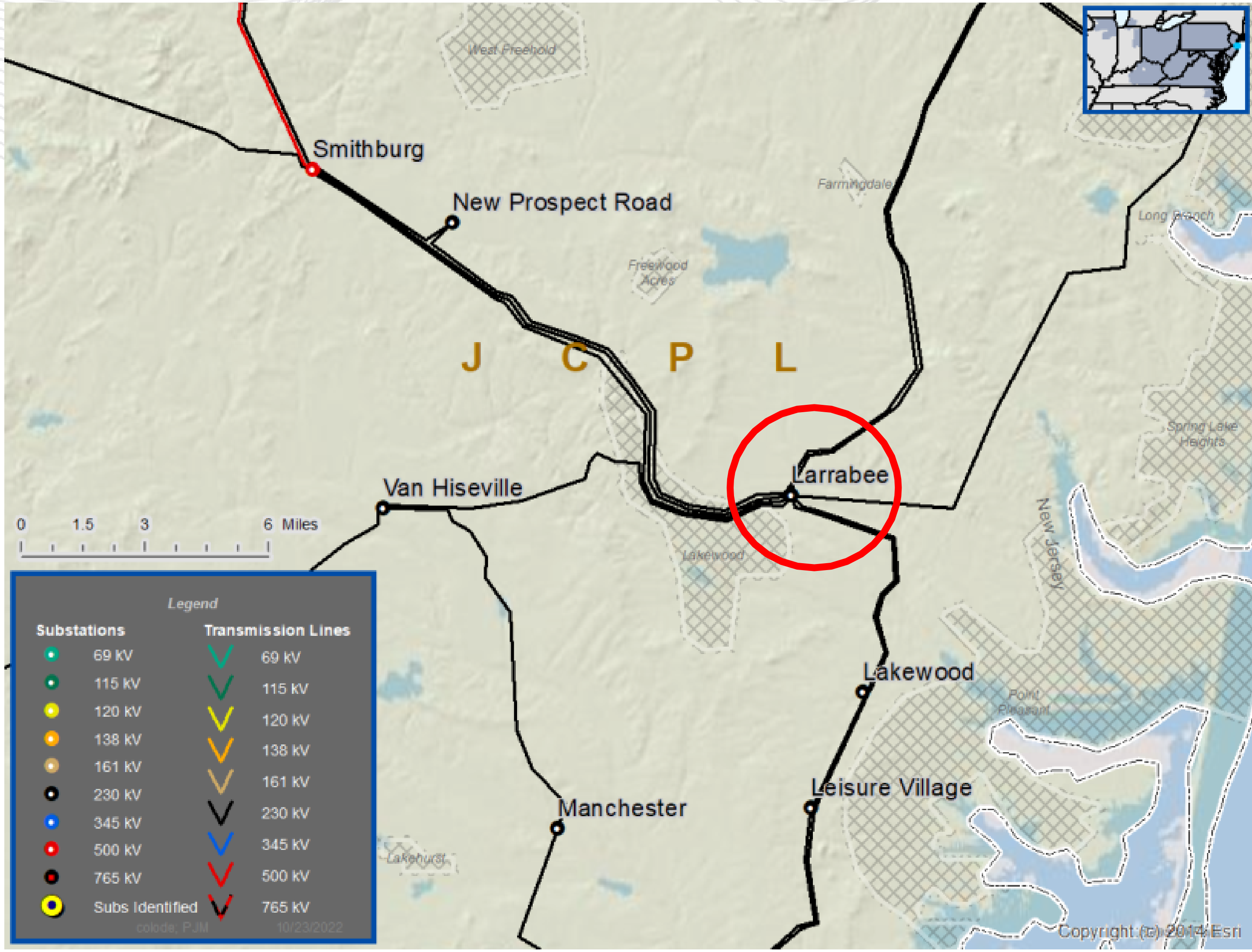
Required IS Date (b3737.22): 12/31/2027

Estimated Cost (b3737.22): ~~$121.10 M~~ $193.3 M

- Perform a Pre-build Infrastructure evaluation study in alignment with the NJBPU Solicitation Guidance Document requirements.

Required Completion Date: 6/2/2023

Estimated Cost: $0.29M



AE Transmission Zone: Baseline NJ SAA Project

Criteria: Summer & Winter Generator Deliverability

Problem Statement:

The Richmond-Waneeta 230 kV line is overloaded for an N-1 outage, and the Cardiff-Lewis 138 kV, Lewis No. 2-Lewis No. 1 138 kV and Cardiff-New Freedom 230 kV lines are overloaded for N-2 outages.

Recommended Solution: Option 1a – Proposal 127 (Partial)

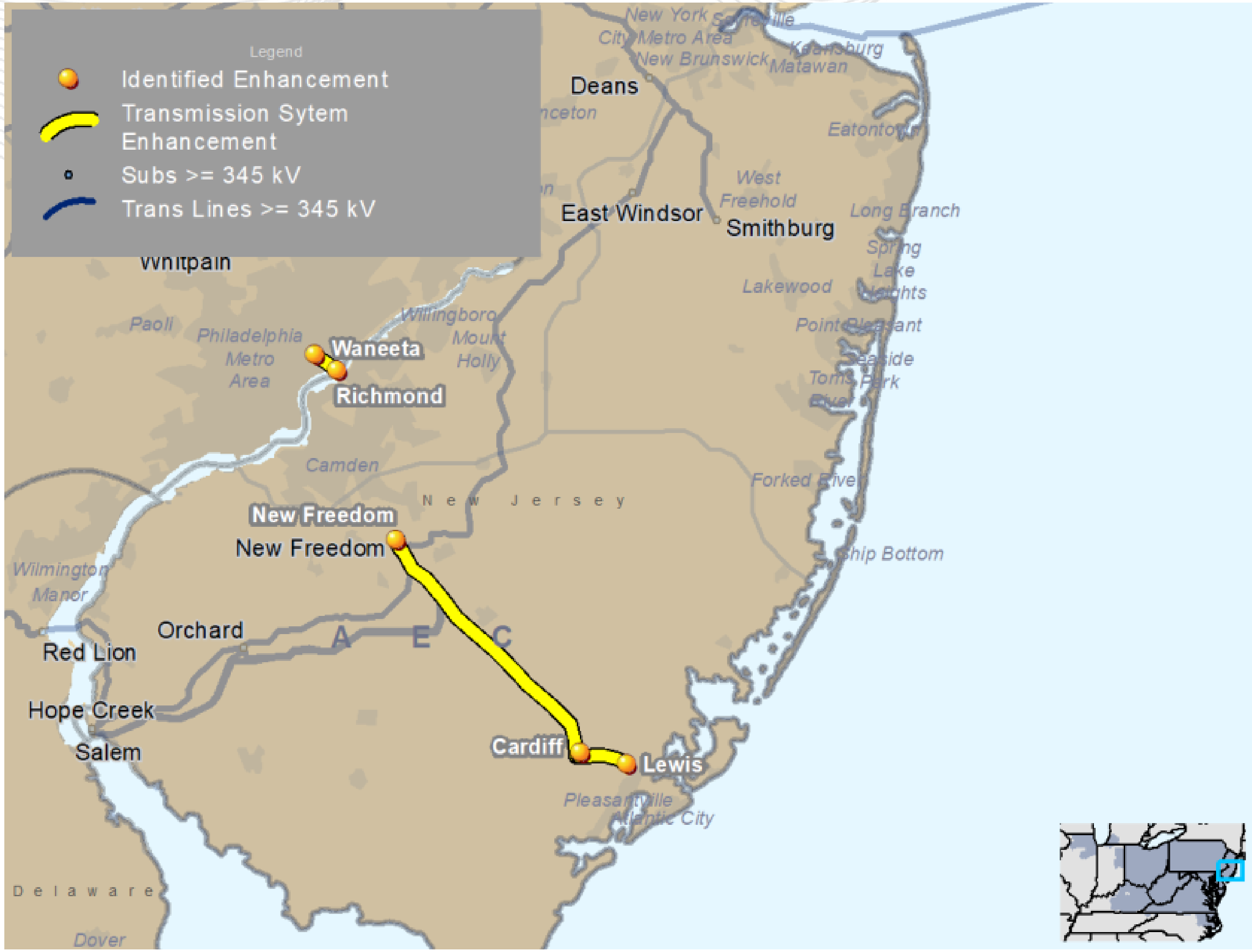
- Rebuild the underground portion of Richmond-Waneeta 230 kV (b3737.23)

Required IS Date (b3737.23): 6/1/2029

- Upgrade Cardiff-Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation (b3737.24)
- Upgrade Lewis No. 2-Lewis No. 1 138 kV by replacing its bus tie with 2000 A circuit breaker (b3737.25)
- Upgrade Cardiff-New Freedom 230 kV by modifying existing relay setting to increase relay limit (b3737.26)

Required IS Date (b3737.24-.26): 4/30/2028

Estimated Cost (b3737.23-.26): $16.9 M



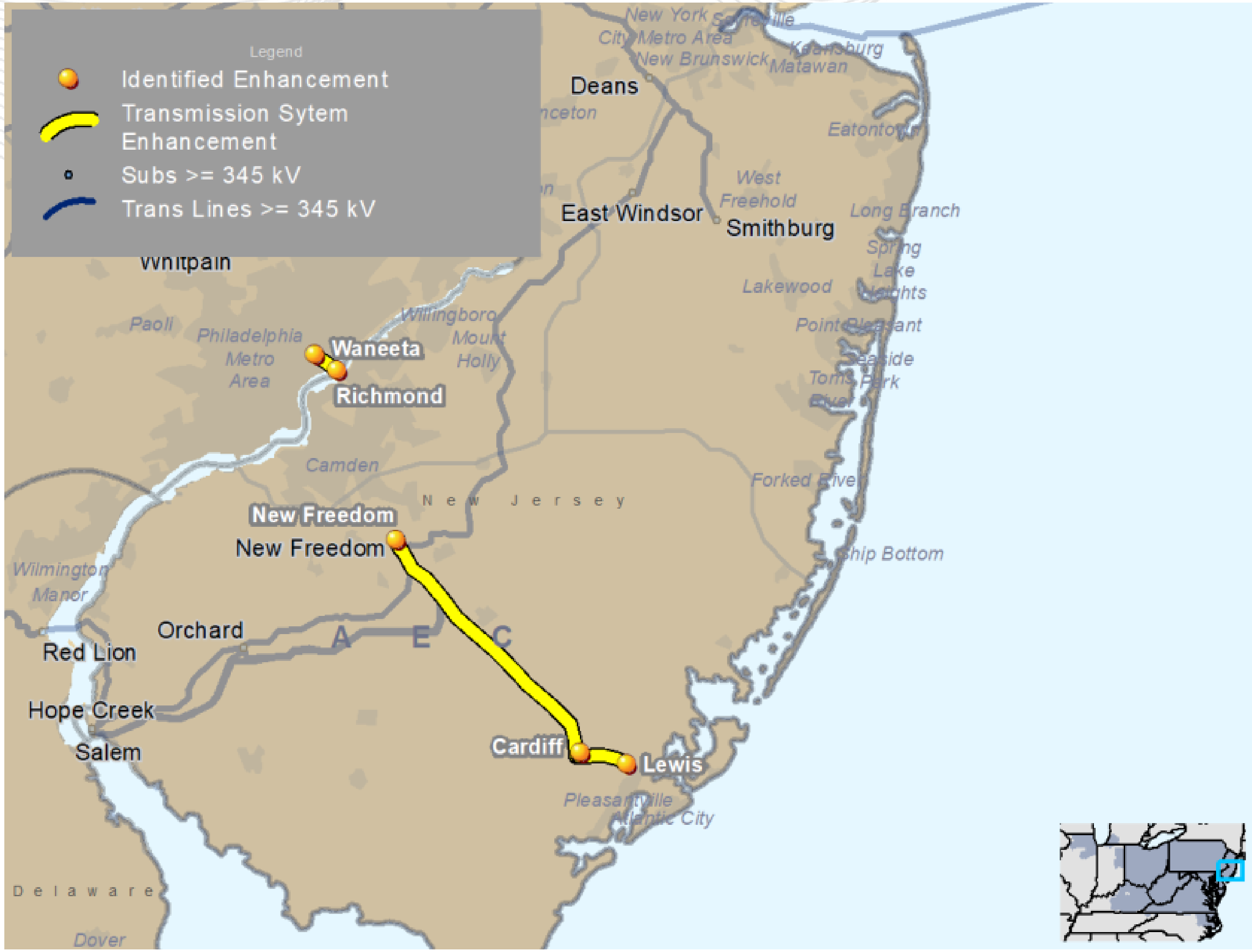
AE Transmission Zone: Baseline NJ SAA Project

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Richmond-Waneeta 230 kV	760/1180/803/1201
Cardiff-Lewis 138 kV	315/400/449/543
Lewis No. 2-Lewis No. 1 138 kV	286.8/286.8/286.8/286.8
Cardiff-New Freedom 230 kV	650/692/692/692

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Richmond-Waneeta 230 kV	1098/1247/1150/1299
Cardiff-Lewis 138 kV	377/478/451/478
Lewis No. 2-Lewis No. 1 138 kV	478/478/478/478
Cardiff-New Freedom 230 kV	650/804/748/906



JCPL Transmission Zone: Baseline NJ SAA Project

Criteria: Summer & Winter Generator Deliverability

Problem Statement:

The Clarksville-Lawrence 230 kV, Kilmer I-Lake Nelson I 230 kV, Smithburg-Windsor 230 kV, Smithburg-Deans 500 kV lines and Smithburg 500/230 kV No. 1 and No. 2 transformers are overloaded for N-2 outages.

Recommended Solution: Option 1a – Proposal 17 (Partial)

- Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63 (b3737.27) - ~~$11.45 M~~ $14.58M
- Reconductor Kilmer I-Lake Nelson I 230 kV (b3737.28) - $4.42 M

Required IS Date (b3737.27-.28): 6/1/2029

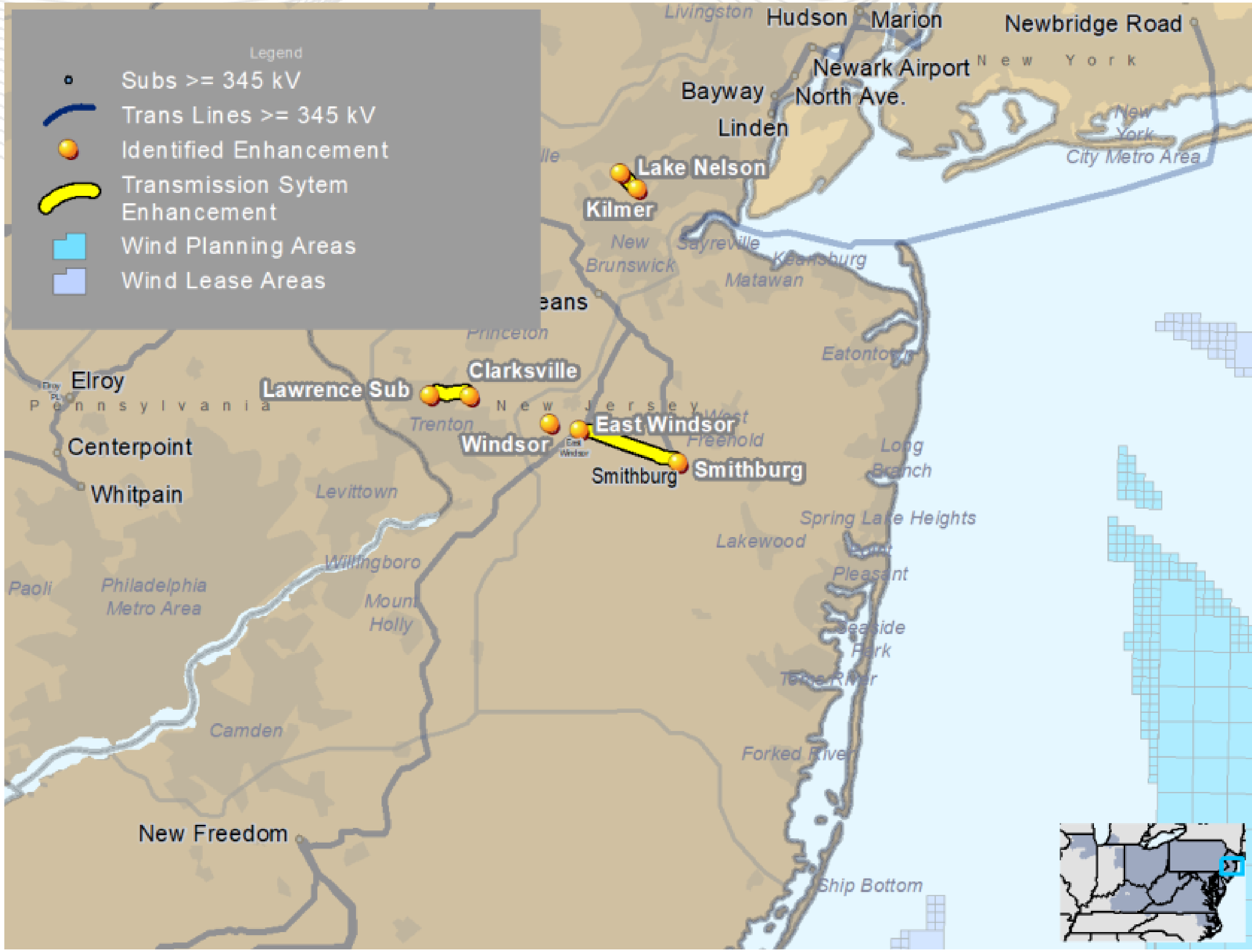
- Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line (b3737.29) - $206.48 M

Required IS Date (b3737.29): 12/31/2028

- Add third Smithburg 500/230 kV transformer (b3737.30) - $13.4 M

Required IS Date (b3737.30): 12/31/2027

Estimated Cost (b3737.27-.30): ~~$235.75 M~~ $238.88 M



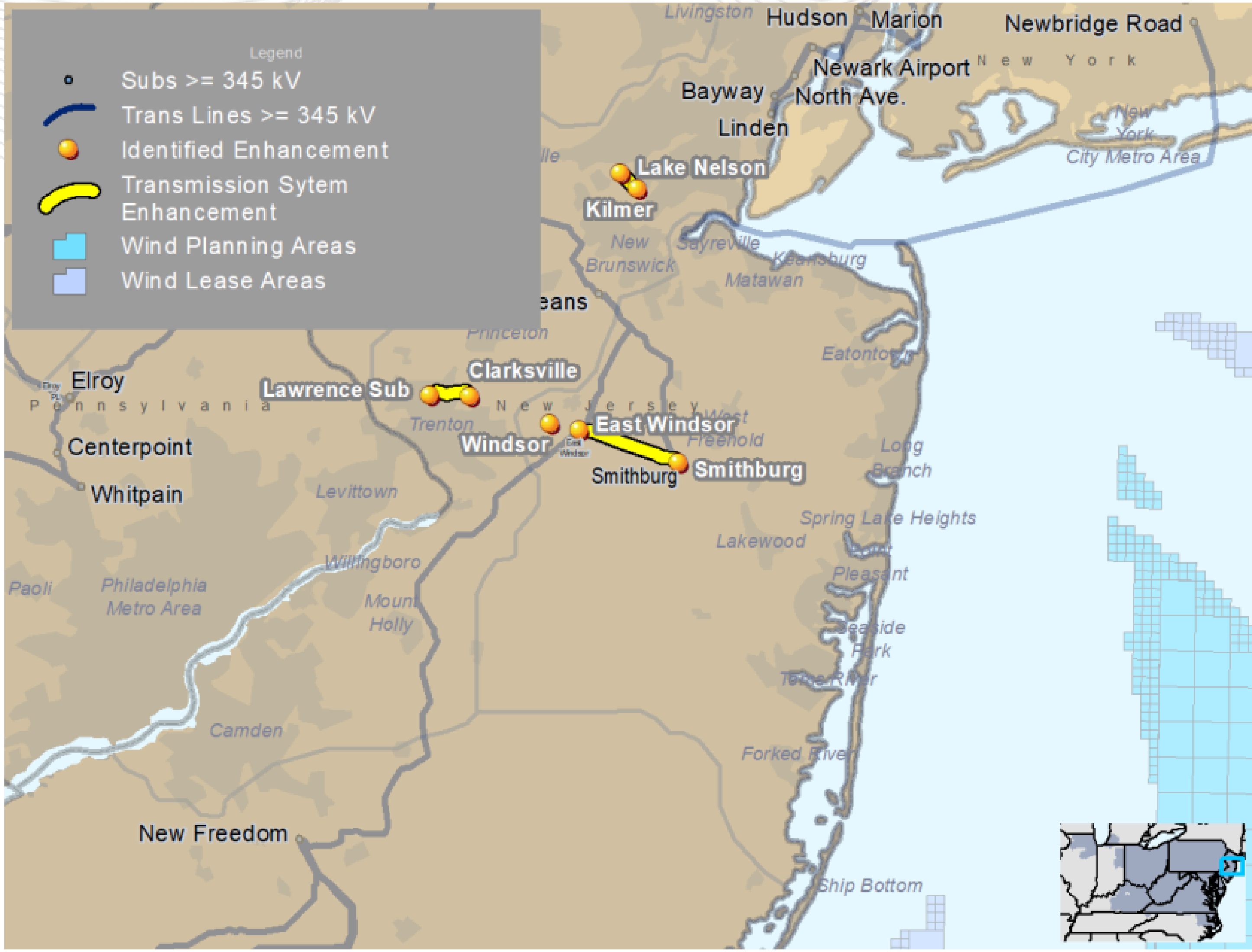
JCPL Transmission Zone: Baseline NJ SAA Project

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Clarksville-Lawrence 230 kV	709/869/805/1031
Kilmer I-Lake Nelson I 230 kV	709/869/805/1031

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Clarksville-Lawrence 230 kV	1140/1387/1342/1495
Kilmer I-Lake Nelson I 230 kV	1136/1311/1139/1379
Smithburg-East Windsor 500 kV	3678/4541/4262/5503
Smithburg 500/230 kV Transformer	1034/1287/1036/1451



JCPL Transmission Zone: Baseline NJ SAA Project

Criteria: Winter Generator Deliverability

Problem Statement:

The Lake Nelson I-Middlesex 230 kV line is overloaded for an N-1 outage.

Recommended Solution: Option 1a – Proposal Email 12/30/21

- Additional reconductoring required for Lake Nelson I-Middlesex 230 kV (b3737.31) - $3.3 M
- Middlesex Substation 230kV - Replace the 2000A Circuit Switcher at Middlesex Switch point for the Lake Nelson I1023 230kV exit **(b3737.55)** - $0.53 M

Required IS Date (b3737.31): 6/1/2029

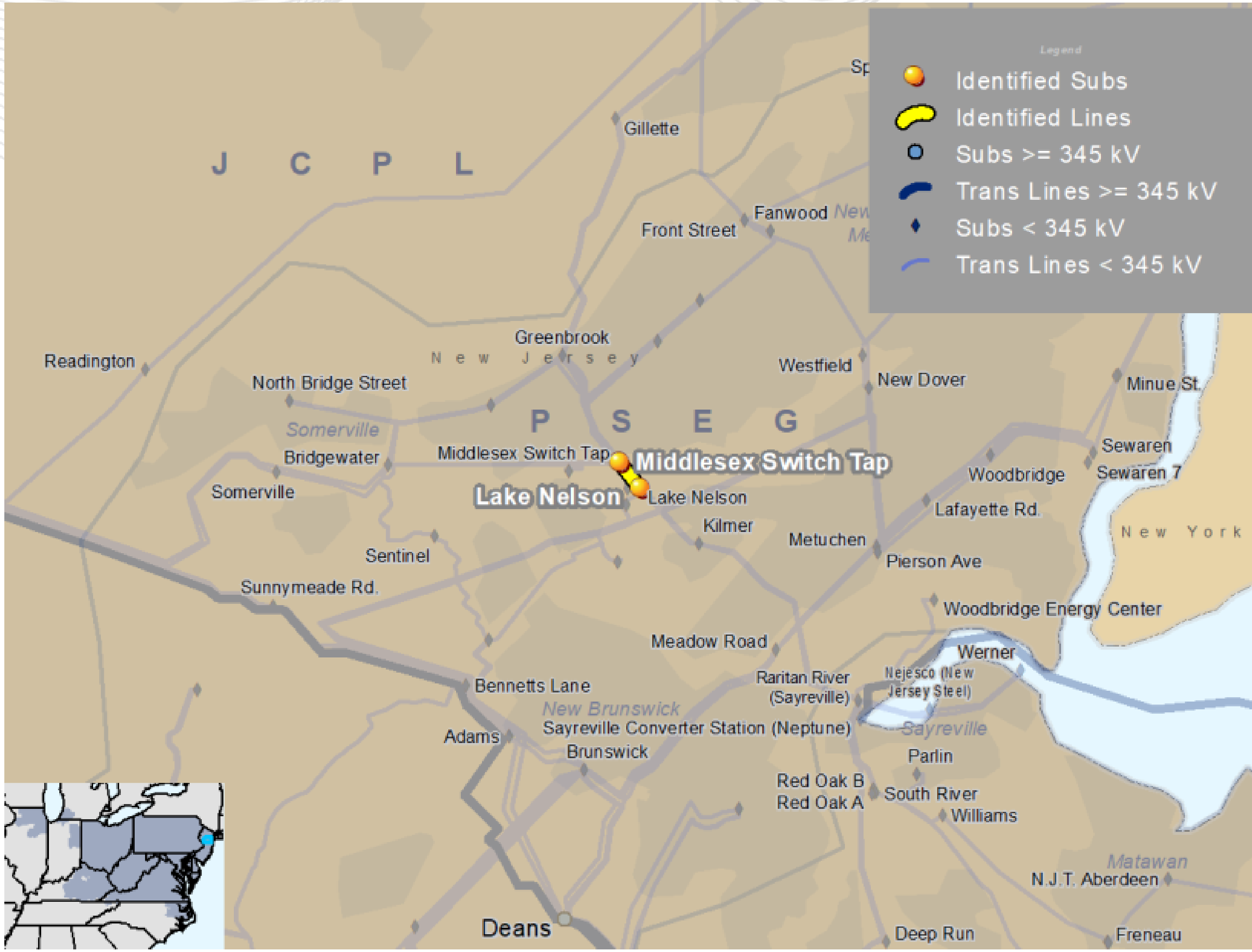
Estimated Cost (b3737.31): ~~$3.3 M~~ $3.83 M

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Lake Nelson I-Middlesex 230 kV	709/819/797/819

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Lake Nelson I-Middlesex 230 kV	1114/1285/1116/1352



JCPL Transmission Zone: Baseline NJ SAA Project

Criteria: Summer & Winter Generator Deliverability

Problem Statement:

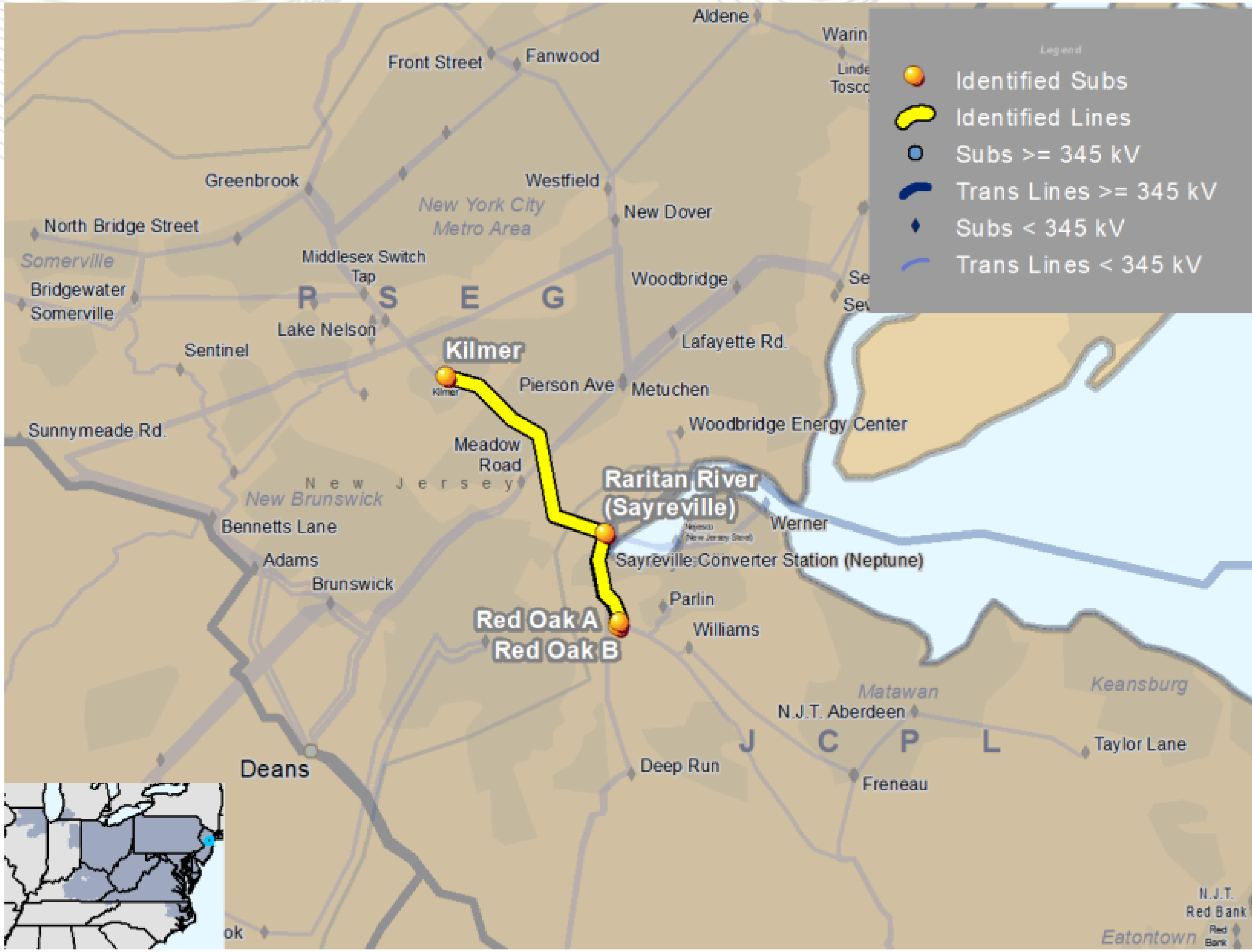
The Raritan River-Kilmer I 230 kV line is overloaded for an N-1 outage, and the Raritan River-Kilmer W 230 kV, Red Oak A-Raritan River 230 kV and Red Oak B-Raritan River 230 kV lines are overloaded for N-2 outages.

Recommended Solution: Option 1a – Proposal Email 2/11/2022

- Reconductor Red Oak A-Raritan River 230 kV (b3737.33) - ~~$11.05 M~~ $12.53 M
- Reconductor Red Oak B-Raritan River 230 kV (b3737.34) - $3.9 M
- Reconductor small section of Raritan River-Kilmer I 230 kV (b3737.35) - ~~$0.2 M~~ $27.3 M
- Replace substation conductor at Kilmer and reconductor Raritan River-Kilmer W 230 kV (b3737.36) - $25.88 M

Required IS Date (b3737.33-.36): 6/1/2029

Estimated Cost (b3737.33-.36): ~~$41.03 M~~ $69.61



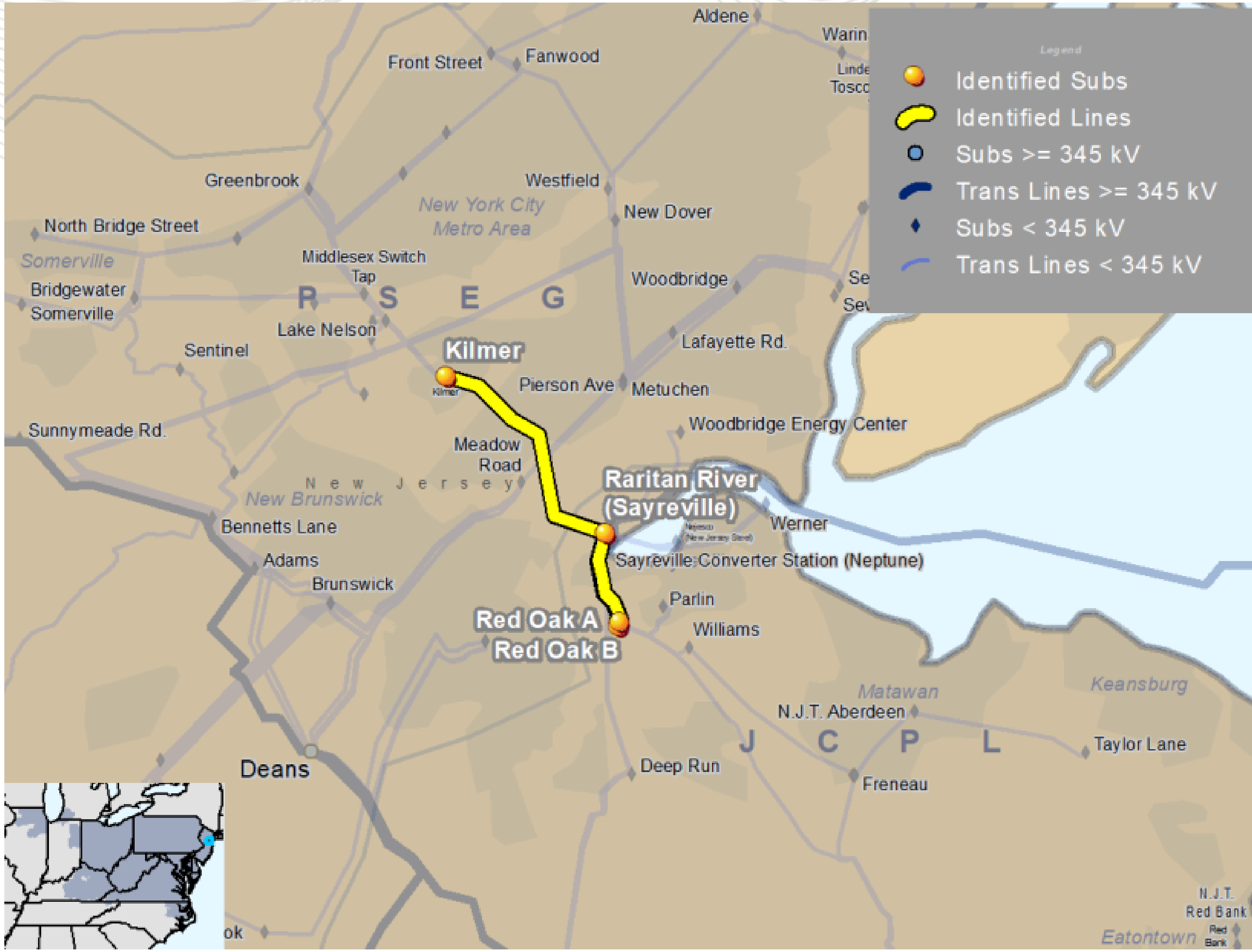
JCPL Transmission Zone: Baseline NJ SAA Project

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Raritan River-Kilmer I 230 kV	709/869/805/1031
Raritan River-Kilmer W 230 kV	650/817/785/943
Red Oak A-Raritan River 230 kV	709/869/805/1031
Red Oak B-Raritan River 230 kV	709/869/805/1031

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Raritan River-Kilmer I 230 kV	1156/1334/1158/1403
Raritan River-Kilmer W 230 kV	1156/1334/1158/1403
Red Oak A-Raritan River 230 kV	1156/1334/1158/1403
Red Oak B-Raritan River 230 kV	1156/1334/1158/1403



LS Power in DPL & PSEG Transmission Zones: Baseline NJ SAA Project

Criteria: Winter Generator Deliverability

Problem Statement:

The Hope Creek-LS Power Cable East 230 kV No. 1 and No. 2 lines are overloaded for an N-1 outage, and the LS Power Cable East-LS Power Silver Run 230 kV line is overloaded for an N-2 outage.

Recommended Solution: Option 1a – Proposal 229

- Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line (b3737.37)

Required IS Date (b3737.37): 6/1/2029

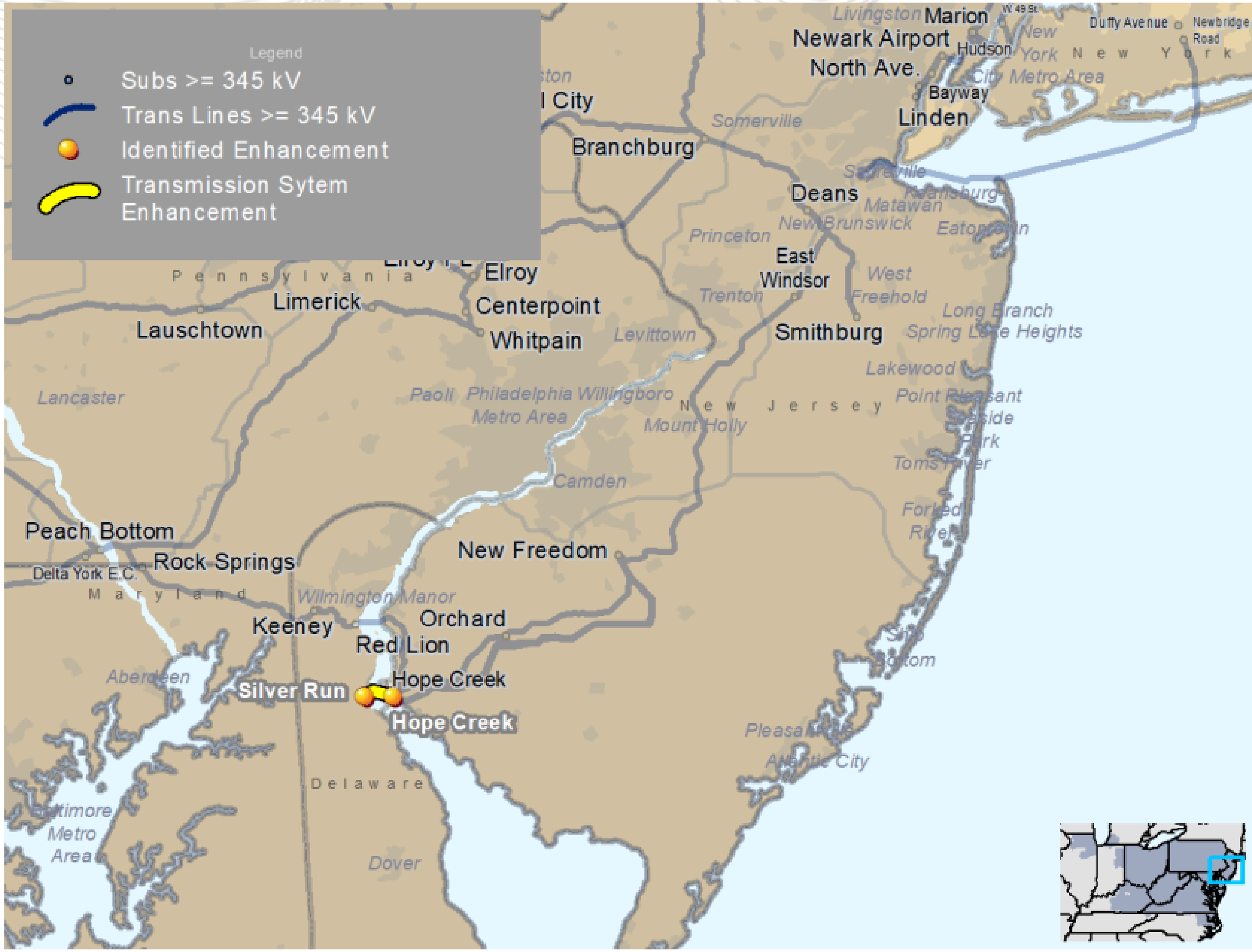
Estimated Cost (b3737.37): $61.2 M

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Hope Creek-LS Power Cable East 230 kV No. 1 and No. 2	470/575/470/575
LS Power Cable East-LS Power Silver Run 230 kV	940/1150/940/1150

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Hope Creek-Silver Run 230 kV	1364/1614/1364/1614



PSEG & JCPL Transmission Zone: Baseline NJ SAA Project

Criteria: Summer Generator Deliverability

Problem Statement:

The Linden-Tosco 230 kV and Windsor-Clarksville 230 kV lines are overloaded for N-2 outages.

Recommended Solution: Option 1a – Proposal 180 (Partial)

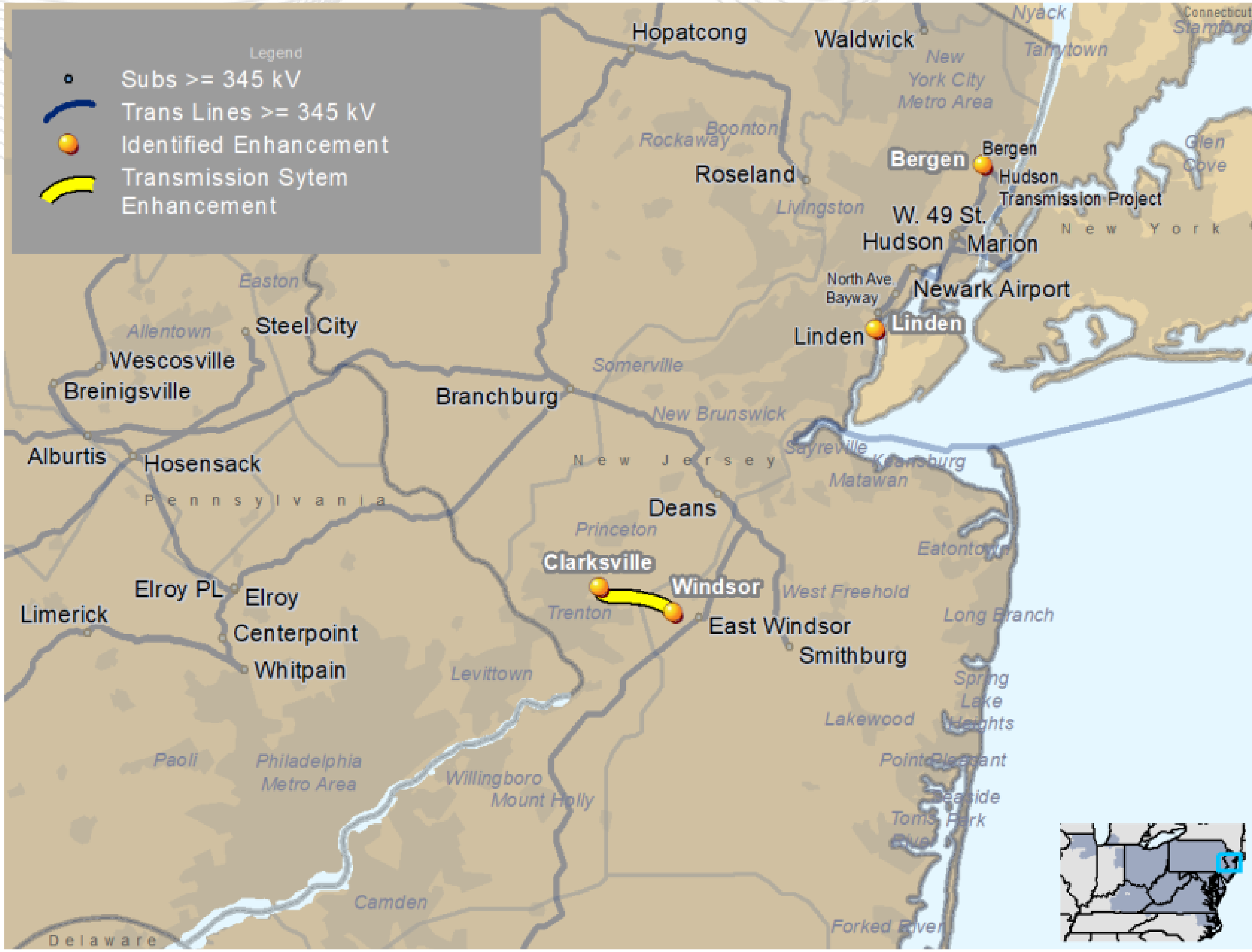
- Linden Subproject: Install a new 345/230 kV transformer at the Linden 345 kV Switching Station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV (b3737.38) - ~~$24.92 M~~ $35.3 M
- Bergen Subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work (b3737.39) - $5.53

Required IS Date (b3737.38-.39): 12/31/2027

- Windsor to Clarksville Subproject: ~~Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV~~ Reconductor one span of the C1017 (Clarksville-Windsor) 230kV line from structure #126 to Windsor Substation with double bundled 1590 ACSR conductor, approximately (0.1) mile. (b3737.40) - ~~$4.28 M~~ $1.72 M
- Windsor to Clarksville Subproject: Upgrade ~~all~~ terminal equipment at ~~Windsor 230 kV and~~ Clarksville 230 kV ~~as necessary to create a paired conductor path between Clarksville and JCPL East Windsor Switch 230 kV~~ (b3737.41) - $1.49 M
- Windsor to Clarksville Subproject: Upgrade terminal equipment at Windsor 230 kV **(b3737.59)** - $1.58 M

Required IS Date (b3737.40-.41, 59): 6/1/2029

Estimated Cost (b3737.38-.41, 59): ~~$36.22 M~~ $45.62 M



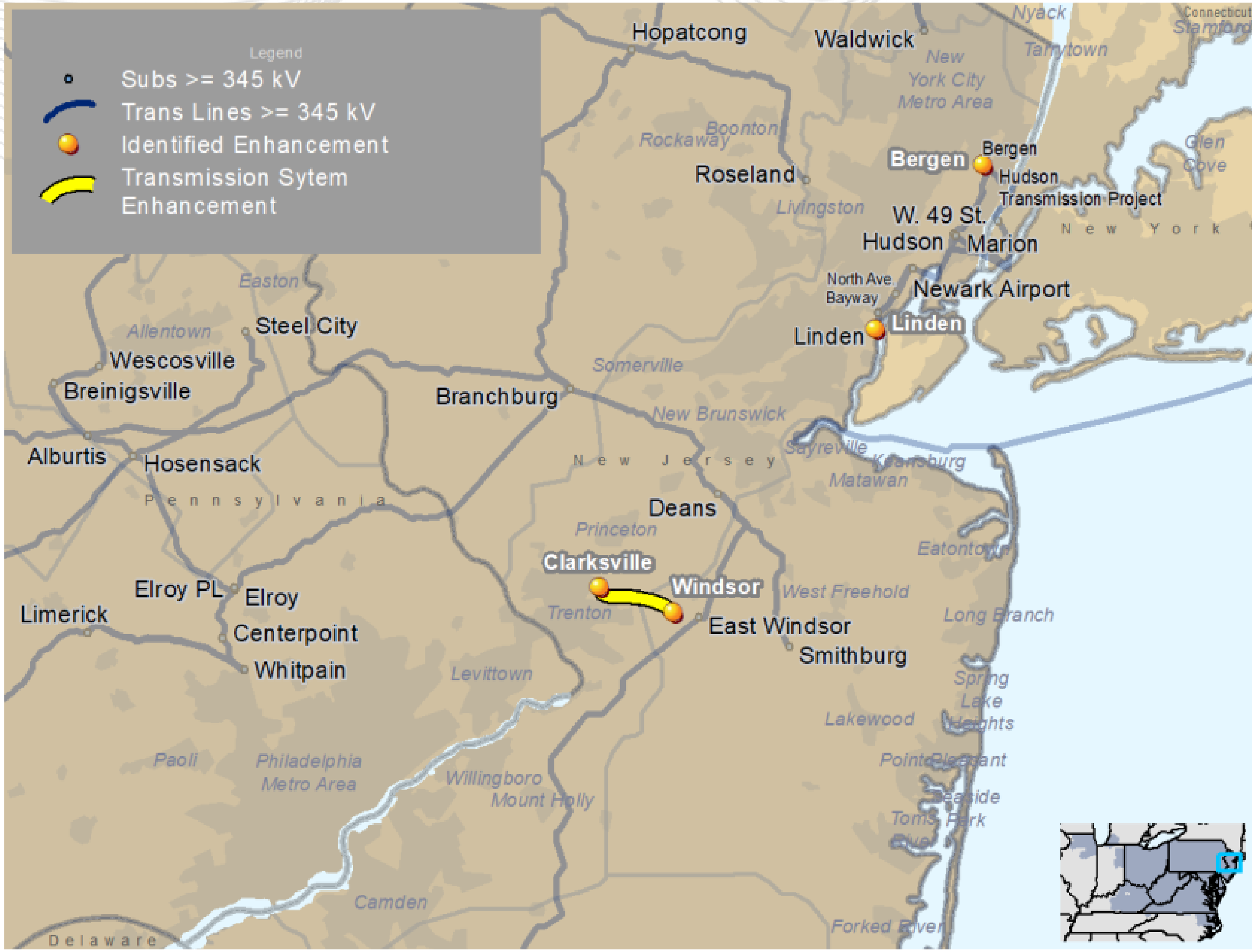
PSEG & JCPL Transmission Zone: Baseline NJ SAA Project

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Windsor-Clarksville 230 kV	678/813/805/929

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
New Linden 345/230 kV transformer	913/1080/999/1143
Windsor-Clarksville 230 kV	1356/1626/1610/1858



PSEG Transmission Zones: Baseline NJ SAA Project

Criteria: Summer & Winter Generator Deliverability

Problem Statement:

The Kilmer-Lake Nelson I and W 230 kV lines are overloaded for an N-1 and an N-2 outage, and the Lake Nelson-Middlesex-Greenbrook W 230 kV line is overloaded for an N-1 outage.

Recommended Solution: Option 1a – Proposal Email 2/4/2022 & 3/11/2022

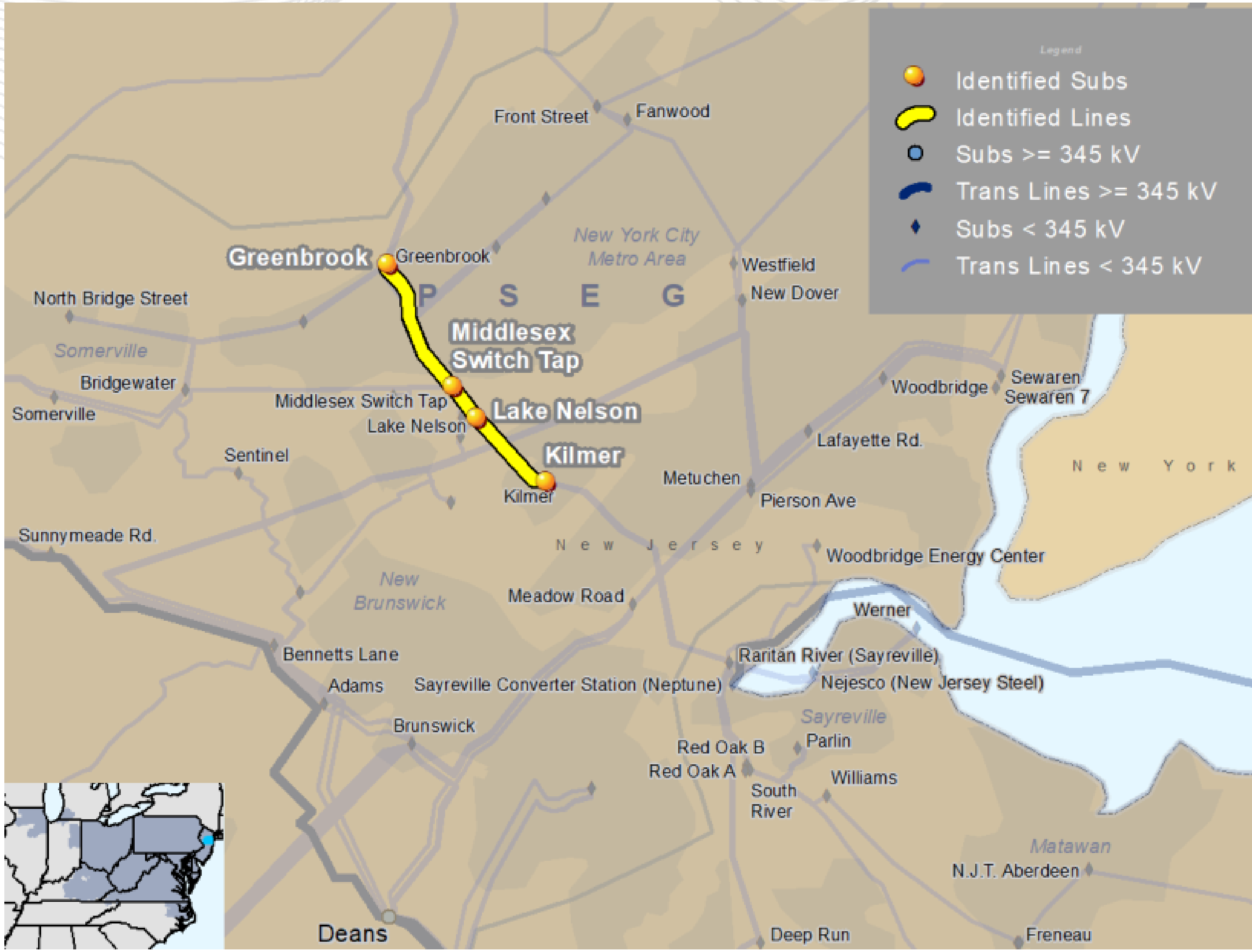
- Upgrade inside plant equipment at Lake Nelson I 230 kV (b3737.42) - ~~$3.8 M~~ $4.8 M
- Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV (b3737.43) - ~~$0.16 M~~ $0.57 M
- Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV (b3737.44) - ~~$0.12 M~~ $0.58 M

Required IS Date (b3737.42-.44): 6/1/2029

Estimated Cost (b3737.42-.44): ~~$4.08 M~~ $5.95 M

Existing Facility Ratings:

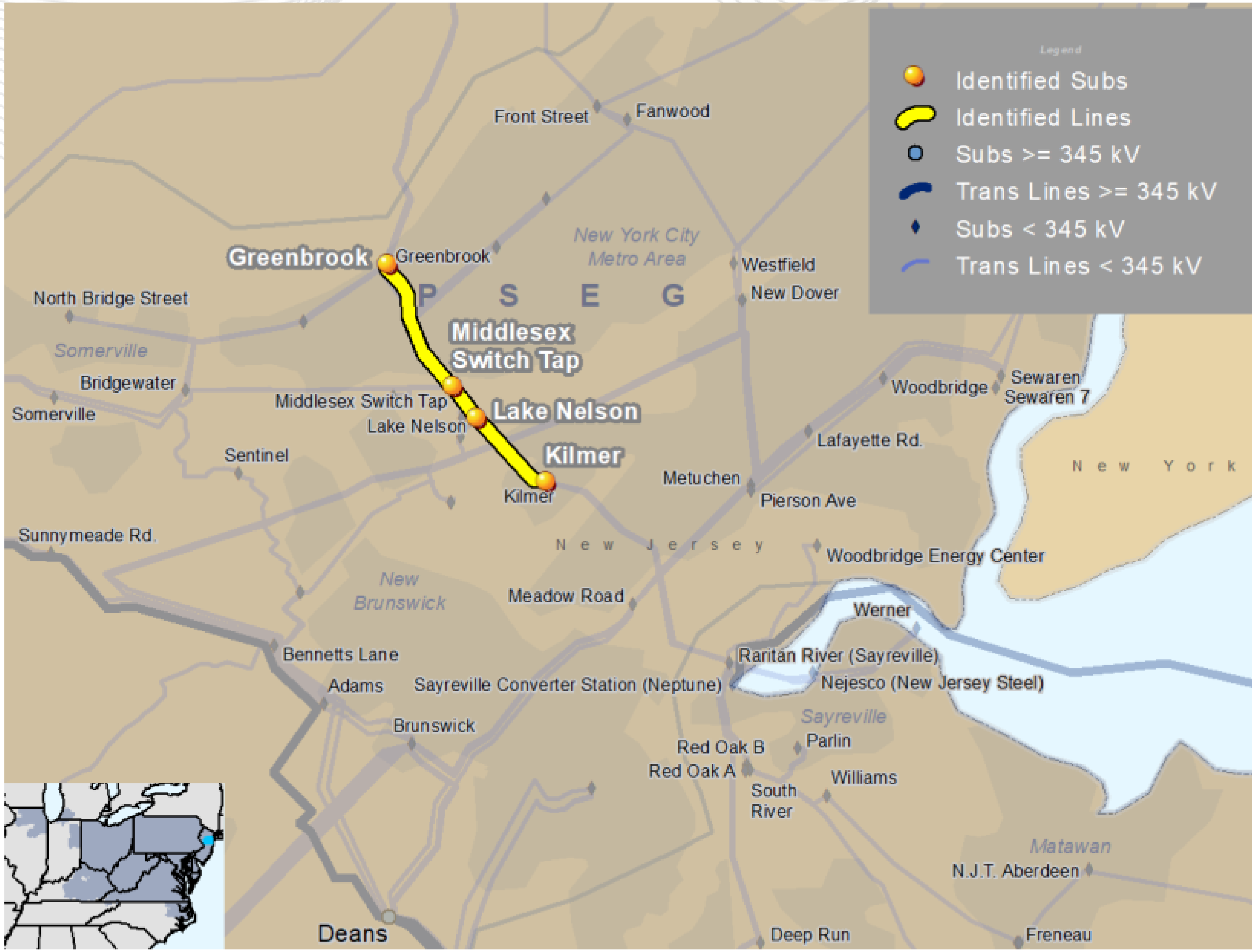
Branch	SN/SE/WN/WE (MVA)
Kilmer-Lake Nelson I 230 kV	704/869/805/1031
Kilmer-Lake Nelson W 230 kV	523/679/644/804
Lake Nelson-Middlesex-Greenbrook W 230 kV	732/887/823/980



PSEG Transmission Zones: Baseline NJ SAA Project

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Kilmer-Lake Nelson I 230 kV	1378/1625/1475/1723
Kilmer-Lake Nelson W 230 kV	934/1080/999/1143
Lake Nelson-Middlesex-Greenbrook W 230 kV	934/1080/999/1143



PPL Transmission Zones: Baseline NJ SAA Project

Criteria: Winter Generator Deliverability

Problem Statement:

The Gilbert-Springfield 230 kV line is overloaded for an N-1 outage.

Recommended Solution: Option 1a – Proposal 330

- Reconductor 0.33 miles of PPL's portion of the Gilbert-Springfield 230 kV line (b3737.45)

Required IS Date (b3737.45): 6/1/2030

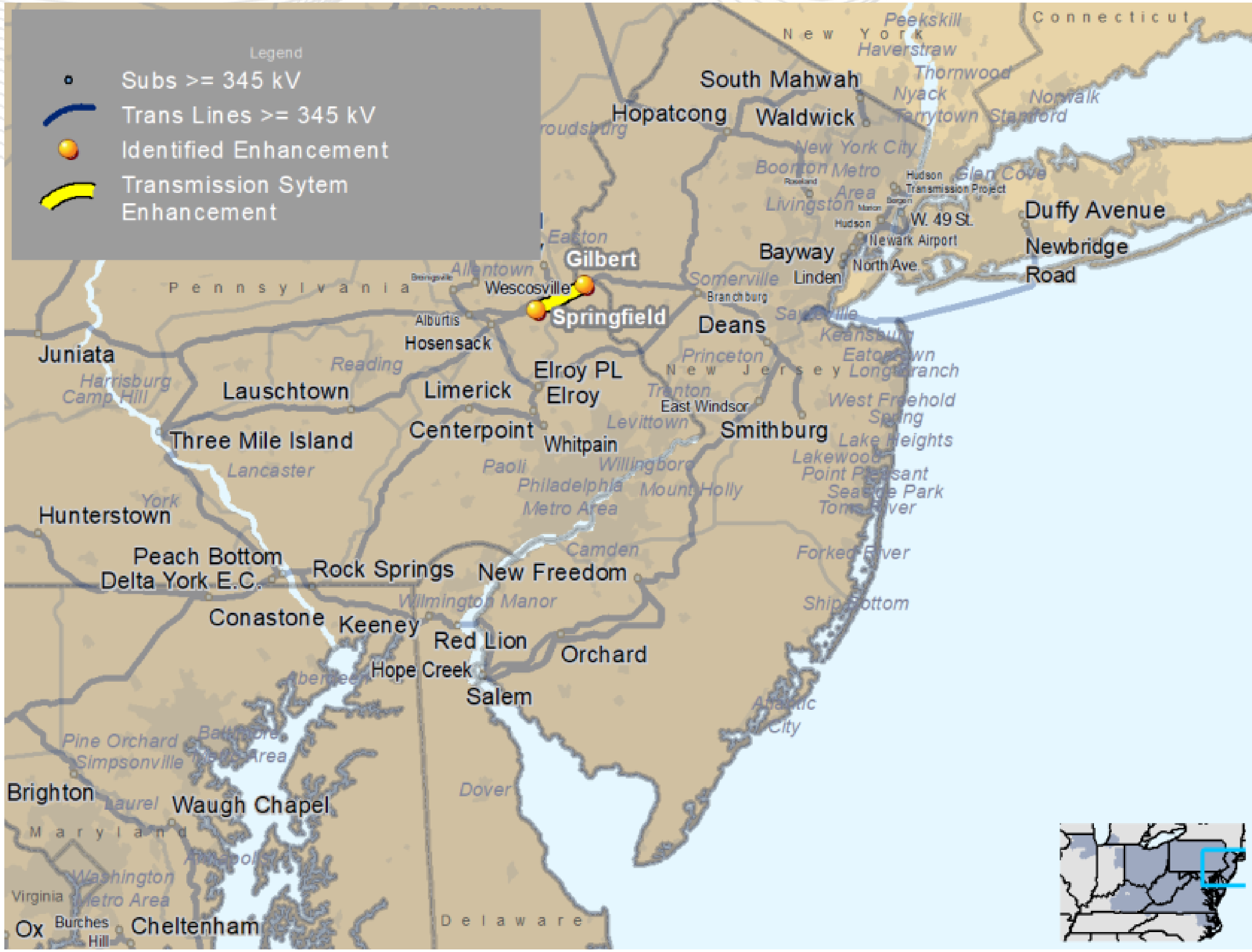
Estimated Cost (b3737.45): $0.38 M

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Gilbert-Springfield 230 kV	647/801/746/903

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Gilbert-Springfield 230 kV	830/954/939/1087



Transource in BGE, ME & PPL Transmission Zones: Baseline NJ SAA Project

Criteria: Winter Generator Deliverability

Problem Statement:

The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded for N-1 outages.

Recommended Solution: Option 1a – Proposal 63

- Install a new 63 kA breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta Station (b3737.46) – BGE - $1.55 M
- Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high side and five low side breakers in ring bus configuration) (b3737.47) – Transource - $76.27 M
- Build a new North Delta-Graceton 230 kV line by rebuilding ~~6.07~~ 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for PECO's portion of the line rebuild which is 4.1 miles. (b3737.48) – PECO - ~~$28.74 M~~ $18.82 M
- Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild which is 2.16 miles. **(b3737.56)** - $9.92 M
- Bring the Copper- Graceton 230 kV line "in and out" of North Delta by constructing a new double-circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines (b3737.49) – PECO - $1.56 M
- Bring the Peach Bottom-Delta Power Plant 500 kV line "in and out" of North Delta by constructing a new Peach Bottom-North Delta 500 kV (0.3 miles) cut-in and cut-out lines (b3737.50) – PECO - $1.56 M

Transource in BGE, ME & PPL Transmission Zones: Baseline NJ SAA Project

Recommended Solution (cont.): Option 1a – Proposal 63

- ~~Replace four 63 kA circuit breakers “205”, “235”, “225” and “255” at Peach Bottom 500 kV with 80 kA (b3737.51) – PECO - $5.6 M~~
- Replace one 63 kA circuit breaker “B4” at Conastone 230 kV with 80 kA (b3737.52) – BGE - $1.3 M

Required IS Date (b3737.46-52): 6/1/2029

Estimated Cost (b3737.46-52): ~~$116.58 M~~ $110.98 M

Existing Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
Peach Bottom-Delta-Delta Power Plant 500 kV	2338/2931/3062/3480
Cooper-Graceton 230 kV	463/578/521/639

Preliminary Facility Ratings:

Branch	SN/SE/WN/WE (MVA)
North Delta 500/230 kV Transformers	1500/1875/1875/2025
Peach Bottom-North Delta 500 kV	2338/2931/3062/3480
North Delta-Delta Power Plant 500 kV	2338/2931/3062/3480
Cooper-North Delta 230 kV	463/578/521/639
North Delta-Graceton 230 kV No.1 & 2	1295/1863/1642/2077

Total Estimated Cost (b3737): ~~$1,064.36 M~~ $1,191.70 M

Contact

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Reliability Analysis Update

Member Hotline

(610) 666 – 8980

(866) 400 – 8980

custsvc@pjm.com

Revision History

Version No.	Date	Description
1	May 4th 2023	• Original slides posted

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Report suspicious email activity to PJM.
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Exhibit No. MAOD-9
Mid-Atlantic Offshore Development, LLC
PJM-MAOD DEA

DESIGNATED ENTITY AGREEMENT

Between

PJM Interconnection, L.L.C.

And

Mid-Atlantic Offshore Development, LLC

PJM RTEP Projects b3737.22 & b3737.60:
New Jersey SAA - Larrabee Collector Station (LCS)

DESIGNATED ENTITY AGREEMENT

Between

PJM Interconnection, L.L.C.

And

Mid-Atlantic Offshore Development, LLC

This Designated Entity Agreement, including the Schedules attached hereto and incorporated herein (collectively, "Agreement") is made and entered into as of the Effective Date between PJM Interconnection, L.L.C. ("Transmission Provider" or "PJM"), and Mid-Atlantic Offshore Development, LLC ("Designated Entity" or "MAOD"), referred to herein individually as "Party" and collectively as "the Parties."

WITNESSETH

WHEREAS, in accordance with FERC Order No. 1000 and Schedule 6 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), Transmission Provider is required to designate among candidates, pursuant to a FERC-approved process, an entity to develop and construct a specified project to expand, replace and/or reinforce the Transmission System operated by Transmission Provider;

WHEREAS, pursuant to Section 1.5.8(i) of Schedule 6 of the Operating Agreement, the Transmission Provider notified Designated Entity that it was designated as the Designated Entity for the Project (described in Schedule A to this Agreement) to be included in the Regional Transmission Expansion Plan;

WHEREAS, pursuant to Section 1.5.8(j) of Schedule 6 of the Operating Agreement, Designated Entity accepted the designation as the Designated Entity for the Project and therefore has the obligation to construct the Project; and

NOW, THEREFORE, in consideration of the mutual covenants herein contained, together with other good and valuable consideration, the receipt and sufficiency is hereby mutually acknowledged by each Party, the Parties mutually covenant and agree as follows:

Article 1 – Definitions

1.0 Defined Terms.

All capitalized terms used in this Agreement shall have the meanings ascribed to them in Part I of the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in the Tariff or defined terms in this Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

1.1 Confidential Information.

Any confidential, proprietary, or trade secret information of a plan, specification, pattern, procedure, design, device, list, concept, policy, or compilation relating to the Project or Transmission Owner facilities to which the Project will interconnect, which is designated as confidential by the party supplying the information, whether conveyed verbally, electronically, in writing, through inspection, or otherwise, and shall include, but may not be limited to, information relating to the producing party's technology, research and development, business affairs and pricing, land acquisition and vendor contracts relating to the Project.

1.2 Designated Entity Letter of Credit.

Designated Entity Letter of Credit shall mean the letter of credit provided by the Designated Entity pursuant to Section 1.5.8(j) of Schedule 6 of the Operating Agreement and Section 3.0 of this Agreement as security associated with the Project.

1.3 Development Schedule.

Development Schedule shall mean the schedule of milestones set forth in Schedule C of this Agreement.

1.4 Effective Date.

Effective Date shall mean the date this Agreement becomes effective pursuant to Section 2.0 of this Agreement.

1.5 Initial Operation.

Initial Operation shall mean the date the Project is (i) energized and (ii) under Transmission Provider operational dispatch.

1.6 Project.

Project shall mean the enhancement or expansion included in the PJM Regional Transmission Expansion Plan described in Schedule A of this Agreement.

1.7 Project Finance Entity.

Project Finance Entity shall mean holder, trustee or agent for holders, of any component of Project Financing.

1.8 Project Financing.

Project Financing shall mean: (a) one or more loans, leases, equity and/or debt financings, together with all modifications, renewals, supplements, substitutions and replacements thereof, the proceeds of which are used to finance or refinance the costs of the Project, any alteration, expansion or improvement to the Project, or the operation of the Project; or (b) loans and/or debt issues secured by the Project.

1.9 Reasonable Efforts.

Reasonable Efforts shall mean such efforts as are consistent with ensuring the timely and effective design and construction of the Project in a manner, which ensures that the Project, once placed in service, meets the requirements of the Project as described in Schedule B and are consistent with Good Utility Practice.

1.10 Required Project In-Service Date.

Required Project In-Service Date shall mean the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedules B this Agreement, (ii) meet the criteria outlined in Schedule D of this Agreement and (iii) be under Transmission Provider operational dispatch.

Article 2 – Effective Date and Term

2.0 Effective Date.

Subject to regulatory acceptance, this Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is filed with FERC for acceptance, rather than reported only in PJM's Electric Quarterly Report, upon the date specified by FERC.

2.1 Term.

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Designated Entity executes the Consolidated Transmission Owners Agreement; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement, (b) meets all relevant required planning criteria, and (c) is under Transmission Provider's operational dispatch; or (iii) the Agreement is terminated pursuant to Article 8 of this Agreement.

Article 3 – Security

3.0 Obligation to Provide Security.

In accordance with Section 1.5.8(j) of Schedule 6 of the Operating Agreement, Designated Entity shall provide Transmission Provider a letter of credit as acceptable to Transmission Provider (Designated Entity Letter of Credit) or cash security in the amount of $5,807,700, which is three percent of the estimated cost of the Project. Designated Entity is required provide and maintain the Designated Entity Letter of Credit, as required by Section 1.5.8(j) of Schedule 6 of the Operating Agreement and Section 3.0 of this Agreement. The Designated Entity Letter of Credit shall remain in full force and effect for the term of this Agreement and for the duration of the obligations arising therefrom in accordance with Article 17.0.

3.1 Distribution of Designated Entity Letter of Credit or Cash Security.

In the event that Transmission Provider draws upon the Designated Entity Letter of Credit or retains the cash security in accordance with Sections 7.5, 8.0, or 8.1, Transmission Provider shall distribute such funds as determined by FERC.

Article 4 – Project Construction

4.0 Construction of Project by Designated Entity.

Designated Entity shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule B and the Development Schedule in Schedule C; (ii) applicable reliability principles, guidelines, and standards of the Applicable Regional Reliability Council and NERC; (iii) the Operating Agreement; (iv) the PJM Manuals; and (v) Good Utility Practice.

4.1 Milestones.

4.1.0 Milestone Dates.

Designated Entity shall meet the milestone dates set forth in the Development Schedule in Schedule C of this Agreement. Milestone dates set forth in Schedule C only may be extended by Transmission Provider in writing. Failure to meet any of the milestone dates specified in Schedule C, or as extended as described in this Section 4.1.0 or Section 4.3.0 of this Agreement, shall constitute a Breach of this Agreement. Transmission Provider reasonably may extend any such milestone date, in the event of delays not caused by the Designated Entity that could not be remedied by the Designated Entity through the exercise of due diligence, or if an extension will not delay the Required Project In-Service Date specified in Schedule C of this Agreement; provided that a corporate officer of the Designated Entity submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule C of this Agreement.

4.1.1 Right to Inspect.

Upon reasonable notice, Transmission Provider shall have the right to inspect the Project for the purposes of assessing the progress of the Project and satisfaction of milestones. Such inspection shall not be deemed as review or approval by Transmission Provider of any design or construction practices or standards used by the Designated Entity.

4.2 Applicable Technical Requirements and Standards.

For the purposes of this Agreement, applicable technical requirements and standards of the Transmission Owner(s) to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project to the extent that the provisions thereof relate to the interconnection of the Project to the Transmission Owner(s) facilities.

4.3 Project Modification.

4.3.0 Project Modification Process.

The Scope of Work and Development Schedule, including the milestones therein, may be revised, as required, in accordance with Transmission Provider's project modification process set forth in the PJM Manuals, or otherwise by Transmission Provider in writing. Such modifications may include alterations as necessary and directed by Transmission Provider to meet the system condition for which the Project was included in the Regional Transmission Expansion Plan.

4.3.1 Consent of Transmission Provider to Project Modifications.

Designated Entity may not modify the Project without prior written consent of Transmission Provider, including but not limited to, modifications necessary to obtain siting approval or necessary permits, which consent shall not be unreasonably withheld, conditioned, or delayed.

4.3.2 Customer Facility Interconnections And Transmission Service Requests.

Designated Entity shall perform or permit the engineering and construction necessary to accommodate the interconnection of Customer Facilities to the Project and transmission service requests that are determined necessary for such interconnections and transmission service requests in accordance with Parts IV and VI, and Parts II and III, respectively, of the Tariff.

4.4 Project Tracking.

The Designated Entity shall provide regular, quarterly construction status reports in writing to Transmission Provider. The reports shall contain, but not be limited to, updates and information specified in the PJM Manuals regarding: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project. Transmission Provider shall use such status reports to post updates regarding the progress of the Project.

4.5 Exclusive Responsibility of Designated Entity.

Designated Entity shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with applicable laws and regulations associated with the Project, including but not limited to obtaining all necessary permits, siting, and other regulatory approvals. Transmission Provider shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 5 – Coordination with Third-Parties

5.0 Interconnection Coordination Agreement with Transmission Owner(s).

By the dates specified in the Development Schedule in Schedule C of this Agreement, Designated Entity shall execute or request to file unexecuted with the Commission: (a) an Interconnection Coordination Agreement; and (b) an interconnection agreement among and between Designated Entity, Transmission Provider, and the Transmission Owner(s) to whose facilities the Project will interconnect.

5.1 Connection with Entities Not a Party to the Consolidated Transmission Owners Agreement.

Designated Entity shall not permit any part of the Project facilities to be connected with the facilities of any entity which is not: (i) a party to Consolidated Transmission Owners Agreement without an interconnection agreement that contains provisions for the safe and reliable interconnection and operation of such interconnection in accordance with Good Utility Practice, and principles, guidelines and standards of the Applicable Regional Reliability Council and NERC or comparable requirements of an applicable retail tariff or agreement approved by appropriate regulatory authority; or (ii) a party to a separate Designated Entity Agreement.

Article 6 – Insurance

6.0 Designated Entity Insurance Requirements.

Designated Entity shall obtain and maintain in full force and effect such insurance as is consistent with Good Utility Practice. The Transmission Provider shall be included as an Additional Insured in the Designated Entity's applicable liability insurance policies. The Designated Entity shall provide evidence of compliance with this requirement upon request by the Transmission Provider.

6.1 Subcontractor Insurance.

In accord with Good Utility Practice, Designated Entity shall require each of its subcontractors to maintain and, upon request, provide Designated Entity evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and hiring of contractors or subcontractors shall be the Designated Entity's discretion, but regardless of bonding or the existence or non-existence of insurance, the Designated Entity shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 7 – Breach and Default

7.0 Breach.

Except as otherwise provided in Article 10, a Breach of this Agreement shall include:

(a) The failure to comply with any term or condition of this Agreement, including but not limited to, any Breach of a representation, warranty, or covenant made in this Agreement, and failure to provide and maintain security in accordance with Section 3.0 of this Agreement;

(b) The failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule C of this Agreement, or as extended in writing as described in Sections 4.1.0 and 4.3.0 of this Agreement;

(c) Assignment of this Agreement in a manner inconsistent with the terms of this Agreement; or

(d) Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.

7.1 Notice of Breach.

In the event of a Breach, a Party not in Breach of this Agreement shall give written notice of such Breach to the breaching Party, and to any other persons, including a Project Finance Entity, if applicable, that the breaching Party identifies in writing prior to the Breach. Such notice shall set forth, in reasonable detail, the nature of the Breach, and where known and applicable, the steps necessary to cure such Breach.

7.2 Cure and Default.

A Party that commits a Breach and does not take steps to cure the Breach pursuant to Section 7.3 shall be in Default of this Agreement.

7.3 Cure of Breach.

The breaching Party may: (i) cure the Breach within thirty days from the receipt of the notice of Breach or other such date as determined by Transmission Provider to ensure that the Project meets its Required Project In-Service Date set forth in Schedule C; or, (ii) if the Breach cannot be cured within thirty days but may be cured in a manner that ensures that the Project meets the Required Project In-Service Date for the Project, within such thirty day time period, commences in good faith steps that are reasonable and appropriate to cure the Breach and thereafter diligently pursue such action to completion.

7.4 Re-evaluation if Breach Not Cured.

In the event that a breaching Party does not cure a Breach in accordance with Section 7.3 of this Agreement, Transmission Provider shall conduct a re-evaluation pursuant to Section 1.5.8(k) of Schedule 6 of the Operating Agreement. If based on such re-evaluation, the Project is retained in the Regional Transmission Expansion Plan and the Designated Entity's designation for the Project also is retained, the Parties shall modify this Agreement, including Schedules, as necessary. In all other events, Designated Entity shall be considered in Default of this Agreement, and this Agreement shall terminate in accordance with Section 8.1 of this Agreement.

7.5 Remedies.

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Upon Default by Designated Entity, Transmission Provider may draw upon the Designated Entity Letter of Credit. Nothing in this Section 7.5 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Designated Entity resulting from Designated Entity's Default of this Agreement.

7.6 Remedies Cumulative.

No remedy conferred by any provision of this Agreement is intended to be exclusive of any other remedy and each and every remedy shall be cumulative and shall be in addition to every other remedy given hereunder or now or hereafter existing at law or in equity or by statute or otherwise. The election of any one or more remedies shall not constitute a waiver of the right to pursue other available remedies.

7.7 Waiver.

Any waiver at any time by any Party of its rights with respect to a Breach or Default under this Agreement, or with respect to any other matters arising in connection with this Agreement, shall not be deemed a waiver or continuing waiver with respect to any other Breach or Default or other matter.

Article 8 – Early Termination

8.0 Termination by Transmission Provider.

In the event that: (i) pursuant to Section 1.5.8(k) of Schedule 6 of the Operating Agreement, Transmission Provider determines to remove the Project from the Regional Transmission Expansion Plan and/or not to retain Designated Entity's status for the Project; (ii) Transmission Provider otherwise determines pursuant to Regional Transmission Expansion Planning Protocol in Schedule 6 of the Operating Agreement that the Project is no longer required to address the specific need for which the Project was included in the Regional Transmission Expansion Plan; or (iii) an event of force majeure, as defined in section 10.0 of this Attachment KK, or other event outside of the Designated Entity's control that, with the exercise of Reasonable Efforts, Designated Entity cannot alleviate and which prevents the Designated Entity from satisfying its obligations under this Agreement, Transmission Provider may terminate this Agreement by providing written notice of termination to Designated Entity, which shall become effective the later of sixty calendar days after the Designated Entity receives such notice or other such date the FERC establishes for the termination. In the event termination pursuant to this Section 8.0 is based on (ii) or (iii) above, Transmission Provider shall not have the right to draw upon the Designated Entity Letter of Credit or retain the cash security and shall cancel the Designated Entity Letter of Credit or return the cash security within thirty days of the termination of this Agreement.

8.1 Termination by Default.

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Sections 7.2 or 7.4 of this Agreement. Upon Default by Designated Entity, Transmission Provider may draw upon the Designated Entity Letter of Credit or retain the cash security.

8.2 Filing at FERC.

Transmission Provider shall make the appropriate filing with FERC as required to effectuate the termination of this Agreement pursuant to this Article 8.

Article 9 – Liability and Indemnity

9.0 Liability.

For the purposes of this Agreement, Transmission Provider's liability to the Designated Entity, any third-party, or any other person arising or resulting from any acts or omissions associated in any way with performance under this Agreement shall be limited in the same manner and to the same extent that Transmission Provider's liability is limited to any Transmission Customer, third-party or other person under Section 10.2 of the Tariff arising or resulting from any act or omission in any way associated with service provided under the Tariff or any Service Agreement thereunder.

9.1 Indemnity.

For the purposes of this Agreement, Designated Entity shall at all times indemnify, defend, and save Transmission Provider and its directors, managers, members, shareholders, officers and employees harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third-parties, arising out of or resulting from the Transmission Provider's acts or omissions associated with the performance of its obligations under this Agreement to the same extent and in the same manner that a Transmission Customer is required to indemnify, defend and save Transmission Provider and its directors, managers, members, shareholders, officers and employees harmless under Section 10.3 of the Tariff.

Article 10 – Force Majeure

10.0 Force Majeure.

For the purpose of this section, an event of force majeure shall mean any cause beyond the control of the affected Party, including but not restricted to, acts of God, flood, drought, earthquake, storm, fire, lightening, epidemic, war, riot, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, acts of public enemy, explosions, orders, regulations or restrictions imposed by governmental, military, or lawfully established civilian authorities, which in any foregoing cases, by exercise of due diligence, it has been unable to overcome. An event of force majeure does not include: (i) a failure of performance that is due to an affected Party's own negligence or intentional wrongdoing; (ii) any removable or remedial causes (other than settlement of a strike or labor dispute) which an affected Party fails to remove or remedy within a reasonable time; or (iii) economic hardship of an affected Party.

10.1 Notice.

A Party that is unable to carry out an obligation imposed on it by this Agreement due to Force Majeure shall notify the other Party in writing within a reasonable time after the occurrence of the cause relied on.

10.2 Duration of Force Majeure.

A Party shall not be responsible for any non-performance or considered in Breach or Default under this Agreement, for any deficiency or failure to perform any obligation under this Agreement to the extent that such failure or deficiency is due to Force Majeure. A Party shall be excused from whatever performance is affected only for the duration of the Force Majeure and while the Party exercises Reasonable Efforts to alleviate such situation. As soon as the non-performing Party is able to resume performance of its obligations excused because of the occurrence of Force Majeure, such Party shall resume performance and give prompt notice thereof to the other Party. In the event that Designated Entity is unable to perform any of its obligations under this Agreement because of an occurrence of Force Majeure, Transmission Provider may terminate this Agreement in accordance with Section 8.0 of this Agreement.

10.3 Breach or Default of or Force Majeure under Interconnection Coordination Agreement

If either of the following events prevents Designated Entity from performing any of its obligations under this Agreement, such event shall be considered a Force Majeure event under this Agreement and the provisions of this Article 10 shall apply: (i) a breach or default of the Interconnection Coordination Agreement associated with the Project by a party to the Interconnection Coordination Agreement other than the Designated Entity; or (ii) an event of Force Majeure under the Interconnection Coordination Agreement associated with the Project.

Article 11 – Assignment

11.0 Assignment.

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 11.0. Except for assignments described in Section 11.1 of this Agreement that may not result in the assignment of all rights, duties, and obligations under this Agreement to a Project Finance Entity, no partial assignments will be permitted. No Party may assign any of its rights or delegate any of its duties or obligations under this Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Designated Entity shall be contingent upon, prior to the effective date of the assignment: (i) the Designated Entity or assignee demonstrating to the satisfaction of Transmission Provider that the assignee has the technical competence and financial ability to comply with the requirements of this Agreement and to construct the Project consistent with the assignor's cost estimates for the Project; and (ii) the assignee is eligible to be a Designated Entity for the Project pursuant to Sections 1.5.8(a) and (f) of Schedule 6 of the Operating Agreement. Except as provided in an assignment to a Finance Project Entity to the contrary, for all assignments by any Party, the assignee must assume in a writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, the Tariff and the Operating Agreement.

11.1 Project Finance Entity Assignments

11.1.1 Assignment to Project Finance Entity

If an arrangement between the Designated Entity and a Project Finance Entity provides that the Project Finance Entity may assume any of the rights, duties and obligations of the Designated Entity under this Agreement or otherwise provides that the Project Finance Entity may cure a Breach of this Agreement by the Designated Entity, the Project Finance Entity may be assigned this Agreement or any of the rights, duties, or obligations hereunder only upon written consent of the Transmission Provider, which consent shall not be unreasonably withheld, conditioned, or delayed. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement.

11.1.2 Assignment By Project Finance Entity

A Project Finance Entity that has been assigned this Agreement or any of the rights, duties or obligations under this Agreement or otherwise is permitted to cure a Breach of this Agreement, as described pursuant to Section 11.1.1 above, may assign this Agreement or any of the rights, duties or obligations under this Agreement to another entity not a Party to this Agreement only: (i) upon the Breach of this Agreement by the Designated Entity; and (ii) with the written consent of the Transmission Provider, which consent shall not be unreasonably withheld, conditioned, or delayed. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement alter or diminish the rights of the Transmission Provider under this Agreement, the Tariff, or the Operating Agreement. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the Tariff and Operating Agreement.

Article 12 – Information Exchange

12.0 Information Access.

Subject to Applicable Laws and Regulations, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement, the Operating Agreement, and the Tariff. Such information shall include but not be limited to, information reasonably requested by Transmission Provider to prepare the Regional Transmission Expansion Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement, the Operating Agreement, and the Tariff.

12.1 Reporting of Non-Force Majeure Events.

Each Party shall notify the other Party when it becomes aware of its inability to comply with the provisions of this Agreement for a reason other than Force Majeure. The Parties agree to cooperate with each other and provide necessary information regarding such inability to comply, including, but not limited to, the date, duration, reason for the inability to comply, and corrective actions taken or planned to be taken with respect to such inability to comply. Notwithstanding the foregoing, notification, cooperation or information provided under this Section 12.1 shall not entitle the receiving Party to allege a cause of action for anticipatory Breach of this Agreement.

Article 13 – Confidentiality

13.0 Confidentiality.

For the purposes of this Agreement, information will be considered and treated as Confidential Information only if it meets the definition of Confidential Information set forth in Section 1.1 of this Agreement and is clearly designated or marked in writing as "confidential" on the face of the document, or, if the information is conveyed orally or by inspection, if the Party providing the information orally informs the Party receiving the information that the information is "confidential." Confidential Information shall be treated consistent with Section 18.17 of the Operating Agreement. A Party shall be responsible for the costs associated with affording confidential treatment to its information.

Article 14 – Regulatory Requirements

14.0 Regulatory Approvals.

Designated Entity shall seek and obtain all required government authority authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule C of this Agreement, as applicable.

Article 15 – Representations and Warranties

15.0 General.

Designated Entity hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Designated Entity during the full time this Agreement is effective:

15.0.1 Good Standing

Designated Entity is duly organized or formed, as applicable, validly existing and in good standing under the laws of its State of organization or formation, and is in good standing under the laws of the respective State(s) in which it is incorporated.

15.0.2 Authority

Designated Entity has the right, power and authority to enter into this Agreement, to become a Party thereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of Designated Entity, enforceable against Designated Entity in accordance with its terms, except as the enforceability thereof may be limited by applicable bankruptcy, insolvency, reorganization or other similar laws affecting creditors' rights generally and by general equitable principles (regardless of whether enforceability is sought in a proceeding in equity or at law).

15.0.3 No Conflict.

The execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, or bylaws or operating agreement, of Designated Entity, or any judgment, license, permit, order, material agreement or instrument applicable to or binding upon Designated Entity or any of its assets.

Article 16 – Operation of Project

16.0 Initial Operation.

The following requirements shall be satisfied prior to Initial Operation of the Project:

16.0.1 Execution of the Consolidated Transmission Owners Agreement

Designated Entity has executed the Consolidated Transmission Owners Agreement and is able to meet all requirements therein.

16.0.2 Execution of an Interconnection Agreement

Designated Entity has executed an Interconnection Agreement with the Transmission Owner(s) to whose facilities the Project will interconnect, or such agreement has been filed unexecuted with the Commission.

16.0.3 Operational Requirements

The Project must meet all applicable operational requirements described in the PJM Manuals.

16.0.4 Parallel Operation

Designated Entity shall have all necessary systems and personnel in place to allow for parallel operation of its facilities with the facilities of the Transmission Owner(s) to which the Project is interconnected consistent with the Interconnection Coordination Agreement associated with the Project.

16.0.5 Synchronization

Designated Entity shall have received any necessary authorization from Transmission Provider and the Transmission Owner(s) to whose facilities the Project will interconnect to synchronize with the Transmission System or to energize, as applicable, per the determination of Transmission Provider, the Project.

16.1 Partial Operation.

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule C of this Agreement, provided that: (i) Designated Entity has notified Transmission Provider of the successful completion of the Project phase; (ii) Transmission Provider has determined that partial operation of the Project will not negatively impact the reliability of the Transmission System; (iii) Designated Entity has demonstrated that the requirements for Initial Operation set forth in Section 16.0 of this Agreement have been met for the Project phase; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, Applicable Reliability Standards, and Good Utility Practice.

Article 17 – Survival

17.0 Survival of Rights.

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Liability and Indemnity provisions in Article 9 also shall survive termination, expiration, or cancellation of this Agreement.

Article 18 – Non-Standard Terms and Conditions

18.0 Schedule E – Addendum of Non-Standard Terms and Conditions.

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule E are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule E that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule E shall control.

Article 19 – Miscellaneous

19.0 Notices.

Any notice or request made to or by any Party regarding this Agreement shall be made by U.S. mail or reputable overnight courier to the addresses set forth below:

Transmission Provider:
PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
Attention: Manager, Infrastructure Coordination

Designated Entity:
Mid-Atlantic Offshore Development, LLC
15445 Innovation Drive
San Diego, CA 92128
Attention: Joshua Pearson

With copies to:
Joshua Pearson: joshua.pearson@edf-re.com
Matthew Virant: matthew.virant@edf-re.com
Alicia Rigler: alicia.rigler@edf-re.com

19.1 No Transmission Service.

This Agreement does not entitle the Designated Entity to take Transmission Service under the Tariff.

19.2 No Rights.

Neither this Agreement nor the construction or the financing of the Project entitles Designated Entity to any rights related to Customer-Funded Upgrades set forth in Subpart C of Part VI of the Tariff.

19.3 Standard of Review.

Future modifications to this Agreement by the Parties or the FERC shall be subject to the just and reasonable standard and the Parties shall not be required to demonstrate that such modifications are required to meet the "public interest" standard of review as described in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

19.4 No Partnership.

Notwithstanding any provision of this Agreement, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit.

19.5 Headings.

The Article and Section headings used in this Agreement are for convenience only and shall not affect the construction or interpretation of any of the provisions of this Agreement.

19.6 Interpretation.

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

19.7 Severability.

Each provision of this Agreement shall be considered severable and if for any reason any provision is determined by a court or regulatory authority of competent jurisdiction to be invalid, void or unenforceable, the remaining provisions of this Agreement shall continue in full force and effect and shall in no way be affected, impaired or invalidated, and such invalid, void or unenforceable provision shall be replaced with valid and enforceable provision or provisions which otherwise give effect to the original intent of the invalid, void or unenforceable provision.

19.8 Further Assurances.

Each Party hereby agrees that it shall hereafter execute and deliver such further instruments, provide all information and take or forbear such further acts and things as may be reasonably required or useful to carry out the intent and purpose of this Agreement and as are not inconsistent with the terms hereof.

19.9 Counterparts.

This Agreement may be executed in multiple counterparts to be construed as one effective as of the Effective Date.

19.10 Governing Law

This Agreement shall be governed under the Federal Power Act and Delaware law, as applicable.

19.11 Incorporation of Other Documents.

The Tariff, the Operating Agreement, and the Reliability Assurance Agreement, as they may be amended from time to time, are hereby incorporated herein and made a part hereof.

[Signature Page Follows]

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

Transmission Provider: PJM Interconnection, L.L.C.

DocuSigned by:

By: A297C9F67213444...   Mgr., TC&A   8/21/2023

Name   Title   Date

Printed name of signer: Augustine Caven

Designated Entity: Mid-Atlantic Offshore Development, LLC

By: EDF-RE Offshore Development, LLC,
its Member executing on behalf of Mid-Atlantic Offshore Development, LLC

DocuSigned by:

By: Luis Silva 43DD5F7F0424424...   CFO   8/18/2023

Name   Title   Date

Printed name of signer: Luis Silva

By: Shell New Energies US LLC,
its Member executing on behalf of Mid-Atlantic Offshore Development, LLC

DocuSigned by:

By: Thomas Stokes FAA1C007576A414...   Manager   8/21/2023

Name   Title   Date

Printed name of signer: Thomas Stokes

SCHEDULE A

Description of Projects

PJM Baseline Upgrade IDs	Description of Project
b3737.22	Construct the Larrabee Collector Station (LCS) AC switchyard, procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation.
b3737.60	Perform a Pre-build Infrastructure evaluation study in alignment with the NJBPU Solicitation Guidance Document requirements.

SCHEDULE B

Scope of Work

PJM Baseline Upgrade ID	Scope of Work
b3737.22	Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A, and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV.
b3737.60	Pre-build Infrastructure scope is intended so that either an Offshore wind developer, or other entity selected by NJBPU, construct the necessary duct banks and access cable vaults for other Offshore wind generators, to fully utilize the Larrabee Tri-Collector Solution. The NJBPU approved that MAOD perform a Pre-build Infrastructure evaluation study in alignment with requirements in Attachment 10 of the NJBPU Solicitation Guidance Document (SGD). The study will include the following configurations: • 4 x 1500MW 525kV (single trench) • 4 x 1400MW 400kV (single trench) • 4 x 1200MW 320kV (single trench) • 2 x 2 x 1500MW 525kV (two trenches) • 2 x 2 x 1400MW 400kV (two trenches) • 2 x 2 x 1200MW 320kV (two trenches) The deliverables will be a desktop study, updated cable routes and cross-section diagrams, detailed scope, schedule and cost estimates for the pre-build infrastructure.

SCHEDULE C

Development Schedule

Designated Entity shall ensure and demonstrate to the Transmission Provider that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

Milestones				
PJM Baseline Upgrade ID	**Execute Interconnection Coordination Agreement:** On or before this date, Designated Entity must execute the Interconnection Coordination Agreement or request the agreement be filed unexecuted.	**Demonstrate Adequate Project Financing:** On or before this date, Designated Entity must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement	**Acquisition of all necessary federal, state, county, and local site permits:** On or before this date, Designated Entity must demonstrate that all required federal, state, county and local site permits have been acquired.	**Required Project In-Service Date:** On or before this date, Designated Entity must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules B of this Agreement; (ii) meets the criteria outlined in Schedule D of this Agreement; and (iii) is under Transmission Provider operational dispatch.
b3737.22	10/31/2023	5/31/2024	3/31/2027	12/31/2027
b3737.60	N/A	N/A	N/A	6/2/2023

SCHEDULE D

PJM Planning Requirements and Criteria and Required Ratings

PJM Baseline Upgrade ID	Required Ratings(MVA): Summer Normal/Summer Emergency/Winter Normal/Winter Emergency	Planning Criteria
b3737.22	N/A	PJM solicited project proposals to build the necessary transmission to meet New Jersey's goal to facilitate the delivery of a total of 6,400 MW of offshore wind. This project represents a partial scope of MAOD's Proposal 551 Option 2 for the new Larrabee Collector Station (LCS).
b3737.60	N/A	N/A

SCHEDULE E

Non-Standard Terms and Conditions

None

Exhibit No. MAOD-10
Mid-Atlantic Offshore Development, LLC
June 29, 2023, NJBPU Order

Agenda Date: 6/29/23
Agenda Item: 8B

STATE OF NEW JERSEY
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY	)	ORDER APPROVING STATE AGREEMENT APPROACH PROJECT SCOPE MODIFICATIONS AND ADDRESSING SCOPE-RELATED COST ESTIMATE ADJUSTMENTS
	)	DOCKET NO. QO20100630

Parties of Record:

Brian O. Lipman, Esq, Director, New Jersey Division of Rate Counsel
Susan McGill, PJM Interconnection LLC
Andrew Hendry, Jersey Central Power & Light Company
Michael Donnelly, Atlantic City Electric Company
Matthew Virant, Mid-Atlantic Offshore Development, LLC
Eric Hayes, LS Power Grid Mid-Atlantic, LLC
Shadab Ali, PPL Electric Utilities
Jodi Moskowitz, **Esq**., Public Service Electric and Gas Company
Maria J. Malguarnera, Transource Energy, LLC

BY THE BOARD:[1]

By this Order, the New Jersey Board of Public Utilities ("Board"): 1) considers scope changes and associated cost increases for State Agreement Approach ("SAA") projects originally approved on October 26, 2022 under this docket and 2) addresses scope-related cost estimate adjustments for some of the SAA projects.[2]

BACKGROUND

As part of New Jersey's offshore wind ("OSW") coordinated transmission solution under the inaugural SAA, the Board awarded a series of projects to construct the on-shore transmission

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[1] Commissioner Marian Abdou abstained from voting on this matter.

[2] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated October 26, 2022 ("SAA Order").

facilities necessary to successfully deliver 7.5 gigawatts ("GW") of OSW generation to New Jersey customers.[3] One of the predominant projects under the Board's SAA award was Mid-Atlantic Offshore Development, LLC's ("MAOD") and Jersey Central Power & Light Company's ("JCP&L") jointly submitted Larrabee Tri-Collector Solution ("Larrabee Tri-Collector Solution"). The Larrabee Tri-Collector Solution includes a new substation ("Larrabee Collector Station") adjacent to the existing JCP&L Larrabee substation and sufficient land for the future installation of up to four High Voltage Direct Current ("HVDC" or "DC") converter stations. The transmission cables delivering the energy output of certain future OSW generators will interconnect at this new Larrabee Collector Station.

The SAA Order noted that future Board-selected OSW generators that are awarded SAA Capability and that will be utilizing the Larrabee Collector Station, must construct and maintain their own individual DC converter stations on the MAOD-acquired land.[4] The Board directed MAOD to coordinate with Board Staff ("Staff") and the future generators awarded SAA capability to ensure these projects have adequate and equal access to the land as is reasonably necessary to develop their individual projects according to the generator's project schedule.[5] The Board encouraged MAOD to engage with Staff subsequent to the project award to design site layouts on the land that would ensure access to up to four HVDC converters at the site.[6]

In the SAA Order, the Board recognized that the development of transmission projects requires years of planning and coordination. Further, the Board found that "future revisions to the awarded projects herein under the Larrabee Tri-Collector Solution may be required depending on changed circumstances unknowable as of the time of award."[7] With the appreciation that some flexibility is necessary, the Board retained the right to enter further orders to reflect "significant updates" to the scope, configuration, and/or costs to the awarded SAA projects on the basis of any future changed circumstances.[8] The Board also authorized Staff to review and accept routine "changes to elements of any awarded projects that would increase the benefits to New Jersey ratepayers."[9]

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[3] Id. at 14. A GW is the equivalent of 1,000 megawatts ("MW"). The SAA Order's reference to 7,500 MW of OSW-generated power is the equivalent to 7.5 GW of OSW-generated power. Id.

[4] In this context, "SAA Capability" means, as set out in the Federal Energy Regulatory Commission ("FERC")-approved PJM Interconnection, LLC ("PJM")Rate Schedule 49 §1.2, all transmission capability created by the combination of approved packages of separate SAA proposals as studied by PJM, including the capability to integrate resources injecting energy up to their maximum facility output, capability which may become Capacity Interconnection Rights, or "CIRs" (the rights to input generation as a capacity resource into the transmission system at the point of interconnection where the facility connect to the PJM transmission system) the through the PJM Interconnection process, and any other capability consistent with studies performed by PJM for the SAA. Id. at 5, 8.

[5] Id. at 71.

[6] Ibid.

[7] Id. at 73.

[8] Ibid.

[9] Ibid.

Scope Change Work

Changes to the scope of several of the awarded SAA projects ("Scope Change Work") have been identified as described below.

Interconnection Work

On March 6, 2023, the Board opened the application window for the New Jersey Third OSW Solicitation ("Third Solicitation"), inviting all interested parties to submit applications for proposed offshore wind facilities to the Board for consideration.[10] In addition to opening the Third Solicitation application window, the Board also issued the Solicitation Guidance Document for the Third Solicitation ("SGD").[11] The SGD provided the timeline and mechanics for the Third Solicitation, the application requirements, and the criteria for evaluating applications.[12]

The SGD also included specifics regarding the prebuild infrastructure ("Prebuild Infrastructure"). As originally outlined in the SAA Order, the Prebuild Infrastructure is a concept that requires a single developer to construct the necessary duct banks and access cable vaults for all OSW generator projects that will be utilizing the Larrabee Collector Station.[13] For clarity, the "Prebuild" involves only the necessary infrastructure (duct banks and cable vaults) to house the transmission cables, but not the cables themselves.[14]

While the SGD outlined many of the requirements each generator must include in its application relating to interconnecting at the Larrabee Collector Station and the Prebuild Infrastructure, the SGD did not indicate which entity—MAOD or the OSW generator—would be responsible for constructing certain interconnection work:

1. The un-energized infrastructure from the end of the Prebuild Infrastructure to the direct current ("DC") converter stations ("Prebuild Extension Work"). More specifically, this work includes the engineering, procurement, and construction of civil work to accommodate four (4) HVDC circuits from the Prebuild Point of Demarcation to each individual generator's DC converter station area within the MAOD parcel awarded under the SAA (each such area, a "Generator Converter Station Area");[15] and

2. The alternating current ("AC") collector lines that run from the generator's DC converter station area to the Larrabee Collector Station's AC interface ("AC Collector Lines Work"). More specifically, this work includes the engineering, procurement, and construction of

[10] In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certifications (OREC), BPU Docket No. QO22080481, March 6, 2023 ("Third Solicitation Order").

[11] The SGD can be accessed at the following location: https://njoffshorewind.com/third-solicitation/solicitation-documents/Final-Solicitation-Guidance-Document-with-attachments.pdf.

[12] See generally SGD.

[13] SAA Order at 8.

[14] Ibid. For further information regarding the Prebuild concept, see the definition of "Prebuild" in the SAA Order.

[15] The "Prebuild Point of Demarcation" is the location where the change of ownership occurs between owning entities for an electrical line and/or supporting ancillary infrastructure. Conceptually, this location represents the terminus of the Prebuild Infrastructure, which will be at or near the Larrabee Collector Station. See SGD at A10-1.

civil works for three (3) separate trenches to accommodate AC collector lines and three (3) sets of AC collector lines that will connect each Generator Converter Station Area's AC interface to the Larrabee Collector Station. The three (3) sets of AC collector lines will consist of a total of 12 230 kilovolt ("kV") AC circuits. MAOD is currently considering underground cables to maximize HVDC converter station installation space within each Generator Converter Station Area; however, MAOD will continue to explore various options through engineering efforts, in coordination with PJM Interconnection L.L.C. ("PJM"), the Board, and OSW generators utilizing the Larrabee Collector Station, to provide a reliable and optimal solution.

The work described above (collectively, "Interconnection Work"), represents a small portion of the total work necessary to interconnect qualified OSW projects to the Larrabee Collector Station and must be done regardless of whether it is constructed by each OSW generator separately, or by MAOD.

Since the SAA Order was issued, Staff, Staff's consultant, The Brattle Group ("Brattle"), PJM, and MAOD routinely meet to discuss ongoing development of the Larrabee Collector Station. In following the Board's direction, MAOD has engaged with Staff to explore the optimal design of the site layouts for the HVDC converter stations at their Generator Converter Station Area, including the Interconnection Work. Through this engagement, Staff determined that there are significant benefits if MAOD constructs the Interconnection Work.

First, by having MAOD take on responsibility for this work now, construction of the Interconnection Work can begin and likely be completed well before it would have been if an OSW generator were to complete it. The enhanced timing provides numerous benefits, including reduction of project-on-project risk and increased certainty to OSW generators that this work will be completed and ready for them to utilize when needed. This will also likely result in lower costs for completion of the Interconnection Work now at one time, compared to each OSW generator completing the Interconnection Work at a series of later dates.

Second, there are numerous operational benefits of having MAOD complete the Interconnection Work, rather than it being done by each individual OSW generator, including:

- Mitigating potential outages and disruptions to the operations of OSW generators already connected to the Larrabee Collector Station;
- Increasing safety by avoiding underground construction near other underground construction and energized facilities;
- Mitigating potential interface issues by having a single entity design for interconnection at the Larrabee Collector Station;
- Optimizing layout of the property where the Generator Converter Station Areas will be, which may be utilized by up to five different entities (MAOD, plus four (4) OSW generators);
- Reducing the footprint of the AC collector lines by using a single construction effort; and
- Maximizing space available for generator HVDC converter stations.

With MAOD constructing the Prebuild Extension, MAOD would be responsible for designing, engineering, permitting, and constructing the civil works from the Prebuild Point of Demarcation to each individual OSW generator's DC converter station area for up to four (4) circuits; and excludes the supply and installation of HVDC cables, which would be performed by the OSW generators. As such, the OSW generators would be responsible for their individual cable supply

and cable installation.
With MAOD constructing the AC Collector Lines Work, MAOD would be responsible for the engineering, procurement, and construction of the civil works for three (3) separate trenches to accommodate AC collector lines and the engineering, procurement, construction, and installation of the AC collector lines.[16] As such, the OSW generators would be responsible for all scope up to the AC interface, consistent with MAOD's modified scope beginning at the AC interface.

After engagement between MAOD and Staff, MAOD provided an update to their project should their scope be modified to accommodate the Interconnection Work. MAOD estimated the cost to construct the Interconnection Work to be $23 million, and stated that it would be constructed on a schedule that would accommodate the expected schedule of all OSW generators anticipated to connect to the Larrabee Collector Station.

The SAA Order detailed the specific work to be included in MAOD's scope under its SAA award. The Interconnection Work was not originally included in MAOD's SAA award; therefore, Staff recommends that MAOD's scope of work under the SAA Order be modified to include the Interconnection Work.

Prebuild Infrastructure Study

The SGD indicated that the awarded SAA projects may be modified to include the Prebuild Infrastructure, and that Staff, PJM, and the awarded SAA projects were exploring this option.[17] In order to further explore this option, MAOD proposed to PJM that it conduct a study to determine the feasibility of including this work as a modification to MAOD's SAA project ("Prebuild Infrastructure Study"). MAOD estimated that the cost to perform the study is $290,000. Staff recommends that MAOD's scope of work under the SAA Order be modified to include the Prebuild Infrastructure Study. With this recommendation, Staff notes that MAOD's study does not negate the requirement for Solicitation 3 proposals to include a proposed prebuild infrastructure.

JCP&L Project Scope Changes

JCP&L has provided information to PJM that identified changes in scope of the SAA project awarded to JCP&L. PJM advises that the new scope involves the removal of a 115kV line and a 230 kV line to accommodate the installation of new larger lines from the MAOD Larrabee tri-collector substation to Smithburg Substation. JCP&L estimated that each effort will cost $8.47 million. Additionally, JCP&L identified the need to replace certain equipment at the Middlesex substation to support the PJM-identified upgrades to the Lake Nelson I1023 230 kV line, costing approximately $0.53 million. PJM has conducted reliability studies indicating that these scope changes are needed, and PJM presented these scope changes at the May 9, 2023 PJM Transmission Expansion Advisory Committee ("TEAC") meeting ("May 9 TEAC Meeting").[18]

[16] Note, while MAOD would be responsible for the AC Collector Lines Work, MAOD intends to coordinate with individual OSW generators and defer the electrical equipment supply, including cables, to align with individual generator projects and construction schedules.

[17] SGD at 40.

[18] PJM Reliability Analysis Update, Sami Abdulsalam, Transmission Expansion Advisory Committee, May 9, 2023 ("May 9, 2023 TEAC").

https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230509/20230509-item-10---

JCP&L estimated that the total cost increase for the additional scope total $17.47 million. Staff recommends that JCP&L's scope of work under the SAA Order be modified to include these project scope changes.

The total cost of all Scope Change Work identified above is $40.76 million.[19]

Scope-Related Cost Estimate Adjustments

As noted in the SAA Order, Staff relied on a robust record to support its SAA recommendation to the Board. Part of the record included Brattle's evaluation report ("Evaluation Report"), which provided an in-depth overview and analysis of the SAA evaluation.[20]

Regarding project cost estimates, the Evaluation Report noted that the SAA bidders, including those that were awarded projects by the Board, provided uncertainty ranges for their SAA proposals' cost estimates.[21] Brattle noted that most cost estimates provided by the bidders carried an uncertainty range of -20% to +30% of the submitted estimate.[22] PJM also modeled, in its final financial analysis report, a scenario with an across-the-board 25% project cost increase, noting that the use of scenarios assist in providing insight into the impact of potential cost increases.[23]

New Jersey's awarded SAA projects are included in PJM's Regional Transmission Expansion Plan ("RTEP"), and SAA projects are required to follow the RTEP guidelines and process, including those established for cost estimate adjustments.[24] The RTEP process does not require Board approval for scope-related cost estimate adjustments for approved RTEP projects.[25] Rather, these adjustments will follow PJM's standard RTEP process and be subject to the same safeguards.[26]

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reliability-analysis-update.ashx

[19] The Interconnection Work of $23 million + the Prebuild Infrastructure Study of $0.29 million + the JCP&L Project Scope Changes of $17.47 million.

[20] Brattle SAA Evaluation Report Final – Public, October, 26, 2022 https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468

[21] Evaluation Report at page 8.

[22] Evaluation Report at page 81.

[23] Financial Analysis Report: 2021 SAA Proposal Window to Support NJ OSW, September 19, 2022, nj-osw-financial-analysis-report-september-final.ashx (pjm.com)

[24] PJM Operating Agreement, Schedule 6; PJM Tariff, Schedule 12.

[25] PJM Operating Agreement, Schedule 6, Section 1.6; PJM Tariff, Schedule 12.

[26] See PJM Operating Agreement, Schedule 6, which sets forth the rules and procedures for the RTEP. The TEAC is a committee established under the PJM Operating Agreement to aid in the development of the RTEP and provides advice and recommendations to the PJM Board of Managers ("PJM Board") for review of RTEP projects, including cost estimate adjustments. Cost estimate adjustments are routinely submitted to PJM by the project developer and then presented to the TEAC where TEAC members can review the cost estimate adjustments, ask questions and state their positions. TEAC members include transmission customers (as defined in the PJM Tariff), any other entity proposing to provide transmission facilities, agencies and offices of customer advocates who exercise regulatory authority over the rates, terms or conditions of electric service; and any other interested entities or persons. PJM Board retains discretion to formally review RTEP cost estimate adjustments. FERC can also review all costs included in transmission rates, including SAA-related costs, and change the resulting transmission rates if it finds that

However, one of the many benefits of the SAA is that it allows for greater transparency and Board involvement than would otherwise be provided under the standard RTEP process.

Since the SAA Order was issued, Staff and PJM regularly meet to discuss ongoing updates related to the awarded projects. As part of these meetings, PJM continues to provide updates to Staff when PJM receives cost estimate adjustments from the awarded SAA projects. PJM has indicated that these updates are not uncommon. In fact, PJM notes that it anticipates future cost estimate adjustments (both increases and decreases) across all the SAA projects, primarily as each project goes through its detailed engineering phase from which it will get more accurate labor and material costs. Further, while typically the Board would not be specifically presented with these common cost estimate adjustments for RTEP projects, the SAA process allows for this additional engagement. Also, unlike with standard RTEP projects, Staff separately meets with SAA project developers to discuss the ongoing development of the projects. This close coordination and engagement provides a greater level of transparency than if the project had been awarded under the standard RTEP process. The coordination also ensures that the Board may exercise its retained right to review and approve "significant updates to the scope, configuration and/or cost,"[27] and Staff's ability to review and accept routine changes.[28]

In light of this, PJM alerted Staff of ongoing cost estimate adjustments and presented this updated information at the May 9 TEAC Meeting where PJM described the specifics of SAA projects' cost adjustments.[29] More specifically, PJM presented a total cost estimate increase to the TEAC of $127.34 million across multiple SAA projects.[30] Subsequent to the TEAC meeting, PJM informed Staff that the MAOD Prebuild Infrastructure Study and the JCP&L Project Scope Changes described above previously considered scope-related cost estimate adjustments should be considered scope changes, reducing the scope-related cost estimate adjustments to $109.58 million.

The scope-related cost estimate updates can be categorized into three (3) areas. The first is a $27.1 million cost increase associated with the reconductor of a small section of Raritan River-Kilmer I 230 kV line reflects updated communication between the developer and PJM.[31] The second is a $71.9 million cost increase resulting from the additional refinement of MAOD's cost estimates for their awarded scope. Such refinements were expected, as at the time of the SAA Order, the Board understood that some of MAOD's proposed cost estimates for their awarded scope would require updating. As such, the SAA Order noted that MAOD was to "perform further assessments to improve its refinement of the estimate and scope of work as requested by the NJBPU."[32] The third includes the remaining $10.58 million of cost estimate updates that reflect common changes to individual components of the projects.

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the inclusion of these costs renders those rates unjust and unreasonable. See 16 U.S.C. § 824e(a)

[27] SAA Order at 73.

[28] Ibid. See also PJM Rate Schedule 49, paragraphs 3, 4, 5, and 7.

[29] See May 9, 2023 TEAC.

https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230509/20230509-item-10---reliability-analysis-update.ashx

[30] Id.

[31] See May 9, 2023 TEAC.

[32] SAA Order at 76.

With an increase in SAA project costs, Staff appreciates the significance of ratepayer impacts. Of critical importance throughout the SAA process was the baseline scenario, or the cost of the transmission facilities that would be necessary to achieve New Jersey's 7,500 MW OSW goal in the absence of the SAA solicitation ("Baseline Scenario"). As outlined in the SAA Order, the Baseline Scenario included the estimated costs and processes associated with the bundled procurement of all offshore and onshore transmission facilities, constructed by or paid for by a generator, necessary to interconnect up to 7,500 MW without an SAA solution. Under the Baseline Scenario, the full costs of building and operating the onshore and offshore transmission facilities would be recovered through the fixed-price Offshore Wind Renewable Energy Certificate ("OREC") payments at the price proposed by the winning generators and approved by the Board, with a true-up mechanism for transmission upgrade costs.

Using the Baseline Scenario cost estimates and the SAA project cost estimates, Brattle and Staff were able to determine that, at the time of the SAA award, New Jersey ratepayers would realize an estimated savings of over $900 million dollars with the awarded SAA projects, compared to the Baseline Scenario. The SAA Order also noted that the SAA solution was tailored to maximize federal tax incentives existing or anticipated at the time, preserving an additional $2.2 billion of ratepayer benefits.

Due to the recent SAA project cost estimate adjustments, Staff requested that Brattle provide an updated comparison between the Baseline Scenario and the SAA projects with the new cost estimate adjustments to determine the current estimated ratepayer savings under the SAA. Brattle found that like the SAA projects' cost estimate adjustments, Baseline Scenario facilities would face similar cost adjustments.[33] Brattle also noted, and PJM agreed, that the SAA projects' cost estimate adjustments are similar to the type expected during this phase of project development.[34] Simply put, while the SAA project costs have increased since the date of the SAA Order, New Jersey ratepayers will nonetheless still receive an estimated $900 million in savings by utilizing the SAA rather than utilizing the Baseline Scenario.[35]

Lastly, as transmission projects develop, it is common, if not expected, for cost estimate adjustments to occur. In fact, PJM typically sees a range of cost estimate adjustments beginning at the time a project is bid into the RTEP until the time of that project's final construction. As such, additional cost estimate adjustments, in addition to the cost estimate adjustments noted herein, may be anticipated in the future. Staff believes that any future SAA project cost estimate adjustments would likely impact Baseline Scenario facilities somewhat equally, as shown for these current cost estimate adjustments. Staff remains committed to closely engaging with PJM and the awarded SAA project developers to ensure all cost estimate adjustments are reasonable, while continuing to prioritize the interests of New Jersey ratepayers.

Rate Counsel Correspondence

By correspondence dated June 5, 2023, the New Jersey Division of Rate Counsel ("Rate Counsel") sought notice and an opportunity to be heard on any proposed "project scope modifications" that the Board might consider. Rate Counsel indicated in its letter that it was aware

[33] Brattle Updated Baseline Costs and SAA Cost Savings Memorandum, June 2, 2023, at 1-2 ("Updated Baseline Memo") https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468

[34] Updated Baseline Memo at 3.

[35] Updated Baseline Memo at 1 and 8.

that the winning bidders in the SAA docket had already increased the overall cost of the project by over $127 million as described at the May 9, 2023 TEAC meeting, but was unaware how the Board intended to address the cost increase or whether additional changes were proposed. Following Rate Counsel's correspondence, Staff discussed the Interconnection Work, Prebuild Infrastructure Study, JCP&L Project Scope Changes, and the Scope-Related Cost Estimate Adjustments with Rate Counsel. Rate Counsel did not object to Staff's assessment of the Scope Change Work as necessary to effectively and reliably complete the SAA projects. Rate Counsel requested that Staff regularly communicate with Rate Counsel's office in order to consider the potential ratepayer impact of future changes in cost or scope.

DISCUSSION AND FINDINGS

Based on thorough review of the Scope Change Work, and in consultation with Brattle and PJM, the Board agrees with Staff's recommendation that there are significant benefits to MAOD completing the Interconnection Work rather than the OSW generators each individually completing the Interconnection Work, and that a Prebuild Infrastructure Study will help to inform Staff of the feasibility of including this work as a modification to MAOD's SAA project. As such, the Board **HEREBY APPROVES** the modification and expansion of MAOD's designated scope of work to include the Interconnection Work and the Prebuild Infrastructure Study, and **DIRECTS** MAOD to engage with PJM so that it may take the necessary steps to effectuate the modification on a timely basis. The Board **FURTHER DIRECTS** MAOD to update Staff regularly on the PJM modification process, including, but not limited to, schedule updates and any cost estimate adjustments.

The Board also **HEREBY APPROVES** the modification and expansion of JCP&L's designated scope of work as discussed above and **DIRECTS** JCP&L to engage with PJM so that it may take the necessary steps to effectuate the modification on a timely basis. The Board **FURTHER DIRECTS** JCP&L to update Staff regularly on the PJM modification process, including, but not limited to, schedule updates and any cost estimate adjustments.

The Board **FURTHER DIRECTS** MAOD to engage and coordinate with Staff, Brattle, PJM and if appropriate, OSW generators to optimize the scope of the Interconnection Work to ensure all aspects of the Interconnection Work are aligned with New Jersey's OSW goals and provide the greatest benefits to New Jersey ratepayers while maintaining safe and reliable service. This engagement and coordination may include non-material adjustments to the scope of the Interconnection Work, at Staff's discretion and without the need for Board approval, including, but not limited to, technology selection and site configuration.

For the scope-related adjustments presented at the May 9 TEAC meeting, the Board **HEREBY ACKNOWLEDGES** those scope-related cost estimate adjustments to the SAA projects. The Board also **HEREBY REAFFIRMS** that all of the benefits associated with the Larrabee Tri-Collector Solution will continue to be realized by the residents of New Jersey, and that New Jersey's ratepayers will continue to see a savings of approximately $900 million as a result of the SAA projects being utilized to achieve New Jersey's OSW public policy.

As stated in the SAA Order and again here, the Board finds that future revisions to the projects awarded under the SAA may be required. The Board **HEREBY RETAINS THE RIGHT** to enter further orders in this docket as deemed necessary to reflect significant updates to the scope, configuration and/or cost of projects on the basis of any future changed circumstances. In addition, should PJM or Staff identify routine changes to elements of any awarded projects that would increase the benefits to New Jersey ratepayers, the Board **HEREBY AUTHORIZES** Staff

to review and accept these revisions, and notify PJM of the same.
The effective date of this Order is July 6, 2023.

DATED: June 29, 2023

BOARD OF PUBLIC UTILITIES
BY:

JOSEPH L. FIORDALISO
PRESIDENT

MARY-ANNA HOLDEN
COMMISSIONER

DR. ZENON CHRISTODOULOU
COMMISSIONER

CHRISTINE GUHL-SADOVY
COMMISSIONER

ATTEST:

SHERRI L. GOLDEN
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY

DOCKET NO. QO20100630

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Exhibit No. MAOD-11
Mid-Atlantic Offshore Development, LLC
PJM July 2023 White Paper

Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board

PJM Staff White Paper

PJM Interconnection
July 2023

For Public Use

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Contents

I. Executive Summary

On April 4, 2023, the PJM Board of Managers approved changes to the Regional Transmission Expansion Plan (RTEP), totaling a net decrease of $85.45 million for baseline projects, to resolve baseline reliability criteria violations and address changes to existing projects.

Since then, PJM has identified new baseline reliability criteria violations, and the transmission system enhancements needed to solve them, at an estimated cost of $795.61 million. Scope changes to an existing project will result in a net increase of $134.1 million. Cancellation to an existing project will result in a net decrease of $4.69 million. This yields an overall RTEP net increase of $925.02 million, for which PJM recommended Board approval. With these changes, RTEP projects will total approximately $43,034.13 million since the first Board approvals in 2000.

PJM sought Reliability and Security Committee consideration and full Board approval of the RTEP baseline projects summarized in this white paper. On July 12, 2023, the Board approved the addition of RTEP baseline projects as well as other changes to the RTEP as summarized in this paper.

II. Baseline Project Recommendations

A key dimension of PJM's RTEP process is baseline reliability evaluation, which is necessary before subsequent interconnection requests can be analyzed. Baseline analysis identifies system violations to reliability criteria and standards, determines the potential to improve the market efficiency and operational performance of the system, and incorporates any public policy requirements. PJM then develops transmission system enhancements to solve identified violations and reviews them with stakeholders through the Transmission Expansion Advisory Committee (TEAC) and subregional RTEP Committees prior to submitting its recommendation to the Board. Baseline transmission enhancement costs are allocated to PJM responsible customers.

III. Baseline Reliability Projects Summary

A summary of baseline projects with estimated costs equal to or greater than $10 million is provided below. A complete listing of all recommended projects and their associated cost allocations is included in Attachment A (allocations to a single zone) and Attachment B (allocations to multiple zones). Projects with estimated costs less than $10 million typically include, by way of example, transformer replacements, line reconductoring, breaker replacements and upgrades to terminal equipment, including relay and wave trap replacements. Also included is a scope change to the first Multi-Driver Project PJM determined to address reliability and market efficiency needs.

A. APS, BGE, PECO & PEPCO Transmission Zones

- Baseline Projects b3780 & b3781 – Brandon Shores Generation Deactivation Reinforcements: $785.8 million

PJM also recommended regional baseline projects totaling $9.81 million, whose individual cost estimates are less than $10 million. The projects include, but are not limited to, modification to existing lines, installation of new 230 kV lines, and necessary substation work associated with the deactivation of Sammis 5, 6 and 7 units.

A more detailed description of the larger-scope projects that PJM recommended to the Board is provided below.

B. Baseline Reliability Project Details

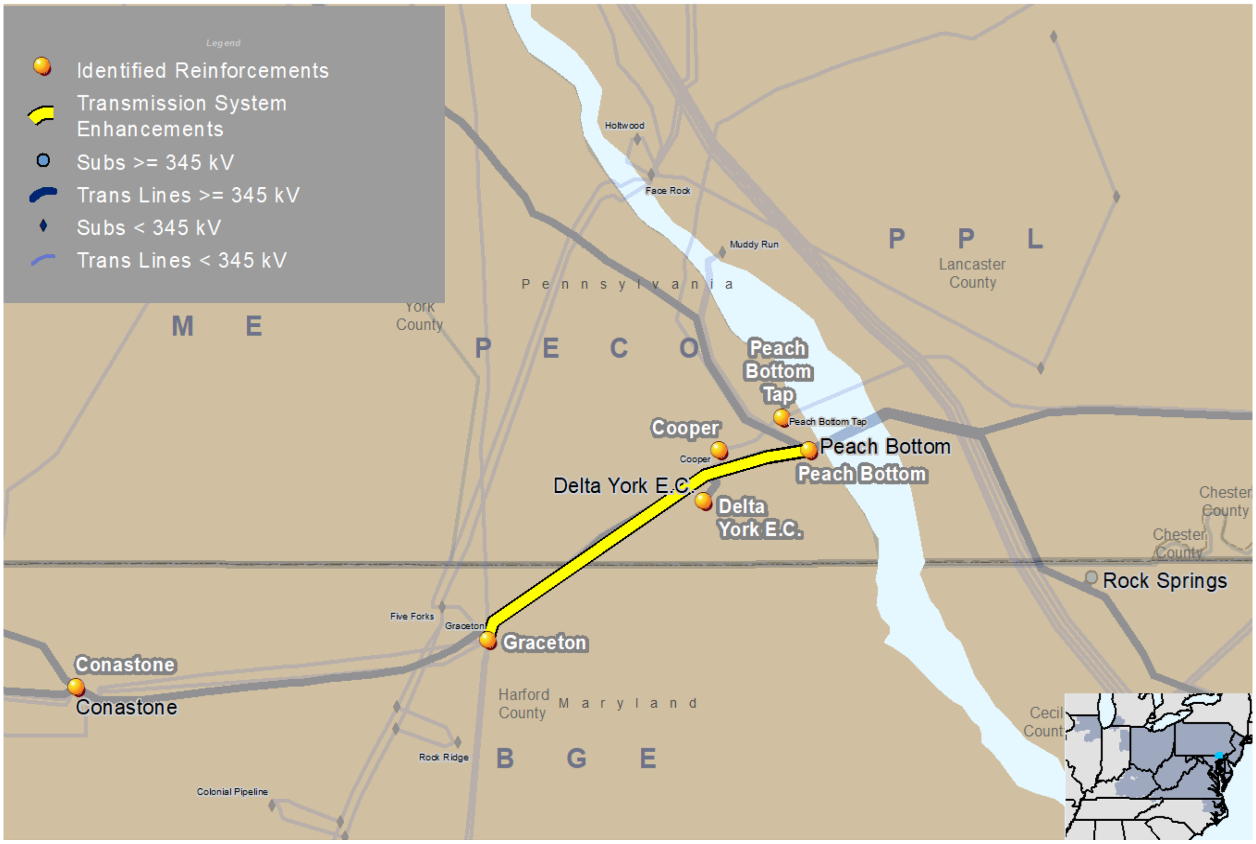
Baseline Project b3780 & b3781 – Brandon Shores Generation Deactivation Reinforcements

APS/BGE/PECO/PEPCO Transmission Zones

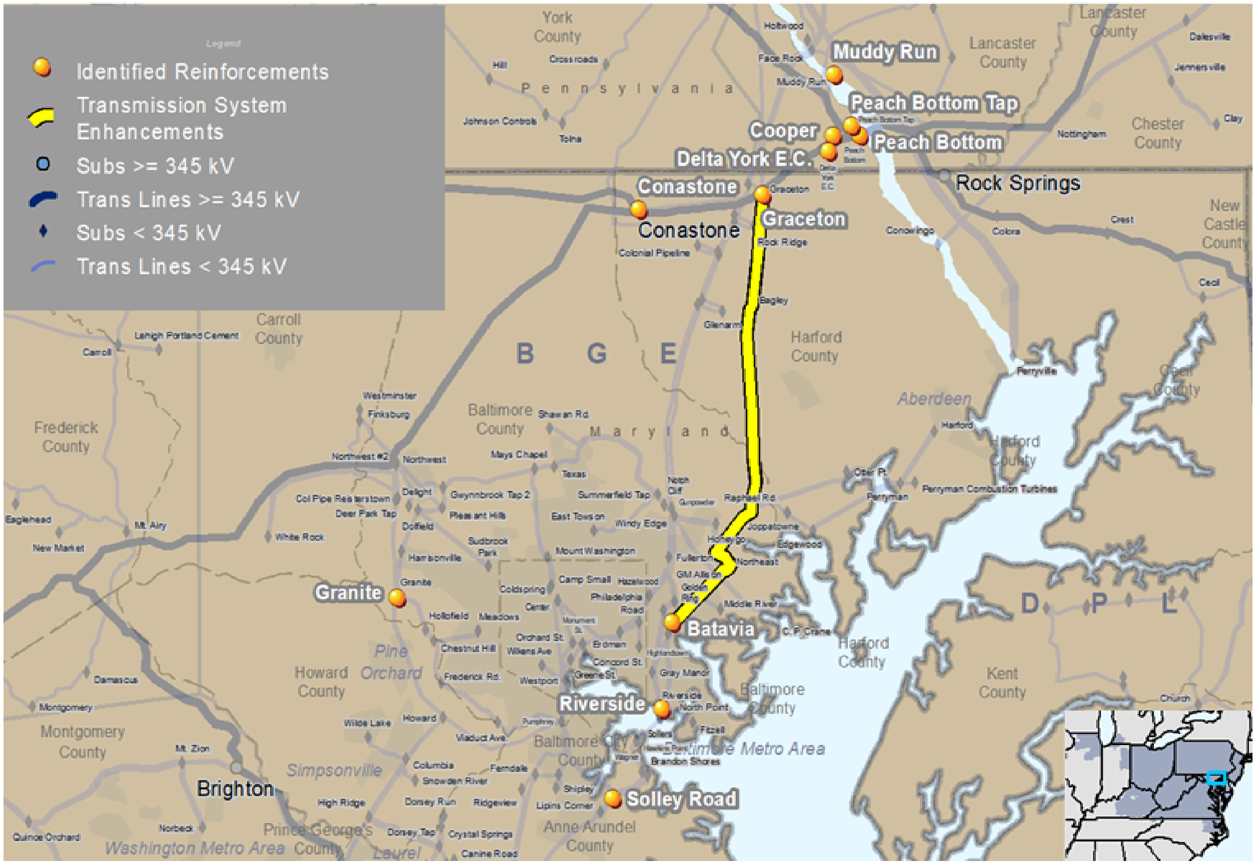
Brandon Shores 1 and 2 are coal units in the BGE zone with a total of approximately 1,282 MW capacity, and have requested to deactivate on June 1, 2025. The deactivation of these units will cause widespread voltage violations in neighboring areas (PEPCO, ME, PPL, PECO, APS and Dominion).The deactivation also results in thermal violations for the following facilities:

- BGE Transmission Zone
  - Five Rock-Rock Ridge 1 115 kV
  - Five Rock-Rock Ridge 2 115 kV
  - Rock Ridge-Colonial Pipeline 1 115 kV
  - Rock Ridge-Colonial Pipeline 2 115 kV
  - Colonial Pipeline-Glenarm 1 115 kV
  - Colonial Pipeline-Glenarm 2 115 kV
  - Chestnut Hill 7-Frederick Road 7 115 kV
  - Chestnut Hill 8-Frederick Road 8 115 kV
- APS Transmission Zone
  - Doubs Transformer 3 500/230 kV
  - Bethel-Riverton 138 kV
- PEPCO Transmission Zone
  - Dickerson-Dickerson H 230 kV

Map 1. b3780.1-.4, .8, .10-.12: Brandon Shores Generation Deactivation 500 kV Reinforcements



Map 2. b3780.5-.7, .9, .13 & b3781: Brandon Shores Generation Deactivation 230 kV Reinforcements



500 kV Reinforcements

The recommended solution includes upgrades at Peach Bottom North substation to add three 500 kV breakers to form a breaker-and-a-half bay; construction of a new Peach Bottom-Graceton 500 kV line; construction of new West Cooper 500 kV and expansion of Graceton 500 kV substations; and installations of a 350 MVAR capacitor at Conastone 500 kV, a 350 MVAR statcom and a 350 MVAR capacitor at Brighton 500 kV, and a 250 MVAR capacitor at Burchess Hill 500 kV. The estimated cost for the 500 kV reinforcements is $333 million. This project is an immediate-need project and has a projected in-service date of December 2028. The local transmission owners, BGE, PECO and PEPCO, will be designated to complete this work.

230 kV Reinforcements

The recommended solution includes the construction of new Solley Road and Granite 230 kV substations, each with 350 MVAR statcoms, construction of a new Batavia Road 230 kV substation, and construction of a Graceton-Batavia Road 230 kV double circuit line. The existing double circuit line from Northeast-Riverside 230 kV will tie into the new Batavia Road 230 kV substation, and the Batavia Road-Riverside 230 kV will be reconductored. The project will also replace 230 kV line drops to Doubs transformer No. 3. The estimated cost for the 230 kV reinforcements is $452.8 million. This project is an immediate-need project, and the majority of the components have a projected in-service date of December 2028. The local transmission owners, APS and BGE, will be designated accordingly to complete this work.

IV. Changes to Previously Approved Projects

Scope/Cost Changes

The following scope/cost modifications were recommended:

State Agreement Approach (SAA)

MOAD's Project Scope

- Baseline project b3737.22 has undergone a scope/cost increase. Constructing the Larrabee Collector station AC switchyard, and procuring and preparing land adjacent to the AC switchyard, resulted in cost increase of $72.2 million. Additional cost and scope for the MOAD pre-build infrastructure evaluation study increases the cost by $0.29 million.

JCPL Transmission Zone Additional Scope

- The following additional scope is required to accommodate the new 500/230 kV lines:
  - Baseline project b3737.53 requires removing approximately 7.7 miles of existing E83 line along the Larrabee-Smithburg ROW that is not in service. This results in a cost increase of $8.47 million.
  - Baseline project b3737.54 will remove the existing H2008 Larrabee-Smithburg No. 2 230 kV transmission line. This results in a cost increase of $8.47 million.
- Baseline b3737.55 at Middlesex 230 kV substation replaces a 2000A circuit switcher at Middlesex Switch point for the Lake Nelson I 1023 230 kV. This results in a cost increase of $0.53 million.

PECO Transmission Zone Scope Update

- Baseline project b3737.51 that replaces four 63 kA circuit breakers with 80 kA is no longer needed due to a case correction, resulting in a cost decrease of $5.6 million.
- Additional cost increases not impacting the New Jersey SAA project's scope of work were also reported, totaling an increase of $42.98 million.
- The net cost increase for the New Jersey SAA project is $127.34 million.

Multi-Driver Project

AEP Transmission Zone Modified Solution

- Baseline project b3775.6 includes sag study mitigation work on the Dumont-Stilwell 345 kV line. More detailed engineering costs were provided for this scope of work, and the description is being modified to clarify two structure replacements and modification to a third structure. Baseline project b3775.7, which upgrades the limiting element at the Stillwell or Dumont substation to increase the rating of the Stillwell-Dumont 345 kV line to match the conductor rating, included AEP and NIPSCO project components. The Stillwell (NIPSCO) scope of work was separated out into a separate new sub-ID b3775.11. The total estimated cost increase for the multi-driver project is $3.78 million.

Reliability Projects

DL Transmission Zone

- Baseline b3717 included project scope required for the deactivation of the Cheswick 1 unit. Cheswick 1 deactivated on March 31, 2022. FirstEnergy recently informed PJM of necessary work associated with the existing baseline projects with Duquesne Light. Additional relay and transmission line work (a new transmission structure and necessary tower work to handle the change in tension at Cheswick 138 kV substation) is needed at Springdale 138 kV substation. This results in a cost increase of $3 million.

PSEG Transmission Zone

- In April 2013, PJM sought proposals to improve operational performance on bulk electric system facilities in the southern New Jersey, Artificial Island area, site of PSE&G's Salem 1 and 2 and Hope Creek 1 nuclear generating units. Based on the latest study, PJM Planning and PJM Ops determined that the tap setting changes for Salem and Hope Creek units' step-up transformers are no longer required. This results in a cost decrease of $0.02 million.
- All of the scope/cost changes described in this section yield a net RTEP increase of $134.1 million.

Cancellations

The following cancellation was recommended:

- Baseline project b3305 (replacement of Pumphrey 230/115 kV transformer) is no longer needed based on a retool analysis performed by PJM. The project had an estimated cost of $4.69 million.

This change yields a net RTEP decrease of $4.69 million.

V. Review by the Transmission Expansion Advisory Committee (TEAC)

Project needs and recommended solutions as discussed in this report were reviewed with stakeholders during 2023, most recently at the June 2023 TEAC meeting. Written comments were requested to be submitted to PJM to communicate any concerns with project recommendations. No comments have been received as of this white paper publication date.

VI. Cost Allocation

Cost allocations for recommended projects are shown in Attachment A (for allocation to a single zone) and Attachment B (for allocation to multiple zones), and Attachment C (for Multi-Driver Project).

Cost allocations are calculated in accordance with Schedule 12 of the Open Access Transmission Tariff (OATT). Baseline reliability project allocations are calculated using a distribution factor methodology that allocates cost to the load zones that contribute to the loading on the new facility. The allocations will be filed at FERC no later than 30 days following approval by the Board.

VII. Board Approval

The PJM Reliability and Security Committee is requested to endorse the additions and changes to the RTEP proposed in this white paper and to recommend to the full Board for approval the new projects and changes to the existing RTEP projects as detailed in this white paper. On July 12, 2023, the Board approved the addition of RTEP baseline projects as well as other changes to the RTEP as summarized in this paper. The RTEP is published annually on PJM's website.

Attachment A – Reliability Project Single-Zone Allocations

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3717.3	Relay work at Springdale 138 kV	$1	APS	APS	12/31/2024
b3717.4	Transmission line work – a new transmission structure and necessary tower work to handle the change in tension at Cheswick 138 kV	$2	APS	APS	1/1/2025
b3777	Disconnect and remove three 345 kV breakers, foundations and associated equipment from Sammis substation. Remove nine 345 kV CVTs. Remove two 345 kV disconnect switches. Install new 345 kV bus work and foundations. Install new fencing. Remove and adjust relaying at Sammis substation.	$2.10	ATSI	ATSI	6/1/2023
b3779	Cut existing 230 kV line #2183 and extend from Poland Road substation to Evergreen Mills substation. Approximately 0.59 miles of new line will be built from the cut-in to the Evergreen Mills substation. Cut and extend the existing 230 kV line #2183 creating a new line #2210 from Brambleton substation to be terminated at Evergreen Mills substation. Approximately 0.59 miles of new line will be built from the cut-in to the Evergreen Mills substation.	$7.71	Dominion	Dominion	6/1/2027
b3780.5	Build Solley Road substation + Statcom. New STATCOM rating: 350 MVAR Add 4x 230 kV breakers bays.	$109	BGE	BGE	12/31/2028
b3780.6	Build Granite substation + Statcom. New STATCOM rating: 350 MVAR Add 4x 230 kV breaker bays.	$91	BGE	BGE	12/31/2028
b3780.7	Build Batavia Road substation. Add 4x 230 kV breaker bays.	$36	BGE	BGE	12/31/2028
b3780.9	Graceton to Batavia Road 230 kV double circuit pole line New rating: 1331 MVA SN/ 1594 MVA SE	$195	BGE	BGE	12/31/2028
b3781	Replace line drops to Doubs transformer 3. New transformer rating: 721MVA SN /862 MVA SE	$0.80	APS	APS	12/31/2025

Attachment B – Reliability Project Multi-Zone Allocations

Note: The cost allocation for project b3737 (New Jersey SAA project) will be in accordance with OATT Schedule 12 Appendix C.

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3737.53	Remove the existing E83 line 115 kV (not in-service) to accommodate the new 500 kV/230 kV lines (~ 7.7 miles).	$8.47	JCPL	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)	12/31/2027
b3737.54	Remove the existing H2008 Larrabee-Smithburg No. 2 230 kV to accommodate the new 500 kV/230 kV lines.	$8.47	JCPL	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)	12/31/2027
b3737.55	Middlesex substation 230 kV – Replace the 2000A circuit switcher at Middlesex switch point for the Lake Nelson I1023 230 kV exit.	$0.53	JCPL	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)	6/1/2029
b3737.56	Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild, which is 2.16 miles.	$9.92	BGE	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)	6/1/2029
b3737.59	Windsor to Clarksville subproject: Upgrade terminal equipment at Windsor 230 kV.	$1.58	JCPL	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)	6/1/2029
b3737.60	Perform a Pre-build Infrastructure evaluation study in alignment with the NJBPU Solicitation Guidance Document requirements.	$0.29	MAOD	AEC (13.55%) / JCPL (31.74%) / PSEG (52.60%) / RE (2.11%)	6/2/2023

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3780.1	Peach Bottom North upgrades – substation work Add 3x 500 kV breakers to form a breaker-and-a-half bay.	$33	PECO	**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS(5.76%) / ATSI (8.04%) / BGE(4.11%) / ComEd (13.39%) / Dayton(2.12%) / DEOK (3.25%) / DL(1.71%) / DPL (2.60%) / Dominion(13.32%) / EKPC (1.89%) / JCPL(3.86%) / ME(1.90%) / NEPTUNE*(0.42%) / OVEC (0.08%) / PECO(5.40%) / PENELEC (1.78%) /PEPCO (3.67%) / PPL (4.72%) /PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** ATSI (0.02%) / BGE (28.40%) / Dominion (33.36%) / DPL (0.02%) / JCPL (6.36%) / Neptune (0.73%) / PECO (0.01%) / PEPCO (17.90%) / PSEG (12.69%) / RE (0.51%)	12/31/2027
b3780.2	Peach Bottom to Graceton (PECO) – New 500 kV transmission line New rating: 4503 MVA SN/ 5022 MVA SE	$48	PECO	**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS(5.76%) / ATSI (8.04%) / BGE(4.11%) / ComEd (13.39%) / Dayton(2.12%) / DEOK (3.25%) / DL(1.71%) / DPL (2.60%) / Dominion(13.32%) / EKPC (1.89%) / JCPL(3.86%) / ME(1.90%) / NEPTUNE*(0.42%) / OVEC (0.08%) / PECO(5.40%) / PENELEC (1.78%) /PEPCO (3.67%) / PPL (4.72%) /PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** ATSI (0.02%) / BGE (28.40%) / Dominion (33.36%) / DPL (0.02%) / JCPL (6.36%) / Neptune (0.73%) / PECO (0.01%) / PEPCO (17.90%) / PSEG (12.69%) / RE (0.51%)	12/31/2027

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3780.3	West Cooper substation (3 breaker ring + transformer, control house + substation build, reconfigure Cooper distribution station feed) New transformer rating: 1559 MVA SN/ 1940 MVA SE	$60	PECO	DPL (41.52%) / PECO (58.48%)	12/31/2028
b3780.4	Peach Bottom to Graceton (BGE) – transmission work New rating: 4503 MVA SN/ 5022 MVA SE	$17	BGE	**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS(5.76%) / ATSI (8.04%) / BGE(4.11%) / ComEd (13.39%) / Dayton(2.12%) / DEOK (3.25%) / DL(1.71%) / DPL (2.60%) / Dominion(13.32%) / EKPC (1.89%) / JCPL(3.86%) / ME(1.90%) / NEPTUNE*(0.42%) / OVEC (0.08%) / PECO(5.40%) / PENELEC (1.78%) /PEPCO (3.67%) / PPL (4.72%) /PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** ATSI (0.03%) / BGE (28.40%) / Dominion (33.36%) / DPL (0.02%) / JCPL (6.36%) / Neptune (0.73%) / PEPCO (17.90%) / PSEG (12.69%) / RE (0.51%)	12/31/2028
b3780.8	Graceton 500 kV expansion Add 3x 500 kV breaker bays, 2x 500/230 kV auto transformer, 1x 500 kV caps. New transformer rating: 1559 MVA SN / 1940 MVA SE New capacitor rating: 250 MVAR	$82	BGE	BGE (81.92%) / PEPCO (18.08%)	12/31/2028

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3780.10	Install new Conastone capacitor. New capacitor rating: 350 MVAR	$15	BGE	**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS(5.76%) / ATSI (8.04%) / BGE(4.11%) / ComEd (13.39%) / Dayton(2.12%) / DEOK (3.25%) / DL(1.71%) / DPL (2.60%) / Dominion(13.32%) / EKPC (1.89%) / JCPL(3.86%) / ME(1.90%) / NEPTUNE*(0.42%) / OVEC (0.08%) / PECO(5.40%) / PENELEC (1.78%) /PEPCO (3.67%) / PPL (4.72%) /PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** BGE (100.00%)	12/31/2027
b3780.11	Brighton Statcom and capacitor New STATCOM rating: 350 MVAR New capacitor rating: 350 MVAR	$63	PEPCO	**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS(5.76%) / ATSI (8.04%) / BGE(4.11%) / ComEd (13.39%) / Dayton(2.12%) / DEOK (3.25%) / DL(1.71%) / DPL (2.60%) / Dominion(13.32%) / EKPC (1.89%) / JCPL(3.86%) / ME(1.90%) / NEPTUNE*(0.42%) / OVEC (0.08%) / PECO(5.40%) / PENELEC (1.78%) /PEPCO (3.67%) / PPL (4.72%) /PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** PEPCO (100.00%)	12/31/2028

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3780.12	Burchess Hill Cap New capacitor rating: 250 MVAR	$15	PEPCO	**Load-Ratio Share Allocation:** AEC (1.65%) / AEP (13.68%) / APS(5.76%) / ATSI (8.04%) / BGE(4.11%) / ComEd (13.39%) / Dayton(2.12%) / DEOK (3.25%) / DL(1.71%) / DPL (2.60%) / Dominion(13.32%) / EKPC (1.89%) / JCPL(3.86%) / ME(1.90%) / NEPTUNE*(0.42%) / OVEC (0.08%) / PECO(5.40%) / PENELEC (1.78%) /PEPCO (3.67%) / PPL (4.72%) /PSEG (6.39%) / RE (0.26%) **DFAX Allocation:** PEPCO (100.00%)	12/31/2027
b3780.13	Batavia Road to Riverside 230 kV reconductor New rating: 1941 MVA SN / 2181 MVA SE	$21	BGE	BGE (51.24%) / PEPCO (48.76%)	12/31/2026

Attachment C – Multi-Driver Project Cost Allocation

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3775.11	Upgrade the limiting element at Stillwell substation to increase the rating of the Stillwell-Dumont 345 kV line to match conductor rating.	$1.78	AEP	**Market Efficiency Driver: (52.75%)** AEC (0.87%) /AEP (24.07%) /APS (3.95%) /BGE (4.30%) /Dayton (3.52%) /DEOK (5.35%) /Dominion (20.09%) /DPL (1.73%) /DL (2.11%) /ECP (0.17%)/EKPC (1.73%) /ATSI (11.04%) /HTP (0.07%) /JCPL (1.98%) /ME (1.63%) /NEPTUNE (0.43%) /OVEC (0.07%) /PECO (3.59%) /PENELEC (1.68%) /PEPCO (3.91%) /PPL (3.64%) /PSEG (3.93%) /RE (0.14%) **Reliability Driver: (47.25%)** AEP (12.38%) / ComEd (87.62%)	12/1/2026

Exhibit No. MAOD-12
Mid-Atlantic Offshore Development, LLC
March 20, 2024 NJBPU Order

Agenda Date: 3/20/24
Agenda Item: 8D

STATE OF NEW JERSEY
Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY	)	ORDER ON THE STATE AGREEMENT APPROACH (SAA) - PROJECT SCOPE MODIFICATIONS AND COST ADJUSTMENTS
	)	DOCKET NO. QO20100630

Parties of Record:

Brian O. Lipman, Esq., Director, New Jersey Division of Rate Counsel
Susan McGill, PJM Interconnection, L.L.C.
Andrew Hendry, Jersey Central Power & Light Company
Michael Donnelly, Atlantic City Electric Company
Matthew Virant, Mid-Atlantic Offshore Development, LLC
Eric Hayes, LS Power Grid Mid-Atlantic, LLC
Shadab Ali, PPL Electric Utilities
Jodi Moskowitz, Public Service Electric and Gas Company
Maria J. Malguarnera, Transource Energy, LLC

BY THE BOARD:

By this Order, the New Jersey Board of Public Utilities ("BPU" or "Board") considers scope changes and cost changes for State Agreement Approach ("SAA" or "SAA 1.0") projects originally approved on October 26, 2022 under this docket, which will result in a cost savings to ratepayers of approximately $29 million.[1]

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[1] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated October 26, 2022 ("SAA Order" or "SAA 1.0 Award Order").

I. BACKGROUND AND PROCEDURAL HISTORY

As part of New Jersey's offshore wind ("OSW") coordinated transmission solution under the inaugural SAA, the Board awarded a series of projects to construct the on-shore transmission facilities necessary to deliver 7.5 gigawatts ("GW") of OSW generation to New Jersey customers.[2] The awarded SAA projects would help the State advance its clean energy targets and save ratepayers over $900 million dollars when compares to an uncoordinated transmission approach.[3] The SAA remains an important part of the State's OSW plans, which progressed on January 24, 2024, when the Board issued two (2) orders, collectively awarding a total of 3,742 MW of new OSW power off the coast of the State.[4] The OSW projects awarded on January 24, 2024 will use the SAA projects to inject their energy into New Jersey's electricity grid.

In the SAA Order, the Board recognized that the development of transmission projects requires years of planning and coordination.[5] Further, the Board found that "future revisions to the awarded projects herein under the Larrabee Tri-Collector Solution may be required depending on changed circumstances unknowable as of the time of award."[6] With the appreciation that some flexibility is necessary, the Board retained the right to enter further orders to reflect "significant updates" to the scope, configuration, and/or costs to the awarded SAA projects on the basis of any future changed circumstances.[7] The Board also authorized Board Staff ("Staff") to review and accept routine "changes to elements of any awarded projects that would increase the benefits to New Jersey ratepayers," and to notify PJM Interconnection, L.L.C. ("PJM") of same.[8]

As noted in the SAA Order, Staff relied on a robust record to support its SAA recommendation to the Board. Part of the record included Brattle's evaluation report ("Evaluation Report"), which provided an in-depth overview and analysis of the SAA evaluation. [9]

On June 29, 2023, the Board issued an order addressing the first round of cost adjustments for the SAA projects.[10] By the June 2023 Order, the Board approved scope and cost changes resulting in a $127.34 million cost increase for the SAA.[11] The Board found that despite the cost

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[2] Id. at 14. A GW is the equivalent of 1,000 megawatts ("MW"). The SAA Order's reference to 7,500 MW of OSW-generated power is the equivalent to 7.5 GW of OSW-generated power. Id.

[3] Id. at 61.

[4] In re Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC), BPU Docket No. QO22080481, Order dated January 24, 2024 ("Attentive January 24, 2024 Order") (approving the Attentive Energy Two 1,342 MW project proposed by Attentive Energy LLC); In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC), BPU Docket No. QO22080481, Order dated January 24, 2024 ("Invenergy January 24, 2024 Order") (approving the Leading Light Wind 2,400 MW project proposed by Invenergy Wind Offshore LLC).

[5] See SAA Order at 71.

[6] Id. at 73.

[7] Ibid.

[8] Ibid.

[9] The Brattle Group, Brattle SAA Evaluation Report Final – Public, October, 26, 2022, https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2109468.

[10] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated June 29, 2023 ("June 2023 Order").

[11] Id. at 7.

increases, the SAA project remained beneficial to New Jersey ratepayers and would continue to provide ratepayers a savings of approximately $900 million as the state progresses to expand its offshore wind capabilities.[12]

II. DESCRIPTION OF CHANGES

Regarding project cost estimates, the Evaluation Report noted that the SAA bidders, including those that were awarded projects by the Board, provided uncertainty ranges for their SAA proposals' cost estimates.[13] Brattle noted that most cost estimates provided by the bidders carried an uncertainty range of -20% to +30% of the submitted estimate.[14] PJM also modeled, in its final financial analysis report, a scenario with an across-the-board 25% project cost increase, noting that the use of scenarios assist in providing insight into the impact of potential cost increases.[15]

New Jersey's awarded SAA projects are included in PJM's Regional Transmission Expansion Plan ("RTEP"), and SAA projects are required to follow the RTEP guidelines and process, including those established for cost estimate adjustments.[16] The RTEP process does not require Board approval for scope-related cost estimate adjustments for approved RTEP projects.[17] Rather, these adjustments will follow PJM's standard RTEP process and be subject to the same safeguards.[18] However, one of the many benefits of the SAA is that it allows for greater transparency and Board involvement than would otherwise be provided under the standard RTEP process.

Since the SAA Order was issued, Staff and PJM regularly meet to discuss ongoing updates related to the awarded projects. As part of these meetings, PJM continues to provide updates to Staff when PJM receives cost estimate adjustments from the awarded SAA projects. PJM has indicated that these updates are not uncommon. In fact, PJM notes that it anticipates future cost estimate adjustments (both increases and decreases) across all the SAA projects, primarily as each project goes through its detailed engineering phase from which it will get more accurate

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[12] Id. at9.

[13] Evaluation Report at 8.

[14] Evaluation Report at 81.

[15] Financial Analysis Report: 2021 SAA Proposal Window to Support NJ OSW, September 19, 2022, nj-osw-financial-analysis-report-september-final.ashx (pjm.com)

[16] PJM Operating Agreement, Schedule 6; PJM Tariff, Schedule 12.

[17] PJM Operating Agreement, Schedule 6, Section 1.6; PJM Tariff, Schedule 12.

[18] See PJM Operating Agreement, Schedule 6, which sets forth the rules and procedures for the RTEP. The Transmission Expansion Advisory Committee ("TEAC") is a committee established under the PJM Operating Agreement to aid in the development of the RTEP and provides advice and recommendations to the PJM Board of Managers ("PJM Board") for review of RTEP projects, including cost estimate adjustments. Cost estimate adjustments are routinely submitted to PJM by the project developer and then presented to the TEAC where TEAC members can review the cost estimate adjustments, ask questions and state their positions. TEAC members include transmission customers (as defined in the PJM Tariff), any other entity proposing to provide transmission facilities, agencies and offices of customer advocates who exercise regulatory authority over the rates, terms or conditions of electric service, and any other interested entities or persons. PJM Board retains discretion to formally review RTEP cost estimate adjustments. FERC can also review all costs included in transmission rates, including SAA-related costs, and change the resulting transmission rates if it finds that the inclusion of these costs renders those rates unjust and unreasonable. See 16 U.S.C. § 824e(a).

labor and material costs. Further, while typically the Board would not be specifically presented with these common cost estimate adjustments for RTEP projects, the SAA process allows for this additional engagement. Additionally, unlike with standard RTEP projects, Staff separately meets with SAA project developers to discuss the ongoing development of the projects. This close coordination and engagement provides a greater level of transparency than if the project had been awarded under the standard RTEP process. The coordination also ensures that the Board may exercise its retained right to review and approve "significant updates to the scope, configuration and/or cost," and Staff's ability to review and accept routine changes.[19]

The SAA updates can be categorized by their cost, scope, and allocation adjustments. The cost and scope adjustments for Public Service Electric and Gas Company's ("PSE&G's") Lake Nelson subproject – located near Piscataway, the Lake Nelson subproject is a component of the awarded SAA projects – are a result of the additional analysis after the SAA project was awarded. The engineering analysis conducted by PSE&G, as detailed to Staff by PJM staff and PSE&G, resulted in additional equipment to meet applicable reliability standards. For the scope and cost changes at Mid-Atlantic Offshore Development's ("MAOD's") Larrabee Collection Station ("LCS") – an onshore substation established by the SAA – engineering analysis by MAOD and PJM revealed that the autotransformers at the LCS were undersized.[20] Additionally, a number of SAA 1.0 projects have been cancelled due to refined needs analyses following initial component upgrades estimates or updates to the North Delta project – planned expansions near the Pennsylvania/Maryland border, near the Susquehanna River – during the 2022 Window 3 RTEP, which was studied in December 2023, that made certain SAA 1.0 upgrades obsolete. The last adjustment captured is a cost allocation adjustment also stemming from the 2022 Window 3 RTEP.[21] Other parts of the North Delta project requiring additional reliability upgrades have been recategorized by PJM under the multi-driver project framework.[22] Per the PJM Operating Agreement and cost allocation methodology, the additional costs associated with this multi-driver will not result in a cost change at this time for the SAA, but the allocation of the total project cost has changed.[23] These cost, scope, and allocation changes will not affect the expected completion dates of the SAA projects, and all projects are expected to be completed on or before schedule.

While this Board Order memorializes an overall cost decrease to the SAA project costs of $29 million, Staff appreciates the significance of cost increases and ratepayer impacts. Of critical importance throughout the SAA process was the baseline scenario, or the cost of the transmission facilities that would be necessary to achieve New Jersey's 7,500 MW OSW goal in the absence of the SAA solicitation ("Baseline Scenario").

Using the Baseline Scenario cost estimates and the SAA project cost estimates, Brattle and Staff were able to determine that, at the time of the SAA award by the Board's issuance of the SAA 1.0 Award Order on October 26, 2022, New Jersey ratepayers would realize an estimated savings of

[19] SAA Order at 73. See also PJM Rate Schedule 49, paragraphs 3, 4, 5, and 7.

[20] The LCS is a new substation adjacent to the existing JCP&L Larrabee substation awarded to enable offshore wind interconnection through SAA 1.0.

[21] A "cost allocation" refers to the mechanisms under which PJM distributes costs amongst parties through its Tariff. See PJM Tariff, Schedule 12.

[22] A "multi-drive" project combines separate solutions for different drivers of transmission enhancements – such as reliability, economic, and public policy projects – into a single more efficient project. PJM Operating Agreement, Schedule 6, section 1.5.10(h).

[23] See PJM Tariff, Schedule 12(b)(xiv).

over $900 million dollars with the awarded SAA projects, compared to the Baseline Scenario.

As transmission projects develop, it is common, if not expected, for cost estimate adjustments to occur. In fact, PJM typically sees a range of cost estimate adjustments beginning at the time a project is bid into the RTEP until the time of that project's final construction. As such, additional cost estimate adjustments, in addition to the cost estimate adjustments noted herein, may be anticipated in the future. Staff remains committed to closely engaging with PJM and the awarded SAA project developers to ensure all cost estimate adjustments are reasonable, while continuing to prioritize the interests of New Jersey ratepayers.

General Scope and Cost Adjustments

Changes to the scope of several of the awarded SAA projects ("Scope Change Work") have been identified. A summary of such scope changes are as follows:

Atlantic City Electric Company ("ACE")

- Cancel b3737.24: Upgrade Cardiff-Lewis 138 kV transmission line (previous cost estimate $0.10 million); and

- Cancel b3737.25: Upgrade Lewis No. 2-Lewis No. 1 138 kV by adding a circuit breaker (previous cost estimate $0.50 million).

    Explanation of change for b3737.24 and b3737.25: A facility inspection identified an incorrect component rating. With the revised rating, this work is no longer needed to address potential reliability criteria violations.

PSE&G

- Cancel b3737.41: Windsor to Clarksville subproject: Upgrade terminal equipment at Clarksville 230 kV (previous cost estimate $1.49 million).[24]

    Explanation of change for b3737.41: After detailed analysis by PSE&G on the Clarksville sub-project, it was determined that the Clarksville terminal scope of work is no longer needed.

- Revised Cost Estimate b3737.42: Upgrade plant equipment at Lake Nelson I 230 kV (previous cost estimate $4.80 million, updated cost estimate $8.00 million);

- Revised Cost Estimate b3737.43: Upgrade Kilmer W-Lake Nelson W 230 kV connections at Lake Nelson 230 kV (previous cost estimate $0.57, updated cost estimate $1.40 million); and

- Revised Cost b3737.44: Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV connections at Lake Nelson 230 kV (previous cost estimate $0.58 million, updated cost estimate $0.70 million).

    Explanation of changes for b3737.42, b3737.43, and b3737.44: PSE&G performed detailed analysis to refine the cost estimates for the Lake Nelson project, leading to an

[24] The Windsor and Clarksville subproject is located in Lawrence Township, New Jersey.

increase in cost. Specifically, PSE&G explained that its engineering team recommended replacements to its dead-end structures to maintain contingencies and reliability.

MAOD

- Revised Cost Estimate b3737.22: Cost increase of $0.8M.

  Explanation of changes for b3737.22: In order to meet compliance with reactive power requirements, the auto transformers sizing on the 500 KV line from the LCS to Smithburg needs to increase from 450 MVA to 480 MVA.[25]

The changes described above and shown below result in a net cost increase of $2.86 million to SAA 1.0. Staff finds that these changes are prudent and recommends Board approval.

Project ID	Developer	Change Description	Original ($M)	Current ($M)	Change ($M)
b3737.24	ACE	Cancel work	$0.10	$0.00	($0.10)
b3737.25	ACE	Cancel work	$0.50	$0.00	($0.50)
b3737.41	PSE&G	Cancel work	$1.49	$0.00	($1.49)
b3737.42	PSE&G	Revised cost estimate	$4.80	$8.20	$3.20
b3737.43	PSE&G	Revised cost estimate	$0.57	$1.50	$0.83
b3737.44	PSE&G	Revised cost estimate	$0.58	$0.70	$0.12
b3737.22	MAOD	Revised cost estimate	$193.59	$194.29	$0.80
				SUM	$2.86

North Delta Project – Cost Reductions for the SAA

The SAA projects required updates to the North Delta station near the Pennsylvania/Maryland border and connecting infrastructure. These updates would be completed by Baltimore Gas and Electric Company ("BGE") and PECO Energy Company ("PECO"). Through the 2022 RTEP, PJM determined that additional upgrades would be needed to account for other changes on the PJM system, such as supporting the added energy injection from offshore wind developments and supporting load demand in Northern Virginia. Certain components of the planned upgrades would be cancelled and replaced with more robust solutions. PJM determined that these new solutions would not be eligible for multi-driver cost allocation, and the SAA would have no longer have cost obligation for the solutions.

[25] "MVA" means Mega Volt Ampere.

BGE

- Cancel b3737.46: Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station (previous cost estimate $1.55 million); and

- Cancel b3737.56: Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild, which is 2.16 miles. (previous cost estimate $9.92 million)

  Explanation of changes for b3737.46 and b3737.56: These projects are no longer needed based on the revised scope of North Delta station.

PECO Energy Company ("PECO")

- Cancel b3737.48: Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for PECO's portion of the line rebuild which is 4.1 miles (previous cost estimate $18.82 million); and

- Cancel b3737.49: Bring the Cooper-Graceton 230 kV line "in and out" of North Delta by constructing a new double-circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines (previous cost estimate $1.56 million).

  Explanation of changes for b3737.48 and b3737.49: These projects are no longer needed based on the revised scope of the North Delta station.

The cancellation of these four (4) projects, as described above, result in a net decrease of $31.85 million from the costs of SAA 1.0.

Project ID	Developer	Change Description	Original ($M)	Current ($M)	Change ($M)
b3737.46	BGE	Cancel work	$1.55	$0.00	($1.55)
b3737.48	PECO	Cancel work	$18.82	$0.00	($18.82)
b3737.49	PECO	Cancel work	$1.56	$0.00	($1.56)
b3737.56	BGE	Cancel work	$9.92	$0.00	($9.92)
				SUM	($31.85)

North Delta Project - Cost Allocation Adjustments

In addition to the changes noted above, PJM's 2022 RTEP found that other changes to the North Delta infrastructure qualify for multi-driver cost allocation.[26] The change in scope for the project makes for a new total cost of $104.1 million, instead of the initially proposed $76.27 million. However, the multi-driver cost allocation results in no net change to the SAA project's cost. The

[26] For detailed description of the North Delta changes and cost allocations, please see PJM's filing at FERC. PJM Interconnection, L.L.C., FERC Docket No. ER24-843 (Jan. 10, 2024).

added costs will be allocated through PJM's reliability framework.[27] The change in scope and treatment results in no net change in the cost estimate allocated to the SAA 1.0 project.

Transource

- Modify b3737.47: Build New North Delta 500 kV substation (four bay breaker and half configuration) - the substation will include 12 – 500 kV breakers and one 500/230 kV transformer, and will allow the termination of six - 500 kV lines.

  Explanation of changes for b3737.47: The scope of the North Delta substation will be expanded to support the additional reliability needs. PJM will treat this project as a multi-driver project to share the costs between the New Jersey SAA public policy project need and 2022 Window 3 reliability needs as follows:

Need	**Cost ($M)**	**% Cost Allocation[28]**
NJSAA	$76.27	73.27%
Reliability	$27.83	26.73%
Total	$104.10	100%

The total cumulative cost changes captured in this Order result in a $29 million cost decrease to the SAA 1.0 project.

Rate Counsel Correspondence

Staff provided the New Jersey Division of Rate Counsel ("Rate Counsel") information on these updates prior to today's Order. Rate Counsel did not object to the Board approving and acknowledging these changes. Rate Counsel continued to request that Staff regularly communicate with Rate Counsel's office to consider the potential ratepayer impact of future changes in cost or scope.

III. DISCUSSION AND FINDINGS

Based on the review of the information presented above and Staff's recommendation, the Board also **HEREBY APPROVES** the modification of PSE&G and MAOD's designated scope of work and costs as discussed above and **HEREBY DIRECTS** PSE&G and MAOD to engage with PJM so that it may take the necessary steps to effectuate such modification on a timely basis. The Board **HEREBY FURTHER DIRECTS** PSE&G and MAOD to update Staff regularly on the PJM amendment process, including, but not limited to, schedule updates and any cost estimate adjustments.

For the scope-related adjustments, including the cancelled projects cost allocation adjustments discussed herein, the Board **HEREBY ACKNOWLEDGES** these adjustments to the SAA 1.0 projects. The Board also **HEREBY REAFFIRMS** that all of the benefits associated with the Larrabee Tri-Collector Solution will continue to be realized by the residents of New Jersey, and

[27] Id. at Appendix A.

[28] The SAA will be responsible for 74.27% of the total cost of $104.10 million, which equates to a cost responsibility of $76.27 million.

that New Jersey's ratepayers will continue to see a savings of approximately $900 million as a result of the SAA projects being utilized to achieve New Jersey's OSW public policy.

As stated in the SAA Order and again here, the Board finds that future revisions to the projects awarded under the SAA may be required. The Board **HEREBY RETAINS THE RIGHT** to enter further orders in this docket as deemed necessary to reflect significant updates to the scope, configuration and/or cost of projects on the basis of any future changed circumstances. In addition, should PJM or Staff identify routine changes to elements of any awarded SAA projects that would increase the benefits to New Jersey ratepayers, the Board **HEREBY AUTHORIZES** Staff to review and accept these revisions, and notify PJM of the same.

The effective date of this Order is March 27, 2024.

DATED: March 20, 2024

BOARD OF PUBLIC UTILITIES
BY:

CHRISTINE GUHL-SADOVY
PRESIDENT

DR. ZENON CHRISTODOULOU
COMMISSIONER

MARIAN ABDOU
COMMISSIONER

MICHAEL BANGE
COMMISSIONER

ATTEST:

SHERRI L. GOLDEN
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

IN THE MATTER OF DECLARING TRANSMISSION TO SUPPORT OFFSHORE WIND A PUBLIC POLICY OF THE STATE OF NEW JERSEY

DOCKET NO. QO20100630

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Exhibit No. MAOD-13
Mid-Atlantic Offshore Development, LLC
PJM February 2024 Whitepaper

Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board

PJM Staff White Paper

PJM Interconnection
February 2024

For Public Use

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Contents

I. Executive Summary

On December 8, 2023, the PJM Board of Managers approved changes to the Regional Transmission Expansion Plan (RTEP), totaling a net increase of $5,085.85 million for baseline projects, to resolve baseline reliability criteria violations, address changes to existing projects and project cancellations. The RTEP approved by the PJM Board of Managers in December 2023 also included a net increase of $138.13 million for network upgrades to address new projects with signed ISAs and project cancellations.

Since then, PJM has identified new baseline reliability criteria violations, and the transmission system enhancements needed to resolve them, at an estimated cost of $186.29 million. Scope changes to an existing project will result in a net increase of $24.15 million. Cancellation to existing projects will result in a net decrease of $66.04 million. This yields an overall RTEP net increase of approximately $144.4 million to resolve baseline criteria violations, for which PJM is recommended Board approval. PJM is also providing an update for RTEP generation and merchant transmission network upgrades. PJM has identified $1,094.87 million in new network upgrades. Additionally, $45.07 million in previously identified network upgrades will be canceled as a result of updates to analysis performed for project withdrawals in the New Services Queue. This yields an overall RTEP net increase of approximately $1,049.8 million associated with RTEP generation and merchant transmission network upgrades. Altogether, the changes result in an overall RTEP net increase of approximately $1,194.20 million. With these changes, RTEP projects will total approximately $49,453.0 million since the first Board approvals in 2000.

PJM sought Reliability and Security Committee consideration and full Board approval of the RTEP baseline projects summarized in this white paper.

On February 28, 2024, the Board approved the addition of RTEP baseline projects as well as other changes to the RTEP as summarized in this paper.

II. Baseline Project Recommendations

A key dimension of PJM's RTEP process is baseline reliability evaluation, which is necessary before subsequent interconnection requests can be analyzed. Baseline analysis identifies system violations to reliability criteria and standards, determines the potential to improve the market efficiency and operational performance of the system, and incorporates any public policy requirements. PJM then develops transmission system enhancements to resolve identified violations and reviews them with stakeholders through the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committees prior to submitting its recommendation to the Board. Baseline transmission enhancement costs are allocated to PJM responsible customers.

III. Baseline Reliability Projects Summary

A summary of baseline projects with estimated costs equal to or greater than $10 million is provided below. Projects with estimated costs less than $10 million typically include, by way of example, transformer replacements, line reconductoring, breaker replacements and upgrades to terminal equipment, including relay and wave trap replacements. A complete listing of all recommended projects and their associated cost allocations is included in Attachment A (allocations to a single zone) and Attachment B (allocations to multiple zones).

A. AEP Transmission Zones

- Baseline project b3786.1 – Abert-Reusens 69 kV Rebuild: $14.4 million

B. APS Transmission Zone

- Baseline project b3796 – Belmont 765/500 kV Transformer Replacement: $42.05 million

C. DPL Transmission Zone

- Baseline project b3846.1 -.3 – Vienna-Mardela 69 kV Rebuild: $21.38 million

D. PENELC Transmission Zones

- Baseline project b3791 – North Meshoppen-Mehoopany Line No. 1 115 kV Rebuild: $17.4 million
- Baseline project b3792 – North Meshoppen-Mehoopany Line No. 2 115 kV Rebuild: $17.7 million

E. PSEG Transmission Zone

- Baseline project b3794.1 -.2 – Waldwick 345 kV and 230 kV Shunt Reactor Replacements: $29.6 million

PJM also recommends regional baseline projects totaling $43.76 million, whose individual cost estimates are less than $10 million. The projects include, but are not limited to, a shunt reactor installation, breaker installation and replacements, a 230 kV line reconductor, a 46 kV line rebuild, a CCVT installation, terminal limiting equipment replacements, a substation reconfiguration, a less than 1-mile 69 kV underground cable rebuild and relay upgrades.

A more detailed description of the larger-scope projects that PJM recommended to the Board is provided below.

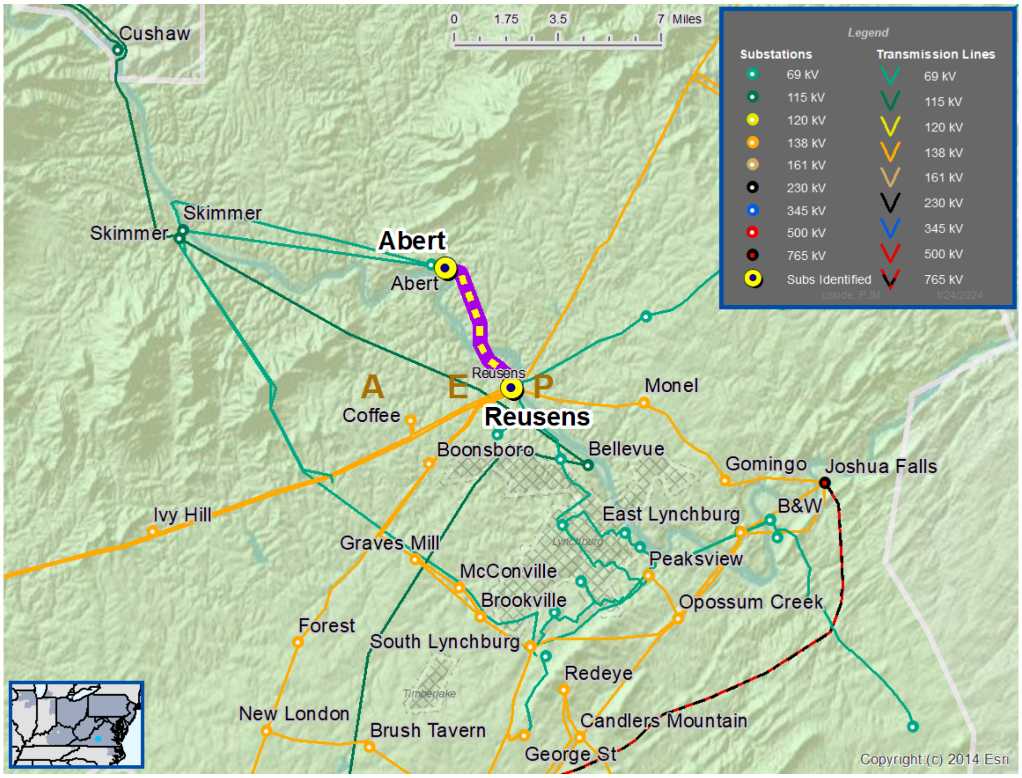
F. *Baseline Reliability Project Details*

Baseline Project b3786.1: Abert-Reusens 69 kV Rebuild

AEP Transmission Zone

In the 2028 RTEP summer case, the Abert-Reusens 69 kV line is overloaded for multiple N-1 outages. The flowgates were posted as part of the 2023 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 1. b3786.1: Abert-Reusens 69 kV



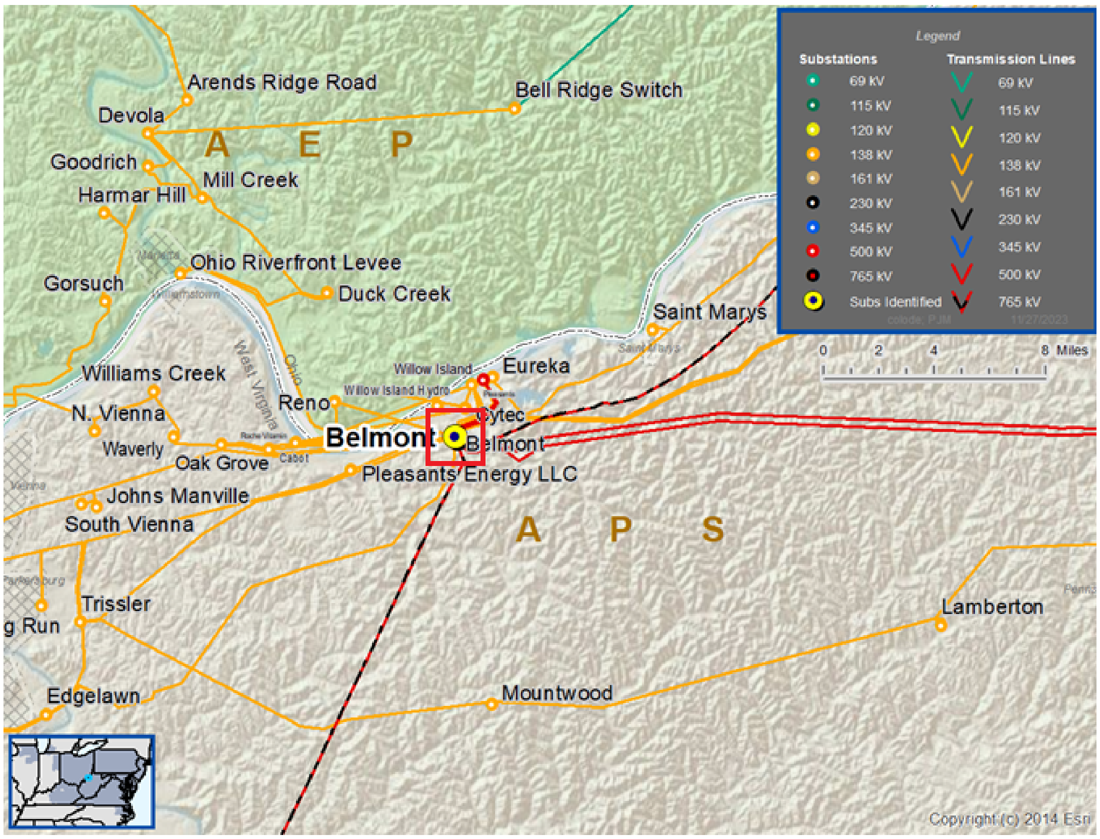
The recommended solution is to rebuild approximately 4.5 miles of 69 kV line between Abert and Reusens substations and update line relay settings at Reusens and Skimmer substations. The estimated cost for this project is $14.4 million. This project has a required and projected in-service date of June 2028, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3796: Belmont 765/500 kV Transformer Replacement

APS Transmission Zone

In the 2028 RTEP summer case, the Belmont 765/500 kV transformer is overloaded under one N-1 and multiple N-2 outages. The flowgates were posted as part of the 2023 RTEP Window 1, and PJM received six proposals, two from FirstEnergy and four from Transource, to address the flowgates.

Map 2. b3796 – Belmont 765/500 kV Transformer



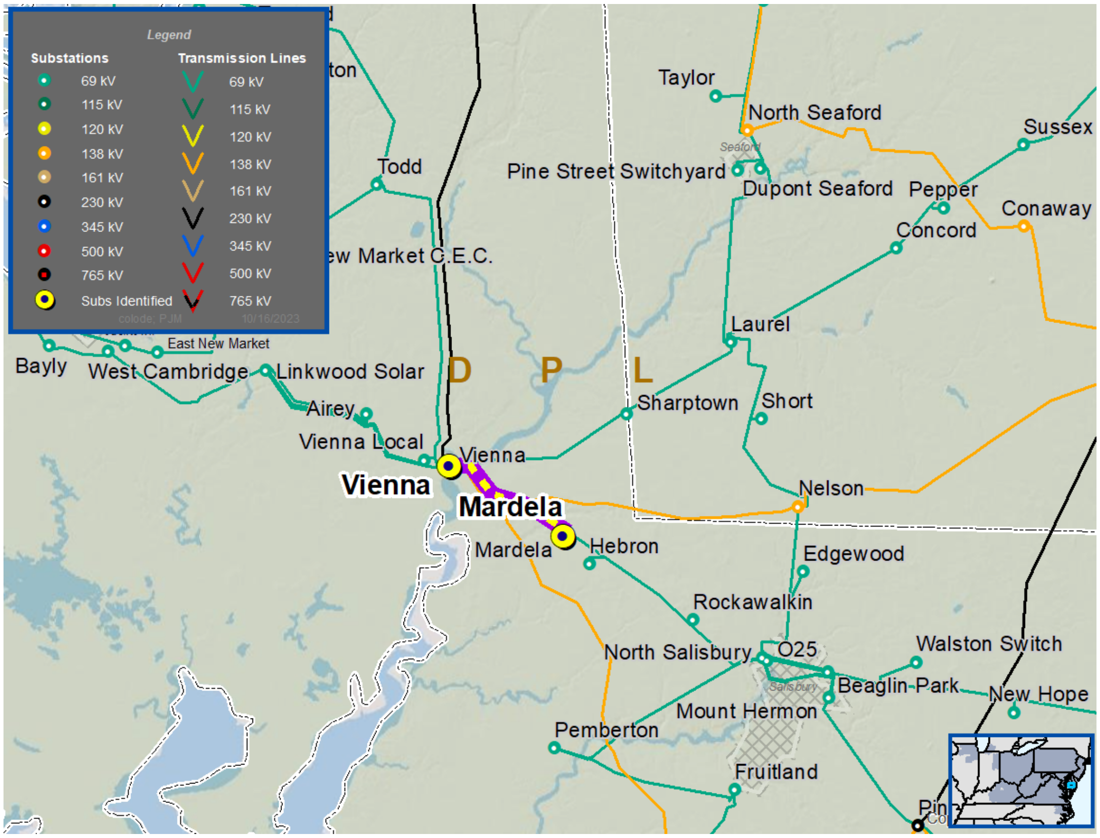
The recommended solution is to replace the Belmont 765/500 kV transformer No. 5 with a new transformer bank, consisting of three single-phase transformers and a spare transformer. The project will also replace 500 kV disconnect switches at the Belmont substation. The estimated cost for this project is $42.05 million. This project has a required and projected in-service date of June 2028, and the local transmission owner, APS, will be designated to complete this work.

Baseline Project b3846.1-.3: Vienna-Mardela 69 kV Rebuild

DPL Transmission Zone

In the 2028 RTEP summer case, the Vienna-Mardela 69 kV line is overloaded under multiple N-2 outages. The flowgates were posted as part of the 2023 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 3. b3846.1-.3: Vienna-Mardela 69 kV



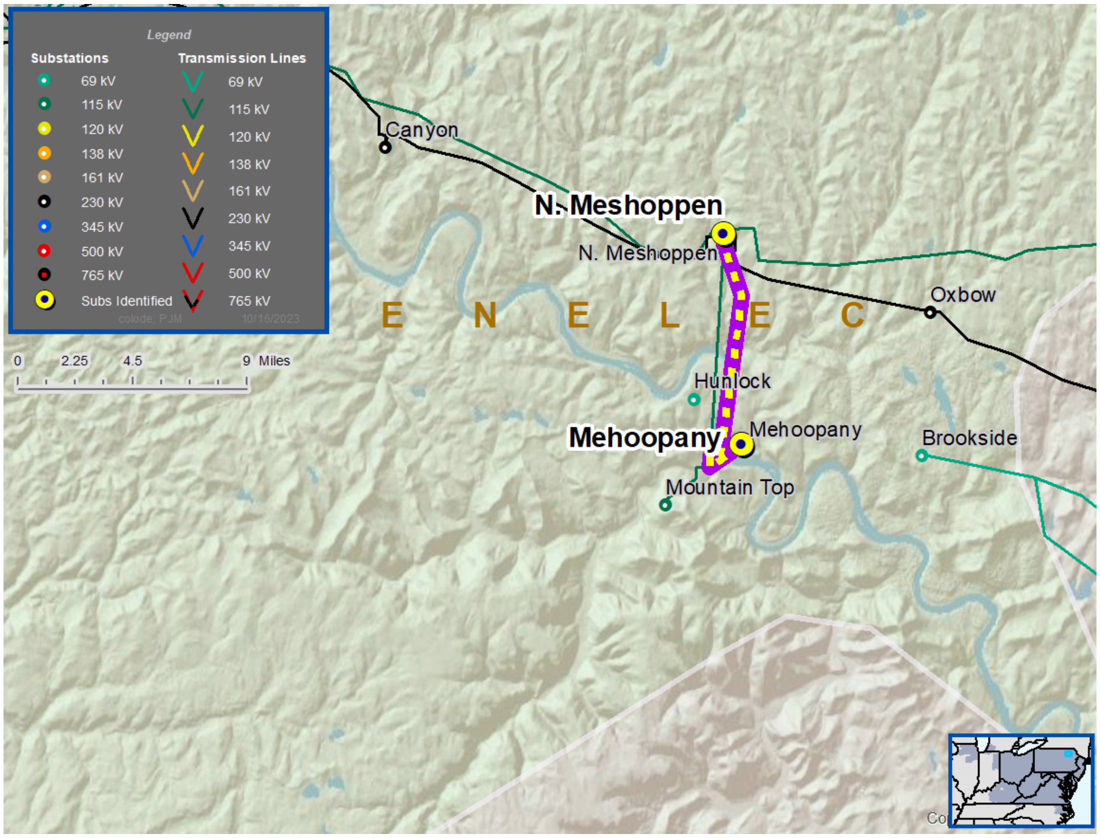
The recommended solution is to rebuild 6.25 miles of 69 kV circuit 6708 (Vienna-Mardela) with new single pole steel structures and with 954 ACSR conductor. This new rebuild will be from the dead-end structure on the east side of the Nanticoke River to the Mardela tap. The project also includes upgrading a disconnect switch at Vienna and three disconnect switches at Mardela to increase ratings of the existing Vienna-Mardela transmission facility. The estimated cost for this project is $21.38 million. This project has a required and projected in-service date of June 2028, and the local transmission owner, DPL, will be designated to complete this work.

Baseline Projects b3791 & b3792: North Meshoppen-Mehoopany No. 1 and No. 2 115 kV Rebuild

PENELEC Transmission Zone

In the 2028 RTEP summer case, the North Meshoppen-Mehoopany 115 kV line No. 1 and No. 2 segments are overloaded under one N-1 and multiple N-2 outages. The flowgates for both line segments were posted as part of the 2023 RTEP Window 1, and PJM received one proposal for each set of flowgates.

Map 4. b3791 & b3792: North Meshoppen-Mehoopany 115 kV



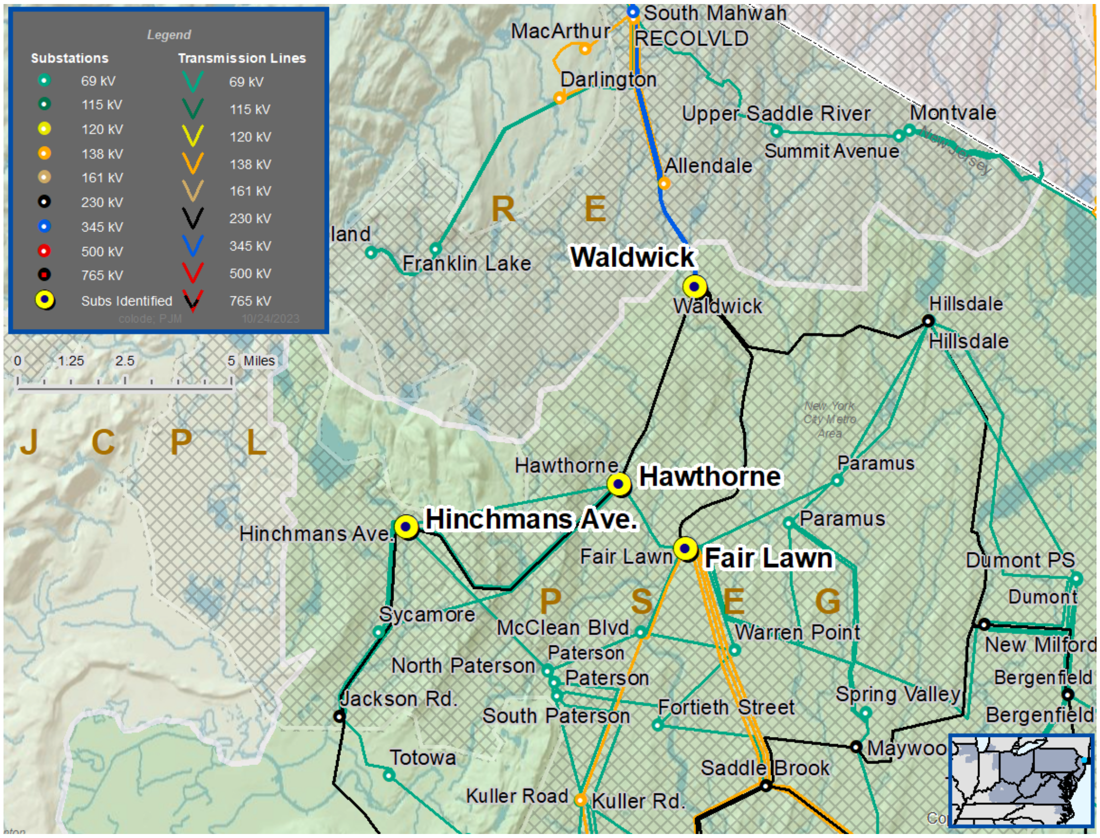
The recommended solutions are to rebuild the North Meshoppen-Mehoopany 115 kV line No. 1 and No. 2 with 795 ACSR 26/7 STR conductors and to upgrade terminal equipment to meet or exceed the transmission line ratings. The estimated cost to rebuild North Meshoppen-Mehoopany 115 kV line No. 1 is $17.4 million, and the estimated cost to rebuild North Meshoppen-Mehoopany 115 kV line No. 2 is $17.7 million. These projects have a required and projected in-service date of June 2028, and the local transmission owner, MAIT, will be designated to complete this work.

Baseline Project b3794.1-.2: Waldwick 345 kV and 230 kV Shunt Reactor Replacements

PSEG Transmission Zone

In the 2028 RTEP light load case, Hinchmans, Hawthorne, Waldwick and Fairlawn 230 kV and Waldwick 345 kV buses are observing high voltage violations under one N-1 and multiple N-2 outages. The flowgates were posted as part of the 2023 RTEP Window 1, and PJM received one proposal to address the flowgates.

Map 5. b3794.1-.2: Hinchmans, Hawthorne, Waldwick and Fairlawn 230 kV and Waldwick 345 kV



The recommended solution is to replace the existing 230 kV 50 MVAR and 345 kV 100 MVAR fixed shunt reactors at Waldwick switching station with 230 kV 150 MVAR and 345 kV 150 MVAR variable shunt reactors. The estimated cost for this project is $29.6 million. This project has a required and projected in-service date of June 2028, and the local transmission owner, PSEG, will be designated to complete this work.

IV. Transmission Owner Criteria Projects

Of the $186.29 million of new recommended baseline transmission system enhancements, approximately $35.82 million is driven by transmission owner planning criteria, which makes up approximately 19% of the new project cost estimates.

V. Changes to Previously Approved Projects

Scope/Cost Changes

The following scope/cost modifications were recommended:

New Jersey State Agreement Approach Project:

The New Jersey Board of Public Utilities requested prebuild provisions around the Larrabee station for civil work to minimize disturbance to the shoreline and in the vicinity of the Larrabee substation. This has resulted in a scope addition for baseline project b3737.22 [Larrabee Collector station scope of the New Jersey State Agreement Approach (SAA) project]. Additional scope includes prebuild extension work, such as duct banks, to accommodate four HVDC circuits from the prebuild point of demarcation to each offshore wind generator's converter station area on the Larrabee Collector station property. Three sets of AC collector lines with a combined total of 12 230 kV AC circuits that will run from each offshore wind generator's converter station area to the Larrabee Collector station AC interface will also be added. The previous cost for b3737.22 was $193.3 million, and the updated cost is $216.3 million, resulting in a cost increase of $23 million.

The following New Jersey SAA project scope is no longer required due to the approved higher capacity, more holistic system upgrades identified and approved for the Brandon Shores deactivation project, and the 2022 RTEP Window 3 project. This results in a net cost decrease of $31.85 million:

- Baseline b3737.46: Installation of new breaker at Graceton 230 kV to terminate a new 230 kV line from the new greenfield North Delta station – $1.55 million
- Baseline b3737.48: PECO's portion of the new North Delta-Graceton 230 kV line by rebuilding 4.1 miles of the existing Cooper-Graceton 230 kV line to double circuit – $18.82 million
- Baseline b3737.49: Brining the Cooper-Graceton 230 kV line "in and out" of North Delta – $1.56 million
- Baseline b3737.56: BGE's portion of the new North Delta-Graceton 230 kV line by rebuilding 2.16 miles of the existing Cooper-Graceton 230 kV line to double circuit – $9.92 million

All of the changes noted above result in a net cost decrease of $8.85 million for the New Jersey SAA project.

Brandon Shores Deactivation Project:

Brandon Shores 1 and 2 are coal units in the BGE zone with a total of approximately 1,282 MW capacity. The deactivation of these units causes widespread voltage violations in neighboring areas (PEPCO, METED, PPL, PECO, APS, Dominion). In July 2023, the PJM Board approved baseline b3780 to address the majority of the identified violations from the Brandon Shores deactivation study. In December 2023, baseline b3780.3 (construction of 500/230 kV West Cooper substation) was canceled with the approval of the 2022 RTEP Window 3 solution. PJM has since worked with the transmission owners to identify the following additional scope originally imbedded in the canceled baseline b3780.3 that is still required for the Brandon Shores deactivation:

- Baseline b3780.14: New 230 kV line from Cooper to North Delta – $3.6 million
- Baseline b3780.15: Loop Peach Bottom-Conastone 500 kV (5012) line into North Delta – $7.86 million
- Baseline b3780.16: Termination for New 230 kV line from Cooper to North Delta – $0.47 million
- Baseline b3780.17: Terminations for Peach Bottom-Conastone 500 kV (5012) line – $1.1 million

All of the changes noted above result in a net cost increase of $13.03 million for the Brandon Shores deactivation project.

2023 RTEP Window 3 Project:

In December 2023, the PJM Board approved baseline b3800 to address the 2022 RTEP Window 3 violations. Through detailed project review following project approval, FirstEnergy and Exelon have provided updated cost estimates for the following scope:

- Baseline b3800.2: Break the existing TMI-Peach Bottom 500 kV line and reterminate into adjacent Otter Creek 500 kV switchyard – Estimated cost has increased from $7.03 million to $18.3 million, resulting in an increase of $11.27 million.
- Baseline b3800.45: North Delta 500 kV termination for the Rock Springs 500 kV line (5034/5014 line) – Estimated cost has decreased from $10.2 million to $0.8 million, resulting in a decrease of $9.4 million.

Additionally, through detailed project review following project selection, Exelon has identified the following additional scope required at Peach Bottom 500 kV:

- Baseline b3800.52: Reconfigure Peach Bottom North and South yards to allow for termination of 500 kV lines from Peach Bottom to North Delta – $7.86 million.

All of the changes noted above result in a net cost increase of $9.73 million for the 2022 RTEP Window 3 project.

Accelerations

PJM's acceleration analysis determines which reliability projects, if any, have an economic benefit if accelerated or modified. The analysis utilized the most recent 2027 Market Efficiency base case available at the time to study the impacts of approved RTEP reliability projects, and identified the following two projects that result in congestion benefits if accelerated:

- Baseline b3694.8: Partial wreck and rebuild 10.34 miles of 230 kV line No. 249 (Carson-Locks) and upgrade of terminal equipment at Carson and Locks substations, if accelerated, results in an estimated annual congestion benefit of $1.8 million. This project will be accelerated from June 2026 to June 2025. While there is no cost to accelerate the project, Dominion has provided a more detailed engineering cost estimate, resulting in a net cost increase of $10.24 million.
- Baseline b3729: Upgrade of dead-end structures on Conowingo-Colora 230 kV line, installation of cable shunts and replacement of the existing insulator bells, if accelerated, results in an estimated annual

congestion benefit of $0.8 million. This project will be accelerated from June 2027 to June 2026, and does not result in any additional cost.

Cancellations

The following cancellations were recommended:

- Baseline b3017.1-.3 (Glade-Warren 230 kV line rebuild) is no longer required with Beaver Valley 1 and 2 deactivation request rescinded. The project was placed on hold, as the base case used to perform interconnection queue studies included the upgrades. Per the latest study, the upgrades are no longer needed for the interconnection queue and will be canceled, yielding a net decrease of $33.4 million.
- Baseline b3162 (new 230 kV Stevensburg switching station) is no longer required, as revised load allocations in the area caused the reliability violations to be resolved within the study time frame. This cancellation and yields a net decrease of $22 million.
- Baseline b3710 (reconductor of two 138 kV lines from Yukon to AA2-161 interconnection project) is no longer required due to the interconnection queue AA2-161 withdrawal. This cancellation and yields a net decrease of $10.64 million.

All of the changes noted above result in a net decrease of $66.04 million.

VI. Interconnection Queue Projects

Throughout 2023, PJM has continued to study new service customer requests that are submitted into the interconnection queue. These studies evaluate the impact of the new service request and include an evaluation of new generation interconnections, increases in generation at existing stations, long-term firm transmission service requests and merchant transmission interconnection requests.

A portion of the network upgrades associated with these projects were presented to the PJM Board in December 2023. The remaining upgrades are shown in Attachment C to this report. New projects with signed ISAs, project scope changes and project cancellations have resulted in a net increase of $1,049.80 million for network upgrades. The cost for the network upgrades associated with these interconnection projects is the responsibility of the developer.

VII. Review by the Transmission Expansion Advisory Committee (TEAC)

Project needs and recommended solutions as discussed in this report were reviewed with stakeholders during 2023 and 2024, most recently at the January 9, 2024, TEAC meeting. Written comments were requested to be submitted to PJM to communicate any concerns with project recommendations. No comments have been received as of this white paper publication date.

VIII. Cost Allocation

Cost allocations for recommended projects are shown in Attachment A (for allocation to a single zone) and Attachment B (for allocation to multiple zones), and Attachment C (for Interconnection Network Upgrades).

Cost allocations are calculated in accordance with Schedule 12 of the Open Access Transmission Tariff. Baseline reliability project allocations are calculated using a distribution factor methodology that allocates cost to the load zones that contribute to the loading on the new facility. The allocations will be filed at FERC 30 days following approval by the Board.

IX. Board Approval

The PJM Reliability and Security Committee is requested to endorse the additions and changes to the RTEP proposed in this white paper and recommended to the full Board for approval the new projects and changes to the existing RTEP projects as detailed in this white paper. The RTEP is published annually on PJM's website.

On February 28, 2024, the Board approved the addition of RTEP baseline projects as well as other changes to the RTEP as summarized in this paper.

Attachment A – Reliability Project Single-Zone Allocations

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3785.1	Replace existing 3000A wave trap at Mountaineer 765 kV, on the Belmont-Mountaineer 765 kV line, with a new 5000 A wave trap.	$0.46	AEP	AEP (100.00%)	6/1/2028
b3786.1	Rebuild ~4.5 miles of 69 kV line between Abert and Reusens substations. Update line settings at Reusens and Skimmer.	$14.40	AEP	AEP (100.00%)	6/1/2028
b3787.1	Install a CCVT on three-phase stand and remove the single phase existing CCVT on the 69 kV Coalton to Bellefonte line exit. The existing CCVT is mounted to lattice on a single-phase CCVT stand, which will be replaced with the three-phase CCVT stand. The line riser between line disconnect and line takeoff is being replaced. This remote end work changes the MLSE of the line section between Coalton-Princess 69 kV line section.	$0.00	AEP	AEP (100.00%)	12/1/2028
b3788.1	Replace AEP-owned station takeoff riser and breaker BB risers at OVEC-owned Kyger Creek station.	$0.41	AEP	AEP (100.00%)	6/1/2028
b3788.2	Replace OVEC-owned breaker AA risers, bus work, and breaker AA disconnect switches at OVEC-owned Kyger Creek station.	$0.75	OVEC	OVEC (100.00%)	6/1/2028
b3789.0	A 69 kV, 60 MVAR shunt reactor will be installed at the Salt Springs substation. The reactor terminal will be connected to the existing 69 kV bus, and an independent-pole operation, 1200A circuit breaker will be installed for reactor switching.	$5.45	ATSI	ATSI (100.00%)	6/1/2028
b3790.0	Replace the overdutied Olive 345 kV circuit breaker "D" with a 5000A 63 kA circuit breaker. Reuse existing cables and a splice box to support the circuit breaker install.	$1.08	AEP	AEP (100.00%)	6/1/2028
b3791.0	Rebuild the North Meshoppen-Mehoopany No. 1 115 kV line with 795 ACSR 26/7 STR conductor. Upgrade terminal equipment to exceed transmission line ratings.	$17.40	PENELEC	PENELEC (100.00%)	6/1/2028
b3792.0	Rebuild the North Meshoppen-Mehoopany No. 2 115 kV line using 795 ACSR 26/7 STR conductor, and upgrade terminal equipment to exceed the transmission line rating.	$17.70	PENELEC	PENELEC (100.00%)	6/1/2028
b3793.1	Reconductor Silver Run-Cedar Creek 230 kV line. Reconductor 8.8 miles of 230 kV circuit with 1594-	$7.68	DPL	DP&L (100.00%)	6/1/2028

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
	T11/ACCR "Lapwing" conductor and replace all insulators with high-temp. hardware.				
b3793.2	Replace three (3) standalone CTs, disconnect switch, stranded bus and rigid bus to achieve higher rating at Cedar Creek.	$0.45	DPL	DPL (100.00%)	6/1/2028
b3793.3	Replace three (3) 1-1590 ACSR jumpers and one (1) air disconnect switch at Silver Run.	$0.58	DPL	DPL (100.00%)	6/1/2028
b3794.1	Replace existing Waldwick 230 kV 50 MVAR fixed shunt reactor with a 230 kV 150 MVAR variable shunt reactor.	$13.60	PSEG	PSEG (100.00%)	6/1/2028
b3794.2	Replace existing Waldwick 345 kV 100 MVAR fixed shunt reactor with a 345 kV 150 MVAR variable shunt reactor.	$16.00	PSEG	PSEG (100.00%)	6/1/2028
b3810.0	Add three 345 kV circuit breakers to Cherry Valley substation.	$7.75	ComEd	ComEd (100.00%)	6/1/2028
b3836.1	Rebuild approximately 1.7 miles of line on the Chemical-Washington Street 46 kV circuit.	$7.60	AEP	AEP (100.00%)	6/1/2028
b3837.1	Replace existing 34.5 kV, 25 kA circuit breaker B at West Huntington station with new 69 kV, 40 kA circuit breaker.	$0.36	AEP	AEP (100.00%)	6/1/2028
b3838.1	Replace breaker A and B at Timken station with 40 kA breakers.	$1.20	AEP	AEP (100.00%)	6/1/2028
b3839.1	Replace 69 kV breaker C at Haviland station with a new 3000A 40 kA breaker.	$0.40	AEP	AEP (100.00%)	6/1/2028
b3840.1	Replace structures 382-66 and 382-63 on Darrah-East Huntington 34.5 kV line to bypass 24th Street station. Retire structures 1 through 5 on 24th Street 34.5 kV extension. Retire 24th Street station. Remove conductors from BASF tap to BASF.	$1.80	AEP	AEP (100.00%)	6/1/2028
b3843.1	Rebuild the underground portion of the Ohio University-West Clark 69 kV line, approximately 0.65 miles.	$4.60	AEP	AEP (100.00%)	6/1/2028
b3844.1	Replacement of relays at Macdade, Printz and Morton to increase rating limits of transmission relay equipment. Line protection relays will be upgraded with latest standard relays used across the PECO system.	$1.40	PECO	PECO (100.00%)	12/31/2026
b3845.1	Add a second breaker next to Nottingham 895 circuit breaker to eliminate stuck breaker contingency.	$1.28	PECO	PECO (100.00%)	5/31/2028

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3846.1	Rebuild 6.25 miles of 69 kV circuit 6708 (Vienna-Mardela) with new single pole steel structures and with 954.0 45/7 "Rail" conductor. This new rebuild will be from the dead-end structure on the east side of the Nanticoke River to the Mardela tap.	$18.63	DPL	DPL (100.00%)	5/31/2028
b3846.2	Upgrade disconnect switch at Vienna to increase ratings of existing Vienna-Mardela transmission facility.	$1.00	DPL	DPL (100.00%)	5/31/2028
b3846.3	Upgrade three disconnect switches at Mardela to increase ratings of existing Vienna-Mardela transmission facility.	$1.75	DPL	DPL (100.00%)	5/31/2028

Attachment B – Reliability Project Multi-Zone Allocations

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3780.14	Reconfigure Cooper transmission feeds by establishing new Cooper-North Delta 230 kV line and rerouting existing transmissions lines by Cooper.	$3.60	PECO	DPL (38.25%)/PECO (61.75%)	6/1/2025
b3780.15	Cut in 5012 Peach Bottom-Conastone 500 kV line into North Delta 500/230 kV substation by rebuilding 5012 between new terminal at Peach Bottom South and North Delta on single circuit structures and terminating at North Delta.	$7.86	PECO	Load-Ratio Share Allocation: AEC (1.65%)/AEP (14.29%)/APS (5.82%)/ATSI (7.49%)/BGE (4.01%)/ComEd (14.06%)/Dayton (2.03%)/DEOK (3.21%)/Dominion (13.89%)/DPL (2.55%)/DL (1.59%)/EKPC (2.35%)/JCPL (3.59%)/ME (1.81%)/OVEC (0.06%)/PECO (5.11%)/PENELEC (1.73%)/PEPCO (3.68%)/PPL (4.43%)/PSEG (5.99%)/RE (0.24%)/Neptune (0.42%) DFAX Allocation: AEC (11.03%)/BGE (37.40%)/DPL (22.90%)/PEPCO (28.67%)	6/1/2025
b3780.16	Terminate new Cooper-North Delta 230 kV line (Transource Scope) at North Delta 230 kV.	$0.47	Transource	DPL (38.25%)/PECO (61.75%)	6/1/2025
b3780.17	Cut in 5012 Peach Bottom-Conastone 500 kV line into North Delta 500/230 kV substation by rebuilding 5012 between new terminal at Peach Bottom South and North Delta on single circuit structures and terminating at North Delta (Transource Scope).	$1.10	Transource	Load-Ratio Share Allocation: AEC (1.65%)/AEP (14.29%)/APS (5.82%)/ATSI (7.49%)/BGE (4.01%)/ComEd (14.06%)/Dayton (2.03%)/DEOK (3.21%)/Dominion (13.89%)/DPL (2.55%)/DL (1.59%)/EKPC (2.35%)/JCPL (3.59%)/ME (1.81%)/OVEC (0.06%)/PECO (5.11%)/PENELEC (1.73%)/PEPCO (3.68%)/PPL (4.43%)/PSEG (5.99%)/RE (0.24%)/Neptune (0.42%) DFAX Allocation: AEC (11.03%)/BGE (37.40%)/DPL (22.90%)/PEPCO (28.67%)	6/1/2025

Upgrade ID	Description	Cost Estimate ($M)	TO	Cost Responsibility	Required In-Service Date
b3796.0	Replace the Belmont 765/500 kV transformer No. 5 with a new transformer bank consisting of three single-phase transformers and an additional single phase spare transformer. The project will also replace 500 kV disconnect switches at the Belmont substation.	$42.05	APS	Load-Ratio Share Allocation: AEC (1.65%)/AEP (14.29%)/APS (5.82%)/ATSI (7.49%)/BGE (4.01%)/ComEd (14.06%)/Dayton (2.03%)/DEOK (3.21%)/Dominion (13.89%)/DPL (2.55%)/DL (1.59%)/EKPC (2.35%)/JCPL (3.59%)/ME (1.81%)/OVEC (0.06%)/PECO (5.11%)/PENELEC (1.73%)/PEPCO (3.68%)/PPL (4.43%)/PSEG (5.99%)/RE (0.24%)/Neptune (0.42%) DFAX Allocation: AEP (0.28%)/APS (0.15%)/Dayton (0.10%)/DEOK (0.18%)/DL (6.57%)/Dominion (92.68%)/EKPC (0.04%)	6/1/2028
b3800.52	Reconfigure Peach Bottom North and South yards to allow for termination of 500 kV lines from Peach Bottom to North Delta. North Delta 500 kV termination for the new Peach Bottom-North Delta 500 kV line.	$7.86	PECO	Load-Ratio Share Allocation: AEC (1.65%)/AEP (14.29%)/APS (5.82%)/ATSI (7.49%)/BGE (4.01%)/ComEd (14.06%)/Dayton (2.03%)/DEOK (3.21%)/Dominion (13.89%)/DPL (2.55%)/DL (1.59%)/EKPC (2.35%)/JCPL (3.59%)/ME (1.81%)/OVEC (0.06%)/PECO (5.11%)/PENELEC (1.73%)/PEPCO (3.68%)/PPL (4.43%)/PSEG (5.99%)/RE (0.24%)/Neptune (0.42%) DFAX Allocation: AEC (11.03%)/BGE (37.40%)/DPL (22.90%)/PEPCO (28.67%)	6/1/2027

Attachment C – Interconnection Network Upgrades

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n104.1	Construct a new three (3) circuit breaker 138 kV station, Snowhill, physically configured in a breaker-and-a-half bus arrangement but operated as a ring bus.	$6.54	12/1/2021
n104.2	Connect Snowhill 138 kV station to existing transmission circuit; update remote end protective relay settings.	$0.81	12/1/2021
n104.3	Replace protective relays at Strawton 138 kV station.	$0.20	12/1/2021
n104.4	Install two (2) fiber-optic paths to facilitate relaying between Snowhill, Deer Creek and Strawton 138 kV stations.	$0.24	12/1/2021
n104.5	Replace three (3) structures, six (6) spans of conductor along the Deer Creek-Makahoy 138 kV circuit.	$0.63	12/1/2021
n4655	Reconfigure the Albright 138 kV substation to a breaker-and-a-half configuration.	$20.70	9/25/2017
n4783	To mitigate the (ACE) Cardiff 230/138 kV bus (from bus 227900 to bus 227934 Ckt 1) overload, substation reinforcements will be required at Cardiff.	$0.60	5/29/2019
n5583	Install 138 kV revenue metering at the Ohio Central substation.	$0.25	11/1/2017
n5865	Install attachment facility line, line disconnect switch, and associated hardware to accept the interconnection customer generator lead line terminating at the AD2-163 interconnection switching station. Install customer-owned revenue metering at the AD2-163 facility.	$0.50	12/1/2021
n5866	Install 138 kV three-breaker ring bus generation interconnection at AD2-163 interconnection substation.	$11.16	12/1/2021
n5986	Settings changes will need to be reviewed; the estimated cost for relay setting review/revision for AD1-130 is $25,000.	$0.03	12/31/2019
n5987	Install new 115 kV three-breaker ring bus substation.	$3.88	9/30/2019
n5988	Loop the 962 (Hunterstown-Lincoln) 115 kV circuit into substation.	$0.47	9/30/2019
n5989	Revenue metering – engineering oversight of specification and design of new revenue metering that will be installed by power producer (interconnection customer) at their location (AD1-020) and connected to the new ring bus station on the Hunterstown-Lincoln line. Coordinate FE MV90 access to the new meter.	$0.00	9/30/2019
n5990	Replace one (1) existing shield wire with optical ground wire (OPGW) on the Hunterstown-Lincoln 115 kV circuit between the proposed AD1-020 ring bus and Lincoln substation, approximately 1.6 miles.	$0.50	9/30/2019
n5991	Replace one (1) existing shield wire with OPGW on the Hunterstown-Lincoln 115 kV circuit between the proposed AD1-020 ring bus and Hunterstown substation, approximately 1.0 miles.	$0.32	9/30/2019
n5992	Install new line relaying and capacitor-voltage transformers (CVT) for the AD1-020 interconnection at Hunterstown substation.	$0.26	9/30/2019
n5993	Install new line relaying and capacitor-voltage transformers (CVT) for the AD1-020 interconnection at Lincoln substation.	$0.26	9/30/2019
n5994	Install estimated MPLS router at new AD1-020 interconnection substation to support new RTU.	$0.15	9/30/2019

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n6023	Rebuild the AB2-135 TAP-Church 69 kV circuit, including the installation of new poles and a new disconnect switch.	$6.60	6/1/2020
n6032	Perform AC1-173 relay settings – convert two-terminal gen lead to three-terminal gen lead (n5648).	$0.06	10/31/2019
n6033	Perform AC1-173 fiber system modifications (n5474).	$0.01	10/31/2019
n6049	Expand existing bay and install one (1) 345 kV circuit breaker, physical structures, protection and control equipment, communications equipment, and associated facilities at the Sullivan 345 kV switching station.	$2.22	12/31/2020
n6070	Reinforcements to increase the emergency rating of the Delco tap to Mickleton 230 kV line require the replacement of substation equipment, including substation bus at Mickleton substation. The estimate to perform this work is $905,000 and will take 18 months to complete.	$0.91	11/1/2017
n6124.1	Reconductor/rebuild 2.78 miles of ACSR ~ 336/556 six-wire conductor on the 05EDAN 1-05DANVL2 138 kV line.	$4.28	6/1/2021
n6124.2	Reconductor/rebuild 0.03 miles of ACSR ~ 1351.5 ~ 45/7 ~ DIPPER - conductor section 3 on the 05EDAN 1-05DANVL2 138 kV line.	$0.04	6/1/2021
n6124.3	Reconductor/rebuild 0.03 miles of ACSR ~ 1351.5 ~ 45/7 ~ DIPPER - conductor section 1 on the 05EDAN 1-05DANVL2 138 kV line.	$0.04	6/1/2021
n6145	Construct a 34.5 line tap/connection and 2-34.5 kV load-break switches with SCADA control at tap location, including one span of 34.5 kV line to the point of interconnection at Gilbert-Morris Park (A27) 34.5 kV generation interconnection. [One (1) 34.5 kV switch on the generator lead line and the span of 34.5 kV circuit are considered attachment facilities.]	$0.07	12/1/2019
n6146	Construct a 34.5 line tap/connection and 2-34.5 kV load-break air switches with SCADA control at tap location, including one span of 34.5 kV line to the point of interconnection at Gilbert-Morris Park (A27) 34.5 kV generation interconnection. [The one (1) switch on the main circuit next to the tap is considered a non-direct connection cost.] Estimated installation of 700 MHz radio system (70% penetration of FE territory) to support the (3) SCADA switch replacements. Assumed SCADA work is included in this cost. Provide and install 34.5 kV instrument transformer package and bi-directional 4G cell meter at AE1-243 site (new battery facility).	$0.82	12/1/2019
n6147	Revise remote relay and metering settings on the Morris Park 34.5 kV terminal at Gilbert substation.	$0.04	12/1/2019
n6148	Revise remote relay and metering settings on the Gilbert 34.5 kV terminal at Morris Park substation.	$0.04	12/1/2019
n6233	Replace two (2) poles and associated PSE&G standard conductor. Install two (2) new poles as H-frame for STATCOM equipment. Install and commission STATCOM equipment. Relocate branch recloser to new poles.	$0.40	12/10/2019
n6236	Build new structures to cut and loop the line into AC1-043 115 kV switching station.	$1.43	10/2/2019

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n6280	Upgrade will be to mitigate sag on ComEd portion of line. A preliminary estimate is $4.5M with an estimated construction timeline of 24 months.	$2.47	11/30/2021
n6287.2	Add two breakers in the Trowbridge 230 kV substation to accommodate AD1-074/75/76.	$4.00	6/1/2020
n6314	Rebuild Shawboro-Elizabeth City 230 kV line No. 2021.	$15.42	6/1/2020
n6329	Perform a sag study on the Pipe Creek-05GRNTTA 138 kV line.	$0.02	12/1/2021
n6330	Perform a sag study on the AD2-071 tap-Pipe Creek 138 kV line.	$0.03	12/1/2021
n6342	To mitigate the (ACE) Cardiff-New Freedom 230 kV line (from bus 227900 to bus 219100 ckt 1) overload, it will require increasing the emergency rating of the Cardiff to New Freedom 230 kV line by rebuilding the circuit. The rebuild will include the installation of new poles, foundations, insulators and conductor. New Ratings: 796/932/932	$105.00	6/1/2022
n6378	Rebuild 6.42 miles of 115 kV line 91 from AE2-092 tap to Sherwood with 2-636 ACSR.	$16.05	10/1/2026
n6385	Replace 230/115 kV transformer TX No. 1 at New Road substation.	$4.90	11/30/2020
n6437	Rebuild 20.57 miles of 230 kV line 2034 from Cashie to Earleys with 2-636 ACSR.	$30.86	11/15/2020
n6472	Construct a new 230 kV substation with a three-position ring bus.	$16.47	10/31/2019
n6496	Increase the maximum operating temperature of the Summershade-Edm. JB Galloway Jct 69 kV line section 266 MCM conductor to 212F (~7.9 miles).	$0.53	4/30/2024
n6587	Reconductor the Oyster Creek-Cedar 230 kV line (JCP&L portion only ~0.1 miles. AE portion ~14 miles). Upgrade terminal equipment at Oyster Creek. Additionally, AE would need to replace their section of the limiting conductor and provide estimates for their replacement.	$2.82	6/1/2023
n6679	Install AC1-033 new line section for interconnection at Kewanee.	$4.00	12/1/2021
n6712	Install AC2-195 ADSS fiber from the new AC2-195 interconnection substation to the anticipated ADSS cable near the intersection of Marion Williamsport Road and N Main Street proposed for PJM queue position AB2-131. The assumed route is a combination of aerial ADSS (0.87 miles) and underground bore (0.14 miles).	$0.17	12/31/2020
n6728	To mitigate the (ACE) Cedar Oyster Creek 230 kV line (from bus 227955 to bus 206302 ckt 1) overload, it will require increasing the emergency rating of the Cedar to Oyster Creek 230 kV line by rebuilding the circuit. The rebuild will include the installation of new poles, foundations, insulators and conductor. In addition, various terminal reinforcements are required at Cedar.	$27.00	2/28/2026
n6786	Build a three-breaker 115 kV substation at the existing Kings Dominion DP substation.	$5.30	12/31/2019
n6787	Build new structures to cut and loop the transmission line into the new Kings Dominion 115 kV ring bus substation.	$0.50	12/31/2020
n6788	Modify protection and communication work to support interconnection of the new Kings Dominion DP three-breaker ring bus substation.	$0.20	12/31/2020

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n6894	Design, install and test/commission MPLS equipment to provide SCADA transport at New Sulphur City 138 kV substation.	$0.25	9/30/2020
n6922	Install new line position for AF1-287 generator interconnection at Edinboro South.	$0.78	3/1/2021
n6923	Primary point of interconnection is to connect directly to the Edinboro South No. 1 34.5 kV bus and 34.5 kV GOAB to interconnect queue project AF1-287. Install 34.5 kV metering in customer's facilities. The customer is responsible to build their own line from their site to PENELEC's existing facilities.	$0.07	3/1/2021
n6924	Review nameplates and customer drawing at AF1-287 sub.	$0.05	3/1/2021
n6950	Tap the Martinsville-Wilmington 69 kV line and install a three-way phase switch to interconnect the AD2-031 project. (One switch covering the generator lead line is considered an attachment facility.)	$0.22	9/1/2019
n6951	Tap the Martinsville-Wilmington 69 kV line and install a three-way phase switch to interconnect the AD2-031 project (two network switches of the three-way switch are considered direct connection facilities).	$0.45	9/1/2019
n6952	Install a new 69 kV breaker at Martinsville substation. This will include the installation of all physical structures, P&C equipment, communications equipment, metering equipment and associated facilities.	$1.61	9/1/2019
n6953	Perform protection system changes at Wilmington substation.	$0.01	9/1/2019
n7009	Install line exit take-off structure, foundations, disconnect switch and associated equipment at ring bus substation at new AE1-101 138 kV switchyard.	$0.64	10/1/2022
n7024	Install line exit take-off structure, foundations, disconnect switch and associated equipment at ring bus substation at new AD1-068 138 kV switchyard.	$0.68	10/1/2022
n7025	Construct a new three-breaker ring bus on the 138 kV line between Albright and Garrett.	$6.93	10/1/2022
n7026	Loop the Albright-Garrett 138 kV line to create the interconnection for AD1-068 three-breaker ring bus (Afton substation), approximately 6.4 miles from Albright substation.	$0.62	10/1/2022
n7027	Replace wave trap and line tuner at Albright. Add anti-islanding relaying. Change carrier frequency and adjust relay settings. Change line name.	$0.31	10/1/2022
n7028	Replace wave trap and line tuner at Garrett. Add anti-islanding and replace line relaying. Change carrier frequency and adjust relay settings.	$0.39	10/1/2022
n7033	Reconductor the AD2-066 tap-Mazon 138 kV line.	$32.20	9/1/2020
n7084	Install line exit take-off structure, foundations, disconnect switch and associated equipment at ring bus substation qt new AE1-071 115 kV switchyard.	$0.69	11/2/2021
n7164.2	Replace relaying (RT, WT, MT, ZR, OR) at Karns City substation.	$0.46	12/31/2022
n7180	Rebuild 7.2 miles of 230 kV line 235 from Prince EDW to Farmville with 2-636 ACSR.	$10.80	12/31/2022

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n7181	Rebuild 5.7 miles of 230 kV line 235 from Briery to Prince EDW with 2-636 ACSR.	$8.55	12/31/2023
n7243.1	Install 138 kV revenue metering.	$0.25	12/31/2021
n7243.2	Construct a new three (3) circuit breaker 138 kV switching station.	$6.00	12/31/2021
n7243.3	Construct facilities to loop the existing Madison-Tanners Creek 138 kV line into the proposed 138 kV interconnection switching station.	$1.00	12/31/2021
n7243.4	Modify relays and/or settings at the Madison 138 kV substation.	$0.25	12/31/2021
n7243.5	Modify relays and/or settings at the Tanners Creek 138 kV substation.	$0.25	12/31/2021
n7245.1	Construct 345 kV revenue metering.	$0.43	9/30/2023
n7245.2	Construct generator lead first span exiting the POI station, including the first structure outside the fence.	$0.69	9/30/2023
n7245.3	Construct a three (3) circuit breaker 345 kV station physically configured and operated as a ring bus including associated protection and control equipment, 345 kV line risers and SCADA.	$12.47	9/30/2023
n7245.4	Install two (2) structures, two (2) spans of conductor; connect Bokes Creek 345 station to existing transmission circuit; update remote end protective relay settings.	$1.90	9/30/2023
n7245.6	Install two (2) fiber-optic paths to the AEP telecom network to facilitate SCADA connectivity at the Boke Creek station; includes telecom upgrades at the Marysville 345 kV substation.	$0.18	9/30/2023
n7261.2	Perform project management, commissioning, environmental, forestry, real estate and right of way at AE1-185.	$0.18	4/1/2021
n7262	Appropriate terminal equipment upgrades required to accommodate higher generation output at Farmingdale 34.5 kV.	$0.01	6/1/2023
n7263	Appropriate terminal equipment upgrades required to accommodate higher generation output at Bennett 34.5 kV.	$0.01	6/1/2023
n7264	Perform required review of relay settings/protection settings at X4-031 34.5 kV.	$0.02	6/1/2023
n7272	Install a 600A gang-operated switch on a new pole to tap the McConnellsburg-Mercersburg 34.5 kV line.	$0.04	12/31/2021
n7273	Provide 34.5 kV Meter Package at LSBP solar facility connection.	$0.01	12/31/2021
n7278	Perform project management, environmental, forestry, real estate and right of way.	$0.06	12/31/2021
n7287	Install of gen tie line connecting Payne station to the IPP generator.	$0.11	9/28/2017
n7288	Install dual fiber telecom from Payne to the IPP station.	$1.73	9/28/2017
n7301	Install new three-breaker 138 kV ring bus for AD2-157 interconnect at Bubbling Springs: Transmission owner will design, furnish and construct the new 138 kV line terminal and take-off structure. This work will include, but not be limited to, installation of a 138 kV line exit take-off structure, foundations, disconnect switch and associated equipment to accommodate the termination of the 138 kV generator lead line.	$0.58	12/31/2020

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n7302	Install new three-breaker 138 kV ring bus for AD2-157 interconnect at Bubbling Springs: A new three-breaker ring bus substation, Bubbling Springs 138 kV, will be constructed along the Gore-Hampshire 138 kV line to interconnect the AD2-157 solar project with the Potomac Edison transmission system. The point of interconnection will be at the TO-owned dead-end structure inside the substation yard where the generator lead line terminates.	$5.23	12/31/2020
n7305	Install fiber from AD2-157 to Gore for communication transport.	$0.29	12/31/2020
n7306	Perform estimated SCADA work at Gore, French Mill and Meadow Brook substations to support updated relay settings. Estimated in-sub fiber run to customer-built fiber to support communications to AD2-157 substation.	$0.11	12/31/2020
n7337	Direct injection cost into Bedington substation to interconnect queue project AE2-333. This includes project management.	$1.07	12/1/2022
n7338	Install (1) in-sub fiber run from Bedington control house to developer-built fiber run to support communications to AE2-333. Perform SCADA work at Bedington to support breaker and relay installations.	$0.06	12/1/2022
n7348	Cut and loop in line 23009 to new 230 kV three-position ring bus substation, occupying two of those positions. The third position will accommodate interconnection of the customer facility.	$2.73	12/1/2023
n7355	Perform protection setting changes at East Lima, RP Mone and Maddox Creek.	$0.05	9/28/2017
n7359	Loop the Jackson-TMI 230 kV line into the new AE2-211 ring bus substation.	$0.78	6/30/2022
n7360	Modify relay settings at Jackson.	$0.06	6/30/2022
n7361	Modify relay settings at Three Mile Island.	$0.06	6/30/2022
n7364	Modify line settings at Hardin switch.	$0.08	9/28/2017
n7365	Modify remote end settings at Gunn Road.	$0.02	9/28/2017
n7366	Modify remote end settings at East Lima.	$0.02	9/28/2017
n7375	Tap the Martinsville-Wilmington 69 kV line and install a three-way phase switch to interconnect the AD2-031 project (two network switches of the three-way switch are considered direct connection facilities).	$0.45	9/1/2019
n7376	Install a new 69 kV breaker at Martinsville substation. This will include the installation of all physical structures, P&C equipment, communications equipment, metering equipment and associated facilities.	$1.61	9/1/2019
n7377	Install protection system changes at Wilmington substation.	$0.01	9/1/2019
n7383	Perform relaying upgrades at TSS 100 Shady Oaks substation including: Install a SEL-411L as current differential line protection on L94701 and make the existing primary relay, SEL-311L, the secondary relay. Modify L16901 circuit breaker and L13901 circuit breaker tripping to accommodate new topology. Install load rejection logic such that transfer trip is initiated on both primary and secondary relaying to TSS 946 GSG-6 Wind Farm if L94701 circuit breakers are open at TSS 100 Shady Oaks.	$0.41	12/31/2020

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n7423	Install harmonic measurement equipment and provide harmonic measurement data to IC for the completion of a 12-month Harmonic Study for the interconnection of AE1-104.	$0.00	10/1/2024
n7502	Convert Hebron 69 kV substation to a five (5)-position ring bus. The ring bus will consist of positions for a new terminal and take-off tower for line 6708, a new terminal and take-off tower for line 6775, an existing terminal for transformer T2, a new terminal for transformer T1, and a new terminal for AC2-023.	$4.84	11/1/2025
n7529	Construct a new 230 kV three-breaker ring bus looping in the Bear Rock-Johnstown 230 kV line to provide interconnection facilities for AE2-224 interconnection sub.	$1.03	3/29/2019
n7530	Design, install and test/commission MPLS equipment for SCADA transport at AE2-224 sub.	$0.22	3/29/2019
n7531	Loop the Bear Rock-Johnstown 230 kV line into the new AE2-224 interconnection substation.	$0.97	3/29/2019
n7532	Upgrade line terminal at Johnstown substation.	$0.43	3/29/2019
n7533	Upgrade line terminal at Lewistown substation.	$0.22	3/29/2019
n7534	Upgrade line terminal at Raystown substation.	$0.37	3/29/2019
n7535	Install nameplates, drawings, relay settings and relay upgrade at Altoona substation.	$0.73	3/29/2019
n7536	Upgrade line terminal at Bear Rock substation.	$0.45	3/29/2019
n7586	Rebuild 7.62 miles of 230 kV line 2104 from Cranes Corner to Stafford with 2-795 ACSR 150 C at dom-282.	$11.43	12/21/2020
n7832	Install 69 kV revenue meter, generator lead transmission line span from the South Cumberland 69 kV station to the point of interconnection, including the first structure outside the South Cumberland 69 kV station, and extend dual fiber-optic from the point of interconnection to the South Cumberland 69 kV station control house.	$0.77	9/28/2018
n7833	Expand the South Cumberland 69 kV station, including the addition of one (1) 69 kV circuit breaker, installation of associated protection and control equipment, 69 kV line risers, and supervisory control and data acquisition (SCADA) equipment.	$0.79	9/28/2018
n7842	Revenue Metering Installation Oversight for the new 138 kV substation for AE2-318	$0.19	3/30/2019
n7843	New 138 kV Station Oversight for the new 138 kV substation for AE2-318	$0.21	3/30/2019
n7844	Modify Ford-Cedarville 138 kV T-Line Loop In/Out for AE2-318 interconnection	$1.17	3/30/2019
n7845	Perform remote protection and communication work at Ford and Cedarville substations to accommodate the interconnection switching substation.	$0.72	3/30/2019
n7846	Install distribution line extension for station power.	$0.19	3/30/2019

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n7854.1	Rearrange line No. 65 to loop into and out of the new three-breaker AE1-155 115 kV switching station. Line 65 is an existing 115 kV line that runs from Northern Neck substation to Harmony Village substation. AE1-155 provides for the construction of a new substation located in the existing line 65 right-of-way between existing structures 65/498 and 65/499 in Farnham, VA.	$1.07	9/15/2022
n7854.2	Build a three-breaker AE1-155 115 kV switching station. The facilities identified provides for the initial construction of a new 115 kV three-breaker ring substation between structures 65/498 and 65/499.	$5.41	9/15/2022
n7854.3	Perform remote protection and communication work. Additional work is required at Northern Neck, Rappahannock and Harmony Village substations. Drawing work, relay resets and field support necessary to change the line 65 destinations at Garner DP, Lancaster, Ocran and White Stone substations will also be completed.	$0.32	9/15/2022
n7879	Perform Marysville 345 kV protection settings change.	$0.02	3/20/2018
n7880	Perform Marysville 345 kV protection settings change.	$0.02	3/20/2018
n7882	Tap the Milton – Millville 69 kV line, MOLBAB switch, poles, structure and foundations for AE2-059 interconnection.	$0.60	3/5/2021
n7883	Complete MILT-MVIL line modifications to tie in the new AE2-059 attachment facilities. This includes connecting the conductors and OPGW from the MILT-MVIL line to the new tap structure.	$0.07	3/5/2021
n7884	Perform short-circuit study, review IC engineering package and remote end work at the Milton 69 kV substation.	$0.12	3/5/2021
n7904	Construct a new three (3) circuit breaker AD2-179 138 kV station.	$4.37	11/1/2020
n7905	Install 138 kV revenue meter, generator lead transmission line first span exiting the point of interconnection station, including the first structure outside the fence.	$1.78	3/28/2018
n7906	Modify Claytor-Glen Lyn 138 kV No. 2 Ckt T-line for AD2-179 new station cut in and install OPGW to Morgans Cut substation.	$1.50	11/1/2020
n7907	Upgrade line protections and controls at the Glen Lyn 138 kV station.	$0.50	3/28/2018
n7908	Replace the Claytor 138 kV station remote end Circuit Breaker “A” line relays with a dual carrier system and implement required settings. Install breaker controls and a second line trap.	$0.42	11/1/2020
n7954	Install a new 115 kV overhead transmission line from Endless Caverns substation.	$1.42	10/31/2023
n7955	Perform required additional work at Endless Caverns including adding a new 115 kV bay, relocating bus No. 3 cap bank, relocating 115 kV line 118, and relocating transformer No. 5 tap position. Control enclosure CE1 will be expanded to the North by 10’ to allow room for new relaying panels to be installed with project and battery and charger replaced as well.	$3.38	10/31/2023
n7962	Install 138 kV revenue meter, generator lead transmission line span from the Fostoria Central 138 kV station to the point of interconnection, including the first four structures outside the Fostoria Central 138 kV station, and extend dual fiber-optic from the point of interconnection to the Fostoria Central 138 kV station control house.	$1.49	8/1/2017

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n7963	Expand the Fostoria Central 138 kV station, including the addition of one (1) 138 kV circuit breaker, installation of associated protection and control equipment, 138 kV line risers, and supervisory control and data acquisition (SCADA) equipment.	$0.85	8/1/2017
n7972	Split line No. 65 between Northern Neck substation and Rappahannock substation. The AD2-074/AF1-042 substation will be built in line with line 65 approximately halfway between existing structures 65/541 and 65/542. This location is approximately 5.4 miles to the southeast of Garner DP. The final location of the substation is subject to change but shall remain within the same vicinity. The portion of the 65 line between the Northern Neck substation and the AD2-074/AF1-042 substation will be assigned a new line number and the structures will be renumbered accordingly.	$0.97	5/31/2025
n7973	Build a three-breaker AD2-074/AF1-042 115 kV switching station. The objective of this project is to build a 115 kV, three-breaker ring bus to support the new solar farm built by Waller Solar I, LLC. The site is located along Dominion Energy's existing 115 kV, 65 line from Northern Neck substation to Rappahannock substation. The cut line will consume two of the positions in the ring bus. The third position will be for the 115 kV feed from Waller Solar I, LLC collector station for the new solar farm.	$5.44	5/31/2025
n7974	Perform remote protection and communication work. Additional work to be required at Harmony Village, Rappahannock, Northern Neck and Garner DP, Lancaster, Ocran & White Stone substations.	$0.32	5/31/2025
n8010	ComEd will be responsible to perform design, procurement and construction to revise remote terminal.	$0.32	12/31/2020
n8011	ComEd will be responsible to perform design, procurement and construction to revise remote terminal to TSS 987 Beason instead of TSS 188 Mount Pulaski.	$0.31	12/31/2020
n8012	ComEd will be responsible for performing design, procurement and construction to build L18806 and L98704 from the cut-in location to TSS 987 Beason. New conductor will match existing conductor rating.	$5.56	12/31/2020
n8013	Engineering and construction oversight for TSS 987 Beason performed by IC.	$1.32	12/31/2020
n8023	Upgrade relays at remote ends.	$0.20	11/1/2021
n8024	Modify line No. 0762 AE1-179 South Millville-Newport 69 kV.	$1.80	11/1/2021
n8025	Install new communication equipment at new ring bus substation.	$0.20	11/1/2021
n8038	Review area relay settings and modify generator lead protection and control scheme to 2-terminal, including fiber jumper and wiring changes.	$0.06	11/30/2019
n8040.1	Construct a new 138 kV three-position ring bus substation.	$8.71	9/30/2021
n8040.2	Cut and loop in 1405 transmission line to the new 138 kV three-position ring bus substation, occupying two of those positions. The third position will accommodate the interconnection of the customer facility.	$0.25	9/30/2021
n8040.3	Install a new lead line (no longer than 500 feet) from the point of interconnection to the new 138 kV ring bus substation.	$0.25	9/30/2021

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8042.1	Convert the East New Market 69 kV substation from a four (4)-position line bus to a six (6)-position ring bus.	$11.34	7/15/2026
n8042.2	Modify lines 6715 and 6719 to align with their new take-off positions at East New Market 69 kV substation.	$1.26	7/15/2026
n8043.1	Install (2) new 230 kV breakers at Oyster Creek 230 kV substation for (1) new point of interconnection connection to AE1-020 (AE2-000) at Oyster Creek substation.	$5.77	6/1/2023
n8043.2	Perform relay settings changes at Manitou substation.	$0.12	6/1/2023
n8044.1	Construct a new 69 kV ring bus.	$8.71	6/30/2022
n8044.2	Cut in transmission line 0716 to the new 69 kV three-position ring bus substation, occupying two of those positions. The third position will accommodate interconnection of the customer facility.	$0.25	6/30/2022
n8044.3	Install protective relaying at the new 69 kV three-position ring bus substation.	$0.25	6/30/2022
n8045.1	Construct three-breaker 138 kV switching station.	$6.49	12/22/2023
n8045.2	Install two (2) new structures, four (4) spans of conductor to the Creek Walker 138 kV interconnection switching station, associated protection and control equipment, and fiber to interconnect to existing transmission circuit. Modify/replace relay settings.	$0.82	12/22/2023
n8045.3	Replace protective relays at Edison 138 kV station.	$0.23	12/22/2023
n8045.4	Install two (2) fiber-optic paths to facilitate relaying between Creek Walker and Edison 138 kV stations.	$0.64	12/22/2023
n8048.1	Upgrade the line relaying equipment at Robinson substation to prevent islanding.	$0.64	12/31/2021
n8048.2	Upgrade the line relaying equipment at Washington Courthouse substation to prevent islanding.	$0.40	12/31/2021
n8049	Build a new 115 kV solar farm to interconnect into the Suffolk station project AE2-104; provides for the construction of one new 115 kV interconnect into Suffolk substation. The objective of this project is to add one new line position and one new 115 kV breaker installed at Suffolk substation to support the new 49 MW solar farm built by Switchgrass Solar I, LLC. Additional modifications will be required to accommodate this additional infrastructure.	$3.35	12/30/2024
n8051	Cut and loop in 13712 transmission line to the AE2-093, 138 kV three-position ring bus substation, occupying two of those positions.	$6.22	12/31/2025
n8058	Modify relay settings.	$0.02	6/1/2020
n8060.1	Replace existing revenue meter CTs at Hardin switch 345 kV station.	$0.24	3/20/2018
n8060.2	Update protective relay settings at the Hardin, East Lima and Gunn Road 345 kV station.	$0.12	3/20/2018
n8061.1	Install fiber from Bartonville substation to backbone for relaying communications transport.	$0.25	11/15/2022
n8061.2	Loop the Bartonville-Meadow Brook 138 kV into the new Long Creek substation.	$1.21	11/15/2022
n8061.3	Install new structure per the Bartonville-Meadow Brook 138 kV line estimate.	$0.52	11/15/2022

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8061.4	Retune single-frequency line trap and replace line tuner on Stephenson line.	$0.23	11/15/2022
n8061.5	Retune single-frequency line trap and replace line tuner for Bartonville and Stonewall lines.	$0.49	11/15/2022
n8061.6	Replace line relaying, modify nameplates and drawings for line name change.	$0.36	11/15/2022
n8061.7	Replace line relying, retune single frequency line trap and replace line tuner on Stephenson line.	$0.53	11/15/2022
n8061.8	Interconnection customer will construct a new three-breaker ring bus substation along the Bartonville-Meadow Brook 138 kV transmission line to electrically interconnect the customer facility with the transmission system.	$0.67	11/15/2022
n8064.1	Review protection relay settings at the Flatlick 765 kV station.	$0.05	3/31/2020
n8067.1	Update protective relay settings at the Hardin, East Lima and Gunn Road 345 kV station.	$0.12	3/20/2018
n8068.1	Update protective relay settings at the Hardin, East Lima and Gunn Road 345 kV station.	$0.12	3/21/2019
n8070.1	Rearrange line No. 2034 to loop into and out of the new three-breaker AD1-022/023 230 kV switching station.	$1.42	6/1/2019
n8070.2	Perform remote protection and communication work. Additional protection and communication work to be required at Cashie, Earleys and Trowbridge 230 kV substations.	$3.38	6/1/2019
n8073	Install relaying at Kewanee for the new bay position. Conduct a detailed review of the IC relay settings.	$0.60	12/31/2019
n8082	The Colonial Trail substation was built with four 230 kV circuit breakers in a ring breaker configuration with an ability to expand to a six-breaker ring configuration. The previous projects (AB2-134 and AC1-216) have connected two solar generation to this substation. This project (AD1-025) will install a fifth 230 kV circuit breaker to accommodate a third generator interconnection point.	$0.56	9/30/2019
n8090.1	Install one (1) new 138 kV circuit breaker, one (1) new box bay, one (1) new line connection; update remote end protective relay settings at the Valley 138 kV station.	$0.91	12/1/2022
n8090.2	Install six (6) structures, seven (7) spans of conductor in the existing Hartford-Valley 138 kV right of way.	$1.11	12/1/2022
n8090.3	Expand the Valley 138 kV station yard, fence and control house.	$0.47	12/1/2022
n8092	Replace protective relays, wave trap and CCVT at Highland 69 kV station.	$0.53	9/1/2019
n8099	Perform fiber installation to Wilmington and Martinsville tap.	$0.85	9/1/2019
n8103.1	Build a three-breaker AE1-103 115 kV switching station. The objective of this project is to build a 115 kV, three-breaker ring bus to support the new 40 MW solar farm built by Aquasan Network Inc. The site is located along Dominion Energy's existing 115 kV line 68 from Holland substation to Union Camp substation. The cut line will consume two of the positions in the ring bus. The third position will be for the 115	$5.94	6/25/2024

Upgrade ID	Description	Cost ($M)	Required In-Service Date
	kV feed from Aquasan Network Inc. collector station for the new 40 MW solar farm.		
n8103.2	Perform remote protection and communication work.	$0.34	6/25/2024
n8103.3	Rearrange line No. 68 to loop into and out of the new three-breaker AE1-103 115 kV switching station. Project AE1-103 will tap into Dominion's line No. 68 between Holland and Union Camp substations. The new substation will be located off the main line between structures 68/98 and 68/99 in Isle of Wight County, Virginia.	$2.40	6/25/2024
n8104.1	Build a new three (3) circuit breaker 138 kV station, Snowhill, physically configured in a breaker-and-a-half bus arrangement but operated as a ring bus.	$6.54	12/1/2021
n8104.2	Connect Snowhill 138 kV station to existing transmission circuit; update remote end protective relay settings.	$0.81	12/1/2021
n8104.3	Replace protective relays at Strawton 138 kV station.	$0.20	12/1/2021
n8104.4	Install two (2) fiber-optic paths to facilitate relaying between Snowhill, Deer Creek and Strawton 138 kV stations.	$0.24	12/1/2021
n8109.1	Build a three-breaker 115 kV switching station.	$5.46	2/28/2025
n8109.2	Rearrange line No. 98 to loop into and out of the new three-breaker 115 kV switching station.	$1.80	2/28/2025
n8109.3	Perform remote station work at Lunenburg 115 kV substation.	$0.14	2/28/2025
n8109.4	Perform remote station work at Butcher Creek 115 kV substation.	$0.02	2/28/2025
n8116.1	Install one new 230 kV interconnect at Harmony Village station.	$3.83	4/1/2025
n8116.2	Relocate existing 230 kV Lanexa line 2016.	$2.61	4/1/2025
n8116.3	Perform remote station work at Lanexa 230 kV substation.	$0.09	4/1/2025
n8117.1	Build a three-breaker AE2-27 115 kV switching station. The objective of this project is to build a 115 kV, three-breaker ring bus to support the new 120 MW solar farm built by Torch Clean Energy. The site is located along Dominion Energy's existing 115 kV, 100 line from Locks substation to Chesterfield 115 kV substation. The cut line will consume two of the positions in the ring bus. The third position will be for the 115 kV feed from Torch Clean Energy Collector station for the new 120 MW solar farm.	$6.79	12/1/2022
n8117.2	Perform remote protection and communication work.	$1.40	12/1/2022
n8117.3	Rearrange line No. 100 to loop into and out of the new three-breaker AE2-027 115 kV switching station. The following estimate is for the construction of a new substation connection on transmission line 100 between Harrowgate substation and Locks substation. The line connection will require the installation of two (2) backbone structures, two (2) static pole structures, and two (2) DDE H-frame structures.	$0.68	12/1/2022

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8120.1	Build a new three (3) circuit breaker 230 kV station, Firefly 230 kV station, physically configured and operated as a ring bus.	$7.10	6/1/2020
n8120.2	Install TLine cut-in and dead-end structure.	$1.51	6/1/2020
n8120.3	Remove remote end tie line metering.	$0.04	6/1/2020
n8120.4	Install 230 kV Duke tie line meter.	$0.40	6/1/2020
n8120.5	Update relay settings, engineering drawings, equipment labels at Roxboro (DEP) 230 kV station.	$0.12	6/1/2020
n8123.1	AE2-019 provides for the initial construction of one new 230 kV interconnect into New Road substation. To facilitate the addition of the attachment facility for the new 230 kV line, the 230 kV bus No. 1 will need to be partially relocated at the point of interconnect. Also, to keep the station design standard, with the addition of the interconnect, a 230 kV motor-operated disconnect switch will need to be added on the high side of transformer No. 1. In addition to the MOAB, three-phase CCVTs on 115 kV bus No. 1, a single-phase CCVT on 230 kV bus No. 1, and a single-phase CCVT on 230 kV bus No. 2 will be installed.	$2.55	11/30/2020
n8123.2	Perform remote protection and communication work.	$0.08	11/30/2020
n8127.1	Engineering oversight of proposed Riverstone 138 kV station for AE1-108 interconnection.	$0.47	9/12/2018
n8127.2	Perform Bremo-Scottsville 138 kV T-Line cut-in and fiber installation.	$0.55	9/12/2018
n8127.3	Upgrade line protection and controls at the Scottsville 138 kV station.	$0.04	9/12/2018
n8127.4	Install 138 kV extension line from Bremo-Scottsville 138 kV circuit tap to the proposed Riverstone 138 kV station.	$1.25	9/12/2018
n8130.1	Install 138 kV revenue meter, generator lead transmission line span from the new Rocky Ford 138 kV station to the point of interconnection, and extend dual fiber-optic from the point of interconnection to the new 138 kV station control house.	$0.98	9/24/2018
n8130.2	Install new 138 kV three-breaker ring bus station along the Ebersole-Fostoria Central No. 2 138 kV line; install associated protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.	$6.16	9/24/2018
n8130.3	Cut in Ebersole-Fostoria Central No. 2 138 kV T-line.	$0.84	9/24/2018
n8130.4	Replace protective relays at Ebersole and Fostoria Central 138 kV stations.	$0.38	9/24/2018
n8130.5	Install two (2) fiber-optic paths to facilitate relaying between Rocky Ford, Ebersole and Fostoria Central 138 kV stations.	$0.24	9/24/2018
n8131.1	Complete DANV-COLU 2 line modifications to tie in the new AE2-110 attachment facilities. This includes connecting the conductors and OPGW from the MILT-MVIL line to the new tap structure. Install (1) MOLBAB just north of the AE2-110 tap point.	$0.28	12/31/2021

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8131.2	Rearrange line No. 2199 to loop into and out of the new three-breaker AE1-153 230 kV switching station. Project AE1-153 will tap into Dominion's line No. 2199 between Remington and Gordonsville substations between transmission structures 2199/144 and 2199/145. The transmission line shall connect to the substation within the existing line right of way. Installation of the substation shall require the line to be renumbered from the new substation to Remington substation. The existing line segment between the new substation to Gordonsville substation shall remain line 2199.	$0.14	12/31/2021
n8133.1	Relay settings need to be updated at TSS 951 Aurora Energy Center L95102. Connect new meters into the SCADA system at TSS 951 Aurora Energy Center.	$0.29	6/1/2024
n8133.2	Relay settings need to be updated at TSS 144 Wayne L14403.	$0.23	6/1/2024
n8133.3	Relay settings need to be updated at TSS 111 Electric Junction L11103.	$0.22	6/1/2024
n8135	Review relay settings and change the carrier frequency at the Greene 345 kV station.	$0.02	6/1/2022
n8136	Review relay settings and change the carrier frequency at the Madison 345 kV station.	$0.02	6/1/2022
n8143	Perform design, procurement and construction to expand 138 kV ESS H-445 Twombly Road substation.	$12.30	12/15/2018
n8150	Expand the Circleville 138 kV station, including the addition of one (1) 138 kV circuit breaker, installation of associated protection and control equipment, line risers, switches, jumpers, a 16' x 12' expansion DICM, and supervisory control and data acquisition (SCADA) equipment.	$1.55	1/31/2017
n8165.1	Modifications to the Acahela-Jackson 69 kV line to tie in the AE2-175 attachment facilities.	$0.10	10/31/2021
n8165.2	Perform relay modifications and remote end work.	$0.14	10/31/2021
n8165.3	Perform relay modifications and remote end work.	$0.14	10/31/2021
n8167.1	Rearrange line No. 2056 to loop into and out of the new three-breaker AD1-056/AD1-057 230 kV switching station.	$1.71	8/14/2017
n8167.2	Build a three-breaker AD1-056/AD1-057 230 kV switching station.	$7.19	8/14/2017
n8167.3	Perform remote protection and communication work at Hathaway 230 kV and Hornertown 230 kV substations.	$0.07	8/14/2017
n8169.1	Construct Millikan 138 kV station. Install associated line protection and control equipment, line risers, switches, jumpers and SCADA at the Millikan 138 kV station.	$6.49	12/31/2022
n8169.2	Install two (2) structures, two (2) spans of conductor; connect Millikan 138 kV station to existing transmission circuit; update remote end protective relay settings.	$0.76	12/31/2022
n8169.3	Install two (2) fiber-optic paths to facilitate relaying between Millikan, Kenzie Creek and Colby tap 138 kV stations.	$0.20	12/31/2022
n8170.1	Construct Fritts 138 kV three-breaker station, associated line protection and control equipment, line risers, switches, jumpers and SCADA at the proposed Fritts 138 kV station.	$5.53	12/31/2022

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8170.2	Install two (2) structures, two (2) spans of conductor; connect Fritts 138 kV station to existing transmission circuit; update remote end protective relay settings at Deer Creek 138 kV station.	$0.64	12/31/2022
n8170.3	Install two (2) fiber-optic paths to facilitate ICON relaying between Fritts and Gaston 138 kV stations.	$0.29	12/31/2022
n8170.4	Replace protective relays at Gaston 138 kV station.	$0.28	12/31/2022
n8176.1	Install one (1) new 345 kV circuit breaker and associated equipment; update protective relay settings; and install jumpers for Sorenson & Tanners Creek 345 kV line reterminations.	$2.18	10/31/2021
n8176.2	Reterminate the Desoto-Tanners Creek and Desoto-Sorenson 345 kV circuits in the Desoto 345 kV "B" string.	$0.50	10/31/2021
n8177.1	Install new 138 kV three-breaker ring bus station along the East Leipsic-Richland 138 kV line. Install a Drop-In Control Module (DICM) and other associated line protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.	$5.90	12/31/2021
n8177.2	Perform final connection of the East Leipsic-Richland 138 kV to the Lammer 138 kV station, and update protective relay settings at East Leipsic 138 kV station.	$0.70	12/31/2021
n8177.3	Install one (1) fiber-optic path to facilitate relaying between Lammer, East Leipsic, and Yellow Creek 138 kV stations.	$0.77	12/31/2021
n8177.4	Update protective relays settings at Richland 138 kV station.	$0.00	12/31/2021
n8178.1	Install new 138 kV three-breaker ring bus station along the Axton-Danville No. 1 138 kV line. Install a Drop-In Control Module (DICM) and other associated line protection and control equipment, line risers, switches, jumpers, and supervisory control and data acquisition (SCADA) equipment.	$4.70	5/31/2022
n8178.2	Perform final connection of the Axton-Danville No. 1 138 kV line to the Lendlease 138 kV station; update remote end protective relay settings.	$1.26	12/31/2021
n8178.3	Install one (1) fiber-optic path to facilitate relaying between Lendlease and Axton 138 kV stations.	$0.76	12/31/2021
n8178.4	Replace protective relays.	$0.24	12/31/2021
n8178.5	Extend two (2) new fiber-optic connections from the AE2-140 proposed Lendlease 138 kV station into AEP's existing fiber-optic network to facilitate SCADA network connectivity.	$0.18	12/31/2021
n8179	Install one (1) new 138 kV circuit breaker and associated equipment, and update protective relay settings at the Cole 345 kV station.	$1.56	12/31/2021
n8181.1	Complete COLU-SCOT line modifications to tie in the new AE2-241 attachment facilities. This includes replacing existing structure (grid # 34537N30614) with a new high pole of a high-low tap structure with a foundation and reframe/modify existing structures on each side of the new tap structure if required.	$0.05	3/5/2021
n8181.2	Perform relay modifications and remote end work.	$0.11	3/5/2021
n8186	Update protective relay settings at Fritts 138 kV station.	$0.05	12/31/2022

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8189.1	Construct new 345 kV TSS 918 Dana substation with three 345 kV circuit breakers arranged in breaker-and-a-half configuration.	$31.27	12/31/2021
n8189.2	Upgrade existing System 1 and System 2 line protection for 345 kV L0303.	$0.59	12/31/2021
n8189.3	Upgrade existing System 1 and System 2 line protection for 345 kV L91815, formerly L0303.	$0.38	12/31/2021
n8189.4	Transmission line cut in: install new line facilities required to connect 345 kV L0303 and 345 kV L91815 into TSS 918 Dana substation.	$9.79	12/31/2021
n8189.5	Install diverse fiber paths from TSS 918 Dana to TSS 908 Mole Creek and from TSS 918 Dana to TSS 98 Nevada.	$4.55	12/31/2021
n8189.6	Install one fiber cable to station 3 Powerton.	$30.58	12/31/2021
n8190	Rearrange lines 167, 168 and 2126 and reroute lines 25 and 1020 at Trowbridge substation and route developer transmission line into Trowbridge substation.	$3.17	6/1/2020
n8195.1	Oversee self-build of TSS 905 Essex construction.	$3.46	9/30/2020
n8195.2	Cut in tap into TSS 905 at Essex transmission line (L2002, L11212).	$20.14	9/30/2020
n8195.3	Perform design, procurement and construction to upgrade existing System 1 and System 2 line protection for 345 kV L90505.	$0.83	9/30/2020
n8195.4	Perform design, procurement and construction to upgrade existing System 1 and System 2 line protection for 345 kV L2002.	$0.83	9/30/2020
n8195.5	Perform design, procurement and construction to upgrade existing System 1 and System 2 line protection for 345 kV L90506.	$0.83	9/30/2020
n8195.6	Perform design, procurement and construction to install a new fiber path between TSS 905 Essex and STA. 20 Braidwood.	$3.14	9/30/2020
n8195.7	Perform design, procurement and construction to install a new fiber path between TSS 905 Essex and TSS 86 Davis Creek.	$8.83	9/30/2020
n8195.8	Perform design, procurement and construction to install a new fiber path between TSS 905 Essex and TSS 93 Loretto.	$10.81	9/30/2020
n8200.1	Construct a new three (3) circuit breaker 69 kV station physically configured and operated as a ring bus.	$3.78	12/15/2021
n8200.2	Install three (3) dead-end structures, four (4) spans of conductor; connect point of interconnection station to existing transmission circuit; update remote end relay settings.	$1.29	12/15/2021
n8202	Increase the maximum operating temperature of the 266 MCM ACSR conductor in the McKinney Corner tap-Knob Lick 69 kV line section to 212 degrees F (12.53 miles).	$0.72	4/30/2024
n8212.1	Expand the Stockton 138 kV station into a four-breaker ring bus arrangement.	$7.14	12/31/2022
n8212.2	Perform transmission line work at Axton-Martinsville; Martinsville remote end settings.	$0.45	12/31/2022
n8212.3	Install a new ICON at the Axton 138 kV station with connectivity to the Stockton 138 kV station. Replace the existing relays at the Axton 138 kV station.	$0.25	12/31/2022
n8212.4	Install Stockton 138 kV circuit switcher.	$0.20	12/31/2022

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8214.1	Cut and loop the L7423 138 kV line into the new TSS 922 Kentville Rd. interconnection substation.	$1.91	12/31/2019
n8214.2	Install dual 87L/SEL-411L current differential scheme via direct fiber. Upgrade L7423 circuit breaker from 25/SEL-279H and 50/2BF SEL-251C to 50BF/25/79 SEL-451. Install SEL-3350 RTAC with redundant RST-2228 switch architecture (Master, Master Aux A/B, Aux A/B switches). Install SEL-3620 port servers as needed for IED that must be connected serially over the available 3350 RTAC ports. Remove any PLC equipment on L7423 including wave trap, line tuner etc.	$1.91	12/31/2019
n8214.3	Construct a new breaker-and-a-half substation, 138 kV TSS 922 Kentville Rd., approximately 0.13 miles south of existing TSS74 Kewanee, which will interconnect via existing 138 kV L7423.	$20.33	12/31/2019
n8214.4	Perform relaying coordination and oversight.	$0.03	12/31/2019
n8214.5	Line 7423 138 kV will require two single-mode fiber paths from TSS 74 Kewanee to TSS 922 Kentville Rd., approximately 0.4 miles. These will be used for 138 kV L7423 System 1 and System 2 relay scheme using direct-on-fiber connections. At least one of these two fiber paths will need to be built per ESP 5.8.1 and 5.8.2 to determine the fiber count and construction. The second single-mode fiber path will require a minimum of 48 fibers. Both of these cables will be owned and maintained by ComEd. These fibers must be built in physically diverse paths from each other. Fiber paths are assumed to be installed underground for an approximate distance of 1000' per fiber path. Fiber count and construction for this fiber path will be determined by ComEd standards.	$1.10	12/31/2019
n8215.1	Construct new three-breaker 138 kV station in a breaker-and-a-half configuration.	$6.47	10/31/2022
n8215.2	Install two (2) structures, two (2) spans of conductor; connect proposed 138 kV station to existing transmission circuit; update remote end protective relay settings at Bluff Point 138 kV station.	$0.88	10/31/2022
n8215.3	Install two (2) fiber-optic paths to facilitate relaying between the Randolph and Proposed 138 kV stations.	$1.20	10/31/2022
n8215.4	Replace protective relays; install ICON at Randolph 138 kV station.	$0.19	10/31/2022
n8222.1	Build new control house and all associated communications and relaying for reconfiguration at Cardiff 230 kV substation.	$25.00	12/1/2029
n8223	Expand existing TSS 86 Davis Creek substation.	$0.68	9/30/2020
n8226.1	Rearrange line No. 15 to loop into and out of the new three-breaker AE1-149 115 kV switching station.	$1.38	12/1/2021
n8226.2	Build a three-breaker AE1-149 115 kV switching station.	$7.04	12/1/2021
n8226.3	Perform remote protection and communication work.	$0.64	12/1/2021
n8232	Install diverse UG/ADSS fiber-optic cable path.	$0.37	11/1/2020
n8233	Add addition at Morgans Cut station circuit breaker and perform associated work.	$1.26	11/1/2020

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8258.1	Rearrange line No. 91 to loop into and out of the new three-breaker AE2-092 230 kV switching station.	$2.51	3/1/2022
n8258.2	Perform remote protection and communication work.	$0.59	3/1/2022
n8258.3	Build a three-breaker AE2-092 230 kV switching station.	$1.06	3/1/2022
n8310	Replace the equipment for the 2310 line termination at New Freedom switching station including A-frame structure, line disconnect switch, relays and associated equipment.	$2.73	6/1/2029
n8315	Install harmonic measurement equipment and collect data for a harmonic study. Provide data and report to interconnection customer and PJM.	$0.30	6/1/2029
n8329.1	Build a new ring bus three-breaker-and-a-half configuration.	$20.68	9/1/2020
n8329.2	Cut and loop L7713 138 kV line to new sub.	$4.07	9/1/2020
n8329.3	Modify relay settings based on the new line topology.	$0.03	9/1/2020
n8329.4	Modify relay settings based on the new line topology.	$0.49	9/1/2020
n8329.5	Install fiber cable in existing right of way.	$2.65	9/1/2020
n8333	Mitigate overvoltage condition at fault clearing at AD1-031.	$0.00	6/15/2027
n8341.1	Modify the Mifflintown tap 69 kV line to tie in the AF2-361 attachment facilities.	$0.10	12/31/2022
n8341.2	Perform relay modifications scope of work at Juniata substation.	$0.24	12/31/2022
n8341.3	Perform relay modifications scope of work at Dauphin substation.	$0.24	12/31/2022
n8342	Install harmonic measurement equipment and collect data for a harmonic study. Provide data and report to interconnection customer and PJM.	$0.40	12/31/2024
n8351.1	Modify the Millville tap 69 kV line to tie in the AF1-226 attachment facilities.	$0.28	3/5/2021
n8351.2	Perform relay modification work for IC and remote end.	$0.14	3/5/2021
n8362.1	New 345 kV, TSS 964 Clear Creek substation to accommodate AD2-100 and AD2-131.	$32.00	12/31/2021
n8362.2	Modify the Kincaid-Pana 345 kV transmission line to tie in the interconnection substation.	$6.50	12/31/2021
n8362.3	Perform relay and fiber upgrades to STA 21 Kincaid.	$0.80	12/31/2021
n8362.4	ComEd coordination with Ameren for relay and fiber upgrades to Ameren's Pana substation.	$0.70	12/31/2021
n8362.5	Install two physically diverse 48-count single-mode fiber cables per ComEd standards from TSS 964 Clear Creek substation to STA 21 Kincaid.	$107.80	12/31/2021
n8362.6	Install two physically diverse 48-count single-mode fiber cables per ComEd standards from TSS 964 Clear Creek substation to Ameren's Pana substation.	$41.30	12/31/2021
n8372.1	Transmission Line (L0303) Cut-in for AE1-163 interconnection. Tap into TSS 915 Dee Mac Road.	$11.12	11/30/2021
n8372.2	Upgrade existing System 1 and System 2 line protection for existing L9150.	$0.38	11/30/2021
n8372.3	Install one (1) 48-count single-mode fiber cable and upgrade existing System 1 and System 2 line protection for existing L0303.	$0.61	11/30/2021

Upgrade ID	Description	Cost ($M)	Required In-Service Date
n8372.4	Perform fiber installation between TSS915 Dee Mac Rd. and existing ComEd facilities.	$0.17	11/30/2021
n8434.2	Install one new bay box, expand the control house, and reterminate the existing 138/12 kV transformer. Install associated line protection and control equipment, line risers, switches, jumpers and SCADA.	$0.77	6/30/2021
n8442.3	Review relay settings at Chester substation.	$0.08	12/17/2021
n8442.4	Review relay settings at Pohatcong Mountain.	$0.08	12/17/2021

Exhibit No. MAOD-14
Mid-Atlantic Offshore Development, LLC
PJM March 12, 2024 Letter

2750 Monroe Boulevard
Audubon, PA 19403

March 12, 2024

Dear Designated Entity:

This letter is notification that Mid-Atlantic Offshore Development (MAOD) is the Designated Entity with construction responsibility for PJM baseline upgrades that were approved by the PJM board on February 26, 2024.

At their meeting on February 26, 2024 the PJM Board of Managers (PJM Board) approved portions of the Regional Transmission Expansion Plan (RTEP) pursuant to Schedule 6 of the PJM Operating Agreement. Schedule 6 – Regional Transmission Expansion Planning Protocol – governs the process for planning the expansion and enhancement of transmission facilities to meet reliability criteria and to enhance market efficiency and to address ARR insufficiency.

Attachment A to this letter identifies MAOD as the Designated Entity for each upgrade as provided for in the RTEP[1] as presently approved by the PJM Board. A complete summary of the total RTEP for reliability and market efficiency can be obtained from the PJM web page at the following link: https://www.pjm.com/planning/project-construction.aspx

Attachment B lists the projects that have experienced a change in scope.

Attachment C lists the projects that are no longer included in the PJM RTEP as baseline upgrades and are cancelled. The Transmission Owner may still wish to construct some or all of these projects. In that case, the corresponding scope of work should be coordinated with PJM and assigned a supplemental project upgrade identifier.

In accordance with the PJM Operating Agreement, Schedule 6, Section 1.5.8, within 30 days of receiving this notification of its designation, the Designated Entity shall notify the Office of the Interconnection of its acceptance of such designation and submit to the Office of the Interconnection a development schedule, which shall include, but not be limited to, milestones necessary to develop and construct the projects to achieve the required in-service dates, including milestone dates for obtaining all necessary authorizations and approvals, including but not limited to, state approvals. Your response should be sent to PJM attention at the following email address: PJM.CRL@pjm.com. You will then be contacted by staff from PJM's Transmission Coordination & Analysis Department to develop and implement the applicable agreements.

Outage coordination of planned upgrades is a critical part of the near term planning process. PJM requests that the identified Transmission Owners and/or the Designated Entity determine preliminary outage schedules associated with the attached construction work and communicate those schedules to PJM by way of the eDART system as soon as possible. In addition the Transmission Owners are reminded to submit, via eDART, updated technical parameters for the upgrades (ratings, impedance, etc.) per PJM Manual requirements prior to placing the upgrades in service.

To timely meet the needed in-service date of the projects, all necessary state approvals should be obtained at least nine months prior to the required in-service dates specified in Attachment A to this document.

If there are any inaccuracies in the data below, such as the cost estimates or in service dates, or there is a disagreement about the construction designee, please contact Augustine Caven, Manager PJM Transmission Coordination & Analysis at Augustine.Caven@pjm.com.

Finally, PJM asks for your assistance in identifying any projects that may require corresponding coordination and/or system enhancements with a neighboring Transmission Owner or other entity. This is to include a review of local remedial action schemes (RASs), including those owned by neighboring Transmission Owner or other entities. Any potential impact and resulting change to an RAS should be coordinated with the RAS owner and PJM. Occasionally, the need for this coordination may be identified after the initial planning identification of the need for the RTEP upgrade.

[1] This letter is not intended to raise any issues regarding the current or future cost allocation for the subject facilities. Any such issues should be addressed as part of the proceedings related to those issues.

2750 Monroe Boulevard
Audubon, PA 19403

Thank you for your timely response to this letter. Our Transmission Coordination & Analysis Staff will be contacting you to coordinate the development of the Designated Entity agreement.

Sincerely,

Paul McGlynn
VP, Planning
cc: Kenneth Seiler; Sami Abdulsalam; Augustine Caven; Asanga Perera; Dave Egan; Susan McGill

2750 Monroe Boulevard
Audubon, PA 19403

Attachment A: New required RTEP projects:

In 2023/2024, it was determined that the baseline reliability projects listed below are required to be constructed. These baseline reliability projects are required to be constructed by the PJM required in-service date.

New required RTEP projects: None

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Audubon, PA 19403

Attachment B: RTEP projects with Change in Scope:
In 2023/2024, it was determined that the baseline reliability projects listed below required a change in scope. These baseline reliability projects are required to be constructed by the PJM required in-service date.

RTEP projects with Change in Scope:

PJM Baseline Upgrade ID	Project Description	Cost Estimate ($M)	Construction Designation	Required In-Service Date	Related To Tie Line	Transmission Owner Projected In-Service Date
b3737.22	Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. Additional scope includes prebuild extension work, and three sets of AC collector lines from the LCS to the offshore wind converter station area.	$216.30	MAOD	12/31/2027	Yes	

2750 Monroe Boulevard
Audubon, PA 19403

Attachment C: Cancelled RTEP projects:

In 2023/2024, it was determined that the projects listed below are no longer included in the PJM RTEP as baseline upgrades. The Transmission Owner may still wish to construct some or all of these projects. In that case, the corresponding scope of work should be coordinated with PJM and assigned a supplemental project upgrade identifier.

Cancelled RTEP projects: None

Exhibit No. MAOD-15
Mid-Atlantic Offshore Development, LLC
November 17, 2023 NJBPU Order

Agenda Date: 11/17/2023
Agenda Item: 8G

STATE OF NEW JERSEY

Board of Public Utilities
44 South Clinton Avenue, 1st Floor
Trenton, New Jersey 08625-0350
www.nj.gov/bpu/

CLEAN ENERGY

IN THE MATTER OF THE OPENING OF A SOLICITATION FOR A TRANSMISSION INFRASTRUCTURE PROJECT TO SUPPORT NEW JERSEY'S OFFSHORE WIND PUBLIC POLICY)	ORDER INITIATING A PREBUILD INFRASTRUCTURE SOLICITATION DOCKET NO. QO23100719

Parties of Record:
Brian O. Lipman, Esq., Director, New Jersey Division of Rate Counsel

BY THE BOARD:

By this Order, the New Jersey Board of Public Utilities ("Board") opens a Board-run solicitation for the Prebuild Infrastructure as discussed further below (the "Prebuild Solicitation"). This Prebuild Solicitation is open to all entities pre-qualified ("Pre-qualified Applicants") by PJM Interconnection, L.L.C. ("PJM") through PJM's pre-qualification planning process[1] as eligible to be a Designated Entity[2] prior to responding to the Prebuild Solicitation. The Prebuild Solicitation follows the Board's recent rejection of all of the Prebuild Infrastructure proposals submitted in response to the third solicitation for offshore wind ("OSW") renewable energy credits ("Third Solicitation").[3] The Board encourages transmission developers, transmission owners, OSW generation developers, and other qualified entities to respond to the Prebuild Solicitation.

The Board's action today is the next step toward procuring necessary coordinated OSW transmission facilities required to satisfy Governor Phil Murphy's OSW goal of 11,000 megawatts

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[1] See Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("PJM Operating Agreement"), Schedule 6, section 1.5.8(a).

[2] A "Designated Entity" is a PJM pre-qualified transmission developer who PJM has selected as the designated entity to construct and own and/or finance a transmission project included in the PJM Regional Transmission Expansion Plan ("RTEP").

[3] In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC), BPU Docket No. QO22080481, Order dated October 25, 2023 ("October 25, 2023 Order").

("MW") of OSW by 2040.[4] This Board action also builds upon New Jersey's national leadership in OSW generation and transmission procurement, including the selection of over 3,700 MW of OSW generation and the utilization of the State Agreement Approach ("SAA") process set forth in the PJM Operating Agreement. As with prior actions relating to transmission needs for OSW, the Board continues ongoing collaboration with its regional grid operator, PJM, to assess and develop approaches that will lower costs, reduce the chance of delays in OSW project development and energy transmitted from these generation resources to PJM, and minimize community and environmental impacts.

BACKGROUND

New Jersey's Offshore Wind Regulatory Landscape & Public Policy

On August 19, 2010, the Offshore Wind Economic Development Act ("OWEDA") was signed into New Jersey law.[5] OWEDA directed the Board to establish a program for Offshore Wind Renewable Energy Certificates ("ORECs") to support at least 1,100 MW of OSW generation capacity from Qualified Offshore Wind Projects ("QOWPs").[6]

Within his first of month of taking office, on January 31, 2018, Governor Phil Murphy signed Executive Order 8 ("EO 8"), which directed the Board to fully implement OWEDA and begin the process of moving the State toward a goal of 3,500 MW of OSW by 2030.[7] In late 2019, Governor Murphy more than doubled the State's OSW goal, to 7,500 MW by 2035, when he signed EO 92 ("EO 92").[8] In 2022, Executive Order 307 ("EO 307") once again expanded the state's goal to the current 11,000 MW of OSW by 2040.[9]

The Board has long recognized that limits on the existing transmission system, as well as the challenges associated with expanding or replacing transmission facilities, represent a major source of cost uncertainty and potential risk of delays in meeting the State's OSW goals. Accordingly, New Jersey's 2019 Energy Master Plan ("EMP") recommends expanding New Jersey's electric grid to accommodate New Jersey's then-current goal of 7,500 MW of OSW by 2035.[10] The EMP explains how "planned transmission to accommodate the State's [OSW] goals

[4] Exec. Order No. 307 (September 21, 2022), 54 N.J.R. 1945(a) (October 17, 2022) ("EO 307").

[5] See OWEDA, N.J.S.A. 48:3-87.1 to -87.2, L. 2010, c. 57, eff. Aug. 19, 2010; amended by 2019 c. 440, §2, effective Jan. 21, 2020; 2021, c.178, §1, effective July 22, 2021.

[6] An OREC is defined as "a certificate issued by the Board or its designee, representing the environmental attributes of one megawatt hour of electric generation from a qualified offshore wind project." N.J.A.C. 14:8-6.1.For each MWh delivered to the transmission grid, an OSW project that is a qualified offshore wind project ("QOWP") will be credited with one OREC.

[7] See Exec. Order No. 8, (January 31, 2018), 50 N.J.R. 887(a) (February 20, 2018). In 2018, the Legislature also directed the Board to establish an OREC program to support "at least 3,500 MW" of OSW generation by 2035. See OWEDA, supra note 4.

[8] Exec. Order No. 92 (November 19, 2019), 51 N.J.R. 1817(b) (December 16, 2019).

[9] Exec. Order No. 307 (September 21, 2022), 54 N.J.R. 1945(a) (October 17, 2022).

[10] EMP, Goal 2.2.1 ("Develop Offshore Wind Energy Generation") at 114.

provides the opportunity to decrease ratepayer costs and optimize the delivery of [OSW] generation into the [S]tate's transmission system."[11] The EMP further states that "[c]oordinating transmission from multiple projects may lead to considerable ratepayer savings, better environmental outcomes, better grid stability, and may significantly reduce permitting risk."[12] The EMP envisions that the Board "should endeavor to collaborate with PJM to ensure that transmission planning and interconnection rules accommodate [OSW] resources."[13] The EMP also recognizes that transmission must be planned and that the Board must exercise its regulatory authority to "actively engage in transmission planning."[14]

On November 12, 2019, Board Staff ("Board Staff" or "Staff") held an OSW transmission technical conference ("Technical Conference") to solicit input from stakeholders on transmission considerations and solutions.[15] On March 27, 2020, the Board authorized a contract with Levitan & Associates, Inc. ("LAI") to prepare an OSW transmission study ("Transmission Study"). LAI completed the Transmission Study in December 2020 and concluded that a coordinated transmission approach would provide significant benefits.[16]

Also in late 2020, the Board, in close coordination with other State agencies, issued the New Jersey Offshore Wind Strategic Plan ("Strategic Plan").[17] The Strategic Plan found that "[i]nvestments in planning and infrastructure are necessary to build the transmission infrastructure and regional markets needed for offshore wind energy to support a clean energy future."[18] Specifically, the Strategic Plan recommends that meeting New Jersey's then-current 7,500 MW OSW goal requires "[c]ollaborat[ing] with PJM, as set forth in the [EMP], to assure transmission infrastructure accommodates renewable energy such as offshore wind."[19] The Strategic Plan also recommends "[w]ork[ing] with PJM and local utilities to develop a grid transmission study. . . ."[20]

New Jersey Coordinated Transmission and the State Agreement Approach

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[11] Id. at 117.

[12] Ibid.

[13] Ibid.

[14] Ibid.; Goal 5.2.1 ("Exercise Regulatory Jurisdiction to Review and Approve the Need for Transmission Projects") Id. at 182.

[15] Offshore Wind Transmission Stakeholder Meeting 11-12-19.pdf (nj.gov)

[16] LAI, Offshore Wind Transmission Study Comparison of Options (December 29, 2020), https://www.nj.gov/bpu/pdf/publicnotice/Transmission%20Study%20Report%2029Dec2020%202nd%20FINAL.pdf.

[17] Ramboll US Corporation, New Jersey Offshore Wind Strategic Plan (September 2020), https://www.nj.gov/bpu/pdf/Final_NJ_OWSP_9-9-20.pdf.

[18] Id. at 77.

[19] Id. at 78.

[20] Ibid.

The same week that Governor Murphy issued the EMP, he also signed legislation authorizing the Board to conduct one (1) or more competitive solicitations for open access OSW transmission facilities.[21] In this legislation, the New Jersey Legislature enshrined the concept of an "open access offshore wind transmission facility" into State law, defined as "an open access transmission facility, located either in the Atlantic Ocean or onshore, used to facilitate the collection of offshore wind energy or its delivery to the electric transmission system in this State."[22] Further, the Legislature provided the Board the authority to "conduct one or more competitive solicitations for open access offshore wind transmission facilities designed to facilitate the collection of offshore wind energy from qualified offshore wind projects or its delivery to the electric transmission system in this State."[23]

Under this authority, and consistent with the findings and directives of the EMP and Strategic Plan, on November 18, 2020, the Board formally requested that PJM incorporate the State's then-current goal of 7,500 MW of OSW by 2035 into the PJM transmission planning process through the SAA.[24] Under this transmission planning process, Staff worked with PJM to include the State's OSW public policy requirement in a PJM Regional Transmission Expansion Planning ("RTEP") window that was opened in April 2021.[25] Pre-qualified entities submitted competitive transmission proposals to PJM by the close of the NJ SAA RTEP window on September 17, 2021, providing a wide variety of detailed OSW transmission solutions, cable corridors, cost estimates, delivery dates, proposals to phase construction, and other project details ("SAA 1.0").

At the close of the SAA 1.0 proposal window, PJM received 80 project proposals from 13 project proposers. After a thorough review by Board Staff, PJM, and The Brattle Group, Inc. ("Brattle"), the Board's SAA consultant, the Board awarded a series of projects to construct the onshore transmission facilities necessary to successfully deliver 7,500 MW of OSW to the electric transmission system in this State.[26] The savings New Jersey ratepayers will realize from the selection of these transmission projects were estimated to be approximately $900 million, compared to the estimated cost of transmission facilities that otherwise would be necessary to achieve New Jersey's then-current 7,500 MW of OSW energy goal in the absence of the SAA 1.0 solicitation.[27]

The Prebuild Infrastructure

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[21] N.J.S.A. 48:3-87.1(e).

[22] N.J.S.A. 48:3-51.

[23] N.J.S.A. 48:3-87.1.

[24] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated November 18, 2020 ("November 2020 Order").

[25] See PJM Competitive Planning Process webpage at https://www.pjm.com/planning/competitive-planning-process.

[26] In re Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated October 26, 2022 ("October 2022 Order" or "SAA 1.0 Order") at Appendix A.

[27] Id. at 61.

As part of the SAA 1.0 project awards, the Board gave special attention to the duct banks and associated access cable vaults that would be installed in a single construction effort for the use by subsequent QOWPs ("Prebuild Infrastructure" or "Prebuild Facilities").[28] The Prebuild Facilities would be constructed between the landing point identified in SAA 1.0, the Sea Girt National Guard Training Center ("Sea Girt NGTC"), and the awarded Point of Interconnection ("POI") with the PJM high-voltage electric grid, the Larrabee Collector Station ("LCS"). These Prebuild Facilities were originally envisioned as a part of the "Option 2" facilities identified by the November 2020 Order and included in the SAA 1.0 solicitation.[29]

Notably, the ongoing consideration and evaluation of multiple pathways to procure the Prebuild Facilities stems naturally from the structure of PJM's competitive procurement process for transmission and the initial SAA 1.0 solicitation. As a result of PJM's "sponsorship" model of procurement (i.e., where the proposer and designer of a transmission project also is selected as the Designated Entity for construction), a wide range of innovative designs were submitted, with no two bidders proposing identical routes and technology types. On the basis of these designs, and following additional consideration during the SAA 1.0 solicitation evaluation process, Staff sought to expand the potential Prebuild Facilities options through the use of clarifying questions, including confirming "whether such transmission developers would be willing to construct the Option 1b-only portion of their Option 2 proposals . . . ."[30] The Option 1b-only components would form the Prebuild Infrastructure.

However, even with similar requests from Staff to each SAA 1.0 bidder, the widely varied submitted designs limited the available comparisons between proposals. Some proposers declined to offer Option 1b-only designs altogether. Bidders that did elect to provide Option 1b-only designs, provided those designs such that they were structured to the design of their own specific submitted project and not to the Sea Girt NGTC to LCS design which the Board ultimately determined to be necessary, with only one exception. This one Option 1b-only design submitted through SAA 1.0 was designed to support the SAA 1.0 awarded projects.

As a result, the SAA 1.0 project awards contemplated these Prebuild Facilities being procured in a subsequent OSW generation solicitation, later determined to be New Jersey's Third Solicitation.[31] However, the Solicitation Guidance Document for the Third Solicitation ("SGD" or "Solicitation 3 Guidance Document") indicated that the SAA might be modified to include the Prebuild Infrastructure.[32]

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[28] Id. at 65-66. "Duct banks" are the concrete structure between cable vaults that house the necessarynumber of physically separate conduits (empty pipes) in which transmission cables can be installed (pulled through, from one point to another). "Cable vaults" are physically-separate, underground vaults (accessible through manhole covers), located at certain distances along the onshore cable route of the PBI, to allow each QOWP to install and maintain its own transmission cables without impacting other QOWPs' transmission cables.

[29] See November 2020 Order at 4; October 2022 Order at 43.

[30] SAA 1.0 Order at 53.

[31] Id. at 53-54.

[32] BPU, Solicitation 3 Guidance Document at A10-2 ("The Board and its Staff will notify Applicants, as early as possible, if the SAA Project is chosen to develop the Prebuild Infrastructure.").

On March 6, 2023, the Board approved and issued the SGD. The SGD required each applicant to submit a separate application for the construction of the Prebuild Infrastructure in accordance with the requirements contained in the SGD, and required that all Third Solicitation applicants utilize the Prebuild Infrastructure. Applications for the Third Solicitation projects and the Prebuild Infrastructure were to be submitted by June 23, 2023.[33] On June 7, 2023, the Board extended the application due date to August 4, 2023.[34]

On August 4, 2023, Third Solicitation applications were received from four (4) OSW developers for OSW generation projects, and separate applications were received from these same four (4) OSW developers for the Prebuild Infrastructure, in accordance with the SGD.

In its October 25, 2023 Order, the Board rejected all of the Prebuild Infrastructure proposals submitted in the four (4) Prebuild Infrastructure applications submitted in response to Third Solicitation and directed Staff to develop a separate solicitation guidance document for Prebuild Infrastructure only ("PSGD" or "Prebuild Solicitation Guidance Document") and to present such PSGD for a Prebuild Infrastructure solicitation ("PBI Solicitation" or "Prebuild Infrastructure Solicitation") to the Board for its consideration within 30 days.[35]

STAFF RECOMMENDATION

In the midst of the ongoing analysis and pursuit of coordinated OSW transmission described above, Staff continued to explore regulatory avenues to pursue the stated goals of the Board (increasing competition in future OSW generation solicitations, reducing permitting and land acquisition requirements associated with an OSW generation developer's necessary onshore transmission facilities, and coordinating access to the POI), while maximizing opportunities for further ratepayer cost savings.[36] Notably, the SAA 1.0 process created significant cost savings by attracting a wide range of innovative proposals that identified an efficient design of an integrated transmission system for delivering OSW to New Jersey customers. However, as described above, because of the structure of the SAA 1.0 solicitation, identification of the preferred design of the Prebuild Infrastructure could not be finalized prior to the Board's selection of the SAA projects awarded. As a result, all of the SAA 1.0 bidders did not have an opportunity to submit a proposal for the Prebuild Infrastructure as ultimately designed.

The SAA 1.0 solicitation demonstrated the benefits of receiving proposals from multiple qualified developers. Opening this Prebuild Solicitation with a further refined scope as set out in the Prebuild Solicitation Guidance Document, included as Attachment A to this Order, will enable the Board to harness and focus the benefits of competition, maximizing ratepayer benefits and

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[33] In re the Opening of New Jersey's Third Solicitation for Offshore Wind Renewable Energy Certificates (OREC), BPU Docket No. QO22080481, Order dated June 7, 2023 ("June 7, 2023 Order") at 1.

[34] Id. at 2.

[35] October 25, 2023 Order, supra note 2 at 6.

[36] See SAA 1.0 Order at 54.

minimizing costs by enabling a broader range of transmission developers to compete together with OSW generation developers in submitting proposals for the Prebuild Infrastructure to further enable achieving New Jersey's OSW goals.[37] Any qualified and interested developer, including those who submitted Prebuild Infrastructure proposals in the Third Solicitation, can participate. In addition, this Prebuild Solicitation is consistent with the Third Solicitation SGD guidance that the SAA may be "modified to include the Prebuild infrastructure . . . ." [38] Staff believes that any additional administrative burden of conducting this Prebuild Infrastructure Solicitation is outweighed by the potential ratepayer benefits that may be captured by issuing such solicitation.

Staff recommends the Board structure the Prebuild Solicitation as follows.

Initiate a Board Solicitation for Prebuild Facilities from Pre-qualified Applicants

Staff recommends the Board open the Prebuild Solicitation based on the requirements included in the PSGD.

The Board is authorized to solicit open access offshore transmission facilities, defined as those "designed to facilitate the collection of offshore wind energy from qualified offshore wind projects or its delivery to the electric transmission system" in New Jersey.[39] The Prebuild Facilities meet this definition.

Staff recommends that the Prebuild Solicitation be open to all Pre-qualified Applicants. To meet this requirement, entities must receive pre-qualification status through PJM's pre-qualified process prior to submitting their proposals.

As set out in the PSGD, Staff recommends that the Prebuild Solicitation be run by the Board, not by PJM. Board Staff and its consultant will review and evaluate Prebuild Solicitation proposals received, with support from PJM, as requested by Staff. Should the Board select a Prebuild Infrastructure proposal for award, Staff recommends that the Board identify the selected proposal as a Public Policy Project under PJM's SAA process, for inclusion in the RTEP under the SAA-specific provisions of Schedule 6 of the PJM Operating Agreement.[40]

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[37] Solicitation 3 Guidance Document at A10-2 ("The Board and Board Staff will notify Applicants, as early as possible, if the SAA Project is chosen to develop the Prebuild Infrastructure.")

[38] Id. at 41.

[39] N.J.S.A. 48:3-87.1(e).

[40] Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Sch. 6, § 1.5.9(b), PJM Docket No. ER22-451-000 (Effective Date January 19, 2022) at 30. ("…the state(s) responsible for cost allocation for a Supplemental Project or a state public policy project in accordance with the Operating Agreement, Schedule 6, section 1.5.9(a) may submit to the Office of the Interconnection the entity(ies) to construct, own, operate and maintain the state public policy project from a list of entities supplied by the Office of the Interconnection that pre-qualified to be Designated Entities pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a)).

Consistent with the approved cost allocation provisions associated with the SAA, the costs of any selected Prebuild Facilities will be recovered through PJM Schedule 12 - SAA Cost Allocation Methodology.[41]

Staff also recommends that Pre-qualified Applicants commit to deliver their project by the expected in-service date specified in the PSGD. Staff further recommends that Pre-qualified Applicants may voluntarily commit to automatically applied reductions in the project's equity returns for late delivery and to filing such automatically applied reductions with the Federal Energy Regulatory Commission ("FERC") as part of the proposed formula rate provisions and Designated Entity Agreement with PJM.

Staff also recommends that bonus provisions be available to Prebuild Facilities developers that deliver the Prebuild Infrastructure ahead of schedule. Preferred Prebuild Infrastructure proposals will also include a binding cost-containment commitment, including reduced return-on-equity associated with recovery of capital costs in excess of a cost cap. Further details on these and all elements of the Solicitation are in the PSGD, which appears as Appendix A to this Order.

Also, Staff recommends that the Board require any State or private entities wishing to partner with New Jersey in the future to bear a pro rata share of any development and operating costs associated with the Prebuild Infrastructure.

DISCUSSION AND FINDINGS

Based on the description and the ultimate purpose of the Prebuild Infrastructure, to facilitate the delivery of OSW energy to New Jersey's electric transmission system, the Board **HEREBY FINDS** that a stand-alone, Board-run solicitation for the Prebuild Infrastructure, for eventual inclusion in the PJM RTEP, is consistent with the authority granted to the Board by N.J.S.A. 48:3-87.1(e).

Accordingly, based on the Board's careful consideration of the benefits identified by Staff and described above, and in conjunction with the findings and requirements of the October 25, 2023 Order, the Board **HEREBY FINDS** that it is in the best interest of the State and its ratepayers to open an application window for the Prebuild Solicitation. The Board **HEREBY OPENS** an application window for Prebuild Infrastructure projects, open to all Pre-qualified Applicants, commencing on the effective date of this Order until 5:00 pm Eastern Time on April 3, 2024. Further, the Board **HEREBY APPROVES** the use of the PSGD included as Appendix A to this Order, including the schedule and cost containment commitments, to inform Applicants of the Prebuild Solicitation process and application requirements under the PSGD.

The Board **HEREBY ORDERS** that any Prebuild Infrastructure project selected as a result of this Prebuild Solicitation would be a Public Policy Project under the SAA, for inclusion in the RTEP under the SAA-specific provisions of Schedule 6 of the PJM Operating Agreement and that all costs of any such project would be recoverable from customers in the State according to a FERC-accepted cost allocation methodology that is agreed to by the Board; provided that any State or

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[41] See 181 FERC ¶ 61,178 (2022). "PJM Schedule 12," particularly Appendix C thereto, covers SAA cost responsibility within the context of PJM Open Access Transmission Tariffs ("OATT"). See PJM, Intra-PJM Tariffs, OATT Table of Contents (51.0.0), Schedule 12 – SAA Cost Responsibility.

private entities wishing to partner with New Jersey in the future would be expected to bear a pro rata share of any development and operating costs associated with the Prebuild Infrastructure.

The Board further **HEREBY ORDERS** that no assignment of costs is authorized until such time, if any, that the Board evaluates the outcome of this Prebuild Solicitation and affirmatively agrees to bind New Jersey ratepayers to pay for any associated transmission expansion.

The effective date of this Order is November 17, 2023.

DATED: November 17, 2023

BOARD OF PUBLIC UTILITIES
BY:

CHRISTINE GUHL-SADOVY
PRESIDENT

MARY-ANNA HOLDEN
COMMISSIONER

DR. ZENON CHRISTODOULOU
COMMISSIONER

MARIAN ABDOU
COMMISSIONER

ATTEST:

SHERRI L. GOLDEN
SECRETARY

I HEREBY CERTIFY that the within document is a true copy of the original in the files of the Board of Public Utilities.

I/M/O THE OPENING OF A SOLICITATION FOR A TRANSMISSION INFRASTRUCTURE PROJECT TO SUPPORT NEW JERSEY'S OFFSHORE WIND PUBLIC POLICY

DOCKET NO. QO23100719

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Attachment A

Prebuild Solicitation Guidance Document

New Jersey Offshore Wind Prebuild Infrastructure Solicitation

Solicitation Guidance Document

Application Submission for Proposed Prebuild Infrastructure Project

New Jersey Board of Public Utilities

44 S. Clinton Ave, Trenton, NJ

November 17, 2023

Table of Contents

List of Acronyms and Defined Terms

Additional Information, additional relevant information beyond the listed requirements, submitted at Applicant's discretion.

Application, a submission by an Applicant into this Prebuild Solicitation, as described in this document.

Applicant, a participant in this Prebuild Solicitation, as described in this document.

Board or BPU, the New Jersey Board of Public Utilities.

Board Decision, a Board Order, awarding the Prebuild or closing this Prebuild Solicitation.

Board Staff or Staff, the staff of the Board.

Cable Vault, physically-separate underground vaults (manholes and associated access vaults enabling maintenance access), located at certain distances (such as every 2,000 feet) along the Corridor, to allow each Qualified Project to install and maintain its own transmission cables without impacting other Qualified Projects' transmission cables.

Circuit, the set of power export cables used to deliver a Qualified Project's power through the Prebuild Infrastructure that uses one of the four Conduits available.

Clarifying Questions, questions asked of Applicants by the Board's Prebuild Solicitation evaluation team throughout the evaluation period.

Cofferdam, an enclosed work area, generally consisting of a large pile driven into the waterbed.

Commission or FERC, the Federal Energy Regulatory Commission.

Conduit (or Cable Conduit), the empty pipes installed as part of the Prebuild Infrastructure capable of future installation of cables to be pulled through from end to end. Also called cable duct, or Duct Bank, for multiple conduit/cable sets.

Corridor, the cable route from the transmission cable's landfall location on the shoreline to the POI into the regional electric grid.

Cost Cap, the amount of capital costs that an Applicant commits it will not exceed with respect to the Prebuild Infrastructure.

Designated Entity, a PJM pre-qualified Transmission Owner or Nonincumbent Developer designated by PJM with the responsibility to construct, own, operate, maintain and finance a transmission project included in the RTEP.

Designated Entity Agreement or DEA, a pro forma agreement set forth in the PJM Tariff at Attachment KK. The DEA is entered into PJM and the Designated Entity as required under Schedule 6 of PJM's Operating Agreement.

DMAVA, New Jersey Department of Military and Veterans Affairs.

DPP, New Jersey Division of Purchase and Property.

Duct Bank, the concrete structure between Cable Vaults that house the necessary number of physically-separate Conduits in which transmission cables can be installed (pulled through, from one point to another).

EMF, electric and magnetic fields.

FERC, the Federal Energy Regulatory Commission.

Firm Cap, the integrated set of provisions related to the preferred Cost Cap mechanism, including a set of declining ROE recovery provisions for costs in excess of the Cost Cap, and preferred Uncontrollable Force provisions (see Attachment 4).

Good Utility Practice, shall mean any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, and acts generally accepted in the region.

HDD or Horizontal Directional Drilling, a trenchless method of installing Conduits for underground cables with limited above ground disruptions between the locations of the drilling equipment. Also called "directional boring."

HVAC, High Voltage Alternating Current.

LCS or Larrabee Collector Station, a new substation adjacent to the existing JCP&L Larrabee substation awarded to enable offshore wind interconnection through SAA 1.0.

Lease Agreement, an agreement entered into between Prebuild Developer and one or more Qualified Projects that sets out the terms of coordination, access, operations and maintenance responsibilities, and other aspects of operating the Prebuild.

Maximum Power Delivery, the amount of power, measured in MW, expected to be delivered from a Qualified Project's HVDC system as measured at the POI on the HVAC system.

MW, megawatts.

NJDEP, the New Jersey Department of Environmental Protection.

OBC, overburdened communities within New Jersey as identified by New Jersey's Environmental Justice Law N.J.S.A.13:1D-157.

OPRA, Open Public Records Act, N.J.S.A. 47:1A-1 et seq.

PJM or PJM Interconnection, L.L.C., is the FERC-approved independent regional transmission organization or the PJM Region covering all or parts of 13 states and the District of Columbia, including New Jersey.

PJM Tariff, is the PJM Open Access Transmission Tariff including any schedules, appendices, or exhibits attached thereto, on file with FERC and as amended from time to time..

Point of Demarcation, location where the change of ownership occurs between entities for supporting ancillary infrastructure. Conceptually, this location represents the terminus of the Prebuild Infrastructure, which will be at or near the Larrabee Collector Station. The current coordinates for this location, and additional details, are located in the *Corridor Details – Larrabee Collector Station* section below. The coordinates of the Point of Demarcation are: Latitude: 40°6'56.84"N; Longitude: 74°11'24.72"W.

POI, Point of Interconnection.

Prebuild or Prebuild Infrastructure or PBI, a concept that requires the construction of the necessary Duct Banks and Cable Vaults associated with the Prebuild for one or more Qualified Projects needed to fully utilize the Larrabee Tri-Collector Solution. For clarity, the Prebuild involves only the necessary infrastructure (Duct Banks and Cable Vaults) to house the transmission cables, but not the cables themselves.

Prebuild Developer, the Applicant ultimately selected by the Board Decision to construct and own the Prebuild.

Prebuild Solicitation or Prebuild Infrastructure Solicitation, the Prebuild solicitation being conducted within the parameters set forth in this Prebuild Solicitation Guidance Document.

Prebuild Solicitation Guidance Document or PSGD, this Solicitation Guidance Document.

Project, a Prebuild Infrastructure project proposed in this Prebuild Solicitation.

Q&A, Question and Answer.

Qualified Project or **Qualified Offshore Wind Project**, a wind turbine electricity generation facility in the Atlantic Ocean and connected to the electric transmission system in this State, and includes the associated transmission-related interconnection facilities and equipment, and approved by the Board pursuant to section 3 of P.L. 2010, c. 57 (N.J.S.A. 48:3-87.1) and N.J.S.A. 48:3-51.

Rate Counsel, the New Jersey Division of Rate Counsel.

ROE, return on equity**.**

ROW or Right of Way, a proposed right to make way over a certain portion of land or in offshore waters.

RTEP, the PJM Regional Transmission Expansion Plan.

SAA, the State Agreement Approach.

SAA 1.0, the inaugural SAA process conducted by the Board, resulting in the selection of the LCS and related transmission infrastructure.

Sea Girt or Sea Girt NGTC, the National Guard Training Center at Sea Girt.

Solicitation Website, https://offshorewind.nj.gov/prebuild-solicitation/, the website for information regarding this Prebuild Solicitation and the main point of information exchange between the Board and potential Applicants.

SMWVBE, New Jersey small, minority, woman, or veteran-owned business enterprise that meets certain criteria and is certified by the New Jersey Division of Revenue.

TEAC, the PJM Transmission Expansion Advisory Committee.

Third Solicitation, the Board's third solicitation for offshore wind generation.

Transition Vault, the underground vault structure used at the shore crossing at Sea Girt NGTC to facilitate transitions between land cables and submarine cables. Also called "transition splice/joint bay."

Uncontrollable Force, has the meaning ascribed to it in Attachment 4.

USACE, the United States Army Corps of Engineers.

1 OVERVIEW

1.1 Background

In the midst of the New Jersey Board of Public Utility's ("Board") analysis of offshore wind ("OSW") transmission options to optimally enable the State's OSW goals and minimize costs and risks to ratepayers, Board Staff continued to explore regulatory avenues to pursue the stated goals of the Board. Notably, these goals include increasing competition, reducing environmental impacts, reducing permitting/land acquisition requirements, and coordinating access to Points of Interconnection ("POI").[1] The Board's first State Agreement Approach, SAA 1.0, conducted in close coordination with PJM Interconnection, LLC. ("PJM"), represented an initial step in furtherance of these goals, creating significant cost savings by attracting a wide range of innovative proposals and resulting in an efficient design of an integrated transmission system for delivering OSW to New Jersey customers.

1.2 Prebuild Overview

As part of the SAA 1.0 project awards, the Board described the benefits of the Prebuild, which is the infrastructure between the identified landing point at Sea Girt National Guard Training Center ("NGTC") and the POI with the PJM high-voltage electric grid, the Larrabee Collector Station, enabling 3,742 MW of OSW generation needed to reach the then-current goal of 7,500 MW of OSW by 2035 to be connected to the grid. The Board explained that the Prebuild envisioned a single construction effort to install the necessary Duct Banks and associated access Cable Vaults to house transmission Conduits for future use of up to four (4) OSW Qualified Projects, thereby enabling these projects to access the wholesale transmission system.[2] The SAA 1.0 Award Order contemplates the Prebuild being procured as part of the Third Solicitation.[3] However, the Third Solicitation Guidance Document ("Solicitation 3 Guidance Document") noted that the potential remained for the SAA to be modified to include the Prebuild.[4]

After this Prebuild Solicitation is conducted by the Board, the Board will submit any awarded Project to PJM for incorporation into the RTEP. The Board will also submit the awarded Project for cost recovery through the cost allocation provisions for Public Policy Projects, approved by FERC, agreed to by the Board, and ultimately recovered from ratepayers through a FERC-approved transmission rate design, as described more fully below.[5] The successful Project will therefore become a baseline Public Policy Project included in PJM's RTEP.

1 In the Matter of Declaring Transmission to Support Offshore Wind a Public Policy of the State of New Jersey, BPU Docket No. QO20100630, Order dated October 26, 2022 at 54 ("SAA 1.0 Award Order").

2 Id. at 65-66. Technical specifications for each element of the Prebuild Infrastructure are provided in Section 3 below. Capitalized terms appearing on these pages in the SAA 1.0 Award Order are defined in the Attached List of Acronyms and Defined Terms.

3 Ibid.

4 Solicitation 3 Guidance Document at A10-2 ("The Board and Board Staff will notify Applicants, as early as possible, if the SAA Project is chosen to develop the Prebuild Infrastructure.").

5 See Section 4.5. See also PJM Operating Agreement, Schedule 6 § 1.5.9(a) (describing Public Policy Projects).

The scope of the Prebuild includes all Cable Vaults, Duct Banks, and related facilities for four (4) separate Qualified Projects, enabling Qualified Project developers to install their cables into the Prebuild by pulling them through the completed Prebuild Infrastructure facilities, as described more fully in Section 3 below. The Prebuild spans from the Cable Vaults at the Point of Demarcation beside the LCS, covering all Cable Vaults and Duct Banks up to the Transition Vaults set to be built and installed at Sea Girt. It continues beyond the Transition Vaults through Horizontal Directional Drilling boreholes, reaching offshore to specified locations enabling future use of the four (4) Qualified Projects.

The design of the Prebuild must ensure that each individual Qualified Project's transmission Circuit can be installed, operated, and maintained independently from other Circuits. There cannot be a single or common point of failure that would result in an outage of more than one Circuit at one time for a single outage event.[6] This aspect of the Prebuild design is of critical importance. In addition, the Prebuild developer will be responsible for the operation and maintenance ("O&M") of the Duct Banks and Cable Vaults consistent with Good Utility Practice, including readiness for installation of future cables, and for developing a lease agreement with future Qualified Projects for coordinating O&M activities on the cables within the Prebuild, as described more fully below.[7]

1.3 Eligibility to Bid

This Prebuild Solicitation is open to companies that are pre-qualified through PJM's planning process to be a Designated Entity pursuant to the PJM Operating Agreement Schedule 6, § 1.5.8 (a) by the Application Submission Deadline described in Section 2, below.[8] The Board encourages various types of entities capable of achieving this PJM pre-qualification to submit proposals into this Prebuild Solicitation, including but not limited to OSW generation developers previously proposing projects in the Board's Third Solicitation, other OSW generation developers that become PJM pre-qualified Applicants, transmission developers, or civil works construction firms.

PJM's Operating Agreement requires Applicants to submit the following information to become pre-qualified Designated Entities:[9]

> Pre-qualification applications shall contain the following information: (i) name and address of the entity; (ii) the technical and engineering qualifications of the entity or its affiliate, partner, or parent company; (iii) the demonstrated experience of the entity or its affiliate, partner, or parent company to develop, construct, maintain, and operate transmission facilities, including a list or other evidence of transmission facilities the entity, its affiliate, partner, or parent

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6 This includes avoiding designs that would result in a NERC Category P7 Multiple Contingency (Common Structure). For more information, see TPL-001-5 — Transmission System Planning Performance Requirements, https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf, at 24.

7 See Section 4.9.

8 PJM Operating Agreement Schedule 6, § 1.5.8 (a) ("*Development of Long-lead Projects, Short-term Projects, Immediate-need Reliability Projects, and Economic-based Enhancements or Expansions – Pre-Qualification Process*"), https://agreements.pjm.com/oa/4777.

9 Id. at § 1.5.8 (a)(1). PJM has confirmed that this Prebuild Solicitation is "good cause" for entities to request pre-qualification status outside the typical annual window. See Id. at § 1.5.8 (a)(4).

company previously developed, constructed, maintained, or operated; (iv) the previous record of the entity or its affiliate, partner, or parent company regarding construction, maintenance, or operation of transmission facilities both inside and outside of the PJM Region; (v) the capability of the entity or its affiliate, partner, or parent company to adhere to standardized construction, maintenance and operating practices; (vi) the financial statements of the entity or its affiliate, partner, or parent company for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the entity, if shorter, or such other evidence demonstrating an entity's or its affiliates, partner's, or parent company's current and expected financial capability acceptable to the Office of the Interconnection; (vii) a commitment by the entity to execute the Consolidated Transmission Owners Agreement, if the entity becomes a Designated Entity; (viii) evidence demonstrating the ability of the entity or its affiliate, partner, or parent company to address and timely remedy failure of facilities; (ix) a description of the experience of the entity or its affiliate, partner, or parent company in acquiring rights of way; and (x) such other supporting information that the Office of Interconnection requires to make the pre-qualification determinations consistent with this Operating Agreement, Schedule 6, section 1.5.8(a).

1.4 Solicitation Overview

The complete set of requirements associated with submitting a response to this Prebuild Solicitation ("Application") are provided in Section 3 below. The Prebuild shall allow for two (2) 1,500 MW Circuits at 525 kV and two (2) 1,360 MW Circuits at 320 kV.

Each Application must include one Corridor, with a specific Right of Way. Additional Applications can be submitted with alternative Corridors. Each submitted Corridor can utilize either a single ROW or split ROW as discussed further in Section 3.

Key aspects of the requirements for this Prebuild Solicitation are summarized below, with detailed requirements contained in subsequent sections of this document.

- **Cost Containment:** While cost containment is voluntary for Applicants, Applications utilizing the cost containment mechanisms specified in Section 4.5 and Attachment 4 are preferred. The preferred cost containment measures include a set of Firm Cap provisions that include eligibility to earn a full ROE (as submitted pursuant to Section 4.5 below and approved by FERC, and within the FERC-approved equity ratio), on up to 100% of the capital Cost Cap amount submitted by the Applicant, conditioned on a progressively declining ROE applied to capital costs over 100% of the Cost Cap. The level of the Cost Cap will be subject to adjustment based on the Uncontrollable Force provisions included in Attachment 4, which limits triggering of Uncontrollable Force to unforeseeable events or circumstances, and the Inflation Adjustment, as defined below. Such ROE adjustments and determinations related to Uncontrollable Force would ultimately occur during the Prebuild Developer's FERC rate recovery filing.

- **Inflation Adjustment:** The preferred Cost Containment commitments will utilize an inflation adjustment, specified in Section 4.5 and Attachment 4 that will automatically adjust the level of the submitted Cost Cap.

- **Schedule Commitments:** While schedule commitments are voluntary for Applicants, Applications utilizing the schedule commitment mechanism specified in Section 4.3 and Attachment 4 below are preferred.[10] The preferred schedule commitment includes downward ROE adjustments as a consequence for failure to complete the Project by the Expected In-Service Date (as defined in Section 2.1, Table 1). As a consequence for late-completion, the Project's ROE will be progressively declining (starting from the rate design submitted pursuant to Section 4.5 and approved by FERC, within the FERC-approved equity ratio) with a 35-basis point reduction for each 90 days of delay, with this reduction applied to the ROE associated with the Project's entire capital cost, and with a minimum return set at the Applicant's cost of debt. Performance-based return adders are available for delivery of the Prebuild ahead of the Project schedule, up to 50-basis points.

2 TIMELINE AND MECHANICS OF THE SOLICITATION

The Board retains the right to amend this Prebuild Solicitation Guidance Document if needed. Any such amendment(s) will be posted to the Solicitation Website, described below.

Timeline for Submission and Evaluation

Table 1: Timeline for Submission and Evaluation of Proposals

Event	Date
Board Consideration of Prebuild Solicitation	November 17, 2023
Solicitation Issued	November 17, 2023
Bidders' Conference for all prospective Applicants	December 1, 2023
Deadline for prospective Applicants to Submit Questions	February 14, 2024, 5 PM Eastern Time
Notice of Intent to Respond Submitted	February 28, 2024, 5 PM Eastern Time
Application Submission Deadline	April 3, 2024, 5 PM Eastern Time
Administrative Completeness Determination Deadline	April 19, 2024, 5pm Eastern Time
Board Decision on Submitted Applications	Q3, 2024
Post-Application Meeting (if requested by Board Staff or Applicant)	Q4, 2024
Expected In-Service Date- Full Scope	January 17, 2029
Expected In-Service Date-Onshore Only	October 18, 2028

2.1 Website and Bidders' Conference

Staff has created a Solicitation Website for this Prebuild Solicitation.[11] The Prebuild Solicitation Website will host all Prebuild Solicitation documents and serve as the main point of information exchange between the Board and potential Applicants. Stakeholders can subscribe to Solicitation-related announcements by e-mailing njoswprebuild@levitan.com with the subject "Subscribe" and providing the name, affiliation, and e-mail address of each person who should receive announcements. Solicitation Website updates will include notifications of posted Questions and Answers ("Q&A").

[10] The schedule commitment is distinct from the performance bond set out in section 4.10 below.

[11] Solicitation Website, https://offshorewind.nj.gov/prebuild-solicitation/.

Stakeholders can also find information related to this Prebuild Solicitation using the Board's Public Document Search tool under Docket No. QO23100719.[12] Additionally, Stakeholders can subscribe to Prebuild Solicitation updates posted in this Docket through Public Document Search tool. Updates will include notification of notices released by the Board, comments received (if public), and Board Orders.

A Bidders' Conference will be held for all prospective Applicants via webinar. Prospective Applicants must register for the Bidders' Conference no later than 5:00 p.m. Eastern Time on November 29, 2023, by e-mailing njoswprebuild@levitan.com. Once registered, prospective Applicants will receive an e-mail confirmation and webinar link.

During the Bidders' Conference, Staff will review key details of the Prebuild Solicitation, including Application requirements and evaluation criteria. Representatives of Sea Girt NGTC will also participate in the Bidders' Conference and be available to answer questions about the required landing point and the Sea Girt NGTC property. An agenda and any additional details on the Bidders' Conference will be released prior to the Bidders' Conference.

To ensure that all Applicants have the same information, a Q&A page will be established on the Solicitation Website. At the Bidders' Conference, Board Staff may verbally respond to questions that are submitted in advance of the Bidders' Conference. Applicants will have the opportunity to submit questions during the Bidders' Conference, which may be answered in real-time or deferred to written responses on the Q&A page of the Solicitation Website. Only written responses on the Q&A page of the Solicitation Website will constitute official guidance. Written responses to questions submitted through the Solicitation Website or during the Bidders' Conference will be posted to the Solicitation Website and will be available to all Applicants. Names and other identifying details of persons submitting questions will be removed from the submitted questions to maintain confidentiality.

2.2 Application Submission, Notice of Intent to Respond

Applications must be submitted by the Application Submission Deadline shown in Table 1. Prospective Applicants must e-mail njoswprebuild@levitan.com no later than 5:00 p.m. Eastern Time 30 days prior to the Application Submission Deadline. The e-mail must contain the subject line "Notice of Intent to Respond" and must identify the Applicant, a primary contact person, a secondary contact person, and the respective contact information for each (name, title, e-mail address, and phone number). The e-mail must also specify whether the Applicant is already a PJM pre-qualified Designated Entity. Submitting a Notice of Intent to Respond does not bind the Applicant to submit Applications, however the Applicant must submit such item as a prerequisite for submitting Applications.

After submitting the Notice of Intent to Respond, the Applicant will receive instructions via e-mail for accessing the portal to submit Application materials. Applicants will be able to upload documents to the portal for transmittal to the Board at any time after receiving the instructions. Applicants are encouraged to begin uploading their Application documents well in advance of the Application Submission Deadline to ensure a successful submission. Applicants will receive a receipt confirmation via

[12] See In the Matter of the Opening of a Solicitation for a Transmission Infrastructure Project to Support New Jersey's Offshore Wind Public Policy, BPU Docket No. QO23100719, Public Document Search at https://publicaccess.bpu.state.nj.us/CaseSummary.aspx?case_id=2112376.

e-mail after submitting their Applications in full. Files larger than 100 MB should be separated into multiple files and named with "Part [X of Y]" added to the end of the file name for each file.

2.3 Application Requirements

The required contents of each Application are detailed more fully in Section 4 below.

Applicants shall meet with representatives of NJDEP no less than 30 days prior to the Application Submission Deadline. Prior to this pre-Application meeting with NJDEP, Applicants must complete and submit a Permit Readiness Checklist to the NJDEP's Office of Permitting and Project Navigation.[13] The checklist can be submitted electronically to David Pepe (David.Pepe@dep.nj.gov) and Katherine Nolan (Katherine.Nolan@dep.nj.gov). In addition, the DMAVA will conduct a site walkthrough of Sea Girt NGTC, no less than 30 days prior to the Application Submission Deadline, which Applicants must attend as a prerequisite to submitting their Applications. Instructions for scheduling meetings with NJDEP, and regarding the DMAVA site walkthrough of Sea Girt NGTC, will be posted to the Solicitation Website.

Once Applications are submitted, Staff will make an initial determination of administrative completeness. Staff will notify Applicants by e-mail within approximately one week after the Application Submission Deadline regarding any identified Application deficiencies ("Deficiency Notice"). Applicants will then have one week following the date on which this Deficiency Notice e-mail was sent to respond to it. Failure to respond satisfactorily to a Deficiency Notice may constitute grounds for disqualification of an Application.

Board Staff expects to ask questions of Applicants regarding administratively complete Applications ("Clarifying Questions") throughout the Application evaluation period. Applicants will generally have one (1) week to respond to Clarifying Questions, although Board Staff reserves the right to establish a shorter response period or to extend the response period. Board Staff may also schedule interviews with Applicants.[14] These activities – Clarifying Questions and interviews – are expected to occur in Q2 2024. All materials provided and statements made during these activities will be considered binding on the Applicant and will be considered as part of Staff's formal evaluation. Staff will endeavor to provide Applicants with as much advance notice as possible regarding expected engagement as the evaluation proceeds.

2.4 Communications with Commissioners and Staff

The Board's rules of practice prohibit Applicants and Commissioners of the Board from discussing the Prebuild Solicitation, or topics directly related to the Prebuild Solicitation, from the date the Prebuild Solicitation is issued until the date the Board Decision is issued in this docket.

If an Applicant has a need to meet with one or more Commissioner(s) on matters unrelated to the Prebuild Solicitation, which is discouraged during the time that the Prebuild Solicitation is open, Applicants must request the Board's Office of General Counsel to review their request to meet with such

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[13] NJDEP, Permit Readiness Checklist, https://view.officeapps.live.com/op/view.aspx?src=https%3A%2F%2Fdep.nj.gov%2Fwp-content%2Fuploads%2Foppn%2Fpermit_readiness_checklist.docx&wdOrigin=BROWSELINK.

[14] The venue and format for interviews will be determined when the interviews are scheduled. Remote participation generally will be permitted.

Commissioner(s). Applicants may continue to communicate with other State agencies and with Staff in the normal course of business.

2.5 Confidentiality of Applications

To facilitate the review process, the Board will require all Applicants to submit public (redacted) and confidential (unredacted) versions of their Applications by the Application Submission Deadline, per the Board's Rules of Practice and Procedure governing submission of confidential materials, N.J.A.C. 14:1-12.1, et seq., and the Open Public Records Act, N.J.S.A. 47:1A-1 et seq. ("OPRA"). Each uploaded file must include "Public" or "Confidential" at the beginning of the file name, and the remainder of the file name must be identical for both the public and confidential versions. All public and confidential versions of all documents must be searchable PDF files, except where a different file type, such as Excel, is required.

The Board intends to make all public versions of submitted Applications available to the general public following the Board Decision. The Applications will be available to the general public by using the Board's Public Document Search tool under BPU Docket No QO23100719.

For the confidential version of the Application, Applicants must include a statement identifying each type of data or materials it asserts are exempt from public disclosure under OPRA and/or the common law, and explaining the basis for the proposed redaction. Assertions that the entire Application and/or costs are exempt from public disclosure under OPRA, the common law, or the U.S. Copyright Act of 1976[15] are overbroad and will not be honored by the Board. If Board Staff determines that an Application is excessively redacted, if may request that the Applicant submit a revised public version of one or more documents. If an Applicant elects not to seek confidential treatment of its Applications in its initial submittal, the entirety of the Application may be subject to public release.

Additionally, to facilitate public transparency, any winning Applicant will be required to make additional materials in its Application publicly available post-award, including, but not limited to, all materials necessary for members of the public to understand the Applicant's commitments to cost and schedule obligations. While there may be limited instances where material may remain confidential after submission of an Application (e.g., specific supply arrangements, Project financial information), the Board will look to the guidance provided by the New Jersey Division of Purchase and Property ("DPP") regarding the release of formal procurements as persuasive authority. The DPP rules state, in pertinent part, that "[a]fter the opening of sealed proposals, all information submitted by bidders in response to a solicitation of proposals is considered public information . . . except . . . as may be exempted from public disclosure by the Open Public Records Act, N.J.S.A. 47:1A-1 et seq. (OPRA), and the common law." N.J.A.C. 17:12-1.2(b).

The Board notes that it may elect to share confidential portions of the Application materials with other New Jersey government entities, including, but not limited to, NJDEP, Rate Counsel, DMAVA, and NJEDA, during the evaluation period or post-award.

[15] 17 U.S.C. §§ 101 – 810.

3 PREBUILD INFRASTRUCTURE SPECIFICATIONS

Each Project must include the Cable Vaults at the Point of Demarcation, the Corridor extending from the Point of Demarcation to Sea Girt NGTC, the Transition Vaults at Sea Girt NGTC, and the HDD bores under the shoreline interface from the Transition Vaults to the offshore termination area, in a manner that meets the specifications of this Section 3. The Prebuild includes only the necessary infrastructure to house the transmission cables, and does not include the cables themselves. The Prebuild will consist of Duct Banks and Cable Vaults to accommodate the transmission Circuits selected in the Third Solicitation and future generation solicitations, and must accommodate a total of four (4) total Circuits for Qualified Projects.

Each Application must incorporate the design, as described below for the Prebuild Infrastructure enabling two (2) Circuits operating at 320 kV (capable of at least 1,360 MW) and two (2) Circuits operating at 525 kV (capable of at least 1,500 MW).

3.1 Reliability Considerations

In each Project, Applicants must ensure that each individual transmission Circuit can be installed, operated, and maintained independently. There cannot be a single or common point of failure that would result in an outage of more than one Circuit at one time for a single event. This aspect of the Prebuild design is of critical importance.

3.2 Maximum Power Delivery (MW) at POI

The maximum power transfer capability requirements for Circuits using the Prebuild must include two (2) Circuits capable of at least 1,360 MW operating at 320 kV, and two (2) Circuits capable of at least 1,500 MW operating at 525 kV.

The Prebuild must be capable of enabling these specified levels of maximum power delivery. These transmission capability ratings and circuit ampacities shall be for continuous operation occurring during the most restrictive seasonal conditions. Applicants are required to include thermal ampacity and total power capability assumptions for the Circuits that will utilize and share the Prebuild. As noted above, each Circuit must be electrically independent from all other Circuits in the shared Prebuild, with every attempt made to limit thermal interference from one Circuit to another that could reduce any of these Projects' applicable Maximum Power Delivery targets.

3.3 Design and Configuration Assumptions

The Third Solicitation required HVDC-based cable and converter technology. Future solicitations for Projects that will utilize the Prebuild will also require HVDC technology. The Duct Banks should be able to accommodate HVDC cables from all major vendors. Applicants are encouraged to consider the future-proof nature of their proposed design while allowing downward compatibility (i.e., Conduits sized for 525 kV cables should also accommodate installation of 320 kV cables).

Each Duct Bank should be structured to accommodate one spare cable per Circuit. For 320 kV cables operating as a monopolar system, this will require three (3) Conduits in total, including one (1) serving as a spare. For 525 kV cables with metallic return in a bipolar system, this will require four (4) Conduits in total, including one (1) serving as a spare. In addition to these primary cable Conduits, each Circuit will require a smaller fiber optic control Conduit(s). These Circuits, their Conduits, and associated design elements (i.e., vault spacing, pulling lengths, and bending radii) should be downward compatible, so that 525 kV design should also be able to accommodate lower voltage cables (i.e., 320 kV).

3.4 Corridor Details – Sea Girt NGTC Landfall and HDD

The Applicant must consider landfall approaches at Sea Girt NGTC. Conducting the directional drilling/boring at landfall for a total of four (4) parallel Conduits is a required part of each proposed Prebuild design. Each Circuit will require an independent Transition Vault for cable splicing and terminating the HDD Conduits/pipe at landfall for a total of four (4) Circuits, consistent with the voltages and Maximum Power Delivery targets. Each Transition Vault will need to be accessed by an individual Qualified Project. Each Transition Vault and associated equipment at landfall must be installed with appropriate access and physical separation between Transition Vaults.

Applicants must design a Corridor with plans for Project sequencing to accommodate access to installation and maintenance of future cables which will avoid future conflicts or constraints. Applicants must identify any known limitations related to the order of installation for each Qualified Project in the respective Circuits when developing the Prebuild design in the Application.

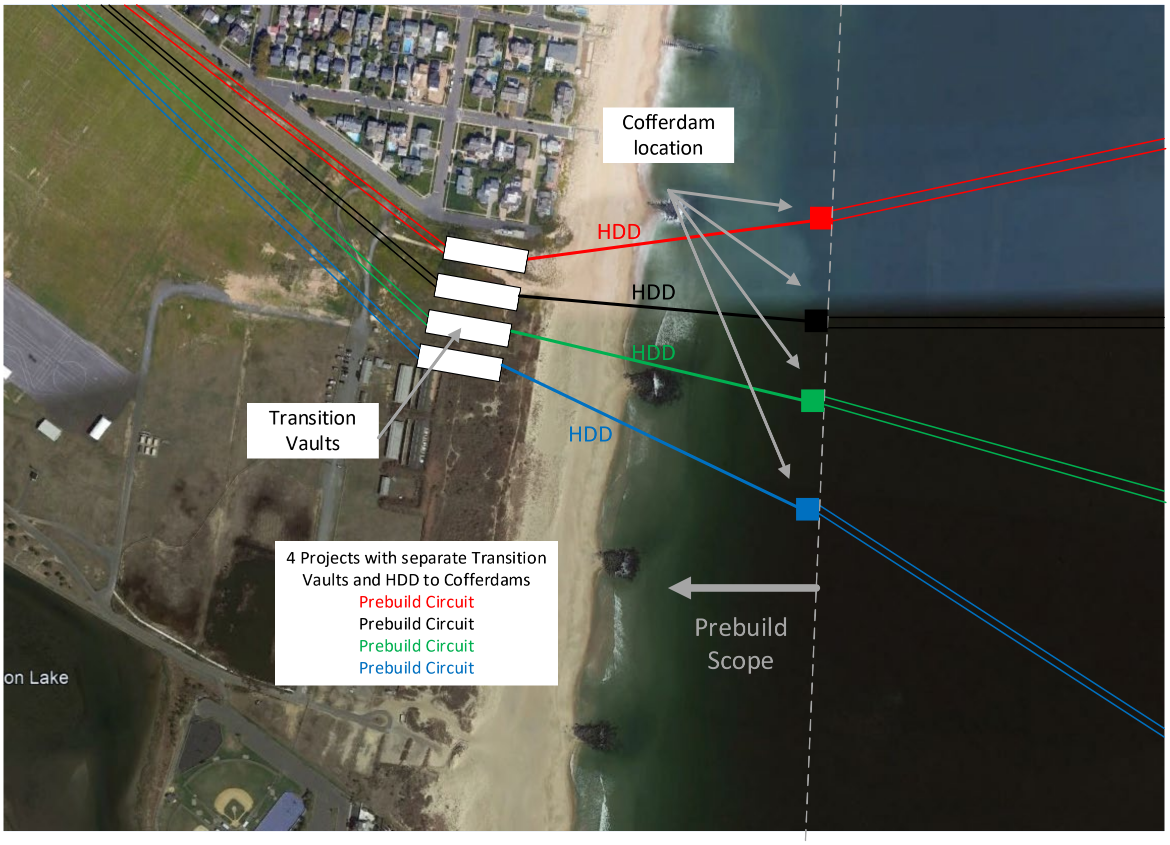
The Prebuild must include the HDD Conduit installation from the Transition Vaults extending to a specified location where the future cable installation will proceed via jet plow as shown in Figure 1. The Application must specify the exact location of the termination of the HDD. Reliability considerations will require independent HDD bores for each Circuit as part of the Prebuild installation to prevent impacts from adjacent Qualified Projects during normal and emergency O&M activities. Cofferdams themselves are not required, but debris containment is expected, consistent with the requirements of the environmental protection plan set out section 4.7.

3.5 Landfall Construction Specification

The parallel HDD bores should be installed as appropriate to maintain adequate separation between bores. The Applicant must keep all elements of the Prebuild, including HDD bores, related Conduits, and submarine exit points, accessible and maintained until such time that they are transferred to or accessed by each Qualified Project that will install cables therein, as described in Section 4.9 below.

For illustrative purposes only, Figure 1 below indicates the general concept for arrangement at the landfall point. It is not intended to indicate specific design requirements or locations of equipment.

Figure 1: Illustrative Example of Circuit Arrangement at Landfall



3.6 Corridor Details – Land Cable

Subject to the Maximum Power Delivery targets, proposed Corridors that demonstrate maximum flexibility to accommodate four (4) Circuits in the Prebuild in a single ROW would be preferred and evaluated favorably. Applicants are encouraged to identify limitations, conflicts, or constraints that can be mitigated to reduce both technology design risk and operating risk during the Project lifetime.

Prebuild designs must provide one proposed Corridor per Application to deliver each Circuit from landfall at Sea Girt NGTC to the Point of Demarcation. Alternate Corridors can be submitted in additional Application(s).

Applicants proposing to utilize Corridors that minimize or avoid land use constraints will be viewed favorably. However, Board action in this proceeding shall not be construed as providing approval for the proposed Corridor(s). The Board is not responsible for obtaining any required property rights or permitting obligations, including any rights associated with landfall at Sea Girt NGTC.

3.7 Special Cable Vaults, Duct Bank Cross Sections, and Crossings

Consistent with the Prebuild design requirements in this Section 3, Applicants must ensure that each Circuit in the Prebuild has its own independent Cable Vault access areas, even for “special” installations at areas of constraints or where HDD is required, to prevent impacts from (or to) adjacent Qualified Projects during normal and emergency O&M activities. Similar to the thermal loading requirements stated above, each of the Circuits in these special Duct Bank or Conduit sections is required to be electrically independent from the others as well as having limited thermal interference (not impacting the target Maximum Power Delivery for each Circuit).

3.8 Proposed Cable Vault Locations and Configuration

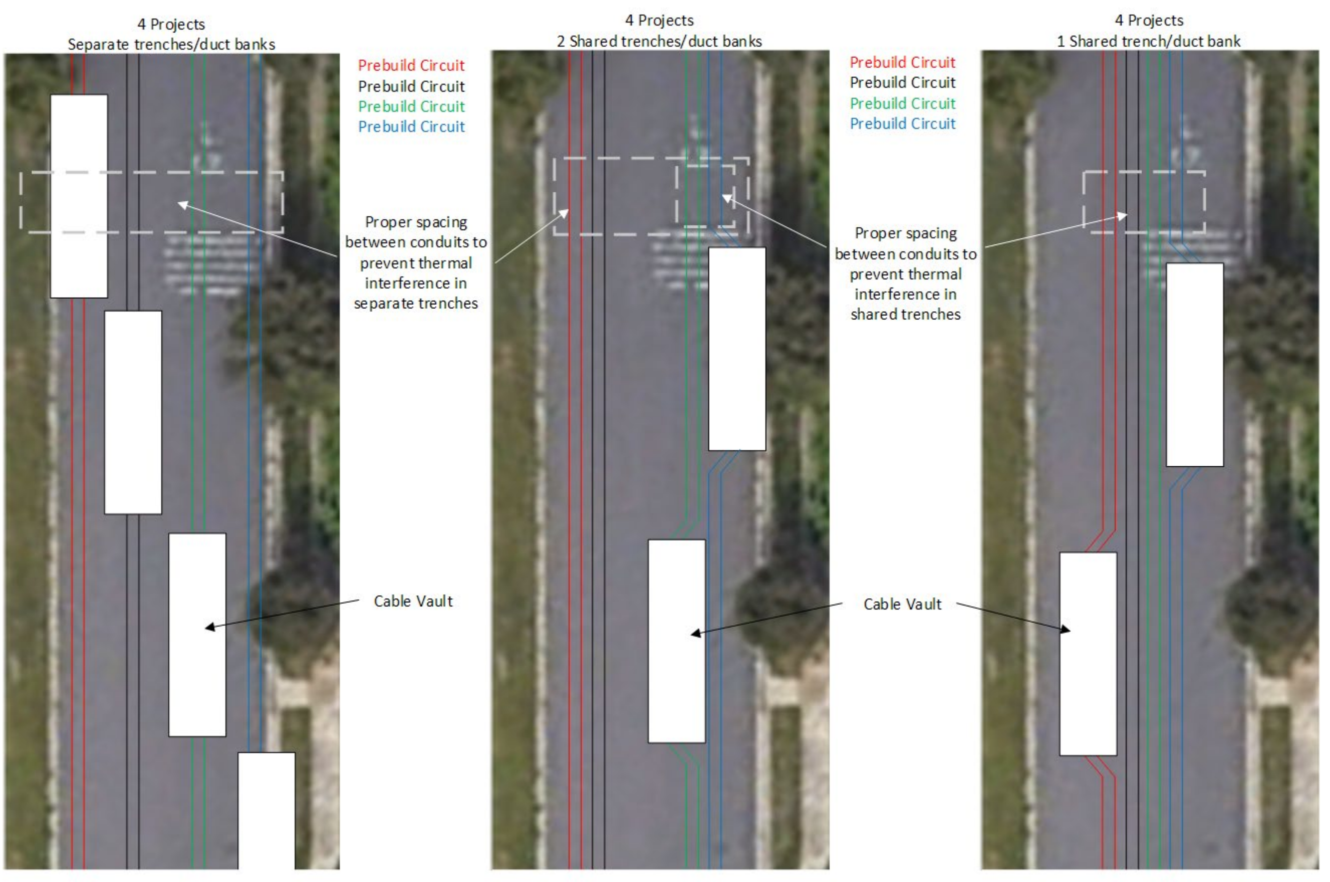
The Duct Bank and Cable Vault system for each Qualified Project is required to be independent from those utilized by the other Qualified Projects. There may be special considerations, however, that cover the planning, positioning, and sequencing of Cable Vault installation along the Corridor to gain the benefits of a single ROW approach. Emphasis on the avoidance of conflicts with local communities is required. When there is sufficient room in the proposed Corridor, the Cable Vaults for each Circuit should be slightly offset from one another so the overall width of the Prebuild can remain within the public ROW.

As previously discussed above, if there are other utilities in the street (or other constraints) which prevent the installation of the Cable Vaults necessary for installing multiple Project Circuits in a single ROW, it may be necessary to use two (2) adjacent streets (e.g., for up to two (2) Circuits each) in a split ROW approach. Each Application must select one Corridor for description in the Application Narrative, and Applicants are encouraged to submit additional Applications for alternative Corridors.[16] Staff recognizes that the conditions between Sea Girt NGTC and the Point of Demarcation may challenge the ability to install independent Cable Vaults and Duct Banks for four (4) Circuits in a single ROW. In certain narrow sections of the ROW, it may be necessary that Cable Vaults be installed with additional space between them, even in a single ROW, most notably at areas where there is a bend or at turns. Staff encourages Applicants to consider viable alternatives.

For illustrative purposes only, Figure 2 indicates the general concepts described above. Figure 2 is not intended to indicate specific design requirements or location of specific equipment.

[16] See id.

Figure 2: Illustrative Example of Duct Bank and Cable Vault Layout



The Cable Vaults for each Circuit must be isolated from one another and contain their own access points and sufficient space for performing necessary cable pulling and joint splicing activity in accord with Good Utility Practice for both safety and reliability purposes, while the other Circuits can be in operation at the same time. Applicants are encouraged to include a plan to ensure all other Circuits may be operational during these installation or maintenance activities. Applicants shall provide a typical layout design and identified probable locations for Cable Vaults along the entire Corridor. Any special vaults for surface conflicts and constrained or challenging areas, as well as designs for the Transition Vaults at Sea Girt NGTC landfall location must be designated.

3.9 Corridor Details – Larrabee Collector Station

Applicants should consider the general arrangement of Project Circuits approaching the Point of Demarcation at or near the LCS, along with the consideration of the future sequencing of cables subsequently installed in the Prebuild. The coordinates of the Point of Demarcation are: Latitude: 40°6'56.84"N; Longitude: 74°11'24.72"W. The approach to the LCS will have independent, parallel, and separated Duct Banks and Cable Vaults with the appropriate cable installation sequencing considered to minimize future conflicts. The awarded Applicant will coordinate final locations of the Cable Vaults at the point of demarcation with MAOD, the LCS developer, after the Project award.

MAOD will be responsible for the scope from the Prebuild Cable Vaults at the Point of Demarcation to the HVDC converter stations. The final design and layout at the Point of Demarcation will need to be coordinated with MAOD after the Prebuild is awarded.

Applicants must consider the appropriate sequencing of Circuit utilization, if required, to minimize any conflicts between Qualified Projects.

4 MATERIALS REQUIRED FROM APPLICANTS

There are two (2) primary components to the Application: (i) the Application Narrative and (ii) the Application Form. Each Application Narrative must be a stand-alone document with "Application Narrative" in the file name that includes the information described in each of the following subsections, with a detailed table of contents. Each Application Narrative must address each requirement of this Section 4. Each Application Narrative must be a fully-searchable PDF document. Each Application Narrative must match the structure of this Section 4. For example, "Applicant Information," as explained in further detail in Section 4.1 below, must be presented in Section 1 of the Application Narrative. If specific content is relevant to multiple sections of the Application Narrative, or multiple Applications (i.e. multiple cable routes), it does not need to be repeated in each of those sections, but instead should be cross-referenced as needed.

Applicants can include additional relevant information beyond the listed requirements at their discretion ("Additional Information"). Additional Information should be included in the most relevant section of the Application Narrative. If the Additional Information does not reasonably fit into one of the required sections, an Applicant may append an additional section titled "Additional Information."

Additional components of the Application include required attachments as noted below and any additional attachments that the Applicant believes provide Additional Information that is necessary to fully describe the included Project Scenarios. Unless specifically required to be provided in a different format such as Excel, attachments for each section of the Application Narrative should be consolidated into a single searchable PDF file with numbered pages, with "Attachments to Section [#]" in the file name.

The Application Form (Attachment 1 below) is an Excel file that requires entry of summary information and standardized quantitative components, including financial details. An Applicant must submit each Application Form as a working Excel (.xlsx) file. An Applicant must submit a separate Application Form for each Application, with "Application Form – [Project Scenario Name]" in the file name.

To assist Applicants in preparing their Applications, an "Administrative Completeness Checklist" Excel file with a condensed statement of the requirements deemed necessary and included in this SGD – is included as Attachment 2 below. Each Applicant must submit as a working Excel (.xlsx) file a single, completed Administrative Completeness Checklist, with the file name "Administrative Completeness Checklist." This Administrative Completeness Checklist is intended to allow Applicants and evaluators to assess whether an Application is administratively complete. However, this checklist is only a tool for Applicants and evaluators. The ultimate requirements are those contained in this Prebuild Solicitation Guidance Document. Each Applicant must submit a single Application Completeness Checklist that will apply to all Applications.

Each Applicant must submit a single, completed Applicant Commitment Form (see Attachment 3) that will apply to all Applications, (Attachment 3 below) signed by an authorized officer who possesses signing authority on behalf of the Applicant, with "Applicant Commitment Form" in the file name. By signing the Applicant Commitment Form, the Applicant's authorized officer acknowledges that the Applicant will comply with all commitments made in the Applicant Commitment Form that will be conditions of the Board Decision. Notably, the Applicant Commitment Form will bind the Applicant to the terms of the voluntary Cost and Schedule Commitments submitted in the Application.[17] The Applicant Commitment Form also contains an acknowledgement that the Board may share confidential information the Applicant provides with other New Jersey agencies, with PJM, and with federal agencies with jurisdiction over the interconnection and permitting of the Project.

The proposed Cost and Schedule Commitments, which appear as Attachment 4, sets forth Staff's preferred binding cost containment and schedule containment commitments. If the Applicant objects to specific terms in these proposed terms and conditions, or proposes an alternate cost and schedule commitment, the Applicant must provide clean and redline (against Attachment 4) versions of the conditions that the Applicant is committing as a condition of accepting the Application. If the Applicant submits revisions to the cost or schedule containment provisions set out in the proposed Cost and Schedule Commitments, they will apply to all Applications, that is, the same cost and schedule containment terms will apply to all Applications a particular Applicant submits.

4.1 Applicant Information

Section 1 of the Application Narrative must contain the following information:

- A demonstration of the Applicant's applicable experience in projects of similar size and scope to the proposed Project,
- List of all of the Applicant's key employees,[18] including resumes for each that detail their individual experience in construction and operation of transmission lines and cable systems of comparable voltages, similar size and scope, including HVDC facilities,[19]
- Description of any work done to date by the Applicant's key employees in developing projects of similar scope,
- If the work described was not performed by the entire team of key employees, the Applicant must delineate the experience or work performed by the applicable key employees,
- A detailed disclosure of any prior business bankruptcies, defaults, disbarments, investigations, indictments, stock exchange de-listings, rating downgrades, or other actions against either the Applicant, its parent company, affiliates, subsidiaries, or any key employees identified above.

[17] These Cost and Schedule Commitments will ultimately be submitted for inclusion as non-standard terms in a Designated Entity Agreement with PJM.

[18] "Key employee" means any individual employed by the Applicant in a supervisory capacity or empowered to make discretionary decisions with respect to the Project.

[19] Resumes for each key employee can be provided in an attachment.

Attachments to Section 1 of the Application Narrative must contain the following information:

- Certification and evidence demonstrating Applicant's status as a PJM pre-qualified Designated Entity.

4.2 Project Descriptions

Section 2 of the Application Narrative must contain the following information, consistent with the Prebuild infrastructure specifications specified in Section 3 of this PSGD:

- A detailed description of the Project, including an explanation of how the Project satisfies each element of the Prebuild infrastructure specifications specified in Section 3, with emphasis placed on safety, reliability, and constructability for four (4) Circuits,
- Maps, surveys, and other visual aids that support the detailed description of the Project,
- A demonstration that the selected technology, construction techniques, and selected materials are technically viable,
- Affirmation that the expected Circuit capacities that the proposed Prebuild can accommodate and meet the Maximum Power Delivery requirements, and
- Overall Corridor diagrams and maps for the Prebuild (Corridor can be a single ROW or split ROW, as described in Section 3 above), including:
    - Sea Girt NGTC landfall location,
    - The locations of the Transition Vaults,
    - The overall Corridor,
    - The locations of all Cable Vaults,
    - The Point of Demarcation, and
    - The locations of any expected conflicts or constraints.
- Details of the estimated landfall configuration:
    - Location of Transition Vaults, including indications in the GIS shapefiles provided with the Application,
    - Installation details of the Transition Vaults, including, but not limited to, the identification of potential approaches and HDD /boring locations at landfall for a total of four (4) parallel Conduits to accommodate multiple Qualified Projects' access to the Prebuild,
    - Design of Transition Vaults (physical dimensions, cable and splicing arrangements within the Transition Vaults, and separation between Transition Vaults and Conduits/pipe),

  - Duct Bank arrangement and Corridor leaving Transition Vaults toward POI (cross section of the Conduit/cable configuration, maximum cable sizes accommodated or assumed, and spare power and/or communication Conduits),

  - Directional drilling/boring method and details,

  - Specification, including GIS maps and feasibility evaluation, of termination areas where future cable installations of Qualified Projects will proceed, and

  - Assumptions used for thermal resistivities of soils, slurries, concrete, and backfill materials.

- A description of the reasons why Applicant selected the Corridor, with a list of any potential problems, constraints or limitations with siting the Prebuild along the selected Corridor, including identification of the locations where the Project will encounter specific and known challenges from a thermal and physical perspective,

- Information regarding the configuration of the Prebuild between Sea Girt NGTC and Point of Demarcation:

  - Typical Duct Bank cross sections (diameters, separation, height, width, and burial depth in various sections) for (i) occupied Conduits, (ii) spare Conduits, (iii) telecommunication Conduits, and (iv) Conduits for cable grounding and bonding connectors,

  - Separation between Duct Banks in separate trenches, and

  - Analysis of thermal interference between Duct Banks, including assumptions used for thermal resistivities of soils, concrete, and backfill materials.

- Information regarding Cable Vault design layouts:

  - Physical dimensions (size and installation depth) for Transition Vaults and Cable Vaults located along the Prebuild Corridor,

  - Cable Vault spacing along each Circuit,

  - Separation/offset between Cable Vaults for adjacent Circuits,

  - Cable and splicing arrangements within Cable Vaults, and

  - Access and Maintenance assumptions.

- Details for any special Cable Vaults or Duct Bank/Conduit segments including, but not limited to:

  - Location and explanation of constraints (tight curves or bending radius issues, narrow ROWs, limitations of cable sizes/types to be pulled, surface constraint requiring drilling, etc.) and method/technique to mitigate the constraints (e.g., directional bores, microtunnels, etc.) and

    - Separation between Duct Banks of adjacent Circuits, including a review of thermal interference between Duct Banks and assumptions used for soil and backfill thermal resistivity at specific locations.

- Information regarding the Prebuild configuration at or near the Point of Demarcation:

    - Relative arrangement of Circuits,
    - Layout of the Prebuild Corridor into vaults at the Point of Demarcation,
    - Sequencing constraints for Circuit utilization, and
    - Identification of any local limitations, special crossings, or conflicts.

- Identification of primary obstructions and other underground facilities located along the Corridor in the plans, including any plans for mitigation (e.g., proposed course of action, timing, involved stakeholders, and estimated costs),

- The assumptions used in the thermal calculations to verify that the Scenario requirements are met, including:[20]

    - Cable voltage (kV),
    - Cable ampacity (A),
    - Cable outer diameter (in or mm),
    - Conductor size (kCmil or mm^2) and material,
    - Maximum conductor operating temperature,
    - Insulation thickness (in or mm),
    - Minimum bending radius,
    - Maximum pulling tension, and
    - Other cable construction details (shielding, sheath, outer jacket, armor, bundling).

- Study results to demonstrate Maximum Power Delivery:

    - When two (2) Circuits are operating at 1,360 MW at 320 kV and two (2) Circuits are operating at 1,500 MW at 525 kV, and
    - When four (4) Circuits are operating at 1,360 MW at 320 kV.

- An identification of the nature of the Applicant's land ownership and lease requirements for all aspects of the Project, a plan for accomplishing remaining steps toward acquiring necessary leases

[20] Assumptions must also be entered in the Application Form.

or land ownership, and a demonstration of adequate financial resources to acquire any land and/or leases needed to undertake the Project,

- A demonstration of the ways in which specific features of the Project strengthen grid reliability objectives, including appropriate separation and independence of each transmission circuit,
- A plan to procure the proposed materials and equipment, including key milestones, status of the procurement process, and expected manufacturer warranty terms for major types of equipment, and
- A description and illustration of the ways in which the Applicant addresses Good Utility Practice in the design of the Prebuild by providing technical documentation for all portions of the Prebuild design and Corridor, including:
    - Duct Bank cross sections,
    - Separation between Duct Banks,
    - Analysis of thermal interference between Duct Banks, including assumptions used for concrete, soil and backfill thermal resistivity,
    - Details of the cable vaults,
    - The installation details of the HDD path, locations and details of transition cable vaults, locations of any expected conflicts, and a description of the method used to install the marine portion of the cable vault and the target depth of cable vault burial, and
    - Demonstration of due separation and independence of each transmission Circuit, and
- Identification of any facilities that will be used to support construction of the Project,

Attachments to Section 2 of the Application Narrative must contain the following information:

- A Letter of Intent ("LOI") or Memorandum of Understanding ("MOU") from the proposed engineering, procurement, and construction contractor, balance of plant contractor, and/or key construction contractors or vendors.

4.3 Schedule Commitment, Consequences, and Incentives

Timely delivery of the Prebuild is of paramount importance to the success of the Board's OSW goals and the SAA. Accordingly, the Board retains a strong preference for Applicants who commit to the proposed schedule commitments as described in this Section for late Project delivery. Staff may delay the Expected In-Service Date of the Prebuild at its discretion.[21] The Application must include a detailed timeline and descriptions for major Project milestones that enable the Project to be completed and in-service (as specified further in Section 4.9) by the Expected In-Service Date specified in Section 2 above, which forms the basis for Schedule Commitments. This timeline must also be included and submitted by

[21] The Expected In-Service Date will not be before January 17, 2029 for the full scope, or October 18th, 2028 for the onshore only scope.

the applicant by completing Attachment 5. The ability for the Project to meet these identified Schedule Commitments and be completed by the Expected In-Service Date is also a criteria for evaluation, as described further in Section 5.

While the Schedule Commitment remains voluntary for Applicants, Applications that provide Schedule Commitments consistent with the structure described in this Section and specified in Attachment 4 will be preferred. Should Applicants desire to submit different elements or a different structure of Schedule Commitment, the Application must include a redlined (against Attachment 4) set of Applicant proposed terms implementing Applicant's proposed commitments. These schedule commitments will ultimately be submitted for inclusion as non-standard terms in a Designated Entity Agreement with PJM.

In the preferred Schedule Commitment structure as set out in Attachment 4, as a consequence for not completing the awarded Project by the Expected In-Service Date, the Project's ROE will progressively decline, with a 35-basis point reduction (as submitted pursuant to Section 4.5 and approved by FERC, and within the FERC-approved equity ratio) for each 90 days of delay beyond the Expected In-Service Date, applied to the Project's entire capital cost, with a minimum ROE set at the Applicant's cost of debt.[22] Each ROE adjustment becomes effective on the first day following each 90-day period of delay of the Expected In-Service Date until the minimum ROE is reached or the project is deemed placed in-service, whichever comes first. Specific terms implementing this preferred Schedule Commitment are included in Attachment 4.

The preferred schedule commitment also includes performance-based return adders, applied for placing the Prebuild facilities in-service ahead of the Expected In-Service Date. For delivery between 30-120 days in advance of the Expected In-Service Date, a 25 basis-point incentive adder will be available; for delivery 121+ days in advance of the Expected In-Service Date, a 50 basis-point incentive adder will be available for the Project.

The preferred Schedule Commitment also provides a definition of Uncontrollable Force, intended to govern exceptions from the Schedule Commitments. Similar to the other terms of the Schedule Commitment, if the Applicant proposes an alternate definition of Uncontrollable Force, the Application must include a redlined (against the Uncontrollable Force provisions in Attachment 4) set of provisions.

In order for their Project to meet the Expected In-Service Date for purposes of this Schedule Commitment, Applicant will commit to provide formal engineering documentation and certification by a third-party engineer of the integrity, based on standard industry requirements, of the full scope of the Prebuild Infrastructure. Applicant will commit to provide such documentation as part of the Applicant Commitment Form. Applicant will provide such documentation regarding Duct Banks, Cable Vaults, HDD bores, Conduits, and any submarine exit points in an informational filing to the Board prior to the utilization by a Qualified Project. Such informational filing will qualify the Prebuild Infrastructure to meet the Expected In-Service Date, for the purposes of this Section.

As detailed in Section 5, Staff will assess the likelihood of timely commercial operation and the constructability of an Applicant's proposed Project on the basis of the timeline and milestones provided

[22] These ROE Adjustments would be additive to the adjustments for preferred Cost Cap measures discussed in Section 4.5, but the preferred measures in no case envision that the Applicant's ROE be set to an amount lower than the cost of debt. See examples in Tables 4 and 5.

in such Applicant's Application and memorialized in Attachment 5. The ability for the proposed Project to meet the stated schedule milestones in the Application will serve as a threshold criteria in the evaluation process as described further in Section 5, below.

Section 3 of the Application Narrative must contain the following information:

- A detailed timeline specifying the sequencing and specific milestone dates for completion of major elements of Project schedule, including permitting (reflecting the Permitting Plan described in Section 4.8), engineering, design, procurement, construction (including HDD), licensing, Expected In-Service Date (as specified in Section 2, above), etc., and

- A detailed explanation of each milestone identified in the provided timeline.

- A description of the Schedule Commitment and Uncontrollable Force provisions proposed to be utilized by the Applicant. If the preferred Schedule Commitment mechanism set out in Attachment 4 is utilized by the Applicant, no further information (beyond the Applicant Commitment Form in Attachment 3) needs to be provided except an indication that Applicant has elected the preferred Schedule Commitment; if an alternate Schedule Commitment is proposed, Applicant must provide a redline set of Applicant proposed terms and conditions (against the Staff proposed terms and conditions that appears as Attachment 4).

Attachments to Section 3 of the Application Narrative must contain the following information:

- An identification of all known potential sources of delays in the Project schedule, and how those delays could be mitigated, or if not mitigated, how they would affect the overall Project schedule.

- Sufficient documentation to support any alternate proposed Schedule Commitment mechanism.

4.4 Cost Estimate

In support of the Project's cost containment measures, discussed in Section 4.5 below, Applicant must submit detailed cost estimates for each discrete element of the Project's construction. These elements must include, but are not limited to engineering, permitting, site control, materials/equipment, construction, construction management, overhead & miscellaneous, and contingency. Applicants are encouraged to supplement these categories with additional details as available. Submitted cost estimates should form the basis of the Project's binding cost containment, described below.

The Application must also describe any tax credits, subsidies, grants, or other federal benefits the Project is anticipating utilizing. Each Application must also fully describe the manner in which the development of its cost estimate or cost containment measures are reliant on any of these identified programs or benefits. Applicant should further assess the likelihood of successfully utilizing the identified programs or benefits.

Section 4 of the Application Narrative must contain the following information:

- A description of the cost estimates for each discrete element of Project construction, including engineering, permitting, site control, materials/equipment, construction, construction management, overhead & miscellaneous, and contingency,[23]
    - A description of the cost estimate for each element set out above related to all work on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore termination areas)
    - A description of the cost estimate of the remainder of the scope, up to and including the Transition Vaults, excluding all elements on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore termination areas)
- The total Project cost,[24] and
    - The total project cost from the cable vaults at the Point of Demarcation up to and including the Transition Vaults, excluding all elements on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore termination areas)
- A description of the process utilized by the Applicant to verify and confirm the provided cost estimate.

Attachments to Section 4 of the Application Narrative must contain the following information:

- A detailed cost build-up of the Project incorporating each discrete element identified by the Applicant, presented in an Excel file and
- The feasibility study used to determine each of these cost components.

4.5 Cost Containment and Rate Design

Cost control over the approved Project remains a priority of the Board. To further this objective, this Prebuild Solicitation includes the design of a preferred cost containment approach. Applicants are encouraged to commit to the form of cost containment set out in Attachment 4. However, cost containment submissions are voluntary; Applicants are free to propose their own cost containment approach, no cost containment approach, or a revised version of the preferred cost containment approach described in this Section 4.5. Similar to the approach outlined in Section 4.3, any alternate cost containment submission must provide a redline of Applicant's proposed terms and conditions against the preferred terms and conditions found in Attachment 4. Any cost containment approach submitted by an Applicant will be binding on that Applicant (under the terms submitted by Applicant) under the terms of the Applicant Commitment Form. These Cost Commitments will ultimately be submitted for inclusion as non-standard terms in a DEA with PJM.

As reflected in the proposed nonstandard terms and conditions in Attachment 4, the preferred terms also provide a definition of Uncontrollable Force, intended to govern exceptions from cost containment.

[23] Cost component data is also required to be entered in the Application Form (see Attachment 1).

[24] Total Project cost is also required to be entered in the Application Form (see Attachment 1).

Any alternative proposed cost containment approach must also include a redlined set of Uncontrollable Force provisions (against Attachment 4).

Preferred cost containment commitments will consist of standard regulated cost recovery via FERC revenue requirement, subject to Applicant's commitment to cap all capital and investment costs pursuant to the "Firm cap" provisions outlined in this Section, and the related Uncontrollable Force described above. This Firm cap structure limits the ROE associated with Project capital expenses over the level of the capital Cost Cap and does not limit recovery of prudently-incurred costs subject to FERC review. Specifically, the preferred cost containment provision results in larger ROE reductions as the level of cost overrun grows. For costs incurred between 100-110% of the binding Cost Cap, the allowable ROE (subject to proposed and approved equity structures) will be limited to the midpoint between the Project's FERC-allowed ROE (including incentive-adders, if any) and the Project's cost of debt. For costs incurred over 110% of the binding Cost Cap, the allowable ROE will be limited to the Project's cost of debt.[25] In either case, the allowable ROE on all costs incurred up to 100% of the binding costs will remain at the requested level pursuant to FERC approval (and subject to schedule commitment adjustments described in Section 4.3 above).

Table 2: Preferred Cost Containment Commitment Provisions

Costs Incurred as a Percent of Cost Cap	Cost Recovery
Up to 100%	FERC-allowed ROE
Between 100-110%	Midpoint between FERC-allowed ROE (including approved adders, if any) and approved cost-of-debt
Over 110%	Approved cost-of-debt.
Note that all other aspects of the FERC formula rate submitted by the Applicant in Section 4.5 and approved by FERC will remain in force, with only the ROE for the designated equity percentage subject to change as a result of these cost containment provisions.	

To account for future changes in underlying component cost while preserving aggressive competition, the level of the capital Cost Cap contained within the Firm Cap paradigm of preferred cost containment commitments described in this Section will be subject to an inflation adjustment mechanism. This mechanism will account for the change in input costs due to inflation across a number of specified indices, between the time of the Application and 18 months before the Expected In-Service Date. The change in the capital cost as a result of the inflation adjustment will be limited to 15%, that is, capital costs subject to the cost containment mechanism will be neither increased nor decreased more than 15%, even if a larger adjustment is indicated by the index values.

This inflation adjustment will alter the total Project costs subject to the capital Cost Cap and contained within the Firm Cap. No petition to the Board will be required to operate the inflation adjustment mechanism; to institute this mechanism, Applicants are expected to include the adjustment within their submitted draft FERC formula rate protocols, which will also include the Firm Cap provisions described

[25] These ROE adjustments are applied to the incremental cost overrun that falls within each tier (e.g. between 100%-110%), and not the entire capital cost of the Project.

above and the Uncontrollable Force provisions outlined in Attachment 4 (or contained in Applicant's proposed alternate cost containment mechanism, as reflected in Applicant's redline of Attachment 4).

The inflation adjustment mechanism is calculated as below:

$$CapCost_{inf} = CapCost_{base} \times \sum \frac{Index_{M,i}}{Index_{I,i}} \times F_i$$

Where,

- $CapCost_{inf}$ is the capital cost after inflation adjustment at the time of FERC's approval of the DEA, to be used as the Firm Cap level for the purposes of preferred cost containment;
- $CapCost_{base}$ is the as-bid Capital Cost, i.e., the level of the Firm Cap, submitted under the terms of the Uncontrollable Force and recovery provisions outlined in this Attachment;
- $Index_{M,i}$ is the average index value for cost component *i* over the three months before and three months after FERC's approval of the DEA;
- $Index_{I,i}$ is the average index value for cost component *i* over the twelve months prior to the Application Submission Deadline; and
- F_i is the fraction associated with cost component *i*, set out in Table 3 below.

Table 3: Fractions Associated with Price Components

Price Component	F Value	Index[26]
Fixed	0.25	N/A
Labor	0.25	BLS Employment Cost Trends Data Series CES2000000003 Average hourly earnings of all employees, construction, seasonally adjusted
Ready-Mix Concrete	0.25	BLS PPI Data Series WPU13330101A: PPI commodity data for Ready-mix Concrete, Northeast Region
Construction Equipment Rental and Leasing	0.25	BLS PPI Data Series PCU5324125324121: PPI industry data for Other Heavy Machinery Rental and Leasing: Construction Equipment Rental and Leasing

The Application must also include a template FERC rate design (stated or FERC formula rate) with all known inputs, and a detailed explanation of this design accounting for the cost containment and Schedule Commitment penalties described in this Section and Section 4.3 above. The description and template should include, but not be limited to, proposed ROE, proposed cost of debt, proposed equity percentage, depreciation schedules, and a list and justification for all incentive adders that will be pursued by Applicant if awarded. This template must also account for the descriptions of any tax-advantaged financing or other federal benefits relied on by the project provided in Section 4.4.

[26] Bureau of Labor Statics (placeholder)

The Schedule Commitment, Firm cap, and performance bonus provisions of this Prebuild Solicitation work together to provide an integrated suite of incentives to Applicants in support of the Board's goals. Two examples are provided below, for illustration purposes only, to clarify the manner in which these provisions are intended to work together.

- **<u>Example 1</u>** - Project Z is placed in-service two (2) months ahead of the Expected In-Service Date, at 115% of its capital Cost Cap.

Table 4: Example 1: Project Z

Costs Incurred as a Percent of Cost Cap	Cost Containment ROE	Schedule Commitment Incentive	After-Adjustment ROE	Weighted Average ROE
0-100%	10%	+0.25%	10.25%	
100-110%	7.5%	+0.25%	7.75%	
110-115%	5%	+0.25%	5.25%	
				9.16%
Note: Requested ROE after FERC incentives assumed to be 10%, cost of debt assumed to be 5%, and that all other aspects of the FERC formula rate submitted by the Applicant in Section 4.5 and approved by FERC will remain in force, with only the ROE for the designated equity percentage subject to change as a result of these cost containment provisions.				

- **<u>Example 2</u>** - Project Y is placed in-service four (4) months after the Expected In-Service Date, at 105% of its capital Cost Cap.

Table 5: Example 2: Project Y

Costs Incurred as a Percent of Cost Cap	Cost Containment ROE	Schedule Commitment Reduction	After-Adjustment ROE	Weighted Average ROE
0-100%	10%	-0.7%	9.3%	
100-105%	7.5%	-0.7%	6.8%	
				9.18%
Note: Requested ROE after FERC incentives assumed to be 10%, cost of debt assumed to be 5%, and that all other aspects of the FERC formula rate submitted by the Applicant in Section 4.5 and approved by FERC will remain in force, with only the ROE for the designated equity percentage subject to change as a result of these cost containment provisions.				

Section 5 of the Application Narrative must contain the following information:

- A description of the proposed FERC formula rate spreadsheets associated with existing or new rate design that will be used to recover the cost of the Project, including all known inputs as described below[27],

- A description of the proposed FERC formula Rate protocols associated with existing or new rates that will be utilized to recover the cost of the Project, including how the Applicant has included the proposed cost containment commitment provisions and Schedule Commitment provisions,[28]

- A description of all FERC rate incentive adders that will be sought by the Applicant, the justification for applying for each adder, and the scope of application for each adder,

- A description of the cost containment, schedule commitments and Uncontrollable Force provisions proposed to be utilized by the Applicant. If the preferred terms set out in Attachment 4 are utilized by the Applicant, no further information (beyond the Applicant Commitment Form in Attachment 3) needs to be provided except an indication that Applicant has elected the preferred terms. and

- A description of any tax advantaged financing, loans, or grants, pursued or awarded to the Applicant, including the financial impact on the Project anticipated from any such awards.

Attachments to Section4.5 5 of the Application Narrative must contain the following information:

- Editable Excel spreadsheets of draft FERC formula rates, proposed or existing (that will be used for the Project), accounting for proposed cost containment provisions and required Schedule Commitment provisions,

- Proposed or existing FERC formula rate protocols,

- Details on revenue requirement inputs, including:

    - O&M, G&A Costs
        - Cost estimates for Operations, Maintenance, and G&A FERC US of A 560-570 series, 920 series.
        - O&M escalation rates
        - Clarification if O&M, G&A expenses are covered in cost containment,

    - Capital Structure
        - Debt-to-Equity ratio (specify if actual or hypothetical)
        - Cost of debt
        - Proposed ROE (identify any embedded/anticipated FERC adders described above),

    - Depreciation
        - Book life by asset class
        - Tax depreciation method e.g., 5-year MACRS, half-year convention

[27] While the Board and Staff will review this information, please note that the review shall not constitute consent or agreement with these documents when they are ultimately filed at FERC.

[28] Same as Footnote 27.

        - Book and tax depreciation schedule for CapEx and On-going CapEx,

    - Taxes
        - Federal and state income tax rates
        - Description of blended income tax rate calculations, if any
        - Property tax rate
        - Deferred income tax schedule, if appropriate,

    - Discount Rate, and

    - Revenue Requirement
        - Estimated annual revenue requirement for each proposed solution from commercial operation through the book life of the plant.
        - Provide revenue requirement build-up workbook, including depreciation, cost of debt, return on equity, federal and state income tax, property tax, and other costs e.g., O&M, G&A other income tax.

- Sufficient documentation to support any alternate proposed cost containment mechanism.

4.6 Stakeholder Engagement

Section 6 of the Application Narrative must contain the following information:

- A description of the Applicant's values and philosophy related to stakeholder engagement;

- Identification of key stakeholders by category and specific organizations or entities, and goals for engagement with these stakeholders, including, but not limited to, tribal nations, community-based organizations, local and county elected officials, recreational and commercial fisheries, labor unions, higher education, coastal residents and business owners, economic and workforce development organizations, environmental and environmental justice groups, OBCs, and New Jersey SMWVBEs;

- A plan for engaging all identified stakeholders, to take place after any award associated with this Prebuild Solicitation.

4.7 Environmental Protection Plan

Projects must be planned to avoid impacts to natural resources, minimize impacts when avoidance is not possible, and mitigate impacts where necessary. Environmental protection measures must span all phases and components of a Project, including on-shore and off-shore HDD and any Cofferdam activities at the termination area, pre-construction surveys, construction, and operation and decommissioning.

Where necessary environmental protection measures are not defined or fall outside the environmental resource categories described below, the Applicant shall commit, as part of its environmental protection plan, to:

- Work collaboratively with the State, federal agencies, and other stakeholders to identify such impacts and to develop approaches that avoid impacts on the environment, biodiversity and ecosystem services,

- Where avoidance is not possible, minimize such impacts,
- When impacts are predicted to occur notwithstanding the implementation of practical avoidance and mitigation measures, rehabilitate or restore ecosystems, and
- Where significant residual impacts are predicted to remain, offset such impacts.

Section 7 of the Application Narrative must contain the following information:

- Description of how the Applicant intends to avoid, minimize, and/or mitigate adverse impacts to biota and habitats, and shall address the following environmental resource categories:
    - Physical Resources:
        - Air quality,
        - Geological resources,
        - Airborne sound (noise),
        - Water quality,
        - Underwater acoustics, and
        - Wetlands and waterbodies,
    - Biological Resources:
        - Benthic & shellfish,
        - Coastal & terrestrial habitats,
        - Finfish & essential fish habitats,
        - Marine mammals & sea turtles,
        - Avian and bat species,
        - Terrestrial wildlife, and
        - Submerged aquatic vegetation,
    - Cultural Resources:
        - Above-ground historic properties,
        - Marine archaeology, and
        - Terrestrial archaeology,
    - Socioeconomic Resources:
        - Visual resources,
        - Commercial and recreational fisheries,
        - Commercial shipping,
        - Vessel & vehicle traffic,
        - Environmental justice,
        - Land use and zoning,
        - Existing cables,
        - Tourism,
        - Public health & safety,
        - Workforce, economy, and

    - Demographics,

  - Open Space/Recreation:
    - Green Acres encumbered lands,
    - State-owned lands, and
    - Wildlife management areas,

  - Hazardous waste, and

  - Electric and magnetic fields (“EMF”),

- A comprehensive description of the anticipated environmental benefits and environmental impacts of the Project including an analysis of the onshore Corridor chosen. If more than one ROW is necessary for the Corridor (e.g., a split ROW as discussed in Section 3), documentation must be provided as to why multiple ROW are needed, how many Circuits will be installed in each ROW, and the environmental impacts and benefits (if any) of multiple ROWs,

- An acreage calculation of habitat disturbance, especially related to wetlands, forested areas, or other sensitive habitats,

- Projected vessels traffic and/or vehicles needed for Project surveys, construction, operation, and project closeout,

- An assessment of the impact to fisheries including:

  - A scientifically rigorous description of the marine resources that exist in the Project area, including biota and commercial and recreational fisheries, that is informed by published studies, fisheries-dependent data, and fisheries-independent data, and identifies species of concern and potentially impacted fisheries,

  - A scientifically rigorous plan to detect impacts to marine resources, including biota and recreational and commercial fisheries,

  - Identification of all potential impacts on fish and on commercial and recreational fisheries off the coast of New Jersey from pre-construction activities through Project close out,

  - An explanation of how the Applicant will provide reasonable accommodations to commercial and recreational fishing for efficient and safe access to fishing grounds, and

  - A description of the Applicant's plan for addressing loss of or damage to fishing gear or vessels from interactions with offshore wind related infrastructure or equipment,

- A description of how the Applicant will identify (or has identified) environmental and fisheries stakeholders, any outreach that has occurred to date, and how the Applicant proposes to communicate with those stakeholders during pre-construction activities through decommissioning, as well as a plan for transparent reporting of how stakeholders’ concerns were addressed, consistent with Section 4.6, above,

- A description of how onshore elements of the Project will be compatible with surrounding land use and communities, and will safeguard environmentally and culturally sensitive areas,

    - A description of the potential impact of the Project on OBCs. If impacts to an OBC are anticipated during or after construction, including, but not limited to, increased noise, dust, impervious surface, truck traffic, or loss of tree canopy or open space, the Applicant shall (1) include a stakeholder engagement plan specific to the impacted OBC, as part of the required content described in Section 4.6, (2) identify relevant impacted-OBC stakeholders including local government entities and community-based organizations, (3) propose draft control measures to avoid, minimize, or otherwise offset those impacts, (4) utilize the stakeholder engagement plan to seek feedback from the impacted OBC on the proposed draft control measures, and (5) propose final control measures and provide explanation for how the final proposal of control measures address public feedback,

Attachments to Section 7 of the Application Narrative must contain the following information:

- A GIS Desktop Study of potential impacts to sensitive resources including tabular summaries of acreage and distance calculations,

- GIS Shapefiles of the Corridor from Sea Girt to the Point of Demarcation, including landfall locations, Transition Vault locations, and ROW(s), that show:

    - ROW width,

    - Descriptions of cable installation methods with locations identified,

    - General footprint and extent of HDD boreholes and cable landings,

    - Footprint of all construction activities related to wetlands, forested areas, or other sensitive habitats,

    - Footprint and extent of all other pre-construction and construction activities, and

    - Any needed exclusion zones around Project infrastructure including any offshore Cofferdams.

4.8 Permitting Plan

Section 8 of the Application Narrative must contain the following information:

- A list of all State and Federal regulatory agency approvals, permits, or other authorizations required pursuant to State, local, and Federal law,

- An identification of all applicable Federal and State statutes and regulations and municipal code requirements, with the names of the Federal, State, and local agencies to contact for compliance,

- An identification of State Lands or Green Acres encumbered lands that may be impacted, and the expected time to obtain such permits and/or approvals,

- A land use compatibility / consistency matrix to identify local zoning laws and the consistency of Applicant's activities in each local jurisdiction, and
- A strategy, including the expected timeline (aligned with the Schedule Commitment described in Section 4.3), to obtain each required permit and/or approval.

Attachments to Section 8 of the Application Narrative must contain the following information:

- Documentation of consultation with the US Army Corps of Engineers ("USACE") regarding beach replenishment projects and sand borrow areas, if applicable and
- Copies of all submitted permit applications and any issued approvals and permits.

4.9 O&M Plan / Ownership Transfer

The Board anticipates that it will submit the awarded Prebuild Project, as designated in the Board Decision, to PJM for inclusion in the RTEP as a New Jersey-sponsored Public Policy Project. Accordingly, the selected Prebuild Project will become a transmission facility subject to the PJM Tariff, the selected Applicant must apply for PJM membership as a Transmission Owner consistent with the PJM Operating Agreement, Tariff and Consolidated Transmission Owners Agreement, and costs associated with the Prebuild (including O&M costs) will be subject to recovery pursuant to the PJM Tariff and any FERC-approved rate (see Section 4.5 above).

As part of certifying the Prebuild for commercial operations, the Applicant (who will become the Prebuild developer and owner as a result of the Board Decision) will provide timely certification of the integrity, based on standard industry requirements, of the full scope of the Prebuild, including but not limited to Duct Banks, Cable Vaults, HDD bores, Conduits, and any submarine exit points in an informational filing to the Board prior to the utilization by a Qualified Project. This filing will require formal engineering documentation and certification by an independent third-party engineering firm to be arranged and delivered by the Prebuild owner to the Board and developers who will utilize the Prebuild, as discussed in Section 4.3 above.

The Applicant will also provide a Form of Lease Agreement as part of the Application. Although this Lease Agreement will not be finalized at the time of the Application or Board Decision, Applicant will be expected to negotiate and execute a Lease Agreement that meets the requirement of this Section with each Qualified Project selected by the Board to utilize the Prebuild Infrastructure. To be clear, the Board will not be approving any lease agreement that is ultimately negotiated between the Applicant and each Qualified Project, but any such lease agreement, upon execution, shall be shared with Staff for informational purposes.

Section 9 of the Application Narrative must contain the following information:

- A proposed O&M plan (including activities, schedules and proposed coordination procedures) for conducting O&M on the Prebuild and coordinating the performance by each Qualified Project developer of its own O&M activities on its own transmission cable and,
- A detailed description of the Form of Lease Agreement.

Attachments to Section 9 of the Application Narrative must contain the following information:

- A Form of Lease Agreement which addresses the following items:
    - Commitment to (a) lease cable conduits to each Qualified Project owner for a nominal cost, (b) perform O&M activities on the Prebuild, and (c) coordinate the performance by each Qualified Project developer of its own O&M activities on its own transmission cable (including any ancillary facilities) in accordance with PJM maintenance requirements,
    - Identification of the facilities to which the Lease Agreement applies,
    - Commitment to use Good Utility Practice in connection with the design, engineering, construction, operation and maintenance of the Prebuild Infrastructure,
    - Requirement to make application for, prosecute, obtain and hold all permits, licenses, authorizations, consents, decrees, waivers, privileges and approvals from, and filings with any governmental department, agency, or authority, as required by law to commence, prosecute and complete construction of the Prebuild in accordance with terms of any Board Order and the Form of Non-Standard DEA,
    - Remedies for failure to perform, including options for a third party to step in to complete the construction of or operate the Prebuild,
    - Financial penalties for failure to perform,
    - Milestones that show key dates including related to land rights; permit/siting approvals; design completion; engineering completion; construction milestones; ISD; etc.,
    - Commitment to milestone schedule, including Schedule Commitments,
    - Standard of performance or availability that would apply after service begins,
    - All proposed FERC formula rate incentives consistent with the description in Section 4.5, and
    - Annual audit rights on cost-of-service rates; requirement to maintain records and accounts.

4.10 Performance Bond

Within 90 days after the effective date of the Board Decision, the Prebuild Developer shall make a compliance filing with the Board ("Compliance Filing") that binds the awarded Prebuild Developer and their successors or assigns to meet the commitment to place the awarded Prebuild Project in-service within one year of, which may be extended upon submission of the Prebuild Developer's petition to the Board for good cause and a finding by the Board that good cause in fact exists, of the Expected In-Service Date as described below. The Compliance Filing shall also include a detailed description and copy of the proposed financial instrument(s) to be used to secure the Prebuild Developer's commitments under this Section ("Commitment Security"). This security is separate and uncoupled from the Schedule Commitment described in Section 4.3.

Upon providing Staff the formal engineering documentation and certification, described in section 4.3 above, which documentation shall include information and supporting documentation demonstrating with reasonable specificity that the awarded Project is complete, Staff shall have 90 days to review this written notice in order to verify the reasonableness of such representation(s) before providing its recommendation to the Board. The Board will issue a Board Order, within 90 days of the conclusion of Board Staff's review, allowing or disallowing the Commitment Security to be returned. Staff may request additional information from the Project Developer about its filing, including additional documentation, access to company personnel, or other information. Upon Staff's receipt of the requested documentation or clarification from the Prebuild Developer, the 90-day review period for Board Staff's application review will re-set and start anew.

4.10.1 Financial Commitment

The Prebuild Developer is required to post Commitment Security in the amount of 10% of the Project's estimated cost. A Prebuild Developer shall post this Commitment Security within six (6) months of the Board Decision.

The Commitment Security may be in the form of:

i. one or more parent company guarantees, if the parent is investment grade (defined as having one or more credit rating of BBB or above from Standard and Poor's or Baa3 or above from Moody's, or comparable alternative rating agency),

ii. one or more letters of credit from an investment-grade third-party financial guarantor (defined as an institution with a rating of BBB or above from Standard and Poor's or Baa3 or above from Moody's), and/or

iii. upon submission of a petition to the Board, one or more other financial instruments acceptable to the Board that provides to ratepayers a level of security comparable to a parent company guarantee or letter of credit, including, but not limited to, corporate guarantees and performance bonds.[29] In the case of a Prebuild Developer with multiple parent companies or parent companies involved in a joint venture, the Prebuild Developer may request that responsibility for the Commitment Security be split between the parent companies, which allocation of proportional share of responsibility the Prebuild Developer shall specify clearly.

A Prebuild Developer shall provide Staff with the final, fully executed version of each Commitment Security described in its Compliance Filing within seven (7) days of the date on which the Commitment Security is fully executed. A Prebuild Developer shall also provide Staff with copies of any amendment made to a Commitment Security, within seven (7) days of the date on which such amendment is fully executed. A Prebuild Developer shall keep Staff informed regularly of the anticipated date of execution of each such Commitment Security or amendment, as applicable.

[29] The performance bond must be issued by a qualified surety that is authorized to do business in the state of New Jersey and listed on the most current edition of the U.S. Treasury Department's Circular 570.

4.10.2 Treatment of Commitment Security

Notwithstanding anything described above, the Commitment Security can otherwise only be terminated upon receipt of Board approval.

Any funds so forfeited will either be committed to development of offshore wind infrastructure in New Jersey, including but not limited to, as appropriate, Prebuild Infrastructure, or returned to ratepayers, in the Board's sole discretion.

5 CRITERIA FOR EVALUATION

This section provides an overview of the criteria for evaluating Applications. To be eligible to win an award for the construction of the Prebuild, an Applicant must satisfy the following threshold criteria:

- Submit an Application found to be administratively complete by Staff, including having conducted the necessary pre-Application meetings described in Section 2,
- Demonstrate to the satisfaction of the Board that the Project is viable, permittable, and likely to begin commercial operation on time, consistent with the Expected In-Service Date and Applicant's commitment to guarantee schedule performance, as described in Section 4.3, and
- Demonstrate to the satisfaction of the Board that the Project meets all applicable environmental requirements, as described in Section 4.7.

Applications determined by Staff to have satisfied the above threshold criteria will be subject to the evaluation scoring framework set out in Table 6.

Table 6: Evaluation Scoring Framework

Criteria	Weight
Threshold Criteria	Yes/No
Price Factors: • Cost, rate impact • Quality of cost and schedule containment commitment measures and exclusions	80%
Non-Price Factors: • Community impacts • Developer experience • Quality of Environmental Protection Plan/Permitting Plan	20%

5.1 Price Factors

- Projects are preferred that result in lower ratepayer impacts to New Jersey customers, on the basis of the details provided in Sections 4.4 and 4.5 above, including all aspects of FERC rate design, proposed revenue requirements, line item operating expenses, assumed federal tax benefits under federal Inflation Reduction Act of 2022 ("IRA")[30] and/or other federal or state tax benefits, and

- Given that schedule and cost containment commitments are voluntary in this Prebuild Solicitation, the quality of the schedule and cost containment commitments provided by Applicants will impact the Price Factors score of the Project. The binding nature of the Cost Cap and schedule commitments will also be considered for evaluation, including any exclusions, exceptions, or Uncontrollable Force provisions associated with the commitments. Projects utilizing the preferred Cost Cap and schedule commitment framework described in this PSGD will be scored higher in this category than those that do not.

5.2 Non-Price Factors

Applicants will be evaluated on Non-Price Factors including:

- Minimum number of Corridors and construction efforts on each Corridor which will limit the overall disturbance of the construction to both communities and the environment. Scenarios that enable achievement of the state's OSW goals with fewer Corridors are preferred, under the condition that these solutions do not increase the risk of a permitting or construction delay,

- Developer experience building, managing, and timely delivering construction projects of similar types in similar terrain, and

- Quality of environmental protection measures proposed by Applicant to minimize potential environmental impacts set out in Section 4.7 above and to minimize permitting/approval risks set out in Section 4.8 above.

[30] IRA, 136 Stat. 1818.

Attachment 1

Application Form

v1

Application Form - Prebuild Solicitation

Applicant		Field is required
Applicant Website		Field is required
Project Scenario Name		Field is required
Primary Contact		
Name		Field is required
Phone 1		Field is required
Phone 2		Field is required
E-Mail		Field is required
Address		Field is required
Secondary Contact		
Name		Field is required
Phone 1		Field is required
Phone 2		Field is required
E-Mail		Field is required

Application Form - Prebuild Solicitation

Applicant	Enter on Applicant Information Worksheet
Project Scenario Name	Enter on Applicant Information Worksheet

	Capacity (MW)	Voltage (kV)	
Circuit 1			Field is required
Circuit 2			Field is required
Circuit 3			Field is required
Circuit 4			Field is required

	Value	Units	
Cable ampacity		A	Field is required
Cable outer diameter			Field is required
Conductor size			Field is required
Conductor material			Field is required
Maximum conductor operating temperature			Field is required
Insulation thickness			Field is required
Minimum bending radius			Field is required
Maximum pulling tension			Field is required

Application Form - Prebuild Solicitation

Applicant Enter on Applicant Information Worksheet
Project Scenario Name Enter on Applicant Information Worksheet

	Total Project Scope	Onshore-Only Scope	
Estimated Total Project Cost ($000)			**Both fields are required**

Component Cost Estimates ($000)	Total Project Scope	Onshore-Only Scope	
Engineering			**Both fields are required**
Permitting			**Both fields are required**
Site Control			**Both fields are required**
Materials/Equipment			**Both fields are required**
Construction			**Both fields are required**
Construction Management			**Both fields are required**
Overhead & Miscellaneous			**Both fields are required**
Contingency			**Both fields are required**

Using Standard Cost Containment?			**Both fields are required**
Firm Cap for Total Project ($000)			**Both fields are required**
Firm Cap subject to inflation adjustment mechanism?			**Both fields are required**

Attachment 2

Administrative Completeness Checklist

New Jersey Board of Public Utilities
Prebuild Solicitation
Solicitation Guidance Document Attachment 2
Administrative Completeness Checklist

This Checklist is meant to serve as an overview of the requirements contained in the Solicitation Guidance Document and will serve as a tool for judging administrative completeness of the Application. Applicants will ultimately be judged against the requirements and are encouraged to review those requirements confirm their ultimate compliance. In the Reference column, please enter the Application Narrative section(s) and/or page number(s) or the Attachment and page number where the information can be found.

Number of Prebuild Scenarios included in the Application (if more than 10, please email njoswprebuild@levitan.com for an expanded file) | | **Number of Scenarios is Required**

Section	Requirement	Complete?	Reference
	Applicant Commitment Form	No	
1 - Applicant Information	A demonstration of the Applicant's applicable experience in projects of similar size and scope to the proposed Project	No	
	List of all key employees, definition of key employees, including resumes for each that detail their individual track record in construction and operation of transmission lines and cable systems of comparable voltages, similar size and scope, including HVDC facilities	No	
	Description of any work done to date by the key employees in developing projects of similar scope	No	
	If the work described was not performed by the entire team of key employees, the Applicant must delineate the experience or work performed by key employees	No	
	A detailed disclosure of any prior business bankruptcies, defaults, disbarments, investigations, indictments, or other actions against either the Applicant, its parent company, affiliates, subsidiaries, or any key employees identified above	No	
	Certification and evidence demonstrating Applicant's status as a pre-qualified PJM Designated Entity	No	
2 - Project Descriptions	A detailed description of the Project, including an explanation of how the Project satisfies each element of the Prebuild infrastructure specifications specified in Section 3, with emphasis placed on safety, reliability, and constructability for four (4) Circuits	No	
	Maps, surveys, and other visual aids that support the detailed description of the Project	No	
	GIS shapefiles for planned route (including location of transition vaults), from Sea Girt to Point of Demarcation	No	
	A demonstration that the selected technology, construction techniques, and selected materials are technically viable	No	
	Affirmation that the expected Circuit capacities that the proposed Prebuild can accommodate and meet the Maximum Power Delivery requirements	No	
	Overall Corridor diagrams and maps for the Prebuild (Corridor can be a single ROW or split ROW, as described in Section 3 above), including: Sea Girt NGTC landfall location, the locations of the Transition Vaults, the overall Corridor, the locations of all Cable Vaults, the Point of Demarcation, and the locations of any expected conflicts or constraints	No	
	Details of the estimated landfall configuration	No	
	Location of Transition Vaults, including indications in the GIS shapefiles provided with the Application	No	
	Installation details of the Transition Vaults, including, but not limited to, the identification of potential approaches and HDD /boring locations at landfall for a total of four (4) parallel Conduits to accommodate multiple Qualified Projects' access to the Prebuild	No	
	Design of Transition Vaults (physical dimensions, cable and splicing arrangements within the Transition Vaults, and separation between Transition Vaults and Conduits/pipe)	No	

Section	Requirement	Complete?	Reference
	Duct Bank arrangement and Corridor leaving Transition Vaults toward POI (cross section of the Conduit/cable configuration, maximum cable sizes accommodated or assumed, and spare power and/or communication Conduits)	No	
	Directional drilling/boring method and details	No	
	Specification, including GIS maps and feasibility evaluation, of Cofferdam areas where future cable installations of Qualified Projects will proceed	No	
	Assumptions used for thermal resistivities of soils, slurries, concrete, and backfill materials	No	
	A description of the reasons why Applicant selected the Corridor, with a list of any potential problems, constraints or limitations with siting the Prebuild along the selected Corridor, including identification of the locations where the Project will encounter specific and known challenges from a thermal and physical perspective	No	
	Information regarding the configuration of the Prebuild between Sea Girt NGTC and Point of Demarcation	No	
	Typical Duct Bank cross sections (diameters, separation, height, width, and burial depth in various sections) for (i) occupied Conduits, (ii) spare Conduits, (iii) telecommunication Conduits, and (iv) Conduits for cable grounding and bonding connectors	No	
	Separation between Duct Banks in separate trenches	No	
	Analysis of thermal interference between Duct Banks, including assumptions used for thermal resistivities of soils, concrete, and backfill materials	No	
	Information regarding Cable Vault design layouts	No	
	Physical dimensions (size and installation depth) for Transition Vaults and Cable Vaults located along the Prebuild Corridor	No	
	Cable Vault spacing along each Circuit	No	
	Separation/offset between Cable Vaults for adjacent Circuits	No	
	Cable and splicing arrangements within Cable Vaults	No	
	Access and Maintenance assumptions	No	
	Details for any special Cable Vaults or Duct Bank/Conduit segments	No	
	Location and explanation of constraints (tight curves or bending radius issues, narrow ROWs, limitations of cable sizes/types to be	No	
	Separation between Duct Banks of adjacent Circuits, including a review of thermal interference between Duct Banks and assumptic	No	
	Information regarding the Prebuild configuration at or near the Point of Demarcation	No	
	Relative arrangement of Circuits	No	
	Layout of the Prebuild Corridor into vaults at the Point of Demarcation	No	
	Sequencing constraints for Circuit utilization	No	
	Identification of any local limitations, special crossings, or conflicts	No	
	Identification of primary obstructions and other underground facilities located along the Corridor in the plans, including any plans f	No	
	The assumptions used in the thermal calculations to verify that the Scenario requirements are met, including: Cable voltage (kV), Cable ampacity (A), Cable outer diameter (in or mm), Conductor size (kCmil or mm^2) and material, Maximum conductor operating temperature, Insulation thickness (in or mm), Minimum bending radius, Maximum pulling tension, and other cable construction details (shielding, sheath, outer jacket, armor, bundling).	No	
	Study results to demonstrate Maximum Power Delivery when two (2) Circuits are operating at 1,360 MW at 320 kV and two (2) Cir	No	
	Study results to demonstrate Maximum Power Delivery when four (4) Circuits are operating at 1,360 MW at 320 kV	No	
	An identification of the nature of the Applicant’s land ownership and lease requirements for all aspects of the Project, a plan for ac	No	
	A demonstration of the ways in which specific features of the Project strengthen grid reliability objectives, including appropriate se	No	
	A plan to procure the proposed materials and equipment, including key milestones, status of the procurement process, and expect	No	

Section	Requirement	Complete?	Reference
	A description and illustration of the ways in which the Applicant addresses Good Utility Practice in the design of the Prebuild by providing technical documentation for all portions of the Prebuild design and Corridor, including: Duct Bank cross sections, separation between Duct Banks, analysis of thermal interference between Duct Banks, including assumptions used for concrete, soil and backfill thermal resistivity, details of the cable vaults, the installation details of the HDD path, locations and details of transition cable vaults, locations of any expected conflicts, and a description of the method used to install the marine portion of the cable vault and the target depth of cable vault burial, and demonstration of due separation and independence of each transmission Circuit	No	
	Identification of any facilities that will be used to support construction of the Project	No	
	A Letter of Intent ("LOI") or Memorandum of Understanding ("MOU") from the proposed engineering, procurement, and construction contractor, balance of plant contractor, and/or key construction contractors or vendors	No	
3 - Schedule Commitment, Penalties, and Incentives	A detailed timeline specifying the sequencing and specific milestone dates for completion of major elements of Project schedule, including permitting (reflecting the Permitting Plan described in Section 4.8), engineering, design, procurement, construction (including HDD), licensing, Expected In-Service Date (as specified in Section 2, above), etc.	No	
	A detailed explanation of each milestone identified in the provided timeline	No	
	A description of the Schedule Commitment and Uncontrollable Force provisions proposed to be utilized by the Applicant. If the preferred Schedule Commitment mechanism set out in Attachment 4 is utilized by the Applicant, no further information (beyond the Applicant Commitment Form in Attachment 3) needs to be provided except an indication that Applicant has elected the preferred Schedule Commitment; if an alternate Schedule Commitment is proposed, Applicant must provide a redline set of Applicant proposed terms and conditions (against the Staff proposed terms and conditions that appears as Attachment 4)	No	
	An identification of all known potential sources of delays in the Project schedule, and how those delays could be mitigated, or if not mitigated, how they would affect the overall Project schedule	No	
	Sufficient documentation to support any alternate proposed Schedule Commitment mechanism	No	
4 - Cost Estimate	A description of the cost estimates for each discrete element of project construction including engineering, permitting, site control, materials/equipment, construction, construction management, overhead & miscellaneous, and contingency	No	
	A description of the cost estimate for each element set out above related to all work on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore Cofferdams)	No	
	A description of the cost estimate of the remainder of the scope, up to and including the Transition Vaults, excluding all elements on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore Cofferdams)	No	
	The total project cost	No	
	The total project cost related to all work on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore Cofferdams)	No	
	The total project cost for the remainder of the scope, up to and including the Transition Vaults, excluding all elements on the offshore side of the Transition Vaults (i.e., HDD at landfall and offshore Cofferdams)	No	
	A description of the process utilized by the Applicant to verify and confirm the provided cost estimate	No	
	A detailed cost build-up of the Project incorporating each discrete element identified by the Applicant, presented in an Excel file	No	
	The feasibility study used to determine each of these cost components	No	
5 - Cost Containment and	A description of the proposed FERC formula rate spreadsheets associated with existing or new rate design that will be used to recover the cost of the Project, including all known inputs as described below	No	

Section	Requirement	Complete?	Reference
Rate Design	A description of the proposed FERC formula Rate protocols associated with existing or new rates that will be utilized to recover the cost of the Project, including how the Applicant has included the proposed cost containment commitment provisions and Schedule Commitment provisions	No	
	A description of all FERC rate incentive adders that will be sought by the Applicant, the justification for applying for each adder, and the scope of application for each adder	No	
	A description of the cost containment, schedule commitments and Uncontrollable Force provisions proposed to be utilized by the Applicant. If the preferred terms set out in Attachment 4 are utilized by the Applicant, no further information (beyond the Applicant Commitment Form in Attachment 3) needs to be provided except an indication that Applicant has elected the preferred terms	No	
	A description of any tax advantaged financing, loans, or grants, pursued or awarded to the Applicant, including the financial impact on the Project anticipated from any such awards	No	
	Editable Excel spreadsheets of draft FERC formula rates, proposed or existing (that will be used for the Project), accounting for proposed cost containment provisions and required Schedule Commitment provisions	No	
	Proposed or existing FERC Formula rate protocols	No	
	Details on revenue requirement inputs	No	
	O&M, G&A Costs	No	
	Cost estimates for Operations, Maintenance, and G&A FERC US of A 560-570 series, 920 series	No	
	O&M escalation rates	No	
	Clarification if O&M, G&A expenses are covered in cost containment	No	
	Capital Structure	No	
	Debt-to-Equity ratio (specify if actual or hypothetical)	No	
	Cost of debt	No	
	Proposed ROE (identify any embedded/anticipated FERC adders described above)	No	
	Depreciation	No	
	Book life by asset class	No	
	Tax depreciation method e.g., 5-year MACRS, half-year convention	No	
	Book and tax depreciation schedule for CapEx and On-going CapEx	No	
	Taxes	No	
	Federal and state income tax rates	No	
	Description of blended income tax rate calculations, if any	No	
	Property tax rate	No	
	Deferred income tax schedule, if appropriate	No	
	Discount Rate	No	
	Revenue Requirement	No	
	Estimated annual revenue requirement for each proposed solution from commercial operation through the book life of the plant	No	
	Provide revenue requirement build-up workbook, including depreciation, cost of debt, return on equity, federal and state income tax, property tax, and other costs e.g., O&M, G&A other income tax	No	
	Sufficient documentation to support any alternate proposed cost containment mechanism	No	
6 - Stakeholder	A description of the Applicant's values and philosophy related to stakeholder engagement	No	

Section	Requirement	Complete?	Reference
Engagement	Identification of key stakeholders by category and specific organizations or entities, and goals for engagement with these stakeholders, including, but not limited to, tribal nations, community-based organizations, local and county elected officials, recreational and commercial fisheries, labor unions, higher education, coastal residents and business owners, economic and workforce development organizations, environmental and environmental justice groups, OBCs, and New Jersey SMWVBEs	No	
	A plan for engaging all identified stakeholders, to take place after any award associated with this Prebuild Solicitation	No	
7 - Environmental Protection Plan	Description of how the Applicant intends to avoid, minimize, and/or mitigate adverse impacts to biota and habitats	No	
	Physical Resources: a) air quality, b) electric and magnetic fields (EMF), c) geological resources, d) airborne sound (noise), e) water quality, f) underwater acoustics, g) wetlands and waterbodies	No	
	Biological Resources: a) benthic & shellfish, b) coastal & terrestrial habitats, c) finfish & essential fish habitats, d) marine mammals & sea turtles, e) avian and bat species, f) terrestrial wildlife, g) submerged aquatic vegetation	No	
	Cultural Resources: a) above-ground historic properties, b) marine archaeology, c) terrestrial archaeology	No	
	Socioeconomic Resources: a) visual resources, b) commercial and recreational fisheries, c) commercial shipping, d) vessel & vehicle traffic, e) environmental justice, f) land use and zoning, g) existing cables, h) tourism, i) public health & safety, j) workforce, economy, k) demographics	No	
	Open Space/Recreation: a) Green Acres encumbered lands, b) State-owned lands, c) wildlife management areas	No	
	Hazardous waste	No	
	Electric and magnetic fields (“EMF”)	No	
	A comprehensive description of the anticipated environmental benefits and environmental impacts of the Project including an analysis of the onshore Corridor chosen. If more than one ROW is necessary for the Corridor (e.g., a split ROW as discussed in Section 3), documentation must be provided as to why multiple ROW are needed, how many Circuits will be installed in each ROW, and the environmental impacts and benefits (if any) of multiple ROWs	No	
	An acreage calculation of habitat disturbance, especially related to wetlands, forested areas, or other sensitive habitats	No	
	Projected vessels traffic and/or vehicles needed for Project surveys, construction, operation, and project closeout	No	
	An assessment of the impact to fisheries	No	
	A scientifically rigorous description of the marine resources that exist in the Project area, including biota and commercial and recreational fisheries, that is informed by published studies, fisheries-dependent data, and fisheries-independent data, and identifies species of concern and potentially impacted fisheries	No	
	A scientifically rigorous plan to detect impacts to marine resources, including biota and recreational and commercial fisheries	No	
	Identification of all potential impacts on fish and on commercial and recreational fisheries off the coast of New Jersey from pre-construction activities through Project close out	No	
	An explanation of how the Applicant will provide reasonable accommodations to commercial and recreational fishing for efficient and safe access to fishing grounds	No	
	A description of the Applicant's plan for addressing loss of or damage to fishing gear or vessels from interactions with offshore wind related infrastructure or equipment	No	
	A description of how the Applicant will identify (or has identified) environmental and fisheries stakeholders, any outreach that has occurred to date, and how the Applicant proposes to communicate with those stakeholders during pre-construction activities through decommissioning, as well as a plan for transparent reporting of how stakeholders’ concerns were addressed, consistent with Section 4.6, above	No	

Section	Requirement	Complete?	Reference
	A description of how onshore elements of the Project will be compatible with surrounding land use and communities, and will safeguard environmentally and culturally sensitive areas	No	
	A description of the potential impact of the Project on OBCs. If impacts to an OBC are anticipated during or after construction, including, but not limited to, increased noise, dust, impervious surface, truck traffic, or loss of tree canopy or open space, the Applicant shall (1) include a stakeholder engagement plan specific to the impacted OBC, as part of the required content described in Section 4.6, (2) identify relevant impacted-OBC stakeholders including local government entities and community-based organizations, (3) propose draft control measures to avoid, minimize, or otherwise offset those impacts, (4) utilize the stakeholder engagement plan to seek feedback from the impacted OBC on the proposed draft control measures, and (5) propose final control measures and provide explanation for how the final proposal of control measures address public feedback	No	
	A GIS Desktop Study of potential impacts to sensitive resources including tabular summaries of acreage and distance calculations	No	
	GIS Shapefiles of the Corridor from Sea Girt to the Point of Demarcation, including landfall locations, Transition Vault locations, and ROW(s), that show: a) ROW width, b) descriptions of cable installation methods with locations identified, c) general footprint and extent of HDD boreholes and cable landings, d) footprint of all construction activities related to wetlands, forested areas, or other sensitive habitats, e) footprint and extent of all other pre-construction and construction activities, and f) any needed exclusion zones around Project infrastructure including offshore Cofferdams.	No	
8 - Permitting Plan	A list of all State and Federal regulatory agency approvals, permits, or other authorizations required pursuant to State, local, and Federal law	No	
	An identification of all applicable Federal and State statutes and regulations and municipal code requirements, with the names of the Federal, State, and local agencies to contact for compliance	No	
	An identification of State Lands or Green Acres encumbered lands that may be impacted, and the expected time to obtain such permits and/or approvals	No	
	A land use compatibility / consistency matrix to identify local zoning laws and the consistency of Applicant’s activities in each local jurisdiction	No	
	A strategy, including the expected timeline (aligned with the Schedule Commitment described in Section 4.3), to obtain each required permit and/or approval	No	
	Documentation of consultation with the US Army Corps of Engineers (“USACE”) regarding beach replenishment projects and sand borrow areas, if applicable	No	
	Copies of all submitted permit applications and any issued approvals and permits	No	
9 - O&M Plan / Ownership Transfer	A proposed O&M plan (including activities, schedules and proposed coordination procedures) for conducting O&M on the Prebuild and coordinating the performance by each Qualified Project developer of its own O&M activities on its own transmission cable	No	
	A detailed description of the Form of Lease Agreement	No	
	A Form of Lease Agreement	No	
	Commitment to (a) lease cable conduits to each Qualified Project owner for a nominal cost, (b) perform O&M activities on the Prebuild, and (c) coordinate the performance by each Qualified Project developer of its own O&M activities on its own transmission cable (including any ancillary facilities) in accordance with PJM maintenance requirements	No	
	Identification of the facilities to which the Lease Agreement applies	No	
	Commitment to use Good Utility Practice in connection with the design, engineering, construction, operation and maintenance of the Prebuild Infrastructure	No	

Section	Requirement	Complete?	Reference
	Requirement to make application for, prosecute, obtain and hold all permits, licenses, authorizations, consents, decrees, waivers, privileges and approvals from, and filings with any governmental department, agency, or authority, as required by law to commence, prosecute and complete construction of the Prebuild in accordance with terms of any Board Order and the Form of Non-Standard DEA	No	
	Remedies for failure to perform, including options for a third party to step in to complete the construction of or operate the Prebuild	No	
	Financial penalties for failure to perform	No	
	Milestones that show key dates including related to land rights; permit/siting approvals; design completion; engineering completion; construction milestones; ISD; etc.	No	
	Commitment to milestone schedule, including Schedule Commitments	No	
	Standard of performance or availability that would apply after service begins	No	
	All proposed FERC formula rate incentives consistent with the description in Section 4.5	No	
	Annual audit rights on cost-of-service rates; requirement to maintain records and accounts	No	
Application Forms	Enter Scenario names below *(Note: number of entries must match the number of Scenarios in Cell C10)*		

Attachment 3

Applicant Commitment Form

Attachment 3

Applicant Commitment Form

The Applicant makes the following commitments for the duration of each of the Prebuild options, should they be accepted by the BPU:

1. The Applicant certifies that the cost, terms, and conditions of the Application are valid and shall remain open, without modification or revision except as authorized by the Board, until the Board issues an Order in response to this Prebuild Solicitation, including but not limited to Applicant's commitment with respect to:
    a. cost commitment;
    b. scheduling and completion;
    c. required PJM and FERC filings (including any Designated Entity Agreement (with standard and/or non-standard terms) or formula rate filings);
    d. operation, maintenance and use of the Prebuild Infrastructure;
    e. financing and ownership of the Prebuild Infrastructure; and
    f. provision of necessary engineering documentation and certifications to allow the Prebuild Infrastructure to be placed "in-service".
2. The Applicant commits to meeting the required January 17, 2029, in-service date for the Prebuild Infrastructure and to meeting the interim milestone dates specified in the Application.
3. Except to the extent specifically modified by the Applicant or authorized by the Board, Applicant agrees to the provisions in the Designated Entity Agreement (including any non-standard terms) included in the Prebuild Solicitation.
4. The Applicant commits to file the submitted schedule containment terms with FERC as part of its non-standard DEA, to be enforceable through regular rate recovery proceedings and the Applicant's FERC formula rate.
5. The Applicant commits to file the submitted cost containment terms with FERC as part of its non-standard DEA, to be enforceable through regular rate recovery proceedings and the Applicant's FERC formula rate.
6. The Applicant commits to provide formal engineering documentation and certification by a licensed third-party engineer as to the integrity and completeness of the Project, based on standard industry requirements, of the full scope of the Prebuild Infrastructure, including Duct Banks, Cable Vaults, HDD bores, Conduits, and any submarine exit points in an informational filing to the Board prior to the utilization by a Qualified Project and to qualify the Prebuild Infrastructure to be placed in-service for the purpose of schedule commitments.
7. The Applicant will notify Board Staff, within 30 days, of the departure of any key employee; submit the expertise and qualifications for any new key employee for approval by Board Staff; seek Board Staff approval for any change to the organizational structure of key employee positions and the level of expertise and qualifications of those key employees; and obtain prior Board approval for an entity to assume a ten percent (10%) or greater non-passive ownership interest in the proposed or approved Prebuild Infrastructure.
8. The Applicant will ensure that the Project is designed, constructed and operated in full compliance with all applicable Federal and State statutes and regulations, and municipal code requirements, and will provide proof of such compliance to Board Staff on an ongoing basis.
9. The Applicant shall notify the Board, in writing, of any changes to the Applicant's proposed financing plan for, or equity or other ownership interests (including any change in control of the non-passive ownership interests) in, the Prebuild Infrastructure within 30 days, and such changes will be subject to Board approval.

10. The Applicant will file financial statements with the Board on a quarterly and annual basis as directed in the Board Order approving the Prebuild Infrastructure.
11. In the event that changes in the Prebuild Infrastructure reduce or eliminate tax benefits that Applicant has assumed would be available, or any assumed tax benefits do not materialize for any reason including changes in tax laws, Applicant shall not seek to recover any resulting loss of benefits or increase in Prebuild Infrastructure costs from the Board, electric ratepayers, equipment or material suppliers or providers, users of the Prebuild Infrastructure, or otherwise.
12. The Applicant will pass along all tax credits or other governmental benefits to ratepayers that are received by Applicant and are greater than projected in its proposal, including any increase in the amount of tax credits or benefits received as a result of cost overruns, and any incremental benefits received due to changes in tax law.
13. Under no circumstances will ratepayers be directly or indirectly responsible for any cost overruns associated with the Prebuild Infrastructure, or for costs associated with non-performance by Applicant or the Prebuild Infrastructure.
14. The Applicant shall provide the Board with copies of each local, State and/or Federal permit and/or approval required to build and operate the Prebuild Infrastructure within 14 days of receipt.
15. The Applicant shall supply the Board with filings made to any other regulatory, governmental administrative agency, including but not limited to, any compliance filings or any inquiries by these agencies.
16. The Applicant acknowledges that the Board may share confidential information the Applicant provides with other New Jersey agencies, PJM, and federal agencies with jurisdiction over the interconnection and permitting of the Project.

If the Applicant cannot make any of the above certifications, an explanation must be attached to this Form, making specific reference to each such certification.

Applicant ____

Signature ____

Print Name and Title ____

Date ____

Attachment 4

Proposed Nonstandard Terms and Conditions

ATTACHMENT 4[1]

Proposed Non-Standard Terms and Conditions

A. DEFINED TERMS

Capitalized terms have the meaning ascribed to them in the Designated Entity Agreement, except as provided or modified below:

1. "BPU Board" means the New Jersey Board of Public Utilities.

2. "BPU Staff" means the Staff of the New Jersey Board of Public Utilities.

3. "Construction Costs" means any and all costs and expenses (including financing costs and expenses) directly or indirectly incurred by the Designated Entity to develop, construct, complete, start-up and commission the Project and place the Project in service in accordance with Scope of Work, including without limitation any such costs and expenses incurred by the Designated Entity in connection with the following, in each case as and to the extent contemplated by the Scope of Work:

   a. obtaining permits and other governmental approvals for the Project,
   b. acquiring land and land rights for the Project,
   c. performing any environmental assessments or environmental mitigation activities in connection with the Project,
   d. designing and engineering the Project,
   e. procuring any equipment, supplies and other materials required to complete construction of the Project and place the Project in service, and
   f. otherwise performing or completing any and all development and construction-related activities required in connection with the Project as part of Scope of Work including but not limited to all site clearing, equipment assembly and erection, testing and commissioning activities contemplated by the Scope of Work, whether performed directly by Designated Entity or by one or more third parties retained by Designated Entity (without regard to whether such third parties are affiliated or non-affiliated).

4. "Construction Cost Amount" shall mean ______________________ Dollars ($________________).

5. "Construction Cost Cap Amount" means the sum of (i) the Adjusted Construction Cost Amount, as determined in accordance with Section F.1 in this Schedule E, *plus* (ii) Uncontrollable Costs.

6. "Cost of Debt" means __________ percent (___%).

[1] Subject to completion/modification by Applicant.

7. “Expected In-Service Date” means the Project completion date bid by the Designated Entity on which Project (x) is to be capable of accepting electric cables and other infrastructure form offshore wind generators designated by the Board, and (y) can be placed-in-service for purposes of operation.

8. “Initial Operation” shall mean the date on which: (i) the Project is completed, (ii) Designated Entity provides formal engineering documentation and certification from a licensed third-party engineer as to the integrity and completeness of the Project, based on standard industry requirements, including duct banks, cable vaults, HDD bores, conduits, and any submarine exit points, to the Board in an informational filing, and (iii) the Designated Entity certifies to Transmission Provider, following BPU Board review and approval, that the Project (x) is capable of accepting electric cables and other infrastructure form offshore wind generators designated by the Board, and (y) can be placed-in-service for purposes of operation.

9. “Initial Operation Date” means the date on which Initial Operation is achieved.

10. “Order” means the ________________, issued by the Board on __________.

11. “Return on Equity” means, exclusive of any FERC-approved adders and incentives, _____________ percent (___%).

12. “Transmission Provider” shall mean PJM Interconnection, L.L.C.

13. “Uncontrollable Costs” means those additional Construction Costs, if any, above the Adjusted Construction Cost Amount which are incurred by the Designated Entity solely as a result of one or more events of Uncontrollable Force.

14. “Uncontrollable Delay” means any delay in achieving the Initial Operation Date on or before the Expected In-Service Date that occurs solely as a result of one of more events of Uncontrollable Force.

15. “Uncontrollable Force” means any occurrence or event (1) that is beyond the reasonable control of the Party claiming Uncontrollable Force, (2) which is not caused by the act or omissions of such Party or the failure of such Party to perform its obligations under this Agreement, and (3) which

such Party has been unable to avoid or overcome by the exercise of due diligence or commercially reasonable efforts.

Notwithstanding the foregoing, Uncontrollable Force shall not include (1) strikes and other labor disputes (including collective bargaining disputes and lockouts) of the labor force under the control of the Party claiming Uncontrollable Force or its affiliates or subcontractors unless the strike is part of a more widespread or general strike extending beyond the Party, affiliate or subcontractor, (2) unavailability, late delivery or failure of equipment or materials, unless the Party claiming Uncontrollable Force can point to an independent event of Uncontrollable Force causing such unavailability, late delivery or failure, (3) a Party's economic hardship or financial inability to perform under this Agreement, (4) delays in transportation, other than resulting from transportation accidents, perils at sea or delays in transportation resulting from (i) closure of roads or other transportation routes (including on-shore or nautical routes) by governmental authorities or (ii) an independent event of Uncontrollable Force to which the Party claiming Uncontrollable Force can point, (5) any delay in obtaining, inability or failure to obtain, suspension, non-renewal or cancellation of any governmental approval to the extent caused by the claiming Party's failure to timely submit a final, complete permit application, renew such governmental approval, or provide any requested responses thereto in accordance with Good Utility Practice, (6) subsurface conditions or environmental contamination at the Project Site that are not caused by Designated Entity, its affiliates or its contractors or subcontractors, but the locations of which are either specifically identified in the studies, reports and assessments provided or reasonably available to Designated Entity, or that were evident or could have been reasonably identified by Designated Entity, or (7) a failure of performance or material increase in cost that is due to an affected Party's own negligence, intentional wrongdoing, or failure to exercise due diligence or use commercially reasonably efforts.

D. COST CONTAINMENT / CONSTRUCTION SCHEDULE

1. Adjusted Construction Cost Amount

This mechanism adjusts the Construction Cost Amount to reflect the change in input costs due to inflation across a number of specified indices prior to the Effective Date of this Agreement. Any change in the Construction Cost Amount as a result of this inflation adjustment will be limited to 15%; that is, capital costs subject to the cost containment mechanism will be neither increased nor decreased more than 15%, even if a larger adjustment is indicated by the index values.

The inflation adjustment mechanism is calculated as below:

$$CapCost_{inf} = CapCost_{base} \times \sum \frac{Index_{M,i}}{Index_{I,i}} \times F_i$$

Where,

- $CapCost_{inf}$ is the Adjusted Capital Cost Amount;
- $CapCost_{base}$ is the Construction Cost Amount;
- $Index_{M,i}$ is the average index value for cost component *i* over the three months prior to and after the Effective Date;
- $Index_{I,i}$ is the average index value for cost component *i* over the twelve months prior to March 27, 2024; and
- F_i is the fraction associated with cost component *i*, set out in Table 1 below.

Table 1: Fractions Associated with Price Components

Price Component	F Value	Index
Fixed	0.25	N/A
Labor	0.25	BLS Employment Cost Trends Data Series CES2000000003 Average hourly earnings of all employees, construction, seasonally adjusted
Ready-Mix Concrete	0.25	BLS PPI Data Series WPU13330101A: PPI commodity data for Ready-mix Concrete, Northeast Region
Construction Equipment Rental and Leasing	0.25	BLS PPI Data Series PCU5324125324121: PPI industry data for Other Heavy Machinery Rental and Leasing: Construction Equipment Rental and Leasing

2. Cost of Capital Commitments

a. Return on Equity ("ROE")

Designated Entity agrees to cap its return on equity for the Project at the lower of: (i) the Return on Equity, plus any FERC-approved incentives or adders, or (ii) the amount approved by FERC for use in the formula rate of the Designated Entity (the "ROE Cap").

b. Capital Structure

The capital structure to be used by Designated Entity during construction of the Project shall be ________ percent (equity) and _________ percent (debt), and on and after the Project Completion Date shall be _____ percent (equity) and _______ percent (debt).

3. Construction Cost Cap

The recovery by Designated Entity of any Construction Costs shall be adjusted as follows (each such adjusted amount, an "Adjusted ROE Cap"):

a. For Construction Costs not exceeding the Construction Cost Cap Amount, Designated Entity shall be entitled to recovery at the ROE Cap.

b. For Construction Costs exceeding and up to one hundred ten percent (110%) of the Construction Cost Cap Amount, Designated Entity shall be entitled to recovery at the average of the ROE Cap and the Cost of Debt.

c. For Construction Costs exceeding one hundred ten percent (110%) of the Construction Cost Cap Amount, Designated Entity shall be entitled to recovery at the Cost of Debt.

4. Operation and Maintenance

Designated Entity shall operate and maintain the Project in compliance with applicable law, the Scope of Work, the PJM Tariff, Good Utility Practice, and the provisions of this Agreement.

5. Project Availability

Designated Entity shall ensure that the Initial Operation Date occurs on or before the Expected In-Service Date, subject to extension only for Uncontrollable Delay.

a. Late Completion

In the event the Initial Operation Date occurs after the Expected In-Service Date, as such date may be extended as a result of Uncontrollable Delay, the recovery by Designated Entity of its Construction Costs shall be subject to adjustment as follows. For the avoidance of doubt, the adjustments set forth below are in addition to any other adjustments set forth in this Agreement.

For each ninety (90) day period, or portion thereof, that the Initial Completion Date occurs after Expected In-Service Date, each Adjusted ROE Cap applicable to the Construction Costs (as set forth in Section D.3 above) shall be decreased by 35-basis points; provided, however, in no event shall the such Adjusted ROE Cap, as further adjusted in this Section D.5.a, be reduced to less than the Cost of Debt. By way of example only, if such a delay lasted for 135 days, each applicable Adjusted ROE Cap would be further reduced by 70-basis points (that is, 35-basis points for the first 90-day period, and an additional 35-basis points for the second 90-day period).

b. Early Completion

In the event the Initial Completion Date occurs prior to the Expected In-Service Date, each Adjusted ROE Cap shall be further adjusted as follows. For delivery between 30-120 days in advance of the Expected In-Service Date, a 25 basis-point incentive adder will be available; for delivery 121+ days in advance of the Expected In-Service Date, a 50 basis-point incentive adder will be available for the Project.

Attachment5

Development Schedule

ATTACHMENT 5[1]

Development Schedule

Designated Entity shall ensure and demonstrate to the Transmission Provider that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

Milestones and Milestone Dates
Execute Interconnection Coordination Agreement. On or before ______, Designated Entity must execute the Interconnection Coordination Agreement or request the agreement be filed unexecuted.
Demonstrate adequate Project financing. On or before ______, Designated Entity must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement.
Acquisition of all necessary federal, state, county, and local site permits. On or before ______, Designated Entity must demonstrate that all required federal, state, county and local site permits have been acquired.
Initiation of Construction: On or before _______, Designated Entity must demonstrate that it has issued a full notice to proceed under the engineering, procurement and construction ("EPC") agreement for the Project for the commencement of on-site construction of the Project.
Expected Project In-Service Date. On or before ______, Designated Entity must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules B[2] of this Agreement; (ii) meets the criteria outlined in Schedule D of this Agreement; and (iii) is under Transmission Provider operational dispatch.

[1] Subject to completion by Applicant.

[2] Schedules B and D will be completed and agreed upon between PJM and the Applicant in a Designated Entity Agreement, once the Applicant is approved as a Designated Entity at PJM.

Exhibit No. MAOD-16
Mid-Atlantic Offshore Development, LLC
Direct Testimony of Joshua C. Nowak

Exhibit No. MAOD-16

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)))	**Docket No. ER24-___-000**

DIRECT TESTIMONY
OF
JOSHUA C. NOWAK

ON BEHALF OF
MID-ATLANTIC OFFSHORE DEVELOPMENT, LLC

July 18, 2024

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)))	**Docket No. ER24-___-000**

DIRECT TESTIMONY
OF
JOSHUA C. NOWAK

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, BY WHOM YOU ARE EMPLOYED AND BUSINESS ADDRESS.

A1. My name is Joshua C. Nowak. I am employed by Concentric Energy Advisors, Inc. ("Concentric") as a Vice President. Concentric is a management consulting and economic advisory firm, focused on the North American energy and water industries. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q2. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES AND YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A2. I hold a Bachelor's degree in Economics from Boston College, and have more than 15 years of experience in providing economic, financial, and strategic advisory services. As a consultant, I primarily advise clients in regulated utility industries and have provided testimony regarding financial matters before multiple regulatory agencies. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have provided testimony before the Federal Energy Regulatory Commission ("FERC" or "Commission") as well as state and provincial jurisdictions in the U.S. and Canada. Prior to joining Concentric in 2018, I was employed by National Grid USA where I was responsible for regulatory filings related to the cost of capital across the company's multiple U.S. operating companies and service territories. A summary of my professional and educational background is presented in Attachment 1.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A3. I am submitting this testimony on behalf of Mid-Atlantic Offshore Development, LLC ("MAOD" or the "Company") as it relates to the appropriate Return on Equity ("ROE"),[1] capital structure, and cost of debt for MAOD's substation and related facilities comprising a portion of the Larrabee Tri-Collector Solution transmission project ("Project") selected by the New Jersey Board of Public Utilities ("NJBPU") to interconnect New Jersey offshore wind projects to onshore points of delivery. The Direct Testimony of MAOD's Director of Development, Mr. Christopher Sternhagen describes the Project in detail.[2]

[1] I use the terms "ROE" and "cost of equity" interchangeably throughout my Direct Testimony.

[2] *See* Exhibit No. MAOD-1, Direct Testimony of Christopher Sternhagen ("Sternhagen Testimony").

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A4. I have been asked by MAOD to prepare an independent estimate of the Company's cost of equity and recommend to the Commission an ROE rate that is fair, allows MAOD to attract capital on reasonable terms and maintain its financial integrity, and results in just and reasonable rates for the Company. In addition, I provide the ROE to be included in the Formula Rate Template as a stated value that will ultimately be used in determining the Annual Transmission Revenue Requirement ("ATRR") as defined in the testimony of MAOD Witness, Mr. William Davis ("Davis Testimony") (Exhibit No. MAOD-21). The data presented in Exhibit No. MAOD-17, Schedules 1 through 5, which have been prepared by me or under my direction, supports my analyses and recommendations. In the remainder of my testimony all references to "Schedules" are to the schedules contained in Exhibit No. MAOD-17.

Q5. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT YOU CONDUCTED TO SUPPORT YOUR ROE RECOMMENDATION.

A5. Consistent with the Commission's decision in Opinion No. 569-A,[3] I have considered the results of multiple methodologies to estimate the ROE for the Company. Because each of the models used to estimate the cost of equity are subject to limiting assumptions or other methodological constraints, investors do not rely solely on one model when establishing

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[3] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.,* Opinion No. 569, 169 FERC ¶ 61,129 (2019), *order on reh'g,* Opinion No. 569-A, 171 FERC ¶ 61,154, *order addressing reh'g arguments and setting aside prior order in part,* Opinion No. 569-B, 173 FERC ¶ 61,159 (2020), *vacated and remanded sub. nom MISO Transmission Owners v. FERC,* 45 F.4th 248 (D.C. Cir. 2022).

their return requirements. Instead, they consider the results of multiple methodologies, including the three models that I have used here, to make their investment decisions.

My ROE recommendation is based primarily on the range of results that I derive from three financial models: (1) the Two-Step Discounted Cash Flow model ("DCF"); (2) the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach ("Risk Premium"). I recognize that FERC's use of the Risk Premium approach has been subject to an appeal. The U.S. Court of Appeals for the District of Columbia Circuit found in its August 9, 2022 decision in *MISO Transmission Owners v. FERC*[4] that FERC "failed to offer a reasoned explanation for its decision to reintroduce the risk-premium model […] after initially, and forcefully, rejecting it" and that FERC "adopted that significant portion of its model in an arbitrary and capricious fashion . . . ."[5] Because the Court ultimately remanded the case to FERC, and FERC has not yet made a determination on the matter, I therefore considered the results both including and excluding the Risk Premium approach.

My recommendation also considered the general economic and capital market environment. I specifically considered the rapidly evolving market environment in which the U.S. Federal Reserve ("Federal Reserve") is aggressively tightening monetary policy and raising interest rates to satisfy its price stability objectives. Because each model's assumptions are affected differently by market conditions, the use of the DCF, CAPM, and Risk Premium methodologies minimize the reliance on any one set of assumptions. Using

[4] *MISO Transmission Owners v. FERC,* 45 F.4th 248, 264 (D.C. Cir. 2022).

[5] *Id.* at 264.

each of the three models better informs FERC's analysis in determining the zone of reasonableness.

In addition to the analyses discussed above, I considered MAOD's participation in the PJM, for which FERC traditionally has included an adder to the base ROE of 50 basis points.[6]

Q6. WHAT IS YOUR CONCLUSION REGARDING THE APPROPRIATE COST OF EQUITY FOR USE IN DETERMINING THE COMPANY'S ATRR?

A6. The ROE results presented in my Direct Testimony indicate a zone of reasonableness from 9.76 percent to 11.10 percent based on the results of the three methods (i.e., DCF, CAPM, and Risk Premium) or 9.81 percent to 10.99 percent based on the results of two methods (i.e., DCF and CAPM). I present the results using both two and three methods to reflect the uncertainty regarding the final determination of FERC's methodology. The proxy group median ROE applying three methods is 10.26 percent, and 10.15 percent applying the DCF and CAPM. The median is the appropriate measure given FERC's previous findings on the measure of central tendency for a single utility, such as MAOD.[7] I therefore recommend the Commission authorize a base ROE of 10.26 percent for the Company plus

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[6] *See Mid-Atlantic Offshore Dev., LLC*, 186 FERC ¶ 61,116, P 48 (2024) ("Incentives Order").

[7] *See* Opinion No. 569-B, P 18, n.53 (quoting Opinion No. 569, P 344: "In determining the central tendency of the zone of reasonableness, the Commission has distinguished between cases involving an RTO-wide ROE and cases involving the ROE of a single utility (or pipeline). In cases involving an RTO-wide ROE, the Commission has held that the midpoint is appropriate. The Commission has reasoned that, because an RTO-wide ROE will apply to a diverse set of companies, the range of results becomes as important as the central value, and the midpoint fully considers that range, because it is derived directly from the endpoints of the range . . . . By contrast, in cases involving a single utility, the Commission has held that using the median is appropriate, because the median 'is the most accurate measure of central tendency for a single utility of average risk.'").

50 basis points in recognition of the Company's participation in the PJM for a total authorized ROE of 10.76 percent.[8]

III. REGULATORY PRINCIPLES

Q7. PLEASE DESCRIBE THE GUIDING PRINCIPLES USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.

A7. Utilities are entitled by law and well-established precedent to receive a fair rate of return sufficient to attract needed capital at reasonable rates. The basic tenets of this regulatory doctrine originate from several bellwether U.S. Supreme Court decisions.[9] Utility regulators across the country, including FERC, adhere to this doctrine when engaging in federal and state-level rate-making. FERC described this standard in the following terms:

> [W]e are guided by the principle, enunciated by the Supreme Court, that an approved ROE should be "reasonably sufficient to assure confidence in the financial soundness of the utility [or, in this case, utilities] and should be adequate under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties."[10]

FERC also has explained that "a key consideration in determining just and reasonable utility ROEs is determining what ROE a utility must offer in order to attract capital, i.e., induce investors to invest in the utility in light of its risk profile."[11]

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[8] I note my analysis is based on market data through January 31, 2024. This represents a conservative estimate of the cost of equity as more current analyses support a base ROE above the end-of-January estimate of 10.26 percent.

[9] *Fed. Power Comm'n v. Hope Nat. Gas Co.,* 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.,* 262 U.S. 679 (1923) ("*Bluefield*").

[10] *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, P 13 (2004) (quoting *Bluefield,* 262 U.S. at 693).

[11] *Coakley v. Bangor Hydro-Elec. Co*., 165 FERC ¶ 61,030, PP 33, 44 (2018).

Q8. PLEASE BRIEFLY DISCUSS HOW THOSE PRINCIPLES APPLY IN THE CONTEXT OF THE REGULATED RATE OF RETURN.

A8. Regulated utilities rely primarily on common stock and long-term debt to finance their permanent property, plant, and equipment. The allowed rate of return for a regulated utility is based on its weighted average cost of capital, where the costs of the individual sources of capital, debt and equity are weighted by their respective book values. The ROE represents the cost of raising and retaining equity capital and is estimated through one or more analytical techniques that use market data to quantify investor expectations regarding equity returns.

The ROE cannot be derived solely through quantitative metrics and models, however. To properly estimate the ROE, the financial, regulatory, and economic context in which the analysis takes place must also be considered. The DCF, CAPM, and Risk Premium approaches, while fundamental to the ROE determination, are still only models. The results of these models cannot be mechanistically applied without also considering informed judgment, the context of capital market conditions, and the relative risk of any company as compared to the proxy group companies. As discussed further below, FERC has recognized the problem of "model risk" and accordingly has stated that it does not intend to rely upon the results of only one cost of equity model when setting a public utility ROE.

Also, it is important to note that the U.S. Supreme Court has held that under the statutory standard of "just and reasonable" it is the result reached, not the method employed, which is controlling.[12] Consequently, it is appropriate to consider a variety of approaches and data sources when arriving at a recommended ROE.

IV. ECONOMIC AND CAPITAL MARKET CONDITIONS

Q9. WHY IS IT IMPORTANT TO CONSIDER THE EFFECTS OF CURRENT AND EXPECTED ECONOMIC AND FINANCIAL MARKET CONDITIONS WHEN SETTING THE APPROPRIATE ROE?

A9. It is important to consider current and expected conditions in the general economy and financial markets because the authorized ROE for a public utility should allow the utility to attract investor capital at a reasonable cost under a variety of economic and financial market conditions, as underscored by the *Hope* and *Bluefield* decisions. In addition, current economic and financial conditions have a bearing on the ROE estimation models and affect MAOD's cost of equity. The inputs to the DCF and CAPM are only samples of the various economic and market forces that determine a utility's required return. The cost of equity is a forward-looking concept, yet ROE models often rely on historical inputs. To the extent that those inputs are impacted by or reflect conditions that are expected to change significantly, it is important to consider those impacts to inform the analyst's judgment regarding the estimation of ROE. Therefore, an assessment of current and projected market conditions is integral to any ROE recommendation.

[12] *Hope,* 320 U.S. at 602.

Q10. WHAT ARE THE KEY FACTORS AFFECTING THE COST OF EQUITY FOR REGULATED UTILITIES SUCH AS MAOD IN THE CURRENT AND PROSPECTIVE CAPITAL MARKETS?

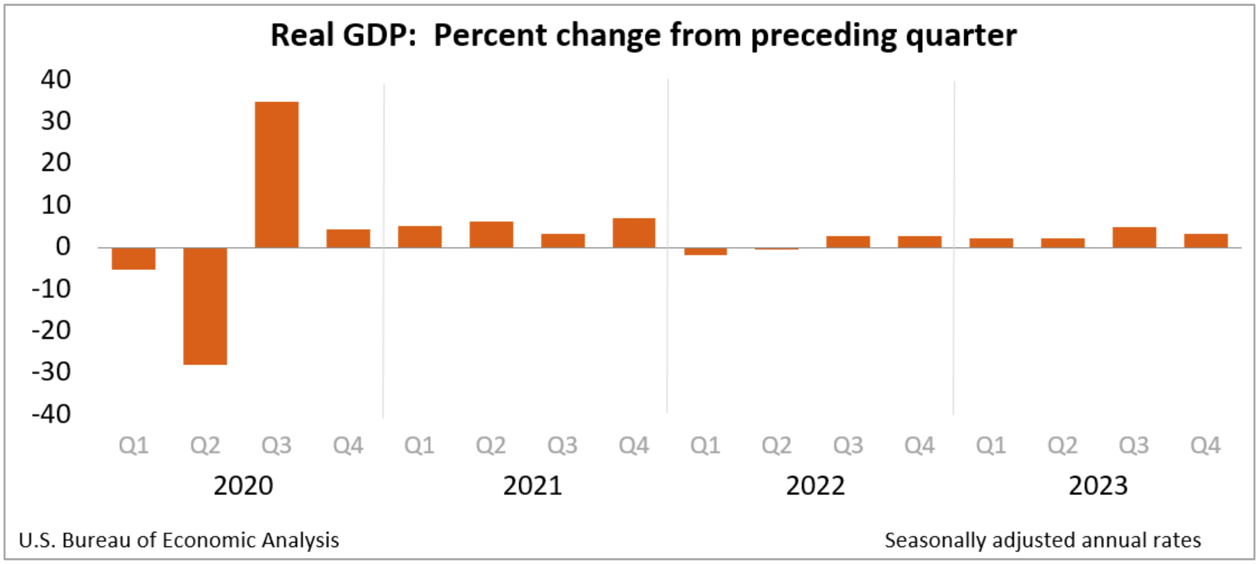
A10. The cost of equity for regulated utility companies such as MAOD is affected by several key factors including ongoing uncertainty and volatility in equity markets, as well as the path of economic growth and inflation levels.

Q11. PLEASE DESCRIBE THE CIRCUMSTANCES THAT HAVE AFFECTED CAPITAL MARKET CONDITIONS.

A11. As shown in Figure 1, the past four years have been a volatile period for the U.S. economy. Gross domestic product ("GDP") sank into a sharp recession during the COVID-19 pandemic, followed by a comparable rebound, and has since oscillated between periods of moderate growth and another short recession.[13] The most recent advanced estimate shows the economy grew at an annual rate of 3.3 percent, suggesting the Federal Reserve has thus far been successful in engineering a "soft landing" following pullback on its monetary policies designed to ease the impacts of the COVID-19 pandemic.

[13] *See* https://www.bea.gov/news/2024/gross-domestic-product-fourth-quarter-and-year-2023-advance-estimate.

Figure 1: U.S. Real GDP Growth – 2020Q1-2024Q4



To stem the consequences of the global COVID-19 pandemic, the federal government took a series of unprecedented steps, and these measures continue to impact the economy and financial markets.

Q12. WHAT STEPS DID THE FEDERAL GOVERNMENT TAKE TO STABILIZE FINANCIAL MARKETS AND SUPPORT THE ECONOMY IN RESPONSE TO THE GLOBAL COVID-19 PANDEMIC?

A12. The Federal Reserve decreased the federal funds rate in March 2020 to a target range of 0.00 percent to 0.25 percent (which remained in effect until March 2022), increased its holdings of both Treasury and mortgage-backed securities, and supported increased credit to both businesses and individual borrowers. These programs allowed the Federal Reserve to purchase government bonds and corporate bonds from banks. The banks then received cash from the Federal Reserve, which resulted in an expansion of the money supply. This increase in the money supply kept short-term interest rates low and increased the ability of banks to lend to consumers and businesses.

In addition to the Federal Reserve's response, the U.S. Congress passed approximately $4.5 trillion in fiscal stimulus programs under the Coronavirus Aid, Relief, and Economic Security Act of March 2020. The Act provided a large fiscal stimulus package aimed at mitigating the economic effects of the global COVID-19 pandemic. In March 2021, the U.S. Congress approved an additional fiscal stimulus of $1.9 trillion in response to the ongoing economic effects of the global COVID-19 pandemic.

The Federal Reserve's and U.S. Congress's extraordinary measures to support the economy and stabilize financial markets impacted bond markets (deliberately decreasing government and corporate yields) and equity markets (creating upward pressure on valuations and downward pressure on yields for dividend paying companies such as utilities).

Q13. PLEASE DESCRIBE THE EFFECT OF THESE POLICIES ON INFLATION.

A13. Inflation has been a significant cause for concern among both policymakers and investors. As shown in Figure 2, below, inflation levels have moved within a relatively narrow band over the past twenty years (other than during the Great Recession of 2007/2008). Starting with the initial stages of the global COVID-19 pandemic in 2020, inflation levels have been driven higher, reaching levels not seen since the early 1980s. Inflation has been driven by strong consumer demand and supply constraints, some of which have been exacerbated by global COVID-19 pandemic related government stimulus programs in the U.S. and international lockdowns. More recently, the war in Ukraine continues to impact the world's supply of food, steel, and fuel, driving costs higher for other products and services, and ultimately general inflation.

As shown in Figure 2, below, inflation spiked in June 2022 at 9.1 percent. Even though the Consumer Price Index has since receded to below 5.0 percent, current levels (3.10 percent in January 2024) remain above the Federal Reserve's target inflation threshold of around 2 percent which has been in place since the mid-1990s. The relationship between recession and lower inflation rates, also reflected in the chart, illustrates the delicate balancing act the Federal Reserve faces as it raises interest rates to rein in inflation. By deliberately slowing economic growth with higher interest rates, inflation will ease, but with a risk of recession.

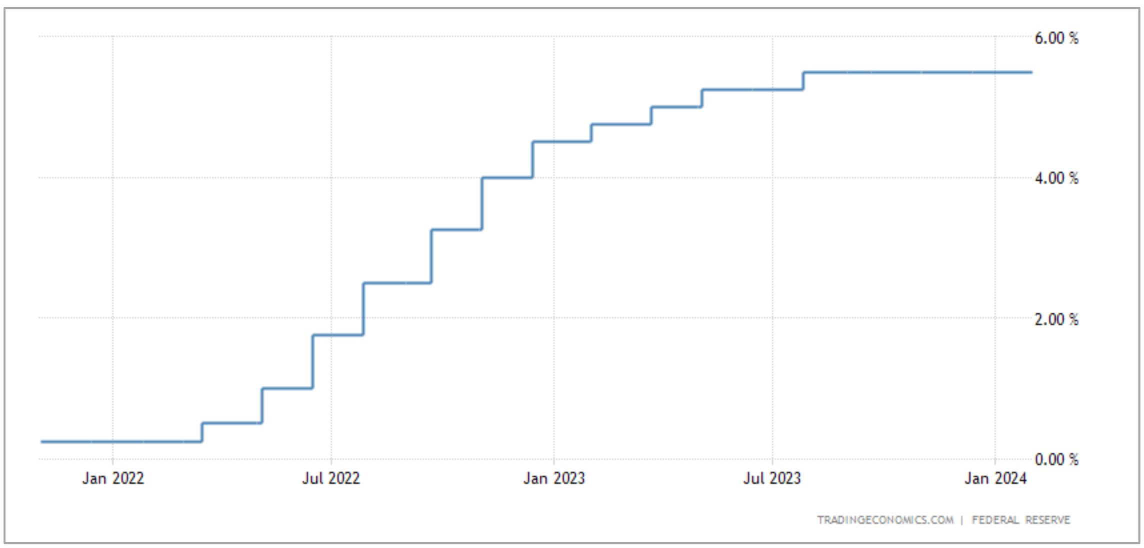
Figure 2: Consumer Price Index, 12-month Percentage Change[14]

[14] Bureau of Labor Statistics, 12-Month Percentage Change, Consumer Price Index, Selected Categories, https://www.bls.gov/charts/consumer-price-index/consumer-price-index-by-category-line-chart.htm, (not seasonally adjusted).

Q14. PLEASE DESCRIBE THE EFFECT OF THESE POLICIES ON SHORT-TERM INTEREST RATES.

A14. As a result of these substantially higher inflation rates, the Federal Reserve has been left little choice but to pull back on its global COVID-19 pandemic-related monetary policies and apply tighter monetary policy with higher interest rates. In 2022, the Federal Reserve increased the target rate seven times, and another four times in 2023, as illustrated in Figure 3, below. The Fed set the target range for the federal funds rate at a 22-year high of 5.25%-5.5% in July and has held this level through its January 2024 meeting.

Figure 3: U.S. Federal Reserve Bank's Target Federal Funds Rate[15]



This demonstrates the level of Federal Reserve action necessary to reel in inflation. The Federal Reserve is willing to risk substantially higher interest rates and a slowdown in the economy, and it is clear that the era of record low interest rates and moderate inflation has ended. In its most recent policy statement, the Federal Reserve confirmed its commitment to a 2 percent inflation target, stating:

[15] Trading Economics, United States Fed Funds Rate, https://tradingeconomics.com/united-states/interest-rate.

> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. The Committee judges that the risks to achieving its employment and inflation goals are moving into better balance. The economic outlook is uncertain, and the Committee remains highly attentive to inflation risks.
>
> In support of these goals, the Committee decided to maintain the target range for the federal funds rate at 5-1/4 to 5-1/2 percent. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities, as described in its previously announced plans. The Committee is strongly committed to returning inflation to its 2 percent objective.[16]

This is significant because the costs of all forms of capital are impacted by the Federal Reserve's actions, even though it only sets the short-term rate for federal funds.

Q15. PLEASE DESCRIBE THE EFFECT OF THESE POLICIES ON LONG-TERM INTEREST RATES.

A15. As the U.S. economy improved in 2021 and the Federal Reserve moved aggressively to tighten monetary policy to fight stubbornly higher inflation, prevailing interest rates have risen to their highest levels since 2010. As shown in Figure 4 below, the 30-year Treasury yield has increased 203 basis points since November 3, 2021 when the Federal Reserve signaled it would begin tapering its asset purchases. Utility bond yields have increased more than 226 basis points over the same period.

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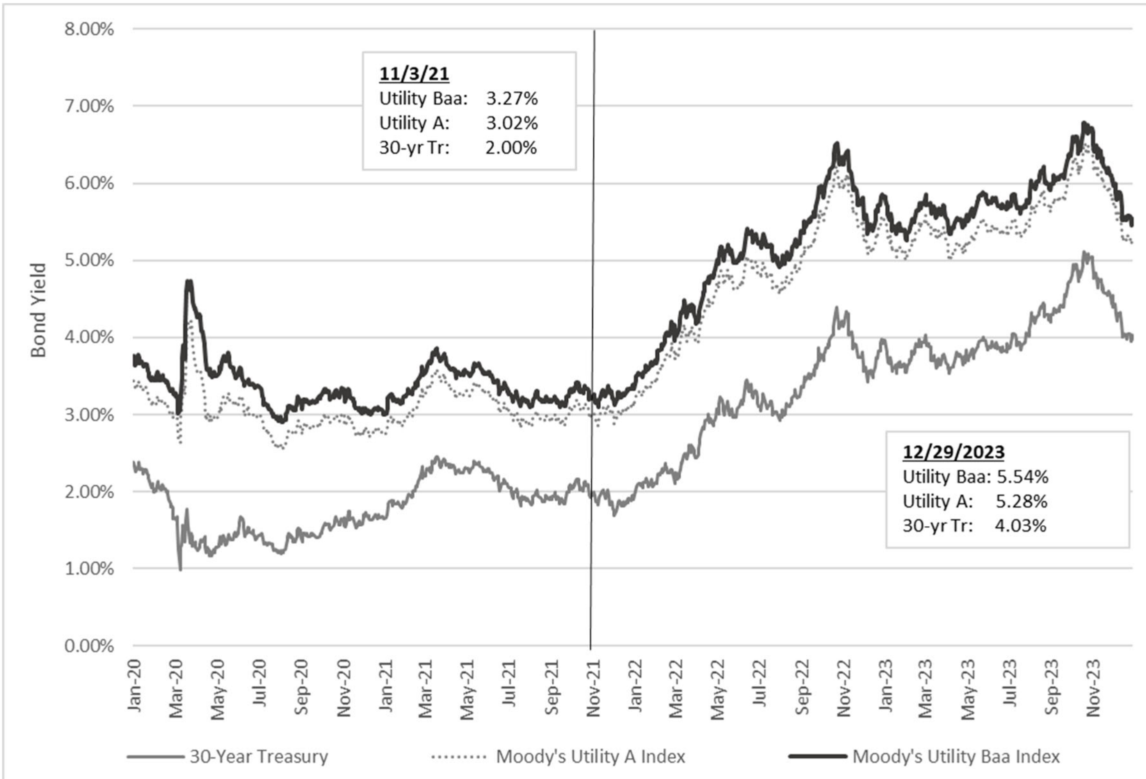
[16] Federal Reserve Press Release January 31, 2024, https://www.federalreserve.gov/newsevents/pressreleases/monetary20240131a.htm.

Figure 4: 30-Year Treasury Bond and Utility Bond Yields (2020-2023)[17]



Q16. HAVE YOU FACTORED THESE CIRCUMSTANCES INTO YOUR COST OF EQUITY ESTIMATES, AND, IF SO, WHAT CONCLUSIONS DO YOU DRAW?

A16. Yes. I have relied on the most recent market data available to me in my analysis. Long-term interest rates have increased substantially since the historical lows of 2020 and are expected to continue to increase as the Federal Reserve focuses on inflation. These circumstances also reinforce the importance of considering the results of multiple models, as I have with the DCF, CAPM, and Risk Premium approaches.

[17] *See* Federal Reserve Bank of St. Louis, FRED Economic Database; Bloomberg Professional.

V. PROXY GROUP SELECTION

Q17. PLEASE DESCRIBE THE SPECIFIC SCREENING CRITERIA YOU HAVE UTILIZED TO SELECT YOUR PROXY GROUP.

A17. I have used the screening criteria prescribed by FERC to select a proxy group for cases involving electric transmission assets. Specifically, I began with the thirty-six companies that Value Line classifies as "Electric Utilities" and then included companies that consistently pay quarterly cash dividends, with no dividend cuts in the six-month study period, and have had no major merger activity in the six-month study period. In addition to these criteria, FERC typically requires each proxy company's credit rating to be within one notch above or below the S&P Global ("S&P") and Moody's rating of the Company.

Q18. WHAT IS THE COMPANY'S CREDIT RATING?

A18. The Company is constructing a single asset transmission facility and does not have a credit rating. Therefore, I included all companies with an investment grade credit rating from S&P or Moody's.

Q19. WHAT IS THE COMPOSITION OF YOUR PROXY GROUP?

A19. Based on the screening criteria discussed above, I arrived at a proxy group consisting of the thirty companies shown in Figure 5, below. Please refer to Schedule 1 for my proxy group screening data and results (Exhibit No. MAOD-17).

Figure 5: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avista Corporation	AVA
Black Hills Corporation	BKH
CenterPoint Energy, Inc.	CNP
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
DTE Energy Company	DTE
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
Exelon Corporation	EXC
IDACORP, Inc.	IDA
MGE Energy, Inc.	MGEE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corp.	PNW
Portland General Electric Company	POR
PPL Corporation	PPL
Public Service Enterprise Group Inc.	PEG
Sempra Energy	SRE
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

VI. DETERMINATION OF THE APPROPRIATE COST OF EQUITY

Q20. WHAT MODELS DID YOU USE IN YOUR ROE ANALYSES?

A20. Consistent with FERC Opinion No. 569-A, I have considered the results of multiple methodologies to estimate the ROE for the Company including the two-step DCF model, the CAPM, and the Risk Premium approach. I address each separately below.

Q21. PLEASE DESCRIBE THE TWO-STEP DCF MODEL.

A21. The two-step DCF analysis approaches ROE from the perspective of an investment in the stock of each of the proxy group companies. The model calculates the internal rate of return of the cash flow stream generated by a cash outflow equal to the average current stock price of the proxy group companies followed by annual cash inflows of the average dividend of the proxy group companies, as those dividends grow according to the appropriate assumed growth rate for two stages. The Stage 1 growth rate is based on equity analysts' forecasts for earnings per share ("EPS") growth rates, while the Stage 2 growth rate is based on a long-term forecast of growth in nominal GDP. FERC has long relied on the DCF model for setting allowed returns for jurisdictional utilities.

Q22. HOW DID YOU CALCULATE THE DIVIDEND YIELD IN YOUR APPLICATION OF THE TWO-STEP DCF MODEL?

A22. I calculated the dividend yield by annualizing the current quarterly dividend payment and dividing that amount by the average high and low stock prices for each company during the six-month period from August 2023 through January 2024.

Q23. WHY IS IT IMPORTANT TO USE AVERAGE STOCK PRICES OVER A PERIOD OF TIME?

A23. It is important to use an average of stock prices over a period of time to calculate a proxy company's dividend yield in the DCF model to ensure that the calculated ROE is not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, it is important to reflect the conditions that have defined the financial markets over the recent past. In my view, the six-month averaging period reasonably balances those concerns and is consistent with FERC's methodology.

Q24. HOW DID YOU ADJUST THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A24. Utility companies tend to increase their quarterly dividends at different times throughout the year, so it is reasonable to assume that such increases will be evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating this component of the DCF model. Accordingly, the DCF estimates reflect one-half of the expected growth in the dividend yield.

Q25. WHAT SOURCES OF EARNINGS GROWTH HAVE YOU USED IN YOUR TWO-STEP DCF ANALYSIS?

A25. In Opinion No. 569-A, FERC accepted the use of a two-step DCF analysis, in which 80 percent weight is given to earnings growth estimates, and 20 percent weight is given to GDP growth estimates in the DCF model.[18] FERC's rationale for aligning electric utilities with gas and oil pipelines is premised on the assumption that long-run earnings growth

[18] Opinion No. 569-A, at PP 56-60.

ultimately will be limited to growth in the overall economy. Consistent with Opinion No. 569-A, I gave 80 percent weight to the consensus analyst five-year growth estimates in EPS from First Call as reported on Yahoo! Finance and 20 percent weight to the average projected GDP growth rate from three sources: (1) Blue Chip Financial Forecasts for the period from 2024–2033; (2) the Energy Information Administration for the period from 2024–2050; and (3) the Social Security Administration for the period from 2024–2075, as shown in Schedule 2.2 (Exhibit No. MAOD-17).

Q26. DID YOU REMOVE ANY RESULTS AS OUTLIERS?

A26. Yes. CenterPoint Energy, Inc. and OGE Energy Corp. had negative growth rates, which violates the basic assumption of the DCF model that dividends grow in perpetuity, so I excluded them from the analysis. In addition, I excluded the result of 6.16 percent for Black Hills Corporation, as it was less than 7.49 percent, which is the yield on the Moody's Baa Utility Bond Index plus 20 percent of the Market Risk Premium. I also excluded the result of 18.66 percent for PPL Corporation as it exceeded two times the median result.

Q27. WHAT ARE THE RESULTS OF YOUR TWO-STEP DCF ANALYSIS?

A27. The results of my two-step DCF analysis are provided in Schedule 2.1 (Exhibit No. MAOD-17) and summarized in Figure 6, below.

Figure 6: Two-Step DCF Results

	Proxy Group
Lower Bound	7.54%
Lower Third	8.64%
Median	9.10%
Upper Third	10.30%
Upper Bound	14.38%

Q28. PLEASE DESCRIBE THE CAPM APPROACH.

A28. The CAPM is a risk premium approach that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security).[19] As shown in the following equation, the CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f)$$

where:

K_e = the required ROE for a given security;

r_f = the risk-free rate of return;

β = the beta of an individual security; and

r_m = the required return for the market as a whole.

[19] Systematic risks are fundamental market risks that reflect aggregate economic measures and therefore cannot be mitigated through diversification. Unsystematic risks reflect company-specific risks that can be mitigated and ultimately eliminated through investments in a portfolio of companies and/or market sectors.

The term (rm – rf) represents the Market Risk Premium ("MRP"). According to the theory underlying the CAPM, because unsystematic risk can be diversified away, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)}$$

where:

r_e = the rate of return for the individual security or portfolio.

The variance of the market return, noted in the above equation, is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the market reflects the extent to which the return on that security will respond to a given change in the market return. Thus, beta represents the risk of the security relative to the market.

Q29. WHAT RISK-FREE RATE DID YOU USE IN YOUR CAPM ANALYSIS?

A29. Consistent with FERC precedent, I have used the average 30-year Treasury bond yield for the past six months. As discussed in Section IV herein, the Federal Reserve raised interest rates and tightened monetary policy to control the highest inflation in the last 40 years, and remains committed to bringing inflation back to its target of 2.0 percent. As such, FERC's reliance on the six-month historical average yield on 30-year Treasury bonds may be conservative.

Q30. WHAT MEASURE OF BETA DID YOU USE IN YOUR CAPM ANALYSIS?

A30. I relied on beta coefficients for the proxy group companies as reported by Value Line in the most recent publication issued for each of the proxy group companies.

Q31. WHAT MRP DID YOU USE IN YOUR CAPM ANALYSIS?

A31. I conducted a constant growth DCF analysis on each of the S&P 500 companies and calculated the expected total market return, weighted by market capitalization. This total market return is based on current dividend yields and the average of projected earnings growth rates as reported by Value Line and Yahoo! Finance for all of the companies in the S&P 500. The forward-looking MRP is calculated by subtracting the risk-free rate from the total market return. This analysis results in an MRP of 6.98 percent, as shown in Schedule 3.2 (Exhibit No. MAOD-17).

Q32. DID YOU DEVELOP THE MRP CONSISTENT WITH THE METHODOLOGY OUTLINED BY THE COMMISSION IN OPINION NO. 569-A?

A32. Yes, I applied the Commission's methodology which calculates the MRP based on the companies that comprise the S&P 500, excluding any non-dividend paying companies, and any companies with a growth rate less than 0 percent or greater than 20 percent.[20]

While I applied the Commission's approach, I do not agree that it is necessary to limit the growth rates used in the calculation of the overall market return. The purpose of the MRP is to estimate the total return that investors would require for an investment in the broad market, as measured by the S&P 500 Index. If an investor were to purchase an investment that tracks the S&P 500 Index, the return that the investor would receive includes companies that do not pay dividends, companies with high, low or negative growth rates, companies that have reduced or eliminated their dividend, and companies that might encounter financial distress or bankruptcy. In the context of the DCF model, companies that do not pay dividends can be assumed to have a dividend yield of 0 percent;

[20] Opinion No. 569-A, at P 83.

therefore, the total return is comprised solely of its rate of capital appreciation, which is estimated by its earnings growth rate. Additionally, some companies tend to use stock buybacks as a cash flow to investors rather than dividends. In fact, evidence suggests "that the payout yield, which includes both dividends and buybacks, is more predictive of changes in expected returns than the dividend yield."[21] Excluding a company due to its method of providing cash flows to investors introduces a bias in the estimate of the market return because the S&P 500 Index includes companies that have regularly employed stock buybacks, but not dividends. To that point, 101 companies included in the S&P 500 Index currently do not pay dividends; excluding 20 percent of the companies that comprise the S&P 500 is not reflective of the overall market, but rather only a subset, which introduces bias.

Lastly, excluding a subset of companies from the MRP estimate introduces an inconsistency with the estimates of beta, which are typically calculated by comparing the relative volatility of a given company to an index of the overall market. Because these indices include non-dividend paying companies and companies with growth rates outside the range of 0 percent to 20 percent, using an MRP calculated for a different subset of the market introduces an inconsistency between measures of the broad market as applied to beta and the MRP. While FERC acknowledged a potential disconnect in calculating MRP using the S&P 500 and betas using the New York Stock Exchange ("NYSE") listed companies (Value Line calculates betas against the NYSE), it did not acknowledge the

[21] Philip U. Straehl and Roger G. Ibbotson, *The Supply of Stock Returns: Adding Back Buybacks*, (Dec. 17, 2015), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=2715098.

more significant bias of excluding several companies from the calculation of the MRP, without making a similar adjustment to betas.[22]

Q33. HOW DOES THE MARKET RETURN ESTIMATE DEVELOPED USING THE COMMISSION'S METHODOLOGY COMPARE WITH THE IMPLIED MARKET RETURN BASED ON S&P'S PUBLISHED ESTIMATES?

A33. The Commission's methodology produces an expected market return of 11.45 percent. As of January 31, 2024, a market return using S&P's published dividend yield of 1.47 percent and a growth rate of 13.15 percent produces a market return of 14.72 percent.[23] Therefore, using the Commission's methodology understates the cost of equity as compared to relying on the data published by S&P in its earnings and estimates report.

Q34. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES?

A34. My CAPM results, using the FERC methodology and inputs, are shown in Schedule 3.1 (Exhibit No. MAOD-17) and summarized in Figure 7.

Figure 7: CAPM Results

	Proxy Group
Lower Bound	9.79%
Lower Third	10.98%
Median	11.20%
Upper Third	11.68%
Upper Bound	12.95%

[22] Opinion No. 569-A, P 76.

[23] S&P Dow Jones Indices, S&P 500 Earnings and Estimate Report (October 31, 2023) (on file with author).

Q35. PLEASE DESCRIBE YOUR RISK PREMIUM ANALYSIS.

A35. In general terms, the Risk Premium approach recognizes that equity is riskier than debt because equity investors bear the residual risk associated with ownership. Equity investors, therefore, require a greater return (i.e., a premium) than bondholders. The Risk Premium approach estimates the cost of equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds, as reflected in the following formula, in which RP = Risk Premium (difference between allowed ROE and the respective bond yield); and Y = Applicable bond yield:

$$ROE = RP + Y$$

Because the Equity Risk Premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate ex-ante, or forward-looking estimates of the cost of equity, and others that consider historical, or ex-post, estimates. My Risk Premium analysis relies on FERC-authorized returns for electric transmission companies from 2006 through 2023, as shown in Schedule 4.2 (Exhibit No. MAOD-17).

To estimate the relationship between interest rates and the cost of equity using the Risk Premium approach, a regression is conducted using the following equation, where a = slope term and b = intercept term:

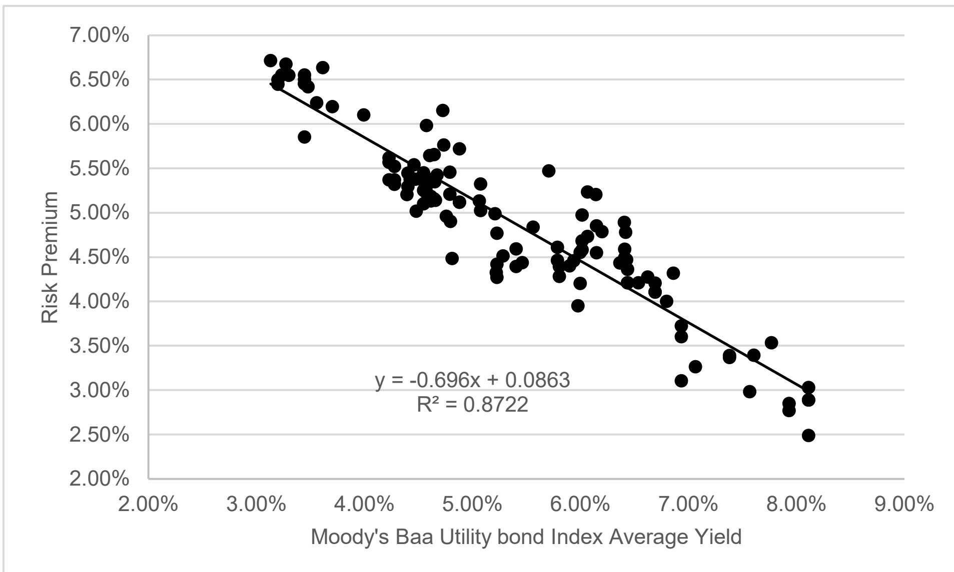
$$RP = ax + b$$ [24]

[24] Figure 7 contains the regression equation where RP is defined as "y," slope term "a" is equal to -0.696, and intercept term "b" is equal to 0.0863.

Q36. WHAT DID YOUR RISK PREMIUM ANALYSIS REVEAL?

A36. My Risk Premium analysis examines the relationship between FERC-authorized ROEs for electric transmission utilities and the respective Moody's Baa Utility Bond Index Yield at the time of the decision. The results of that regression are detailed in Figure 8, below.

Figure 8: Risk Premium Regression Results vs. 30-Year Treasury Yield[25]



As the chart illustrates, the risk premium varies with the level of the bond yield, and generally increases as bond yields decrease, and vice versa. Based on the regression coefficients in Figure 8, above,[26] which allows for the estimation of the risk premium at varying bond yields, the results of my Risk Premium analysis are shown in Figure 9 below.

[25] Figure 8 also appears in Schedule 4.1, along with detailed regression statistics (Exhibit No. MAOD-17).

[26] Schedule 4.1 contains more detailed regression statistics (Exhibit No. MAOD-17).

Figure 9: Risk Premium Results

	6-month Average Yield on Moody's Baa Utility Index
Yield	6.08%
Risk Premium	4.40%
ROE	10.48%

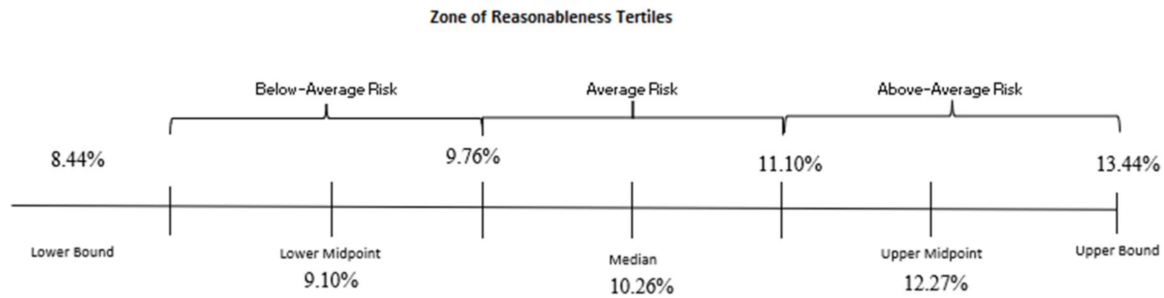
Q37. WHY ARE AUTHORIZED ROES RELEVANT?

A37. Authorized ROEs are a significant part of the market information that investors consider when evaluating their investment alternatives. The level of authorized ROE also provides a signal to investors about the level of regulatory support that a company can expect with regard to its ability to compete for capital and its financial integrity. Authorized ROEs also provide a broad benchmark of returns available to other regulated electric utilities, consistent with the *Hope* and *Bluefield* "comparable return" standard. An improperly depressed ROE for a given period may be an impediment to MAOD's ability to attract capital and invest in the infrastructure necessary to provide safe and reliable electric service to its customers.

Q38. HOW DID YOU CALCULATE THE ZONE OF REASONABLENESS FOR THE PROXY GROUP?

A38. In Opinion No. 569-A, the Commission included the DCF, CAPM, and Risk Premium analyses to construct a composite zone of reasonableness, and then divided that zone into thirds. As shown in Figure 10, below, based on that calculation, the presumptive zone of reasonableness for the middle third of the composite zone of reasonableness is 9.76 percent to 11.10 percent with a median of 10.26 percent.

Figure 10: Summary of Results[27]

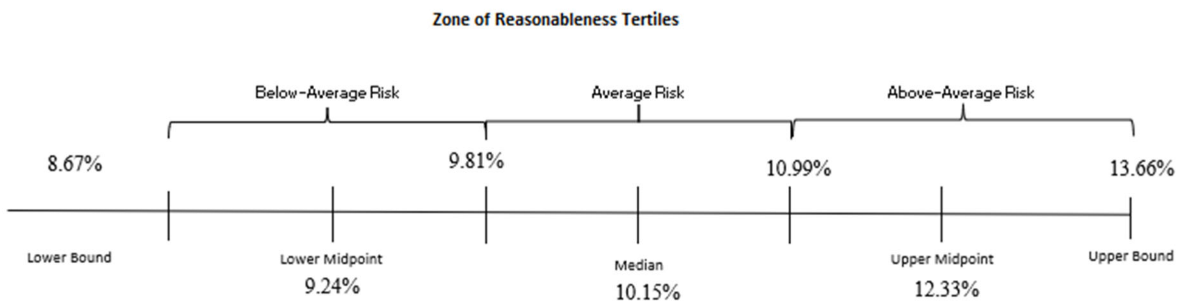


Given the recent U.S. Court of Appeals for the District of Columbia Circuit decision rejecting the application of the Risk Premium approach,[28] I also considered a composite zone of reasonableness including only the DCF and CAPM analyses, and then divided that zone into thirds. As shown in Figure 11, below, based on that calculation, the presumptive zone of reasonableness for the middle third of the composite zone of reasonableness is 9.81 percent to 10.99 percent with a median of 10.15 percent.

[27] *See* Schedule 5 (Exhibit No. MAOD-17).

[28] *See supra*, note 7.

Figure 11: Summary of Results[29]



Q39. IS IT APPROPRIATE TO INCLUDE ANY ADDERS TO THE BASE ROE ESTIMATE?

A39. Yes. In addition to the analyses discussed above, I considered MAOD's participation in PJM, for which FERC traditionally has included an adder to the base ROE of 50 basis points.[30] This brings my overall ROE recommendation to 10.76 percent (3-model base ROE of 10.26 percent plus 50 basis points).

VII. CAPITAL STRUCTURE

Q40. WHAT IS THE CAPITAL STRUCTURE YOU ARE APPLYING IN THE FORMULA RATE?

A40. MAOD is applying a hypothetical capital structure of 50 percent debt and 50 percent equity during the Project's development and construction period for purposes of calculating the Allowance for Funds Used During Construction ("AFUDC"). This capital structure is the same as that requested by MAOD in its Petition for Declaratory Order for Authorization to Utilize Incentive Rate Treatment ("MAOD PDO") and approved in the Incentives Order

[29] *See* Schedule 5 (Exhibit No. MAOD-17).

[30] *See* Incentives Order, at P 48.

issued on February 15, 2024 in Docket No. EL23-101-000.[31] MAOD will use its actual capital structure after the Project is placed into service.

Q41. HOW DOES MAOD EXPECT TO RAISE CAPITAL AT A REASONABLE COST?

A41. As described in the Sternhagen Testimony, the Project will be financed on a single-asset project finance basis and lenders will initially be exposed to construction risk until the Project is placed in service. Although there will be construction risk, MAOD is targeting a credit profile that is within the guidelines set forth by nationally recognized rating agencies for "investment grade" credit ratings based on the stable cash flow profile of the ATRR. An "investment grade" credit profile will allow MAOD to raise debt to build the Project at an attractive, low cost of debt.

Q42. WHY IS IT IMPORANT TO TARGET A CREDIT PROFILE THAT SUPPORTS AN INVESTMENT GRADE RATING?

A42. A financially healthy utility with a strong credit profile is able to access capital at reasonable costs and has the flexibility to manage financial modeling and cash flow through difficult times, either when access to capital may be limited due to macroeconomic conditions that may affect capital markets or when the utility must manage through the unforeseen cash flow volatility related to building complex transmission projects. Consequently, as a developer of a project with a development and construction timeline that will span several years, it is imperative for MAOD to maintain access to capital throughout all types of economic cycles.

[31] *See* Incentives Order, at P 46.

Q43. HOW DOES MAOD EXPECT TO ACHIEVE ITS TARGETED CREDIT PROFILE?

A43. The combination of MAOD's recommended capital structure, depreciation rates, ROE, and formula rate recovery should produce financial metrics that are within the guidelines provided by the rating agencies for companies facing similar business risks.

Q44. WHAT CAPITAL STRUCTURE IS MAOD USING IN ITS FILING?

A44. In the Incentives Order, the Commission authorized use of a hypothetical capital structure of 50% equity and 50% debt until the Project enters COD.[32] Therefore, MAOD will use this hypothetical capital structure until COD and then MAOD will apply its actual capital structure after the Project is placed into service. A 50% equity capital structure is one of the major components to achieving a strong credit profile and investment grade credit rating. As discussed above, it is critical that a utility maintain its credit quality in order to maintain access to capital and avoid the increased costs of financing that would be incurred with a weaker credit profile. Given its risks as a non-incumbent, transmission-only entity developing its first transmission asset, it will be critical for MAOD to have a capital structure that is at least as robust as other transmission-owning utilities. The capital structure being requested should help alleviate some of these risks because it is consistent with capital structure guidelines for an investment grade rating.

Q45. IS THE 50/50 CAPITAL STRUCTURE REASONABLE AND IN THE BEST INTEREST OF RATEPAYERS?

A45. Yes. MAOD's requested 50 percent debt and 50 percent equity hypothetical capital structure should allow MAOD to achieve reasonable costs of capital, which will benefit

[32] *See* Incentives Order, at P 46.

customers in New Jersey who will pay the cost of service in their utility rates. MAOD's requested hypothetical capital structure during the development and construction phase of the Project will offset development risks, and their effect on project financing, associated with the Project. Among other things, as recognized by the Commission when approving the MAOD PDO, MAOD will require significant borrowings, as well as equity capital contributions, as development and construction of the Project progresses. MAOD's precise debt-to-equity ratio during the construction period consequently will fluctuate as new borrowings are made and equity is invested, and will also be affected by negotiations with lenders. MAOD is, in essence, a single asset transmission company. Given the diversity of assets and scale of these mature utilities compared to MAOD, the proposed capital structure is conservative and provides direct benefits to customers with the leverage of a more mature utility. The requested capital structure is also consistent with those allowed by FERC for other transmission development projects.[33]

[33] *See* MAOD PDO, at 38, n.141 (citing *MidAmerican Cent. Cal. Transco, LLC,* 147 FERC ¶ 61,179, P 6 (2014) (52% equity and 48% debt); *Xcel Energy Sw. Transmission Co., LLC,* 149 FERC ¶ 61,182, P 5 (2014); *Xcel Energy Transmission Dev. Co., LLC,* 149 FERC ¶ 61,181, P 5 (2014) (55% equity and 45% debt); *Midwest Indep. Transmission Sys. Operator, Inc.,* 141 FERC ¶ 61,121, P 51 (2012) (56% equity and 44% debt); *Transource Mo., LLC,* 141 FERC ¶ 61,075, P 66 (2012) (60% equity and 40% debt); *Green Power Express LP,* 127 FERC ¶ 61,031, at P 72 (60% equity and 40% debt); *Primary Power, LLC,* 131 FERC ¶ 61,015, P 141 (2010) (60% equity and 40% debt); *Atl. Grid Operations A LLC, et al.,* 135 FERC ¶ 61,144, P 121 (2011) (60% equity and 40% debt). *Compare Midcontinent Indep. Sys. Operator, Inc.,* 182 FERC ¶ 61,039, PP 21, 25 (2023) (50% equity and 50% debt); *PJM Interconnection, L.L.C. and Northeast Transmission Dev., L.L.C.,* 155 FERC ¶ 61,097, PP 50-52 (2016), *order on reh'g,* 158 FERC ¶ 61,060, P 4 (2017) (50% equity and 50% debt); *DCR Transmission, L.L.C.,* 153 FERC ¶ 61,295, at P 45 (50% equity and 50% debt)).

VIII. COST OF DEBT

Q46. WHAT IS MAOD'S PLAN TO PROCURE DEBT AS PART OF ITS CAPITAL STRUCTURE?

A46. As explained by the Sternhagen Testimony, once the Commission has accepted the proposed Formula Rate and authorized the proposed rate incentives, MAOD plans to put in place a construction loan agreement to provide financing for project-related construction expenditures and short-term working capital requirements. MAOD currently anticipates that this construction financing will occur in the later part of 2025 but this date may change.

Q47. WHAT COST OF DEBT IS MAOD REQUESTING TO USE TO DETERMINE ITS COST OF CAPITAL UNTIL A CONSTRUCTION LOAN IS PUT IN PLACE?

A47. For the purposes of calculating AFUDC, in the period before MAOD obtains construction debt financing, debt will be priced at the three-month Term Secured Overnight Financing Rate ("SOFR") plus 200 basis points (the "Proxy Debt Rate"). The credit spread estimate was provided to the Company by Crédit Agricole Corporate and Investment Bank ("CACIB"), which is a leading bank in the project finance market.[34] Using recent, comparable US-based project finance transactions in the utility, transmission, and power sectors, CACIB estimated the credit spread above SOFR that commercial banks would require if the Project sought financing in the bank market today.

As of May 1, 2024 the three-month Term SOFR published was 5.3190 percent. Accordingly, at that time, the Proxy Debt Rate was 7.3190 percent. The Proxy Debt Rate will be updated monthly based on the monthly change in the three-month Term SOFR and used in the AFUDC calculation until construction debt financing is placed, at which point

[34] CACIB was ranked in the top four Mandated Arrangers by volume in 2022 Project finance loans worldwide (Refinitiv X02).

the actual cost of the construction debt financing will be reflected in the calculation of AFUDC. At or near the time of commercial operation, MAOD would expect to refinance the construction loan with longer-term debt financing, which would then be reflected as the actual cost of debt in the Formula Rate Template.

IX. <u>CONCLUSIONS AND RECOMMENDATIONS</u>

Q48. WHAT ARE YOUR RECOMMENDED COSTS OF CAPITAL FOR PURPOSES OF ESTABLISHING MAOD'S FORMULA RATES?

A48. Figure 12 below summarizes my recommendations. The stated return on equity is included in Attachment 8, Stated Value Inputs of the Formula Rate Template as explained in Exhibit No. MAOD-21, Davis Testimony. Mr. Davis further explains how the actual capital structure and cost of debt will be reflected in the formula rate.

Figure 12: Cost of Capital Summary

Model	Lower Third	Median	Upper Third
Two-Step DCF	8.64%	9.10%	10.30%
CAPM	10.98%	11.20%	11.68%
Risk Premium	9.65%	10.48%	11.31%
Three-Model Average	9.76%	10.26%	11.10%
Two-Model Average	9.81%	10.15%	10.99%
Recommended Base ROE		10.26%	
RTO Participation Incentive		0.50%	
Return on Equity		**10.76%**	
Cost of Debt		**3-Month Term SOFR + 2.00%**[35]	
Capital Structure		**50/50**[36]	

[35] Proxy Debt Rate until construction or permanent debt financing is obtained, then the actual cost of debt.

[36] MAOD will use its actual capital structure after the Project is placed into service.

Q49. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A49. Yes.

Attachment 1
Joshua C. Nowak Resume

JOSHUA C. NOWAK

VICE PRESIDENT

Mr. Nowak is a financial and economic consultant with more than fifteen years of experience in the energy industry. He has provided expert testimony on regulatory issues in several proceedings before the Federal Energy Regulatory Commission and regulatory commissions in Alaska, California, Connecticut, Kentucky, Minnesota, New Brunswick, New Hampshire, New York, North Dakota, Ohio, and Texas. Mr. Nowak specializes in providing rate case services on economic conditions and financial market matters related to the cost of capital. He is also experienced in providing strategic direction on financing activities including bond offerings, credit rating analysis, and investor relations. Previously, Josh was the Director of Regulatory Strategy & Integrated Analytics at National Grid where he was responsible for issues related to the cost of capital across its federal and state jurisdictional operating companies. He holds a Bachelor's Degree in Economics and History from Boston College.

REPRESENTATIVE EXPERIENCE

Expert Testimony and Litigation Support

Mr. Nowak's work includes regulatory project management, research, and analysis for expert witness testimony. His work has included:

- Expert testimony on cost of capital, financial markets, return on equity, capital structure, and debt financing issues
- Regulatory strategy in return on equity proceedings, including coordination across several utilities in joint-party proceedings
- Extensive support for expert testimony in cost of capital and return on equity proceedings through research, financial analysis, and testimony development
- Expert testimony, sponsoring lead-lag studies, in support of utility cash working capital requirements
- Project management of expert testimony assignments, including all phases of the regulatory schedule
- Performing analysis to support expert testimony regarding affiliate expenses and allocations

Policy Analysis

Mr. Nowak has contributed to projects related to policy review including:

- A review of natural gas capacity options and a cost-benefit analysis for state regulators seeking to reduce energy costs for ratepayers
- Analysis of the economic and environmental benefits of changes to natural gas ratemaking/expansion policy

Management and Operations Consulting

Mr. Nowak has taken a lead analytical role in developing benchmarking analyses and process reviews. Specifically, he has:

- Developed benchmarking analyses, in support of expert testimony, comparing electric and gas utilities' cost and operational efficiency, taking into account a situational assessment of exogenous factors
- Performed a process review of a gas utility's expansion projects, including an evaluation of policies, procedures, and financial models
- Supported analysis for a report of the reasonableness of a shared service company's administrative and general costs

Financial Analysis

Other financial analysis Mr. Nowak has conducted include:

- Extensive analysis on issues related to utilities' cost of capital
- Developing dispatch models to estimate revenues for merchant powerplants
- Estimating damages for breach of contract in fuel delivery commitment
- Researching strategic investment opportunities for merchant generators
- A report on the profitability of various generation technologies in a deregulated energy market
- Reviewing internal financial models used by utility clients
- Supporting utility asset appraisals, including research and analysis for income approach, cost approach, and sales comparison approach

Other Experience

In his previous work, Mr. Nowak contributed to the evaluation of regulatory policy for government clients. His experience included performing policy analysis, including economic impact assessments, for federal regulations.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2018 – Present)
Vice President
Assistant Vice President

National Grid USA (2017 – 2018)
Director, Regulatory Strategy & Integrated Analytics

ScottMadden, Inc. (formerly Sussex Economic Advisors, LLC) (2012 – 2016)
Director
Principal

Concentric Energy Advisors, Inc. (2007 – 2012)
Senior Consultant
Consultant
Assistant Consultant
Analyst

RTI International (2006 – 2007)
Economist

EDUCATION

Boston College
B.A., Economics and History, 2006

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company, a Division of Semco Energy, Inc.	06/16	ENSTAR Natural Gas Company, a Division of Semco Energy, Inc.	TA 285-4	Cash Working Capital
California Public Utilities Commission				
Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company	02/24	Pacific Gas and Electric Company, Southern California Edison Company, Southern California Gas Company, and San Diego Gas & Electric Company	A.22-04-008 / A.22-04-009 / A.22-04-011 / A.22-04-012	Return on Equity Policy
Southern California Gas Company and San Diego Gas & Electric Company	01/24	Southern California Gas Company and San Diego Gas & Electric Company	A.22-04-011 / A.22-04-012	Return on Equity Policy
Connecticut Public Utilities Regulatory Authority				
Aquarion Water Company of Connecticut	08/22	Aquarion Water Company of Connecticut	Docket No. 22-07-01	Return on Equity
Aquarion Water Company of Connecticut	01/22	Aquarion Water Company of Connecticut	Docket No. 13-02-20RE06	Return on Equity and Cost of Debt
Federal Energy Regulatory Commission				
Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation	04/21	Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation	EL21-66-000, ER21-1647-000	Transmission Ownership Risk and Returns
Central Hudson Gas & Electric Corporation	12/19	Central Hudson Gas & Electric Corporation	ER20-715-000	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Kentucky Public Service Commission				
Duke Energy Kentucky, Inc.	12/22	Duke Energy Kentucky, Inc.	Case No. 2022-00372	Return on Equity
Minnesota Public Utilities Commission				
Northern States Power Company (Xcel Energy Inc.)	11/23	Northern States Power Company (Xcel Energy Inc.)	G-002/GR-23-413	Return on Equity
New Brunswick Energy and Utilities Board				
New Brunswick Power Corporation (NB Power)	11/22	New Brunswick Power Corporation (NB Power)	Matter 541	Macroeconomic Environment and Capital Market Conditions
Public Utilities Commission of New Hampshire				
Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities	04/16	Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities	Docket No. DE 16-383	Cash Working Capital
New York Public Service Commission				
Niagara Mohawk Power Corporation d/b/a National Grid	05/24	Niagara Mohawk Power Corporation d/b/a National Grid	Case 24-E-0322/ Case 24-G- 0323	Return on Equity
National Fuel Gas Distribution Corporation	10/23	National Fuel Gas Distribution Corporation	Case 23-G-0627	Return on Equity
Central Hudson Gas & Electric Corporation	07/23	Central Hudson Gas & Electric Corporation	Case 23-E-0418/ Case 23-G-0419	Return on Equity
The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY) and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI")	04/23	The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY) and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI")	Case 23-G-0225/ Case 23-G-0226	Return on Equity

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Niagara Mohawk Power Corporation d/b/a National Grid	07/20	Niagara Mohawk Power Corporation d/b/a National Grid	Case 20-E-0380/ Case 20-G- 0381	Return on Equity
Niagara Mohawk Power Corporation d/b/a National Grid	07/17	Niagara Mohawk Power Corporation d/b/a National Grid	Case 17-E-0238 / Case 17-G- 0239	Capital Structure and Overall Cost of Capital
North Dakota Public Service Commission				
Northern States Power Company (Xcel Energy Inc.)	12/23	Northern States Power Company (Xcel Energy Inc.)	Docket No. PU-23-367	Return on Equity
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	01/23	Duke Energy Ohio, Inc.	Case No. 22-1153-EL-UNC	Return on Equity
Public Utility Commission of Texas				
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Cash Working Capital
Lone Star Transmission, LLC	05/14	Lone Star Transmission, LLC	Docket No. 42469	Cash Working Capital
Railroad Commission of Texas				
Texas Gas Service Company, a Division of One Gas, Inc.	06/16	Texas Gas Service Company, a Division of One Gas, Inc.	GUD No. 10526	Cash Working Capital
Texas Gas Service Company, a Division of One Gas, Inc.	03/16	Texas Gas Service Company, a Division of One Gas, Inc.	GUD No. 10506	Cash Working Capital
Texas Gas Service Company, a Division of One Gas, Inc.	12/15	Texas Gas Service Company, a Division of One Gas, Inc.	GUD No. 10488	Cash Working Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/14	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD No. 10432	Cash Working Capital

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)))	**Docket No. ER24-___-000**

VERIFICATION

I, Joshua C. Nowak, declare that I am the author of the foregoing testimony, that the facts set forth herein are true and correct to the best of my knowledge, information, and belief, and that if asked the same questions contained therein, my answers would be the same.

Joshua C. Nowak

Dated: 7/18/2024

Subscribed and sworn to before me, a Notary Public, this 18th day of July, 2024.

Notary

My commission expires: 5/28/2028

CATHERINE SPENCE
Notary ID #4231566
My Commission Expires
May 28, 2028

Exhibit No. MAOD-17
Mid-Atlantic Offshore Development, LLC
Return on Equity Exhibits

PROXY GROUP SCREENING DATA AND RESULTS

Company	Ticker	[1] Pays Dividends, No Reductions or Cuts in Study Period	[2] S&P Credit Rating	[3] Moody's Credit Rating	[4] Engaged in Merger during Study Period (8/1/2023 through 1/31/2024)	[5] In Proxy Group
ALLETE, Inc.	ALE	Yes	BBB	Baa1	No	Yes
Alliant Energy Corporation	LNT	Yes	A-	Baa2	No	Yes
Ameren Corporation	AEE	Yes	BBB+	Baa1	No	Yes
American Electric Power Company, Inc.	AEP	Yes	A-	Baa2	No	Yes
Avangrid, Inc.	AGR	Yes	BBB+	Baa2	Yes	
Avista Corporation	AVA	Yes	BBB	Baa2	No	Yes
Black Hills Corporation	BKH	Yes	BBB+	Baa2	No	Yes
CenterPoint Energy, Inc.	CNP	Yes	BBB+	Baa2	No	Yes
CMS Energy Corporation	CMS	Yes	BBB+	Baa2	No	Yes
Consolidated Edison, Inc.	ED	Yes	A-	Baa1	No	Yes
Dominion Resources, Inc.	D	Yes	BBB+	Baa2	Yes	
DTE Energy Company	DTE	Yes	BBB+	Baa2	No	Yes
Duke Energy Corporation	DUK	Yes	BBB+	Baa2	No	Yes
Edison International	EIX	Yes	BBB	Baa2	No	Yes
Entergy Corporation	ETR	Yes	BBB+	Baa2	No	Yes
Eversource Energy	ES	Yes	A-	Baa2	No	Yes
Exelon Corporation	EXC	Yes	BBB+	Baa2	No	Yes
FirstEnergy Corporation	FE	Yes	BBB-	Ba1	Yes	
Evergy, Inc.	EVRG	Yes	BBB+	n/a	No	Yes
Hawaiian Electric Industries, Inc.	HE	No	B-	B1	No	
IDACORP, Inc.	IDA	Yes	BBB	Baa2	No	Yes
MGE Energy, Inc.	MGEE	Yes	AA-	n/a	No	Yes
NextEra Energy, Inc.	NEE	Yes	A-	Baa1	No	Yes
NorthWestern Corporation	NWE	Yes	BBB	n/a	No	Yes
OGE Energy Corporation	OGE	Yes	BBB+	Baa1	No	Yes
Otter Tail Corporation	OTTR	Yes	BBB	Baa2	No	Yes
PG&E Corporation	PCG	No	BB-	Ba2	No	
Pinnacle West Capital Corporation	PNW	Yes	BBB+	Baa1	No	Yes
PNM Resources, Inc.	PNM	Yes	BBB	Baa3	Yes	
Portland General Electric Company	POR	Yes	BBB+	A3	No	Yes
PPL Corporation	PPL	Yes	A-	Baa1	No	Yes
Public Service Enterprise Group Inc.	PEG	Yes	BBB+	Baa2	No	Yes
Sempra Energy	SRE	Yes	BBB+	Baa2	No	Yes
Southern Company	SO	Yes	BBB+	Baa2	No	Yes
Wisconsin Energy Corporation	WEC	Yes	A-	Baa1	No	Yes
Xcel Energy Inc.	XEL	Yes	A-	Baa1	No	Yes
						30

Notes:
[1] Source: Bloomberg Professional
[2] Source: S&P Capital IQ Pro
[3] Source: S&P Capital IQ Pro
[4] Source: S&P Capital IQ Pro

DCF ANALYSIS

Company		[1] Average Dividend Yield	[2] Expected Dividend Yield	[3] Yahoo! Finance Near Term Growth	[4] GDP Growth	[5] Average Weighted 2 Stage Growth	[6] ROE	[7] Outliers
ALLETE, Inc.	ALE	4.83%	5.02%	8.10%	4.21%	7.32%	12.34%	
Alliant Energy Corporation	LNT	3.63%	3.75%	6.55%	4.21%	6.08%	9.83%	
Ameren Corporation	AEE	3.30%	3.38%	4.80%	4.21%	4.68%	8.06%	
American Electric Power Company, Inc.	AEP	4.35%	4.44%	4.20%	4.21%	4.20%	8.64%	
Avista Corporation	AVA	5.38%	5.55%	6.20%	4.21%	5.80%	11.35%	
Black Hills Corporation	BKH	4.74%	4.76%	0.70%	4.21%	1.40%	6.16%	x
CenterPoint Energy, Inc.	CNP	2.78%	NA	negative	4.21%			x
CMS Energy Corporation	CMS	3.46%	3.59%	7.70%	4.21%	7.00%	10.59%	
Consolidated Edison, Inc.	ED	3.61%	3.71%	5.66%	4.21%	5.37%	9.08%	
DTE Energy Company	DTE	3.76%	3.86%	5.10%	4.21%	4.92%	8.78%	
Duke Energy Corporation	DUK	4.47%	4.62%	6.55%	4.21%	6.08%	10.70%	
Edison International	EIX	4.48%	4.58%	4.60%	4.21%	4.52%	9.11%	
Entergy Corporation	ETR	4.49%	4.74%	11.00%	4.21%	9.64%	14.38%	
Eversource Energy	ES	4.50%	4.59%	3.60%	4.21%	3.72%	8.31%	
Exelon Corporation	EXC	3.74%	3.82%	4.20%	4.21%	4.20%	8.02%	
Evergy, Inc.	EVRG	4.82%	4.88%	2.50%	4.21%	2.84%	7.72%	
IDACORP, Inc.	IDA	3.38%	3.46%	4.40%	4.21%	4.36%	7.82%	
MGE Energy, Inc.	MGEE	2.37%	2.44%	5.40%	4.21%	5.16%	7.60%	
NextEra Energy, Inc.	NEE	3.10%	3.22%	7.81%	4.21%	7.09%	10.31%	
NorthWestern Corporation	NWE	5.08%	5.18%	4.08%	4.21%	4.11%	9.29%	
OGE Energy Corporation	OGE	4.83%	NA	negative	4.21%			x
Otter Tail Corporation	OTTR	2.16%	2.25%	9.00%	4.21%	8.04%	10.30%	
Pinnacle West Capital Corporation	PNW	4.71%	4.85%	5.90%	4.21%	5.56%	10.41%	
Portland General Electric Company	POR	4.48%	4.58%	4.60%	4.21%	4.52%	9.10%	
PPL Corporation	PPL	3.77%	4.09%	17.21%	4.21%	14.61%	18.70%	x
Public Service Enterprise Group Inc.	PEG	3.76%	3.84%	4.60%	4.21%	4.52%	8.37%	
Sempra Energy	SRE	3.32%	3.39%	4.14%	4.21%	4.15%	7.54%	
Southern Company	SO	4.07%	4.22%	7.10%	4.21%	6.52%	10.74%	
Wisconsin Energy Corporation	WEC	3.74%	3.85%	5.45%	4.21%	5.20%	9.05%	
Xcel Energy Inc.	XEL	3.49%	3.60%	6.57%	4.21%	6.10%	9.70%	
MEAN			4.08%	5.99%			9.50%	
MEDIAN							9.10%	

Zone of Reasonableness High:	14.38%
Upper Third	10.30%
Median	9.10%
Lower Third	8.64%
Zone of Reasonableness Low:	7.54%
Upper Threshold [7]	18.21%
Lower Threshold [7]	7.49%

Notes:
[1] Six month average dividend yields - August 1, 2023 through January 31, 2024
[2] Equals Column [1] x (1 + (0.5 x Column [5]))
[3] Yahoo! Finance dated January 31, 2024
[4] Source: Schedule 2.2
[5] Equals (2/3)* Column [3] + (1/3) * Column [4]
[6] Equals Column [2] + Column [5]
[7] Per FERC precedent, results less than the cost of debt (Moody's Baa-rated Utility Bond Index six-month average plus 20% of MRP) or more than 200% of proxy group median are excluded from consideration

LONG-TERM GDP GROWTH ESTIMATE

Long-Term
U.S. Gross Domestic Product (GDP)
Growth Forecasts

	[A]	[B]	[C]
Source	**Beginning Year**	**Ending Year**	**Annual GDP Growth**
BCFF [1]	2024	2033	4.24%
EIA [2]	2024	2050	4.30%
SSA [3]	2024	2075	4.07%
Average			**4.21%**

Notes:
[1] Blue Chip Financial Forecasts, Vol. 42, No. 12, December 1, 2023, at 14. Nominal GDP = (Real GDP) * (GDP Chained Price Index)

[2] Energy Information Administration Annual Energy Outlook 2023 with projections to 2050, March 2023, Table A20. Macroeconomic Indicators. Nominal GDP=(Real GDP)*(GDP Chain Type Price Index). https://www.eia.gov/outlooks/aeo/tables_ref.php

[3] Social Security Administration: The 2023 OASDI Trustees Report, Table VI.G4.—OASDI and HI Annual and Summarized Income, Cost, and Balance as a Percentage of GDP, Calendar Years 2023-2100 https://www.ssa.gov/OACT/TR/2023

CAPM ANALYSIS

		[4]	[5]			[7]
Risk Free Rate [1]			4.47%			
Market Return [2]			11.45%			
Market Risk Premium [3]			6.98%			

		Value Line Beta	Unadjusted CAPM	Small size premium	Adjusted CAPM	Outliers
ALLETE, Inc.	ALE	0.95	11.10%	0.93%	12.03%	
Alliant Energy Corporation	LNT	0.90	10.75%	0.45%	11.20%	
Ameren Corporation	AEE	0.90	10.75%	0.45%	11.20%	
American Electric Power Company, Inc.	AEP	0.80	10.05%	-0.26%	9.79%	
Avista Corporation	AVA	0.95	11.10%	0.93%	12.03%	
Black Hills Corporation	BKH	1.00	11.45%	0.93%	12.38%	
CenterPoint Energy, Inc.	CNP	1.15	12.50%	0.45%	12.95%	
CMS Energy Corporation	CMS	0.85	10.40%	0.45%	10.85%	
Consolidated Edison, Inc.	ED	0.75	9.70%	0.45%	10.15%	
DTE Energy Company	DTE	1.00	11.45%	0.45%	11.90%	
Duke Energy Corporation	DUK	0.85	10.40%	-0.26%	10.14%	
Edison International	EIX	1.00	11.45%	0.45%	11.90%	
Entergy Corporation	ETR	0.95	11.10%	0.45%	11.55%	
Eversource Energy	ES	0.90	10.75%	0.45%	11.20%	
Exelon Corporation	EXC	NMF	NA	-0.26%		x
Evergy, Inc.	EVRG	0.95	11.10%	0.57%	11.67%	
IDACORP, Inc.	IDA	0.85	10.40%	0.58%	10.98%	
MGE Energy, Inc.	MGEE	0.75	9.70%	0.93%	10.63%	
NextEra Energy, Inc.	NEE	0.95	11.10%	-0.26%	10.84%	
NorthWestern Corporation	NWE	0.95	11.10%	0.93%	12.03%	
OGE Energy Corporation	OGE	1.05	11.80%	0.57%	12.37%	
Otter Tail Corporation	OTTR	0.90	10.75%	0.93%	11.68%	
Pinnacle West Capital Corporation	PNW	0.95	11.10%	0.57%	11.67%	
Portland General Electric Company	POR	0.90	10.75%	0.58%	11.33%	
PPL Corporation	PPL	1.05	11.80%	0.45%	12.25%	
Public Service Enterprise Group Inc.	PEG	0.90	10.75%	0.45%	11.20%	
Sempra Energy	SRE	1.00	11.45%	-0.26%	11.19%	
Southern Company	SO	0.90	10.75%	-0.26%	10.49%	
Wisconsin Energy Corporation	WEC	0.85	10.40%	0.45%	10.85%	
Xcel Energy Inc.	XEL	0.85	10.40%	-0.26%	10.14%	
MEAN		0.922			11.33%	
MEDIAN		0.900			11.20%	
				Zone of Reasonableness High:	12.95%	
				Upper Third	11.68%	
				Median	11.20%	
				Lower Third	10.98%	
				Zone of Reasonableness Low:	9.79%	
				Upper Threshold [8]	22.40%	
				Lower Threshold [8]	7.49%	

Notes
[1] Source: Schedule 4.1
[2] Source: Schedule 3.2
[3] Source: Equals [2] - [1]
[4] Source: Bloomberg Professional
[5] Equals (Column [5], Line [1]) + Column [4] x (Column [5], Line [3])
[6] Equals (Column [6], Line [1]) + Column [4] x (Column [6], Line [3])
[7] Equals (Column [7], Line [1]) + Column [4] x (Column [7], Line [3])
[8] Per FERC precedent, results less than the cost of debt (Moody's Baa-rated Utility Bond Index six-month average plus 20% of MRP) or more than 200% of proxy group median are excluded from consideration

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.93%
[2] Estimated Weighted Average Long-Term Growth Rate	9.43%
[3] S&P 500 Estimated Required Market Return	11.45%
[4] Risk-Free Rate	4.47%
[5] Implied Market Risk Premium	6.98%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[6] % of Total Market Cap.	[7] Current Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Yahoo! Finance Earnings Growth	[10] Value Line Earnings Growth	[11] Average Earnings Growth	[12] Cap. Weighted Long-Term Growth
LyondellBasell Industries NV	LYB	n/a	5.31	n/a	-3.17	0.50	-1.34	n/a
American Express Co	AXP	0.54%	1.20	0.01%	14.60	8.50	11.55	0.06%
Verizon Communications Inc	VZ	0.67%	6.28	0.04%	1.47	1.50	1.49	0.01%
Broadcom Inc	AVGO	n/a	1.78	n/a	13.80	30.00	21.90	n/a
Boeing Co/The	BA	n/a	n/a	n/a	139.71		139.71	n/a
Caterpillar Inc	CAT	0.57%	1.73	0.01%	12.66	14.50	13.58	0.08%
JPMorgan Chase & Co	JPM	1.88%	2.41	0.05%	3.00	8.50	5.75	0.11%
Chevron Corp	CVX	1.04%	4.10	0.04%	-5.00	19.50	7.25	0.08%
Coca-Cola Co/The	KO	0.96%	3.09	0.03%	6.34	8.00	7.17	0.07%
AbbVie Inc	ABBV	n/a	3.77	n/a	-3.78	2.00	-0.89	n/a
Walt Disney Co/The	DIS	n/a	0.62	n/a	16.72	30.00	23.36	n/a
FleetCor Technologies Inc	FLT	n/a	n/a	n/a	11.85	15.50	13.68	n/a
Extra Space Storage Inc	EXR	0.11%	4.49	0.01%	6.00	5.00	5.50	0.01%
Exxon Mobil Corp	XOM	n/a	3.70	n/a	-10.74	7.00	-1.87	n/a
Phillips 66	PSX	0.24%	2.91	0.01%	-11.10	15.50	2.20	0.01%
General Electric Co	GE	n/a	0.24	n/a	33.38	29.50	31.44	n/a
HP Inc	HPQ	0.11%	3.84	0.00%	7.73	12.50	10.12	0.01%
Home Depot Inc/The	HD	1.31%	2.37	0.03%	1.80	6.50	4.15	0.05%
Monolithic Power Systems Inc	MPWR	0.11%	0.66	0.00%	25.00	15.00	20.00	0.02%
International Business Machines Corp	IBM	0.63%	3.62	0.02%	2.80	3.00	2.90	0.02%
Johnson & Johnson	JNJ	1.43%	3.00	0.04%	4.70	5.00	4.85	0.07%
Lululemon Athletica Inc	LULU	n/a	n/a	n/a	18.66	16.50	17.58	n/a
McDonald's Corp	MCD	0.79%	2.28	0.02%	9.68	10.50	10.09	0.08%
Merck & Co Inc	MRK	1.14%	2.55	0.03%	10.34	8.50	9.42	0.11%
3M Co	MMM	0.19%	6.36	0.01%	4.10	4.50	4.30	0.01%
American Water Works Co Inc	AWK	0.09%	2.28	0.00%	7.78	3.00	5.39	0.00%
Bank of America Corp	BAC	1.00%	2.82	0.03%	3.90	5.00	4.45	0.04%
Pfizer Inc	PFE	0.57%	6.20	0.04%	-1.20	2.00	0.40	0.00%
Procter & Gamble Co/The	PG	1.38%	2.39	0.03%	8.03	6.00	7.02	0.10%
AT&T Inc	T	0.47%	6.27	0.03%	0.77	1.50	1.14	0.01%
Travelers Cos Inc/The	TRV	0.18%	1.89	0.00%	16.20	7.50	11.85	0.02%
RTX Corp	RTX	0.49%	2.59	0.01%	10.91	15.00	12.96	0.06%
Analog Devices Inc	ADI	0.36%	1.79	0.01%	-1.51	11.50	5.00	0.02%
Walmart Inc	WMT	1.66%	1.38	0.02%	8.32	6.50	7.41	0.12%
Cisco Systems Inc	CSCO	0.76%	3.11	0.02%	6.41	6.50	6.46	0.05%
Intel Corp	INTC	n/a	1.16	n/a	43.08		43.08	n/a
General Motors Co	GM	0.17%	1.24	0.00%	11.35	7.50	9.43	0.02%
Microsoft Corp	MSFT	11.04%	0.75	0.08%	16.30	10.50	13.40	1.48%
Dollar General Corp	DG	n/a	1.79	n/a	-5.65	2.00	-1.83	n/a
Cigna Group/The	CI	0.33%	1.63	0.01%	11.22	10.00	10.61	0.03%
Kinder Morgan Inc	KMI	0.14%	6.68	0.01%	0.30	17.50	8.90	0.01%
Citigroup Inc	C	0.40%	3.77	0.02%	1.20	2.50	1.85	0.01%
American International Group Inc	AIG	0.18%	2.07	0.00%	14.41	14.00	14.21	0.03%
Altria Group Inc	MO	0.27%	9.77	0.03%	2.43	6.00	4.22	0.01%
HCA Healthcare Inc	HCA	0.31%	0.87	0.00%	8.94	12.50	10.72	0.03%
International Paper Co	IP	0.05%	5.16	0.00%	19.20	6.00	12.60	0.01%
Hewlett Packard Enterprise Co	HPE	0.07%	3.40	0.00%	2.47	7.50	4.99	0.00%
Abbott Laboratories	ABT	0.73%	1.94	0.01%	7.80	4.50	6.15	0.05%
Aflac Inc	AFL	0.18%	2.37	0.00%	7.40	8.00	7.70	0.01%
Air Products and Chemicals Inc	APD	0.21%	2.77	0.01%	10.45	10.50	10.48	0.02%
Royal Caribbean Cruises Ltd	RCL	n/a	n/a	n/a	-160.40		-160.40	n/a
Hess Corp	HES	0.16%	1.25	0.00%	7.95	23.50	15.73	0.03%
Archer-Daniels-Midland Co	ADM	0.11%	3.60	0.00%	-6.60	7.50	0.45	0.00%
Automatic Data Processing Inc	ADP	0.38%	2.28	0.01%	10.93	11.00	10.97	0.04%
Verisk Analytics Inc	VRSK	0.13%	0.56	0.00%	11.70	9.00	10.35	0.01%
AutoZone Inc	AZO	n/a	n/a	n/a	9.15	13.00	11.08	n/a
Linde PLC	LIN	0.73%	1.26	0.01%	12.00	8.50	10.25	0.08%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.93%
[2] Estimated Weighted Average Long-Term Growth Rate	9.43%
[3] S&P 500 Estimated Required Market Return	11.45%
[4] Risk-Free Rate	4.47%
[5] Implied Market Risk Premium	6.98%

STANDARD AND POOR'S 500 INDEX

	Ticker	[6] % of Total Market Cap.	[7] Current Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Yahoo! Finance Earnings Growth	[10] Value Line Earnings Growth	[11] Average Earnings Growth	[12] Cap. Weighted Long-Term Growth
Avery Dennison Corp	AVY	0.06%	1.62	0.00%	7.82	9.50	8.66	0.01%
Enphase Energy Inc	ENPH	n/a	n/a	n/a	10.90	21.00	15.95	n/a
MSCI Inc	MSCI	0.18%	1.07	0.00%	13.13	12.50	12.82	0.02%
Ball Corp	BALL	0.07%	1.44	0.00%	3.10	10.50	6.80	0.00%
Axon Enterprise Inc	AXON	n/a	n/a	n/a	38.40	24.00	31.20	n/a
Dayforce Inc	CDAY	n/a	n/a	n/a	39.66		39.66	n/a
Carrier Global Corp	CARR	0.18%	1.39	0.00%	9.80	13.50	11.65	0.02%
Bank of New York Mellon Corp/The	BK	0.16%	3.03	0.00%	11.76	7.00	9.38	0.01%
Otis Worldwide Corp	OTIS	0.14%	1.54	0.00%	9.80	11.50	10.65	0.01%
Baxter International Inc	BAX	0.07%	3.00	0.00%	4.07	6.00	5.04	0.00%
Becton Dickinson & Co	BDX	0.26%	1.59	0.00%	8.40	5.00	6.70	0.02%
Berkshire Hathaway Inc	BRK/B	n/a	n/a	n/a	23.30	6.00	14.65	n/a
Best Buy Co Inc	BBY	0.06%	5.08	0.00%	-1.10	3.00	0.95	0.00%
Boston Scientific Corp	BSX	n/a	n/a	n/a	12.40	13.50	12.95	n/a
Bristol-Myers Squibb Co	BMY	n/a	4.91	n/a	-0.03		-0.03	n/a
Brown-Forman Corp	BF/B	0.06%	1.59	0.00%	11.00	16.50	13.75	0.01%
Coterra Energy Inc	CTRA	n/a	3.22	n/a	-11.25		-11.25	n/a
Campbell Soup Co	CPB	0.05%	3.32	0.00%	5.09	5.00	5.05	0.00%
Hilton Worldwide Holdings Inc	HLT	0.18%	0.31	0.00%	16.76		16.76	0.03%
Carnival Corp	CCL	n/a	n/a	n/a	269.00		269.00	n/a
Qorvo Inc	QRVO	n/a	n/a	n/a	10.00	14.50	12.25	n/a
Builders FirstSource Inc	BLDR	n/a	n/a	n/a	-12.30	11.00	-0.65	n/a
UDR Inc	UDR	n/a	4.66	n/a	-34.21	17.00	-8.61	n/a
Clorox Co/The	CLX	0.07%	3.30	0.00%	7.04	11.00	9.02	0.01%
Paycom Software Inc	PAYC	0.04%	0.79	0.00%	15.14	21.00	18.07	0.01%
CMS Energy Corp	CMS	0.06%	3.41	0.00%	7.70	5.50	6.60	0.00%
Colgate-Palmolive Co	CL	0.26%	2.28	0.01%	8.38	8.50	8.44	0.02%
EPAM Systems Inc	EPAM	n/a	n/a	n/a	4.90	20.50	12.70	n/a
Comerica Inc	CMA	n/a	5.40	n/a	-10.70	3.00	-3.85	n/a
Conagra Brands Inc	CAG	0.05%	4.80	0.00%	0.98	3.50	2.24	0.00%
Airbnb Inc	ABNB	n/a	n/a	n/a	21.40		21.40	n/a
Consolidated Edison Inc	ED	0.12%	3.65	0.00%	5.66	6.00	5.83	0.01%
Corning Inc	GLW	0.10%	3.45	0.00%	7.13	17.50	12.32	0.01%
Cummins Inc	CMI	0.13%	2.81	0.00%	12.08	9.00	10.54	0.01%
Caesars Entertainment Inc	CZR	n/a	n/a	n/a	230.70		230.70	n/a
Danaher Corp	DHR	0.66%	0.40	0.00%	2.55	7.50	5.03	0.03%
Target Corp	TGT	0.24%	3.16	0.01%	20.27	11.00	15.64	0.04%
Deere & Co	DE	0.41%	1.49	0.01%	-5.05	12.50	3.73	0.02%
Dominion Energy Inc	D	n/a	5.84	n/a	-5.12	0.50	-2.31	n/a
Dover Corp	DOV	0.08%	1.36	0.00%	8.45	6.50	7.48	0.01%
Alliant Energy Corp	LNT	0.05%	3.95	0.00%	6.55	6.50	6.53	0.00%
Steel Dynamics Inc	STLD	n/a	1.41	n/a	-15.40	2.00	-6.70	n/a
Duke Energy Corp	DUK	0.28%	4.28	0.01%	6.55	5.00	5.78	0.02%
Regency Centers Corp	REG	0.04%	4.28	0.00%	-5.59	15.50	4.96	0.00%
Eaton Corp PLC	ETN	0.37%	1.40	0.01%	12.87	12.50	12.69	0.05%
Ecolab Inc	ECL	0.21%	1.15	0.00%	14.64	10.00	12.32	0.03%
Revvity Inc	RVTY	n/a	0.26	n/a	-7.20	-3.50	-5.35	n/a
Emerson Electric Co	EMR	0.20%	2.29	0.00%	10.70	6.50	8.60	0.02%
EOG Resources Inc	EOG	0.25%	3.20	0.01%	-1.00	15.00	7.00	0.02%
Aon PLC	AON	0.22%	0.82	0.00%	9.10	9.50	9.30	0.02%
Entergy Corp	ETR	0.08%	4.53	0.00%	11.00	0.50	5.75	0.00%
Equifax Inc	EFX	0.11%	0.64	0.00%	12.63	3.50	8.07	0.01%
EQT Corp	EQT	n/a	1.78	n/a	22.00		22.00	n/a
IQVIA Holdings Inc	IQV	n/a	n/a	n/a	8.44	14.50	11.47	n/a
Gartner Inc	IT	n/a	n/a	n/a	6.30	13.00	9.65	n/a
FedEx Corp	FDX	0.23%	2.09	0.00%	4.50	7.00	5.75	0.01%
FMC Corp	FMC	0.03%	4.13	0.00%	4.49	10.00	7.25	0.00%
Brown & Brown Inc	BRO	0.08%	0.67	0.00%	11.90	6.50	9.20	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[1] Estimated Weighted Average Dividend Yield	1.93%
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[3] S&P 500 Estimated Required Market Return	11.45%
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STANDARD AND POOR'S 500 INDEX

	Ticker	[6] % of Total Market Cap.	[7] Current Dividend Yield	[8] Cap. Weighted Div. Yield	[9] Yahoo! Finance Earnings Growth	[10] Value Line Earnings Growth	[11] Average Earnings Growth	[12] Cap. Weighted Long-Term Growth
Ford Motor Co	F	0.17%	5.12	0.01%	-7.81	43.00	17.60	0.03%
NextEra Energy Inc	NEE	0.44%	3.19	0.01%	7.81	9.50	8.66	0.04%
Franklin Resources Inc	BEN	0.05%	4.66	0.00%	10.33	2.00	6.17	0.00%
Garmin Ltd	GRMN	0.09%	2.44	0.00%	5.60	5.00	5.30	0.00%
Freeport-McMoRan Inc	FCX	0.21%	1.51	0.00%	-1.07	12.50	5.72	0.01%
Dexcom Inc	DXCM	n/a	n/a	n/a	30.25		30.25	n/a
General Dynamics Corp	GD	0.27%	1.99	0.01%	12.64	9.50	11.07	0.03%
General Mills Inc	GIS	0.14%	3.64	0.01%	7.21	5.50	6.36	0.01%
Genuine Parts Co	GPC	0.07%	2.71	0.00%	8.90	9.00	8.95	0.01%
Atmos Energy Corp	ATO	0.06%	2.83	0.00%	7.50	7.00	7.25	0.00%
WW Grainger Inc	GWW	0.17%	0.83	0.00%	27.95	11.50	19.73	0.03%
Halliburton Co	HAL	n/a	1.91	n/a	14.60	27.50	21.05	n/a
L3Harris Technologies Inc	LHX	0.15%	2.19	0.00%	1.14	16.00	8.57	0.01%
Healthpeak Properties Inc	PEAK	0.04%	6.49	0.00%	-13.30	14.50	0.60	0.00%
Insulet Corp	PODD	n/a	n/a	n/a	36.00		36.00	n/a
Catalent Inc	CTLT	n/a	n/a	n/a	29.37	21.00	25.19	n/a
Fortive Corp	FTV	0.10%	0.41	0.00%	8.60	16.00	12.30	0.01%
Hershey Co/The	HSY	0.11%	2.46	0.00%	7.27	9.50	8.39	0.01%
Synchrony Financial	SYF	n/a	2.57	n/a	-3.62	47.00	21.69	n/a
Hormel Foods Corp	HRL	0.06%	3.72	0.00%	8.20	7.50	7.85	0.00%
Arthur J Gallagher & Co	AJG	0.19%	1.03	0.00%	13.20	22.00	17.60	0.03%
Mondelez International Inc	MDLZ	0.38%	2.26	0.01%	8.70	11.00	9.85	0.04%
CenterPoint Energy Inc	CNP	0.07%	2.86	0.00%	-1.07	8.50	3.72	0.00%
Humana Inc	HUM	0.17%	0.94	0.00%	5.19	12.50	8.85	0.02%
Willis Towers Watson PLC	WTW	0.10%	1.36	0.00%	9.90	9.00	9.45	0.01%
Illinois Tool Works Inc	ITW	0.29%	2.15	0.01%	2.88	11.00	6.94	0.02%
CDW Corp/DE	CDW	0.11%	1.09	0.00%	7.90	7.00	7.45	0.01%
Trane Technologies PLC	TT	0.21%	1.19	0.00%	14.88	14.50	14.69	0.03%
Interpublic Group of Cos Inc/The	IPG	0.05%	3.76	0.00%	4.80	8.50	6.65	0.00%
International Flavors & Fragrances Inc	IFF	n/a	4.02	n/a	-6.18	2.50	-1.84	n/a
Generac Holdings Inc	GNRC	n/a	n/a	n/a	-1.44	11.00	4.78	n/a
NXP Semiconductors NV	NXPI	0.20%	1.93	0.00%	10.00	8.50	9.25	0.02%
Kellanova	K	0.07%	4.09	0.00%	-0.49	1.50	0.51	0.00%
Broadridge Financial Solutions Inc	BR	0.09%	1.57	0.00%	11.80	8.50	10.15	0.01%
Kimberly-Clark Corp	KMB	0.15%	4.03	0.01%	5.05	7.00	6.03	0.01%
Kimco Realty Corp	KIM	n/a	4.75	n/a	-23.27	11.00	-6.14	n/a
Oracle Corp	ORCL	1.15%	1.43	0.02%	10.67	10.00	10.34	0.12%
Kroger Co/The	KR	0.12%	2.51	0.00%	8.00	6.00	7.00	0.01%
Lennar Corp	LEN	0.14%	1.33	0.00%	0.60	4.50	2.55	0.00%
Eli Lilly & Co	LLY	n/a	0.81	n/a	26.86	19.00	22.93	n/a
Bath & Body Works Inc	BBWI	0.04%	1.88	0.00%	4.88	26.50	15.69	0.01%
Charter Communications Inc	CHTR	n/a	n/a	n/a	10.86	12.50	11.68	n/a
Loews Corp	L	0.06%	0.34	0.00%	14.03	24.50	19.27	0.01%
Lowe's Cos Inc	LOW	0.46%	2.07	0.01%	4.40	8.00	6.20	0.03%
Hubbell Inc	HUBB	0.07%	1.45	0.00%	19.50	10.00	14.75	0.01%
IDEX Corp	IEX	0.06%	1.21	0.00%	12.00	6.00	9.00	0.01%
Marsh & McLennan Cos Inc	MMC	0.36%	1.47	0.01%	6.50	9.00	7.75	0.03%
Masco Corp	MAS	0.06%	1.69	0.00%	4.49	6.00	5.25	0.00%
S&P Global Inc	SPGI	0.53%	0.81	0.00%	13.58	7.50	10.54	0.06%
Medtronic PLC	MDT	0.44%	3.15	0.01%	3.37	7.50	5.44	0.02%
Viatris Inc	VTRS	n/a	4.08	n/a	-2.50		-2.50	n/a
CVS Health Corp	CVS	0.36%	3.58	0.01%	2.34	8.50	5.42	0.02%
DuPont de Nemours Inc	DD	0.10%	2.33	0.00%	7.20	9.50	8.35	0.01%
Micron Technology Inc	MU	0.35%	0.54	0.00%	-2.62	22.00	9.69	0.03%
Motorola Solutions Inc	MSI	0.20%	1.23	0.00%	9.18	11.00	10.09	0.02%
Cboe Global Markets Inc	CBOE	0.07%	1.20	0.00%	9.91	13.00	11.46	0.01%
Laboratory Corp of America Holdings	LH	n/a	1.30	n/a	-3.18	-3.00	-3.09	n/a
Newmont Corp	NEM	0.15%	4.64	0.01%		8.00	8.00	0.01%

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STANDARD AND POOR'S 500 INDEX

		[6]	[7]	[8]	[9]	[10]	[11]	[12]
	Ticker	% of Total Market Cap.	Current Dividend Yield	Cap. Weighted Div. Yield	Yahoo! Finance Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Cap. Weighted Long-Term Growth
NIKE Inc	NKE	0.46%	1.46	0.01%	14.17	17.00	15.59	0.07%
NiSource Inc	NI	0.04%	4.08	0.00%	8.30	9.50	8.90	0.00%
Norfolk Southern Corp	NSC	0.20%	2.30	0.00%	2.23	8.50	5.37	0.01%
Principal Financial Group Inc	PFG	0.07%	3.39	0.00%	9.10	5.50	7.30	0.01%
Eversource Energy	ES	0.07%	5.27	0.00%	3.60	6.00	4.80	0.00%
Northrop Grumman Corp	NOC	0.25%	1.67	0.00%	29.91	8.50	19.21	0.05%
Wells Fargo & Co	WFC	0.68%	2.79	0.02%	6.67	10.50	8.59	0.06%
Nucor Corp	NUE	n/a	1.16	n/a	-7.50	2.00	-2.75	n/a
Occidental Petroleum Corp	OXY	n/a	1.25	n/a	-17.90	17.00	-0.45	n/a
Omnicom Group Inc	OMC	0.07%	3.10	0.00%	9.10	7.00	8.05	0.01%
ONEOK Inc	OKE	0.15%	5.80	0.01%	11.60	12.00	11.80	0.02%
Raymond James Financial Inc	RJF	0.09%	1.63	0.00%	13.90	12.50	13.20	0.01%
PG&E Corp	PCG	0.13%	0.24	0.00%	10.50	8.50	9.50	0.01%
Parker-Hannifin Corp	PH	0.22%	1.27	0.00%	10.38	12.50	11.44	0.03%
Rollins Inc	ROL	0.08%	1.39	0.00%	14.70	10.50	12.60	0.01%
PPL Corp	PPL	0.07%	3.66	0.00%	17.21	8.00	12.61	0.01%
ConocoPhillips	COP	n/a	0.52	n/a	-10.12	9.00	-0.56	n/a
PulteGroup Inc	PHM	0.08%	0.77	0.00%	5.30	8.50	6.90	0.01%
Pinnacle West Capital Corp	PNW	0.03%	5.11	0.00%	5.90	2.50	4.20	0.00%
PNC Financial Services Group Inc/The	PNC	0.22%	4.10	0.01%	10.96	6.50	8.73	0.02%
PPG Industries Inc	PPG	0.12%	1.84	0.00%	10.42	3.00	6.71	0.01%
Progressive Corp/The	PGR	0.39%	0.22	0.00%	26.00	12.00	19.00	0.07%
Veralto Corp	VLTO	n/a	0.47	n/a				n/a
Public Service Enterprise Group Inc	PEG	0.11%	3.93	0.00%	4.60	4.00	4.30	0.00%
Robert Half Inc	RHI	0.03%	2.41	0.00%	-1.30	7.00	2.85	0.00%
Cooper Cos Inc/The	COO	n/a	n/a	n/a	10.00	12.00	11.00	n/a
Edison International	EIX	0.10%	4.62	0.00%	4.60	4.50	4.55	0.00%
Schlumberger NV	SLB	n/a	2.26	n/a	19.70	26.00	22.85	n/a
Charles Schwab Corp/The	SCHW	0.42%	1.59	0.01%	5.08	10.00	7.54	0.03%
Sherwin-Williams Co/The	SHW	0.29%	0.80	0.00%	11.37	7.00	9.19	0.03%
West Pharmaceutical Services Inc	WST	0.10%	0.21	0.00%	4.19	17.00	10.60	0.01%
J M Smucker Co/The	SJM	0.05%	3.22	0.00%	6.53	5.50	6.02	0.00%
Snap-on Inc	SNA	0.06%	2.57	0.00%	4.60	7.50	6.05	0.00%
AMETEK Inc	AME	0.14%	0.62	0.00%	10.00	13.00	11.50	0.02%
Uber Technologies Inc	UBER	n/a	n/a	n/a	23.17		23.17	n/a
Southern Co/The	SO	0.28%	4.03	0.01%	7.10	6.50	6.80	0.02%
Truist Financial Corp	TFC	0.18%	5.61	0.01%	16.00	6.00	11.00	0.02%
Southwest Airlines Co	LUV	n/a	2.41	n/a	25.99		25.99	n/a
W R Berkley Corp	WRB	0.08%	0.54	0.00%	9.00	15.00	12.00	0.01%
Stanley Black & Decker Inc	SWK	0.05%	3.47	0.00%	13.91	3.50	8.71	0.00%
Public Storage	PSA	n/a	4.24	n/a	-20.02	7.50	-6.26	n/a
Arista Networks Inc	ANET	n/a	n/a	n/a	19.40	17.00	18.20	n/a
Sysco Corp	SYY	0.15%	2.47	0.00%	12.25	16.00	14.13	0.02%
Corteva Inc	CTVA	0.12%	1.41	0.00%	10.01	13.50	11.76	0.01%
Texas Instruments Inc	TXN	0.54%	3.25	0.02%	10.00	3.50	6.75	0.04%
Textron Inc	TXT	0.06%	0.09	0.00%	17.50	16.00	16.75	0.01%
Thermo Fisher Scientific Inc	TMO	0.78%	0.26	0.00%	4.25	9.50	6.88	0.05%
TJX Cos Inc/The	TJX	0.40%	1.40	0.01%	13.39	17.00	15.20	0.06%
Globe Life Inc	GL	0.04%	0.73	0.00%	14.89	9.00	11.95	0.01%
Johnson Controls International plc	JCI	0.13%	2.81	0.00%	11.85	11.00	11.43	0.02%
Ulta Beauty Inc	ULTA	n/a	n/a	n/a	6.57	13.50	10.04	n/a
Union Pacific Corp	UNP	0.56%	2.13	0.01%	9.86	7.50	8.68	0.05%
Keysight Technologies Inc	KEYS	n/a	n/a	n/a	4.32	13.00	8.66	n/a
UnitedHealth Group Inc	UNH	1.77%	1.47	0.03%	12.66	12.00	12.33	0.22%
Blackstone Inc	BX	0.33%	3.02	0.01%	12.25	15.00	13.63	0.05%
Marathon Oil Corp	MRO	0.05%	1.93	0.00%	-8.79	25.50	8.36	0.00%
Bio-Rad Laboratories Inc	BIO	n/a	n/a	n/a	17.80	11.50	14.65	n/a
Ventas Inc	VTR	0.07%	3.88	0.00%	-19.70	23.00	1.65	0.00%

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STANDARD AND POOR'S 500 INDEX

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	Ticker	% of Total Market Cap.	Current Dividend Yield	Cap. Weighted Div. Yield	Yahoo! Finance Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Cap. Weighted Long-Term Growth
VF Corp	VFC	0.02%	2.19	0.00%	0.65	9.00	4.83	0.00%
Vulcan Materials Co	VMC	0.11%	0.76	0.00%	20.80	9.50	15.15	0.02%
Weyerhaeuser Co	WY	0.09%	0.43	0.00%	5.00	-2.00	1.50	0.00%
Whirlpool Corp	WHR	n/a	6.39	n/a	-11.67	-1.00	-6.34	n/a
Williams Cos Inc/The	WMB	0.16%	5.48	0.01%	2.00	10.50	6.25	0.01%
Constellation Energy Corp	CEG	n/a	0.92	n/a	26.30		26.30	n/a
WEC Energy Group Inc	WEC	0.10%	4.14	0.00%	5.45	6.00	5.73	0.01%
Adobe Inc	ADBE	n/a	n/a	n/a	14.32	14.50	14.41	n/a
AES Corp/The	AES	0.04%	4.14	0.00%	7.50	14.00	10.75	0.00%
Expeditors International of Washington Inc	EXPD	n/a	1.09	n/a	-16.80	10.00	-3.40	n/a
Amgen Inc	AMGN	0.63%	2.86	0.02%	5.38	5.50	5.44	0.03%
Apple Inc	AAPL	10.66%	0.52	0.06%	11.00	8.50	9.75	1.04%
Autodesk Inc	ADSK	n/a	n/a	n/a	12.44	10.00	11.22	n/a
Cintas Corp	CTAS	0.23%	0.89	0.00%	12.17	14.00	13.09	0.03%
Comcast Corp	CMCSA	0.69%	2.66	0.02%	9.78	9.00	9.39	0.06%
Molson Coors Beverage Co	TAP	n/a	2.65	n/a	12.98	42.00	27.49	n/a
KLA Corp	KLAC	0.30%	0.98	0.00%	6.02	13.50	9.76	0.03%
Marriott International Inc/MD	MAR	0.26%	0.87	0.00%	17.50	17.50	17.50	0.05%
Fiserv Inc	FI	n/a	n/a	n/a	15.00	9.50	12.25	n/a
McCormick & Co Inc/MD	MKC	0.06%	2.46	0.00%	6.70	4.50	5.60	0.00%
PACCAR Inc	PCAR	0.20%	1.08	0.00%	6.76	5.00	5.88	0.01%
Costco Wholesale Corp	COST	1.15%	0.59	0.01%	8.76	10.50	9.63	0.11%
Stryker Corp	SYK	0.48%	0.95	0.00%	11.02	8.50	9.76	0.05%
Tyson Foods Inc	TSN	n/a	3.58	n/a	-24.20	6.00	-9.10	n/a
Lamb Weston Holdings Inc	LW	0.06%	1.41	0.00%	16.80	12.00	14.40	0.01%
Applied Materials Inc	AMAT	0.51%	0.78	0.00%	14.97	4.00	9.49	0.05%
American Airlines Group Inc	AAL	n/a	n/a	n/a	48.69		48.69	n/a
Cardinal Health Inc	CAH	0.10%	1.83	0.00%	16.31	7.50	11.91	0.01%
Cincinnati Financial Corp	CINF	0.06%	2.92	0.00%	18.20	13.00	15.60	0.01%
Paramount Global	PARA	n/a	1.37	n/a	-8.10	-2.50	-5.30	n/a
DR Horton Inc	DHI	0.18%	0.84	0.00%	5.88	3.00	4.44	0.01%
Electronic Arts Inc	EA	0.14%	0.55	0.00%	11.10	17.50	14.30	0.02%
Fair Isaac Corp	FICO	n/a	n/a	n/a	22.53	19.50	21.02	n/a
Fastenal Co	FAST	0.15%	2.29	0.00%	6.33	6.50	6.42	0.01%
M&T Bank Corp	MTB	n/a	3.77	n/a				n/a
Xcel Energy Inc	XEL	0.12%	3.47	0.00%	6.57	6.00	6.29	0.01%
Fifth Third Bancorp	FITB	0.09%	4.09	0.00%	4.84	4.00	4.42	0.00%
Gilead Sciences Inc	GILD	0.36%	3.83	0.01%	4.12	13.50	8.81	0.03%
Hasbro Inc	HAS	0.03%	5.72	0.00%	0.27	8.50	4.39	0.00%
Huntington Bancshares Inc/OH	HBAN	0.07%	4.87	0.00%	-2.15	10.50	4.18	0.00%
Welltower Inc	WELL	n/a	2.82	n/a	-32.93	12.00	-10.47	n/a
Biogen Inc	BIIB	n/a	n/a	n/a	0.15	-6.50	-3.18	n/a
Northern Trust Corp	NTRS	0.06%	3.77	0.00%	3.30	3.00	3.15	0.00%
Packaging Corp of America	PKG	n/a	3.01	n/a	-14.29	9.00	-2.65	n/a
Paychex Inc	PAYX	0.16%	2.92	0.00%	8.51	10.00	9.26	0.02%
QUALCOMM Inc	QCOM	0.62%	2.15	0.01%	6.46	5.50	5.98	0.04%
Ross Stores Inc	ROST	0.18%	0.96	0.00%	11.95	14.00	12.98	0.02%
IDEXX Laboratories Inc	IDXX	n/a	n/a	n/a	16.40	10.50	13.45	n/a
Starbucks Corp	SBUX	0.39%	2.45	0.01%	16.03	16.00	16.02	0.06%
KeyCorp	KEY	n/a	5.64	n/a	-5.80		-5.80	n/a
Fox Corp	FOXA	0.03%	1.61	0.00%	0.80	8.00	4.40	0.00%
Fox Corp	FOX	n/a	1.73	n/a				n/a
State Street Corp	STT	0.08%	3.74	0.00%	5.56		5.56	0.00%
Norwegian Cruise Line Holdings Ltd	NCLH	n/a	n/a	n/a	-745.30		-745.30	n/a
US Bancorp	USB	0.24%	4.72	0.01%	6.00	4.00	5.00	0.01%
A O Smith Corp	AOS	0.04%	1.65	0.00%	8.00	11.50	9.75	0.00%
Gen Digital Inc	GEN	0.06%	2.13	0.00%	12.55	10.50	11.53	0.01%
T Rowe Price Group Inc	TROW	0.09%	4.57	0.00%	0.70	1.50	1.10	0.00%

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STANDARD AND POOR'S 500 INDEX

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	Ticker	% of Total Market Cap.	Current Dividend Yield	Cap. Weighted Div. Yield	Yahoo! Finance Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Cap. Weighted Long-Term Growth
Waste Management Inc	WM	0.28%	1.51	0.00%	10.00	6.50	8.25	0.02%
Constellation Brands Inc	STZ	0.17%	1.45	0.00%	11.40	6.50	8.95	0.01%
DENTSPLY SIRONA Inc	XRAY	0.03%	1.61	0.00%	8.00	12.00	10.00	0.00%
Zions Bancorp NA	ZION	0.02%	3.91	0.00%	4.83	2.50	3.67	0.00%
Invesco Ltd	IVZ	0.03%	5.05	0.00%	6.89	3.00	4.95	0.00%
Intuit Inc	INTU	0.66%	0.57	0.00%	14.78	14.50	14.64	0.10%
Morgan Stanley	MS	0.54%	3.90	0.02%	8.00	7.50	7.75	0.04%
Microchip Technology Inc	MCHP	0.17%	2.06	0.00%	12.10	10.00	11.05	0.02%
Chubb Ltd	CB	0.37%	1.40	0.01%	17.70	17.00	17.35	0.06%
Hologic Inc	HOLX	n/a	n/a	n/a	10.00	-3.50	3.25	n/a
Citizens Financial Group Inc	CFG	0.06%	5.14	0.00%	0.85	4.50	2.68	0.00%
Jabil Inc	JBL	0.06%	0.26	0.00%	12.00	16.00	14.00	0.01%
O'Reilly Automotive Inc	ORLY	n/a	n/a	n/a	12.20	11.00	11.60	n/a
Allstate Corp/The	ALL	n/a	2.29	n/a	107.60	10.50	59.05	n/a
Equity Residential	EQR	n/a	4.40	n/a	-1.06	-5.00	-3.03	n/a
BorgWarner Inc	BWA	0.03%	1.30	0.00%	11.00	6.50	8.75	0.00%
Keurig Dr Pepper Inc	KDP	0.16%	2.74	0.00%	6.91	12.50	9.71	0.02%
Host Hotels & Resorts Inc	HST	n/a	4.16	n/a	28.40	51.00	39.70	n/a
Incyte Corp	INCY	n/a	n/a	n/a	23.00	32.00	27.50	n/a
Simon Property Group Inc	SPG	0.17%	5.48	0.01%	8.60	3.50	6.05	0.01%
Eastman Chemical Co	EMN	0.04%	3.88	0.00%	4.83	6.00	5.42	0.00%
AvalonBay Communities Inc	AVB	n/a	3.80	n/a	-11.27	6.00	-2.64	n/a
Prudential Financial Inc	PRU	0.14%	4.77	0.01%	10.60	3.00	6.80	0.01%
United Parcel Service Inc	UPS	n/a	4.59	n/a	-6.35	5.50	-0.43	n/a
Walgreens Boots Alliance Inc	WBA	n/a	4.43	n/a	-4.77	-1.50	-3.14	n/a
STERIS PLC	STE	0.08%	0.95	0.00%	10.00	10.00	10.00	0.01%
McKesson Corp	MCK	0.25%	0.50	0.00%	9.77	9.00	9.39	0.02%
Lockheed Martin Corp	LMT	0.39%	2.93	0.01%	6.83	7.00	6.92	0.03%
Cencora Inc	COR	0.17%	0.88	0.00%	10.07	9.00	9.54	0.02%
Capital One Financial Corp	COF	0.19%	1.77	0.00%	-0.97	4.00	1.52	0.00%
Waters Corp	WAT	n/a	n/a	n/a	3.84	10.00	6.92	n/a
Nordson Corp	NDSN	0.05%	1.08	0.00%	13.00	9.50	11.25	0.01%
Dollar Tree Inc	DLTR	n/a	n/a	n/a	2.40	9.00	5.70	n/a
Darden Restaurants Inc	DRI	0.07%	3.22	0.00%	9.95	15.00	12.48	0.01%
Evergy Inc	EVRG	0.04%	5.06	0.00%	2.50	7.50	5.00	0.00%
Match Group Inc	MTCH	n/a	n/a	n/a	26.13	13.50	19.82	n/a
Domino's Pizza Inc	DPZ	0.06%	1.14	0.00%	12.25	11.50	11.88	0.01%
NVR Inc	NVR	n/a	n/a	n/a	-3.66	3.50	-0.08	n/a
NetApp Inc	NTAP	0.07%	2.29	0.00%	6.70	8.00	7.35	0.00%
Old Dominion Freight Line Inc	ODFL	0.16%	0.53	0.00%	8.25	9.00	8.63	0.01%
DaVita Inc	DVA	n/a	n/a	n/a	18.27	8.00	13.14	n/a
Hartford Financial Services Group Inc/The	HIG	0.10%	2.16	0.00%	10.50	8.00	9.25	0.01%
Iron Mountain Inc	IRM	0.07%	3.85	0.00%	4.70	4.00	4.35	0.00%
Estee Lauder Cos Inc/The	EL	0.11%	2.00	0.00%	19.37	8.00	13.69	0.02%
Cadence Design Systems Inc	CDNS	n/a	n/a	n/a	18.00	12.00	15.00	n/a
Tyler Technologies Inc	TYL	n/a	n/a	n/a	10.60	10.00	10.30	n/a
Universal Health Services Inc	UHS	0.04%	0.50	0.00%	13.22	6.00	9.61	0.00%
Skyworks Solutions Inc	SWKS	0.06%	2.60	0.00%	15.00		15.00	0.01%
Quest Diagnostics Inc	DGX	0.05%	2.21	0.00%	-0.57	2.50	0.97	0.00%
Rockwell Automation Inc	ROK	0.11%	1.97	0.00%	8.06	9.50	8.78	0.01%
Kraft Heinz Co/The	KHC	0.17%	4.31	0.01%	5.12	5.00	5.06	0.01%
American Tower Corp	AMT	0.34%	3.48	0.01%	5.68	5.00	5.34	0.02%
Regeneron Pharmaceuticals Inc	REGN	n/a	n/a	n/a	2.20		2.20	n/a
Amazon.com Inc	AMZN	n/a	n/a	n/a	87.00	19.50	53.25	n/a
Jack Henry & Associates Inc	JKHY	0.05%	1.25	0.00%	7.10	6.50	6.80	0.00%
Ralph Lauren Corp	RL	0.02%	2.09	0.00%	12.52	13.00	12.76	0.00%
Boston Properties Inc	BXP	n/a	5.89	n/a	-50.84	-1.00	-25.92	n/a
Amphenol Corp	APH	0.23%	0.87	0.00%	4.00	12.50	8.25	0.02%

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	Ticker	% of Total Market Cap.	Current Dividend Yield	Cap. Weighted Div. Yield	Yahoo! Finance Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Cap. Weighted Long-Term Growth
Howmet Aerospace Inc	HWM	0.09%	0.36	0.00%	21.39	12.00	16.70	0.01%
Pioneer Natural Resources Co	PXD	0.20%	5.57	0.01%	-4.00	8.50	2.25	0.00%
Valero Energy Corp	VLO	n/a	3.08	n/a	-17.40	9.50	-3.95	n/a
Synopsys Inc	SNPS	n/a	n/a	n/a	18.06	12.50	15.28	n/a
Etsy Inc	ETSY	n/a	n/a	n/a	16.00	2.00	9.00	n/a
CH Robinson Worldwide Inc	CHRW	n/a	2.90	n/a	-16.33	5.50	-5.42	n/a
Accenture PLC	ACN	0.91%	1.42	0.01%	7.70	12.50	10.10	0.09%
TransDigm Group Inc	TDG	n/a	n/a	n/a	16.50	33.00	24.75	n/a
Yum! Brands Inc	YUM	0.14%	2.07	0.00%	13.74	11.50	12.62	0.02%
Prologis Inc	PLD	n/a	2.75	n/a	-6.05	2.50	-1.78	n/a
FirstEnergy Corp	FE	0.08%	4.47	0.00%	6.30	4.50	5.40	0.00%
VeriSign Inc	VRSN	n/a	n/a	n/a	8.00	13.00	10.50	n/a
Quanta Services Inc	PWR	0.11%	0.19	0.00%	17.22	15.00	16.11	0.02%
Henry Schein Inc	HSIC	n/a	n/a	n/a	8.50	9.00	8.75	n/a
Ameren Corp	AEE	0.07%	3.62	0.00%	4.80	6.50	5.65	0.00%
ANSYS Inc	ANSS	n/a	n/a	n/a	9.35	8.50	8.93	n/a
FactSet Research Systems Inc	FDS	0.07%	0.82	0.00%	10.45	10.50	10.48	0.01%
NVIDIA Corp	NVDA	n/a	0.03	n/a	102.45	40.00	71.23	n/a
Cognizant Technology Solutions Corp	CTSH	0.14%	1.50	0.00%	4.39	8.00	6.20	0.01%
Intuitive Surgical Inc	ISRG	n/a	n/a	n/a	12.36	12.50	12.43	n/a
Take-Two Interactive Software Inc	TTWO	n/a	n/a	n/a	52.00		52.00	n/a
Republic Services Inc	RSG	0.20%	1.25	0.00%	8.89	12.50	10.70	0.02%
eBay Inc	EBAY	0.08%	2.43	0.00%	7.29	7.00	7.15	0.01%
Goldman Sachs Group Inc/The	GS	0.47%	2.86	0.01%	9.85	1.50	5.68	0.03%
SBA Communications Corp	SBAC	0.09%	1.52	0.00%	15.31	22.00	18.66	0.02%
Sempra	SRE	0.17%	3.33	0.01%	4.14	6.50	5.32	0.01%
Moody's Corp	MCO	0.27%	0.79	0.00%	13.53	6.00	9.77	0.03%
ON Semiconductor Corp	ON	n/a	n/a	n/a	4.61	14.50	9.56	n/a
Booking Holdings Inc	BKNG	n/a	n/a	n/a	28.39	22.00	25.20	n/a
F5 Inc	FFIV	n/a	n/a	n/a	9.40	10.00	9.70	n/a
Akamai Technologies Inc	AKAM	n/a	n/a	n/a	7.90	5.00	6.45	n/a
Charles River Laboratories International Inc	CRL	n/a	n/a	n/a	3.77	8.00	5.89	n/a
MarketAxess Holdings Inc	MKTX	0.03%	1.31	0.00%	9.28	8.50	8.89	0.00%
Devon Energy Corp	DVN	0.10%	7.33	0.01%	-2.94	10.50	3.78	0.00%
Alphabet Inc	GOOGL	n/a	n/a	n/a	19.25		19.25	n/a
Bio-Techne Corp	TECH	0.04%	0.46	0.00%	9.50	13.00	11.25	0.00%
Teleflex Inc	TFX	0.04%	0.56	0.00%	10.40	10.00	10.20	0.00%
Allegion plc	ALLE	0.04%	1.45	0.00%	10.60	10.00	10.30	0.00%
Netflix Inc	NFLX	n/a	n/a	n/a	24.67	13.00	18.84	n/a
Warner Bros Discovery Inc	WBD	n/a	n/a	n/a	20.00		20.00	n/a
Agilent Technologies Inc	A	0.14%	0.73	0.00%	7.70	13.50	10.60	0.02%
Trimble Inc	TRMB	n/a	n/a	n/a	10.00	5.50	7.75	n/a
Elevance Health Inc	ELV	0.43%	1.32	0.01%	11.81	12.50	12.16	0.05%
CME Group Inc	CME	0.28%	2.14	0.01%	8.17	7.50	7.84	0.02%
Juniper Networks Inc	JNPR	0.04%	2.38	0.00%	11.00	10.50	10.75	0.00%
BlackRock Inc	BLK	0.43%	2.63	0.01%	10.04	7.50	8.77	0.04%
DTE Energy Co	DTE	0.08%	3.87	0.00%	5.10	4.50	4.80	0.00%
Celanese Corp	CE	0.06%	1.91	0.00%	-3.58	4.50	0.46	0.00%
Nasdaq Inc	NDAQ	0.12%	1.52	0.00%	4.13	7.00	5.57	0.01%
Philip Morris International Inc	PM	0.53%	5.72	0.03%	5.89	5.00	5.45	0.03%
Ingersoll Rand Inc	IR	0.12%	0.10	0.00%	14.04	12.50	13.27	0.02%
Salesforce Inc	CRM	n/a	n/a	n/a	26.77	18.00	22.39	n/a
Roper Technologies Inc	ROP	0.21%	0.56	0.00%	10.30	8.50	9.40	0.02%
Huntington Ingalls Industries Inc	HII	0.04%	2.01	0.00%	7.84	10.00	8.92	0.00%
MetLife Inc	MET	0.19%	3.00	0.01%	11.50	7.50	9.50	0.02%
Tapestry Inc	TPR	0.03%	3.61	0.00%	11.00	16.50	13.75	0.00%
CSX Corp	CSX	0.26%	1.23	0.00%	9.83	8.00	8.92	0.02%
Edwards Lifesciences Corp	EW	n/a	n/a	n/a	7.98	10.50	9.24	n/a

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	Ticker	% of Total Market Cap.	Current Dividend Yield	Cap. Weighted Div. Yield	Yahoo! Finance Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Cap. Weighted Long-Term Growth
Ameriprise Financial Inc	AMP	0.15%	1.40	0.00%	17.60	11.00	14.30	0.02%
Zebra Technologies Corp	ZBRA	n/a	n/a	n/a	4.62	-2.50	1.06	n/a
Zimmer Biomet Holdings Inc	ZBH	0.10%	0.76	0.00%	6.93	6.50	6.72	0.01%
Camden Property Trust	CPT	n/a	4.26	n/a	-36.40	-3.00	-19.70	n/a
CBRE Group Inc	CBRE	n/a	n/a	n/a	11.00	8.50	9.75	n/a
Mastercard Inc	MA	1.56%	0.59	0.01%	19.21	16.00	17.61	0.28%
CarMax Inc	KMX	n/a	n/a	n/a	6.30	-3.50	1.40	n/a
Intercontinental Exchange Inc	ICE	0.27%	1.32	0.00%	7.79	6.50	7.15	0.02%
Fidelity National Information Services Inc	FIS	0.14%	3.34	0.00%	2.00		2.00	0.00%
Chipotle Mexican Grill Inc	CMG	n/a	n/a	n/a	26.06	21.50	23.78	n/a
Wynn Resorts Ltd	WYNN	n/a	1.06	n/a	154.60	27.00	90.80	n/a
Live Nation Entertainment Inc	LYV	n/a	n/a	n/a	80.30		80.30	n/a
Assurant Inc	AIZ	0.03%	1.71	0.00%	11.70	10.50	11.10	0.00%
NRG Energy Inc	NRG	0.04%	3.07	0.00%	4.00	-2.50	0.75	0.00%
Monster Beverage Corp	MNST	n/a	n/a	n/a	22.81	13.00	17.91	n/a
Regions Financial Corp	RF	0.06%	5.14	0.00%	-0.88	9.00	4.06	0.00%
Baker Hughes Co	BKR	n/a	2.81	n/a	30.20		30.20	n/a
Mosaic Co/The	MOS	n/a	2.74	n/a	-39.50	-3.00	-21.25	n/a
Expedia Group Inc	EXPE	n/a	n/a	n/a	24.70		24.70	n/a
CF Industries Holdings Inc	CF	n/a	2.65	n/a	-25.80	7.50	-9.15	n/a
APA Corp	APA	0.04%	3.19	0.00%	-10.40	19.50	4.55	0.00%
Leidos Holdings Inc	LDOS	0.06%	1.38	0.00%	8.40	6.00	7.20	0.00%
Alphabet Inc	GOOG	n/a	n/a	n/a	19.25	13.00	16.13	n/a
First Solar Inc	FSLR	n/a	n/a	n/a	67.40	27.50	47.45	n/a
TE Connectivity Ltd	TEL	0.16%	1.66	0.00%	11.00	10.50	10.75	0.02%
Discover Financial Services	DFS	n/a	2.65	n/a	-7.29	4.00	-1.65	n/a
Visa Inc	V	1.62%	0.76	0.01%	13.28	13.50	13.39	0.22%
Mid-America Apartment Communities Inc	MAA	n/a	4.65	n/a	-4.43	-12.50	-8.47	n/a
Xylem Inc/NY	XYL	0.10%	1.17	0.00%	18.76	15.50	17.13	0.02%
Marathon Petroleum Corp	MPC	0.24%	1.99	0.00%	-9.85	14.50	2.33	0.01%
Tractor Supply Co	TSCO	0.09%	1.83	0.00%	5.40	11.50	8.45	0.01%
Advanced Micro Devices Inc	AMD	n/a	n/a	n/a	24.95	25.50	25.23	n/a
ResMed Inc	RMD	0.10%	1.01	0.00%	11.60	9.50	10.55	0.01%
Mettler-Toledo International Inc	MTD	n/a	n/a	n/a	6.00	11.00	8.50	n/a
VICI Properties Inc	VICI	0.12%	5.51	0.01%	6.30	8.00	7.15	0.01%
Copart Inc	CPRT	n/a	n/a	n/a	22.30	7.00	14.65	n/a
Jacobs Solutions Inc	J	0.06%	0.86	0.00%	11.80	10.00	10.90	0.01%
Albemarle Corp	ALB	n/a	1.39	n/a	-8.76	-4.50	-6.63	n/a
Fortinet Inc	FTNT	n/a	n/a	n/a	16.06	24.00	20.03	n/a
Moderna Inc	MRNA	n/a	n/a	n/a	-55.10	-20.00	-37.55	n/a
Essex Property Trust Inc	ESS	0.06%	3.96	0.00%	-0.39	1.50	0.56	0.00%
CoStar Group Inc	CSGP	n/a	n/a	n/a	20.00	14.00	17.00	n/a
Realty Income Corp	O	0.17%	5.66	0.01%	22.62	5.50	14.06	0.02%
Westrock Co	WRK	n/a	3.01	n/a	-18.40	10.00	-4.20	n/a
Westinghouse Air Brake Technologies Corp	WAB	0.09%	0.52	0.00%	13.80	10.50	12.15	0.01%
Pool Corp	POOL	0.05%	1.19	0.00%	-8.75	14.00	2.63	0.00%
Western Digital Corp	WDC	n/a	n/a	n/a	-26.80	13.00	-6.90	n/a
PepsiCo Inc	PEP	0.87%	3.00	0.03%	8.60	7.50	8.05	0.07%
Diamondback Energy Inc	FANG	0.10%	8.77	0.01%	2.00		2.00	0.00%
Palo Alto Networks Inc	PANW	n/a	n/a	n/a	22.49		22.49	n/a
ServiceNow Inc	NOW	n/a	n/a	n/a	22.84	61.00	41.92	n/a
Church & Dwight Co Inc	CHD	0.09%	1.09	0.00%	6.70	6.00	6.35	0.01%
Federal Realty Investment Trust	FRT	n/a	4.29	n/a	-10.85	2.50	-4.18	n/a
MGM Resorts International	MGM	n/a	n/a	n/a	-250.50	25.00	-112.75	n/a
American Electric Power Co Inc	AEP	0.15%	4.50	0.01%	4.20	6.50	5.35	0.01%
Invitation Homes Inc	INVH	0.08%	3.40	0.00%	13.04		13.04	0.01%
PTC Inc	PTC	n/a	n/a	n/a	16.74	29.00	22.87	n/a
JB Hunt Transport Services Inc	JBHT	0.08%	0.86	0.00%	4.50	9.00	6.75	0.01%

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

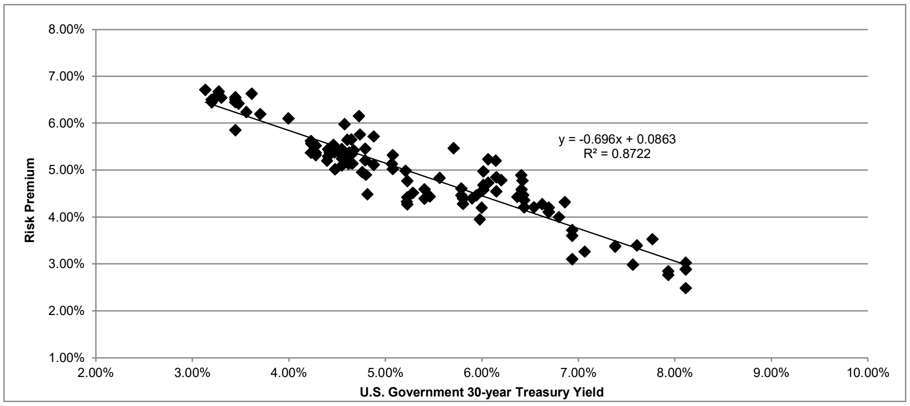
[1] Estimated Weighted Average Dividend Yield	1.93%
[2] Estimated Weighted Average Long-Term Growth Rate	9.43%
[3] S&P 500 Estimated Required Market Return	11.45%
[4] Risk-Free Rate	4.47%
[5] Implied Market Risk Premium	6.98%

STANDARD AND POOR'S 500 INDEX

		[6]	[7]	[8]	[9]	[10]	[11]	[12]
	Ticker	% of Total Market Cap.	Current Dividend Yield	Cap. Weighted Div. Yield	Yahoo! Finance Earnings Growth	Value Line Earnings Growth	Average Earnings Growth	Cap. Weighted Long-Term Growth
Lam Research Corp	LRCX	0.40%	0.97	0.00%	7.64	9.00	8.32	0.03%
Mohawk Industries Inc	MHK	n/a	n/a	n/a	-5.21	2.50	-1.36	n/a
GE HealthCare Technologies Inc	GEHC	n/a	0.16	n/a				n/a
Pentair PLC	PNR	0.05%	1.26	0.00%	11.15	12.00	11.58	0.01%
Vertex Pharmaceuticals Inc	VRTX	n/a	n/a	n/a	11.87	10.00	10.94	n/a
Amcor PLC	AMCR	0.05%	5.30	0.00%	5.40	11.50	8.45	0.00%
Meta Platforms Inc	META	n/a	n/a	n/a	32.00	17.00	24.50	n/a
T-Mobile US Inc	TMUS	n/a	1.61	n/a	26.91	20.00	23.46	n/a
United Rentals Inc	URI	0.16%	1.04	0.00%	16.70	17.00	16.85	0.03%
Alexandria Real Estate Equities Inc	ARE	0.08%	4.20	0.00%	-5.92	10.00	2.04	0.00%
Honeywell International Inc	HON	0.50%	2.14	0.01%	7.58	10.50	9.04	0.05%
Delta Air Lines Inc	DAL	n/a	1.02	n/a	20.12		20.12	n/a
United Airlines Holdings Inc	UAL	n/a	n/a	n/a	42.79		42.79	n/a
Seagate Technology Holdings PLC	STX	n/a	3.27	n/a	213.07	15.00	114.04	n/a
News Corp	NWS	n/a	0.78	n/a				n/a
Centene Corp	CNC	n/a	n/a	n/a	11.71	10.00	10.86	n/a
Martin Marietta Materials Inc	MLM	0.12%	0.58	0.00%	20.70	12.50	16.60	0.02%
Teradyne Inc	TER	0.06%	0.50	0.00%	7.68	12.50	10.09	0.01%
PayPal Holdings Inc	PYPL	n/a	n/a	n/a	18.20	12.00	15.10	n/a
Tesla Inc	TSLA	n/a	n/a	n/a	9.05	28.00	18.53	n/a
Arch Capital Group Ltd	ACGL	n/a	n/a	n/a	19.70	26.00	22.85	n/a
Dow Inc	DOW	0.14%	5.22	0.01%	29.52	3.00	16.26	0.02%
Everest Group Ltd	EG	0.06%	1.82	0.00%	29.00	10.00	19.50	0.01%
Teledyne Technologies Inc	TDY	n/a	n/a	n/a	6.04	9.50	7.77	n/a
News Corp	NWSA	0.04%	0.81	0.00%	-2.38	19.00	8.31	0.00%
Exelon Corp	EXC	0.13%	4.14	0.01%	4.20		4.20	0.01%
Global Payments Inc	GPN	0.13%	0.75	0.00%	14.90	13.50	14.20	0.02%
Crown Castle Inc	CCI	n/a	5.78	n/a	-10.87	7.00	-1.94	n/a
Aptiv PLC	APTV	n/a	n/a	n/a	28.15	33.50	30.83	n/a
Align Technology Inc	ALGN	n/a	n/a	n/a	43.25	17.00	30.13	n/a
Illumina Inc	ILMN	n/a	n/a	n/a	3.30	6.50	4.90	n/a
Kenvue Inc	KVUE	0.15%	3.85	0.01%	1.48		1.48	0.00%
Targa Resources Corp	TRGP	n/a	2.35	n/a	21.30		21.30	n/a
Bunge Global SA	BG	n/a	3.01	n/a	-8.60	1.50	-3.55	n/a
LKQ Corp	LKQ	n/a	2.57	n/a	33.50	7.00	20.25	n/a
Zoetis Inc	ZTS	0.32%	0.92	0.00%	10.45	9.00	9.73	0.03%
Equinix Inc	EQIX	0.29%	2.05	0.01%	24.30	15.00	19.65	0.06%
Digital Realty Trust Inc	DLR	n/a	3.47	n/a	-7.84	-3.00	-5.42	n/a
Molina Healthcare Inc	MOH	n/a	n/a	n/a	15.58	11.50	13.54	n/a
Las Vegas Sands Corp	LVS	0.14%	1.64	0.00%	7.00		7.00	0.01%

Notes:
[1] Equals sum of col. [8]
[2] Equals sum of col. [11]
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]
[4] Source: Bloomberg Professional
[5] Equals [3] - [4]
[6] Equals weight in S&P 500 based on market capitalization
[7] Source: Bloomberg Professional
[8] Equals [6] x [7]
[9] Source: Yahoo Finance
[10] Source: Value Line
[11] Equals average of col. [9] and col. [10]
[12] Equals [6] x [11]

BOND YIELD PLUS RISK PREMIUM ANALYSIS



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.93393
R Square	0.87222
Adjusted R Square	0.87114
Standard Error	0.00343
Observations	120

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.0095	0.0095	805.4592	0.0000
Residual	118	0.0014	0.0000		
Total	119	0.0108			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0863	0.00135	63.89273	0.00000	0.08364	0.08899	0.08364	0.08899
X Variable 1	-0.6960	0.02452	-28.38061	0.00000	-0.74459	-0.64746	-0.74459	-0.64746

	[1]	[2]	[3]
	Moody's Baa Utility Yield	Risk Premium	ROE
Current 6-month average of Moody's Baa Utility Yield	6.08%	4.40%	10.48%

Notes:
[1] Source: Bloomberg Professional
[2] Equals 0.086315 + (-0.696020 x Column [6])
[3] Equals Column [1] + Column [2]

BOND YIELD PLUS RISK PREMIUM ANALYSIS - FERC ROE DECISIONS

Utility	Docket	[1] Base Authorized ROE	[2] 6-Month Daily Baa Yield Avg	[3] Risk Premium
Baltimore Gas & Elec.	ER05-515	10.80%	6.07%	4.73%
Baltimore Gas & Elec.	ER05-515	11.30%	6.07%	5.23%
Westar Energy Inc.	ER05-925	10.80%	6.37%	4.43%
San Diego Gas & Elec.	ER07-284	11.35%	6.14%	5.21%
Idaho Power Co.	ER06-787	10.70%	6.15%	4.55%
Wisconsin Elec. Pwr. Co.	ER06-1320	11.00%	6.15%	4.85%
Commonwealth Edison Co.	ER07-583	11.00%	6.41%	4.59%
Duequesne	ER06-1549	10.90%	6.41%	4.49%
Virginia Elec. & Power Co.	ER08-92	10.90%	6.43%	4.47%
Atlantic Path 15	ER08-374	10.65%	6.44%	4.21%
Startrans IO, LLC	ER08-413	10.65%	6.44%	4.21%
Westar Energy Inc.	ER08-396	10.80%	6.44%	4.36%
Pepco Holdings, Inc.	ER08-686	11.30%	6.41%	4.89%
Trans-Allegheny	ER07-562	11.20%	6.42%	4.78%
Arizona Public Service Co.	ER07-1142	10.75%	6.54%	4.21%
Virginia Elec. & Power Co.	ER08-1207	10.90%	6.63%	4.27%
Duquesne Light Co.	ER08-1402	10.90%	6.69%	4.21%
Pepco Holdings, Inc.	ER08-1423	10.80%	6.69%	4.11%
Black Hills Power Co.	ER08-1584	10.80%	6.69%	4.11%
Tallgrass / Prairie Wind	ER09-35/36	10.80%	6.80%	4.00%
Public Service Elec. & Gas	ER09-249	11.18%	6.86%	4.32%
ITC Great Plains	ER09-548	10.66%	6.94%	3.72%
Pioneer Transmission	ER09-75	10.54%	6.94%	3.60%
So. Cal Edison (b)	ER09-187	10.04%	6.94%	3.10%
So. Cal Edison (a)	ER08-375	10.55%	7.57%	2.98%
Baltimore Gas & Elec.	ER09-745	11.30%	7.77%	3.53%
AEP - SPP Zone	ER07-1069	10.70%	7.93%	2.77%
Green Power Express	ER09-681	10.78%	7.93%	2.85%
Oklahoma Gas & Elec.	ER08-281	10.60%	8.11%	2.49%
PPL Elec. Utilities Corp.	ER08-1457	11.00%	8.11%	2.89%
PPL Elec. Utilities Corp.	ER08-1457	11.14%	8.11%	3.03%
Kentucky Utilities Co.	ER08-1588	11.00%	8.11%	2.89%
Niagara Mohawk Pwr. Co.	ER08-552	11.00%	7.61%	3.39%
National Grid Generation LLC	ER09-628	10.75%	7.38%	3.37%
Southwestern Public Service Co.	ER08-313	10.77%	7.38%	3.39%
So. Cal Edison (c)	ER10-160	10.33%	7.07%	3.26%
AEP - PJM Zone	ER08-1329	10.99%	6.20%	4.79%
Kansas City Power & Light Co.	ER10-230	10.60%	6.02%	4.58%
AEP Transcos - PJM	ER10-355	10.99%	6.02%	4.97%
AEP Transcos - SPP	ER10-355	10.70%	6.02%	4.68%
So. Cal Edison	ER11-1952	10.30%	5.90%	4.40%
Atlantic Grid Operations	EL11-13	10.09%	5.81%	4.28%
Duke Energy Carolinas	ER11-2895	10.20%	5.81%	4.39%
Northern Pass Transmission	ER11-2377	10.40%	5.79%	4.61%
PSCo	ER12-2300	10.25%	5.79%	4.46%
Northern States Power Co. (MN)	ER10-1377	10.40%	5.94%	4.46%
Northern States Power Co.	ER10-992	10.20%	6.00%	4.20%
South Carolina Elec. & Gas	ER10-516	10.55%	6.00%	4.55%
RITELine	ER11-4069	9.93%	5.98%	3.95%
PJM & PSE&G	ER12-296	11.18%	5.71%	5.47%
PATH	ER08-386	10.40%	5.56%	4.84%
Entergy Arkansas	ER11-2560	10.20%	5.21%	4.99%
Public Service Co. of Colorado	ER11-2853	10.10%	5.08%	5.02%
Public Service Co. of Colorado	ER11-2853	10.40%	5.08%	5.32%
Cleco Power LLC	ER12-1378	10.50%	4.74%	5.76%
Transource Missouri	ER12-2554	9.80%	4.65%	5.15%
Puget Sound Energy	ER12-778	9.80%	4.65%	5.15%
Puget Sound Energy - PSANI	ER12-778	10.30%	4.65%	5.65%
PacifiCorp	ER11-3643	9.80%	4.62%	5.18%
Maine Public Service Co.	ER12-1650	9.75%	4.62%	5.13%
So. Cal Edison	ER11-3697	9.30%	4.81%	4.49%

BOND YIELD PLUS RISK PREMIUM ANALYSIS - FERC ROE DECISIONS

Utility	Docket	[1] Base Authorized ROE	[2] 6-Month Daily Baa Yield Avg	[3] Risk Premium
San Diego Gas & Electric	ER13-941	9.55%	5.22%	4.33%
Public Service Co. of Colorado	ER12-1589	9.72%	4.76%	4.96%
Duke Energy Ohio	ER12-91	10.88%	4.73%	6.15%
Niagara Mohawk Power Corp.	EL12-101	9.80%	4.66%	5.14%
Public Service Company of New Mexico	ER13-685	10.00%	4.63%	5.37%
MidAmerican Central Calif. Transco	ER14-1661	9.80%	4.58%	5.22%
American Transmission Systems, Inc.	ER15-303	9.88%	4.58%	5.30%
American Transmission Systems, Inc.	ER15-303	10.56%	4.58%	5.98%
Westar Energy	EL14-93	9.80%	4.58%	5.22%
Duke Energy Florida	EL12-39	10.00%	4.65%	5.35%
Southwestern Public Service Co.	ER14-192	10.00%	4.79%	5.21%
Kentucky Utilities Co.	ER13-2428	10.25%	4.79%	5.46%
XEST Xcel Energy Southwest Trans. Co. (Gen)	ER14-2751	10.20%	5.07%	5.13%
Baltimore G&E / Pepco Holdings, Inc.	EL15-27	10.00%	5.23%	4.77%
New York Transco LLC	ER15-572	9.50%	5.23%	4.27%
Kanstar Transmission, LLC	ER15-2237	9.80%	5.41%	4.39%
Transource West Virginia, LLC	ER15-2114	10.00%	5.41%	4.59%
ATX Southwest, LLC	ER15-1809	9.90%	5.46%	4.44%
Transource Kansas, LLC	ER15-958	9.80%	5.29%	4.51%
NorthWestern Corp.	ER15-2069	9.65%	4.55%	5.10%
NextEra Energy Transmission West	ER15-2239	9.70%	4.41%	5.29%
TransCanyon DCR, LLC	ER15-1682	9.80%	4.55%	5.25%
Northeast Transmission Development	ER16-453	9.85%	4.41%	5.44%
Duke Energy Carolinas	EL16-30	10.00%	4.55%	5.45%
New York Transco, LLC	ER15-572	9.65%	5.23%	4.42%
Rockland Electric Co.	ER17-856	9.50%	4.48%	5.02%
Emera Maine	ER15-1429	9.60%	4.40%	5.20%
Transource Pennsylvania/Maryland, LLC	ER17-419	9.90%	4.52%	5.38%
NextEra Energy Trans. Southwest LLC	ER16-2720	9.80%	4.23%	5.57%
NextEra Energy Trans. MidAtlantic, LLC	ER16-2716	9.60%	4.28%	5.32%
Mid-Atlantic Interstate Transmission	ER17-211	9.80%	4.42%	5.38%
GridLiance West Transco LLC	ER17-706	9.60%	4.23%	5.37%
NextEra Energy Trans. New York LLC	ER16-2719	9.65%	4.28%	5.37%
DesertLink, LLC	ER17-135	9.80%	4.28%	5.52%
AEP East Cos.	EL17-13	9.85%	4.23%	5.62%
Alabama Power Co.	ER19-1427	10.60%	4.88%	5.72%
AEP West Cos	ER19-1396	10.00%	4.88%	5.12%
Southwestern Electric Power Co	ER18-1225	10.10%	4.67%	5.43%
Gulf Power Co.	ER18-1953	10.25%	4.60%	5.65%
Oklahoma G&E	EL18-58	10.00%	4.88%	5.12%
Southern California Edison	ER18-169-002	9.70%	4.80%	4.90%
PECO	ER17-1519	9.85%	4.47%	5.38%
San Diego Gas & Electric	ER19-221	10.10%	4.00%	6.10%
Cheyenne Light, Fuel & Power	ER19-697-001	9.90%	3.70%	6.20%
Southern California Edison	ER19-1553	9.80%	3.56%	6.24%
Pacific Gas & Electric Co.	ER19-13	9.95%	3.27%	6.68%
NorthWestern Corp.	ER19-1756	9.65%	3.20%	6.45%
Dayton Power & Light Co.	ER20-1150	9.85%	3.13%	6.72%
Jersey Central Power & Light Co.	ER20-227	9.70%	3.20%	6.50%
Duke Energy Progress	ER21-1319	9.85%	3.30%	6.55%
Public Service Elec. & Gas Co.	ER21-2450	9.90%	3.48%	6.42%
TransCanyon Western Development, LLC	ER21-1065	9.90%	3.45%	6.45%
Morongo Transmission LLC	ER21-669	9.30%	3.45%	5.85%
PPL Elec. Utilities Corp.	EL20-48	9.90%	3.45%	6.45%
PPL Elec. Utilities Corp.	EL20-48	9.95%	3.45%	6.50%
PPL Elec. Utilities Corp.	EL20-48	10.00%	3.45%	6.55%
Tucson Electric Power Co.	ER19-2019	9.79%	3.24%	6.55%
Pacific Gas & Electric Co.	ER20-2878	10.25%	3.62%	6.63%
Duke Energy Progress	ER22-2125	10.00%	4.46%	5.54%

Notes:
[1] Source: Westlaw
[2] Source: Bloomberg Professional, bond yields are the average of each trading day in the year
[3] Equals Column [1] − Column [2]

SUMMARY RESULTS

Model	Lower Bound	Lower Third	Median	Upper Third	Upper Bound
DCF	7.54%	8.64%	9.10%	10.30%	14.38%
CAPM	9.79%	10.98%	11.20%	11.68%	12.95%
Risk Premium	7.98%	9.65%	10.48%	11.31%	12.98%
Measure of Central Tendency Base ROE			**10.26%**		
Upper / Lower Bounds	**8.44%**	**9.76%**		**11.10%**	**13.44%**

Model	Lower Bound	Lower Third	Median	Upper Third	Upper Bound
DCF	7.54%	8.64%	9.10%	10.30%	14.38%
CAPM	9.79%	10.98%	11.20%	11.68%	12.95%
Measure of Central Tendency Base ROE			**10.15%**		
Upper / Lower Bounds	**8.67%**	**9.81%**		**10.99%**	**13.66%**

Exhibit No. MAOD-18
Mid-Atlantic Offshore Development, LLC
Direct Testimony of Larry E. Kennedy

Exhibit No. MAOD-18

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Mid-Atlantic Offshore Development	)	**Docket No. ER24-___-000**
	)	

DIRECT TESTIMONY

OF

LARRY E. KENNEDY

ON BEHALF

OF

MID-ATLANTIC OFFSHORE DEVELOPMENT, LLC

July 18, 2024

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development	)))	**Docket No. ER24-___-000**

DIRECT TESTIMONY
OF
LARRY E. KENNEDY

I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A1. My name is Larry E. Kennedy. I am employed by Concentric Energy Advisors ("Concentric") as a Senior Vice President. My business address is 200 Rivercrest Drive SE, Suite 277, Calgary, Alberta, T2C 2X5.

Q2. WHAT IS THE NATURE OF THE WORK PERFORMED BY YOUR FIRM?

A2. Concentric provides financial and economic advisory services to various energy and utility clients across North America. In addition, Concentric provides litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

Q3. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A3. I have a diploma in Business Administration (Accounting) from the Northern Alberta Institute of Technology (1978). Since 1978, I have completed numerous courses in regulatory theory, utility depreciation, and capital recovery. I am a Certified Depreciation Professional ("CDP") and have over 40 years of regulatory plant accounting and depreciation experience. I am also a member of the teaching faculty of the Society of

Depreciation Professionals. I also have over 20 years of depreciation and plant accounting consulting experience, which I provide to the regulated utility, pipeline, and railway industries. I have advised numerous energy and utility clients on a wide range of accounting, property tax and utility depreciation matters. Many of these assignments have also included the discussion of the appropriate procedures to use to fund future decommissioning, abandonment, and retirement costs.

Q4. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A4. I am submitting this Direct Testimony before the Federal Energy Regulatory Commission ("FERC" or "Commission") on behalf of Mid-Atlantic Offshore Development, LLC ("MAOD").

Q5. ARE YOU SPONSORING ANY EXHIBITS TO YOUR DIRECT TESTIMONY?

A5. Yes, I am sponsoring the following Exhibits:

- Exhibit No. MAOD-19 – Summary of Average Service Life Estimates of Peer Electric Transmission Plant; and
- Exhibit No. MAOD-20 – Proposed Electric Transmission Depreciation Rates.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES?

A6. Yes. I have provided expert testimony in over 140 proceedings throughout North America. A list of proceedings in which I have testified is provided in Attachment 1 to this Direct Testimony. Of relevance, I have prepared testimony in a number of FERC dockets on topics that are discussed within this testimony.

II. PURPOSE AND SUMMARY

Q7. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A7. The purpose of my Direct Testimony is to present to FERC a schedule outlining fair and appropriate depreciation rates to use for financial and regulatory reporting and ratemaking purposes.

Q8. PLEASE SUMMARIZE YOUR TESTIMONY.

A8. MAOD was selected by the New Jersey Board of Public Utilities ("NJBPU"), in coordination with PJM Interconnection, L.L.C. ("PJM"), to construct, own, operate, and maintain a transmission substation designated as the "Larrabee Collector Station" and acquire adjacent land to accommodate up to four high-voltage direct current ("HVDC") converter stations, which will be used to interconnect New Jersey offshore wind generation to the PJM transmission system (collectively, the "Project"). My testimony provides a summary of the appropriate depreciation rates to be used by MAOD in the determination of the depreciation expense for regulatory and financial purposes associated with the Project. The depreciation rates will be included as stated values in MAOD's Formula Rate as described in Exhibit No. MAOD-21, Direct Testimony of William ("Bill") R. Davis ("Davis Testimony"). The Proposed Electric Transmission Depreciation Rates are summarized in Exhibit No. MAOD-20.

Q9. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR RECOMMENDED DEPRECIATION RATES.

A9. The Project is currently under development and not currently in service. As such, some of the activities that normally would be undertaken in the development of depreciation rates for a FERC-regulated electric transmission substation and associated equipment cannot be completed as part of my review. Normally, a statistical mortality study of historic retirement activity is completed. While I could not complete a mortality study on the Project, as a proxy, I was able to review the mortality studies completed on more mature electric transmission peer systems to gain an understanding of the historical mortality patterns of more aged systems. Additionally, in determining depreciation, I typically would tour the site to understand the physical and technological differences between the system being studied and other peer systems. Because the facilities are being developed, I could not undertake field tours and reviews. Instead, I participated in a number of interviews with company management, including review of system maps and facility plans, to understand the system configuration and gain an overall project understanding.

In developing the depreciation rates, I reviewed the relevant transmission system configuration, and assembled and reviewed depreciation studies of similarly sized and configured, aged and new electric transmission systems, as summarized in Exhibit No. MAOD-19. This review included similar North American transmission systems and recent studies on more mature systems within the United States and Canada.

Q10. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A10. In Section III, I provide a discussion of appropriate depreciation rates for the Project and in Section IV, I provide my Conclusion.

III. CALCULATION OF DEPRECIATION RATES

Q11. PLEASE BRIEFLY DESCRIBE MAOD.

A11. As described in greater detail in the Direct Testimony of Mr. Christopher Sternhagen ("Sternhagen Testimony"), provided as Exhibit No. MAOD-1, MAOD is a non-incumbent transmission developer whose only business is to develop, own, and maintain transmission facilities in the area operated by PJM. MAOD is currently a single asset transmission company.

As described in the Sternhagen Testimony, the Larrabee Collector Station is an alternating current ("AC") switchyard composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A, and four single phase 500/230 kV autotransformers to step up the voltage of one circuit for connection to JCP&L's Smithburg 500 kV substation in Freehold Township, Monmouth County, New Jersey ("JCP&L Smithburg Substation"). The other two circuits within the Larrabee Collector Station will be connected to JCP&L's Larrabee 230 kV substation in Howell Township, Monmouth County, New Jersey ("JCP&L Larrabee Substation") and JCP&L's Atlantic 230 kV substation in Colts Neck Township, Monmouth County, New Jersey ("JCP&L Atlantic Substation"). The Project also includes land adjacent to the Larrabee Collector Station, on which MAOD will perform some site work to prepare it for offshore wind generators to construct up to four future Direct Current ("DC") to AC converter stations for interconnection of DC circuits from offshore wind generation. The Project will also include the "Interconnection Work" described in the Sternhagen Testimony.[1] Construction is expected to begin in the fourth quarter of 2025. The Project will function as a single, onshore point-of-interconnection for electricity generated from offshore New Jersey wind generation facilities.

It is expected that the Project will be energized and in service on December 31, 2027.

[1] *See* Exhibit No. MAOD-1, Sternhagen Testimony at Q34-Q37, Q28.

Q12. PLEASE PROVIDE A SUMMARY OF THE RESULTS OF YOUR ANALYSIS.

A12. I performed an analysis to determine depreciation rates for MAOD's transmission and general plant assets. The results of my analysis are provided in Exhibit No. MAOD-20, which includes the appropriate depreciation rates for each account.

Q13. WHAT IS DEPRECIATION?

A13. Depreciation, as applied to depreciable electric plant, means:

> the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[2]

Q14. PLEASE BRIEFLY DISCUSS THE PROCESS THAT YOU FOLLOWED IN THE DEVELOPMENT OF APPROPRIATE DEPRECIATION RATES.

A14. Long life assets, such as those to be constructed by MAOD, are impacted by physical forces, such as wear and tear, physical deterioration, and long-term economic forces. As such, appropriate depreciation rates developed for newly constructed electric transmission assets in accordance with the causes to be given consideration, as described in the above FERC definition of depreciation, require depreciation methodologies based on four factors: (1) average service life, (2) forecast retirement dispersion curves (the so called "Iowa curve"), (3) consideration of any economic or other constraints to the recovery of investment, and (4) consideration of the estimated cost of retirement (i.e., net salvage costs).

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[2] 18 C.F.R. Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act, Definitions, (12) Depreciation (2022).

Q15. HOW WERE THE AVERAGE SERVICE LIFE, RETIREMENT DISPERSION CURVES, AND NET SALVAGE ESTIMATES DETERMINED?

A15. I determined the average service life, retirement dispersion estimates, and net salvage estimates (i.e., the depreciation parameters) based on my review of currently approved depreciation parameters by way of peer analysis. I reviewed the approved parameters for electric transmission systems recently constructed in Canada with which I was familiar, which included the following companies:

- Newfoundland & Labrador Hydro ("NLH")[3] – Engages in the development, generation, transmission, and sale of electricity in Canada. NLH's provincial transmission system spans thousands of kilometers, and includes dozens of high-voltage terminal stations and lower-voltage distribution stations. Through the 1,100 km Labrador Island Link, the two 250 km Labrador Transmission Assets between Muskrat falls and Churchill Falls, and the Soldier Pond power converter station, they connect power from Labrador to Newfoundland.
- AltaLink LP ("AltaLink")[4] – AltaLink owns and operates regulated electricity transmission facilities in Alberta, Canada. The company connects generation plants to major load centers, cities, and industrial plants throughout its 226,000-square-kilometer service area. It owns and operates approximately 13,000 km of high-

[3] *See In the Matter of the Electrical Power Control Act, 1994 SNL 1994, Chapter E-5.1 (the "EPCA") and the Public Utilities Act, RSNL 19990, Chapter P-47 (the "Act"), as amended, and regulations thereunder; and In the Matter of a General Rate Application by Newfoundland and Labrador Hydro to Establish Customer Electricity Rates for 2018 and 2019,* 2017 General Rate Application, Revision 5, Newfoundland and Labrador Board of Comm'rs of Pub. Utils. (filed Jul. 4, 2018).

[4] *See AltaLink Mgmt Ltd.,* 2022-2023 General Tariff Application and 2020 Direct Assigned Capital Deferral Account Reconciliation Application, Application 26509-A001, Exhibit 26509-X0013 (Appendix 8, 2019 Depreciation Study) (filed Sept. 3, 2021); *see also AltaLink Mgmt. Ltd.,* Alberta Utilities Comm'n, Decision 26509-D01-2022 (2022).

voltage transmission lines (energized at approximately 500 kV) and 308 substations in Alberta.

- ATCO Electric Transmission ("ATCO")[5] – ATCO Electric builds, owns, operates, and maintains a system of transmission and distribution lines. They deliver electricity to nearly 229,000 customers in north and east-central Alberta and own and operate approximately 88,000 km of transmission and distribution lines.

The above utilities each have constructed new electric transmission assets since 2015, where I developed depreciation parameters that have either been reviewed by the relevant regulatory jurisdiction or have parameters that have settled through a negotiated settlement process.

I also included a review of depreciation studies that have included electric transmission assets owned and operated by utilities in various U.S. jurisdictions, which were completed by other recognized experts. The following utilities were included in the peer analysis primarily because they own and operate assets similar to the Project in comparable geographic locations and climates, and therefore have similar forces of retirement to MAOD:

- National Grid d/b/a Niagara Mohawk Power Corporation[6] – Engages in the provision of regulated energy delivery in New York State. The company offers electric services to approximately 1.7 million customers.

[5] *See ATCO Electric Ltd.,* 2020-2022 Transmission General Tariff Application, March 1, 2021, Exhibit 24964-X0033.02 (Appendix 10, 2018 Depreciation Study, revised Nov. 2019) (filed Oct. 26, 2020); *see also ATCO* Electric Ltd., Alberta Utilities Comm'n, Decision 24964-D01-2021 (2021).

[6] *See Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, N.Y. State Pub. Serv. Comm'n, Matter No. 17-00887,

- New York Power Authority – Provides transmission service in various parts of New York State over more than 1,400 circuit-miles of transmission facilities.
- Commonwealth Edison[7] – Engages in the purchase and regulated retail sale of electricity. It is also involved in the distribution and transmission of electricity to over four million retail customers in Northern Illinois. It manages more than 90,000 miles of power lines in an 11,400-square-mile territory.
- Consolidated Edison Company of New York, Inc.[8] – Offers electric delivery services to its customers in New York City, Manhattan, the Bronx, parts of Queens, and Westchester County. The company operates 40 transmission substations and 62 area stations, and its transmission facilities have over 560 miles of overhead circuits and over 750 miles of underground circuits.
- ITC Midwest LLC[9] – Operates and maintains more than 6,600 circuit miles of electric transmission lines across Iowa, Illinois, Minnesota, and Missouri.

Case No. 17-E-0238, Direct Testimony of Dr. Kimbugwe A. Kateregga, Exhibit __ (KAK-2), 2016 Electric Depreciation Rate Study (filed Apr. 28, 2017).

[7] *See Commonwealth Edison Co., Petition for Petition for Approval of a Multi-Year Rate Plan under Section 16-108.19 of the Public Utilities Act,* Ill. Commerce Comm'n, Docket No. 23-0055, ComEd Ex. 16.0, Direct Testimony of Ned W. Allis, ComEd Ex. 16.03, "Depreciation Study, Calculated Annual Depreciation Accruals Related to Electric Plant as of December 31, 2021" (filed Jan. 17, 2023).

[8] *See Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service,* N.Y. State Pub. Serv. Comm'n, Matter No. 19-00317, Case Nos. 19-E-0065, 19-G-0066, "Study on Depreciation and Climate Change, May 2021" (filed Jun. 1, 2021).

[9] *See Midcontinent Indep. Sys. Operator, Inc. and ITC Midwest LLC*, Attachment O Depreciation Revisions, "Prepared Direct Testimony of Ned W. Allis on Behalf of ITC Midwest LLC," Attachment NWA-2, "2020 Depreciation Study," Docket No. ER22-3-000 (filed Oct. 1, 2021). *See also Midcontinent Indep. Sys. Operator Inc.,* 177 FERC ¶ 61,157 (2021) (approving ITC Midwest LLC's Attachment O depreciation revisions).

- Pacific Gas and Electric Company[10] – Provides natural gas and electric service to approximately 16 million people throughout a 70,000-square-mile service area in northern and central California. The company has over 100,000 circuit miles of electric distribution lines and 18,466 circuit miles of interconnected transmission lines.
- Southern California Edison Company[11] – The company delivers electricity to 15 million people across Southern, Central, and Coastal California. Their transmission facilities consist of lines approximately 13,000 circuit-miles long, ranging from 55kV to 500kV.

A summary of the peer review is attached as Exhibit No. MAOD-19 and has resulted in the following ranges of average service life and net salvage estimates for the relevant transmission and general plant accounts:

[10] *See Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2020*, Calif. Pub. Util. Comm'n, Proceeding A.18-12-009, Exhibit No. PG&E-10 (filed Dec. 17, 2018); *see also Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service Effective on January 1, 2020 (U39M),* "Decision Addressing the Test Year 2020 General Rate Case of Pacific Gas & Electric Company," CPUC A.18-12-009, Decision 20-12-005, Settlement Agreement, Appendix D (issued Dec. 11, 2020).

[11] *Application Of Southern California Edison Company (U 338-E) For Authority To Increase Its Authorized Revenues For Electric Service In 2021, Among Other Things, And To Reflect That Increase In Rates,* Calif. Pub. Util. Comm'n, Proceeding A.19-08-13, , SCE Asset Depreciation Study, Exhibit No. SCE-07V03 WP Bk A, Tables 1-2 and 1-4, authorized depreciation parameters pursuant to Decision 19-05-020 (filed Aug. 30, 2019).

Account	Life Range	Net Salvage Range
Transmission Plant		
Account 351 - Energy Storage	See Footnote[12]	-5 percent
Account 352 – Structures and Improvements	55 - 75 years	-5 to -50 percent
Account 353 – Station Equipment	36 - 55 years	-5 to -60 percent
Account 354 – Towers and Fixtures	57 - 75 years	-13 to -100 percent
Account 355 – Poles and Fixtures	50 – 75 years	-20 to -90 percent
Account 356 – Overhead Conductors and Devices	55 – 75 years	-8 to -110 percent
Account 357 – Underground Conduit	55 – 75 years	-5 to -15 percent
Account 358 – Underground Conductor and Devices	45 – 75 years	-10 to -30 percent
Account 359 – Roads and Trails	60 – 75 years	-8 to -10 percent
General Plant		
Account 382 – Computer Hardware	5 years	No Salvage
Account 383 – Computer Software	3 – 10 years	No Salvage
Account 391 – Office Furniture and Equipment	10 – 22 years	No Salvage
Account 392.1 – Transportation Equipment – Light Duty Vehicles	7 – 10 years	10 to 15 percent
Account 392.2 – Transportation Equipment – Heavy Duty Vehicles	8 – 19 years	10 to 15 percent
Account 394 – Tools, Shop and Garage Equipment	10 – 25 years	No Salvage
Account 397 – Communication Equipment	8 – 22 years	No Salvage
Account 398 – Miscellaneous Equipment	15 – 22 years	No Salvage

[12] As there is minimal history for peer utilities related to Account 351 – Energy Storage, I based my average service life and net salvage estimate on research performed by Concentric in the area of Battery Energy Storage Solutions.

Q16. HOW DID YOU UTILIZE THE PEER STATISTICS?

A16. As shown in the above table, the range of service life estimates was relatively narrow, which provided an ability to select an average service life estimate within the peer range for each asset account.

Q17. PLEASE DESCRIBE THE PROCESS FOLLOWED TO DEVELOP THE AVERAGE SERVICE LIFE ESTIMATES.

A17. I have based my estimates of average service lives on both the midpoint and the average of the life estimates from the peer analysis. Upon review of each account's midpoint and average service life, expert judgement was used to determine the final estimates that were incorporated into the resulting depreciation rates. This review ensured that the estimates would reasonably reflect the annual consumption of the service value of the assets within each account.

The majority of MAOD's assets fall within Account 353 – Station Equipment. This account has a number of assets with differing life characteristics. In order to ensure that all assets are considered within the average service life, I based the estimated service life on the weighted average of each component that MAOD expects to track separately (i.e., transformers, buswork, and towers; breakers and switches; and control system assets). The average service lives of the components were based on peer analysis and expert judgement. The recommended average service life is near the lower range of peer estimates due to MAOD's station assets being slightly more unique and complex than its peers (i.e., coastal collector station connected to offshore wind generation facilities). The computation of the weighted average service life of Account 353 is included in Exhibit No. MAOD-20.

Q18. PLEASE DESCRIBE THE PROCESS FOLLOWED TO DEVELOP THE NET SALVAGE ESTIMATES

A18. I have based my estimates of net salvage on the lower end of the range of estimates from the peer analysis. This moderated approach does not suggest partial net salvage collection. MAOD's assets will be newly constructed and until more information is available (i.e., when 10 or more years of costs of removal data are recorded), I recommend a conservative estimate closer to the lower end of the range. The net salvage estimates for each asset account are provided in Exhibit No. MAOD-20.

Q19. WHAT IS NET SALVAGE?

A19. FERC defines "net salvage value" to mean the salvage value of property retired less the cost of removal, with "cost of removal" being defined as the cost of demolishing, dismantling, tearing down, or otherwise removing electric plant, including the cost of transportation and handling incidental thereto.[13] The net salvage ratio is the net salvage value divided by the original cost of the facility being retired, expressed as a percentage. The Uniform System of Accounts[14] defines depreciation as "the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance." The operative words in this definition are service *value*. The Uniform System of Accounts goes on to define service value as "the difference between original cost and

[13] All referenced definitions are as per Chapter 1 – Federal Energy Regulatory Commission, Department of Energy, and Part 101 – Uniform System of Accounts Prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, Definitions Section. *See* 18 C.F.R. Parts 1, 101.

[14] As defined in the commonly used Uniform System of Accounts published by FERC (18 C.F.R. Part 101), and as used by the National Association of Regulatory Utility Commissions, by the National Energy Board of Canada, by the Ontario Energy Board, and by the Alberta Utilities Commission.

net salvage value of electric plant," not as just the original cost. The service value rendered by an asset (i.e., depreciation), must reflect both its original cost and its net salvage. As indicated, the regulatory principles incorporated into Uniform System of Accounts were developed for public utilities and adopted by most regulatory commissions throughout North America to provide useful information for regulatory reporting and ratemaking purposes.

Q20. WHAT ARE THE FERC GUIDELINES REGARDING THE COLLECTION OF NET SALVAGE?

A20. FERC typically follows National Association of Regulatory Utility Commissioners ("NARUC") Manual guidelines, which state that the company's historical data be used to estimate future net salvage values.[15] The Commission has also previously explained that net salvage ratios must be consistent with costs typically seen in the industry,[16] and industry data may be considered when determining appropriate net salvage ratios.

Q21. WHY SHOULD MAOD BE PERMITTED TO COLLECT NET SALVAGE?

A21. Allocating net salvage costs during the life of the related plant is appropriate and equitable and is in accordance with authoritative texts[17] and most Uniform Systems of Accounting including those published by NARUC, many State Commissions, FERC, and many Canadian Provincial and Federal Regulatory Commissions. Delaying collection until such costs are incurred results in intergenerational inequities, whereby customers are charged

[15] *See* Nat'l Ass'n of Reg. Utils. Comm'rs, "Public Utility Depreciation Practices Manual," at 157-158 (2021) ("Normally the process should start by analyzing past salvage and cost of removal data and by using the results of this analysis to project future gross salvage and cost of removal.") ("NARUC Manual").

[16] *Pacific Gas & Elec. Co.,* Opinion No. 572, 173 FERC ¶ 61,045, P 111, n. 278 (2020).

[17] *See, e.g.* Depreciation Systems, Frank K. Wolf and W. Chester Fitch, Published, Iowa State University Press, 1994; Introduction to Public Utility Accounting, American Gas Association/Edison Electric Institute, 1997.

for plant from which they did not receive service and, as a result of the delay in recovery, also results in higher revenue requirements related to net salvage.

Additionally, the FERC Uniform System of Accounts requires that depreciation be recognized through accrual accounting. That is, the service value of an asset must be accrued during the life of the asset. Since net salvage is a part of the service value, it must be accrued during the life of the related asset in order to comply with the FERC Uniform System of Accounts. As such, regulatory decisions that require the expensing of costs of removal or that mandate the inclusion of costs of removal of retired plant as part of future capital costs of replacement plant need to understand that the decisions are in contrast to the FERC published and long-followed net salvage concepts from regulatory jurisdictions throughout North America.

Since MAOD has no historical transactions on which to base future requirements, its initial estimate of net salvage must be based on an analysis of peer data and expert judgement. A similar method was accepted by FERC for the New York Power Authority ("NYPA") when NYPA was applying for the collection of net salvage related to general plant replacement activity previously charged to Operating and Maintenance expenses. The resulting net salvage estimates for the related asset accounts were based in part on the removal costs estimated for a current transmission replacement project as well as industry norms (i.e., analysis of peers).[18]

[18] *See N. Y. Power Auth.*, "Single Issue Depreciation Rate Filing," Docket No. ER22-2581-000 (filed Aug. 1, 2022; supplemented Sep. 9, 2022); *see also N.Y. Power Auth.*, Docket No. ER22-2581-000, unpublished letter order (issued Sep. 23, 2022) (accepting NYPA depreciation filing).

Q22. HAVE YOU INCLUDED ANY ASSET RETIREMENT OBLIGATION IN THE DEPRECIATION RECOMMENDATIONS?

A22. No, there is not an Asset Retirement Obligation ("ARO") at this point in the Project development. If an ARO is required at a later date, then the depreciation expense for those affected FERC accounts would need to forgo the inclusion of the component of Net Salvage related to terminal retirements and be replaced with an ARO depreciation and accretion expense to avoid double recovery of future retirement costs.

Q23. HOW DID YOU DETERMINE THE DEPRECIATION RATES PROVIDED IN EXHIBIT NO. MAOD-20?

A23. The calculation of the depreciation rate was based on use of the straight-line method, the Average Life Group procedure, and applied on a whole life basis. The straight-line method and Average Life Group procedure are used in most depreciation studies filed with FERC. Here, for newly constructed transmission assets, applying the depreciation lives on a whole life basis is correct, as the remaining life of the assets is equal to the whole life estimate.

Q24. HOW LONG WILL THE DEPRECIATION RATES REMAIN AS PROPOSED?

A24. As described in the Direct Testimony of William Davis, the stated values will be used in MAOD's Formula Rate until changed pursuant to a Federal Power Act section 205 or section 206 filing. It is common to revisit depreciation periodically over the life of the assets and I recommend waiting at least five years to build up a minimum set of historical data to inform whether initial adjustments should be made to the rates. As more historical data is recorded, additional aspects of the depreciation rates, net salvage for instance, can be fine-tuned.

Q25. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A25. Yes.

Attachment 1
Larry E. Kennedy Resume

LARRY E. KENNEDY, CDP

Senior Vice President

Mr. Kennedy has been in the pipeline, electric, gas utility and municipal infrastructure business for 40 years. As Senior Vice President, Concentric Advisors, ULC, Mr. Kennedy has provided professional consulting services to gas and electric utilities including generation facilities (including nuclear facilities), and high voltage transmission lines, large diameter transmission pipelines, railway systems and municipally owned utility systems. Previously, Mr. Kennedy was with Gannett Fleming Canada ULC, for over 17 years, where he was responsible for completing depreciation studies and provided advice related to large capital program spending and controls for many regulated North American utilities. Mr. Kennedy was also employed by Interprovincial Pipelines Limited (now Enbridge Pipelines) for 15 years in several plant accounting and regulatory positions and with Nova Gas Transmission Pipelines (now TC Energy) for three years as a Depreciation Specialist.

Mr. Kennedy has provided expert witness testimony related to depreciation, stranded costs, capital accounting issues, utility valuation, and property tax issues before several North American regulatory bodies. Mr. Kennedy has completed numerous seminars and all courses offered by Depreciation Programs, Inc. Mr. Kennedy is a member of the teaching faculty of the Society of Depreciation Professionals ("SDP") and has presented depreciation, stranded cost, and capital accounting related topics to the SDP, Canadian Electric Association, Canadian Gas Association, Canadian Property Taxpayers Association, Alberta Utilities Commission, British Columbia Utilities Commission and the Canadian Energy Pipeline Association. Mr. Kennedy is a past Society of Depreciation Professionals President.

PERSONAL INFORMATION

- Diploma, Applied Arts - Business Administration, Northern Alberta Institute of Technology, 1978
- Member, Society of Depreciation Professionals
- Certified Depreciation Professional

EXPERIENCE

Representative Project Experience

- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and in 2015 for submission to the FERC (Docket No. RP15-1022-000) to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.

- Viking Gas Transmission Company - The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and

Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons, including discussion related to the long demand of natural gas.

- Midwestern Gas Transmission Company: The assignment included development of a detailed depreciation study and Testimony to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Federal Energy and Regulatory Commission, incorporated the concepts of time-based depreciation for gas transmission accounts and development of Economic Planning Horizons. The Direct Testimony included significant discussion related to the topics of Decarbonization and changing political climate towards removal of fossil fuel demand forecasts.
- Enbridge Lakehead System: A Technical Update to a 2016 full depreciation study was prepared and filed with the FERC in 2021 in support of updating depreciation rate and resultant depreciation expense. The technical update also included an analysis and recommendation of a 20-year Economic Planning Horizon (Economic Life).

- Consolidated Edison Company of New York, Inc.: Mr. Kennedy co-authored a study and report which presented the results of research focusing on prior periods of transformative change and more recent discussions of policy tools that could address the impacts of climate change on the Company's electric, steam, and natural gas businesses.
- Montana-Dakota Utilities Co.: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study and associated expert testimony were submitted to the Montana Public Service Commission in 2018 and to the North Dakota Public Service Commission in 2022. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of the retirement of generation facilities due to environmental legislation and estimation of net salvage requirements.
- Commonwealth Edison Company: Mr. Kennedy sponsored extensive Rebuttal Testimony related to the average service life, net salvage estimations, and appropriate depreciation practices in a 2020 rate proceeding.
- Great Plains Natural Gas Co.: Annual updates of depreciation rates and net salvage requirements were calculated and submitted to the Minnesota Department of Commerce annually since 2017.
- National Grid USA Service Company Limited: A depreciation study was completed in 2020 for the National Grid High Voltage Direct Current (HVDC) electric interstate transmission line. The study included consideration of the average service life of the system components, the level of components of the system and the compliance of the recommended componentization to the FERC Uniform System of Accounts. The resultant study was used by the company in filings with the Federal Energy and Regulatory Commission (FERC)
- Society of Depreciation Professionals (SDP): Mr. Kennedy has presented at the annual conferences on the topic of the erosion of the regulatory compact throughout North America, the Future of Energy transition and its impacts on recovery of investment. Additionally, Mr. Kennedy is a member of the SDP teaching faculty and has lead a number of workshops on various aspects of decarbonization and has co-instructed on the topic of the future of energy.

Other Representative Project Experience

- Alberta Departments of Energy and Forestry and Agriculture: Detailed toll comparison and valuation models were developed to provide a comparison of the toll fairness of each of the Provinces Rural Electrification Associations ("REA") to the comparable Investor Owned Utilities ("IOU") for the 32 REA's currently operating in Alberta. In addition to providing a toll comparison of the REA and IOU, a fair market valuation for each of the REA's was also prepared. The final report of the toll compatibility and specific valuations were submitted to the Alberta Department of Energy and the Alberta Department of Forestry and Agriculture. Mr. Kennedy was the Responsible Officer on this project.
- Alliance Pipeline L.P. A number of depreciation studies have been completed by Mr. Kennedy for both the Canadian and US assets of Alliance Pipelines. The most recent studies completed in 2012 for Submission to the National Energy Board of Canada and to the Federal Energy Regulatory included operational discussions related to the gas transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the inclusion of an Economic Planning Horizon.
- AltaGas Utilities Inc.: A number of depreciation studies have been completed, which included the assembly of basic data from the Company's accounting systems, statistical analysis of retirements for service life and net salvage indications, discussions with management regarding the outlook for property, and the calculations of annual and accrued depreciation. The studies were prepared for submission to the Alberta Energy and Utilities Board ("Board"). Mr. Kennedy has appeared before the Alberta Utilities Commission on behalf of AltaGas on a number of occasions.
- AltaLink LP: An initial study was developed for submission to the Alberta Utilities Commission ("AUC") in 2002. The study included the estimation of service life characteristics, and the estimation of net salvage requirements for all electric transmission assets. A net salvage study and technical update was also filed with the Board in 2004. Since 2004, additional depreciation studies were filed in 2005, 2010 and 2012, 2016 and 2018. The 2010, 2012, 2016 and 2018 studies included a number of provisions in order to ensure compliance to Alberta's Minimum Filing Requirements for depreciation studies and for compliance to the International Financial Reporting Standards. These studies also specifically analyzed the pace of technical change in the Alberta Electric system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- ATCO Electric: Studies have included the development of annual and accrued depreciation rates for the electric transmission and distribution systems for the Alberta assets of ATCO Electric, in addition to the generation, transmission, and distribution assets of Northland Utilities Inc. (NWT) and the distribution assets of Northland Utilities (Yellowknife) Inc. The ATCO Electric studies were submitted to the AUC for review, while the NWT and Northland Utilities (Yellowknife) Inc. studies were submitted to the Northwest Territories Utilities Board and Yukon Electric Company Limited (YECL) was submitted to the Yukon Public Utilities Board. These studies also specifically analyzed the pace of technical and recently

have specifically considered the impacts of early retirements caused by storms and forest fires.

- ATCO Gas: Studies were prepared in 2010 and 2018 which were the subject of a review by the AUC. Elements of all of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. These studies also specifically analyzed the pace of technical change in the Alberta Gas system, and recently have specifically considered the impacts of early retirements caused by storms and forest fires.
- Centra Gas Manitoba, Inc.: The study included development of annual and accrued depreciation rates for all gas plant in service. Elements of the study included a field inspection of metering and compression facilities, service buildings and other gas plant; service life analysis for all accounts using the retirement rate analysis on a combined database developed from actuarial data and data developed through the computed method; discussions with management regarding outlook; and the estimation of net salvage requirements. A similar study was completed in 2006, 2011, and 2015. The 2011 and 2015 studies were the subject of a review by the Manitoba Public Utilities Board in 2012 and 2016. Mr. Kennedy has also consulted on issues regarding International Financial Reporting Standards ("IFRS") compliance and required componentization.
- Enbridge Gas Distribution Inc.: Full and comprehensive depreciation studies have been completed in 2009 and 2011. The 2009 study also included review of the company's gas storage operations. Both studies included the development of annual and accrued depreciation rates for all depreciable natural gas distribution, transmission and general plant assets. Elements of the studies included the service life analysis for all accounts using the computed mortality method of analysis, discussion with management regarding outlook and the estimation of net salvage requirements. Studies were prepared for submission to the Ontario Energy Board.
- Mr. Kennedy has also completed an allocation of the accumulated depreciation accounts into the amounts related to the recovery of original cost and the amounts recovered in tolls for the future removal of assets currently in service. The allocations were determined as of December 31, 2009 and were deemed by the company's external auditors to be in conformance with proper accounting standards and procedures. In 2013, a review of the reserve required for the future removal of assets currently in service was undertaken by Mr. Kennedy. The results of the review were summarized in evidence presented by Mr. Kennedy to the Ontario Energy Board.
- ENMAX Power Corporation: Studies have included the development of annual and accrued depreciation rates for all depreciable electric transmission assets. Elements of the studies included the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook, and the estimation of net salvage requirements. Studies were prepared for submission to the Alberta Department of Energy and more recently for submission to the Alberta Energy and Utilities Board. Similar studies have also been completed for submission for the ENMAX Electric Distribution assets for

submission to the AUC. The ENMAX distribution asset assignments also included an extensive asset verification project where the plant accounting and operational asset records were verified to the field assets actually in service.

- Fortis Group of Companies: Studies have included the development of annual and accrued depreciation rates for the electric distribution assets in Alberta and for the generation, transmission, and distribution assets in British Columbia. The FortisBC Inc. studies were completed and filed with the British Columbia Utilities Commission ("BCUC") in 2005, 2010, 2011 and 2018 encompassing both the FortisBC electric and natural gas companies. FortisAlberta Inc. studies were completed in 2004 (updated in 2005), 2009 and 2010. Elements of the studies included the development of average service lives using the retirement rate method of analysis, development of net salvage estimates, compliance with IFRS, and the determination of appropriate annual accrual and accrued depreciation rates. The most recent studies also specifically analyzed the pace of technical change in the Electric systems, and specifically considered the impacts of retirements, system modernization and technical enchantments to the assets.
- International Financial Reporting Standards ("IFRS"): Mr. Kennedy has been retained by numerous clients encompassing most Canadian Provinces and Territories. The assignments included the review of company's assets and depreciation practices to provide opinion on the compliance to the IFRS. The assignments have also included the issuance of opinion to the External Auditors of Utilities to comment on the manner in which the Utilities can minimize differences in the regulatory ledgers and the accounting records used for financial disclosure purposes. Mr. Kennedy has also presented to the Canadian Electric Association, the Society of Depreciation Professionals, the Canadian Energy Pipeline Association and to the BCUC on this topic.
- Mackenzie Valley Pipeline Project: This assignment included the review of the proposed depreciation schedule for the proposed Mackenzie Valley Pipeline. The review included a discussion of the policies used by the company and the depreciation concepts to be included in a depreciation schedule for a Greenfield pipeline. The review was supported through appearance at the oral public hearings before the National Energy Board of Canada ("NEB").
- Manitoba Hydro: A study was developed to determine the appropriate depreciation parameters for all electric generation, transmission and distribution assets. The study was submitted to the Manitoba Public Utilities Board. Elements of the study included a field review of electric generation and transmission plant, the service life analysis for all accounts using the retirement rate analysis, discussion with management regarding outlook and the estimation of net salvage requirements. A similar study was also completed in 2006 and in 2011. The 2011 depreciation study was the subject of a review by the Manitoba Public Utilities Board in 2012. Mr. Kennedy has also consulted with Manitoba Hydro on issues regarding IFRS compliance and required componentization.
- New Brunswick Power: Mr. Kennedy completed a comprehensive depreciation review of the electric generation (including the nuclear facilities), transmission, distribution and general plant assets. The review, which was prepared for submission to the New Brunswick Public

Utilities Board, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report.

- Newfoundland and Labrador Hydro (NALCOR): Mr. Kennedy developed comprehensive depreciation studies that included the development of depreciation policy and rates for NALCOR. The studies provided a significant review of the previous depreciation policy, which included use of a sinking fund depreciation method and provided justification for the conversation to the straight-line depreciation method. The study, which was prepared for submission to the Newfoundland and Labrador Utilities Commission, included a significant amount of discussion regarding the development of depreciation policy for the company. The study also included development of procedures to extract data from the company databases, tours of the company facilities, interviews with operational and management representatives, development of appropriate net salvage rates, development of average service life estimates, and the compilation of the report for submission in a General Tariff Application. Additional studies were also completed in 2008 and 2010. The 2010 and 2017 studies were the subject of Regulatory Review in 2012 and 2019.

- Ontario Power Generation: Assignments have included a review of the Depreciation Review Committee process completed in 2007. This review provided recommendations for enhanced internal processes and controls in order to ensure that the depreciation expense reflects the annual consumption of service value. Additionally, full assessments of the lives of the regulated assets of the company's electric generation hydro and nuclear plants were completed in 2011 and 2013 and were submitted to the Ontario Energy Board for review.

- TransCanada Pipelines Limited - Alberta Facilities: The assignment included working with the company to develop the appropriate depreciation policy to align with the organization's overall goals and objectives. The resulting depreciation study, which was submitted to the Alberta Energy and Utilities Board, incorporated the concepts of time-based depreciation for gas transmission accounts and unit-based depreciation for gathering facilities. The data was assembled from two different accounting systems and statistical analysis of service life and net salvage were performed. For gathering accounts, the assignment included the oversight of the development of appropriate gas production and ultimate gas potential studies for specific areas of gas supply. Field inspections of gas compression, metering and regulating, and service operations were conducted. Studies were completed in 2002 and 2004, 2007, 2009 and 2012, 2015, and 2018.

- TransCanada Pipelines Limited - Mainline Facilities: The study prepared for submission to the NEB included the development of annual and accrued depreciation rates for gas transmission plant east of the Alberta - Saskatchewan border. Elements of the study included a field inspection of compression and metering facilities, service life and net salvage analysis for all accounts. The study was completed in 2002 and was supported through an appearance before the NEB. Study updates have been completed in 2005, 2007, 2009 and an additional full and comprehensive study was completed in 2011, and 2017. The 2011 study was fully supported through an appearance before the NEB in 2012.

Designations and Professional Affiliations

- Society of Depreciation Professionals -Certified Depreciation Professional
- Society of Depreciation Professionals (former President)

EVIDENCE ENTERED INTO PROCEEDINGS IN THE UNITED STATES

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2015	Alliance Pipeline LP	Alliance Pipeline LP	Federal Energy and Regulatory Commission	Docket No. RP15-1022
2019	Viking Gas Transmission Company	Viking Gas Transmission Company	Federal Energy Regulatory Commission	RP19-1340
2020	National Grid USA Service Company Limited	National Grid USA Service Company Limited	Federal Energy Regulatory Commission	Settled through Negotiation
2018	Great Plains Natural Gas Co.	Great Plains Natural Gas Co.	Minnesota Department of Commerce	Annual Depreciation Filing
2018	Montana-Dakota Utilities	Montana-Dakota Utilities	Montana Public Service Commission	Docket D2019.9
2019	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Cascade Natural Gas Corporation	Cascade Natural Gas Corporation	Oregon Public Utility Commission	UM - 2073
2020	Missouri-American Water Company	Missouri-American Water Company	Missouri Public Service Commission	WR-2020-0344
2020	Great Plains Natural Gas Co	Great Plains Natural Gas Co	Minnesota Department of Commerce	Annual Depreciation Filing
2020	Commonwealth Edison Company	Commonwealth Edison Company	State of Illinois – Illinois Commerce Commission	Docket 20-0393
2021	Intermountain Gas Company	Intermountain Gas Company	Idaho Public Utilities Commission	Case No. INT-21-01
2021	Midwestern Gas Transmission Company	Midwestern Gas Transmission Company	Federal Energy Regulatory Commission	RP21-525-000
2021	Enbridge Lakehead System	Enbridge Lakehead System	Federal Energy Regulatory Commission	DO21-15-000
2021	Consolidated Edison of New York	Consolidated Edison of New York	New York State Public Service Commission	19-G-0066
2022	United Illuminating Company	United Illuminating Company	Connecticut Public Utilities Regulatory Authority	22-08-08
2022	Montana-Dakota Utilities	Montana-Dakota Utilities	North Dakota Utilities Commission	Case No. PU-22-194
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0130
2022	Evergy Missouri West	Evergy Missouri West	Evergy Missouri West	ER-2022-0155

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2022	Northern Natural Gas Company	Northern Natural Gas Company	Federal Energy Regulatory Commission	RP22-1033-0000
2023	Indiana American Water Company	Indiana American Water Company	Indiana Utility Regulatory Commission	Cause No. 45870
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	Public Service Commission of the State of Montana	2022.11.099
2023	Montana-Dakota Utilities	Montana-Dakota Utilities	South Dakota Public Utilities Commission	NG23

EVIDENCE ENTERED INTO PROCEEDINGS IN CANADA

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
1999	ENMAX Power Corporation	Edmonton Power Corporation	Alberta Energy and Utilities Board	980550
2000	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	Decision 2002-43
2001	City of Calgary	ATCO Pipelines South	Alberta Energy and Utilities Board	2000-365
2001	City of Calgary	ATCO Gas South	Alberta Energy and Utilities Board	2000-350
2001	City of Calgary	ATCO Affiliate Proceeding	Alberta Energy and Utilities Board	1237673
2001	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2002	Centra Gas British Columbia	Centra Gas British Columbia	British Columbia Utilities Commission	N/A
2002	ENMAX Power Corporation	ENMAX Power Corporation - Transmission	Alberta Department of Energy	N/A
2003	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1279345
2003	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2003	City of Calgary	ATCO Pipelines	Alberta Energy and Utilities Board	1292783
2003	City of Calgary	ATCO Electric-ISO Issues	Alberta Energy and Utilities Board	N/A
2003	City of Calgary	ATCO Gas	Alberta Energy and Utilities Board	1275466
2003	City of Calgary	ATCO Electric	Alberta Energy and Utilities Board	1275494

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2003	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2003	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-1-2002
2004	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1305995
2004	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1336421
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	Central Alberta Midstream	Central Alberta Midstream	Municipal Government Board of Alberta	N/A
2004	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Energy and Utilities Board	1306819
2004	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2004	NOVA Gas Transmission Limited	NOVA Gas Transmission Limited	Alberta Energy and Utilities Board	1315423
2004	Westridge Utilities Inc.	Westridge Utilities Inc.	Alberta Energy and Utilities Board	1279926
2005	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Energy and Utilities Board	1378000
2005	ATCO Electric	ATCO Electric	Alberta Energy and Utilities Board	1399997
2005	ATCO Power	ATCO Power	Municipal Government Board of Alberta	N/A
2005	British Columbia Transmission Corporation	British Columbia Transmission Corporation	British Columbia Utilities Commission	N/A
2005	Centra Gas Manitoba	Centra Gas Manitoba	Manitoba Public Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Transmission	Alberta Energy and Utilities Board	N/A
2005	ENMAX Power Corporation	ENMAX Power Corporation – Distribution Assets	Alberta Energy and Utilities Board	1380613
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	1371998
2005	FortisAlberta Inc.	FortisAlberta Inc.	Alberta Energy and Utilities Board	N/A
2005	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2005	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	N/A
2005	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	New Brunswick Board of Commissioners of Public Utilities	N/A
2005	Northland Utilities (NWT) Inc.	Northland Utilities (NWT) Inc.	Northwest Territories Utilities Board	N/A
2005	Northland Utilities (Yellowknife) Inc.	Northland Utilities (Yellowknife) Inc.	Northwest Territories Utilities Board	N/A
2005	NOVA Gas Transmission Ltd.	NOVA Gas Transmission Ltd.	Alberta Energy and Utilities Board	1375375
2005	City of Red Deer	City of Red Deer Electric System	Alberta Energy and Utilities Board	1402729
2005	Yukon Energy Corporation	Yukon Energy Corporation	Yukon Utilities Board	N/A
2006	AltaLink LP	AltaLink LP	Alberta Energy and Utilities Board	1456797
2006	BC Hydro	BC Hydro	British Columbia Utilities Commission	N/A
2006	Imperial Oil Resources Ventures Limited	McKenzie Valley Pipeline Project	National Energy Board of Canada	GH-1-2004
2007	Enbridge Pipelines Limited	Enbridge Pipelines Limited	National Energy Board of Canada	RH-2-2007
2007	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Energy and Utilities Board	1514140
2007	Kinder Morgan	Terasen (Jet fuel) Pipeline Limited	British Columbia Utilities Commission	N/A
2008	ATCO Electric	Yukon Electrical Company Limited	Yukon Utilities Board	N/A
2008	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1553052
2008	City of Lethbridge Electric System	City of Lethbridge	Alberta Utilities Commission	N/A
2008	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1512089
2008	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2009	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	N/A
2009	Fortis Alberta Inc.	Fortis Alberta, Inc.	Alberta Utilities Commission	1605170
2010	ATCO Electric	ATCO Electric	Alberta Utilities Commission	1606228
2010	Enbridge Pipelines Limited· Line 9	Enbridge Pipelines Limited - Line 9	National Energy Board of Canada	N/A
2010	Gazifere	Gazifere	La Regie de L'Energie	R-3724-2010

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2010	Kinder Morgan	Kinder Morgan	National Energy Board of Canada	N/A
2010	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	N/A
2011	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	1606694
2011	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1606895
2011	ATCO Electric	Northland Utilities (NWT) Inc.	Northwest Territories Utility Board	N/A
2011	ATCO Gas	ATCO Gas	Alberta Utilities Commission	1606822
2011	FortisAlberta Inc.	Fortis Alberta Inc.	Alberta Utilities Commission	1607159
2011	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	3698627
2011	GazMetro	GazMetro	La Regie de L'Energie	R-3752-2011
2011	Heritage Gas Ltd.	Heritage Gas Ltd.	Nova Scotia Utility and Review Board	N/A
2011	Qulliq	Qulliq	Utilities Rates Review Council	N/A
2011	SaskPower	SaskPower	Internal Review Committee	N/A
2011	TransAlta Utilities Corporation	TransAlta Utilities Corporation	Municipal Government Board of Alberta	N/A
2012	City of Red Deer	City of Red Deer	Alberta Utilities Commission	1608641
2012	Enbridge Gas Distribution Inc.	Enbridge Gas Distribution Inc.	Ontario Energy Board	EB 2011-0345
2012	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	3698620
2012	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2013/2013 GRA
2012	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2012	Northwest Territories Power Corporation	Northwest Territories Power Corporation	Northwest Territories Public Utilities Board	N/A
2012	TransCanada Pipelines Limited	TransCanada Pipelines Limited	National Energy Board of Canada	RH-003 -2011
2013	AltaLink LP	AltaLink LP	Alberta Utilities Commission	1608711
2013	lntraGaz Incorporated	lntraGaz Incorporated	La Regie de L'Energie	R-3807-2012

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2013	Yukon Electrical Company Limited (YECL)	Yukon Electrical Company Limited (YECL)	Yukon Utilities Board	2013-2015 GRA
2014	Enbridge Gas Distribution	Enbridge Gas Distribution	Ontario Energy Board	EB-2012-0459
2014	ENMAX Power Corporation	ENMAX Power Corporation	Alberta Utilities Commission	1609674
2015	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 3524
2015	EPCOR Distribution & Transmission	EPCOR Distribution & Transmission	Alberta Utilities Commission	Proceeding 20407
2015	FortisBC Energy, Inc.	FortisBC Energy, Inc.	British Columbia Utilities Commission	N/A
2015	FortisBC, Inc.	FortisBC, Inc.	British Columbia Utilities Commission	N/A
2015	GazMetro	GazMetro	La Regie de L'Energie	N/A
2015	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	2014/15 & 2015/16 GRA
2015	Newfoundland and Labrador Hydro	Newfoundland and Labrador Hydro	Newfoundland and Labrador Board of Commissioners of Public Utilities	N/A
2016	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 20272
2017	NALCOR	NALCOR	Newfoundland Public Utilities Board	Settled
2017	TransCanada Pipelines Limited – Mainline Facilities	TransCanada Pipelines Limited – Mainline Facilities	National Energy Board of Canada	RH-1-2018
2017	TransCanada Pipelines Limited – NGTL Facilities	TransCanada Pipelines Limited – NGTL Facilities	National Energy Board of Canada	RH-001-2019
2018	WestCoast Transmission System	WestCoast Transmission System	National Energy Board of Canada	Settled
2018	ATCO Electric	ATCO Electric	Alberta Utilities Commission	Proceeding 24195
2018	ATCO Gas	ATCO Gas	Alberta Utilities Commission	Proceeding 24188
2018	SaskEnergy Inc.	SaskEnergy Inc.	Saskatchewan Review Board	N/A
2018	SaskPower	SaskPower	Saskatchewan Review Board	N/A
2018	AltaGas Utilities Inc.	AltaGas Utilities Inc.	Alberta Utilities Commission	Proceeding 24161
2018	AltaLink LP	AltaLink LP	Alberta Utilities Commission	Proceeding 23848

YEAR	CLIENT	APPLICANT	REGULATORY BOARD	PROCEEDING NUMBER
2018	FortisBC Energy Inc.	FortisBC Energy Inc.	British Columbia Utilities Commission	N/A
2018	FortisBC Inc.	FortisBC Inc.	British Columbia Utilities Commission	N/A
2019	Capital Power Corporation	Capital Power Corporation	Municipal Government Board of Alberta	N/A
2019	TransAlta Corporation	TransAlta Corporation	Municipal Government Board of Alberta	N/A
2019	Trans Mountain Pipeline ULC	Trans Mountain Pipeline ULC	Canadian Energy Regulator	T260-2019-04-01
2019	NB Power	NB Power	New Brunswick Energy Utility Regulator	Pending
2019	ATCO Electric	ATCO Electric Transmission	Alberta Utilities Commission	Proceeding 24964
2020	Enbridge Pipelines Inc.	Enbridge Pipelines Inc.	Canada Energy Regulator (CER)	RH-001-2020
2021	Ontario Power Generation	Ontario Power Generation	Ontario Energy Board	N/A
2021	AltaLink L.P	AltaLink L.P	Alberta Utilities Commission	Proceeding 26059
2022	Enbridge Gas Inc.	Enbridge Gas Inc.	Ontario Energy Board	EB-2022-0200
2022	IntraGaz LP	IntraGaz LP	La Regie de L'Energie	R-4189-2022
2022	BC Hydro	BC Hydro	British Columbia Utilities Commission	Project 1599243
2022	Manitoba Hydro	Manitoba Hydro	Manitoba Public Utilities Board	Manitoba Hydro 2023/24 & 2024/25 General Rate Application
2023	Pacific Northern Gas	Pacific Northern Gas	British Columbia Utilities Commission	Application No. PNG NE2023 to 2024 RRA

Exhibit No. MAOD-18

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)))	**Docket No. ER24-___-000**

VERIFICATION

I, Larry E. Kennedy, declare that I am the author of the foregoing testimony, that the facts set forth herein are true and correct to the best of my knowledge, information, and belief, and that if asked the same questions contained therein, my answers would be the same.

Larry E. Kennedy

Dated: July 18/2024

Subscribed and sworn to before me, a Notary Public, this 18th day of July, 2024.

Notary

My commission expires: 5/28/2028

NOTARY PUBLIC STATE OF TEXAS
CATHERINE SPENCE
Notary ID #4231566
My Commission Expires
May 28, 2028

Exhibit No. MAOD-19
Mid-Atlantic Offshore Development, LLC
Summary of Average Service Life Estimates
of Peer Electric Transmission Plant

Mid-Atlantic Offshore Development
Summary of Average Service Life Estimates of Peer Electric Transmission Plant

Account	Discription	NL Hydro		AltaLink LP		ATCO Electric Transmission		DCRT		Niagara Mohawk Power		Consolidated Edison		New York Power Authority		ITC Midwest		Commonwealth Edison		PG&E		SCE		Service Life Peer Average	Net Salvage Peer
		Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage	Life	Net Salvage		
	Transmission Plant:																								
352	Structures and Improvements	-	-	-	-	-	-	-	-	55	-30	75	-50	65	-25	60	-5	65	-45	70	-20	55	-	63.6	-29.2
353	Station Equipment	50	-6	47	- (1)	49	-20 (1)	36	-10	45	-15 (2)	50	-40	45	-20	43	-5	55	-35	47	-60	45	-	46.5	-23.4
354	Towers and Fixtures	65	-20	57	-	60	-30	58	-13	70	-40	65	-40	70	-59	65	-30	75	-70	75	-100	65	-80	65.9	-48.2
355	Poles and Fixtures	57	-20	52	-	55	-90	-	-	65	-40	-	-	60	-59	50	-30	75	-70	56	-80	65	-90	59.4	-59.9
356	O/H Conductors and Devices	60	-20	70	-	65	-30	58	-8	75	-40	55	-35	65	-59	55	-30	65	-60	65	-110	61	-100	63.1	-49.2
357	U/G Conduit	-	-	-	-	-	-	-	-	75	-5	70	-15	65	-10	60	-	75	-10	65	-	55	-	66.4	-10.0
358	U/G Conductor and Devices	-	-	55	-	-	-	-	-	75	-25	60	-25	45	-10	55	-10	55	-30	55	-10	45	-30	55.6	-20.0
359	Roads and Trails	60	-8	-	-	-	-	-	-	75	-	-	-	75	-	75	-	75	-	60	-10	60	-	68.6	-9.0
	Regional Transmission and Market Operation Plant																								
384	Communication Equipment																								
	General Plant:											Plant Not Studied													
391	Office Furniture and Equipment	20	0	-	-	15	-	-	-	22	-	-	-	10	-	20	-	15	-	20	-	-	-		
394	Tools, Shop and Garage Equipment	20	0	-	-	10	-	-	-	22	-	-	-	20	-	20	-	25	-	25	-	-	-		
383	Computer Software	7	0	-	-	3 - 10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
382	Computer Hardware	5	0	-	-	5	-	-	-	-	-	-	-	-	-	5	-	-	-	-	-	-	-		
392.1	Transportation Equipment - Light Duty Vehicles	7	15	8	0	8 / 9	10	-	-	-	-	-	-	10	-	10	10	8-10	10	-	-	-	-		
392.2	Transportation Equipment - Heavy Duty Vehicles	10 / 12	15	8	0	19	15	-	-	-	-	-	-	10	-	10	10	14-18	10	-	-	-	-		
397	Communication Equipment	-	-	-	-	-	-	-	-	22/8	-	-	-	10	-	15	-	15	-	15	-	-	-		
398	Miscellaneous Equipment	-	-	-	-	-	-	-	-	22	-	-	-	20	-	-	-	15	-	20	-	-	-		

(1) Relaying and Control is sub-componitized with a 25 year life
(2) SCADA and Remote Terminal Units sub-componitized with a 20-year life

References to cases and documents reviewed:

NL Hydro	2017 General Rate Application 2017-07-28, Revision 5 filed 2018-07-04 (Volume 2)
Altalink LP	Exhibit 26509-X0013 of Proceeding 26509, Approved in Alberta Utilities Commission Decision 26509-D01-2022, 2019 Depreciation Study
ATCO Electric Transmission	Exhibit 24964-X0033.02 of Proceeding 24964, Approved in Alberta Utilities Commission Decision 24964-D01-2021, 2018 Depreciation Study
DCR Transmission	FERC Docket No. ER23-2309, Exhibit No. DCRT-16, Filed June 2023 and not yet decided
Consolidated Edison Company of New York	State of New York Public Service Commission Case No. 19-E-0065
New York Power Authority	Docket No. ER22-2581-000
Niagara Mohawk Power Corporation	Niagara Mohawk Power Corporation 2017 Electric Depreciation Study, NYSDPS Matter No. 17-00887, Case No. 17-E-0238
ITC Midwest	ER22-3-000, Testimony of Ned Allis, Schedule 1, depreciation rates approved 177 FERC 61,157 (12/3/21)
Commonwealth Edison	Docket No. 2023-0055, 2021 Depreciation Study - ComEd Ex. 16.03 (https://icc.illinois.gov/docket/P2023-0055/documents/332515)
Pacific Gas and Electric (PG&E)	CPUC A.18-12-009 (2020 GRC), Decision 20-12-005, Settlement Agreement, Appendix D
Southern California Edison (SCE)	CPUC A.19-08-13 (2021 GRC), SCE Asset Depreciation Study, Exhibit No. SCE-07V03 WP Bk A, Tables 1-2 and 1-4, authorized depreciation parameters pursuant to Decision 19-05-020
San Diego Gas and Electric (SDG&E)	CPUC A.17-10-007 (2019 GRC), Decision 19-09-051, authorized no change to existing depreciation parameters approved in D.16-06-054, see SDG&E 2016 FERC Form 1 Annual Report

Exhibit No. MAOD-20
Mid-Atlantic Offshore Development, LLC
Summary of Proposed Electric Transmission Depreciation Rates

Exhibit No. MAOD-20

Mid-Atlantic Offshore Development
Summary of Proposed Electric Transmission Depreciation Rates

FERC Capital Category			Average Service Life Estimate	Salvage %	Depreciation Rate
Transmission Plant:					
351	Energy Storage		20	-5%	5.25%
352	Structures and Improvements		60	-25%	2.08%
353	Station Equipment	(1)	40	-30%	3.25%
354	Towers and Fixtures		65	-40%	2.15%
355	Poles and Fixtures		60	-60%	2.67%
356	Overhead Conductors and Devices		65	-35%	2.08%
357	U/G Conduit		65	-10%	1.69%
358	U/G Conductor and Devices		55	-10%	2.00%
359	Roads and Trails		65	0%	1.54%
General Plant:					
382	Computer Hardware		5	0%	20.00%
383	Computer Software		7	0%	14.29%
391	Office Furniture and Equipment		15	0%	6.67%
392.1	Transportation Equipment - Light Duty Vehicles		7	5.0%	13.57%
392.2	Transportation Equipment - Heavy Duty Vehicles		12	5.0%	7.92%
394	Tools, Shop and Garage Equipment		15	0%	6.67%
397	Communication Equipment		15	0%	6.67%
398	Miscellaneous Equipment		15	0%	6.67%
Other Amortized Accounts:					
182.3	Other Regulatory Assets - Dev. Costs/Rate Case Expen:	(2)	5		20.00%

Notes:

1 Weighted Average Life of Station Equipment determined as follows:

	Weighting (%)	Average Service Life Estimate	Weighted Avg. Service Life
Transformers, buswork, towers, etc.	0.75	45	33.75
Breakers, switches, and other	0.15	35	5.25
Control system and other	0.10	15	1.50
	1.00		
	Weighted Average life		40.50

2 Five-year amortization period as defined in the incentive request.

Exhibit No. MAOD-21
Mid-Atlantic Offshore Development, LLC
Direct Testimony of William ("Bill") R. Davis

Exhibit No. MAOD-21

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)))	**Docket No. ER24-___-000**

DIRECT TESTIMONY
OF
WILLIAM ("BILL") R. DAVIS

ON BEHALF OF
MID-ATLANTIC OFFSHORE DEVELOPMENT, LLC

July 18, 2024

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	)))	**Docket No. ER24-___-000**

DIRECT TESTIMONY
OF
<u>WILLIAM R. DAVIS</u>

I. INTRODUCTION AND QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME, BY WHOM YOU ARE EMPLOYED, AND BUSINESS ADDRESS.

A1. My name is William ("Bill") R. Davis, and I am employed by Concentric Energy Advisors, Inc. ("Concentric") as an Assistant Vice President. Concentric is a management consulting and economic advisory firm, focused on the North American energy utility and water industries. Based in Marlborough, Massachusetts and Washington, D.C., Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q2. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES AND YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.

A2. Before joining Concentric Energy Advisors in 2022, I had seventeen years of energy industry professional experience at a major Midwest electric and gas utility (Ameren).

My career covers a variety of topics including load research, sales and revenue forecasting, integrated resource planning, project oversight, renewable energy standards, rate design, class cost of service studies, standby rates, demand-side resources pre-approval filings, demand-side resources market potential studies, implementation of energy efficiency portfolios, design of performance mechanisms for demand-side portfolios, lost revenue recovery, and prudence reviews. I earned a Masters' of Science degree and a Bachelor of Science degree in Economics from Illinois State University. My educational and professional background is summarized more fully in Attachment 1, hereto.

Q3. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A3. I am submitting this testimony on behalf of Mid-Atlantic Offshore Development, LLC ("MAOD").

II. PURPOSE OF TESTIMONY AND BACKGROUND

Q4. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A4. The purpose of my Direct Testimony is to present and support MAOD's proposed statement of its annual transmission revenue requirement ("ATRR Statement"), formula rate template ("Formula Rate Template"), and formula rate implementation protocols ("Protocols") (collectively, "Formula Rate").

Q5. PLEASE DESCRIBE MAOD.

A5. MAOD is a non-incumbent transmission developer whose only business is to develop, own, and maintain transmission facilities in the area operated by PJM Interconnection, L.L.C. ("PJM"). MAOD is a Delaware limited liability company that is a joint venture between EDF-RE Offshore Development, LLC ("EDFR") and Shell New Energies US, LLC ("Shell New Energies"). EDFR and Shell New Energies each own a 50 percent interest in MAOD. As described in the Direct Testimony of Mr. Christopher Sternhagen, provided as Exhibit No. MAOD-1 with this filing ("Sternhagen Testimony"), MAOD is developing facilities that will make up a significant portion of the New Jersey Board of Public Utilities' ("NJBPU") Larrabee Tri-Collector Solution to inject New Jersey offshore wind generation to onshore delivery points within the PJM transmission system. MAOD's facilities consist of a new alternating current ("AC") 230/500 kilovolt ("kV") substation (the "Larrabee Collector Station") and adjacent land required for future High Voltage Direct Current ("HVDC") converter stations (collectively, the "Project").

Q6. OTHER THAN YOUR TESTIMONY, ARE YOU SPONSORING ANY EXHIBITS?

A6. Yes. Along with this testimony, I am sponsoring: (i) Exhibit No. MAOD-22, which is the proposed statement of MAOD's annual transmission revenue requirement ("ATRR"); (ii) Exhibit No. MAOD-23, which includes the proposed Formula Rate Template and supporting Attachments and Workpapers; and (iii) Exhibit No. MAOD-24, which includes the proposed Protocols.

Q7. IS MAOD REQUESTING APPROVAL OF A DEFERRAL COST RECOVERY MECHANISM?

A7. Yes, MAOD is requesting approval to defer rate case expense for recovery once the Project is in-service. Rate case expenses are material and, for a new transmission project without any current rates, there is no opportunity to recover rate case expense without deferring the costs for recovery. Therefore, MAOD is proposing to defer its rate case expense in a regulatory asset (Account 182.3, Other Regulatory Assets) and recover those costs over a three-year period (amortized through Account 566, Miscellaneous Transmission Expenses), starting with the first year of cost recovery. Further, the deferred rate case expense will not accrue interest and will not be included in rate base. Although this approach does not compensate MAOD for the time-value of money, it at least provides an avenue for recovery of expenses that would otherwise be unrecoverable. Once the formula rate is in effect, then future rate cases expenses will be recovered in Account 928, Regulatory Commission Expenses, as an expense.

III. OVERVIEW

Q8. PLEASE PROVIDE AN OVERVIEW OF MAOD'S FORMULA RATE.

A8. MAOD's Formula Rate will consist of three components to be included as part of Attachment H to the PJM Open Access Transmission Tariff ("PJM Tariff"). First, Exhibit No. MAOD-22 Attachment H-35 will consist of MAOD's ATRR Statement, which PJM will use to determine charges for the use of MAOD facilities in providing transmission service within PJM. Second, the Formula Rate Template will be included as Exhibit No. MAOD-23 Attachment H-35A to the PJM Tariff and will calculate MAOD's ATRR. Third, the Protocols will be included as Exhibit No. MAOD-24 Attachment H-35B to the PJM Tariff, and will guide the annual "true-up" calculation, posting, and review of MAOD's ATRR.

Q9. PLEASE EXPLAIN WHY THE PROPOSED FORMULA RATE IS JUST AND REASONABLE.

A9. MAOD's proposed ATRR Statement, Formula Rate Template, and Protocols allow MAOD to collect a revenue requirement that is representative of its operating and capital costs during the rate period; provide for greater certainty for cost recovery of capital expenditures used to provide and improve the transmission infrastructure; and ensure that transmission customers pay only the costs incurred to serve them over the lives of the Project, including a Commission-authorized return on equity ("ROE").

Q10. HOW DID YOU DEVELOP MAOD'S PROPOSED FORMULA RATE?

A10. Broadly speaking, MAOD's Formula Rate is based on those of other companies with Commission-approved formula rates within PJM. For example, MAOD's Formula Rate is similar to those of the following companies within PJM: Mid-Atlantic Interstate Transmission, LLC, NextEra Energy Transmission MidAtlantic Indiana, Inc., and Silver Run Electric, LLC. Recent Commission-approved formula rate templates were reviewed[1] to ensure that MAOD's proposed Formula Rate Template is consistent with Commission precedent.[2]

[1] From the PJM Open Access Transmission Tariff:
Mid-Atlantic Interstate Transmission, LLC - Attachment H-28: Effective Date: 7/1/2017 - Docket No.: ER17-211-000, Attachment H-28A: Effective Date: 1/27/2020 - Docket No.: ER20-1951-004, Attachment H-28B: Effective Date: 5/1/2018 - Docket No.: ER17-211-004.
NextEra Energy Transmission MidAtlantic Indiana, Inc. - Attachment H-33: Effective Date: 10/29/2020 - Docket No.: ER20-1783-002, Attachment H-33A Effective Date: 10/29/2020 - Docket No.: ER20-1783-002, Attachment H33B Effective Date: 10/29/2020 - Docket No.: ER21-1163-000.
Silver Run Electric, LLC - Attachment H-27 Effective Date: 6/27/2018 - Docket No.: ER18-1983-000, Attachment H-27A: Effective Date: 5/25/2020 - Docket No.: ER20-1633-001, Attachment H-27B: Effective Date: 9/23/2020 - Docket No.: ER20-2504-000.

[2] Further, MAOD's proposed Protocols were developed in compliance with the July 17, 2014, Commission Staff guidance document on formula rate updates and Commission policy expressed in the MISO Protocol Orders. S*ee Midwest Indep. Transmission Sys. Operator, Inc.,* 139 FERC ¶ 61,127 (2012), *order on investigation,* 143 FERC ¶ 61,149 (2013), *order on reh'g,* 146 FERC ¶ 61,209, *order on compliance,* 146 FERC ¶ 61,212 (2014), *order on reh'g*, 150 FERC ¶ 61,024, *order on compliance*, 150 FERC ¶ 61,025 (2015) ("MISO Protocol Orders").

Q11. WHAT ORDER NO. 679 INCENTIVE RATES HAS MAOD RECEIVED PRIOR TO THIS FILING AND HOW ARE THOSE INCENTIVES REFLECTED IN MAOD'S PROPOSED FORMULA RATE?

A11. On February 15, 2024, the Commission granted MAOD the following Order No. 679 incentives for the Project: (1) Regulatory Asset Incentive; (2) Abandoned Plant Incentive; (3) Hypothetical Capital Structure Incentive; and (4) RTO Participation Incentive.[3] These incentives were based on a Petition for Declaratory Order filed by MAOD on September 21, 2023, as supplemented on November 22, 2023, in Docket No. EL23-101 ("MAOD PDO"). The incentives apply to the Project as described in the MAOD PDO.

The Regulatory Asset Incentive for pre-commercial costs not capitalized is an adjustment to Rate Base and can be seen as a line item in the revenue requirement in Attachment H-35A as well as the supporting Attachment 3.[4] Similarly, the Abandoned Plant Incentive can be seen as a line item in the revenue requirement in Attachment H-35A as well as the supporting Attachment 3.[5] The Hypothetical Capital Structure Incentive is utilized to calculate the Allowance For Funds Used During Construction ("AFUDC"). Because AFUDC is capitalized with the Project as an input to the Formula Rate, the Hypothetical Capital Structure Incentive is not specified within the Formula Rate Template. The RTO Participation Incentive is utilized in the calculation of the actual and projected revenue requirements and is specified in Attachment H-35A as well as the supporting Attachment 4.

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[3] *See Mid-Atlantic Offshore Dev., LLC*, 186 FERC ¶ 61,116, PP 1-2, 34-48 (2024) ("Incentives Order").

[4] MAOD will defer eligible costs and the associated carrying charges to Account 182.3, Other Regulatory Assets and amortize the allowed costs through Account 566, Miscellaneous Transmission Expenses.

[5] *See* Exhibit No. MAOD-23, Attachment H-35, at Page 2 of 5, lines 28 and 29.

Q12. IS MAOD PROPOSING TO EXTEND ITS INCENTIVES TO RECENT ADDITIONS TO THE PROJECT AND HOW IS THIS REFLECTED IN THE FORMULA RATE?

A12. Yes. After MAOD filed for approval of the incentives listed above, but before the Commission issued the Incentives Order granting them, the NJBPU and PJM approved a change of scope for the Project through its Regional Transmission Expansion Plan ("RTEP"), referred to as the "Interconnection Work." As described in the transmittal letter for this filing[6] and in the Sternhagen Testimony,[7] MAOD is requesting that the Commission confirm that the four incentives already approved for the Project also apply to the Interconnection Work. MAOD also is requesting that the Commission confirm that the four granted incentives will apply to future changes to the scope of the Project approved by the NJBPU and PJM in the coordinated SAA Process and RTEP process, so long as those changes do not materially alter the basis of the Commission's grant of the original incentives. To the extent the Order No. 679 incentives are applicable to only a portion of MAOD's investments (for example, if only a portion of the Project were to be abandoned for reasons beyond MAOD's control) then those adjustments will be supported by separate workpapers and the Formula Rate Template will incorporate Commission approved amounts.

Q13. PLEASE DESCRIBE MAOD'S PROPOSED ATRR STATEMENT.

A13. MAOD's proposed ATRR Statement specifies its annual transmission revenue requirement, which PJM will use to determine the charges to MAOD's customers for

[6] *See* Transmittal Letter, at 3, 10, 17-20.

[7] *See* Exhibit No. MAOD-1, Sternhagen Testimony, at Q13, Q47-Q53.

the use of MAOD facilities in providing transmission service within PJM. MAOD's proposed ATRR Statement is attached as Exhibit No. MAOD-22 to my testimony.

IV. FORMULA RATE TEMPLATE

Q14. PROVIDE A SUMMARY LIST OF AND A BRIEF DESCRIPTION OF EACH SHEET IN THE FORMULA RATE TEMPLATE.

A14. The Formula Rate Template and Supporting Attachments are shown below:

Formula Rate Template	
Exhibit No. MAOD-23, Attachment H-35A	MAOD's Rate Formula Template
Exhibit No. MAOD-23, Attachment 1	Project Revenue Requirement Worksheet
Exhibit No. MAOD-23, Attachment 2	Formula Rate True-Up
Exhibit No. MAOD-23, Attachment 3	Rate Base Worksheet
Exhibit No. MAOD-23, Attachment 4	Return on Rate Base Worksheet
Exhibit No. MAOD-23, Attachment 5	Interest on True-Up
Exhibit No. MAOD-23, Attachment 5a	True-Up Interest Rate Calculator
Exhibit No. MAOD-23, Attachment 6	Accumulated Deferred Income Taxes
Exhibit No. MAOD-23, Attachment 7	Expense and Other Support
Exhibit No. MAOD-23, Attachment 8	Stated Value Inputs
Exhibit No. MAOD-23, Attachment 9	Debt Cost Calculation
Exhibit No. MAOD-23, Workpaper 1a	Utility Gross Plant in Service
Exhibit No. MAOD-23, Workpaper 1b	Utility Gross Plant in Service Summary
Exhibit No. MAOD-23, Workpaper 2	Accumulated Depreciation and Amortization
Exhibit No. MAOD-23, Workpaper 3a	Depreciation and Amortization Expenses by Type
Exhibit No. MAOD-23, Workpaper 3b	Depreciation and Amortization Expenses by Account
Exhibit No. MAOD-23, Workpaper 4	Specified Plant Accounts and Deferred Debits
Exhibit No. MAOD-23, Workpaper 5	Permanent Difference Tax Adjustment
Exhibit No. MAOD-23, Workpaper 6	Operation and Maintenance Expenses - FERC Account
Exhibit No. MAOD-23, Workpaper 7	Formula Rate True-Up Support

Q15. PLEASE DESCRIBE MAOD'S PROPOSED RATE FORMULA TEMPLATE.

A15. MAOD proposes to use a forward-looking Rate Formula Template, which includes a true-up for historical actuals (once available) and a forecast to estimate MAOD's ATRR for the upcoming rate year. The data to be used in the proposed Rate Formula Template will be drawn primarily from MAOD's FERC Form No. 1, supplemented with MAOD's accounting data. MAOD's proposed Formula Rate Template is submitted herewith as Exhibit No. MAOD-23, Attachment H-35A.

The projected net revenue requirement for each rate year will be trued-up annually in accordance with the Protocols based on the operating and capital costs actually incurred by MAOD during the preceding rate year. Any over- or under-collection identified through the true-up process will be applied as an addition or subtraction from the subsequent rate year's net revenue requirement (i.e., rate year plus two). MAOD's annual projected net revenue requirement will be provided to PJM, which will include it in calculating transmission rates under the PJM Tariff. Prior period adjustments may be required to correct information used in previous filings. These adjustments are subtracted from, or added to, MAOD's gross revenue requirement as part of the calculation of MAOD's net annual transmission revenue requirement.

Under the proposed Rate Formula Template, MAOD's rate base is calculated by combining: (i) the 13-month average original cost of specific transmission assets and an allocated share of general and intangible assets owned by MAOD, less the assets' accumulated depreciation; (ii) adjustments for accumulated deferred income taxes and unfunded reserves; (iii) plant held for future use; and (iv) working capital items, including a cash working capital allowance, materials and supplies, and prepayments. The expense component of MAOD's revenue requirement includes: (i) direct billed operating and maintenance expenses and administrative and general expenses associated with MAOD's transmission assets; (ii) an allocated portion of operating and maintenance expenses and administrative and general expenses; (iii) depreciation and amortization expenses on MAOD's assets; and (iv) taxes other than income taxes (e.g., payroll and property).

MAOD's overall rate of return is calculated using the cost of debt and ROE multiplied by MAOD's respective capital structure ratios. The debt component of MAOD's capital structure is the 13-month average of its long-term debt balances, while the equity component is the 13-month average of MAOD's book propriety capital. MAOD's proposed ROE of 10.76% shown on Exhibit No. MAOD-23, MAOD Formula Rate Template, Attachment H-35A consists of a 10.26% base ROE and a 50-basis point adder for its RTO Participation Incentive. MAOD's requested ROE is supported by Exhibit No. MAOD-16, Direct Testimony of Joshua C. Nowak ("Nowak Testimony"). The return on investment included in MAOD's revenue requirement is the product of rate base and overall rate of return, with the income tax expense associated with this return being calculated after deducting synchronized interest expense and other applicable adjustments.

Q16. PLEASE DESCRIBE ATTACHMENT 1 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A16. Attachment 1 of the Formula Rate Template is designed so that the different MAOD projects can be separately identified and tracked. The Project is the first transmission project for which MAOD has been selected in the PJM region. However, MAOD may own other PJM transmission projects in the future, whose revenue requirement would be recovered either through this proposed Formula Rate Template or through a separate rate schedule, which would need to be filed with the Commission at that time.

Accordingly, Attachment 1 is designed to allow for separately identifying additional MAOD transmission projects should they materialize.

Attachment 1 is also designed to compute a separate revenue requirement for any project that needs a project-specific revenue requirement for purposes of the PJM Tariff. In general, project-specific revenue requirements are calculated for projects with specific rate incentives. In PJM, project-specific revenue requirements are recovered through Schedule 12 to the PJM Tariff. Attachment 1 also allows MAOD to include project-specific incentives without the need to modify the Formula Rate Template.

Q17. PLEASE DESCRIBE ATTACHMENT 2 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A17. Attachment 2 of the Formula Rate Template calculates the annual true-up for the Rate Formula Template. For a transmission asset with a project-specific revenue requirement calculated on Attachment 1, the annual true-up for the project is calculated on an individual basis on Attachment 2. Actual inputs for the prior rate year are used to populate Attachment 2, with the resulting project-specific revenue requirement being entered as a separate line item. Any interest (if necessary) and prior period adjustments are added to and/or removed from the trued-up revenue requirement to calculate the total true-up adjustment. This attachment is further supported by Workpaper 7, which details the actual revenue received during the true-up period. Transmission-related revenues included in these accounts are subtracted from MAOD's gross revenue requirement to determine MAOD's net annual transmission revenue requirement in Attachment H-35A.

Q18. PLEASE DESCRIBE ATTACHMENT 3 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A18. Attachment 3 of the Formula Rate Template calculates the average balances of amounts included in rate base, accumulated depreciation, plant held for future use, and any necessary adjustments to rate base by FERC account, including unfunded reserves. This attachment is further supported by Workpapers 1a, 1b, 2 and 4. Workpapers 1a, 1b, and 2 show MAOD's monthly and average total gross plant-in-service and Transmission gross plant-in-service, respectively. Workpaper 2 includes the monthly and average accumulated depreciation amounts. Workpaper 4 shows the breakout rate base adjustments. As mentioned earlier, Attachment 3 also has specific locations to capture MAOD's approved Order No. 679 incentives of a Regulatory Asset for pre-commercial costs not capitalized and Abandoned Plant if that were necessary in the future.

Q19. PLEASE DESCRIBE ATTACHMENT 4 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A19. Attachment 4 of the Formula Rate Template develops the overall rate of return that is applied to MAOD's rate base. Specifically, 13-month average capital structure ratios and the cost of debt are developed, which are then combined with MAOD's Commission-approved stated ROE to calculate an overall rate of return.

Q20. PLEASE DESCRIBE ATTACHMENT 5 AND 5A OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A20. In Attachment 5 of the Formula Rate Template, the amount of interest associated with over- or under-collections determined as part of the annual true-up is calculated. The average interest rate applied to over- or under-collections is computed in Attachment 5a of the Formula Rate Template. The monthly interest rates to be used in the calculation are those prescribed in Section VII.2, Exhibit No. MAOD-24, MAOD Formula Rate Protocols.

Q21. PLEASE DESCRIBE ATTACHMENT 6 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A21. Attachment 6 of the Formula Rate Template calculates the breakout of projected Accumulated Deferred Income Taxes ("ADIT") by Account. The total ADIT is then shown in the Attachment 3, Rate Base Worksheet of the Formula Rate Template.

Q22. PLEASE DESCRIBE ATTACHMENT 7 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A22. Attachment 7 of the Formula Rate Template is used to show the monthly projections for operation and maintenance ("O&M"), administrative and general, lease payments, depreciation and amortization, taxes, and other expenses included in the ATRR on pages 3 and 4 of Attachment H-35A. This Attachment also shows revenue credits used to determine the net revenue requirement. This attachment is further supported by Workpapers 3a, 3b, 5 and 6. Workpapers 3a and 3b show the calculation detail for the depreciation and amortization expenses, described further in the description below of Attachment 8. Workpaper 5 shows the calculation detail for the permanent book/tax differences which captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H-35A that are not the result of a timing difference. Workpaper 6 shows the Transmission O&M by FERC account as well as the split of O&M between labor and non-labor.

Q23. PLEASE DESCRIBE ATTACHMENT 8 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A23. Attachment 8 of the Formula Rate Template lists MAOD's stated value inputs consistent with Section VIII of Exhibit No. MAOD-24, MAOD Formula Rate Protocols. The attachment includes the stated depreciation rates, which are used to calculate the depreciation expense included in MAOD's revenue requirement and the stated ROE, inclusive of the 50-basis point RTO Participation Incentive. The depreciation rates are further explained in Exhibit No. MAOD-18, Direct Testimony of Larry Kennedy, while the ROE is explained in Exhibit No. MAOD-16, Nowak Testimony (as stated above).

Q24. PLEASE DESCRIBE ATTACHMENT 9 OF MAOD'S PROPOSED FORMULA RATE TEMPLATE.

A24. Attachment 9 of the Formula Rate Template is used to further support MAOD's cost of debt. This attachment provides detailed support for each series of outstanding long term debt issuances, such as the issuance and maturity date, the amount issued and net proceeds, the coupon rate, and the effective rate and the weighted cost rate. The total weighted average debt cost for outstanding debt calculated in this attachment is included in Attachment 4, Return on Rate Base Worksheet and on page 4, line 20, column 4 of the Formula Rate Attachment H-35A. As explained in the Nowak Testimony, for the purposes of calculating AFUDC in the period before MAOD obtains construction debt financing, debt during the construction period will be priced at the three-month Term Secured Overnight Financing Rate ("SOFR"), plus 200 basis points (the "Proxy Debt Rate").[8] The Proxy Debt Rate will be updated monthly based on the monthly change in the three-month Term SOFR and used in the AFUDC calculation until the actual Construction Debt financing is placed, at which point the actual cost of the Construction Debt financing will be reflected in the calculation of AFUDC. At or near the time of commercial operation, MAOD would expect to refinance the construction loan with longer-term debt financing, which would then be reflected as the actual cost of debt in Attachment 9.

V. PROTOCOLS

Q25. PLEASE DESCRIBE MAOD'S PROPOSED PROTOCOLS.

A25. MAOD's proposed Protocols, which are provided as Exhibit No. MAOD-24, describe the procedures that MAOD will follow when calculating and posting its projected and actual net revenue requirement (including true-up adjustments) for each rate year, and that MAOD's customers and other interested parties may follow to review and challenge each of MAOD's calculations. With respect to both the projected and actual net revenue requirement, the Protocols require that MAOD post a functional Formula Rate Template in Microsoft Excel format with all formulas intact and with sufficient support for all inputs so that interested parties can verify that each input is consistent with the Formula Rate. Finally, the Protocols require MAOD to make an annual Informational Filing that discloses MAOD's projected net revenue requirement (including the true-up adjustment), explains adjustments and corrections made by MAOD, and lists any inputs that are subject to ongoing dispute.

[8] *See* Exhibit No. MAOD-16, Nowak Testimony, at Q43.

The Protocols allow interested parties up to 240 days to review the projected and actual net revenue requirement, to serve reasonable information requests on MAOD, and to submit written informal challenges to specific items included in the Formula Rate Template. MAOD will make a good faith effort to respond to information requests within 15 business days. If MAOD and a party are unable to resolve an informal challenge, the party may file a formal challenge with the Commission. These procedures do not limit MAOD's right to file under Section 205 of the Federal Power Act ("FPA") to modify the Formula Rate or any of its inputs, or the right of any other party to file a complaint requesting such a change under Section 206 of the FPA.

Q26. PLEASE DESCRIBE AN EXAMPLE OF WHAT MAOD EXPECTS WITH ITS FIRST PUBLICATION AND INFORMATIONAL FILING PURSUANT TO THE PROTOCOLS AND THE EXPECTED CADENCE OF EVENTS THEREAFTER.

A26. For this example, given the expected in-service date for the Project, assume the first rate year is calendar year 2028. Since this is the first rate year, the Protocols anticipate there will not be an Annual True-up because MAOD will not have had a rate in effect yet. Therefore, no later than September 30, 2027, MAOD will provide PJM with its Projected Net Revenue Requirement for the 2028 calendar rate year, and will submit the same to FERC in an Informational Filing. An Annual Projected Rate Meeting will be held between October 20 - October 31, 2027, to discuss the projections with interested parties. The Rate Year 1 (2028) rates will be effective January 1, 2028 through December 31, 2028.

In 2028, this process will be repeated with the publication of MAOD's Projected Net Revenue Requirement for the second rate year (*i.e.,* calendar year 2029).

The Protocols anticipate there will not be an Annual True-Up posted in 2028 because MAOD will not have had a rate in effect for a full year yet. Therefore, no later than September 30, 2028, MAOD will provide PJM with its Projected Net Revenue Requirement for the 2029 calendar rate year and submit the same to FERC in an Informational Filing. An Annual Projected Rate Meeting will be held between October 20 - October 31, 2028 to discuss the projections with interested parties. The Rate Year 2 (2029) rates will be effective January 1, 2029 through December 31, 2029.

MAOD's publications for the third rate year will begin with the Annual True-Up provided to PJM on or before June 1, 2029, with subsequent notification thereof to stakeholders. The Annual True-Up will include the actual costs and revenues from 2028 (the first rate year). An Annual True-Up Meeting will be held between June 21, 2029 and September 1, 2029 to discuss actual costs and revenues from 2028 with interested parties. Subsequently, on September 30, 2029, MAOD will provide PJM with its Projected Net Revenue Requirement for the 2030 calendar rate year, and submit the same to FERC in an Informational Filing. An Annual Projected Rate Meeting will be held between October 20 - October 31, 2029, to discuss the projections with interested parties. The Rate Year 3 (2030) rates will be effective January 1, 2030 through December 31, 2030. Subsequent rate years will follow this cadence of events.

Q27. DOES THIS CONCLUDE YOUR TESTIMONY?

A27. Yes, it does.

Attachment 1
William ("Bill") R. Davis Resume

WILLIAM (BILL) R. DAVIS
ASSISTANT VICE PRESIDENT

Mr. Davis is an energy industry professional with sixteen years of experience from a major Midwest electric and gas utility (Ameren). His career covers a variety of topics including load research, sales and revenue forecasting, integrated resource planning, project oversight, renewable energy standards, rate design, class cost of service studies, standby rates, demand-side resources pre-approval filings, demand-side resources market potential studies, implementation of energy efficiency portfolios, design of performance mechanisms for demand-side portfolios, lost revenue recovery, and prudence reviews.

AREAS OF EXPERTISE

Regulatory & Ratemaking

- Collaborated with regulators, interveners, including political and special interest groups, to obtain consensus, support, and/or regulatory approval.
- Analyzed the economic and financial impacts of regulatory and legislative initiatives.
- Developed and analyzed pricing options for Ameren Missouri's retail customers.
- Provided expert testimony to the Missouri Public Service Commission in Ameren Missouri's electric rate case regarding a proposal to mitigate the negative financial effects to the company caused by the implementation of energy efficiency programs.
- Championed the analysis and adoption of a new residential rate design for Ameren Missouri's natural gas distribution business that significantly reduced the volatility of revenues and prevented a sustained annual revenue shortfall.

Implementation

- Provided strategic direction for Ameren Missouri's energy efficiency and renewable energy programs. Responsible for the planning, implementation, and evaluation of Ameren Missouri's annual $50-$70 million energy efficiency portfolio.
- Served as public spokesperson for energy efficiency on live or recorded television and radio.
- Responsible for meeting or exceeding Ameren Missouri's approved energy efficiency performance targets; resulting in annual $6-$13 million of additional revenue.
- Led cross-functional projects including workgroups such as budgeting, demand-side management, regulatory, legal, forecasting, power operations, transmission and distribution planning, treasury, environmental, renewables, and power trading.
- Team leader to implement a custom application that automated and streamlined project oversight reporting and workflows.
- Provided oversight for projects in excess of $10 million to ensure projects follow proper project management procedures and reduce risk associated with project execution.

- Acted as a change agent to drive behavioral changes in project management practices.

Forecasting and Planning

- Provided quantitative analysis and recommended actions directly to Ameren executive leadership regarding long-term resource and regulatory decisions.
- Team leader for Ameren Missouri's 2011 Integrated Resource Plan which provides the long-term direction for future demand-side and supply-side resource decisions.
- Statistical modeling to forecast long-term electric and gas sales to support resource planning and budgeting. Other responsibilities included load research, sample design, weather normalization, margin impacts of weather, unbilled estimation, profiling, revenue/customer forecasting, regulatory support, and process optimization.

ACCOMPLISHMENTS

- Public Utilities Fortnightly Under 40 class of 2020. Public Utilities Fortnightly is the forum for stakeholders in utility regulation and policy and the Under 40 classes are a nomination-based recognition of rising stars in the public utility industry.
- 2019/2020 Leadership St. Louis Class. The Leadership St. Louis program is an immersive experience into the community to learn directly about regional challenges and opportunities.
- 2018 Zhi-Xing Eisenhower Fellow, one of nine Americans to spend 4 weeks in China for a cultural immersion and professional development experience. The Eisenhower Fellowship mission is to connect innovative leaders in a global network committed to creating a world more peaceful, prosperous and just.
- Leadership Missouri Class of 2014 graduate, which is a program hosted by the Missouri Chamber of Commerce designed to enhance leadership skills and deepen knowledge of the State's opportunities and challenges.
- Project leader of an End-to-End Energy Efficiency Study which received a Technology Transfer Award from the Electric Power Research Institute.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2022-Present)
Assistant Vice President

Ameren – St. Louis, MO (2005 - 2021)
Director, Energy Solutions (2016-2021)
Economic Analysis and Pricing Manager (2013-2016)
Senior Corporate Planning Analyst (2011-2013)
Senior Load Research Specialist – Corporate Planning (2007-2011)
Forecasting and Load Research Specialist – Corporate Planning (2005-2007)

Caterpillar Inc. – Peoria, IL (Feb. 2004 - May 2005)
Advanced Quantitative Analyst – Business Economic Group

EDUCATION

Illinois State University
Bachelor of Science in Economics (2002)
Masters of Science Degree in Economics (2003)

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

50249076.1

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Federal Energy Regulatory Commission				
DCR Transmission, L.L.C.	2023	DCR Transmission, L.L.C.	Docket No. ER23-2309-000	Transmission revenue requirement
Illinois Commerce Commission				
Ameren Illinois Company	2012	Ameren Illinois	Docket No. 12-0244	Cost benefit analysis
Missouri Public Service Commission				
Union Electric Company	2010 2011	Ameren Missouri	Case No. ER-2011-0028	Alternative ratemaking approaches
Union Electric Company	2012	Ameren Missouri	Case No. ER-2012-0166	Revenue requirement and rate design
Union Electric Company	2012 2016	Ameren Missouri	File No. EO-2012-0142	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2014 2015	Ameren Missouri	File No. ER-2014-0258	Rate design, pricing, cost of service
Union Electric Company	2014	Ameren Missouri	Case No. ER-2015-0132	Revenue requirement (energy efficiency)
Union Electric Company	2014	Ameren Missouri	File No. EC-2014-0224	Cost of service, pricing
Union Electric Company	2014	Ameren Missouri	Case No. EA-2014-0136	Renewable energy justification
Union Electric Company	2015 2016 2017 2018	Ameren Missouri	File No. EO-2015-0055	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2015	Ameren Missouri	Case No. ER-2016-0131	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2015	Ameren Missouri	File No. ET-2016-0152	Pricing, Tariff design
Union Electric Company	2016 2017	Ameren Missouri	File No. ER-2016-0179	Rate design, cost of service study, tariff design
Union Electric Company	2016	Ameren Missouri	Case No. ER-2017-0149	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2017	Ameren Missouri	File No. ER-2018-0144	Revenue requirement, incentive ratemaking, prudence review (energy efficiency)

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Union Electric Company	2018	Ameren Missouri	Case No. ER-2019-0151	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2018 2020	Ameren Missouri	File No. EO-2018-0211	Pre-approval, alternative ratemaking (energy efficiency)
Union Electric Company	2019	Ameren Missouri	Case No. ER-2020-0147	Revenue requirement, incentive ratemaking (energy efficiency)
Union Electric Company	2020	Ameren Missouri	Case No. ER-2021-0158	Revenue requirement, incentive ratemaking (energy efficiency)
New York Public Service Commission				
Liberty Utilities Corp.	2023	Liberty Utilities (New York Water) Corp.	Case No. 23-W-0235	Rate Design, Billing Determinants, Forecasting, Class Cost of Service

Exhibit No. MAOD-21

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC	))))	**Docket No. ER24-___-000**

VERIFICATION

I, William ("Bill") R. Davis, declare that I am the author of the foregoing testimony, that the facts set forth herein are true and correct to the best of my knowledge, information, and belief, and that if asked the same questions contained therein, my answers would be the same.

William R Davis
____
William ("Bill") R. Davis

Dated: 7/18/2024

Subscribed and sworn to before me, a Notary Public, this 18th day of July, 2024.

____
Notary

My commission expires: 5/28/2028

CATHERINE SPENCE
Notary ID #4231566
My Commission Expires
May 28, 2028

Exhibit No. MAOD-22
Attachment H-35
Annual Transmission Rates - Mid-Atlantic Offshore Development, LLC

Attachment H-35

Annual Transmission Rates - Mid-Atlantic Offshore Development, LLC

1. The Mid-Atlantic Offshore Development, LLC ("MAOD") annual transmission revenue requirement ("ATRR") is equal to the results of the formula and its associated attachments, as shown in Attachment H-35A posted on the PJM Internet site, which reflect MAOD's facilities within PJM. The ATRR determined pursuant to Attachment H-35A shall be implemented pursuant to the Formula Rate Implementation Protocols set forth in Attachment H-35B.

2. The ATRR posted in (1) shall be effective until amended by MAOD or modified by the Commission.

Exhibit No. MAOD-23
Mid-Atlantic Offshore Development, LLC
Attachment H-35A
Formula Rate Template

Rate Formula Template Attachment H-35A For the 12 months ended mm/dd/yyyy Utilizing FERC Form 1 Data

Mid-Atlantic Offshore Development, LLC

Line No.	(1)	(2) Source	(3)		(4)	(5) Allocated Amount	
1	GROSS REVENUE REQUIREMENT	(page 3, Line 47)				$ -	
	REVENUE CREDITS	(Note O)	Total	Allocator (Note Z)			
2	Account No. 454	(page 4, Line 29)	-	TP	1.00	-	
3	Account No. 456.1	(page 4, Line 33)	-	TP	1.00	-	
4	Account No. 457.1 Scheduling	Attachment 7, line 39, col e	-	TP	1.00	-	
5	Revenues from Grandfathered Interzonal Transactions	(Note N)	-	TP	1.00	-	
6	Revenues from service provided by the ISO at a discount		-	TP	1.00	-	
7	TOTAL REVENUE CREDITS	(Sum of Lines 2 through 6)	-				-
8	NET REVENUE REQUIREMENT	(Line 1 minus Line 7)					$ -
9	Prior Period Adjustment	Attachment 2, Line 11	-	DA	1.00000		-
10	True-up Adjustment with Interest	Attachment 2, line 9, Col. J	-	DA	1.00000		0
11	NET REVENUE REQUIREMENT	(Line 8 plus Line 9 and 10)					$ -

Formula Rate - Non-Levelized | Rate Formula Template Attachment H-35A, Utilizing FERC Form 1 Data, Mid-Atlantic Offshore Development, LLC | For the 12 months ended mm/dd/yyyy

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator			(5) Transmission (Col 3 times Col 4)
	RATE BASE:						
	GROSS PLANT IN SERVICE (Notes U and R)						
1	Production	205.46.g for end of year, records for other months	-	N/A			-
2	Transmission	Attachment 3, Line 14, Col. (b)	-	TP		1.00	-
3	Distribution	207.75.g for end of year, records for other months	-	NA		-	-
4	General & Intangible	Attachment 3, Line 14, Col. (c)	-	W/S		1.00	-
5	Common	356.1 for end of year, records for other months	-	CE		1.00	-
6	TOTAL GROSS PLANT	(Sum of Lines 1 through 5)	-		GP=	1.00	-
7	ACCUMULATED DEPRECIATION (Notes U and R)						
8	Production	219.20-24.c for end of year, records for other months	-	NA			-
9	Transmission	Attachment 4, Line 14, Col. (h)	-	TP		1.00	-
10	Distribution	219.26.c for end of year, records for other months	-	NA		-	-
11	General & Intangible	Attachment 4, Line 14, Col. (i)	-	W/S		1.00	-
12	Common	356.1 for end of year, records for other months	-	CE		1.00	-
13	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 8 through 12)	-				-
14	NET PLANT IN SERVICE						
15	Production	(Line 1 minus Line 8)	-				-
16	Transmission	(Line 2 minus Line 9)	-				-
17	Distribution	(Line 3 minus Line 10)	-				-
18	General & Intangible	(Line 4 minus Line 11)	-				-
19	Common	(Line 5 minus Line 12)	-			I/D	-
20	TOTAL NET PLANT	(Sum of Lines 15 through 19)	-		NP=	1.00	-
21	ADJUSTMENTS TO RATE BASE (Note R)						
22	Account No. 281 (enter negative)	Attach 3, Line 28, Col. (d)/Attach 6, Line 72, Col. H (Note B)	-	NA		zero	-
23	Account No. 282 (enter negative)	Attach 3, Line 28, Col. (e)/Attach 6, Line 108, Col. H (Note B)	-	NP		1.00	-
24	Account No. 283 (enter negative)	Attach 3, Line 28, Col. (f)/Attach 6, Line 144, Col. H (Note B)	-	NP		1.00	-
25	Account No. 190	Attach 3, Line 28, Col. (g)/Attach 6, Line 36, Col. H (Note B)	-	NP		1.00	-
26	Account No. 255 (enter negative)	Attachment 3, Line 28, Col. (h) (Note B)	-	NP		1.00	-
26a	Unfunded Reserves (enter negative)	Attachment 3, Line 31, Col. (h) (Note Y)	-	DA		1.00	-
27	CWIP	Attachment 3, Line 14, Col. (d)	-	DA		1.00	-
28	Unamortized Regulatory Asset	Attachment 3, Line 28, Col. (b) (Note T)	-	DA		1.00	-
29	Unamortized Abandoned Plant	Attachment 3, Line 28, Col. (c) (Note S)	-	DA		1.00	-
30	TOTAL ADJUSTMENTS	(Sum of Lines 22 through 29)	-				-
31	PLANT HELD FOR FUTURE USE	Attachment 3, Line 14, Col. (e) (Note C)	-	TP		1.00	-
32	WORKING CAPITAL	(Note D)					
33	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	-				-
34	Materials & Supplies	Attachment 3, Line 14, Col. (f) (Note C)	-	TP		1.00	-
35	Prepayments (Account 165)	Attachment 3, Line 14, Col. (g)	-	GP		1.00	-
36	TOTAL WORKING CAPITAL	(Sum of Lines 33 through 35)	-				-
37	RATE BASE	(Sum of Lines 20, 30, 31, and 36)	-				-

Formula Rate - Non-Levelized

Rate Formula Template Attachment H-35A
Utilizing FERC Form 1 Data
Mid-Atlantic Offshore Development, LLC

For the 12 months ended mm/dd/yyyy

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b Attach. 7, Line 13, Col. (a)	0	TP	1.00	-
2	Less Account 566 (Misc Trans Expense)	321.97.b Attach. 7, Line 13, Col. (b)	-	TP	1.00	-
3	Less Account 565	321.96.b Attach. 7, Line 13, Col. (c)	-	TP	1.00	-
4	A&G	323.197.b Attach. 7, Line 13, Col. (d)	-	W/S	1.00	-
5	Less FERC Annual Fees	Attach. 7, Line 13, Col. (e)	-	W/S	1.00	-
6	Less EPRI & Reg. Comm. Exp. & Non-safety Ad.	(Note E) Attach. 7, Line 13, Col. (f)	-	W/S	1.00	-
7	Plus Transmission Related Reg. Comm. Exp.	(Note E) Attach. 7, Line 13, Col. (g)	-	TP	1.00	-
8	Common	356.1	-	CE	1.00	-
9	Transmission Lease Payments	Attach. 7, Line 13, Col (h)	-	DA	1.00	-
10	Account 566					
11	Amortization of Regulatory Asset	(Note T) Attach. 7, Line 13, Col. (i)	-	DA	1.00	-
12	Miscellaneous Transmission Expense (less amortization of reg	Attach. 7, Line 13, Col .(j)	-	TP	1.00	-
13	Total Account 566	(Line 11 plus Line 12) Ties to 321.97.b	-			-
14	TOTAL O&M	(Sum of Lines 1, 4, 7, 8, 9, 13 less Lines 2, 3, 5, 6)	-			-
15	DEPRECIATION EXPENSE (Note U)					
16	Transmission	336.7.b, d &e Attach. 5, Line 13, Col. (k)	-	TP	1.00	-
17	General & Intangible	336.10.b, d &e, 336.1.b, d &e Attach. 7, Line 26, Col. (a)	-	W/S	1.00	-
18	Common	336.11.b, d &e	-	CE	1.00	-
19	Amortization of Abandoned Plant	(Note S) Attach. 7, Line 26, Col. (b)	-	DA	1.00	-
20	TOTAL DEPRECIATION	(Sum of Lines 16 through 19)	-			-
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	263.i Attach. 7, Line 26, Col. (c)	-	W/S	1.00	-
24	Highway and vehicle	263.i Attach. 7, Line 26, Col. (d)	-	W/S	1.00	-
25	PLANT RELATED					
26	Property	263.i Attach. 7, Line 26, Col. (e)	-	GP	1.00	-
27	Gross Receipts	263.i Attach. 7, Line 26, Col. (f)	-	NA	zero	-
28	Other	263.i Attach. 7, Line 26, Col. (g)	-	GP	1.00	-
29	Payments in lieu of taxes	263.i Attach. 7, Line 26, Col. (h)	-	GP	1.00	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	-			-
31	INCOME TAXES	(Note G)				
32	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)}	WCLTD = Page 4, Line 20	28.11%			
33	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 23	23.21%			
34	FIT & SIT & P	(Note G)				
35	IT Gross Up Factor (T/(1-T))		39.10%			
36	1 / (1 - T) = (T from line 32)		1.39			
37	Amortized Investment Tax Credit	266.8f (enter negative) Attach. 7, Line 26, Col. (i)	-			
38	Excess Deferred Income Taxes	(enter negative) Attach. 7, Line 26, Col. (j)	-			
39	Tax Effect of Permanent Differences	Attach. 7, Line 5, Col. (a) (Note W)	-			
40	Income Tax Calculation	(Line 33 times Line 46)	-	NA		-
41	ITC adjustment	(Line 36 times Line 37)	-	NP	1.00	-
42	Excess Deferred Income Tax Adjustment	(Line 36 times Line 38)	-	NP	1.00	-
43	Permanent Differences Tax Adjustment	(Line 36 times Line 39)	-	NP	1.00	-
44	Total Income Taxes	(Sum of Lines 40 through 43)	-			-
45	RETURN					
46	Rate Base times Return	(Page 2, Line 37 times Page 4, Line 23)	-	NA		-
47	REV. REQUIREMENT	(Sum of Lines 14, 20, 30, 44 and 46)	-			-

Formula Rate - Non-Levelized | Rate Formula Template Attachment H-35A | For the 12 months ended mm/dd/yyyy

Utilizing FERC Form 1 Data
Mid-Atlantic Offshore Development, LLC

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)		(4)	(5)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total Transmission plant	(Page 2, Line 2, Column 3)				-		
2	Less Transmission plant excluded from ISO rates	(Note H)				-		
3	Less Transmission plant included in OATT Ancillary Services	(Note I)				-		
4	Transmission plant included in ISO rates	(Line 1 minus Lines 2 & 3)				-		
5	Percentage of Transmission plant included in ISO Rates	(Line 4 divided by Line 1)			TP=	1.0000		
6	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
7	Production	354.20.b	-	-	-			
8	Transmission	354.21.b	-	1.00	-			
9	Distribution	354.23.b	-	-	-	W&S Allocator		
10	Other	354.24,25,26.b	-	-	-	($ / Allocation)		
11	Total (W& S Allocator is 1 if lines 7-10 are zero)	(Sum of Lines 7 through 10)	-		- =	1.00000	=	W/S
12	COMMON PLANT ALLOCATOR (CE) (Note J and X)		$		% Electric	W&S Allocator		
13	Electric	200.3.c	-		(line 13 / line 16)	(line 11)		CE
14	Gas	201.3.d	-		- *	1.00000	=	1.00000
15	Water	201.3.e	-					
16	Total	(Sum of Lines 13 through 15)	-					
17	RETURN (R)	(Note V)				$		
18					Cost			
19			$	%	(Notes K, Q, & R)	Weighted		
20	Long Term Debt	(Attachment 4, line 8 Notes P, Q & R)	1	50.0%	7.37%	0.0369	=WCLTD	
21	Preferred Stock (112.3.c)	(Attachment 4, line 9 Notes Q & R)	-	0.0%	-	-		
22	Common Stock	(Attachment 4, line 10 Notes K, Q & R)	1	50.0%	10.76%	0.0538		
23	Total	(Sum of Lines 20 through 22)	1			0.0907	=R	
24	REVENUE CREDITS							
25	ACCOUNT 447 (SALES FOR RESALE) (Note L)	310 -311						
26	a. Bundled Non-RQ Sales for Resale	311.x.h				-		
27	b. Bundled Sales for Resale	Attach 7, line 39, col (a)				-		
28	Total of (a)-(b)					-		
29	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note M) Attach 5, line 39, col (b)				-		
30	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	330.x.n						
31	a. Transmission charges for all transmission transactions	Attach 7, line 39, col (c)				-		
	b. Transmission charges associated with Project detailed on the							
32	Project Rev Req Schedule Col. 10.	Attach 7, line 39, col (d)				-		
33	Total of (a)-(b)					-		

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Reserved
B	The balances in Accounts 190, 281, 282 and 283 are allocated to transmission plant included in rate base based on Company accounting records. Accumulated deferred income tax amounts associated with asset or liability accounts excluded from rate base (such as ADIT related to asset retirement obligations and certain tax-related regulatory assets or liabilities) do not affect rate base. To the extent that the normalization requirements apply to ADIT activity in the projected net revenue requirement calculation or the true-up adjustment calculation, the ADIT amounts are computed in accordance with the proration formula of Treasury regulation Section 1.167(l)-1(h)(6). The remaining ADIT activity is averaged.
C	Identified in Form 1 as being only transmission related.
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1.
E	Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1 found at 323.191.b. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 36). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:	FIT =	21.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

H	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
I	Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
J	Enter dollar amounts
K	The cost of common stock includes both MAOD's base return on equity ("ROE") and the 50 basis point ROE adder for RTO participation granted Mid-Atlantic Offshore Development, LLC, 186 FERC ¶ 61,116, P 48 (2024).
L	Page 4, Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1.
M	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
N	Company does not have any grandfathered agreements.
O	The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. Revenue Credits do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not included in this template (e.g., direct assignment facilities and GSUs) the costs of which are not recovered under this Rate Formula Template.
P	For the purposes of calculating AFUDC in the period before MAOD obtains construction debt financing, debt during the construction period will be priced at the three-month Term Secured Overnight Financing Rate ("SOFR"), plus 200 basis points (the "Proxy Debt Rate"). The Proxy Debt Rate will be updated monthly based on the monthly change in the three-month Term SOFR and used in the AFUDC calculation until the actual Construction Debt financing is placed, at which point the actual cost of the Construction Debt financing will be reflected in the calculation of AFUDC. At or near the time of commercial operation, MAOD would expect to refinance the construction loan with longer-term debt financing, which would then be reflected as the actual cost of debt on Attachment 9.
Q	The capital structure will be 50% equity and 50% debt until Mid-Atlantic Offshore Development, LLC's first transmission project enters service, after which the capital structure will be the actual capital structure.
R	Calculate using 13 month average balance, except ADIT.
S	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must receive FERC authorization before recovering the cost of abandoned plant.
T	Recovery of Regulatory Asset is permitted only for pre-commercial expenses incurred prior to the date when Mid-Atlantic Offshore Development, LLC may first recover costs under the PJM Tariff, as authorized by the Commission. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.
U	Excludes Asset Retirement Obligation balances
V	Company shall be allowed recovery of costs related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.
W	The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference
X	Reserved
Y	Unfunded Reserves are customer contributed capital such as when employee vacation expense is accrued but not yet incurred. Also, pursuant to Special Instructions to Accounts 228.1 through 228.4, no amounts shall be credited to accounts 228.1 through 228.4 unless authorized by a regulatory authority or authorities to be collected in a utility's rates.
Z	DA = Direct Assignment; GP = Gross Plant Allocator (page 2, line 6); N/A = Not Applicable; NP = Net Plant Allocator (page 2, line 20); TP = Transmission Plant Allocator (page 4, line 5); WS = Wage and Salary Allocator (page 4, line 11); CE = Common PLant Allocator (page 4, line 14).

For the 12 months ended mm/dd/yyyy

Attachment 1
Project Revenue Requirement Worksheet
Mid-Atlantic Offshore Development, LLC

To be completed in conjunction with Attachment H-XXA.

Line No.	(1)	(2) Attachment H, Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant plus CWIP	Attach H-XX, p 2, line 2 col 5 (Note A)	-	
2	Net Transmission Plant plus CWIP and Abandoned Plant	Attach H-XX, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note B)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H-XX, p 2, line 14 col 5 (Note A)	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col 3)	0.00%	0.00%
	GENERAL AND INTANGIBLE (G&I) DEPRECIATION EXPENSE			
5	Total G&I Depreciation Expense	Attach H-XX, p 3, line 17, col 5 (Note H)	-	
6	Annual Allocation Factor for G,I & C Depreciation Expense	(line 5 divided by line 1, col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H-XX, p 3, line 30 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col 3)	0.00%	0.00%
9	Less Revenue Credits	Attach H-XX, p 1, line 7 col 5	-	
10	Annual Allocation Factor for Revenue Credits	(line 9 divided by line 1, col 3)	0.00%	0.00%
11	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6, 8, and 10**		**0.00%**
	INCOME TAXES			
12	Total Income Taxes	Attach H-XX, p 3, line 44 col 5	-	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2, col 3)	0.00%	0.00%
	RETURN			
14	Return on Rate Base	Attach H-XX, p 3, line 46 col 5	-	
15	Annual Allocation Factor for Return on Rate Base	(line 14 divided by line 2, col 3)	0.00%	0.00%
16	**Annual Allocation Factor for Return**	**Sum of lines 13 and 15**		**0.00%**

Attachment 1
Project Revenue Requirement Worksheet
Mid-Atlantic Offshore Development, LLC

This worksheet is used to compute project specific revenue requirements for any projects for which such calculation is required by PJM. Other projects which comprise the remaining revenue requirement on Attachment H-35 will not be entered on this schedule.

Any hypothetical amounts or project names in a filed template will be removed and replaced with actual amounts in the first year actual values are available without the need for a section 205 filing to modify the template.

	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	**Project Name**	**PJM Category**	**RTEP Project Number Or Other Identifier**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant or CWIP balance**	**Annual Allocation Factor for Return**	**Annual Return Charge**
				(Note D)	(Page 1, line 11)	(Col. 3 * Col. 4)	(Note E)	(Page 1, line 16)	(Col. 6 * Col. 7)
1a	Project A	Schedule 12	AAAA	-	0.00%	-	$ -	0.00%	-
1b	Project B		BBBB	-	0.00%	-	$ -	0.00%	-
2	Total Schedule 12			-		-	$ -		-
3a	Project C		CCCC	-	0.00%	-	$ -	0.00%	-
3b	Project D		DDDD	-	0.00%	-	$ -	0.00%	-
4	Total Zonal			-		-	$ -		-
5	Other			-	0.00%	-	$ -	0.00%	-
6	Annual Totals			-		-	-		-

For the 12 months ended mm/dd/yyyy

Attachment 1
Project Revenue Requirement Worksheet
Mid-Atlantic Offshore Development, LLC

Line No.	(9) Project Depreciation/Amortization Expense	(10) Annual Revenue Requirement	(11) Incentive Return in Basis Points	(12) Total Annual Revenue Requirement	(13) True-Up Adjustment	(14) Net Revenue Requirement
	(Note F)	(Sum Col. 5 + Col. 9 + (Column 6 * Line 16))	(Note G)	(Sum Col. 10)	(Note I)	(Sum Col. 12 & 13)
1a	-	-	50	-	-	-
1b	-	-	-		-	-
2	-	-	50	-	-	-
3a	-	-	-	-	-	-
3b	-	-	-	-	-	-
4	-	-		-	-	-
5	-	-	-	-	-	-
6	-	-	50	-	-	-

Notes

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-XX inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order.

B Net Plant is that identified on page 2 line 14 of Attachment H-XX inclusive of any CWIP or unamortized Abandoned Plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.

C General and Intangible Depreciation and Amortization Expense includes all expense not directly associated with a project, which is entered on page 3, column 9.

D Project Gross Plant is the total capital investment including CWIP for the project calculated from Company books and records in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

E Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation plus CWIP in rate base if applicable and Unamortized Abandoned Plant.

F Project Depreciation Expense is the actual value booked for the project (excluding General and Intangible depreciation) at Attachment H-XXA, page 3, line 16, plus amortization of Abandoned Plant at Attachment H-XXA, page 3, line 19.

G The Annual Return Charge on Page 2, column 2 the 50 basis point ROE adder for RTO participation granted Mid-Atlantic Offshore Development, LLC, 186 FERC ¶ 61,116, P 48 (2024).

H Reserved

I True-Up Adjustment is calculated on the Project True-up Schedule for the relevant true-up year.

J For each project listed on this Attachment 1 that is a Required Transmission Enhancement, the net revenue requirement shown in Column (16) is: (i) the annual transmission revenue requirement for purposes of determining the PJM OATT Schedule 12 Transmission Enhancement Charges associated with that Required Transmission Enhancement, and (ii) the Annual Revenue Requirement for purposes of Schedule 12, Appendix A for that Required Transmission Enhancement.

For the 12 months ended mm/dd/yyyy

Attachment 2
Formula Rate True-Up
Mid-Atlantic Offshore Development, LLC

This Attachment is used to calculate the annual formula rate true-up. Any projects for which the RTO requires a true-up on an individual project basis, as shown on Attachment 1, will be computed separately. The remainder of the revenue requirement will also be trued up. The utility will individually enter the projected true-up year revenue requirements in Column C. A percentage of total will be calculated in Column D. Actual revenue received during the true-up year is entered into Column E, line 2 and allocated using the Column D percentage. The utility will prepare this formula rate template with the actual inputs for the true-up year, with the resulting revenue requirement for each line being separately entered in Column F. In Col. G, Col. F is subtracted from Col. E to calculate the true-up adjustment. Interest on the true-up is computed in Column H. Any adjustments to prior period true-ups are entered in Col. I. Col. J computes the total true-up as the sum of Col. G, H and I.

Any hypothetical amounts or project names in a filed template will be removed and replaced with actual amounts in the first year actual values are available without the need for a section 205 filing to modify the template.

Line				Projected True-Up Year Revenue Requirement Calculation		True-Up Year Revenue Received[1]	Actual True-Up Year Revenue Req.	Annual True-Up Calculation			
1	**True-Up Year**										
2	YYYY					-					
	A		B	C	D	E	F	G	H	I	J
	Project Name	PJM Category	Project # Or Other Identifier	Net Revenue Requirement[2]	% of Total Revenue Requirement	Allocation of Revenue Received (E, Line 2) x (D)	True-Up Net Revenue Requirement[3]	Net Under/(Over) Collection (F)-(E)	True-Up Interest Income (Expense)[4] (D) x (H, line 10)	Prior Period Adjustment with Interest[5]	Total True-Up (G) + (H) + (I)
3	Remaining Attachment H-XX	-		-	-	-	-	-	-	-	-
4a	Project A	Schedule 12	AAAA	-	-	-	-	-	-	-	-
4b	Project B	-	BBBB	-	-	-	-	-	-	-	-
5	Total Schedule 12			-		-		-	-	-	-
6a	Project C	-	CCCC	-	-	-	-	-	-	-	-
6b	Project D	-	DDDD	-	-	-	-	-	-	-	-
7	Total Zonal			-		-		-	-	-	-
8	Other	-		-	-	-	-	-	-	-	-
9	Total Annual Revenue Requirements			-	0.0%	-	-	-	-	-	-
10							Total Interest on True-Up - Attachment 6		-		

Prior Period Adjustment

Line	A		B
	Prior Period Adjustment (Note 5)	Source	Adjustment Amount
11	Description of Adjustment		-

Notes
1) The revenue received is the total amount of revenue distributed to company in the year as shown on pages 328-330 of the Form No 1. The Revenue Received is input on line 2, Col. E.
2) From the Attachment 1, lines 1a through 6, col. 16 from the template in which the true-up year revenue requirement was initially projected.
3) From True-Up revenue requirement template Attachment 1, lines 1a through 6, col. 14.
4) Interest due on the true up is calculated for the 24 month period from the start of the true-up year until the end of the year following the true-up year when the true up will be included in rates. Total True up Interest calculated on Attachment 5 and allocated to projects based on the percentage in Column D.
5) Corrections to true-ups for previous rate years including interest will be computed and entered on the appropriate line 3-8 above.

Attachment 3
Rate Base Worksheet
Mid-Atlantic Offshore Development, LLC

		Gross Plant In Service		CWIP	PHFFU	Working Capital		Accumulated Depreciation	
Line No	Month	Transmission	General & Intangible	CWIP in Rate Base	Plant Held for Future Use	Materials & Supplies	Prepayments	Transmission	General & Intangible
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Attachment H, Page 2, Line No:	2	4	27	31	34	35	9	11
		207.58.g for end of year, records for other months	205.5.g & 207.99.g for end of year, records for other months	(Note C)	214.x.d for end of year, records for other months	227.8.c & 227.16.c for end of year, records for other months	111.57.c for end of year, records for other months	219.25.c for end of year, records for other months	219.28.c & 200.21.c for end of year, records for other months
1	December Prior Year	-	-	-	-	-	-	-	-
2	January	-	-	-	-	-	-	-	-
3	February	-	-	-	-	-	-	-	-
4	March	-	-	-	-	-	-	-	-
5	April	-	-	-	-	-	-	-	-
6	May	-	-	-	-	-	-	-	-
7	June	-	-	-	-	-	-	-	-
8	July	-	-	-	-	-	-	-	-
9	August	-	-	-	-	-	-	-	-
10	September	-	-	-	-	-	-	-	-
11	October	-	-	-	-	-	-	-	-
12	November	-	-	-	-	-	-	-	-
13	December	-	-	-	-	-	-	-	-
14	Average of the 13 Monthly Balances	-	-	-	-	-	-	-	-

Adjustments to Rate Base

Line No	Month	Unamortized Regulatory Asset	Unamortized Abandoned Plant	Account No. 281 Accumulated Deferred Income Taxes (Note D)	Account No. 282 Accumulated Deferred Income Taxes (Note D)	Account No. 283 Accumulated Deferred Income Taxes (Note D)	Account No. 190 Accumulated Deferred Income Taxes (Note D)	Account No. 255 Accumulated Deferred Investment Credit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Attachment H, Page 2, Line No:	28	29	22	23	24	25	26
		Notes A & E	Notes B & F	272.8.b & 273.8.k	274.2.b & 275.2.k	276.9.b & 277.9.k	234.8.b & c	Consistent with 266.8.b & 267.8.h
15	December Prior Year	-	-	-	-	-	-	-
16	January	-	-	[redacted]				
17	February	-	-					
18	March	-	-					
19	April	-	-					
20	May	-	-					
21	June	-	-					
22	July	-	-					
23	August	-	-					
24	September	-	-					
25	October	-	-					
26	November	-	-					
27	December	-	-	-	-	-	-	-
28	Average of the 13 Monthly Balances	-	-	-	-	-	-	-
		$0.00						

Unfunded Reserves (Notes G & H)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
29	List of all reserves:		Amount	Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account	Enter 1 if the accrual account is included in the formula rate, enter (0) if the accrual account is NOT included in the formula rate	Enter the percentage paid for by the transmission formula customers	Allocation (Plant or Labor Allocator)	Amount Allocated, col. c x col. d x col. e x col. f x col. g
30a		Reserve 1	-	-				-
30b		Reserve 2	-	-				-
30c		Reserve 3						
30d		Reserve 4						
30e		…						
30f		…	-	-				-
31		Total	-					-

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.

B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.

C Includes only CWIP authorized by the Commission for inclusion in rate base.

D ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances.

E Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.

F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.

G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account.

H Calculate using 13 month average balance, except ADIT.

For the 12 months ended mm/dd/yyyy

Attachment 4
Return on Rate Base Worksheet
Mid-Atlantic Offshore Development, LLC

RETURN ON RATE BASE (R)

			$
1	Long Term Interest (117, sum of 62.c through 67.c) (Note D)		
2	Preferred Dividends (118.29c) (positive number)		-
3	Proprietary Capital (Line 25 (c))		-
4	Less Preferred Stock (Line 9)		-
5	Less Account 216.1 Undistributed Subsidiary Earnings (Line 25 (d))		-
6	Less Account 219 Accum. Other Comprehensive Income (Line 25 (e))		-
7	Common Stock	(Sum of Lines 3 through 6)	-

			$	%	Cost	Weighted	
8	Long Term Debt	Line 25 (a), Note A and Attachment H-XX Note Q	0.5	50.00%	7.37%	3.69%	=WCLTD
9	Preferred Stock	Line 25 (b), Note B and Attachment H-XX Note Q	-	0.00%	0.00%	0.00%	
10	Common Stock	Line 7, Note C and Attachment H-XX Note K	0.5	50.00%	10.76%	5.38%	
11	Total	(Sum of Lines 8 through 10)	1			9.065%	=R

	Monthly Balances for Capital Structure	(a) Long Term Debt (112.24.c)	(b) Preferred Stock (112.3.c)	(c) Proprietary Capital (112.16.c)	(d) Undistributed Sub Earnings 216.1	(e) Accum Other Comp. Income 219
12	December Prior Year	$ -	-	$ -	-	-
13	January	$ -	-	$ -	-	-
14	February	$ -	-	$ -	-	-
15	March	$ -	-	$ -	-	-
16	April	$ -	-	$ -	-	-
17	May	$ -	-	$ -	-	-
18	June	$ -	-	$ -	-	-
19	July	$ -	-	$ -	-	-
20	August	$ -	-	$ -	-	-
21	September	$ -	-	$ -	-	-
22	October	$ -	-	$ -	-	-
23	November	$ -	-	$ -	-	-
24	December	$ -	-	$ -	-	-
25	Average of the 13 Monthly Balances	$ -	-	$ -	-	-

Notes

A Long Term debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c to 21.c in the Form No. 1, the cost is calculated by dividing line 1 by the Long Term Debt balance on line 8.

B Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c in the Form No. 1

C Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on Form 1 page 112 line 16.c less lines 3.c , 12.c, and 15.c

D Long-term interest will exclude any short-term interest included in FERC Account 430, Interest on Debt to Associated Companies

For the 12 months ended mm/dd/yyyy

Attachment 5
Interest on True-Up
Mid-Atlantic Offshore Development, LLC

Line	YYYY Projected Revenue Requirement (Note A)		YYYY Actual Net Revenue Requirement (Note B)		Over (Under) Recovery
1	$ -	Less	$ -	Equals	$ -

Note A - Projected ATRR for the true-up year from Page 1, Line 1 of Projection Attachment H-XXA minus Line 6 of Projection Attachment H-XXA.
Note B - Actual Net ATRR for the true-up year from Page 1, Line 9 of True-Up Attachment H-XXA.

	Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Monthly Interest Rate on Attachment 6a	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2				0.000%				

An over or under collection will be recovered pro rata over year collected, held for one year and returned pro rata over next year

	Calculation of Interest					**Monthly**		
3	January	YYYY	-	0.000%	12	-		-
4	February	YYYY	-	0.000%	11	-		-
5	March	YYYY	-	0.000%	10	-		-
6	April	YYYY	-	0.000%	9	-		-
7	May	YYYY	-	0.000%	8	-		-
8	June	YYYY	-	0.000%	7	-		-
9	July	YYYY	-	0.000%	6	-		-
10	August	YYYY	-	0.000%	5	-		-
11	September	YYYY	-	0.000%	4	-		-
12	October	YYYY	-	0.000%	3	-		-
13	November	YYYY	-	0.000%	2	-		-
14	December	YYYY	-	0.000%	1	-		-
15						-		-
						Annual		
16	January through December	YYYY+1	-	0.000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
17	January	YYYY+2	-	0.000%		-	-	-
18	February	YYYY+2	-	0.000%		-	-	-
19	March	YYYY+2	-	0.000%		-	-	-
20	April	YYYY+2	-	0.000%		-	-	-
21	May	YYYY+2	-	0.000%		-	-	-
22	June	YYYY+2	-	0.000%		-	-	-
23	July	YYYY+2	-	0.000%		-	-	-
24	August	YYYY+2	-	0.000%		-	-	-
25	September	YYYY+2	-	0.000%		-	-	-
26	October	YYYY+2	-	0.000%		-	-	-
27	November	YYYY+2	-	0.000%		-	-	-
28	December	YYYY+2	-	0.000%		-	-	-
29						-		
30	Total Amount of True-Up Adjustment						-	
31	Less Over (Under) Recovery						-	
32	Total Interest						-	

For the 12 months ended mm/dd/yyyy

Attachment 5a
True-Up Interest Rate Calculator
Mid-Atlantic Offshore Development, LLC

This Attachment is used to compute the interest rate to be applied to each year's revenue requirement true-up.

	Applicable FERC Interest Rate (Note A):		
1	YYYY	January	0.00%
2	YYYY	February	0.00%
3	YYYY	March	0.00%
4	YYYY	April	0.00%
5	YYYY	May	0.00%
6	YYYY	June	0.00%
7	YYYY	July	0.00%
8	YYYY	August	0.00%
9	YYYY	September	0.00%
10	YYYY	October	0.00%
11	YYYY	November	0.00%
12	YYYY	December	0.00%
13	YYYY+1	January	0.00%
14	YYYY+1	February	0.00%
15	YYYY+1	March	0.00%
16	YYYY+1	April	0.00%
17	YYYY+1	May	0.00%
18	YYYY+1	June	0.00%
19	YYYY+1	July	0.00%
20	YYYY+1	August	0.00%
21	YYYY+1	September	0.00%
22	Average Rate		0.00%
23	Monthly Average Rate		0.00%

Note A - Lines 1-21 are the FERC interest rates under section 35.19a of the regulations for the period shown. Line 22 is the average of lines 1-21.

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

1 **Account 190**

	Days in Period					Averaging with Proration - Projected		
2	A	B	C	D	E	F	G	H
3	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)
4								
5	December 31st balance Prorated Items							-
6	January	31	31	335	0.92		-	-
7	February	28	28	307	0.84		-	-
8	March	31	31	276	0.76		-	-
9	April	30	30	246	0.67		-	-
10	May	31	31	215	0.59		-	-
11	June	30	30	185	0.51		-	-
12	July	31	31	154	0.42		-	-
13	August	31	31	123	0.34		-	-
14	September	30	30	93	0.25		-	-
15	October	31	31	62	0.17		-	-
16	November	30	30	32	0.09		-	-
17	December	31	31	1	0.00		-	-
18		Total	365			-	-	
19								
20	Beginning Balance							-
21	Less: Portion not related to transmission							-
22	Less: Portion not reflected in rate base							-
23	Subtotal: Portion reflected in rate base				Line 20 minus Lines 21 and 22			-
24	Less: Portion subject to proration							-
25	Portion subject to averaging				Line 23 minus Line 24			-
26								
27	Ending Balance							-
28	Less: Portion not related to transmission							-
29	Less: Portion not reflected in rate base							-
30	Subtotal: Portion reflected in rate base				Line 27 minus Lines 28 and 29			-
31	Less: Portion subject to proration (before proration)							-
32	Portion subject to averaging (before averaging)				Line 30 minus Line 31			-
33								
34	Ending balance of portion subject to proration (prorated)				(Line 17, Col H)			-
35	Average balance of portion subject to averaging				(Line 25 + Line 32)/2			-
36	Amount reflected in rate base				Line 34 plus Line 35			-

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

37 **Account 281**

Line	Days in Period					Averaging with Proration - Projected		
38	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**
39	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)
40								
41	December 31st balance Prorated Items							-
42	January	31	31	335	0.92	-	-	-
43	February	28	28	307	0.84	-	-	-
44	March	31	31	276	0.76	-	-	-
45	April	30	30	246	0.67	-	-	-
46	May	31	31	215	0.59	-	-	-
47	June	30	30	185	0.51	-	-	-
48	July	31	31	154	0.42	-	-	-
49	August	31	31	123	0.34	-	-	-
50	September	30	30	93	0.25	-	-	-
51	October	31	31	62	0.17	-	-	-
52	November	30	30	32	0.09	-	-	-
53	December	31	31	1	0.00	-	-	-
54		Total	365			-	-	
55								
56	Beginning Balance							-
57	Less: Portion not related to transmission							-
58	Less: Portion not reflected in rate base							-
59	Subtotal: Portion reflected in rate base				Line 56 minus Lines 57 and 58			-
60	Less: Portion subject to proration							-
61	Portion subject to averaging				Line 59 minus Line 60			-
62								
63	Ending Balance							-
64	Less: Portion not related to transmission							-
65	Less: Portion not reflected in rate base							-
66	Subtotal: Portion reflected in rate base				Line 63 minus Lines 64 and 65			-
67	Less: Portion subject to proration (before proration)							-
68	Portion subject to averaging (before averaging)				Line 66 minus Line 67			-
69								
70	Ending balance of portion subject to proration (prorated)				(Line 53, Col H)			-
71	Average balance of portion subject to averaging				(Line 61 + Line 68)/2			-
72	Amount reflected in rate base				Line 70 plus Line 71			-

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

Line	A	B	C	D	E	F	G	H
73	**Account 282**							
74	**Days in Period**					**Averaging with Proration - Projected**		
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**
75	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)
76								
77	December 31st balance Prorated Items							-
78	January	31	31	335	0.92		-	-
79	February	28	28	307	0.84		-	-
80	March	31	31	276	0.76		-	-
81	April	30	30	246	0.67		-	-
82	May	31	31	215	0.59		-	-
83	June	30	30	185	0.51		-	-
84	July	31	31	154	0.42		-	-
85	August	31	31	123	0.34		-	-
86	September	30	30	93	0.25		-	-
87	October	31	31	62	0.17		-	-
88	November	30	30	32	0.09		-	-
89	December	31	31	1	0.00		-	-
90		Total	365			-	-	
91								
92	Beginning Balance							-
93	Less: Portion not related to transmission							-
94	Less: Portion not reflected in rate base							-
95	Subtotal: Portion reflected in rate base				Line 92 minus Lines 93 and 94			-
96	Less: Portion subject to proration							-
97	Portion subject to averaging				Line 95 minus Line 96			-
98								
99	Ending Balance							-
100	Less: Portion not related to transmission							-
101	Less: Portion not reflected in rate base							-
102	Subtotal: Portion reflected in rate base				Line 99 minus Lines 100 and 101			-
103	Less: Portion subject to proration (before proration)							-
104	Portion subject to averaging (before averaging)				Line 102 minus Line 103			-
105								
106	Ending balance of portion subject to proration (prorated)				(Line 89, Col H)			-
107	Average balance of portion subject to averaging				(Line 97 + Line 104)/2			-
108	Amount reflected in rate base				Line 106 plus Line 107			-

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

Line	A	B	C	D	E	F	G	H
109	**Account 283**							
110	**Days in Period**					**Averaging with Proration - Projected**		
111	**A** Month	**B** Days in the Month	**C** Number of Days Prorated	**D** Total Days in Future Portion of Test Period	**E** Proration Amount (C / D)	**F** Projected Monthly Activity	**G** Prorated Projected Monthly Activity (E x F)	**H** Prorated Projected Balance (Cumulative Sum of G)
112								
113	December 31st balance Prorated Items							-
114	January	31	31	335	0.92		-	-
115	February	28	28	307	0.84		-	-
116	March	31	31	276	0.76		-	-
117	April	30	30	246	0.67		-	-
118	May	31	31	215	0.59		-	-
119	June	30	30	185	0.51		-	-
120	July	31	31	154	0.42		-	-
121	August	31	31	123	0.34		-	-
122	September	30	30	93	0.25		-	-
123	October	31	31	62	0.17		-	-
124	November	30	30	32	0.09		-	-
125	December	31	31	1	0.00		-	-
126		Total	365			-	-	
127								
128	Beginning Balance							-
129	Less: Portion not related to transmission							-
130	Less: Portion not reflected in rate base							-
131	Subtotal: Portion reflected in rate base				Line 128 minus Lines 129 and 130			-
132	Less: Portion subject to proration							-
133	Portion subject to averaging				Line 131 minus Line 132			-
134								
135	Ending Balance							-
136	Less: Portion not related to transmission							-
137	Less: Portion not reflected in rate base							-
138	Subtotal: Portion reflected in rate base				Line 135 minus Lines 136 and 137			-
139	Less: Portion subject to proration (before proration)							-
140	Portion subject to averaging (before averaging)				Line 138 minus Line 139			-
141								
142	Ending balance of portion subject to proration (prorated)				(Line 125, Col H)			-
143	Average balance of portion subject to averaging				(Line 133 + Line 140)/2			-
144	Amount reflected in rate base				Line 142 plus Line 143			-

Attachment 7
Expense and Other Support
Mid-Atlantic Offshore Development, LLC

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	A&G Expenses	FERC Annual Fees	EPRI & Reg. Comm. Exp. & Non-safety Ad.	Transmission Related Reg. Comm. Exp.	Transmission Lease Payments	Amortization of Regulatory Asset	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Depreciation Expense - Transmission
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H, Page 3, Line No.:	1	2	3	4	5	6	7	9	11	12	16
	Form No. 1	321.112.b	321.97.b	321.96.b	323.197.b	(Note E)	(Note E)	(Note E)	Portion of Transmission O&M	Portion of Account 566	Balance of Account 566	336.7.b, d & e
1	January	-	-	-	-	-	-	-	-	-	-	-
2	February	-	-	-	-	-	-	-	-	-	-	-
3	March	-	-	-	-	-	-	-	-	-	-	-
4	April	-	-	-	-	-	-	-	-	-	-	-
5	May	-	-	-	-	-	-	-	-	-	-	-
6	June	-	-	-	-	-	-	-	-	-	-	-
7	July	-	-	-	-	-	-	-	-	-	-	-
8	August	-	-	-	-	-	-	-	-	-	-	-
9	September	-	-	-	-	-	-	-	-	-	-	-
10	October	-	-	-	-	-	-	-	-	-	-	-
11	November	-	-	-	-	-	-	-	-	-	-	-
12	December	-	-	-	-	-	-	-	-	-	-	-
13	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Month	Depreciation Expense - General & Intangible	Amortization of Abandoned Plant	Payroll Taxes	Highway & Vehicle Taxes	Property Taxes	Gross Receipts Taxes	Other Taxes	Payments in lieu of Taxes	Amortized Investment Tax Credit (266.8f)	Excess Deferred Income Taxes	Tax Effect of Permanent Differences
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H, Page 3, Line Number	17	19	23	24	26	27	28	29	37	38	39
	Form No. 1	336.10.b, d & e, 336.1.b, d & e	(Note S)	263.i	263.i	263.i	263.i	263.i	263.i	266.8.f	(Note G)	(Note W)
14	January	-	-	-	-	-	-	-	-	-	-	-
15	February	-	-	-	-	-	-	-	-	-	-	-
16	March	-	-	-	-	-	-	-	-	-	-	-
17	April	-	-	-	-	-	-	-	-	-	-	-
18	May	-	-	-	-	-	-	-	-	-	-	-
19	June	-	-	-	-	-	-	-	-	-	-	-
20	July	-	-	-	-	-	-	-	-	-	-	-
21	August	-	-	-	-	-	-	-	-	-	-	-
22	September	-	-	-	-	-	-	-	-	-	-	-
23	October	-	-	-	-	-	-	-	-	-	-	-
24	November	-	-	-	-	-	-	-	-	-	-	-
25	December	-	-	-	-	-	-	-	-	-	-	-
26	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Attachment 7
Expense and Other Support
Mid-Atlantic Offshore Development, LLC

		(a)	(b)	(c)	(d)	(e)
		Bundled Sales for Resale included on page 4 of Attachment H	**ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)**	**Transmission charges for all transmission transactions**	**Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10.**	**Account No. 457.1 Scheduling**
	Attachment H, Page 4, Line No:	27	29	31	32	Attach H, p 1 line 4
		(Note L)	(Note M)	Portion of Account 456.1	Portion of Account 456.1	
27	January	-	-	-	-	-
28	February	-	-	-	-	-
29	March	-	-	-	-	-
30	April	-	-	-	-	-
31	May	-	-	-	-	-
32	June	-	-	-	-	-
33	July	-	-	-	-	-
34	August	-	-	-	-	-
35	September	-	-	-	-	-
36	October	-	-	-	-	-
37	November	-	-	-	-	-
38	December	-	-	-	-	-
39	Total	$ -	$ -	$ -	$ -	$ -
40						

Notes

For the 12 months ended mm/dd/yyyy

Attachment 8
Stated Value Inputs
Mid-Atlantic Offshore Development, LLC

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

MAOD's stated ROE is set to: 10.26% plus an RTO participation incentive of 50 basis points for a total of 10.76%

2. Depreciation Rates

FERC Account	Depr %
351	5.25%
352	2.08%
353	3.25%
354	2.15%
355	2.67%
356	2.08%
357	1.69%
358	2.00%
359	1.54%
382	20.00%
383	14.29%
391	6.67%
392.1	13.57%
392.2	7.92%
394	6.67%
397	6.67%
398	6.67%

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED mm/dd/yyyy

Line			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		**t=N**	Issue Date	Maturity Date	ORIGINAL ISSUANCE	Net Proceeds At Issuance	Net Amount Outstanding at t=N	Months Outstanding at t=N	Average Net Outstanding in Year* z*	Weighted Outstanding Ratios	Effective Cost Rate	Weighted Debt Cost at t = N
2	**Long Term Debt Cost at Year Ended:**	**mm/dd/yyyy**			(table 2, col. cc)	(table 2, col. gg)			((col e. * col. F)/12)	(col. g/col. g total)	(Table 2, Col. kk)	(h) * (i)
3	First Mortgage Bonds:											
4	(1)				$ -	$ -			$ -			
5	(2)				$ -	$ -			$ -			
6	(3)				$ -	$ -			$ -			
7	(4)				$ -	$ -			$ -			
8	(5)				$ -	$ -			$ -			
9	(6)				$ -	$ -			$ -			
10					$ -		$ -		$ -	0.000%		7.37% **

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (6.8200%, 5.7504%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (6.95%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 20, column 4 of formula rate Attachment H-XX. Before debt is obtained, a proxy interest rate which will be priced at the three-month Term Secured Overnight Financing Rate ("SOFR") plus 200 basis points (See also, H-XX, Note P).

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED mm/dd/yyyy

Line			(aa)	(bb)	(cc)	(dd)	(ee)	(ff)	(gg)	(hh)	(ii)	(jj)	(kk)
11	**Long Term Debt Issuances**	Affiliate	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss/Gain on Reacquired Debt	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Annual Interest	Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
12									(col. cc + col. dd - col. ee - col. ff)	((col. gg / col. cc)*100)	Percentage (%)	(col. cc * col. ii)	
13													
14	(1)								$ -		0.00%	$ -	
15	(2)								$ -			$ -	
16	(3)								$ -			$ -	
17	(4)								$ -			$ -	
18	(5)								$ -			$ -	
19	(6)								$ -			$ -	
	TOTALS				$ -	$ -	$ -	$ -	$ -			$ -	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow Co equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows (Ct=1, Ct=2, etc.).

For the 12 months ended mm/dd/yyyy

Workpaper 1a
Utility Gross Plant in Service
Mid-Atlantic Offshore Development,LLC

Line No.	Month/Year	Transmission Plant	General Plant	Intangible Plant	Total
1	December Prior Year	-	-	-	$0
2	January	-	-	-	$0
3	February	-	-	-	$0
4	March	-	-	-	$0
5	April	-	-	-	$0
6	May	-	-	-	$0
7	June	-	-	-	$0
8	July	-	-	-	$0
9	August	-	-	-	$0
10	September	-	-	-	$0
11	October	-	-	-	$0
12	November	-	-	-	$0
13	December	-	-	-	$0
14	13 Month Average	$0	$0	$0	$0
15	Beginning/Ending Average	$0	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 1b
Utility Gross Plant in Service Summary
Mid-Atlantic Offshore Development,LLC

Line No.	FERC Account	FERC Capital Category	Gross Plant in Service
1	350	Land	-
2	351	Energy Storage	-
3	352	Structures and improvements	-
4	353	Station equipment	-
5	354	Towers and fixtures	-
6	355	Poles and fixtures	-
7	356	Overhead conductors and devices	-
8	357	Underground Conduit	-
9	358	Underground conductors and devices	-
10	359	Roads and trails	-
11	359.1	Asset retirement costs for transmission plant	-
12		Total Gross Transmission Plant	$0
13	382	Computer Hardware	-
14	383	Computer Software	-
15	391	Office Furniture and Equipment	-
16	392.1	Transportation Equipment - Light Duty Vehicles	-
17	392.2	Transportation Equipment - Heavy Duty Vehicles	-
18	394	Tools, Shop and Garage Equipment	-
19	397	Communication Equipment	-
20	398	Miscellaneous Equipment	-
21		Total Gross General Plant	$0

For the 12 months ended mm/dd/yyyy

Workpaper 2
Accumulated Depreciation and Amortization
Mid-Atlantic Offshore Development, LLC

		Depreciation			Amortizations		Totals	
Line No.	Month/Year	Transmission Plant	General Plant	Intangible Plant	Rate Base Reg. Asset Pre-development	Deferred Rate Case Expense	Rate Base Subtotal	Total Depreciation and Amortization
1	December Prior Year	-	-	-	-	-	$0	$0
2	January	-	-	-	-	-	$0	$0
3	February	-	-	-	-	-	$0	$0
4	March	-	-	-	-	-	$0	$0
5	April	-	-	-	-	-	$0	$0
6	May	-	-	-	-	-	$0	$0
7	June	-	-	-	-	-	$0	$0
8	July	-	-	-	-	-	$0	$0
9	August	-	-	-	-	-	$0	$0
10	September	-	-	-	-	-	$0	$0
11	October	-	-	-	-	-	$0	$0
12	November	-	-	-	-	-	$0	$0
13	December	-	-	-	-	-	$0	$0
14	13 Month Average	$0	$0	$0	$0	$0	$0	$0
15	Beginning/Ending Average	$0	$0	$0	$0	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 3a
Depreciation and Amortization Expenses
Mid-Atlantic Offshore Development, LLC

Line No.	Description	Amount
1	Transmission Plant	$0
2	General Plant	$0
3	Intangible Plant	$0
4	Total Depreciation Expense	$0
5	Asset retirement costs for transmission plant.	$0
6	ARO Accretion Expense Paid By Customers	$0
7	Rate Base Reg. Asset of Dev. Costs	$0
8	Reg. Asset of Rate Case Expense	$0
9	Total Amortization Expense	$0
10	Total Depreciation and Amortization Expense	$0

Workpaper 3b
Depreciation and Amortization Expenses
Mid-Atlantic Offshore Development, LLC

For the 12 months ended mm/dd/yyyy

Line No.	FERC Account	FERC Capital Category	Gross Plant in Service	Life	Salvage %	Depr Rate	Salvage Expense	Depreciation Expense	Total Salvage and Depreciation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	INTANGIBLE PLANT								
1	301.0	Organization	-	-	-	-	-	-	-
2	302.0	Franchises and Consents	-	-	-	-	-	-	-
3	303.0	Computer Software	-	-	-	-	-	-	-
4	303.1	Contributions in Aid of Construction	-	-	-	-	-	-	-
		Subtotal	-				-	-	-
	TRANSMISSION PLANT								
5	350.0	Land		ND	0.00%	0.00%			$0
6	351.0	Energy Storage		20	-5.00%	5.25%	$0	$0	$0
7	352.0	Structures and improvements		60	-25.00%	2.08%	$0	$0	$0
8	353.0	Station equipment		40	-30.00%	3.25%	$0	$0	$0
9	354.0	Towers and fixtures		65	-40.00%	2.15%	$0	$0	$0
10	355.0	Poles and fixtures		60	-60.00%	2.67%	$0	$0	$0
11	356.0	Overhead conductors and devices		65	-35.00%	2.08%	$0	$0	$0
12	357.0	Underground Conduit		65	-10.00%	1.69%	$0	$0	$0
13	358.0	Underground conductors and devices		55	-10.00%	2.00%	$0	$0	$0
14	359.0	Roads and trails		65	0.00%	1.54%	$0	$0	$0
15									
16		Subtotal	$0			#DIV/0!	$0	$0	$0
17	359.1	Asset retirement costs for transmission plant.	-	-	-	-	-	-	$ -
18	411.10	ARO Accretion Expense Paid By Customers	-	-	-	-	-	-	$ -
	GENERAL PLANT								
19	382.0	Computer Hardware		5	0.00%	20.00%	$0	$0	$0
20	383.0	Computer Software		7	0.00%	14.29%	$0	$0	$0
22	391.0	Office Furniture and Equipment		15	0.00%	6.67%	$0	$0	$0
23	392.1	Transportation Equipment - Light Duty Vehicles		7	5.00%	13.57%	$0	$0	$0
24	392.2	Transportation Equipment - Heavy Duty Vehicles		12	5.00%	7.92%	$0	$0	$0
25	394.0	Tools, Shop and Garage Equipment		15	0.00%	6.67%	$0	$0	$0
26	397.0	Communication Equipment		15	0.00%	6.67%	$0	$0	$0
27	398.0	Miscellaneous Equipment		15	0.00%	6.67%	$0	$0	$0
28		Subtotal	-				-	-	-
	AMORTIZATION								
29	182.3	Rate Base Reg. Asset of Dev. Costs		5	N/A	20.00%		$0	$0
30	186.0	Reg. Asset of Rate Case Expense		3	N/A	33.33%		$0	$0
31		**Grand Total**							$0

For the 12 months ended mm/dd/yyyy

Workpaper 4
Specified Plant Accounts and Deferred Debits
Mid-Atlantic Offshore Development, LLC

Line No.		Balance	Balance	Average Balance
1	Electric Plant Held For Future Use - Account 105	$0	$0	$0
		$0	$0	$0
2	Construction Work in Progress - Account 107	$0	$0	$0
3	Unamoritzed Debt Expenses - Account 181			
4	Other Regulatory Assets - Account 182.3			
	Rate Base Reg. Asset Pre-development	$0	$0	$0
	Total	$ 0	$ 0	$ 0
5	Preliminary Survey and Investigation Charges - Account 183	$0	$0	$0
6	Miscellaneous Deferred Debits - Account 183			
	Deferred Rate Case Expense	$0	$0	$0
7	Accumulated Deferrred Income Taxes - Account 190	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 5
Permanent Difference Tax Adjustment
Mid-Atlantic Offshore Development, LLC

The permanent book/tax differences reflected in recoverable income tax expense are differences between revenues and expenses reflected in the revenue requirement and revenue and deductions reflected in taxable income. As such, non-operating (below-the-line) expenses and income are not included (e.g., accrual of AFUDC-equity, certain lobbying costs). Book depreciation of capitalized AFUDC-equity is reflected in ratemaking, but not for income tax purposes, and, thus, is a permanent book/tax difference in this context. Similarly, amortization of the regulatory asset for pre-commercial carrying charges accrued at an after-tax equity rate of return is permanent difference between recoverable expenses and tax deductions.

Line No.	**Permanent book/tax differences**	Source:	**Amount per Formula Rate Template (a)**
1	Depreciation of AFUDC-equity		-
2	Amortization of carrying charge-equity		-
3	Total permanent book/tax differences		-
4	Tax rate		28.11%
5	Tax effect of permanent book/tax differences		-
6	Tax gross-up factor (1 / (1 - T) from Attachment H-XXA, page 3, line 38)		1.3910
7	Permanent Differences Tax Adjustment		-

For the 12 months ended mm/dd/yyyy

Workpaper 6
Operation and Maintenance Expenses - FERC Account
Mid-Atlantic Offshore Development, LLC

TRANSMISSION OPERATION AND MAINTENANCE EXPENSES

Line No.		Description	Labor	Non-Labor	Total
	Operation				
1	560	Operation Supervision and Engineering	$0	$0	$0
2	561	Load Dispatching	$0	$0	$0
3	562	Station Expenses	$0	$0	$0
4	563	Overhead Line Expenses	$0	$0	$0
5	564	Underground Line Expenses	$0	$0	$0
6	565	Transmission of Electricity by Others	$0	$0	$0
7	566	Miscellaneous Transmission Expenses	$0	$0	$0
8	567	Rents	$0	$0	$0
9		Total Operation	$0	$0	$0
	Maintenance				
10	568	Maintenance Supervision and Engineering	$0	$0	$0
11	566	Maintenance of Structures	$0	$0	$0
12	570	Maintenance of Station Equipment	$0	$0	$0
13	571	Maintenance of Overhead Lines	$0	$0	$0
14	572	Maintenance of Underground Lines	$0	$0	$0
15	573	Maintenance of Miscellaneous Transmission Plant	$0	$0	$0
16		Total Maintenance	$0	$0	$0
17		Total Transmission Expenses	$0	$0	$0

ADMINISTRATIVE AND GENERAL EXPENSES

Line No.		Description	Labor	Non-Labor	Total
	Operation				
18	920	Administrative and General Salaries	$0	$0	$0
19	921	Office Supplies and Expenses	$0	$0	$0
20	922	(Less) Administrative Expenses Transferred -Credit	$0	$0	$0
21	923	Outside Services Employed	$0	$0	$0
22	924	Property Insurance	$0	$0	$0
23	925	Injuries and Damages	$0	$0	$0
24	926	Employee Pensions and Benefits	$0	$0	$0
25	927	Franchise Requirements	$0	$0	$0
26	928	Regulatory Commission Expenses	$0	$0	$0
27	929	(Less) Duplicate Charges - Credit	$0	$0	$0
28	930.1	General Advertising Expenses	$0	$0	$0
29	930.2	Miscellaneous General Expenses	$0	$0	$0
30	931	Rents	$0	$0	$0
31		Total Operation	$0	$0	$0
	Maintenance				
32	935	Maintenance Supervision and Engineering	$0	$0	$0
33		Total Maintenance	$0	$0	$0
34		Total Administrative and General Expenses	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 7

Support for Attachment 2 - Formula Rate True-Up

Mid-Atlantic Offshore Development, LLC

Line No.			
1	Actual Annual Revenue Earned Account 456.1 330.x.n	-	
2	Less ATRR Balancing Entry Included in Account 456.1	-	
3	Less ATRR revenue credits that are accounted separately on Attachment H-35A, page 1,	-	
4	Actual Annual Revenue Received from PJM toward 20XX ATRR	-	To Attachment 2, line 2, column E

Notes

A On its Form No. 1, Mid-Atlantic Offshore Development, LLC may report the revenue earned or accrued rather than the cash received.

B This workpaper reconciles the Form No. 1 value with the cash received value used in Attachment 2 necessary for proper calculation.

Exhibit No. MAOD-24
Mid-Atlantic Offshore Development, LLC
Attachment H-35B
Formula Rate Implementation Protocols

Attachment H-35B
Mid-Atlantic Offshore Development, LLC
FORMULA RATE IMPLEMENTATION PROTOCOLS

Definitions

"Actual Net Revenue Requirement" means the actual net transmission revenue requirement calculated and posted on the PJM website. The Actual Net Revenue Requirement will be calculated in accordance with MAOD's Formula Rate and based upon MAOD's actual costs and expenditures for the relevant rate year. The posting of MAOD's Actual Net Revenue Requirement on the PJM website will be provided on June 1 of each year following the First Rate Year.

"Annual True-Up" means MAOD's Actual Net Revenue Requirement for the prior Rate Year. The Annual True-Up will include the True-Up Adjustment for the prior Rate Year.

"First Rate Year" means the first Rate Year in which MAOD receives revenues pursuant to its Formula Rate.

"Formal Challenge" means a written challenge to an Annual True-Up or Projected Net Revenue Requirement submitted to the Federal Energy Regulatory Commission (the "Commission" or "FERC") as provided in Section IV of these Mid-Atlantic Offshore Development, LLC ("MAOD") Formula Rate Implementation Protocols ("Protocols").

"Formula Rate" means these Protocols (to be included as Attachment H-35B of the PJM Interconnection, L.L.C. ("PJM") FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.

"Formula Rate Template" means the collection of formulas and worksheets, unpopulated with any data, to be included as Attachment H-35A of the PJM Tariff.

"Interested Parties" include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.

"Informal Challenge" means a written challenge to the Annual True-Up or Projected Net Revenue Requirement submitted to MAOD as provided in Section IV of these Protocols.

"Projected Net Revenue Requirement" means the projected net transmission revenue requirement calculated for the relevant, upcoming Rate Year. As applicable, the Projected Net Revenue Requirement includes the most recently calculated True-Up Adjustment, with interest.

"Publication Date" means the date on which the Annual True-Up is posted on the PJM website.

The posting of the Projected Net Revenue Requirement will be the Publication Date for periods before the first Annual True-Up.

"Rate Year" means the twelve (12) consecutive month period that begins on January 1 and continues through December 31 of the relevant year.

"True-Up Adjustment" means the incremental difference between the revenues collected by PJM based on the Projected Net Revenue Requirement (net of the True-Up Adjustment from the prior Rate Year) and the Actual Net Revenue Requirement for the same Rate Year, which shall be provided in the Annual True-Up. The True-Up Adjustment will be a component of the Projected Net Revenue Requirement.

Section I. Applicability

The following procedures shall apply to the calculation of the Actual Net Revenue Requirements, True-Up Adjustments, and Projected Net Revenue Requirements of MAOD.

If a due date referenced in these Protocols falls on a weekend or a holiday recognized by FERC, the deadline shall be extended to the next business day consistent with 18 C.F.R. § 385.2007.

Section II. Annual True-Up and Projected Net Revenue Requirement

A. On or before June 1 of each Rate Year following MAOD's First Rate Year, MAOD shall determine its Annual True-Up in accordance with its Formula Rate and Section VII of these Protocols, including the True-Up Adjustment to be included in its Projected Net Revenue Requirement for the subsequent Rate Year.

B. Following MAOD's First Rate Year, on or before June 1, MAOD shall provide its Annual True-Up, including the Actual Net Revenue Requirement and True-Up Adjustment, to PJM and cause such information to be posted on the PJM website and OASIS. Within five (5) days of such posting, PJM shall provide notice of such posting via the PJM Members Committee email subscription ("PJM Exploder List"). Interested Parties can subscribe to the PJM Exploder List on the PJM website.

C. No later than September 30 preceding the First Rate Year and each Rate Year thereafter, MAOD shall provide its Projected Net Revenue Requirement to PJM and cause such information to be posted on the PJM website and OASIS. Within five (5) days of posting of the Projected Net Revenue Requirement, PJM shall provide notice of such posting to the PJM Exploder List.

   1. In the event that MAOD's Projected Net Revenue Requirement for the First Rate Year will be collected during only part of the calendar year and is not provided to PJM by September 30 of the preceding year, MAOD will prepare a Projected Net Revenue Requirement for the First Rate Year using the most recent information available, and the Projected Net Revenue Requirement will be posted on the PJM website and OASIS and distributed to the PJM Exploder List at least sixty (60) days prior to the rates becoming effective. The Projected Net Revenue

Requirement for a partial First Rate Year will reflect MAOD's net revenue requirement only for the applicable partial Rate Year.[1] MAOD will conduct a virtual meeting with Interested Parties on the Projected Net Revenue Requirement for the First Rate Year between twenty (20) to forty (40) days after posting. Notice of the customer meeting, including the time, date, and remote access information, shall be posted on the PJM website and OASIS and distributed to the PJM Exploder List no less than seven (7) days prior to such meeting.

D. Any delay in the Publication Date will result in an equivalent extension of time for the submission of information requests discussed in Section III of these Protocols.

E. The Annual True-Up shall:

1. Include a workable data-populated Formula Rate Excel template and underlying workpapers in native format with all formulas and links intact;

2. Be based on MAOD's FERC Form No. 1 for the prior calendar year;[2]

3. Provide the Formula rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Annual True-Up that are not otherwise available in the FERC Form No. 1;

4. Provide sufficient information to enable Interested Parties to replicate the calculation of the Annual True-Up results from the FERC Form No. 1;

5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;

6. Identify all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;

7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;

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[1] If the initial use of the Formula Rate covers only part of a calendar year, the initial Projected Net Revenue Requirement will be divided by the number of months the Formula Rate will be in effect to calculate the monthly projected cost of service to be collected each month of the First Rate Year. Similarly, the Actual Net Revenue Requirement will be divided by the number of months the rate is in effect to calculate the actual cost of service to be collected each month of the First Rate Year. The first True-up Adjustment will compare the Projected Net Revenue Requirement collected and the actual Net Revenue Requirement for that initial Rate Year.

[2] It is the intent of the Formula Rate, including the supporting explanations and allocations described therein, that each input to the Formula Rate for purposes of determining the Actual Net Revenue Requirement for a given Rate Year will be either taken directly from the FERC Form No. 1 or reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the referenced form is superseded, the successor form(s) shall be utilized and supplemented as necessary to provide equivalent information as that provided in the superseded form. If the referenced form is discontinued, equivalent information as that provided in the discontinued form shall be utilized.

8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):

   a. Identify Accounting Changes, including

      i. the initial implementation of an accounting standard or policy;

      ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

      iii. correction of errors and prior period adjustments that impact the True-Up Adjustment calculation;

      iv. the implementation of new estimation methods or policies that change prior estimates; and

      v. changes to income tax elections.

   b. Identify items included in the Annual True-Up at an amount other than on a historic cost basis (e.g., fair value adjustments);

   c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Annual True-Up; and

   d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c of these Protocols, a narrative explanation of the individual impact of such changes on the True-Up Adjustment.

9. Provide for the applicable Rate Year the following information related to affiliate costs for shared services, if applicable: (1) a detailed description of the methodologies used to allocate and directly assign costs between MAOD and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year and the reasons and justifications for those changes; and (2) the magnitude of such costs that have been allocated or directly assigned between MAOD and each affiliate by service category or function.

F. The Projected Net Revenue Requirement shall:

1. Include a workable data-populated Formula Rate template and underlying

workpapers in native format with all formulas and links intact;

2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and workpapers for data that are used in the Projected Net Revenue Requirement;

3. Provide sufficient information to enable Interested Parties to replicate the calculation of the Projected Net Revenue Requirement; and

4. With respect to any Accounting Change:

    a. Identify any Accounting Changes, including

        i. the initial implementation of an accounting standard or policy;

        ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;

        iii. correction of errors and prior period adjustments that impact the Projected Net Revenue Requirement calculation;

        iv. the implementation of new estimation methods or policies that change prior estimates; and

        v. changes to income tax elections.

    b. Identify items included in the Projected Net Revenue Requirement at an amount other than on a historic cost basis (e.g., fair value adjustments);

    c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the Projected Net Revenue Requirement; and

    d. Provide, for each item identified pursuant to items II.F.4.a - II.F.4.c of these Protocols, a narrative explanation of the individual impact of such changes on the Projected Net Revenue Requirement.

G. Following the posting of an Annual True-Up, MAOD shall hold an open virtual meeting among Interested Parties (“Annual True-Up Meeting”) no sooner than twenty (20) days after the Publication Date. The Annual True-Up Meeting shall occur no later than September 1. No less than seven (7) days prior to such Annual True-Up Meeting, MAOD shall provide notice on the PJM website and OASIS of the time, date, and remote access information for the Annual True-Up Meeting and PJM shall provide notice of such meeting to the PJM Exploder List. The Annual True-Up Meeting shall (i) permit MAOD to explain and clarify its Annual True-Up and (ii) provide Interested Parties an opportunity to seek reasonable information and clarifications from MAOD about the Annual True-Up.

H. MAOD shall hold an open virtual meeting among Interested Parties ("Annual Projected Rate Meeting") no sooner than twenty (20) days after the date that the Projected Net Revenue Requirement is posted on the PJM website and OASIS (as described in Section II.C of these Protocols). The Annual Projected Rate Meeting shall occur no later than October 31. No less than seven (7) days prior to such Annual Projected Rate Meeting, MAOD shall provide notice on the PJM website and OASIS of the time, date, and remote access information for the Annual Projected Rate Meeting and PJM shall provide notice of such meeting to the PJM Exploder List. The Annual Projected Rate Meeting shall (i) permit MAOD to explain and clarify its Projected Net Revenue Requirement and (ii) provide Interested Parties an opportunity to seek reasonable information and clarifications from MAOD about the Projected Net Revenue Requirement.

1. Revisions to the Projected Net Revenue Requirement. To the extent MAOD agrees to make changes in the Projected Net Revenue Requirement for a particular Rate Year, such revised Projected Net Revenue Requirement shall be promptly posted on the PJM website and OASIS and distributed to the PJM Exploder List. Changes posted prior to December 1 of the preceding Rate Year, shall be reflected in the Projected Net Revenue Requirement collected during the Rate Year; changes posted after that date will be reflected, as appropriate, in the True-up Adjustment for the Rate Year.

Section III. Information Exchange Procedures

Each Annual True-Up and Projected Net Revenue Requirement shall be subject to the following information exchange procedures ("Information Exchange Procedures"):

A. Interested Parties shall have one hundred and eighty (180) days following the Publication Date (unless such period is extended with the written consent of MAOD) to serve reasonable information and document requests on MAOD ("Information Exchange Period"). Such information and document requests shall be limited to what is necessary to determine:

1. the extent or effect of an Accounting Change;
2. whether the Annual True-Up or Projected Net Revenue Requirement fails to include data properly recorded in accordance with these Protocols;
3. the proper application of the Formula Rate, including the procedures in these Protocols;
4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual True-Up or Projected Net Revenue Requirement;
5. the prudence of actual costs and expenditures, including procurement methods and cost control methodologies;

6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

7. any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the Formula Rate.

The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.

B. MAOD shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. MAOD shall respond to all information and document requests by no later than two hundred and twenty (220) days following a Publication Date, unless otherwise agreed by MAOD and the relevant stakeholder.

C. MAOD will cause to be posted on the PJM website and OASIS all information requests from Interested Parties and MAOD's response(s) to such requests. Informational requests and responses that include confidential information will not be posted and instead will be made available to parties who have executed a Protective Agreement.

Section IV. Challenge Procedures

A. Interested Parties shall have until two hundred and forty (240) days following a Publication Date (unless such period is extended with the written consent of MAOD) to review the inputs, supporting explanations, allocations and calculations and to notify MAOD in writing of any specific Informal Challenges to the Annual True-Up or Projected Net Revenue Requirement. The period of time from the Publication Date until the date that is two hundred and forty (240) days later shall be referred to as the Review Period. Failure to pursue an issue through an Informal Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual True-Up or Projected Net Revenue Requirement shall bar pursuit of such issue with respect to that Annual True-Up or Projected Net Revenue Requirement under the challenge procedures set forth in these Protocols; however, it shall not bar pursuit of such issue through an Informal Challenge or the lodging of a Formal Challenge as to such issue if it also relates to a subsequent Annual True-Up or Projected Net Revenue Requirement. This Section IV.A. in no way shall affect a party's rights under section 206 of the Federal Power Act ("FPA") as set forth in Section IV.I. of these Protocols.

B. Informal Challenges shall be subject to the resolution procedures and limitations in this Section IV.A. party submitting an Informal Challenge to MAOD must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge. MAOD shall make a good faith effort to respond to any Informal Challenge within twenty (20) business days of service of such challenge. MAOD, and where applicable, PJM, shall appoint a senior representative to work with the party that submitted the Informal Challenge (or its representative) toward a resolution of the challenge. If MAOD disagrees with such challenge, MAOD will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information. No Informal Challenge may be submitted after the final day of the Review Period, and MAOD must respond to all Informal Challenges by no later than thirty (30) days after the end of the Review Period, unless the Review Period is extended by MAOD.

C. Formal Challenges shall be filed pursuant to these Protocols and shall satisfy all of the following requirements.

1. A Formal Challenge shall:

a. Clearly identify the action or inaction which is alleged to violate the filed rate formula or Protocols;

b. Explain how the action or inaction violates the filed rate formula or Protocols;

c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:

i. The extent or effect of an Accounting Change;

ii. Whether the Annual True-Up or Projected Net Revenue Requirement fails to include data properly recorded in accordance with these Protocols;

iii. The proper application of the Formula Rate and procedures in these Protocols;

iv. The accuracy of data and consistency with the Formula Rate of the charges shown in the Annual True-Up or Projected Net Revenue Requirement;

v. The prudence of actual costs and expenditures;

vi. The effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or

vii. Any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the action or inaction;

e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;

f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;

g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and

h. State whether the filing party utilized the Informal Challenge procedures described in these Protocols to dispute the action or inaction raised by the Formal Challenge, and, if not, describe why not.

2. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on MAOD. Service to MAOD must be simultaneous with the filing of the Formal Challenge within the same docket as MAOD's Informational Filing. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3). The party filing the Formal Challenge shall serve the individual listed as the contact person on MAOD's Informational Filing required under Section VI of these Protocols.

D. Informal and Formal Challenges shall be limited to all issues that may be necessary to determine: (1) the extent or effect of an Accounting Change; (2) whether the Annual True-Up or Projected Net Revenue Requirement fails to include data properly recorded in accordance with these Protocols; (3) the proper application of the Formula Rate and procedures in these Protocols; (4) the accuracy of data and consistency with the Formula Rate of the calculations shown in the Annual True-Up and Projected Net Revenue Requirement; (5) the prudence of actual costs and expenditures; (6) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or (7) any other information that may reasonably have substantive effect on the calculation of the charge pursuant to the formula.

E. MAOD will cause to be posted on the PJM website and OASIS all Informal Challenges from Interested Parties and MAOD's response(s) to such Informal Challenges. Informal Challenges and responses that include confidential information will not be posted and instead will be made available to parties who have executed a Protective Agreement.

F. Any changes or adjustments to the Annual True-Up or Projected Net Revenue Requirement resulting from the Information Exchange Procedures and Informal Challenge processes that are agreed to by MAOD will be reported in the Informational Filing required pursuant to Section VI of these Protocols. Any such changes or adjustments agreed to by MAOD on or before the last day of the Information Exchange Period will be reflected in the Projected Net Revenue Requirement for the upcoming Rate Year plus interest calculated in accordance with Section VII.2. Any changes or adjustments agreed to by MAOD after the last day of the Information Exchange Period will be reflected in the following year's Annual True-Up, as discussed in Section V of these Protocols.

G. An Interested Party shall have until seventy-five (75) days following the Review Period (unless such date is extended with the written consent of MAOD) to make a Formal Challenge with FERC. A Formal Challenge shall be filed in the same docket as MAOD's Informational Filing discussed in Section VI of these Protocols. MAOD shall respond to the Formal Challenge by the deadline established by FERC. A party may not pursue a Formal Challenge if that party did not submit an Informal Challenge regarding the applicable issue during the applicable Review Period.

H. In any proceeding initiated by FERC concerning the Annual True-Up or Projected Net Revenue Requirement or in response to a Formal Challenge, MAOD shall bear the burden, consistent with section 205 of the FPA, of proving that it has correctly applied the terms of the Formula Rate consistent with these Protocols, and that it followed the applicable requirements and procedures in these Protocols. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.

I. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of MAOD to file unilaterally, pursuant to section 205 of the FPA and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the FPA and the regulations thereunder.

J. No party shall seek to modify the Formula Rate under the Challenge Procedures set forth in these Protocols and the Annual True-Up and Projected Net Revenue Requirement shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, an FPA section 205 or section 206 filing.

K. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1, shall first raise the matter with MAOD through an Informal Challenge in accordance with this Section IV before pursuing a Formal Challenge.

Section V. Changes to Annual True-Up Adjustment or Projected Net Revenue Requirement

Except as provided in Section IV.F. of these Protocols, any changes to the data inputs, including but not limited to revisions to MAOD's FERC Form No. 1, or as a result of any FERC proceeding to consider the Annual True-Up or Projected Net Revenue Requirement, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the next annual posting of the Projected Net Revenue Requirement. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these Protocols.

Section VI. Informational Filings

A. When MAOD submits its first Projected Net Revenue Requirement to PJM and by September 30 of each year thereafter, MAOD shall submit to FERC an informational filing ("Informational Filing") of its Projected Net Revenue Requirement for the upcoming Rate Year, including its Annual True-Up (reflecting any changes that have been resolved as of the Informational Filing). This Informational Filing must include the information that is reasonably necessary to determine: (1) that input data under the Formula Rate are properly recorded in any underlying workpapers; (2) that MAOD has properly applied the Formula Rate and these procedures; (3) the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review; (4) the extent of accounting changes that affect Formula Rate inputs; and (5) the reasonableness of projected costs. The Informational Filing must also describe any corrections or adjustments made as a result of the Information Exchange Procedures, Informal or Formal Challenge Procedures, or otherwise, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Informal or Formal Challenge Procedures.

Additionally, the Informational Filing must include the following information related to affiliate services cost allocation for the applicable Rate Year: (1) a detailed description of the methodologies used to allocate and directly assign costs between MAOD and its affiliates by service category or function, including any changes to such cost allocation and methodologies from the prior year, and the reasons and justification for those changes; and (2) the magnitude of such costs that have been allocated or directly assigned between MAOD and each affiliate by service category or function. Within five (5) days of such Informational Filing, PJM shall provide notice of the Informational Filing via the PJM Exploder List and by posting the docket number assigned to MAOD's Informational Filing on the PJM website and OASIS.

B. Any challenges to the implementation of the MAOD Formula Rate must be made through the Challenge Procedures described in Section IV of these Protocols or in a separate complaint proceeding, and not in response to the Informational Filing.

Section VII. Calculation of True-Up Adjustment

The True-Up Adjustment will be determined in the following manner:

1. Actual transmission revenues received the previous calendar year ("True-Up Year") shall be compared to the Actual Net Revenue Requirement (calculated in accordance with MAOD's Formula Rate) for the True-Up Year, as determined using MAOD's completed FERC Form No. 1 report, to determine any excess or shortfall. The excess or shortfall due to the actual revenue received versus the Actual Net Revenue Requirement shall constitute the True-Up Adjustment. The True-Up Adjustment and related calculations shall be posted on the PJM website and OASIS no later than June 1 following the issuance of the FERC Form No. 1 for the previous year, as set forth in Section II of these Protocols.

2. Interest on any over recovery of the Actual Net Revenue Requirement shall be determined based on the Commission's regulation at 18 C.F.R § 35.19a. Interest on any under recovery of the Actual Net Revenue Requirement shall be determined using the interest rate equal to: (i) MAOD's actual short-term debt costs capped at the interest rate determined based on the Commission's regulation at 18 C.F.R § 35.19a; or (ii) if MAOD does not have short-term debt, then the interest rate determined based on the Commission's regulation at 18 C.F.R § 35.19a.

   In either case, an average interest rate shall be used to calculate the interest payable for the twenty-four (24) months during which the over or under recovery in the revenue requirement exists. The interest rate to be applied to the over or under recovery amounts will be determined using the average rate for the twenty-one (21) months preceding October of the current year. The interest amount will be included in the Projected Net Revenue Requirement posted by September 30.

3. MAOD may accelerate the refund of any over recovery amounts by one year. The interest calculation will be adjusted to reflect the period the over recovery exists.

Section VIII. Stated Inputs to the Formula Rate

For (i) rate of return on common equity; and (ii) depreciation and/or amortization rates, the values used in the Formula Rate shall be stated values in the Formula Rate Template that may only be changed pursuant to an FPA section 205 or section 206 filing. These stated-value inputs are specified in Attachment 8 of the Formula Rate Template.

Workpapers of William (“Bill”) R. Davis
Mid-Atlantic Offshore Development, LLC

Rate Formula Template Attachment H-35A
Utilizing FERC Form 1 Data
Mid-Atlantic Offshore Development, LLC

For the 12 months ended mm/dd/yyyy

Line No.	(1)	(2) Source	(3)		(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, Line 47)					$ -
	REVENUE CREDITS	(Note O)	Total		Allocator (Note Z)		
2	Account No. 454	(page 4, Line 29)	-	TP		1.00	-
3	Account No. 456.1	(page 4, Line 33)	-	TP		1.00	-
4	Account No. 457.1 Scheduling	Attachment 7, line 39, col c	-	TP		1.00	-
5	Revenues from Grandfathered Interzonal Transactions	(Note N)	-	TP		1.00	-
6	Revenues from service provided by the ISO at a discoun		-	TP		1.00	-
7	TOTAL REVENUE CREDITS	(Sum of Lines 2 through 6)	-				-
8	NET REVENUE REQUIREMENT	(Line 1 minus Line 7)					$ -
9	Prior Period Adjustment	Attachment 2, Line 11	-	DA		1.00000	-
10	True-up Adjustment with Interest	Attachment 2, line 9, Col. J	-	DA		1.00000	0
11	NET REVENUE REQUIREMENT	(Line 8 plus Line 9 and 10)					$ -

Formula Rate - Non-Levelized | Rate Formula Template Attachment H-35A | For the 12 months ended mm/dd/yyyy

Utilizing FERC Form 1 Data

Mid-Atlantic Offshore Development, LLC

Line No.	(1)	(2) Source	(3) Company Total		(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:						
	GROSS PLANT IN SERVICE (Notes U and R)						
1	Production	205.46.g for end of year, records for other months	-	N/A			-
2	Transmission	Attachment 3, Line 14, Col. (b)	-	TP		1.00	-
3	Distribution	207.75.g for end of year, records for other months	-	NA		-	-
4	General & Intangible	Attachment 3, Line 14, Col. (c)	-	W/S		1.00	-
5	Common	356.1 for end of year, records for other months	-	CE		1.00	-
6	TOTAL GROSS PLANT	(Sum of Lines 1 through 5)	-		GP=	1.00	-
7	ACCUMULATED DEPRECIATION (Notes U and R)						
8	Production	219.20-24.c for end of year, records for other months	-	NA			-
9	Transmission	Attachment 4, Line 14, Col. (h)	-	TP		1.00	-
10	Distribution	219.26.c for end of year, records for other months	-	NA		-	-
11	General & Intangible	Attachment 4, Line 14, Col. (i)	-	W/S		1.00	-
12	Common	356.1 for end of year, records for other months	-	CE		1.00	-
13	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 8 through 12)	-				-
14	NET PLANT IN SERVICE						
15	Production	(Line 1 minus Line 8)	-				-
16	Transmission	(Line 2 minus Line 9)	-				-
17	Distribution	(Line 3 minus Line 10)	-				-
18	General & Intangible	(Line 4 minus Line 11)	-				-
19	Common	(Line 5 minus Line 12)	-			I/D	-
20	TOTAL NET PLANT	(Sum of Lines 15 through 19)	-		NP=	1.00	-
21	ADJUSTMENTS TO RATE BASE (Note R)						
22	Account No. 281 (enter negative)	Attach 3, Line 28, Col. (d)/Attach 6, Line 72, Col. H (Note B)	-	NA		zero	-
23	Account No. 282 (enter negative)	Attach 3, Line 28, Col. (e)/Attach 6, Line 108, Col. H (Note B)	-	NP		1.00	-
24	Account No. 283 (enter negative)	Attach 3, Line 28, Col. (f)/Attach 6, Line 144, Col. H (Note B)	-	NP		1.00	-
25	Account No. 190	Attach 3, Line 28, Col. (g)/Attach 6, Line 36, Col. H (Note B)	-	NP		1.00	-
26	Account No. 255 (enter negative)	Attachment 3, Line 28, Col. (h) (Note B)	-	NP		1.00	-
26a	Unfunded Reserves (enter negative)	Attachment 3, Line 31, Col. (h) (Note Y)	-	DA		1.00	-
27	CWIP	Attachment 3, Line 14, Col. (d)	-	DA		1.00	-
28	Unamortized Regulatory Asset	Attachment 3, Line 28, Col. (b) (Note T)	-	DA		1.00	-
29	Unamortized Abandoned Plant	Attachment 3, Line 28, Col. (c) (Note S)	-	DA		1.00	-
30	TOTAL ADJUSTMENTS	(Sum of Lines 22 through 29)	-				-
31	PLANT HELD FOR FUTURE USE	Attachment 3, Line 14, Col. (e) (Note C)	-	TP		1.00	-
32	WORKING CAPITAL	(Note D)					
33	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	-				-
34	Materials & Supplies	Attachment 3, Line 14, Col. (f) (Note C)	-	TP		1.00	-
35	Prepayments (Account 165)	Attachment 3, Line 14, Col. (g)	-	GP		1.00	-
36	TOTAL WORKING CAPITAL	(Sum of Lines 33 through 35)	-				-
37	RATE BASE	(Sum of Lines 20, 30, 31, and 36)	-				-

Formula Rate - Non-Levelized

Rate Formula Template Attachment H-35A
Utilizing FERC Form 1 Data
Mid-Atlantic Offshore Development, LLC

For the 12 months ended mm/dd/yyyy

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b Attach. 7, Line 13, Col. (a)	0	TP	1.00	-
2	Less Account 566 (Misc Trans Expense)	321.97.b Attach. 7, Line 13, Col. (b)	-	TP	1.00	-
3	Less Account 565	321.96.b Attach. 7, Line 13, Col. (c)	-	TP	1.00	-
4	A&G	323.197.b Attach. 7, Line 13, Col. (d)	-	W/S	1.00	-
5	Less FERC Annual Fees	Attach. 7, Line 13, Col. (e)	-	W/S	1.00	-
6	Less EPRI & Reg. Comm. Exp. & Non-safety Ad.	(Note E) Attach. 7, Line 13, Col. (f)	-	W/S	1.00	-
7	Plus Transmission Related Reg. Comm. Exp.	(Note E) Attach. 7, Line 13, Col. (g)	-	TP	1.00	-
8	Common	356.1	-	CE	1.00	-
9	Transmission Lease Payments	Attach. 7, Line 13, Col (h)	-	DA	1.00	-
10	Account 566					
11	Amortization of Regulatory Asset	(Note T) Attach. 7, Line 13, Col. (i)	-	DA	1.00	-
12	Miscellaneous Transmission Expense (less amortization of re	Attach. 7, Line 13, Col .(j)	-	TP	1.00	-
13	Total Account 566	(Line 11 plus Line 12) Ties to 321.97.b	-			-
14	TOTAL O&M	(Sum of Lines 1, 4, 7, 8, 9, 13 less Lines 2, 3, 5, 6)	-			-
15	DEPRECIATION EXPENSE (Note U)					
16	Transmission	336.7.b, d &e Attach. 5, Line 13, Col. (k)	-	TP	1.00	-
17	General & Intangible	336.10.b, d &e, 336.1.b, d &e Attach. 7, Line 26, Col. (a)	-	W/S	1.00	-
18	Common	336.11.b, d &e	-	CE	1.00	-
19	Amortization of Abandoned Plant	(Note S) Attach. 7, Line 26, Col. (b)	-	DA	1.00	-
20	TOTAL DEPRECIATION	(Sum of Lines 16 through 19)	-			-
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	263.i Attach. 7, Line 26, Col. (c)	-	W/S	1.00	-
24	Highway and vehicle	263.i Attach. 7, Line 26, Col. (d)	-	W/S	1.00	-
25	PLANT RELATED					
26	Property	263.i Attach. 7, Line 26, Col. (e)	-	GP	1.00	-
27	Gross Receipts	263.i Attach. 7, Line 26, Col. (f)	-	NA	zero	-
28	Other	263.i Attach. 7, Line 26, Col. (g)	-	GP	1.00	-
29	Payments in lieu of taxes	263.i Attach. 7, Line 26, Col. (h)	-	GP	1.00	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	-			-
31	INCOME TAXES	(Note G)				
32	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)}	WCLTD = Page 4, Line 20	28.11%			
33	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 23	23.21%			
34	FIT & SIT & P	(Note G)				
35	IT Gross Up Factor (T/(1-T))		39.10%			
36	1 / (1 - T) = (T from line 32)		1.39			
37	Amortized Investment Tax Credit	266.8f (enter negative) Attach. 7, Line 26, Col. (i)	-			
38	Excess Deferred Income Taxes	(enter negative) Attach. 7, Line 26, Col. (j)	-			
39	Tax Effect of Permanent Differences	Attach. 7, Line 5, Col. (a) (Note W)	-			
40	Income Tax Calculation	(Line 33 times Line 46)	-	NA		-
41	ITC adjustment	(Line 36 times Line 37)	-	NP	1.00	-
42	Excess Deferred Income Tax Adjustment	(Line 36 times Line 38)	-	NP	1.00	-
43	Permanent Differences Tax Adjustment	(Line 36 times Line 39)	-	NP	1.00	-
44	Total Income Taxes	(Sum of Lines 40 through 43)	-			-
45	RETURN					
46	Rate Base times Return	(Page 2, Line 37 times Page 4, Line 23)	-	NA		-
47	REV. REQUIREMENT	(Sum of Lines 14, 20, 30, 44 and 46)	-			-

Formula Rate - Non-Levelized | Rate Formula Template Attachment H-35A Utilizing FERC Form 1 Data Mid-Atlantic Offshore Development, LLC | For the 12 months ended mm/dd/yyyy

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)		(4)		(5)		
	TRANSMISSION PLANT INCLUDED IN ISO RATES								
1	Total Transmission plant	(Page 2, Line 2, Column 3)					-		
2	Less Transmission plant excluded from ISO rates	(Note H)					-		
3	Less Transmission plant included in OATT Ancillary Services	(Note I)					-		
4	Transmission plant included in ISO rates	(Line 1 minus Lines 2 & 3)					-		
5	Percentage of Transmission plant included in ISO Rates	(Line 4 divided by Line 1)				TP=	1.0000		
6	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
7	Production	354.20.b	-	-	-				
8	Transmission	354.21.b	-	1.00	-				
9	Distribution	354.23.b	-	-	-		W&S Allocator		
10	Other	354.24,25,26.b	-	-	-		($ / Allocation)		
11	Total (W& S Allocator is 1 if lines 7-10 are zero)	(Sum of Lines 7 through 10)	-		-	=	1.00000	=	W/S
12	COMMON PLANT ALLOCATOR (CE) (Note J and X)		$		% Electric		W&S Allocator		
13	Electric	200.3.c	-		(line 13 / line 16)		(line 11)		CE
14	Gas	201.3.d	-		-	*	1.00000	=	1.00000
15	Water	201.3.e	-						
16	Total	(Sum of Lines 13 through 15)	-						
17	RETURN (R)	(Note V)					$		
18					Cost				
19			$	%	(Notes K, Q, & R)		Weighted		
20	Long Term Debt	(Attachment 4, line 8 Notes P, Q & R)	1	50.0%	7.37%		0.0369	=WCLTD	
21	Preferred Stock (112.3.c)	(Attachment 4, line 9 Notes Q & R)	-	0.0%	-		-		
22	Common Stock	(Attachment 4, line 10 Notes K, Q & R)	1	50.0%	10.76%		0.0538		
23	Total	(Sum of Lines 20 through 22)	1				0.0907	=R	
24	REVENUE CREDITS								
25	ACCOUNT 447 (SALES FOR RESALE) (Note L)	310 -311							
26	a. Bundled Non-RQ Sales for Resale	311.x.h					-		
27	b. Bundled Sales for Resale	Attach 7, line 39, col (a)					-		
28	Total of (a)-(b)						-		
29	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	(Note M) Attach 5, line 39, col (b)					-		
30	ACCOUNT 456.1 (OTHER ELECTRIC REVENUES)	330.x.n							
31	a. Transmission charges for all transmission transactions	Attach 7, line 39, col (c)					-		
	b. Transmission charges associated with Project detailed on the								
32	Project Rev Req Schedule Col. 10	Attach 7, line 39, col (d)					-		
33	Total of (a)-(b)						-		

Formula Rate - Non-Levelized | Rate Formula Template Attachment H-35A | For the 12 months ended mm/dd/yyyy
Utilizing FERC Form 1 Data
Mid-Atlantic Offshore Development, LLC

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	Reserved
B	The balances in Accounts 190, 281, 282 and 283 are allocated to transmission plant included in rate base based on Company accounting records. Accumulated deferred income tax amounts associated with asset or liability accounts excluded from rate base (such as ADIT related to asset retirement obligations and certain tax-related regulatory assets or liabilities) do not affect rate base. To the extent that the normalization requirements apply to ADIT activity in the projected net revenue requirement calculation or the true-up adjustment calculation, the ADIT amounts are computed in accordance with the proration formula of Treasury regulation Section 1.167(l)-1(h)(6). The remaining ADIT activity is averaged.
C	Identified in Form 1 as being only transmission related
D	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 14, column 5 minus amortization of Regulatory Asset at page 3, line 11, column 5. Prepayments are the electric related prepayments booked to Account No. 165 and reported on pages 111, line 57 in the Form 1.
E	Page 3, Line 6 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1 found at 323.191.b. Page 3, Line 7-Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
F	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
G	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 36). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:	FIT =	21.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes

H	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test
I	Removes dollar amount of transmission plant to be included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
J	Enter dollar amounts
K	The cost of common stock includes both MAOD's base return on equity ("ROE") and the 50 basis point ROE adder for RTO participation granted Mid-Atlantic Offshore Development, LLC, 186 FERC ¶ 61,116, P 48 (2024)
L	Page 4, Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.
M	Includes income related only to transmission facilities, such as pole attachments, rentals and special us
N	Company does not have any grandfathered agreements.
O	The revenues credited on page 1 lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. Revenue Credits do not include revenues associated with FERC annual charges, gross receipts taxes, facilities not included in this template (e.g., direct assignment facilities and GSUs) the costs of which are not recovered under this Rate Formula Template.
P	For the purposes of calculating AFUDC in the period before MAOD obtains construction debt financing, debt during the construction period will be priced at the three-month Term Secured Overnight Financing Rate ("SOFR"), plus 200 basis points (the "Proxy Debt Rate"). The Proxy Debt Rate will be updated monthly based on the monthly change in the three-month Term SOFR and used in the AFUDC calculation until the actual Construction Debt financing is placed, at which point the actual cost of the Construction Debt financing will be reflected in the calculation of AFUDC. At or near the time of commercial operation, MAOD would expect to refinance the construction loan with longer-term debt financing, which would then be reflected as the actual cost of debt on Attachment 9.
Q	The capital structure will be 50% equity and 50% debt until Mid-Atlantic Offshore Development, LLC's first transmission project enters service, after which the capital structure will be the actual capital structu
R	Calculate using 13 month average balance, except ADIT
S	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must receive FERC authorization before recovering the cost of abandoned pl
T	Recovery of Regulatory Asset is permitted only for pre-commercial expenses incurred prior to the date when Mid-Atlantic Offshore Development, LLC may first recover costs under the PJM Tariff, as authorized by the Commission. Recovery of any other regulatory assets requires authorization fron Commission. A carrying charge will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.
U	Excludes Asset Retirement Obligation balances
V	Company shall be allowed recovery of costs related to interest rate locks. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedg
W	The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference
X	Reserved
Y	Unfunded Reserves are customer contributed capital such as when employee vacation expense is accrued but not yet incurred. Also, pursuant to Special Instructions to Accounts 228.1 through 228.4, no amounts shall be credited to accounts 228.1 through 228.4 unless authorized by a regulatory authority or authorities to be collected in a utility's rates.
Z	DA = Direct Assignment; GP = Gross Plant Allocator (page 2, line 6); N/A = Not Applicable; NP = Net Plant Allocator (page 2, line 20); TP = Transmission Plant Allocator (page 4, line 5); WS = Wage and Salary Allocator (page 4, line 11); CE = Common PLant Allocator (page 4, line 14).

For the 12 months ended mm/dd/yyyy

Attachment 1
Project Revenue Requirement Worksheet
Mid-Atlantic Offshore Development, LLC

To be completed in conjunction with Attachment H-XXA.

Line No.	(1)	(2) Attachment H, Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant plus CWIP	Attach H-XX, p 2, line 2 col 5 (Note A)	-	
2	Net Transmission Plant plus CWIP and Abandoned Plant	Attach H-XX, p 2, line 16 col 5 plus line 27 & 29 col 5 (Note B)	-	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H-XX, p 2, line 14 col 5 (Note A)	-	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col 3)	0.00%	0.00%
	GENERAL AND INTANGIBLE (G&I) DEPRECIATION EXPENSE			
5	Total G&I Depreciation Expense	Attach H-XX, p 3, line 17, col 5 (Note H)	-	
6	Annual Allocation Factor for G,I & C Depreciation Expense	(line 5 divided by line 1, col 3)	0.00%	0.00%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H-XX, p 3, line 30 col 5	-	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col 3)	0.00%	0.00%
9	Less Revenue Credits	Attach H-XX, p 1, line 7 col 5	-	
10	Annual Allocation Factor for Revenue Credits	(line 9 divided by line 1, col 3)	0.00%	0.00%
11	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6, 8, and 10**		**0.00%**
	INCOME TAXES			
12	Total Income Taxes	Attach H-XX, p 3, line 44 col 5	-	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2, col 3)	0.00%	0.00%
	RETURN			
14	Return on Rate Base	Attach H-XX, p 3, line 46 col 5	-	
15	Annual Allocation Factor for Return on Rate Base	(line 14 divided by line 2, col 3)	0.00%	0.00%
16	**Annual Allocation Factor for Return**	**Sum of lines 13 and 15**		**0.00%**

For the 12 months ended mm/dd/yyyy

Attachment 1
Project Revenue Requirement Worksheet
Mid-Atlantic Offshore Development, LLC

This worksheet is used to compute project specific revenue requirements for any projects for which such calculation is required by PJM. Other projects which comprise the remaining revenue requirement on Attachment H-35 will not be entered on this schedule.

Any hypothetical amounts or project names in a filed template will be removed and replaced with actual amounts in the first year actual values are available without the need for a section 205 filing to modify the template.

	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	**Project Name**	**PJM Category**	**RTEP Project Number Or Other Identifier**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant or CWIP balance**	**Annual Allocation Factor for Return**	**Annual Return Charge**
				(Note D)	(Page 1, line 11)	(Col. 3 * Col. 4)	(Note E)	(Page 1, line 16)	(Col. 6 * Col. 7)
1a	Project A	Schedule 12	AAAA	-	0.00%	-	$ -	0.00%	-
1b	Project B		BBBB	-	0.00%	-	$ -	0.00%	-
2	Total Schedule 12			-		-	$ -		-
3a	Project C		CCCC	-	0.00%	-	$ -	0.00%	-
3b	Project D		DDDD	-	0.00%	-	$ -	0.00%	-
4	Total Zonal			-		-	$ -		-
5	Other			-	0.00%	-	$ -	0.00%	-
6	Annual Totals			-		-	-		-

For the 12 months ended mm/dd/yyyy

Attachment 1
Project Revenue Requirement Worksheet
Mid-Atlantic Offshore Development, LLC

	(9)	(10)	(11)	(12)	(13)	(14)
Line No.	**Project Depreciation/Amortization Expense**	**Annual Revenue Requirement**	**Incentive Return in Basis Points**	**Total Annual Revenue Requirement**	**True-Up Adjustment**	**Net Revenue Requirement**
	(Note F)	(Sum Col. 5 + Col. 9 + (Column 6 * Line 16))	(Note G)	(Sum Col. 10)	(Note I)	(Sum Col. 12 & 13)
1a	-	-	50	-	-	-
1b	-	-	-		-	-
2	-	-	50	-	-	-
3a	-	-	-	-	-	-
3b	-	-	-	-	-	-
4	-	-		-	-	-
5	-	-	-	-	-	-
6	-	-	50	-	-	-

Notes

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-XX inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order.

B Net Plant is that identified on page 2 line 14 of Attachment H-XX inclusive of any CWIP or unamortized Abandoned Plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.

C General and Intangible Depreciation and Amortization Expense includes all expense not directly associated with a project, which is entered on page 3, column 9.

D Project Gross Plant is the total capital investment including CWIP for the project calculated from Company books and records in the same method as the gross plant value in line 1. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.

E Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation plus CWIP in rate base if applicable and Unamortized Abandoned Plant.

F Project Depreciation Expense is the actual value booked for the project (excluding General and Intangible depreciation) at Attachment H-XXA, page 3, line 16, plus amortization of Abandoned Plant at Attachment H-XXA, page 3, line 19.

G The Annual Return Charge on Page 2, column 2 the 50 basis point ROE adder for RTO participation granted Mid-Atlantic Offshore Development, LLC, 186 FERC ¶ 61,116, P 48 (2024).

H Reserved

I True-Up Adjustment is calculated on the Project True-up Schedule for the relevant true-up year.

J For each project listed on this Attachment 1 that is a Required Transmission Enhancement, the net revenue requirement shown in Column (16) is: (i) the annual transmission revenue requirement for purposes of determining the PJM OATT Schedule 12 Transmission Enhancement Charges associated with that Required Transmission Enhancement, and (ii) the Annual Revenue Requirement for purposes of Schedule 12, Appendix A for that Required Transmission Enhancement.

For the 12 months ended mm/dd/yyyy

Attachment 2
Formula Rate True-Up
Mid-Atlantic Offshore Development, LLC

This Attachment is used to calculate the annual formula rate true-up. Any projects for which the RTO requires a true-up on an individual project basis, as shown on Attachment 1, will be computed separately. The remainder of the revenue requirement will also be trued up. The utility will individually enter the projected true-up year revenue requirements in Column C. A percentage of total will be calculated in Column D. Actual revenue received during the true-up year is entered into Column E, line 2 and allocated using the Column D percentage. The utility will prepare this formula rate template with the actual inputs for the true-up year, with the resulting revenue requirement for each line being separately entered in Column F. In Col. G, Col. F is subtracted from Col. E to calculate the true-up adjustment. Interest on the true-up is computed in Column H. Any adjustments to prior period true-ups are entered in Col. I. Col. J computes the total true-up as the sum of Col. G, H and I.

Any hypothetical amounts or project names in a filed template will be removed and replaced with actual amounts in the first year actual values are available without the need for a section 205 filing to modify the template.

Line				**Projected True-Up Year Revenue Requirement Calculation**		**True-Up Year Revenue Received[1]**	**Actual True-Up Year Revenue Req.**	**Annual True-Up Calculation**			
1	**True-Up Year**										
2	YYYY					-					
	A		B	C	D	E	F	G	H	I	J
	Project Name	PJM Category	Project # Or Other Identifier	Net Revenue Requirement[2]	% of Total Revenue Requirement	Allocation of Revenue Received (E, Line 2) x (D)	True-Up Net Revenue Requirement[3]	Net Under/(Over) Collection (F)-(E)	True-Up Interest Income (Expense)[4] (D) x (H, line 10)	Prior Period Adjustment with Interest[5]	Total True-Up (G) + (H) + (I)
3	Remaining Attachment H-XX	-		-	-	-	-	-	-	-	-
4a	Project A	Schedule 12	AAAA	-	-	-	-	-	-	-	-
4b	Project B	-	BBBB	-	-	-	-	-	-	-	-
5	Total Schedule 12			-		-		-	-	-	-
6a	Project C	-	CCCC	-	-	-	-	-	-	-	-
6b	Project D	-	DDDD	-	-	-	-	-	-	-	-
7	Total Zonal			-		-		-	-	-	-
8	Other	-		-	-	-	-	-	-	-	-
9	Total Annual Revenue Requirements			-	0.0%	-	-	-	-	-	-
10							Total Interest on True-Up - Attachment 6		-		

Prior Period Adjustment

Line	A		B
	Prior Period Adjustment (Note 5)	Source	Adjustment Amount
11	Description of Adjustment		-

Notes
1) The revenue received is the total amount of revenue distributed to company in the year as shown on pages 328-330 of the Form No 1. The Revenue Received is input on line 2, Col. E.
2) From the Attachment 1, lines 1a through 6, col. 16 from the template in which the true-up year revenue requirement was initially projected.
3) From True-Up revenue requirement template Attachment 1, lines 1a through 6, col. 14.
4) Interest due on the true up is calculated for the 24 month period from the start of the true-up year until the end of the year following the true-up year when the true up will be included in rates. Total True up Interest calculated on Attachment 5 and allocated to projects based on the percentage in Column D.
5) Corrections to true-ups for previous rate years including interest will be computed and entered on the appropriate line 3-8 above.

		Gross Plant In Service		CWIP	PHFFU	Working Capital		Accumulated Depreciation	
Line No	Month	Transmission	General & Intangible	CWIP in Rate Base	Plant Held for Future Use	Materials & Supplies	Prepayments	Transmission	General & Intangible
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Attachment H, Page 2, Line No:	2	4	27	31	34	35	9	11
		207.58.g for end of year, records for other months	205.5.g & 207.99.g for end of year, records for other months	(Note C)	214.x.d for end of year, records for other months	227.8.c & 227.16.c for end of year, records for other months	111.57.c for end of year, records for other months	219.25.c for end of year, records for other months	219.28.c & 200.21.c for end of year, records for other months
1	December Prior Year	-	-	-	-	-	-	-	-
2	January	-	-	-	-	-	-	-	-
3	February	-	-	-	-	-	-	-	-
4	March	-	-	-	-	-	-	-	-
5	April	-	-	-	-	-	-	-	-
6	May	-	-	-	-	-	-	-	-
7	June	-	-	-	-	-	-	-	-
8	July	-	-	-	-	-	-	-	-
9	August	-	-	-	-	-	-	-	-
10	September	-	-	-	-	-	-	-	-
11	October	-	-	-	-	-	-	-	-
12	November	-	-	-	-	-	-	-	-
13	December	-	-	-	-	-	-	-	-
14	Average of the 13 Monthly Balances	-	-	-	-	-	-	-	-

Adjustments to Rate Base

Line No	Month	Unamortized Regulatory Asset	Unamortized Abandoned Plant	Account No. 281 Accumulated Deferred Income Taxes (Note D)	Account No. 282 Accumulated Deferred Income Taxes (Note D)	Account No. 283 Accumulated Deferred Income Taxes (Note D)	Account No. 190 Accumulated Deferred Income Taxes (Note D)	Account No. 255 Accumulated Deferred Investment Credit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Attachment H, Page 2, Line No:	28	29	22	23	24	25	26
		Notes A & E	Notes B & F	272.8.b & 273.8.k	274.2.b & 275.2.k	276.9.b & 277.9.k	234.8.b & c	Consistent with 266.8.b & 267.8.h
15	December Prior Year	-	-	-	-	-	-	-
16	January	-	-	[redacted]				
17	February	-	-					
18	March	-	-					
19	April	-	-					
20	May	-	-					
21	June	-	-					
22	July	-	-					
23	August	-	-					
24	September	-	-					
25	October	-	-					
26	November	-	-					
27	December	-	-	-	-	-	-	-
28	Average of the 13 Monthly Balances	-	-	-	-	-	-	-
		$0.00						

Unfunded Reserves (Notes G & H)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
29	List of all reserves:		Amount	Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account	Enter 1 if the accrual account is included in the formula rate, enter (0) if the accrual account is NOT included in the formula rate	Enter the percentage paid for by the transmission formula customers	Allocation (Plant or Labor Allocator)	Amount Allocated, col. c x col. d x col. e x col. f x col. g
30a		Reserve 1	-	-				-
30b		Reserve 2	-	-				-
30c		Reserve 3						
30d		Reserve 4						
30e		…						
30f		…	-	-				-
31		Total	-					-

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.

B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.

C Includes only CWIP authorized by the Commission for inclusion in rate base.

D ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances.

E Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.

F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.

G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account.

H Calculate using 13 month average balance, except ADIT.

For the 12 months ended mm/dd/yyyy

Attachment 4
Return on Rate Base Worksheet
Mid-Atlantic Offshore Development, LLC

RETURN ON RATE BASE (R)

			$
1	Long Term Interest (117, sum of 62.c through 67.c) (Note D)		
2	Preferred Dividends (118.29c) (positive number)		-
3	Proprietary Capital (Line 25 (c))		-
4	Less Preferred Stock (Line 9)		-
5	Less Account 216.1 Undistributed Subsidiary Earnings (Line 25 (d))		-
6	Less Account 219 Accum. Other Comprehensive Income (Line 25 (e))		-
7	Common Stock	(Sum of Lines 3 through 6)	-

			$	%	Cost	Weighted	
8	Long Term Debt	Line 25 (a), Note A and Attachment H-XX Note Q	0.5	50.00%	7.37%	3.69%	=WCLTD
9	Preferred Stock	Line 25 (b), Note B and Attachment H-XX Note Q	-	0.00%	0.00%	0.00%	
10	Common Stock	Line 7, Note C and Attachment H-XX Note K	0.5	50.00%	10.76%	5.38%	
11	Total	(Sum of Lines 8 through 10)	1			9.065%	=R

	Monthly Balances for Capital Structure	(a) Long Term Debt (112.24.c)	(b) Preferred Stock (112.3.c)	(c) Proprietary Capital (112.16.c)	(d) Undistributed Sub Earnings 216.1	(e) Accum Other Comp. Income 219
12	December Prior Year	$ -	-	$ -	-	-
13	January	$ -	-	$ -	-	-
14	February	$ -	-	$ -	-	-
15	March	$ -	-	$ -	-	-
16	April	$ -	-	$ -	-	-
17	May	$ -	-	$ -	-	-
18	June	$ -	-	$ -	-	-
19	July	$ -	-	$ -	-	-
20	August	$ -	-	$ -	-	-
21	September	$ -	-	$ -	-	-
22	October	$ -	-	$ -	-	-
23	November	$ -	-	$ -	-	-
24	December	$ -	-	$ -	-	-
25	Average of the 13 Monthly Balances	$ -	-	$ -	-	-

Notes

A Long Term debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c to 21.c in the Form No. 1, the cost is calculated by dividing line 1 by the Long Term Debt balance on line 8.

B Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c in the Form No. 1

C Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on Form 1 page 112 line 16.c less lines 3.c , 12.c, and 15.c

D Long-term interest will exclude any short-term interest included in FERC Account 430, Interest on Debt to Associated Companies

For the 12 months ended mm/dd/yyyy

Attachment 5
Interest on True-Up
Mid-Atlantic Offshore Development, LLC

Line	YYYY Projected Revenue Requirement (Note A)		YYYY Actual Net Revenue Requirement (Note B)		Over (Under) Recovery
1	$ -	**Less**	$ -	**Equals**	$ -

Note A - Projected ATRR for the true-up year from Page 1, Line 1 of Projection Attachment H-XXA minus Line 6 of Projection Attachment H-XXA.
Note B - Actual Net ATRR for the true-up year from Page 1, Line 9 of True-Up Attachment H-XXA.

Line	**Interest Rate on Amount of Refunds or Surcharges**		**Over (Under) Recovery Plus Interest**	**Monthly Interest Rate on Attachment 6a**	**Months**	**Calculated Interest**	**Amortization**	**Surcharge (Refund) Owed**
2				0.000%				
	An over or under collection will be recovered pro rata over year collected, held for one year and returned pro rata over next year							
	Calculation of Interest					**Monthly**		
3	January	YYYY	-	0.000%	12	-		-
4	February	YYYY	-	0.000%	11	-		-
5	March	YYYY	-	0.000%	10	-		-
6	April	YYYY	-	0.000%	9	-		-
7	May	YYYY	-	0.000%	8	-		-
8	June	YYYY	-	0.000%	7	-		-
9	July	YYYY	-	0.000%	6	-		-
10	August	YYYY	-	0.000%	5	-		-
11	September	YYYY	-	0.000%	4	-		-
12	October	YYYY	-	0.000%	3	-		-
13	November	YYYY	-	0.000%	2	-		-
14	December	YYYY	-	0.000%	1	-		-
15						-		-
						Annual		
16	January through December	YYYY+1	-	0.000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
17	January	YYYY+2	-	0.000%		-	-	-
18	February	YYYY+2	-	0.000%		-	-	-
19	March	YYYY+2	-	0.000%		-	-	-
20	April	YYYY+2	-	0.000%		-	-	-
21	May	YYYY+2	-	0.000%		-	-	-
22	June	YYYY+2	-	0.000%		-	-	-
23	July	YYYY+2	-	0.000%		-	-	-
24	August	YYYY+2	-	0.000%		-	-	-
25	September	YYYY+2	-	0.000%		-	-	-
26	October	YYYY+2	-	0.000%		-	-	-
27	November	YYYY+2	-	0.000%		-	-	-
28	December	YYYY+2	-	0.000%		-	-	-
29						-		
30	Total Amount of True-Up Adjustment						-	
31	Less Over (Under) Recovery						-	
32	Total Interest						-	

For the 12 months ended mm/dd/yyyy

Attachment 5a
True-Up Interest Rate Calculator
Mid-Atlantic Offshore Development, LLC

This Attachment is used to compute the interest rate to be applied to each year's revenue requirement true-up.

	Applicable FERC Interest Rate (Note A):		
1	YYYY	January	0.00%
2	YYYY	February	0.00%
3	YYYY	March	0.00%
4	YYYY	April	0.00%
5	YYYY	May	0.00%
6	YYYY	June	0.00%
7	YYYY	July	0.00%
8	YYYY	August	0.00%
9	YYYY	September	0.00%
10	YYYY	October	0.00%
11	YYYY	November	0.00%
12	YYYY	December	0.00%
13	YYYY+1	January	0.00%
14	YYYY+1	February	0.00%
15	YYYY+1	March	0.00%
16	YYYY+1	April	0.00%
17	YYYY+1	May	0.00%
18	YYYY+1	June	0.00%
19	YYYY+1	July	0.00%
20	YYYY+1	August	0.00%
21	YYYY+1	September	0.00%
22	Average Rate		0.00%
23	Monthly Average Rate		0.00%

Note A - Lines 1-21 are the FERC interest rates under section 35.19a of the regulations for the period shown. Line 22 is the average of lines 1-21.

For the 12 months ended mm/dd/yyyy

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

Line	A	B	C	D	E	F	G	H
1	**Account 190**							
2	**Days in Period**					**Averaging with Proration - Projected**		
3	**A** Month	**B** Days in the Month	**C** Number of Days Prorated	**D** Total Days in Future Portion of Test Period	**E** Proration Amount (C / D)	**F** Projected Monthly Activity	**G** Prorated Projected Monthly Activity (E x F)	**H** Prorated Projected Balance (Cumulative Sum of G)
4								
5	December 31st balance Prorated Items							-
6	January	31	31	335	0.92		-	-
7	February	28	28	307	0.84		-	-
8	March	31	31	276	0.76		-	-
9	April	30	30	246	0.67		-	-
10	May	31	31	215	0.59		-	-
11	June	30	30	185	0.51		-	-
12	July	31	31	154	0.42		-	-
13	August	31	31	123	0.34		-	-
14	September	30	30	93	0.25		-	-
15	October	31	31	62	0.17		-	-
16	November	30	30	32	0.09		-	-
17	December	31	31	1	0.00		-	-
18		Total	365			-	-	
19								
20	Beginning Balance							-
21	Less: Portion not related to transmission							-
22	Less: Portion not reflected in rate base							-
23	Subtotal: Portion reflected in rate base				Line 20 minus Lines 21 and 22			-
24	Less: Portion subject to proration							-
25	Portion subject to averaging				Line 23 minus Line 24			-
26								
27	Ending Balance							-
28	Less: Portion not related to transmission							-
29	Less: Portion not reflected in rate base							-
30	Subtotal: Portion reflected in rate base				Line 27 minus Lines 28 and 29			-
31	Less: Portion subject to proration (before proration)							-
32	Portion subject to averaging (before averaging)				Line 30 minus Line 31			-
33								
34	Ending balance of portion subject to proration (prorated)				(Line 17, Col H)			-
35	Average balance of portion subject to averaging				(Line 25 + Line 32)/2			-
36	Amount reflected in rate base				Line 34 plus Line 35			-

For the 12 months ended mm/dd/yyyy

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

37 **Account 281**

Line	Days in Period					Averaging with Proration - Projected		
	A	**B**	**C**	**D**	**E**	**F**	**G**	**H**
39	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)
40								
41	December 31st balance Prorated Items							-
42	January	31	31	335	0.92	-	-	-
43	February	28	28	307	0.84	-	-	-
44	March	31	31	276	0.76	-	-	-
45	April	30	30	246	0.67	-	-	-
46	May	31	31	215	0.59	-	-	-
47	June	30	30	185	0.51	-	-	-
48	July	31	31	154	0.42	-	-	-
49	August	31	31	123	0.34	-	-	-
50	September	30	30	93	0.25	-	-	-
51	October	31	31	62	0.17	-	-	-
52	November	30	30	32	0.09	-	-	-
53	December	31	31	1	0.00	-	-	-
54		Total	365			-	-	

Line	Description	Reference	Amount
55			
56	Beginning Balance		-
57	Less: Portion not related to transmission		-
58	Less: Portion not reflected in rate base		-
59	Subtotal: Portion reflected in rate base	Line 56 minus Lines 57 and 58	-
60	Less: Portion subject to proration		-
61	Portion subject to averaging	Line 59 minus Line 60	-
62			
63	Ending Balance		-
64	Less: Portion not related to transmission		-
65	Less: Portion not reflected in rate base		-
66	Subtotal: Portion reflected in rate base	Line 63 minus Lines 64 and 65	-
67	Less: Portion subject to proration (before proration)		-
68	Portion subject to averaging (before averaging)	Line 66 minus Line 67	-
69			
70	Ending balance of portion subject to proration (prorated)	(Line 53, Col H)	-
71	Average balance of portion subject to averaging	(Line 61 + Line 68)/2	-
72	Amount reflected in rate base	Line 70 plus Line 71	-

For the 12 months ended mm/dd/yyyy

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

73 **Account 282**

Line								
74	**Days in Period**					**Averaging with Proration - Projected**		
75	**A** Month	**B** Days in the Month	**C** Number of Days Prorated	**D** Total Days in Future Portion of Test Period	**E** Proration Amount (C / D)	**F** Projected Monthly Activity	**G** Prorated Projected Monthly Activity (E x F)	**H** Prorated Projected Balance (Cumulative Sum of G)
76								
77	December 31st balance Prorated Items							-
78	January	31	31	335	0.92		-	-
79	February	28	28	307	0.84		-	-
80	March	31	31	276	0.76		-	-
81	April	30	30	246	0.67		-	-
82	May	31	31	215	0.59		-	-
83	June	30	30	185	0.51		-	-
84	July	31	31	154	0.42		-	-
85	August	31	31	123	0.34		-	-
86	September	30	30	93	0.25		-	-
87	October	31	31	62	0.17		-	-
88	November	30	30	32	0.09		-	-
89	December	31	31	1	0.00		-	-
90		Total	365			-	-	
91								
92	Beginning Balance							-
93	Less: Portion not related to transmission							-
94	Less: Portion not reflected in rate base							-
95	Subtotal: Portion reflected in rate base				Line 92 minus Lines 93 and 94			-
96	Less: Portion subject to proration							-
97	Portion subject to averaging				Line 95 minus Line 96			-
98								
99	Ending Balance							-
100	Less: Portion not related to transmission							-
101	Less: Portion not reflected in rate base							-
102	Subtotal: Portion reflected in rate base				Line 99 minus Lines 100 and 101			-
103	Less: Portion subject to proration (before proration)							-
104	Portion subject to averaging (before averaging)				Line 102 minus Line 103			-
105								
106	Ending balance of portion subject to proration (prorated)				(Line 89, Col H)			-
107	Average balance of portion subject to averaging				(Line 97 + Line 104)/2			-
108	Amount reflected in rate base				Line 106 plus Line 107			-

For the 12 months ended mm/dd/yyyy

Attachment 6
Accumulated Deferred Income Taxes
Mid-Atlantic Offshore Development, LLC

Line	A	B	C	D	E	F	G	H
109	**Account 283**							
110	**Days in Period**					**Averaging with Proration - Projected**		
111	Month	Days in the Month	Number of Days Prorated	Total Days in Future Portion of Test Period	Proration Amount (C / D)	Projected Monthly Activity	Prorated Projected Monthly Activity (E x F)	Prorated Projected Balance (Cumulative Sum of G)
112								
113	December 31st balance Prorated Items							-
114	January	31	31	335	0.92		-	-
115	February	28	28	307	0.84		-	-
116	March	31	31	276	0.76		-	-
117	April	30	30	246	0.67		-	-
118	May	31	31	215	0.59		-	-
119	June	30	30	185	0.51		-	-
120	July	31	31	154	0.42		-	-
121	August	31	31	123	0.34		-	-
122	September	30	30	93	0.25		-	-
123	October	31	31	62	0.17		-	-
124	November	30	30	32	0.09		-	-
125	December	31	31	1	0.00		-	-
126		Total	365			-	-	
127								
128	Beginning Balance							-
129	Less: Portion not related to transmission							-
130	Less: Portion not reflected in rate base							-
131	Subtotal: Portion reflected in rate base				Line 128 minus Lines 129 and 130			-
132	Less: Portion subject to proration							-
133	Portion subject to averaging				Line 131 minus Line 132			-
134								
135	Ending Balance							-
136	Less: Portion not related to transmission							-
137	Less: Portion not reflected in rate base							-
138	Subtotal: Portion reflected in rate base				Line 135 minus Lines 136 and 137			-
139	Less: Portion subject to proration (before proration)							-
140	Portion subject to averaging (before averaging)				Line 138 minus Line 139			-
141								
142	Ending balance of portion subject to proration (prorated)				(Line 125, Col H)			-
143	Average balance of portion subject to averaging				(Line 133 + Line 140)/2			-
144	Amount reflected in rate base				Line 142 plus Line 143			-

Attachment 7
Expense and Other Support
Mid-Atlantic Offshore Development, LLC

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	A&G Expenses	FERC Annual Fees	EPRI & Reg. Comm. Exp. & Non-safety Ad.	Transmission Related Reg. Comm. Exp.	Transmission Lease Payments	Amortization of Regulatory Asset	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Depreciation Expense - Transmission
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H, Page 3, Line No.:	1	2	3	4	5	6	7	9	11	12	16
	Form No. 1	321.112.b	321.97.b	321.96.b	323.197.b	(Note E)	(Note E)	(Note E)	Portion of Transmission O&M	Portion of Account 566	Balance of Account 566	336.7.b, d & e
1	January	-	-	-	-	-	-	-	-	-	-	-
2	February	-	-	-	-	-	-	-	-	-	-	-
3	March	-	-	-	-	-	-	-	-	-	-	-
4	April	-	-	-	-	-	-	-	-	-	-	-
5	May	-	-	-	-	-	-	-	-	-	-	-
6	June	-	-	-	-	-	-	-	-	-	-	-
7	July	-	-	-	-	-	-	-	-	-	-	-
8	August	-	-	-	-	-	-	-	-	-	-	-
9	September	-	-	-	-	-	-	-	-	-	-	-
10	October	-	-	-	-	-	-	-	-	-	-	-
11	November	-	-	-	-	-	-	-	-	-	-	-
12	December	-	-	-	-	-	-	-	-	-	-	-
13	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	Month	Depreciation Expense - General & Intangible	Amortization of Abandoned Plant	Payroll Taxes	Highway & Vehicle Taxes	Property Taxes	Gross Receipts Taxes	Other Taxes	Payments in lieu of Taxes	Amortized Investment Tax Credit (266.8f)	Excess Deferred Income Taxes	Tax Effect of Permanent Differences
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H, Page 3, Line Number	17	19	23	24	26	27	28	29	37	38	39
	Form No. 1	336.10.b, d & e, 336.1.b, d & e	(Note S)	263.i	263.i	263.i	263.i	263.i	263.i	266.8.f	(Note G)	(Note W)
14	January	-	-	-	-	-	-	-	-	-	-	-
15	February	-	-	-	-	-	-	-	-	-	-	-
16	March	-	-	-	-	-	-	-	-	-	-	-
17	April	-	-	-	-	-	-	-	-	-	-	-
18	May	-	-	-	-	-	-	-	-	-	-	-
19	June	-	-	-	-	-	-	-	-	-	-	-
20	July	-	-	-	-	-	-	-	-	-	-	-
21	August	-	-	-	-	-	-	-	-	-	-	-
22	September	-	-	-	-	-	-	-	-	-	-	-
23	October	-	-	-	-	-	-	-	-	-	-	-
24	November	-	-	-	-	-	-	-	-	-	-	-
25	December	-	-	-	-	-	-	-	-	-	-	-
26	Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Attachment 7
Expense and Other Support
Mid-Atlantic Offshore Development, LLC

		Bundled Sales for Resale included on page 4 of Attachment H	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY)	Transmission charges for all transmission transactions	Transmission charges associated with Project detailed on the Project Rev Req Schedule Col. 10.	Account No. 457.1 Scheduling
		(a)	(b)	(c)	(d)	(e)
	Attachment H, Page 4, Line No:	27	29	31	32	Attach H, p 1 line 4
		(Note L)	(Note M)	Portion of Account 456.1	Portion of Account 456.1	
27	January	-	-	-	-	-
28	February	-	-	-	-	-
29	March	-	-	-	-	-
30	April	-	-	-	-	-
31	May	-	-	-	-	-
32	June	-	-	-	-	-
33	July	-	-	-	-	-
34	August	-	-	-	-	-
35	September	-	-	-	-	-
36	October	-	-	-	-	-
37	November	-	-	-	-	-
38	December	-	-	-	-	-
39	Total	$ -	$ -	$ -	$ -	$ -
40						

Notes

For the 12 months ended mm/dd/yyyy

Attachment 8
Stated Value Inputs
Mid-Atlantic Offshore Development, LLC

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

MAOD's stated ROE is set to: 10.26% plus an RTO participation incentive of 50 basis points for a total of 10.76%

2. Depreciation Rates

FERC Account	Depr %
351	5.25%
352	2.08%
353	3.25%
354	2.15%
355	2.67%
356	2.08%
357	1.69%
358	2.00%
359	1.54%
382	20.00%
383	14.29%
391	6.67%
392.1	13.57%
392.2	7.92%
394	6.67%
397	6.67%
398	6.67%

For the 12 months ended mm/dd/yyyy

Attachment 9
Debt Cost Calculation
Mid-Atlantic Offshore Development, LLC

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED mm/dd/yyyy

Line			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1		t=N	Issue Date	Maturity Date	ORIGINAL ISSUANCE	Net Proceeds At Issuance	Net Amount Outstanding at t=N	Months Outstanding at t=N	Average Net Outstanding in Year* z*	Weighted Outstanding Ratios	Effective Cost Rate	Weighted Debt Cost at t = N
2	**Long Term Debt Cost at Year Ended**	**mm/dd/yyyy**			(table 2, col. cc)	(table 2, col. gg)			((col e. * col. F)/12)	(col. g/col. g total)	(Table 2, Col. kk)	(h) * (i)
3	First Mortgage Bonds:											
4	(1)				$ -	$ -			$ -			
5	(2)				$ -	$ -			$ -			
6	(3)				$ -	$ -			$ -			
7	(4)				$ -	$ -			$ -			
8	(5)				$ -	$ -			$ -			
9	(6)				$ -	$ -			$ -			
10					$ -		$ -		$ -	0.000%		7.37% **

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (6.8200%, 5.7504%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (6.95%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 20, column 4 of formula rate Attachment H-XX. Before debt is obtained, a proxy interest rate which will be priced at the three-month Term Secured Overnight Financing Rate (“SOFR”) plus 200 basis points (See also, H-XX, Note P).

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances

YEAR ENDED mm/dd/yyyy

Line		Affiliate	(aa)	(bb)	(cc)	(dd)	(ee)	(ff)	(gg)	(hh)	(ii)	(jj)	(kk)
11	**Long Term Debt Issuances**		Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss/Gain on Reacquired Debt	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Annual Interest	Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
12									(col. cc + col. dd - col. ee - col. ff)	((col. gg / col. cc)*100)	Percentage (%)	(col. cc * col. ii)	
13													
14	(1)								$ -		0.00%	$ -	
15	(2)								$ -			$ -	
16	(3)								$ -			$ -	
17	(4)								$ -			$ -	
18	(5)								$ -			$ -	
19	(6)								$ -			$ -	
	TOTALS				$ -	$ -	$ -	$ -	$ -			$ -	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow Co equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows (Ct=1, Ct=2, etc.).

For the 12 months ended mm/dd/yyyy

Workpaper 1a
Utility Gross Plant in Service
Mid-Atlantic Offshore Development, LLC

Line No.	Month/Year	Transmission Plant	General Plant	Intangible Plant	Total
1	December Prior Year	-	-	-	$0
2	January	-	-	-	$0
3	February	-	-	-	$0
4	March	-	-	-	$0
5	April	-	-	-	$0
6	May	-	-	-	$0
7	June	-	-	-	$0
8	July	-	-	-	$0
9	August	-	-	-	$0
10	September	-	-	-	$0
11	October	-	-	-	$0
12	November	-	-	-	$0
13	December	-	-	-	$0
14	13 Month Average	$0	$0	$0	$0
15	Beginning/Ending Average	$0	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 1b
Utility Gross Plant in Service Summary
Mid-Atlantic Offshore Development, LLC

Line No.	FERC Account	FERC Capital Category	Gross Plant in Service
1	350	Land	-
2	351	Energy Storage	-
3	352	Structures and improvements	-
4	353	Station equipment	-
5	354	Towers and fixtures	-
6	355	Poles and fixtures	-
7	356	Overhead conductors and devices	-
8	357	Underground Conduit	-
9	358	Underground conductors and devices	-
10	359	Roads and trails	-
11	359.1	Asset retirement costs for transmission plant	-
12		Total Gross Transmission Plant	$0
13	382	Computer Hardware	-
14	383	Computer Software	-
15	391	Office Furniture and Equipment	-
16	392.1	Transportation Equipment - Light Duty Vehicles	-
17	392.2	Transportation Equipment - Heavy Duty Vehicles	-
18	394	Tools, Shop and Garage Equipment	-
19	397	Communication Equipment	-
20	398	Miscellaneous Equipment	-
21		Total Gross General Plant	$0

For the 12 months ended mm/dd/yyyy

Workpaper 2
Accumulated Depreciation and Amortization
Mid-Atlantic Offshore Development, LLC

		Depreciation			Amortizations		Totals	
Line No.	Month/Year	Transmission Plant	General Plant	Intangible Plant	Rate Base Reg. Asset Pre-development	Deferred Rate Case Expense	Rate Base Subtotal	Total Depreciation and Amortization
1	December Prior Year	-	-	-	-	-	$0	$0
2	January	-	-	-	-	-	$0	$0
3	February	-	-	-	-	-	$0	$0
4	March	-	-	-	-	-	$0	$0
5	April	-	-	-	-	-	$0	$0
6	May	-	-	-	-	-	$0	$0
7	June	-	-	-	-	-	$0	$0
8	July	-	-	-	-	-	$0	$0
9	August	-	-	-	-	-	$0	$0
10	September	-	-	-	-	-	$0	$0
11	October	-	-	-	-	-	$0	$0
12	November	-	-	-	-	-	$0	$0
13	December	-	-	-	-	-	$0	$0
14	13 Month Average	$0	$0	$0	$0	$0	$0	$0
15	Beginning/Ending Average	$0	$0	$0	$0	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 3a
Depreciation and Amortization Expenses
Mid-Atlantic Offshore Development, LLC

Line No.	Description	Amount
1	Transmission Plant	$0
2	General Plant	$0
3	Intangible Plant	$0
4	Total Depreciation Expense	$0
5	Asset retirement costs for transmission plant.	$0
6	ARO Accretion Expense Paid By Customers	$0
7	Rate Base Reg. Asset of Dev. Costs	$0
8	Reg. Asset of Rate Case Expense	$0
9	Total Amortization Expense	$0
10	Total Depreciation and Amortization Expense	$0

Workpaper 3b
Depreciation and Amortization Expenses
Mid-Atlantic Offshore Development, LLC

For the 12 months ended mm/dd/yyyy

Line No.	FERC Account	FERC Capital Category	Gross Plant in Service	Life	Salvage %	Depr Rate	Salvage Expense	Depreciation Expense	Total Salvage and Depreciation
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	INTANGIBLE PLANT								
1	301.0	Organization	-	-	-	-	-	-	-
2	302.0	Franchises and Consents	-	-	-	-	-	-	-
3	303.0	Computer Software	-	-	-	-	-	-	-
4	303.1	Contributions in Aid of Construction	-	-	-	-	-	-	-
		Subtotal	-				-	-	-
	TRANSMISSION PLANT								
5	350.0	Land		ND	0.00%	0.00%			$0
6	351.0	Energy Storage		20	-5.00%	5.25%	$0	$0	$0
7	352.0	Structures and improvements		60	-25.00%	2.08%	$0	$0	$0
8	353.0	Station equipment		40	-30.00%	3.25%	$0	$0	$0
9	354.0	Towers and fixtures		65	-40.00%	2.15%	$0	$0	$0
10	355.0	Poles and fixtures		60	-60.00%	2.67%	$0	$0	$0
11	356.0	Overhead conductors and devices		65	-35.00%	2.08%	$0	$0	$0
12	357.0	Underground Conduit		65	-10.00%	1.69%	$0	$0	$0
13	358.0	Underground conductors and devices		55	-10.00%	2.00%	$0	$0	$0
14	359.0	Roads and trails		65	0.00%	1.54%	$0	$0	$0
15									
16		Subtotal	$0			#DIV/0!	$0	$0	$0
17	359.1	Asset retirement costs for transmission plant.	-	-	-	-	-	-	$ -
18	411.10	ARO Accretion Expense Paid By Customers	-	-	-	-	-	-	$ -
	GENERAL PLANT								
19	382.0	Computer Hardware		5	0.00%	20.00%	$0	$0	$0
20	383.0	Computer Software		7	0.00%	14.29%	$0	$0	$0
22	391.0	Office Furniture and Equipment		15	0.00%	6.67%	$0	$0	$0
23	392.1	Transportation Equipment - Light Duty Vehicles		7	5.00%	13.57%	$0	$0	$0
24	392.2	Transportation Equipment - Heavy Duty Vehicles		12	5.00%	7.92%	$0	$0	$0
25	394.0	Tools, Shop and Garage Equipment		15	0.00%	6.67%	$0	$0	$0
26	397.0	Communication Equipment		15	0.00%	6.67%	$0	$0	$0
27	398.0	Miscellaneous Equipment		15	0.00%	6.67%	$0	$0	$0
28		Subtotal	-				-	-	-
	AMORTIZATION								
29	182.3	Rate Base Reg. Asset of Dev. Costs		5	N/A	20.00%		$0	$0
30	186.0	Reg. Asset of Rate Case Expense		3	N/A	33.33%		$0	$0
31		**Grand Total**							$0

For the 12 months ended mm/dd/yyyy

Workpaper 4
Specified Plant Accounts and Deferred Debits
Mid-Atlantic Offshore Development, LLC

Line No.		Balance mm/dd/yyyy	Balance mm/dd/yyyy	Average Balance
1	Electric Plant Held For Future Use - Account 105	$0	$0	$0
2	Construction Work in Progress - Account 107	$0	$0	$0
3	Unamoritzed Debt Expenses - Account 181	$0	$0	$0
4	Other Regulatory Assets - Account 182.3			
	Rate Base Reg. Asset Pre-development	$0	$0	$0
	Total	$ 0	$ 0	$ 0
5	Preliminary Survey and Investigation Charges - Account 183	$0	$0	$0
6	Miscellaneous Deferred Debits - Account 183			
	Deferred Rate Case Expense	$0	$0	$0
7	Accumulated Deferrred Income Taxes - Account 190	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 5
Permanent Difference Tax Adjustment
Mid-Atlantic Offshore Development, LLC

The permanent book/tax differences reflected in recoverable income tax expense are differences between revenues and expenses reflected in the revenue requirement and revenue and deductions reflected in taxable income. As such, non-operating (below-the-line) expenses and income are not included (e.g., accrual of AFUDC-equity, certain lobbying costs). Book depreciation of capitalized AFUDC-equity is reflected in ratemaking, but not for income tax purposes, and, thus, is a permanent book/tax difference in this context. Similarly, amortization of the regulatory asset for pre-commercial carrying charges accrued at an after-tax equity rate of return is permanent difference between recoverable expenses and tax deductions.

Line No.	**Permanent book/tax differences**	Source:	**Amount per Formula Rate Template (a)**
1	Depreciation of AFUDC-equity		-
2	Amortization of carrying charge-equity		-
3	Total permanent book/tax differences		-
4	Tax rate		28.11%
5	Tax effect of permanent book/tax differences		-
6	Tax gross-up factor (1 / (1 - T) from Attachment H-XXA, page 3, line 38)		1.3910
7	Permanent Differences Tax Adjustment		**-**

For the 12 months ended mm/dd/yyyy

Workpaper 6
Operation and Maintenance Expenses - FERC Account
Mid-Atlantic Offshore Development, LLC

TRANSMISSION OPERATION AND MAINTENANCE EXPENSES

Line No.	Description		Labor	Non-Labor	Total
	Operation				
1	560	Operation Supervision and Engineering	$0	$0	$0
2	561	Load Dispatching	$0	$0	$0
3	562	Station Expenses	$0	$0	$0
4	563	Overhead Line Expenses	$0	$0	$0
5	564	Underground Line Expenses	$0	$0	$0
6	565	Transmission of Electricity by Others	$0	$0	$0
7	566	Miscellaneous Transmission Expenses	$0	$0	$0
8	567	Rents	$0	$0	$0
9		Total Operation	$0	$0	$0
	Maintenance				
10	568	Maintenance Supervision and Engineering	$0	$0	$0
11	566	Maintenance of Structures	$0	$0	$0
12	570	Maintenance of Station Equipment	$0	$0	$0
13	571	Maintenance of Overhead Lines	$0	$0	$0
14	572	Maintenance of Underground Lines	$0	$0	$0
15	573	Maintenance of Miscellaneous Transmission Plant	$0	$0	$0
16		Total Maintenance	$0	$0	$0
17		Total Transmission Expenses	$0	$0	$0

ADMINISTRATIVE AND GENERAL EXPENSES

Line No.	Description		Labor	Non-Labor	Total
	Operation				
18	920	Administrative and General Salaries	$0	$0	$0
19	921	Office Supplies and Expenses	$0	$0	$0
20	922	(Less) Administrative Expenses Transferred -Credit	$0	$0	$0
21	923	Outside Services Employed	$0	$0	$0
22	924	Property Insurance	$0	$0	$0
23	925	Injuries and Damages	$0	$0	$0
24	926	Employee Pensions and Benefits	$0	$0	$0
25	927	Franchise Requirements	$0	$0	$0
26	928	Regulatory Commission Expenses	$0	$0	$0
27	929	(Less) Duplicate Charges - Credit	$0	$0	$0
28	930.1	General Advertising Expenses	$0	$0	$0
29	930.2	Miscellaneous General Expenses	$0	$0	$0
30	931	Rents	$0	$0	$0
31		Total Operation	$0	$0	$0
	Maintenance				
32	935	Maintenance Supervision and Engineering	$0	$0	$0
33		Total Maintenance	$0	$0	$0
34		Total Administrative and General Expenses	$0	$0	$0

For the 12 months ended mm/dd/yyyy

Workpaper 7
Support for Attachment 2 - Formula Rate True-Up
Mid-Atlantic Offshore Development, LLC

Line No.			
1	Actual Annual Revenue Earned Account 456.1 330.x.n	-	
2	Less ATRR Balancing Entry Included in Account 456.1	-	
3	Less ATRR revenue credits that are accounted separately on Attachment H-XXA, page 1,	-	
4	Actual Annual Revenue Received from PJM toward 20XX ATRR	-	To Attachment 2, line 2, column E

Notes
A On its Form No. 1, Mid-Atlantic Offshore Development, LLC may report the revenue earned or accrued rather than the cash received.
B This workpaper reconciles the Form No. 1 value with the cash received value used in Attachment 2 necessary for proper calculation.

Exhibit No. MAOD-25
Mid-Atlantic Offshore Development, LLC
ATTESTATION

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore)
Development, LLC) **Docket No. ER24-___-000**
)

ATTESTATION

I, Christopher Sternhagen, Director – MAOD Development of Mid-Atlantic Offshore Development, LLC, hereby attest that to the best of my knowledge, information, and belief, the cost of service statements and supporting data submitted in this proceeding are true, accurate, and current representations of Mid-Atlantic Offshore Development, LLC's books, records, budgets, or other corporate documents.

Christopher Sternhagen

Executed on July 8, 2024.

Subscribed and sworn to before me, a Notary Public, this 8th day of July, 2024.

Notary

My commission expires: 5/28/2028

CATHERINE SPENCE
Notary ID #4231566
My Commission Expires
May 28, 2028

Exhibit No. MAOD-26
Mid-Atlantic Offshore Development, LLC
Form of Protective Agreement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC) Docket No. ER24-____-000

PROTECTIVE AGREEMENT

This Protective Agreement ("Agreement") is entered into this _____ day of ____________________, _____by and between Mid-Atlantic Offshore Development, LLC ("MAOD"), and ____________________ ("Intervenor"), and shall govern the use of all Privileged Materials produced by MAOD to Intervenor, or vice versa, in connection with the proceeding before the Federal Energy Regulatory Commission (the "Commission") in Docket No. ER24-____-000. MAOD and Intervenor are sometimes referred to herein individually as a "Party" or jointly as the "Parties."

1. MAOD filed in the above-referenced proceeding Privileged Material and/or Critical Energy/Electric Infrastructure Information ("CEII"), as those terms are defined herein. Intervenor is a Participant in such proceeding, as the term Participant is defined in 18 C.F.R. Section 385.102(b), or has filed a motion to intervene or a notice of intervention in such proceeding. MAOD and Intervenor enter into this Agreement to govern the use of Privileged Material and/or CEII produced by, or on behalf of, MAOD and/or Intervenor in the above-referenced proceeding. Notwithstanding any order terminating such proceeding, this Agreement shall remain in effect unless and until specifically modified or terminated by the Commission or a court of competent jurisdiction.

2. The Commission's regulations[1] and its policy governing the labeling of controlled unclassified information ("CUI"),[2] establish and distinguish the respective designations of Privileged Material and CEII. As to these designations, this Agreement provides that a Party:

A. *may* designate as Privileged Material any material which customarily is treated by that Party as commercially sensitive or proprietary or material subject to a legal privilege, which is not otherwise available to the public, and which, if disclosed, would subject that Party or its customers to risk of competitive disadvantage or other business injury; and

B. *must* designate as CEII, any material that meets the definition of that term as provided by 18 C.F.R. §§ 388.113(a), (c).

3. For the purposes of this Agreement, the listed terms are defined as follows:

A. Party and Parties: As defined above.

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[1] *Compare* 18 C.F.R. § 388.112 with 18 C.F.R. § 388.113.
[2] *Notice of Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission Staff*, 82 Fed. Reg. 18632 (Apr. 20, 2017) (issued by Commission Apr. 14, 2017).

B. Privileged Material:[3]

i. Material (including depositions) provided by a Party in response to discovery requests or filed with the Commission, and that is designated as Privileged Material by such Party;[4]

ii. Material that is privileged under federal, state, or foreign law, such as work-product privilege, attorney-client privilege, or governmental privilege, and that is designated as Privileged Material by such Party;[5]

iii. Any information contained in or obtained from such designated material;

iv. Any other material which is made subject to this Agreement by a Presiding Administrative Law Judge ("Presiding Judge") or the Chief Administrative Law Judge ("Chief Judge") in the absence of a Presiding Judge or where no presiding judge is designated, the Commission, any court, or other body having appropriate authority, or by agreement of the Parties (subject to approval by the relevant authority);

v. Notes of Privileged Material (memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses Privileged Material);[6] or

vi. Copies of Privileged Material.

vii. Privileged Material does not include:

a. Any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be privileged by such agency or court;

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[3] The Commission's regulations state that "[f]or the purposes of the Commission's filing requirements, non-CEII subject to an outstanding claim of exemption from disclosure under FOIA, . . ., will be referred to as privileged material." 18 C.F.R. § 388.112(a). The regulations further state that "[f]or material filed in proceedings set for trial-type hearing or settlement judge proceedings, a participant's access to material for which privileged treatment is claimed is governed by the presiding official's protective order." 18 C.F.R. § 388.112(b)(2)(v).

[4] *See infra* P 11 for the procedures governing the labeling of this designation.

[5] The Commission's regulations state that "[a] presiding officer may, by order . . . restrict public disclosure of discoverable matter in order to . . . [p]reserve a privilege of a participant. . . ." 18 C.F.R. § 385.410(c)(3). To adjudicate such privileges, the regulations further state that "[i]n the absence of controlling Commission precedent, privileges will be determined in accordance with decisions of the Federal courts with due consideration to the Commission's need to obtain information necessary to discharge its regulatory responsibilities." 18 C.F.R. § 385.410(d)(1)(i).

[6] Notes of Privileged Material are subject to the same restrictions for Privileged Material except as specifically provided in this Agreement.

b. Information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Agreement; or

c. Any information or document labeled as "Non-Internet Public" by a Party, in accordance with Paragraph 30 of Commission Order No. 630.[7]

viii. Additional Subcategory of Privileged Material:

a. Highly Confidential Privileged Material: A Participant may use this designation for those materials that are of such a commercially sensitive nature among the Participants or of such a private, personal nature that the producing Participant is able to justify a heightened level of confidential protection with respect to those materials.

C. Critical Energy/Electric Infrastructure Information ("CEII"): As defined at 18 C.F.R. §§ 388.113(a), (c).

D. Non-Disclosure Certificate: The certificate attached to this Agreement, by which persons granted access to Privileged Material and/or CEII must certify their understanding that such access to such material is provided pursuant to the terms and restrictions of this Agreement, and that such persons have read the Agreement and agree to be bound by it. All executed Non-Disclosure Certificates must be provided to the Parties.

E. Reviewing Representative: A person who has signed a Non-Disclosure Certificate and who is:

i. Commission Trial Staff designated as such in this proceeding;

ii. An attorney who has made an appearance in this proceeding for a Party;

iii. Attorneys, paralegals, and other employees associated for purposes of this case with an attorney who has made an appearance in this proceeding on behalf of a Party;

iv. An expert or an employee of an expert retained by a Party for the purpose of advising, preparing for, submitting evidence or testifying in this proceeding;

v. A person designated as a Reviewing Representative by order of a Presiding Judge, the Chief Judge, or the Commission; or

[7] FERC Stat. & Reg. ¶ 31,140.

vi. Employees or other representatives of Parties appearing in this proceeding with significant responsibility for this docket.

F. The term "Reviewing Representative" for purposes of reviewing Highly Confidential Privileged Material defined in Paragraph 3(B)(viii)(a) shall mean a person who has signed a Non-Disclosure Certificate and who is:

i. listed in Paragraph 3(E) but is not Competitive Duty Personnel as defined in Paragraph 3(G); or

ii. designated as a Reviewing Representative for purposes of reviewing Highly Confidential Privileged Material by agreement of the producing Participant or by order of the Presiding Judge.

G. The term "Competitive Duty Personnel" shall mean any individual(s) whose scope of employment or engagement includes direct involvement in or direct supervisory responsibility over (i) the purchase, sale, or marketing of electricity (including transmission service) at retail or wholesale, (ii) the negotiation or development of participation or cost-sharing arrangements for transmission or generation facilities, or similar activities or transactions, or (iii) the acquisition or disposition of generating facilities; except that Competitive Duty Personnel shall not include employees of the Federal Energy Regulatory Commission, any state utilities commission which is a Participant, or in-house or outside attorneys.

4. Privileged Material and/or CEII shall be made available under the terms of this Agreement only to Parties and only to their Reviewing Representatives as provided in Paragraphs 6-10 of this Agreement. The contents of Privileged Material, CEII, or any other form of information that copies or discloses such materials shall not be disclosed to anyone other than in accordance with this Agreement and shall be used only in connection with this specific proceeding.

5. All Privileged Material and/or CEII must be maintained in a secure place. Access to those materials must be limited to Reviewing Representatives specifically authorized pursuant to Paragraphs 7-9 of this Agreement.

6. Privileged Material and/or CEII must be handled by each Party and by each Reviewing Representative in accordance with the Non-Disclosure Certificate executed pursuant to Paragraph 9 of this Agreement. Privileged Material and/or CEII shall not be used except as necessary for the conduct of this proceeding, nor shall they (or the substance of their contents) be disclosed in any manner to any person except a Reviewing Representative who is engaged in this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Material and/or CEII, but such copies automatically become Privileged Material and/or CEII. Reviewing Representatives may make notes of Privileged Material, which shall be treated as Notes of Privileged Material if they reflect the contents of Privileged Material.

7. If a Reviewing Representative's scope of employment includes any of the activities listed under this Paragraph 7, such Reviewing Representative may not use information contained in any

Privileged Material and/or CEII obtained in this proceeding for a commercial purpose (*e.g.*, to give a Party or competitor of any Party a commercial advantage):

A. Energy marketing;

B. Direct supervision of any employee or employees whose duties include energy marketing; or

C. The provision of consulting services to any person whose duties include energy marketing.

8. In the event that a Party wishes to designate a person not described in Paragraph 3.E above as a Reviewing Representative, the Party must seek agreement from the Party providing the Privileged Material and/or CEII. If an agreement is reached, the designee shall be a Reviewing Representative pursuant to Paragraph 3.D of this Agreement with respect to those materials. If no agreement is reached, the matter must be submitted to a Presiding Judge, the Chief Judge, or the Commission for resolution.

9. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Material and/or CEII pursuant to this Agreement until three business days after that Reviewing Representative first has executed and served a Non-Disclosure Certificate.[8] However, if an attorney qualified as a Reviewing Representative has executed a Non-Disclosure Certificate, any participating paralegal, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. Attorneys designated Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Agreement, and must take all reasonable precautions to ensure that Privileged Material and/or CEII are not disclosed to unauthorized persons. Reviewing Representatives that are Competitive Duty Personnel as defined in Paragraph 3.G must execute a Non-Disclosure Certificate for Competitive Duty Personnel in the form attached hereto. All executed Non-Disclosure Certificates must be served on the Parties.

10. Any Reviewing Representative may disclose Privileged Material and/or CEII to any other Reviewing Representative as long as both Reviewing Representatives have executed a Non-Disclosure Certificate authorizing them to receive the particular Privileged Material and/or CEII in question. In the event any Reviewing Representative to whom Privileged Material and/or CEII are disclosed ceases to participate in this proceeding, or becomes employed or retained for a position that renders him or her ineligible to be a Reviewing Representative under Paragraph 3.D of this Agreement, access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Agreement and the Non-Disclosure Certificate for as long as the Agreement is in effect.[9]

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[8] During this three-day period, a Party may file an objection with the other Party, a Presiding Judge or the Commission contesting that an individual qualifies as a Reviewing Representative, and the individual shall not receive access to the Privileged Material and/or CEII until resolution of the dispute.

[9] *See infra* P 21.

11. All Privileged Material and/or CEII in this proceeding filed with the Commission, submitted to a Presiding Judge, or submitted to any Commission personnel, must comply with the Commission's *Notice of Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission Staff.*[10] Consistent with those requirements:

A. Documents that contain Privileged Material must include a top center header on each page of the document with the following text: CUI//PRIV. Any corresponding electronic files must also include this text in the file name.

B. Documents that contain Highly Confidential Privileged Material must include a top center header on each page of the document with the following text: CUI//PRIV-HC. Any corresponding electronic files must also include this text in the file name.

C. Documents that contain CEII must include a top center header on each page of the document with the following text: CUI//CEII. Any corresponding electronic files must also include this text in the file name.

D. Documents that contain both Privileged Material or Highly Confidential Privileged Material and CEII must include a top center header on each page of the document with the following text: CUI//CEII/PRIV or CUI//CEII/PRIV-HC. Any corresponding electronic files must also include this text in the file name.

E. The specific content on each page of the document that constitutes Privileged Material and/or CEII must also be clearly identified. For example, lines or individual words or numbers that include both Privileged Material and CEII shall be prefaced and end with "BEGIN CUI//CEII/PRIV" and "END CUI//CEII/PRIV".

12. If either Party desires to include, utilize, or refer to Privileged Material or information derived from Privileged Material in testimony or other exhibits during the hearing in this proceeding in a manner that might require disclosure of such materials to persons other than Reviewing Representatives, that Party first must notify both counsel for the disclosing Party and any Presiding Judge, and identify all such Privileged Material. Thereafter, use of such Privileged Material will be governed by procedures determined by the Parties or, if applicable, the Presiding Judge.

13. Nothing in this Agreement shall be construed as precluding any Party from objecting to the production or use of Privileged Material and/or CEII on any appropriate ground.

14. Nothing in this Agreement shall preclude any Party from requesting a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority, to find this Agreement should not apply to all or any materials previously designated Privileged Material pursuant to this Agreement. A Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority may alter or amend this Agreement as circumstances warrant at any time during the course of this proceeding.

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[10] 82 Fed. Reg. 18632 (Apr. 20, 2017) (issued by Commission Apr. 14, 2017).

15. Each Party governed by this Agreement has the right to seek changes in it as appropriate from a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority.

16. Subject to Paragraph 18, a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), or the Commission shall resolve any disputes arising under this Agreement pertaining to Privileged Material according to the following procedures. Prior to presenting any such dispute to a Presiding Judge, the Chief Judge, or the Commission, the Parties to the dispute shall employ good faith best efforts to resolve it.

A. Any Party that contests the designation of material as Privileged Material (or Highly Confidential Privileged Material) shall notify the Party that provided the Privileged Material by specifying in writing the material for which the designation is contested.

B. In any challenge to the designation of material as Privileged Material (or Highly Confidential Privileged Material), the burden of proof shall be on the Party seeking protection. If a Presiding Judge, the Chief Judge, or the Commission finds that the material at issue is not entitled to the designation, the procedures of Paragraph 18 shall apply.

C. The procedures described above shall not apply to material designated by a Party as CEII. Material so designated shall remain subject to the provisions of this Agreement, unless a Party requests and obtains a determination from the Commission's CEII Coordinator that such material need not retain that designation.

17. The designator will have five (5) days in which to respond to any pleading filed with a Presiding Judge, the Chief Judge, or the Commission requesting disclosure of Privileged Material. Should such Presiding Judge, the Chief Judge, or the Commission, as appropriate, determine that the information should be made public, such Presiding Judge, the Chief Judge, or the Commission will provide notice to the designator no less than five (5) days prior to the date on which the material will become public. This Agreement shall automatically cease to apply to such material on the sixth (6th) calendar day after the notification is made unless the designator files a motion with such Presiding Judge, the Chief Judge, or the Commission, as appropriate, with supporting affidavits, demonstrating why the material should continue to be privileged. Should such a motion be filed, the material will remain confidential until such time as the interlocutory appeal or certified question has been addressed by the Motions Commissioner or Commission, as provided in the Commission's regulations, 18 C.F.R. §§ 385.714, 385.715. No Party waives its rights to seek additional administrative or judicial remedies after a Presiding Judge or Chief Judge decision regarding Privileged Material or the Commission's denial of any appeal thereof or determination in response to any certified question. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act (5 U.S.C. § 552) for Privileged Material and/or CEII in the files of the Commission.

18. Privileged Material and/or CEII shall remain available to Parties until the later of 1) the date an order terminating this proceeding no longer is subject to judicial review, or 2) the date any other Commission proceeding relating to the Privileged Material and/or CEII is concluded and no

longer subject to judicial review. After this time, the Party that produced the Privileged Material and/or CEII may request (in writing) that all other Parties return or destroy the Privileged Material and/or CEII. This request must be satisfied with within fifteen (15) days of the date the request is made. However, copies of filings, official transcripts and exhibits in this proceeding containing Privileged Material, or Notes of Privileged Material, may be retained if they are maintained in accordance with Paragraph 5 of this Agreement. If requested, each Party also must submit to the Party making the request an affidavit stating that to the best of its knowledge it has satisfied the request to return or destroy the Privileged Material and/or CEII. To the extent Privileged Material and/or CEII are not returned or destroyed, they shall remain subject to this Agreement.

19. Nothing in this Agreement shall be deemed to preclude either Party from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Agreement. Neither Party waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Privileged Material and/or CEII.

IN WITNESS WHEREOF, the Parties each have caused this Agreement to be signed by their respective duly authorized representatives as of the date first set forth above.

By:______________________	By:______________________
Name:______________________	Name:______________________
Title:______________________	Title:______________________
Representing MAOD	Representing Intervenor

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC, Docket No. ER24-____-000

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Materials in the above-captioned case is provided to me pursuant to the terms and restrictions the Agreement dated _________________, 20___ by and between Mid-Atlantic Offshore Development, LLC and _________________ concerning materials in Federal Energy Regulatory Commission Docket No. ER24-____-000 (the “Agreement”), that I have been given a copy of and have read the Agreement, and that I agree to be bound by it. I hereby certify my understanding that access to Privileged Material and/or Critical Energy/Electric Infrastructure Information (CEII) is provided to me pursuant to the terms and restrictions of the Protective Agreement in this proceeding, that I have been given a copy of and have read the Protective Agreement, and that I agree to be bound by it. I understand that the contents of Privileged Material and/or CEII, any notes or other memoranda, or any other form of information that copies or discloses such materials, shall not be disclosed to anyone other than in accordance with the Protective Agreement. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ______________________________________

Printed Name: _____________________________

Title: ____________________________________

Representing: _____________________________

Date: ____________________________________

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Mid-Atlantic Offshore Development, LLC, Docket No. ER24-____-000

NON-DISCLOSURE CERTIFICATE
FOR COMPETITIVE DUTY PERSONNEL

I hereby certify my understanding that access to Privileged Materials in the above-captioned case is provided to me pursuant to the terms and restrictions the Agreement dated _________________, 20___ by and between Mid-Atlantic Offshore Development, LLC and _________________ concerning materials in Federal Energy Regulatory Commission Docket No. ER24-____-000 (the "Agreement"), that I have been given a copy of and have read the Agreement, and that I agree to be bound by it. I understand that the contents of the Privileged Materials and/or Critical Energy/Electric Infrastructure Information (CEII), any notes or other memoranda, or any other form of information that copies or discloses Privileged Materials and/or CEII shall not be disclosed to anyone other than in accordance with that Protective Agreement and shall be used only in connection with this proceeding. I acknowledge that my duties and responsibilities include "Competitive Duties" as described in the Protective Agreement and, as such, I understand that I shall neither have access to, nor disclose, the contents of the Privileged Materials that are marked "CUI//PRIV-HC," any notes or other memoranda, or any other form of information that copies or discloses Privileged Materials that are marked as "CUI//PRIV-HC." I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ______________________________

Printed Name: _____________________

Title: _____________________________

Representing: ______________________

Date: _____________________________