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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application Of NextEra Energy Transmission MidAtlantic, Inc., for All of the Necessary Authority, Approvals, and Certificates of Public Convenience (1) to Begin to Furnish and Supply Electric Transmission Service in Greene County and Fayette County, Pennsylvania; (2) for Certain Affiliated Interest Agreements; and (3) for any Other Approvals Necessary to Complete the Contemplated Transactions	:	**Docket No. A-2026-_____**
and		
Application of NextEra Energy Transmission MidAtlantic, Inc., Filed Pursuant to 52 Pa. Code Chapter 57 Subchapter G, for Approval to Site and Construct a 500 kV Transmission Line Associated with the MidAtlantic Resiliency Link Project Located in Portions Of Greene County and Fayette County, Pennsylvania, Pennsylvania	:	**Docket No. A-2026-_____** A-2026-3060856-AEL-3/4/26

NextEra Energy Transmission MidAtlantic, Inc.
MidAtlantic Resiliency Link Project – Pennsylvania Segment

Statement No. 3

Direct Testimony of
Sami Abdulsalam, Ph.D., P.Eng.
Director of Transmission Planning, PJM Interconnection, L.L.C.

Topics Addressed: **Description of PJM's RTEP Process**
PJM's 2022 Window 3 Process
The Reliability Need for the Mid-Atlantic Reliability Project

Date: March 3, 2026

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I. BACKGROUND

Q1. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A1. My name is Sami Abdulsalam, Ph.D., P.Eng. I am the Director of Transmission Planning for PJM Interconnection, L.L.C. ("PJM"). My business address is 2750 Monroe Boulevard, Audubon, Pennsylvania 19403.

Q2. PLEASE DESCRIBE YOUR RESPONSIBILITIES AT PJM AND ANY OTHER RELEVANT PROFESSIONAL EXPERIENCE.

A2. I joined PJM in January of 2022. I have been in my current position as the Director of PJM Transmission Planning since March 2024, and I previously served as the Senior Manager of PJM Transmission Planning. My principal responsibility is to lead the development of PJM's Regional Transmission Expansion Plan ("RTEP").[1] This function centers on the planning of the regional transmission system for the provision of reliable electric service in accordance with North American Electric Reliability Corporation ("NERC") Reliability Standards, as well as PJM and Transmission Owner[2] reliability and operational criteria.

Prior to this position, I served as Senior Manager, Consulting at Siemens PTI where I was responsible for power system analysis, transmission planning, and protection studies; as Principal Engineer at Sustainable Grid Power, Inc.; and, for more than ten years, held various transmission planning positions of increasing responsibility, including Director,

[1] All terms not otherwise defined herein shall have the meaning set forth in the PJM Open Access Transmission Tariff ("Tariff") or the PJM Amended and Restated Operating Agreement ("Operating Agreement").

[2] A "Transmission Owner" is a PJM member that "owns or leases with rights equivalent to ownership Transmission Facilities and is a signatory to the PJM Transmission Owners Agreement." (Operating Agreement, Definitions, S-T). An incumbent Transmission Owner is a Transmission Owner that has signed the Consolidated Transmission Owner Agreement ("CTOA").

Transmission Planning and Director, Transmission System Projects, at the Alberta Electric System Operator, Canada.

Earlier in my career, I held various positions in the oil and gas industry, and was an Operational Engineer in thermal power plants in Egypt.

My academic research focused on power system performance under voltage stability/high power transfer conditions as well as dynamic and transient behavior of power systems.

Q3. PLEASE PROVIDE A SUMMARY OF YOUR EDUCATIONAL BACKGROUND.

A3. I hold a Bachelor of Science degree and Master of Science degree in Electrical Engineering received from the University of El-Mansoura in Egypt in 1997 and 2001, respectively. I received a Ph.D. in Electrical Engineering from the University of Alberta in Edmonton, Alberta, Canada in 2007. I also held a post-doctoral fellowship in the Electrical and Computer Engineering Department at the University of Alberta, Edmonton, Canada from 2007 to 2008. In addition, I am a registered Professional Engineer (P.Eng.) in Alberta, Canada.

Q4. ON WHOSE BEHALF ARE YOU PROVIDING TESTIMONY IN THIS PROCEEDING?

A4. I am testifying in this proceeding in support of NextEra Energy Transmission MidAtlantic, Inc. ("NEET MA" or the "Company"). As part of PJM's 2022 Window 3 competitive solicitation process ("2022 Window 3") – which I describe in more detail in my testimony below – PJM designated NEET MA to construct, own, and maintain certain transmission enhancements and expansions that are necessary to address and resolve certain reliability

violations forecasted to impact the bulk electric transmission system that serves the PJM Region,[3] which includes the state of Pennsylvania.

Q5. WERE YOU INVOLVED IN THE 2022 WINDOW 3 COMPETITIVE SOLICITATION PROCESS?

A5. Yes, I had primary responsibility for supervising the 2022 Window 3 process, including the performance of all analyses; the evaluation of solution options; interaction with incumbent Transmission Owners, Nonincumbent Developers[4] and PJM stakeholders; documentation of the RTEP; and review with the PJM Board of Managers ("PJM Board").

With respect to the PJM stakeholder process (which I will describe in more detail below), I led PJM's review of the numerous proposed reliability solutions that were submitted by various incumbent Transmission Owners and Nonincumbent Developers as part of 2022 Window 3 and reviewed with the Transmission Expansion Advisory Committee ("TEAC") in accordance with the provisions of the PJM Operating Agreement, which has been accepted by the Federal Energy Regulatory Commission ("FERC").

I was involved in each of these capacities as PJM selected a modified version of NEET MA's proposal (which I describe below) as part of the overall package of solutions that PJM determined were the more efficient or cost-effective solutions to address the transmission reliability violations PJM identified through the 2022 Window 3 process.

[3] The "PJM Region" includes all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.

[4] A "Nonincumbent Developer" is "(1) a transmission developer that does not have an existing Zone in the PJM Region as set forth in Tariff, Attachment J; or (2) a Transmission Owner that proposes a transmission project outside of its existing Zone in the PJM Region as set forth in Tariff, Attachment J." Operating Agreement, Definitions, M-N.

Q6. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY AUTHORITIES?

A6. Yes. Further information on my professional qualifications, including provision of expert witness testimony and professional affiliations, can be found in my curriculum vitae, included here as **Exhibit SA-1**.

Q7. ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A7. Yes, I am including the following as Exhibits to my testimony:

- **Exhibit SA-1**: Curriculum Vitae of Sami Abdulsalam, Ph.D., P.Eng.
- **Exhibit SA-2**: Operating Agreement, Schedule 6, PJM's Regional Transmission Expansion Planning Protocol
- **Exhibit SA-3**: PJM Manual 14B - PJM Region Transmission Planning Process (Revision 56)
- **Exhibit SA-4**: PJM RTEP – 2022 RTEP Proposal Window 3, Problem Statement and Requirements
- **Exhibit SA-5**: Special TEAC Materials, 2023 RTEP 2028 Preliminary Summer & Winter Generation Deliverability 500 kV and Above Violation Summary (April 27, 2023)
- **Exhibit SA-6**: Reliability Analysis Report, 2022 Window 3 (December 8, 2023)
- **Exhibit SA-7**: TEAC Materials, Reliability Analysis Update (October 3, 2023)
- **Exhibit SA-8**: Constructability & Financial Analysis Report, 2022 Window 3 (November 17, 2023)
- **Exhibit SA-9**: TEAC Materials, Reliability Analysis Update, 2022 Window 3 Upgrades – Scope Changes / Cancellations Baseline Reliability Projects (July 9, 2024)

II. OVERVIEW AND EXECUTIVE SUMMARY

Q8. PLEASE PROVIDE AN OVERVIEW OF THE TRANSMISSION ENHANCEMENTS AND EXPANSIONS THAT WERE SELECTED TO ADDRESS THE REGIONAL WEST TO EAST TRANSFER NEEDS.

A8. As I will describe in more detail below, as part of 2022 Window 3, for the 2027 and 2028 study years, PJM identified extensive, severe, and widespread thermal and voltage violations throughout the PJM Region, requiring the development of backbone solutions[5] to resolve these conditions and maintain transmission system reliability.

PJM observed voltage collapse conditions and thermal reliability violations in both the 2027 and 2028 study years due to the high demand for west to east power flow (the "Regional West to East Transfer Needs"). Several entities – including NEET MA – proposed transmission solutions to address the Regional West to East Transfer Needs. For the reasons I describe below, PJM initially selected a modified version of a proposal submitted by NEET MA ("Modified Proposal No. 853") as the solution to address the Regional West to East Transfer Needs. As shown in **Map 1**, as initially modified and selected by PJM, Modified Proposal No. 853 consisted of the following:

- A proposed new 500/138-kV Woodside substation in Frederick County, Virginia ("Woodside Substation"),[6] designated to NEET MA;
- A new 121-mile 500 kV transmission line from the existing 502 Junction Substation in Greene County, Pennsylvania, crossing first into Monongalia and Preston

[5] When I say "backbone solutions" or "backbone transmission lines," I am referring to transmission lines in the PJM Region that are 500 kV or above and that connect and support the "bulk" power transfers between the PJM zones.

[6] The new Woodside Substation will include: (i) looping the Bismark to Doubs 500 kV line; (ii) two 500 kV/138 kV transformers; (iii) additional reactive support devices, including capacitors and a STATCOM; and (iv) line termination scope for Doubs to Bismark 500 kV line.

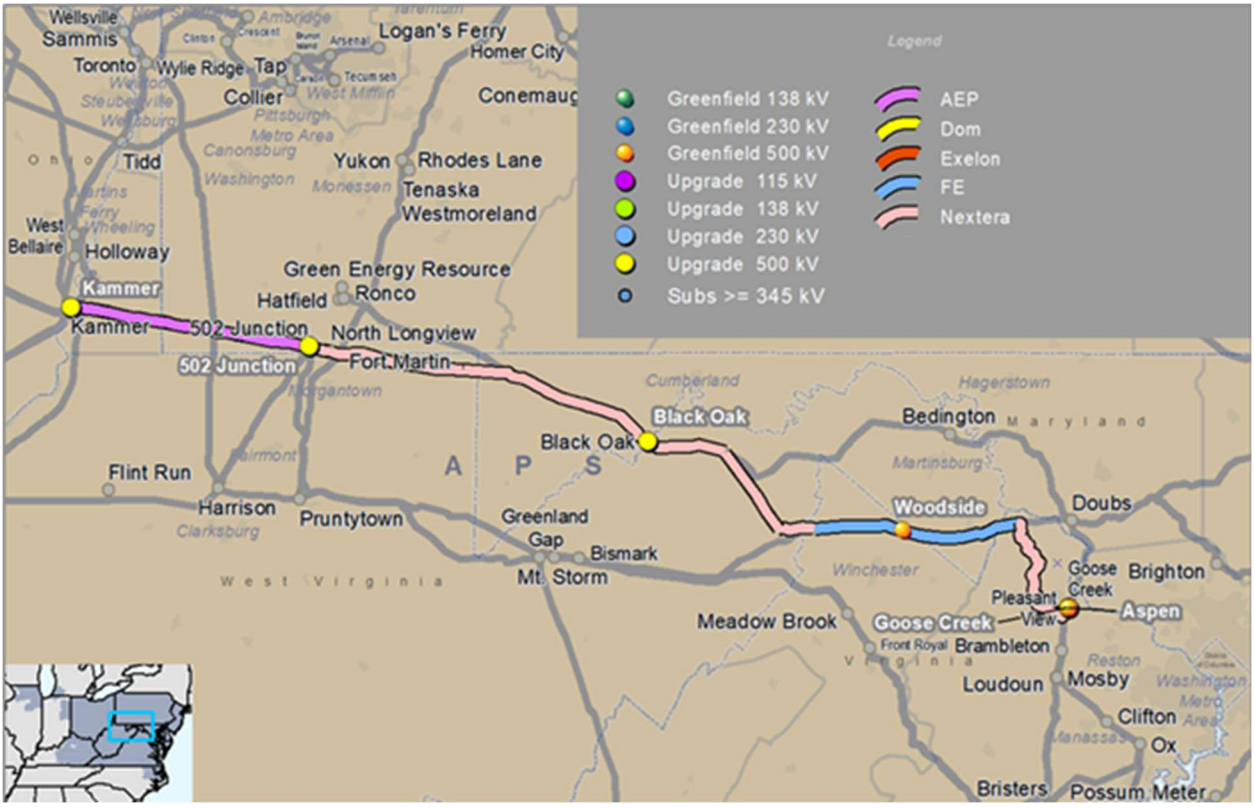
Counties, West Virginia, into Allegany and Garrett Counties in Maryland, back into Mineral and Hampshire Counties, West Virginia, and finally to a proposed Woodside Substation in Frederick County, Virginia (bypassing the existing Black Oak substation in Allegany County, Maryland) (the "502 Junction to Woodside Segment"), 105 miles of which was designated to NEET MA and 16 miles of which was designated to Potomac Edison Company (a subsidiary of FirstEnergy Corp. and referred to herein as "FirstEnergy") (utilizing FirstEnergy's existing ROW);

- A new approximately 47-mile 500 kV transmission line from the proposed Woodside Substation in Virginia to the proposed Aspen Substation in Virginia, designated to NEET MA (the "Woodside to Aspen Segment"), 21 miles of which was designated to FirstEnergy utilizing FirstEnergy's existing ROW) and approximately 26 miles of which was designated to NextEra ("NextEra Greenfield Line");
- Terminating the Woodside to Aspen Segment into a proposed new 500 kV Aspen substation in Loudon County, Virginia ("Aspen Substation") (close to the existing Goose Creek substation), designated to Virginia Electric and Power Company d/b/a Dominion ("Dominion");[7] and
- Conducting a sag study[8] to assess emergency rating needed to upgrade the Kammer to 502 Junction 500 kV line, designated to American Electric Power ("AEP").

[7] Note that the Aspen Substation, designated to Dominion, is not part of the scope of this application.

[8] A "sag study" is an engineering analysis that measures the clearance, or "sag," of overhead power lines along transmission line spans between supporting towers. A sag study seeks to identify whether the sag needs adjustment to keep tension within safe limits while maintaining needed ratings within the conductor and structure mechanical strength limits.

Map 1: Modified Proposal No. 853



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Modified Proposal No. 853 was approved by the PJM Board on December 11, 2023 as part of the set of solutions recommended by PJM staff to resolve the reliability violations identified in 2022 Window 3. I will refer to the entire scope of Modified Proposal No. 853, including the portions designated to NEET MA, FirstEnergy, Dominion, and AEP, as initially approved by the PJM Board as the "Initial Western Cluster Solution."

As indicated above, when initially approved by the PJM Board, the Initial Western Cluster Solution included the NextEra Greenfield Line (assigned PJM RTEP baseline ID b3800.119). For the reasons discussed more fully in NEET MA Witness McCormick's

testimony in NEET MA Statement No. 1, in response to stakeholder feedback, after being awarded Modified Proposal No. 853, NEET MA began to work collaboratively with FirstEnergy, Dominion, and Exelon – the incumbent Transmission Owners along the proposed route of that segment – to investigate options to reduce the overall impacts of the project and enhance utilization of existing rights-of-way owned by the incumbent Transmission Owners.

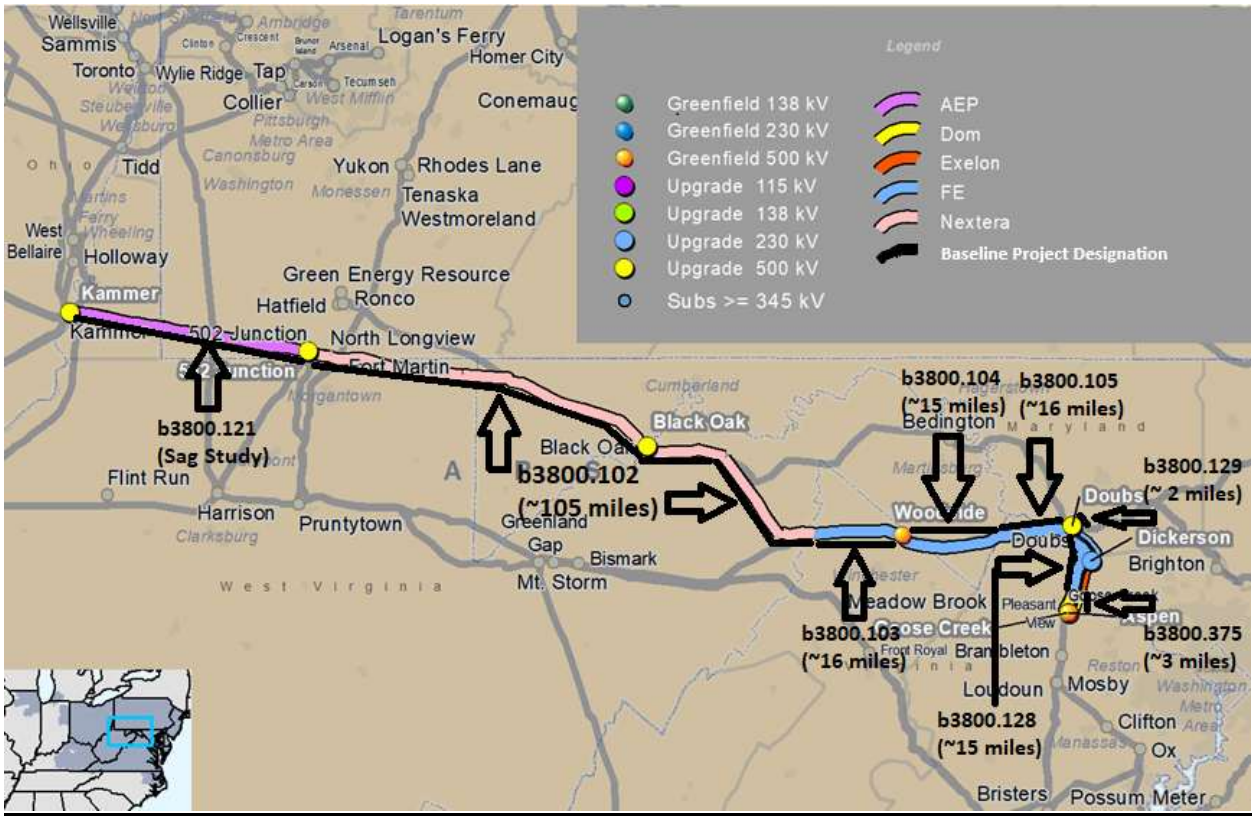
As a result of the discussions, PJM cancelled the NextEra Greenfield Line and worked with NEET MA, FirstEnergy and Dominion on a revised scope of the Initial Western Cluster Solution facilities to be located in Maryland and Virginia. Specifically, in place of the NextEra Greenfield Line, the incumbent Transmission Owners agreed to use their own rights-of-way and expand their existing transmission corridor(s) to accommodate the revised proposed route from the demarcation point to a point of interconnection west of Doubs along the Millville – Doubs Corridor through the Doubs – Goose Creek Corridor ("Revised Western Cluster Solution").[9]

The PJM Board approved the Revised Western Cluster Solution on August 7, 2024. **Map 2**, below, depicts the scope of the Revised Western Cluster Solution including, as relevant to this proceeding, NEET MA's portion of the 502 Junction to Woodside Segment and the Woodside Substation that are designated to NEET MA. The portion of the Revised

[9] PJM discussed the revised Western Cluster Solution with the TEAC at the July 9, 2024 TEAC meeting. *See* **Exhibit SA-9**, slides 40-44.

Western Cluster Solution that is designated to NEET MA is referred to herein as the MidAtlantic Reliability Link ("MARL" or "Project").[10]

Map 2: Revised Western Cluster Solution



NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should ***not*** *be relied upon for exact geographical substation locations or line routes.*

PJM determined that the Initial Western Cluster Solution (including the MARL Project) was needed by June 1, 2027, and NEET MA committed to an in-service date for the Project of December 31, 2031 for the MARL Project in a FERC-accepted Designated Entity Agreement between PJM and the Company.

[10] The following PJM baseline projects comprise the MARL: b3800.102, b3800.106 to b3800.110, b3800.113, b3800.115, b3800.117 and b4000.14. Additional information about these individual baseline projects is available on the Project Status & Cost Allocation portion of PJM's website: https://www.pjm.com/planning/m/project-construction.

Q9. HOW IS THE REST OF YOUR TESTIMONY ORGANIZED?

A9. The remainder of my testimony is organized as follows:

- In this **Section II**, I summarize my testimony and provide a high-level summary of the conclusions that I reach herein regarding the need for the Revised Western Cluster Solution (including the MARL Project);

- In **Section III**, I discuss the relevant and respective roles of FERC, NERC, PJM and the PJM stakeholders in addressing transmission system reliability. Specifically, Section III summarizes the requirements that led to NERC's establishment of mandatory Reliability Standards and FERC's enforcement of those standards. I also describe how PJM complies with NERC Reliability Standards, as well as the additional relevant reliability and planning criteria to which PJM plans the PJM transmission system. I also provide a high-level overview of PJM's planning process, which is referred to as the RTEP process. Finally, in Section III, I provide a high-level explanation of how stakeholders, states, state consumer advocates, and other interested parties participate in the RTEP process.

- In **Section IV**, I explain how PJM conducts the RTEP process to maintain the reliability of the PJM transmission system. Since the Revised Western Cluster Solution (including the MARL Project was selected by PJM as a Reliability Project,[11] I focus my discussion on the analyses PJM performs and the criteria that PJM applies to identify future reliability violations on the PJM transmission system. I also explain what would happen if any of the identified reliability violations were to occur, and explain how PJM identifies transmission solutions to avoid the future occurrence of such reliability violations.
- In **Section V**, I explain PJM's annual RTEP process for 2022, including a description of (i) all of the competitive proposal windows that PJM opened as part of the 2022 RTEP cycle, and (ii) the immediate reliability needs for which PJM directed Immediate-need Reliability Projects[12] as part of the 2022 RTEP – all of which have an impact on the 2022 Window 3 process. I also explain in detail PJM's rationale for opening 2022 Window 3 in February 2023, including the additional load growth and announced deactivations that formed the basis for PJM to open the window. This window also took into account then recently-adopted methodological changes part of the 2022 Windows 3 process. Integrating these methodological changes into the 2022 Window 3 process ensures the solutions would be compatible

[11] Reliability Projects are projects that are designed to address one or more reliability violations or to address operational adequacy or performance issues. *See* Tariff, Schedule 12(b)(i)(A)(2).

[12] An "Immediate-need Reliability Project" is a "reliability-based transmission enhancement or expansion that [PJM] has identified to resolve a need that must be addressed within three years or less from the year [PJM] identified the existing or projected limitations on the Transmission System that gave rise to the need for such enhancement or expansion pursuant to the study process described in Operating Agreement, Schedule 6, section 1.5.3." PJM Operating Agreement, Definitions I-L.

with the 2023 Window 1 solutions,[13] and ensures efficient development of needed transmission reinforcements. This section also details the severe and widespread reliability violations that PJM observed in the 2027 and 2028 study years, for which PJM sought solutions through the 2022 Window 3 competitive window process.

- In **Section VI**, I explain how PJM analyzed the 72 proposals it received from ten different entities as part of 2022 Window 3 (50 of which were greenfield[14] proposals, while 22 were upgrades to existing facilities). Specifically, I explain the criteria PJM studied to determine whether proposed transmission enhancements or expansions would be the more efficient or cost-effective solution to address the 2022 Window 3 reliability violations (which is the standard required by FERC Order No. 1000 and PJM's FERC-accepted Operating Agreement, Schedule 6). I also explain how PJM identified proposals or components of proposals to be included on PJM's 2022 Window 3 shortlist, which included those proposals or proposal components that PJM determined warranted more detailed analyses with respect to risks associated with their cost estimates, cost containment provisions, proposed schedules, constructability, and brownfield/outage coordination. I explain how PJM identified three scenarios as part of this shortlist evaluation and explain that the Initial Western Cluster Solution (including the MARL Project) was on the shortlist and included for additional evaluation in one of the three shortlisted scenarios. I also explain: (i) the reasons that PJM ultimately recommended that the

[13] *See* Question 32, below.

[14] When I say a "greenfield proposal," I mean a proposed new transmission infrastructure project, like a transmission line or substation, primarily utilizing undeveloped land or not paralleling existing linear disturbances.

proposals or components in one of the three scenarios be included in the RTEP; (ii) the relative benefits of the selected solutions generally; and (iii) the benefits of the Revised Western Cluster Solution (including the MARL Project) specifically. In Section VI, I also explain why PJM determined that many of the identified violations must be resolved through new (greenfield) transmission facilities, rather than reconductored or upgraded facilities.

- In **Section VII**, I explain the most significant steps that PJM took to open, develop, and solicit public feedback with respect to the 2022 Window 3 project selection.
- In **Section VIII**, I explain the analyses and sensitivities that PJM conducted after the set of 2022 Window 3 projects were selected which confirm that the Revised Western Cluster Solution (including the MARL Project) is needed to maintain reliability in the PJM Region.

III. THE ROLES OF FERC, NERC, PJM, AND PJM STAKEHOLDERS IN ADDRESSING TRANSMISSION SYSTEM RELIABILITY

Q10. PLEASE EXPLAIN THE ROLE OF FERC AND NERC IN ADDRESSING TRANSMISSION SYSTEM RELIABILITY.

A10. The Energy Policy Act of 2005 ("EPAct 2005") created a mandatory compliance and enforcement regime for reliability standards governing the nation's bulk electric transmission system under the oversight of FERC. Pursuant to EPAct 2005, FERC designated NERC[15] as the Electric Reliability Organization for the United States. In that

[15] NERC is a not-for-profit international regulatory authority whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel.

capacity, NERC has proposed various Reliability Standards[16] to maintain the continued safe and reliable operation of the nation's bulk electric transmission system, most of which have been adopted by FERC for enforcement as FERC rules, with mandatory compliance that began on June 1, 2007. PJM has been applying the NERC Reliability Standards and the PJM deliverability standards, codified in the PJM Tariff and PJM Transmission Planning Manuals (Manuals 14A through 14H),[17] on a mandatory basis since the initiation of the RTEP process.

Q11. ARE THE NERC RELIABILITY STANDARDS ENFORCEABLE THROUGH THE IMPOSITION OF MONETARY PENALTIES FOR NON-COMPLIANCE?

A11. Yes. Penalties for violation of the Reliability Standards developed by NERC and approved by FERC may be as high as $1 million per violation per day (as may be adjusted for inflation).

Q12. PLEASE DESCRIBE PJM'S ROLE IN ADDRESSING TRANSMISSION SYSTEM RELIABILITY.

A12. PJM is the Regional Transmission Organization ("RTO") responsible for maintaining the reliability of the electric transmission system under its functional control and coordinating the movement of wholesale electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. The PJM system serves approximately 67 million people. PJM dispatches more than 182,000 MW of generation capacity over more than 88,000 miles of transmission lines – a system that serves over 20

[16] The NERC Reliability Standards are available at https://www.nerc.com/pa/Stand/Pages/ReliabilityStandards.aspx.

[17] The PJM Transmission Planning Manuals are available on PJM's website at https://www.pjm.com/library/manuals.

percent of the United States economy. PJM presently has more than 1,100 members. These members include power generators, transmission owners, electricity distributors, power marketers and large consumers.

PJM is registered in the ReliabilityFirst and SERC regions[18] for the following reliability functions, as defined in the NERC Reliability Functional Model: Balancing Authority, Interchange Authority, Planning Coordinator, Reliability Coordinator, Resource Planner, Transmission Operator, Transmission Planner, and Transmission Service Provider.

In these roles, PJM acts independently and impartially to develop the RTEP, which identifies the transmission system additions and improvements needed to maintain the reliability of the transmission system in the PJM Region.

Q13. PLEASE SUMMARIZE PJM'S RTEP PROCESS.

A13. As part of its ongoing responsibilities as an RTO, PJM is charged by FERC with maintaining the safety, reliability and security of the bulk electric transmission system in the PJM Region. As part of its regional transmission planning function, PJM prepares the RTEP each year in order to identify transmission system enhancements or expansions needed for reliable grid operations now and in the future for the 67 million people in the PJM Region. PJM evaluates the aggregate needs across the transmission system, identifying potential needs impacting the transmission system and solutions to those needs on a regional basis.

[18] NERC oversees six regional reliability entities including, as relevant to the PJM Region, SERC Reliability Corporation ("SERC") and ReliabilityFirst Corporation ("ReliabilityFirst").

PJM's FERC-accepted Regional Transmission Expansion Planning Protocol ("RTEP Protocol") incorporates FERC's transmission planning requirements and is set forth in Schedule 6 of the PJM Operating Agreement, attached hereto as **Exhibit SA-2**. The RTEP Protocol describes the requirements for the RTEP to remain compliant with NERC Reliability Standards and other applicable reliability criteria.

Each year, PJM conducts a long-range RTEP process to prepare the high-voltage transmission system to meet the projected demand and supply. As further described in the testimony of Andrew Gledhill in NEET MA Statement No. 4, projected demand comes from the PJM load forecast, which is an independent work product based in statistical modeling that is reviewed by stakeholders.[19] The RTEP process integrates transmission, generation (existing, deactivated and planned), and demand response resources when assessing transmission system reliability constraints. The result is one process that integrates many system factors as detailed in PJM Manual 14B.

PJM's RTEP process applies NERC's Transmission Planning ("TPL") Standard TPL-001-5[20] through a wide range of reliability analyses, including those listed under the PJM planning criteria (described below). These analyses include load and generation deliverability tests (explained later in further detail below).[21] These tests are applied and

[19] The process for developing the PJM Load Forecast is described more fully in the direct testimony of my colleague Andrew Gledhill at NEET MA St. No. 4.

[20] NERC TPL-001-5 sets the requirements for transmission system planning, ensuring utilities have the redundancy in place to maintain system reliability under any condition. *See* https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf.

[21] The PJM Planning Manuals, including Manual 14B, include the processes and procedures PJM uses to comply with applicable NERC standards.

the results are evaluated over a 15-year planning horizon. PJM documents all instances where the transmission system does not meet applicable reliability criteria and develops system reinforcements or upgrades (through the competitive solicitation and/or the immediate need processes) to ensure compliance with the standard and maintain reliability of the bulk electric system.

The RTEP process is further described in extensive detail in the PJM Transmission Planning Manuals. The PJM Transmission Planning Manuals, which are developed through PJM's public stakeholder process, include the technical criteria and procedures used to implement the RTEP. PJM Manual 14B, "PJM Region Transmission Planning Process," details the technical assumptions, procedures and protocol used to evaluate electric system performance and identify reliability violations, including those discussed in my testimony below. PJM Manual 14B is attached to my testimony as **Exhibit SA-3**.

Q14. WHAT ARE THE DIFFERENT TYPES OF TRANSMISSION PROJECTS THAT EMERGE FROM PJM'S PLANNING PROCESS?

A14. As set forth in PJM Manual 14B, there are three types of transmission projects that emerge from PJM's planning processes. These include:

- *Regional RTEP Projects and Subregional RTEP Projects*, which are also referred to as "baseline upgrades" or "baseline projects." As discussed further below, baseline projects, among other things, ensure compliance with national and regional reliability standards. Specifically, PJM selects RTEP baseline projects as needed to comply and resolve the following reliability criteria: (i) NERC, SERC, ReliabilityFirst, PJM, and other applicable reliability criteria, including operational performance; (ii) individual Transmission Owner planning criteria as filed in the

Transmission Owner's respective FERC Form No. 715; (iii) criteria to address economic constraints; and (iv) State Agreement Approach (public policy) expansions or enhancements as set forth in the Operating Agreement at Schedule 6, section 1.5.9. I will refer to these reliability and other planning criteria collectively herein as "Planning Criteria." After PJM identifies a need for a baseline transmission upgrade, PJM may, consistent with the requirements of the RTEP Protocol, open a competitive proposal window that seeks solutions from qualified incumbent Transmission Owners and Nonincumbent Developers[22] to address these identified reliability needs, depending on a project's required in-service date, voltage level and scope.[23]

- *Network upgrades*, which are transmission system enhancements needed for integrating generation interconnections seeking long-term transmission service and connection to the grid.
- *Supplemental Projects,* which are transmission system enhancements developed through the Subregional RTEP Committees (for below 230 kV transmission facilities) and the TEAC (for 230 kV and above transmission facilities). Supplemental projects are transmission expansions or enhancements by Transmission Owners to address local reliability needs, such as customer service and load growth, equipment condition, operational performance and risk, and

[22] Per the terms of the PJM Operating Agreement, incumbent Transmission Owners and Nonincumbent Developers are required to pre-qualify as eligible to be designated by PJM to develop a baseline project under the RTEP Protocol.

[23] Baseline projects may include Immediate-need Reliability Projects, which solve more urgent reliability violations or system conditions that need to be addressed in three years or less.

infrastructure resilience. PJM evaluates these projects to ensure they do not harm the regional grid from a reliability perspective.

Q15. PLEASE DESCRIBE THE ROLE OF THE TEAC IN THE DEVELOPMENT OF THE RTEP.

A15. The TEAC is established under the PJM RTEP Protocol (set forth in Schedule 6 of the Operating Agreement). The TEAC is an advisory-only, open PJM stakeholder committee, which holds regular (at least monthly) public meetings to review RTEP activities, analyses, and proposed transmission solutions, and to provide advice to PJM regarding the preparation of the PJM RTEP for review and approval by the PJM Board. TEAC activities are at the core of stakeholder input in the RTEP process. The scope of the TEAC's responsibility includes the review of and the provision of comments and input on the following:

- Scope and assumptions of RTEP studies;
- RTEP analyses at defined points during the RTEP process cycle;
- RTEP recommendations to be proposed to the PJM Board for approval; and
- Specified RTEP process matters as requested by the PJM Board.

TEAC participation is open to all Transmission Owners, transmission customers, Nonincumbent Developers, all PJM members, representatives of state commissions, the agencies and offices of state consumer advocates of states in the PJM Region, and any other interested parties. The TEAC meetings in which PJM reviewed the 2022 Window 3 projects, including the Initial Western Cluster Solution and the Revised Western Cluster Solution (including the MARL Project), were widely attended. Following the presentation of analyses, assumptions or results to the TEAC, stakeholders are able to provide feedback

or ask questions during the meeting itself or provide written comments and or requests. These comments are provided to the PJM Board for their consideration and serve as the basis for ongoing dialogue at subsequent TEAC meetings.[24]

IV. IDENTIFICATION OF RELIABILITY NEEDS IN THE PJM REGION

Q16. PLEASE EXPLAIN THE CONCEPT OF "ELECTRIC RELIABILITY."

A16. "Electric reliability" or "reliability," as used by industry experts, refers to the ability to continuously deliver electricity to customers in the amounts desired under normal and abnormal (disturbance) conditions within acceptable standards.

Q17. PLEASE PROVIDE A HIGH-LEVEL EXPLANATION OF HOW PJM ASSESSES THE RELIABILITY NEEDS OF THE TRANSMISSION SYSTEM THROUGH THE RTEP PROCESS.

A17. PJM's reliability planning encompasses a comprehensive series of detailed analyses to ensure reliability under various forecasted operating conditions and using the applicable Planning Criteria that I described earlier. For the near-term, PJM identifies needs for transmission upgrades using a five-year-out system model (base case suite) that incorporates PJM's official load forecast (*see* further description of the load forecast process in the Gledhill Direct Testimony, NEET MA Statement No. 4). The RTEP five-year-out base case(s) also consider generation additions and announced generator deactivations, local transmission upgrades scheduled to be in service within the five-year timeframe, and the forecasted load that is projected to materialize in the next five years. As appropriate, PJM also may utilize various load growth scenarios that represent more recent

[24] As I will discuss in more detail later in my testimony, PJM Staff presented to the TEAC for discussion and comment the MARL, along with the other solutions offered in the 2022 RTEP Window 3, throughout the RTEP process and in more detail during the October 2023 and December 2023 TEAC meetings.

information (or information that has developed following the release of PJM's annual load forecast).

As I describe in more detail later in my testimony, in the case of 2022 Window 3, PJM supplemented the window base case(s) to include additional scenarios capturing changes (increases) in the forecasted load; changes to the generation mix and associated flows due to additional announced generation deactivations; and changes to the reflect the recently-approved generation deliverability testing procedures. All of these study models are collectively referred to herein as the "base case suite."

Once the base case suite is developed and PJM identifies the reliability violations that need to be addressed pursuant to the Planning Criteria, PJM may open a competitive window to solicit proposals from qualified Transmission Owners and Nonincumbent Developers to address the identified needs through robust, holistic and expandable solutions that address and resolve the identified reliability violations.

Q18. ARE THERE POWER SYSTEM FUNDAMENTALS THAT DRIVE TRANSMISSION SYSTEM RELIABILITY?

A18. Yes, transmission system reliability is a function of thermal, voltage, stability, and short-circuit power system fundamentals. The Planning Criteria define the conditions to which the transmission system must be tested against and the associated acceptable performance. The transmission system must be able to operate to the applicable criteria without violating (exceeding) any of the defined reliability fundamental thresholds. I describe each in more detail below:

- **Thermal Overloads:** Power flows through each transmission facility according to the relationship of its impedance (opposition to electrical flow) and the relative

location of generation and load to the specific facility with respect to the broader network. Thermal ratings, or the amount of power that can be reliably transmitted through a given facility, are established by examining the most limiting element of a facility: for example, transmission conductors or substation terminal equipment. PJM identifies facilities that have power flow loadings expected to exceed applicable thermal ratings for pre-contingency[25] conditions and for the loss of a single or multiple generator(s), transmission line(s), transformer(s), or combinations of those elements which are contingencies evaluated part of the PJM Planning Criteria.

- **Voltage Limits:** Voltage levels are critical to reliable, on-demand electricity delivery. NERC Reliability Standards require that a transmission system remain stable within applicable thermal ratings and within established substation voltage ranges. Both voltage that is too low and voltage that is too high can become a serious concern, depending on the availability of resources – both generation and transmission – to produce or absorb reactive power to aid in voltage support and control. In real time, operators use transmission system equipment to control voltage, up to and including switching transmission lines in and out of service, switching capacitors or reactors, or adjusting voltage set points on static volt ampere reactive ("VAR") compensators.

[25] A contingency is an unexpected event that could impact the power system, such as the loss of a generator or transmission facility. Pre-contingency conditions refer to system conditions that exist prior to the contingency taking place.

- **System Stability:** System instability can arise under various conditions. A frequency (or angular stability) condition is when a fault occurs on the transmission system, resulting in a generator going into an over- or under-speed condition, causing it to trip off-line. Under such conditions, if there is insufficient inertia to compensate, or if there is limited transmission transfer capability, that generator may trip, along with additional cascading transmission and generator trippings, up to the point where blackouts can occur. Another form of stability includes voltage stability conditions where the transmission network itself does not have sufficient "transfer capability" to carry the generated power from where it is sourced to where it is consumed. Both angular and voltage stability conditions pose risk to the reliability of the power system and indicate a need to enhance the transmission system transfer capability to ensure the reliability of the interconnected system (and local load areas) is maintained. PJM performs multiple tiers of stability analysis, consistent with NERC criteria, to develop transmission solutions that ensure generators remain synchronized with the rest of the grid.
- **Short Circuit Limits:** NERC requires that each bulk electric system circuit breaker have adequate fault-interrupting capability to isolate the transmission facility and isolate the fault, interrupting the high electric current that can negatively influence the broader transmission system. PJM runs short circuit simulations that utilize circuit breaker ratings provided by the transmission owner to evaluate the breaker-interrupting capabilities. Any deficiencies in breaker ratings are identified by PJM, and necessary enhancements are developed. Solutions may require replacing the

breaker itself to implement a higher current-interrupting rating, or sometimes even redesigning significant portions of the electrical infrastructure. All breakers whose calculated fault currents exceed breaker-interrupting capabilities are considered over-dutied, or operating in excess of equipment ratings, and are reported to transmission owners for confirmation and solution development where required.

Q19. WHAT HAPPENS WHEN A TRANSMISSION LINE OVERLOADS OR EXCEEDS ITS LOADING CAPACITY?

A19. The power system is evaluated, planned and operated in a way that, under normal and credible stressed scenarios or conditions, the transmission network reliability will be maintained and no thermal, voltage or stability limits are violated. Hypothetically, when a transmission line overloads, the conductor, the hardware securing the conductor, and the line terminal equipment are subject to flows beyond their ratings which will lead to overheating of any or all of these elements. Overheating the conductor may cause the line to sag low enough to bring the line into contact with whatever is underneath it. Under these conditions, the metal in the conductor may also lose its mechanical strength properties, rendering it dangerous to operate. In addition, the line may break and fall to the ground causing a potentially dangerous situation for those near the line, as well as the crews required to respond to the event. In short, overloading transmission lines may cause permanent damage to transmission infrastructure and power outages.

Q20. WHAT ACTIONS WOULD PJM TAKE TO TRY TO PREVENT LINE OVERLOADS?

A20. As mentioned, PJM plans the transmission system in a way that all operating conditions are accounted for as per Planning Criteria requirements. However, in real-time operations,

multiple outages may overlap or abnormal weather conditions may materialize to push the transmission system beyond the level to which it was planned. The transmission system, however, will always be planned and operated reliably to the next contingency or event. To prevent the consequences of a potential transmission line overload, immediate action must be taken by system operators before the line or related equipment is subject to unacceptable risk (for example, unrecoverable stress). The action may include turning specific generating units off or on, opening or closing specific transmission elements, or discontinuing electric service to certain customers or groups of customers in specific areas to reduce the line loading. These are emergency or temporary measures only, which prevent a specific breakdown on that occasion but do not solve the underlying problem causing the situation, *i.e.*, reliability vulnerability. On a long-term basis, the construction of new transmission lines or enhancements to existing lines is necessary to address such vulnerability or reliability violation. In some cases, where the overload is driven by the load demand downstream and without sufficient generation capacity to offload the transmission element, operators may need to shed load to maintain the overall reliability of the greater area of concern and the overall system.

Q21. PLEASE EXPLAIN VOLTAGE STABILITY AND LOW VOLTAGE CONCERNS.

A21. Voltage stability refers to the ability of a power system to maintain steady voltages within prescribed limits at all buses in the system after being subjected to a disturbance from a given initial operating condition. It is normally associated with lack of local reactive power compensation inside the load pocket/area (an area with more load than generation) or the excessive reactive power loss along the transmission network itself due to high flows (even

if those flows are below the thermal conductor limits) and long distances with respect to the amount of power being transmitted. This is a serious system performance concern that has led to many voltage collapses and blackout conditions in the past. It is normally addressed through providing sufficient reactive compensation resources locally inside load pockets and transmission system enhancements. When sufficient local reactive power is provided in a load pocket leading to a healthy voltage profile in pre-contingency conditions, while severe and widespread low voltages occurring under contingency conditions, transmission enhancements to strengthen the source side or the transmission path carrying the power transfer to the load pocket will be required.

Q22. PLEASE DESCRIBE THE PLANNING EVENTS THAT PJM TESTS TO ENSURE THAT THE SYSTEM MEETS THE SPECIFIED PLANNING CRITERIA.

A22. Under NERC Reliability Standard TPL-001-5, "planning events" (as NERC refers to them) are categorized as P0 through P7 and defined in the context of system contingency events to be evaluated as part of transmission reliability assessments. PJM studies each event as part of one or more steady-state analyses as described in PJM Manual 14B, which is included as **Exhibit SA-3** to this testimony. The planning events are:

- P0 – No Contingency (Normal Condition)
- P1 – Single Contingency
- P2 – Single Contingency (bus section)
- P3 – Multiple Contingency
- P4 – Multiple Contingency (fault plus stuck breaker)

- P5 – Multiple Contingency (fault plus relay failure to operate)
- P6 – Multiple Contingency (two overlapping single contingencies)
- P7 – Multiple Contingency (common structure)

PJM tests for compliance with all Planning Criteria against the NERC Reliability Standards.

For instance, NERC Category P0 criteria require that, for all transmission facilities in service, equipment thermal ratings and system voltage limits are respected and that the system is stable. NERC Category P1 and P2 criteria impose similar requirements with one facility removed from service. This is referred to as the "N minus 1" or "N-1" criteria. NERC Category P4, P5 and P7 criteria impose similar requirements with two facilities removed from service and can be referred to as the "N minus 2" or "N-2" criteria. NERC Category P3 and P6 criteria again impose similar requirements with two facilities removed from service, however these analyses permit adjustments to the system dispatch between the removal of the first and the second facility from service. This is referred to as the "N minus 1 minus 1" or "N-1-1" criteria.

The PJM Planning Criteria, as described in PJM Manual 14B, defines the conditions to which the PJM transmission system will be tested and these planning events will be applied. For example, PJM's generation deliverability test evaluates how the system will reliably perform to various flow conditions by varying or "ramping" generation up or down to evaluate the impact of generation dispatch variations on the ability of the system

to reliably deliver generated power to load while maintaining the NERC reliability performance standard.

Q23. WHAT ANALYSES DOES PJM CONDUCT TO ASSESS COMPLIANCE WITH NERC PLANNING EVENTS?

A23. PJM conducts various studies, including load and generation deliverability tests which are discussed below and in more detail in PJM Planning Manual 14B.

NERC Standard TPL-001-5 includes extreme events as well. PJM studies system conditions following several extreme events, also known as maximum credible disturbances, judged to be critical from an operational perspective for risk and consequences to the system (such as equipment damage, cascading loss of system elements, and electric service interruption).

PJM conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operations throughout PJM's planning horizon. NERC criteria disturbances are those required by the NERC planning criteria applicable to system-normal (P0), single-element outage (P1 and P2) and common mode, multiple-element outage conditions (P3 through P7).

Q24. HOW ARE THE PLANNING CRITERIA THAT YOU JUST DESCRIBED USED TO DETERMINE WHETHER NEW OR ENHANCED TRANSMISSION FACILITIES ARE NEEDED?

A24. PJM conducts studies of the PJM transmission system that apply the Planning Criteria to specific conditions on the transmission system. When the studies show that the transmission system is unable to meet a specific Planning Criteria under these conditions, this means that the transmission system cannot be reliably operated under the forecasted and modeled system conditions. System upgrades will therefore be required so that the

reliability performance requirements are met. These upgrades could take the form of construction of one or more new transmission elements or one or more enhancements to existing transmission facilities.

Baseline reliability analyses ensure the security and adequacy of the transmission system to serve all existing and projected load and transmission firm services. RTEP baseline reliability analyses include system voltage and thermal analysis, and stability, load deliverability, and generation deliverability testing. These tests variously entail single and multiple contingency testing for violations of established Planning Criteria regarding stability, thermal line loadings and voltage limits.

Q25. WHAT STUDIES DOES PJM CONDUCT TO TEST SYSTEM DELIVERABILITY?

A25. There are two primary deliverability studies used by PJM to test system conditions: (1) the load deliverability test and (2) the generator deliverability test. These two tests complement each other because to maintain reliability, capacity resources must contribute to the deliverability of energy within PJM in two ways. First, within an area experiencing a localized capacity emergency or deficiency (meaning generation capacity is lower than load in a specific area), energy must be deliverable from the aggregate of the available capacity resources to load. Second, capacity resources within a given electrical area must, in aggregate, be able to be deliverable (transferred out) to other areas of the PJM Region. PJM has therefore developed the load deliverability and generator deliverability tests to verify compliance with each of these deliverability requirements. Planning the PJM transmission system to the unified load and generator deliverability tests as described in

PJM Planning Manual M14B ensures that the system is planned consistently to the same, uniform standard of service throughout.

Q26. PLEASE DESCRIBE PJM'S LOAD DELIVERABILITY TESTS.

A26. The load deliverability tests are a unique set of analyses designed to ensure that the transmission system provides a comparable transmission function throughout the system. These tests ensure that the transmission system is adequate to deliver each load area's requirements from the aggregate of system generation. The purpose of load deliverability test is to ensure there is minimal transmission risk serving each Locational Deliverability Area ("LDA") in PJM.

The load deliverability test, as described in more detail in PJM Planning Manual 14B, examines the deliverability under the stressed conditions of a 90/10 summer and winter load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC P0 and P1 Category criteria) using two separate power flow cases (probabilistic dispatches and deterministic dispatches) created for each LDA. The "Rest of PJM" LDA is assumed to be operating normally and generation is scaled up uniformly to supply the LDA under emergency.

This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission and voltage tests applied by PJM, the applicable transmission owner normal and emergency ratings and voltage limits are applied. The steady state and single contingency power flows are solved

consistent with the similar solutions described for the baseline thermal and voltage analyses.

Q27. PLEASE DESCRIBE PJM'S GENERATION DELIVERABILITY TEST.

A27. PJM's generation deliverability testing method is an established means for addressing system deliverability. The testing method conforms to industry standard. Generation deliverability ensures that clusters of capacity resources within PJM have sufficient transmission capability to be delivered to the aggregate of PJM load during circumstances where the capacity of that cluster of resources is needed due to higher-than-normal unavailability of resources elsewhere in PJM. In other words, the generation deliverability test ensures the ability of the transmission system to deliver energy from the aggregate of generation in one area to the aggregate of load in another under various generation operating conditions.

These tests are periodically reviewed and needed enhancements are evaluated and adopted as system operating characteristics merits change. The latest enhancements to the generation deliverability tests were adopted in the first quarter of 2023, where generation ramping procedures, new block dispatch,[26] and effective load carrying capacity values were updated to account for the evolving resource mix incorporating renewable generation resources. Further enhancements were also adopted to the generation dispatch of the system models where a generic merit order dispatch is applied to mimic a dispatch profile closer to what would normally occur in day-to-day operations.

[26] The block dispatch procedure considers how generation units are dispatched according to their fuel and historical behavior merits, and more accurately reflects real-time operations dispatch.

Q28. IF PJM IDENTIFIES FUTURE RELIABILITY CRITERIA VIOLATIONS THROUGH THE ANALYSES DESCRIBED ABOVE, WHAT IS PJM REQUIRED TO DO?

A28. As I previously stated, compliance with NERC Reliability Standards is mandatory. Therefore, if PJM identifies system conditions under which the PJM transmission system will violate NERC Reliability Standards, PJM is obligated to identify a transmission solution that will resolve the identified violation. If PJM does not resolve the identified reliability violation, then PJM could be subject to FERC-imposed penalties as high as $1 million per violation per day (as may be adjusted for inflation) in addition to exposing the transmission system to an unnecessary operational risk that may lead to load curtailments (*i.e.*, dropping customers) in real-time.

In addition to compliance obligations, planning the system to the Planning Criteria summarized earlier and in more detail in the PJM Transmission Planning Manuals, ensures a uniform reliability level for all load and generation within the PJM Region. The PJM Planning Criteria are documented in PJM Planning Manual 14B and are transparently vetted and approved by the PJM Planning Committee and the Markets and Reliability Committee as the criteria are updated on an as-needed basis.

Q29. IF PJM IDENTIFIES FUTURE RELIABILITY CRITERIA VIOLATIONS THROUGH THE ANALYSES DESCRIBED ABOVE, HOW DOES PJM IDENTIFY SOLUTIONS?

A29. As relevant to this proceeding, when PJM identifies a reliability need through its RTEP annual planning cycle, PJM opens a competitive window to solicit proposals from qualified Transmission Owners and Nonincumbent Developers that meet the identified needs through robust, holistic, and expandable solutions that address the identified reliability

violations. The PJM competitive planning process encourages innovative, cost-effective, and timely transmission solutions to the challenges of building and maintaining a reliable electric transmission system.

The competitive planning process begins with PJM notifying both incumbent Transmission Owners and Nonincumbent Developers – through a TEAC meeting – of PJM's intention to solicit competitive solutions to the identified planning needs. PJM will then publish a set of specific Planning Criteria violations for which PJM is soliciting solutions. Transmission developers then have a stated period before the window closes to submit their proposed solutions for addressing the identified Planning Criteria violations. PJM does not itself propose any solutions to address identified reliability needs. PJM, however, may combine and/or stage different proposed solutions based on need in order to develop the more efficient or cost-effective solution to address the identified competitive window needs.

Once the proposal window is closed, PJM engages in a robust process to analyze the submitted solutions based on a variety of criteria as described above. PJM then selects the more efficient or cost-effective solution(s) for potential inclusion in the RTEP, and presents these proposed solutions to PJM stakeholders in a public TEAC meeting for stakeholder input. After the proposed solutions are presented during at least two TEAC meetings, the selected projects are recommended to the PJM Board for approval.

The competitive window process is described more fully in PJM Manuals 14B and 14F.

V. DEVELOPMENT OF THE 2022 RTEP AND 2022 WINDOW 3

Q30. PLEASE EXPLAIN THE DEVELOPMENT OF THE 2022 RTEP.[27]

A30. Each year, PJM commences an annual RTEP cycle to determine the needs of the transmission system. PJM develops an RTEP baseline power flow model which incorporates, among other things, the Load Forecast Report for the calendar year in which PJM is commencing the RTEP cycle. The January 2022 PJM Load Forecast that PJM used to develop the baseline power flow model for the 2022 annual RTEP cycle included forecast data for the 2022 through 2037 planning horizon, and indicated high load growth activity, particularly in Maryland and northern Virginia.

Throughout 2022, PJM facilitated several competitive windows as part of the 2022 RTEP cycle to address reliability criteria violations and market efficiency congestion needs resulting from the increased load forecast as modified during 2022 (described in more detail in Mr. Gledhill's Direct Testimony, NEET MA Statement No. 4); generation deactivations; generation deliverability testing methodology updates, including a new block dispatch procedure (approved in Q1 2023); and other drivers necessitating the need for transmission development. As part of the 2022 RTEP cycle, PJM also directed that certain Immediate-need Reliability Projects be incorporated into the 2022 RTEP, which were needed to (i) enable the integration of the forecasted data center load in the DOM (Virginia) zone[28] up to and including year 2025 and (ii) address reliability violations caused

[27] The "2022 RTEP" refers to the transmission enhancements or expansions that were approved by the PJM Board as part of the 2022 annual RTEP cycle, which I describe in more detail herein.

[28] A map depicting the transmissions zones in the PJM Region is included in Attachment J of the PJM Open Access Transmission Tariff.

by the proposed deactivation of a number of generation facilities, most notably the Brandon Shores generation units in Maryland (BGE zone).[29] Specifically, as relevant to the 2022 RTEP:

- From July 1, 2022 through August 30, 2022, PJM conducted **2022 Window 1** to seek solutions to address thermal and voltage violations identified as part of the 2022 RTEP;
- In July 2022, PJM identified the immediate need to address specific and targeted reliability violations in the DOM (Northern Virginia) zone up to and including 2025 (building on top of already planned supplemental and baseline upgrades);[30]
- From November 1, 2022 through December 1, 2022, PJM conducted **2022 Window 2** to seek solutions to address economic, thermal and voltage reliability criteria violations identified as part of the 2022 RTEP (Multi-Driver window covering both reliability and economic needs), which were not addressed as part of 2022 Window 1;
- From February 24, 2023 through May 31, 2023, PJM conducted **2022 Window 3** (which I will discuss in more detail below) to seek solutions to address additional thermal and voltage reliability criteria violations that were identified using the

[29] On April 6, 2023, Talen Energy Corp. ("Talen Energy") notified PJM that it intended to deactivate the Brandon Shores two-unit, 1,280 MW coal-fired generation facility in Anne Arundel County, Maryland ("Brandon Shores Units") by June 1, 2025.

[30] *See* PJM Statement regarding Dominion Northern Virginia Area Violations Immediate Need, July 1, 2022, *available at*: item-08---dominion-northern-virginia-area-violations---need-statement.ashx; and Transmission Expansion Advisory Committee, Reliability Analysis Update Immediate Need, Sept. 6, 2022, *available at*: item-09a---reliability-analysis-update---immediate-need.ashx (further explaining the basis for the PJM's identification of an immediate reliability need and the identification of the transmission solutions to address the Dominion-related immediate reliability need, respectively).

Modified 2022 Load Forecast (as defined in Mr. Gledhill's Direct Testimony in NEET MA Statement No. 4), which violations were not addressed as part of 2022 Windows 1 and 2; and

- In May 2023, PJM identified the immediate need to address severe voltage drop and thermal violations across seven PJM zones in Baltimore, Maryland and the immediately surrounding areas (*e.g.*, the BGE, DOM, Allegheny Power ("APS"), Metropolitan Edison ("ME"), PPL Electric Utilities ("PPL"), PECO Energy ("PECO"), and Potomac Electric Power ("PEPCO") zones), which PJM determined[31] would occur upon the deactivation of the Brandon Shores generation units without timely, adequate and properly-located replacement generation.[32]

The transmission enhancements or expansions that were ultimately approved by the PJM Board following the competitive solicitation windows and the immediate need reliability processes described above were all included in the 2022 RTEP.

[31] *See* PJM Transmission Expansion Advisory Committee, Generation Deactivation Notification Update, May 7, 2023, *available at* https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230509/20230509-item-02---generation-deactivation-notification-update.ashx; PJM Transmission Expansion Advisory Committee, Generation Deactivation Notification Update, June 6, 2023, *available at* https://www.pjm.com/-/media/committees-groups/committees/teac/2023/20230606/20230606-item-02---generation-deactivation-notification-update.ashx (further explaining the basis for the PJM's identification of an immediate reliability need and the identification of the transmission solutions to address the Brandon Shores-related immediate reliability need, respectively). The transmission solutions identified to address the Brandon Shores-related immediate reliability need are referred to herein as the "Brandon Shores Deactivation Reinforcements."

[32] To be clear, the deactivation of the Brandon Shores Units was not announced when PJM opened 2022 Window 3, so the 2027 base case did not consider those units as deactivated, nor did it include the Brandon Shores Deactivation Reinforcements. However, as I will discuss below, PJM extended 2022 Window 3 and created a supplemental base case for the window that took into consideration the impact of the deactivation of the Brandon Shores Units and other announced deactivations. PJM sought holistic solutions that would address the impact of these deactivations.

Q31. CAN YOU PLEASE EXPLAIN IN MORE DETAIL WHY PJM OPENED 2022 WINDOW 3?

A31. Throughout 2022, projected load growth continued to increase rapidly and beyond what was originally anticipated as part of the 2022 PJM Load Forecast published in January 2022. PJM observed that: (i) new data center load was being proposed in Maryland near the Doubs substation (APS zone); and (ii) data center loads within northern Virginia (DOM zone) were projected to continue to increase significantly. PJM further identified several additional system-wide reliability drivers (particularly in the SWMAAC LDA[33] and the APS and DOM zones) necessitating the need for transmission development. Specifically, PJM identified the following additional reliability drivers:

- The cumulative impact of generation changes and deactivations, including 11,100 MW of announced deactivations to the west and south of Conastone (including the Brandon Shores Units noted above, and discussed further below[34]);
- Regional constraints to support higher regional transfer flows resulting from imports into load center areas;
- Reactive power needs necessary for the 2027/28 baseline scenario; and

[33] SWMAAC refers to the Southwest Mid-Atlantic Area Council, an LDA within the PJM Region. Essentially, PJM divides service territory into different LDAs to help maintain grid reliability within specific geographic regions, especially considering transmission grid constraints. SWMAAC is one of these sub-regions within the larger Mid-Atlantic Area Council ("MAAC") LDA. The SWMAAC LDA includes the PEPCO, SMECO and BGE zones in Maryland.

[34] As discussed further below, on October 16, 2023, Talen Energy announced that the three oil-fired steam units and one gas combustion turbine (CT) (Units 1, 3, 4 and CT) at its H.A. Wagner Generating Station in Anne Arundel County, Maryland, with a combined capacity of 844 MW, would seek deactivation on June 1, 2025 (the "Wagner Units"). Since Talen had not yet submitted the Wagner Units' deactivation notification to PJM at the time PJM opened 2022 Window 3, the impact of the deactivation of the Wagner Units was not considered until after the 2022 Window 3 solutions were selected. PJM subsequently tested the 2022 Window 3 solutions and confirmed they were sufficient to handle the reliability needs associated with the deactivation of the Wagner Units.

- Recently-approved reliability criteria changes, particularly to the generation deliverability assessment methodology and the introduction of block-dispatch methodology for generation scheduling in planning models.

In addition to the Immediate-need Reliability Projects that PJM directed to ensure reliable transmission service up to and including 2025 (described above), incumbent Transmission Owners also identified numerous supplemental transmission projects to address localized reliability concerns caused by the projected load growth described above through the established process for Transmission Owner supplemental projects. However, these immediate need and supplemental projects would not address the much broader and extensive regional constraints and associated needs in the PJM Region that are caused by the projected sustained load growth, anticipated generation deactivations and other reliability drivers described above. Rather, the projected strong load growth, coupled with the generation deactivations and resulting change in generation profile shifts, all collide to form the need for holistic, regional solutions through the RTEP to address them.

For these reasons, PJM opened 2022 Window 3. *See* **Exhibit SA-4** ("PJM RTEP – 2022 RTEP Proposal Window 3, Problem Statement and Requirements").

Q32. PLEASE EXPLAIN HOW PJM DEVELOPED THE BASE CASE SUITE USED FOR THE 2022 WINDOW 3 PROCESS.

A32. When PJM initially opened 2022 Window 3 on February 24, 2023, the window included two base cases,[35] one of which relied upon the 2022 load forecast (as set forth in the 2022

[35] To conduct power flow analyses of a future study year, PJM develops a study "case" for the specific study year being analyzed that reflects all known transmission upgrades that are expected to be in service by or before that study year.

Load Forecast Report), and the other of which relied on the 2022 Modified Load Forecast (as defined in Mr. Gledhill's Direct Testimony in NEET MA Statement No. 4) (these two cases are collectively referred to as the "2027 base case").

Before the 2022 Window 3 competitive proposal submission period ended, PJM recognized the need to supplement the window with an additional base case suite to recognize the impact of both significant generator deactivations and the then recently-modified block dispatch methodology and generation deliverability testing procedures (which impacts the base case models and analysis procedure). As such, in April 2023, PJM developed a 2028 base case suite (5 year-out models) which: (i) adopted the updated 2023 load forecast (as set forth in the 2023 Load Forecast Report); (ii) incorporated a total of approximately 11,100[36] MW of generator deactivations (described above); and (iii) implemented the new block dispatch methodology (the "Supplemental 2028 Base Case Suite") (*see* **Exhibit SA-5** (materials for the April 27, 2023 Special TEAC meeting where the Supplemental 2028 Base Case Suite was described to stakeholders)). The Supplemental 2028 Base Case Suite analysis results showed an increase in both the number and severity of reliability violations in the PJM Region, as compared to the 2027 base case analysis. PJM decided to extend 2022 Window 3 for an additional 30 days to allow developers to submit proposal adjustments in light of the results of the Supplemental 2028 Base Case Suite analysis.

[36] *See* Slide 11 of the PJM Reliability Analysis update slide deck; https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230606/20230606-item-11---reliability-analysis-update.pdf.

PJM used the Supplemental 2028 Base Case suite to evaluate the competitive proposals submitted in the 2022 Window 3 competitive window process, and to evaluate and select the final solutions for 2022 Window 3. This process is described more fully in the PJM Reliability Analysis Report, 2022 RTEP Window 3, dated December 8, 2023 ("Reliability Analysis Report"), which is included as **Exhibit SA-6** to this testimony.

It is important to note that PJM also used the Supplemental 2028 Base Case Suite to develop 2023 Window 1, which was open from July 24, 2023 through September 22, 2023. This is relevant because PJM observed the same severe and widespread reliability violations as it developed the 2023 RTEP; however, the 2023 Window 1 solicitation process excluded from consideration proposals to resolve reliability violations that were already targeted through the 2022 Window 3 study area. I will nonetheless include information below about the violations observed in the 2022 Window 3 study area during the 2023 Window 1 solicitation process, as that confirms the extensive, widespread and severe nature of the reliability needs identified and addressed in 2022 Window 3.

Q33. HOW EXTENSIVE ARE THE RELIABILITY VIOLATIONS THAT PJM IDENTIFIED FOR THE 2027 AND 2028 STUDY YEARS?

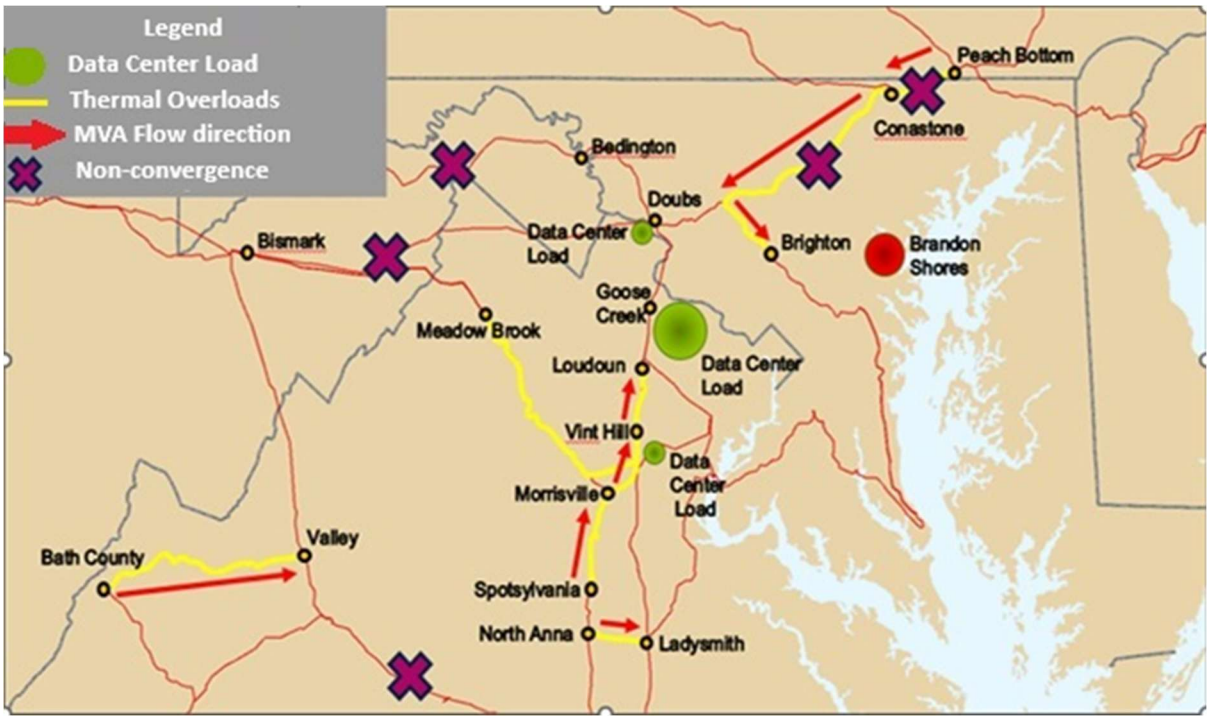
A33. Very extensive. PJM has identified two broad sets of substantial reliability violations – voltage and thermal – in the 2027 and 2028 study years. Each identified violation has an impact on regional transfer capability – an important component of transmission system reliability. Indeed, severe voltage issues were identified as part of both base case development and baseline reliability analysis. I focus my discussion of the identified voltage and thermal reliability constraints on the regional transmission system infrastructure needs in SWMAAC LDA (encompassing the PEPCO, SMECO and BGE

zones in Maryland), the northern Virginia area of the Dominion zone, the Doubs, Maryland area of the APS zone, as well the broader surrounding area shown in Map 3, below. Specifically, Map 3 illustrates at a high level the severity and locations of the voltage limit and thermal overload reliability violations occurring in the 2027 and 2028 study years. On the map (only on key transfer paths and locations[37]):

- **Yellow lines** indicate a transmission line that is overloaded – *i.e.*, a thermal reliability criteria violation - in the 2027/28 study years;
- **Red arrows** indicate the direction power is flowing in power flow studies.
- An **"X" over a line** indicates that, in the 2027/28 study years an "n-1" outage of that facility caused a non-convergent power flow study result indicating a voltage collapse condition. Analytically, this means that regional power grid system conditions are of such severity that power flow analysis tools cannot fully solve to yield a final result for a given scenario. Reliability criteria in the face of identified voltage collapse conditions require that the transmission system must be strengthened by building additional transmission to effectively deliver power to load centers by maintaining voltages within thresholds established by NERC and regional reliability criteria;
- A **green dot** on the map identifies a dense pocket of new load growth comprising major data center power requirements; and
- The **red dot** on the map shows the location of the Brandon Shores Units.

[37] These are representative violations and contingencies leading to severe collapse conditions only. For a full list of violations, please refer to **Exhibit SA-4**, 2022 Window 3 Problem Statement.

Map 3: Severity and Location of Reliability Violations in 2027/28 Study Years



NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should ***not*** *be relied upon for exact geographical substation locations or line routes.*

These voltage and thermal reliability criteria violations, if left unsolved, could compromise overall PJM system reliability, including for Maryland, Virginia, Pennsylvania, and West Virginia customers, and could lead to widespread and extreme conditions, such as potential system collapse and blackouts. As I describe in more detail below, PJM concluded that given the breadth and severity of the reliability criteria violations impacting the existing backbone 500 kV system, multiple transmission system upgrades and additional new greenfield facilities, including the Revised Western Cluster Solution (including the MARL Project), will be required in and through Virginia, Maryland, West Virginia and Pennsylvania to address these needs as discussed above.

Q34. PLEASE DESCRIBE THE VOLTAGE RELIABILITY ISSUES YOU IDENTIFIED AS PART OF THE BASE CASE DEVELOPMENT IN MORE DETAIL.

A34. Importantly, PJM first identified extensive overall system voltage collapse and severe low voltage violations as part of the RTEP process in the 2027 and 2028 base case suite development. In order for these power cases to solve (*i.e.*, meet the requirements of the system even without outages), PJM needed to model fictitious reactive devices[38] across the area described above, totaling 4,500 MVAR in the 2027 case and, more extensively, 26,000 MVAR[39] at eight 500 kV substations and nine other 230 and 138 kV substations in the 2028 case.40 The need to do this means that regional power grid system conditions are of such severity that power flow analysis tools cannot fully solve to yield an analytical result. West-to-east power flow levels on existing lines in the area are of such magnitude that adequate voltage levels cannot be sustained to support elevated base case flows.

The solved suite of 2027 and 2028 base cases, as discussed here, were then used for identifying low voltage, voltage collapse, and thermal overload reliability criteria violations as part of baseline reliability studies, discussed below. The number of actual

[38] A fictitious reactive device is a transmission element that is temporarily added to the power flow case model (for model building purposes), to provide reactive power support to the grid in instances in which a power flow tool is unable to reach a convergent solution. Such devices are removed from the model and replaced with proposed solutions replacing the need for such fictitious devices.

[39] This does not mean that adding reactive sources – *e.g.*, static VAR compensators ("SVCs") – totaling 26,000 MVAR as an RTEP solution would have solved all reliability criteria violations. Doing so was merely an analytical step to allow cases to solve.

[40] For example, in order for the 2028 base case to solve, PJM needed to add: (i) nearly 4,400 MVAR along the Hatfield to Black Oak to Bedington to Doubs 500 kV line; 4,000 MVAR along the Mount Storm to Meadow Brook to Front Royal to Morrisville to Bristers 500 kV line; and (iii) 2,000 MVAR along the Mount Storm to Bismark to Doubs 500 kV line. PJM's "2023 RTEP Proposal Window #1 Problem Statement & Requirements" document describes this in more detail: https://www.pjm.com/-/media/DotCom/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/2023-rtep-window-2/without-analytical-files-v1.zip.

voltage and thermal violations are consequently much larger than those observed with the addition of these temporary, fictitious VAR resources.

Q35. PLEASE DESCRIBE THE VOLTAGE RELIABILITY ISSUES YOU IDENTIFIED AS PART OF BASELINE RELIABILITY ANALYSIS IN MORE DETAIL.

A35. As discussed below and as more fully summarized in the Reliability Analysis Report (**Exhibit SA-6**), PJM observed thousands of voltage collapse and extreme low voltage (non-sustainable) violations in various areas (including Maryland, the SWMAAC LDA in general, and the APS and DOM zones). The low voltage and voltage magnitude reliability criteria violations shown in **Table 1** and **Table 2** were identified in baseline reliability analysis after the base case reactive reinforcements discussed above were added for the 2027 and 2028 suite of power flow models.

Table 1 summarizes 500 kV baseline reliability voltage collapse reliability criteria violations under "N-1" single contingency events. The contingency type in **Table 1** signifies a loss of a generator, transmission circuit, transformer, shunt device or single pole of a DC line. I note that conducting the baseline reliability tests, PJM applied the other NERC Planning Events, for instance, P2, P4, P5 and P7 (as described earlier[41]). The results of these analyses are voluminous, but not included in **Table 1**, because the **Table 1** violations and require potential greenfield solutions to address them.

The voltage violations identified in the 2027 and 2028 study years are so severe, widespread, and extensive that the violations cannot be solved via transmission line reconductoring or local substation reactive devices.

[41] *See* Response to Question 22, above.

Table 1

2022 Window 3 Voltage Result (2027 base case)		
2022 Window 3 Reactive Assumption		
Total of 4,500 MVAR reactive devices at various locations added to compensate the reactive deficiency	The 2022 Window 3 posted cases included the 4,500 MVAR reactive devices	The voltage Violations below assume the 4,500 MVAR reactive device model pre-contingency

2022 Window 3 PJM N-1 Voltage Collapse Result		
Contingency	**Cont. Type**	**Analysis Type**
Meadow Brook - Vint Hill 500 kV	Single	Voltage Drop
Black Oak - Bedington 500 kV	Single	Voltage Drop
Hatfield - Black Oak 500 kV	Single	Voltage Drop
Calvert Cliff generator #1	Single	Voltage Drop
Calvert Cliff generator #2	Single	Voltage Drop
Peach Bottom - Conastone 500 kV	Single	Voltage Drop
Conastone - Brighton 500 kV	Single	Voltage Drop
Bismark - Mt. Storm 500 kV	Single	Voltage Drop
Front Royal - Warren City (generation lead line) 500 kV	Single	Voltage Drop
Belmont - X4-039 generation lead line	Single	Voltage Drop
Elmont - Cunninghum 500 kV	Single	Voltage Drop
Doubs - Bismark 500 kV	Single	Voltage Drop
Black Oak - Bedington 500 kV	Single	Voltage Magnitude

Table 2 summarizes the amount of VARs added in order for the power flow analysis tools to solve and yield an analytical result, primarily for the purpose of allowing the models to yield indicative thermal and voltage performance violations as a starting point to develop needed solutions. The fictitious VARs added pre-contingency show the severity of the issue which becomes even larger in the subsequent base case, further reinforcing the need for a potential greenfield solution.

Table 2

2023 Window 1 Voltage Result (2028 base case)		
2023 Window 1 Reactive Assumption		
Total of 26,000 MVAR reactive devices at various locations added to compensate the reactive deficiency	The voltage Violations assume the 26,000 MVAR reactive device model pre-contingency	The fictitious MVARs suppress valid voltage violation resulting in less violations during reliability analysis
Winter voltage Drop and Voltage magnitude Violation		
Widespread voltage drop and voltage magnitude for single contingency, loss of Peach Bottom - Conastone 500 kV	Widespread voltage drop and voltage magnitude for 4 line fault stuck breaker contingencies involving the Peach Bottom - Conastone 500 kV	

Q36. PLEASE SUMMARIZE THE THERMAL OVERLOAD RELIABILITY ISSUES YOU IDENTIFIED.

A36. As I will detail below, in addition to the reactive violations discussed above, PJM's 2027/28 RTEP process baseline analysis – under generator deliverability test conditions, in particular – identified numerous NERC thermal reliability criteria violations on 500 kV transmission lines (*i.e.*, backbone transmission lines). For example, baseline reliability analysis identified NERC thermal reliability criteria violations on three key west-to-east 500 kV transmission lines that deliver power to the area described above, and to Goose Creek specifically, as shown on Map 4:

- The Meadow Brook to Vint Hill 500 kV line is loaded to 109.68% of its thermal rating under contingency conditions;
- The Pruntytown to Mt. Storm 500 kV backbone line loaded to 107.78% of its thermal rating under contingency conditions; and
- The Greenland Gap to Meadow Brook 500 kV backbone line is loaded to 106.24% of its thermal rating under contingency conditions.

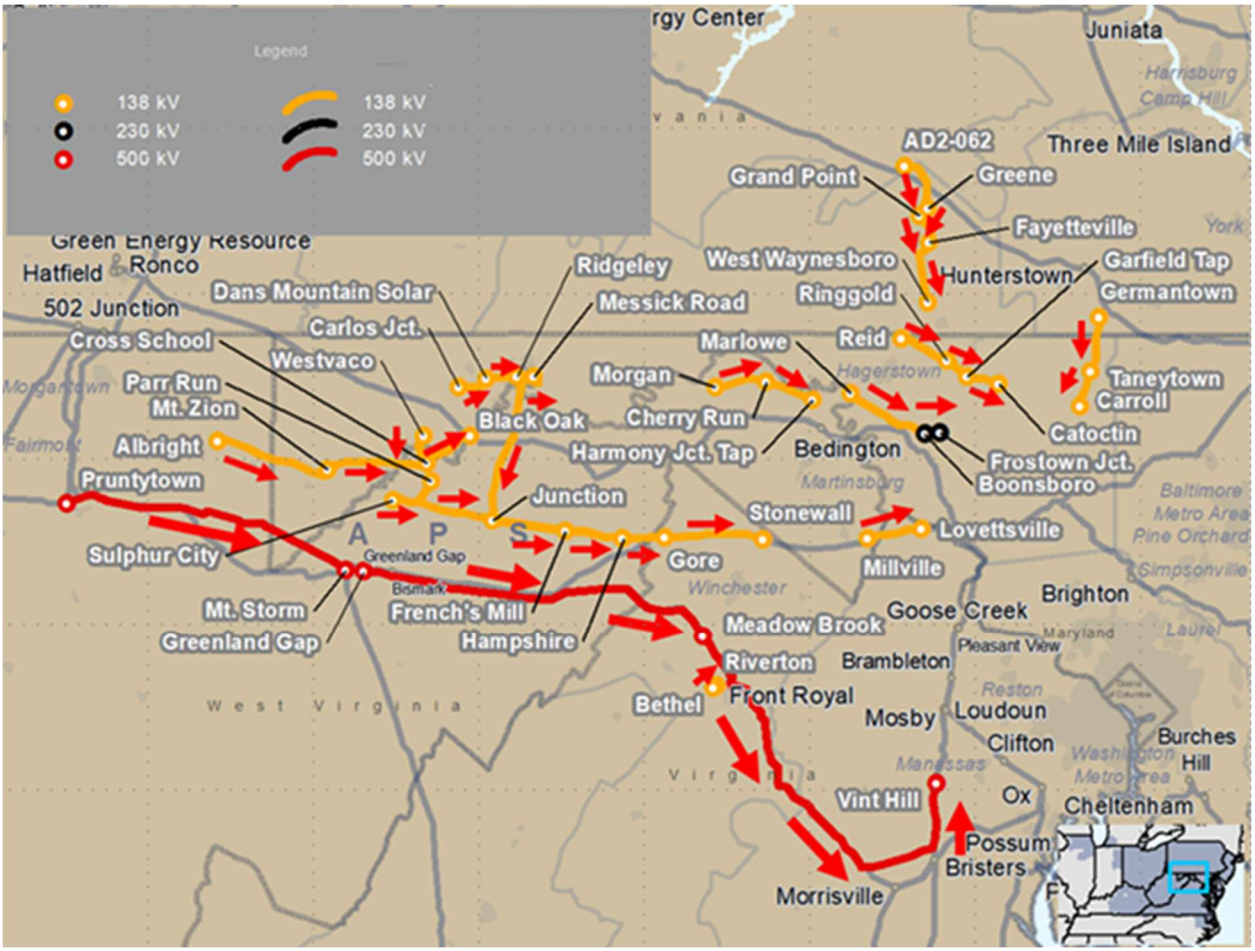
As discussed earlier, 500 kV lines loaded to these levels have depleted the reactive power available to support those levels, causing non-convergent power flow cases.

In addition to 500 kV thermal overloads, PJM also identified twenty-nine (29) 138 kV transmission line thermal overloads and one (1) 230 kV overload, mostly due to 500 kV contingencies. **Map 4**, below, depicts: (i) 2028 Summer Generator Deliverability analysis results that identified overloaded 138 kV and 230 kV APS transmission lines; and, (ii) overloaded 500 kV lines in the same area. Of the 29 overloads identified on 138 kV transmission lines during the generation deliverability analysis, 12 facilities were also overloaded for N-1 contingency analysis.

As noted previously in my testimony, when transmission lines are overloaded, the transmission system is transmitting more power than that for which it was designed. Transmission element overloads this severe can lead to cascading line outages and potential blackouts.

Map 4: 2028 Study Year Generator Deliverability (Thermal) Analyses
138 kV, 230 kV and Area 500 kV Thermal Overloads
(Along the West to East Transfer Corridor Only)

(Red arrows indicate the direction of flow through the overloaded facilities)



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Q37. DO THE GENERATOR DELIVERABILITY THERMAL OVERLOAD RELIABILITY CRITERIA VIOLATIONS PJM IDENTIFIED INDICATE THAT

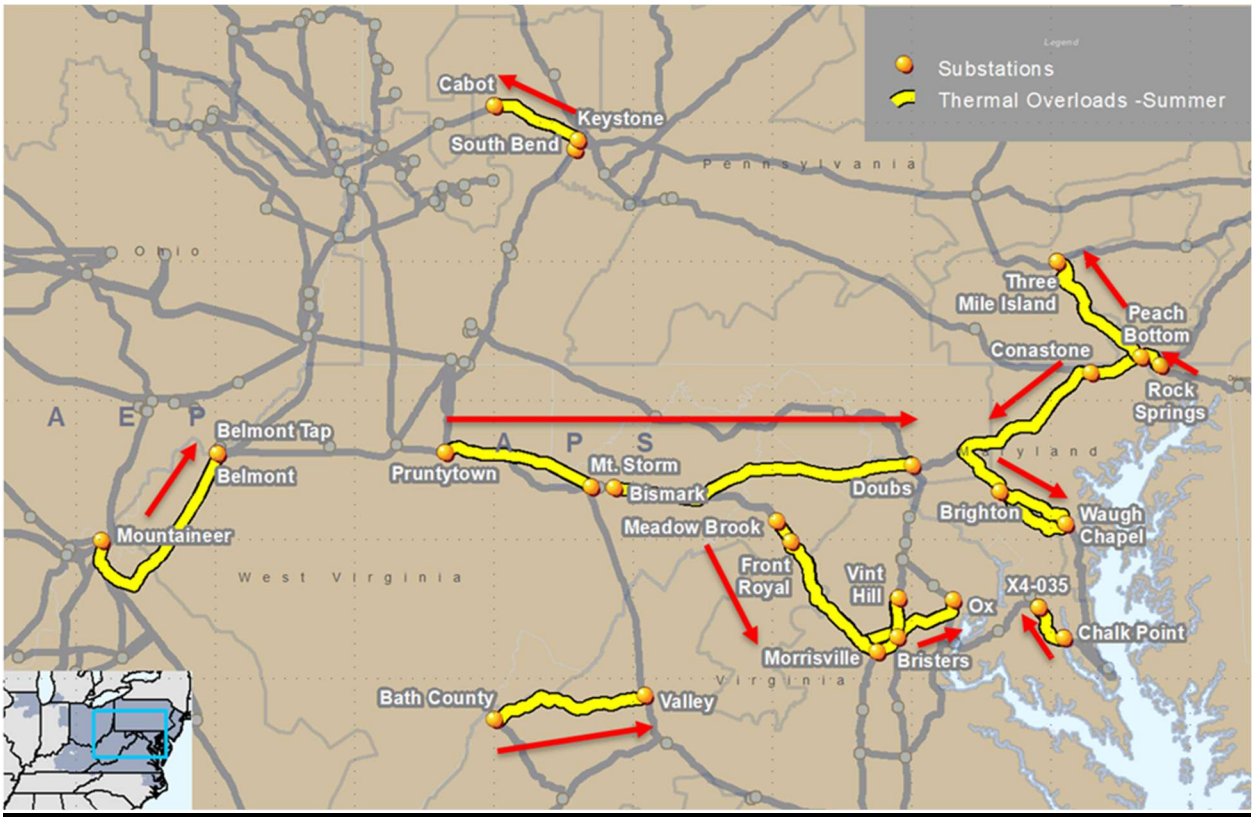
NEW TRANSMISSION LINES NEED TO BE ADDED TO THE REGIONAL TRANSMISSION GRID?

A37. Yes. As shown in the initial 2022 Window 3 posted violations and the 2023 Window 1 information presented at the April 27, 2023 Special TEAC meeting (*see* **Exhibit SA-5**), PJM identified twenty-seven (27) 500 kV (backbone) facilities that are thermally overloaded in the 2027/28 study years. The majority of those overloaded 500 kV facilities occur during both summer and winter peak conditions. Twelve (12) of these overloaded facilities are identified to be "limited by conductor," which means that new or replacement transmission lines are needed to resolve the overloads.[42] In this case, the magnitude of the overloads is so significant that replacement (upgraded) transmission lines would not be enough to resolve the overloads and additional new facilities are needed. To illustrate the breadth of the geographic scope of these overloaded facilities in the 2027/28 study years, *see* **Map 5** and **Map 6**, below, which identify overloaded facilities 500 kV and above during summer and winter peak.

[42] A transmission facility can be "limited by conductor" when the capacity of the entire transmission system is primarily restricted by the physical capabilities of the electrical conductors used, meaning the wires carrying the electricity are the main factor limiting how much power can be transmitted through the facility, often due to factors like their size, temperature limitations, or current carrying capacity.

Map 5: Overloaded 500 kV and Above Facilities in Summer Generator Deliverability (2028)

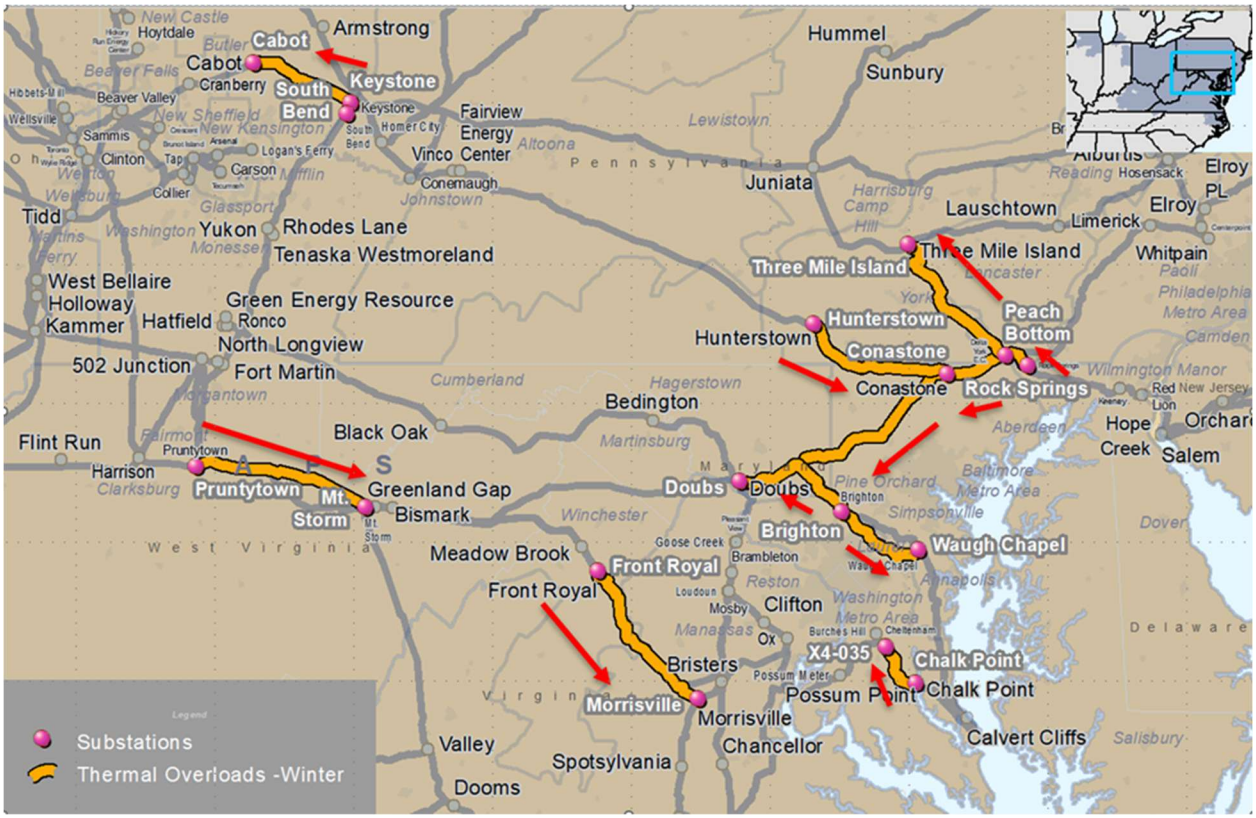
(Red arrows indicate the direction of flow through the overloaded facilities)



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Map 6: Overloaded 500 kV and Above Facilities in Winter Generator Deliverability (2028)

(Red arrows indicate the direction of flow through the overloaded facilities)



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

As previously discussed, the generator deliverability test evaluates the capability of the transmission system to assure that capacity resources can be delivered to the remainder of the PJM system at peak load. PJM identified numerous thermal violations on 500 kV transmission lines when applying the generator deliverability test for the 2027/28 study years, as set shown in **Table 3**, below. Note that for the reasons I describe above, **Table 3**

includes the total number of thermal violations observed in 2022 Window 3, as well as the preliminary and final results of 2023 Window 1.[43]

Table 3: Total Number of Thermal Violations on 500 kV and Above Facilities in 2027/28 Study Years Resulting From Generator Deliverability Test[44]

	Total Number of Thermal Violations		
	2022 Window 3 (2027) (500 kV)	2023 Window 1 (2028) Preliminary (500 kV)	2023 Window 1 (2028) Final (500 kV)
P0	4	13	6
P1	45	90	79
P2	0	54	44
P4	31	144	135
P7	78	57	49

As I also previously described, N-1-1 contingency violations (P3 and P6) occur when two independent generation or transmission facilities are removed from service. In the 2027/28 study years, PJM observed *thousands* of thermal violations across all voltage levels (not identified in the table given the number of them), as a result of P3 and P6 N-1-1 contingencies.

Q38. SPECIFICALLY, WHAT THERMAL OVERLOAD IMPACTS DID PJM IDENTIFY ON 500 KV BACKBONE TRANSMISSION LINES?

A38. A complete list of 500 kV transmission lines that PJM identified as "limited by conductor" is provided below in **Table 4** and **Table 5**. **Table 4** shows the results for 2022 Window 3 and **Table 5** shows the results from 2023 Window 1 as presented at the April 2023 Special TEAC meeting. Note the overlapping extent of the reliability criteria violations identified

[43] *See* Response to Question 32.

[44] The definitions of P0, P1, P2, P4, and P7 are set forth in the Response to Question 22.

in both Windows. As I stated above, lines that are identified as being limited by conductor require significant upgrades through rebuilds (with associated extended outages) and/or development of new greenfield facilities. For all identified violations, PJM is required to develop system reinforcements to ensure compliance with all Planning Criteria.

Importantly, I also note that with respect to Column #5 in both **Table 4** and **Table 5**, "Pre-contingency Loading," PJM has identified facilities that have pre-contingency loadings "as is" that exceed applicable normal thermal ratings, *i.e.*, are greater than 100 percent even without applied contingency analysis, examples of which I discussed earlier in my testimony.

Table 4

2022 W3 Posted Results Conductor Limited Facility (Generation Deliverability)

Name	(1) Circuit #	(2) kVs	(3) Areas	(4) Pre Contingency Loading	(5) # of Single Contingencies and Worst Loading	(6) # of Breaker Contingencies and Worst Loading	(7) # of Tower Contingencies and Worst Loading	(8) # of Bus Contingencies and Worst Loading
Bath County –Valley SC	1	500	345		(1) 104%			
Morrisville – Vint Hill	1	500	345		(9)126%	(5) 120	(2) 126	
North Anna – Ladysmith	1	500	345		(1)101%			
Spotsylvania– Morrisville	1	500	345		(1) 102%			
Valley SC – Valley	1	500	345		(2) 104%			
Vint Hill – Loudoun	1	500	345		(1) 101%	(4) 108%	(8) 105%	
Peach Bottom 1S – Conastone	1	500	232/230	(2)128%	(11) 121%	(2) 119%		
Peach Bottom 2S – Peach Bottom 1N	2	500	230			(1) 102%		
Peach Bottom 2S – Peach Bottom 1S	Z1	500	230			(2) 105%		
Peach Bottom 2S – Peach Bottom 1S	Z2	500	230			(1) 102%		

Table 5

2023 W1 (2022W3- 2028 results) Result Presented at the 4/27/2023 Special TEAC Meeting
List of Facilities Limited by Conductor Summary[45]

Name	(1) Circuit #	(2) kVs	(3) Areas	(4) Pre Contingency Loading (P0) Rate A	(5) # of Single Contingencies and Worst Loading (P1) Rate B	(6) # of Breaker Contingencies and Worst Loading (P2-3, P2-4 and P4) Rate b	(7) # of Tower Contingencies and Worst Loading (P7) Rate B	(8) # of Bus Contingencies and Worst Loading (P2-2) Rate B
Meadow Brook – Vint Hill	1	500	APS/ DOM		(1)103%	(4)113%		
Belmont transformer	5	765/ 500	APS/ AEP		(3) 110%	(3) 136%		
Bath County – Valley SC	1	500	DOM		(1) 102%			
Brister – Ox	1	500	DOM				(1) 104%	
Front Royal – Morrisville	1	500	DOM		(1) 113%			
Morrisville – Vint Hill	1	500	DOM		(7) 123%	(10) 131%	(3) 132%	
Valley SC – Valley	1	500	DOM		(1) 102%			
Conastone – Brighton	1	500	PJM 500 kV	185%	(13) 183%	(11) 188%	(12) 210%	(13) 179%
Peach Bottom 1S – Conastone	1	500	PJM 500 kV	213%	(12) 188%	(15) 197%	(13) 195%	(12) 192%
Peach Bottom 1N – Peach Bottom 2S	2	500	PJM 500 kV			(2) 141%		
Peach Bottom 2S – Peach Bottom 1S	Z1	500	PJM 500 kV	100%	(2) 147%	(4) 215%		
Peach Bottom 2S – Peach Bottom 1S	Z2	500	PJM 500 kV	114%	(9) 200%	(9) 211%	(4) 103%	(3) 105%

[45] With respect to **Table 5**, please note: (i) in columns # 5, 6, 7, 8 and 9, the number parentheses is the number of violations; and (ii) cells that are blank indicate that no violations were identified.

VI. ANALYSIS OF 2022 WINDOW 3 PROPOSAL SOLUTIONS

Q39. HOW MANY PROPOSED SOLUTIONS DID PJM RECEIVE TO ADDRESS THE WIDESPREAD RELIABILITY VIOLATIONS IDENTIFIED IN 2022 WINDOW 3?

A39. PJM received 72 proposals from ten different entities as part of 2022 Window 3. Of the ten proposing entities, six were incumbent Transmission Owners and four were Nonincumbent Developers. PJM received 22 proposals that are upgrades to existing facilities, and received 50 greenfield proposals.

Q40. BASED ON WHAT CRITERIA DID PJM STUDY AND SELECT TRANSMISSION ENHANCEMENTS OR EXPANSIONS TO DETERMINE WHETHER THEY ARE THE MORE EFFICIENT OR COST-EFFECTIVE SOLUTION TO ADDRESS THE NEEDS IDENTIFIED IN 2022 WINDOW 3?

A40. Per the terms of the Operating Agreement, Schedule 6, PJM is required to identify the more efficient or cost-effective solution to address identified transmission system needs. In making this determination, PJM's driving approach is to determine the more efficient, cost-effective, constructible, robust, and scalable set of projects to serve the system reliability needs in a timely fashion.[46]

PJM employs a variety of expertise – including independent outside consultants – to analyze submittals. As part of this review, PJM and independent outside consultants also analyze any cost containment provisions voluntarily submitted by the developer. PJM is aware of environmental and social impacts and takes them into consideration when evaluating all submitted proposals.[47] PJM also considers future needs ensuring project

[46] *See* https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20230307/20230307-item-08---reliability-analysis-update.pdf, slide 3.

[47] As described in the Constructability & Financial Analysis Report for 2022 Window 3 (**Exhibit SA-8**), PJM conducts a high-level analysis of 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. PJM's

selections are expandable and compatible with future and evolving system reinforcement needs to minimize incurring sunk cost, negatively impacting rights-of-way, and avoiding difficult to schedule outages due to stressed operational conditions.

Specifically, when evaluating the solutions proposed in response to the 2022 Window 3 competitive solicitation, PJM considered several factors, including:

- Performance: the ability of the solution to meet the identified system needs and being flexible to address near-term future needs;
- Scalability: robust design able to scale up and meet future needs;
- Impact: utilizing existing rights of way where possible and efficient;
- Cost: validated by third-party benchmarking metrics, including consideration of any cost containment provisions voluntarily submitted by developers;
- Risks: factors that might trigger additional costs, such as difficulty securing the number or type of permits required or inability to meet in-service date; and
- Efficiencies: avoidance of redundant capital investment, including recognizing synergies with retiring facilities and overlaps with previously approved or imminent upgrades.

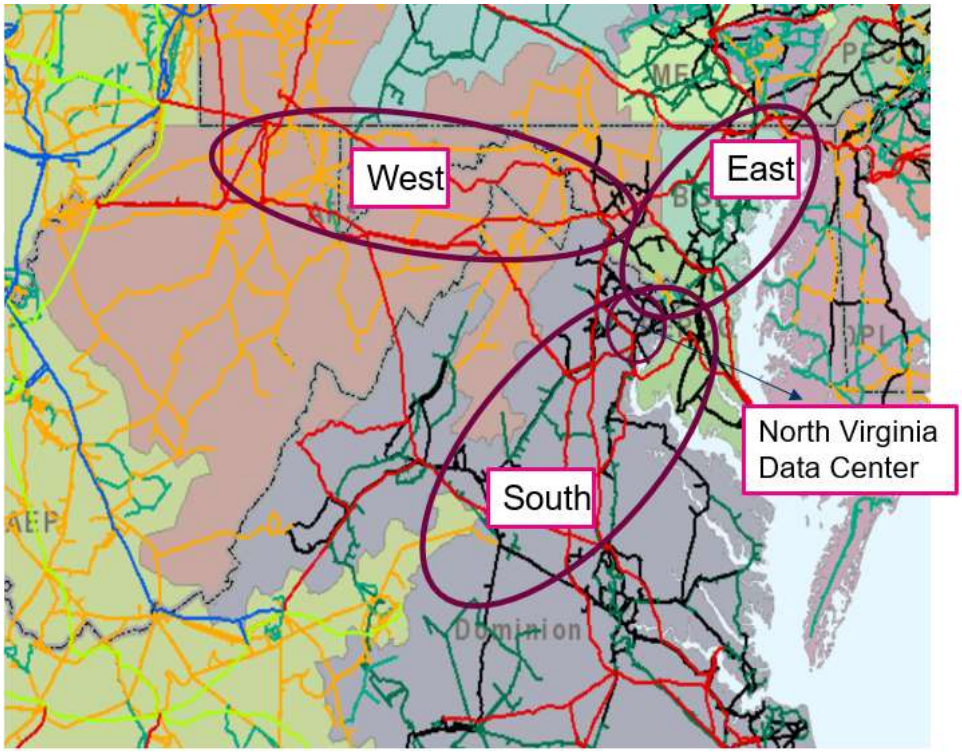
Q41. PLEASE EXPLAIN HOW PJM EVALUATED THE PROPOSED SOLUTIONS.

A41. As I stated above, when PJM opened 2022 Window 3, it made clear that it was seeking solutions to address reliability violations showing up in the 2022 Window 3 study area and

constructability review is not as extensive as the detailed analysis the transmission developer conducts to determine the proposed project route.

the surrounding zones to these areas.[48] PJM divided the 2022 Window 3 study area into four geographic regions (or regional clusters) so that PJM could evaluate proposed solutions that were intended to address reliability issues in each of these four geographic areas. The four regional clusters were: East, West, South, and Northern Virginia/Doubs (MD), as depicted in Map 7, below:

Map 7: 2022 Window 3 Regional Clusters



PJM then developed scenarios, which were combinations of proposals and/or components from different proposals, addressing all areas of need, and evaluated them against the 2027 and 2028 base case models. Over 30 scenarios were analyzed for the 2027 base case model,

[48] As previously explained, the 2022 Window 3 study area encompasses SWMAAC LDA (encompassing the PEPCO, SMECO and BGE zones in Maryland), the APS (Maryland) and DOM (Virginia) zones, as well other surrounding regions.

and over 100 scenarios were developed and analyzed for the 2028 base case model. Certain scenarios were full combination scenarios submitted by the proposing entities; PJM also optimized scenarios by using select components from certain proposals by incumbent Transmission Owners and Nonincumbent Developers.

Several scenarios were found adequate to address the needs present in the 2027 base case analysis; however, the 2028 base case evaluations showed the need for more robust reinforcements.

A full list of the scenarios PJM analyzed is provided in Appendix B of PJM's Reliability Analysis Report, which is included as **Exhibit SA-6** to this testimony.

Q42. IN WHICH CLUSTER WAS THE COMPANY'S PROPOSAL NO. 853 GROUPED?

A42. PJM grouped the Company's proposal (Proposal No. 853) with the other proposed West cluster solutions.

The West cluster needs primarily focus on (i) enhancing the high west to east bulk power transfers, (ii) supporting the load deliverability and reliability needs for the APS (Maryland) and DOM (Virginia) zones, (iii) supporting the additional load demands of the APS (Maryland) and northern Virginia transmission systems where a large amount of load growth is being forecasted, and (iv) enhancing the reactive power capability of the system.

NEET MA's Proposal No. 853 was proposed to address regional reliability issues, as well as support the system in the APS and DOM zones under certain contingency and operating conditions and reduce the reactive power demand on the system due to heavy West-East bulk system flows.

Q43. CAN YOU PLEASE DESCRIBE THE OTHER 2022 WINDOW 3 PROPOSED SOLUTIONS (ALTERNATIVES) THAT WERE ALSO DESIGNED TO ADDRESS REGIONAL RELIABILITY ISSUES IN THE WEST CLUSTER?

A43. Yes, four (4) proposing entities submitted 21 proposals to address the Regional West to East Transfer Needs.[49] All proposals approached the Regional West to East Transfer Needs through new (greenfield) 500 kV or 765 kV lines.

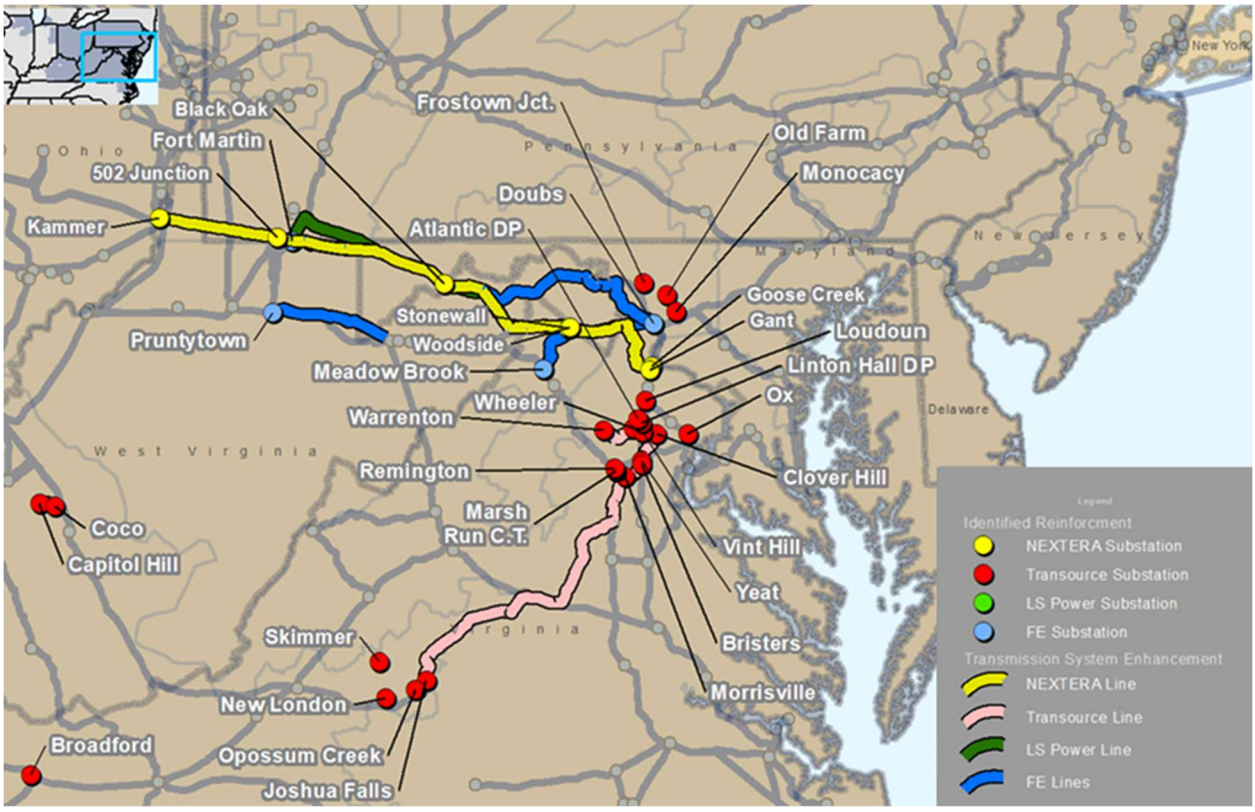
The Reliability Report (**Exhibit SA-6**), Tables 6 and 7, describe the components of each of the 21 proposals submitted to address the Regional West to East Transfer Needs. After conducting multiple scenario studies,[50] PJM narrowed this list to a shortlist of five West Cluster solutions to address the Regional West to East Transfer Needs ("Western Cluster Solutions"). All of the proposed Western Cluster Solutions attempt to enhance the power transfer capability into and through Maryland, as well as Pennsylvania, West Virginia, and Virginia, and reduce loadings on existing facilities, including the 500 kV backbone transmission system in APS territory.

The five shortlisted Western Cluster Solutions, all of which propose building 500 kV or 765 kV transmission lines to support the west to east transfer corridor reinforcement, are shown on **Map 8** and further described below.

[49] *See* Reliability Report, **Exhibit SA-6**, at Table 6. Note that Transource's proposed 765 kV development was initially grouped in the Southern cluster, but since it included proposed solutions to address the West to East Power Flow Violations, PJM considered Transource's proposal when it was evaluating the Western Cluster solutions as well. *See also* Constructability Report, **Exhibit SA-8**.

[50] *See* Reliability Report, **Exhibit SA-6**, Table 10 (pages 56-73) (explaining PJM's rationale for including or excluding various proposal components).

Map 8: West Cluster Proposals[51]



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

- FirstEnergy proposed: (i) approximately 158 miles of new 500 kV line from the Fort Martin 500 kV substation to the Doubs 500 kV substation (**single circuit**), (ii) approximately 50 miles of new 500 kV line from Pruntytown 500 kV substation to structure No. 5 on the Meadow Brook to Mount Storm 500 kV line located adjacent to Mt. Storm 500 kV substation; and (iii) approximately 55 miles of new 500 kV

[51] FirstEnergy had two proposals that were on the shortlist. The proposed lines would have the same route, but have a different number of circuits for one component of one the proposals. Because they would have the same route, the blue lines shown on Map 8 overlap.

line from Meadowbrook 500 kV substation to Doubs 500 kV substation (Proposal ID No. 2022-W3-837).

- FirstEnergy proposed: (i) approximately 158 miles of new 500 kV line from the Fort Martin 500 kV substation to the Doubs 500 kV substation (**double circuit**), (ii) approximately 50 miles of new 500 kV line from Pruntytown 500 kV substation to structure No. 5 on the Meadow Brook to Mount Storm 500 kV line located adjacent to Mt. Storm 500 kV substation; and (iii) approximately 55 miles of new 500 kV line from Meadowbrook 500 kV substation to Doubs 500 kV substation (Proposal ID No. 2022-W3-23).
- LS Power proposed to construct approximately 73 miles of new 500 kV line from 502 Junction 500 kV substation to Black Oak 500 kV substation, and approximately 82 miles of new 500 kV line from Black Oak 500 kV substation to Doubs 500 kV substation (Proposal ID No. 2022-W3-548).
- Transource proposed to construct approximately 135 miles of new 765 kV line from existing Joshua Falls 765 kV substation to a new Yeat 765 kV substation (Proposal ID No. 2022-W3-904).
- NEET MA proposed: (i) approximately 67 miles of new 500 kV line from the 502 Junction 500 kV substation to the Black Oak 500 kV substation, (ii) approximately 53 miles of new 500 kV line from Black Oak 500 kV substation to a new 500 kV Woodside substation line; and (iii) approximately 47 miles of new 500 kV Woodside substation to Goose Creek 500 kV substation (Modified Proposal No. 853).

The fact that so many competitive greenfield proposals were submitted to support the reinforcement of the west to east transfer corridor speaks to the severity of the reliability needs in the area requiring development of strong transmission system enhancements beyond just existing transmission line reconductoring.

Q44. WHICH OF THE FIVE SHORTLISTED WESTERN CLUSTER SOLUTIONS DID PJM RECOMMEND FOR FURTHER REVIEW AND ANALYSIS, AND WHY?

A44. As I explain above, PJM selected a modified version of the proposal submitted by NEET MA (*i.e.* the Modified Proposal No. 853) as the solution to address the Regional West to East Transfer Needs.[52] PJM determined that transmission reinforcements in the Western Cluster are critical due to the high demand for west to east power flow into the APS (Maryland) and Dominion (Northern Virginia) areas. As also demonstrated above, PJM determined that outages along the transmission corridor extending from the Western part of the PJM Region towards the eastern edge of the APS system (Doubs area) and the northern edge of the Dominion system (Goose Creek area) would lead to voltage collapse conditions, throughout the system, and particularly within Maryland, Virginia, West Virginia and Pennsylvania under the high transfer demands represented in both the 2027 and 2028 study years.

PJM determined that NEET MA's Modified Proposal No. 853, which included transmission development initiating at the 502 Junction Substation in the west and ultimately terminating into the planned Aspen 500 kV development, was the more efficient or cost-effective solution to address the Regional West to East Transfer Needs.

[52] *See* Reliability Report, **Exhibit SA-6**, at 54 (describing Modified Proposal No. 853).

Specifically, this proposal offered the needed reliability reinforcements to serve both the West to East transfer needs. Additionally, Modified Proposal No. 853 provided a third 500 kV line along the Doubs to Goose Creek area, whereas the other proposals terminated their proposals at or near the Doubs substation. Modified Proposal No. 853 also proposed to tie into a new substation (the Woodside Substation) in Virginia, which no other entities proposed. The Woodside Substation provides PJM with needed reactive support and operational flexibility by connecting three other 500 kV substations (Black Oak, Bismark, and Doubs) in the region. The STATCOM at Woodside will provide dynamic reactive support along the west-east 500 kV transmission corridor and thus will improve the voltage profile and overall transfer capability along the corridor. Additionally, the 500/138 kV transformation at Woodside reinforces the underlying 138 kV system and addresses numerous overloads on the 138 kV system in the APS system. None of the other proposals have reinforcement to beef up the underlying 138 kV transmission system that directly feeds load in MD, WV, VA and PA.

PJM further determined that Modified Proposal No. 853 was the more efficient or cost-effective solution as compared to the competing proposals on the Western Cluster shortlist for several reasons.[53] First, FirstEnergy's proposed 500 kV developments included a very similar route as compared to Modified Proposal No. 853, with the exception of the starting and end points. FirstEnergy's proposals both initiated at the Fort Martin 500 kV substation, which is several busses to the east from the 502 Junction Substation (the

[53] As previously stated, all of the Western Cluster shortlisted proposals would address West to East Power Flow Violations either through greenfield 500 kV (in the north) or 765 kV (in the south) transmission path developments.

initiation point of NEET MA's Modified Proposal No. 853). FirstEnergy's proposed solutions would not solve the reliability violations that PJM identified between the 502 Junction Substation and the Fort Martin Substation, leaving the Doubs to Goose Creek 500 kV corridor congested and unable to deliver the needed flows to Northern Virginia. Modified Proposal No. 853 would provide a needed third 500 kV transmission line in the Goose Creek area, whereas FirstEnergy's proposals terminated at Doubs.

Second, PJM determined that FirstEnergy's proposals did not resolve all of the Regional West to East Transfer Needs. Through additional scenario analysis, PJM determined that building a western line in the northern part provides the most optimized path of power transfer from west to east.

Third, PJM determined that Transource's proposal, the Joshua Falls-Yeat 765 kV greenfield line and substation, which would span across multiple counties across Virginia and include new greenfield lines and a greenfield substation, as well as multiple line and substation upgrades, imposed higher schedule and constructability risk due to its predominately greenfield nature. Transource's proposal also did not address the reliability violations around the Doubs area. None of the other competing proposals has a concept similar to the Woodside 500/138 kV substation under NEET MA's Modified Proposal No. 853.

Q45. PLEASE PROVIDE MORE DETAILS ABOUT HOW PJM DEVELOPED THE FINAL SHORTLISTED COMBINATION SCENARIOS.

A45. As I have previously stated, PJM divided the 2022 Window 3 study area into four geographic clusters: East, West, South, and Northern Virginia/Doubs. After its initial assessment of each of the individual proposals, PJM created, for each Cluster, an initial

shortlist of proposals warranting more detailed analyses of their cost estimate, cost containment, scheduling, constructability, brownfield and outage coordination risks. PJM announced the shortlist of proposals at its October 3, 2023 TEAC meeting together with associated rationale of eliminating non-shortlisted proposals (*see* **Exhibit SA-7**, October 3, 2023 Reliability Analysis Update).

PJM evaluated each proposal on the Cluster shortlists individually, and also evaluated various combinations of the Cluster shortlist proposals and components of such proposals to enhance solution efficiency and robustness. From the shortlists for each of the four regions, PJM identified three cluster scenarios for further review as potential solutions to the 2022 Window 3 reliability needs:

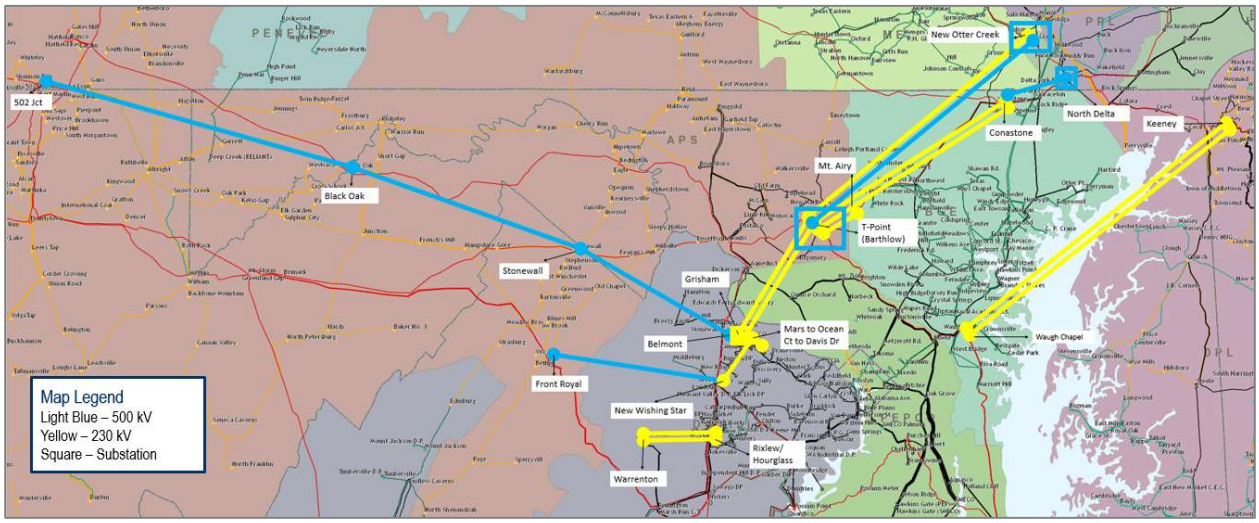
- NEET MA's proposal #175 (which was evaluated as proposed by NEET MA and not modified by PJM) (the "NextEra #175 Scenario");
- a combination of proposals and proposal components submitted by NEET MA (including Proposal No. 853), PSEG Renewable Transmission, Virginia Electric and Power Company (Dominion Virginia Power) ("Dominion"), subsidiaries of Exelon, subsidiaries of FirstEnergy Service Company ("FirstEnergy") and PPL Electric Utilities Corporation (the "PJM Combination – 500 kV Scenario"); and
- a high-level scenario designed by PJM to address 2028 system needs (the "PJM Combination – 765 kV Scenario").

Q46. PLEASE DESCRIBE EACH OF THE THREE SHORTLIST SCENARIOS IN MORE DETAIL.

A46. I discuss each of these three scenarios in more detail below.

1. **NextEra # 175 Scenario**: A high-level scope of NextEra # 175 Scenario is shown on **Map 9**, below. This scenario focused on expanding the 500 kV transmission system by building: (i) a new (greenfield) 500 kV transmission line from a new 500 kV substation (New Otter Creek) in Pennsylvania to a new 500 kV substation (Bartholow) in Maryland; (ii) a new (greenfield) 500 kV transmission line from a new 500 kV substation in Pennsylvania (North Delta (subsequently re-named Bramah)) to the Conastone substation in Maryland; (iii) multiple new 230 kV lines, six (6) of which would be built in Maryland, including two (2) new lines that would be constructed between the Keeney substation on the Delmarva Peninsula, across the Chesapeake Bay and connecting to the Waugh Chapel substation in the BGE (Maryland) area; (iv) a new (greenfield) 500 kV transmission line from the 500 kV Front Royal substation in Virginia to a new 500 kV Wishing Star substation in Virginia; and (v) a new (greenfield) 500 kV transmission line from the 502 Junction substation in West Virginia to Northern Virginia (nearby the existing Goose Creek substation).

Map 9: NextEra # 175 Scenario



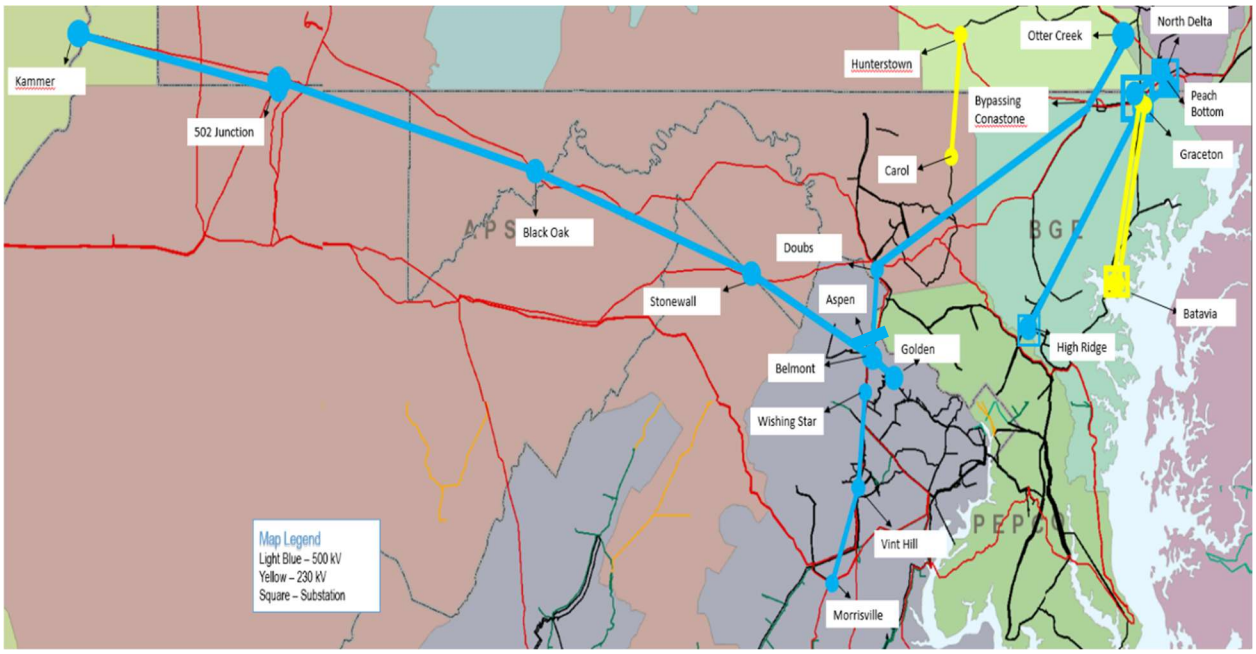
*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

2. **PJM Combination – 500 kV Scenario**: A high-level scope of PJM Combination – 500 kV Scenario is shown on **Map 10**, below. As indicated above, this scenario includes proposal components from several entities, including a modified version of a proposal submitted by NEET MA ("Modified Proposal No. 853").[54] This scenario focused on expanding the 500 kV transmission system by: (i) incorporating Modified Proposal No. 853, which involved constructing a new 121-mile 500 kV transmission line from the existing 502 Junction Substation in to a proposed Woodside Substation in Virginia (bypassing the existing Black Oak substation in Allegany County, Maryland) and a new approximately 47-mile 500 kV transmission line from the proposed Woodside Substation in Virginia to the proposed Aspen Substation in Virginia, designated to NEET MA;[55] (ii) building the

[54] *See* Response to Question 8, above.
[55] *See* Response to Question 8, above.

Maryland Piedmont Reliability Project, proposed by PSEG to be an approximately 67-mile new 500 kV transmission line from Conastone (Maryland) to Doubs (Maryland), a portion of which parallels an existing transmission; (iii) building new 500 kV lines from Peach Bottom (Pennsylvania) to Graceton (Pennsylvania), Peach Bottom (Pennsylvania) to North Delta (Pennsylvania), and North Delta (Pennsylvania) to High Ridge (Maryland), resulting in approximately 75 miles of new transmission that utilizes the existing rights-of-way for the majority of the length; (iv) rebuilding of an existing 500 kV line from Peach Bottom (Pennsylvania) to Conastone (Maryland); (v) using the planned build of a new 500 kV substation (the North Delta (subsequently re-named Bramah) substation) in the Peach Bottom (Pennsylvania) area; (vi) reconfiguring the Peach Bottom substation to avoid short-circuit issues that require the Peach Bottom (Pennsylvania) station rebuild; and (vii) building several new 230 kV lines in Maryland.

Map 10: PJM Combination – 500 kV Scenario

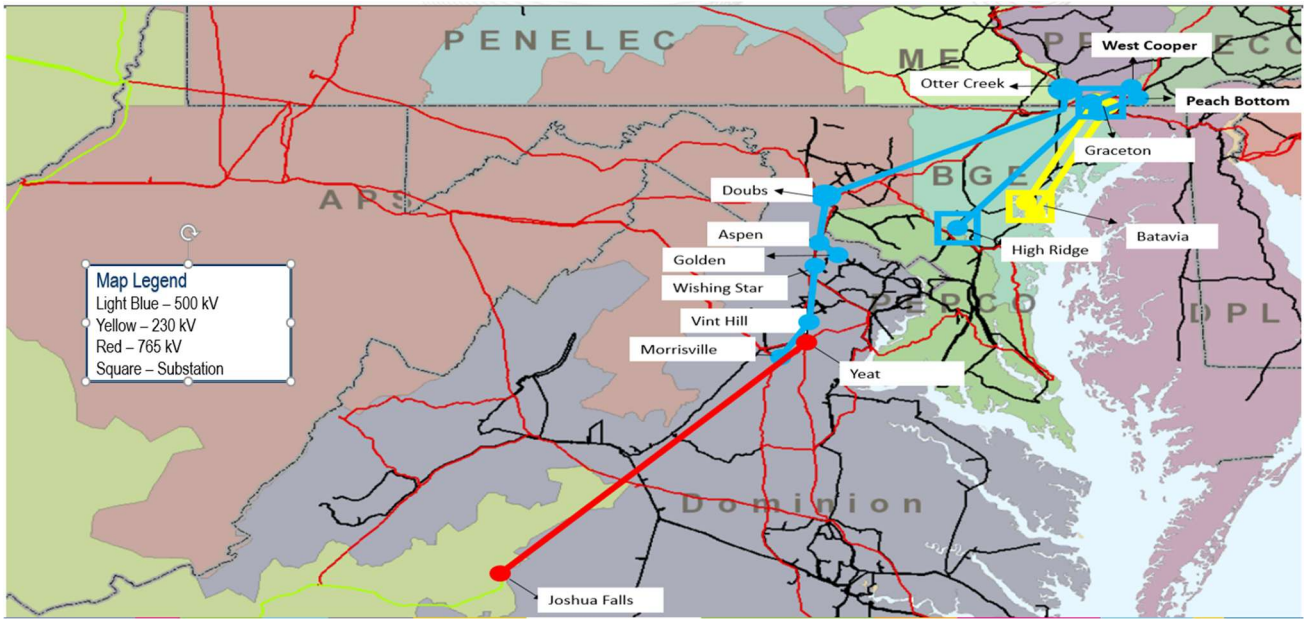


*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

3. **PJM Combination – 765 kV Scenario**: A high-level scope of PJM Combination – 765 kV Scenario is shown on **Map 11**, below. This scenario primarily replaces the 500 kV developments in the northern West cluster with a 765 kV proposed development by Transource in the South/West. The proposal meets the 2022 Window 3 needs, but offers more flexibility to meet needs further in the South as the load growth will likely shift southward in future years. It also provides balanced supply between the North and South supply direction rather than concentrating the supply from the North. The 765 kV development also reduces the flow on the four existing 500 kV lines in APS running west-to-east. This scenario focuses on offering an alternate West-East transfer path reinforcement and relies on

maintaining the East cluster solutions the same as those proposed under the PJM Combination – 500 kV Scenario described earlier, which includes MARL.

Map 11: PJM Combination – 765 kV Scenario



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Q47. WHICH SCENARIO DID PJM ULTIMATELY DETERMINE CONTAINED THE MORE EFFICIENT OR COST-EFFECTIVE SOLUTIONS TO ADDRESS THE RELIABILITY ISSUES IDENTIFIED IN 2022 WINDOW 3?

A47. All three shortlisted scenarios (and associated projects) that I describe above address the regional needs, except for NextEra # 175 Scenario (which was not selected and is not before the Commission in this proceeding) that did not pass the load deliverability requirements. PJM selected the PJM Combination – 500 kV Scenario, which includes the Initial Western Cluster Solution (including the MARL Project), as more efficient and cost-effective to address those identified reliability needs for the following reasons:

- The PJM Combination – 500 kV Scenario offers a robust solution addressing the needed reliability enhancements with the least amount of infrastructure development and with much higher reliability margin compared to the NextEra # 175 Scenario, which is both of higher cost and involves developing a significantly higher number of facilities;
- The PJM Combination – 500 kV Scenario offers full utilization of existing right of ways where possible and particularly through the Peach Bottom-Conastone Corridor, BGE and APS/DOM zones), and congestion relief in the historically constrained Peach Bottom – Conastone 500 kV transmission corridor;
- The PJM Combination – 500 kV Scenario addresses the load deliverability needs into the BGE system which is further exacerbated by the deactivation of key power plant(s) in the BGE zone;
- The NextEra proposal (Proposal ID No. 175) failed the load deliverability test for the 2027/28 year (even with the extensive number of proposed greenfield developments), while the PJM Combination – 500 kV Scenario meets the reliability needs with a healthy margin to spare following the deactivation of the Brandon Shores Units.

Q48. CAN YOU FURTHER EXPLAIN WHY THE INITIAL WESTERN CLUSTER SOLUTION (INCLUDING MARL) WAS SELECTED AS THE MORE EFFICIENT OR COST-EFFECTIVE SOLUTION TO INCLUDE IN THE PJM COMBINATION – 500 KV SCENARIO?

A48. PJM determined that, together, the PJM-selected proposals to address the West cluster regional needs as set forth in the PJM Combination – 500 kV Scenario, including the Initial Western Cluster Solution (including MARL), are the more efficient or cost-effective

solutions to address those needs. These solutions offer the needed reliability reinforcements with the least amount of infrastructure development that is robust and with much higher reliability margin[56] compared to other shortlisted options. These selected proposals, including the MARL Project, also offer congestion relief in the historically constrained Peach Bottom – Conastone 500 kV transmission corridor, and addresses the load deliverability needs into the BGE system which is further exacerbated by the deactivation of key generation facilities in the BGE zone (which I describe above).

Q49. DID PJM CONSIDER ANY NON-GREENFIELD FACILITIES TO ADDRESS THE REGIONAL WEST TO EAST TRANSFER NEEDS?

A49. No. There were no proposals submitted to resolve the Regional West to East Transfer Needs that were not greenfield solutions.

Q50. COULD RECONDUCTORING THE EXISTING 500 KV LINES IN PENNSYLVANIA USING ADVANCED CONDUCTORS POTENTIALLY BE A MORE COST-EFFECTIVE OR EFFICIENT SOLUTION?

A50. No. As I explained earlier, the high regional transfer needs coupled with equivalent net increase in load in SWMAAC and BGE due to deactivation of large sums of generation capability leads to both thermal and voltage violations. The widespread voltage violations indicate the need for new backbone transfer paths (*i.e.*, new 500 kV or above transmission lines) to address these types of needs that would not be addressed by reconductoring. I also described above that extensive thermal and voltage violations occur under N-1-1 conditions which will also occur as first contingency events during the reconductoring exercise itself,

[56] As shown later in this testimony, the robustness of the 2022 Window 3 solutions was proven through the ability of the transmission system to handle the retirement of the Wagner facility that was requested following the finalization and approval of the 2022 Window 3 RTEP plan.

exposing the risk to all load served by the aforementioned line and to the system as a whole, without addressing the core need, which is limited transfer capability under outage conditions let alone constraints during extended outage periods including a line rebuild process. Therefore, reconductoring would not be an effective solution in such conditions, particularly when there are multiple major outages required, each requiring its own outage window and each introducing its own operational challenges during construction.

Q51. IS PJM REASONABLY CERTAIN THAT THE REGIONAL TRANSMISSION RELIABILITY CONSTRAINTS IDENTIFIED IN THE 2022 WINDOW 3 WOULD RESULT IN WIDESPREAD NERC RELIABILITY CRITERIA VIOLATIONS IN 2027 AND 2028 ACROSS THE BULK 500 KV SYSTEM THAT SERVES THE PJM REGION IF THEY ARE NOT RESOLVED BY TRANSMISSION UPGRADES OR THE CONSTRUCTION OF NEW TRANSMISSION FACILITIES?

A51. Yes, PJM has conducted extensive analysis of the 2027 and 2028 study years, and if the projects selected in the 2022 RTEP Window 3 are not constructed, then PJM is reasonably certain that the bulk 500 kV system serving the PJM Region would experience widespread thermal overloads and voltage violations. As I explain above, these violations could compromise overall system reliability in the PJM Region, including for Pennsylvania customers, and could lead to widespread and extreme conditions, such as system collapse and blackouts.

VII. PJM STAKEHOLDER REVIEW AND BOARD APPROVAL OF THE 2022 WINDOW SOLUTIONS

Q52. CAN YOU PLEASE PROVIDE A TIMELINE OF THE 2022 WINDOW 3 PROCESS, INCLUDING ANY OPPORTUNITIES FOR STAKEHOLDER INPUT INTO THE PROCESS.

A52. Below is a list of the most significant steps PJM took to open, develop, and solicit public feedback with respect to the Window 3 Project selection:

- PJM opened 2022 Window 3 on February 24, 2023, by publicly posting status and timeline information to the TEAC on February 7, 2023 and a transmission planning reliability analysis update on March 7, 2023.
- On April 27, 2023, PJM held a special TEAC meeting to discuss 2022 Window 3 and how its solutions must be robust enough to address the evolving needs reflected in the 2028 base case model (described below).
- The 2022 Window 3 closed on May 31, 2023, and PJM provided an updated timeline and status update and a reliability analysis report to the TEAC on June 6, 2023, and publicly posted the material on the PJM TEAC website.
- PJM provided a proposal summary, an evaluation progress report and proposals maps with respect to the 2022 Window 3 at the July 11, 2023 TEAC meeting, and progress updates on scenario development, analysis and work plan on August 8, 2023 and September 5, 2023 TEAC meetings, and publicly posted the material on the PJM TEAC website.
- At the October 3, 2023 TEAC meeting, PJM presented a comprehensive reliability analysis update on the 2022 Window 3 that included need statement summary, load forecast and generation assumptions, summary of proposals, summary of scenarios studies, detailed review of proposals and shortlist scenarios, and provided a summary of short circuit and load deliverability results.
- On October 31, 2023, at the TEAC meeting PJM did a first read of the 2022 Window 3 proposals, where PJM again presented its comprehensive reliability analysis update and answered numerous questions from stakeholders who

participated in person or remotely. PJM answered numerous questions from stakeholders and members of the public at the TEAC.

- On November 17, 2023, PJM took additional steps, not required by its processes, of posting drafts of its Constructability & Financial Analysis and Reliability Analysis Reports, two weeks ahead of the December 5, 2023 TEAC meeting.
- At its December 5, 2023 TEAC meeting, PJM held a second read of the 2022 Window 3 solutions and took additional steps, not required by its processes, to discuss its final versions of the Constructability & Financial Analysis Report (**Exhibit SA-8**) and Reliability Analysis Report (**Exhibit SA-6**), as well as a separate document explaining PJM's role in regional planning that aimed to answer frequently asked questions by individual stakeholders. At the same TEAC meeting, PJM posted its formal Reliability Analysis Report on 2022 Window 3. The TEAC meeting was well attended by numerous stakeholders representing consumer advocates, state commissions, individual consumers, generation developers, and transmission owners who attended either in person or remotely. PJM answered numerous questions from stakeholders and members of the public at the TEAC.
- At the October and December 2023 TEAC meetings, stakeholders were informed how to submit their feedback to the PJM and/or the PJM Board with respect to the 2022 Window 3 Projects. All feedback addressed to the PJM Board was publicly posted. Stakeholders were informed about the PJM Board's decision publicly and by email.

The PJM Board carefully considered all of the input provided by stakeholders and members

of the public throughout the 2022 Window 3 process. PJM staff briefed the PJM Board on several occasions during the nine-month 2022 Window 3 process on the magnitude of upgrades that would be needed to address the identified reliability violations, the types of projects PJM was considering recommending for Board approval, and the volume and type of feedback received from stakeholders and members of the public regarding 2022 Window 3. The PJM Board considered all of this public feedback, in addition to the recommendations of the PJM staff and the TEAC, when it ultimately decided to approve the 2022 Window 3 Projects for inclusion in the RTEP.

VIII. FURTHER NEED ASSESSMENT FOR THE REVISED WESTERN CLUSTER SOLUTION (INCLUDING MARL)

Q53. YOU PREVIOUSLY EXPLAINED WHY PJM RECOMMENDED THAT THE MARL PROJECT BE INCLUDED IN THE RTEP. HAS PJM CONDUCTED ANY ADDITIONAL ANALYSES TO DETERMINE WHAT RELIABILITY STANDARDS WOULD BE VIOLATED IF THE REVISED WESTERN CLUSTER SOLUTION (INCLUDING THE MARL PROJECT) IS NOT CONSTRUCTED?

A53. Yes. In preparing this Testimony, PJM conducted additional analyses to demonstrate the need for the Revised Western Cluster Solution (including the MARL Project) and whether the PJM Region would experience reliability violations if the planned Revised Western Cluster Solution (including the MARL Project) is not in-service. Specifically, PJM took the 2028 base case I described above, assumed that all other selected 2022 Window 3 solutions were in-service, and assumed that the Revised Western Cluster Solution (including the MARL Project) was not in-service. PJM summarizes the analysis conducted on the 2028 Summer Peak base case, as it reflects the increased modeled load for the need year(s) based on the official PJM load forecast. PJM also observed thermal and voltage violations in the 2027 RTEP cases and the 2028 RTEP Winter Peak case.

The analysis resulted in thermal overloads on several 500 kV, 230 kV and 138 kV transmission lines, with additional thermal overloads on several 500 kV transformers due to single, breaker and bus contingencies. These violations are detailed in **Table 6** below.

Table 6

				Summer	
Name	Circuit #	kVs	Areas	Highest AC %LD	# of FGs
Front Royal – Morrisville	1	500	DVP	105.29%	2
Spotsylvania – Morrisville	1	500	DVP	104.22%	1
Elmont – Ladysmith	1	500	DVP	103.87%	2
North Anna - Spotsylvania	1	500	DVP	101.42%	1
Pruntytown – Mount Storm	1	500	APS/ DVP	100.03%	2
Profit – Hollymead	1	230	DVP	103%	2
Sedge Hill – AC1-221 TAP	1	230	DVP	106.62%	2
French's Mill – Hampshire	1	138	APS	106.8%	2
Junction – French's Mill	1	138	APS	101.46%	2
Morgan – Cherry Run	1	138	APS	103.42	2
Mt. Zion – West Vaco	1	138	APS	118.32	5
West Vaco – Cross School	1	138	APS	117.94	5
Bethel – Riverton	1	138	APS	106.16	5
Hampshire – Gore	1	138	APS	106.76	2
Dans Mountain - Ridgeley	1	138	APS	100.78	3

PJM also observed voltage violations for N-1 and more severe violations under N-1-1 contingencies across PJM at all voltage levels, further reinforcing the need for additional path from West to East. These violations are summarized in **Table 7** and **Table 8**, below.

Table 7: N-1 Voltage Summary Result

N-1 Voltage Summary Result
Voltage Drop
Voltage Drop at Black Oak, Meadow Brook, Bismark, Greenland Gap and South Bend 500 kV in the summer and winter case

Table 8: N-1-1 Voltage Summary Result

N-1-1 Voltage Summary Result	
Summer N-1-1 voltage Magnitude	
Over 300 new violations on Bismark, Mount Storm, Front Royal, Cunningham and Generator 500 kV substations and several other 138 and 115 kV substations	
Summer N-1-1 voltage Drop	
40 new voltage drop violations on Bedington, Black Oak, Meadow Brook, Yukon, Front Royal & Generator 500 kV substations. Most of these substations are along the west to east transfer 500 kV path	Over 90 new Voltage drop violations on the 230 kV and 138 kV in APS and DVP territory

Finally, as I previously explained, PJM explored different solutions to address the Regional West to East Transfer Needs and associated proposed solutions. However, it was observed that the reliability concerns would require further reinforcement to increase the transfer capability along the Doubs-Goose corridor (enhancing the transfer capability directly into the Northern Virginia network) via a third 500 kV circuit. As stated, PJM's analysis showed that the power termination needed to be around the Goose Creek/Aspen Substation which provides the additional transfer capability directly into the load pocket in northern Virginia.

In short, PJM conducted analyses to determine the impact of removing the Revised Western Cluster Solution – including the MARL Project – from the set of 2022 Window 3 solutions. PJM observed that, if the Revised Western Cluster Solution – including MARL – was removed, but all selected 2022 Window 3 solutions moved forward, there would still be thermal and voltage violations, thus further demonstrating the need for Revised Western Cluster Solution (including the MARL Project). Note that the analysis conducted by removing one cluster at a time does not reveal the magnitude or extent of the reliability violations, especially voltage violations, that all of the projects when combined together

collectively address. Each of the 2022 Window 3 selected-solutions work in tandem to collectively address the broader and more severe list of reliability violations than would be observed by conducting analysis by removing each project of 2022 Window 3 solution individually one at a time.

Q54. DO THE ANALYSES DESCRIBED ABOVE DEMONSTRATE THAT THE REVISED WESTERN CLUSTER SOLUTION (INCLUDING THE MARL PROJECT) IS NEEDED FOR RELIABILITY?

A54. Yes, they do.

IX. CONCLUSION

Q55. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A55. Yes, it does, although I reserve the right to supplement this testimony as appropriate.

Sami Abdulsalam, Ph.D. P.Eng
Director – Transmission Planning, PJM

Sami.Abdulsalam@PJM.com
Audubon, PA – 445-942-5834

SUMMARY OF QUALIFICATIONS:

- Transmission Planning expert, with 25+ years of experience in the fields of transmission system planning, long term planning, renewable energy integration, energy transition, project development, grid interconnections and power system dynamic analysis
- Led the transmission planning department in PJM as Sr. Mgr then Director of Transmission Planning responsible for the development of the PJM Regional Transmission Expansion Plan.
- Expert witness testifying in public regulatory hearings (with FERC and in Canada) supporting transmission development for load and renewable integration expansion plans for multi-billion dollar utility projects.
- PJM primary representative to the United States DOE National Transmission Planning Study.
- Led the development of the largest Regional Transmission Expansion Plan in PJM (largest competitively solicited transmission development initiative in eastern United Stated and nation-wide) totaling more than $5Bn in 2023.
- Led (Technical Advisory Committee) and managed the Western Regional Electricity Cooperation and Strategic Infrastructure (RECSI) Study (Canada Federal Government Funded) in 2018
- Alberta Electric System Operator (AESO) representative to the Transmission Facilities Cost Monitoring Committee (TFCMC). Alberta-Canada
- Represented the AESO as primary lead to the Western Electricity Coordinating Council (NERC WECC) MVWG and Planning Committee as well as to WIRES (United States / Canada).
- Hands on experience with power system engineering and analysis tools (PSSE and PSLF), power system transients (PSCAD and EMTP), dynamic oscillations/resonance
- Experience with leading transmission planning and cost benefit assessments using production simulations (GE MAPS and AURORA).
- Proven track record in Transmission System projects planning for long and short-term(s) in compliance with NERC TPL standards.
- Institute of Electrical and Electronics Engineers (IEEE) Top-Tier journal paper reviewer on Power Systems and Industry applications with more than 10 highly cited journal and conference papers.
- Solid planning and engineering background in the fields of generation facility integration (850 to 50 MWs scale), Oil and Gas project interconnections, and Renewable Energy integration and enablement.
- Proven experience with transmission system short circuit assessment and mitigation via innovative solutions as well as impacts of low short circuit capability on generator and HVDC (converter-based systems) systems dynamic performance and interactions (SSO/SSR analyses).
- A passionate, effective communicator and collaborator. Ensuring the overall team success through developing strategies and plans aligned with the collective needs/vision via setting SMART goals.
- Ability to build trust and manage relationships with internal and external stakeholders.
- Familiar with the legislative power industry framework in the United States and Canada.
- Skilled in resource planning and budgeting, ensuring successful execution/delivery of the planned target deliverables and timelines.

WORK EXPERIENCE:

March 1st 2024 - Present	**Director, Transmission Planning** **PJM Interconnection**
Jan 1st 2022 - March 2024	**Senior Manager, Transmission Planning** **PJM Interconnection**
June 1st 2020 – Dec. 2021	**Senior Consulting Portfolio Manager** **Siemens PTI, Schenectady, NY, US**
Nov 1st 2019 – May 31st, 2020	**Principal Engineer,** **Sustainable Grid Power Inc., Transmission Division, Calgary, AB**
2017 – Oct 30th, 2019	**Director, Transmission Planning,** **AESO, Transmission Division**
2016 – 2017	**Director, Transmission System Projects** **AESO, Transmission Division**
2015 – 2016	**Manager, Operations Planning** **AESO, Operations Planning and Engineering**
2011 - 2015	**Manager, Projects and System Access Studies** **AESO, Transmission Project Delivery**
2009 - 2011	**Senior Engineer** **AESO, Transmission Project Delivery**
2008 - 2009	**Senior Engineer** **AESO, Transmission-Technical Services**
2007 - 2008	**Post Doctoral Fellow** **ECE Dept., University of Alberta, Edmonton, Canada.** **Main-Project: Determining acceptable synchronization parameters for the Alberta Interconnected Power Systems (AIES).**
2002 - 2007	**Research Assistant (Mitigation of Electromagnetic Transients) ECE Dept., University of Alberta, Edmonton, Canada.** **Thesis Title: Modelling and Mitigation of Transformer Inrush Transients.**
2004 - 2005	**Research Assistant (Power Quality and Harmonics Project) ECE Dept., University of Alberta, Edmonton, Canada.**
2001 - 2002	**Electrical and Instrumentation Engineer**

Enppi, Instrumentation and Control Systems Department, Cairo, Egypt.

2001 **Electrical Engineer (Protection)**
EOMPC/BECHTEL, El-Kureimat, Egypt.

1999 - 2001 **Research Assistant**
Electrical Power and Machines Dept., University of El-Mansoura, Egypt.
Thesis Title: Effect of Protection Performance on Power System Voltage Stability

PUBLIC HEARINGS – EXPERT WITNESS (Regulatory Experience):

2025 **PA PUC Docket No. A-2025-3056951**, Mid-Atlantic Interstate Transmission, LLC for a Certificate of Public Convenience and Necessity to Upgrade a 24-mile transmission line between the Hunterstown Substation in Adams County, Pennsylvania, and the Carroll Substation in Carroll County, Maryland

2025 **MD PSC Case No. 9803** - The Potomac Edison Company, Application for a Certificate of Public Convenience and Necessity to Upgrade a 24-mile transmission line between the Hunterstown Substation in Adams County, Pennsylvania, and the Carroll Substation in Carroll County, Maryland

2024 **MD PSC Case No. 9773** - PSEG Renewable Transmission LLC, Application for a Certificate of Public Convenience and Necessity to Construct a New 500 kV Transmission Line in Portions of Baltimore, Carroll and Frederick Counties, Maryland

2024 **FERC Docket No. ER24-843** – PJM Interconnection, L.L.C., Affidavit in Support of 2022 Window 3 Cost Allocation Assignments (Feb. 2024)

2021 **NCUC (North Carolina Utilities Commission) Docket No. EMP-119, SUB 0 AND EMP-119, SUB 1, PRE-FILE REBUTAL TESTIMONY – MCADAMIA SOLAR LLC – Expert Witness –(Dec 2021) (United States)**

2021 **FERC Docket No. RM21-17-00 – Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection – Expert**
Witness – Written Testimony on behalf of NextEra Energy (Nov 2021) (United States)

2021 **FERC Docket No. ER19-2019 and ER19-2023 –** Tucson Electric Company Loss Study **(June 2021) (United States)**

2019 **AUC Application No. 23429-A001 / Proceeding ID 23429** – PENV Transmission Development Project, January 2019 **– (Approved – Under Construction) (Canada)**

2018 **AUC Application No. 23105-A001 / Proceeding ID 23105** – Rycroft Area Transmission Development, December 2018 **– (Approved – Energized) (Canada)**

2018 **AUC Application No. 23339-A001 / Proceeding ID 23339** – Provost Reliability Upgrade Project, October 2018 **– Approved (under construction) (Canada)**

2014 **AUC Application No. 1609123 / Proceeding ID No. 2303 –** South and West Edmonton Area Transmission Reinforcement Needs Identification Document, March 2014 **– Approved (Energized) (Canada)**

2012 **AUC Application No. 1607818/ Proceeding ID No. 1530** - Spruce Grove 595S

Substation Connection Needs Identification Document, August 2012 **– Approved (Energized) (Canada)**

2012 **AUC Application No. 1607512/Proceeding ID No. 1363** - Weasel Creek 947S and Abee 993S Substations Needs Identification Document, May 2012 **– Approved (Energized) (Canada)**

TRANSMISSION PROJECTs PORTFOLIO (Key Projects – Transmission Planning – United States and Canada)

PJM Regional Transmission Expansion Plan – RTEP 2022 – Window 3 (United States).	Board Approved	$5,000.0M
PJM Regional Transmission Expansion Plan – RTEP 2022 Window 1 and 2 (United States).	Board Approved	$2,210.0M
PJM Data Center Alley Immediate Need – Dominion – Oct 2022 (United States).	Under Construction	$627.0M
Chapel Rock to Pincher Creek Development - 240-500kV (Canada)	Consultation Completed	$450M
Central East Transfer Out Project - 240kV - (Canada)	Consultation Completed	$500M
Alberta-BC Intertie Restoration Project – 500 kV - (Canada)	Consultation Completed	$100M
PENV Transmission Development – 138-240kV - (Canada)	Approved	$240.0M
Rycroft Transmission Development – 138kV - (Canada)	Approved	$50.0M
Fort McMurray West 500kV Transmission Line – 500kV - (Canada)	Energized	$1,450.0M
South and West of Edmonton Development - 240-138kV - (Canada)	Energized	$280.0M
SATR – CBW 240 kV Transmission Development – 240kV - (Canada)	Energized	$1,000.0M
SATR-South of Foothills Development – 240kV - (Canada)	Energized	$800.0M

PROFESSIONAL ACTIVITY/AFFILIATIONS/VOLUNTEERING:

Chair, IRC Planning Committee (US and Canada) 2018 – Oct 2019
Member, WIRES North America, Alberta Rep 2018 – Oct 2019
Member, AESO TFCMC Representative, 2017 - Oct 2019
Member, IRC Planning Committee (US and Canada)- Alberta Representative 2016 - Oct 2019
Prosci Change Management Certification 2015/16
Chair, IEEE PES/IAS Northern Canada Chapter (2008).
Secretary, IEEE PES/IAS Northern Canada Chapter (2004-2007).
Member, IEEE Power Engineering Society (2003-Present).
Member, IEEE Industry Application Society (2009-Present)
Journal Research Paper Reviewer for the following Publications;

- IEEE Transactions on Power Delivery (2003-Present)
- IEEE Transactions on Power Systems (2003-Present)
- IEEE Transactions on Industry Applications (2003-Present)
- Conferences including IEEE, CIGRE, EPEC, and others (by invitation) Professional Engineer, Egyptian Syndicate of Engineers, (1997-Present).

Project Manager, ESANA Canadian Book Campaign, (2005-2007).
P. Eng (APEGA), Registered Professional Engineer in Alberta
Robot Inspection Manager, First Robotics Canada (2013, 2014, 2015) - Volunteer

EDUCATION:

2002 - 2007	**Doctor of Philosophy**, June 2007, University of Alberta, Edmonton, Alberta. Thesis title "**Modeling and Mitigation of Transformer Inrush Currents**."
1999 - 2001	**Master of Science**, May 2001, University of El-Mansoura, El-Mansoura, Egypt. Thesis title "**Effect of Protection Performance on Power System Voltage Stability.**"
1992 - 1997	**Bachelor of Science,** University of El-Mansoura, El-Mansoura, Egypt. Graduation Project: "**Power System Dynamic Simulation for Voltage Stability Studies**"

SCHEDULE 6 -
REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

References to section numbers in this Schedule 6 refer to sections of this Schedule 6, unless otherwise specified.

1. REGIONAL TRANSMISSION EXPANSION PLANNING PROTOCOL

1.1 Purpose and Objectives.

This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the Office of the 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.

1.2 Conformity with NERC *Reliability Standards* and Other Applicable Reliability Criteria.

(a) NERC establishes Reliability Standards to promote the reliability, adequacy and security of the North American bulk power supply as related to the operation and planning of electric systems.

(b) ReliabilityFirst Corporation is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the geographic region described in the applicable agreements between NERC and ReliabilityFirst Corporation, as approved by the FERC, through coordinated operations and planning of generation and transmission facilities. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System of the ReliabilityFirst Corporation.

(c) [Reserved]

(c.01) [Reserved]

(c.02) SERC is responsible for ensuring the reliability, adequacy and security of the bulk electric supply systems in the VACAR subregion of SERC. Toward that end, it has adopted the NERC Reliability Standards and has established detailed Reliability Principles and Standards for Planning the Bulk Electric Supply System for SERC.

(d) The Regional Transmission Expansion Plan shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation and SERC, and other Applicable Regional Entities in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals.

(e) The Regional Transmission Expansion Plan planning criteria shall include, Office of the Interconnection planning procedures, NERC Reliability Standards, Regional Entity reliability principles and standards, and the individual Transmission Owner FERC filed planning criteria as filed in FERC Form No. 715, and posted on the PJM website. FERC Form No. 715 material will be posted to the PJM website, subject to applicable Critical Energy Infrastructure Information (CEII) requirements.

(f) The Office of the Interconnection will also provide access through the PJM website, to the planning criteria and assumptions used by the Transmission Owners for the development of the current Local Plan.

1.3 Establishment of Committees.

(a) The Planning Committee shall be open to participation by (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region and the State Consumer Advocates; and (v) any other interested entities or persons and shall provide technical advice and assistance to the Office of the Interconnection in all aspects of its regional planning functions. The Transmission Owners shall supply representatives to the Planning Committee, and other Members may provide representatives as they deem appropriate, to provide the data, information, and support necessary for the Office of the Interconnection to perform studies as required and to develop the Regional Transmission Expansion Plan.

(b) The Transmission Expansion Advisory Committee established by the Office of the Interconnection will meet periodically with representatives of the Office of the Interconnection to provide advice and recommendations to the Office of the Interconnection to aid in the development of the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee participants shall be given an opportunity to provide advice and recommendations for consideration by the Office of the Interconnection regarding sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives in the studies and analyses to be conducted by the Office of the Interconnection. The Transmission Expansion Advisory Committee participants shall be given the opportunity to review and provide advice and recommendations on the projects to be included in the Regional Transmission Expansion Plan. The Transmission Expansion Advisory Committee meetings shall include discussions addressing interregional planning issues, as required. The Transmission Expansion Advisory Committee shall be open to participation by: (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates; and (v) any other interested entities or persons. The Transmission Expansion Advisory Committee shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional Planning Process Manual (PJM Manual M-14 series) and by the rules and procedures applicable to PJM committees.

(c) The Subregional RTEP Committees established by the Office of the Interconnection shall facilitate the development and review of the Local Plans. The Subregional RTEP Committees will be responsible for the initial review of the Subregional RTEP Projects, and to provide recommendations to the Transmission Expansion Advisory Committee concerning the Subregional RTEP Projects. A Subregional RTEP Committee may of its own accord or at the request of a Subregional RTEP Committee participant, also refer specific Subregional RTEP Projects to the Transmission Expansion Advisory Committee for further review, advice and recommendations.

(d) The Subregional RTEP Committees shall be responsible for the timely review of the criteria, assumptions and models used to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements, proposed solutions and written comments prior to finalizing the Local Plan, the coordination and integration of the Local Plans into the RTEP, and addressing any stakeholder issues unresolved in the Local Plan process. The Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the criteria, assumptions, and models used in local planning activities prior to finalizing the Local Plan. The Subregional RTEP Committees shall also be responsible for the timely review of the Transmission Owners' criteria, assumptions, and models used to identify Supplemental Projects that will be considered for inclusion in the Local Plan for each Subregional RTEP Committee. The Subregional RTEP Committees meetings shall include discussions addressing interregional planning issues, as required. Once finalized, the Subregional RTEP Committees will be provided sufficient opportunity to review and provide written comments on the Local Plans as integrated into the RTEP, prior to the submittal of the final Regional Transmission Expansion Plan to the PJM Board for approval. In addition, the Subregional RTEP Committees will provide sufficient opportunity to review and provide written comments to the Transmission Owners on any Supplemental Projects included in the Local Plan, in accordance with Additional Procedures for Planning of Supplemental Projects set forth in Tariff, Attachment M-3.

(e) The Subregional RTEP Committees shall be open to participation by: (i) all Transmission Customers and applicants for transmission service; (ii) any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region; (iii) all Members; (iv) the electric utility regulatory agencies within the States in the PJM Region, the Independent State Agencies Committee, and the State Consumer Advocates and (v) any other interested entities or persons.

(f) Each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions and models to identify reliability criteria violations, economic constraints, or to consider Public Policy Requirements. Each Subregional RTEP Committee shall schedule and facilitate an additional Subregional RTEP Committee meeting, per planning cycle, and as required to review the identified criteria violations and potential solutions. The Subregional RTEP Committees may facilitate additional meetings to incorporate more localized areas in the subregional planning process. At the discretion of the Office of the Interconnection, a designated Transmission Owner may facilitate Subregional RTEP Committee meeting(s), or the additional meetings incorporating the more localized areas.

(g) The Subregional RTEP Committees shall schedule and facilitate meetings regarding Supplemental Projects, as described in the Tariff, Attachment M-3.

(h) The Subregional RTEP Committees shall be governed by the Transmission Expansion Advisory Committee rules and procedures set forth in the PJM Regional

Planning Process Manual (Manual M-14 series) and by the rules and procedures applicable to PJM committees.

1.4 Contents of the Regional Transmission Expansion Plan.

(a) 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.

(b) 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.

(c) The Regional Transmission Expansion Plan shall, at a minimum, include a designation of the Transmission Owner(s) or other entity(ies) that will construct, own, maintain, operate, and/or finance each transmission enhancement and expansion and how all reasonably incurred costs are to be recovered.

(d) The Regional Transmission Expansion Plan shall (i) avoid unnecessary duplication of facilities; (ii) avoid the imposition of unreasonable costs on any Transmission Owner or any user of Transmission Facilities; (iii) take into account the legal and contractual rights and obligations of the Transmission Owners; (iv) provide, if appropriate, alternative means for meeting transmission needs in the PJM Region; (v) provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans; and (vi) strive for consistency in planning data and assumptions that may relieve transmission congestion across multiple regions.

1.5 Procedure for Development of the Regional Transmission Expansion Plan.

1.5.1 Commencement of the Process.

(a) The Office of the Interconnection shall initiate the enhancement and expansion study process if: (i) required as a result of a need for transfer capability identified by the Office of the Interconnection in its evaluation of requests for interconnection with the Transmission System or for firm transmission service with a term of one year or more; (ii) required to address a need identified by the Office of the Interconnection in its on-going evaluation of the Transmission System's market efficiency and operational performance; (iii) required as a result of the Office of the Interconnection's assessment of the Transmission System's compliance with NERC Reliability Standards, more stringent reliability criteria, if any, or PJM planning and operating criteria; (iv) required to address constraints or available transfer capability shortages, including, but not limited to, available transfer capability shortages that prevent the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7.4.2(b), constraints or shortages as a result of expected generation retirements, constraints or shortages based on an evaluation of load forecasts, or system reliability needs arising from proposals for the addition of Transmission Facilities in the PJM Region; or (v) expansion of the Transmission System is proposed by one or more Transmission Owners, Interconnection Customers, Network Service Users or Transmission Customers, or any party that funds Network Upgrades pursuant to the Operating Agreement, Schedule 1, section 7.8. The Office of the Interconnection may initiate the enhancement and expansion study process to address or consider, where appropriate, requirements or needs arising from sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives.

(b) The Office of the Interconnection shall notify the Transmission Expansion Advisory Committee participants of, as well as publicly notice, the commencement of an enhancement and expansion study. The Transmission Expansion Advisory Committee participants shall notify the Office of the Interconnection in writing of any additional transmission considerations they would like to have included in the Office of the Interconnection's analyses.

1.5.2 Development of Scope, Assumptions and Procedures.

Once the need for an enhancement and expansion study has been established, the Office of the Interconnection shall consult with the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, to prepare the study's scope, assumptions and procedures.

1.5.3 Scope of Studies.

In conducting the enhancement and expansion studies, the Office of the Interconnection shall not limit its analyses to bright line tests to identify and evaluate potential Transmission System limitations, violations of planning criteria, or transmission needs. In addition to the bright line tests, the Office of the Interconnection shall employ sensitivity studies, modeling assumption variations, and scenario analyses, and shall also consider Public Policy Objectives in the studies and analyses, so as to mitigate the possibility that bright line metrics may inappropriately include

or exclude transmission projects from the transmission plan. Sensitivity studies, modeling assumption variations, and scenario analyses shall take account of potential changes in expected future system conditions, including, but not limited to, load levels, transfer levels, fuel costs, the level and type of generation, generation patterns (including, but not limited to, the effects of assumptions regarding generation that is at risk for retirement and new generation to satisfy Public Policy Objectives), demand response, and uncertainties arising from estimated times to construct transmission upgrades. The Office of the Interconnection shall use the sensitivity studies, modeling assumption variations and scenario analyses in evaluating and choosing among alternative solutions to reliability, market efficiency and operational performance needs. The Office of the Interconnection shall provide the results of its studies and analyses to the Transmission Expansion Advisory Committee to consider the impact that sensitivities, assumptions, and scenarios may have on Transmission System needs and the need for transmission enhancements or expansions. Enhancement and expansion studies shall be completed by the Office of the Interconnection in collaboration with the affected Transmission Owners, as required. In general, enhancement and expansion studies shall include:

(a) An identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance, with accompanying simulations to identify the costs of controlling those limitations. Potential enhancements and expansions will be proposed to mitigate limitations controlled by non-economic means.

(b) Evaluation and analysis of potential enhancements and expansions, including alternatives thereto, needed to mitigate such limitations.

(c) Identification, evaluation and analysis of potential transmission expansions and enhancements, demand response programs, and other alternative technologies as appropriate to maintain system reliability.

(d) Identification, evaluation and analysis of potential enhancements and expansions for the purposes of supporting competition, market efficiency, operational performance, and Public Policy Requirements in the PJM Region.

(e) Identification, evaluation and analysis of upgrades to support Incremental Auction Revenue Rights requested pursuant to the Operating Agreement, Schedule 1, section 7.8.

(f) Identification, evaluation and analysis of upgrades to support all transmission customers, including native load and network service customers.

(g) Engineering studies needed to determine the effectiveness and compliance of recommended enhancements and expansions, with the following PJM criteria: system reliability, operational performance, and market efficiency.

(h) Identification, evaluation and analysis of potential enhancements and expansions designed to ensure that the Transmission System's capability can support the simultaneous feasibility of all stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7.4.2(b). Enhancements and expansions related to stage 1A

Auction Revenue Rights identified pursuant to this Section shall be recommended for inclusion in the Regional Transmission Expansion Plan together with a recommended in-service date based on the results of the ten (10) year stage 1A simultaneous feasibility analysis. Any such recommended enhancement or expansion under this Operating Agreement, Schedule 6, section 1.5.3(h) shall include, but shall not be limited to, the reason for the upgrade, the cost of the upgrade, the cost allocation identified pursuant to the Operating Agreement, Schedule 6, section 1.5.6(m) and an analysis of the benefits of the enhancement or expansion, provided that any such upgrades will not be subject to a market efficiency cost/benefit analysis.

1.5.4 Supply of Data.

(a) The Transmission Owners shall provide to the Office of the Interconnection on an annual or periodic basis as specified by the Office of the Interconnection, any information and data reasonably required by the Office of the Interconnection to perform the Regional Transmission Expansion Plan, including but not limited to the following: (i) a description of the total load to be served from each substation; (ii) the amount of any interruptible loads included in the total load (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (iii) a description of all generation resources to be located in the geographic region encompassed by the Transmission Owner's transmission facilities, including unit sizes, VAR capability, operating restrictions, and any must-run unit designations required for system reliability or contract reasons; the (iv) current local planning information, including all criteria, assumptions and models used by the Transmission Owners, such as those used to develop Supplemental Projects. The data required under this Section shall be provided in the form and manner specified by the Office of the Interconnection.

(b) In addition to the foregoing, the Transmission Owners, those entities requesting transmission service and any other entities proposing to provide Transmission Facilities to be integrated into the PJM Region shall supply any other information and data reasonably required by the Office of the Interconnection to perform the enhancement and expansion study.

(c) The Office of the Interconnection also shall solicit from the Members, Transmission Customers and other interested parties, including but not limited to electric utility regulatory agencies within the States in the PJM Region, Independent State Agencies Committee, and the State Consumer Advocates, information required by, or anticipated to be useful to, the Office of the Interconnection in its preparation of the enhancement and expansion study, including information regarding potential sensitivity studies, modeling assumption variations, scenario analyses, and Public Policy Objectives that may be considered.

(d) The Office of the Interconnection shall supply to the Transmission Expansion Advisory Committee and the Subregional RTEP Committees reasonably required information and data utilized to develop the Regional Transmission Expansion Plan. Such information and data shall be provided pursuant to the appropriate protection of confidentiality provisions and Office of the Interconnection's CEII process.

(e) The Office of the Interconnection shall provide access through the PJM website, to the Transmission Owner's local planning information, including all criteria, assumptions and models

used by the Transmission Owners in their internal planning processes, including the development of Supplemental Projects ("Local Plan Information"). Local Plan Information shall be provided consistent with: (1) any applicable confidentiality provisions set forth in the Operating Agreement, section 18.17; (2) the Office of the Interconnection's CEII process; and (3) any applicable copyright limitations. Notwithstanding the foregoing, the Office of the Interconnection may share with a third party Local Plan Information that has been designated as confidential, pursuant to the provisions for such designation as set forth in the Operating Agreement, section 18.17 and subject to: (i) agreement by the disclosing Transmission Owner consistent with the process set forth in this Operating Agreement; and (ii) an appropriate non-disclosure agreement to be executed by PJM Interconnection, L.L.C., the Transmission Owner and the requesting third party. With the exception of confidential, CEII and copyright protected information, Local Plan Information will be provided for full review by the Planning Committee, the Transmission Expansion Advisory Committee, and the Subregional RTEP Committees.

1.5.5 Coordination of the Regional Transmission Expansion Plan.

(a) The Regional Transmission Expansion Plan shall be developed in accordance with the principles of interregional coordination with the Transmission Systems of the surrounding Regional Entities and with the local transmission providers, through the Transmission Expansion Advisory Committee and the Subregional RTEP Committee.

(b) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordinated regional transmission expansion planning established under the following agreements:

- Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C., which is found at http://www.pjm.com/~/media/documents/agreements/joa-complete.ashx;

- Northeastern ISO/RTO Planning Coordination Protocol, which is described at Schedule 6-B and found at http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx;

- Joint Operating Agreement Among and Between New York Independent System Operator Inc., which is found at http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx;

- Interregional Transmission Coordination Between the SERTP and PJM Regions, which is found at Operating Agreement, Schedule 6-A ;

- Allocation of Costs of Certain Interregional Transmission Projects Located in the PJM and SERTP Regions, which is located at Tariff, Schedule 12-B;

- Joint Reliability Coordination Agreement Between PJM Interconnection, L.L.C., Tennessee Valley Authority, and Louisville Gas and Electric Company and Kentucky Utilities.

(i) Coordinated regional transmission expansion planning shall also incorporate input from parties that may be impacted by the coordination efforts, including but not limited to, the Members, Transmission Customers, electric utility regulatory agencies in the PJM Region, and the State Consumer Advocates, in accordance with the terms and conditions of the applicable regional coordination agreements.

(ii) An entity, including existing Transmission Owners and Nonincumbent Developers, may submit potential Interregional Transmission Projects pursuant to the Operating Agreement, Schedule 6, section 1.5.8.

(c) The Regional Transmission Expansion Plan shall be developed by the Office of the Interconnection in consultation with the Transmission Expansion Advisory Committee during the enhancement and expansion study process.

(d) The Regional Transmission Expansion Plan shall be developed taking into account the processes for coordination of the regional and subregional systems.

1.5.6 Development of the Recommended Regional Transmission Expansion Plan.

(a) The Office of the Interconnection shall be responsible for the development of the Regional Transmission Expansion Plan and for conducting the studies, including sensitivity studies and scenario analyses on which the plan is based. The Regional Transmission Expansion Plan, including the Regional RTEP Projects, the Subregional RTEP Projects and the Supplemental Projects shall be developed through an open and collaborative process with opportunity for meaningful participation through the Transmission Expansion Advisory Committee and the Subregional RTEP Committees.

(b) The Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall each facilitate a minimum of one initial assumptions meeting to be scheduled at the commencement of the Regional Transmission Expansion Plan process. The purpose of the assumptions meeting shall be to provide an open forum to discuss the following: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) Public Policy Requirements identified by the states for consideration in the Office of the Interconnection's transmission planning analyses; (iii) Public Policy Objectives identified by stakeholders for consideration in the Office of the Interconnection's transmission planning analyses; (iv) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, price responsive demand, generating additions and retirements, market efficiency and other trends in the industry; and (v) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by the Committee participants. Prior to the initial assumptions meeting, the Transmission Expansion Advisory Committee and Subregional RTEP Committees participants will be afforded the opportunity to provide input and submit suggestions regarding the information identified in items (i) through (v) of this subsection. Following the assumptions meeting and prior to performing the evaluation and analyses of transmission needs, the Office of the Interconnection shall determine the range of assumptions to be used in the studies and

scenario analyses, based on the advice and recommendations of the Transmission Expansion Advisory Committee and Subregional RTEP Committees and, through the Independent State Agencies, the statement of Public Policy Requirements provided individually by the states and any state member's assessment or prioritization of Public Policy Objectives proposed by other stakeholders. The Office of the Interconnection shall document and publicly post its determination for review. Such posting shall include an explanation of those Public Policy Requirements and Public Policy Objectives adopted at the assumptions stage to be used in performing the evaluation and analysis of transmission needs. Following identification of transmission needs and prior to evaluating potential enhancements and expansions to the Transmission System the Office of the Interconnection shall publicly post all transmission need information identified as described further in the Operating Agreement, Schedule 6, section 1.5.8(b) herein to support the role of the Subregional RTEP Committees in the development of the Local Plan and support the role of Transmission Expansion Advisory Committee in the development of the Regional Transmission Expansion Plan. The Office of the Interconnection shall also post an explanation of why other Public Policy Requirements and Public Policy Objectives introduced by stakeholders at the assumptions stage were not adopted.

(c) The Subregional RTEP Committees shall also schedule and facilitate meetings related to Supplemental Projects, as described in the Tariff, Attachment M-3.

(d) After the assumptions meeting(s), the Transmission Expansion Advisory Committee and the Subregional RTEP Committees shall facilitate additional meetings and shall post all communications required to provide early opportunity for the committee participants (as defined in the Operating Agreement, Schedule 6, sections 1.3(b) and 1.3(c)) to review, evaluate and offer comments and alternatives to the following arising from the studies performed by the Office of the Interconnection, including sensitivity studies and scenario analyses: (i) any identified violations of reliability criteria and analyses of the market efficiency and operational performance of the Transmission System; (ii) potential transmission solutions, including any acceleration, deceleration or modifications of a potential expansion or enhancement based on the results of sensitivities studies and scenario analyses; and (iii) the proposed Regional Transmission Expansion Plan. These meetings will be scheduled as deemed necessary by the Office of the Interconnection or upon the request of the Transmission Expansion Advisory Committee or the Subregional RTEP Committees. The Office of the Interconnection will provide updates on the status of the development of the Regional Transmission Expansion Plan at these meetings or at the regularly scheduled meetings of the Planning Committee.

(e) In addition, the Office of the Interconnection shall facilitate periodic meetings with the Independent State Agencies Committee to discuss: (i) the assumptions to be used in performing the evaluation and analysis of the potential enhancements and expansions to the Transmission Facilities; (ii) regulatory initiatives, as appropriate, including state regulatory agency initiated programs, and other Public Policy Objectives, to consider including in the Office of the Interconnection's transmission planning analyses; (iii) the impacts of regulatory actions, projected changes in load growth, demand response resources, energy efficiency programs, generating capacity, market efficiency and other trends in the industry; and (iv) alternative sensitivity studies, modeling assumptions and scenario analyses proposed by Independent State Agencies Committee. At such meetings, the Office of the Interconnection also shall discuss the

current status of the enhancement and expansion study process. The Independent State Agencies Committee may request that the Office of Interconnection schedule additional meetings as necessary. The Office of the Interconnection shall inform the Transmission Expansion Advisory Committee and the Subregional RTEP Committees, as appropriate, of the input of the Independent State Agencies Committee and shall consider such input in developing the range of assumptions to be used in the studies and scenario analyses described in section (b), above.

(f) Upon completion of its studies and analysis, including sensitivity studies and scenario analyses the Office of the Interconnection shall post on the PJM website the violations, system conditions, economic constraints, and Public Policy Requirements as detailed in the Operating Agreement, Schedule 6, section 1.5.8(b) to afford entities an opportunity to submit proposed enhancements or expansions to address the posted violations, system conditions, economic constraints and Public Policy Requirements as provided for in the Operating Agreement, Schedule 6, section 1.5.8(c). Following the close of a proposal window, the Office of the Interconnection shall: (i) post all proposals submitted pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c); (ii) consider proposals submitted during the proposal windows consistent with the Operating Agreement, Schedule 6, section 1.5.8(d) and develop a recommended plan. Following review by the Transmission Expansion Advisory Committee of proposals, the Office of the Interconnection, based on identified needs and the timing of such needs, and taking into account the sensitivity studies, modeling assumption variations and scenario analyses considered pursuant to the Operating Agreement, Schedule 6, section 1.5.3, shall determine, which more efficient or cost-effective enhancements and expansions shall be included in the recommended plan, including solutions identified as a result of the sensitivity studies, modeling assumption variations, and scenario analyses, that may accelerate, decelerate or modify a potential reliability, market efficiency or operational performance expansion or enhancement identified as a result of the sensitivity studies, modeling assumption variations and scenario analyses, shall be included in the recommended plan. The Office of the Interconnection shall post the proposed recommended plan for review and comment by the Transmission Expansion Advisory Committee. The Transmission Expansion Advisory Committee shall facilitate open meetings and communications as necessary to provide opportunity for the Transmission Expansion Advisory Committee participants to collaborate on the preparation of the recommended enhancement and expansion plan. The Office of the Interconnection also shall invite interested parties to submit comments on the plan to the Transmission Expansion Advisory Committee and to the Office of the Interconnection before submitting the recommended plan to the PJM Board for approval.

(g) The recommended plan shall separately identify enhancements and expansions for the three PJM subregions, the PJM Mid-Atlantic Region, the PJM West Region, and the PJM South Region, and shall incorporate recommendations from the Subregional RTEP Committees.

(h) The recommended plan shall separately identify enhancements and expansions that are classified as Supplemental Projects.

(i) The recommended plan shall identify enhancements and expansions that relieve transmission constraints and which, in the judgment of the Office of the Interconnection, are economically justified. Such economic expansions and enhancements shall be developed in

accordance with the procedures, criteria and analyses described in the Operating Agreement, Schedule 6, sections 1.5.7 and 1.5.8.

(j) The recommended plan shall identify enhancements and expansions proposed by a state or states pursuant to the Operating Agreement, Schedule 6, section 1.5.9.

(k) The recommended plan shall include proposed Merchant Transmission Facilities within the PJM Region and any other enhancement or expansion of the Transmission System requested by any participant which the Office of the Interconnection finds to be compatible with the Transmission System, though not required pursuant to the Operating Agreement, Schedule 6, 1.5.6, or Tariff Parts VII or VIII, provided that (1) the requestor has complied, to the extent applicable, with the procedures and other requirements of the Tariff, Parts IV and VI, or Tariff, Parts VII or VIII, as applicable; (2) the proposed enhancement or expansion is consistent with applicable reliability standards, operating criteria and the purposes and objectives of the regional planning protocol; (3) the requestor shall be responsible for all costs of such enhancement or expansion (including, but not necessarily limited to, costs of siting, designing, financing, constructing, operating and maintaining the pertinent facilities), and (4) except as otherwise provided by the Tariff, Parts IV and VI, , or Tariff, Parts VII or VIII, as applicable with respect to Merchant Network Upgrades, the requestor shall accept responsibility for ownership, construction, operation and maintenance of the enhancement or expansion through an undertaking satisfactory to the Office of the Interconnection.

(l) For each enhancement or expansion that is included in the recommended plan, the plan shall consider, based on the planning analysis: other input from participants, including any indications of a willingness to bear cost responsibility for such enhancement or expansion; and, when applicable, relevant projects being undertaken to ensure the simultaneous feasibility of Stage 1A ARRs, to facilitate Incremental ARRs pursuant to the provisions of the Operating Agreement, Schedule 1, section 7.8, or to facilitate upgrades pursuant to the Tariff, Parts II, III, or VI, or Tariff, Parts VII or VIII, as applicable and designate one or more Transmission Owners or other entities to construct, own and, unless otherwise provided, finance the recommended transmission enhancement or expansion. Any designation under this paragraph of one or more entities to construct, own and/or finance a recommended transmission enhancement or expansion shall also include a designation of partial responsibility among them. Nothing herein shall prevent any Transmission Owner or other entity designated to construct, own and/or finance a recommended transmission enhancement or expansion from agreeing to undertake its responsibilities under such designation jointly with other Transmission Owners or other entities.

(m) Based on the planning analysis and other input from participants, including any indications of a willingness to bear cost responsibility for an enhancement or expansion, the recommended plan shall, for any enhancement or expansion that is included in the plan, designate (1) the Market Participant(s) in one or more Zones, or any other party that has agreed to fully fund upgrades pursuant to this Agreement or the PJM Tariff, that will bear cost responsibility for such enhancement or expansion, as and to the extent provided by any provision of the PJM Tariff or this Agreement, (2) in the event and to the extent that no provision of the PJM Tariff or this Agreement assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered through

charges established pursuant to the Tariff, Schedule 12, and (3) in the event and to the extent that the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility, the Market Participant(s) in one or more Zones from which the cost of such enhancement or expansion shall be recovered. Any designation under clause (2) of the preceding sentence (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants and, (B) subject to FERC review and approval, shall be incorporated in any amendment to the Tariff, Schedule 12 that establishes a Transmission Enhancement Charge Rate in connection with an economic expansion or enhancement developed under the Operating Agreement, Schedule 6, sections 1.5.6(i) and 1.5.7, (C) the costs associated with expansions and enhancements required to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights allocated pursuant to the Operating Agreement, Schedule 1, section 7 shall (1) be allocated across transmission zones based on each zone's stage 1A eligible Auction Revenue Rights flow contribution to the total stage 1A eligible Auction Revenue Rights flow on the facility that limits stage 1A ARR feasibility and (2) within each transmission zone the Network Service Users and Transmission Customers that are eligible to receive stage 1A Auction Revenue Rights shall be the Responsible Customers under the Tariff, Schedule 12, section (b) for all expansions and enhancements included in the Regional Transmission Expansion Plan to ensure the simultaneous feasibility of stage 1A Auction Revenue Rights, and (D) the costs associated with expansions and enhancements required to reduce to zero the Locational Price Adder for LDAs as described in the Tariff, Attachment DD, section 15 shall (1) be allocated across Zones based on each Zone's pro rata share of load in such LDA and (2) within each Zone, to all LSEs serving load in such LDA pro rata based on such load.

Any designation under clause (3), above, (A) shall further be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants, and (B), subject to FERC review and approval, shall be incorporated in an amendment to a Schedule of the PJM Tariff which establishes a charge in connection with the pertinent enhancement or expansion. Before designating fewer than all customers using Point-to-Point Transmission Service or Network Integration Transmission Service within a Zone as customers from which the costs of a particular enhancement or expansion may be recovered, Transmission Provider shall consult, in a manner and to the extent that it reasonably determines to be appropriate in each such instance, with affected state utility regulatory authorities and stakeholders. When the plan designates more than one responsible Market Participant, it shall also designate the proportional responsibility among them. Notwithstanding the foregoing, with respect to any facilities that the Regional Transmission Expansion Plan designates to be owned by an entity other than a Transmission Owner, the plan shall designate that entity as responsible for the costs of such facilities.

(n) Certain Regional RTEP Project(s) and Subregional RTEP Project(s) may not be required for compliance with the following PJM criteria: system reliability, market efficiency or operational performance, pursuant to a determination by the Office of the Interconnection.

These Supplemental Projects shall be separately identified in the RTEP and are not subject to approval by the PJM Board.

1.5.7 Development of Economic-based Enhancements or Expansions.

(a) Each year the Transmission Expansion Advisory Committee shall review and comment on the assumptions to be used in performing the market efficiency analysis to identify enhancements or expansions that could relieve transmission constraints that have an economic impact ("economic constraints"). Such assumptions shall include, but not be limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. The discount rate shall be based on the Transmission Owners' most recent after-tax embedded cost of capital weighted by each Transmission Owner's total transmission capitalization. Each year, each Transmission Owner will be requested to provide the Office of the Interconnection with the Transmission Owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by the Commission for comparable facilities. Prior to PJM Board consideration of such assumptions, the assumptions shall be presented to the Transmission Expansion Advisory Committee for review and comment. Following review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection shall submit the assumptions to be used in performing the market efficiency analysis described in this Operating Agreement, Schedule 6, section 1.5.7 to the PJM Board for consideration.

(b) Following PJM Board consideration of the assumptions, the Office of the Interconnection shall perform a market efficiency analysis to compare the costs and benefits of: (i) accelerating reliability-based enhancements or expansions already included in the Regional Transmission Plan that if accelerated also could relieve one or more economic constraints; (ii) modifying reliability–based enhancements or expansions already included in the Regional Transmission Plan that as modified would relieve one or more economic constraints; and (iii) adding new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified. Economic constraints include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR requests as described in the Operating Agreement, Schedule 1, section 7.4.2(c); or (3) significant simulated congestion as forecasted in the market efficiency analysis. The timeline for the market efficiency analysis and comparison of the costs and benefits for items in the Operating Agreement, Schedule 6, section 1.5.7(b)(i-iii) is described in the PJM Manuals.

(c) The process for conducting the market efficiency analysis described in subsection (b) above shall include the following:

(i) The Office of the Interconnection shall identify and provide to the Transmission Expansion Advisory Committee a list of economic constraints to be evaluated in the market efficiency analysis.

(ii) The Office of the Interconnection shall identify any planned reliability-based enhancements or expansions already included in the Regional Transmission Expansion Plan,

which if accelerated would relieve such constraints, and present any such proposed reliability-based enhancements and expansions to be accelerated to the Transmission Expansion Advisory Committee for review and comment. The PJM Board, upon consideration of the advice of the Transmission Expansion Advisory Committee, thereafter shall consider and vote to approve any accelerations.

(iii) The Office of the Interconnection shall evaluate whether including any additional Economic-based Enhancements or Expansions in the Regional Transmission Expansion Plan or modifications of existing Regional Transmission Expansion Plan reliability-based enhancements or expansions would relieve an economic constraint. In addition, pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c), any market participant may submit to the Office of the Interconnection a proposal to construct an additional Economic-based Enhancement or Expansion to relieve an economic constraint. Upon completion of its evaluation, including consideration of any eligible market participant proposed Economic-based Enhancements or Expansions, the Office of the Interconnection shall present to the Transmission Expansion Advisory Committee a description of new Economic-based Enhancements or Expansions for review and comment. Upon consideration and advice of the Transmission Expansion Advisory Committee, the PJM Board shall consider any new Economic-based Enhancements or Expansions for inclusion in the Regional Transmission Plan and for those enhancements and expansions it approves, the PJM Board shall designate (a) the entity or entities that will be responsible for constructing and owning or financing the additional Economic-based Enhancements or Expansions, (b) the estimated costs of such enhancements and expansions, and (c) the market participants that will bear responsibility for the costs of the additional Economic-based Enhancements or Expansions pursuant to the Operating Agreement, Schedule 6, section 1.5.6(m). In the event the entity or entities designated as responsible for construction, owning or financing a designated new Economic-based Enhancement or Expansion declines to construct, own or finance the new Economic-based Enhancement or Expansion, the enhancement or expansion will not be included in the Regional Transmission Expansion Plan but will be included in the report filed with the FERC in accordance with the Operating Agreement, Schedule 6, sections 1.6 and 1.7. This report also shall include information regarding PJM Board approved accelerations of reliability-based enhancements or expansions that an entity declines to accelerate.

(d) To determine the economic benefits of accelerating or modifying planned reliability-based enhancements or expansions or of constructing additional Economic-based Enhancements or Expansions and whether such Economic-based Enhancements or Expansion are eligible for inclusion in the Regional Transmission Expansion Plan, the Office of the Interconnection shall perform and compare market simulations with and without the proposed accelerated or modified planned reliability-based enhancements or expansions or the additional Economic-based Enhancements or Expansions as applicable, using the Benefit/Cost Ratio calculation set forth below in this Operating Agreement, Schedule 6, section 1.5.7(d). An Economic-based Enhancement or Expansion shall be included in the Regional Transmission Expansion Plan recommended to the PJM Board, if the relative benefits and costs of the Economic-based Enhancement or Expansion meet a Benefit/Cost Ratio Threshold of at least 1.25:1.

The Benefit/Cost Ratio shall be determined as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for the 15 year *period starting with the RTEP Year (defined as current year plus five) minus benefits for years when the project is not yet in-service*] ÷ [Present value of the Total Enhancement Cost for the *same* 15 year *period*]

Where

Total Annual Enhancement Benefit = Energy Market Benefit + Reliability Pricing Model Benefit

and

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(i) the Energy Market Benefit is as follows:

Energy Market Benefit = [.50] * [Change in Total Energy Production Cost] + [.50] * [Change in Load Energy Payment]

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(v) the Energy Market Benefit is as follows:

Energy Market Benefit = [1] * [Change in Load Energy Payment]
and

Change in Total Energy Production Cost = [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without the Economic-based Enhancement or Expansion] – [the estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region with the Economic-based Enhancement or Expansion]. The change in costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured, if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP.

and

Change in Load Energy Payment = [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly

estimated zonal Locational Marginal Price for each Zone without the Economic-based Enhancement or Expansion)] – [the annual sum of (the hourly estimated zonal load megawatts for each Zone) * (the hourly estimated zonal Locational Marginal Price for each Zone with the Economic-based Enhancement or Expansion)] – [the change in value of transmission rights for each Zone with the Economic-based Enhancement or Expansion (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion)]. The Change in the Load Energy Payment shall be the sum of the Change in the Load Energy Payment only of the Zones that show a decrease in the Load Energy Payment.

And

For economic-based enhancements and expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(i) the Reliability Pricing Benefit is as follows:

Reliability Pricing Benefit = [.50] * [Change in Total System Capacity Cost] + [.50] * [Change in Load Capacity Payment]

and

For economic-based enhancements or expansions for which cost responsibility is assigned pursuant to the Tariff, Schedule 12, section (b)(v) the Reliability Pricing Benefit is as follows:

Reliability Pricing Benefit = [1] * [Change in Load Capacity Payment]

Change in Total System Capacity Cost = [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under the Tariff, Attachment DD) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the megawatts that are estimated to be cleared in the Base Residual Auction under the Tariff, Attachment DD) * (the prices that are estimated to be contained in the Sell Offers for each such cleared megawatt with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]

and

Change in Load Capacity Payment = [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD without the Economic-based Enhancement or Expansion) * (the number of days in the study year)] – [the sum of (the estimated zonal load megawatts in each Zone) * (the estimated Final Zonal Capacity Prices under the Tariff, Attachment DD with the Economic-based Enhancement or Expansion) * (the number of days in the study year)]. The Change in Load Capacity Payment shall take account of the change in value of Capacity Transfer Rights in each Zone, including any additional Capacity Transfer Rights made available by the proposed acceleration or modification of the planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion. The Change in the Load Capacity Payment shall be the sum of the change in the Load Capacity Payment only of the Zones that show a decrease in the Load Capacity Payment.

and

Total Enhancement Cost (except for accelerations of planned reliability-based enhancements or expansions) = the estimated annual revenue requirement for the Economic-based Enhancement or Expansion.

Total Enhancement Cost (for accelerations of planned reliability-based enhancements or expansions) = the estimated change in annual revenue requirement resulting from the acceleration of the planned reliability-based enhancement or expansion, taking account of all of the costs incurred that would not have been incurred but for the acceleration of the planned reliability-based enhancement or expansion.

(e) For informational purposes only, to assist the Office of the Interconnection and the Transmission Expansion Advisory Committee in evaluating the economic benefits of accelerating planned reliability-based enhancements or expansions or of constructing a new Economic-based Enhancement or Expansion, the Office of the Interconnection shall calculate and post on the PJM website the change in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs);(ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new Economic-based Enhancement or Expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Office of the Interconnection's Commission-approved capacity construct.

(f) To assure that new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan continue to be cost beneficial, the Office of the Interconnection annually shall review the costs and benefits of constructing such enhancements and expansions. In the event that there are changes in these costs and benefits, the Office of the Interconnection shall review the changes in costs and benefits with the Transmission Expansion Advisory Committee and recommend to the PJM Board whether the new Economic-based Enhancements or Expansions continue to provide measurable benefits, as determined in accordance with subsection (d), and should remain in the Regional Transmission Expansion Plan. The annual review of the costs and benefits of constructing new Economic-based Enhancements or Expansions included in the Regional Transmission Expansion Plan shall include review of changes in cost estimates of the Economic-based Enhancement or Expansion, and changes in system conditions, including but not limited to, changes in load forecasts, and anticipated Merchant Transmission Facilities, generation, and demand response, consistent with the requirements of the Operating Agreement, Schedule 6, section 1.5.7(i). The Office of the Interconnection will not be required to review annually the costs and benefits of constructing Economic-based Enhancements or Expansions with capital costs less than $20 million if, based on updated cost estimates and the original benefits, the Benefit/Cost Ratio remains at or above 1.25. The Office of the Interconnection shall no longer be required to review costs and benefits of constructing Economic-based Enhancements and Expansions once: (i) a certificate of public convenience and necessity or its equivalent is granted by the state or relevant regulatory authority in which such enhancements or expansions will be located; or (ii) if a certificate of public convenience and necessity or its equivalent is not required by the state or relevant regulatory authority in which an economic-based enhancement or expansion will be located, once construction activities commence at the project site.

(g) For new economic enhancements or expansions with costs in excess of $50 million, an independent review of such costs shall be performed to assure both consistency of estimating practices and that the scope of the new Economic-based Enhancements or Expansions is consistent with the new Economic-based Enhancements or Expansions as recommended in the market efficiency analysis.

(h) At any time, market participants may submit to the Office of the Interconnection requests to interconnect Merchant Transmission Facilities or generation facilities pursuant to the Tariff, Parts IV and VI that could address an economic constraint. In the event the Office of the Interconnection determines that the interconnection of such facilities would relieve an economic constraint, the Office of the Interconnection may designate the project as a “market solution” and, in the event of such designation, the Tariff, Part VI, Subpart B, section 216, as applicable, shall apply to the project.

(i) The assumptions used in the market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) shall include, but not be limited to, the following:

(i) Timely installation of Qualifying Transmission Upgrades, that are committed to the PJM Region as a result of any Reliability Pricing

Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(ii) Availability of Generation Capacity Resources, as defined by the RAA, section 1.33, that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(iii) Availability of Demand Resources that are committed to the PJM Region as a result of any Reliability Pricing Model Auction pursuant to the Tariff, Attachment DD or any FRR Capacity Plan pursuant to the RAA, Schedule 8.1.

(iv) Addition of Customer Facilities or Generating Facilities, as applicable, pursuant to an executed Interconnection Service Agreement or executed Interim Interconnection Service Agreement for which Interconnection Service Agreement is expected to be executed, or Generating Facilities pursuant to an executed Generation Interconnection Agreement or executed Engineering and Procurement Agreement for which Generation Interconnection Agreement is expected to be executed. Facilities with an executed Facilities Study Agreement or suspended Interconnection Service Agreement, or that have an approved Decision Point II submission, under Tariff Part VII or VIII, as applicable, may be included by the Office of the Interconnection after review with the Transmission Expansion Advisory Committee.

(v) Addition of Customer-Funded Upgrades pursuant to an executed Interconnection Construction Service Agreement or an Upgrade Construction Service Agreement.

(vi) Expected level of demand response over at least the ensuing fifteen years based on analyses that consider historic levels of demand response, expected demand response growth trends, impact of capacity prices, current and emerging technologies.

(vii) Expected levels of potential new generation and generation retirements over at least the ensuing fifteen years based on analyses that consider generation trends based on existing generation on the system, generation in the PJM interconnection queues or Cycles as applicable and Capacity Resource Clearing Prices under the Tariff, Attachment DD. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses then it will model Customer Facilities or Generating Facilities pursuant to an

executed Facilities Study Agreement approved Decision Point II submission under Tariff Part VII or VIII, or suspended Interconnection Service Agreement, ranked by their commercial probability. Commercial probability utilizes historical data from the PJM interconnection queues or Cycles as applicable to determine the likelihood of a Customer Facility or Generating Facility, pursuant to an executed Facilities Study Agreement approved Decision Point II submission under Tariff Part VII or VIII, or suspended Interconnection Service Agreement, reaching commercial operation. If the Office of the Interconnection finds that the PJM reserve requirement is not met in any of its future year market efficiency analyses, following inclusion of the Customer Facilities or Generating Facilities discussed above in this section 1.5.7(i)(vii), then it will model adequate future generation based on type and location of generation in existing PJM interconnection queues or Cycles as applicable and, if necessary, add transmission enhancements to address congestion that arises from such modeling.

(viii) Items (i) through (v) will be included in the market efficiency assumptions if qualified for consideration by the PJM Board. In the event that any of the items listed in (i) through (v) above qualify for inclusion in the market efficiency analysis assumptions, however, because of the timing of the qualification the item was not included in the assumptions used in developing the most recent Regional Transmission Expansion Plan, the Office of the Interconnection, to the extent necessary, shall notify any entity constructing an Economic-based Enhancement or Expansion that may be affected by inclusion of such item in the assumptions for the next market efficiency analysis described in subsection (b) and any review of costs and benefits pursuant to subsection (f) that the need for the Economic-based Enhancement or Expansion may be diminished or obviated as a result of the inclusion of the qualified item in the assumptions for the next annual market efficiency analysis or review of costs and benefits.

(j) For informational purposes only, with regard to Economic-based Enhancements or Expansions that are included in the Regional Transmission Expansion Plan pursuant to subsection (d) of this section 1.5.7, the Office of the Interconnection shall perform sensitivity analyses consistent with the Operating Agreement, Schedule 6, section 1.5.3 and shall provide the results of such sensitivity analyses to the Transmission Expansion Advisory Committee.

1.5.8 Development of Long-lead Projects, Short-term Projects, Immediate-need Reliability Projects, and Economic-based Enhancements or Expansions.

(a) **Pre-Qualification Process**.

(a)(1) On September 1 of each year, the Office of the Interconnection shall open a thirty-day pre-qualification window for entities, including existing Transmission Owners and Nonincumbent Developers, to submit to the Office of the Interconnection: (i) applications to pre-qualify as eligible to be a Designated Entity; or (ii) updated information as described in the Operating Agreement, Schedule 6, section 1.5.8(a)(3). 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 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 affiliate's, 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).

(a)(2) No later than October 31, the Office of the Interconnection shall notify the entities that submitted pre-qualification applications or updated information during the annual thirty-day pre-qualification window, whether they are, or will continue to be, pre-qualified as eligible to be a Designated Entity. In the event the Office of the Interconnection determines that an entity (i) is not, or no longer will continue to be, pre-qualified as eligible to be a Designated Entity, or (ii) provided insufficient information to determine pre-qualification, the Office of the Interconnection shall inform that the entity it is not pre-qualified and include in the notification the basis for its determination. The entity then may submit additional information, which the Office of the Interconnection shall consider in re-evaluating whether the entity is, or will continue to be, pre-qualified as eligible to be a Designated Entity. If the entity submits additional information by November 30, the Office of the Interconnection shall notify the entity of the results of its re-evaluation no later than December 15. If the entity submits additional information after November 30, the Office of the Interconnection shall use reasonable efforts to re-evaluate the application, with the additional information, and notify the entity of its determination as soon as practicable. No later than December 31, the Office of the Interconnection shall post on the PJM website the list of entities that are pre-qualified as eligible to be Designated Entities. If an entity is notified by the Office of the Interconnection that it does not pre-qualify or will not continue to be pre-qualified as eligible to be a Designated Entity, such entity may request dispute resolution pursuant to the Operating Agreement, Schedule 5.

(a)(3) In order to continue to pre-qualify as eligible to be a Designated Entity, such entity must confirm its information with the Office of the Interconnection no later than three years following its last submission or sooner if necessary as required below. In the event the information on which the entity's pre-qualification is based changes with respect to the upcoming year, such entity must submit to the Office of the Interconnection all updated information during the annual thirty-day pre-qualification window and the timeframes for notification in the Operating Agreement, Schedule 6, section 1.5.8(a)(2) shall apply. In the event the information on which the entity's pre-qualification is based changes with respect to the current year, such entity must submit to the Office of the Interconnection all updated information at the time the information changes and the Office of the Interconnection shall use reasonable efforts to evaluate the updated information and notify the entity of its determination as soon as practicable.

(a)(4) As determined by the Office of the Interconnection, an entity may submit a pre-qualification application outside the annual thirty-day pre-qualification window for good cause shown. For a pre-qualification application received outside of the annual thirty-day pre-qualification window, the Office of the Interconnection shall use reasonable efforts to process the application and notify the entity as to whether it pre-qualifies as eligible to be a Designated Entity as soon as practicable.

(a)(5) To be designated as a Designated Entity for any project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8, existing Transmission Owners and Nonincumbent Developers must be pre-qualified as eligible to be a Designated Entity pursuant to this Operating Agreement, Schedule 6, section 1.5.8(a). This Operating Agreement, Schedule 6, section 1.5.8(a) shall not apply to entities that desire to propose projects for inclusion in the recommended plan but do not intend to be a Designated Entity.

(b) **Posting of Transmission System Needs**. Following identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance in the enhancement and expansion analysis process described in this Operating Agreement, Schedule 6 and the PJM Manuals, and after consideration of non-transmission solutions, and prior to evaluating potential enhancements and expansions to the Transmission System, the Office of the Interconnection shall publicly post on the PJM website all transmission need information, including violations, system conditions, and economic constraints, and Public Policy Requirements, including (i) federal Public Policy Requirements; (ii) state Public Policy Requirements identified or agreed-to by the states in the PJM Region, which could be addressed by potential Short-term Projects, Long-lead Projects or projects determined pursuant to the State Agreement Approach in the Operating Agreement, Schedule 6, section 1.5.9, as applicable. Such posting shall support the role of the Subregional RTEP Committees in the development of the Local Plans and support the role of the Transmission Expansion Advisory Committee in the development of the Regional Transmission Expansion Plan. The Office of the Interconnection also shall post an explanation regarding why transmission needs associated with federal or state Public Policy Requirements were identified but were not selected for further evaluation.

(c) **Project Proposal Windows**. The Office of the Interconnection shall provide notice to stakeholders of a 60-day proposal window for Short-term Projects and a 120-day proposal window for Long-lead Projects and Economic-based Enhancements or Expansions. The specifics regarding whether or not the following types of violations or projects are subject to a proposal window are detailed in the Operating Agreement, Schedule 6, section 1.5.8(m) for Immediate-need Reliability Projects; Operating Agreement, Schedule 6, section 1.5.8(n) for reliability violations on transmission facilities below 200 kV; and Operating Agreement, Schedule 6, section 1.5.8(p) for violations on transmission substation equipment. The Office of Interconnection may shorten a proposal window should an identified need require a shorter proposal window to meet the needed in-service date of the proposed enhancements or expansions, or extend a proposal window as needed to accommodate updated information regarding system conditions. The Office of the Interconnection may shorten or lengthen a proposal window that is not yet opened based on one or more of the following criteria: (1) complexity of the violation or system condition; and (2) whether there is sufficient time remaining in the relevant planning cycle to accommodate a standard proposal window and timely address the violation or system condition. The Office of the Interconnection may lengthen a proposal window that already is opened based on or more of the following criteria: (i) changes in assumptions or conditions relating to the underlying need for the project, such as load growth or Reliability Pricing Model auction results; (ii) availability of new or changed information regarding the nature of the violations and the facilities involved; and (iii) time remaining in the relevant proposal window. In the event that the Office of the Interconnection determines to lengthen or shorten a proposal window, it will post on the PJM website the new proposal window period and an explanation as to the reasons for the change in the proposal window period. During these windows, the Office of the Interconnection will accept proposals from existing Transmission Owners and Nonincumbent Developers for potential enhancements or expansions to address the posted violations, system conditions, economic constraints, as well as Public Policy Requirements.

(c)(1) All proposals submitted in the proposal windows must contain: (i) the name and address of the proposing entity; (ii) a statement whether the entity intends to be the Designated Entity for the proposed project; (iii) the location of proposed project, including source and sink, if applicable; (iv) relevant engineering studies, and other relevant information as described in the PJM Manuals pertaining to the proposed project; (v) a proposed initial construction schedule including projected dates on which needed permits are required to be obtained in order to meet the required in-service date; (vi) cost estimates and analyses that provide sufficient detail for the Office of Interconnection to review and analyze the proposed cost of the project; and (vii) with the exception of project proposals submitted with cost estimates of $5 million or less, a $5,000 non-refundable deposit must be included with each project proposal submitted by a proposing entity that indicates an intention to be the Designated Entity.

(c)(1)(i) In addition, any proposing entity indicating its intention to be the Designated Entity will be responsible for and must pay all actual costs incurred by the Transmission Provider to evaluate the submitted project proposal. To the extent the Transmission Provider incurs costs to evaluate multiple submitted project proposals where such costs are not severable by individual project proposal, the Transmission Provider shall invoice equal shares of the non-severable costs among the project proposals that cause such non-

severable costs to be incurred. Notwithstanding this method of invoicing non-severable costs, non-severable costs will be jointly and severally owed by the proposing entities that cause such costs to be incurred.

(c)(1)(ii) All non-refundable deposits will be credited towards the actual costs incurred by the Transmission Provider as a result of the evaluation of a submitted project proposal.

(c)(1)(iii) Following the close of a proposal window but before the Transmission Provider incurs any third-party consultant work costs to evaluate a submitted project proposal, the Transmission Provider will issue to the proposing entity an initial invoice seeking payment of estimated costs to evaluate each submitted project proposal. The estimated costs will be determined by considering the: potential cost of consultant work, historical estimates for project proposals of similar scope, complexity and nature of the need, and/or technology and nature of the project proposal. The Transmission Provider may issue additional invoices to the proposing entity prior to the completion of the evaluation activities associated with a project proposal if the Transmission Provider receives updated actual cost information and/or upon consideration of the factors specified in this section.

(c)(1)(iv) At the completion of the evaluation activities associated with a project proposal, the Transmission Provider will reconcile the actual costs with monies paid and, to the extent necessary, issue either a final invoice or refund.

(c)(1)(v) The proposing party must pay any invoiced costs within fifteen (15) calendar days of the Transmission Provider sending the invoice to the proposing entity or its agent. For good cause shown, this fifteen (15) calendar day time period may be extended by the Transmission Provider. If the proposing entity fails to pay any invoice within the time period specified and/or extended by the Transmission Provider in accordance with this section, the proposing entity's pre-qualification status may be suspended and the proposing entity will be ineligible to be a Designated Entity for any projects that do not yet have an executed Designated Entity Agreement. Such a suspension and/or ineligibility will remain in place until the proposing entity pays in full all outstanding monies owed to the Transmission Provider as a result of the evaluation of the proposing entity's project proposal(s).

(c)(2) Proposals from all entities (both existing Transmission Owners and Nonincumbent Developers) that indicate the entity intends to be a Designated Entity, also must contain information to the extent not previously provided pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) demonstrating: (i) technical and engineering qualifications of the entity, its affiliate, partner, or parent company relevant to construction, operation, and maintenance of the proposed project; (ii) experience of the entity, its affiliate, partner, or parent company in developing, constructing, maintaining, and operating the type of transmission facilities contained in the project proposal; (iii) the emergency response capability of the entity that will be operating and maintaining the proposed project; (iv) evidence of transmission facilities the entity, its affiliate, partner, or parent company previously constructed, maintained, or operated; (v) the ability of the entity or its affiliate, partner, or parent company to obtain adequate financing relative to the proposed project, which may include a letter of intent from a

financial institution approved by the Office of the Interconnection or such other evidence of the financial resources available to finance the construction, operation, and maintenance of the proposed project; (vi) the managerial ability of the entity, its affiliate, partner, or parent company to contain costs and adhere to construction schedules for the proposed project, including a description of verifiable past achievement of these goals; (vii) a demonstration of other advantages the entity may have to construct, operate, and maintain the proposed project, including any binding cost commitment proposal the entity may wish to submit; and (viii) any other information that may assist the Office of the Interconnection in evaluating the proposed project. To the extent that an entity submits a cost containment proposal the entity shall submit sufficient information for the Office of Interconnection to determine the binding nature of the proposal with respect to critical elements of project development. PJM may not alter the requirements for proposal submission to require the submission of a binding cost containment proposal, in whole or in part, or otherwsise mandate or unilaterally alter the terms of any such proposal or the requirements for proposal submission, the submission of any such proposals at all times remaining voluntary.

(c)(3) The Office of the Interconnection may request additional reports or information from an existing Transmission Owner or Nonincumbent Developers that it determines are reasonably necessary to evaluate its specific project proposal pursuant to the criteria set forth in the Operating Agreement, Schedule 6, sections 1.5.8(e) and 1.5.8(f). If the Office of the Interconnection determines any of the information provided in a proposal is deficient or it requires additional reports or information to analyze the submitted proposal, the Office of the Interconnection shall notify the proposing entity of such deficiency or request. Within 10 Business Days of receipt of the notification of deficiency and/or request for additional reports or information, or other reasonable time period as determined by the Office of the Interconnection, the proposing entity shall provide the necessary information.

(c)(4) The request for additional reports or information by the Office of the Interconnection pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c)(3) may be used only to clarify a proposed project as submitted. In response to the Office of the Information's request for additional reports or information, the proposing entity (whether an existing Transmission Owner or Nonincumbent Developer) may not submit a new project proposal or modifications to a proposed project once the proposal window is closed. In the event that the proposing entity fails to timely cure the deficiency or provide the requested reports or information regarding a proposed project, the proposed project will not be considered for inclusion in the recommended plan.

(c)(5) Within 30 days of the closing of the proposal window, the Office of the Interconnection may notify the proposing entity that additional per project fees are required if the Office of the Interconnection determines the proposing entity's submittal includes multiple project proposals. Within 10 Business Days of receipt of the notification of insufficient funds by the Office of the Interconnection, the proposing entity shall submit such funds or notify the Office of the Interconnection which of the project proposals the Office of the Interconnection should evaluate based on the fee(s) submitted.

(d) **Posting and Review of Projects**. Following the close of a proposal window, the Office of the Interconnection shall post on the PJM website all proposals submitted pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). All proposals addressing state Public Policy Requirements shall be provided to the applicable states in the PJM Region for review and consideration as a Supplemental Project or a state public policy project consistent with the Operating Agreement, Schedule 6, section 1.5.9. The Office of the Interconnection shall review all proposals submitted during a proposal window and determine and present to the Transmission Expansion Advisory Committee the proposals that merit further consideration for inclusion in the recommended plan. In making this determination, the Office of the Interconnection shall consider the criteria set forth in the Operating Agreement, Schedule 6, sections 1.5.8(e) and 1.5.8(f). The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee for review and comment descriptions of the proposed enhancements and expansions, including any proposed Supplemental Projects or state public policy projects identified by a state(s). Based on review and comment by the Transmission Expansion Advisory Committee, the Office of the Interconnection may, if necessary conduct further study and evaluation. The Office of the Interconnection shall post on the PJM website and present to the Transmission Expansion Advisory Committee the revised enhancements and expansions for review and comment. After consultation with the Transmission Expansion Advisory Committee, the Office of the Interconnection shall determine the more efficient or cost-effective transmission enhancements and expansions for inclusion in the recommended plan consistent with this Operating Agreement, Schedule 6.

(e) **Criteria for Considering Inclusion of a Project in the Recommended Plan**. In determining whether a Short-term Project or Long-lead Project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c), individually or in combination with other Short-term Projects or Long-lead Projects, is the more efficient or cost-effective solution and therefore should be included in the recommended plan, the Office of the Interconnection, taking into account sensitivity studies and scenario analyses considered pursuant to the Operating Agreement, Schedule 6, section 1.5.3, shall consider the following criteria, to the extent applicable: (i) the extent to which a Short-term Project or Long-lead Project would address and solve the posted violation, system condition, or economic constraint; (ii) the extent to which the relative benefits of the project meets a Benefit/Cost Ratio Threshold of at least 1.25:1 as calculated pursuant to the Operating Agreement, Schedule 6, section 1.5.7(d); (iii) the extent to which the Short-term Project or Long-lead Project would have secondary benefits, such as addressing additional or other system reliability, operational performance, economic efficiency issues or federal Public Policy Requirements or state Public Policy Requirements identified by the states in the PJM Region; and (iv) the ability to timely complete the project, and project development feasibility; and (v) other factors such as cost-effectiveness, including the quality and effectiveness of any voluntary-submitted binding cost commitment proposal related to Transmission Facilities which caps project construction costs (either in whole or in part), project total return on equity (including incentive adders), or capital structure. In scrutinizing the cost of project proposals, the Office of Interconnection shall determine for each project finalist's proposal, including any Transmission Owner Upgrades, the comparative risks to be borne by ratepayers as a result of the proposal's binding cost commitment or the use of non-binding cost estimates. Such comparative analysis shall detail, in a clear and transparent manner, the method by which the Office of Interconnection scrutinized the cost and overall cost-effectiveness of each

finalist's proposal, including any binding cost commitments. Such comparative analysis shall be presented to the TEAC for review and comment. In evaluating any cost, ROE and/or capital structure proposal, PJM is not making a determination that the cost, ROE or capital structure results in just and reasonable rates, which shall be addressed in the required rate filing with the FERC. Stakeholders seeking to dispute a particular ROE analysis utilized in the selection process may address such disputes with the Designated Entity in the applicable rate proceeding where the Designated Entity seeks approval of such rates from the Commission. PJM may modify the technical specifications of a proposal, as outlined in the PJM Manuals, which may result in the modified proposal being determined to be the more efficient or cost-effective proposal for recommendation to the PJM Board. Neither PJM, the Designated Entity nor any stakeholders are waiving any of their respective FPA section 205 or 206 rights through this process. Challenges to the Designated Entity Agreements are subject to the just and reasonable standard.

(f) **Entity-Specific Criteria Considered in Determining the Designated Entity for a Project**. In determining whether the entity proposing a Short-term Project, Long-lead Project or Economic-based Enhancement or Expansion recommended for inclusion in the plan shall be the Designated Entity, the Office of the Interconnection shall consider: (i) whether in its proposal, the entity indicated its intent to be the Designated Entity; (ii) whether the entity is pre-qualified to be a Designated Entity pursuant to Operating Agreement, Schedule 6, section 1.5.8(a); (iii) information provided either in the proposing entity's submission pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) or 1.5.8(c)(2) relative to the specific proposed project that demonstrates: (1) the technical and engineering experience of the entity or its affiliate, partner, or parent company, including its previous record regarding construction, maintenance, and operation of transmission facilities relative to the project proposed; (2) ability of the entity or its affiliate, partner, or parent company to construct, maintain, and operate transmission facilities, as proposed, (3) capability of the entity to adhere to standardized construction, maintenance, and operating practices, including the capability for emergency response and restoration of damaged equipment; (4) experience of the entity in acquiring rights of way; (5) evidence of the ability of the entity, its affiliate, partner, or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the project, if it is accepted into the recommended plan; and (iv) any other factors that may be relevant to the proposed project, including but not limited to whether the proposal includes the entity's previously designated project(s) included in the plan.

(g) **Procedures if No Long-lead Project or Economic-based Enhancement or Expansion Proposal is Determined to be the More Efficient or Cost-Effective Solution**. If the Office of the Interconnection determines that none of the proposed Long-lead Projects received during the Long-lead Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation, or system condition, the Office of the Interconnection may re-evaluate and re-post on the PJM website the unresolved violations, or system conditions pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b), provided such re-evaluation and re-posting would not affect the ability of the Office of the Interconnection to timely address the identified reliability need. In the event that re-posting and conducting such re-evaluation would prevent the Office of the Interconnection from timely addressing the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion, the Office

of the Interconnection shall propose a project to solve the posted violation, or system condition for inclusion in the recommended plan and shall present such project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the project is to be located shall be the Designated Entity(ies) for such project. In determining whether there is insufficient time for re-posting and re-evaluation, the Office of the Interconnection shall develop and post on the PJM website a transmission solution construction timeline for input and review by the Transmission Expansion Advisory Committee that will include factors such as, but not limited to: (i) deadlines for obtaining regulatory approvals, (ii) dates by which long lead equipment should be acquired, (iii) the time necessary to complete a proposed solution to meet the required in-service date, and (iv) other time-based factors impacting the feasibility of achieving the required in-service date. Based on input from the Transmission Expansion Advisory Committee and the time frames set forth in the construction timeline, the Office of the Interconnection shall determine whether there is sufficient time to conduct a re-evaluation and re-post and timely address the existing and projected limitations on the Transmission System that give rise to the need for an enhancement or expansion. To the extent that an economic constraint remains unaddressed, the economic constraint will be re-evaluated and re-posted.

(h) **Procedures if No Short-term Project Proposal is Determined to be the More Efficient or Cost-Effective Solution**. If the Office of the Interconnection determines that none of the proposed Short-term Projects received during a Short-term Project proposal window would be the more efficient or cost-effective solution to resolve a posted violation or system condition, the Office of the Interconnection shall propose a Short-term Project to solve the posted violation, or system condition for inclusion in the recommended plan and will present such Short-term Project to the Transmission Expansion Advisory Committee for review and comment. The Transmission Owner(s) in the Zone(s) where the Short-term Project is to be located shall be the Designated Entity(ies) for the Project.

(i) **Notification of Designated Entity**. Within 15 Business Days of PJM Board approval of the Regional Transmission Expansion Plan, the Office of the Interconnection shall notify the entities that have been designated as the Designated Entities for projects included in the Regional Transmission Expansion Plan of such designations. In such notices, the Office of the Interconnection shall provide: (i) the needed in-service date of the project; and (ii) a date by which all necessary state approvals should be obtained to timely meet the needed in-service date of the project. The Office of the Interconnection shall use these dates as part of its on-going monitoring of the progress of the project to ensure that the project is completed by its needed in-service date.

(j) **Acceptance of Designation**. Within 30 days of receiving notification of its designation as a Designated Entity, the existing Transmission Owner or Nonincumbent Developer 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 project to achieve the required in-service date, including milestone dates for obtaining all necessary authorizations and approvals, including but not limited to, state approvals. For good cause shown, the Office of the Interconnection may extend the deadline for submitting the development schedule. The Office of the Interconnection then shall review the development schedule and within 15 days or other reasonable time as

required by the Office of the Interconnection: (i) notify the Designated Entity of any issues regarding the development schedule identified by the Office of the Interconnection that may need to be addressed to ensure that the project meets its needed in-service date; and (ii) tender to the Designated Entity an executable Designated Entity Agreement setting forth the rights and obligations of the parties. To retain its status as a Designated Entity, within 60 days of receiving an executable Designated Entity Agreement (or other such period as mutually agreed upon by the Office of the Interconnection and the Designated Entity), the Designated Entity (both existing Transmission Owners and Nonincumbent Developers) shall submit to the Office of the Interconnection a letter of credit as determined by the Office of Interconnection to cover the incremental costs of construction resulting from reassignment of the project, and return to the Office of the Interconnection an executed Designated Entity Agreement containing a mutually agreed upon development schedule. In the alternative, the Designated Entity may request dispute resolution pursuant to the Operating Agreement, Schedule 5, or request that the Designated Entity Agreement be filed unexecuted with the Commission.

(k) **Failure of Designated Entity to Meet Milestones**. In the event the Designated Entity fails to comply with one or more of the requirements of the Operating Agreement, Schedule 6, section 1.5.8(j); or fails to meet a milestone in the development schedule set forth in the Designated Entity Agreement that causes a delay of the project's in-service date, the Office of the Interconnection shall re-evaluate the need for the Short-term Project or Long-lead Project, and based on that re-evaluation may: (i) retain the Short-term Project or Long-lead Project in the Regional Transmission Expansion Plan; (ii) remove the Short-term Project or Long-lead Project from the Regional Transmission Expansion Plan; or (iii) include an alternative solution in the Regional Transmission Expansion Plan. If the Office of the Interconnection retains the Short-term or Long-term Project in the Regional Transmission Expansion Plan, it shall determine whether the delay is beyond the Designated Entity's control and whether to retain the Designated Entity or to designate the Transmission Owner(s) in the Zone(s) where the project is located as Designated Entity(ies) for the Short-term Project or Long-lead Project. If the Designated Entity is the Transmission Owner(s) in the Zone(s) where the project is located, the Office of the Interconnection shall seek recourse through the Consolidated Transmission Owners Agreement or FERC, as appropriate. Any modifications to the Regional Transmission Expansion Plan pursuant to this section shall be presented to the Transmission Expansion Advisory Committee for review and comment and approved by the PJM Board.

(l) **Transmission Owners Required to be the Designated Entity**. Notwithstanding anything to the contrary in this Operating Agreement, Schedule 6, section 1.5.8, in all events, the Transmission Owner(s) in whose Zone(s) a project proposed pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) is to be located will be the Designated Entity for the project, when the Short-term Project or Long-lead Project is: (i) a Transmission Owner Upgrade; (ii) located solely within a Transmission Owner's Zone and the costs of the project are allocated solely to the Transmission Owner's Zone; (iii) located solely within a Transmission Owner's Zone and is not selected in the Regional Transmission Expansion Plan for purposes of cost allocation; or (iv) proposed to be located on a Transmission Owner's existing right of way and the project would alter the Transmission Owner's use and control of its existing right of way under state law. Transmission Owner shall be the Designated Entity when required by state law,

regulation or administrative agency order with regard to enhancements or expansions or portions of such enhancements or expansions located within that state.

(m) **Immediate-need Reliability Projects**:

(m)(1) Pursuant to the expansion planning process set forth in Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify immediate reliability needs that must be addressed within three years or less. For those immediate reliability needs for which PJM determines a proposal window may not be feasible, PJM shall identify and post such immediate need reliability criteria violations and system conditions for review and comment by the Transmission Expansion Advisory Committee and other stakeholders. Following review and comment, the Office of the Interconnection shall develop Immediate-need Reliability Projects for which a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2) is infeasible. The Office of the Interconnection shall consider the following factors in determining the infeasibility of such a proposal window: (i) nature of the reliability criteria violation; (ii) nature and type of potential solution required; and (iii) projected construction time for a potential solution to the type of reliability criteria violation to be addressed. The Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the Immediate-need Reliability Projects for which a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2) is infeasible. Stakeholders shall be afforded no less than ten days to review Immediate-need Reliability Project materials prior to providing comments at stakeholder meetings. However, PJM may review Immediate-need Reliability Project materials with stakeholders without the requisite ten-day notice so long as: (i) stakeholders do not object to reviewing the materials or (ii) PJM identifies in its posting to the meeting materials extenuating circumstances identified by PJM that require review of the materials at the stakeholder meeting. The descriptions shall include an explanation of the decision to designate the Transmission Owner as the Designated Entity for the Immediate-need Reliability Project rather than conducting a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(m)(2), including an explanation of the time-sensitive need for the Immediate-need Reliability Project, other transmission and non-transmission options that were considered but concluded would not sufficiently address the immediate reliability need, the circumstances that generated the immediate reliability need, and why the immediate reliability need was not identified earlier. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments to the Office of the Interconnection. All comments received by the Office of the Interconnection shall be publicly available on the PJM website. Based on the comments received from stakeholders and the review by Transmission Expansion Advisory Committee, the Office of the Interconnection shall, if necessary, conduct further study and evaluation and post a revised recommended plan for review and comment by the Transmission Expansion Advisory Committee. The PJM Board shall approve the Immediate-need Reliability Projects for inclusion in the recommended plan. In January of each year, the Office of the Interconnection shall post on the PJM website and file with the Commission for informational purposes a list of the Immediate-need Reliability Projects for which an existing Transmission Owner was designated in the prior year as the Designated Entity in accordance with this Operating Agreement, Schedule 6, section 1.5.8(m)(1). The list

shall include the need-by date of Immediate-need Reliability Project and the date the Transmission Owner actually energized the Immediate-need Reliability Project.

(m)(2) If, in the judgment of the Office of the Interconnection, there is sufficient time for the Office of the Interconnection to accept proposals in a shortened proposal window for Immediate-need Reliability Projects, the Office of the Interconnection shall post on the PJM website the violations and system conditions that could be addressed by Immediate-need Reliability Project proposals, including an explanation of the time-sensitive need for an Immediate-need Reliability Project and provide notice to stakeholders of a shortened proposal window. Proposals must contain the information required in the Operating Agreement, Schedule 6, section 1.5.8(c) and, if the entity is seeking to be the Designated Entity, such entity must have pre-qualified to be a Designated Entity pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a). In determining the more efficient or cost-effective proposed Immediate-need Reliability Project for inclusion in the recommended plan, the Office of the Interconnection shall consider the extent to which the proposed Immediate-need Reliability Project, individually or in combination with other Immediate-need Reliability Projects, would address and solve the posted violations or system conditions and other factors such as cost-effectiveness, the ability of the entity to timely complete the project, and project development feasibility in light of the required need. After PJM Board approval, the Office of the Interconnection, in accordance with the Operating Agreement, Schedule 6, section 1.5.8(i), shall notify the entities that have been designated as Designated Entities for Immediate-need Projects included in the Regional Transmission Expansion Plan of such designations. Designated Entities shall accept such designations in accordance with the Operating Agreement, Schedule 6, section 1.5.8(j). In the event that (i) the Office of the Interconnection determines that no proposal resolves a posted violation or system condition; (ii) the proposing entity is not selected to be the Designated Entity; (iii) an entity does not accept the designation as a Designated Entity; or (iv) the Designated Entity fails to meet milestones that would delay the in-service date of the Immediate-need Reliability Project, the Office of the Interconnection shall develop and recommend an Immediate-need Reliability Project to solve the violation or system needs in accordance with the Operating Agreement, Schedule 6, section 1.5.8(m)(1).

(n) **Reliability Violations on Transmission Facilities Below 200 kV.** Pursuant to the expansion planning process set forth in the Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify reliability violations on facilities below 200 kV. The Office of the Interconnection shall not post such a violation pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b) for inclusion in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) unless the identified violation(s) satisfies one of the following exceptions: (i) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV that are impacted by a common contingent element, such that multiple reliability violations could be addressed by one or more solutions, including but not limited to a higher voltage solution; or (ii) the reliability violations are thermal overload violations identified on multiple transmission lines and/or transformers rated below 200 kV and the Office of the Interconnection determines that given the location and electrical features of the violations one or more solutions could potentially address or reduce the flow on multiple lower voltage facilities, thereby eliminating the multiple reliability violations. If the reliability violation is identified on multiple facilities rated below

200 kV that are determined by the Office of the Interconnection to meet one of the two exceptions stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). If the Office of the Interconnection determines that the identified reliability violations do not satisfy either of the two exceptions stated above, the Office of the Interconnection shall develop a solution to address the reliability violation on below 200 kV Transmission Facilities that will not be included in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). The Office of Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the below 200 kV reliability violations that will not be included in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the below 200 kV reliability violation(s) in Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, a description of the facility on which the violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such below 200 kV reliability violation will be designated to the incumbent Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. With the exception of Immediate-need Reliability Projects under the Operating Agreement, Schedule 6, section 1.5.8(m), PJM will not select an above 200 kV solution for inclusion in the recommended plan that would address a reliability violation on a below 200 kV transmission facility without posting the violation for inclusion in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

(o) **[Reserved]**

(p) **Thermal Reliability Violations on Transmission Substation Equipment.** Pursuant to the regional transmission expansion planning process set forth in the Operating Agreement, Schedule 6, sections 1.5.1 through 1.5.6, the Office of the Interconnection shall identify thermal reliability violations on existing transmission substation equipment. The Office of the Interconnection shall not post such thermal reliability violations pursuant to the Operating Agreement, Schedule 6, section 1.5.8(b) for inclusion in a proposal window pursuant to the Operating Agreement, Schedule 6, section 1.5.8(c) if the Office of the Interconnection determines that the reliability violations would be more efficiently addressed by an upgrade to replace in kind transmission substation equipment with higher rated equipment, excluding power transmission transformers, but including station service transformers and instrument transformers. If the Office of the Interconnection determines that the reliability violation does not meet the exemption stated above, the Office of the Interconnection shall post on the PJM website the reliability violations to be included in a proposal window consistent with the Operating Agreement, Schedule 6, section 1.5.8(c). If the Office of the Interconnection determines that the identified thermal reliability violations satisfy the above exemption to the proposal window process, the Office of the Interconnection shall post on the PJM website for review and comment by the Transmission Expansion Advisory Committee and other stakeholders descriptions of the transmission substation equipment thermal reliability violations that will not be included in a proposal window pursuant to Operating Agreement, Schedule 6, section 1.5.8(c). The descriptions shall include an explanation of the decision to not include the

transmission substation equipment thermal reliability violation(s) in Operating Agreement, Schedule 6, section 1.5.8(c) proposal window, a description of the facility on which the thermal violation(s) is found, the Zone in which the facility is located, and notice that such construction responsibility for and ownership of the project that resolves such transmission substation equipment thermal violations will be designated to the incumbent Transmission Owner. After the descriptions are posted on the PJM website, stakeholders shall have reasonable opportunity to provide comments for consideration by the Office of the Interconnection. All written comments received by the Office of the Interconnection shall be publicly available on the PJM website.

1.5.9 State Agreement Approach.

(a) State governmental entities authorized by their respective states, individually or jointly, may agree voluntarily to be responsible for the allocation of all costs of a proposed transmission expansion or enhancement that addresses state Public Policy Requirements identified or accepted by the state(s) in the PJM Region. As determined by the authorized state governmental entities, such transmission enhancements or expansions may be included in the recommended plan, either as a (i) Supplemental Project or (ii) state public policy project, which is a transmission enhancement or expansion, the costs of which will be recovered pursuant to a FERC-accepted cost allocation proposed by agreement of one or more states and voluntarily agreed to by those state(s). All costs related to a state public policy project or Supplemental Project included in the Regional Transmission Expansion Plan to address state Public Policy Requirements pursuant to this Section shall be recovered from customers in a state(s) in the PJM Region that agrees to be responsible for the projects. No such costs shall be recovered from customers in a state that did not agree to be responsible for such cost allocation. A state public policy project will be included in the Regional Transmission Expansion Plan for cost allocation purposes only if there is an associated FERC-accepted allocation permitting recovery of the costs of the state public policy project consistent with this Section.

(b) Subject to any designation reserved for Transmission Owners in the Operating Agreement, Schedule 6, section 1.5.8(l), 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).

1.5.10 Multi-Driver Project.

(a) When a proposal submitted by an existing Transmission Owner or Nonincumbent Developer pursuant to Operating Agreement, Schedule 6, section 1.5.8(c) meets the definition of a Multi-Driver Project and is designated to be included in the Regional Transmission Expansion Plan for purposes of cost allocation, the Office of the Interconnection shall designate the Designated Entity for the project as follows: (i) if the Multi-Driver Project does not contain a state Public Policy Requirement component, the Office of the Interconnection shall designate the Designated Entity pursuant to the criteria in the Operating Agreement, Schedule 6, section 1.5.8; or (ii) if the Multi-Driver Project contains a state Public Policy Requirement component, the

Office of the Interconnection shall evaluate potential Designated Entity candidates based on the criteria in the Operating Agreement, Schedule 6, section 1.5.8, and provide its evaluation to and elicit feedback from the sponsoring state governmental entities responsible for allocation of all costs of the proposed state Public Policy Requirement component ("state governmental entity(ies)") regarding its evaluation. Based on its evaluation of the Operating Agreement, Schedule 6, section 1.5.8 criteria and consideration of the feedback from the sponsoring state governmental entity(ies), the Office of the Interconnection shall designate the Designated Entity for the Multi-Driver Project and notify such entity consistent with the Operating Agreement, Schedule 6, section 1.5.8(i). A Multi-Driver Project may be based on proposals that consist of (1) newly proposed transmission enhancements or expansions; (2) additions to, or modifications of, transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan; and/or (3) one or more transmission enhancements or expansions already selected for inclusion in the Regional Transmission Expansion Plan.

(b) A Multi-Driver Project may contain an enhancement or expansion that addresses a state Public Policy Requirement component only if it meets the requirements set forth in the Operating Agreement, Schedule 6, section 1.5.9(a) and its cost allocations are established consistent with the Tariff, Schedule 12, section (b)(xii)(B).

(c) If a state governmental entity(ies) desires to include a Public Policy Requirement component after an enhancement or expansion has been included in the Regional Transmission Expansion Plan, the Office of the Interconnection may re-evaluate the relevant reliability-based enhancement or expansion, Economic-based Enhancement or Expansion, or Multi-Driver Project to determine whether adding the state-sponsored Public Policy Requirement component would create a more cost effective or efficient solution to system conditions. If the Office of the Interconnection determines that adding the state-sponsored Public Policy Requirement component to an enhancement or expansion already included in the Regional Transmission Expansion Plan would result in a more cost effective or efficient solution, the state-sponsored Public Policy Requirement component may be included in the relevant enhancement or expansion, provided all of the requirements of the Operating Agreement, Schedule 6, section 1.5.10(b) are met, and cost allocations are established consistent with the Tariff, Schedule 12, section (b)(xii)(B).

(d) If, subsequent to the inclusion in the Regional Transmission Expansion Plan of a Multi-Driver Project that contains a state Public Policy Requirement component, a state governmental entity(ies) withdraws its support of the Public Policy Requirement component of a Multi-Driver Project, then: (i) the Office of the Interconnection shall re-evaluate the need for the remaining components of the Multi-Driver Project without the state Public Policy Requirement component, remove the Multi-Driver Project from the Regional Transmission Expansion Plan, or replace the Multi-Driver Project with an enhancement or expansion that addresses remaining reliability or economic system needs; (ii) if the Multi-Driver Project is retained in the Regional Transmission Expansion Plan without the state Public Policy Requirement component, the costs of the remaining components will be allocated in accordance with the Tariff, Schedule 12; (iii) if more than one state is responsible for the costs apportioned to the state Public Policy Requirement component of the Multi-Driver Project, the remaining state governmental entity(ies) shall have the option to continue supporting the state Public Policy component of the

Multi-Driver Project and if the remaining state governmental entity(ies) choose this option, the apportionment of the state Public Policy Requirement component will remain in place and the remaining state governmental entity(ies) shall agree upon their respective apportionments; (iv) if a Multi-Driver Project must be retained in the Regional Transmission Expansion Plan and completed with the State Public Policy component, the state Public Policy Requirement apportionment will remain in place and the withdrawing state governmental entity(ies) shall continue to be responsible for its/their share of the FERC-accepted cost allocations as filed pursuant to the Tariff, Schedule 12, section (b)(xii)(B).

(e) The actual costs of a Multi-Driver Project shall be apportioned to the different components (reliability-based enhancement or expansion, Economic-based Enhancement or Expansion and/or Public Policy Requirement) based on the initial estimated costs of the Multi-Driver Project in accordance with the methodology set forth in the Tariff, Schedule 12.

(f) The benefit metric calculation used for evaluating the market efficiency component of a Multi-Driver Project will be based on the final voltage of the Multi-Driver Project using the Benefit/Cost Ratio calculation set forth in the Operating Agreement, Schedule 6, section 1.5.7(d) where the Cost component of the calculation is the present value of the estimated cost of the enhancement apportioned to the market efficiency component of the Multi-Driver Project for each of the first 15 years of the life of the enhancement or expansion.

(g) Except as provided to the contrary in this Operating Agreement, Schedule 6, section 1.5.10 and Operating Agreement, Schedule 6, section 1.5.8 applies to Multi-Driver Projects.

(h) The Office of the Interconnection shall determine whether a proposal(s) meets the definition of a Multi-Driver Project by identifying a more efficient or cost effective solution that uses one of the following methods: (i) combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project ("Proportional Multi-Driver Method"); or (ii) expanding or enhancing a proposed single driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers ("Incremental Multi-Driver Method").

(i) In determining whether a Multi-Driver Project may be designated to more than one entity, PJM shall consider whether: (i) the project consists of separable transmission elements, which are physically discrete transmission components, such as, but not limited to, a transformer, static var compensator or definable linear segment of a transmission line, that can be designated individually to a Designated Entity to construct and own and/or finance; and (ii) each entity satisfies the criteria set forth in the Operating Agreement, Schedule 6, section 1.5.8(f). Separable transmission elements that qualify as Transmission Owner Upgrades shall be designated to the Transmission Owner in the Zone in which the facility will be located.

1.6 Approval of the Final Regional Transmission Expansion Plan.

(a) Based on the studies and analyses performed by the Office of the Interconnection under Operating Agreement, Schedule 6, the PJM Board shall approve the Regional Transmission Expansion Plan in accordance with the requirements of Operating Agreement, Schedule 6. The PJM Board shall approve the cost allocations for transmission enhancements and expansions consistent with Tariff, Schedule 12. Supplemental Projects shall be integrated into the Regional Transmission Expansion Plan approved by the PJM Board but shall not be included for cost allocation purposes.

(b) The Office of the Interconnection shall publish the current, approved Regional Transmission Expansion Plan on the PJM Internet site. Within 30 days after each occasion when the PJM Board approves a Regional Transmission Expansion Plan, or an addition to such a plan, that designates one or more Transmission Owner(s) or Designated Entity(ies) to construct such expansion or enhancement, the Office of the Interconnection shall file with FERC a report identifying the expansion or enhancement, its estimated cost, the entity or entities that will be responsible for constructing and owning or financing the project, and the market participants designated under Operating Agreement, Schedule 6, section 1.5.6(l) to bear responsibility for the costs of the project.

(**c**) If a Regional Transmission Expansion Plan is not approved, or if the transmission service requested by any entity is not included in an approved Regional Transmission Expansion Plan, nothing herein shall limit in any way the right of any entity to seek relief pursuant to the provisions of Section 211 of the Federal Power Act.

(d) Following PJM Board approval, the final Regional Transmission Expansion Plan shall be documented, posted publicly and provided to the Applicable Regional Entities.

1.7 Obligation to Build.

(a) Subject to the requirements of applicable law, government regulations and approvals, including, without limitation, requirements to obtain any necessary state or local siting, construction and operating permits, to the availability of required financing, to the ability to acquire necessary right-of-way, and to the right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all reasonably incurred costs, plus a reasonable return on investment, Transmission Owners or Designated Entities designated as the appropriate entities to construct, own and/or finance enhancements or expansions specified in the Regional Transmission Expansion Plan shall construct, own and/or finance such facilities or enter into appropriate contracts to fulfill such obligations. Except as provided in Operating Agreement, Schedule 6, section 1.5.8(k), nothing herein shall require any Transmission Owner to construct, finance or own any enhancements or expansions specified in the Regional Transmission Expansion Plan for which the plan designates an entity other than a Transmission Owner as the appropriate entity to construct, own and/or finance such enhancements or expansions.

(b) Nothing herein shall prohibit any Transmission Owner from seeking to recover the cost of enhancements or expansions on an incremental cost basis or from seeking approval of such rate treatment from any regulatory agency with jurisdiction over such rates.

(c) The Office of the Interconnection shall be obligated to collect on behalf of the Transmission Owner(s) or Designated Entity(ies) all charges established under Tariff, Schedule 12 in connection with facilities which the Office of the Interconnection designates one or more Transmission Owners or Designated Entity(ies) to build pursuant to this Regional Transmission Expansion Planning Protocol. Such charges shall compensate the Transmission Owner(s) or Designated Entity(ies) for all costs related to such RTEP facilities under a FERC-approved rate and will include any FERC-approved incentives.

(d) In the event that a Transmission Owner declines to construct an economic transmission enhancement or expansion developed under sections 1.5.6(d) and 1.5.7 of this Schedule 6 that such Transmission Owner is designated by the Regional Transmission Expansion Plan to construct (in whole or in part), the Office of the Interconnection shall promptly file with the FERC a report on the results of the pertinent economic planning process in order to permit the FERC to determine what action, if any, it should take.

1.8 Interregional Expansions

(a) PJM shall collect from Midwest Independent System Operator, Inc., for distribution to the applicable Transmission Owners, in accordance with Schedule 12 of the PJM Tariff, revenues collected by the Midwest Independent System Operator, Inc. under the Open Access Transmission Tariff of the Midwest Independent System Owner, Inc. with respect to transmission enhancements or expansions for which the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C. assigns cost responsibility for transmission enhancements or expansions in the PJM Region to market participants in the region of the Midwest Independent System Operator, Inc.

(b) PJM shall disburse to the Midwest Independent System Operator, Inc., for distribution to applicable transmission owners of the Midwest Independent System Operator, Inc., revenues collected under Schedule 12 of the PJM Tariff which establishes a charge in connection with enhancements or expansions in the region of the Midwest Independent System Operator, Inc. the cost responsibility for which has been assigned to market participants in the PJM Region under the Coordinated System Plan developed under the Joint Operating Agreement Between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.

(c) Nothing in this Section 1.8 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the PJM Tariff and applicable agreements.

1.9 Relationship to the PJM Open Access Transmission Tariff.

Nothing herein shall modify the rights and obligations of an Eligible Customer or a Transmission Customer with respect to required studies and completion of necessary enhancements or expansions. An Eligible Customer or Transmission Customer electing to follow the procedures in the PJM Tariff instead of the procedures provided herein, shall also be responsible for the related costs. The enhancement and expansion study process under this Protocol shall be funded as a part of the operating budget of the Office of the Interconnection.

PJM Manual 14B:

PJM Region Transmission Planning Process

Revision: 57

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Prepared By
Transmission Planning Department

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Sami Abdulsalam

Director, Transmission Planning

Current Revision

Revision 57 (09/25/2024):

- Updated Section 2.3.10 Generator Deliverability Analysis to clarify that the P2-1 contingency, opening of a line section w/o a fault, is not included as part of the analysis
- Updated Attachment C Section C3.1.3 and Attachment H Section H1.5 to reflect that load levels in the light load case can be modelled in excess of 50% of each area's non-coincident summer peak forecast where applicable.
- Updated Attachment F: Determination of System Operating Limits used for planning the Bulk Electric System to align with the retirement of NERC Standard FAC-010-3: System Operating Limits Methodology for the Planning Horizon and with the latest revisions to FAC-014-3: Establish and Communicate System Operating Limits. Updated the definition of System Operating Limit (SOL) to align with the revised definition in the NERC glossary of Terms.
- Updated Attachment G.10 NERC Standard PRC-023 – Transmission Relay Loadability to reflect the latest version: PRC-023-6.
- Added Attachment G.13 NERC Standard PRC-026 – Relay Performance During Stable Power Swings.
- Added Attachment G.14 NERC Standard TPL-007 – Transmission System Planned Performance for Geomagnetic Disturbance Events.

Introduction

Welcome to the **PJM Region Transmission Planning Process Manual.** In this Introductory Section you will find information about PJM manuals in general, an overview of this PJM Manual in particular and information on how to use this manual.

About PJM Manuals

The PJM Manuals are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM RTO and the PJM Energy Market. The manuals are grouped under the following categories:

- Transmission
- PJM Energy Market
- PJM Regional Transmission Expansion
- Reserve
- Accounting and billing
- PJM administrative services

For a complete list of all PJM manuals, go to the Library section on PJM.com.

About This Manual

The **PJM Region Transmission Planning Process Manual** is one of the PJM manuals in the PJM Regional Transmission Expansion group. This manual focuses on the process for planning baseline expansion facilities under the PJM Region Transmission Planning Process. Capitalized terms not defined as they are used have the meaning defined in the PJM's Open Access Transmission Tariff (OATT) and in the Operating Agreement (OA.)

This **PJM Region Transmission Planning Process Manual** consists of two sections and related attachments. All sections and attachments are listed in the Table of Contents.

Note:
While the PJM Manuals provide instructions and summaries of the various rules, procedures and guidelines for all phases of PJM's planning process, the PJM Operating Agreement and the PJM Open Access Transmission Tariff (OATT) contain the authoritative provisions.

Intended Audience

The intended audiences for this PJM Region Transmission Planning Process Manual include:

- Generation and Transmission Project Developers and their engineering staff

Note:
Prior to the Transition Date, the Interconnection Service Agreement (ISA) was the form agreement included in the Tariff used to facilitate interconnection to PJM's transmission system, which used term "Interconnection Customer" to refer to generation interconnection customers, similar to the Project Developer. While the ISA is no longer used for interconnection to the transmission system, pre-existing ISAs remain active. On and after the Transition Date, the Generation Interconnection Agreement (GIA) is used as the form agreement included in the Tariff to facilitate interconnection to PJM's transmission system.

The Tariff defines the Transition Date as the later of: (i) the effective date of PJM's Docket No. ER22-2110 transition cycle filing seeking FERC acceptance of Tariff, Part VII (which is January 3, 2023) or (ii) the date by which all AD2 and prior queue window Interconnection Service Agreements or wholesale market participation agreements have been executed or filed unexecuted. Because this second condition happened last, this date establishes the Transition Date.

- Transmission Owners and their respective engineering staff
- Federal and state regulatory bodies
- PJM Members
- PJM staff

References

There are other PJM documents that provide both background and detail on specific topics that may be related to topics in this manual. References with related information include:

- PJM Manual 1: *Control Center and Data Exchange Requirements*
- PJM Manual 2: *Transmission Service Request*
- PJM Manual 3: *Transmission Operations*
- PJM Manual 14A: *Generation and Transmission Interconnection Process*
- PJM Manual 14C: *Generation and Transmission Interconnection Facility Construction*
- PJM Manual 14D: *Generator Operational Requirements*
- PJM Manual 14E: *Merchant Transmission Specific Requirements*
- PJM Manual 14H: New Service Request Process
- PJM Manual 21: *Rules and Procedures for Determination of Generating Capability*

Using This Manual

We believe that explaining concepts is just as important as presenting procedures. This philosophy is reflected in the way we organize the material in this manual. We start each section

with an overview. Then we present details, procedures or references to procedures found in other PJM manuals. The following provides an orientation to the manuals' structure.

What You Will Find In This Manual

- A table of contents.
- An approval page that lists the required approvals and a brief outline of the current revision.
- This Introduction and sections containing the specific transmission planning process details including assumptions, criteria, procedures and stakeholder interactions.
- Attachments that include additional supporting documents, forms, or tables.
- A section at the end detailing all previous revisions of this PJM Manual.

Section 1A: Critical Energy Infrastructure Information (CEII)

1A.1 CEII Definition

PJM adopts the Federal Energy Regulatory Commission's ("FERC" or "Commission") definitions of Critical Energy Infrastructure Information ("CEII") and Critical Infrastructure at 18 CFR §388.113 (c) as follows:

- Critical Energy Infrastructure Information means specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that:
  - Relates details about the production, generation, transportation, transmission, or distribution of energy;
  - Could be useful to a person in planning an attack on critical infrastructure;
  - Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
  - Does not simply give the general location of the critical infrastructure.
- Critical Infrastructure means existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters.

1A.2 Introduction

1A.2.1 General Intent

PJM's intent is to provide a process for eligible recipients to access CEII consistent with the Commission's standards for handling CEII material. PJM information that contains CEII can only be obtained by complying with PJM's CEII authorization process.

1A.2.2 Examples of CEII

The Commission considers certain information to be CEII. For example, information filed in the FERC-715, Part 2, Part 3, and Part 6 (http://www.ferc.gov/legal/ceii-foia/ceii.asp) is considered by the FERC to be CEII. This information contains electrical models, detailed one-line diagrams and analysis of the filer's actual transmission system including potential weaknesses of the filer's transmission system. PJM treats all such power flow and associated system modeling data as CEII. This includes all power flow models that are developed using or including data and related information used in transmission system analysis such as contingency and monitored element files. Power flows specifically configured for short circuit analysis that do not contain load and generation dispatch are not considered CEII. Other information may also qualify as CEII under the Commission's definitions.

1A.2.3 Rules When CEII Includes Confidential Member Information

Regarding all types of PJM information, additional consideration must be given to whether or not PJM received or originated the information as confidential information prior to decisions regarding its release. Confidential information is governed by the PJM Operating Agreement Section 18.17 and the Open Access Transmission Tariff Sections 222-223. Certain information is a combination of CEII information filed or provided by a number of "owners" and may include confidential information. To the extent CEII material sought from PJM includes confidential information of a PJM Member, including PJM Transmission Owners or Generation Owners, PJM will require the requester to demonstrate the affected members give consent to the release of the confidential information contained within the CEII material by PJM to comply with the Tariff and Operating Agreement. Power flows may, but generally do not, contain confidential information. Some PJM power flows are special cases that contain both confidential information and CEII. For example, PJM power flows originating from system operations and used for near term operational studies often contain confidential information in addition to CEII. Confidential information of members, if any, may be redacted prior to release of CEII if the CEII requester is unable to demonstrate to PJM that the affected members give consent to the release of the confidential material.

1A.2.4 Reservation of Rights to Amend CEII Rules

PJM reserves the right to revise its process from time-to-time, to limit access to CEII as may be appropriate in any specific instance in accordance with PJM's manual revision procedures posted on PJM.com.

1A.3 PJM CEII Rules

1A.3.1 CATEGORIES OF PJM CEII REQUESTERS PROCEDURES

1A.3.1.1 Authorized Entities Procedures

The process to request CEII from PJM is as follows for an employee or authorized agent/ consultant of : (i) a PJM Member; (ii) a PJM Transmission Owner; (iii) a PJM Generation Owner or operator of generating units in the PJM Region; (iv) a NERC registered Transmission Owner/ Operator; (v) a PJM Project Developer; (vi) another RTO or similar independent system operator recognized by the Federal Energy Regulatory Commission; (vii) a NERC Planning Coordinator or Transmission Planner; (viii) a Non-incumbent Developer pre-qualified to be a Designated Entity pursuant to Schedule 6 of the Operating Agreement; or (viii) a natural gas local distribution company and/or a natural gas pipeline operator serving customers within the PJM Region (individually "Authorized Entity" and together "Authorized Entities"). The process outlined below allows for individual employees or individual authorized consultants of Authorized Entities to obtain CEII. PJM's procedures set forth below allow an organization to submit requests on behalf of multiple individuals within Authorized Entities.

Except in the case of Organizational CEII requests described below, each individual requester of CEII from employees or authorized agents/consultants of Authorized Entities must complete a PJM CEII Request Form and must execute the appropriate PJM CEII Nondisclosure Agreement ("NDA"). Employee, authorized agent or an Authorized Entity must submit a PJM CEII Authorization Form (in addition to the requester's completed PJM CEII Request Form and appropriate PJM CEII NDA) that identifies each individual agent/consultant who may make individual requests for PJM CEII on behalf of such entity.

Once the CEII requester has been verified by PJM as a legitimate CEII requester (i.e., a legitimate employee or authorized consultant of one of the organizations listed in paragraph 1A.3.1.1 above), such CEII requester may obtain CEII.

Organizational CEII Requests: Authorized Entities may enter into an organizational agreement with PJM which will allow the receiving organization to share CEII information under the terms of an applicable PJM CEII NDA however, PJM may use other forms of organizational CEII NDAs as appropriate. Such organizational NDA will require individual recipients of CEII material to be listed and sign an attachment to the NDA which will require each individual to acknowledge his or her understanding of the restrictions on the use of CEII or further disclosures except as allowed under the terms of the organizational NDA. Each organization is required to keep the list of authorized individual recipients up to date and notify in PJM in writing of any changes to the status of the authorized individual recipients in accordance with the applicable NDA.

1A.3.1.2 Federal Agency and NERC Procedures

If the requester of CEII material is a representative of FERC, Department of Energy, Department of Homeland Security, NERC or a NERC Regional Entity (e.g. RF, SERC, etc.), PJM will release the information if PJM confirms that the requestor (requestors) are employees of these agencies and the CEII material is subject to the agencies rules of procedures applicable to CEII.

1A.3.1.3 PJM Authorized State Commission

The process to request CEII from PJM is as follows for an employee of a PJM Authorized State Commission: Each individual requester of CEII must complete a PJM CEII Request Form and must execute a PJM CEII Government NDA located on the PJM website.

- After such CEII requester has been verified by PJM as a legitimate CEII requester (i.e., a legitimate employee of one of the governmental organizations listed above), such CEII requester may obtain the requested CEII.

1A.3.1.4 Procedures Applicable to Other CEII Requests

The process to request CEII from PJM is as follows for any other requester seeking CEII from PJM:

- Each individual requester of CEII must establish or have a PJM.com account. A PJM.com account can be created here: https://accountmanager.pjm.com/accountmanager/pages/public/new-user.jsf
- Each individual requester of CEII must then complete a PJM CEII Request Form and must execute an appropriate PJM CEII NDA. The PJM CEII NDA form will come up when a link to CEII is clicked on many places on PJM.com. There are prepopulated PJM CEII Request Forms at various locations throughout PJM.com. A blank generic PJM CEII Request Form is located at: https://www.pjm.com/library/request-access.aspx. Where the individual requester of CEII is an authorized agent/consultant for another entity, then an authorized employee of such entity must submit a PJM CEII Authorization Form (in addition to the requester's completed PJM CEII Request Form and the appropriate PJM CEII NDA) that identifies each individual agent(s)/consultant(s) who may make individual requests for PJM CEII on behalf of such entity. The PJM CEII Authorization Form is located on the PJM website at: https://www.pjm.com/library/request-access/form-ceii-consultant-request.aspx
- Upon receiving all completed required CEII forms, PJM will determine if the requested information is CEII, and, if it is, whether to release the CEII to the requester. PJM will use the information provided by the requester in the PJM CEII Request Form to (1) establish whether a requester has presented a legitimate need for the CEII; and (2) weigh the need for the CEII against the potential harmful effects of its release. In reviewing the request from such individual, PJM will confirm the authenticity of the CEII requester and whether the request is consistent with the requestor's business or educational interest as determined from a review of publicly available data such as the requestor's website. If PJM is unable to determine from publicly available information that the request is consistent with the requestor's business or educational interest in such data, the request will be denied. A requester shall provide additional information (beyond the PJM CEII Request Form) to PJM upon PJM's request.

1A.3.2 PJM CEII Handling

A recipient of PJM CEII shall maintain it in a secure place. Access to PJM CEII shall be limited to the recipient and other recipients of the identical CEII. Recipients may make copies of PJM CEII, but such copies are PJM CEII and subject to the same required handling. Recipient may make notes regarding the PJM CEII, but those notes shall be treated as PJM CEII notes if they contain CEII or were derived from PJM CEII.

Section 1: Process Overview

In this section you will find an overview of PJM's transmission planning process that culminates in the Regional Transmission Expansion Plan (RTEP). This process (referred to in this Manual interchangeably as the RTEP process or more generically as the PJM regional transmission planning process) is one of the primary functions of Regional Transmission Organizations (RTOs.) As such, PJM implements this function in accordance with the Regional Transmission Expansion Planning Protocol set forth in Schedule 6 of the PJM Operating Agreement.

As further described in following portions of this manual, the PJM RTEP process consists of baseline reliability reviews as well as analysis to identify the transmission needs associated with generation interconnection and merchant transmission interconnection. PJM implements the planning of interconnections as part of the broader RTEP process pursuant to the PJM Open Access Transmission Tariff (OATT.) The relationship between Interconnection planning and the RTEP is discussed in later sections of this manual and in related manuals.

1.1 Planning Process Work Flow

The Manual 14 series provides information regarding PJM's regional transmission expansion planning protocol (RTEPP) to complement planning provisions in the PJM Operating Agreement, Schedule 6 and the PJM Open Access Transmission Tariff (OATT), Attachment M-3 (Attachment M-3 Process). These agreements can be found on-line at https://www.pjm.com/library/governing-documents.aspx.

This ongoing process has continued to evolve since 1997, when PJM's RTEPP (codified in PJM's Operating Agreement, Schedule 6) was approved by the Federal Energy Regulatory Commission (FERC). Since that time, the process has been expanded and enhanced in response to member and regulatory input as documented in the Operating Agreement, Schedule 6; OATT, Attachment M-3; and the PJM Manual 14 series. The current PJM regional transmission expansion plan (RTEP) process includes ample opportunity for stakeholder input through frequent oral and written exchange of information and reviews via the Transmission Expansion Advisory Committee (TEAC) and PJM's three (3) Subregional RTEP Committees (Mid-Atlantic, Southern and Western).

PJM and PJM Transmission Owners' planning processes are incorporated in an 18-month overlapping planning cycle which begins in September of the previous calendar year and extends through a full calendar year to the February of the next calendar year. This overlapping planning cycle is illustrated in Exhibit 1 in this Manual.

The PJM planning process activities, culminating in PJM's annual RTEP, constitute PJM's single, Order No. 890 compliant, transmission planning process.

All PJM OATT facilities are planned through and included in this open, fully participatory, and transparent process.

There are three (3) planning paths that ultimately culminate in the PJM RTEP base case, also referred to as the planning model. Facilities identified in each path allow for the opportunity for early, full and transparent participation by interested PJM stakeholders. The three paths include planning activities associated with: (i) Regional RTEP Project and Subregional RTEP Project (baseline upgrades), (ii) Supplemental Projects; and (iii) Customer-Funded Upgrades. Baseline upgrades include projects planned for (i) reliability, (ii) operational performance, (iii) FERC Form No. 715 criteria, (iv) economic planning, and (v) public policy planning (State Agreement Approach). Supplemental Projects refer to transmission expansion or enhancements not needed to comply with PJM reliability, operational performance, FERC Form No. 715, economic criteria or State Agreement Approach projects; Supplemental Project drivers, or needs, are "supplemental" to those Operating Agreement specified criteria. Transmission Owners plan Supplemental Projects in accordance with the OATT, Attachment M-3 Process. Projects planned through the Attachment M-3 Process include those that expand or enhance the transmission system. By way of example, a Supplemental Project could include a Transmission Owner project needed to address transmission facilities at the end of their useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes. Customer-Funded Upgrades refer to Network Upgrades, Distribution Upgrades or Merchant Network Upgrades identified pursuant to OATT Parts II, III and VIII and paid for by the Project Developer or Eligible Customer or voluntarily undertaken by an Upgrade Customer in fulfillment of an Upgrade Request.

Planning of Baseline Upgrades:

Baseline upgrades are produced from PJM's planning Cycle activities described in this manual, Operating Agreement Schedule 6, and illustrated in Exhibit 1 in this Manual. PJM leads the analysis and development of baseline upgrades related to reliability , operational performance, FERC Form No. 715 criteria and economic planning for all facilities 100 kV and above under PJM's operational control. These facilities are designated as Bulk Electric System (BES) facilities and are subject to the North American Electric Reliability Corporation (NERC) standards and criteria for such facilities. The PJM analyses ensure compliance with NERC, PJM and any applicable Regional Entity criteria (e.g. Reliability First (RF) or SERC Reliability Corporation (SERC)). In addition, the PJM-led analyses also include analysis of and solutions for transmission facilities with nominal voltages below 100kV to the extent such facilities are under PJM's operational control (see http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx). The TEAC and Subregional RTEP Committees provide the opportunity for stakeholders to engage in the PJM transmission planning process of such facilities, as described in this Manual.

In addition, for transmission facilities under PJM operational control, the Transmission Owner may submit its local planning criteria in its FERC Form No. 715 filing.

Transmission Owner Supplemental Projects:

Supplemental Projects refer to a transmission expansion or enhancement not needed to comply with PJM reliability, operational performance, FERC Form No. 715 or economic criteria. Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process could include those that: (i) expand or enhance the transmission system; (ii) address Transmission Owner zonal reliability issues; (iii) maintain the existing transmission system; (iv) comply with regulatory requirements or (v) implement Transmission Owner asset management activities (which could include needs related to a transmission facility approaching the end of its useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes).

Pursuant to the Attachment M-3 Process, Supplemental Projects are presented through the TEAC (230 kV and above facilities) or the Subregional RTEP Committees (below 230 kV facilities) for review and comment in a three-part meeting process that includes at a minimum (i) an Assumptions Meeting, (ii) a Needs Meeting and (iii) a Solutions Meeting. The Solutions Meetings are followed by a round of comments before the Transmission Owners finalize the Supplemental Projects. The stakeholders are provided a final comment period before the Supplemental Project is included in the Local Plan. Supplemental Projects included in the Local Plan are provided to the TEAC and the PJM Board as informational before integrating the Supplemental Project into the RTEP base case. Supplemental Projects are not approved by the PJM Board.

It should also be noted that prior to integrating a Supplemental Project into the RTEP base case PJM performs a "do no harm study" to evaluate whether a proposed Supplemental Project will adversely impact the reliability of the Transmission System as represented in the planning models used in all other PJM reliability planning studies. If as a result of the do no harm study, system upgrades are required, such upgrades will be considered part of the Supplemental Project and are the responsibility of the Transmission Owner sponsoring the Supplemental Project.

As part of the review of Supplemental Projects, PJM will inform stakeholders if PJM determines that a proposed Supplemental Project does not meet the Operating Agreement definition of a Supplemental Project. Additionally, PJM will monitor the status of the projects being developed through the Attachment M-3 Process in order to associate the Supplemental Project with the need identified by the Transmission Owner in the Attachment M-3 Process. For Supplemental Projects, the transparent identification of the need is important to PJM's regional planning process and, accordingly, the identification of the need should include a description of the need in sufficient detail that together with the applicable criteria and supporting documentation stakeholders are capable of reviewing the Transmission Owner's need determination as well as replicating the results of the planning studies.

A Project proposed as a Supplemental Project that does not meet the definition of Supplemental Project or cannot be associated with the need identified by the Transmission Owner in the Attachment M-3 Process will not be included in the Local Plan. Supplemental Projects, to the extent they are developed through the Attachment M-3 Process and can be associated with a supplemental need(s) identified by the relevant TO, will be included in the next annual RTEP base case.

Through the Attachment M-3 Process, Supplemental Projects are subject to similar open, transparent and participatory PJM committee activities, as are baseline upgrades developed through the TEAC and the Subregional RTEP Committee meetings (see discussion of TEAC and Subregional RTEP Committees).

As part of the review of Supplemental Projects PJM will also apprise the relevant Transmission Owner if a baseline upgrade might alleviate or partially mitigate the need for a Supplemental Project. In addition, PJM will determine if a Supplemental Project might impact a baseline need identified through the RTEP process, which might be in progress. A discussion of guidelines associated with potential for overlapping needs in included in this Manual below in section 1.4.2.

Planning for Customer-Funded Upgrades is performed in response to a New Service Request or Upgrade Request, and includes Network Upgrades, Distribution Upgrades or Merchant Network Upgrades identified pursuant to OATT Parts II, III and VIII. Studies of interconnection and transmission service requests and any resulting transmission modifications are posted to PJM's website in the project Cycle area (http://www.pjm.com/planning/generation-interconnection.aspx). In addition, any necessary transmission facility modifications are brought to the TEAC for presentation and stakeholder participation. Interconnection planning is discussed in more detail in Manual 14H.

1.2 TEAC and Subregional RTEP Committee and Related Activities

The PJM TEAC functions in accordance with its established charter and provisions of the Operating Agreement, Schedule 6. Additionally, in 2008 PJM began to facilitate more localized planning functions through the Subregional RTEP Committees.

The TEAC and Subregional RTEP Committees provide a transparent and participatory planning process throughout the development of the RTEP, from early assumptions-setting stages to discussion of criteria violations and/or identified system needs, review of recommendations for alternative solutions and then review and comment regarding the solutions incorporated into the RTEP base case.

The Subregional RTEP Committees allow more focused and meaningful stakeholder participation and attention to the subregional and local Transmission Owner zonal issues. Currently, there are three PJM RTEP subregions: Mid-Atlantic, Southern, and Western. When a Subregional RTEP Committee meeting is needed and scheduled, it generally will be implemented as a separate meeting for each subregion.

All PJM stakeholders can participate in any or all subregional activities on a voluntary basis, with one exception. The exception is that the Transmission Owners that comprise each of the various subregions must participate in the Subregional RTEP Committee meeting that includes their area and each Transmission Owner must be present at the TEAC meeting where its Supplemental Projects are presented. PJM will facilitate TEAC and Subregional RTEP Committees to review Regional RTEP Projects, Subregional RTEP Projects and Supplemental Projects.

PJM, with stakeholder input, may initiate additional Subregional RTEP Committees meetings consistent with the Attachment M-3 Process to review and address stakeholder questions or concerns regarding needs or proposed solutions, as may be necessary or beneficial. Separate local meetings or more localized reviews may also be held by individual PJM Transmission Owners in the event that the individual Transmission Owner decides that it is a more appropriate way to address local issues. In addition to their participation in the TEAC and Subregional RTEP Committees meetings, stakeholders can also provide written comments on the development of baseline upgrades and Supplemental Projects. Written comments can be provided to PJM through the Planning Community on PJM.com.

For administrative convenience, RTEP projects (i.e., baseline upgrades) are separated into Regional RTEP Projects (230 kV and above) and Subregional RTEP Projects (below 230 kV) (referred to collectively herein as “RTEP Projects”), as defined in the Operating Agreement, in order to make an initial categorization and posting of violations and upgrades that will enable stakeholders to more easily sort through and review issues of interest.

Regional RTEP Projects and Supplemental Projects (230 kV and above) will be reviewed at the TEAC. Subregional RTEP Projects and Supplemental Projects (below 230 kV) will be reviewed at the applicable Subregional RTEP Committee. The Subregional RTEP Committee is responsible for the initial review of Subregional RTEP Projects. For Regional and Subregional RTEP Projects, the TEAC and Subregional RTEP Committees follow the procedure set forth in the Operating Agreement, Schedule 6 specific to the TEAC and other applicable PJM committee procedures. For Supplemental Projects subject to Attachment M-3, the Attachment M-3 Process will apply.

Review of RTEP Projects and Supplemental Projects at the TEAC and/or Subregional RTEP Committees normally occurs during the February through August RTEP stakeholder analysis and review periods (see Exhibit 1). However, additional Supplemental Projects for unforeseen needs that a PJM Transmission Owner identifies later in the year will follow OATT, Attachment M-3 Process for inclusion in the RTEP.

Stakeholders will be provided the information necessary for participation in the discussions and evaluations, including: (1) the PJM and/or Transmission Owners models, criteria and assumptions that underlie transmission system plans, (2) the procedure to access the study information necessary to replicate the PJM and/or Transmission Owner planning studies and participate in the evaluation and discussion of the identified need, (3) information regarding the

project proposed to address the identified need, (4) the current cost estimate for the project, and (5) a description of the proposed modifications to existing facilities that may be part of the project.

In addition, projects that originate through Transmission Owner planning will be posted on the PJM web site. This site will include all currently planned baseline upgrades and newly planned Supplemental Projects and Transmission Owner Initiated projects from past RTEP cycles that are yet to be placed in-service). This website provides tracking information about the status of listed projects and planned in-service dates. It also includes information regarding criteria, assumptions and availability of study cases.

1.3 Planning Assumptions and Model Development

1.3.1 Reliability Planning (including Operational Performance and Public Policy Planning)

PJM's planning analyses are based on a consistent set of fundamental assumptions regarding load, generation and transmission built into power flow models. Load assumptions are based on the annual PJM entity load forecast independently developed by PJM (found at http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.) This forecast includes the basis for all load level assumptions for planning analyses throughout the 15 year planning horizon. Generation and transmission planning assumptions are embodied in the base case power flow models developed annually by PJM and derived from the Eastern Reliability Assessment Group processes and procedures pursuant to NERC standard MOD-032, as well as Transmission Owners' assumptions included in their respective FERC Form No. 715. As necessary, PJM updates its models (e.g., power flow, short circuit, and stability) with the most recent data available for its own regional studies. All PJM base power flow and related information are available pursuant to applicable Critical Energy Infrastructure Information, Non-Disclosure and OATT-related requirements (accessible via http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx or by contacting the PJM Planning Committee contacts.) Each type of RTEP analysis (e.g., load deliverability, generator deliverability etc.) encompasses its own methodological assumptions as further described throughout the rest of this Manual. Additional details regarding the reliability planning criteria, assumptions, and methods can be found in following sections and this manual's Attachments.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

1.3.2 Economic Planning

Each year as part of the 24-Month Market Efficiency Cycle, PJM performs a market efficiency analysis, following the completion of the near- term reliability plan for the region. PJM's market efficiency planning analyses will utilize many of the same starting assumptions applicable to the reliability planning phase of the RTEP development. In addition, key market efficiency input

assumptions, used in the projection of future market inefficiencies; include load and energy forecasts for each PJM zone, fuel costs and emissions costs, expected levels of potential new generation and generation retirements and expected levels of demand response. PJM will input its study assumptions into a commercially available market simulation data model that is available to all stakeholders. The data model contains a detailed representation of the Eastern Interconnection power system generation, transmission and load. In addition, the market efficiency analysis of the cost/benefit of potential market efficiency upgrades will also include the discount rate and annual revenue requirement rate. The discount rate is used to determine the present value of the enhancements' annual benefits and annual cost. The annual revenue requirement rate is used to determine the enhancements' annual cost. PJM will finalize the market efficiency analysis input assumptions soon after the development of the PJM load forecast that is generally available approximately in late January. Prior to finalizing, PJM will review the proposed assumptions at the PJM Transmission Expansion Advisory Committee. This review will provide the opportunity for stakeholder review of and input to all of the key assumptions that form the basis of the market efficiency analysis. In this way, PJM will facilitate a comprehensive stakeholder review and input regarding RTEP study assumptions. All final assumptions and analysis parameters will be presented to the TEAC for discussion and review and to the PJM Board for consideration.

1.3.3 FERC Form No. 715

The Transmission Owner's process specific to the Transmission Owner's zone, including projects that could address the end of useful life of existing facilities, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes, may be memorialized as Transmission Owner planning criteria under the Transmission Owner's FERC Form No. 715.

1.3.4 Supplemental Projects

Supplemental Projects are included in both PJM and Transmission Owners planning models for the applicable reliability studies conducted outside the Attachment M-3 Process, to the extent the Supplemental Project impacts the transmission system.

The Transmission Owners' planning of Supplemental Projects follows the sequence of steps set out in the Attachment M-3 Process. Commencing September of the year preceding the next RTEP year, PJM will include as part of the model development for the next year's RTEP base case (see 18-month planning cycle illustrated in Exhibit 1 in this Manual), those Supplemental Projects submitted by the Transmission Owners for inclusion in the Local Plans in the July timeframe.

Additional Supplemental Projects for unforeseen needs that a PJM Transmission Owner identifies later in the year, and which are finalized after July, may be included in the base case if the inclusion of these projects would not disrupt analysis associated with the development of the RTEP violations. Such additional Supplemental Projects must comply with the Attachment M-3 Process. Once PJM issues its preliminary RTEP models for verification of topology and dispatch

prior to initiation of any preliminary RTEP analysis and quality control check in preparation for opening a proposal window, PJM will not consider for inclusion in the RTEP base case a subsequently-submitted proposed Supplemental Project(s) that would alleviate a violation identified in the proposal window. However, a Transmission Owner, or any other pre-qualified Designated Entity, may submit a project proposal for consideration in the proposal window to address a posted violation that would also address a related need identified in the Attachment M-3 Process.

1.4 RTEP Process Key Components

PJM's goal is to ensure electric supply adequacy and to enhance the robustness of energy and capacity markets. Achieving these objectives requires the successful completion of PJM's planning, facility construction and operational and market infrastructure requirements.

1.4.1 Key Process Drivers

Key components of PJM's 15-year transmission planning process discussed in this Manual include:

1.4.1.1 Baseline reliability analyses

The PJM Transmission System ("PJM System") provides the means for delivering the output of interconnected generators to the load centers in the PJM energy and capacity markets. Baseline reliability analyses ensure the security and adequacy of the Transmission System to serve all existing and projected long term firm transmission use including existing and projected native load growth as well as long term firm transmission service. RTEP baseline analyses include system voltage and thermal analysis, and stability, load deliverability, and generator deliverability testing. These tests variously entail single and multiple contingency testing for violations of established NERC reliability criteria regarding stability, thermal line loadings and voltage limits. Baseline reliability analyses are discussed in more detail in Section 2 and Attachment C.

1.4.1.2 Economic analyses (Market Efficiency studies)

In addition to reliability based analyses PJM also evaluates the economic merit of proposed transmission enhancements. These analyses focus on the economic impacts of security constraints on production cost, congestion charges to load and other econometric measures of market impacts. PJM's market efficiency analyses are discussed in Section 2 of this Manual and Attachment E. PJM development of economic transmission enhancements is also codified under Schedule 6 of the PJM Operating Agreement.

1.4.1.3 Operational performance issue reviews and accompanying analyses

Maintaining a safe and reliable Transmission System also requires keeping the transmission system equipment in safe, reliable operating condition as well as addressing actual operational needs. On an ongoing basis, PJM operating and planning personnel assess the PJM

transmission development needs based on recent actual operations. This may lead to special studies or programs to address actual system conditions that may not be evident through projections and system modeling.

To ensure that system facilities are maintained and operated to acceptable reliability performance levels, PJM has implemented an Aging Infrastructure Initiative to evaluate appropriate spare transformer levels and optimum equipment replacement or upgrade requirements. This initiative, based on a Probability Risk Assessment (PRA) process, is intended to result in a proactive, PJM-wide approach to assess the risk of facility failures and to mitigate operational and market impacts. Section 2 of this manual provides further discussion of the PRA process.

1.4.1.4 FERC Form No. 715

Each Transmission Owner specifies reliability criteria it uses to evaluate system performance in its FERC Form No. 715 filing. As part of the RTEP process, PJM will identify system needs using each Transmission Owner's planning criteria, which could include end of useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes and other asset management activities, reflected in the Transmission Owner's FERC Form No. 715.

1.4.1.5 Supplemental Project Planning

Transmission Owner may identify a need associated with a transmission expansion or enhancement not required to comply with the PJM reliability, operational performance, FERC Form No. 715 or economic criteria. The PJM Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process. Projects planned through the Attachment M-3 Process could include those that: (i) expand or enhance the transmission system; (ii) address local reliability issues; (iii) maintain the existing transmission system; (iv) comply with regulatory requirements; or (v) implement Transmission Owner asset management activities (which could include needs related to a transmission facility approaching the end of its useful life, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes.

1.4.1.6 Customer-Funded Upgrade analyses

A Customer-Funded Upgrade is a Network Upgrade, Distribution Upgrade or Merchant Network Upgrade (Network Upgrade) the cost of which is paid for by a Project Developer, Eligible Customer or Upgrade Customer. All entities requesting interconnection of a generating facility (including increases to the capacity of an existing generating unit) or requesting interconnection of a merchant transmission facility within the PJM region must do so through PJM's interconnection process detailed in OATT, Parts IV and VIII. PJM studies the interconnection and deliverability of New Service Requests or Upgrade Requests in the local area at the Point of Interconnection to determine whether Customer-Funded Upgrades are required to either interconnect to the system or upgrade existing facilities operated by PJM. The interconnection process and deliverability testing procedures are discussed further in this Manual in Attachment

C and Manual 14H. The evaluation of generation and merchant transmission New Service Requests is codified in the Tariff, Parts IV and VIII.

1.4.1.7 The Final RTEP Plan

Based on all of the requirements for firm transmission service on the PJM System, PJM develops an annual RTEP to meet those requirements on a reliable, economic system development and environmentally acceptable basis.

Furthermore, by virtue of its regional scope, the RTEP process assures coordination of expansion plans across multiple transmission owners' systems, permitting the identification of the most efficient or cost-effective expansion plan for the region. The RTEP developed through this process is reviewed and approved by PJM's Board of Managers. The Supplemental Projects are integrated into the RTEP, however the Board does not approve individual Supplemental Projects. The following Section 2 describes the PJM RTEP Process analysis.

1.4.1.8 Maintaining reliability associated with critical substations

To ensure the reliability of the transmission grid into the future, PJM has implemented a set of analysis to further enhance system reliability as discussed in Section 2.9 of this Manual 14B. This study is based on technical analysis performed, such as that performed using the PJM cascading trees tool software, and incorporates standard analytical methods of power flow study. As part of the RTEP process, PJM will analyze all transmission system enhancements to ensure that acceptable critical substation planning analysis objectives are maintained based on the analysis.

1.4.2 Coordination of Baseline Upgrades, Supplemental Projects and Customer-Funded Upgrades

Changes to the transmission system are incorporated into the RTEP base case based on the process drivers outlined in section 1.4.1 above in the form of three different types of upgrades or projects: 1) baseline upgrades (see sections 1.4.1.1 – 1.4.1.4); 2) Supplemental Projects (see sections 1.4.1.5); and 3) Customer-Funded Upgrades (see sections 1.4.1.6).

During the course of reviewing any upgrade or project, PJM will work with stakeholders to identify any upgrades or projects, or portions thereof that interact electrically. By doing so, PJM is able to determine the proper classification of a project based on one or more types of drivers, as well as develop the more efficient or cost-effective solutions.

1.4.2.1 When a Need is identified in the Attachment M-3 Process that requires development of a Supplemental Project (not yet included in RTEP base case)

During a review of the RTEP analysis, it may become apparent that a supplemental need identified in the Attachment M-3 Process may interact with an identified violation, system condition, economic constraint, or public policy requirement posted on the PJM website. In this case, PJM will provide notice of the potential interaction associated with the posted system

condition by posting the newly available information to the PJM website and provide notification to stakeholders. In addition, PJM may determine whether to lengthen an open proposal window in order to permit project proposers additional time to consider the availability of new or changed information. PJM can consider proposals, including proposals in its open proposal window that more efficiently and cost-effectively address both the identified baseline need(s) and any related needs identified in the Attachment M-3 Process.

1.4.2.2 When a Supplemental Project is submitted for inclusion in the Local Plan (not yet included in RTEP case)

During a review of the RTEP analysis, including input from stakeholders, it may become apparent that a Supplemental Project submitted for inclusion in the Local Plan, but not yet included in the RTEP base case, may interact with an identified violation, system condition, economic constraint, or public policy requirement posted on the PJM website. In this case, PJM will provide notice of the potential interaction associated with the posted system condition included in the PJM open proposal window. In addition, PJM may determine whether to lengthen the open proposal window in order to permit project proposers additional time to consider the availability of new or changed information regarding the facilities associated with the open proposal window, including any related needs identified in the Attachment M-3 Process.

In the development of the RTEP, PJM shall examine whether a possible baseline upgrade would more efficiently and cost-effectively address the identified regional need, as well as a supplemental need addressed by a proposed Supplemental Project.

If PJM identifies that a possible baseline upgrade would more efficiently and cost-effectively address the identified regional need, as well as a supplemental need, PJM will discuss with the relevant Transmission Owner and other stakeholders at the next appropriate Subregional RTEP or TEAC meeting. PJM shall submit the proposed baseline upgrade to the PJM Board for inclusion in the RTEP.

The Transmission Owner shall determine whether the baseline upgrade meets the supplemental need addressed by the proposed Supplemental Project and, if so, the Transmission Owner will withdraw the project from inclusion in the Local Plan. The Transmission Owner will inform PJM and the stakeholders at the next appropriate Subregional RTEP or TEAC meeting that the Supplemental Project will not be submitted for inclusion in the Local Plan.

If the Transmission Owner subsequently determines that the supplemental need is not met, the TO at the next appropriate Subregional RTEP or TEAC meeting will: (1) provide documentation to PJM and the stakeholders on the rationale supporting its determination; and, (2) inform PJM and the stakeholders that the Supplemental Project will be submitted for inclusion in the Local Plan. Accordingly, PJM will include the proposed Supplemental Project in the next RTEP base case. After discussion with the relevant Transmission Owner, PJM will notify the relevant regulatory siting authority, if applicable, when a Supplemental Project is being reviewed that

PJM has identified a baseline violation for which the baseline solution may impact the supplemental need for the Supplemental Project.

Any disputes arising under Attachment M-3, including any substantive and procedural disputes arising from the transmission planning process, may be resolved in accordance with the dispute resolution procedures in Schedule 5 of the Operating Agreement.

1.4.2.3 When a baseline upgrade is included in RTEP base case (in a prior RTEP cycle) and a Supplemental Project or Customer-Funded Upgrade is identified which interacts with the need for the baseline upgrade

PJM will review the needs for each of the upgrades or projects and review these needs with the stakeholders. This review will include, but is not limited to, the determination of how each upgrade or project may or may not satisfy the needs of one or more of the processes, and a review of the proposed schedules for the upgrades or projects and the system timing needs in order to inform these discussions.

Following a review of the applicable information, PJM shall determine the steps to be taken in order to preserve baseline reliability while also accommodating other system needs for the M-3 and the Cycle and Upgrade Request evaluation processes. Stakeholders will be provided an opportunity to discuss PJM's findings prior to PJM making a decision as to how PJM will proceed.

The Transmission Owners provide status updates in accordance with Section 6 of Manual 14C. Such status updates should include an indication of any relevant regulatory siting authority approval necessary for the project and the status of such approval. If at any time, PJM identifies a baseline need where a possible baseline upgrade would more efficiently and cost-effectively address the baseline need, as well as the identified needs for any proposed Supplemental Project, PJM will notify the relevant regulatory siting authority where the Supplemental Project is being reviewed that PJM has identified a baseline violation for which the baseline upgrade may impact the supplemental need for the Supplemental Project.

1.4.2.4 Incorporation of EOL Needs into the RTEP

The Transmission Owners shall prepare and provide to PJM, on an annual basis, a Candidate EOL Needs List. This The candidate EOL list shall be comprised of a Transmission Owners its non-public confidential, non-binding projection of up to 5 years of EOL Needs that it has identified under the Transmission Owner's processes for identification of EOL Needs. The methodology used by the Transmission Owner to determine inclusion in this EOL list shall be presented to stakeholders annually, and will generally be provided during the assumptions meeting as part of the M-3 process as outlined in Section 1.1. PJM shall identify any potential substantial electrical overlap between an identified PJM planning criteria need identified during the current PJM planning cycle, under the RTEP process and a projected EOL need facility on a Transmission Owner's Candidate EOL Needs List that could potentially be addressed by a single solution., PJM will consult with the relevant Transmission Owner to confirm the projected

EOL need still exists. If Transmission Owner confirms the projected EOL need still exists, PJM would post both the PJM planning criteria need and projected EOL need facility as required pursuant to Schedule 6 open window process, noting the overlap on the list of violations posted for the proposal window.

1.4.3 Addition and Removal of System Projects or Upgrades from the RTEP Base Cases

The development of an RTEP requires PJM to maintain a base case that includes all previously-identified system reinforcements regardless of the driver to be used in its analysis of system needs.

Each year, PJM must lock down the assumptions included in the annual RTEP base case in order to move forward with its analysis. PJM will employ the following guidelines regarding when to include the following types of projects or upgrades in the annual RTEP base case:

1. Baseline upgrades will be included in the next RTEP base case once the baseline upgrade is approved by the PJM Board in accordance with Schedule 6 of the Operating Agreement
2. Customer-Funded Upgrades will be included in the next RTEP base case once: (1) the Customer-Funded Upgrades are included in an executed Generation Interconnection Agreement, Upgrade Construction Service Agreement, Wholesale Market Participation Agreement or Transmission Services Agreement; or, (2) if the completion of the RTEP requires inclusion of New Service Requests that have met all Decision Point II requirements in order to meet the new load requirements resulting from normal forecasted load growth.
3. Supplemental Projects will be included in the next RTEP base case following inclusion of the Supplemental Project in the Local Plan, consistent with section 1.4.2.2 above.
4. A Customer-Funded Upgrade may be removed from the RTEP base case upon termination or cancellation of an executed service agreement provided such upgrade is not required by another New Service Request in the same Cycle.

5. If a relevant regulatory siting authority denies a siting application for a project included in the RTEP or refuses to allow the project to move forward under the conditions specified in such order and such order is a final regulatory order exhausting all regulatory process, the following guidance is provided:
    a. The entity receiving a final regulatory order from the relevant regulatory siting authority shall promptly notify and provide PJM with a copy of such order;
        i. Upon receipt of such notice, PJM will review the impacts associated with removing the project from the RTEP or continuing to include such project in light of such final regulatory order (see section 1.4.2 above for guidance relative to the review process);
    b. PJM shall present to the TEAC the results of PJM's re-evaluation for review and comment.
    c. A project denied siting authority in a final regulatory order by the relevant regulatory siting authority will generally be removed from the RTEP base case as determined by PJM after discussion with the relevant Transmission Owner(s) or Designated Entity and vetting with stakeholders at the TEAC. A project will generally not remain in the RTEP base case during the duration of a court appellate action. Decisions to remove a baseline upgrade from the RTEP base case will be submitted to the PJM Board and decisions to remove a Supplemental Project from the RTEP base case will be provided to the applicable Transmission Owner. In those circumstances in which PJM determines the need to deviate from this guidance, PJM will discuss such decisions with the TEAC.

1.5 Planning Criteria

1.5.1 Reliability Planning

PJM and/or Transmission Owners' planning information, including models, criteria and assumptions, provided pursuant to Operating Agreement, Schedule 6 or OATT, Attachment M-3 must be adequate to allow stakeholders to replicate the results of planning studies.

Stakeholders have the opportunity at a national level through the participatory standards development process of the North American Electric Reliability Corporation (NERC) to influence the industry planning criteria that form the basis of PJM's planning process (found at http://www.nerc.com/Pages/default.aspx.) NERC regional criteria development, applicable to PJM, is also open to stakeholder input through the open and participatory process of ReliabilityFirst Corporation (found at https://rfirst.org/ProgramAreas/Standards/.)

Additionally, regional and Transmission Owner planning criteria that go beyond and complement the NERC Reliability Standards can be created and incorporated into PJM planning through participation in PJM's Planning Committee and other related stakeholder processes (please refer to http://pjm.com/committees-and-groups/committees.aspx.) In this manner, PJM, as the independent planning authority, avails stakeholders full opportunity to participate in the planning

process from assumptions setting to the final plan. The PJM annual regional plan is based on the effective criteria in place at the time of the analyses, including applicable standards and criteria of the NERC and the applicable regional reliability entity[1], the various Nuclear Plant Licensees' Final Safety Analysis Report grid requirements and the PJM and Transmission Owner Reliability Planning Criteria (Attachment D). Section 2 details the specific criteria applicable to each transmission planning process study phase. Criteria are comparably applicable to all similarly situated Native Load Customers and other Transmission Customers.

1.5.2 Market Efficiency Planning

Market efficiency planning is an evaluation process that results in facilities planned to achieve economic efficiencies rather than an analysis that produces violations measured against criteria. This process compares alternative plans' cost effectiveness in improving transmission efficiency and produces RTEP recommendations from this process. The metrics of economic inefficiency include historic and projected congestion. The measures of historic congestion are gross congestion, unhedgeable congestion, and pro-ration of auction revenue rights. The measure of projected congestion is based on a market analysis of future system conditions performed with a commercially available security constrained, economic dispatch market analysis tool. This market analysis results in future projections of the congestion and its binding constraint drivers. These congestion measures are posted and available to stakeholders by binding constraint and form the basis for PJM and stakeholder development of remedies. Transmission plans from the reliability analysis or a new plan presented that economically relieves historical or projected congestion are candidates for market efficiency solutions. The successful candidates will be those facilities that pass PJM's threshold test and bright line economic efficiency test. This test specifies that a proposed solution's savings must exceed its projected revenue requirements, on a 15 year present worth basis, by at least 25% (the threshold cost/benefit test). Each of this process' elements, its underlying assumptions and its methods is described in more detail in the accompanying sections of this manual 14B and in Attachment E.

1.5.3 FERC Form No. 715 Planning

The Transmission Owner's local planning criteria may be included in its FERC Form No. 715 filing. These documents may include criteria governing the planning of upgrades to the transmission system, which is in addition to the PJM Planning criteria and may include information specific to a Transmission Owner's asset management activities.

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1 The Reliability*First* Regional Reliability Corporation (RRC) for the PJM Mid-Atlantic and Western Regions (which replaced the former ECAR, MAAC and MAIN RRCs on January 1, 2006) and the Virginia-Carolinas (VACAR) Area Reliability subregion of the SERC Reliability Corporation for PJM Southern Region.

1.5.4 Supplemental Project Planning

The criteria driving the need for Supplemental Projects (which could include criteria required to address end of useful life of existing transmission facilities, and which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes) are provided by each Transmission Owner consistent with the OATT Attachment M-3 process.

Section 2: Regional Transmission Expansion Plan Process

In this section you will find an overview of the PJM Region transmission planning process covering the following areas:

- Components of PJM's 15-Year planning
- The need and drivers for a regional transmission expansion plan
- Reliability planning overview
- Specific components of reliability planning and the Stakeholder process
- Interconnection request drivers of RTEP
- Cost responsibility for reliability related upgrades
- Market efficiency planning review
- Specific components of market efficiency planning and the Stakeholder process.
- Operational performance driven planning
- Specific components of operational performance driven planning

2.1 Transmission Planning = Reliability Planning + Market Efficiency+ FERC Form No. 715 + Public Policy + Supplemental Project Planning

Effective with the 2006 RTEP, PJM, after stakeholder review and input, expanded its RTEP Process to extend the horizon for consideration of expansion or enhancement projects to fifteen years. This enables planning to anticipate longer lead-time transmission needs on a timely basis.

Fundamentally, the Baseline reliability analysis underlies all planning analyses and recommendations. On this foundation, PJM's annual 15-year planning review now yields a regional plan that encompasses the following:

1. Baseline reliability upgrades, discussed in this Section 2;
2. Operational Performance issue driven upgrades, discussed in Section 2;
3. Market efficiency driven upgrades, discussed in this Section 2;
4. FERC Form No. 715 projects, discussed in Section 2;
5. Public Policy Requirements based elements via State Agreement Approach;
6. Supplemental Projects by a Transmission Owner, addressed via OATT, Attachment M-3, which could include projects addressing the end of useful life of existing facilities, which, as determined in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes.
7. Avoidance of system enhancements that do not meet critical substation planning analysis objectives discussed in Section 2.

2.1.1 Multi-Driver Approach

In the event that a proposed project is driven by more than one of the above stated drivers, PJM can develop a Multi-Driver Approach Project, as defined in Schedule 6 of PJM's Operating Agreement by identifying a more efficient or cost effective solution that follows one of the following methods:

Proportional Multi-Driver Method: Combining separate solutions that address reliability, economics and/or public policy into a single transmission enhancement or expansion that incorporates separate drivers into one Multi-Driver Project.

Incremental Multi-Driver Method: Expanding or enhancing a proposed single-driver solution to include one or more additional component(s) to address a combination of reliability, economic and/or public policy drivers.

2.1.1.1 Principles and Guidelines for New Service Requests as an input to Multi-Driver Approach

Customer-Funded upgrades, as identified in PJM Manual 14H may be incorporated into the Multi-Driver Approach Project per the Regional Transmission Expansion Plan. Project Developers, other than those proposing Merchant Network Upgrades, have the option, but not obligation to participate in a Multi-Driver Approach Project, at the direction of PJM. The following principles and guidelines must be adhered to for a Project Developer wishing to participate in a Multi-Driver Approach Project:

1. The Multi-Driver Approach Project must be more cost effective as a whole, than the sum of the individual projects
2. Project Developer has the option, but not the obligation to participate in a Multi-Driver Approach Project. The Project Developer must execute an agreement committing to be financially responsible for its portion of the Multi-Driver Approach Project, the cost of which shall not exceed the cost of the incremental upgrade required as part of the New Service Request, unless agreed to by the sponsoring Project Developer(s).
3. Project Developer's participation in the Multi-Driver Approach Project shall not impact the Project Developer's Cycle position.
4. Commencement of service for the Project Developer's Customer Facilities may be impacted by the in-service date of the Multi-Driver Approach Project.
5. The following cost allocation rules will apply to Multi-Driver Approach Projects: Schedule 12 of the PJM Tariff for the component of the upgrade to be funded for reliability violations or operational performance, economic constraints and/or Public Policy Requirements; and Part VIII of the PJM Tariff for the Project Developer's portion of the Multi-Driver Approach Project.

2.1.2 Reliability Planning

Exhibit 1 shows the 24-month Reliability planning process used for the 15-year RTEP horizon. This 24-month planning process integrates the upgrades noted above with information transparency, stakeholder input and review and PJM Board of Manager approvals. Activities shown on this diagram and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

The 24-month planning process is made up of overlapping 18-month planning cycles (Refer to Exhibit 1) to identify and develop shorter lead-time transmission upgrades and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades that may be required to satisfy planning criteria. Consistent with the requirements of the NERC TPL Reliability Standards the 24-month planning process includes both near-term (years one through five) and long-term (years six through fifteen) assessments of the transmission system as described below.

The first step in the process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at Transmission Expansion Advisory Committee and Subregional RTEP Committees meetings. A series of power-flow base cases are then developed based on the assumptions. The yearly series of cases include the latest information and assumptions available related to load, resources and transmission topology. A new 5-year base case is developed for near-term baseline reliability analysis. Base cases for retool analyses of years closer than 5-years are developed as required. Retool analysis is used to review previously established assumptions, later in the planning cycle, as those assumptions may have changed.

In addition to these near-term base cases additional power-flow base cases are developed for long-term planning. These long-term cases are used to evaluate the need for more significant projects requiring a longer time to develop. These longer lead time projects generally provide a more regional benefit. The long-term base case developed at the start of each 24-month planning cycle is based on the system conditions that are expected to exist in year eight. As noted in Exhibit 1, this 8-year out base case is updated and retooled at the start of the second year of the 24-month planning cycle (i.e. at that point a 7-year out base case), with additional criteria analysis being run to validate the findings from the analysis that was conducted during the first year of the 24-month planning cycle.

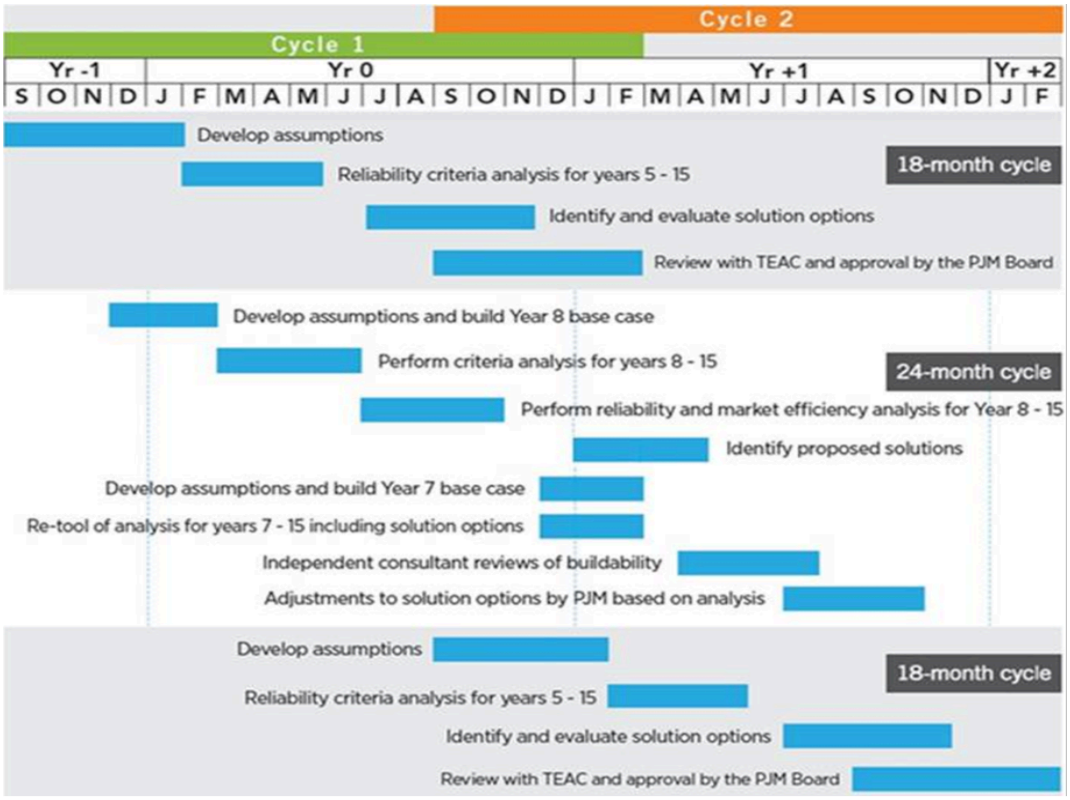


Exhibit 1: 24-Month Reliability Planning Cycle

The scope of the near-term baseline analysis that is completed as part of each 12-month planning cycle includes an exhaustive review of applicable reliability planning criteria on all BES facilities as described in section 2.3 of this manual. As noted above, PJM typically performs this near-term analysis on a 5-year out base case. Retool analyses of previous near-term assessments are also completed, as required. Any identified criteria violations are reviewed with stakeholders throughout the planning process. Ultimately, solutions to address the criteria violations are developed, reviewed with the TEAC and/or Sub-regional RTEP Committee as applicable, and submitted to the PJM Board of Managers for approval. Through this planning process, a baseline system without any criteria violations is developed for the near-term (i.e., 5-year baseline). This baseline system, without any criteria violations, is then used for subsequent Cycle studies.

Long-term planning is also completed as part of the development of the RTEP to identify solutions to planning criteria violations that require longer lead times to implement. As part of the 24-month planning cycle PJM initially develops an 8-year out base case that is used to evaluate planning criteria for the long-term planning horizon. Long term criteria analysis is completed on this base case during the first year of the 24-month cycle. A combination of a full

AC power flow solution and linear analysis, as described in this manual, is used to determine the loading on facilities for years 8 through 15. Violations and proposed solutions to address them are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 2, during the second year of the 24-month planning cycle, the base case used for the long-term analysis during the first year (i.e., now year 7) is updated to reflect the latest assumptions about load, generation, DR, EE, and transmission topology. Long term criteria analysis is completed on this base case during the second year of the 24-month cycle. A combination of a full AC power flow solution and linear analysis, as described in this manual, is again used to determine the loading on facilities for years 7 through 15. Potential violations identified during the first year are validated and the proposed solutions to address those violations are refined during the second year of the 24–month planning cycle. An independent consultant may be used to develop an independent cost estimate and evaluate the constructability of proposed solutions. Results from these long-term analyses, including potential violations and their solutions, are reviewed with the TEAC throughout the 24-month planning process. Ultimately, any required long-lead time solutions that are identified through this planning process are presented to the PJM Board of Managers for approval.

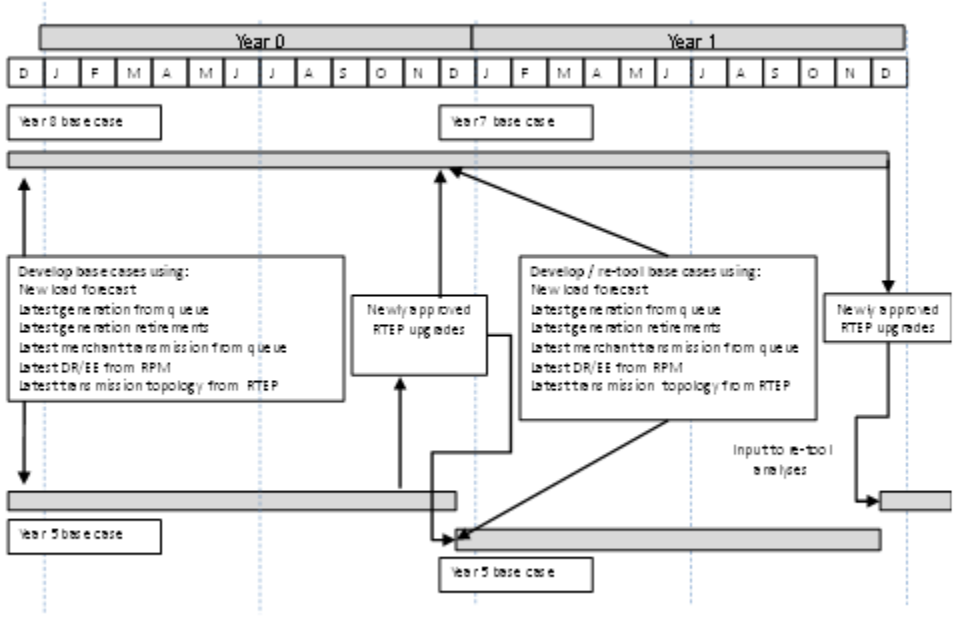


Exhibit 2: Base Case Development

2.1.3 Market Efficiency Planning

Exhibit 3 shows the 24-month Market Efficiency process used for the 15-year RTEP horizon. Activities shown on this diagram and their timing are for illustrative purposes. The actual timeline may vary to some degree to be responsive to the RTEP and stakeholder needs.

The 24-month Market Efficiency process is made up of two similar 12-month cycles to identify approved RTEP projects that may be accelerated or modified and one 24-month planning cycle to provide sufficient time for the identification and development of longer lead-time transmission upgrades.

The first step in the Market Efficiency process is to develop the set of assumptions that will be used for the subsequent analyses. These assumptions are vetted with stakeholders at the Transmission Expansion Advisory Committee meetings.

The scope of the near-term Market Efficiency analysis that is completed as part of each 12-month planning cycle includes a review of the congestion in year 1 and year 5 and existing approved RTEP projects. This review will identify approved RTEP projects that may be accelerated or modified and meet the Market Efficiency Benefit/Cost criteria as explained in accompanying sections of this Manual 14B.

Long-term Market Efficiency planning is also completed as part of the development of the RTEP to identify solutions that require longer lead times to implement. As part of the 24-month Market Efficiency planning cycle, PJM initially develops a base case for years 1, 5, 8, 11, and 15 that are used to evaluate congestion for the long-term planning horizon. A higher level base case is developed for year 15 and may require a less detailed model of the transmission system below the 500 kV level as explained in section 2.6.5 of this manual. Proposed solutions to address Market Efficiency projected congestion are developed by stakeholders and PJM staff during the first year of the 24-month planning cycle. As shown in Exhibit 3, during the second year of the 24-month cycle, the base cases used for the long-term analysis during the first year (i.e., now year 0, 4, 7, 10, and 14) will be updated, as appropriate, to reflect the latest assumptions regarding load, generation, demand response, transmission topology, or other input assumptions.

Congestion issues identified during the first year are validated and the proposed solutions are refined during the second year of the 24–month cycle. An independent consultant may be used to develop a cost estimate and evaluate the constructability of proposed solutions. Results from these long-term analyses are reviewed with the Transmission Expansion Advisory Committee throughout the 24-month planning process, and, ultimately, presented to the PJM Board of Managers for approval.

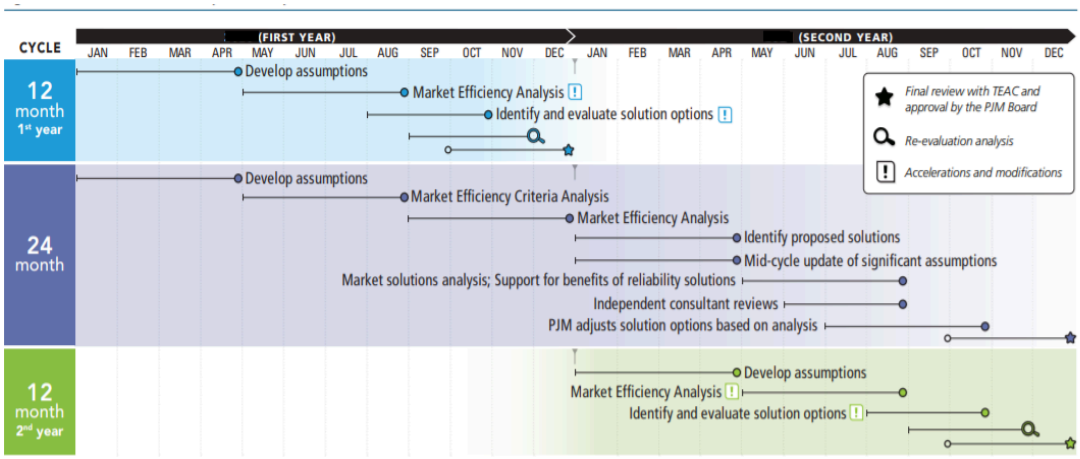


Exhibit 3: 24-Month Market Efficiency Cycle

2.2 The RTEP Process Drivers

The continuing evolution and growth of PJM's robust and competitive regional markets rests on a foundation of bulk power system reliability, ensuring PJM's ongoing ability to meet control area load-serving obligations. It also includes a commitment to enhance the robustness and competitiveness of Energy and Capacity markets by incorporating analysis and development of market efficiency projects. Schedule 6 of the PJM Operating Agreement describes the PJM RTEP process, governing the means by which PJM coordinates the preparation of a plan for the enhancement and expansion of the Transmission Facilities – on a reliable and environmentally sensitive basis and in full consideration of available economic and market efficiency factors and alternatives - in order to meet the demands for firm transmission service in the PJM region. PJM's FERC-approved RTEP process preserves this foundation through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single RTEP.

The PJM Region transmission planning process is driven by a number of planning perspectives and inputs, including the following:

- ReliabilityFirst Regional Reliability Corporation[2] (RFC) Reliability Assessment – forward-looking assessments performed to assure compliance with NERC and applicable regional

2 Reliability*First*, a new regional reliability corporation under the North American Electric Reliability Corporation (NERC), replaced three existing PJM-related reliability councils (ECAR, MAAC and MAIN) on January 1, 2006.

reliability corporation (ReliabilityFirst or SERC Reliability Corporation) reliability standards, as appropriate.

- SERC Reliability Corporation (SERC) Reliability Assessment
- PJM Annual Report on Operations – an assessment of the previous year's operational performance to assure that any bulk power system operational conditions which have emerged, e.g., congestion, are adequately considered going forward.
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests – submitted by the developers of new generating sources and new Merchant Transmission Facilities, these requests seek interconnection in the PJM Region (or seek needed enhancements as the result of increases in existing generating resources.)
- Transmission Owner and other stakeholder transmission development plans
- Interregional transmission development plans – the transmission expansion plans of those power systems adjoining PJM, and in some cases, beyond.
- Long-term Firm Transmission Service Requests
- Activities under the PJM committee structure especially, the Planning Committee (PC), the Transmission Expansion Advisory Committee (TEAC), the Subregional RTEP Committee, and local groups facilitated by PJM within the TEAC established processes (see section 1 "TEAC, Subregional RTEP Committee, and related planning activities".)
- PJM Development of Economic Transmission Enhancements based on Economic and Market Efficiency factors
- Operational performance assessments and reviews such as the aging Infrastructure Initiative – a Probabilistic Risk Assessment of equipment that poses significant risk to the Transmission System.

The cumulative effect of these drivers is analyzed through the PJM Region transmission planning process to develop a single RTEP which recommends specific transmission facility enhancements and expansion on a reliable and environmentally sensitive basis and in full consideration of economic and market efficiency analyses. See Attachment B for details of the RTEP – Scope and Procedure.

Note:
The most recent version of the PJM RTEP is available PJM Web site at http://www.pjm.com/planning/rtep-upgrades-status.aspx.

These analyses are conducted on a continual basis, reflecting specific new customer needs as they are introduced, but also readjusting as the needs of Transmission Customers and Developers change. One such RTEP baseline regional plan will be developed and approved each year.

Note:

Generation deactivations, depending on the date of the announced retirement to PJM, have the potential to impact study results for any New Service Request that does not have an executed final agreement. Generation retirements that are announced to PJM by the Application Deadline of a Cycle will be turned offline in the base case model created for that particular Cycle and available to be turned on to contribute to but not back off flowgate loadings per the PJM Generator Deliverability Test procedures. Per Tariff Part VIII, Subpart E, Section 426, the unit will remain offline in the model until the CIRs expire (if not claimed by a New Service Request), one year after their actual deactivation date. If the CIRs do expire, the unit will be removed from the model.

In this way, the plan continually represents a reliable means to meet the power system requirements of the various Transmission Customers and Project Developers in a fully integrated fashion, at the same time preserving the rights of all parties with respect to the Transmission System. The assurance of a reliable Transmission System and the protection of the Transmission Customer/Developer rights with respect to that system coupled with the timely provision of information to stakeholders are the foundation principles of the PJM transmission planning process.

The PJM Region transmission planning process also establishes the cost responsibility for the following types of facility enhancements as defined in the PJM Tariff:

- Attachment Facilities
- Direct Assignment Facilities
- Network Upgrades (Direct and Non-direct)
- Distribution Upgrades
- Merchant Network Upgrades

Each RTEP encompasses a range of proposed power system enhancements: circuit breaker replacements to accommodate increased current interrupting duty cycles; new capacitors to increase reactive power support; new lines, line reconductoring and new transformers to accommodate increased power flows; and, other circuit reconfigurations to accommodate power system changes as revealed by the drivers discussed above.

Requests for interconnection of new generators or transmission facilities, while not the sole drivers of the PJM Region transmission planning process, are a key component of the RTEP. Analyzing these requests has required adoption of an approach that establishes baseline system improvements driven by known inputs, followed by separate Cycle-defined, cluster-based impact study analyses. Overall, PJM‘s RTEP process – under a FERC-approved RTO model – encompasses independent analysis, recommendation and approval to ensure that facility enhancements and cost responsibilities can be identified in a fair and non-discriminatory

manner, free of any market sector's influence. All PJM market participants can be assured that the proposed RTEP was created on a level playing field.

2.3 RTEP Reliability Planning

2.3.1 Establishing a Baseline

In order to establish a reference point for the annual development of the RTEP reliability analyses a 'baseline' analysis of system adequacy and security is necessary. The purpose of this analysis is threefold:

- To identify areas where the system, as planned, is not in compliance with applicable NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards including equipment replacement and/or upgrade requirements under PJM's Aging Infrastructure Initiative. The baseline system is analyzed using the same criteria and analysis methods that are used for assessing the impact of proposed new interconnection projects. This ensures that the need for system enhancements due to baseline system requirements and those enhancements due to new projects are determined in a consistent and equitable manner.
- To develop and recommend facility enhancement plans, including cost estimates and estimated in-service dates, to bring those areas into compliance.
- To establish the baseline facilities and costs for system reliability. This forms the baseline for determining facilities and expansion costs for interconnections to the Transmission System that cause the need for facilities beyond those required for system reliability.

The system as planned to accommodate forecast demand, committed resources, and commitments for firm transmission service for a specified time frame is tested for compliance with NERC and the applicable regional reliability council (ReliabilityFirst or SERC) standards, Nuclear Plant Licensee requirements, PJM Reliability Standards and PJM design standards. Areas not in compliance with the standards are identified and enhancement plans to achieve compliance are developed.

The 'baseline' analysis and the resulting expansion plans serve as the base system for conducting Phase I System Impact Studies for all proposed generation and/or merchant transmission facility interconnection projects and subsequent System Impact Studies.

2.3.2 Baseline Reliability Analysis

PJM's most fundamental responsibility is to plan and operate a safe and reliable Transmission System that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. This responsibility is addressed by PJM RTEP reliability planning. Reliability planning is a series of detailed analyses that ensure reliability under the most stringent of the applicable NERC, PJM or local criteria. To accomplish this each year, the RTEP cycle extends and updates the transmission expansion plan with a 15 year review. This cycle entails several steps. The following sections describe each step's assumptions, process and

criteria. Attachments A through F of this manual add essential details of various aspects of the reliability planning process.

Reliability planning involves a near-term and a longer term review. The near term analysis is applicable for the current year through the current year plus 5. The longer term view is applicable for the current year plus 6 through plus 15. Each review entails multiple analysis steps subject to the specific criteria that depend on the specific facilities and the type of analysis being performed.

The analysis is initiated following the completion of case builds and concludes with review by the TEAC and approval by the PJM Board (TEAC and the PJM Board are appraised regularly throughout the process and partial reviews and approvals of the plan may occur throughout the year.) The TEAC, Subregional RTEP and PJM Planning Committee roles in the development of the reliability portion of the RTEP are described in Schedule 6 of the PJM Operating Agreement.

2.3.3 Near-Term Reliability Review

The near-term reliability review (current year plus 5) provides reinforcement for criteria violations that are revealed by applicable contingency analysis. Limits used in the analysis are established consistent with the requirements of NERC standards FAC-010 and FAC-014. The methodology used to determine system operating limits is included in Attachment-F of this manual. System conditions revealed as near violations will be monitored and remedied as needed in the following year near-term analysis. Violations that occur in many deliverability areas or severe violations in any one area will be referred to the long term analysis for added study of possible more robust system enhancement. PJM annually conducts this detailed review of the current year plus 5. The annual review shall include system peak load for either year one or year two, and for year five.

For the annual evaluation of the near-term, sensitivity cases shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible conditions that demonstrate a measurable change in system response.

- Real and reactive forecasted load
- Expected transfers
- Expected in service dates of new or modified transmission facilities
- Reactive resource capability
- Generation additions, retirements, or other dispatch scenarios
- Controllable loads and demand side management

Duration or timing of known transmission outages

Each year of the period through the current year plus 4 (“in-close” years) has been the subject of previous years’ detailed analyses. In addition, for each of these “in-close” years, PJM updates and issues addendum to address changes as necessary throughout the year. For example planned generation modifications or changes in transmission topology can trigger restudy and the issuance of a baseline addendum. This is referred to as a “retool” study. (For example generators that drop from the Cycle cause restudy and an addendum to be issued for affected baseline analyses.) Also each year during the establishment of the assumptions for the new annual baseline analysis, current updated views of load, transmission topology, installed generation, and generation and transmission maintenance are assessed for the “in-close” range of years to validate the continued applicability of each of the “in-close” baseline analyses and resulting upgrades (including any addendum.) Adjustments in the “in-close” analyses are performed as deemed necessary by PJM. PJM, therefore, annually verifies the continued need for or modification of past recommended upgrades through its retool studies, reassessment of current conditions and any needed adjustments to analyses. All criteria thermal and voltage violations resulting from the near term analyses are produced using solved AC power flow solutions. Initial massive contingency screening may use DC power flow solution techniques.

There are seven steps in an annual near-term reliability review. They are:

- Develop a Reference System Power Flow Case
- Baseline Thermal
- Baseline Voltage
- Load Deliverability - Thermal
- Load Deliverability - Voltage
- Generator Deliverability - Thermal
- Baseline Stability

These reliability related steps are followed by a scenario analysis that ensures the robustness of the plan by looking at impacts of variations in key parameters selected by PJM. Each of these steps is described in more detail in the following material.

2.3.4 Reference System Power Flow Case

The reference power flow case and the analysis techniques comprise the full set of analysis assumptions and parameters for reliability analysis. Each case is developed from the most recent set of Eastern Reliability Assessment Group system models. PJM transmission planning revises this model as needed to incorporate all of the current system parameters and assumptions. These assumptions include current loads, installed generating capacity, transmission and generation maintenance, system topology, incorporation of the most recently finalized Local Plans and firm transactions. These assumptions will be provided to and reviewed by the Subregional RTEP Committee. The subregional modeling review and modeling assumptions meeting provides the opportunity for stakeholders to review and provide input to the development of the reference power system models used to perform the reliability analyses.

The results of any locational capacity market auction(s) will be used to help determine the amount and location of generation or demand side resources to be included in the reliability modeling. Generation or demand side resources that are cleared in any locational capacity market auction will be included in the reliability modeling, and generation or demand side resources that either do not bid or do not clear in any locational capacity market auction will not be included in the reliability modeling. All such modeling described here will comport with the capacity construct provisions approved by the FERC.

Subsequent to the subregional stakeholder modeling reviews facilitated by PJM, PJM will develop the final set of reliability assumptions to be presented to TEAC for review and comment, after which PJM will finalize the reliability review reference power flow. This model is expected to be available in early January of each year to interested stakeholders, subject to applicable confidentiality and CEII requirements, to facilitate their review of the results of the reliability modeling analyses.

2.3.5 Contingency Definitions

Contingency definitions used in RTEP analysis are the same as applicable NERC TPL contingency definitions. In addition to studying all contingency types listed in TPL-001 Table 1, PJM also studies bus tie breaker openings without a fault as a single contingency. Where the physical design of connections or breaker arrangements results in the outage of more than the faulted equipment when a fault is cleared, the additional facilities are also taken out of service in the contingency definition. For example, if a transformer is tapped off a line without a breaker, both the line and transformer are removed from service as a single contingency event.

Contingency definitions for double circuit tower line outages shall include any two adjacent (vertically or horizontally) circuits on a common structure, but shall exclude circuits that share a common structure for one mile or less. The loss of more than two circuits on a common structure constitutes a NERC extreme event.

PJM will coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems which may impact their system are included in the contingency list.

2.3.6 Baseline Thermal Analysis

Baseline thermal analysis is a thorough analysis of the reference power flows for light load, summer and winter to ensure thermal adequacy based on normal (applicable to system normal conditions prior to contingencies) and emergency (applicable after the occurrence of a contingency) thermal ratings specific to the Transmission Owner facilities being examined. It is based on a 50/50 load forecast for the applicable period from the latest available PJM Load Forecast Report (50% probability that the actual load is higher or lower than the projected load.) It encompasses an exhaustive analysis of all single and common mode (NERC P0, P1, P2, P4, P5 and P7 events). Final results are supported with AC power flow solutions. Demand Response is not considered in the baseline analysis.

2.3.7 Baseline Voltage Analysis

Baseline voltage analysis parallels the thermal analysis. It uses the same power flow models for light load, summer and winter and examines voltage criteria for all the same NERC P0, P1, P2, P4, P5, and P7 set of single and common mode outage events.

Analysis will simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. Those devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. PJM examines system performance for both a voltage drop criteria (where applicable) and a voltage magnitude criteria. The voltage drop is calculated as the decrease in bus voltage from the initial steady state power flow to the post-contingency power flow. The post-contingency power flow is solved with generators holding a local generator bus voltage to a pre-contingency level consistent with specific Transmission Owner specifications. In most instances this is the pre-contingency generator bus voltage. Additionally, all phase shifters, transformer taps, switched shunts, and DC lines are locked for the post-contingency solution. SVC's are allowed to regulate and fast switched capacitors are enabled.

The voltage magnitude criteria is examined for the same contingency set by allowing transformer taps, switched shunts and SVC's to regulate, locking phase shifters and allowing generators to hold steady state voltage criteria (generally an agreed upon voltage on the high voltage bus at the generator location.)

In all instances, specific Transmission Owner voltage criteria are observed. All violations are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Post-Contingency voltage analysis shall also include the impact of tripping generators where the simulated generator bus voltages or the high side of the generation step up (GSU) transformer are less than known or assumed minimum generator steady state of ride through voltage limitations. All violations will be reported and tentative solutions will be developed. The results of these studies will be reviewed through the TEAC.

2.3.8 NERC P3 and P6 "N-1-1" Analysis

Purpose

N-1-1 studies are conducted as part of the annual RTEP to determine if all monitored facilities can be operated:

- Within normal thermal and voltage limits after N-1 (single) contingency assuming re-dispatch and system adjustments, and
- Within the applicable emergency thermal ratings and voltage limits after an additional single contingency (N-1-1) condition.

All violations of the applicable thermal ratings are recorded and reported and tentative solutions will be developed. These study results will be presented to and reviewed with stakeholders.

Model

Annually, the N-1-1 study is conducted on a 50/50 non-diversified summer and winter peak case. The case building details are defined in Attachment C (C7 3.0 Step 1: Develop Base Case). Non-firm Merchant Transmission withdrawals can be removed. All BES facilities in PJM and ties to PJM will be monitored. In addition, non-BES facilities included in the real-time congestion management facility list will be examined on the light load case. Areas of the system that become radial post-contingency will be excluded from monitoring, with the following exceptions

- If the radial system contains greater than 300 MW of load, or
- Specific local TO Planning Criteria require that it be monitored.

Contingencies considered:

- All BES single contingencies as defined in NERC P3 and P6 as well as lower voltage facilities that are monitored by PJM Operations will be included in the assessment. Non-BES contingencies, defined by Transmission Owners, need to be included to check for greater than 300 MW load loss impacting numerous customers. Non-BES facilities that are included in the assessment will also have corresponding contingencies defined.

AC Solution Options in the PSS/E program:

- For the first single contingency (N-1 Condition) and to ensure the system remains within emergency thermal ratings
  - Transformer tap adjustment enabled
  - Switched shunt adjustment enabled
- After the first single contingency (N-1 Condition) and to return the system back within normal thermal ratings
  - Phase shifter adjustment enabled
  - System re-dispatched
  - Topology changes implemented
- For the second single contingency (N-1-1 Condition) – Voltage Drop Test (if applicable)
  - Transformer tap adjustment disabled
  - Phase shifters locked to control angle, not flow
  - Switched shunt adjustment disabled except for fast switched capacitors
  - Generators are set to regulate their terminal bus
  - SVC’s are allowed to regulate
  - Automatic shunt adjustment disabled

- For the second single contingency (N-1-1 Condition) – Thermal and Voltage Magnitude Test
  - Transformer tap adjustment enabled
  - Phase shifters locked to control angle, not flow
  - Switched shunt adjustment enabled
  - Automatic shunt adjustment enabled

PJM NERC P3 and P6 “N-1-1” Methodology

Thermal Test Methodology:

The PJM NERC P3 and P6 “N-1-1” Analysis will test the outage of every single contingency (N-1 condition)

The first step of the test is to ensure that post-contingency loadings of all facilities shall be within their emergency thermal ratings immediately following the first N-1 contingency

The second step of the test is to ensure that post contingency loadings of all facilities shall be within their normal thermal ratings after the first N-1 contingency and subsequent re-dispatch and system adjustments. Allowable system adjustments include generation dispatch, phase shifter adjustment, system reconfiguration and load throw-over.

The third step is to take the second N-1-1 contingency. Every second N-1-1 contingency is taken on every optimized N-1 scenario case to model the N-1-1 condition. After the second N-1-1 contingency, the thermal loading of any monitored facility that is above the applicable emergency thermal rating (long-term or short-term) is considered a reliability criteria violation and a mitigation plan will be needed.

Voltage Drop Test Methodology

The N-1-1 Voltage Drop Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency voltage drop limit after the second contingency (N-1-1 condition.) The calculation of voltage drop is defined in section 2.3.7.

Voltage Magnitude Test

The N-1-1 Voltage Magnitude Test procedure follows a similar method as the thermal test method, except all monitored facilities are monitored for the emergency low and high limit after the second contingency (N-1-1 condition.)

Voltage Collapse

Voltage collapse is considered to be a severe reliability violation, and consequently each N-1-1 condition that exhibits voltage collapse needs to be investigated, validated, and resolved with remedial actions, or network upgrades.

System Adjustments

Allowable System Adjustments following the first contingency (N-1 condition):

- Application of all effective actions and emergency procedures, with the exception of load shedding
- Redispatch using only PJM generators with capacity rights during the generation redispatch process
- Application of a PJM pool-wide generation availability rate during generator re-dispatch to ensure that the re-dispatch is statistically possible
- Un-faulted facilities in multiple facility outages may be restored
- Manual system switching and re-configuration
- Opening of transmission facilities
- Including bus-ties
- Closing of non-faulted transmission facilities
- Including bus-ties
- Adjustment of Static VAR Compensators (SVCs)
- Phase shifter adjustment
- Wind, solar, and other variable resources will be dispatchable up to their capacity delivery rights if they back off simulated facility loadings.
- The rest of resources can be either off line or dispatched between Pmin and (1- PJM generator average outage rate)* Pmax

Allowable System Adjustments following the second contingency (N-1-1 condition):

No manual system adjustments permitted

2.3.9 Load Deliverability Analysis

The load deliverability tests are a unique set of analyses designed to ensure that the Transmission System provides a comparable transmission function throughout the system. These tests ensure that the Transmission System is adequate to deliver each load area's requirements from the aggregate of system generation. The tests develop an "expected value" of loading after testing an extensive array of probabilistic dispatches to determine thermal limits. A deterministic dispatch method is used to create imports for the voltage criteria test. The Transmission System reliability criterion used is 1 event of failure in 25 years. This is intended to design transmission so that it is not more limiting than the generation system which is planned to a reliability criterion of 1 failure event in 10 years.

Each load areas' deliverability target transfer level to achieve the transmission reliability criterion is separately developed using a probabilistic modeling of the load and generation system. The load deliverability tests described here measure the design transfer level supported by the Transmission System for comparison to the target transfer level. Transmission upgrades are specified by PJM to achieve the target transfer level as necessary. Details of the load deliverability procedure can be found in Attachment C.

Thermal

This test examines the deliverability under the stressed conditions of a 90/10 summer and winter load forecast. That is, a forecast that only has a 10% chance of being exceeded. The transfer limit to the load is determined for system normal and all single contingencies (NERC P0 and P1 criteria) under ten thousand load study area dispatches with calculated probabilities of occurrence. The dispatches are developed randomly based on the availability data for each generating unit. This results in an expected value of system transfer capability that is compared to the target level to determine system adequacy. As with all thermal transmission tests applied by PJM the applicable Transmission Owner normal and emergency ratings are applied. The steady state and single contingency power flows are solved consistent with the similar solutions described for the baseline thermal analyses.

Voltage

This testing procedure is similar to the thermal load deliverability test except that voltage criteria are evaluated and that a deterministic dispatch procedure is used to increase study area imports. The voltage tests and criteria are the same as those performed for the baseline voltage analyses.

2.3.10 Generator Deliverability Analysis

The generator deliverability test ensures that the Transmission System is capable of delivering the aggregate system generating capacity at summer peak load with all firm transmission service modeled. Additionally, to help ensure that generating resources are deliverable year round, expected generation output levels during light load and winter conditions are examined as part of the generator deliverability analysis. As a result, there are three separate periods examined as part of the generator deliverability analysis. The procedure ensures sufficient transmission capability in all areas of the system to export an amount of generation capacity at least equal to the amount of certified Capacity Resources in each "area". Areas, as referred to in the generator deliverability test, are unique to each study and depend on the electrical system characteristics that may limit transfer of Capacity Resources. For generator deliverability, areas are defined with respect to each transmission element that may limit transfer of the aggregate of certified installed generating capacity. The cluster of generators with significant impacts on the potentially limiting element is the "area" for that element. The starting point power flow cases for the light load, summer and winter are the same power flow case set up for the baseline analysis, but the applicable baseline load and ratings criteria apply for the period under consideration. The flowgates ultimately used in the reliability analysis are determined by running

all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. Single and common mode contingencies (NERC TPL P1, P2-2, P2-3, P2-4, P4 and P7) in PJM and just outside of PJM are examined during the generator deliverability analysis. Details of the generator deliverability procedure including methods of creating the study dispatch can be found in Attachment C.

2.3.11 Spare Equipment Strategy Review

PJM will annually evaluate an entity's spare equipment strategy that could result in the unavailability of major transmission equipment that has a lead time of one year or more (such as a transformer). Steady state analysis is performed for the P0, P1 and P2 planning event categories and stability analysis is performed for the P1 and P2 planning event categories defined in Table 1 of NERC TPL-001-5.1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

2.3.12 Baseline Stability Analysis

PJM ensures generator and system stability during its interconnection studies for each new generator. In addition, PJM annually performs stability analysis for approximately one third of the existing generators on the system. Analysis is performed on the RTEP baseline stability cases. These analyses ensure the system is transiently stable and that all system oscillations display positive damping with damping ratio consistent with section G.2.2. Generator stability studies are performed for critical system conditions, which include light load and peak load for three phase faults with normal clearing plus single line to ground faults with delayed clearing. Also, specific Transmission Owner designated faults are examined for plants on their respective systems.

Finally, PJM will initiate special stability studies on an as needed basis. The trigger for such special studies commonly includes but is not limited to conditions arising from operational performance reviews or major equipment outages.

2.3.13 Extreme Event Review

The extreme review identifies specific extreme contingencies as defined in Table 1 of NERC Standard TPL-001-5.1 and assesses their impact on system reliability. If the initial analysis shows cascading caused by the occurrence of extreme events, PJM will perform an evaluation of possible action designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s). This can include a stability analysis of the area and an evaluation of possible actions to reduce the likelihood of the event or mitigate the consequences and impacts on the system.

PJM will also assess the impact of extreme events using stability analysis. Extreme events contained in Table 1 of NERC TPL-001-5.1 that produce more severe impacts shall be identified and a list created of those events will be maintained and distributed to the appropriate entities. The rationale for those contingencies selected for evaluation shall be available as supporting information. If the initial analysis shows cascading by the occurrence of extreme events, PJM

will perform an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s).

2.3.14 Long Term Reliability Review

The PJM RTEP reliability review process examines the longer term planning horizon, which spans the current year plus 6 through the current year plus 15, using a 24-month reliability planning cycle. At the beginning of the first year of the cycle, a 5-year out base case, a long-term 8-year out base case and a 10-year out base case are developed and evaluated. At the beginning of the second year of the cycle, new 5-year out, 7-year out and 10-year out base cases are developed and evaluated. Assumptions and model development regarding this longer term view will be presented and reviewed and stakeholder input will be considered in the same process used for the near-term review. The longer term view of system reliability is subject to increased uncertainty due to the increased likelihood of changes in the analysis as time progresses. The purpose of the long term review is to anticipate system trends which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation during the near term horizon 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. 7 and/or 8 year analysis is only required when 15 year analysis shows potential issues.

Current Year Plus 15 Analysis

The Longer term reliability review involving single and multiple contingency analyses is conducted to detect system conditions which may need a solution with a lead-time to operation exceeding five years. Two processes will be used as indicators to determine the need for contingency analysis in the longer term horizon. The first is a review of the near-term results to detect violations that occur for multiple deliverability areas or multiple or severe violations clustered in a one area of the system. This review may suggest larger projects to collectively address groups of violations. The second is a thermal analysis including double circuit towerline outages at voltages exceeding 100 kV performed on the current year plus fifteen system. All of the current year plus fifteen results produced will be reviewed to determine if any issues may require longer lead time solutions. If so such solutions will be determined and considered for inclusion in RTEP.

This evaluation of the need for longer lead time solutions considers that the NERC P2, P3, P4, P5, P6 and P7 results may employ load shedding and/or curtailment of firm transactions to ease potential violations. Also this review considers that the current year plus fifteen planning horizon exceeds the required NERC planning horizon. The main effect of this extension to 15 years is to examine a load level that is significantly higher than the base forecast year-ten planning load level. This year fifteen analysis, therefore, captures the equivalent (in a 10-year horizon) of a higher load forecast plus weather sensitivity. To the extent that this long term reliability thermal review indicates marginal system conditions that may require a longer lead time solution, PJM will undertake additional longer term analyses as may be needed.

The long term deliverability analyses follow a similar pattern to the near-term load and generator deliverability analyses. The long term, however, relies solely on linear DC analysis whereas all near term violations result from analysis solutions that rely on the full AC power flow. The load deliverability case is set up for a 90/10 load level and the generator deliverability case is set up for a 50/50 load level. Generation dispatches are determined consistent with the methods for the near term analyses. The analysis for the longer term horizon evaluates all NERC P0 and P1 single contingencies against the same normal and emergency thermal ratings criteria used for the near term (subject to any upgrades that may be applicable for the longer term.)

Reactive Analysis

In addition, the longer term review includes a current year plus 10 reactive analysis. This focuses on contingencies involving facilities above 200 kV in areas where the preceding year-15 analysis uncovered thermal violations. Areas experiencing thermal violations that also show earlier reactive deficiencies will be reviewed for possible acceleration of any longer lead time thermal solutions that were suggested by the year-15 analysis. This analysis, as necessary from year to year, will also consider long-term upgrade sensitivity to key variables such as load power factor delivered from the Transmission System or heavy transfers. If uncovered violations are insufficient to justify acceleration of upgrades and are all amenable to shorter lead-time upgrades, then the violations will continue to be monitored in future RTEP analyses.

2.3.15 Stakeholder review of and input to Reliability Planning

RTEP reliability planning, through the operation of the TEAC and Subregional RTEP Committees, provides interested parties with the opportunity to review and provide meaningful and timely input to all phases of the reliability planning analyses. This section extends the Section 1 discussion of the TEAC and Subregional RTEP Committee process specifically as it relates to reliability planning. Exhibit 1 shows the workflow and timing for the reliability planning process steps. PJM anticipates at least two Subregional RTEP Committee reliability reviews. The initial subregional meeting will present and address reliability study assumptions and parameters. The second meeting will provide the opportunity for stakeholder comment and input on criteria violations and presentations of alternative remedies to identified violations. Between the two meetings PJM will provide feedback on interim study progress sufficient to enable stakeholder preparation for the second set of subregional meetings. Additional subregional meetings will be facilitated as PJM determines is necessary for adequate input and review. The relative timing of the TEAC and subregional activities are illustrated in Exhibit 1.

Subregional RTEP Committee initial assumptions meeting

This meeting is expected to occur in ***December*** of each year in preparation for the upcoming annual RTEP review. Prior to the meeting PJM will post its anticipated inputs and assumptions to enable stakeholder review and preparation for the meeting. At the meeting PJM will present the assumptions for discussion and input by all interested parties. Subsequent to this meeting stakeholders will have additional opportunity to provide input to PJM in preparation for the next TEAC meeting, at which PJM will present the final reliability assumptions for TEAC review.

Although the initial Subregional assumptions meeting will discuss anticipated assumptions for both the reliability and market efficiency phase of the RTEP, The final TEAC review of each will likely occur at separate TEAC meetings (see also the market efficiency discussion following.) The TEAC endorsement of final RTEP reliability assumptions is expected to occur in early ***January***.

PJM development of criteria violations and stakeholder participation

After the TEAC endorsement of PJM's RTEP analysis assumptions, PJM will finalize its reference system power flow which is the starting point of its series of reliability analyses. This power flow is available to stakeholders subject to applicable confidentiality and CEII requirements. PJM will perform its series of detailed RTEP reliability analyses encompassing the 15-year planning horizon. Details of the methods and procedures for the reliability analyses can be found elsewhere in this Manual 14B and its attachments. The five-year and longer time-frame criteria violations will be posted for review, evaluation and development of remedy alternatives by all interested parties. The PJM production of the reliability analysis raw results is expected to occur about ***January through July*** of each year. Posting of the results and stakeholder review and consideration of alternative remedies is expected to occur about ***February through August*** of each year. PJM will post TO and other stakeholder alternative upgrade remedies made available throughout this process. Throughout this time frame, TEAC typically has monthly or more frequent regularly scheduled meetings. PJM will periodically apprise TEAC of the progress of the violations identification and production of upgrade alternatives. Stakeholders may use these meetings to raise and discuss issues found in their reviews. Depending on the issues raised and input from stakeholders PJM may facilitate Subregional RTEP Committee meetings instead of or in addition to a scheduled TEAC meeting. These subregional meetings are intended for more focused review of subregional violations and alternative solutions.

Subregional RTEP Committee criteria violations and upgrade alternative meeting

This meeting is expected to occur, as may be necessary in various subregions, in the ***July / August*** timeframe each year. If a subregional meeting is unnecessary, the regularly scheduled TEAC meetings will provide the opportunity for that subregion's participants open discussion of violations and upgrades. In any event, all regional and subregional projects will be appropriately presented and reviewed at a TEAC meeting. Prior to a subregional violations and upgrade meeting, PJM will post the upgrade solutions that it proposes to remedy the identified criteria violations. At this subregional meeting PJM will present the reliability upgrades of specific violations and alternative upgrades as may be appropriate. By this Subregional RTEP Committee meeting, interested parties will have had the opportunity for ongoing participation in the ***February through August*** process of violation review and solution identification along with PJM and Transmission Owners. This subregional criteria violations and upgrade meeting is the forum for a final open discussion of the subregional reviews which have been occurring, prior to presentation to TEAC.

PJM TEAC Committee RTEP review

PJM expects that about ***August*** of each year, the final RTEP upgrade facilities will be available for presentation, review and endorsement at a scheduled TEAC meeting. PJM will post its recommendations of RTEP upgrades for identified violations as early as possible in the month prior to the TEAC meeting at which the final RTEP facilities will be reviewed (see RTEP@pjm.com). This posting will distinguish facilities that are deemed Supplemental RTEP Projects. After the TEAC RTEP review meeting, there will be about a month of additional time for final written comments on the proposed RTEP facilities, after which the PJM Board will consider the final RTEP plan excluding Supplemental Projects for approval.

2.3.16 Corrective Action Plan

PJM will prepare an annual Planning Assessment of its portion of the BES. For planning events shown in Table 1, when the analysis indicates an inability of the system to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned system shall continue to meet the performance requirements in Table 1. The Corrective Action Plan shall list system deficiencies and associated actions need to achieve required system performance. Examples of such actions include:

- Installation, modification, retirement or removal of Transmission and Generation facilities and any associated equipment
- Installation, modification or removal of Protection Systems or Remedial Action Schemes.
- Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan

Additionally, the Corrective Action Plan shall include action to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.4 RTEP integrates Baseline Assumptions, Reliability Upgrades and Request Evaluations

PJM's robust energy market has attracted numerous requests from generator and transmission Project Developers for interconnections with the Transmission System. These Interconnection Requests constitute a significant driver of regional transmission expansion needs. This

subsection discusses this driver in the context of the RTEP preparation. Details of this process are contained in Manual 14H.

Requests for Long Term Firm Transmission Service and generator deactivations are other types of request that are evaluated and incorporated into RTEP.

Demand Response (DR) can be a load response solution to the need for transmission upgrades. DR solutions enter the PJM process in the Reliability Pricing Model (RPM) through the associated base residual and incremental auctions. The DR cleared in the auction is included in the assumptions for RTEP development and physically modeled in the baseline power flows. In this manner, load can mitigate or delay the need for RTEP upgrades.

The RTEP process baseline analyses include previously processed generators and transmission modifications as starting point assumptions. The current year RTEP evaluations performed on this baseline case are incremental to the baseline and establish a “revised” baseline for the year of the annual RTEP analysis. This revised baseline forms the starting case for the reviews of new interconnection requests. The new interconnection request analyses result in system modifications beyond RTEP upgrades that are caused by interconnection requests. New interconnection request evaluations also include a review of their effects on newly approved RTEP upgrades that are not yet committed to construction. If previously identified RTEP upgrades can be delayed because of new interconnection requests, the projects responsible for the upgrade deferrals will be credited for the benefits of the delayed need for the upgrades.

The RTEP integrates reliability upgrades, interconnection request upgrades and plan modifications and DR effects into a single process that accounts for the mutual interaction of the various market forces. In this way, transmission upgrades, interconnection requests and DR receive comparable treatment with respect to their opportunity to relieve transmission constraints.

Timing of Long-Term Firm Transmission Service Requests, and Generation and Transmission Interconnection Requests are based on the business needs of the party requesting the service. Such requests, therefore, enter the RTEP planning process throughout the RTEP planning year. Expansion plans that result from New Service Request evaluations are incorporated into the RTEP once a New Service Request’s applicable final agreement has been executed. In addition, if needed to satisfy assumed planning reserve requirements for future planning year analyses, generators in Phase III System Impact Study may also be included. Only the generators with completed signed final agreements, however, are allowed to be used to alleviate constraints.

2.5 RTEP Cost Responsibility for Required Enhancements

The RTEP encompasses two types of enhancements: Network Reinforcements and Direct Connection Attachment Facilities. Network Reinforcements can be required in order to

accommodate the interconnection of a merchant project (generation or transmission) or to eliminate a Baseline problem as a result of system changes such as load growth, known transmission owner facility additions, etc. Merchant project driven upgrades are addressed in Manual 14H. The cost responsibility for each baseline-revealed Network Reinforcement is borne by transmission owners based on the contribution to the need for the network reinforcement. Such costs are recoverable by each transmission owner through FERC-filed transmission service rates. Network reinforcements may also be proposed by PJM to mitigate unhedgeable congestion. Allocation procedures for Baseline and Market Efficiency upgrades are discussed in Attachment A.

Overall, the RTEP is best understood from the perspective of the studies that revealed the recommended Plan enhancements. To that end, the Baseline Analysis and Impact Studies identify the enhancements required to meet defined NERC and applicable regional reliability council (Reliability First or VACAR/SERC) standards, Nuclear Plant Licensee requirements and PJM reliability standards.

2.6 RTEP Market Efficiency Planning

Market efficiency analysis is performed as part of the overall PJM Regional Transmission Expansion Planning (RTEP) process to accomplish the following objectives:

- Identify new transmission enhancements or expansions that could relieve transmission constraints that have an economic impact.
- Review cost and benefits of economic-based transmission projects previously included in the Regional Transmission Expansion Plan (RTEP) to assure that they continue to be cost beneficial.
- Determine which reliability-based transmission projects, if any, have an economic benefit if accelerated or modified

Each year, as part of the 24-Month Market Efficiency Cycle, PJM performs a market efficiency analysis following the completion of the near-term reliability plan for the region. As a result, there is a mechanism in place for regularly identifying transmission enhancements or expansions that will relieve transmission constraints that also have an economic impact. Constraints that have an economic impact include, but are not limited to, constraints that cause: (1) significant historical gross congestion; (2) pro-ration of Stage 1B ARR; (3) significant future congestion as forecast in the market efficiency analysis; or (4) Reliability Pricing Model constraints identified in accordance to OATT Attachment DD Section 15.

In the market efficiency analysis, PJM will compare the costs and benefits of the economic-based transmission improvements. To calculate the benefits of these potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed accelerated reliability-based enhancements or the newly proposed economic-based enhancements for selected future years within the planning horizon of the RTEP. The relative benefits and costs of the economic-based enhancement or expansion must meet the benefit/

cost ratio threshold test to be included in the RTEP recommended to the PJM Board of Managers for approval (This test and its implementation is described in detail in Attachment E.) PJM will present all the RTEP market efficiency enhancements to the TEAC Committee for review and comment. Subsequent to TEAC review, PJM will address the TEAC review and present the final RTEP market efficiency plan to the PJM Board, along with the advice, comments, and recommendations of the TEAC Committee, for Board approval.

2.6.1 Market Efficiency Analysis and Stakeholder Process

PJM's market efficiency analysis involves several phases. The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM will collect and publicly post relevant drivers. These metrics will be reviewed by PJM and all stakeholders to assess the system areas that are most likely candidates for market efficiency upgrades. In addition, PJM will perform market simulations to determine projections of future market congestion based on the anticipated RTEP upgraded system. This process facilitates concurrent PJM and stakeholder review of the same information considered by PJM in preparation for PJM's solicitation of stakeholder input for upgrades that may economically alleviate market inefficiencies. This solicitation of input will be at a Transmission Expansion Advisory Committee meeting. Following the evaluation of congestion drivers and solicitation of remedies, PJM will initiate an analysis phase which first examines the potential economic costs and benefits that may be associated with any upgrades specified during the reliability analysis. After this assessment, PJM will evaluate the economic costs and benefits of any identified new potential upgrades target specifically at economic efficiency. The following information looks at each of these phases in more detail.

2.6.2 Determination and evaluation of historical congestion drivers

Transmission solutions to mitigate congestion causing a pro-ration of existing or future Stage 1A ARR requests will be determined and recommended for inclusion in the RTEP with a recommended in-service date based on the 10-year Stage 1A simultaneous feasibility analysis results. This recommendation will also include a high-level analysis of the cost and economic benefits of the upgrade as additional information but such upgrades will not be subject to market efficiency cost/benefit analysis. More information on the ARR allocation auction process can be found in Manual 6.

Congestion causing pro-ration of Stage 1B ARR requests will be addressed using the "with and without" analysis and the benefit/cost ratio threshold described previously in this market efficiency material.

2.6.3 Determination of projected congestion drivers and potential remedies

PJM will provide all stakeholders with estimates of the projected congestion by performing annual hourly market simulations of future years using a commercially available market analysis software modeling tool (see assumptions and criteria material in Section 1.) This simulation will produce and PJM will post projected binding constraints, binding hours, average economic

impact of binding constraints, and cumulative economic impact of binding constraints for the four RTEP market efficiency analyses.

At this time PJM will also facilitate a TEAC meeting, as appropriate, to review congestion and solicit feedback from the stakeholders' review of the projected congestion data. All stakeholders can provide input to PJM's consideration of the congestion data to be considered for market efficiency solutions to identified economic issues.

Parties wishing formally to submit proposals to address congestion as identified in the Market Efficiency Analysis may do so as described in section 2.6.7 of this manual.

2.6.4 Evaluation of cost / benefit of advancing reliability projects

PJM will perform annual market simulations and produce cost / benefit analysis of advancing reliability projects. An initial set of simulations will be conducted for current year plus 1 and current year plus 5 using the "as is" transmission network topology without modeling future RTEP upgrades. A second set of simulations will be conducted for each year using the as planned RTEP upgrades. A comparison of the "as is" and "as planned" simulations will identify constraints which have caused significant historical or simulated congestion costs but for which an as-planned upgrade will eliminate or relieve the congestion costs to the point that the constraint is no longer an economic concern. A comparison of these simulations will also reveal if a particular RTEP upgrade is a candidate for acceleration or expansion. For example, if a constraint causes significant congestion in year 1 but not in year 5 then the upgrade which eliminates this congestion in the year 5 simulation may be a candidate for acceleration. The benefit of accelerating this upgrade would then be compared to the cost of acceleration as described below before recommendation for acceleration is made.

When the reliability project economic acceleration analyses have been completed, PJM will schedule a TEAC or Subregional Committee meeting, as appropriate, to review the results. The timing of this meeting will depend, to some extent, on the amount and complexity of analysis that must be performed. However, it is anticipated that this meeting will take place during the ***fourth quarter*** of each year. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis and a description of any recommendations for accelerating reliability projects based on economic considerations.

2.6.5 Determination and evaluation of cost / benefit of potential RTEP projects specifically targeted for economic efficiency

PJM will perform market simulations and produce cost / benefit analysis of projects specifically targeted for economic efficiency. The benefit component of the cost / benefit analysis (Total Annual Enhancement Benefit) could consist of an energy market benefit, a Reliability Pricing Model (RPM) benefit, or both if the project addresses both energy market and RPM constraints. The net present value of annual benefits will be calculated for the 15 year period starting with the RTEP year defined as current year plus 5 minus benefits for years where the project is not

yet in service. The net present value of annual benefits will be compared to the net present value of the upgrade revenue requirement for the same 15 year period.

2.6.5.1 Determination of Energy Market Benefits

An initial set of simulations will be conducted for each of four years for the current 24-month cycle (current year plus 1, current year plus 5, current year plus 8 and current year plus 11) using the as planned transmission network topology and the as planned generation expansion as defined by the most recent RTEP. A second set of simulations will be conducted for each of the four years using the as planned transmission network topology plus the upgrade being studied. The upgrade will be included in each of the four simulation years regardless of the actual anticipated in-service date of the upgrade. A comparison of these simulations will identify the benefit of the upgrade in each of the four years analyzed. The simulated benefits will provide a forecast of annual upgrade benefits for each of the anticipated first 15 years beginning from the RTEP year. Annual benefits within the 10-year time frame for years which were not simulated would be interpolated using these simulation results. A forecast of annual benefits for years beyond the 10-year simulation time frame would be based on an extrapolation of the market simulation results from the studied years. A higher-level annual market simulation will be made for future year 15 to validate the extrapolation results and the extrapolation of annual benefits for years beyond the 10-year simulation time frame may be adjusted accordingly. This high level simulation of future year 15 may require a less detailed model of the transmission system below the 500 kV level.

2.6.5.2 Determination of Reliability Pricing Model (RPM) Benefits

To determine RPM benefits, PJM will perform and compare RPM simulations with and without the upgrade for the RPM year (current year plus 3) and the RTEP year (current year plus 5). A comparison of these simulations will identify the annual economic impact of the upgrade for each of these study years. A forecast of annual benefits for years beyond the RTEP year will be based on a linear extrapolation of the market simulation results from the studied years.

2.6.5.3 Determination of Benefits/Cost ratio

An extrapolation of the simulation results will provide a forecast of annual upgrade benefits for each of the 15 years, beginning from the RTEP year. The present value of annual benefits projected for the 15 year period starting with the RTEP year defined as current year plus 5 minus benefits for years where the project is not yet in service will be compared to the present value of the upgrade revenue requirement for the same period to determine if the upgrade is cost beneficial and recommended for inclusion in the PJM RTEP. For informational purposes only, when comparing competing projects PJM will set the annual revenue requirement for projects not yet in service to zero and include annual benefits as a negative number to reflect loss of benefits to PJM. If the ratio of the present value of benefits to the present value of costs exceeds 1.25 then the upgrade is recommended for inclusion in the RTEP.

When the economic efficiency project evaluations have been completed, PJM will schedule a TEAC meeting, as appropriate, to review the results. The timing of this meeting may depend on the amount and complexity of analysis that must be performed. At this meeting PJM will provide a summary of the analysis results, including an update of the Market Efficiency analysis.

2.6.6 Determination of final RTEP market efficiency upgrades

PJM will perform a combined review of the accelerated reliability projects and new market efficiency projects that passed the economic screening tests to determine if there are potential upgrades with electrical similarities. This may result in new projects to replace the original projects to form a more efficient overall market solution. PJM will evaluate the cost / benefits of any such resulting "hybrid" projects[3]. The final list of reliability projects and market efficiency projects, including any "hybrid" projects will be presented and discussed at a TEAC meeting. At this TEAC meeting PJM will review all the Market efficiency plans resulting from this cycle of market efficiency studies. Recommended projects will be taken to the PJM Board for endorsement, and will either be included in subsequent RTEP analysis if there is a "volunteer" to build the project, or a report will be filed with FERC in accordance with Schedule 6 of the PJM Operating Agreement. As part of this request for endorsement, PJM will provide the written comments submitted by the parties, and will discuss these written comments with the PJM Board.

Within the limits of confidential, market sensitive, trade secret, and proprietary information, PJM will make all of the information used to develop the Market Efficiency recommendations available to market participants to use in their own, independent analyses.

For each enhancement which is analyzed, PJM will calculate and post on its website changes in the following metrics on a zonal and system-wide basis: (i) total energy production costs (fuel costs, variable O&M costs and emissions costs); (ii) total load energy payments (zonal load MW times zonal load Locational Marginal Price); (iii) total generator revenue from energy production (generator MW times generator Locational Marginal Price); (iv) Financial Transmission Right credits (as measured using currently allocated Auction Revenue Rights plus additional Auction Revenue Rights made available by the proposed acceleration or modification of a planned reliability-based enhancement or expansion or new economic-based enhancement or expansion); (v) marginal loss surplus credit; and (vi) total capacity costs and load capacity payments under the Reliability Pricing Model construct.

3 Hybrid transmission upgrades include solutions which encompass modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

For each market efficiency project proposed for RTEP, PJM will also post, as soon as practical, the following:

- Anticipated high-level project schedule and milestone dates
- Final commitment date after which any change to input factors or drivers will not result in transmission project deferral or cancellation.

After this TEAC meeting, any member of the TEAC can provide written comments within sixty (60) days of this meeting. These written comments will consist of three (3) sections:

- Introduction, which will describe the party submitting the comments and their reason for submitting these comments
- Summary, which will consist of no more than 3 pages summarizing the positions described in the written comments
- Discussion, which will consist of no more than 20 pages describing in detail the positions taken by the party

2.6.7 Submitting Proposals

Any TEAC member or other entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit proposals for evaluation under the Market Efficiency analysis within the RTEP proposal window. These proposals will be posted on the PJM Website. Market Efficiency Proposals will not be accepted for acceleration or modifications to existing approved RTEP projects.

Regardless of all proposals considered – whether proposed by PJM or other parties - PJM will establish a “go/no-go” decision-point deadline (or final commitment date) after which existing RTEP transmission components will not be deferred or cancelled. This will provide certainty to developers, owners and investors.

2.6.8 Ongoing Review of Project Costs

To assure that projects selected by the PJM Board for Market Efficiency continue to be economically beneficial, both the costs and benefits of these projects will be reviewed on an annual basis. Substantive changes in the costs and/or benefits of these projects will be reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide measurable economic benefit and should remain in the RTEP.

For Market Efficiency projects included in the RTEP with capital costs under $20M, PJM will not be required to reevaluate both updated costs and benefits annually if the project’s benefit/cost ratio remains at or above 1.25, using the original benefits. However, if the benefit/cost ratio of such projects falls below 1.25 based on PJM’s annual review of the project’s updated cost estimate, PJM will reevaluate the need for the project using both updated cost estimates and benefits.

PJM will no longer be required to review updated costs and benefits of a market efficiency project once the certificate of public convenience and necessity or its equivalent is granted by the state in which the facilities will be located. If no certificate of public convenience or necessity or its equivalent is required by the state in which the transmission facilities will be located, PJM will no longer be required to review updated costs and benefits of a market efficiency project once the project commences construction activities at the project site. Notwithstanding the foregoing, PJM reserves the right to reevaluate any project.

For projects with a total cost exceeding $50 million, an independent review of project costs and benefits will be performed to assure both consistency of estimating practices across PJM and that the scope of the project is consistent with the project as proposed in the Market Efficiency analysis.

2.7 Evaluation of Operational Performance Issues

As per Schedule 6, section 1.5 of the PJM Operating Agreement, PJM is required to address operational performance issues and include system enhancements, as may be appropriate, to adequately address identified problems. To fulfill this obligation, PJM Transmission Planning staff and Operations Planning staff annually review actual operating results to assess the need for transmission upgrades that would address identified issues. Typical operating areas of interest in these reviews include Transmission Loading Relief (TLR), Post Contingency Local Load Relief Warning (PCLLRW) events, and persistent uplift payments.

The first operational performance issue to be addressed through the RTEP was an upgrade of the Wylie Ridge 500/345 kV transformation. The metric applied to designate Wylie Ridge an operational performance issue was the TLR metric. This same metric is applied consistently across the PJM footprint.

In addition, PJM has also developed and initiated use of a tool for Probabilistic Risk Assessment (PRA) of transmission infrastructure. PJM's 500/230 kV transformer infrastructure has been identified as particularly suited for assessment using this tool. PRA is further discussed in following sections.

2.7.1 Operational Performance Metrics

Events and metrics considered in the annual operational performance reviews are not limited to a specifically defined list and will be responsive to events and conditions that may arise. In addition, PJM stakeholders may raise operational issues to PJM's attention for consideration during the RTEP process through interactions with the Planning, TEAC or Subregional RTEP Committees.

The PJM TLR metric identifies facilities that result in over 1,000 hours or 100 occurrences of TLR level 3 or higher on an annual basis. These facilities will be evaluated through the RTEP process for system enhancement.

For PCLLRW events, PJM will review all such events after the conclusion of the peak season. The initiating facilities will be determined and the expected impacts of planned RTEP upgrades will be reviewed and the need for additional planned upgrades will be evaluated.

For Uplift payments, PJM will annually review the persistent uplift payments and the system condition or driver for the payment. PJM will assess the impact of planned RTEP upgrades on the drivers for the uplift and the need for additional planned upgrades will be evaluated. The evaluation of the need for additional upgrades will consider the frequency and amount of the uplift payment as well as any outage or short term system conditions that may have caused the uplift. Upgrades will be considered to mitigate uplift payments that are expected to continue in the future.

PRA evaluation uses an economic analysis of the cost of the investment that mitigates a risk and the dollar value of the avoided risk. The mitigation strategy cost, prime rate and payback period are used to determine if the strategy cost is less than the value of risk. Projects with lower cost than risk are candidates for the RTEP.

2.7.2 Probabilistic Risk Assessment of PJM 500/230 kV Transformers

One significant element of PJM's operational performance reviews involves a risk evaluation aimed at anticipating significant transmission loss events. PJM integrates aging infrastructure decisions into the ongoing RTEP process: analysis, plan development, stakeholder review, PJM Board approval, and implementation, over PJM's entire footprint. Thus, the aging infrastructure initiative implements a proactive, PJM-wide approach to assess the risk of transmission facility loss and to mitigate operational and market impacts of such losses.

PRA's initial implementation at PJM is a risk management tool employed to reduce the potential economic and reliability consequences of transmission system equipment losses. In collaboration with academia, vendors and member TOs, PJM integrated various input drivers into a transformer PRA initiative to manage 500/230 kV transformer risk. In the case of the 500/230 kV transformers, risk is the product of the probability of incurring a loss and the economic consequence of the loss. Probability of loss is determined based on the individual transformer unit's condition assessments and vintage history. Economic loss impact is based upon the duration of the loss and the accumulation of unhedgeable congestion costs, or the increased cost of running out of merit generation to meet load requirements after a transformer loss. If lead times for 500/.230 kV transformer units are as great as eighteen months, then outage durations can be long if adequate loss mitigation is not in place. The PRA outputs the annual risk to the PJM system of each transformer unit in terms of dollars. The annual risk dollars are then used to justify mitigating solutions such as redundant bank deployment, proactive replacement or adding spares. The deployment strategy chosen will depend on the level of risk mitigation and reliability benefit.

While initially developed for aging 500/230 kV transformers, the PRA tool is capable of assessing other equipment types and other transformer voltage classes. The PRA tool is commercially available software.

2.8 End of Useful Life Issues

For each transmission need identified pursuant to FERC Form No. 715 or other Transmission Owner planning criteria addressing the end of useful life of an existing facility, which, in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes, each Transmission Owner should provide information, to the extent available, that supports the need for the project consistent with the Transmission Owner's planning criteria in accordance with the RTEP process or Attachment M-3 Process, as applicable.

2.9 Critical Substation Planning Analysis

PJM will evaluate all proposed system reinforcements, consistent with RTEP critical substation planning analysis methods incorporated in cascading trees tool software. This analysis is performed as part of the 5 year annual RTEP cycle, as described in Section 2.3.3 of this manual, to determine if any projects addressing other drivers cause concern from a critical substation planning analysis perspective.

Critical substation planning analysis is performed to identify Instability, Uncontrolled Separation, or Cascading resulting in one or more of the following outcomes due to the loss of all voltage levels 69 kV and above at a single transmission facility that has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation:

Voltage Value of a Line	Weight Value per Line
Less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

1. Loss of load approaching 1000 MW impacting numerous customers
    - Includes consequential load loss and tripped load
    - Total loss of load should be considered
2. Three levels of facility trips
    - Includes line, transformers and generators
    - Tripped elements should include 69kV and above facilities.
3. Case fails to converge after tripping of facilities, assuming non-convergence isn't due to modeling issues or load pockets

If a proposed project fails the critical substation planning analysis, PJM may modify the technical specifications of a proposal so that is avoids a failure of the critical substation planning analysis (CSPA), as defined above in this Section 2.9. This may result in the modified proposal being determined to be the more efficient or cost-effective proposal for recommendation to the PJM Board.

Attachment A: PJM Baseline Reliability Upgrade Cost Allocation Procedures

A.1 Purpose

One of the responsibilities of PJM as an RTO is to allocate the cost responsibility for all system reinforcement projects including projects required for Customer interconnection requests and baseline transmission reliability upgrades. Manual 14H addresses request-driven upgrade cost allocation procedures. The cost allocation procedures used by PJM for baseline reliability upgrades are described below. The methodology in Schedule 12 of the PJM Tariff that is the bases of these cost allocation procedures was developed and filed by the PJM Transmission Owner and approved by FERC for PJM implementation.

A.2 Scope

The PJM Cost Allocation Procedures are presented in two parts: “PJM Generation and Transmission Interconnection Cost Allocation Methodologies” discusses the cost allocation methodology for projects required for generator and transmission interconnections in Manual 14H and: “Schedule 12 Cost Allocation Process for Baseline Transmission Reliability” describes the cost allocation methodology and procedures for baseline transmission reliability projects.

A.3 Schedule 12 Cost Allocation Process for Baseline Transmission Reliability Upgrades

In addition to allocating the costs of interconnection projects (described above), PJM is responsible, under Schedule 6 of the Operating Agreement and Schedule 12 of the Tariff, for determining the cost allocation of all RTEP baseline reliability upgrades and submitting them to the PJM Board for approval. Allocation of transmission upgrades for reliability is beneficiary based. With respect to reliability projects, while a definitive benefit is from the elimination of a reliability criteria violation, the benefit quantified for the purpose of cost allocation is the use of the upgrade by PJM load zones. The usage of the reliability project by a PJM load zone relative to the usage by all other PJM load zones will be used to determine the percentage cost responsibility to be assigned to the zone. As the usage changes with system topology changes, PJM shall recalculate the cost allocation percentage on an annual basis

A.3.1 RTEP Baseline Reliability Upgrade Cost Allocation

PJM’s allocation of cost responsibility for RTEP reliability baseline upgrades in accordance with these provisions is beneficiary based. Typically, load growth creates conditions that constitute violations of reliability criteria, which in turn require upgrades for eliminating the violations. The benefit to load from elimination of the violation will differ from the benefit of having the resultant

upgrade available for use to deliver PJM generation to serve them. However, the benefit derived by the load in a transmission zone can only be determined by the use of the upgrade to deliver PJM generation to this load zone relative to similar uses of the upgrade by other zonal loads. This quantifiable benefit is then used to determine the relative responsibility for the cost of the system upgrade(s) for each zone.

To the extent that a criteria violation is based on the thermal limits of a transmission facility, the cost allocation is based directly on the relative use of the upgrade facility by the load in each zone. However, for criteria violations based on voltage criteria, thermal surrogates are developed and employed for the allocation such that the flow on the surrogate (i.e., a transmission facility or group of facilities) best correlates to the reactive performance of the system at the point of the criteria violation. The same approach described above is then utilized to simulate the relative use of the thermal surrogates. Accordingly, the cost allocation for the solution to the voltage criteria violation is based on the relative use of thermal surrogates by load in each zone.

Under this approach to cost allocation, it is entirely possible, and certainly consistent with the allocation philosophy, that the costs of upgrades in one transmission zone may be allocated in significant part to load in other transmission zones. While many required transmission upgrades are allocated entirely to load within the same zone where the criteria violation and the related upgrade are located, the nature of large, integrated transmission systems like the PJM system is such that transmission facilities in one area can be used significantly to serve loads in other areas. The planning process identifies the most effective solutions to criteria violations and the resultant use of these solutions by loads may not be related to the physical location of the transmission upgrade. Therefore, responsibility for the costs of baseline reliability upgrades likewise shall be allocated to those who use these solutions, regardless of their physical location relative to the location of the baseline reliability upgrade required to ensure the reliability of their service.

The basic categories of baseline reliability upgrades and the associated cost allocation procedures can be summarized as follows:

Regional and Necessary Lower Voltage Facilities with estimated costs greater than or equal to $5 million

50% of the cost of the upgrade will be assigned annually on a load-ratio share using the PJM Network Transmission Service Peak Load and the applicable load values for Merchant Transmission having Firm Transmission Withdrawal Rights for the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined

50% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology

Lower Voltage Facilities with estimated costs greater than or equal to $5 million

100% of the cost of the upgrade will be assigned annually on a directionally-weighted solution-based DFAX methodology

The above allocation method accounts for the bi-directional hourly use of the upgrade. The percentage of net energy flow on the facility in each direction will be determined via an 8,760 hourly production cost simulation. Those load zones having distribution factors that indicate they contribute to power flow on the facility in the same direction as the net energy flow from the production cost simulation will be responsible for the portion of the cost assigned to the use of the upgrade in that direction.

Lower Voltage Facilities with estimated costs below $5 million

100% of the cost will be assigned to the zone where the upgrade is to be located

The basic steps of the directionally-weighted, solution-based DFAX methodology are:

- Obtain peak MW loads from the most recent PJM load report

Calculate the Distribution Factor (DFAX) for each transmission zone and merchant transmission facility with firm withdrawal rights based on its use of the upgrade to deliver PJM generation to serve its load. PJM will use the annual RTEP starting base case to develop all DFAX values for new RTEP upgrades. Other than the addition of new RTEP upgrades, the starting base case will not be modified during the year. A DFAX represents a measure of the use of the upgrade by each MW of a zone's load served by a MW of PJM generation, as determined by power flow analysis. The source used for the DFAX calculation is the aggregate of all PJM generation and the sink is each Transmission Owners peak zonal load or applicable MW values for a merchant transmission with firm withdrawal rights. The import objective to the Locational Deliverability Areas (LDA) in which the transmission zone is located will also be considered during DFAX calculation as follows. In modeling the system generation and load, the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA is the external (or internal) Participation Factor and shall equal the ratio of (i) the CETO associated within that LDA (or generation internal to the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, PJM shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity.

The following example demonstrates the usage of CETO in the calculation of the internal and external Participation Factors described above. In LDA 1, for example, 66.67% of the zonal load in the LDA is served by internal generation and 33.33% of the zonal load in the LDA is served by external PJM generation.

Table 1 - CETO Application in Participation Factor Calculation for Cost Allocation

AREA	LDA 1	LDA 2	LDA 3	LDA 4
CETO (MW)	3,000	6,000	< 0	3,000
Actual Capacity (MW)	6,000	3,000	6,000	0
Internal Participation Factor	66.67%	33.33%	100.00%	0.00%
External Participation Factor	33.33%	66.67%	0.00%	100.00%

- Apply a DFAX threshold of 0.01 such that and DFAX with a magnitude less than 0.01 will be set to zero.

Select the DFAX with the lowest magnitude for zones with more than one DFAX for a particular upgrade as these zones are embedded in multiple LDAs.

- Multiply each DFAX by each zonal peak load to determine the zone's use of the upgrade in the direction indicated by the sign of the DFAX.
  - Sum the MW use of the upgrade corresponding to the same directional use of the upgrade.
  - Calculate the percentage use by each zone in each direction.
- Perform a separate 8,760 hour production cost simulation to determine the expected total energy (MH-Hour) use of the upgrade in each direction for the simulated year.
- Calculate the weighting factor (in percent) for each directional use of the upgrade.
- Calculate the cost allocation percentage from the solution-based DFAX method by multiplying the percentage use of each zonal load in each direction with the weighting factor having the same directional use of the upgrade.

RTEP Baseline Reliability Upgrade Cost Allocation Representative Example

The following representative example illustrates the cost allocation steps.

Step	Reference	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Total
1. Peak Load (MW)	From PJM Load Report	10,000	6,000	4,000	3,000	2,000	25,000
2. DFAX	From DFAX Analysis	0.050	-0.100	0.009	-0.030	0.100	
2a. Apply DFAX Threshold	Set |DFAX|<0.01 to 0	0.050	-0.100	0	-0.030	0.100	
2b. Select lowest DFAX		0.050	-0.100	0	-0.030	0.100	
3. Zonal Use of the Upgrade	Line 1 * Line 2b	500	(600)	-	(90)	200	
3a. Zonal Use in [+] Direction		500	-	-	-	200	700
3a. Zonal Use in [-] Direction		-	(600)	-	(90)	-	(690)
3b. % use in [+] Direction	Line 3a / Line 3a Total	71.43%				28.57%	100%
3b. % use in [-] Direction	Line 3a / Line 3a Total	-	86.96%	-	13.04%	-	100%
4a. Weighting Factor in [+] direction	From Production Cost simulation	80%	-	-	-	80%	
4a. Weighting Factor in [-] direction	From Production Cost simulation	-	20%	-	20%	-	
5. Calculate cost allocation Percentage	Line 3b * Line 4a	57.14%	17.39%	-	2.61%	22.86%	100%

*For regional and Necessary Lower Voltage facilities greater than or equal to $5 Million, the allocation for each LDA will be the average of the DFAX allocation and the LDA load ratio share based on the appropriate Network Service Peak Loads.

Attachment B: Regional Transmission Expansion Plan—Scope and Procedure

B.1 Purpose

The purpose of the Regional Transmission Expansion Plan (RTEP) is to develop plans which will assure reliability and meet the demands for firm transmission service in the PJM Region as described in Schedule 6 of the Operating Agreement.

B.2 Scope

As part of its ongoing responsibility, PJM Interconnection, LLC (PJM) will prepare a Regional Transmission Expansion Plan (RTEP) which shall consolidate the transmission needs of the region into a single plan. The RTEP shall reflect transmission enhancements and expansions, load and capacity forecasts, and generation additions and retirements for the ensuing five years. The RTEP shall also reflect new transmission construction and right-of-way acquisition required to support load growth in years 6 through 15.

The RTEP will:

- Provide a 5-year plan (“near term plan”) to address needs for which a commitment to expand or enhance the transmission system must be made in the near term in order to meet scheduled in service dates.
- PJM will develop the necessary documentation of previous year’s RTEP analyses and updates to demonstrate compliance with applicable criteria. Such documentation may include the most recent Baseline study for each year in the near-term planning horizon (current year through current year plus 5,) annual changes to each year’s baseline study assumptions for generation, transmission and load compared to the current year's assumptions for each respective study year, and retool studies to evaluate and ensure compliance with applicable standards and criteria for significant changes proposed to the system (Interconnection and New Service Requests.) The need for additional baseline retools will be considered and any needed restudy will be performed and reported. Retool analysis is used to review previously established assumptions, later in the planning cycle, as those assumptions may have changed.
- Provide a 15-year plan (“long term plan”) to address new transmission construction and right-of-way acquisition. System evaluations will be performed to:
    - Identify overloads 230 kV and above due to load growth for years 6 through 15. This will be completed using DC analysis only.
    - Include in the RTEP any new 230 kV or 345 kV circuits identified as required to support load growth in years 6 through 8.

  - Include in the RTEP any right-of-way acquisition required for any new 230 kV or 345 kV circuits identified as required to support load growth in years 9 and 10.
  - Include in the RTEP any new circuits 500 kV or greater identified as required to support load growth in years 6 through 12.
  - Include in the RTEP any right-of-way acquisition required for any new circuits 500 kV or greater identified as required to support load growth in years 13 through 15.
- Include reactive planning to determine if any new transmission identified in the 15-year plan should be accelerated to mitigate identified voltage criteria violations. Additional details for the reactive planning follow:
  - Development of a 10-year RTEP base case that will include Transmission Owner reactive plans.
  - The long term plan voltage analysis will be performed using contingencies 345 kV and greater and monitoring substation voltages 345 kV and greater. Analysis of lower voltage systems will be completed on an exception basis only.
  - Voltage analysis will be performed for areas where PJM identified thermal problems in years 6 through 15 or other areas as identified by PJM.
  - Based on the results of the voltage analysis, PJM will recommend appropriate modifications to the RTEP through the Transmission Expansion Advisory Committee.
- Provide an assessment based on maintaining the PJM region's reliability in an economic manner.
- Avoid any unnecessary duplication of facilities.
- Avoid the imposition of unreasonable costs on any Interconnected Transmission Owner (ITO) or any user of transmission facilities.
- Take into account the legal and contractual rights and obligations of the Interconnected Transmission Owners.
- Provide, if appropriate, alternative means for meeting transmission needs in the PJM Region.
- Provide for coordination with existing transmission systems and with appropriate interregional and local expansion plans.
- Include a designation of the Interconnected Transmission Owner or Owners or other entity that will own a transmission facility and how all reasonably incurred costs are to be recovered.
- Identify local system limitations discovered in analyzing the Transmission System.
- Include Scenario Planning evaluations beginning in mid-2006. Scenario Planning examines the long-term impacts on the reliability of the PJM system from uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the Load Forecast, Circulating transmission flow effects on system deliverability and generation scaling sensitivities.

- Include Probabilistic Risk Assessment (PRA) of Aging Transmission System Infrastructure beginning in 4Q, 2006. PRA is employed to mitigate transformer risk on the bulk power system. The consequences of a failure, both reliability and economic impacts, are then considered to implement, when appropriate, a proactive, PJM-wide approach to mitigate operational and market impacts to such failures.

The RTEP will not:

- Include an evaluation of Transmission Owner transmission expansion or enhancement plans for local area load supply, which are not needed for reliability, market efficiency or operational effectiveness of the Transmission System and do not otherwise negatively impact the Transmission System. These Transmission Owner projects (Supplemental Projects) will be identified in the RTEP for information purposes and tracked for possible future impact implications.
- Include any upgrades based solely on scaling up of generation to solve load flow studies for years 6 through 15.

B.3 Procedure

Solicit input and coordinate with Transmission Expansion Advisory Committee (TEAC) and, as appropriate, TEAC's Subregional RTEP Committee.

- Present the preliminary results of the most recent, applicable NERC regional reliability council (ReliabilityFirst and SERC) Reliability Assessments and the most recent PJM Regional Transmission Expansion Plan (RTEP).
- Present a summary of the transmission expansion or enhancement needs that will be addressed in the RTEP.
- Provide periodic updates to the TEAC on status of the RTEP.
- Solicit input on future transmission needs and requirements from those who will not be contacted directly as listed below.
- Schedule and facilitate Subregional RTEP committee reviews as may be needed to foster the goal of a transparent and participatory planning process.

Identify known Transmission System expansion or enhancement needs from the following plans and analysis results:

- Most recent, applicable Reliability Assessments (ReliabilityFirst and SERC) – (on PJM website)
- Most recent PJM Annual Report on Operations – (on PJM website)
- PJM Load Serving Entity (LSE) capacity plans
- Generator and Transmission Interconnection Requests
- Transmission Owner transmission plans
- Interregional transmission plans.

- Firm Transmission Service Requests
- PJM Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee input
- PJM Development of Economic Transmission Enhancements

PJM will consider the RTEP impacts of each Generation Project Developer ("GPD") and/or Transmission Project Developer that is currently engaged in discussion with PJM concerning plans for siting generating and/or transmission facilities.

- Typical items to be included are as follows:
  - GPD and/or Merchant Transmission Facilities developer project status, schedule, and milestones.
  - PJM will review the status of studies currently being performed or scheduled to be performed by PJM for the GPD and/or Merchant Transmission Facilities developer.
- GPD and/or Merchant Transmission Facilities developer plans will be included in the RTEP based on the following criteria:
  - Developer must be presently engaged in discussion with PJM concerning their plans for siting generating and/or transmission facilities and actively pursuing those plans. Interconnection Studies in response to requests for Generator and/or Transmission Interconnections will be conducted in accordance with the following scope:
    - Identify transmission enhancements required to meet reliability requirements over the next 5 years.
    - No studies will be conducted beyond 5 years for interconnection projects.
    - "But-for" costs will be applicable toward all system upgrades identified in the RTEP Baseline.
- GPD and/or Merchant Transmission Facilities developer plans will be treated equal to LSE plans submitted via EIA 411 in that they will be explicitly modeled and explicitly included in the RTEP report.
- GPD and/or Merchant Transmission Facilities developer plans, which have not been released publicly, will be masked to the greatest extent possible to preserve the confidentiality of the developer's identity and specific site location(s).
- GPD and/or Merchant Transmission Facilities developer plans, which were developed as a result of a PJM Phase I System Impact Study or are being developed in conjunction with a PJM Phase I System Impact Study being performed concurrent with the RTEP process, will be evaluated explicitly during the RTEP.
- GPD and/or Merchant Transmission Facilities developer plans which have not undergone a PJM Phase I System Impact Study or are not actively being developed as a result of an agreement executed with PJM to perform a Phase I System Impact Study concurrent with the RTEP process, will only be considered to the extent that the GPD generator installation or Merchant Transmission Facilities developer facility may affect the sensitivity of transmission enhancement or expansion alternatives which are being evaluated.

PJM will exchange information and data with each Transmission Owner (TO) for the purpose of developing RTEP assumptions in preparation for the Subregional RTEP Committee assumptions meeting. Typical items to be included are as follows:

- TOs will verify their transmission and capacity plans.
- TOs and PJM will discuss the status, impact, and schedule of relevant studies in which they are mutually engaged in performing.
- TOs will provide information concerning the contractual rights and obligations which PJM must consider per the RTEP protocol as listed in Schedule 6 of the PJM Operating Agreement.
- TOs will provide PJM with any information related to concerns, operating procedures, or special conditions for each of the TO's systems that PJM should consider related to the analysis to be performed for the RTEP.
- TOs will discuss the accuracy of PJM's load flow representation for each of the TO's systems including the impact of using the present representation for each of the TO's underlying systems.
- TOs will identify system needs which are currently not identified by published transmission plans but could be included for consideration during the RTEP analysis.
- TOs will provide the names, addresses, telephone numbers, FAX number, and email address for personnel identified to interact with PJM on matters dealing with the RTEP process.
- TOs will provide a confidentiality statement regarding all information released to the TO by PJM during the course of the RTEP process.
- TOs will provide information on new loads or changing loads that will impact the transmission plan.

PJM will include available information from neighboring TOs / Regional Transmission Operators, gained in the course of interregional planning activities, related to plans in other regions which may impact the PJM RTEP.

RTEP Analysis General Assumptions:

- PJM System Models will be drawn from the PJM and applicable regional reliability council (ReliabilityFirst and SERC) central planning database which includes transmission plans consistent with the most recent FERC 715 Report and most recent Regional EIA-411 Reports.
- LSE capacity models are to be based on the most recent Regional EIA-411 Reports.
- GPD capacity plans will be modeled as described in Procedures III and IV.
- When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed final agreement, PJM will model new generation to accommodate additional load growth by including generation in Phase III System Impact Study if needed to support the highest forecast load in 15 year horizon.

- PJM Load Forecasts are to be based on the most recent LAS Report.
- Power Flow models for world load, capacity, and topology will be based on the most recent Eastern Reliability Assessment Group (ERAG) power flow base cases.
- Generation outage rates will be based on the most recent generator unavailability data available to PJM. Estimates, based on historical outage rates for similar in-service units, will be used for all generating units in the neighboring regions and for all future PJM units.
- Firm sales to, and firm purchases from, regions external to PJM will be modeled consistent with the provisions for the interchange schedule as outlined in section H.1.2 of Attachment H to this manual.
- Only PJM's share of generation will be modeled to serve PJM load. Generation located within PJM, but not committed to PJM, will be accounted for in the interchange schedule.
- The Reliability Principles and Standards as shown on Attachment D to this Manual 14B, "PJM Reliability Planning Criteria."
- Stability analysis and short circuit studies will also be performed.
- All PJM Transmission System facilities 100 kV and greater, and all tie lines to neighboring systems will be monitored.
- Contingency analysis will include all facilities operated by PJM.
- The published line and transformer daytime thermal ratings at ambient temperatures of 50F (10C) winter, 95F (35C) summer and 59F (15C) light load will be used as the default rating sets for all facilities. PJM will apply alternate Transmission Owner ambient temperature rating sets wherever variations exist.
- The voltage limits applied for planning purposes will be the same as applied in PJM Operations for both normal and single contingency scenarios. For non-single contingency scenarios that are not covered in TO criteria, the voltage limits used in PJM Operations will apply.
- PJM/NYISO PAR Flows: Model 15% of the PJM to NYISO firm interchange, exclusive of merchant transmission facilities, on the Waldwick PARs, 7% on the Goethals and Farragut PARs, and 32% on the Ramapo PARs. In addition, model 80% of RECO load on the Ramapo PARs.
- Assumptions used for the economic analysis and comparison of alternatives will be included in the report.
- Planning and Markets will, annually based on historical data, develop a circulation model to be applied to the 5 year RTEP base case. This assumption will be reviewed with the PJM Planning Committee prior to implementation.

Evaluate Transmission enhancement and expansion alternatives and develop a coordinated Regional Transmission Expansion Plan.

- Develop solution alternatives for regional and subregional transmission needs.
- Evaluate solutions on a regional basis and optimize solutions to address needs on a coordinated regional basis in a single plan.

- Test the single regional plan for reliability, economy, flexibility, and operational performance based on forecasts for future years.

RTEP Deliverables

- A 5-year plan, which includes recommended regional transmission enhancements, including alternatives if applicable, that address the transmission needs for which commitments need to be made in the near term in order to meet scheduled in-service dates.
- The 5-year plan will include planning level cost estimates and construction schedules.
- The 5-year plan will specify the level of budget commitments which must be made in order to meet scheduled in-service dates. The commitment may include facility engineering and design, siting and permitting of facilities, installation or modification of metering system(s) required by Manual 01, or arrangements to construct transmission enhancements or expansions.
- The 15-year plan will identify new transmission construction and right-of-way acquisition requirements to support load growth.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

B.4 Scenario Planning Procedure

Beginning in mid-2006, PJM will include scenario planning evaluations as part of the RTEP process. Scenario planning examines the long-term impacts on the reliability of the PJM system due to uncertainty with respect to certain assumptions implicit in the development of the RTEP. PJM will examine the effects of uncertainty with respect to selected variables such as economic growth effect on the load forecast, circulating transmission flow effects on system deliverability and generation sensitivities. In the course of the RTEP planning cycle scenario planning will evaluate Transmission System requirements, as may be necessary to ensure the robustness of the RTEP. The following sensitivities will be considered:

- Load forecast for economic growth
    - The current 90/10 load values only account for weather uncertainty and do not consider economic growth deviations. An economic growth sensitivity may consider the effects of high economic growth factors and higher than forecast loads to determine the impact on RTEP baseline upgrades identified for years 6 through 10 for:
        - Eastern PJM Mid-Atlantic Region (PSE&G, JCP&L, PECO, Delmarva, AE and RECO).
        - Southwestern PJM Mid-Atlantic Region (PEPCO and BG&E).
        - Western PJM Mid-Atlantic Region (MetEd, PPL, UGI and Penelec).

        - PJM Western Region (ComEd, AEP, Dayton, Duquesne, AP, ATSI, DEOK and EKPC).
        - PJM Southern Region (Dominion).
    - System upgrades identified as required in years 6 through 10 may be advanced if the initiating overload occurs in an earlier year due to the high economic growth factor scenario.
- Circulation
    - Circulation assumptions included in the RTEP baseline analysis will be reviewed for appropriate sensitivities.
- Generation sensitivities
    - When the PJM load in the RTEP model exceeds the sum of the available in-service generation plus generation with an executed final agreement, PJM will model new generation in Phase III System Impact Study to accommodate additional load growth. This newly added generation could affect the load deliverability results either by advancing or mitigating limits. Generation sensitivities may be examined as appropriate to add information regarding the impacts of any such generators with less certain in-service dates. In addition, in areas that are experiencing load deliverability issues, sensitivities to the mitigating effects of new local generation may also be quantified.
    - PJM will analyze the results of any generation sensitivities for consideration of adjustments to any new transmission or ROW acquisition previously identified in the RTEP for years 6 through 15.
- Additional Information
    - For any overloads that resulted in transmission or ROW acquisition in years 6 through 15, PJM will provide the level of new generation or DSM per region that would eliminate the need for the transmission or ROW acquisition.

Attachment C: PJM Deliverability Testing Methods

C.1 Introduction

C.1.1 Purpose of Deliverability Requirements

Schedule 10 of the PJM Reliability Assurance Agreement states that Capacity Resources must be deliverable, consistent with a loss of load expectation as specified by the Reliability Principles and Standards, to the total system load, including portion(s) of the system in the PJM Control Area that may have a capacity deficiency at any time. Certification of deliverability means that the physical capability of the transmission network has been tested by the Office of the Interconnection and found to provide service consistent with the assessment of transfer capability internal to PJM as set forth in the PJM Tariff and, for Capacity Resources owned or contracted for by a Load Serving Entity, that the Load Serving Entity has obtained Network Transmission Service or Firm Point-to-Point Transmission Service to have capacity delivered on a firm basis under specified terms and conditions.

PJM determines the installed capacity requirements for the entire PJM footprint assuming sufficient network transfer capability will exist to ensure deliverability of these resources. In order to satisfy this assumption, the energy from generating facilities that is ultimately committed to meet this capacity requirement must be deliverable within PJM to wherever it is needed.

Deliverability ensures that the transmission system within PJM can be operated within applicable reliability criteria and ensures within those criteria that regional load will receive energy, with no guarantee as to price, from the aggregate of Capacity Resources available to PJM as demonstrated in the applicable planning studies.

C.1.2 Types of Deliverability Requirements

To maintain reliability in a competitive capacity market, Capacity Resources must contribute to the deliverability of energy within PJM in two ways. First, within an area experiencing a localized capacity emergency, or deficiency, energy must be deliverable from the aggregate of the available Capacity Resources to load. This type of deliverability is referred to as load deliverability. Failure of load deliverability tests will result in the initiation of appropriate mitigation actions, including securing additional Capacity Resources or an enhancement to the Transmission System, in order to increase the area's ability to import power.

Second, Capacity Resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM. This type of deliverability is referred to as generator deliverability. The generator deliverability test determines whether a generator qualifies for the status of a certified Capacity Resource with respect to the installed capacity obligations imposed under the Reliability Assurance Agreement. It does not guarantee any rights to specific generators to deliver energy to specific loads within PJM. Nor does it guarantee any rights to

generators to produce energy during any particular set of operational circumstances. Failure of the deliverability test for a new Capacity Resource will result in denial of full capacity rights for the generator until such generator deliverability deficiencies are corrected.

These deliverability tests ensure that the PJM Transmission System is adequate for delivery of energy from the aggregate of Capacity Resources to the aggregate of PJM load. PJM has developed comprehensive testing methodologies to verify compliance with each of these deliverability requirements.

C.2 Load Deliverability

C.2.1 Overview of Load Deliverability

C.2.1.1 Purpose of Load Deliverability

The first of these deliverability tests involves confirming that within accepted probabilities the Transmission System can support the delivery of energy from the aggregate of available PJM Capacity Resources to PJM electrical areas experiencing a capacity deficiency. This test is often discussed in the context of demonstrating deliverability to the load as opposed to deliverability of individual generation resources.

To ensure the adequacy of the generating capacity of the entire PJM footprint, the acceptable loss of load expectation (LOLE) is based on load exceeding available capacity, on average, not more than one occurrence in ten years (1/10). This concept of deliverability to load coincides with the assumptions inherent in the determination of the PJM Installed Reserve Margin (IRM), i.e. the total amount of installed capacity necessary to be at the disposal of the PJM operator to ensure delivery of energy to load consistent with an LOLE of 1/10. The determination of the IRM is based on the assumption that the delivery of energy from the aggregate of available Capacity Resources to load within the PJM footprint will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout PJM and the strength of the Transmission System to deliver energy to portions of PJM experiencing capacity deficiencies.

C.2.1.2 Locational Deliverability Areas

To test the deliverability assumptions inherent in the development of the PJM Installed Reserve Margin, electrically cohesive load areas must first be defined. The historical implementation of this test based these areas on Transmission Owner service territories and larger geographical zones comprised of a number of those service territories. Current study areas also include the definition of smaller areas within service territory boundaries. Twenty-seven Locational Deliverability Areas (LDAs) have thus far been identified including five global LDAs, which are geographical combinations of Transmission Owner service territories, and three sub-LDAs, which are portions of Transmission Owner service territories.

PJM will analyze the need for the addition of an LDA if such a need is identified through either the RTEP market efficiency or other RTEP long-term planning studies. Constrained facilities identified utilizing market efficiency studies that are not resolved by an existing approved RTEP upgrade are identified for further consideration. In addition, future constrained facilities identified utilizing the RTEP long-term planning studies may also result in the need for the addition of a new LDA. These future constrained facilities are screened using thresholds that are included in the RTEP long-term planning studies. This analysis is updated annually based on approved RTEP upgrades. 500 kV and above constrained facilities or other sets of critical facilities that advance more than three years between RTEP cycles are identified for further consideration. If the driver for such constraints advancing more than three years is linked to a specific event (e.g. significant generation retirement), it may require further analysis and the creation of a new LDA.

Once a constrained facility or group of constrained facilities has been identified under these criteria, distribution factor analysis is performed to determine the specific busses to be included in the proposed LDA. The model used to determine the distribution factors will include all approved RTEP upgrades. The specific distribution factor cutoff to be used in the development of a new LDA will be dependent upon an analysis of the specific system topology, generation and load characteristics in the vicinity of the identified constrained facility(s).

C.2.1.3 General Assumptions

C.2.1.3.1 Independent Study Area Generation Capacity Deficiency

For the purposes of analysis, each LDA within PJM is assumed to be experiencing a generation deficiency independently. Thus, the remainder of PJM is assumed to be operating normally and able to supply the study area with emergency power up to the limit of its available reserves. Load in all other PJM areas beyond the area under test will be modeled at 50/50 load level.

C.2.1.3.2 Consistency with PJM Emergency Operations Procedures

In all cases, the study area CETL analysis should reflect actual PJM emergency operations procedures designed to make as much power available to the deficient study area as possible under the prevailing system conditions. This should include but is not limited to

- The operation and redispatch of any available PJM generation external to the LDA regardless of system economics. Redispatch of Capacity Resources are allowed internal to the study area as well to relieve an overload provided that the CETO is increased by the amount of generation reduction required to eliminate the internal overload.
- The activation of any PJM Load Management (LM) schemes within the LDA that may serve to unload limiting facilities to the extent that doing so does not reduce the load in the area under test below the expected 50/50 load.
- The adjustment of any Phase Angle Regulators (PARs) which PJM or PJM member companies control within existing agreements for emergency operation. The PJM/NYISO PAR flows will be set according to Attachment B Section (B.3)(VII)(P).

- The activation of any approved PJM or PJM member company operating procedure. Operating procedures are described in PJM Manual M03 -Transmission Operations.

C.2.1.4 General Procedures

The load deliverability procedures are consistent with the changing nature of load responsibility under wholesale and retail access and provide a wide range of information about the performance of the Transmission System as electrical areas of different sizes are evaluated. The sequence of evaluating areas of differing size involves nesting small sub-areas into larger areas and finally areas into larger geographical areas of PJM to help identify the interrelationships between local and large geographical area deliverability problems.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of both Capacity Emergency Transfer Objectives (CETO) and Capacity Emergency Transfer Limits (CETL) for the various electrical areas of PJM. A CETO value represents the amount of energy that a given area must be able to import in order to meet specified applicable criteria as described in Manual 20A. CETO calculation takes into account all generation within the study area including that which may not be a PJM Capacity Resource. The CETL represents the actual ability of the Transmission System to support deliveries of energy to an electrical area experiencing such a capacity emergency. Provided that the CETL for a given area exceeds the CETO for that area, the test is passed and, on a probabilistic level, the area will be able to import sufficient energy during emergencies. The Transmission System is tested that the transmission risk does not appreciably diminish the overall target of a 1/10 LOLE for PJM.

After an LDA is defined, two generation patterns must be established. The first represents the Capacity Resource deficiency within the LDA. Based on the calculated CETO for the LDA, sufficient resources must be removed from service to create a need to import energy into the LDA. As the magnitude of the deficiency is adjusted, single contingency analysis is used to establish the CETL value. The second generation pattern required represents the dispatch of the remainder of PJM and surrounding non-PJM areas, and is comprised of a much larger number of generators that are not experiencing any emergency conditions. The larger area in PJM is modeled as experiencing only normal levels of unit outages simulated through existing RTEP base case procedures (see also “Deliverability of Generation”).

Both thermal and voltage studies under single contingency conditions are performed at the CETO to determine potential overload conditions and substations with voltage issues. For each LDA, two different dispatches at the CETO import level are examined. The first dispatch is based on a probabilistic approach whereby up to 10,000 different generation outage scenarios within the study area are simulated to create a statistically-based Mean Dispatch Case. The second dispatch uses a combination of discrete generator outages and scaled generator outputs in the LDA to create a Discrete Outage Case.

C.2.2 Current Locational Deliverability Area Definitions

A study area, also referred to as a Locational Deliverability Area (LDA), area may consist of a single PJM transmission owner's transmission system (345 kV and below for the Mid-Atlantic system) with its connected load and generation. The study area may also consist of a portion of such an LDA. In both of these cases, the study area is referred to as a Zonal study area. A study area may also consist of a geographical combination of various transmission systems (with all connected load and generation) sharing common bulk facilities for importing power. Study areas comprised of combinations of Zonal study areas are referred to as Global study areas. Assessment of both Zonal and Global study areas will identify the most restrictive emergency import margins with respect to reliability criteria and deliverability of Capacity Resources to load within the PJM footprint.

PJM Global CETL Study Areas

Eastern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in PECO, PSE&G, JCP&L, Delmarva, AE, and RECO.

Southern Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in BG&E and PEPCO.

Western Mid-Atlantic Area – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed, PP&L and UGI.

Mid-Atlantic Region – Comprises all load and generation connected 500 kV and lower in Penelec, Met-Ed, PP&L, UGI, BG&E, PEPCO, PECO, PSE&G, JCP&L, Delmarva, AE and RECO.

Western Region – Comprises all load and generation connected 765 kV and lower in ComEd, ATSI, AEP, Dayton, DEOK, Duquesne, AP, OVEC, and EKPC. Note that CPP is within the ATSI transmission Zone.

PJM Zonal CETL Study Areas

Penelec – All load and generation connected at 345 kV and below.

AP – All load and generation connected at 500 kV and below.

ATSI – All load and generation connected at 345 kV and below.

Cleveland – All load and generation connected at 345 kV and below as defined in Figure E-3

DEOK – All load and generation connected at 345kV and below.

EKPC – All load and generation connected at 345 kV and below.

Met-Ed - All load and generation connected at 230 kV and below.

PP&L - All load and generation connected at 230 kV and below.

BG&E - All load and generation connected at 230 kV and below.

PEPCO - All load and generation connected at 230 kV and below.

JCP&L - All load and generation connected at 230 kV and below.

PECO - All load and generation connected at 230 kV and below.

AE - All load and generation connected at 230 kV and below.

PSE&G - All load and generation connected at 345 kV and below.

Delmarva - All load and generation connected at 230 kV and below.

ComEd - All load and generation connected at 765 kV and below.

AEP - All load and generation connected at 765 kV and below.

Dayton - All load and generation connected at 345 kV and below.

Duquesne - All load and generation connected at 345 kV and below.

Dominion – All load and generation connected at 500 kV and below.

Delmarva South - All load and generation connected at 230 kV and below as defined in Figure E-1.

PSE&G North - All load and generation connected at 345 kV and below as defined in Figure E-2.

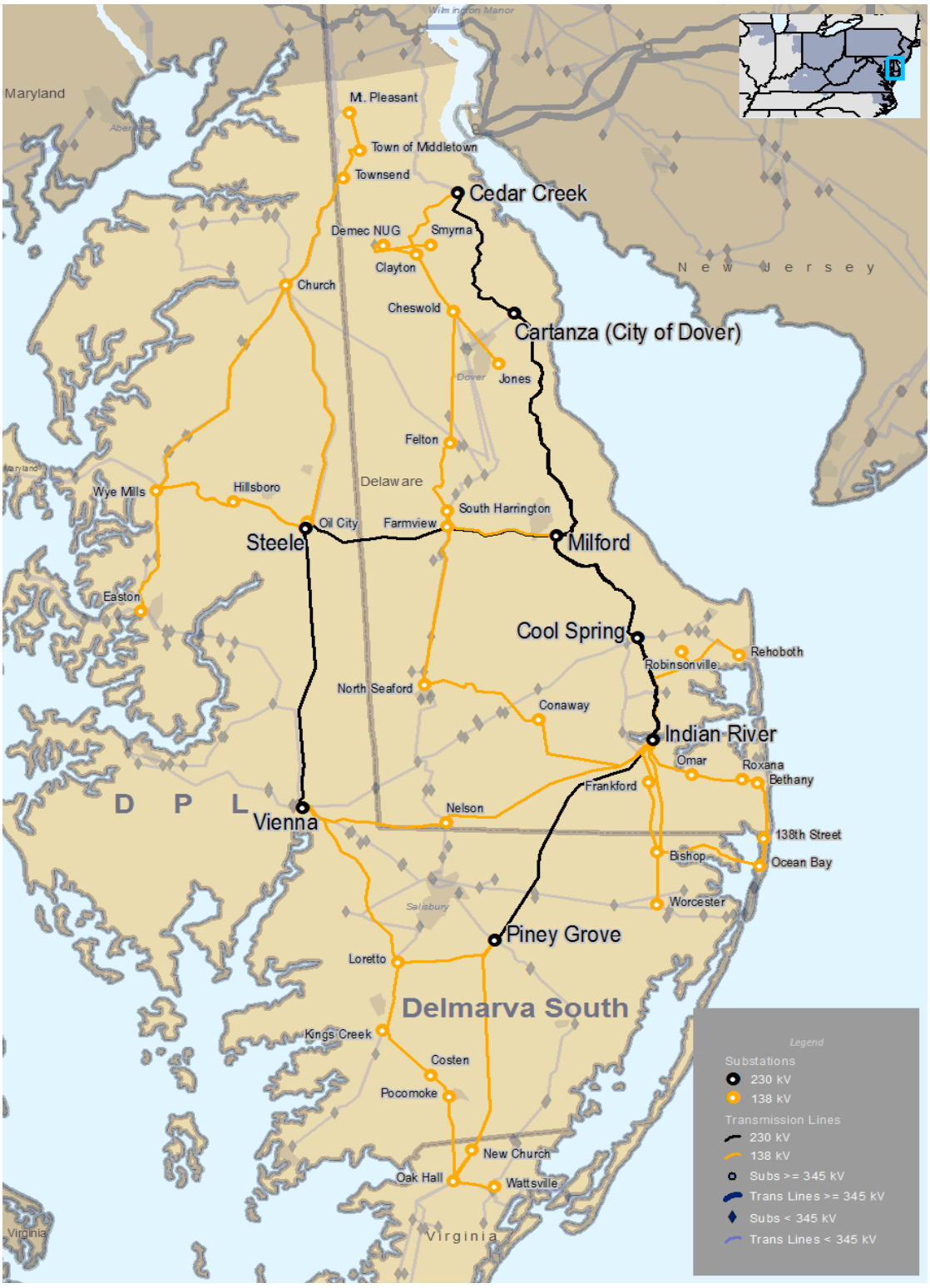

Maryland
M. Pleasant
Town of Middletown
Townsend
Cedar Creek
Demec NUG
Smyrna
Clayton
Church
Cheswold
Cartanza (City of Dover)
Jones
Dover
Felton
Delaware
Wye Mills
Hillsboro
Oil City
Farmview
South Harrington
Steele
Milford
Easton
Cool Spring
Rehoboth
Robinsonville
North Seaford
Conaway
Indian River
Omar
Roxana
Bethany
Frankford
D P L
Vienna
Nelson
138th Street
Bishop
Ocean Bay
Worcester
Salisbury
Piney Grove
Loretto
Delmarva South
Kings Creek
Costen
Pocomoke
New Church
Oak Hall
Wattsville
Virginia
New Jersey
Legend
Substations
230 kV
138 kV
Transmission Lines
230 kV
138 kV
Subs >= 345 kV
Trans Lines >= 345 kV
Subs < 345 kV
Trans Lines < 345 kV

Figure E-1 (Delmarva South)

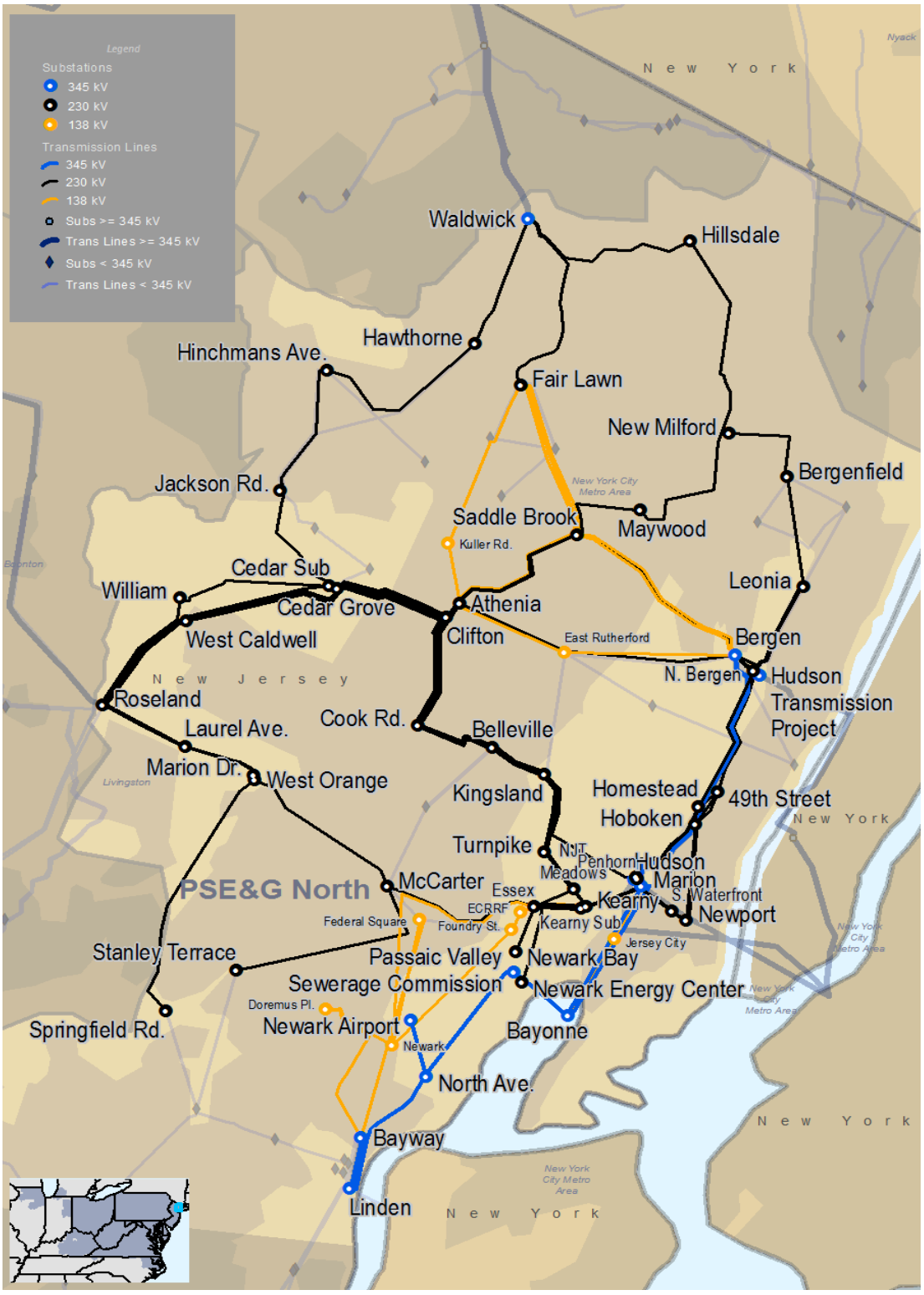

Legend
Substations
345 kV
230 kV
138 kV
Transmission Lines
345 kV
230 kV
138 kV
Subs >= 345 kV
Trans Lines >= 345 kV
Subs < 345 kV
Trans Lines < 345 kV
New York
Nyack
Waldwick
Hillsdale
Hawthorne
Hinchmans Ave.
Fair Lawn
New Milford
Bergenfield
Jackson Rd.
New York City Metro Area
Saddle Brook
Kuller Rd.
Maywood
Cedar Sub
William
Cedar Grove
Athenia
Leonia
West Caldwell
Clifton
East Rutherford
Bergen
N. Bergen
Hudson Transmission Project
New Jersey
Roseland
Laurel Ave.
Cook Rd.
Belleville
Marion Dr.
West Orange
Livingston
Kingsland
Homestead
49th Street
Hoboken
New York
Turnpike
NJT Meadows
Penhorn
Hudson
Marion
S. Waterfront
Newport
PSE&G North
McCarter
Essex
Kearny
ECRRF
Federal Square
Foundry St.
Kearny Sub
Jersey City
Stanley Terrace
Passaic Valley
Newark Bay
Sewerage Commission
Newark Energy Center
Doremus Pl.
Springfield Rd.
Newark Airport
Newark
Bayonne
North Ave.
Bayway
Linden
New York
New York City Metro Area
New York

Figure E-2 (PSE&G North)

Figure E-3 (Cleveland LDA)

C.2.3 Base Case Development

Two separate base case models are developed as necessary; a PJM summer peak case to study summer-peaking study areas and a PJM winter peak case to study winter-peaking study areas. The RTEP load flow case nearest to the study time period should be selected and modified as required (modeling the projected load, generation, interchange and transmission system configuration for the target study period).

C.2.3.1 Load Deliverability Area Assumptions

The study area being evaluated is assumed to be experiencing a generation emergency due to a combination of higher-than-expected load demand (a 90/10 load forecast) and greater-than-expected generator unavailability. The 90/10 load forecast level is modeled by using the value of the 90/10load contained in the latest PJM Load Forecast Report along with generator outage scenario(s) that would lead to a generation emergency inside the LDA and thereby potentially cause a transmission import limitation. All Capacity Resources in the LDA are initially modeled online and then generator outage scenarios are developed.

To calculate plausible generator outage scenarios, a file containing the installed MW capacity and the five-year planning equivalent forced outage rate demand (EFORd) for every PJM Capacity Resource will be developed. The EFORds are developed using the Generator Availability Data System (eGADs). Information related to eGADs can be found at http://pjm.com/markets-and-operations/etools/egads.aspx.

Below is a list of additional assumptions that are made when setting up and analyzing the LDA.

- Behind the Meter and energy only generation should be modeled at the average historic MW output during the previous year's 10 highest load hours for the study area each hour being selected from a different day. If this historic information is not available, then these units will be turned off in the power flow model and not included in the load deliverability study.
- Merchant Transmission Facilities, capable of meeting the requirements under the PJM Tariff to obtain Firm Transmission Withdrawal Rights, will be modeled at the greater of their long-term firm transmission service reservation value or Firm Transmission Withdrawal Rights. Refer to Exhibit 4.
- No study areas will be defined with less than a peak load of 1500 MW.
- Generator reactive output will be reduced in proportion to the MW scaling reduction for any generation that is modeled below the rated capability.
- The 90/10 load adder is assumed to be at 0.8 power factor.
- Normal and emergency ratings included in the power flow will be those applied in Operations (at 35C).
- PARs located within PJM may be operated as needed subject to the appropriate agreements (if any) and PJM Operating Company practices. The PJM/NYISO PAR flows will be set according to Attachment B Section (B.3) (VII) (P).
- If the forecast 90/10 MW load minus the available DR (MW) is less than the 50/50 MW load, then the 50/50 MW load will be used in the area being tested. If this situation arises, then the 50/50 MVAR load will need to be adjusted upwards to account for the reduction of the 90/10 MW load to the 50/50 MW load at the same power factor as the 50/50 load instead of at the higher power factor of the 90/10 load, i.e., DR is assumed to have the same power factor as the 50/50 load.

C.2.3.2 Dispatch for Load Deliverability Study Area

Two separate power flow cases are created for each LDA. The Mean Dispatch case models the average value of each generator's output for the LDA under study from over 10,000 unique dispatches at the CETO. The Discrete Outage case models the most likely discrete generator outage pattern within the LDA at the CETO. As described in the CETL determination section, thermal and voltage analysis is performed on both of these power flow cases.

C.2.3.2.1 Dispatch Procedure for Mean Dispatch Case

1. All generators in the study area are sampled until 10,000 generation outage scenarios are found where the amount of generation selected is within +/- 2% of the amount needed to meet the target generator outage value required to model the import objective.
2. The 10,000 generation outage scenarios are determined by using a Monte Carlo simulation and assigning a random value between 1 and 0 to each generator in the study area. If the random value is greater than the generator forced outage rate, then that generator is turned on at its full capability. If the value is less than the generator forced outage rate, then that generator is turned off. There is no limit to the number of units that can be simultaneously outaged at a station.
3. Determine the average MW output of each generator in the study area by using its dispatched values in the 10,000 generator outage scenarios.
4. The reactive capability of each unit is reduced by the ratio of each unit's average MW output from the preceding step to the unit's maximum MW output.
5. Create a base case modeling the average MW output and reactive capability of each generator determined using the above steps.

C.2.3.2.2 Dispatch Procedure for Discrete Outage Case

1. Derate all generators in the zone by their EFORd.
2. Rank generators by EFORd^(1/PMAX).
3. To model discrete generator outages, select generators in rank order until the next selected generator would exceed 105% of the target generator outage value at the CETO.
    a. LDA target generator outage value = LDA UCAP – LDA target generation
    b. LDA UCAP = Sum (1-EFORd)*PMAX for each LDA generator
    c. LDA target generation = LDA load – LDA CETO
4. Multiple generators at the same substation may be taken off line unless the outaged MW to installed MW ratio is greater than 60%. (For example, if a station had 3-100 MW units, 1 unit would be outaged since 100 MW/300 MW = 33% but two units would not be outaged since 200 MW/300 MW = 66%)
5. Any remaining MW outages required to meet the target generator outage value will be obtained through a uniform scale of all on-line generation's MWs and MVARs in the study area.
6. The Transmission Owner(s) may request analysis of a different outage pattern. If this outage pattern results in more severe reliability problems it will be used in place of the original outage pattern only if both the Transmission Owner and PJM accept the new outage pattern.

C.2.3.3 Dispatch for PJM Areas not in a Capacity Emergency

As part of the starting dispatch for PJM Areas not in a Capacity Emergency PJM generators should be dispatched per existing RTEP base case procedures (see also “Deliverability of Generation”).

C.2.3.4 Dispatch for non-PJM Areas not in a Capacity Emergency

One of the base principles for the load deliverability test is that the study area is the only area that is in a capacity emergency. All adjacent external areas to PJM are assumed to be at a peak load but in a non-emergency condition. The PJM firm interchange shall not be adjusted as part of the load deliverability test.

No dispatch or other adjustments will be made to the non-PJM areas to support the PJM area experiencing the capacity emergency.

C.2.4 Capacity Emergency Transfer Objective (CETO) Procedure

The Capacity Emergency Transfer Objective (CETO) analysis determines a target MW import value for an LDA that ensures sufficient transmission capability exists to access available PJM capacity reserves located outside the LDA. The import value determined is a measure of the transmission capability required by the LDA so that the study area does not experience a planned, transmission-induced loss of load event more frequently, on average, than the LDA resource adequacy criteria as described in Manual 20A.

The CETO for each LDA in PJM is determined using PJM’s reliability software to perform a single area reliability study for each LDA. The system models are based on the latest load and capacity data available at the time of the study. Only the load and capacity within the study area are modeled while the capacity supply from outside the study area is assumed to be unlimited. The transmission system is not modeled. The CETO is the import capability value that is necessary for the study area to achieve the CETO reliability standard.

More detail about the CETO is available in PJM Manual 20 – Resource Adequacy Analysis at http://www.pjm.com/library/manuals.aspx

C.2.5 Capacity Emergency Transfer Limit (CETL) Procedure

The goal of a PJM Load Deliverability study is to establish the amount of emergency power, or CETL, that can be reliably transferred to the study area from the remainder of PJM in the event of a generation deficiency within the study area. This transfer limit, in combination with its corresponding CETO, is then used to determine if the import capability required in order to meet the reliability objective is sufficient. An indicator of the amount of reserve transfer capacity available is provided by the difference between the CETL and CETO.

C.2.5.1 Procedure for Determining Load Deliverability Facility List

The following procedures outline the process for determining which facilities will be monitored for the PJM Load Deliverability test. The first procedure provides the details for internal PJM facilities and the second procedure concentrates on external PJM facilities.

C.2.5.1.1 Internal PJM Load Deliverability Facility List

- PJM monitors all internal transmission facilities for its load deliverability test and screens criteria violations for upgrades that pass an outage transfer distribution factor (OTDF) cutoff test and are on PJM's monitored facility list (lists of PJM monitored lines and substations are available at http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx.) The resulting list of facilities constitutes the PJM Load Deliverability Facility List and may vary from study to study because changes in system topology may change the OTDF.
- PJM ensures load deliverability for its entire region by individually studying each LDA. A different subset of the Transmission Facilities is therefore the primary focus for each study area. PJM Transmission Facilities that are not included in the Load Deliverability Facility List are still considered in the load deliverability test. However, they will not be considered as limiting Transmission Facilities for imports into an LDA unless there is also one or more Load Deliverability Facilities simultaneously limiting imports into the LDA, or unless both PJM and the Transmission Owner agree that the facility should be included in the Load Deliverability Facility List regardless of the OTDF.
- The following list of rules defines the OTDF (TDF for pre-contingency violations) cutoff for PJM facilities that will be included in the separate Load Deliverability Facility List for each study area. A TDF is the MW flow over a facility that results from a MW transfer from a source point of all PJM generation external to the study area and a sink point of all load internal to the study area. An OTDF is the TDF after a transmission outage has occurred on the system. Note that if a 100 kV and up facility has a OTDF that is below the OTDF cutoff for each LDA, then that facility will either be addressed in the generator deliverability test or become subject to reliability screening under the standard NERC TPL-001-5.1 criteria[4].
    - All non-radial facilities with a low side voltage 345 kV or greater will be included if their OTDF is greater than or equal to 5%.
    - All non-radial facilities with a low side voltage 345 kV or greater will be included if their OTDF is greater than 2% and less than 5% unless both PJM and the TO agree that the facility should not be included.

[4] Any 100 kV and above facility that is not subject to upgrade screening in the load deliverability analysis will be evaluated in a subsequent screening that evaluates the NERC TPL-001-5.1 criteria in the 50/50 peak load scenario. All facilities failing these standard NERC criteria will be identified for upgrade requirements.

- All non-radial facilities with a low side voltage 345 kV or greater will be not included if their OTDF is less than 2% unless both PJM and the TO agree that the facility should be included.
- All non-radial facilities with a low side below 345 kV with an OTDF greater than 10% will be included.
- All non-radial facilities with a low side below 345 kV with an OTDF between 5% and 10% will be included unless both PJM and the TO agree that the facility should not be included.
- All non-radial facilities with a low side below 345 kV with an OTDF less than 5% will not be included unless both PJM and TO agree that the facility should be included.

- All PJM monitored facilities will be included when determining any generation redispatch or PAR movements required for the base case development. However, only the facilities on the Load Deliverability Facility List will require a system upgrade if overloaded for this load deliverability test.
- The substations to be included for voltage analysis will be developed based on the Load Deliverability Facility List. In other words, the OTDF for a substation will be determined based on the highest OTDF of the transmission facilities directly connected to the substation under the contingency conditions that result in voltage issues. Additional substations will be included for voltage analysis if agreed to by PJM and the TO.

C.2.5.1.2 External PJM Load Deliverability Facility List

For transmission facilities outside of but electrically close to PJM, PJM conducts joint coordinated interregional studies on a periodic basis that examine and address deliverability issues between PJM and adjacent external systems. Based on the results of these joint studies, PJM may choose to include specific non-PJM transmission facilities in the load deliverability test in order to account for significant loop flows that occur through non-PJM transmission systems when large transfers within PJM are present. In order for a non-PJM transmission facility to be included as an External Load Deliverability Facility in either the thermal or voltage load deliverability analysis, it must meet same OTDF cutoff rules that are required for Internal Load Deliverability Facilities.

C.2.5.2 CETL Determination

The CETL for the LDA under study will be the lower of the CETLs identified during the load deliverability studies for thermal and voltage constraints.

C.2.5.2.1 CETL for Thermal Problems

1. Perform an AC contingency thermal analysis on both the Mean Dispatch Case and the Discrete Outage Case to obtain the percent loading on each flowgate for each case at the CETO.
2. If any overloads exist, any of the system adjustments noted in section C.2.1.3.2 can be implemented.

3. Any overloads that still remain will require mitigation in order for the study area CETL to exceed the CETO.
4. If no overloads remain at the CETO import level, then additional transfers into the LDA will be simulated and system adjustments will be applied as necessary. This procedure will be repeated until a transfer level is found (CETL) where one or more transmission facilities on the PJM Load Deliverability Facility list for the LDA under study reaches its applicable thermal limit.
5. The thermal CETL will be the lower of the CETLs determined from the Mean Dispatch and the Discrete Outage Cases

C.2.5.2.2 CETL for Voltage Problems

1. Perform an AC contingency voltage analysis on both the Mean Dispatch Case and the Discrete Outage Case after system adjustments have been implemented to resolve any thermal overloads. Redispatch procedures may be considered to alleviate voltage issues.
2. Any voltage issue that appears at the CETO will require mitigation in order for the study area CETL to exceed the CETO.
3. If no voltage issues exist at the CETO import level, then additional transfers into the LDA will be simulated and system adjustments will be applied as necessary. This procedure will be repeated until a transfer level is found (CETL) where one or more substations on the PJM Load Deliverability Facility list for the LDA under study reaches its applicable voltage limit.
4. The voltage CETL will be the lower of the CETLs determined from the Mean Dispatch and the Discrete Outage Cases.

C.2.6 CETO/CETL as an Input to RPM

PJM follows a similar procedure for the CETO/CETL analysis used as an input to the RPM Base Residual Auction (BRA). This analysis is based on the CETO/CETL analysis used in the RTEP Load Deliverability procedure, but focuses on a 3 year out case. Units without a final GIA or ISA that have cleared in a prior BRA are also included.

In addition to the CETO/CETL analysis performed as an input to the RPM BRA, PJM also determines if there are any easily resolved constraints that could improve the ratio between the CETL and the CETO beyond the threshold of 115%. The process for determining the inclusion of an easily resolved constraint as a transmission upgrade in the RTEP is documented in the PJM OATT (Tariff) in Section 15 of Attachment DD. Criteria needed to be met to include an easily resolved constraint as a transmission upgrade in the RTEP include

- The transmission upgrade(s) will result in a Capacity Emergency Transfer Limit that exceeds 1.15 times the Capacity Emergency Transfer Objective for the LDA; and
- The transmission upgrade(s) is/are expected to be in-service prior to June 1 of the Delivery Year for which the Base Residual Auction is being conducted; and
- The transmission upgrade cost is expected to be less than $5 million; and

- There are no Merchant Network Upgrades that have or are expected to have met all Decision Point II requirements by 45 days prior to the Base Residual Auction that are designed to resolve the same constraint for which the RTEP upgrade is designed to resolve.

The annual costs of such upgrade shall be allocated as specified in Schedule 12 of the tariff.

C.3 Deliverability of Generation

The second deliverability test examines the ability of an electrical area to export Capacity Resources to the remainder of PJM. This test is applied to ensure that capacity is not "bottled" from a reliability perspective. This requires that each electrical area be able to export its capacity, at a minimum, during the summer peak load period as this represents the condition where PJM reserve margins have historically been at their lowest levels. But just demonstrating deliverability in the summer period is not sufficient to ensure operational performance and flexibility is maintained during other part of the year. PJM examines export capabilities under winter and light load conditions as well. All three generator deliverability tests are required to be passed in order for a generator to become certified as a PJM Capacity Resource. Deliverability, from the perspective of individual generator resources, ensures that, under normal system conditions, if Capacity Resources are available and called on, their ability to provide energy to the system will not be limited by the dispatch of other certified Capacity Resources. This test does not guarantee that a given resource will be chosen to produce energy at any given system load condition. Rather, its purpose is to demonstrate that the installed capacity in any electrical area can be run simultaneously, and that the excess energy above load in that electrical area can be exported to the remainder of PJM, subject to the same single contingency testing used when examining deliverability from the load perspective. In addition, common mode outages are examined as part of the generator deliverability test. In short, the test attempts to ensure that bottled capacity conditions that limit the availability and usefulness of certified Capacity Resources to system operators will not exist. In actual operating conditions, energy-only resources may displace Capacity Resources in the economic dispatch that serves load.

This test demonstrates that Capacity Resources in any given electrical area could simultaneously deliver energy to the remainder of PJM. The premise of the generator deliverability test is that all PJM Capacity Resources within an electrical region within PJM are required; hence the remainder of the system outside this electrical region is experiencing a significant reduction in available capacity. The dispatch pattern in the remainder of the system is uniformly reduced according to the relative amounts of online generation at each location.

C.3.1 Generator Deliverability Procedure

C.3.1.1 Introduction

To maintain reliability in a competitive capacity market, resources must contribute to the deliverability within the PJM Control Area in two ways. First, energy must be deliverable, from

the aggregate of resources available to the PJM Control Area to load in portions of the applicable PJM areas experiencing a localized capacity emergency. PJM utilizes the Load Deliverability procedure to ensure this requirement. Second, Capacity Resources within a given electrical area must, in aggregate, be able to be exported to other areas of PJM when required. PJM utilizes the Generator Deliverability procedure to ensure the deliverability of individual generation resources. The following sections describe the Generator Deliverability procedure.

C.3.1.2 Study Objectives

The goal of the PJM Generator Deliverability study is to determine if the aggregate of generators in a given area can be reliably transferred to the remainder of PJM. Any generators requesting interconnection to PJM must be deliverable in order to be a PJM installed Capacity Resource. Addendum 1 to this section describes procedure for modeling Merchant Transmission Facilities in the generator deliverability test. Addendum 2 to this section describes procedures for examining deliverability of any single generating plant up to its maximum facility output and any single Merchant Transmission Facility at its full capability. Addendum 3 to this section describe procedures for evaluating Long Term Firm Transmission Services Requests. Addendum 4 to this section describes gas pipeline contingencies examine as part of the winter test.

C.3.1.3 General Procedures and Assumptions

Step 1: Develop Base Case

The RTEP base case is developed for a reference year 5 years in the future. All identified RTEP Baseline and Supplemental Projects projected to be in service by

- April 15 of the reference year are including in the system model for the Light Load RTEP Base case
- June 1 of the reference year are including in the system model for the Summer RTEP Base case
- December 1 of the reference year are including in the system model for the Winter RTEP Base case

Load is modeled at a non-diversified forecasted 50/50 load level for the period being examined.

- Light Load Period: Those hours between 10AM and 3PM where the PJM coincident peak load is between 40-60% of the annual peak. In the Light Load base case, load levels are modelled at 50% of each area's non-coincident summer peak forecast. [5]
- Summer Period: June through August hours 2PM-6PM
- Winter Period: December through February hours 5AM-9AM and 6PM-10PM

[5] **Note:** For regions experiencing greater than 50% average light loads, PJM will model light loads in excess of 50% of 50/50 peak load in planning cases in coordination with the service provider. PJM will share the updated LL modeling ratio part of the reliability assumptions at the beginning of the RTEP cycle in January.

In coordination with individual TOs, PJM will select and apply a Transmission Facility temperature degree ratings set as appropriate. PJM will apply the ratings set on an individual TO basis. The default temperature degree ratings sets are:

- Light Load: 59 °F
- Summer: 95 °F
- Winter: 50 °F, 41 °F or 32 °F

All long-term firm transmission service confirmed for the reference year and service with rollover rights that has been coordinated with the applicable PJM neighboring region is included in the model. Generation and Merchant Transmission Facilities that have proceeded at least through the execution of the final agreement stage of the interconnection process are considered in the model along with any associated network upgrades. If existing Capacity Resources and those with an executed final agreement are not sufficient to meet overall system demand levels then Capacity Resources that have met all Decision Point II requirements may be considered as well.

The starting point dispatch is developed as explained in the next step. PJM uses a block dispatch approach to dispatch the generation and limits the maximum output of any single generator to account for the PJM system-wide forced outage rate and regional weather-related unavailability. This approach to dispatching the generation attempts to broadly account for the economics and operating limitations of individual resource types during the period under examination and avoids direct consideration of any particular resource's confidential economic and operating limitations and the significant bias a less generic dispatch pattern can have on the final overload results.

Step 2: Establish initial RTEP dispatch for unit under study

PJM uses a block dispatch coupled with system wide outage and regional weather considerations to dispatch generation. As shown in Table 1 below, the block dispatch procedure starts with the required generation target to satisfy system wide demand (load, losses and firm interchange) and sequentially dispatches existing units and those with a final agreement in blocks 1, 2 and 3 as needed. If a particular block is only partially needed to meet system demand, then the resources in this block are dispatched as necessary to act as the slack generation and provide constraint control, i.e. certain generators may be dispatched online to relieve base case overloads. Capacity factors used during the block dispatch will be updated and published annually as part of the RTEP assumptions.

In order to ensure that the dispatch does not result in a capacity emergency condition in any of the PJM areas, further redispatch within the area may need to be performed to ensure the area is not importing more than its Capacity Emergency Transfer Objective (CETO). The redispatch methodology will follow the block dispatch approach described above and ensure that the online generation in each area is no less than

- Minimum area generation = (Load + losses – CETO) / (1 – PJM Avg EEFORd)

The denominator in the above equation adds a small margin to the CETO in order to account for the generation ramping that will occur during the actual generator deliverability test. This approach avoids the need to consider the CETO directly in the test itself and helps provide a reasonable starting dispatch for each area. In order to set the minimum area generation, the last block of generation in each area is dispatched to ensure a simultaneous dispatch across PJM where no area is exceeding its CETO plus a small margin and the overall system demand is satisfied. This represents the starting dispatch in the RTEP baseline generator deliverability studies.

Table 1 – Block Dispatch for RTEP Base Cases

Block	Resource Type	Initial Dispatch
1	Nuclear	PMAX * (1 - PJM Avg EEFORd)
	Wind	Capacity Factor
	Solar	Capacity Factor
	Pumped Hydro	PMIN * (1 – PJM Avg EEFORd) LL; PMAX * (1 - PJM Avg EEFORd) Winter & Summer
	Non-Pumped Hydro	PMAX * (1 - PJM Avg EEFORd)
	Other Renewable	PMAX * (1 - PJM Avg EEFORd)
2	Coal	PMAX * (1 - PJM Avg EEFORd)
	Combined Cycle	PMAX * (1 - PJM Avg EEFORd)
3	Simple Cycle	PMAX * (1 - PJM Avg EEFORd)
Note 1: PMAX represents the unit's maximum output for the period. Note 2: Capacity Factor represents the average output for the period. Note 3: In summer, PMAX is replaced with the lower of the Capacity Factor or Capacity Interconnection Rights (CIRs).Note 4: Batteries will be modeled offline but available to be ramped.		

During the generator deliverability evaluation of a New Service Request, additional dispatch procedures are employed. More specifically, all New Service Requests in prior Cycles that are queued ahead of the Cycle under study are available to be turned on. The New Service Request in the Cycle under study is also set at 0 MW but available to be turned on to contribute to but not back off flowgate loadings. New Service Requests in later Cycles that are queued after the Cycle under study are not modeled.

Step 3: Determine potential overloads

PJM uses a linear (DC) power flow program to analyze each facility for which PJM is responsible to determine whether any single or common mode contingency can overload the

facility. These results are utilized to determine which flowgates will be used in the generator deliverability analysis, i.e., the program examines each PJM flowgate (contingency / monitored element pair) in the entire PJM footprint as well flowgates near the border of PJM. The procedure below explains conceptually how the program works; following the procedure below would yield the same results as the program. The procedure uses a load flow set up according to step 2.

Determine the distribution factor for each generator on each flowgate. The distribution factor for a particular generator is referenced to the PJM online generation. For each flowgate, group the Generation Capacity Resources based on whether the distribution factor is positive, in which case increases in the generator's output contribute to the loading on the flowgate and the generator is considered a "Harmer", or negative, in which case increases in the generator's output reduce the loading on the flowgate and the generator is considered a "Helper". Note that the light load test considers pumped storage units in the pumping mode and batteries in both the discharging and charging mode and the appropriate mode to ramp will be based on whether the distribution factor is positive for that mode. For generators with a positive distribution factor on the flowgate, multiply the distribution factor of each generator by the offline portion of the generator to obtain the MW impact the generator would have on a particular flowgate if it were ramped from its output in the initial load flow to its full output. For wind and solar generators with a negative distribution factor on the flowgate, multiply the distribution factor by the online output of the resources to obtain the MW impact the generator would have if it were turned off. This latter step will account for the high variability of the output levels of wind and solar units and the fact that a stressed dispatch should consider lower than average outputs from these resource types. The summation of these MW impacts on the flowgate is the cumulative ramping impact.

For all flowgates determine the cumulative ramping impact of generators with greater than a 1% distribution factor. The total amount of ramped generation as part of this initial identification of potential overloads is capped to limit the number of potential overloads to a reasonable number of the worst impacts. A typical cap for the total ramping of internal generation is 10,000 MW (20,000 MW for studies examining the impacts of external generators as well) but the actual value can vary to establish a reasonable scope for the potential overloads. For each flowgate, add the cumulative ramping impact to the initial DC loading. If the resulting DC loading is greater than the flowgate rating, then this flowgate is a potential overload.

Step 4: Determine Wind and Solar and 50/50 Harmer impacts

The number of generators having greater than a 1% distribution factor in Step 3 is often large enough that having them all simultaneously outputting their full installed capacity or simultaneously be offline in the case of wind and solar would be extremely improbable. As a result, in this step the number of generators contributing to the cumulative ramping impact on a flowgate is further restricted in the following manner.

Dispatch blocks 1 through 3 are available for ramping in the summer and winter testing and wind and solar resources are available for ramping in the light load test. In addition, batteries in

the discharging mode will be considered in light load, summer and winter generator deliverability testing. Also, during the light load condition pumped storage in the pumping mode and batteries in the charging mode will also be considered.

The ramping limit for wind and solar units are applied. For summer, single contingency testing conditions, the ramping level for wind and solar units with a positive distribution factor is restricted to its Capacity Interconnection Rights (CIR). For winter, single contingency testing conditions and summer and winter, common mode outage testing conditions, wind and solar units with a positive distribution factor are restricted to the following regional ramping levels.

- Onshore Wind: P90%
- Offshore Wind: P80%
- Fixed Solar: P80%
- Tracking Solar: P80%

For light load, single contingency and common mode outage testing conditions, wind and solar units with a positive distribution factor are restricted to the following regional ramping levels.

- Onshore Wind: P90%
- Offshore Wind: P80%
- Fixed Solar: Light Load Capacity Factor
- Tracking Solar: Light Load Capacity Factor

These percentiles are used to define the seasonal output levels for the resource type in the region in which it is located as a percent of its maximum facility output for the period under study below which the specified percentage of output levels would occur, e.g. the P90% for onshore wind units in the Mid-Atlantic Region over the summer period is 38% of the MFO. These seasonal output levels are also referred to as the summer deliverability MW, Winter deliverability MW and light load deliverability MW.

For example, onshore wind units will be ramped to a level that is unlikely to be exceeded more than 10% of the time on a wide-area basis. The output levels are based on 10 years of historical or backcast data and are determined by resource type and PJM region (MAAC, PJM West, Dominion) by using the capacity-weighted output level for each area where the resource type is located within the region. The output levels associated with these percentiles will be updated and published annually.

Generation Capacity Resources modeled in the power flow with greater than a 5% distribution factor (or 10% distribution factor for flowgates whose monitored element's lowest terminal voltage level is equal to or greater than 500 kV) that contribute to the cumulative ramping impact are ranked according to their distribution factor on a potentially overloaded flowgate. These are called "Harmer" generators.

Wind and solar units are not assigned an EEFORd because their output levels are based on historical data that inherently accounts for forced outages. For each flowgate, all wind and solar Harmer unit outputs are increased to their ramping levels defined above. The multiplication of the resulting MW output for each wind and solar resource by it DFAX on the flowgate is the wind and solar Harmer impact.

For Generation Resources other than wind and solar resources, the availability (1 – EEFORd) of the unit with the highest distribution factor is then multiplied by the availability of the unit with the second highest distribution factor and so on until the expected availability of the selected units is as close to but not less than 50%. Also, generating plants whose maximum output level is less than 50 MW will not be assigned an EEFORD to help ensure that the impacts of larger units are not masked during this process. This resulting “50/50” cumulative ramping impact is then added to the initial DC loading on the flowgate from the base case dispatch under the specified contingency condition. This resulting loading is the 50/50 DC loading and the generators chosen to contribute to the cumulative ramping impact are the 50/50 generators.

All default ramping limits and Capacity Factors used in the generator deliverability test for all study periods will be updated and published annually.

Step 5: Determine other flowgate impacts

This Step 5 addresses contributions to a flowgate loading beyond those created by the 50/50 dispatch.

- Step 5a addresses offline generators that have a positive distribution factor on the flowgate.
- Step 5b addresses online wind and solar generators that have a negative distribution factor on the flowgate.
- Step 5c addresses interchange considerations.
- Step 5d addresses non-PJM ramping considerations.

Step 5a: Determine Facility Loading Adder

Existing generators which have submitted a request to deactivate, active generators that are in the interconnection queue or Cycle and merchant transmission projects that do not yet have a signed final agreement or have a suspended final agreement may be modeled offline, and, if so, are available to be turned on to contribute to but not back off flowgate loadings. The ramping impact of this set of generators determines the Facility Loading Adder. Facility Loading Adders do not consider offline wind and solar units which are handled separately in Step 4. Further, they are only applied in the summer generator deliverability test where the offline resources will likely be required.

First, for their ramping impact to be considered, off-line generators must pass the impact threshold of at least a 5% DFAX (10% for flowgates with monitored elements having the lowest

terminal voltage 500 kV and above) on a flowgate or with an impact (DFAX times a generator's full energy output rating) greater than 5% of the flowgate's rating.

All studies in Phase I, II and III will use 100% commercial probability.

The ramping impact on a flowgate from each offline resource that meets the above conditions is calculated. These offline resources will be ramped to the same percent output level that other generators of the same resource type are dispatched on average in the case. For example, if the generator is in block 2, and block 2 resources are dispatched at 50% on average, then the resource will be ramped to 50%. Merchant transmission projects will be assigned 100% percent of their firm rights for their output level. The resulting impact defines the Facility Loading Adder.

Step 5b: Account For Lower Than Expected Wind and Solar Outputs

Online wind and solar units with a negative distribution factor are assigned the following lower ramping levels, which are derived in a similar manner to the percentiles developed for wind and solar in Step 4.

- Onshore Wind: P20%
- Offshore Wind: P20%
- Fixed Solar: P20%
- Tracking Solar: P20%

The output levels associated with these percentiles will be updated and published annually.

Step 5c: Interchange Considerations

In order to account for generation assistance from outside PJM in the summer and winter generator deliverability test each receiving end area will be assigned a portion of the PJM Capacity Benefit Margin (CBM) based on the receiving end areas' share of the PJM load. CBM is the amount of import that PJM assumes will be available from neighboring regions during a RTO-wide capacity deficiency.

In the winter and summer generator deliverability test, average historical utilization of PJM firm transmission service is considered to ensure that a range of actual firm usage can be supported. The test examines whether the system can support any combination of firm transmission service between the average historical level up to the full reserved amount.

In the light load generator deliverability test, the average historical interchange levels achieved for this period between PJM and the five external regions defined in the PJM Capacity Import Limit study (see Attachment G.11) and controllable Merchant Transmission Facilities will be examined in addition to the full amount of reserved transmission service.

Step 5d: Account for Non-PJM Ramping Considerations

Under heavy penetration of intermittent resources, it is expected that system dispatches will become more volatile. PJM will incorporate into its generator deliverability test non-PJM dispatch considerations that have resulted in or are expected to result in operational performance issues which hinder the ability of PJM Capacity Resources to deliver their output.

At present, there is a growing penetration of onshore wind in the MISO region that occasionally results in such operational performance concerns on the PJM system. These concerns occur outside of the summer period. As a result, PJM includes ramping of the MISO wind in both the light load and winter generator deliverability testing. The ramping level is the same as that used for onshore wind in the PJM West region in PJM. The sink for the MISO onshore wind ramping is the Northern part of the MISO system.

PJM will periodically assess the need to incorporate other non-PJM dispatch considerations into the generator deliverability test to ensure impacts to the ability of PJM Capacity Resources to deliver their output are appropriately accounted for.

Step 6: Determine Final Flowgate Loading

- The total amount of 50/50 and Facility Loading Adder generation shall not be any more than the online generation × PJM average EEFord. This rule is enforced by curtailing generators that contribute to both the 50/50 list and the Facility Loading Adder. Similarly, the amount of wind and solar generation increased in step 4 to account for higher than expected outputs as well as the amount of wind and solar reduced in Step 5b to account for lower than expected outputs will capped at the same level.

If a flowgate has a final DC loading less than 90% of its rating, it is not considered to be overloaded and is not tested further. If a flowgate has a final DC loading greater than or equal to 90% of its rating, the 50/50 generators are ramped up to their installed capacity in the load flow from step 2 and all remaining PJM generators are uniformly ramped down such that the PJM firm interchange is maintained. The resulting flowgate loading is the 50/50 AC loading.

The Facility Loading Adder can sometimes have a significant impact on the results of a deliverability study. However, ramping up the units associated with the adder in the load flow will sometimes create a localized capacity emergency condition elsewhere when the rest of PJM is proportionally displaced to maintain the firm interchange. Therefore, to account for the effect of these units on the facility in question, the Facility Loading Adder, which is a DC value as determined in Step 5, is added to the 50/50 AC loading to result in the Final Flowgate Loading.

Addendum 1: Modeling Merchant Transmission Facilities (MTFs)

Controllable MTFs, i.e. HVDC which interconnects PJM to another system, may have some combination of firm rights (Transmission Withdrawal Rights, Transmission Injection Rights or long-term firm transmission service). Existing MTFs with firm rights and MTFs with an executed ISA or GIA with firm rights are modeled as a transmission facility carrying the firm rights. Refer to Exhibit 4.

In the case of a bi-directional MTF, the rights associated with the injection into PJM are modeled as an offline generator at the PJM MTF terminal. A net injection from the terminal into PJM equal to the firm injection rights is simulated, consistent with the 50/50 and Facility Loading Adder rules, when such injection contributes to a flowgate's loading.

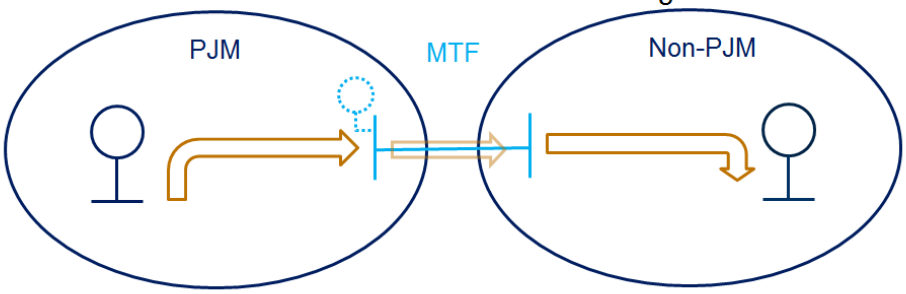
If the MTF request does not have an executed ISA or GIA it will be modeled offline but be allowed to contribute to flowgate loadings consistent with the 50/50 and Facility Loading Adder rules.

Scenario	LTF TS?	Firm TWRs?
1	No	No
2	No	Yes
3	Yes	No
4	Yes	Yes

*LTF TS = Long-term Firm Transmission Service; Firm TWRs = Firm Transmission Withdrawal Rights

Load & Generator Deliverability

- Scenario 1 not considered
- Scenarios 2, 3 & 4 modeled at greater of LTF TS or Firm TWRs
- Firm TIRs modeled as offline generator at MTF PJM terminal in generator deliverability test and able to contribute to but not back off loadings



*Arrows represent firm flows

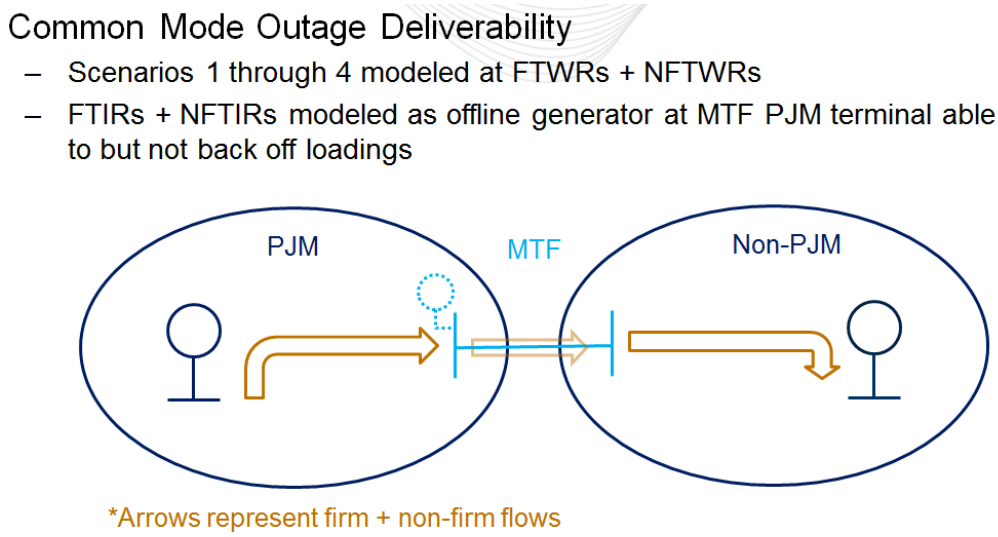


Exhibit 4: Modeling Rights for Merchant Transmission Facilities

Addendum 2: Individual Plant Deliverability Procedure

PJM planning criteria requires that each individual generating plant can be ramped up to its seasonal maximum facility output and each controllable Merchant Transmission Facility can be ramped up to its maximum capability in each direction that it is capable of operating. Under these conditions, the system must be secure for single and common mode contingencies.

Addendum 3: Transmission Service Study Procedures

During the conduct of New Service Request studies, for the evaluation of Transmission Service impacts during generator deliverability testing and common mode outage testing, contribution thresholds have been developed to account for the proximity of the source of the service in relation to the PJM footprint. During testing of transmission service seeking to import energy into PJM, PJM shall use a 3% distribution factor or 3% rating cutoff to select the service which shall be allowed to contribute to flowgates under study. During testing of transmission service seeking to export energy from PJM, PJM shall use these same distribution factor and rating cutoffs to select the service which shall be allowed to contribute to flowgates under study when that flowgate involves a facility outside of PJM's footprint; however, PJM shall maintain all thresholds for impacts to flowgates that involve PJM facilities consistent with the requirements listed outside this Addendum 3.

In both baseline and New Service Request studies, constraints identified in the PJM Capacity Import Limit procedure (Section G.11 PJM Capacity Import Limit Calculation Procedure) are studied in the same manner as internal PJM constraints. With regard to transmission service, in baseline studies any transmission service which impacts a constraint identified in the CIL study

shall have the full impact of the service added to the loading of the applicable facility in determining the final facility loading. In New Service Request studies any transmission service which impacts a constraint identified in the CIL study at greater than the thresholds identified above in this section shall have the full impact of the service added to the loading of the applicable facility in determining the final facility loading.

In both baseline and New Service Request studies, existing import and export reservations which back off overloads will be ramped down to a percentage consistent with the peak historical usage in order to reduce the counter flow for confirmed service to expected levels.

In both baseline and New Service Request studies, PJM shall preserve the Capacity Benefit Margin (CBM) by ensuring that the full amount, specified in the PJM Reliability Assurance Agreement Schedule 4.D, can be imported in addition to the net firm interchange. The distribution of the CBM from each of the five external supply zones shall be determined during the annual PJM Capacity Import Limit (CIL) study, and the CBM impacts will only be considered when they contribute to the loading on a constraint.

Addendum 4: Gas Pipeline Contingencies

PJM will maintain and apply a gas pipeline contingency analysis in winter studies. The gas pipeline contingency set will include gas pipeline contingencies due to the failure of a gas pipeline or a compressor station. The gas pipeline contingency list will be reviewed periodically to validate its accuracy. In addition to the gas pipeline contingencies, gas temperature threshold contingencies will be evaluated. At a pre-determined temperature threshold, assume that non-firm customers (i.e. non-heating demand and 100% of natural gas generation customers in that zone) will be interrupted.

C.4 Long-Term Deliverability Analysis

The purpose of the long-term deliverability analysis is to identify any reliability violations on the PJM system that may require an upgrade that requires more than a 5 year lead time to implement. The PJM RTEP long-term reliability review process examines generator deliverability, load deliverability and common mode outage analysis for years 6 through 15. The long-term analysis starts with the deliverability results from the near-term base case and extrapolates the thermal results using distribution factors and forecast load growth to each year in the long-term planning horizon. If units that have met all Decision Point II requirements are not included in the base case, a second near-term base case will be created to examine whether any long-lead time facilities would be required to support these generators. In addition, a long-term base case is developed from the near-term base case each planning cycle, a limited set of deliverability studies are performed on this long-term base case if the need for long lead time upgrades are identified during extrapolation of the thermal results using the near-term base case, and the deliverability thermal results are extrapolated in a similar manner as is done with the near-term base case in order to produce a second set of long-term results.

C.4.1 Base Case Development

PJM has a 24-month reliability planning cycle. At the beginning of the first year of the cycle, a near-term 5-year out base case and a long-term 8-year out base case are developed. At the beginning of the second year of the cycle, a new 5-year out base case and a long-term 7-year out base case are developed. The same general rules of construction described in section C.3.1.3 of this manual that are used to create the near-term base case are used to create the long-term base case. As a result, the long-term base case is similar to the near-term base case but accounts load growth, generation additions and deactivations, and transmission additions that are forecast to occur between years 5 through 8.

C.4.2 Analysis

The PJM RTEP long-term reliability review process examines generator deliverability, load deliverability and common mode outage analysis for years 6 through 15. The two categories of contingency events considered as part of the long-term studies are single and tower line contingencies. The reason for limiting the long-term review to only these two categories of contingency events is that these events are much more likely than other types of contingency events PJM studies to lead to long-lead-time upgrades.

The deliverability analysis performed on the near-term base case includes a full AC power flow analysis including generator deliverability, load deliverability and common mode outages. The deliverability analysis performed on the long-term base case considers these same tests except that in the load deliverability test, LDAs are selected only if their CETL/CETO ratio was less than 150% in a recent RTEP. Since the objective of the long-term reliability analysis is to identify long-lead-time upgrades, the following types of overloads are not considered.

- overloads on transmission lines below 230 kV
- overloads on transformers
- overloads that are below the conductor rating of the circuit

C.4.3 Linear Extrapolation

The first step of the linear extrapolation of the thermal results is to compile a list of flowgates (monitored facility and contingency pairs) from the near-term and, if required, the long-term base case deliverability results. The calculated base case AC loadings serve as the starting point for the linear extrapolation out through year 15.

Table 1 below is an example of a flowgate that is close to a calculated overload in the near-term analysis that was performed in 2009.

Table 1: Example Flowgate

Electrical Occurrence	Electrical Result	PJM Reliability Test	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Outage of Bedington - Black Oak 500 kV line	Mt. Storm - Doubs 500 kV exceeds its emergency rating and overloads (2016)	Mid-Atlantic Load Deliverability	97.1	98.8	100.5	102.3	104.0	105.9	107.8	109.7	111.6	113.6	115.5

The next step is to determine a factor to increase the loading of the flowgate by for years 6 through 15 to account for load growth. An example of the zonal load forecast by year for selected PJM zones is shown in Table 2. The applicable loads are the forecasted 50/50 load MW values from the PJM Load Forecast Report.

Table 2: Yearly 50/50 Load Forecast by PJM Zone

Company	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AECO	2,692	2,761	2,980	3,120	3,240	3,301	3,351	3,402	3,448	3,494	3,533	3,572	3,617	3,658	3,687	3,722
AEP	23,682	23,817	24,419	25,109	25,469	25,669	25,897	26,082	26,268	26,426	26,554	26,692	26,804	26,914	27,016	27,097
APS	8,538	8,705	8,949	9,125	9,257	9,378	9,487	9,580	9,683	9,775	9,889	10,038	10,156	10,258	10,375	10,478
BGE	7,303	7,446	7,668	7,764	7,887	8,022	8,176	8,304	8,447	8,586	8,745	8,913	9,050	9,184	9,323	9,483
COMED	22,472	22,803	23,725	24,848	25,552	26,052	26,434	26,766	27,053	27,366	27,722	28,058	28,294	28,468	28,619	28,777
DAY	3,399	3,414	3,552	3,725	3,795	3,825	3,856	3,880	3,909	3,929	3,945	3,961	3,972	3,983	3,991	4,001
DLCO	2,862	2,865	2,915	2,984	3,026	3,065	3,105	3,143	3,185	3,224	3,257	3,292	3,320	3,347	3,375	3,401
DPL	3,972	4,002	4,138	4,289	4,395	4,483	4,554	4,630	4,712	4,789	4,882	4,969	5,059	5,142	5,232	5,317
JCPL	6,357	6,504	6,717	6,931	7,073	7,173	7,269	7,364	7,457	7,541	7,621	7,691	7,763	7,841	7,912	7,983
METED	2,866	2,906	2,995	3,079	3,142	3,182	3,219	3,253	3,284	3,305	3,334	3,364	3,384	3,407	3,424	3,442
PECO	8,455	8,459	8,681	8,893	9,008	9,103	9,212	9,307	9,386	9,467	9,538	9,616	9,678	9,728	9,765	9,806
PENLC	2,786	2,806	2,877	2,949	3,001	3,047	3,098	3,152	3,205	3,252	3,305	3,355	3,401	3,445	3,489	3,529
PEPCO	6,960	7,026	7,141	7,252	7,358	7,437	7,512	7,578	7,657	7,736	7,823	7,911	7,987	8,063	8,140	8,217
PPL	7,106	7,155	7,319	7,494	7,613	7,683	7,757	7,816	7,878	7,932	7,985	8,032	8,066	8,108	8,134	8,170
PS	10,858	11,022	11,292	11,570	11,753	11,885	12,013	12,135	12,257	12,354	12,470	12,572	12,677	12,763	12,859	12,951
RECO	435	441	451	461	467	472	477	482	487	491	496	501	505	509	512	516
UGI	190	191	195	199	201	203	204	205	206	207	207	208	208	209	209	209
VAP	18,982	19,264	19,921	20,675	21,140	21,518	21,895	22,294	22,721	23,130	23,603	24,059	24,506	24,974	25,440	25,929

The yearly forecasted load data is used to determine the yearly load increase by PJM zone. For example, AECO has a forecasted load of 2,761 MW in 2010 and 2,692 MW in 2009. The difference is 69 MW. This value is recorded as the yearly load increase for AECO for 2010. This process is repeated for every year and zone to complete Table 3.

Table 3: Yearly Load Increase by PJM Zone

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
AECO	69	219	140	120	61	50	51	46	46	39	39	45	41	29	35
AEP	135	602	690	360	200	228	185	186	158	128	138	112	110	102	81
APS	167	244	176	132	121	109	93	103	92	114	149	118	102	117	103
BGE	143	222	96	123	135	154	128	143	139	159	168	137	134	139	160
COMED	331	922	1,123	704	500	382	332	287	313	356	336	236	174	151	158
DAY	15	138	173	70	30	31	24	29	20	16	16	11	11	8	10
DLCO	3	50	69	42	39	40	38	42	39	33	35	28	27	28	26
DPL	30	136	151	106	88	71	76	82	77	93	87	90	83	90	85
JCPL	147	213	214	142	100	96	95	93	84	80	70	72	78	71	71
METED	40	89	84	63	40	37	34	31	21	29	30	20	23	17	18
PECO	4	222	212	115	95	109	95	79	81	71	78	62	50	37	41
PENLC	20	71	72	52	46	51	54	53	47	53	50	46	44	44	40
PEPCO	66	115	111	106	79	75	66	79	79	87	88	76	76	77	77
PPL	49	164	175	119	70	74	59	62	54	53	47	34	42	26	36
PS	164	270	278	183	132	128	122	122	97	116	102	105	86	96	92
RECO	6	10	10	6	5	5	5	5	4	5	5	4	4	3	4
UGI	1	4	4	2	2	1	1	1	1	0	1	0	1	0	0
VAP	282	657	754	465	378	377	399	427	409	473	456	447	468	466	489

Load distribution factors are calculated for each flowgate using all online PJM generation as a source and load in each respective zone as a sink. Table 4 contains sample load distribution factors for each PJM zone on the example flowgate involving Mt. Storm – Doubs 500kV. A table of load distribution factors is calculated individually for every flowgate.

Table 4: Area Load DFAX by PJM Zone

Zone	Load DFAX
AECO	0.04591
AEP	-0.03006
APS	0.00818
BGE	0.07542
COMED	-0.02906
DAY	-0.03057
DLCO	-0.0333
DPL	0.04847
JCPL	0.04195
METED	0.04646
PECO	0.04578
PENLC	-0.00404
PEPCO	0.08219
PPL	0.04074
PS	0.04188
RECO	-0.00708
UGI	0.03454
VAP	0.02689

The increase in loading on each flowgate in year 6 is determined by summing the products of the yearly load increases for 2015 and the load DFAX for each zone. This process is repeated for each year through year 15 to determine the final 15 year loading. Table 5 contains an example flowgate that is overloaded in year 7 (2016). The final loading in year 15 (2024) is calculated to be 115.6%. This process is then repeated for every flowgate to complete the system-wide 15 year analysis.

Table 5: Calculated 15 Year Loading of Example Flowgate

Electrical Occurrence	Electrical Result	PJM Reliability Test	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Outage of Bedington - Black Oak 500 kV line	Mt. Storm - Doubs 500 kV exceeds its emergency rating and overloads (2016)	Mid-Atlantic Load Deliverability	97.1	98.8	100.5	102.3	104.0	105.9	107.8	109.7	111.6	113.6	115.6

The linear extrapolation methodology that is performed in the long-term analysis for the remaining years in the planning horizon uses the same methodology described above for the near-term analysis. However, in order to be consistent with this method of matching generation to load growth, the incremental load growth that occurs between the near-term and the long-term case year is assumed to be served by a uniform increase of online PJM generation when creating the long-term base case and when performing the associated long-term CETO calculations.

C.4.4 Long-Term Upgrades

The outcome of the long-term deliverability analysis will identify the need to include in the RTEP any:

- New 230 kV or 345 kV circuits to support load growth in years 6 through 8,
- Right-of-way acquisition for any new 230 kV or 345 kV circuits to support load growth in years 9 and 10,
- New 500 kV or greater circuits to support load growth in years 6 through 12.

Attachment D: PJM Reliability Planning Criteria

The PJM Reliability Planning Criteria consist of multiple standards and applicable planning principles that include PJM planning procedures, NERC Planning Standards, NERC Regional Council planning criteria, and the individual Transmission Owner FERC filed planning criteria. PJM applies all applicable planning criteria when identifying reliability problems and determining the need for system upgrades on the PJM system. Details of specific criteria applicable to the various stages of reliability planning are discussed along with the corresponding discussion of each procedure found elsewhere in this manual.

The PJM Transmission Owners are required to follow NERC and Regional Planning Standards and criteria as well as the Transmission Owner FERC filed criteria. References to the various planning standards and criteria can be found at http://www.pjm.com/planning/planning-criteria.aspx.

- ReliabilityFirst Approved Standards will be applied for all ReliabilityFirst Bulk Electric System facilities.
- SERC Reliability Criteria will be applied to all SERC networked transmission systems rated 100 kV and higher.
- Transmission Owner standards filed in their FERC 715 filings will be applied to all facilities included in the PJM Open Access Transmission Tariff facility list. Also, interconnections to Transmission Owner facilities are subject to owner standards found at: http://www.pjm.com/planning/design-engineering.aspx (these are technical interconnection requirements and do not factor into near-term and long-term planning analyses.

PJM maintains a list (http://www.pjm.com/markets-and-operations/ops-analysis/transmission-facilities.aspx) of all PJM Open Access Transmission Tariff facilities along with which facilities are included in the PJM real-time congestion management control facility list. Both facility lists are referenced in the PJM Reliability Planning Criteria.

The PJM Generator Deliverability Procedure and Load Deliverability Procedure will be applied to all facilities in the PJM real-time congestion management control facility list. These procedures are described in Attachment C.

For all tests, PJM will not accept a loss of load of more than 300 MW, impacting numerous customers. Attachment D-1 contains a description of the various load loss types.

Facilities included in the PJM real-time congestion management control facility list but not included in the applicable regional council planning criteria as defined in section I above will be evaluated against the following criteria. For all tests, PJM will not accept a planned loss of load of more than 300 MW impacting numerous customers. Attachment D-1 contains a description of the various load loss types referred to in this document. This criterion is in addition to, not in place of, each Transmission Owners Planning Criteria as reported in the FERC 715 filing.

- The loss of any single transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or applicable voltage limit. (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) The single contingency test will be applied as per the RTEP Generator Deliverability Procedure. (See Attachment C of this PJM Manual 14B.)
- The RTEP base case which includes a 5-year horizon system representation and non-diversified forecasted 50/50 summer peak load will be used for this analysis.
- System load will be represented at an area or zone wide minimum power factor of 0.97 lagging as measured at the transmission / distribution interface point.
- The 300 MW load limit referenced above does not include load that is immediately restored via automatic switching to adjacent substations. The 300 MW load limit is meant to represent contingencies impacting numerous customers that aggregate to 300 MW or higher.
- Automatic or supervisory switching as proposed by the Transmission Owner to sectionalize the system for single contingency events must receive acceptance by PJM Operations.
- During normal conditions with all facilities initially in-service, no uncontrolled load loss or load loss due to automatic schemes is allowed for a single contingency event. Consequential load loss is allowed.

After the occurrence of the transmission line, cable, generator or transformer outage, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.

During maintenance of any single transmission line, cable, generator, transformer, bus or circuit breaker, the loss of a transmission line, cable, generator, or transformer may not result in any monitored facility exceeding the applicable emergency rating or voltage limit (The applicable emergency rating and voltage limits will be as defined in PJM Operations.) However, for practical purposes, PJM Planning will only include a specific bus or circuit breaker maintenance condition in all future analysis if PJM Operations experiences operational problems as a result of the bus or circuit breaker maintenance condition.

- Pre-contingency generation redispatch will be considered acceptable for mitigation of a potential overload or voltage limit.
- This test will be applied at 70% of the diversified forecasted 50/50 summer peak load, as modeled in the RTEP base case, unless the Transmission Owner provides information to PJM Operations demonstrating sufficient maintenance windows at a lower load level.

- No cascading or uncontrolled load loss is allowed under any circumstance.
- Consequential load loss is allowed.
- After occurrence of the maintenance outage and the subsequent facility outage as defined in the previous test #3, the system must be capable of re-adjustment such that no facility exceeds the maximum continuous rating or voltage limits as defined in PJM Operations.

The PJM Light Load Reliability Analysis Procedure will be applied to all facilities in the PJM real-time congestion management control facility list.

Attachment D-1: Load Loss Definitions

Uncontrolled Load Loss – Uncontrolled load loss would require operator interaction to prevent system cascading or to return the system to applicable ratings or voltage limits. Manual load dump as defined in PJM Operations would be included in this category. The PJM Reliability Planning Criteria does not allow for the system design to permit Uncontrolled Load Loss for any contingencies that are studied.

Examples:

- Voltage collapse
- A facility overload without automatic schemes to drop load and with no available generation to re-dispatch pre-contingency.

Consequential Load Loss – Consequential load loss occurs due to the design of the system but does not include automatic schemes designed to drop load under various conditions.

Examples:

- A transformer serving radial load that taps a networked circuit.
- Load that is served from a radial circuit.

Controlled Load Loss due to Automatic Schemes – Controlled load loss occurs due to the operation of automatic schemes that are designed to drop load under specific maintenance conditions.

Planned Load Loss = Consequential load loss + Controlled load loss due to automatic schemes.

The 300 MW total load loss limit is based, in part, on a Federal reporting requirement for major system incidents on electric power systems (refer to Electric Power System Emergency Report - Form EIA-417R) impacting numerous customers.

Non-Consequential Load Loss – If situations arise that are beyond the control of PJM that prevent the implementation of a Corrective Action Plan in the required timeframe, then Non-Consequential Load Loss and curtailment of Firm Transmission Service are permitted to correct the situation that would normally not be permitted in Table 1, provided that PJM documents that they are taking actions to resolve the situation. PJM shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

For Table 1 contingency categories that permit non-consequential load loss, PJM will only use this allowance for facilities that become radial after the contingency. Under such conditions,

PJM will not allow any more than 300 MW of non-consequential load loss impacting numerous customers.

Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test

PJM uses a Benefit/Cost Ratio test to determine whether an economic-based enhancement or expansion will be included in the RTEP. Specifically, to be included in the RTEP recommended to the PJM Board of Managers for approval, the relative benefits and costs of the economic-based enhancement or expansion must meet a Benefit/Cost Ratio Threshold of at least 1.25:1. The Benefit/Cost Ratio is calculated by dividing the present value of the total annual benefit projected for the 15 year period starting with the RTEP year defined as current year plus 5

minus benefits for years where the enhancement is not yet in service by the present value of the revenue requirement for the same period. Assumptions for determining the present value of the benefits and costs (e.g. discount rate and annual revenue requirement) will be among the assumptions that are considered by the PJM Board each year to be used in the economic planning process.

The Benefit/Cost Ratio is expressed as follows:

Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for the 15 year period starting with the RTEP Year (defined as current year plus five) minus benefits for years when the project is not yet in-service] ÷ [Present value of the Total Enhancement Cost for the same 15 year period]

The purpose of a Benefit/Cost Ratio Threshold is to hedge against the uncertainty of estimating benefits in the future and to provide a degree of assurance that a project with a 15-year net benefit near zero will not be approved. At the same time the threshold is not so restrictive as to unreasonably limit the economic-based enhancements or expansions that would be eligible for inclusion in the RTEP.

E.1 Total Annual Enhancement Benefit

The benefit component of the Benefit/Cost Ratio (Total Annual Enhancement Benefit) is the sum of two metrics: the “Energy Market Benefit” and the “Reliability Pricing Model (RPM) Benefit.” By including these two metrics, the benefits to customers from reductions in both energy prices and capacity prices as a result of an economic-based enhancement or expansion will be taken into account in the formulaic analysis. This comprehensive test captures customers’ benefits in the energy markets and the capacity markets that may correspond to responsibilities related to obtaining reasonably priced energy as well adequate capacity.

Energy Market Benefit

The energy-market benefit analysis is conducted using an energy market simulation tool that models the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. A detailed generation, load, and transmission system model is used as input into the simulation tool in order to mimic the hourly commitment and dispatch of generation to meet load, while recognizing constraints imposed on the economic commitment and dispatch of generation by the physical limitations of the transmission system. Benefits of potential economic-based enhancements, PJM will perform and compare market simulations with and without the proposed enhancement for selected future years within the planning horizon of the RTEP. A comparison of these simulations will identify the annual economic impact of the enhancement for each of the future study years. An extrapolation of these results provides a projection of annual benefits for each of the 15 year period starting with the RTEP year.

The Energy Market Benefit component of the Benefit/Cost Ratio for Regional Projects is expressed as:

inlinescroll*Energy Market Benefit* =

inlinescroll[.50]*[*Change in Total Energy Production Cost*]

inlinescroll+[.50]*[*Change in Load Energy Payment*]

The Energy Market Benefit component of the Benefit/Cost Ratio for Lower Voltage Projects is expressed as:

inlinescroll*Energy Market Benefit* = [1]*[*Change in Load Energy Payment*]

The Change in Total Energy Production Cost is the difference in estimated total annual fuel costs, variable O&M costs, and emissions costs of the dispatched resources in the PJM Region without and with the enhancement or expansion. Costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured if appropriate. Purchases will be valued at the Load Weighted LMP and sales will be valued at the Generation Weighted LMP.

The Change in Load Energy Payment is the difference between the annual sum of the hourly estimated zonal load megawatts for each PJM transmission zone multiplied by the hourly estimated zonal Locational Marginal Price for each PJM transmission zone minus the value of Transmission Rights for each PJM transmission zone without and with the economic-based enhancement or expansion. In determining the Change in Load Energy Payments, only zones that show a decrease will be considered in determining the Change in Load Energy Payments.

Reliability Pricing Model Benefit

Reliability pricing benefit analysis is conducted using the Reliability Pricing Model software. The Reliability Pricing Model Benefit component of the Benefit/Cost Ratio evaluates the benefits of a proposed economic-based enhancement or expansion that will be realized in the capacity market and is expressed as:

inlinescroll*Reliability Pricing Benefit for Regional Projects*

inlinescroll = [.50]*[*Change in Total System Capacity Cost*]

inlinescroll+[.50]*[*Change in Load Capacity Payment*]

inlinescroll*Reliability Pricing Benefit for Lower Voltage Projects*

inlinescroll = [1]*[*Change in Load Capacity Payment*]

The Change in Total System Capacity Cost is the difference between the sum of the megawatts that are estimated to be cleared in the Base Residual Auction under PJM's Reliability Pricing Model capacity construct times the prices that are estimated to be contained in the offers for each such cleared megawatt (times the number of days in the study year) without and with the economic-based enhancement or expansion.

The Change in Load Capacity Payment is the sum of the estimated zonal load megawatts in each PJM transmission zone times the estimated Final Zonal Capacity Prices (payments paid by load in each transmission zone) for capacity under the Reliability Pricing Model construct (times the number of days in the study year) minus the value of Capacity Transfer Rights for each PJM transmission zone without and with the economic-based enhancement or expansion. The Change in Load Capacity Payment will be evaluated in the same manner as the Change in Energy Load Payment. Like for the Change in Energy Load Payment, in determining the Change in Load Capacity Payment, only PJM transmission zones that show a decrease will be considered in determining the Change in Load Capacity Payment.

E.2 Total Annual Enhancement Cost

The annual cost of the enhancement is the revenue requirement of the enhancement. The enhancement's annual revenue requirement is an assumption that is developed by PJM and presented to the TEAC for discussion and review. As stated earlier, the benefits and costs will be considered over the same time period, the 15 year period starting with the RTEP year (defined as current year plus 5) minus years where the project is not yet in-service.

Attachment F: Determination of System Operating Limits used for planning the Bulk Electric System

This document describes the process and measures used by PJM to develop System Operating Limits (SOL) and Interconnection Reliability Operating Limits (IROL) used for the planning horizon. In PJM Planning, all BES facilities and “Reliability and Markets” sub-BES facilities, as listed on the PJM Transmission Facilities pages, are considered System Operating Limits (SOL).

Definitions

A System Operating Limit (SOL) is defined in the NERC Glossary of Terms as:

All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post- Contingency operating states.

PJM’s Planning analyses are designed to ensure all applicable PJM, NERC, regional and Transmission Owner criteria are enforced. This is accomplished through exhaustive application of established PJM facility ratings in the on-going system power flow and short circuit analysis. PJM ensures that its exhaustive application of facility ratings are also within system dynamic limits through system dynamic testing. This dynamic testing confirms that PJM system operating limits are not more limiting than the limits established using facility ratings.

A Facility Rating is defined in the NERC Glossary of Terms as:

- The maximum or minimum voltage, current, frequency or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Facility ratings determine the fundamental limits of transmission system equipment. SOLs shall not exceed the facility ratings. The facility rating is based on which ever device or component is the limiting element of the facility such as a conductor, current transformer, disconnect switch, circuit breaker, wave trap or protective relay. PJM plans its system such that no facility exceeds the limit/rating consistent with NERC Standard TPL-001-5.1. In general, Facility ratings included in the planning models are equally limiting or more limiting than the facility ratings established in accordance with PJM Operation's SOL methodology. Less limiting facility ratings are used in instances where future Corrective Action Plans (CAPs) are implemented and/or ambient temperature assumptions in the seasonal planning models vary from the assumptions used in the operational analyses and monitoring in real time. Additional information concerning SOL can be found in the PJM Transmission Operations Manual (M-03), and PJM Reliability Coordination Manual (M-37).

An Interconnection Reliability Operating Limit (IROL) is defined in the NERC Glossary of Terms as:

- A System Operating Limit that, if violated, could lead to instability, uncontrolled separation or Cascading Outages that adversely impact the reliability of the Bulk Electric System.

In the planning horizon PJM analyses examine and reveal the violations of applicable criteria. This includes violations affecting PJM monitored facilities at all voltage levels as well as violations that may have widespread impacts affecting the Bulk Electric System and any lower voltage facilities that are monitored by PJM Operations, which may be eligible for designation as IROLs. PJM plans system upgrades for violations of applicable criteria, thus IROL designations are not typically required for the upgraded system in the planning horizon. PJM closely tracks the project status and milestones of all planned upgrades on a frequent and recurring basis. For baseline reliability upgrades, the project tracking is coordinated with the entity that has been designated the construction responsibility, typically the Transmission Owner. If the schedule for implementation for a planned upgrade does not meet the in-service date required for system reliability in the planning or operating horizon, PJM will perform additional analysis to determine any alternative plans that need to be taken to ensure system reliability, including the establishment of an IROL. For additional information on IROLs for the operating horizon see the **PJM Transmission Operation Manual (M03)** and the **PJM Reliability Coordination Manual (M37).**

PJM's Planning methodology to determine IROL facilities simulates transfers across a facility or interface (combination of facilities), comparing thermal and voltage violations associated with a facility. The transfer scenarios used by PJM Planning are established through the application of PJM's deliverability criteria. Additional information on PJM's deliverability criteria is included in Attachment C of this manual. PJM classifies a facility as an IROL facility on the network if wide-area voltage violations occur at transfer levels that are near the Load Dump thermal limit.

As part of the development of the PJM Regional Transmission Expansion Plan, SOLs which could result in system instability or uncontrolled cascading outages are identified and system reinforcements are developed. All SOLs are monitored for violations.

SOL and IROL use in Planning

PJM plans its system based on the most restrictive System Operating Limits (such as MW, MVAr, Amperes, Frequency or Volts) of its facilities for the system configurations and contingency conditions that represent the most stringent of the applicable PJM, NERC, regional or Transmission Owner criteria over the planning horizon. The System Operating Limits used to plan the system are consistent with the facility ratings, system voltage limits and stability limits used in Operations. Voltage limits and any exception to those limits are identified in the PJM Transmission Operation Manual (M-03).

An Interconnection Reliability Operating Limit is the value (such as MW, MVAr, Amperes, Frequency or Volts) that is derived from or is a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability,

uncontrolled separation(s) or cascading outages. PJM Reliability Coordination Manual (M37) defines PJM's methodology for determining, monitoring, and controlling IROL facilities.

Nuclear Power Plant Generator Operators are required to transmit Nuclear Plant Interface Requirement (NPIR) to transmission entities. The transmission entities are required to include those parameters into planning and operational analysis, operate to meet those parameters, and inform the nuclear licensees when those parameters cannot be met for any reason. For details please refer to Manual M03 Section 3: http://www.pjm.com/~/media/documents/manuals/m03.ashx

PJM Planning SOL Methodology

PJM's Reliability Planning methodology for determining SOLs utilizes multiple standards and applicable planning procedures including the PJM Reliability Planning Criteria, NERC Planning Standards (TPL-001-5.1), Regional Reliability Organization criteria, and individual Transmission Owner FERC filed criteria. In all cases, PJM applies the most conservative of all applicable planning criteria when identifying reliability problems. PJM tests these criteria on a regional basis including all facilities within its footprint. All SOLs are monitored for thermal, voltage and stability violations. Remediation plans are developed to mitigate the violations that exceed the established SOL limits.

PJM's develops models for specific planning horizons using the latest Eastern Reliability Assessment Group (ERAG formerly MMWG) modeling information available for the applicable planning period. A detailed model is utilized for PJM's internal system (transmission owner under PJM's footprint) while the latest ERAG model for that planning period is used for facilities outside of PJM to incorporate critical modeling details of other control areas. Additional information about PJM's base case development procedures can be found in section 2 of this manual.

PJM reliability planning criteria requires that the system be tested for all BES single contingency outages and all common mode outages. Common mode outages consist of line faults coupled with a stuck breakers that result in multiple facility outages, double circuit towerline outages and bus faults in the PJM system. PJM's planning procedures require all NERC P0, P1, P2, P3, P4, P5, P6 and P7 conditions be tested.

When appropriate PJM will identify and implement Remedial Action Schemes. If the scheme is required for reliability purposes, operational performance, or to restore the system to a reliable state following a significant transmission facility event, operation of the scheme will be tested in the on-going planning analysis. See the Transmission Operations Manual (M-03) (http://www.pjm.com/~/media/documents/manuals/m03.ashx) for additional information concerning Remedial Action Schemes.

The PJM planning process includes a series of detailed analyses to ensure reliability under the most stringent of applicable NERC, PJM or local criteria. Through this process, violations of system operating limits are identified. System reinforcements required to mitigate the violations

are developed and included in the Regional Transmission Expansion Plan for implementation. As a result PJM's application of its System Operating Limits for the planning horizon ensures system operation within Interconnection Reliability Operating Limits.

PJM Planning will communicate to PJM Operations any potential IROL facilities resulting from PJM deliverability criteria analysis. PJM Planning and Operations work to develop new IROL Reactive Interfaces and associated operating procedures as required.

Attachment G: PJM Stability, Short Circuit and Special RTEP Practices and Procedures

G.1 Stability

PJM Planning conducts stability studies to ensure that the planned system can withstand NERC criteria disturbances and maintain stable operation throughout the PJM planning horizon.

NERC criteria disturbances are those required by the NERC planning criteria applicable to system normal, single element outage and common-mode multiple element outage conditions. These conditions are specified in the NERC approved Transmission Planning (TPL) Reliability Standards that can be found on the NERC website (www.NERC.com). Because these standards change from time to time they are included here by reference. In addition, PJM's analyses also satisfy the Transmission Owner specific stability practices and procedures as may be applicable when these are more demanding tests than the standard NERC criteria tests applied by PJM. All Transmission Owner specific information and criteria that exceed *standard testing of NERC criteria* and are applicable to PJM reliability based RTEP stability analyses are included or referenced in the Appendix to this Attachment. Transmission Owner stability criteria filed as FERC Form No. 715 and posted on PJM's website and not included in the Appendix may be used to support Transmission Owner funded upgrades. The currently approved version of this Appendix at the commencement of the RTEP process will be the basis for that baseline RTEP and related generator Cycle assessments. PJM's stability analyses verify satisfactory projected system performance over the range of anticipated load levels and identify any need for upgrades, operating guides, or Remedial Action Schemes that may be indicated based on stability or short circuit testing as a primary driver. In general, the most appropriate remedy to NERC criteria violations is a system upgrade. In circumstances involving criteria that go beyond PJM's standard testing of NERC criteria, operating guides or Remedial Action Scheme remedies may also be considered as discussed further in this Attachment and its Appendix. New Remedial Action Schemes, however are generally avoided and, if considered, require case-by-case review and justification. Also certain specific areas of PJM have been identified through PJM or Transmission Owner analysis as stability limited areas of the system. In such areas of the system, stability operating guides may apply. For related information see PJM Manual 03 at http://www.pjm.com/library/manuals.aspx.

Critical system conditions for stability analysis on the PJM system are generally characterized by light load and peak load. System peak load levels shall include a load model where applicable which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. An aggregate system load model which represents the overall dynamic behavior of the load is also acceptable where applicable. In exceptional cases, PJM may add alternate load testing when PJM determines that an alternate load level may be the critical load level for system stability for the limitation under review. Peak

load stability analysis related to new interconnections of wind turbines and their low voltage ride through performance will also be performed.

System conditions most critical for stability analysis on the PJM system are generally characterized by light load. Peak load analysis is added for stability reviews that involve new connections of wind turbines and performance of low voltage ride through testing. In exceptional cases, PJM may add heavy load testing for other types of units when PJM determines that heavy load may be the critical load level for system stability for the limitation under review.

PJM's stability analyses ensure the dual objectives of stability of new interconnection projects and system-wide stability. PJM conducts New Service Request stability studies. These analyses ensure newly connecting projects and nearby changes to the system configuration maintain the stability of the project and the system. Study of these projects located throughout PJM provides a thorough, ongoing review of PJM both at the project level and system-wide. In addition, each year, PJM conducts a re-study of one third of existing PJM generation stations. This results in a three-year cycle of on-going re-study of the entire PJM system. PJM also performs additional system-wide stability analyses during the annual RTEP review. In addition, as may be required from time to time, PJM conducts stability analyses to evaluate the dynamic performance of actual or possible major future system developments. For example a proposed new backbone transmission project or prolonged unexpected backbone transmission outage in a stability sensitive area would be cause for a specifically targeted system study. Another cause could be the need to evaluate system performance resulting from major developments affecting power and energy policy.

G.2 Dynamics Procedures

This section provides a high level review of the process of setting up and performing dynamics analyses.

G.2.1 Dynamics Reference Cases

Reference power flow cases for stability analysis are created in a similar manner to that of the power flow reference cases. Additional information, however, is necessary for stability studies to simulate the combined dynamic responses of various power system components. Included in this additional information are dynamics models for generators, excitation systems, power system stabilizers, governors, loads and various other equipment. The required dynamic and other modeling information that must be supplied by generators interconnecting to the PJM system is detailed in Manual 14H. A dynamic simulation links the system model or power flow information with the dynamic data or models to determine if the system and generators will remain stable for steady-state and various disturbances. The current RTEP summer peak case is used as a starting point to create new dynamics cases (light load and peak load.) For example the RTEP analysis is performed for the current year plus five (available early in each calendar year and updated for the five-year-out RTEP analyses in early fall of each calendar year). The stability case setup is for the same study year using the updated RTEP case. This

updated RTEP power flow case and the associated stability case become the baseline cases for the Phase II System Impact Studies that evaluate New Service Requests. In the event that stability analysis is needed beyond the Near-Term, the Long-Term Transmission Planning Horizon portion of the stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies and shall include documentation to support the technical rationale for determining material changes.

G.2.2 Dynamics Analysis

The two dynamics cases Originate from the RTEP Power Flow Case that is created for the annual RTEP Plan analyses. The RTEP cycle is depicted in Manual 14B, Exhibit 1. The reference power flow case is reviewed and modified as necessary to correspond to the dynamics database (which includes external world dynamics data from the Eastern Interconnection Reliability Assessment group's Multi-Regional Modeling Working Group as well as PJM data.) In addition, the case is modified to include generator step-up transformers and explicit modeling of generator station service power use along with gross generator rating. Also, because of the demands of dynamics analyses, constant power load representations in the power flow case are replaced with Transmission Owner provided load model representations. In light load representations, pumped storage resources are in pumping mode.

This process is followed to develop stability setups for analysis of all PJM interconnection requests. In addition PJM's system stability analyses will use the most current available setup from this continuous development process.

Testing

After the dynamics model setup, dynamic case initialization and acceptance test are conducted. After case verification, the final, initialized set of power flows and the associated snap-shots, along with the associated dynamic run files are available upon request to Project Developers and others who have a legitimate need for the information, subject to applicable Confidentiality and Critical Energy Infrastructure Information processes (see PJM Operating Agreement §18.17 and http://www.pjm.com/library/request-access/form-ceii-request.aspx.

Dispatch

The assumptions used for generation dispatch can be critical to the results. It is generally accepted that units operating at their highest possible power output and generating as little reactive power as necessary to maintain voltages are likely to be less stable. Normally, and to the extent where no resulting thermal overloads occur under system normal and N-1 contingency conditions, the units in the vicinity of the project under study as well as the study unit(s) will be turned on to their maximum real power output with unity power factor at the high side of the GSUs, or units' VAR output will be adjusted to hold scheduled voltages, depending on specific Transmission Owner criteria. Wind facilities are tested at light load for stability and peak load for low voltage ride through at 100% of their maximum energy value. In addition,

stability test scenarios necessitated by any applicable Transmission Owner operating guides will also factor into each analysis.

Simulations to determine required upgrades (also see the Appendix to this Attachment)

Fault Criteria:

- Fault Types: For interconnection and system stability analyses, three phase faults, single line to ground faults with stuck breaker and single line to ground faults with the communications failure cleared within zone 2 time will be examined. Each analysis will include a determination of the most critical faults to apply. Planning events expected to produce more severe impacts shall be identified. A list of these contingencies as well as the rationale for selection shall be available as supporting information.
- Clearing Times: Dynamic simulation issues are identified using estimates of actual (nominal) clearing times, including relay trip times, breaker interrupting time, fault extinguishing time, intentional delay time, and a margin for error.
- Reclosing: Only high speed reclosing (less than one second) is modeled if present. Successful high speed reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized will be examined.
- Fault locations: For interconnection analysis, see section G.3.2 New Service Request Stability Study Procedure. For system analyses, the scope will determine the most critical locations to apply criteria faults.
- Maintenance outages: Interconnection analyses of planned line maintenance outage conditions prior to fault application are system conditions that can be anticipated and that are generally of limited duration. The least cost remedy to issues during such system conditions is to require generation to curtail output. Such analyses are, therefore, of primary interest in the operating horizon and are not generally considered to determine upgrade facilities required prior to interconnection. Nevertheless, prior to commercial operation, or prior to completion of the Phase II System Impact Study at the request of the Project Developer, Planning will screen critical faults for issues during line maintenance. The results of the line maintenance study will be conveyed to PJM Operations, the Project Developer and affected Transmission Owners.
- PJM addresses Power System Stabilizer (PSS) outages in a similar fashion. If there are existing PSS installations nearby a new interconnection or if PSS is required on the new interconnection, critical faults for the outage of these devices will be studied prior to commercial operation and the results will be conveyed to PJM Operations, the Project Developer, and affected Transmission Owners.
- Tripping of transmission lines and transformers where transient swings cause protection system operation shall be analyzed using generic relay models.
- For NERC Transmission Planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not results in the tripping of any transmission system elements other than the generating unit and

directly connected facilities. Directly connected facilities for this requirement are facilities intended to or designed to trip as a consequence of the out-of-step event.

Margins:

The margins applied by PJM are intended to be applied in System Impact Study stability analysis that uses a project's final stability study data as further discussed below. As such, these margins account primarily for uncertainty in actual clearing times, and the final data represents the "as built" performance. With the machine modeled at net unity power factor at the high-side of the GSU (or unity power factor at the generator terminals for wind turbine installations), transient stability must be maintained for tested faults when the following margins are included:

- Add 0.25 cycles to the nominal primary clearing time for 3 phase, normally cleared faults.
- Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 0.5 cycles added to the nominal backup clearing time for stuck breaker (.75 cycle total clearing time margin).
- Add 0.25 cycles to the nominal primary clearing time for single-line-to-ground faults, plus an additional 1.25 cycles to the nominal Zone 2 clearing time for failure of primary relaying (1.5 cycle total clearing time margin).

Monitoring requirements:

Rotor angle, real/reactive power output, EFD, speed and terminal voltage of units under study are monitored. Bus Voltages in the same area are also monitored.

Acceptable Transient Voltage Recovery

When a fault occurs on the transmission system, system voltages are temporarily reduced. Once the fault is cleared, voltages follow transient voltage recovery trajectories governed by system dynamics.

The transient voltage recovery criteria should be satisfied at BES buses.

Regardless of the load model that is selected, the voltage following fault clearing shall recover to a minimum of 0.7 p.u. after 2.5 seconds. If a plant-specific document (such as NPIR) or local Transmission Owner specific planning criteria requires a more conservative voltage recovery criterion that specific criterion will be applied. More conservative limits may be agreed upon by PJM and the TO.

Acceptable Damping:

Following the disturbance, the oscillations of the monitored parameters display positive damping. The positive damping is determined with a damping coefficient calculation algorithm. This characterizes the degree of positive (damped) or negative (undamped) damping based on

the damping trend, over the duration of the stability run, of the envelope of machine angle oscillation peaks. This trend can be observed by drawing an envelope connecting each succeeding peak or valley of the oscillation of the monitored element. An acceptable oscillation envelope will demonstrate a positive decay within the appropriate test period (normally 10 to 15 seconds). A sustained oscillatory system response, even if slightly damped, will cause the system to be in a vulnerable state and exposed to adverse impacts for subsequent changes to the system over some prolonged time. To limit this system exposure PJM uses a 3% damping margin. Such positive damping demonstrates an acceptable response by the system, and no further analysis is required. Failure to meet the damping standard will require application of some combination of power system stabilizers, excitation system upgrade and tuning, and system upgrade.

G.3 New Service Request Stability Study Procedures

PJM performs New Service Request stability analysis as a part of the Phase II System Impact Study. PJM's standards for stability analyses satisfy NERC criteria and are the generally applicable criteria for all PJM stability analyses. In addition, Transmission Owner stability criteria may apply. PJM or Transmission Owner analysis have identified certain specific areas of PJM as stability limited areas of the system. In such areas, stability operating guides may apply. See PJM Manual 03 at http://www.pjm.com/-/media/documents/manuals/m03.ashx for more information on PJM stability operating guides.

G.3.1 New Service Requests Stability Data Requirements

PJM Manual 14H details data submission requirements for each phase of the Cycle process.

G.3.2 New Service Request Stability Procedure

This section outlines the process of coordination and execution of the stability study among the representatives of PJM, the Project Developers and Transmission Owners during a Cycle. These procedures apply to stability studies required as part of the New Service Requests process. These stability studies identify needed reinforcements and determine cost responsibility for these reinforcements due to New Service Requests stability issues. The upgrade responsibilities become part of the Generation Interconnection Agreement (GIA).

During Phase I, all verified and accepted Dynamic Models submitted by each Project Developer will be added to the selected dynamics basecase (light load, and/or summer peak load) being used for that Cycle. The New Service Requests in that Cycle will be grouped into clusters based on a clustering methodology. Once the clusters are identified, the New Service Request will remain in that cluster until the end of the Cycle, or until the New Service Request withdraws or is terminated. A scope of work will be developed for each cluster of projects, which will include, but not be limited to the following items:

1. A list of the projects included in the cluster along with a brief description of each project's POI location, MW size and other relevant information. The stability evaluation is performed at the maximum MW output specified for the project.
2. A detailed fault list to test NERC, PJM and Transmission Owner criteria faults, as applicable. The fault specification list will include:
    a. Fault location
    b. Phase involvement
    c. Fault Impedance
    d. Clearing times and reclosing, if applicable
    e. Explicit timing or other margins to be added
    f. Justification of any procedures that exceed PJM standard methods

At a minimum, faults will be developed at the POI bus and one bus away from that bus. In addition, other fault locations judged by PJM as critical to cluster response will be added to the scope.

1. For areas in the cluster affected by established operating guides or Remedial Action Schemes (RAS), as noted in Manual 03, scenarios designed to test the proper operation of the existing guides or RAS may be included, as deemed necessary by PJM. In such cases, the scope will be augmented to examine and specify modified procedures or facilities that ensure the integrity of the system operation.
2. All special study conditions, scenarios or simulations, if any, required by guides or sensitive areas and specific clearing times.
3. A table listing the generating units that will be dispatched for the cluster stability study.

The affected Transmission Owner(s) will have five business days to review the scope of work developed, and provide comments/input to PJM representatives if any additional specific scenarios should be considered. The finalized scope of work will be used for the stability study in Phase II.

During Phase II, changes from Decision Point I will be incorporated into the dynamics basecase, the stability clusters and scope of work, as needed. Contingencies for the faults in each cluster are created. The stability study is run based on the scope of work developed for the cluster. If any issues are identified in the stability results, the Transmission Owner will provide upgrades to mitigate the instability, along with cost and time estimates. PJM will review and test the

upgrades to verify it resolves the issues identified. Cost allocation will be done in accordance with M14H Att 02. The completed stability study report and results are sent to the affected Transmission Owner(s) to review. Upon completion of the Transmission Owner review PJM will issue the final Phase II System Impact study report to the project developer.

In situations when the required system modifications or upgrades cannot be accomplished by the projected in-service date of the project, PJM will develop a scope and schedule to determine interim solutions and dates along with provided interim capability.

During Phase III, changes from Decision Point II will be incorporated into the dynamics basecase as needed, and if a restudy for a cluster is required, it will be performed during Phase III. The process to restudy and finalize the stability study results is the same as outlined in Phase II above.

Changes during Decision Point III will be incorporated on an as needed basis for each cluster.

G.4 System Stability Studies

In addition to the stability analyses of new generating interconnections, the three year cycle testing of all existing generating units interconnected to the PJM system, and certain “ad hoc” stability testing required by special circumstances that occur from time to time, PJM also conducts system stability testing of its most critical stressed system conditions during the annual Regional Transmission Expansion Plan study cycle. The RTEP stability testing examines and ensures system performance within criteria for heavy system transfer conditions. Power flow criteria are ensured on a local and system-wide basis for heavy transfers during the application of PJM’s load deliverability testing (see Manual 14B Attachment C.) These test scenarios examine emergency conditions involving extreme generating outages and loads coupled with single transmission element outages. Such circumstances are critical when the system is stressed at heavy load, rather than light load.

Based on the results of each annual RTEP cycle and previously completed stability analyses, PJM determines the load delivery limits for the case that represents the most critical conditions for PJM system stability testing. The transfers into the selected Region emanate from external PJM and non-PJM generation. Imports from external areas are based on historical levels for heavy load. An example of the type of PJM scenario that could represent the critical study condition may have local load of 65,000 MW with a transfer into the area caused by the simultaneous outage about 10,000 MW of internal area generation. This may cause a thermal limit to transfers well in excess of 6000 MW.

The transmission outage that sets the limit for transfers during the Mid-Atlantic load delivery testing is modeled for stability to ensure that the region is not stability limited. PJM also determines several more critical three-phase and single-line-to-ground fault tests to apply from a stability perspective to ensure robust, stable and adequately damped system performance. Fault testing for system stability includes the most critical Bulk Electric System lines.

G.4.1 NERC P3 and P6 "N-1-1" System Stability Studies

INTRODUCTION

An N-1-1 contingency pair is defined as a single line to ground (SLG) or 3-phase fault with normal clearing, manual system adjustments, followed by another SLG or 3-phase fault with normal clearing. In the NERC TPL standard, N-1-1 contingencies belong to P3 and P6. Manual adjustments after first (N-1) contingency are allowed to relieve any thermal or voltage violations for applicable ratings and/or to prepare for second (N-1-1) contingency.N-1-1 stability analysis is defined as a stability analysis for given N-1-1 contingency scenarios. For a given N-1-1 contingency scenario, the first (N-1) contingency is applied to a pre-disturbance base case. If the system is stable, a new operating point is computed and manual adjustments are made if necessary, and then stability is monitored following second (N-1-1) single contingency. Because of the assumed long time delay (from a stability point of view) between two single contingencies, the N-1-1 stability analysis is similar to maintenance outage study for operational guidelines.

DISPATCH

Initial base case creation for N-1-1 stability analysis follows the procedure in Attachment G, section 2.2. When an N-1 base case is created, care needs to be taken before an N-1-1 contingency is applied. First, all thermal or voltage violations in the N-1 base case should be resolved through system adjustment. Second, if available, any existing operating guidelines for the N-1 outage condition needs to be applied to the N-1 base case.

N-1-1 STABILITY ANALYSIS PROCEDURE

Considering the number of generating machines in the PJM system and the number of possible N-1-1 contingency pairs, it is very challenging to cover all of them within a reasonable lead time. In general testing all N-1-1 contingency pairs for stability is impractical and not necessary due to the fact that most contingency pairs are electrically far away from a study plant or independent from each other. It is essential to screen out critical contingency pairs which have potential stability problems without missing any potentially unstable N-1-1 contingency pairs.

Overall procedure of N-1-1 stability analysis for generating units in PJM area is as follows:

- Selection of plants for the N-1-1 stability study
  - The scope of annually studied plants will include the same plants included in the scope of the baseline stability study that year. Similar to the baseline stability study, one third of generators in PJM will be considered for the N-1-1 stability analysis each year resulting in every PJM generator being studied at least once every three years.
  - If PJM Transmission Planning determines that the scope cannot be completed within a reasonable lead time, PJM Transmission Planning will prioritize the plants in the scope of the study and higher priority plants will be studied first.
  - With the request of PJM Operation or Transmission Owners due to special operation need, the study for specific plants would be performed.

- Selection of N-1-1 contingency pairs for each plant.
  - N-1-1 contingency pairs within one bus from the high tension bus of the study plant are tested. If the number of branches connected to the high tension bus is less than three, the boundary of N-1-1 contingency pairs is extended to two buses away.
- Conduct N-1-1 stability study
  - Assume N-1 stability results are available from the baseline stability analysis.
  - If an N-1contingency is transient unstable, the N-1 stability issue must be resolved first. For each N-1-1 contingency pair, create an N-1 base case by solving a power flow after the N-1 contingency is applied to the N-0 base case. If there are any thermal or voltage violations, resolve them through system adjustments. Also if available, apply existing operating guidelines for the N-1 outage condition to the N-1 base case.
  - Conduct comprehensive time-domain simulation for the N-1-1 contingency and assess stability.
    - Following standard PJM stability criteria, both transient stability and damping will be monitored
  - Consider RASs or other specific operating guidelines.

STUDY PLANTS SELECTION

The factors taken into account in prioritizing plants include the size of a plant, N-1 baseline stability study results, plant fuel type, and the unavailability rate of neighboring branches of the study plant. The following plants are given the highest priority for the N-1-1 stability study.

- Nuclear plants take the highest priority and will be studied if they are in the scope of the annual baseline stability study
- Plants with the maximum output of 1000 MW or above.
- Plants having weak stability performance in baseline stability study.
- Plants that experienced operational stability issues in real-time.
- Plants having neighboring branches with high unavailability rate due to planned and/or unplanned outages.

N-1-1 CONTINGENCY SELECTION

Due to the number of combinations of N-1-1 contingencies, only single contingencies that are 1-bus away from the high-tension buses of the study plant are considered. In the example below, five single transmission line outages are considered in the N-1-1 stability study as shown in Fig. 1.

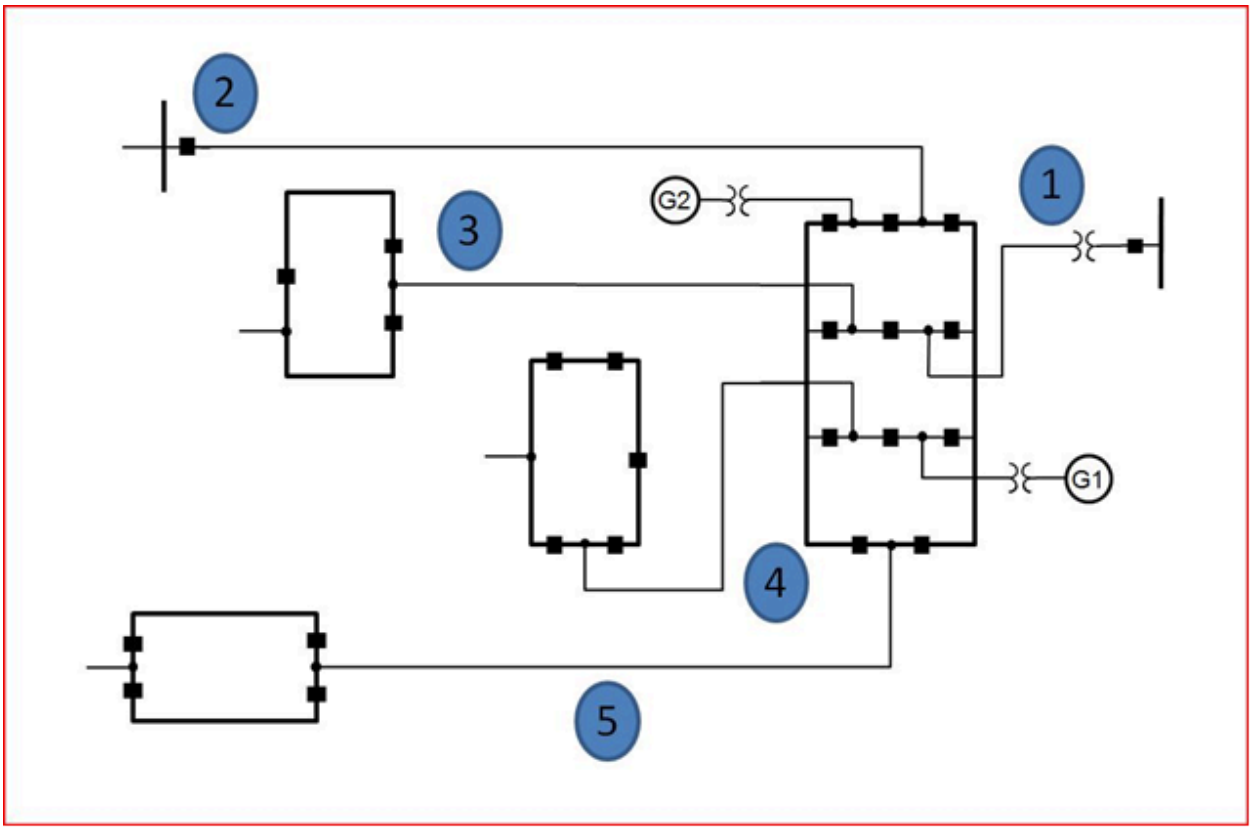


Figure 1 – Example of Five transmission lines for the N-1-1 stability study of a generic location.

It is necessary to analyze total 25 (5 N-1 and 20 N-1-1 contingency scenarios) contingency scenarios for the example plant in Figure 1. It is also noted that 3-phase fault cleared by primary relays is considered for all single contingencies. Fault clearing times are in form of possible ranges for different areas, kV and fault clearance options and the upper values of the respective ranges are used. Existing Remedial Action Schemes are, if available, incorporated in the N-1-1 contingency scenarios.

MITIGATION

Any violation of PJM or other applicable stability criteria as described in this Attachment will be addressed and documented as part of the annual RTEP process.

G.5 Impact Study Procedures Applicable to Wind Turbine Analyses

PJM follows a process of procedures and studies when handling requests to interconnect to the transmission system. These procedures are outlined in PJM Manuals and agreements, particularly PJM's Manuals 14H and 14B and the PJM Open Access Transmission Tariff

(OATT.) In recognition of some of the unique characteristics and challenges posed by wind projects, however, the PJM OATT procedures include certain special provisions applicable to wind farm interconnection requests. Project Developers should familiarize themselves with all applicable PJM procedures and requirements, in consultation with their assigned PJM project manager.

G.5.1 Wind Project LVRT Requirements

In addition to all facets of the standard stability study scope previously discussed, wind generators will be studied during their impact study stability analysis for compliance with the Low Voltage Ride Through Criteria (LVRT.) The LVRT criteria tests the ability to the wind farm generator to maintain operation and interconnection with the system during events that cause extremely low voltage transients as measured at the high side of the transformer that steps up the Wind Farm's voltage to the transmission system (high side of the wind farm GSU.) Peak load conditions are the most stressful for maintaining system voltage so this analysis will be conducted on a peak load power flow model (in contrast to the standard stability analysis that is conducted on an off-peak model.) Based on the results of the standard stability analysis, PJM will determine the most critical three phase faults with normal clearing and phase to ground faults with delayed clearing. The wind generator will be required to maintain its power output to the system following three phase faults cleared in up through 9 cycles (9 cycles includes any applicable margins) and that produce a voltage as low as zero at the high side of the GSU. Actual clearing times plus applicable margins will be used, which may be less than 9 cycles and high side GSU voltages may be somewhat greater than zero. Also the wind farm must maintain output to the system following the most critical phase to ground faults with delayed clearing, using actual clearing times. Applicable clearing time margins will apply to the LVRT test.

G.5.2 Wind Project Reactive Power Modeling

Stability tests will be conducted on a system model with the GSU modeled and zero generator reactive power output (unity power factor.) When power flow analysis does not model the generator step up transformer, the zero generator reactive power output is applied at the collector bus. This base case and the stability analysis will establish power factor or reactive power delivery requirements only if impact study analysis is conducted that demonstrates that the safety or reliability of the system is impacted by the lack of the requirement. System transient, oscillatory, or voltage instability during any phase of the impact study is evidence of system safety or reliability impact. For such results, the least cost remedy that considers system protection, transmission upgrades, or reactive requirements will be determined and specified.

In the event that the transient or voltage instability only affects the wind project (for example when long radial interconnection facilities cause the inability of the wind facility to remain stably interconnected), the wind project will be notified and be requested to provide project design remedies. PJM's analysis of possible remedies will be limited to specifying the size of dynamic reactive device or increased transmission interconnection capacity if such a remedies are sufficient.

G.6 Stability Analyses of Stability Sensitive Local Areas in PJM

The PJM system generally operates to limits determined by thermal and reactive criteria. In some specific instances local areas of PJM or individual plants operate to stability limitations. The PJM transmission system conditions and procedures due to localized thermal, reactive and stability considerations are outlined in PJM Manual 03.

The PJM Transmission Owners are often owners of the facilities that are subject to these procedures and carry out PJM's operating instructions ensuring safe and reliable operation consistent with these guidelines and procedures. PJM, therefore, closely coordinates review of the stability guides and procedures with the Transmission Owners and, when appropriate, Transmission Owners may conduct analysis, subject to PJM's review.

Stability guides applicable to specific plants are reviewed as part of PJM's three year cycle of generator stability analysis that ensures continued compliance with NERC criteria. Local stability guides and procedures are reviewed as necessary when interconnections or transmission changes cause the need for review. Each review is specific to the area or plants operating procedures and guides and confirms or develops modifications to the guide and system upgrades, as appropriate, to maintain reliable operation within applicable criteria.

G.7 Short Circuit

PJM performs short circuit analysis as part of the annual Regional Transmission Expansion Plan (RTEP) baseline assessment. This analysis includes a study of the entire PJM system based on its current configuration and equipment to determine if the short circuit current interrupting duty of circuit breakers is sufficient for the 2 year planning case. In addition, PJM also performs the analysis on the planned system configuration using a 5-year out case. Additional sensitivity studies are performed on years 3 and 4 as needed. The generation and merchant transmission interconnection process (see Manual 14H) also includes short circuit analysis for each requested new interconnection project. The addition of new sources and BES equipment drives most breaker replacements. PJM Planning conducts short circuit analysis to ensure the high-voltage circuit breakers on the transmission system are sufficiently rated to safely interrupt fault currents. These short circuit studies are also referred to as breaker interrupting studies. Since new sources only become committed with relative assurance a few years before scheduled commercial operation and since breaker replacement lead times are only a few years, these analysis are only conducted within the 5-year planning horizon.

The short circuit analysis is performed in accordance with the following industry standards:

- ANSI/IEEE 551-2006 "IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems"
- ANSI/IEEE C37.04-1999 "IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers"

- ANSI/IEEE C37.010-1999 “IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis”
- 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”

The system condition most critical for short circuit analysis on the PJM system is all available generation in-service. This condition is modeled in short circuit reference cases that are specially configured for short circuit analysis. PJM Planning maintains the following short circuit base case representations and associated data:

- 2 year planning representation consisting of the current system plus all facilities planned to be in-service within the next 2 years.
- 5 year planning representation using the 2 year planning representation as the base model and including all system upgrades, generation projects, and merchant transmission projects planned to be in-service from years 2 through 5. This 5 year planning representation is consistent with the PJM RTEP 5 year load flow base case.
- Data file containing current circuit breaker interrupting ratings and other relevant circuit breaker nameplate data for all BES circuit breakers.

The short circuit base cases are maintained using Aspen One Liner and short circuit analysis is performed using the Aspen Breaker Rating Module. The PJM short circuit 2 year planning representation is developed annually with the assistance of the transmission owners and maintained by the PJM Planning.

G.8 Nuclear Plant Specific Impact Study Procedures

Stability analysis of nuclear facilities is conducted during PJM’s three-year cycle of stability review of all existing generating units. Also, interconnections or transmission modifications in the vicinity of existing generating stations, including nuclear stations, may necessitate additional reviews. PJM conducts these reviews consistent with the NERC criteria and certain added criteria specified by the Transmission Owner or plant operator or owner. PJM stability studies take into account coordination with any applicable Remedial Action Schemes. Results of PJM Planning analyses can be found under the “planning” tab material and “committees & groups” tab material on PJM.com particularly:

http://www.pjm.com/planning/planning-criteria.aspx

http://www.pjm.com/planning/rtep-development.aspx

http://www.pjm.com/planning/generation-interconnection.aspx

http://www.pjm.com/committees-and-groups/committees/teac.aspx

PJM will notify PJM System Operations and the affected Transmission Owner in the event that PJM's planning analyses indicate planning study results that violate PJM planning criteria or nuclear specific planning criteria. In addition, results of PJM Impact Studies affecting nuclear facilities are communicated to the affected Nuclear owner and operator.

PJM applies some nuclear plant study procedures that exceed *standard NERC criteria* to be consistent with certain regulatory and safety requirements specific to these facilities. Material contained in the Appendix to this Attachment G provides Nuclear Plant Interface Requirements (NPIR) regarding the nuclear specific testing procedures applied by PJM and Transmission Owner Planning.

G.9 Appendix to Manual 14B Attachment G

This appendix contains Transmission Owner specific criteria applicable to RTEP stability study analyses that may go beyond the NERC system stability performance tests routinely applied by PJM. PJM normal stability testing enforces the NERC criteria that are based on single contingencies and common-mode multiple contingencies. PJM does not permit planned load loss or interruption of firm transmission service for these events, even when such service curtailment may be permitted by the NERC standards. These contingencies are also referred to in this Attachment and Appendix as the "standard" NERC criteria and include the following events:

- System normal,
- Single phase and/or three phase fault (N-1),
- Single phase fault stuck breaker (N-2),
- Three phase fault tower (N-2), and
- Single Phase fault and communication failure (N-2).

More stringent NERC criteria that involve multi-phase faults, non-common mode multiple contingencies, and higher order contingencies (also referred to as "beyond" *standard NERC criteria*) do not routinely form the basis for required PJM RTEP upgrades. Some Transmission Owner criteria, however, as detailed in this Appendix, go beyond the *standard* PJM stability screening criteria and do require remedies. These procedures, as applicable, are applied during PJM RTEP (including interconnection related) stability analyses in addition to PJM thorough testing of *standard NERC criteria* tests and system performance is verified to be stable and within criteria. The Transmission Owner specific criteria are limited to interconnections with the transmission facilities of the respective Transmission Owners.

All PJM testing applies the clearing margins and damping criteria discussed in Attachment G and more stringent criteria when the specific Transmission Owner criteria exceed these standard margins. In all cases PJM applies the criteria in a comparable and not unduly discriminatory fashion to new interconnection projects and existing generators. Violations based on *standard NERC criteria* and standard margins must be remedied by upgrade modifications to

the system. Operating curtailments will generally be an available remedy for issues found for line maintenance outage tests.

G.9.1 Testing of Transmission Owner Criteria

For interconnection studies that pass the *standard* NERC and PJM criteria but produce localized violations based on criteria that are beyond the *standard NERC criteria* and/or margins that exceed standard PJM margins, PJM, in consultation with the affected Transmission Owners, will determine lower cost remedies. For these Transmission Owner tests, planned load loss or interruption of firm transmission service is not allowed when lower cost remedies are available. An available lower cost remedy will be required to address such violations. For example, lower cost remedies that may be considered include:

- Relaying modifications
- Sectionalizing schemes
- breaker upgrades
- Independent pole tripping
- High speed breaker failure schemes
- High speed reclosing
- Fast closing of steam intercept valves
- Braking resistors.

If the search for lower cost upgrades produces none, or in the case of wide-spread system violations such as may be encountered during RTEP baseline stability analysis, then PJM, in consultation with the affected Transmission Owners, will make a more detailed assessment of the violation(s) including factors such as the extent of violations, the events' likelihood, system impact and cost to remedy. Based on the gathered information, PJM will specify a remedy including possible consideration of operating guides, Remedial Action Schemes, and more extensive high voltage upgrade options. See Transmission Owner Planning Criteria at https://pjm.com/planning/planning-criteria/to-planning-criteria for more information.

G.9.2 Nuclear Station Testing

With regard to nuclear station related planning stability analysis, in addition to the *standard NERC criteria* and specific Transmission Owner criteria testing, PJM reviews and enforces criteria testing that can be found under the Planning section of the Nuclear Plant Interface Requirement (NPIR) documents. In some cases the Transmission Owner also performs special nuclear unit stability testing as described in PJM Manual 39 and the NPIR. Together, the analyses that may be performed by the Transmission Owner and PJM's testing incorporate the voltage and stability requirements of the station. PJM ensures Transmission System performance to the specified criteria that enables the station equipment and systems to perform as designed. Nuclear voltage criteria at the Transmission System level, including any voltage drop criteria, are enforced on a system normal and post-contingency basis as described in the NPIR planning requirements. Observed criteria violations during planning assessments affecting

nuclear stations will be evaluated jointly by PJM Planning and PJM Operations consistent with procedures outlined in PJM Manual 39. Appropriate remedies, consistent with this Attachment and the PJM Manuals and Agreements, will be specified to ensure applicable criteria are met. As part of these analyses redispatch of nuclear units is not permitted in an effort to relieve violations. The nuclear owner will be responsible for reinforcements necessary to comply with criteria that are specific to the Nuclear Plant and that are more stringent than the standard PJM and Transmission Owner tests.

The specific nuclear unit planning criteria contained in the NPIR documents are included in the Appendix to this Attachment G when the nuclear plant owner has consented to these excerpts being included here for convenient planning reference. In any instances of a nuclearplant owner preference to maintain confidentiality of this information, it is not reproduced in this manual but is still evaluated and enforced during planning studies.

G.9.3 BG&E Specific Criteria

Additional stability testing applicable to interconnections with BG&E transmission facilities includes tests of three-phase faults at a point 80% of the circuit impedance away from the station under study with delayed (zone two) clearing.

G.9.4 ComEd Specific Criteria

Additional stability testing applicable to interconnections with ComEd transmission facilities includes:

- Three-phase fault on any transmission or generation element with delayed clearing due to a stuck breaker or other protective equipment failure. For situations involving independent pole operated breakers, it is assumed that only one phase of the breaker fails to open and the delayed clearing time is used for the remaining single-phase fault.
- Three-phase fault on any transmission or generation element with delayed clearing due to failure of a Remedial Action Scheme.
- Three-phase fault on all transmission lines on a multiple circuit tower with normal clearing.
- Three-phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element.

It should be noted that a one-cycle margin is included in all primary-clearing times for faults on the ComEd system, instead of the PJM margins. For more severe, lower probability events such as faults occurring during maintenance outages or faults cleared in delayed time, if lower cost remedies are not available, PJM will retest with the PJM's standard margins as a possible remedy.

The dynamic voltage recovery (DVR) criteria should be satisfied at buses categorized as BES facilities at peak load, given all transmission elements are in 'normal' configuration preceding the event. Following a three-phase fault on the transmission system that results in loss of a

single generator or transmission element, the transmission system DVR must conform to the recovery 'envelope' described below.

- Following the successful clearing of a fault (normal clearing = 6 cycles), the voltage magnitudes should be no less than 70% of their nominal values.
- Within 20 cycles following the clearing of a fault, the voltage magnitudes should be no less than 80% of their nominal values.
- Within 0.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than 90% of their nominal values.
- Within 1.5 seconds following the clearing of a fault, the voltage magnitudes should be no less than the steady-state voltage minimum, typically 92-95% of nominal.

Violation of the DVR criteria can increase the potential for severe voltage problems following a fault and should be mitigated with appropriate reinforcements.

G.9.5 PPL Specific Criteria

Additional stability testing applicable to interconnections with PPL transmission facilities includes:

• **Stuck Breaker and Relay Failure**: Permanent three-phase fault with stuck breaker or other cause of delayed clearing.

• **Double Circuit Tower (DCT) Line Fault**: Permanent three-phase fault involving both circuits of a double circuit line with normal clearing and reclosing sequences, if applicable.

• **Overtripping**: Permanent three-phase fault on one line with an overtrip of another unfaulted line. Both the overtrip and clearing of the faulted line occur in normal primary clearing time. Reclosing sequences, if applicable, should be included.

If assessment of any of the contingency types noted above results in identification of stability concerns in the PPL system, see the table below to determine if a reliability solution is required by PPL ("should be stable"), or if the study results should be reported to PPL for information only ("information only") for awareness and further consideration of the severity of the consequences of the event.

Contingency	TPL-001-4 Contingency Category	Clearing Time	Fault Type		
			230 kV and Above	100 - 229 kV	< 100 kV
Stuck Breaker	E2-A through D	Breaker Failure Clearing Time	3PH (information only)	3PH (information only)	Not Applicable
Relay Failure	E2-A through D	Zone 2 Clearing Time	3PH (should be stable)	3PH (information only)	Not Applicable
DCT Line Fault	E2-F	Normal Clearing Time	3PH (information only)	3PH (information only)	Not Applicable
Overtripping	E2-F	Normal Clearing Time	SLG (information only)	SLG (information only)	Not Applicable

G.9.6 Implementation of the NPIR for Planning Analysis

PJM incorporates the Nuclear Plant Interface Requirements (NPIRs) into its planning processes in accordance with the applicable NERC standards. PJM performs these planning analyses consistent with the NPIR planning requirements and its Regional Transmission Expansion Planning requirements.

G.10 NERC Standard PRC-023 – Transmission Relay Loadability

Background

The purpose of the standard is to ensure that protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults. There are a number of requirements that specify how protective relays should be set so that they will not limit loadability of a circuit. One of the requirements of the Standard (R6) is for the Planning Coordinator to determine the facilities that must comply with requirements R1 through R5 of NERC standard PRC-023.

In accordance with Attachment B of PRC-023, the following circuits are subject to Requirement R6:

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
- Transmission lines operated below 100kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

Process to determine PRC-023 Critical Facilities

PJM staff will conduct an assessment at least once each calendar year, with no more than 15 months between assessments applying the criteria in accordance with Attachment B of PRC-023 to determine the circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. PJM will maintain a list of circuits subject to PRC-023 per application of Attachment B and provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 days of any changes to that list. The test will monitor all required facilities in accordance with Attachment B of PRC-023 as described below.

NERC Standard PRC-023 Transmission Relay Loadability - Attachment B

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

- The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.
- The circuit is selected by the Planning Coordinator or Transmission Planner based on Planning Assessments of the Near-Term Transmission Planning Horizon that identify instances of instability, Cascading, or uncontrolled separation, that adversely impact the reliability of the Bulk Electric System for planning events.
- The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.
- The circuit is identified through the following sequence of power flow analyses performed by the Planning Coordinator for the one-to-five-year planning horizon
    - Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
    - For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
    - When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.
    - The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.
- If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.
- If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.
- If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.
    - The Radially operated circuits serving only load are excluded.

- The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in the NERC Standard PRC-023 Transmission Relay Loadability - Attachment B Criteria above, in consultation with the Facility Owner
- The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

G.11 PJM Capacity Import Limit Calculation Procedure

Introduction

- The purpose of PJM Capacity Import Limit Calculation Procedure is to establish the amount of power that can be reliably transferred to PJM from defined regions external to PJM.
- The PJM Capacity Import Limit is calculated annually and is used to confirm that import capability into the PJM system is greater than the sum of the PJM Capacity Benefit Margin (CBM) and confirmed Long Term Firm Transmission Service. The imports into PJM will therefore be comprised of firm transmission service reservations and non-firm energy purchases from the external supply regions described in section 3 below.

General Procedures and Assumptions

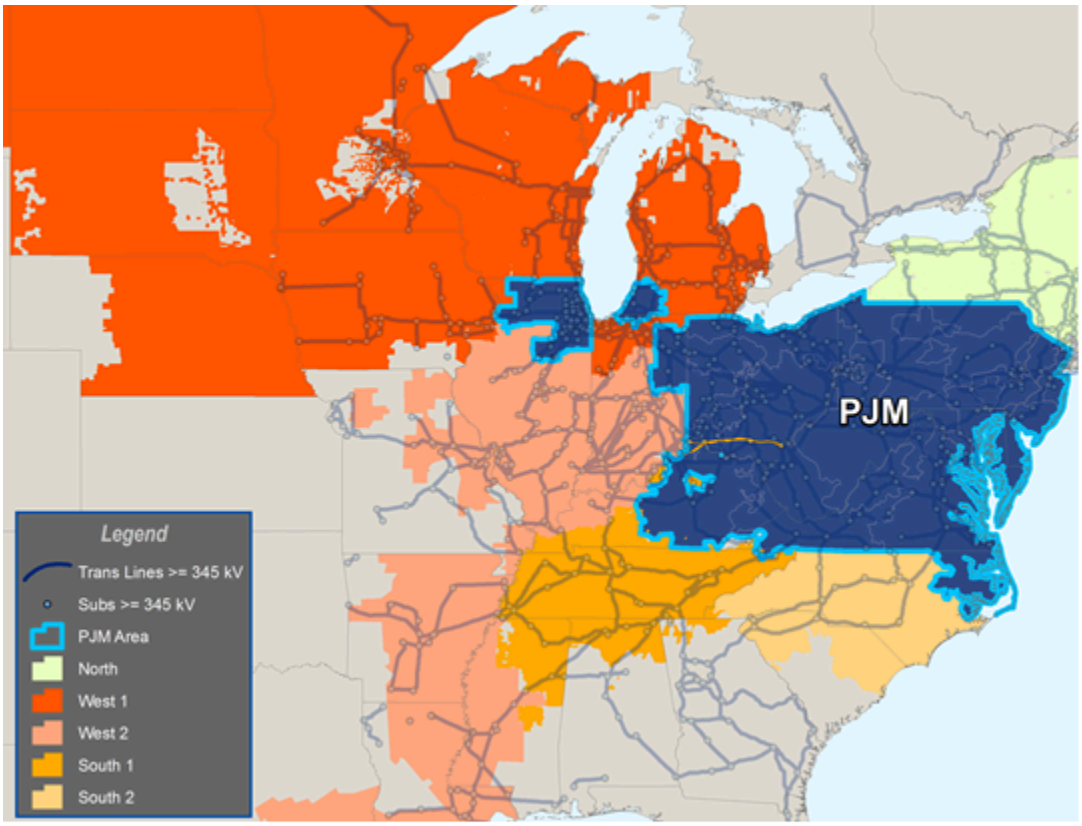
The system power flow model will be based on the latest summer peak RTEP base case.

- The base case will contain confirmed Long Term Firm Transmission Service for the study period as identified in the PJM OASIS.-.
- The PJM dispatch will reflect a PJM generation deficiency situation independent of the defined regions external to PJM. Thus, non-PJM regions are operating normally and are assumed to be able to supply PJM with power up to the lower of the Capacity Import Limit or the limit of their available reserves. Load in PJM and all external regions will be modeled at a 50/50 load level and load. The amount of reserves considered available from any adjacent non-PJM area may be adjusted to reflect historical data and expected future conditions.
- For thermal analyses, all Eastern Interconnection BES facilities (100 kV and above) will be monitored. All PJM internal BES single contingency events and selected non-PJM BES contingency events will be considered.
- For voltage analyses, all PJM BES facility voltage magnitude and drop limits will be monitored and selected non-PJM BES facility voltage limits will be observed. In addition, any part of the Eastern Interconnection that would experience voltage collapse will be evaluated. The voltage analyses are subject to all PJM internal BES single contingency events and selected non-PJM BES contingency events.
- The following operating procedures will be employed as necessary.
    - Adjustments of Phase Angle Regulators (PARS which PJM or PJM member companies control (within existing agreements for emergency operation). For the

PJM/NYISO PARs in particular, flows will be set according to the ratios provided in Attachment B Section (B.3) (VII) (P), but be based on both the firm and any non-firm emergency assistance from NYISO.

- The activation of any approved PJM or PJM member company operating procedure (procedure descriptions are available in Manual 3.)

- The activation of any approved PJM or PJM member company operating procedure (procedure descriptions are available in Manual 3.)
  - Redispatch and implementation of load management schemes will not be considered as part of this study.
- Methodology
  - The external supply will come from those regions within the Eastern Interconnection that are considered as part of the PJM Reserve Requirement Study. These external supply regions will be divided into five zones for the purpose of determining both a simultaneous import limit and five directional non-simultaneous import limits. During the simulation of the simultaneous limit, the amount of power from each source zone will be optimized. The five zones are:
    - Northern Zone: NYISO & ISO NE
    - Western Tier 1 Zone: MISO East and MISO West
    - Western Tier 2 Zone: MISO Central & MISO South
    - Southern Tier 1 Zone: TVA & LGEE
    - Southern Tier 2 Zone: VACAR (non-PJM)
- These zones may be periodically modified based on changing system patterns or historical operational data.



- PJM will scale the load uniformly down at a constant power factor in the external supply zone(s) and scale PJM generation (MW) down uniformly to simulate the power imported from external resources.
- In order to exclude transmission facilities from the monitored list which are not significantly affected by the increase in import power from the external resources, PJM will employ an outage transfer distribution factor cutoff of 3% based on the external zone(s) supplying the resources.
- The aggregate power transfer into PJM, at the point where any increase in this MW transfer would result in a reliability criteria violation, less the applicable PJM Capacity Benefit Margin (CBM) will be defined as the simultaneous PJM Capacity Import Limit.
- Similar approach will be employed to determine the maximum power transfer from any one of the five defined zones into PJM. For determining the non-simultaneous limits, a portion of the CBM will be allocated to each of the five directional transfer paths in proportion to the ratio of their transfer amount divided by the simultaneous Capacity Import Limit plus the PJM CBM.

G.12 NERC Standard FAC-002 – Facility Interconnection Studies

Background

As the Transmission Planner and Planning Coordinator, PJM is responsible for the development of the Regional Transmission Expansion Plan (RTEP) for the PJM system. The planning process which ultimately culminates in the PJM RTEP base case is driven by three planning paths. The three paths include planning activities associated with:

- Baseline Projects
- Supplemental Projects
- Customer-Funded Upgrades

Each of the planning activities examine the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) existing interconnections of generation, transmission, or electricity end-user Facilities seeking to make a qualified change as defined by PJM under Requirement R6 of FAC-002.

Qualified Change

For the purposes of FAC-002 R6, PJM defines a qualified change for a facility interconnection as follows:

Table G.12.1 Qualified Change for End-User Facilities

Description	Examples
Facility change leading to change in: 1. End-User Facility topology or 2. Protection system changes impacting contingency definition or 3. The electrical characteristics of the facility or 4. Facility ratings that either of which may impact BES performance	• Increase or decrease in load • Changes to the number of feeds in an existing End-User Facility

Table G.12.2 Qualified Change for Transmission

Description	Examples
Facility change leading to change in: 1. Transmission system topology or	• Increase or decrease in rating

Table G.12.2 Qualified Change for Transmission	
2. Protection system changes impacting contingency definition or 3. The electrical characteristics of the facility or 4. Facility ratings that either of which may impact BES performance	• Change in facility impedance • Reconfiguration

Table G.12.3 Qualified Change for Generation	
Description	**Examples**
Go reports anticipated changes of the electrical characteristics following execution of the applicable interconnection agreement. PJM evaluation of changes requires more detailed analytical studies	• Change in generator electrical characteristics • Chang ein turbine type

Examples provided are for illustrative purposes only and are not meant to be exhaustive.

G.13 NERC Standard PRC-026 – Relay Performance During Stable Power Swings

Background

The purpose of PRC-026 is to ensure that load-responsive protective relays are expected not to trip in response to stable power swings in non-Fault conditions.

As the Planning Coordinator, PJM is required to provide notification of each generator, transformer and transmission line BES Element in its area, at least once each calendar year, that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner:

Criteria:

1. Generator(s) where an angular stability constraint, identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event, that is addressed by limiting the output of a generator or a Remedial Action Scheme (RAS), and those Elements terminating at the Transmission station associated with the generator(s).
2. Elements associated with angular instability identified in Planning Assessments of the Near-Term Transmission Planning Horizon for a planning event.

3. An Element that forms the boundary of an island in the most recent underfrequency load shedding (UFLS) design assessment based on application of the Planning Coordinator's criteria for identifying islands, only if the island is formed by tripping the Element due to angular instability.
4. An Element identified in the most recent annual Planning Assessment of the Near-Term Transmission Planning Horizon where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance for a planning event.

Process to determine PRC-026 BES Elements

PJM staff will conduct an assessment at least once each calendar year, applying the criteria in accordance with requirement R1 of PRC-026 to determine the applicable BES Elements. PJM will maintain the list of BES Elements in Attachment A of PJM Manual 03B: Transmission Operating Procedures (CEII). Notification will be provided when the manual has been updated with the latest list.

The required access forms are located here:

- https://www.pjm.com/library/request-access.aspx

G.14 NERC Standard TPL-007 – Transmission System Planned Performance for Geomagnetic Disturbance Events

Background

The purpose of TPL-007 is to establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

As the Planning Coordinator and Transmission Planner, PJM is responsible for maintaining System models and GIC System models of its planning area, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessments, and implementing process(es) to obtain GMD measurement data as specified in the standard.

Developing and maintaining GMD models is a collaborative effort between PJM and its members. Accurate modeling data is a key component of quality GMD studies. To that end, PJM will require the assistance of its members to provide the appropriate modeling data on a periodic basis. Modeling data from Transmission Owners are submitted via an Excel spreadsheet template that PJM will provide while modeling data from Generator Owners are submitted through the Planning Center: Gen Model tool.

Steady State Voltage Criteria

To assess system steady state voltage performance during the benchmark and supplemental GMD events that are described in Attachment 1 of the Standard, PJM has developed criteria for acceptable system steady state voltage performance for its system

Steady state voltage criteria is established pursuant to the following PJM manuals:

- PJM Manual 03: Transmission Operations
  - Section 3: Voltage & Stability Operating Guidelines
- PJM Manual 14B: PJM Region Transmission Planning Process
  - Section 2: Regional Transmission Expansion Plan Process
- PJM Manual 39: Nuclear Plant Interface Coordination
  - Section 1: Nuclear Plant Interface Requirements

Voltage performance during GMD events are examined in three stages:

- **Stage 1:** Initial Condition
  - The System may be postured in anticipation of a GMD event with adjustments that are executable in response to space weather information. Steady state voltage performance shall be consistent with Category P0 (No Contingency) per the TPL-001 standard. Voltage limits for planning purposes applied during Stage 1 will be the same as applied in PJM Operations for normal scenarios.
- **Stage 2:** GMD Event
  - A GMD event occurs but prior to loss of elements per Event description in Table 1 of TPL-007. The effects of GMD are modeled as reactive losses on the transmission system where reduced voltages are expected. Steady state voltage performance shall be consistent with Category P1 (Single Contingency) per the TPL-001 standard. Voltage limits for planning purposes applied during Stage 2 will be the same as applied in PJM Operations for contingency scenarios.
- **Stage 3:** GMD Event with Outages
  - Facilities that are susceptible to harmonics are removed from service as a result of protection system operation / misoperation. Voltage limits applied during Stage 3 will be the Load Dump (LD) limit used in PJM Operations.

Before and during the GMD event, all PJM Transmission System facilities 100 kV and greater will be monitored. Cascading, voltage collapse and uncontrolled islanding shall not occur, Nuclear Plant Interface Requirement (NPIR) voltage limits will be respected and TO criteria if more restrictive than baseline voltage limits will be used.

Geomagnetically-Induced Currents (GIC)

PJM will provide GIC flow information to be used for the benchmark and supplemental thermal impact assessment of transformers specified in requirements R6 & R10 of TPL-007 respectively

to each impacted Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area.

Benchmark and Supplemental Vulnerability Assessments

PJM will conduct benchmark and supplemental GMD Vulnerability Assessments of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. The benchmark and supplemental GMD Vulnerability Assessments shall use a study or studies based on models identified in requirement R2 of TPL-007, document assumptions, and document summarized results of the steady state analysis.

If PJM concludes through the benchmark and supplemental GMD Vulnerability Assessments that the System does not meet the performance requirements for the steady state planning benchmark and supplemental GMD events contained in Table 1 of TPL-007, PJM shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The Corrective Action Plan shall list system deficiencies and associated actions needed to achieve required system performance.

GMD Measurement Data Processes

PJM will obtain GIC monitor data from at least one GIC monitor located within the PJM footprint as per requirement R12 of TPL-007. GIC values are currently sent to PJM via the Inter-Control Center Communications Protocol (ICCP). Data will be collected for the duration of a space weather event where the Kp index ≥ 7 and stored. Future GIC monitor installations will be based on system studies. Monitor specifications (i.e., data range & ambient temperature ratings) will be determined based on input from impacted entities. PJM will obtain magnetometer data from United States Geological Survey (USGS) geomagnetic observatories. Currently the closest one is in Fredericksburg, VA. Data will be collected for the duration of a space weather event where the Kp index ≥ 7 and stored.

Attachment H: Power System Modeling Data

H.1 Power System Modeling Data

Accurate power system modeling data is a key component of quality power system analysis. PJM System Planning uses a variety of models and analytical techniques to create and maintain the simulation models used for the RTEP studies. The intended use of this Attachment is to supplement existing documentation by PJM and other entities that specify accurate modeling data requirements. PJM will continue to follow the data guidelines and standards set forth by NERC as part of the MOD standards and the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) Procedural Manual.

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

H.1.1 Load Flow Analysis Models

Base case creation is a collaborative process between PJM and its members. From a technical standpoint PJM follows the guidelines set forth in the ERAG MMWG Procedural Manual. In the following sections, the logistics and transfer of information between PJM and its members are detailed.

Annual Updates

In the late third quarter of each year, PJM will ask Transmission Owners to review and update base case and project files in Model on Demand. The base case updates will include committing case corrections along with in service projects with as built data to the base case. Project files will be updated for status, scope change, and in service date change. PJM will then use Model On Demand to build trial 1 cases for +5 year Summer, Light Load, and Winter, which will be sent to Transmission Owners for review. Transmission Owners will provide:

- Network updates to the model that will advance the case to represent a current year + 5 base case with respect to the 1st Quarter of the following year. This update should be reviewed for correctness and compatibility with the final version of the base case under development
- Complete NERC P1, P2, P3, P4, P5, P6 and P7 contingency file updates that correspond to the updated network model (Include any contingencies which may not change the powerflow model, but change contingency definitions)
- Maximum credible disturbance (NERC TPL-001-5.1 Table 1 Extreme Events) contingencies
- Any other significant changes such as new load or block load additions

- Support, if necessary, for the development of network models for additional years and demand levels for both near term (years 1 through 5) and longer term (beyond 5 years) analyses.
- Verification that all baseline, network and supplemental upgrades are included in the updated case along with a written description of any case modifications.
- Notification of any changes to tie lines whether they are ties internal to PJM or to external companies.

Interim Updates and Communication of Significant Modeling Updates

In the event that PJM makes a major update to the RTEP analysis models outside of the annual model update window, PJM will notify PJM Transmission Owners of the modeling update through the Transmission Expansion Advisory Committee (TEAC) meetings. Also,

PJM will notify neighboring entities that PJM determines may be impacted. In addition to the notification, PJM will make the updated affected models available upon request.

Generation Owner Requirements:

- Specific information regarding generator capability per MOD-032

H.1.2 Load Flow Modeling Requirements

In addition to the guidelines set forth by NERC and the ERAG MMWG procedural manual, PJM uses several specific procedures in establishing the base case so that it represents the best starting point for the annual RTEP analysis.

Generator step-up transformers

Generator models should represent the physical plant lay-out to the extent possible, explicitly modeling generator step-up transformers (GSUs) and Station Service loads (aka Auxiliary loads). This applies to units above 20 MW and connected to the BES system, consistent with BES requirements. Plants consisting of multiple units aggregating to 75 MW or more also require explicit representation of GSUs and station service loads.

Modeling of Outages

Known outages of Generation or Transmission Facilities are selected based on a documented technical rationale and will be included under those system peak or off-peak conditions in the appropriate base case model. PJM may not model these outages in every case that is used for RTEP analysis, but will select appropriate scenarios to asses these changes. PJM will perform analysis on the P0 and P1 planning event categories for steady state analysis and the P1 planning event category for stability analysis as defined in Table 1 of TPL-001-5.1. Additionally PJM will analyze a subset of maintenance outages submitted through eDart under those system peak or off-peak conditions.

Interchange

The PJM net interchange in the summer peak case is determined by the firm interchanges that are represented in the PJM OASIS system. That interchange, in the summer peak case, shall be represented as 100% of the confirmed full path (must be confirmed in both PJM and external zone OASIS) firm import and export reservations. Reservations associated with individual generation units, or group of units at a facility, shall be used in representing the interchange. The interchange in light load cases follows the light load criteria as defined in the Light Load Reliability Analysis in section 2.3.10 of this manual.

Generator Reactive Capability

Annually, PJM updates the model for the generator reactive capability (GCAP) of each generator based on data used by PJM Operations, which includes default limits obtained from the most up to date d-curves as well as data provided by the Generator Owners.

Interconnection Projects With Final Agreements

PJM includes projects with a signed final agreements into the base case as well as verifying the accuracy of projects that have not yet signed a final agreement. PJM also includes the interconnection, ratings and associated upgrades for each of these projects. Transmission Owners will verify the accuracy of the points of interconnection and the associated upgrades in their zones.

Real and Reactive Load

Each TO is responsible for modeling the active (real) and reactive load profile in its zone. PJM will scale the load in each zone to the targeted values reported in the latest annual PJM load forecast report.

Real loads will be scaled uniformly in each zone to meet the PJM 50/50 load forecast less any Demand Response (DR), or Behind the Meter (BTM) generation as necessary. Real loads will also be scaled uniformly within each zone for off-peak analysis. Reactive load in each area will be scaled at a constant power factor along with the real load for peak load analysis. For off-peak analysis including light-load, PJM will provide a case to the Transmission Owners, at their discretion, for updating their zonal reactive load profile.

Any deviation from the above method of load modeling method, associated with specific test procedures such as the PJM Load Deliverability Procedure or the PJM Light Load Reliability Test Procedure will be defined specifically in other sections of this manual.

PJM will coordinate with TOs on an individual basis to ensure that non-conforming loads are properly modeled and not uniformly scaled.

Voltage Schedules

The setting of voltage schedules is crucial to the robustness of cases. PJM allows Transmission Owners to supply generator voltage schedule data. If the data is not provided PJM will use the default voltage schedules as defined in PJM Manual 03.

H.1.3 Submittal of Load Flow Data

Attachment J contains the checklist for the new equipment energization process to be utilized by Transmission Owners and Designated Entities from inception to energization of upgrade projects.

Acceptable Data Formats

PJM sanctioned software:

- PSS/E – power flow modeling software
- TARA – steady state power flow analysis tool

For PSS/E users, cases should be submitted to PJM in a ".SAV" format in a PSS/E version that is readable by the current version of PSS/E that MMWG is using.

For users of PSLF or other modeling software, cases shall be submitted to PJM in a ".RAW" format that is PSS/E compatible and is readable by the current version of PSS/E that MMWG is using.

PJM's migration of PSS/E versions may slightly lag MMWG, in that case it is acceptable to provide updates formatted for the current version that PJM is using.

TO's can submit data in an agreed to version if they are unable to export to the latest MMWG compatible version.

Timing

Transmission Owners must comply with the schedule dictating the timeliness of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files for the first iteration, and 2 weeks for the second iteration.

Load Flow Data Quality

In the event that data provided by Transmission Owners does not pass all of the testing included in the MMWG data checker, PJM may request updated data.

Transmission Owners must provide unique bus names or circuit ID's for each winding of all transformers.

Bus numbers must be within the allocated bus number range for each company.

Conventions used for the naming of Machine ID's vary for different TO zones. PJM will coordinate with each TO individually to align with their preferred convention.

Certain specific modeling and naming conventions which must be followed by all TO's include:

- High/Low Pressure units should be modeled on the same bus and designated with the corresponding machine ID "H" and "L".
- No other machine ID should be named "H" or "L".

With the exception of High/Low Pressure units, multiple machines modeled on the same bus must have the same status. Offline machines should not be modeled on the same bus as machines which have a status of online.

Machines at the same plant with different statuses should be modeled on separate busses connected by a very low impedance line (X=.002) as defined in the MMWG manual.

H.1.4 Short Circuit Analysis Models

Short Circuit data procedures are documented in the Attachment G.7 of this manual, which references ANSI/IEEE 551. The intended use of this attachment is to supplement these procedures and outline the data requirements which PJM follows in creating the short circuit cases used for analysis.

Short circuit models should be provided in Aspen ".olr" format, if possible.

Each TO provided Aspen ".OLR" case should model only the TO area and its tie lines. No outside areas should be included in the submission.

All area numbers in the TO provided cases should be consistent with MMWG designated area numbering convention. Area numbers such as 1, 2, 3, etc. are not acceptable.

Generation owners must submit to PJM all their breaker data for breakers rated above 100 kV.

Transmission Owners must submit an excel sheet containing explanations for outaged and out-of-service equipment that is normally in-service.

Timing

In the 1st quarter of each year, PJM will send the Transmission Owners an initial current year +5 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and generation projects that have completed Decision Point II requirements identified during that RTEP cycle.

In the 4th quarter of each year, PJM will send the Transmission Owners an initial current year +2 impedance network model. This case is based on the most up to date PJM short circuit case combined with the previous year's RTEP case containing all upgrades, MTX projects, and

generation projects that have completed Decision Point II requirements identified during that RTEP cycle.

Transmission Owners must comply with the time schedule of the case creation process which will be included in the initial email sent to kick off the process. This schedule will include a minimum of 4 weeks to provide updates to the case and corresponding files. Once all cases and corresponding files have been submitted to PJM, a +2 case is created and analysis performed to determine overdutied breakers. TOs are then given another 4 weeks to confirm any new overdutied breakers. After the +2 year short circuit case is finalized, the +2 year case is then used to create the+5 year short circuit case for performing the short circuit studies and identifying the new system issues. The identified issues will be sent out to the Transmission Owners who will have 4 weeks to provide solutions to address these issues.

H.1.5 Stability Analysis Models

The case used for stability and dynamic studies is developed by PJM based on information from the Regional Transmission Expansion Plan (RTEP) case prepared by PJM Interconnection and the MMWG case prepared by Powertech Labs for the Eastern Interconnection Reliability Assessment Group (ERAG).

When preparing the base case for stability and dynamics, the ERAG case provides the information for the areas outside PJM while the RTEP case provides the PJM information (e.g. load forecast, network configuration). When combining the ERAG and the RTEP cases, care should be taken to preserve the ties between the PJM areas and the rest of the Eastern Interconnection.

All generator projects active in the PJM interconnection process that have been studied must be included in the base case for stability and dynamics. In some instances, the RTEP model for such projects may not be detailed enough for use in stability studies. In this situation, the case must be updated to make sure that all detailed components associated with this project are included in the stability and dynamics power flow model (e.g. generator step-up transformer, loads).

In addition to updating the power flow case with the latest network information, the dynamic models must also be updated to reflect the changes introduced by the RTEP case and the stability and dynamic studies performed by PJM. In this regard, the dynamic data file from the ERAG MMWG case is updated so that the dynamic models for the generators in the PJM areas are matched against the new power flow information from the RTEP. The dynamic model for each generator in the Cycle must also be added to the dynamic data file.

The resulting power flow case, the dynamic data file and supporting files required for a complete stability and dynamics base case need also to be correlated and reviewed to determine inconsistencies as well as missing or questionable data. A base case is considered to be finished when, after the review, it compiles, links the models to the PSS/E main structure and initializes correctly. An acceptable condition for a finished base case is when simulated system

dynamics, using this case, do not deviate from the initial conditions for any simulation setup with no disturbances applied to the system.

Timing

In the first half of each year, PJM will build stability cases based on updated previous year RTEP power flow model and the latest ERAG dynamic cases. In this period, PJM may request the Transmission Owners for load models for dynamic studies, and for other supporting data if necessary. Transmission Owners must comply with the time schedule of the stability case creation process which will be included in the request email.

Stability and dynamics base cases:

- Stability is assessed using a summer peak load and a light load condition. The summer peak stability case has the load profile of the RTEP summer peak case and corresponds to the demand expected to be served in the specific planning year. The light load stability case represents 50% of the summer peak load and is developed by scaling down the summer peak load case at the same power factor.[16]
- For simplicity, it is recommended to first build the summer peak case and then update that case to reflect the second load condition (light load). This approach provides two cases that are common in bus numbers and network information. Updates to both cases, such as addition or removal of proposed lines or interconnection projects would be easy to handle due to the uniformity.

After the power flow case has been finalized and revised, the dynamic data file from the dynamic data file will be updated to reflect the changes that were introduced by the addition of the PJM areas from the RTEP case and generation interconnection studies. It is important to note that the RTEP case and the ERAG case complement each other. RTEP case information is used for future generation projects and transmission upgrades which don't exist in the ERAG case and ERAG case consists of information of existing units.

The light load case (50% peak) is derived from the summer peak case. This approach ensures consistent bus numbers and network information in both cases, making addition or removal of proposed lines or interconnection projects easy to handle. After the summer peak case is completed, the PJM load is scaled down to a load representing 50% of the 50/50 load. The areas outside PJM are updated with the light load case from the corresponding ERAG MMWG case. Note that generation and shunt capacitors may be turned off or disabled in order to achieve convergence of the power flow. In addition, all pumped storage hydro units are modeled

[6] **Note:** For regions experiencing greater than 50% average light loads, PJM will model light loads in excess of 50% of 50/50 peak load in planning cases in coordination with the service provider. PJM will share the updated LL modeling ratio part of the reliability assumptions at the beginning of the RTEP cycle in January.

in the pumping mode with their governors and power systems stabilizers deactivated or adjusted to reflect the appropriate operating condition.

Generation/Transmission Owner Responsibilities:

- Provide necessary supporting data for stability case build upon PJM's request including but not limited to: topology information and dynamic modeling and station loads
- Provide station loads, including power factors and load representation data (CONL file) if the load representation is different from the one in the ERAG MMWG series
- Verify upgrades and generator modeling (MVA base & Topology)

If there is any discrepancy between the RTEP case and the ERAG MMWG case for existing units, PJM will follow up with the Generation owner with assistance from the TO to insure that the most current data is used.

A complete base case (summer peak or light load) must include at least:

- A power flow file: This file contains the network information and provides the initial conditions for the dynamic models.
- A dynamic data file: This file contains all the information necessary to simulate the dynamic response of the various system components.
- A gnet file: This file contains the information of those generators that do not have a dynamic model. Any generator listed in this file is considered as a negative MVA load.
- A conl file: This file indicates how loads will be modeled based on a combination of constant MVA, constant current and constant admittance. It is strongly recommended that each TO develop more accurate load representation for stability and dynamics studies

Dynamics Data Submittal Requirements and Guidelines:

The Multiregional Modeling Working Group (MMWG) provides the following topics pertaining to dynamics data submittal requirements and guidelines. This information is accessible in Appendix II of the MMWG Procedure Manual V5. A hyperlink to the manual is located at the bottom of this section.

- Power Flow Modeling Requirements
- Bus name identifiers for synchronous condensers, Static VAr Compensators (SVCs) modeled as generators, switched shunts, relays, and HVDC terminals.
- Step-up transformer representation requirements for both MMWG power flow cases and non-MMWG power flow cases.
- Resistance and reactance data placements for step-up transformers represented in the power flow generator data records.
- Xsource value representations in the power flow generator data record.
- SVC representation requirements in power flows.
- Dynamic Modeling Requirements

- Synchronous generator and condenser modeling / associated data requirements and exceptions.
- Additional representation requirements and exceptions for synchronous generators and condensers modeled as described in Requirement II.1.
- PSS/E modeling requirements for any other types of generating units and dynamic devices.
- Exceptions to the use of standard PSS/E dynamic models.
- Required written documentation and its submittal procedures for user-defined modeling in MMWG cases.
- Generating unit, synchronous condenser, and other dynamic device requirements for netting.
- Lumping conditions of similar or identical generating units at a plant.
- Location requirements for per unit data.
- Exception procedure for any requirements listed.
- Dynamics Data Validation Requirements
- Dynamics data screening requirements
- Preliminary procedures to undergo before regional data submittal to the MMWG coordinator.
- Material required by each region to validate the dynamics model.
- Guidelines
- Additional documentation that should be submitted with dynamics data.
- Information pertaining to parameters for representing loads via the PTI PSS/E CONL activity that the regions should provide to the MMWG.

Location of MMWG Procedural Manual:

https://rfirst.org/ProgramAreas/ESP/ERAG/MMWG/ERAG%20%20MMWG%20Library/MMWG_Procedural_Manual_V29.pdf

Attachment I: Steady State & Stability Performance Planning Events

I.1 NERC TPL-001-5.1 Table 1

Manual or automatic load shed is not permitted for any P0 - P7 condition.

NERC TPL-001 Events				PJM		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P0 No Contingency	Normal System	None	N/A	Apply normal limits, the actual % may differ, depending on the TO zone	PJM Planning will use the same voltage limits that are used in PJM Operations for both voltage magnitude and voltage deviation. Emergency limits are used for normal, single contingencies and multiple contingencies. For Transmission Owner Criteria, PJM will default to the operations limits unless the TO limits are more conservative.	
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	Apply emergency limits, the actual % may differ, depending on the TO zone		
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A			
		2. Bus Section Fault	SLG			
		3. Internal Breaker Fault[8] (non-Bus-tie Breaker)	SLG			

		4. Internal Breaker Fault (Bus- tie Breaker) [8]	SLG		

NERC TPL-001 Events				PJM		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	Normal limits after the 1st contingency, emergency limits after the 2nd contingency		
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker)*[10]	Normal System	Loss of multiple elements caused by a stuck breaker10 (non-Bus-tie Breaker) Attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	Apply emergency limits, the actual % may differ, depending on the TO zone		
		6. Loss of multiple elements caused				

		by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus			

P5 Multiple Contingency *(Fault plus non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG		

NERC TPL-001 Events				PJM		
NERC Category	**Initial Condition**	**Event[1]**	**Fault Type[2]**	**Thermal Limits**	**Low Voltage Limit ****	**High Voltage Limit ****
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5]	3Ø	Normal limits after the 1st contingency, emergency limits after		

	2. Transformer[5] 3. Shunt Device[6] 4. Single pole of a DC line	3. Shunt Device[6]		the 2nd contingency	
		4. Single pole of a DC line	SLG		
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of any two adjacent (vertically or horizontally) circuits on common structure[11]	SLG	Apply emergency limits, the actual % may differ, depending on the TO zone	

Note:
(*please note that footnotes 3, 4 and 12 have been intentionally skipped to preserve alignment with subsequent footnote numbering.)

1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.

2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.

6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.

8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.

9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled ‘Initial Condition’) and a corrective action when achieved through the

appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.

11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.

13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:

a. 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

b. A single communications system associated with protective functions, necessary for correct operating of a communication-aided protection scheme required for Normal Clearing (and exception is a single communications system that is both monitored and reported at a Control Center);

c. A single station dc supply associated with protective function 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);

d. A single control circuitry (including auxiliary relays and lockout relays) associate with protective functions, from the dc supply through and including the trip coil(s) of the circuit

breakers or other interruption devices, required for Normal Clearing (the trip coil may be excluded if it is both monitored and reported at a Control Center).

Attachment J: Checklist for New Equipment Energization Process

The following checklist has been created for use by Transmission Owners and Designated Entities as a guideline for what is required by PJM throughout the baseline/supplemental transmission upgrade process from inception to energization.

For more detailed information please refer to the training series: Transmission Planning, Modeling, and Energization which can be accessed from any of the following pages on pjm.com:

http://www.pjm.com/planning/rtep-development.aspx;

http://www.pjm.com/planning/rtep-development/powerflow-cases.aspx

http://www.pjm.com/planning/design-engineering.aspx;

http://www.pjm.com/markets-and-operations/ops-analysis.aspx

Project Phase [1]	Task	Delivery	Timeframe	PJM Manual Reference	PJM Contact Depart
P	Submit minimum required rating (lines and xfmrs)	Email to contact	Before Project Approval	M-14B	Transmission Planning
P	Submit planning model parameters	IDEV/Project File	Before Project Approval	M-14B	System Planning Modeli Support
P	Submit planning contingency changes	CON File	Before Project Approval	M-14B	Transmission Planning
P	Submit breaker diagrams	Email to contact	Before Project Approval	M-14B	Transmission Planning
P	Project Description/	Email to contact	Before Project Approval	M-14B	Transmission Planning

Project Phase [1]	Task	Delivery	Timeframe	PJM Manual Reference	PJM Contact Depart
	Cost/Time Estimate				
EP	Construction Schedule/ Project Sequence	Email to contact	6-8 months prior to UC phase	M-14C	Infrastructure Coordinati
EP	Submit projected outage timeframes	Email to contact	6-8 months prior to UC phase	M-14C	Infrastructure Coordinati
UC	Quarterly updates	Email to contact	Throughout UC phase	M-14C	Infrastructure Coordinati
EP/UC	Submit as built impedance and all other applicable equipment parameters (i.e. Tap Settings, Capacitor Size etc.)	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit final In-Service Date	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit target build date	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit equipment names	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management

Project Phase [1]	Task	Delivery	Timeframe	PJM Manual Reference	PJM Contact Depart
EP/UC	Submit final one-line diagrams	eDART – Network Model Ticket	6-12 months prior to IS	M-03A; 3.2	Model Management
EP/UC	Submit Transmission Outage Tickets	eDART	2-12 months prior to IS	M-03; 4.2	Transmission Operations
EP/UC	Submit Ratings (Lines and Transformers)	eDART – TERM	No later than 2 weeks prior to IS	M-03A; 3.2	Real-Time Data Manage TERMTickets@pjm.com
EP/UC	Submit Telemetry	Email	No later than 2 weeks prior to IS	M-03A; 3.2	Real-Time Data Manage PJMTelemetrySupport@
EP/UC	Submit As built data	Project File	IS Date	M14B	System Planning Modeli Support
UC/IS	Notification of In-Service status	Email	Once facility is energized	M-14C	Infrastructure Coordinati

1Key: **P** = Pending (or before Pending), **EP** = Engineering and Procurement, **UC** = Under Construction, **IS** = In-Service

Note:
For maximum exposure to various members, identical copies of this table can be found in PJM Manuals 03A, 14B, and 14C

Attachment K: CIR for ELCC Transition

- A “transitional resource” refers to any resource that by April 10, 2023 either has an ISA (“existing unit”) or is active in the PJM interconnection queue (“existing queue unit”) and submits a CIR uprate request into the New Services Queue along with a request to be considered as a transitional resource. PJM will post the transitional resource request form to the PJM website along with the 1/25/2023 Markets & Reliability Committee meeting materials that will contain the instructions for filling out and submitting the form and the information required. Only CIR uprate requests that do not involve a physical modification to the resource will be eligible for transitional resource designation. The submittal of the CIR uprate request into the New Services Queue and any subsequent withdrawal of the request from the New Services Queue will be done and treated in a manner that is consistent with the PJM Manuals and PJM Governing Agreements. The resource will no longer be considered a transitional resource if it withdraws its CIR uprate request.

- The **“**transitional resource MW ceiling” refers to, for Variable Resources, up to the lower of the summer regional percentile output for the resource type or the requested CIRs. For all other resource types, up to the lower of their MFO or requested CIRs. PJM will post the summer regional percentile outputs for Variable Resources in the TEAC RTEP assumptions slides that will typically be released in January each year during the transition period in a slide entitled “Wind & Solar Harmer Dispatch As Percent of Maximum Facility Output”. PJM will also post the summer regional percentile outputs for Variable Resources for the 2025/2026 BRA to the PJM website along with the 1/25/2023 Markets & Reliability Committee meeting materials.

- The “transition period” refers to the period of time required to process a CIR uprate request for a transitional resource in the PJM interconnection queue such that the amount of CIRs requested under the CIR uprate request in the New Services Queue is eligible to participate in RPM. During the transition period, a transitional resource may receive transitional system capability up to the transitional resources’ MW ceiling. After the transition period or upon withdrawal of the CIR uprate request from the PJM interconnection queue, the designation of transitional resource is removed.

- The “transitional system capability” refers to identified locational transmission system injection capability that is available in the full summer generator deliverability test (single contingency and common mode outage) for the applicable BRA Delivery Year during the transition period beyond that required to support all PJM CIRs considered in the interim CIR study. The transitional capability is calculated for transitional resources that are eligible to participate in the BRA Delivery Year under study and is capped at the transitional resource MW ceiling. The transitional capability may vary for each BRA during the transition period and is subject to other known locational reliability restrictions such as stability and voltage. The allocation of the transitional system capability prior to each BRA

during the transition period will be based on a cluster approach using the distribution factors and the transitional resource MW ceilings along with identified reliability constraints.

- The **"**transitional system capability study" refers to a study performed prior to each BRA during the transition period for CIR uprate requests for all transitional resources that are eligible to participate in the BRA Delivery Year under consideration. Transitional resources that submit a request for higher CIRs to PJM along with a request to be considered as a transitional resource by April 10, 2023 will have their CIR uprates processed in the New Services Queue and will be part of a transitional system capability study prior to each BRA (estimated 2025/26 through 2029/30 BRAs) during the transition period to determine whether the transmission system is capable of delivering outputs above the existing queue unit's eligible CIRs. Such eligible transitional resources will have their hourly output capped in the ELCC study and accreditation process at the resource's transitional system capability, which will consider summer generator deliverability testing (single and common mode outages) and other reliability tests as needed to ensure the resources are deliverable for the Delivery Year under consideration. The transitional system capability assigned to the resource will be the greater of the existing queue unit's eligible CIRs for the applicable BRA Delivery Year or the transitional resource MW ceiling.

A transitional system capability study will be performed prior to each BRA during the transition period for CIR uprate requests for all resource types. Transitional resources that submit a request for additional CIRs to PJM along with a request to be considered as a transitional resource by April 10, 2023 will have their CIR uprates processed in the New Services Queue of the PJM interconnection queue and will be part of a transitional system capability study prior to each BRA (estimated 2025/26 through 2029/30 BRAs) during the transition period. The transitional system capability study will determine whether the transmission system is capable of delivering outputs above existing queue unit's eligible CIRs. Such qualifying transitional resources will have their hourly output capped in the summer portion of the ELCC study and accreditation process at the resource's transitional system capability, which will consider summer generator deliverability testing (single and common mode outages) and other reliability tests for the Delivery Year. The transitional system capability assigned to the resource will be the greater of the existing queue unit's eligible CIRs for the applicable BRA Delivery Year or the transitional resource MW ceiling.

The allocation of identified additional system capability among the transitional resources will be performed using the following steps.

1. Gather inputs for allocation of transitional system capability:
    a. Overloaded flowgates and overloaded amounts with and without the CIR uprate requests
    b. DFAX and MW value requested to be considered in the study

2. Pre-processing:
    a. Eliminate overloaded flowgates where the CIR uprate request does not contribute
    b. Eliminate any CIR uprate request that contributes to a flowgate that is already overloaded without any CIR uprate requests; such transitional resources will not receive any transitional system capability.
3. Determine allocation of additional system capability among the transitional resources:
    a. For remaining flowgates (not overloaded but for the CIR uprate requests) use DFAX and MW [value of the CIR uprate requests plus available headroom to determine amount of CIR uprate request MWs the system can accommodate from each transitional resource.
    b. For transitional resources connected at the same electrical location, allocation of additional system capability shall be done on a pro-rata basis according to the amount of CIR uprate MWs requested for each transitional resource.
4. Once allocation of additional system capability among the transitional resources is complete, then rerun generator deliverability to ensure no remaining thermal or voltage violations exist.

Revision History

Revision 56 (06/27/2024):

- Added clarifications to sections C.2.1.4, C.2.4, and C.2.5 that reflect the changes to the calculation of CETO and reliability targets based on the FERC approved docket ER24-99.
- Conforming changes were made to the following sections to incorporate provisions of FERC's CIFP-RA order (ER24-99):
- C.2.1.4 General Procedures
- C.2.4 Capacity Emergency Transfer Objective (CETO) Procedure
- C.2.5 Capacity Emergency Transfer Limit (CETL) Procedure

Revision 55 (12/20/2023):

- Periodic Review
- Added qualifying language to the manual where losing more than 300 MW of load will impact numerous customers. Sections that were revised include:
  - 2.3.8 NERC P3 and P6 "N-1-1" Analysis
  - Attachment D: PJM Reliability Planning Criteria
  - Attachment D-1: Load Loss Definitions
- Revised Section 2.9 CSPA Analysis bullet 1 to include the concept of impacting numerous customers under loss of load approaching 1000 MW.
- Added Attachment G.12 NERC Standard FAC-002 – Facility Interconnection Studies to address FAC-002-4 Requirement R6 regarding the definition of Qualified Change to existing interconnections.

Revision 54 (07/26/2023):

- Updated references from TPL-001-4 to TPL-001-5.1.
- Revised Manual 14B language to align with updated requirements in TPL-001-5.1:
  - 2.3.11 Spare Equipment Strategy Review
  - H.1.2 Load Flow Modeling Requirements
- Updated Attachment I: Steady State & Stability Performance Planning Events table to align with TPL requirements

Revision 53 (07/26/2023):

- Introduction: Revised terminology to align with new tariff language, updated references
- Section 1A.3.1.1: Updated terminology
- Section 1.1: Updated terminology/references
- Section 1.4.1.6: Updated terminology/references

- Section 1.4.2.3: Updated terminology
- Section 1.4.3: Updated terminology
- Section 2.1.1.1: Updated terminology/references
- Section 2.1.2: Updated terminology
- Section 2.2: Updated terminology, revised note to clarify potential impact of generation retirements
- Section 2.3.1: Updated terminology
- Section 2.3.3: Updated terminology
- Section 2.4: Updated terminology/references, streamlined language
- Section 2.5: Updated reference
- Section 2.9: Format and terminology correction
- Attachment A, A.1: Updated reference
- Attachment A, A.2: Updated reference
- Attachment B, B.3: Updated terminology
- Attachment B, B.4: Updated terminology
- Attachment C, C.2.6: Updated terminology
- Attachment C, C.3.1.3: Updated terminology throughout, removed statement referencing serial queue process in step 2, and revised statement on commercial probability to align with IPRTF material in step 5a
- Attachment C, C.4: Updated terminology
- Attachment G, G.1: Updated terminology
- Attachment G, G.2.1: Updated terminology/references
- Attachment G, G.2.2: Updated terminology and stability language to align with current process
- Attachment G, G.3: Updated terminology
- Attachment G, G.3.1: Updated terminology/references
- Attachment G, G.3.2: Updated terminology/references and stability language to align with current process
- Attachment G, G.5: Updated terminology/references, and removed section G.5.1 – Wind Project Final Impact Study Data
- Attachment G, G.7: Updated reference
- Attachment G, G.9.1: Updated terminology and added reference to Transmission Owner Planning Criteria
- Attachment G, G.9.4: Addition of ComEd transient voltage recovery criteria
- Attachment H, H.1.2: Updated terminology
- Attachment H, H.1.4: Updated terminology

- Attachment H, H.1.5: Updated terminology

Revision 52 (4/10/2023):

- Updates to the Generator Deliverability Procedure to implement block dispatch
  - New Exhibit 4 – Block Dispatch for RTEP Cases
  - Section 2.3
  - Sections 2.3.11 (Light Load) and 2.3.13 (Winter Peak) removed, now addressed in 2.3.10
  - Attachment B
  - Attachment C.3
  - Attachment D-1
  - Attachment D-2 and D-3 removed, now addressed in C.3
- Section 1A.3.2 added to clarify PJM CEII Handling
- Added Attachment K: CIR for ELCC Transition

Administrative Change (01/21/2022):

- Updated manual ownership from Aaron Berner to Sami Abdulsalam

Revision 51 (12/15/2021):

- Changes to grammar in 1.3.2 Economic Planning
- Added a new subsection 1.4.2.4 Incorporation of EOL Needs into the RTEP
- Added new language detailing analysis in 2.1.2 Reliability Planning
- Added new graphics in 2.2.1 Reliability Planning
- Updated language to include Winter Peak Cases in 2.3.8 NERC P3 and P6 “N-1-1” Analysis
- Changed the title of subsection 2.3.15 to Extreme Event Review
- Added new objectives in 2.6 RTEP Market Efficiency Planning
- Added language in the following Attachments
  - B.2 and B.3
  - C.2.6
  - D.1
  - F
  - G.9.2 and G.9.6
  - H.1.2 and H.1.3

Revision 50 (07/01/2021):

- Added a new subsection 1.4.1.8 Maintaining reliability associated with critical substations

- Added a new bullet in section 2.1 Transmission Planning
- Added a new section 2.9 Critical Substation Planning Analysis

Revision 49 (06/23/2021):

- Changes to section 2.6 RTEP Market Efficiency Planning
  - Added Reliability Pricing Model constraints to the list of constraints that have an economic impact.
  - Inserted new subsection 2.6.5.2 Determination of Reliability Pricing Model (RPM)Benefits in section 2.6.5 Determination of Market Benefits - RPM benefits are determined using RPM simulations for the RPM and RTEP years.
- Attachment E: Market Efficiency Analysis Economic Benefit / Cost Ratio Threshold Test
  - Updated obsolete language regarding the 15 year period used for the B/C ratio to conform to the B/C ratio changes, PJM OA Section 1.5.7, accepted by FERC Order Docket No. ER19-80-001) (Issued 2019-02-19)

Revision 48 (10/01/2020):

- Add metering systems to section B.3 Procedure RTEP Deliverables third Bullet

Revision 47 (09/01/2020):

- Updated sections G.3, G.4 and G.5 to incorporate the FERC Order 845 Second Compliance Filing Tariff changes.
- Clarified that stability analysis will be performed during the Facilities Study

Revision 46 (08/28/2019):

- Changes to section 2.6.8 Market Efficiency project reevaluation process

Revision 45 (08/22/2019):

- Conform changes for context and alignment of terms (multiple locations)
- Update links for PJM.com
- Section 1.1, 1.3.4:
  - Provide additional clarity as to the process of integrating Supplemental Projects in the RTEP
- Section 1.3:
  - Define the applicability of modeling requirements associated with the RTEP
- Section 1.4:
  - Update outline numbering
  - Conform discussions for Customer Funded Upgrades to the definitions and processes from the Tariff
- Section 1.4.2:

- Clarify how overlapping needs are addressed in the RTEP

- Section 1.4.3:
  - Provide information as to the process used for the removal of projects from the RTEP under various conditions

Revision 44 (02/21/2019)

- Cover to Cover Periodic Review
- Revision to Section 1A on CEII
- Updated Attachment C
  - Various updates for clarity and alignment with current processes
  - Section C.2
    - Added language that non-radial facilities 345 kV and up will only automatically be considered as CETL limits for an LDA if they have greater than a 2% OTDF
    - Clarified that PJM may choose to include specific non-PJM transmission facilities in the load deliverability test in order to account for significant loop flows
    - Removed sentence that states that Load Deliverability Facility List will be locked down prior to each baseline
    - New procedure added to require both thermal and voltage analysis on both Discrete Outage Case and Mean Dispatch Case
    - Procedure modified to examine mean thermal loadings instead of median thermal loadings

Revision 43 (01/24/2019):

- Revise Section 1 and 2 to incorporate references to the Open Access Transmission Tariff, Attachment M-3 process
- Revise Sections 1 and 2 to include improved discussion of workflow and alignment to current processes

Revision 42 (08/23/2018):

- Updated Section 2.6.5 to include RTEP+15 b/c cap and for benefits adjustments due to in-service year later than RTEP. Also added language to note fixed generation and transmission topology for each simulation year.

Revision 41 (04/19/2018):

- Cover to Cover Periodic Review
- Updated Section 1.3 and Attachment H.1 per NERC MOD requirement standard numbering
- Updated Section 2.3.8 bullet formatting
- Updated Section 2.3.13 by removing language regarding winter temperature ratings sets

- Updated Attachment C.5.3.3 to add OVEC to study area definitions
- Updated Attachment C.7.3 to reference low side of transformer in generator deliverability procedures
- Updated Attachment D.2.2 to correct references to contingency types in table 2 and step 3

Administrative Change (01/31/2018):

- Manual ownership updated from Mark Sims to Aaron Berner

Revision 40 (10/26/2017):

- Updated Section 2.3.5 for bus tie breaker contingencies

Revision 39 (9/28/2017):

- Updates for termination of PJM/NYISO Wheel Agreement
- Updates to Attachment J(New Equipment Energization Checklist) for updated PJM Contact Department
- Updated Attachment G.7 for PJM Short Circuit model build contact

Revision 38 (07/27/2017):

- Removed references to the annual RTEP cycle in order to reflect the new 18-month RTEP cycle.
- Updated Exhibit 1 to also reflect new 18 month cycle.

Revision 37 (4/28/2017):

- Updated baseline thermal analysis section (2.3.6) to reflect correct N-1 analysis process
- Updated SPS to RAS per NERC definition change
- Updated PRC-023-3 to PRC-023 to account for future Standard revisions including PRC-023-4 which goes into effect 4/1/2017
- Updated for removal of EE (Energy Efficiency) References – as they are now included within the load forecast

Revision 36 (11/17/2016):

- Updated Attachment G.11 to reflect changes to Capacity Import Limit test as applicable to Long term Firm Service requests
- Updated hyperlinks throughout document to update for web changes

Administrative Change (10/01/2016):

- Attachment J:
  - Added hyperlinks for Training Series: Transition Planning, Modeling and Energization
  - Removed column entitled “Online Training Links”

Revision 35 (10/01/2016):

- Updated Section 2.3.13 and Attachment D-3.2 for ratings used in Winter Analysis
- New Appendix J: Checklist for New Equipment Energization Process and associated references in sections: 1.3.1; B.3; H.1; and H.1.3

Revision 34 (08/09/2016):

- Manual Ownership changed from Paul McGlynn to Mark Sims
- Added new Section 1A - About Critical Energy Infrastructure Information (CEII)
- Administrative Change: Updated Ramping Limits in winter peak study section
- Added Required In Service Dates for Light Load Reliability Analysis and Winter Peak Reliability Analysis
- Corrected references to TPL-001-4 in the PJM Planning SOL Methodology Section
- Updated Attachment G.9.6 including compliance language

Revision 33 (05/05/2016):

- Updated to revise Attachment G, Section 9.6.

Revision 32 (01/28/2016):

- Updated Attachment B, C and H for Transmission Service Study Procedures

Revision 31 (12/31/2015):

- Corrected references in C.5.7
- Updates to Section 2.1 for Multi Driver Approach
- Added a Winter Peak Reliability Analysis Criteria
- Updated section 2.7 for the inclusion of Energy Market Uplift
- Updates throughout this manual per TPL-001-4
- Periodic Review

Revision 30 (02/26/2015):

- Updated Section 2.3.13 to add more detail to the Long Term Deliverability Analysis
- Updated Attachment A to include a detailed cost allocation example
- Updated C.7 in Attachment C to add more detail to the Generator Deliverability Procedure
- Added C.8 in Attachment C to add more detail to the Long term Deliverability Analysis
- Updated G.2.2 to clarify the voltage drop test procedure
- Revision 29 (11/21/2014)
- Added “Modeling of Outages” section to Attachment H Section H.1.2
- Updated Section G.10 of Attachment for new version of PRC-023 standard

Revision 28 (08/21/2014):

- Added Section 4.8 to Attachment C for CETO/CETL as an input to RPM
- Updated Section numbering in Attachment C
- Updated Attachment A to reflect the current approved cost allocation methodology as described in the PJM OATT

Revision 27 (4/23/2014):

- Updated Attachment E for confirming changes associated with Market Efficiency Analysis and Benefit/Cost test

Revision 26 (3/28/2014):

- Updated Attachment C for changes to the use of commercial probability during the feasibility and impact study phases of the interconnection process
- Updated Attachment H for +2 year short circuit study cleanup
- Corrected typo/incomplete sentence in section G.4.1
- Added Section G.11: PJM Capacity Import Limit Calculation Procedure

Revision 25 (10/24/2013):

- Updated Attachment G.7 (Short Circuit) to a current year +2 short circuit planning representation
- Added confirming changes to Market Efficiency related to two year cycle process and timeline

Revision 24 (06/05/2013):

- Updated Attachment G.10 (PRC-023 – Transmission Relay Loadability)

Revision 23 (03/01/2013):

- Updated the Light Load Reliability Analysis Procedure
- Updated the SOL/IROL Definition in Planning to reflect inclusion of all PJM Markets Monitored facilities in alignment with PJM Operations
- Added Interim Updates and Communication of Significant Modeling Updates to Attachment H: Power System Modeling Data
- Correct typographical errors in section 2.3.3

Revision 22 (10/25/2012):

- Updated Exhibits for Base case development and 24 month cycle
- Addition of EKPC and Cleveland LDA, including Cleveland LDA map

Revision 21 (04/26/2012):

- Revised Generator Deliverability procedure to limit the “Adder” contribution based on an estimated CETO for generation in the receiving end area.

Revision 20 (12/22/2011):

- Added additional detail to the NERC Category C3 “N-1-1” section
- Created NERC Category C3 “N-1-1” stability section
- Added references to DUKE Energy Ohio/Kentucky
- Added additional detail to the NERC Standard PRC-023 Transmission Relay Loadability Section
- Updated Section 2 to reflect 24 Month Planning Process
- Fixed two small typos in the alt paragraph on P55 in the C.3 Section

Revision 19 (09/15/2011):

- Added Attachment H Power System Modeling Data

Revision 18 (7/20/2011):

- Added Light Load Reliability Analysis criteria and created a new attachment D-2 to contain the criteria.
- Added description of reactive load modeling in CETL base cases.

Revision 17 (4/13/2011):

- Added references where appropriate to reflect the inclusion of the American Transmission Systems, Inc. (ATSI) and Cleveland Public Power (CPP).
- Clarified the methodology to establish an IROL in the Planning Horizon.
- Updated the short circuit methodology to include the existing process to study all BES breakers.

Revision 16 (11/18/2010):

- Added a Contingency Definitions section (10/20/2010 MRC approval)
- Added Appendix G.10 NERC Standard PRC-023 – Transmission Relay Loadability (10/20/2010 MRC approval)
- Modified PJM Critical Energy Infrastructure Information Release Guidelines (08/05/2010 MRC approval)
- Added clarifying language to Baseline Voltage Analysis test methodology (08/05/2010 MRC approval)Updated the IROL definition to align with the latest NERC IROL definition (08/05/2010 MRC approval)

Revision 15 (04/21/2010):

- Added new Attachment F describing PJM stability, short circuit and special RTEP practices and procedures. This Attachment includes the special requirements for coordination of planning for nuclear interfaces

Revision 14 (02/01/2010):

- Attachment C: Added language to specify how energy efficiency is incorporated into deliverability tests. Added additional language to specify the load level modeled in the load deliverability test for the area being tested. (1/22/10 MRC Approval)

Revision 13 (11/16/2009):

- Inserted Commercial Probability technique in Attachment C, Generator Deliverability Procedure Step 5 (10/2/08 MRC approval)
- Added Attachment F: Determination of System Operating Limits for Planning the Bulk Electric System (06/17/09 MRC approval)
- Attachment C: Cap on generation delivery adders (12/21/09 MRC approval)
- Attachment C: Added language to Overview of Deliverability to Load to clarify criteria that may trigger analysis of potential new LDAs (11/11/09 MRC approval)
- Updated hyperlinks throughout the manual
- Temperature correction and clarification to Attachment B Section VII.N.

***Revision* 12 (08/08/2008):**

The following revisions primarily consist of additions, clarifications and reorganization to address FERC Order No. 890 requirements:

- Additions to Section 1 to update, clarify, and expand the RTEP overview.
- Combine old Sections 6 and 2 into an expanded Section 2.
- Move wind, power factor and behind the meter generation material to a reconstituted Section 6
- Include additional reliability planning process and criteria information
- Market Efficiency Process revisions (section 2 and Attachment E) plus additional editorial and consistency changes throughout including Attachments D, E, and G.
- Added Exhibit 1 edits to Intro, Sections 1, 2, related attachments
- Multiple passes of CEII revisions.
- Generation Delivery clarifications in Attachment C.
- Removed the final material in Section 2 that is related to Interconnections to Manual 14A and revised the remaining material appropriately for Manual 14B.
- Exhibit 1 update for quarterly queues
- Attachment D criteria clarifications

- Added final RPPWG comments of Nov 30, 2007 meeting, added minor clarifications, and cut material to move to the appropriate generation or transmission interconnection related portions of revised 14A and 14E as to be determined. Sections deleted from here and moved to either 14A or 14E are: (the following attachment designations are according to the previous version Manual 14B lettering)
- Moved Section 3: Generator and Transmission Interconnection Planning Process
- Generation and Transmission Interconnection Feasibility Study
- System Impact study
- Generation and Transmission Interconnection Facilities Study
- Moved Section 4: Small Resource Interconnection Process
- Moved Section 5: Interconnection Service, Construction & Other Service Agreements
- Moved Section 6: Additional Generator Requirements
- Behind The Meter Generation Projects
- Generator Power Factor Requirements
- Wind-Powered Generation Projects
- Moved Attachment A: PJM Generation and Transmission Interconnection Planning Process Flow
- Attachment B: PJM Cost Allocation Procedures
- Moved PART 1: PJM GENERATION AND TRANSMISSION INTERCONNECTION COST ALLOCATION
- Moved Attachment C : PJM Generation and Transmission Interconnection Planning Team Role Diagram
- Moved Attachment F: General Description of Facilities Study Procedure
- Moved Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standard
- Moved Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards
- Moved Annex 1: SCADA Requirements by Transmission Owner Region

Revision 11 (10/05/2007):

- The Manual Title has been changed. The RTEP process has evolved over the past 5+ years and so has the scope of Manual 14B. The title of the manual has been changed from "Generation and Transmission Interconnection Planning" to "PJM Regional Planning Process"
- Section 6 and Attachment I have been revised to reflect the implementation of the 15-year horizon component of PJM's Regional Planning Process cycle, including that for market efficiency. These changes are made in accordance with the mmm, dd 2006 FERC

approval of PJM's subject Operating Agreement and Open Access Transmission Tariff (OATT) revisions.

- Conforming editorial revisions have been made throughout the remainder of the document.

Revision 10 (03/01/2007):

- Attachment B: Regional Transmission Expansion Plan revised to include steps for reactive planning in the RTEP.
- Revised hyperlinks in Attachment D: PJM Reliability Planning Criteria.
- Attachment H: Small Generator (10 MW and Below) Technical Requirements and Standards replaces former attachment on Small Generators of 2 MW and less.
- Attachment H-1: Small Generator (above 10 MW to 20 MW) Technical Requirements and Standards added.
- References to PJM OATT provisions in Sections 2 and 5 are revised to indicate that they are now in the new Part VI of the OATT (along with their former Part IV locations)
- Wording in Section 2 under "Summary of RTEPProcess" and again in Attachment E is revised to reflect that generation retirements included in project studies will be those announced as of the date a project enters the project queue.
- Introduction trimmed to eliminate redundant information.
- List of PJM Manuals exhibit removed, with directions given to PJM Web site where all the manuals can be found.
- Revision History permanently moved to the end of the manual.

Revision 09 (06/07/06):

- Manual sections 1 and 2 and Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) are revised to include Probability Risk Analysis (PRA) of Aging Infrastructure as an input to the PJM Region transmission planning process. The timeline in Section 5 is revised to require the Transmission Owner to submit a final invoice to PJM within 120 days after project completion. Attachment B (Regional Transmission Expansion Plan – Scope and Procedure) is also revised to add guidelines for Scenario Planning. Replaced references throughout to "ECAR, MAAC and MAIN" with ReliabilityFirst, the new replacement regional reliability council as of January 1, 2006.
- Revisions were made on the following pages: 8, 10, 12 through 16, 23, 24, 41, 56, 62, 63, 65, 67, 68 and 98.

Revision 08 (01/16/06):

- Section 1 is revised to state that all analyses of Transmission System adequacy are conducted using the load forecast produced annually by PJM. Attachments E and G are revised to state that load is modeled in the RTEP base case used for the Generator Deliverability procedure at a "non-diversified" 50/50 summer peak load level as per the latest load forecast.

Revision 07 (01/04/06):

- Section 2 is revised to add process for “Evaluation of Operational Performance Issues.” Attachment A is revised to clarify the Load Flow Cost Allocation Method and to add the Schedule 12 Cost Allocation process. Attachment C is revised to include references to Dominion and to add Addendum 2 “Common Mode Outage Procedure” to the Generator Deliverability Procedure. Attachment D is revised to include a minimum power factor for system “load”.

Revision 06 (11/21/05):

- Section 2 is revised to indicate that “One RTEP baseline regional plan will be developed and approved each year” and that “Generation retirements will not affect the study results” for any project that has received an Impact Study Report. Attachment B is revised to clarify and expand the scope and procedure of the Regional Transmission Expansion Planning Process.

Revision 05 (06/23/05):

- Revision includes a change in Section 6 to include reference to new Attachment E, re-writes of Attachment C (PJM Deliverability Testing Methods) and Attachment D (PJM Reliability Planning Criteria) and the addition of new Attachment E (Economic Planning Process, Congestion Relief Evaluation).

Revision 04 (12/17/04):

- Revision includes the changes in Sections 2 and 4 necessitated for compliance with FERC Order 2003 for standardized Generator Interconnection Agreements and Procedures, re-write of Attachment F: Facilities Study Guidelines, re-write of Attachment D: PJM Reliability Planning Criteria, and the addition of Attachment H: Small Generator (2MW or less) Technical Requirements and Standards.

Revision 03 (06/08/04):

- Revision includes the addition of rules for Generator Power Factor Requirements and Behind the Meter Generation in Section 2, the designation of small resources as 20 MW or less in Section 4, the addition of the Economic Planning Process in Section 6 and general updates.

Revision 02 (10/31/03):

- Revision includes the addition of Wind-Powered Generator Specific Requirements to Section 2, a placeholder for the addition of the Economic Planning Process in new Section 6 (currently under development) and the addition of Attachments D (Regional Transmission Expansion Plan – Scope and Procedure), E (PJM Deliverability Testing Methods), F (General Description of Facilities Study Procedure) and G (PJM Reliability Planning Criteria); also, text changes throughout to conform with Nuclear Plant Licensee Final Safety Analysis Report grid requirements and with new Manual M-14E (Merchant Transmission Specific Requirements – also currently under development).

Revision 01 (02/26/03):

- Revision includes a manual title change from PJM Manual for Generation Interconnection Transmission Planning (M-14B) to PJM Manual for Generation and Transmission Interconnection Planning (M-14B); also, text changes throughout to conform to new Manuals M-14C and M-14D.

Revision 00 (12/18/02):

- This document is the initial release of the PJM Manual for Generation Interconnection Transmission Planning (M-14B).
- Manual M-14, Revision 01 (03/03/01) has been restructured to create five new manuals:
- M-14A: “Generation Interconnection Process Overview”
- M-14B: “Generation Interconnection Transmission Planning”
- M-14C: “Generation Interconnection Facility Construction”
- M-14D: “Generation Operational Requirements”
- M-14E: “Merchant Transmission Specific Requirements”

PJM RTEP - 2022 RTEP PROPOSAL WINDOW #3

PROBLEM STATEMENT & REQUIREMENTS

Document Scope: 2027-28 Summer Reliability Analysis; 2027-28 Winter Reliability Analysis; 2027-28 Light Load Reliability Analysis; 2027-28 Short Circuit Analysis

2022 RTEP PROPOSAL WINDOW #3

Purpose of Proposal Window

PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on facilities identified below in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC, and Local Transmission Owner criteria).

Criterion Applied by PJM for this Proposal Window

- 2027-28 Summer

  Baseline Thermal and Voltage N-1 Contingency Analysis

  Generator Deliverability and Common Mode Reliability Analysis

  N-1-1 Thermal and Voltage Analysis and Voltage Collapse

  Load Deliverability Thermal and Voltage Analysis

  Dynamic Stability Assessment

- 2027-28 Winter

  Baseline Thermal and Voltage N-1 Contingency Analysis

  Generator Deliverability and Common Mode Reliability Analysis

  N-1-1 Thermal and Voltage Analysis and Voltage Collapse

  Load Deliverability Thermal and Voltage Analysis

  Dynamic Stability Assessment

- 2027-28 Light Load*

  Baseline Thermal and Voltage N-1 Contingency Analysis

  Generator Deliverability and Common Mode Reliability Analysis

  *PJM aims to provide the Light Load cases early in March 2023, on or before March 6th.

Terminology for Proposal Windows

Through the analyses listed above, PJM has compiled a list of criteria violations. 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.

- Immediate Need Exclusion: For immediate reliability needs that must be addressed within three years or less and for which PJM determines a proposal window may not be feasible , 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(m)
- 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). Please note that some flowgates are substation equipment limited, eligible for exclusion but were still included in the competitive window. Since these flowgates are in the cluster of a group of violations, PJM provided these in the window for visibility and consideration part of the window proposal package.
- Supplemental Projects scope: These cover violations to be addressed through supplemental solutions, primarily to address 300 MW load loss criteria due to preliminary allocation of load.
- Areas external to the study area that will be covered part of upcoming 2023 RTEP: These cover violations identified in the basecase extensively remote from the study area within ATSI, ComEd and AEP zones). These violations are not associated with eth Data Center Loads increase in APS and Dominion zones and will be covered part of the upcoming 2023 RTEP.

Analysis Procedure

Participants are expected to develop solutions to the identified criteria violations and perform analysis to validate that the solutions remove these violations identified under the 2027-28 baseline cases. 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

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.

Scope of Work

PJM is seeking proposals to resolve identified reliability criteria violations associated with data center load growth in the Dominion and APS (FirstEnergy) service territories.

OBJECTIVES:

1. Develop robust, holistic and expandable solutions that address the 2027-28 baseline violations associated with:
    a. Local constraints which are constraints resulting from directly serving the data center loads in APS and Dominion zones through the respective 230 kV networks and into the points of delivery. Examples include reinforcements to transmission path segments:
        i. Goose Creek- Ashburn – Mars - Wishing Star and Brambleton

    b. Regional constraints resulting from imports into load center areas to serve data center loads. These primarily cover the following 500 kV transmission paths (together with their paralleling 230 kV circuits):
        i. Doubs - Goose Creek
        ii. Front Royal - Morrisville – Vint Hill – Loudoun/Mosby
        iii. Meadow Brook - Loudoun/Mosby
        iv. Morrisville – Bristers - Ox
        v. Peach Bottom – Conastone – Brighton – Doubs

    c. Needed reactive power VAR reinforcements, both static and dynamic as deemed necessary, to address the reactive power needs of the system for the 2027-28 baseline scenario

2. Develop solutions to address all (if any) new criteria violations generated as a consequence of proposed solution. Solutions to these secondary violations are required for the proposal to be considered.

3. Adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and Local Transmission Owner Criteria.

REQUIREMENTS:

- Holistic solutions are to be designed such that they are robust and expandable as the load grows within the area. A scalable solution ensures, at a minimum, near-term reliability needs are addressed while also enabling future expansion (beyond the 2027-28 baseline levels) as data center load increases in the Dominion and APS zones.

    - Consider flexibility, robustness and scalability of 2027-28-baseline solutions against the Interim 2027-28 Summer, Winter and Light Load basecases.
    - Evaluate proposals for their effectiveness towards existing reactive interfaces in the area, particularly those supporting the Dominion and APS zones.
    - Evaluate the effectiveness of the proposed solutions towards the transmission system load deliverability into the Dominion and APS zones (CETL).

ASSUMPTIONS:

- Preliminary Reactive Support:
  - The provided 2027-28 basecases include a set of reactive VAR support at existing/proposed substations to partially meet the system reactive load demand particularly under system normal, N-0 conditions.
  - These preliminary reactive VAR support reinforcements are already provided at specific locations as indicated in Table 1.a and Table 1.b. They are further detailed through the VAR support inclusion IDEVs part of the 2022 RTEP Window 3 modeling files.
  - The preliminary VAR support included in the basecases do not imply final VAR level, type or location. The assumed VAR support levels were only adequate for need analysis purposes. These Temporary VAR support measures in the case(s) should be removed and replaced consistent with an entities proposal to provide the necessary VAR support. The preliminary VAR support should not be relied upon as part of the proposal.
  - PJM expects that proposals will provide for the needed reactive VAR support through either transmission development or static/dynamic VAR support devices or a combination of both.
  - There are a number of non-convergent contingencies due to deficient VAR support and excessive reactive power loss in the 2027-28 modeling basecases.
  - Based on the preliminary VAR resource assumptions in the cases, the provided voltage performance results are for guiding purposes only. Proposal developers are to re-evaluate the voltage performance part of their proposal development to ensure compliance with voltage performance requirements.
- Basecase N-0 thermal Violations:
  - The 2027-28 baseline case(s) show thermal violations along the Peach Bottom-Conastone and Conastone-Brighton 500kV paths.
  - These 500 kV segments are also showing marginal overloads approaching 98% to 100% under N-1 conditions for the baseline summer conditions.
- Non-Converged N-1 Contingencies:
  - A number of key non-convergent N-1 contingencies are provided in Table 2. These contingencies lead to voltage collapse on the 500kV system due to insufficient transmission system transfer capability and VAR support inadequacy.
  - Following development of VAR support enhancements, thermal loading on all system elements needs to be monitored and overloads, if any, need to be addressed part of the proposed solutions.
- N-1-1 Analysis;
  - Due to the significant load growth presented in the baseline 2027-28 basecases, a large number of N-1-1 contingencies lead to unsolvable security constraint redispatch conditions. Hence, the provided N-1-1 results are to be revaluated as part of the proposal solution development process.
  - PJM aims provide the interim 2027-28 basecase N-1-1 results by early March and no later than March 6th 2023 on the PJM website in the competitive planning section.
- Load Deliverability analysis:
  - PJM requires the proposed solutions are evaluated for their effectiveness towards load deliverability into the APS and Dominion zones.
  - PJM will provide the load deliverability modeling instructions and parameters during the week of March 6th.

Table 1.a 2027-28 Baseline - Preliminary Reactive VAR support (to be replaced by 2022 RTEP Window 3 Proposals)

Station	kV	MVAR
Barrister	230	300
Stratus	230	150
Prentice	230	150
Mars 500kV	500	150
Mars 500kV	500	150
Wishing Star 500 kV	500	150
Wishing Star 500 kV	500	150
Winters Branch	230	150
Winters Branch	230	150
Rixlew	230	150
Rixlew	230	150
Ocean Court	230	150
Ocean Court	230	150
Rollings Ford	230	150
Rollings Ford	230	150
Kyser	230	150
Nimbus	230	150
Nimbus	230	150
DTC	230	150
Pleasant View 500kV	230	300
Spotsylvania 500kV	500	300
Loudoun 500kV	500	300
Wakefield	230	150
Wakefield	230	150
Dawkins Branch	230	150
Youngs Branch	230	150
Total		**4500**

Table 1.b 2027-28 Intermediate - Preliminary Reactive VAR support (to be replaced by 2022 RTEP Window 3 Proposals)

Station	kV	MVAR
Barrister	230	150
Dawkins Branch	230	150
Youngs Branch	230	150
DTC	230	150
Stratus	230	150
Mars	500	150
Wishing star	500	294
Ocean Court	230	150

Station	kV	MVAR
Ocean Court	230	150
Total		**1494**

Table 2 2027-28 Baseline Summer Non-Convergent Contingencies

Contingency Name	Cont. Type	Analysis Type	Error Type
AP_P1-2_PE-500-001_SRT-SL	Single	Voltage Drop	Blown Up
AP_P1-2_WP-500-DRT17_SRT-SL	Single	Voltage Drop	Blown Up
PJM_500_BG_P1_5011_SRT-A	Single	Voltage Drop	Blown Up
AP_P2-3_PE-500-015_SRT-A	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-016_SRT-SL	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-018C_SRT-SL	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-018D_SRT-SL	Line_FB	Voltage Drop	Blown Up
AP_P2-3_PE-500-019D_SRT-SL	Line_FB	Voltage Drop	Blown Up

WHAT PJM PROVIDES:

The information listed below is provided to allow replication of PJM analyses. Some of this data is 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. Power Flow Base Cases. Identifies one or more system configurations to which planning criteria are applied.
2. Contingency List: Lists all contingency types (single, bus, tower, line w/ stuck breaker).
3. Subsystem Files: Identifies all subsystem zones to be considered in analysis.
4. Monitor Files: Identify specific ranges of facilities by area and kV level to be considered in analysis.
5. Facility Ratings: (if different from those included in the base cases)
6. 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.
7. Short Circuit Base Case. This case reflects the 2027-28 RTEP base case.
8. Breaker Change Files. Lists all over-duty breakers in a specific TO area.
9. TO Criteria Setting Files. Lists settings used for short circuit analysis for each specific TO.
10. TARA Generation Deliverability options files.
11. Generator Data files used in Generation Deliverability tests
12. Dynamic modeling files for dynamic stability assessments (to be provided during the week of March 6th 2023).

Response Back To PJM (Deliverables)

This section describes the required elements of a complete proposal. The absence of any element renders the proposal incomplete and the proposal will not be considered for selection.

Often there are several viable solutions to a given violation. Include alternate approaches in separate proposals. PJM will not accept proposals with multiple options.

Four categories of information are described below: three are required for a complete package and one is conditional.

- Technical analysis files and documentation
- Completed proposal submittal template
- Project diagrams
- Company evaluation and operations and maintenance information (if required)

Technical Analysis Files and Documentation

Include the following technical information to provide a complete project proposal package:

1. A detailed analysis spreadsheet showing the planning analysis results for the project.
2. A set of updates to the power flow cases which model the proposed solution. Provide files in a format compatible with PSS/E version 34.7. Provide only solvable and convergent solutions. Include an idv, or equivalent type, file in order to apply changes to other models. Assign a unique identifier when new busses are required. Provide contingencies in a single file for each contingency type. Organize the contingencies into one of three categories:
    a. Modified Contingencies
    b. New Contingencies
    c. Deleted Contingencies
3. List of all proposed equipment along with relevant parameters and assumptions.
    a. All necessary parameters, e.g., equipment ratings, impedances, line lengths, etc.
    b. For reactive devices, settings and outputs
    c. For synchronous machines, MW and MVAR output assumptions
4. An analysis report of proposed solution which identifies the issues being addressed.
5. Additional documentation required to verify the proposal.

PJM Proposal Submittal

The PJM Competitive Planner Tool is used for proposal(s) submittal and captures project details, such as the criteria violations or system constraints that are being targeted by the proposed solution, the overall and specific project descriptions and the details of cost commitment, if included. The Competitive Planner Tool and user guide are available on the Competitive Planning Process page: https://www.pjm.com/planning/competitive-planning-process.aspx.

All proposals will be made public and posted on pjm.com after the proposal window is closed. Mark all CEII and business confidential information for redaction from this public posting. Redact only information which meets the criteria of CEII or business proprietary and confidential information.

Redaction guidelines can be found in PJM Manual 14F, Section 6.2. Please note that this section provides guidance only. PJM reserves the right to challenge proposed redaction of information in order to ensure the appropriate level of transparency.

Project Diagrams

Provide project diagrams in the PJM Competitive Planner Tool to detail how the proposed solution will modify existing infrastructure, how new infrastructure will be configured and where new infrastructure will be sited. Project diagrams should include, but are not limited to, the following detail:

- Single line diagrams
- Substation general arrangement and station layout. If expanding the substation, identify the following:
  - Area to be modified
  - Land ownership or acquisition plan
- Line routing diagram:
  - Identify proposed route of new or upgraded transmission lines
  - Clearly identify where acquisition of additional right-of-way is required
- Detailed project schedule. Include, at minimum, the following major work activities:
  - Engineering and Design
  - Siting and Permitting
  - ROW and Land acquisition
  - Material procurement
  - Construction
  - Testing/Commissioning

Company Evaluation and Operations and Maintenance Information

For proposers seeking Designated Entity status, provide additional information which will aid PJM in understanding how the proposed solution will be developed, constructed, operated and maintained. Include this information in the PJM Competitive Planner Tool.

Relevant PJM Operating Agreement, Schedule 6, section 1.5.8(f).

Entity-Specific Criteria Considered in Determining the Designated Entity for a Project. In determining whether the entity proposing a Short-term Project, Long-lead Project or Economic-based Enhancement or Expansion recommended for inclusion in the plan shall be the Designated Entity, the Office of the Interconnection shall consider: (i) whether in its proposal, the entity indicated its intent to be the Designated Entity; (ii) whether the entity is

pre-qualified to be a Designated Entity pursuant to Operating Agreement, Schedule 6, section 1.5.8(a); (iii) information provided either in the proposing entity's submission pursuant to the Operating Agreement, Schedule 6, section 1.5.8(a) or 1.5.8(c)(2) relative to the specific proposed project that demonstrates: (1) the technical and engineering experience of the entity or its affiliate, partner, or parent company, including its previous record regarding construction, maintenance, and operation of transmission facilities relative to the project proposed; (2) ability of the entity or its affiliate, partner, or parent company to construct, maintain, and operate transmission facilities, as proposed, (3) capability of the entity to adhere to standardized construction, maintenance, and operating practices, including the capability for emergency response and restoration of damaged equipment; (4) experience of the entity in acquiring rights of way; (5) evidence of the ability of the entity, its affiliate, partner, or parent company to secure a financial commitment from an approved financial institution(s) agreeing to finance the construction, operation, and maintenance of the project, if it is accepted into the recommended plan; and (iv) any other factors that may be relevant to the proposed project, including but not limited to whether the proposal includes the entity's previously designated project(s) included in the plan.

Transmittal of Proposals

Proposal submissions along with all files required for submission will be done with the PJM Competitive Planner Tool for each submitted proposal.

Proposal Fees

All proposals, upgrade and greenfield solutions, with the exception of solutions submitted with an estimated cost of $5M or less, submitted for consideration in the 2022 RTEP Proposal Window 3 are subject to an initial $5,000 deposit per the PJM Operating Agreement 1.5.8(c).

Relevant PJM Operating Agreement language in Section 1.5.8(c):

(c)(1) All proposals submitted in the proposal windows must contain: (i) the name and address of the proposing entity; (ii) a statement whether the entity intends to be the Designated Entity for the proposed project; (iii) the location of proposed project, including source and sink, if applicable; (iv) relevant engineering studies, and other relevant information as described in the PJM Manuals pertaining to the proposed project; (v) a proposed initial construction schedule including projected dates on which needed permits are required to be obtained in order to meet the required in-service date; (vi) cost estimates and analyses that provide sufficient detail for the Office of Interconnection to review and analyze the proposed cost of the project; and (vii) with the exception of project proposals submitted with cost estimates of $5 million or less, a $5,000 non-refundable deposit must be included with each project proposal submitted by a proposing entity that indicates an intention to be the Designated Entity.

(c)(1)(i) In addition, any proposing entity indicating its intention to be the Designated Entity will be responsible for and must pay all actual costs incurred by the Transmission Provider to evaluate the submitted project proposal. To the extent the Transmission Provider incurs costs to evaluate multiple submitted project proposals where such costs are not severable by individual project proposal, the Transmission Provider shall invoice equal shares of the non-severable costs among the project proposals that cause such non-severable costs to be incurred. Notwithstanding this method of invoicing non-severable costs, non-severable costs will be jointly and severally owed by the proposing entities that cause such costs to be incurred.

(c)(1)(ii) All non-refundable deposits will be credited towards the actual costs incurred by the Transmission Provider as a result of the evaluation of a submitted project proposal.

(c)(1)(iii) Following the close of a proposal window but before the Transmission Provider incurs any third-party consultant work costs to evaluate a submitted project proposal, the Transmission Provider will issue to the proposing entity an initial invoice seeking payment of estimated costs to evaluate each submitted project proposal. The estimated costs will be determined by considering the: potential cost of consultant work, historical estimates for project proposals of similar scope, complexity and nature of the need, and/or technology and nature of the project proposal. The Transmission Provider may issue additional invoices to the proposing entity prior to the completion of the evaluation activities associated with a project proposal if the Transmission Provider receives updated actual cost information and/or upon consideration of the factors specified in this section.

(c)(1)(iv) At the completion of the evaluation activities associated with a project proposal, the Transmission Provider will reconcile the actual costs with monies paid and, to the extent necessary, issue either a final invoice or refund.

(c)(1)(v) The proposing party must pay any invoiced costs within fifteen (15) calendar days of the Transmission Provider sending the invoice to the proposing entity or its agent. For good cause shown, this fifteen (15) calendar day time period may be extended by the Transmission Provider. If the proposing entity fails to pay any invoice within the time period specified and/or extended by the Transmission Provider in accordance with this section, the proposing entity's pre-qualification status may be suspended and the proposing entity will be ineligible to be a Designated Entity for any projects that do not yet have an executed Designated Entity Agreement. Such a suspension and/or ineligibility will remain in place until the proposing entity pays in full all outstanding monies owed to the Transmission Provider as a result of the evaluation of the proposing entity's project proposal(s).

The non-refundable deposit is due at the time of submission. Pay the non-refundable deposit by wire transfer to PJM Interconnection at:

Wire transfer funds to:	PJM Interconnection, LLC
Bank Name:	PNC Bank, N.A. New Jersey
ABA Number:	031207607 (Fed Wire and ACH)
Account Number:	80-1358-9826
Provide Reference*:	Order 1000

To ensure the non-refundable deposit is properly accounted for, include a reference to "Order 1000 – Competitive submittal PJM Id ###" in the subject, notes or addenda field of the wire transfer form. Please note that the PJM ID ### will be displayed on the confirmation email you receive after submitting the proposal and is also identified on the competitive planner tool once a competitive proposal is initially saved.

The proposer also needs to provide the following information to PJM:

Company Info, Primary contact name, Billing email & Tax ID#.

The PJM Proposal ID can be located on the Existing Proposal screen in the PJM Competitive Planner Tool

Timeline

2/24/2023: Opening of 2022 RTEP Proposal Window 3

4/25/2023: Close of 2022 RTEP Proposal Window 3 at 11:59 p.m. Eastern Daylight Time

Notes:

- Confidentiality of individual proposals will be maintained for the duration of the window.
- Proposals received after close of the proposal window will not be accepted.

Questions

Submit all questions about the proposal window to the PJM Planning Community. Submit questions involving confidential information or CEII under the "Confidential" topic on the Planning Community. Answers will be provided to all participants in the proposal window.

Please reference 2022 RTEP Proposal Window 3 in all correspondence.

Specialized Requirements

PJM seeks proposals to evaluate the identified needs in this window. PJM has not determined specialized requirements that PJM is seeking in project proposals in this window for consideration in its evaluation.

Notice

In accordance with the Open Access Transmission Tariff, Attachment M, the MMU has access to all data submitted to PJM through PJM's competitive proposal window process. See Manual 14F, section 8.4.4.

Document Revision History

02/24/2023 - V1 - Original Problem Statement posted to the PJM Competitive Planning Process webpage: https://www.pjm.com/planning/competitive-planning-process.aspx.

2023 RTEP 2028 Preliminary Summer & Winter Gen Deliv 500KV and above Violation Summary

Sami Abdulsalam
Wenzheng Qiu
Nebiat Tesfa

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Purpose

- Summarize bulk transfer needs identified in the 2028 RTEP
- Summarize changes in the 2028 RTEP models impacting earlier and newly identified needs.
- Discuss how the 2028 RTEP needs may influence solutions to the 2027 RTEP Window 3.
- Focus on bulk transfer needs:
  - Vast majority of relevant overlapping needs are due to bulk transmission constraints for regional transfers.

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What's new in the 2028 RTEP Models?

- 2023 Load Forecast
- Implementation of New Planning Methodology:
  - Generation Block Dispatch (Area transfer limits considerations)
  - Generation Deliverability Testing Requirements
- Recent Major Generation Retirements
- NJ Offshore Wind (Partial)

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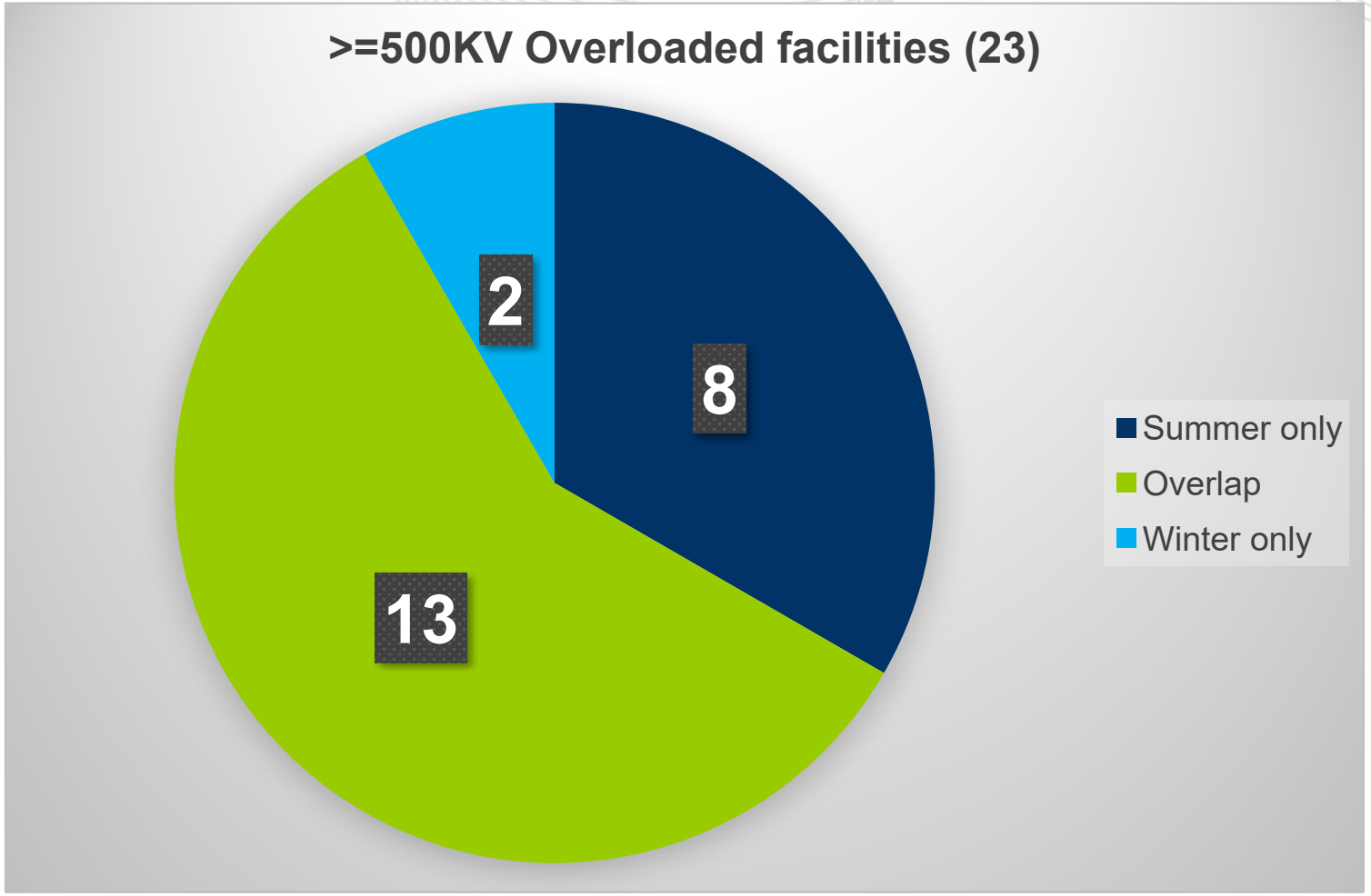
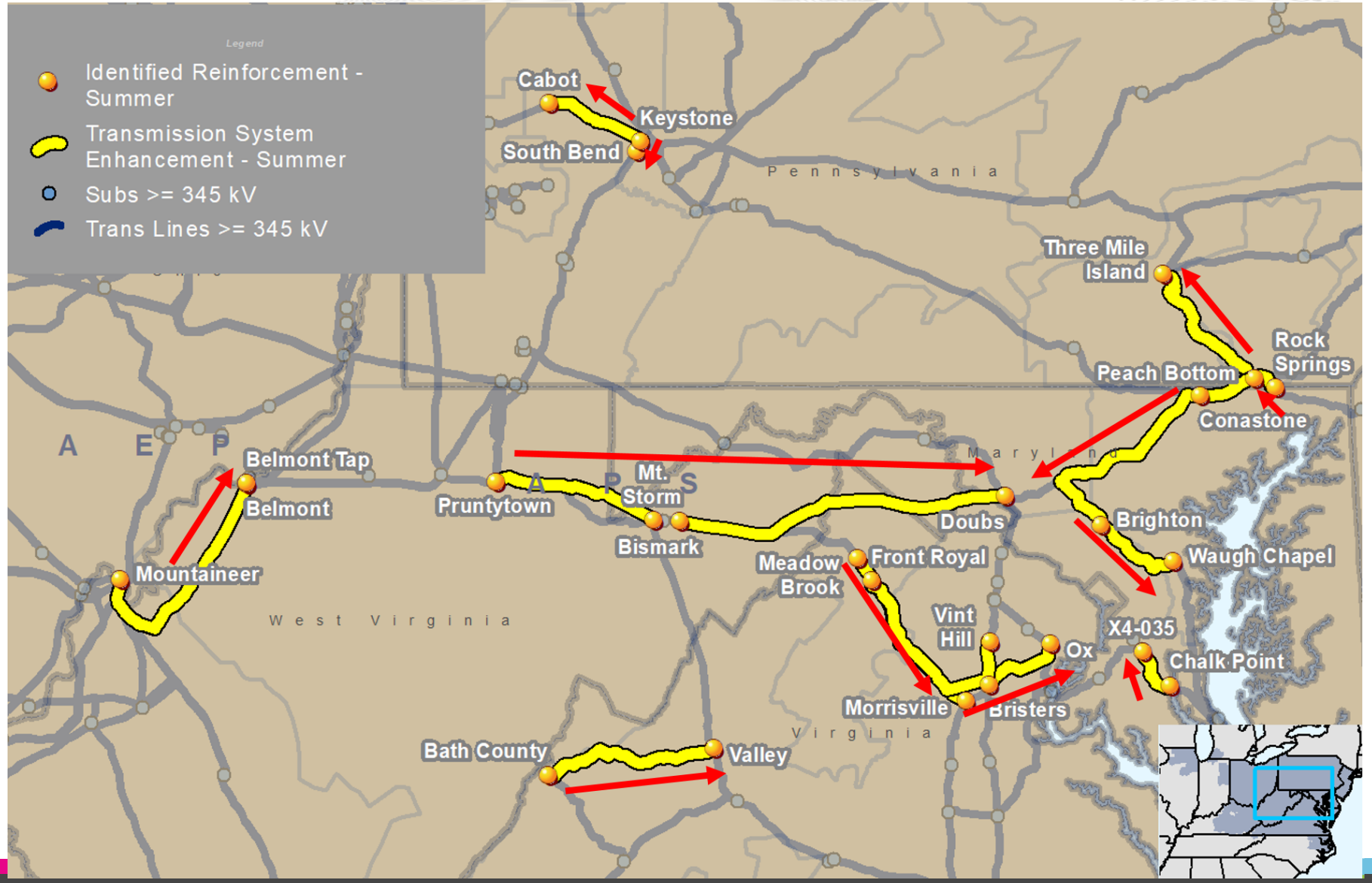
High Level Summary



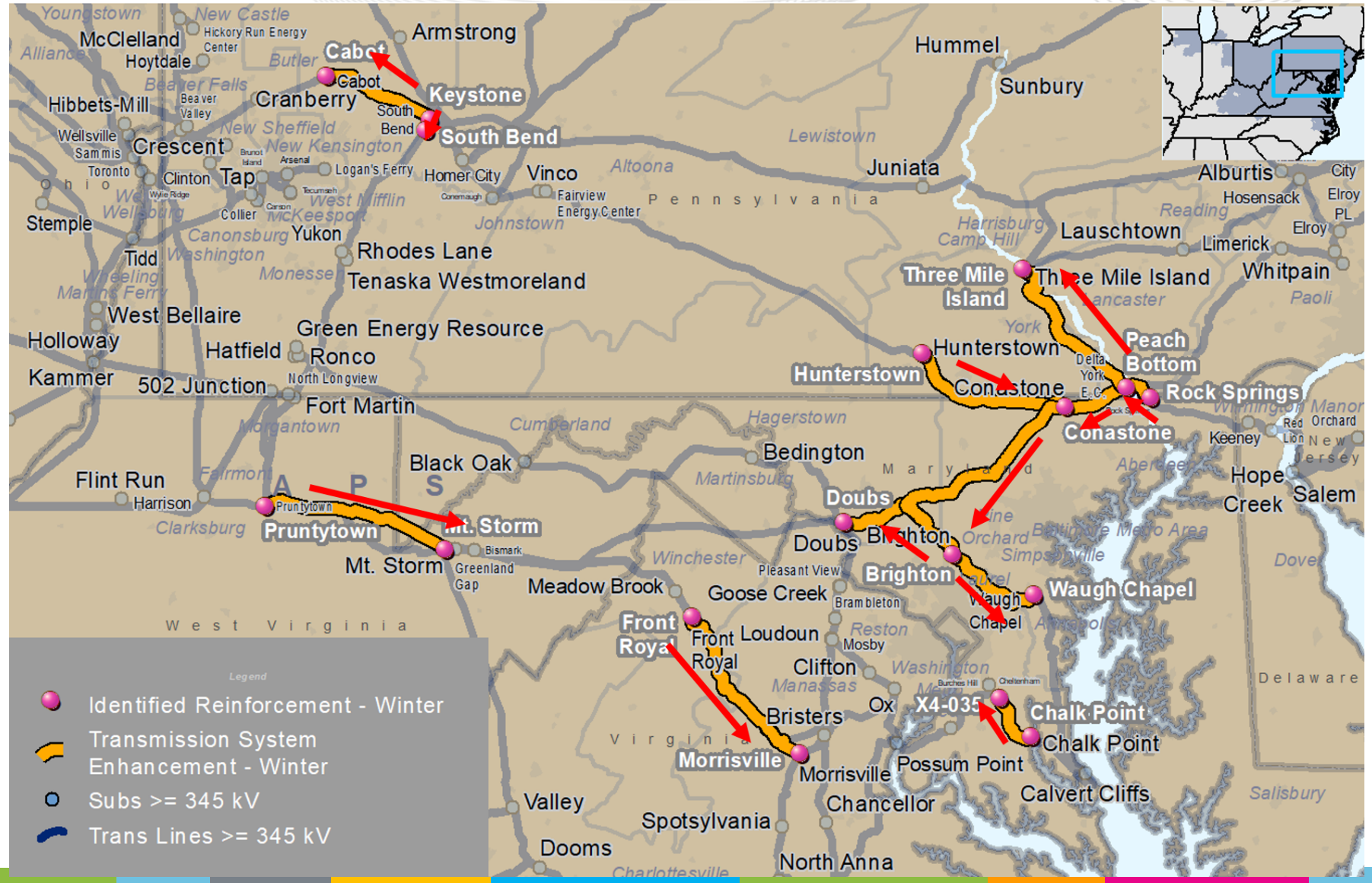
PJM©2023

Overloaded 500kV and above facilities in Summer Gen Deliv



PJM©2023

Overloaded 500kV and above facilities in Winter Gen Deliv



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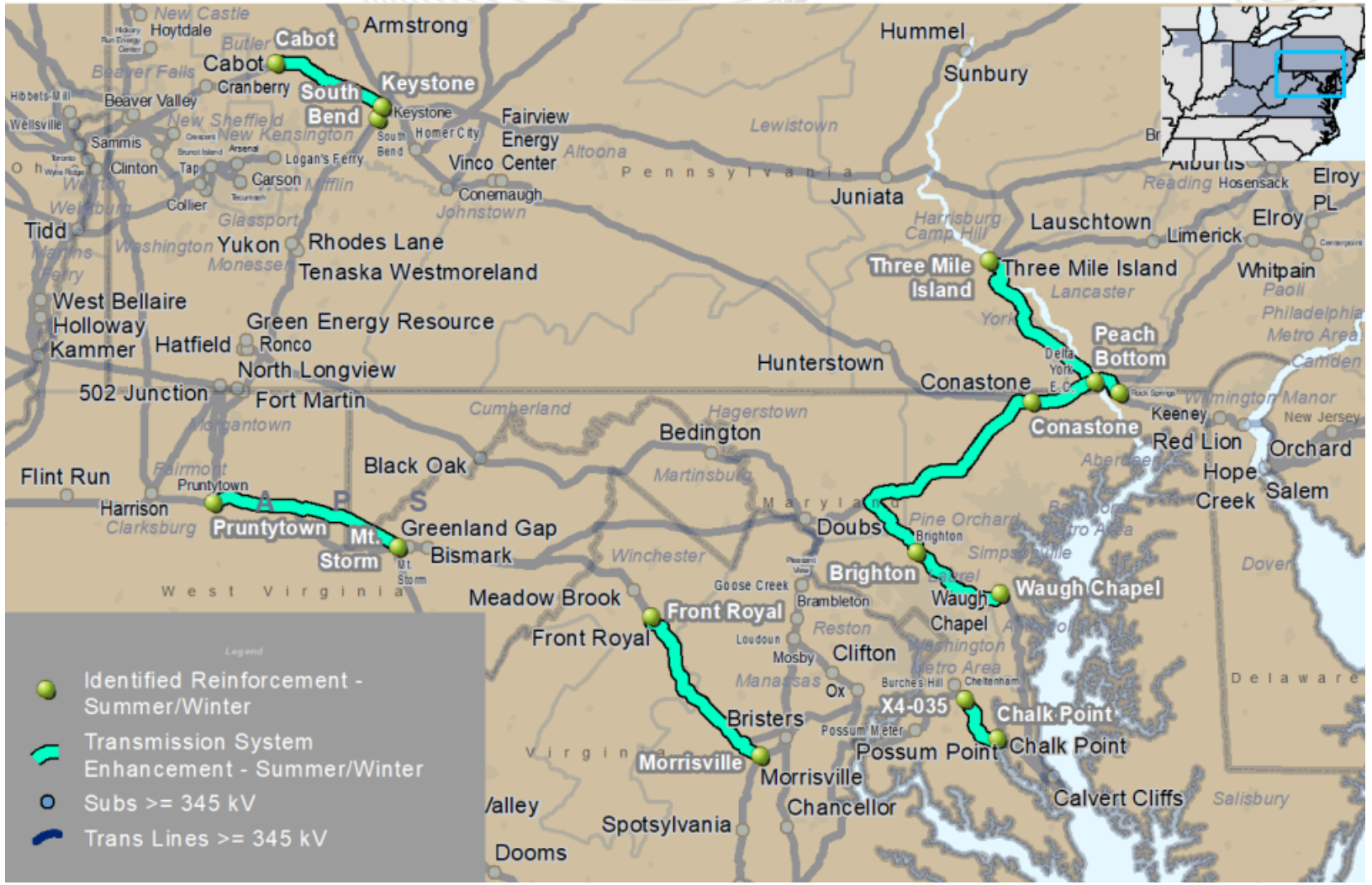
Overlap between Summer and Winter Violations



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Overloaded 500kV and above facilities

Fr Bus	Fr Name	To Bus	To Name	CKT	kVs	Summer	Winter
235110	01MDWBRK	313440	8VINTHIL	1	500	Y	N
235112	01PRNTY	314937	8MT STORM2	1	500	Y	Y
242920	05BELMON	235102	01BELMNT	5	765/500	Y	N
242516	05MOUNTN	242920	05BELMON	1	765	Y	N
314901	8BATH CO	314991	8VALLEY SC	1	500	Y	N
314941	8BISMARK	235105	01DOUBS	1	500	Y	N
314900	8BRISTER	314919	8OX	1	500	Y	N
314929	8FRONT ROYAL	314916	8MORRSVL	1	500	Y	Y
314916	8MORRSVL	313440	8VINTHIL	1	500	Y	N
314991	8VALLEY SC	314926	8VALLEY	1	500	Y	N
200003	BRIGHTON	200025	W CHAPEL	1	500	Y	Y
200018	CHALK PT	200301	X4-035 TAP	1	500	Y	Y
200004	CNASTONE	200003	BRIGHTON	1	500	Y	Y
200011	KEYSTONE	235118	01SOBEND	1	500	Y	Y
200011	KEYSTONE	235104	01CABOT	1	500	Y	Y
200066	PCHBTM1N	200016	3 MILE I	1	500	Y	Y
200066	PCHBTM1N	200065	PCHBTM2S	2	500	Y	Y
200064	PCHBTM1S	200004	CNASTONE	1	500	Y	Y
200065	PCHBTM2S	200064	PCHBTM1S	Z1	500	Y	Y
200065	PCHBTM2S	200064	PCHBTM1S	Z2	500	Y	Y
200065	PCHBTM2S	200066	PCHBTM1N	2	500	Y	Y
200051	ROCKSPGS	200065	PCHBTM2S	1	500	Y	Y
200003	BRIGHTON	235105	01DOUBS	1	500	N	Y
200026	HUNTERTN	200004	CNASTONE	1	500	N	Y

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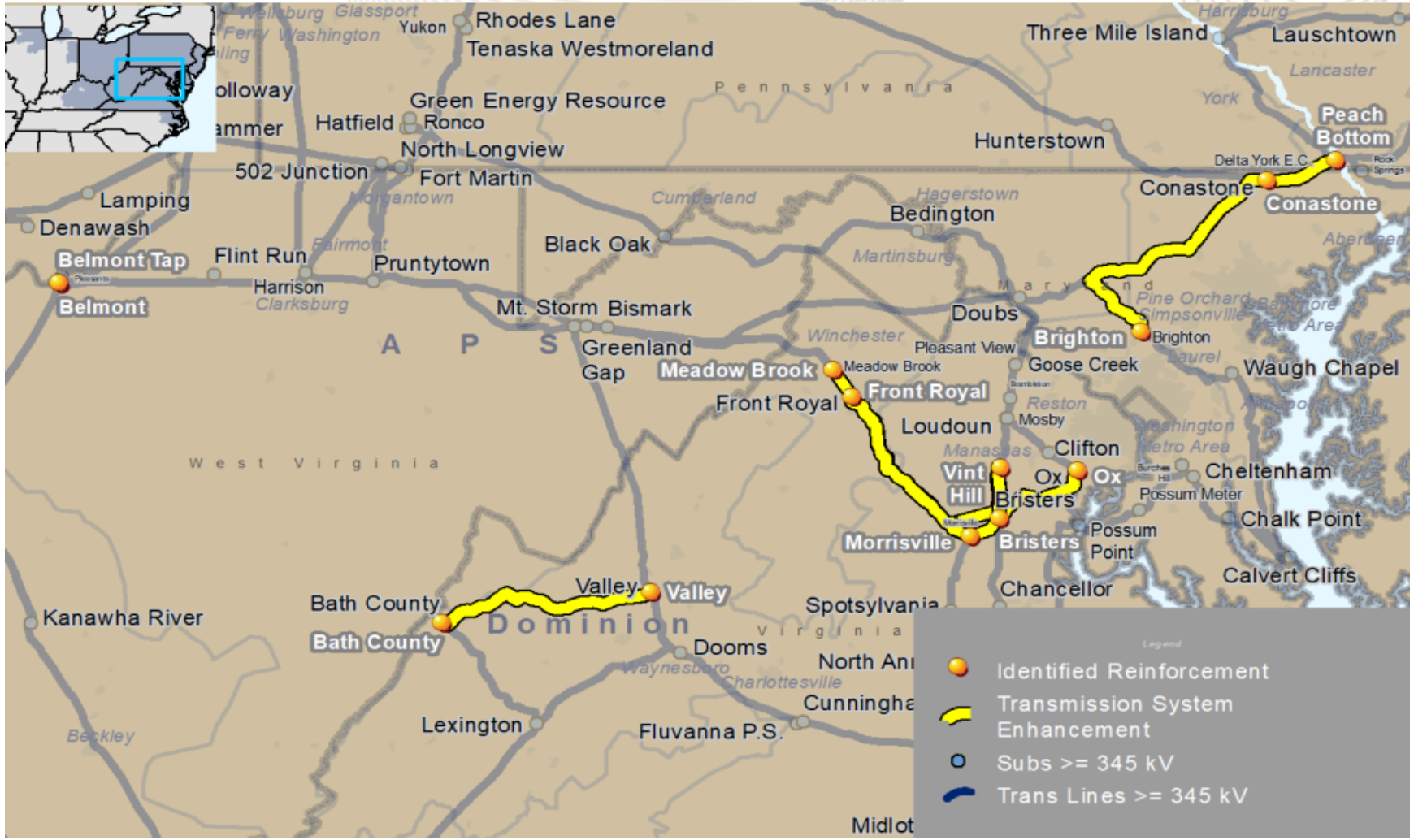
500kV and above Facilities Limited by Conductor



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List of Facilities Limited by Conductor Summary

Fr Bus	Fr Name	To Bus	To Name	CKT	kVs	Areas	Pre Contingency Loading	Number of Single Contingencies and Worst Loading	Number of Breaker Contingencies and Worst Loading	Number of Tower Contingencies and Worst Loading	Number of Bus Contingencies and Worst Loading
235110	01MDWBRK	313440	8VINTHIL	1	500	201/345		(1)103%	(4)113%		
242920	05BELMON	235102	01BELMNT	5	765/500	201/205		(3) 110%	(3) 136%		
314901	8BATH CO	314991	8VALLEY SC	1	500	345		(1) 102%			
314900	8BRISTER	314919	8OX	1	500	345				(1) 104%	
314929	8FRONT ROYAL	314916	8MORRSVL	1	500	345		(1) 113%			
314916	8MORRSVL	313440	8VINTHIL	1	500	345		(7) 123%	(10) 131%	(3) 132%	
314991	8VALLEY SC	314926	8VALLEY	1	500	345		(1) 102%			
200004	CNASTONE	200003	BRIGHTON	1	500	225	185%	(13) 183%	(11) 188%	(12) 210%	(13) 179%
200064	PCHBTM1S	200004	CNASTONE	1	500	225	213%	(12) 188%	(15) 197%	(13) 195%	(12) 192%
200066	PCHBTM1N	200065	PCHBTM2S	2	500	225			(2) 141%		
200065	PCHBTM2S	200064	PCHBTM1S	Z1	500	225	100%	(2) 147%	(4) 215%		
200065	PCHBTM2S	200064	PCHBTM1S	Z2	500	225	114%	(9) 200%	(9) 211%	(4) 103%	(3) 105%

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Summary on the >= 500kV overloaded facilities

12 facilities are limited by conductor and expect to drive regional solutions

- **North:** Peach Bottom-Conastone –Brighton 500KV path is the most severe overload in the study (and overloaded in window 3). Peach Bottom 500kV station buses are heavily overloaded.
  - Loss of the Peach Bottom – Conastone 500kV line causes overloads on 22 different 230KV circuits
  - Loss of the Conastone – Brighton 500kV line causes overloads on 23 different 230kV circuits
  - Reinforcing the Peach Bottom-Conastone-Brighton path will relieve/avoid the associated 230 kV overloads in addition to addressing the existing 500kV path overload.
- **South:**
  - Morrisville – Vint Hill 500kV line and Bath County – Valley 500KV line are overloaded in Window 3,
  - The proposed solution for the above line could potential address/impact Meadow Brook – Vint Hill 500kV, Morrisville –Front Royal 500KV and Brister – OX 500KV overloads.
- **West:**
  - Belmont 765/500kV transformer

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Summary on the >= 500kV overloaded facilities -Continued

11 facilities are terminal equipment limited, can be addressed by substation equipment upgrades (subject to confirmation)

- **North:**
  - Peach Bottom – TMI 500KV line
  - Brighton – Doubs 500kV line
  - Chalk Point – X4-035 Tap 500kV line
  - Huntertown – Conastone 500kVline
  - Brighton – Waugh Chapel 500kVline
  - Rockspring – Peach Bottom 500KVline

- **West:**
  - Pruntytown –Mt. Storm 500kV line
  - Mountaineer - Belmont 765kV line
  - Bismark - Doubs 500KV line
  - Keystone – South Bend 500kV line
  - Keystone – Cabot 500kV line

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Key Takeaways

- Preliminary 2028 RTEP needs further affirm the earlier identified needs under 20227 RTEP W3 and the need for robust solutions.

- 2027 RTEP W3 solutions need to be robust
  - ➢ This allows for prudent right sizing of solutions
  - ➢ Solutions offered under 2027 W3 need to be “compatible” with the needs identified part of the 2028 RTEP.
  - ➢ Minimizes scope of the planned 2028 RTEP retool (towards end of 2023); enhances efficiency and timely development.

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1	4/26/2023	• Original slides posted

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Reliability Analysis Report

2022 RTEP Window 3

December 8, 2023 – R3

For Public Use

The information contained herein is based on information provided in project proposals submitted to PJM by third parties through its 2022 RTEP Window 3. PJM analyzed such information for the purpose of identifying potential solutions for the 2022 RTEP Window 3. 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.

This maps contained in this report are only intended to illustrate the general electrical connectivity of the projects and should not be relied upon for exact geographical substation locations or line routes.

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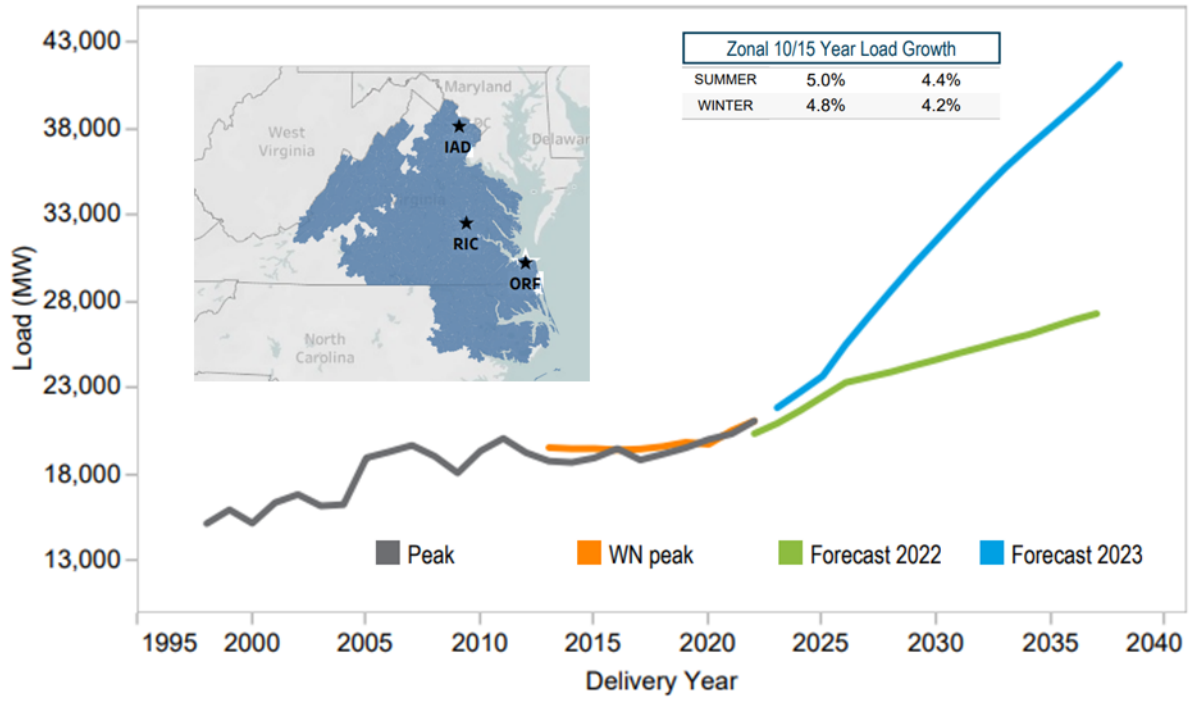
2022 RTEP Window 3 Reliability Analysis

Background

In early 2022, PJM shared its 2022 load forecast, which indicated high data center load growth activity, particularly in northern Virginia. In July 2022, PJM directed an immediate need transmission enhancement project to enable the integration of the forecasted data center load up to and including year 2025. Since then, data center loads within northern Virginia have been increasing at an unprecedented rate, and new data center load is being proposed in Maryland near the Doubs substation. As shown in **Table 1**, the recorded actual summer peak in 2022 was 21,156 MW while the 2022 forecast called for 20,424 MW. In an effort to stay ahead of these rapid increases, PJM continued its consultation efforts with Transmission and Distribution Owners in the area to refine its forecast and further enhance its need assessment.

PJM began receiving near and long term forecast input from Dominion, First Energy and NOVEC for data center load growth projections up to and including 2038 (15-year planning horizon). The PJM 2023 forecast calls for between 4.2% and 5.0% annual load growth in the Dominion area over the next 10- to 15-year time frame as shown in **Figure 1** below. The Load Forecast information was refined and modeled at a bus/substation level for the 2028 and 2030 study years, and PJM reassessed the transmission development needs in the area based on the refined forecast information and localized allocation of load.

Figure 1. Dominion 2023 Summer Peak Load Forecast



The data center load growth rate (currently concentrating in areas of northern Virginia) continues to increase. FirstEnergy's APS zone (just north of Virginia) is also experiencing data center load development, driving high flows within the northern Virginia transmission system, into the data center concentrated load pocket. The 2027 and 2027/28 study cases summer zonal load for Dominion and First Energy is provided in **Table 1**.

There are regional flows from the following:

- West and East toward Doubs-Goose Creek
- South into and out of Bristers toward Loudon

Major voltage support needs within Dominion and APS will be required. Some of the voltage violations are observed under N-0 conditions (fictitious MVARs were modeled in order to solve the case), and heavy regional transfers will require additional reinforcements to support the regional transfers.

Table 1. 2027/28 Case Summer Zonal Load for Dominion and FirstEnergy

	Summer Zonal Load (MW)	
Study Case	**Dominion/NOVEC**	**FirstEnergy (APS)**
2022 Peak	20,424 (forecast)/21,156 (actual)	8,675 (forecast)/8,412 (actual)
2027 RTEP	23,681	8,780
2027 Baseline	26,393	9,607
2027 High Load Growth	28,893	10,559
2028 RTEP (2023 Load Forecast)	28,705	9,568
Data Center Component Load (modeled in cases)	~5,700	~1,500

Case Development

2027

The 2022 RTEP Window 3 cases are based upon the 2022 RTEP, five-year out 2027 case with the following included:

- 2027 Dominion immediate need solution b3718
- 33 Dominion supplemental projects presented through the M-3 process from January to September of 2022
- Bus level data center load additions
- Summer, winter and light load cases were developed for baseline and high load growth scenarios

The immediate need baseline project, b3718, builds a new 500/230 kV substation called Wishing Star near Brambleton substation and installs 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.

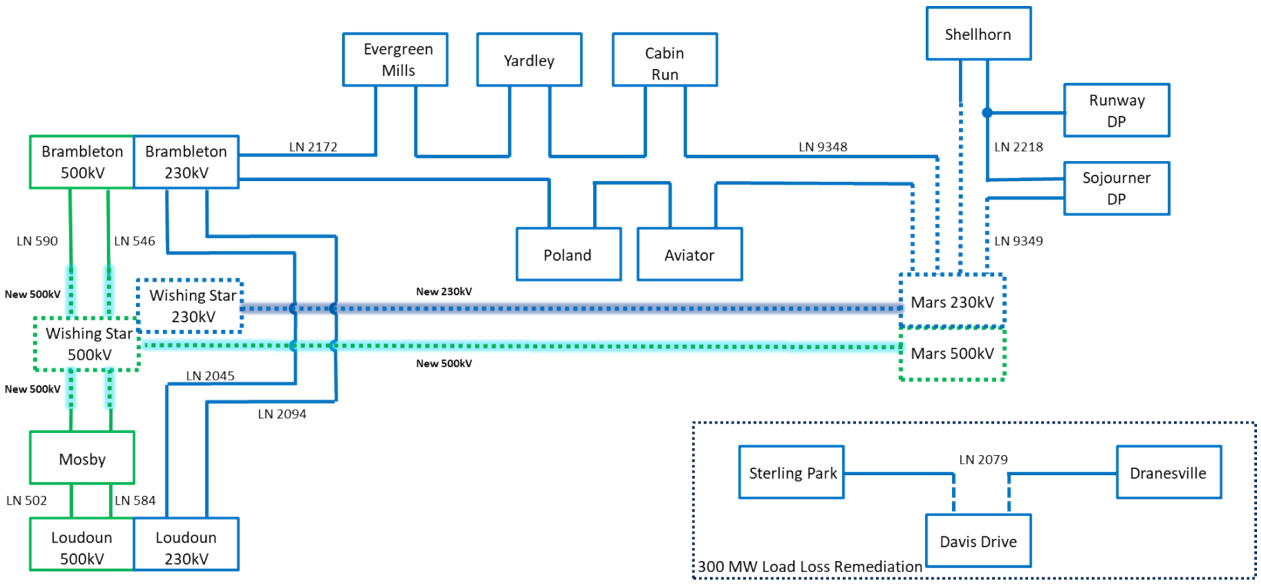
The project will reconductor the approximate mileage of the following lines:

- 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)
- 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. **Figure 2** below shows a high-level illustration of the project scope. The PJM Board approved cost for this project is $627.62 million. This project is identified as immediate need, with a required in-service date of June 2025. The projected in-service date for all project components is December 2026. The local transmission owner, Dominion, was designated to complete this work.

Figure 2. Dominion Immediate Need Solution b3718



2028

In addition to the data center load growth currently forecasted by 2027/2028 in Dominion (northern Virginia) and APS (Doubs) zones, there are a number of additional drivers necessitating the need for transmission development. Over the past two years, there has been approximately 11,100 MW of announced generator deactivations to the west and south of Conastone, about 5,300 MW of which occurred after the Window 3 2027 case was created. The replacement generation is coming from the region to the east of Peach Bottom as well as west of Doubs to meet projected load growth.

PJM has also implemented a new block dispatch procedure in the 2023 RTEP that more accurately reflects real-time operations dispatch and no longer tries to maintain historical intraregional transfer levels. The old dispatch procedure would have dispatched most of the generators in the Dominion zone at 100% or higher to maintain historical regional interchange. The 2028 case is subject to new generator deliverability testing requirements. After observing initial

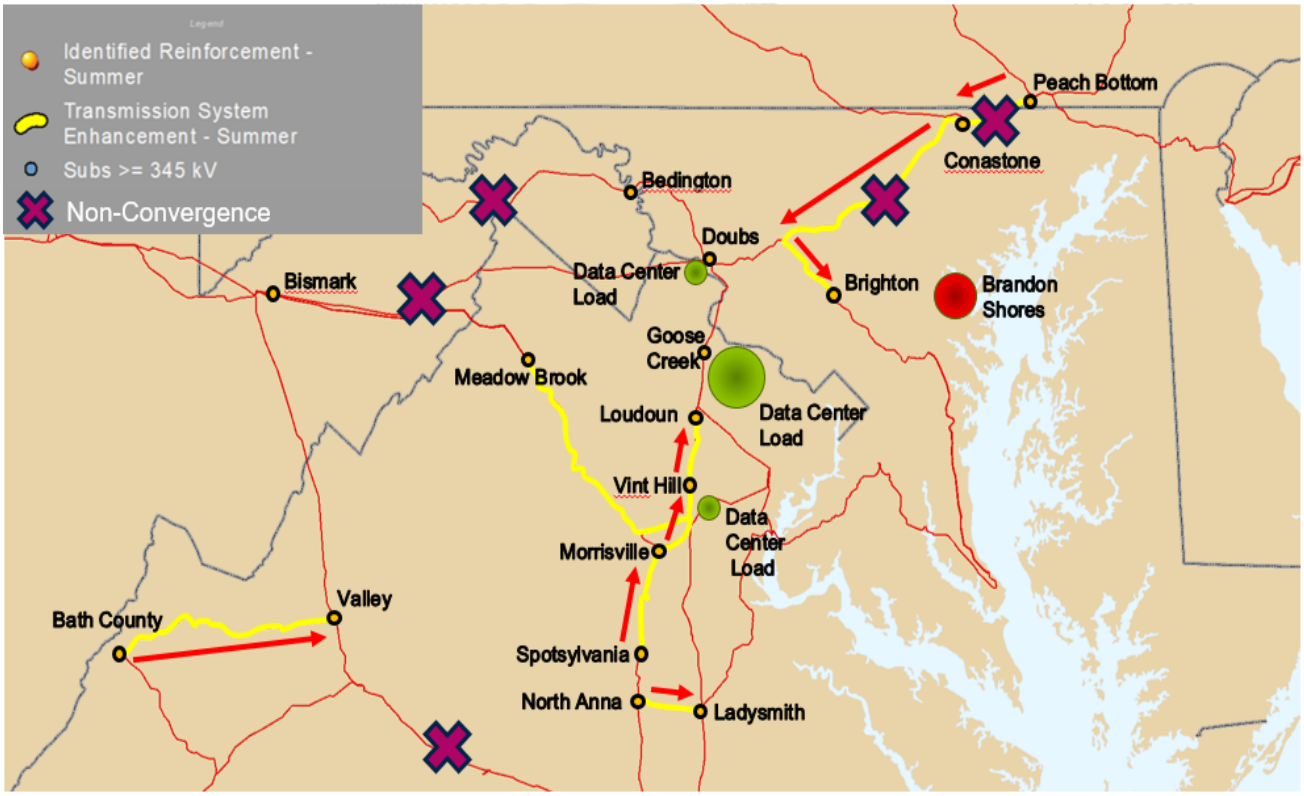
2028 analysis results, which showed an increased number and severity of overloads, PJM determined it would be prudent to utilize the 2028 cases to evaluate the proposals for robustness.

Window Objective

The objective of the 2022 RTEP Window 3 is to develop robust, holistic and expandable solutions that address the 2027/28 baseline violations as illustrated in **Map 1** associated with:

- **Local Constraints:** Resulting from directly serving the data center loads in APS and Dominion zones through the respective 230 kV networks and into the points of delivery:
  - Goose Creek-Ashburn-Mars-Wishing Star and Brambleton
- **Regional Constraints:** Resulting from imports into load center areas (500 kV primarily):
  - Doubs-Goose Creek
  - Front Royal-Morrisville-Vint Hill-Loudoun/Mosby
  - Meadow Brook-Loudoun/Mosby
  - Morrisville-Bristers-Ox
  - Peach Bottom-Conastone-Brighton-Doubs
- **Reactive Power Needs:** Needed reactive power MVAR reinforcements, both static and dynamic as deemed necessary, to address the reactive power needs of the system for the 2027/28 baseline scenario
- **Cummulative Impact of Generation Changes and Deactivations**:
  - 11,100 MW of announced deactivations to the west and south of Conastone
  - Approximately 5,300 MW occurring after the 2022 RTEP 2027 case was created
  - The vast majority of the new generation with signed ISAs has been solar, which has low availability during the winter period.
  - The replacement generation is coming from the region to the east of Peach Bottom as well as west of Doubs to meet projected load growth.
  - PJM has implemented a new block dispatch procedure.
  - The old dispatch procedure in the past (including that implemented in the 2027 study cases) maintained historical intraregional transfers, dispatching most of the generators in the Dominion zone at 100%.
- **Adherance to All Applicable Criteria:** The recommended solution must adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and local Transmission Owner FERC 715 criteria.

Map 1. 2022 RTEP Window 3 Map of Regional/Local Needs



Reliability Solutions and Initial Screening

PJM received 72 proposals from ten different entities as part of this window (**Table 2**). Of the ten proposing entities, six were incumbent Transmission Owners (TOs) and four were non-incumbent entities. PJM received 22 proposals that are upgrades, and received 50 greenfield proposals. The total cost of all proposals, not all of which are required, add up to approximately $54.4 billion. The proposals include:

- 230 kV, 500 kV and 765 kV developments
- HVDC developments
- Underground 500 kV AC cable developments
- 500 kV GIS substations
- Double circuit 500 kV proposals

Proposal Clusters/Groupings

The below **Map 2** shows the regional nature of the proposals, concentrating in four clusters: West, South, East, and Northern Virginia data center areas. Each cluster included proposals by different entities in the same need area and/or addressed the same local/regional needs.

Map 2. Regional Clusters

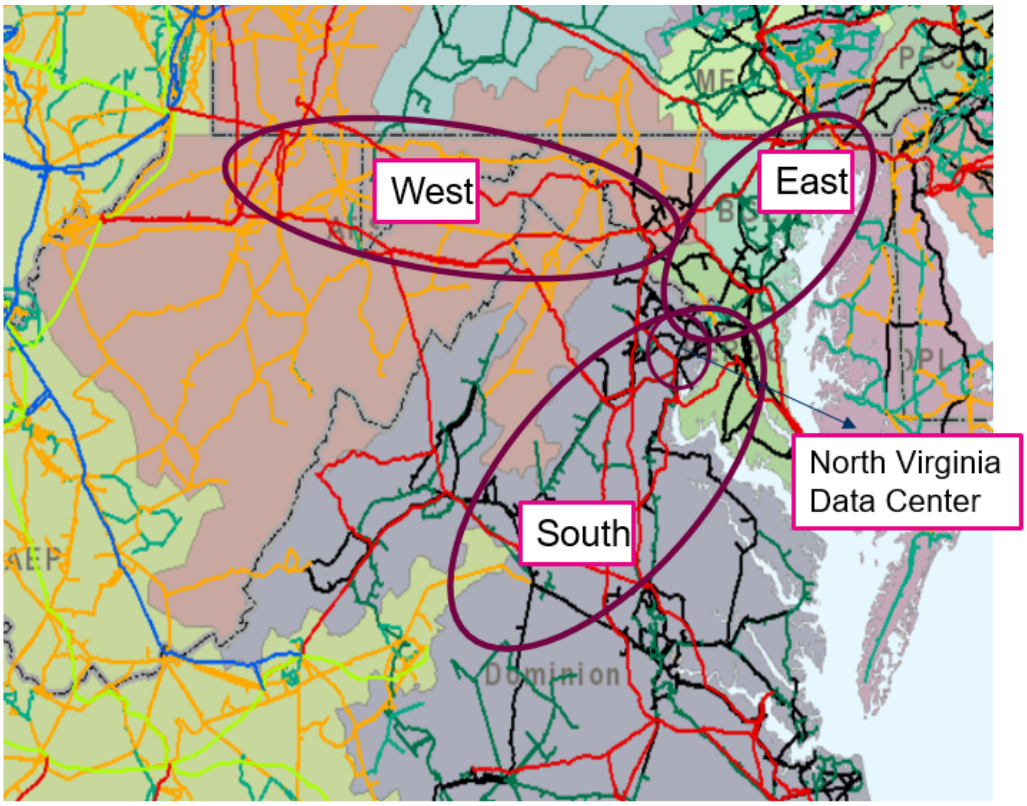


Table 2. 2022 RTEP Window 3 Submitted Proposals

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
1	9	AEP	Local AEP	Scottsville-Bremo Sag Study	$1.27
2	55			Boxwood-Scottsville 138 kV Rebuild	$104.88
3	181			Boxwood-Scottsville 138 kV Sag Study	$4.26
4	196			Glen Lyn-Peters Mountain Rebuild	$21.89
5	202			Cloverdale Transformer Addition	$57.29
6	234			Glen Lyn-Peters Mountain Sag Study	$0.80
7	410			Cloverdale Breaker Reconfiguration	$11.59
8	477			Fieldale-Franklin Rebuild	$74.89
9	524			Opossum Creek and New London Reactors	$8.86
10	537			Fieldale-Franklin Sag Study	$30.19
11	629			Scottsville-Bremo Rebuild	$31.31
12	856			Leesville-Altavista Rebuild	$28.85
13	487	AEP - Transource	Combo	Maryland & Pennsylvania Baseline Reliability Solution	$492.75
14	858		South	Stork-Flys 500 kV Greenfield Line and Substations	$510.44
15	904		Combo	Joshua Falls-Yeat 765 kV Greenfield Line and Substation	$1,048.10
16	977		South	Yeat 500/230 kV Greenfield Station	$232.14
17	30	Dominion	Local DOM	Charlottesville-Hollymead Line No. 2054 Rebuild	$159.87

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
18	74	Dominion	Local DOM	Line No. 2090 (Ladysmith CT-Fredericksburg) Rebuild	$57.34
19	129		South	Dominion Aggregate 500 kV Proposal	$3,035.05
20	211		Local DOM	Hollymead-Gordonsville Line No. 2135 Rebuild	$54.85
21	231			Reactive Power VAR Reinforcements	$155.82
22	516		East	Interregional solution- Aspen-Doubs Second 500 kV Line	$61.72
23	671		South	Line No. 541 (Front Royal to Morrisville) Rebuild	$299.03
24	692		South	Data Center Alley Local solution-New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	$1,058.45
25	704		Local DOM	Hollymead-Gordonsville Line No. 2135 Rebuild	$36.89
26	711		South	Regional Solution-500 kV North Anna-Wishing Star Upgrades	$1,227.84
27	731		Local DOM	Locks Substation 230/115 kV Transformer Upgrade	$7.14
28	923		South	Second 500 kV line from Lexington to Dooms	$232.18
29	967		Local DOM	Charlottesville-Hollymead Line No. 2054 Rebuild	$183.48
30	548	LSPower	Scenario	RTEP Window 3 Solution	$2,404.48
31	28	NextEra	East/West	Hunterstown-Doubs-Goose Creek, Black Oak-Pike-Goose Creek, Pike SVC + Cap Banks	$884.05
32	116			Hunterstown-Doubs-Gant Solution	$478.87
33	175		Scenario	Combination of PEBO 215A + WOP 1F + SOP 8E	$6,265.95*
34	217		East	North Delta-Conastone Solution	$155.99
35	255		West	Hunterstown-Doubs-Gant Solution	$411.61
36	279			Black Oak-Woodside-Goose Creek, Woodside SVC + Cap Banks Solution	$429.18
37	347			Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$483.83
38	385		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$1,140.73
39	419		East/West	Hunterstown-Doubs-Audobon-Goose Creek	$548.75
40	445		East	Muddy Creek/Delta-Conastone/Hunterstown-Doubs-Goose Creek Solution	$637.80
41	530			Muddy Creek/North Delta-Conastone Solution	$166.74
42	564			New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$876.88
43	577		South	Front Royal-Racefield, Warrenton-Wheeler, North Anna-Lady Smith	$258.38
44	598		Scenario	Combination of PEBO 220 + WOP 1F + SOP 8E	$2,036.47
45	631		East	Muddy Creek/North Delta-Conastone Solution	$184.47
46	642		West	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table	$747.31
47	663		South	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	$284.17
48	676	NextEra	West	Black Oak-Stonewall-Gant, Stonewall SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table Solution	$552.49
49	685			Ft. Martin-Black Oak-Woodside, Woodside SVC + Cap Banks Solution	$609.78
50	719			Ft. Martin-Black Oak-Pike, Pike SVC + Cap Banks Solution	$600.90

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
51	728			Barnhart Substation, Bartholow Substation, Barnhart-Bartholow-Goose Creek solution	$385.36
52	766		South	Front Royal-Racefield, Warrenton-Wheeler	$239.59
53	846		West	Hunterstown-Doubs-Goose Creek, Black Oak-Woodside-Goose Creek, Stonewall SVC + Cap Banks	$892.94
54	853			502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$683.55
55	948		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.	$5,381.25*
56	951		West	Black Oak-Gore-Goose Creek, Pike SVC + Cap Bank Solution	$419.86
57	344	PECO	East	PECO Expansion Plan for DOM Window 2023	$302.86
58	600		Local Other	Exelon Replacement Upgrades	$423.79
59	660	PEPCO	East	West Cooper BGE-PEPCO	$1,105.62
60	691			Mid-Atlantic Power Pathway (MAPP)	$1,990.28
61	23	POTOED - FirstEnergy	Combo	Data Center Reinforcement Proposal No. 2	$3,503.86
62	837			Data Center Reinforcement Proposal No. 1	$2,991.77
63	374	PPL	East	Otter Creek-Conastone 500 and 230 kV DCT Line	$154.21
64	606		Local Other	Juniata-Lewistown 230 kV No. 2 line	$141.16
65	24	PSEG	East	Proposal A-North Delta-New Raphael-Waugh Chapel 500 kV	$739.40
66	125		Local Other	Proposal B-North Delta-Northeast 230 kV	$313.34
67	229		East	Proposal C-Hunterstown-New Green Valley 500 kV	$529.11
68	325		Combo	Proposal E-Brambleton-Hinsons Ford Rd 500 kV	$944.05
69	637		East	Proposal D-Conastone-Doubs 500 kV	$684.22
70	741			Proposal G-Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	$1,065.32
71	808			Proposal F-Peach Bottom-New Raphael-Waugh Chapel 500 kV; Peach Bottom-Doubs 500 kV	$1,150.80
72	962			Proposal H-Peach Bottom-Doubs 500 kV (Circuits No. 1 and No. 2)	$977.71
				Total:	**$54,408.06**

**The proposal cost was increase due to cost revision provided by proposing entity from approximately $1.6 billion to $5.4 billion.*

Proposal Screening

PJM performed a generator deliverability screening of all proposals on the 2027 cases to obtain a preliminary understanding of performance. It is important to note that many of the proposals are not intended to be standalone projects, as they are intended to be combined with other proposals in order to address flowgate violations. **Table 3** and **Table 4** summarize the performance evaluation results of all 72 submitted proposals. The tables summarize the intended flowgates by each proposal as specified in the proposing entity submission, the remediated flowgates as confirmed by PJM testing, the total addressed/unaddressed flowgates out of all window flowgates and whether the proposal, on its own, introduces any new flowgates. Where a high number of unaddressed flowgates are shown in the

Table 3, such as for some of Dominion and NextEra proposals, the specific proposals are either combined with other entitys' proposals and/or part of a larger scenario proposal.

Table 3. 2027 Proposal Summary by Number of Flowgates (FG)

#	ID	Proposing Entity	Focus Area	Project Intended FG	Remediated FG Intended	Unaddressed FG Intended	Addressed FG Posted (out of 527)	Unaddressed FG Posted (out of 527)	New FG Attributed to Project
1	9	AEP	Local AEP	0	0	0	36	491	13
2	55			16	16	0	61	466	17
3	181			16	14	2	55	472	6
4	196			1	1	0	44	483	17
5	202			1	1	0	43	484	11
6	234			1	1	0	43	484	10
7	410			1	1	0	180	347	79
8	477			2	2	0	176	351	81
9	524			2	2	0	176	351	82
10	537			2	2	0	169	358	20
11	629			0	0	0	175	352	83
12	856			2	1	1	175	352	87
13	30	Dominion	Local DOM	3	3	0	47	480	22
14	74[1]			108	4	104	44	483	7
15	129[1]		South	117	84	33	149	378	46
16	211[1]		Local DOM	113	7	106	52	475	11
17	231[1]			108	11	97	58	469	16
18	516		PB-C	15	15	0	195	332	25
19	671		Local DOM	0	0	0	43	484	8
20	692		South	62	62	0	127	400	11
21	704		Local DOM	2	2	0	49	478	7
22	711		South	35	33	2	127	400	143
23	731[1]		Local DOM	108	4	104	47	480	7
24	923		South	3	3	0	49	478	11
25	967[1]		Local DOM	114	7	107	47	480	22
26	600	Exelon	Local Other	126	124	2	287	240	81
27/28	660/344		PB-C	96	96	0	309	218	91
29	23[1]	FE (POTOMAC)	Combo	501	419	82	433	94	35
30	837[1]			501	421	80	434	93	21
31	548	LS Power	Scenario	515	509	6	518	9	32
32	28[1]	NextEra	West	339	263	76	306	221	102
33	116[1]			294	246	48	275	252	66
34	217[1]		PB-C	170	139	31	244	283	82
35	255[1]		West	298	189	109	249	278	86

[1] These proposals are designed to work in tandem with other proposal components submitted by the same proposing entity. The performance of these proposals is further judged through the scenario analysis exercise instead of individually only

#	ID	Proposing Entity	Focus Area	Project Intended FG	Remediated FG Intended	Unaddressed FG Intended	Addressed FG Posted (out of 527)	Unaddressed FG Posted (out of 527)	New FG Attributed to Project
36	279[1]			260	170	90	239	288	102
37	347[1]			228	165	63	237	290	105
38	385		PB-C	378	372	6	500	27	313
39	419[1]		West	492	242	250	272	255	81
40	445[1]		PB-C	318	268	50	306	221	105
41	530			1	1	0	236	291	86
42	564[1]			375	333	42	355	172	38
43	577[1]		South	127	75	52	163	364	208
44	598		Scenario	634	630	4	510	17	10
45	631[1]		PB-C	181	150	31	248	279	93
46	642[1]		West	353	257	96	303	224	176
47	663[1]		South	170	100	70	166	361	211
48	676[1]		West	253	189	64	277	250	93
49	685[1]			299	210	89	265	262	227
50	719[1]			297	197	100	252	275	231
51	728[1]			494	189	305	206	321	153
52	766[1]		South	127	74	53	160	367	208
53	846[1]		West	344	270	74	314	213	102
54	853[1]			301	210	91	266	261	99
55	948[1]		PB-C	382	341	41	365	162	31
56	951[1]		West	220	162	58	231	296	111
57	175		Scenario	466	463	3	510	17	11
58	374	PPL	PB-C	8	8	0	142	385	27
59	606[1]		Local Other	14	10	4	46	481	17
60	24	PSEG	PB-C	158	148	10	286	241	76
61	125		Local Other	111	110	1	268	259	71
62	229[1]		PB-C	191	177	14	295	232	93
63	325[1]		Combo	192	168	24	304	223	81
64	637		PB-C	161	148	13	281	246	101
65	741			194	184	10	290	237	88
66	808			198	188	10	327	200	79
67	962			181	164	17	283	244	97
68	487	TRANSRC	Combo	317	307	10	438	89	5
69	858		South	63	61	2	169	358	18
70	904		Combo	148	142	6	295	232	39
71	977		South	26	26	0	196	331	26

NOTE: Proposal 691 case did not converge, so no results are shown.

[1] These proposals are designed to work in tandem with other proposal components submitted by the same proposing entity. The performance of these proposals is further judged through the scenario analysis exercise instead of individually only

Table 4. 2027 Proposal Summary by Number of Facilities

#	ID	Proposing Entity	Focus Area	No Longer Overloaded (out of 146)	Remaining Overloads (out of 146)	New Overloads
1	9	AEP	Local AEP	15	131	1
2	55			20	126	1
3	181			19	127	0
4	196			16	130	0
5	202			16	130	0
6	234			16	130	0
7	410			45	101	10
8	477			45	101	9
9	524			44	102	10
10	537			48	98	0
11	629			44	102	11
12	856			42	104	10
13	30	Dominion	Local DOM	19	127	0
14	74			17	129	0
15	129		South	43	103	6
16	211		Local DOM	17	129	0
17	231			15	131	1
18	516		PB-C	65	81	3
19	671		Local DOM	18	128	0
20	692		South	37	109	2
21	704		Local DOM	17	129	0
22	711		South	39	107	7
23	731		Local DOM	16	130	0
24	923		South	18	128	0
25	967		Local DOM	19	127	0
26	600	Exelon	Local Other	63	83	11
27/28	660/344		PB-C	60	86	22
29	23	FE (POTOMAC)	Combo	97	49	6
30	837			100	46	3
31	548	LS Power	Scenario	114	32	11
32	28	NextEra	West	52	94	16
33	116			50	96	13
34	175		Scenario	117	29	4
35	217		PB-C	54	92	10
36	255		West	44	102	16
37	279			41	105	7
38	347			41	105	7
39	385		PB-C	81	65	13

#	ID	Proposing Entity	Focus Area	No Longer Overloaded (out of 146)	Remaining Overloads (out of 146)	New Overloads
40	419		West	55	91	18
41	445		PB-C	58	88	21
42	530			53	93	12
43	564			81	65	13
44	577		South	32	114	25
45	598		Scenario	117	29	3
46	631		PB-C	54	92	16
47	642		West	64	82	17
48	663		South	38	108	26
49	676		West	56	90	5
50	685			45	101	25
51	719			43	103	21
52	728			40	106	23
53	766		South	33	113	26
54	846		West	49	97	16
55	853			49	97	9
56	948		PB-C	80	66	10
57	951		West	36	110	7
58	374	PPL	PB-C	32	114	1
59	606		Local Other	16	130	1
60	24	PSEG	PB-C	53	93	16
61	125		Local Other	59	87	12
62	229		PB-C	58	88	22
63	325		Combo	52	94	19
64	637		PB-C	51	95	18
65	741			58	88	18
66	808			70	76	16
67	962	PSEG	PB-C	56	90	19
68	487	TRANSRC	Combo	100	46	0
69	858		South	56	90	0
70	904		Combo	69	77	2
71	977		South	49	97	1

NOTE: Proposal 691 case did not converge, so no results are shown.

The proposals submitted by AEP were intended to address local AEP flowgates posted with the window and were not included in the cluster evaluations. The proposals were evaluated in the 2027 and 2028 cases and addressed the posted flowgate violations.

Regional Proposal Components

The first step to scenario development was to cluster the 500 kV and above proposal components to determine the more efficient or cost-effective combination of backbone solution components. **Table 5** through **Table 8** organize the backbone proposal components into regional clusters.

Table 5. East Cluster

Proposal ID	Proposing Entity	List Components
344/660-1	Exelon	Peach Bottom North-Graceton New 500 kV West Cooper-Peach Bottom South New 500 kV Line West Cooper-High Ridge 500 kV Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
344/660-2		West Cooper-Peach Bottom South New 500 kV Line West Cooper-High Ridge 500 kV Rebuild 5012 500 kV (will be looped in to West Cooper)
344/660-3		Peach Bottom North-Graceton New 500 kV West Cooper-Peach Bottom South New 500 kV Line Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
691		230 mile, 500 kV AC/400 kV DC (Possum Pt-Burches Hill-Cheltenham-Chalk Pt. Mission to Salem 500 kV) Hallowing (HVDC)-Mission (HVDC)
548	LS Power	Conastone-North Delta 500 kV
		Huntersdown-Doubs 500 kV
217	NextEra	North Delta-Conastone 500 kV
385/564		New Otter Creek-Bartholow (Conastone-Brighton tap, Doubs-Brighton Tap) 500 kV
385/564		North Delta-Conastone 500 kV
530		North Delta-Conastone 500 kV
948	NextEra	New Otter Creek-Bartholow (Conastone-Brighton tap, Doubs-Brighton Tap) 500 kV
948		North Delta-Conastone 500 kV
374	PPL	Otter Creek-Conastone 500 and 230 kV DCT Line
229	PSEG	Hunterstown-Green Valley 500 kV
24		N. Delta-New Raphael-W. Chapel 500 kV
325		N. Delta-New Raphael-W. Chapel 500 kV
637		Conastone-Doubs 500 kV
741		Peach Bottom-Brandon Shore 500 kV
741		Peach Bottom-Doubs 500 kV
808		Peach Bottom-Raphael-W. Chapel 500 kV
808		Peach Bottom-Doubs 500 kV
962		Peach Bottom-Doubs 500 kV (two lines)

Table 6. West Cluster

Proposal ID	Proposing Entity	List Components
23	FE	Fort Martin-Doubs 500 No. 1 & 2
23		Meadow Brook-Doubs 500 kV
23		Meadow Brook-Pruntytown 500 kV
837		Fort Martin-Doubs 500 No. 1
837		Meadow Brook-Doubs 500 kV
837		Meadow Brook-Pruntytown 500 kV
548	LS Power	502 Junction-Black Oak-Doubs 500 kV
279	NextEra	Black Oak-Stonewall-Goose Creek 500 kV
28		Black Oak-Gore-Goose Creek 500 kV
347		Black Oak-Stonewall-Goose Creek 500 kV
642		Build new 500 kV line from 502 Junction to Black Oak to Stonewall to new Belmont/Gant 500 kV
676		Black Oak-Stonewall-Goose Creek 500 kV
685		Build new 500 kV line from Fort Martin to Black Oak to Stone Wall to Goose Creek
719		Fort Martin to Black Oak to Gore to Goose Creek 500 kV
846		Black Oak-Stonewall-Goose Creek 500 kV
853		Build new 500 kV line from 502 Junction to Black Oak to Stonewall to new Belmont/Gant 500 kV
951		Black Oak-Gore-Goose Creek 500 kV
116		Hunterstown-Doubs 500 kV
255		Hunterstown-Doubs 500 kV
28		Hunterstown-Doubs 500 kV
419		Hunterstown-Doubs 500 kV
445		Hunterstown-Doubs 500 kV
116		Hunterstown-Doubs 500 kV
255		Hunterstown-Doubs 500 kV

Table 7. South Cluster

Proposal ID	Proposing Entity	List Components
711	Dominion	New 500 kV Line (North Anna-Spotsylvania)
711		New 500 kV Line (Spotsylvania to Vint Hill)
711		New 500 kV Line (Vint Hill to Wishing Star)
923		Second 500 kV line from Lexington to Dooms
548	LS Power	Front Royal-VintHill 500 kV
577	NextEra	Front Royal to New Wishing Star sub 500 kV
663		Front Royal to New Wishing Star sub 500 kV
766		Front Royal to New Wishing Star sub 500 kV
325	PSEG	Brambleton-Hinsons Ford 500 kV

Proposal ID	Proposing Entity	List Components
904	TRANSRC	Joshua Falls to Yeat 765 kV

Table 8. Northern Virginia Data Center Cluster

Proposal ID	Proposing Entity	List Components
516	Dominion	Aspen-Doubs Second 500 kV Line | Line No. 514 (Goose Creek-Doubs) Rebuild
692		Aspen-Golden 500 kV Line Build
692		New Mars-Golden 500 kV
692		Aspen to Goose Creek 500 kV
23	FE	Aspen-Doubs Second 500 kV Line | Line No. 514 (Goose Creek-Doubs) Rebuild
837		Aspen-Doubs Second 500 kV Line | Line No. 514 (Goose Creek-Doubs) Rebuild
548	LS Power	Doubs-Goose Creek 500 kV
548		Goose Creek-Beaumeade 500 kV
116	NextEra	Doubs-Gant (new Belmont) 500 kV
255		Doubs-Gant (new Belmont) 500 kV
28		Doubs-Goose Greek 500 kV
419		Doubs-Beaumeade-Goose Creek 500 kV
445		Doubs -Goose Creek 500 kV
846		Doubs-Goose Greek 500 kV
858	TRANSRC	Stork-Flys 500 kV Underground Line

Window 3 Evaluations Process

Consultation Meetings With Proposing Entities

PJM held two rounds of meetings with each of the proposing entities, and the discussions focused on gaining clarity on proposed developments, assumptions, rationale of proposed alternatives and variations. The first round of meetings were conducted in June/July of 2023, and the second round was initiated in late July and concluded mid-August. The latter half of the discussions focused on outage scheduling, routing, risk and cost assumptions and considerations. In addition to the primary two consultation rounds, several additional consultation meetings were organized by PJM with short-listed proposing entities to assist with refining and finalizing the 2022 Window 3 selected proposal list.

Scenario Development

PJM developed scenarios, which were combinations of proposals and/or components from different proposals, addressing all areas of need and evaluated them against the 2027 and 2028 2022 Window 3 base cases. Over 30 scenarios were analyzed for the 2027 model, and over 100 scenarios were developed and analyzed for the 2028 model. Certain scenarios were full combination scenarios submitted by the proposing entities, such as those

submitted by the incumbent Transmission Owners, or other entities including NextEra, LS Power and Transource. PJM also optimized scenarios using components from incumbent and non-incumbent proposing entities. Several scenarios were found adequate to address the needs present in the 2027 analysis; however, the 2028 evaluations show the need for more robust reinforcements in the Eastern cluster and introduced changes to solutions in the Southern cluster. The Western cluster needs are less sensitive, though still impacted by the robustness test. A number of proposals that were developed by proposing entities to address the 2027 needs specifically did not offer the needed scalability and robustness to address the needs posed by the 2028 system conditions. Please refer to the scenario list and abbreviated description provided in Appendix B.

The scenarios were evaluated based on the following principles:

- **Performance**
  - Meeting the system needs of 2027 and being flexible to address 2028 needs
- **Scalability**
  - Scenario/development longevity – system robustness and utilization
- **Impact**
  - Utilization of existing right of way (ROW) where possible and efficient.
- **Validated Cost**
  - Cost evaluation using third-party benchmarking metrics
- **Risks**
  - Triggering additional costs:
    - Substation rebuilds due to extreme short-circuit levels
  - Avoid extended critical outages (Peach Bottom/Conastone rebuilds)
  - Imposing high permitting
  - Inability to meeting in-service date
- **Efficiencies**
  - Avoidance of redundant capital investment including recognizing synergies with EOL facilities and overlaps of previously approved (or imminent) supplemental/baseline upgrades

The scenarios were developed and tested to first address the regional needs and then were refined through new scenarios to address local needs. Scenarios were further refined using more effective proposal components as demonstrated through their performance in the analysis.

2027 Reliability Evaluation Summary

As described earlier on in this report, initial screening was performed on all submitted individual proposals for 2027. These proposals included proposed upgrades at voltage levels of 230 kV to 765 kV. Some of the proposals attempted to address all four cluster needs and were evaluated as standalone scenarios. PJM also developed a scenario by combining the incumbent Transmission Owner proposals, along with further refined scenarios that

utilized select components from various proposals. The 2027 reliability analysis results indicated that all submitted combination proposals could address the 2027 needs to a varying degree. In order to test the robustness of the proposal, PJM evaluated the scenarios on the 2028 cases.

This section outlines the key needs identified as part of the PJM 2022 RTEP Window 3, together with a brief summary of how each of the key proposals addressed those needs in the 2027 study base case scenario.

Eastern Quadrant:

For the eastern quadrant, all submitted proposals acknowledged the need to reinforce the Peach Bottom to Doubs 500 kV transmission corridor via various 230 kV and 500 kV proposals. Generally, all combination proposals submitted by proposing entities addressed the reliability evaluation tests including Gen Deliverability and N-1 analysis with varying degrees. Some of the proposals that did not consider the robustness evaluation requirement part of the PJM 2022 RTEP Window 3 Problem Statement were not designed to handle the higher power transfer demands from the East toward West and hence offered little room beyond meeting the 2027 needs. These proposals are primarily LS Power proposal 548 and Transource combined proposal. Both LS Power and Transource indicated that their proposed solutions were neither designed considering the 2028 robustness and needs base case scenarios nor tested against the 2028 cases.

Exelon proposal 344/660, PSEG proposal 229, 637, 741 ,808, Nextera proposal 217, 385, 445, 728, 948, PPL proposal 374 and Ls Power proposal 548 all proposed 500 kV transmission line developments to address the debottlenecking need of the Peach Bottom to Conastone corridor as well as provide additional supply into the northern Virginia system.

Western Quadrant:

In the west, three proposing entities (First Energy, Nextera and LS Power) offered 500 kV transmission developments to address the higher APS to northern Virginia (West to East) transfer capability needs. One entity (Transource) proposed a 765 kV development. All of these developments proved adequate, from a technical transfer capability perspective, in addressing the identified needs in the western quadrant either in combination or individually.

It is to be noted that although the proposed 765 kV development by Transource has merits from diversifying the West-East transfer path over a wider geographic area, it does pose its own routing, siting and construction risks that may delay meeting the needs in the area in 2027 or as close to that timeline as possible.

Other smaller proposal components, such as the Front Royal to Wishing Star/Loudon area 500 kV developments by Nextera (proposal numbers: 766, 577, 663), offer limited transfer enhancements once the needed bulk transmission reinforcements are in place. These developments, as outlined in the PJM constructability evaluation report pose much higher elevated construction risk and when compared to the limited incremental transfer capability offered were dropped from further consideration.

Southern Quadrant:

The 2027 analysis indicated that the proposed 500 kV line rebuilds in the existing 500 kV corridor currently running between Front Royal and Vint Hill are effective in addressing the identified overloads under the 2027 scenario. LS Power also proposed to build a new, greenfield 500 kV line along that corridor to enhance its transfer capability, which was proven also effective technically. It is to be noted, however, that the 2022 RTEP Window 3, 2027 basecase scenario adopted the older PJM generation dispatch and deliverability rules (in effect at the time) where each load zone tends to hold its import interchange with the rest of the PJM system constant at historical levels. With the much higher and material load increase forecasted in Dominion and APS (up to 7,500 MW), this is difficult to

justify and would require the local generation within Dominion to be dispatched up or close to their maximum capability. This higher Dominion dispatch affects the flows along the 500 kV corridor between North Anna and Morrisville 500 kV substations. With a more reasonable dispatch pattern, according to PJM's new block dispatch methodology, the higher South-to-North flow will drop in the 2028 robustness test scenarios, as further highlighted in the following section.

2027/28 Reliability Evaluation Summary

The 2028 case for the 2023 RTEP was still under development when the 2022 Window 3 opened, and once preliminary study results were available, PJM shared the results with stakeholders at the April 2023 special TEAC.

The 2028 evaluation indicated the need for further regional transfer reinforcements, beyond those offered through the 2027 and changes to a number of needs, particularly within the southern region due to:

- Major deactivation requests in the study area (e.g., Brandon Shores, among others)
- Higher regional transfers as a result of the new block dispatch and generator deliverability test

For this reason, PJM utilized the 2027/28 cases to further assess the robustness of the proposals. The LS Power (proposal 548), NextEra (proposal 598) and Transource (proposal combo) combination proposals did not prove effective in the 2027/28 initial testing. However, PJM further tested the components of LS Power and Transource proposals in developing additional scenarios. NextEra proposed a standalone add-on component upgrade to its 2027 combination proposal (proposal 598) to address 2028 needs through proposal No. 175. PJM evaluations showed that the NextEra proposal 175 and the incumbent Transmission Owners (Exelon, FirstEnergy and Dominion) combination proposal scenarios showed promising performance, and thus were used as starting points for further scenario development and assessments.

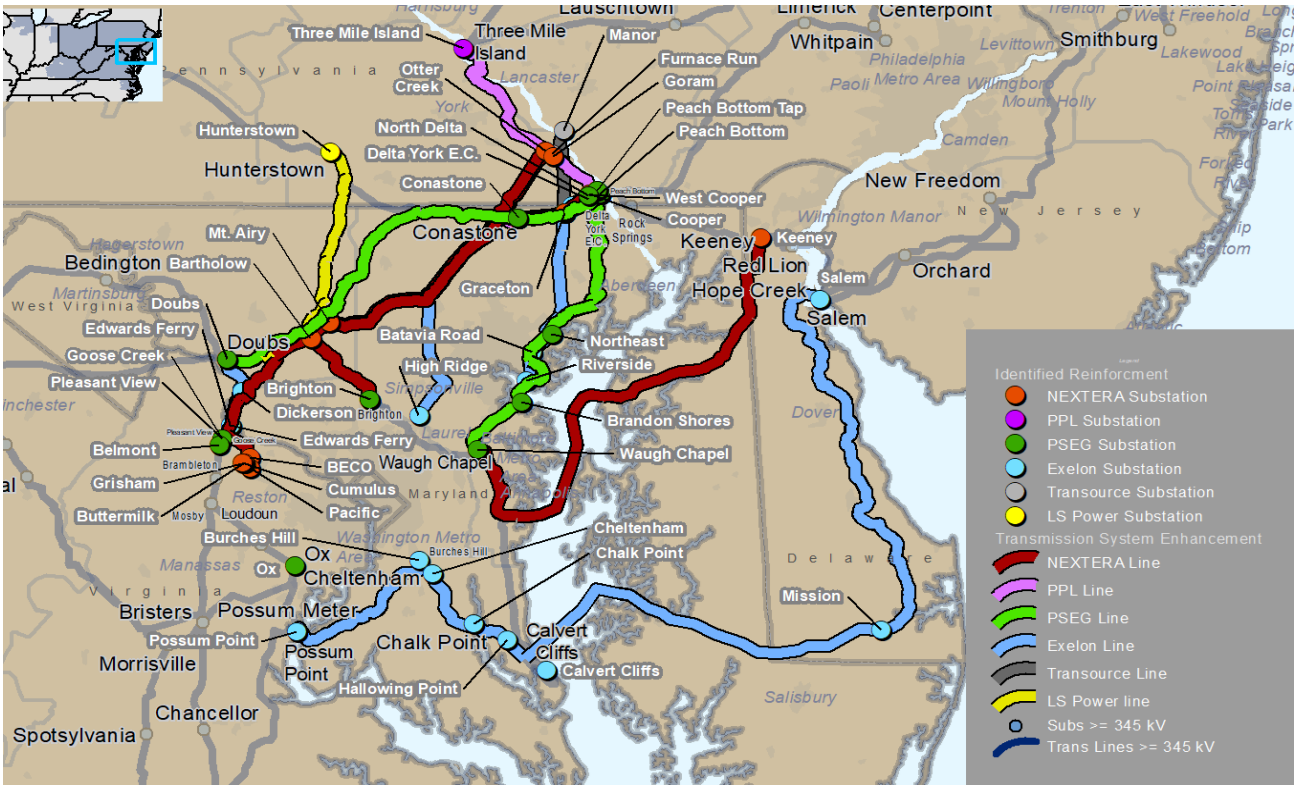
PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution. Based on different combinations of scenarios performed, PJM identified the need for three regional/local transmission solutions in the East cluster, and results are reflected in the short-listed scenarios.

East Proposal Cluster

Six proposing entities submitted over 15 proposals to address the East cluster violations, as illustrated in **Map 3**. During the window evaluations, PJM confirmed the need for regional and local reinforcements into the BGE system, along with regional reinforcements between Peach Bottom and northern Virginia.

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the more efficient or cost-effective solution. Based on different combinations of scenarios performed, PJM identified the need for three regional/local transmission solutions in the East cluster, which are reflected in the short-listed scenarios.

Map 3. East Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Listed below are groups of solutions evaluated as potential solutions to address the BGE local as well as regional transfers:

Solutions evaluated to address BGE local/regional

- **North Delta-High Ridge 500 kV (proposal ID 344/660):**

Approximately a 67-mile AC overhead line proposed by Exelon, the incumbent Transmission Owner. One hundred percent of the line will utilize existing ROW. The solution addresses all of the BGE violations and a majority of the violations due to transfer limitations. The proposed cost is approximately $550 million.

- **Peach Bottom/N. Delta-Raphael-Waugh Chapel 500 kV (Proposal ID 808):**

Approximately a 72-mile AC overhead line proposed by PSEG. The line would be greenfield and require new ROW (a portion of the circuit will parallel existing ROW). The solution will require additional upgrade(s), and there are potential short-circuit issues at Peach Bottom substation that will require rebuilding of the substation. The proposed cost is approximately $511 million in addition to any substation components included in the proposal.

- **Peach Bottom-Brandon Shore 500 kV (Proposal ID 741):**

Approximately a 56-mile AC overhead line proposed by PSEG. The line would be greenfield and require new ROW, majority of which will parallel existing ROW. The solution is comparable to the Exelon solution; however, there are potential short-circuit issues at Peach Bottom substation that will require rebuilding of the substation. The proposed cost is approximately $434 million in addition to any substation components included in the proposal.

- **Keeney-Waugh Chapel 230 kV double circuit (Proposal ID 948):**

Approximately a 73-mile AC overhead line, along with 31 miles of submarine cable, solution proposed by NextEra. The line would be greenfield and require new ROW (approximately 15% of the length would parallel existing ROW). Not only would the solution require additional upgrades to address the BGE local and regional needs, it has a proposed cost of over $4 billion.

Solutions evaluated to address BGE local area solutions (focused on Brandon Shores deactivation)

- **Graceton-Batavia double circuit 230 kV (Proposal ID 344/660):**

Approximately a 29-mile AC overhead line proposed by Exelon, the incumbent Transmission Owner. The solution will be adjacent to an existing circuit, will utilize an existing ROW, and addresses the majority of the local needs. The proposed cost is approximately $195 million.

- **Peach Bottom/N. Delta-Raphael-Waugh Chapel 500 kV *(Proposal ID 808)*:**

The same notes as described above in the "BGE Local/Regional Solutions" section for the same line would apply.

- **Peach Bottom-Brandon Shore 500 kV (Proposal ID 741):**

The same notes as described above in the "BGE Local/Regional Solutions" section for the same line would apply.

- **Keeney-Waugh Chapel 230 kV double circuit (Proposal ID 948):**

The same notes as described above in the "BGE Local/Regional Solutions" section for the same line would apply.

Listed below are solutions evaluated by PJM to address the regional transfer needs, mainly related to transfer to northern Virginia/APS areas:

Proposals evaluated to address regional transfer

- **Peach Bottom-Graceton-Conastone/N. Delta 500 kV upgrade (Proposal ID 344/660):**

A solution proposed by both Exelon and Transource that builds a new 500 kV substation (N. Delta) in the Peach Bottom area and reconfigures the Peach Bottom substation to avoid short-circuit issues that require the Peach Bottom station rebuild. The project includes a new Peach Bottom-Graceton 500 kV, Peach Bottom-N. Delta 500 kV, and N. Delta-High Ridge 500 kV lines, resulting in approximately 75 miles of new transmission that utilizes the existing ROW for the majority of the length, rebuilding of an existing 500 kV line from Peach Bottom-Conastone.

- **Peach Bottom-Doubs 500 kV (Proposal ID 741/808):**

Approximately 87 miles AC overhead greenfield line proposed by PSEG. This solution does not address the Peach Bottom short-circuit issue along with space constraints at the substation.

- **Conastone-Doubs 500 kV (Proposal ID 637):**

Approximately 69 miles AC overhead greenfield with small portion paralleling an existing line proposed by PSEG. The project along with the PPL-proposed project 374 provides the needed transfer capability into the northern Virginia area.

- **Otter Creek-Conastone 500 kV (Proposal ID 374):**

Approximately 17 miles AC overhead line proposed by PPL. The line will expand existing ROW to build the line. The Otter Creek-Conastone 500 kV line will tie in to the PSEG proposed Conastone-Doubs, bypassing the Conastone substation.

- **Hunterstown-Green Valley 500 kV (Proposal ID 229):**

Approximately a 40 miles AC overhead greenfield line proposed by PSEG. The Hunterstown termination causes 500 kV overloads in the Peach Bottom area. The proposal also results in short-circuit issues at Conastone substation, requiring a substation rebuild.

- **Hunterstown-Doubs-Goose Creek 500 kV (Proposal ID 548/846):**

This path is proposed by NextEra and LS Power. The NextEra proposal includes approximately 71 miles AC overhead greenfield line from Hunterstown-Doubs 500 kV, with 25% of the new ROW paralleling existing ROW. The Doubs-Groose Creek 500 kV section would be approximately 19 miles of greenfield line, 20% of which will be underground. The LS Power proposal includes approximately a 66-mile AC overhead Hunterstown-Doubs 500 kV line, of which, 20 miles would utilize existing ROW. The Doubs-Groose Creek 500 kV section would be approximately 18 miles, of which eight miles would utilize existing ROW. The lines out of the Hunterstown-Doubs cause violations on the PECO and BGE system requiring additional upgrades.

- **Otter Creek-T-Point 500 kV (Proposal ID 948):**

Approximately a 61-mile AC overhead greenfield line paralleling existing ROW proposed by NextEra. The solution results in short-circuit issues at Conastone substation requiring rebuild of the station.

- **Barnhart (Hunterstown-Conastone Tap)-T-Point 500 kV *(Proposal ID 728)*:**

Approximately a 37 mile AC overhead greenfield line, 5% of which is paralleling existing ROW, proposed by NextEra. The solution results in short-circuit issues at Conastone substation requiring rebuild of the station.

- **N. Delta-Conastone 500 kV (Proposal ID 217/385/530/564/548):**

This path is proposed by NextEra and LS Power, both of which are approximately 15 miles. The majority of the ROW parallels existing ROW or utilizes existing ROW. Exelon who is the owner of the ROW is utilizing the same ROW in their proposal.

- **T-Point-Data Center Alley 230 kV (Proposal ID 728):**

Approximately a 35-mile two greenfield single 230 kV circuits proposed by NextEra. Of the total length, 95% is AC overhead, and the remaining 5% would be underground. The 230 kV system can't be built without the 500 kV T-Point, which will cause a short-circuit issue at Conastone substation requiring the Conastone station rebuild.

- **Transource 230 kV development between Peach Bottom and Conastone (Proposal ID 487–IEC East):**

Scope includes Transource's 500/230 kV developments between Peach Bottom and Conastone. The project doesn't address the BGE local need.

Proposals evaluated to address PA/MD tie lines

- **Transource 230 kV development between New Rice-Ringgold (Proposal ID 487- IEC West):**

Scope includes Transource's new 500/230 kV Rice substation (tie into Vinco-Hunterstown 500 kV circuit) and approximately 29 miles of new double circuit 230 kV AC overhead greenfield transmission line between Rice and Ringgold (FE station).

- **First Energy new Hunterstown-Carroll 230 kV (Proposal ID 837)**

The project includes approximately 24 miles of rebuilding an existing Hunterstown-Carroll 115/138 circuit to 230 kV double circuit construction.

West Proposal Cluster

Four proposing entities submitted solutions to address the West cluster violations, as illustrated in **Map 4**. All proposals approached the West needs through new 500 kV or 765 kV lines.

Regional Solutions

- **502 Junction-Black Oak-Stonewall-New Belmont (Gant) 500 kV: (NextEra)**

Approximately 67 miles of one 500 kV line on existing or parallel to existing ROW to Black Oak 500 kV substation. The next portion of the line will be approximately 53 miles long terminating at Stonewall substation to existing or parallel to existing ROW. PJM's analysis did not show additional benefits of looping the line into Black Oak 500 kV substation. The 500 kV line will continue east for roughly 22 miles on existing or parallel to existing ROW before turning south for 25 miles as greenfield development to be terminated at New Belmont/Gant 500 kV substation.

- **Fort Martin-Doubs 500 kV double/single circuits: (FE)**

Construct approximately 158 miles of new 500 kV (double/single) line(s) from Fort Martin 500 kV substation to Doubs 500 kV substation. The new transmission line will require installation of new 500 kV breakers at Doubs and Fort Martin 500 kV substation and the expansion of Doubs 500 kV substation.

- **Pruntytown-Mt. Storm and Meadow Brook-Doubs 500 kV: (FE)**

- Construct approximately 50 miles of new 500 kV line from Pruntytown 500 kV substation to structure No. 5 of on the Meadow Brook to Mount Storm 500 kV line located adjacent to Mt. Storm 500 kV substation. Cut the existing Meadow Brook 500 kV to Mount Storm 500 kV line from the Mount Storm line terminal, and connect the new 500 kV line from Pruntytown 500 kV substation. The new transmission line will require expansion of Pruntytown 500 kV substation.

- Constuct approximately 55 miles of new 500 kV line from Meadowbrook 500 kV substation to Doubs 500 kV substation. Reterminate existing Meadow Brook to Loudon 500 kV line and existing Meadow Brook to Front Royal 500 kV line. The new transmission line will require installation of new 500 kV breakers at Doubs and Meadow Brook 500 kV substation and the expansion of Doubs 500 kV substation.

- **502 Junction-Black Oak-Doubs 500 kV: (LS Power)**

Construct approximately 73 miles of new 500 kV line from 502 Junction 500 kV substation to Black Oak 500 kV substation. Construct approximately 72 miles of new 500 kV line from Black Oak 500 kV substation to Doubs 500 kV substation. Approximately 52 miles of the 72-mile line will be built by rebuilding the existing 138 kV circuit to a double 500/138 kV circuit.

- **Joshua Falls-Yeat 765 kV: (Transource)**

Construct approximately 135 miles of new 765 kV line from existing Joshua Falls 765 kV substation to a new Yeat 765 kV substation. The new transmission line will require installation of new 765 kV breakers at Joshua Falls 765 kV substation.

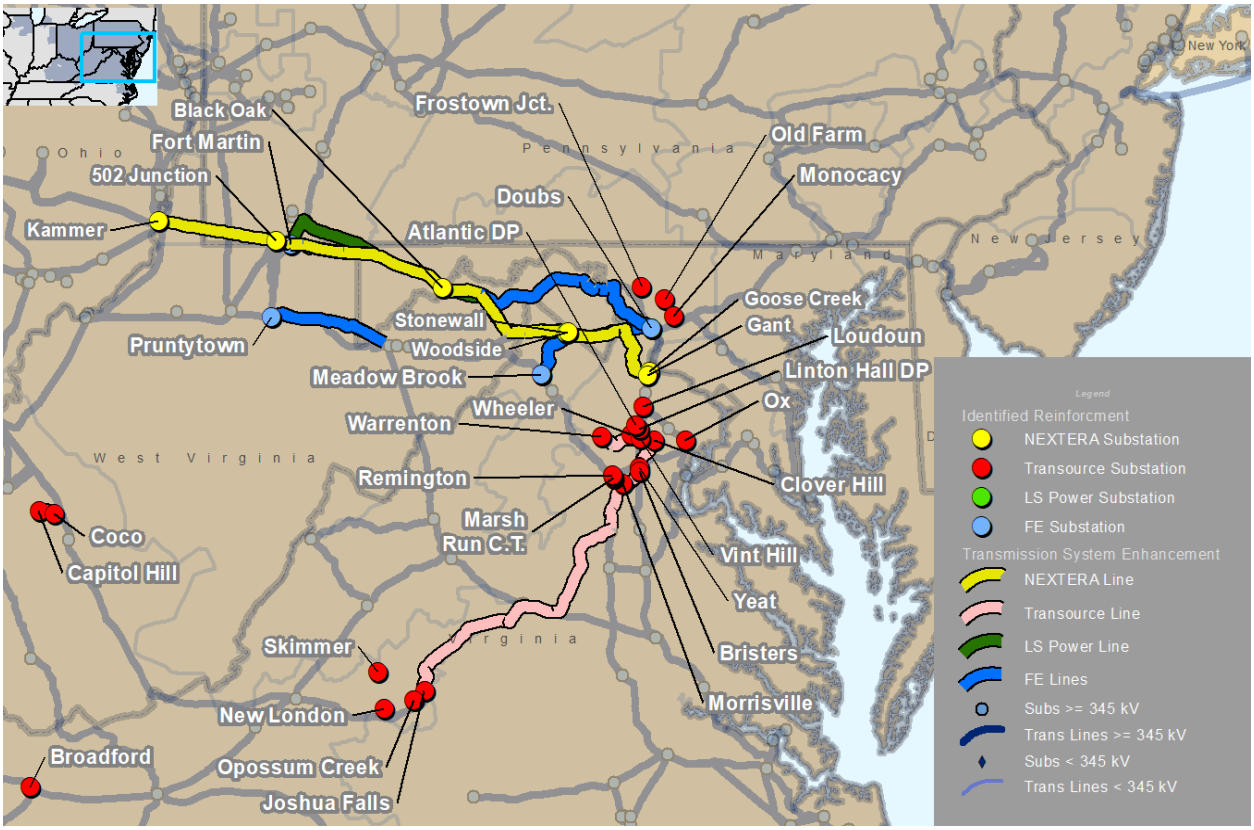
The above-proposed 500 kV solutions, regardless of proposing entity, overlapped in terms of proposed ROW with the exception of First Energy's proposal of new line from Pruntytown-Mt. Storm and Meadow Brook-Doubs. PJM also tested less effective/efficient solutions, two examples of which are provided below:

- Front Royal-New Wishing Star 500 kV: (NextEra)

- Black Oak-Goose Creek 500 kV: (NextEra)

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution. Based on different combinations of scenarios performed, PJM identified that with adequate reinforcements in the East (three lines), only one 500 kV or 765 kV line with dedicated dynamic VAR support would be required. For the 500 kV reinforcement options terminating at Doubs, additional transfer capability would be required into Goose Creek (Northern VA area).

Map 4. West Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

South Proposal Cluster

Four proposing entities submitted solutions to address the South cluster violations, as illustrated in **Map 5**. All proposals approached the South needs primarily through new 500 kV lines.

Regional Solutions

- **Front Royal-New Wishing Star (Racefield) 500 kV: (NextEra)**

Approximately a 48-mile AC overhead line proposed by NextEra with about 70% greenfield ROW, 25% adjacent to road ROW and 5% an expansion of existing transmission ROW. This solution is the most direct route, from west to east, into the Loudoun area and is similar in nature to the originally proposed Trail project (Meadow Brook-Loudoun). The Trail project was a 500 kV line proposed by Dominion and Allegheny Power, through their subsidiary TrAILCo. It began in western Pennsylvania, crossed through West Virginia, and into Loudoun County, Virginia. Due to the amount of opposition at the time, the line took a much longer route heading south toward Morrisville before heading back up to Loudoun. PJM performed sensitives with and without the new Front Royal-New Wishing Star 500 kV line and did not see a substantial impact on solved violations. PJM believes obtaining new ROW will be difficult following the TrAILCo project.

- **Front Royal-Vint Hill 500 kV: (NextEra)**

Approximately a 64-mile AC overhead greenfield line proposed by LS Power. The line primarily parallels existing ROW along Front Royal-Morrisville and Meadow Brook-Vint Hill (previously Loudoun).

- **Hinsons Ford Rd-Brambleton 500 kV: (PSEG)**

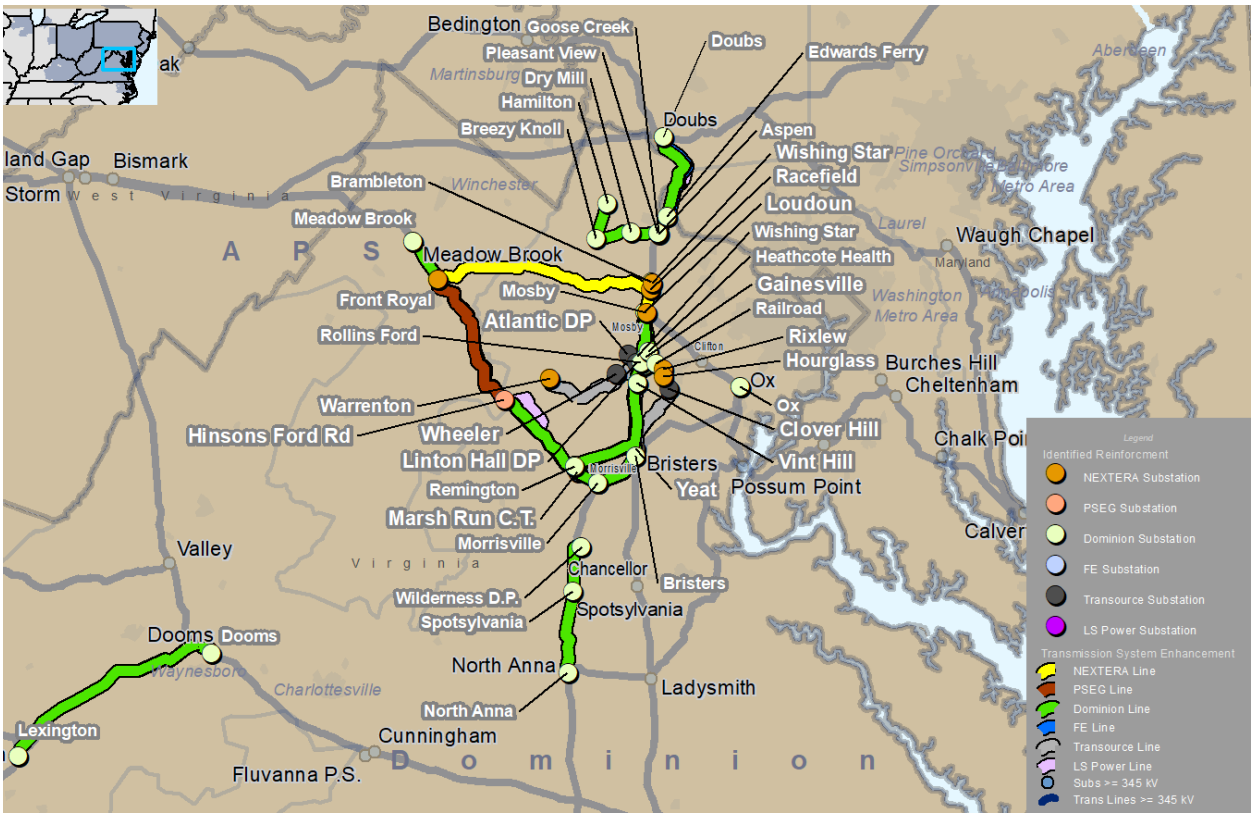
Approximately 34-mile AC overhead greenfield line proposed by PSEG. The proposal shows some similarities to the two above proposals by NextEra and LS Power. While not going directly from west to east or travels as far south to Morrisville, the line would cut across to Brambleton/Loudon area.

- **North Anna-Wishing Star 500 kV: (Dominion)**

The Dominion solution brings a 500 kV line from North Anna all the way up to Wishing Star connecting to Spotsylvania and Vint Hill along the way. In order to fit the additional 500 kV line in their existing corridor, Dominion would wreck and rebuild structures from Morrisville to Wishing Star, which will impact two 500 kV and two 230 kV lines. The North Anna-Spotsylvania section is approximately a 14 mile, the Spotsylvania-Vint Hill section is approximately 38 miles and the Vint Hill-Wishing Star section is approximately 17 miles, all of which would be new AC overhead lines using existing ROW. However, PJM observed that some violations seen in the 2027 results are not present in 2028, likely due to the assumption and methodology changes, and so it may not be necessary to go as far south as North Anna, but rather start at Morrisville instead.

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution.

Map 5. South Proposal Cluster Map



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Northern Virginia Data Center Cluster

Three proposing entities submitted solutions to address the Northern VA data center cluster violations, as illustrated in **Map 6**. Proposals approached the data center needs primarily either through underground 500 kV cables or an overhead 500 kV and 230 kV line.

Data Center Alley Solutions

- **Goose Creek-Beaumeade 500 kV underground (LS Power) – 2308/3596 MVA for SN/SE**

Approximately a 5-mile greenfield underground double circuit cable proposed by LS Power. The proposal would expand Dominion's existing Goose Creek and Beaumeade substations to accommodate the new line. LS Power proposes to follow the W&OD Trail in which Dominion currently owns the ROW.

- **Stork-Flys 500 kV underground:**

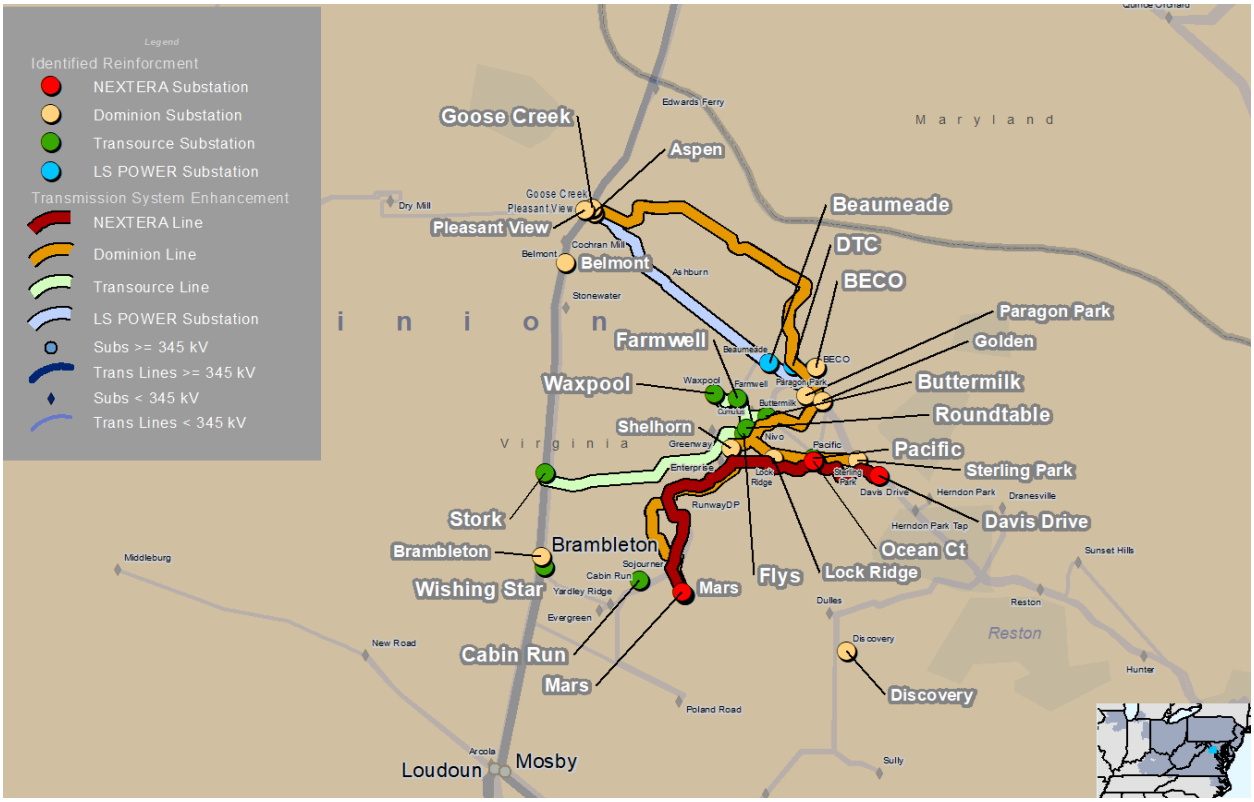
Approximately a 5-mile greenfield underground cable proposed by Transource. The line would be built along the center median of a road. The summer normal and emergency ratings would be 3302/3302 MVA (SN/SE)

- **Aspen-Golden-Mars 500/230 kV overhead (Dominion) – 4357/4357 MVA for SN/SE**

The proposal builds a new Aspen substation adjacent to Goose Creek, along with another new substation called Golden southeast of Aspen. The new line would start at Aspen, move southeast toward Golden, and then eventually close the 500 kV ring around the data center area to Mars. The Aspen-Golden section of the line would be approximately 8.5 miles, and the Golden-Mars section would be approximately 8.3 miles, both of which would be 500 kV AC overhead with 230 kV underneath. The project cost is approximately $1 billion.

PJM evaluated every proposal individually, as well as various combinations of the proposals and components to identify the most effective solution. All three proposals have comparable performance in terms of solving the violations in the Data Center Alley area.

Map 6. Northern VA Data Center (Data Center Alley) Proposal Cluster Map



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Short-Circuit Analysis

Drivers for the 2022 Window 3 are reliability violations stemming from load flow analysis, not short-circuit analysis. Short-circuit analysis followed a screening process to support the 2022 Window 3 evaluation of proposals. The short-circuit screening identified potential additional scope attributed to overduty breakers, and potential switchyard rebuilds. Short-circuit analysis was applied holistically, where the scenario under study was comprised of one or more proposals, designed to address all Window violations at once which ensures accounting for all short-circuit contributions by all proposed solution facilities of each scenario.

The screening process considered 11 separate TO breaker sets[2] using the window posted 2027 baseline case, then analyzed the proposals and scenarios using a single Aspen OSF (Options Settings File) based on PECO's study parameters. Short-circuit screening was performed on all scenarios deemed promising based on power flow analysis results and on the final selected proposals base case.

As part of the scenario screening process, breakers identified as overduty attributed to the scenario under study were reviewed. For proposals that included breaker replacements, those breakers were reviewed for adequacy of their proposed interrupting capability. The study also identified breakers that became overdutied as a consequence of the scenario under study, but were not addressed in the individual proposals received by PJM. If replacing the consequential overduty breaker with a breaker having a greater interrupting capability could remediate the overduty condition, then the cost of the breaker replacement was factored into the overall scenario cost.

However, in some scenarios, the identified fault level increase was quite high, exceeding the ratings of the substation ground grid and other fault-sensitive facilities within the substation. In these situations, simply upsizing the breaker does not fully address the high fault level violation. For example, at the Conastone 500 kV yard, excessively high fault level would require the entire substation to be rebuilt.

The Peach Bottom 500 kV North and South yards were also monitored closely. Remediation of excessively high fault levels could require a long duration outage of the 500 kV Peach Bottom switchyards, which may impact the availability and operability of the Peach Bottom nuclear plant during the rebuild if so required. Scenarios that created excessively high fault levels at either Conastone or Peach Bottom were hence flagged, and impacts to both cost and schedule factors were given due consideration when evaluation feasibility of proposed solutions.

The 2022 Window 3 selected scenario underwent a subsequent short-circuit analysis more rigorous than the short-circuit screening. An Aspen Breaker Duty Report, using the native TO Option Settings File, was generated for each TO area where overduty breakers were identified in the initial screening. Results were shared with the impacted TOs for validation and breaker replacement cost estimation.

Objectives of the short-circuit analysis were achieved with the 2022 Window 3 selected scenario. Neither the Conastone nor Peach Bottom substations were impacted for excessively high fault levels that exceed the existing short-circuit capability reported by the transmission owner. There were, however, 36 breakers identified as overdutied, which were not included in the submitted proposals. These breakers are located in APS and Dominion substations at nominal voltages of 138kV, 230 kV and 500 kV. Costs to remediate these overduty breakers are incorporated into the selected scenario cost estimate.

[2] AE-DPL, AEP, APS, ATSI, FirstEnergy(JCPL-MetEd-Penelec), BGE, DOM, PECO, PEPCO, PPL, PSEG

Table 9. Identified Circuit Breaker Upgrades/Replacements (beyond those proposed by proposing entities)

TO Area	Substation	kV	BREAKER (Qty)
APS	Double Toll Gate	138	1
	Doubs	500	1
DOM	Ashburn	230	1
	Beaumeade	230	1
	Beco	230	2
	Belmont	230	1
	Brambleton	230	6
	Gainesville	230	1
	Loudon	230	2
	Ox	230	7
	Paragon Park	230	4
	Reston	230	1
	Stonewater	230	4
	Waxpool	230	4

Load Deliverability Analysis

Load Deliverability is one of the studies conducted in evaluating the 2022 Window 3 proposals. PJM performed the load deliverability analysis to determine the increased CETL (Capacity Emergency Transfer Limit) enabled by the proposed proposals individually and in combination within a specific scenario. The CETL Calculation focused on specific LDAs based on the potential impact of the 2022 Window 3 proposals on the transfer limit to the LDAs. PJM selected APS, BGE, Dominion and SWMAAC LDAs for evaluation.

The load deliverability analysis was performed according to PJM Manual 14B requirements.[3] The study was conducted using the 2023 series RTEP 2028 base case, with 2022 Window 3 scenario solutions applied.

PJM conducted the CETL test on the short-list scenarios and observed the following:

- The APS CETL/CETO margin is well above 115% for all scenarios and the CETL value is comparable.

The NextEra Proposal 175:

- The CETL/CETO for the SWMAAC is <115%, while the CETL/CETO for BGE barely meeting 100%.

PJM Combined Proposal 500 kV or 765 kV Option:

- The CETL/CETO margin for BGE, SWMAAC and Dominion LDA are well above 115%.

PJM examined the Dominion CETL for different components related to the West 500 kV proposals, including the First Energy proposed ID 837 solution. The analysis has identified the need to terminate the West solution into the Dominion Data Center vicinity, as such the NextEra proposal ID 853 option yielded higher CETL.

The CETL study result also revealed the addition of the Otter Creek-Doubs 500 kV line increases the Dominion CETL by ≈20%.

[3] PJM Manual 14B: PJM Region Transmission Planning Process: https://www.pjm.com/~/media/documents/manuals/m14b.ashx

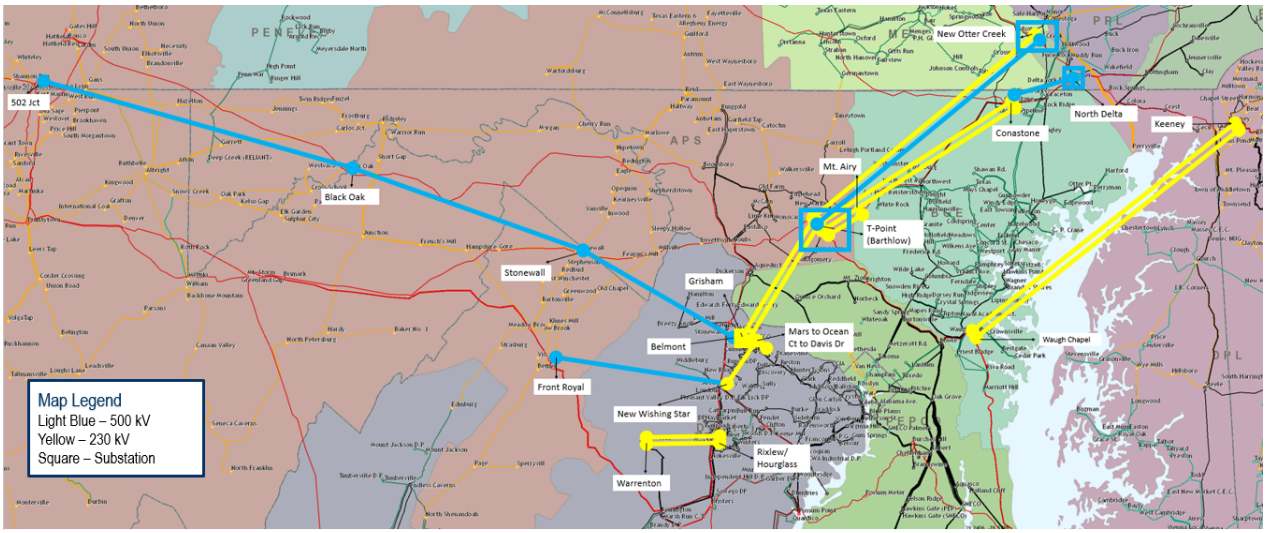
Selection of Short-Listed Scenarios and Proposal Components

Scenarios listed below represent the initial short list of scenarios presented at the October 3, 2023, TEAC. The merits and shortcomings of each are further detailed along with a very high-level point-to-point illustration of the project components on the associated maps.

NextEra Proposal 175

The simplified map illustration below in **Map 7** summarizes the high-level scope of the NextEra proposal 175 designed to address 2028 needs. The proposal from an analytical perspective appears to address the needs identified on the system; however, the majority of the lines are greenfield, some of which cross sensitive areas such as Front Royale-Wishing Star in the West and the Chesapeake Bay crossing in the South. The proposal as a whole, while theoretically may appear acceptable, results in a considerably higher-risk profile and does not have significant cost difference to the two scenarios that PJM built using a combination of proposal and components.

Map 7. NextEra Proposal 175



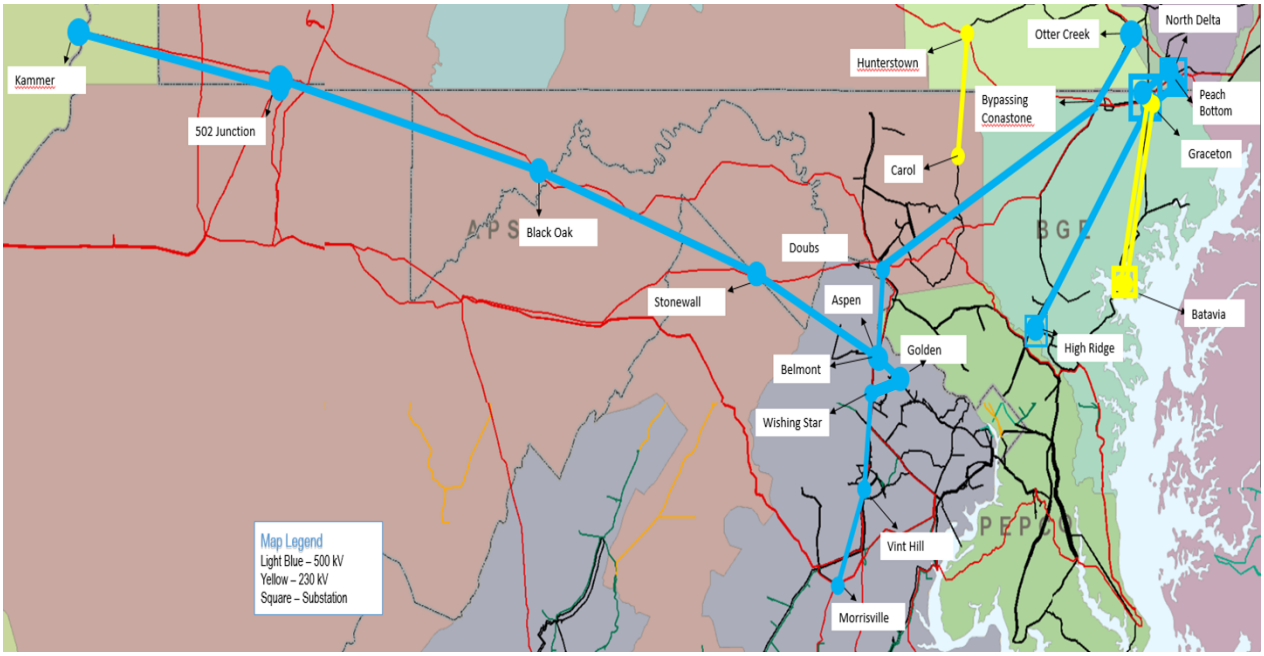
*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

PJM Combination – 500 kV Scenario

The simplified map illustration below in **Map 8** summarizes the high-level scenario designed by PJM to address 2028 needs. The scenario includes proposal components from both incumbent Transmission Owners (Dominion, Exelon, FirstEnergy and PPL) and non-incumbent entities (NextEra and PSEG). The scenario attempts to address the reliability needs with less impact on sensitive geographic areas at a comparable cost. The scenario results in overall lower land and social impacts due to the number of circuits proposed at the appropriate voltage level, including two 500 kV lines in the East and only a single 500 kV line in the West, combined with Dominion local solutions. This scenario includes a non-incumbent 500 kV component in the East that establishes a new 500 kV path between MAAC and the northern Virginia/West area. It is important to note that some of these proposed components were very similar. For example, for the 500 kV reinforcements identified in the West, FirstEnergy, NextEra and LS Power proposed very similar proposals. What is selected in this scenario is NextEra's proposal between 502 Junction to Black Oak to Stonewall to directly into Data Center Alley. This proposal adds one additional 500 kV line between the

APS system and Dominion while also following very similar ROW adjacent to existing facilities. PJM refined this short-listed scenario further in order to come up with the final recommended solution.

Map 8. PJM Combination – 500 kV Scenario



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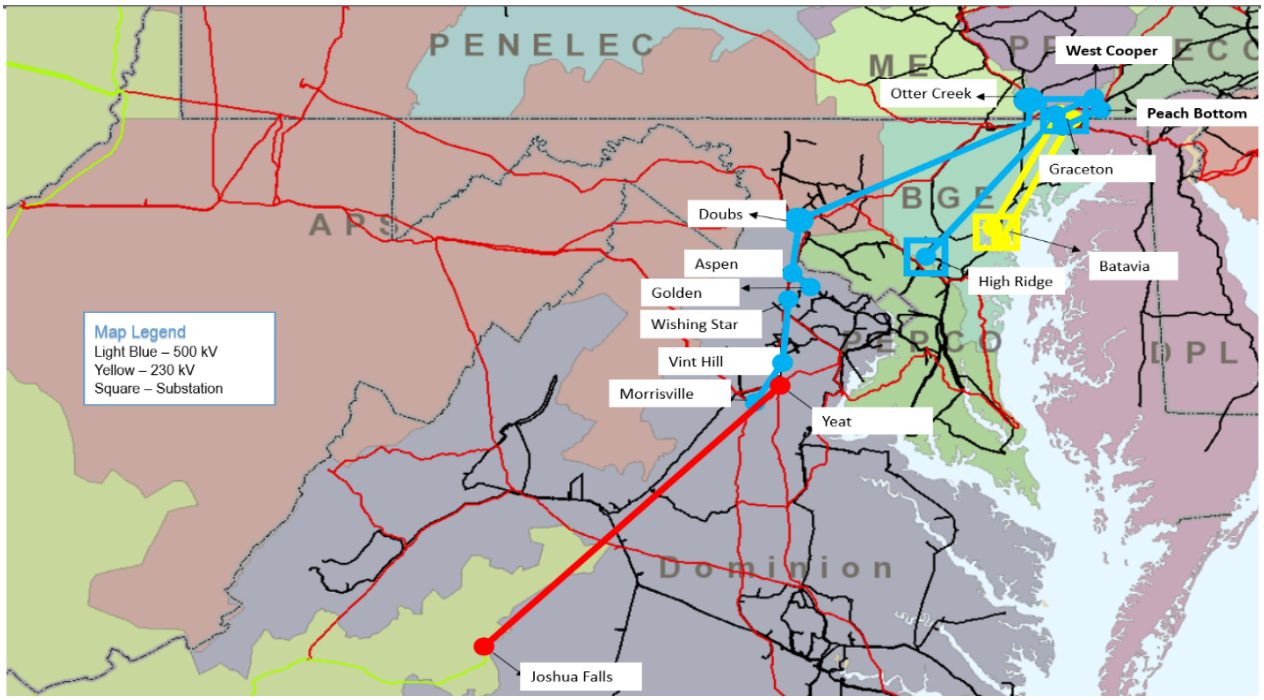
PJM Combination – 765 kV Scenario

The simplified map illustration below in **Map 9** summarizes the high-level scenario designed by PJM to address 2028 needs. The scenario primarily replaces the 500 kV developments in the northern West cluster with a 765 kV proposed development by Transource in the South/West. The proposal is performs comparably to meet the system needs, but offers more flexibility to meet needs further in the South as the load growth will likely shift southward in future years. It also provides balanced supply between North and South supply direction rather than concentrating the supply from the North. The 765 kV development also reduces the flow on the four existing 500 kV lines in APS running west-to-east. The main risk for this scenario is the timeline to construct the 765 kV circuit.

Map 9. PJM Combination – 765 kV Scenario



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Final Reliability Analysis and Recommended Solution

While PJM provided a short list of scenarios at the October 3, 2023, TEAC meeting, PJM since then further refined the 500 kV scenario and presented the recommended solution for 2022 Window 3 at the October 31, 2023, and December 5, 2023, TEAC meetings. This section summarizes the selected set of proposals and associated rationale to address the reliability needs for the 2022 RTEP Window 3. **Table 10** at the end of this section provides summary of evaluation rationale, relevant study scenarios supporting the selection as well as a high-level summary of the scenario build up and analysis.

Eastern Quadrant

As discussed earlier, the eastern quadrant needs primarily focus on; (1) enhancing the east to west bulk power transfers, (2) support the load deliverability and reliability needs for the BGE system and (3) support the additional load demands of the APS and northern Virginia transmission systems where a large amount of load growth is being forecasted.

All three shortlisted scenarios, discussed in the preceding section address this need. However, PJM selected the eastern cluster proposals part of the PJM 500 kV combination scenario to be the most effective and efficient solutions to address those needs for the following reasons;

1. Both the PJM developed 500 kV and 765 kV shortlisted combination scenarios have the same eastern quadrant solutions (cluster).
2. The PJM 500 kV combination scenario offers the needed reliability reinforcements with the least amount of infrastructure development and with much higher reliability margin compared to the NextEra proposal which is both of higher cost and involves developing a significantly higher amount of facilities.
3. The PJM 500 kV combination proposal offers full utilization of existing right of ways, debottlenecking the historically constrained Peach Bottom – Conastone 500 kV transmission corridor.
4. Addresses the load deliverability needs into the BGE system which is further exacerbated by the deactivation of key power plant(s) in the BGE zone. The NextEra proposal fails the load deliverability test for the 2027/28 year while the PJM 500 kV proposal combination meets the reliability needs with a healthy margin to spare following the deactivation of the Brandon Shores plant.

Western Quadrant

The western quadrant reinforcements are critical due to the high demand for west to east power flow and into the APS and northern Virginia networks. This transmission corridor extending from the Kammer 765 kV substation in the West towards the eastern edge of the APS system (Doubs) and the northern edge of the Dominion transmission network (Goose Creek area) was experiencing voltage collapse conditions under the higher transfer demands represented in both the 2027 and 2027/28 scenarios.

Again all shortlisted scenarios address the need for the west to east transfer, either through a single 500 kV (in the north) or 765 kV (in the south) transmission path developments.

The NextEra proposed 500 kV transmission development between 502 Junction in the west towards Stonewall and then terminating into the planned Aspen 500 kV development offers the needed reliability reinforcement to serve both the West to east transfer need and also provide a third 500 kV supply source into the northern Dominion load center region.

The 765 kV development proposed by Transource imposed higher schedule and constructability risk due to its predominantly greenfield nature which will impose an avoidable reliability and operational risks in the northern Virginia and APS areas if the schedule of the project is delayed.

Southern Quadrant

PJM selected the southern cluster part of the PJM 500 kV combination scenario to be the more effective and cost efficient solution to the needs in the southern quadrant. This solution predominantly utilizes the existing 500 kV corridor while meets the reliability and load deliverability needs for the system.

This proposed selection avoids introduced multiple and unnecessary green field developments that may not be effective in the longer term and do not contribute to reinforce the greater 500 kV transmission corridor extending between the Goose Creek area in northern Virginia and the existing Morrisville substation further to the south within the Dominion footprint.

Dominion Quadrant

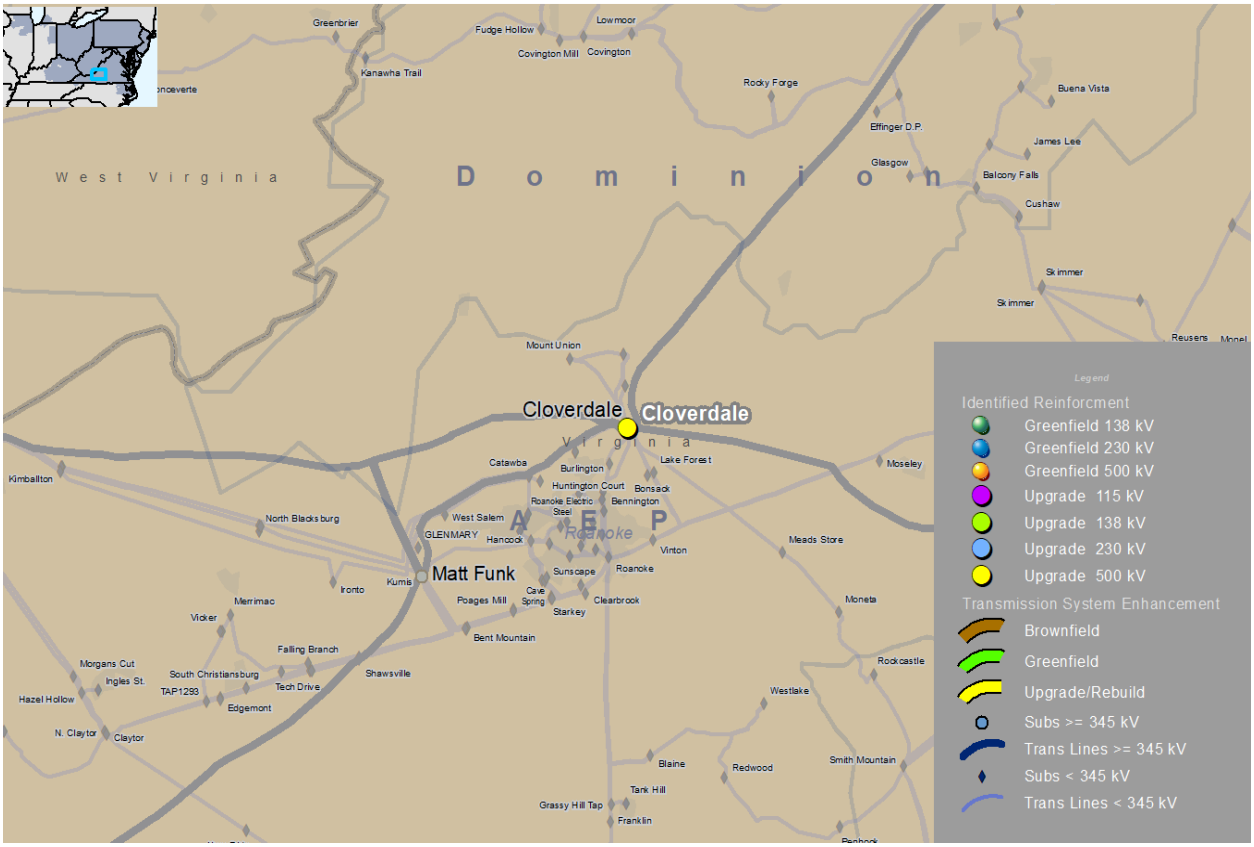
PJM selected the Dominion/northern Virginia cluster of its shortlisted 500 kV combination solution to be the more cost effective and efficient solutions to address the needed reliability needs in northern Virginia. The selected solutions offer the needed local transmission system reinforcement to support the local data center load concentration in northern Virginia and establishes a robust, high capacity overhead transmission line reinforcement through the data center load area. This allows for easy access to integrate load as demand increases and also offers reinforcement to the 500 kV path between Goose Creek and Loundon/Brambelton substations that is currently served via a single 500 kV circuit.

The total cost estimate for the recommended solution is approximately $5,142.98 million. The following sections summarize the selected project components by cluster:

AEP Local

PJM recommends proposal 410 by AEP to address the AEP local area needs. The project will establish a new 500 kV breaker position for the low side of the existing 765/500 kV transformer at Cloverdale station. The new position will be between two new 500 kV circuit breakers located in a new breaker string, electrically converting the 500 kV yard to “double-bus double-breaker” configuration. The estimated cost is $11.59 million, and the required in-service date is June 2027 with a projected in-service date of October 2026. The local transmission owner, AEP will be designated to complete this work.

Map 10. AEP Local Area Improvements



South

PJM recommends a revised scope of proposal 711, proposal 967, proposal 211, proposal 731, partial scope of proposal 74 and proposal 231 proposed by Dominion to address the South cluster needs. There are also a number of additional upgrades identified by PJM.

The revised scope of proposal 711 includes a new Morrisville-Vint Hill-Wishing Star 500 kV line (approximately 36.3 miles) while maximizing the use of existing ROW within this corridor. The project scope also includes wrecking and rebuilding both the 500/230 kV double circuit towers (horizontal, stacked layout) in the Morrisville-Loudoun-Brambleton corridor to free up space for the new single 500 kV monopole within the same corridor. Below is a list of line rebuilds:

- 500 kV Line No. 545 (Bristers-Morrisville) rebuild
- 500 kV Line No. 569 (Loudoun-Morrisville) rebuild
- 500 kV Line No. 535 (Vint Hill-Loudoun) resag/rebuild
- 500 kV Line No. 546 (Mosby-Wishing Star) rebuild
- 500 kV Line No. 590 (Mosby-Wishing Star) rebuild
- 230 kV Line No. 2030 (Gainesville-Loudoun) rebuild

- 230 kV Line No. 2045 (Loudoun-Brambleton) rebuild
- 230 kV Line No. 2094 & 2227 (Brambleton-Racefield-Loudoun) rebuild
- 230 kV Line No. 2101 (Bristers-Vint Hill) rebuild
- 230 kV Line No. 2114 (Remington CT-Rollin Ford) rebuild
- 230 kV Line No. 2140 (Loudoun-Heathcote) rebuild
- 230 kV Line No. 2151 (Railroad DP-Gainesville) rebuild
- 230 kV Line No. 2163 (Vint Hill-Liberty) rebuild
- 230 kV Line No. 2176 (Heathcote-Gainesville) rebuild
- 230 kV Line No. 2222 (Rollins Ford-Gainesville) rebuild
- 115 kV Line No. 183 (Bristers-Ox) rebuild

The project includes substation upgrades at the following substations:

- **Bristers:** Upgrade and install equipment at Bristers substation to support the new conductor 5000A rating for 500 kV Line No. 545.
- **Brambleton:** Upgrade and install equipment at Brambleton substation to support the new conductor termination. All terminal equipment for 230 kV Lines No. 2045 & No. 2094 to be rated for 4000A continuous current rating.
- **Dawkins Branch:** Revise relay settings at 230 kV Dawkins Branch.
- **Gainesville:** Upgrade and install equipment at Gainesville substation to support the new conductor termination. All terminal equipment for 230 kV Line No. 2030 to be rated for 4000A continuous current rating.
- **Heathcote:** Revise relay settings at 230 kV Heathcote.
- **Loudoun:** Upgrade and install equipment at Loudoun substation to support the new conductor 5000A rating for line 569 (500 kV), 2030 (230 kV), 2045 (230 kV), and 2094 (230 kV).
- **Mint Springs:** Revise relay settings at 230 kV Mint Springs.
- **Morrisville:** Upgrade and install equipment at Morrisville substation to support the new 500 kV conductor termination. All terminal equipment to be rated for 5000A for 500 kV Line No. 545 & No. 569. Upgrade 500 kV bus 2 to 5000A.
- **Mosby:** Upgrade and install equipment at Mosby substation to upgrade terminal equipment to be rated for 5000A for line 546 and line 590.
- **North Star:** Revise relay settings at 230 kV North Star.
- **Racefield:** Revise relay settings at 230 kV Racefield.
- **Railroad:** Revise relay settings at 230 kV Railroad.
- **Vint Hill:** Install terminal equipment at Vint Hill substation to support a 500 kV 5000A line to Spotsylvania. Update relay settings for 230 kV Lines No. 2101, No. 2163, and 500 kV Line No. 535.

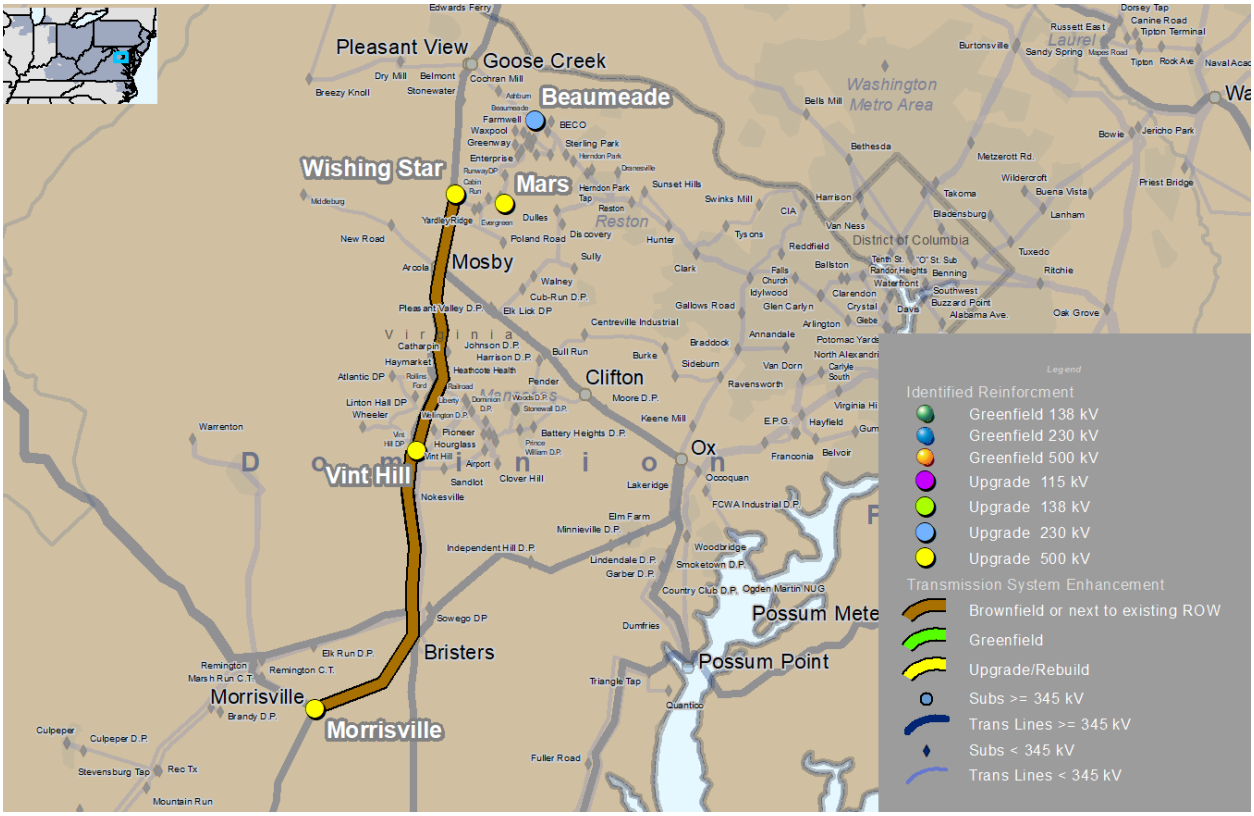
- **Wishing Star:** Install terminal equipment at Wishing Star substation to support a 500 kV 5000A line to Vint Hill. It also provides for new relay settings for 500 kV lines 546 and 590.
- **Youngs Branch:** Revise relay settings at 230 kV Youngs Branch

Breaker upgrades will also be required as follows:

- Replace 4 overdutied 230 kV breakers at Loudoun substation with 80 kA breakers.
- Replace 1 overdutied 500 kV breaker at Ox Substation with a 63 kA breaker.

The estimated cost is $842.19 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 11. South Area Improvements – Revised Scope of Proposal 711

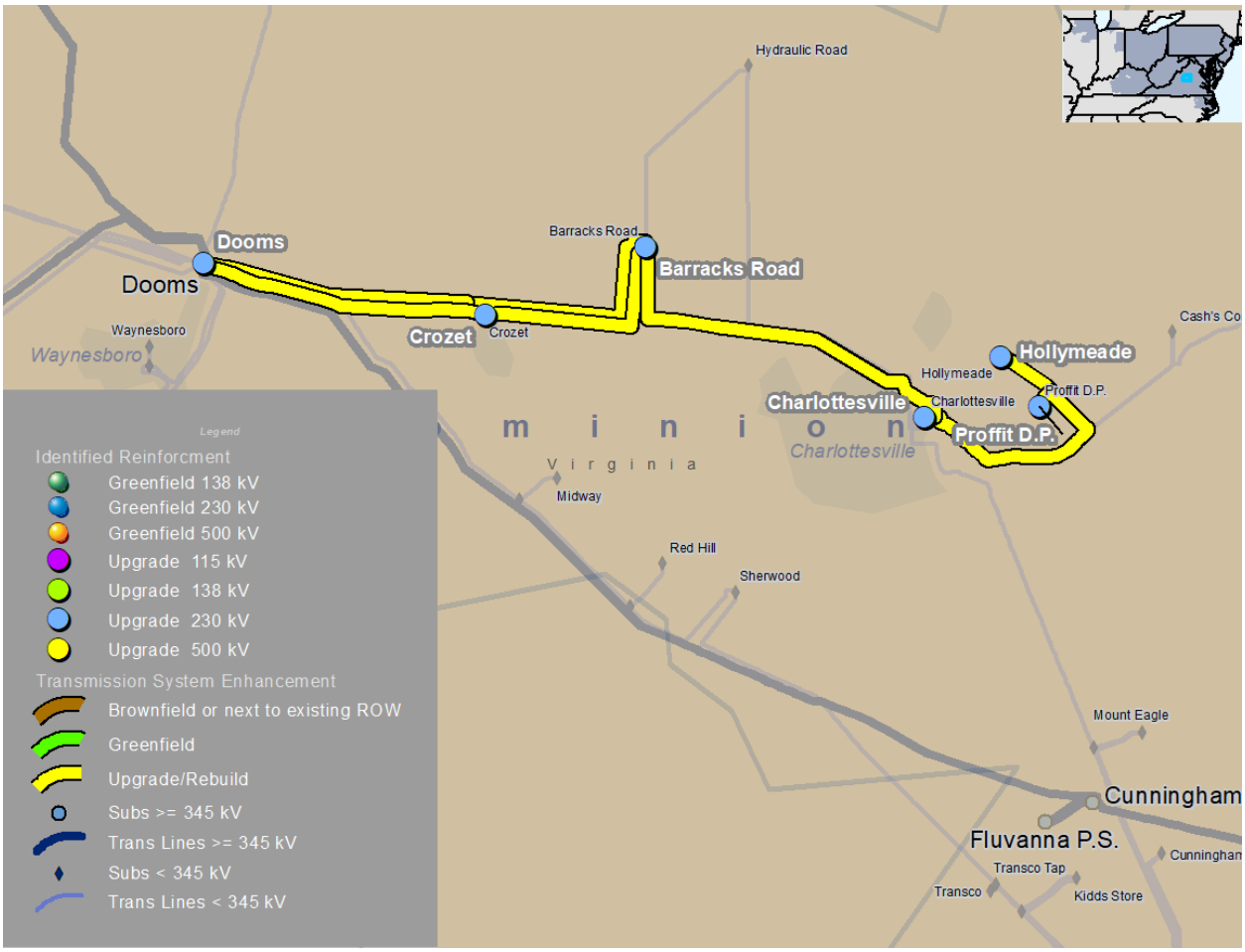


Proposal 967 includes the following 230 kV line rebuilds, along with relay resets/revisions at Hollymeade, Proffit, Barracks Road and Crozet substations:

- Line No. 2054 (Charlottesville-Proffit DP) rebuild using double circuit capable 500/230 kV poles (the 500 kV circuit will not be wired as part of this project)
- Line No. 233 (Charlottesville-Hydraulic Rd-Barracks Road-Crozet-Dooms) rebuild
- Line No. 291 (Charlottesville-Barracks Road-Crozet-Dooms) rebuild

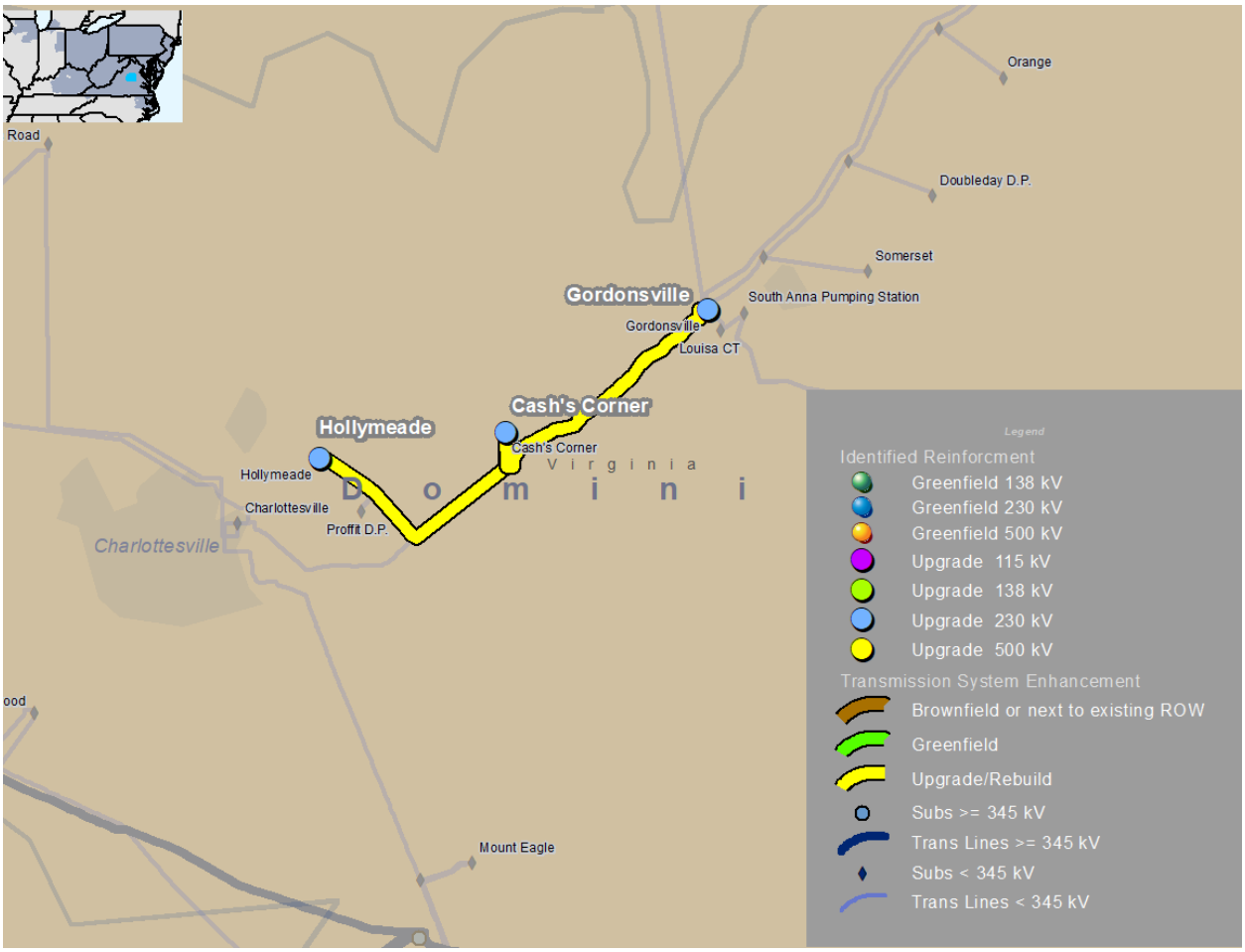
Terminal equipment upgrades will also be required at Charlottesville substation for the Line No. 2054, Line No. 233 & Line No. 291 rebuilds, Hydraulic Road for the Line No. 233 & Line No. 291 rebuilds and Dooms substation for the Line No. 233 & No. 291 rebuilds. The estimated cost is $183.49 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 12. South Area Improvements – Proposal 967



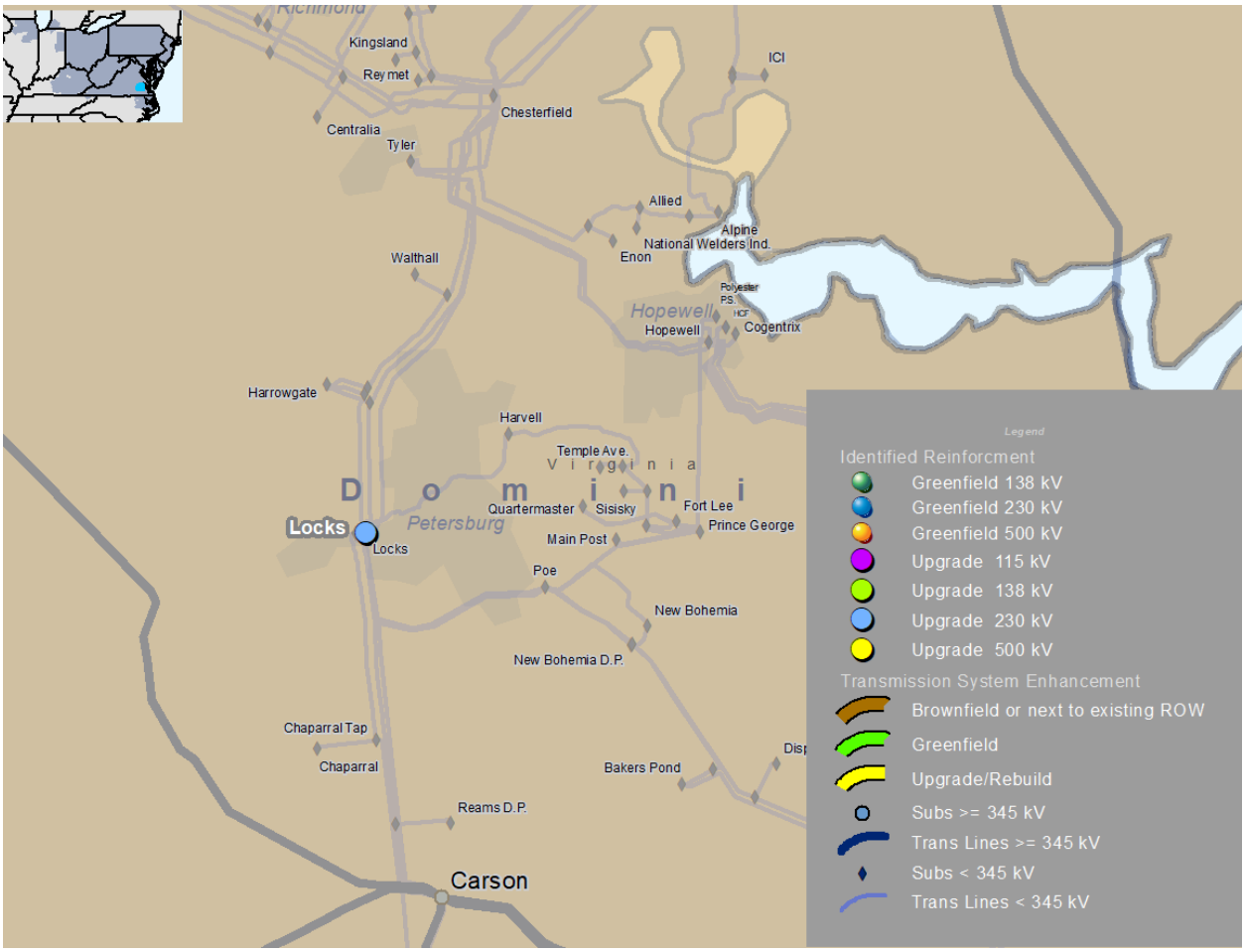
Proposal 211 includes the rebuild of line No. 2135, Hollymeade-Gordonsville 230 kV, using double circuit capable 500/230 kV poles (the 500 kV circuit will not be wired as part of this project). Terminal equipment will also be upgraded at the Hollymeade, Gordonsville and Cash's Corner 230 kV substations. The estimated cost is $54.85 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 13. South Area Improvements – Proposal 211



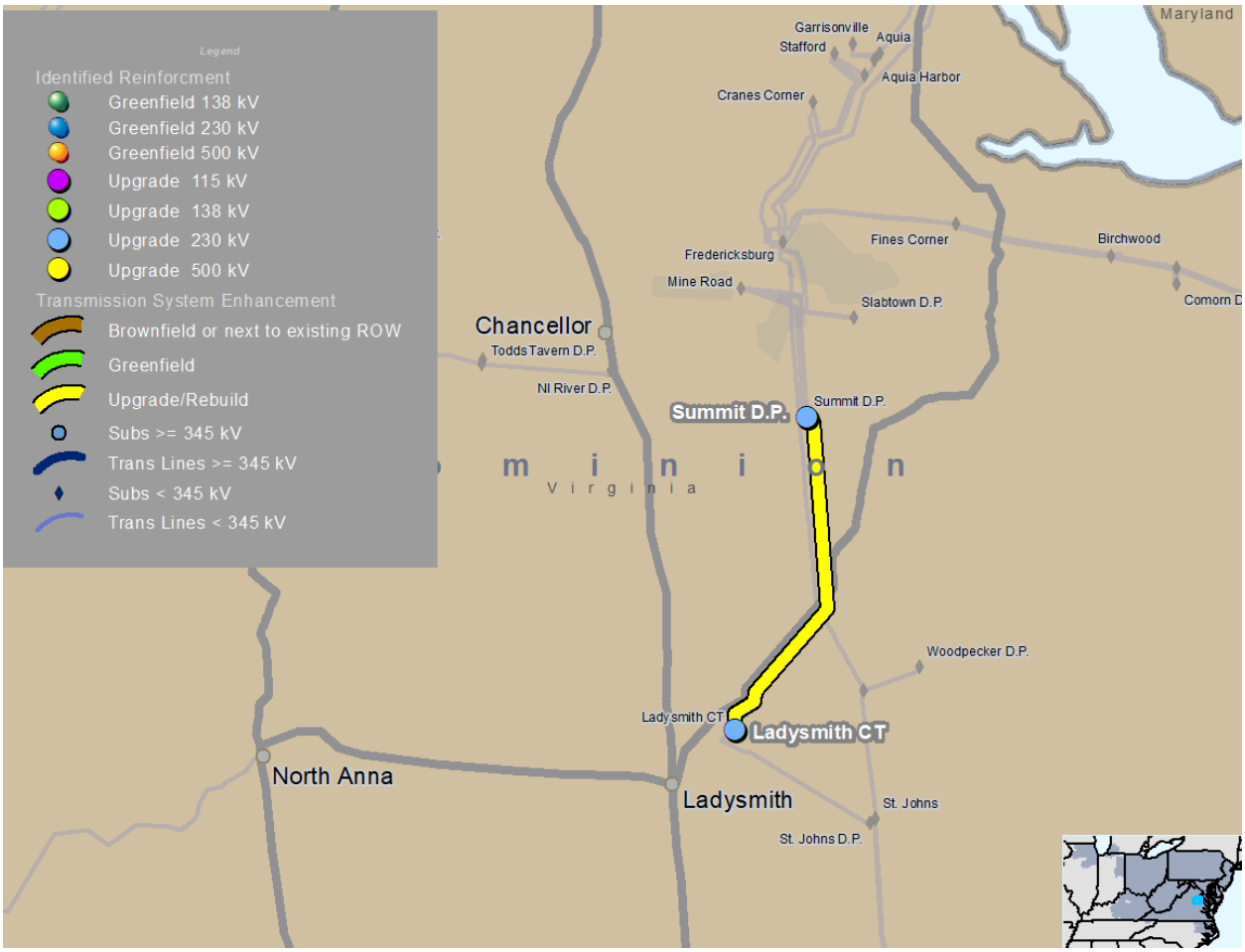
Proposal 731 replaces the single unit Locks 230/115 kV 168 MVA transformer TX No. 7 with a new single unit transformer with a rating of 224 MVA. The leads line at the 115 kV level would also be upgraded to 2000A. The estimated cost is $7.14 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 14. South Area Improvements – Proposal 731



The partial scope of proposal 74 includes the wreck and rebuild of line No. 2090, Ladysmith CT-Summit D.P. 230 kV segment as a double circuit 230 kV line; however, only one circuit will be wired at this stage. Circuit breaker leads, switches and line leads will be upgraded at Ladysmith CT 230 kV substation. The estimated cost is $36.50 million, and the required in-service date is June 2027 with a projected in-service date of December 2027. The local transmission owner, Dominion, will be designated to complete this work.

Map 15. South Area Improvements – Partial Scope of Proposal 74

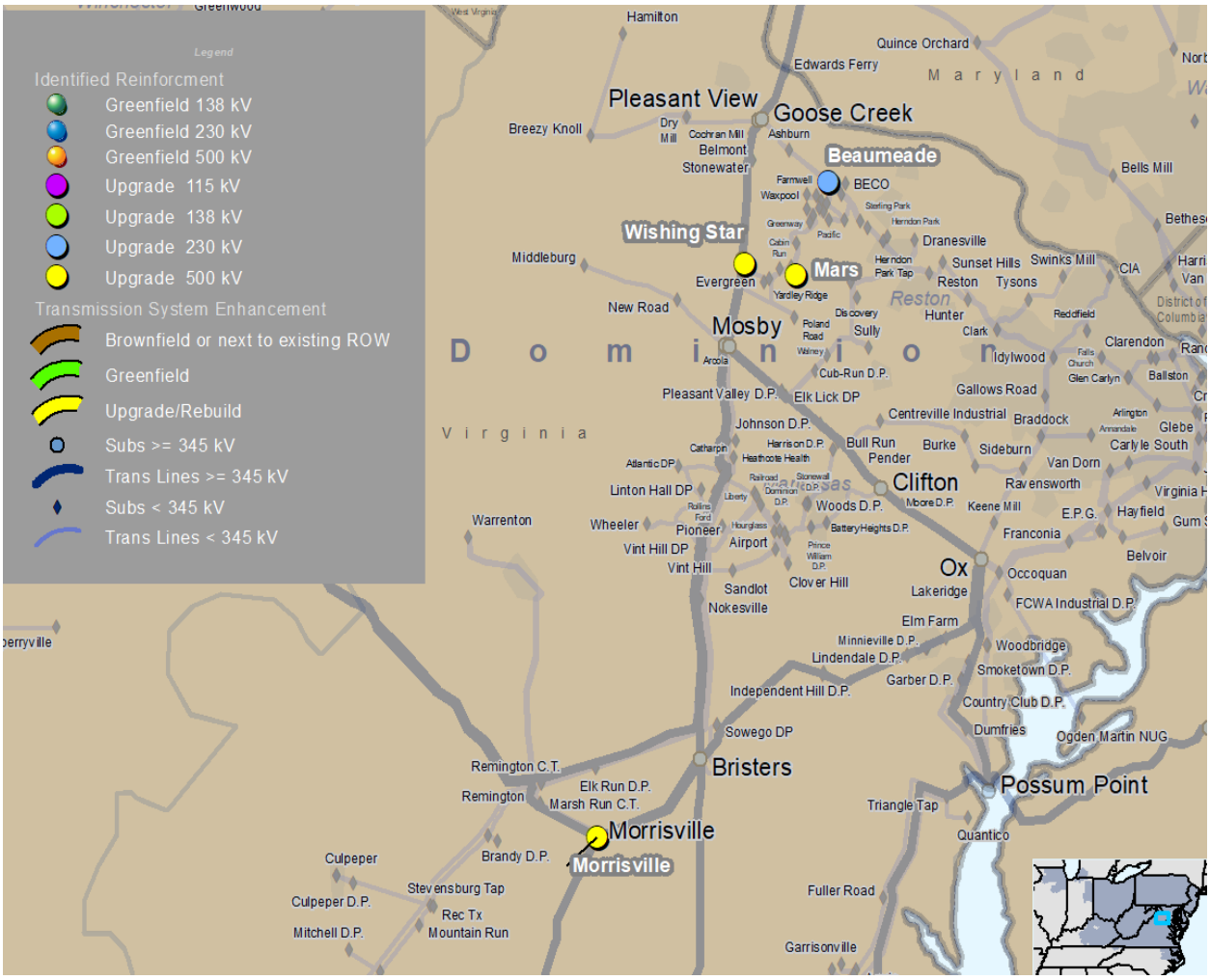


Proposal 231 entails the installation of 230 kV and 500 kV shunt cap banks (static devices) as well as STATCOMs (dynamic devices) and associated equipment to address the reactive power needs of the system. Below is the list of the devices:

- One 500 kV, 150 MVAR shunt capacitor bank and associated equipment at Morrisville substation
- One 230 kV, 150 MVAR shunt capacitor bank and one 500 kV, 293.8 MVAR shunt capacitor bank and associated equipment at Wishing Star substation
- One 500 kV, 300 MVAR static synchronous compensator (STATCOM) and one 230 kV, 150 MVAR shunt capacitor bank and associated equipment at Mars substation
- One 230 kV, 300 MVAR static synchronous compensator (STATCOM) and associated equipment at Beaumeade substation

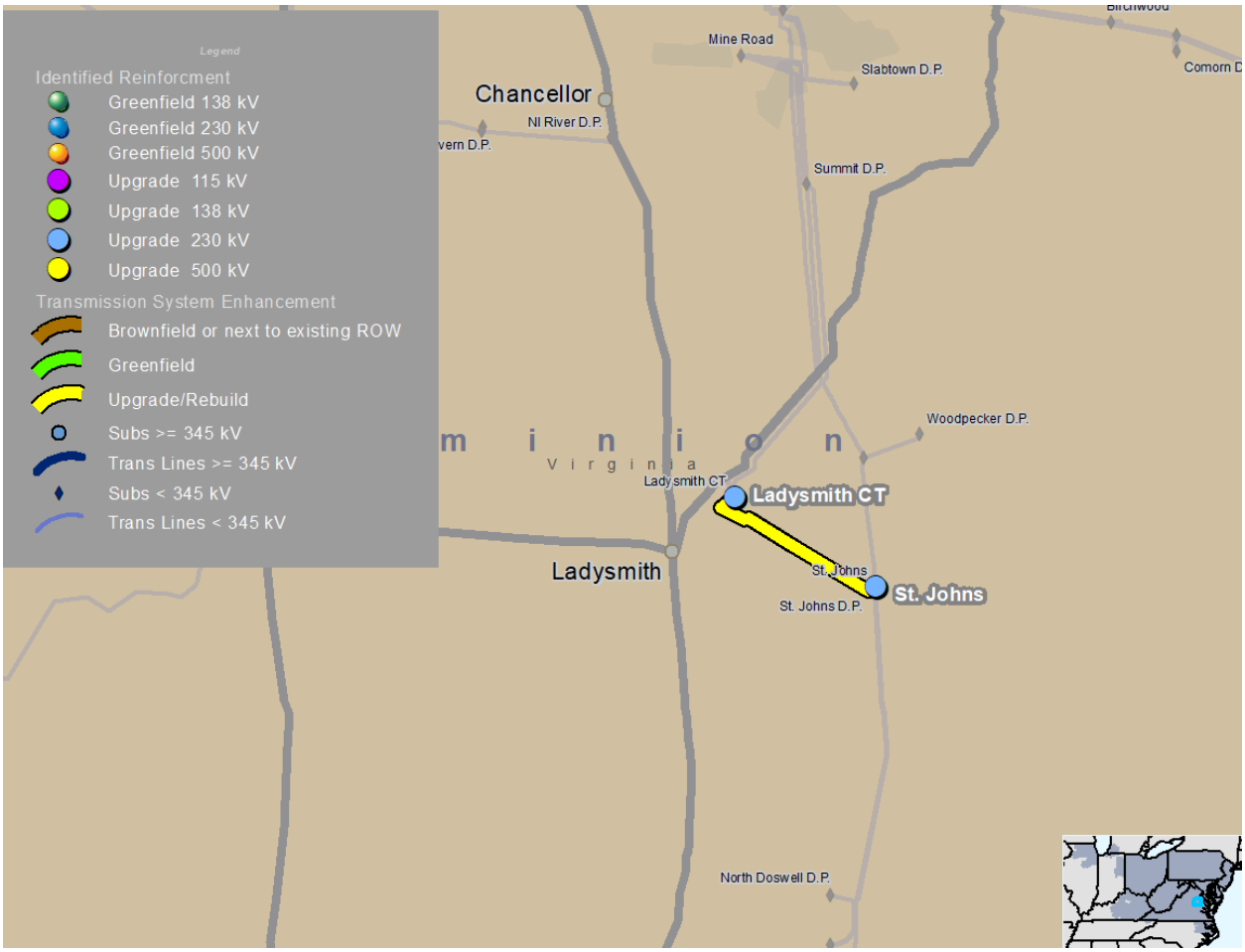
The estimated cost is $103.79 million, and the required in-service date is June 2027 with a projected in-service date of December 2027. The local transmission owner, Dominion, will be designated to complete this work.

Map 16. South Area Improvements – Proposal 231



In addition to the proposals identified above, there are a number of required upgrades identified by PJM. The recommended solution will uprate 12.44 miles of 230 kV circuit 256 from St. Johns to Ladysmith CT. Approximately 7.14 miles of the line from St. Johns substation to structure 256/108 is supported by a mix of single circuit wood and steel H-frames installed in 1991. This portion of the line will be rebuilt with a mix of light duty steel DOM pole tangent H-frames and engineered steel three-pole dead-end angle structures. The proposed conductor for the rebuilt line will be 2-768 ACSS "Maumee" with dual 48 fiber DNO-11410 for shielding. The remaining 5.3 miles of the line from structure 256/107 to Ladysmith CT is supported on double circuit lattice towers installed in 2010–2011. This portion of the line will be reconductored with proposed 2-768 ACSS "Maumee" conductor, and the existing structures and shield wire will remain. Transmission line switch 25666 will be upgraded to 4000A at St. Johns substation. Terminal equipment at remote end substations will be upgraded to 4000A continuous current rating to support new conductor ratings. The estimated cost is $37.89 million, with a required and projected in-service date is June 2028. The local transmission owner, Dominion, will be designated to complete this work.

Map 17. South Area Improvements – PJM Identified Upgrades



Overall, the total cost estimate for the recommended south area improvements is approximately $1,265.85 million.

Northern Virginia Data Center

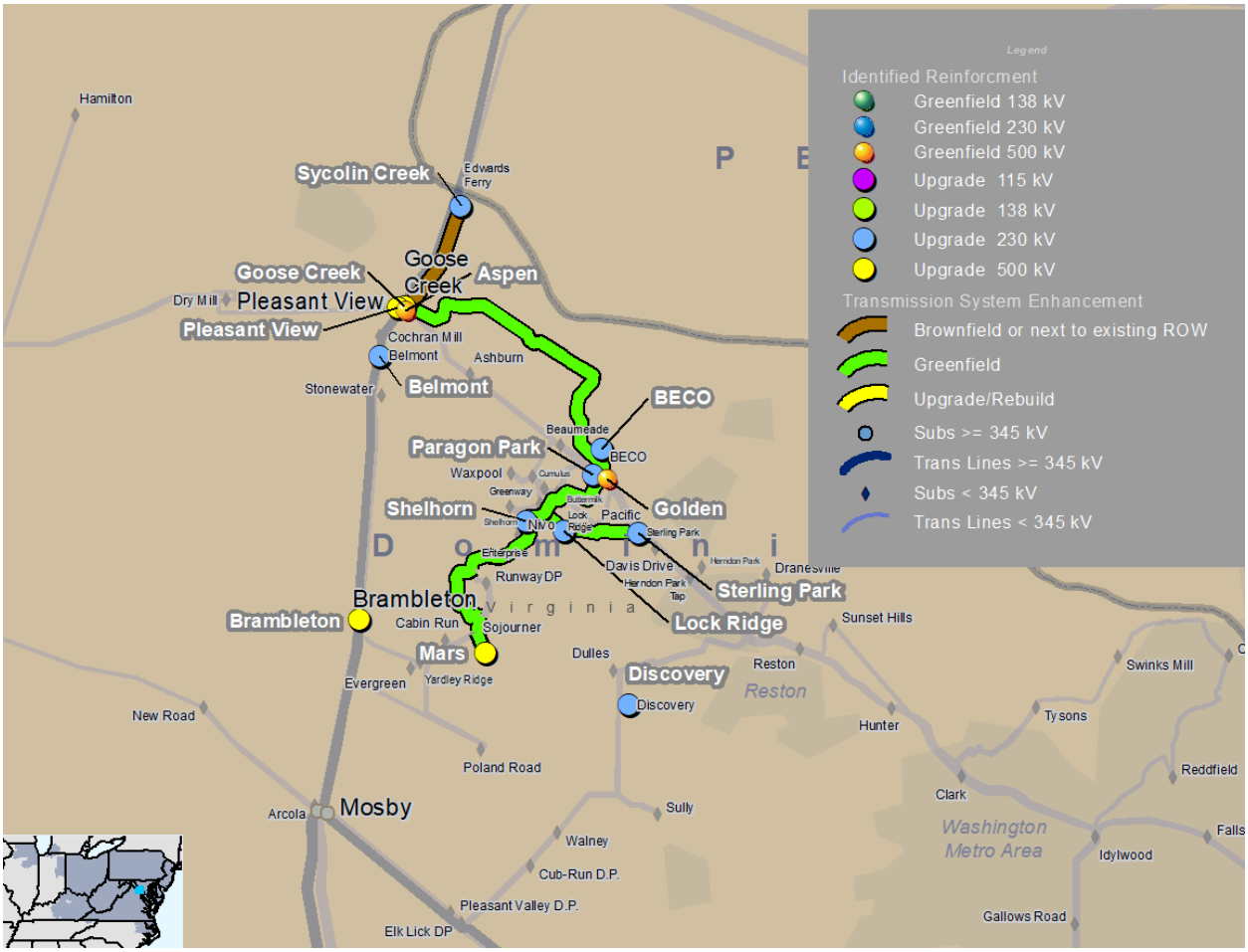
PJM recommends proposal 692 and 516 proposed by Dominion, proposal 344/660 proposed by Exelon and proposal 837 proposed by FirstEnergy to address the northern Virginia data center cluster needs. There are also a number of additional upgrades identified by PJM.

Proposal 692 includes the construction of two new 500/230 kV substations, Aspen and Golden. The Aspen substation will be tapping the 500 kV line No. 558. New double circuit 500/230 kV lines from Aspen to Golden substation will be constructed, where the 230 kV line will connect Aspen-Sycolin Creek-Golden. Similarly, the proposal also includes construction of new double circuit 500/230 kV lines from Golden to Mars, where the 230 kV line will connect Golden-Lockridge-Mars. The project will build a new Aspen-Goose Creek 500 kV line, and install a second 500/230 kV 1440 MVA transformer at the Mars substation. The existing double circuit Golden-Paragon Park 230 kV lines (lines No. 2150 and 2081) will be upgraded, along with the existing single circuit Paragon Park-BECO 230 kV line (line No. 2207). The latter 230 kV line will require a minimum normal summer rating of 1573 MVA, and equipment at each substation will be upgraded to support the new conductor rating of 4000A. The relay settings at Golden substation will be reset, and the overdutied breakers at Belmont, BECO, Beaumeade, Pleasant View, Shellhorn and Discovery will be replaced. The estimated cost is $1,025.06 million, and the required in-service date is

June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

In addition to the scope identified above, there are a couple of reconductors that will be needed. Specifically, 1.47 miles of the Sterling Park-Golden 230 kV double circuit lines (line No. 2081 and 2150), and 0.67 miles of the Davis Drive-Sterling Park 230 kV double circuit lines (lines No. 2194 and 9231) will need to be reconductored. The estimated cost is $13.5 million, and the required in-service date is June 2027 with a projected in-service date of June 2028. The local transmission owner, Dominion, will be designated to complete this work.

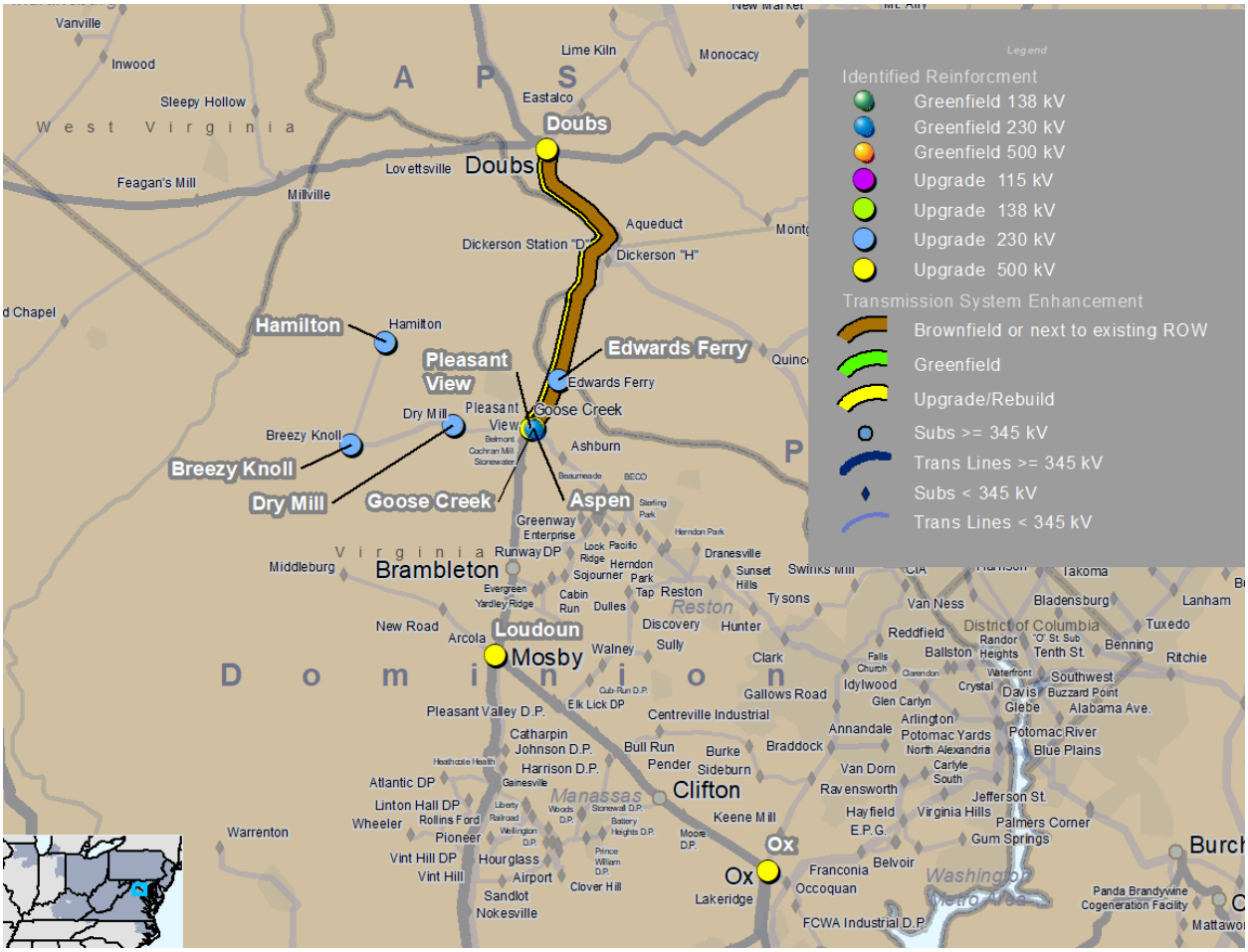
Map 18. Data Center Area Improvements – Proposal 692 and Additional Reconductors



Proposal 516 includes the rebuild of Doubs-Goose Creek 500 kV (line No. 514) using double circuit 500/230 kV towers on foundations. This scope covers line construction between Goose Creek and the Doubs Interconnection point, which is south of the Potomac River. The proposal also constructs a new 500 kV line between Doubs and the new Aspen substation, including line construction between Aspen and the Doubs Interconnection point, which is south of the Potomac River. The Pleasant View-Dickerson 230 kV line (line No. 203), from Pleasant View substation and structure 203/15 within the existing ROW, will be rebuilt using double circuit 500/230 kV towers on foundations. Approximately 1 mile of 230 kV line No. 2098 between Pleasant View and Structure 2098/9, where line No. 2098 turns toward Hamilton Substation, will be wrecked and rebuilt. The one-mile portion will share the new double circuit 500/230 kV towers with line No. 514, which is being rebuilt as part of the project. Relays will be reset or revised at Breezy, Dry Mill and Hamilton 230 kV substations. The terminal equipment at Goose Creek, Pleasant View and

Edwards Ferry 230 kV substations will be upgraded, and overdutied breakers will be replaced at the Loudon, Ox and Pleasant View 500 kV substations. The estimated cost is $78.4 million, and the required in-service date is June 2027 with a projected in-service date of December 2027. The local transmission owner, Dominion, will be designated to complete this work.

Map 19. Data Center Area Improvements – Proposal 516

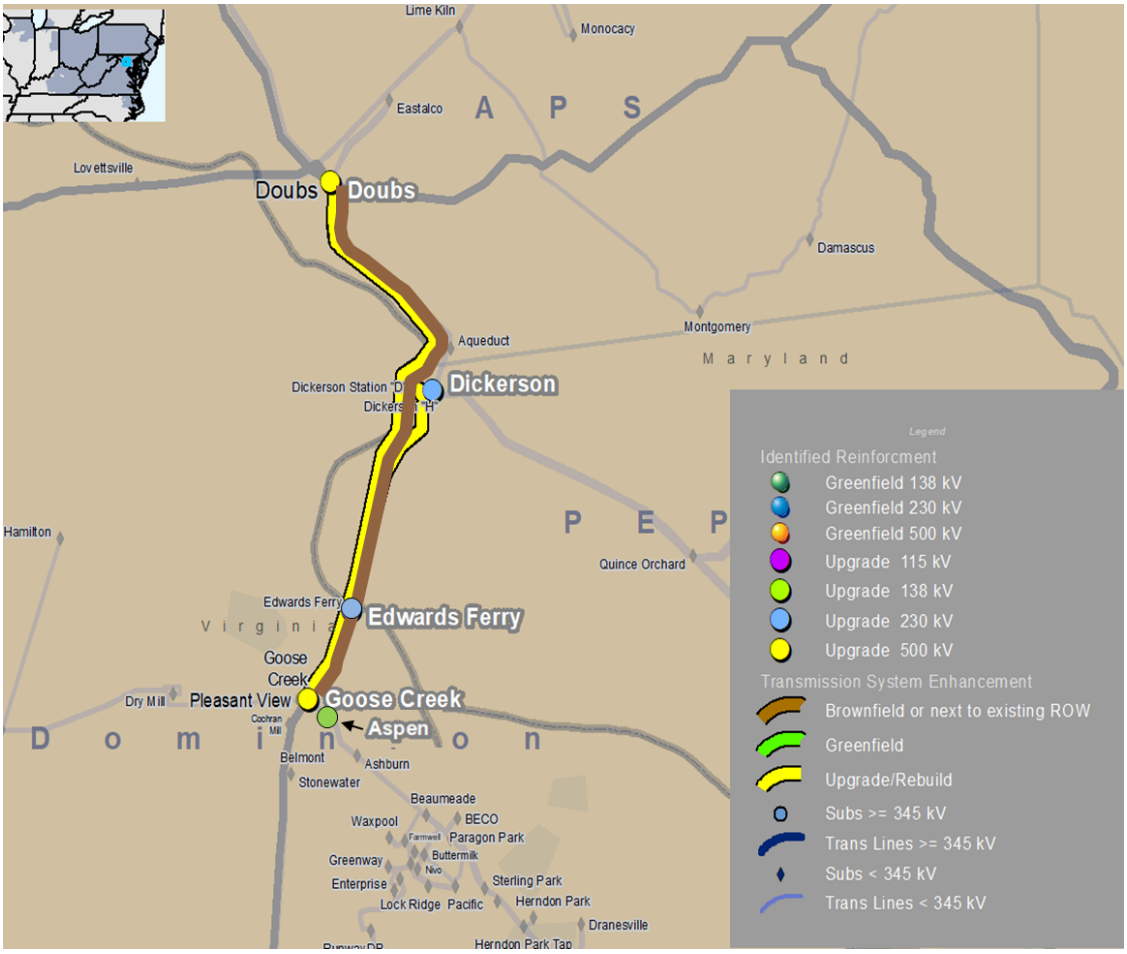


The recommended scope from proposal 344/660 by Exelon includes rebuilding 7.26 miles of existing 230 kV circuit from Dickerson Station H to Ed's Ferry area to accommodate the new 500 kV circuit between Doubs and Goose Creek. The new structure will carry both 500 kV and the 230 kV from Dickerson Station H to Ed's Ferry circuits. The Dickerson H 230 kV substation will be reconfigured and terminal equipment upgraded. The Exelon portion of the new Doubs-Goose Creek 500 kV scope utilizes existing Exelon ROW. The estimated cost is $66.38 million, and the required in-service date is June 2027 with a projected in-service date between 2028 and 2030. The local transmission owner, Exelon, will be designated to complete this work.

Proposal 837 from FirstEnergy includes the rebuild of the Doubs-Goose Creek 500 kV (line No. 514). The proposal also builds a new Doubs-Aspen 500 kV line (the Aspen substation is part of Dominion's proposal 692 detailed above). The Doubs – Dickerson 230kV line will be rebuilt. The Doubs-Aqueduct and Aqueduct-Dickerson 230 kV lines will be rebuilt and attached on the same structures as those for the Doubs-Aspen 500 kV line. At Doubs substation, the rebuilt Doubs-Goose Creek 500 kV line will be reterminated in its existing bay, and the new Doubs-Aspen 500 kV line will be terminated in the open bay at Doubs. Additionally, three circuit breakers, terminal

equipment including disconnect switches, CTs and substation conductor, and relaying will be replaced at the Doubs 500 kV substation. The estimated cost is $234.96 million, and the required in-service date is June 2027 with a projected in-service date of June 2030. The local transmission owner, FirstEnergy, will be designated to complete this work.

Map 20. Data Center Area Improvements – Proposals 344/660 and 837



Overall, the total cost estimate for the recommended northern Virginia data center area improvements is approximately $1,418.3 million.

East

PJM recommends proposal 344/660 by Exelon, proposal 374 by PPL, proposal 637 by PSEG and proposal 837 by FirstEnergy to address the East cluster needs.

PJM is sought to utilize and incorporate already Board-approved NJ SAA project scope at North Delta substation, and adjusted the Exelon proposal 344/660 scope accordingly. The recommended solution expands the North Delta 500 kV substation (scope beyond that proposed under Brandon Shore deactivation) to accommodate the termination of the new 500 kV lines as well as reconfiguration of the Peach Bottom substation. The North Delta 500 kV substation expansion will include a four bay breaker and a half configuration. The proposal includes building a High Ridge 500 kV substation, which will cut into the Brighton-Waugh Chapel 500 kV line. The High Ridge 500 kV substation will include

three bay breaker and a half configuration with two 500/230 kV transformers, and terminal equipment will require replacement at both Brighton and Waugh Chapel 500 kV substations.

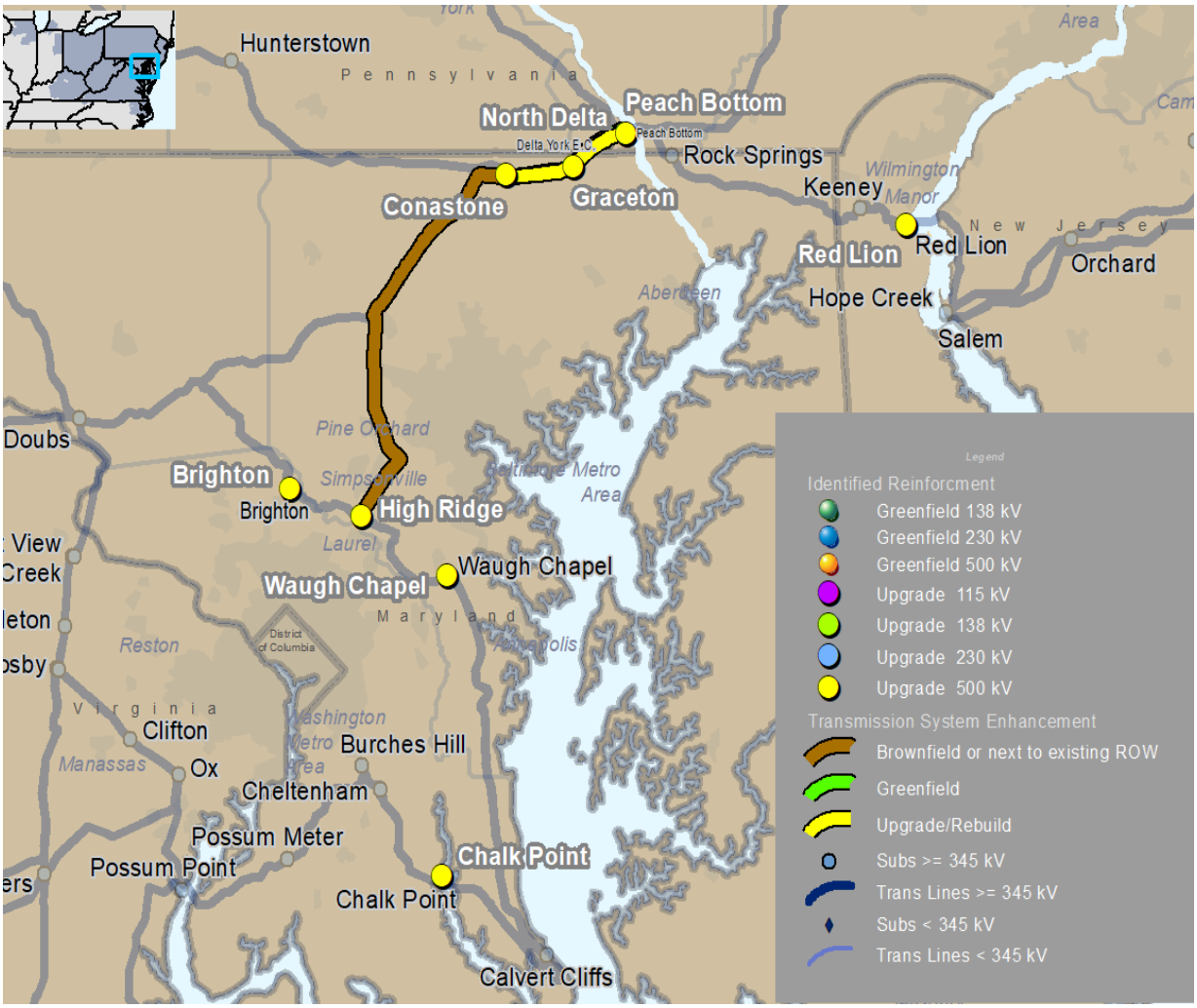
The proposal builds a new Peach Bottom South-North Delta 500 kV line by cutting into Peach Bottom tie No. 1 and extending the line to North Delta, which entails approximately 1.25 miles new ROW. The existing Peach Bottom-Conastone 500 kV line (5012L) will be rebuilt on single circuit structures within existing ROW and cut into North Delta 500 kV and Gracetone 500 kV stations. Furthermore, the proposal builds a new North Delta-High Ridge 500 kV line, which will extend approximately 65 miles.

In addition to the regional proposal scope described above, there following Exelon proposal components would be required:

- Conastone-Brighton 500 kV (5011 circuit) – Replace terminal equipment limitations at both Conastone and Brighton 500 kV
- Brighton-Waugh Chapel 500 kV (5053) – Replace terminal equipment limitations at Brighton 500 kV
- Chalk Point-Cheltanham 500 kV (5073) – Replace relay at Chalk Point 500 kV
- Conastone-Peach Bottom 500 kV (5012 circuit) – Upgrade two existing 500 kV breakers at Conastone from 4000A to 5000A
- Peach Bottom 500 kV – Reconfigure and upgrade several terminal/substation equipment at both North and South Peach Bottom 500 kV substations
- Red Lion-Hope Creek 500 kV – Replace terminal equipment at Red Lion

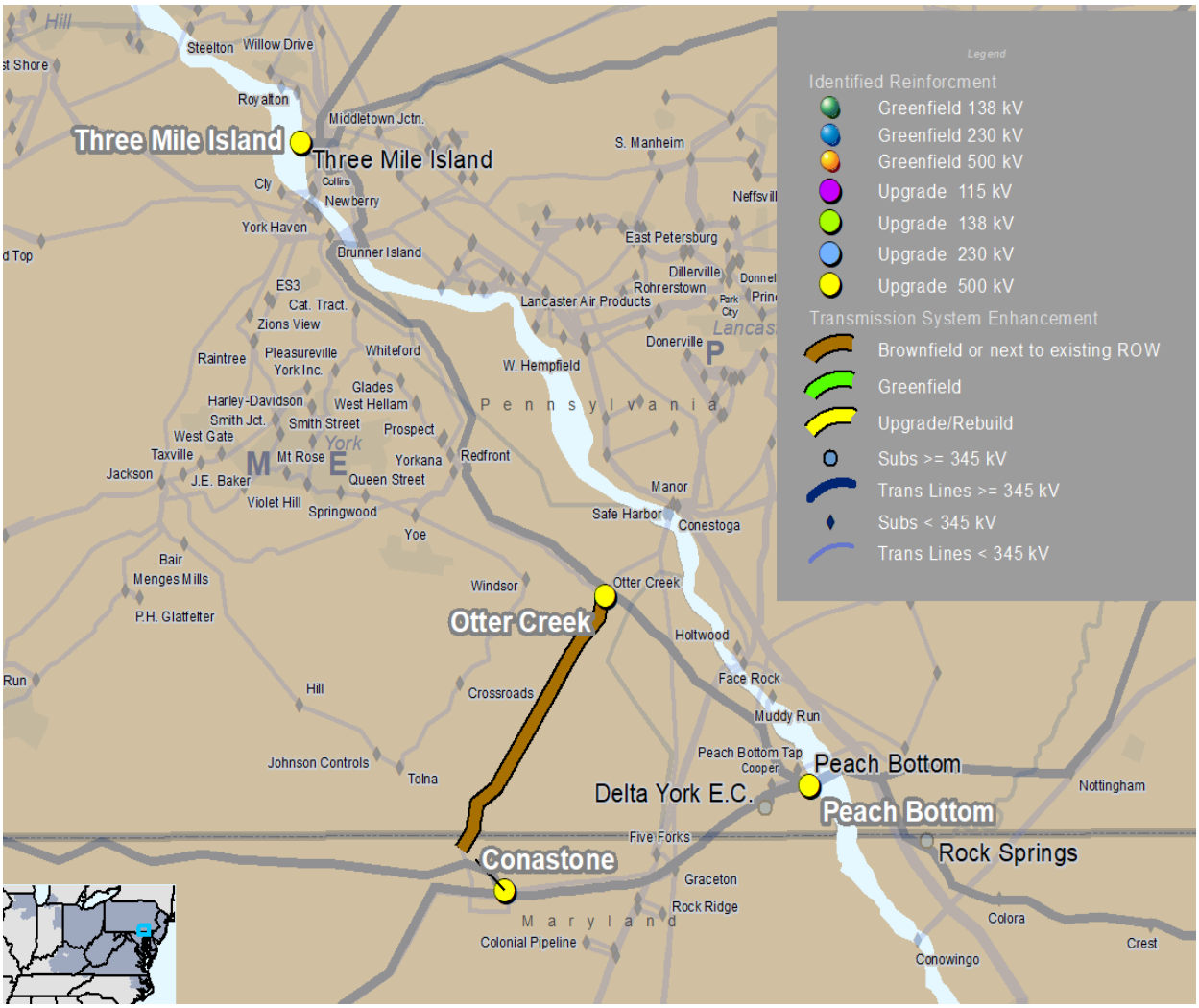
The estimated cost for the work described above is $708.77 million, and the required in-service date is June 2027 with a projected in-service date between 2028 and 2030. The local transmission owners, Exelon, will be designated to complete this work.

Map 21. East Area Improvements – Proposal 344/660



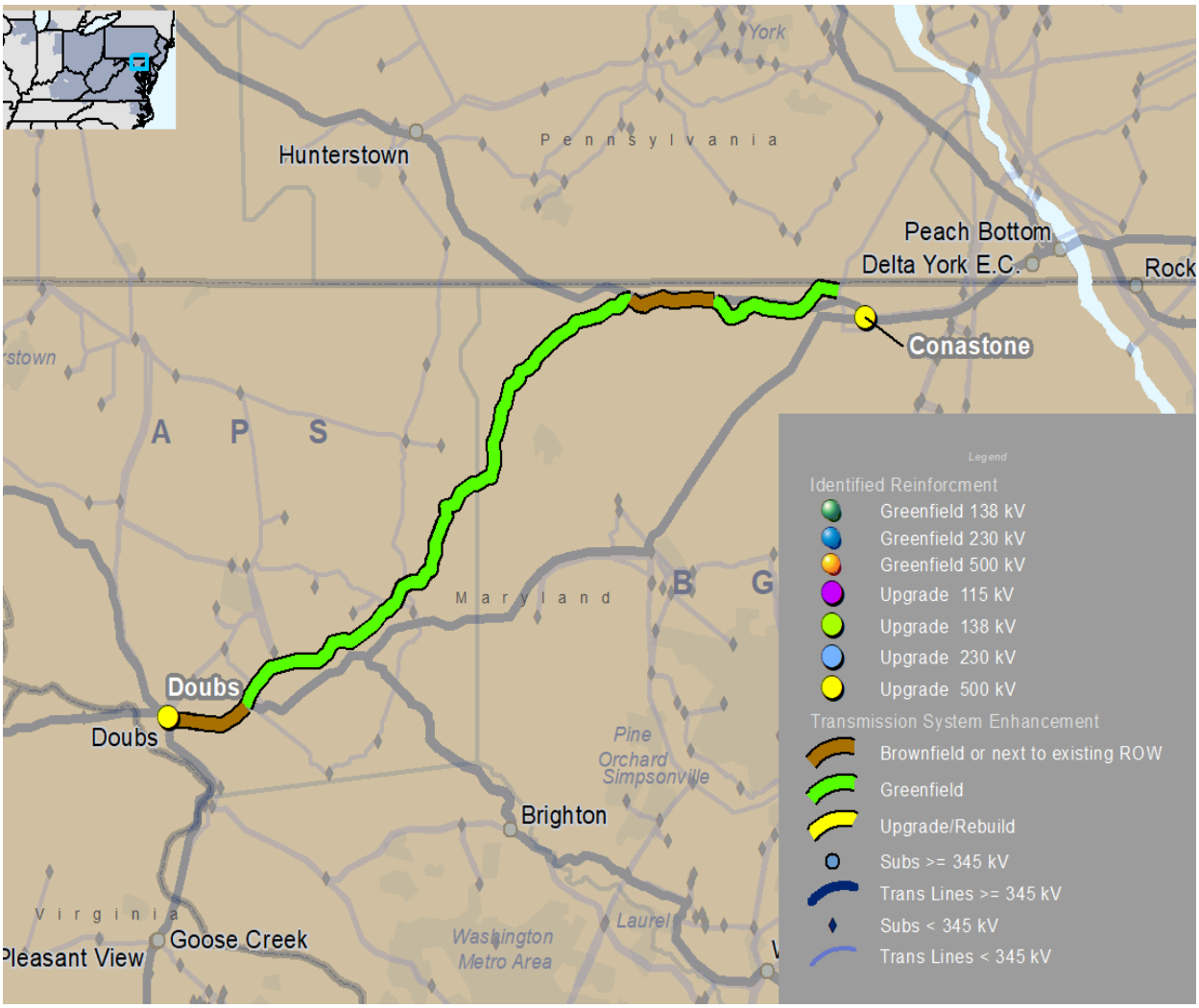
Proposal 374 by PPL includes building a new Otter Creek 500 kV switching station, with two bay three-breaker configuration, that cuts into the Peach Bottom-TMI 500 kV line. An approximately 17-mile new 500 kV line from Otter Creek toward the Conastone station fence (Conastone demarcation point) would be built, and the existing Otter Creek-Conastone 230 kV line would be rebuild to become a double circuit 500 and 230 kV line. Additionally, terminal equipment will be upgraded at the Peach Bottom and TMI 500 kV substations. The estimated cost is $134.2 million, with a required and projected in-service date of June 2027. The local transmission owners, PPL and BGE, will be designated to complete this work.

Map 22. East Area Improvements – Proposal 374



Proposal 637 by PSEG includes an approximately 40-mile new 500 kV line from the Conastone demarcation point (with the PPL Otter Creek line) to Doubs substation. The Conastone substation is referenced for this demarcation point only for general reference and does not have to necessarily be in the area of the Conastone substation. The new 500 kV line will tie into the PPL-proposed Otter Creek-Conastone 500 kV, bypassing the actual Conastone substation. The Doubs 500 kV substation will be reconfigured and terminal equipment upgraded to terminate the new line. The estimated cost is $447.5 million, with a required and projected in-service date of June 2027. The proposing entity, PSEG, will be designated to complete this work.

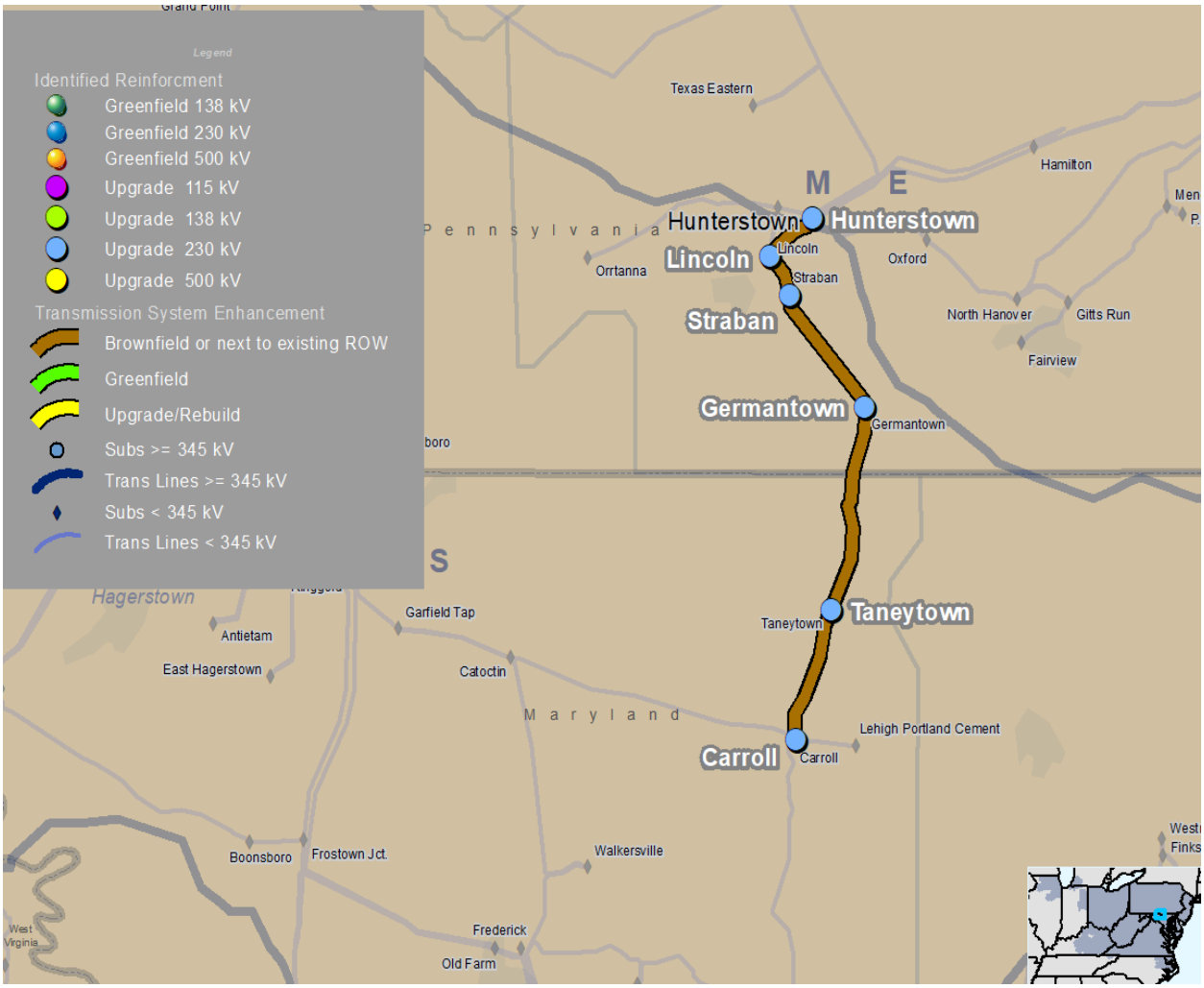
Map 23. East Area Improvements – Proposal 637



Proposal 837 by FirstEnergy builds a new Hunterstown-Carroll 230 kV line in addition to rebuilding the existing 115/138 kV corridor as double circuit using 230 kV construction standards.

In addition to the Hunterstown-Carroll 230 kV line scope, there are a few PJM identified upgrades that will be needed. Specifically, the Lincoln-Orrtanna 115 kV line will be reconductored, and the line trap at the Grand Point 138 kV substation for the Fayetteville-Grand Point 138 kV line will be replaced. The proposal also includes the replacement of the line trap, substation conductor, breaker, relaying and CTs at Ringgold 138 kV substation for the Reid-Ringgold 138 kV line. Furthermore, with this additional scope, the baseline project b3768, which rebuilds/reconductors the Germantown-Lincoln 115 kV line ($17.36 million) is not required and the baseline project would be canceled. The total estimated cost of the proposal 837 scope of work and the additional PJM identified upgrades is $152.65 million, and the required in-service date is June 2027 with a projected in-service date between 2028 and 2030. The local transmission owner, FirstEnergy, will be designated to complete this work.

Map 24. East Area Improvements – Proposal 837



Overall, the total cost estimate for the recommended East area improvements is approximately $1,443.12 million.

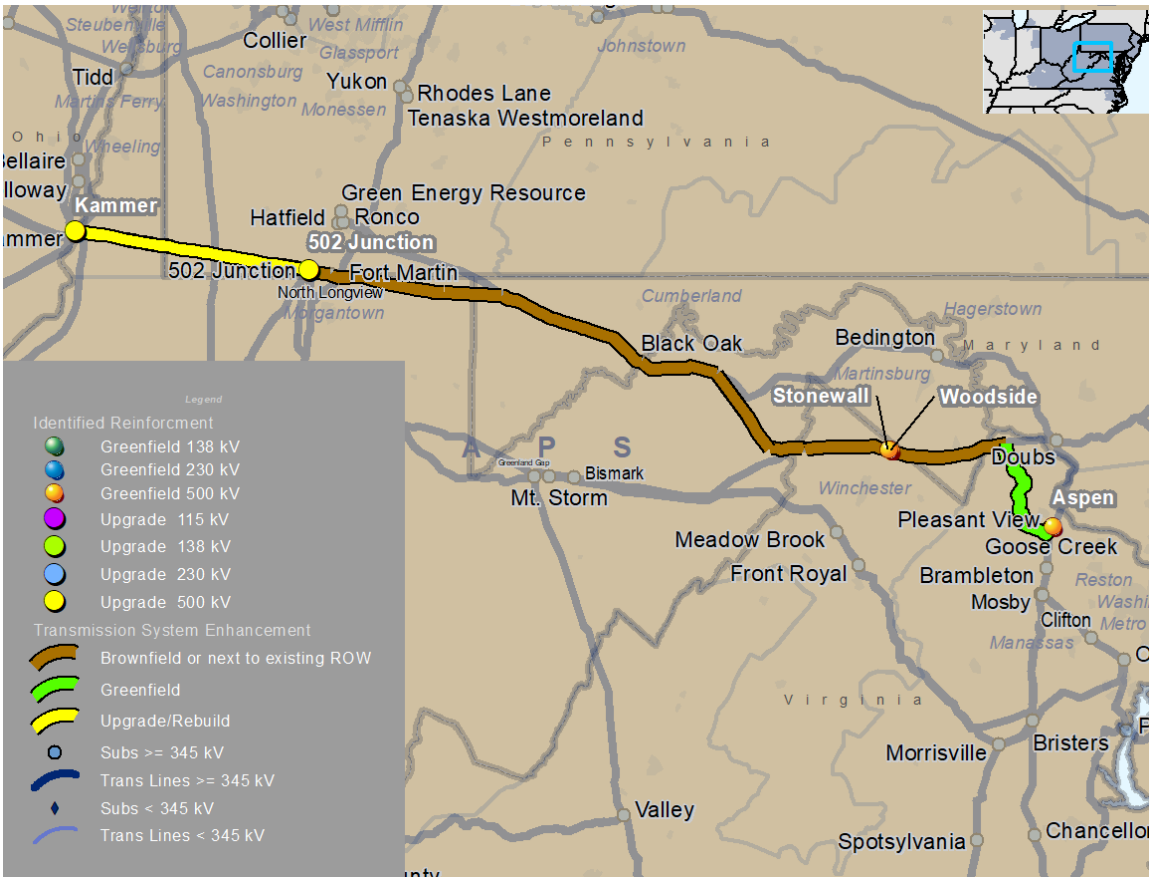
West

PJM recommends a modified scope of proposal 853 proposed by NextEra to address the West cluster needs. The recommended scope includes a new 500 kV line from the existing 502 Junction substation to a Woodside 500 kV substation, noting that the line will bypass the Black Oak substation. The existing First Energy substation, primarily 502 Jct 500 kV and Stonewall 138 kV will be upgraded by adding additional bay position via new breakers. The Woodside 500 kV substation will be a breaker and half configuration built adjacent to the existing Stonewall 138 kV substation, and loop in the Bismark-Doubs 500 kV line. The substation will include two 500/138 kV transformers, and two 150 MVAR capacitor banks as well as one +500/-300 MVAR STATCOM. Furthermore, the project will also build a new 500 kV line from the Woodside substation to the new Aspen substation (part of Northern Virginia Data Center cluster recommended solution). Aspen substation work will be required to terminate the Woodside-Aspen 500 kV line. The 500 kV line to be built east and west of existing Stonewall 138 kV will be assigned to First Energy's on existing ROW with 500 kV overbuilt. First Energy will be assigned roughly 36 miles of the 500 kV overbuilt.

The recommended solution also includes a LIDAR sag study to assess the summer emergency rating and any needed upgrades on the Kammer-502 Junction 500 kV line to adequately increase the line rating.

The estimated cost of work assigned to FE is $392.55 million. The estimated cost of work assigned to NextEra is $512.61 million and the estimated cost of work assigned to Dominion is $35.59 million. The estimated cost of work assigned to AEP is $0.1 million. The required in-service date is June 2027 with a projected in-service date between 2027 and 2030. The proposing entity, NextEra, along with the local transmission owners, FirstEnergy, Dominion and AEP, will be designated to complete this work. Overall, the total cost estimate for the recommended West area improvements is approximately $940.85 million.

Map 25. West Area Improvements – Modified Proposal 853



Short Circuit

Stemming from PJM's short-circuit analysis, PJM recommends the replacement of 36 circuit breakers, as detailed in the Short-Circuit Analysis section of this report. The total cost estimate to for the breaker replacements is approximately $63.27 million.

Table 10. Rationale – All Clusters

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios	
1	9	**AEP**	Local AEP	Scottsville-Bremo Sag Study	$1.27	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A	
2	23	**POTOED – FirstEnergy**	West	Data Center Reinforcement Proposal No. 2 • 2 - 500 kV circuits from Fort Martin-Doubs • 1 - 500 kV circuit from Prutnytown-Meadow Brook-Doubs • Second 500 kV from Doubs-Aspen and Rebuild the existing Doubs-Goose Creek 500 kV • Rebuild Hunterstown-Caroll 115/138 kV line for 230 kV double circuit construction	$3,503.86	**Yes**	**No**	Yes *(partial)*	• Proposal attempts to address the west-east transfer needs and voltage collapse concerns along the transfer path • PJM analysis indicated that the system reliability benefits more from spreading the reinforcements for transfer between the East and West corridors instead of just the Western corridor • All options provide injections into Doubs; however, no solutions offered to debottleneck the Doubs-Goose Creek corridor • Currently there is no need for 2x500 kV double circuit development along the West-East corridor • Only 1x500 kV is required part of the PJM selected solution • Cost is higher than similar 500 kV proposals by other entities that provide stronger cost containment provisions • Proposal utilizes existing ROWs for parts of the projects including the new Doubs-Aspen 500 kV and Huntertown-Caroll 230 kV, which both components are in the list of PJM selected projects	• 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0M	• 0N • 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
3	24	**PSEG**	EAST	Proposal A - North Delta-New Raphael-Waugh Chapel 500 kV	$739.40	**Yes**	**Yes**	No	Selected proposal meets needed system performance with less impact (Green Field vs Brownfield and Timeline/construction risk considerations)	OS-REV	

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
4	28	**NextEra**	East/ West/ Northern Virginia	Hunterstown-Doubs-Goose Creek, Black Oak-Pike-Goose Creek, Pike SVC + Cap Banks	$884.05	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2
5	30	**Dominion**	South	Charlottesville-Hollymead Line No. 2054 Rebuild	$159.87	**Yes**	**Yes**	No	Dominion proposal No. 967 chosen over proposal No. 30. Both proposals include a wreck and rebuild of 230 kV Line No. 2054. However, proposal No. 30 utilizes double-circuit capable 230 kV poles, whereas proposal No. 967 utilizes double-circuit capable 500/230 kV poles.	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
6	55	**AEP**	Local AEP	Boxwood-Scottsville 138 kV Rebuild	$104.88	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500kV solutions (that address the primary need drivers for the window)	N/A
7	74	**Dominion**	South	Line No. 2090 (Ladysmith CT-Fredericksburg) Rebuild	$57.34	**Yes**	**Yes**	Yes *(partial)*	Required for reliability needs. Most efficient or cost-effective solution	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West / 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
8	116	**NextEra**	East/ Northern Virginia	Hunterstown-Doubs-Gant Solution, two new 230 kV line from new Belmont to Farmwell and Roundtable substation to feed data center alley	$478.87	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2
9	125	**PSEG**	EAST	Proposal B - North Delta-Northeast 230 kV	$313.34	**Yes**	**No**	No	Not required to meet the 2022W3 needs (inferior to selected solutions) with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
10	129	**Dominion**	Northern Virginia/ South	Dominion Aggregate 500 kV Proposal	$3,035.05	**Yes**	**Yes**	Yes *(Partial)*	Offers robust solution to serve the data center loads in the Dominion zone (northern Virginia) and also offers parallel 500 kV path to the single 500 kV line between Goose Creek and Wishing Star	• 1A / 1B / 1C / 1C-1 • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
11	175	**NextEra**	ALL	Combination of PEBO 215A + WOP 1F + SOP 8E	$6,265.95	**Yes**	**Yes**	No	• Solution (as one package) is more expensive, less effective and less efficient than selected proposal. • The combination solutions fails the load deliverability test in BGE and SW-MAAC • The combination proposal, particularly in the Eastern cluster introduces significant additional number of 230 kV circuits, while this elected proposal addresses those needs via 2x500 kV circuits predominantly along existing ROWs	• 0B / 0B2 / 0B3 • 0O / 0O2 / 0O3 • 0R / 0R2
12	181	**AEP**	Local AEP	Boxwood-Scottsville 138 kV Sag Study	$4.26	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

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13	196	**AEP**	Local AEP	Glen Lyn-Peters Mountain Rebuild	$21.89	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
14	202	**AEP**	Local AEP	Cloverdale Transformer Addition	$57.29	**Yes**	**Yes**	No	Much higher cost comparing to Proposal 410	N/A
15	211	**Dominion**	South	Hollymead-Gordonsville Line No. 2135 Rebuild	$54.85	**Yes**	**Yes**	Yes	Required for reliability needs. Considers future load growth in Culpeper and Louisa area by supporting 500 kV developments with double-circuit capable 500/230 kV poles.	• 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
16	217	**NextEra**	East	North Delta-Conastone Solution	$155.99	**Yes**	**Yes**	No	Solution offered part of an alternate more efficient and cost-effective proposal while utilizing existing ROW and with limited impacts	• 2 / 2A / 2B / 2C / 2D / 2E / 2F • QT1 / QT3
17	229	**PSEG**	East	Proposal C - Hunterstown-New Green Valley 500 kV	$529.11	**Yes**	**No**	No	Hunterstown supply into the northern Virginia system is inferior to supplying the northern Virginian system from the Peach Bottom area	0E2
18	231	**Dominion**	Northern Virginia/ South	Reactive Power VAR Reinforcements	$155.82	**Yes**	**Yes**	Yes *(partial)*	Required for reliability needs. Most efficient or cost-effective solution	0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-10-A / 0E11-11 / 0E11-12
19	234	**AEP**	Local AEP	Glen Lyn-Peters Mountain Sag Study	$0.80	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
20	255	**NextEra**	East/ Northern Virginia	Hunterstown-Doubs-Gant Solution	$411.61	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2

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21	279	**NextEra**	West/ Northern Virginia	Black Oak-Woodside-Goose Creek, Woodside SVC + Cap Banks Solution	$429.18	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-12
22	325	**PSEG**	East/ South	Proposal E - Brambleton-Hinsons Ford Rd 500 kV, North Delta-New Raphael Road-Waugh Chapel 500 KV	$944.05	**Yes**	**No**	No	Limited overall effectiveness of solution to meet the needs if bulk transfer solutions are adequately addressed. Line has high greenfield construction risk and high project delay risk are identified	2D
23	344	**PECO**	East	PECO Expansion Plan for DOM Window 2023	$302.86	**Yes**	**Yes**	Yes	• Meets performance requirements and efficiently utilizes existing ROW • Most efficient or cost-effective • Provides solid robust performance to meet the needs in the PB-Conastone and BGE areas	• 1A • 1B • 0E Series • 0F • 0G • 0H / 0H2 • 0H2 • 0I • 0J / 0J-2/ 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S • 2 / 2A / 2B / 2C / 2D / 2E
24	347	**NextEra**	West/ Northern Virginia	Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$483.83	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
25	374	**PPL**	East	Otter Creek-Conastone 500 and 230 kV DCT Line	$154.21	**Yes**	**Yes**	Yes	• Most cost-effective or efficient solution to achieve additional East-West bulk transfer reinforcements and also assist with clearing capacity along the PB-Conastone corridor • Line supports the BGE/PEPCO system under outage conditions, Load Deliverability and needed supply source capability into northern Virginia/APS	0E Series (except for 0E2 / 0E3 / 0E6 / 0E6-1 / 0E7)

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26	385	**NextEra**	East/ Northern Virginia	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$1,140.73	**Yes**	**Yes**	No	• New substation (Barthlow) not needed part of the selected solution set • Major substation with 12 - 230 and 500 kV lines terminating into it that could be eliminated • No need for a new North Delta substation (one already approved and well-ahead through process) • Grisham and Goran substations are both new proposed substation, which are both avoided under the PJM selected proposal	• 0O • 0R
27	410	**AEP**	Local AEP	Cloverdale Breaker Reconfiguration	$11.59	**Yes**	**Yes**	Yes	Required part of the PJM 500 kV selected solution for 2022W3	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-10 / 0E11-10-A / 0E11-11
28	419	**NextEra**	East/ Northern Virginia	Hunterstown-Doubs-Audobon-Goose Creek	$548.75	**Yes**	**No**	No	The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need	0H/0H2
29	445	**NextEra**	East	Muddy Creek / Delta-Conastone / Hunterstown-Doubs-Goose Creek Solution	$637.80	**Yes**	**Yes**	No	• Similar 500 kV solution that is planned for construction efficiently and effectively along existing ROW is part of the PJM selected proposal • The selected PJM proposal achieves the needed transfer capability East-West with less impact (fewer lines and much less new substations)	• 2E • 0H / 0H2
30	477	**AEP**	Local AEP	Fieldale-Franklin Rebuild	$74.89	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

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21	487	**AEP - Transource**	East	Maryland & Pennsylvania Baseline Reliability Solution	$492.75	**Yes**	**No**	No	• Does not meet the 2027/28 needs • Solution designed predominantly to address the 2027 case needs only • More cost-effective and efficient solutions were offered part of the 2022W3 RTEP • The solutions are less effective than those selected by PJM • Proposal does not offer solutions to the BGE local needs and fails the load deliverability test/needs • Solution is predominantly greenfield	• 1C / 1C-1 • 0A • 0E5 • 0E8-2 • 0E11-7-B+IEC West • 0E11-7-B + Hunterstown-Carrol Rebuild + IEC West • 0E11-8 • 0E11-11 • 0P / 0P2
32	516	**Dominion**	Northern Virginia	Aspen-Doubs Second 500 kV Line	$61.72	**Yes**	**Yes**	Yes	Provides a second 500 kV line into the Load Center area in Dominion and utilizes existing/advacent ROW across the Potomac river	• 1A / 1B / 1C / 1C-1 • 2 / 2A / 2B / 2C / 2D / 2E / 2F • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 /0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 0S
33	524	**AEP**	Local AEP	Opossum Creek and New London Reactors	$8.86	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
34	530	**NextEra**	East	Muddy Creek / North Delta-Conastone Solution	$166.74	**Yes**	**Yes**	No	Same as for proposal 38	2 / 2A / 2B / 2C / 2D / 2E / 2F
35	537	**AEP**	Local AEP	Fieldale-Franklin Sag Study	$30.19	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

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36	548	**LSPower**	ALL	RTEP Window 3 Solution	$2,404.48	**Yes**	**No**	No	• Does not meet the 2027/28 needs • Solution designed predominantly to address the 2027 case needs only • The western 500 kV solution does terminate at the existing Doubs substation and does not offer an outlet capacity from Doubs into the Goose Creek area • More cost-effective and efficient solutions were presented part of the 2022W3 RTEP • The eastern cluster solutions are less effective than those selected by PJM • Proposal does not offer solutions to the BGE local needs and fails the load deliverability test/needs • High constructability risk (ROW owned by Dominion) for the 500 kV UG line portion of proposal from Goose Creek to Beaumeade and technically inferior to the PJM selected 500 kV development in the area.	• 2B • 2C • 0E11-9
37	564	**NextEra**	East/ Northern Virginia	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$876.88	**Yes**	**Yes**	No	• New substation (Barthlow) not needed part of the selected solution set • Major substation with 12x230 and 500 kV lines terminating into it that could be eleminated by PJM selected 500 kV solutions • No need for a new North Delta substation (one already approved and well-ahead through process) • Grisham and Goran substations are both new proposed substation, which are both avoided under the PJM selected proposal	0O and 0R

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38	577	**NextEra**	South	Front Royal-Racefield, Warrenton-Wheeler, North Anna-Lady Smith	$258.38	**Yes**	**Yes**	No	Not required with the development of the needed 500 kV selected proposal by PJM, particularly the third 500 kV feed into Aspen and the looped 500 kV development in Dominion (Aspen-Golden-Mars). Avoids highly sensitive, high risk greenfield ROW	0B
39	598	**NextEra**	ALL	Combination of PEBO 220 + WOP 1F + SOP 8E	$2,036.47	**Yes**	**No**	No	• Solution does not meet the 2027/28 needs and robustness test. • Proposals relies heavily on 230 kV developments which introduces significant impacts in the East that could be effectively and mitigated by just 2x500 kV developments in the same area, predominantly on existing ROWs • For this combination proposal to meet the 2027/28 needs, an expensive ~4Bn additional 2x230 kV circuits are required across the Chesapeake bay • Even with the above development, the solution fails the Load Deliverability test in BGE and SW-MAAC	0C
40	600	**PECO**	East	Exelon Replacement Upgrades	$423.79	**No**	**No**	No	The proposal is upgrades to an existing Exelon system and is not enough to address the violations identified in the 2022 Window 3	N/A
41	606	**PPL**	Local Other	Juniata-Lewistown 230 kV No. 2 line	$141.16	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A
42	629	**AEP**	Local AEP	Scottsville-Bremo Rebuild	$31.31	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500 kV solutions (that address the primary need drivers for the window)	N/A

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43	631	**NextEra**	East	Muddy Creek / North Delta-Conastone Solution	$184.47	**Yes**	**Yes**	No	Same as for proposal 38	2 / 2A / 2B / 2C / 2D / 2E / 2F
44	637	**PSEG**	East	Proposal D-Conastone-Doubs 500 kV	$684.22	**Yes**	**Yes**	Yes	Addresses the reliability needs effectively and efficiently (in combination with PPL's proposal 374)	• 0E Series (except for 0E2 / 0E3 / 0E6 / 0E6-1 / 0E7) • 0K • 0O • 0R
45	642	**NextEra**	West/ Northern Virginia	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table	$747.31	**Yes**	**No**	No	The Gant-Farmwell and Cochran Tap-Round Table are, not as robust as the selected 500 kV loop established by the selected DOM proposal between Aspen, Golden and Mars	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
46	660	**PEPCO**	East	West Cooper BGE-PEPCO	$1,105.62	**Yes**	**Yes**	Yes	• Meets performance requirements and efficiently utilizes existing ROW • Most efficient or cost-effective • provides solid robust performance to meet the needs in the PB-Conastone and BGE areas	• 1A • 1B • 0E Series • 0F • 0G • 0H / 0H2 • 0H2 • 0I • 0J / 0J-2/ 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S • 2 / 2A / 2B / 2C / 2D / 2E
47	663	**NextEra**	Northern Virginia/ South	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	$284.17	**Yes**	**Yes**	No	Not required with the development of the needed 500 kV selected proposal by PJM, particularly the 3rd 500 kV feed into Aspen and the looped 500 kV development in Dominion (Aspen-Golden-Mars). Avoids highly sensitive, high risk greenfield ROW	0L

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48	671	**Dominion**	West/ South	Lines No. 541 (Front Royal to Morrisville) Rebuild	$299.03	**Yes**	**Yes**	No	Not required with the PJM selected 500 kV solution.	• 2 / 2A / 2B / 2E • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
49	676	**NextEra**	West/ Northern Virginia	Black Oak-Stonewall-Gant, Stonewall SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table Solution	$552.49	**Yes**	**No**	No	Not as robust as the selected 500 kV loop established by the selected DOM proposal between Aspen, Golden and Mars	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
50	685	**NextEra**	West	Ft. Martin-Black Oak-Woodside, Woodside SVC + Cap Banks Solution	$609.78	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
51	691	**PEPCO**	East	Mid-Atlantic Power Pathway (MAPP)	$1,990.28	**No**	**No**	No	Project not considered due to supply chain and long lead times requirements	N/A
52	692	**Dominion**	Northern Virginia	Data Center Alley Local solution-New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	$1,058.45	**Yes**	**Yes**	Yes	Required for reliability needs. Most efficient or cost-effective solution. Offers robust solution to serve the data center loads in the dominion zone (northern Virginia) and also offers parallel 500 kV path to the single 500 kV line between Goose Creek and Wishing Star	• 1A / 1B / 1C / 1C-1 • 2 / 2C / 2D / 2E / 2F • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

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53	704	**Dominion**	South	Hollymead-Gordonsville Line No. 2135 Rebuild	$36.89	**Yes**	**Yes**	No	Dominion proposal No. 211 chosen over proposal No. 704. Both proposals include a wreck and rebuild of 230 kV Line No. 2135. However proposal No. 704 utilizes double-circuit capable 230 kV poles, whereas proposal No. 211 utilizes double-circuit capable 500/230 kV poles.	• 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
54	711	**Dominion**	South	Regional Solution - 500 kV North Anna-Wishing Star Upgrades	$1,227.84	**Yes**	**Yes**	Yes *(Partial)*	Offers robust solution to serve the data center loads in the dominion zone (northern Virginia). Proposal utilizes efficiently the existing ROW between Morrisville and Wishing Star. Segment between Morssisville and North Anna eliminated by PJM 500 kV solution.	• 1A / 1B / 1C / 1C-1 • 0E Series • 0F • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
55	719	**NextEra**	West	Ft. Martin-Black Oak-Pike, Pike SVC + Cap Banks Solution	$600.90	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12

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56	728	**NextEra**	East/ Northern Virginia	Barnhart Substation, Bartholow Substation, Barnhart-Bartholow-Goose Creek solution	$385.36	**Yes**	**No**	No	• Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers) • Barthlow substation deemed not required with the PJM selected proposal, which has much less overall impact (many 500 and 230 kV greenefield lines compared to just 2x500 kV lines under PJM proposal and without Barthlow sub)	0E2
57	731	**Dominion**	South	Locks Substation 230/115 kV Transformer Upgrade	$7.14	**Yes**	**Yes**	Yes	Required for reliability needs. Most efficient or cost-effective solution	0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown - Carrol Rebuild / 0E11-7-B + Hunterstown - Carrol Rebuild + IEC West / 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S
58	741	**PSEG**	East	Proposal G - Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	$1,065.32	**Yes**	**Yes**	No	• Selected incumbent proposal addresses the needs for bulk transfers between Peach Bottom and Conastone (in combination with other proposals) predominantly using existing ROW in the PB-Conastone corridor • PSEG proposal to develop a line from Conastone to Doubs has already been selected part of Proposal No. 637 - in combination with PPL proposal 374	• 0E4-1-2 / 0E11-7-B Final • 0Q

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
59	766	**NextEra**	South	Front Royal-Racefield, Warrenton-Wheeler	$239.59	**Yes**	**Yes**	No	Not required with the development of the needed 500 kV selected proposal by PJM, particularly the 3rd 500 kV feed into Aspen and the looped 500 kV development in Dominion (Aspen-Golden-Mars). Avoids highly sensitive, high risk greenfield ROW	QT3
60	808	**PSEG**	East	Proposal F - Peach Bottom-New Raphael-Waugh Chapel 500 kV; Peach Bottom-Doubs 500 kV	$1,150.80	**Yes**	**Yes**	No	Immediate need proposal to address the Peach Bottom deactivation needs in BGE has a much lower risk of construction, more cost-effective and efficient solution	• 0E4-1-1 / 0E13 / 0E13-1 • 0S
61	837	**POTOED - FirstEnergy**	East/ West/ Northern Virginia	Data Center Reinforcement Proposal No. 1 • 1 - 500 kV circuits from Fort Martin-Doubs • 1 - 500 kV circuit from Prutnytown-Meadow Brook-Doubs • Second 500 kV from Doubs-Aspen and Rebuild the existing Doubs-Goose Creek 500 kV • Rebuild Hunterstown-Caroll 115/138 kV line for 230 kV double circuit construction	$2,991.77	**Yes**	**No**	Yes *(partial)*	• Proposal attempts to address the west-east transfer needs and voltage collapse concerns along the transfer path • PJM analysis indicated that the system reliability benefits more from spreading the reinforcements for transfer between the East and West corridors instead of just the Western corridor • All options provide injections into Doubs, however, no solutions offered to debottleneck the Doubs-Goose Creek corridor • Currently there is no need for 2x500 kV double circuit development along the West-East corridor • only 1x500kV is required part of the PJM selected solution • Cost is higher than similar 500 kV proposals by other entities that provide stronger cost containment provisions • Proposal utilizes existing ROWs for parts of the projects including the new Doubs-Aspen 500 kV and Huntertown-Caroll 230 kV, which	• 1A / 1B / 1C / 1C-1 • 2 / 2A / 2B / 2C / 2D / 2E / 2F • 0E Series (except for 0E8-2 / 0E11-3 / 0E11-5 / 0E11-6) • 0L

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
									both components are in the list of PJM selected projects	
62	846	**NextEra**	East/ West/ Northern Virginia	Hunterstown-Doubs-Goose Creek, Black Oak-Woodside-Goose Creek, Stonewall SVC + Cap Banks	$892.94	**Yes**	**No**	No	• The proposed 500 kV line is similar in length to the PJM selected 500 kV line from Otter Creek to Doubs, which is more effective in meeting the reliability need • PJM selected 500 kV combination is more effective in meeting the reliability need	0H/0H2
63	853	**NextEra**	West/ Northern Virginia	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$683.55	**Yes**	**Yes**	Yes *(partial)*	• Effective solution to address the reliability needs for West to East transfers and offers a 3rd 500 kV supply line to the load center in Dominion • The selected component is modified to bypass the Black Oak and terminate at Aspen (original proposal terminate at Gant)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
64	856	**AEP**	Local AEP	Leesville-Altavista Rebuild	$28.85	**Yes**	**Yes**	No	Not required to meet the 2022W3 needs with the selected PJM 500kV solutions (that address the primary need drivers for the window)	N/A

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
65	858	**AEP - Transource**	Northern Virginia	Stork-Flys 500 kV Greenfield Line and Substations	$510.44	**Yes**	**Yes**	No	High constructability risk (proposes use of Loudoun County roadways which was deemed high concern by VDOT officials) and technically inferior to the PJM selected 500 kV development in the area.	• 2A • 0A • 0M
66	904	**AEP - Transource**	West/ South	Joshua Falls-Yeat 765 kV Greenfield Line and Substation	$1,048.10	**Yes**	**Yes**	No	Project proposes new, greenfield 765 kV development close to 135 miles long. Introduces high risk to area reliability due to delayed project construction and in service year risk. PJM selected 500 kV solution addresses the need cost-effective and efficiently. The 765 kV solution could be pursued part of the longer term solutions in the area depending on how load and generation materialize.	• 2F • 0A • 0E8 / 0E8-1/ 0E8-1-1 / 0E8-2 / 0E8-2-1 / 0E8-2-2 / 0E11-4 / 0E11-5 / 0E11-7-B + Yeat / 0E11-10-A / 0E11-11
67	923	**Dominion**	South	Second 500 kV line from Lexington to Dooms	$232.18	**Yes**	**Yes**	No	Not required under the 2027/28 analysis scenario	• 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In: 2027 Model	Meet Reliability Needs In: 2028 Model	Selected Y/N	Rationale	Applicable Scenarios
68	948	**NextEra**	East/ Northern Virginia	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.	$5,381.25 *	**Yes**	**Yes**	No	• New substation (Barthlow) not needed part of the selected solution set • Major substation with 12x230 and 500kV lines terminating into it that could be eliminated by PJM selected 500 kV solutions • No need for a new North Delta substation (one already approved and well-ahead through process) • Grisham and Goran substations are both new proposed substation, which are both avoided under the PJM selected proposal • The proposal includes expensive ~4Bn and high constructability/schedule risk additional 2x230 kV circuits across the Chesapeake bay	• 0E4-1-3 • 0I • 0J / 0J-2 / 0J-3 • 0B
69	951	**NextEra**	West/ Northern Virginia	Black Oak-Gore-Goose Creek, Pike SVC + Cap Bank Solution	$419.86	**Yes**	**No**	No	Does not provide the needed supply source into the Dominion northern Virginia transmission system (Load Centers)	0E11-3 / 0E11-4 / 0E11-5 / 0E11-6 / 0E11-7 / 0E11-7-A / 0E11-7-B / 0E11-7-B + Yeat / 0E11-7-B +IEC West / 0E11-7-B + Hunterstown -Carrol Rebuild / 0E11-7-B + Hunterstown -Carrol Rebuild + IEC West / 0E11-7-B Final / 0E11-8 / 0E11-9 / 0E11-10 / 0E11-11 / 0E11-12
70	962	**PSEG**	East	Proposal H - Peach Bottom-Doubs 500 kV (Circuits No. 1 and No. 2)	$977.71	**Yes**	**Yes**	No	See comments associated with Proposal No. 741	N/A
71	967	**Dominion**	South	Charlottesville-Hollymead Line No. 2054 Rebuild	$183.48	**Yes**	**Yes**	Yes *(partial)*	Required for reliability needs. Considers future load growth in Culpeper and Louisa area by supporting 500 kV developments with double-circuit capable 500/230 kV poles.	• 0E11-7-B Final • 0G • 0H / 0H2 • 0I • 0J / 0J-2 / 0J-3 • 0K • 0L • 0M • 0N • 0O / 0O2 / 0O3 • 0P / 0P2 / 0P NGME • 0Q / 0Q2 / 0Q3 / 0Q4 • 0R / 0R2 • 0S

#	Proposal ID	Proposing Entity	Focus Area (s)	Project Title	Submitted Cost ($M)	Meet Reliability Needs In:		Selected Y/N	Rationale	Applicable Scenarios
						2027 Model	2028 Model			
72	977	**AEP - Transource**	South	Yeat 500/230 kV Greenfield Station	$232.14	**Yes**	**Yes**	No	Project proposes new, greenfield 765 kV development close to 135 miles long. Introduces high risk to area reliability due to delayed project construction and in service year risk. PJM selected 500 kV solution addresses the need cost-effective and efficiently. The 765 kV solution could be pursued part of the longer term solutions in the area depending on how load and generation materialize.	• 0A • 0E6 / 0E6-1 / 0E7

Critical Substation Planning Analysis

The Critical Substation Planning Analysis (CSPA)[4] was created as an extension of the PJM Transmission Owners' Attachment M-4 process. The purpose of the CSPA is to conduct additional screening as part of a five-year annual PJM RTEP cycle to ensure no new CIP-14 facilities is introduced to the PJM system as the transmission network evolves.

PJM CSPA evaluates system reinforcements, consistent with RTEP CSPA methodology as described in Section 2.9 of Manual 14B. CSPA is performed to identify Instability, Uncontrolled Separation, or Cascading resulting in one or more of the following outcomes due to the loss of all voltage levels 69 kV and above at a single transmission facility that meet the NERC CIP-14 substation criteria.

- Loss of load approaching 1000 MW
- Three levels of facility trips
- Case non-convergence issue in steady-state or dynamic analysis covering both angular and voltage stability tests

For 2022 Window 3, PJM conducted CSPA for proposals in 12 scenarios based on PJM RTEP 2028 summer peak case. No new critical substation was identified due to selected system upgrades in 2020 Window 3.

Power System Stability Analysis

The 2022 Window 3 needs are predominantly driven by steady state (both thermal and voltage) reliability violations. However, PJM conducted stability analysis to ensure the final recommended solution meet all applicable planning stability criteria (PJM, NERC, and Local Transmission Owner criteria) with the PJM-selected reinforcements capturing the impact of the load increase, change in generation resource mix and dispatch pattern. The dynamic performance of PJM system with the final selected solution was analyzed from three key stability aspects: transient (angle) stability, small signal (damping) stability and transient voltage stability.

Critical system conditions for stability analysis on the PJM system are generally characterized by light load and peak load conditions. In this stability study, PJM RTEP 2028 summer peak and light load dynamics cases were used. The assumptions used for generation dispatch can be critical to the stability results. PJM followed PJM's stability dispatch methodology to create conservative system conditions for stability analysis. Dynamic models of the proposed STATCOMs at Stonewall, Mars, Beaumeade, Granite and Brighton stations were properly incorporated in the study dynamics cases.

PJM selected more than 70 critical NERC Planning events (P1, P4, P6 and P7) at 22 key substations associated with the final solution from East, West, South and Northern Virginia data center loads areas. The critical contingencies were selected based on system topology, loading interruption size by contingency events, and the size of dynamic reactive devices, as well as past study experiences and engineering judgement. PSS/E, which is well-accepted

[4] *See* PJM Manual 14B, section 2.9

power system analysis software, was used as a stability simulation tool. The findings from the stability study are summarized as follows:

- No potential stability criteria violations were identified.
- There are no transient (angle) stability issues at major generation stations including Peach Bottom, Limerick and North Anna nuclear plants.
- PJM system demonstrated acceptable damping performance after system disturbances by the contingencies.
- No transient voltage recovery performance issue around major load centers was identified.

Appendix A: Scope of Final Reliability Analysis

PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on facilities identified below in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC and Local Transmission Owner criteria).

Criterion Applied by PJM for this Proposal Window

- 2027–28 Summer
- Baseline Thermal and Voltage N-1 Contingency Analysis
- Generator Deliverability and Common Mode Reliability Analysis
- N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- Load Deliverability Thermal and Voltage Analysis
- Dynamic Stability Assessment
- 2027–28 Winter
- Baseline Thermal and Voltage N-1 Contingency Analysis
- Generator Deliverability and Common Mode Reliability Analysis
- N-1-1 Thermal and Voltage Analysis and Voltage Collapse
- Load Deliverability Thermal and Voltage Analysis
- Dynamic Stability Assessment
- 2027–28 Light Load
- Baseline Thermal and Voltage N-1 Contingency Analysis
- Generator Deliverability and Common Mode Reliability Analysis

Appendix B: Window 3 Scenarios and Screening Performance

Listed below are high-level descriptions and screening performance of some of the major scenarios.

Scenario 1A

Scenario Components

Primary Incumbent TOs Proposals – regional components

- Exelon: 2022-W3-344/660
- Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
- West Cooper-Peach Bottom South New 500 kV Line
- West Cooper-High Ridge 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-711
- New 500 kV Line (North Anna-Spotsylvania)
- New 500 kV Line (Spotsylvania to Vint Hill)
- New 500 kV Line (Vint Hill to Wishing Star)
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	20
115 kV Overloads	6

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	74
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	14
115 kV Overloads	10

Scenario 1B

Scenario Components

Primary Incumbent TOs Proposals – No Dominion South – regional components

- Exelon: 2022-W3-344/660
- Rebuild 5012 500 kV (will be looped in to West Cooper and Gracetone)
- West Cooper-Peach Bottom South New 500 kV Line
- West Cooper-High Ridge 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	54
500 kV Overloads	10
345 kV Overloads	2
230 kV Overloads	6
138 kV Overloads	26
115 kV Overloads	5

Scenario 1C

Scenario Components

Primary Incumbent TOs Proposals – regional components – use TRANSRC ID 487 east component (IEC-East)

- Transource: 2022-W3-487 IEC-East
- Furnace Run 500/230 kV station
- Furnace Run-Conastone 230 kV
- Furnace Run-Gracetone 230 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-711
- New 500 kV Line (North Anna-Spotsylvania)
- New 500 kV Line (Spotsylvania to Vint Hill)
- New 500 kV Line (Vint Hill to Wishing Star)
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	5
138 kV Overloads	25
115 kV Overloads	11

Scenario 1C-1

Scenario Components

Primary Incumbent TOs Proposals – regional components – use TRANSRC ID 487 east component (IEC-East) + b3737

- Transource: 2022-W3-487 IEC-East
- Furnace Run 500/230 kV station
- Furnace Run-Conastone 230 kV
- Furnace Run-Gracetone 230 kV
- B3737
- North Delta 500/230 and N. Delta-Graceton 230 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-711
- New 500 kV Line (North Anna-Spotsylvania)
- New 500 kV Line (Spotsylvania to Vint Hill)
- New 500 kV Line (Vint Hill to Wishing Star)
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	40
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	2
138 kV Overloads	23
115 kV Overloads	10

Scenario 2

Scenario Components

Primary Incumbent TOs Proposals – regional components – Upgrade F Royal-Morsvl + NextEra - ND – Conastone + Full DOM local

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	88
500 kV Overloads	17
345 kV Overloads	1
230 kV Overloads	16
138 kV Overloads	32
115 kV Overloads	12

Scenario 2A

Scenario Components

Primary Incumbent TOs Proposals – regional components – Upgrade F Royal-Morsvl + NextEra - ND – Conastone + TRANSC - 500 kV UG

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- Transource: 2022-W3-858
- Stork-Flys 500 kV Underground Line

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	83
500 kV Overloads	14
345 kV Overloads	1
230 kV Overloads	17
138 kV Overloads	32
115 kV Overloads	11

Scenario 2B

Scenario Components

Primary Incumbent TOs Proposals – regional components – Upgrade F Royal-Morsvl + NextEra - ND – Conastone + LSP - 500 kV UG

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- LS Power: 2022-W3-548
- Goose Creek-Beaumeade 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	96
500 kV Overloads	17
345 kV Overloads	1
230 kV Overloads	24
138 kV Overloads	32
115 kV Overloads	12

Scenario 2C

Scenario Components

Primary Incumbent TOs Proposals – regional components – NextEra - ND – Conastone + LSP - West 500 kV FRoyl-Vhill

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- LS Power: 2022-W3-548
- Front Royal –VintHill 500 kV
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	48
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	1
138 kV Overloads	25
115 kV Overloads	11

Scenario 2D

Scenario Components

Primary Incumbent TOs Proposals – regional components – NextEra - ND – Conastone + PSEG Bramb-HinsonsF 500 kV

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- FE: 2022-W3-837
- Fort Martin-Doubs 500 No. 1
- PSEG: 2022-W3-325
- Brambleton-Hinsons Ford 500 kV
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	2
138 kV Overloads	25
115 kV Overloads	11

Scenario 2E

Scenario Components

Primary Incumbent TOs Proposals – regional components – NextEra - ND – Conastone + Hunt-Doubs 500 kV

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- NEET: 2022-W3-445
- Hunterstown -Doubs 500 kV
- DOM: 2022-W3-671
- Line No. 541 (Front Royal to Morrisville) Rebuild
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	84
500 kV Overloads	14
345 kV Overloads	2
230 kV Overloads	22
138 kV Overloads	34
115 kV Overloads	6

Scenario 2F

Scenario Components

Primary Incumbent TOs Proposals – regional components – TRASRC - 765 kV + NextEra - ND – Conastone + Full DOM local

- NEET: 2022-W3-530
- North Delta-Conastone 500 kV
- Transource: 2022-W3-904
- Joshua Falls to Yeat 765 kV
- DOM/FE: 2022-W3-516/837
- Aspen-Doubs Second 500 kV Line
- Line No. 514 (Goose Creek-Doubs) Rebuild
- DOM: 2022-W3-692 (include 230 kV)
- Aspen-Golden 500 kV Line Build
- New Mars-Golden 500 kV
- Aspen to Goose Creek 500 kV

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	78
500 kV Overloads	10
345 kV Overloads	0
230 kV Overloads	10
138 kV Overloads	33
115 kV Overloads	11

Scenario 0A

Scenario Components

- Transource: 2022-W3-487
- Transource: 2022-W3-904
- Transource: 2022-W3-977
- Transource: 2022-W3-858

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	18
500 kV Overloads	1
345 kV Overloads	1
230 kV Overloads	4
138 kV Overloads	8
115 kV Overloads	1

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	113
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	47
138 kV Overloads	11
115 kV Overloads	27

Scenario 0B

Scenario Components

- NEET: 2022-W3-175

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	23
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	2
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	28
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	9
138 kV Overloads	3
115 kV Overloads	4

7,500 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	52
500 kV Overloads	9
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	4
115 kV Overloads	4

11,000 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	74
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	31
138 kV Overloads	4
115 kV Overloads	4

Scenario 0B2

Scenario Components

- NEET: 2022-W3-175
- Removal of two 230 kV line from Warrenton-Rixlew/Hourglass, 500 kV line from Front Royal-New Wishing Star

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	28
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	10
138 kV Overloads	3
115 kV Overloads	4

Scenario 0B3

2028 Scenario Components

- NEET: 2022-W3-175
- Removal of two 230 kV line from Warrenton-Rixlew/Hourglass, 500 kV line from Front Royal-New Wishing Star
- Removal of Keeney to Waugh Chapel 230 kV circuit 1 and 2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	40
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	7

Scenario 0C

Scenario Components

- NEET: 2022-W3-598

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	23
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	2
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	2
115 kV Overloads	6

Scenario 0D

Scenario Components

- LS Power: 2022-W3-548

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	2
138 kV Overloads	11
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	93
500 kV Overloads	17
345 kV Overloads	0
230 kV Overloads	38
138 kV Overloads	6
115 kV Overloads	21

Scenario 0E

Scenario Components

1A_ALL

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	24
500 kV Overloads	0
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	16
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	26
138 kV Overloads	4
115 kV Overloads	6

Scenario 0E1

Scenario Components

0E + PPL (374) + PSEG (637 component 5 and 8) → It will 0E +PPL (Otter to Conastone 500 kV) + PSEG (Conastone to Doubs 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	22
500 kV Overloads	0
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	15
115 kV Overloads	2

7,500 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	10
345 kV Overloads	0
230 kV Overloads	33
138 kV Overloads	3
115 kV Overloads	4

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	4

11,000 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	80
500 kV Overloads	15
345 kV Overloads	0
230 kV Overloads	41
138 kV Overloads	8
115 kV Overloads	5

Scenario 0E2

Scenario Components

0E + PSEG (229 component 8&9) → It will be 0E + PSEG (Hunterstown to Green Valley 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PSEG: 2022-W3-229 – only component 8&9

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	53
500 kV Overloads	16
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	1
115 kV Overloads	3

Scenario 0E3

Scenario Components

0E Modified (500 kV Morrisville Start)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	4
115 kV Overloads	6

Scenario 0E4

Scenario Components

0E1 + T-Point (loop Conastone-Brighton, Brighton-Doubs and Conastone-Doubs 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- DOM/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 – (Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	35
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E4-1

Scenario Components

0E4 and bypass the Otter Creek-Conastone-T-Point at Conastone (the new line will be Otter Creek-T-Point 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 –(Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E4-1-1

Scenario Components

0E4-1 and replace Cooper-High Ridge 500 kV with Peach Bottom-Waugh Chapel 500 kV

- Exelon: 2022-W3-344/660 – Remove component 3&7 (Remove Cooper-High Ridge 500 kV and High Ridge 500/230 kV transformers)
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 –(Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- PSEG: 2022-W3-808 – Add Peach Bottom-Waugh Chapel 500 kV – exclude/bypass Raphael 500 kV bus

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	38
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E4-1-2

Scenario Components

0E4-1 and replace Cooper-High Ridge 500 kV with Peach Bottom-Brandon Shore 500 kV

- Exelon: 2022-W3-344/660 – Remove component 3&7 (Remove Cooper-High Ridge 500 kV and High Ridge 500/230 kV transformers)
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 –(Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- PSEG: 2022-W3-741 – Add Peach Bottom-Brandon Shore 500 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	2
115 kV Overloads	5

Scenario 0E4-1-3

Scenario Components

0E4-1 and replace Cooper-High Ridge 500 kV with Keeney-Waugh 230 kV double circuit

- Exelon: 2022-W3-344/660 – Remove component 3&7 (Remove Cooper-High Ridge 500 kV and High Ridge 500/230 kV transformers)
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 (Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- NextEra: 2022-W3-948 – Add Keeney-Waugh 230 kV double circuit

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	3
115 kV Overloads	5

Scenario 0E5

Scenario Components

0E1 – FE 837 (component C18-30) + TRANSRC 487 (Component IEC-West)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 – (Otter Creek-Conastone 500 kV)
- PSEG: 2022-W3-637 – only component 5&8 (Conastone-Doubs 500 kV new line)
- Remove FE: 2022-W3-837 component C18-30_MAIT_Germantown-Carroll
- Add TRANSRC: 2022-W3-487 component IEC-West

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	1
115 kV Overloads	2

Scenario 0E6

Scenario Components

0E3 (500 kV Morrisville Start) - remove part of FE 837(Fort Martin-Doubs 500 kV) + Add Part of 977 (Yeat sub and Joshua-Yeat 765 kV line)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 Modified (remove Fort Martin-Doubs 500 kV)
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- Transource: 2022-W3-977 (only add Yeat sub and Joshua-Yeat 765 kV line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	55
500 kV Overloads	11
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	9
115 kV Overloads	6

Scenario 0E6-1

Scenario Components

0E6_Remove Prnty-Mt. Storm & Meadow Brook-Doubs

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 Modified (remove Fort Martin-Doubs 500 kV)
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- Transource: 2022-W3-977 (only add Yeat sub and Joshua-Yeat 765 kV line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	66
500 kV Overloads	11
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	17
115 kV Overloads	7

Scenario 0E7

Scenario Components

0E6 - remove all FE 837

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 Modified
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- Transource: 2022-W3-977 (only add Yeat sub and Joshua-Yeat 765 kV line)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	75
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	20
115 kV Overloads	10

Scenario 0E8

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV lines and add Joshua Falls to Yeat 765 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV line(s)
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904-Joshua Falls (AEP) to Yeat (Transource) 765 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	40
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	11
115 kV Overloads	5

Scenario 0E8-1

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV lines and add Joshua Falls to Yeat 765 kV line + Removal of North Anna to Morrisville 500 kV line + Removal of Golden-Mars 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV line(s)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – Joshua Falls (AEP) to Yeat (Transource) 765 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	38
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	11
115 kV Overloads	5

Scenario 0E8-1-1

Scenario Components

0E8-1 + Remove Golden-Mars 230 kV side line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV & Pruntytown-Mt. Storm 500 kV & Meadowbrook-Doubs 500 kV line(s)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – Joshua Falls (AEP) to Yeat (Transource) 765 kV

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	39
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	11
115 kV Overloads	5

Scenario 0E8-2

Scenario Components

0E8-1 + Remove the rest of the FE837 + Add Transouce 487 (Component IEC-West only)

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV
- Transource: 2022-W3-487 (Component IEC-West only)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	29
500 kV Overloads	1
345 kV Overloads	1
230 kV Overloads	2
138 kV Overloads	17
115 kV Overloads	2

7,500 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	57
500 kV Overloads	9
345 kV Overloads	0
230 kV Overloads	31
138 kV Overloads	7
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	6
115 kV Overloads	2

11,000 MW OSW Screening Performance

Overload	Number of Overloads
Total Overloads	75
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	38
138 kV Overloads	11
115 kV Overloads	2

Scenario 0E8-2-1

Scenario Components

0E8-2 + Remove Golden-Mars 230 kV side line

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV
- Transource: 2022-W3-487 (Component IEC-West only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	32
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	6
115 kV Overloads	2

Scenario 0E8-2-2

Scenario Components

0E8-2-1 + Remove uprate on 500 kV Line Meadow Brook-Vint Hill

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV
- Transource: 2022-W3-487 (Component IEC-West only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	32
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	6
115 kV Overloads	2

Scenario 0E9

Scenario Components

0E1 + Modified DOM_711 (500 kV Morrisville Start) + Modified DOM_692 (Remove Golden-2-Mars Extension)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711 Modified (500 kV Morrisville Start)
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 Modified (Remove Golden-2-Mars Extension)
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	35
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	5

Scenario 0E10

Scenario Components

0E1 modified (the Otter Creek-Conastone-Doubs 500 kV circuit will bypass the Conastone station and will be Otter Creek-Doubs 500 kV)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	37
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	2
115 kV Overloads	5

Scenario 0E11

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV line
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	46
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-1

Scenario Components

0E1 + Removal of remove Doubs-Fort Martin No. 1 500 kV line + Removal of North Anna to Morrisville 500 kV line+ Removal of Golden-Mars 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV line
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	45
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-1-1

Scenario Components

0E11-1 + Remove Golden-Mars 230 kV side line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Removal of Doubs-Fort Martin No. 1 500 kV line
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	46
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-2

Scenario Components

0E11-1-1 + Remove Pruntytown to Mt.Storm and Meadow Brook to Doubs 500 kV line & Add Fort Martin to Doubs 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 – Remove Pruntytown to Mt.Storm and Meadow Brook to Doubs 500 kV lines, Add Fort Martin to Doubs 500 kV line
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	38
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	3
115 kV Overloads	5

Scenario 0E11-3

Scenario Components

0E11-1-1 + Remove all FE 2022-W3 -837 + Add NextEra 2022-W3-853

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- NextEra: 2022-W3-853

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	37
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	4
115 kV Overloads	7

Scenario 0E11-4

Scenario Components

0E11-3 + Add Joshua Falls-Yeat 765 kV line

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- NextEra: 2022-W3-853
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV & Yeat 765/500 kV substation

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-5

Scenario Components

0E11-4 + Remove uprate on 500 kV Line Meadow Brook-Vint Hill

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- NextEra: 2022-W3-853
- Transource: 2022-W3-904 – only Joshua Falls (AEP) to Yeat (Transource) 765 kV & Yeat 765/500 kV substation

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	7
115 kV Overloads	5

Scenario 0E11-6

Scenario Components

0E11-3 + Remove Otter Creek-Conastone-Doubs 500 kV

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- NextEra: 2022-W3-853

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	60
500 kV Overloads	11
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	7
115 kV Overloads	9

Scenario 0E11-7

Scenario Components

0E11-3+ (bypass Conastone for the Otter Creek-Doubs line) +/- reactive

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	3
115 kV Overloads	6

Scenario 0E11-7-A

Scenario Components

0E11-7 with full proposal 692 modeled

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	3
115 kV Overloads	6

Scenario 0E11-7-B

Scenario Components

0E11-7-A + bypass Black Oak + AEP 410 (cloverdale breaker) + DOM additional_Post Fixes

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	26
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	12
138 kV Overloads	3
115 kV Overloads	6

2030 Screening Performance

Overload	Number of Overloads
Total Overloads	60
500 kV Overloads	12
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	11
115 kV Overloads	9

Scenario 0E11-7-B + Yeat

Scenario Components

0E11-7-B + YEAT 765 kV line

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	9
138 kV Overloads	6
115 kV Overloads	5

2030 Screening Performance

Overload	Number of Overloads
Total Overloads	50
500 kV Overloads	9
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	12
115 kV Overloads	7

Scenario 0E11-7-B + IEC West

Scenario Components

0E11-7-B + IEC West

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- Transource: 2022-W3-487(only include IEC West)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	0
115 kV Overloads	2

Scenario 0E11-7-B + Hunterstown-Carrol Rebuild

Scenario Components

0E11-7-B + Hunterstown -Carrol Rebuild

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- FE: 2022-W3-837 (only include Hunterstown-Carrol Rebuild (C18-30), but UPDATED idv from FE)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	2
115 kV Overloads	3

Scenario 0E11-7-B + Hunterstown-Carrol Rebuild + IEC West

Scenario Components

0E11-7-B + Hunterstown-Carrol Rebuild + IEC West

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Bypass Black Oak)
- Transource: 2022-W3-487(only include IEC West)
- FE: 2022-W3-837 (only include Hunterstown-Carrol Rebuild (C18-30) – the idv in the proposal was wrong, use updated idvs PJM sent later)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- AEP: 2022-W3-410
- DOM Additional:
- 2022-W3-30: Line No. 2054 (Charlottesville to Hollymead) Rebuild (Option 1) (exclude DNH portion for now)
- 2022-W3-704: Line No. 2135 (Holly Meade to Gordonsville) Rebuild (Option 1)
- 2022-W3-731: Locks Substation 230/115 kV Transformer Upgrade
- 2022-W3-74: Line No. 2090 (Ladysmith to Fredericksburg) Rebuild
- Post Fixes:
  - Line No. 256 Rebuild St. Johns-Ladysmith CT
  - Sterling Park-Golden
  - Davis Drive-Sterling Park

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	22
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	0
115 kV Overloads	2

Scenario 0E11-7-B Final

Scenario Components

- Exelon: 2022-W3-344/660
- DOM: 2022-W3-711 (Remove North Anna to Morrisville 500 kV line)
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374 and PSEG: 2022-W3-637 (only component 5&8) – Bypass Conastone
- NextEra: 2022-W3-853 (bypass Black Oak, end at Aspen)
- DOM: 2022-W3-231 (Partial)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom
- AEP: 2022-W3-410
- FE: 2022-W3-837 (Partial): Hunterstown-Carrol rebuild (use the updated idv PJM sent later)
- DOM: 2022-W3-731
- DOM: 2022-W3-211
- DOM: 2022-W3-967 (Partial)
- Entire Line No. 2054 (Charlottesville to Hollymead) Rebuild, Entire Line No. 291 Rebuild and Portion of Line No. 233 rebuild
- 230 kV Line No. 2054
- 6CHARLVL (314749) – 6PROFFIT (314772) ckt 1
- 230 kV Line No. 233
- 6BARRCK2 (314742) – 6CROZET1 (314751) ckt 1
- 230 kV Line No. 291
- 6CROZET2 (314752) – 6DOOMS (314794) ckt 1
- 6BARRCK1 (314741) – 6CROZET2 (314752) ckt 1
- 6BARRCK1 (314741) – 6CHARLVL (314749) ckt 1
- DOM: 2022-W3-74 (Partial)
- 6SUMMIT (313837) – 6LDYSMITH CT (314197) ckt 1
- Sterling Park-Golden Rebuild ($7.97M)
- Davis Drive-Sterling Park Rebuild ($5.5M)
- Red Lion-Hope Creek 500 kV line terminal equipment upgrade
- Peach Bottom terminal equipment upgrades
- Carrol-Mt Airy 230 kV Terminal Equipment upgrades
- Reconductor the Lincoln-Orrtanna 115 kV line
- FAYETT-GRANDP 138 kV line terminal equipment upgrades

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	13
138 kV Overloads	1
115 kV Overloads	2

Scenario 0E11-8

Scenario Components

0E11-7+ IEC West (Transource 487)

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar
- Transourse: 2022-W3-487 (Only include the IEC West)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	1
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	1
115 kV Overloads	2

Scenario 0E11-9

Scenario Components

0E11-7+ Modified West line (part of 853 + Part of 548)

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- LS Power: 2022-W3-548 (only include 502 J- Black Oak-Doubs 500 kV line but bypass Black Oak), connect with the Doubs-Apsen 500 kV line in 516 and bypass Doubs
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-853 (Only include Stonewall tap-Belmont tap 500 kV line, including the Stonewall and Belmont sub)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	36
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	3
115 kV Overloads	6

Scenario 0E11-10

Scenario Components

0E11-7+ Replace the NEET 853 with Transource 765 kV line

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- FE: 2022-W3-837 (Only include Bedington SVC, no lines)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar (part of Brandon Shores deactivation)
- AEP: AEP: 2022-W3-410

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	42
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	13
138 kV Overloads	13
115 kV Overloads	7

Scenario 0E11-10-A

Scenario Components

0E11-10 with full proposal 692 modeled

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- FE: 2022-W3-837 (Only include Bedington SVC, no lines)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar (part of Brandon Shores deactivation)
- AEP: AEP: 2022-W3-410

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	42
500 kV Overloads	3
345 kV Overloads	0
230 kV Overloads	13
138 kV Overloads	13
115 kV Overloads	7

Scenario 0E11-11

Scenario Components

0E10 + IEC West (Transource 487)

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- FE: 2022-W3-837 (Only include Bedington SVC, no lines)
- Transource: 2022-W3-904 (only include Yeat sub and Joshua Falls-Yeat 765 kV line)
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar (part of Brandon Shores deactivation)
- AEP: AEP: 2022-W3-410
- Transource: 2022-W3-487 (IEC West Only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	**34**
500 kV Overloads	**2**
345 kV Overloads	**0**
230 kV Overloads	**18**
138 kV Overloads	**6**
115 kV Overloads	**2**

Scenario 0E11-12

Scenario Components

0E11-7 + Remove 853 + Add 279

- Exelon: 2022-W3-344/660 (remove the 500 kV cap banks at Gracetone and Conastone)
- DOM: 2022-W3-711 – Remove North Anna to Morrisville 500 kV line + Remove uprate on 500 kV Line Meadow Brook-Vint Hill
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-Mars 500 kV line & Remove Golden-Mars 230 kV side line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8 – bypass Conastone
- NextEra: 2022-W3-279
- DOM: 2022-W3-231 (only include the components below)
- 150 MVARs at Morrsivlle 500 kV,
- 293 MVARs at Wishing Star 500 kV
- 150 MVARs at Mars 230 kV
- 150 MVARs at Wishing Star 230 kV
- 300 MVARs STATCOM at Mars 500 kV
- 300 MVARs STATCOM at Beaumeade 230 kV
- Granite Statcom: +/- 350 MVar

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	42
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	8
115 kV Overloads	6

Scenario 0E12

Scenario Components

(0E1 + Addition of one additional 500 kV line between Doubs and Aspen + Remove Golden-Mars 500 kV + Remove North Anna-Morrisville 500 kV) or (0E9 + Additional one 500 kV line from Doubs to Aspen)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837
- DOM: 2022-W3-711 – Remove North Anna-Morrisville 500 kV line
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692 – Remove Golden-March 500 kV line
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- Additional one 500 kV line from Doubs to Aspen

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	33
500 kV Overloads	2
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	4

Scenario 0E13

Scenario Components

0E1 + Remove Exelon 344 component 4&5 + add PSEG 808 (Peach Bottom-Raphael-W. Chapel 500 kV)

- Exelon: 2022-W3-344/660 – Remove component 4&5
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- PSEG: 2022-W3-808 – add the Peach Bottom-Raphael Rd-W. chapel 500 kV component

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	30
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	1
115 kV Overloads	4

Scenario 0E13-1

Scenario Components

0E13 + Remove Graceton 500/230 kV transformers

- Exelon: 2022-W3-344/660 – Remove component 4&5 and Graceton 500/230 kV transformers
- FE: 2022-W3-837
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/837
- DOM: 2022-W3-692
- PPL: 2022-W3-374
- PSEG: 2022-W3-637 – only component 5&8
- PSEG: 2022-W3-808 – add the Peach Bottom-Raphael Rd-W. chapel 500 kV component

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	32
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	1
115 kV Overloads	4

Scenario 0F

Scenario Components

1A-Alter_ALL

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	22
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	13
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	55
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	25
138 kV Overloads	4
115 kV Overloads	5

Scenario 0G

Scenario Components

1A-Alter_ALL (Full DOM proposals)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	18
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	11
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	50
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	22
138 kV Overloads	3
115 kV Overloads	5

Scenario 0H

Scenario Components

1A-Alter_ALL (Full DOM proposals) _Hunterstown-Doubs-Goose Creek

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 2022-W3-445 (Hunterstown-Doubs-Goose Creek 500 kV part)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	15
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	9
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	44
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	1
115 kV Overloads	2

Scenario 0H2

Scenario Components

0G (1A-Alter_ALL (Full DOM proposals) _Hunterstown-Doubs-Goose Creek) + Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 (Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line)
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 2022-W3-445 (Hunterstown-Doubs-Goose Creek 500 kV part)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	45
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	3
115 kV Overloads	5

Scenario 0I

Scenario Components

1A-Alter_ALL (Full DOM proposals) _T-Point substation

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap, no lines)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	14
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	47
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	19
138 kV Overloads	2
115 kV Overloads	5

Scenario 0J

Scenario Components

1A-Alter_ALL (Full DOM proposals) _T-Point substation + two T-Point-Doubs or Goose Creek 230 kV lines

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap, two 230 kV line from T- Point-Doubs or Goose Creek)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	13
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	16
345 kV Overloads	0
230 kV Overloads	20
138 kV Overloads	2
115 kV Overloads	5

Scenario 0J-2

Scenario Components

1A-Alter_ALL (Full DOM proposals) _T-Point substation + T-Point-Doubs 500 kV lines

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap, T- Point-Doubs 500 kV line)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	21
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	14
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	48
500 kV Overloads	17
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	2
115 kV Overloads	5

Scenario 0J-3

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ 0J-2 with REMOVING West Cooper-High Ridge 500 kV line

- Exelon: 2022-W3-344/660 (Remove West Cooper-High Ridge 500 kV line)
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: Part of 2022-W3-948 (T-Point sub, just the Tap) + T- Point-Doubs 500 kV line

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	2
345 kV Overloads	2
230 kV Overloads	1
138 kV Overloads	14
115 kV Overloads	4

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	82
500 kV Overloads	17
345 kV Overloads	0
230 kV Overloads	29
138 kV Overloads	6
115 kV Overloads	16

Scenario 0K

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ Conastone-Doubs 500 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- PSEG: Part of 2022-W3-637 (Conastone-Doubs 500 kV line)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	19
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	12
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	45
500 kV Overloads	16
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	1
115 kV Overloads	4

Scenario 0L

Scenario Components

1A-Alter_ALL (Full DOM proposals)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-837 (not include Meadow Brook-Doubs line)
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: 663 (Add Front Royal-New Wishing Star 500 kV line)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	20
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	13
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	21
138 kV Overloads	3
115 kV Overloads	5

Scenario 0M

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ 500 kV Stork-Flys UG Line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- TRANSRC: 2022-W3-858 (500 kV Stork-Flys UG Line)
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

Note: Grab Aspen bus + 2nd 500 kV line from Aspen to Goose Creek from 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	20
500 kV Overloads	0
345 kV Overloads	1
230 kV Overloads	2
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	49
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	18
138 kV Overloads	4
115 kV Overloads	5

Scenario 0N

Scenario Components

1A-Alter_ALL (Full DOM proposals)_500 kV Goose Creek-Beaumeade UG Line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- LSPower: 2022-W3-548 (500 kV Goose Creek-Beaumeade UG Line + Loop 230 kV Beaumeade - DTC through BECO)
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

Note: Grab Aspen bus + 2nd 500 kV line from Aspen to Goose Creek from 2022-W3-692

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	25
500 kV Overloads	0
345 kV Overloads	1
230 kV Overloads	0
138 kV Overloads	18
115 kV Overloads	4

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	52
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	4
115 kV Overloads	5

Scenario 0O

Scenario Components

1A-Alter_OK+ Conastone-Doubs 500 kV line loop in T-Point + Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- PSEG: Part of 2022-W3-637 (Conastone-Doubs 500 kV line) and loop in T-Point
- NEET: part of 175 (Otter Creek-T-Point)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	19
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	13
115 kV Overloads	2

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	31
500 kV Overloads	8
345 kV Overloads	0
230 kV Overloads	15
138 kV Overloads	1
115 kV Overloads	2

Scenario 0O2

Scenario Components

1A-Alter_OK+ Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 175 (Otter Creek-T-Point)

2027 Screening Performance

Overload	Number of Overloads
Total Overloads	18
500 kV Overloads	1
345 kV Overloads	2
230 kV Overloads	0
138 kV Overloads	11
115 kV Overloads	3

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	7
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	1
115 kV Overloads	4

Scenario 0O3

Scenario Components

0O2 (1A-Alter_OK+ Otter Creek-T-Point-Doubs 500 kV) + Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 175 (Otter Creek - T-Point-Doubs)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	6
345 kV Overloads	0
230 kV Overloads	16
138 kV Overloads	3
115 kV Overloads	5

Scenario 0P

Scenario Components

(OG + updated 9A)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Transource: part of 2022-W3-487 (IEC)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	35
500 kV Overloads	4
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	1
115 kV Overloads	3

Scenario 0P2

Scenario Components

(OG + updated 9A East)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Transource: part of 2022-W3-487 (IEC East only)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	44
500 kV Overloads	5
345 kV Overloads	0
230 kV Overloads	24
138 kV Overloads	4
115 kV Overloads	5

Scenario 0P NGME

Scenario Components

1A-Alter_ALL (Full DOM proposals) _ Remove Golden-2-Mars Extension

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	53
500 kV Overloads	13
345 kV Overloads	0
230 kV Overloads	23
138 kV Overloads	4
115 kV Overloads	5

Scenario 0Q

Scenario Components

0G remove Graceton-High Ridge 500 kV line + Peach Bottom -Brandon Shore 500 kV line (Part of 741)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Remove Graceton-High Ridge 500 kV line
- Add Peach Bottom -Brandon Shore 500 kV line (Part of 741)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	67
500 kV Overloads	15
345 kV Overloads	0
230 kV Overloads	29
138 kV Overloads	6
115 kV Overloads	8

Scenario 0Q2

Scenario Components

0G [1A-Alter_ALL (Full DOM proposals)] + Remove Pruntytown-Mt Storm, Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Pruntytown-Mt Storm, Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	83
500 kV Overloads	15
345 kV Overloads	0
230 kV Overloads	26
138 kV Overloads	26
115 kV Overloads	10

Scenario 0Q3

Scenario Components

0G [1A-Alter_ALL (Full DOM proposals)] + Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Fort Martin-Doubs ckt 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	60
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	25
138 kV Overloads	7
115 kV Overloads	9

Scenario 0Q4

Scenario Components

0G (1A-Alter_ALL (Full DOM proposals))_ Remove Fort Martin-Doubs ckt 1 and 2 and Hunterstown-Carroll 230 kV line

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23 – Remove Fort Martin-Doubs ckt 1 and 2 and Hunterstown-Carroll 230 kV line
- DOM: 2022-W3-711 (Regional Solution South)
- DOM/FE: 2022-W3-516/23 (DOM/FE Interregional Solution)
- DOM: 2022-W3-692 (DC Alley Solution) – Remove Golden-2-Mars Extension
- DOM: 2022-W3-923 (500 kV Dooms-Lexington)
- DOM: 2022-W3-671 (Front Royale-Morrisville)
- DOM: 2022-W3-731 (Locks TX Upgrade)
- DOM: 2022-W3-704/211 (Hollymeade-Gordonsville)
- DOM: 2022-W3-30/967 (Charlottesville-Hollymeade-Dooms)
- DOM: 2022-W3-74 (Ladysmith-Fredericksburg)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	72
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	27
138 kV Overloads	16
115 kV Overloads	10

Scenario 0R

Scenario Components

1A-Alter_OK+ Conastone-Doubs 500 kV line loop in T-Point + Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- PSEG: Part of 2022-W3-637 (Conastone-Doubs 500 kV line) and loop in T-Point
- NEET: part of 175 (Otter Creek-T-Point)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	30
500 kV Overloads	8
345 kV Overloads	0
230 kV Overloads	14
138 kV Overloads	1
115 kV Overloads	2

Scenario 0R2

Scenario Components

1A-Alter_OK+ Otter Creek-T-Point 500 kV

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- NEET: part of 175 (Otter Creek-T-Point)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	34
500 kV Overloads	7
345 kV Overloads	0
230 kV Overloads	17
138 kV Overloads	1
115 kV Overloads	4

Scenario 0S

Scenario Components

0G + remove Graceton-High Ridge 500 kV line + Remove High Ridge 500/230 station + Add Peach Bottom-New Raphael-Waugh Chapel 500 kV line and Raphael 500/230 station (Part of 808)

- Exelon: 2022-W3-344/660
- FE: 2022-W3-23
- DOM: 2022-W3-711
- Dom/FE: 2022-W3-516/23
- DOM: 2022-W3-692
- DOM: 2022-W3-923
- DOM: 2022-W3-671
- DOM: 2022-W3-731
- DOM: 2022-W3-704
- DOM: 2022-W3-211
- DOM: 2022-W3-30
- DOM: 2022-W3-967
- DOM: 2022-W3-74
- Remove Graceton-High Ridge 500 kV line and Remove High Ridge 500/230 kV station
- PSEG: 2022-W3-808 Part (Add Peach Bottom-New Raphael-Waugh Chapel 500 kV line and Raphael 500/230 station)

2028 Screening Performance

Overload	Number of Overloads
Total Overloads	55
500 kV Overloads	14
345 kV Overloads	0
230 kV Overloads	26
138 kV Overloads	4
115 kV Overloads	5

Document Revision History

10/17/2023 – R1: original version posted

11/30/2023 – R2:

- Update to cost estimates included in the "Final Reliability Analysis and Recommended Solution" section, reflecting latest estimates received.
- Correction to Map 5 - South Proposal Cluster Map.

12/8/2023 – R3:

- Update to cost estimates included in the "Final Reliability Analysis and Recommended Solution" section, reflecting latest estimates received consistent with Dec. 5, 2023 TEAC.
- Corrected footnote in Table 3.
- Clarification of sentences on pages 20, 22 and 23.

Reliability Analysis Update

Sami Abdulsalam

Transmission Expansion Advisory Committee

October 3, 2023

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2023 Reliability Proposal Window 1

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2023 Reliability Proposal Window 1

- Window opened on 7/24/2023
- Window closed on 9/22/2023
- For this Window, PJM seeks technical solutions, also called proposals, to resolve potential reliability criteria violations on facilities identified in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC, and Local Transmission Owner criteria).
- 20 total proposals submitted from 9 different entities (7 Incumbents & 2 Non Incumbents)
  - 7 Greenfields
  - 13 Upgrades
- Cost Estimates: Approximate range from $1.08 M – $1,300 M
- 5 proposals with Cost Containment

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2022 RTEP Window 3
Transmission Planning Update

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Presentation Outline

- Background
- 2022 RTEP Window 3 purpose and timeline
- Need statement summary
- Load forecast and generation assumptions
- Summary of proposals
- Summary of scenarios studied
- Proposals detailed review and short list scenarios
- Summary of short circuit results
- Summary of load deliverability results

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2022 RTEP Window 3
Purpose and Timeline

- **Purpose:**
  - Address reliability needs in the Dominion and APS zones primarily associated with Data Center Load forecasts (up to 7,500 MWs by 2027-28)
  - Seeking robust and flexible solutions to address the reliability needs in those specific areas

- **Window Opened; February 24th 2023 / Closed May 31st 2023**
  - PJM posted preliminary planning basecases on January 31st 2023
  - 90 Day Window – Extended from April 25th to May 31st 2023

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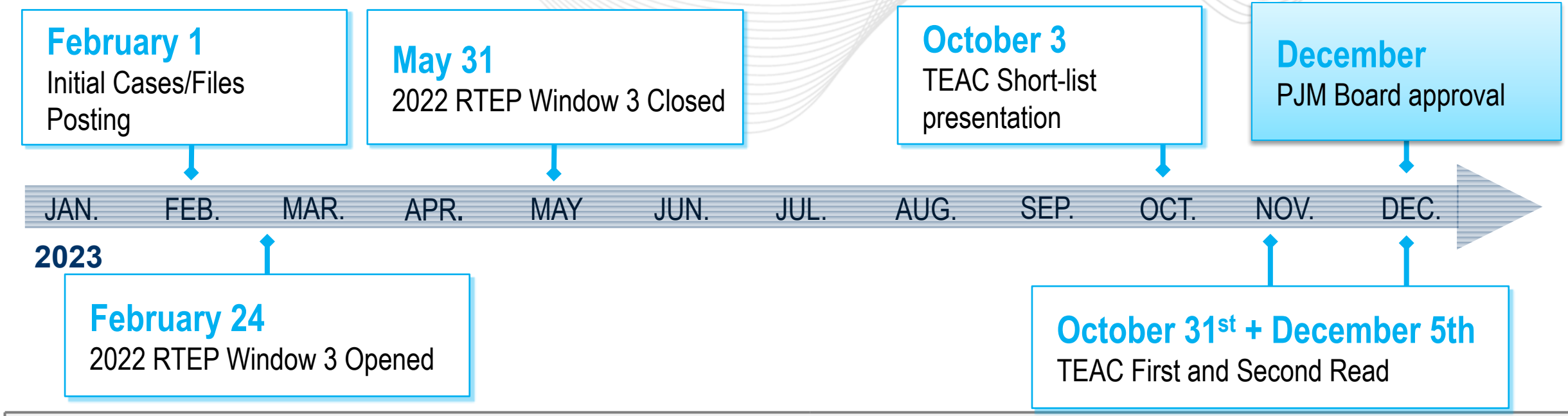
2022W3 RTEP Timeline



- Currently, system models with the data center loads (starting 2027) do not solve without reinforcements.
- Supplemental (M3 Process) can not evaluate project impacts until the reliability constraints are resolved.
- In 2024, PJM needs clean base cases for interconnections, NJOSW 2.0, Offshore Wind studies and LTRTP.
- Reinforcements need to be finalized by end of 2023.

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Competitive Window Submissions

72 Proposals Were Received From 10 Entities

6 incumbent, 4 non-incumbent	22 projects are upgrades, while 50 are greenfield	Total ~$50.7B * (sum of all proposal costs – not all are required)

Proposals include:

- 230 kV, 500 kV and 765 kV developments
- 500 kV GIS substations
- UG 500 kV AC cable developments
- Double circuit 500 kV proposals
- HVDC development

***One proposal cost was revised by submitting entity from $1.6B to $5.4B**

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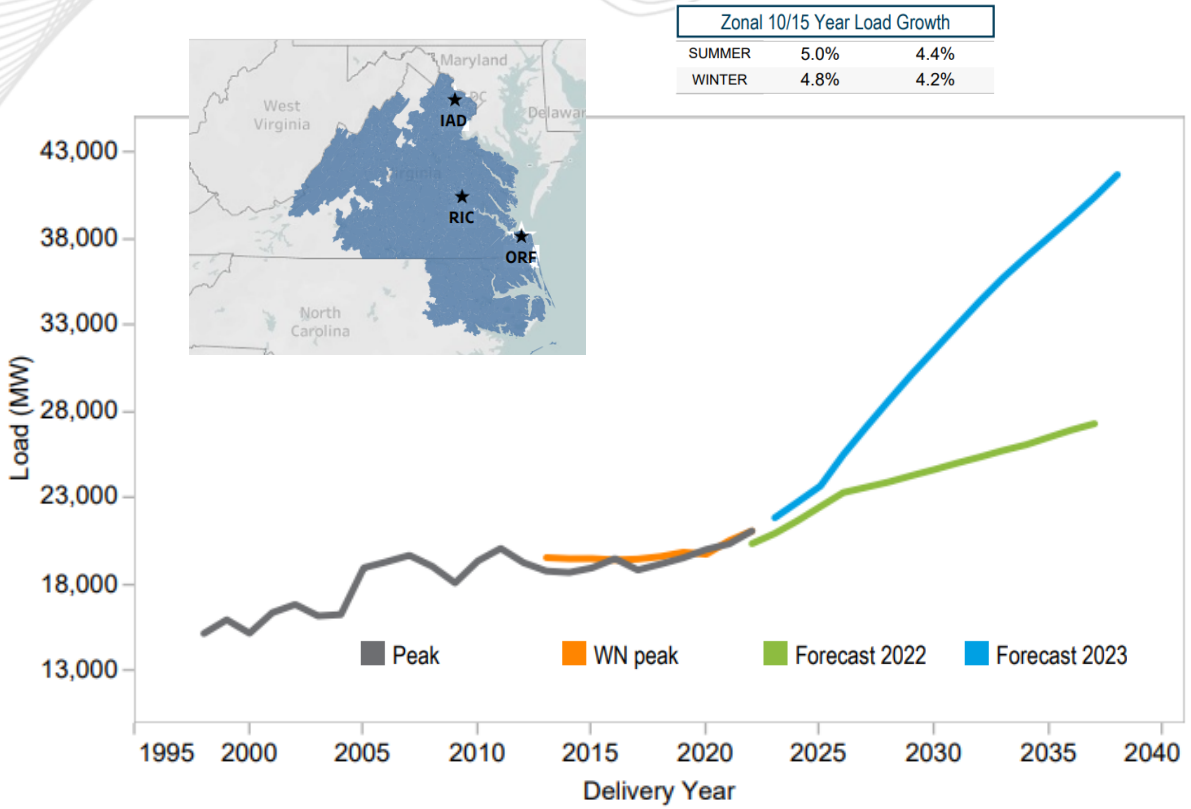
Load Forecast and Planning Approach

- PJM began receiving near and long term forecast input from Dominion, First Energy and NOVEC for Data Center load growth projections up to and including 2038 (15 year planning horizon).
- The PJM 2023 Forecast calls for approximately between 4.2% to 5.0% annual load growth in the Dominion area over the next 10-15 year timeframe.
- The Load Forecast information was refined and developed down to a bus/substation level for the 2028 and 2030 study years.
- PJM reassessed the transmission development needs in the area based on the refined forecast information and localized allocation of load.



https://pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx

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2022 RTEP Window 3 - Objective

- Develop robust, holistic and expandable solutions that address the 2027-28 baseline violations associated with:
  - Local constraints: resulting from directly serving the data center loads in APS and Dominion zones through the respective 230 kV networks and into the points of delivery:
    - Goose Creek- Ashburn – Mars - Wishing Star and Brambleton
  - Regional constraints resulting from imports into load center areas (500 kV primarily):
    - Front Royal - Morrisville – Vint Hill – Loudoun/Mosby
    - Meadow Brook - Vint Hill
    - Morrisville – Bristers - Ox
    - Peach Bottom – Conastone – Brighton – Doubs
  - Needed reactive power VAR reinforcements, both static and dynamic as deemed necessary, to address the reactive power needs of the system for the 2027-28 baseline scenario
- Adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and Local Transmission Owner Criteria.

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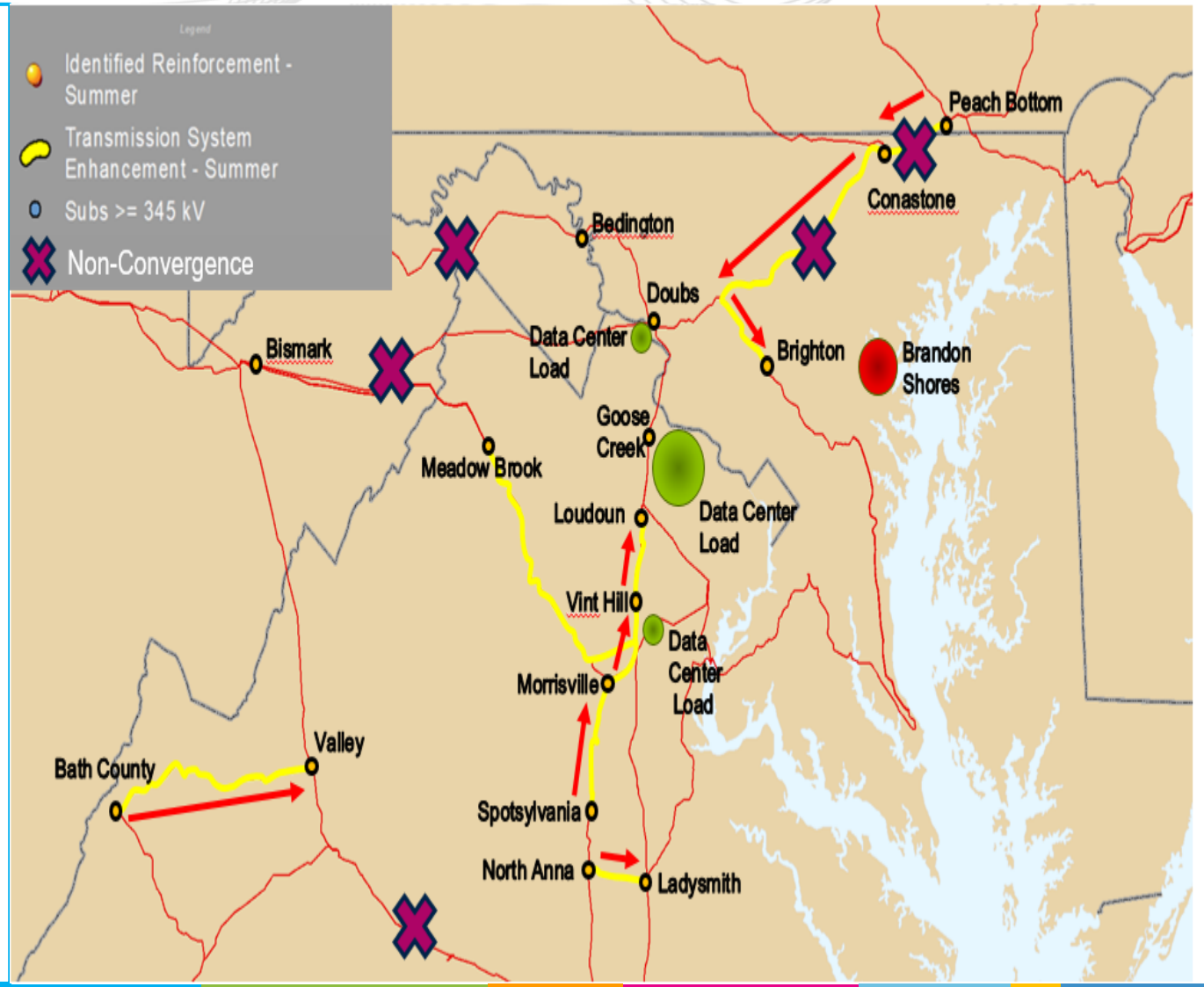
2022W3 RTEP- Summary of Drivers/Needs

- PJM has had unprecedented data center load growth (up to~7,500 MW) currently forecasted by 2027- 28 in Dominion (Northern Virginia) and APS (Doubs)
- 11,100 MW of announced deactivations to the west and south of Conastone
  - Approximately 5,300 MW occurring after the 2022 RTEP 2027 case was created
- The vast majority of the new generation with signed ISAs has been solar
  - Solar has low availability during the winter period
- The replacement generation is coming from the region to the east of Peach Bottom as well as west of Doubs to meet projected load growth.
- PJM has implemented a new block dispatch procedure
  - The old dispatch procedure maintained historical intraregional transfers, dispatching most of the generators in the Dominion zone at 100%.



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Brandon Shores Deactivation Assumptions

- Initial 2022 Window 3 2027 basecase has Brandon Shores generators modeled and dispatched
- The 2022 Window 3 2028 basecase has Brandon Shores generators removed as per the deactivation notice
- As will be shown, PJM received proposals from PSEG, NextEra, and Exelon addressing the Brandon Shores deactivation covering 2028 robustness test
- All proposals submitted to address only 2027 base case needs do not consider Brandon Shores deactivation
- PJM evaluated effectiveness of all submitted proposals to address Brandon Shores deactivation against the PJM Board approved project.

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2022 RTEP Window 3
Criterion Applied by PJM

- **2027-28 Summer / Winter**
  - Baseline Thermal and Voltage N-1 Contingency Analysis
  - Generator Deliverability and Common Mode Reliability Analysis
  - N-1-1 Thermal and Voltage Analysis
  - Load Deliverability Thermal and Voltage Analysis
  - Dynamic Stability Assessment
  - Short Circuit Assessment
- **2027-28 Light Load**
  - Baseline Thermal and Voltage N-1 Contingency Analysis
  - Generator Deliverability and Common Mode Reliability Analysis
- **2027-28 CSPA Study**

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2022 RTEP Window 3 - Requirements

- Holistic solutions are to be designed such that they are robust and expandable as the load grows within the area.

- A scalable solution ensures, at a minimum, near-term reliability needs are addressed while also enabling future expansion (beyond the 2027-28 baseline levels) as data center load increases in the Dominion and APS zones.

  - Consider flexibility, robustness and scalability of 2027-28-baseline solutions against the Interim 2027-28 Summer, Winter and Light Load basecases.
  - Evaluate proposals for their effectiveness towards existing reactive interfaces in the area, particularly those supporting the Dominion and APS zones.
  - Evaluate the effectiveness of the proposed solutions towards the transmission system load deliverability into the Dominion and APS zones (CETL).

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2022 RTEP Window 3 – Assumptions 1/3

- **Preliminary Reactive Support:**
  - 2027-28 basecases included a set of reactive VAR support at existing/proposed substations to partially meet the system reactive demand under system normal, N-0 conditions.
  - Included at specific locations as indicated in PJM's 2022 RTEP Window 3 Problem Statement.
  - Initial VARs not imply final VAR level, type or location.
    - Only adequate for need analysis purposes.
    - Should be removed and replaced consistent with an entity's proposal to provide the necessary VAR support.
  - PJM expects that proposals will provide for the needed reactive VAR support through either transmission development or static/dynamic VAR support devices or a combination of both.
  - A number of non-convergent contingencies due to deficient VAR support and excessive reactive power loss in the 2027-28 modeling basecases.
  - Based on the preliminary VAR resource assumptions in the cases, the provided voltage performance results are for guiding purposes only.
    - Proposal developers are to re-evaluate the voltage performance part of their proposal development to ensure compliance with voltage performance requirements.

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2022 RTEP Window 3 – Assumptions 2/3

- **Basecase N-0 thermal Violations:**
  - 2027-28 baseline case(s) show thermal violations along the Peach Bottom-Conastone and Conastone-Brighton 500kV paths.
  - These 500 kV segments are also showing marginal overloads approaching 98% to 100% under N-1 conditions for the baseline summer conditions.

- **Non-Converged N-1 Contingencies:**
  - Key contingencies lead to voltage collapse on the 500kV system due to insufficient transmission system transfer capability and VAR support inadequacy.
  - Following development of VAR support enhancements, thermal loading on all system elements needs to be monitored and overloads, if any, need to be addressed part of the proposed solutions.

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2022 RTEP Window 3 – Assumptions 3/3

- **N-1-1 Analysis;**
  - Due to the significant load growth presented in the baseline 2027-28 basecases, a large number of N-1-1 contingencies lead to unsolvable security constraint redispatch conditions.
  - Hence, the provided N-1-1 results are to be revaluated as part of the proposal solution development process.
  - PJM posted the interim 2027-28 basecase N-1-1 results early March on the PJM website in the competitive planning section.

- **Load Deliverability analysis:**
  - PJM requires that proposed solutions are evaluated for their effectiveness towards load deliverability into the APS and Dominion zones.

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2022 RTEP W3 – Window Evaluation

Two Rounds of PJM Meetings With Proposing Entities:

- Discussions to clarify details of proposed developments, assumptions, rationale of proposed alternatives/variations
- First round was conducted in June/July 2023.
- Second round was initiated in late July and concluded mid-August:
  - Focus on outage scheduling, routing, risk and cost assumptions/considerations

Scenario Development and Analysis

To date, PJM developed and analyzed:

- >30 scenarios for the 2027 model (Combination of proposals and components from different proposals)
- >80 scenarios for the 2028 model

Scenarios Were Built Based On:

- Full combination scenarios by proposing entities (Incumbents, Nextera, LS Power and Transource)
- Optimized scenarios using components from incumbent and non-incumbent proposing entities

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2022W3 – Window Evaluation Criteria

Scenarios With Their Associated Proposed Developments Will Be Evaluated Based On the Following Principles:

Performance	Scalability	Impact	Validated Cost
Meeting the system needs of 2027 and being flexible to address 2028 needs	Scenario/development longevity – system robustness and utilization	Utilization of existing ROWs where possible and efficient.	Cost evaluation using third-party benchmarking metrics

Risks

- Triggering additional costs:
  - Substation rebuilds due to extreme short-circuit levels
  - Avoid extended critical outages (Peach Bottom / Conastone rebuilds)
- Imposing high permitting
- Inability to meeting in-service date

Efficiencies

- Avoidance of redundant capital investment including recognizing synergies with EOL facilities and overlaps of previously approved (or imminent) supplemental/baseline upgrades.

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2022 RTEP Window 3

Overview of Submitted Proposals

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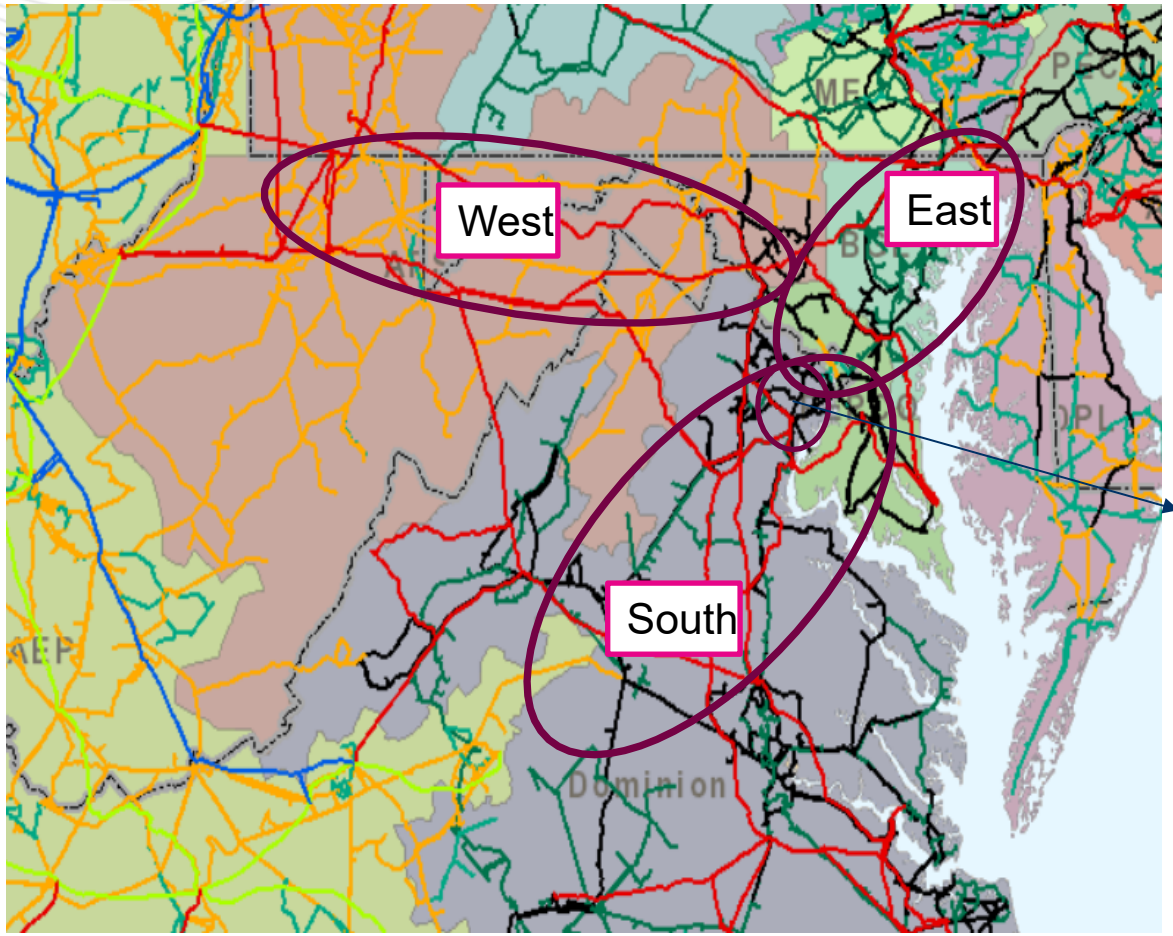
Proposal Groupings

- Proposals were grouped in 4 main clusters (East, West, South and Dominion)
- Each cluster included proposals by different entities in the same need area and/or addressing the same local/regional needs
- Scenarios were developed and tested:
  - First; address regional needs
  - Next; scenarios were refined (building new scenarios) to cover local needs
  - Scenarios were further refined using more effective proposal components as demonstrated through performance



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Proposal evaluation – 2027 RTEP cases

- Initial screening was conducted for all proposals on 2027 RTEP cases

- Scenario studies followed by developing and assessing:
  - Combination Proposals from various proposing entities
  - Combination of components from different proposals

- 2027 Results indicate all combination proposals can address the 2027 needs to a varying degree
  - All 2027 combination proposals offered 500 kV or 765kV solutions in the West
  - Three out of four proposed combinations offered 500 kV reinforcements in the East
    - Several other proposing entities offered 500kV and HVDC solutions
    - Some 230 kV reinforcements were also offered as options to address eastern cluster needs

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Proposal evaluation – 2028 RTEP cases

- 2028 Robustness test was utilized to further assess the merit of all proposals
  - 2028 evaluations indicated need for further regional transfer reinforcements (beyond those offered for 2027)
  - Account for major deactivations in the study area (Brandon Shores among others)
  - Account for higher regional transfers as a result of block dispatch and new gen deliverability test

- LS Power, Transource and NextEra (598) combination proposals show more significant violations in 2028 initial testing
  - PJM further tested components from LS Power and Transource proposal in developing additional scenarios
  - Nextera proposed a standalone add-on component to upgrade its 2027 combination proposal (598) to address 2028 needs (175)

- NextEra 175 and the Incumbent (Exelon, FE and Dominion) proposal scenarios showed promising performance – These were used as starting point for further assessments

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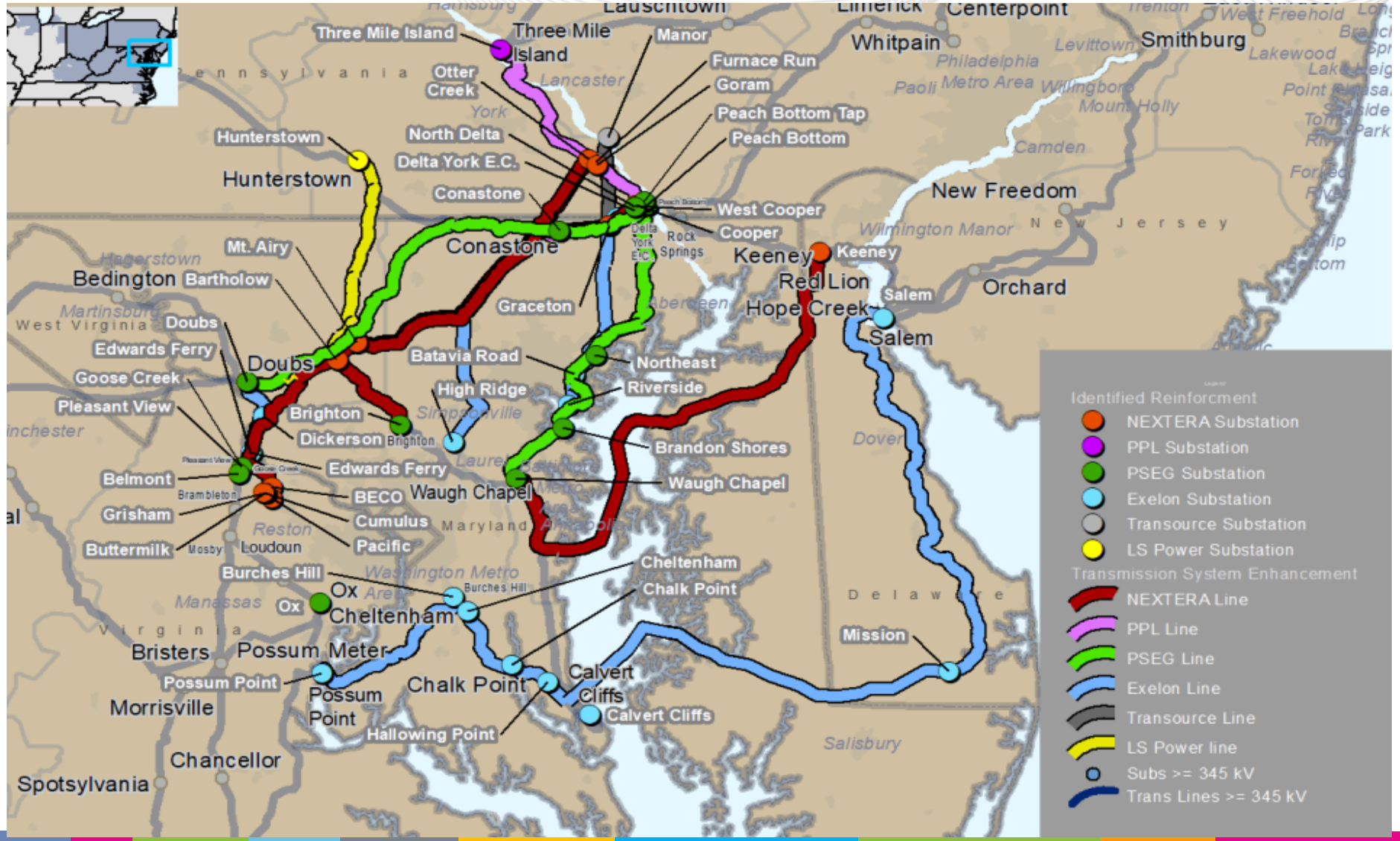
Summary of Proposal Clusters - East



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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Summary of Proposal Clusters - East

- Six proposing entities submitted proposals to address the East cluster violations
- PJM confirmed the need for the following
  - Regional reinforcements between Peach Bottom area and Northern Virginia
  - Regional and local reinforcements into BGE
- PJM evaluated various combinations of the proposals/components to identify the most effective solution
- PJM is finalizing its evaluations of the Ring Gold – Rice proposal against a number of alternatives.

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Summary of Proposal Clusters – East

- BGE local/regional solution
  - West Cooper – High Ridge 500 kV (Exelon)
  - Peach Bottom/N. Delta – Raphael - Waugh Chapel 500 kV (PSEG)
  - Peach Bottom – Brandon Shore 500 kV (PSEG)
  - Keeney – Waugh Chapel double 230 kV (Nextera)

- BGE local area solution (Focused on Brandon Shores Deactivation)
  - Graceton – Batavia double circuit 230 kV (Exelon-Deactivation Scope)
  - Peach Bottom/N. Delta – Raphael - Waugh Chapel 500 kV (PSEG)
  - Peach Bottom – Brandon Shore 500 kV (PSEG)
  - Keeney – Waugh Chapel 230 kV double circuit (Nextera)

* Red boxes refer to solutions proposed by incumbent to address BGE area needs.

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Summary of Proposal Clusters - East

- Regional solution (Regional Transfers)
  - Peach Bottom – Graceton - Conastone/N. Delta 500kV upgrade (Exelon/Transource)
  - Peach Bottom – Doubs 500 kV (PSEG)
  - Conastone – Doubs 500 kV (PSEG)
  - Hunterstown – Green Valley 500 kV (PSEG)
  - Hunterstown – Doubs – Goose Creek 500 kV (NextEra and LS Power)
  - Otter Creek – T-Point 500 kV (NextEra)
  - Conastone – T-Point 500 kV (NextEra)
  - Otter Creek – Conastone 500kV (PPL)
  - North Delta – Conastone 500kV (NextEra and LS Power)
  - T-Point – Data Center Alley 230 kV (NextEra)
  - Transource 230kV development between Peach Bottom and Conastone (Transource)

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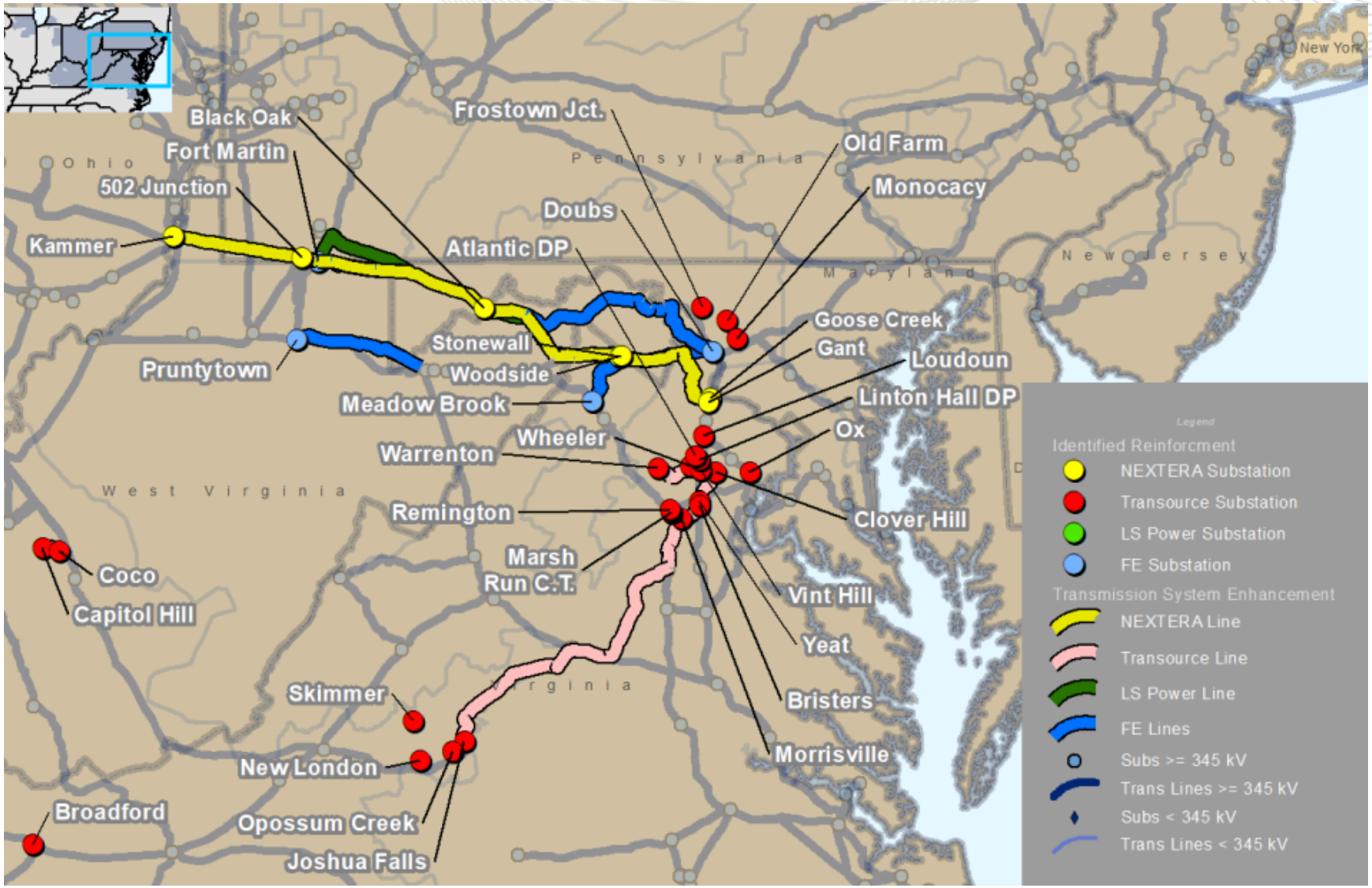
2022 Window 3 proposals – West Projects



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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Summary of Proposal Clusters - West

- West regional solutions
  - 502 J – Black Oak – Stonewall – New Belmont (Gant) 500 kV (NextEra)
  - Fort Martin – Doubs 500 kV double/single circuits (FE)
  - Pruntytown – Mt. Storm and Meadow Brook – Doubs 500 kV (FE)
  - 502J – Black Oak – Doubs 500 kV (LS Power)
  - Joshua Falls – Yeat 765 kV (Transource)
- All of the 500 kV proposals listed above overlap or use similar ROWs adjacent to existing transmission developments in the area.
- Less effective/efficient solutions were also tested, for example:
  - Front Royal – New Wishing Star 500 kV (NextEra)
  - Black Oak - Goose Creek 500 kV (NextEra)

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Summary of Proposal Clusters - West

- Four proposing entities submitted proposals to address the West cluster violations
  - All proposals are approaching the western needs by 500 kV or 765 kV new lines
  - PJM evaluated every proposal individually
- PJM evaluated various combinations of proposals or their components to identify the most effective solution
- PJM confirmed the need for the following
  - Regional reinforcements from West (a minimum of 1x500 kV or 1x765 kV development – both require dedicated dynamic VAR support)
  - For the 500 kV reinforcement options terminating at Doubs, additional transfer capability is required into Goose Creek area (Northern Virginia)

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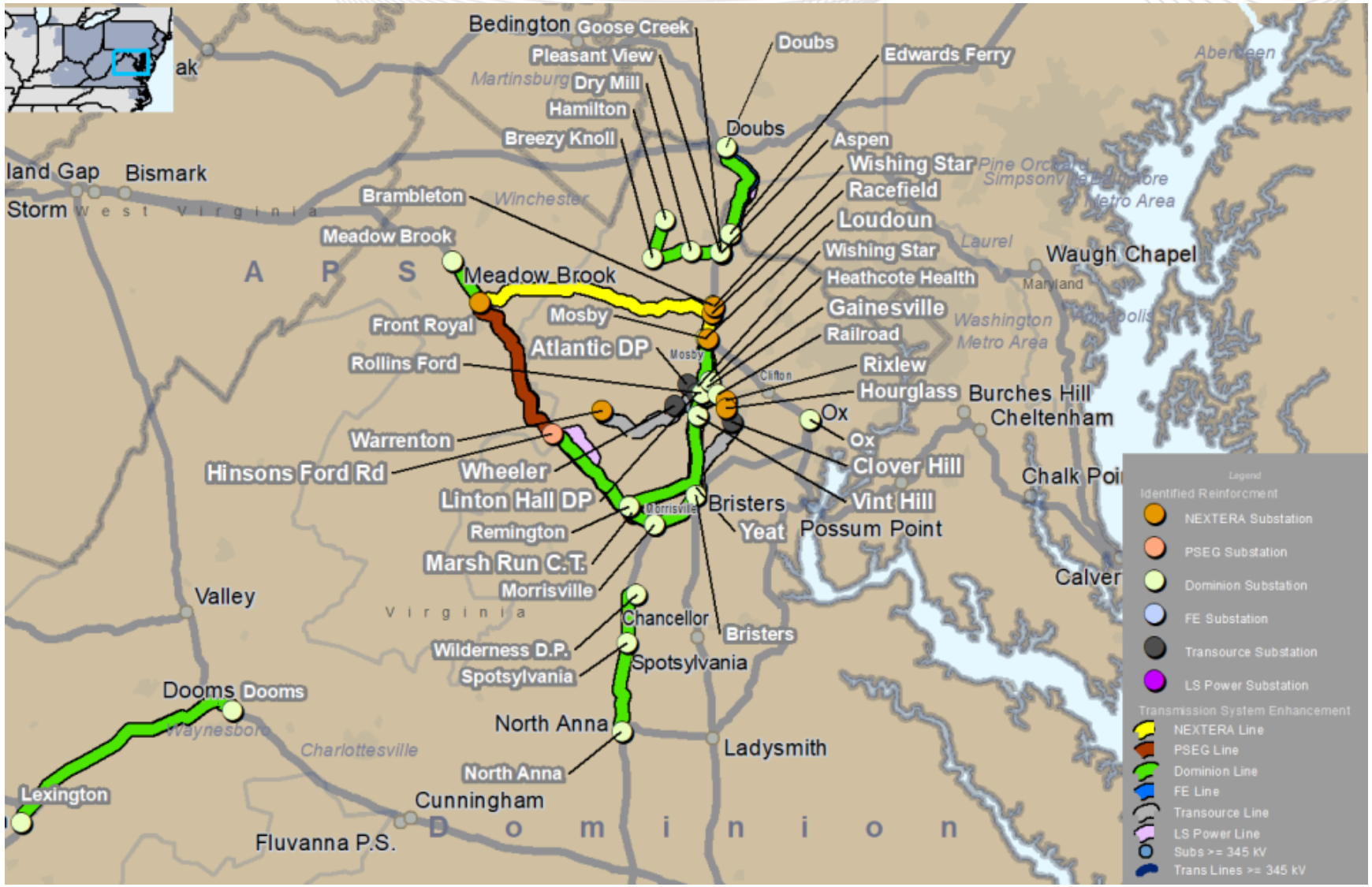
Summary of Proposal Clusters - South



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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Summary of Proposal Clusters - South

- Four proposing entities submitted proposals to address the South cluster violations
  - All proposals are addressing the South needs by proposing new 500kV lines primarily
  - PJM evaluated every proposal individually and in combination

- South Regional Solutions
  - Front Royal – Vint Hill 500 kV (LS Power)
  - Hinsons Ford Rd – Brambleton 500 kV (PSEG)
  - Front Royal – New Wishing Star (Racefield) 500kV (NextEra)
  - North Anna – Wishing Star 500kV (Dominion)

- PJM is evaluating the need for a portion of the North Anna – Wishing Star 500 kV

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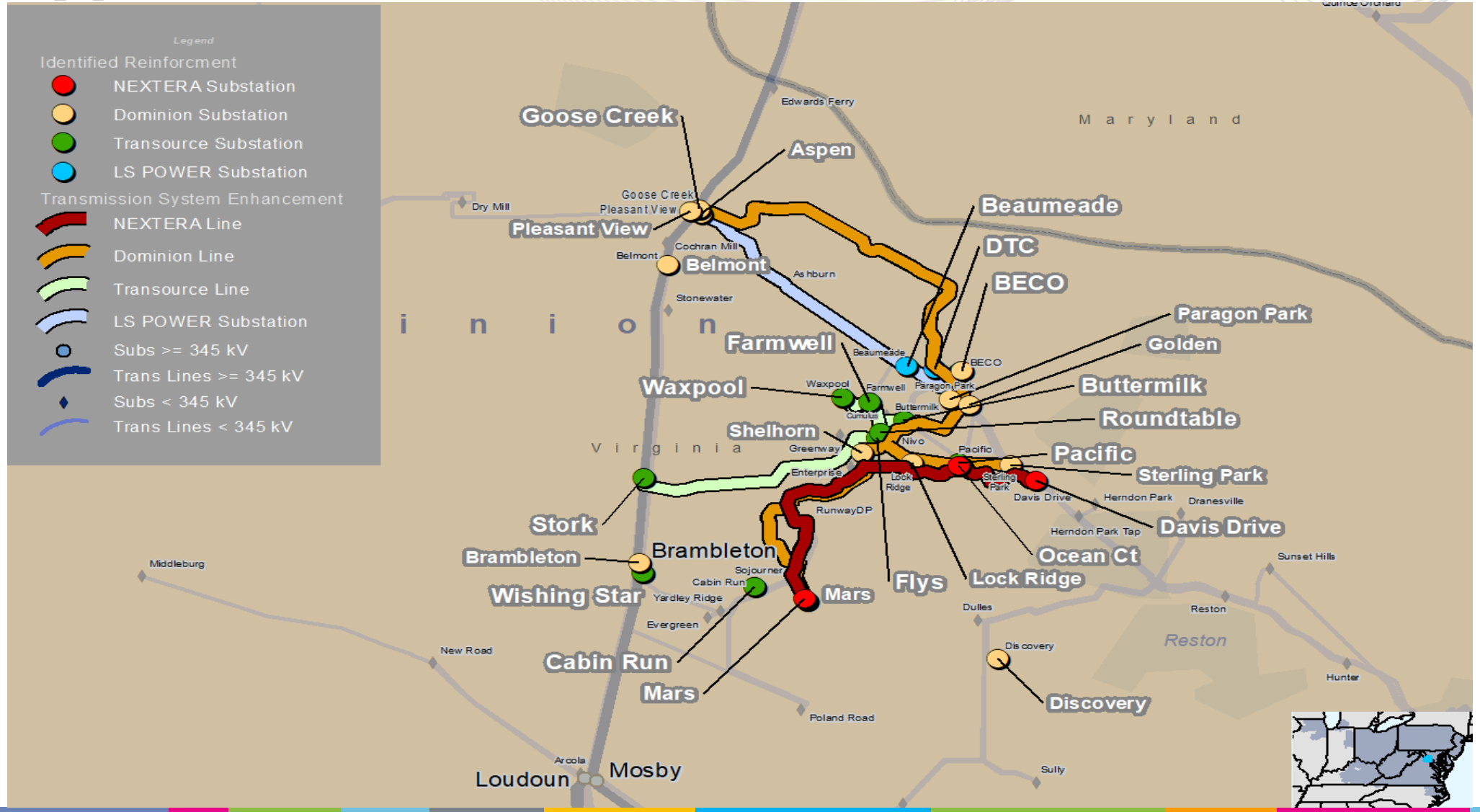
Summary of Proposal Clusters - Dominion



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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Summary of Proposal Clusters - Dominion

- Three proposing entities submitted proposals to address the Data Center Alley violations
  - Two underground 500kV cables Vs. One overhead 500/230KV
  - PJM evaluated every proposal individually

- Dominion Data Center Alley Solutions
  - Goose Creek – Beaumeade 500KV underground (LS Power) – 2308/3596 MVA for SN/SE
  - Stork – Flys 500 kV underground (Transource) – 3302/3302 MVA for SN/SE
  - Aspen – Golden –Mars 500/230kV overhead (Dominion) – 4357/4357 MVA for SN/SE
    - This solution attempts to establish a second 500kV path along the existing 500kV path between Brambleton and Goose Creek
    - Existing substations in the area are congested/space limited and hence the two new substations (Aspen and Golden) will establish two new main substations
    - Both the 500kV and 230kV systems will be accessible to serve additional load and Delivery Points

- PJM is evaluating the need for Golden – Mars 500kV extension
  - Closing the Aspen-Golden-Mars 500kV loop could take place in stages.

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Proposals Detailed Constructability Review and Scenario Short List

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PJM Risk Assessment Criteria

PJM Risk Assessment Criteria

Risk Assessment	Cost Estimate Risks	Cost Containment Risk	Schedule Risks	Constructability Risks	Use of Existing ROW/Brownfield	Outage Coordination Risks
Low	Greater than or within 0-10% of Independent Estimate	Hard cost cap	Ratings assessed based on independent assessment of proposed in-service dates, and assessment of significant schedule risks such as such as permitting and constraint mitigation, long-lead material procurement, land/ROW acquisition, construction complexity.	Ratings assessed based on independent assessment of the number and severity of constructability risks assessed for the proposed project scope, such as permitting and constraint mitigation, land/ROW acquisition, construction complexity.	Rebuild/Reconductor Upgrades or Pure Brownfield	Minimal existing facility outages required, beyond short outages to cut-in to existing facilities
Medium	Within 10-20% of Independent Estimate	Soft cost containment (e.g ROE caps)			Mostly Brownfield (i.e. Uses/Overlaps existing ROW but requires expansion)	Significant existing facility outages required, with reasonable outage coordination plan proposed
Medium-High	Within 20-30% of Independent Estimate	Minimal cost containment/Excessive Exclusions			Greenfield paralleling existing ROW	Significant existing facility outages required, with no coordination plan proposed
High	Less than 30% of Independent Estimate	No cost containment			Pure Greenfield	Significant existing facility outages required, with known operational concerns and no coordination plan proposed.

NOTE:

- PJM conducted its constructability evaluation of the project data submitted by proposers, and engaged expert consultants to evaluate the constructability, cost estimation, and cost containment risks of the projects.
- PJM also reached out to key regulatory agencies for their insight on certain projects to help clarify permitting risks.
- This risk assessment is not intended as a pass/fail or quantitive test, but rather as qualitative information on potential risks PJM has considered along with the reliability performance in selection of the finalist scenarios, and ultimately the recommended solution.

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Risk Assessment Matrix - East

East Cluster Projects – Selected for Detailed Evaluation

PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
344	Exelon	PECO Expansion Plan for DOM Window 2023	12/1/2029	$ 168.63	$ 186.06	Low	Medium-High	Low	Low	Low	Medium
660	Exelon	West Cooper BGE-PEPCO	12/1/2030	$ 1,105.62	$ 1,060.63	Low	Medium-High	Low	Low	Low	Medium
548	LS Power	RTEP Window 3 Solution (East Components)	6/1/2030	$ 495.83	$ 609.44	Medium	Medium	Low	Low	Medium	Medium-High
637	PSEG	Proposal D-Conastone-Doubs 500kV	6/1/2027	$ 684.22	$ 676.36	Low	Low	Low	Medium	High	Low
741	PSEG	Proposal G - Peach Bottom-New Brandon Shores 500kV; Peach Bottom-Doubs 500kV	6/1/2028	$ 1,065.32	$ 1,178.75	Medium	Low	Medium-High	High	High	Low
487	Transource	Maryland & Pennsylvania Baseline Reliability Solution	3/1/2027	$ 492.75	$ 503.43	Low	Medium	Low	Low	Medium	Medium
374	PPL	Otter Creek - Conastone 500 and 230 kV DCT Line	5/1/2027	$ 154.21	$ 162.69	Low	Medium-High	Low	Low	Medium	Medium
948	NextEra	New 500/230kV Bartholow substation, new 500/230kV North Delta substation, new 230kV Grisham switchyard, new 500/230kV Goram substation, and Keeney to Waugh Chapel tie-in	6/1/2028	$ 5,381.25	$ 6,265.88	Medium	Medium	High	High	High	Low

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Risk Assessment Matrix - West

West Cluster Projects – Selected for Detailed Evaluation

PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
837	POTOED - FirstEnergy	Data Center Reinforcement Proposal #1	6/1/2030	$ 2,394.96	$ 2,095.63	Low	High	Medium	Medium-High	Medium-High	Low
548	LS Power	RTEP Window 3 Solution (West Components)	6/1/2030	$ 972.71	$ 876.03	Low	Medium	Medium	Medium-High	Medium-High	Low
853	NextEra	502 Junction - Black Oak - Woodside - Gant, Woodside SVC + Cap Banks	6/1/2027	$ 683.55	$ 1,195.24	High	Medium	Medium-High	Medium-High	Medium-High	Low
904	AEP - Transource	Joshua Falls - Yeat 765kV Greenfield Line and Substation	12/1/2029	$ 1,048.10	$ 1,136.50	Low	Medium	High	Medium	High	Low

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Risk Assessment Matrix - South

South Cluster Projects – Selected for Detailed Evaluation

PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
516	Dominion	Interregional solution- Aspen-Doubs Second 500 kV Line	12/1/2027	$ 61.72	$ 77.95	Medium-High	High	Low	Medium	Medium	Medium
711	Dominion	Regional Solution - 500 kV North Anna-Wishing Star Upgrades	12/1/2027	$ 1,227.84	$ 1,284.62	Low	High	Medium	Low	Low	Medium
548	LSPower	RTEP Window 3 Solution (South Components)	6/1/2030	$ 628.56	$ 617.00	Low	Medium	Medium-High	Medium-High	Medium-High	Medium
325	PSEG	Proposal E - Brambleton-Hinsons Ford Rd 500kV	6/1/2027	$ 267.38	$ 275.56	Low	Low	High	High	High	Low
837	POTOED - FirstEnergy	Data Center Reinforcement Proposal #1 (South Components)	6/1/2030	$ 203.38	$ 209.16	Low	High	Low	Medium	Medium	Medium
663	NextEra	Front Royal - Racefield, Warrenton - Rixlew, Warrenton - Hourglass, Mars - Ocean Court - Davis Drive	6/1/2027	$ 284.17	$ 514.17	High	Medium	High	High	High	Low

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Risk Assessment Matrix – Dominion

Dominion Cluster Projects – Selected for Detailed Evaluation

PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
692	Dominion	Data Center Alley Local solution - New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	12/1/2027	$ 1,058.45	$ 1,098.96	Low	High	Medium	Low	High	Low
858	AEP - Transource	Stork - Flys 500kV Greenfield Line and Substations	12/1/2027	$ 510.44	$ 516.60	Low	Medium	Medium-High	High	High	Low
548	LSPower	RTEP Window 3 Solution (Dominion Components)	6/1/2030	$ 283.78	$ 307.52	Low	Medium	Medium-High	High	Medium-High	Low

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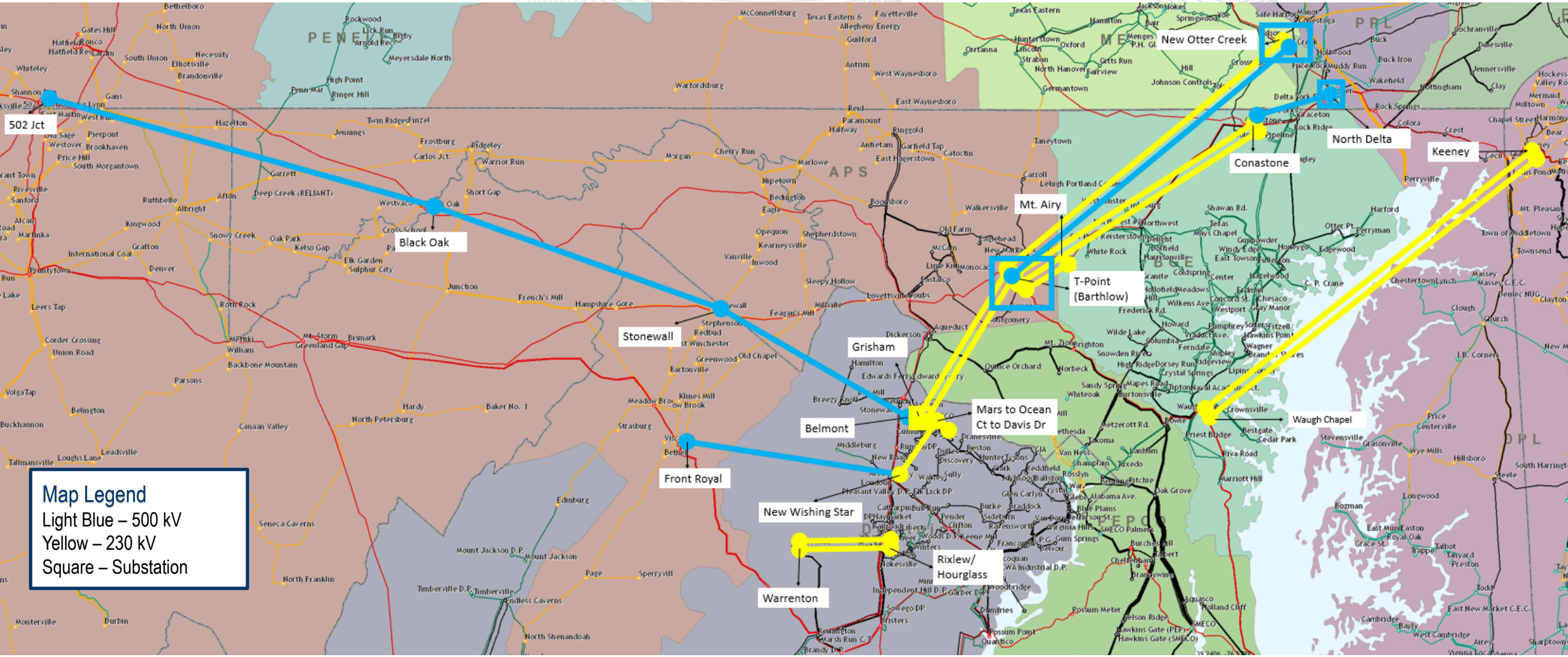
NextEra Proposal 175



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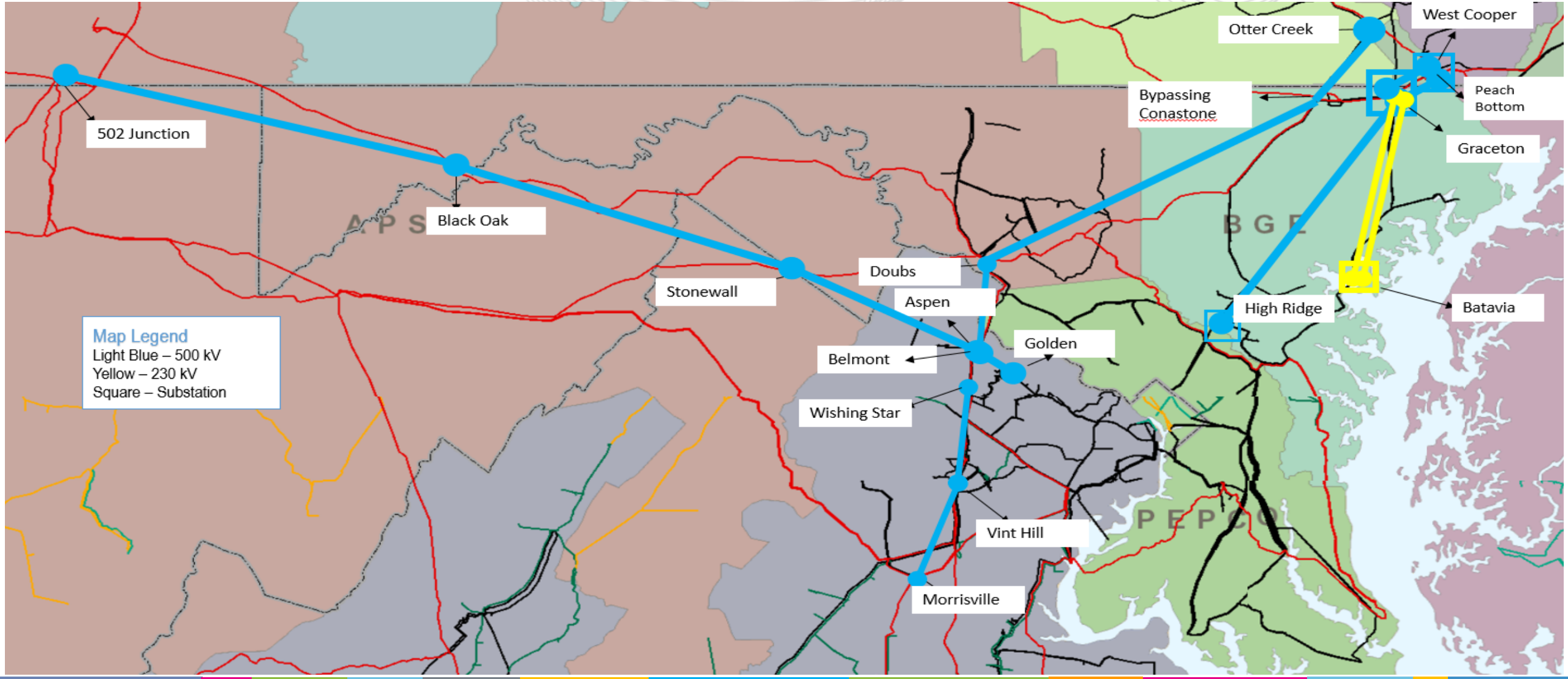
PJM Combination - 500 kV Scenario



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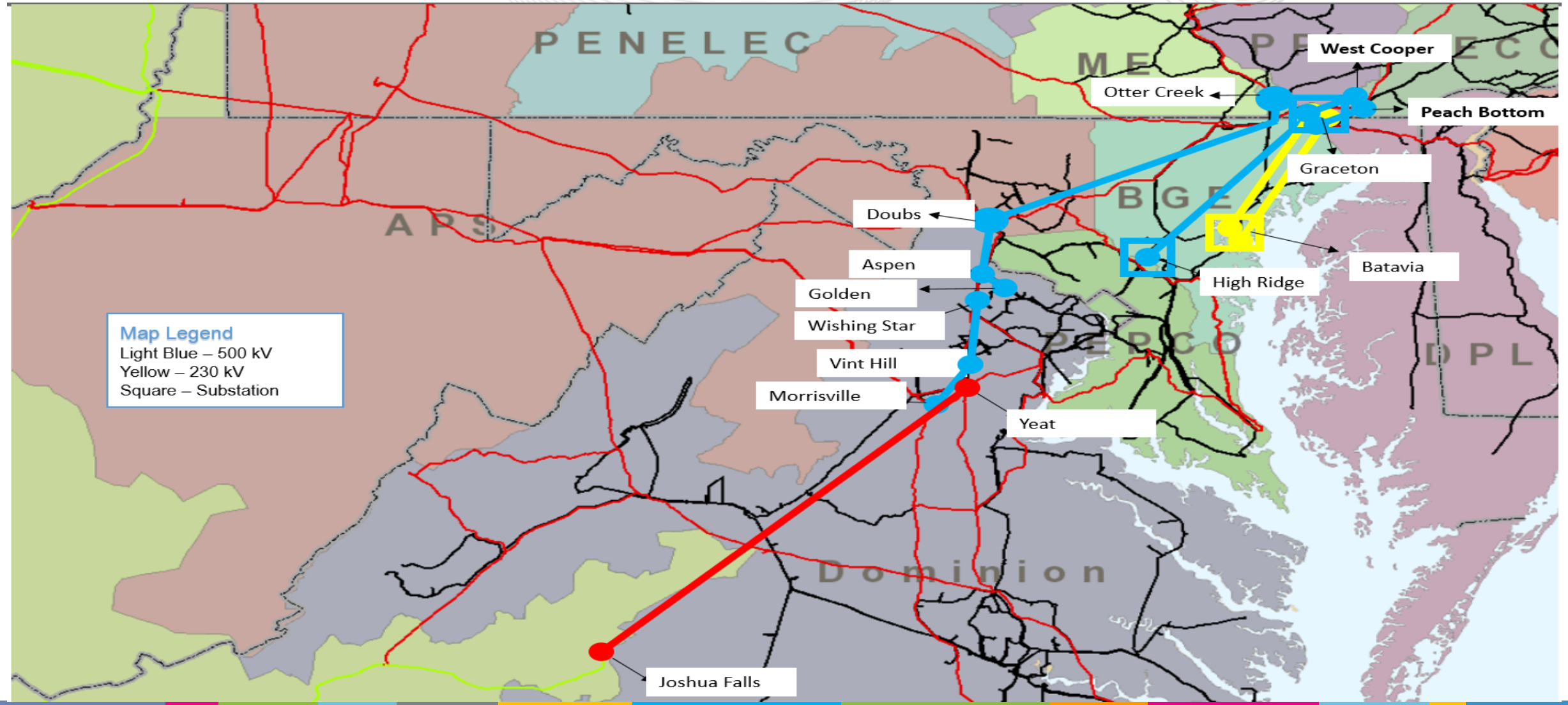
PJM Combination - 765 kV Scenario



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2022 RTEP W3

Initial Short Circuit Evaluation

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Short Circuit Evaluation

- Posted window case based on 2027 topology
- Considered impacts to existing breakers in 11 TO areas
- Sample results provided below

	Over Duty Bus (Qty)						Over Duty CBs	Maximum Fault Duty (kA)						
Scenario Description	115 kV	138 kV	230 kV	345 kV	500 kV	765 kV	Total	765 kV	500 kV	345 kV	230 kV	138 kV	115 kV	Comments
Nextera Proposal 175	0	1	26	0	1	0	97	38.3	62.9	59.7	75.4	74.4	58.8	Conastone 500kV bus operating well above capability will require rebuild. Peach Bottom 500kV bus operating just below 63kA capability
PJM combination 500 kV - Scenario	1	1	13	0	4	0	63	38.3	61.7	59.7	75.4	74.4	59.1	Conastone 500kV bus operating below the 52kA rated capability Peach Bottom 500kV bus operating below the 63kA rated capability

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2022 RTEP W3

Initial Load Deliverability Evaluation

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Load Deliverability Evaluation
Initial findings

- PJM conducted Load Deliverability assessment covering the 3 shortlisted scenarios evaluating BGE, SWMAC and Dominion zones.
- NextEra's 175 Proposal combo did not meet the 115% (barely meeting 100% CETO for BGE) CETL/CETO ratio requirement for the 2028 year
- PJM combination proposals, both at 500kV and 765 kV well-exceeded the 115% requirement for BGE, SWMAC and Dominion zones.
- Results are being finalized and will be shared at the Oct 31st TEAC.

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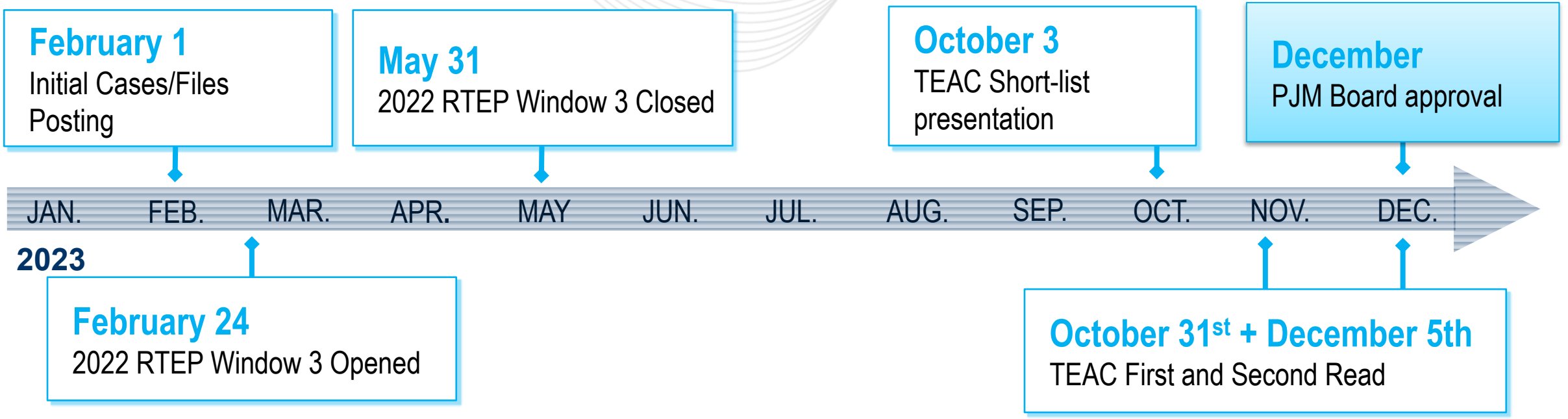
Next Steps



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Appendix

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2022 RTEP W3

List of Proposal

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2022 RTEP W3 Submitted Proposals

#	Proposal ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
1	9	AEP	Local AEP	Scottsville-Bremo Sag Study	$1.27
2	55	AEP	Local AEP	Boxwood-Scottsville 138 kV Rebuild	$104.88
3	181	AEP	Local AEP	Boxwood-Scottsville 138 kV Sag Study	$4.26
4	196	AEP	Local AEP	Glen Lyn-Peters Mountain Rebuild	$21.89
5	202	AEP	Local AEP	Cloverdale Transformer Addition	$57.29
6	234	AEP	Local AEP	Glen Lyn-Peters Mountain Sag Study	$0.80
7	410	AEP	Local AEP	Cloverdale Breaker Reconfiguration	$11.59
8	477	AEP	Local AEP	Fieldale-Franklin Rebuild	$74.89
9	524	AEP	Local AEP	Opossum Creek and New London Reactors	$8.86
10	537	AEP	Local AEP	Fieldale-Franklin Sag Study	$30.19
11	629	AEP	Local AEP	Scottsville-Bremo Rebuild	$31.31
12	856	AEP	Local AEP	Leesville-Altavista Rebuild	$28.85
13	487	AEP - Transource	Combo	Maryland & Pennsylvania Baseline Reliability Solution	$492.75
14	858	AEP - Transource	South	Stork - Flys 500kV Greenfield Line and Substations	$510.44
15	904	AEP - Transource	Combo	Joshua Falls - Yeat 765kV Greenfield Line and Substation	$1,048.10
16	977	AEP - Transource	South	Yeat 500/230kV Greenfield Station	$232.14
17	30	Dominion	Local DOM	Charlottesville - Hollymead Line # 2054 Rebuild	$159.87
18	74	Dominion	Local DOM	Line #2090 (Ladysmith CT - Fredericksburg) Rebuild	$57.34
19	129	Dominion	South	Dominion Aggregate 500kV Proposal	$3,035.05
20	211	Dominion	Local DOM	Hollymead - Gordonsville Line # 2135 Rebuild	$54.85

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2022 RTEP W3 Submitted Proposals

#	Proposal ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
21	231	Dominion	Local DOM	Reactive Power VAR Reinforcements	$155.82
22	516	Dominion	East	Interregional solution- Aspen-Doubs Second 500 kV Line	$61.72
23	671	Dominion	Local DOM	Lines #541 (Front Royal to Morrisville) Rebuild	$299.03
24	692	Dominion	South	Data Center Alley Local solution - New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	$1,058.45
25	704	Dominion	Local DOM	Hollymead - Gordonsville Line # 2135 Rebuild	$36.89
26	711	Dominion	South	Regional Solution - 500 kV North Anna-Wishing Star Upgrades	$1,227.84
27	731	Dominion	Local DOM	Locks Substation 230/115 kV Transformer Upgrade	$7.14
28	923	Dominion	South	Second 500 kV line from Lexington to Dooms	$232.18
29	967	Dominion	Local DOM	Charlottesville - Hollymead Line # 2054 Rebuild	$183.48
30	548	LSPower	Scenario	RTEP Window 3 Solution	$2,404.48
31	28	NextEra	East/West	Hunterstown - Doubs - Goose Creek, Black Oak - Pike - Goose Creek, Pike SVC + Cap Banks	$884.05
32	116	NextEra	West	Hunterstown - Doubs - Gant Solution	$478.87
33	175	NextEra	Scenario	Combination of PEBO 215A + WOP 1F + SOP 8E	$6,265.95
34	217	NextEra	East	North Delta - Conastone Solution	$155.99
35	255	NextEra	East/West	Hunterstown - Doubs - Gant Solution	$411.61
36	279	NextEra	West	Black Oak - Woodside - Goose Creek, Woodside SVC + Cap Banks Solution	$429.18
37	347	NextEra	West	Black Oak - Woodside - Gant, Woodside SVC + Cap Banks	$483.83
38	385	NextEra	East	New 500/230kV Bartholow substation, new 500/230kV North Delta substation, new 230kV Grisham switchyard, new 500/230kV Goram substation	$1,140.73
39	419	NextEra	East/West	Hunterstown - Doubs - Audobon - Goose Creek	$548.75
40	445	NextEra	East	Muddy Creek / Delta - Conastone / Hunterstown - Doubs - Goose Creek Solution	$637.80

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2022 RTEP W3 Submitted Proposals

#	Proposal ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
41	530	NextEra	East	Muddy Creek / North Delta - Conastone Solution	$166.74
42	564	NextEra	East	New 500/230kV Bartholow substation, new 500/230kV North Delta substation, new 230kV Grisham switchyard, new 500/230kV Goram substation	$876.88
43	577	NextEra	South	Front Royal - Racefield, Warrenton - Wheeler, North Anna - Lady Smith	$258.38
44	598	NextEra	Scenario	Combination of PEBO 220 + WOP 1F + SOP 8E	$2,036.47
45	631	NextEra	East	Muddy Creek / North Delta - Conastone Solution	$184.47
46	642	NextEra	West	502 Junction - Black Oak - Woodside - Gant, Woodside SVC + Cap Banks, Gant - Farmwell, Cochran Tap - Round Table	$747.31
47	663	NextEra	South	Front Royal - Racefield, Warrenton - Rixlew, Warrenton - Hourglass, Mars - Ocean Court - Davis Drive	$284.17
48	676	NextEra	West	Black Oak - Stonewall - Gant, Stonewall SVC + Cap Banks, Gant - Farmwell, Cochran Tap - Round Table Solution	$552.49
49	685	NextEra	West	Ft. Martin - Black Oak - Woodside, Woodside SVC + Cap Banks Solution	$609.78
50	719	NextEra	West	Ft. Martin - Black Oak - Pike, Pike SVC + Cap Banks Solution	$600.90
51	728	NextEra	West	Barnhart Substation, Bartholow Substation, Barnhart - Bartholow - Goose Creek solution	$385.36
52	766	NextEra	South	Front Royal - Racefield, Warrenton - Wheeler	$239.59
53	846	NextEra	East/West	Hunterstown - Doubs - Goose Creek, Black Oak - Woodside - Goose Creek, Stonewall SVC + Cap Banks	$892.94
54	853	NextEra	West	502 Junction - Black Oak - Woodside - Gant, Woodside SVC + Cap Banks	$683.55
55	948	NextEra	East	New 500/230kV Bartholow substation, new 500/230kV North Delta substation, new 230kV Grisham switchyard, new 500/230kV Goram substation, and Keeney to Waugh Chapel tie-in.	$5,381.25
56	951	NextEra	West	Black Oak - Gore - Goose Creek, Pike SVC + Cap Bank Solution	$419.86

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2022 RTEP W3 Submitted Proposals

#	Proposal ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
56	951	NextEra	West	Black Oak - Gore - Goose Creek, Pike SVC + Cap Bank Solution	$419.86
57	344	PECO	East	PECO Expansion Plan for DOM Window 2023	$302.86
58	600	PECO	Local Other	Exelon Replacement Upgrades	$423.79
59	660	PEPCO	East	West Cooper BGE-PEPCO	$1,105.62
60	691	PEPCO	East	Mid-Atlantic Power Pathway (MAPP)	$1,990.28
61	23	POTOED - FirstEnergy	Combo	Data Center Reinforcement Proposal #2	$3,503.86
62	837	POTOED - FirstEnergy	Combo	Data Center Reinforcement Proposal #1	$2,991.77
63	374	PPL	East	Otter Creek - Conastone 500 and 230 kV DCT Line	$154.21
64	606	PPL	Local Other	Juniata - Lewistown 230 kV # 2 line	$141.16
65	24	PSEG	East	Proposal A - North Delta - New Raphael - Waugh Chapel 500kV	$739.40
66	125	PSEG	Local Other	Proposal B - North Delta-Northeast 230kV	$313.34
67	229	PSEG	East	Proposal C - Hunterstown-New Green Valley 500kV	$529.11
68	325	PSEG	Combo	Proposal E - Brambleton-Hinsons Ford Rd 500kV	$944.05
69	637	PSEG	East	Proposal D-Conastone-Doubs 500kV	$684.22
70	741	PSEG	East	Proposal G - Peach Bottom-New Brandon Shores 500kV; Peach Bottom-Doubs 500kV	$1,065.32
71	808	PSEG	East	Proposal F - Peach Bottom-New Raphael-Waugh Chapel 500kV; Peach Bottom-Doubs 500kV	$1,150.80
72	962	PSEG	East	Proposal H - Peach Bottom-Doubs 500kV (Circuits #1 and #2)	$977.71

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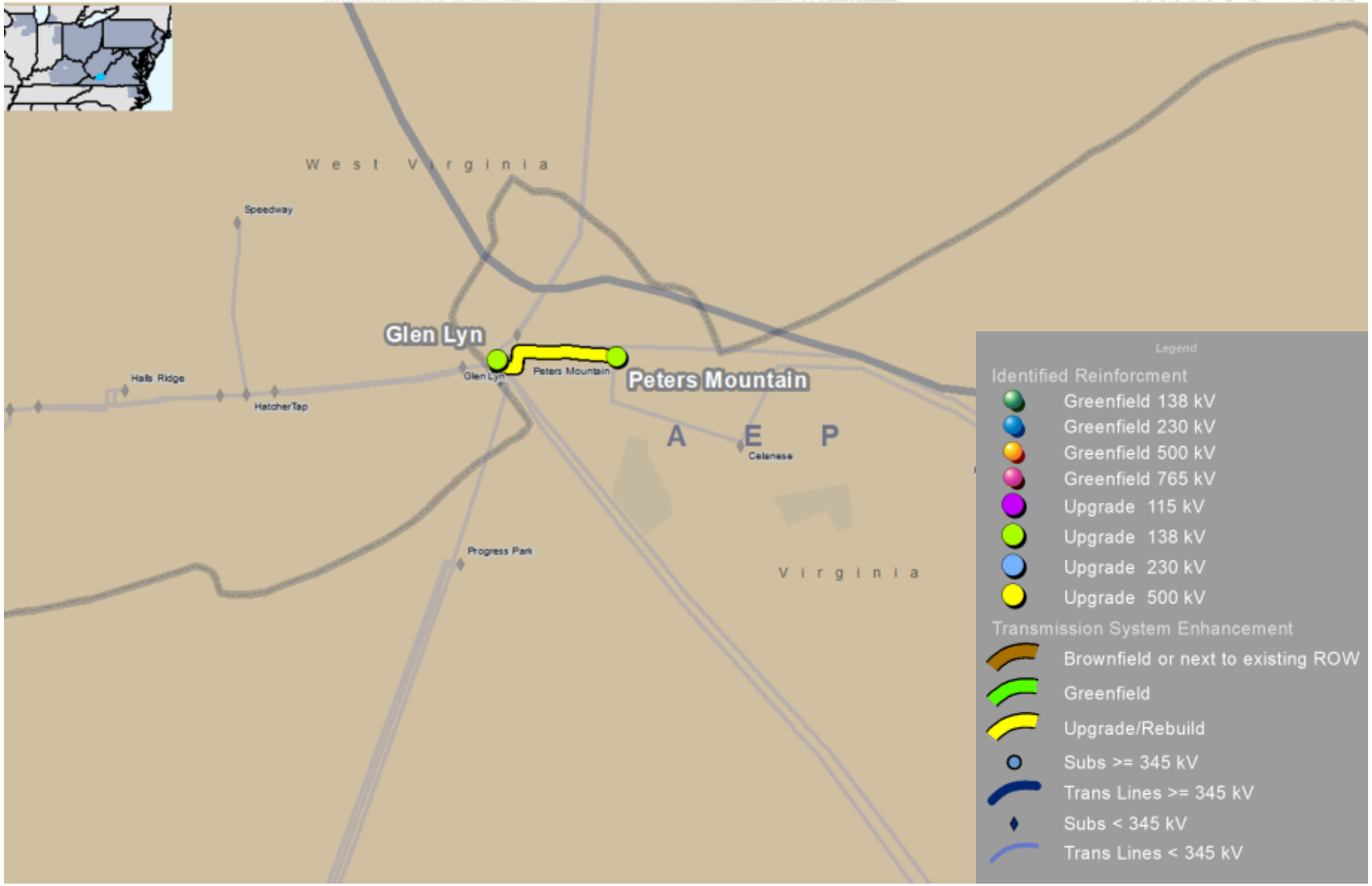
2022 Window 3 proposals – AEP – 196 & 234



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should <u>not</u> be relied upon for exact geographical substation locations or line routes.*

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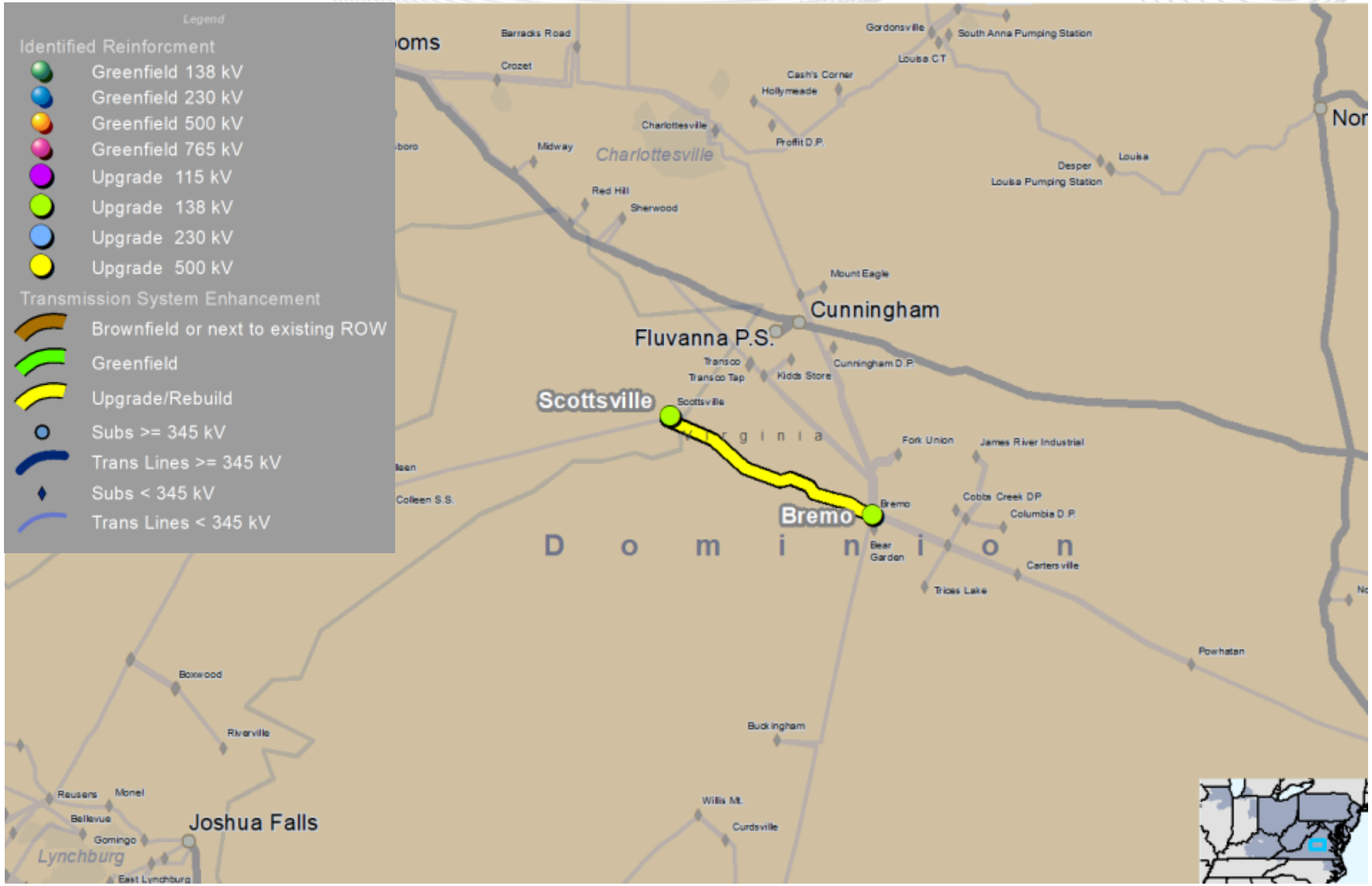
2022 Window 3 proposals – AEP - 9 & 629



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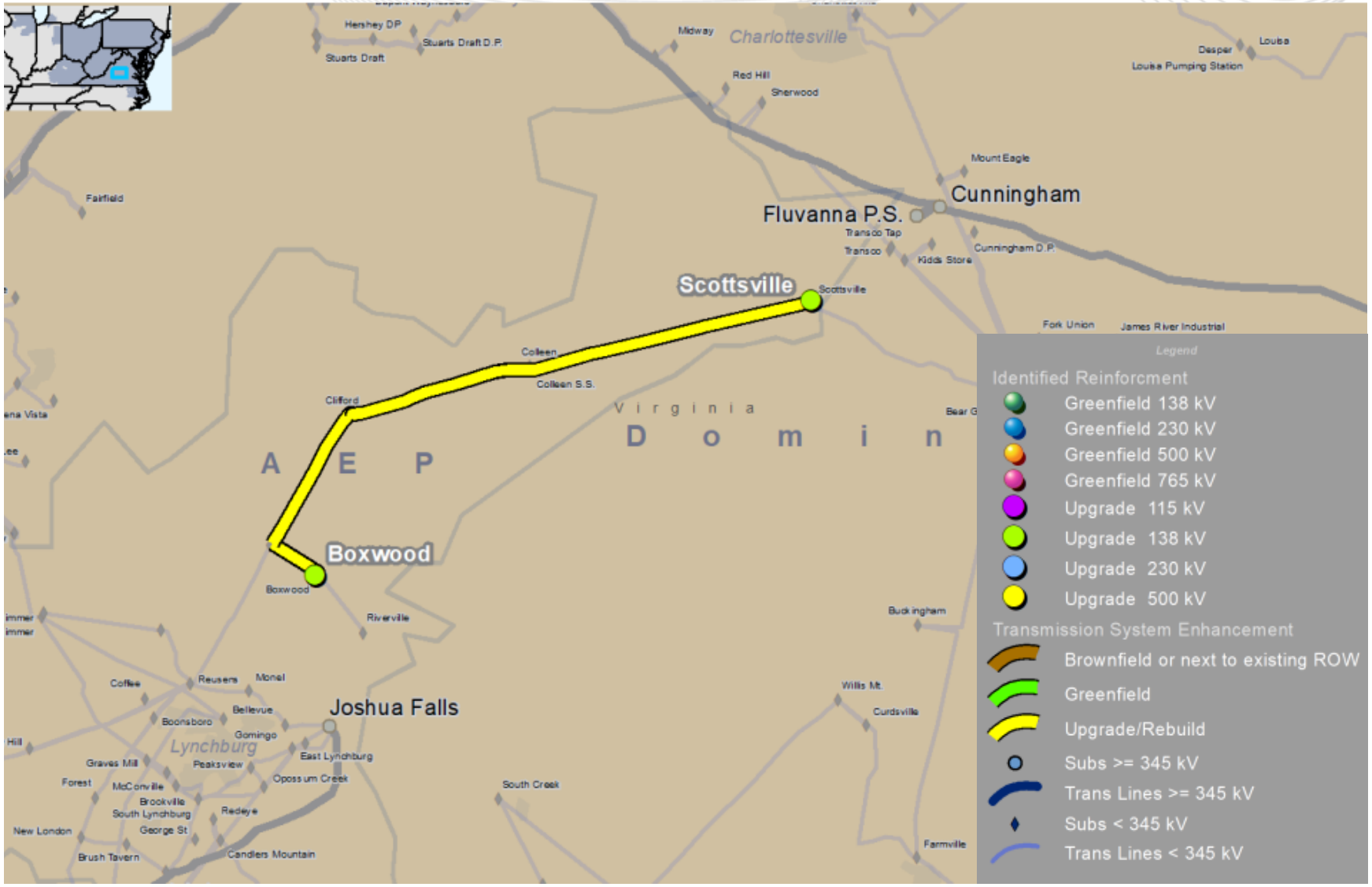
2022 Window 3 proposals – AEP – 55 & 181



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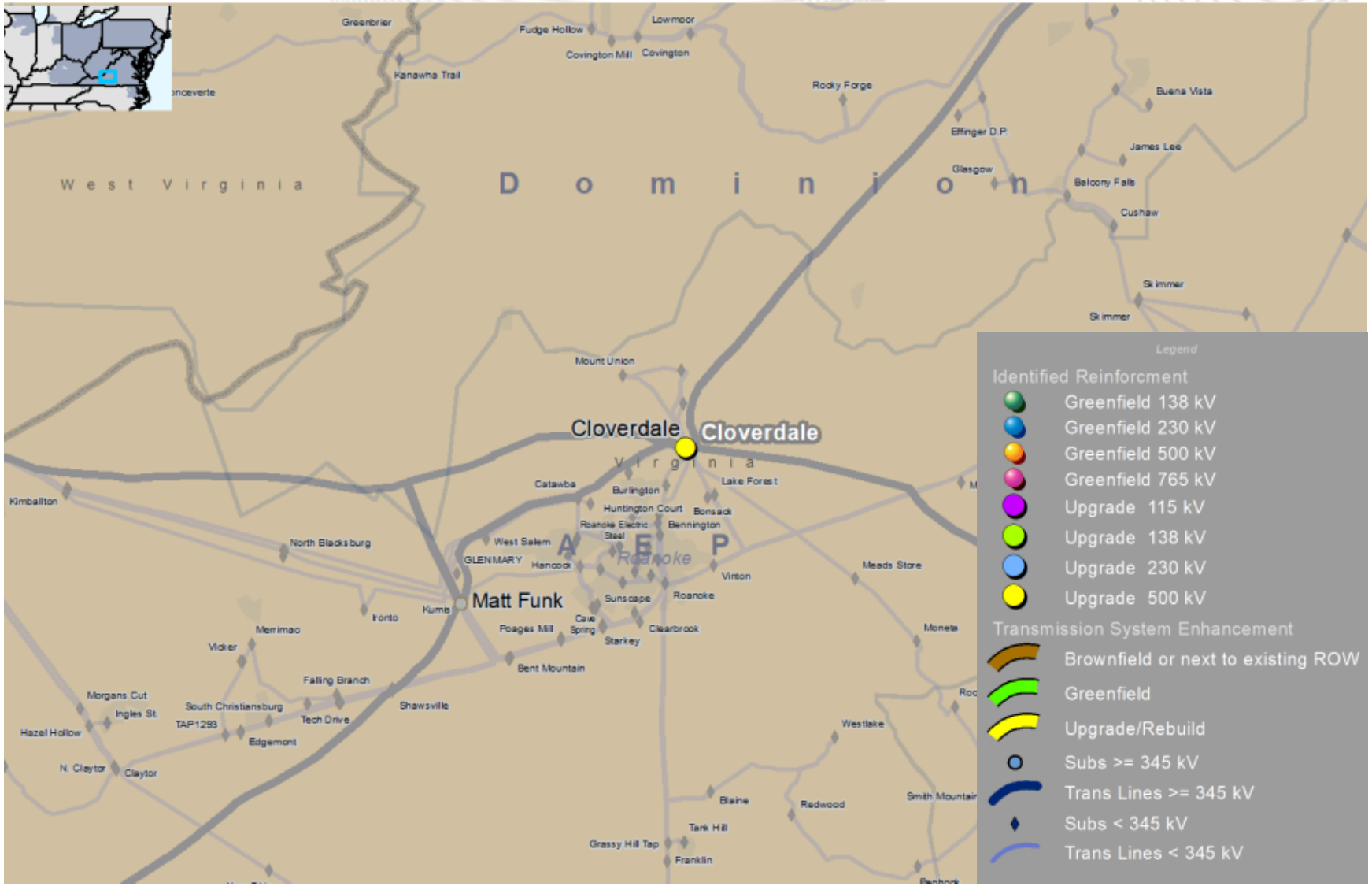
2022 Window 3 proposals – AEP - 202 & 410



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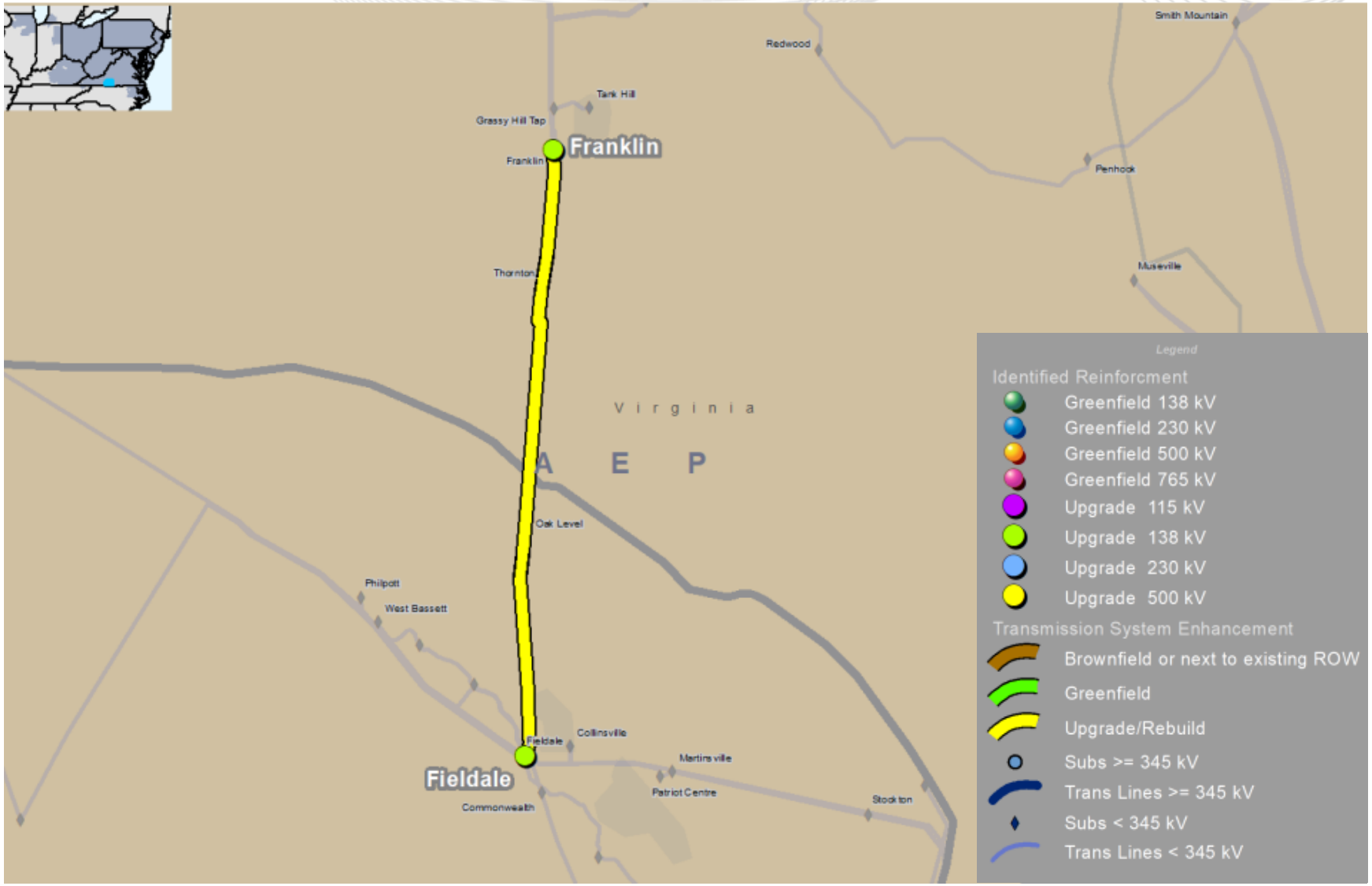
2022 Window 3 proposals – AEP - 477 & 537



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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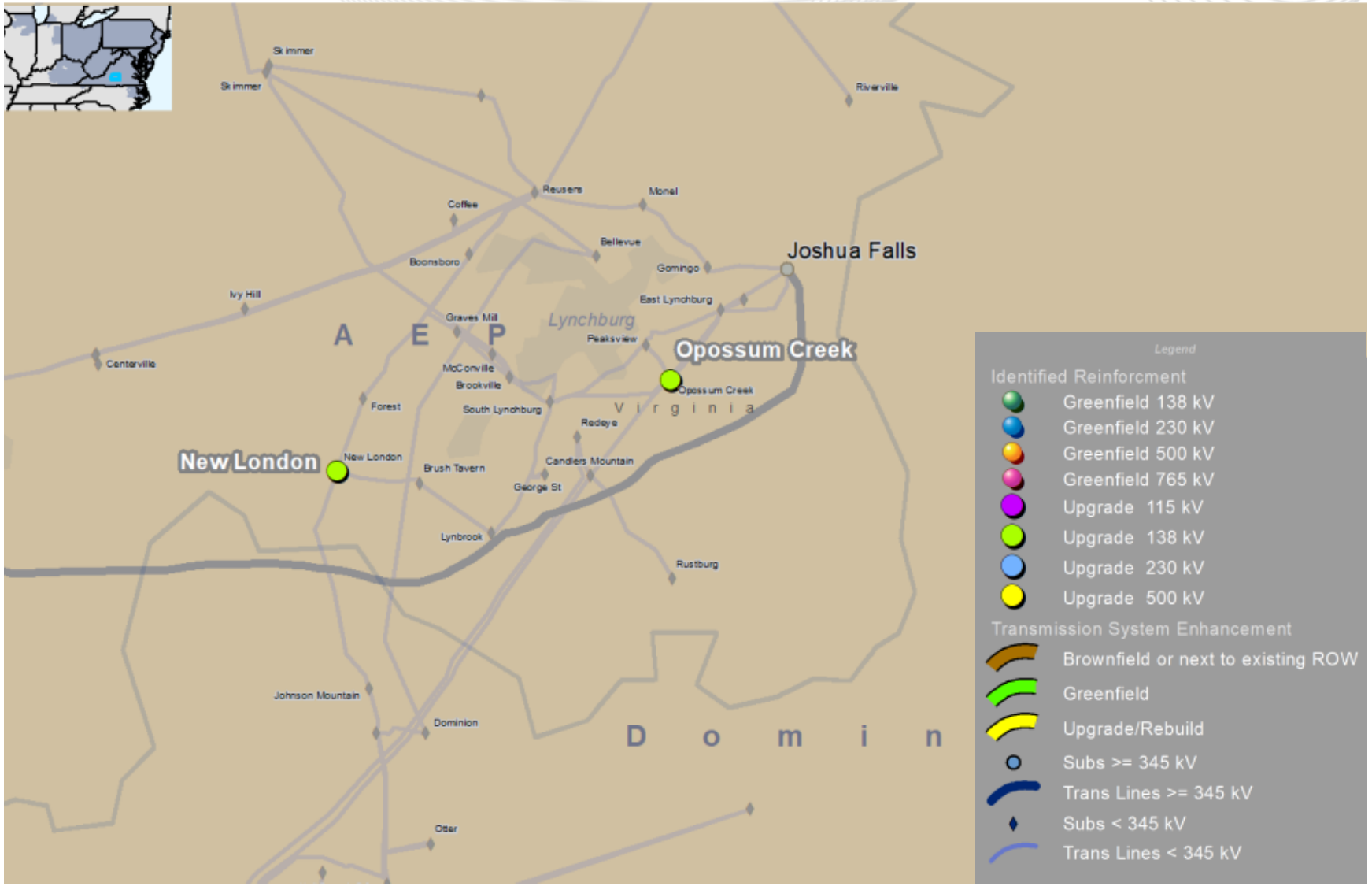
2022 Window 3 proposals – AEP - 524



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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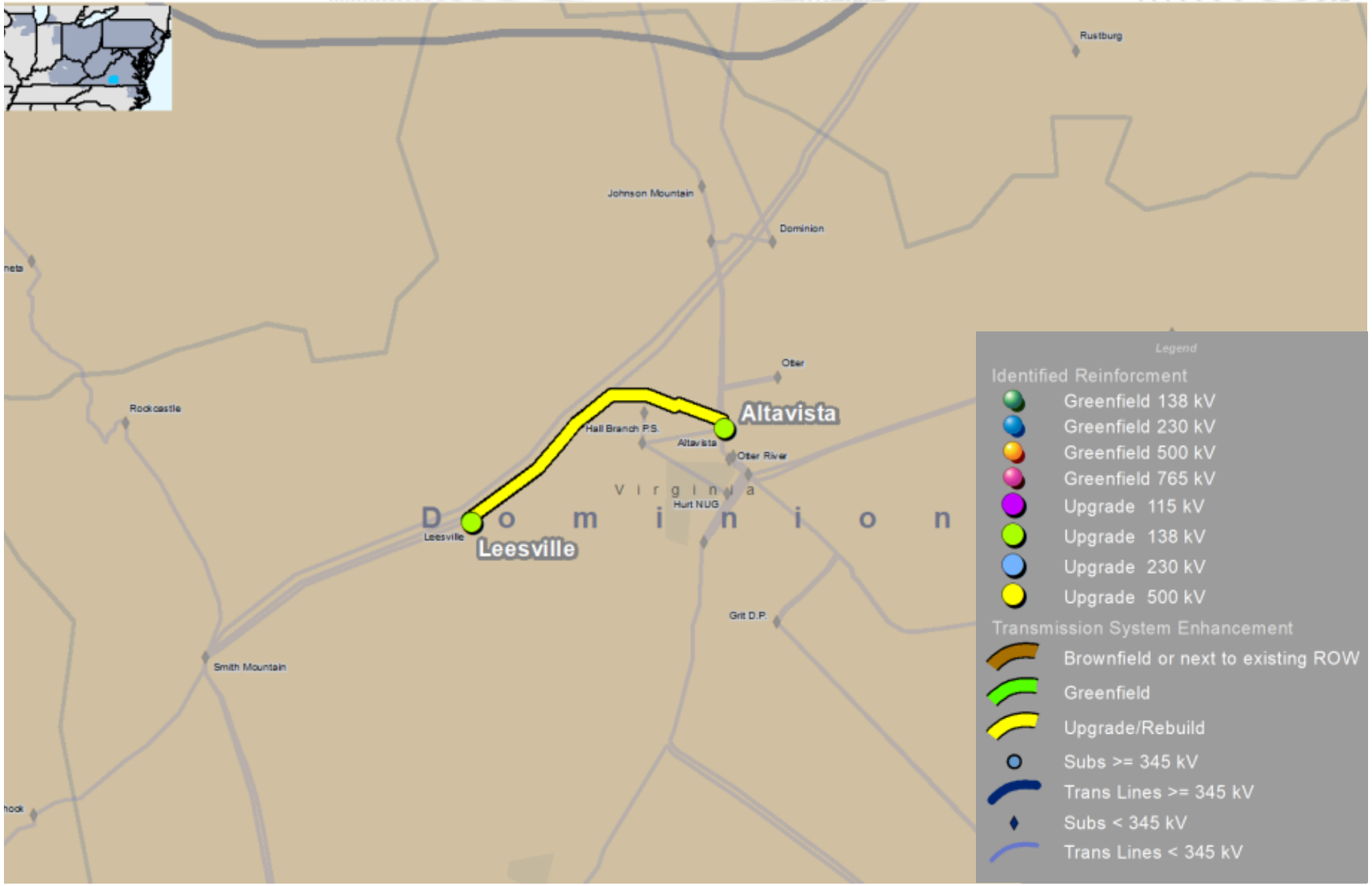
2022 Window 3 proposals – AEP - 856



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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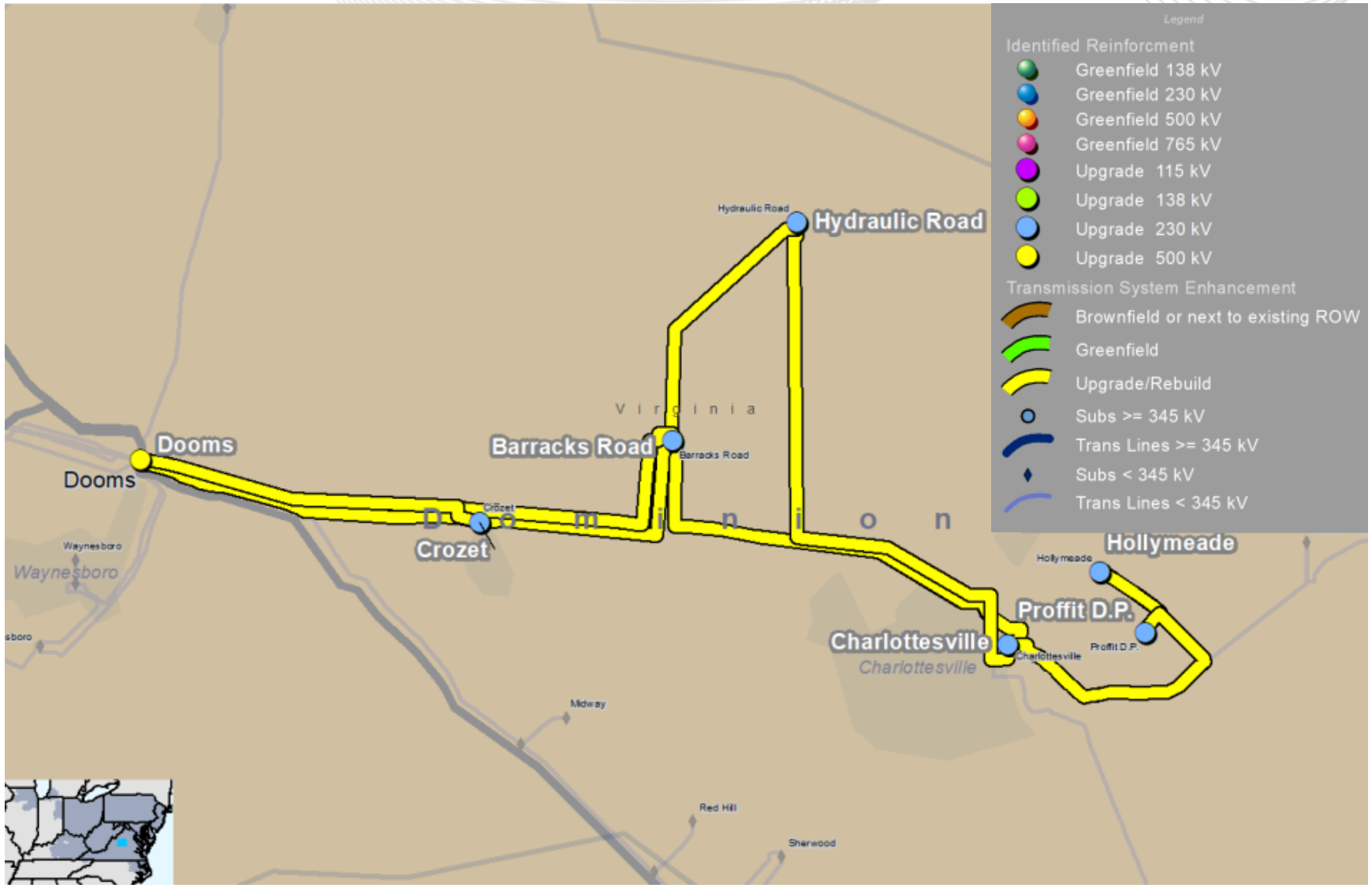
2022 Window 3 proposals – Dominion - 30



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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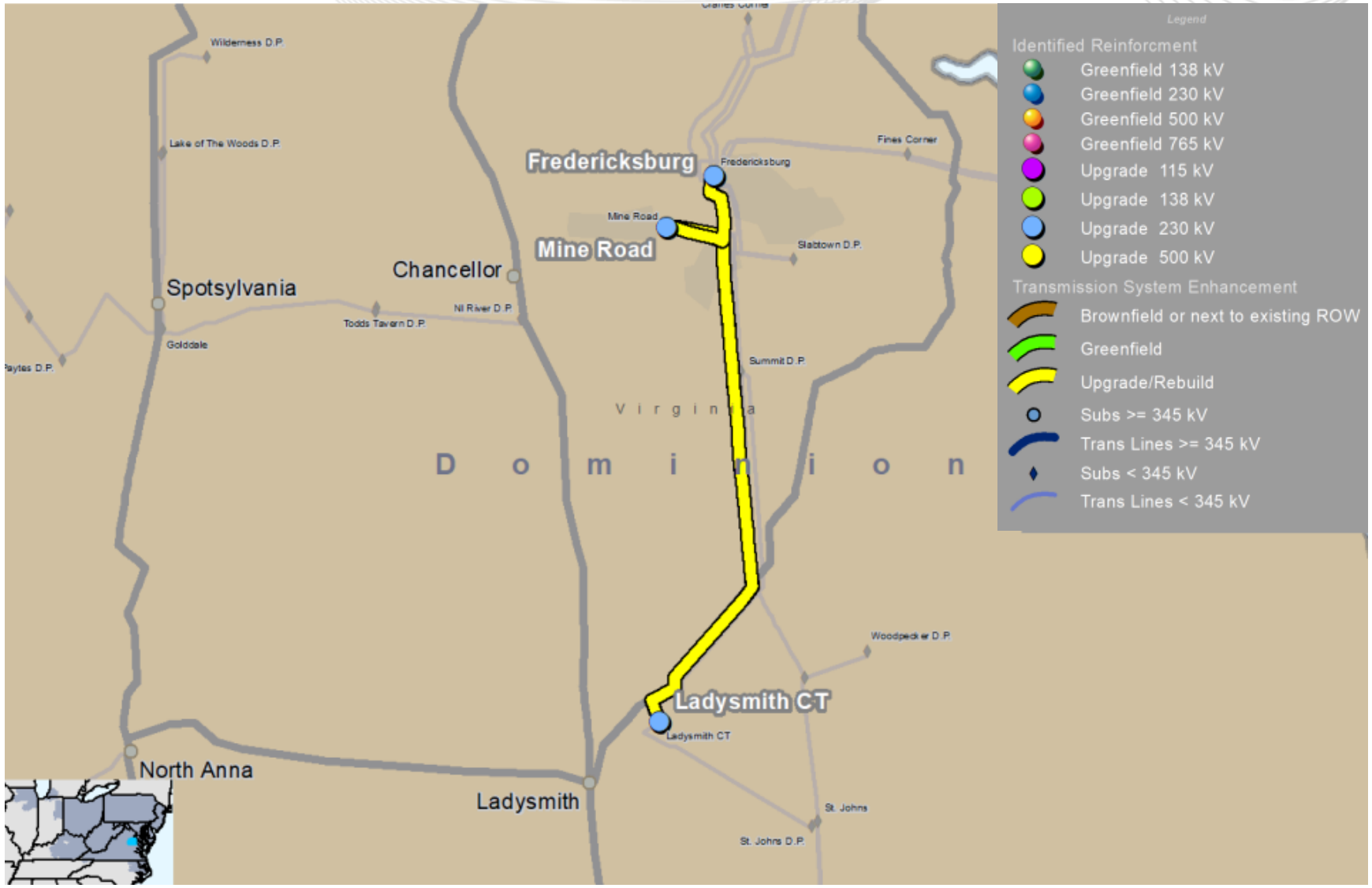
2022 Window 3 proposals – Dominion - 74



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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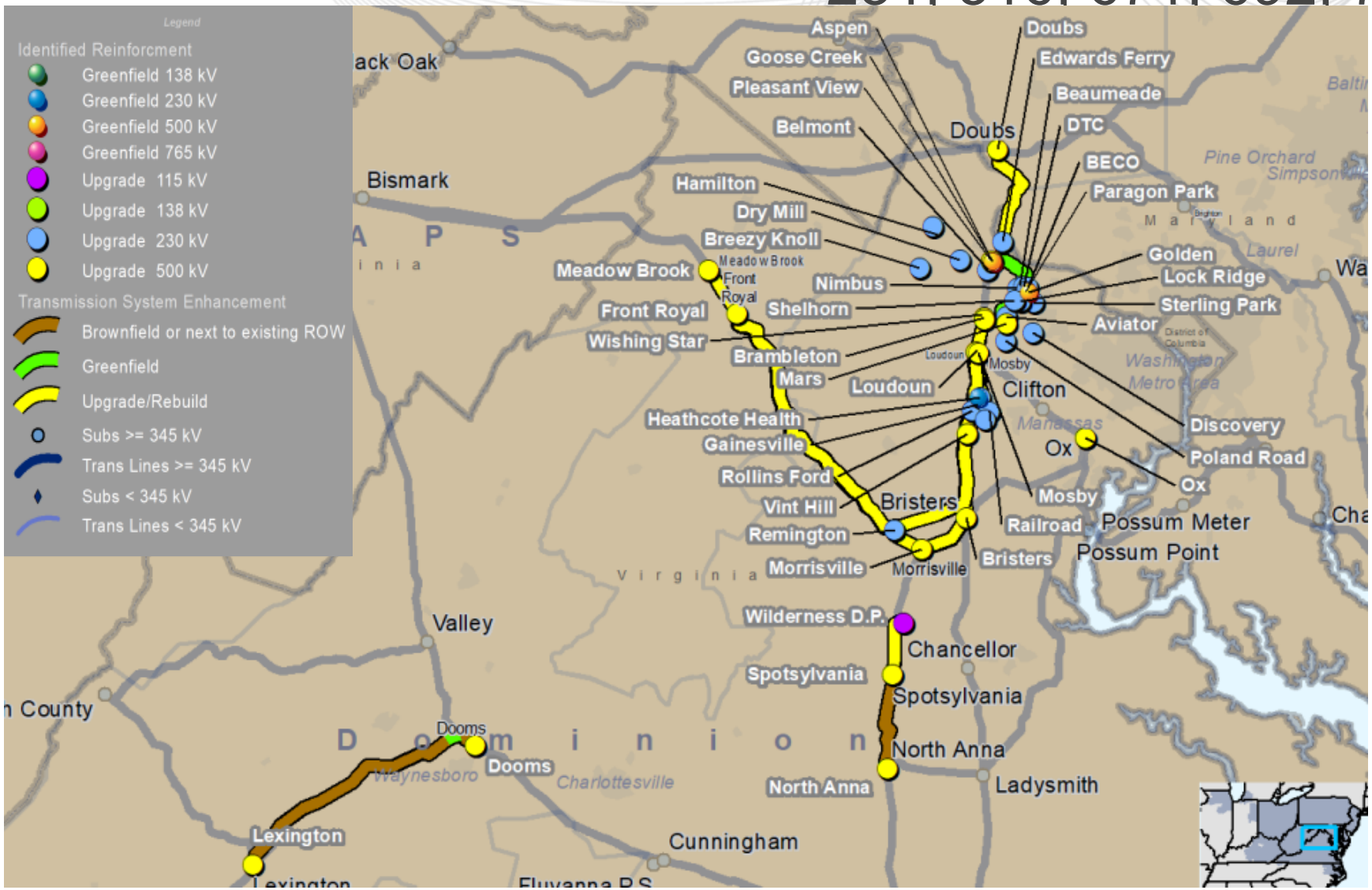
2022 Window 3 proposals – Dominion – 129
231, 516, 671, 692, 711, 923



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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2022 Window 3 proposals – Dominion - 231

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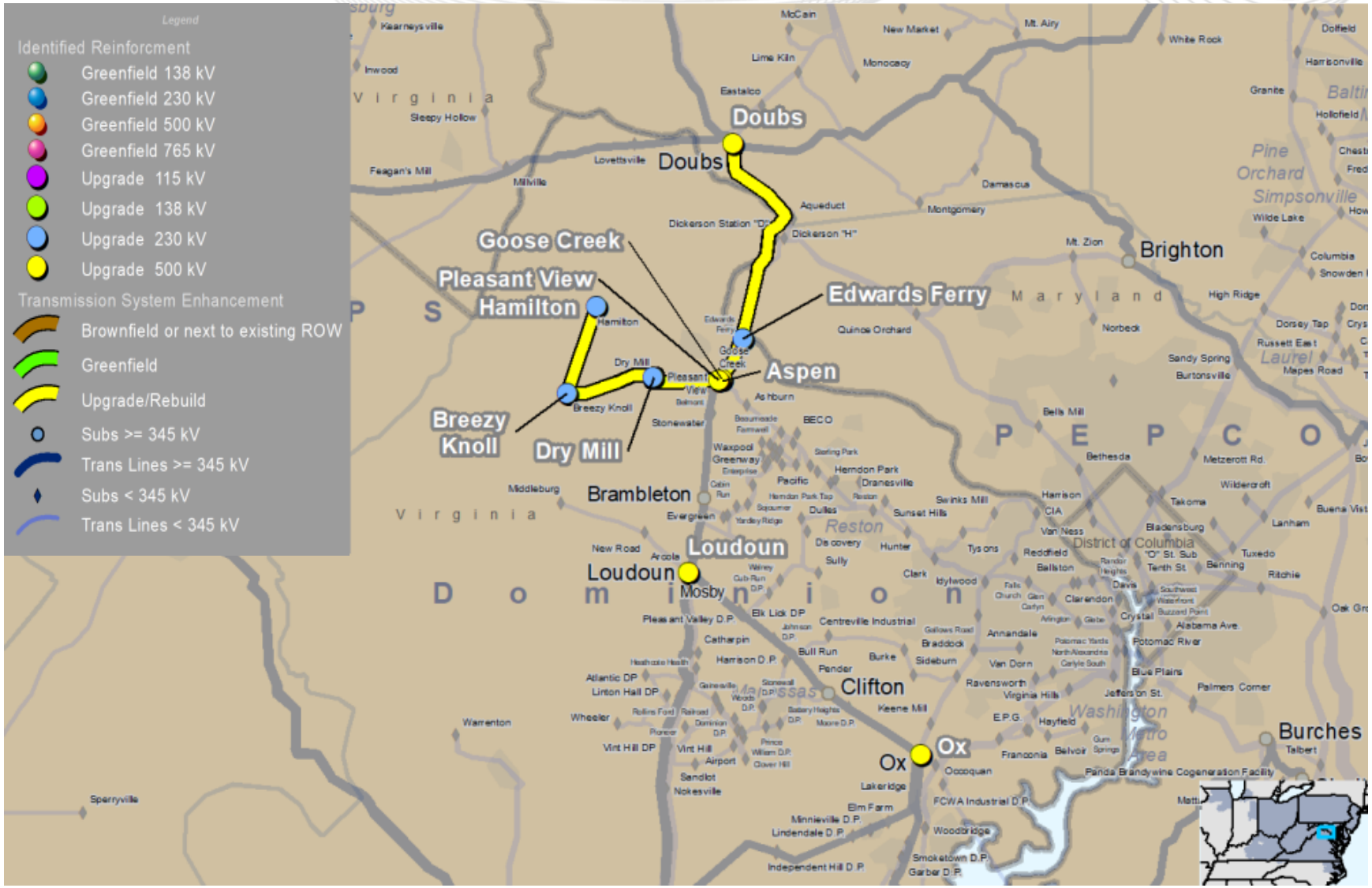
2022 Window 3 proposals – Dominion - 516



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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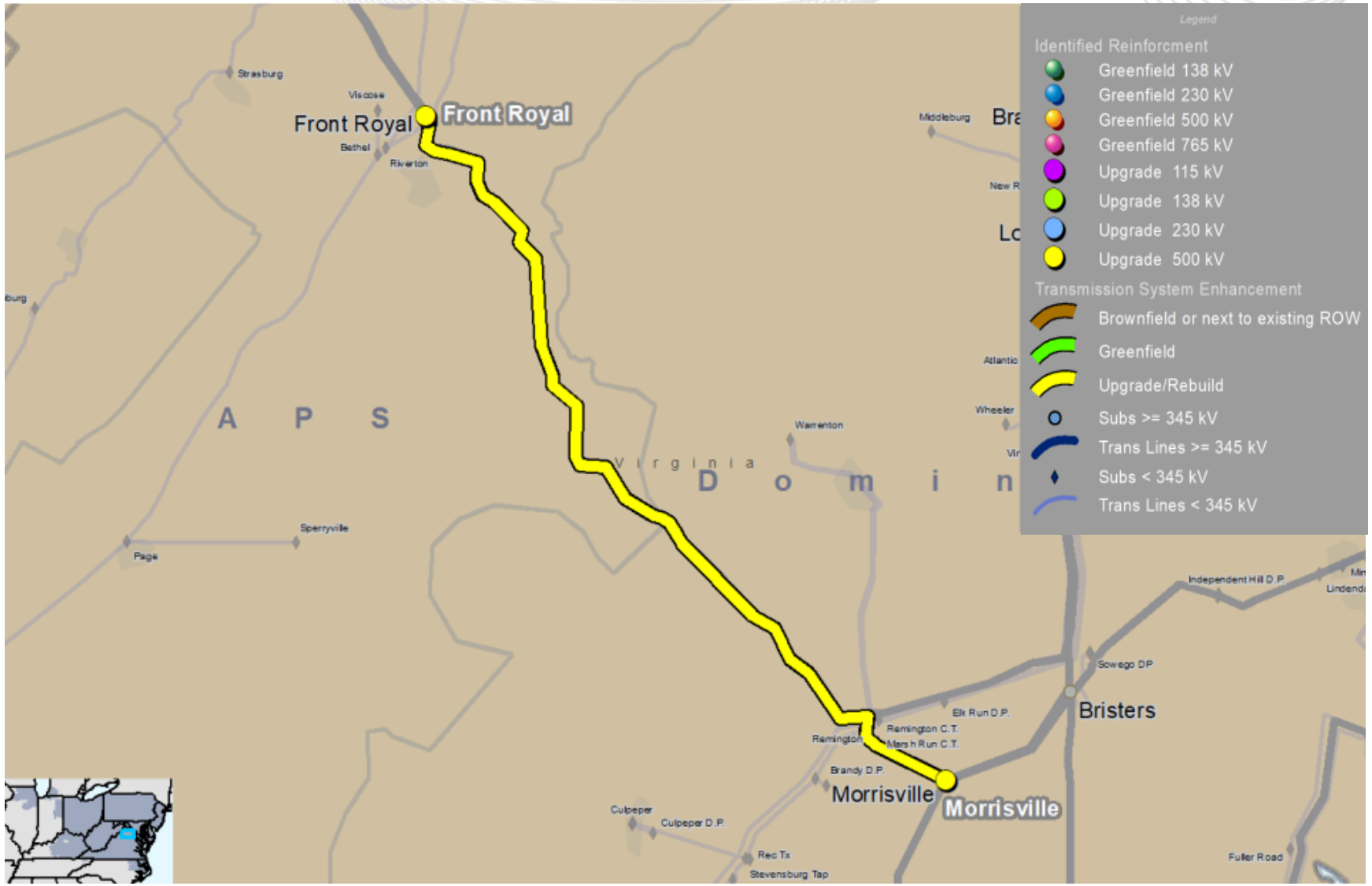
2022 Window 3 proposals – Dominion - 671



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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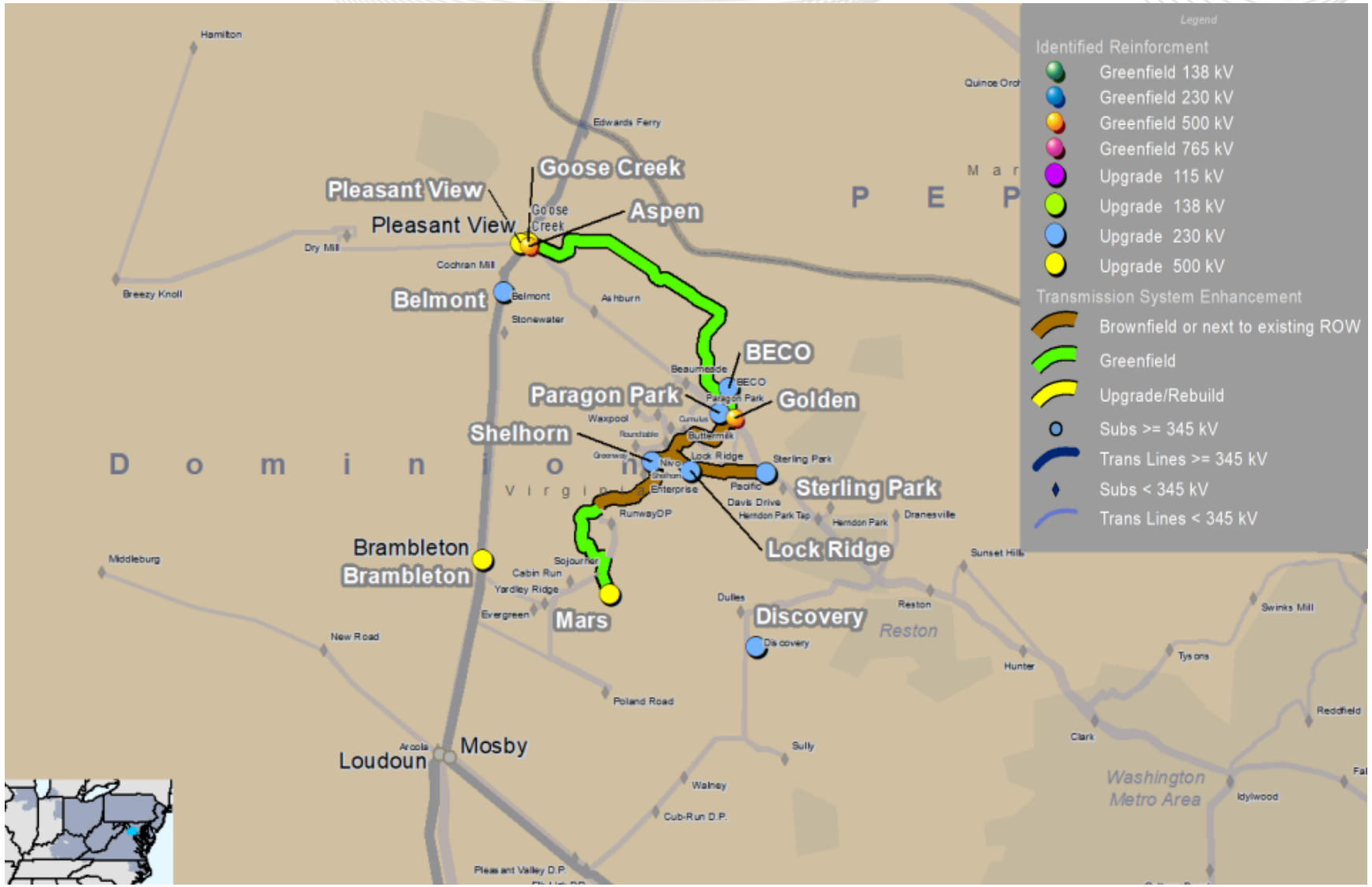
2022 Window 3 proposals – Dominion - 692



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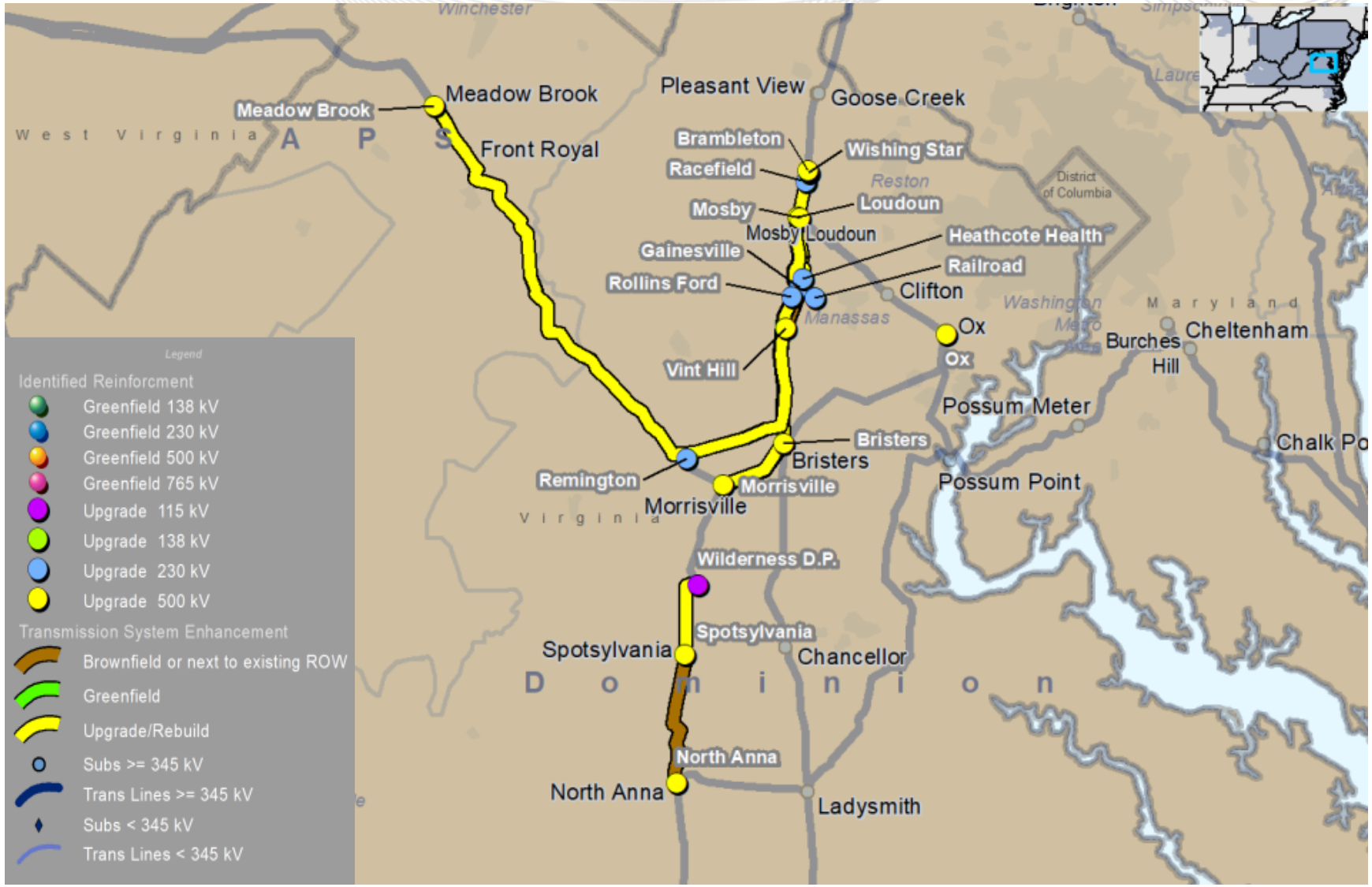
2022 Window 3 proposals – Dominion - 711



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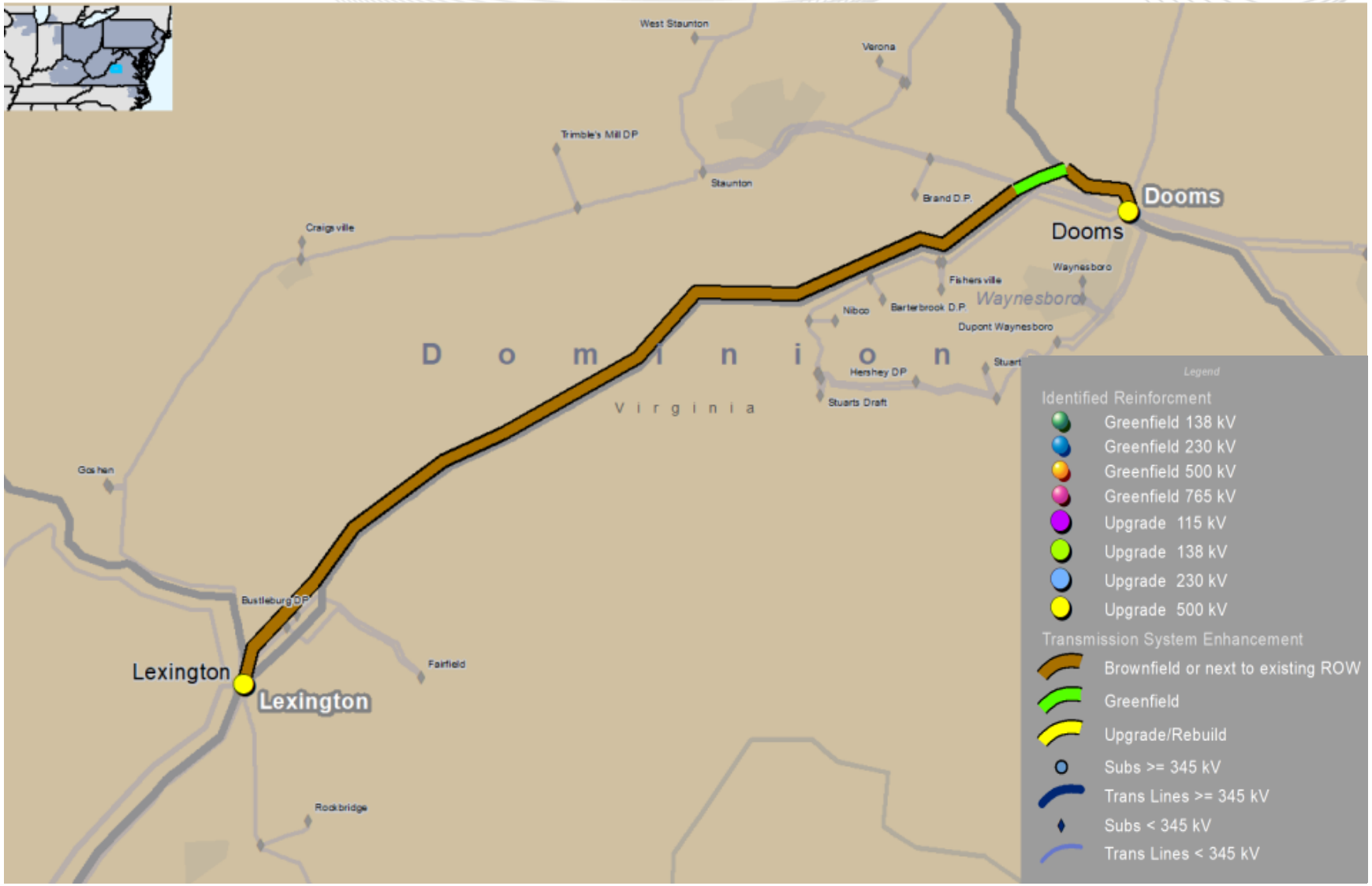
2022 Window 3 proposals – Dominion - 923



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2022 Window 3 proposals – Dominion - 211

NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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2022 Window 3 proposals – Dominion - 704

NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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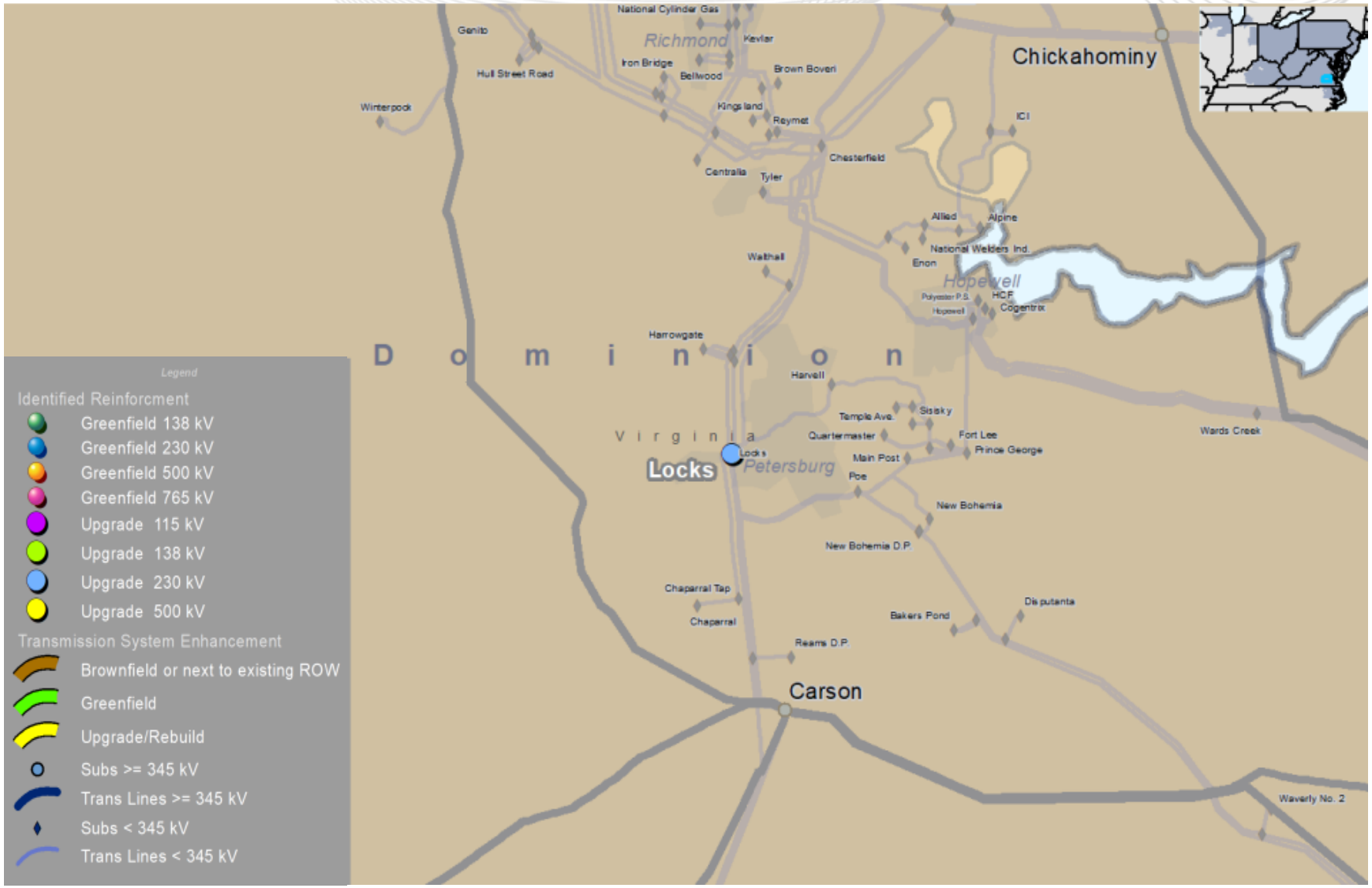
2022 Window 3 proposals – Dominion – 731



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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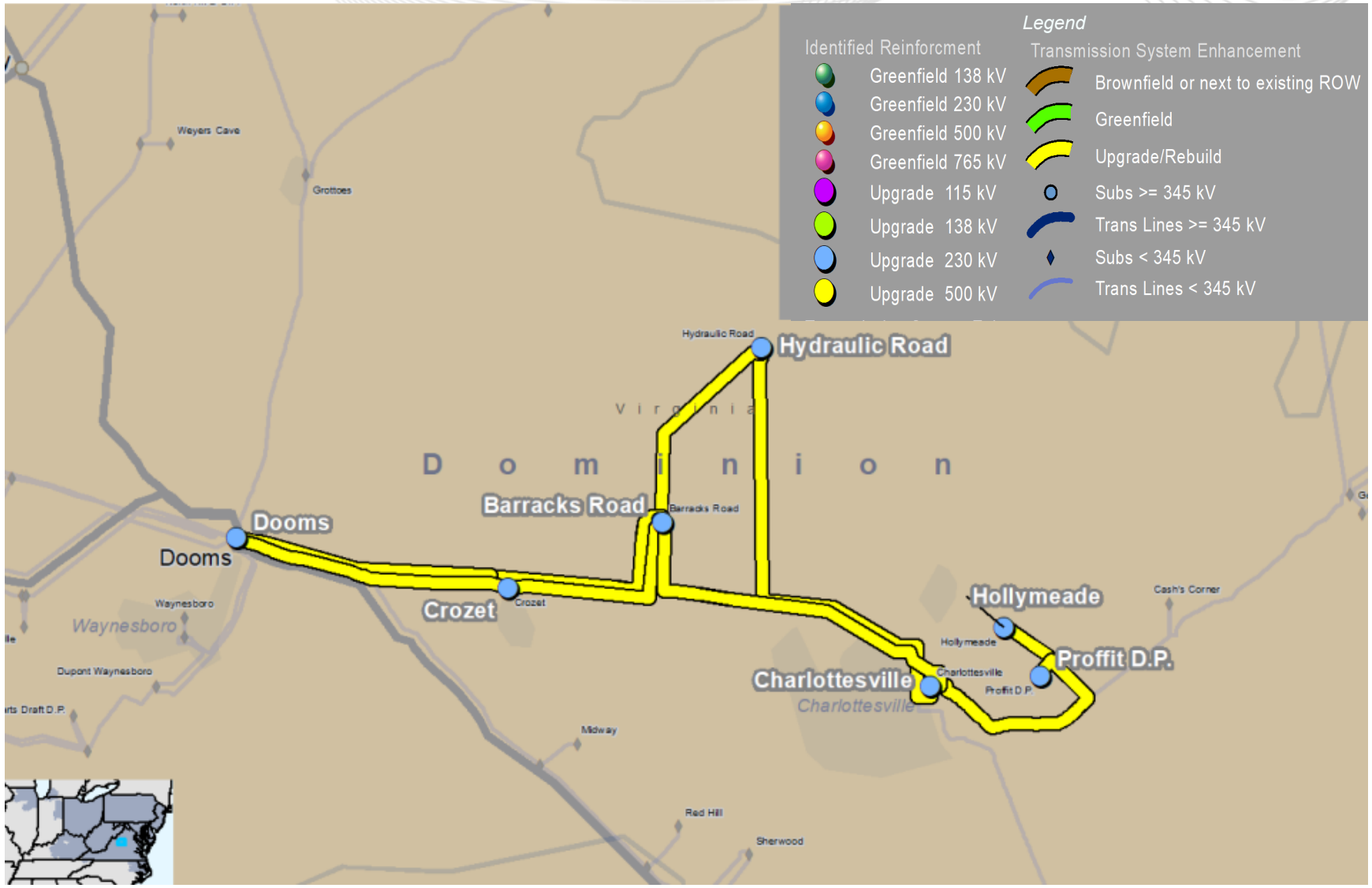
2022 Window 3 proposals – Dominion - 967



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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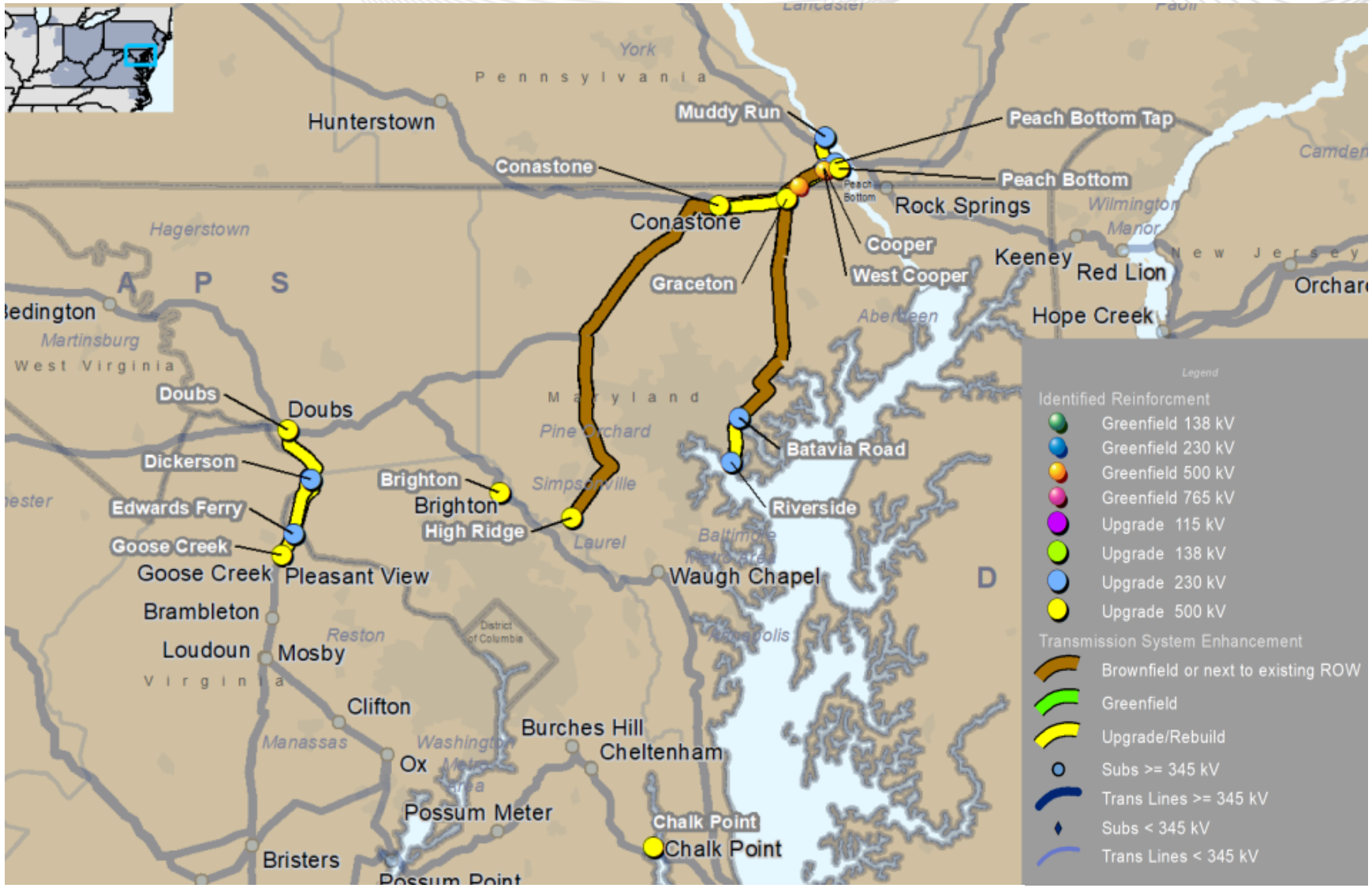
2022 Window 3 proposals – Exelon – 344 & 660



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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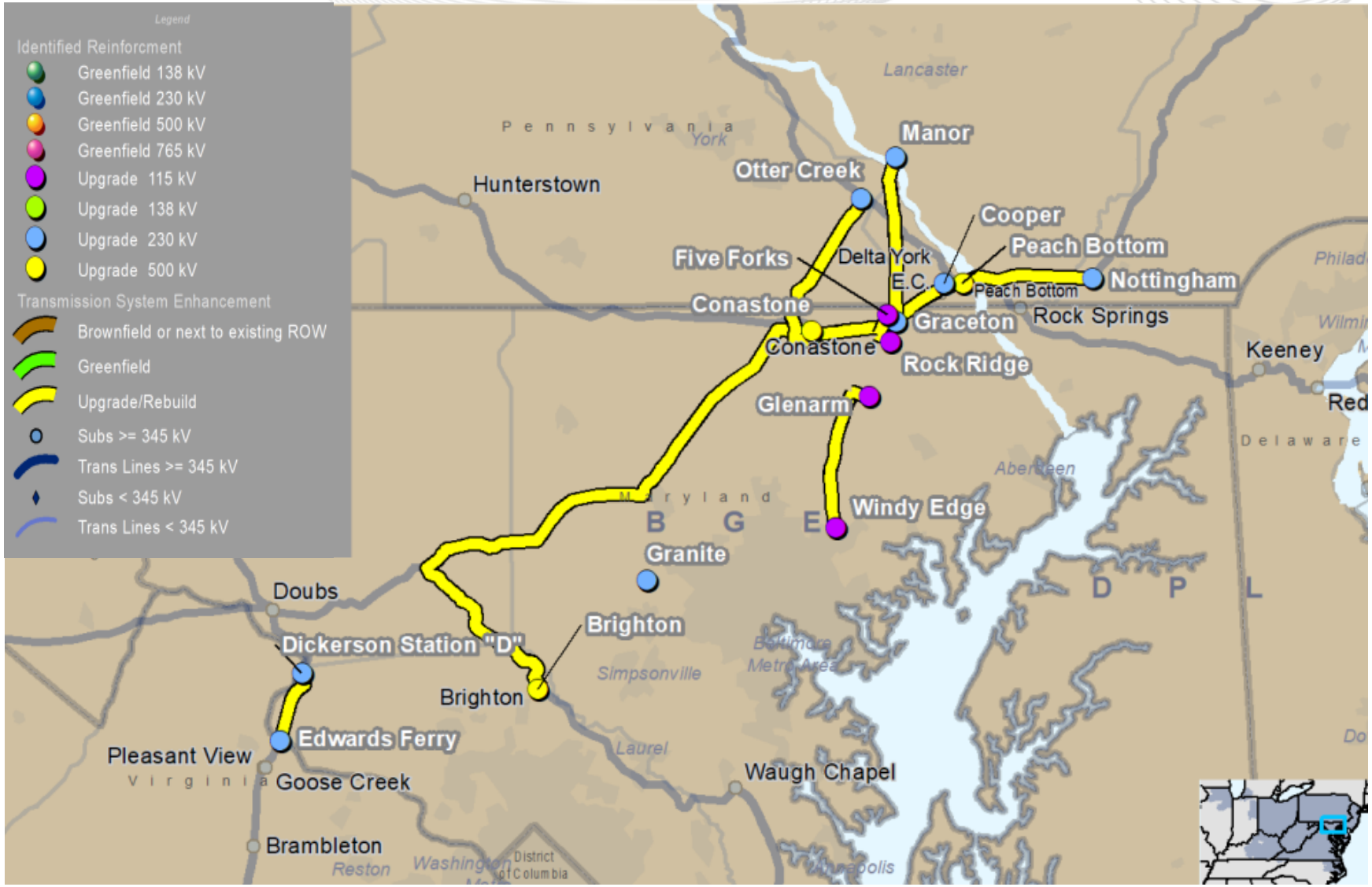
2022 Window 3 proposals – Exelon - 600



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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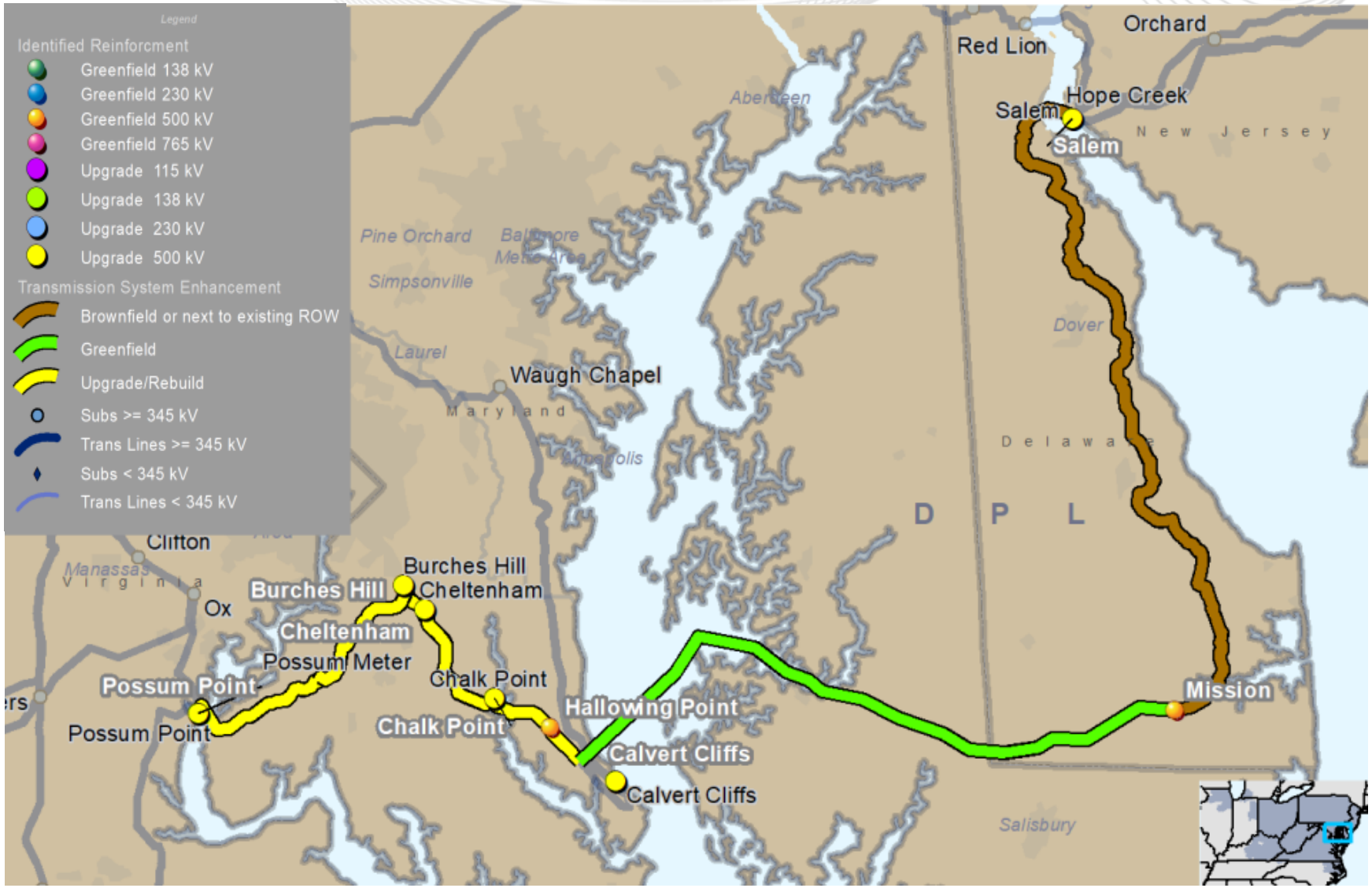
2022 Window 3 proposals – Exelon - 691



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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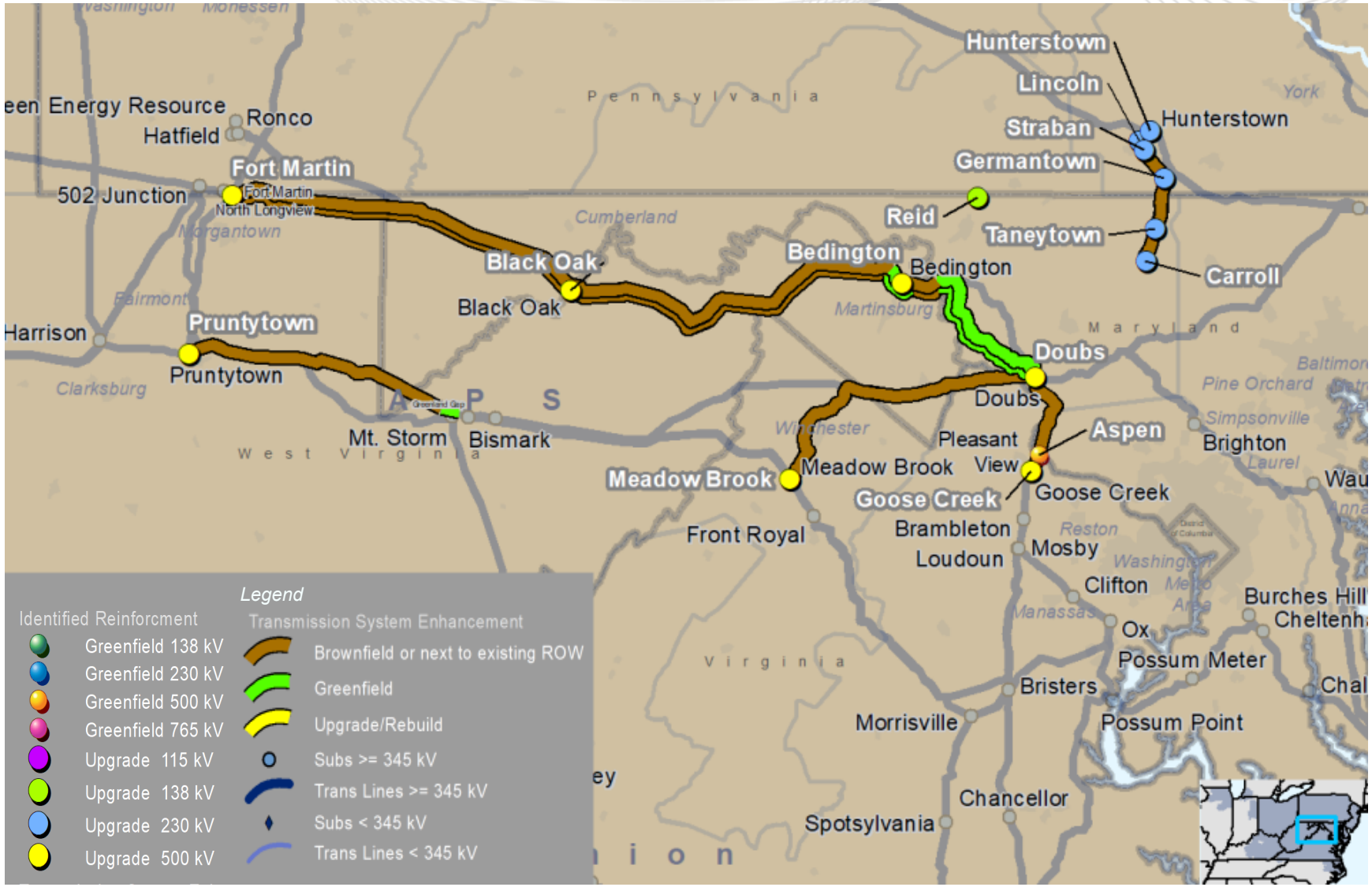
2022 Window 3 proposals – FE – 23



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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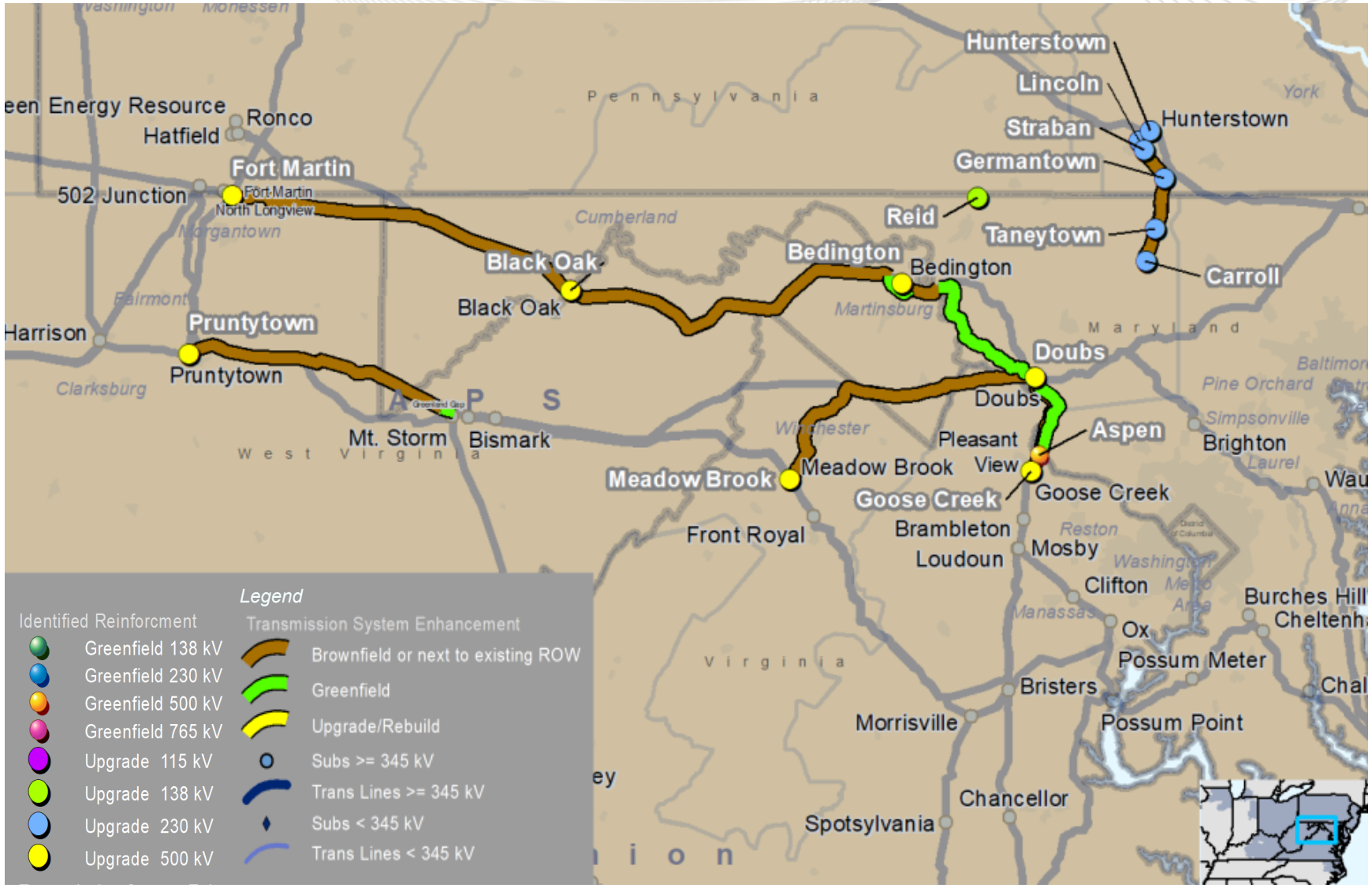
2022 Window 3 proposals – FE – 837



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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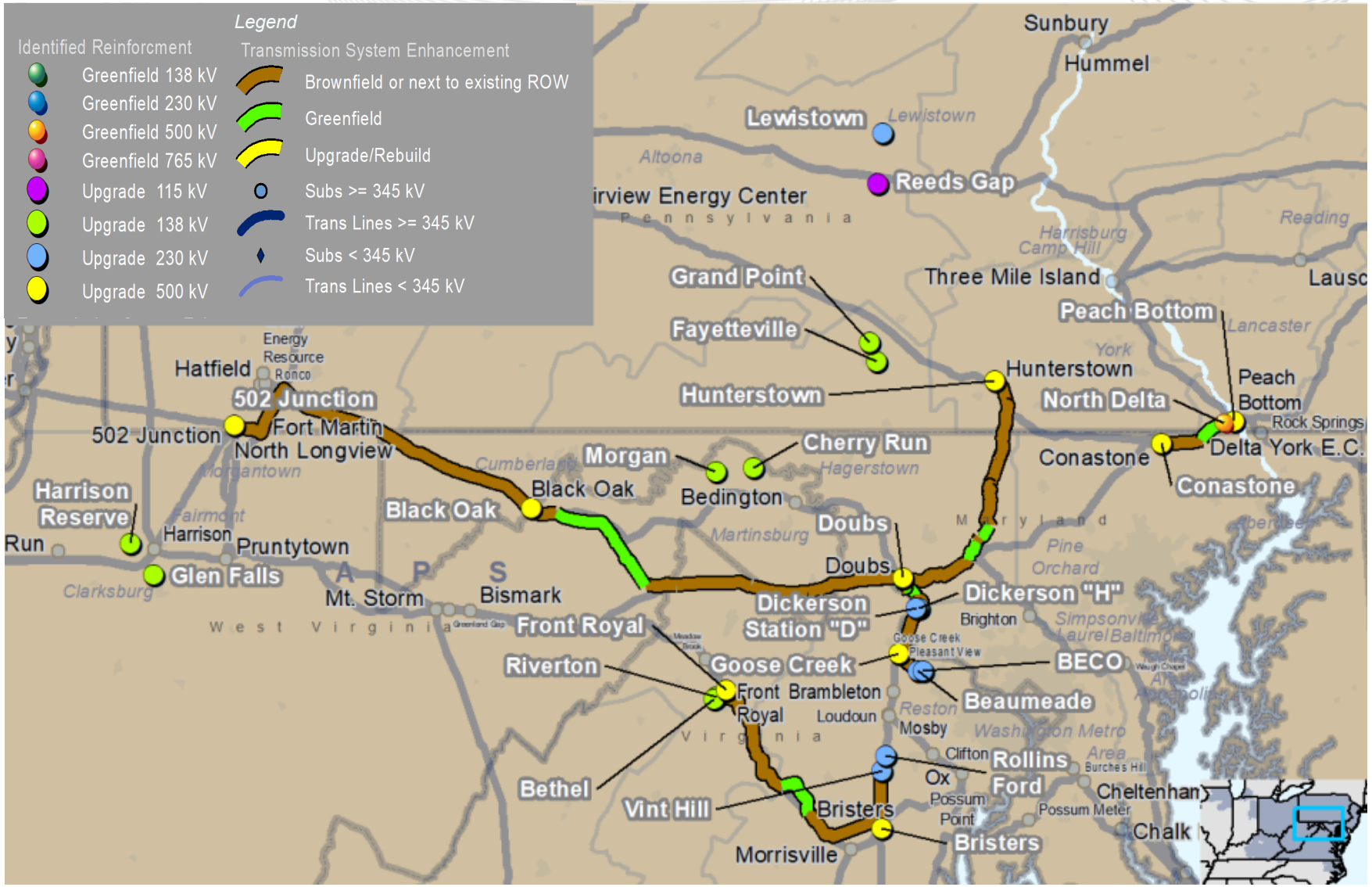
2022 Window 3 proposals – LS Power - 548



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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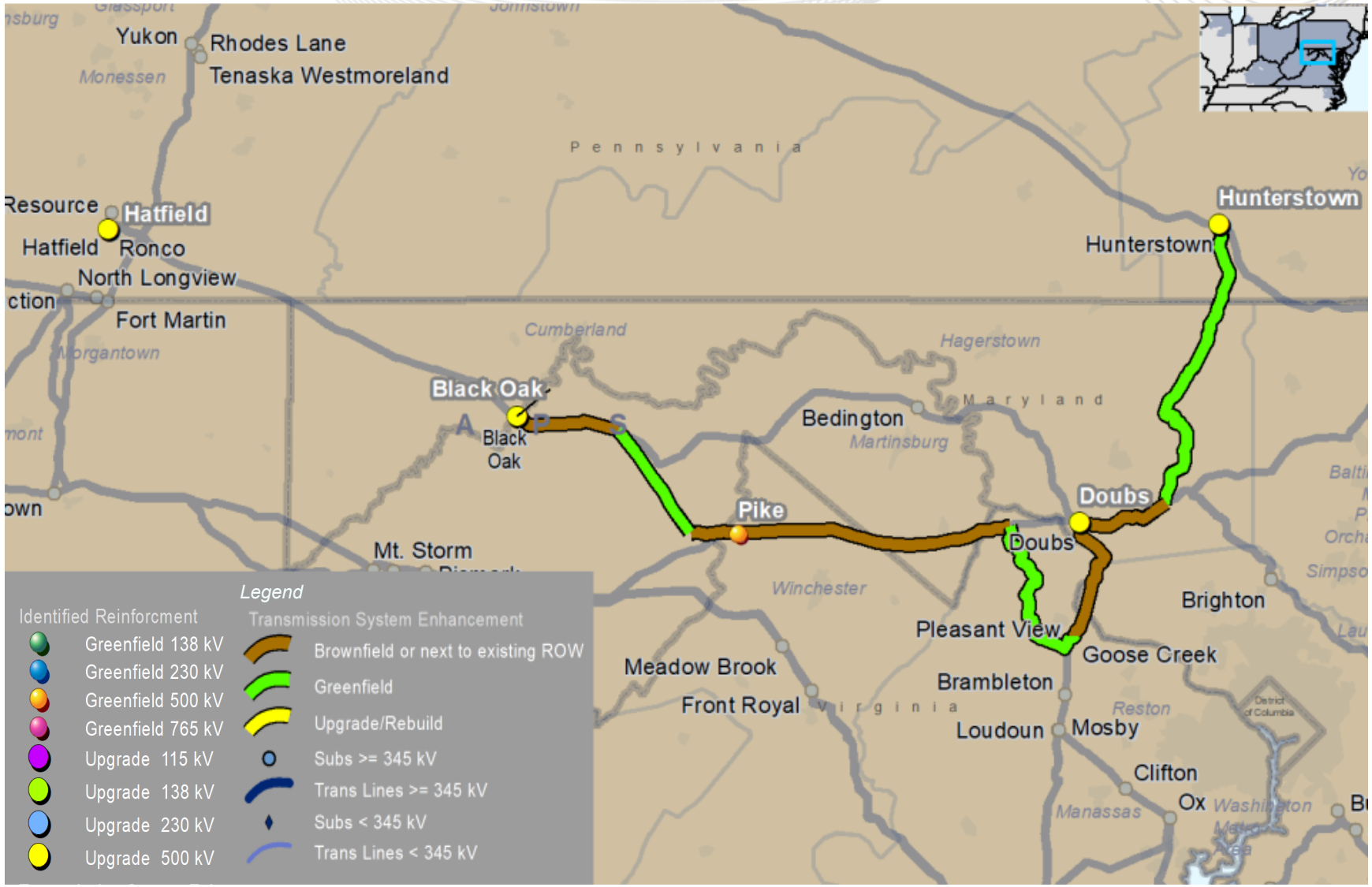
2022 Window 3 proposals – Nextera- 28



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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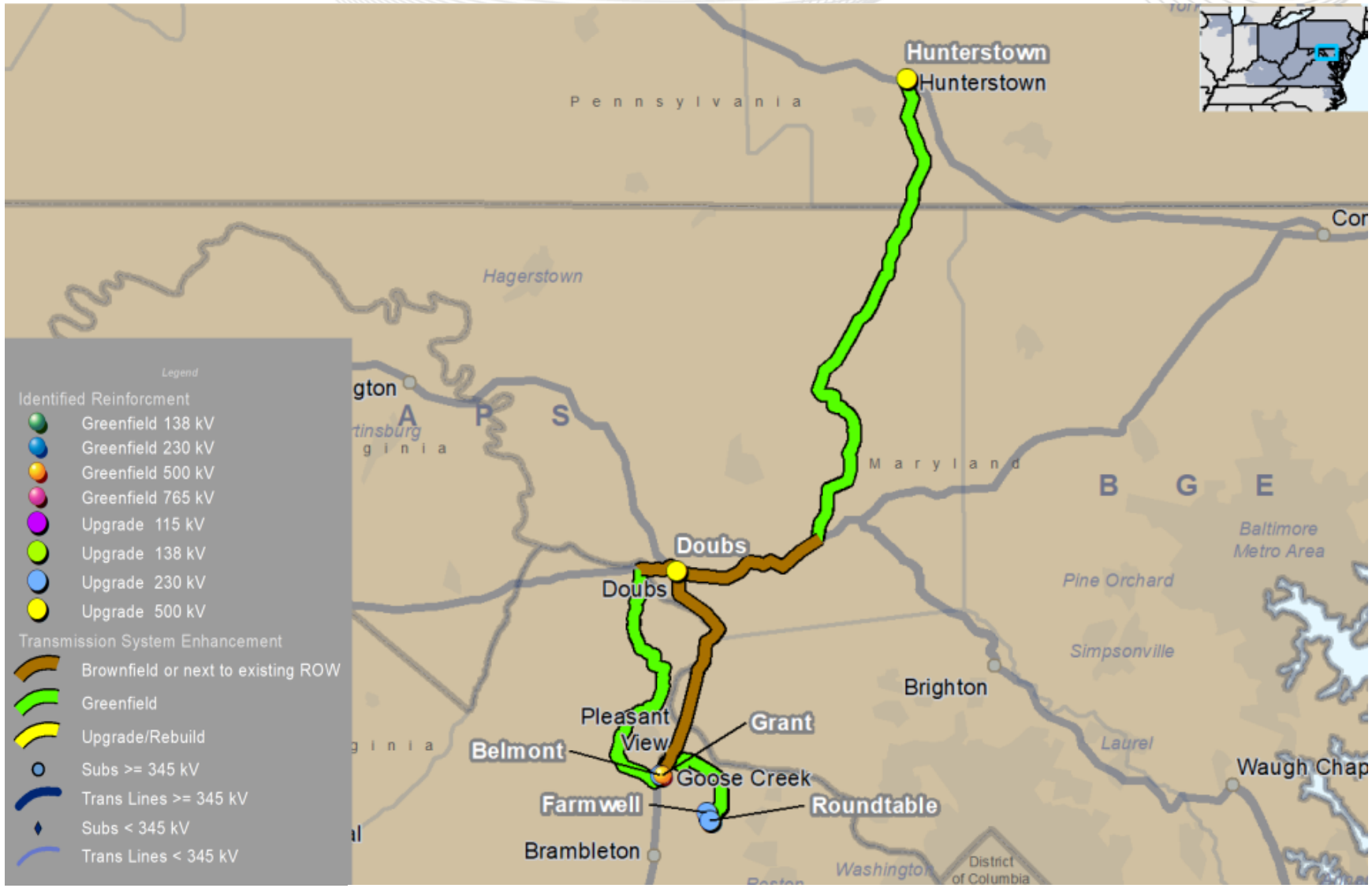
2022 Window 3 proposals – Nextera - 116



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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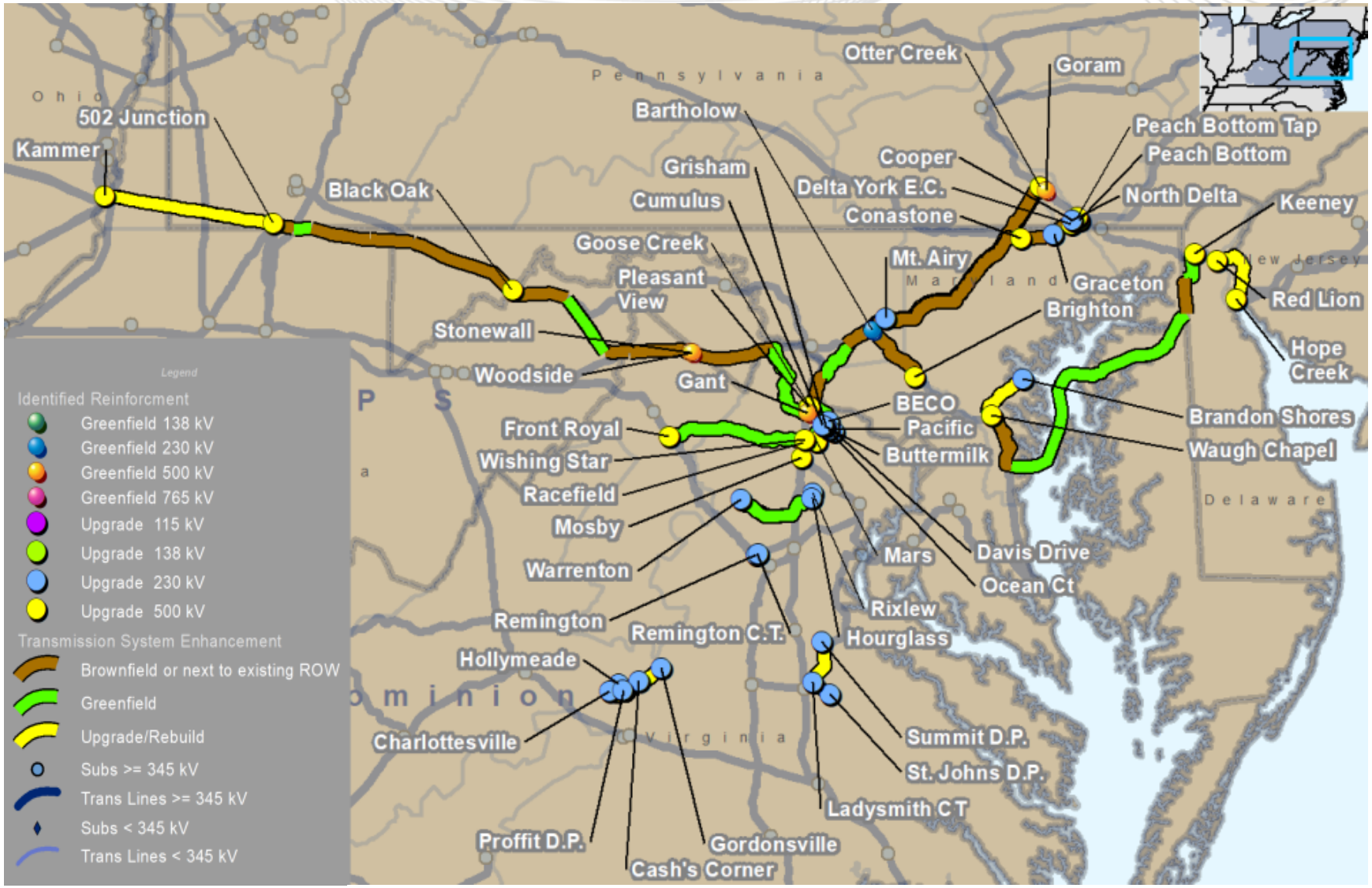
2022 Window 3 proposals – Nextera - 175 with 663, 853, 948



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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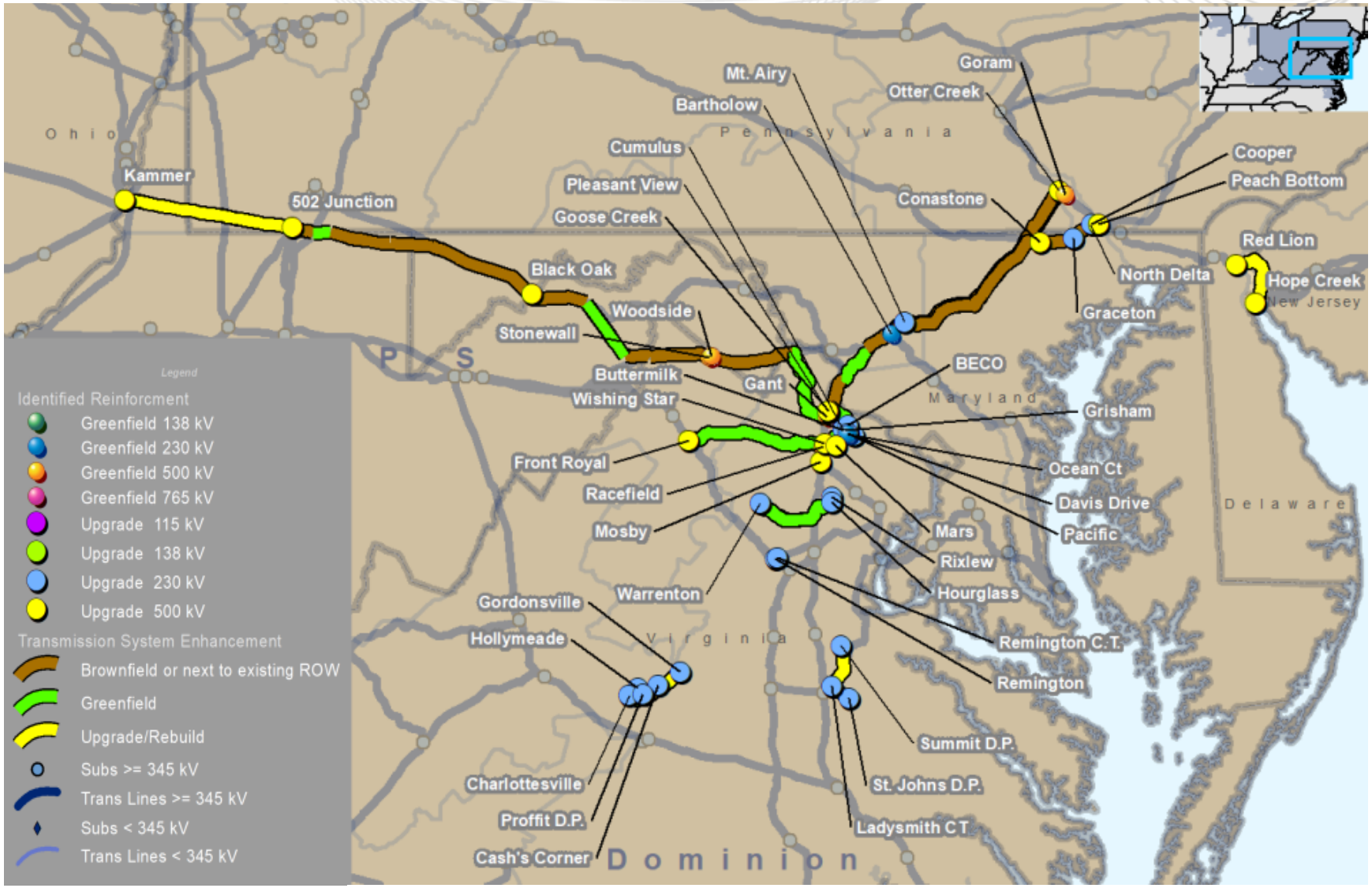
2022 Window 3 proposals – Nextera - 598 with 663, 853, 385



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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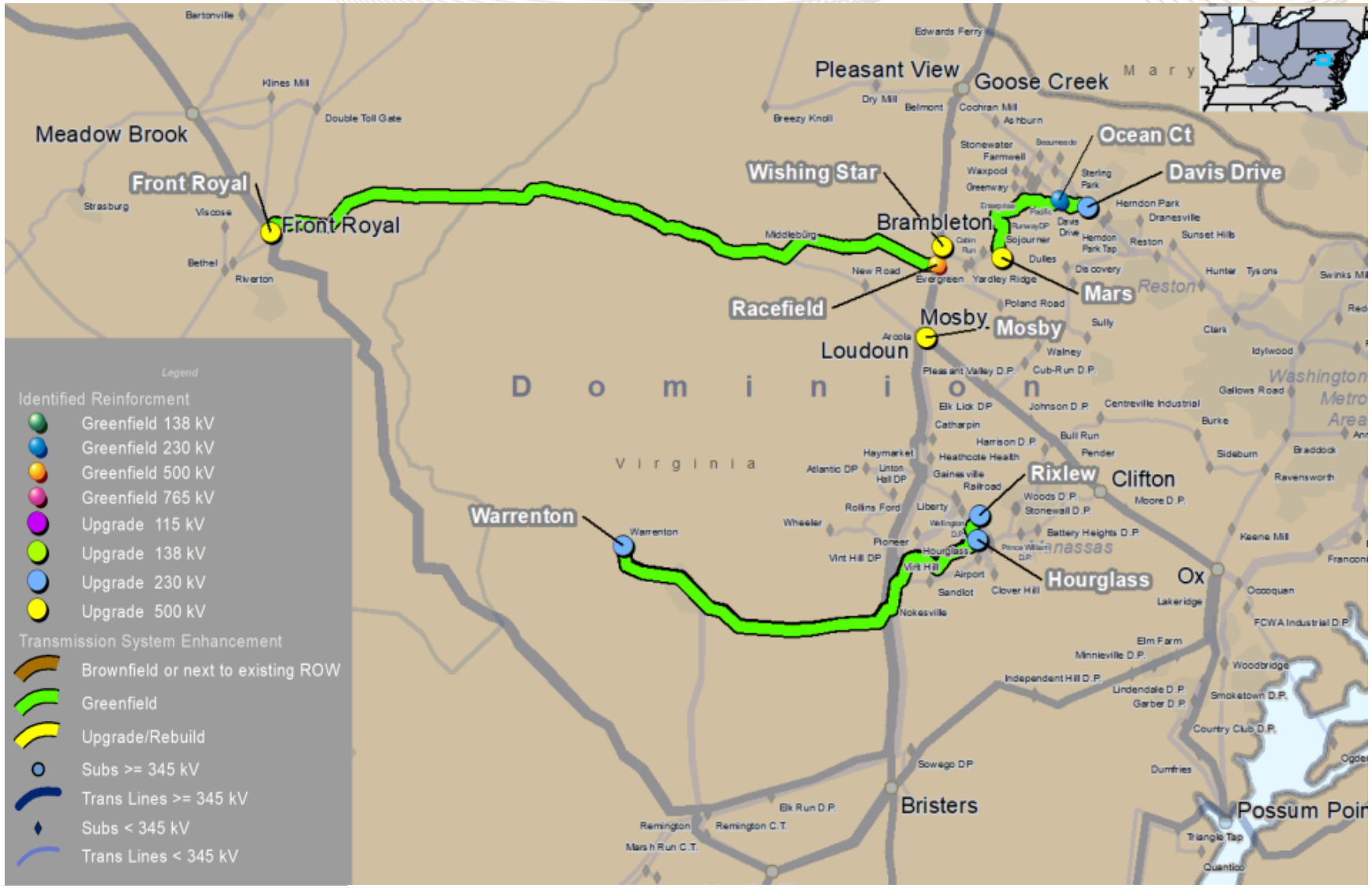
2022 Window 3 proposals – Nextera - 663



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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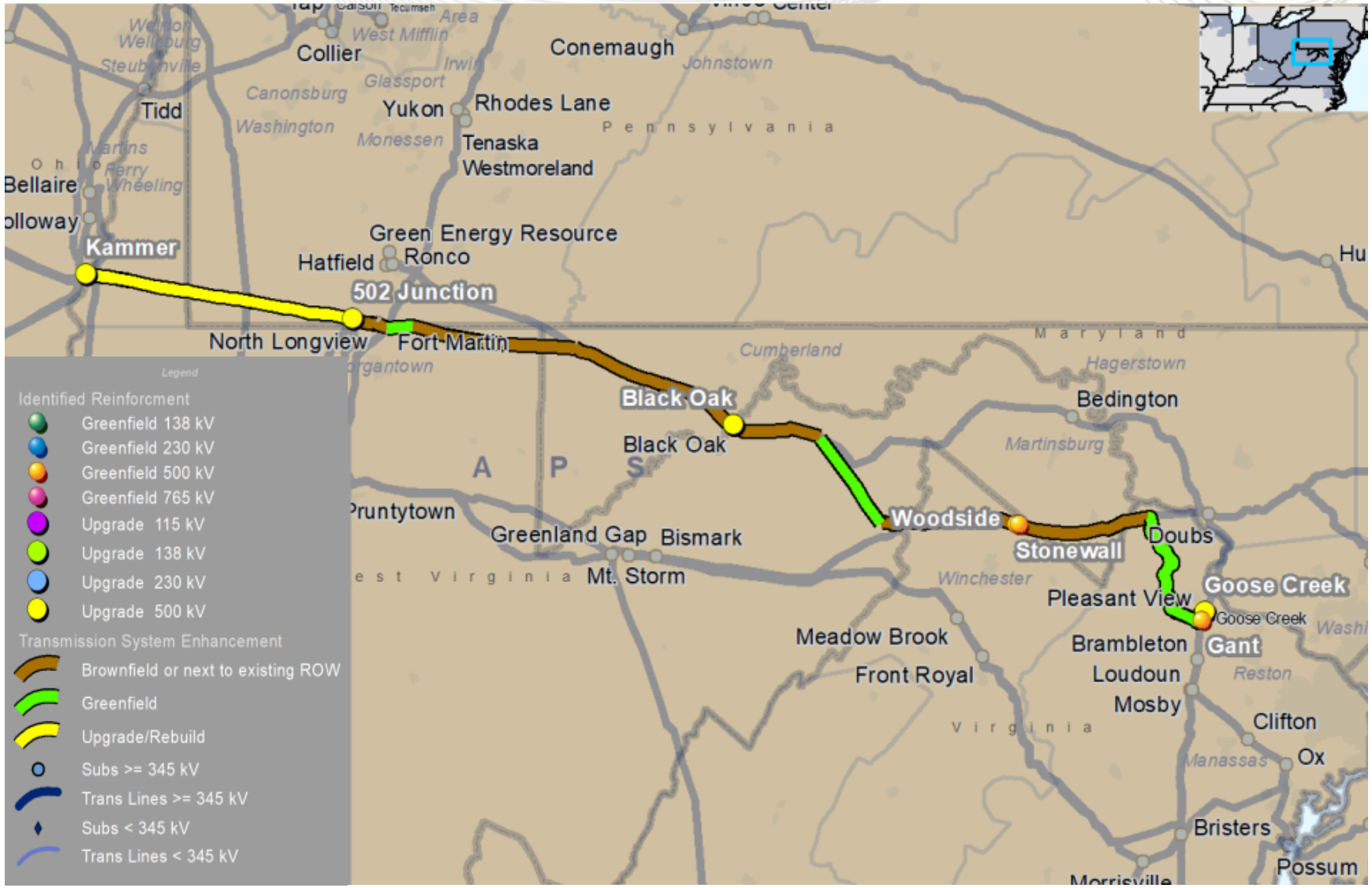
2022 Window 3 proposals – Nextera - 853



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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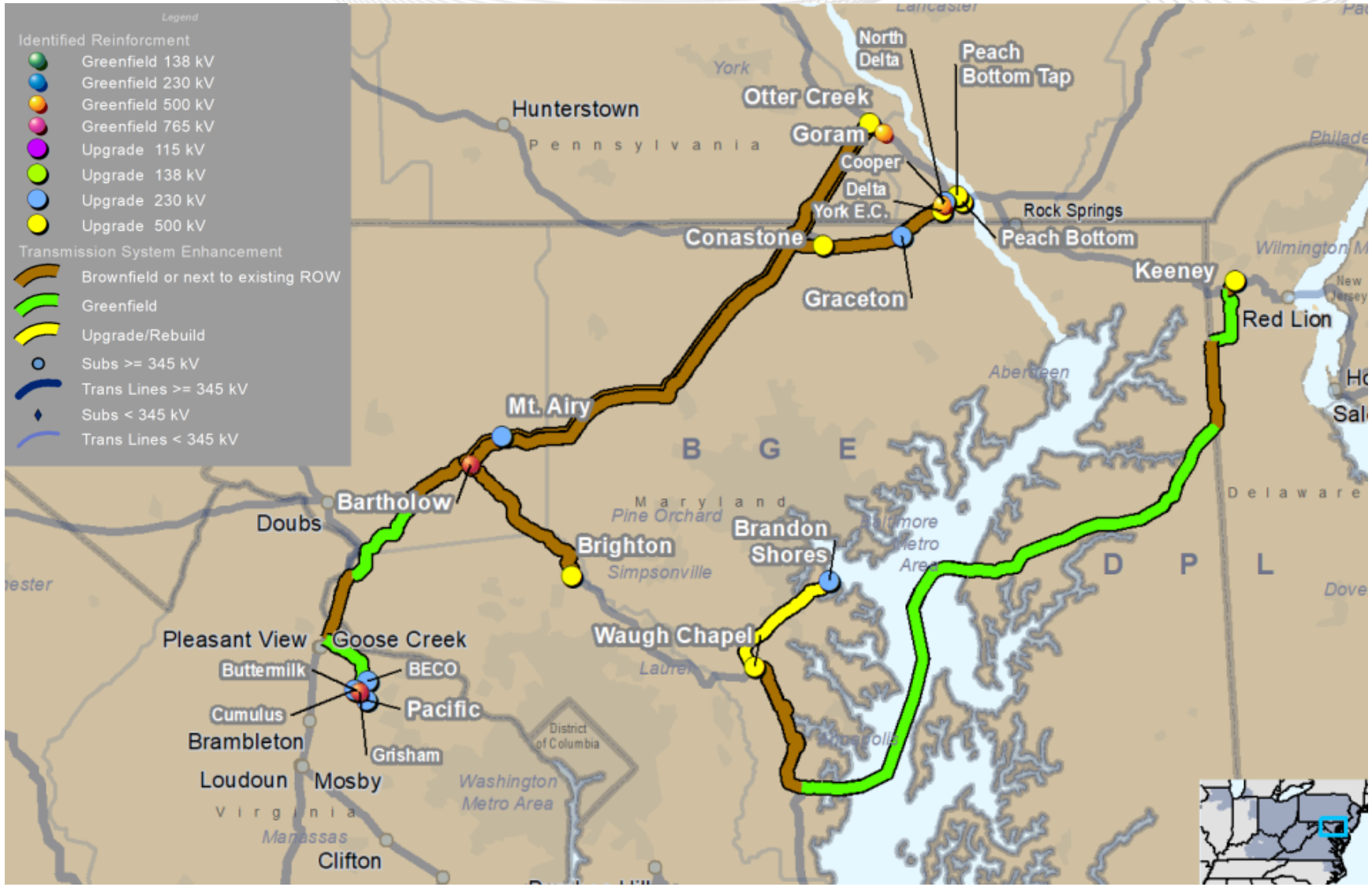
2022 Window 3 proposals – Nextera - 948



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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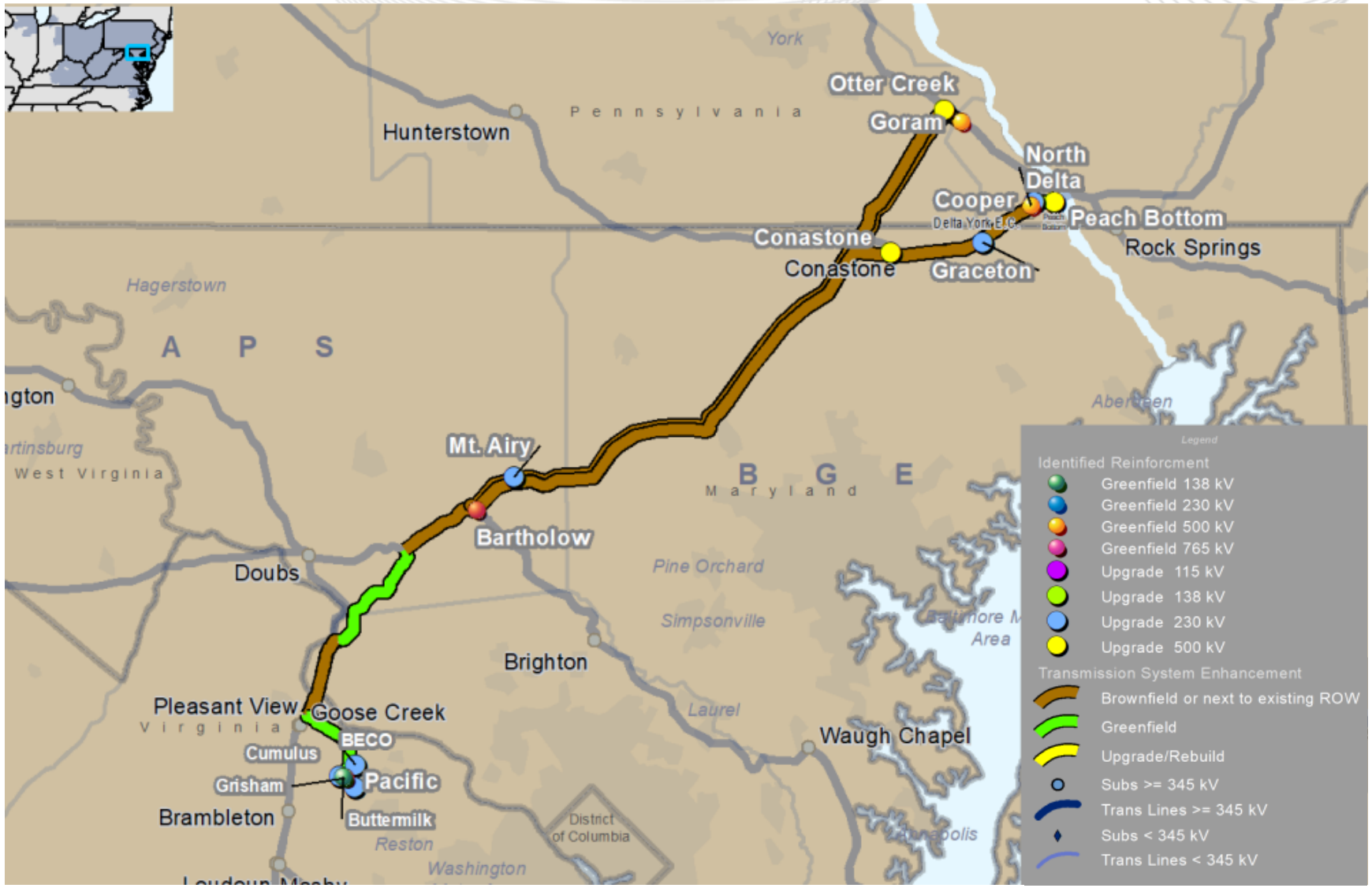
2022 Window 3 proposals – Nextera 385



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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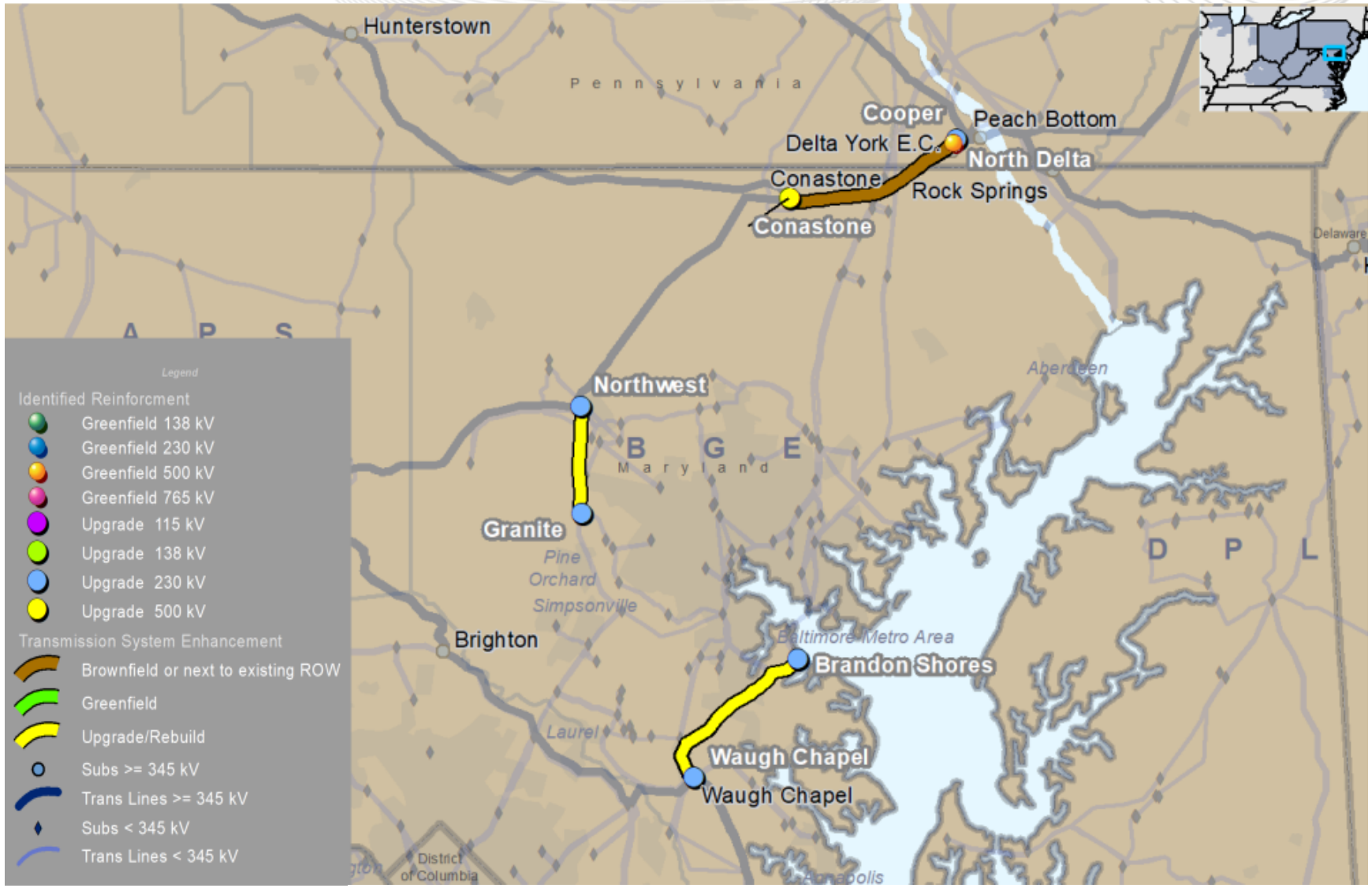
2022 Window 3 proposals – Nextera - 217



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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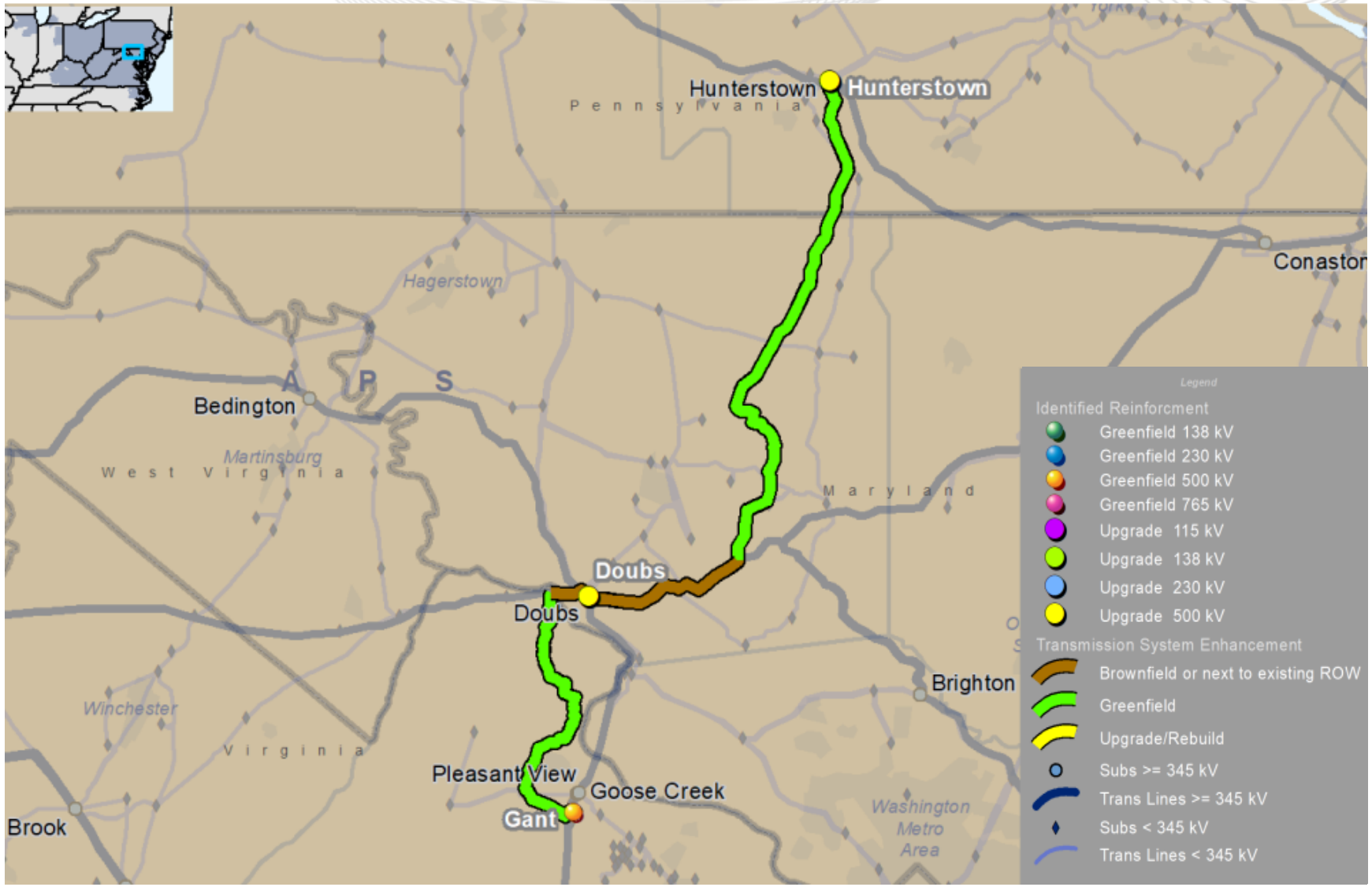
2022 Window 3 proposals – Nextera - 255



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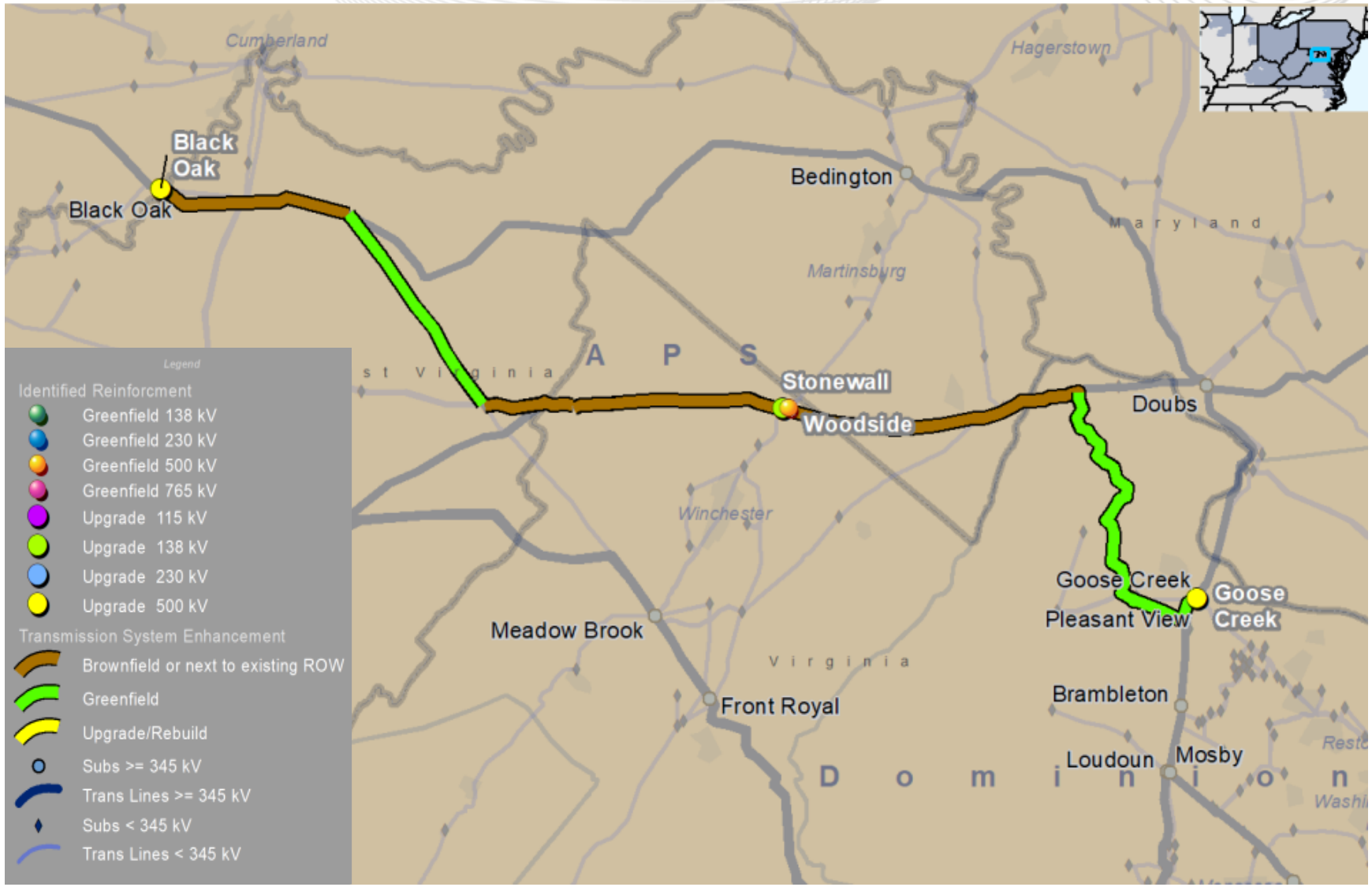
2022 Window 3 proposals – Nextera - 279



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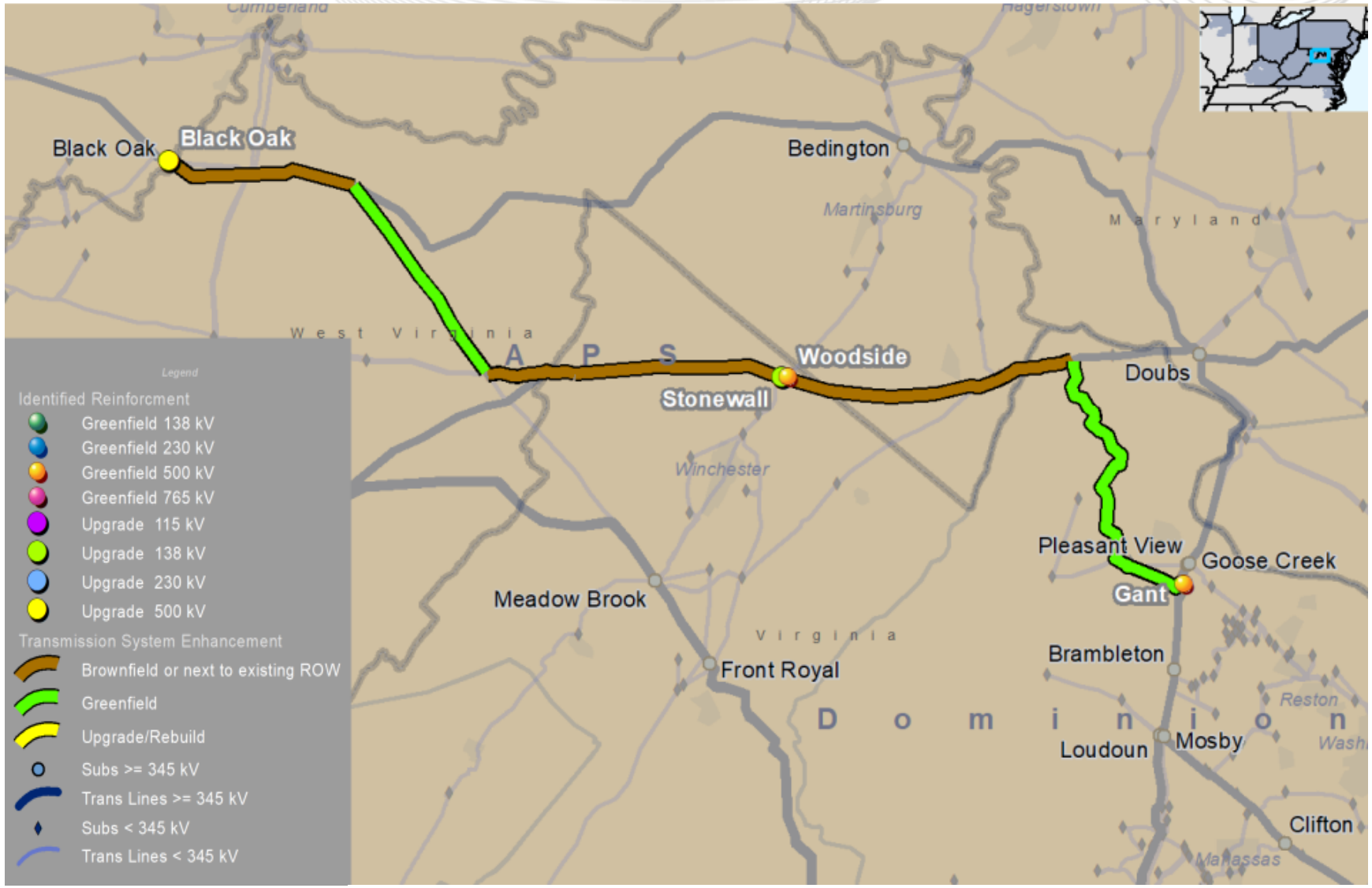
2022 Window 3 proposals – Nextera - 347



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2022 Window 3 proposals – Nextera – 419

NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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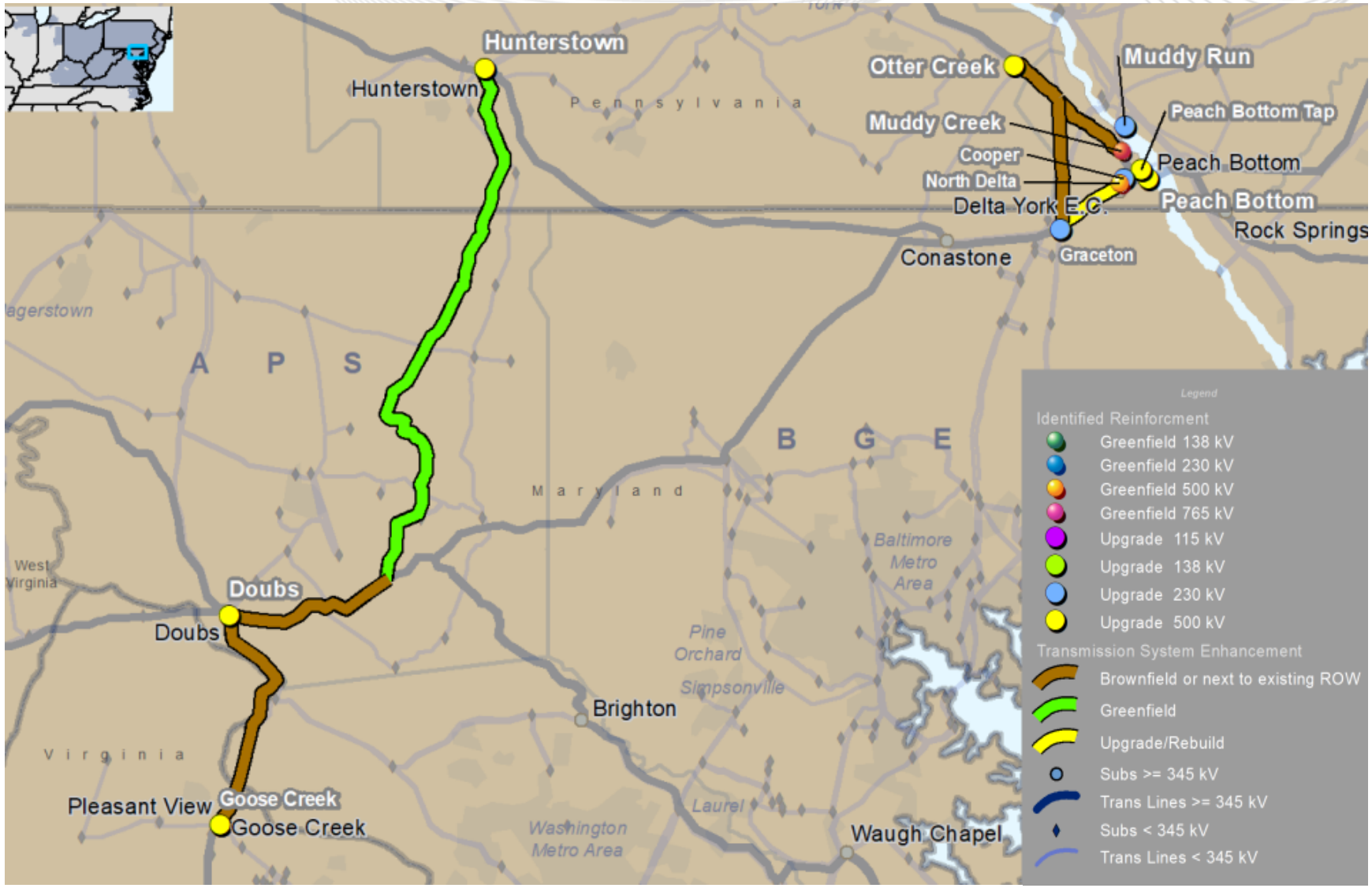
2022 Window 3 proposals – Nextera - 445



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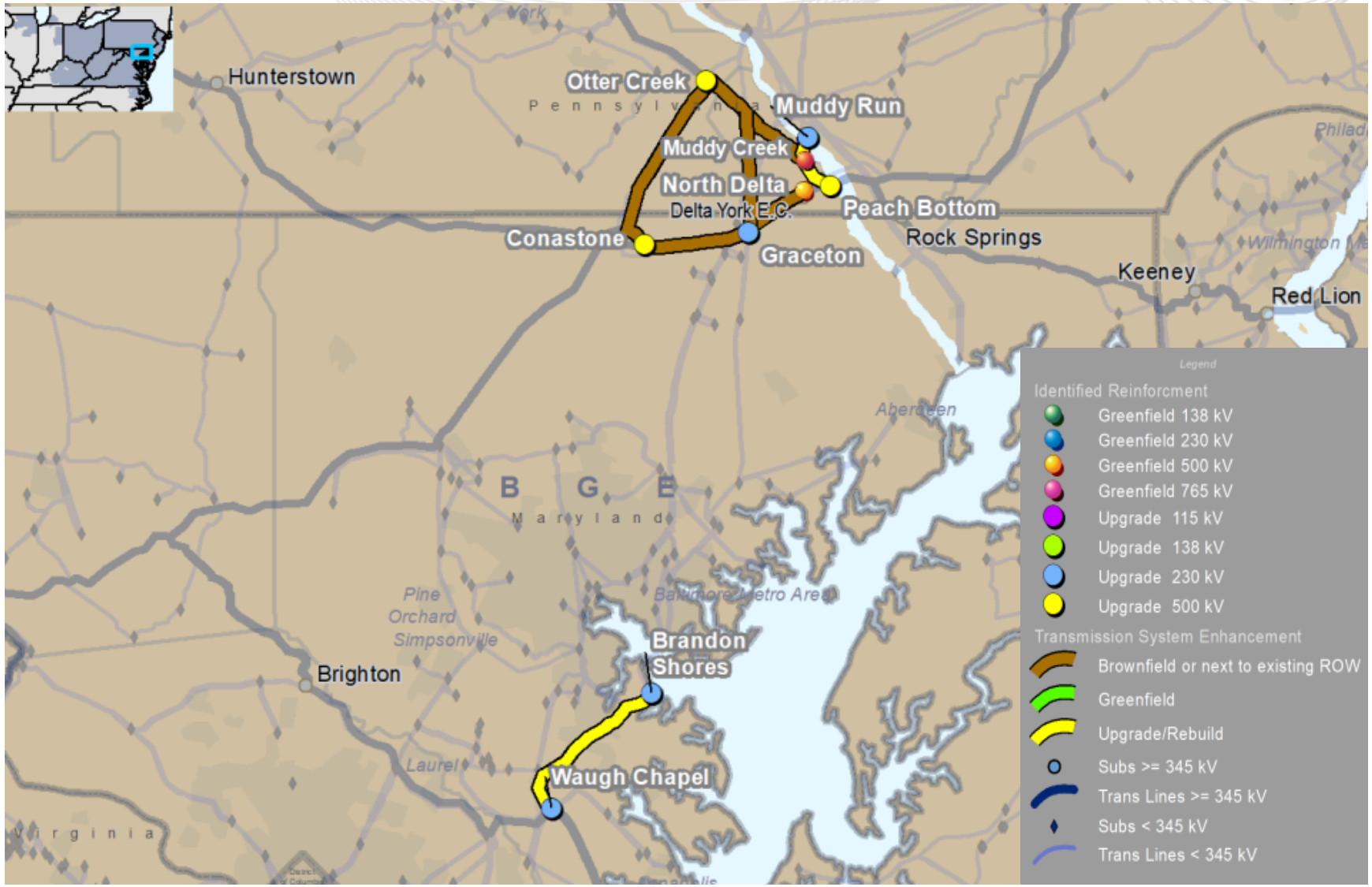
2022 Window 3 proposals – Nextera - 530



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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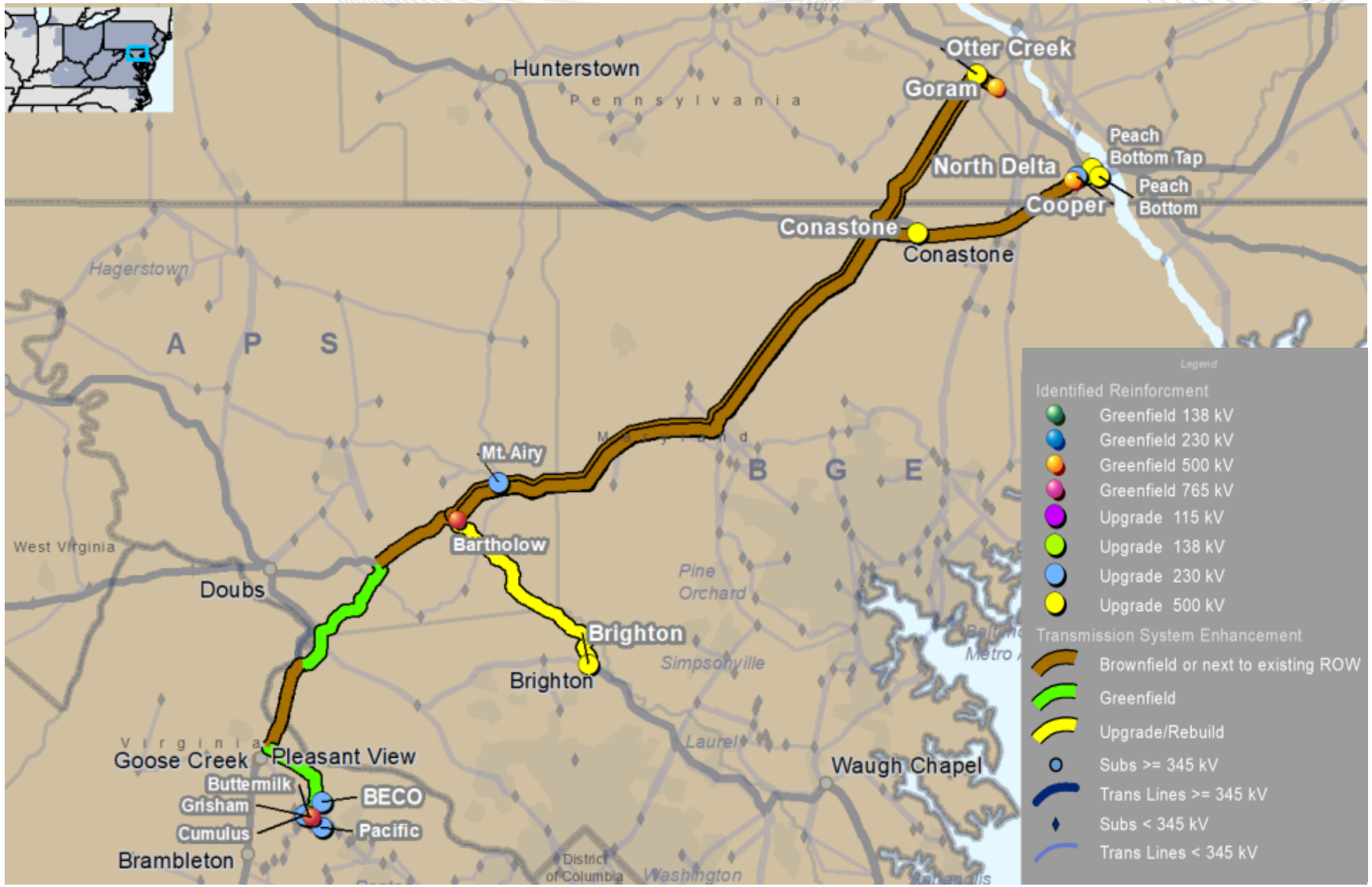
2022 Window 3 proposals – Nextera - 564



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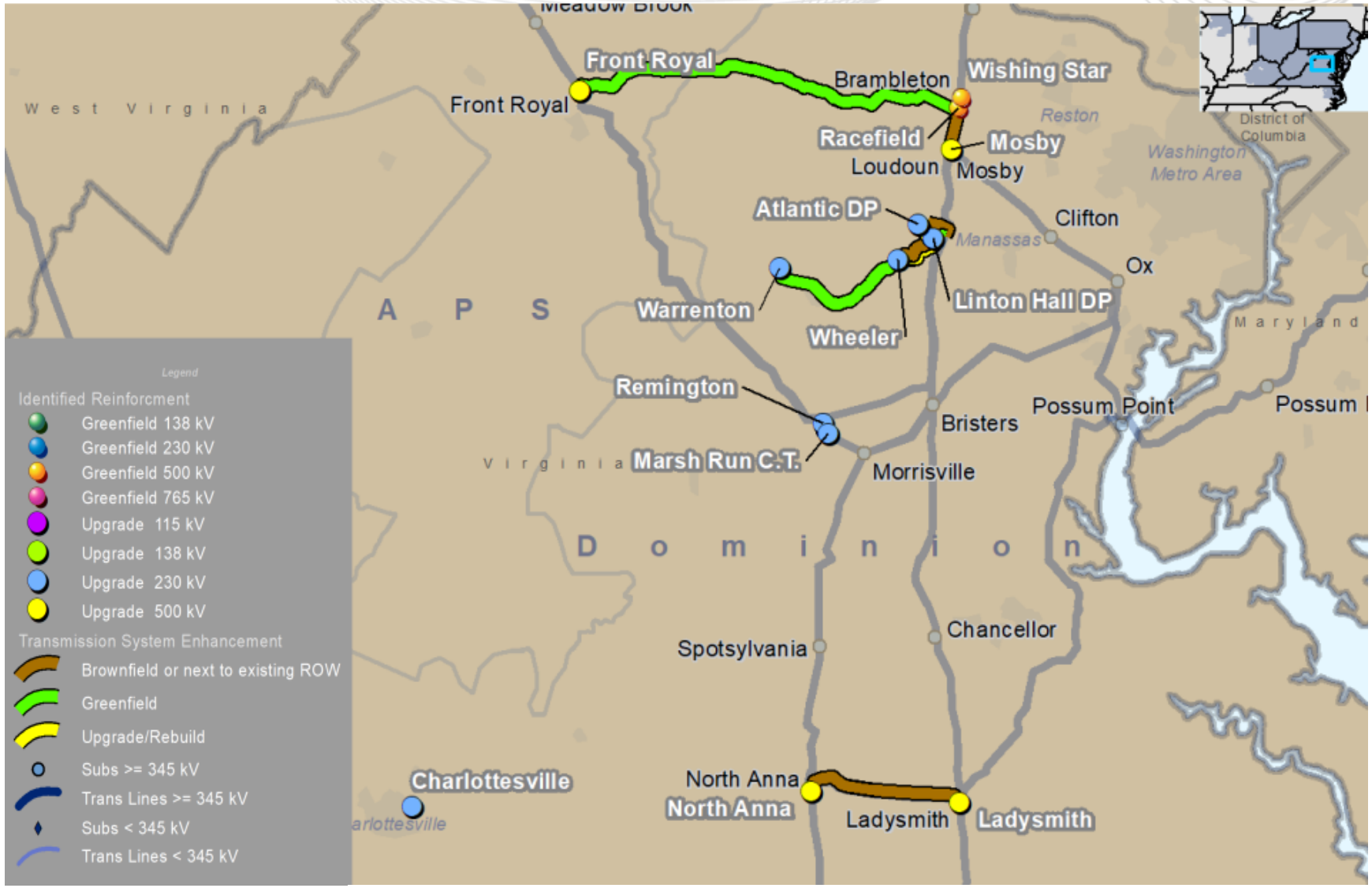
2022 Window 3 proposals – Nextera - 577



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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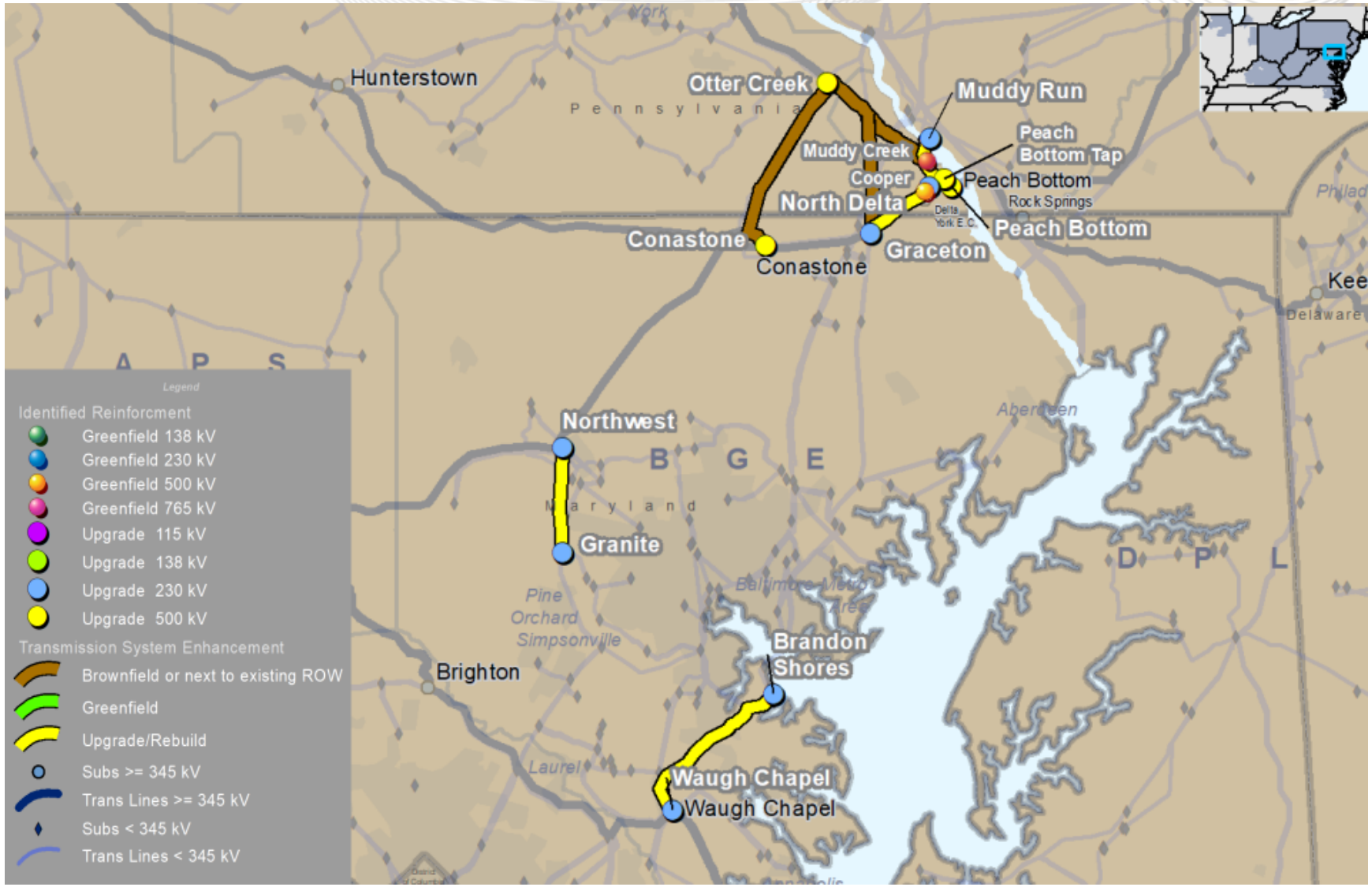
2022 Window 3 proposals – Nextera - 631



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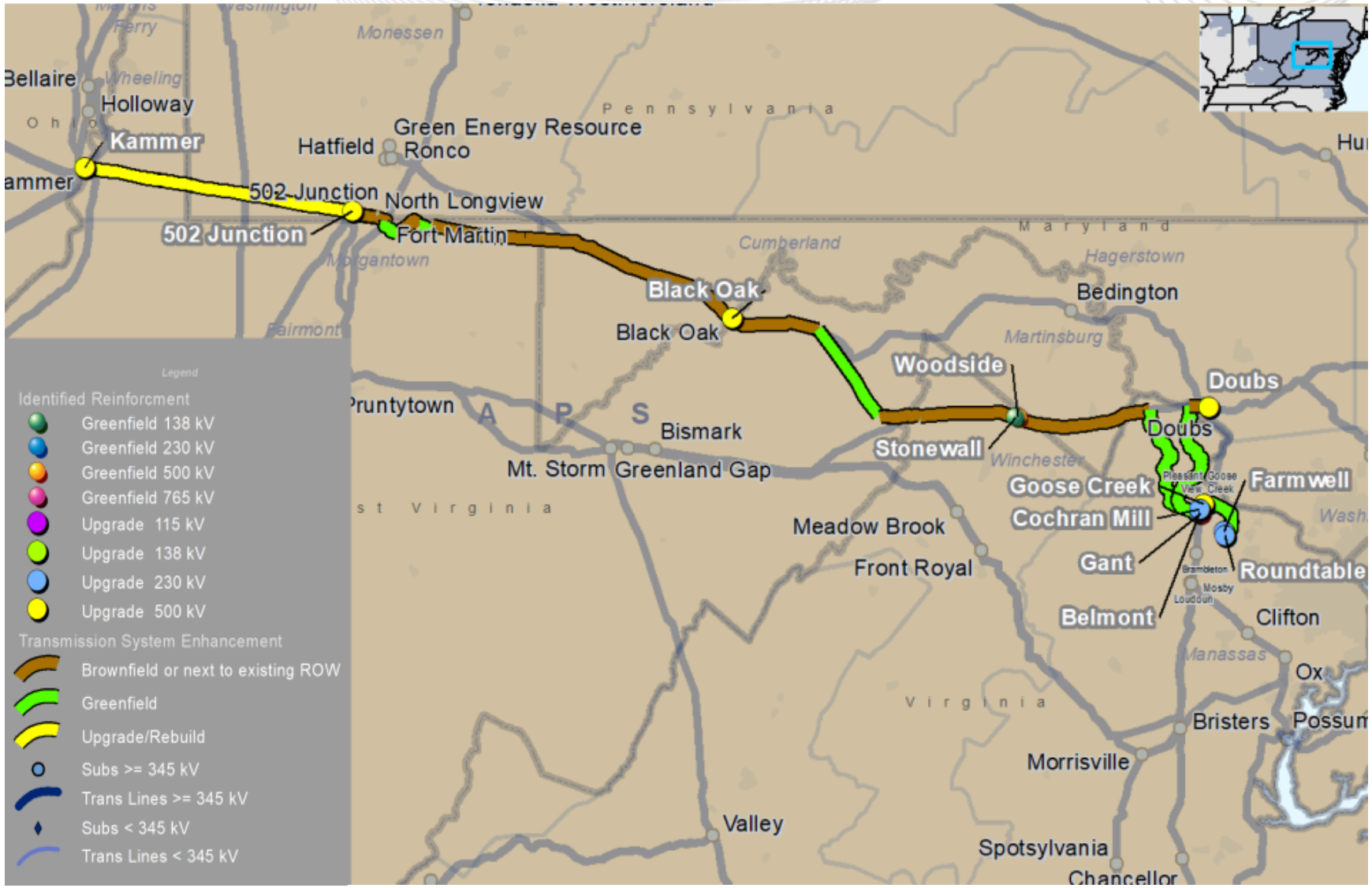
2022 Window 3 proposals – Nextera - 642



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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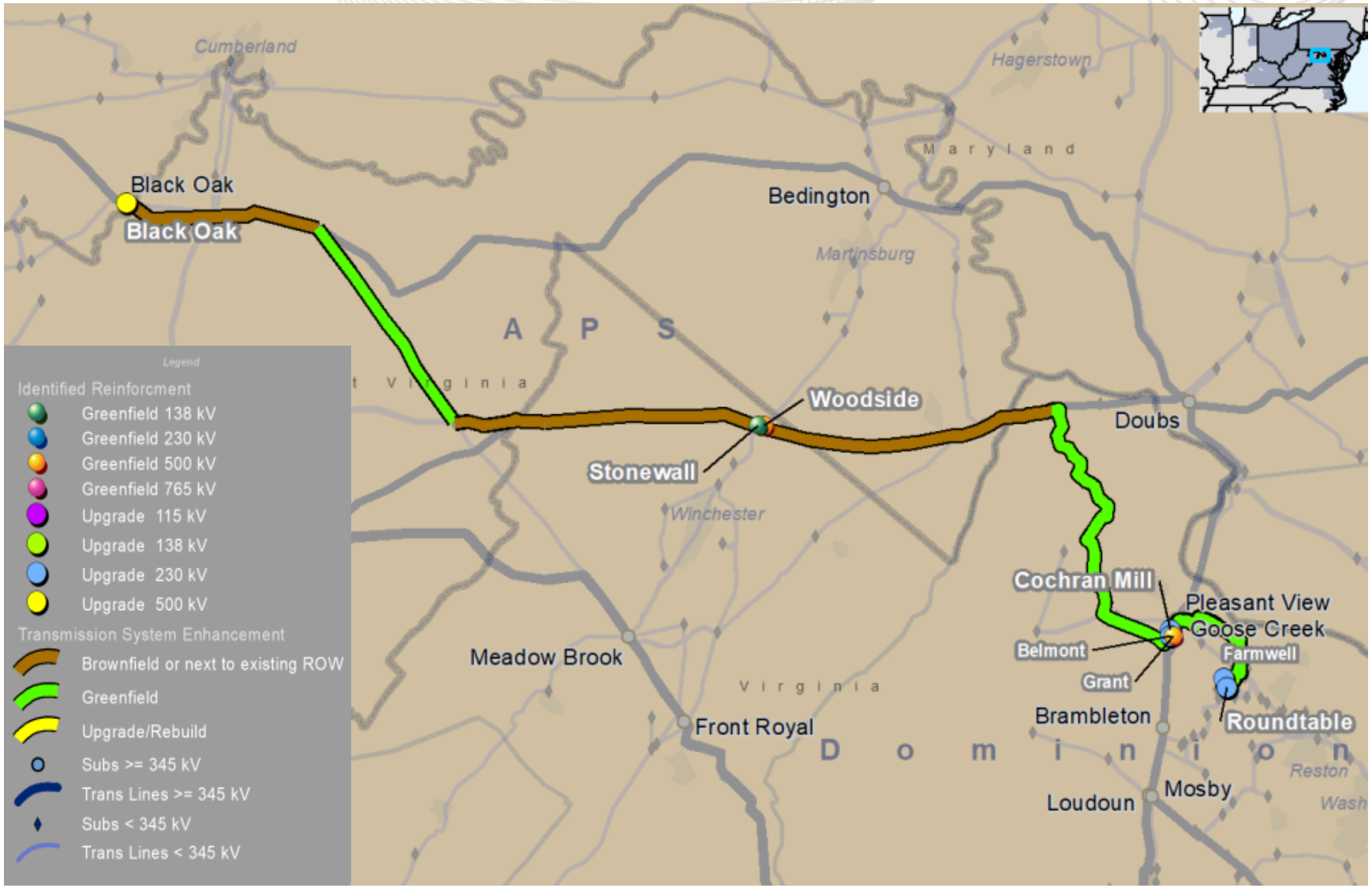
2022 Window 3 proposals – Nextera - 676



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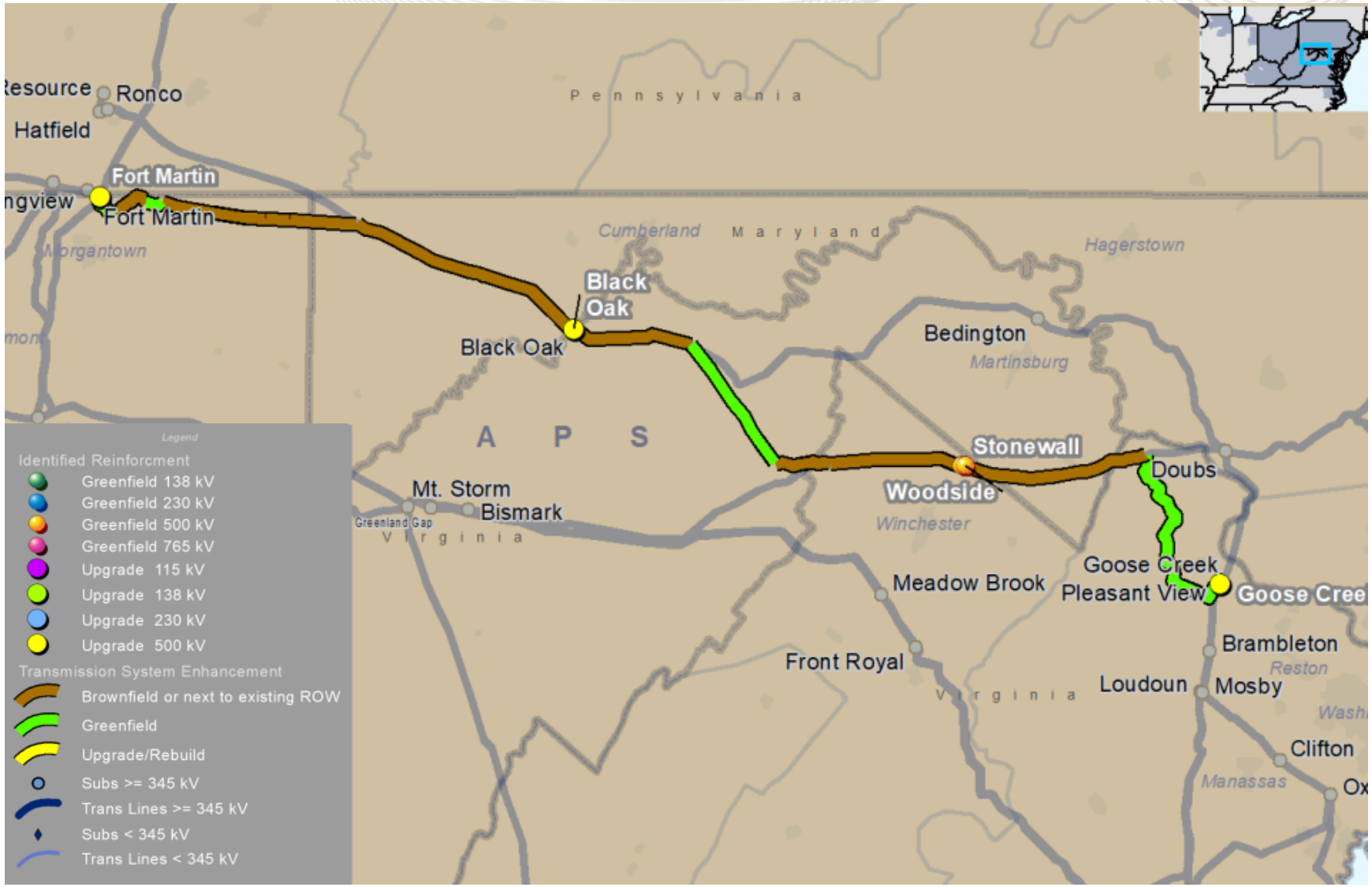
2022 Window 3 proposals – Nextera - 685



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2022 Window 3 proposals – Nextera - 719

NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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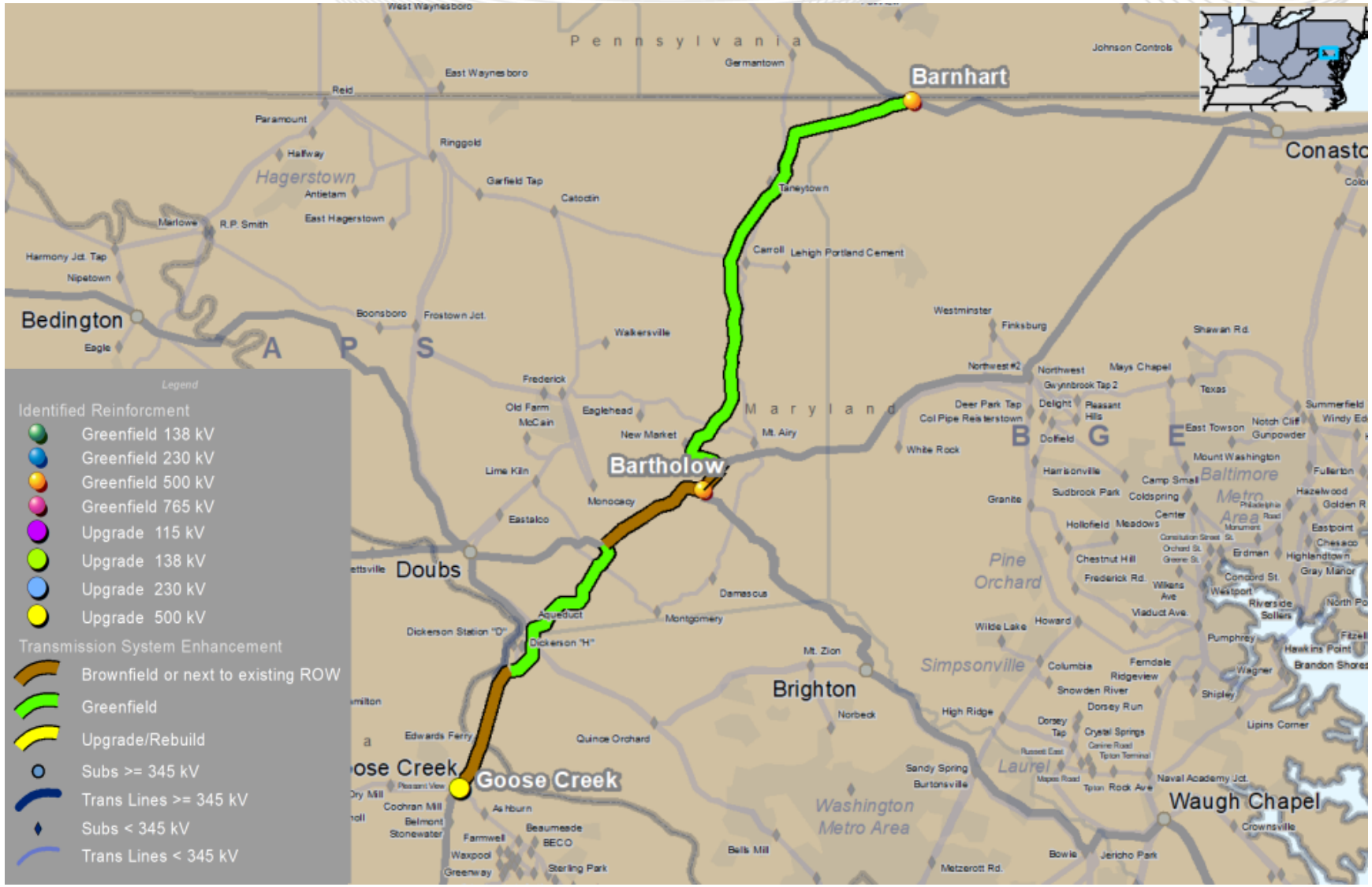
2022 Window 3 proposals – Nextera - 728



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2022 Window 3 proposals – Nextera - 766

NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should <u>not</u> be relied upon for exact geographical substation locations or line routes.*

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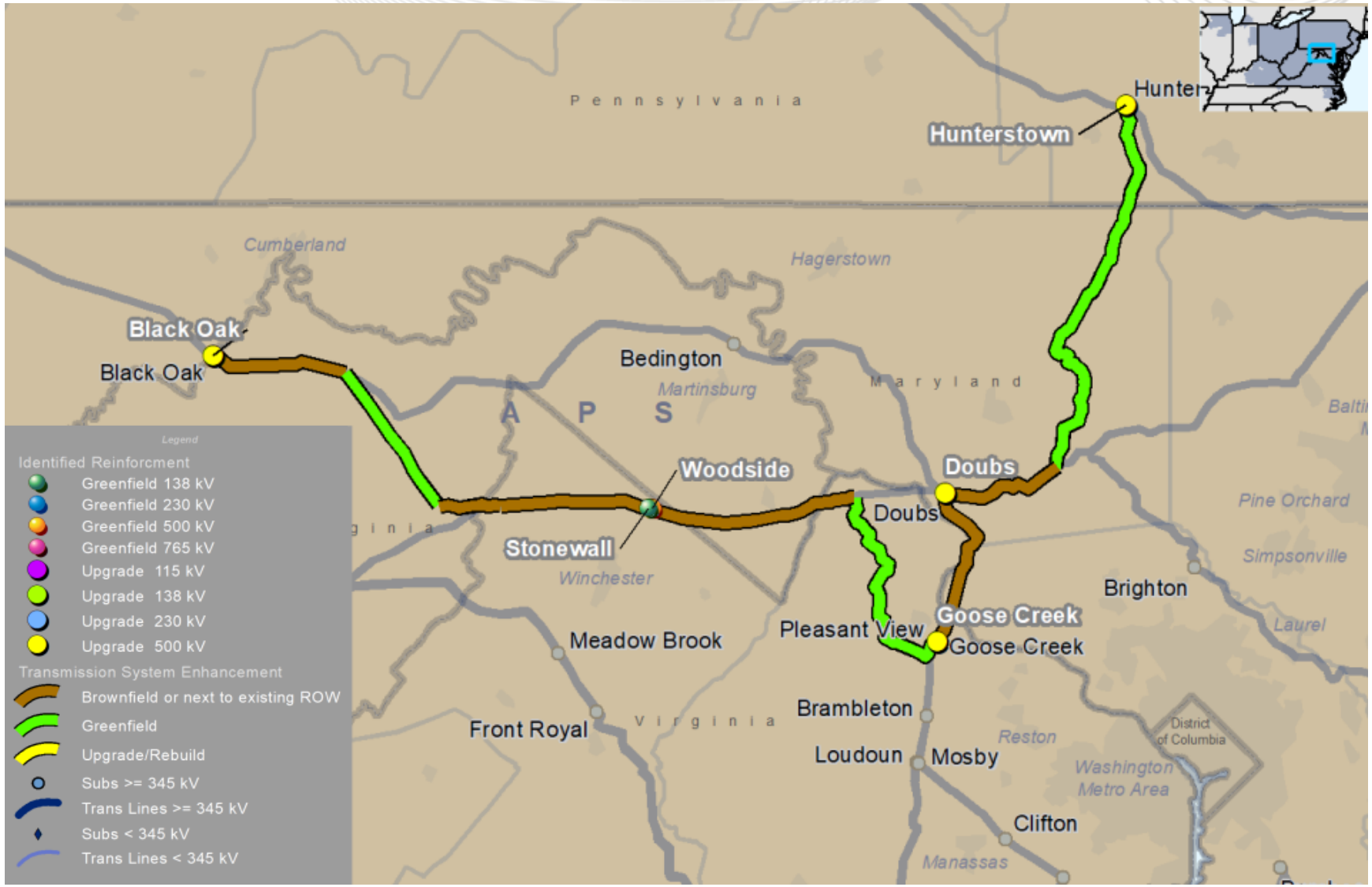
2022 Window 3 proposals – Nextera - 846



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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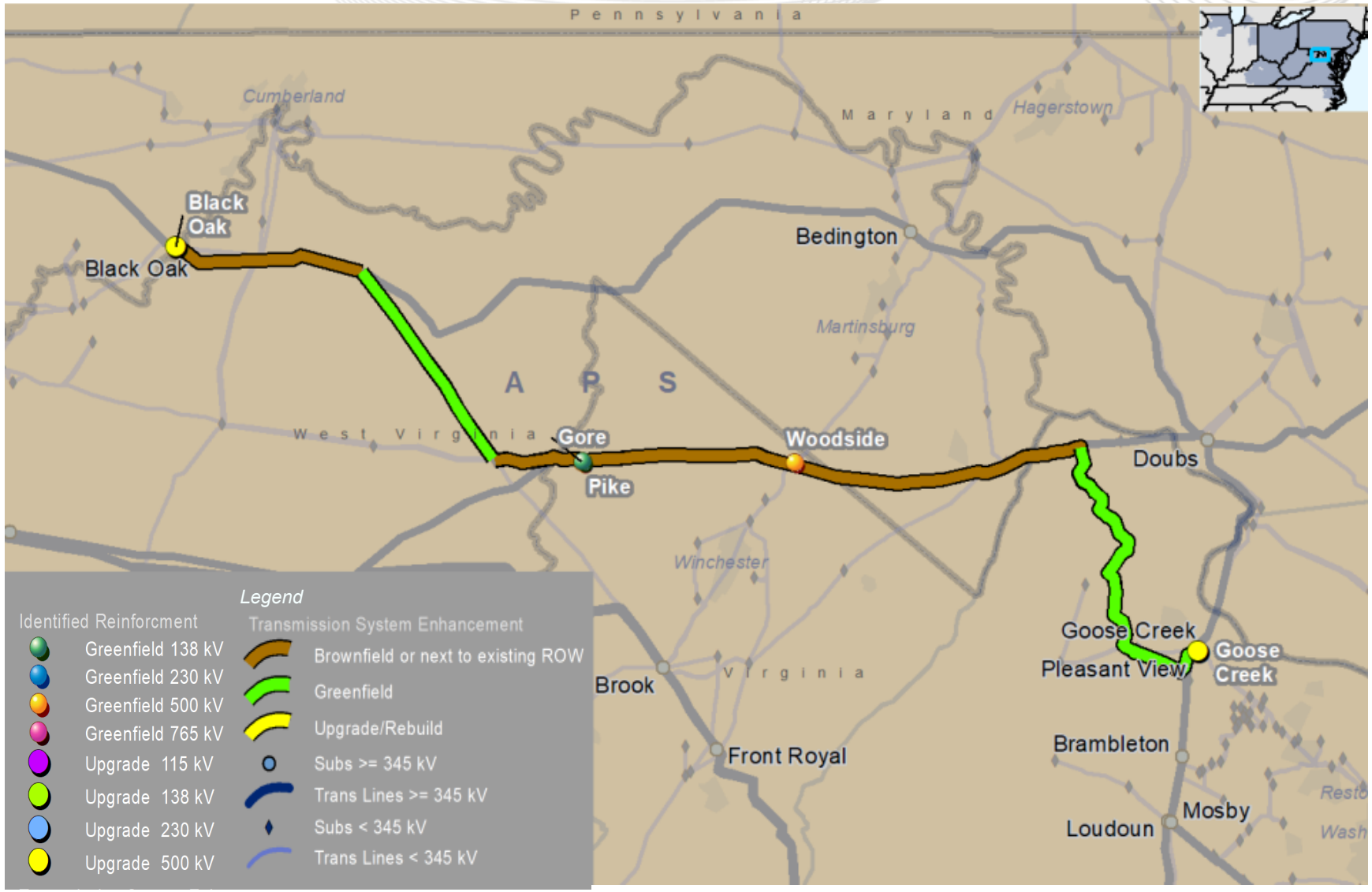
2022 Window 3 proposals – Nextera - 951



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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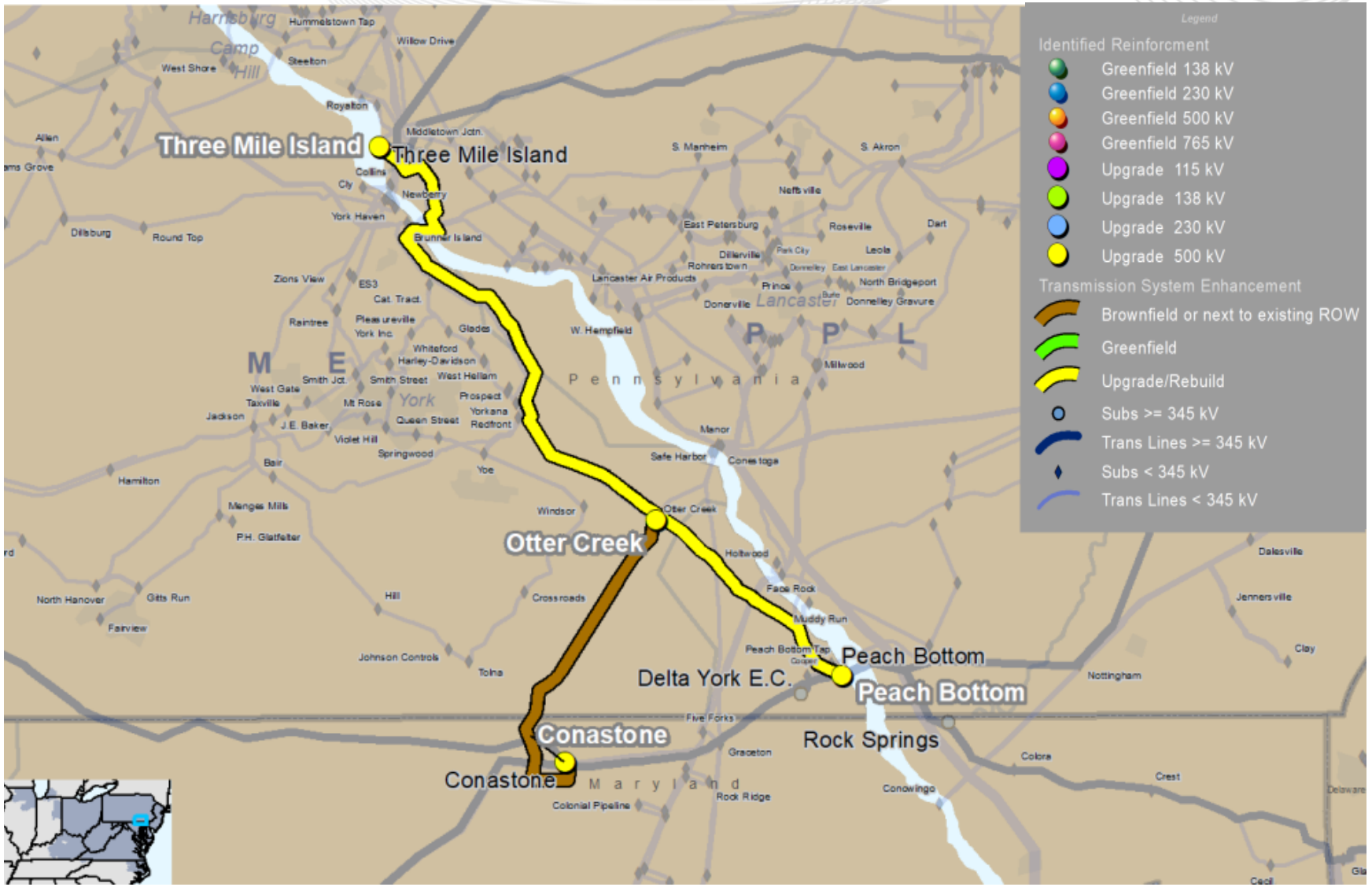
2022 Window 3 proposals – PPL - 374



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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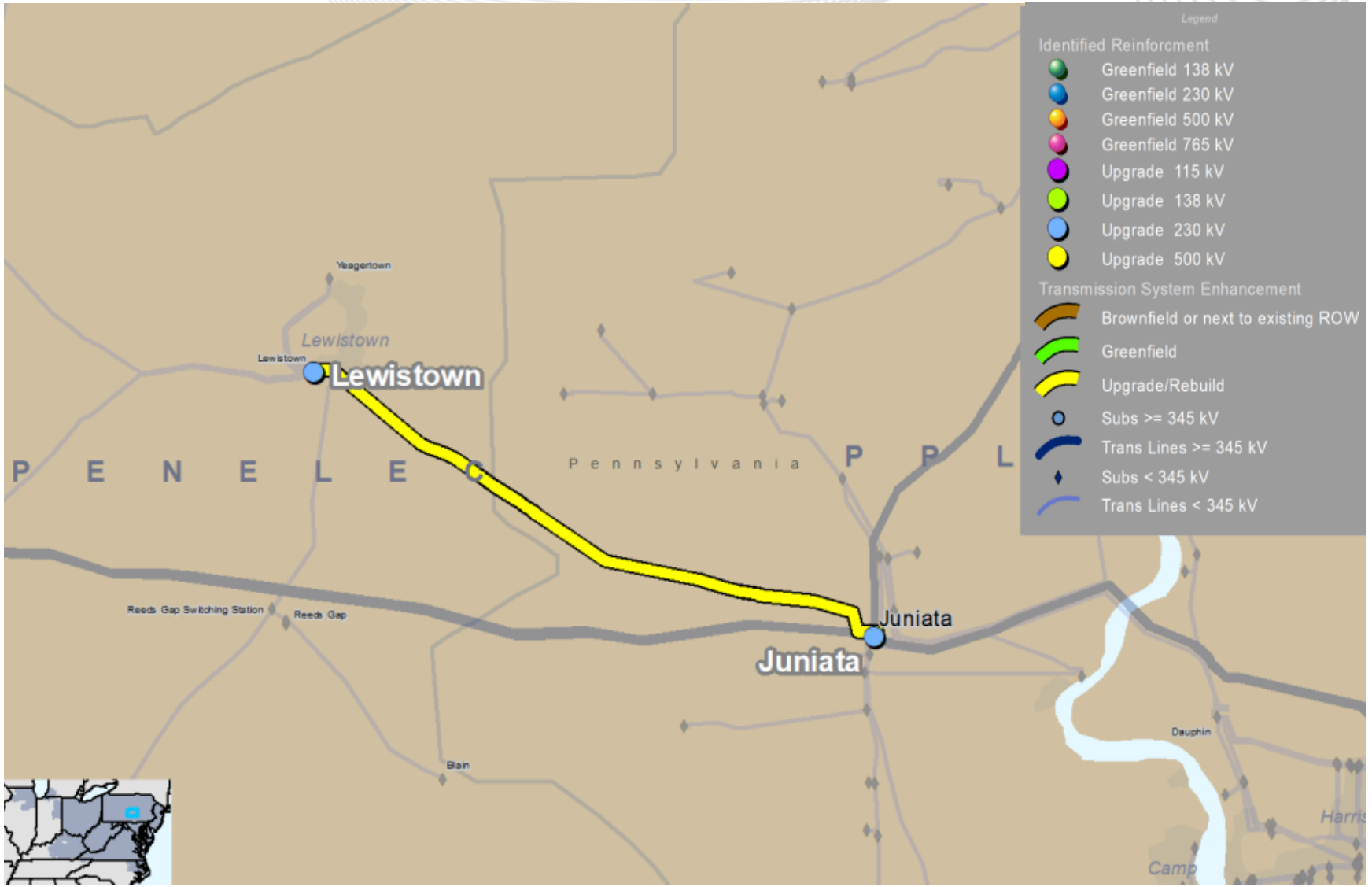
2022 Window 3 proposals – PPL - 606



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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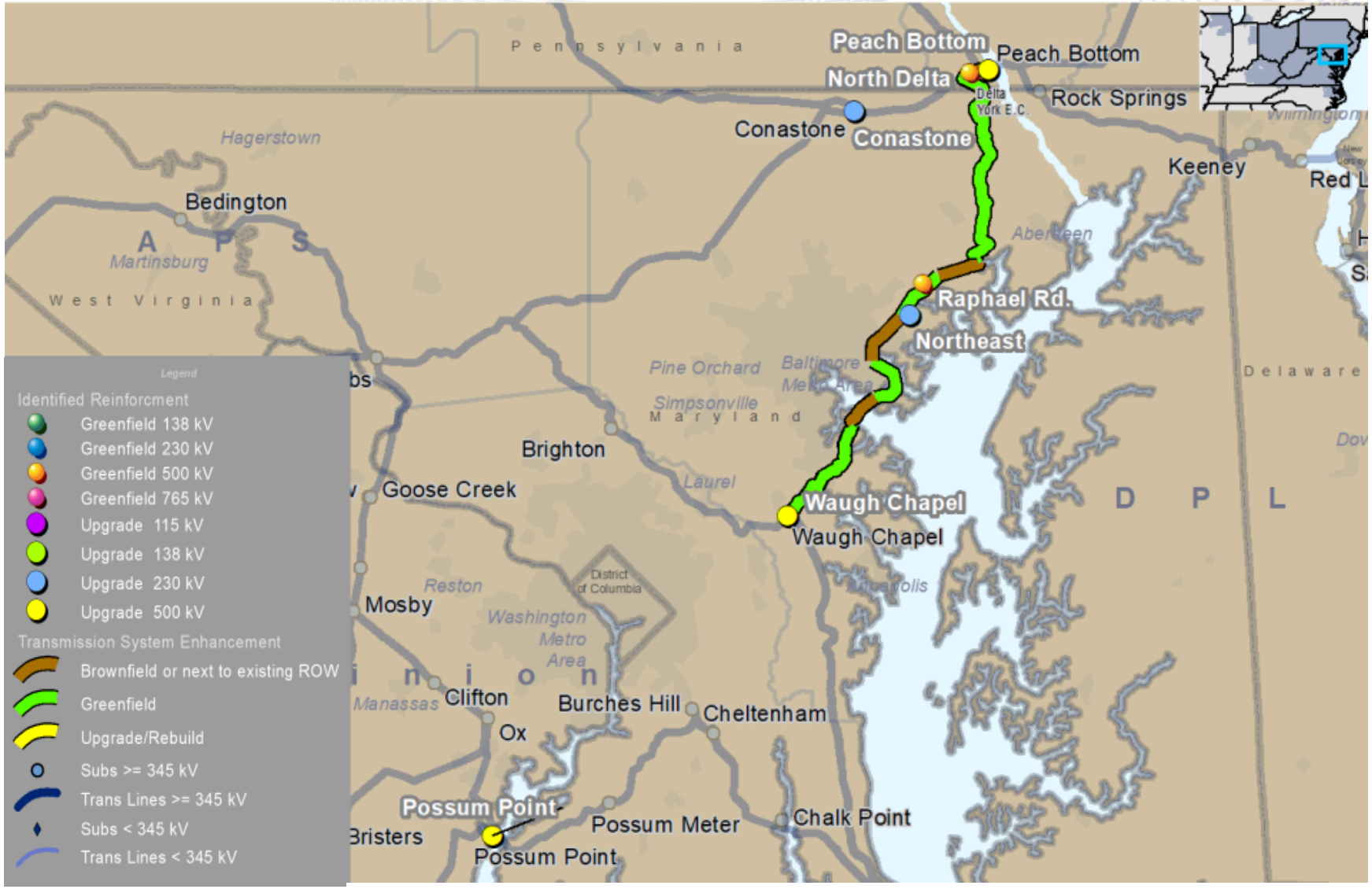
2022 Window 3 proposals – PSEG - 24



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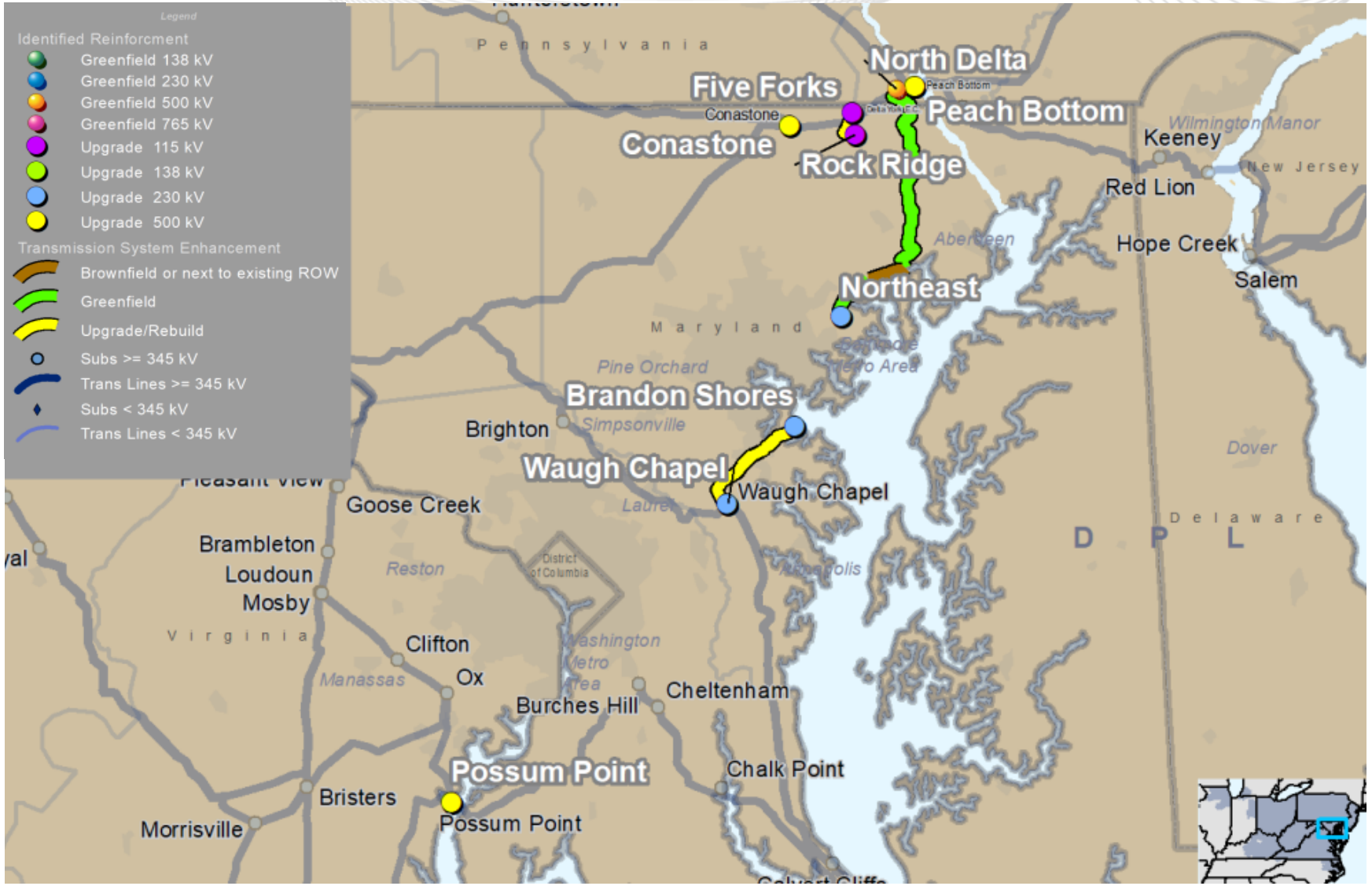
2022 Window 3 proposals – PSEG - 125



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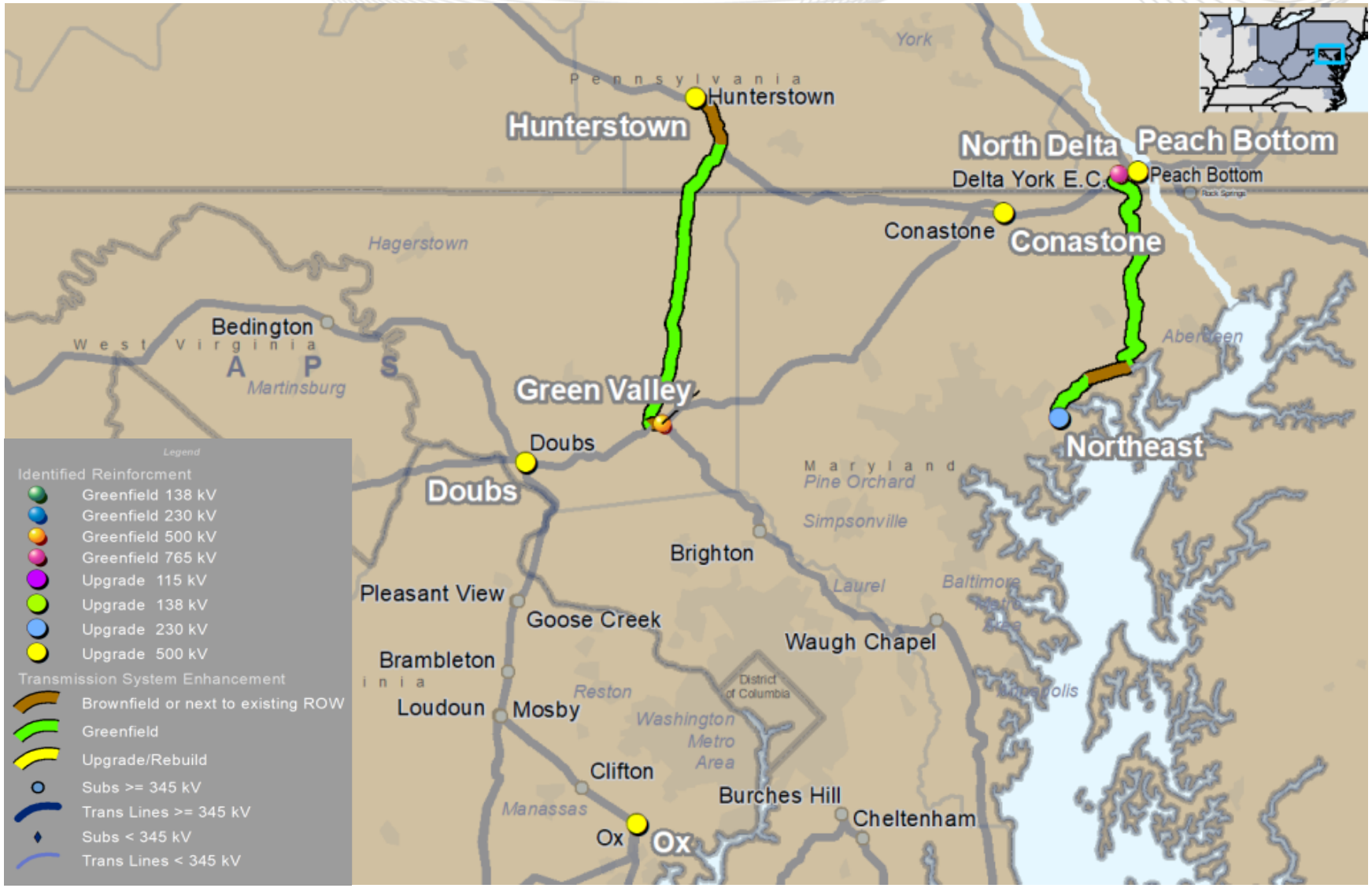
2022 Window 3 proposals – PSEG - 229



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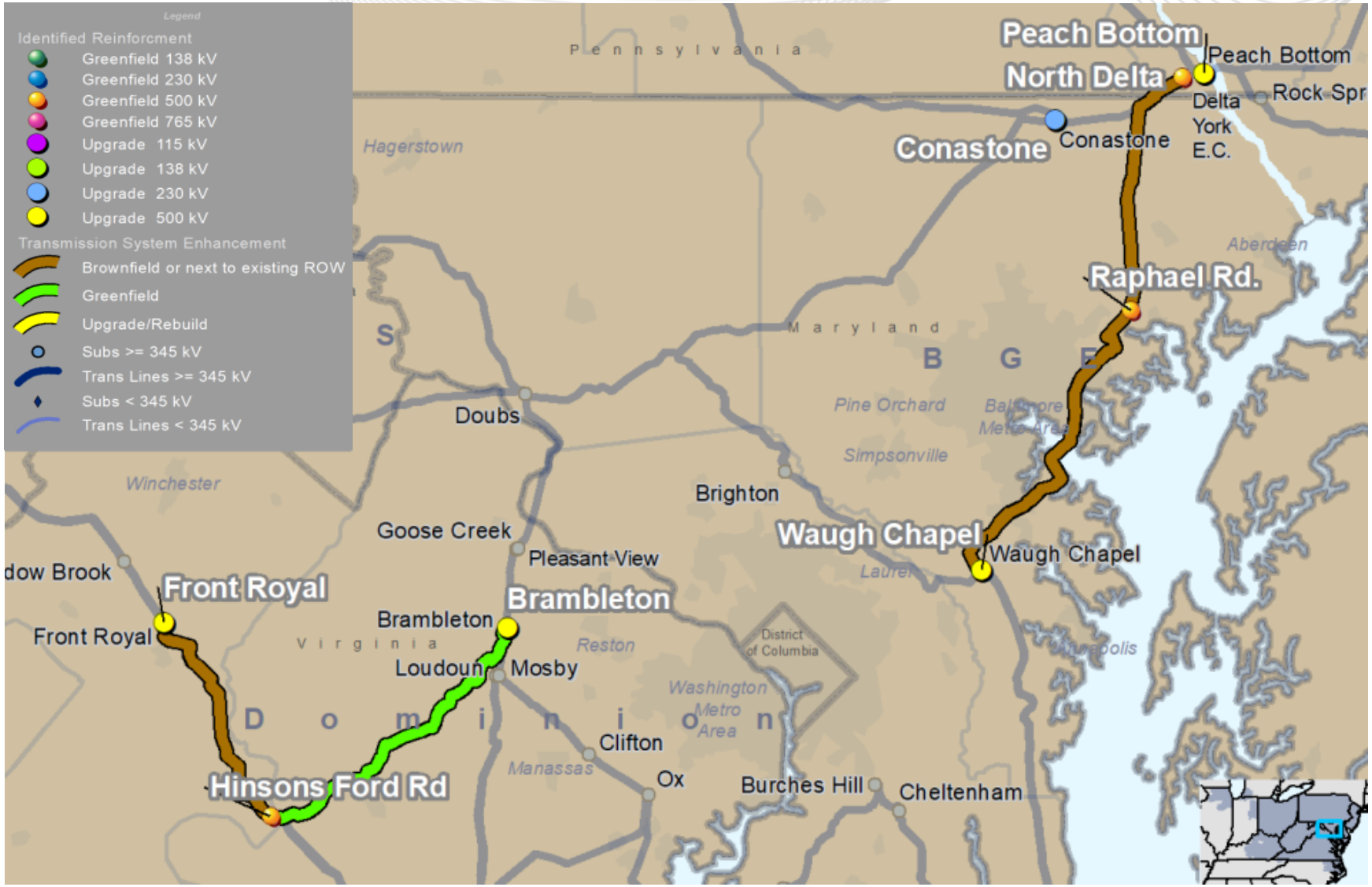
2022 Window 3 proposals – PSEG - 325



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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2022 Window 3 proposals – PSEG - 637

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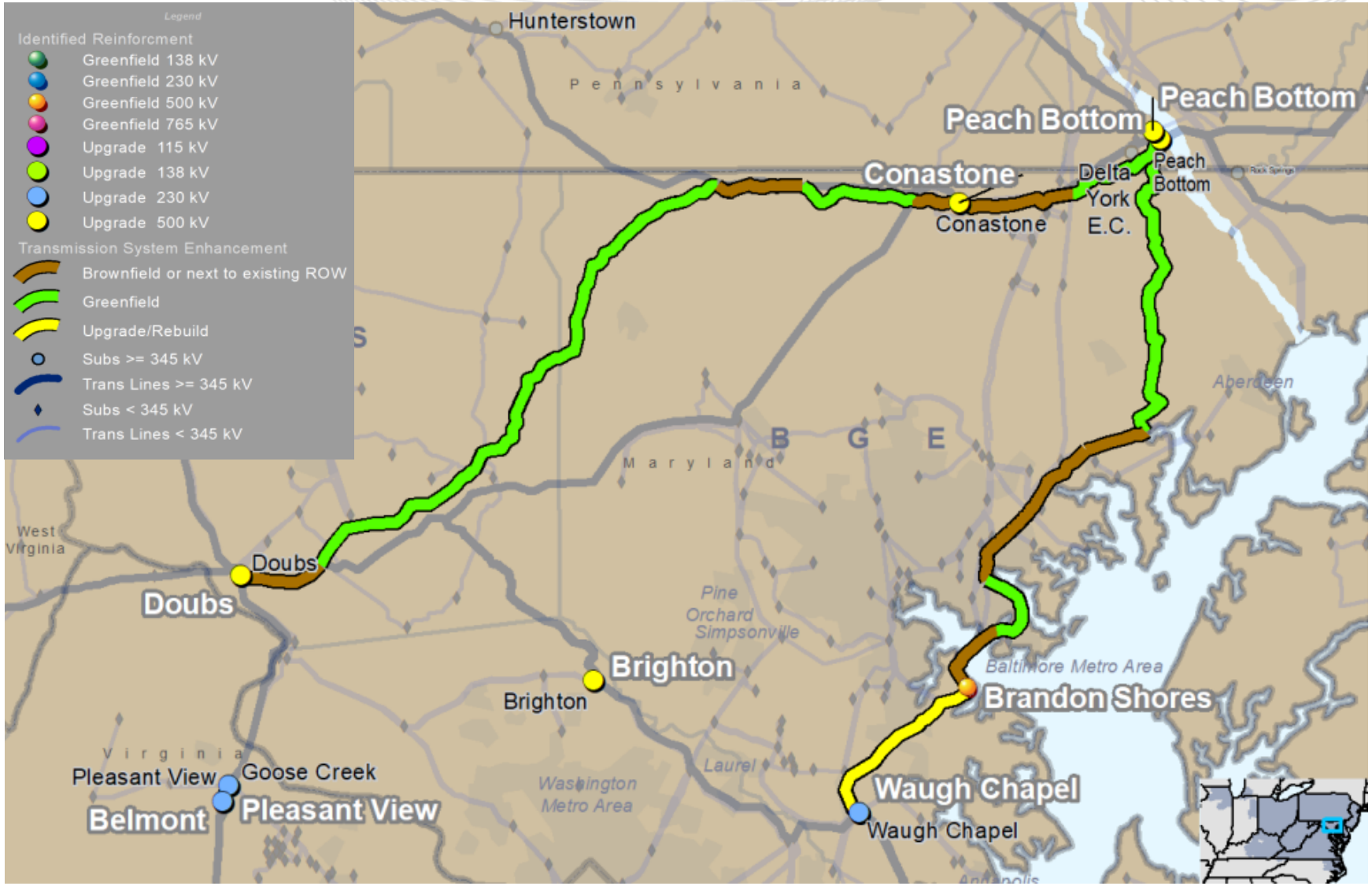
2022 Window 3 proposals – PSEG - 741



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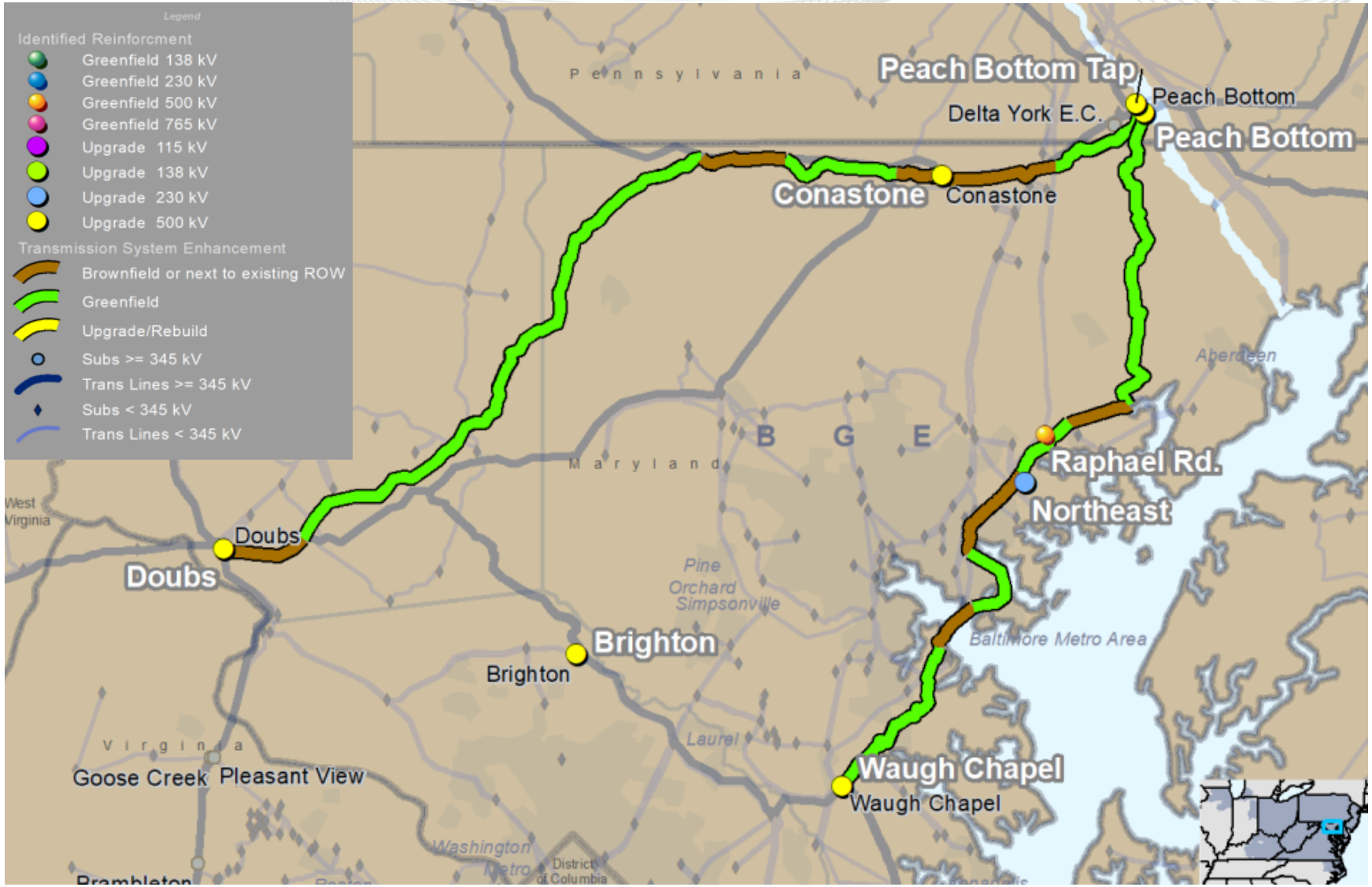
2022 Window 3 proposals – PSEG - 808



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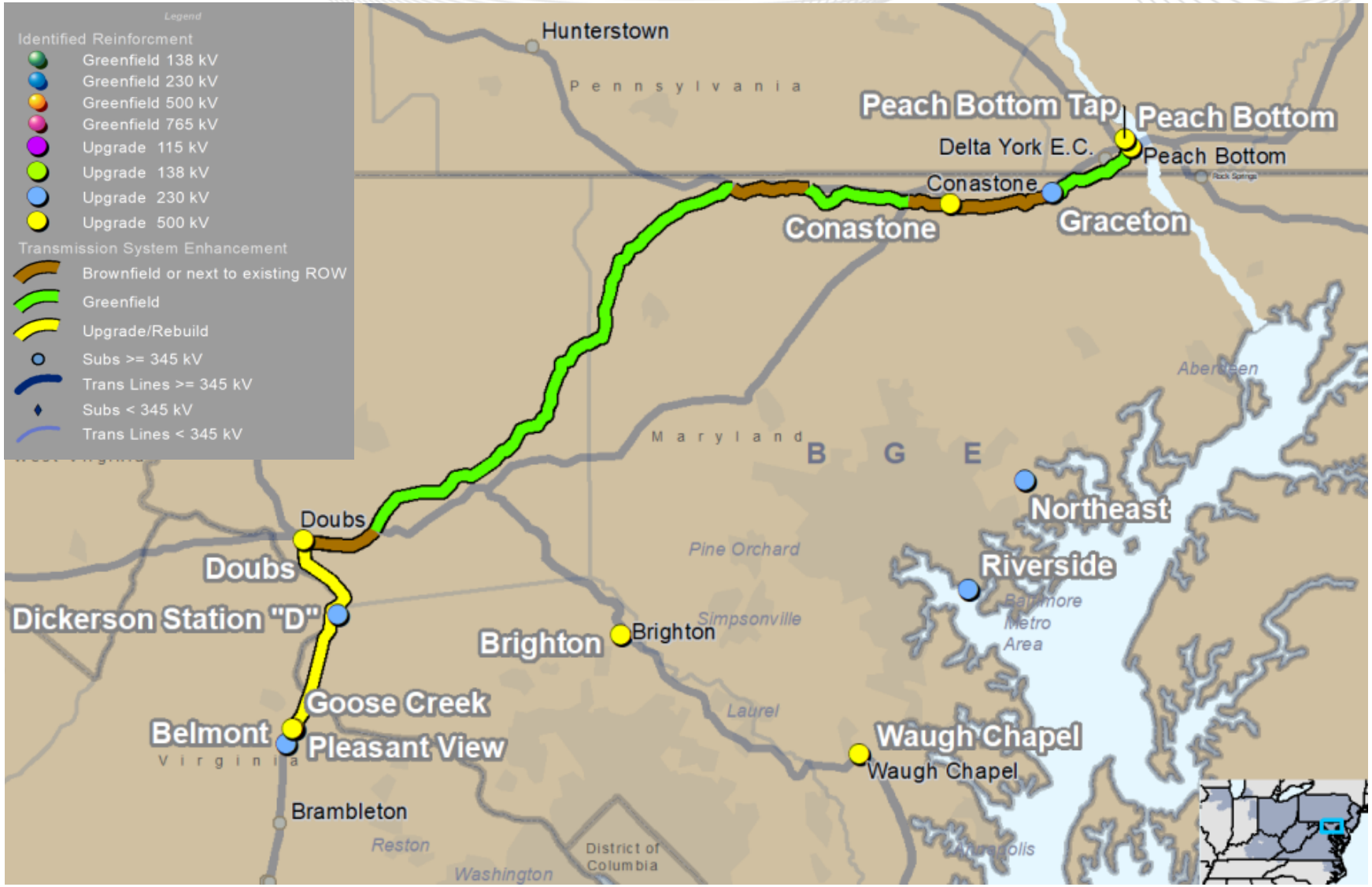
2022 Window 3 proposals – PSEG – 962



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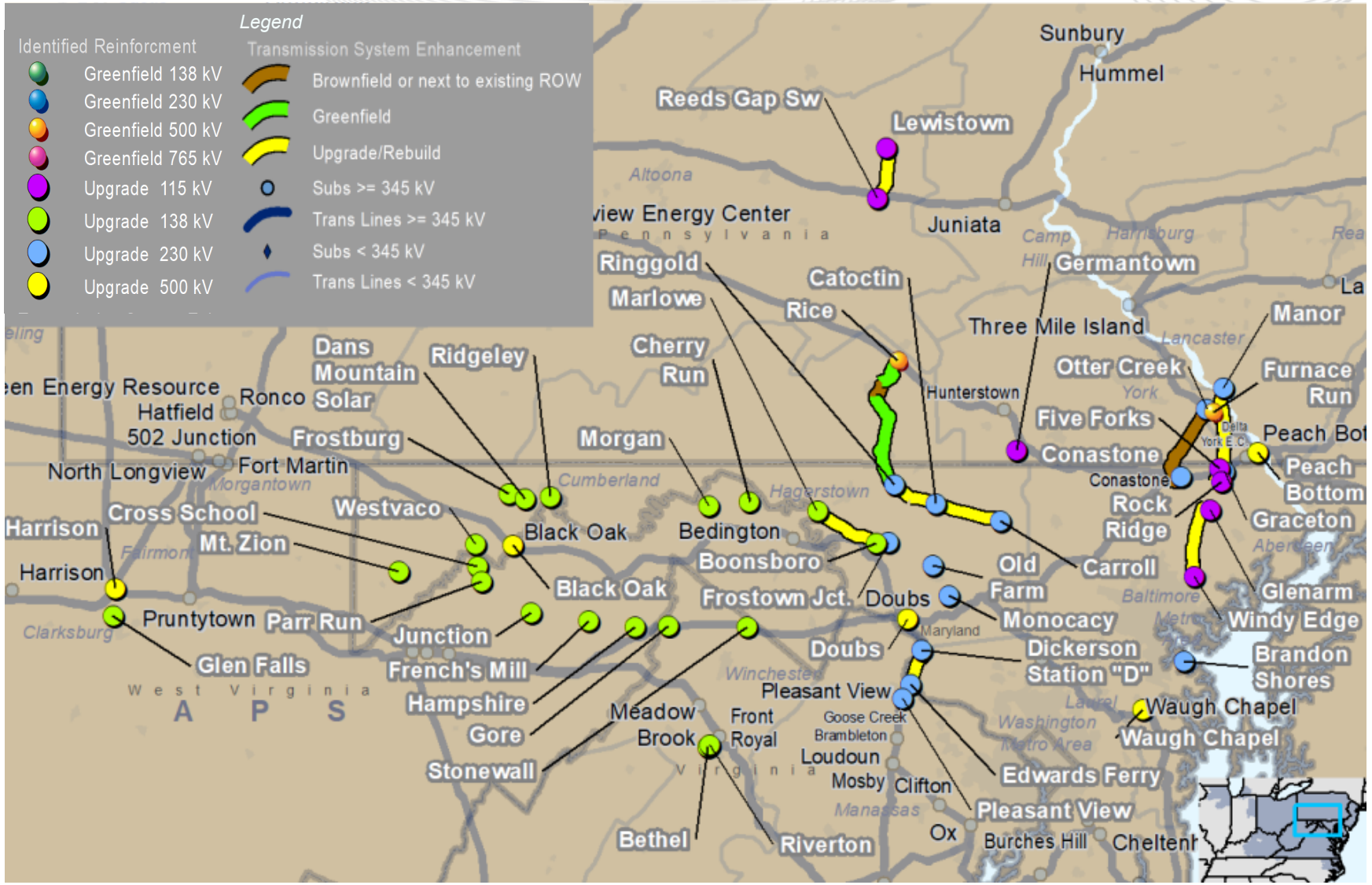
2022 Window 3 proposals – Transource - 487



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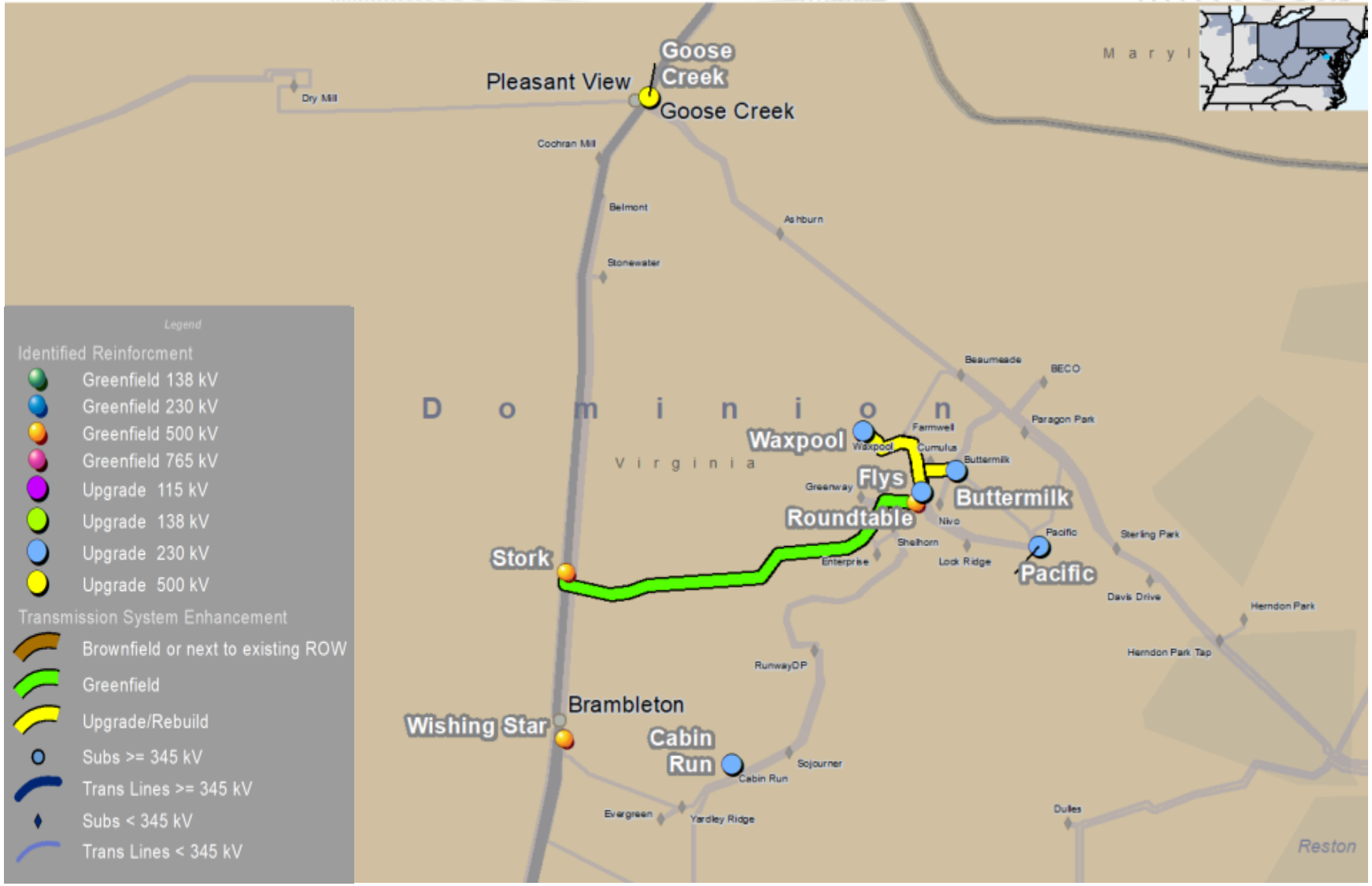
2022 Window 3 proposals – Transource - 858



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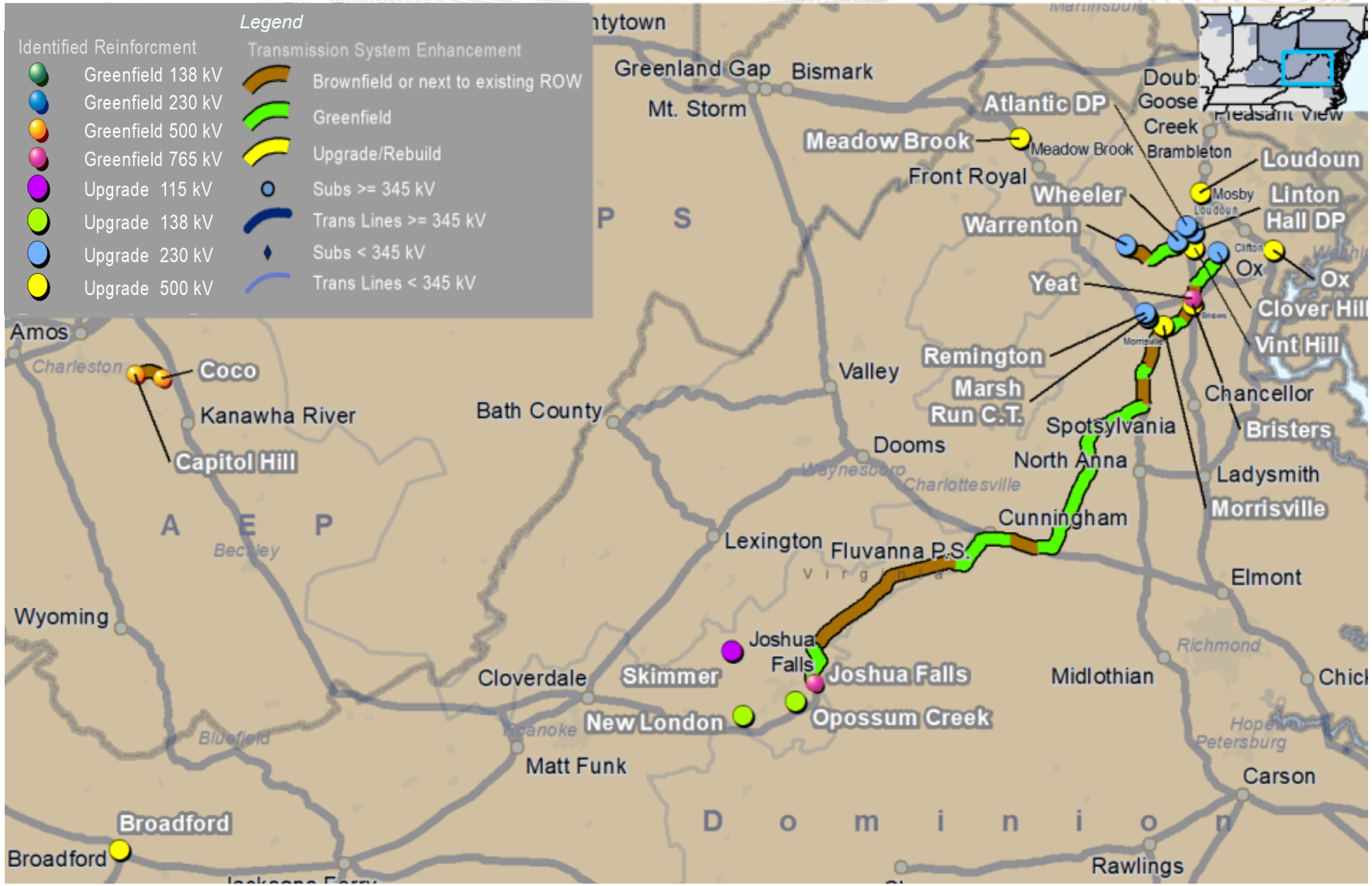
2022 Window 3 proposals – Transource - 904



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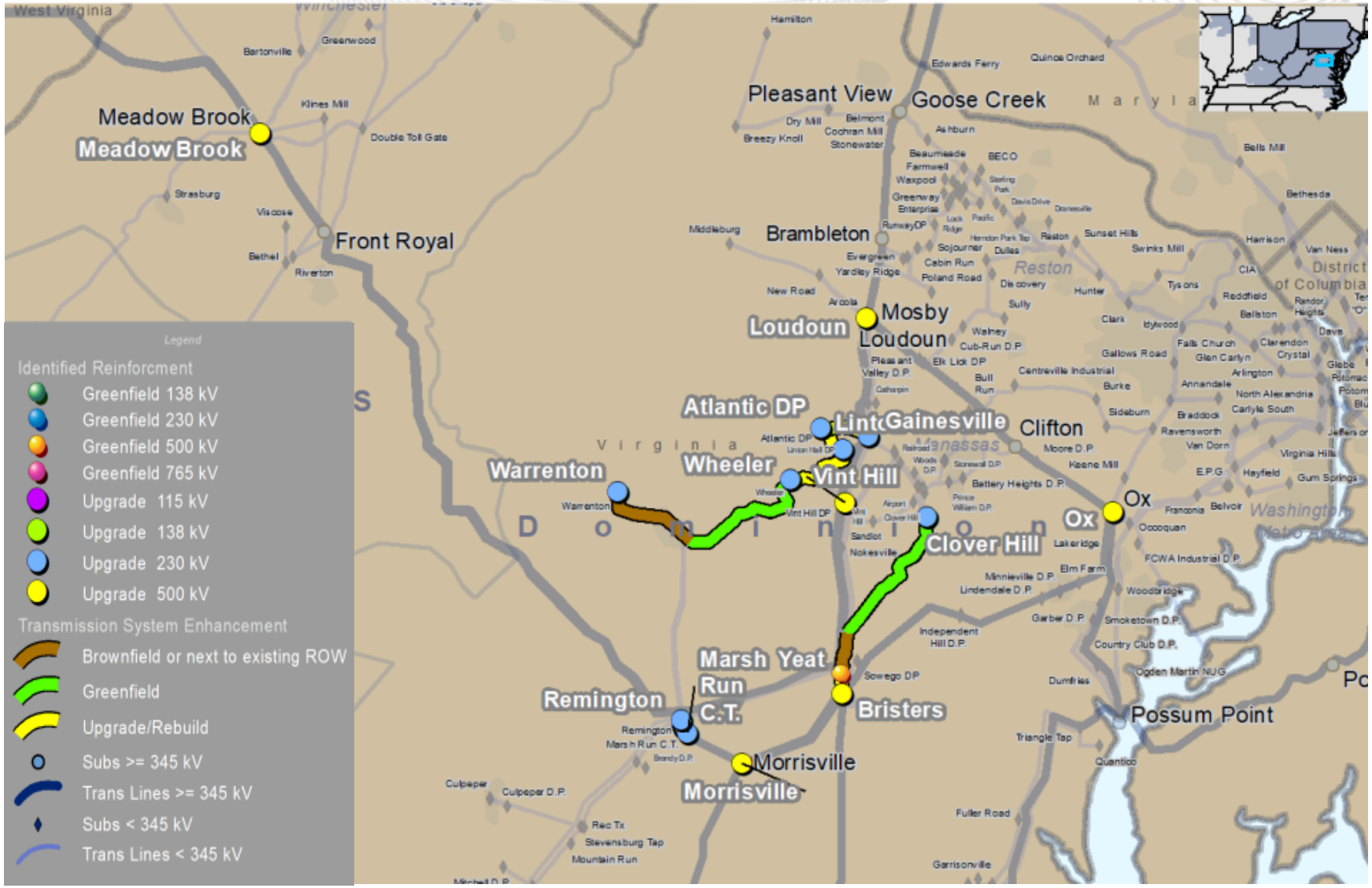
2022 Window 3 proposals – Transource - 977



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Revision History

- V1 – 9/29/2023 – Original slides posted

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Constructability & Financial Analysis Report

2022 RTEP Window 3

November 17, 2023

For Public Use

The information contained herein is based on information provided in project proposals submitted to PJM by third parties through its 2022 RTEP Window 3. PJM analyzed such information for the purpose of identifying potential solutions for the 2022 RTEP Window 3. 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.

This maps contained in this report are only intended to illustrate the general electrical connectivity of the projects and should not be relied upon for exact geographical substation locations or line routes.

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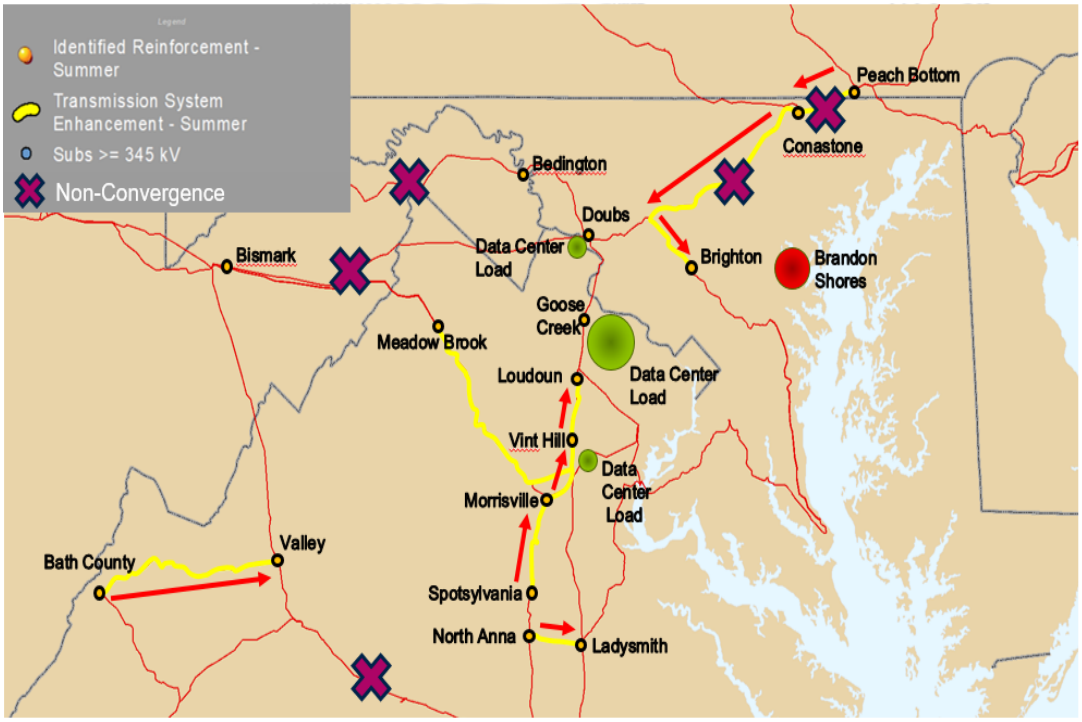
INTRODUCTION

Window Objective

The objective of the 2022 RTEP Window 3 is to develop robust, holistic and expandable solutions that address the 2027/28 baseline violations as illustrated in **Map 1** associated with:

- **Local Constraints:** Resulting from directly serving the data center loads in APS and Dominion zones through the respective 230 kV networks and into the points of delivery:
  - Goose Creek-Ashburn-Mars-Wishing Star and Brambleton
- **Regional Constraints:** Resulting from imports into load center areas (500 kV primarily):
  - Doubs-Goose Creek
  - Front Royal-Morrisville-Vint Hill-Loudoun/Mosby
  - Meadow Brook-Loudoun/Mosby
  - Morrisville-Bristers-Ox
  - Peach Bottom-Conastone-Brighton-Doubs
- **Reactive Power Needs:** Needed reactive power MVAR reinforcements, both static and dynamic as deemed necessary, to address the reactive power needs of the system for the 2027/28 baseline scenario
- **Cummulative Impact of Generation Changes and Deactivations**:
  - 11,100 MW of announced deactivations to the west and south of Conastone
  - Approximately 5,300 MW occurring after the 2022 RTEP 2027 case was created
  - The vast majority of the new generation with signed ISAs has been solar, which has low availability during the winter period.
  - The replacement generation is coming from the region to the east of Peach Bottom as well as west of Doubs to meet projected load growth.
  - PJM has implemented a new block dispatch procedure.
  - The old dispatch procedure in the past (including that implemented in the 2027 study cases) maintained historical intraregional transfers, dispatching most of the generators in the Dominion zone at 100%.
- **Adherance to All Applicable Criteria:** The recommended solution must adhere to all applicable planning criteria, including PJM, NERC, SERC, RFC and local Transmission Owner FERC 715 criteria.

Map 1. 2022 RTEP Window 3 Map of Regional/Local Needs



Proposals Submitted to PJM

PJM received 72 proposals from ten different entities as part of this window. Of the ten proposing entities, six were incumbent Transmission Owners (TOs) and four were non-incumbent entities. PJM received 22 proposals that involve upgrades to existing facilities, and 50 proposals that include new greenfield/brownfield facilities. The total cost of all proposals received, not all of which are required, add up to approximately $50.7 billion. The proposals include:

- 230 kV, 500 kV and 765 kV developments
- HVDC developments
- Underground 500 kV AC cable developments
- 500 kV GIS substations
- Double circuit 500 kV proposals

Proposal Clusters/Groupings

Map 2 below shows the regional nature of the proposals, concentrating in four clusters: West, South, East and Northern Virginia (VA) Data Center areas. Each cluster included proposals by different entities in the same need area and/or addressed the same local/regional needs.

Map 2. Regional Clusters

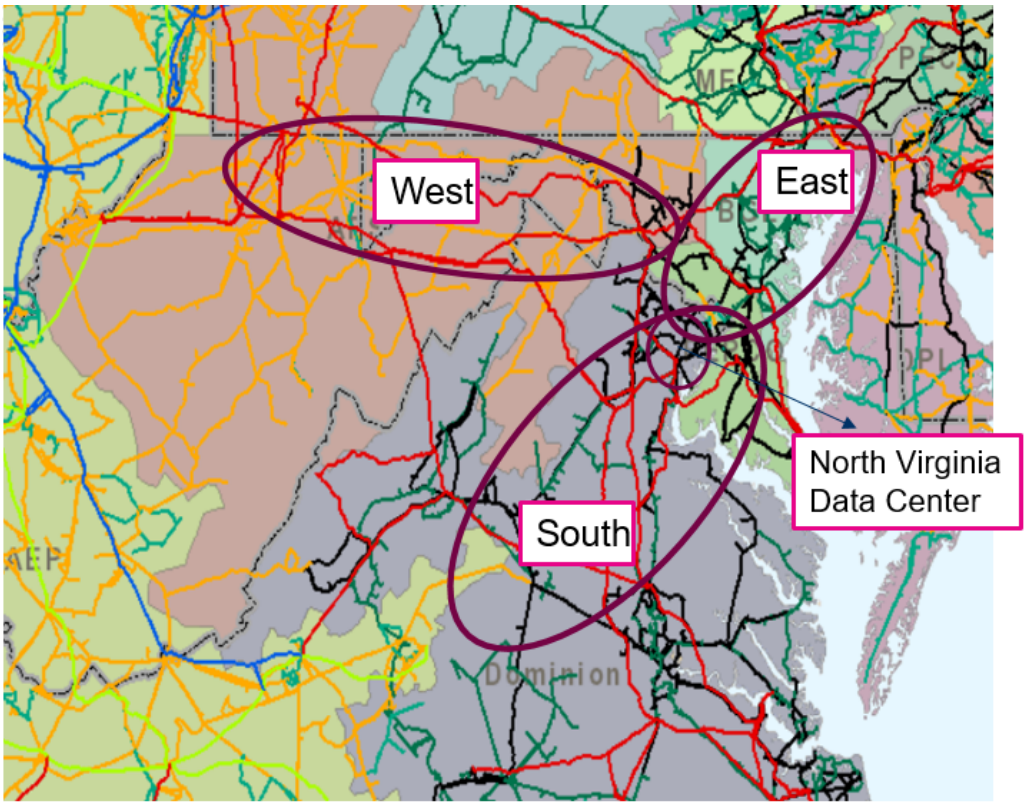


Table 1. 2022 RTEP Window 3 Submitted Proposals

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
1	9	AEP	Local AEP	Scottsville-Bremo Sag Study	$1.27
2	55			Boxwood-Scottsville 138 kV Rebuild	$104.88
3	181			Boxwood-Scottsville 138 kV Sag Study	$4.26
4	196			Glen Lyn-Peters Mountain Rebuild	$21.89
5	202			Cloverdale Transformer Addition	$57.29
6	234			Glen Lyn-Peters Mountain Sag Study	$0.80
7	410			Cloverdale Breaker Reconfiguration	$11.59
8	477			Fieldale-Franklin Rebuild	$74.89
9	524			Opossum Creek and New London Reactors	$8.86
10	537			Fieldale-Franklin Sag Study	$30.19
11	629			Scottsville-Bremo Rebuild	$31.31
12	856			Leesville-Altavista Rebuild	$28.85
13	487	Transource	Combo	Maryland & Pennsylvania Baseline Reliability Solution	$492.75
14	858		Northern VA	Stork-Flys 500 kV Greenfield Line and Substations	$510.44

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
15	904		Combo	Joshua Falls-Yeat 765 kV Greenfield Line and Substation	$1,048.10
16	977		South	Yeat 500/230 kV Greenfield Station	$232.14
17	30	Dominion	Local DOM	Charlottesville-Hollymead Line No. 2054 Rebuild	$159.87
18	74			Line No. 2090 (Ladysmith CT-Fredericksburg) Rebuild	$57.34
19	129		South	Dominion Aggregate 500 kV Proposal	$3,035.05
20	211		Local DOM	Hollymead-Gordonsville Line No. 2135 Rebuild	$54.85
21	231			Reactive Power VAR Reinforcements	$155.82
22	516		East	Interregional solution-Aspen-Doubs Second 500 kV Line	$61.72
23	671		Local DOM	Lines No. 541 (Front Royal to Morrisville) Rebuild	$299.03
24	692		Northern VA	Data Center Alley Local solution-New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	$1,058.45
25	704		Local DOM	Hollymead-Gordonsville Line No. 2135 Rebuild	$36.89
26	711		South	Regional Solution-500 kV North Anna-Wishing Star Upgrades	$1,227.84
27	731		Local DOM	Locks Substation 230/115 kV Transformer Upgrade	$7.14
28	923		South	Second 500 kV line from Lexington to Dooms	$232.18
29	967		Local DOM	Charlottesville-Hollymead Line # 2054 Rebuild	$183.48
30	548	LS Power	Combo	RTEP Window 3 Solution	$2,404.48
31	28	NextEra	West	Hunterstown-Doubs-Goose Creek, Black Oak-Pike-Goose Creek, Pike SVC + Cap Banks	$884.05
32	116			Hunterstown-Doubs-Gant Solution	$478.87
33	175	NextEra	Combo	Combination of PEBO 215A + WOP 1F + SOP 8E	$6,265.95*
34	217		East	North Delta-Conastone Solution	$155.99
35	255		West	Hunterstown-Doubs-Gant Solution	$411.61
36	279		West	Black Oak-Woodside-Goose Creek, Woodside SVC + Cap Banks Solution	$429.18
37	347		West	Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$483.83
38	385		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$1,140.73
39	419		West	Hunterstown-Doubs-Audobon-Goose Creek	$548.75
40	445		East	Muddy Creek/Delta-Conastone/Hunterstown-Doubs-Goose Creek Solution	$637.80
41	530		East	Muddy Creek/North Delta-Conastone Solution	$166.74
42	564		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation	$876.88

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
43	577		South	Front Royal-Racefield, Warrenton-Wheeler, North Anna-Lady Smith	$258.38
44	598		Combo	Combination of PEBO 220 + WOP 1F + SOP 8E	$2,036.47
45	631		East	Muddy Creek/North Delta-Conastone Solution	$184.47
46	642		West	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table	$747.31
47	663		South	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	$284.17
48	676		West	Black Oak-Stonewall-Gant, Stonewall SVC + Cap Banks, Gant-Farmwell, Cochran Tap-Round Table Solution	$552.49
49	685		West	Ft. Martin-Black Oak-Woodside, Woodside SVC + Cap Banks Solution	$609.78
50	719		West	Ft. Martin-Black Oak-Pike, Pike SVC + Cap Banks Solution	$600.90
51	728		West	Barnhart Substation, Bartholow Substation, Barnhart-Bartholow-Goose Creek solution	$385.36
52	766		South	Front Royal-Racefield, Warrenton-Wheeler	$239.59
53	846		West	Hunterstown-Doubs-Goose Creek, Black Oak-Woodside-Goose Creek, Stonewall SVC + Cap Banks	$892.94
54	853		West	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	$683.55
55	948		East	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in	$5,381.25*
56	951	**NextEra**	West	Black Oak-Gore-Goose Creek, Pike SVC + Cap Bank Solution	$419.86
57	344	**PECO**	East	PECO Expansion Plan for DOM Window 2023	$302.86
58	600		Local Other	Exelon Replacement Upgrades	$423.79
59	660	**PEPCO**	East	West Cooper BGE-PEPCO	$1,105.62
60	691			Mid-Atlantic Power Pathway (MAPP)	$1,990.28
61	23	**POTOED-FirstEnergy**	Combo	Data Center Reinforcement Proposal No. 2	$3,503.86
62	837			Data Center Reinforcement Proposal No. 1	$2,991.77
63	374	**PPL**	East	Otter Creek-Conastone 500 and 230 kV double circuit Line	$154.21
64	606		Local Other	Juniata-Lewistown 230 kV No. 2 line	$141.16
65	24	**PSEG**	East	Proposal A-North Delta-New Raphael-Waugh Chapel 500 kV	$739.40
66	125		Local Other	Proposal B-North Delta-Northeast 230 kV	$313.34
67	229		East	Proposal C-Hunterstown-New Green Valley 500 kV	$529.11
68	325		Combo	Proposal E-Brambleton-Hinsons Ford Rd 500 kV	$944.05

#	ID	Proposing Entity	Focus Area	Project Title	Submitted Cost ($M)
69	637		East	Proposal D-Conastone-Doubs 500 kV	$684.22
70	741			Proposal G-Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	$1,065.32
71	808			Proposal F-Peach Bottom-New Raphael-Waugh Chapel 500 kV; Peach Bottom-Doubs 500 kV	$1,150.80
72	962			Proposal H-Peach Bottom-Doubs 500 kV (Circuits No. 1 and No. 2)	$977.71
				Total:	**$54,408.06**

**The NextEra proposal No. 175 cost was increased due to cost revision provided by proposing entity from approximately $1.6 billion to $5.4 billion.*

Overview of Evaluation Approach

Following the submittal of proposals in a competitive planning solicitation, PJM performs technical analysis 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 analysis and screening phase 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. The detailed analysis included reliability, constructability, financial and legal reviews.

As noted in the previous section, PJM received 72 proposals from ten different entities as part of this window – six incumbent Transmission Owners (TOs) and four non-incumbent entities.

PJM performed an initial analysis and screening of all proposals as depicted in **Figure 1**. This phase of analysis also included a minimum of two rounds of PJM meetings with the proposing entities. The first round of meetings was conducted between June and July 2023, with the discussions intended to clarify details of proposed developments, assumptions and rationale of proposed alternatives/variations. The second round of meetings was conducted between July and August, with the focus of these discussions on outage scheduling, routing, risk and an explanation of cost containment mechanisms proposed.

PJM's initial analysis and screening involved generator deliverability screening of proposals for a preliminary understanding of reliability performance, and to ascertain how each proposal and its components may be used as stand-alone solutions or combined with other proposals to address the identified system needs. To aid in this process, PJM organized the proposals into regional clusters (East, West, South and Northern VA Data Center), thereby enabling selection of proposals and their components from each cluster to form holistic scenarios that address the overall system needs.

A select group of proposals were identified for detailed constructability and financial analysis, based on their performance in the initial analysis and screening. These selected proposals were then used to create a number of holistic scenarios to address the overall system needs that were then subject to further evaluation.

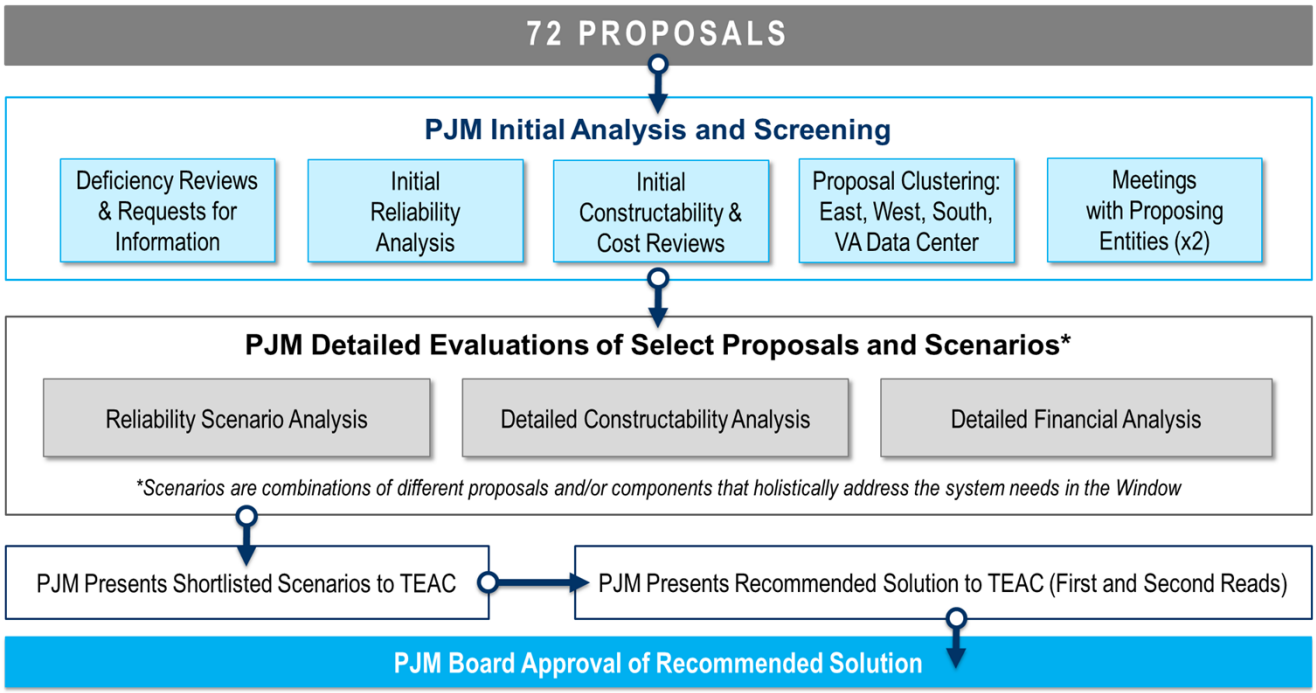
These scenarios, with their associated proposed developments, were evaluated based on the following principles:

- **Performance**
  - Meeting the system needs of 2027 and being flexible to address 2028 needs

- **Scalability**
  - Scenario/development longevity – system robustness and utilization
- **Impact**
  - Utilization of existing Right-of-Way (ROW) where possible and efficient.
- **Validated**
  - Cost evaluation using third-party benchmarking metrics
- **Risks**
  - Triggering additional costs:
    - Substation rebuilds due to extreme short-circuit levels
  - Avoid extended critical outages (Peach Bottom/Conastone rebuilds)
    - Imposing high permitting
    - Inability to meeting required in-service date
- **Efficiencies**
  - Avoidance of redundant capital investment including recognizing synergies with EOL facilities and overlaps of previously approved (or imminent) supplemental/baseline upgrades

The scenarios were developed and tested to first address the regional needs, then were refined through new scenarios to address local needs. Scenarios were further refined using more effective proposal components as demonstrated through their performance in the analysis.

Figure 1. Evaluation Process Overview



Proposals Selected for Detailed Evaluations

East Proposal Cluster

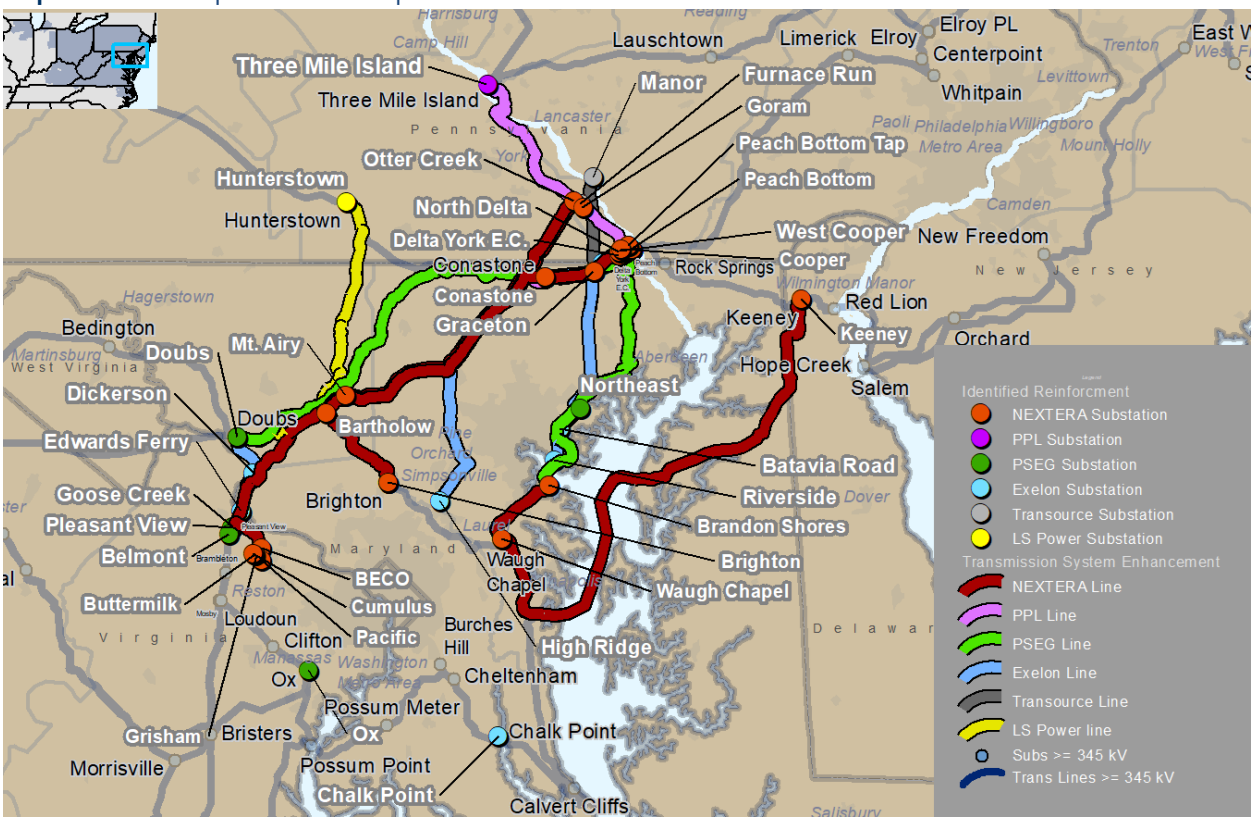
Seven entities submitted proposals to address the East cluster violations, and the selected proposals for detailed evaluations are provided in **Table 2** and **Map 3** below.

Table 2. East Proposal Cluster

PJM Proposal ID	Proposing Entity	Project Title	Component ID	Component Name
344	Exelon (PECO)	PECO Expansion Plan for DOM Window 2023	1	New 500 kV 4 Leg Breaker and a Half Substation (West Cooper): PECO
			2	New 230 kV Line from Cooper to West Cooper: PECO
			4	Peach Bottom North (PECO)-Graceton (BGE) New 500 kV Line: PECO Portion

PJM Proposal ID	Proposing Entity	Project Title	Component ID	Component Name
344 Cont.			5	West Cooper-Peach Bottom South New 500 kV Line: PECO
			6	Rebuild 5012 500 kV Line and Cut-in West Cooper (Peach Bottom South-West Cooper): PECO
			7	Rebuild 5012 500 kV Line and Cut-in West Cooper (Graceton-West Cooper): PECO Portion
			8	New Breaker and a Half Leg at Peach Bottom North: PECO
			10	West Cooper (PECO)-High Ridge (BGE) New 500 kV Line: PECO Portion
			14	Calpine-Peach Bottom South 500 kV Line Cut In: PECO
			15	Peach Bottom South Substation Bypass: PECO
660	Exelon (BGE-PEPCO)	West Cooper BGE-PEPCO	All	All
548 (East)	LS Power	RTEP Window 3 Solution-East Components	10	Conastone Substation Upgrade
			13	Hunterstown Substation Upgrade
			14	North Delta Substation Upgrade
			21	Peach Bottom Substation Upgrade
			23	Conastone-Peach Bottom Rebuild
			27	Hunterstown-Doubs Greenfield 500 kV Transmission Line
			32	Hunterstown-Doubs Greenfield 500 kV Transmission Line (Shared ROW)
			35	Conastone-North Delta Greenfield 500 kV Transmission line (Shared ROW)
			37	Peach Bottom-North Delta Reconductor
637	PSEG	Proposal D-Conastone-Doubs 500 kV	All	All
741	PSEG	Proposal G-Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	All	All
487	Transource	Maryland & Pennsylvania Baseline Reliability Solution	All	All
374	PPL	Otter Creek-Conastone 500 and 230 kV double circuit Line	All	All
948	NextEra	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.	All	All

Map 3. East Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

West Proposal Cluster

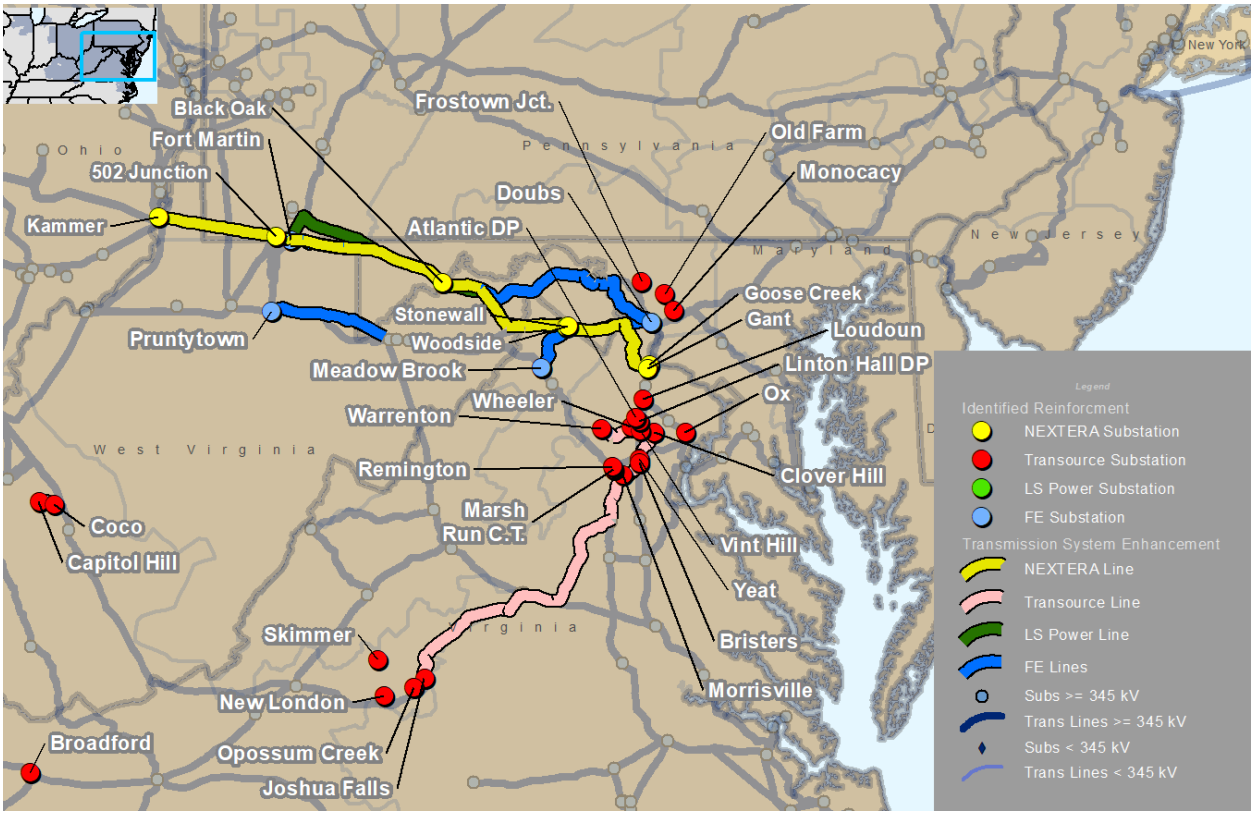
Four entities submitted proposals to address the West cluster violations, and the selected proposals for detailed evaluations are provided in **Table 3** and **Map 4** below.

Table 3. West Proposal Cluster

PJM Proposal ID	Proposing Entity	Project Title	Component ID	Component Name
837 (West)	POTOED – FirstEnergy	Data Center Reinforcement Proposal No. 1	1	Doubs Substation – Install 500 kV Breaker
			2	Doubs Substation – Expand 500 kV Switchyard
			3	Meadow Brook Substation - Expand 500 kV Switchyard
			4	Fort Martin Substation – Install 500 kV Breaker
			5	Pruntytown Substation – Expand 500 kV Switchyard
			6	Bedington Substation – Rebuild & Install 600 MVAR STATCOM
			7	Fort Martin-Doubs 500 kV No. 1 Line
			8	Meadow Brook-Doubs 500 kV Line

PJM Proposal ID	Proposing Entity	Project Title	Component ID	Component Name
837 (West) Cont.			9	Meadow Brook-Pruntytown 500 kV Line
			10-13	Relaying Upgrades – Various Stations
			14,15	Overduty Breaker Replacements – Doubs & Pruntytown
			18-30	Carroll-Hunterstown 230 kV Line
548 (West)	LS Power	RTEP Window 3 Solution – West Components	7	502 Junction Substation Upgrade
			9	Black Oak Substation Upgrade
			11	Doubs Substation Upgrade
			25	502 Junction-Black Oak 500 kV Transmission Line
			26	Black Oak-Doubs Greenfield 500 kV Transmission Line
			29	Black Oak-Doubs Greenfield 500 kV Transmission Line (Shared ROW)
853	NextEra	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	All	All
904	Transource	Joshua Falls-Yeat 765kV Greenfield Line and Substation	All	All

Map 4. West Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

South Proposal Cluster

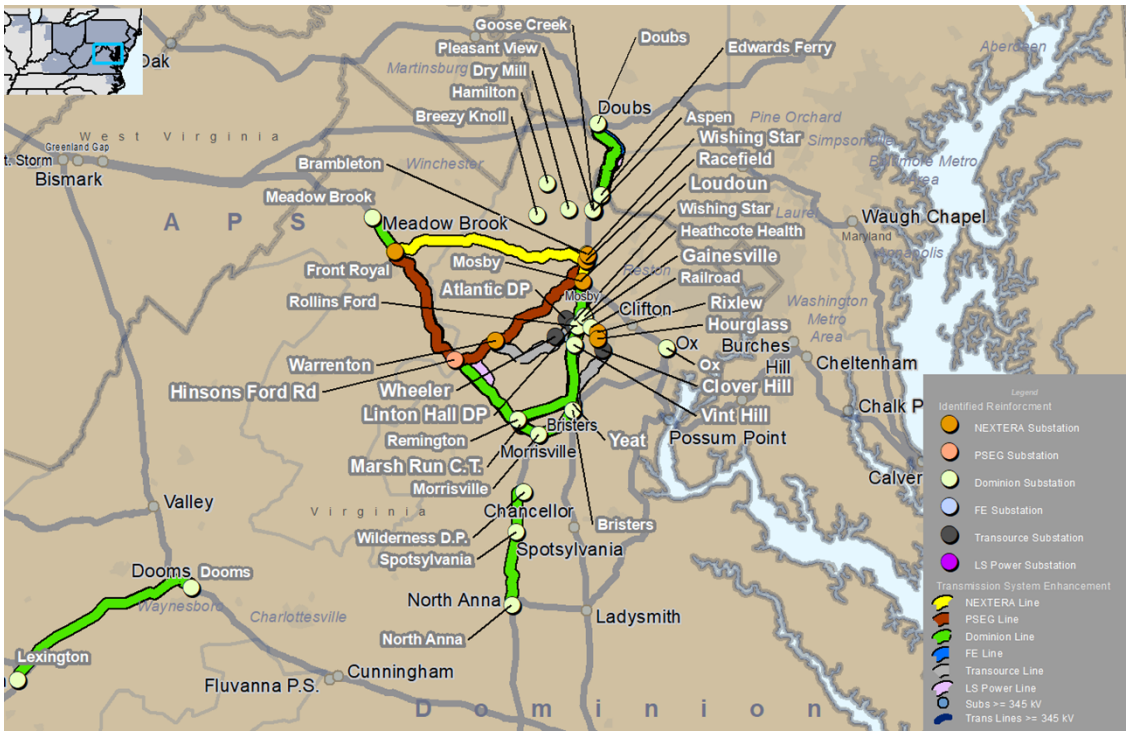
Five entities submitted proposals to address the South cluster violations, and the selected proposals for detailed evaluations are provided in **Table 4** and **Map 5** below.

Table 4. South Proposal Cluster

PJM proposal ID	Proposing Entity	Project Title	Component ID	Component Name
516	**Dominion**	Interregional solution-Aspen-Doubs Second 500 kV Line	**All**	All
711	**Dominion**	Regional Solution-500 kV North Anna-Wishing Star Upgrades	**All**	All
548 (South)	**LS Power**	RTEP Window 3 Solution	**12**	Goose Creek Substation Upgrade
			15	Vint Hill Substation Upgrade
			22	Vint Hill-Loudoun Reconductor

			28	Doubs-Goose Creek Greenfield 500 kV Transmission Line
			30	Front Royal Substation Upgrade
			33	Doubs-Goose Creek Greenfield 500 kV Transmission Line (Shared ROW)
			34	Front Royal-Vint Hill Greenfield 500 kV Transmission Line
325	**PSEG**	Proposal E-Brambleton-Hinsons Ford Rd 500 kV	**9**	New Brambleton to Hinsons Ford Rd 500 kV Line
			10	Reconductor Front Royal-Hinson Ford Rd 500 kV
			12	Hinsons Ford Rd 500 kV
837 (South)	**POTOED - FirstEnergy**	Data Center Reinforcement Proposal No. 1	**16**	Doubs-Goose Creek 500 kV Rebuild
			17	Doubs-Aspen 500 kV Line
663	**NextEra**	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	**All**	All

Map 5. South Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

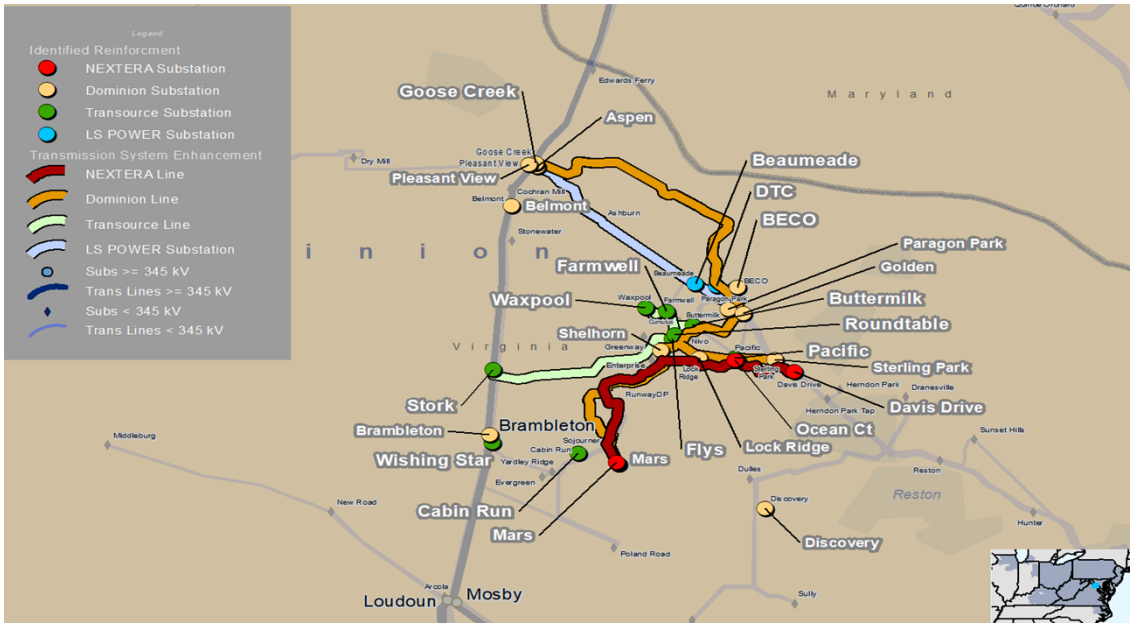
Northern VA Data Center Proposal Cluster

Three entities submitted proposals to address the Northern VA Data Center cluster violations, and the selected proposals for detailed evaluations are provided in **Table 5** and **Map 6** below.

Table 5. Northern VA Data Center Cluster

PJM Proposal ID	Proposing Entity	Project Title	Component ID	Component Name
692	Dominion	Data Center Alley Local solution – New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	**All**	All
858	Transource	Stork-Flys 500 kV Greenfield Line and Substations	**All**	All
548 (Dominion)	LSPower	RTEP Window 3 Solution	**8**	Beaumeade Substation Upgrade
			16	DTC Substation Upgrade
			17	Mars Substation Upgrade
			24	Beaumeade-BECO-DTC 230 kV Transmission Line Upgrade
548 (Dominion) Cont.			**31**	BECO Substation Upgrade
			36	Goose Creek-Beaumeade Greenfield Underground 500 kV Double Circuit Transmission Line

Map 6. Northern VA Data Center Proposal Cluster Map



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

CONSTRUCTABILITY ANALYSIS

Approach

The following is an outline of PJM and its consultant's approach for detailed constructability analysis of the selected 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.

The following target information will be referenced by as required and as allowable by available public data sources:

- National Wetland Inventory mapping from United States Fish and Wildlife Service (USFWS), which will include counts and acreages of:
  - Total Wetlands
  - Non-Tidal (Non-Forested) Wetlands
  - Non-Tidal (Forested) Wetlands
  - Total Non-Tidal Wetlands
  - Wetlands of Special State Concern
  - Subaqueous Lands
- Mapping of specially designated wetlands, streams or rivers, which will include:
  - Non-Tidal Waterbodies (Count/Acres)
  - 100-Year Flood Plain (Acres)
  - Watershed Boundaries (Count)
  - Outstanding and Exceptional Waters (Count)
  - Wild and Scenic Rivers (Count
  - United States Geologic Survey Blue Line Streams (Count)
- United States Department of Agriculture(USDA)/The Natural Resources Conservation Service (NRCS) Land Cover mapping, which will include acreages of:
  - Sub-Aquatic Vegetation
  - Forested Uplands
  - Unforested Uplands
  - Agricultural Lands
- Land Use Mapping, which will include:
  - Residences within 100 feet (Count)
  - Residences within 250 feet (Count)
  - Land Zoned Conservation (Acres)
  - Rural Legacy (Acres)
  - Program Open Space (Acres)
  - Private Conservation Easements (Acres & Count)
  - Public Land (Acres & Count)
  - Parcels Crossed (Count)
  - Green Infrastructure/Green Acres program (Acres)
  - National Estuarine Research Reserve Project Areas (Acres & Count)
  - Natural Heritage Areas (Acres & Count)
  - Environmental Trust Easements (Acres & Count)
  - Forest Legacy Easements (Acres & Count)
  - Tidelands

- Public Lands Mapping Review, which will include the types, counts and acreages of the following:
  - State/National Forests
  - Natural Areas
  - Preserves
  - Game Lands
  - Recreation Areas
- Cultural Resources Mapping Review, including the count of previously identified resources, which will include the types, counts, and acreages of the following:
  - Listed and Eligible Historic Structures
  - Listed and Eligible Historic Districts
  - Listed and Eligible Archeological Sites
- Aquatic Resource Mapping, including the count of Submerged Historic Resources (if applicable)
- Online distribution data of rare, threatened and endangered species within a 0.5 mile radius of the study area
- Major utility and transportation (roads and rail lines) corridors

(b) Identify those permits and agency consultations that are complex and require long lead times, therefore, potentially significantly affecting 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, 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. Anticipated permit requirements may include the following:

- U.S. Army Corps of Engineers (USACE) – Section 404 Clean Water Act and Section 10 Rivers and Harbors Act
- U.S. Fish and Wildlife Service (USFWS) – Section 7 Endangered Species Act, Migratory Bird Treaty Act, and Bald and Golden Eagle Protection Acts
- U.S. Forest Service – National Forest Special Use Permit and Archaeological Protection Resources Act
- National Oceanic and Atmospheric Administration (NOAA) National Marine Fisheries Service – Magnuson-Stevens Fishery Conservation and Management Act (MSA)
- U.S. Bureau of Ocean Energy Management
- U.S. Bureau of Land Management – ROW Grant and Archaeological Protection Resources Act
- Federal Aviation Administration (FAA) – Obstruction Determination and FAA Hazard Evaluation
- U.S. Coast Guard – Aids to Navigation
- State Commission approvals
- State Agency – Rare, threatened, and endangered species issues and clearance requirements
- State Historic Preservation Office (SHPO) and clearance requirements
- State Agency – Section 401 Water Quality Certifications and other applicable water permits
- State Agency – National Pollutant Discharge Elimination System permit
- Local and/or State floodplain permit requirements
- State Department of Transportation and clearance requirements

(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, ROWs 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 seven (8) categories, as required: materials and equipment; engineering and design; construction and commissioning; permitting/routing/siting; right of-way (ROW)/land acquisition; construction management; company overheads and other miscellaneous costs; and project contingency (30%).

Analysis Results

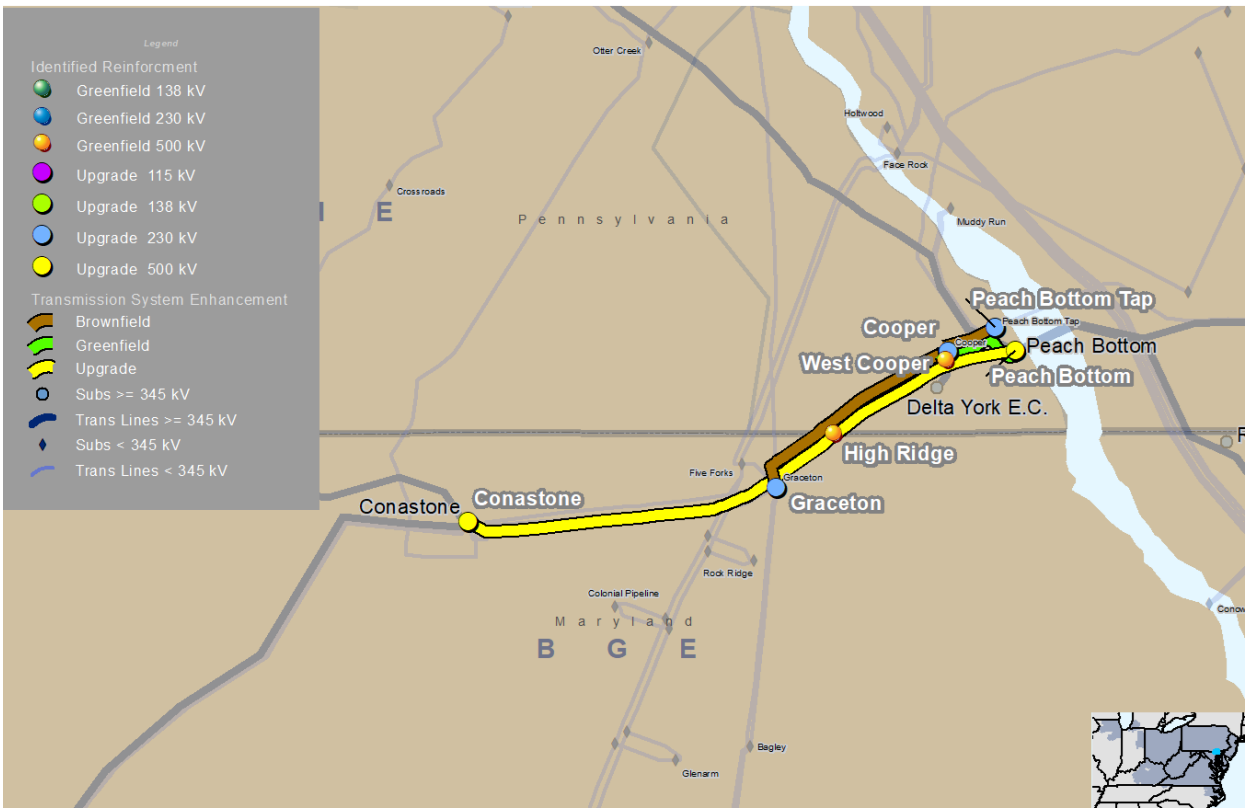
The following sections outline the results of PJM and its consultants' detailed constructability evaluations performed on select proposals and their components organized into the regional clusters defined by PJM. These results are also the basis for the Constructability Risk Assessment matrices that are included in **Appendix A** – Constructability Matrices of this report.

East Proposal Cluster

Proposal 344 – Exelon (PECO)

Proposal No. 344 (**Map 7**), described as PECO Expansion Plan for DOM Window 2023, is located within York, Lancaster and Chester counties, Pennsylvania, and includes the construction of several new lines and other distribution components. The majority of the components will be developed within existing ROWs. The proposed components will traverse within York County, Pennsylvania. Proposal No. 344 comprises the PECO portion of Exelon's West Cooper Max solution and is intended to be combined with Proposal No. 660, the BGE/PEPCO portion of Exelon's West Cooper Max solution.

Map 7. Proposal 344



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Proposal No. 344 includes seventeen components, representing two alternative solutions proposed by Exelon:

- The primary West Cooper Max solution, which involves building a new West Cooper 500/230 kV substation by cutting into and reconfiguring several 500 kV lines near Cooper substation, rebuilding the 5012 Peach Bottom-Conastone 500 kV, and building two new 500 kV lines from Peach Bottom to Graceton and the new West Cooper to High Ridge
- The alternative Peach Bottom Expansion solution, which involves expanding Peach Bottom substation to build two new 500 kV lines to Graceton (BGE) and High Ridge substation by retiring the 220-93 Cooper to Graceton to utilize the existing ROW, and also building new 230 kV substation to serve Cooper by cutting into existing 220-07 Muddy Run-Peach Bottom 230 kV line and building new line to Cooper, and rebuild of the 5012 Peach Bottom-Conastone 500 kV line

From Proposal 344, based on PJM's initial screening and analysis, only the 10 out of the 17 components associated with the West Cooper Max solution were selected for the detailed evaluations. These components are as follows:

- Component 1: New 500 kV 4 Leg breaker-and-a-half substation (West Cooper): PECO
- Component 2: New 230 kV line from Cooper to West Cooper: PECO

- Component 4: Peach Bottom North (PECO)-Graceton (BGE) new 500 kV line: PECO portion
- Component 5: West Cooper-Peach Bottom South new 500 kV line: PECO
- Component 6: Rebuild 5012 500 kV line and cut-in West Cooper (Peach Bottom South-West Cooper): PECO
- Component 7: Rebuild 5012 500 kV line and cut-in West Cooper (Graceton-West Cooper): PECO portion
- Component 8: New breaker-and-a-half leg at Peach Bottom North: PECO
- Component 10: West Cooper (PECO)-High Ridge (BGE) new 500 kV line: PECO portion
- Component 14: Calpine-Peach Bottom South 500 kV line cut in: PECO
- Component 15: Peach Bottom South substation bypass: PECO

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Peach Bottom North (PECO)-Graceton (BGE) New 500 kV Line: PECO Portion

This component of the proposal is for PECO's approximately 5.5-mile portion of greenfield 500 kV overhead transmission line from Peach Bottom North substation heading toward the Graceton substation. The line will travel through new ROW parallel to the existing Peach Bottom-Conastone 5012 500 kV line ROW for about 1.6 miles between Peach Bottom North and Cooper, transitioning to existing ROW from Cooper to Graceton by rebuilding Cooper to Graceton 230 kV line up to the Maryland/Pennsylvania state line. The line continues on to Graceton under BGE's portion of the line as part of Proposal 660.

West Cooper-Peach Bottom South New 500 kV Line: PECO

This component of the proposal is for an approximate 2.5-mile portion of 500 kV overhead transmission line from Peach Bottom South substation to the new West Cooper substation. The line will travel within new ROW between Peach Bottom South and West Cooper parallel to the existing Peach Bottom-Conastone 5012 500 kV line ROW. As proposed, the project will repurpose existing tie No. 1 transmission line between Peach Bottom North and Peach Bottom South; this is an additional feed line to West Cooper.

West Cooper (PECO)-High Ridge (BGE) New 500 kV Line: PECO Portion

This component of the proposal is for an approximate 4-mile portion of 500 kV greenfield overhead transmission line from the new West Cooper substation heading toward the expanded High Ridge substation. The line will travel on single circuit structures within existing ROW created by the demolition of Cooper to Graceton 230 kV and rebuild of Peach Bottom to Conastone 5012 500 kV line up to the Maryland/Pennsylvania state line. The line continues on to High Ridge under BGE's portion of the line as part of Proposal 660.

Overall, the ROW risk for components of this proposal is low, with extensive usage of existing ROWs for most of its alignment. It is anticipated that the proposal could require permits, consultations, clearances and authorizations from York County in Pennsylvania. State PSC Approval, CPCN and DOT utility permits and driveway/local road permits may be required.

Environmental Risk Analysis

Peach Bottom North (PECO)-Graceton (BGE) New 500 kV Line: PECO Portion

Wetlands, waterbodies and high-risk flood zones appear to be crossed by the proposed line routes. The routes intersect seven waters that are subject to USACE Section 404 permitting. An on-site delineation would be required to

determine the actual location and extent of wetlands and waterbodies present and to assess permitting implications for jurisdictional features.

The proposed project components are within the range of both federally and state-listed species. The majority of the proposed routes are in woodlands. Construction restrictions, time frame, or mitigation may be necessary to comply with avoidance of sensitive species; however, the extent of which cannot be known until field studies are completed, and coordination with the USFWS and state wildlife agencies takes place.

Proposed routes intersect with protected areas (Private Easements). Coordination with NRCS Admin State PA; Pennsylvania State Government; and Pennsylvania Department of Agriculture – Farmland Preservation Program may be required.

Overall, the constructability risk for components of this proposal is low, with extensive usage of existing ROWs for most of its alignment.

Transmission Line Risk Analysis

Given the extensive reuse of existing ROW for this proposal, transmission line construction risks are low and limited to concerns with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence, and potential design limitations for reuse of existing infrastructure/assets.

A medium risk for this project involves the existing facility outages that will be necessary for the project, particularly for the extensive line rebuilds and substation expansions. To mitigate these risks, Exelon provided a detailed schedule outlining a sequence of construction that will ensure that new brownfield transmission lines are energized within the corridor prior to the rebuild of existing facilities that will require lengthy outages.

Substation Risk Analysis

New West Cooper 500/230 kV Substation

The West Cooper substation is a proposed new 500/230 kV breaker-and-a-half substation in York County, Pennsylvania that would tie into two existing 500 kV lines and one existing 230 kV line in the area. The proposed substation will be a four bay breaker-and-a-half air-insulated 500 kV substation with 14, 5000A, 500 kV live tank circuit breakers, and a new 200 MVA, 500/34.5/13 kV autotransformer that will feed the new Cooper distribution substation.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, if selected, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 6**.

Table 6. Proposal 344 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	New 500 kV 4 Leg Breaker and a Half Substation (West Cooper): PECO	68.75	93.88
2	New 230 kV Line from Cooper to West Cooper: PECO	1.96	2.98
4	Peach Bottom North (PECO)-Graceton (BGE) New 500 kV Line: PECO Portion	13.05	30.39
5	West Cooper-Peach Bottom South New 500 kV Line: PECO	5.50	9.40
6	Rebuild 5012 500 kV Line and Cut-in West Cooper (Peach Bottom South-West Cooper): PECO	7.86	13.09
7	Rebuild 5012 500 kV Line and Cut-in West Cooper (Graceton-West Cooper): PECO Portion	29.86	22.26
8	New Breaker and a Half Leg at Peach Bottom North: PECO	25.93	22.99
10	West Cooper (PECO)-High Ridge (BGE) New 500 kV Line: PECO Portion	13.36	16.45
14	Calpine-Peach Bottom South 500 kV Line Cut In: PECO	1.57	1.75
15	Peach Bottom South Substation Bypass: PECO	0.79	1.64
	Total	**168.63**	**214.81**

The total proposal cost estimate is within 10–20% of the independent cost estimate and is considered medium risk.

Schedule Review

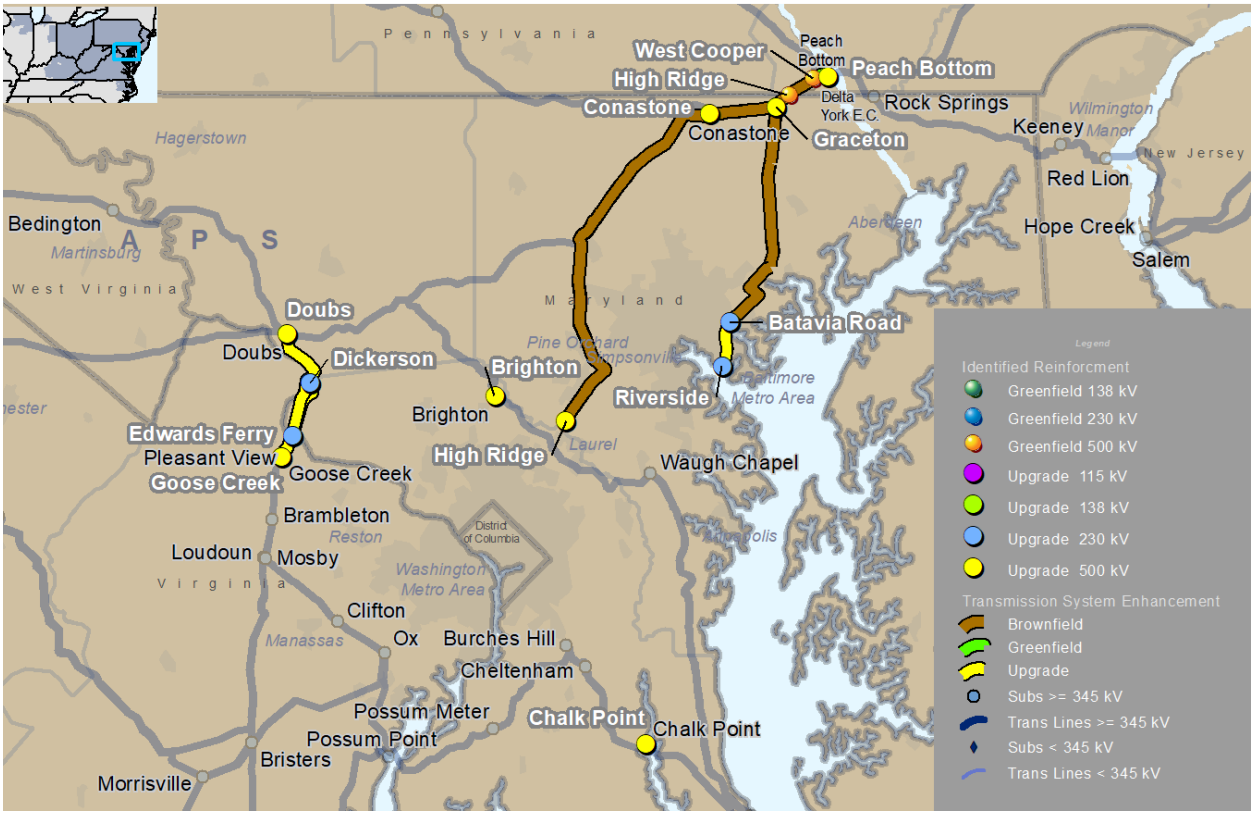
The proposed in-service date of December 2029 is reasonable for the proposed scope of the project, given the extensive use of existing ROW for routing the brownfield transmission lines. The most significant schedule risks to the project involve the long lead time anticipated for procurement of substation equipment such as EHV breakers and transformers for the proposed new substations and substation expansions.

Proposal 660 – Exelon (BGE-PEPCO)

Proposal No. 660 (**Map 8**), described as West Cooper BGE-PEPCO, is located within Howard, Baltimore and Harford counties, Maryland, and includes the construction of several new substations. The majority of the components will be developed within existing ROWs. Proposal No. 660 comprises the BGE-PEPCO portion of Exelon's West Cooper Max solution and is intended to be combined with Proposal No. 344, the PECO portion of Exelon's West Cooper Max

solution. In addition, two components within this proposal is in coordination with a FirstEnergy and Dominion's joint rebuild of the Doubs to Goose Creek corridor to accommodate a new 500 kV circuit, with further details provided in FirstEnergy Proposal 837 (South) and Dominion Proposal (516) reviews.

Map 8. Proposal 660



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Proposal No. 660 includes 22 components all of which are selected for the detailed evaluations.

- Component 1: Graceton 500 kV substation expansion
- Component 2: Batavia Road 230 kV switching station
- Component 3: High Ridge 500 kV substation expansion
- Component 4: West Cooper-High Ridge (500 kV)
- Component 5: Graceton-Batavia Rd (230 kV)
- Component 6: Peach Bottom-Graceton (500 kV)
- Component 7: 5012 line rebuild Graceton-Conastone (BGE Only)
- Component 8: 5012 line rebuild West Cooper-Graceton (BGE Only)
- Component 9: 230 line rebuild Batavia Road to Riverside

- Component 10: 230 kV Dickerson station H to Ed's Ferry
- Component 11: Graceton 230 kV terminal eqp. (BGE)
- Component 12: High Ridge 230 kV terminal eqp. (BGE)
- Component 13: Conastone 500 kV cap bank (BGE)
- Component 14: Conastone 500 kV 5012 line terminal eqp. (BGE)
- Component 15: Brighton 5053 terminal eqp. (PEPCO)
- Component 16: Brighton Statcom (PEPCO)
- Component 17: Brighton 500 kV cap bank (PEPCO)
- Component 18: Brighton 5011 terminal eqp. (PEPCO)
- Component 19: Dickerson to Ed's Ferry terminal eqp. (PEPCO) – associated with proposals FE 837 and DOM 516
- Component 20: Conastone 500 kV 5011 terminal eqp. (BGE)
- Component 21: Chalk Point 500 kV 5073 relay upgrade (PEPCO)
- Component 22: 500 kV Doubs to Goose Creek (PEPCO only) – associated with proposals FE 837 and DOM 516

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Peach Bottom North (PECO)-Graceton (BGE) New 500 kV Line: BGE Portion

The line is a continuation from PECO's portion of the line as part of Proposal 344 that terminated at the Maryland/Pennsylvania state line. This component of the proposal is for BGE's approximately 2-mile portion of greenfield 500 kV overhead transmission line from the Maryland/Pennsylvania state line, to the expanded Graceton substation. The new 500 kV line route entails rebuilding existing Cooper to Graceton 230 kV line as a 500 kV circuit.

West Cooper (PECO)-High Ridge (BGE) New 500 kV Line: BGE Portion

The line is a continuation from PECO's portion of the line as part of Proposal 344 that terminated at the Maryland/Pennsylvania state line. This component of the proposal is for BGE's approximately 59.4-mile portion of greenfield 500 kV overhead transmission line from the MD/PA state line to the expanded High Ridge substation.

The line will travel on single circuit structures within existing ROW created by the demolition of Cooper to Graceton 230 kV and rebuild of Peach Bottom to Conastone 5012 500 kV line from the Maryland/Pennsylvania state line up to Graceton. From Graceton to Conastone, the proposal entails building new 500 kV single circuit poles on the edge of the current ROW (8.6 mi) and transfer existing 5012 circuit to new poles, allowing for the new West Cooper High Ridge 500 kV circuit to be built in place of legacy 5012 structures. From Conastone to Northwest No. 2, the proposal entails building new 500 kV single circuit poles on the edge of the current ROW (24.2 miles) and transfer existing 5011 circuit to new poles, allowing for the new West Cooper-High Ridge 500 kV circuit to be built in place of legacy 5011 structures. The next portion of the route (20.5 miles) entails using free ROW space available on Northwest No. 2 Pleasant Hills 230 kV, Pleasant Hills to Granite 230 kV, Granite to Howard 230 kV, Howard to Columbia 230 kV, and then rebuilds of the Columbia to Snowden River 230 kV and Snowden River to High Ridge 230 kV for 4.6 miles to accommodate the West Cooper-High Ridge 500 kV circuit.

Graceton to Batavia (BGE) New Double Circuit 230 kV Line

This component of the proposal is for an approximately 29-mile double circuit 230 kV greenfield overhead transmission line from the existing Graceton substation to the new Batavia substation. This line will be constructed on the edge of the current ROW of the Graceton to Bagley to Raphael Road to Northeast 230 kV line corridor, with no expansion required.

Overall, the ROW risk for components of this proposal is low, with extensive usage of existing ROWs for its entire alignment. It is anticipated that the proposal could require permits, consultations, clearances and authorizations from three counties in Maryland (Howard, Baltimore and Harford). State PSC approval, CPCN and DOT utility permits and driveway/local road permits may be required.

Environmental Risk Analysis

Wetlands, waterbodies and high-risk flood zones appear to be crossed by the project components of the proposal.

Proposed project intersects waters subject to USACE Section 404 and/or Section 10 permitting. Numerous wetlands subject to USACE Section 404 intersect the project. Coordination with USACE is required for jurisdictional determination. An on-site delineation would be required to determine the actual location and extent of wetlands and waterbodies present and to assess permitting implications for jurisdictional features.

The proposed project components are within the range of both federally and state-listed species. The majority of the proposed routes are in woodlands. Construction restrictions, time frame or mitigation may be necessary to comply with avoidance of sensitive species; however, the extent of which cannot be known until field studies are completed and coordination with the USFWS and state wildlife agencies takes place.

Proposed project components do not intersect conservation easements/protected areas. Coordination with easement holders is not anticipated.

Transmission Line Risk Analysis

Given the extensive reuse of existing ROW for this proposal, transmission line construction risks are low and limited to concerns with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence, and potential design limitations for reuse of existing infrastructure/assets.

Other moderate risks for this project involve the existing facility outages that will be necessary for the project, particularly for the extensive line rebuilds, and substation expansions. To mitigate these risks, Exelon provided a detailed schedule outlining a sequence of construction that will ensure that new brownfield transmission lines are energized within the corridor prior to the rebuild of existing facilities that will require lengthy outages.

Substation Risk Analysis

New Batavia Road 230 kV Station

The Batavia Road 230 kV switching station is a proposed new four four-bay, eight-position 230 kV switching station to be built with ten 230 kV 4000A breakers, associated station bus, control house, relaying and grounding.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 7**.

Table 7. Proposal 660 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	Graceton 500 kV Substation Expansion	78.96	82.52
2	Batavia Road 230 kV Switching Station	32.91	44.73
3	High Ridge 500 kV Substation Expansion	116.00	70.03
4	West Cooper-High Ridge (500 kV)	407.11	304.57
5	Graceton-Batavia Rd (230 kV)	176.84	247.94
6	Peach Bottom-Graceton (500 kV)	10.44	19.58
7	5012 Line Rebuild Graceton-Conastone (BGE ONLY)	70.00	45.94
8	5012 Line Rebuild West Cooper-Graceton (BGE ONLY)	10.44	9.66
9	230 Line Rebuild Batavia Road to Riverside	20.16	22.09
10	230 kV Dickerson Sta H to Ed's Ferry	18.60	42.80
11	Graceton 230 kV Terminal Eqp. (BGE)	8.77	5.32
12	High Ridge 230 kV Terminal Eqp. (BGE)	6.11	4.72
13	Conastone 500 kV Cap Bank (BGE)	14.31	10.33
14	Conastone 500 kV 5012 Line Terminal Eqp. (BGE)	4.93	5.99
15	Brighton 5053 Terminal Eqp. (PEPCO)	4.13	6.23
16	Brighton Statcom (PEPCO)	52.20	67.46
17	Brighton 500 kV Cap Bank (PEPCO)	14.31	11.42
18	Brighton 5011 Terminal Eqp. (PEPCO)	4.13	6.54
19	Dickerson To Ed's Ferry Terminal Eqp. (PEPCO)	10.58	8.51
20	Conastone 500 kV 5011 Terminal Eqp. (BGE)	7.16	8.99
21	Chalk Point 500 kV 5073 Relay Upgrade (PEPCO)	0.34	0.57
22	500 kV Doubs to Goose Creek (PEPCO Only)	37.20	34.68
	Total	**1,105.62**	**1,060.63**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

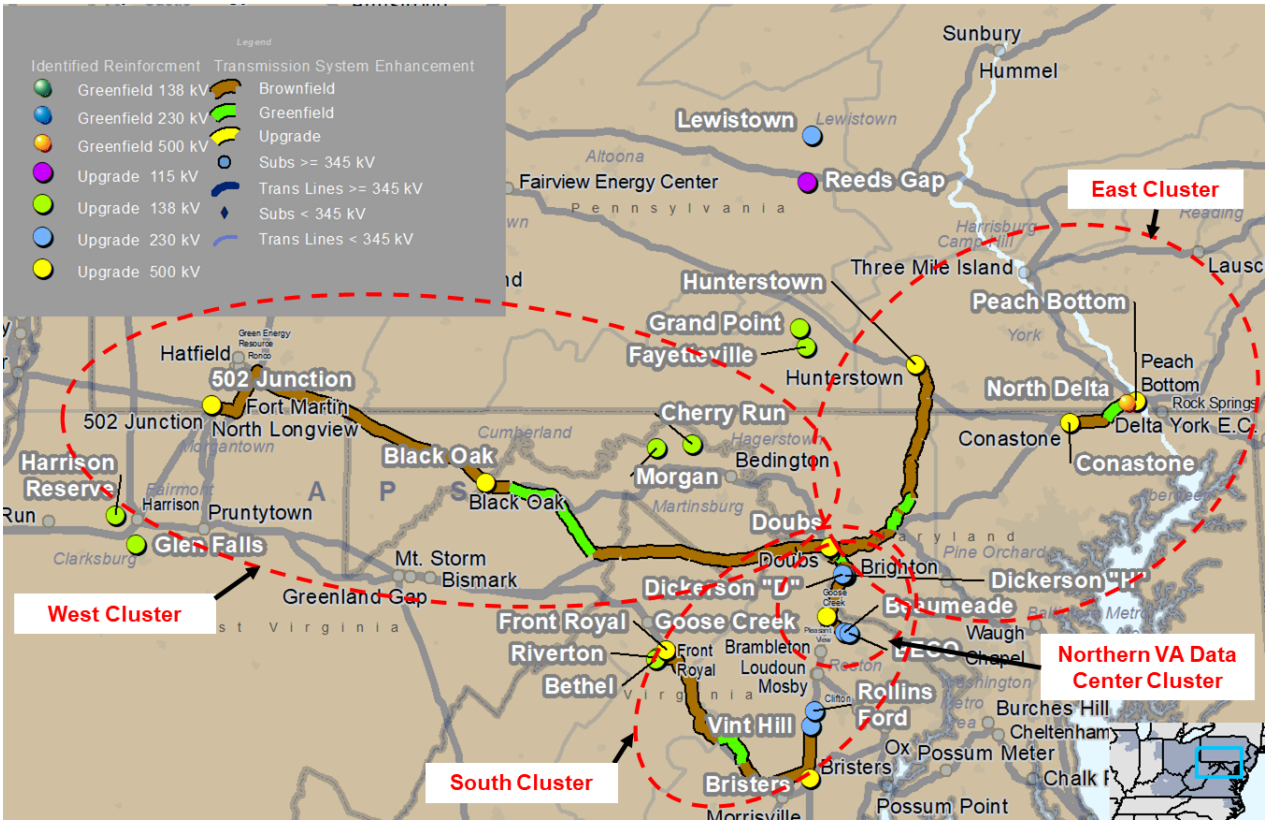
Schedule Review

The proposed in-service date of December 2030 is reasonable for the proposed scope of the project, given the extensive use of existing ROW for routing the brownfield transmission lines. The most significant schedule risks to the project involve the long lead time anticipated for procurement of substation equipment such as EHV breakers and transformers for the proposed new substations and substation expansions.

Proposal 548 (East) – LS Power

LS Power Proposal No. 548 (**Map 9**), described as RTEP Window 3 Solution, provides a holistic solution to the RTEP Window 3 needs, comprising 37 components, which can be grouped into the four regional clusters identified for the Window. Specifically for the East cluster, LS Power proposed several components within multiple counties in Pennsylvania (York, Adams) and Maryland (Harford, Carroll, Frederick).

Map 9. Proposal 548



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

LS Power Proposal 548 components selected for evaluation in the East cluster are as follows:

- Component 10: Conastone substation upgrade
- Component 13: Hunterstown substation upgrade
- Component 14: North Delta substation upgrade
- Component 21: Peach Bottom substation upgrade
- Component 23: Conastone-Peach Bottom rebuild
- Component 27: Hunterstown-Doubs Greenfield 500 kV transmission line
- Component 32: Hunterstown-Doubs Greenfield 500 kV transmission line (shared ROW)
- Component 35: Conastone-North Delta Greenfield 500 kV transmission line (shared ROW)
- Component 37: Peach Bottom-North Delta reconductor

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Conastone to Peach Bottom – 500/230 kV OH Line Rebuild

This component of the proposal is for a double circuit approximately 8-mile 500/230 kV overhead transmission line rebuild from Conastone substation to the Peach Bottom substation. The new line will utilize the existing ROW and is assumed will be able to be completely built within the existing ROW. The existing lattice towers will be taken down and replace with the new double circuit 500/230 kV structures.

The ROW risk for this component is low due to the rebuild occurring within the existing ROW.

Huntertown to Doubs 500 kV OH Line

This component of the proposal is for a 55-mile single circuit, partially greenfield 500 kV overhead transmission line from the existing Huntertown substation to the Existing Doubs substation. The line parallels an existing 500 kV ROW for the first 7 miles of the line, and then follow its own new ROW for approximately 3 miles. At this point, it will replace Germantown-Taneytown 138 kV line and become a double circuit 500/138 kV line for ~13 miles. It will then break off to single circuit for a few structures, and then meet the existing Carroll-Mt Airy 230 kV corridor, which it will rebuild as a 500/230 kV line for about seven miles. Then it becomes a single 500 kV circuit with its own new ROW for ~10 miles, before paralleling Doubs-Brighton 500 kV ROW for the remaining ~15 miles to Doubs substation.

The ROW risk for this component is medium-high to high, with about 35 miles of greenfield route, although only 13 miles are pure greenfield for its entire alignment.

Conastone to North Delta 500 kV OH Line

This component of the proposal is for a ~5.5 mile 500 kV overhead transmission line rebuild from Peach Bottom substation to the North Delta substation. The new line will utilize the existing ROW and is assumed will be able to be completely built within the existing ROW. The existing lattice towers will be taken down and replaced with the new double circuit 500/230 kV structures.

The ROW risk for this component is low due to the rebuild occurring within the existing ROW.

Peach Bottom to North Delta 500 kV OH Line Upgrades

This component of the proposal is for a ~2.5 mile 500 kV overhead transmission line reconductor from Peach Bottom substation to the North Delta substation. It is assumed that existing structures will be used for the upgrades. No new ROW is anticipated for this project.

The ROW risk for this component is low, as this is an upgrade occurring within the existing ROW.

Overall, due primarily to the Hunterstown to Doubs 500 kV OH line component, LS Power's East components ROW risk are considered medium-high.

Environmental Risk Analysis

The proposed Hunterstown-Doubs greenfield route entails seven railroad crossings, 16 transmission line crossings, and 96 road crossings in Adams County, Pennsylvania, and Carroll and Frederick counties in Maryland.

Proposed project components do not intersect conservation easements/protected areas. Coordination with easement holders is not anticipated.

Transmission Line Risk Analysis

The Hunterstown-Doubs component poses some medium construction risks as the design ROW is based on assumed ROW limits. It is not clear that the existing ROW will be adequate to contain the new line (sections that include 138 kV and 230 kV rebuilt to 500/138 kV and 500/230 kV respectively), as requirements may be larger for the 500 kV portion that what the existing ROW can hold. Alongside this, there are many portions where new ROW needs to be obtained, both paralleling existing ROW, and completely new ROW. It should also be noted that the conductor selection for each section may not be adequate to support the specified ratings, especially for the 500 kV line. Final conductor selection can affect span lengths, structure heights, material cost and hardware costs.

Medium-high risks are assessed for outage coordination for the proposed Conastone to Peach Bottom – 500/230 kV OH line rebuild component. This will involve extensive outage of the Conastone-Peach Bottom 500 kV line for its rebuild, and no details were provided regarding mitigation for the anticipated issues with these outages.

Substation Risk Analysis

The substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 8**.

Table 8. Proposal 548 (East) Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
10	Conastone Substation Upgrade	7.56	11.83
13	Hunterstown Substation Upgrade	14.34	17.00
14	North Delta Substation Upgrade	7.56	11.02
21	Peach Bottom Substation Upgrade	4.99	5.26
23	Conastone-Peach Bottom Rebuild	77.26	111.35
27 & 32	Hunterstown-Doubs Greenfield 500 kV Transmission Line	303.98	348.36
35	Conastone-North Delta Greenfield 500 kV Transmission line (Shared ROW)	77.26	100.28
37	Peach Bottom-North Delta Reconductor	2.88	4.34
	Total	495.83	609.44

The total proposal cost estimate is within 10–20% of the independent cost estimate and is considered medium risk.

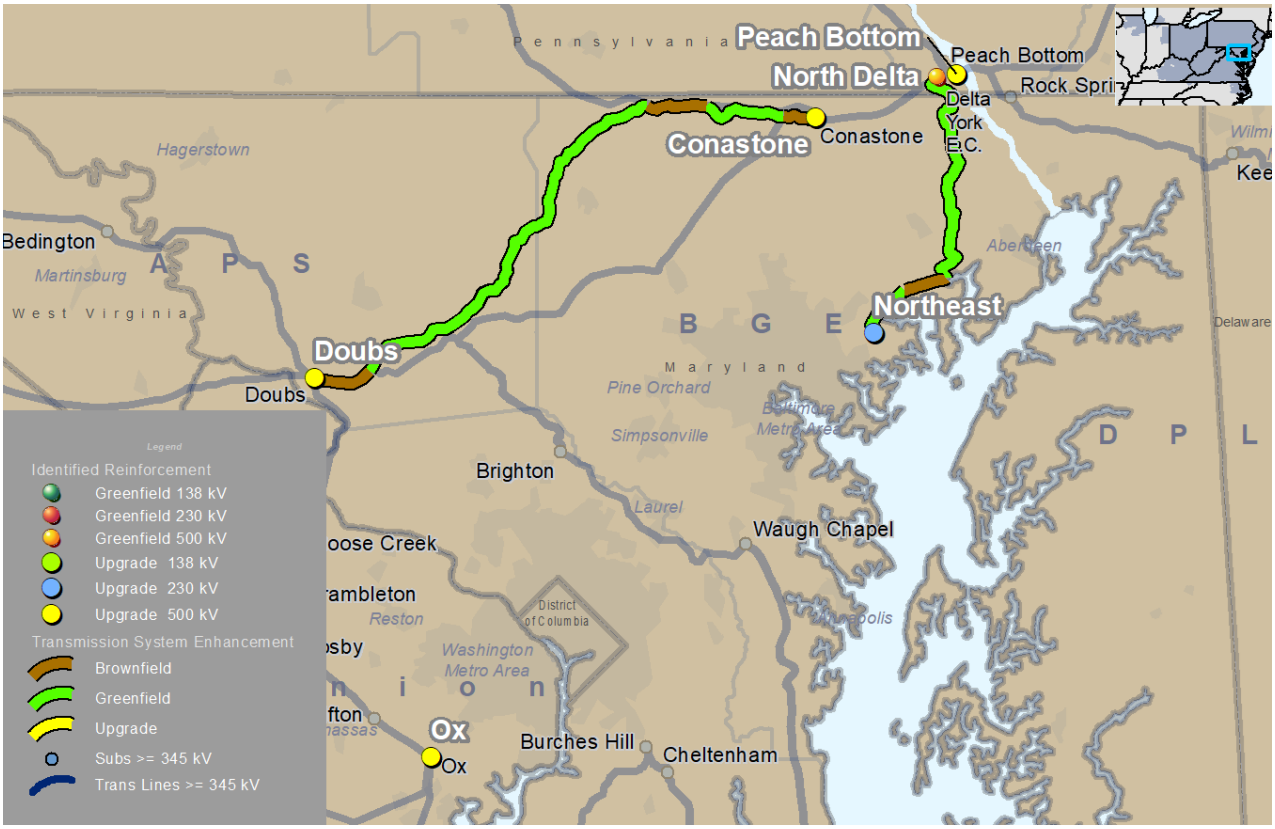
Schedule Review

The proposed in-service date of December 2030 appears to be reasonable for the proposed scope of the project, with a conservative time required to manage outage scheduling risks for Conastone-Peach Bottom rebuild and the ROW risks that may be associated with the Hunterstown-Doubs component.

Proposal 637 – PSEG

PSEG Proposal No. 637 (**Map 10**), described as Proposal D: Conastone-Doubs 500 kV, is located within York County, Pennsylvania, and Frederick, Carroll, Baltimore, and Harford counties, Maryland, and includes the upgrade of multiple substations as well as two greenfield lines.

Map 10. Proposal 637



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

PSEG Proposal 637 components selected for evaluation in the East cluster are as follows:

- Component 1: North Delta 500/230 kV upgrade
- Component 2: Northeast 230 kV upgrade
- Component 3: Peach Bottom 500 kV upgrade
- Component 4: Doubs 500/230 kV upgrade
- Component 5: Conastone 500/230 kV upgrade
- Component 6: Ox 500 kV upgrade
- Component 7: North Delta-Northeast 230 kV
- Component 8: Conastone-Doubs 500 kV

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New 230 kV Line From North Delta to Northeast

This component of the proposal is for a 36.5-mile greenfield 230 kV overhead transmission line tie from the North Delta substation to the Northeast substation. The line will travel through new ROW between North Delta and Northeast.

The ROW risk for this component is high due to the pure greenfield nature of the route.

New 500 kV Line From Conastone to Doubs

This component of the proposal is for an approximate 40.1-mile portion of a greenfield 500 kV overhead transmission line from Conastone substation to the Doubs substation. The line will travel through new ROW between Conastone and Doubs.

The ROW risk for this component is high due to the pure greenfield nature of the route.

Overall, with both transmission line components using a pure greenfield route, this proposal's ROW risk are considered high.

Environmental Risk Analysis

New 230 kV Line From North Delta to Northeast

The proposed North Delta to Northeast route has the potential to impact environmental and cultural resources including: the Lower Deer Creek Valley Historic District, flood plains, streams/wetlands subject to USACE permitting, and woodlands with the potential to serve as a suitable habitat for federally listed threatened and endangered species.

Impacts to these resources will require: coordination with the VA SHPO, the county flood plain administrator, USACE Section 404 and/or Section 10 permitting, and USFWS consultation.

The proposed route intersects a recorded underground storage tank (UST) that may require further soil characterization studies.

Nine easements are intersected by the proposed route. Coordination with easement holders will be required.

New 500 kV Line From Conastone to Doubs

Approximately six railroad crossings with CSXT and one is with Maryland Midland Railway (MMID). Approximately 121 road crossings (242 road entrances) in four counties. Approximately one cemetery crossing. Notification/Agreement may be required with Mount Zion United Methodist Church Cemetery. Approximately one crossing at Torrey C Brown Rail Trail, with the operator MD Department of Natural Resources.

The proposed route has the potential to impact environmental resources including: 19 FEMA High-Risk Flood Zones, 187 streams and 155 wetlands subject to USACE Section 404 and/or Section 10 permitting, and woodlands with the potential to serve as suitable habitat for federally listed threatened and endangered species. Impacts to these resources will require: USACE Section 404 and/or Section 10 permitting and USFWS consultation. The proposed

route intersects six Karst zones. Geotechnical studies are needed to verify subsurface conditions before digging and/or trenching. The proposed route intersects a property listed on the National Register of Historic Places – National Park Service (Chambers, Whitakker, Farms), Parker Conservation Area, Union Mills Reservoir Park and a unnamed local park. Coordination with entities is required.

Transmission Line Risk Analysis

The primary transmission line risks are those associated with permitting and land acquisition for the proposed greenfield lines.

Substation Risk Analysis

The substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 9**.

Table 9. Proposal 637 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates($M)
1	North Delta 500/230 kV Upgrade	8.44	10.42
2	Northeast 230 kV Upgrade	56.43	39.45
3	Peach Bottom 500 kV Upgrade	6.57	7.83
4	Doubs 500/230 kV Upgrade	25.20	31.80
5	Conastone 500/230 kV Upgrade	8.14	9.84
6	Ox 500 kV Upgrade	1.17	1.71
7	North Delta-Northeast 230 kV	187.98	139.81
8	Conastone-Doubs 500 kV	390.28	435.50
	Total	**684.22**	**673.36**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

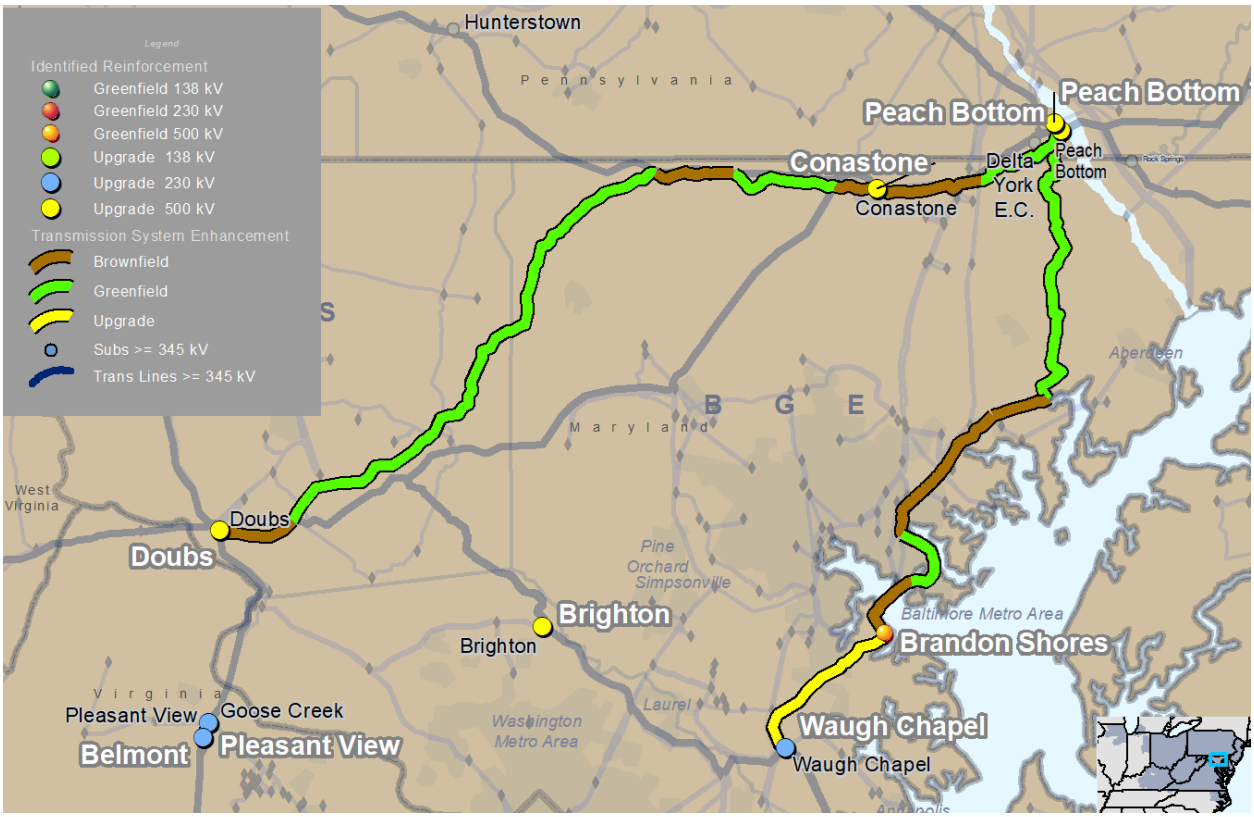
Schedule Review

The proposed in-service date of June 2027 seems to be aggressive for the proposed scope of the project, with a more conservative time required to manage ROW permitting and land acquisition risks associated with the two greenfield line routes.

Proposal 741 – PSEG

PSEG Proposal No. 741 (**Map 11**), is described as Proposal G: Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV is located within York County, Pennsylvania, and Frederick, Carroll, Baltimore, Anne Arundel, and Harford counties, Maryland, and includes new greenfield substations and lines, as well as multiple substation and line upgrades.

Map 11. Proposal 741 (see next page)



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

PSEG Proposal 741 includes 10 components, all of which are selected for the detailed evaluations.

- Component 1: New 500 kV line from Peach Bottom station to Brandon Shores station
- Component 2: New 500 kV line from Doubs Station to Peach Bottom station
- Component 3: Reconductor 230 kV line from Brandon Shores to Waugh Chapel
- Component 4: Reconductor Peach Bottom North to Peach Bottom South Tie #1 and #2
- Component 5: New Brandon Shores 500 kV station
- Component 6: Peach Bottom 500 kV upgrade
- Component 7: Doubs 500/230 kV upgrade
- Component 8: Brandon Shores 230 kV upgrade
- Component 9: Conastone/Brighton 500 kV upgrade
- Component 10: Pleasant View/Belmont 230 kV upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New 500 kV Line From Peach Bottom to Brandon Shores

This component of the proposal is for a 56-mile portion of a greenfield 500 kV overhead transmission line from the existing Peach Bottom substation to the existing Brandon Shores substation. The line is a single circuit steel monopole of either vertical or delta configuration. Part of the line passes through the urban Baltimore area. A major river crossing over the Patapsco River is required. The crossing will have 10–12 structures and will require major permitting and construction costs. Portions of this route parallel existing utility corridors, while the remainder are pure greenfield.

The ROW risk for this component is high due to the extensive greenfield nature of the proposed route.

New 500 kV Line From Doubs to Peach Bottom

This component of the proposal is for an 87-mile portion of a greenfield 500 kV overhead transmission line from the existing Doubs substation to the existing Peach Bottom substation. The line is a single circuit steel H-frame in a horizontal configuration. The line is in a mostly hilly rural area.

The ROW risk for this component is high due to the pure greenfield nature of the proposed route.

Environmental Risk Analysis

New 500 kV Line From Peach Bottom Station to Brandon Shores Station

The proposed route has the potential to impact environmental and cultural resources including: Lower Deer Creek Valley Historic District; 45 FEMA High-Risk Flood Zones; 13 waters subject to USACE Section 10 permitting; numerous streams/wetlands subject to USACE Section 404 permitting; and woodlands with the potential to serve as suitable habitat for federally listed threatened and endangered species. Tree removal restrictions will likely apply due to the likelihood of the presence of listed endangered bats. Field verification of bat habitat is needed to determine presence. Coordination with the following is recommended: MD SHPO, flood plain administrator from each county,

USACE, USFWS. Nine conservation easements are intersected by the proposed route. Coordination with easement holders will be required.

This project will require ROWs with widths of 80–85 feet in residential areas, 125–130 feet in farmland, 150 feet in farmland, and 170 feet at the Patapsco River.

Approximately 39 transmission line crossings with BG&E. Approximately six park crossings: two state parks owned by MD Department of Natural Resources, one local park crossing with Baltimore County, three local park crossings with Harford County. Approximately 32 railroad crossings with the Federal Railroad Administration. Approximately 132 road crossings (264 road entrances) in four counties.

New 500 kV Line From Doubs Station to Peach Bottom Station

Proposed route has the potential to impact environmental resources including: 19 FEMA High-Risk Flood Zones; 187 streams and 155 wetlands subject to USACE Section 404 and/or Section 10 permitting; and woodlands with the potential to serve as suitable habitat for federally listed threatened and endangered species. Impacts to these resources will require: USACE Section 404 and/or Section 10 permitting and USFWS consultation. The proposed route intersects six Karst zones. Geotechnical studies are needed to verify subsurface conditions before digging and/or trenching. The proposed route intersects property listed on the National Register of Historic Places – National Park Service (Chambers, Whitakker, Farms) and 46 conservation easements including Parker Conservation Area, Union Mills Reservoir Park and an unnamed local park. Coordination with entities is required.

Approximately six railroad crossings. Five are with CSXT and one is with Maryland Midland Railway (MMID). Approximately 11 transmission line crossings. Approximately 148 road crossings (296 road entrances) in five counties. Approximately one cemetery crossing. Notification/Agreement may be required with Mount Zion United Methodist Church Cemetery. Approximately two park crossings with the operator MD Department of Natural Resources.

Transmission Line Risk Analysis

For the Peach Bottom to Brandon Shores line route, river crossing is a major risk due to engineering, construction and permitting unknowns.

For both routes, conductor selection for each section may not be adequate to support the specified ratings, especially for the 500 kV line. Final conductor selection can affect span lengths, structure heights, material cost and hardware costs. ROW widths may not be adequate for the line to be reliably operated.

Substation Risk Analysis

New Brandon Shores 500 kV Substation

Brandon Shores is a proposed new 500 kV substation that will include two 500/230 kV transformers and a four breaker ring bus.

The other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 10**.

Table 10. Proposal 741 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	New 500 kV line from Peach Bottom station to Brandon Shores station	433.99	424.67
2	New 500 kV line from Doubs Station to Peach Bottom Station	464.48	574.36
3	Reconductor 230 kV line from Brandon Shores to Waugh Chapel	20.79	14.38
4	Reconductor Peach Bottom North to Peach Bottom South Tie #1 and #2	3.01	1.27
5	New Brandon Shores 500 kV station	90.05	74.79
6	Peach Bottom 500 kV Upgrade	31.75	40.95
7	Doubs 500/230 kV Upgrade	17.94	20.19
8	Brandon Shores 230 kV Upgrade	3.31	8.09
9	Conastone/Brighton 500 kV Upgrade	0.00	14.37
10	Pleasant View/Belmont 230 kV Upgrade	0.00	5.69
	Total	**1,065.32**	**1,178.75**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

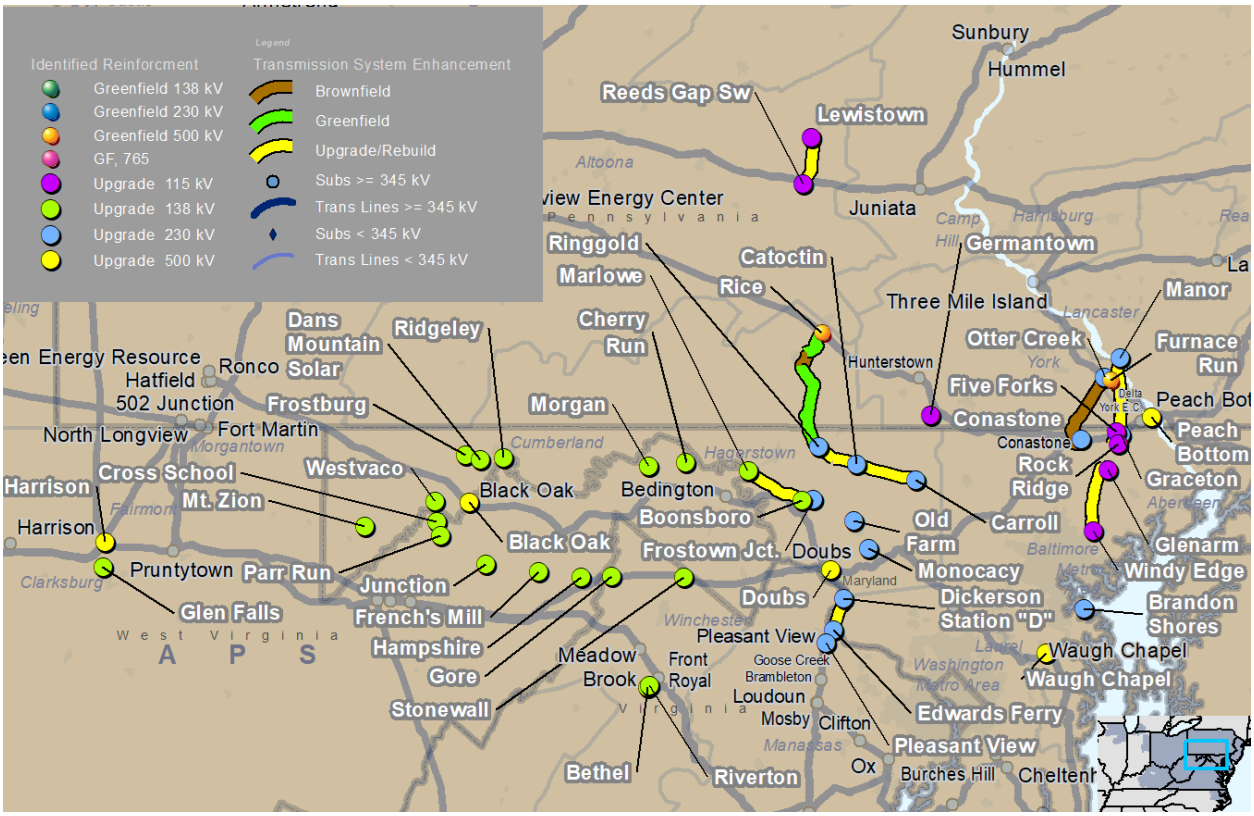
Schedule Review

The proposed in-service date of December 2028 is quite aggressive for the proposed scope of the project, considering the ROW permitting and land acquisition risks associated with the two Greenfield line routes. In particular, the permitting, engineering and construction risks anticipated with the Peach Bottom to New Brandon Shores route have potential to introduce significant schedule challenges. Overall, the schedule risk is considered medium-high.

Proposal 487 – Transource

Transource Proposal No. 487 (**Map 12**), described as the Maryland & Pennsylvania Baseline Reliability Solution, is based on the Transource IEC East and West projects (Project 9A) previously approved by PJM but currently under suspension. This project was submitted with additional incumbent upgrades to address more violations in the Maryland-Pennsylvania corridor. The IEC East components span across Harford and Baltimore counties in Maryland, and York County in Pennsylvania. The IEC West components span across Washington County in Maryland and Franklin County in Pennsylvania.

Map 12. Proposal 487



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Transource Proposal 487 includes 39 components that make up the IEC East and West proposal.

- Component 1: Rice-Ringgold 230 kV greenfield transmission line
- Component 2: Ringgold 230/138 kV station upgrade
- Component 3: Rice 500/230 kV greenfield station
- Component 4: Manor-Graceton 230 kV upgrade
- Component 5: Conastone-Otter Creek 230 kV transmission line upgrade

- Component 6: Furnace Run 500/230 kV greenfield station
- Component 7: Graceton station upgrade
- Component 8: Conastone station upgrade
- Component 9: Ringgold-Catoctin line upgrade (138 kV to 230 kV)
- Component 10: Dickerson station upgrade
- Component 11: Conemaugh-Hunterstown 500 kV line tie-in
- Component 12: Peach Bottom-Three Mile Island tie-in
- Component 13: Catoctin to Carroll line upgrade (138 kV to 230 kV)
- Component 14: Catoctin station upgrade
- Component 15: Carroll station upgrade
- Component 16: Glen Arm 2-Windy Edge 1 115 kV line upgrade
- Component 17: Five Forks-Rock Ridge 1 115 kV line upgrade
- Component 19: Peach Bottom station upgrade
- Component 21: Marlowe-Boonesboro 138 kV series reactor
- Component 22: Germantown station capacitor upgrade
- Component 23: Garrett to Garrett Tap 115 kV line upgrade
- Component 25: Dickerson-Edwards Ferry-Twin Creek-Pleasant View 230 kV rebuild and terminal equipment upgrade
- Remaining components: terminal upgrades at various stations

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New 230 kV Line From Rice to Ringgold

This component of the proposal is for a 29-mile portion of a greenfield 230 kV overhead transmission line from the new 500/230 kV Rice substation to the existing Ringgold substation. While this constitutes a greenfield route with about 42% of its ROW paralleling existing ROWs, the ROW risk for this component is medium due to the extensive permitting and acquisition that has already been completed with 70% of the required ROW obtained by the proposing entity.

Environmental Risk Analysis

Rice 500/230 kV Greenfield Station

The proposed substation footprint intersects with a Karst zone. Geotechnical studies are needed to verify subsurface conditions before digging and/or trenching.

Transmission Line Risk Analysis

A medium risk for this project involves the existing facility outages that will be necessary to perform the numerous line and terminal upgrades.

Substation Risk Analysis

Rice 500/230 kV Greenfield Station

The proposed substation, which the proposing entity already has under option for purchase, will tie into the existing Hunterstown-Conemaugh 500 kV line. The Rice station will be laid out as a three-breaker 500 kV ring bus on the 500 kV side with six single-phase 500 kV/230 kV/13.8 kV transformers for two transformer banks.

Furnace Run 500/230 kV Greenfield Station

The proposed substation, which the proposing entity already has under option for purchase, will tie into the existing TMI-Peach Bottom 500 kV line. The Rice station will be laid out as an eight-breaker 500 kV GIS in a breaker-and-a-half configuration, and a fourteen breaker 230 kV AIS in a breaker-and-a-half configuration, with three 500/230 kV transformer banks.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 11**.

Table 11. Proposal 487 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	Rice-Ringgold 230 kV Greenfield Transmission Line	64.55	70.00
2	Ringgold 230/138 kV Station Upgrade	14.80	16.00
3	Rice 500/230 kV Greenfield Station	31.62	35.00
4	Manor-Graceton 230 kV Upgrade	21.80	16.50
5	Conastone-Otter Creek 230 kV Transmission Line Upgrade	29.00	35.00
6	Furnace Run 500/230 kV Greenfield Station	75.82	75.00
7	Graceton Station Upgrade	9.40	9.30
8	Conastone Station Upgrade	9.00	9.30
9	Ringgold-Catoctin Line Upgrade (138 kV to 230 kV)	47.20	47.00

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
10	Dickerson Station Upgrade	1.00	1.13
11	Conemaugh-Hunterstown 500 kV line Tie-in	15.20	12.00
12	Peach Bottom-Three Mile Island Tie-in	15.20	12.00
13	Catoctin to Carroll Line Upgrade (138 kV to 230 kV)	45.51	47.00
14	Catoctin Station Upgrade	9.10	8.00
15	Carroll Station Upgrade	10.19	8.00
16	Glen Arm 2-Windy Edge 1 115 kV Line Upgrade	3.06	3.00
17	Five Forks-Rock Ridge 1 115kV Line Upgrade	7.41	7.50
19	Peach Bottom Station Upgrade	4.70	4.80
21	Marlowe-Boonesboro 138 kV Series Reactor	3.92	4.00
22	Germantown Station Capacitor Upgrade	0.72	1.00
23	Garrett to Garrett Tap 115 kV Line Upgrade	9.41	9.90
25	Dickerson-Edwards Ferry-Twin Creek-Pleasant View 230 kV Rebuild and Terminal Equipment Upgrade	28.62	35.00
Remaining Components	Terminal Upgrades at various substations	35.52	37.00
	Total	**492.75**	**503.43**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

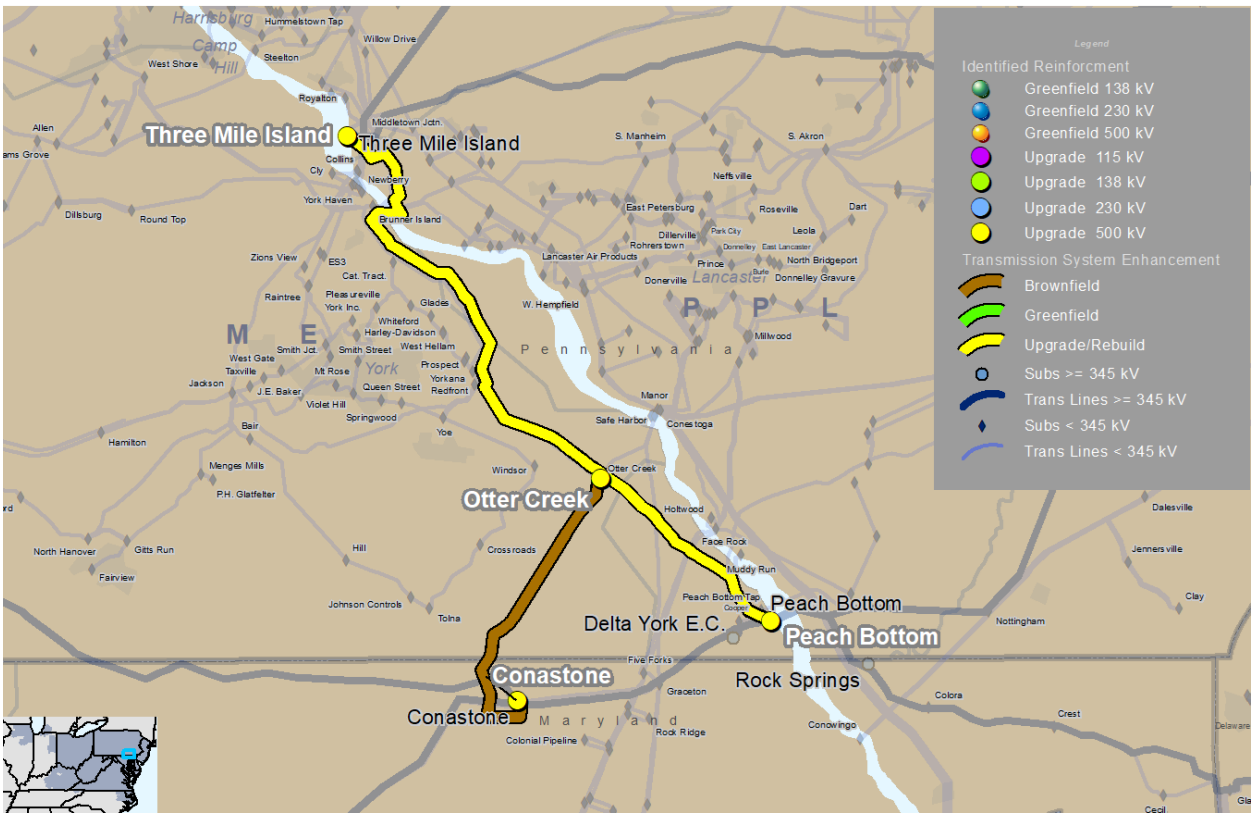
Schedule Review

The proposed in-service date of March 2027 is reasonable for the proposed scope of the project considering the extensive amount of permitting, land acquisition and equipment procurement that has already been completed for this project. Overall, this project poses a low schedule risk.

Proposal 374 – PPL

PPL Proposal No. 374 (**Map 13**), described as Otter Creek-Conastone 500 and 230 kV double circuit line, is located within York County, Pennsylvania, and Baltimore and Harford counties in Maryland and includes a greenfield substation and a greenfield double circuit transmission line.

Map 13. Proposal 374



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

PPL Proposal 374 has the following components:

- Component 1: Tap TMI-Peach Bottom 500 kV line
- Component 2: Otter Creek-Conastone 500 and 230 kV double circuit line (PPL EU section)
- Component 3: Otter Creek-Conastone 500 and 230 kV double circuit line (BGE section)
- Component 4: Otter Creek 500 kV switchyard
- Component 5: Conastone 500 kV substation upgrade
- Component 6: Peach Bottom South Yard bus upgrades

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New 500/230 kV Line From Otter Creek to Conastone

This component of the proposal is for an approximately 17-mile greenfield 230 kV overhead transmission line tie from the new Otter Creek 500 kV substation, which taps into the existing TMI to Peach Bottom 500 kV line to the existing

Conastone station. This will involve expanding existing Otter Creek-Conastone 230 kV line ROW and wrecking and rebuilding the existing 230 kV structures to accommodate a double circuit 500 kV and 230 kV line. The first 12 miles of the line from Otter Creek is owned by PPL, and about 4.76 miles of the remainder of the line to Conastone is owned by BG&E. Additional ROW will need to be acquired to widen the existing transmission line corridor from 150 feet to 200 feet.

The ROW risk for this component is medium, as this project is routed entirely within the existing ROW with the noted expansion included.

Environmental Risk Analysis

New 500/230 kV Line From Otter Creek to Conastone

Wetlands, waterbodies and high-risk flood zones appear to be crossed by project components.

Proposed project intersects with waters subject to USACE Section 404 and/or Section 10 permitting. Coordination with USACE is required for jurisdictional determination. An on-site delineation would be required to determine the actual location and extent of wetlands and waterbodies present and to assess permitting implications for jurisdictional features.

The proposed project components are within the range of both federally and state-listed species. Project components intersect with woodlands. Due to the likelihood of endangered bat species being present, tree-clearing seasonal restrictions are recommended. The project proponents should conduct an independent TE species review once the potential limits of disturbance and environmental impacts are better known. Construction restrictions, time frame or mitigation may be necessary to comply with avoidance of sensitive species; however, the extent of which cannot be known until field studies are completed and coordination with the USFWS and state wildlife agencies takes place.

The proposed project components do not intersect with historic districts. No impacts to cultural resources are anticipated.

Proposed project components intersect conservation easements. Coordination with easement holders is anticipated.

It is anticipated that the proposal could require permits, consultations, clearances and authorizations from three counties in Maryland (Baltimore & Harford) and Pennsylvania (York). State PSC approval, CPCN and DOT utility permits and driveway/local road permits may be required with about 31 road crossings estimated.

Transmission Line Risk Analysis

Given the extensive reuse of existing ROW for this proposal, transmission line construction risks are low and limited to concerns with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence, and potential design limitations for reuse of existing infrastructure/assets.

Other moderate risks for this project involve the existing facility outages that will be necessary for the project, particularly for the line rebuild and substation upgrades.

Substation Risk Analysis

New Otter Creek 500 kV Substation

Otter Creek is a proposed new 500 kV substation tapped into the TMI-Peach Bottom 500 kV line that will include a double-bus double-breaker design with two bays and three breakers with a location for one future breaker.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 12**.

Table 12. Proposal 374 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	Tap TMIS-Peach Bottom 500 kV line	6.33	6.00
2	Otter Creek-Conastone 500 and 230 kV double circuit line (PPL EU Section)	77.40	74.23
3	Otter Creek-Conastone 500 and 230 kV double circuit line (BGE Section)	29.95	30.60
4	Otter Creek 500 kV Switchyard	30.44	41.87
5	Conastone 500 kV Substation upgrade	8.86	7.98
6	Peach Bottom South Yard bus upgrades	1.24	2.00
	Total	**154.21**	**162.69**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

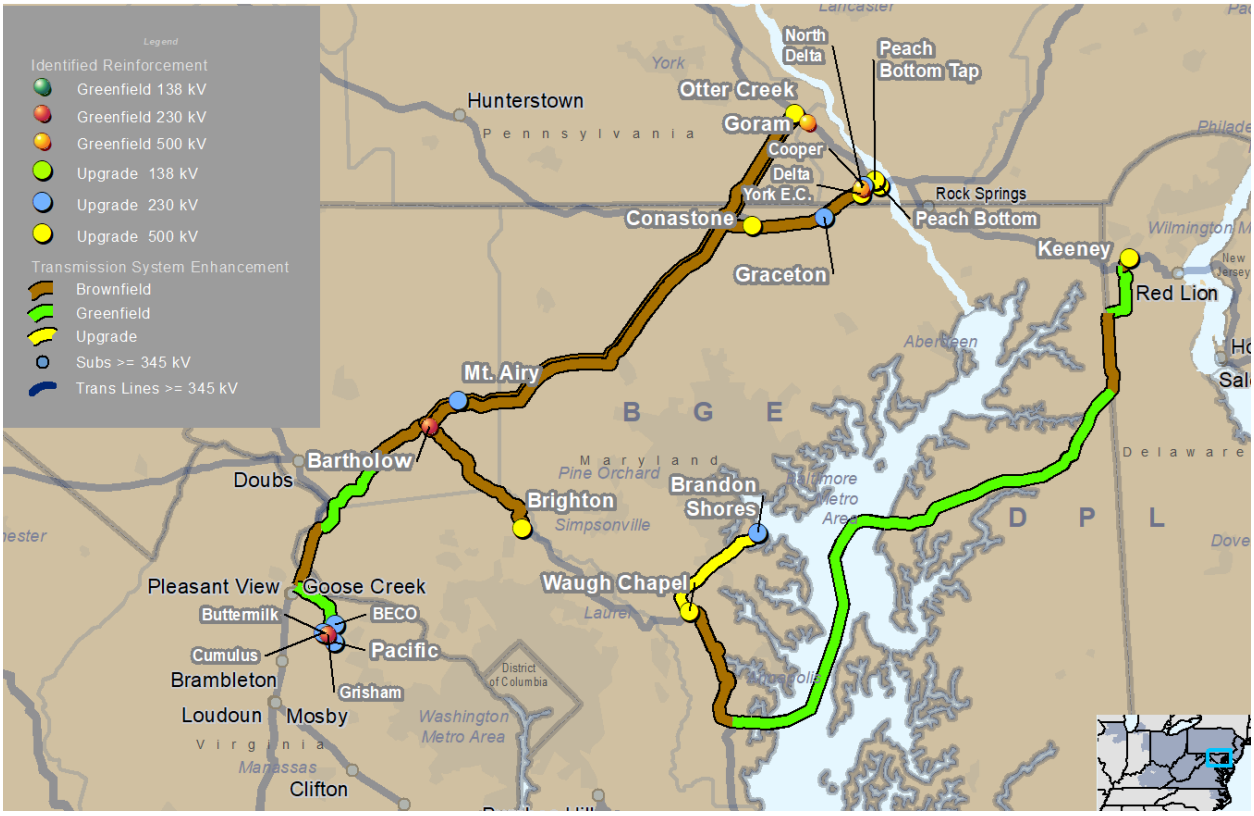
Schedule Review

The proposed in-service date of May 2027 is reasonable for the proposed scope of the project, given the extensive use of the incumbent's existing ROW for the new line construction.

Proposal 948 – NextEra

NextEra Proposal No. 948 (**Map 14**), described as New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in, is located York County, Pennsylvania; Frederick, Montgomery, Anne Arundel, Kent, Baltimore, Cecil, Carroll and Harford counties, Maryland; Loudoun County, Virginia; and New Castle County, Delaware, and includes new greenfield substations and lines, as well as multiple substation and line upgrades.

Map 14. Proposal 948



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

NextEra Proposal 948 includes the following components:

- Component 1: 24e – North Delta to Cooper 230 kV rebuild
- Component 2: 24f – North Delta to Graceton 230 kV rebuild
- Component 3: 26A – New 500 kV transmission line from new North Delta substation to BGE's Conastone substation
- Component 4: 40AB1 – New two single circuit 230 kV transmission lines from new Bartholow substation to new Grisham substation
- Component 5: 27d – North Peach Bottom to South Peach Bottom 500 kV upgrade

- Component 6: 39H1 – New Grisham substation – 6 terminal
- Component 7: 45F1 – New Bartholow substation – 12 terminal
- Component 8: 26b2 – New North Delta substation – 10 terminal
- Component 9: 26c2 – Conastone substation 500 kV and 230 kV substation expansion
- Component 10: 39h1a – Nimbus to Buttermilk 230 kV loop in/out work
- Component 11: 39h1b – Pacific to Beco 230 kV loop in/out work
- Component 12: 47ab – New 230 kV transmission from new Goram substation to existing Otter Creek substation
- Component 13: 47abc – New 500 kV transmission line from new Goram substation to new Bartholow substation
- Component 14: 47ad – New 230 kV transmission line from existing Otter Creek substation to new Bartholow substation
- Component 15: 47b – New double circuit 230 kV transmission from the existing Conastone substation to new Bartholow substation
- Component 16: 47A – New Goram substation
- Component 17: 47ax– Loop in Conastone to Brighton 500 kV line to new Bartholow substation
- Component 18: 43EF – Mt Airy 230 kV substation single breaker expansion
- Component 19: 43e – New 230 kV transmission line from new Bartholow substation to existing Mt. Airy substation
- Component 20: 48b – Two (2) new 230 kV single circuit transmission lines from the existing Keeney substation to existing Waugh Chapel substation
- Component 21: 47ac – Otter Creek 230 kV four circuit breaker expansion
- Component 22: 48C – Keeney substation two new 230 kV terminations
- Component 23: 48d – Waugh Chapel substation two new 230 kV terminations
- Component 24: 50B – Peach Bottom to North Delta 500 kV upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

26A – New 500 kV Transmission Line From New North Delta Substation to BGE's Conastone Substation

This component of the proposal is for an approximate 15-mile portion of new 500 kV overhead transmission line from new North Delta substation to BGE's Conastone substation. The line will largely travel within new ROW between North Delta and Conastone.

40AB1 – New Two Single Circuit 230 kV Transmission Lines From Bartholow to Grisham Substation

This component of the proposal is for an approximate 35-mile portion of two new 230 kV overhead and underground transmission lines from new Bartholow substation to new Grisham substation. The two lines will travel on single circuit structures within new ROW for approximately 60% of the route length. The ROW will be an expansion of existing ROWs for approximately 35% of the route length, while approximately 5% of the route will be underground in narrower and congested areas.

47ab – New 230 kV Transmission From New Goram Substation to Existing Otter Creek Substation

This component of the proposal is for an approximate 1-mile 230 kV greenfield overhead transmission line from the new Goram substation to the existing Otter Creek substation. The line will travel on single circuit structures within new ROW.

47abc – New 500 kV Transmission Line From New Goram Substation to New Bartholow Substation
This component of the proposal is for an approximate 61-mile 500 kV greenfield overhead transmission line from the new Goram substation to the new Bartholow substation. The line will travel on new single circuit monopoles within a new ROW as part of expanded easement alongside existing ROW.

47ad – New 230 kV Transmission Line From Existing Otter Creek Substation to New Bartholow Substation
This component of the proposal is for an approximate 61-mile 230 kV greenfield overhead transmission line from the existing Otter Creek substation to the new Bartholow substation. The line will largely travel on new single circuit monopoles within a new ROW as part of expanded easement alongside existing ROW.

47b – New Double Circuit 230 kV Transmission From the Existing Conastone Substation to New Bartholow Substation
This component of the proposal is for an approximate 48-mile 230 kV greenfield overhead transmission line double circuit project from existing Conastone substation to new Bartholow substation. The line will largely travel on new double circuit monopoles within a new ROW as part of expanded easement alongside existing ROW.

43e – New 230 kV Transmission Line From New Bartholow Substation to Existing Mt. Airy Substation
This component of the proposal is for an approximate 5-mile 230 kV greenfield overhead transmission line from the new Bartholow substation to the existing Mt. Airy substation. The line will largely travel on new single circuit monopoles within a new ROW as part of expanded easement alongside existing ROW.

48b – Two New 230 kV Single Circuit Transmission Lines From Existing Keeney to Existing Waugh Chapel Substation
This component of the proposal is for an approximate 104-mile section of 230 kV line with 34 miles of submarine cable, and roughly 70 miles of new 230 kV overhead transmission from the existing Keeney substation to the existing Waugh Chapel substation. The two single circuit 230 kV lines will be staggered and offset to utilize the same ROW width as a 230 kV double circuit design. The submarine cable will be used to cross the Chesapeake Bay. The ROW will have its own corridor for approximately 85% of the route length. The ROW will be an expansion of an existing transmission corridor for approximately 15% of the route length. Approximately 30% of the route will be submarine.

Overall, the ROW risk for components in this proposal is high due to the extensive greenfield nature of the proposed new transmission line routes.

Environmental Risk Analysis

48b – Two New 230 kV Single Circuit Transmission Lines From Existing Keeney to Existing Waugh Chapel Substation
The proposed route has the potential to impact environmental and cultural resources including New Castle and Frenchtown Railroad ROW, Delaware Boundary Markers, Odessa Historic District (Boundary Increase), and Cooch's Bridge Historic District (Boundary Decrease).

Fifty-seven designated high-risk flood zones, 156 streams and 225 wetlands subject to USACE Section 404 and/or Section 10 permitting are required for crossing the Chesapeake Bay and woodlands with the potential to serve as suitable habitat for federally listed threatened and endangered species.

Coordination with the USACE; USFWS; National Park Service; SHPO (PA); and the county flood plain administrator from New Castle County, Pennsylvania; Cecil County, Kent County, Anne Arundel County, and Queen Anne's County, Maryland, will be required. Proposed route intersects 23 conservation easements and 13 parks/conservation areas. Coordination with easement holders will be required.

New Castle and Frenchtown railroad ROW, Delaware boundary markers, Odessa Historic District (boundary increase), and Cooch's Bridge Historic District (boundary decrease) are intersected by the proposed route.

47abc – New 500 kV Transmission Line From New Goram Substation to New Bartholow Substation
The proposed route has the potential to impact environmental resources including 13 designated high-risk flood zones, 96 streams, and 150 wetlands subject to USACE Section 404 and/or Section 10 permitting, and woodlands with the potential to serve as suitable habitat for federally listed threatened and endangered species.

Coordination with the USACE; USFWS; MD Dept. of Natural Resources; and the county flood plain administrator from Frederick County, Carroll County, Baltimore County, Maryland; and York County, Pennsylvania, will be required.

Proposed route intersects 45 conservation easements. Coordination with easement holders: Maryland Rural Legacy Program; Maryland Environmental Trust; Maryland Agricultural Land Preservation Foundation; NRCS - Admin State PA; Pennsylvania State Government; York County Agricultural Land Preservation Program, Pennsylvania; York County, Pennsylvania; Pennsylvania Department of Agriculture - Farmland Preservation Program; unknown local government will be required.

The proposed route intersects with parks/conservation areas including: Morgan Run Natural Environment Area (MD Department of Natural Resources). Coordination is recommended to determine construction constraints such as special-use permits, construction timing during public use, sound and/or noise considerations, traffic plans and restoration requirements.

New Grisham 230 kV Substation
Proposed location of the Grisham substation appears to intersect with wetlands.

Transmission Line Risk Analysis

48b – Two New 230 kV Single Circuit Transmission Lines From Existing Keeney to Existing Waugh Chapel Substation
Significant engineering, permitting and constructions risks anticipated for the proposed Keeney to Waugh Chapel line route, particularly the 34 miles of submarine line required to cross the Chesapeake Bay. Cable supply constraints are also a significant concern for this proposed route with cost and schedule risks associated with this component.

Substation Risk Analysis

New Grisham 230 kV Substation
Grisham is a proposed new three-bay breaker-and-a-half 230 kV substation to be connected by tapping Pacific to BECO and Buttermilk to Nimbus 230 kV lines. The proposed scope includes looping in and out existing Buttermilk to Nimbus and Pacific to BECO 230 kV lines and terminating two new single circuit 230 kV lines from new Bartholow (T-Point) substation. Major equipment proposed for the new Grisham 230 kV (breaker-and-a-half) switchyard includes three bays, six line terminals, two 150 MVAR shunt capacitor banks, one -300 to +500 MVAR Static VAR

Compensator (SVC), and eleven 230 kV, 5000A, 80 kAIC breakers. The capacitor banks are proposed to be installed on the east bus, and the SVC is proposed to be installed on the west bus.

New Bartholow 230 kV Substation

Bartholow is a proposed new 500-230 kV substation near the location where Conastoane-Brighton and Doubs-Brighton 500 kV lines form a "T-Point." The proposed substation will include two 500/230 transformer banks, a 500 kV switchyard, and a 230 kV breaker-and-a-half switchyard. The new 500 kV switchyard is proposed to be built with three bays, six line terminals, twelve 500 kV, 5000A, 63 kAIC breakers, two shunt 150 MVAR capacitor banks, one -300 to +500 MVAR Static VAR Compensator (SVC), and two 500-230 kV transformer banks. The new breaker-and-a-half 230 kV switchyard is proposed to be built with three bays, six line terminals, and eleven 230 kV, 5000A, 80 kAIC breakers. The proposal includes looping in of existing 500 kV Conastone-Brighton and existing 500 kV Doubs-Brighton lines and termination of one new 500 kV line and six new 230 kV lines.

New Goram 230 kV Substation

Goram is a proposed new 500 kV breaker-and-a-half switchyard to be constructed near existing Otter Creek substation with two bays, three line terminals, six 500 kV, 5000A, 63 kAIC breakers, one 500/230 kV transformer bank, and one 230 kV, 5000A, 80 kAIC breaker. It is also proposed to loop in existing 500 kV Peach Bottom-Three Mile Island line, terminate one new 500 kV line, and terminate one new 230 kV line to existing Otter Creek.

The other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering, and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 13**.

Table 13. Proposal 948 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	24e – North Delta to Cooper 230 kV rebuild	1.84	3.49
2	24f – North Delta to Graceton 230 kV rebuild	15.93	43.47
3	26A – New 500 kV transmission line from new North Delta substation to BGE's Conastone substation.	76.24	106.22
4	40AB1 – New two single circuit 230 kV transmission lines from new Bartholow substation to new Grisham substation	273.05	350.14
5	27d – North Peach Bottom to South Peach Bottom 500 kV upgrade	1.51	1.72
6	39H1 – New Grisham Substation – 6 terminal	40.92	135.78
7	45F1 – New Bartholow Substation – 12 terminal	99.29	221.49
8	26b2 – New North Delta Substation – 10 terminal	71.44	90.83
9	26c2– Conastone substation 500 kV and 230 kV substation expansion	2.80	10.54
10	39h1a – Nimbus to Buttermilk 230 kV loop in/out work	5.00	2.61
11	39h1b – Pacific to Beco 230 kV loop in/out work	5.00	2.61
12	47ab – New 230 kV transmission from new Goram substation to existing Otter Creek substation	2.37	9.27
13	47abc – New 500 kV transmission line from new Goram substation to new Bartholow substation	165.08	415.13
14	47ad – New 230 kV transmission line from existing Otter Creek substation to new Bartholow substation	141.43	267.93
15	47b – New double circuit 230 kV transmission from the existing Conastone substation to new Bartholow substation	142.21	204.43
16	47A – New Goram substation	53.27	72.89
17	47ax – Loop in Conastone to Brighton 500 kV line to new Bartholow substation	5.00	6.22
18	43EF – Mt Airy 230 kV substation single breaker expansion	2.80	5.71
19	43e – New 230 kV transmission line from new Bartholow substation to existing Mt. Airy substation	11.87	23.91
20	48b – Two new 230 kV single circuit transmission lines from the existing Keeney substation to existing Waugh Chapel substation	4250.00*	4250.00*
21	47ac – Otter Creek 230 kV four circuit breaker expansion	1.40	12.06
22	48C – Keeney substation two new 230 kV terminations	5.00	10.01
23	48d – Waugh Chapel substation two new 230 kV terminations	2.80	8.96
24	50B – Peach Bottom to North Delta 500 kV Upgrade	5.00	10.47
	Total	**5,381.25**	**6,265.88**

**Note: The cost estimate for the Component 20 for Keeney – Waugh Chapel was revised by the proposing entity from $490 M to $4,250 M due to cost estimation error, which raised the overall proposal cost estimate from $1,622 M to $5,381 M.*

The total proposal cost estimate is within 10–20% of the independent cost estimate and is considered medium risk.

Schedule Review

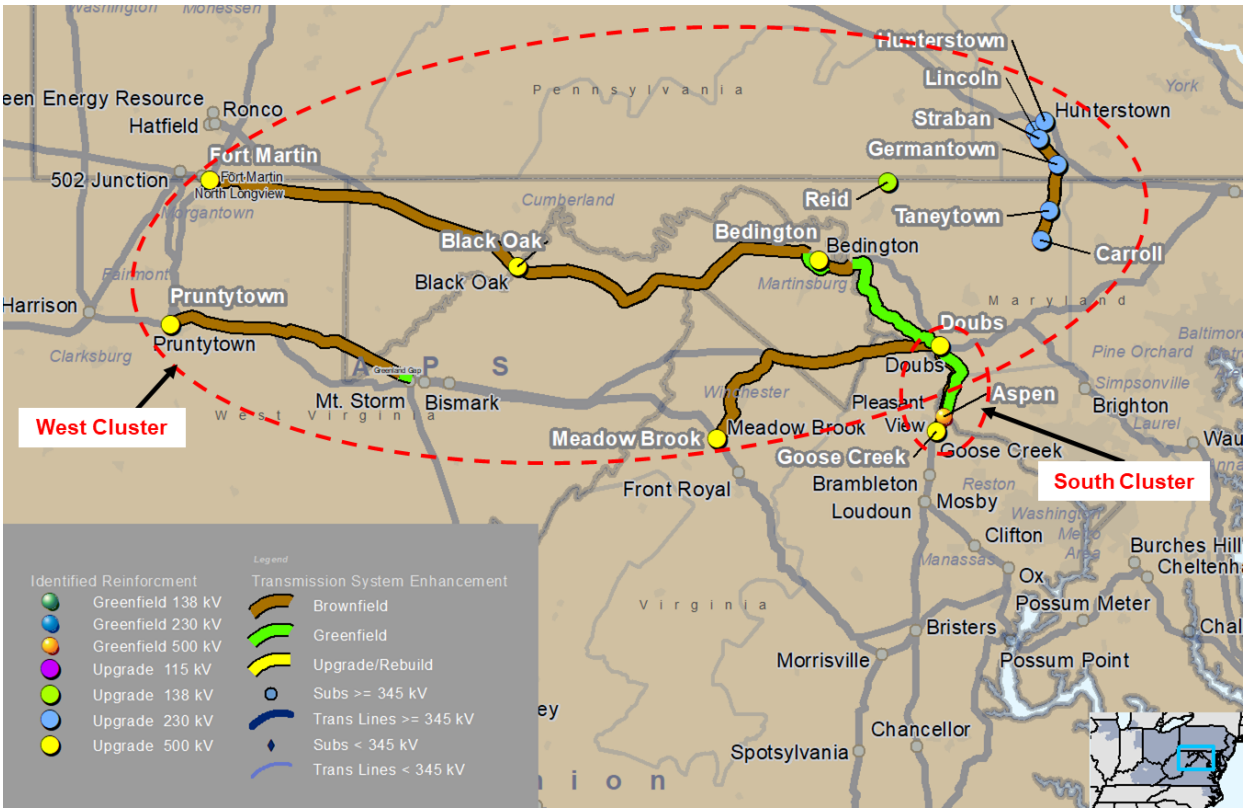
The proposed in-service date of June 2028 is very aggressive for the proposed scope of the project, considering the significant permitting, engineering and construction and land acquisition risks associated with the greenfield line routes. In particular, the permitting, engineering and construction risks anticipated with the Keeney to Waugh Chapel route has the potential to introduce significant schedule challenges. Overall, the schedule risk is considered high.

West Proposal Cluster

Proposal 837 (West) – FirstEnergy (Potomac Edison)

FirstEnergy Proposal No. 837 (**Map 15**), described as Data Center Reinforcement Proposal No. 1, has 30 components, which PJM has grouped into West and South clusters. Specifically for the West cluster, FirstEnergy proposed components in multiple counties across Pennsylvania, West Virginia, Virginia and Maryland, and includes new greenfield lines, as well as multiple substation upgrades.

Map 15. Proposal 837



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

FirstEnergy Proposal 837 includes the following components for the West Cluster:

- Component 1: Doubs substation – Install 500 kV breaker
- Component 2: Doubs substation – Expand 500 kV switchyard
- Component 3: Meadow Brook substation – Expand 500 kV switchyard
- Component 4: Fort Martin substation – Install 500 kV breaker
- Component 5: Pruntytown substation – Expand 500 kV switchyard
- Component 6: Bedington substation – Rebuild & Install 600 MVAR STATCOM
- Component 7: Fort Martin-Doubs 500 kV No. 1 line
- Component 8: Meadow Brook-Doubs 500 kV line
- Component 9: Meadow Brook-Pruntytown 500 kV line
- Components 10–13: Relaying Upgrades – Various stations
- Components 14–15: Overduty Breaker Replacements – Doubs & Pruntytown
- Components 18–30: Carroll-Hunterstown 230 kV line

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Fort Martin to Doubs 500 kV OH Line

This component of the proposal is for a single circuit 158-mile greenfield 500 kV overhead transmission line from the existing Fort Martin substation to the existing Doubs substation. The project is located across West Virginia, Virginia and Maryland. The new 500 kV is assumed to parallel an existing ROW for 85.6 miles of the route and has its own ROW that is not adjacent to any existing ROW for approximately 74.4 miles. The terrain for the route is hilly and passes through state and national parks, which may require alternative access route and construction methods.

Meadow Brook to Doubs 500 kV OH Line

This component of the proposal is for a 55.3-mile single circuit greenfield 500 kV overhead transmission line from the existing Meadow Brook substation to the existing Doubs substation. The project is located across West Virginia, Virginia and Maryland. The new 500 kV is assumed to parallel an existing ROW for 22.8 miles of the route and has its own ROW that is not adjacent to any existing ROW for approximately 32.5 miles. The terrain for the route is hilly and passes through state and national parks, which may require alternative access route and construction methods.

Meadow Brook to Pruntytown 500 kV OH Line

This component is for a 50.8-mile new 500 kV transmission line from the existing Pruntytown substation to the structure just north of the existing Mt. Storm substation. It will then cut the existing Meadow Brook to Mt. Storm line and connect to Pruntytown substation to create the new Meadow Brook to Pruntytown line. The project is located across West Virginia and Maryland. The new 500 kV is assumed to parallel an existing ROW for 14.5 miles of the route and has its own ROW that is not adjacent to any existing ROW for approximately 36.3 miles.

Hunterstown to Carroll 230 kV OH Line
This component is for a 24.3-mile new 230 kV overhead transmission line from the existing Hunterstown substation to the existing Carroll substation, using single circuit tubular steel monopole suspension structures. The project spans across Carroll County, Maryland, and Adams County, Pennsylvania. The new line will use the existing ROW of the 115/138 kV transmission corridor from Hunterstown-Lincoln-Germantown-Carroll substations. No additional ROW is required for this proposed line route.

Overall, the ROW risk for the new transmission line components in this proposal is medium-high to high, as the proposed new transmission lines are routed parallel to an existing ROW for most of their alignment, or use entirely new ROW, with the exception of the Hunterstown to Carroll 230 kV line that is an entirely brownfield development.

Environmental Risk Analysis

Fort Martin to Doubs 500 kV OH Line
The proposed route intersects floodways, flood plains, wetlands, navigable waters and public lands, and as a result, permitting is expected to be a lengthy process. This route crosses Cheat and Sleepy Creek lakes, and the Potomac River, and also goes through several national scenic and historic trails (South Mountain State Park and the Appalachian Scenic Trail), historical areas (Antietam, Harpers Ferry and Sharpsburg), intersects public lands, and crosses the Chesapeake and Ohio Canal National Historical Park. This may require permission from the National Park Service (NPS) and require an Environmental Assessment (EA) pursuant to the National Environmental Policy Act (NEPA) to analyze the impacts to the environment and park resource, which could be a lengthy process. Route crosses MD Department of Natural Resource (DNR)-recognized public lands and is also within a short distance of residential areas.

Meadow Brook to Doubs 500 kV OH Line
The proposed route crosses the Potomac River, and also goes through several national scenic and historic trails (Harpers Ferry National Historical Park and the Appalachian Scenic Trail), intersects public lands and conservation easements, and intersects the Chesapeake and Ohio Canal National Historical Park. This may require permission from the National Park Service (NPS) and require an Environmental Assessment (EA) pursuant to the National Environmental Policy Act (NEPA) to analyze the impacts to the environment and park resource, which could be a lengthy process. This route is also within a short distance of residential and commercial areas.

Meadow Brook to Pruntytown 500 kV OH Line
This route crosses national forests in West Virginia and is within a short distance of residential areas.

Medium-high constructability risks assessed for the proposed line routes due to anticipated lengthy regulatory process, potential public opposition, construction difficulty, environmental constraints and property acquisition, which may have significant impacts on the cost and schedule for the proposed project.

Transmission Line Risk Analysis

Significant engineering and construction challenges anticipated for the Ft Martin-Doubs line to construct a 158-mile transmission line through three states, and will require parallel crews and construction where possible to mitigate schedule challenges that will be introduced by the anticipated lengthy permitting process. This is also true, although to a lesser extent, for the Meadow Brook to Doubs and Meadow Brook to Pruntytown lines.

Substation Risk Analysis

The substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 14**.

Table 14. Proposal 837 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	Doubs Substation – Install 500 kV Breaker	4.72	5.41
2	Doubs Substation – Expand 500 kV Switchyard	14.44	16.65
3	Meadow Brook Substation – Expand 500 kV Switchyard	16.55	17.88
4	Fort Martin Substation – Install 500 kV Breaker	6.04	5.41
5	Pruntytown Substation – Expand 500 kV Switchyard	28.21	26.32
6	Bedington Substation – Rebuild & Install 600 MVAR STATCOM	131.38	219.32
7	Fort Martin – Doubs 500 kV #1 Line	1445.81	1502.52
8	Meadow Brook – Doubs 500 kV Line	460.60	275.45
9	Meadow Brook – Pruntytown 500 kV Line	418.59	245.99
10-13	Relaying Upgrades – Various Stations	8.27	8.14
14-15	Overduty Breaker Replacements – Doubs & Pruntytown	116.33	116.67
18-30	Carroll-Hunterstown 230 kV Line	137.45	202.30
	Total	**2,788.40**	**2,642.05**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

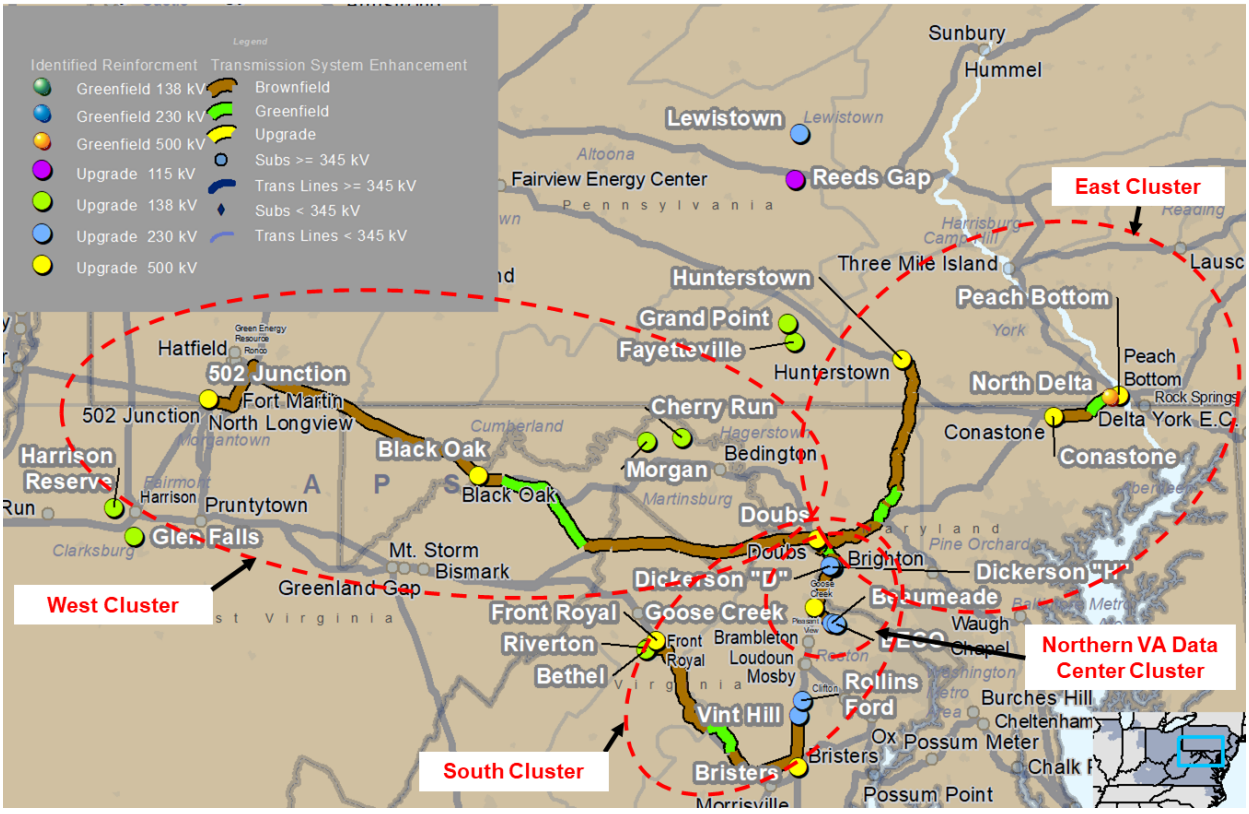
Schedule Review

The proposed in-service date of June 2030, although more reasonable compared to other West cluster proposals of similar scale, is still aggressive for the proposed scope of the project, considering the significant permitting and land acquisition challenges associated with the three proposed 500 kV greenfield line routes through three states. Overall, the schedule risk is considered medium.

Proposal 548 (West) – LS Power

LS Power Proposal No. 548 (**Map 16**), described as RTEP Window 3 Solution, provides a holistic solution to the RTEP Window 3 needs, comprising 37 components that can be grouped into the four regional clusters identified for the window. Specifically for the West cluster, LS Power proposed components in multiple counties across Pennsylvania, West Virginia, Virginia and Maryland and includes new greenfield lines as well as multiple substation upgrades.

Map 16. Proposal 548 (see next page)



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

LS Power Proposal 548 includes the following components for the West Cluster:

- Component 7: 502 Junction substation upgrade
- Component 9: Black Oak substation upgrade
- Component 11: Doubs substation upgrade
- Component 25: 502 Junction-Black Oak 500 kV transmission line
- Components 26 and 29: Black Oak-Doubs Greenfield 500 kV transmission line

Constructability Review

Right-of-Way/Land Usage Risk Analysis

502 Junction-Black Oak 500 kV OH Line

This component of the proposal is for a 73-mile single circuit greenfield 500 kV overhead transmission line from the existing 502 Junction substation to the existing Black Oak substation. The line parallels existing 500 kV ROWs for the entirety of the line, outside of a few short sections to route around constraints adjacent to the existing corridor.

Black Oak to Doubs 500 kV OH Line

This component of the proposal is for an 83-mile single circuit, partially greenfield 500 kV overhead transmission line from the existing Black Oak substation to the existing Doubs substation. The line parallels existing 500 kV ROWs for of the first 31 miles of the line, outside of a 10-mile section to route around constraints adjacent to the existing corridor. At the 32-mile mark, the line route will then involve a rebuild of the existing Hampshire to Stonewall 138 kV line, Stonewall to Millville 138 kV, and Millville to Doubs 138 kV lines as 500/138 kV line until a few spans outside of Doubs substation. At that point, the 500 kV circuit will diverge from the 138 kV centerline to connect to Doubs as single circuit 500 kV. The proposing entity assumes that the entire 52 miles of the 500/138 kV underbuilt development will fit entirely within the existing ROW. This assumption was not researched by the proposing entity with a high degree of confidence, and there is reasonable risk that this underbuilt segment will require additional ROW to accommodate the 500/138 kV double circuit structures.

Overall, the ROW risk for the new West cluster transmission line components in this proposal is medium-high, as the proposed new transmission lines are routed parallel to an existing ROW for majority of their alignment.

Environmental Risk Analysis

502 Junction-Black Oak 500 kV OH Line

Route crosses Pennsylvania and MD Department of Natural Resource (DNR)-recognized public lands and is also within a short distance of residential areas.

Black Oak to Doubs 500 kV OH Line

The proposed route crosses the Potomac River and goes through several national scenic and historic trails (Harpers Ferry National Historical Park and the Appalachian Scenic Trail), intersects public lands and conservation easements, and intersects the Chesapeake and Ohio Canal National Historical Park. This may require permission

from the National Park Service (NPS) and require an Environmental Assessment (EA) pursuant to the National Environmental Policy Act (NEPA) to analyze the impacts to the environment and park resource, which could be a lengthy process. This route is also within a short distance of residential and commercial areas.

Medium-high constructability risks assessed for the proposed line routes due to anticipated lengthy regulatory process, potential public opposition, construction difficulty, environmental constraints and property acquisition, which may have significant impacts on the cost and schedule for the proposed project.

Transmission Line Risk Analysis

Significant engineering and construction challenges anticipated for the proposed lines to construct a total of 156 miles of new transmission through four states and will require parallel crews and construction where possible to mitigate schedule challenges that will be introduced by the anticipated lengthy permitting process.

For the rebuild portions of the proposed line routes, there are challenges with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence and potential design and ROW limitations for reuse of existing infrastructure/assets.

Other medium risks for this project involve the existing facility outages that will be necessary for the project, particularly for the line rebuild, and substation upgrades.

Substation Risk Analysis

The substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 15**.

Table 15. Proposal 548 (West) Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
7	502 Junction Substation Upgrade	7.56	9.94
9	Black Oak Substation Upgrade	11.35	13.20
11	Doubs Substation Upgrade	17.02	24.00
25	502 Junction-Black Oak 500 kV Transmission Line	458.92	335.91
26	Black Oak-Doubs Greenfield 500 kV Transmission Line	200.02	173.55
29	Black Oak-Doubs Greenfield 500 kV Transmission Line (Shared ROW)	277.84	319.42
	Total	**972.71**	**876.03**

The total proposal cost estimate is more conservative than the independent cost estimate and is considered low risk.

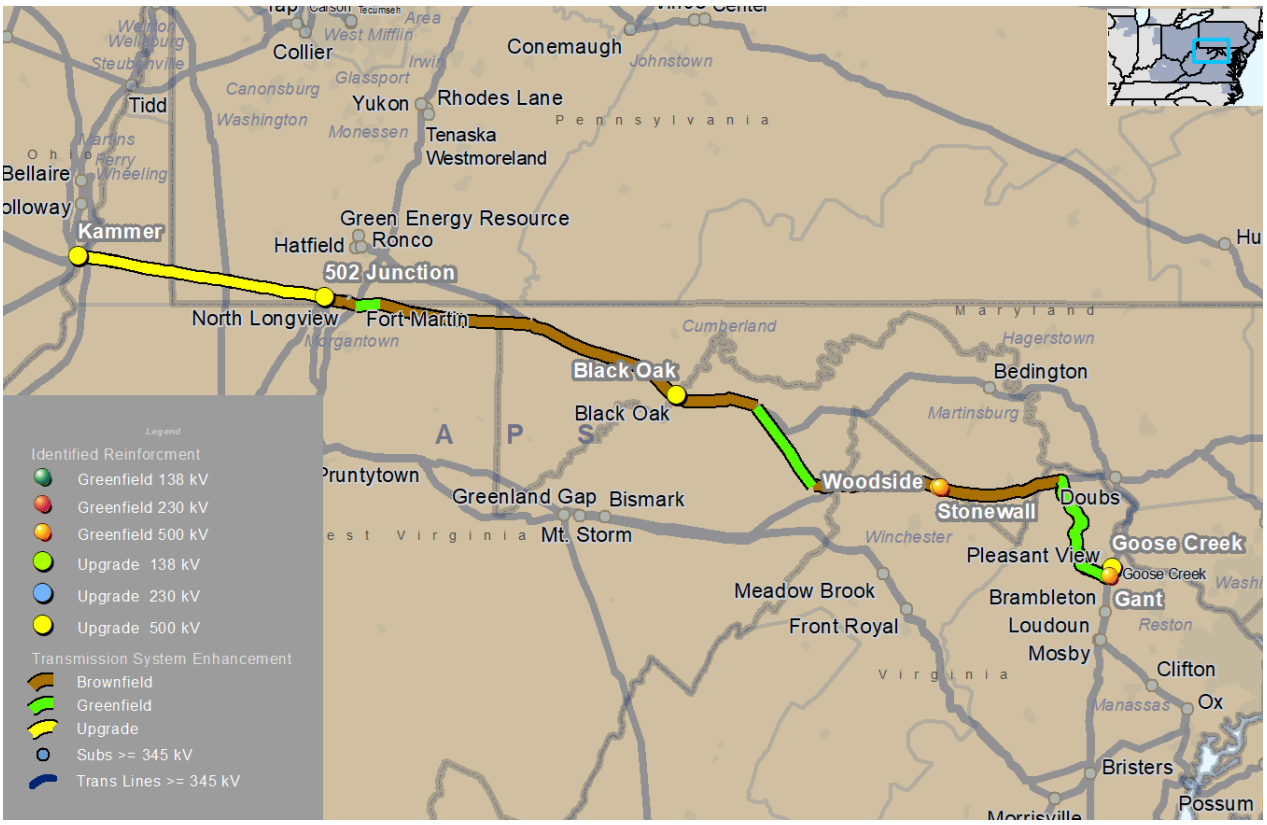
Schedule Review

The proposed in-service date of June 2030, although more reasonable compared to other West cluster proposals of similar scale, is still aggressive for the proposed scope of the project considering the significant permitting and land acquisition challenges associated with the two proposed 500 kV greenfield line routes through four states. Overall, the schedule risk is considered medium.

Proposal 853 – NextEra

NextEra Proposal No. 853 (**Map 17**), described as 502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks, includes components in multiple counties across Pennsylvania, West Virginia, Virginia and Maryland and includes new greenfield lines and substations as well as multiple substation upgrades.

Map 17. Proposal 853



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

NextEra Proposal 853 includes the following components for the West cluster:

- Component 1: 4CA – New 500 kV transmission line from existing Black Oak substation and new Woodside substation
- Component 2: 10C1A – New 500 kV transmission line from new Woodside substation to new Gant substation (Segment 1)
- Component 3: 23s5 – New Woodside Substation – 6 terminal
- Component 4: 23sb – Stonewall substation two 138 kV breaker expansion
- Component 5: 04AE – Black Oak substation 500 kV six breaker and new transformer expansion
- Component 6: 10C3 – New 500 kV line between new Woodside substation and new Gant substation (Segment 2)
- Component 7: 39a3 – New Gant substation – 3 terminal
- Component 8: 46a – New 500 kV line from existing 502 Junction substation to existing Black Oak substation
- Component 9: 46b – 502 Junction substation two 500 kV circuit breaker expansion
- Component 10: 46b1 – Kammer to 502 Junction 500 kV upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

46a – 502 Junction to Black Oak OH 500 kV Line

This component of the proposal is for a single circuit 67-mile 500 kV overhead transmission line from the existing 502 substation to the existing Black Oak substation. The project follows an existing transmission ROW, paralleling 502 Jct-Ft Martin 500 kV, then West Run-Lake Lynn-Hazelton-Jennings 138 kV, and then Black Oak-Hatfield 500 kV, only deviating from the existing ROW to route around potential conflict areas. The ROW width for the project will be 165 ft. and will be an expansion of the existing transmission corridor, and this additional ROW width will be reduced to a 75 ft. row for about 5% of the line due to ROW constraints.

4CA – Black Oak to Woodside OH 500 kV Line

This component of the proposal is for a single circuit 53-mile 500 kV overhead transmission line from the new Black Oak substation to the Woodside substation. The line utilizes existing ROW, paralleling Black Oak-Bedington 500 kV, then Hampshire-Ridgeley 138 kV, Hampshire-Gore 138 kV, and then Doubs-Bismark 500 kV up to Gore substation. Starting at Gore, the Gore-Stonewall 138 kV line is rebuilt as a 500/138 kV double circuit for 15 miles to the new Woodside substation. The ROW width will range between 125 ft.–165 ft. depending on location.

10C1A – Woodside to Gant (Segment 1) OH 500 kV Line

This component of the proposal is for a single circuit 22-mile 500 kV overhead transmission line from the new Woodside substation to the point east of the Appalachian Trail where the component 10C3 Segment 2 of the Woodside to Gant line begins to continue the route to Goose Creek substation. For approximately 80% of the route, the line uses existing ROW, rebuilding the Stonewall-Feagan's Mill-Millville-Lovettsville 138 kV lines as double 500/138 kV double circuit, and a ROW width expansion of 30 ft. will be required from the assumed ROW edge. The remaining 20% of the line will use new greenfield ROW with a corridor width of 115 ft.–165 ft. depending on location.

10C3 – Woodside to Gant (Segment 2) OH 500 kV Line

This component of the proposal picks up from the end of the component 10C1A Segment 1 of the proposed Woodside to Gant line. This component is a single circuit 25-mile-long line, which parallels Doubs-Bismark 500 kV for about 0.5 miles before continuing on its own greenfield ROW to the new Gant substation. The anticipated ROW width for this segment of the line route is 165 ft.

Overall, the ROW risk for the new West cluster transmission line components in this proposal is medium-high to high, as the proposed new transmission lines are routed parallel to an existing ROW for majority of their alignment.

Environmental Risk Analysis

46a – 502 Junction to Black Oak OH 500 kV Line

Route crosses West Virginia and MD Department of Natural Resource (DNR)-recognized public lands and is also within a short distance of residential areas.

4CA – Black Oak to Woodside OH 500 kV Line

Route crosses through the Appalachian Mountains and intersects with VA Natural Heritage easements.

10C1A – Woodside to Gant (Segment 1) OH 500 kV Line

The proposed route for this line segment goes through several national scenic and historic trails (Harpers Ferry National Historical Park and the Appalachian Scenic Trail), and intersects public lands and conservation easements. This may require permission from the National Park Service (NPS) and require an Environmental Assessment (EA) pursuant to the National Environmental Policy Act (NEPA) to analyze the impacts to the environment and park resource, which could be a lengthy process. This route is also within a short distance of residential and commercial areas.

10C3 – Woodside to Gant (Segment 2) OH 500 kV Line

The proposed route for this greenfield line segment goes through highly developed residential and commercial developments, as well as state and local conservation easements. This route also crosses the Washington & Old Dominion (W&OD Trail), a regional park in northern Virginia. There is significant risk of public opposition to the proposed route, which may lead to rerouting this segment along the existing corridor from Doubs to Goose Creek.

Overall, for Proposal 853, medium-high constructability risks are assessed for the proposed line routes due to anticipated lengthy regulatory process, potential public opposition, construction difficulty, environmental constraints and property acquisition, which may have significant impacts on the cost and schedule for the proposed project.

Transmission Line Risk Analysis

Significant engineering and construction challenges are anticipated for the proposed lines to construct a total of 167 miles of new transmission through four states and will require parallel crews and construction where possible to mitigate schedule challenges that will be introduced by the anticipated lengthy permitting and land acquisition process.

For the rebuild portions of the proposed line routes, there are challenges with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence, and potential design and ROW limitations for reuse of existing infrastructure/assets.

Other medium risks for this project involve the existing facility outages that will be necessary for the project, particularly for the line rebuild and substation upgrades.

Substation Risk Analysis

New Woodside 500/138 kV Substation

Woodside substation is a proposed new 3-bay breaker-and-a-half 500/138 kV switchyard to be located on about 18 acres. Proposed new equipment to be installed includes three bays; five line terminals; twelve 500 kV, 5000A 63 kAIC breakers; two 500 kV, 150 MVAR shunt capacitor banks; one -300 to +500 MVAR Static VAR Compensator (SVC); two 500 kV–138 kV transformer banks; and two 138 kV, 5000A 80 kAIC breakers. Additionally, termination of one new 500 kV line to Gant and one new 500 kV line Black Oak are proposed along with looping in of the existing 500 kV Doubs-Bismark line.

New Gant 500/230 kV Substation

Gant substation is a proposed new 500/230 kV breaker-and-a-half substation. New 500 kV breaker-and-a-half switchyard equipment proposed includes two bays; three line terminals; seven 500 kV, 5000A 63 kAIC breakers; and two 500/230 kV transformer banks. There is also a proposed 230 kV ring bus switchyard with seven line terminals;

seven 230 kV 80 kAIC breakers; and two 1% reactance series reactors. The proposed scope includes looping in existing 500 kV Goose Creek-Brambleton line, terminating one new 500 kV line, terminating one new 230 kV line, and looping in existing 230 kV Pleasant View-Roundtable line.

The other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 16**.

Table 16. Proposal 853 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates($M)
1	4CA – New 500 kV transmission line from existing Black Oak substation and new Woodside substation	163.50	258.98
2	10C1A – New 500 kV transmission line from new Woodside substation to Goose Creek substation	58.45	114.07
3	23s5 – New Woodside Substation – 6 terminal	125.30	167.58
4	23sb – Stonewall substation two 138kV breaker expansion	2.80	5.18
5	04AE – Black Oak substation 500 kV six breaker and new transformer expansion	14.00	23.31
6	10C3 – New 500 kV line between new Woodside substation and new Gant substation	64.72	155.23
7	39a3 – New Gant substation – 3 terminal	58.08	93.85
8	46a – New 500 kV line from existing 502 Junction substation to existing Black Oak substation	181.90	314.70
9	46b – 502 Junction substation two 500 kV circuit breaker expansion	9.80	9.09
10	46b1 – Kammer to 502 Junction 500 kV upgrade	5.00	53.23
	Total	**683.55**	**1,195.24**

The total proposal cost estimate is less than 30% of the independent cost estimate and is considered high risk

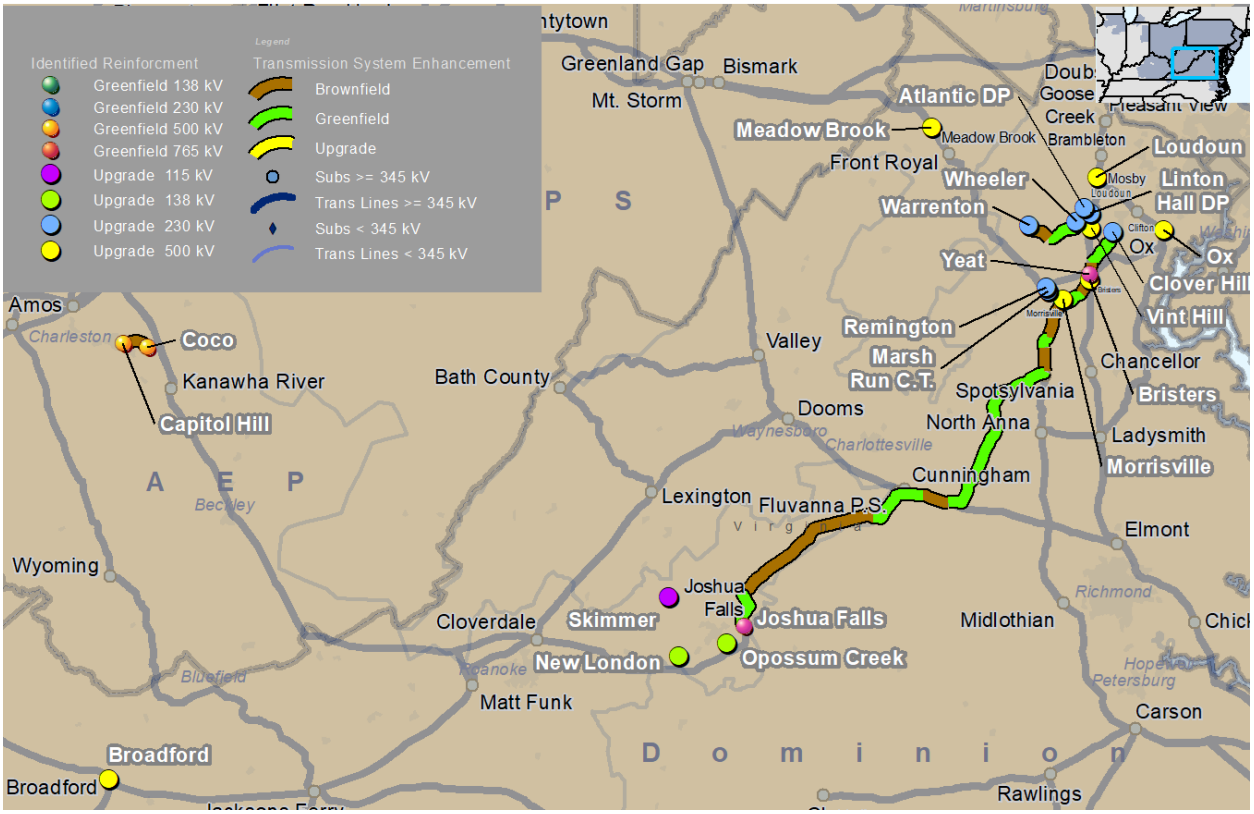
Schedule Review

The proposed in-service date of June 2027 is very aggressive for the proposed scope of the project considering the significant permitting and land acquisition challenges associated with the proposed 500 kV greenfield line routes through four states. Overall, the schedule risk is considered medium-high.

Proposal 904 – Transource

Transource Proposal No. 904 (**Map 18**), described as Joshua Falls-Yeat 765 kV greenfield line and substation, spans across multiple counties across Virginia and includes new greenfield lines and a greenfield substation, as well as multiple line and substation upgrades.

Map 18. Proposal 904



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Transource Proposal 904 includes the following components for the West Cluster:

- Component 1: Joshua Falls-Yeat 765 kV greenfield transmission line
- Component 2: Yeat greenfield station

- Component 3: Bristers-Ox 500 kV and Meadowbrook-Vint Hill 500 kV tie-in lines
- Component 4: Yeat-Clover Hill 230 kV greenfield transmission line
- Component 5: Warrenton-Wheeler 230 kV greenfield transmission line
- Component 6: Vint Hill-Morrisville series reactor
- Component 7: Vint Hill-Loudon 1 series reactor
- Component 8: Marsh Run-Remington Ct 230 kV line upgrade
- Component 9: Wheeler-Linton Tap-Atlantic 230 kV line upgrade
- Component 10: Bristers-Yeat 500 kV line upgrade
- Component 11: Wheeler station 230 kV breaker upgrade
- Component 12: Opossum Creek series reactor
- Component 13: New London station series reactor
- Component 14: Broadford station upgrade
- Component 15: Skimmer station upgrade
- Component 16: Coco-Capitol Hill 500 kV line upgrade
- Component 17: Joshua Falls station upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Joshua Falls-Yeat 765 kV OH Line

A major component of this proposal is the Joshua Falls-Yeat 765 kV transmission line. The proposed route is approximately 135 miles in length and traverses through 11 counties (Albemarle, Amherst, Buckingham, Campbell, Culpeper, Fauquier, Fluvanna, Louisa, Nelson, Orange and Spotsylvania) in Virginia. Land use in the area is mostly agricultural and wooded parcels in relatively hilly terrain. The proposed route parallels existing transmission corridors (ranging from 46 kV sub transmission to 500 kV transmission) for 59 miles (44%) of its alignment and has its own corridor for the remaining 76 miles, with a ROW width of 200 feet.

Yeat-Clover Hill 230 kV OH Line

This component has an 11.69-mile-long route, from the new Yeat substation to the existing Clover Hill substation using a greenfield corridor. The line crosses mostly residential and agricultural parcels in Fauquier and Prince William counties in Virginia.

Warrenton-Wheeler 230 kV OH Line

This component has an 8.8-mile-long route, and from the existing Warrenton substation to the existing Wheeler substation, using a mostly new greenfield corridor, paralleling existing transmission corridors for a portion of its alignment. The line crosses woodland, residential and agricultural parcels in Fauquier and Prince William counties in Virginia.

Environmental Risk Analysis

Joshua Falls-Yeat 765 kV OH Line

The proposed line route has the potential to impact environmental and cultural resources including: the Southern Albemarle Rural Historic District, a FEMA High-Risk Flood Zone, wetlands and several waters subject to USACE Section 10 permitting, the most significant being the James River. The route also intersects local conservation easements and appears to co-locate with pipeline ROWs.

Warrenton-Wheeler 230 kV OH Line

The line crosses woodland, residential and agricultural parcels in Fauquier and Prince William counties in Virginia. The route intersects local conservation easements and potentially impacts environmental resources such as Auburn Battlefield Historic District, flood plains and wetlands.

There are medium constructability risks assessed for the proposed line routes due to anticipated lengthy land acquisition process, potential public opposition and environmental constraints, which will have impacts on the cost and schedule for the proposed project.

Transmission Line Risk Analysis

Transource has an optimistic schedule for several aspects of this component and would require a near perfect execution to maintain the proposed in-service date. Given the scale of the component, a 135 mile 765 kV line with everything from permitting to land acquisition to construction poses a risk for delay, the most critical being land acquisition.

For the 230 kV developments, Yeat-Clover Hill and Warrenton-Wheeler, these facilities will utilize BOLD (Breakthrough Overhead Line Design), which is a structure family developed by AEP. The design features a monopole structure with two arched crossarms to hold two circuits in a delta configuration. Benefits of BOLD include increased line capacity with lower-profile structures. However, utilizing this structure family poses risks to the schedule, specifically procurement of the arched crossarms, construction and maintenance of a non-typical design.

Substation Risk Analysis

Joshua Falls 765 kV Substation Upgrade

The Joshua Falls substation is an existing 765 kV substation with a single 765 kV circuit breaker. The proposed modification of the substation would expand the substation by adding two additional 765 kV circuit breakers to the existing substation. This would require expansion of the existing substation layout. It is not clear if additional space is available for this site expansion. The modification would also require work in the proximity to existing energized facilities, which would limit construction activities without utilizing outages. There is a high risk to the schedule due to the difficult nature of scheduling prolonged outages at a 765 kV facility.

Yeat 765/500/230 kV Greenfield Substation

The Yeat substation is proposed with a Phase 1 construction consisting of 10-500 kV circuit breakers and two 500 kV-230 kV transformers in a breaker-and-a-half configuration. The 500 kV-230 kV transformers are proposed to be connected to common bus in the break-and-a-half configuration, instead of the industry standard of the breaker positions. During Phase 2, the construction would consist of installing one 765 kV circuit breaker and two 765 kV-500 kV 750 MVA transformers. The 765 kV transformers are proposed to be installed in parallel and connected to a single

breaker location on the 500 kV breaker and a half. Proper operation of this substation may require additional equipment and an expanded arrangement compared to what is proposed.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 17**.

Table 17. Proposal 904 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates($M)
1	Joshua Falls-Yeat 765 kV Greenfield Transmission Line	671.16	742.50
2	Yeat Greenfield Station	184.92	200.00
3	Bristers-Ox 500 kV, and Meadowbrook-Vint Hill 500 kV Tie-in Lines	8.60	9.00
4	Yeat-Clover Hill 230 kV Greenfield Transmission Line	45.17	41.00
5	Warrenton-Wheeler 230 kV Greenfield Transmission Line	32.46	31.00
6	Vint Hill-Morrisville Series Reactor	5.76	5.00
7	Vint Hill-Loudon 1 Series Reactor	5.76	5.00
8	Marsh Run-Remington Ct 230 kV Line Upgrade	5.83	6.00
9	Wheeler-Linton Tap-Atlantic 230 kV Line Upgrade	1.47	6.00
10	Bristers-Yeat 500 kV Line Upgrade	3.33	4.50
11	Wheeler Station 230 kV Breaker Upgrade	1.96	3.00
12	Opossum Creek Series Reactor	2.16	1.50
13	New London Station Series Reactor	4.03	1.50
14	Broadford Station Upgrade	17.64	17.64
15	Skimmer Station Upgrade	1.96	1.96

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates($M)
16	Coco-Capitol Hill 500 kV Line Upgrade	11.80	16.80
17	Joshua Falls Station Upgrade	44.10	30.00
	Total	**1,048.10**	**1,122.40**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

Schedule Review

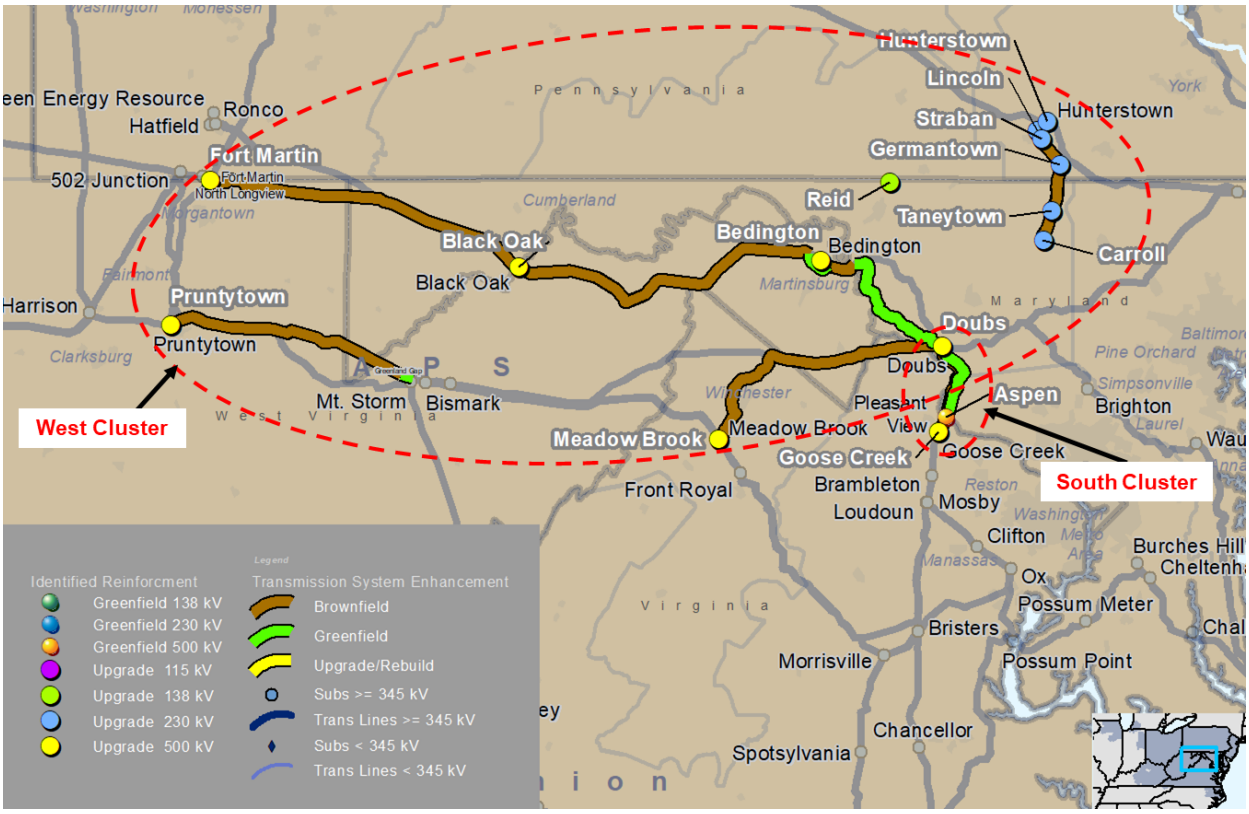
This proposal includes 765 kV substation and transmission line construction, as well as utilization of BOLD (Breakthrough Overhead Line Design) technology for the greenfield 230 kV lines. The sum of all components is a very aggressive undertaking to be completed within the proposed schedule. The primary risks for this proposal are related to the magnitude of the scope of work, procurement and construction of 765 kV equipment and BOLD structures, state permitting and land acquisition for both the 765 kV and 230 kV developments. These all pose a medium-high risk to the December 2029 in-service date proposed by Transource.

South Proposal Cluster

Proposal 837 (South) – FirstEnergy (Potomac Edison)

FirstEnergy Proposal No. 837 (**Map 19**), described as Data Center Reinforcement Proposal No. 1, has 30 components, which PJM has grouped into West and South clusters. Specifically for the South cluster, FirstEnergy proposed components in a joint proposal with Dominion's Proposal 516 that rebuilds the Doubs-Goose Creek 500 kV line and adds a new Doubs to Aspen 500 kV line within the same corridor.

Map 19. Proposal 837



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

FirstEnergy Proposal 837 includes the following components for the South cluster:

- Component 16: Doubs-Goose Creek 500 kV rebuild
- Component 17: Doubs-Aspen 500 kV line

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Doubs to Aspen 500 kV OH Line and Doubs to Goose Creek 500 kV Rebuild

The new line from existing Doubs to new Aspen 500 kV OH line and Doubs to Goose Creek 500 kV rebuild projects will occur in the same transmission corridor, which currently contains the existing Doubs-Goose Creek '514' 500 kV, Doubs to Dickerson/Doubs to Aqueduct to Dickerson double circuit 230 kV, and Dickerson to Edwards Ferry to Pleasant View '203' 230 kV. These existing circuits will be rebuilt to accommodate the rebuilt Doubs to Goose Creek line, the existing 230 kV lines, and a new Doubs to Aspen 500 kV line using double circuit 500/230 kV structures for about 8 miles to Dickerson, and as two single circuit 500 kV lines for 7.5 miles up to the Maryland/Virginia state line.

Exelon (PEPCO) will have responsibility for their portion of the scope of work for the Dickerson-Edwards Ferry-Pleasant View 230 kV rebuild to double circuit 500/230 kV to accommodate the new Doubs-Aspen 500 kV line up to the Maryland/Virginia state line, and this scope is incorporated within PEPCO's proposal 660, component 22.

FirstEnergy proposal 837 scope ends at the Maryland/Virginia state line, and Dominion's proposal 516 continues with the rebuild of the Doubs to Goose Creek '514' 500 kV line as a double circuit 500/230 kV, and a rebuild of the Dickerson-Edwards Ferry-Pleasant View '203' 230 kV line as a double circuit 500/230 kV to accommodate the both the new Doubs to Aspen 500 kV line and the existing '203' 230 kV line. Dominion's scope will occur within the same transmission corridor which is about 3 miles long.

Overall, the ROW risk for both FirstEnergy proposal 837 and Dominion proposal 516 is low due to the utilization of existing ROW for the entire alignment of the proposed new line and rebuild projects.

Environmental Risk Analysis

Doubs to Aspen 500 kV OH Line and Doubs to Goose Creek 500 kV Rebuild

The project area is in the northern Virginia Piedmont region, which is predominately vegetated utilizing existing ROW. The proposed line routes will cross the Potomac and Monocacy rivers, the Dickerson Conservation Park, and parallels the Chesapeake and Ohio Canal National Historical Park. However, given the use of existing ROW for the route's entire alignment, permitting impacts are likely to be reasonable.

Transmission Line Risk Analysis

For the rebuild portions of the proposed line routes, there are challenges with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence and potential design and ROW limitations for reuse of existing infrastructure/assets.

Other medium risks for this project involve the existing facility outages that will be necessary for the project, particularly for the line rebuild, and required substation upgrades.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 18**.

Table 18. Proposal 837 (South) Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
16	Doubs-Goose Creek 500 kV Rebuild	87.74	76.56
17	Doubs-Aspen 500 kV Line	115.64	132.60
	Total	**203.38**	**209.16**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

Schedule Review

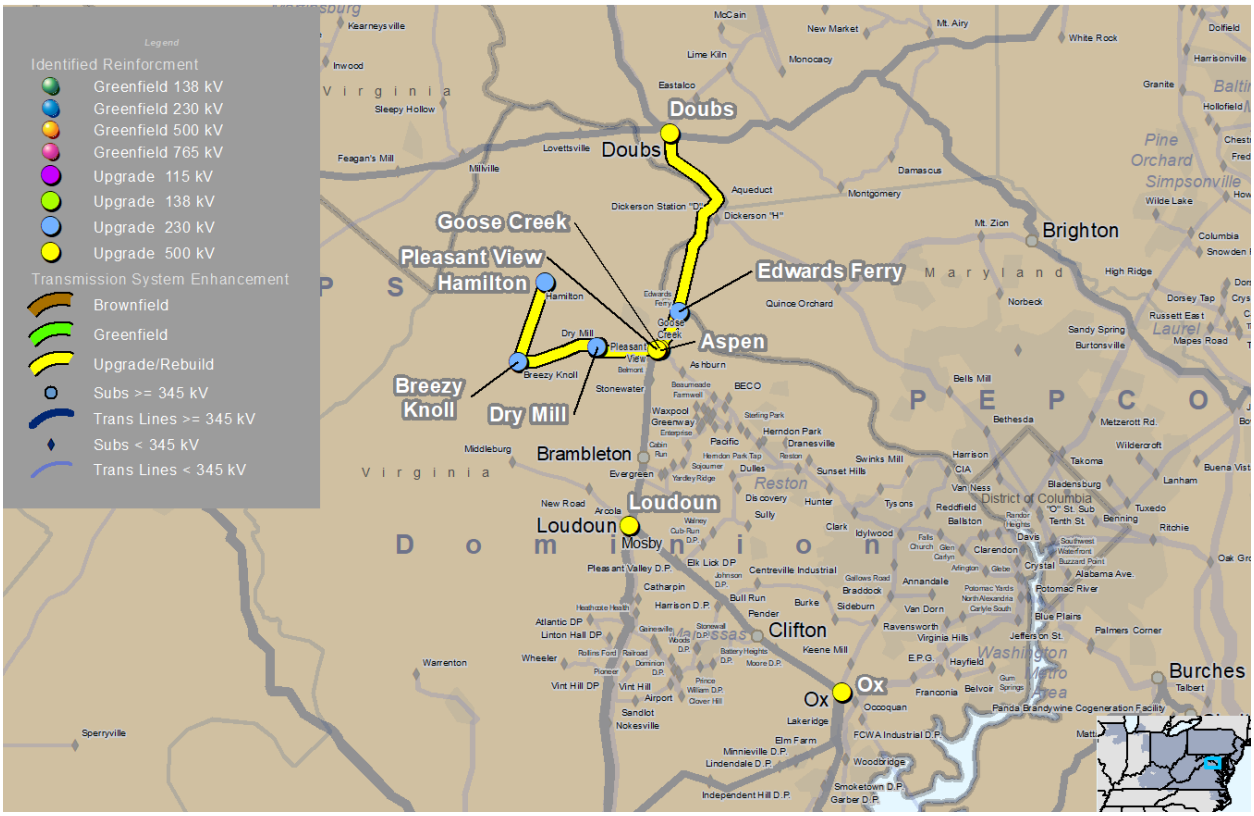
FirstEnergy proposal 837 South components are assumed to have the same December 2027 in-service date as Dominion joint-proposal proposal 516, instead of the overall Proposal 837 in-service date of June 2030, which is more applicable to the Proposal 837's West cluster components.

Given the low-risk brownfield development proposed for proposals 837 and 516, the proposed December 2027 in-service date is reasonable, and schedule risk is considered low.

Proposal 516 – Dominion

Dominion's Proposal No. 516 (**Map 20**), described as interregional solution Aspen-Doubs second 500 kV line, is a joint proposal with FirstEnergy's Proposal 837 that rebuilds the Doubs-Goose Creek 500 kV line, and adds a new Doubs to Aspen 500 kV line within the same corridor.

Map 20. Proposal 516



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Dominion's Proposal 516 includes the following components for the South cluster:

- Component 1: Aspen substation terminal equipment installation for 5000A line to Doubs
- Component 2: Breezy Knoll relay reset
- Component 3: Dry Mill South relay reset
- Component 4: Goose Creek substation equipment upgrade
- Component 5: Hamilton relay reset
- Component 6: Pleasant View substation equipment upgrade
- Component 7: Line No. 203 (Pleasant View-Dickerson) rebuild
- Component 8: New 500 kV line (Aspen to Doubs)
- Component 9: Line No. 514 (Goose Creek-Doubs) rebuild
- Component 10: Line No. 2098 (Pleasant View-Hamilton) partial rebuild
- Component 11: Loudoun substation overdutied breaker replacement
- Component 12: Ox substation overdutied breaker replacement
- Component 13: Pleasant View substation overdutied breaker replacement
- Component 14: Edwards Ferry substation equipment upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

Doubs to Aspen 500 kV OH Line and Doubs to Goose Creek 500 kV Rebuild

The new line from existing Doubs to new Aspen 500 kV OH line and Doubs to Goose Creek 500 kV rebuild projects will occur in the same transmission corridor, which currently contains the existing Doubs-Goose Creek '514' 500 kV, Doubs to Dickerson/Doubs to Aqueduct to Dickerson double circuit 230 kV, and Dickerson to Edwards Ferry to Pleasant View '203' 230 kV. These existing circuits will be rebuilt to accommodate the rebuilt Doubs to Goose Creek line, the existing 230 kV lines, and a new Doubs to Aspen 500 kV line, using double circuit 500/230 kV structures for about 8 miles to Dickerson, and as two single circuit 500 kV lines for 7.5 miles up to the Maryland/Virginia state line. Exelon (PEPCO) will have responsibility for the Proposal 837 scope of work for the Dickerson-Edwards Ferry-Pleasant View 230 kV rebuild to double circuit 500/230 kV to accommodate Doubs-Aspen up to the Maryland/Virginia state line.

FirstEnergy proposal 837 scope ends at the MD/VA state line, and Dominion's proposal 516 continues with the rebuild of the Doubs to Goose Creek '514' 500 kV line as a double circuit 500/230 kV, and a rebuild of the Dickerson-Edwards Ferry-Pleasant View '203' 230 kV line as a double circuit 500/230 kV to accommodate the both the new Doubs to Aspen 500 kV line and the existing '203' 230 kV line. Dominion's scope will occur within the same transmission corridor which is about 3 miles long.

Overall, the ROW risk for both FirstEnergy proposal 837 and Dominion proposal 516 is low due to the utilization of existing ROW for the entire alignment of the proposed new line and rebuild projects.

Environmental Risk Analysis

Doubs to Aspen 500 kV OH Line and Doubs to Goose Creek 500 kV Rebuild

The project area is in the northern Virginia Piedmont region, which is predominately vegetated utilizing existing ROW. The proposed line routes will cross the Potomac and Monocacy rivers, the Dickerson Conservation Park, and parallels the Chesapeake and Ohio Canal National Historical Park. However, given the use of existing ROW for the route's entire alignment, permitting impacts are likely to be reasonable.

Transmission Line Risk Analysis

For the rebuild portions of the proposed line routes, there are challenges with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence and potential design and ROW limitations for reuse of existing infrastructure/assets.

Other medium risks for this project involve the existing facility outages that will be necessary for the project, particularly for the line rebuild, and required substation upgrades.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 19**.

Table 19. Proposal 516 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates($M)
1	Aspen Substation Terminal Equipment Installation for 5000A Line to Doubs	12.99	16.00
2	Breezy Knoll Relay Reset	0.02	0.05
3	Dry Mill South Relay Reset	0.02	0.05
4	Goose Creek Substation Equipment Upgrade	4.09	5.60
5	Hamilton Relay Reset	0.01	0.05
6	Pleasant View Substation Equipment Upgrade	3.62	5.00
7	Line #203 (Pleasant View-Dickerson) Rebuild	6.87	7.90
8	New 500 kV Line (Aspen to Doubs)	12.02	14.00
9	Line #514 (Goose Creek-Doubs) Rebuild	12.02	14.00
10	Line #2098 (Pleasant View-Hamilton) Partial Rebuild	3.44	3.50

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates($M)
11	Loudoun Substation Overdutied Breaker Replacement	2.32	5.00
12	Ox Substation Overdutied Breaker Replacement	2.51	4.20
13	Pleasant View Substation Overdutied Breaker Replacement	1.29	2.10
14	Edwards Ferry Substation Equipment Upgrade	0.51	0.50
	Total	**61.72**	**77.95**

The total proposal cost estimate is within 20–30% of the independent cost estimate and is considered medium-high risk.

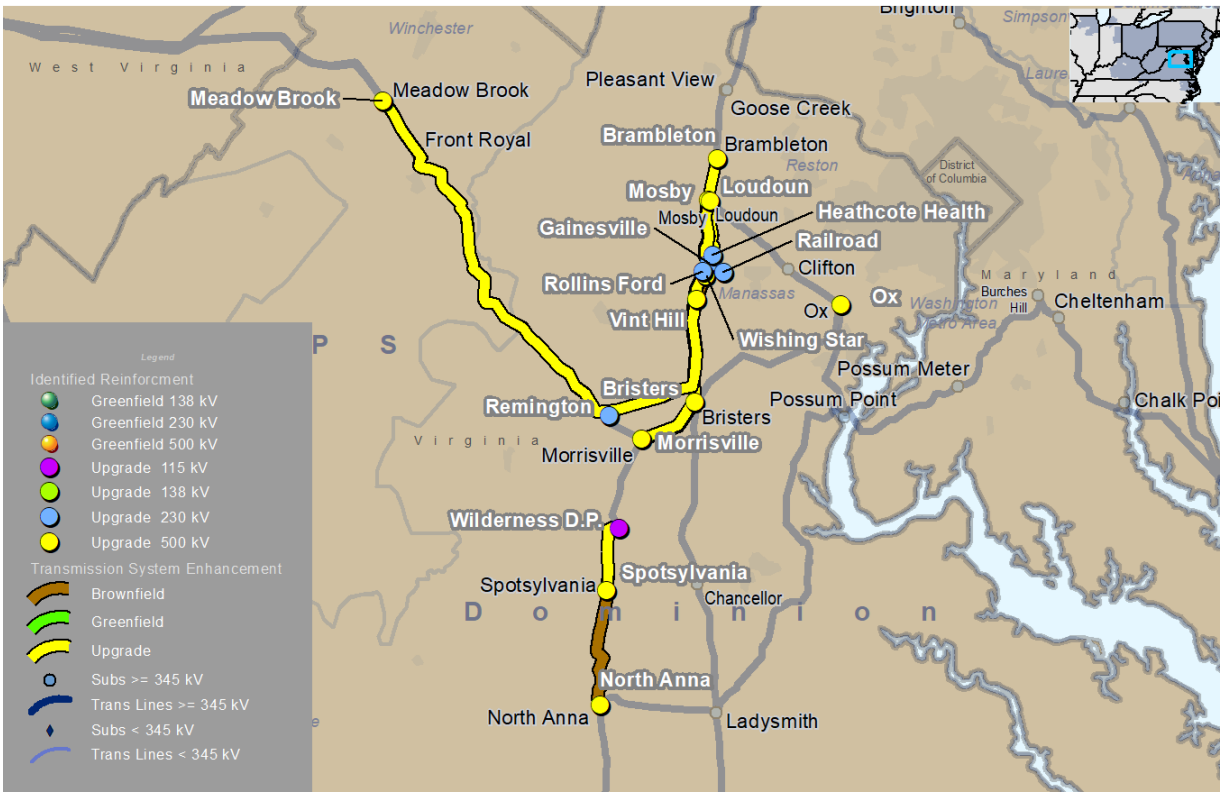
Schedule Review

Given the low-risk brownfield development proposed for Dominion's Proposal 516 and FirstEnergy Proposal 837, the proposed December 2027 in-service date is reasonable, and schedule risk is considered low.

Proposal 711 – Dominion

Dominion's Proposal No. 711 (**Map 21**), described as Regional Solution 500 kV North Anna-Wishing Star Upgrades, involves a comprehensive solution to add new 500 kV transmission lines from North Anna to Wishing Star with extensive use of existing transmission ROWs. The project spans multiple counties in Virginia and involves addition of three new greenfield 500 kV transmission lines and multiple existing line rebuilds and substation upgrades.

Map 21. Proposal 711



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Dominion's Proposal 711 includes the following components:

- Component 1: New 500 kV line (North Anna-Spotsylvania) (993169)
- Component 2: North Anna equipment uprate (993169)
- Component 3: Spotsylvania equipment uprate (993169)
- Component 4: Loudoun 230 kV overdutied breaker replacement (993208_2)
- Component 5: North Anna 500 kV overdutied breaker replacement (993208_2)
- Component 6: Ox 500 kV overdutied breaker replacement (993208_2)
- Component 7: New 500 kV line (Spotsylvania to Vint Hill) (993232)
- Component 8: New 500 kV line (Vint Hill to Wishing Star) (993232)
- Component 9: Line No. 37 (Spotsylvania-Wilderness D.P.) rebuild
- Component 10: Line No. 545 (Bristers-Morrisville) rebuild
- Component 11: Line No. 569 (Loudoun to Morrisville) rebuild
- Component 12: Line No. 535 (Meadow Brook-VintHill- Loudoun) rebuild

- Component 13: Line No. 546 (Mosby-Wishing Star) rebuild
- Component 14: Line No. 590 (Mosby-Wishing Star) rebuild
- Component 15: Line No. 2030 (Gainesville-Loudoun) rebuild
- Component 16: Line No. 2045 (Loudoun-Brambleton) rebuild
- Component 17: Line No. 2094 & 2227 (Brambleton-Racefield-Loudoun) rebuild
- Component 18: Line No. 2101 (Bristers-Vint Hill) rebuild
- Component 19: Line No. 2114 (Remington CT-Rollin Ford) rebuild
- Component 20: Line No. 2140 (Loudoun-Heathcote) rebuild
- Component 21: Line No. 2151 (Railroad DP-Gainesville) rebuild
- Component 22: Line No. 2163 (Vint Hill-Liberty) rebuild
- Component 23: Line No. 2176 (Heathcote-Gainesville) rebuild
- Component 24: Line No. 2222 (Rollins Ford-Gainesville) rebuild
- Component 25: Line No. 183 (Bristers-Ox) rebuild
- Component 26: Line No. 535 (Meadow Brook-VintHill- Loudoun) Resag
- Component 27: Bristers substation
- Component 28: Brambleton substation
- Component 29: Dawkins branch substation
- Component 30: Gainesville substation
- Component 31: Heathcote substation
- Component 32: Loudoun substation
- Component 33: Mint Springs substation
- Component 34: Morrisville substation
- Component 35: Mosby substation
- Component 36: North Star substation
- Component 37: Racefield substation
- Component 38: Railroad substation
- Component 39: Spotsylvania substation
- Component 40: Vint Hill substation
- Component 41: Wishing Star substation
- Component 42: Youngs branch substation

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New 500 kV OH Line (North Anna-Spotsylvania) (993169)

The new 13.94-mile 500 kV OH line from existing North Anna to existing Spotsylvania will be built parallel to the existing North Anna to Spotsylvania '573' line, using the same transmission corridor, which will not require any expansion. The line route is located in a predominantly vegetated area within Virginia Piedmont region.

New 500 kV OH Lines (Spotsylvania to Vint Hill and Vint Hill to Wishing Star) (993232)

The project involves a rebuild of Dominion's existing two 500/230 kV line corridor from Spotsylvania-Morrisville-Bristers-Nokesville-Vint Hill in order to accommodate the new Spotsylvania to Vint Hill (16.59 miles) and Vint Hill to Wishing Star (38.45 miles) 500 kV OH lines The final configuration will be a three-structure configuration, with the new 500 kV lines on single circuit monopoles, and the existing 500 kV and 230 kV lines on two 500/230 kV double circuit poles existing transmission corridor all fitting within the same existing transmission ROW, which will not require any expansion in width.

Overall, the ROW risk for this proposal is low due to the utilization of existing ROW for the entire alignment of the proposed new lines and rebuild projects.

Environmental Risk Analysis

The project area is in the northern Virginia Piedmont region, which is predominately vegetated utilizing existing ROW. Given the use of existing ROW for the route's entire alignment, environmental impacts are expected to be minimal.

Transmission Line Risk Analysis

The proposed three structure configuration for the Spotsylvania to Wishing Star line route poses some design risk and will require significant detailed engineering to ensure construction feasibility. Special considerations may need to be taken into account for the close proximity of the lines for outage scheduling when pulling conductor and swinging from wind gusts.

The outage coordination required for rebuilding multiple transmission line rebuilds and building three new transmission lines in existing ROW is significant. Delays to any project component would have a cascading effect on the following outage schedule for other components. To help address these concerns, Dominion provided a reasonable outage sequencing plan for the project, with potential transmission outage windows already identified. Overall, a medium risk was assessed for outage coordination for the project.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 20**.

Table 20. Proposal 516 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	New 500 kV Line (North Anna-Spotsylvania) (993169)	119.37	105.00
2	North Anna Equipment Uprate (993169)	11.43	12.00
3	Spotsylvania Equipment Uprate (993169)	7.06	6.50
4	Loudoun 230 kV Overdutied Breaker Replacement (993208_2)	1.72	4.00
5	North Anna 500 kV Overdutied Breaker Replacement (993208_2)	1.33	2.80
6	Ox 500 kV overdutied Breaker Replacement (993208_2)	1.29	2.80
7	New 500 kV Line (Spotsylvania to Vint Hill) (993232)	219.53	230.00
8	New 500 kV Line (Vint Hill to Wishing Star) (993232)	87.81	99.00
9	Line #37 (Spotsylvania-Wilderness D.P.) Rebuild	17.56	17.84
10	Line #545 (Bristers-Morrisville) Rebuild	65.86	59.00
11	Line #569 (Loudoun to Morrisville) Rebuild	175.62	185.00
12	Line #535 (Meadow Brook-VintHill- Loudoun) Rebuild	65.86	62.00
13	Line #546 (Mosby-Wishing Star) Rebuild	43.91	36.00
14	Line #590 (Mosby-Wishing Star) Rebuild	43.91	36.00
15	Line #2030 (Gainesville-Loudoun) Rebuild	17.56	22.00
16	Line #2045 (Loudoun-Brambleton) Rebuild	17.56	17.78
17	Line #2094 & 2227 (Brambleton-Racefield-Loudoun) Rebuild	17.56	17.00
18	Line #2101 (Bristers-Vint Hill) Rebuild	17.56	43.00
19	Line #2114 (Remington CT-Rollin Ford) Rebuild	17.56	47.00
20	Line #2140 (Loudoun-Heathcote) Rebuild	17.56	20.00
21	Line #2151 (Railroad DP-Gainesville) Rebuild	4.39	2.45
22	Line #2163 (Vint Hill-Liberty) Rebuild	17.56	18.00
23	Line #2176 (Heathcote-Gainesville) Rebuild	8.78	3.00
24	Line #2222 (Rollins Ford-Gainesville) Rebuild	13.17	4.86
25	Line #183 (Bristers-Ox) Rebuild	8.78	7.20
26	Line #535 (Meadow Brook-VintHill- Loudoun) Resag	111.53	128.70
27	Bristers Substation	5.72	5.72
28	Brambleton Substation	4.65	4.00
29	Dawkins Branch Substation	0.02	0.02
30	Gainesville Substation	3.71	3.20
31	Heathcote Substation	0.02	0.02
32	Loudoun Substation	16.70	13.00
33	Mint Springs Substation	0.03	0.03
34	Morrisville Substation	9.30	14.00
35	Mosby Substation	11.75	11.20
36	North Star Substation	0.03	0.03
37	Racefield Substation	0.03	0.03
38	Railroad Substation	0.02	0.03

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
39	Spotsylvania Substation	7.98	8.40
40	Vint Hill Substation	23.73	24.00
41	Wishing Star Substation	12.30	12.00
42	Youngs Branch Substation	0.02	0.02
	Total	**1,227.84**	**1,284.62**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

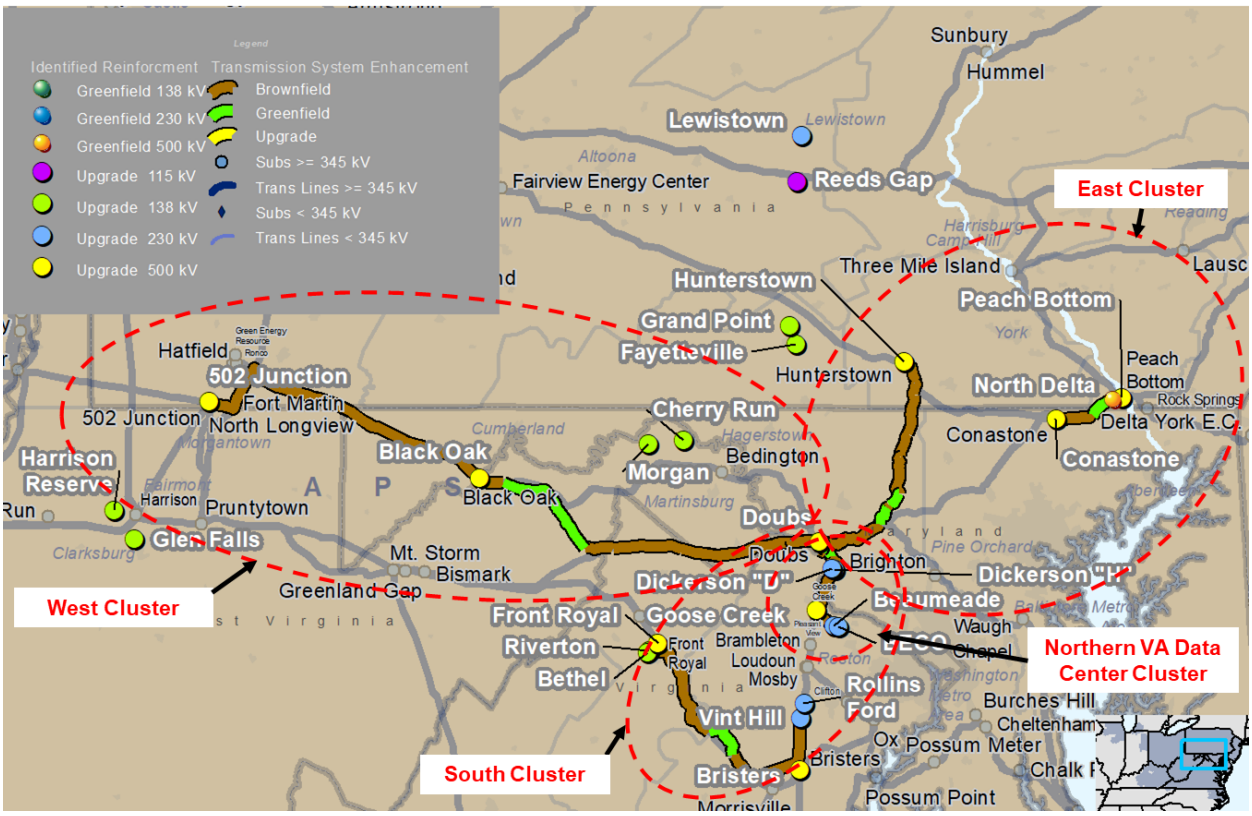
Schedule Review

Given the low-risk brownfield development proposed for Dominion's Proposal 711, the proposed December 2027 in-service date is achievable, but in consideration of the outage coordination risks posed by the significant number of line rebuilds, a medium schedule risk is assessed for this project.

Proposal 548 (South) – LS Power

LS Power Proposal No. 548 (**Map 22**), described as RTEP Window 3 Solution, provides a holistic solution to the RTEP Window 3 needs, comprising 37 components, which can be grouped into the four regional clusters identified for the Window. Specifically for the South cluster, LS Power proposed components in multiple counties across Maryland and Virginia, and includes new greenfield lines, as well as multiple substation upgrades.

Map 22. Proposal 548



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

LS Power Proposal 548 includes the following components for the South cluster:

- Component 12: Goose Creek substation upgrade
- Component 15: Vint Hill substation upgrade
- Component 22: Vint Hill-Loudoun reconductor
- Component 28: Doubs-Goose Creek greenfield 500 kV transmission line
- Component 30: Front Royal substation upgrade
- Component 33: Doubs-Goose Creek greenfield 500 kV transmission line (shared ROW)
- Component 34: Front Royal-Vint Hill greenfield 500 kV transmission line

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New Doubs to Goose Creek 500 kV Line

The new approximately 20-mile 500 kV line route from existing Doubs to existing Goose Creek 500 kV starts with the first 10 miles on new ROW parallel to the Doubs to Dickerson 230 kV line, up to Dickerson station D, and then the Dickerson station D to Pleasant View 230 kV line will be rebuilt as a double circuit 500/230 kV line to accommodate the 500 kV line for about 8 miles up to Pleasant View, and then the Pleasant View to Hamilton 230 kV line is added onto the line in a rebuilt 500/230/230 kV configuration for about 1 mile before the 500 kV circuit enters the Goose Creek substation.

New Front Royal-Vint Hill 500 kV Line

The new 64-mile 500 kV line route from existing Front Royal to existing Vint Hill starts from Front Royal and parallels Front Royal-Morrisville until it meets up with Remington substation. The line then parallels the Remington CT to Gainesville 230 kV line corridor all the way to Vint Hill substation. The proposed route only deviates from paralleling the existing corridor to avoid any conflicts adjacent to the existing corridor.

Overall, the ROW risk for both LS Power proposed line routes is medium-high due to the extensive utilization of greenfield paralleling existing ROW for the majority of the proposed project's alignment.

Environmental Risk Analysis

New Doubs to Goose Creek 500 kV Line

The project area is in the northern Virginia Piedmont region which is predominately vegetated utilizing existing ROW. The proposed line route will cross the Potomac and Monocacy rivers, the Dickerson Conservation Park, and parallels the Chesapeake and Ohio Canal National Historical Park.

New Front Royal – Vint Hill 500 kV Line

The proposed route for this line segment goes through national scenic trails (Appalachian Scenic Trail). This may require permission from the National Park Service (NPS) and require an Environmental Assessment (EA) pursuant to the National Environmental Policy Act (NEPA) to analyze the impacts to the environment and park resource, which could be a lengthy process. The route also intersects multiple conservation easements and recreation areas crossing in five counties (Fauquier, Prince William, Culpeper, Rappahanock, Warren) in Virginia.

Medium-high constructability risks assessed for the proposed Front Royal to Vint Hill line routes due to anticipated challenges with permitting, property acquisition and public opposition given historical difficulty with permitting projects in Fauquier and Prince William counties, and the need to expand the existing TRAIL corridor for the new Front Royal-Vint Hill line.

Transmission Line Risk Analysis

For the rebuild portions of the proposed line routes, there are challenges with existing overhead transmission infrastructure components needing to be removed/salvaged before construction of proposed brownfield lines can commence and potential design and ROW limitations for reuse of existing infrastructure/assets.

Other medium risks for this project involve the existing facility outages that will be necessary for the project, particularly for the line rebuild components, and required substation upgrades.

Substation Risk Analysis

The substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 21**.

Table 21. Proposal 548 (South) Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
12	Goose Creek Substation Upgrade	52.36	54.00
15	Vint Hill Substation Upgrade	20.32	21.00
22	Vint Hill-Loudoun Reconductor	13.23	15.00
28 & 33	Doubs-Goose Creek Greenfield 500 kV Transmission Line	105.52	114.00
30	Front Royal Substation Upgrade	33.42	35.00
34	Front Royal-Vint Hill Greenfield 500 kV Transmission Line	403.70	378.00
	Total	**628.56**	**617.00**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

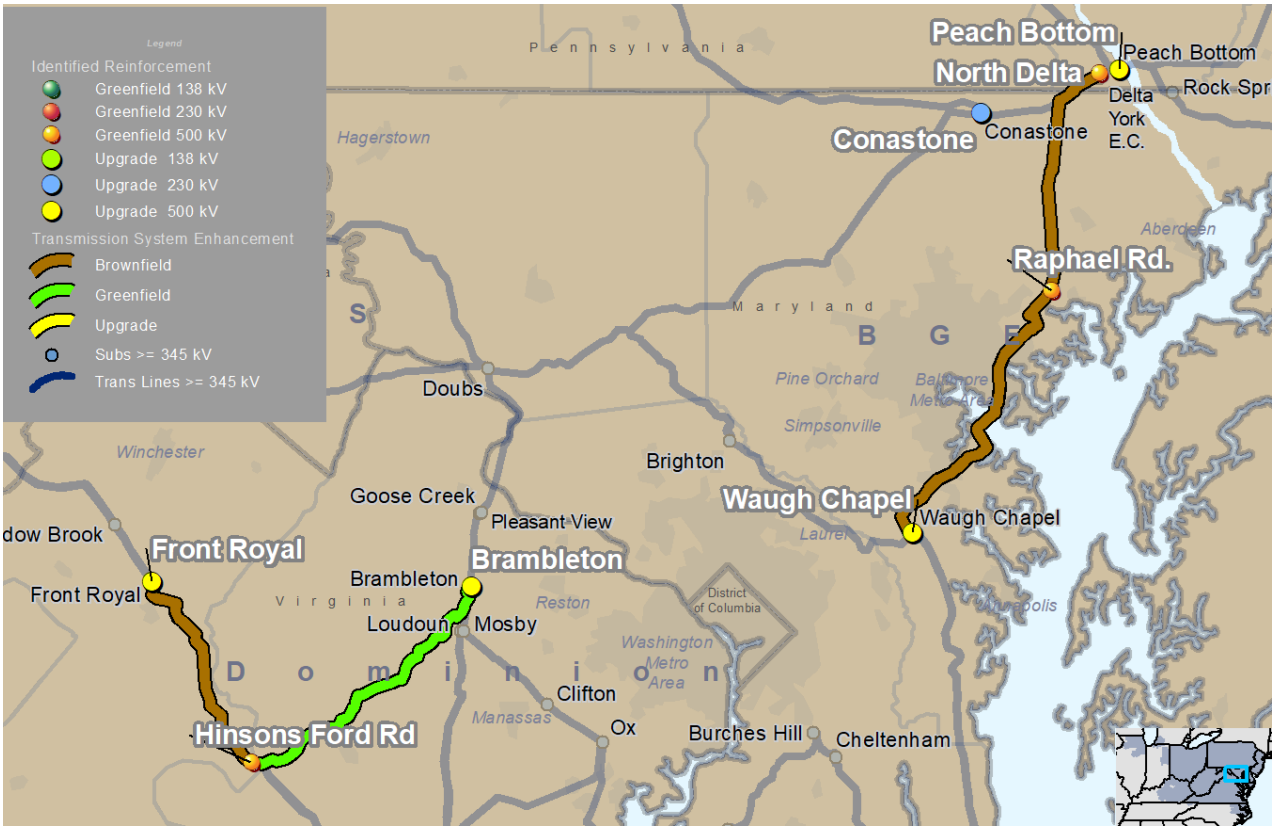
Schedule Review

The proposed in-service date of June 2030 is considered a medium-high risk due to the anticipated constructability challenges with the new Front Royal-Vint Hill line.

Proposal 325 – PSEG

PSEG Proposal No. 325 (**Map 23**), described as Proposal E – Brambleton-Hinsons Ford Rd 500 kV, has 12 components out of which three were included for evaluation in the South clusters. These components involve greenfield lines and a greenfield substation, as well as a line upgrade in four counties (Prince William, Fauquier, Rappahannock, Loudoun) within Virginia.

Map 23. Proposal 325



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

PSEG Proposal 325 includes the following components for the South cluster:

- Component 9: New Brambleton to Hinsons Ford Rd 500 kV line
- Component 10: Reconductor Front Royal-Hinson Ford Rd 500 kV
- Component 12: Hinsons Ford Rd 500 kV

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New Brambleton to Hinsons Ford Rd 500 kV Line

The new line from existing Brambleton to new Hinsons Ford 500 kV OH line involves a 34-mile route in an entirely greenfield corridor, with the terrain a combination of urban and rural areas.

The ROW risk for this project is high due to the pure greenfield nature of the proposed development.

Environmental Risk Analysis

New Brambleton to Hinsons Ford Rd 500 kV Line

The proposed route intersects flood plains, multiple conservation easements and a local park in four counties (Fauquier, Prince William, Rappahanock, Loudoun) in Virginia.

High constructability risks assessed for the proposed route due to anticipated challenges with permitting, property acquisition and public opposition given historical difficulty with permitting projects in Fauquier and Prince William counties, and also considering the greenfield nature of the project.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 22**.

Table 22. Proposal 325 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
9	New Brambleton to Hinsons Ford Rd 500 kV line	185.48	204.00
10	Reconductor Front Royal-Hinson Ford Rd 500 kV	43.18	43.56
12	Hinsons Ford Rd 500 kV	38.71	28.00
	Total	**267.38**	**275.56**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

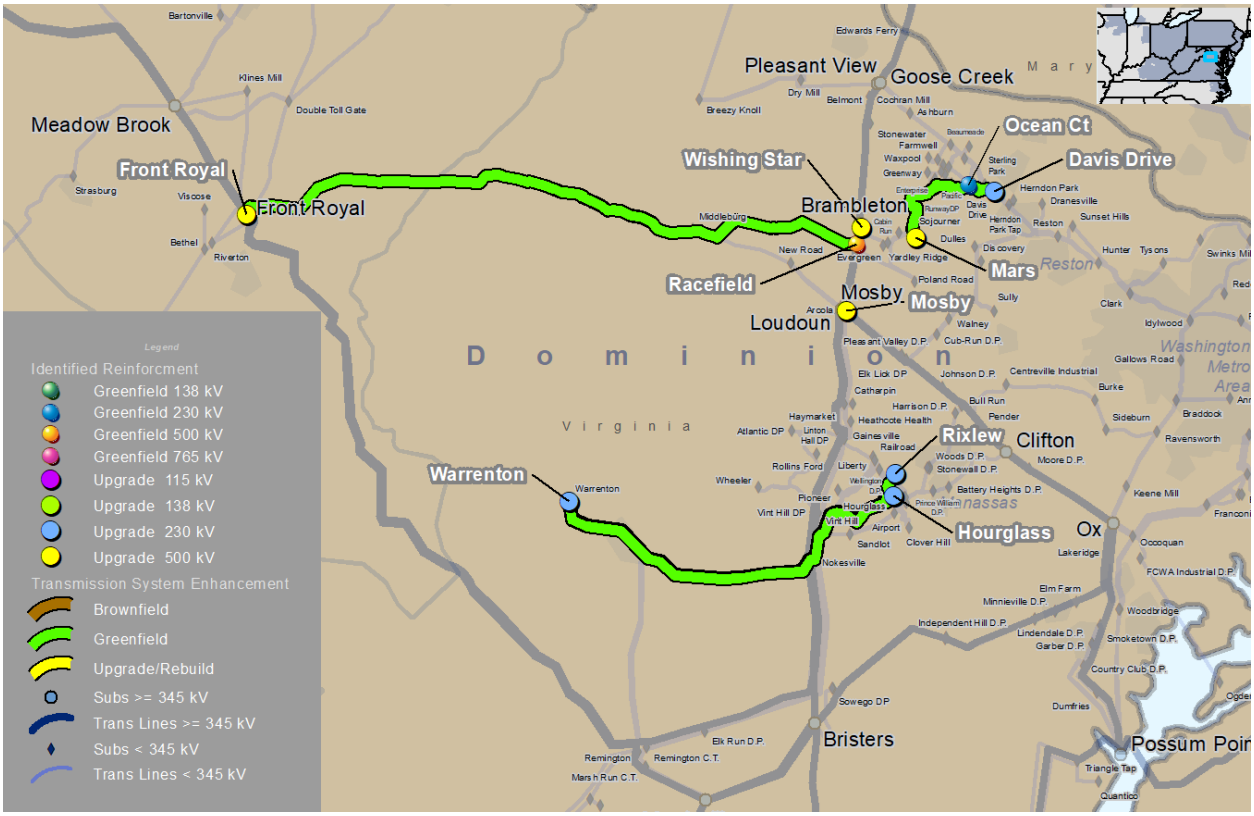
Schedule Review

The proposed in-service date of June 2027 is considered a high schedule risk due to the anticipated constructability challenges with the new Brambleton-Hinsons Ford Rd 500 kV line.

Proposal 663 – NextEra

NextEra Proposal No. 663 (**Map 24**), described as Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive, has components that span Fauquier, Prince William and Loudoun counties in Virginia. These components involve greenfield lines and a greenfield GIS substation, as well as multiple substation upgrades.

Map 24. Proposal 663 (see next page)



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

NextEra Proposal 663 includes the following components for the South cluster:

- Component 1: 1B – New 500 kV transmission line from Allegheny substation Front Royal to new Racefield switchyard
- Component 2: 01A – New 500 kV line termination at Front Royal substation
- Component 3: 1F – New Racefield GIS substation – 5 terminal
- Component 4: 33E – Warrenton substation 230 kV ring bus expansion
- Component 5: 40C – Mars substation 230 kV ring bus expansion

- Component 6: 40a – New 230 kV transmission line from existing Mars substation to existing Ocean Court substation
- Component 7: 40b – New 230 kV transmission line from existing Ocean Court substation to existing Davis Drive substation
- Component 8: 40f – New 230 kV transmission line from existing Warrenton substation to existing Hourglass substation
- Component 9: 40g – New 230 kV transmission line from existing Warrenton substation to future Rixlew substation
- Component 10: 40D – Ocean Court substation 230 kV ring bus expansion
- Component 11: 40E – Davis Drive 230 kV line termination
- Component 12: 40h – Hourglass substation 230 kV single breaker expansion
- Component 13: 40i – Rixlew substation 230 kV single-breaker expansion
- Component 14: 50C – Mosby to Wishing Star 500 kV upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

1B – New Front Royal to Racefield 500 kV OH Line

The new line from existing Front Royal to new Racefield 500 kV OH line involves a 48-mile route in an entirely greenfield corridor. The project is located in the rolling hills and pastures of the Virginia Piedmont region, crossing Fauquier and Loudoun counties.

40f and 40g – Warrenton to Hourglass and Warrenton to Rixlew 230 kV Lines

The existing Warrenton to existing Hourglass 230 kV line route is approximately 16 miles long, with its entire route a new greenfield ROW. The existing Warrenton to future Rixlew 230 kV line route is approximately 18 miles long, with its entire route a new greenfield ROW. Both projects are located within the Prince William and Fauquier counties in Virginia.

40a and 40b – Mars to Ocean Court and Ocean Court to Davis Drive 230 kV Lines

The existing Mars to existing Ocean Court line is a new approximately 6-mile line, with about 60% of its route a new greenfield ROW, and the remaining 40% paralleling an existing transmission line. The existing Ocean Court to existing Davis Drive line is a new approximately 2-mile line, with its entire route a new greenfield ROW. Both projects are located in the valley south of the Potomac River in Loudoun County, Virginia.

Overall, the ROW risk for this Proposal 663 is high due to the extensive greenfield development involved in the proposed line routes.

Environmental Risk Analysis

1B – New Front Royal to Racefield 500 kV OH Line

The proposed route for this line segment goes through national scenic trails (Appalachian Scenic Trail) and intersects public lands and conservation easements. This may require permission from the National Park Service (NPS) and require an Environmental Assessment (EA) pursuant to the National Environmental Policy Act (NEPA) to analyze the

impacts to the environment and park resource, which could be a lengthy process. The proposed route also intersects flood plains, multiple conservation easements, and recreation lands in Fauquier and Loudoun counties in Virginia.

Overall, High constructability risks assessed for the proposed line routes, especially for the Front Royal to Racefield 500 kV line, due to anticipated challenges with permitting, property acquisition and public opposition given historical difficulty with permitting projects in Fauquier and Loudoun counties, and also considering the greenfield nature of the project.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 23**.

Table 23. Proposal 663 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	1B – New 500 kV Transmission Line from Allegheny Substation Front Royal to new Racefield switchyard	143.02	288.00
2	01A – New 500 kV line termination at Front Royal substation	2.80	6.00
3	1F – New Racefield GIS Substation – 5 terminal	23.44	48.00
4	33E – Warrenton substation 230 kV ring bus expansion	1.40	8.00
5	40C – Mars substation 230 kV ring bus expansion	1.40	2.00
6	40a – New 230 kV transmission line from existing Mars substation to existing Ocean Court substation	11.51	20.47
7	40b – New 230 kV transmission line from existing Ocean Court substation to existing Davis Drive substation	4.51	7.00
8	40f – New 230 kV transmission line from existing Warrenton substation to existing Hourglass substation	40.92	56.00
9	40g – New 230 kV transmission line from existing Warrenton substation to future Rixlew substation	43.88	63.00
10	40D – Ocean Court substation 230 kV Ring Bus Expansion	2.80	4.00
11	40E – Davis Drive 230 kV line termination	0.70	0.70
12	40h – Hourglass substation 230 kV single breaker expansion	1.40	2.00
13	40i – Rixlew substation 230 kV single breaker expansion	1.40	2.00
14	50C – Mosby to Wishing Star 500 kV Upgrade	5.00	7.00
	Total	**284.17**	**514.17**

The total proposal cost estimate is less than 30% of the independent cost estimate and is considered high risk

Schedule Review

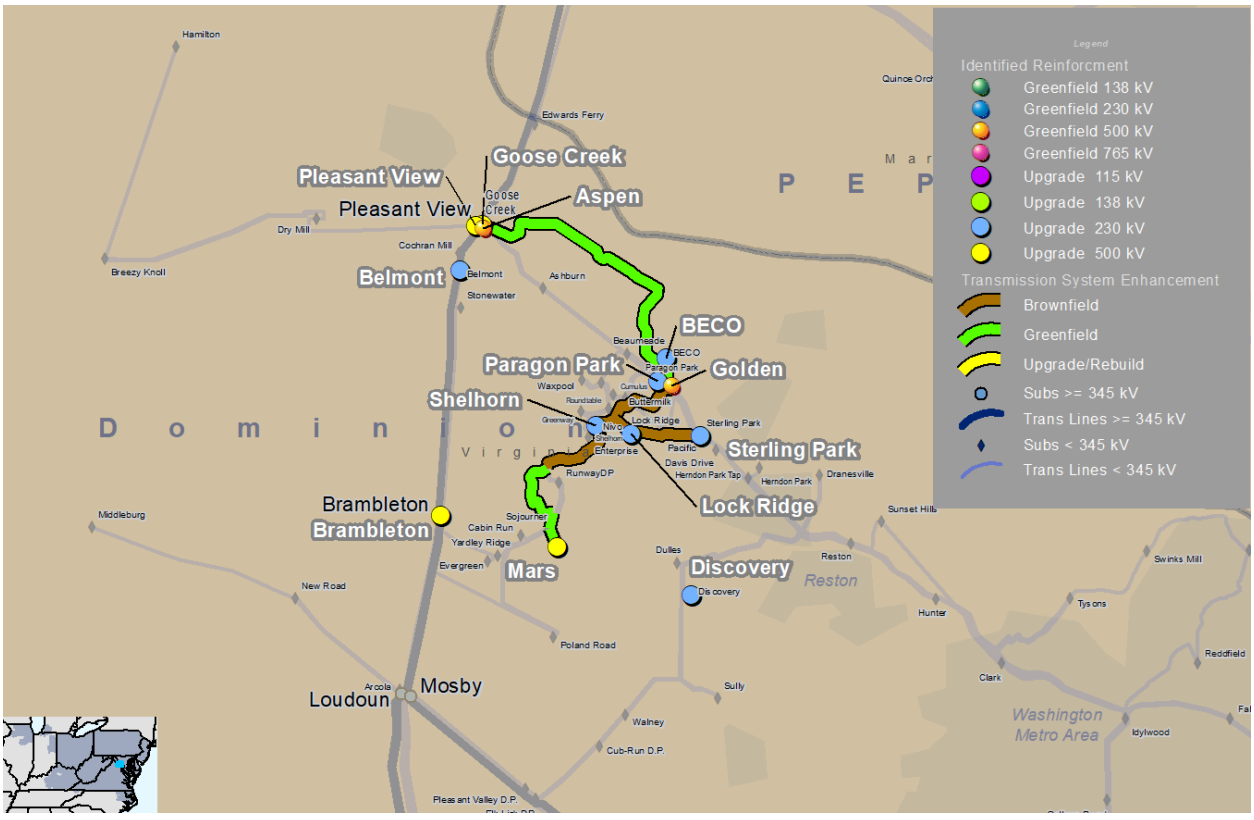
The proposed in-service date of June 2027 is considered a high schedule risk due to the anticipated constructability challenges with the proposed line routes.

Northern VA Data Center Proposal Cluster

Proposal 692 – Dominion

Dominion's Proposal No. 692 (**Map 25**), described as Data Center Alley Local solution – New 500 kV/230 kV Aspen-Golden and Golden-Mars lines, involves a local solution intended to facilitate interconnections of data centers in the Dominion Service area. The project includes new greenfield transmission lines and substations, as well as multiple existing line and substation upgrades, all within Loudoun County, Virginia.

Map 25. Proposal 692



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Dominion's Proposal 692 includes the following components:

- Component 1: Aspen-Golden 500 kV line build (99-2971)
- Component 2: Mars 500-230 kV transformer installation (99-3197)
- Component 3: Line No. 2150 (Golden to Paragon Park Circuit 1) reconductoring (99-3188)
- Component 4: Line No. 2081 (Golden to Paragon Park Circuit 2) reconductoring (99-3188)
- Component 5: Paragon Park substation equipment rating upgrade (99-3188)
- Component 6: Golden relay setting upgrade reset (99-3188)
- Component 7: Line No. 2207 (Paragon Park-Beco) reconductoring (99-3200)
- Component 8: Paragon Park substation equipment rating upgrade (99-3200)
- Component 9: Beco substation equipment rating upgrade (99-3200)
- Component 10: New Mars-Lockridge-Golden 230 kV line construction (99-2970)
- Component 12: New Mars-Golden 500 kV line construction (99-2970)
- Component 13: 500 kV line No. 558 (Brambleton-Goose Creek) cut-in to Aspen (99-2971)
- Component 14: New 500 kV line from Aspen to Goose Creek (99-2971)
- Component 15: Line No. 2150 (Sterling Park to Paragon Park Circuit 1) cut-in to Golden (99-2971)
- Component 16: Line No. 2081 (Sterling Park to Paragon Park Circuit 2) cut-in to Golden (99-2971)
- Component 17: New 230 kV line from Aspen-Golden (99-2971)
- Components 1–19: Golden, Lockridge and Mars substation upgrades (99-2970)
- Components 20–25: Beaumeade, Beco, Belmont, Discovery, Pleasant View and Shellhorn substation overdutied breaker replacements (99-3208)
- Component 26: New Aspen 500/230 kV substation (99-2971)
- Component 27: New Golden 500/230 kV substation (99-2971)
- Components 28–32: Brambleton, Goose Creek, Paragon Park, Sterling Park and Sycolin Creek substation upgrades (99-2971)

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New Aspen to Golden 500 kV and 230 kV OH Lines

The new 8.5-mile 500 kV OH lines from new Aspen to new Golden substation will require an entirely new ROW corridor for the line route using 500/230 kV double circuit two-pole structures. The line route is located in a predominantly vegetated and urban development area within northern Virginia Piedmont region in Loudoun County, Virginia.

New Golden to Mars 500 kV and 230 kV OH Lines

The new 8.3-mile 500 kV OH lines from new Golden to future Mars substation will require an entirely new ROW corridor for the line route using 500/230 kV double circuit two-pole structures. The line route is located in a predominantly vegetated and urban development area within northern Virginia Piedmont region in Loudoun County, Virginia.

Overall, the ROW risk for this proposal is high due to the utilization of greenfield ROW for the entire alignment of the proposed new lines.

Environmental Risk Analysis

The proposed routes go through wetlands, and the Mars-Golden line appears to cross the Dulles Greenway.

Medium constructability risks assessed due to anticipated challenges for land acquisition, and public opposition, given historical difficulty siting projects in Loudoun County and the greenfield nature of the project.

Transmission Line Risk Analysis

Given the short length of the proposed greenfield lines, the main transmission line risks are associated with land acquisition, siting and schedule risks.

Substation Risk Analysis

New Aspen 500/230 kV Substation

Aspen is a proposed new 500/230 kV substation located in Loudoun County, Virginia. Dominion has already acquired the land for this site. The substation includes a 500 kV double breaker, double bus GIS bus, one 500/230 kV transformer bank, and a 230 kV Breaker and a Half GIS bus.

New Golden 500/230 kV Substation

Golden is a proposed new 500/230 kV substation located in Loudoun County, Virginia. The substation includes a 500 kV double-breaker, double-bus GIS bus, two 500/230 kV transformer banks, and a 230 kV breaker-and-a-half GIS bus.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects). Specifically for this proposal, there is some schedule risk for the procurement of the transformers and GIS bus components.

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 24**.

Table 24. Proposal 692 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	Aspen-Golden 500 kV Line Build (99-2971)	98.35	93.50
2	Mars 500-230 kV Transformer Installation (99-3197)	42.19	38.00
3	Line #2150 (Golden to Paragon Park Circuit 1) Reconductoring (99-3188)	1.44	2.65
4	Line #2081 (Golden to Paragon Park Circuit 2) Reconductoring (99-3188)	1.44	2.65
5	Paragon Park Substation Equipment Rating Upgrade (99-3188)	0.09	0.10
6	Golden Relay Setting Upgrade Reset (99-3188)	0.02	0.05
7	Line #2207 (Paragon Park-Beco) Reconductoring (99-3200)	3.36	3.50
8	Paragon Park Substation Equipment Rating Upgrade (99-3200)	0.10	50.00
9	Beco Substation Equipment Rating Upgrade (99-3200)	1.86	2.00
10	New Mars-Lockridge -Golden 230 kV Lines Construction (99-2970)	76.52	78.15
11	New Mars-Golden 500 kV Line Construction (99-2970)	142.10	148.00
12	500 kV Line # 558 (Brambleton-Goose Creek) Cut-In to Aspen (99-2971)	10.93	10.93
13	New 500 kV Line from Aspen to Goose Creek (99-2971)	21.86	21.86
14	Line #2150 (Sterling Park to Paragon Park Circuit 1) Cut-In to Golden (99-2971)	16.39	16.39
15	Line #2081 (Sterling Park to Paragon Park Circuit 2) Cut-In to Golden (99-2971)	16.39	16.39
16	New 230 kV Line from Aspen-Golden (99-2971)	54.64	53.00
17 - 19	Golden, Lockridge and Mars Substation upgrades (99-2970)	42.74	44.00
20 - 25	Various Substation Overdutied Breaker Replacement (99-3208)	8.66	13.65
21	Beco Substation Overdutied Breaker Replacement (99-3208)	1.81	2.86
22	Belmont Substation Overdutied Breaker Replacement (99-3208)	1.90	2.86
23	Discovery Substation Overdutied Breaker Replacement (99-3208)	0.49	0.72
24	Pleasant View 230 kV Substation Overdutied Breaker Replacement (99-3208)	0.51	0.72

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
25	Shellhorn Substation Overdutied Breaker Replacement (99-3208)	0.93	1.50
26	New Aspen 500/230 kV Substation (99-2971)	195.13	196.00
27	New Golden 500/230 kV Substation (99-2971)	315.68	295.00
28 - 32	Various Substation Upgrades (99-2971)	8.56	13.14
	Total	**1,058.45**	**1,098.96**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

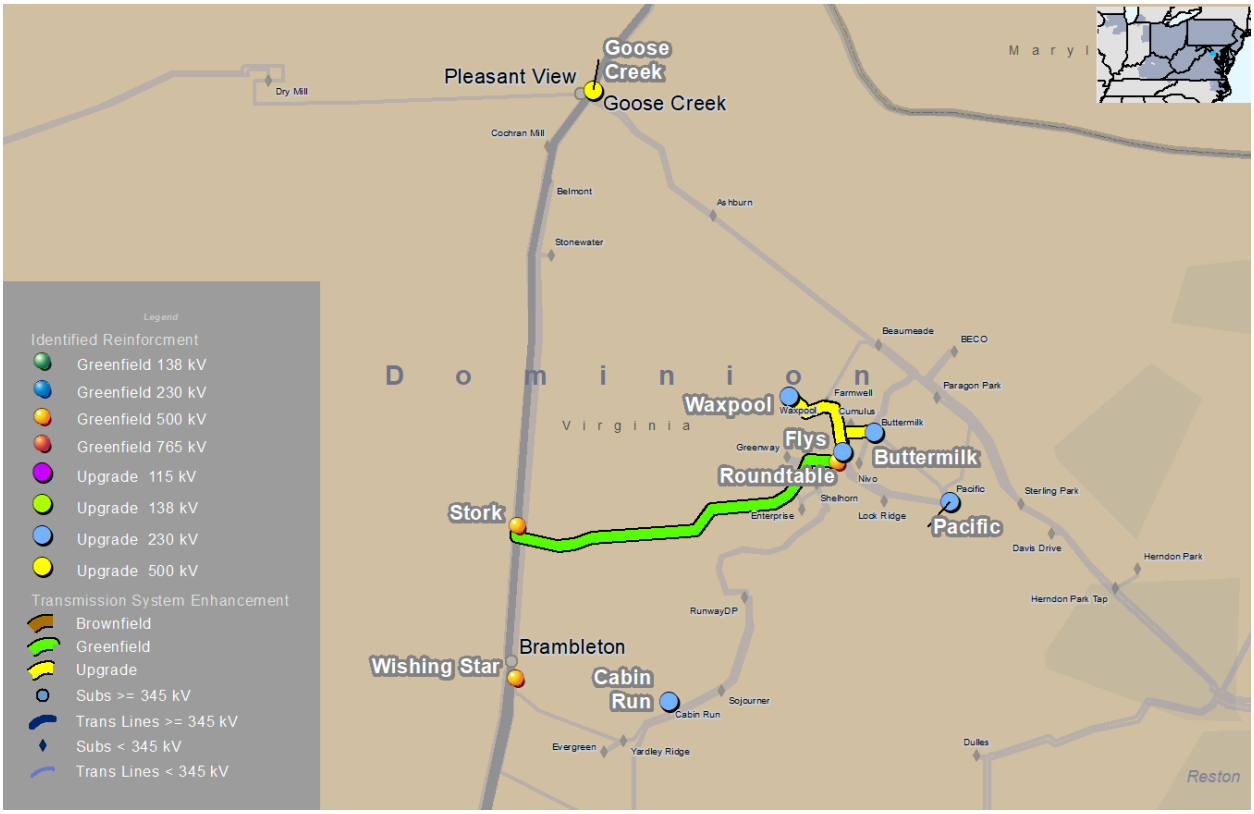
Schedule Review

Given the greenfield nature of the proposal and the noted concerns with siting transmission projects in Loudoun County, and potential schedule risks with the new Aspen and Golden substation equipment procurement, a medium schedule risk is assessed for this project.

Proposal 858 – Transource

Transource's Proposal No. 858 (**Map 26**), described as Stork-Flys 500 kV greenfield line and substations, involves a local solution intended to facilitate interconnections of data centers in the Dominion Service area. The project includes a new greenfield underground transmission line, greenfield substations, as well as multiple existing line and substation upgrades, all within Loudoun County, Virginia.

Map 26. Proposal 858



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

Transource's Proposal 858 includes the following components:

- Component 1: Stork 500 kV greenfield substation
- Component 2: Stork-Flys 500 kV underground line
- Component 3: Flys 500/230 kV substation
- Component 4: Roundtable-Buttermilk 230 kV line rebuild
- Component 5: Roundtable-Waxpool 230 kV line rebuild
- Component 6: Waxpool-Farmwell 230 kV line rebuild
- Component 7: Roundtable station upgrade
- Component 8: Wishingstar station upgrade
- Component 9: Cabin Run station upgrade
- Component 10: Pacific station upgrade
- Component 11: Goose Creek station upgrade

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New Stork to Flys 500 kV Underground Line

The main transmission line component for this proposal is the Storks-Flys 500 kV underground cable line, which is 5.04 miles long. The proposed route is entirely within public road right of way, and the proposed facilities are expected to occupy a 50 ft. corridor, with the specific plans to use the median of the public roads – Loudon County Pkwy. and Ryan Rd., which are large, divided thoroughfares.

Overall, the ROW risk for this proposal is high due to the utilization of greenfield ROW for the entire alignment of the proposed new lines. Although the project proposed use of public road ROW, it is considered greenfield due to the absence of an existing transmission corridor for the proposed route, which would mitigate concerns with permitting feasibility.

Environmental Risk Analysis

The transmission line is in a dense residential and commercial area and the proposed construction will have significant impact on Loudon County Pkwy. and Ryan Rd. due to the route feasibility being largely dependent on permitting approval from state and local permitting agencies, especially the Virginia Department of Transportation (VDOT). PJM consulted VDOT to obtain their feedback on the proposed underground route.

VDOT officials shared overall concerns with feasibility of the proposed project and specifically cited concerns with the construction approach for the proposed underground circuits and potential undermining of the road integrity, traffic mitigation concerns with anticipated lengthy closures to the impacted roads, and potential conflicts with existing sensitive underground fiber communication infrastructure that already occupy the public ROW. VDOT also noted the possibility that any issued single-use permit could still be rescinded by VDOT in order to accommodate future road improvement projects, resulting in the need to move the underground transmission line.

Due to the above risks, an overall high constructability risk was assessed for the proposed project.

Transmission Line Risk Analysis

Proposed route is along public roadways with numerous adjacent residential and commercial properties. Route crosses a major highway interchange, several busy intersections, and several culverts likely requiring trenchless crossing methods (HDD or boring). Road restoration will be required following construction. Given the short length of the proposed underground greenfield line route, the primary transmission line risks are those associated with permitting and some schedule risk associated with availability of 500 kV XLPE cables and accessories (e.g., splices).

Substation Risk Analysis

New Stork 500 kV Substation

Stork is a proposed new 500/230 kV substation located in Loudoun County, Virginia. The substation includes a 500 kV three-position GIS ring bus with three 500 kV CBs.

New Flys 500/230 kV Substation

Flys is a proposed new 500/230 kV substation located in Loudoun County, Virginia. The substation includes a 500 kV GIS building with one 500 kV CB and connections for the Stork-Flys underground line and two transformers, two 500/230 kV transformer banks, and a four-leg 230 kV double breaker, double bus GIS bus, with eight 230 kV CBs.

Other substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk. Schedule risk for the procurement of the transformers and GIS bus components.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 25**.

Table 25. Proposal 858 Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
1	Stork 500 kV Greenfield Substation	46.42	48.00
2	Stork-Flys 500 kV Underground Line	266.73	263.50
3	Flys 500/230 kV Substation	155.26	170.00
4	Roundtable-Buttermilk 230 kV Line Rebuild	3.41	3.00
5	Roundtable-Waxpool 230 kV Line Rebuild	9.88	6.30
6	Waxpool-Farmwell 230 kV Line Rebuild	5.00	3.30
7	Roundtable Station Upgrade	2.97	3.00
8	Wishingstar Station Upgrade	6.86	6.00
9	Cabin Run Station Upgrade	2.94	4.00
10	Pacific Station Upgrade	6.08	4.50
11	Goose Creek Station Upgrade	4.90	5.00
	Total	**510.44**	**516.60**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

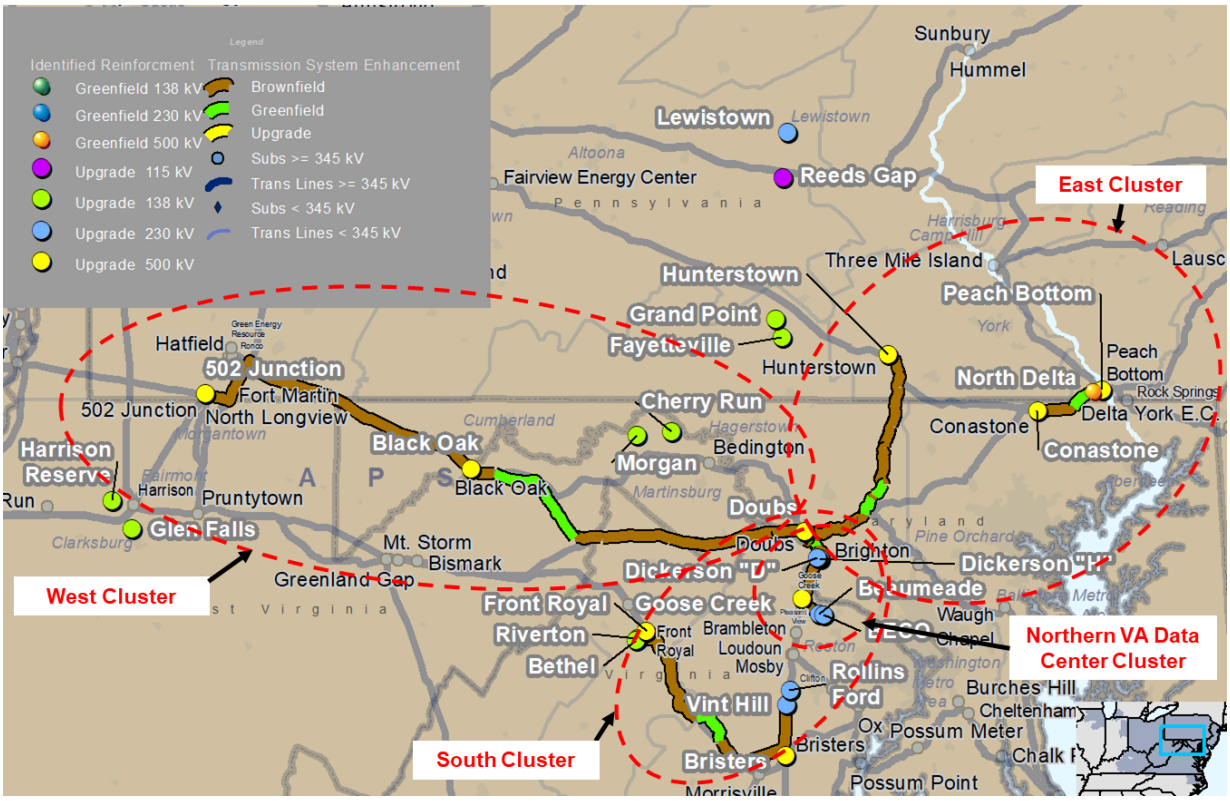
Schedule Review

Given the noted constructability concerns with permitting the underground Stork to Flys 500 kV line, and potential schedule risks with the new Stork and Flys GIS substation equipment procurement, a medium-high schedule risk is assessed for this project's proposed December 2027 in-service date.

Proposal 548 (Northern VA Data Center) – LS Power

LS Power Proposal No. 548 (**Map 27**), described as RTEP Window 3 Solution, provides a holistic solution to the RTEP Window 3 needs, comprising 37 components that can be grouped into the four regional clusters identified for the Window. Specifically for the Northern VA Data Center cluster, LS Power proposed components in Loudoun County, Virginia, which includes new greenfield underground line, as well as multiple substation and line upgrades.

Map 27. Proposal 548



*NOTE: This map is only intended to illustrate the general electrical connectivity of the projects and should **not** be relied upon for exact geographical substation locations or line routes.*

Project Overview

LS Power Proposal 548 includes the following components for the Northern VA Data Center cluster:

- Component 8: Beaumeade substation upgrade
- Component 16: DTC substation upgrade
- Component 17: Mars substation upgrade
- Component 24: Beaumeade-BECO-DTC 230 kV transmission line upgrade
- Component 31: BECO substation upgrade
- Component 36: Goose Creek-Beaumeade greenfield underground 500 kV double circuit transmission line

Constructability Review

Right-of-Way/Land Usage Risk Analysis

New Goose Creek-Beaumeade Greenfield Underground 500 kV Double Circuit Line

The main transmission line component for this proposal is the Beaumeade to Goose Creek 500 kV underground cable line, which is about 5.7 miles long. The Goose Creek-Beaumeade 500 kV underground double circuit line proposes the use of existing overhead line ROW, which also contains bicycle and walking trails on a former railroad ROW, known as the Washington and Old Dominion Trail (W&OD Trail) that traverses suburban residential areas. A ROW width of 8 feet was given for the underground corridor, but there was no information given on the need for construction or O&M easements which would undoubtedly be required.

The ROW risk for this proposal is medium-high due to the route paralleling existing overhead transmission for the entire length of greenfield ROW for the entire alignment of the proposed new lines.

Environmental Risk Analysis

Route is already occupied by multiple overhead transmission lines and passes through many dense residential neighborhoods with homes abutting the trail. Several water and roadway crossings will require trenchless crossing methods (HDD or jack and bore).

This route proposes use of the Washington and Old Dominion Trail (W&OD Trail) and will require permitting with the Northern Virginia Regional Park Authority, which adds a layer of complexity to the overall process given the recreational use of this corridor and the NOVA Park's requirement that any construction projects must ensure continued access to the park's recreational facilities at all times. An added significant concern is that the NOVA Park's indication that the Dominion Virginia Power owns the easement for the entire W&OD Park and that construction on the park would require Dominion's explicit approval.

LS Power noted potential alternative routes were considered, with the VA State Route 7 as an example but did not offer any detailed information on these alternatives.

Due to the above risks with permitting and siting of the underground line, an overall high constructability risk was assessed for the proposed project.

Transmission Line Risk Analysis

Given the short length of the proposed underground greenfield line route, the primary transmission line risks are those associated with permitting and some schedule risk associated with availability of 500 kV XLPE cables and accessories (e.g., splices).

Substation Risk Analysis

The substation components of this proposal focus primarily on upgrading substations and substation equipment to achieve higher ratings. These types of upgrades in general are low risk.

There are currently long lead times of two to three years for all circuit breakers above 115 kV. Therefore, the procurement of these circuit breakers will most likely be the critical path for the majority of the substation components (projects).

Given the above lead-time constraints, it will be critical that detailed and strategic project procurement plans be developed and implemented as soon as possible for all projects.

Cost Review

As part of the detailed constructability analysis, PJM and its consultants prepared a high-level conceptual independent cost estimate for the components of this proposal. This estimate is based on a high-level assessment of probable costs for the current conceptual design and is reflective of recent supplier quotes and previous experience with substation engineering, transmission line engineering and construction. The independent cost estimate includes a contingency of 30%, as it is a concept-level estimate. A side-by-side comparison of proposing entity costs and independent cost estimates are contained in **Table 26**.

Table 26. Proposal 548 (Dominion) Cost Review

Component ID	Component Description	Proposal Cost Estimates ($M)	Independent Cost Estimates ($M)
8	Beaumeade Substation Upgrade	61.30	45.00
16	DTC Substation Upgrade	6.38	7.00
17	Mars Substation Upgrade	46.21	50.00
24	Beaumeade-BECO-DTC 230 kV Transmission Line Upgrade	2.30	3.00
31	BECO Substation Upgrade	5.67	6.00
36	Goose Creek-Beaumeade Greenfield Underground 500 kV Double Circuit Transmission Line	161.93	196.52
	Total	**283.78**	**307.52**

The total proposal cost estimate is within 10% of the independent cost estimate and is considered low risk.

Schedule Review

Given the noted constructability concerns with permitting the underground Goose Creek to Beaumeade underground 500 kV double circuit line, a medium-high schedule risk is assessed for this project's proposed December 2030 in-service date.

FINANCIAL ANALYSIS

Approach

Altogether, PJM received 72 proposals submitted by 10 different entities, including both incumbent transmission owners and non-incumbent entities, and each proposal was reviewed for completeness and consistency of cost information. Ultimately, a subset of projects were selected for a more detailed 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' present value revenue requirements (PVRR) 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, component current year and escalated costs, and key dates (construction start, capital spend start and in service).
- Project Financial Information Schedule (Attachment 7 or CapEx Template) – Developers completed the financial information schedule for each proposed project. The financial information schedule depicts annual capital spend by project element for both the proposer and "Work by Others" entities. It also includes an estimate of AFUDC (Allowance for Funds Used During Construction), the Capital Spend Start Date, Construction Start Date, and Commercial Operation Date.
- 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 for all projects, described later in this report, to ensure comparability. However, the proposer's revenue requirement schedule was used to obtain model inputs, such as operations and maintenance (O&M), property taxes and working capital.

Additional documents submitted by some proposers included:

- Cost Containment Legal Language (Attachment 11) – Developers proposing projects with cost-capping mechanisms submitted a separate document describing their cost containment in detail and typically in the form of a draft Schedule E for potential inclusion in the non-standard terms of a Designated Entity Agreement (DEA).

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

With the common template developed, PJM and its consultants then conducted a detailed cost analysis for the 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 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 PVRR 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, a well-capped proposal could considerably lower-cost overrun risks, while a poorly capped or uncapped proposal could result in millions of extra ratepayer dollars over the lifetime of the project if actual project costs are higher than proposed.
- Sensitivity Analysis – In addition to the base case NPVRR comparison for the modeled proposals, PJM also modeled eight scenarios that alter one or multiple model inputs. Seven of the scenarios alter a single variable (setting the return on equity to 12%, increasing the cost of debt to 9%, increasing project costs by 50% or 100%, increasing O&M by 50%, setting the capital structure at 60% equity, and increasing work by others "WBO" project costs by 50%). An eighth, referred to as "downside," combines the impacts of the multiple 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.

Analysis Results

The following sections outline the results of PJM and its consultant's detailed financial evaluations performed on select proposals. The outcome of the financial analysis factors into the cost containment risk assessment, a category within the risk assessment matrices that are included in Appendix A of this report.

Cost Containment

Proposal Cost Containment Overview

The cost containment mechanisms for each proposal are defined by developer and are summarized in **Figure 2** and **Figure 3** detailed in the supporting text below:

Figure 2. Overview of Cost Containment by Developer

Cap Type	Transource	LSP	NextEra	PSEG	PECO	PEPCO	PPL
Project Cost		✓	✓	✓	✓	✓	✓
Soft (Hybrid) Cap	✓	✓	✓		✓	✓	
Hard Cap				✓			✓
ROE Cap (inclusive of adders)		✓	✓	✓			
Equity % Cap		✓	✓	✓			
Schedule Guarantee			✓				

Note: *Proposals from AEP, Dominion and First Energy did not provide cost containment mechanisms.*

Detailed Cost Containment Review

Transource

Transource provided a hybrid cost cap. For any capital expenditures that exceed their original cost estimate, Transource's ROE on that incremental capital is reduced from 10% to 9.5%, as it is foregoing the 50 basis point RTO participation adder. Transource is still recovering all depreciation expense and debt costs associated with the incremental capital spend.

For three of their four proposals (858, 904, 977), Transource only capped four specific cost elements deemed to be within their control (Engineering and Design, Materials and Equipment, Construction and Commissioning, Construction Management).

For proposal 487, Transource capped all cost elements except contingency. Transource did not offer a binding ROE cap.

LS Power

LS Power provided a hybrid cost cap. For any capital expenditures that exceed their original cost estimate, LS Power's ROE on that incremental capital is reduced based on the amount of the exceedance. LS Power is still recovering all depreciation expense and debt costs associated with the incremental capital spend.

The ROE LS Power will request on incremental capital spend above the original cost estimate is reduced from 9.8% according to the tiers listed below:

- For capital cost overages of 1–25% (inclusive), LSP's ROE on the incremental capital spend shall be 8.5%.
- For capital cost overages above 25% up to and including 50%, LS Power's ROE on the incremental capital spend shall be 7%.
- For capital cost overages above 50%, LSP's ROE on the incremental capital spend shall be 5.5%.

LS Power offered a binding ROE cap of 9.8% and a binding equity percentage cap of 50%. The ROE cap adjusts downward due to the project cost cap reducing total project ROE if actual capital costs exceed the CapEx estimate according to the tiers above.

NextEra

NextEra offered a binding ROE cap of 9.8% and a binding equity percentage cap of 45%.

NextEra provided a hybrid cost cap. For any capital expenditures that exceed their original cost estimate, NextEra's ROE on that incremental capital is reduced from 9.8% to 0%. NextEra is still recovering all depreciation expense and debt costs associated with the incremental capital spend.

Twenty-three of 26 NextEra proposals have a "Soft Cap," which means that regardless of other cost containment provisions, the total earned ROE cannot be lower than 7% or 7.5%, depending on the proposal. The three proposals with a "Hard Cap" do not have a minimum earned ROE. All three NextEra proposals modeled in this evaluation (663, 853, 948) have a "Soft Cap."

NextEra provided a schedule guarantee where the total project ROE is reduced by 2.5 basis points for each month delay past the guaranteed completion date up to a maximum of 30 basis points.

PSEG

PSEG submitted a traditional binding Hard Cap on capital costs, in which they will not request recovery of any depreciation expense, return on equity, or debt costs associated with any capital expenditures above their cost cap. All of PSEG's cost caps were set at 120% of their original capital expenditure estimate.

PSEG offered a binding ROE cap of 9.60% and a binding equity percentage cap of 45%.

Exelon (PECO & PEPCO)

PECO and PEPCO both submitted proposals with a hybrid cost cap, which entailed a special mechanism to provide a return of 1–2% of cost overruns to ratepayers once project costs exceed 5% of estimates. This mechanism is uncapped and covers a small percentage of cost overruns relative to other proposals. However, this hybrid cost cap mechanism was not modeled due to excessive exclusions.

PECO and PEPCO excluded the following from their cost cap that led PJM's consultant to the decision to not model their cost cap for the sensitivity analysis:

- All components of proposal are not selected by PJM.
- An easement or corridor is not available as described in bid.
- Deratings of transmission lines
- A transmission line crossing is not available.
- Labor cost escalation exceeds 5% annually until 2030.
- Steel, copper and aluminum prices exceed 2.5% compound increase from date of purchase.

PPL

PPL submitted proposals with a traditional hard cost cap, but the hard cost caps were not modeled due to excessive exclusions.

PPL excluded the following from their cost cap that led PJM's consultant to the decision to not model their cost cap for the sensitivity analysis.

- Inability to acquire land rights
- Environmental permitting delays
- Cost of materials, components or equipment increase by 10%.
- 3.5% annual increase in labor costs
- PJM does not award project before Oct. 1, 2023.

Cost Containment Observations

As shown in the above section, developers submitted varying levels of cost containment. The most common cost containment mechanism was a project cost cap, with seven of ten developers offering some type of project cost cap. NextEra, LS Power and PSEG also submitted binding ROE caps and equity percentage caps.

Despite a majority of developers offering a project cost cap, it is important to differentiate between a true "traditional" Hard cost cap and what is considered as a Soft "hybrid" cost cap.

A traditional cost cap prevents the developer from requesting recovery in rates for any depreciation expense, cost of debt, or return on equity associated with incremental dollars of CapEx spent above the cost cap. A "hybrid" cost cap is one that allows the developer to recover depreciation expenses and cost of debt associated with incremental dollars above the cost cap, while the return on equity on the incremental CapEx is reduced (as low as 0%). This is a significantly less-effective cost cap, as shown by the results from the sensitivity analysis in later sections of this report. Additionally, as discussed in the above section, some entities submitted a cost cap, but the exclusions to the cost cap were so excessive that led to the decision not to model the cost cap.

Modeling Approach & Assumptions

Modeling Approach

To evaluate a proposal's lifetime cost to ratepayers, Consultant computes the Present Value Revenue Requirement (PVRR). Revenue requirement, or cost of service, reflects the total revenue that needs to be collected in rates for a company to recover its capital, operational expenses, tax expenses and earn a fair return on its capital investments.[1] In the revenue requirement model, revenue requirement in each modeling period is calculated as the sum of O&M/A&G (administrative & general) expenses, depreciation on capital investment, income and property taxes, cost of debt (interest), and equity return on rate base. The revenue requirement model was developed using a standard FERC-accepted cost recovery approach. Consultant built up the various components of revenue requirement for every month during the project's useful life, then discounted future streams of revenue requirement using a common discount rate for all proposals.

The cost-of-service inputs used in the model are mostly provided directly by developers. For fair comparison, Consultant also made several common assumptions that may be different from developers' inputs, such as the inflation rate and discount rate. These assumptions are explained in more detail in the following Modeling Assumptions section.

For certain components included in proposals, the entity responsible for construction is not the proposing entity or one of its affiliates. These are known as "Work by Others" or "WBO" components. All results shown in this report include Work by Others.

[1] The rate of return on equity will be reviewed and approved/adjusted by FERC for transmission projects.

If a proposal included WBO, the developer also provided an estimated CapEx for these WBO elements.

For some proposals, a total estimated WBO CapEx was provided, rather than an estimated CapEx in each year. In these cases, the WBO is assumed to follow the same spend curve as the proposer.

Baseline Assumptions

Across all proposals, Consultant applied several standardizing assumptions, summarized in **Table 27**, to ensure a fair comparison of present value outcomes:

Table 27. Baseline Model Assumptions

Discount Rate	6.81%
Inflation Rate	2.10%[2]
Earliest Capital Spend Start Date	1/1/2024
Date Used for Discounting	1/1/2024

Modeling Period Assumptions

Projects with construction periods starting in 2023 were adjusted to begin on Jan. 1, 2024. No project spending was modeled until 2024. Any CapEx submitted the year after the in-service date was moved to the final year of construction. Additionally, property tax and O&M were not modeled until a project is placed in service.

For projects with partial in-service dates (in which some parts of the project are placed in service during the construction period), Consultant still assumed that revenue requirement recovery does not begin until the final in-service date unless the project is earning a return on CWIP.

The revenue requirement model uses monthly granularity. While developers provided specific month-year clarity around construction start and in-service dates, much of the revenue requirement and capital spend data is provided on an annual basis. To account for this, Consultant divided annual expenditures by the number of relevant months when partial-year spending data occurs (typically only the first and last year of the project).

CapEx and Depreciation Assumptions

CapEx

Capital costs are collected from Attachment 7, which provides a year-by-year spend schedule broken down by cost element (Engineering & Design, Materials and Equipment, etc.).

[2] For the year 2024, a 3.1% inflation rate was used, but 2.1% is used for every year after 2024.

The associated financing costs of construction are modeled using either return on Construction Work In Progress (CWIP) or AFUDC for each proposal. Both returns on CWIP and AFUDC are calculated using the developer-specific after-tax WACC. If a developer does not specify collecting a return on CWIP versus AFUDC, Consultant modeled AFUDC. Transource is the only developer that clearly claimed a return on CWIP.

Capital Streams

To isolate the financial behavior of different parts of each proposal, three capital streams were developed and modeled independently. Streams isolate the behavior of different types of CapEx:

- CapEx Stream 1 – Capped work by the proposer
- CapEx Stream 2 – Uncapped work by the proposer
- CapEx Stream 3 – Uncapped work by others

Contingency is modeled separately for each CapEx stream for the purposes of the capital spend increase sensitivities but is included in total CapEx.

All revenue requirement results in this report show the sum of the revenue requirements of each of the three CapEx streams.

Book Depreciation

Straight-line depreciation method is used for all proposals, assuming no salvage value or removal cost. Book depreciation is calculated using the useful life, which is derived from the developer-provided revenue requirement workbooks.

Tax Depreciation

Each project uses the 15-Year Modified Accelerated Cost Recovery System (MACRS) mid-year convention schedule for tax depreciation.

O&M/A&G Assumptions

In instances where O&M/A&G is not provided, it was estimated using the following methodology:

- Consultant assumed that 1% of total CapEx would yield a reasonable estimate of Year 1 O&M. This is an industry-standard value. Additionally, Consultant verified this estimate by calculating the proportion of total capital expenditures spent on O&M for all revenue requirement workbooks that did include O&M. On average, O&M was 1.06% of total capital expenditures.
- For each proposal, Consultant calculated 1% of the proposal total CapEx and assumed this value as the Year 1 annual O&M (adjusted for in-service date as necessary).

- After the first year of in-service date, Consultant inflated O&M by 2.1% annually over the useful life of the project.

In cases where cash working capital was not provided, it was modeled as one-eighth of the total O&M for each year, which is another industry-standard value.

Consultant did not model pre-in-service O&M/A&G when a developer submitted it as part of their revenue requirement.

Tax Assumptions

Each developer submitted a unique tax profile, which is used to gross up ROE requirements. Different state tax rates are provided based on the specific state geography of the projects.

Property Tax

Consultant did not model pre-in-service property taxes when a developer submitted it as part of their revenue requirement. If property tax estimates were not provided by the developers, property tax was calculated as 1% of net plant.

In any year in which the project is not in service for the entire year (the first and last year of the project life if the in-service date is anything other than Jan. 1), Consultant scaled the depreciation by the number of months in service to calculate partial-year property tax.

Income Tax

Deferred taxes were calculated based on tax-book life differences and used accordingly to reduce rate base each month.

Contingency

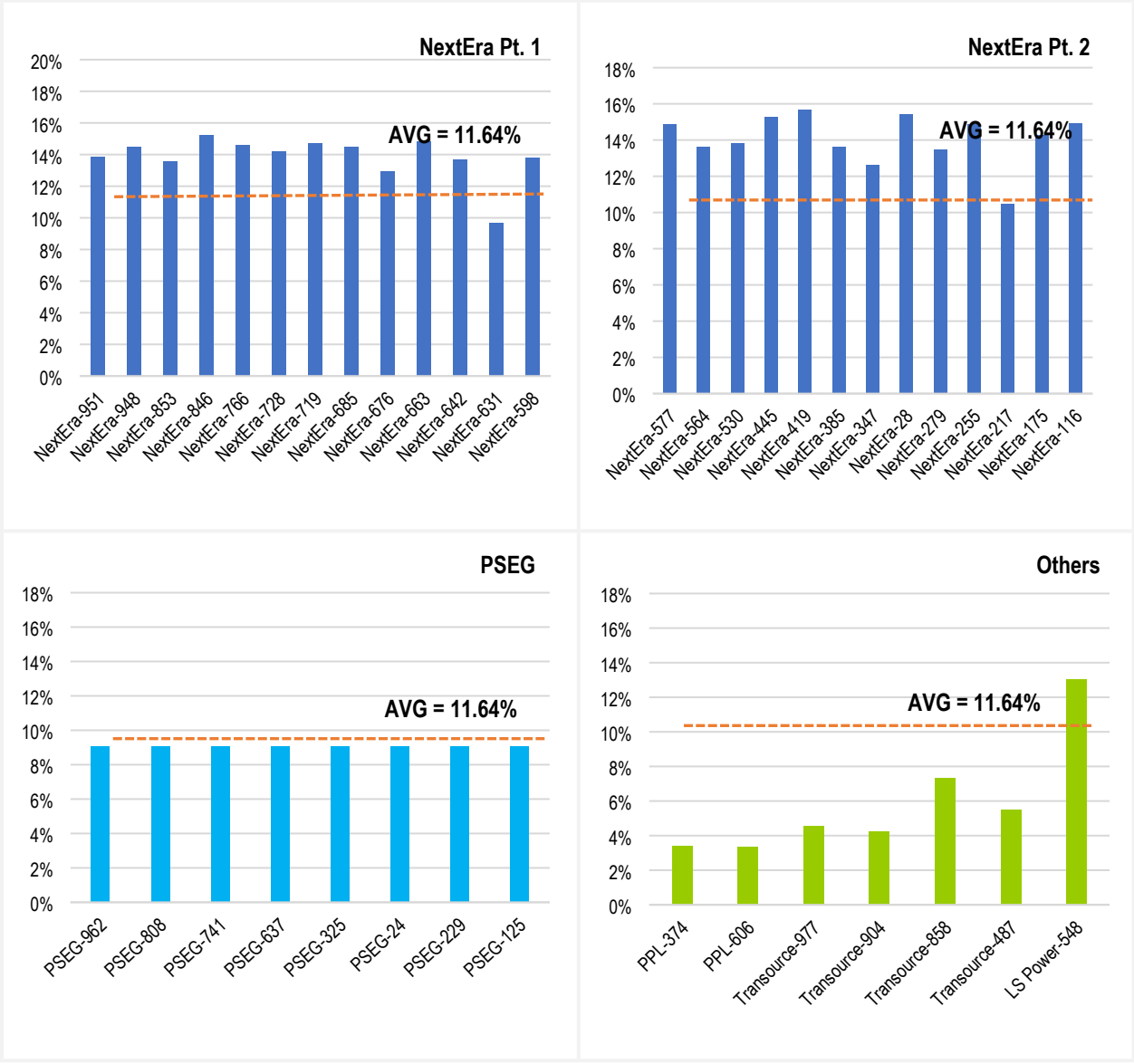
All proposers, with the exception of the Exelon companies (PECO and PEPCO), provided some level of contingency in their cost estimates. The revenue requirement model provides a vehicle to compare the revenue requirement resulting from the various proposals' submitted costs. Consultant did not choose to standardize contingency because each proposer strategically developed its own level of contingency. Additionally, there could be multiple "layers" of contingency built into each CapEx element. With that said, a brief analysis of the various levels of contingency proposed is useful in adding to the information available in the selection process.

While a low level of contingency allows the total costs to be lower than similar proposals with higher contingencies, that cost advantage comes with a greater risk of exceeding cost estimates and risking the ability to recover costs when cost containment measures are in place. **Contingency (**Cost-Contained Proposals) below, provides a comparison of contingency levels by proposer. Developers listed in the tables are split by whether the developer offered cost containment or not. All contingency amounts apply only to costs incurred by the proposer and exclude costs incurred by other entities (WBO). The percentages are calculated by dividing the contingency amount by the total proposer CapEx, excluding the contingency.

The contingency as a percentage of total cost across all proposals, excluding WBO, ranges from 0% to 15.67%. For the proposers that offered cost containment, the average contingency is 11.64%; however, there is significant variation.

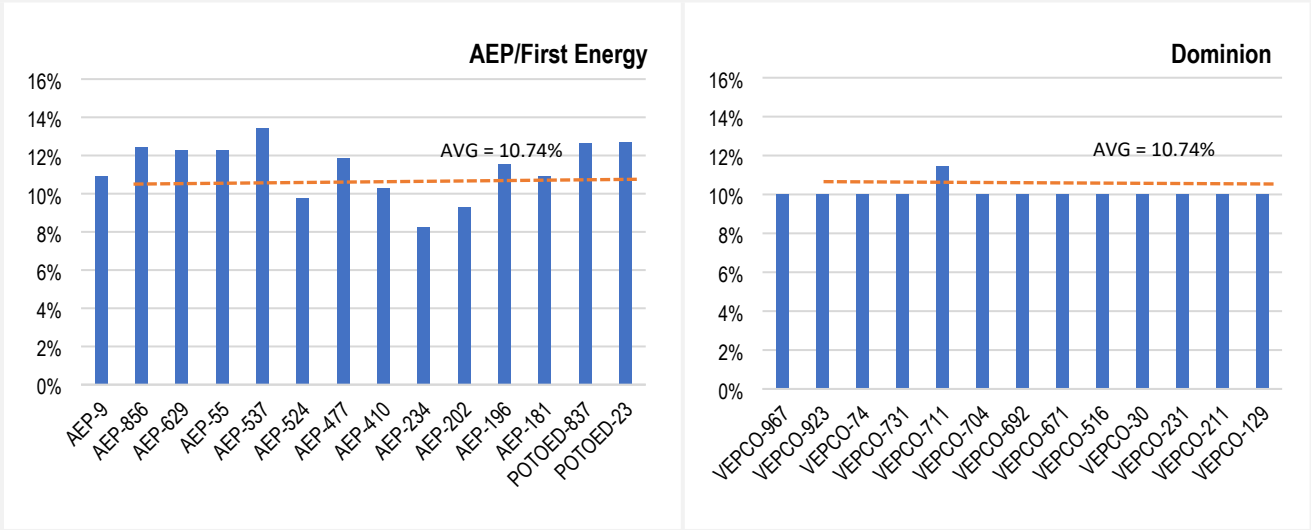
PPL proposals have a contingency of 3.37%, which is the lowest among proposers offering contingency estimates. Transource proposal contingencies range from 4.21% to 7.34%, PSEG proposals have a contingency of 9.09%, NextEra proposal contingencies range from 9.65% to 15.65%, and the LSP proposal has a contingency of 13.04%.

Figure 3. Contingency (Cost-Contained Proposals)



In **Contingency (**Cost-Contained Proposals) illustrates the proposals that did not offer cost containment, the contingency ranges from 8.26% to 13.43%, with an average of 10.74%. Dominion has contingencies that range from 9.99% to 11.45%, AEP ranges from 8.26% to 13.43%, and FirstEnergy ranges from 12.67% to 12.69%.

Figure 4. Contingency (Non-Cost-Contained Proposals)



For model sensitivities where capital cost increases, contingency is removed from capital cost prior to the 125% or 150% multiplier being applied (See Section 0 for Model Sensitivities). This is because Consultant assumes that the contingency will be used to absorb project cost increases. Once the contingency is fully exhausted, the sensitivity will increase the project cost accordingly, subject to cost containment.

PJM Proposal Scenarios

PJM's proposal scenarios are a combination of individual proposals and are representative of the solutions being offered by the participating entities. These scenarios will be subjected to the sensitivity analysis. The scenarios are identified in **Table 28** through **Table 35** defined below:

Table 28. Transource Scenario A Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
487	Maryland & Pennsylvania Baseline Reliability Solution	Transource
858	Stork-Flys 500 kV Greenfield Line and Substations	Transource
904	Joshua Falls-Yeat 765 kV Greenfield Line and Substation	Transource

Table 29. NextEra Scenario B Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
663	Front Royal-Racefield, Warrenton-Rixlew, Warrenton-Hourglass, Mars-Ocean Court-Davis Drive	NextEra
853	502 Junction-Black Oak-Woodside-Gant, Woodside SVC + Cap Banks	NextEra
948	New 500/230 kV Bartholow substation, new 500/230 kV North Delta substation, new 230 kV Grisham switchyard, new 500/230 kV Goram substation, and Keeney to Waugh Chapel tie-in.	NextEra

Table 30. LS Power Scenario C Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
548	RTEP Window 3 Solution	LS Power

Table 31. Exelon Scenario D Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
344	PECO Expansion Plan for DOM Window 2023	PECO
660	West Cooper BGE-PEPCO	PEPCO

Table 32. First Energy Scenario E Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
837	Data Center Reinforcement Proposal #1	POTOED

Table 33. Dominion Scenario F Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
74	Line #2090 (Ladysmith CT-Fredericksburg) Rebuild	Dominion
211	Hollymead-Gordonsville Line # 2135 Rebuild	Dominion
516	Interregional solution – Aspen-Doubs Second 500 kV Line	Dominion
671	Lines #541 (Front Royal to Morrisville) Rebuild	Dominion
692	Data Center Alley Local solution – New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	Dominion
711	Regional Solution – 500 kV North Anna-Wishing Star Upgrades	Dominion
731	Locks Substation 230/115 kV Transformer Upgrade	Dominion
923	The second 500 kV line from Lexington to Dooms	Dominion
967	Charlottesville-Hollymead Line # 2054 Rebuild	Dominion

Table 34. PPL Scenario G Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
374	Otter Creek-Conastone 500 and 230 kV double circuit Line	PPL
606	Juniata-Lewistown 230 kV # 2 line	PPL

Table 35. PSEG Scenario H Definition

Proposal ID Combination	Proposal ID Combination	Proposing Entity
741	Proposal G – Peach Bottom-New Brandon Shores 500 kV; Peach Bottom-Doubs 500 kV	PSEG

Model Sensitivities

Eight sensitivities, summarized in **Table 36**, were applied to each proposal to assess financial performance. They were used to test the effectiveness of cost-containment mechanisms against potential project cost increases.

Table 36. Model Sensitivities

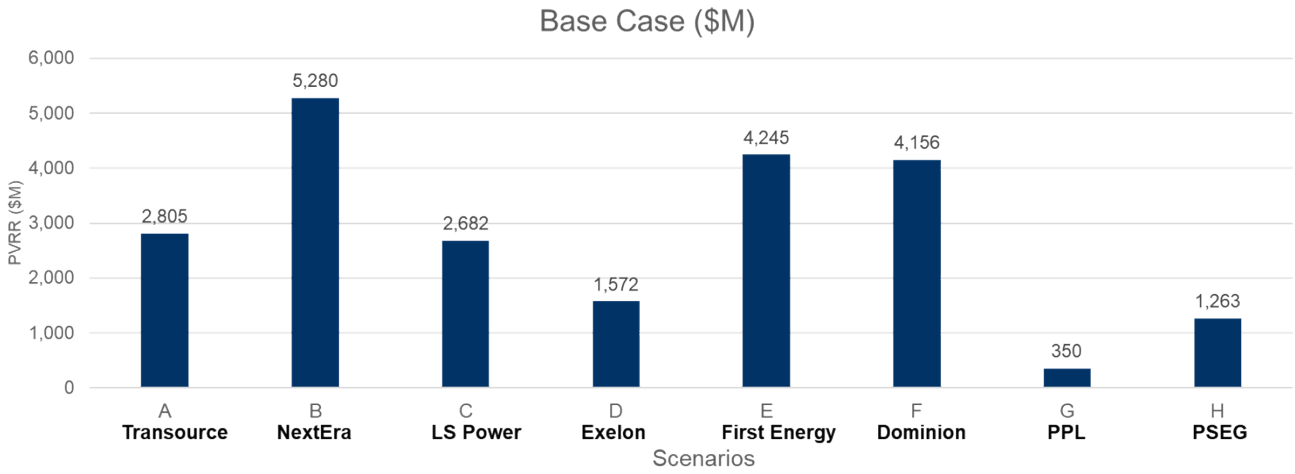
#	Sensitivity	Variable	Description
1	**Base Case**	None	Model the proposal using inputs from developer and revenue requirement model calculations
2	**WBO +50%**	Single Variable	Work by others project cost increased by 50% for all periods
3	**Project Cost +50%**	Single Variable (*changes to capex may affect Return On Equity ("ROE") for some developers*)	Proposer's project cost increased by 50% for all periods *(unless capped)*
4	**Project Cost +100%**	Single Variable (*changes to capex may affect Return On Equity ("ROE") for some developers*)	Proposer's project cost increased by 100% for all periods *(unless capped)*
5	**ROE 12%**	Single Variable	Return on Equity raised to 12% for all periods *(unless capped)*
6	**Cost of Debt 9%**	Single Variable	Cost of Debt raised to 9% for all periods
7	**Equity 60%**	Single Variable (*changes to Debt-to-Equity ratio may affect ROE for some developers*)	Equity thickness set to 60% for all periods *(unless capped)*
8	**O&M +50%**	Single Variable	O&M expense increased by 50% for all periods *(unless capped)*

#	Sensitivity	Variable	Description
9	**Downside** (*includes various changes above*)	Multiple Variables (*changes to capex and equity % may affect ROE for some developers*)	Proposer's project cost +50% *(unless capped)* O&M +50% *(unless capped)* ROE 12% *(unless capped)* COD 9% Equity 60% *(unless capped)*

Results and Key Observations

Scenario Base Case PVRR Comparisons

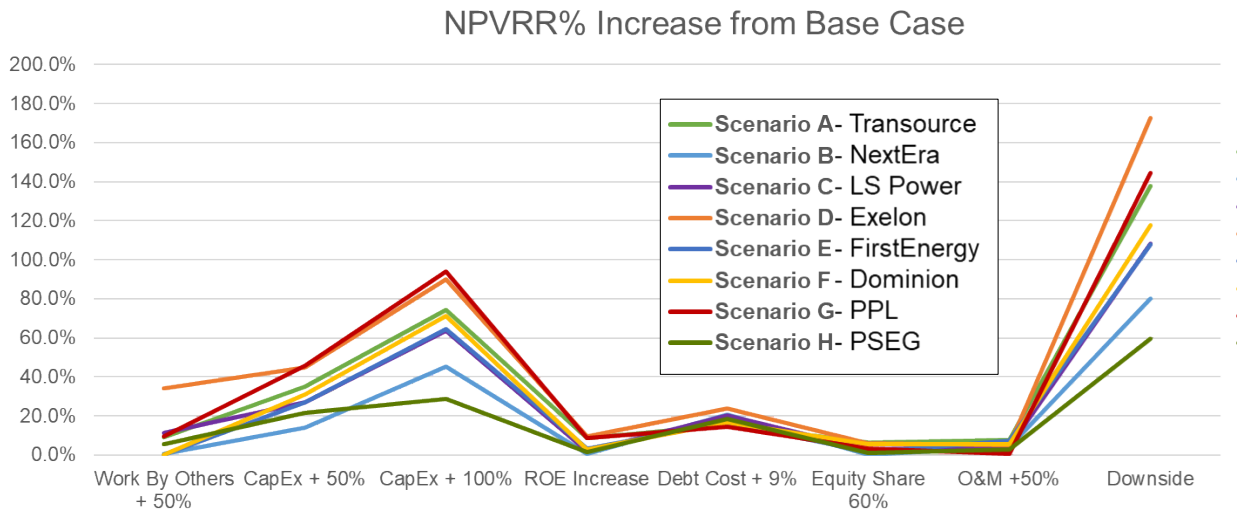
Figure 5. Base Case PVRR Comparison



PJM Scenario Results: The final PJM scenarios are grouped by developer and vary in PVRR from $0.4 B to $5.3 B based on the projects included in each scenario. Because the projects are not analogous, comparisons between proposal scenarios for the base case PVRR can best be viewed in conjunction with project benefits, which are not included in the above **Figure 5**. However, the next set of results focusing on scenario sensitivities are more informative about the relative performance of the developer's cost containment mechanisms in mitigating cost overruns.

Scenario PVRR Sensitivity Comparisons

Figure 6. Scenario Sensitivity Results



PJM Scenario Results: The above **Figure 6** demonstrates the volatility of scenarios across modeled sensitivities. PSEG Scenario H, with the traditional Hard Cost Cap displays the best performance and is least volatile in most sensitivities, including the downside sensitivity.

APPENDIX A – CONSTRUCTABILITY MATRICES

Risk Assessment Criteria

PJM Risk Assessment Criteria						
Risk Assessment	**Cost Estimate Risks**	**Cost Containment Risk**	**Schedule Risks**	**Constructability Risks**	**Use of Existing ROW/Brownfield**	**Outage Coordination Risks**
Low	Greater than or within 0-10% of Independent Estimate	Hard cost cap	Ratings assessed based on independent assessment of proposed in-service dates, and assessment of significant schedule risks such as such as permitting and constraint mitigation, long-lead material procurement, land/ROW acquisition, construction complexity.	Ratings assessed based on independent assessment of the number and severity of constructability risks assessed for the proposed project scope, such as permitting and constraint mitigation, land/ROW acquisition, construction complexity.	Rebuild/Reconductor Upgrades or Pure Brownfield	Minimal existing facility outages required, beyond short outages to cut-in to existing facilities
Medium	Within 10-20% of Independent Estimate	Soft cost containment (e.g ROE caps)			Mostly Brownfield (i.e. Uses/Overlaps existing ROW but requires expansion)	Significant existing facility outages required, with reasonable outage coordination plan proposed
Medium-High	Within 20-30% of Independent Estimate	Minimal cost containment/Excessive Exclusions			Greenfield paralleling existing ROW	Significant existing facility outages required, with no coordination plan proposed
High	Less than 30% of Independent Estimate	No cost containment			Pure Greenfield	Significant existing facility outages required, with known operational concerns and no coordination plan proposed.

NOTE:

- PJM conducted its constructability evaluation of the project data submitted by proposers, and engaged expert consultants to evaluate the constructability, cost estimation and cost containment risks of the projects.
- PJM also reached out to key regulatory agencies for their insight on certain projects to help clarify permitting risks.
- This risk assessment is not intended as a pass/fail or quantitive test, but rather as qualitative information on potential risks PJM has considered along with the reliability performance in selection of the finalist scenarios, and ultimately the recommended solution.

East Cluster Constructability Matrix

East Cluster Projects – Selected for Detailed Evaluation											
PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
344	Exelon	PECO Expansion Plan for DOM Window 2023	12/1/2029	$ 168.63	$ 214.81	Medium	Medium-High	Low	Low	Low	Medium
660	Exelon	West Cooper BGE-PEPCO	12/1/2030	$ 1,105.62	$ 1,060.63	Low	Medium-High	Low	Low	Low	Medium
548	LS Power	RTEP Window 3 Solution (East)	6/1/2030	$ 495.83	$ 609.44	Medium	Medium	Low	Medium	Medium-High	Medium-High
637	PSEG	Proposal D-Conastone-Doubs 500kV	6/1/2027	$ 684.22	$ 676.36	Low	Low	Medium	Medium	High	Low
741	PSEG	Proposal G - Peach Bottom-New Brandon Shores 500kV; Peach Bottom-Doubs 500kV	6/1/2028	$ 1,065.32	$ 1,178.75	Low	Low	Medium-High	High	High	Low
487	Transource	Maryland & Pennsylvania Baseline Reliability Solution	3/1/2027	$ 492.75	$ 503.43	Low	Medium	Low	Low	Medium	Medium
374	PPL	Otter Creek - Conastone 500 and 230 kV DCT Line	5/1/2027	$ 154.21	$ 162.69	Low	Medium-High	Low	Low	Medium	Medium
948	NextEra	New 500/230kV Bartholow substation, new 500/230kV North Delta substation, new 230kV Grisham switchyard, new 500/230kV Goram substation, and Keeney to Waugh Chapel tie-in	6/1/2028	$ 5,381.25	$ 6,265.88	Medium	Medium	High	High	High	Low

West Cluster Constructability Matrix

West Cluster Projects – Selected for Detailed Evaluation											
PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
837	POTOED - FirstEnergy	Data Center Reinforcement Proposal #1 (West)	6/1/2030	$ 2,788.40	$ 2,642.05	Low	High	Medium	Medium-High	High	Low
548	LS Power	RTEP Window 3 Solution (West)	6/1/2030	$ 972.71	$ 876.03	Low	Medium	Medium	Medium-High	Medium-High	Medium
853	NextEra	502 Junction - Black Oak - Woodside - Gant, Woodside SVC + Cap Banks	6/1/2027	$ 683.55	$ 1,195.24	High	Medium	Medium-High	Medium-High	High	Medium
904	AEP - Transource	Joshua Falls - Yeat 765kV Greenfield Line and Substation	12/1/2029	$ 1,048.10	$ 1,122.40	Low	Medium	Medium-High	Medium	High	Low

South Cluster Constructability Matrix

South Cluster Projects – Selected for Detailed Evaluation											
PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
516	Dominion	Interregional solution- Aspen-Doubs Second 500 kV Line	12/1/2027	$ 61.72	$ 77.95	Medium-High	High	Low	Low	Low	Medium
711	Dominion	Regional Solution - 500 kV North Anna-Wishing Star Upgrades	12/1/2027	$ 1,227.84	$ 1,284.62	Low	High	Medium	Low	Low	Medium
548	LS Power	RTEP Window 3 Solution (South Components)	6/1/2030	$ 628.56	$ 617.00	Low	Medium	Medium-High	Medium-High	Medium-High	Medium
325	PSEG	Proposal E - Brambleton-Hinsons Ford Rd 500kV	6/1/2027	$ 267.38	$ 275.56	Low	Low	High	High	High	Low
837	POTOED - FirstEnergy	Data Center Reinforcement Proposal #1 (South)	6/1/2030	$ 203.38	$ 209.16	Low	High	Low	Low	Low	Medium
663	NextEra	Front Royal - Racefield, Warrenton - Rixlew, Warrenton - Hourglass, Mars - Ocean Court - Davis Drive	6/1/2027	$ 284.17	$ 514.17	High	Medium	High	High	High	Low

Northern VA Data Center Cluster Constructability Matrix

Northern VA Data Center Cluster Projects – Selected for Detailed Evaluation											
PJM Proposal ID	Proposing Entity	Project Title	Proposed In-Service Date	Proposal Costs ($M)	Independent Costs ($M)	Cost Estimate Risks	Cost Containment Risks	Schedule Risks	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
692	Dominion	Data Center Alley Local solution - New 500 kV/230 kV Aspen-Golden & Golden-Mars lines	12/1/2027	$ 1,058.45	$ 1,098.96	Low	High	Medium	Medium	High	Low
858	AEP - Transource	Stork - Flys 500kV Greenfield Line and Substations	12/1/2027	$ 510.44	$ 516.60	Low	Medium	Medium-High	High	High	Low
548	LS Power	RTEP Window 3 Solution (Dominion Components)	6/1/2030	$ 283.78	$ 307.52	Low	Medium	Medium-High	High	Medium-High	Low

DOCUMENT REVISION HISTORY

11/17/2023 - V1: Original version posted

12/01/2023 – V2: Version 2 incorporating stakeholder feedback posted

Reliability Analysis Update

Sami Abdulsalam, Director
PJM Transmission Planning

Transmission Expansion Advisory Committee
July 9, 2024

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Outline

- 2024 Window 1 Updates
- 2023 Window 2 Projects 2nd Read
- 2022 Window 3 Scope Changes

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2024 RTEP Window 1 Updates

Baseline Reliability Projects

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2024 Window 1
Progress and Timeline Update & Assumptions

- Current schedule
  - Targeting open 2024 RTEP proposal Window 1 on July 12th, 2024
  - 60 day window
  - Solutions to be brought forward to the TEAC starting Oct 2024 and through Jan 2025
  - Board approvals in Nov 2024 and Feb 2025
- Solutions identified in 2023 Window 2 are included in the model
- 2022 Window 3 scope change for 502 Jct-Woodside-Aspen 500 kV & Doubs Corridor Project is included in model

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2023 RTEP 2028 W2 vs 2024 RTEP 2029 W1 PJM System-Wide Needs Evolution Summary

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Load and Gen Dispatch – **Summer** (2028 to 2029)

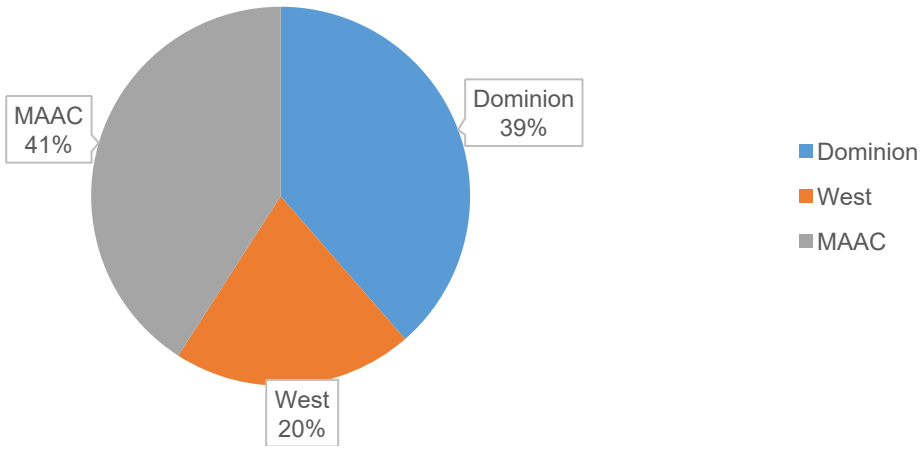
Load

PJM	MW Increase Load
Dominion	2,536
West	1,347
MAAC	2,689
Grand Total	**6,571**

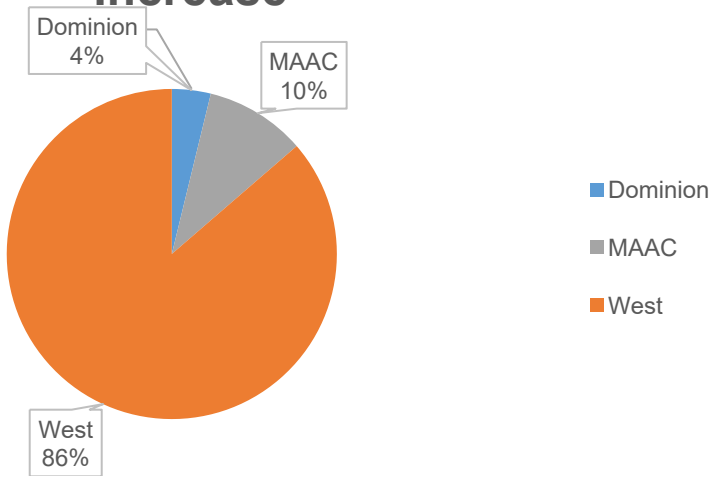
Generation

PJM	MW Increase Gen Dispatch
Dominion	322
West	7,317
MAAC	835
Grand Total	**8,475**

Year Over Year Load Increase



Year Over Year Gen Dispatch Increase



Most of the additional generation required to meet load growth 2028 vs 2029 is sourced from PJM West

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Load and Gen Dispatch – **Winter** (2028 to 2029)

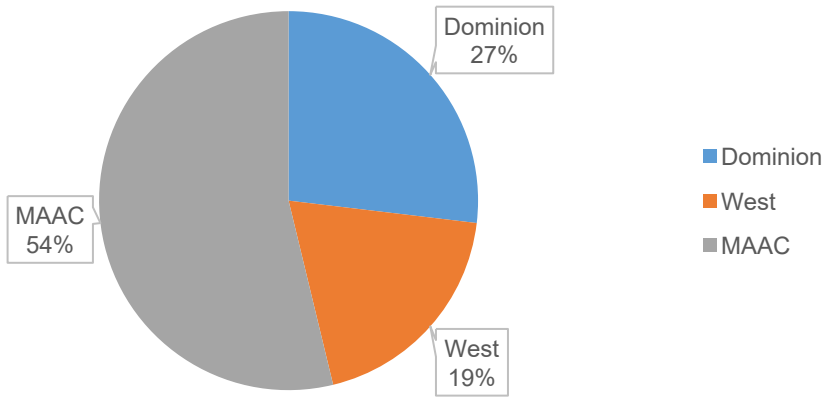
Load

Row Labels	MW Increase Load
Dominion	2,704
West	1,945
MAAC	5,410
Grand Total	**10,059**

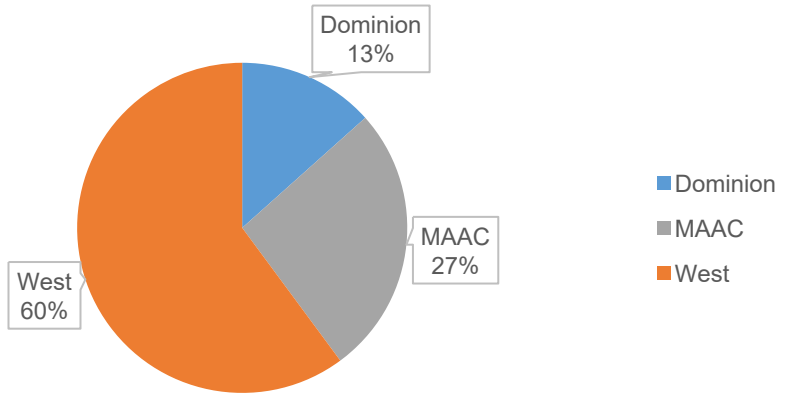
Generation

Row Labels	MW Increase Gen Dispatch
Dominion	1,611
West	7,233
MAAC	3,185
Grand Total	**12,029**

Year Over Year Load Increase



Year Over Year Gen Dispatch Increase



Most of the additional generation required to meet load growth 2028 vs 2029 is sourced from PJM West

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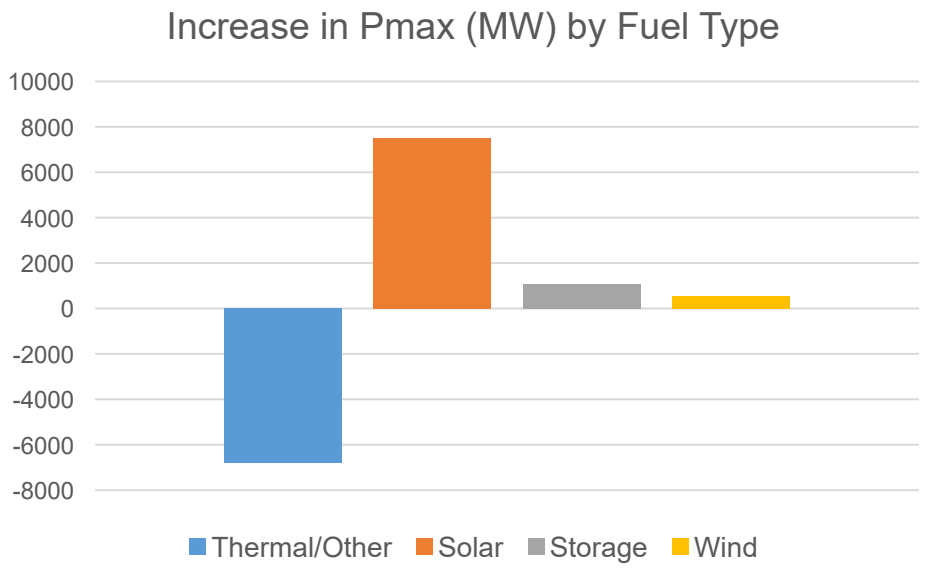
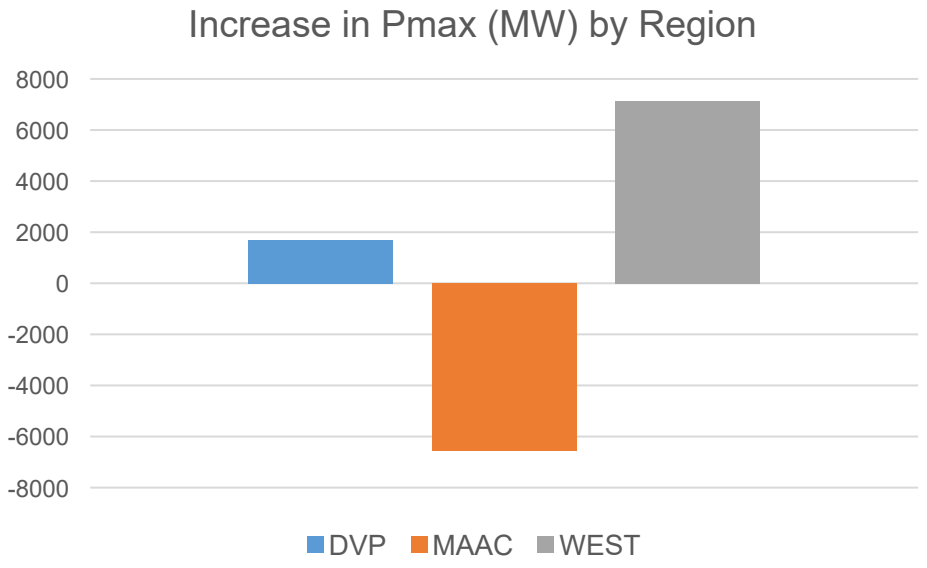
Generation Pmax Tables: 2028W2 versus 2029W1

Increase in Pmax (MW) from 2028W2 to 2029W1

	Thermal/Other	Solar	Storage	Wind	Totals
DVP	62	1372	380	-111	1702
MAAC	-6310	677	200	-1113	-6547
WEST	-567	5446	497	1757	7132
Totals	-6816	7496	1077	532	2288





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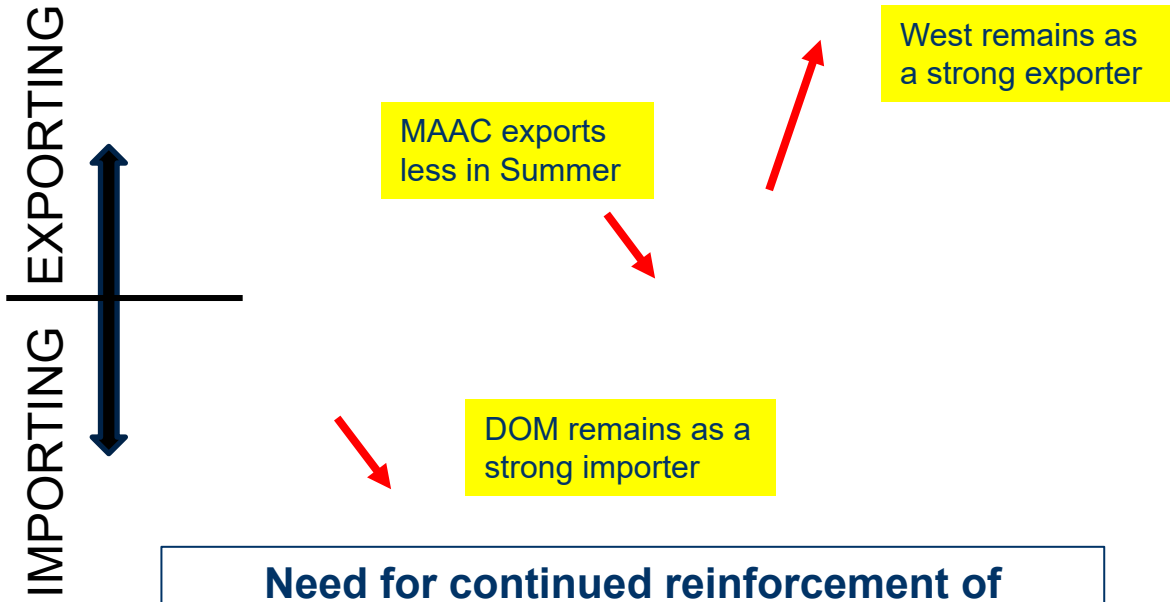
Area Interchange - Ties (2028 vs 2029)

SUMMER

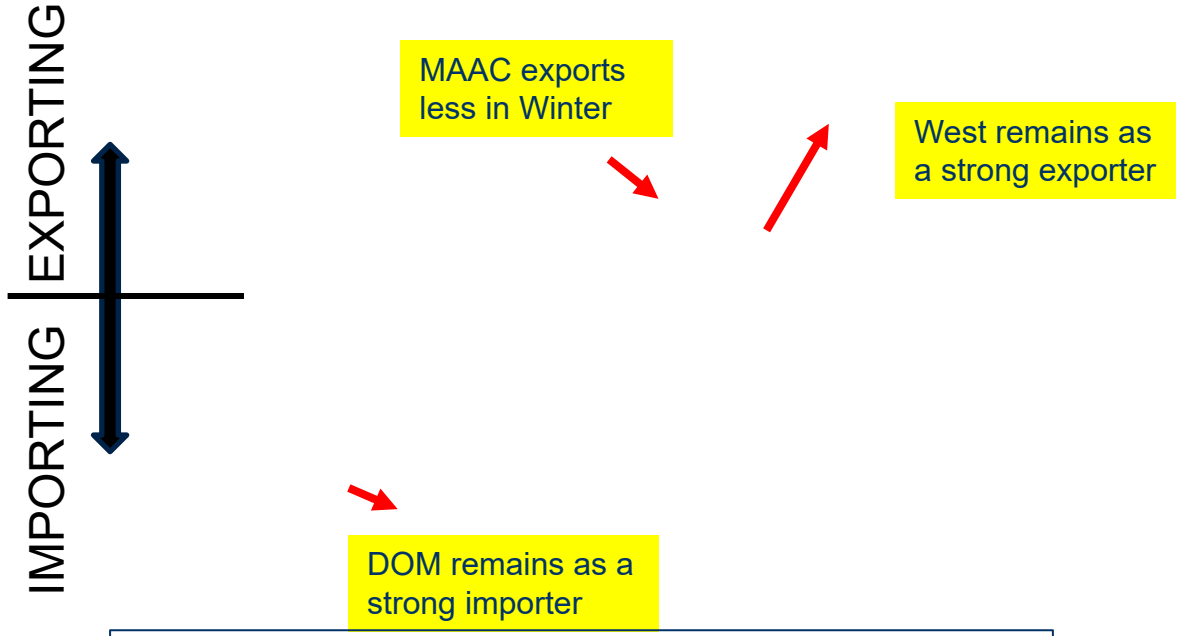
Row Labels	MW FLOW 2028	MW FLOW 2029	MW Change
Dominion	-4,279	-6,887	-2,608
West	3,532	9,021	5,489
MAAC	2,446	403	-2,044
Grand Total	**1,700**	**2,537**	**837**



Need for continued reinforcement of West/APS-DOM transfer path

WINTER

Row Labels	Sum of 2028	Sum of 2029	Sum of MW Increase
Dominion	-8,900	-10,315	-1,415
MAAC	6,825	4,328	-2,497
West	3,501	8,343	4,842
Grand Total	**1,426**	**2,356**	**929**



Consistent need for high West/APS – MAAC transfer capability

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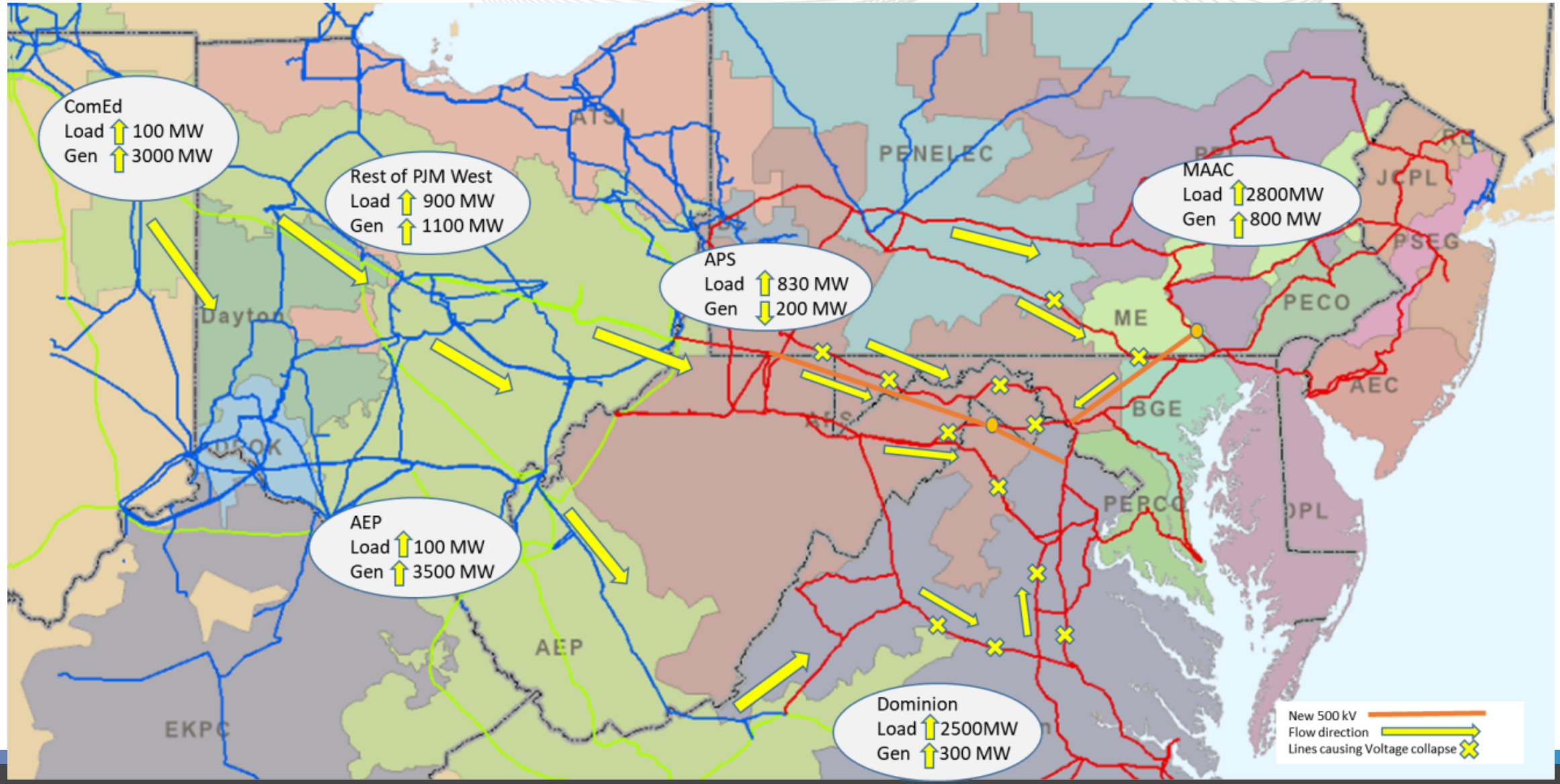
2028 RTEP W2 vs 2029 RTEP W1 Summer comparison



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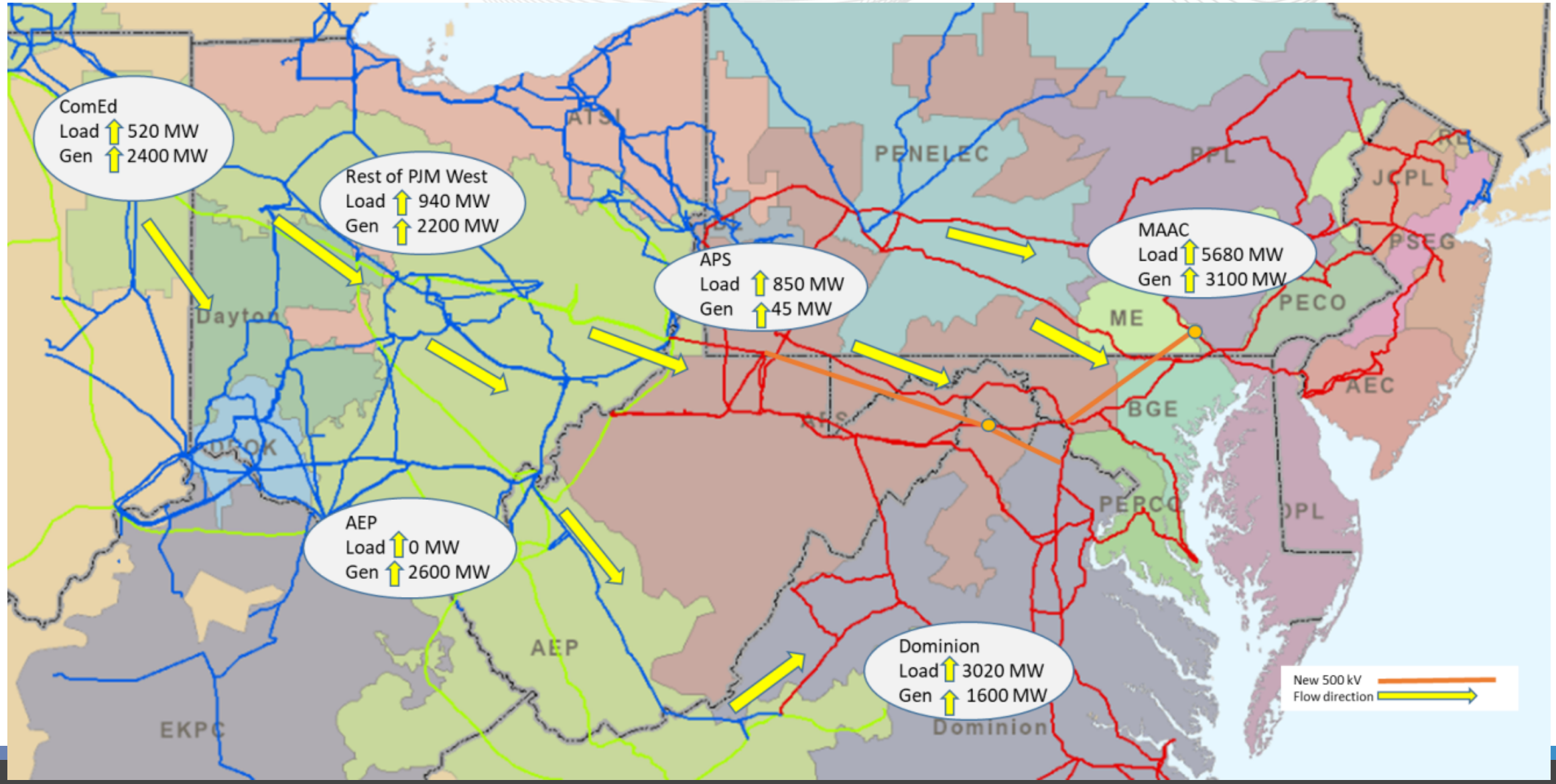
2028 RTEP W2 vs 2029 RTEP W1 Winter comparison



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2024W1 RTEP – Needs Summary (5-Years)

- Heavy transmission interface flows West-East driven by load increase in Dominion/East and sourced generation in both Western and Eastern PJM
- PJM earlier identified need for additional West-East reinforcement is materializing earlier – higher anticipated load in MAAC/Dominion
- Proposed reinforcement through 2022W3 and 2023W1/W2 performing well
- Additional upgrades within AEP and ComEd will be needed to support West-East interface bulk flows

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2032 (8-Year) RTEP Model

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2032 (8-Year RTEP Model) - Purpose

- Right size solutions of the 5-Year RTEP needs
- Check/Confirm impact of “forecast” generation on transmission needs identified in the 5-Years model
  - Model reasonably anticipated generation “forecast” in Dominion
  - Confirm whether forecast resources available in the west supports needed West-East transfers
  - Evaluate whether forecast generation offsets regional path transfer need (DOM and MAAC resources)

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Certainty of Transmission Need against Generation Forecast

- The need for West-East transfer path will rely on net import capability into Dominion/APS/Eastern PJM – relies on both internal zone load and gen development
- The 5-year model will confirm the need for West-East path reinforcement – requirement exceeds the inherent remnant transfer capability offered by 2022W3 reinforcements
- The 8-year (2032) model will have
  - ~4500MWs of additional load in Dominion compared to the 5-year case
  - Expect the impact of CVOW OSW + Chesterfield Generation to not offset the 2029-32 load growth, let alone the need already identified in 2029 (5-Year model).
- Resource requirements to satisfy load serving adequacy are expected to develop heavily in western PJM compared to eastern PJM

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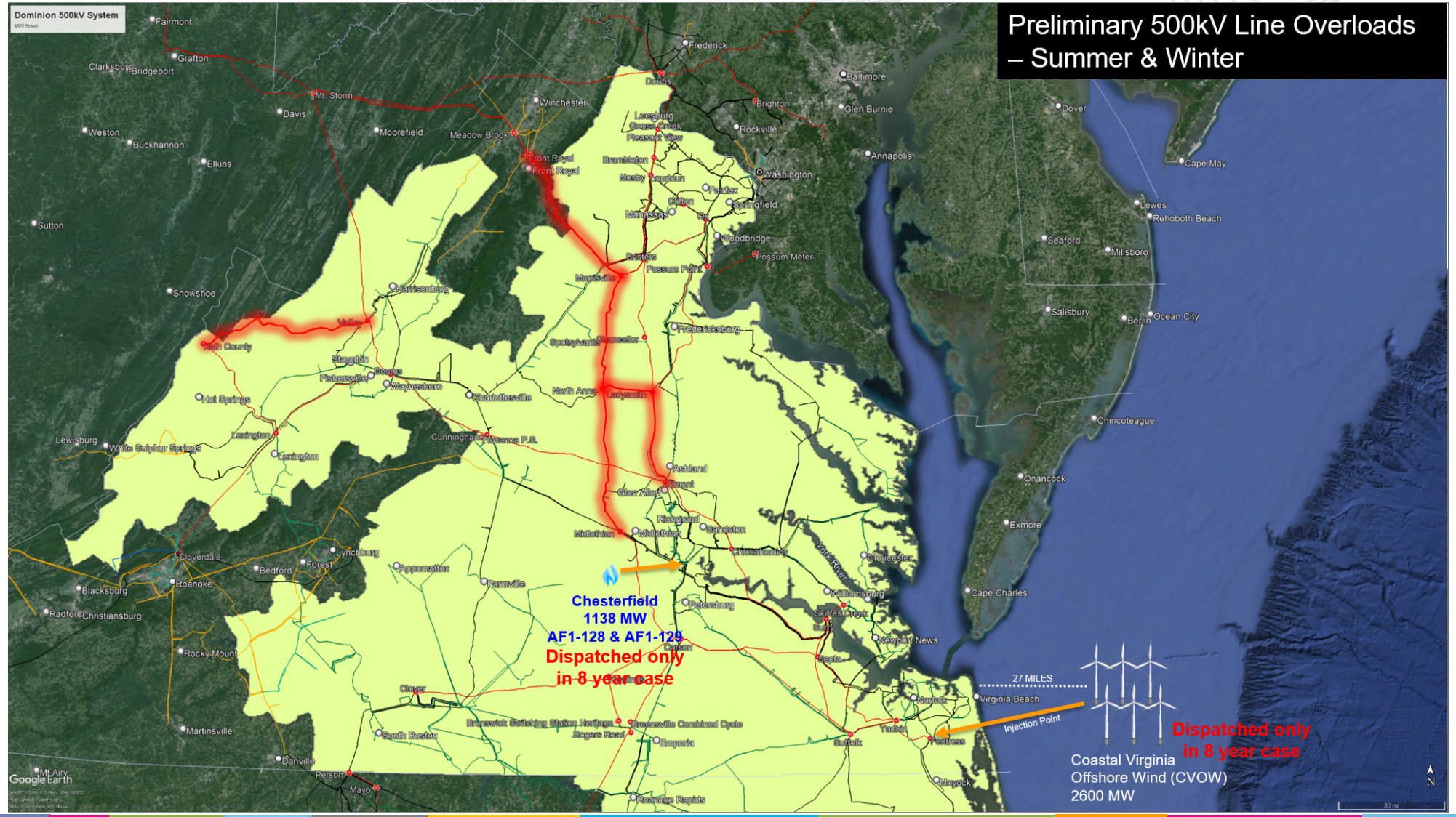
Forecast Generation Impact – Internal DOM upgrades



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Sensitivity Scenario to Assess Impact of load growth - Western PJM

- AEP is forecasting load growth in the next 5 to 8 years (up to 2032)
- Forecast update submissions ongoing and will be captured part of the 2025 PJM Load Forecast (to be published in Dec 2024/ Jan 2025)
- PJM will bring forward additional information regarding load and generation assumptions to the August TEAC.
- This sensitivity analysis to be conducted by PJM will focus on ensuring selection of the right solutions out of 2024W1 RTEP – will not introduce new needs/solutions.

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2024 W1 RTEP - Next Steps

- PJM will open the competitive transmission window on July 12th 2024 (5-Year RTEP model)
- 8-Year model will be posted around July 26th 2024
- AEP/Western Load growth sensitivity model (to inform selection of needed transmission) will be posted around August 9th
- 2024W1 RTEP will be running for 60 days and targeting PJM Board Approvals (Nov 2024 and Feb 2025)
  - TEAC 1st and 2nd reads to span between Oct 2024 and Jan 2025

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2023 RTEP Window 2 Second Review

Baseline Reliability Projects

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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 4 & 6

Process Stage: Recommended Solution – Second Read

Criteria: Summer/Winter Generator Deliverability

Assumption Reference: 2023 RTEP assumptions

Model Used for Analysis: 2028 RTEP cases

Proposal Window Exclusion: None

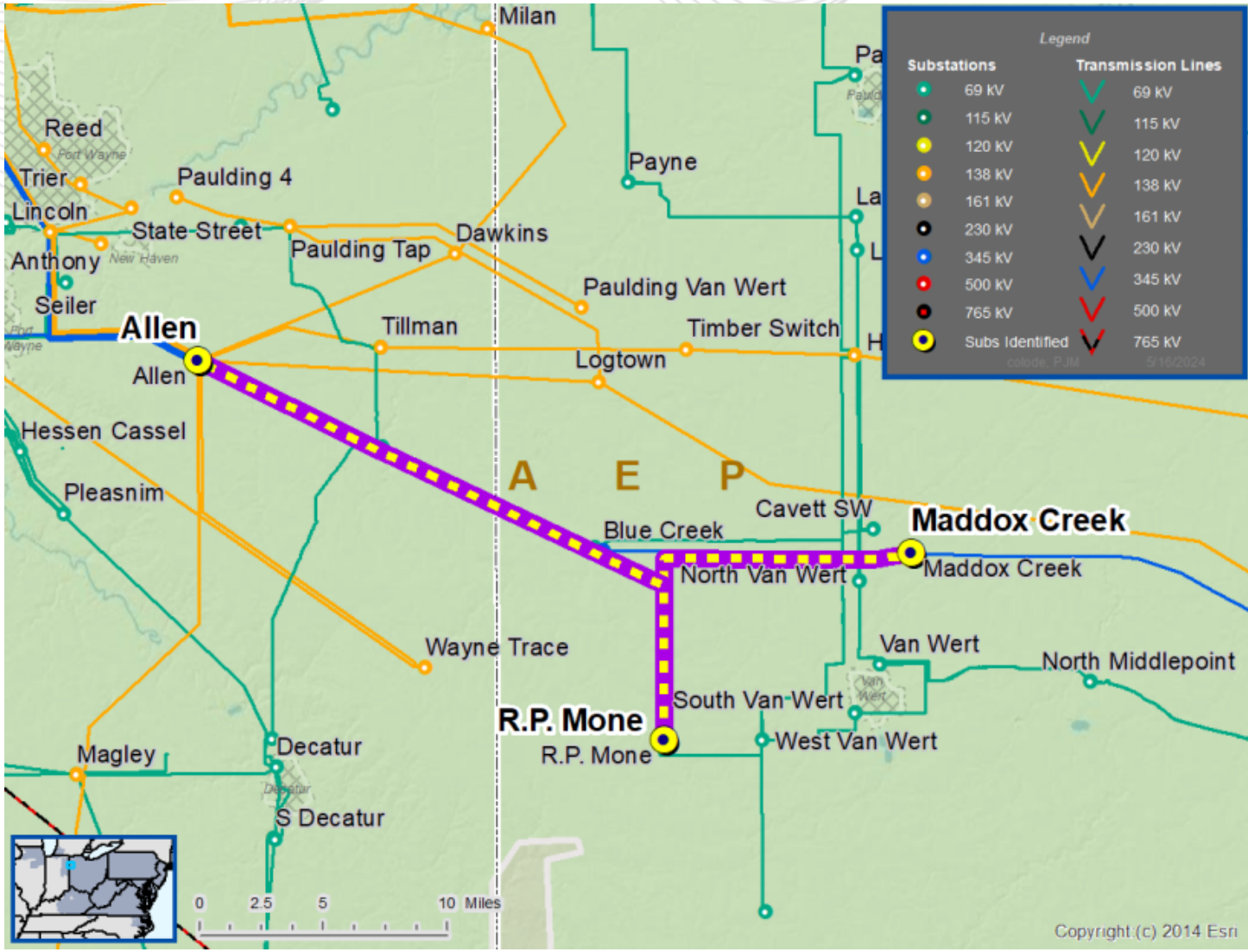
Problem Statement:

Cluster 4: 2023W2-GD-S170, 2023W2-GD-S142, 2023W2-GD-W213, 2023W2-GD-W58

In 2028 RTEP summer and winter cases, the R.P. Mone – Maddox Creek 345 kV line is overloaded in generator deliverability test for both N-1 and N-2 outages

Cluster 6: 2023W2-GD-W12

In 2028 RTEP winter cases, the Allen – R.P. Mone 345kV line is overloaded in generator deliverability test for a N-1 outage



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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 4 & 6

- As part of the 2023 RTEP Window #2, projects listed in the table below were proposed to address the violations in cluster 4, 6 or 4&6
- 7 total proposals submitted: all Upgrades from the same proposing entity - AEP

Proposal ID #	Cluster	Project Description	Total Cost ($M)	Analysis Summary
561	Cluster 4	Reconductor the 9.4 mile 345 kV line between RP Mone and Maddox Creek stations.	16.719	Solves the target FGs, causes overload on Maddox -E. Lima 345kV line, increases the loading on Alllen - RP Mone line
957	Cluster 4	Rebuild the 9.4 mile 345 kV line between RP Mone and Maddox Creek stations.	39.034	Solves the target FGs, causes overload on Maddox -E. Lima 345kV line, increases the loading on Alllen - RP Mone line
683	Cluster 6	Mitigate three clearance issues on Allen - RP Mone 345 kV line to allow line to operate to conductor's designed rating.	0.450	Solves the target FG. Margin is not big though (93.4%)
169	Cluster 6	Reconductor approximately 18.6 miles of 345 kV line between Allen and RP Mone stations.	32.486	Solves the target FG, increases the loading on the RPMORE- Maddox, causes overload on the Maddox - E Lima 345KV line
819	Cluster 6	Rebuild approximately 18.6 miles of 345 kV line between Allen and RP Mone stations.	49.875	Solves the target FG, increases the loading on the RPMORE- Maddox, causes overload on the Maddox - E Lima 345KV line
11	4 & 6	Install 345 kV Phase Shifting Transformer at East Lima station on line towards Fostoria Central.	40.301	Solves the target FGs ,causes overload on E. Lima transformer #2, W. Fremont - Fremont AEP/ATSI 138KV tie
334	4 & 6	String the open positions of the 345 kV line between Maddox Creek and Sorenson stations to establish a new 345 kV circuit between the two stations (42.6 miles). Reconductor the existing conductors on the line. Perform station work at Maddox Creek, Sorenson, and East Lima stations.	134.397	Solves the target FGs

AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 4 & 6

R.P. Mone – Maddox Creek 345kV line (in AEP EOL list)

- 9.4 miles of Paper Expanded (PE) Conductor originally installed in 1955
- All but one of the existing structures on the line were originally installed in 1955

Allen – R.P. Mone 345kV line (in AEP EOL list)

- 24.6 miles of Paper Expanded (PE) Conductor originally installed in 1955 and 1968
- All but two of the existing structures on the line were originally installed in 1955 or 1968

Options	Proposal #169 (Allen – R.P. Mone reconductor) Proposal #561 (R.P. Mone – Maddox Creek reconductor) Portion of Proposal #334 (Station work at E. Lima & Maddox Creek)	Proposal #819 (Allen – R.P. Mone rebuild) Proposal #957 (R.P. Mone – Maddox Creek rebuild) Portion of Proposal #334 (Station work at E. Lima & Maddox Creek)	Proposal #334
Cost ($M)	**52.766**	**92.470**	**134.397**
EOL factors	Partially addresses the EOL issues for both Allen - RP Mone and RP Mone - Maddox Creek 345kV circuits	Addresses the EOL issues for both Allen - RP Mone and RP Mone - Maddox Creek 345kV circuits	Partially addresses the EOL issues for both Allen - RP Mone and RP Mone - Maddox Creek 345kV circuits

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AEP Transmission Zone: Baseline 2023 RTEP Window 2 Clusters 4 & 6

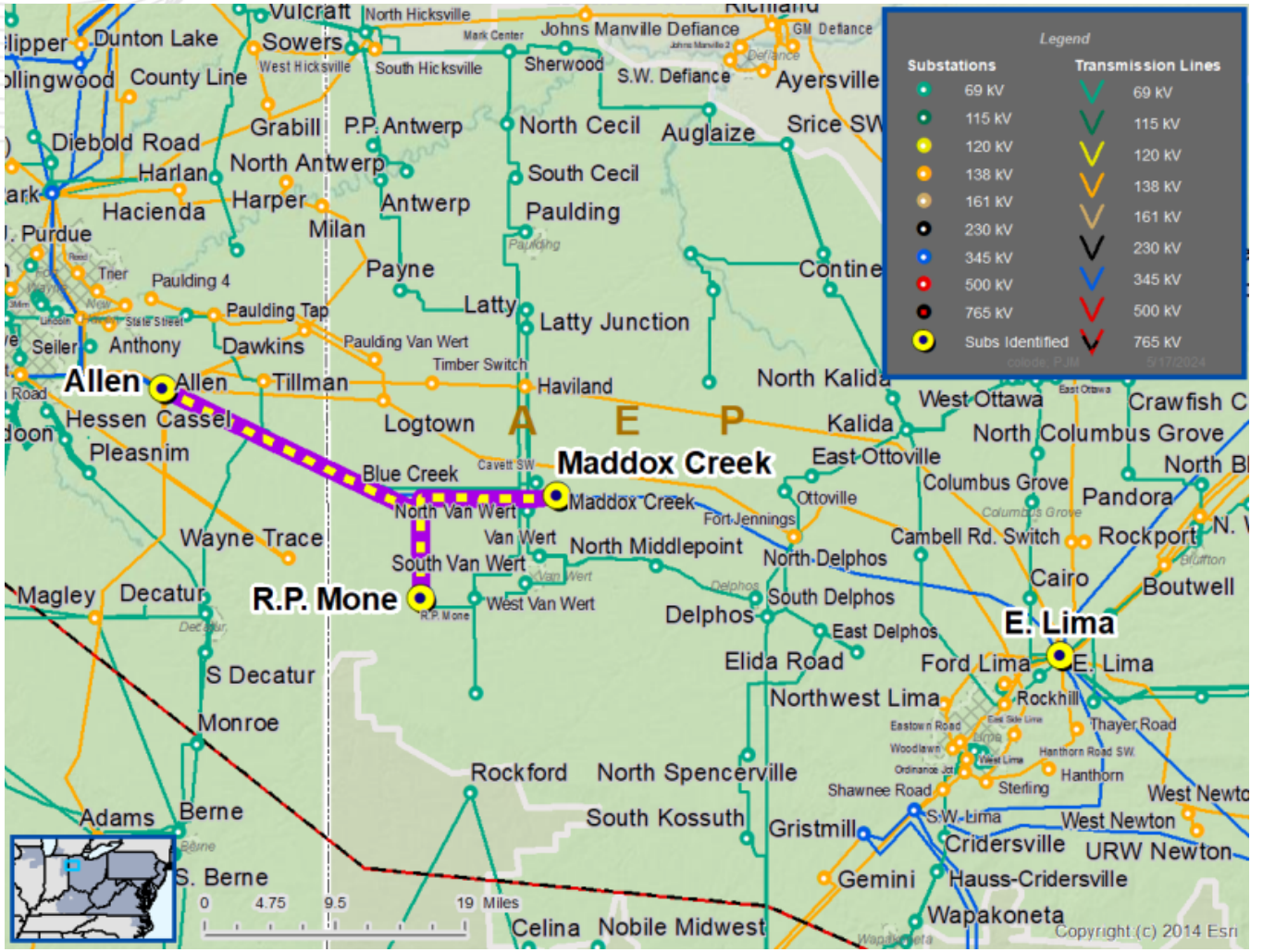
Recommended Solution:

- Proposal #819: Rebuild Allen –R.P. Mone 345kV line (18.6 miles). **(B3851.1)** Estimated Cost: **$49.875M**
- Proposal #957: Rebuild R.P. Mone – Maddox Creek 345kV line (9.4 miles) **(B3851.2)** . **Estimated Cost: $39.034M**
- Portion of Proposal #334:
  - Replace breakers 'B1' and 'B' at Maddox Creek. **(B3851.3) Estimated Cost: $1.8M**
  - Replace two 345kV breakers 'M' and 'M2' at East Lima Station. **(B3851.4) Estimated Cost: $1.761M**

Total Estimated Cost: $92.470 M

Required IS Date: 6/1/2027
Projected IS Date: 6/1/2027
Previously Presented: 6/4/2024

Branch	Existing Facility Ratings SN/SE/WN/WE (MVA)	Preliminary Facility Ratings SN/SE/WN/WE (MVA)
Allen – RP Mone 345kV	897/897/1138/1138	1677/1737/1737/1737
RP Mone – Maddox 345kV	897/1301/1138/1452	1676/1868/2022/2219
Maddox – E. Lima 345 kV	1188/1539/1506/1737	1916/2246/2425/2672



AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

Process Stage: Recommended Solution – Second Read

Criteria: Summer/Winter Generator Deliverability, N-1-1

Assumption Reference: 2023 RTEP assumptions

Model Used for Analysis: 2028 RTEP cases

Proposal Window Exclusion: None

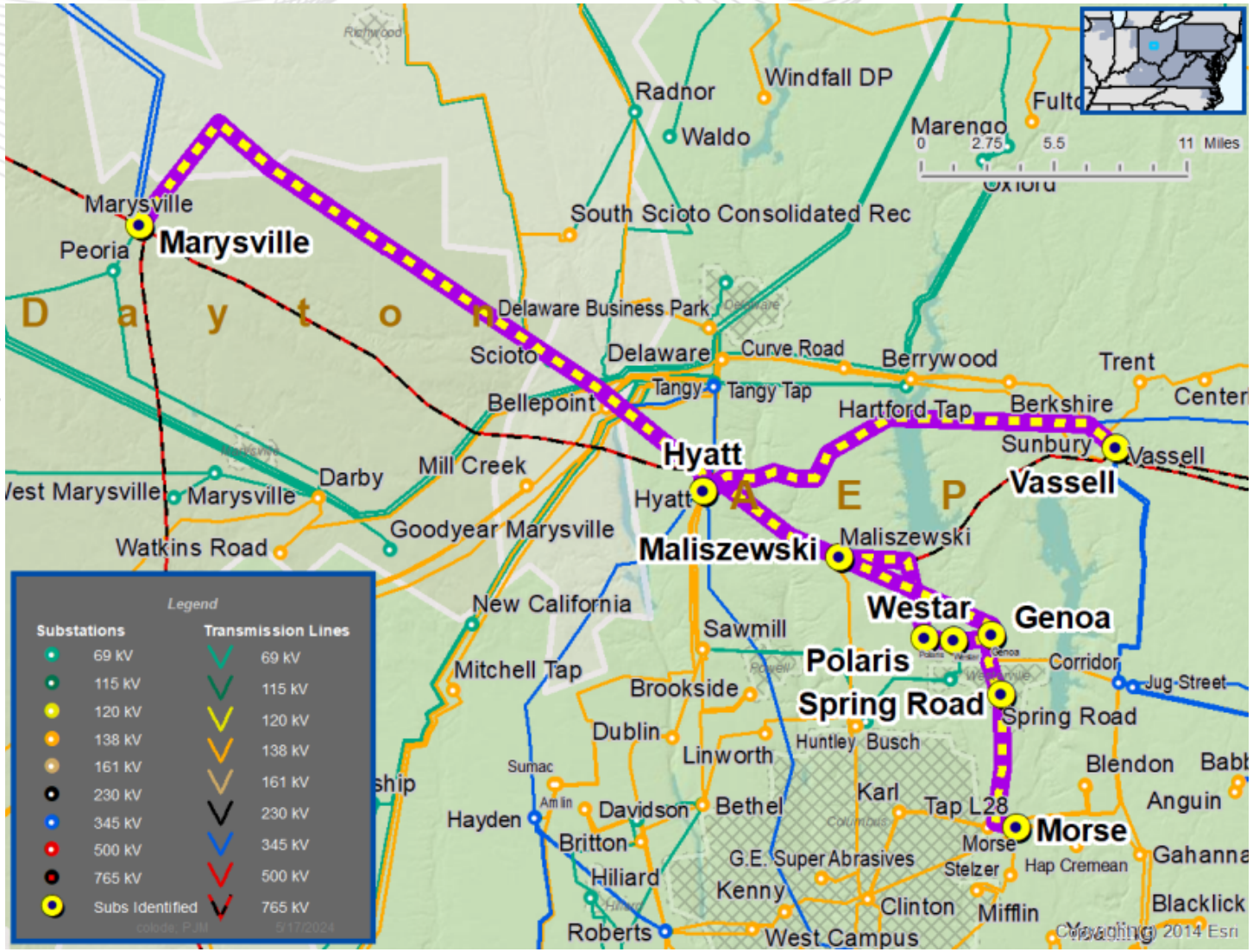
Problem Statement:

Cluster 3: 2023W2-GD-S186, 2023W2-GD-S141, 2023W2-N2-WT1, 2023W2-N2-ST4, 2023W2-N2-ST2, 2023W2-N1-ST15, 2023W2-N2-ST1, 2023W2-N2-ST30, 2023W2-N2-ST31, 2023W2-N2-WT4, 2023W2-N2-ST7, 2023W2-N2-ST28, 2023W2-N2-ST39, 2023W2-N2-ST37, 2023W2-N2-ST48, 2023W2-N2-ST46

In 2028 RTEP summer case, the **Genoa – Westar 138 kV** line is overloaded in generator deliverability test for N-2 outages; and in 2028 RTEP summer and winter cases, the Genoa – Westar 138 kV line is overloaded in N-1-1 test for multiple contingency pairs

Cluster 5: 2023W2-N2-ST6, 2023W2-N2-ST5, 2023W2-N1-ST14, 2023W2-GD-S165, 2023W2-N1-ST13, 2023W2-N2-ST3, 2023W2-GD-S135, 2023W2-N2-ST32, 2023W2-N2-ST43, 2023W2-N2-ST22, 2023W2-N2-ST44, 2023W2-N2-ST40, 2023W2-N2-WT5, 2023W2-N2-ST8, 2023W2-N2-WT3, 2023W2-N2-ST17, 2023W2-N2-ST49, 2023W2-N2-ST18, 2023W2-N2-ST13, 2023W2-N2-ST25, 2023W2-N2-ST47, 2023W2-N2-ST24

In 2028 RTEP summer case, **the Maliszewski – Polaris 138** kV line is overloaded in generator deliverability test and basecase analysis test for N-2 outages; and in 2028 RTEP summer and winter cases, the Maliszewski – Polaris 138 kV line is overloaded in N-1-1 test for multiple contingency pairs



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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

Problem Statement (Conti.):

Single floaters:

2023W2-N2-ST50, 2023W2-N2-ST9, 2023W2-N2-ST16, 2023W2-N2-ST34, 2023W2-N2-ST45

In 2028 RTEP summer case, the **Genoa – Spring Road138 kV** line is overloaded in N-1-1 test for multiple contingency pairs.

2023W2-N2-ST11, 2023W2-N2-ST41, 2023W2-N2-WT8, 2023W2-N2-ST10, 2023W2-N2-WT7, 2023W2-N2-ST36, 2023W2-N2-ST12, 2023W2-N2-ST23, 2023W2-N2-ST14

In 2028 RTEP summer and winter cases, the **Polaris – Westar 138kV** line is overloaded in N-1-1 test for multiple contingency pairs.

Cluster 2: <u>All of the above (cluster 3 &5, and single floaters), plus</u>

2023W2-N1-ST21, 2023W2-N1-ST20, 2023W2-N1-ST23, 2023W2-N1-ST22, 2023W2-N1-ST25, 2023W2-N1-ST24, 2023W2-N1-ST27, 2023W2-N1-ST26, 2023W2-N1-ST19, 2023W2-N2-ST33, 2023W2-N2-ST38, 2023W2-N2-ST35, 2023W2-GD-S170, 2023W2-N1-ST10, 2023W2-N1-ST12, 2023W2-N1-ST16, 2023W2-N1-ST18, 2023W2-N1-ST17, 2023W2-N1-ST1, 2023W2-N2-ST21, 2023W2-N1-ST3, 2023W2-N1-ST2, 2023W2-N2-ST20, 2023W2-N1-ST5, 2023W2-N1-WT1, 2023W2-N1-ST4, 2023W2-N1-ST7, 2023W2-N1-WT3, 2023W2-N1-ST6, 2023W2-N1-WT2, 2023W2-N2-ST29, 2023W2-N2-ST27, 2023W2-N2-ST26, 2023W2-GD-S4, 2023W2-GD-S3, 2023W2-N2-WT6, 2023W2-GD-W154, 2023W2-GD-W155, 2023W2-GD-W153, 2023W2-GD-W156, 2023W2-GD-S115, 2023W2-GD-S114, 2023W2-N2-ST42, 2023W2-GD-S6, 2023W2-GD-W162, 2023W2-GD-W165, 2023W2-GD-W163, 2023W2-GD-W164, 2023W2-GD-S122, 2023W2-GD-S121, 2023W2-GD-S123, 2023W2-GD-S126, 2023W2-GD-S125, 2023W2-GD-S116, 2023W2-GD-W59, 2023W2-GD-W58, 2023W2-N1-WT10, 2023W2-N1-WT13, 2023W2-N1-WT14, 2023W2-N1-WT11, 2023W2-N1-WT12, 2023W2-GD-W213, 2023W2-N2-WT2, 2023W2-GD-W214, 2023W2-N2-ST3, 2023W2-GD-W217, 2023W2-GD-W215, 2023W2-GD-W216, 2023W2-GD-S127, 2023W2-N1-ST9, 2023W2-N1-WT5, 2023W2-N1-ST8, 2023W2-N1-WT4, 2023W2-N1-WT7, 2023W2-N1-WT6, 2023W2-N1-WT9, 2023W2-N1-WT8, 2023W2-N2-ST11, 2023W2-N2-ST19, 2023W2-N2-ST15, 2023W2-GD-W19, 2023W2-GD-W25

In 2028 RTEP summer and winter cases, **Maliszewski transformer 765/138KV transformer and Maliszewski 138kV series reactor bypass** are overload in generator deliverability test and basecase analysis test for N-1 and N-2 outages.

In 2028 RTEP Summer case, the **Morse – Spring Road 138kV** line, **the Marysville – Hyatt 345kV** line, the **Hyatt – Vassell 345kV** line, the **Hyatt – Maliszewski #2 138kV** line, the **Genoa – Maliszewski 138kV #2** line are overloaded in N-1-1 test for multiple contingency pairs.

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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

- As part of the 2023 RTEP Window #2, projects listed in the table below were proposed to address the violations in Cluster 2
- 3 total proposals submitted from 3 different entities
  - 2 Greenfields
  - 1 Upgrades
- Both greenfield proposals identified with cost containment

Proposal ID	Proposing Entity	Project Type	Project Description	Cost As Proposed ($M)
117	AEP	UPGRADE	Connect and energize a second 765/345 kV bank at Vassell station. Replace 765 kV breaker D at Maliszewski station.	33.729
27	CNTLTM	GREENFIELD	1) new 765/345kV Barron substation, 2) A new double circuit 345kV transmission line from the new Barron Substation to the existing Hayden Substation, 3) Splitting the existing Conesville - Hyatt 345kV single circuit line and looping it into the existing Vassel substation, 4) Sag studies for the Genoa - Westar and Genoa - Spring Road 138kV transmission lines to increase their ratings, 5) Reconductoring the existing Maliszewski - Polaris and Polaris - Westar 138kV transmission lines.	203.830
343	TRANSRC	GREENFIELD	Jester greenfield 765/345kV station approximately 18.5 miles south of Marysville 765kV and 12 miles west of Hayden 345kV station; Reroute Hyatt – West Millersport 345kV line and loop into Corridor 345kV substation; Rebuild Kenny – Roberts 138kV circuit.	229.311

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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

- As part of the 2023 RTEP Window #2, projects listed in the table below were proposed to address the violations in clusters 3, 5 and single floaters partially overlapped with Cluster 2
- 6 total proposals, all are upgrades from AEP
- None of the 6 proposals identified with cost containment

Cluster	Proposal ID	Project Description	Cost As Proposed ($M)
3	596	Mitigate clearance issues on Westar - Genoa 138 kV line to allow line to operate to conductor's designed rating	2.815
3	729	Rebuild the approximately 2 mile 138 kV line between Westar and Genoa stations..	8.789
5	188	Reconductor the 2.8 mile 138 kV line between Maliszewski and Polaris stations.	7.231
5	340	Rebuild the 2.8 mile 138 kV line between Maliszewski and Polaris stations.	8.884
-	426	Mitigate clearance issues on Genoa - Spring Rd SW 138 kV line. Replace a station riser at Genoa station.	3.461
-	92	Rebuild the majority of the 3.7 mile 138 kV line between Polaris and Westar stations. Replace station equipment at Polaris station.	12.196

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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

Proposal ID	Reliability Evaluation Results	Cost As Proposed ($M)	Cost Adjustment *($M)	Total Cost ($M)
117	Solves all the target issues with good margin. No new reliability violations identified.	33.729	0	33.729
27	Solves all the target issues with good margin. Causes overload on the Kenny – Roberts 138KV circuit. The following components are not needed and can be removed. 4) Sag studies for the Genoa - Westar and Genoa - Spring Road 138kV transmission lines to increase their ratings, 5) Reconductoring the existing Maliszewski - Polaris and Polaris - Westar 138kV transmission lines.	203.830	+49.860 -6.644	247.046
343	Solves all the target issues with good margin. No new reliability violations identified.	229.311	0	229.311

* Cost adjustment associated with scope additions or removals

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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

Proposal ID	Cost Estimate Risks	Cost Containment Risks	Schedule Risk	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
343	Low	Medium	Medium-High	Medium-High	High	Medium
27	Low	Low	Medium-High	Medium-High	High	Medium
117	Low	High	Low	Low	Low	Low

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AEP Transmission Zone: Baseline
2023 RTEP Window 2 Clusters 2, 3 & 5

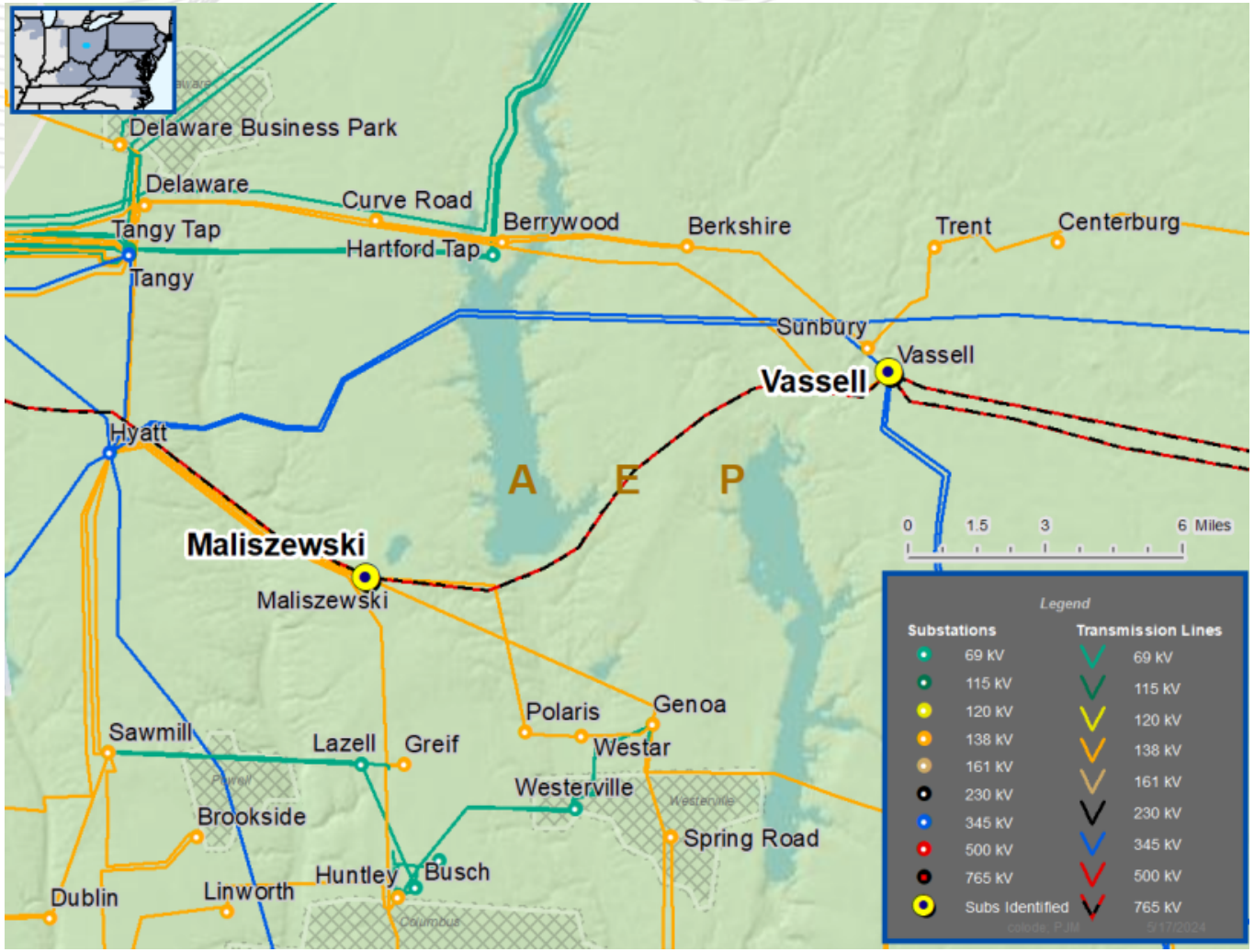
Recommended Solution: Proposal #117
Connect and energize a second 765/345 kV bank at Vassell station. **(B3852.1) Estimated Cost:** $30.829M
Replace 765 kV breaker D at Maliszewski station. **(B3852.2)**
Estimated Cost: $2.900M

Total Estimated Cost: $33.729 M

Required IS Date: 6/1/2027
Projected IS Date: 6/1/2027
Previously Presented: 6/4/2024

Facility Ratings:

Branch	Existing Facility Ratings SN/SE/WN/WE (MVA)	Preliminary Facility Ratings SN/SE/WN/WE (MVA)
Vassell 765/345 Transformer #2	-	2855/2897/2897/2897
Maliszewski – Marysville 765KV	4047/4142/4484/4961	4047/4571/4484/4961



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PSEG Cluster 1 Evaluation and Recommended Solution

Process Stage: Second Review

Criteria: Summer N-1-1 Thermal violation

Assumption Reference: 2028 RTEP assumption

Model Used for Analysis: 2028 RTEP cases

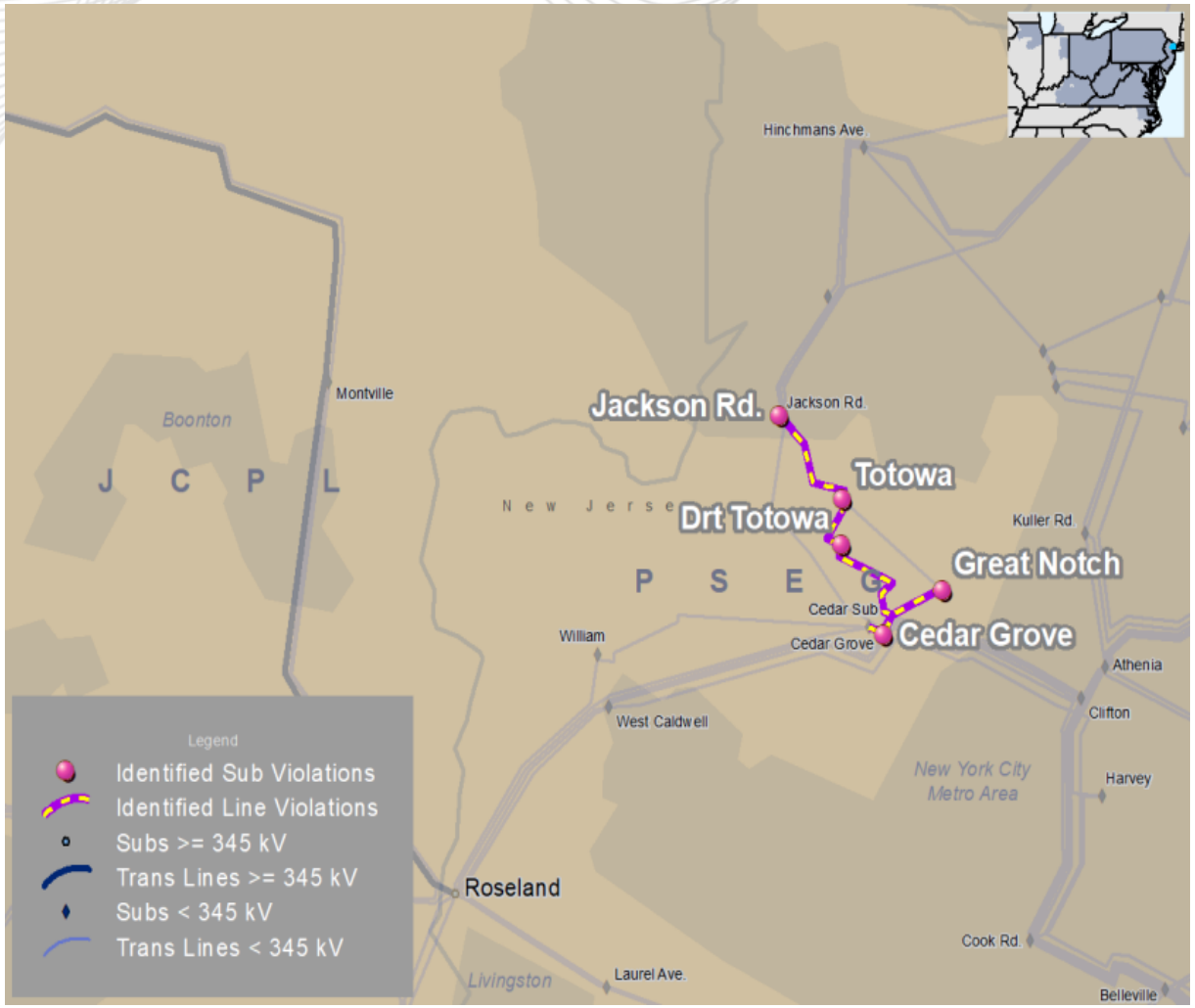
Proposal Window Exclusion: No

Problem Statement:

- PSEG N-1-1 thermal violation in the Northern New Jersey (Cedar Grove and Jackson area). Four 69 kV lines overloaded for several N-1-1 contingency combinations.

Violations were posted as part of the 2023 Window 2:

2023W2-PSEG-T1	2023W2-PSEG-T6	2023W2-PSEG-T11
2023W2-PSEG-T2	2023W2-PSEG-T7	2023W2-PSEG-T12
2023W2-PSEG-T3	2023W2-PSEG-T8	2023W2-PSEG-T13
2023W2-PSEG-T4	2023W2-PSEG-T9	2023W2-PSEG-T14
2023W2-PSEG-T5	2023W2-PSEG-T10	2023W2-PSEG-T15



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PSEG Cluster 1 Evaluation and Recommended Solution

2023 Window 2 Cluster 1 Proposals

- Four projects proposed by Two Entities
  - 1 – 69 kV new line, partial overhead and partial underground
  - 2 – 230 kV new underground lines
  - 1 – 345 kV new underground construction and 230 kV operation

Proposal ID	Proposing Entity	Project Description	Estimated Cost (M)
2023-W2-998	PSEG	New 69 kV from Cedar Grove - Jackson Rd (3.73mi OH, 1.2mi - UG) and new 69kV from I-633 top to Jackson Rd (0.8mi OH, 1.2mi - UG)	60.6
2023-W2-496	PSEG	4 miles New 230kV XLPE Circuit using (230kV rated 3500kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station	78.9
2023-W2-627	PSEG	4 miles New 230kV XLPE Circuit using (345kV rated 5000kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station	84.6
2023-W2-716	PPL Translink	Build a 7.6 mile 230kV underground circuit using (345kV rated 5000kcmil cable)from the JCPL Montville Substation to the PSEG Jackson Rd Substation.	211.1

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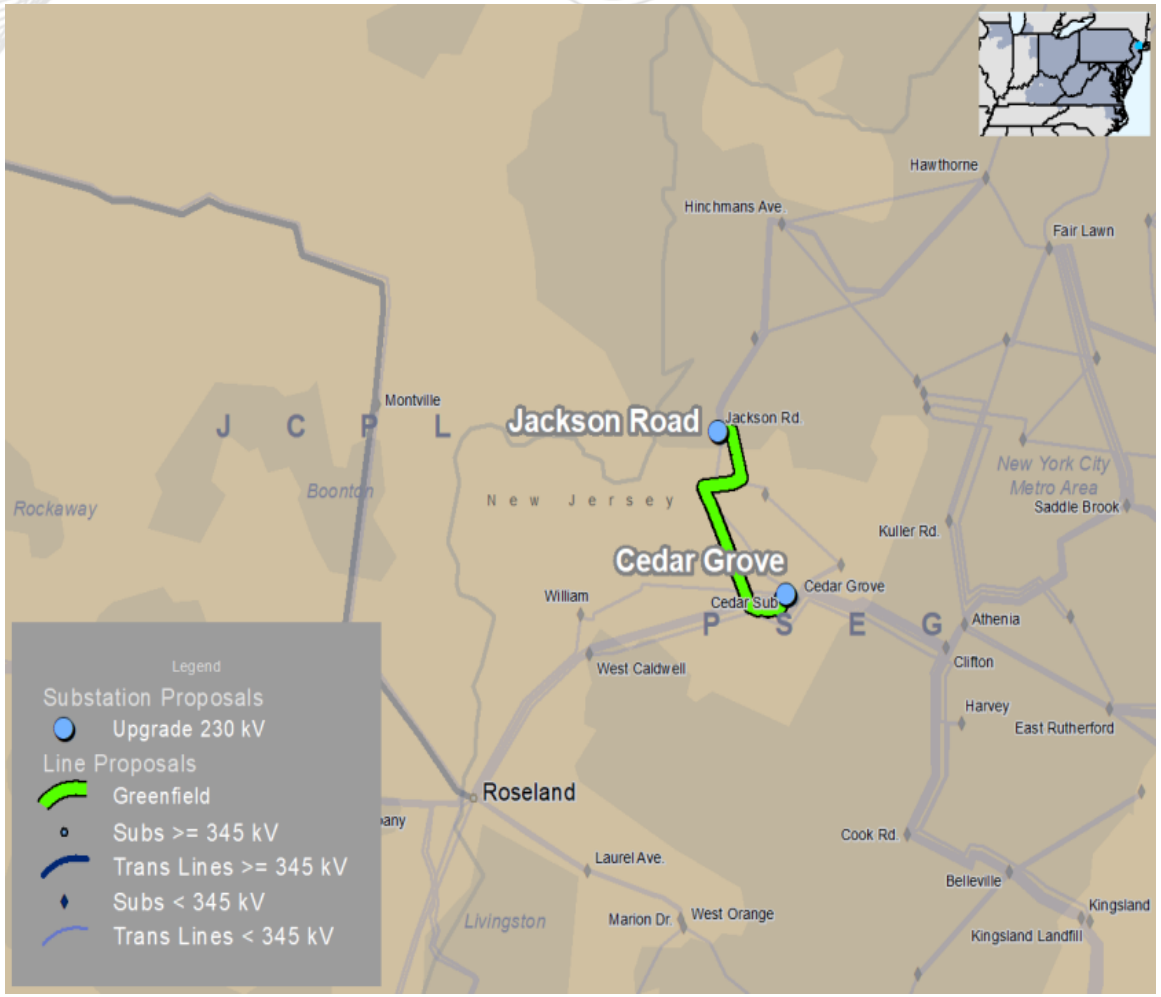
PSEG Cluster 1 Evaluation and Recommended Solution
Proposal 2023-W2-998

Proposal ID 998:

- Build new direct 69kV connection from Jackson Road to Cedar Grove (approximately 4.5 mi). This circuit will have both underground and overhead portions
- Replace (3) 72.5kV 40kA breakers with (3) 72.5 kV 63kA breakers. For the new 69kV line between Cedar Grove and Jackson Road. Replace the existing overhead termination structure with an underground termination structure. Replace line relay for the new 69kV line and the new extension
- For the new 69kV line between Cedar Grove and Jackson Road, installing a new UG termination structure. Replace line relay for the new 69kV line and the new extension
- Reroute a Portion of the existing N-664 underground and Tap into the existing I-633 creating a 3-ended circuit
- Reroute approximately 0.5 miles of the existing E-759 69kV line near the intersection of Vreeland Ave and Riverview Drive underground back to Jackson Road



Proposed Facility Rating: 95SN/131SE, 128WN/155WE MVA

Estimated Cost: $60.6 M

Required In-Service: 6/1/2028

Projected In-Service: 6/1/2028

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PSEG Cluster 1 Evaluation and Recommended Solution
Proposal 2023-W2-496

Proposal ID 496:

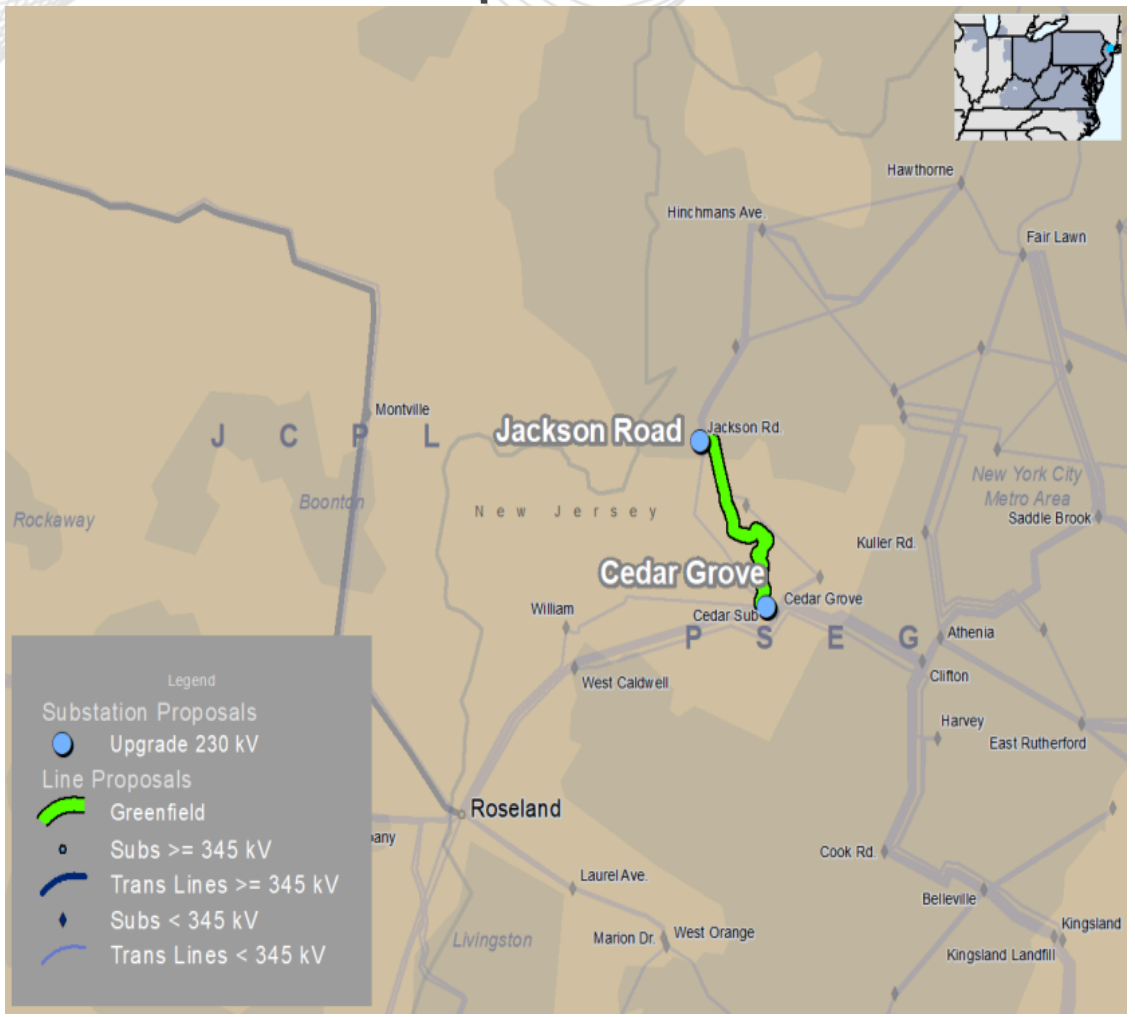
- Build 4 miles New 230kV XLPE Circuit using (230kV rated 3500kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station
- Expand a new 230kV bay at the existing Cedar Grove with one line position by adding two 230kV circuit breaker and associated disconnect switches
- Replace the existing HPFF termination structure with a new XLPE termination structure to connect to spare GIS bay position circuit breaker and associated disconnect switches

Proposed Facility Rating: 457SN/677SE, 492WN/700WE MVA

Estimated Cost: $78.9 M

Required In-Service: 6/1/2028

Projected In-Service: 6/1/2028



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PSEG Cluster 1 Evaluation and Recommended Solution
Proposal 2023-W2-627

Proposal ID 627:

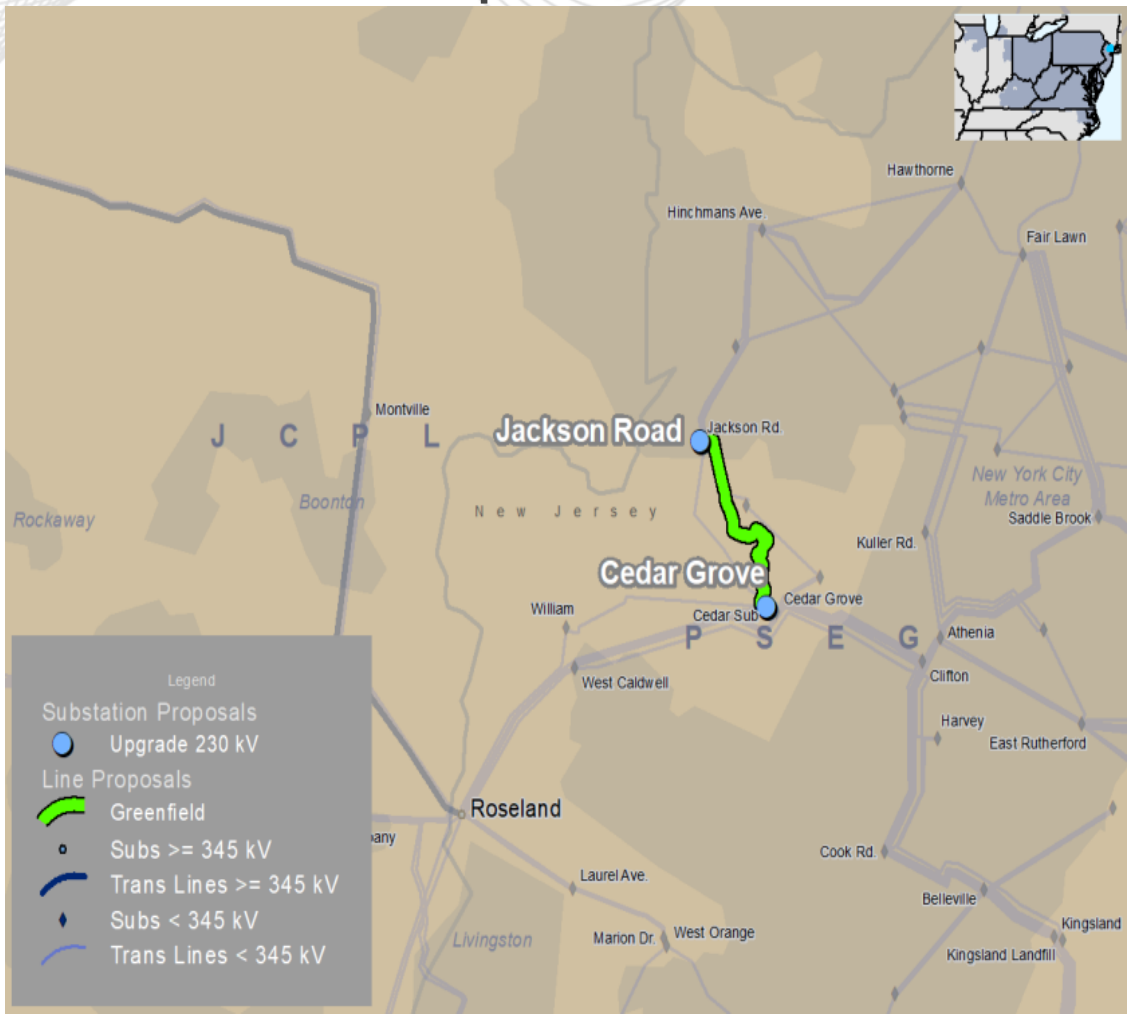
- Build 4 miles New 230kV XLPE Circuit using (345kV rated 5000kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station
- Expand a new 230kV bay at the existing Cedar Grove Station with one line position by adding two 230kV circuit breakers and associated disconnect switches
- Replace the existing HPFF termination structure with a new XLPE termination structure to connect to spare GIS bay position

Proposed Facility Rating: 512SN/796SE, 552WN/821WE MVA

Estimated Cost: $84.6 M

Required In-Service: 6/1/2028

Projected In-Service: 6/1/2028



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PSEG Cluster 1 Evaluation and Recommended Solution
Proposal 2023-W2-716

Proposal ID 716:

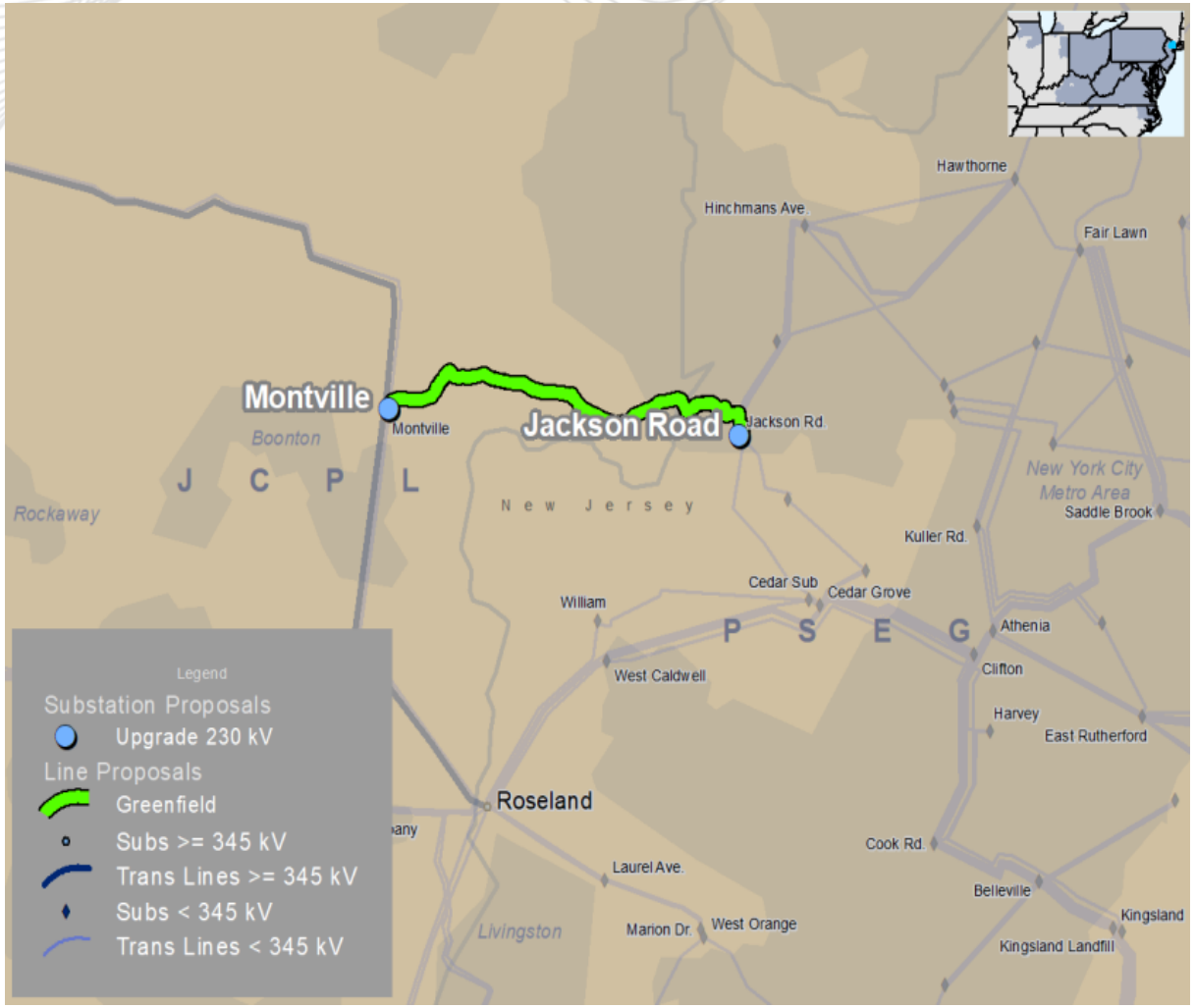
- Build a 7.6 mile 230 kV underground circuit using (345kV rated 5000kcmil cable) from the JCPL Montville Substation to the PSEG Jackson Rd Substation
- Expand the Montville 230 kV to a breaker and a half configuration by adding one new bay on the west side of the yard to terminate the new line
- At Jackson Rd, terminate the new line in the open bay position next to transformer 40

Proposed Facility Rating: 624SN/830SE, 659WN/850WE MVA

Estimated Cost: $211.1 M

Required In-Service: 6/1/2028

Projected In-Service: 6/1/2028



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PSEG Cluster 1 Evaluation and Recommended Solution

2023 Window 2 Cluster 1 Proposals study

PJM evaluated all four Proposals:

- Performed the DNH analysis to ensure the proposals solve the identified violations and don't cause a harm to the system
- Evaluated the proposals for their performance in future load growth

Proposals Performance Comparison:

Proposal ID	2023-W2-998	2023-W2-496	2023-W2-627	2023-W2-716
Address all Cluster 1 Violations	Y	Y	Y	Y
Provides Margin for Future Needs	N	Y	Y	N
Future Expandability	N	N	Y	Y

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PSEG Cluster 1 Evaluation and Recommended Solution

Proposal ID	Proposing Entity	Project Type	Project Description	Cost As Proposed ($M)
998	PSEG	UPGRADE	New 69 kV from Cedar Grove - Jackson Rd (3.73mi OH, 1.2mi - UG) and new 69kV from I-633 top to Jackson Rd (0.8mi OH, 1.2mi - UG)	60.6
496	PSEG	GREENFIELD	4 miles New 230kV XLPE Circuit using (230kV rated 3500kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station	78.9
627	PSEG	GREENFIELD	4 miles New 230kV XLPE Circuit using (345kV rated 5000kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station	84.6
716	PPL Translink	GREENFIELD	Build a 7.6 mile 230 underground circuit using (345kV rated 5000kcmil cable) from the JCPL Montville Substation to the PSEG Jackson Rd Substation	211.1

Proposal ID	Cost Estimate Risks	Cost Containment Risks	Schedule Risk	Constructability Risks	Use of Existing ROW & Brownfield	Outage Coordination Risks
998	Low	High	Medium	Medium	Medium-High	Low
496	Low	Low	Medium-High	Medium	Medium-High	Low
627	Low	Low	Medium-High	Medium	Medium-High	Low
716	Low	Medium-High	High	High	High	Low

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PSEG Cluster 1 Proposals Evaluation Progress
Proposal 2023-W2-627

Process Stage: Second Review

Criteria: Summer N-1-1 Thermal violation

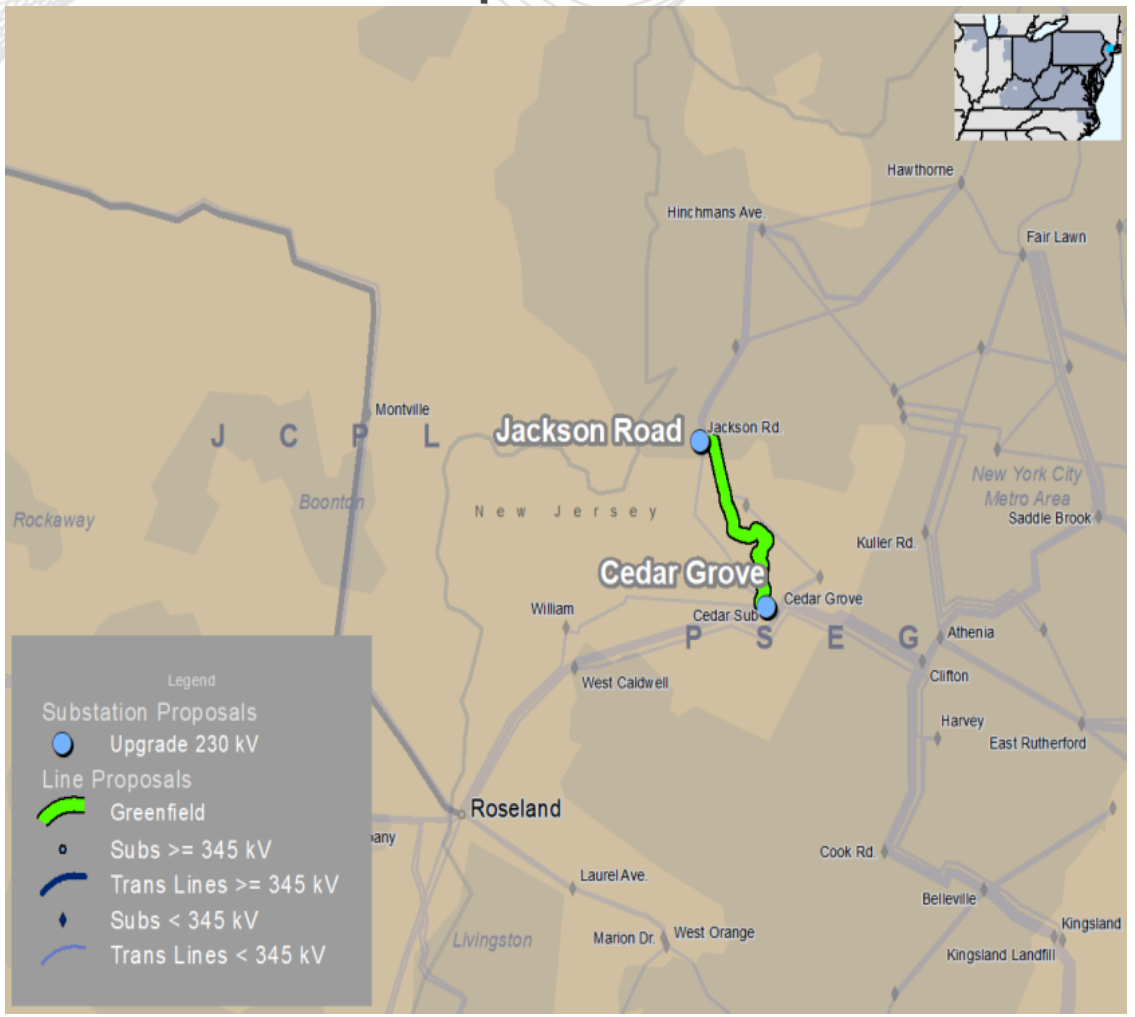
Problem Statement:

- PSEG N-1-1 thermal violation in the Northern New Jersey (Cedar Grove and Jackson area). Four 69 kV lines overloaded for several N-1-1 contingency combinations.

Recommended Solution:

Proposal ID 627:

- Build 4 miles New 230kV XLPE Circuit using (345kV rated 5000kcmil cable) from Jackson Road 230kV Station to Cedar Grove 230kV Station **(b3855.1)**
- Expand a new 230kV bay at the existing Cedar Grove Station with one line position by adding two 230kV circuit breakers and associated disconnect switches **(b3855.2)**
- Replace the existing HPFF termination structure with a new XLPE termination structure to connect to spare GIS bay position at Jackson 230kV **(b3855.3)**



Proposed Facility Rating: 512SN/796SE, 552WN/821WE MVA

Estimated Cost: $84.6 M

Required In-Service: 6/1/2028

Projected In-Service: 6/1/2028

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2022 Window 3 Upgrades – Scope Changes / Cancellations
Baseline Reliability Projects

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2022 RTEP Window 3 Solution: 502 Jct-Woodside-Aspen 500 kV & Doubs Corridor Projects

502 Jct – Woodside – Aspen 500 kV RTEP Projects

NextEra Scope

- **b3800.102:** New 500 kV line from existing 502 Junction substation to New Stonewall/Woodside substation (bypass Black Oak) - $315.64M
- **b3800.106 – b3800.110:** Woodside substation adjacent to existing Stonewall 138 kV substation - $80.01M
- **b3800.113, b3800.115, b3800.117:** Woodside reactive components, and NEET scope for Doubs to Bismark line terminations into Woodside - $45.24M
- **b3800.119:** New 500 kV transmission line from Woodside substation to Aspen substation (in DOM zone). (NEET Portion) - $71.72M

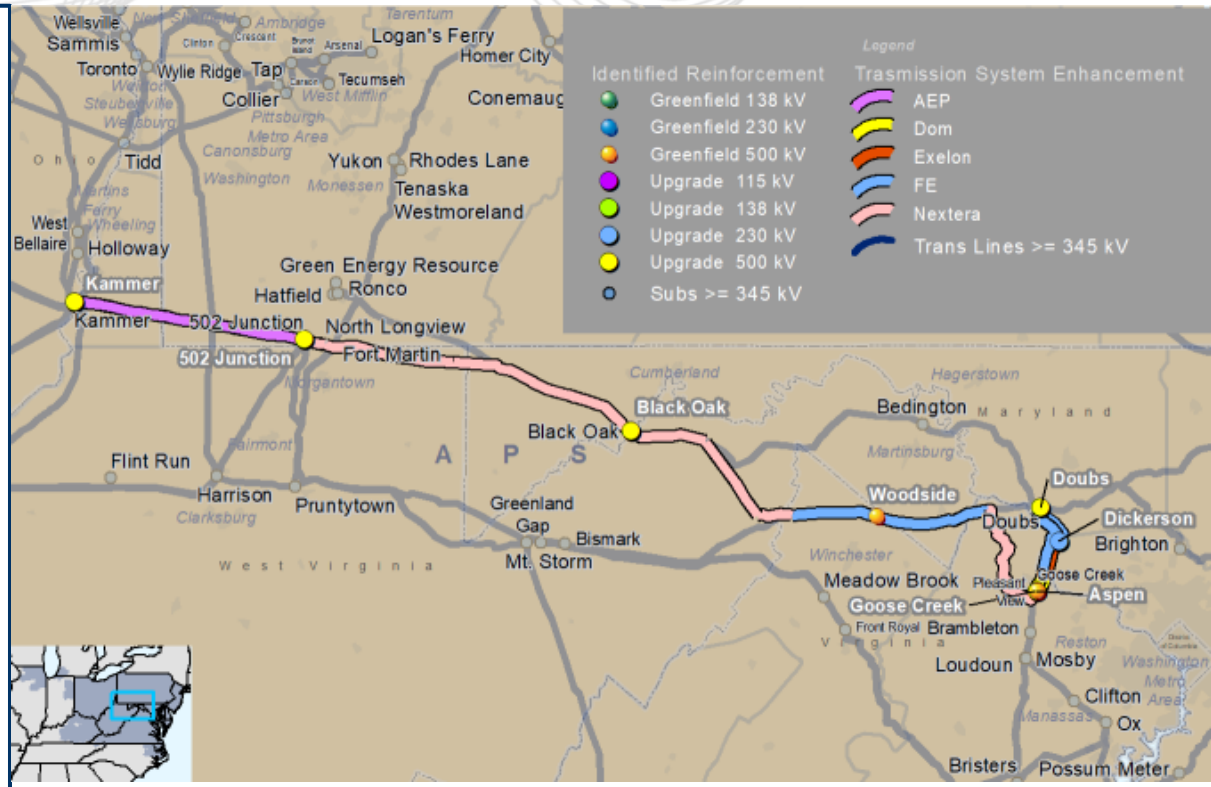
Total NextEra Cost Estimate: $512.61M

FE Scope

- **b3800.101:** 502 Junction substation two 500 kV circuit breaker expansion - $30.60M
- **b3800.103:** Rebuild ~16 miles of the Gore-Stonewall 138 kV line with 500 kV overbuild - $151.72M
- **b3800.104:** Rebuild ~15 miles of the Stonewall-Millville 138 kV line with 500 kV overbuild - $136.93M
- **b3800.105:** Rebuild ~6 miles of the Millville-Doubs 138 kV line with 500 kV overbuild - $52.35M
- **b3800.111, b3800.112, b3800.114 :** Woodside-Stonewall 138 kV lines 1&2 and Stonewall 138 kV substation two 138 kV breaker expansion - $20.89M
- **b3800.116:** FE scope for terminating Doubs to Bismark line into Woodside 500 kV substation $0.06M

Total FE Cost Estimate: $392.55M

Dominion Scope



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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2022 RTEP Window 3 Solution: 502 Jct-Woodside-Aspen 500 kV & Doubs Corridor Projects

Doubs Corridor RTEP Projects

FE Scope

b3800.122: Rebuild 500 kV line #514 from Doubs-Goose Creek 500 kV line using double circuit 500kV/230kV towers (APS Portion) – $103.27M

b3800.123: Doubs substation work to re-terminate rebuilt Doubs-Goose Creek, and terminate new Doubs – Aspen 500 kV - $31.7M

b3800.124 – b3800.127: FE Portion of new Doubs to Aspen 500 kV line installed by rebuilding existing 230 kV circuits between Doubs and Dickerson H using 500/230 kV structures; the existing 230 kV circuits will be underbuilt on the new 500/230 kV structures (APS Portion) – $99.99 M

Total FE Cost Estimate: $234.96M

Exelon (PEPCO) Scope

b3800.243, b3800.244: Exelon Portion of new Doubs to Aspen 500 kV line installed by rebuilding 7.26 miles of existing 230 kV circuits between Dickerson Station H and Edwards Ferry on 500/230 kV structures; the existing 230 kV circuits will be underbuilt on new 500/230 kV structures (Exelon Portion) $55.8M

b3800.245: Reconfigure Dickerson H 230 kV Substation and upgrade terminal equipment - $10.58M

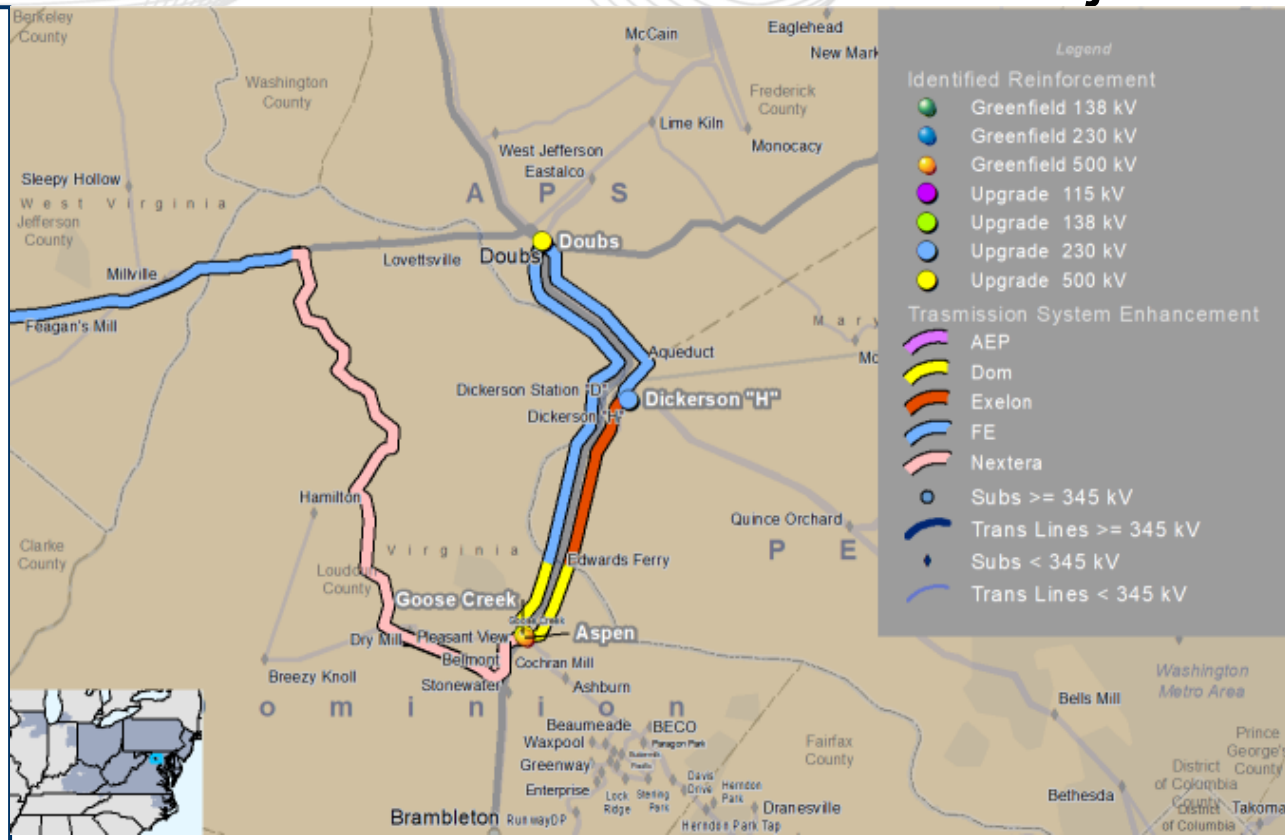
Total Exelon Cost Estimate: $66.38M

Dominion Scope

b3800.239: Wreck and rebuild 230kV Line #203 between Pleasant View and structure 203/15 using double circuit 500/230kV structures – $6.87M

b3800.240: Construct a new 500kV Line between Doubs and new substation Aspen - $41.68M

b3800.241: Rebuild 500kV line #514 from Doubs – Goose Creek using double circuit 500kV/230kV towers **b3800.230 – b3800.238, b3800.242:** Various Substation Upgrades



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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Scope Changes: 502 Jct-Woodside-Aspen 500 kV & Doubs Corridor Projects

502 Jct – Woodside – Aspen 500 kV Project Scope Changes

Rationale for Scope Changes:

The line section from Woodside to Aspen will be rerouted from the originally proposed greenfield line route to an alternate route within existing transmission line rights of way along the Doubs Corridor containing the rebuilt Doubs – Goose Creek and the new Doubs – Aspen 500 kV lines. This reroute is the outcome of successful collaboration between NextEra and the incumbent Transmission Owners to determine the most feasible route and minimize area impact for the new Woodside to Aspen 500 kV line segment.

As part of this change, the new 500 kV line from Woodside will now terminate into Goose Creek substation due to space constraints within the Corridor and also to minimize unnecessary line crossings.

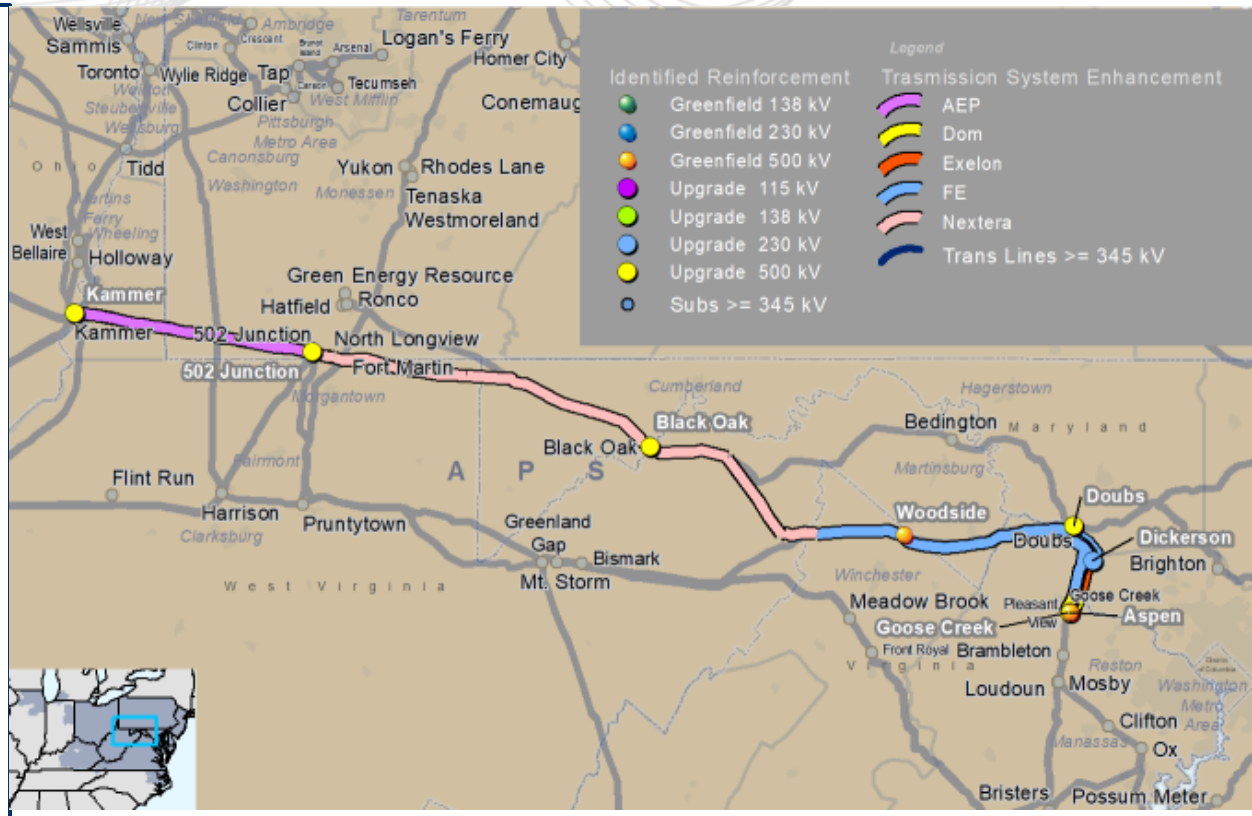
Revised NextEra Scope

- **Cancel b3800.119:** New 500 kV transmission line from Woodside substation to Aspen substation (in DOM zone) (NEET Portion) -$71.72M

Revised NextEra Total Cost: $440.89M, Delta: -$71.72M

Revised FE Scope

- **Scope Change for b3800.105:** Rebuild Millville-Doubs 138 kV for ~16 miles from structure MVF1-39 to structure MVF1-101(outside of Doubs Substation) with 500 kV overbuild - $147.45M
- **New Baseline Project b3800.128:** ~~Construct 500 kV Line from existing structure MVF1-101 on the Doubs – Millville 138 kV Line, around Doubs Substation, and into the entrance of the Doubs – Goose Creek Corridor. (~2 miles) - $13.20M~~ Construct new Woodside – Goose Creek 500 kV line for ~15 miles on single circuit monopole structures within the Doubs – Goose Creek Corridor. (FE Portion) - $115.30M
- **New Baseline Project b3800.129:** ~~Construct new Woodside – Goose Creek 500 kV line for ~15 miles on single circuit monopole structures within the Doubs – Goose Creek Corridor. (FE Portion) - $115.30M~~ Construct 500 kV Line from existing structure MVF1-101 on the Doubs – Millville 138 kV Line, around Doubs Substation, and into the entrance of the Doubs – Goose



NOTE: *This map is only intended to illustrate the general electrical connectivity of the projects, and should not be relied upon for exact geographical substation locations or line routes.*

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Scope Changes: 502 Jct-Woodside-Aspen 500 kV & Doubs Corridor Projects

502 Jct – Woodside – Aspen 500 kV Project Scope Changes (cont.)

Revised DOM Scope

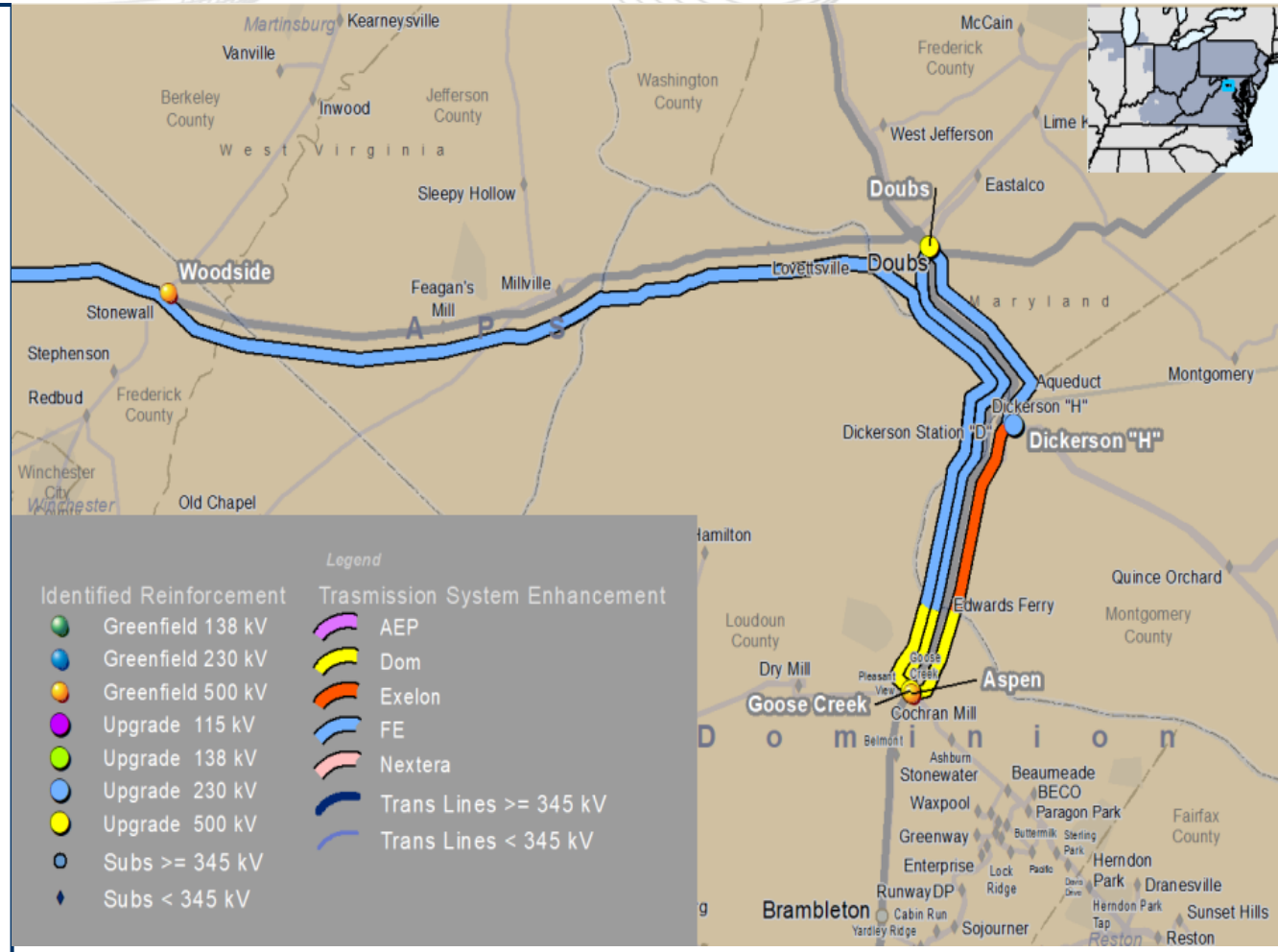
- **Scope Change for b3800.120:** Terminate new NextEra 500 kV line from Woodside into Goose Creek substation. The Goose Creek 500kV cap bank will be moved to Aspen substation. - $30.49M (No Cost Change)
- **New Baseline Project b3800.375:** Construct new Woodside – Goose Creek 500 kV line for ~3 miles on single circuit monopole structures within the Doubs – Goose Creek Corridor. (DOM Portion) - $15.60M
- **Revised DOM Total Cost: $51.19, Delta: +$15.60M**

Net Cost Change to 502 Jct – Woodside – Aspen Projects: +$167.48M

Doubs Corridor RTEP Project Impacts

- No significant scope/cost changes to the approved FE, Exelon and Dominion projects in Doubs Corridor beyond considerations to ensure sufficient space for the new Woodside – Goose Creek 500 kV line within the Corridor.

Net Cost Change to Doubs Corridor RTEP Projects: $0



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Revision History

Version No.	Date	Description
1	7/3/2024	• Original slides posted
2	7/9/2024	• Number of proposals received listed on slide 27 corrected from 7 to 6
3	3/4/2025	• Slide 43: b3800.128 and b3800.129 description and cost updated swapped

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