PJM Baseline Reliability Assessment 2019 - 2034 Period

PJM

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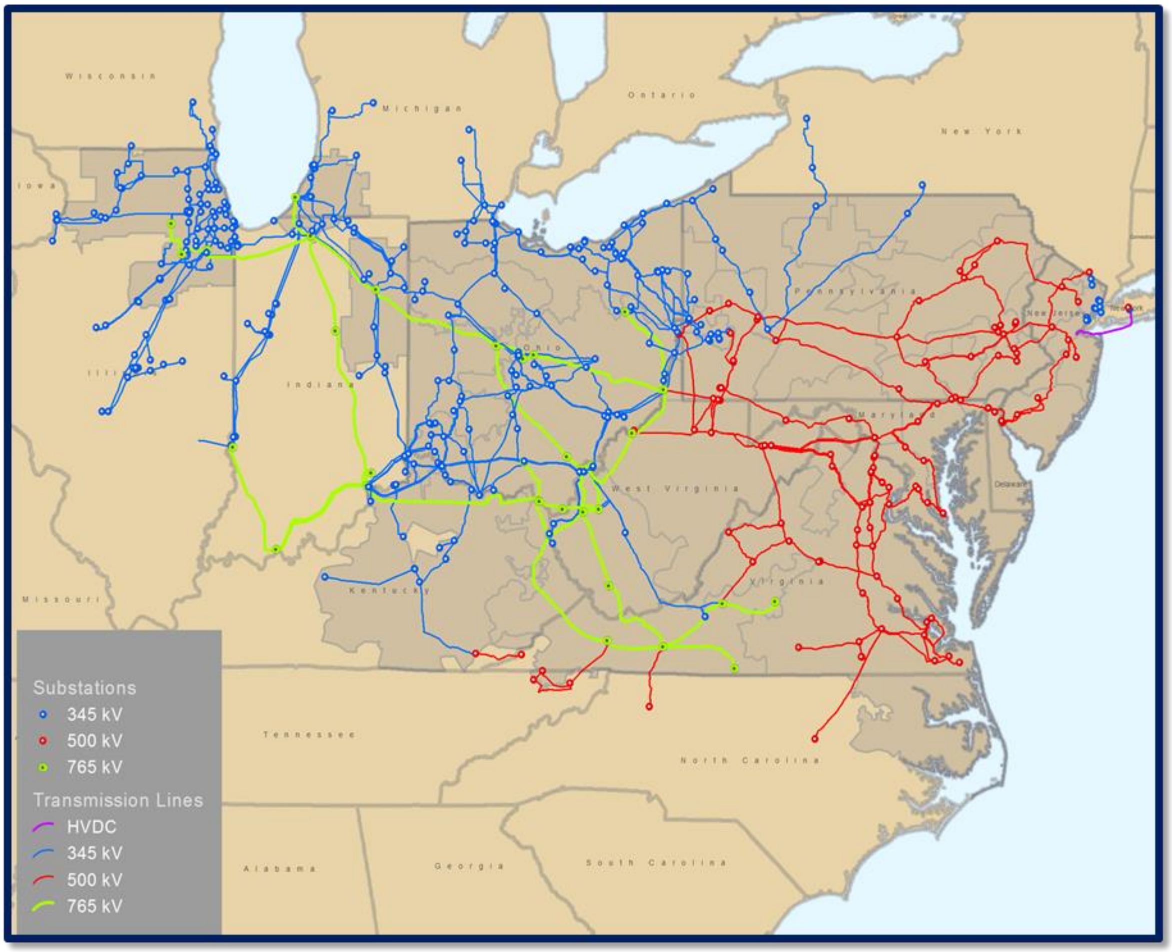
Contents

Introduction

The PJM system covers more than 369,000 square miles in 13 states and the District of Columbia. Serving approximately 65 million people, the PJM system includes major U.S. load centers from the western border of Illinois to the Atlantic coast including the metropolitan areas of Baltimore, Chicago, Cleveland, Columbus, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond, and Washington D.C. PJM dispatches more than 180,000 megawatts of generation capacity over more than 84,000 miles of transmission lines – a system that serves nearly 21 percent of the U.S. economy. The PJM system is electrically continuous and consists of multiple electrical service territories. PJM's Bulk Electric System (BES) includes a robust network of 765kV, 500kV, 345kV, 230kV, 161kV, 138kV, and 115kV facilities. The map below depicts the PJM service territory footprint overlaid with PJM high voltage lines operated at 345 kV and above.

Map 1. Existing PJM 345 kV, 500 kV, and 765 kV Network



As a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO), one of PJM's core functions encompasses regional transmission planning. PJM is also a North American Electric Reliability Corporation (NERC) registered Reliability Coordinator, Planning Coordinator, and Transmission Planner. PJM's annual planning process is known as the PJM Regional Transmission Expansion Plan (RTEP). The RTEP process is established in the PJM Operating Agreement – Schedule 6 – Regional Transmission Expansion Planning Protocol. The RTEP processes and procedures are described in detail in the PJM Regional Transmission Planning Process Manuals. PJM Manual 14B – PJM Region Transmission Planning process contains the process used to complete the annual baseline reliability assessment.

PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission upgrades and enhancements that are required to preserve the reliability of the transmission system. The PJM system is planned such that it can be operated to applicable System Operating Limits (SOL) while supplying projected customer demands and projected firm transmission service over a range of forecast system demands under contingency conditions that have a reasonable probability of occurrence. PJM reliability planning encompasses a comprehensive series of detailed analyses that ensure reliability and compliance under the most stringent of the applicable NERC, Regional Entity (RFC or SERC as applicable), PJM and local criteria. To accomplish this each year, a baseline assessment is completed for applicable facilities over the near term (1-5 years) and longer term (years 6-15). All Bulk Electric System (BES) facilities are included in the RTEP baseline assessment process as required by NERC Standards.

PJM is registered with the North American Electric Reliability Corporation (NERC) as the Reliability Coordinator (RC), Interchange Authority (IA), Transmission Operator (TOP), Balancing Authority (BA), Planning Coordinator (PC), Transmission Planner (TP), Transmission Service Provider (TSP), and Resource Planner (RP). There are multiple transmission zones within PJM. Table 1 lists individual transmission zones in the PJM footprint. A few smaller PJM transmission owners are modeled within another larger PJM transmission area and are not explicitly listed on this table. A few examples of this are Neptune Regional Transmission System LLC, Linden VFT LLC, and Essential Power/Rock Springs.

Table 1. **PJM area Transmission Zones**

AP	Allegheny Power System, Inc.
AE	Atlantic Electric
AEP	American Electric Power Co., Inc.
ATSI	American Transmission Systems, Inc.
BG&E	Baltimore Gas & Electric Co.
CE	Commonwealth Energy System
DAY	Dayton Power and Light Co
DEO&K	Duke Energy Ohio and Kentucky
DLCO	Duquesne Light Co
DP&L	Delmarva Power and Light Co
EKPC	Eastern Kentucky Power Cooperative
ITCI	ITC Interconnection
JCP&L	Jersey Central Power and Light
METED	Metropolitan Edison Co
OVEC	Ohio Valley Electric Corporation
PECO	PECO Energy Co.
PENELEC	Pennsylvania Electric Co
PEPCO	Potomac Electric Power Co.
PPL	PPL Electric Utilities
PSE&G	Public Service Electric and Gas Company
RECO	Rockland Electric Company
UGI	UGI Utilities Inc.
DVP	Virginia Power (Dominion)

PJM is interconnected with neighboring systems and has over 100 BES transmission ties to these adjacent systems. Table 2 lists PJM's neighboring systems and associated entities. PJM coordinates planning analyses with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems are studied as part of PJMs RTEP process.

Table 2. **PJM Neighboring Systems**

ALTE	Alliant Gas and Electric – East
ALTW	Alliant Gas and Electric – West
AMIL	Ameren Illinois
AMMO	Ameren Missouri
BREC	Big Rivers Electric Corporation
CPLE	Carolina Power and Light Company - East
CPLW	Carolina Power and Light Company - West
DEI	Duke Energy Indiana
DUKE	Duke Energy Carolinas
IPL	Indianapolis Power and Light Company
ITCT	International Transmission Company
LAGN	Louisiana Generating Company
LGEE	LGE Energy
LIPA	Long Island Power Authority
MEC	MidAmerican Energy
METC	Michigan Electric Transmission Co.
National Grid	National Grid
NIPS	Northern Indiana Public Service Company
NYISO	New York ISO
OMU	Owensboro Municipal Utilities
ORU	Orange & Rockland
SMT	Brookfield/Smoky Mountain Hydropower LLC
SIGE	Southern Indiana Gas & Electric Company
TVA	Tennessee Valley Authority
WEC	Wisconsin Electric Power Company

The PJM RTEP process requires that cost responsibility for facility enhancements be established. In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities, a 'baseline' assessment of system adequacy and security is necessary. The purpose of this assessment is threefold:

1. To identify areas where the system as planned under previous assessments does not meet the applicable reliability criteria and standards as a result of load increases on the system or changes to methodologies associated with the analyses.
2. To develop and recommend facility expansion plans which will bring areas where the system does not meet performance requirements specified in an applicable standard into compliance. These plans include cost estimates and required in-service dates.
3. To establish what will be included as baseline costs in the allocation of the costs of expansion for those generation and merchant transmission projects proposing to connect to the PJM system.

The system as planned is evaluated for its compliance with all applicable reliability standards to accommodate the forecast demand, committed resources, and commitments for firm transmission services for a specified time frame. Areas that are found to not meet applicable reliability criteria are identified and enhancement plans are developed to achieve compliance within an identified timeframe. The lead time necessary to implement the system enhancement is considered as part of the overall plan. In addition, the status and progress of each upgrade is tracked closely to ensure that the required in-service dates are met.

The 'baseline' assessment and the resulting expansion plans serve as the base system for the conduct of Interconnection Feasibility Studies and System Impact Studies associated with new generation, merchant transmission and long term firm transmission service. The interconnection process is described by Manual 14A: Generation and Transmission Interconnection Process. This report details the results of the 'baseline' assessment from 2019 through 2034 for the PJM footprint.

Executive Summary

PJM is responsible for the development of a Regional Transmission Expansion Plan (RTEP) for the PJM system that will meet the needs of the region in a reliable, economic and environmentally acceptable manner. As further described in following portions of this assessment, the PJM RTEP combines a broad set of analysis into a single plan. The annual RTEP process consists of a baseline reliability review, analysis to identify the transmission needs associated with both generation interconnection and merchant transmission, review of conditions experienced in real time operations, inter-regional reliability analysis, and many other special studies. The RTEP incorporates the unique needs identified by in-depth thermal, stability, short circuit, and voltage reliability analysis. PJM ensures a robust and comprehensive annual RTEP by incorporating all of these diverse needs into a single plan.

The annual RTEP planning assessment includes a comprehensive review of PJM Bulk Electric System (BES) facilities as required by NERC standards TPL-001-4. PJM maintains a series of power flow, short circuit and stability cases that represent a range of critical system conditions for a range of forecast demand levels and study years. The annual RTEP baseline analysis performs the following tests at a minimum to ensure NERC TPL compliance:

1) Thermal Analysis
    a) Normal system (all facilities in service), single, and multiple contingency analysis as required by NERC TPL standards
    b) Generation deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
    c) Common mode outage procedure analysis, as described in PJM Manual 14B Section 2 RTEP Process
    d) Load deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
    e) N-1-1 analysis
    f) Light Load Reliability Analysis
    g) Winter Reliability Analysis
    h) 15 Year Analysis
    i) Transfer Limit Analysis
2) Short Circuit fault duty analysis
3) Voltage Analysis
    a) Voltage limit testing, including voltage magnitude and voltage drop monitoring for many of the test methods listed above for the thermal analysis
    b) Voltage collapse, including non-convergent events
    c) PV analysis, including Transfer Limits
4) Stability Analysis
    a) Transient stability (short and long term)
    b) Small signal stability (oscillations)
    c) Voltage Stability
    d) Nuclear Plant Interface Requirements (NPIR)

PJM also studies, requests for new generation, merchant transmission, and long term firm transmission service. The process for studying these requests is described in PJM Manual 14A. In Calendar year 2019, PJM completed 227 system impact studies to accommodate new generation, merchant transmission, and long term firm transmission service. The 2019 RTEP includes any upgrades associated with the queue projects that are required to maintain the reliability of the PJM system.

1) New Services Queue Analysis
    a) Generation interconnection queue
    b) Merchant transmission queue
    c) Yearly long term firm transmission service queue

Information related to the generation, merchant transmission, and yearly long term firm transmission service request queues can be found on the PJM website at the following link.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Information that is posted on the PJM website includes the status of the New Services Queues, as well as the technical study reports. The technical reports include the feasibility, impact, and facility study reports. PJM agreements such as interconnection service agreements (ISA) and construction service agreements (CSA) are also posted on the website.

PJM coordinates inter-regional activities with neighboring systems pursuant to PJM's Tariff and interregional agreements. PJM participated in several inter-regional studies as part of the 2019 RTEP.

PJM coordinates inter-regional activities with neighboring systems pursuant to PJM's Tariff and interregional agreements. PJM annually participates in a wide range of inter-regional groups and committees. Several significant efforts in 2019 are listed below.

1) Inter-regional planning groups
    a) Independent System Operator / Regional Transmission Organization (ISO/RTO) Council (IRC)
    b) Eastern Interconnection Planning Collaborative (EIPC): Planning Coordinators of the Eastern Interconnection
        i) EIPC work associated with the 2015/16 planning cycle budget and scope of work
    c) Joint Operating Agreement with Mid-Continent ISO (MISO)
    d) Joint Operating Agreement with New York ISO (NYISO)
        i) Joint ISO/RTO Planning Committee (JIPC) activities pursuant to the PJM/NYISO/ISO-NE Northeast Planning Coordination Protocol
            (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability and Market Efficiency Analysis
        ii) Joint RTO Planning Committee (JRPC) activities pursuant to the MISO/PJM Joint Operating Agreement
            (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability and Market Efficiency Analysis

  e) Southeastern Regional Transmission Planning: (SERTP)
    i) Joint Operating Agreement with Duke Energy Progress (DEP)
    ii) Joint Operating Agreement with Tennessee Valley Authority (TVA)
  f) Joint Reliability Coordination Agreement between PJM and TVA
  g) North Carolina Transmission Planning Collaborative (NCTPC) planning and data sharing agreement
2) North American Electric Reliability Corporation (NERC) and Eastern Interconnection Reliability Assessment Group (ERAG) related activities
    i) SERC Reliability Corporation and associated committees and working groups
    ii) RFC Reliability Corporation and associated committees and working groups

PJM Planning also coordinates with PJM Operations to review operational performance issues. In addition, sensitivity studies may be requested by stakeholders. Examples of these studies include:

Additional Studies

- Evergreen Mills scope change – DOM

Operating guideline and other sensitivity studies

- Removal of the 500 kV portion of the Skiffes Creek project sensitivity study

The RTEP assesses the needs of the system, at peak load for year one, two, three four and year 5 in the near term and over the longer term (up to 15 years) to identify baseline transmission enhancements that require more time to implement. Additionally, PJM evaluates an off peak load seasonal assessment for year 5 PJM also is responsible for recommending the assignment of any transmission expansion costs to the appropriate parties. In order to carry out these responsibilities, it is necessary to establish a starting point or 'baseline' from which the need and responsibility for enhancements can be determined.

As the NERC registered Planning Coordinator, PJM is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems for both the near term and longer term. The planned network upgrades required by the RTEP serve as a central repository for the BES related reliability plans of the individual PJM transmission owners. By integrating the individual plans into a single plan, the RTEP is able to provide a robust reliability plan for the PJM Bulk Electric System.

In order to establish the long term plan, PJM has defined the fifteen (15) year period from 2019 through 2034 as the 2019 "baseline" planning period. This assessment is inclusive of the previous years' baseline assessments, models, and required upgrades. As such, the existing system plus any planned modifications to the transmission system including reactive resources that are scheduled to be in service prior to the 2024 summer peak period were chosen as the base system for the near-term assessment. This ensures the system as planned remains compliant with reliability standards. Appendix A represents a snapshot of all upgrades identified in RTEP evaluations prior to 2019. These identified upgrades, when added to the previously existing system, function as the base system for future models. In addition, assessments for delivery years prior to 2024 were updated with current assumptions to validate the on-going need for identified upgrades and to ensure continued compliance with reliability criteria.

For the 2019 RTEP cycle, PJM has studied 73 generator deactivation notifications resulting in over 12,873 MW of existing generation deactivating in 2019 or some point in the near term planning horizon. In order to establish a model which accurately included all expected generation retirements, PJM performed many sets of analysis to study the effects of these generation retirements on the system. Many baseline transmission upgrades were identified as a result of these deactivations. The upgrades resulting from the deactivations were modeled in the basecase before approving new RTEP upgrades for any of the standard RTEP analysis for the 2019 RTEP cycle. The scope of the deactivation notification analysis was significant and included a review of system impacts in years 2019 through 2024. The scope and results of the generation deactivation analysis is discussed in subsequent sections of this report.

All new generation and merchant transmission projects in queues A through AD1 that executed a Facility Study Agreement were also included in this baseline system along with any associated transmission enhancements as identified in the System Impact Studies associated with those requests. Queued generation, merchant transmission, and firm transmission service is studied and subsequently included in the basecase. The process for these studies is detailed in PJM manual 14A. PJM manual 14B attachments A-I describe the analysis that is performed to ensure the reliability of new generation, merchant transmission, and firm transmission service. Any supplemental transmission enhancements independent of those associated with new generation or merchant transmission projects were also included. All firm transmission service currently committed for the period was represented.

PJM has conducted a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria. The applicable reliability planning criteria are listed below:

- NERC Planning Standards
  http://www.nerc.com/pa/Stand/Pages/default.aspx
- RFC Reliability Standards
  https://rfirst.org/ProgramAreas/Standards/Regional/Pages/Regional.aspx
- SERC Reliability Corporation
  http://www.serc1.org/Application/HomePageView.aspx
- PJM Reliability Planning Criteria as contained in PJM Regional Transmission Planning Process Manuals http://www.pjm.com/library/manuals.aspx
- Transmission Owner Reliability Planning Criteria as filed in their respective FERC Form 715 filing http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

In completing this assessment, PJM has documented all conditions where the system did not meet applicable reliability criteria and identified the system reinforcements required to bring the system into compliance along with estimated cost and lead-time to implement them.

Those areas that were found to not meet applicable reliability standards establish the need for reinforcement in those areas independent of any future interconnection projects not included in the baseline analysis. The resulting system with the identified reinforcements to bring the system into compliance, is anticipated to be used in evaluating the impact of the projects in queues AG1 and AG2 that qualify and elect to proceed with the system impact studies. The extent to which reinforcements identified in the baseline assessment are advanced, deferred, modified or eliminated will be used in determining cost responsibility for the final plans in the RTEP.

It should be recognized that the reinforcements identified in this baseline analysis may be modified, advanced, deferred or eliminated as a result of future system assumptions. Future assumptions include generation projects, merchant transmission projects, generation retirements, or transmission service being added to or removed from the system. The development of the RTEP for PJM is an ongoing process, which includes the conduct of system impact studies and development of plans to accommodate the new interconnection projects. Upon completion of the system impact studies some projects may elect not to proceed. When it is determined which projects will commit to proceed, PJM develops a new baseline RTEP to meet the needs of the region, including the accommodation of all new projects committed to connect, during the next 5 year period.

Key Findings

Inclusive of the baseline upgrades identified in the Results Section of this assessment, PJM assesses its system as being compliant with the thermal, reactive, short circuit, and stability requirements of all applicable standards including NERC Standards TPL-001-4 for both the near term and longer term. The results section of this assessment includes all planned upgrades needed to meet the performance requirements of Table 1 in each respective TPL standard throughout the planning horizon.

The reinforcements identified as part of the 2019 RTEP that are required to achieve compliance having an estimated cost of at least $10 million are described below. The required in-service date of these upgrades is also included. A complete list of projects along with detailed descriptions of the conditions that are driving the need for them, are described in the Results section and Appendix A of this report. PJM staff from the Infrastructure Coordination group coordinates with the transmission owners and generation or merchant transmission developers to monitor project schedules for implementation of these reinforcements and coordinate any required outage activities to ensure these reinforcements are completed by their required in-service dates. The cost estimates below are based on those provided by the responsible entities and discussed at the monthly Transmission Expansion Advisory Committee (TEAC) meetings during the calendar year.

PJM MID ATLANTIC

JCPL

- Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), Rebuild/Reconductor two 34.5 kV circuits (total of 5.5 miles) and install a 2nd 115/34.5 kV transformer (Werner) - 6/1/2016 - $175.00M

ODEC

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview substation (21 miles) and create a line terminal at Belle Haven delivery point (three-breaker ring bus) - 6/1/2019 - $22.00M

PSEG

- Rebuild 20 miles of the East Towanda - North Meshoppen 115 kV line - 6/1/2024 - $58.60M

PJM SOUTH

Dominion

- Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed. - 6/1/2023 - $21.00M
- Rebuild 230 kV line No.2063 (Clifton – Ox) and part of 230 kV line No.2164 (Clifton – Keene Mill) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2019 - $22.00M
- Rebuild 9.8 miles of 115kV Line #141 between Balcony Falls and Skimmer and 3.8 miles of 115kV Line #28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA. - 6/1/2019 - $20.00M
- Rebuild Clubhouse-Lakeview 230 kV Line #254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1047 MVA. - 6/1/2019 - $27.00M
- Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV Line #2181 and Line #2058 with double circuit steel structures using double circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA. - 6/1/2019 - $13.00M
- Rebuild Line #2008 between Loudoun to Dulles Junction using single circuit conductor at current 230 kV northern Virginia standards with minimum summer ratings of 1200 MVA. Cut and loop Line #265 (Clifton – Sully) into Bull Run Substation. Add three (3) 230 kV breakers at Bull Run to accommodate the new line and upgrade the substation. - 6/1/2019 - $14.00M
- Rebuild the 18.6 mile section of 115 kV Line #81 which includes 1.7 miles of double circuit Line #81 and 230 kV Line #2056. This segment of line of 81 will be rebuilt to current standards with a minimum rating of 261 MVA. Line 2056 rating will not change. - 6/1/2019 - $25.00M
- Replace 19 - 63 kA 230 kV breakers with 19 – 80 kA 230 kV breakers - 6/1/2023 - $19.00M

PJM WEST

AEP

- Construct a single circuit 138 kV line (~3.5 miles) from Amlin to Dublin using 1033 ACSR Curlew (296 MVA SN), convert Dublin Station into a ring configuration, and re-terminating the Britton UG cable to Dublin Station. - 6/1/2020 - $39.29M
- Install a 138 kV 3000 A 40 kA circuit switcher on the high side of the existing 138/34.5 kV transformer No.5 at Holston station. - 6/1/2022 - $19.00M
- Install a 138/69 kV transformer at Royerton station. Install a 69 kV bus with one 69 kV breaker toward Bosman station. Rebuild the 138 kV portion into a ring bus configuration built for future breaker and a half with four 138 kV breakers. - 6/1/2022 - $10.25M
- Rebuild 3.11 miles of the LaPorte Junction – New Buffalo 69 kV line with 795 ACSR - 6/1/2022 - $12.30M
- Rebuild 5.2 mile Bethel-Sawmill 138 kV line including ADSS. - 6/1/2019 - $34.50M

- Rebuild Columbia station in the clear as a 138/69 kV station with two (2) 138/69 kV transformers and 4-breaker ring buses on the high and low side. Station will reuse 69 kV breakers “J” & “K” and 138 kV breaker “D”. - 6/1/2024 - $15.00M
- Rebuild the ~30 mile Gateway – Wallen 34.5 kV circuit as the ~27 mile Gateway – Wallen 69 kV circuit. - 6/1/2024 - $43.30M
- Rebuild the ~8.4 mile 69 kV Pletcher – Buchanan Hydro line as the ~9 mile Pletcher – Buchanan South 69 kV line using 795 ACSR. - 6/1/2024 - $20.00M
- Rebuild the 10.5 mile Berne – South Decatur 69 kV line using 556 ACSR in order to alleviate the overload and address a deteriorating asset. - 6/1/2022 - $16.60M
- Rebuild the 13 mile Columbia – Richland 69 kV line. - 6/1/2024 - $29.30M
- Rebuild the 138 kV portion of Jay station as a 6 breaker, breaker and a half station re-using the existing breakers “A”, “B” and “G”. Rebuild the 69 kV portion of this station as a 6 breaker ring bus re-using the 2 existing 69 kV breakers. Install a new 138/69kV transformer. - 6/1/2022 - $18.73M
- Rebuild the 34.5 kV Delaware – Bosman line as the 69 kV Royerton – Strawboard line. Retire the line section from Royerton to Delaware stations. - 6/1/2022 - $12.78M
- Rebuild the 46 kV Bradley-Scarbro line. The new line will be rebuilt adjacent to the existing one leaving the old line in service until the work is completed. The new 46 kV line will be built with 795 ACSR (120 MVA) and 69 kV standards. - 12/1/2021 - $22.20M
- Rebuild the 69 kV Hartford City – Armstrong Cork line but instead of terminating it into Armstrong Cork, terminate it into Jay station. - 6/1/2022 - $21.12M
- Rebuild the Delaware – Hyatt 138 kV line (~ 4.3 miles) along with replacing conductors at both Hyatt and Delaware substations. - 6/1/2020 - $16.00M
- Rebuild the Garden Creek - Whetstone 69 kV line (~4 mile) - 6/1/2023 - $15.00M
- Rebuild the Jay – Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station - 6/1/2022 - $38.10M
- Retire approximately 38 miles of the 44 mile Clifford-Scottsville 46 kV circuit. Build new 138 kV “in and out” to two new Distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Construct new 138 kV lines from Joshua Falls-Riverville (~10 mi.) and Riverville-Gladstone (~5 mi.). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen – Monroe 69 kV (~4 mi.) - 12/1/2022 - $85.00M

APS

- Construct a new Elrama - Route 51 138 kV No.3 line: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at APS Route 51 substation. - 6/1/2020 - $18.10M

ATSI

- Reconductor the 8.4 mile section of the Leroy Center - Mayfield Q1 line between Leroy Center - Pawnee Tap to achieve a rating of at least 160 MVA / 192 MVA (SN/SE). - 6/1/2024 - $14.10M

NIPSCO

- Rebuild Michigan City-Trail Creek - Bosserman 138 kV (10.7 mi) - 1/1/2023 - $24.69M[1]

Objective and Scope

The objectives of this assessment were as follows:

a) To identify system reinforcements as required to ensure compliance with NERC standards TPL-001-4.
b) To identify areas where the system as planned for the near term period 2019 through 2024 would not meet applicable reliability standards.
c) To develop and recommend preliminary facility expansion plans, including cost estimates and required in service dates, to ensure all areas meet applicable reliability criteria.
d) To identify areas where the system as planned for the longer term period 2025 through 2034 that would not meet applicable reliability criteria, and where appropriate, develop expansion plans. These plans include required in service dates of the facilities needed to bring those areas into compliance. This longer term planning is in consideration of larger scope projects that may require long lead time to implement.
e) To establish what will be included as baseline expansion costs for the allocation of the costs of expansion for those projects included in New Services Queues.

The scope of this assessment included analysis for the period 2019 through 2034 to ensure the system would meet all applicable reliability planning criteria. These assessments include baseline thermal, baseline voltage, thermal and voltage Load Deliverability, generation deliverability, and baseline stability analysis. The baseline thermal and voltage analysis encompasses an exhaustive analysis of all BES facilities for compliance with NERC P0 – P7 (TPL-001-4) events. In addition, consistent with NERC standard TPL-001-4, a number of extreme events as defined in Table 1 of TPL-001-4 were evaluated for risk and consequences to the system. Results of this study are not documented in this report due to their sensitive nature, and can be found in the 2019 Extreme Event Report.

The PJM Load Deliverability testing methods are described in Manual 14B, section 2. The tests ensure that an area of the transmission system that is experiencing higher than normal load levels (90/10) with higher than normal internal generation unavailability has the transmission capability to import energy to meet the transmission system reliability criteria. The generation deliverability testing ensures sufficient transmission capability so that generation can be ramped to full output so that excess energy can be exported to an area that is experiencing a capacity deficiency. PJM also performed a stability analysis consistent with NERC and local transmission owner criteria to ensure the system is stable for critical system conditions including fault conditions that include multi-phase faults and faults with delayed clearing and light load conditions.

[1] NIPSCO is an interregional project with a PJM interregional cost allocation of 89.1% totaling 22 M

Analytical testing is performed annually on a range of study years and system conditions to satisfy NERC standards. Every year analysis is performed on the 5 year out case, while the other nearer term cases (years 0 through 4) are retooled to be studied for specific projects as changes to system conditions warrant. Additional analysis is also performed for the longer term to identify marginal conditions that may require long lead time solutions. Currently as part of the RTEP a year 7 or year 8 case is studied in detail as part of the annual RTEP. During the 2019 RTEP, a year 7 (2026 study year) was studied.

PJM Generator Deliverability testing, which simulates higher than normal generation availability in an area, is performed at 50/50 load levels. PJM Load Deliverability testing, which is performed on 27 Locational Deliverability Areas (LDA's) within PJM's footprint, simulates an internal generation deficiency within the LDA (which simulates higher than expected forced outage conditions) being tested with the area at 90/10 load levels. Single and multiple contingency analyses were also performed on a shoulder peak case as described in subsequent sections of this document.

The combination of these tests includes simulation of various system conditions over a range of forecast system demands and generation availability scenarios that simulate planned and forced outage conditions. This analysis is performed for both the near term and longer term.

The continued need for the system reinforcements previously identified in prior RTEP Baseline Assessment Reports and the queue A through AD1 System Impact Studies were evaluated. Any previously identified reinforcements that are no longer required were documented and removed from the list of RTEP Reinforcements. PJM adjusts required in-service dates based on updated forecasts that can affect the modeling of the system conditions. In the event that changing system conditions delay the need for a baseline upgrade beyond the 5 year planning horizon, PJM will re-evaluate the need for that upgrade. When evaluating the continued need for previous reinforcements, analysis is performed to test for system performance under all event categories listed in Table 1 of TPL-001-4.

Analysis methodology

PJM completed a robust series of analysis over a broad spectrum of system conditions encompassing a range of study years and forecast demand levels. The following sections detail the assumptions of the modeling and analysis. The analysis sub-sections are grouped by the analysis type. The modeling assumptions of the 2024 cases and analysis are discussed in detail. The modeling assumptions for the retool cases are not discussed in detail but followed the same procedure as the 2024 case, which can be found in PJM Manual 14B, Attachment H The modeling assumptions of all of the cases follow the procedure in PJM Manual 14B, Attachment B. All study year cases model all normal (NERC TPL P0) operating procedures in place. PJM Manual 3 – Transmission Operations contains all PJM operating procedures that are applicable to PJM planning studies.

Table 3. **Analysis Type Summary**

Analysis Type	NERC Contingency Category from Table 1 of TPL Standard	Applicable Limits Monitored	Monitored Elements	Contingencies Considered
normal system (no contingency)	P0	All System Operating Limits, including the most limiting thermal, voltage limit (magnitude and deviation), voltage collapse	All BES & select lower voltage facilities, all ties to neighboring systems regardless of voltage	Normal system, All BES & select lower voltage facilities. N-1-1 considers all possible combinations of single contingencies
single contingency	P1, P2			
multiple contingency	P3, P4, P5, P6, P7			
Load Deliverability	P1, P2			
Light Load Reliability analysis	P0, P1, P2, P3, P4, P5, P6, P7			
N-1-1 analysis	P3, P6			
generation deliverability	P1, P2	thermal, voltage collapse		
common mode outage procedure	P3, P4, P5, P6, P7			

Modeling Assumptions & Critical System Conditions

PJM selected a range of forecast demand levels for the year 2024.

- 2024 90/10 Summer Peak
- 2024 50/50 Summer Peak
- 2024 Light Load Reliability Analysis (50% of 50/50 Summer Peak)
- 2024 Winter Reliability Analysis

In addition to the analysis of the 2024 system, as part of this assessment, PJM also performed analysis of multiple critical system conditions in the near term and longer term planning horizons. The assessments of the critical system conditions within these study years will be discussed in subsequent sections of this document.

The load forecast from the 2024 PJM Load Forecast Report was used and can be found on the PJM website at the following address:

https://www.pjm.com/-/media/library/reports-notices/load-forecast/2019-load-report.ashx

The 2024 summer peak analysis used the 2024 summer model from the 2018 series MMWG (Multiregional Model Working Group) case. The model was updated according to the procedures in PJM Manual 14B, Attachment H. The case build is a collaborative process that involves PJM, PJM transmission owners, and neighboring entities. The case was reviewed with all PJM transmission owners to ensure that all existing and planned facilities were modeled. All future transmission upgrades with a required in-service date up to and including June 1, 2024 were modeled as in service. The list of future upgrades along with a schedule for implementation is contained in Appendix A.

All existing generation was modeled in the base case. Future generation that had an executed interconnection Service Agreement (ISA) and Facilities Study Agreement (FSA) was modeled along with any upgrades required to maintain the reliability of the PJM system including the future generation. Future merchant transmission facilities that had an executed Facility Study Agreement (FSA) were modeled along with any upgrades required to maintain the reliability of the PJM system including the future merchant transmission. Information regarding all of these projects can be found on the PJM website at the address below.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Adequate Reactive Power resources were included in the base model to ensure system voltage performance. Some of the reactive power resources modeled are existing and in-service equipment while some are planned with a future implementation date. A list of the planned reactive upgrades along with a schedule for implementation is contained in Appendix A. Table 4 below is a summary of the reactive power resources included in the 2024 case (note these are in addition to the reactive power associated with the generation noted above).

Table 4. **Reactive Power Resources in base case Static MVAR: Capacitor Banks, Switched Shunts; Dynamic MVAR: SVCs, Synchronous Condensers, and Dynamic Switched Shunts.**

Area Name	Static	Dynamic	Total
AE	1158	450	1609
AEP	14432	712	15144
AP	5221	1670	6891
BGE	5705	0	5705
CE	8477	1800	10277
DAY	1369	0	1369
DEO&K	809	0	809
DLCO	293	0	293
DP&L	1473	381	1854
DVP	9798	1750	11548
EKPC	1363	0	1363
FE	6682	1614	8296
JCPL	4706	315	5021
METED	797	0	797
PECO	4587	0	4587
PENELEC	1796	424	2220
PEPCO	1286	0	1286
PJM	2799	1100	3899
PPL	2632	0	2632
PSEG	8743	0	8743
RECO	0	0	0
UGI	60	0	60
Grand Total	**84186**	**10216**	**94403**

The interchange targets in Table 5 below represents the net sum of all existing and planned yearly long-term firm transmission service commitments between PJM and neighboring systems for the 2024 summer period. A 2024, 2018 Series, MMWG case was used as a starting point for the modeling, all PJM firm transactions were included in the RTEP base case modeling. The base dispatch is set as defined in PJM Manual 14B, Attachment B.

Table 5. **Net Yearly Long Term Firm Interchange**

2024 RTEP Interchange		
Source	**Sink**	**Total (MW)**
PJM	NYISO	817
PJM	LGEE	-502.5
PJM	DEI	-156
PJM	WEC	90
PJM	LAGN	-100
PJM	CPLE	24
PJM	DUK	-100
PJM	TVA	400
PJM	EEI	0
PJM	AMIL	-1805
PJM	OMUA	-54
PJM	MEC	438
PJM	SMT	-285
Total		**-1233.5**

In all cases, where the physical design of connections or breaker arrangements resulted in the outage of more than the faulted facility when the fault was cleared, the additional facilities were also outaged in the load flow. That is, the breaker arrangements and system topology are used to develop and maintain the contingency files. For example, if a transformer is tapped off a line without a breaker, both the line and transformer were outaged as a single contingency event.

In addition, approved operating procedures were utilized as applicable. These operating procedures include the use of control devices such as Phase Angle Regulators (PARs) to manage flows on the system. Also, the expected operation of Remedial Action Schemes (RAS) were modeled and additionally tested where applicable. A complete listing of applicable remedial action schemes and operating procedures can be found in the Transmission Operation Manual (M-03) at the following link:

https://www.pjm.com/library/manuals.aspx

Contingencies Considered

The thermal and voltage analysis used a set of contingencies as required by NERC TPL standards. PJM's rationale was to define and select a comprehensive set that includes every possible BES contingency. Every possible single and multiple contingency loss of PJM BES elements is as described on Table 1 of NERC TPL standards was defined in contingency files and included in the assessment. No single or multiple BES contingencies were excluded from this assessment. The contingency set also included an inclusive set of single contingencies of non-BES elements that are modeled in the base case. A set of multiple facility contingencies involving non-BES facilities was included in the contingency set. A complete set of multiple facility contingencies involving non-BES facilities was not included in the contingency set given that issues on non-BES facilities are not expected to propagate to the BES system.

Contingency analysis takes into account the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. This includes tripping of generators and transmission elements when protection equipment may exceed its performance capabilities.

In addition to the contingencies studied within PJM's footprint, analysis includes contingencies located in areas outside of PJM's footprint. PJM worked with its neighboring ISO's and RTO's to identify off-system contingencies that could affect PJM's system. All contingencies identified by these entities have been included I PJM's RTEP analysis.

- Over 11,000 Single contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- Over 14,000 Multiple Contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- The N-1-1 analysis considers every possible combination of single contingencies, a total of over 121,000,000 combinations.

PJM's 2019 analysis focused on contingencies as defined by TPL-001-4 Table 1 – Steady State & Stability Performance Planning Events.

Planned Outages in the Transmission Planning Horizon

Although there are situations in which outages are planned and scheduled more than 12 months in advance, more often outages are submitted no more than one year in advance of the planned outage. Most maintenance plans are developed, and therefore the associated outages are planned with less lead time. In cases where outages are scheduled less than one year out, the lead time makes it impractical for inclusion in planning studies under the TPL timeframe. Outages planned with a lead time of less than one year are evaluated by PJM Operations.

PJM performed additional analysis of planned maintenance outages in the planning horizon by studying certain combinations of scheduled maintenance outages as reported through PJM's eDART, outage coordination software used by PJM operations. To increase the conservatism of the simulation, planned outages of BES equipment were studied on a Summer Peak case, which reflects a higher load than the historical maintenance outage season, and therefore a more conservative test. PJM Planning notified PJM operations of the results of this analysis. The results of this analysis are documented in the PJM Maintenance Outage Analysis report, which is published annually. This report also includes the analysis of known outages of generation or Transmission Facilities with duration of at least six months.

Planned outages are typically not scheduled at peak demand levels. In addition to the targeted maintenance outage analysis described above, the deliverability tests are performed at peak demand levels, which produce more severe results and impacts than studies performed at off peak demand levels.

Monitored Facilities

All cases used for this assessment model all PJM Bulk Electric System facilities. The specific facilities monitored for each analysis is described in detail in subsequent sections of this document. PJM also monitored every tie line to neighboring systems regardless of voltage. Over 20,000 individually modeled BES facilities are monitored in the analysis that supports this assessment. In addition to all BES elements, PJM monitors lower voltage, non-BES, facilities that are monitored by PJM operations. As part of the 2019 RTEP, PJM expanded its monitored facility list to include BES facilities in the MISO footprint. PJM also completed several joint studies of neighboring systems as described in the scope contained in the Executive Summary above.

Analysis of Near-Term

As part of the near-term assessment, PJM evaluated a range of critical system conditions. The range of system conditions included thermal and voltage analysis of a 2024 90/10 summer peak scenario, thermal and voltage analysis of a 2024 50/50 summer peak scenario, and thermal and voltage analysis of a light load scenario. The thermal analysis included applicable thermal limit checking. The voltage limit analysis included checking applicable voltage magnitude and voltage drop limits. PV analysis is an important part of the RTEP analysis and is performed for selected scenarios. The methodology for selecting the PV scenarios is discussed in a subsequent section of this document.

Analysis is performed for planning events listed in Table 1 of TPL-001-4 to ensure that all performance requirements are met, or upgrades to the system are implemented to address required performance issues.

The forecast demand level, analysis type, and mapping to TPL standards are summarized in tables in this section. In addition, a summary of the analysis type, contingencies considered, monitored elements, and monitored limits are summarized in the Analysis Methodology Section. Stability tests are detailed in a subsequent section of this document.

Normal System (All Facilities in Service) Analysis

The 2024 90/10 summer peak, 50/50 summer peak, light load and shoulder peak cases were evaluated for system performance under normal conditions. These models use data consistent with information provided in MOD-010 and MOD-012 standards. The normal system analysis as defined in P0 on Table 1 of NERC TPL-001-4 does not include a contingency event. Rather, all facilities are assumed to be in-service. Every BES facility and select lower voltage facilities in PJM were monitored for thermal limits, voltage limits, and voltage stability. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Single Contingency Analysis

The 2024 50/50 summer peak, 90/10 summer peak and light load cases were evaluated for system performance following the loss of a single element. The single elements included all of the P1 and P2 events defined on Table 1 of NERC TPL-001-4. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage collapse. Additionally select off-system contingencies which may affect PJM's system were included in the single contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Contingency Analysis

The 2024 50/50 summer peak and light load cases were evaluated for system performance following the loss of two or more (multiple) elements. The multiple elements included all common mode events defined in Table 1 of NERC TPL-001-4. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage stability. Additionally select off-system contingencies which may affect PJM's system were included in the Common Mode contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

N-1-1 Analysis

The purpose of the N-1-1 analysis is to determine if all monitored facilities can be operated within normal thermal and voltage limits after an actual N-1 contingency and within the applicable emergency thermal and voltage limits after an additional simulated contingency. The 2024 50/50 summer peak was evaluated for system performance following a single contingency, followed by manual system adjustments, followed by another single contingency. The N-1-1 analysis monitored all BES facilities. The set of single contingencies that was used to compile the contingency pairs included all single contingencies in PJM regardless of voltage, all PJM tie lines regardless of voltage, and selected contingencies in neighboring systems. The contingency pairs that were considered included every possible combination of single contingencies, a total of over 121,000,000 combinations. The N-1-1 analysis also analyzed the contingency pairs in both possible orders to assess every combination and order of event. Reinforcements were developed for areas where the system failed to meet the applicable normal rating after the first contingency or the applicable emergency rating after the second contingency.

The N-1-1 analysis also assessed applicable voltage magnitude and voltage drop limits. For voltage magnitude and voltage drop testing, PJM screened for potential voltage violations. Voltage violations include exceeding the normal low voltage limit after the first contingency, emergency low limit after the second contingency, or exceeding the emergency voltage drop limit after the second contingency. Reinforcements were developed for areas where voltage violations were identified.

Deliverability Analysis

The 2024 base case was also used to analyze the capability of PJM's transmission system, including all PJM BES elements. To maintain reliability in a competitive capacity market, a resource must be deliverable to the overall network. PJM has developed the Load Deliverability and Generator Deliverability test methods for evaluating the adequacy of network capability for each of these deliverability requirements. Common mode outage analysis uses a procedure similar to Generator Deliverability to assess the impact of P3, P4, P5, P6 and P7 contingencies, as defined in PJM Manual 14B, Addendum 2.

A broad range of critical system conditions are established and analyzed through the deliverability test methods. The Generator Deliverability test establishes a critical stressed generation dispatch for every flowgate (monitored element and contingency pair) that could potentially be overloaded by the test. For every monitored facility, a critical stressed dispatch is created for all normal (all facilities in service) and single contingency conditions that could potentially overload the facility. This method results in the analysis of a large number of critical system conditions.

The load deliverability test procedure evaluates multiple critical system conditions though the evaluation of 27 individual stressed Locational Deliverability Areas, one thermal and one voltage case, for each of the defined Locational Deliverability Areas (LDA's) resulting in a minimum of 54 cases. The Locational Deliverability Areas are defined in Manual 14B – Attachment C. The load deliverability cases model stressed 90/10 summer peak loads in the LDA under study in each of the cases. A Capacity Emergency Transfer Objective (CETO) is identified. The CETO is the amount of energy an LDA will need to be able to import so that the area is not expected to have a loss of load event more frequently than one event in 25 years. A Capacity Emergency Transfer Limit (CETL) is calculated for each LDA (i.e. 54 cases) to determine the energy that can be imported into the area under test. In each case, the CETL ("the limit") is compared to the target Capacity Emergency Transfer Objective (CETO). Through this method, a large number of critical system conditions are also developed as part of the Load Deliverability Analysis. The system is planned to ensure that each of the LDAs meet the CETO at a minimum. System reinforcements were developed for any condition where the calculated import capability into any LDA would not meet the CETO.

Generator Deliverability Analysis

The PJM Generation Deliverability procedure was used to determine if the PJM transmission system, including all PJM BES elements, was adequate to deliver all PJM capacity resources to the network. Generator Deliverability analysis is performed to ensure that capacity resources within a given electrical area will, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes the Generator Deliverability procedure to study the normal system and single contingencies under a stressed generation dispatch. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The Generator Deliverability procedure is defined in PJM Manual 14B Attachment C.

PJM performed the Generator Deliverability test on the 2024 50/50 summer peak model. The Generator Deliverability test examined system performance under normal and single contingency conditions. The contingency set included a complete set of single contingencies as defined by P1 and P2 in Table 1 of TPL-001-4.

The 2024 generator deliverability analysis tested a large number of critical system conditions. Every facility was monitored for applicable thermal limits for both the normal system and following the loss of every possible contingency. This process considers every one of the 11,000+ possible single contingencies for each monitored facility. As described in PJM Manual 14B, Attachment C a stressed dispatch was also developed and applied to each potentially overloaded flowgate to determine if an overload could be simulated. Through the method of applying a stressed dispatch to every possible single flowgate, the Generator Deliverability test identifies a large number of critical system conditions.

Reinforcements were developed for areas where the system failed to meet thermal limits or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Outage Analysis

Common mode outage analysis procedures are similar to the generation deliverability analysis procedure; however this analysis focuses specifically on the loss of multiple elements. The common mode outage analysis studies all events listed as P3, P4, P5, P6 and P7 under a stressed generation dispatch. Over 14,000 multiple contingency events were analyzed. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The common mode outage procedure is defined in Addendum 2 of PJM Manual 14B.

Reinforcements were developed for areas where the system failed to meet thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Load Deliverability Analysis

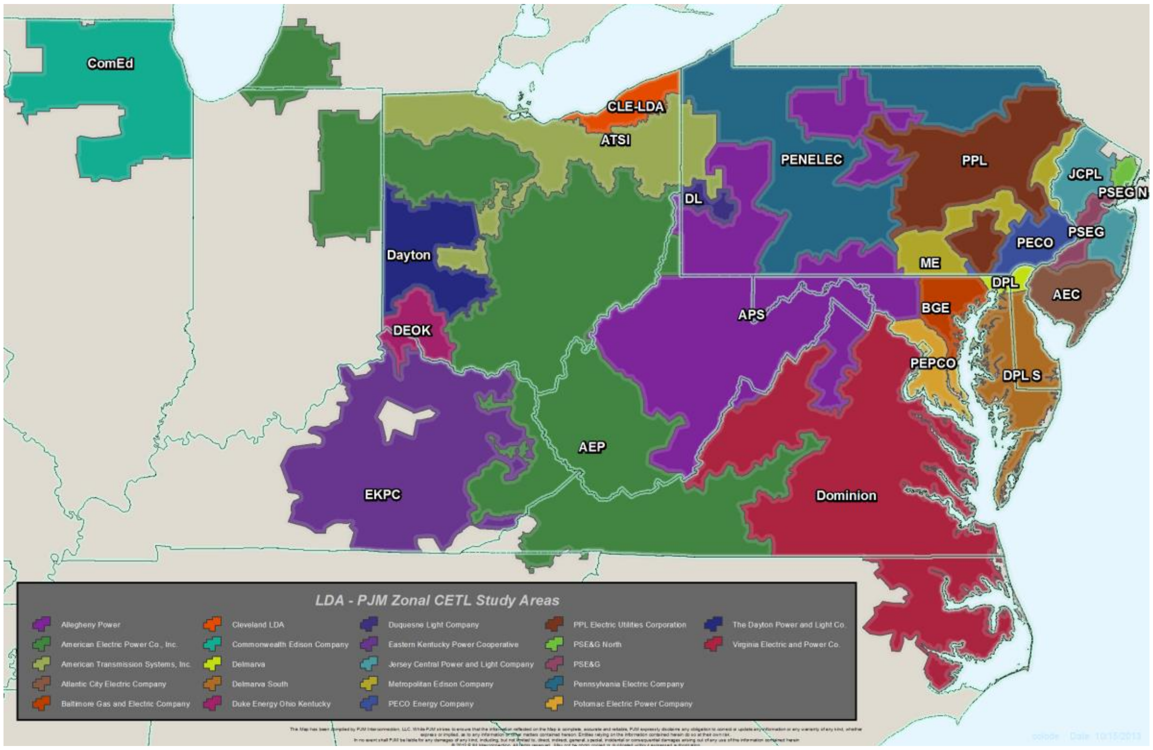
The Load Deliverability test procedures were used to determine if the Capacity Emergency Transfer Limit (CETL) for each of the various electrical areas of PJM is greater than each respective area’s Capacity Emergency Transfer Objective (CETO).

There are currently 27 Locational Deliverability areas defined in PJM, including the recently established Cleveland zone. The electrical areas within each of the 27 Locational Deliverability areas are described in table 6 and Map 2.

Table 6. **PJM Locational Deliverability Areas (LDA)**

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM WEST	APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, Cleveland, OVEC
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTH	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
ComEd	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	Eastern Kentucky Power Cooperative
Cleveland	Cleveland Area

Map 2. PJM Load Deliverability Areas



The 2024 Load Deliverability test used the 2024 summer peak base case as a starting point. From that starting point, 27 individual thermal Load Deliverability cases were built following the Load Deliverability thermal procedure as defined in PJM Manual 14B Attachment C. In addition, 27 individual voltage Load Deliverability cases were built following the Load Deliverability voltage procedure defined in PJM Manual 14B, Attachment C. This process developed one thermal and one voltage study case for each of the 27 Locational Deliverability Areas (LDA) resulting in 54 cases. These studies cover critical system conditions with load levels in the cases set to a 90/10 summer peak for the respective LDA under study and a 50/50 summer load level for all other areas. Modeling of specific system conditions such as load, reactive resources, and phase angle regulator settings were modeled as specified in PJM Manual 14B, Attachment G for the Load Deliverability tests. Manual 14B, Attachment C also specifies a procedure to dispatch generation in both the area assumed to be under a capacity emergency and the areas assumed not to be under a capacity emergency.

Capacity emergency transfer objectives (CETO's) for each of the 27 LDA's were used to set the target net interchange for the LDA under study in each of the thermal and voltage cases.

A thermal Load Deliverability study was then performed on each of the 27 thermal Load Deliverability cases. The thermal Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Reinforcements were developed for areas where the system failed to meet thermal limits. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

A voltage Load Deliverability study was then performed on each of the 27 voltage Load Deliverability cases. The voltage Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Critical system conditions were analyzed and reinforcements were developed for areas where the system failed to meet voltage magnitude limits, voltage drop limits, or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Light Load Reliability Analysis

PJM also performed a year 2024 light load reliability analysis. The 50% of 50/50 summer peak demand level was chosen as being representative of a stressed light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level. In addition to the generation dispatch, the Light Load Reliability Analysis procedure also requires that PJM set interchanges within PJM and neighboring regions to their historical values.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The flowgates ultimately used in the light load reliability analysis were determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis included single and multiple contingencies, with the exception of the N-1-1criteria. Normal system conditions (P0) were also studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list were monitored.

Winter Reliability Analysis

PJM also performed a year 2024 winter reliability analysis. This analysis included Generator Deliverability Studies, as well as Load Deliverability studies using a 2024 RTEP case with winter loadings and winter transmission line ratings. PJM focused these studies on Locational Deliverability Areas which had a Winter Loss of Load Expectation greater than 50%.

Voltage Stability

PV analysis was used to study a set of contingencies from the 2024 Load Deliverability voltage studies that were very severe or non-convergent. A set of single contingencies was selected for further study in the PV analysis. The methodology used to select the contingencies was to choose 500 kV or above contingencies that did not converge in a Load Deliverability voltage test. Also, contingencies that created a severe voltage drop or severe low magnitude violation on the BES were selected.

A PV analysis was then run on each of the selected contingencies. The analysis monitored all PJM facilities while simulating a transfer from all PJM generation outside the CETO area to all generation inside the CETO area where the contingency was identified. Typical to a PV analysis, the transfer was backed off until each contingency solved, and was then incrementally increased until a voltage collapse was simulated.

Retool Analysis of the Near-Term 2019-2024

Retool analysis is analysis that is performed during the current assessment to verify analysis that was performed in previous assessment. The retool analysis of the near-term was performed to verify the RTEP for the near-term due to forecasted changes in system conditions. Due to the recent overall net decrease in the projected load forecast for the PJM system, the retool work performed by PJM was a significant part of the 2019 RTEP. The retool analysis of the near-term included Generator Deliverability, Load Deliverability, common mode outage, and N-1-1 analysis. The methodologies for each of these analyses was performed as described in the detailed 2024 method descriptions in previous sections of this document. Through this approach, an extensive set of critical system conditions were analyzed. The conditions studies are summarized below.

Cases and contingency files for each year under study were updated in coordination with the Transmission Owners to reflect the most recent planned and existing facilities. The updated 2019 PJM load forecast was used to determine the load in the individual cases. The modeling updates included a review of the modeling of existing and planned facilities.

The retool analysis performed as part of the 2019 RTEP included the following groups of analysis. This analysis was in addition to the work performed as part of the near term and long term assessments required by the TPL standards. As a result of the significant generation deactivation notifications received throughout 2019, PJM performed a significant reliability review of years 2019 through 2024. As part of the 2019 RTEP, PJM performed system wide assessment of normal system, single contingency, multiple contingency, N-1-1, generator deliverability and load deliverability testing for year 2019 through 2024 summer peak models as needed for the widespread generation deactivations. PJM completed studies and developed system reinforcements related to generation deactivation requests for each year in the near-term in addition to the specific retool efforts outlined below. System enhancements, including an implementation schedule, were developed for every system performance issue that was identified as a result of the generation deactivation notifications. The system enhancements required as a result of the generation deactivations are described in more detail in the results section of this report. In addition to deactivation related retool studies PJM continually validates that previously identified system enhancements are still necessary.

2020 Retool

- Quad City RAS removal reliability study (ComEd)
- S0864 project removed (PPL)

2021 Retool

- Delay of S0322 (DAY)
- Delay of S0328 (DAY)
- B2889 scope change (AEP)

2022 Retool

- S0330 cancellation (DAY)
- S0331 cancellation (DAY)

2023 Retool

- S1083 scope change (DLCO)
- B3036 sensitivity (AEP)
- B2833 sensitivity (AEP)
- City of Hamilton (Argentum) BES exemption study
- S0330 cancellation (DAY)
- S0331 cancellation (DAY)
- Lisle RAS removal reliability study (ComEd)
- Marengo SPOG removal (ComEd)
- S1828 scope change DNH (ComEd)
- S0864 project removed (PPL)
- Completed the 9A/3A alternative studies on the 2023 case
- 9A/3A Evaluated several proposed alternatives on the 2023 case

2024 Retool

- Davis Besse 1, Perry 1 and Sammis 5,6,7 Reinstatement
- B2889 scope change (AEP)
- B2609.4 in service lower line ratings, DNH (AEP)
- Dumont 765/345KV transformer outage study (AEP)
- S0330 cancellation (DAY)
- S0331 cancellation (DAY)
- B2827 scope change (EKPC)
- Dresden new voltage limit check (ComEd)
- NIPSCO new ties to AEP East Elkhart
- S1106 project reevaluation/replacement (PPL)
- Completed the 9A/3A alternative studies on the 2024 case
- B1690 upgrades to replace MCRP project (JCPL)
- S1267 sensitivity study (BGE)

15 Year Planning and Analysis of the Longer-Term System

The purpose of the long term review is to simulate system trends to identify problems which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation of a reinforcement project in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon. The detailed description of the 15 year planning process is described in PJM Manual 14B.

The 2019 RTEP also included a review of the fifteen year planning horizon through 2034. The analyses conducted as part of the review included normal system, single, and multiple (tower) contingency analysis of the 2024 50/50 Summer Peak case as summarized in Table 7. Following the 15 year procedure, the calculated loading on every flowgate was then scaled by a factor consistent with the forecasted load growth to determine a facility loading in years 2025 through 2034 (years 6 through 15). Both the Generator Deliverability and Load Deliverability procedures were used to establish the critical system conditions under which the system was evaluated.

Table 7. **15 Year Planning Analysis**

Analysis Type	Monitored Flowgates	Contingencies Considered	Years Considered
Load Deliverability	Any BES element loaded at 75% or greater in the 2024 analysis	normal system, single, double circuit tower line	2025 through 2034
Generation Deliverability		normal system, single	

Load forecasts for the years 2025 through 2034 from the 2019 PJM Load Forecast Report were used to generate load growth scaling factors for each of the highest loaded flowgates in each year. The DC scaling factors were then used to calculate a loading for each flowgate for each year 2025 through 2034.

Analysis of the Longer-Term System

PJM evaluated a 2026 (year 7) 50/50 Summer Peak case. One purpose of this evaluation was to identify any thermal or voltage reliability criteria violations in year 2026 that would require a longer term lead time to resolve. The evaluation of the 2026 Summer Peak case did not identify any reliability criteria violations that would require a longer lead time solution. In addition, this targeted analysis of 2026 summer conditions was benchmarked for consistency to the 2026 results from the 15 year analysis procedure.

Verification of Planned Reinforcements

Analysis was performed to verify that all planned reinforcements that were identified as part of the 2019 RTEP and all previously identified reinforcements acceptably resolved all criteria violations throughout the planning horizon. Analysis was also performed to verify that no new potential criteria violations were created as a result of implementing the required system reinforcements.

New Services Queue Analysis

Analysis for customer requests in the New Services Queue was performed for several different types of New Service Requests: Generator interconnection, long term firm transmission service, ARR requests, and Merchant transmission requests. The reliability of the requests is determined through two separate technical studies, the feasibility study and system impact study.

The feasibility study is the first study that is performed and is an initial look at the effect of the New Service Request on the transmission system. This study includes generator deliverability analysis that is performed on a summer peak load case to analyze the normal system, single contingency, and tower contingencies. Additionally Short Circuit analysis is performed.

If a developer elects to move forward and executes a System Impact Study Agreement PJM performs a more detailed study of the impact of the proposed request. The system impact study includes thermal analysis (AC Generator Deliverability) of the normal system and all single and multiple contingencies (Excluding N-1-1) as well as short circuit and stability assessments. Additionally, and as required based on the type of request made, load deliverability analysis may also be performed.

As part of the system impact study process, steady state voltage studies are performed for all interconnection projects. The steady state voltage studies included a check of the applicable voltage magnitude limits under normal and contingency conditions. The voltage of every BES facility was monitored. The contingencies included in the steady state voltage analysis included all multiple contingencies except N-1-1contingencies.

Specific results of interconnection studies can be found at:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Short Circuit Assessment

PJM conducts short circuit analysis annually to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and transmission facilities in service which could impact the study area. Short circuit analysis is performed consistent with the following industry standards:

1) ANSI/IEEE 551-2006 —IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems
   a) This standard is used to provide short circuit current information for breakers and power system equipment used to sense and interrupt fault currents.
2) ANSI/IEEE C37.04-1999 —IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers
   a) This standard is used to establish the rating structure for circuit breakers and equipment associated with breakers.
3) ANSI/IEEE C37.010-1999 —IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Symmetrical Current Basis taking into consideration reclosing duration, X/R ratio differences, temperature conditions, etc.

4) ANSI/IEEE C37.5-1979 —IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Total Current Basis.

Each of these standards is used jointly with transmission owners' methodologies as a basis to calculate fault currents on all BES breakers.
By using these standards, single phase to ground and three phase fault currents are calculated and compared to the breaker interrupting capability, provided by the transmission owners, for each BES breaker within the PJM footprint. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation. All breakers are used in specific short circuit cases which help to identify the cause and year breakers are likely to become overdutied.

Short circuit cases are built consistent with a 2 year planning representation and a 5 year planning representation. The 2 year planning case consists of the current system in addition to all facilities planned to be in-service within the next year. The 5 year planning case uses the 2 year planning case as its base model and it is updated to include all system upgrades, generation projects, and merchant transmission projects planned to be in-service within 5 years. The 5 year planning case is similar to the 5 year PJM RTEP load flow basecase.

Once an overdutied breaker is confirmed breaker replacement and reinforcements along with cost estimates are determined. Breaker replacements and reinforcements, along with a schedule for implementation, were presented at monthly TEAC stakeholder meetings and are contained in the results section of this document.

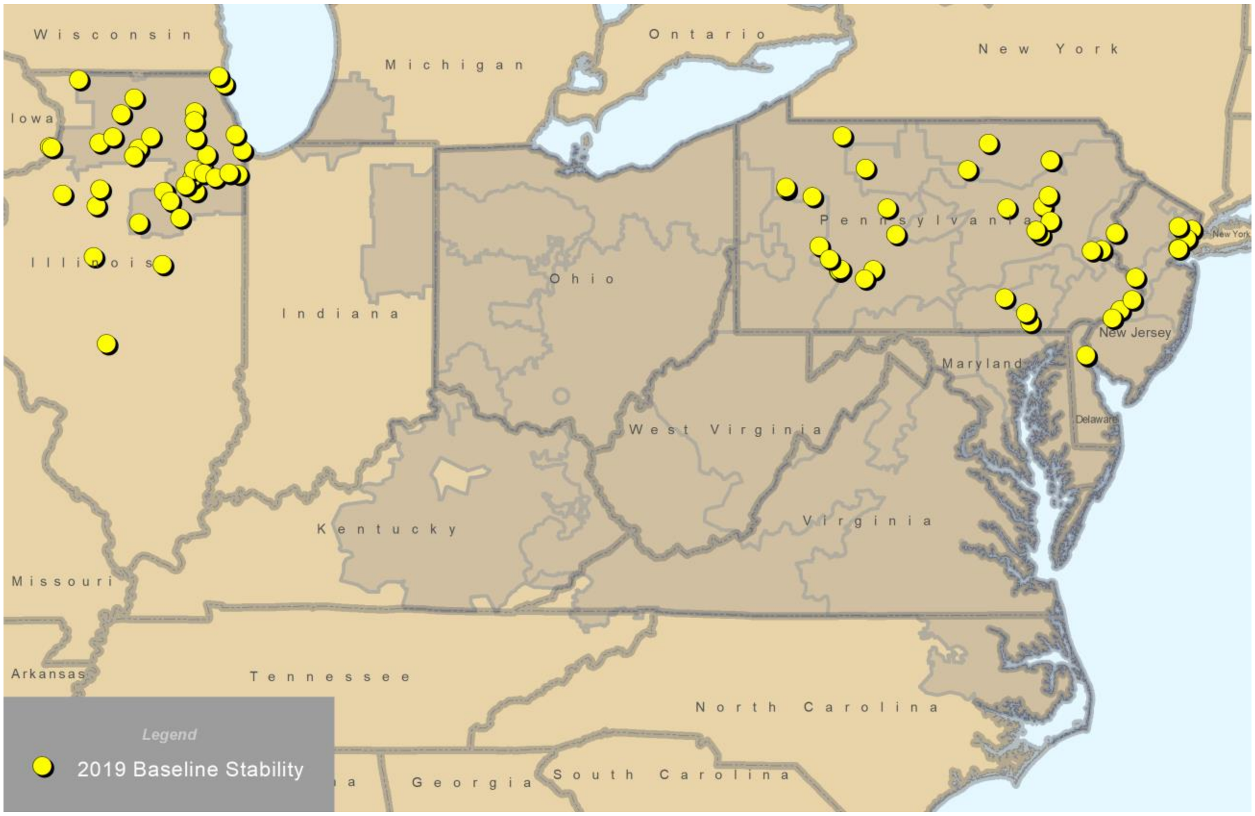
Stability Assessment

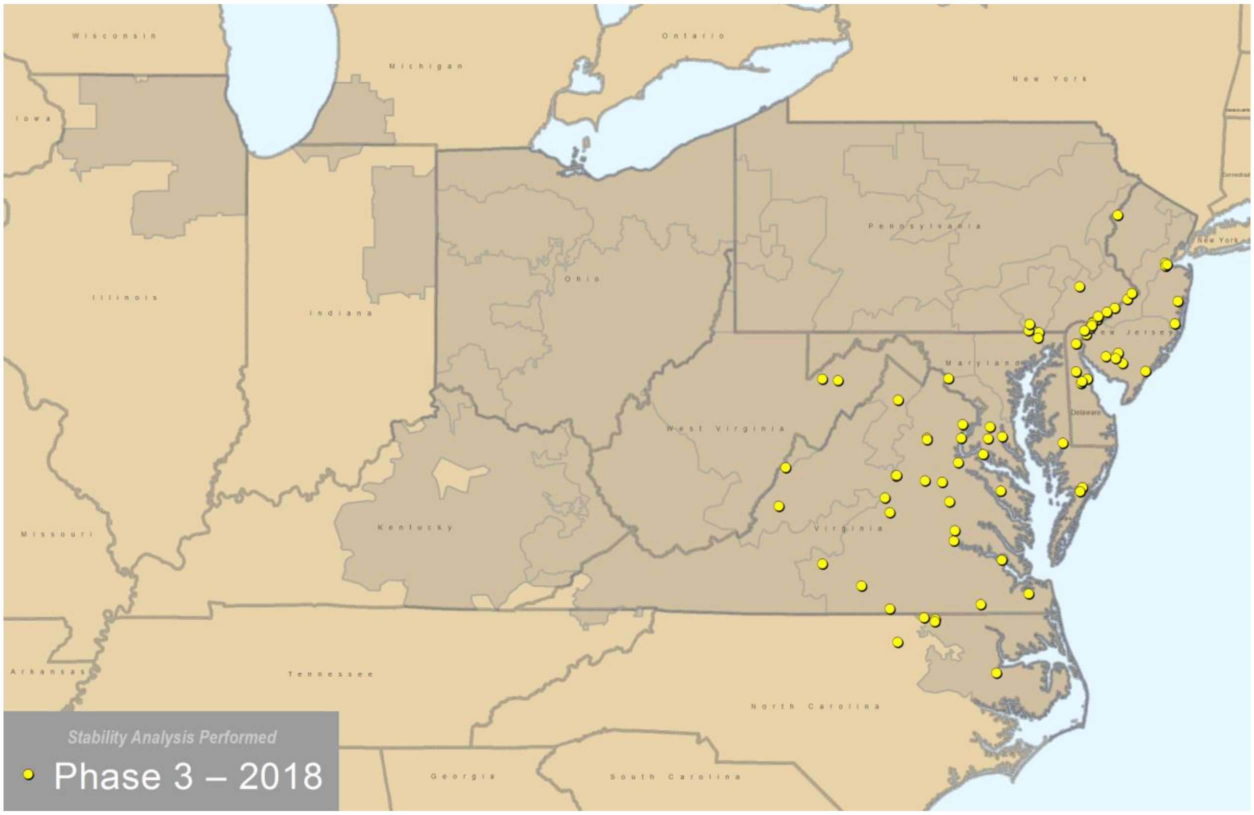
PJM performs multiple tiers of analysis to ensure the system will remain stable and have satisfactory dynamic performance for disturbances that are consistent with Table 1 of the NERC TPL-001-4 standards. Collectively, the studies performed assess system dynamic performance over a wide range of load levels. Whenever system dynamic performance does not meet criteria, appropriate reinforcements are incorporated in the system plans and design. These measures include the installation of PSS (Power System Stabilizer), Excitation system refinements, dynamic or static reactive supports for wind generation plants, relaying and breaker configuration modifications.

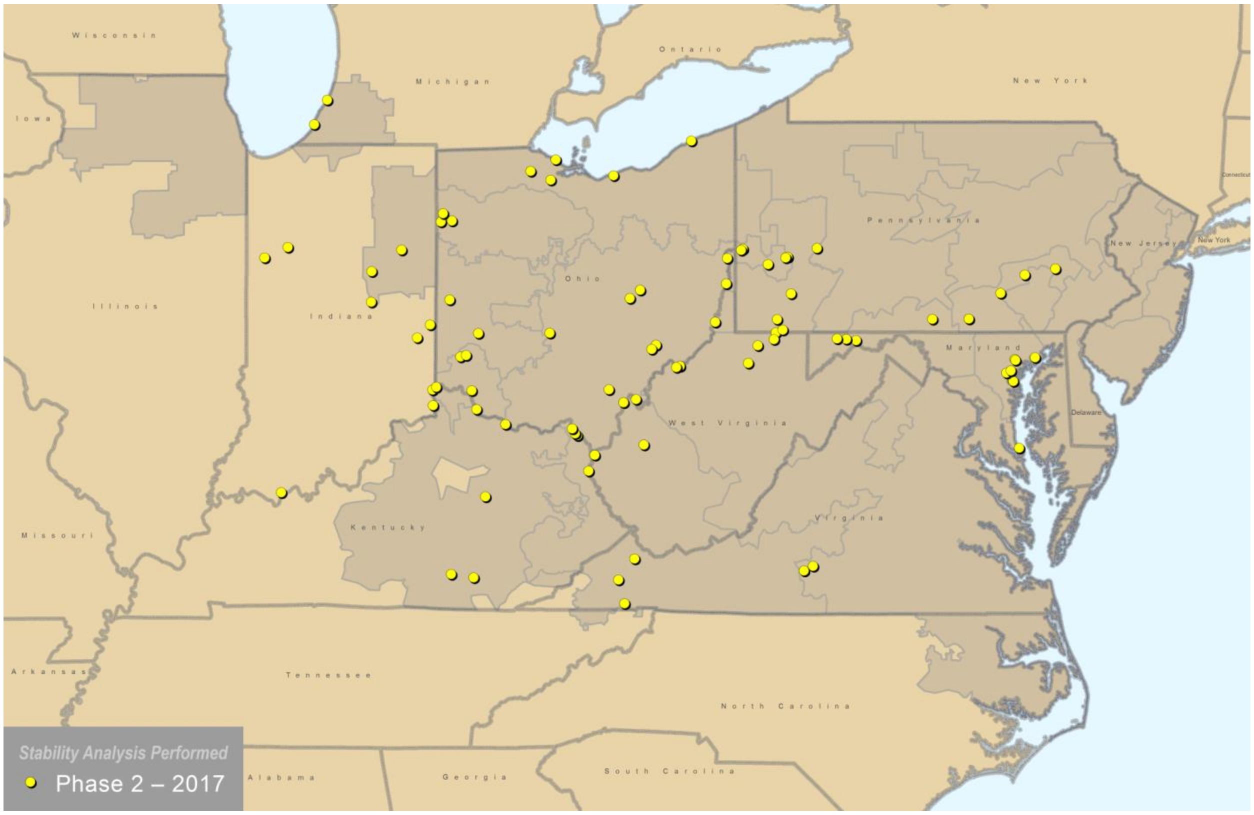
Table 8. **Number of Generation Stations Studied for Stability as Part of the 2019 RTEP**

Stability Studies	2019 RTEP
Annual baseline stability analysis of 1/3 of existing stations	100
New Services Queue stability analysis	184
Total	**284**

Map 3. Three Year Baseline Stability Cycle







Good engineering practices as related to ensuring adequate system dynamic performance for the Bulk Electric System starts with proper base case models. PJM uses full ERAG MMWG models as a starting point for the dynamic stability analysis. All known transmission system as well as generation model changes available from approved system plans are incorporated. Step response simulations are conducted to detect and correct any modeling errors. Case initialization results are carefully analyzed to make sure that all the initial conditions are satisfactory. A 20 second no fault simulation is performed to ensure proper parameters are used in the models.

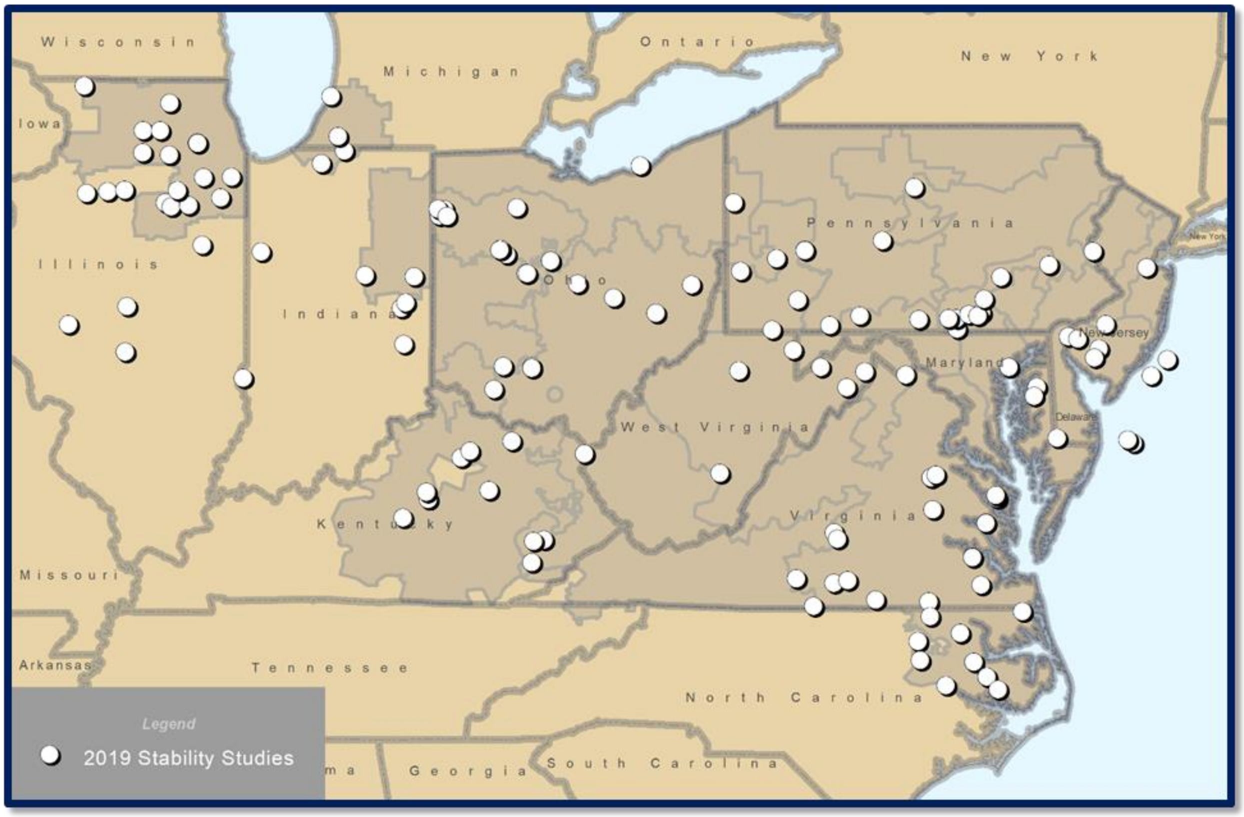
As part of the 2019 RTEP, several tiers of system stability analysis were performed. The first tier of this analysis includes PJM's annual comprehensive transient stability assessment of generating stations in the system. The annual analysis is performed for one third of the PJM footprint each year.

The annual baseline analysis includes an evaluation of the system under light load conditions as well as peak load conditions. PJM's rationale for choosing a light load case is that the light load system conditions are found to be the most challenging and severe from a transient stability perspective. The analysis also includes an evaluation of the system under summer peak loading (50/50) conditions.

PJM incorporates dynamic load models in peak load stability study to consider the behaviors of dynamic loads including induction motor loads. Various contingencies near load centers and generation stations are studied to ensure PJM system meets dynamic voltage recovery criteria as well as transient stability and damping criteria. In addition PJM evaluates the impact of dynamic load models on the system performance under a stressed power transfer condition across PJM eastern interface.

All PJM stability studies start by testing the system for a major transmission line switching operation. This examines the system under system normal conditions, as specified in TPL-001-4. The system response is verified by monitoring generating unit angle curves over a 20 second time frame. This test also provides the information to verify that all dynamic parameters are correctly initiating and responding properly. The stability test procedure includes a simulation of all applicable disturbances on all outlets of generating plants for multiple contingency (P3-P7) conditions. Additionally, all existing Remedial Action Schemes and their controlling actions are evaluated to ensure their effectiveness. A visual depiction of the coverage of the three latest baseline stability study cycles is shown in Map 3 above.

Map 4. Locations of proposed generation studied for stability in 2019



A second tier of PJM's stability assessment includes stability analysis for all proposed generator interconnections that exceed 20 MWs. New generator interconnections represent a significant modification to the system that could affect stability. In 2019 as part of the generation interconnection process, PJM completed transient stability analysis for 172 proposed generator interconnections within the PJM footprint. The locations of these proposed generators are shown in Map 4. In this analysis P0, P1, P2, P3, P4, P5, P6 and P7 conditions were analyzed for disturbances on all generating plant outlets as well as on transmission lines at a minimum, one bus away and more than one bus away from the point of interconnection if warranted by the system topology. In general, the analysis associated with proposed generation additions identifies any potential transient stability concerns among the generators electrically close to the portion of the system being modified. The proposed generation interconnections span all transmission system voltage levels and are widespread throughout PJM's footprint. Hence, the resulting stability analysis covers broad sections of PJM's Bulk Electric System. Solutions to the identified problems are developed and implemented prior to the proposed generation being placed in service.

As depicted in Map 4, the locations of the proposed generation additions are dispersed throughout the PJM footprint. In addition to monitoring the stability of the proposed generation, existing generation within several layers of the interconnection bus are also monitored. The transient stability analysis that is run for proposed generation interconnections not only ensures that the proposed unit will remain stable but also ensures that the transient stability of existing generation at nearby buses will not be compromised. It is important to note that the relative queue position is respected for this analysis, so that potential transient stability concerns are identified for the proposed unit and nearby existing generation. This ensures that violations will be allocated to the correct project based on queue order. The results of this analysis and any required upgrades or other mitigation measures needed, are identified in the System Impact Study for each New Service Request and are posted on the PJM web at the following address:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

A third tier of PJM's stability analysis includes ad-hoc studies that were performed in 2019 and occur annually to support PJM operations.

The transient stability analysis performed by PJM is done with forward looking cases representing the system as planned in future years. Given the continued load growth within the PJM footprint and the on-going transmission system reinforcements that are identified as part of the regional transmission expansion plan, the transient stability of the system is expected to continue to improve.

As a result of PJM integrating each of these tiers of stability assessment, PJM has ensured its compliance to all applicable standards including the assessments required by Table 1 of the NERC TPL001-4 standard.

Based on PJM's knowledge and evaluation of current and forecasted system conditions, stability related upgrades would not require a lead time during the longer-term (year 6 and beyond) time frame, therefore stability analysis is not performed beyond 5 years out.

N-1-1 Stability Assessment

N-1-1 stability study for 80 plants was performed in 2019 RTEP. Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. PJM will continue to conduct N-1-1 stability study for selected plants on a rotating basis.

Critical contingency pairs which may lead to potential stability issues were applied to the study. SPS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. No transient stability issues and damping violations were identified during the study.

NPIR Plant Specific Stability & Voltage Assessment

PJM has a total of 17 plants that fit the criteria for NPIR stability study. Eight of those plants were studied as part of the 2019 RTEP and the remaining 9 were studied as part of the 2017 and 2018 RTEPs. PJM will continue to study these 17 plants on a rotating basis with analysis as part of the 2020 and 2021 RTEPs. RAS or specific operation guidelines were implemented if necessary. Also several nuclear plant NPIR studies were performed to verify and validate 2019 new dynamic models per TOs request.

In addition to the NPIR stability studied, PJM also performed NPIR voltage studies. As part of the 2019 RTEP, all 17 PJM nuclear plants were studied to ensure these plants comply with voltage monitoring criteria. Voltage magnitude and voltage drop were monitored under selected contingencies. Study results have been sent to NGOs.

Results of 2019 RTEP

The results of the baseline assessment for the 2019 – 2034 periods are presented below. This report, containing all corrective reinforcements, is provided to applicable regional entities annually in compliance with TPL-001-4. All of the upgrades below were presented to the TEAC stakeholder committee at one of the monthly TEAC stakeholder meetings in 2019.

PJM found the following areas of the PJM system to not meet reliability criteria during the assessment of the 2019 – 2034 study periods. These baseline upgrades were all identified as part of the 2019 RTEP. The list of required upgrades contains a summary of the system deficiencies and the associated action needed to achieve required system performance. This includes deficiencies identified in multiple sensitivity studies. The expected required in-service date of each upgrade is also included. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. System enhancements and corrective action plans are reviewed in subsequent annual studies for continued validity and implementation status of identified system facilities and operating procedures. Additionally, results include all recommended upgrades where short circuit analysis shows that existing breakers exceed their equipment rating.

Upgrades identified and established in previous RTEP cycles are detailed in Appendix A.

The most up to date information concerning in-service dates and schedule for implementation can be found at the following link:

https://www.pjm.com/planning/project-construction.aspx

With the exception of the baseline upgrades noted below, all other areas of the system were found to meet applicable reliability criteria.

1) Baseline Upgrade b1570.4

- Overview of Reliability Problem
  - Criteria Violation: Overload of Staunton Tap - Eldean 138 kV line and Quincy - East Sidney - Shelby 138 kV line and low voltage at several buses in North West area of DAYTON
  - Contingency: Loss of Shelby - Miami 345 kV line with stuck breaker at Shelby, loss of Darby 138/69 kV XFMR and Urbana 138/69 kV XFMR and various pairs of contingencies
  - Criteria Test: NERC TPL-003 Category C (Thermal)
- Overview of Reliability Solution
  - Description of Upgrade: Add a 345 kV breaker at Marysville station and a 0.1 mile 345 kV line extension from Marysville to the new 345/69 kV Dayton transformer.
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $4.10M
  - Construction Responsibility: AE

2) Baseline Upgrade b2443.6

- Overview of Reliability Problem
  - Criteria Violation: Overload of the Possum Point 500/230 kV transformer
  - Contingency: Loss of the Possum Point - Ox 500 kV line
  - Criteria Test: N-1
- Overview of Reliability Solution
  - Description of Upgrade: Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $21.00M
  - Construction Responsibility: Dominion

3) Baseline Upgrade b2443.7

- Overview of Reliability Problem
    - Criteria Violation: Overload of the Possum Point 500/230 kV transformer
    - Contingency: Loss of the Possum Point - Ox 500 kV line
    - Criteria Test: N-1
- Overview of Reliability Solution
    - Description of Upgrade: Replace 19 - 63 kA 230 kV breakers with 19 – 80 kA 230 kV breakers
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $19.00M
    - Construction Responsibility: Dominion

4) Baseline Upgrade b2686.4

- Overview of Reliability Problem
    - Criteria Violation: The Remington CT 230kV breaker "2114T2155" is overdutied.
    - Contingency: Fault at Remington CT
    - Criteria Test: Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Replace the Remington CT 230 kV breaker "2114T2155" with a 63 kA breaker
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: Dominion

5) Baseline Upgrade b2970.5

- Overview of Reliability Problem
    - Criteria Violation: Overload of Ringgold 230/138 kV transformers No.3 and No.4

- Contingency: multiple contingencies
- Criteria Test: Gen Deliv, baseline and N-1-1 thermal

- Overview of Reliability Solution
  - Description of Upgrade: Convert Garfield 138/12.5 kV substation to 230/12.5 kV
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $2.20M
  - Construction Responsibility: APS

6) Baseline Upgrade b2996.3

- Overview of Reliability Problem
  - Criteria Violation: Overduty of the Rider 50 and transformer No.1 and No.4 138 kV breakers at Glen Falls 138 kV substation
  - Contingency: Fault at Glen Falls 138 kV substation
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade two (2) existing 138 kV breakers (Rider 50 and #1/4 transformer breaker) at Glen Falls with 63 kA, 3000 A units
  - Upgrade In-Service Date: 5/31/2020
  - Estimated Upgrade Cost: $0.49M
  - Construction Responsibility: APS

7) Baseline Upgrade b3011.7

- Overview of Reliability Problem
  - Criteria Violation: Overduty of Elwyn Z-70 138 kV line breaker at Dravosburg
  - Contingency:
  - Criteria Test: Short Circuit
- Overview of Reliability Solution

- Description of Upgrade: Replace the line terminal equipment and line breaker #85 at Dravosburg 138 kV substation in the Elwyn Z-70 line position/bay, with the breaker duty as 63KA
- Upgrade In-Service Date: 6/1/2021
- Estimated Upgrade Cost: $0.90M
- Construction Responsibility: DL

8) Baseline Upgrade b3012.3

- Overview of Reliability Problem
  - Criteria Violation: Overload of multiple 138 kV facilities in AP and DL zones and overload of the Wylie Ridge 500/345 kV transformer
  - Contingency: Various contingencies in APS and DL zones
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new Elrama - Route 51 138 kV No.3 line: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at APS Route 51 substation.
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $18.10M
  - Construction Responsibility: APS

9) Baseline Upgrade b3012.4

- Overview of Reliability Problem
  - Criteria Violation: Overload of multiple 138 kV facilities in AP and DL zones and overload of the Wylie Ridge 500/345 kV transformer
  - Contingency: Various contingencies in APS and DL zones
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Establish the new tie line in place of the existing Elarama - Mitchell 138 kV line

- Upgrade In-Service Date: 6/1/2021
- Estimated Upgrade Cost: $1.00M
- Construction Responsibility: DL

10) Baseline Upgrade b3015.8

- Overview of Reliability Problem
  - Criteria Violation: Overload of multiple 138 kV facilities in AP and DL zones and overload of the Wylie Ridge 500/345 kV transformer
  - Contingency: Various contingencies in AP and DL zones
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: APS

11) Baseline Upgrade b3064.2

- Overview of Reliability Problem
  - Criteria Violation: Short Circuit
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Replace the West Mifflin 138 kV breakers “Z-94”, “Z-74”, “Z14”, and “Z-13” with 63 kA breakers
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $3.10M
  - Construction Responsibility: DL

12) Baseline Upgrade b3064.3

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork – Elrama 138 kV line and Bethel Park – Elrama 138 kV line.
  - Upgrade In-Service Date: 6/1/2021
  - Estimated Upgrade Cost: $0.60M
  - Construction Responsibility: APS

13) Baseline Upgrade b3094

- Overview of Reliability Problem
  - Criteria Violation: Low voltage at Pleasant Grove 69 kV bus
  - Contingency: Loss of Bullitt County 161/69 kV transformer and LGE/KU Mill Creek Unit #4
  - Criteria Test: EKPC Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Move 69 kV 12.0 MVAR capacitor bank from Greenbriar to Bullitt Co 69kV substation
  - Upgrade In-Service Date: 6/1/2018
  - Estimated Upgrade Cost: $0.30M
  - Construction Responsibility: EKPC

14) Baseline Upgrade b3096

- Overview of Reliability Problem
  - Criteria Violation: Loss of Line #2164 creates a radial line in excess of 100 MW.
    Loss of Line #2063 drops load at Moore DP.

- Contingency: Loss of Line #2164 segment beytween Clifton and Keene Mill
  Loss of Line #2063

- Criteria Test: Dominion FERC 715 Criteria

- Overview of Reliability Solution

  - Description of Upgrade: Rebuild 230 kV line No.2063 (Clifton – Ox) and part of 230 kV line No.2164 (Clifton – Keene Mill) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA.

  - Upgrade In-Service Date: 6/1/2019

  - Estimated Upgrade Cost: $22.00M

  - Construction Responsibility: Dominion

15) Baseline Upgrade b3097

- Overview of Reliability Problem

  - Criteria Violation: Loss of Line #86 segment between Chesterfield and Centralia creates a radial line that exceeds the 700 MW-Mile limit.

  - Contingency: Loss of Line #86 segment between Chesterfield and Centralia

  - Criteria Test: Dominion FERC 715 Criteria

- Overview of Reliability Solution

  - Description of Upgrade: Rebuild 4 miles of 115kV Line #86 between Chesterfield and Centralia to current standards with a minimum summer emergency rating of 393 MVA.

  - Upgrade In-Service Date: 6/1/2019

  - Estimated Upgrade Cost: $7.00M

  - Construction Responsibility: Dominion

16) Baseline Upgrade b3098

- Overview of Reliability Problem

  - Criteria Violation: Loss of Line #141 creates a radial line that exceeds the 700 MW-Mile limit. Loss of Line #28 strands generation at Cushaw

  - Contingency: Loss of Line #141 and Loss of line #28

- Criteria Test: Dominion FERC 715 Criteria

- Overview of Reliability Solution

  - Description of Upgrade: Rebuild 9.8 miles of 115kV Line #141 between Balcony Falls and Skimmer and 3.8 miles of 115kV Line #28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA.

  - Upgrade In-Service Date: 6/1/2019

  - Estimated Upgrade Cost: $20.00M

  - Construction Responsibility: Dominion

17) Baseline Upgrade b3099

- Overview of Reliability Problem

  - Criteria Violation: Thermal overload of Kingsport 34.5 kV sub-transmission network

  - Contingency: Loss of the 138/34.5 kV Holstom transformer No. 5 and loss of the Nagel-Reedy Creek 138 kV line

  - Criteria Test: AEP Criteria

- Overview of Reliability Solution

  - Description of Upgrade: Install a 138 kV 3000 A 40 kA circuit switcher on the high side of the existing 138/34.5 kV transformer No.5 at Holston station.

  - Upgrade In-Service Date: 6/1/2022

  - Estimated Upgrade Cost: $19.00M

  - Construction Responsibility: AEP

18) Baseline Upgrade b3100

- Overview of Reliability Problem

  - Criteria Violation: Themal overload of Chemical transformer #2

  - Contingency: under a N-1-1 contingency condition involving the loss of the Chemical transformer #6 (which includes the loss of XFR #4, Chemical – Turner 138 kV line and Chemical – Ortin 138 kV, due to the loss of 138 kV bus #1) paired with the loss of the Capitol Hill – Chemical 138 kV line

  - Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
    - Description of Upgrade: Replace 138 kV MOAB switch "YY" with a new 138 kV circuit switcher on the high side of Chemical transformer No.6.
    - Upgrade In-Service Date: 12/1/2022
    - Estimated Upgrade Cost: $0.70M
    - Construction Responsibility: AEP

19) Baseline Upgrade b3101

- Overview of Reliability Problem
    - Criteria Violation: Overload of Fort Robinson – Moccasin Gap 69 kV line section
    - Contingency: loss of the Hill – Gate City 69 kV line section, Hill 138/69/34.5 kV transformer or the Clinch River – Nagel 138 kV circuit
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the 1/0 Cu. conductor sections (~1.5 miles) of the Fort Robinson - Moccasin Gap 69 kV line section (~5 miles) utilizing 556 ACSR conductor and upgrade existing relay trip limit (WN/WE: 63 MVA , line limited by remaining conductor sections).
    - Upgrade In-Service Date: 12/1/2023
    - Estimated Upgrade Cost: $3.00M
    - Construction Responsibility: AEP

20) Baseline Upgrade b3102

- Overview of Reliability Problem
    - Criteria Violation: Overload of Fremont 138/69 kV transformers #1 and #2
    - Contingency: loss of the Garden Creek – Clinch River 138 kV circuit paired with a loss of one of the aforementioned 138/69 kV transformers at Fremont, or loss of the Clinchfield 138/69 kV transformer paired with a loss of one of the aforementioned 138/69 kV transformers at Fremont.
    - Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
    - Description of Upgrade: Replace existing 50 MVA 138/69 kV transformers #1 and #2 (both 1957 vintage) at Fremont station with new 130 MVA 138/69 kV transformers.
    - Upgrade In-Service Date: 12/1/2022
    - Estimated Upgrade Cost: $4.10M
    - Construction Responsibility: AEP

21) Baseline Upgrade b3103.1

- Overview of Reliability Problem
    - Criteria Violation: Multiple overloads
    - Contingency: Multiple Contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Install a 138/69 kV transformer at Royerton station. Install a 69 kV bus with one 69 kV breaker toward Bosman station. Rebuild the 138 kV portion into a ring bus configuration built for future breaker and a half with four 138 kV breakers.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $10.25M
    - Construction Responsibility: AEP

22) Baseline Upgrade b3103.2

- Overview of Reliability Problem
    - Criteria Violation:
    - Contingency:
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the Bosman/Strawboard station in the clear across the road to move it out of the flood plain and bring it up to 69kV standards.

- Upgrade In-Service Date: 6/1/2022
- Estimated Upgrade Cost: $4.47M
- Construction Responsibility: AEP

23) Baseline Upgrade b3103.3

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Retire 138 kV breaker L at Delaware station and re-purpose 138 kV breaker M for the Jay line.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $0.18M
  - Construction Responsibility: AEP

24) Baseline Upgrade b3103.4

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Retire all 34.5 kV equipment at Hartford City station. Re-purpose breaker M for the Bosman line 69 kV exit.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $0.88M
  - Construction Responsibility: AEP

25) Baseline Upgrade b3103.5

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 138 kV portion of Jay station as a 6 breaker, breaker and a half station re-using the existing breakers “A”, “B” and “G”. Rebuild the 69 kV portion of this station as a 6 breaker ring bus re-using the 2 existing 69 kV breakers. Install a new 138/69kV transformer.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $18.73M
  - Construction Responsibility: AEP

26) Baseline Upgrade b3103.6

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 69 kV Hartford City – Armstrong Cork line but instead of terminating it into Armstrong Cork, terminate it into Jay station.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $21.12M
  - Construction Responsibility: AEP

27) Baseline Upgrade b3103.7

- Overview of Reliability Problem

- Criteria Violation:
- Contingency:
- Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
    - Description of Upgrade: Build a new 69 kV line from Armstrong Cork – Jay station.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $2.35M
    - Construction Responsibility: AEP

28) Baseline Upgrade b3103.8

- Overview of Reliability Problem
    - Criteria Violation:
    - Contingency:
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the 34.5 kV Delaware – Bosman line as the 69 kV Royerton – Strawboard line. Retire the line section from Royerton to Delaware stations.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $12.78M
    - Construction Responsibility: AEP

29) Baseline Upgrade b3104

- Overview of Reliability Problem
    - Criteria Violation: Overload of the Polaris - Westerville 138 kV line
    - Contingency: Loss of Vassel - Vassel Transformer No. 1 Lead 345 kV followed by the loss of Genoa - Maliszewski #2 138 kV line and loss of Vassel 765/345 kV transformer followed by the loss of Genoa - Maliszewski 2 138 kV line and loss of Genoa - Maliszewski 2 138 kV line followed by loss of Vassel - Vassel transformer 1 Lead 345 kV and loss of Genoa - Maliszewski 2 138 kV line followed by loss of Vassel 765/345 kV transformer.

- Criteria Test: N-1-1

- Overview of Reliability Solution
  - Description of Upgrade: Perform a sag study on the Polaris - Westerville 138 kV line (~ 3.6 miles) to increase the Summer Emergency rating to 310 MVA.
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: AEP

30) Baseline Upgrade b3105

- Overview of Reliability Problem
  - Criteria Violation: Overload of the Delaware - Hyatt 138 kV line
  - Contingency: Loss of Delaware - Vassel 138 kV (N-1-0) and theloss of Vassel 345/138 kV transformer (N-1-0)
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Delaware – Hyatt 138 kV line (~ 4.3 miles) along with replacing conductors at both Hyatt and Delaware substations.
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $16.00M
  - Construction Responsibility: AEP

31) Baseline Upgrade b3106

- Overview of Reliability Problem
  - Criteria Violation: Overload of Hyatt - Maliszewski 138 kV
  - Contingency: For the loss of Hyatt 345/138 kV 1A & 1B transformers followed by the loss of Hyatt - Maliszewski No. 2 138 kV and Loss of Marysville 765/345 kV No.2 transformer followed by Hyatt - Maliszewski No. 2 138 kV
  - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution

- Description of Upgrade: Hyatt-Maliszewski: Perform a sag study (6.8 miles of line) to increase the SE rating to 310 MVA. Note that results from the sag study could cover a wide range of outcomes, from no work required to a complete rebuild.
- Upgrade In-Service Date: 6/1/2020
- Estimated Upgrade Cost: $0.50M
- Construction Responsibility: AEP

32) Baseline Upgrade b3108.1

- Overview of Reliability Problem
  - Criteria Violation: High voltage across the Dayton system
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Install 100 MVAR reactor at Miami 138 kV substation
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $5.00M
  - Construction Responsibility: Dayton

33) Baseline Upgrade b3108.2

- Overview of Reliability Problem
  - Criteria Violation: High voltage across the Dayton system
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Install 100 MVAR reactor at Sugarcreek 138 kV substation
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $5.00M

- Construction Responsibility: Dayton

34) Baseline Upgrade b3108.3

- Overview of Reliability Problem
  - Criteria Violation: High voltage across the Dayton system
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Install 100 MVAR reactor at Hutchings 138 kV substation
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $5.00M
  - Construction Responsibility: Dayton

35) Baseline Upgrade b3109

- Overview of Reliability Problem
  - Criteria Violation: Overload of Bethel – Brookside and Brookside-Sawmil 138 kV line sections
  - Contingency: Multiple contingencies
  - Criteria Test: N-1 and N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild 5.2 mile Bethel-Sawmill 138 kV line including ADSS.
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $34.50M
  - Construction Responsibility: AEP

36) Baseline Upgrade b3110.1

- Overview of Reliability Problem

- Criteria Violation: Load drop more than 311 MW
- Contingency: Loss of Line #2008 segement between Loudoun and Dulles and a breaker failure at Reston
- Criteria Test: Dominion FERC 715 Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Line #2008 between Loudoun to Dulles Junction using single circuit conductor at current 230 kV northern Virginia standards with minimum summer ratings of 1200 MVA. Cut and loop Line #265 (Clifton – Sully) into Bull Run Substation. Add three (3) 230 kV breakers at Bull Run to accommodate the new line and upgrade the substation.
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $14.00M
  - Construction Responsibility: Dominion

37) Baseline Upgrade b3110.2

- Overview of Reliability Problem
  - Criteria Violation: Overduty of the Bull Run 230 kV breakers “200T244” and “200T295”
  - Contingency: Fault at Bull Run
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Bull Run 230 kV breakers “200T244” and “200T295” with 50 kA breakers.
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $0.54M
  - Construction Responsibility: Dominion

38) Baseline Upgrade b3111

- Overview of Reliability Problem
  - Criteria Violation: Instability at TSS 946 University Park E.C.

  - Contingency: 3-phase-to-gound fault at the 80% of 138 kV line L6603 from E. Frankfort 138kV blue bus w/ delayed clearing at E. Frankfort 138 kV blue bus
  - Criteria Test: ComEd Stability
- Overview of Reliability Solution
  - Description of Upgrade: Install high-speed backup clearing scheme on the E. Frankfort – Matteson 138 kV line (L6603)
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: ComEd

39) Baseline Upgrade b3112

- Overview of Reliability Problem
  - Criteria Violation: Overload of the Dublin-Sawmill 138 kV circuit
  - Contingency: Loss of Bethel-Davidson & Davidson-Roberts 138 kV circuits
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a single circuit 138 kV line (~3.5 miles) from Amlin to Dublin using 1033 ACSR Curlew (296 MVA SN), convert Dublin Station into a ring configuration, and re-terminating the Britton UG cable to Dublin Station.
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $39.29M
  - Construction Responsibility: AEP

40) Baseline Upgrade b3113

- Overview of Reliability Problem
  - Criteria Violation: End of Life
  - Contingency: Loss of 115 kV Line No.72 segment between Plaza and Chesterfield and loss of 115 kV Line No.53 segment between Kevlar and Chesterfield
  - Criteria Test: Dominion FERC 715 Criteria

- Overview of Reliability Solution
    - Description of Upgrade: Rebuild approximately 1 mile of 115 kV Line #72 and #53 to current standards with a minimum summer emergency rating of 393 MVA. The resulting summer emergency rating of Line #72 segment from Brown Boveri to Bellwood is 180 MVA. There is no change to Line #53 ratings.
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $3.00M
    - Construction Responsibility: Dominion

41) Baseline Upgrade b3114

- Overview of Reliability Problem
    - Criteria Violation: End of Life
    - Contingency: Loss of 115 kV Line No.81
    - Criteria Test: Dominion FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the 18.6 mile section of 115 kV Line #81 which includes 1.7 miles of double circuit Line #81 and 230 kV Line #2056. This segment of line of 81 will be rebuilt to current standards with a minimum rating of 261 MVA. Line 2056 rating will not change.
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $25.00M
    - Construction Responsibility: Dominion

42) Baseline Upgrade b3115

- Overview of Reliability Problem
    - Criteria Violation:
    - Contingency:
    - Criteria Test:
- Overview of Reliability Solution

- Description of Upgrade: Provide new station service to control building from 230 kV bus (served from plant facilities presently).
- Upgrade In-Service Date: 9/30/2019
- Estimated Upgrade Cost: $1.50M
- Construction Responsibility: ME

43) Baseline Upgrade b3116

- Overview of Reliability Problem
  - Criteria Violation: Thermal overload of Mullens 138/46 kV transformer No.4
  - Contingency: loss of the Bradley – Jehu Branch 138 kV line plus the loss of the Tams Mountain – Mullens 138 kV line
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace existing Mullens 138/46 kV 30 MVA transformer No.4 and associated protective equipment with a new 138/46 kV 90 MVA transformer and associated protective equipment.
  - Upgrade In-Service Date: 12/1/2022
  - Estimated Upgrade Cost: $3.00M
  - Construction Responsibility: AEP

44) Baseline Upgrade b3118.1

- Overview of Reliability Problem
  - Criteria Violation: Multiple thermal and voltage violations
  - Contingency: Multiple contingencies
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Expand existing Chadwick station and install a second 138/69 kV transformer at a new 138 kV bus tied into the Bellefonte – Grangston 138 kV circuit. The 69 kV bus will be reconfigured into a ring bus arrangement to tie the new transformer into the existing 69 kV via installation of four 3000A 63 kA 69 kV circuit breakers.

    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $9.30M
    - Construction Responsibility: AEP

45) Baseline Upgrade b3118.10

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations
    - Contingency: Multiple contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Replace 69 kV line risers (towards Chadwick) at Leach station
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $0.10M
    - Construction Responsibility: AEP

46) Baseline Upgrade b3118.2

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations
    - Contingency: Multiple contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Perform 138 kV remote end work at Grangston station.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $0.50M
    - Construction Responsibility: AEP

47) Baseline Upgrade b3118.3

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations
    - Contingency: Multiple contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Perform 138 kV remote end work at Bellefonte station.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $0.50M
    - Construction Responsibility: AEP

48) Baseline Upgrade b3118.4

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations
    - Contingency: Multiple contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Relocate the Chadwick – Leach 69 kV circuit within Chadwick station.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $0.50M
    - Construction Responsibility: AEP

49) Baseline Upgrade b3118.5

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations

    - Contingency: Multiple contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Terminate the Bellefonte – Grangston 138 kV circuit to the Chadwick 138 kV bus
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $1.10M
    - Construction Responsibility: AEP

50) Baseline Upgrade b3118.6

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations
    - Contingency: Multiple continguencies
    - Criteria Test:
- Overview of Reliability Solution
    - Description of Upgrade: Chadwick – Tri-State #2 138 kV circuit will be reconfigured within the station to terminate into the newly established 138 kV bus #2 at Chadwick due to construability aspects.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $0.10M
    - Construction Responsibility: AEP

51) Baseline Upgrade b3118.7

- Overview of Reliability Problem
    - Criteria Violation: Multiple thermal and voltage violations
    - Contingency: Multiple contingencies
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution

- Description of Upgrade: Reconductor Chadwick-Leach and Chadwick-England Hill 69 kV lines with 795 ACSS conductor. Perform a LiDAR survey and a sag study to confirm that the reconductored circuits would maintain acceptable clearances.
- Upgrade In-Service Date: 6/1/2022
- Estimated Upgrade Cost: $3.30M
- Construction Responsibility: AEP

52) Baseline Upgrade b3118.8

- Overview of Reliability Problem
  - Criteria Violation: Multiple thermal and voltage violations
  - Contingency: Multiple contingencies
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace 20 kA 69 kV circuit breaker ‘F’ at South Neal station with a new 3000A 40 kA 69 kV circuit breaker. Replace line risers towards Leach station.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

53) Baseline Upgrade b3118.9

- Overview of Reliability Problem
  - Criteria Violation: Multiple thermal and voltage violations
  - Contingency: Multiple contingencies
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild 336 ACSR portion of Leach - Miller S.S 69 kV line section (~0.3 miles) with 795 ACSS conductor.
  - Upgrade In-Service Date: 6/1/2022

- Estimated Upgrade Cost: $1.50M
- Construction Responsibility: AEP

54) Baseline Upgrade b3119.1

- Overview of Reliability Problem
  - Criteria Violation: North Portland, Trinity, Berne, South Berne, Monroe and S. Decatur drop below .92 PU
  - Contingency: Loss of Bluff Point – Portland 69 kV and Adams – Berne 69 kV line
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Jay – Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $38.10M
  - Construction Responsibility: AEP

55) Baseline Upgrade b3119.2

- Overview of Reliability Problem
  - Criteria Violation: North Portland, Trinity, Berne, South Berne, Monroe and S. Decatur drop below .92 PU
  - Contingency: Loss of Bluff Point – Portland 69 kV and Adams – Berne 69 kV lines
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Install three (3) 69 kV breakers to create the “U” string and add a low side breaker on the Jay transformer 2
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $3.40M
  - Construction Responsibility: AEP

56) Baseline Upgrade b3119.3

- Overview of Reliability Problem
    - Criteria Violation: North Portland, Trinity, Berne, South Berne, Monroe and S. Decatur drop below .92 PU
    - Contingency: Loss of Bluff Point – Portland 69 kV and Adams – Berne 69 kV lines
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Install two (2) 69 kV breakers at North Portland station to complete the ring and allow for the new line.
    - Upgrade In-Service Date: 6/1/2022
    - Estimated Upgrade Cost: $1.90M
    - Construction Responsibility: AEP

57) Baseline Upgrade b3120

- Overview of Reliability Problem
    - Criteria Violation: Overduty of the Whitpain 230 kV breaker "125"
    - Contingency: Fault at Whitpain station
    - Criteria Test: Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Replace the Whitpain 230 kV breaker "125" with a 63 kA breaker.
    - Upgrade In-Service Date: 6/1/2021
    - Estimated Upgrade Cost: $0.60M
    - Construction Responsibility: PECO

58) Baseline Upgrade b3121

- Overview of Reliability Problem
    - Criteria Violation: Loss of Line #254 results in thermal overloads in accordance with P1, P2, P4, P6 and P7 criteria violations.

- Contingency: Loss of 230 kV Line #254
- Criteria Test: Dominion FERC 715 Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Clubhouse-Lakeview 230 kV Line #254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1047 MVA.
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $27.00M
  - Construction Responsibility: Dominion

59) Baseline Upgrade b3122

- Overview of Reliability Problem
  - Criteria Violation: With Lines #2181 and #2058 removed from service, N-1 loss of Line #218 Everetts – Greensville (Duke Energy Progress) overloads Line #123 Battleboro – Rocky Mount (Duke Energy Progress) (NERC Category P1 – Single Contingency).
  - Contingency: Loss of 230kV Line #2058 & #2181
  - Criteria Test: Dominion FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV Line #2181 and Line #2058 with double circuit steel structures using double circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA.
  - Upgrade In-Service Date: 6/1/2019
  - Estimated Upgrade Cost: $13.00M
  - Construction Responsibility: Dominion

60) Baseline Upgrade b3123

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:

- Criteria Test:

- Overview of Reliability Solution

  - Description of Upgrade: At Sammis 345 kV station: Install a new control building in the switchyard, construct a new station access road, install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes

  - Upgrade In-Service Date: 6/1/2022

  - Estimated Upgrade Cost: $8.00M

  - Construction Responsibility: ATSI

61) Baseline Upgrade b3124

- Overview of Reliability Problem

  - Criteria Violation: FE Technical Standards

  - Contingency:

  - Criteria Test:

- Overview of Reliability Solution

  - Description of Upgrade: Separate metering, station power, and communication at Bruce Mansfield 345 kV station

  - Upgrade In-Service Date: 12/31/2020

  - Estimated Upgrade Cost: $0.40M

  - Construction Responsibility: ATSI

62) Baseline Upgrade b3125

- Overview of Reliability Problem

  - Criteria Violation:

  - Contingency:

  - Criteria Test:

- Overview of Reliability Solution

   - Description of Upgrade: At Davis Bessie 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes
   - Upgrade In-Service Date: 5/31/2020
   - Estimated Upgrade Cost: $1.80M
   - Construction Responsibility: ATSI

63) Baseline Upgrade b3126

- Overview of Reliability Problem
   - Criteria Violation:
   - Contingency:
   - Criteria Test:
- Overview of Reliability Solution
   - Description of Upgrade: At Perry 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and construct a new station access road
   - Upgrade In-Service Date: 6/1/2021
   - Estimated Upgrade Cost: $0.60M
   - Construction Responsibility: ATSI

64) Baseline Upgrade b3127

- Overview of Reliability Problem
   - Criteria Violation:
   - Contingency:
   - Criteria Test:
- Overview of Reliability Solution
   - Description of Upgrade: At Bay Shore 138 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and construct a new station access road.

- Upgrade In-Service Date: 12/31/2021
- Estimated Upgrade Cost: $1.50M
- Construction Responsibility: ATSI

65) Baseline Upgrade b3128

- Overview of Reliability Problem
  - Criteria Violation:
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Relocate 34.5 kV lines from generating station roof R. Paul Smith 138 kV station
  - Upgrade In-Service Date: 12/31/2021
  - Estimated Upgrade Cost: $0.40M
  - Construction Responsibility: APS

66) Baseline Upgrade b3129

- Overview of Reliability Problem
  - Criteria Violation: AEP Technical Standards
  - Contingency:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: At Conesville 138 kV station: Remove line leads to generating units, transfer plant AC service to existing station service feeds in Conesville 345/138 kV yard, and separate and reconfigure protection schemes
  - Upgrade In-Service Date: 12/31/2020
  - Estimated Upgrade Cost: $1.50M
  - Construction Responsibility: AEP

67) Baseline Upgrade b3130

- Overview of Reliability Problem
    - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
    - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
    - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), Rebuild/Reconductor two 34.5 kV circuits (total of 5.5 miles) and install a 2nd 115/34.5 kV transformer (Werner)
    - Upgrade In-Service Date: 6/1/2016
    - Estimated Upgrade Cost: $175.00M
    - Construction Responsibility: JCPL

68) Baseline Upgrade b3130.1

- Overview of Reliability Problem
    - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
    - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
    - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Construct a new 34.5 kV circuit from Oceanview to Allenhurst 34.5 kV (4.0 Miles)
    - Upgrade In-Service Date: 6/1/2016
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: JCPL

69) Baseline Upgrade b3130.10

- Overview of Reliability Problem
    - Criteria Violation: Potential local voltage collapse on the 34.5 kV system

    - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
    - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Install 2nd 115/34.5 kV Transformer at Werner Substation
    - Upgrade In-Service Date: 6/1/2016
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: JCPL

70) Baseline Upgrade b3130.2

- Overview of Reliability Problem
    - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
    - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
    - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Construct a new 34.5 kV circuit from Atlantic to Red Bank 34.5 kV (12.0 Miles)
    - Upgrade In-Service Date: 6/1/2016
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: JCPL

71) Baseline Upgrade b3130.3

- Overview of Reliability Problem
    - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
    - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
    - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution

- Description of Upgrade: Construct a new 34.5 kV circuit from Freneau to Taylor Lane 34.5 kV (6.5 Miles)
- Upgrade In-Service Date: 6/1/2016
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: JCPL

72) Baseline Upgrade b3130.4

- Overview of Reliability Problem
  - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
  - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
  - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 34.5 kV circuit from Keyport to Belford 34.5 kV (6.0 Miles)
  - Upgrade In-Service Date: 6/1/2016
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: JCPL

73) Baseline Upgrade b3130.5

- Overview of Reliability Problem
  - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
  - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
  - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 34.5 kV circuit from Red Bank to Belford 34.5 kV (5.0 Miles)
  - Upgrade In-Service Date: 6/1/2016
  - Estimated Upgrade Cost: $0.00M

- Construction Responsibility: JCPL

74) Baseline Upgrade b3130.6

- Overview of Reliability Problem
  - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
  - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
  - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 34.5 kV circuit from Werner to Clark Street (7.0 Miles)
  - Upgrade In-Service Date: 6/1/2016
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: JCPL

75) Baseline Upgrade b3130.7

- Overview of Reliability Problem
  - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
  - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
  - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 34.5 kV circuit from Atlantic to Freneau (13.0 Miles)
  - Upgrade In-Service Date: 6/1/2016
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: JCPL

76) Baseline Upgrade b3130.8

- Overview of Reliability Problem

        - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
        - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
        - Criteria Test: FE Planning Criteria
    - Overview of Reliability Solution
        - Description of Upgrade: Rebuild/Reconductor the Atlantic - Camp Woods Switch Point (3.5 Miles) 34.5 kV circuit
        - Upgrade In-Service Date: 6/1/2016
        - Estimated Upgrade Cost: $0.00M
        - Construction Responsibility: JCPL

77) Baseline Upgrade b3130.9

- Overview of Reliability Problem
    - Criteria Violation: Potential local voltage collapse on the 34.5 kV system
    - Contingency: Loss of the Atlantic - Red Bank S1033 & T2020 230 kV lines
    - Criteria Test: FE Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild/Reconductor the Allenhurst - Elberon (2.0 Miles) 34.5 kV circuit
    - Upgrade In-Service Date: 6/1/2016
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: JCPL

78) Baseline Upgrade b3131

- Overview of Reliability Problem
    - Criteria Violation: Overload of Haviland - East Lima 138 kV line and overload of the Haviland 1 - Haviland 2 138 kV bus tie
    - Contingency: Multiple contingencies in the winter gen deliv and basecase analysis; Loss of the East Lima - Maddoz 345 kV line with a stuck break at East Lima.

- Criteria Test:

- Overview of Reliability Solution

  - Description of Upgrade: At East Lima and Haviland 138 kV stations, replace line relays and wavetrap on the East Lima-Haviland 138 kV facility.

  - Upgrade In-Service Date: 12/1/2024

  - Estimated Upgrade Cost: $1.50M

  - Construction Responsibility: AEP

79) Baseline Upgrade b3132

- Overview of Reliability Problem

  - Criteria Violation: Overload of LaPorte Junction - New Buffalo 69 kV line

  - Contingency: Loss of: Derby – Cook Thornton 69 kV and Bridgman – Pletcher 69 kV lines; Bridgman – Cook Thoronton 69 kV and Bridgman – Pletcher 69 kV lines; Derby – Cook Thornton 69 kV line and Pletcher 138/69 kV tranformer No.1; or Bridgman – Cook Thoronton 69 kV line and Pletcher 138/69kV transformer No.1

  - Criteria Test: N-1-1 Thermal

- Overview of Reliability Solution

  - Description of Upgrade: Rebuild 3.11 miles of the LaPorte Junction – New Buffalo 69 kV line with 795 ACSR

  - Upgrade In-Service Date: 6/1/2022

  - Estimated Upgrade Cost: $12.30M

  - Construction Responsibility: AEP

80) Baseline Upgrade b3133

- Overview of Reliability Problem

  - Criteria Violation: Botkins 69 kV voltage drop

  - Contingency: Loss of Sidney - Botkins 69 kV line

  - Criteria Test: Voltage Drop

- Overview of Reliability Solution

- Description of Upgrade: Move the existing Botkins 69 kV capacitor from the Sidney-Botkins side of the existing breaker at Botkins to the Botkins-Jackson Center side. This will keep the capacitor in-service for the loss of Sidney-Botkins. This reduces the voltage drop to less than 3% and also resolves the overload on the Blue Jacket Tap-Huntsville 69 kV line.
- Upgrade In-Service Date: 6/1/2024
- Estimated Upgrade Cost: $0.20M
- Construction Responsibility: Dayton

81) Baseline Upgrade b3134

- Overview of Reliability Problem
    - Criteria Violation: MW-Mile criteria (load exposure)
    - Contingency:
    - Criteria Test: ODEC 715 criteria
- Overview of Reliability Solution
    - Description of Upgrade: Build a new single circuit 69 kV overhead from Kellam sub to new Bayview substation (21 miles) and create a line terminal at Belle Haven delivery point (three-breaker ring bus)
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $22.00M
    - Construction Responsibility: ODEC

82) Baseline Upgrade b3134.1

- Overview of Reliability Problem
    - Criteria Violation: MW-Mile criteria (load exposure)
    - Contingency:
    - Criteria Test: ODEC 715 criteria
- Overview of Reliability Solution
    - Description of Upgrade: Reconfigure the Belle Haven 69 kV bus to three-breaker ring bus and create a line terminal for the new 69 kV circuit to Bayview

- Upgrade In-Service Date: 6/1/2019
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: ODEC

83) Baseline Upgrade b3134.2

- Overview of Reliability Problem
    - Criteria Violation: MW-Mile criteria (load exposure)
    - Contingency:
    - Criteria Test: ODEC 715 criteria
- Overview of Reliability Solution
    - Description of Upgrade: Build a new single circuit 69 kV overhead from Kellam sub to new Bayview Substation (21 miles)
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: ODEC

84) Baseline Upgrade b3135

- Overview of Reliability Problem
    - Criteria Violation: Overload and voltage violation on several 138 and 69 kV stations
    - Contingency: P5 contingency Loss of Carson 138 kV station due to relay failure
    - Criteria Test: N-1 Thermal and Voltage
- Overview of Reliability Solution
    - Description of Upgrade: Install back-up relay on the 138 kV bus at Corson substation
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $0.30M
    - Construction Responsibility: AEC

85) Baseline Upgrade b3136

- Overview of Reliability Problem
    - Criteria Violation: Overload on Smith Tap - Smith St. 115 kV
    - Contingency: Middletown Junction 230/115 kV transformer #2 and #5
    - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution
    - Description of Upgrade: Replace bus conductor at Smith 115 kV substation
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $0.15M
    - Construction Responsibility: ME

86) Baseline Upgrade b3137

- Overview of Reliability Problem
    - Criteria Violation: Overload on East Towanda - North Meshoppen 115 kV line
    - Contingency: Single contingency loss of the East Towanda - Canyon - North Meshoppen 230 kV circuit
    - Criteria Test: Generation Deliverability Winter
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild 20 miles of the East Towanda - North Meshoppen 115 kV line
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $58.60M
    - Construction Responsibility: PENELEC

87) Baseline Upgrade b3138

- Overview of Reliability Problem
    - Criteria Violation: Master – Westmoreland East – Pencoyd 69 kV

- Contingency: Line fault stuck breaker contingency loss of Roxborough 230/69 kV transformer and Roxborough – Westmoreland West 69 kV

- Criteria Test: N-1 Thermal and Generation Deliverability

- Overview of Reliability Solution

  - Description of Upgrade: Move 2 MVA load from the Roxborough to Bala substation. Adjust the tap setting on the Master 138/69 kV transformer No.2

  - Upgrade In-Service Date: 6/1/2024

  - Estimated Upgrade Cost: $0.02M

  - Construction Responsibility: PECO

88) Baseline Upgrade b3139

- Overview of Reliability Problem

  - Criteria Violation: Overload of the Garden Creek – Whetstone 69 kV line

  - Contingency: Single contingency loss of Richland - Broadford 138 kV line followed by single contingency loss of the Garden Creek - Shack Mills 138 kV line & single contingency loss of Richlands - Broadford 138 kV line followed by single contingency loss of the Whitewood – Hales Branch 138 kV line.

  - Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution

  - Description of Upgrade: Rebuild the Garden Creek - Whetstone 69 kV line (~4 mile)

  - Upgrade In-Service Date: 6/1/2023

  - Estimated Upgrade Cost: $15.00M

  - Construction Responsibility: AEP

89) Baseline Upgrade b3140

- Overview of Reliability Problem

  - Criteria Violation: Overload of Whetstone - Knox Creek - Coal Creek 69kV line

  - Contingency: Single contingency loss of Richlands - Broadford 138 kV line followed by single contingency loss of the Whitewood – Hales Branch 138 kV line & single contingency loss of Clinch River – Hales Branch 138 kV line followed by single contingency loss of the

Richlands – Whitewood 138 k line.

- Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Whestone - Knox Creek 69 kV line (3.1 mile)
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $9.00M
  - Construction Responsibility: AEP

90) Baseline Upgrade b3141

- Overview of Reliability Problem
  - Criteria Violation: Overload of Whetstone - Knox Creek - Coal Creek 69kV line
  - Contingency: Single contingency loss of Richlands - Broadford 138 kV line followed by single contingency loss of the Whitewood – Hales Branch 138 kV line & single contingency loss of Clinch River – Hales Branch 138 kV line followed by single contingency loss of the Richlands – Whitewood 138 k line.
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Knox Creek - Coal Creek 69 kV line (2.9 mile)
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $9.00M
  - Construction Responsibility: AEP

91) Baseline Upgrade b3142

- Overview of Reliability Problem
  - Criteria Violation: Congestion Relief
  - Contingency: none
  - Criteria Test: Market Efficiency
- Overview of Reliability Solution

- Description of Upgrade: Rebuild Michigan City-Trail Creek - Bosserman 138 kV (10.7 mi)
- Upgrade In-Service Date: 1/1/2023
- Estimated Upgrade Cost: $24.69M
- Construction Responsibility: NIPSCO

92) Baseline Upgrade b3143.1

- Overview of Reliability Problem
  - Criteria Violation: Overload on Silverside – Darley - Naamans
  - Contingency: Tower contingency loss of Edge Moor - Linwood and Edge Moor -Claymont 230 kV circuits
  - Criteria Test: Generation Deliverability (Summer, Winter)
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor the Silverside – Darley 69 kV circuit
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $1.39M
  - Construction Responsibility: DPL

93) Baseline Upgrade b3143.2

- Overview of Reliability Problem
  - Criteria Violation: Overload on Silverside – Darley - Naamans
  - Contingency: Tower contingency loss of Edge Moor - Linwood and Edge Moor -Claymont 230 kV circuits
  - Criteria Test: Generation Deliverability (Summer, Winter)
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor the Darley – Naamans 69 kV circuit
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $2.09M

- Construction Responsibility: DPL

94) Baseline Upgrade b3143.3

- Overview of Reliability Problem
  - Criteria Violation: Overload on Silverside – Darley - Naamans
  - Contingency: Tower contingency loss of Edge Moor - Linwood and Edge Moor -Claymont 230 kV circuits
  - Criteria Test: Generation Deliverability (Summer, Winter)
- Overview of Reliability Solution
  - Description of Upgrade: Replace three (3) existing 1200 A disconnect switches with 2000 A disconnect switches and install three (3) new 2000 A disconnect switches at Silverside 69 kV station
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $0.48M
  - Construction Responsibility: DPL

95) Baseline Upgrade b3143.4

- Overview of Reliability Problem
  - Criteria Violation: Overload on Silverside – Darley - Naamans
  - Contingency: Tower contingency loss of Edge Moor - Linwood and Edge Moor -Claymont 230 kV circuits
  - Criteria Test: Generation Deliverability (Summer, Winter)
- Overview of Reliability Solution
  - Description of Upgrade: Replace two (2) 1200 A disconnect switches with 2000 A disconnect switches, replace existing 954 ACSR and 500 SDCU stranded bus with (2) 954 ACSR stranded bus. Reconfigure four (4) CTs from 1200 A to 2000 A and install two (2) new 2000 A disconnect switches, new (2) 954 ACSR stranded bus at Naamans 69 kV station
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $0.60M

- Construction Responsibility: DPL

96) Baseline Upgrade b3143.5

- Overview of Reliability Problem
    - Criteria Violation: Overload on Silverside – Darley - Naamans
    - Contingency: Tower contingency loss of Edge Moor - Linwood and Edge Moor -Claymont 230 kV circuits
    - Criteria Test: Generation Deliverability (Summer, Winter)
- Overview of Reliability Solution
    - Description of Upgrade: Replace four (4) 1200 A disconnect switches with 2000 A disconnect switces. Replace existing 954 ACSR and 1272 MCM AL stranded bus with (2) 954 ACSR stranded bus. Reconfigure eight (8) CTs from 1200 A to 2000 A and install Four (4) new 2000 A (310 MVA SE / 351 MVA WE) disconnect switches, new (2) 954 ACSR (331 MVA SE / 369 MVA WE) stranded bus at Darley 69 kV station
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $0.95M
    - Construction Responsibility: DPL

97) Baseline Upgrade b3145

- Overview of Reliability Problem
    - Criteria Violation: Congestion Relief
    - Contingency: none
    - Criteria Test: Market Efficiency
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the Hunterstown - Lincoln 115 kV line (No.962) (~2.6 mi.). Upgrade limiting terminal equipment at Hunterstown and Lincoln.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $7.21M
    - Construction Responsibility: MAIT

98) Baseline Upgrade b3146

- Overview of Reliability Problem
    - Criteria Violation: Overduty of Richmond 69kV breaker “140"
    - Contingency: Fault at the Richmond station
    - Criteria Test: Short Circuit
- Overview of Reliability Solution
    - Description of Upgrade: Replace the Richmond 69 kV breaker "140" with 40 kV breaker (b)
    - Upgrade In-Service Date: 6/1/2021
    - Estimated Upgrade Cost: $0.42M
    - Construction Responsibility: PECO

99) Baseline Upgrade b3147

- Overview of Reliability Problem
    - Criteria Violation: instability at TSS 951 Aurora EC units 3 and 4
    - Contingency: Delayed-clearing of three-phase faults at Electric Junction 138kV blue bus on TSS111 Electric Junction 345/138 kV Transformer 81 or 82, or line 11106 or line 11102.
    - Criteria Test: ComEd Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Modify 138 kV blue bus total clearing times at TSS111 Electric Junction to 11 cycles for fault on 345/138 kV Transformer 81, and to 13 cycles for faults on 138 kV Line 11106, 138 kV Line 11102 and 345/138 kV Transformer 82
    - Upgrade In-Service Date: 12/31/2020
    - Estimated Upgrade Cost: $0.25M
    - Construction Responsibility: ComEd

100) Baseline Upgrade b3148.1

- Overview of Reliability Problem

- Criteria Violation: Thermal overload of Bradley – Sun & Tams Mountain – Glen White 46 kV line sections. Voltage magnitude drops at Beckley, Whitestick, Bradley, Mt. Hope and Sun 46 kV buses. Voltage deviations at Sun, Mt. Hope, Bradley, Whitestick, and Beckley 46 kV stations.
- Contingency: Loss Bradley 138/69/46 kV transformer and Pemberton – Beckley 46 kV line
- Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 46 kV Bradley-Scarbro line. The new line will be rebuilt adjacent to the existing one leaving the old line in service until the work is completed. The new 46 kV line will be built with 795 ACSR (120 MVA) and 69 kV standards.
  - Upgrade In-Service Date: 12/1/2021
  - Estimated Upgrade Cost: $22.20M
  - Construction Responsibility: AEP

101) Baseline Upgrade b3148.2

- Overview of Reliability Problem
  - Criteria Violation: Thermal overload of Bradley – Sun & Tams Mountain – Glen White 46 kV line sections. Voltage magnitude drops at Beckley, Whitestick, Bradley, Mt. Hope and Sun 46 kV buses. Voltage deviations at Sun, Mt. Hope, Bradley, Whitestick, and Beckley 46 kV stations.
  - Contingency: Loss Bradley 138/69/46 kV transformer and Pemberton – Beckley 46 kV line
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Bradley remote end station work, replace 46 kV bus, install new 12 MVAR capacitor bank.
  - Upgrade In-Service Date: 12/1/2021
  - Estimated Upgrade Cost: $3.30M
  - Construction Responsibility: AEP

102) Baseline Upgrade b3148.3

- Overview of Reliability Problem
    - Criteria Violation: Thermal overload of Bradley – Sun & Tams Mountain – Glen White 46 kV line sections. Voltage magnitude drops at Beckley, Whitestick, Bradley, Mt. Hope and Sun 46 kV buses. Voltage deviations at Sun, Mt. Hope, Bradley, Whitestick, and Beckley 46 kV stations.
    - Contingency: Loss Bradley 138/69/46 kV transformer and Pemberton – Beckley 46 kV line
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: The switch at Sun Station will be replaced with a 2-way SCADA-controlled MOAB switch
    - Upgrade In-Service Date: 12/1/2021
    - Estimated Upgrade Cost: $0.90M
    - Construction Responsibility: AEP

103) Baseline Upgrade b3148.4

- Overview of Reliability Problem
    - Criteria Violation: Thermal overload of Bradley – Sun & Tams Mountain – Glen White 46 kV line sections. Voltage magnitude drops at Beckley, Whitestick, Bradley, Mt. Hope and Sun 46 kV buses. Voltage deviations at Sun, Mt. Hope, Bradley, Whitestick, and Beckley 46 kV stations.
    - Contingency: Loss Bradley 138/69/46 kV transformer and Pemberton – Beckley 46 kV line
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Remote end work and associated equipment at Scarbro Station.
    - Upgrade In-Service Date: 12/1/2021
    - Estimated Upgrade Cost: $1.30M
    - Construction Responsibility: AEP

104) Baseline Upgrade b3148.5

- Overview of Reliability Problem
    - Criteria Violation: Thermal overload of Bradley – Sun & Tams Mountain – Glen White 46 kV line sections. Voltage magnitude drops at Beckley, Whitestick, Bradley, Mt. Hope and Sun 46 kV buses. Voltage deviations at Sun, Mt. Hope, Bradley, Whitestick, and Beckley 46 kV stations.
    - Contingency: Loss Bradley 138/69/46 kV transformer and Pemberton – Beckley 46 kV line
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Retire Mt. Hope Station and transfer load to existing Sun Station.
    - Upgrade In-Service Date: 12/1/2021
    - Estimated Upgrade Cost: $0.00M
    - Construction Responsibility: AEP

105) Baseline Upgrade b3149

- Overview of Reliability Problem
    - Criteria Violation: Overload of the Decatur – South Decatur 69kV circuit
    - Contingency: Loss of Marathon – Limberlost 69 kV and Adams – Berne 69 kV
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the 2.3 mile Decatur – South Decatur 69 kV line using 556 ACSR in order to alleviate the overloads.
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $9.30M
    - Construction Responsibility: AEP

106) Baseline Upgrade b3150

- Overview of Reliability Problem
    - Criteria Violation: Overload of the Hillcrest – Ferguson 69 kV line to 107.7% of the 54 MVA 4/0 CU conductor rating. The line is also overloaded for multiple other contingency pairs.
    - Contingency: Loss of Desoto – Jay 138 kV and Magley – Allen 138 kV lines
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild Ferguson 69/12 kV station in the clear as the 138/12 kV Bear station and connect it to a ~1 mile double circuit 138 kV extension from the Aviation – Ellison Rd 138 kV line to remove the load from the 69 kV line.
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $6.40M
    - Construction Responsibility: AEP

107) Baseline Upgrade b3151

- Overview of Reliability Problem
    - Criteria Violation:
    - Contingency:
    - Criteria Test:
- Overview of Reliability Solution
    - Description of Upgrade: Western Fort Wayne Improvements
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: M
    - Construction Responsibility: AEP

108) Baseline Upgrade b3151.1

- Overview of Reliability Problem

- Criteria Violation: Numerous overloads, voltage violations
- Contingency: Loss of multiple lines under N-1-1 conditions
- Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the ~30 mile Gateway – Wallen 34.5 kV circuit as the ~27 mile Gateway – Wallen 69 kV circuit.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $43.30M
  - Construction Responsibility: AEP

109) Baseline Upgrade b3151.10

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 2.5 mile Columbia – Gateway 69 kV line.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $6.20M
  - Construction Responsibility: AEP

110) Baseline Upgrade b3151.11

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Columbia station in the clear as a 138/69 kV station with two (2) 138/69 kV transformers and 4-breaker ring buses on the high and low side. Station will reuse 69 kV breakers “J” & “K” and 138 kV breaker “D”.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $15.00M
  - Construction Responsibility: AEP

111) Baseline Upgrade b3151.12

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 13 mile Columbia – Richland 69 kV line.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $29.30M
  - Construction Responsibility: AEP

112) Baseline Upgrade b3151.13

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 0.5 mile Whitley – Columbia City No.1 line as 69 kV.
  - Upgrade In-Service Date: 6/1/2024

- Estimated Upgrade Cost: $1.00M
- Construction Responsibility: AEP

113) Baseline Upgrade b3151.14

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 0.5 mile Whitley – Columbia City No.2 line as 69 kV.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $0.70M
  - Construction Responsibility: AEP

114) Baseline Upgrade b3151.15

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 0.6 mile double circuit section of the Rob Park – South Hicksville / Rob Park – Diebold Road as 69 kV
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $1.00M
  - Construction Responsibility: AEP

115) Baseline Upgrade b3151.2

- Overview of Reliability Problem
    - Criteria Violation: Numerous overloads, voltage violations
    - Contingency: Loss of multiple lines under N-1-1 conditions
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Retire the ~3 miles Columbia – Whitley 34.5 kV line.
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $0.50M
    - Construction Responsibility: AEP

116) Baseline Upgrade b3151.3

- Overview of Reliability Problem
    - Criteria Violation: Numerous overloads, voltage violations
    - Contingency: Loss of multiple lines under N-1-1 conditions
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: At Gateway station, remove all 34.5 kV equipment and install one 69 kV circuit breaker for the new Whitley line entrance.
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $1.00M
    - Construction Responsibility: AEP

117) Baseline Upgrade b3151.4

- Overview of Reliability Problem
    - Criteria Violation: Numerous overloads, voltage violations

- Contingency: Loss of multiple lines under N-1-1 conditions
- Criteria Test: AEP Planning Criteria

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Whitley as a 69 kV station with two (2) line and one (1) bus tie circuit breakers.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $4.20M
  - Construction Responsibility: AEP

118) Baseline Upgrade b3151.5

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Union 34.5 kV switch with a 69 kV switch structure.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $0.60M
  - Construction Responsibility: AEP

119) Baseline Upgrade b3151.6

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution

- Description of Upgrade: Replace the Eel River 34.5 kV switch with a 69 kV switch structure.
- Upgrade In-Service Date: 6/1/2024
- Estimated Upgrade Cost: $0.60M
- Construction Responsibility: AEP

120) Baseline Upgrade b3151.7

- Overview of Reliability Problem
    - Criteria Violation: Numerous overloads, voltage violations
    - Contingency: Loss of multiple lines under N-1-1 conditions
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Install a 69 kV Bobay switch at Woodland Station.
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $0.60M
    - Construction Responsibility: AEP

121) Baseline Upgrade b3151.8

- Overview of Reliability Problem
    - Criteria Violation: Numerous overloads, voltage violations
    - Contingency: Loss of multiple lines under N-1-1 conditions
    - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two (2) line circuit breakers, one (1) bus tie circuit breaker and a 14.4 Mvar cap bank
    - Upgrade In-Service Date: 6/1/2024
    - Estimated Upgrade Cost: $8.70M

- Construction Responsibility: AEP

122) Baseline Upgrade b3151.9

- Overview of Reliability Problem
  - Criteria Violation: Numerous overloads, voltage violations
  - Contingency: Loss of multiple lines under N-1-1 conditions
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Remove 34.5 kV circuit breaker "AD" at Wallen station.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $0.30M
  - Construction Responsibility: AEP

123) Baseline Upgrade b3152

- Overview of Reliability Problem
  - Criteria Violation: Thermal overload of the Leroy Center - Pawnee 138 kV Tap
  - Contingency: Loss of the Juniper – Northfield 138 kV and Nash – Painesville 138 kV lines
  - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor the 8.4 mile section of the Leroy Center - Mayfield Q1 line between Leroy Center - Pawnee Tap to achieve a rating of at least 160 MVA / 192 MVA (SN/SE).
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $14.10M
  - Construction Responsibility: ATSI

124) Baseline Upgrade b3153

- Overview of Reliability Problem

- Criteria Violation: MW-Mile criteria (load exposure)
- Contingency: N/A
- Criteria Test: TO Criteria: MW-Mile

- Overview of Reliability Solution
  - Description of Upgrade: Construct a greenfield 0.3 mile 138 kV double circuit line tapping the Beaver-Black River (ATSI) 138 kV line; Install five (5) monopole 138 kV double circuit steel structures with concrete foundations and string 1590 ACSR conductor.
    Expand the Amherst No.2 substation with the installation of three (3) 138 kV circuit breakers; one (1) 138/69/12 kV 130 MVA transformers; two (2) 69 kV circuit breaker.
    Install one (1) 69 kV breaker towards Nordson.
  - Upgrade In-Service Date: 6/1/2020
  - Estimated Upgrade Cost: $7.50M
  - Construction Responsibility: AMPT

125) Baseline Upgrade b3154

- Overview of Reliability Problem
  - Criteria Violation: Low voltage violations at Yeagertown, Logan, Mcveytwn, Maitland, and Atknson 46 kV stations, in the Winter study.
  - Contingency: Loss of the Yeagertown 230/46 kV transformer No.4
  - Criteria Test: FE FERC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Install one (1) 13.2 MVAR 46 kV capacitor at the Logan substation
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $1.70M
  - Construction Responsibility: PENELEC

126) Baseline Upgrade b3156

- Overview of Reliability Problem
  - Criteria Violation: N-1-1 Summer Thermal

- Contingency:
- Criteria Test: N-1-1

- Overview of Reliability Solution
  - Description of Upgrade: Replace line relaying and fault detector on the Wylie Ridge terminal at Smith 138 kV Substation
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $0.85M
  - Construction Responsibility: APS

127) Baseline Upgrade b3157

- Overview of Reliability Problem
  - Criteria Violation: Generator Deliverability
  - Contingency:
  - Criteria Test: Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace line relaying and fault detector relaying at Messick Rd. and Morgan 138 kV substations; Replace wave trap at Morgan 138 kV substation
  - Upgrade In-Service Date: 12/1/2024
  - Estimated Upgrade Cost: $0.23M
  - Construction Responsibility: APS

128) Baseline Upgrade b3158

- Overview of Reliability Problem
  - Criteria Violation: N-1-1 Summer Thermal
  - Contingency:
  - Criteria Test: N-1-1
- Overview of Reliability Solution

- Description of Upgrade: Replace line relays on the Ridgeley line terminal at Messick Rd. 138 kV substation
- Upgrade In-Service Date: 12/1/2024
- Estimated Upgrade Cost: $0.14M
- Construction Responsibility: APS

129) Baseline Upgrade b3159

- Overview of Reliability Problem
  - Criteria Violation: TO Crtieria
  - Contingency:
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Build a new 138/69 kV substation. Install one (1) 138 kV circuit breaker, one (1) 138/69 kV 130 MVA transformer, three (3) 69 kV circuit breakers. Build a 0.15 mile 138 kV 795 ACSR transmission line between the FE Brim 138/69 kV substation and the newly proposed AMPT substation (three steel poles). Loop the Bowling Green Sub No.5 – Bowling Green Sub No.2 69 kV lines in and out of the newly established substation.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $5.70M
  - Construction Responsibility: AMPT

130) Baseline Upgrade b3160.1

- Overview of Reliability Problem
  - Criteria Violation: AEP Planning Criteria
  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.
  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage
- Overview of Reliability Solution

- Description of Upgrade: Construct a ~2.4 mile double circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network.

- Upgrade In-Service Date: 6/1/2024

- Estimated Upgrade Cost: $6.00M

- Construction Responsibility: AEP

131) Baseline Upgrade b3160.2

- Overview of Reliability Problem

  - Criteria Violation: AEP Planning Criteria

  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.

  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage

- Overview of Reliability Solution

  - Description of Upgrade: Retire the ~2.5 mile 34.5 kV Niles – Simplicity Tap line.

  - Upgrade In-Service Date: 6/1/2024

  - Estimated Upgrade Cost: $1.20M

  - Construction Responsibility: AEP

132) Baseline Upgrade b3160.3

- Overview of Reliability Problem

  - Criteria Violation: AEP Planning Criteria

  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.

  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage

- Overview of Reliability Solution

  - Description of Upgrade: Retire the ~4.6 mile Lakehead 69 kV Tap

- Upgrade In-Service Date: 6/1/2024
- Estimated Upgrade Cost: $1.40M
- Construction Responsibility: AEP

133) Baseline Upgrade b3160.4

- Overview of Reliability Problem
  - Criteria Violation: AEP Planning Criteria
  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.
  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage
- Overview of Reliability Solution
  - Description of Upgrade: Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $4.00M
  - Construction Responsibility: AEP

134) Baseline Upgrade b3160.5

- Overview of Reliability Problem
  - Criteria Violation: AEP Planning Criteria
  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV

    lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.
  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the ~1.2 mile Buchanan South 69 kV Radial Tap using 795 ACSR

- Upgrade In-Service Date: 6/1/2024
- Estimated Upgrade Cost: $3.00M
- Construction Responsibility: AEP

135) Baseline Upgrade b3160.6

- Overview of Reliability Problem
  - Criteria Violation: AEP Planning Criteria
  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.
  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the ~8.4 mile 69 kV Pletcher – Buchanan Hydro line as the ~9 mile Pletcher – Buchanan South 69 kV line using 795 ACSR.
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $20.00M
  - Construction Responsibility: AEP

136) Baseline Upgrade b3160.7

- Overview of Reliability Problem
  - Criteria Violation: AEP Planning Criteria
  - Contingency: N-1 loss of the Niles 69/34 kV transformer, Niles 69kV bus or any of the Niles 69kV breakers: N-1-1 loss of: Pokagon – Lake Street & South Bend – Niles 69 kV lines, Niles 69/34.5 kV transformer & tPokagon 138/69 kV transformer, or Lake Street 69/34 kV transformer & South Bend – Niles 69kV line.
  - Criteria Test: N-1 thermal and N-1-1 thermal and voltage
- Overview of Reliability Solution
  - Description of Upgrade: Install a PoP switch at Buchanan South station with 2 line Moabs.
  - Upgrade In-Service Date: 6/1/2024

- Estimated Upgrade Cost: $0.60M
- Construction Responsibility: AEP

137) Baseline Upgrade b3207

- Overview of Reliability Problem
  - Criteria Violation: Overload of Beatty - Adkins 345 kV
  - Contingency:
  - Criteria Test: Generator Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Beatty-Adkins: Replace station conductor at Adkins station and perform a sag study on the line. Note that results from the sag study could cover a wide range of outcomes, from no work required to a complete rebuild.
  - Upgrade In-Service Date: 6/2/2020
  - Estimated Upgrade Cost: $1.50M
  - Construction Responsibility: AEP

138) Baseline Upgrade b3208

- Overview of Reliability Problem
  - Criteria Violation: Multiple thermal and voltage violations in the Winter peak case
  - Contingency: Multiple continguencies
  - Criteria Test: AEP Planning Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Retire approximately 38 miles of the 44 mile Clifford-Scottsville 46 kV circuit. Build new 138 kV "in and out" to two new Distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Construct new 138 kV lines from Joshua Falls-Riverville (~10 mi.) and Riverville-Gladstone (~5 mi.). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen – Monroe 69 kV (~4 mi.)
  - Upgrade In-Service Date: 12/1/2022
  - Estimated Upgrade Cost: $85.00M

- Construction Responsibility: AEP

139) Baseline Upgrade b3209

- Overview of Reliability Problem
  - Criteria Violation: Overloads of the Berne-Monroe and Monroe-South Decatur 69 kV lines
  - Contingency: Loss of the Magley-Decatur 69 kV line and the Lincoln 138/69/34.5 kV transformer
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 10.5 mile Berne – South Decatur 69 kV line using 556 ACSR in order to alleviate the overload and address a deteriorating asset.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $16.60M
  - Construction Responsibility: AEP

140) Baseline Upgrade b3210

- Overview of Reliability Problem
  - Criteria Violation: Overload of the Beatty-Galloway 69 kV line
  - Contingency: loss of the Trabue 138/69 kV transformer No.3 or Nautilus – Trabue 69 kV circuit
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Replace approx. 0.7 miles Beatty - Galloway 69 kV line with 4000 kcmil XLPE cable
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $5.30M
  - Construction Responsibility: AEP

141) Baseline Upgrade b3211

- Overview of Reliability Problem
    - Criteria Violation: Thermal overloads in accordance with P6 NERC criteria violations.
    - Contingency: Loss of 500 kV line No.569
    - Criteria Test: Dominion FERC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild the 1.3 mile section of 500 kV Line No.569 (Loudoun - Morrisville) with single-circuit 500 kV structures at the current 500 kV standard. This will increase the rating of the line to 3424 MVA.
    - Upgrade In-Service Date: 6/1/2019
    - Estimated Upgrade Cost: $4.50M
    - Construction Responsibility: Dominion

Deactivation Analysis: Mansfield 1, 2 and 3; Eastlake 6; Sammis Diesel, Sammis 5, 6, and 7

Baseline Projects: b3061, b3062, b3063, b3064, b3065, b3066, b3067, b3068, b3069, b3070, b3071, b3072, b3073, b3074, b3075, b3076, b3077, b3078, b3079, b3080, b3081, b3082, b3083, b3084, b3085 –On August 28, 2018, PJM received the following generator deactivation notices from First Energy Nuclear, as shown on **Map 5**:

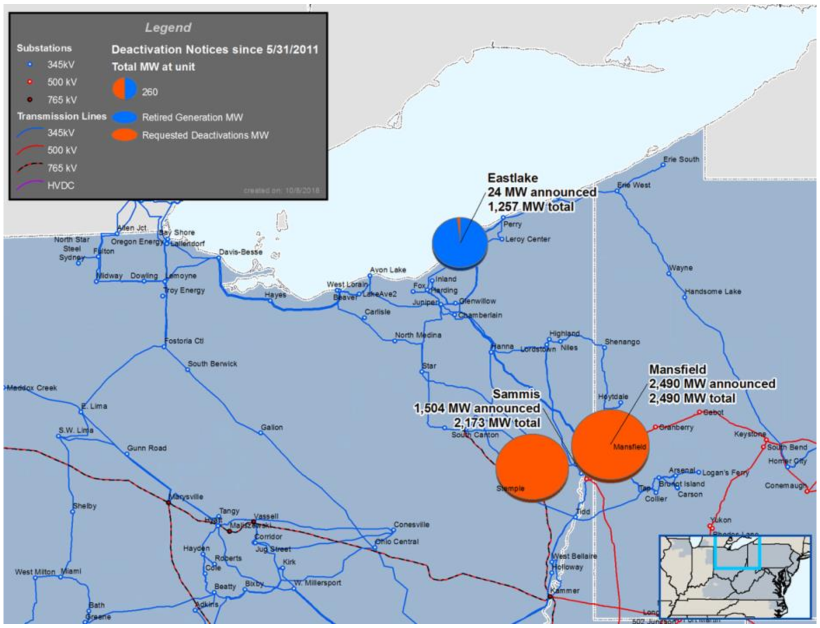
•Bruce Mansfield Units 1, 2 and 3 (ATSI) – 2490 MW – Deactivation Date = June 1, 2021

•Eastlake Unit 6 (ATSI) – 24 MW – Deactivation Date = June 1, 2021

•Sammis Diesel (ATSI) – 13 MW – Deactivation Date = June 1, 2021

•Sammis 5,6 and 7 (ATSI) – 1491 MW – Deactivation Date = June 1, 2019

Map 5. Mansfield, Eastlake, and Sammis



PJM conducted reliability analyses to identify the impacts of the announced Mansfield, Eastlake, and Sammis retirements. Based on those analyses, PJM determined the transmission system enhancements needed for the units to retire as requested without causing reliability criteria violations. Removing Mansfield, Eastlake and Sammis generation from service caused reliability criteria violations in the AEP, APS, ATSI, Duquesne and Penelec transmission zones. In particular, generator deliverability violations were identified on 500 kV, 345 kV, and 138 kV facilities in the Yukon, Elrama, Dravosburg and Route 51 areas of those zones. PJM has determined that the following baseline transmission projects solve identified impacts such that these units can retire as scheduled. PJM can implement operational measures to bridge any delays between actual retirements and transmission actual in-service dates.

Existing Baseline Project Scope Changes Driven by Deactivations

A modification to the scope of one existing RTEP baseline project – shown in **Table 9** – is required to address identified reliability violations driven by the deactivations.

Table 9. **Existing Baseline Project Scope Changes Driven by Deactivations**

UpgradeId	Description	TransmissionOwner	RequiredInServiceDate
b3012	Modify the scope of existing baseline project b3012 - Construct new ties from Elrama - Route 51 - to construct two separate lines on two separate sets of structures	ATSI/DLCO	6/1/2021

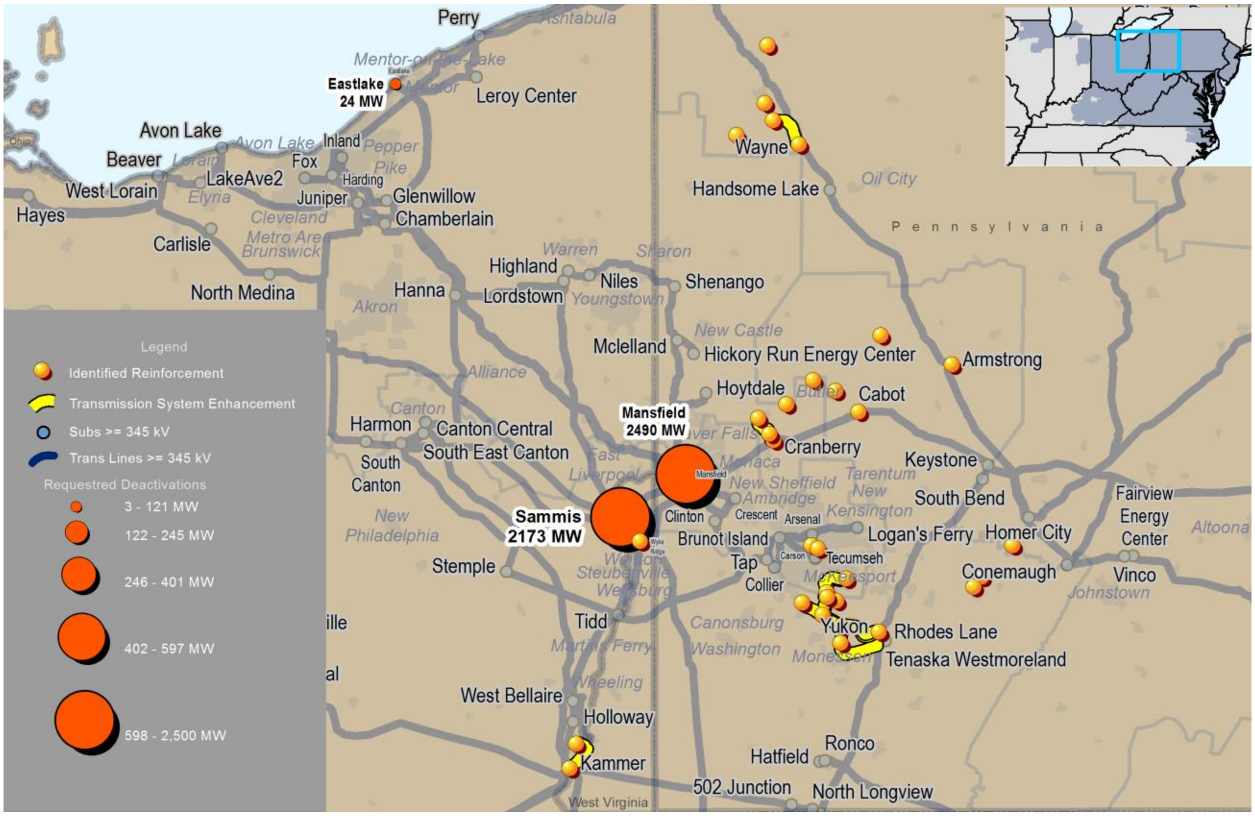
New Baseline Projects Driven by Deactivations

PJM recommends the new baseline projects in **Table 10** and shown on **Map 6** for inclusion in the RTEP to address identified reliability violations driven by the deactivations. The 25 new projects total $122.24 million. The localtransmission owners AEP, APS ATSI, Duquesne and Penelec, as shown above, will be designated to complete this work.

Table 10. New Baseline Projects Driven by Deactivations

Baseline Upgrade ID	Description	TransmissionOwner	RequiredInServiceDate
b3085	Reconductor Kammer - George Washington 138 kV line (~0.08 miles). Replace the wave trap at Kammer 138 kV.	AEP	6/1/2022
b3075	Replace the 500/138 kV transformer breaker and bus conductor at Cabot substation	APS	6/1/2022
b3084	Reconductor the Oakland - Panther Hollow 138 kV line	DL	6/1/2022
b3083	Replace bus conductor at Butler 138 kV and replace bus conductor and line trap at Karns City 138 kV	APS	6/1/2022
b3082	Construct 4-breaker ring bus at Geneva 115 kV	PENELEC	6/1/2022
b3081	Replace breaker and bus conductor at Krendale 138 kV	ATSI	6/1/2022
b3080	Replace bus conductor	ATSI	6/1/2022
b3079	Replace the Wylie Ridge #7 500/345 kV transformer	APS	6/1/2022
b3078	Replace the line trap, relays, bus conductor at Morgan Street 138 kV bus. Replace bus conductor at Venango Junction 138 kV.	PENELEC	6/1/2022
b3077	Reconductor the Franklin Pike B - Wayne 115 kV line (6.78 miles)	PENELEC	6/1/2022
b3076	Reconductor the Edgewater - Loyalhanna (0.67 miles) and upgrade terminals	APS	6/1/2022
b3074	Replace bus conductor at Armstrong substation	APS	6/1/2022
b3073	Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor	PENELEC	6/1/2022
b3072	Reconductor the Yukon - Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV	APS	6/1/2022
b3071	Reconductor the Yukon - Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV	APS	6/1/2022
b3070	Reconductor the Yukon - Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV	APS	6/1/2022
b3069	Reconductor the Westraver - Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV	APS	6/1/2022
b3068	Reconductor the Yukon - Westraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Westraver 138 kV	APS	6/1/2022
b3067	Reconductor the Jackson - Maple 138 kV line (4.7 miles), replace line switches at Jackson 138 kV and replace the line traps and relays at Maple 138 kV	ATSI	6/1/2022
b3066	Reconductor the Cranberry - Jackson 138 kV line (2.1 miles), replace bus conductor at Cranberry 138 kV and replace line switches at Jackson 138 kV	ATSI	6/1/2022
b3065	Add Wilson tie breaker	DL	6/1/2022
b3064	Expand Elrama 138 kV substation to loop in the existing USS Steel Clariton - Piney Fork 138 kV line	DL	6/1/2022
b3063	Reconductor the Wilson - Dravosburg (Z-72) 138 kV line	DL	6/1/2022
b3062	Add West Mifflin 138 kV tie breaker	DL	6/1/2022
b3061	Reconductor the West Mifflin - Dravosburg (Z-73) and Dravosburg - Elrama (Z-75) 138 kV lines	DL	6/1/2022

Map 6. RTEP Baseline Projects Driven by Deactivation of Mansfield 1, 2 and 3; Eastlake 6; Sammis Diesel, Sammis 5, 6, and 7



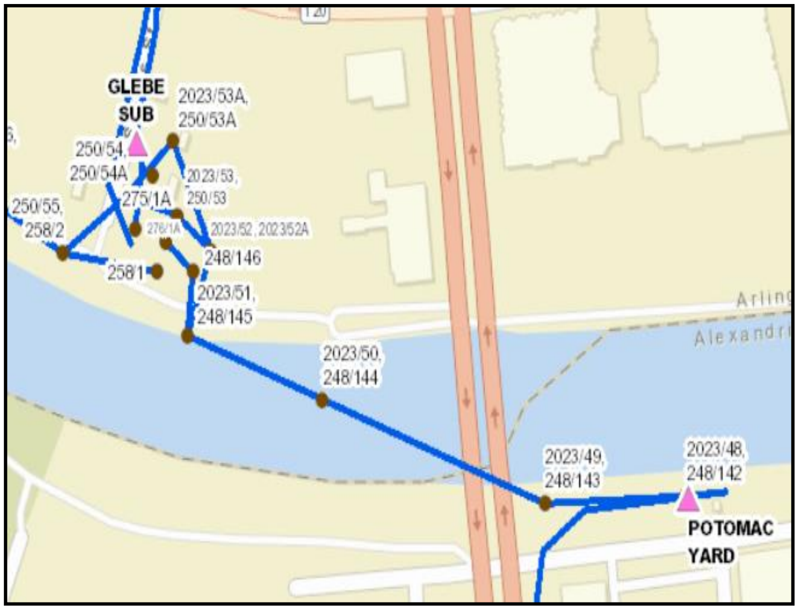
Baseline Project b3090: Potomac Yards North Special Use Permit Expiration

Dominion Transmission Zone – TO Operational Performance

The special use permit (SUP) issued by the City of Alexandria for Potomac Yards North substation will expire on January 1, 2021. The City has indicated they will not extend, nor renew, the permit, which will require the removal of the Potomac Yards North-Glebe 230 kV lines. Reliability studies indicate that doing so will cause numerous NERC criteria violations and significant load loss in the Arlington/Alexandria area.

Absent renewal of the SUP, PJM's recommended solution – Baseline Project b3090 – is to convert the overhead portion of the Potomac Yards North-Glebe 230 kV Lines to underground and convert the Glebe substation to gas insulated equipment. Doing so will create the additional space requirements of the two underground cable termination points and convert the existing substation to configuration into a breaker-and-a-half scheme. The estimated cost for this immediate need project is $120 million. The local transmission owner, Dominion, will be designated to complete this work.

Map 7. Potomac Yards and Glebe Substations



Dominion Transmission Zone End-of-lie 230 kV Line Rebuilds

Baseline Projects b3059, b3060, b3089

Three 230 kV lines in the Dominion Transmission zone are at a point that they violate Dominion's FERC Form No. 715 filed "End of Life Criteria", Section C.2.9 regarding age and facility condition, including towers:

1. Loudoun-Elklick 230 kV Line
2. Elklick-Bull Run 230 kV Line
3. Lanexa-Northern Neck 230 kV line

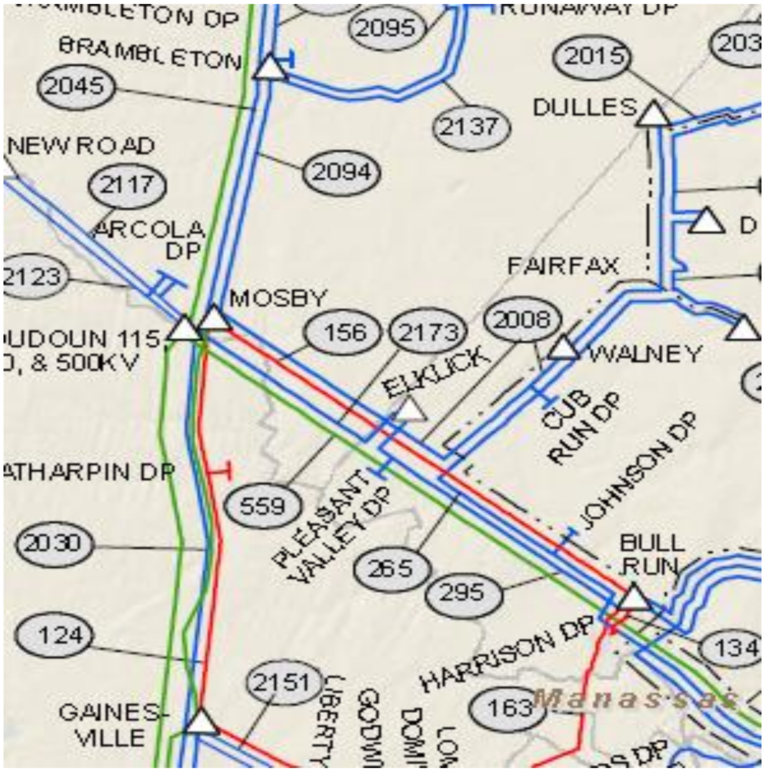
The lines were built in the 1960s using Cor-Ten lattice and wood H-frame towers and now exhibit a number of aging issues that violate Dominion criteria.

Loudoun- to Elklick 230 kV Line

The towers on along this 4.18 miles line – shown on **Map 8 -** show inherent corrosion problems, subjecting steel members to continuous deterioration. This line is part of the network feeding 100 MW of load at Elklick substation. Removing the line from service creates numerous N-1-1 thermal violations on the transmission system.

Recommended solution – Baseline Project b3059: Rebuild Loudoun–Elklick 230 kV with double circuit steel structures with a single circuit conductor at current 230kV standards with a minimum rating of 1200 MVA. This project is estimated to cost $13.5 million. The local transmission owner, Dominion, will be designated to complete this work.

Map 8. Elklick–Loudoun 230 kV line

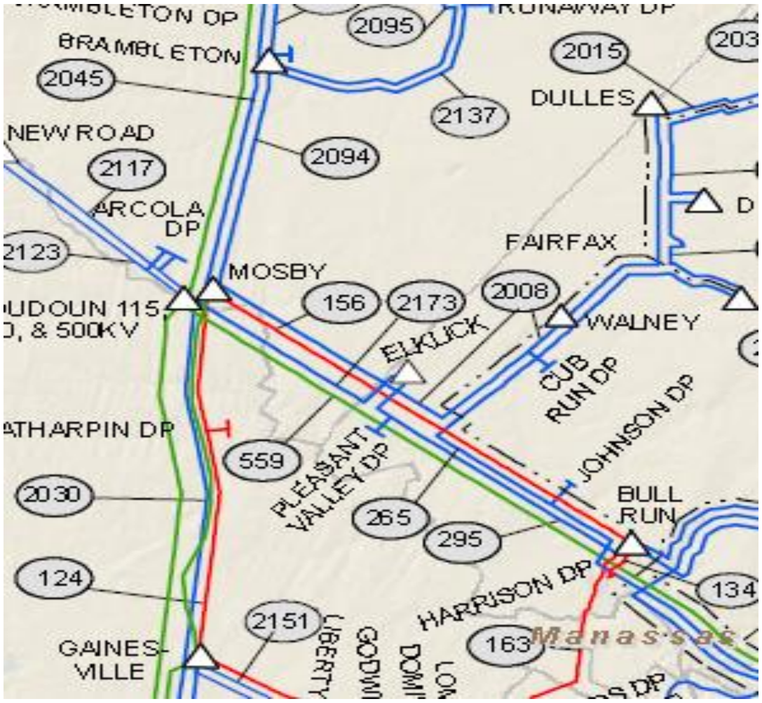


Elklick-Bull Run 230 kV Line

A 3.85 mile long section of the Clifton-Walney 230 kV line is on the same structures as the 4.64 mile long Elklick-Bull Run line, as shown on **Map 9**. show inherent corrosion problems subjecting steel members to continuous deterioration. The line must be rebuilt to solve Dominion end-of-life criteria violations. Removing these lines from service creates numerous N-1-1 thermal and voltage violations on the transmission system.

Recommended solution – Baseline Project b3060:Rebuild Elklick–Bull Run and Clifton–Walney 230 kV lines using double circuit steel structures and double circuit conductor, at current 230 kV standards, with a minimum rating of 1200 MVA. This project is estimated to cost $15.5 million. The local transmission owner, Dominion, will be designated to complete this work.

Map 9. Elklick–Bull Run 230 kV line



Lanexa-Northern Neck 230 kV Line

The current state of this 41 mile long line - shown on **Map 10 -** violates industry guidelines: equipment life for wood structures is 35-55 years, for steel structures is 40 to 60 years, for conductor and connectors is 40-60 years, and for porcelain insulators is 50 years. The line provides network transmission service to over 7,500 customers at Dunnsville substation, including over 4,650 Co-op customers at Howerton. Removing the line causes over 300 MW load loss under N-1-1 conditions.

Recommended solution – Baseline Project b3089: Rebuild Lanexa-Northern Neck line utilizing double circuit structures to current 230kV standards, stringing only one side of the towers. This project is estimated to cost $86 million. The local transmission owner, Dominion, will be designated to complete this work.

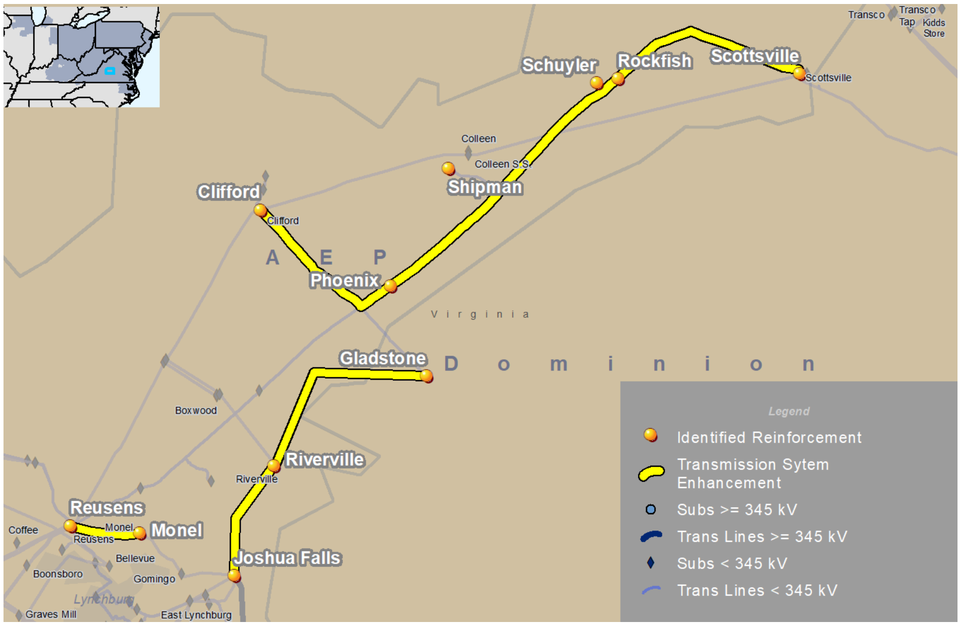
Map 10. Lanexa-Northern Neck 230 kV line

Baseline Project b3208: Clifford – Scottsville, VA Area

AEP Transmission Zone

In the 2022 PJM Winter RTEP case, PJM identified both thermal and voltage violations of AEP's Transmission Owner criteria. For the loss of both 138/46 kV transformers at Scottsville, the Clifford 138/69-46 kV transformer; the Clifford – Gladstone Tap 46 kV and the Gladstone Tap - Phoenix 46 kV line sections exceed their emergency ratings. In addition, all the 46 kV busses served by the Clifford-Scottsville 46 kV circuit experience extreme low voltage magnitude and drop violations resulting in a voltage collapse scenario. The 46 kV bus voltage violations include Scottsville, Esmont, Rockfish, Schuyler, Shipman, Phoenix, Gladstone, Clifford, and Piney River. Additionally, for the loss of both Clifford 138/69-46 kV transformers the Scottsville 138/46 kV transformer No. 5 exceeds its emergency rating and the same 46 kV bus voltages served by the Clifford – Scottsville 46 kV circuit experience extreme low voltage magnitude and drop violations.

Map 11. Clifford - Scottsville, VA Area



The recommended solution – Baseline Project b3208 – to address the Transmission Owner planning criteria violations has several components. The solution retires approximately 38 miles of the 44 mile long Clifford – Scottsville 46 kV circuit and builds two new distribution stations, along the Clifford-Scottsville line to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Additional components of this solution include new 138 kV lines from Joshua Falls to Riverville (approximately 10 miles) and Riverville to Gladstone (approximately 5 miles), and associated terminal equipment at Joshua Falls, Riverville, and Gladstone stations to accommodate the new 138 kV circuits. The project also includes the rebuild of Reusen – Monroe 69 kV (approximately 4 miles).

There are also supplemental needs in the area that were evaluated together with the baseline violations. The supplemental needs in the area are driven by equipment condition for the Amherst – Clifford 69 kV and Clifford – Scottsville 46 kV circuits. The lines were built in 1960 and 1926 respectively, on wood pole structures and have many open conditions due to rot, woodpecker/insect damage, split poles, broken insulators, and damaged shield wire. The recommended solution addresses both the baseline and supplemental needs in the area and is the most cost effective. The estimated cost for this project is $85 million, and the required in-service date is December, 2022. Based on their FERC 715 TO Criteria, the local transmission owner, AEP, will be designated to complete this work.

Increased Real-Time Operational Capability

AEP and Dayton Transmission Zones

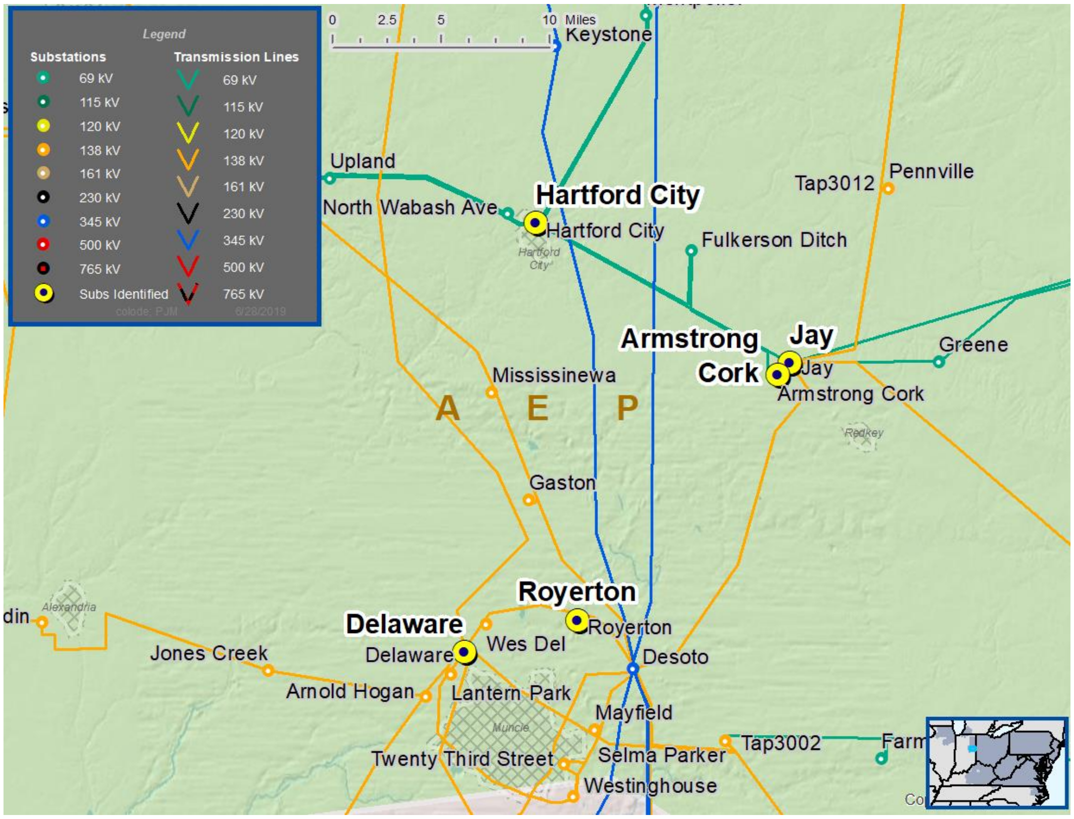
PJM worked closely with the AEP and Dayton to develop the following baseline upgrades to address operational performance and increase real-time operational capability:

- Baseline upgrade b3103 (Hartford City, IN area improvements) in AEP
- Baseline upgrade b3108 (Install 100 MVAR reactors at Miami, Sugarcreek, and Hutchings 138 kV stations) in Dayton

Baseline Project b3103: Hartford City, IN Area Improvements

In the 2022 and 2023 Summer RTEP case, following the correction of the Armstrong Cork load model (increase of approximately 10MW), PJM identified thermal violations of AEP's Transmission Owner criteria. For the loss of the Jay and Deer Creek 138/69/34.5kV banks, the Delaware – Bosman 34.5kV and Bosman – Hartford 34.5kV circuits are overloaded. Additionally, for the loss of the Deer Creek 138/69/34.5kV transformer and Bosman – Delaware 34.5kV line, the Armstrong Cork – Fulkerson 69kV and Fulkerson – 3M 69 kV circuits are overloaded. These issues were validated by the high number of Post Contingency Local Load Relief Warnings (PCLLRWs) in the area. This area has received PCLLRW's on February 26, 2018 (two different instances on this day due to Deer Creek 138/69/34.5kV transformer being out of service); February 6, 2018; January 9, 2018; July 24, 2017; and July 14, 2017 for the loss of Jay transformer with several of these PCLLRW's lasting multiple days. PJM worked closely with AEP and Operations to review the issues to develop the recommended solution.

Map 12. Hartford City, Indiana Area



The recommended solution – Baseline Project b3103 – to address the Transmission Owner planning criteria violations and real-time operational issues has several components that affect the following stations and lines:

- <u>Royerton</u>: Install a 138/69kV transformer. Install a 69kV bus with one 69kV breaker toward Bosman station. Rebuild the 138kV portion into a ring bus configuration built for future breaker and a half with 4 138kV breakers.
- <u>Bosman/Strawboard</u>: Rebuild this station in the clear across the road to move it out of the flood plain and bring it up to 69kV standards.
- <u>Delaware</u>: Retire Breaker L and re-purpose M for the Jay line.
- <u>Hartford City</u>: Retire all 34.5kV equipment. Re-purpose breaker M for the Bosman line 69kV exit.
- <u>Jay</u>: Rebuild the 138kV portion of this station as a 6 breaker, breaker and a half station re-using the existing breakers “A”, “B” and “G”. Rebuild the 69kV portion of this station as a 6 breaker ring bus re-using the 2 existing 69kV breakers. Install a new 138/69kV transformer.
- <u>Hartford City – Jay</u>: Rebuild the 69kV Hartford City – Armstrong Cork line but instead of terminating it into Armstrong Cork, terminate it into Jay station.
- <u>Armstrong Cork – Jay #2</u>: Build a new 69kV line from Armstrong Cork – Jay station.

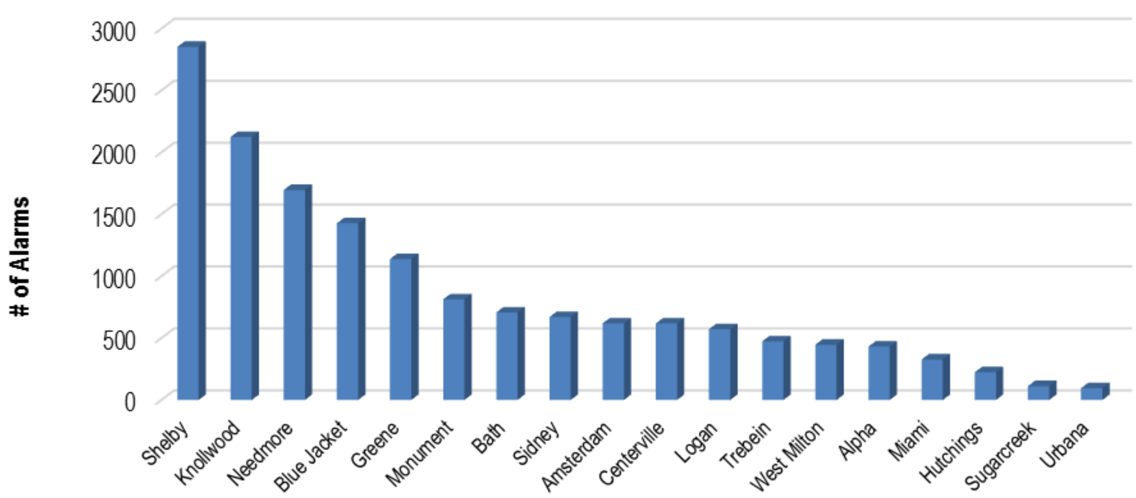
- Delaware – Bosman: Rebuild the 34.5kV Delaware – Bosman line as the 69kV Royerton – Strawboard line. Retire from Royerton – Delaware station

The recommended solution addresses AEP Transmission Owner planning criteria violations and is expected to improve real-time operational capability. The estimated cost for this project is $70.75 million, with a required in-service date of June, 2022. Based on their FERC 715 TO Criteria, the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3108: Installation of Reactors at Miami, Sugarcreek, and Hutchings 138 kV stations

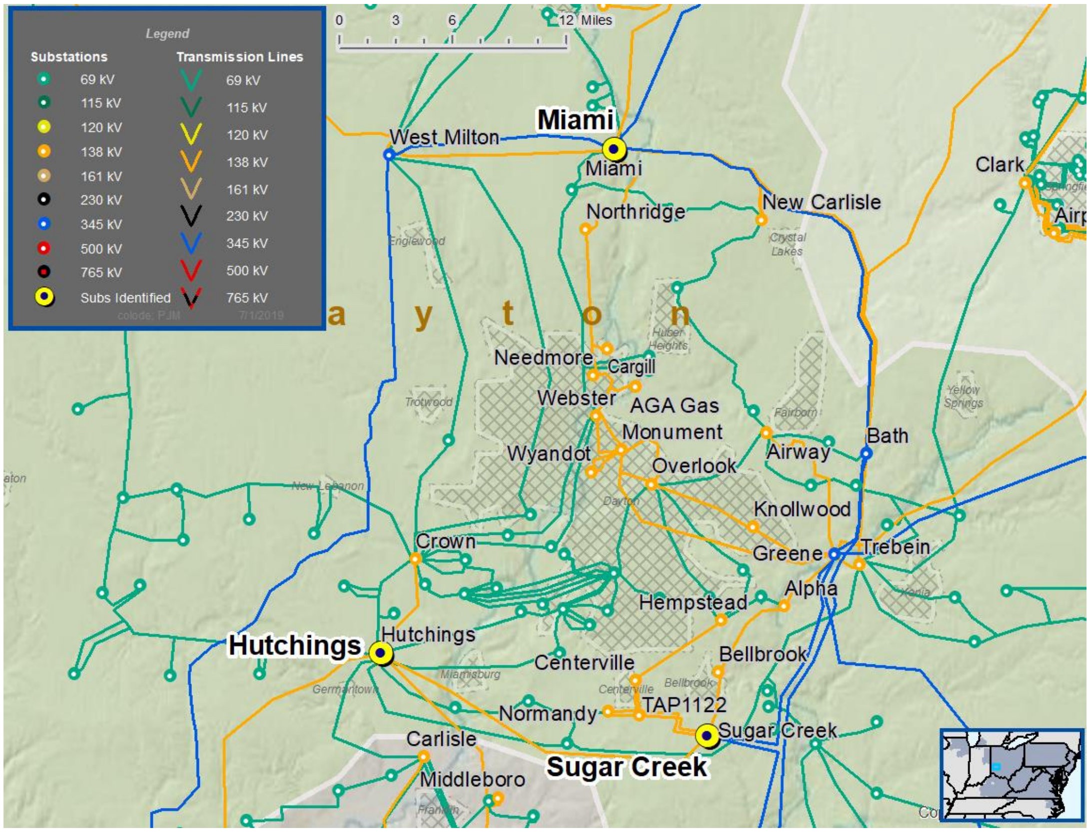
Dayton has been experiencing an excessive amount of high voltage alarms during light load periods, amounting to approximately 19,000 operational alarms which were logged in 2017 and 2018, including 327 alarms at 345 kV buses. It appears the number of the high voltage alarms has been trending up, as more alarms were logged in 2018 with fewer minimum load hours in comparison to 2017. The high voltage alarms to minimum load hour ratio almost doubled from 2017 to 2018. Figure 1 below shows the number of alarms by 138 kV station, starting in January, 2017 through December, 2018:

Figure 1.**Alarms by 138 kV Substation 1/2017 - 12/2018**



Dayton also has limited means to control high voltage due to the Killen and Stuart generator retirements in 2018 and the Hutchings retirements in 2015, which resulted in a total loss of approximately 600 MVAR of reactive absorption capability. After exhausting all typical operating procedures, Dayton is frequently forced to switch out equipment to avoid long-term damage from high voltage exposure. This practice of switching out equipment is not a sustainable operating practice and does not effectively solve the high voltage issues. As a result of the retirements, there are only peaking plants left in the Dayton transmission zone, and there are no existing or planned devices such as SVC's, Statcoms, or reactors.

Map 13. Miami, Sugarcreek, & Hutchings 138 kV



PJM worked closely with Dayton to determine what operational and planning changes are available, including the review of EMS snapshots to confirm the high voltage issues experienced during light load periods, and examining impacts of planned, approved reactive upgrades. The outcome of the investigation resulted in the recommended solution, which is to install a total of three 100 MVAR reactors, one each at the Miami, Sugarcreek, and Hutchings 138 kV substations. The estimated cost for this project is $15 million, and it is an immediate need project with a projected in-service date of December, 2021. Dayton will be designated to complete this work.

Dominion Transmission Zone End-of-life Rebuilds

There are six baseline projects recommended for approval in the Dominion Transmission zone, which include complete and partial rebuilds of 230 kV and 115 kV lines, due to violation of Dominion's FERC Form No. 715 filed "End of Life Criteria", Section C.2.9 regarding age and facility condition. All of the projects are immediate need, and the projected in-service date is provided below. Industry guidelines indicate the following equipment life:

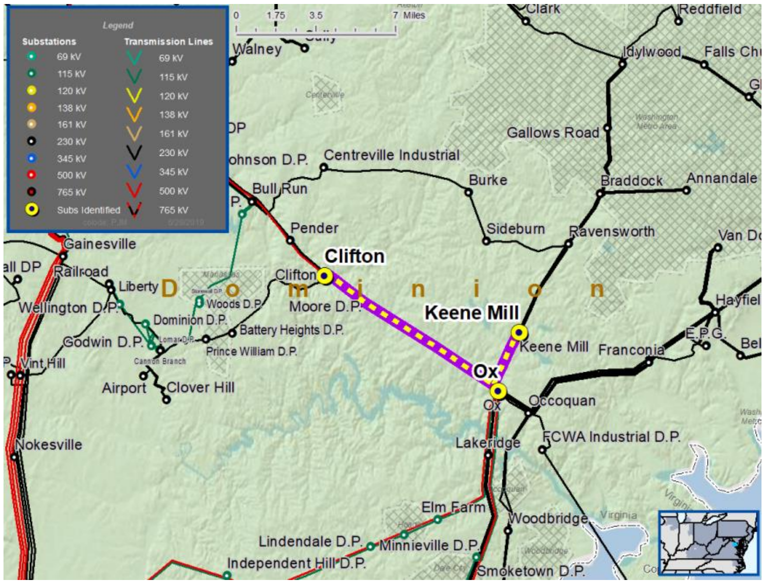
- Wood structures: 35-55 years
- Conductor and connectors: 40-60 years
- Porcelain insulators: 50 years

The lines and structures identified under Dominion's "End of Life Criteria" show sufficient deterioration, indicating they have reached the end of their useful service life.

Baseline Project b3096: Rebuild Clifton – Ox 230kV and Part of Clifton – Keene Mill 230kV Lines

The Clifton – Ox 230kV line is about 7.16 miles long and was constructed on Cor-ten lattice-type double circuit towers in the 1960s. Roughly 7.1 mile long section from Clifton – Keene Mill 230kV is on the same structures. These towers have inherent corrosion problems that continuously deteriorate the steel members. Clifton – Keene Mill 230kV is also part of the network feed to Idylwood substation supplying over 100 MW of load required to meet Dominion's Transmission planning criteria.

Map 14. Clifton - Ox - Keene Mill 230 kV



The recommended solution is to rebuild the Clifton – Ox 230kV and part of Clifton – Keene Mill 230kV lines with double circuit steel structures, using double circuit conductor at current 230kV northern Virginia standards, with a minimum rating of 1200 MVA. The estimated cost for this project is $22 million, and the projected in-service date is December, 2024. Dominion will be designated to complete this work.

Baseline Project b3097: Rebuild Chesterfield – Centralia 115kV Line

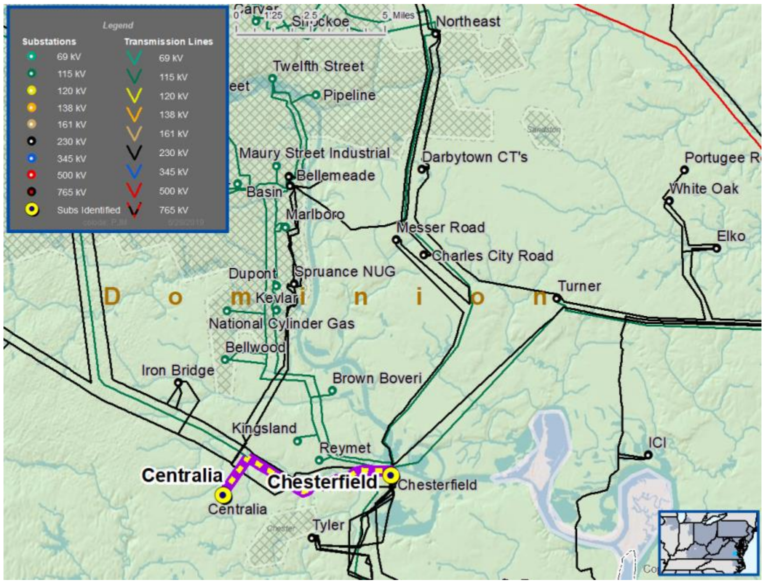
The line section from Chesterfield – Centralia 115kV, approximately 4 miles long, was constructed on wood H-frame structures in 1951. Additionally, the circuit provides service to River Road, Stratford Hills and Centralia substation with a total load of 50 MWs. Removing Chesterfield – Centralia 115kV section from service creates a 20.7-mile radial line from Northwest to Centralia with 50 MWs, which is a violation of Dominion's 700 MW-Mile planning criteria[2].

[2] C.2.6. Radial transmission lines

A Radial transmission line is defined as a single line that has one transmission source, serves load, and does NOT tie to any other transmission source (line or substation). Dominion Energy – Electric Transmission Planning Criteria Version 16 Effective 3/15/2019 Page 17 of 32 Unlike load served from a network transmission line having two sources where a downed conductor or structure can be sectionalized for load to be served before repairs are completed, load served from a single source radial transmission line cannot be reenergized until all repairs to the line are completed. Accordingly, loading on single source radial transmission lines will be limited to the following:

- 100 MW Maximum
- 700 MW-Mile Exposure (MW-Mile = Peak MW X Radial Line Length)

Map 15. Chesterfield – Centralia 115kV



The recommended solution is to rebuild Chesterfield – Centralia 115kV to current standards with a minimum summer emergency rating of 393 MVA. The estimated cost for this project is $7 million, and the projected in-service date is May, 2020. Dominion will be designated to complete this work.

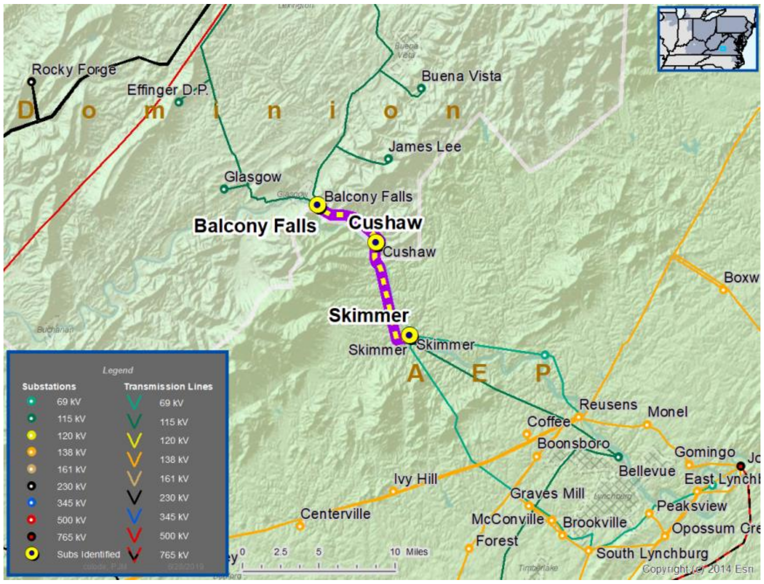
Baseline Project b3098: Rebuild Balcony Falls – Skimmer 115kV and Balcony Falls – Cushaw 115 kV Lines

The Balcony Falls – Skimmer 115kV circuit extends 9.8 miles, and shares structures with a secondary line, Balcony Falls – Cushaw 115 kV, which is 3.8 miles in length. The lines were constructed in the 1920's on a combination of double circuit Blaw Knox structures and single circuit wood H-frame structures. Removing Balcony Falls – Skimmer 115kV from service creates a 29 mile radial line from Skimmer to Altavista that violates Dominion's 700 MW-Mile planning criteria. The secondary line Balcony Falls – Cushaw 115 kV connects to a radial hydroelectric generator, and not rebuilding the line strands the generation at Cushaw 115 kV.

Once a radial loading limit exceeds any of these thresholds, an additional transmission source is required. Acceptable transmission source includes but is not limited to the following:

- Network from a separate transmission substation source (Preferred)
- Loop back to same transmission substation source
- Normally open network or loop transmission source

Map 16. Balcony Falls - Cushaw - Skimmer 115 kV

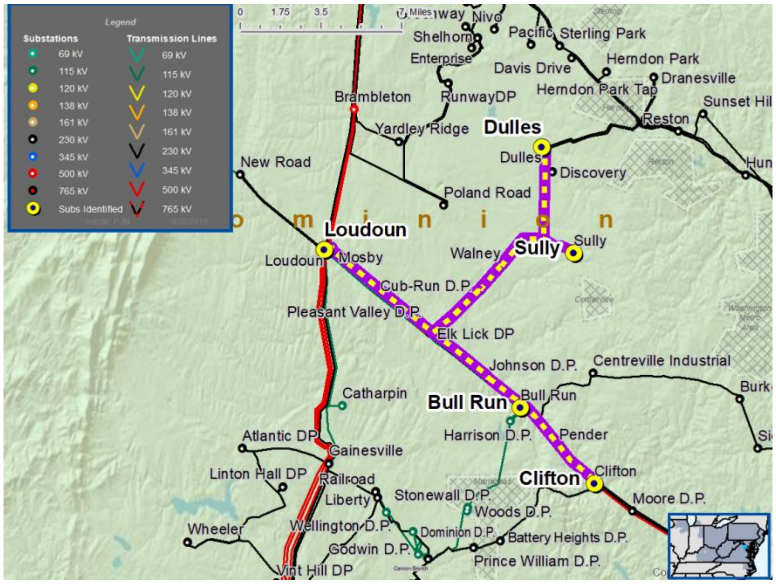


The recommended solution is to rebuild 9.2 miles of Balcony Falls – Skimmer 115kV and 3.8 miles of Balcony Falls – Cushaw 115 kV to current standards with a minimum rating of 261 MVA. The estimated cost for this project is $20 million, and the projected in-service date is December, 2023. Dominion will be designated to complete this work.

Baseline Project b3110: Rebuild Loudoun – Dulles Junction 230 kV Line

The 4.4 mile long section between Loudoun – Dulles Junction 115kV and 230kV circuits were constructed on Cor-ten lattice-type double circuit towers. These towers have inherent corrosion problems that continuously deteriorate the steel members, and have been identified to be rebuilt or retired as part of Dominion's "End of Life Criteria". Removing the section of Loudoun – Dulles Junction 230 kV would cause over 241 MWs of load, including the whole Dulles Substation, to be radial. Additionally, a failed breaker contingency at Reston Substation would lead to over 311 MW of load to be dropped, which are required to meet Dominion's Transmission planning criteria.

Map 17. Loudoun – Dulles Junction 230 kV & 115 kV Area

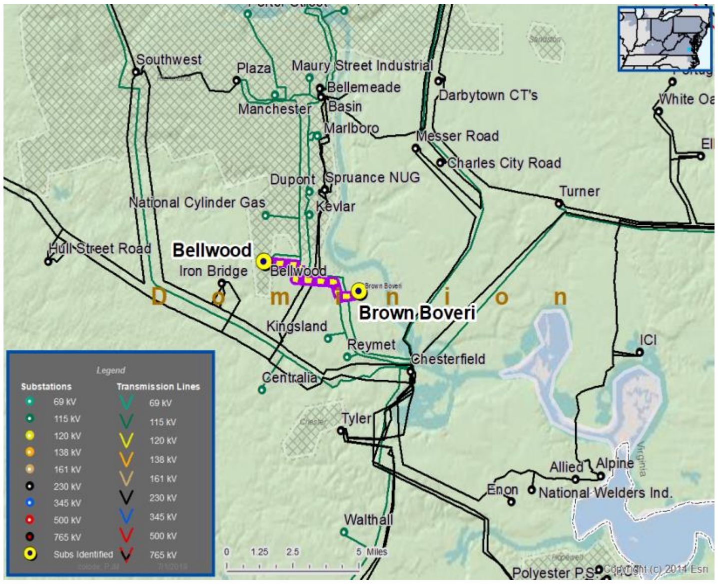


The recommended solution is to rebuild Loudoun – Dulles Junction 230 kV using single circuit conductor with minimum summer ratings of 1200 MVA. The project also includes the retirement of the Loudoun – Bull Run 115 kV line, which is approximately 8.44 miles, and to cut and loop Clifton – Sully 230 kV into Bull Run Substation. The solution adds three 230kV breakers at Bull Run to accommodate the new line and upgrade the substation, and replaces the Bull Run 230kV breakers "200T244" and "200T295" with 63kA breakers, which were identified in short circuit analysis during the evaluation of this project. The estimated cost for this project is $14.54 million, and the projected in-service date is December, 2023. Dominion will be designated to complete this work.

Baseline Project b3113: Rebuild Plaza – Chesterfield and Kevlar – Chesterfield 115 kV Lines

Approximately 1 mile of Plaza – Chesterfield 115 kV and Kevlar – Chesterfield 115 kV lines were constructed in 1956 on double circuit 3 pole wood H-frame structures, which had been identified to be rebuilt or retired as part of Dominion's "End of Life Criteria". Plaza – Chesterfield 115 kV provides service to National Cylinder Gas, Bellwood, Brown Boveri, Kingsland and Reymet substations with a total load of 21.5 MWs. Brown Boveri substation is tapped from the identified 1 mile line section to be rebuilt.

Map 18. Map 1: Brown Boveri – Bellwood 115 kV

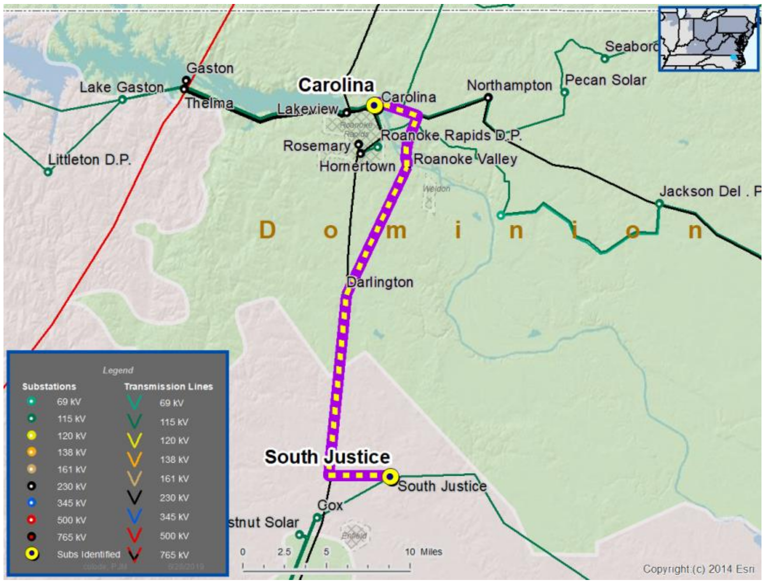


The recommended solution is to rebuild approximately 1 mile of Plaza – Chesterfield 115 kV and Kevlar – Chesterfield 115 kV to current standards with a minimum summer emergency rating of 393 MVA. The resulting summer emergency rating of Plaza – Chesterfield 115 kV segment from Brown Boveri to Bellwood is 180 MVA. There is no change to the Kevlar – Chesterfield 115 kV ratings. The estimated cost for this project is $3 million, and the projected in-service date is December, 2019. Dominion will be designated to complete this work.

<u>Baseline Project b3114: Rebuild Carolina – South Justice Branch 115 kV Line</u>

The Carolina – South Justice Branch 115 kV, which is 21.6 miles, serves 3 delivery points: Roanoke Rapids DP, Darlington DP, and Hornertown. The majority of the circuit is wood H-frames, constructed in 1959. There are two sections, 1.7 miles total, within the 18.6 mile section, which has 115 kV and 230 kV double circuit structures that are V series Corten. The remaining 3 mile 115 kV double circuit tap to South Justice Branch was constructed in 2015 and does not require replacement.

Map 19. Carolina – South Justice Branch 115 kV



The recommended solution is to rebuild the 18.6 mile section of Carolina – South Justice Branch 115 kV which includes 1.7 miles of double circuits. This segment of Carolina – South Justice Branch 115 kV will be rebuilt to current standards with a minimum rating of 261 MVA. The secondary circuit rating will not change. The estimated cost for this project is $25 million, and the projected in-service date is December, 2025. Dominion will be designated to complete this work.

Transmission Owner Criteria Projects

Of the $400.08 million of the new recommended baseline transmission system enhancements, approximately $331.54 million is driven by Transmission Owner planning criteria, which makes up almost 83% of the new project cost estimates. All but one of the detailed project descriptions provided above are driven by the local Transmission Owner planning criteria.

Baseline Project b3130: Monmouth County Reliability Project –Red Bank, NJ Area

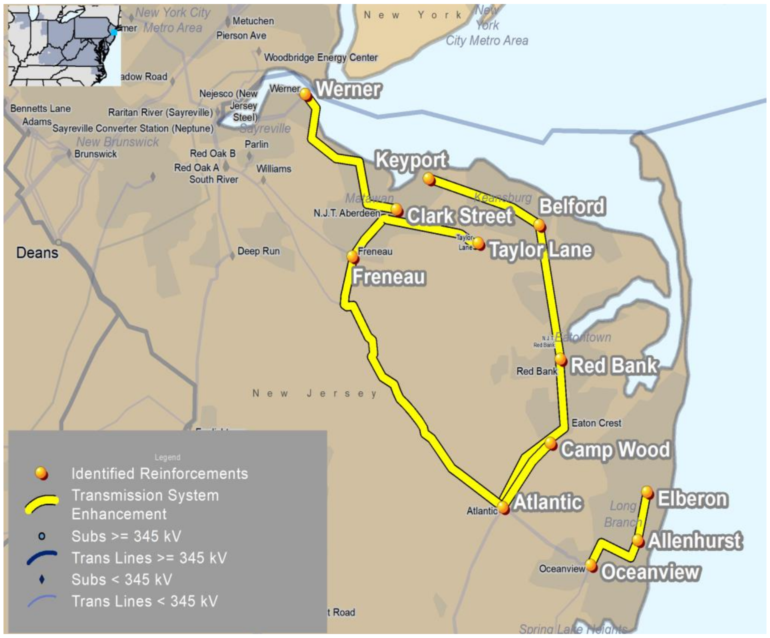
JCPL Transmission Zone

At the February 2019 TEAC meeting, PJM recommended the cancellation of the b1690 project (build a new third 230 kV line into the Red Bank 230 kV substation), which was previously approved by the PJM Board of Managers for inclusion in the RTEP to address voltage violations identified in the Red Bank, NJ area. The project was canceled as a result of the proceedings from the New Jersey Board of Public Utilities.

PJM worked closely with JCPL to re-evaluate the voltage violations, and after confirming the validity of the violations, developed alternative solutions.

Several alternatives were evaluated to replace the canceled b1690 project, including alternate 230 kV lines, battery installations and a Remedial Action Scheme (RAS). These alternatives were determined to be less cost effective than the proposed solution.

Map 20. MCRP – Red Bank, NJ Area



The recommended solution – Baseline Project b3130 (which fully replaces b1690) – addresses the voltage drop, voltage magnitude and potential loss of load reliability criteria violations when fully completed. The solution constructs seven new 34.5 kV circuits on existing pole lines for a total of 53.5 miles (44.1 miles will be converting existing single circuit to double circuit 34.5 kV construction, and 9.4 miles of 34.5 kV will be added to existing distribution poles). The Atlantic-Camp Woods and Allenhurst-Elberon 34.5 kV lines will be reconductored and a second 115/34.5 kV transformer will be installed at Werner substation. The recommended solution addresses the baseline needs in the area and is the most cost effective in response to the actions by the New Jersey Board of Public Utilities. The project is an immediate-need project with an estimated cost of $175 million, and has projected in-service dates between June 2021 and July 2026. The local transmission owner, JCPL, will be designated to complete this work.

Dominion Transmission Zone End-of-Life Rebuilds

There are two baseline projects recommended for approval in the Dominion Transmission zone. The projects include complete and partial rebuilds of 230 kV lines due to the violation of Dominion's FERC Form No. 715 filed end-of-life criteria, Section C.2.9, regarding age and facility condition. Both projects are immediate need, and the projected in-service dates are provided below. Industry guidelines indicate the following equipment life:

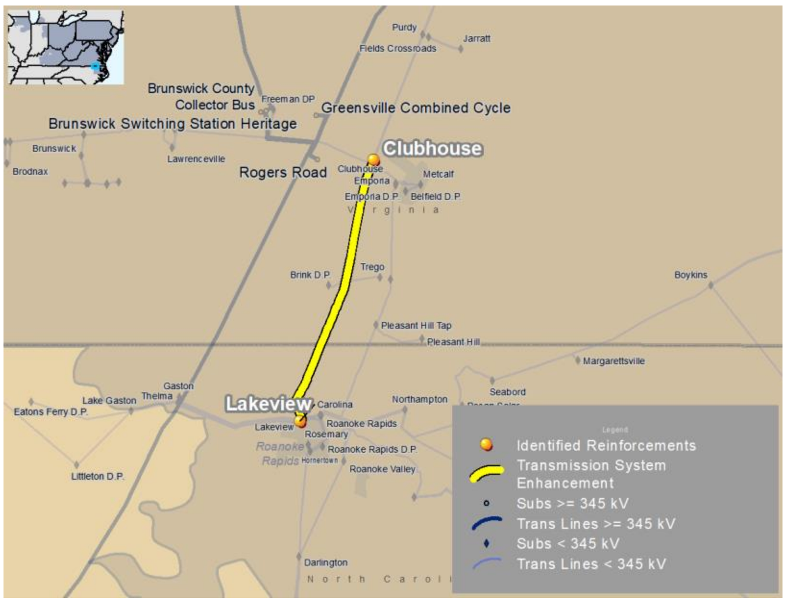
- Wood structures: 35–55 years
- Conductor and connectors: 40–60 years
- Porcelain insulators: 50 years

The lines and structures identified under Dominion's end-of-life criteria show sufficient deterioration, indicating they have reached the end of their useful service life.

Baseline Project b3121: Rebuild Clubhouse-Lakeview 230 kV Line

The Clubhouse-Lakeview 230 kV line is about 18-miles long and was constructed on wooden H-frame structures in 1962. These towers have reached their end of life based on industry guidelines. Reliability studies indicate that retiring this line will result in thermal overloads in accordance with P1, P2, P4, P6 and P7 NERC criteria violations. There is also an operational performance need for this line, as generator AB2-100 would be left unserved if the line were retired.

Map 21. Clubhouse-Lakeview 230 kV

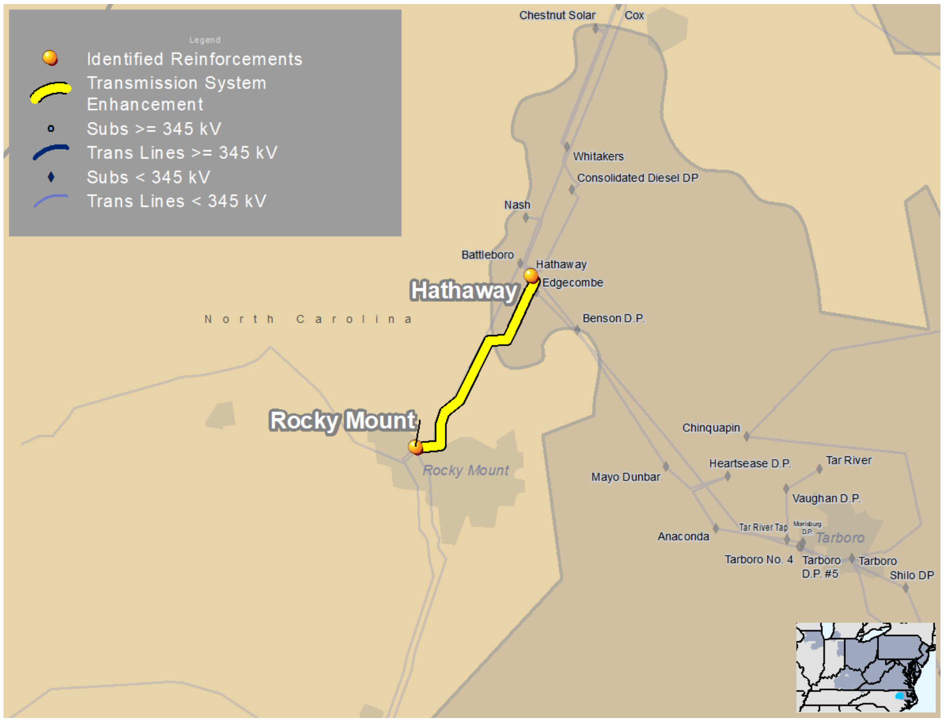


The recommended solution is to rebuild the Clubhouse-Lakeview 230 kV line with single circuit wood pole equivalent structures at the current 230 kV standard, with a minimum rating of 1047 MVA (Existing Rating = 399 MVA). The estimated cost for this project is $27 million, and the projected in-service date is December 2024. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3122: Rebuild Hathaway-Rocky Mount 230 kV Line

The line section from Hathaway-Nash-Rocky Mount (Duke Energy Progress) and Hathaway-Rocky Mount 230 kV lines (approximately 4.1-miles each) was constructed on Cor-ten lattice-type double circuit towers in the 1960s. These towers have been shown to have inherent corrosion problems that continuously deteriorate the steel members. These lines have been identified to be rebuilt as part of Dominion's end-of-life criteria. The line provides service to Nash and City of Rocky Mount #4 substations with approximately 16 MW and 54 MW tapped load. Reliability studies indicate that retiring Hathaway-Nash-Rocky Mount 230 kV lines will overload the Battleboro-Rocky Mount 115 kV line for the loss of the Everetts-Greensville 230 kV circuit.

Map 22. Hathaway-Rocky Mount 230 kV



The recommended solution is to rebuild Hathaway-Rocky Mount (Duke Energy Progress) and Hathaway-Nash-Rocky Mount 230 kV lines with double circuit steel structures, using double circuit conductor at current 230 kV standards, with a minimum rating of 1047 MVA (Existing Rating = 478 MVA). The estimated cost for this project is $13 million, and the projected in-service date is December 2024. The local transmission owner, Dominion, will be designated to complete this work.

Transmission Owner Criteria Projects

Of the $265.6 million of the new recommended baseline transmission system enhancements, approximately $88.7 million is driven by transmission owner planning criteria, which makes up 33.4 percent of the new project cost estimates. All but one of the detailed project descriptions provided above are driven by the local transmission owner planning criteria.

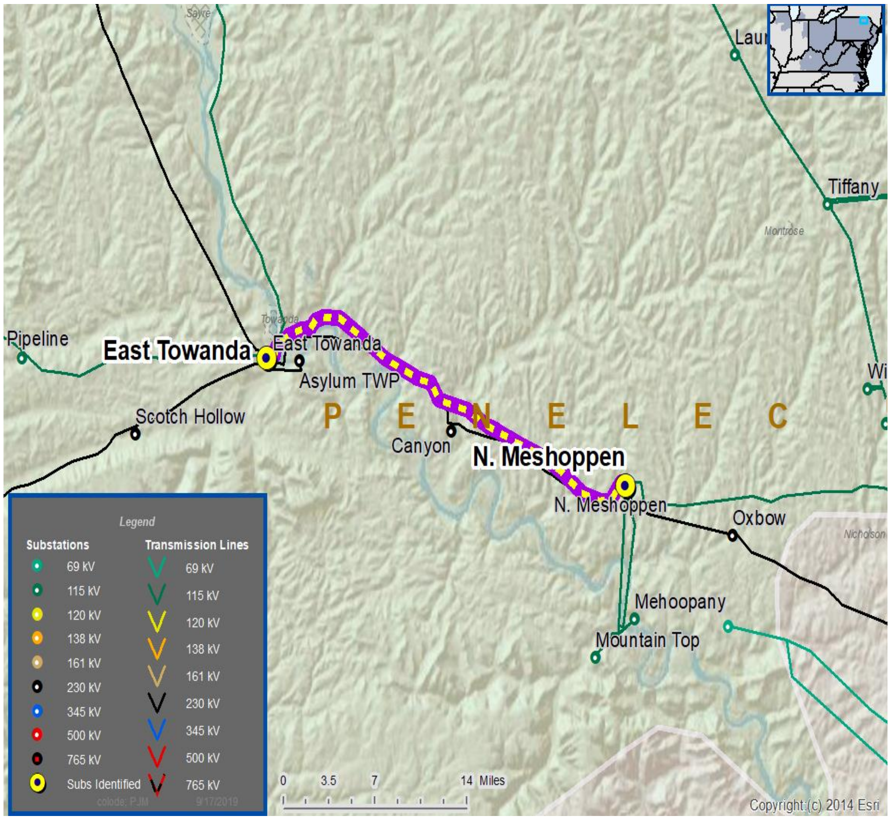
Baseline Project b3137: East Towanda – North Meshoppen 115 kV Line Rebuild

Penelec Transmission Zone

PJM RTEP analysis revealed a thermal violation in the winter generator deliverability results. The East Towanda – North Meshoppen 115 kV circuit (existing rating 167N/202E summer 188N/239E winter).is overloaded for the single contingency loss of the East Towanda – Canyon – North Meshoppen 230 kV circuit.

PJM worked closely with Penelec to evaluate the violation, and developed the following recommended solution:

Map 23. East Towanda – North Meshoppen 230 kV Line.



The recommended solution – Baseline Project b3137, rebuilds 20 miles of the East Towanda - North Meshoppen 115 kV line and adjusts relay settings at East Towanda and North Meshoppen 115 kV substations (new rating 202N/245E summer 228N/290E winter). The recommended solution addresses the baseline needs in the area. The estimated cost for this project is $58.6 million, and the projected in-service date is June 2024. The local transmission owner, Penelec, will be designated to complete this work.

Transmission Owner Criteria Projects

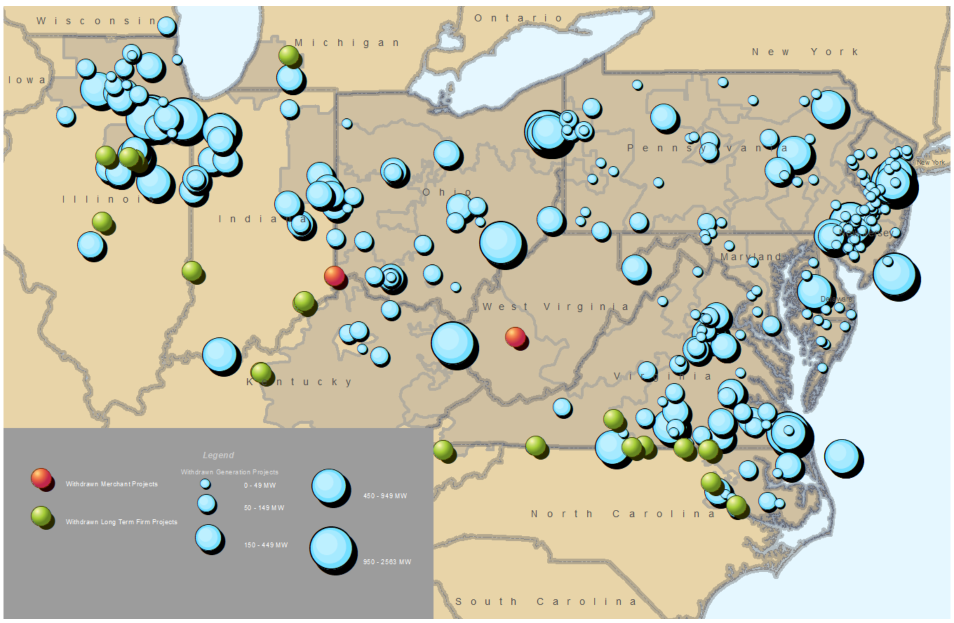
Of the $134 million of the new recommended baseline transmission system enhancements, approximately $39 million is driven by transmission owner planning criteria, which makes up 28.5 percent of the new project cost estimates.

New Services Queue Projects

Throughout 2019, PJM has continued to study new service customer requests that are submitted into our New Services Queue. These studies evaluate the impact of the new service request and include an evaluation of new generation interconnections, increases in generation at existing stations, long-term firm transmission service requests and merchant transmission interconnection requests.

These studies were last reviewed with the Reliability Committee of the Board in December of 2018. Since that time PJM has completed 292 System Impact Studies and 312 new service requests have withdrawn. Projects with ISA (Interconnection Service Agreement) and above including several long-standing projects have resulted in $107.3M in network upgrades. Figure 1 below shows the location of the new units associated with the completed interconnection System Impact Studies along with the fuel type and relative size. A listing of the projects with recently completed system impact studies is provided in Attachment C to this white paper. A listing of the network upgrades associated with these projects is shown in Attachment D to this report. The cost for the network upgrades associated with these interconnection projects is the responsibility of the developer.

Map 24. Completed Interconnection System Impact Studies



2018/2019 RTEP Long-Term Proposal Window Activity

PJM opened its third Long Term proposal window starting on November 2, 2018 through March 15, 2019 to solicit proposals addressing the identified congestion drivers shown in Table 1.

Market efficiency analysis is a part of the overall RTEP process to accomplish the following objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated or modified.
2. Identify new transmission upgrades that may result in economic benefits.
3. Identify economic benefits associated with “hybrid” transmission upgrades. Hybrid transmission upgrades include proposed solutions, which encompass modifications to reliability-based enhancements already included in the RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed to provide economic benefits in addition to resolving reliability issues.

PJM conducts market efficiency analysis using market simulation tools of future annual periods for both the capacity market and energy market. Economic benefits of specific transmission projects are determined by comparing results of simulations that include each project with simulations that do not include the project. Projects are measured using two Tariff/Operating Agreement criteria. First, the project must address either an identified congestion driver or a capacity market constraint. Second, the project's total energy and capacity benefits must exceed costs (benefit to cost ratio) by at least 25 percent. Project energy benefits are measured by comparing the benefits in the form of net load payments and/or production costs with and without the proposed project for a 15-year study period. Projects affecting the capacity market derive additional capacity benefits in the form of net load capacity payments and/or capacity costs.

Identified Congestion Drivers

PJM posted a list of identified congestion drivers – facilities and their simulated congestion levels -- as part of soliciting proposals during the 2018/2019 Long-Term Proposal Window, as shown in Table 11.

Table 11. **2018/2019 Long-Term Window Congestion Drivers**

Constraint	Area	2023 Congestion Frequency (hours)	2023 Market Congestion ($, million)	2026 Congestion Frequency (hours)	2026 Market Congestion ($, million)
Hunterstown-Lincoln 115 kV Line	MetEd (PJM)	1,720	$20.77	1,832	$29.62
Monroe #1 and #2– Wayne 345 kV Lines	MISO	45	$1.44	30	$0.61
Marblehead North Bus #1 161/138 kV Transformer	MISO	195	$1.41	138	$1.18
Bosserman-Trail Creek 138 kV Line	AEP-MISO	66	$1.47	89	$1.69

Twelve parties submitted 34 proposals during the 2018/19 RTEP Long-Term Proposal Window that closed in March of 2019. Proposals ranged in cost from $0.1 million to $290.95 million and included transmission upgrades from transmission owners and greenfield projects from incumbent transmission owners and non-incumbent entities, as summarized in Table 12.

Table 12. **Proposals by Type Submitted in the 2018/2019 Long Term Proposal Window**

Congestion Driver	Number of Proposals	Greenfield Proposals	TO Upgrade Proposals
Hunterstown-Lincoln 115 kV Line	22	19	3
Bosserman-Trail Creek 138 kV Line	5	4	1
Marblehead #1 161/138 kV Transformer	2	1	1
Monroe #1 and #2-Wayne 345 kV Lines	3	0	3
No PJM Driver	2	1	1
Total	**34**	**25**	**9**

PJM evaluated the proposals according to Schedule 6 of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (Operating Agreement). PJM is recommending for Board approval a market efficiency interregional solution to provide congestion relief on the Bosserman-Trail Creek line. PJM is also recommending for Board approval the Hunterstown-Lincoln 115 kV rebuild as part of a combination of transmission projects to address congestion in South-Central Pennsylvania and Northern Maryland. Because the proposals submitted to address congestion on the Marblehead transformer and the Monroe-Wayne transmission lines did not satisfy PJM criteria, PJM is not recommending any of those proposals to the Board for approval.

Recommendation: PJM-MISO Interregional Baseline Project b3142: Rebuild Michigan City-Trail Creek-Bosserman 138 kV Line

PJM-MISO interregional baseline project b3142, a rebuild of the Michigan City-Trail Creek-Bosserman 138 kV Line, is the first interregional proposal submitted during the Long-Term Proposal Window that PJM is recommending to the Board for approval and inclusion in the RTEP.

PJM, working with MISO through the Interregional Planning Stakeholder Advisory Committee (IPSAC), completed a two-year Interregional Market Efficiency Project (IMEP) study in parallel with PJM's 2018/2019 Long-Term Proposal Window process. As part of the IMEP Study, PJM and MISO separately received project proposals that addressed at least one congestion driver identified in each region's respective planning process. Under the terms of the PJM/MISO

Joint Operating Agreement, interregional proposals are separately submitted to, and evaluated by PJM and MISO, and subject to each RTO's respective regional processes.

As shown earlier in Table 2, The Bosserman-Trail Creek 138 kV line in Northern Indiana Public Service Company (NIPSCO) – in the MISO footprint – was identified as an interregional targeted congestion facility. Simulations performed in advance of the 2018/2019 Long Term proposal window identified over $1.4 million in market congestion on this facility based on 2023 input assumptions and simulation results. PJM received a cluster of five proposals (four greenfield proposals and one upgrade proposal) from five entities to address the Bosserman-Trail Creek congestion. The proposed project cost estimates ranged from $19 million to $266 million.

Solution Selection

The energy benefits associated with the proposed projects were determined using the methodologies specified in Schedule 6 of the Operating Agreement. PJM's annual energy benefits calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load payments as a result of the proposed project. Change in net load payments comprises the change in gross load payments offset by the change in transmission rights credits. No capacity benefits were identified with these proposed projects.

PJM evaluated each of the five proposals, out of which two exceeded the 1.25 benefit-to-cost ratio and fully mitigated congestion: (1) proposal BT_481 to rebuild the Michigan City-Trail Creek-Bosserman 138 kV line; and, (2) proposal BT_129 to build a new Kuchar substation and new Kuchar-Luchtman 138 kV line. PJM conducted further analysis on these two proposals to determine how the projects addressed the identified congestion and to evaluate project constructability risk.

Based on the analysis performed, PJM selected proposal BT_481 shown on Map 25 – a rebuild of the Michigan City-Trail Creek-Bosserman 138 kV line – as the more efficient or cost effective solution to the identified congestion driver. Proposal BT_481:

- Has a benefit-to-cost ratio of 2.63, which was the highest benefit-to-cost ratio across the proposals submitted for the Bosserman-Trail Creek constraint; cost estimates were from PJM's own constructability analysis
- Fully addresses the congestion driver
- Is an upgrade and has lower constructability risk compared to the four greenfield proposals, including BT_129

In addition to the market efficiency base case analysis for the recommended proposal BT_481, PJM also performed sensitivity analysis on key input variables: natural gas prices, PJM load forecasts, generation expansions, and generator outage patterns. The benefit to cost ratio exceeded 1.25 in each instance. An RTEP process reliability analysis of the project did not identify any reliability criteria violations. PJM also conducted a constructability review of the components proposed by project BT_481 and did not identify any significant issues.

In conclusion, PJM is recommending proposal BT_481 to the PJM Board for provisional approval as an interregional baseline project, pending approval by the MISO Board as well. Both the PJM and MISO boards must approve the project in order for it to be included in each entity's regional transmission plan. BT_481 project elements will be designated to NIPSCO, the proposing entity and transmission owner of the project elements in the MISO footprint:

- Reconductor Bosserman-Trail Creek 138 kV line
- Reconductor Michigan City-Trail Creek 138 kV line
- Michigan City Substation Upgrades
- Trail Creek Substation Upgrades

The estimated cost for the project is $24.69 million (in service dollars) with a January 2023 in-service date required. Based on the PJM to MISO benefit ratio, 89.1 percent of the cost ($22.00 million) will be allocated to PJM.

Map 25. Baseline Project b3142: Bosserman-Trail Creek-Michigan City 138 kV Proposal

South-Central Pennsylvania and Northern Maryland Congestion

The following discussion relates to three projects addressing congestion in South-Central Pennsylvania and Northern Maryland, including congestion on the AP South Interface and related constraints. The first project (Project 9A) was submitted in the 2014/2015 RTEP Long-Term Proposal Window and approved by the PJM Board in August 2016. The second project (Project 5E) was submitted in the 2016/2017 RTEP Long-Term Proposal Window and approved by the PJM Board in April 2018. PJM is recommending the third project (Project H-L), which was submitted in the 2018/2019 RTEP Long-Term Proposal Window, for approval by the PJM Board. Because this combination of projects addresses interrelated congestion drivers, PJM has reviewed these projects to consider interactions among them given the dynamic nature of the market efficiency base case through changes in the 2014/2015, 2016/2017, and

2018/2019 RTEP Years, and in light of potential reliability criteria violations otherwise found to arise in 2023 in South-Central Pennsylvania and Northern Maryland with certain of these projects removed from the base case.

Recommendation

PJM's RTEP analyses relative to the South-Central Pennsylvania and Northern Maryland congestion include a review of Project 9A, Project 5E, and Project H-L, as well as a review of Alternative Project 9A, Project 5E, and Project H-L.

As discussed in greater detail below, PJM's RTEP analyses have determined that in the combinations described, these projects exceed the benefit-to-cost ratio of 1.25, significantly reduce congestion, and solve reliability criteria violations identified in study year 2023 that otherwise were found to arise with certain of these projects removed from the base case.

As such, PJM recommends that:

- Project H-L be added to the RTEP
- Project 5E, as approved, remain in the RTEP
- Project 9A, as approved by the Board, continues to exceed the benefit-to-cost ratio and should remain in the RTEP
- Alternative Project 9A exceeds the benefit-to-cost ratio and, if approved by the Maryland and Pennsylvania Commissions through their respective CPCN application processes, Alternative Project 9A would be recommended for approval by the PJM Board of Managers as memorialized in a Board Resolution. Upon approval by both State Commissions, PJM would present Alternative Project 9A to the Board for final approval and inclusion in the RTEP.

As is made clear below, the benefit-to-cost ratios exceeded the 1.25 threshold in the scenarios where PJM studied Project 9A, Project 5E, and Project H-L in the aggregate, and Alternative Project 9A, Project 5E, and Project H-L in the aggregate.

Table 13. **Summary of Recent RTEP Analyses**

RTEP Analyses[3]	Date Presented	Benefit to Cost Ratio
Alternative Project 9A	May 8, 2019	1.39 (using $466.44M as cost est.) - 1.52 (using $426.02M as cost est.)
Re-evaluation of Project 9A	Oct. 17, 2019	2.10
Re-evaluation of Project 5E	Nov. 14, 2019	1.11[4]
Project H-L	Nov. 14, 2019	76.41
Alternative Project 9A	Nov. 14, 2019	1.60
Re-evaluation of Project 5E (assuming Board approval of Project H-L)	Nov. 14, 2019	1.80
Project 9A + Project 5E + Project H-L	To be presented at the December TEAC.	2.87, aggregate
Alternative Project 9A + Project 5E + Project H-L	To be presented at the December TEAC.	2.25 (using $561.68M as cost est.) - 2.33 (using $533.99M as cost est.), aggregate

The individual elements of each of the projects described above are shown schematically in Table 13.

PJM conducted RTEP analyses of the two combinations noted in the last two rows of Table 3, above. PJM proceeded in this manner because the two combinations are comprised of:

- Project 9A or Alternative Project 9A, a project that is nearing a decision in the state siting processes (and, notably, in the case of Alternative Project 9A, the siting processes might culminate in a Commission-approved settlement reflecting a compromise among certain parties to the proceeding)
- Project 5E, a project that is advanced in both its engineering and procurement phases
- Project H-L, which is a relatively modest upgrade

In the aggregate, PJM's RTEP analyses show that these combinations of projects exceed the benefit-to-cost ratio of 1.25, significantly reduce congestion, and solve reliability criteria violations identified in study year 2023 that otherwise were found to arise with certain of these projects removed from the base case.

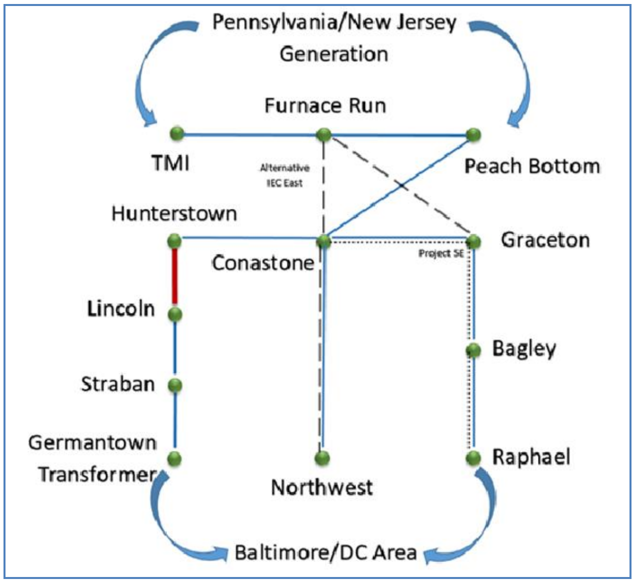
It is important to note that if Project 9A or Alternative Project 9A were to be removed from further consideration, PJM's RTEP analysis has previously identified a number of reliability criteria violations starting in the 2023 study year. Some of these reliability criteria violations include conductor overloads on 500 kV transmission lines which, in PJM's experience, are likely to be resolved only through the construction of additional greenfield transmission. Should these combinations of projects inclusive of Project 9A or Alternative Project 9A be removed from the RTEP, resultant reliability criteria violations would be identified during the 2020 RTEP analysis, and potential solutions to

[3] The market efficiency base case was updated in July 2019 and further revised in September 2019.

[4] For further discussion, see the section of this paper regarding Project 5E, below.

such reliability criteria violations would not be identified to the Board until late 2020 or early 2021. Furthermore, removing these combinations of projects from the RTEP would fail to address the congestion that would be re-introduced into South-central Pennsylvania and Northern Maryland. Any proposal window to address this re-introduced congestion would not be held until 2021, with solutions not likely to be presented to the Board until late 2021. In light of this timing, and based on the likely need for greenfield transmission, PJM predicts that new CPCN applications for not-yet-identified reliability and market efficiency drivers would not be filed until 2022 or 2023. Conservatively assuming one to two years for state siting proceedings, reliability and market efficiency solutions likely could not be constructed sufficiently quickly to remediate reliability criteria violations, and further would leave customers subject to significant congestion for a number of years to come.

Figure 2.**South-Central Pennsylvania and Northern Maryland Congestion**



Project 9A and Alternative Project 9A

Project 9A, as approved by the Board, continues to exceed the 1.25 Benefit-to-Cost Ratio

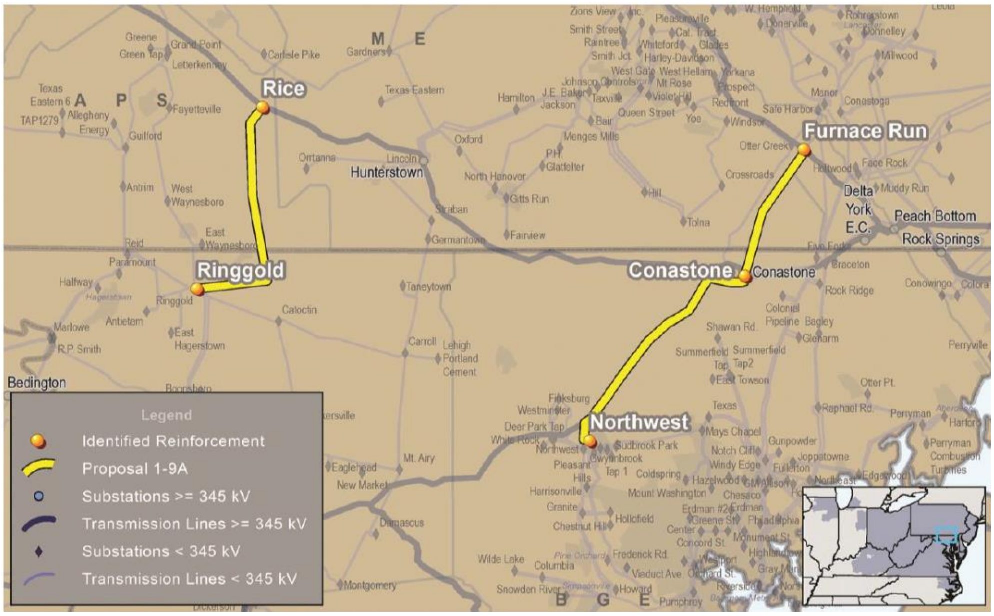
The PJM Board approved Project 9A in August 2016 to address persistent congestion in South-Central Pennsylvania and Northern Maryland. Project 9A includes a western component – the Rice-Ringgold 230 kV line – and an eastern component – the Furnace Run-Conastone-Northwest 230 kV line – shown on Figure 2.

Five subsequent re-evaluations (Sept. 14, 2017; Feb. 8, 2018; Sept. 13, 2018; March 7, 2019; and Sept. 24, 2019) reaffirm PJM's recommendation that Project 9A be included in the RTEP, as discussed in detail in PJM's Nov. 15, 2018 white paper[5] and in testimony filed in the pending state siting proceedings. The below chart summarizes RTEP analyses of Project 9A from its presentation to the Board in August 2016 through the present, demonstrating that Project 9A continues to exceed the 1.25 benefit-to-cost ratio.

[5] https://www.pjm.com/-/media/committees-groups/committees/teac/20181108/20181108-transource-white-paper.ashx

For the reasons discussed in this paper, Project 9A, as approved by the Board, continues to exceed the benefit to cost ratio and should remain in the RTEP.

Map 26. Project 9A



Alternative Project 9A Exceeds the 1.25 Benefit-to-Cost Ratio and Reflects a Compromise Among Certain Parties in the Pending CPCN Proceedings in Maryland and Pennsylvania

Alternative Project 9A is the product of data requests, analysis and agreement among several of the parties[6] in the Maryland and Pennsylvania siting proceedings. Those parties have executed and filed a proposed settlement before the Maryland and Pennsylvania state Commissions seeking the approval of Alternative Project 9A (such approval being in the alternative to state Commission approval of Board-approved Project 9A). Discovery is ongoing and additional procedural orders are anticipated relating to Alternative Project 9A and the settlement.

Alternative Project 9A (as shown on Map 26**)** is comprised of the same western segment in Project 9A, as approved by the Board. Alternative Project 9A reflects modifications to the eastern segment of Board-approved Project 9A and involves less greenfield transmission than Project 9A because Alternative Project 9A uses a pre-existing right of way that requires expansion. In Maryland, the eastern segment of Alternative Project 9A would be constructed, owned and maintained by Baltimore Gas and Electric Company (BGE) within its existing utility rights-of-way. BGE would add a second 230 kV circuit on the existing Otter Creek-Conastone 230 kV line. BGE would also replace eight lattice structures that currently hold the single-circuit Manor-Graceton 230 kV line with approximately eight monopole structures, which would then carry a second 230 kV line. In Pennsylvania, PPL Electric Utilities Corporation (PPL) would construct, own and maintain the lines within PPL's expanded existing rights-of-way.

[6] PJM is not a party to that proceeding, though PJM has run analysis, offered testimony and sponsored data requests in the matter.

Table 14 summarizes the body of RTEP analyses PJM has conducted regarding Alternative Project 9A.

Table 14. **Summary of Recent RTEP Analyses Involving Alternative Project 9A**

RTEP Analyses[7]	Date Presented	Benefit-to-Cost Ratio
Alternative Project 9A	May 8, 2019	1.39 (using $466.44M as cost est.) - 1.52 (using $426.02M as cost est.)
Alternative Project 9A	Nov. 14, 2019	1.60
Alternative Project 9A[8] + Project 5E + Project H-L	Dec. 12, 2019	2.25 (using $561.68M as cost est.) - 2.33 (using $533.99M as cost est.), aggregate

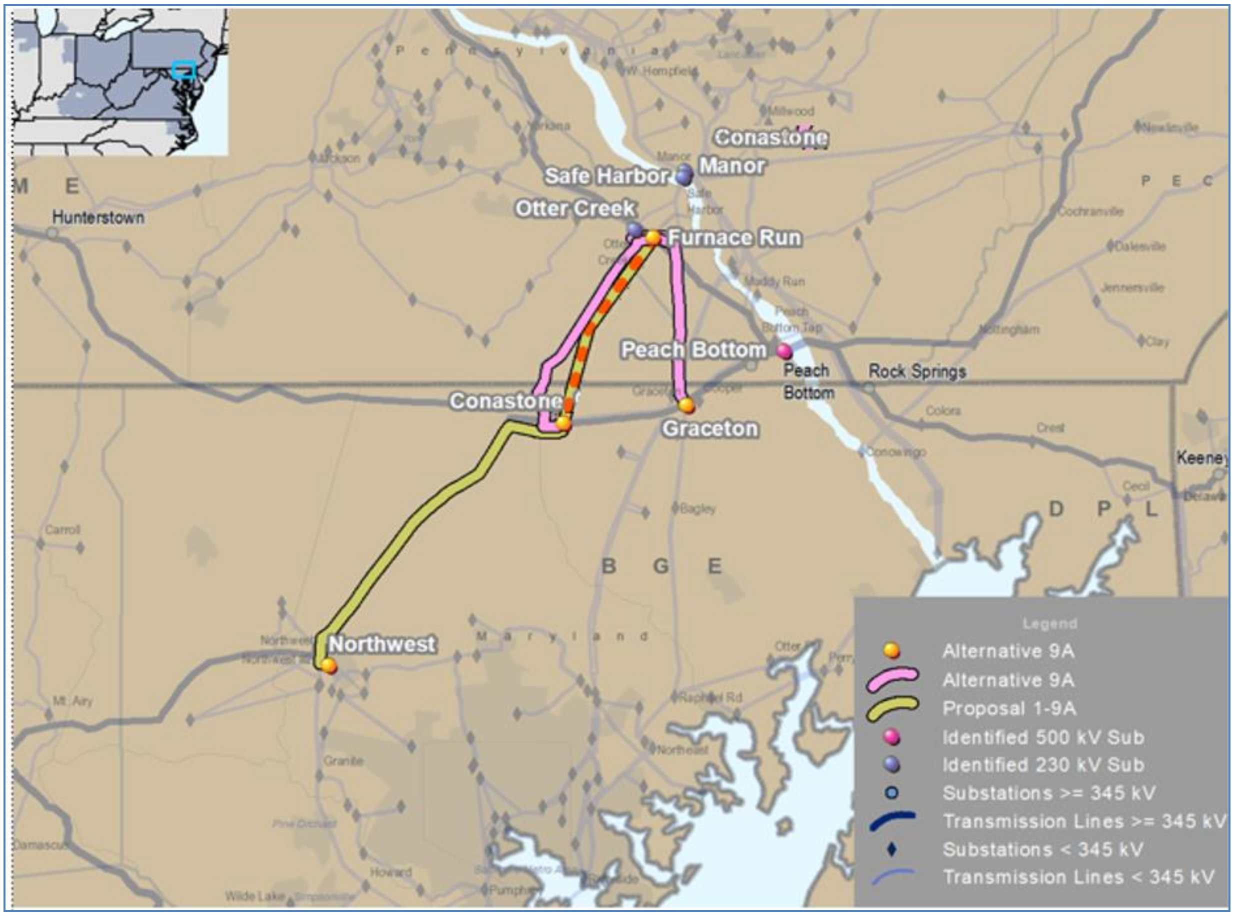
PJM's RTEP analyses show that a combination of Alternative Project 9A, Project 5E, and Project H-L exceed the benefit-to-cost ratio of 1.25, significantly reduce congestion, and solve reliability criteria violations identified in study year 2023 that otherwise were found to arise with Alternative Project 9A removed from the base case.

For the reasons discussed in this paper, Alternative Project 9A exceeds the benefit-to-cost ratio and, if approved by the Maryland and Pennsylvania Commissions through their respective CPCN application processes, Alternative Project 9A would be recommended for approval by the PJM Board of Managers as memorialized in a Board Resolution. Upon approval by both State Commissions, PJM would present Alternative Project 9A to the Board for final approval and inclusion in the RTEP.

[7] The market efficiency base case was updated in July 2019 and further revised in September 2019.

[8] PJM has performed a constructability analysis of the western portion of Alternative Project 9A and used a cost for Alternative Project 9A's eastern segment that reflects a 25 percent sensitivity to the PPL and BGE elements (elements that have not been reviewed for constructability). Costs for the alternative configuration of the eastern portion would have to increase by a significant margin in order for the benefit-to-cost ratio for Alternative Project 9A to fall below the 1.25 threshold. At this stage of the CPCN proceedings and based on the significant margin that exists in the benefit-to-cost ratio, it is unnecessary to commission a partial constructability analysis of the alternative configuration of the eastern portion of Alternative Project 9A.

Map 27. The Alternative Configuration of the Eastern Portion of Project 9A (the Alternative IEC East Portion)*



** Note: Dotted red line depicts originally proposed Furnace Run-Conastone 230 kV line now being rerouted*

Project 5E, as Approved by the Board

In April 2018, the PJM Board approved baseline Project 5E with a benefit to cost ratio of 5.23 (calculated using an initial cost estimate of $39.65 million). This market efficiency project would alleviate congestion on the Conastone-Graceton-Bagley 230 kV line in the BGE zone. Submitted by BGE, the project comprises reconductoring the Conastone-Graceton and Raphael Road-Northeast 230 kV lines together with adding bundled conductor to the Graceton-Bagley-Raphael Road double circuit lines, as shown on Map 28.

A re-evaluation of Project 5E in September 2018 yielded a benefit to cost ratio of 9.18, reaffirming the basis for PJM's recommendation that Project 5E be included in the RTEP.

At present, the estimated cost for Project 5E is $48,295,868 (2021 dollars). Table 15 summarizes the recent body of RTEP analyses PJM has conducted regarding Project 5E.

Table 15. **Summary of Recent RTEP Analyses Involving Project 5E**

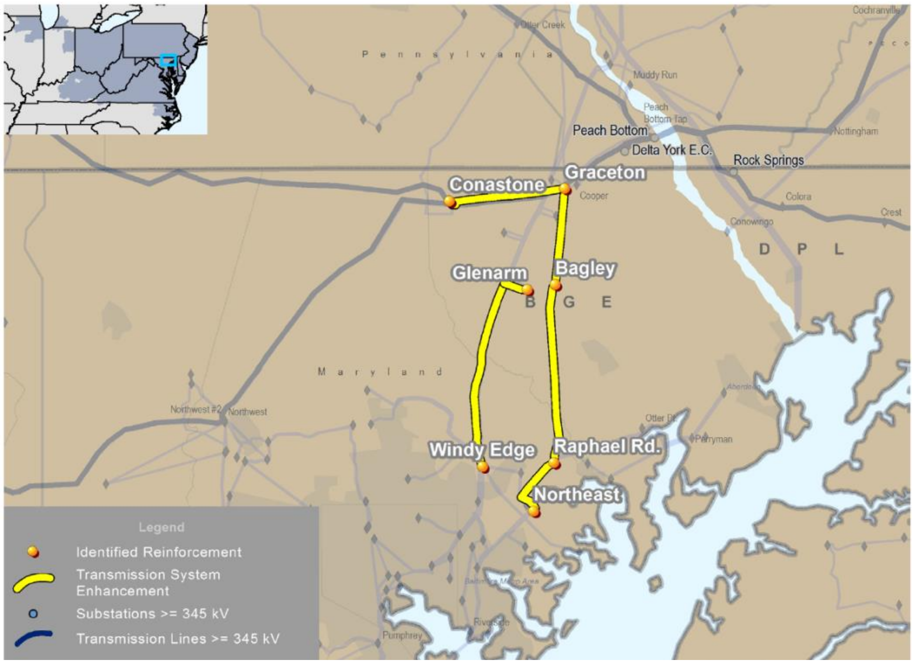
RTEP Analyses[9]	Date Presented	Benefit-to-Cost Ratio
Re-evaluation of Project 5E	Nov. 14, 2019	1.11[10]
Re-evaluation of Project 5E (assuming Board approval of Project H-L)	Nov. 14, 2019	1.80
Project 9A + Project 5E + Project H-L	Dec. 12, 2019	2.87, aggregate
Alternative Project 9A + Project 5E + Project H-L	Dec. 12, 2019	2.25 (using $561.68M as cost est.) - 2.33 (using $533.99M as cost est.), aggregate

Although an initial re-evaluation of Project 5E indicated that the project no longer satisfied the benefit-to-cost criteria due to the continued evolution of the RTEP and increased cost estimates, PJM's RTEP analyses described above have studied the interaction of Project 5E, Project H-L and Project 9A or Alternative Project 9A. PJM's analyses indicate that it would not be accurate to conclude that Project 5E is no longer performing because the project combinations analyzed show that when Project 5E is studied in context, it no longer binds first and continues to exceed the 1.25 benefit-to-cost ratio threshold. For the reasons discussed above, PJM recommends that Project 5E remain in the RTEP.

[9] The market efficiency base case was updated in July 2019 and further revised in September 2019.

[10] For further discussion, see the section of this paper regarding Project 5E, below.

Map 28. Project 5E



PJM's Recommendation of Project H-L

PJM opened a Long-Term Proposal Window on Nov. 2, 2018, that closed on March 15, 2019. For the reasons that follow, and because of the interactions between Project H-L, Project 5E and Project 9A or Alternative Project 9A, PJM recommends that the Board approve Project H-L and include it in the RTEP.

Project H-L consists of upgrades and changes to existing equipment designated to the incumbent transmission owner:

- Rebuild the Hunterstown to Lincoln 115kV line
- Upgrade substation equipment at Hunterstown Substation
- Upgrade substation equipment at Lincoln Substation

The estimated cost for proposal Project H-L is $7.21 million, and the in-service date is June 2023.

PJM identified the Hunterstown-Lincoln 115 kV line as a targeted congestion facility. Simulations performed in advance of the 2018/2019 Long-Term Proposal Window identified over $20.77 million in market congestion on this facility based on 2023 input assumptions and simulation results. The below serves as a description of the analysis that was conducted for this proposal window.

PJM received a cluster of 22 proposals (19 greenfield proposals and three upgrade proposals) from seven entities to address the Hunterstown-Lincoln congestion driver. The proposed project costs ranged from $4.65 million to $290.95 million.

PJM analyzed the proposals to determine which, if any, satisfied the 1.25 benefit-to-cost ratio criteria and provided the greatest degree of congestion relief. The energy benefits associated with the proposed projects were determined using the methodologies specified in Schedule 6 of the Operating Agreement. PJM's annual energy benefits calculation for lower voltage facilities is weighted 100 percent to zones with a decrease in net load payments as a result of the proposed project. Change in net load payments comprises the change in gross load payments offset by the change in transmission rights credits. No capacity benefits were identified with these proposed projects.

PJM delevloped a list of the proposals that passed the benefit-to-cost ratio criteria in the base case, then PJM selected the highest five benefit-to-cost ratio proposals for further evaluation. PJM then conducted market efficiency sensitivity analysis with those five proposals.

When examining the five solutions chosen for further review, PJM found that three proposals fully addressed the congestion driver. These three proposals included: (1) Project H-L (presented to stakeholders as HL_622), which rebuilds the Hunterstown-Lincoln 115 kV line; (2) HL_ 469, which installs a SmartValve[11] on the Hunterstown-Lincoln 115 kV line; and (3) HL_960, which builds an additional Hunterstown-Lincoln 115kV line. PJM ultimately narrowed this list of three projects to two.

Figure 3 shows a comparison of the top two proposals highlighting the challenges involved with the SmartValve proposal.

Figure 3.**Comparison of Proposals for Hunterstown-Lincoln 115 kV Line**

Criteria	HL_622 Upgrade Solution	HL_469 SmartValve™* Solution
Constructability Risk	Upgrade, no additional property needed	Greenfield, permitting risk related to new property for substation due to location near historically sensitive area
PJM Operations and Markets	No changes needed to real-time operations procedures and practices	At this time, real-time operations would not be able to fully utilize the dynamic capabilities of this device without additional changes
Additional Integration Cost with Operations and Markets	No additional costs	May require updating Day-Ahead, Real-Time, SCADA systems to support full operational range of this type of device
Industry experience	Established well known solution	Limited experience with SmartValve™ device
Additional System Capability/Flexibility	Yes/No	No/Yes

**SmartValve is a Trademark of Smart Wires Inc.*

11 SmartValve, a Smart Wires Inc. product, acts as a variable impedance device that can vary the impedance on the line the device is installed on.

Based on the analysis performed, PJM selected Project H-L (HL_622), which rebuilds the Hunterstown-Lincoln 115 kV line as more efficient or cost effective solution because Project H-L:

- Has a benefit-to-cost ratio of 76.41
- Fully addresses the target congestion driver
- Is an upgrade and has less constructability risk
- Consistently delivers a high benefit-to-cost ratio, passes all sensitivity scenarios, and given the comparison criteria shown in Table 6, was the preferred solution
- Did not cause any reliability issues under PJM's RTEP reliability analysis.

PJM's RTEP analyses described above examined the interaction of Project 5E, Project H-L, and Project 9A or Alternative Project 9A. PJM's analyses indicate that Project H-L continues to play an important role in the mitigation of congestion in South-Central Pennsylvania and Northern Maryland as reflected in Table 6. In conclusion, Project H-L shown in Table 6 is being recommended to the Board for approval for inclusion in the RTEP. The local transmission owner/proposing entity, Mid-Atlantic Interstate Transmission (MAIT), would be designated to complete this work. Cost allocation for the project can be found in Table 7.

Table 16. **Summary of Recent RTEP Analyses Involving Project H-L**

RTEP Analyses[12]	Date Presented	Benefit to Cost Ratio
Project H-L	Nov. 14, 2019	76.41
Project 9A + Project 5E + Project H-L	To be presented at the December TEAC.	2.87, aggregate
Alternative Project 9A + Project 5E + Project H-L	To be presented at the December TEAC.	2.25 (using $561.68M as cost est.) - 2.33 (using $533.99M as cost est.), aggregate

Table 17. **Identified Market Efficiency Projects**

PJM Baseline ID	PJM Window Project ID	Project Description	Transmission Zone	Constraint Project Addresses	Project Cost ($M)	In-Service Date	B/C Ratio
b3145	201819_1-622	Rebuild the Hunterstown - Lincoln 115 kV 962 line (~2.6 mi.). Upgrade limiting terminal equipment at Hunterstown and Lincoln.	MetEd	Hunterstown -Lincoln 115 kV	7.21	2023	76.41

[12] The market efficiency base case was updated in July 2019 and further revised in September 2019.

Map 29. Project H-L

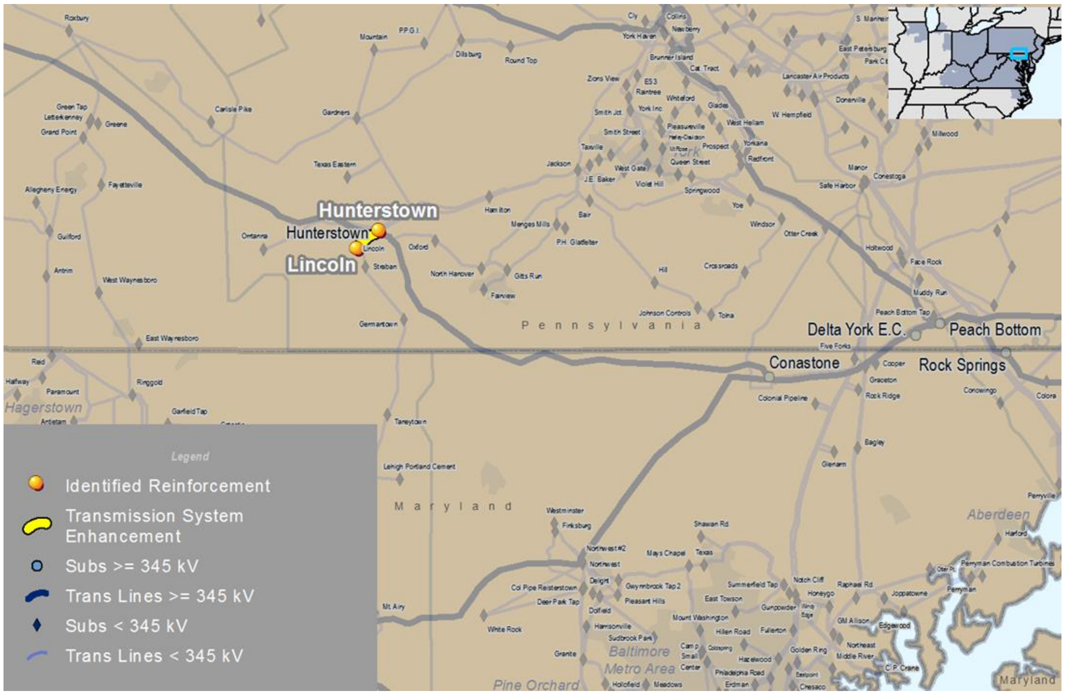


Table 18. **Cost Allocation Factors for Project H-L**

b3145	Rebuild the Hunterstown - Lincoln 115 kV line (No.962) (~2.6 mi.). Upgrade limiting terminal equipment at Hunterstown and Lincoln.	$7.21	ME	AEP (16.60%) APS (8.09%) BGE (2.74%) Dayton (2.00%) DEOK (0.35%) DL (1.31%) Dominion (52.77%) EKPC (1.54%) OVEC (0.06%) PEPCO (14.54%)	June 1, 2023

Appendix

Appendix A - Previously Identified RTEP Baseline Upgrades

Appendix A contains all currently required baseline upgrades that were identified in previous RTEP assessments. This appendix also contains expected required in-service dates for facilities. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. The continuing need for these required system facilities was evaluated as part of the 2019 RTEP assessment and will be evaluated in future RTEP assessments. This list of upgrades represents a snapshot of all required planned facilities in the RTEP as of 12/31/2019.

1) Baseline Upgrade b0866

- Replace Chalk Point 230 kV breaker (6C) with 80 Ka breaker - 6/1/2012 - $2.00M

2) Baseline Upgrade b1205

- Siegfried-East Palmerton #1 69 kV Line- Install new 69 kV LSAB, Sectionalize, and Transfer Treichlers Substation - 5/31/2014 - $0.27M

3) Baseline Upgrade b1269

- Reconductor / Rebuild West Milton - Salem 69kV and West Milton - Englewood - 6/1/2015 - $4.80M

4) Baseline Upgrade b1270

- Reconductor Bath - Trebein 138kV - 6/1/2015 - $1.30M

5) Baseline Upgrade b1273

- Add 2nd Bath 345/138kV Xfr - 6/1/2015 - $7.00M

6) Baseline Upgrade b1274

- Add 2nd Trebein 138/69kV Xfr - 6/1/2015 - $5.30M

7) Baseline Upgrade b1275

- Add 2nd W. Milton 138/69kV Xfr - 6/1/2015 - $8.80M

8) Baseline Upgrade b1276

- Add 2nd W. Milton 345/138 Xfr - 6/1/2015 - $5.50M

9) Baseline Upgrade b1345

- Install Martinsville 4-breaker 34.5 ring bus - 6/1/2012 - $20.10M

10) Baseline Upgrade b1570

- Add a 345/69 kV transformer at Dayton's Peoria 345 kV bus - 6/1/2014 - $16.00M

11) Baseline Upgrade b1570.1

- Add/reconductor Peoria - Darby 69 kV line - 6/1/2014 - $0.00M

12) Baseline Upgrade b1570.2

- Add / reconductor Peoria - Union REA 69 kV line - 6/1/2014 - $0.00M

13) Baseline Upgrade b1570.3

- Reconductor Union REA - Honda MT 69 kV line - 6/1/2014 - $0.00M

14) Baseline Upgrade b1572

- Construct a new 138 kV line from West Milton to Eldean - 6/1/2014 - $16.00M

15) Baseline Upgrade b1696

- Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV - 5/1/2016 - $103.05M

16) Baseline Upgrade b1696.1

- Replace the Idylwood 230 kV '25112' breaker with 50 kA breaker - 6/1/2017 - $0.35M

17) Baseline Upgrade b1696.2

- Replace the Idylwood 230 kV '209712' breaker with 50 kA breaker - 6/1/2017 - $0.35M

18) Baseline Upgrade b1880

- Rebuild the 15 miles of the Moseley - Roanoke 138 kV line. This project would consist of rebuilding both circuits on the double circuit line - 6/1/2016 - $30.00M

19) Baseline Upgrade b1881

- Replace existing 600 Amp switches, station risers and increase the CT ratios associated with breaker 'G' at Sterling 138 kV Station. It will increase the rating to 296 MVA S/N and 384 MVA S/E - 6/1/2016 - $0.60M

20) Baseline Upgrade b2003

- Construct a Whippany to Montville 230 kV line (6.4 miles) - 6/1/2015 - $80.60M

21) Baseline Upgrade b2212

- Shawville Substation: Relocate 230 kV and 115 kV controls from the generating station building to new control building - 12/1/2014 - $6.70M

22) Baseline Upgrade b2220

- Install two 115 kV breakers at Chestnut Hill and remove sag limitations on the Pumphrey - Frederick Rd 115 kV circuits 110527 and 110528 to obtain a 125 deg. Celsius rating (161/210 MVA) - 6/1/2017 - $11.58M

23) Baseline Upgrade b2257

- Rebuild the Pokagon - Corey 69 kV line as a double circuit 138 kV line with one side at 69 kV and the other side as an express circuit between Pokagon and Corey stations - 6/1/2017 - $84.70M

24) Baseline Upgrade b2334

- Install a 69 kV, 22.96 MVAR capacitor bank at the Owen County substation - 6/1/2017 - $0.36M

25) Baseline Upgrade b2361

- Construct a 230kV UG line approx. 4.5 miles from Idylwood to Tysons. Tysons Substation will be rebuilt, within its existing footprint, with a 6-breaker ring bus using GIS equipment. - 6/1/2017 - $121.79M

26) Baseline Upgrade b2396.1

- Install a tie breaker at Mays Chapel 115 kV substation - 6/1/2018 - $5.25M

27) Baseline Upgrade b2436.90

- Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades - 6/1/2015 - $40.21M

28) Baseline Upgrade b2496

- Replace Franklin 115/34.5 kV transformer #2 with 90 MVA transformer - 6/1/2015 - $3.00M

29) Baseline Upgrade b2501.4

- Build 2 new 69 kV exits to reinforce 69 kV facilities and upgrade conductor between Irish Run 69 kV Switch and Bowerstown 69 kV Switch - 6/1/2014 - $30.54M

30) Baseline Upgrade b2505

- Install structures in river to remove the 115 kV #65 line (Whitestone - Harmony Village 115 kV) from bridge and improve reliability of the line - 5/31/2016 - $100.00M

31) Baseline Upgrade b2552.1

- Reconductor the North Meshoppen – Oxbow - Lackawanna 230 kV circuit and upgrade terminal equipment (PENELEC portion) - 6/1/2019 - $89.50M

32) Baseline Upgrade b2555

- Reconductor 0.5 miles of Tiltonsville - Windsor 138 kV and string the vacant side of the 4.5 mile section using 556 ACSR in a six wire configuration - 6/1/2019 - $2.00M

33) Baseline Upgrade b2555.1

- Upgrade the terminal equipment and replace the last span of transmission line conductor into the Windsor substation - 6/1/2019 - $0.25M

34) Baseline Upgrade b2556

- Install two 138 kV prop structures to increase the maximum operating temperature of the Clinch River - Clinch Field 138 kV line - 6/1/2019 - $1.10M

35) Baseline Upgrade b2557

- Re-configure the existing Avon 345kV substation into a breaker-and-a-half layout - 6/1/2019 - $13.60M

36) Baseline Upgrade b2564

- Add two breakers at Miami Fort 138 kV; Interim solution to violation driven by Beckjord GTs deactivations is to lower generation at Miami Fort to 120 MW - 6/1/2019 - $1.50M

37) Baseline Upgrade b2568

- Reconductor Northwest – Northwest #2 115kV 110574 substation tie circuit with 2167 ACSR to achieve ratings of 400/462 MVA SN/SE - 6/1/2019 - $3.38M

38) Baseline Upgrade b2586

- Upgrade the V74 34.5 kV transmission line between Allenhurst and Elberon Substations - 6/1/2018 - $16.00M

39) Baseline Upgrade b2593

- Rebuild existing West Bellaire - Glencoe 69 kV line with 138 kV & 69 kV circuits and install 138/69 kV transformer at Glencoe Switch - 6/1/2019 - $30.00M

40) Baseline Upgrade b2594

- Rebuild 1.0 mile of Brantley - Bridge Street 69 kV Line with 1033 ACSR overhead conductor - 6/1/2019 - $1.50M

41) Baseline Upgrade b2597

- Rebuild approximately 1 mi. section of Dragoon-Virgil Street 34.5 kV line between Dragoon and Dodge Tap switch and replace Dodge switch MOAB to increase thermal capability of Dragoon-Dodge Tap branch - 6/1/2019 - $2.15M

42) Baseline Upgrade b2598

- Rebuild approximately 1 mile section of the Kline-Virgil Street 34.5 kV line between Kline and Virgil Street tap. Replace MOAB switches at Beiger, risers at Kline, switches and bus at Virgil Street. - 6/1/2019 - $1.69M

43) Baseline Upgrade b2599

- Rebuild approximately 0.1 miles of 69 kV line between Albion and Albion tap - 6/1/2019 - $0.20M

44) Baseline Upgrade b2602.2

- Construct 2.5 Miles of 138 kV 1033 ACSR from East Huntington to Darrah 138 kV substations - 6/1/2019 - $0.00M

45) Baseline Upgrade b2602.3

- Install breaker on new line exit at Darrah towards East Huntington - 6/1/2019 - $0.00M

46) Baseline Upgrade b2602.4

- Install 138 kV breaker on new line at East Huntington towards Darrah - 6/1/2019 - $1.67M

47) Baseline Upgrade b2602.5

- Install 138 kV breaker at East Huntington towards North Proctorville - 6/1/2019 - $2.07M

48) Baseline Upgrade b2603

- Boone Area Improvements - 6/1/2019 - $43.18M

49) Baseline Upgrade b2603.1

- Purchase approximately a 200X300 station site near Slaughter Creek 46 kV station (Wilbur Station) - 6/1/2019 - $0.00M

50) Baseline Upgrade b2603.3

- Construct 1 mi. of double circuit 138 kV line on Wilbur - Boone 46 kV line with 1590 ACSS 54/19 conductor @ 482 Degree design temp. and 1-159 12/7 ACSR and one 86 Sq.MM. 0.646" OPGW Static wires - 6/1/2019 - $12.06M

51) Baseline Upgrade b2605

- Rebuild and reconductor Kammer - George Washington 69 kV circuit and George Washington - Moundsville Ckt #1, designed for 138kV. Upgrade limiting equipment at remote ends and at tap stations - 6/1/2019 - $26.00M

52) Baseline Upgrade b2610

- Rebuild Pax Branch - Scaraboro as 138 kV - 6/1/2019 - $11.80M

53) Baseline Upgrade b2611

- Skin Fork Area Improvements - 6/1/2019 - $25.98M

54) Baseline Upgrade b2611.1

- New 138/46 kV station near Skin Fork and other components - 6/1/2019 - $0.00M

55) Baseline Upgrade b2611.2

- Construct 3.2 miles of 1033 ACSR double circuit from new Station to cut into Sundial-Baileysville 138 kV line - 6/1/2019 - $0.00M

56) Baseline Upgrade b2621

- Replace relays at East Towanda and East Sayre 115 kV substations (158/191 MVA SN/SE) - 6/1/2018 - $1.40M

57) Baseline Upgrade b2626

- Rebuild the 115 kV Line No.34 (Skiffes Creek - Yorktown) and the double circuit portion of 115kV Line No.61 to current standards with a summer emergency rating of 353 MVA at 115 kV. Rebuild the 2.5 mile tap line to Fort Eustis as Double Circuit line to loop line No.34 in and out of Fort Eustis station to current standard with a summer emergency rating of 393 MVA at 115 kV. Install a 115 kV breaker in line No.34 at Fort Eustis station. - 12/31/2018 - $24.20M

58) Baseline Upgrade b2633

- Artificial Island Solution - 4/1/2019 - $0.00M

59) Baseline Upgrade b2633.1

- Build a new 230 kV transmission line between Hope Creek and Silver Run - 4/1/2019 - $129.60M

60) Baseline Upgrade b2633.10

- Interconnect the new Silver Run 230 kV substation with existing Red Lion - Cartanza and Red Lion - Cedar Creek 230 kV lines - 4/1/2019 - $2.00M

61) Baseline Upgrade b2633.2

- Construct a new Silver Run 230 kV substation - 4/1/2019 - $16.40M

62) Baseline Upgrade b2633.4

- Add a new 500 kV bay at Hope Creek (Expansion of Hope Creek substation) - 4/1/2019 - $46.70M

63) Baseline Upgrade b2633.5

- Add a new 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation - 4/1/2019 - $58.30M

64) Baseline Upgrade b2633.91

- Implement changes to the tap settings for the two Salem units' step up transformers - 4/1/2019 - $0.01M

65) Baseline Upgrade b2633.92

- Implement changes to the tap settings for the Hope Creek unit's step up transformers - 4/1/2019 - $0.01M

66) Baseline Upgrade b2643

- Replace the Darrah 138 kV breaker 'L' with 40kA rated breaker - 6/1/2019 - $2.30M

67) Baseline Upgrade b2650

- Rebuild Twittys Creek - Pamplin 115 kV Line #154 (17.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV. - 12/31/2020 - $18.10M

68) Baseline Upgrade b2651

- Rebuild Buggs Island - Plywood 115 kV Line #127 (25.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV. The line should be rebuilt for 230 kV and operated at 115 kV. - 12/31/2021 - $42.41M

69) Baseline Upgrade b2652

- Rebuild Greatbridge - Hickory 115 kV Line #16 and Greatbridge - Chesapeak E.C. to current standard with summer emergency rating of 353 MVA at 115 kV. - 12/1/2021 - $26.70M

70) Baseline Upgrade b2656

- Reconductor the Leon - Airport Road 69 kV line section (5.72 miles) using 556.5 MCM ACTW conductor - 12/1/2018 - $1.65M

71) Baseline Upgrade b2668

- Reconductor Dequine - Meadow Lake 345 kV circuit #1 utilizing dual 954 ACSR 54/7 cardinal conductor - 6/1/2020 - $5.10M

72) Baseline Upgrade b2671

- Replace/upgrade/add terminal equipment at Bradley, Mullensville, Pinnacle Creek, Itmann, and Tams Mountain 138 kV substations. Sag study on Mullens – Wyoming and Mullens – Tams Mt. 138 kV circuits - 6/1/2020 - $5.36M

73) Baseline Upgrade b2673

- Rebuild the existing double circuit tower line section from Beaver substation to Brownhelm Jct. approx. 2.8 miles - 6/1/2020 - $10.00M

74) Baseline Upgrade b2675

- Install 26.4 MVAR capacitor and associated terminal equipment at Lincoln Park 138 kV substation - 6/1/2020 - $1.00M

75) Baseline Upgrade b2678

- Convert the East Towanda 115 kV substation to breaker and half configuration - 6/1/2020 - $18.80M

76) Baseline Upgrade b2679

- Install a 115 kV Venango Jct. line breaker at Edinboro South - 6/1/2020 - $2.07M

77) Baseline Upgrade b2681

- Install a 115 kV breaker on the Eclipse #2 115/34.5 kV transformer - 6/1/2020 - $0.70M

78) Baseline Upgrade b2682

- Install two 21.6 MVAR capacitors at the Shade Gap 115 kV substation - 6/1/2020 - $5.00M

79) Baseline Upgrade b2683

- Install a 36 MVAR 115 kV capacitor and associated equipment at Morgan Street substation - 6/1/2020 - $1.52M

80) Baseline Upgrade b2684

- Install a 36 MVAR 115 kV capacitor at Central City West substation - 6/1/2020 - $1.50M

81) Baseline Upgrade b2685

- Install a second 115 kV 3000A bus tie breaker at Hooversville substation - 6/1/2020 - $1.42M

82) Baseline Upgrade b2686

- Pratts Area Improvement - 6/1/2018 - $111.95M

83) Baseline Upgrade b2686.1

- Build a 230 kV line from Remington Substation to Gordonsville Substation utilizing existing ROW - 6/1/2018 - $0.00M

84) Baseline Upgrade b2686.11

- Upgrading sections of the Gordonsville - Somerset 115 kV circuit - 6/1/2018 - $0.00M

85) Baseline Upgrade b2686.12

- Upgrading sections of the Somerset - Doubleday 115 kV circuit - 6/1/2018 - $0.00M

86) Baseline Upgrade b2686.14

- Upgrading sections of the Mitchell - Mt. Run 115 kV circuit - 6/1/2018 - $0.00M

87) Baseline Upgrade b2686.2

- Install a 3rd 230/115 kV transformer at Gordonsville Substation - 6/1/2018 - $0.00M

88) Baseline Upgrade b2686.3

- Upgrade Line 2088 between Gordonsville Substation and Lousia CT Station - 6/1/2018 - $0.00M

89) Baseline Upgrade b2697.1

- Mitigate violations identified by sag study to operate Fieldale-Thornton-Franklin 138 kV overhead line conductor at its max. operating temperature. 6 potential line crossings to be addressed. - 6/1/2019 - $1.30M

90) Baseline Upgrade b2697.2

- Replace terminal equipment at AEP's Danville and East Danville substations to improve thermal capacity of Danville - East Danville 138 kV circuit - 6/1/2019 - $1.40M

91) Baseline Upgrade b2708

- Replace the Oceanview 230/34.5 kV transformer #1 - 6/1/2020 - $4.07M

92) Baseline Upgrade b2709

- Replace the Deep Run 230/34.5 kV #1 - 6/1/2020 - $2.43M

93) Baseline Upgrade b2715

- Install a 69 kV ring bus at Flushing instead of a 69/34.5 kV transformer, Convert Smyrna to 69 kV and install two 69 kV breakers, Convert Vail to 69 kV and serve AEP Distribution via a 69/34.5 kV transformer, Build the Flushing – Smyrna line to 69 kV instead of 34.5 kV. - 6/1/2020 - $29.40M

94) Baseline Upgrade b2727

- Replace the South Canton 138 kV breakers 'K', 'J','J1', and 'J2' with 80 kA breakers. - 6/1/2018 - $1.20M

95) Baseline Upgrade b2729

- Optimal Capacitors Configuration: New 175 MVAR 230 kV capacitor bank at Brambleton substation, new 175 MVAR 230 kV capacitor bank at Ashburn substation, new 300 MVAR 230 kV capacitor bank at Shelhorn substation, new 150 MVAR 230 kV capacitor bank at Liberty substation. - 12/1/2019 - $8.98M

96) Baseline Upgrade b2733

- Replace South Canton 138 kV breakers 'L' and 'L2' with 80 kA rated breakers - 6/1/2021 - $0.78M

97) Baseline Upgrade b2743.1

- Tap the Conemaugh - Hunterstown 500 kV line & create new Rice 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $31.93M

98) Baseline Upgrade b2743.2

- Tie in new Rice substation to Conemaugh-Hunterstown 500 kV - 6/1/2020 - $15.16M

99) Baseline Upgrade b2743.3

- Upgrade terminal equipment at Conemaugh 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.35M

100) Baseline Upgrade b2743.4

- Upgrade terminal equipment at Hunterstown 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.20M

101) Baseline Upgrade b2743.5

- Build new 230 kV double circuit line between Rice and Ringgold 230 kV, operated as a single circuit. - 6/1/2020 - $94.42M

102) Baseline Upgrade b2743.6

- Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme - 6/1/2020 - $7.87M

103) Baseline Upgrade b2743.6.1

- Replace the two Ringgold 230/138 kV transformers - 6/1/2020 - $6.26M

104) Baseline Upgrade b2743.7

- Rebuild/Reconductor the Ringgold - Catoctin 138 kV circuit and upgrade terminal equipment on both ends - 6/1/2020 - $47.22M

105) Baseline Upgrade b2743.8

- Replace Ringgold Substation 138 kV breakers '138 BUS TIE' and 'RCM0' with 40 kA breakers - 6/1/2020 - $0.71M

106) Baseline Upgrade b2745

- Rebuild 21.32 miles of existing line between Chesterfield - Lakeside 230 kV - 6/1/2018 - $41.50M

107) Baseline Upgrade b2752.1

- Tap the Peach Bottom – TMI 500 kV line & create new Furnace Run 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $39.80M

108) Baseline Upgrade b2752.2

- Tie in new Furnace Run substation to Peach Bottom-TMI 500 kV - 6/1/2020 - $10.50M

109) Baseline Upgrade b2752.3

- Upgrade terminal equipment and required relay communication at Peach Bottom 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $1.70M

110) Baseline Upgrade b2752.4

- Upgrade terminal equipment and required relay communication at TMI 500 kV: on the Peach Bottom -

TMI 500 kV circuit - 6/1/2020 - $2.00M

111) Baseline Upgrade b2752.5

- Build new 230 kV double circuit line between Furnace Run and Conastone 230 kV, operated as a single circuit. - 6/1/2020 - $51.12M

112) Baseline Upgrade b2752.6

- Conastone 230 kV substation tie-in work (install a new circuit breaker at Conastone 230 kV and upgrade any required terminal equipment to terminate the new circuit) - 6/1/2020 - $6.14M

113) Baseline Upgrade b2752.7

- Reconductor/Rebuild the two Conastone - Northwest 230 kV lines and upgrade terminal equipment on both ends - 6/1/2020 - $52.14M

114) Baseline Upgrade b2752.8

- Replace the Conastone 230kV '2322 B5' breaker with a 63kA breaker - 6/1/2020 - $1.51M

115) Baseline Upgrade b2752.9

- Replace the Conastone 230kV '2322 B6' breaker with a 63kA breaker - 6/1/2020 - $1.51M

116) Baseline Upgrade b2753.2

- Replace Dilles Bottom 69/4 kV Distribution station as breaker and a half 138 kV yard design including AEP Distribution facilities but initial configuration will constitute a 3 breaker ring bus. - 5/31/2020 - $9.00M

117) Baseline Upgrade b2753.3

- Holloway Station – Connect two 138kV 6-wired ckts from "Point A" (currently de-energized and owned by First Energy) in ckt positions previously designated Burger #1 & Burger #2. Install interconnection settlement metering on both circuits exiting Holloway station. - 5/31/2020 - $2.00M

118) Baseline Upgrade b2753.4

- Double capacity for 6 wire "Burger-Cloverdale No. 2" 138 kV line and connect at Holloway and "Point A" - 5/31/2020 - $2.10M

119) Baseline Upgrade b2753.5

- Double capacity for 6 wire "Burger-Longview" 138 kV line and connect at Holloway and "Point A" - 5/31/2020 - $2.10M

120) Baseline Upgrade b2753.6

- Build double circuit 138 kV line from Dilles Bottom to "Point A". Tie each new AEP circuit in with a 6 wired line at Point A. This will create a Dilles Bottom - Holloway 138 kV circuit and a George Washington - Holloway 138 kV circuit. - 5/31/2020 - $5.00M

121) Baseline Upgrade b2753.7

- Retire line sections (Dilles Bottom - Bellaire and Moundsville - Dilles Bottom 69 kV lines) south of First Energy 138 kV line corridor, near "Point A". Tie George Washington - Moundsville 69 kV circuit to

George Washington - West Bellaire 69 kV circuit. - 5/31/2020 - $5.52M

122) Baseline Upgrade b2753.8

- Rebuild existing 69 kV line as double circuit from George Washington - Dilles Bottom 138 kV. One circuit will cut into Dilles Bottom 138 kV initially and the other will go past with future plans to cut in. - 5/31/2020 - $3.56M

123) Baseline Upgrade b2753.9

- Remove/Open Kammer 345/138 kV transformer #301 - 5/31/2020 - $0.00M

124) Baseline Upgrade b2754.2.1

- Install 0.6 mi of optical ground wire (OPGW) between Gilbert and Springfield 230 kV substations - 6/1/2017 - $0.40M

125) Baseline Upgrade b2754.2.2

- Install 4.4 mi of optical ground wire (OPGW) between Gilbert and Springfield 230 kV substations - 6/1/2017 - $3.00M

126) Baseline Upgrade b2754.3.1

- Install 3 mi of all-dielectric self-supporting (ADSS) fiber optic cable between Morris Park and Northwood 230 kV substations - 6/1/2017 - $0.25M

127) Baseline Upgrade b2754.3.2

- Install 4 mi of all-dielectric self-supporting (ADSS) fiber optic cable between Morris Park and Northwood 230 kV substations - 6/1/2017 - $0.75M

128) Baseline Upgrade b2754.4

- Use ~ 40 route mi. of existing fibers on PPL 230 kV system to establish direct fiber circuits - 6/1/2017 - $0.02M

129) Baseline Upgrade b2754.5

- Upgrade relaying at Martins Creek 230 kV - 6/1/2017 - $0.14M

130) Baseline Upgrade b2754.6

- Upgrade relaying at Morris Park 230 kV substation - 6/1/2017 - $0.14M

131) Baseline Upgrade b2754.7

- Upgrade relaying at Gilbert 230 kV substation - 6/1/2017 - $0.14M

132) Baseline Upgrade b2758

- Rebuild Line #549 Dooms – Valley 500kV - 6/1/2016 - $62.25M

133) Baseline Upgrade b2759

- Rebuild Line #550 Mt. Storm – Valley 500kV - 6/1/2016 - $288.19M

134) Baseline Upgrade b2760

- Perform a Sag Study of the Saltville - Tazewell 138 kV line to increase the thermal rating of the line -

6/1/2021 - $0.10M

135) Baseline Upgrade b2761.1

- Replace and relocate the Hazard 161/138 kV Transformer and circuit breaker 'M'. Upgrade protection scheme on the new Transformer including installation of low side breaker. - 6/1/2021 - $2.30M

136) Baseline Upgrade b2761.2

- Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line - 6/1/2021 - $0.00M

137) Baseline Upgrade b2761.3

- Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating). Replace line relaying and associated termination equipment. - 6/1/2021 - $16.48M

138) Baseline Upgrade b2762

- Perform a Sag Study of Nagel - West Kingsport 138 kV line to increase the thermal rating of the line - 6/1/2021 - $0.10M

139) Baseline Upgrade b2764

- Upgrade Fairview Substation 138 kV breaker risers and disconnect leads; Replace 500 CU breaker risers and 556 ACSR disconnect leads with 795 ACSR - 6/1/2021 - $0.03M

140) Baseline Upgrade b2765

- Upgrade bus conductor at Gardners 115 kV substation; Upgrade bus conductor and adjust CT ratios at Carlisle Pike 115 kV - 6/1/2021 - $0.10M

141) Baseline Upgrade b2766.1

- Upgrade substation equipment at Conastone 500 kV (on the Peach Bottom – Conastone 500 kV circuit) to increase facility rating to 2826 MVA normal and 3525 MVA emergency - 6/1/2021 - $2.70M

142) Baseline Upgrade b2766.2

- Upgrade substation equipment at Peach Bottom 500 kV (on the Peach Bottom – Conastone 500 kV circuit) to increase facility rating to 2826 MVA normal and 3525 MVA emergency - 6/1/2021 - $4.30M

143) Baseline Upgrade b2767

- Construct a new 345 kV breaker string with three (3) 345 kV breakers at Homer City substation and move the North autotransformer connection to this new breaker string - 6/1/2021 - $6.00M

144) Baseline Upgrade b2774

- Reconductor the Emilie - Falls 138 kV line, and and replace station cable and relay - 6/1/2017 - $4.50M

145) Baseline Upgrade b2776

- Reconductor the entire Dequine - Meadow Lake 345 kV circuit #2 - 6/1/2021 - $6.60M

146) Baseline Upgrade b2777

- Reconductor the entire Dequine - Eugene 345 kV circuit #1 - 6/1/2021 - $22.19M

147) Baseline Upgrade b2778

- Add 2nd 345/138 kV transformer at Chamberlin substation - 6/2/2021 - $4.00M

148) Baseline Upgrade b2779.1

- Construction a new 138 kV station, Campbell Road, tapping into the Grabill – South Hicksville138 kV line - 6/1/2016 - $107.70M

149) Baseline Upgrade b2779.2

- Reconstruct sections of the Butler-N.Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road station - 6/1/2016 - $0.00M

150) Baseline Upgrade b2779.3

- Construct a new 345/138 kV SDI Wilmington Station which will be sourced from Collingwood 345 kV and serve the SDI load at 345 kV and 138 kV respectively - 6/1/2016 - $0.00M

151) Baseline Upgrade b2779.4

- Looped 138 kV circuits in-out of the new SDI Willington station resulting in a direct circuit to Auburn and in direct circuit to Auburn and Rob Park via Dunton Lake, and a circuit to Campbell Road; Reconductor 138kV line section between Dunton Lake – SDI Wilmington - 6/1/2016 - $0.00M

152) Baseline Upgrade b2779.5

- Expand Auburn 138 kV bus - 6/1/2016 - $0.00M

153) Baseline Upgrade b2783

- Rebuild the Davis - Fayette 69kv line section to 556.5 MCM (3.15 miles) - 12/1/2021 - $1.30M

154) Baseline Upgrade b2787

- Reconductor 0.53 miles (14 spans) of the Kaiser Jct-Air Force Jct Sw section of the Kaiser-Heath 69 kV circuit/line with 336 ACSR to match the rest of the circuit (73 MVA rating, 78% loading). - 6/1/2021 - $1.10M

155) Baseline Upgrade b2788

- Install a new 3-way 69kV line switch to provide service to AEP's Barnesville distribution station. Remove a portion of the #1 copper T-Line from the 69kV through-path. - 6/1/2021 - $5.00M

156) Baseline Upgrade b2789

- Rebuild the Brues-Glendale Heights 69kV line section (5 miles) with 795 ACSR (128 MVA rating, 43% loading) - 6/1/2021 - $5.00M

157) Baseline Upgrade b2791

- Rebuild Tiffin-Howard, new transformer at Chatfield - 6/1/2021 - $20.39M

158) Baseline Upgrade b2791.2

- Rebuild Tiffin-Howard 69kV line from St. Stephen's Switch to Hinesville (14.7 miles) using 795 ACSR Drake conductor (90 MVA rating, non-conductor limited, 38% loading). - 6/1/2021 - $18.63M

159) Baseline Upgrade b2791.3

- New 138/69kV transformer with 138kV & 69kV protection at Chatfield station. - 6/1/2021 - $0.00M

160) Baseline Upgrade b2791.4

- New 138kV & 69kV protection at existing Chatfield transformer. - 6/1/2021 - $2.50M

161) Baseline Upgrade b2792

- Replace the Elliott transformer with a 130 MVA unit. Reconductor 0.42 miles of the Elliott – Ohio University 69 kV line with 556 ACSR to match the rest of the line conductor (102 MVA rating, 73% loading) and rebuild 4 miles of the Clark Street – Strouds Run 69 kV with 556 ACSR conductor (102 MVA rating, 76% loading). - 6/1/2021 - $12.65M

162) Baseline Upgrade b2793

- Energize the spare Fremont Center 138/69 kV 130 MVA transformer #3. Reduces overloaded facilities to 46% loading. - 6/1/2021 - $1.30M

163) Baseline Upgrade b2794

- Construct new 138/69/34 kV station and one(1)34 kV circuit (designed for 69 kV) from new station to Decliff station, approximately 5.5 miles, with 556 ACSR conductor (51 MVA rating). - 6/1/2021 - $3.20M

164) Baseline Upgrade b2795

- Install a 34.5 kV 4.8 MVAR capacitor bank at Killbuck 34.5kV station. - 6/1/2021 - $4.80M

165) Baseline Upgrade b2796

- Rebuild the Malvern-Oneida Switch 69kV line section with 795 ACSR (1.8 miles, 125 MVA rating, 55% loading). - 6/1/2021 - $2.60M

166) Baseline Upgrade b2799

- Rebuild Valley-Almena, Almena-Hartford, Riverside-South Haven 69kV lines. New line exit at Valley Station. New transformers at Almena and Hartford - 6/1/2021 - $62.50M

167) Baseline Upgrade b2799.2

- Rebuild 3.2 miles of Almena to Hartford 69kV line using 795 ACSR conductor (90 MVA rating). - 6/1/2021 - $33.38M

168) Baseline Upgrade b2799.3

- Rebuild 3.8 miles of Riverside – South Haven 69V line using 795 ACSR conductor (90 MVA rating). - 6/1/2021 - $39.90M

169) Baseline Upgrade b2799.4

- At Valley station, add new 138kV line exit with a 3000 A 40 kA breaker for the new 138 kV line to Almena and replace CB D with a 3000 A 40 kA breaker. - 6/1/2021 - $0.67M

170) Baseline Upgrade b2799.5

- At Almena station, install a 90MVA 138kV/69kV transformer with low side 3000 A 40 kA breaker and establish a new 138kV line exit towards Valley. - 6/1/2021 - $1.57M

171) Baseline Upgrade b2799.6

- At Hartford station, install a second 90MVA 138/69kV transformer with a circuit switcher and 3000 A 40 kA low side breaker. - 6/1/2021 - $6.60M

172) Baseline Upgrade b2800

- The 7 mile section from Dozier to Thompsons Corner of line #120 will be rebuilt to current standardsusing 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115kV. Line is proposed to be rebuilt on single circuit steel monopole structures. - 6/1/2017 - $12.60M

173) Baseline Upgrade b2801

- Line #76 and #79 will be rebuilt to current standard using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115kV. Proposed structure for rebuild is double circuit steel monopole structure - 12/30/2020 - $24.50M

174) Baseline Upgrade b2816.1

- Modify the Crane – Windy Edge 110591 & 110592 115 kV circuits by terminating Windy Edge Circuits 110591 & 110592 into Northeast Substation with the addition of new 115kV breaker positions at Northeast sub - 6/1/2018 - $5.16M

175) Baseline Upgrade b2816.2

- Modify the Crane – Windy Edge 110591 & 110592 115 kV circuits by terminating Crane Circuits 110591 & 110592 into Northeast Substation with the addition of new 115kV breaker positions at Northeast sub - 6/1/2018 - $5.16M

176) Baseline Upgrade b2818

- Replace West Huntington 138 kV breaker 'F' with a 40 kA breaker - 6/1/2019 - $1.00M

177) Baseline Upgrade b2819

- Replace Madison 138 kV breaker 'V' with a 63 kA breaker - 6/1/2019 - $1.00M

178) Baseline Upgrade b2820

- Replace Sterling 138 kV breaker 'G' with a 40 kA breaker - 6/1/2019 - $2.90M

179) Baseline Upgrade b2821

- Replace Morse 138 kV breakers '103', '104', '105', and '106' with 63 kA breakers - 6/1/2019 - $4.00M

180) Baseline Upgrade b2822

- Replace Clinton 138 kV breakers '105' and '107' with 63 kA breakers - 6/1/2019 - $2.00M

181) Baseline Upgrade b2827

- Upgrade the current 5% impedance 1200A line reactor, which connects the 4SPURLOCK - 4SPUR-KENT-R and 4SPUR-KENT-R - 4KENTON 138kV line sections, to a 6.5% impedance 1600A line reactor - 6/1/2021 - $0.60M

182) Baseline Upgrade b2828

- Install 10% reactors at Miami Fort 138 kV to limit current - 6/1/2021 - $1.00M

183) Baseline Upgrade b2830

- Expand Garver 345 kV sub to include 138 kV. Install 1-345 kV breaker, 1-345/138 kV 400 MVA transformer, 6-138 kV Breakers and bus work. Connect local 138 kV circuits from Todhunter, Rockies Express, and Union. - 6/1/2021 - $20.00M

184) Baseline Upgrade b2831.1

- Upgrade Tanner Creek to Miami Fort 345 kV line (AEP portion) - 12/1/2021 - $0.64M

185) Baseline Upgrade b2831.2

- Rebuild the Tanner Creek – Miami Fort 345kV line (DEOK portion) - 12/1/2021 - $16.10M

186) Baseline Upgrade b2832

- Six wire the Kyger Creek - Sporn 345 kV circuits #1 and #2 and convert them to one circuit - 12/1/2021 - $0.30M

187) Baseline Upgrade b2833

- Reconductor the Maddox Creek - East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor - 12/1/2021 - $18.20M

188) Baseline Upgrade b2834

- Reconductor and string open position and sixwire 6.2 miles of the Chemical - Capitol Hill 138 kV circuit - 12/1/2021 - $7.30M

189) Baseline Upgrade b2836

- Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits - 12/31/2021 - $302.00M

190) Baseline Upgrade b2836.1

- Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Hunterglen) - 12/31/2021 - M

191) Baseline Upgrade b2836.2

- Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) - 12/31/2021 - M

192) Baseline Upgrade b2836.3

- Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) - 12/31/2021 - M

193) Baseline Upgrade b2836.4

- Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) - 12/31/2021 - M

194) Baseline Upgrade b2837

- Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits - 6/1/2022 - $312.00M

195) Baseline Upgrade b2837.1

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) - 6/1/2022 - M

196) Baseline Upgrade b2837.10

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) - 6/1/2022 - M

197) Baseline Upgrade b2837.11

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) - 6/1/2022 - M

198) Baseline Upgrade b2837.2

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) - 6/1/2022 - M

199) Baseline Upgrade b2837.3

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) - 6/1/2022 - M

200) Baseline Upgrade b2837.4

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) - 6/1/2022 - M

201) Baseline Upgrade b2837.5

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) - 6/1/2022 – M

202) Baseline Upgrade b2837.6

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) - 6/1/2022 - M

203) Baseline Upgrade b2837.7

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) - 6/1/2022 – M

204) Baseline Upgrade b2837.8

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) - 6/1/2022 - M

205) Baseline Upgrade b2837.9

- Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) - 6/1/2022 - M

206) Baseline Upgrade b2838

- Build a new 230/69 kV substation by tapping the Montour - Susquehanna 230 kV double circuits and

Berwick - Hunlock & Berwick - Colombia 69 kV circuits - 6/1/2017 - $57.00M

207) Baseline Upgrade b2842

- Update the nameplate for Mount Storm 500kV "57272" to be 50kA breaker - 6/1/2019 - $0.00M

208) Baseline Upgrade b2857

- Replace the Parrish 230kV "CS 825" with 63kA breaker - 6/1/2019 - $0.38M

209) Baseline Upgrade b2858

- Replace the Parrish 230kV "CS 935" with 63kA breaker - 6/1/2019 - $0.38M

210) Baseline Upgrade b2862

- Replace the Grays Ferry 230kV "705" with 63kA breaker - 6/1/2019 - $0.38M

211) Baseline Upgrade b2864

- Replace the Grays Ferry 230kV "775" with 63kA breaker - 6/1/2019 - $0.38M

212) Baseline Upgrade b2870

- Build new 138/26 kV Newark GIS station in a building (layout #1A) located adjacent to the existing Newark Switch and demolish the existing Newark Switch - 6/1/2017 - $275.00M

213) Baseline Upgrade b2871

- Rebuild 230kV line #247 from Swamp to Suffolk (31 miles) to current standards with a summer emergency rating of 1047 MVA at 230kV. - 12/30/2022 - $31.00M

214) Baseline Upgrade b2872

- Replace the South Canton 138 kV breaker ‘K2’ with an 80 kA breaker . - 6/1/2019 - $0.60M

215) Baseline Upgrade b2873

- Replace the South Canton 138 kV breaker "M" with a 80 kA breaker - 6/1/2022 - $0.60M

216) Baseline Upgrade b2874

- Replace the South Canton 138 kV breaker "M2" with a 80 kA breaker - 6/1/2022 - $0.60M

217) Baseline Upgrade b2876

- Rebuild Line #101 from Mackeys - Creswell 115 kV, 14 miles, with double circuit structures. Install one circuit with provisions for a second circuit. The conductor used will be at current standards with a summer emergency rating of 262 MVA at 115kV. - 12/30/2022 - $36.70M

218) Baseline Upgrade b2877

- Rebuild Line #112 from Fudge Hollow - Lowmoor 138 kV (5.16 miles) to current standards with a summer emergency rating of 314 MVA at 138kV. - 10/31/2020 - $12.60M

219) Baseline Upgrade b2880

- Rebuild approximately 4.77 miles of the Cannonsburg – South Neal 69 kV line section utilizing 795 ACSR conductor (90 MVA rating, 83%) - 6/1/2021 - $17.39M

220) Baseline Upgrade b2881

- Rebuild ~1.7 miles of the Dunn Hollow – London 46kV line section utilizing 795 26/7 ACSR conductor (58 MVA rating, non-conductor limited, 55%). - 6/1/2021 - $4.00M

221) Baseline Upgrade b2882

- Rebuild Reusens-Peakland Switch 69kV line. Replace Peakland Switch. - 6/1/2021 - $2.90M

222) Baseline Upgrade b2882.1

- Rebuild the Reusens - Peakland Switch 69 kV line (approximately 0.8 miles) utilizing 795 ACSR conductor (86 MVA rating, non-conductor limited, 67%) - 6/1/2021 - $11.80M

223) Baseline Upgrade b2882.2

- Replace existing Peakland S.S with new 3 way switch phase over phase structure. - 6/1/2021 - $0.70M

224) Baseline Upgrade b2883

- Rebuild the Craneco – Pardee – Three Forks – Skin Fork 46kV line section (approximately 7.2 miles) utilizing 795 26/7 ACSR conductor (108 MVA rating, 43%) - 6/1/2021 - $16.60M

225) Baseline Upgrade b2884

- Install a second transformer at Nagel station, comprised of 3 single phase 250MVA 500/138kV transformers. Presently, TVA operates their end of the Boone Dam – Holston 138 kV interconnection as normally open preemptively for the loss of the existing Nagel 500/138 kV XF. By adding a second 500/138 kV transformer at Nagel, TVA will close in the interconnection, providing an additional source to the Kingsport area. - 6/1/2021 - $15.80M

226) Baseline Upgrade b2885.3

- Replace Coalton Switch with a new three breaker ring bus (Heppner). - 3/1/2018 - $5.33M

227) Baseline Upgrade b2887

- Add 2-138kV CB's and relocate 2-138kV circuit exits to different bays at Morse Road. Eliminate 3 terminal line by terminating Genoa-Morse circuit at Morse Road. - 12/31/2019 - $3.00M

228) Baseline Upgrade b2889

- Expand Cliffview station - 6/1/2021 - $32.00M

229) Baseline Upgrade b2889.1

- Rebuild Cliffview station in the clear as Wolf Glade 138/69 kV station. Build a 138 kV bus. Install one 138/69 kV (130 MVA) transformer, five 138 kV (40kA 3000A) breakers and three 69 kV (40kA 3000A) breakers. - 6/1/2021 - $0.00M

230) Baseline Upgrade b2889.2

- Retire Byllesby – Wythe 69 kV line: 13.77 miles of 1/0 CU (~4 miles currently in national forest). - 6/1/2021 - $0.00M

231) Baseline Upgrade b2889.3

- Retire 13.53 miles of Galax–Wythe 69 kV line (1/0 CU section) from Lee Highway down to Byllesby.

This section is currently double circuited with Byllesby – Wythe 69 kV. Terminate the southern 3/0 ACSR section into the newly opened position at Byllesby 69 kV, creating a new Galax – Byllesby 69 kV circuit. - 6/1/2021 - $0.00M

232) Baseline Upgrade b2889.4

- Tap the existing Pipers Gap – Jubal Early 138 kV line section. Construct double circuit in/out (~2 miles) to the new Wolf Glade 138/69 kV station, utilizing 795 26/7 ACSR conductor. - 6/1/2021 - $0.00M

233) Baseline Upgrade b2890.1

- Rebuild 23.55 miles of the East Cambridge – Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV. - 6/1/2021 - $34.00M

234) Baseline Upgrade b2890.2

- East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge – Smyrna 69 kV circuit. - 6/1/2021 - $0.54M

235) Baseline Upgrade b2890.3

- Old Washington: Install 69 kV 2000 A two way phase over phase switch. - 6/1/2021 - $0.51M

236) Baseline Upgrade b2890.4

- Antrim Switch: Install 69 kV 2000 A two way phase over phase switch. - 6/1/2021 - $2.50M

237) Baseline Upgrade b2891

- Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area. - 6/1/2021 - $4.80M

238) Baseline Upgrade b2894

- Replace Todhunter 138 kV breakers ‘931’, ‘919’, and ‘913’ with 80 kA breakers - 6/1/2021 - $2.40M

239) Baseline Upgrade b2895

- Replace Dicks Creek 138 kV breaker ‘963’ with 63 kA breaker - 6/1/2019 - $0.30M

240) Baseline Upgrade b2898

- Reconductor the Beaver - Black River 138kV) with 954Kcmil ACSS conductor and upgrade terminal equipment on both stations - 6/1/2021 - $25.00M

241) Baseline Upgrade b2899

- Rebuild 230kV Line #231 to current standard with a summer emergency rating of 1046 MVA. Proposed conductor is 2-636 ACSR. - 12/1/2020 - $19.00M

242) Baseline Upgrade b2900

- Build a new 230-115kV switching station connecting to 230kV network Line #2014 (Earleys – Everetts). Provide a 115kV source from the new station to serve Windsor DP. - 12/30/2022 - $11.50M

243) Baseline Upgrade b2901

- Reconductor the Port Union – Mulhauser 138kV line with 954ASCR bringing the summer ratings to

A/B/C=300/300/300 MVA. - 6/1/2021 - $4.40M

244) Baseline Upgrade b2902

- Rebuild the Brodhead - Three Links Jct. 69 kV line section (8.2 miles) using 556.5 MCM ACTW wire. - 12/1/2018 - $4.72M

245) Baseline Upgrade b2907

- Upgrade the metering CT associated with the Clay Village - KU Clay Village 69 kV Tap line section to 600 A; at least 64 MVA Winter LTE; Upgrade the distance relay associated with the Clay Village - KU Clay Village 69 kV Tap line section to at least 64 MVA Winter LTE. - 12/1/2024 - $0.13M

246) Baseline Upgrade b2910

- Upgrade the distance relay at the Hodgenville station associated with the Glendale - Hodgenville 69 kV line section to at least 90 MVA Winter LTE. - 12/1/2026 - $0.00M

247) Baseline Upgrade b2912

- Upgrade the existing S408-605, 600 A KU Russell Springs Tap -Russell County 69 kV disconnect switch to 1200 A. - 12/1/2025 - $0.15M

248) Baseline Upgrade b2913

- Upgrade distance relay at the Stephensburg station associated with Stephensburg - Glendale 69kV line section to at least winter LTE 100 MVA. - 12/1/2024 - $0.00M

249) Baseline Upgrade b2914

- Rebuild Tharp Tap-KU Elizabethtown 69kV line section to 795 MCM (2.11 miles). - 12/1/2024 - $1.22M

250) Baseline Upgrade b2915

- Resize the Sideview 69 kV capacitor bank from 6.12 MVAR to 9.18 MVAR. - 12/1/2023 - $0.07M

251) Baseline Upgrade b2921

- New TVA 161kV Interconnection to TVA's East Glasgow Tap-East Glasgow 161 KV line section (~1 mile due West of Fox Hollow). Add Fox Hollow 161/69 KV 150 MVA transformer. Construct new Fox Hollow-Fox Hollow Jct 161 KV line section using 795 MCM ACSR (~1 mile) and new 161kV switching station at point of interconnection with TVA. - 6/1/2018 - $18.10M

252) Baseline Upgrade b2922

- Rebuild 8 of 11 miles of 230kV Lines #211 and #228 to current standard with a summer emergency rating of 1046 MVA for rebuilt section. Proposed conductor is 2-636 ACSR. - 12/1/2020 - $28.54M

253) Baseline Upgrade b2923

- Replace the China Tap 230kV 'CS 15' breaker with 63kA breaker - 6/1/2019 - $0.60M

254) Baseline Upgrade b2924

- Replace the Emilie 230kV 'CS 15' breaker with 63kA breaker - 6/1/2019 - $0.60M

255) Baseline Upgrade b2925

- Replace the Emilie 230kV 'CS 25' breaker with 63kA breaker - 6/1/2019 - $0.60M

256) Baseline Upgrade b2929

- Rebuild 230kV Line #2144 from Winfall to Swamp (4.3 miles) to current standards with a standard conductor (bundled 636 ACSR) having a summer emergency rating of 1047 MVA at 230kV. - 12/30/2022 - $6.00M

257) Baseline Upgrade b2931

- Upgrade substation equipment at Pontiac Midpoint station to increase capacity on Pontiac-Brokaw 345 kV line. - 6/1/2021 - $5.62M

258) Baseline Upgrade b2932

- Replace terminal equipment at Tanners Creek on Tanners Creek Dearborn 345 kV line. - 6/1/2021 - $1.50M

259) Baseline Upgrade b2933

- Third Source for Springfield Rd. and Stanley Terrace Stations - 6/1/2018 - $189.49M

260) Baseline Upgrade b2933.1

- Construct a 230/69 kV station at Springfield. - 6/1/2018 - $0.00M

261) Baseline Upgrade b2933.2

- Construct a 230/69 kV station at Stanley Terrace - 6/1/2018 - $0.00M

262) Baseline Upgrade b2933.31

- Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Front Street - Springfield) - 6/1/2018 – M

263) Baseline Upgrade b2933.32

- Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Springfield – Stanley Terrace) - 6/1/2018 - M

264) Baseline Upgrade b2934

- Build a new 69kV line between Hasbrouck Heights and Carlstadt - 6/1/2018 - $15.94M

265) Baseline Upgrade b2935

- Third Supply for Runnemede 69kV and Woodbury 69kV - 6/1/2018 - $100.60M

266) Baseline Upgrade b2935.1

- Build a new 230/69 kV switching substation at Hilltop utilizing the PSE&G property and the K-2237 230 kV line. - 6/1/2018 - $0.00M

267) Baseline Upgrade b2935.2

- Build a new line between Hilltop and Woodbury 69 kV providing the 3rd supply - 6/1/2018 - $0.00M

268) Baseline Upgrade b2935.3

- Convert Runnemede's straight bus to a ring bus and construct a 69 kV line from Hilltop to Runnemede 69 kV. - 6/1/2018 - $0.00M

269) Baseline Upgrade b2936.1

- Rebuild approximately 6.7 miles of 69kV line between Mottville and Pigeon River using 795 ACSR conductor (129 MVA rating). New construction will be designed to 138kV standards but operated at 69kV. - 6/1/2020 - $12.00M

270) Baseline Upgrade b2937

- Replace the existing 636 ACSR 138 kV Bus at Fletchers Ridge with a larger 954 ACSR conductor. - 6/1/2022 - $0.63M

271) Baseline Upgrade b2938

- Perform a sag mitigations on the Broadford – Wolf Hills 138kV circuit to allow the line to operate to a higher maximum temperature. - 6/1/2022 - $2.60M

272) Baseline Upgrade b2940

- Upgrade the distance relay on the Wayne Co – Wayne Co KY 161kV line to increase the line winter rating would be 167/167 - 12/1/2022 - $0.00M

273) Baseline Upgrade b2941

- Build an indoor new Elk Grove 138kV GIS substation at the point where Rolling Meadows & Schaumburg tap off from the main lines, between Landmeier and Busse. The four 345 kV circuits in the ROW will be diverted into Gas Insulated Bus (GIB) and go through the basement of the building to provide clearance for the above ground portion of the building. - 12/31/2017 - $90.00M

274) Baseline Upgrade b2943

- Perform a LIDAR study on the Clifty Creek - Dearborn 345 kV line to increase the Summer Emergency rating above 1023MVA). - 6/1/2018 - $0.17M

75) Baseline Upgrade b2945.1

- Rebuild the BL England – Middle Tap 138kV line to 2000A on double circuited steel poles and new foundations - 6/1/2022 - $22.64M

276) Baseline Upgrade b2945.2

- Re-conductor BL England – Merion 138kV (1.9miles) line - 6/1/2022 - $3.92M

277) Baseline Upgrade b2945.3

- Re-conductor Merion – Corson 138kV (8miles) line - 6/1/2022 - $9.85M

278) Baseline Upgrade b2946

- Convert existing Preston 69 kV Substation to DPL's current design standard of a 3-breaker ring bus. - 6/1/2022 - $5.00M

279) Baseline Upgrade b2947.1

- Upgrade terminal equipment at DPL's Naamans Substation (Darley-Naamans 69 kV) - 6/1/2022 - $0.15M

280) Baseline Upgrade b2947.2

- Re-conductor 0.11 mile section of Darley-Naamans 69 kV circuit - 6/1/2022 - $0.20M

281) Baseline Upgrade b2948

- Upgrade terminal equipment at DPL's Silverside Road Substation (Dupont Edge Moor –Silver R. 69 kV) - 6/1/2022 - $0.15M

282) Baseline Upgrade b2950

- Upgrade limiting 115 kV switches on the 115 kV side of the 230/115 kV Northwood substation and adjust setting on limiting ZR relay - 6/1/2022 - $0.25M

283) Baseline Upgrade b2952

- Replace the North Meshoppen #3 230/115kV transformer eliminating the old reactor and installing two breakers to complete a 230kV ring bus at North Meshoppen - 6/1/2022 - $6.80M

284) Baseline Upgrade b2953

- Replace the Keystone 500kV breaker "NO.14 Cabot" with 50kA breaker - 6/1/2020 - $1.24M

285) Baseline Upgrade b2954

- Replace the Keystone 500kV breaker "NO.16 Cabot" with 50kA breaker - 6/1/2020 - $1.24M

286) Baseline Upgrade b2955

- Wreck and re-build the VFT – Warinanco – Aldene 230 kV circuit with paired conductor. - 6/1/2018 - $90.40M

287) Baseline Upgrade b2956

- Replace existing cable on Cedar Grove-Jackson Rd. with 5000kcmil XLPE cable. - 6/1/2018 - $69.86M

288) Baseline Upgrade b2957

- Replace existing cable on Maywood-Saddle Brook with 5000kcmil XLPE cable. - 6/1/2018 - $57.50M

289) Baseline Upgrade b2960.1

- Replace fixed series capacitors on 500kV Line #547 at Lexington - 4/1/2020 - $17.70M

290) Baseline Upgrade b2960.2

- Replace fixed series capacitors on 500kV Line #548 at Valley - 4/1/2020 - $16.80M

291) Baseline Upgrade b2961

- Rebuild approximately 3 miles of Line #205 & Line #2003 from Chesterfield to Locks & Poe respectively. - 12/31/2022 - $11.07M

292) Baseline Upgrade b2963

- Reconductor the Woodbridge to Occoquan 230kV line segment of Line 2001 with 1047 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan - 6/1/2022 - $4.70M

293) Baseline Upgrade b2964.1

- Replace terminal equipment at Pruntytown and Glen Falls 138 kV station. - 6/1/2022 - $0.26M

294) Baseline Upgrade b2964.2

- Reconductor approximately 8.3 miles of the McAlpin - White Hall Junction 138 kV circuit - 6/1/2022 - $3.79M

295) Baseline Upgrade b2965

- Reconductor the Charleroi –Allenport 138KV Line with 954 ACSR Conductor, Replace Breaker Risers at Charleroi and Allenport - 6/1/2022 - $7.50M

296) Baseline Upgrade b2967

- Convert the existing 6 wire Butler - Shanor Manor - Krendale 138 kV Line into two separate 138 kV lines. New lines will be Butler - Keisters and Butler - Shanor Manor - Krendale 138 kV - 6/1/2022 - $6.96M

297) Baseline Upgrade b2968

- Upgrade existing 345kV terminal equipment at Tanners Creek station on Tanners Creek - Miami Fort 345kV line - 6/1/2022 - $1.20M

298) Baseline Upgrade b2969

- Replace terminal equipment on Maddox Creek - East Lima 345kV circuit - 6/1/2022 - $1.48M

299) Baseline Upgrade b2970

- Ringgold - Catoctin Solution - 6/1/2020 - $0.00M

300) Baseline Upgrade b2970.1

- Install two new 230 kV positions at Ringgold for 230/138 kV transformers. - 6/1/2020 - $3.20M

301) Baseline Upgrade b2970.2

- Install new 230 kV position for Ringgold – Catoctin 230 kV line. - 6/1/2020 - $1.60M

302) Baseline Upgrade b2970.3

- Install one new 230 kV breaker at Catoctin substation. - 6/1/2020 - $7.60M

303) Baseline Upgrade b2970.4

- Install new 230 / 138 kV transformer at Catoctin substation. Convert Ringgold-Catoctin 138 kV Line to 230 kV operation. - 6/1/2020 - $0.90M

304) Baseline Upgrade b2971

- Reconfigure Munster 345kV as ring bus - 6/1/2020 - $6.70M

305) Baseline Upgrade b2972

- Reconductor limiting span of Lallendorf - Monroe 345kV (crossing of Maumee river) - 11/1/2019 - $3.90M

306) Baseline Upgrade b2973

- Reconductor Michigan City - Bosserman 138kV - 12/1/2019 - $6.00M

307) Baseline Upgrade b2974

- Replace terminal equipment at Reynolds on the Reynolds - Magnetation 138kV - 6/1/2019 - $0.12M

308) Baseline Upgrade b2975

- Reconductor Roxana - Praxair 138kV - 6/1/2020 - $6.10M

309) Baseline Upgrade b2976

- Upgrade terminal equipment at Tanners Creek 345kV station. Upgrade 345kV Bus and Risers at Tanners Creek for the Dearborn circuit. - 6/1/2021 - $0.30M

310) Baseline Upgrade b2977

- Portion of 2017_1-6A - 6/1/2021 - $9.17M

311) Baseline Upgrade b2977.1

- Install a new 345kV breaker “1422” so Pierce 345/138KV transformer #18 is now fed in a double breaker, double bus configuration. - 6/1/2021 - $0.00M

312) Baseline Upgrade b2977.2

- Remove X-533 No. 2 to the first tower outside the station. Install a new first tower for X-533 No.2. - 6/1/2021 - $0.00M

313) Baseline Upgrade b2977.3

- Install new 345KV breaker B and move the Buffington-Pierce 345kV feeder to the B-C junction. Install a new tower at the first tower outside the station for Buffington-Pierce 345kV line. - 6/1/2021 - $0.00M

314) Baseline Upgrade b2977.4

- Remove breaker A and move the Pierce 345/138kV transformer #17 feed to the C-D junction. - 6/1/2021 - $0.00M

315) Baseline Upgrade b2977.5

- Replace breaker 822 at Beckjord 138kV substation to increase the rating from Pierce to Beckjord 138kV to 603MVA. - 6/1/2021 - $0.00M

316) Baseline Upgrade b2978

- Install 2-125 MVAR STATCOMs at Rawlings and 1-125 MVAR STATCOM at Clover 500 kV Substations - 5/31/2021 - $47.00M

317) Baseline Upgrade b2980

- Rebuild 115kV Line #43 between Staunton and Harrisonburg (22.8 miles) to current standards with a summer emergency rating of 261 MVA at 115kV - 10/31/2022 - $39.60M

318) Baseline Upgrade b2981

- Rebuild 115 kV Line No.29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV) - 12/31/2022 - $19.24M

319) Baseline Upgrade b2982

- Construct a 230/69kV station at Hillsdale Substation and tie to Paramus and Dumont at 69kV. - 6/1/2018 - $99.06M

320) Baseline Upgrade b2982.1

- Install a 69kV ring bus and one (1) 230/69kV transformer at Hillsdale. - 6/1/2018 - $0.00M

321) Baseline Upgrade b2982.2

- Construct a 69kV network between Paramus, Dumont, and Hillsdale Substation using existing 69kV circuits - 6/1/2018 - $0.00M

322) Baseline Upgrade b2983

- Convert Kuller Road to a 69/13kV station - 6/1/2018 - $81.09M

323) Baseline Upgrade b2983.1

- Install 69kV ring bus and two (2) 69/13kV transformers at Kuller Road. - 6/1/2018 - $0.00M

324) Baseline Upgrade b2983.2

- Construct a 69kV network between Kuller Road, Passaic, Paterson, and Harvey (new Clifton area switching station). - 6/1/2018 - $0.00M

325) Baseline Upgrade b2984

- Reconfigure the bus at Glory and install a 50.4 MVAR 115 kV capacitor - 6/1/2021 - $6.30M

326) Baseline Upgrade b2985

- Replace the 230 kV CB #225 at Linwood Substation (PECO) with a double circuit breaker (back to back circuit breakers in one device). - 6/1/2022 - $1.40M

327) Baseline Upgrade b2986.1

- Roseland-Branchburg 230kV corridor rebuild - 6/1/2018 - $300.00M

328) Baseline Upgrade b2986.11

- Roseland-Branchburg 230kV corridor rebuild (Roseland - Readington) - 6/1/2018 - M

329) Baseline Upgrade b2986.12

- Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) - 6/1/2018 – M

330) Baseline Upgrade b2986.2

- Branchburg-Pleasant Valley 230kV corridor rebuild - 6/1/2018 - $246.00M

331) Baseline Upgrade b2986.21

- Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington) - 6/1/2018 - M

332) Baseline Upgrade b2986.22

- Branchburg-Pleasant Valley 230kV corridor rebuild (East Flemington - Pleasant Valley) - 6/1/2018 – M

333) Baseline Upgrade b2986.23

- Branchburg-Pleasant Valley 230kV corridor rebuild (Pleasant Valley - Rocktown) - 6/1/2018 - M

334) Baseline Upgrade b2986.24

- Branchburg-Pleasant Valley 230kV corridor rebuild (the PSEG portion of Rocktown - Buckingham) - 6/1/2018 - M

335) Baseline Upgrade b2987

- Install a 30 MVAR capacitor bank at DPL's Cool Springs 69 kV Substation. The capacitor bank would be installed in two separate 15 MVAR stages allowing DPL operational flexibility - 6/1/2022 - $1.75M

336) Baseline Upgrade b2989

- Install a second 230 -115 kV Transformer(224 MVA) approximately 1 mile north of Bremo and tie 230 kV Line #2028(Bremo – Charlottesville) and 115 kV Line #91 (Bremo-Sherwood) together. A three breaker 230 kV ring bus will split Line #2028 into two lines and Line #91 will also be split into two lines with a new three breaker 115 kV ring bus. Install a temporary 230-115 kV transformer at Bremo substation for the interim until the new substation is complete. - 6/1/2018 - $27.00M

337) Baseline Upgrade b2992.1

- Reconductor the Conastone to Graceton 230 kV 2323 & 2324 circuits. Replace 7 disconnect switches at Conastone Substation - 3/1/2021 - $18.49M

338) Baseline Upgrade b2992.2

- Add Bundle conductor on the Graceton-Bagley-Raphael Road 2305 & 2313 230kV circuits - 3/1/2021 - $20.31M

339) Baseline Upgrade b2992.3

- Replacing short segment of substation conductor on the Windy Edge to Glenarm 110512 115kV circuit - 3/1/2021 - $0.24M

340) Baseline Upgrade b2992.4

- Reconductor the Raphael Road - Northeast 2315 & 2337 230kV circuits - 3/1/2021 - $9.26M

341) Baseline Upgrade b2993

- Rebuild the Torrey – South Gambrinus Switch – Gambrinus Road 69kV line section (1.3 miles) with 1033 ACSR 'Curlew' conductor and steel poles. - 6/1/2018 - $4.60M

342) Baseline Upgrade b2994

- Acquire land and build a new switching station (Skippers) at the tap serving Brink DP with a 115kV four breaker ring to split line #130 and terminate the end points. - 5/1/2020 - $8.00M

343) Baseline Upgrade b2996

- New Flint Run 500-138 kV substation - 6/1/2019 - $58.00M

344) Baseline Upgrade b2998

- Install a 120 MVAR 345 kV shunt inductor at Powerton (the 345 kV yard already contains an empty bus position on the ring we only need a switching breaker for the inductor) - 6/1/2021 - $9.00M

345) Baseline Upgrade b2999

- Rebuild the 12.36 mile Schauff Road to Nelson tap 138kV line L15508. - 11/1/2019 - $17.00M

346) Baseline Upgrade b3000

- Replace South Canton 138kV breaker 'N' with an 80kA breaker - 6/1/2020 - $1.00M

347) Baseline Upgrade b3001

- Replace South Canton 138kV breaker 'N1' with an 80kA breaker - 6/1/2020 - $1.00M

348) Baseline Upgrade b3002

- Replace South Canton 138kV breaker 'N2' with an 80kA breaker - 6/1/2020 - $1.00M

349) Baseline Upgrade b3003

- Construct a 230/69kV station at Maywood - 6/1/2018 - $80.20M

350) Baseline Upgrade b3003.1

- Purchase properties at Maywood to accommodate new construction - 6/1/2018 - $0.00M

351) Baseline Upgrade b3003.2

- Extend Maywood 230kV bus and install one (1) 230kV breaker - 6/1/2018 - $0.00M

352) Baseline Upgrade b3003.3

- Install one (1) 230/69kV transformer at Maywood - 6/1/2018 - $0.00M

353) Baseline Upgrade b3003.4

- Install Maywood 69kV ring bus - 6/1/2018 - $0.00M

354) Baseline Upgrade b3003.5

- Construct a 69kV network between Spring Valley Road, Hasbrouck Heights, and Maywood - 6/1/2018 - $0.00M

355) Baseline Upgrade b3004

- Construct a 230/69/13kV station by tapping the Mercer - Kuser Rd 230kV circuit - 6/1/2018 - $65.40M

356) Baseline Upgrade b3004.1

- Install a new Clinton 230kV ring bus with one (1) 230/69kV transformer Mercer - Kuser Rd 230kV circuit

- 6/1/2018 - $0.00M

357) Baseline Upgrade b3004.2

- Expand existing 69kV ring bus at Clinton Ave with two (2) additional 69kV breakers. - 6/1/2018 - $0.00M

358) Baseline Upgrade b3004.3

- Install two (2) 69/13kV transformers at Clinton Ave - 6/1/2018 - $0.00M

359) Baseline Upgrade b3004.4

- Install 18 MVAR capacitor bank at Clinton Ave 69 kV - 6/1/2018 - $0.00M

360) Baseline Upgrade b3005

- Reconductor 3.1 mile 556 ACSR portion of Cabot to Butler 138 kV with 556 ACSS and upgrade terminal equipment. 3.1 miles of line will be reconductored for this project. The total length of the line is 7.75 miles. - 6/1/2021 - $5.88M

361) Baseline Upgrade b3006

- Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus - 6/1/2021 - $64.50M

362) Baseline Upgrade b3007.1

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - AP portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Social Hall, meters, relays, bus conductor, a wavetrap, circuit breaker and disconnects will be replaced. - 6/1/2021 - $4.42M

363) Baseline Upgrade b3007.2

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - PENELEC portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Blairsville East, the wave trap and breaker disconnects will be replaced. - 6/1/2021 - $7.00M

364) Baseline Upgrade b3008

- Upgrade Blairsville East 138/115 kV transformer terminals. This project is an upgrade to the tap of the Seward – Shelocta 115 kV line into Blairsville substation. The project will replace the circuit breaker and adjust relay settings. - 6/1/2021 - $0.32M

365) Baseline Upgrade b3009

- Upgrade Blairsville East 115 kV terminal equipment. Replace 115 kV circuit breaker and disconnects. - 6/1/2021 - $0.26M

366) Baseline Upgrade b3010

- Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wavetrap, and meter will be replaced. At Cabot, a wavetrap and bus conductor will be replaced. - 6/1/2021 - $0.78M

367) Baseline Upgrade b3011.1

- Construct new Route 51 substation and connect 10 138 kV lines to new substation - 6/1/2021 - $36.34M

368) Baseline Upgrade b3011.2

- Upgrade terminal equipment at Yukon to increase rating on Yukon to Charleroi #2 138 kV line (New Yukon to Route 51 #4 138 kV line) - 6/1/2021 - $0.63M

369) Baseline Upgrade b3011.3

- Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #1 138 kV line - 6/1/2021 - $0.63M

70) Baseline Upgrade b3011.4

- Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #2 138 kV line - 6/1/2021 - $0.63M

371) Baseline Upgrade b3011.5

- Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #3 138 kV line - 6/1/2021 - $0.63M

372) Baseline Upgrade b3011.6

- Upgrade remote end relays for Yukon –Allenport – Iron Bridge 138 kV line - 6/1/2021 - $1.97M

373) Baseline Upgrade b3012.1

- Construct two new 138 kV ties with the single structure from APS's new substation to DUQ's new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase. - 6/1/2021 - $23.10M

374) Baseline Upgrade b3012.2

- Construct two new ties from a new First Energy substation to a new Duquesne substation by using two separate structures - Duquesne portion. - 6/1/2021 - $7.90M

375) Baseline Upgrade b3013

- Reconductor Vasco Tap to Edgewater Tap 138 kV line. 4.4 miles. The new conductor will be 336 ACSS replacing the existing 336 ACSR conductor. - 6/1/2021 - $5.88M

376) Baseline Upgrade b3014

- Replace the existing Shelocta 230/115 kV transformer and construct a 230 kV ring bus - 6/1/2021 - $7.35M

377) Baseline Upgrade b3015.1

- Construct new Elrama 138 kV substation and connect 7 138 kV lines to new substation - 6/1/2021 - $19.70M

378) Baseline Upgrade b3015.2

- Reconductor Elrama to Wilson 138 kV line. 4.8 miles - 6/1/2021 - $7.60M

379) Baseline Upgrade b3015.3

- Reconductor Dravosburg to West Mifflin 138 kV line. 3 miles - 6/1/2021 - $2.90M

380) Baseline Upgrade b3015.4

- Run new conductor on existing tower to establish the new Dravosburg-Elrama (Z-75) circuit. 10 miles - 6/1/2021 - $14.90M

381) Baseline Upgrade b3015.5

- Reconductor Elrama to Mitchell 138 kV line - DL portion. 4.2 miles total. 2x795 ACSS/TW 20/7 - 6/1/2021 - $5.20M

382) Baseline Upgrade b3015.7

- Reconductor Wilson to West Mifflin 138 kV line. 2 miles. 795ACSS/TW 20/7 - 6/1/2021 - $3.60M

383) Baseline Upgrade b3017.1

- Rebuild Glade to Warren 230 kV line with hi-temp conductor and substation terminal upgrades. 11.53 miles. New conductor will be 1033 ACSS. Existing conductor is 1033 ACSR. - 6/1/2021 - $42.40M

384) Baseline Upgrade b3017.2

- Glade substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

385) Baseline Upgrade b3017.3

- Warren substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

386) Baseline Upgrade b3018

- Rebuild Line #49 between New Road and Middleburg substations with single circuit steel structures to current 115kV standards with a minimum summer emergency rating of 261 MVA. - 12/31/2021 - $12.70M

387) Baseline Upgrade b3019

- Rebuild 500kV Line #552 Bristers to Chancellor – 21.6 miles long - 6/1/2018 - $62.15M

388) Baseline Upgrade b3019.1

- Update the nameplate for Morrisville 500 kV breaker "H1T594" to be 50 kA - 6/1/2018 - $0.00M

389) Baseline Upgrade b3019.2

- Update the nameplate for Morrisville 500 kV breaker "H1T545" to be 50 kA - 6/1/2018 - $0.00M

390) Baseline Upgrade b3020

- Rebuild 500kV Line #574 Ladysmith to Elmont - 26.2 miles long - 6/1/2018 - $65.50M

391) Baseline Upgrade b3021

- Rebuild 500kV Line #581 Ladysmith to Chancellor - 15.2 miles long - 6/1/2018 - $44.38M

392) Baseline Upgrade b3022

- Replace Saxton 115kV breaker 'BUS TIE' with a 40kA breaker - 6/1/2020 - $0.21M

393) Baseline Upgrade b3023

- Replace West Wharton 115kV breakers 'G943A' and 'G943B' with 40kA breakers - 6/1/2020 - $0.50M

394) Baseline Upgrade b3024

- Upgrade terminal equipment at Corry East 115 kV to increase rating of Warren to Corry East 115 kV line. Replace bus conductor. - 6/1/2021 - $0.05M

395) Baseline Upgrade b3025

- Construct two (2) new 69/13kV stations in the Doremus area and relocate the Doremus load to the new stations - 6/1/2018 - $155.00M

396) Baseline Upgrade b3025.1

- Install a new 69/13 kV station (Vauxhall) with a ring bus configuration - 6/1/2018 - $0.00M

397) Baseline Upgrade b3025.2

- Install a new 69/13 kV station (area of 19th Ave) with a ring bus configuration - 6/1/2018 - $0.00M

398) Baseline Upgrade b3025.3

- Construct a 69kV network between Stanley Terrace, Springfield Road, McCarter, Federal Square, and the two new stations (Vauxhall & area of 19th Ave) - 6/1/2018 - $0.00M

399) Baseline Upgrade b3026

- Re-conductor the entire 230 kV Line No.274 (Pleasant View – Ashburn – Beaumeade) using a higher capacity conductor with an approximate rating of 1572 MVA. - 6/1/2021 - $10.00M

400) Baseline Upgrade b3027.1

- Add a 2nd 500/230 kV 840 MVA transformer at Dominion's Ladysmith Substation - 6/1/2021 - $25.00M

401) Baseline Upgrade b3027.2

- Re-conductor Line #2089 between Ladysmith and Ladysmith CT Substations to increase the line rating from 1047 MVA to 1225 MVA. - 6/1/2021 - $5.00M

402) Baseline Upgrade B3027.3

- Replace the Ladysmith 500kV breaker "H1T581" with 50kA breaker - 6/1/2021 - $0.52M

403) Baseline Upgrade B3027.4

- Update the nameplate for Ladysmith 500kV breaker "H1T575" to be 50kA breaker - 6/1/2021 - $0.52M

404) Baseline Upgrade B3027.5

- Update the nameplate for Ladysmith 500kV breaker "568T574" (will be renumbered as "H2T568") to be 50kA breaker - 6/1/2021 - $0.00M

405) Baseline Upgrade b3029

- Install 69 kV underground transmission line from Harings Corner Station terminating at Closter Station (about 3 miles). - 5/31/2020 - $22.00M

406) Baseline Upgrade b3029.1

- Reconfigure Closter Station to accommodate the UG transmission line from Harings Corner Station - 5/31/2020 - $0.00M

407) Baseline Upgrade b3029.2

- Loop in the existing 751 Line (Sparkill - Cresskill 69 kV) into Closter 69 kV station - 5/31/2020 - $0.00M

408) Baseline Upgrade b3031

- Transfer load off of the Leroy Center-Mayfield Q2 138 kV line by reconfiguring the Pawnee Substation primary source, via the existing switches, from the Leroy Center-Mayfield Q2 138 kV line to the Leroy Center-Mayfield Q1 138 kV line. - 6/1/2021 - $0.10M

409) Baseline Upgrade b3033

- Ottawa-Lakeview 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $20.00M

410) Baseline Upgrade b3034

- Lakeview-Greenfield 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $2.40M

411) Baseline Upgrade B3036

- Rebuild 15.4 miles of double circuit North Delphos - Rockhill 138 kV line - 12/1/2023 - $24.50M

412) Baseline Upgrade b3037

- Upgrades at the Natrium substation - 6/1/2023 - $1.10M

413) Baseline Upgrade b3038

- Reconductor the Capitol Hill - Coco 138 kV line section - 12/1/2023 - $3.80M

414) Baseline Upgrade b3039

- Line Swaps at Muskingum 138 kV Station - 12/1/2023 - $0.10M

415) Baseline Upgrade b3040

- Ravenswood - 6/1/2022 - $0.00M

416) Baseline Upgrade b3040.1

- Rebuild Ravenswood - Racine Tap 69 kV line section (~15 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 6/1/2022 - $39.20M

417) Baseline Upgrade b3040.2

- Rebuild existing Ripley - Ravenswood 69 kV circuit (~9 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 6/1/2022 - $23.60M

418) Baseline Upgrade b3040.3

- Install new 3-way phase over phase switch at Sarah Lane station to replace the retired switch at

Cottageville. - 6/1/2022 - $1.00M

419) Baseline Upgrade b3040.4

- Install new 138/12 kV 20 MVA transformer at Polymer station to transfer load from Mill Run Station to help address overload on the 69 kV network. - 6/1/2022 - $3.50M

420) Baseline Upgrade b3040.5

- Retire Mill Run station. - 6/1/2022 - $0.00M

421) Baseline Upgrade b3040.6

- Install 28.8 MVAR Cap Bank at South Buffalo station. - 6/1/2022 - $0.80M

422) Baseline Upgrade b3041

- Peach Bottom - Furnace Run 500kV Terminal Equipment - 6/1/2021 - $3.50M

423) Baseline Upgrade b3042

- Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal - 6/1/2023 - $0.05M

424) Baseline Upgrade b3043

- Install one 115 kV 36 MVAR capacitor at Westfall 115 kV substation - 6/1/2023 - $0.90M

425) Baseline Upgrade b3045

- Increase the MOT of Liberty Church Tap-Bacon Creek Tap 69kV line 266.8 MCM conductor from 212°F to 266°F - 6/1/2020 - $0.25M

426) Baseline Upgrade b3046

- Increase the MOT of Summer Shade-JB Galloway Jct. 69kV line 266.8 MCM conductor to from 167°F to 212°F. - 6/1/2020 - $0.75M

427) Baseline Upgrade b3047

- Upgrade the existing 4/0 CU line jumpers with double 500 MCM CU associated with the Green Co-KU Green Co 69 KV line section. Also, replace the existing 600 A disconnect switches with 1200 A associated with the Green Co 161/69 KV transformer - 6/1/2020 - $0.25M

428) Baseline Upgrade b3048

- Replace 138 kV breakers 937, 941 and 945 at TODHunter station - 12/31/2020 - $1.90M

429) Baseline Upgrade b3049

- Replace 345kV breaker at Joliet Substation - 6/1/2020 - $4.00M

430) Baseline Upgrade b3050

- Install redundant relay to Port Union 138 kV Bus#2 - 6/1/2023 - $0.37M

431) Baseline Upgrade b3051.1

- Ronceverte Cap Bank and Terminal Upgrades - 6/1/2018 - $0.72M

432) Baseline Upgrade b3051.2

- Adjust CT tap ratio at Ronceverte 138 kV - 6/1/2018 - $0.01M

433) Baseline Upgrade b3052

- Install a 138 kV capacitor (29.7 MVAR effective) at West Winchester 138 kV. - 6/1/2018 - $1.01M

434) Baseline Upgrade b3053

- Upgrade terminal equipment on Gibson - Petersburg 345kV - 10/29/2018 - $0.30M

435) Baseline Upgrade b3054

- Install a battery storage device at Grasonville Substation * Rebuild Wye Mills - Stevensville 69 kV Line * Construct a new 69 kV line from Wye Mills to Grasonville. - 12/1/2023 - $0.00M

436) Baseline Upgrade b3055

- Install spare 230/69 kV transformer at Davis Substation - 6/1/2023 - $0.54M

437) Baseline Upgrade b3056

- Partial Rebuild 230 kV Line #2113 Waller to Lightfoot - 6/1/2018 - $4.00M

438) Baseline Upgrade b3057

- Rebuild 6.1 miles of Waller-Skiffess Creek 230 kV Line (#2154) between Waller and Kings Mill to current standards with a minimum summer emergency rating of 1047 MVA utilizing single circuit steel structures. Remove this 6.1 mile section of Line #58 between Waller and Kings Mill. Rebuild the 1.6 miles of Line #2154 and #19 between Kings Mill and Skiffes Creek to current standards with a minimum summer emergency rating of 1047 MVA at 230 kV for Line #2154 and 261 MVA at 115 kV for Line #19, utilizing double circuit steel structures. - 6/1/2018 - $10.00M

439) Baseline Upgrade b3058

- Partial Rebuild of 230 kV lines between Clifton and Johnson DP (#265, #200 and #2051) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2018 - $11.50M

440) Baseline Upgrade b3059

- Rebuild Line #2173 Loudoun to Elklick - 12/31/2022 - $13.50M

441) Baseline Upgrade b3060

- Rebuild 4.6 mile Elk Lick-Bull Run 230 kV Line (#295) and the portion (3.85 miles) of the Clifton-Walney 230kV Line (#265) which shares structures with line #295 - 10/30/2018 - $15.50M

442) Baseline Upgrade b3061

- Reconductor the West Mifflin - Dravosburg (Z-73) and Dravosburg - Elrama (Z-75) 138 kV lines - 6/1/2021 - $6.70M

443) Baseline Upgrade b3062

- Install 138 kV tie breaker at West Mifflin - 6/1/2021 - $4.40M

444) Baseline Upgrade b3063

- Reconductor the Wilson - Dravosburg (Z-72) 138 kV line (~5 miles) - 6/1/2021 - $6.60M

445) Baseline Upgrade b3064

- Expand Elrama 138 kV substation to loop in the existing USS Steel Clariton - Piney Fork 138 kV line - 6/1/2021 - $11.10M

446) Baseline Upgrade b3065

- Install 138 kV tie breaker at Wilson - 6/1/2021 - $4.00M

447) Baseline Upgrade b3066

- Reconductor the Cranberry - Jackson 138 kV line (2.1 miles), reconductor 138 kV bus at Cranberryand replace 138 kv line switches at Jackson - 6/1/2022 - $2.90M

448) Baseline Upgrade b3067

- Reconductor the Jackson - Maple 138 kV line (4.7 miles), replace line switches at Jackson 138 kV and replace the line traps and relays at Maple 138 kV - 6/1/2022 - $7.10M

449) Baseline Upgrade b3068

- Reconductor the Yukon - Westraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Westraver 138 kV - 6/1/2022 - $2.50M

450) Baseline Upgrade b3069

- Reconductor the Westraver - Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV - 6/1/2022 - $7.50M

451) Baseline Upgrade b3070

- Reconductor the Yukon - Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV - 6/1/2022 - $10.00M

452) Baseline Upgrade b3071

- Reconductor the Yukon - Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

453) Baseline Upgrade b3072

- Reconductor the Yukon - Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

454) Baseline Upgrade b3073

- Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor - 6/1/2022 - $2.10M

455) Baseline Upgrade b3074

- Replace Substation conductor on the 345/138 kV transformer at Armstrong substation - 6/1/2022 - $0.10M

456) Baseline Upgrade b3075

- Replace substation conductor and 138 kV circuit breaker on the #1 transformer (500/138 kV) at Cabot substation - 6/1/2022 - $0.30M

457) Baseline Upgrade b3076

- Reconductor the Edgewater - Loyalhanna 138 kV line (0.67 miles) - 6/1/2022 - $2.00M

458) Baseline Upgrade b3077

- Reconductor the Franklin Pike - Wayne 115 kV line (6.78 miles) - 6/1/2022 - $11.40M

459) Baseline Upgrade b3078

- Reconductor 138 kV bus and replace the line trap, relays at Morgan Street. Reconductor 138 kV bus at Venango Junction - 6/1/2022 - $1.00M

460) Baseline Upgrade b3079

- Replace the Wylie Ridge 500/345 kV transformer #7 - 6/1/2022 - $6.37M

461) Baseline Upgrade b3080

- Reconductor 138 kV bus at Seneca - 6/1/2022 - $0.07M

462) Baseline Upgrade b3081

- Replace 138 kV breaker and substation conductor at Krendale - 6/1/2022 - $0.30M

463) Baseline Upgrade b3082

- Construct a 4-breaker 115 kV ring bus at Franklin Pike - 6/1/2022 - $8.00M

464) Baseline Upgrade b3083

- Replace substation conductor at Butler (138 kV) Replace substation conductor and line trap at Karns City (138 kV) - 6/1/2022 - $0.20M

465) Baseline Upgrade b3084

- Reconductor the Oakland - Panther Hollow 138 kV line (~1 mile) - 6/1/2021 - $6.80M

466) Baseline Upgrade b3085

- Reconductor Kammer - George Washington 138 kV line (~0.08 miles). Replace the wave trap at Kammer 138 kV. - 6/1/2022 - $0.50M

467) Baseline Upgrade b3086.1

- Rebuild New Liberty – Findlay 34 kV Line Str's 1 – 37 (1.5 miles), utilizing 795 26/7 ACSR conductor - 6/1/2022 - $3.40M

468) Baseline Upgrade b3086.2

- Rebuild New Liberty – North Baltimore 34 kV Line Str's 1-11 (0.5 miles), utilizing 795 26/7 ACSR conductor - 6/1/2022 - $1.80M

469) Baseline Upgrade b3086.3

- Rebuild West Melrose – Whirlpool 34 kV Line Str's 55- 80 (1 mile), utilizing 795 26/7 ACSR conductor -

6/1/2022 - $2.37M

470) Baseline Upgrade b3086.4

- North Findlay Station: Install a 138 kV 3000 A 63 kA line breaker and low side 34.5 kV 2000 A 40 kA breaker, high side 138 kV circuit switcher on T1 - 6/1/2022 - $1.70M

471) Baseline Upgrade b3086.5

- Ebersole Station: Install second 90 MVA 138/69/34 kV transformer. Install two low side (69 kV) 2000A 40kA breakers for T1 and T2. - 6/1/2022 - $3.75M

472) Baseline Upgrade b3087.1

- Construct a new greenfield station to the west (~1.5 mi.) of the existing Fords Branch Station potentially in/near the new Kentucky Enterprise Industrial Park. . This new station
will consist of 4 -138 kV breaker ring bus and two 30 MVA 138/34.5 kV transformers. The existing Fords Branch Station will be retired. - 12/1/2018 - $3.40M

473) Baseline Upgrade b3087.2

- Construct approximately 5 miles of new double circuit 138 kV line in order to loop the new Fords Branch station into the existing Beaver Creek – Cedar Creek 138 kV circuit. - 12/1/2018 - $19.90M

474) Baseline Upgrade b3087.3

- Remote end work will be required at Cedar Creek Station. - 12/1/2018 - $0.50M

475) Baseline Upgrade b3089

- Rebuild 230kV Line #224 between Lanexa and Northern Neck utilizing double circuit structures to current 230kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA. - 6/1/2018 - $86.00M

476) Baseline Upgrade b3090

- Convert the OH portion (approx. 1500 Feet) of 230 kV Lines #248 & #2023 to UG and convert Glebe substation to GIS. - 1/1/2021 - $120.00M

477) Baseline Upgrade b3095

- Rebuild Lakin – Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 12/1/2022 - $23.90M

478) Baseline Upgrade b3155

- Rebuild approximately 12 miles of Wye Mills - Stevensville line to achieve needed ampacity - 12/1/2023 - $15.00M

Revision History:

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Approver: Aaron Berner, Manager Transmission Planning