



Transmission Expansion Advisory Committee
(TEAC)
Recommendations to the PJM Board

PJM Staff Whitepaper
August 2016



EXECUTIVE SUMMARY

On February 16, 2016 the PJM Board of Managers approved changes to the Regional Transmission Expansion Plan (RTEP), totaling \$104.74 million, primarily to include several market efficiency projects and cost changes to previously approved projects.

Since that time PJM has identified additional baseline reliability criteria violations within the planning horizon as part of the 2016 RTEP. Transmission upgrades have been identified to resolve these reliability criteria violations. The increase in the RTEP to include the upgrades to resolve the new baseline reliability criteria violations is \$169.9 million. In addition to the reliability criteria driven upgrades, PJM staff also recommended a market efficiency project. The market efficiency project, which was solicited through the 2014/15 long-term RTEP proposal window, has an estimated cost of \$320.19 million and is expected to mitigate at least \$622 million in energy market congestion over the next 15 years. Additionally, a number of previously approved baseline projects have been cancelled, replaced by alternate projects, or the cost and scope has changed resulting in an increase of \$146.36 million. The net impact due to these changes is an increase of \$636.45 million.

With these changes, the RTEP will include over \$29,019.42 million of transmission additions and upgrades since the first plan was approved by the Board in 2000.

The additional baseline upgrades were presented for the Board Reliability Committee's consideration and recommendation to the Board for approval. At the August 2016 meeting, the PJM Board approved the updated RTEP as requested.

SUMMARY OF RESULTS

2016 Baseline Transmission Upgrades Changes and Additions

One aspect of the development of the Regional Transmission Expansion Planning Process is an evaluation of the “baseline” system, i.e. the transmission system without any of the generation interconnection requests included in the current planning cycle. This baseline analysis determines the compliance of the existing system with reliability criteria and standards. Transmission upgrades required to maintain a reliable system are identified and reviewed with the Transmission Expansion Advisory Committee (TEAC). The cost of transmission upgrades to mitigate such criteria violations are the responsibility of the PJM loads.

Baseline Reliability:

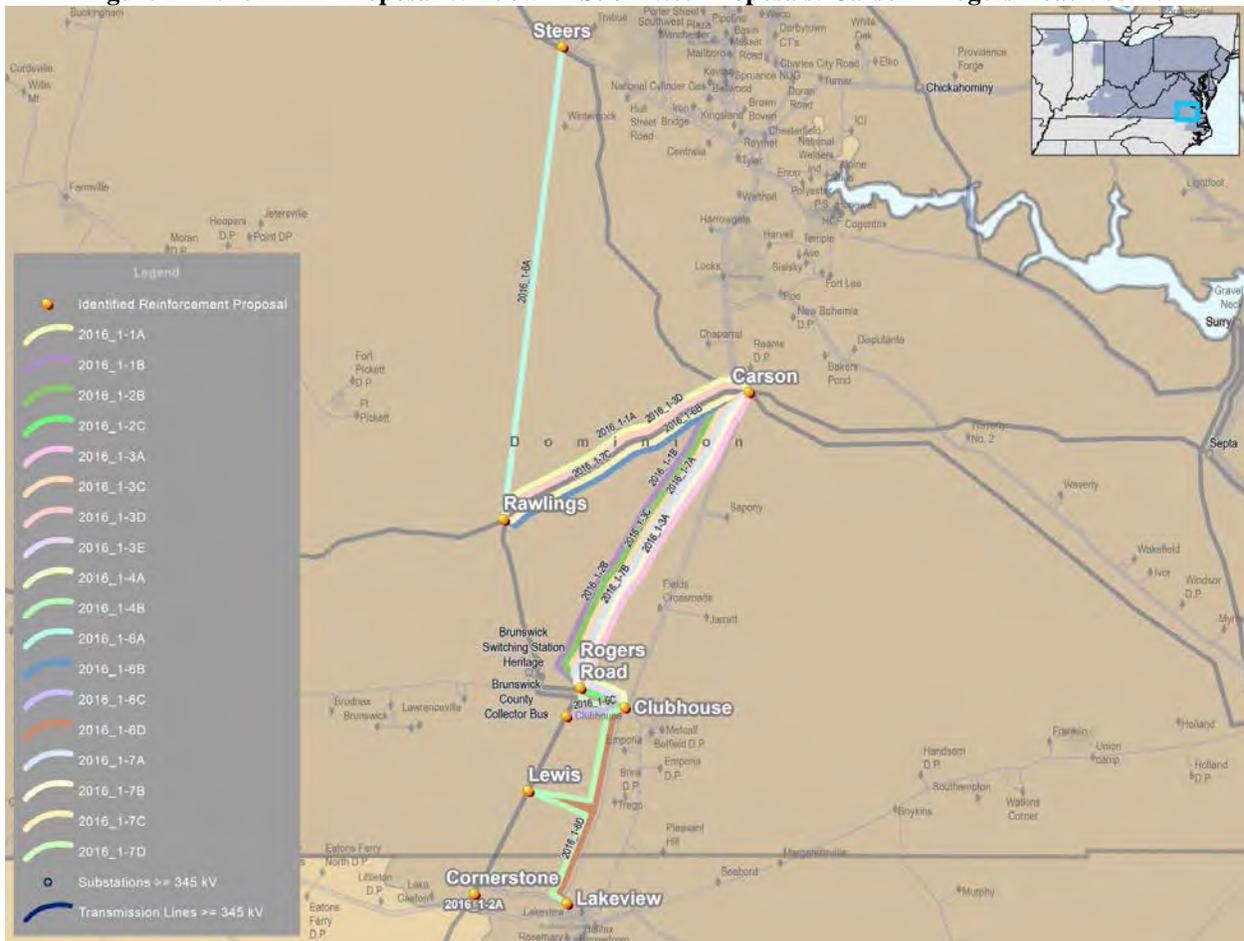
In February of this year PJM opened a 30-day proposal window, which was administered as the PJM 2016 RTEP Proposal Window #1, to solicit proposals to a number of PJM reliability criteria violations and local transmission owner criteria violations that were identified in the Dominion zone as part of the 2016 RTEP. The PJM reliability criteria violations included Generator Deliverability and Common Mode Outage violations. The local transmission owner violations were associated with Dominion’s end of life criteria. PJM staff identified potential reliability criteria violations associated with 13 flow gates (transmission facility and contingency/outage pairs). The violations were identified in two areas on the Dominion transmission system. Thermal issues were identified on the 230 kV system between Chesterfield, Charles City Road and Messer Road substations. The Chesterfield – Lakeside 230 kV facility, which includes the Chesterfield – Charles City Road – Messer Road 230 kV circuit, has also already reached its end of life and needed to be addressed per the Dominion FERC filed 715 local transmission owner planning criteria. In addition, thermal issues were identified on the 500 kV system between Carson and Rogers Road. In addition to the thermal issues, the Carson – Rogers Road 500 kV facility is expected to be at its end-of-life within the 15-year planning horizon.

In response to the 2016 RTEP Proposal Window #1, PJM received 25 baseline proposals to address these reliability criteria violations. The proposals were received from 7 distinct entities, including incumbent transmission owners and non-incumbent transmission developers. The non-incumbent transmission developers included ITC Mid-Atlantic Development, Mid-Atlantic MCN (an affiliate of GridLiance and other entities, including The Blackstone Group), NextEra Energy Transmission, Northeast Transmission Development/LS Power, Transource Energy, and Public Service Electric & Gas. Of the 25 proposals, 3 were Transmission Owner Upgrades and 22 were Greenfield Projects. The locations of the proposals associated with the Chesterfield – Charles City – Messer Road issues are shown below on Figure 1. The location of the proposals associated with the Carson – Rogers Road issues are shown in Figure 2 below.

Figure 1 - 2016 RTEP Proposal Window #1 Submitted Proposals: Chesterfield – Messer Road – Charles City Road 230 kV



Figure 2 - 2016 RTEP Proposal Window #1 Submitted Proposals: Carson - Rogers Road 500 kV



PJM staff reviewed all of the proposals and our evaluation of the effectiveness of each of the proposals with stakeholders through the Transmission Expansion Advisory Committee (TEAC). PJM recommended two projects to address the violations in the Dominion zone. The projects include the rebuild of existing lines by the incumbent transmission owner (Dominion Virginia Power). Additional information about the recommended projects is included in this white paper.

In addition to the 2016 RTEP Proposal Window #1, PJM previously opened a 120-day long term proposal window which spanned from November 2014 through February 2015. This window was administered as the PJM 2014/2015 RTEP Long Term Proposal Window to solicit solutions for market efficiency and one thermal violation driven by EKPC local transmission owner criteria.

In response to the one EKPC local transmission owner criteria violation, PJM received one baseline upgrade proposal from a transmission owner. PJM staff reviewed the proposal and the effectiveness of it with stakeholders through the Transmission Expansion Advisory Committee (TEAC). PJM recommended the project to address the violation in EKPC. The project upgrades an existing line, and additional information about the recommended project is included in this white paper.

Additionally, 9 projects were recommended to address immediate need baseline reliability issues. The immediate need baseline reliability projects include transmission enhancements with a need date of 3 years or less. Due to the critical timing of immediate need projects, PJM did not have time to administer a proposal window to solicit alternative solutions from PJM stakeholders for the associated reliability drivers.

The immediate need projects are being driven by several main categories of issues. The issues included short circuit fault duty issues to which the most efficient solution is a Transmission Owner upgrade of the associated breaker, Dominion Transmission Owner criteria for "End of Life" criteria where the associated facilities have already reached their end of life, Dominion Transmission Owner criteria for limitations on direct-connect load, AEP Transmission Owner thermal and voltage criteria, generation deactivations within the three year horizon, as well as several PJM operational performance issues.

A summary of the more significant baseline projects with estimated costs greater than \$5 million are detailed below. A complete listing of all of the projects that were recommended along with their associated cost allocations is included as Attachment A and B to this white paper. The projects with estimated costs less than \$5 million include replacing circuit breakers to address short circuit issues, upgrades to existing lines to address thermal issues and eliminating end-of-life facilities.

Mid-Atlantic Region System Upgrade

- PPL Transmission Zone
 - Add a 200 MVAR shunt reactor at Lackawanna 500 kV substation - \$10 M
- PSE&G Transmission Zone
 - Reconductor the 1 mile Bergen – Bergen GT 138 kV circuit (B-1302) - \$6.5 M

Western Region System Upgrades

- ATSI Transmission Zone
 - Build a new 345/138 kV Lake Avenue substation and a breaker replacement at Murray 138 kV - \$40.28 M
- AEP Transmission Zone
 - Convert the Sunnyside - East Sparta - Malvern 23 kV sub-transmission network to 69 kV (lines are already built to 69 kV standards) - \$5.7 M
- ComEd Transmission Zone
 - Balance station load at Goodings Grove 345 kV and replace 138 kV bus tie 2-3 - \$5.4 M
 - Cut-in of Tazewell - Kendall 345 kV line into Dresden and raise towers to remove the sag limitation on Pontiac – Loretto 345 kV line - \$20.4

Southern Region System Upgrades

- Dominion Transmission Zone
 - Rebuild the Carson - Rogers Rd 500 kV circuit - \$48.5 M
 - Rebuild 21.32 miles of existing line between Chesterfield - Lakeside 230 kV - \$22 M
 - Expand Perth substation and add a 115kV four breaker ring, extend the Hickory Grove DP tap 0.28 miles to Perth, and split line at Perth to terminate it into the new ring bus with 2 breakers separating each of the line terminals - \$7 M

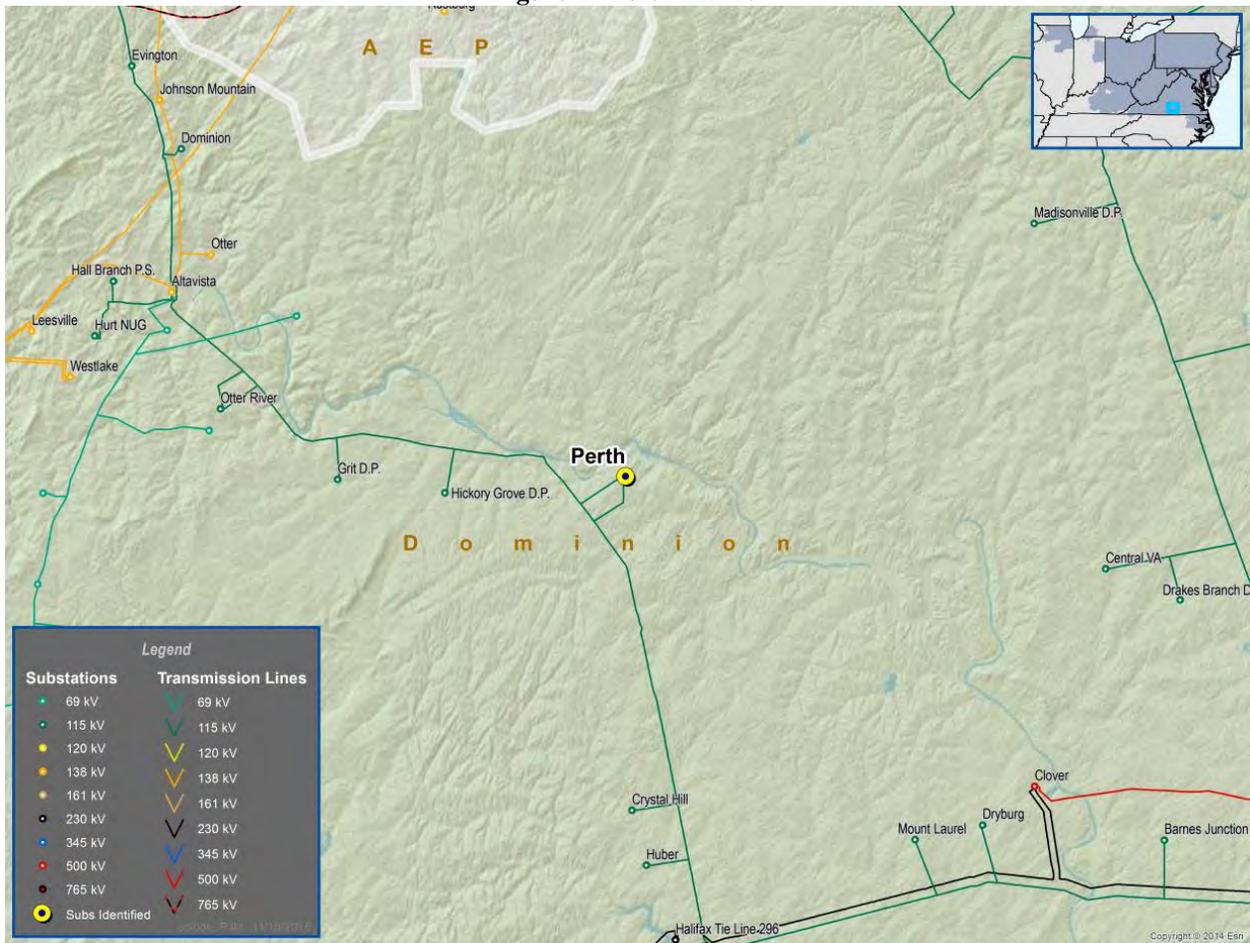
Following is a more detailed description of the larger scope upgrades that are being recommended to the PJM Board for their consideration. A description of the criteria driving the need for the upgrade as well as the required in-service date is provided.

Baseline Project B2716 – Lackawanna 500 kV Shunt Reactor

Several regions in PJM have experienced a large increase in high voltage alarms over the past year. These conditions, which generally occur during light load periods, have several drivers: changes in dynamic reactive support due to new and deactivated generation, reactive support deficiencies, and increased line charging from new transmission facilities. Approved RTEP reactive devices planned to come in service over the next several years will help lower the voltages to some extent, but anticipated generation deactivations and additional line charging from planned transmission facilities will further aggravate the problem.

Several switchable shunt reactors and an SVC were approved by the Board in December 2015 to help with controlling high voltages in these regions. Since that time staff has evaluated additional PJM operational data beyond what was used for the previous recommendations, and has re-studied the system with the combination of reactive devices that had been previously approved by the Board. As a result, a need for additional voltage control in the PPL transmission zone was identified at the Lackawanna 500 kV substation. The recommended solution to address the high voltage conditions is to install a 200 MVAR shunt reactor at Lackawanna 500 kV substation. The estimated cost for this project is \$10 million and the projected in-service date is December 1, 2018. Since this upgrade is an immediate need solution and the timing required to include them in an RTEP proposal window is infeasible, the local Transmission Owner, PPL, will be the designated entity to construct the upgrade.

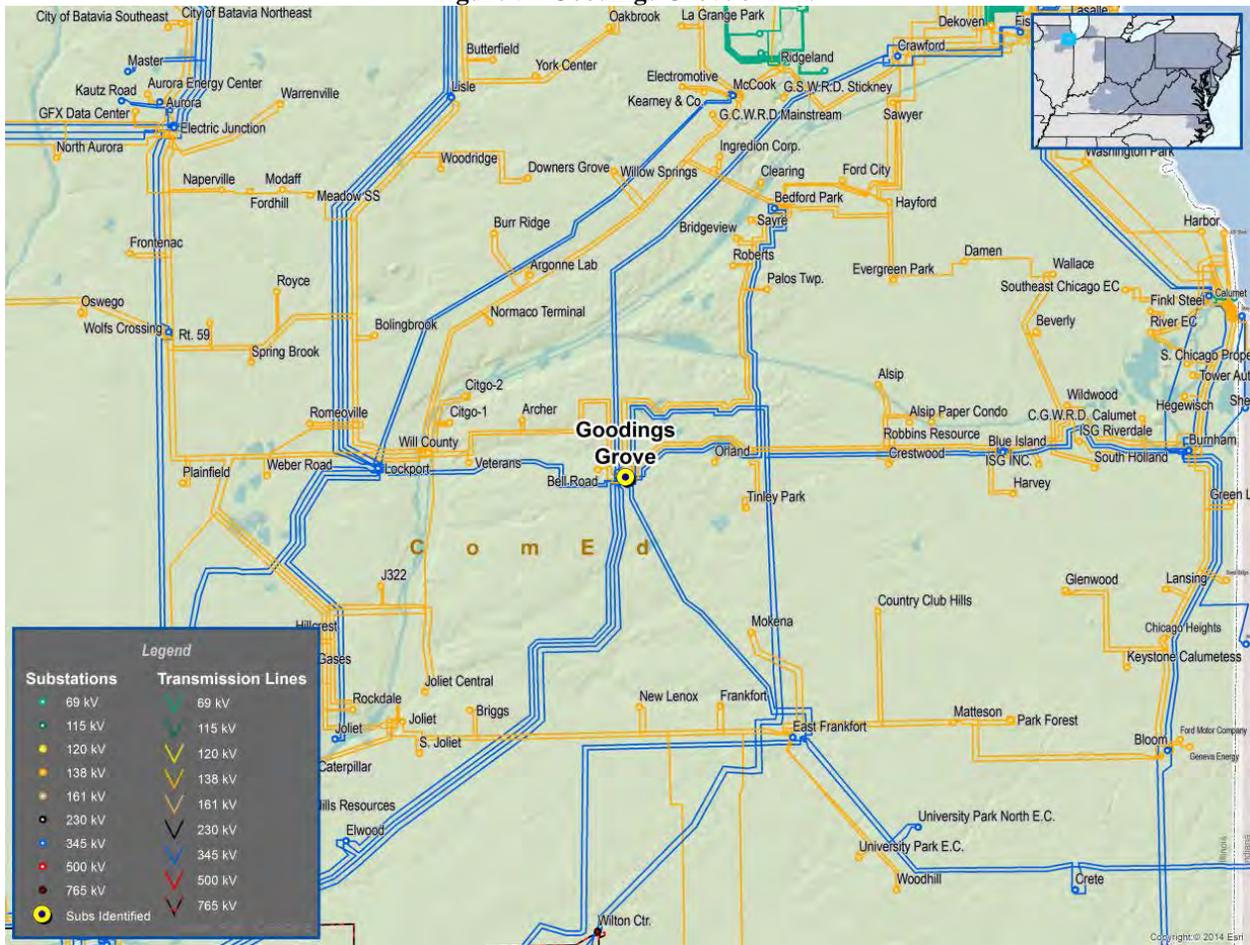
Figure 4 - Perth 115 kV



Baseline Project B2721 – Goodings Grove Station Load Balancing

In December of 2015 PJM was notified that the Will County 4 generator (approximately 510 MW) in the ComEd transmission zone would be deactivating just prior to the summer in 2018. Deactivation analysis showed the Goodings Grove 345/138 kV transformer in the ComEd zone is overloaded for the single contingency loss of the Goodings Grove 345 kV line as well as being overloaded for the line fault stuck breaker contingency loss of Blue Island Tap Red – Blue Island Red 345 kV line and Goodings Grove – Blue Island Tap Red – Wilton Red 345 kV line. ComEd had previously identified a supplemental upgrade to balance the Goodings Grove station load by swapping bus positions for several 345 kV lines and replacing a 138 kV bus tie. This supplemental upgrade also addresses the thermal issues on the Goodings Grove transformer. The recommended solution to address the reliability criteria is to convert this supplemental project to a baseline reliability upgrade. The new baseline project was developed with the expectation that it was immediate need project given the proposed deactivation date in 2018. However, after the recommended upgrade had been reviewed with stakeholders, the generator subsequently notified PJM that the deactivation date would be deferred to year 2020. The estimated cost is \$5.4 million and the required in service date is now June 1, 2020.

Figure 5 - Goodings Grove 345 kV



Baseline Project B2732 – Tazewell - Kendall 345 kV Line Cut-In to Dresden 345 kV

The Will County Unit 4 deactivation studies also showed the Dresden 345/138 kV transformer in the ComEd zone is overloaded for the line fault stuck breaker contingency loss of Dresden – Elwood 345 kV circuit and Elwood 345/138 kV transformers. The studies also showed, the Pontiac – Loretto 345 kV line in the ComEd zone is overloaded for the loss of the Pontiac 345/138 kV transformer. The recommended solution to address these issues is to cut in the Tazewell – Kendall 345 kV line into Dresden 345 kV and to raise the towers to remove the sag limitation on the Pontiac – Loretto 345 kV line. The new baseline project was developed with the expectation that they were immediate need, and the required in service date was June 1, 2018. However, after the recommended upgrades had been reviewed with stakeholders, the generator subsequently notified PJM that the deactivation date would be deferred to year 2020. The total estimated cost is \$20.4 million and the required in service date is now June 1, 2020. Given the projects are upgrades to existing facilities the local Transmission Owner, ComEd, will be the entity designated to construct the upgrades.

Figure 6 - Dresden 345 kV

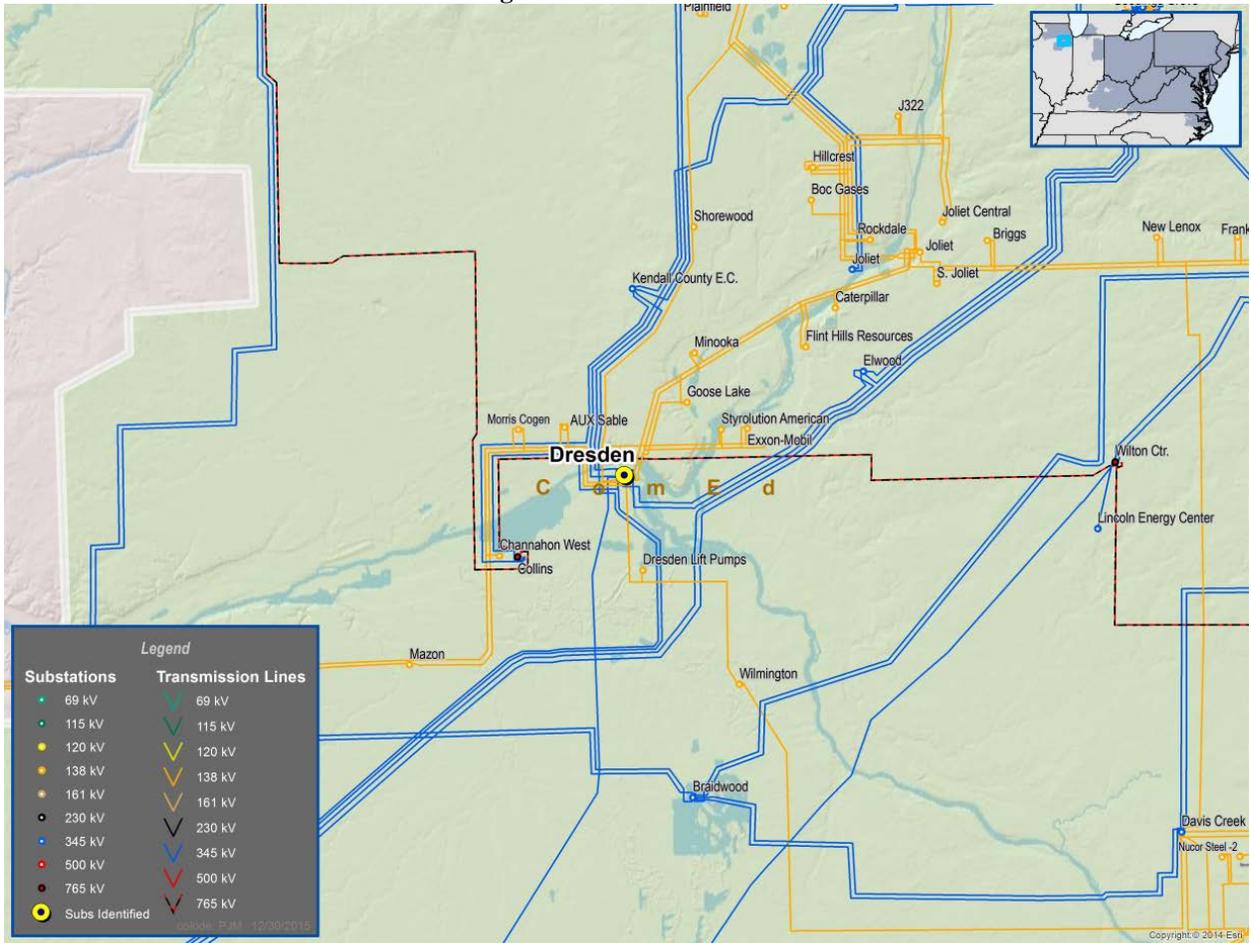
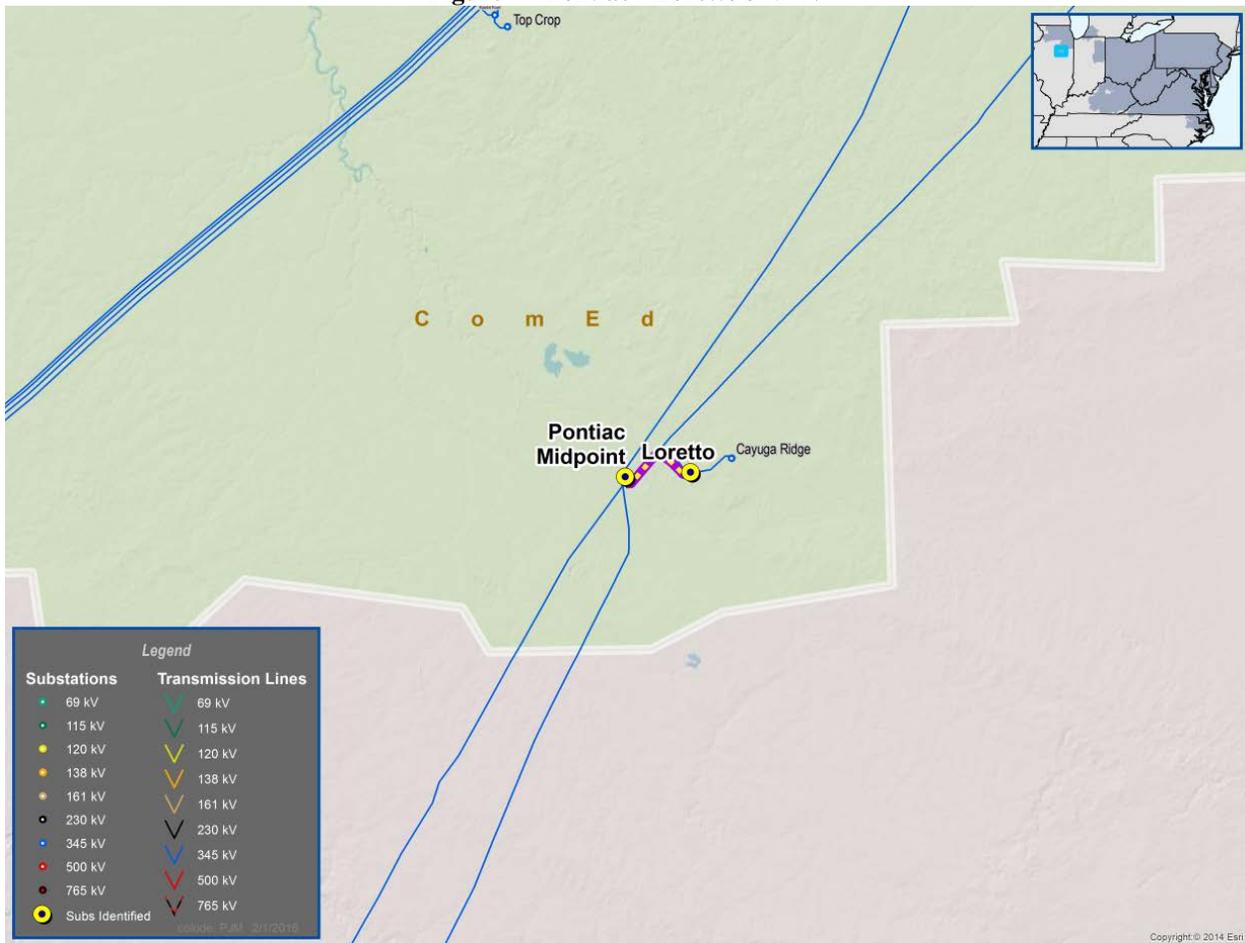


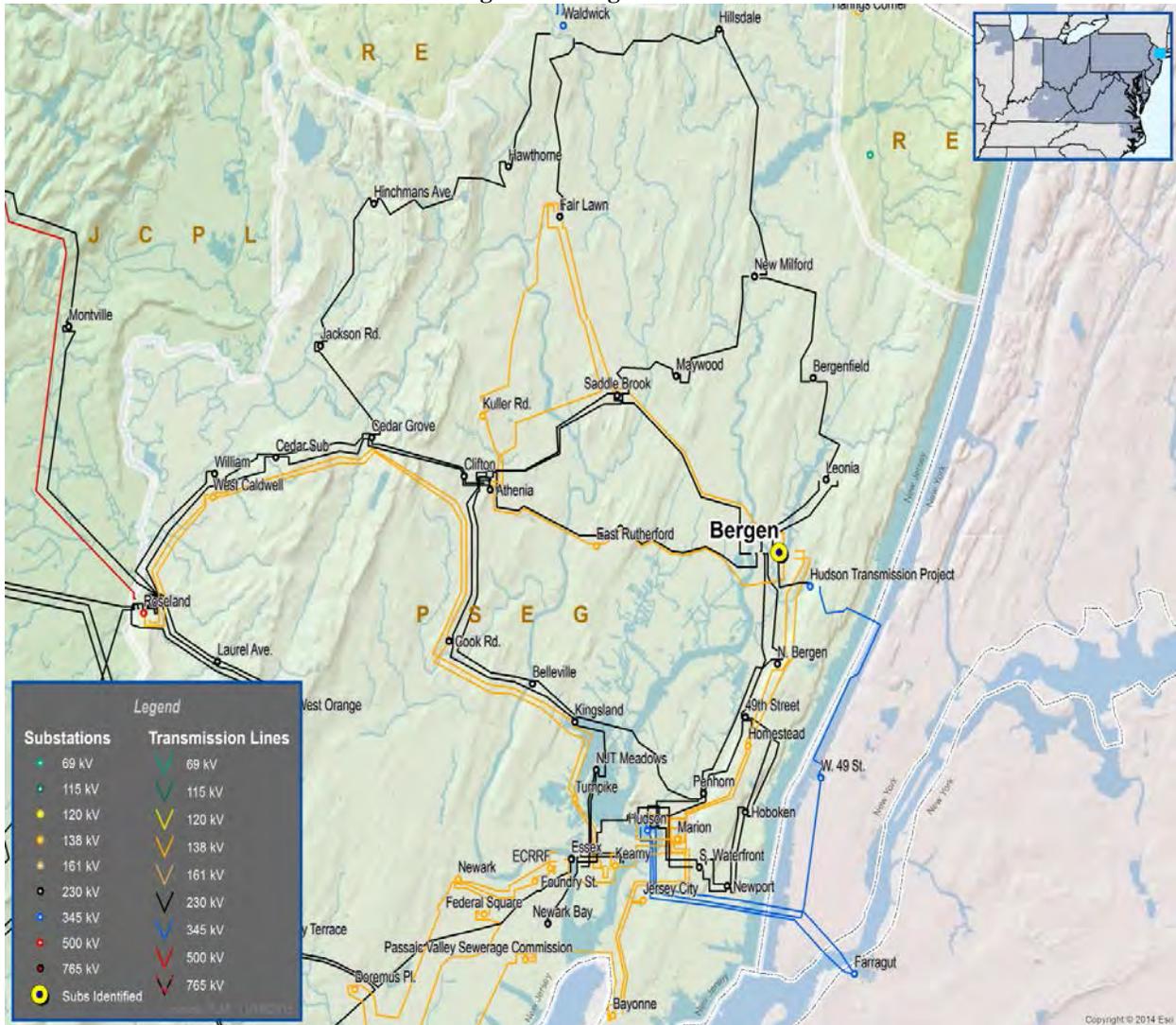
Figure 7 - Pontiac - Loretto 345 kV



Baseline Project B2722 – Bergen - Bergen GT 138 kV Reconductoring

The Bergen – Bergen GT 138 kV circuit in the PSE&G zone is overloaded for pre-contingency conditions with the Bergen GT generator at full output. Previous planning analyses did not identify this issue as the line connecting the generator to the Bergen 230 kV bus was not explicitly modeled. The recommended solution to address this issue is to reconductor the 1 mile Bergen – Bergen GT 138 kV circuit. The estimated cost to reconductor the line is \$6.5 million and the expected in service date is October 30, 2016. Since this upgrade is an immediate need solution and the timing required to include them in an RTEP proposal window is infeasible, the local Transmission Owner, PSE&G, will be the designated entity.

Figure 8 - Bergen 138 kV



Baseline Project B2725 – Beaver - Lake Avenue 345 kV

In December of 2015 PJM was notified the Avon Lake Unit 7 generator (approximately 94 MW) in the ATSI transmission zone would be deactivating in 2016. The deactivation study identified one of the Beaver – Lake Avenue 345 kV circuits in the ATSI zone is overloaded for the line fault stuck breaker contingency outage of Beaver – Lake Avenue 345 kV and Beaver – Carlisle 345 kV lines for the breaker ‘B121’ failure at Beaver 345 kV. There is an existing supplemental upgrade to build a new 345/138 kV Lake Avenue substation with a breaker and a half configuration on the 345 kV side, two 345/138 kV transformers, and breaker and a half configuration on the 138 kV side. The substation will tie two Avon – Beaver 345 kV circuits and two Black River – Johnson circuits. Additional scope of the project also includes the replacement of a circuit breaker at Murray 138 kV. The supplemental upgrade addresses the overload on the Beaver – Lake Avenue 345 kV line. The recommended solution is to convert the supplemental project to a baseline reliability upgrade. The estimated cost is \$40.28 million and the required in service date is June 1, 2016 with a projected in service date of December 31, 2016. Since this upgrade is an immediate

need solution and the timing required to include them in an RTEP proposal window is infeasible, the local Transmission Owner, ATSI, will be the designated entity. The unit actually deactivated on 4/16/2016. Temporary operating procedures are in place to manage the situation until the upgrade can be placed in-service.

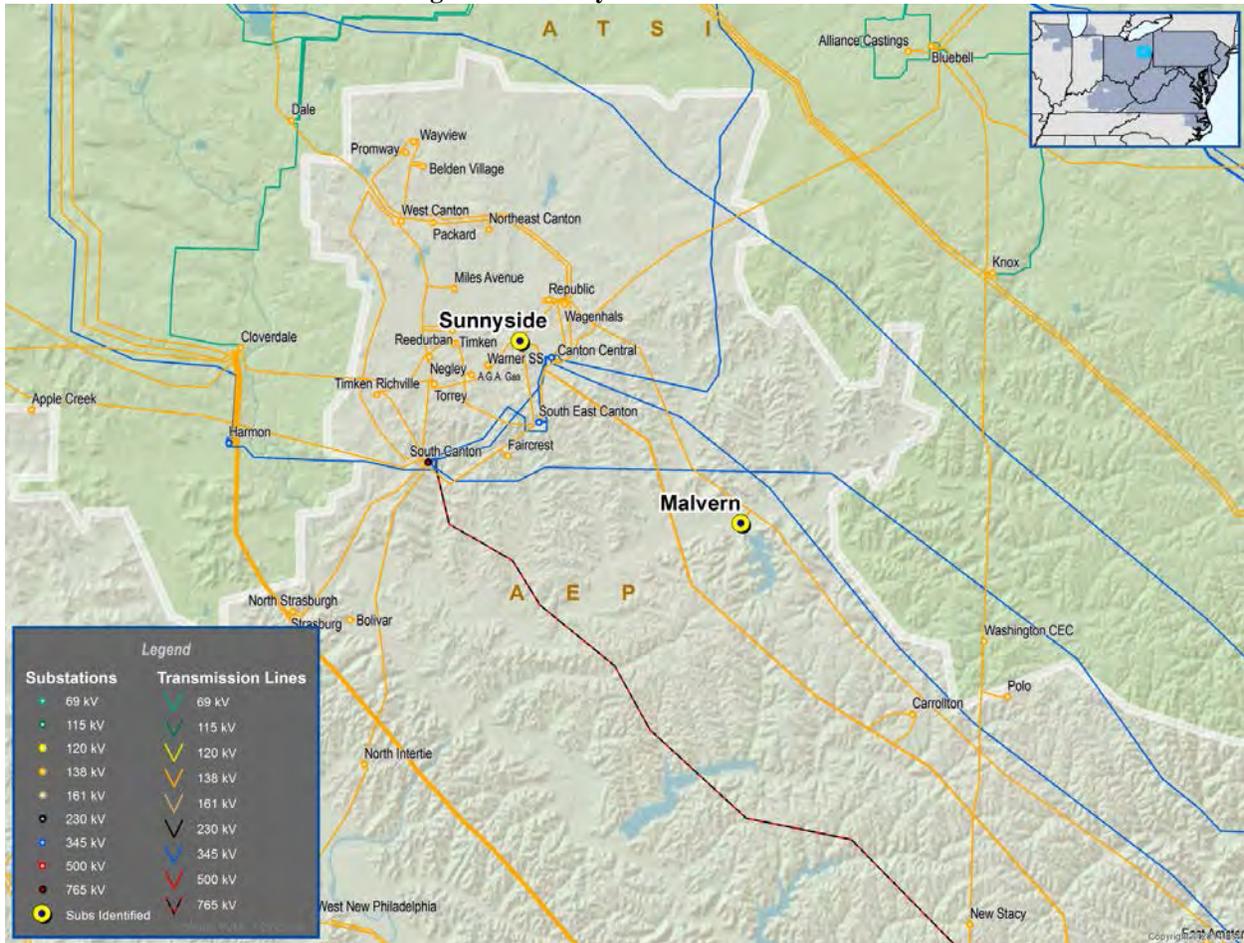
Figure 9 - Beaver - Lake Avenue 345 kV



Baseline Project B2731 – Sunnyside - Malvern 69 kV Conversion

The Malvern – Sandy VL 23 kV line and Malvern 138/23 kV transformer in the AEP zone are overloaded for the loss of the Sunnyside – Part PM 23 kV line. Low voltages at multiple buses for the same contingency could also lead to possible local voltage collapse. These issues are being driven by new local load increase with significant motor-start requirements. The recommended solution is to convert the Sunnyside – East Sparta – Malvern 23 kV sub-transmission network to 69 kV. Many of the facilities are already built to 69 kV standards. The estimated cost is \$ 5.7 million and the required in service date is August 1, 2016. Since this upgrade is an immediate need solution and the timing required to include them in an RTEP proposal window is infeasible, the local Transmission Owner, AEP, will be the designated entity.

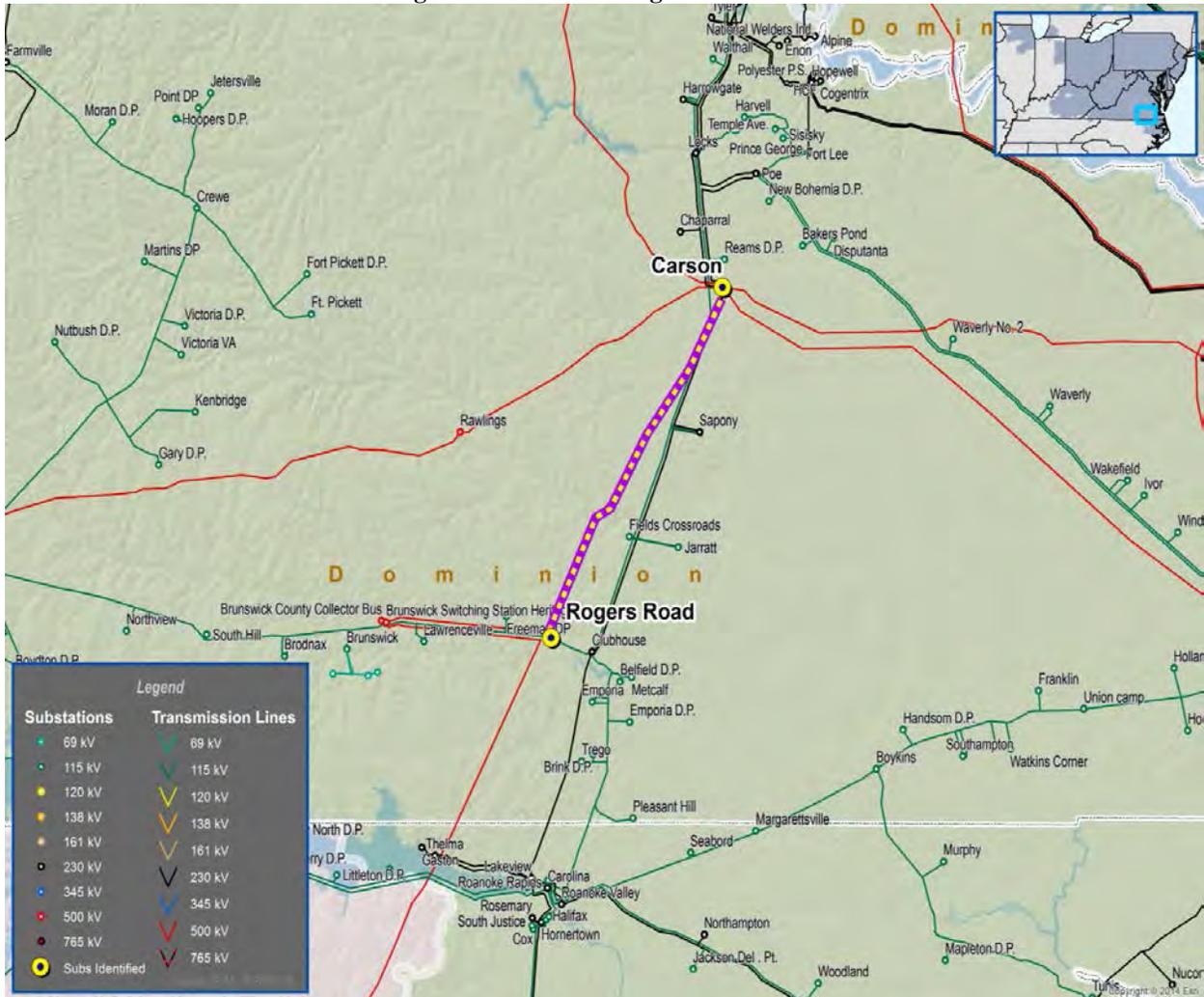
Figure 10 - Sunnyside - Malvern 23 kV



Baseline Project B2744 – Rebuild Carson - Rogers Rd 500 kV

The Carson – Rogers Rd 500 kV line in Dominion zone is overloaded for the loss of the Carson – Rawlings 500 kV line in 2020. This overload was included as part of the 2016 RTEP Proposal Window #1. A total of nineteen baseline proposals from six entities, including incumbent transmission owners and non-incumbent transmission developers were submitted to address this reliability criteria violation. The non-incumbent transmission developers included ITC Mid-Atlantic Development, NextEra Energy Transmission, Northeast Transmission Development/LS Power, Transource Energy, and Public Service Electric & Gas and the cost of the proposals ranged from \$24 million to \$115 million. Twelve proposals entailed a second 500 kV circuit, and while all the proposals mitigated the 500 kV reliability criteria violation, they caused additional violations in the year 2021 analysis and required significant new right-of-way acquisition. Six of the proposals included a 230 kV Clubhouse solution to mitigate the 500 kV reliability criteria violation, but resulted in line loadings exceeding 90% for the year 2020 analysis. The one proposal to rebuild exiting infrastructure resolved the reliability criteria violation by a significant margin, requires no new right-of-way, and also addresses the long term End of Life need for the Carson – Rogers Road 500 kV facility. For these reasons, the recommended solution to address the issue is to rebuild the Carson – Rogers Rd 500 kV circuit. The estimated cost is \$48.5 million and the required in service date is June 1, 2020.

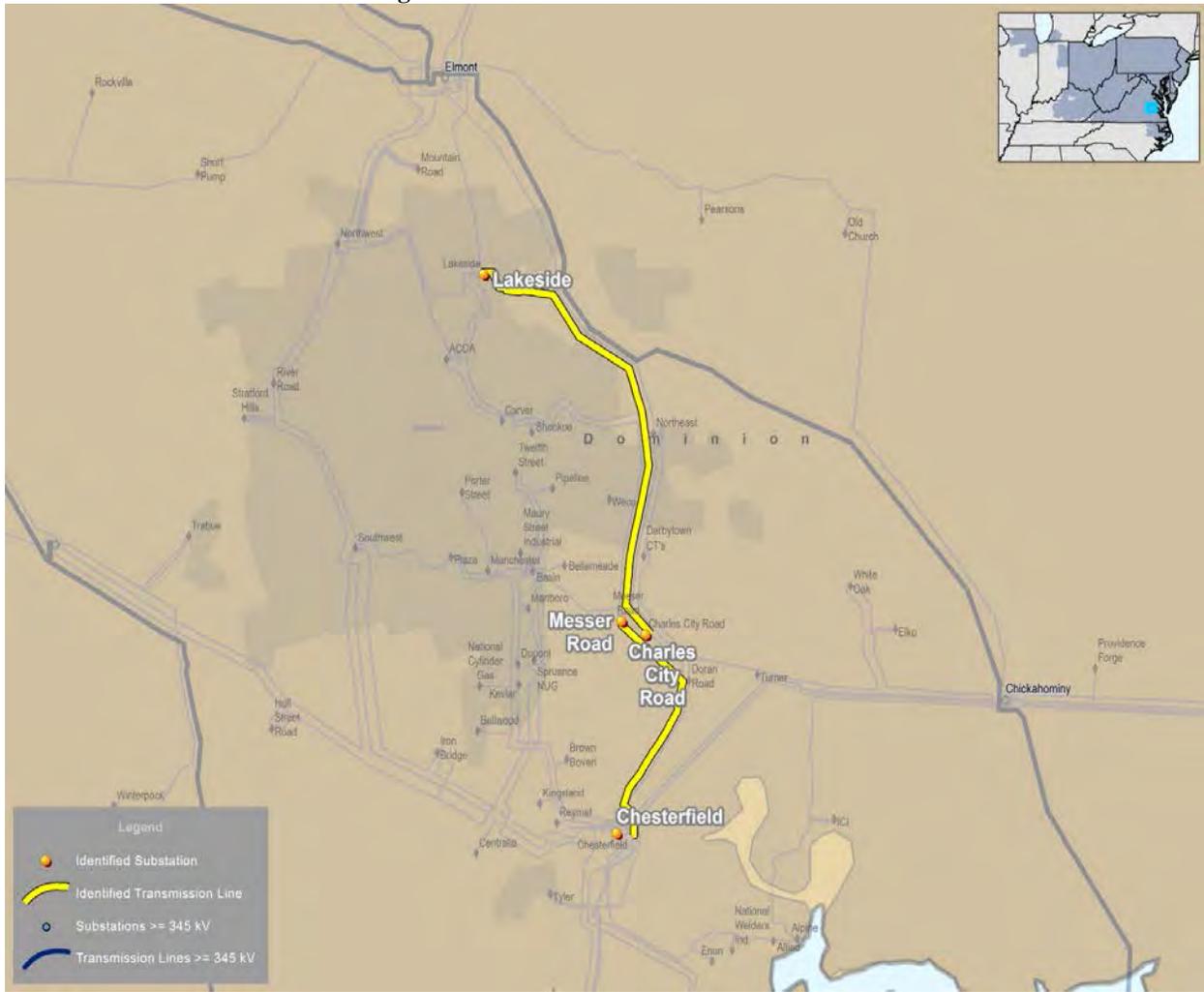
Figure 11 - Carson - Rogers Rd 500 kV



Baseline Project B2745 – Rebuild Chesterfield - Lakeside 230 kV

The Chesterfield – Messer Road – Charles City Road 230 kV circuit in Dominion zone is overloaded for several contingencies in 2020. Additionally, the Chesterfield – Lakeside 230 kV facility has reached its end of life. PJM solicited proposals to address these issues as the 2016 RTEP Proposal Window #1. A total of six baseline proposals from two entities, Dominion and Mid-Atlantic MCN, were submitted to address this reliability criteria violation. The cost of proposals ranged from approximately \$8 million to \$59 million. Four proposals entailed building new 500/230 kV facilities that required new right-of-way. However these proposals did not address the End of Life facility. One 230 kV upgrade proposal was also submitted, but it caused additional violations in combination with other 500 kV solutions. The one proposal to rebuild exiting infrastructure solved the reliability criteria violation by a significant margin, does not require new right-of-way, and also addressed the End of Life criteria violation. For these reasons, the recommended solution to address the issue is to rebuild 21.32 miles of existing line between Chesterfield 230 kV and Lakeside 230 kV. The estimated cost is \$22 million and the required in service date is June 1, 2020.

Figure 12 - Chesterfield - Lakeside 230 kV



Market Efficiency

Market Efficiency Analysis is a part of the overall Regional Transmission Planning Process (RTEP) 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 modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such hybrid upgrades resolve reliability issues but are intentionally designed in a more robust manner to provide economic benefits in addition to resolving those reliability issues.

Market Efficiency analysis is conducted using a market simulation tool which models the hourly security-constrained commitment and dispatch of generation over a future annual period. Economic benefits of transmission upgrades are determined by comparing results of simulations which include the study upgrade to results of simulations which do not include the study upgrade. Projects are measured using two Tariff/Operating Agreement criteria. First, the project must address congestion as simulated in the Market Efficiency analysis. Second, the project benefits must exceed the costs by at least 25 percent. Project 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.

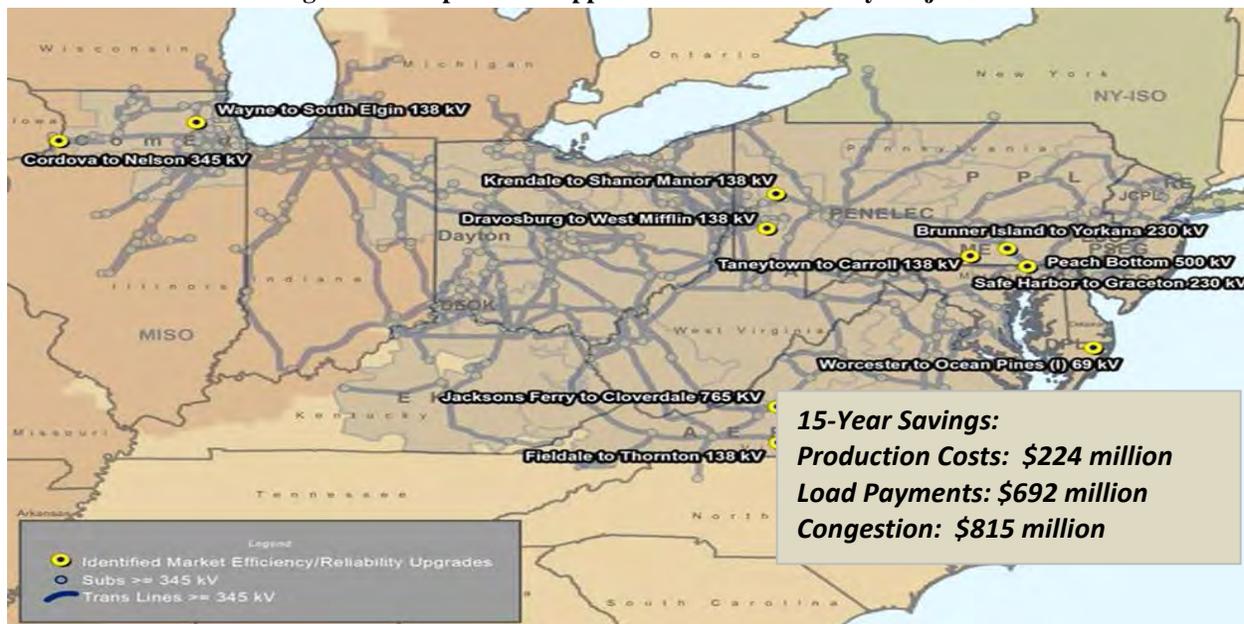
Order 1000 Long-Term Market Efficiency Proposal Window

In October of 2014, PJM opened the first Order 1000 Long Term Market Efficiency proposal window to solicit proposals to address future simulated congestion. Prior to the implementation of Order 1000, RTEP Market Efficiency projects were assigned to the incumbent transmission owners. Assignment to the incumbent transmission owners resulted in less competition and corresponding fewer approved Market Efficiency projects. The implementation of Order 1000, and the corresponding Market Efficiency proposal windows, has resulted in more proposals because of the open competition among incumbent and non-incumbent transmission owners.

There were ninety-three proposals submitted during the Long Term window that closed in February of 2015. Projects submitted ranged in costs from \$0.1 to \$432 million. Proposals included both Transmission Owner upgrades and Greenfield projects from both incumbent transmission owners and non-incumbent entities.

In 2015, the PJM Board approved 11 Market Efficiency projects for inclusion into the 2015 RTEP. These projects consisted of upgrades to existing equipment and were designated to the incumbent transmission owners. Figure 13 below shows the location of the approved projects.

Figure 13: Map of 2015 Approved Market Efficiency Projects



Additionally, at the February 2016 Board meeting, the PJM board approved two projects. The first project addressed congestion associated with PJM IROL (Interconnected Reliability Operating Limit) reactive interfaces, and the second project addressed increased capacity costs from restricted Capacity Emergency Transfer Limits (CETL) encountered in PJM's Reliability Pricing Model (RPM) auctions for the COMED Locational Deliverability Area (LDA). These projects are shown in Figures 14 and 15.

Figure 14: Map of February 2016 Board Approved Optimal Capacitors Project (B2729)

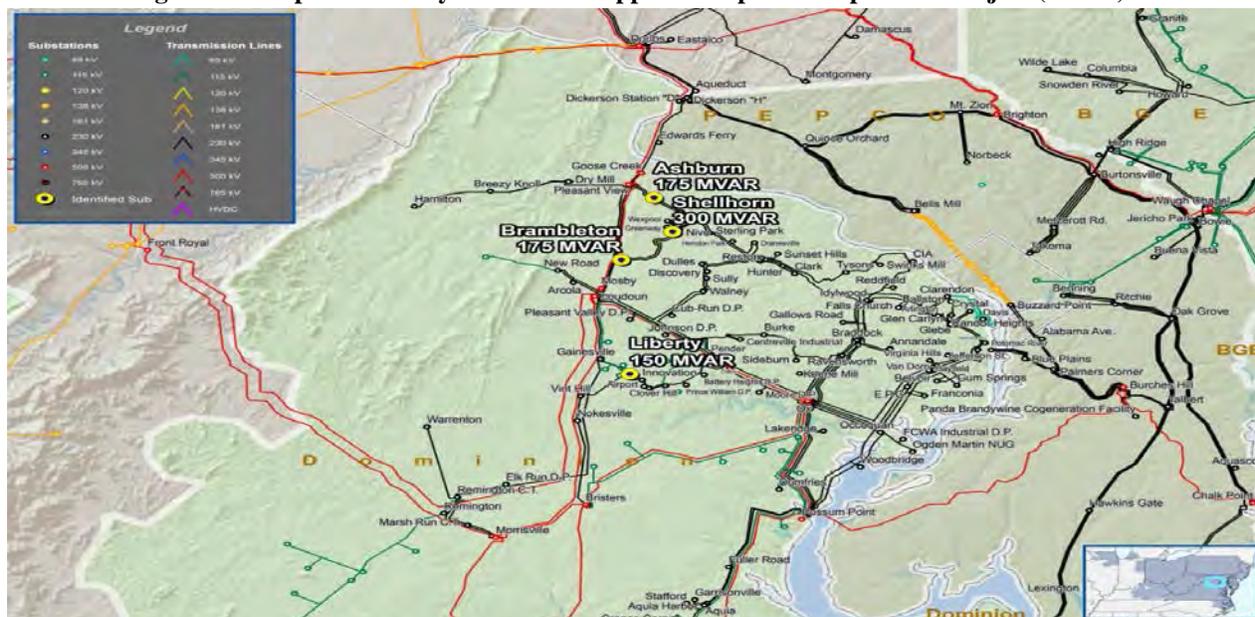
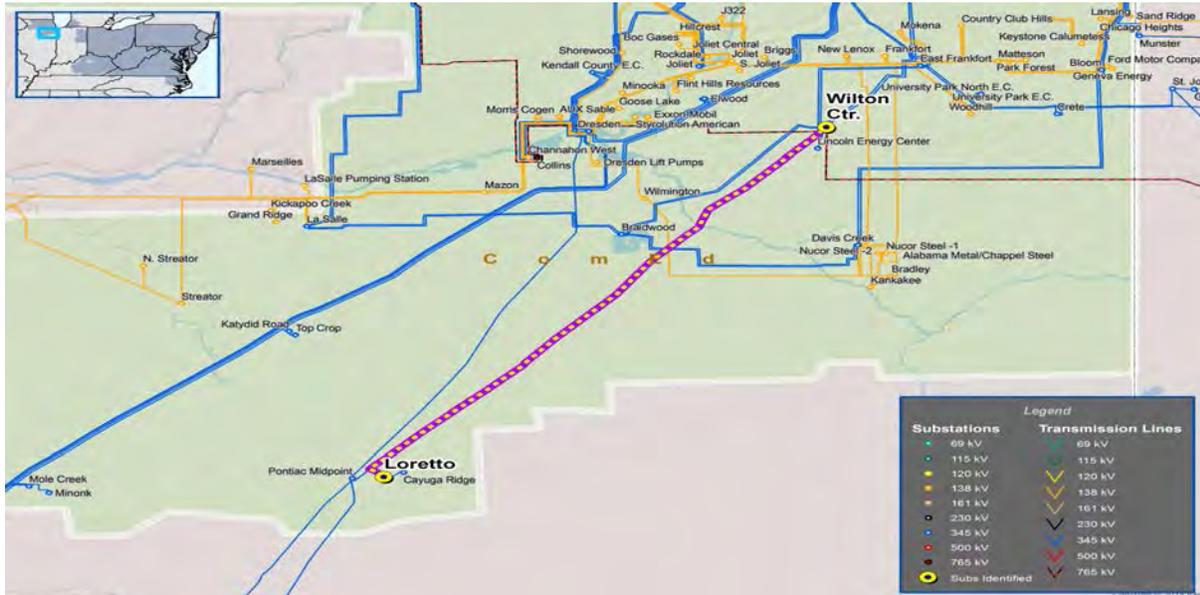
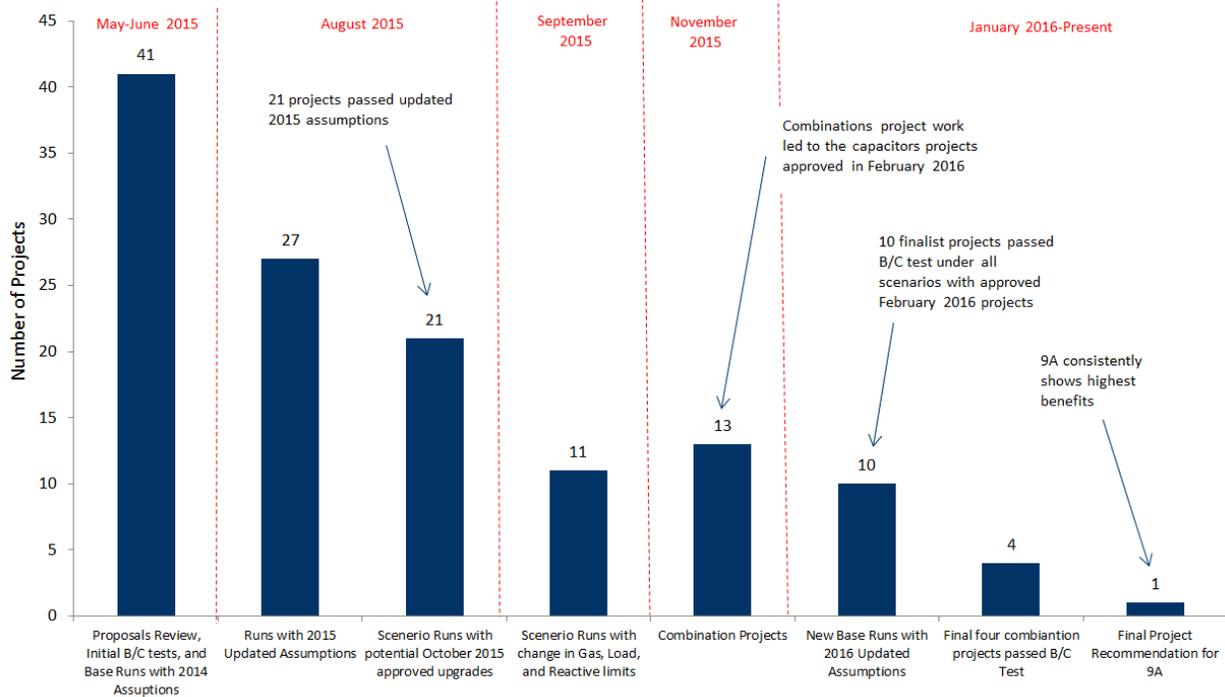


Figure 15: Map of February 2016 Board Approved RPM Project (B2728)



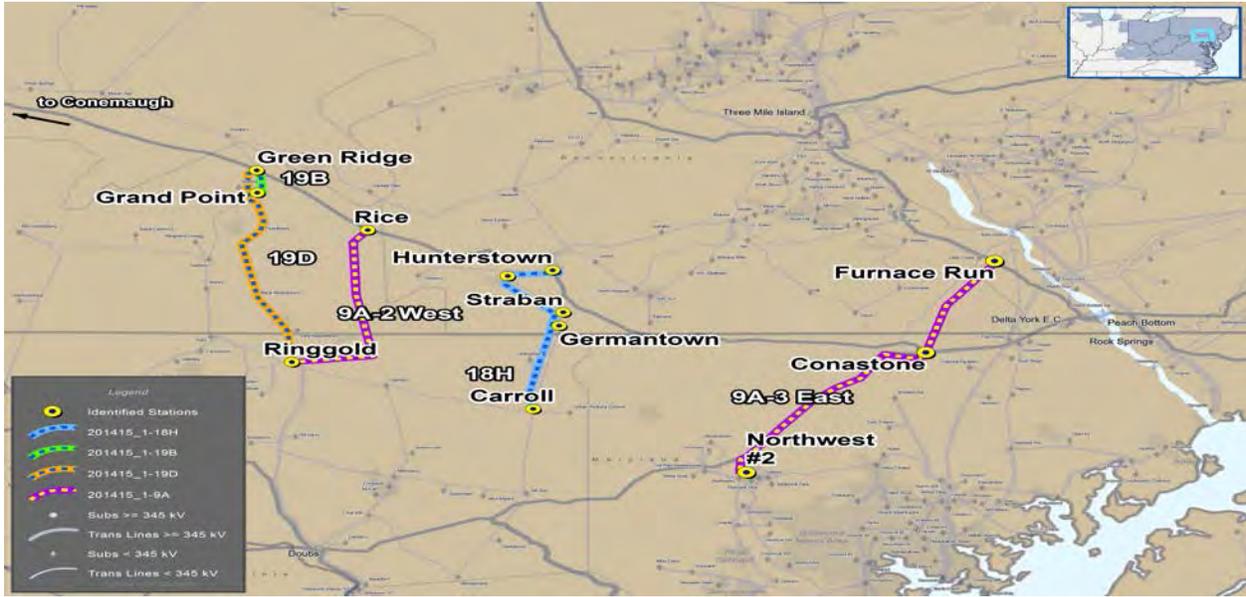
Following the February 2016 Board meeting, PJM staff continued to assess the group of projects submitted to address congestion associated with the PJM IROL (Interconnected Reliability Operating Limit) reactive interface, ApSouth. The analysis was extensive and involved several steps as displayed in the timeline shown below. Of the 41 projects proposed to address this congestion, 11 projects were ultimately competitive. Additional sensitivities further reduced the list to four projects. In total, approximately 23,000 hours of computation time was necessary to run all the ApSouth analysis.

Figure 16: Market Efficiency Timeline for ApSouth Analysis
Market Efficiency ApSouth Analysis Timeline

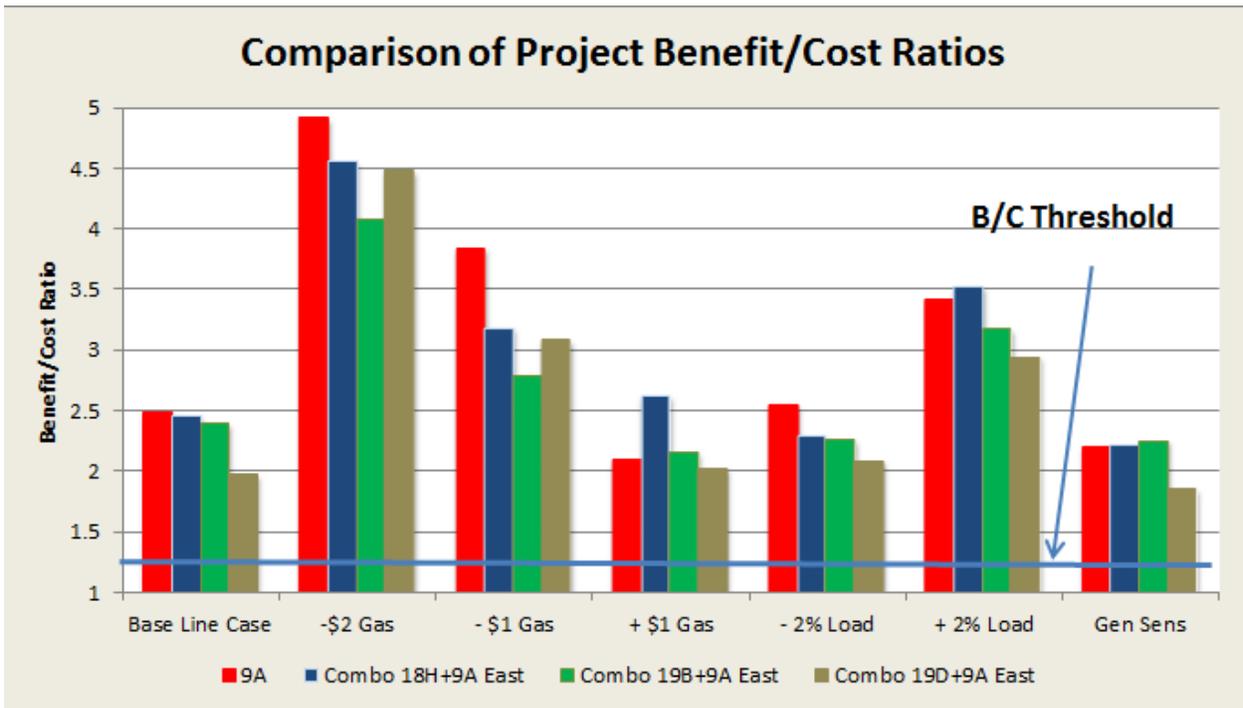


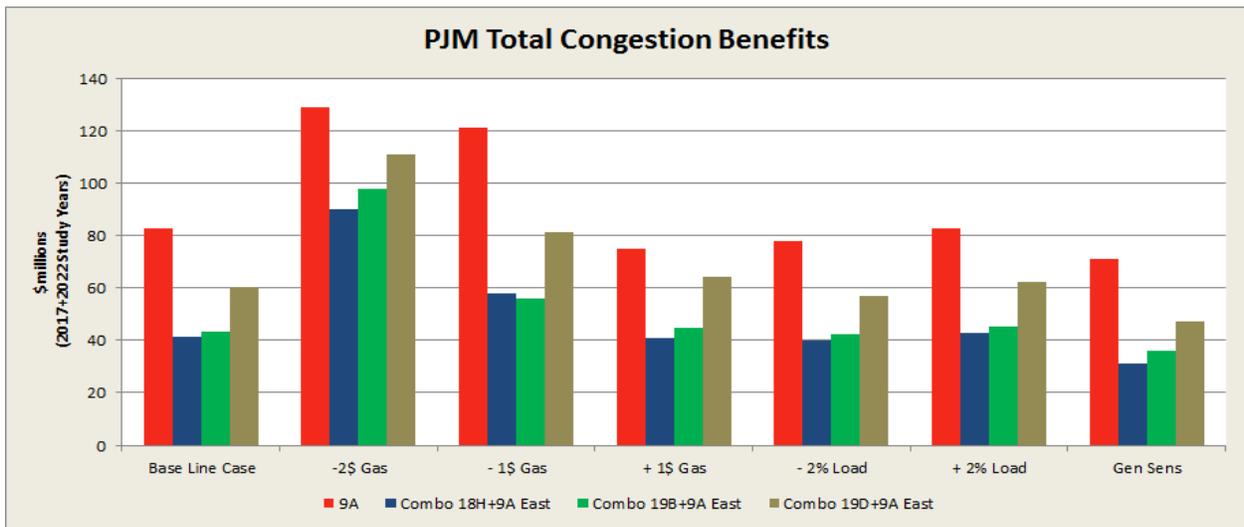
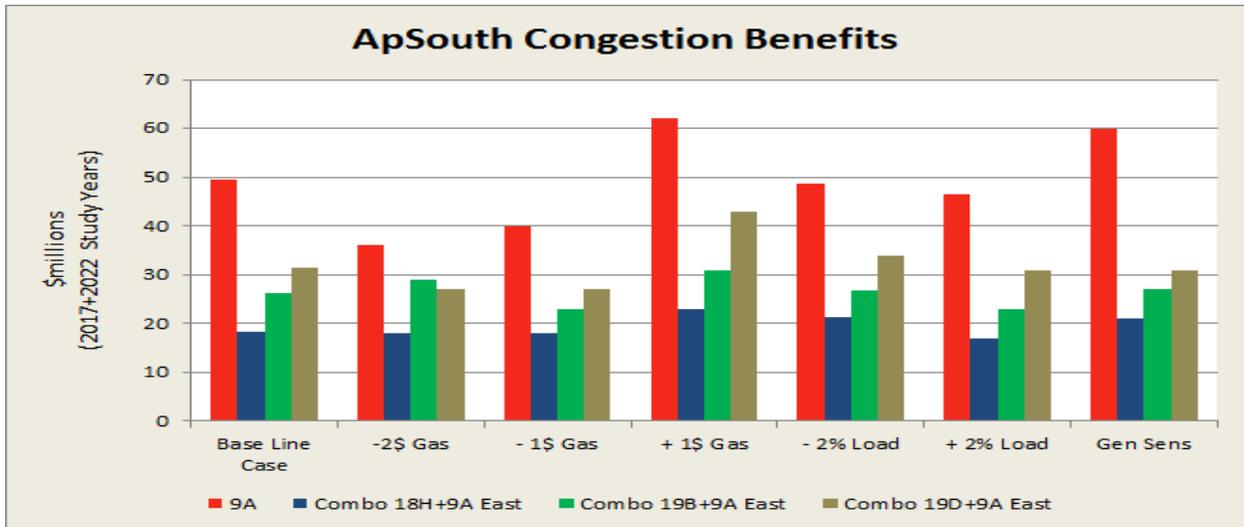
The final four projects that PJM considered competitive because they satisfied the required benefit/cost threshold of 1.25 and provided significant reduction to the congestion on the ApSouth interface are shown in the figure below. These projects are in the Southern Pennsylvania area. Ultimately, the project that provided the most benefits was a project proposed by Transource Energy LLC, project 9A. This project involved a western and an eastern set of transmission facilities. The combination of both western and eastern transmission provides significant benefits because it allows energy to divert from the regional high voltage system to lower voltage load areas. If only the western transmission was included, which involves moving energy from the Conemaugh-Hunterstown 500 kV line, than increased congestion will occur on the eastern portion of PJM because of new energy flow patterns and available generation. Although project 9A provided the most congestion benefits and highest benefit/cost ratio, PJM performed additional studies of combinations of different projects because of the similarity of projects in the Southwestern Pennsylvania area. The figure below shows that the eastern portion of project 9A, labeled 9A-3 East, is geographically and electrically distant from the western submitted projects.

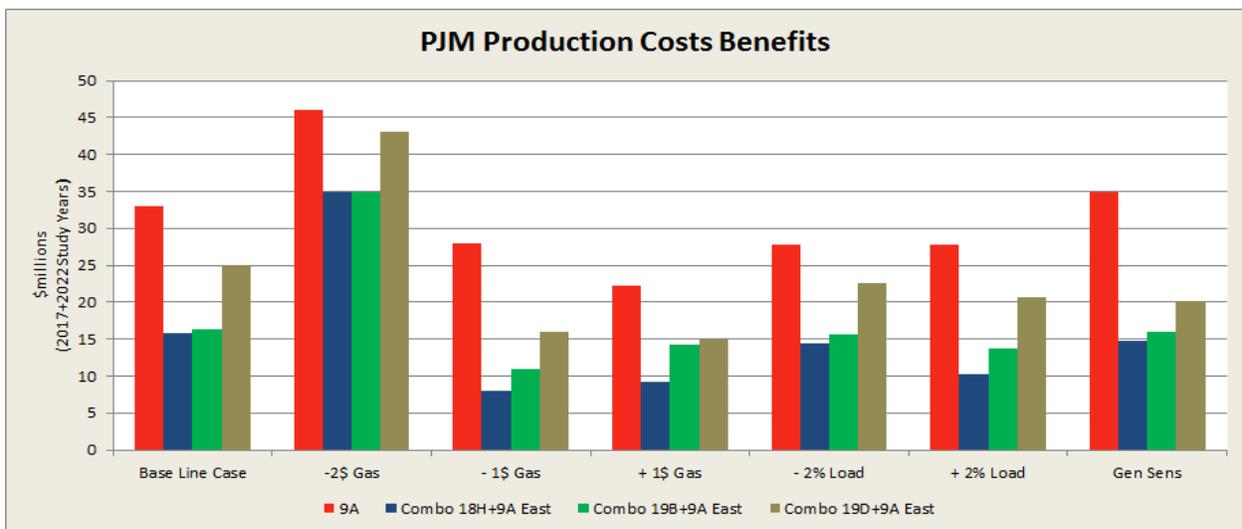
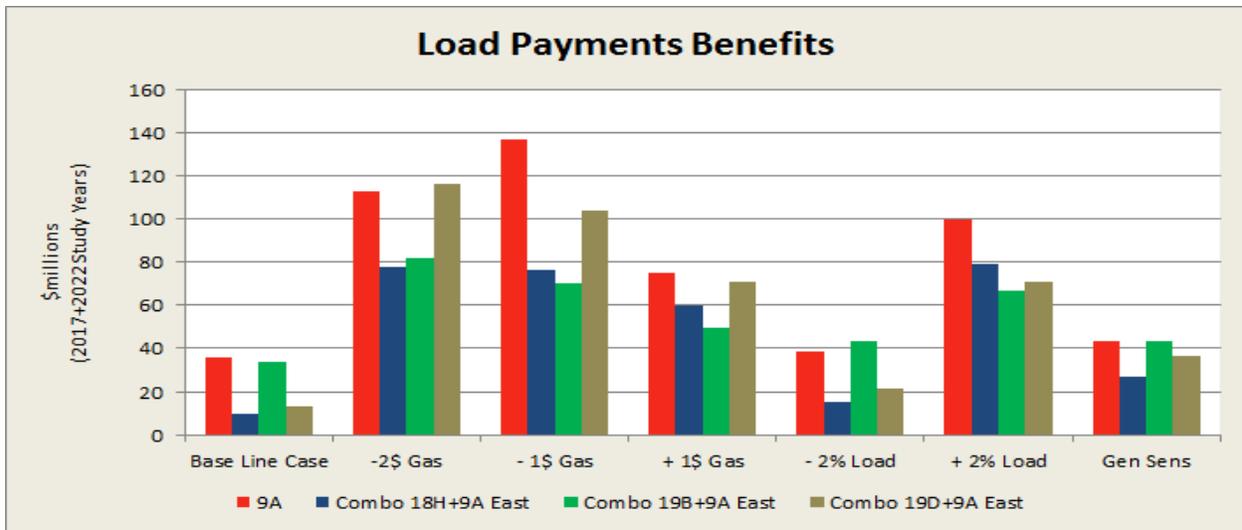
Figure 17: Map of Market Efficiency Final Combination Projects



The analysis of the different combination of projects solidified PJM's staff's confidence in recommending project 9A. This analysis included different scenario analysis using various assumptions to ensure the recommended project was robust. The scenario analysis included variations in load forecast, fuel prices, and important generator assumptions. Many of these scenarios were done based on feedback from PJM stakeholders. The results of the various scenario analyses are displayed in the below graphs. The graphs show that the 9A project provided the most benefits for the different scenarios.







In addition to the sensitivities described above PJM also evaluated the finalist projects with the 9A project also included in the case. The result was that with the inclusion of project 9A, the remaining finalist projects no longer passed the benefit/cost threshold test of 1.25. Finally, PJM evaluated the recommended project 9A using assumptions for the Clean Power Plant (CPP) and forecasted fuel prices. The result was that the benefit/cost ratio for project 9A was equal to 4.67.

In accordance with the Operating Agreement PJM also had an independent consultant validate the cost estimate for the recommended project. The whitepaper at the following link summarizes the independent cost, schedule and constructability analyses completed for the evaluation of some of the Market Efficiency projects that were proposed in the window. The results of this analysis validated the estimated cost of the recommended project.

<http://www.pjm.com/-/media/committees-groups/committees/teac/20160512/20160512-2014-2015-long-term-proposal-window-independent-cost-review-white-paper.ashx>

PJM staff recommended the project 9A as an Market Efficiency project to be included in the RTEP. This project involves incumbent transmission owner work at existing substations as well as new substation and transmission line construction that will be designated to a non-incumbent transmission owner (Transource an affiliate of AEP). The project is expected to cost \$320.19 million and the required in service date is June 1, 2020. The expected 15-year congestion and load payment savings are \$619 million and \$269 million, respectively. The cost allocation and designated entities for this project are provided in Attachment B, of this document. Details of the recommended project are as follows.

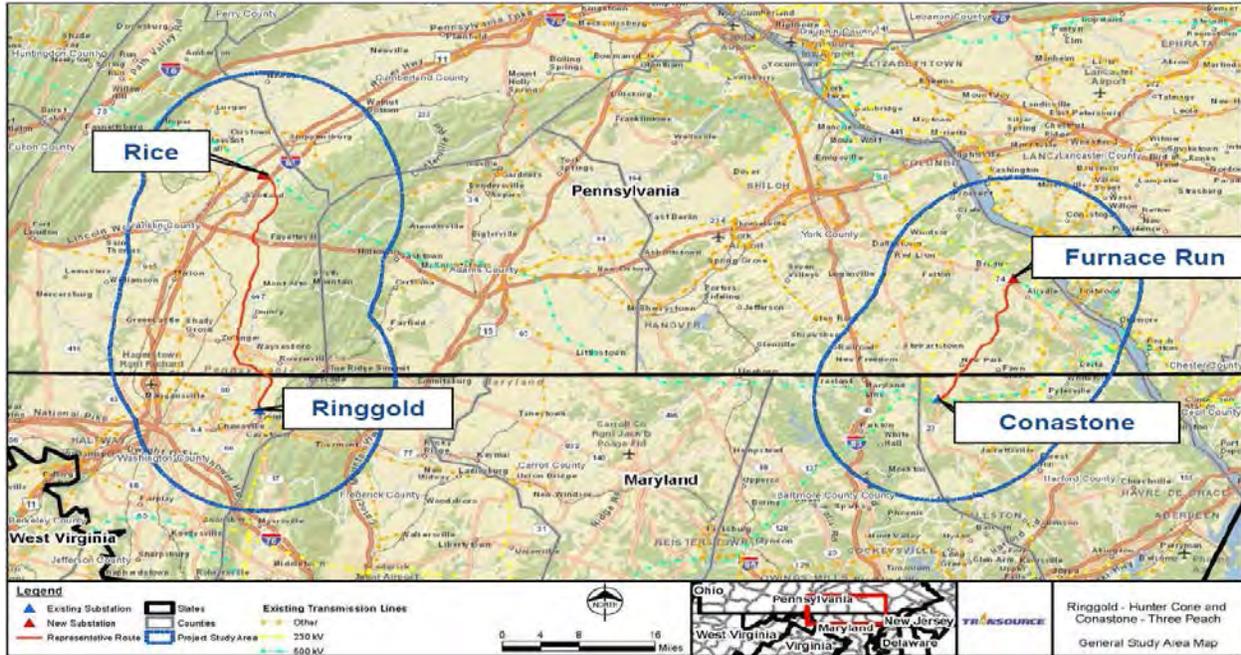
Market Efficiency project 9A: IROL Market Efficiency Baseline Project B2743 and B2752 – Southern Pennsylvania Project

The final recommended solution includes the following facilities:

- The West Line: approximately 27 miles of new double-circuit 230 kV alternating current overhead transmission line configured in a six-wired arrangement between the existing Ringgold Substation to a new Rice Substation that will tie into the existing Conemaugh-Hunterstown 500 kV line.
- The Ringgold Substation will be expanded to accommodate the new 230 kV circuits with one new 230 kV breaker. The expansion required at Ringgold is assumed to be designated to the incumbent transmission owner as an upgrade.
- The new Rice Substation will include two 900 MVA, 500/230 kV transformers, two 245kV breakers in a single bus double breaker configuration and four 500kV breakers in a ring bus configuration.
- The East Line: approximately 14.5 miles of new double-circuit 230 kV alternating current overhead transmission line configured in a six-wired arrangement between the existing Conastone Substation to a new Furnace Run Substation that taps the existing Three Mile Island-Peach Bottom 500 kV line.
- The new Furnace Run Substation will include two 900 MVA, 500/230 kV transformers, two 245kV breakers in a double breaker single bus configuration, and four 500kV breakers in a ring bus configuration.
- The Conastone Substation will be expanded to accommodate the new double circuit 230 kV lines and two new 230 kV breakers. The expansion required at Conastone is assumed to be designated to the incumbent transmission owner as an upgrade.
- Reconnector the Conastone to Northwest double circuit 230 kV line.

- Replace the Ringgold #3 and #4 transformers with 230/138 kV autotransformers
- Reconfigure the Ringgold bus.
- Reconnector the Ringgold-Catoctin 138 kV line.

Figure 18: Location of Recommended Market Efficiency Project 9A: Baseline Project B2743 & B2752 Project in Southern Pennsylvania/Northern Maryland



Recommended Market Efficiency Project for PJM IROL Reactive interface

PJM Baseline ID	PJM Window Project ID	Project Description	Transmission Zone	Constraint Project Addresses	Project Cost (\$M)	ISD
B2743 & B2752	201415-9A modified	Southern Pennsylvania Project	Transource Energy LLC, Baltimore Gas & Electric, Allegheny Power	ApSouth	\$320.19	2020

Changes to Previously Approved Projects

Cost and scope of a number of previously approved RTEP baseline projects have changed. In addition, a number of projects were cancelled as they are no longer required. The net result of these changes to previously approved baseline projects is a net increase in the RTEP of \$146.36 million. Some of the more significant cost changes are noted below.

The cost of the previously approved RTEP project B1794 in the Dominion zone to build a new substation near the Edgcomb NUG is expected to increase as the intended location for the new substation is not available. A new site for the substation was pursued however the cost of the project is expected to

increase by \$11 million to account for increased real estate costs and additional construction cost. The expected cost for the project is approximately \$19 million.

The cost of previously approved RTEP project B2230 in the AEP zone to replace existing 150 MVAR reactor at the Amos 765 kV substation on the Amos – N. Proctorville – Hanging Rock 765 kV circuit with a 300 MVAR reactor has increased. Several factors including increased civil engineering and structure costs, increased disposal costs of the existing reactor and additional environmental remediation work resulted in an increase of approximately \$26 million. The revised total cost estimate for the project is \$31 million.

The scope of previously approved RTEP project B2234 in the JCPL zone to install a 260 MVAR reactor at West Wharton 230 kV was changed to install a -260/+40 MVAR SVC. The SVC will utilize the existing 350 MVAR capacitors at the station. The new configuration will help to replace the loss of dynamic reactive reserve due to generator retirements in the area. The estimated change in cost is an increase of \$33.4 million, and the revised total cost estimate is approximately \$41 million.

The scope and cost of previously approved RTEP project B2423 in the AEP zone to install a 300 MVAR shunt reactor at the Wyoming 765 kV station has increased. The scope has increased to include a switchable spare reactor. Multiple factors contributed to the cost increase including the substation expansion costs were greater than anticipated as well as increased structural work than initially anticipated to connect the reactor to the Jackson Ferry 765 kV line. The estimated cost change is an increase of \$15 million, and the revised total cost estimate is \$25 million.

The cost of previously approved RTEP project B2505 in the Dominion zone to reconfigure the Harmony Village – Northern Neck 115 kV line has increased. The increased costs are due to several factors including additional structure costs for the river crossing and permitting costs for FAA, Army Corps, Virginia Marine Resource Commission, and local wetland board (Lancaster and Middlesex Co) permitting. The estimated change in cost is an increase of \$20 million, and the revised total cost estimate is \$30 million.

The scope and cost of previously approved RTEP projects B2702, B2705, and B2707 in the PSE&G zone have been modified. The B2702 upgrade to install a 350 MVAR reactor at Roseland 500 kV was changed to install two 175 MVAR reactors at Hopatcong 500 kV due to space limitations at Roseland. The B2705 upgrade to install a 200 MVAR reactor at Bergen 345 kV was changed to install two 100 MVAR reactors at Marion 345 kV to provide greater operational flexibility. The scope of B2707 upgrade to install a 100 MVAR reactor at Bayonne 345 kV remains the same but the estimated cost was lowered. The scope and cost changes for these projects result in a net decrease of \$29.7 million, and the revised total cost estimate is approximately \$74 million for all three projects.

Review by the Transmission Expansion Advisory Committee (TEAC)

The results of the analyses summarized in this report were reviewed with the TEAC and Subregional RTEP Committees over several meetings throughout 2016. The most recent analyses, along with recommended

solutions, were reviewed during the June 23, 2016 TEAC webcast. Written comments were requested to be submitted to PJM communicating any concerns with the recommendation and any alternative transmission solutions for consideration.

Cost Allocation

Preliminary cost allocations for the projects being recommended are shown in Attachment A for projects that will be allocated to a single transmission zone and in Attachment B for projects that will be allocated to multiple transmission zones.

Cost allocations for the projects were calculated in accordance with the Schedule 12 of the OATT. Baseline reliability project allocations are calculated using a distribution factor methodology that allocates the cost to the load zones that contribute to the loading on the new facility. The costs for the market efficiency project are allocated to load in the transmission zones that benefit from the project. The allocations will be filed at the FERC 30 days following approval by the Board.

Board Approval

The PJM Board Reliability Committee endorsed the new baseline reliability projects and associated cost allocations. The PJM Board Reliability Committee recommended to the Board approval of the baseline upgrades to the 2016 RTEP, and the PJM Board of Managers have approved the changes to the RTEP.

Reliability Project Single Zone Allocations

Upgrade ID	Description	Cost Estimate (\$M)	Trans Owner	Cost Responsibility	Required IS Date
b2717.1	De-energize Davis–Rosslyn #179 and #180 69 kV Lines	\$2.50	Dominion	Dominion	5/31/2016
b2717.2	Remove splicing and stop joints in manholes	\$0.00	Dominion	Dominion	5/31/2016
b2717.3	Evacuate and dispose of insulating fluid from various reservoirs and cables	\$0.00	Dominion	Dominion	5/31/2016
b2717.4	Remove all cable along the approx. 2.5 mile route, swab and cap-off conduits for future use, leave existing communication fiber in place	\$0.00	Dominion	Dominion	5/31/2016
b2719.1	Expand Perth substation and add a 115kV four breaker ring.	\$7.00	Dominion	Dominion	6/1/2017
b2719.2	Extend the Hickory Grove DP tap 0.28 miles to Perth and terminate it at Perth.	\$0.00	Dominion	Dominion	6/1/2017
b2719.3	Split Line #31 at Perth and terminate it into the new ring bus with 2 breakers separating each of the line terminals to prevent a breaker failure from taking out both 115 kV lines.	\$0.00	Dominion	Dominion	6/1/2017
b2720	Replace the Loudoun 500kV 'H1T569' breakers with 50kA breaker.	\$0.90	Dominion	Dominion	6/1/2018
b2721	Goodings Grove – Balance Station Load (swap bus positions for 345 kV lines 1312 & 11620 and 345 kV lines 11604 & 11622) and replace 138 kV bus tie 2-3	\$5.40	ComEd	ComEd	6/1/2018
b2722	Reconductor the 1 mile Bergen – Bergen GT 138 kV circuit (B-1302)	\$6.50	PSEG	PSEG	10/30/2016
b2725	Build new 345/138 kV Lake Avenue substation w/breaker and a half high side (2 strings), 2-345/138 kV transformers and breaker and a half (2 strings) low side (138 kV). Substation will tie Avon - Beaver	\$40.00	ATSI	ATSI	4/16/2016
b2725.1	Replace the Murray 138 kV breaker '453-B-4' with 40kA breaker.	\$0.28	ATSI	ATSI	4/16/2016
b2730	Upgrade Denny - Gregory Tap 69 kV line facility	\$0.72	EKPC	EKPC	6/1/2025
b2731	Convert the Sunnyside - East Sparta - Malvern 23 kV sub-transmission network to 69 kV. The lines are already built to 69 kV standards.	\$5.70	AEP	AEP	8/1/2016
b2732.1	Cut-in of line 93505 Tazewell - Kendall 345 kV line into Dresden	\$17.00	ComEd	ComEd	6/1/2018

b2732.2	Raise towers to remove the sag limitations on Pontiac - Loretto 345 kV line	\$3.40	ComEd	ComEd	6/1/2018
b2745	Rebuild 21.32 miles of existing line between Chesterfield - Lakeside 230 kV	\$22.00	Dominion	Dominion	6/1/2020

Reliability Project Multiple Zone Allocations

Upgrade ID	Description	Cost Estimate (\$M)	Trans Owner	Cost Responsibility	Required IS Date
b2716	Add a 200 MVAR shunt reactor at Lackawanna 500 kV substation	\$10.00	PPL	AEC - 0.79%, AEP - 7.59%, APS - 2.95%, ATSI - 3.8%, BGE - 2.06%, ComEd - 6.19%, ConEd - 0.28%, Dayton - 1.01%, DEOK - 1.58%, DL - 0.86%, Dominion - 6.65%, DPL - 1.27%, ECP - 0.1%, EKPC - 1.07%, HTP - 0.1%, JCPL - 1.79%, ME - 0.86%, NEPTUNE - 0.21%, PECO - 2.49%, PENELEC - 0.93%, PEPCO - 1.93%, PPL - 52.48%, PSEG - 2.95%, RE - 0.12%	12/1/2018
b2744	Rebuild the Carson - Rogers Rd 500 kV circuit	\$48.50	Dominion	AEC - 0.79%, AEP - 7.59%, APS - 2.95%, ATSI - 3.8%, BGE - 2.06%, ComEd - 6.19%, ConEd - 0.28%, Dayton - 1.01%, DEOK - 1.58%, DL - 0.86%, Dominion - 56.65%, DPL - 1.27%, ECP - 0.1%, EKPC - 1.07%, HTP - 0.1%, JCPL - 1.79%, ME - 0.86%, NEPTUNE - 0.21%, PECO - 2.49%, PENELEC - 0.93%, PEPCO - 1.93%, PPL - 2.48%, PSEG - 2.95%, RE - 0.12%	6/1/2020
b2743 & b2752	Market Efficiency Project 9A: Tap the Conemaugh - Hunterstown 500 kV line and build a new 230 kV double circuit line between Rice and Ringgold; build new 230 kV double circuit line between Furnace Run and Conastone 500 kV; rebuild the Conastone - Northwest 230 kV line; replace the Ringgold #3 and #4 transformers with 230/138 kV autotransformers; Ringgold bus reconfiguration;	\$320.19	Transource, BGE, APS, PE, ME	AEP - 6.46%, APS - 8.73%, BGE - 19.73%, ComEd - 2.16%, ConEd - 0.06%, Dayton - 0.59%, DEOK - 1.02%, DL - 0.01%, Dominion - 39.92%, EKPC - 0.45%, PEPCO - 20.87%	6/1/2020

	reconductor Ringgold - Catoctin 138 kV.				
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