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BEFORE THE
OHIO POWER SITING BOARD

In the Matter of the Application of American Transmission Systems Incorporated for a Certificate Relative to the Bruce Mansfield-Glenwillow 345 kV Transmission Line Project	)))))))	Case No. 12-1726-EL-BLN

JOINT COMMENTS OF THE ENVIRONMENTAL LAW & POLICY CENTER, THE OHIO ENVIRONMENTAL COUNCIL, AND THE SIERRA CLUB

INTRODUCTION

In a December 10, 2012 Entry, the Administrative Law Judge requested comments on the Bruce Mansfield-Glenwillow 345 kV Transmission Line ("Mansfield Line") proposed by American Transmission Systems, Inc. ("ATSI"). The Environmental Law & Policy Center ("ELPC"), the Ohio Environmental Council ("OEC"), and the Sierra Club, collectively "Environmental Advocates," have all filed motions to intervene that are pending in front of the Ohio Power Siting Board ("Board"). The Environmental Advocates' overarching concern is that the application submitted by ATSI does not contain sufficient information or detail to evaluate the proposed Mansfield Line. The Board should require ATSI to supplement its application with the information described below, and the Board should take the time necessary to thoroughly review the Mansfield Line, which is approximately 114.5 miles long and estimated to cost over $130 million. A thorough review will likely require the Board to suspend ATSI's application for 90 days, as allowed under statutes and Board rules.

The following comments explain the Environmental Advocates' concerns with the Mansfield Line and ATSI's application:

1. The Letter of Notification process is inadequate for review of major transmission projects like the Mansfield Line.

2. ATSI's filing is deficient because it fails to explain the need for the proposed Mansfield Line and fails to present sufficient details necessary to make that determination.

3. The North American Electric Reliability Corporation ("NERC") standards are changing, and ATSI does not explain which standards were used or how those changing standards would affect the proposed line.

4. ATSI does not provide sufficient detail related to its load flow study.

5. The use of operating procedures is not accurately or completely portrayed in ATSI's filing.

6. In making a determination on the Mansfield Line, the Board should consider that the transmission system reinforcement needs are in a state of flux.

BACKGROUND

ATSI filed a pre-application notification letter for the Mansfield Line on June 1, 2012, originally intending for the line to go through the normal Certificate Application process as described in Ohio Administrative Code ("OAC") § 4906-15. Shortly after this pre-application, however, the Ohio legislature passed SB 315, which requires the Board to adopt rules providing for "accelerated review of an application for a construction certificate for . . . [a]n electric transmission line that is . . . [n]ecessary to maintain reliable electric service as a result of the retirement or shutdown of an electric generating facility within the state." Ohio Revised Code ("ORC") § 4906.03(F). The Board has initiated rulemaking proceedings to address this accelerated review, but in the meantime has allowed qualifying lines to go through the expedited Letter of Notification ("LON") process. *In the Matter of the Ohio Power Siting Board's Review of Chapters 4906-1, 4906-5, 4906-7, 4906-9, 4906-11, 4906-13, 4906-15, and 4906-17 of the Ohio Administrative Code*, Case No. 12-1981-GE-BRO, Finding and Order (Sept. 4, 2012). The

LON process was previously reserved for simple lines such as those that are less than 125 kV and less than two miles in length.

ATSI was granted permission to transfer to the expedited LON process and filed its application November 9, 2012. According to the application, the new, single circuit 345 kV transmission line would extend approximately 114.5 miles between the Bruce Mansfield Substation in Beaver County, Pennsylvania, to the proposed new Glenwillow Switching Station in Glenwillow, Ohio. The new transmission facilities would cost in excess of $130 million. *See* ATSI Application, page 37, Estimated Costs.

COMMENTS

1. **The Letter of Notification process is inadequate for review of major transmission projects like the Mansfield Line.**

As explained below, the need determination for a major line, including load flow analysis, is a complicated and time-consuming process. This is just one reason why the LON process is largely inadequate when applied to major transmission projects such as the $130 million, 114-mile 345 kV Mansfield Line. The LON process, which previously applied to only minor transmission lines, usually lasts only 63 days, includes less in-depth filing requirements, and does not involve an automatic hearing. *See* OAC § 4906-5-02 (explaining LON form, content, and processing); OAC § 4906-11-01 (explaining LON application requirements). Typically, a LON docket will only include a short filing from the applicant and a two-to-three page report by Board Staff.[1]

This process is grossly inadequate to address the evaluation of major lines like the Mansfield Line. However, the Board has certain options to expand the review of these lines, even under the LON process, and it should consider those options in this case and others. First,

[1] As an example, *see Yellow Creek 138 kV Extension*, Case No. 11-4805-EL-BLN.

SB 315 allows for a total of 180 days to make a determination on a line qualifying for the expedited review process.[2] While far from ideal, 180 days would allow the Board to adopt an appropriate procedural schedule and adequately evaluate many transmission projects. Second, pursuant to the Board rules addressing LONs, the Board may "[d]ocket its decision," as it did in this case, and "may direct the applicant to furnish . . . additional information." OAC § 4906-5-02(3)(a). Finally, the Board has the authority to "set the matter for hearing." OAC § 4906-5-02(3)(a). In this case and others, the Board should take advantage of these procedural safeguards to ensure that major transmission lines are adequately reviewed.

2. **ATSI's filing is deficient because it fails to explain the need for the proposed Mansfield Line and fails to present sufficient details necessary to make that determination.**

OAC § 4906-11-01(B)(2) requires an applicant, even under the expedited LON process, to provide "a statement explaining the need for the proposed" transmission line. In the case of an electric transmission line, ORC § 4906.10 explains that the Board "shall not grant a certificate for [its] construction . . . unless it finds and determines" a number of findings, including "[t]he basis of the need for the facility." The Board also must make a determination that "the facility will serve the public interest, convenience, and necessity." ORC § 4906.10. Especially given the high price tag associated with this proposed line, a thorough review of all the information is necessary to make these public interest and need determinations.

As explained more fully in the comments below, ATSI presents only generalizations about the need for the Mansfield Line, with no opportunity for interested parties to obtain access to specific details about this need. Without additional information, the Board cannot establish

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[2] The statute states that the Board must make a determination or suspend the application within ninety days. The suspension may last for an additional ninety days before a final determination must be made. ORC § 4906.03.

that this project is needed and in the public interest, and interested parties cannot meaningfully participate in the evaluation process. For example, in order to evaluate the need for the Mansfield Line, more details are needed regarding the load and resource assumptions incorporated into this need, about the contingencies that drive this need, about the costs and specific reliability performance of alternatives, and other related information. More is reasonably required to justify the need for new transmission facilities costing in excess of $130 million.

At a minimum, the Board should require ATSI to provide the following information, which is essential to making a legitimate determination as to whether the Mansfield Line meets the need and public interest requirements set by law:

a. Information related to the load flow analysis for the proposed Mansfield Line, including:

    a. Peak load assumptions used

    b. Facilities assumed to be in-service

    c. Generating unit dispatch assumed

    d. Thermal violations and the contingencies that produce them

    e. Voltage violations and the contingencies that produce them

    f. Scenarios that will not solve and the contingencies that produce them

    g. Load flow model data reflecting the above

b. An explanation of how changing NERC standards may affect the evaluation of the Mansfield Line

c. A more thorough explanation of the available "operating procedures" and their ability to address system loads and contingencies

3. The North American Electric Reliability Corporation ("NERC") standards are changing, and ATSI does not explain which standards were used or how those changing standards would affect the proposed line.

As explained below, NERC sets mandatory transmission planning standards that apply to the determination of whether a proposed transmission line is needed. The Federal Energy Regulatory Commission ("FERC") is currently considering changes to these standards. It is unclear from ATSI's application which standards were used and whether the change in standards affects the evaluation of alternatives or any other aspect of the analysis. The Board should consider these changing standards and require ATSI to clarify these issues and supplement its application with an explanation of how these new standards affect the Mansfield Line.

NERC sets planning standards that are mandatory for bulk electric system ("BES") facilities. These facilities include transmission lines, substation transformers, electric substations, and other facilities operating at a voltage of 100 kV or higher. NERC requires that the electric transmission system, along with the projected peak loads and expected resources, be studied under normal conditions (with no forced outages of transmission lines, substation transformers, substation busses, generating units, or other electric system components), and under contingency conditions (where one or more transmission lines, substation transformers, substation busses, generating units, or other electric system components experience a forced outage).

NERC's mandatory transmission planning requirements are largely included in NERC Standards TPL-001-0.1, TPL-002-0b, and TPL-003-0a, which address planning requirements at projected peak loads five or more years into the future for (1) normal system conditions (with no system contingencies), (2) system conditions with all possible single contingencies, studied one at a time, and (3) system conditions with specified multiple contingencies.

Typically, under normal system conditions (no contingencies), all load-sensitive system elements, most typically transmission lines and substation transformers, will be loaded up to not higher than their normal maximum capabilities,[3] and all substation busses will be within normal voltage limits. Under single contingency conditions, electric service will generally be maintained up to most firm loads, all load-sensitive system elements will be loaded up to not higher than their emergency maximum capabilities, and all substation busses will be within emergency voltage limits. Under multiple contingency conditions, firm loads may be dropped under certain conditions, but the electric system must not have a cascading outage, and those system elements remaining in service must be operating within emergency thermal and voltage limits. If reasonable planning assumptions are used in the modeling, as explained below, when system components are found to be loaded above the applicable capabilities, or are found to be at a voltage level outside the required range, this is typically referred to as a planning violation, which must be addressed before they actually occur.

FERC is currently considering a new NERC transmission system reliability standard, Standard TPL-001-2, which, when approved, will consolidate and replace the above referenced standards. It is unclear how these new standards may affect the alternatives analysis, planning violations, or any other aspect of the proposed Mansfield Line application. The Board should consider these issues and require ATSI to explain the effect these new standards will have on the proposed line.

4. ATSI does not provide sufficient detail related to its load flow study.

Load flow studies are used to study compliance with the NERC transmission planning standards and are run using commercially available computer models. These load flow models incorporate numerous assumptions about the future, including what the level of forecast peak loads will be, which projected transmission facilities will be in service, what generating units are

[3] Typically referred to as thermal loading, since these operating capabilities are limited by the heat that a system component experiences as its loading increases.

expected to be in service, which generating units are actually operating, and at what level of output. By changing these assumptions, the reliability need for future system reinforcements, such as the proposed Mansfield Line, can be enhanced or diminished. Therefore, the information surrounding the load flow studies is extremely important to the Board's determination of the need for the proposed project, as required by statute, and ATSI provides little of this information in its filing.

The load flow model takes data that describes the electric system and calculates the amount of power flowing through each transmission line and through each substation transformer, as well as the voltage level of every substation bus. For a contingency study, the load flow model takes the component suffering the forced outage out of service and recalculates the loading of all remaining system components and the voltage of all substation busses. Depending on the system configuration, including loads and resources, that the model is trying to calculate load flows and voltages for, the model's calculations may refuse to converge, in which case it is said that the model did not solve. Such scenarios can indicate a potential for future system-wide voltage collapse and/or an electric system blackout.

The load flow model uses data representing an electric system of substation busses, the load served off of each such bus, the generating units connected to each such bus and the level of generation from each such unit, the connections between each substation bus (transmission lines) and the impedance of each such connection, and the presence of all transformers on any of the connectors between busses. The transmission system in the entire eastern part of the U.S. is electrically integrated and needs to be reflected in the modeling data used to model the transmission system in Ohio. Because of this, a large amount of data is needed to perform load flow studies.

In addition to the fact that ATSI failed to provide much of this important information, the Board should consider that additional time may be necessary to evaluate the information. Some of the data needed to run a load flow study is classified by FERC as critical energy infrastructure information ("CEII"). Therefore, access to this data is restricted and requires execution of a non-disclosure agreement. Because of this, gaining access to load flow model data and then actually using it to examine transmission planning requirements can be time-consuming.

The modeling of all single contingencies is a detailed process, but is achievable with modern models. However, the modeling of all required double contingencies can require the modeling of many thousands of scenarios, many with system adjustments required between the first two contingencies. Without much more detailed information from ATSI, the Board is faced with trying to access load flow data and run hundreds of hours of transmission system modeling to study the reasonableness of ATSI's assertions within a wholly inadequate time frame. There is really no way for ATSI to prove a need for the proposed Mansfield Line, or for the Board or intervenors to determine whether the facilities are needed, unless these analyses are done. The Board should require ATSI to provide the necessary information and allow adequate time for the Board and intervenors to evaluate the data and meaningfully participate in the application evaluation process.

5. The use of operating procedures is not accurately or completely portrayed in ATSI's filing.

ATSI mentions operating procedures as a means of dealing with system loads and contingencies prior to the completion of the proposed Mansfield Line but limits this discussion to manual load shedding. While manual load shedding is certainly a possibility in response to contingencies on the transmission system, it is not the only operating procedure available to ATSI, and in fact it may be one of the most onerous. Other available operating procedures, such as redispatch of the generating units that are operating or reconfiguring the transmission system, do not necessarily involve loss of service to customers. The Board and intervenors should be given the opportunity to determine if operating procedures can maintain system reliability instead of the proposed Mansfield Line. ATSI should provide a complete accounting of the available operating procedures that could reduce or eliminate the need for the Mansfield Line, their costs to implement, and their pros and cons regarding system operation and reliability.

It is important to note that ATSI's admission that operating procedures are a means of dealing with system loads and contingencies prior to the completion of the Mansfield Line *may indicate that the project is not needed.* If operating procedures can eliminate any potential overloads, the need for the proposed line disappears.

Also, it should be recognized that NERC transmission system reliability planning requirements do not provide for service to customers to be maintained under all possible contingency scenarios. There are multiple contingency scenarios in which load shedding is the proper system design response to the multiple contingencies, and would be so, regardless of whether the Mansfield Line has been completed or not. As a result, if some NERC-allowed load shedding could eliminate any potential future issues, then there may not be any NERC violations that need to be addressed by the Mansfield Line. These questions, as well as the issues surrounding possible operating procedures, need to be vetted by the Board prior to approval of the Mansfield Line.

6. In making a determination on the Mansfield Line, the Board should consider that the transmission system reinforcement needs are in a state of flux.

Despite PJM's studying of the transmission system reinforcement needed to permit FirstEnergy's coal unit retirements since April 2012, PJM is still making changes to the new transmission lines it says are needed. For example, PJM recently said that the Toronto-Harmon

345 kV transmission line, which was previously thought to be needed to facilitate the FirstEnergy coal unit retirements, is now no longer needed in 2017. As addressed in PJM's Transmission Expansion Advisory Committee meeting documents dated December 13, 2012,[4] construction of a new 345 kV transmission line between the Toronto and Harmon substations is now not needed in 2017 based on current 2012 Regional Transmission Expansion Plan ("RTEP") assumptions. PJM intends to re-evaluate the need for this transmission in the near future using updated 2013 RTEP assumptions.

This is typical of transmission system planning, which does not reflect the design of a single plan so much as it reflects an on-going iterative process with constantly changing assumptions. The fact that PJM recently rejected the need for another major transmission line suggests that the Board should conduct a thorough, deliberate, and exacting review of the proposed Mansfield Line to determine whether it is really needed or whether a cheaper, less intrusive project should proceed instead. As explained above, in order to conduct this review, ATSI must provide more information and the Board should allow for adequate time to conduct the review.

CONCLUSION

The Board should require ATSI to supplement its application and further address the issues discussed in these comments. A thorough review will likely require the Board to utilize close to the full 180 days allowed under statutes and Board rules. The Environmental Advocates appreciate the opportunity to comment on the proposed Mansfield Line and look forward to participating further in the Board's review process.

[4] *See* PJM Transmission Expansion Advisory Committee Meeting Materials, Attachment A, page 66 (December 13, 2012).

Respectfully submitted,

/s/ Nicholas McDaniel
Nicholas McDaniel
Environmental Law & Policy Center
1207 Grandview Avenue, Suite 201
Columbus, OH 43212
P: 614-488-3301
F: 614-487-7510

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing Comments submitted on behalf of the Environmental Law & Policy Center, the Ohio Environmental Council, and the Sierra Club was served by electronic mail, upon the following Parties of Record, this 27th day of December, 2012.

/s/ Nicholas McDaniel

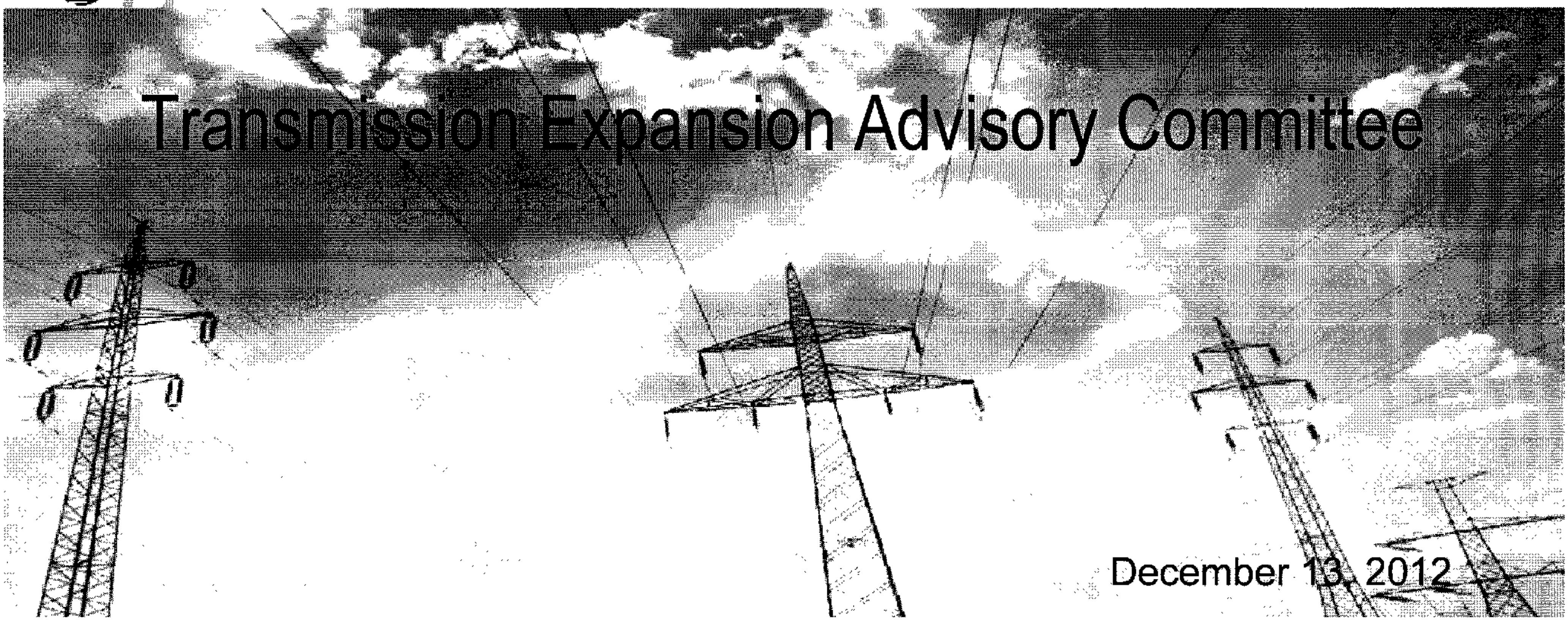
Nicholas McDaniel

Robert J Schmidt
Porter Wright Morris & Arthur
41 South High St.
Columbus OH 43215
Phone: (614) 227-2028
Fax: (614) 227-2100
rschmidt@porterwright.com

Trent Dougherty, Counsel of Record
Cathryn N. Loucas
The Ohio Environmental Council
1207 Grandview Avenue, Suite 201
Columbus, Ohio 43212-3449
(614) 487-7506 - Telephone
(614) 487-7510 - Fax
TDougherty@theOEC.org
CLoucas@theOEC.org

Sandra Coffey
Public Utilities Commission of Ohio
180 E. Broad St.
Columbus OH 43215
Phone: (614) 728-2516
Fax: (614) 728-8373
Sandra.Coffey@puc.state.oh.us

Christopher J. Allwein, Counsel of Record
Williams, Allwein and Moser, LLC
1373 Grandview Ave., Suite 212
Columbus, Ohio 43212
Telephone: (614) 429-3092
Fax: (614) 670-8896
callwein@williamsandmoser.com


Transmission Expansion Advisory Committee
December 13, 2012

Issues Tracking

Issues Tracking

- Open Issues
  - None
- New Issues

2013 RTEP Assumptions

Overview

- Update of standard assumptions
- Scenario & Sensitivity analysis
- TEAC input & feedback

2013 RTEP Assumptions

- Load Flow Modeling
  - Power flow models for world load, capacity and topology will be based on the 2018 summer case from the 2012 ERAG MMWG series power flow base case
  - Update of adjacent areas with latest topology
  - PJM topology will be based on the 2017 RTEP case that was used in the 2012 RTEP
    - Include all PJM Board approved upgrades through the December 5, 2012 PJM Board of Manager approvals as well as all anticipated February 2013 PJM Board approvals
  - East Kentucky Power Cooperative (EKPC) included

Locational Deliverability Areas (LDAs)

- Includes the existing 25 LDAs.
- East Kentucky Power Cooperative (EKPC) included
  - Was also part of the 2012 RTEP
- Recently implemented Cleveland LDA
- Total of 27 LDAs
  - All 27 to be evaluated for 2016/2017 delivery year RPM base residual auction

2013 RTEP Assumptions

- Firm Commitments
  - Long term firm transmission service will be consistent with operations
- Outage Rates
  - Generation outage rates will be based on the most recent Reserve Requirement Study (RRS) performed by PJM
  - Generation outage rates for future PJM units will be estimated based on class average rates

2013 RTEP Load Modeling

- Peak Load
  - Load will be modeled consistent with the 2013 PJM Load Forecast Report
  - The final load forecast data is expected to be available late December 2012
  - Include Demand Response (DR) and Energy Efficiency (EE) that cleared in the 2015/16 BRA

- Light Load
  - Modeled at 50% of the Peak Load forecast per M14B
  - The Light Load Reliability Criteria case will be modeled consistent with the procedure defined in M14B

- Load Management, where applicable, will be modeled consistent with the 2013 Load Forecast Report
  - Used in LDA under study in load deliverability analysis

2013 RTEP Generation Assumptions

- All existing generation expected to be in service for the year being studied will be modeled.

- Future generation with a signed Interconnection Service Agreement will be modeled along with any associated upgrades.

  - Generation with a signed ISA will contribute to and be allowed to back-off problems.

- Generation with an executed Facility Study Agreement (FSA) will be modeled along with any associated network upgrades.

2013 RTEP Generation Assumptions

- Generation with an FSA will be modeled consistent with the procedures noted in manual 14B

- Generation with an executed FSA will be modeled off-line but will be allowed to contribute to problems in the generation deliverability testing.

  - Generation with an executed FSA will not be allowed to back-off problems.

- If the PJM load exceeds the sum of the available generation and generation with an executed ISA then queued generation that has an executed FSA will be turned on to meet firm interchange.

- Additional generation information (i.e. machine lists) will be posted to the TEAC page.

Deactivation Notification Generation

- Generation that has officially notified PJM of deactivation will be modeled offline in RTEP base cases for all study years after the intended deactivation date

- RTEP baseline upgrades associated with generation deactivations will be modeled

2013 RTEP Assumptions

- All PJM bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM will be monitored.

- Contingency analysis will include all bulk electric system facilities, all tie lines to neighboring systems and all lower voltage facilities operated by PJM.
  - Contingencies in neighboring systems

- Thermal and voltage limits will be consistent with those used in operations.

24 Month RTEP

- As part of the 24-month RTEP cycle, a year 7 (2020) base case will be developed and evaluated as part of the 2013 RTEP

- The year 7 case will be based on the 2020 case that was developed as part of this year's RTEP
  - The case will be updated to be consistent with the 2013 RTEP assumptions.

- Purpose: To identify and develop longer lead time transmission upgrades

2013 Scenario Analysis

- Recap of 2012 RTEP
  - Renewable Portfolio Standards (RPS)
  - At-Risk Generation
  - High Load Growth Forecast

- 2013 RTEP Potential Scenarios

Stakeholder Input and Review of Assumptions and Scenarios

- Assumptions review

- Scenarios review

- Email RTEP@pjm.com

2012 RTEP Scenario Analysis

2012 RTEP Scenario Analysis - At Risk Generation

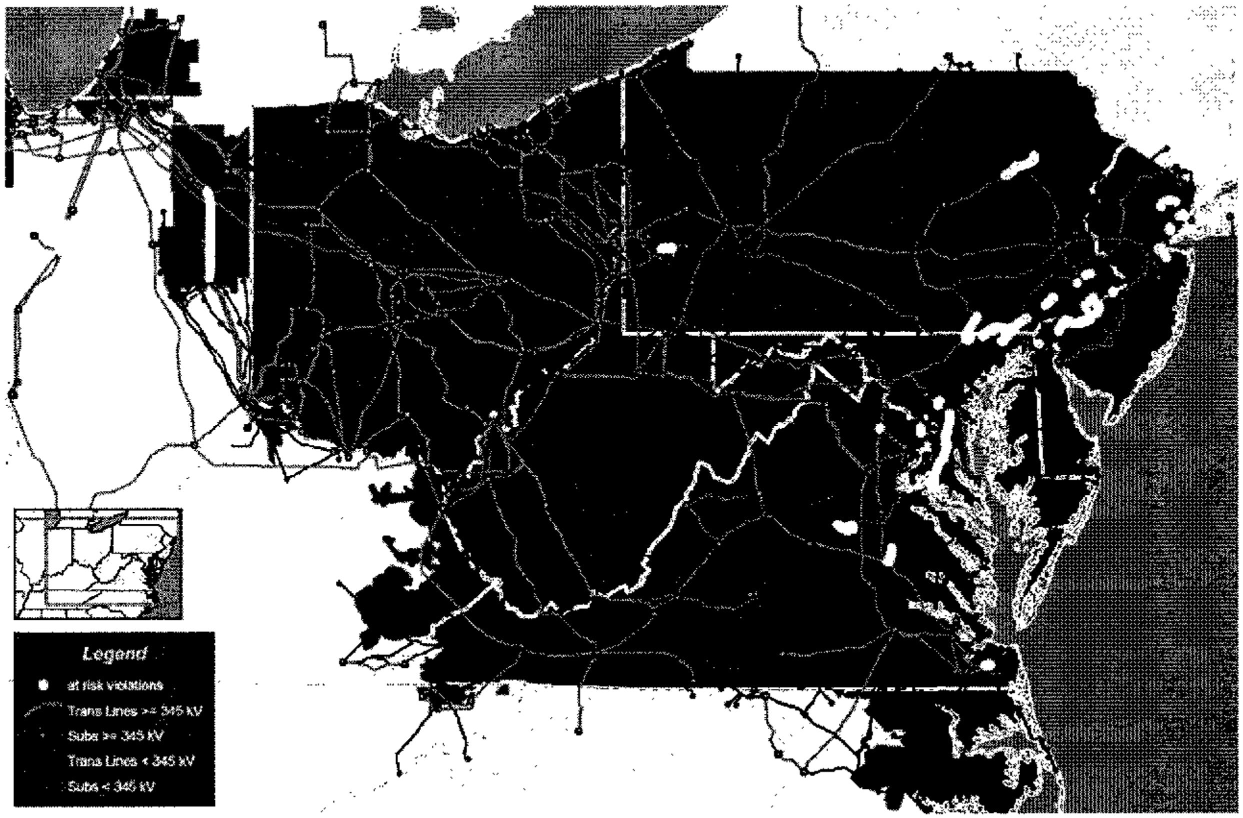
At-Risk Generation

- Assumptions
  - Same as 2012 RTEP base except “at-risk” generation
  - Total 6362 MW plus Oyster Creek (614 MW) “at-risk” generation
- Analysis
  - Reliability Analysis monitored 230 kV and above facilities
    - Generator Deliverability (50/50 load level)
      - Thermal
    - Common Mode Outage test (50/50 load level)
      - Thermal
    - Load Deliverability (90/10 load level)
      - MAAC (Thermal and voltage)
      - EMAAC (Thermal and voltage)
    - N-1-1 (50/50 load level)
      - Thermal and Voltage

At-Risk Generation

- Results of 15 year analysis
  - PJM Mid-Atlantic Thermal Overloads
    - 4 - 500/230 kV transformers
    - >20 - 230 kV circuits
  - PJM South Thermal Overloads
    - 1 – 500/230 kV transformer
    - 6 – 230 kV circuits
  - PJM West Thermal Overloads
    - 4 – 345 kV circuits
  - EMAAC Voltage
    - Potential voltage violations for several contingencies
  - N-1-1
    - Several thermal and voltage potential violations

At-Risk Generation – Thermal Overloads



Consider Queued FSA Generation

- The At-Risk analysis was performed assuming the worst case scenario, where no new generation will be built. However PJM have several queue projects in FSA stage with historical probability of 56% of them moving forward
  - FSA generators in PJM → 13,000+ MW
  - FSA generators in MAAC → 9,000+ MW

- Consider modeling 56% of the FSA generation MW's and re-evaluate

At-Risk Generation – Next Steps

- Re-run analysis assuming some amount of the FSA generation will move forward and go into service
- Evaluate result to determine any action plan resulting from at-risk generation

2012 RTEP
Renewable Portfolio Standards (RPS) Scenarios

RPS Overview

Renewable Portfolio Standards

- Overall Assumptions
  - Model the latest Renewable Portfolio Standards (RPS) state targets
    - Assume production from renewable wind
    - Update target PJM installed renewable MW requirements
    - Update installed reserve calculation
  - 2012 PJM Load Forecast Report
    - 15 Year Load Forecast
    - Include Demand Response (DR) and Energy Efficiency (EE)
  - Incorporate findings from 2011 RTEP RPS scenario studies

RPS – Scenario #1

- Assumptions
  - Assume RPS supply from PJM resources
  - **7 GW Offshore**
  - Study year: 2027
- Analysis
  - Reliability Analysis
    - Generator Deliverability (50/50 load level)
    - Common Mode Outage test (50/50 load level)
  - Market Efficiency Analysis
    - Security Constrained Optimal Power Flow (SCOPF)
    - Production cost simulation using PROMOD
- Result
  - Thermally overloaded facilities
  - Congestion $'s
  - Develop transmission overlay

RPS – Scenario #1

2027 RPS Study		
Target Installed Nameplate for Renewables based on State Targets*	Solar	7,600
	Wind	35,600
	Total	43,200
Existing Installed Nameplate	Solar	192
	Wind	6,036
	Total	6,228
Forecast Restricted Demand ** (2012 PJM Load Forecast)		169,539
Installed Reserve Margin		20%
Installed Capacity Needed		203,447
Installed Capacity Credit for new Renewables based on State Targets***	Solar	2,820
	Wind	4,430
	Total	7,250
Current Installed Capacity		184,562
Pending Deactivations		14,216
Expected Non-Renewable Capacity in 2017 Base Case		12,173
Expected Non-Renewable Capacity Scheduled after 2017		2,120
Additional Capacity Needed		11,558

* Capacity factors will be based GE PRIS Task 2 Scenario Development - Final Report
** Assumes ~15,000 MW of DR
*** Assumes 38% for solar and 15% for wind

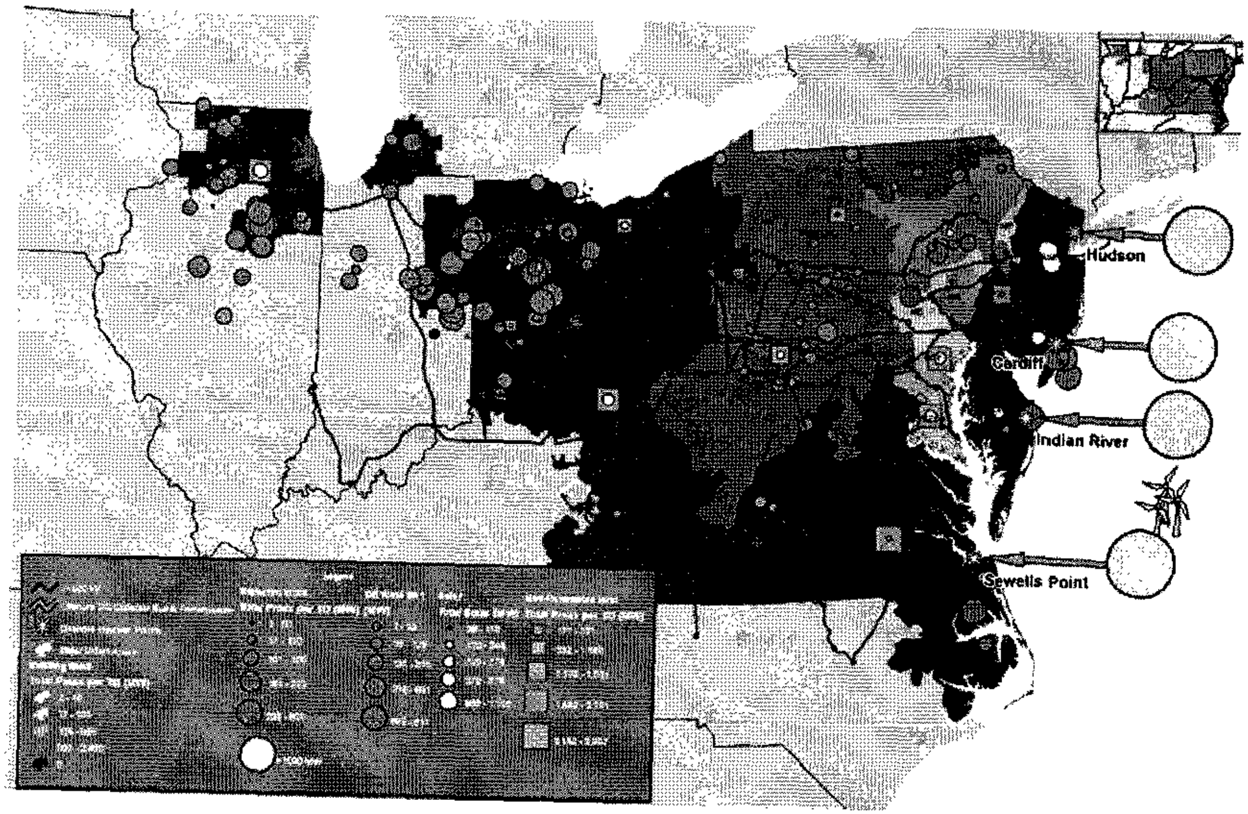
Capacity Factors			
Location	Onshore	Offshore	Solar
DC			18%
Delware		36%	19%
Illinois	41%		17%
Indiana	38%		
Maryland	36%		19%
Michigan	36%		
New Jersey		37%	18%
North Carolina	26%		19%
Ohio	35%		17%
Pennsylvania	34%		18%
Virginia	34%	37%	20%
West Virginia	35%		

RPS – Scenario #1

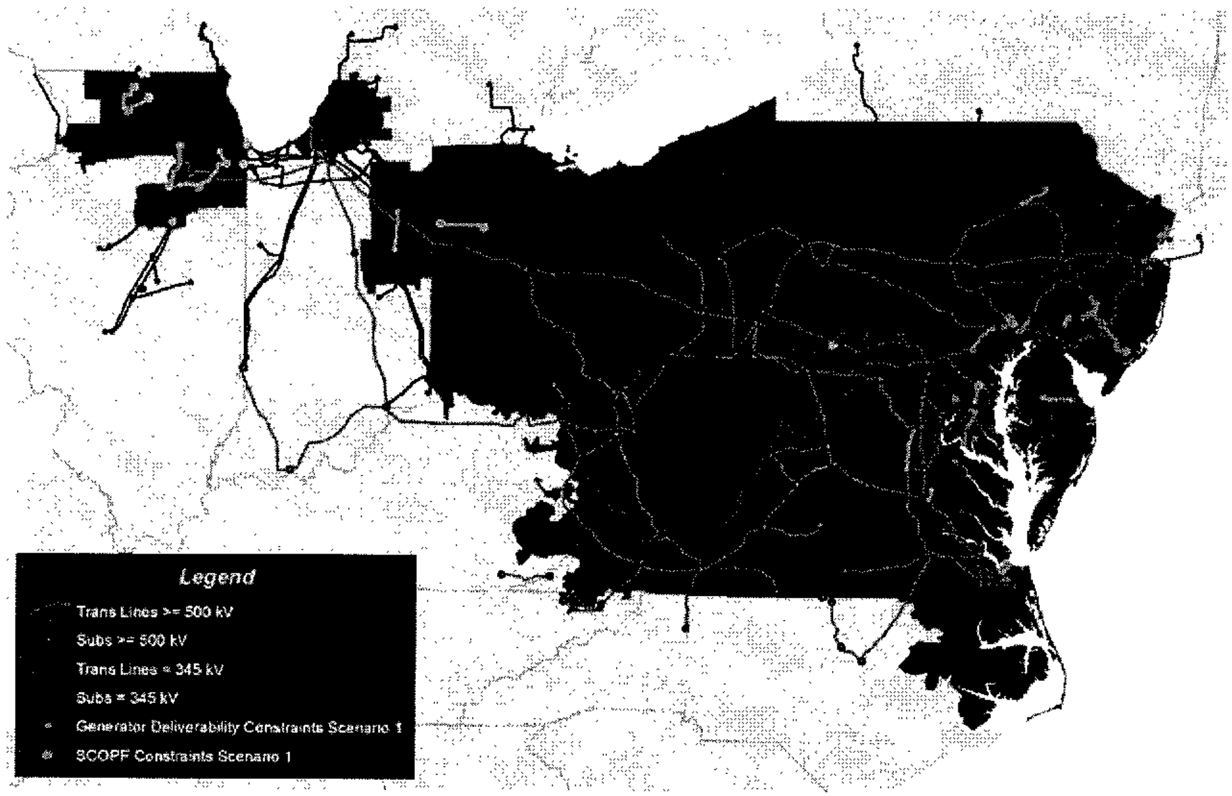
			MODELED NAMEPLATE MW			
			Existing	*Queue**	*Additional***	TOTAL
Renewable Resources	Solar		[illegible]	[illegible]	[illegible]	[illegible]
	Wind	AT	0	0	0	0
		AEP	1,702	6,539	3,531	11,772
		APS	909	607	221	1,010
		ATSI	0	0	227	227
		BGE	16	0	0	16
		COMED	2,490	4,480	3,621	10,590
		DAY	0	600	50	650
		DEOK	0	0	0	0
		DLCO	0	0	0	0
		DOM	0	850	593	1,443
		DPL	0	0	0	0
		JCPL	0	0	0	0
		METED	5	0	0	5
		PECO	0	0	0	0
		PENLC	720	706	535	2,049
		PEPCO	2	0	0	2
		PL	105	200	70	375
		PS	0	20	0	20
		RECO	0	0	0	0
		UGI	0	0	0	0
		OFFSHORE	0	1,521	5,479	7,000
		MISO	0	0	0	0
	Total		6,220	17,399	19,924	43,551
Other Resources To Meet IRM	Natural Gas					9,123
	Nuclear					3,425
	Other (Coal, Diesel, Oil, etc.)					1,745

* Generator Interconnection projects that are not yet in service and are modelled in the 2012 RTEP 2017 base case
** Based on amount of wind & solar projected in each PJM state in GE PRIS Task 2 Scenario Development - Final Report

RPS – Scenario #1



Scenario #1 Reliability Constraints



RPS – Scenario #2

- Assumptions
  - **Low GW Offshore**
  - Otherwise, same as RPS – Scenario #1 but with a low GW offshore assumption (1,521 MW)
  - The remainder of the state target RPS will be sourced from inland PJM resources

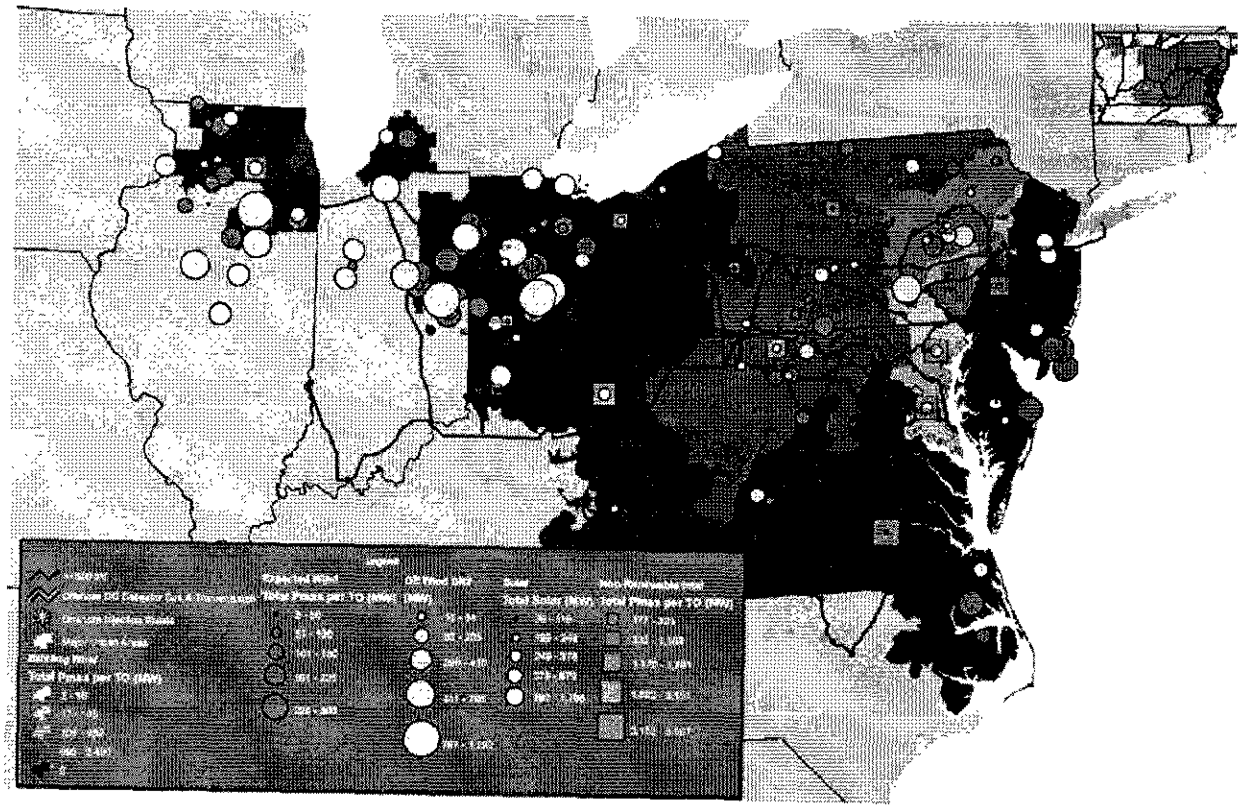
RPS Scenario #2

			MODELED NAMEPLATE MW			
			Existing	Queue*	Additional**	TOTAL
Renewable Resources	Solar		192	1,788	5,587	7,566
	Wind	AE	0	0	0	0
		AEP	1,707	6,539	5,025	13,066
		APS	989	607	355	1,950
		ATSI	0	0	302	302
		BGE	16	0	0	16
		COMED	2,490	4,400	5,700	12,737
		DAY	0	600	92	692
		DEOK	0	0	0	0
		DLCO	0	0	0	0
		DOM	0	850	945	1,795
		DPL	0	0	0	0
		JCPL	0	0	0	0
		METED	5	0	0	5
		PECO	0	0	0	0
		PENLC	728	786	852	2,367
		PEPCO	2	0	0	2
		PL	105	208	112	425
		PS	0	20	0	20
		RECO	0	0	0	0
		UGI	0	0	0	0
		OFFSHORE	0	1,521	0	1,521
		MISO	0	0	0	0
	Total		6,228	17,399	19,697	43,324
Other Resources To Meet IRM	Natural Gas					9,123
	Nuclear					3,425
	Other (Coal, Diesel, Oil, etc.)					1,745

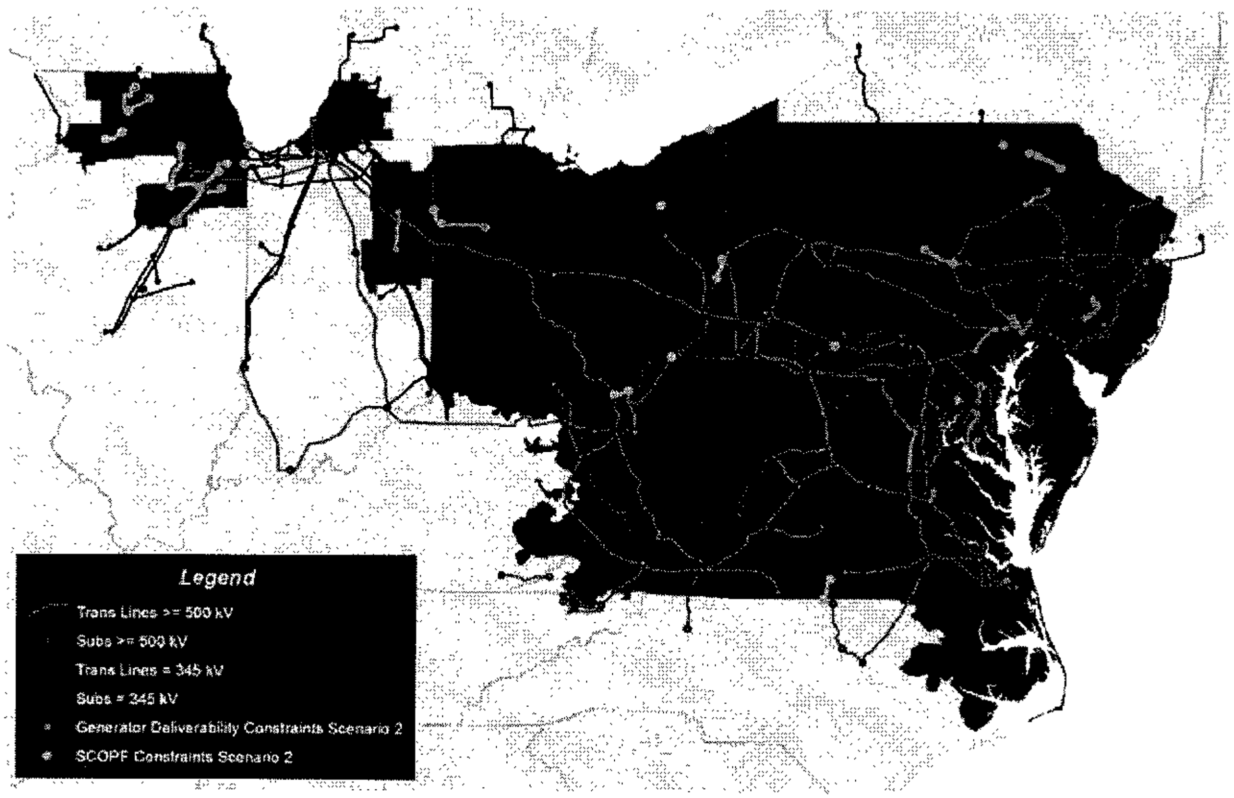
* Generator Interconnection projects that are not yet in service and are modelled in the 2012 RTEP 2017 base case

** Based on amount of wind & solar projected in each PJM state in GE PRIS Task 2 Scenario Development Final Report

RPS Scenario #2



Scenario #2 Reliability Constraints



RPS – Scenario #3

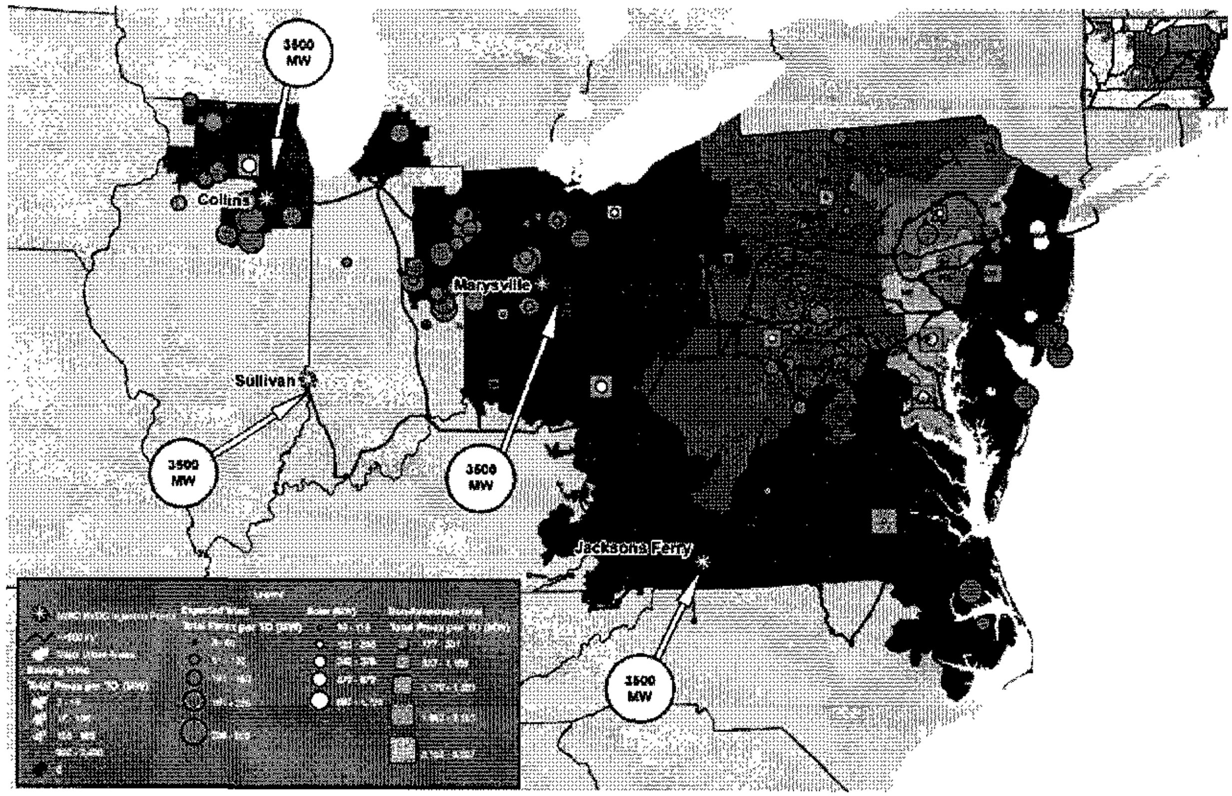
- Assumptions
  - **RPS Source from Neighboring Entities**
  - Otherwise, same as RPS – Scenario #2 (low MW offshore)
  - The remainder of the state target RPS will be sourced from inland PJM resources
- Neighboring Entities
  - Assume 40% of the PJM RPS supplied from renewable wind in the Midwest ISO (MISO)
    - Assume DC injection points from external areas to PJM

RPS Scenario #3

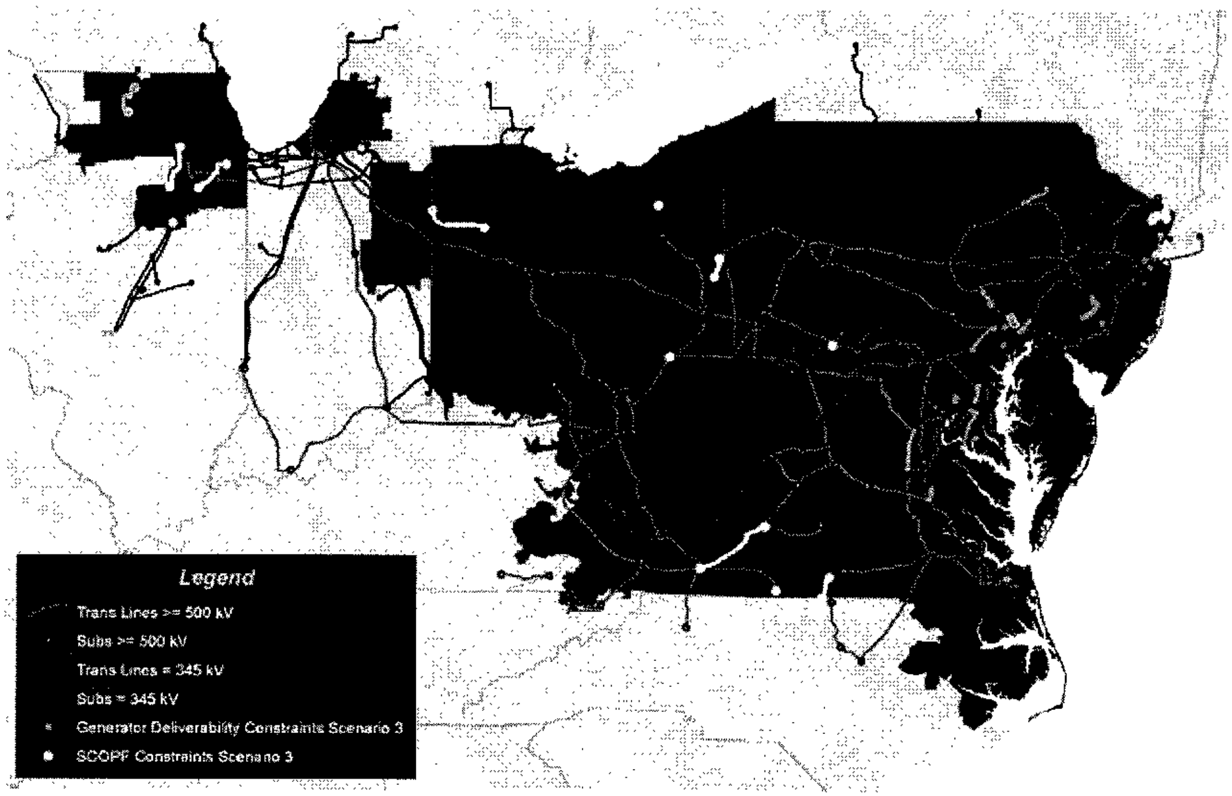
			MODELED NAMEPLATE MW			
			Existing	Queue*	Additional**	TOTAL
Renewable Resources	Solar		192	1,788	5,587	7,566
	Wind	AE	0	0	0	0
		AEP	1,702	6,539	0	8,241
		APS	989	607	0	1,596
		ATSI	0	0	0	0
		BGE	16	0	0	16
		COMED	2,490	4,480	0	6,970
		DAY	0	600	0	600
		DEOK	0	0	0	0
		DLCO	0	0	0	0
		DOM	0	850	0	850
		DPL	0	0	0	0
		JCPL	0	0	0	0
		METED	5	0	0	5
		PECO	0	0	0	0
		PENLC	728	786	0	1,514
		PEPCO	2	0	0	2
		PL	105	208	0	313
		PS	0	20	0	20
		RECO	0	0	0	0
		UGI	0	0	0	0
		OFFSHORE	0	1,521	0	1,521
		MISO***	0	0	14,249	14,249
	Total		6,228	17,399	19,836	43,463
Other Resources To Meet IRM	Natural Gas					9,123
	Nuclear					3,425
	Other (Coal, Diesel, Oil, etc.)					1,745

* Generator Interconnection projects that are not yet in service and are modelled in the 2012 RTEP 2017 base case
** Based on amount of wind & solar projected in each PJM state in CE PRPS Task 2 Scenario Development – Final Report
*** Assumes 38% capacity factor

RPS Scenario #3



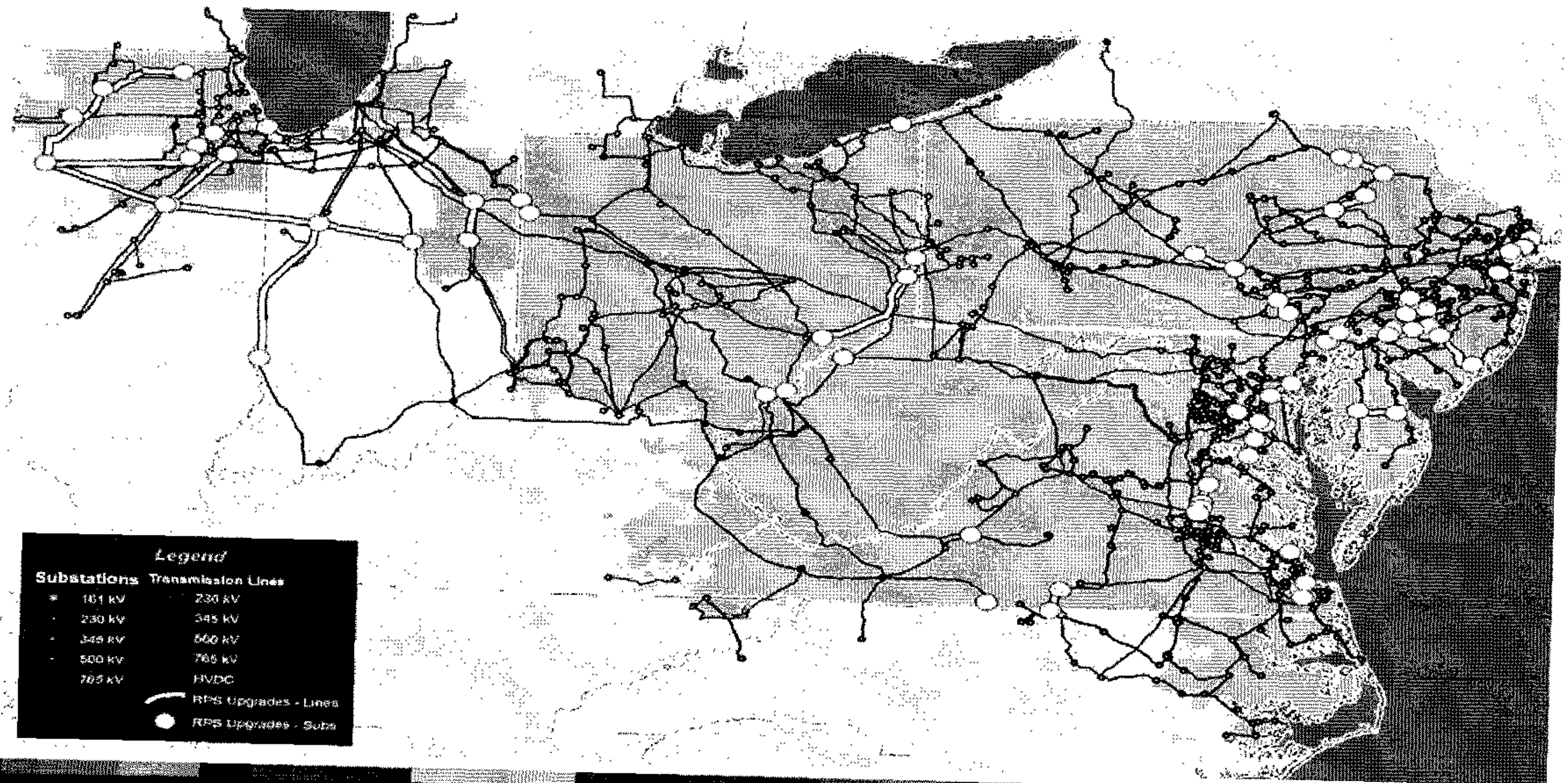
Scenario #3 Reliability Constraints



Transmission Overlay

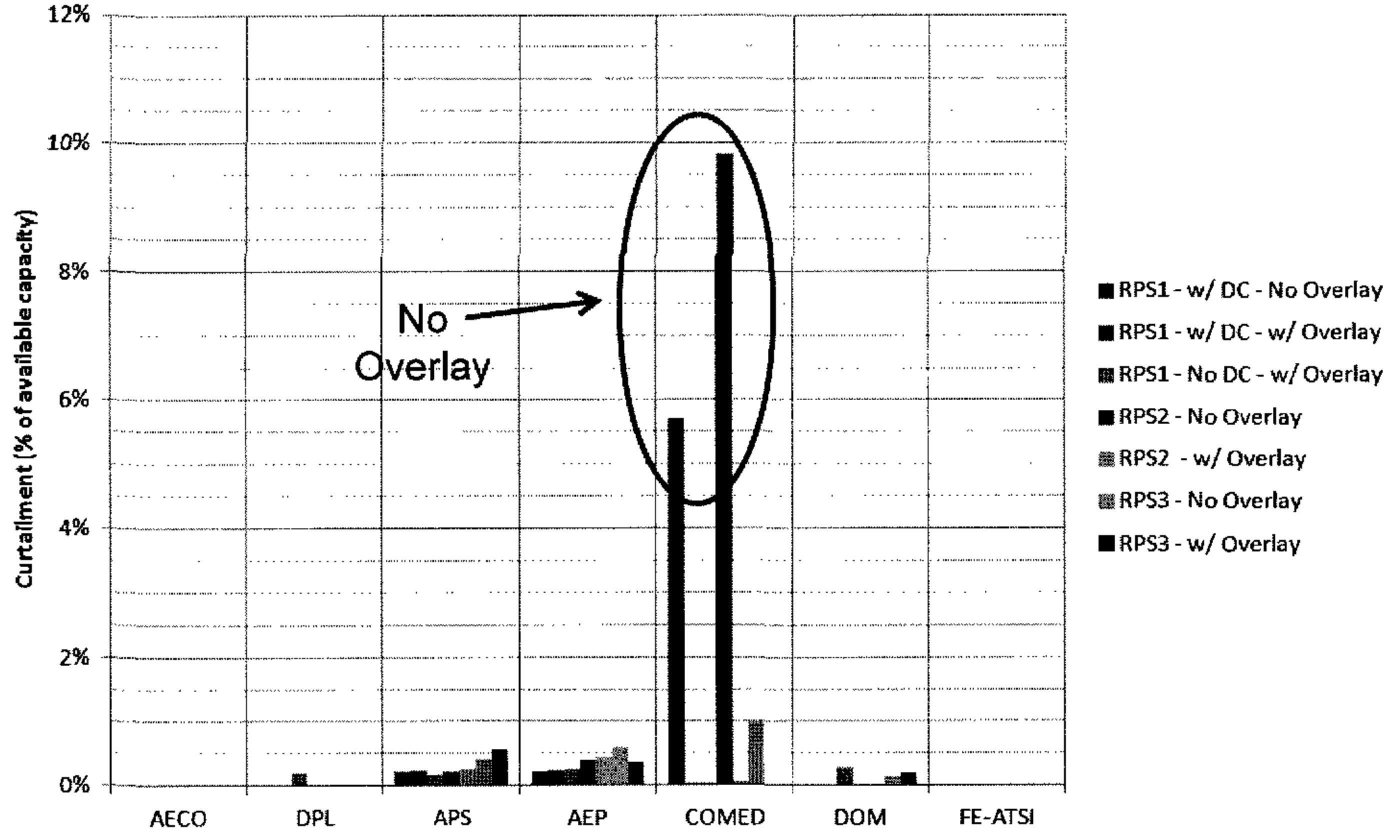
- Developed by considering both reliability analyses and market efficiency analysis
- Reliability analysis included generation deliverability as well as a power flow analysis that approximates PJM's light load criteria
- Market efficiency analysis used production cost simulations and considered wind curtailment and congestion
- Files posted with detailed information on the overlay

RPS Transmission Overlay



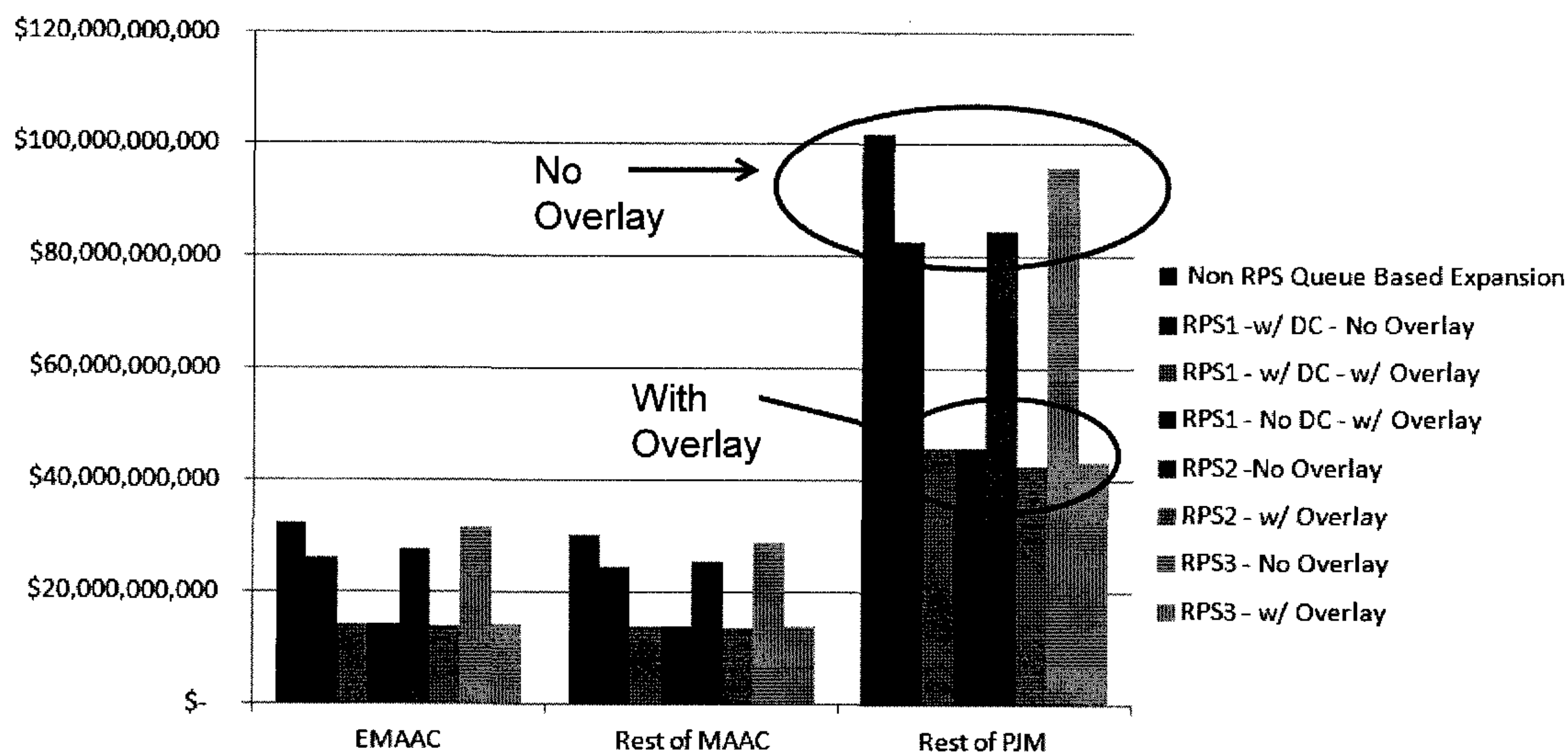
RPS
Transmission Overlay Drivers

Transmission Overlay Driver – Wind Curtailment

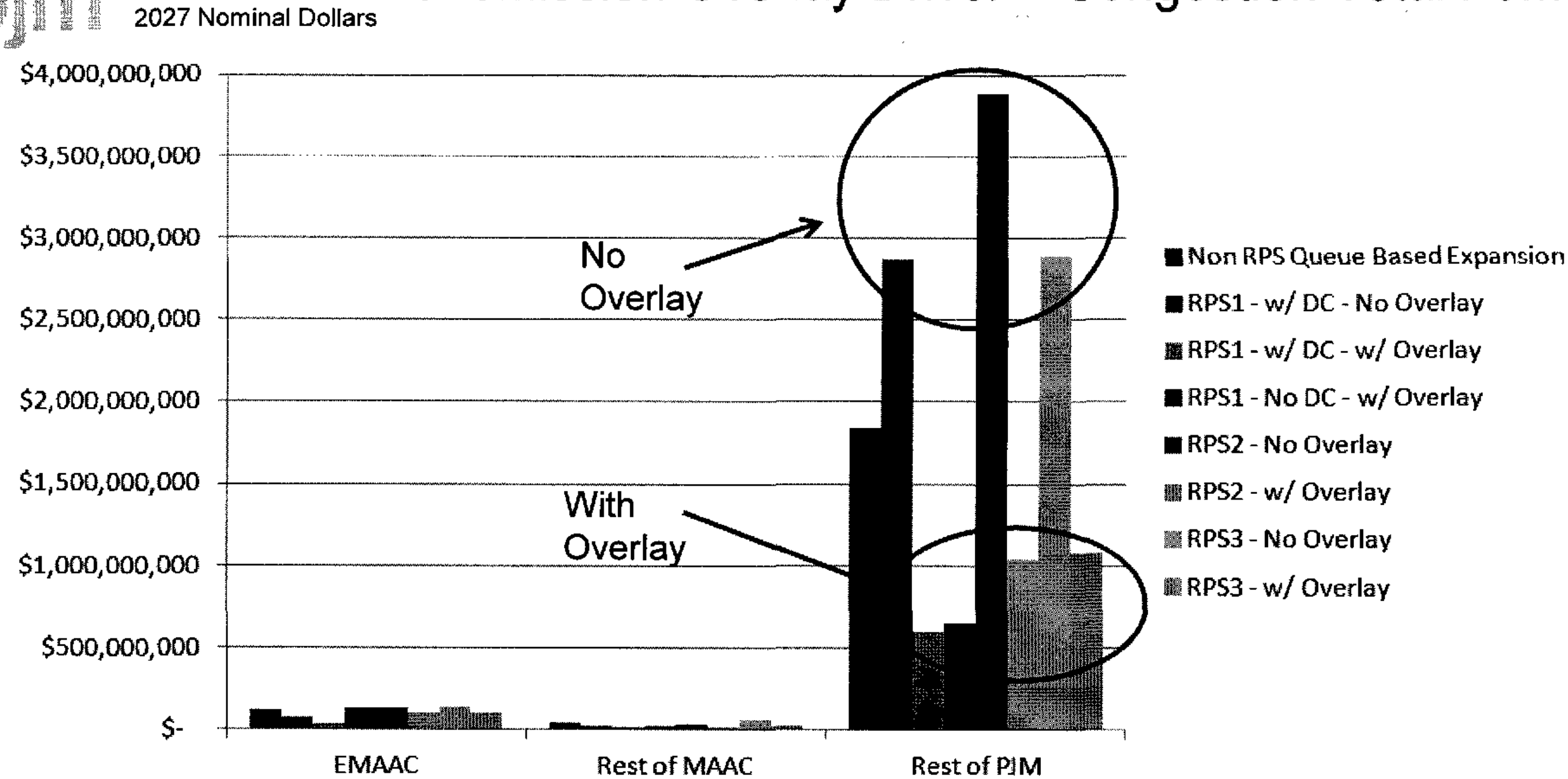


Transmission Overlay Driver - Load Payments

2027 Nominal Dollars



Transmission Overlay Driver – Congestion Total PJM



RPS
Scenario Comparisons

Scenario Comparison – Base and Incremental Load Cost

*2027 Nominal Dollars

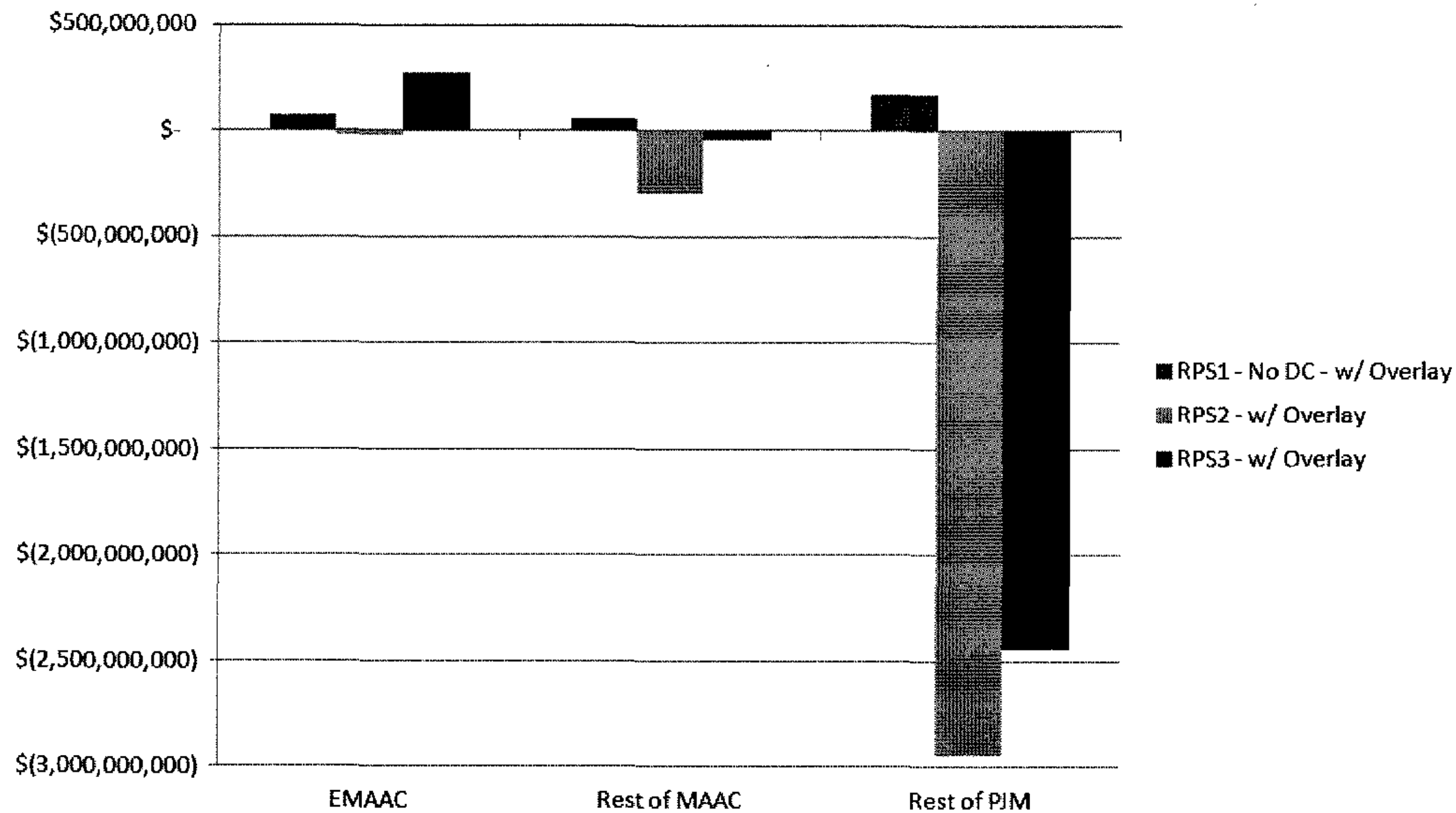
Annual Load Cost Differences Compared to RPS1 Base Cost			
Base Cost RPS1 w/ DC w/ Overlay	RPS1 No DC w/ Overlay	RPS2 w/ Overlay	RPS3 w/ Overlay
$74 Billion	+ $300 M	- $3 Billion	- $2 Billion
	0.4% Increase	4.4% Decrease	3.0% Decrease

Scenario Comparison – Incremental Load Cost

2027 Nominal Dollars

Load Payments Relative to RPS1 – w/ DC – w/ Overlay

Base Cost: $74B



Scenario Comparison – Base and Incremental Congestion

2027 Nominal Dollars

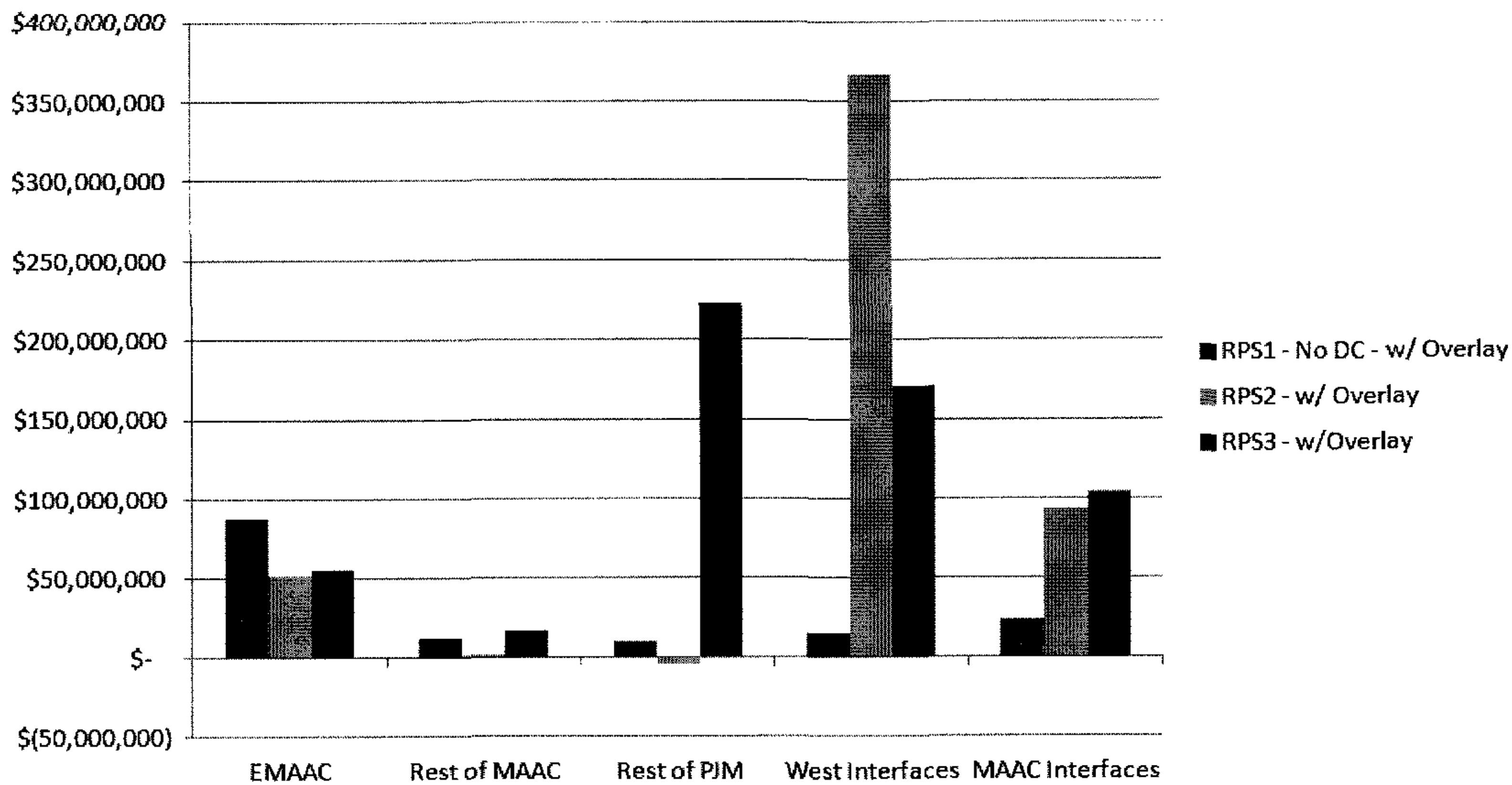
Congestion Cost Differences Compared to RPS1 Base Cost			
Base Cost RPS1 w/ DC w/ Overlay	RPS1 No DC w/ Overlay	RPS2 w/ Overlay	RPS3 w/ Overlay
$650 Million	+ $150 M	+ $500 M	+ $570 M
	23% increase	78% increase	88% increase

Scenario Comparison – Incremental Congestion

Congestion Cost Relative to RPS1 – w/ DC – w/ Overlay

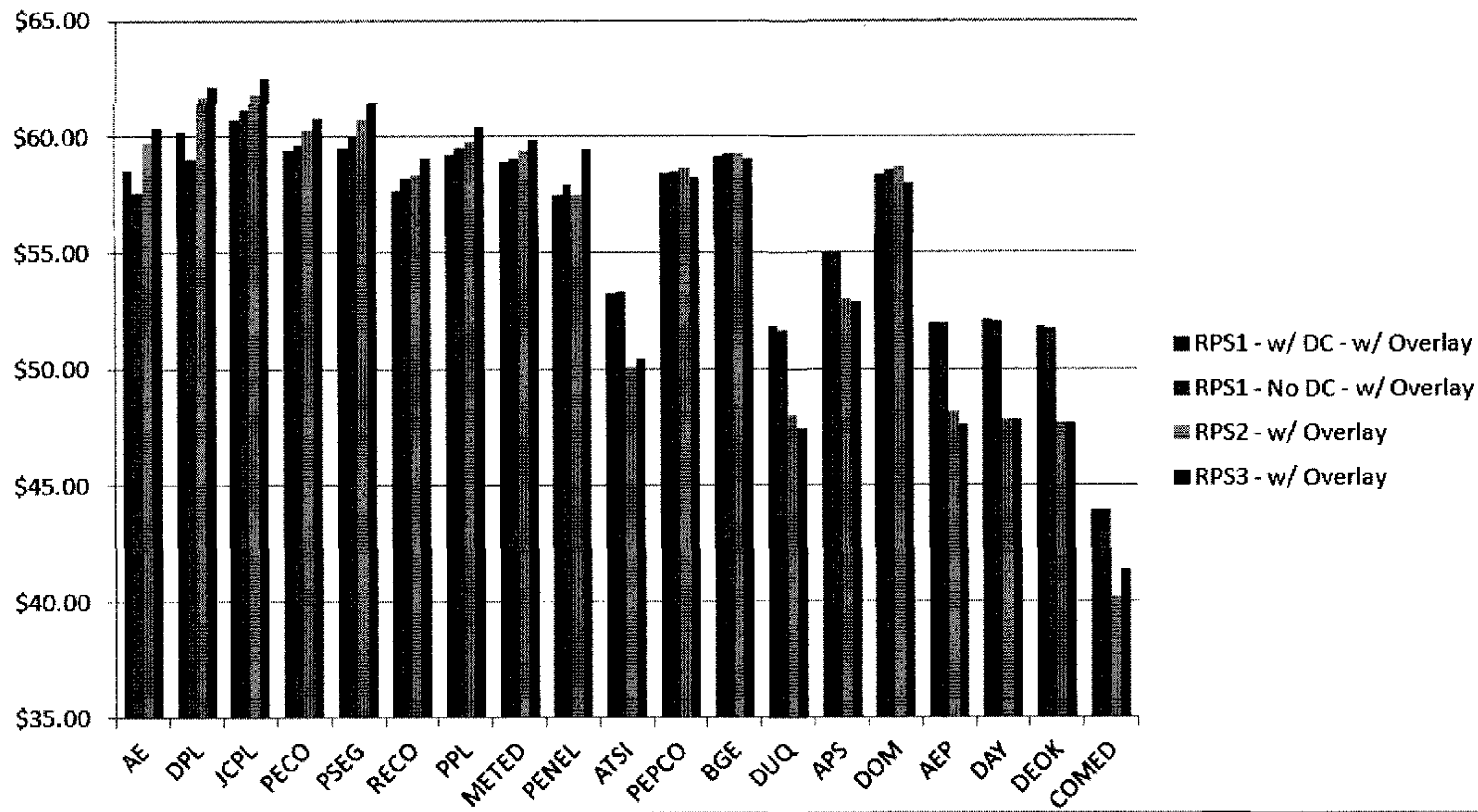
Base Cost: $650M

2027 Nominal Dollars

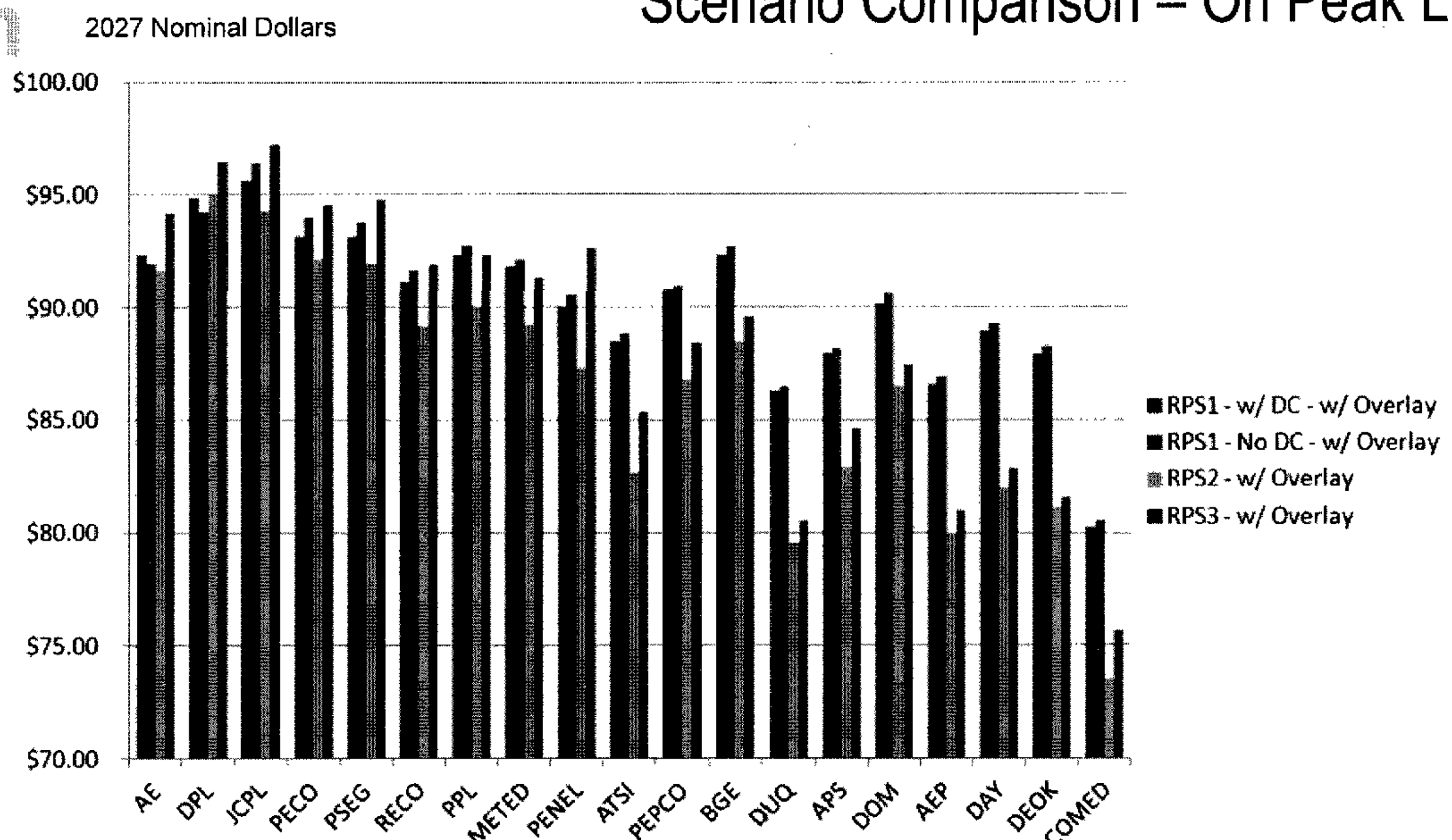


Scenario Comparison – Off Peak LMP

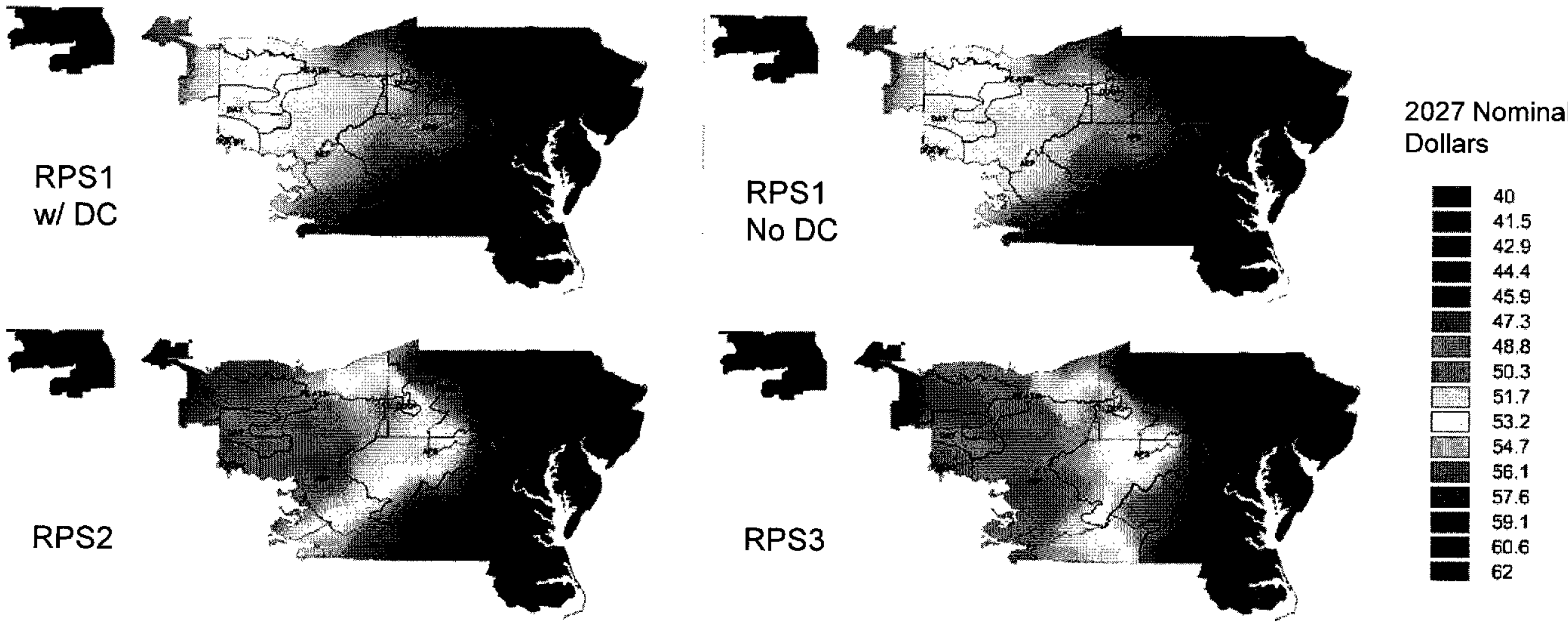
2027 Nominal Dollars



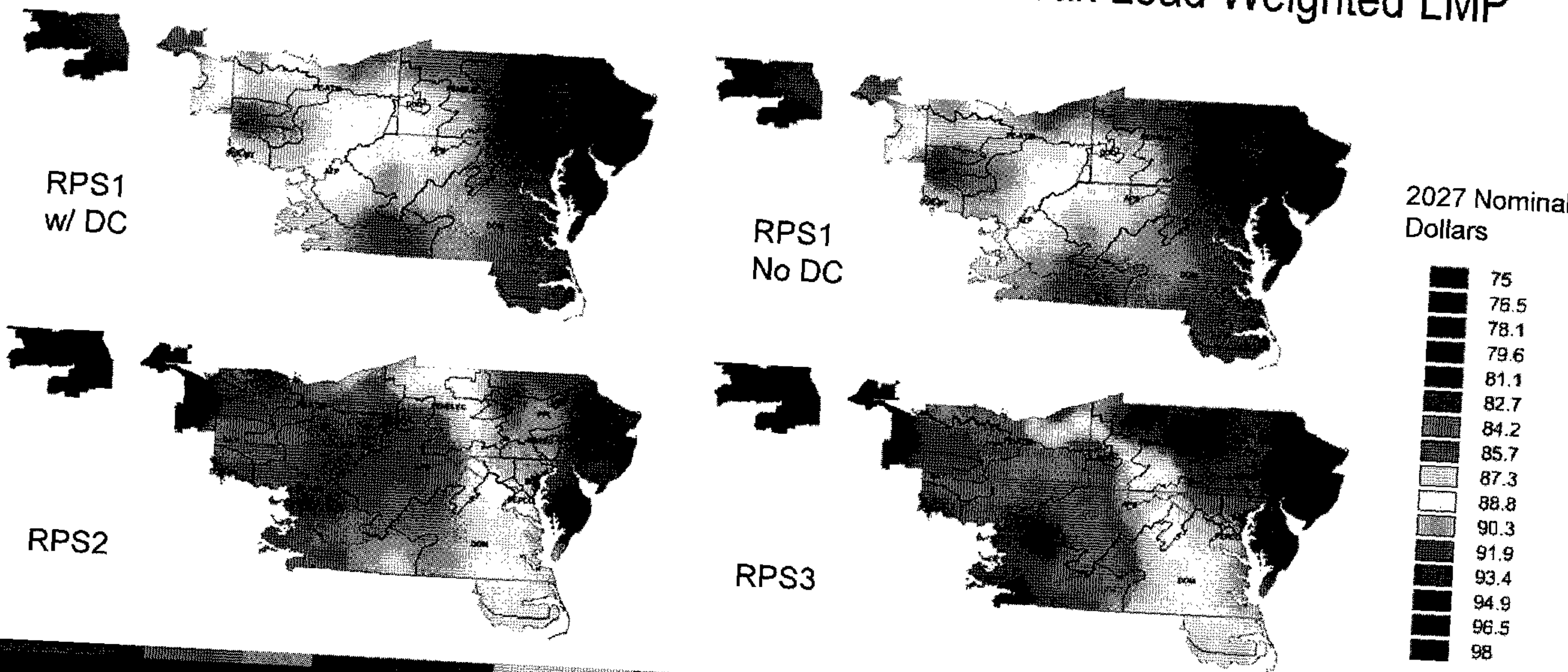
Scenario Comparison – On Peak LMP



Scenario Comparison - Full Year, Off-Peak Load Weighted LMP



Scenario Comparison – Full Year, On Peak Load Weighted LMP



High Voltage in PJM Operations Analysis Update

Progress Update

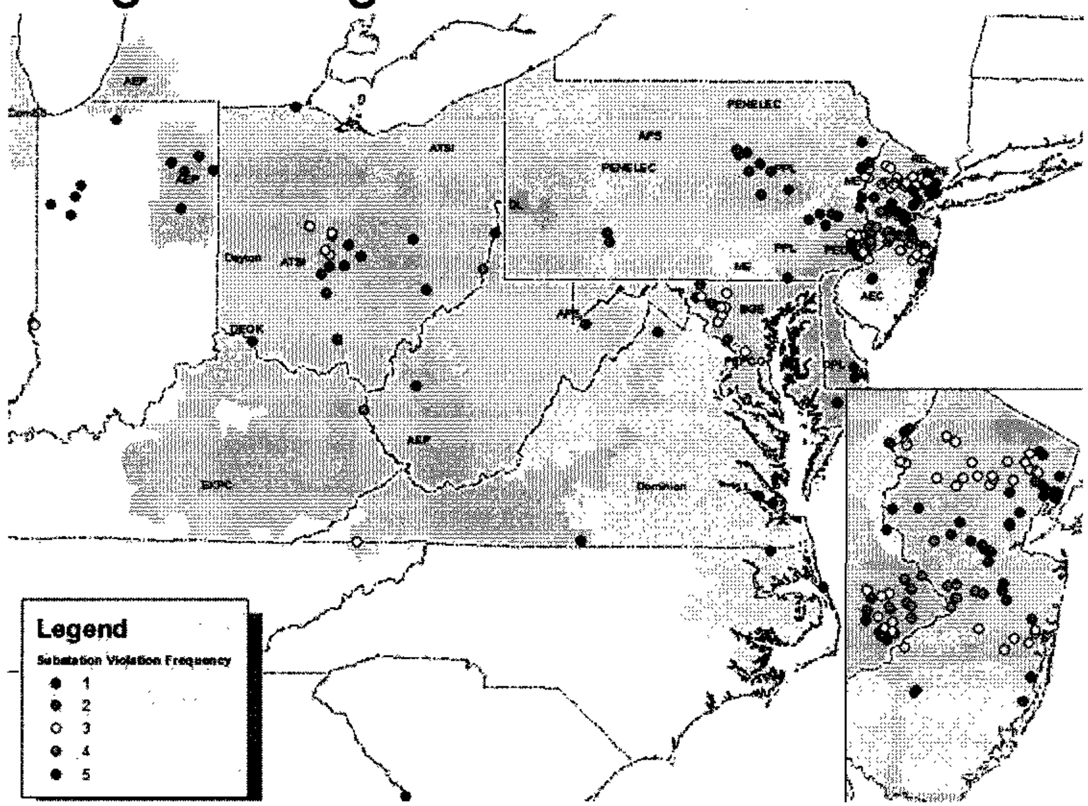
- Determined potential reactor locations
  - from historical PI data and high voltage alarm data

- Modeled and simulated reactors in several operational cases to determine the potential magnitude that is necessary to control high voltage

- Also simulated high voltage conditions and reactors in a planning case to determine system needs beyond the operational cases

High Voltage Locations from PJM Operations Cases

Locations noted in the 5 Cases from PJM Operations



Progress Update

- Provided TOs with historic high voltage alarm data and voltage analysis performed on five historic EMS cases
- Currently gathering feedback from TOs
- Potential solutions received to date include
  - Shunt reactors
  - SVCs
  - Modifications to / optimization of existing facilities
    - Generator voltage schedules
    - Transformer tap settings
    - Switched shunt settings

pjm

Preliminary Solutions

- AEC
  - 50 MVAR shunt reactor at Mickleton 230 kV
  - +150/-100 MVAR SVC at Cedar 230 kV
- AEP
  - Under review
- ComEd
  - Optimization of existing facilities at Twin Grove and Kincaid
- DLCO
  - 200 MVAR shunt reactor at Brunot Island 345 kV
  - 200 MVAR shunt reactor on future Brunot Island – Carson 345 kV circuit

Preliminary Solutions

- Dominion
  - RTEP upgrades b1805, b2125 and b2126
- DPL
  - RTEP upgrades b0876 and b1899.1-b1899.3
- FE
  - Investigating optimization of existing facilities
  - Additional planning studies required
- PPL
  - 150 MVAR shunt reactor at Alburtis 500 kV
  - 100 MVAR shunt reactor at Elimsport 230 kV
  - Change generator voltage schedule at Montour

Preliminary Solutions

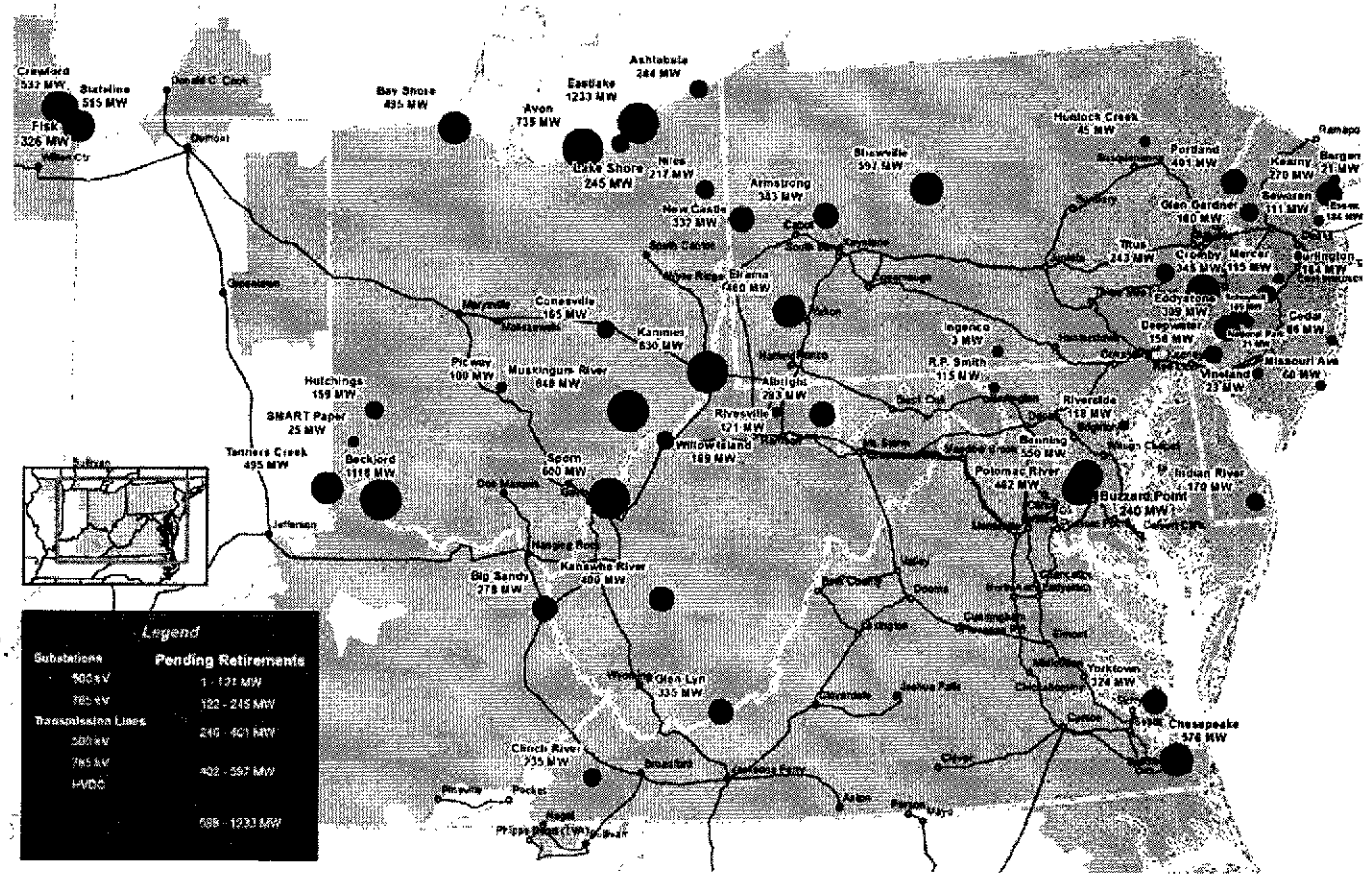
- PSEG
  - Near Term: Investigating optimization of existing facilities
  - Longer Term: Shunt reactors

Location	Number	Size (MVAR)
Saddlebrook	1	50
Athenia	1	50
Bergen	1	50
Hudson	1	50
Stanley Tce	2	50
West Orange	1	50
Aldene	1	50
Camden	1	150
Gloucester	1	100
Clarksville	1	50
Hawthorne/Hinchmans/ Jackson Rd	1	50
Total	12	700

Generation Deactivation Notification (Retirements) Update

Generation Deactivation Notifications – As of 12/10/2012

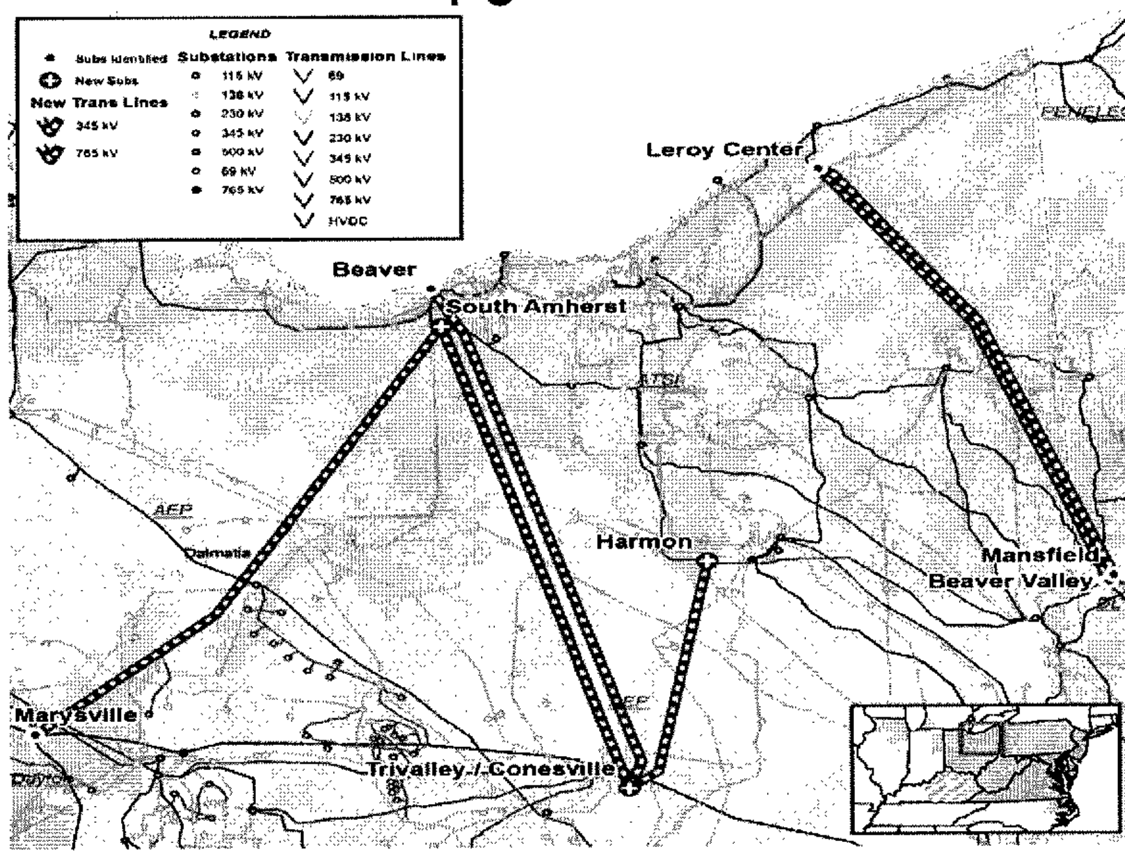
- **Essex 12**
  - #121 – 46 MW
  - #122 – 46 MW
  - #123 – 46 MW
  - #124 – 46 MW
  - PSE&G Transmission Zone
  - 184 MW Total
  - Notification received 11/20/2012
  - Anticipated deactivation date 5/31/2015
  - Reliability Analysis underway. Capacity Interconnection rights to be re-used in interconnection project(s) T107, X3-004, and / or Y2-019



Ohio Area Deactivation Upgrade Alternative Analysis

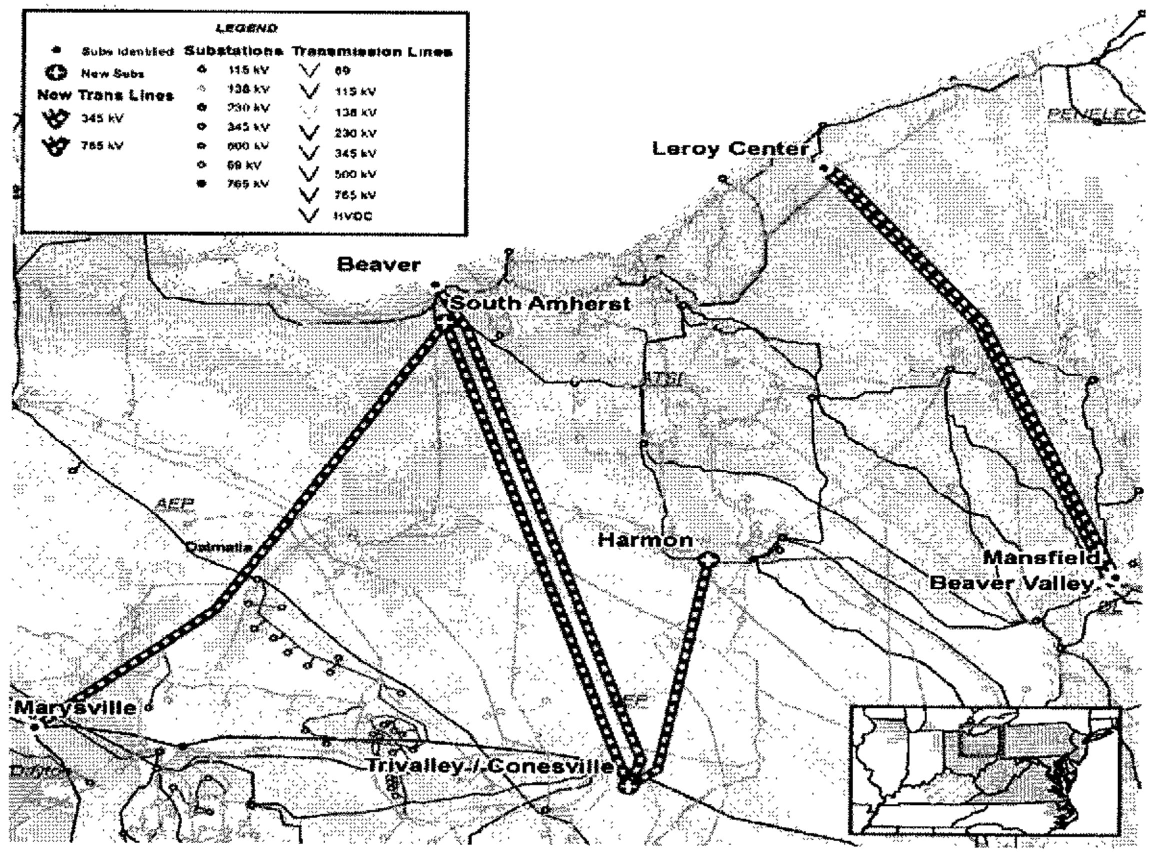
Ohio Area Retirement Upgrades - Evaluation

- 2015 – 2017 analysis of criteria tests of the zones impacted by the Ohio area generation deactivations
- 2017 analysis including all recently approved upgrades
- Solution alternatives evaluated:
  - Marysville – South Amherst 765 kV
  - Trivalley – South Amherst 765 kV
  - Conesville – Beaver 345 kV
  - Conesville – Harmon 345 kV
  - Beaver Valley - Leroy Center 345kV + Mansfield – Leroy Center 345kV line



Ohio Area - 2017 Findings

- Existing, approved RTEP transmission
  - Existing approved baseline upgrade (B1977.1) - Build a new Toronto-Harmon 345kV line not needed in 2017 using current 2012 RTEP assumptions
  - Will re-evaluate B1977.1 need with 2013 RTEP assumptions
- Solution alternatives considered:
  - The following solution alternatives are not needed in 2017 with current 2012 RTEP assumptions
    - Marysville – South Amherst 765 kV
    - Trivalley – South Amherst 765 kV
    - Conesville – Beaver 345 kV
    - Conesville – Harmon 345 kV
    - Beaver Valley - Leroy Center 345kV + Mansfield – Leroy Center 345kV line



Ohio Area Retirement Upgrades – Next Steps

- Finalize 2015 – 2017 reliability criteria testing
- Review and recommend solutions to remaining criteria violations as well as any modification to approved transmission
- Evaluate the need for Toronto – Harmon 345 kV and proposed alternatives as part of the 2013 RTEP

15 Year Analysis Update

2012 RTEP 15 Year Planning Result

- Highest loading from applicable contingencies in all of the deliverability tests
- Conductor ratings applied
- Reinforcements may already be in development or approved for some of these potential issues

Single Contingency Result

Fr Bus	Fr Name	To Bus	To Name	CKT	KVs	Areas	100% Year
314222	6HANOVER	314218	6ELMONT	1	230/230	DOM	2021
219125	CAMDEN	213922	RICHMOND	1	230/230	PSEG/PECO	2020
219108	CUTHBERT	219125	CAMDEN	1	230/230	PSEG	2021
219108	CUTHBERT	219125	CAMDEN	2	230/230	PSEG	2022
290891	S17TAP81230	223994	BURCH230	1	230/230	PEPCO	2026
217079	ESSEX	217060	KRNY 1-3	1	230/230	PSEG	2027
219110	GLOUCSTR	219108	CUTHBERT	1	230/230	PSEG	2018
219110	GLOUCSTR	219108	CUTHBERT	2	230/230	PSEG	2018
213750	LINWOOD	213490	CHICHST2	2	230/230	PECO	2019
213750	LINWOOD	213490	CHICHST2	1	230/230	PECO	2019
314901	8BATH CO	314926	8VALLEY	1	500/500	DOM	2025
223990	TALB 068	290891	S17TAP81230	1	230/230	PEPCO	2022
314901	8BATH CO	314912	8LEXNGTN	1	500/500	DOM	2025
314074	6POSSUM	314029	6DUMFRES	1	230/230	DOM	2022
314514	6YADKIN	314449	6CHESAPK	1	230/230	DOM	2024
213519	CONOWG01	231006	COLOR_PE	1	230/230	PECO/DPL	2022
213520	CONOWG03	213844	NOTTNGHM	1	230/230	PECO	2021
213922	RICHMOND	214012	WANEETA3	1	230/230	PECO	2021

2012 RTEP 15 Year Planning Result

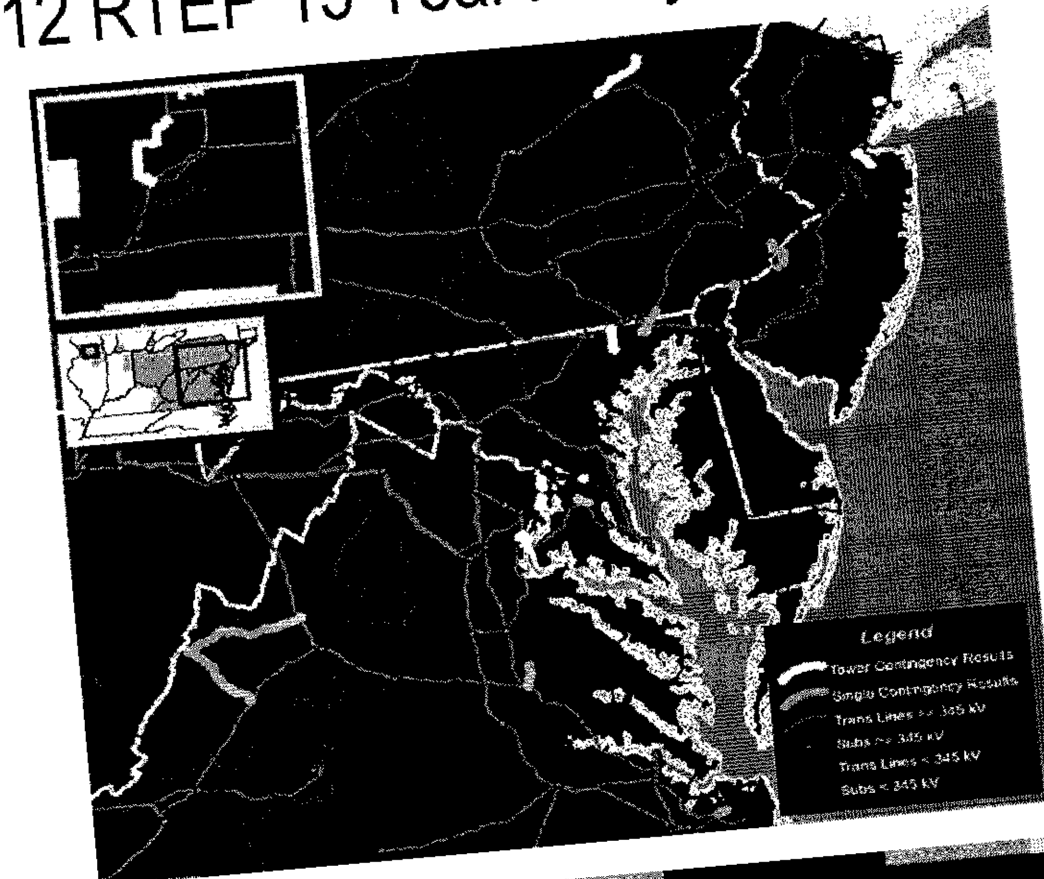
- Highest loading from applicable contingencies in all of the deliverability tests
- Conductor ratings applied
- Reinforcements may already be in development or approved for some of these potential issues

Tower Contingency Result

Fr Bus	Fr Name	To Bus	To Name	CKT	KVs	Areas	100% Year
206314	RED OAKA	206305	RAR RVR	1	230/230	PECO	2021
206322	PARLIN	206298	WILLIAMS	1	230/230	JCPL	2026
270679	BYRON; R	270919	WEMPL; R	1	345/345	COMED	2027
224600	AQUASCO1	224060	OAKGV054	1	230/230	PEPCO	2027
217079	ESSEX	217061	KRNY 4-6	1	230/230	PSEG	2018
314033	6FRANCON	314088	6VANDORN	1	230/230	DOM	2027
208113	SUSQ	208001	JENK TR2	1	230/230	PPL	2022
314041	6GLEBE	314185	6RADNOR	1	230/230	DOM	2023
314074	6POSSUM	314029	6DUMFRES	1	230/230	DOM	2017
206298	WILLIAMS	206292	FRENEAU	1	230/230	JCPL	2026
220964	GRACETON	221000	BAGLEY	1	230/230	BGE	2020

2012 RTEP 15 Year Analysis Result

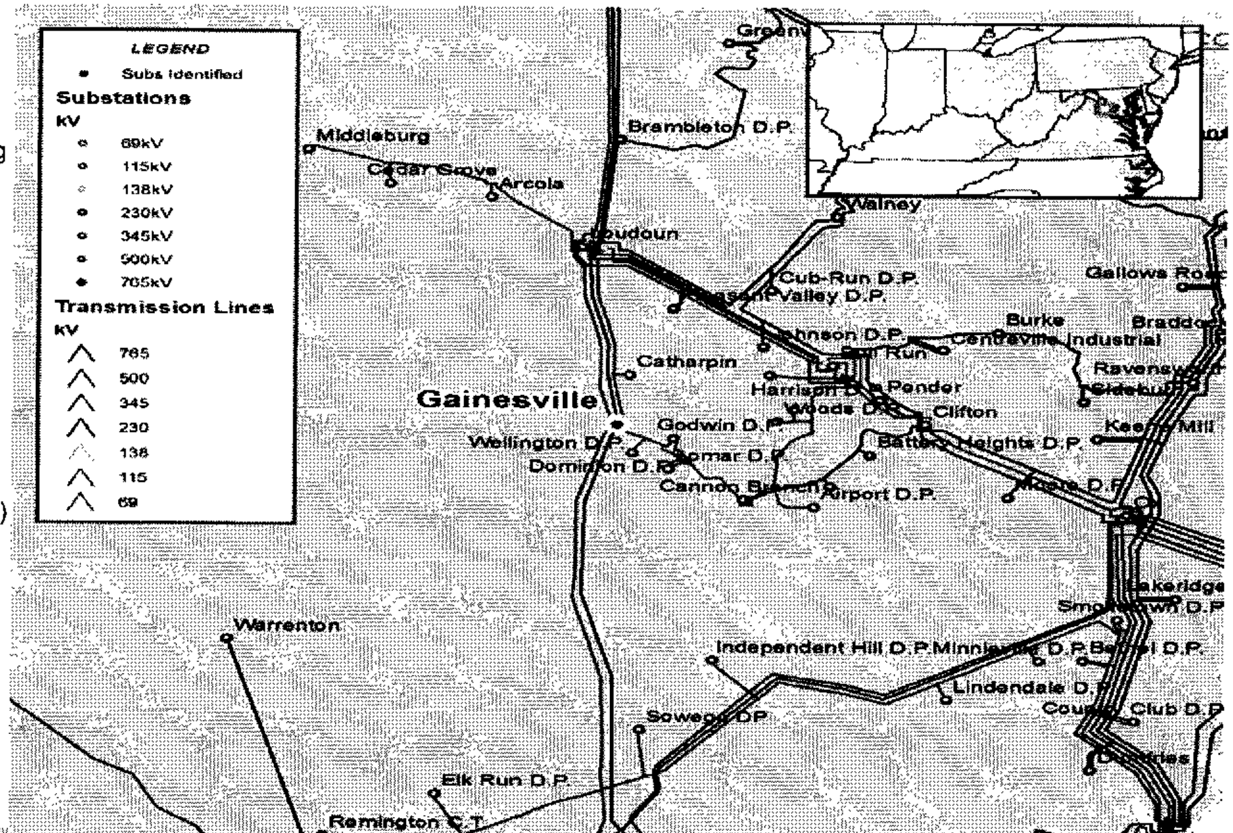
- Observations
  - Benchmark to year 8 (2020) case
- Next Steps



Dominion Transmission Zone

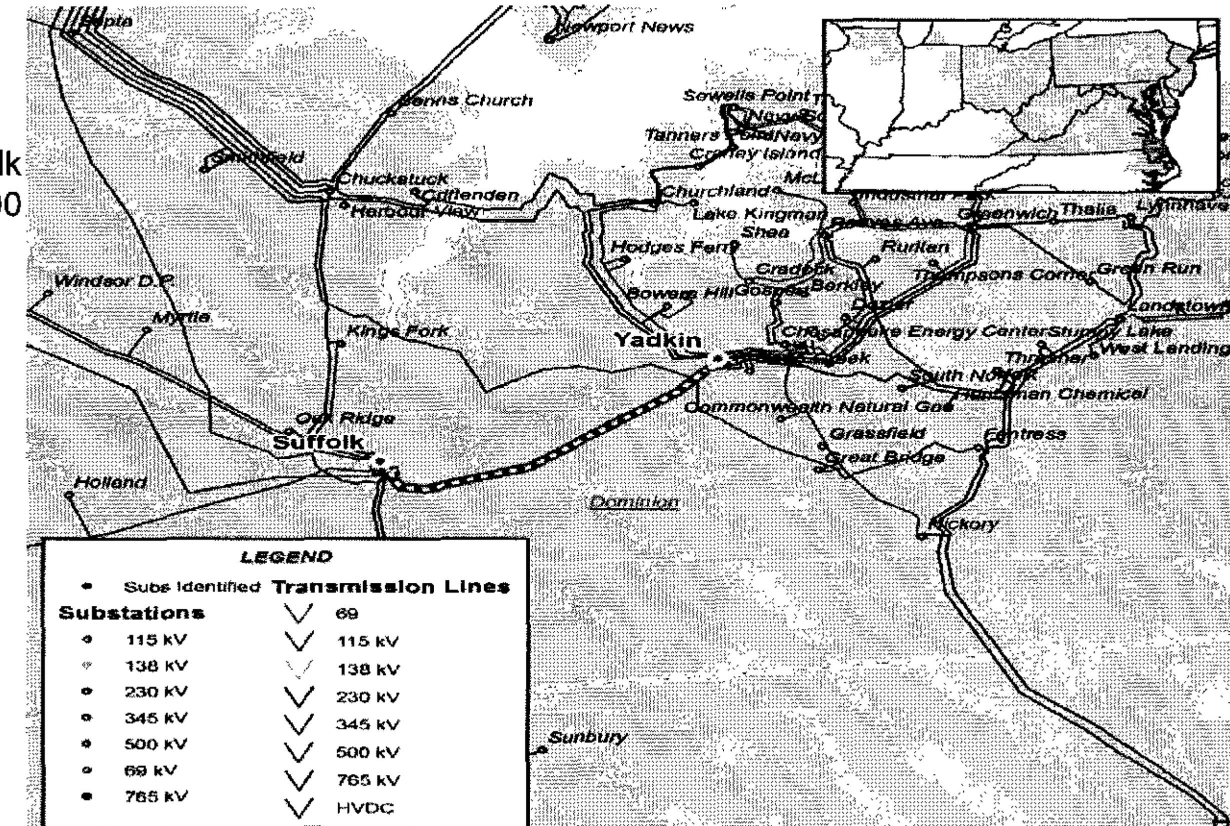
NERC Category A Violation

- **Project b1506 – Scope change**
- Problem: Block load additions at NOVEC's Gainesville DP is increasing load by 120-140 MW over the next several years. By summer 2012, the transformer feeding their DP will be above its emergency rating (269.1 MVA) under normal conditions.
- Proposed Solution:
  - At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker
  - Upgrade Line 124 (radial from Loudoun) to a minimum continuous rating of 500 MVA and network it into the 115 kV bus feeding NOVEC's DP at Gainesville
  - Install two additional 230 kV breakers in the ring at Gainesville (may require substation expansion) to accommodate conversion of NOVEC's Gainesville to Wheeler line.
  - Install 168MVA, 230/115kV transformer to feed NOVEC's Gainesville-Wheeler line.
- Estimated Project Cost $8.0 M
- Projected IS Date: May 2013



Dominion Transmission Zone

- Project: b1910
- N-1-1 Thermal Violation
- Huntsman – Thrasher 230 kV is over its emergency rating for the loss of the Suffolk – Yadkin 500 kV and Fentress – Septa 500 kV lines
- Build a Suffolk – Yadkin 230 kV line (14 miles)
  - Install two 230 kV breakers at both Suffolk and Yadkin Substation to interconnect
  - Primarily along existing towers
- Estimated Project Cost: $40 M
- Old Projected IS Date: 6/1/2016
- Due to Yorktown 2 and Chesapeake 3&4 Retirements
- New Projected IS Date: 6/1/2015



Short Circuit

AE Transmission Zone

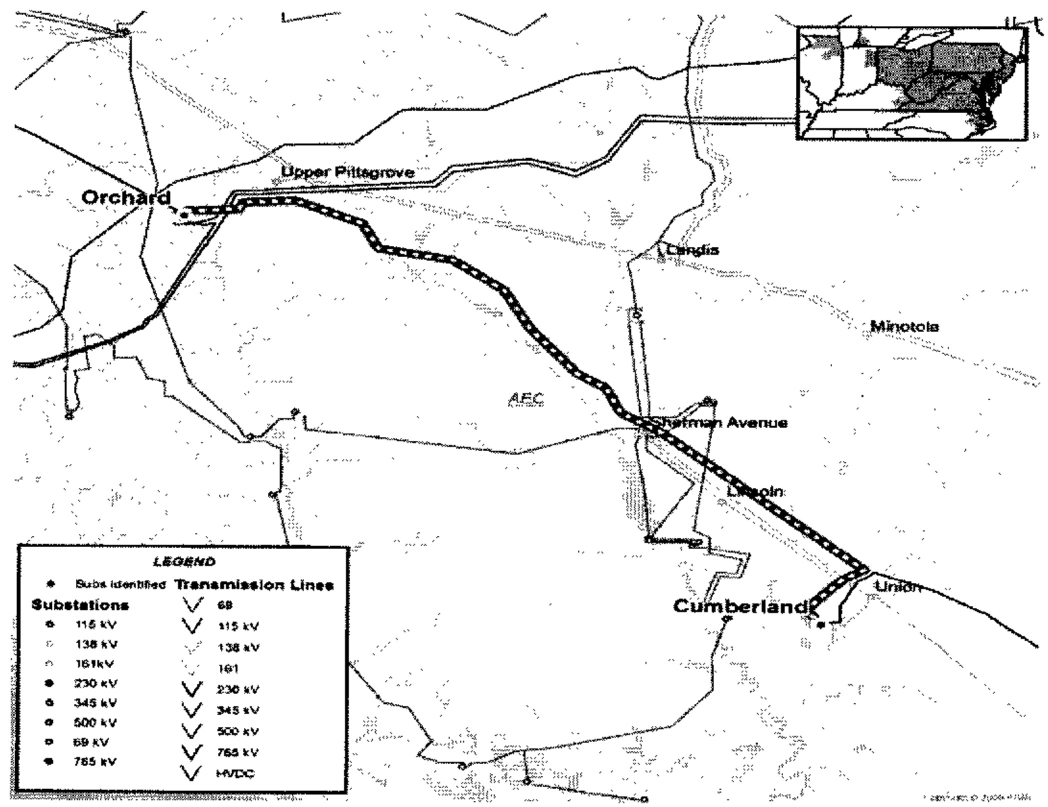
- Increase Cost Estimate:
- B210.1 (Orchard – Cumberland – Install second 230 kV line)
- The cost is increased as a result of changing the route of the circuit.

  The new scope includes re-building an existing 138 kV circuit to double circuit steel pole line so that a portion of the new 230 kV circuit will share the double circuit
- Estimated Project Cost:

  Existing $ 4 M

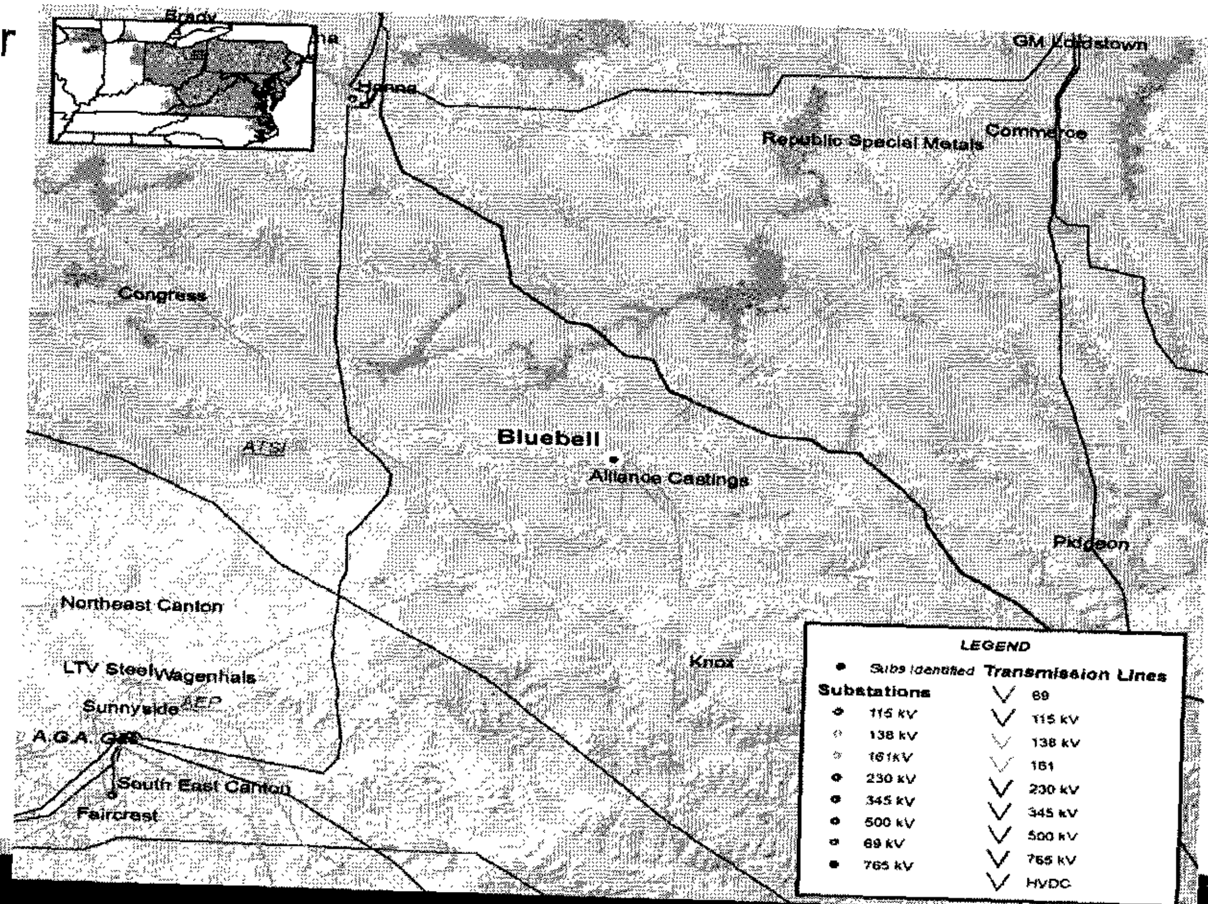
  New $ 8 M
- Expected IS Date:

  12/31/2014



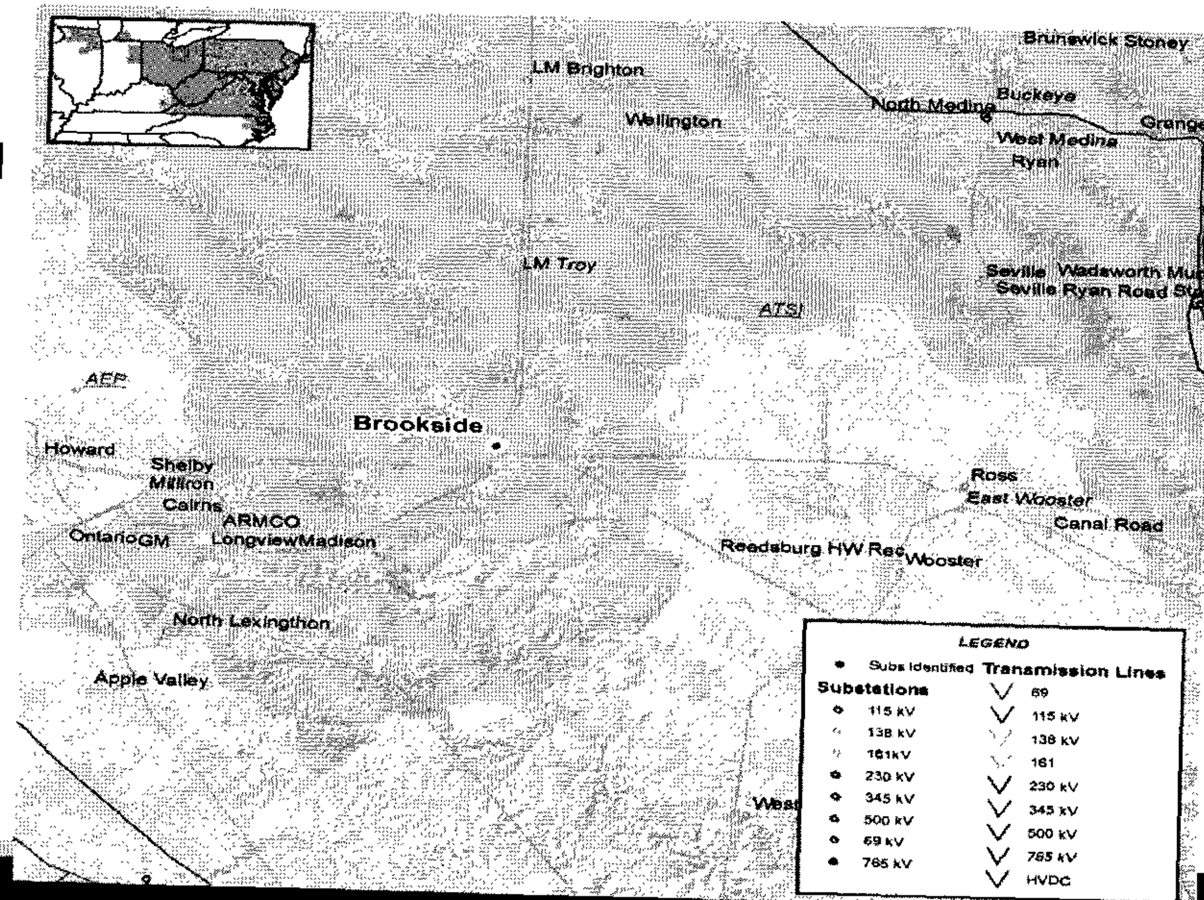
ATSI Transmission Zone

- The Bluebell138 kV breaker '301-B-94' is overstressed
- Proposed Solution: Revise the reclosing for the Bluebell 138 kV breaker '301-B-94' (b2188)
- Estimated Project Cost: $25 K
- Expected IS Date: 06/01/2017



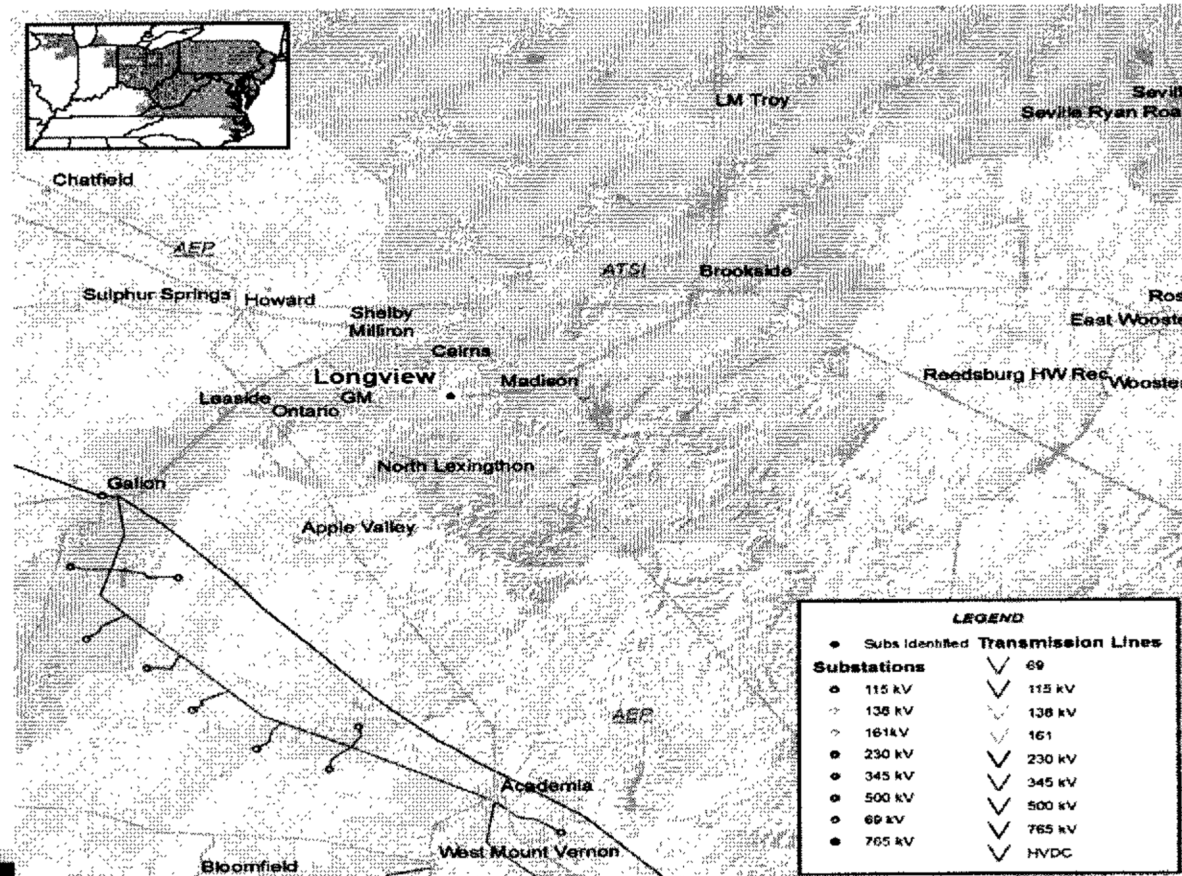
ATSI Transmission Zone

- The Brookside I138 kV breakers '701-B-59' and '701-B-60' are overstressed
- Proposed Solution: Revise the reclosing for the Brookside 138 kV breakers '701-B-59' and '701-B-60' (b2189-b2190)
- Estimated Project Cost: $25 K per breaker
- Expected IS Date: 06/01/2017



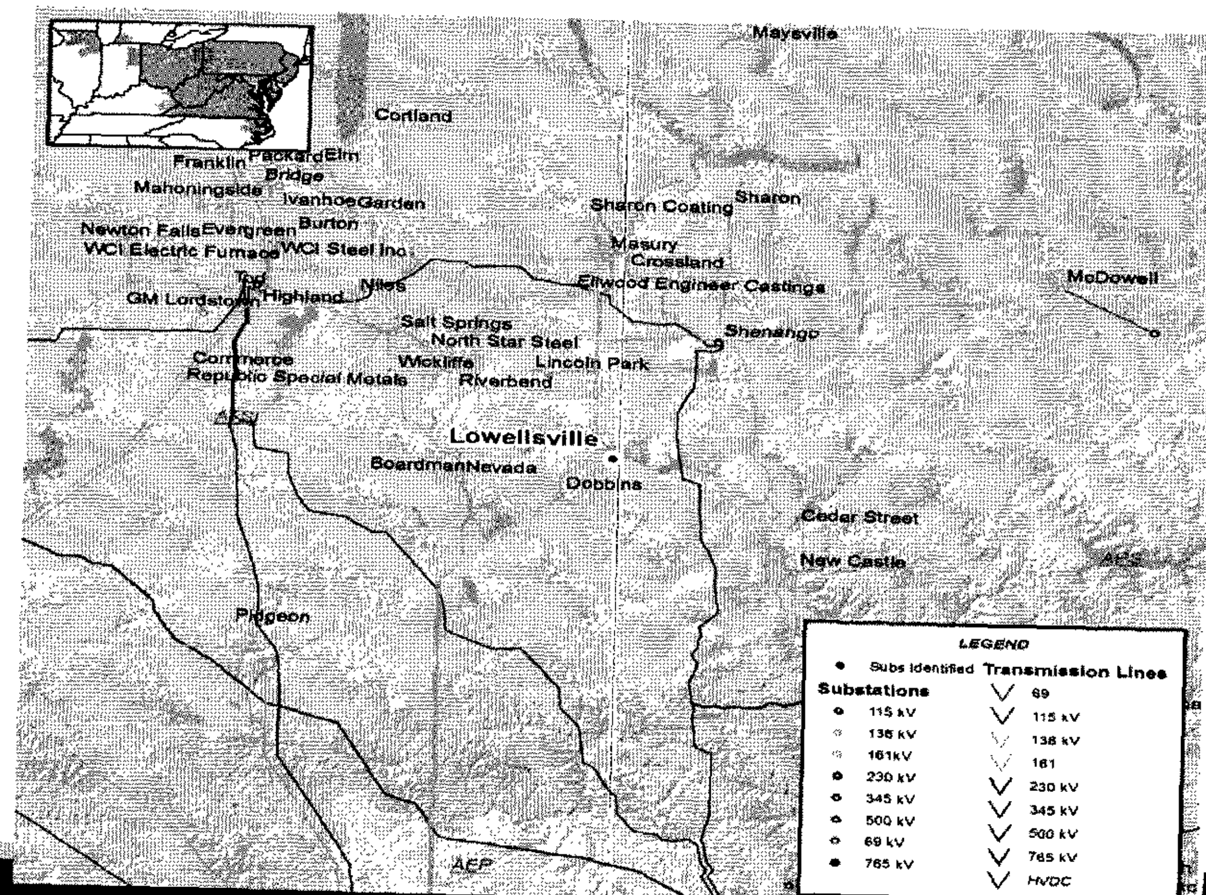
ATSI Transmission Zone

- The Longview 138 kV breaker '651-B-219 ' and '651-B-32' are overstressed
- Proposed Solution: Replace the Longview 138 kV breaker '651-B-219 ' and '651-B-32'(b2191-b2192)
- Estimated Project Cost: $175 K per breaker
- Expected IS Date: 06/01/2017



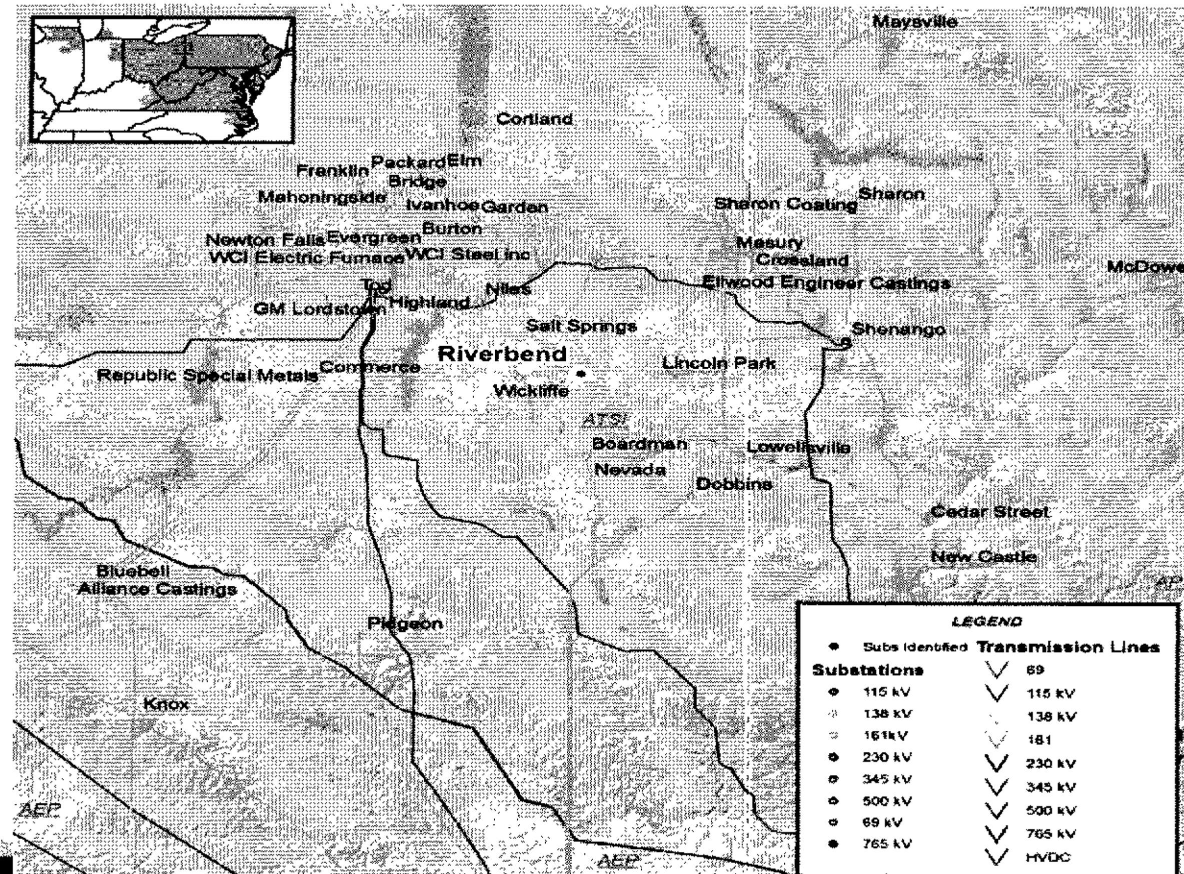
ATSI Transmission Zone

- The Lowellsville 138 kV breaker '110-B-4' is overstressed
- Proposed Solution: Replace the Lowellsville 138 kV breaker '110-B-4' (b2193)
- Estimated Project Cost: $175 K
- Expected IS Date: 06/01/2017



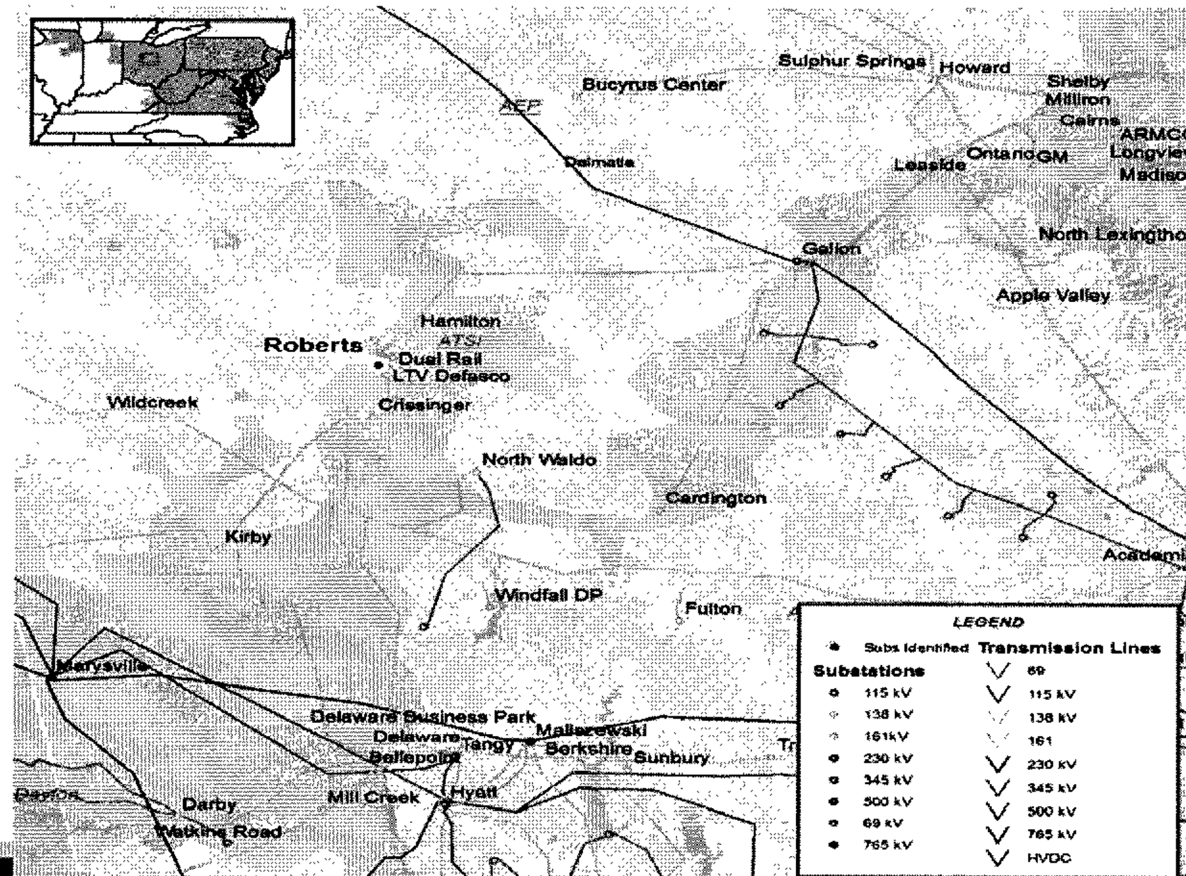
ATSI Transmission Zone

- The Riverbend 138 kV breaker '119-B-11' is overstressed
- Proposed Solution: Replace the Riverbend 138 kV breaker '119-B-11' (b2194)
- Estimated Project Cost: $175 K
- Expected IS Date: 06/01/2017



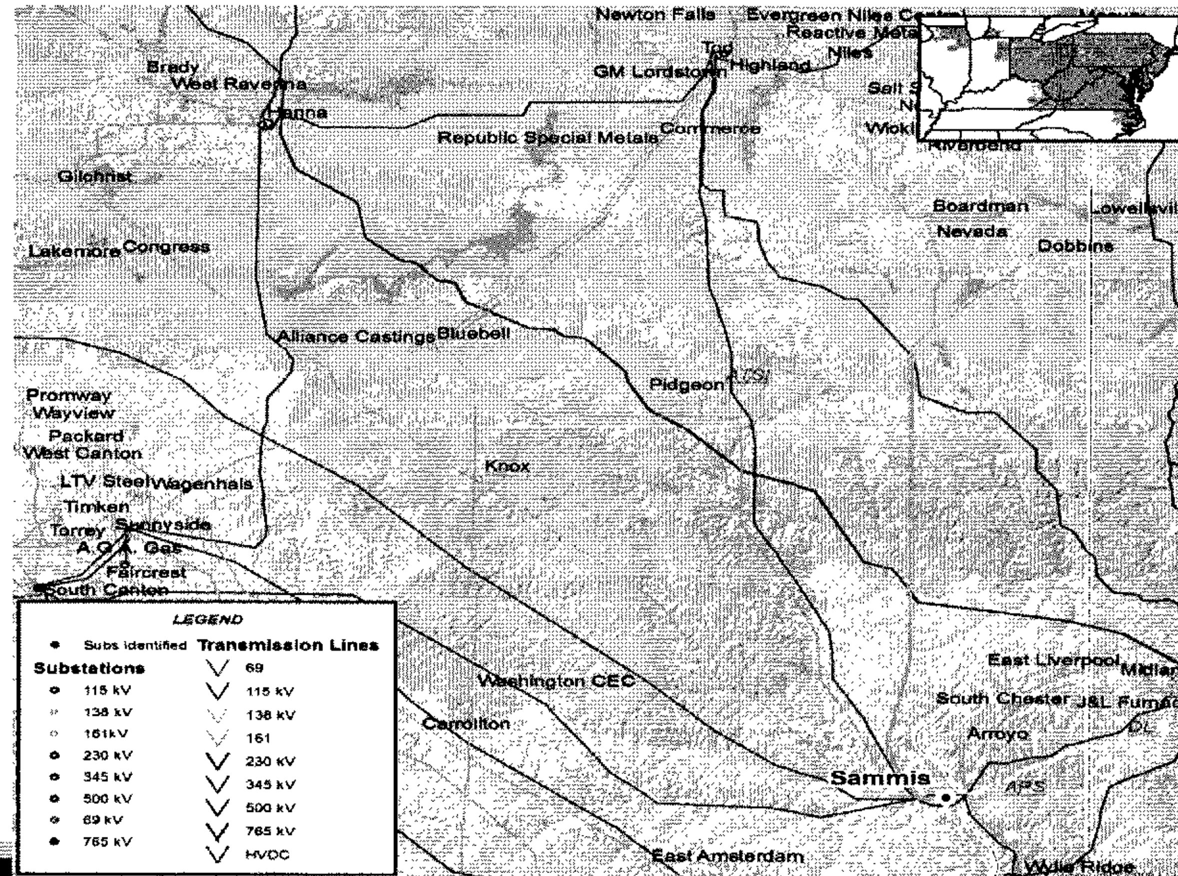
ATSI Transmission Zone

- The Roberts 138 kV breaker ‘601-B-60’ is overstressed
- Proposed Solution: Replace the Roberts 138 kV breaker ‘601-B-60’ (b2195)
- Estimated Project Cost: $175 K
- Expected IS Date: 06/01/2017



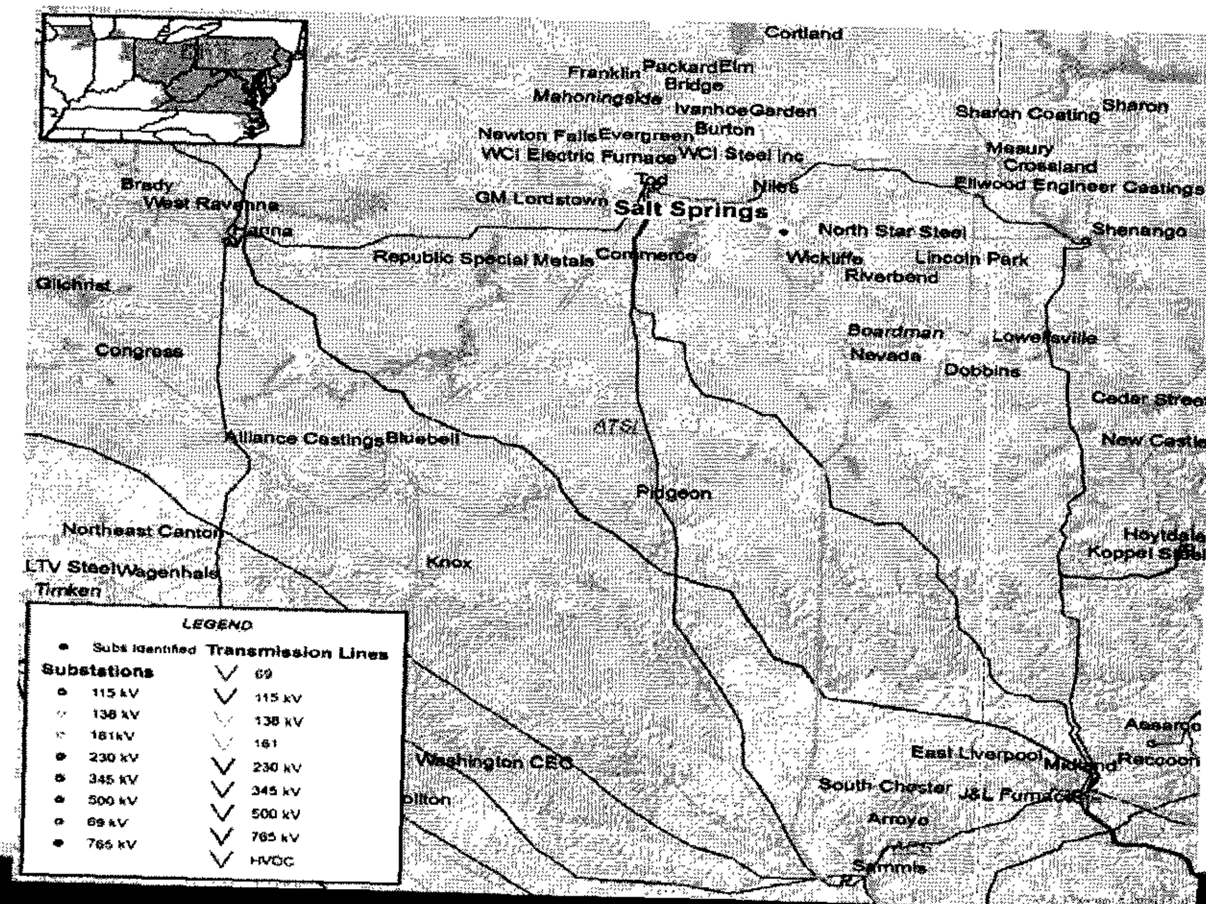
ATSI Transmission Zone

- The Sammis 138 kV breaker '780-B-76' is overstressed
- Proposed Solution: Replace the Sammis 138 kV breaker '780-B-76' (b2196)
- Estimated Project Cost: $175 K
- Expected IS Date: 06/01/2017



ATSI Transmission Zone

- The Salt Springs 138 kV breaker '105-B-35' is overstressed
- Proposed Solution: Replace Salt Springs 138 kV breaker '105-B-35' (b2197)
- Estimated Project Cost: $175 K
- Expected IS Date: 06/01/2017



Supplemental Projects

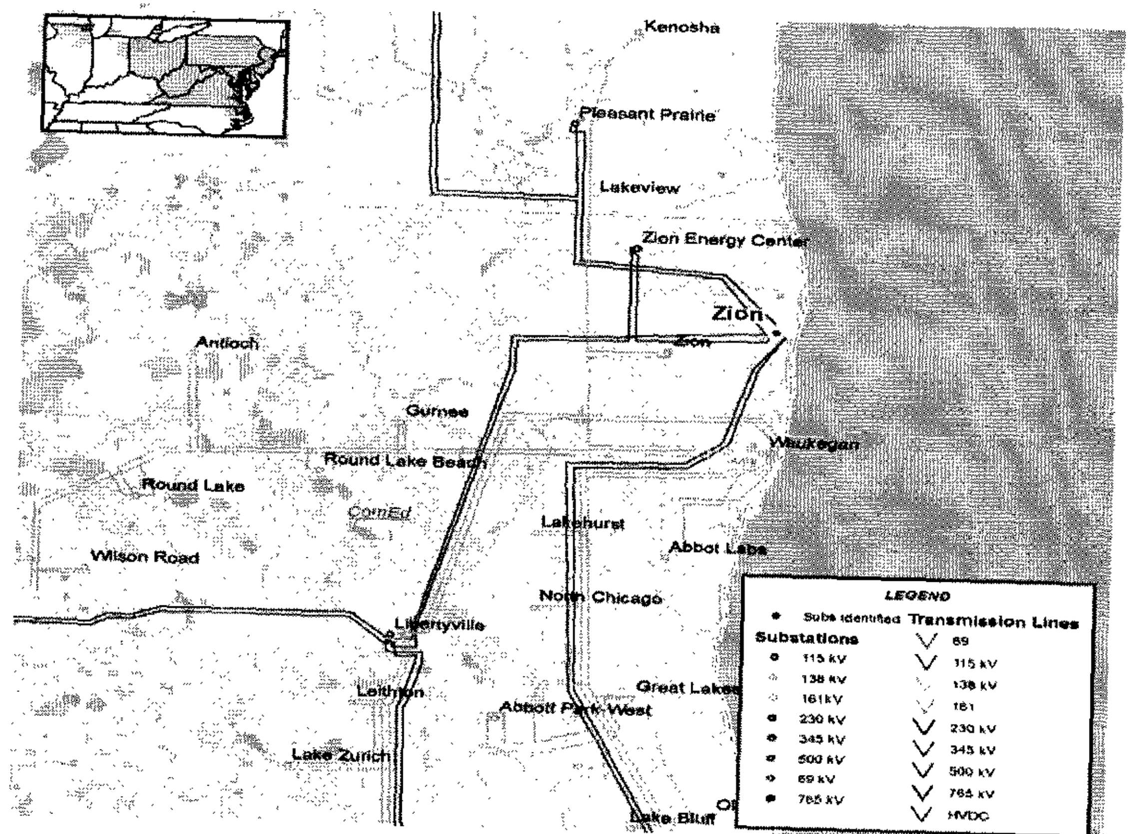
ComEd Transmission Zone

- **Supplemental Project**

- Add a 4th breaker to the Zion EC 345 kV bus to accommodate the Zion – Pleasant Prairie 345 kV (ATC) interconnection (S0502)

- Estimated Cost: $4.6M

- Projected IS Date: 06/01/2013



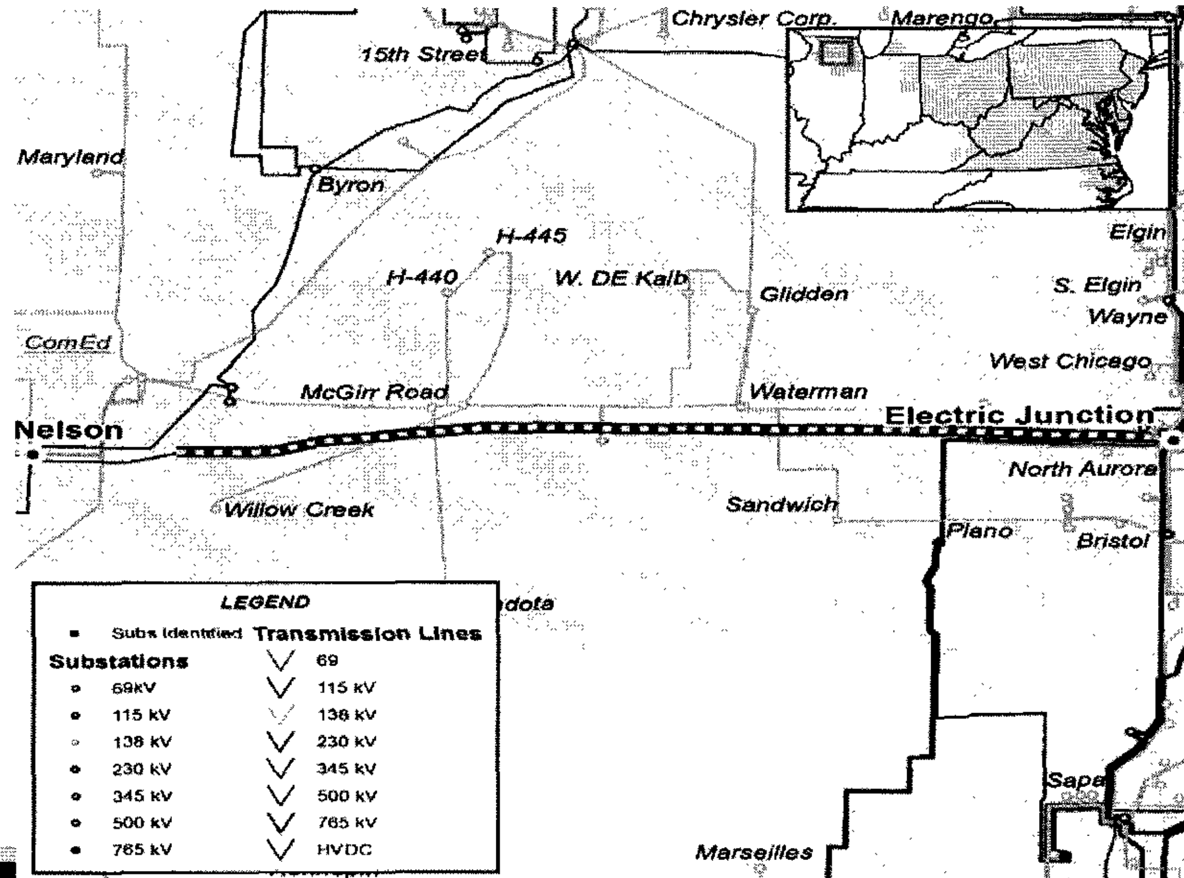
ComEd Transmission Zone

- **Supplemental Project**

- Change the no-load transformer taps from 338.25 kV to 346.5 kV at TSS 155 Nelson 345/138 substation.(S0503)

- Estimated Cost: $0.005M

- Projected IS Date: 06/01/2013



Next Steps

Questions?

Email: RTEP@pjm.com