

## Section 10: Market Efficiency Analysis



### 10.0: Introduction

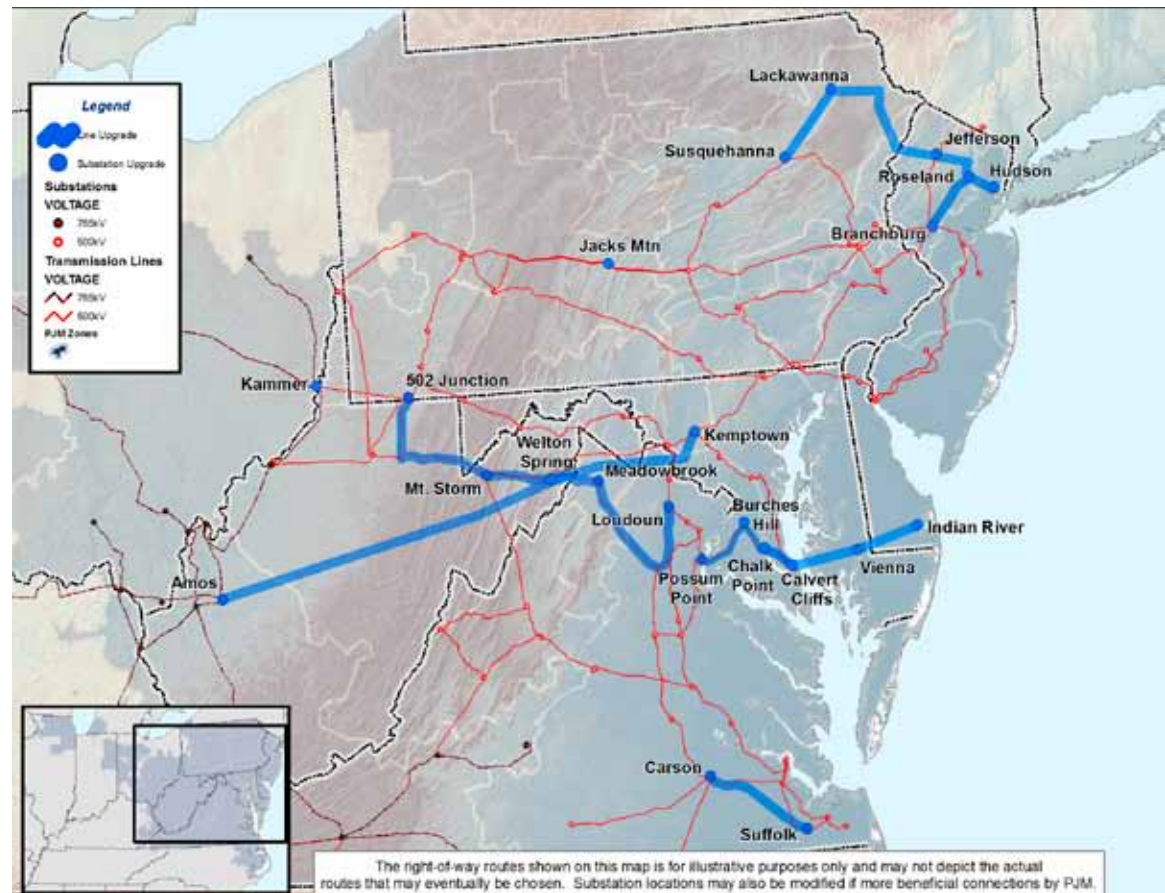
PJM's RTEP Process includes market efficiency analysis, designed to accomplish the following objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated.
2. Identify new transmission upgrades that may result in economic benefits.
3. Identify economic benefits associated with modification to reliability-based enhancements already included in RTEP that when modified would relieve one or more economic constraints. Such upgrades resolve reliability issues but are intentionally designed in a manner to provide economic benefits in addition to resolving those reliability issues.

For reference, Map 10.1 shows PJM Board approved RTEP Backbone Upgrades to resolve reliability criteria violations.

As a result of PJM's 2009 market efficiency analysis, an upgrade in the Conemaugh area of the Penelec system will be recommended for possible inclusion into the PJM RTEP based on the economic benefit that it is projected to provide. The economic upgrade includes the addition of

Map 10.1: PJM Board Approved RTEP Backbone Upgrades



a 500/230 kV transformer at Conemaugh along with a new 230 kV line between the Conemaugh and Seward facilities. This upgrade is the first project to be recommended for inclusion in the PJM RTEP based on the economic evaluation process described in section 1.5.7 of Schedule 6 of the PJM Operating Agreement, accessible from PJM's Web site via the following URL: <http://www.pjm.com/documents/agreements/~media/documents/agreements/oa.ashx>

**10.0.1 – Simulation Methodology and Assumptions**

PJM market efficiency analysis employs a market simulation tool that models hourly security-constrained generation commitment and dispatch over a defined future annual period. Economic benefits of transmission upgrades are determined by comparing results of simulations with and without defined transmission upgrades.

PJM's 2009 market efficiency analysis included market simulations for 2009, 2012, 2015 and 2018. Prior to the initiation of each annual market efficiency analysis, PJM reviews key analysis parameters with the Transmission Expansion Advisory Committee (TEAC) These include fuel costs, emissions costs, future generation scenarios, load forecasts and demand response projections, shown in Figure 10.1

**Figure 10.1: Market Efficiency Analysis Parameters**





## 10.2: 2009 RTEP Market Efficiency Analysis

### 10.2.1 – Summary of Results

PJM’s 2009 market efficiency analysis assessed the economic impact of all upgrades identified as part of PJM’s RTEP process up through and including those identified as part of the 2008 RTEP cycle. This set of upgrades included the following BES baseline backbone lines, shown earlier on Map D-1000-1:

- 502 Junction - Loudoun 500 kV Line (TrAIL)
- Amos - Kemptown 765 kV Line (PATH)
- Susquehanna - Roseland 500 kV Line
- Possum Point - Calvert Cliffs 500 kV Line, HVDC from Calvert Cliffs to Vienna/ Indian River (MAPP)
- Branchburg - Roseland - Hudson 500 kV line

Results have indicated that approved RTEP upgrades will significantly reduce PJM constrained operations. PJM system congestion costs fall to levels 90% lower than costs expected absent the upgrades. The majority of the congestion cost reduction can be attributed to the addition of the new 765 kV and 500 kV RTEP backbone projects listed above.

### 10.2.2 – 2009 and 2012 Study Year Results

Assessments of transmission system topology impacts are conducted with different transmission system models while keeping all other input assumptions constant for a given study year. Market simulations for study years 2009 and 2012 were conducted under two transmission topology models:

1. 2009 “as-is” PJM transmission system topology.
2. 2013 RTEP PJM transmission system topology (includes all upgrades up through the 2008 RTEP process cycle including the baseline backbone lines noted earlier).

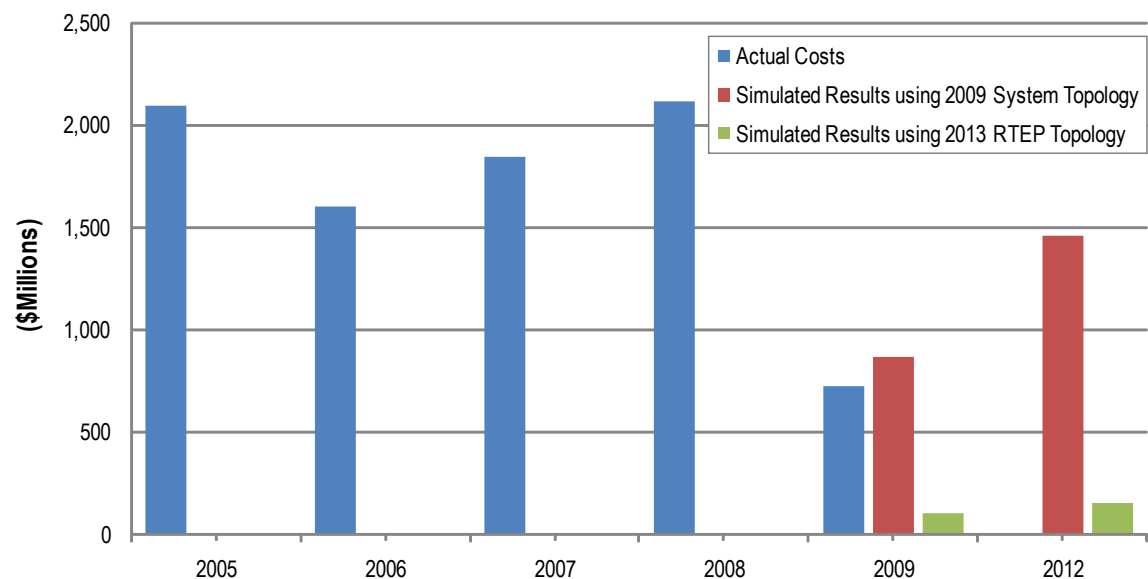
Figure 10.2 shows actual PJM system

congestion costs for years 2005, 2006, 2007, 2008 and 2009 and congestion costs derived from market simulations for years 2009 and 2012 using the above two transmission topologies.

### 2009 Study Results

Figure 10.2 shows that PJM RTEP upgrades have a significant impact on PJM system congestion costs. Simulations using the 2009 transmission system topology show PJM system congestion costs of nearly \$900 million. PJM system congestion costs for study year 2009 are reduced to nearly \$100 million when using the 2013 RTEP transmission topology.

**Figure 10.2: Actual and Simulated PJM System Congestion Costs**



**2012 Study Results**

For study year 2012, simulations made using the 2009 transmission system topology show PJM system congestion costs of nearly \$1.5 billion. PJM system congestion costs for study year 2012 are reduced to nearly \$150 million when using the 2013 RTEP transmission topology.

**Congestion Impact of New Transmission**

The simulations for study years 2009 and 2012 under the two system study topologies show similar impacts of new transmission on transmission congestion. In both study years, the addition of RTEP upgrades reduce total PJM system congestion costs to levels approximately 90% lower than congestion costs absent the upgrades. The bulk of the congestion cost reduction is attributable to the addition of the major 765 kV and 500 kV backbone projects contained in the RTEP.

**Comparing 2009 and 2012 Results**

Figure 10.2 shows that actual congestion costs for 2009 have dropped off significantly from those of recent years. This drop in congestion cost level is mainly due to lower fuel prices and lower weather and recession related load levels. The simulation results correctly predict these lower congestion cost levels for 2009 but show a return to higher congestion levels in 2012 due to projections of higher gas prices relative to coal prices and generation additions primarily in the western part of the system. While estimates of future congestion costs vary with changes in assumptions regarding key input parameters, the simulations show that the addition of the new transmission contained in the 2013 RTEP consistently reduce congestion costs to levels approximately 90% lower than congestion costs expected absent the upgrades.

### 10.2.3 – 2015 and 2018 Study Results

To identify future transmission system bottlenecks, PJM conducted market simulations for study years 2015 and 2018 using the 2013 RTEP transmission system topology. The results summarized in Table 10.1 include those constraints causing more than \$5 million of congestion costs in either of the study years. Table 10.1 shows congestion costs increasing over time but remaining below historical levels due to the addition of the backbone projects contained in the 2013 RTEP.

While a majority of the total congestion cost is associated with 500 kV reactive interface limits (AP South Interface, Central Interface, Eastern Interface and Black Oak - Bedington Interface), a significant level of congestion occurs throughout the study period on the Altoona - Bear Rock 230 kV line in the Penelec Zone and the Clover 500/230 kV transformer in the Dominion Zone. Upgrades intended to relieve congestion on the Altoona - Bear Rock 230 kV line and the Clover 500/230 kV transformer were developed and a cost/benefit analysis of these upgrades was conducted.

#### **Conemaugh BES Upgrades**

In addition to the Altoona - Bear Rock 230 kV congestion, the simulations showed lower levels of congestion on several other underlying facilities on the Penelec system (less than the \$5 million reporting threshold of Table 10.1). Congestion on Altoona - Bear Rock 230 kV line and the other facilities is aggravated by west-to-east transfers and is especially sensitive to the addition of wind generation in the Penelec zone. The addition of a 500/230 kV transformer at Conemaugh and a new 230 kV line between Conemaugh and Seward was found to relieve congestion of the Altoona - Bear

**Table 10.1: Congestion-Causing Constraints for Study Years 2015 and 2018**

Constraints with Congestion Greater than \$5 million	2015 Study Year		2018 Study Year	
	Frequency (hours)	Market Congestion (\$Millions)	Frequency (hours)	Market Congestion (\$Millions)
AP South 500 kV Interface	1285	74.6	3081	366.5
Altoona - Bear Rock 230 kV Line	799	28.9	2195	106.4
PJM 500 kV Central Interface	1566	23.6	2585	84.6
Clover 500 / 230 kV Transformer	767	16.9	1696	65.7
PJM 500 kV Eastern Interface	48	5.7	61	3.2
Blackoak - Bedington 500 kV Interface	13	2.9	20	5.9
Ironwood - South Lebanon 230 kV Tap	683	2.2	1022	11.2
Cloverdale - Lexington 500 kV Line	201	1.7	1001	32.1
Pontiac - Wilton 345 kV Line	10	0.1	212	14.3
<b>Total</b>		<b>156.6</b>		<b>689.9</b>

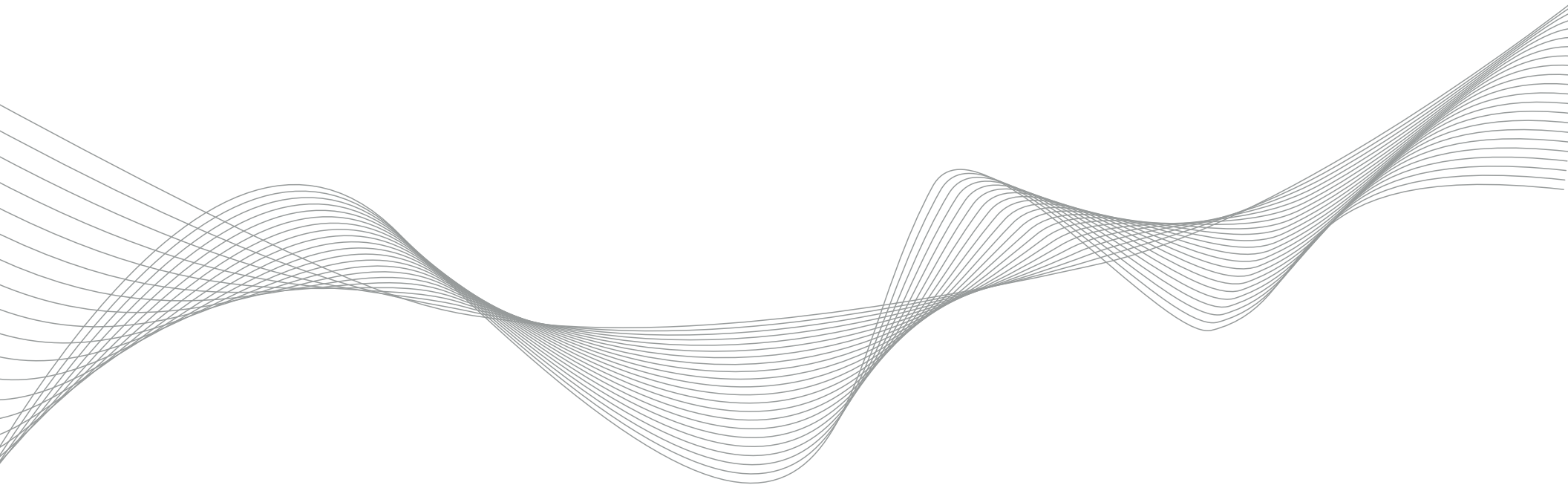
Rock 230 kV line and the other facilities. Based on application of the cost/benefit analysis procedures described in Section 1.5.7 of Schedule 6 of the PJM Operating Agreement, this upgrade was found to be economically justified and is recommended for inclusion in the PJM RTEP.

#### **Second Clover 500/230 kV Transformer**

The addition of a second Clover 500/230 kV transformer was tested for its ability to relieve congestion of the existing 500/230 kV transformer at Clover. Congestion on the Clover 500/230 kV transformer is also aggravated by west-to-east transfers and is especially sensitive to interchange between PJM and systems to the south of PJM.

Based on an application of the cost/benefit analysis procedures described in Section 1.5.7 of Schedule 6 of the PJM Operating Agreement,

this upgrade was found to be economically justified; however, due to the constraint's sensitivity to interchange levels with systems to the south of PJM, a recommendation for the addition of a second Clover 500/230 kV transformer is being deferred until analysis results are validated against results from a joint TVA/Duke/PJM analysis currently being conducted. This joint analysis will contain a more comprehensive model of interchange between PJM and systems south recommendation for a second Clover 500/230 kV transformer will be deferred until PJM market efficiency analysis results can be confirm the results of the joint study analysis.





### 10.3: Market Simulation Model Input Assumptions

Prior to the initiation of each annual RTEP Process market efficiency analysis, PJM reviews key parameters with the Transmission Expansion Advisory Committee (TEAC). Fuel costs, emissions costs, future generation scenarios, load forecasts and demand response projections are described in the proceedings of the TEAC, available on PJM's Web site via the following URL link: <http://www.pjm.com/committees-and-groups/committees/teac.aspx>.

#### **General Fuel Cost Assumptions**

PJM uses a commercially available Ventyx Powerbase database tool which includes fuel cost forecasts for each fuel type. Forecasts for short-term gas and oil prices are derived from NYMEX futures prices. Long-term forecasts are obtained from Platts and the DOE's Energy Information Administration (EIA). Coal price forecasts are obtained from Platts directly. Powerbase uses basis adders to account for commodity transportation cost to each PJM zone.

#### **Load and Energy Forecasts**

PJM's January 2009 PJM Load Forecast Report provided the source of load and energy data modeled in these market simulations.

#### **Demand Response**

The 2009 study year values were based on the sum of the ILR and DR (cleared and fixed resource requirement) from the 2009/2010 RPM auction. The values used for study year 2012 and beyond are based DR (cleared and fixed resource requirement) from the 2012/2013 RPM simulation. Demand response MWs are distributed among the PJM zones based on the zonal apportionment of cleared DR and fixed resource requirement.

#### **Generation Modeling**

The generation capacity modeled included in-service generation plus active queue generation with an executed Interconnection Service Agreement (ISA) minus expected future deactivations.

The net internal demand is consistent with the 2009 PJM Load Forecast Report and equates to the PJM Summer unrestricted peak forecast minus the projection of load management placed under PJM control. Overall, projected total capacity is expected to be able to meet expected reserve margin through 2013. The PJM reserve requirement exceeds the total capacity of installed generation by approximately 3,900 MW, 10,200 MW and 18,100 MW in the years 2015, 2018 and 2023, respectively.

New generation needed to maintain PJM's reserve margin in study years 2015, 2018 and 2023 was added to the model according to the location and fuel type of generation interconnection requests in recent PJM queues.

#### **Emission Allowance Price Assumptions**

The powerbase uses models four major effluents: SO<sub>2</sub>, NO<sub>x</sub>, Hg and CO<sub>2</sub>. Each is assigned to generators based on location. Release rates are from a variety of sources including Platt's BASECASE and the EPA. Emissions allowance prices are also from a variety of sources including Platt's BASECASE, Evomarkets.com and EPA.

A national CO<sub>2</sub> allowance trading program was assumed in-place beginning with study year 2011. The Powerbase database does not include a CO<sub>2</sub> allowance price forecast. Instead, the allowance prices assumed for CO<sub>2</sub> are based on Synapse Energy Economics forecasts.

