Transmission Expansion Advisory Committee

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February 22, 2008

Long Term Reactive Plan

- In 2006 the Planning Committee approved including reactive planning for a 10 year RTEP model.
- Analysis focuses on 345 kV, 500 kV and 765 kV to determine the more global reactive needs in year 10 – 2017
- Analysis is limited to areas of the system where thermal problems were identified in the 6 -15 year analysis
- For the 2007 RTEP thermal problems were identified in the Eastern Mid-Atlantic, Southwest Mid-Atlantic and Mid-Atlantic regions of PJM

- PJM completed load deliverability voltage analysis for 2017 of the Mid-Atlantic, Southwest Mid-Atlantic and Eastern Mid-Atlantic
- Load deliverability was the main driver for the majority of the overloads identified in years 6 through 15
- High load conditions modeled in the load deliverability analysis are when PJM typically sees voltage issues on the system

- PJM identified the need for approximately 3,000 MVAR of reactive devices by 2017 in order to provide for an adequate voltage profile for N-0 and N-1 conditions
- If the entire 3,000 MVAR were static switched capacitors the cost would be estimated at $60 M
- If 20% of the 3,000 MVAR were required to be dynamic with the remaining switched capacitors the estimated cost would be $108 M
- PJM used $20K per MVAR for static reactive and $100 K per MVAR for dynamic reactive

- PJM performed sensitivity analysis around zonal power factor to determine the magnitude of the reactive reinforcements that would be required if all zones were at unity power factor
- With all transmission owner zones at unity power factor analysis showed we would need approximately 750 MVAR of reactive by 2017 for N-0 and N-1 contingencies
- If the entire 750 MVAR were static capacitors the estimated cost would be $15 M
- If 20% of the 750 MVAR were dynamic reactive devices with the remaining 80% static capacitors the estimated cost would be $27 M

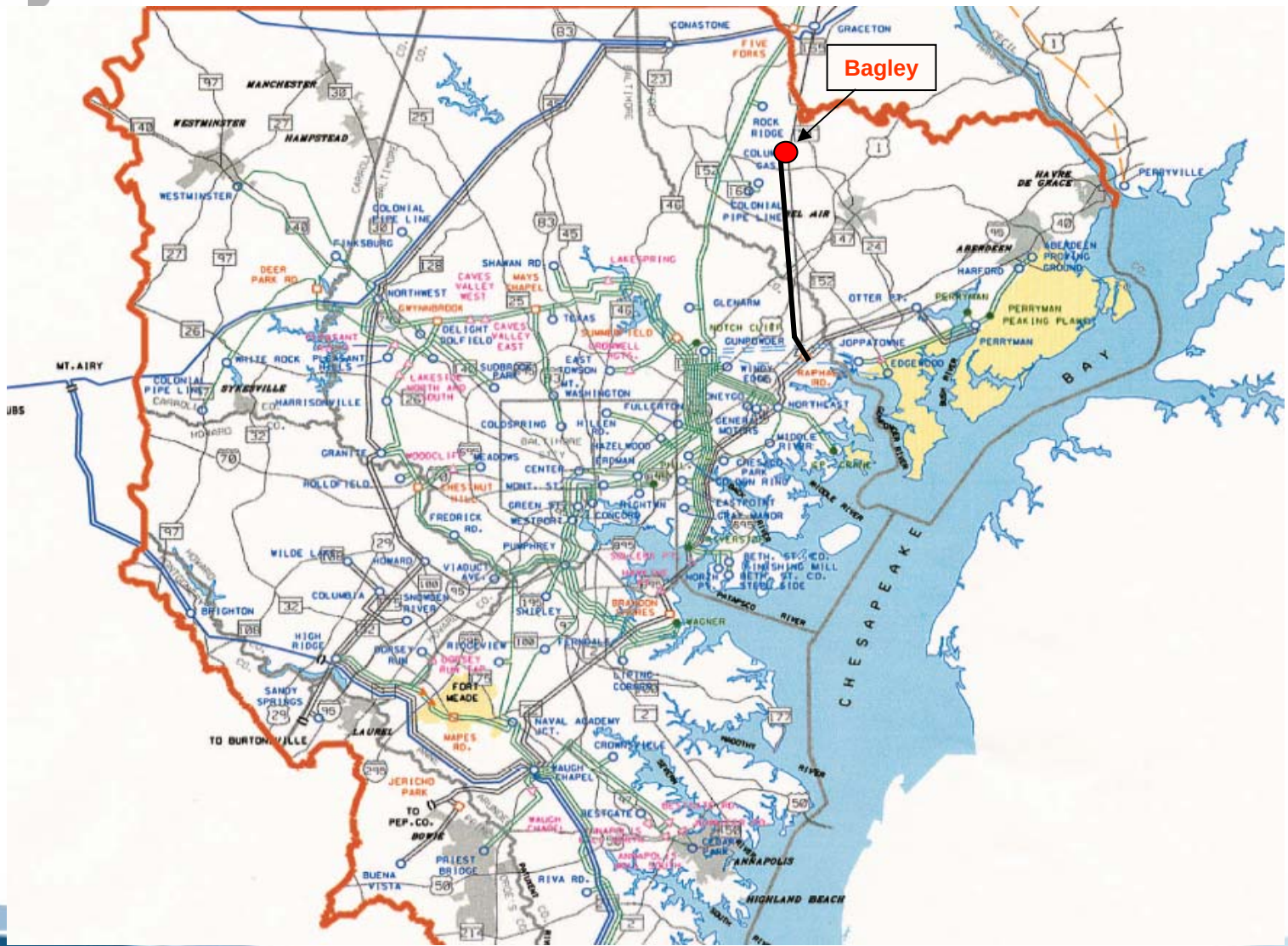
- Last year's long term reactive analysis identified the need for approximately 10,000 MVAR or reactive reinforcements by 2016.
- Addition of the backbone transmission projects that were identified as part of the 2007 RTEP are likely the main reason for the reduction in reactive requirements.

Supplemental Projects

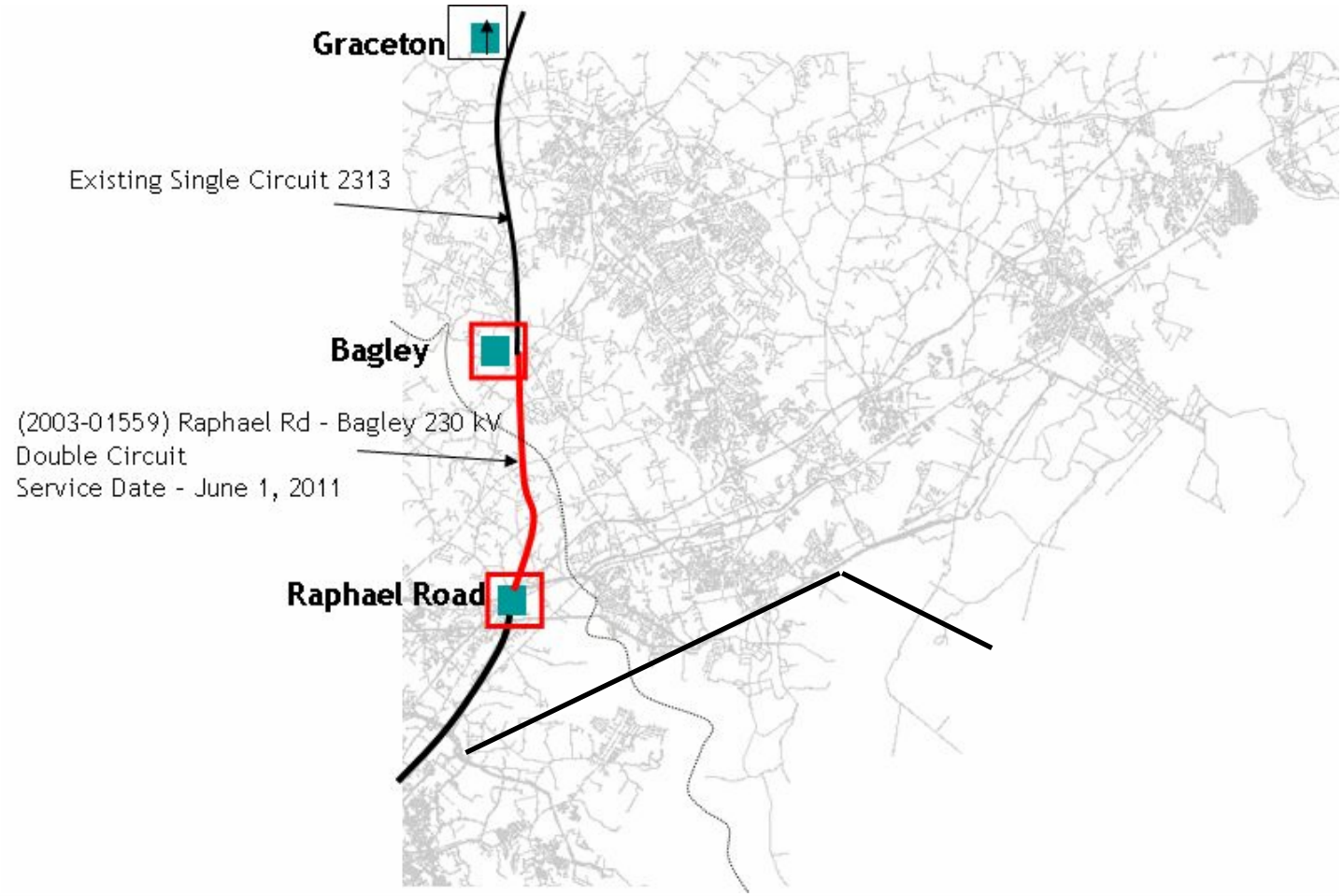
Supplemental Project – BG&E Zone

- The Harford County area of the BGE system is experiencing high growth in part due to the Army's Base Realignment and Closure (BRAC) process.
- A new distribution Master Substation, Bagley, is planned to provide the needed capacity in Harford County.
- This Bagley site is adjacent to the existing Raphael Rd. to Graceton 230 kV line.
- To serve Bagley while not reducing the functionality of the 230 kV circuit for importing power into the Baltimore area, BGE plans to construct a second 230 kV line from Raphael Rd. to the Bagley substation.
- BGE is also taking this opportunity to reconfigure the Raphael Rd. 230 kV bus design to breaker and a half to meet BGE's published design standards. With the current configuration a line fault will drop a 230kV line and a 230/115kV transformer and other line outages can split the 230kV station.

BGE System



Local Area Map



- The Bagley Substation is projected to be needed by summer 2011
- Total cost of transmission portion of the project is $20M
  - Rebuild 5.9 miles Raphael Road – Bagley 230 kV to double circuit ($8.5M)
  - Raphael Rd 230kV Substation upgrade to breaker/half ($9.0M)
  - New Bagley 230/34.5kV Station install two 230kV breakers ($2.5M)

2008 RTEP Assumptions

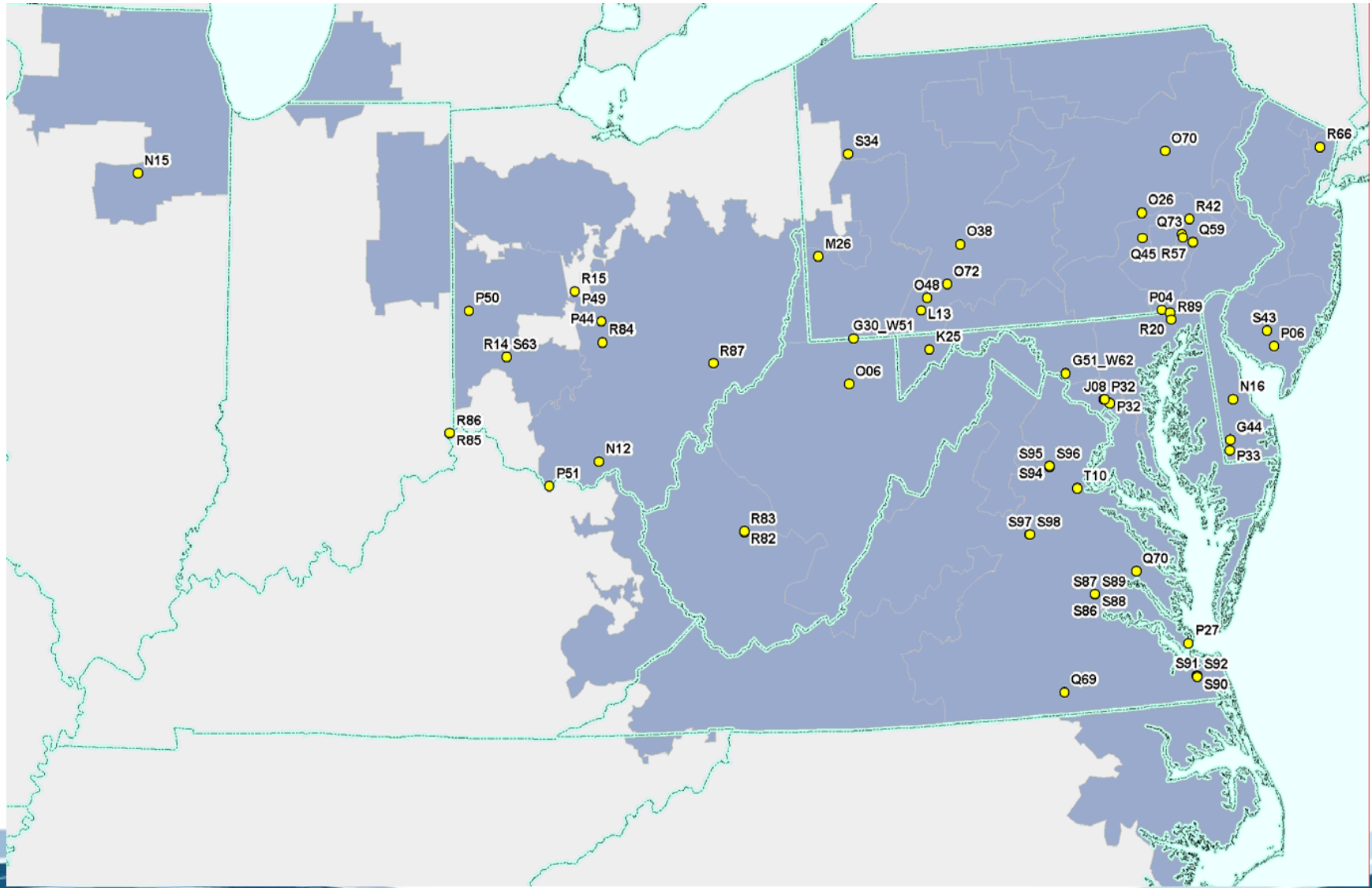
- Power flow models for world load, capacity and topology will be based on the most recent MMWG power flow base cases.
- PJM topology will be based on the latest 2012 base case.
- Long term firm transmission service will be consistent with operations.
- Generation outage rates will be based on the most recent unavailability data available to PJM.
- Generation outage rates for future PJM units will be estimated based on historical outage rates.

- Load will be modeled consistent with the 2008 Load Forecast Report.
- PJM RTO Peak: 149,495 MW
  - PJM South Peak: 21,315 MW
  - PJM West Peak: 66,090 MW
  - PJM Mid-Atlantic: 65,850 MW
- Load Management will be modeled consistent with the 2008 Load Forecast Report
  - Used in LDA under study in load deliverability analysis

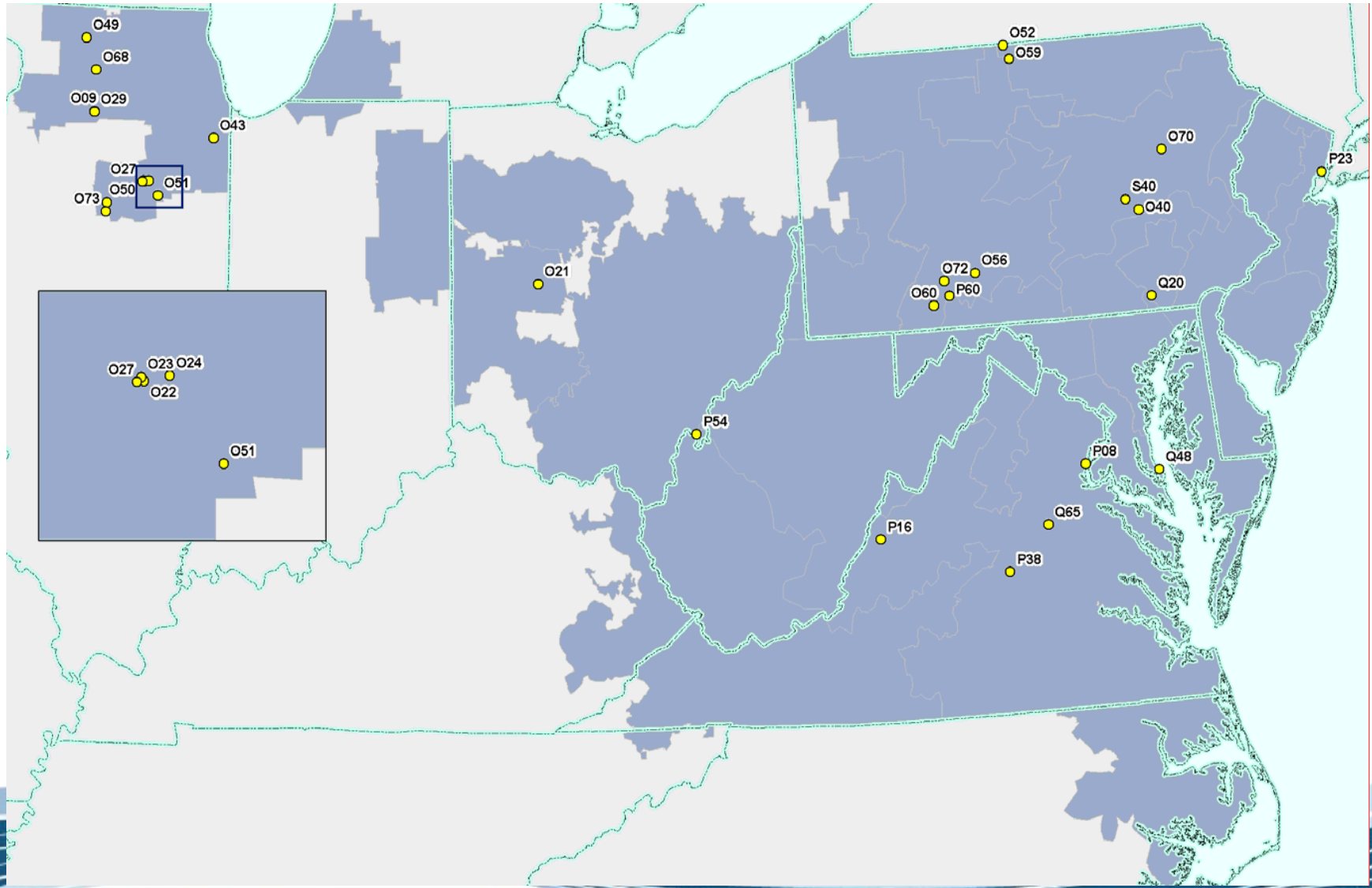
2008 RTEP Generation Assumptions

- 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 a signed Facility Study Agreement (FSA) will be modeled along with any associated network upgrades.
- Generation with a signed FSA will be modeled off-line except for generation deliverability testing to contribute to problems.
- Generation with a signed FSA, but not an ISA, 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 modeled.

New Generation with an ISA



New Generation with an FSA



- **Mid-Atlantic**
  - Parlin, Sewaren, BL England included
  - Benning, Buzzard, Bergen CC, Indian River 1&2 not included
  - New generation with a signed ISA – 1031 MW
  - New generation with a signed FSA – 2438 MW
- **Southern**
  - New generation with a signed ISA – 287 MW
  - New generation with a signed FSA – 3209 MW
- **West**
  - Will County 1 & 2 , Waukegan 6 not included
  - New generation with a signed ISA – 1717 MW
  - New generation with a signed FSA – 3674 MW

2013 RTEP Interchange

2013 RTEP IINTERCHANGE		
FROM	**TO**	**MW**
PJM	AMRN	127
PJM	CIN	708
PJM	EKPC	0
PJM	FE	644
PJM	IP	0
PJM	LGEE	137
PJM	OVEC	-1853
PJM	ALTW	264
PJM	ALTE	155
PJM	CPLE	270
PJM	CPLW	250
PJM	DUKE	63
PJM	MEC	1370
PJM	MECS	574
PJM	NIPS	0
PJM	NYIS	1957
PJM	WEC	1215
PJM	TVA	918
TOTAL		**6799**

- All PJM bulk electric system facilities 100 kV and greater, 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 100 kV and greater, all tie lines to neighboring systems and all lower voltage facilities operated by PJM.
- Thermal and voltage limits will be consistent with those used in operations.

- Started developing case back in December
- Case has gone through a number of iterations
- Contingency files have been updated for new topology
- Contingency files have been checked for errors
- Case completed
- Initial analysis just getting under way
- Initial results and potential violations will be posted as they become available
- Future TEAC and Subregional RTEP Committee meetings will be scheduled

Transmission Expansion Advisory Committee Meeting

2008 Market Efficiency Analysis Preliminary Input Assumptions

February 22, 2008

Market Simulation Input Data

- Study years: 2008, 2011, 2014, 2017, 2022
- PROMOD IV model from New Energy Associates (NEA)
- Underlying input data contained in NEA's Powerbase (November 2007 update) including generating units and unit characteristics, fuel costs and emissions costs
- NEA Powerbase data based on a variety of sources including Platts, EIA, NYMEX, Evomarkets.com, EPA, FERC, NERC, etc.
- Powerflow Cases
  - 2008 power flow case to represent today's "as-is" system
  - 2012 RTEP power flow case to represent future system

Key Input Parameters

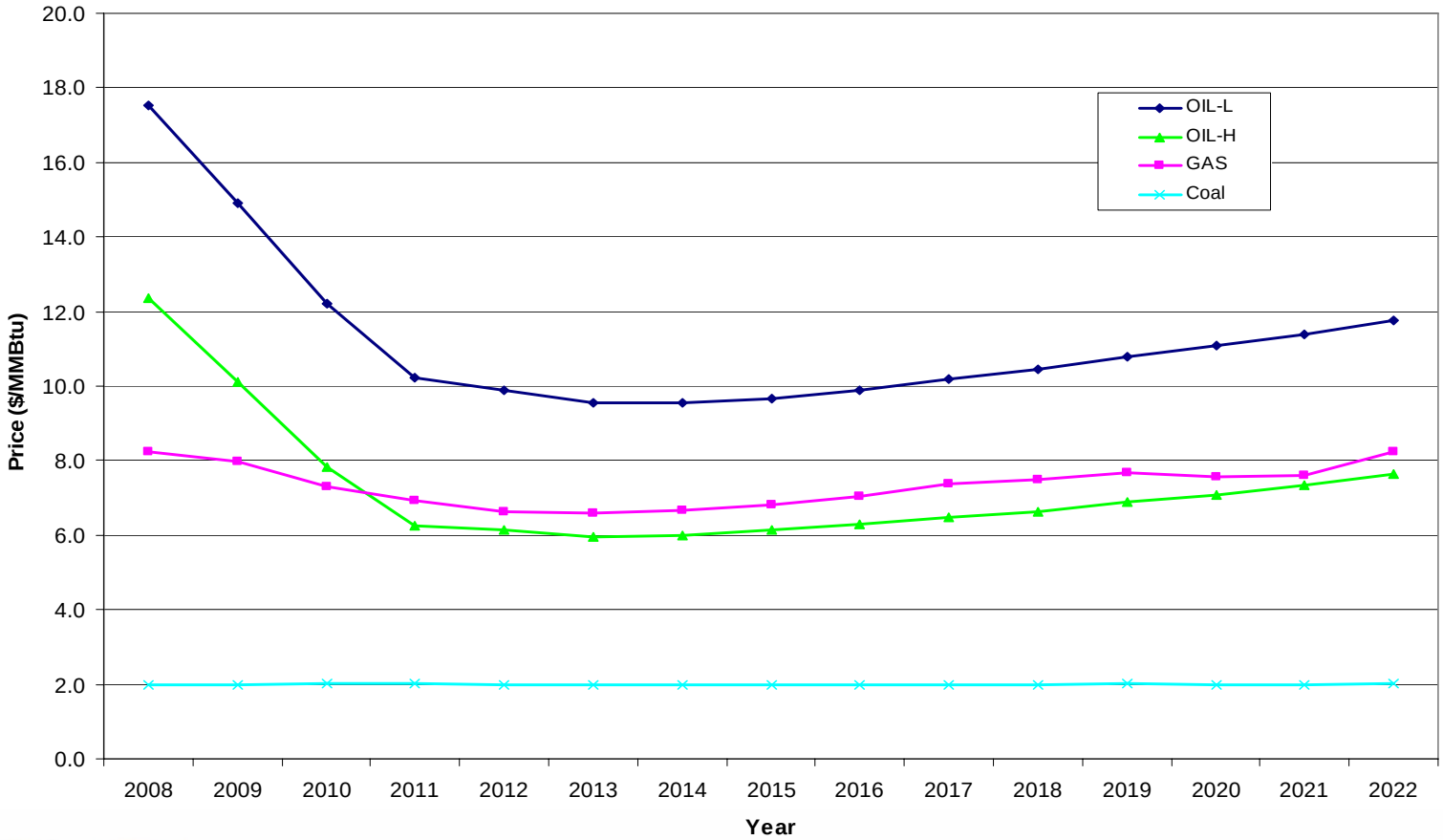
- Fuel prices
- Load and energy
- Future generation scenario
- Emissions prices
- Transmission topology
- Discount rate
- Upgrade Revenue Requirement
- RPM

Fuel Prices

- Powerbase fuel prices based on NYMEX futures prices and long-run forecasts from Platts and the Energy Information Administration (EIA)

Fuel Price Forecasts

Figure 1 - Fuel Price Assumptions



Load & Energy Data

- PJM zonal peak and zonal energy forecast from PJM 2008 Load Forecast Report
- Historical zonal hourly loads used to develop zonal hourly load shape

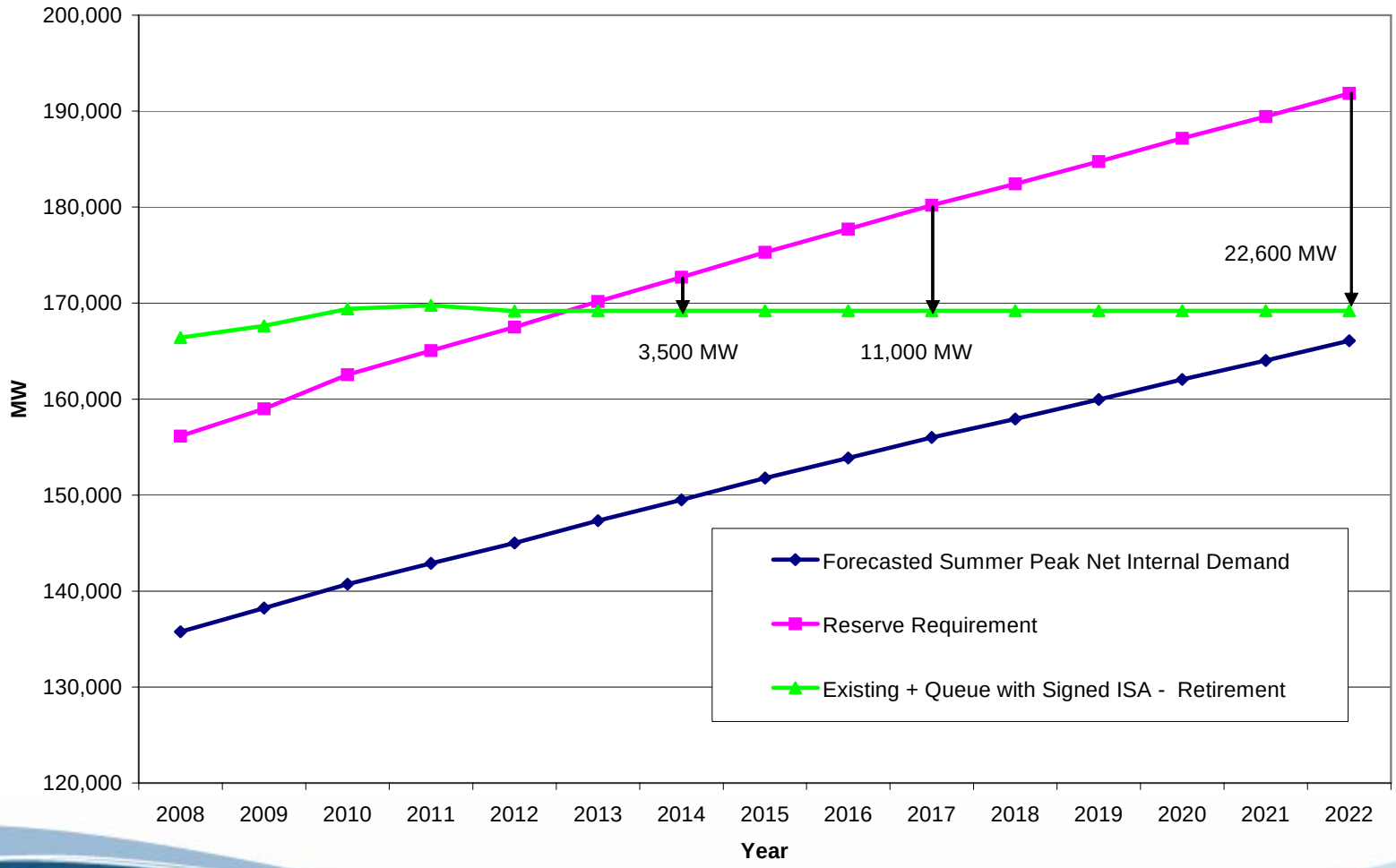
Table 1 - Forecast PJM Peak and Energy

	2008	2011	2014	2017	2022
Peak (MW)	137,948	145,061	151,675	158,176	168,258
Energy (GWh)	729,819	764,785	798,307	831,606	883,531

Future Generation Scenarios

- generation model includes all existing in-service generation plus active queue generation with executed ISA minus expected future deactivations
- installed reserve requirement is met through 2012
- To meet installed reserve requirement for study years 2014, 2017 and 2022, 3,500 MW, 11,000 MW and 22,600 MW of new generation will be added to model, respectively
- New generation will be added to PJM regions in proportion to the regional location and regional generation type of future generation projects in Generation Interconnection Queues through Queue T

Figure 2 - PJM Market Efficiency Reserve Margin



Future Generation Scenario

Table 2 - Location and Type of Generation Additions to Maintain Reserve Margin

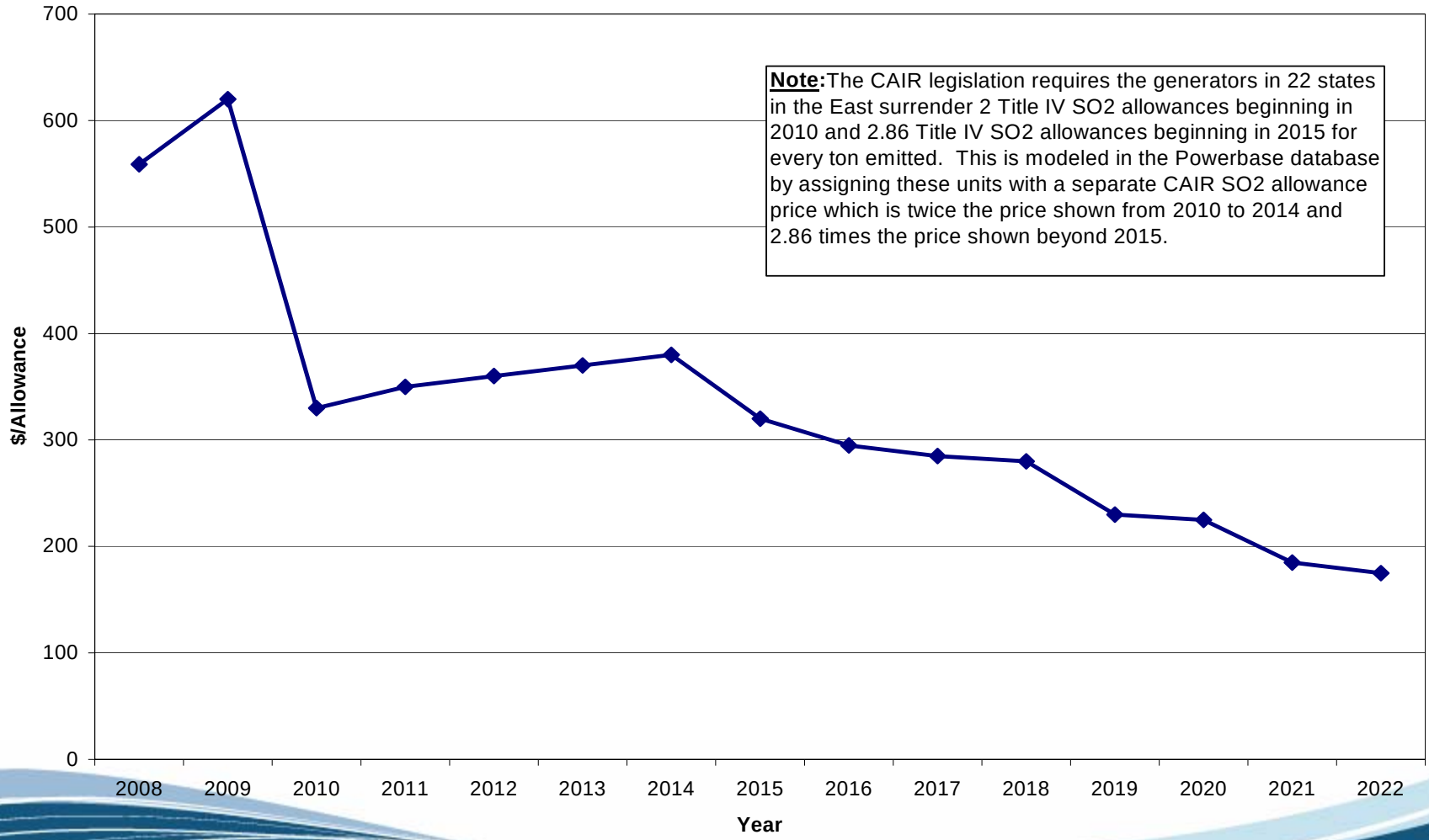
Region	Nuclear	Coal	Gas	Oil	Wind	Other Renewable	Total Region
AECO/DPL/JCPL/PECO/PSEG	0.3%	2.7%	20.6%	1.5%	1.2%	0.1%	**26.4%**
AEP/APS/COM/DAY/DUQ	0.6%	20.4%	6.3%	0.0%	12.0%	0.8%	**40.1%**
BGE/PEP	3.4%	0.0%	8.3%	0.0%	0.0%	0.0%	**11.6%**
DOM	4.0%	0.4%	4.6%	0.1%	0.0%	0.5%	**9.5%**
ME/PN/PPL	3.3%	4.5%	2.8%	0.0%	1.5%	0.4%	**12.4%**

Emissions Prices

- Powerbase emissions allowance prices from variety of sources including Platt's BASECASE, Evomarkets.com, and EPA studies
- Powerbase emissions release rates from a variety of sources including Platt's BASECASE, EPA CEMS data and EPA studies
- Powerbase includes emission release rates but no prices for CO2
- CO2 assumption will be for national program by study year 2011 with allowance prices based on Synapse study

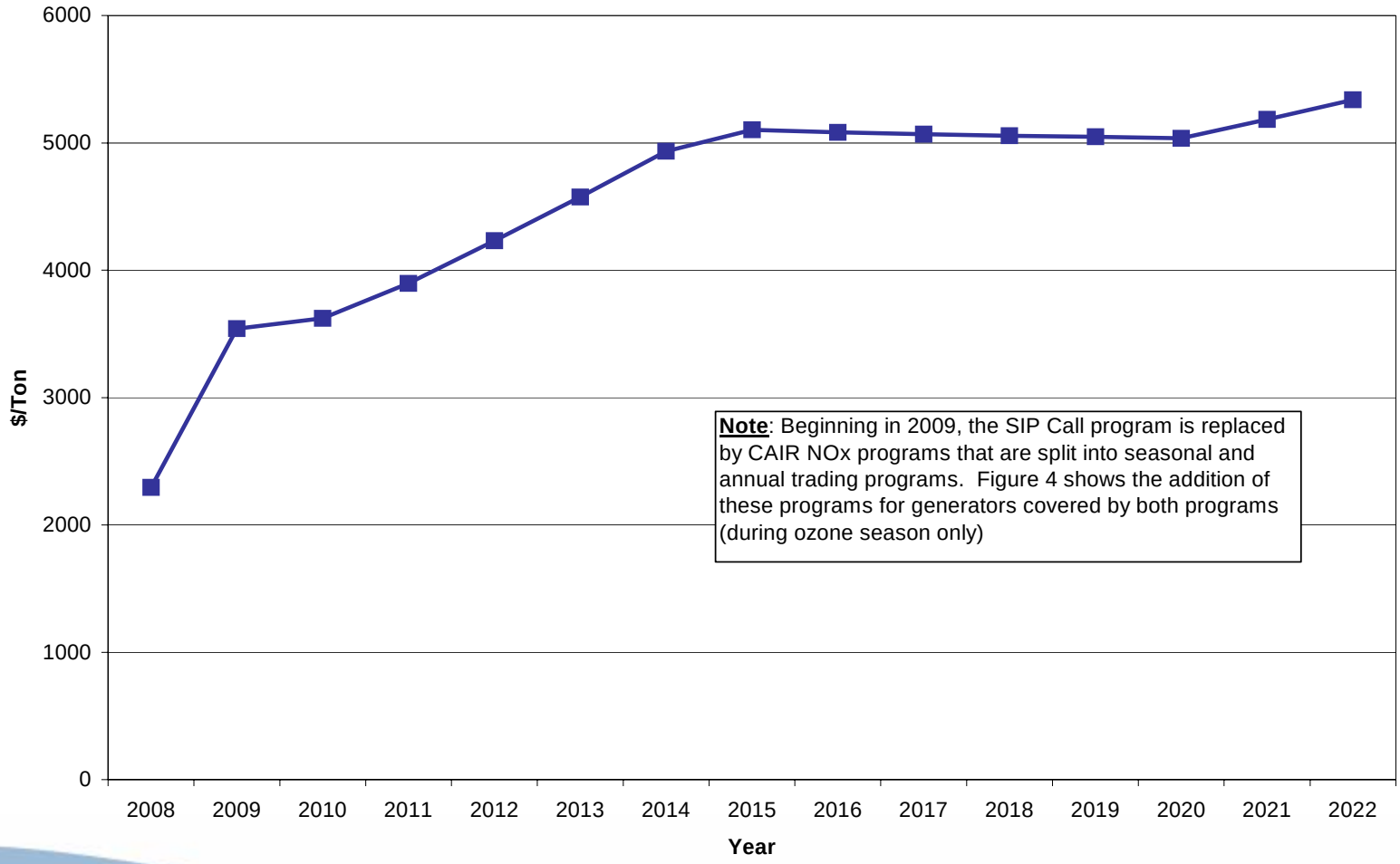
SO2 Emission Prices

Figure 3 - SO2 Emission Allowance Price Assumptions



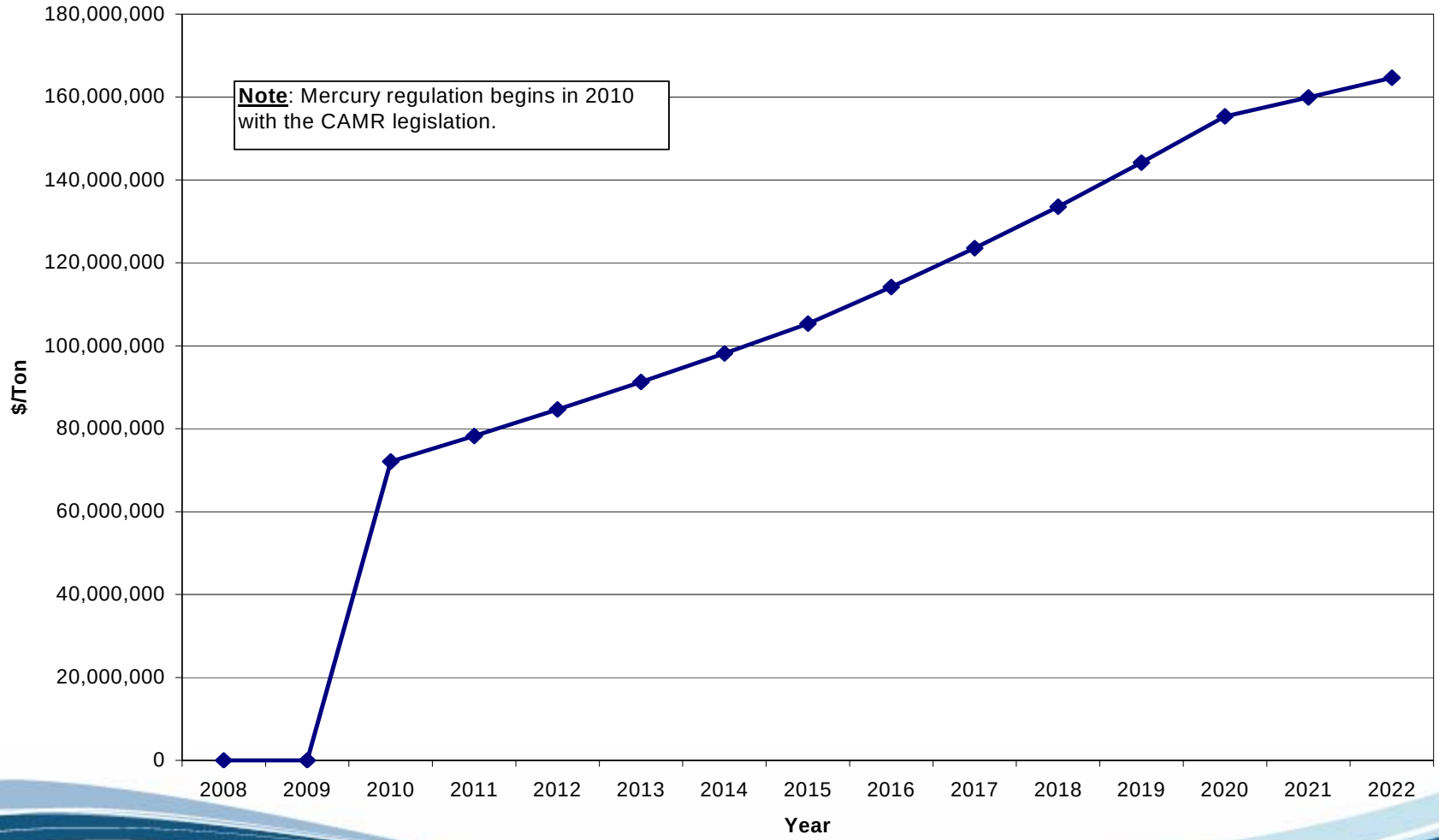
NOx Emission Prices

Figure 4 - NOx Emission Price Assumptions



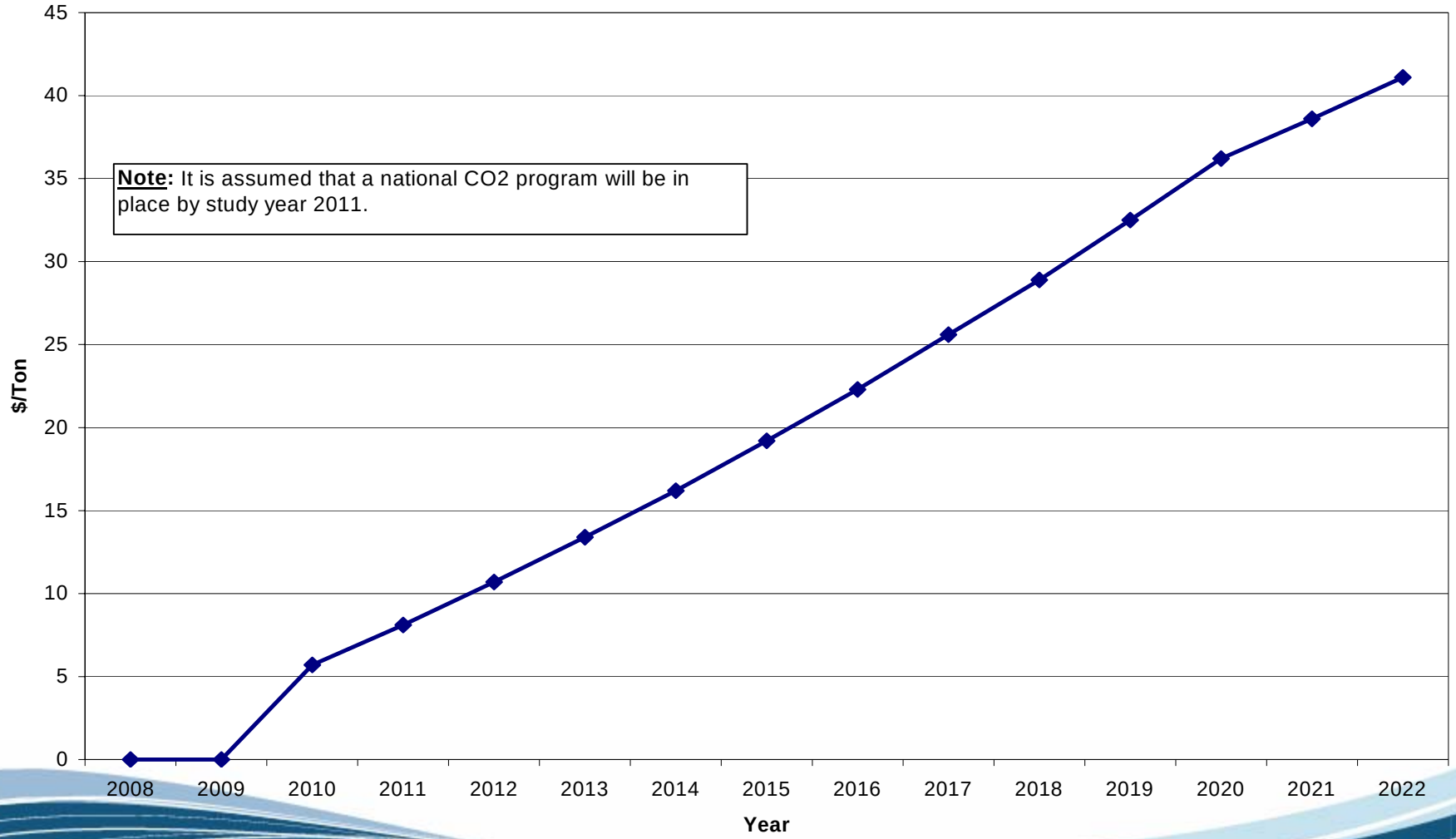
Hg Emissions Prices

Figure 5 - Mercury Price Assumptions



CO2 Emissions Prices

Figure 6 - CO2 Emission Assumptions



Transmission Topology and Constraints

- Powerflow Cases
  - 2008 power flow case to represent today's "as-is" system
  - 2012 RTEP power flow case to represent future system
- Thermal Constraints
  - monitor/contingency pairs
  - NERC Book of Flowgates
  - Historical PJM congestion events
- Voltage Constraints
  - PJM reactive interface limits
  - MW limits based on historical values for "as-is" case adjusted for future upgrade impacts in 2012 case

Discount Rate & Revenue Requirement

Discount Rate

- Federal Office of Management and Budget guidance is to use 7% rate with sensitivity analysis at 5% and 9%
- Bright line test dictates use of a single value with no sensitivity analysis
- Discount rate of 9% recommended for cost-benefit analysis conducted as part of 2008 market efficiency analysis

Revenue Requirement

- Use recently approved filings to develop a revenue requirement to project cost ratio to apply to study projects

RPM Benefits

- 2010/2011 RPM results show a single clearing price across majority of RTO footprint
- future major RTEP upgrades should cause this trend to continue
- Recommended that RPM-related benefits of study upgrades not be calculated in 2008 market efficiency analysis