Transmission Planning and Delivery in PJM:
Process, Market Drivers and Trends

International Experience in Transmission Planning and Delivery
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London, UK

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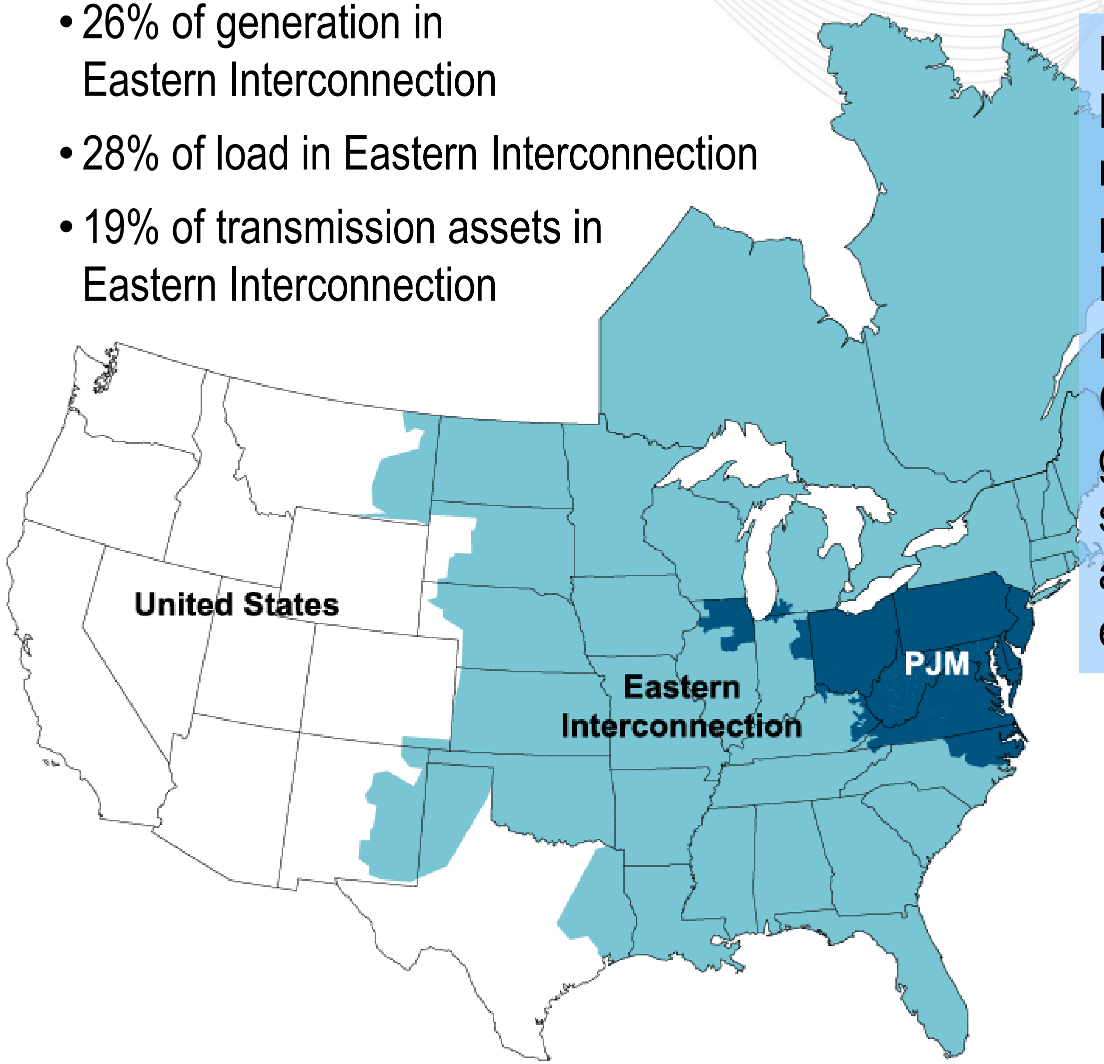
PJM Interconnection

PJM Broad Overview

PJM as Part of the Eastern Interconnection

- 26% of generation in Eastern Interconnection
- 28% of load in Eastern Interconnection
- 19% of transmission assets in Eastern Interconnection



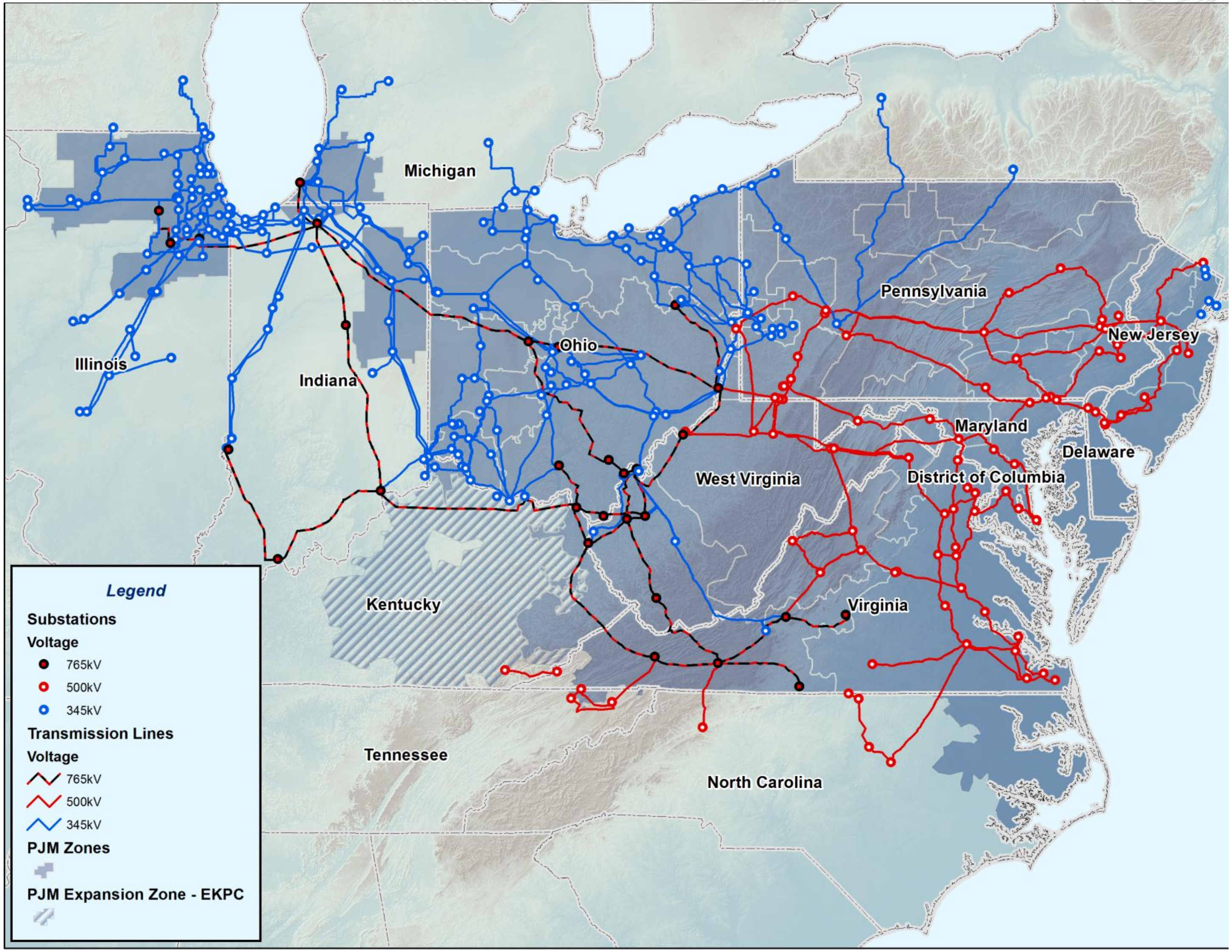
KEY STATISTICS	
PJM member companies	800+
millions of people served	60
peak load in megawatts	163,848
MWs of generating capacity	185,600
miles of transmission lines	59,750
GWh of annual energy	832,331
generation sources	1,365
square miles of territory	214,000
area served	13 states + DC
externally facing tie lines	142

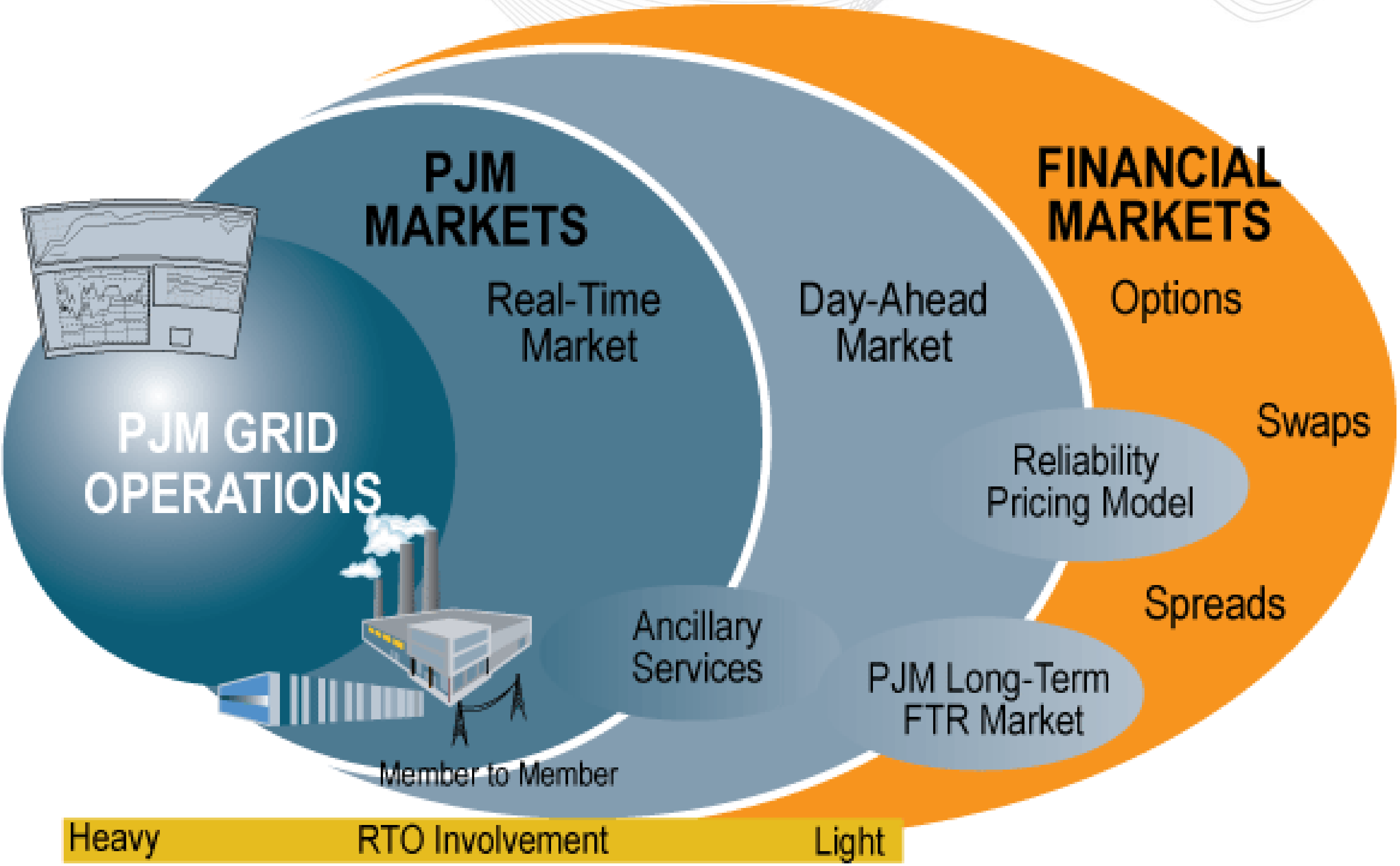
21% of U.S. GDP produced in PJM

As of 9/7/2012

PJM – Focus on Just 3 Things

PJM Backbone Transmission System

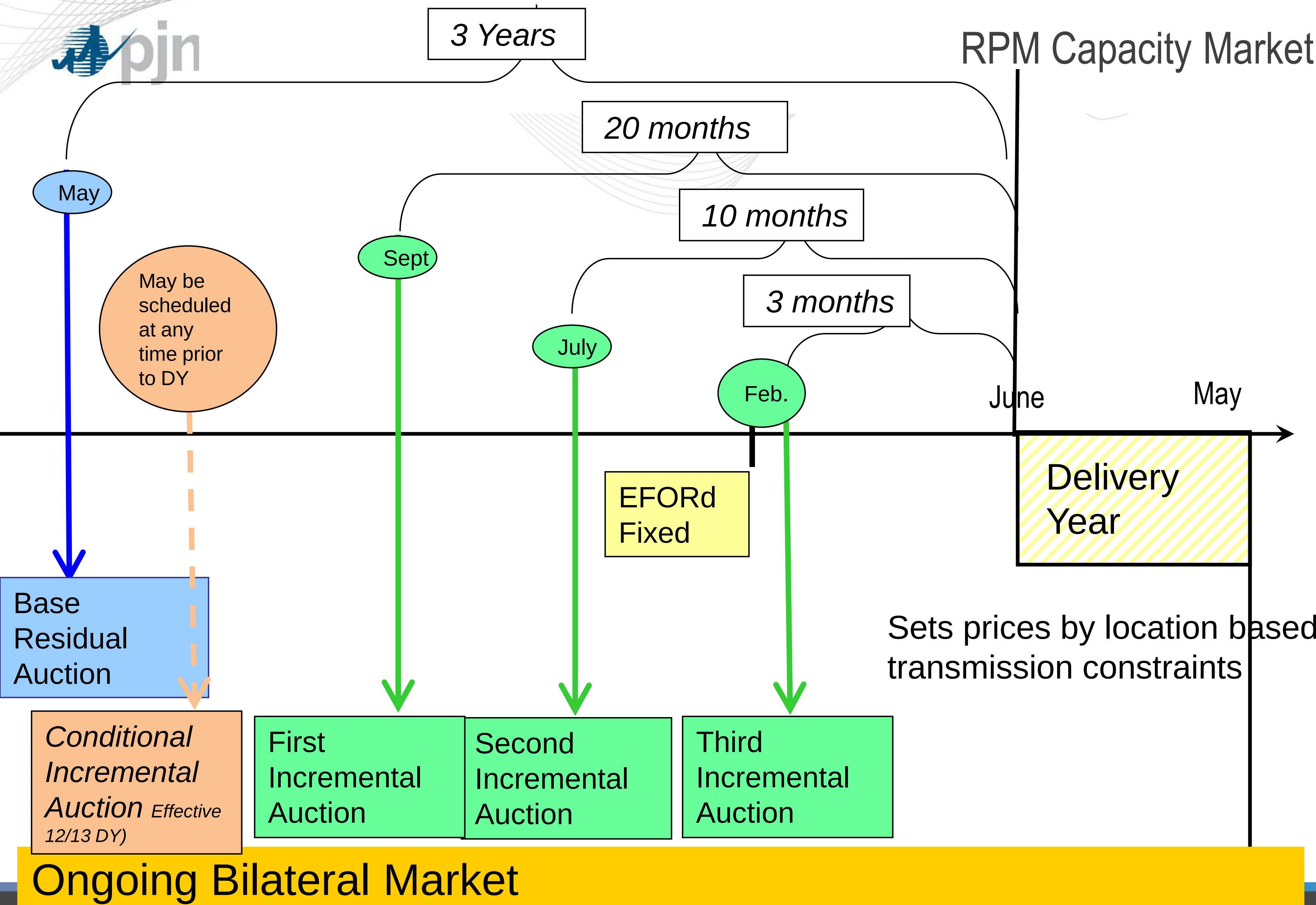



PJM MARKETS
Real-Time Market
Day-Ahead Market
FINANCIAL MARKETS
Options
Swaps
Spreads
Reliability Pricing Model
PJM GRID OPERATIONS
Ancillary Services
PJM Long-Term FTR Market
Member to Member
Heavy
RTO Involvement
Light

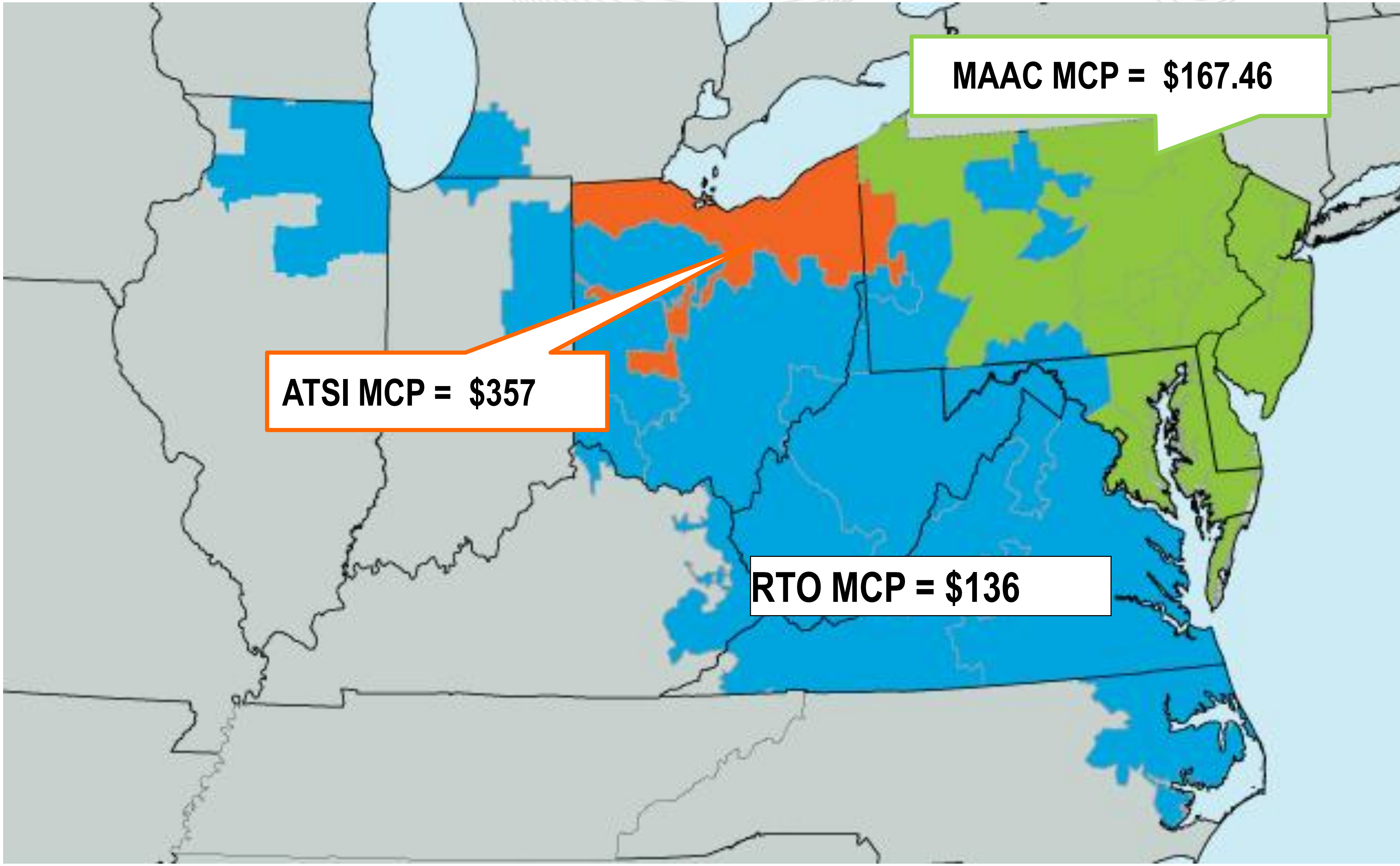
Locational Marginal Pricing (aka LMP or Nodal pricing)

- Pricing method PJM uses to:
  - price energy purchases and sales in PJM Market
  - price transmission congestion costs to move energy within PJM RTO
  - price losses on the bulk power system
- Physical, flow-based pricing system:
  - how energy actually flows, NOT contract paths
  - Marginal cost of delivering one more MW to any location on the system

RPM Capacity Market

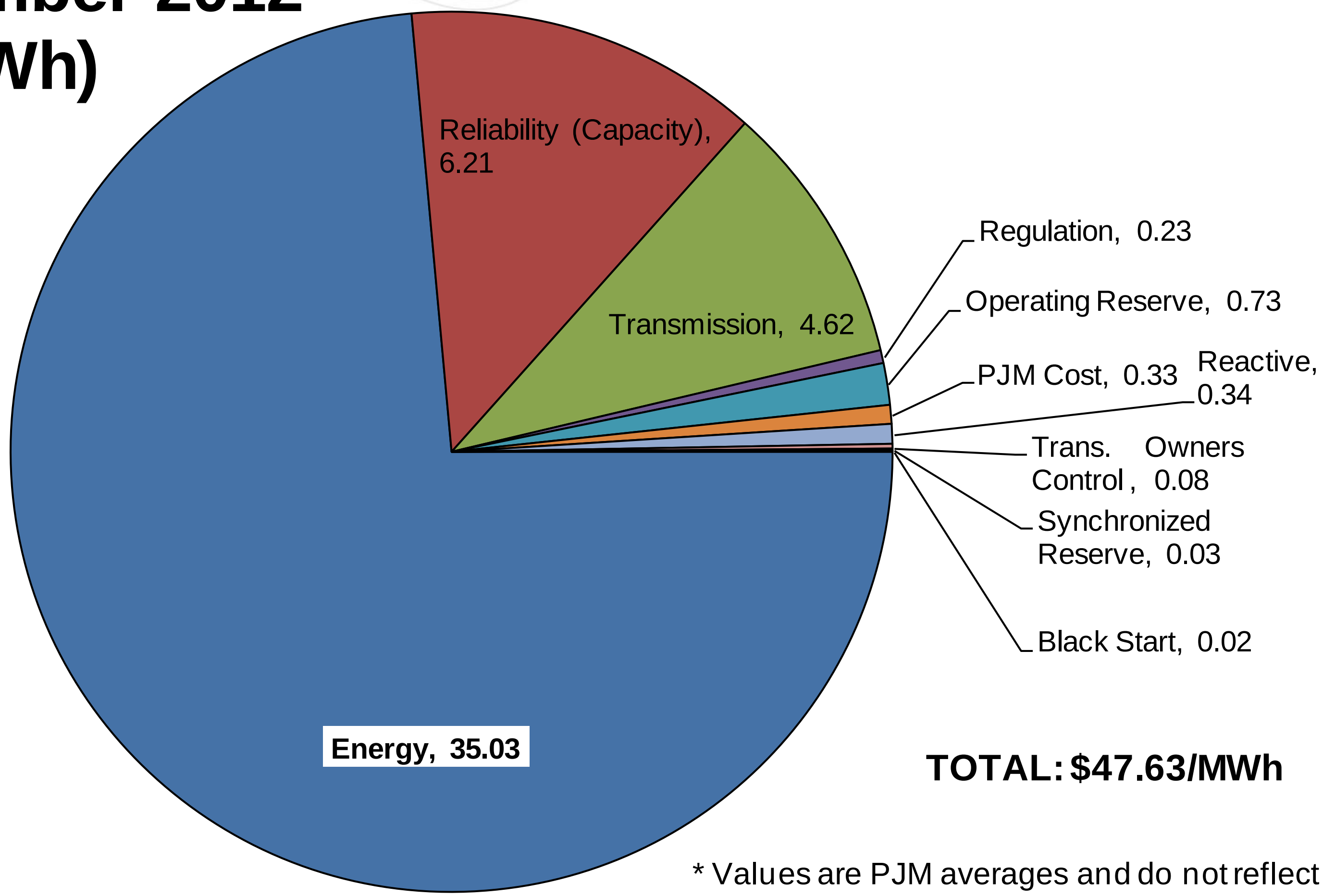


2015/2016 Base Residual Auction Clearing Prices ($/MW-Day)



Putting the Cost of Reliability Services in Perspective

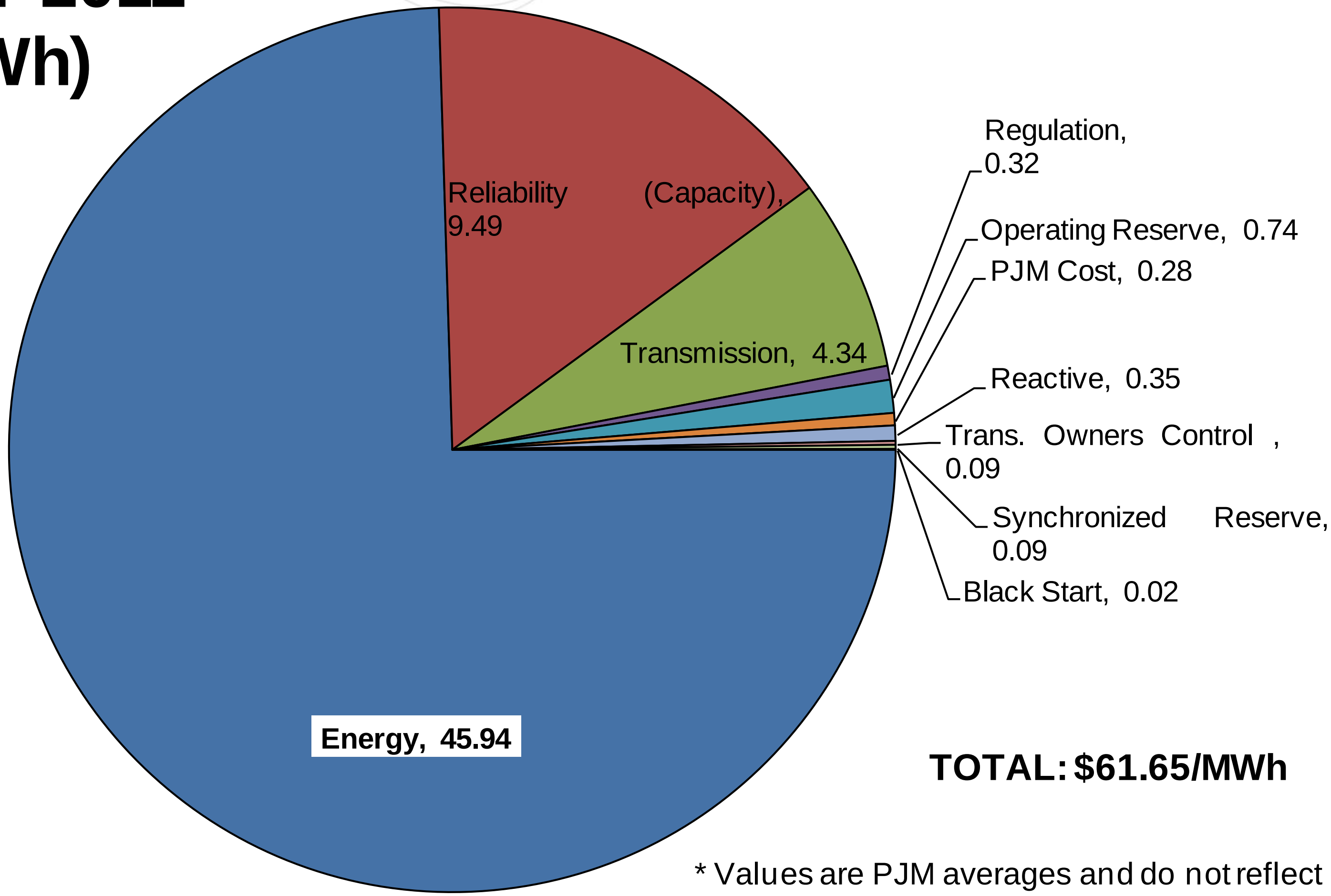
PJM Wholesale Cost YTD September 2012 ($/MWh)



TOTAL: $47.63/MWh

* Values are PJM averages and do not reflect potential locational cost differences.

PJM Wholesale Cost Full-Year 2011 ($/MWh)



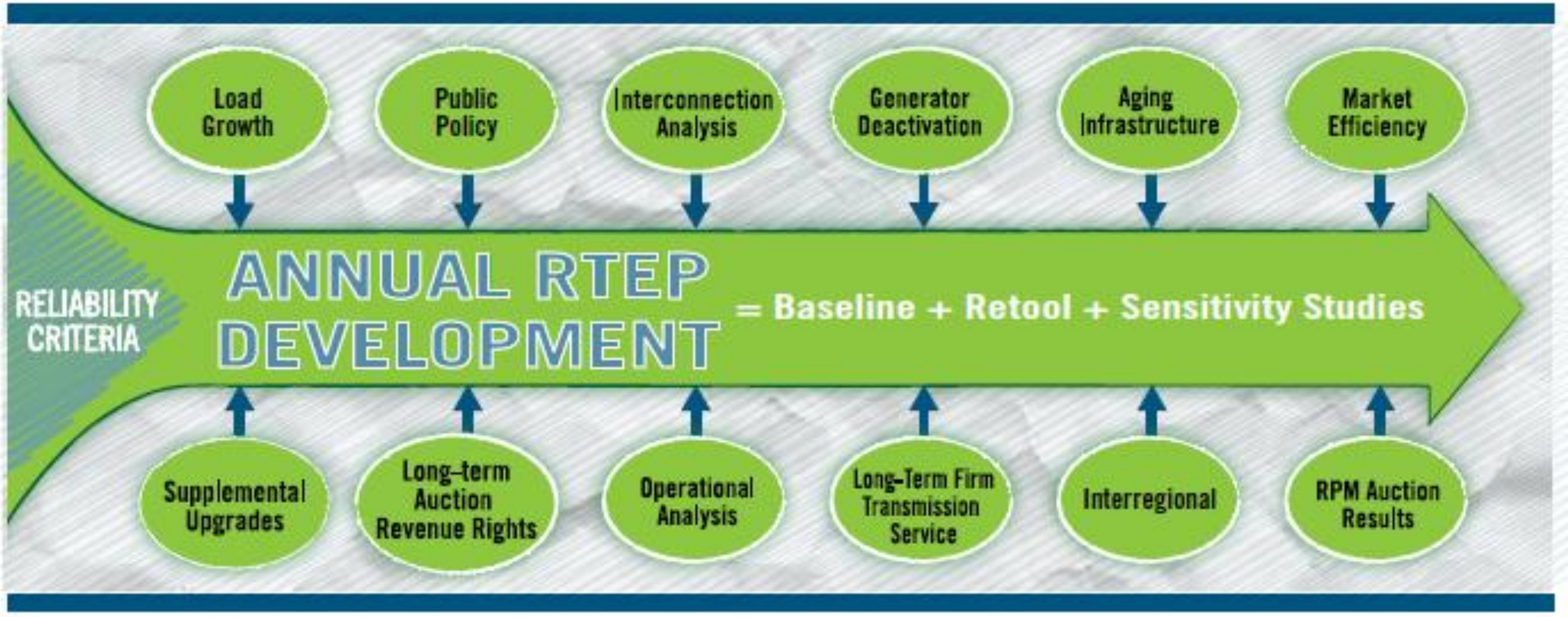
TOTAL: $61.65/MWh

* Values are PJM averages and do not reflect potential locational cost differences.

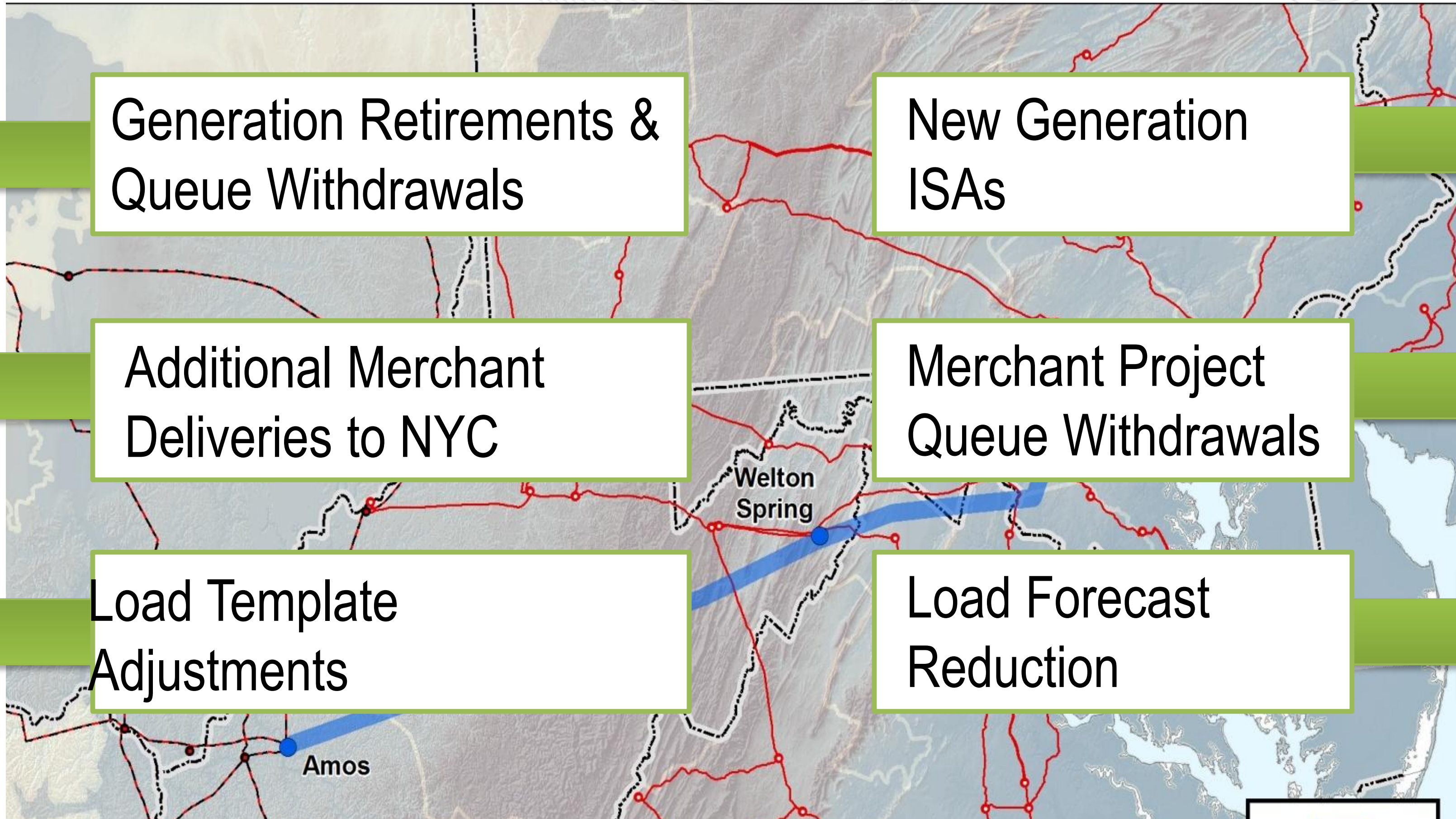
Region Transmission Expansion Planning (RTEP) Process

PJM Regional Transmission Expansion Planning (RTEP)

- Ongoing and cyclical
- 15 year planning horizon
- Comprehensive and Holistic
- Collaborative
- NERC, RFC, PJM compliance
- FERC-approved



Factors Impacting Timing Of Need



- Generation Retirements & Queue Withdrawals
- Additional Merchant Deliveries to NYC
- Load Template Adjustments

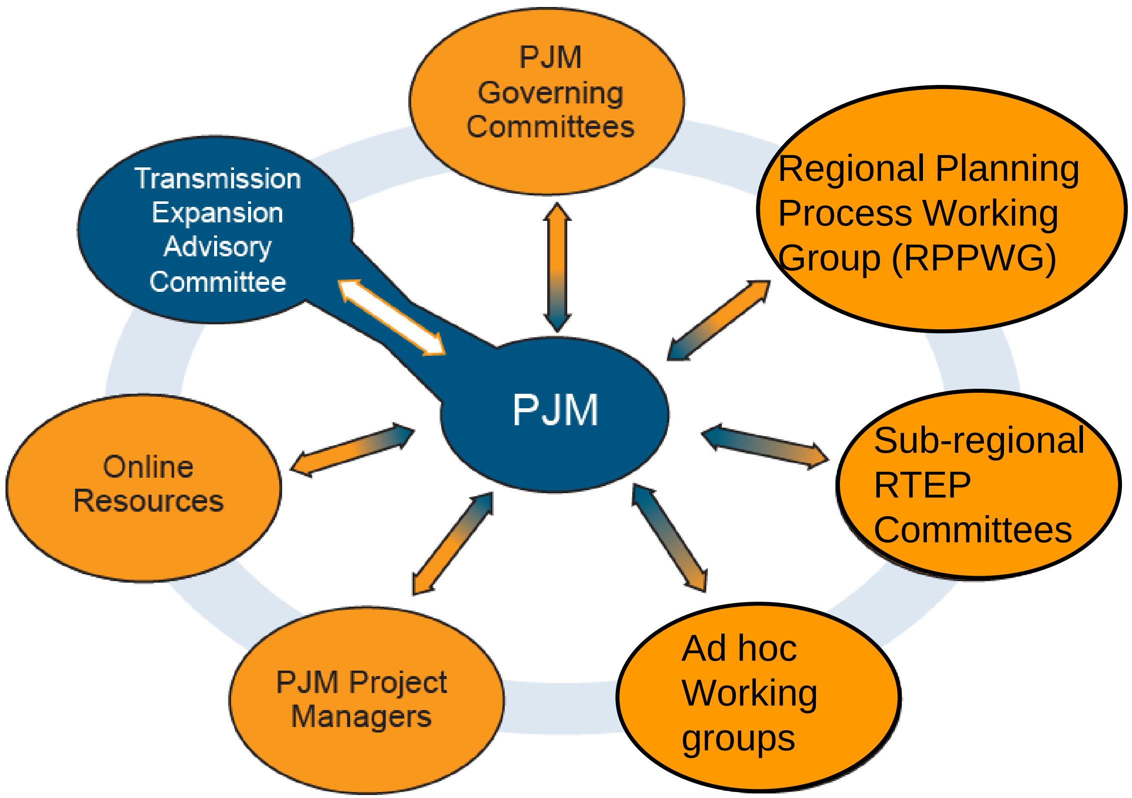
- New Generation ISAs
- Merchant Project Queue Withdrawals
- Load Forecast Reduction

2012 2013 2014 2015 2016 2017 2018 2019 2020

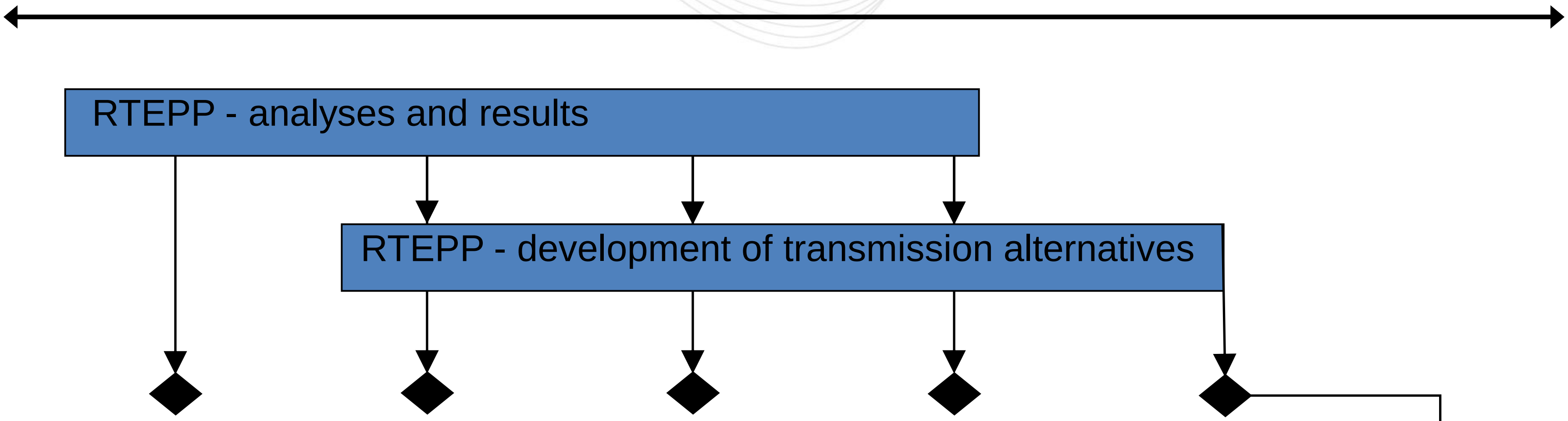
RTEP - Stakeholder Participation

- Open
- Transparent
- Collaborative

- Topics…process, plans, FERC compliance, implementation issues…etc



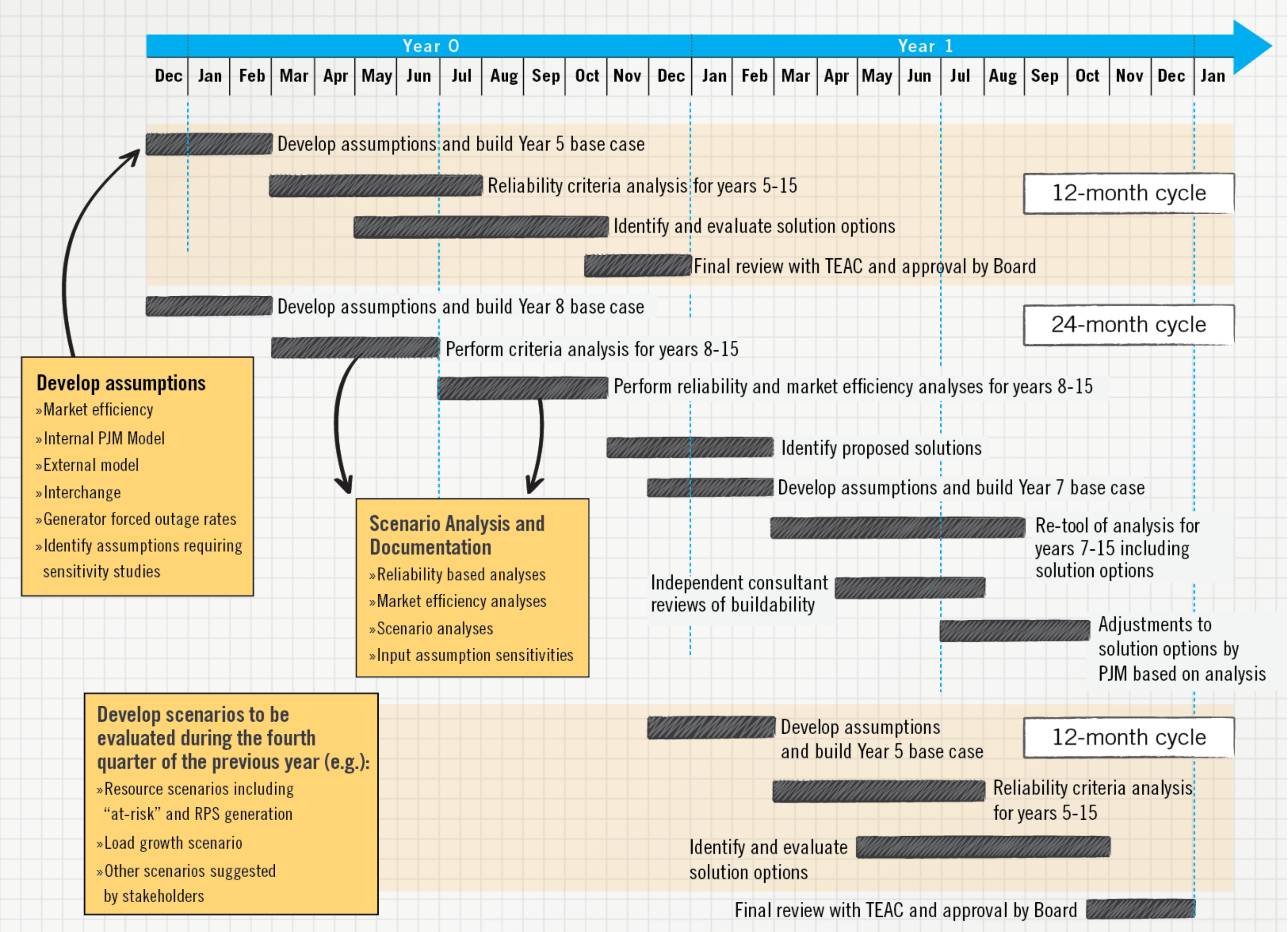
Conceptual Time Line



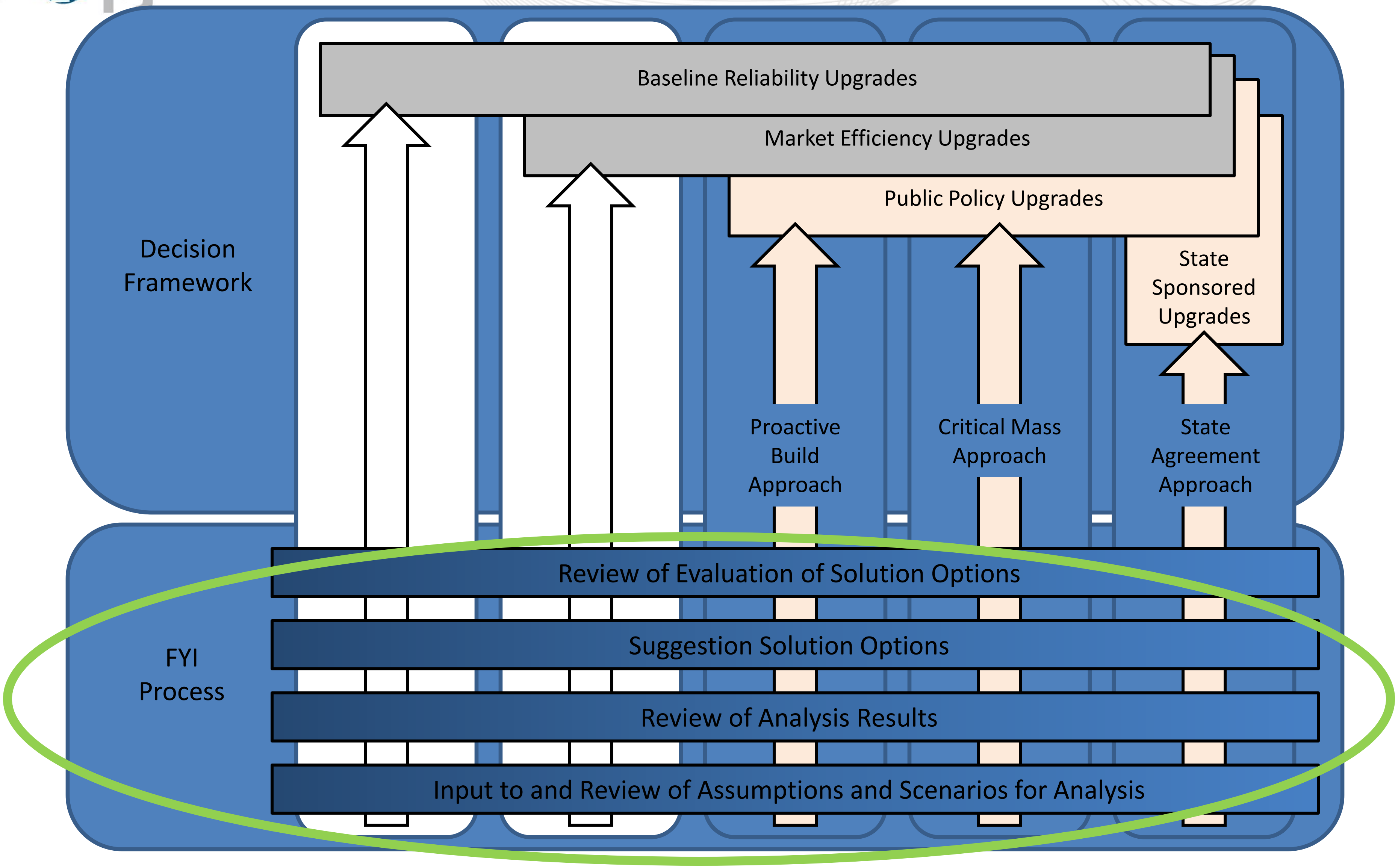
TEAC – Meeting presentations; review and provide comment and recommendations on results and proposed alternatives…BUT… TEAC does not approve transmission plans.

Board of Managers – Reviews and approves system enhancements proposed by PJM. If approved, thereafter formally part of RTEP. (15-year reliability planning and endorsement for further market efficiency studies.)

24 Month Planning Cycle



FYI Process—Scenario Planning



NERC Transmission Planning Reliability Standards… Driver of Baseline Expansion

A No Contingencies	All Facilities in Service
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault
	Single Pole Block, Normal Clearing[e]: 4. Single Pole (dc) Line
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[e]: 1. Bus Section 2. Breaker (failure or internal Fault)
	SLG or 3Ø Fault, with Normal Clearing[e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency
	Bipolar Block, with Normal Clearing[e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[e]: 5. Any two circuits of a multiple circuit towerline[f]
	SLG Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section

D[d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service.	3Ø Fault, with Delayed Clearing[e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section
	3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault)
	6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.

Adopted by NERC Board of Trustees: February 8, 2005
Effective Date: April 1, 2005

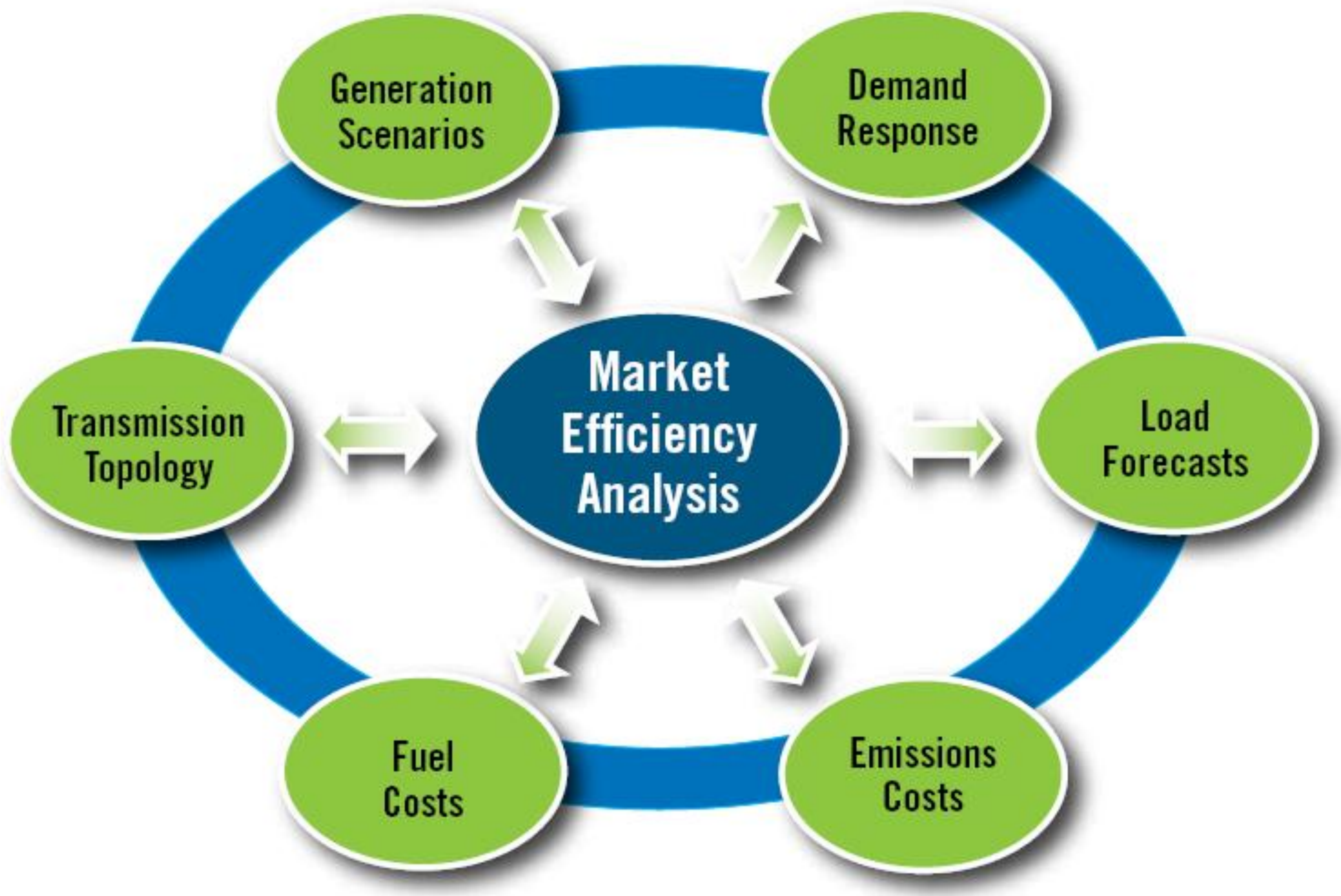
Terminology…

- **Category A = "n" = Standard TPL-001**
- **Category B = "n-1" = Standard TPL-002**
- **Category C = "n-1-1", "n-2" = Standard TPL-003**
- **Category D = "Extreme Events" = Standard TPL-004**

PJM Applied Analysis	Baseline	Feasibility Study	System Impact Study
Normal system / as-is, all facilities in service	Yes	Yes	Yes
System contingency analyses – single and multiple facility outages	Yes	Yes (limited set historically, moving forward all)	Yes
CETO/CETL load deliverability analyses	Yes	No	Generation = No Merch Xmiss = Yes
Generation deliverability	Yes	No	Generation = Yes Merch Xmiss = Yes
Short Circuit Analysis	Yes	Limited	Yes
Stability Analysis	Yes	No	Yes
"But for" cost allocation analysis	Yes	No	Yes

- Generation or Merchant Transmission Interconnection and Generator Deactivation
  - Market driven…based on market opportunity
  - Attachment Facilities are allocated to developer
  - Network Upgrades based on deliverability tests based on cost causality or impacts on the limiting facility
- Baseline Upgrades at 500 kV or above
  - Zonal peak-load ratio share of system peak
  - Merchant transmission allocated costs based on transmission withdrawal rights in their ISA
- Baseline Upgrades below 500 kV
  - $5 million and less allocated to the zone in which the upgrade is located
  - Over $5 million allocated based on zonal or merchant transmission DFAX (flow based) impact on the constrained facility…what is causing the need for the upgrade…proposed to be changed based on usage

Market Efficiency Analysis: Expediting Reliability Projects or Projects for Economics Alone

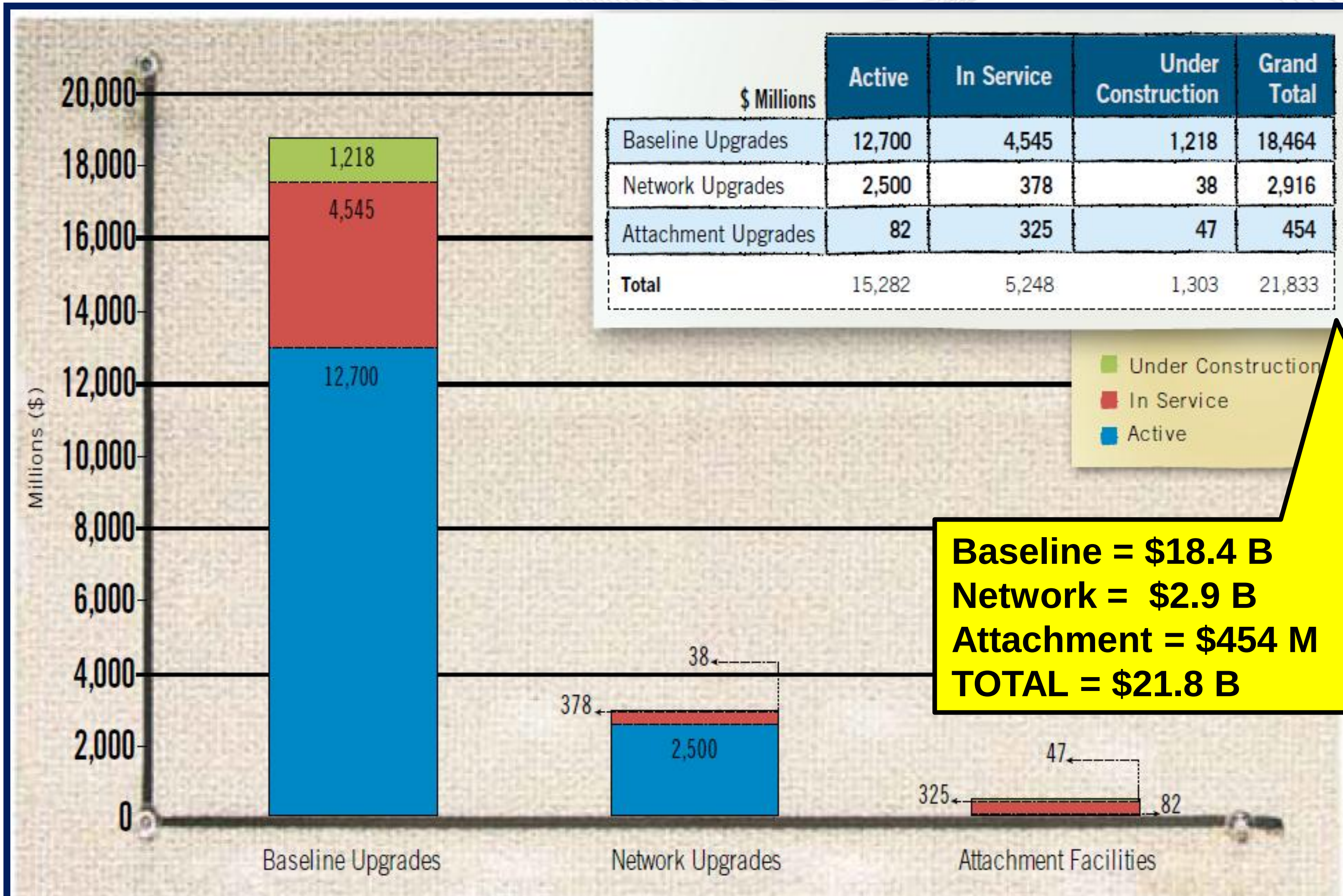


- Must have a benefit-cost ratio of 1.25 to 1
- Costs
  - PV of total upgrade cost over 15 years based on estimated annual revenue requirement
- Energy and Capacity Market Benefits (15 year PV)
  - Changes in total production costs (70%)
  - Changes in total load energy and capacity payments (30%)
    - For 500 kV and above this would be all zones
    - For below 500 kV this would be only for zones that realize a decrease in payments

PJM Cost Allocation: Economic Upgrades

- Baseline Upgrades at 500 kV or above
  - Same reliability upgrades
  - Zonal peak-load ratio share of system peak
  - Merchant transmission allocated costs based on transmission withdrawal rights in their ISA
- Modifications to Baseline Upgrades below 500 kV
  - Same as reliability upgrades
- Acceleration of Baseline Upgrades below 500 kV
  - Compare allocation factors based on:
    1. DFAX impact on constraint relieved;
    2. LMP benefit over acceleration period, per LSE load payments;
  - If differential ≥ 10%, use relative LMP benefit; otherwise, use DFAX methodology
- Economic Only Upgrades below 500 kV
  - Pro rata share of reduction in load energy payments only to zones with reduced load payments

Value of Approved Upgrades Since 2000



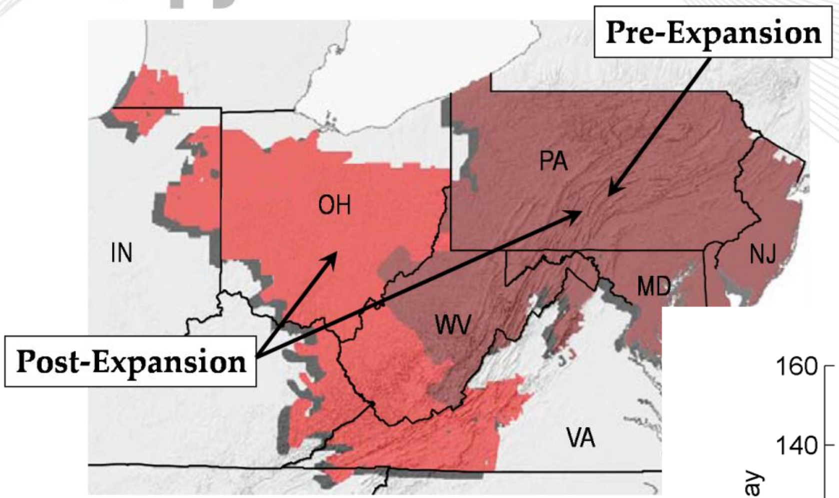
$ Millions	Active	In Service	Under Construction	Grand Total
Baseline Upgrades	12,700	4,545	1,218	18,464
Network Upgrades	2,500	378	38	2,916
Attachment Upgrades	82	325	47	454
Total	15,282	5,248	1,303	21,833

Baseline = $18.4 B
Network = $2.9 B
Attachment = $454 M
TOTAL = $21.8 B [8/31/12]

*** As of 12/31/2011**

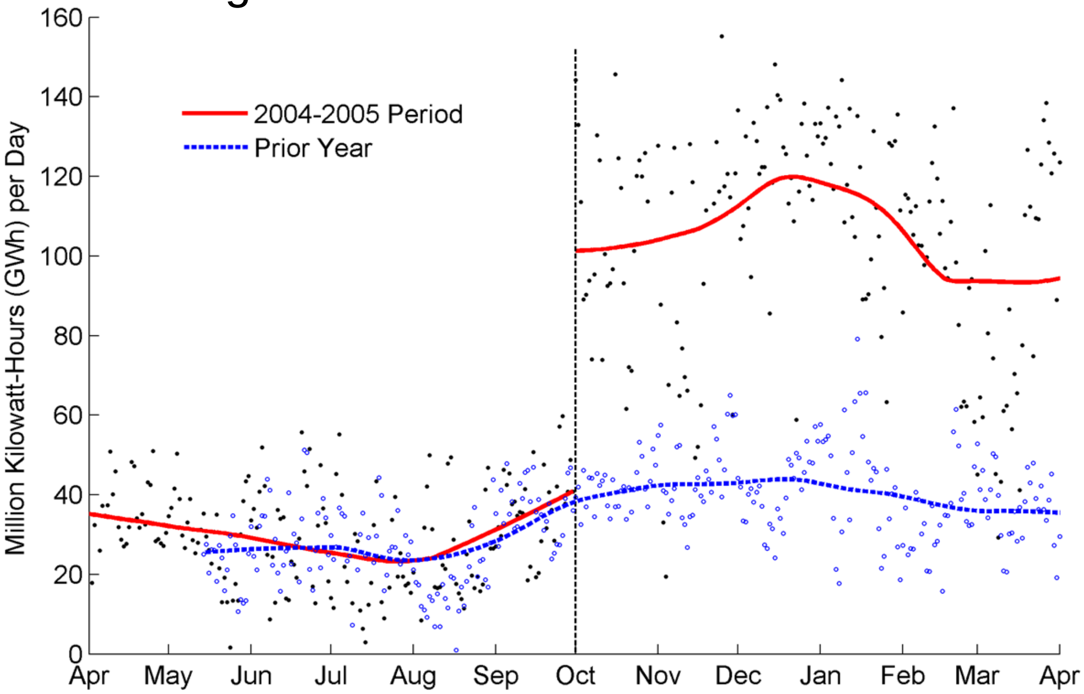
Efficiency Gains through Expanding the RTO

PJM Market Expansion – A Case Study



AEP / Dayton / Commonwealth Edison Integration into the PJM Market

Change in Transmission Interconnector flows



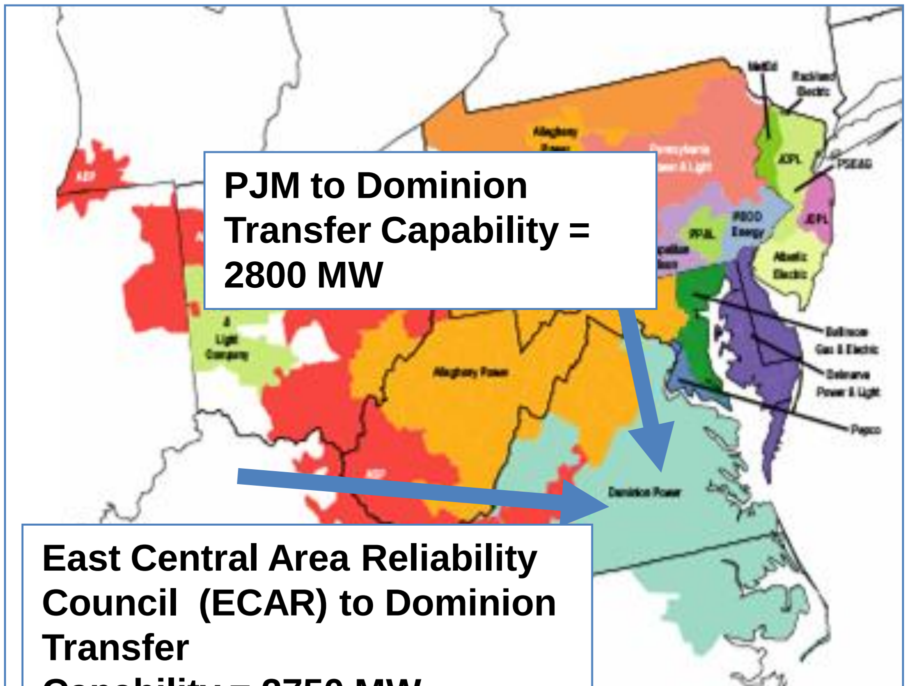
Key Study Conclusions:

- Bilateral Trading could only achieve 40% of the efficiency gains of LMP-based market
- Incremental benefit of LMP Market Integration = $180 Million annually, Net Present Value over 20 yrs is $1.5 Billion

Referenced with Permission: Source: Erin T. Mansur and Matthew W. White, “Market Organization and Efficiency in Electricity Markets,” March 31, 2009, Figure 2,pg 50, discussion draft.

Dominion Integration Benefit: Increased Transfer Capability

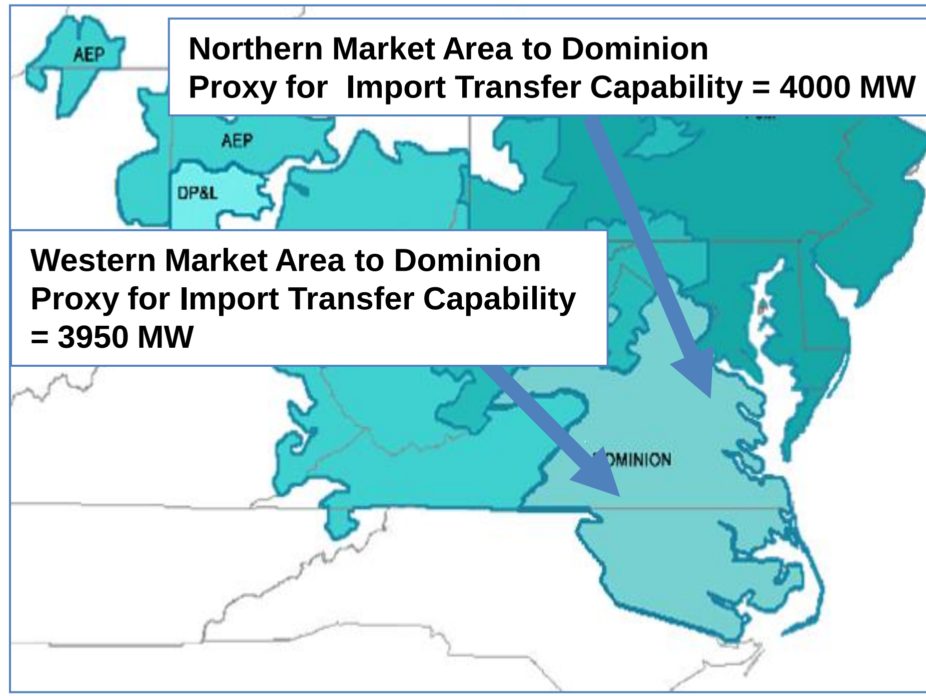
Prior to Integration



PJM to Dominion Transfer Capability = 2800 MW

East Central Area Reliability Council (ECAR) to Dominion Transfer Capability = 2750 MW

After Integration

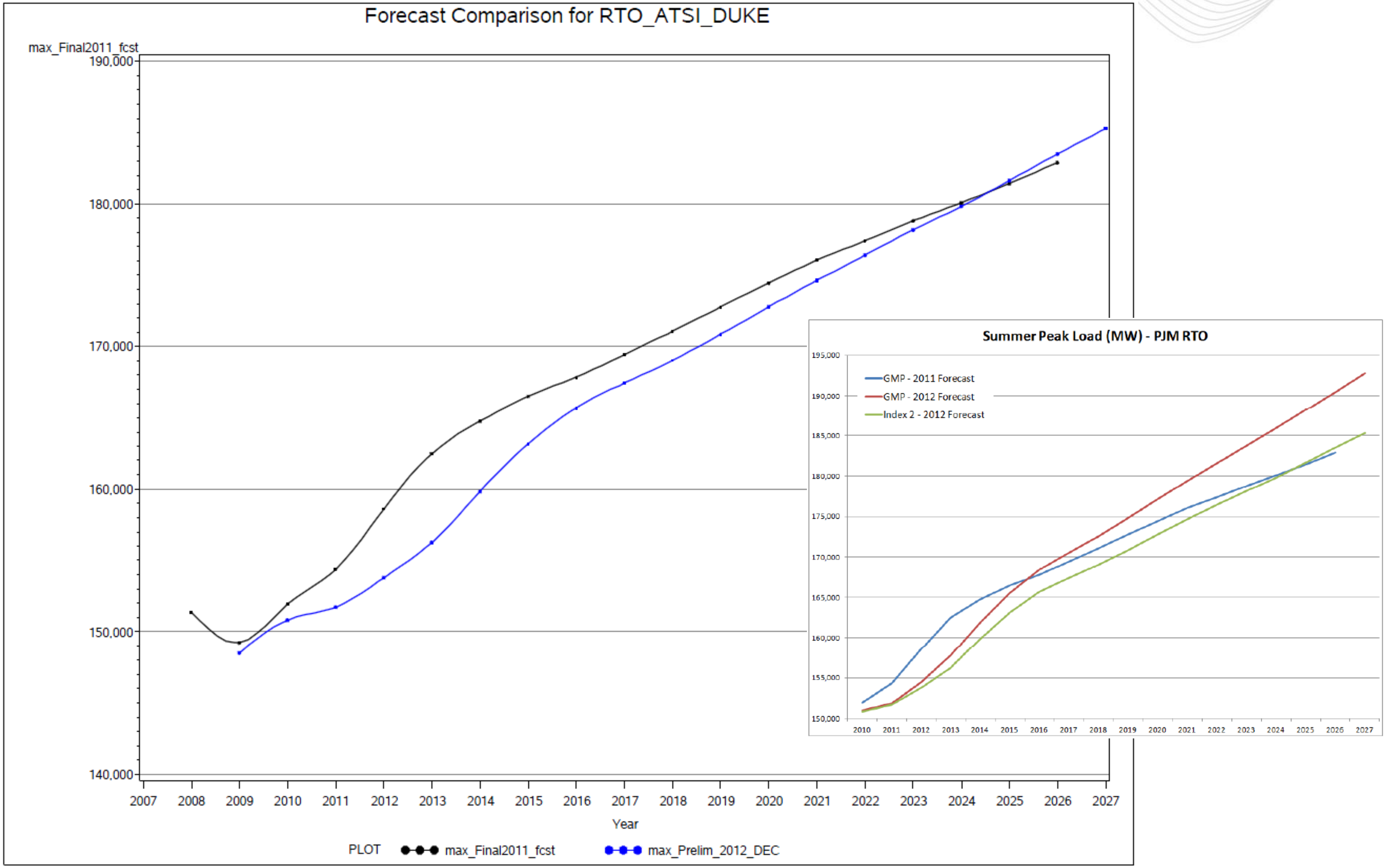


Northern Market Area to Dominion Proxy for Import Transfer Capability = 4000 MW

Western Market Area to Dominion Proxy for Import Transfer Capability = 3950 MW

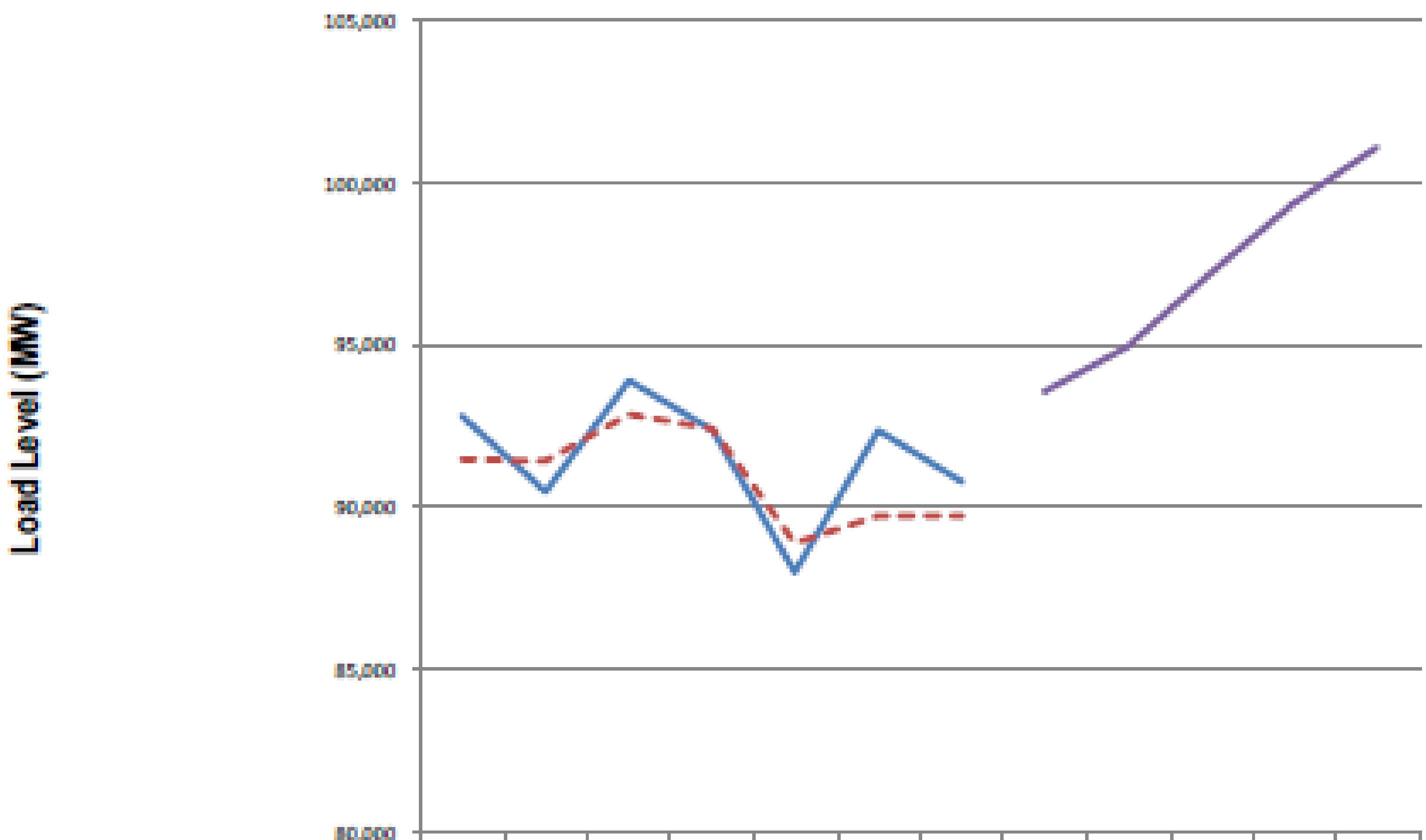
Recent Market and Policy Drivers Affecting Transmission Expansion

2012 Load Forecast Report—Declining Forecasts



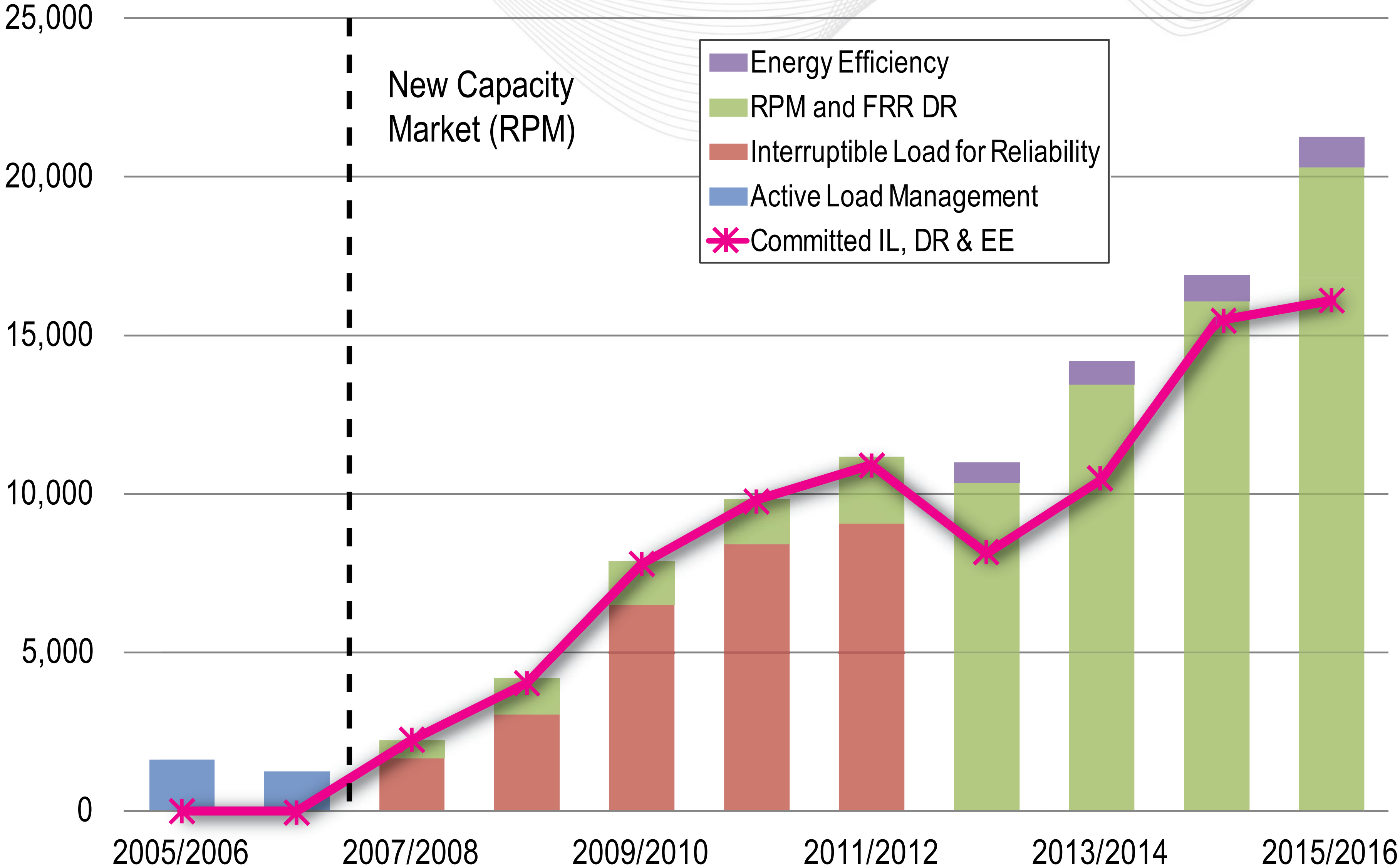
Total Energy Not Bouncing Back with Recovery

PJM (w/ ATSI and DEOK) Average Hourly Loads 2005-2016

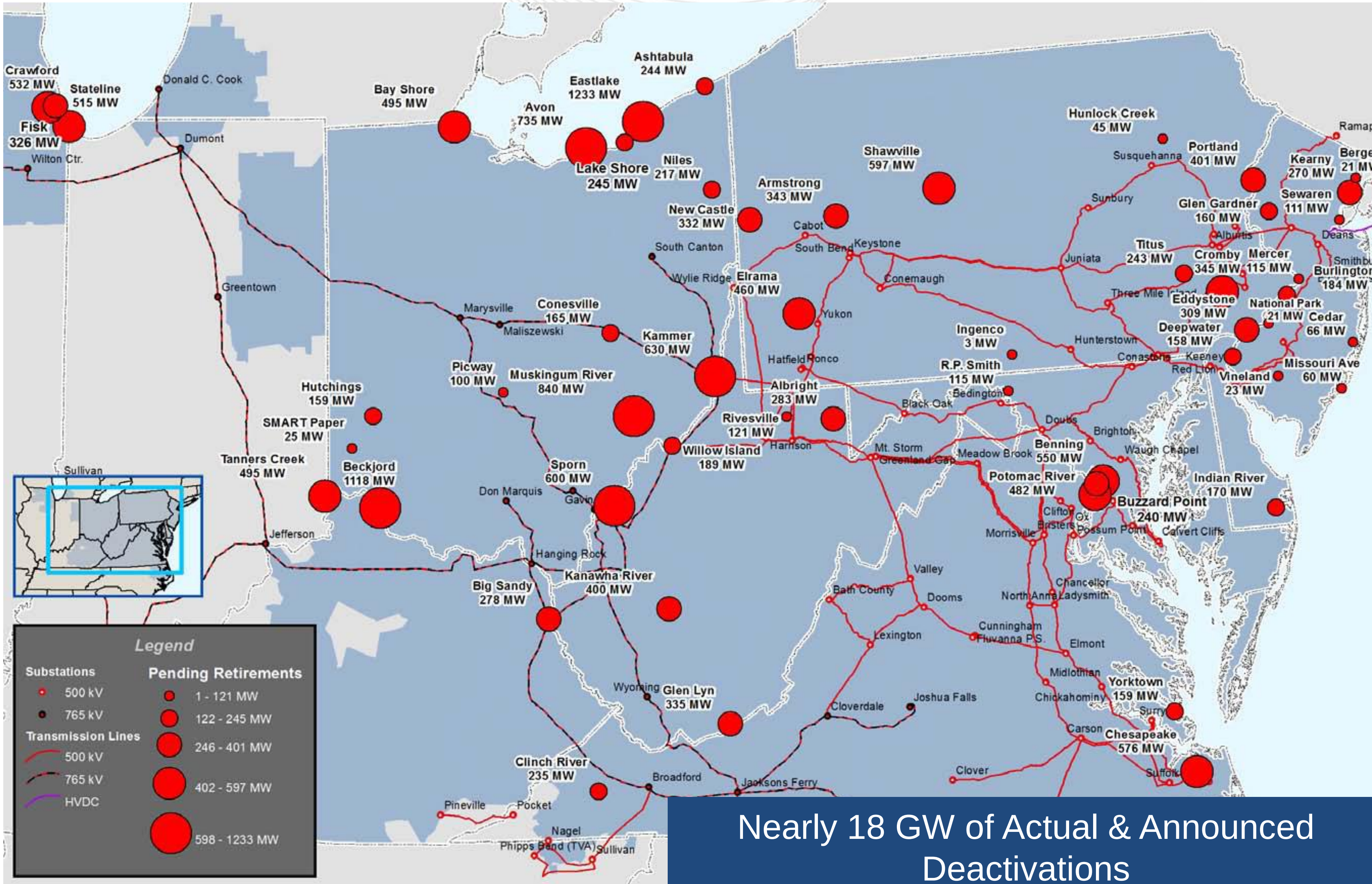


	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Actual Average Hourly Load	92,803	90,500	93,918	92,362	87,987	92,349	90,796					
Weather Normalized Avg. Hourly Load	91,470	91,386	92,841	92,396	88,893	89,725	89,745					
2012 Forecast Average Hourly Load								93,555	94,966	97,229	99,388	101,104

Encouraging Demand Resources

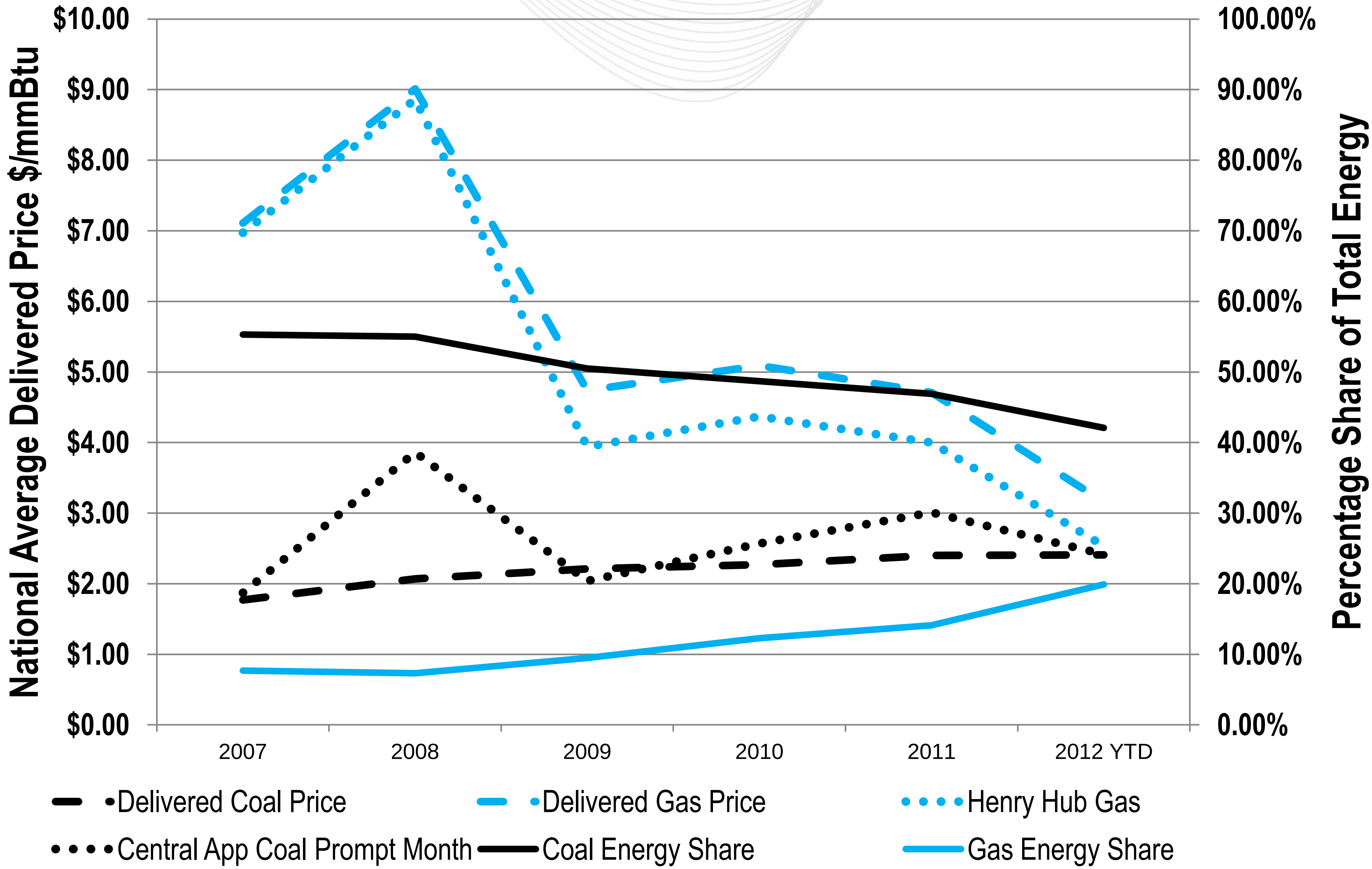


Generation Resource Retirement Status

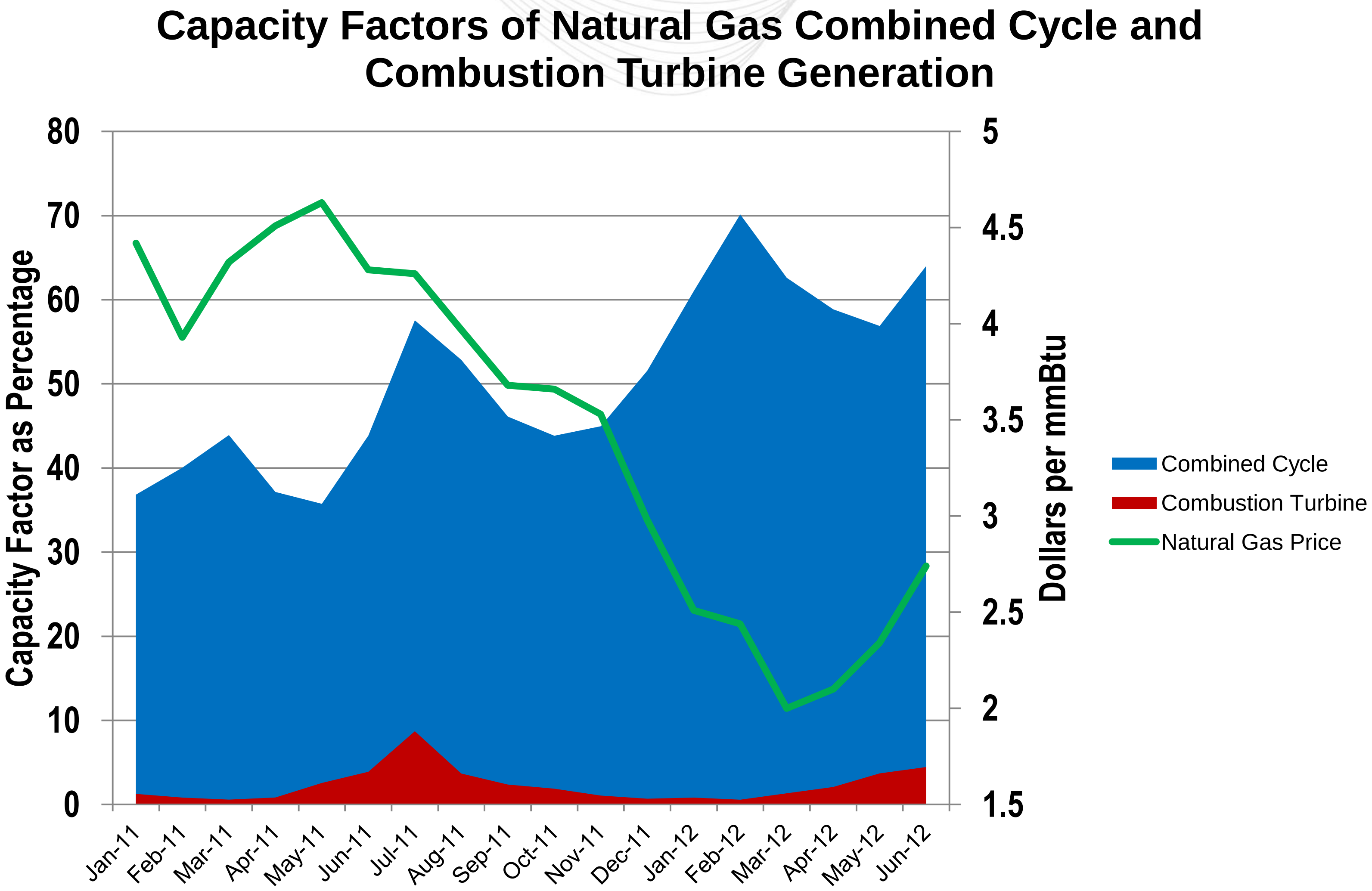


Nearly 18 GW of Actual & Announced Deactivations

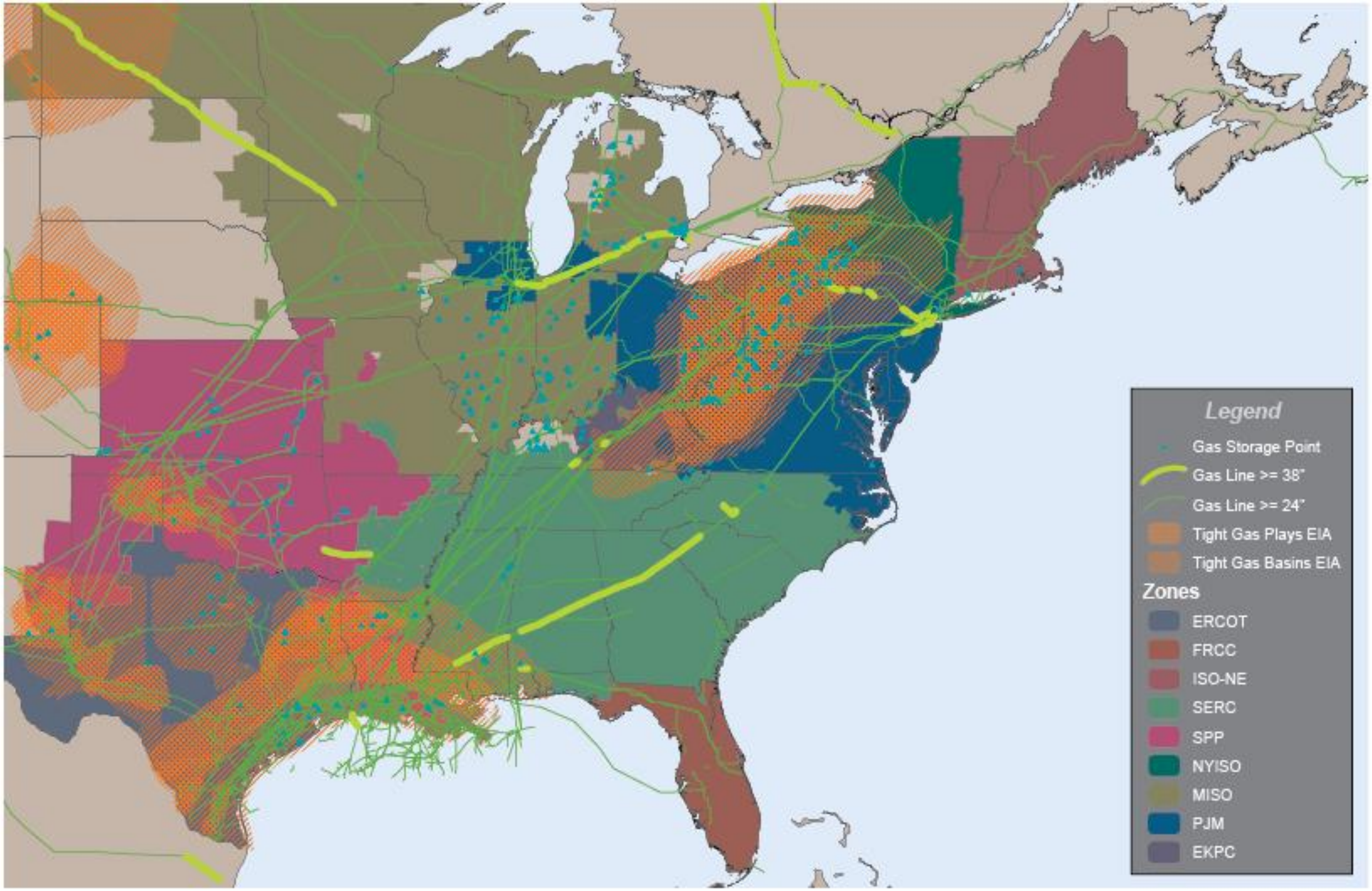
National Average Delivered Prices, Spot Prices, and Energy Shares of Coal and Natural Gas in PJM



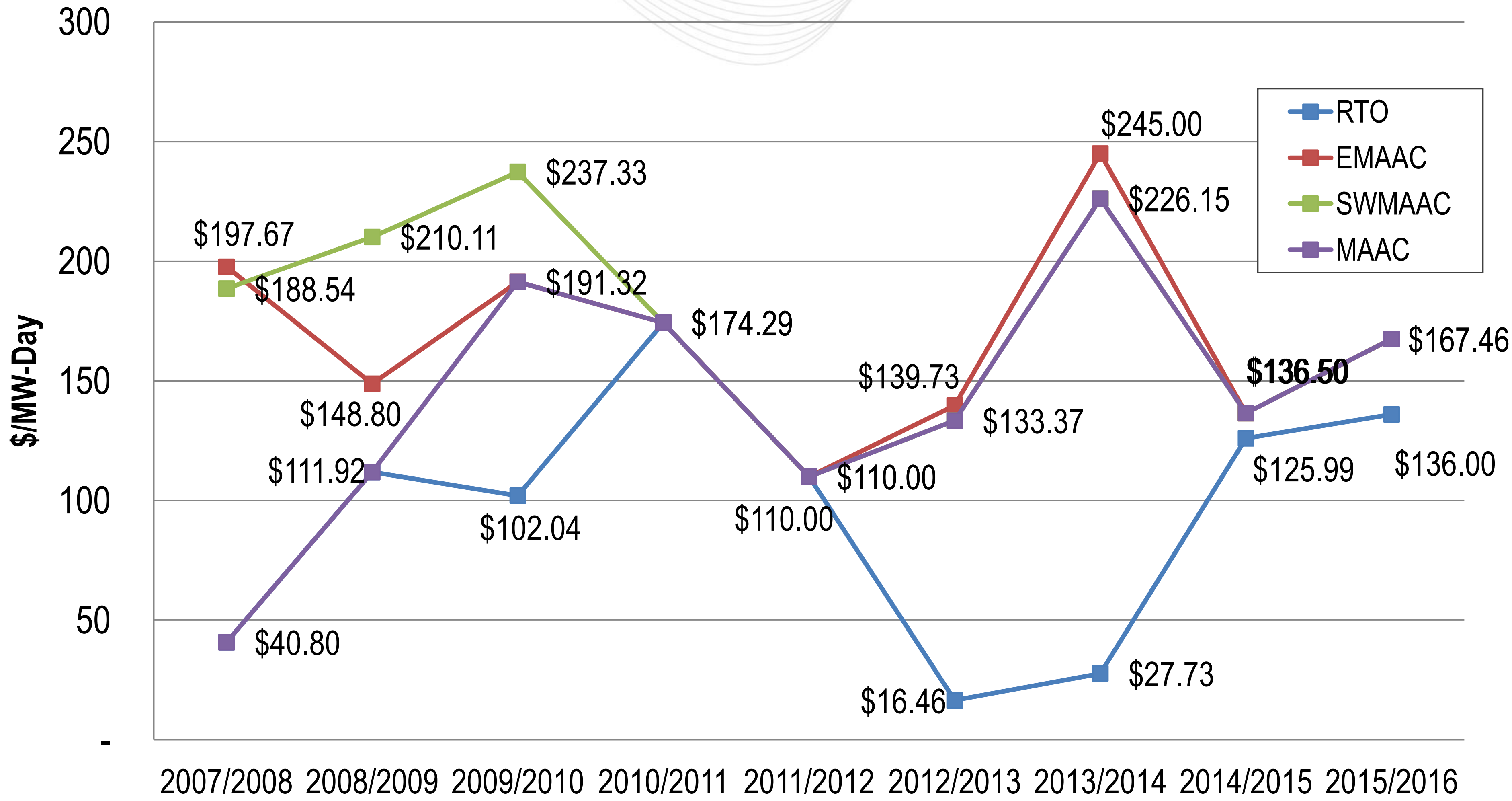
Combined Cycle Gas is Leading the Way as Gas Prices Fall



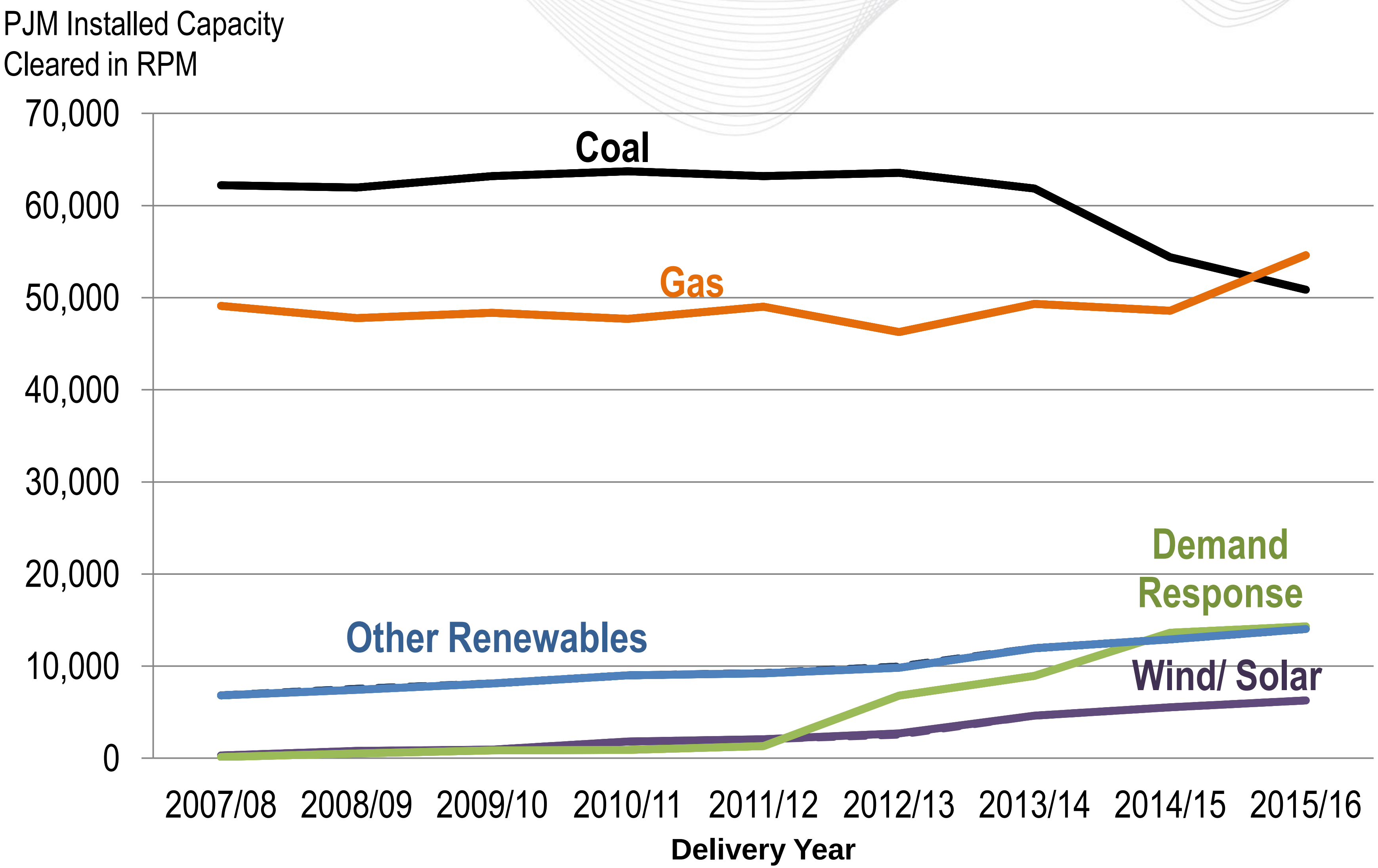
PJM at the Center of New Shale Production and Storage



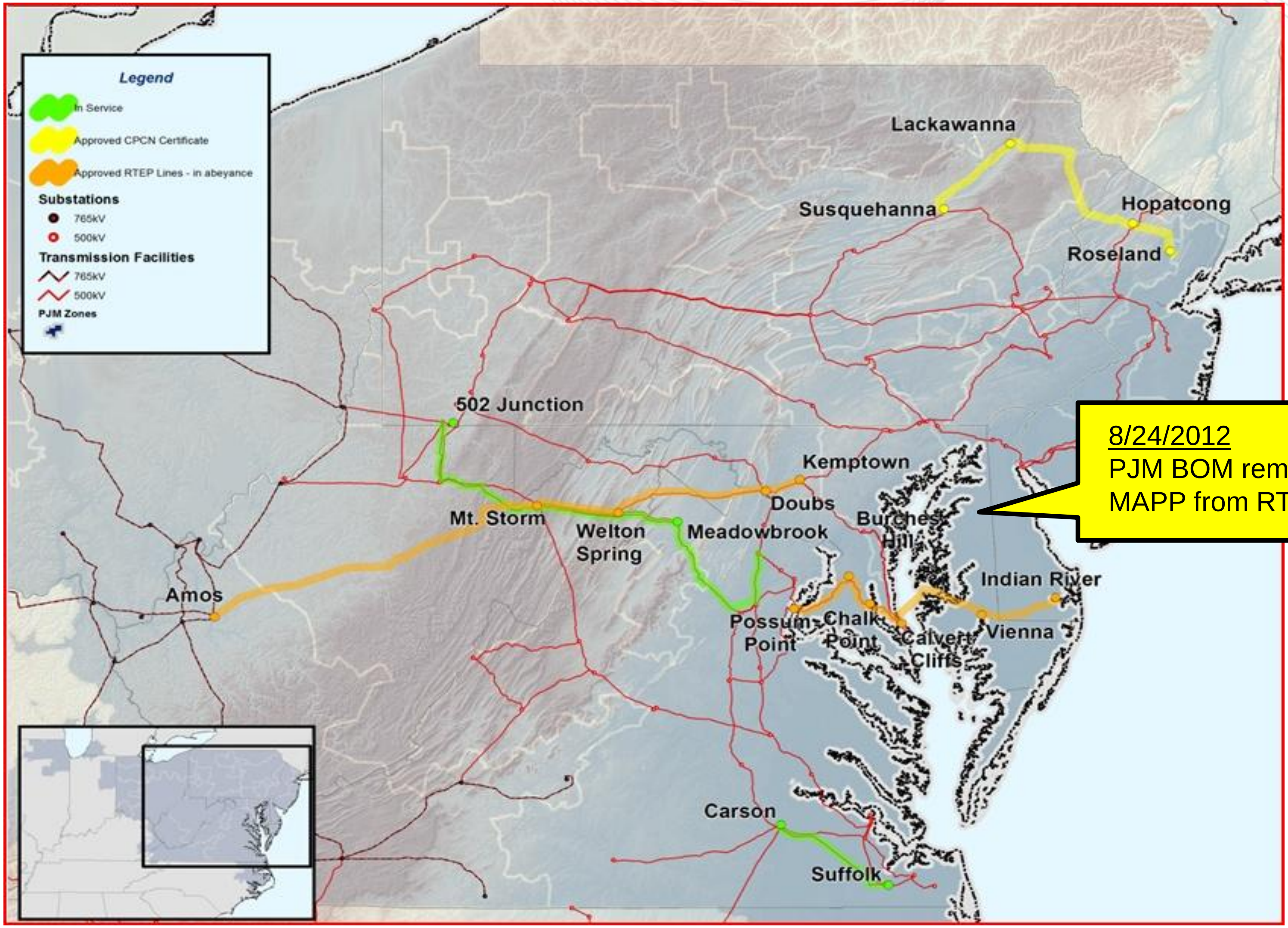
RPM Base Residual Auction Resource Clearing Prices (By Zone)



Configuration of Capacity is Changing



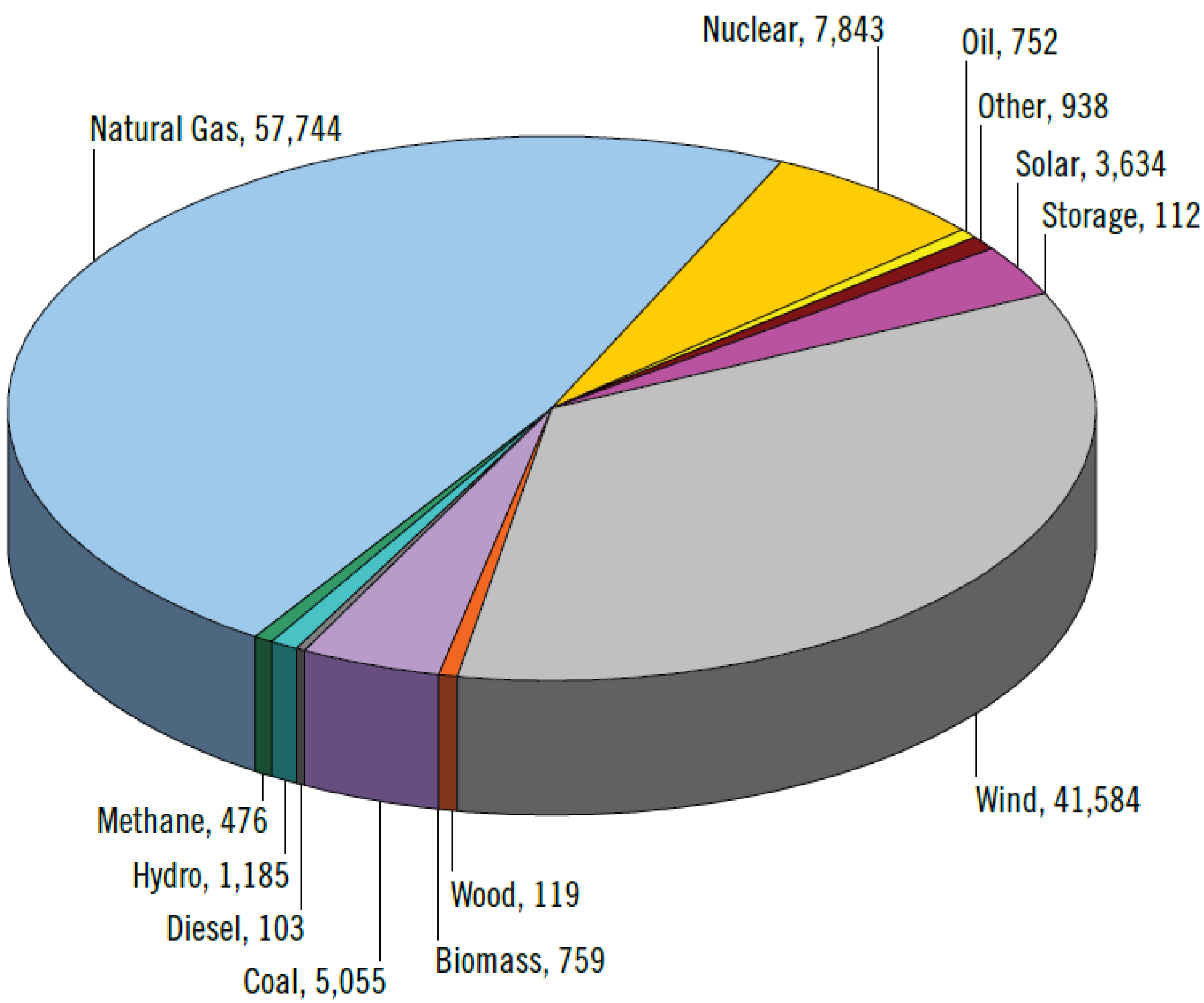
PJM BOM-Approved Backbone Transmission Lines



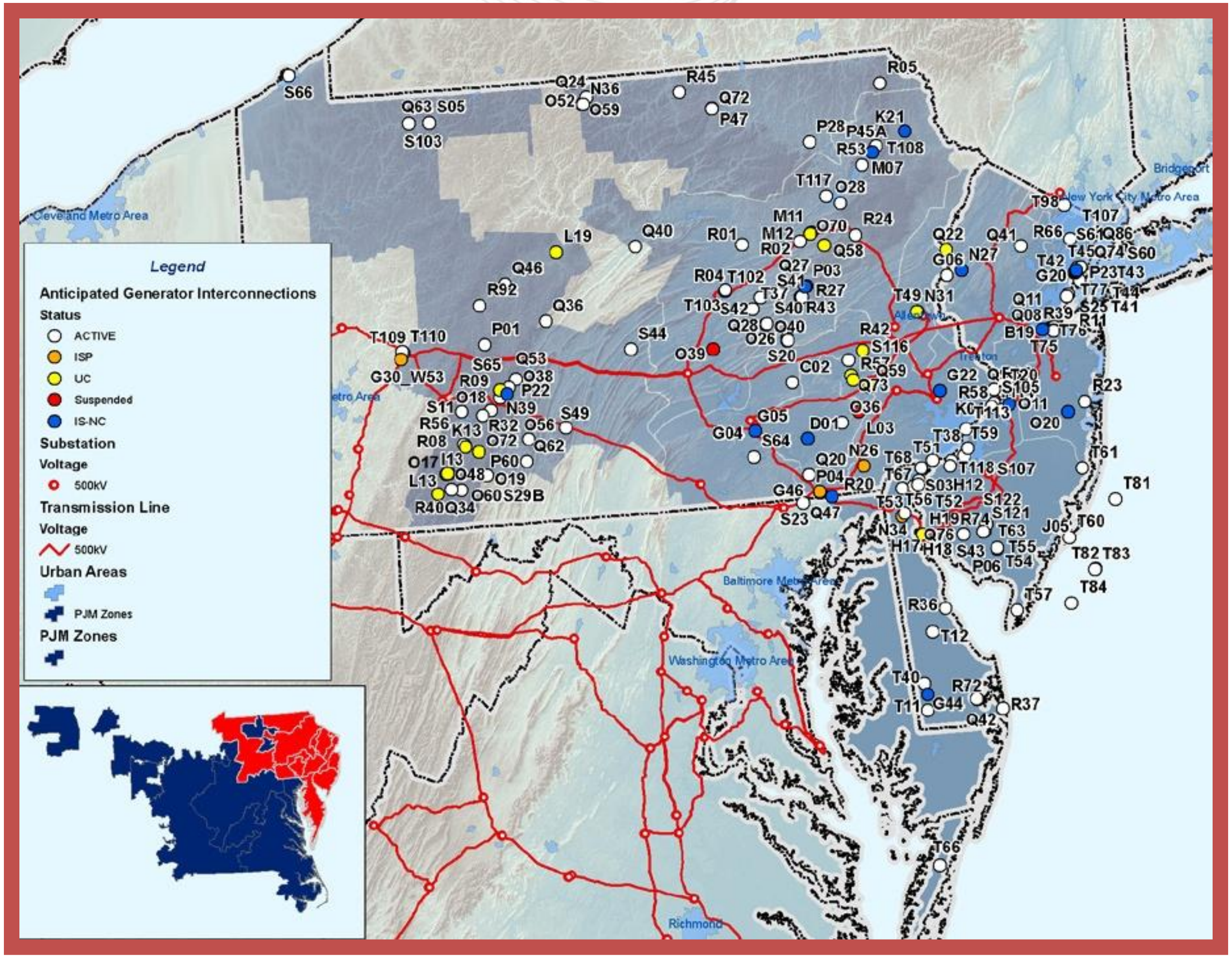
8/24/2012
PJM BOM removes PATH and MAPP from RTEP.

Looking Ahead toward Future Expansion

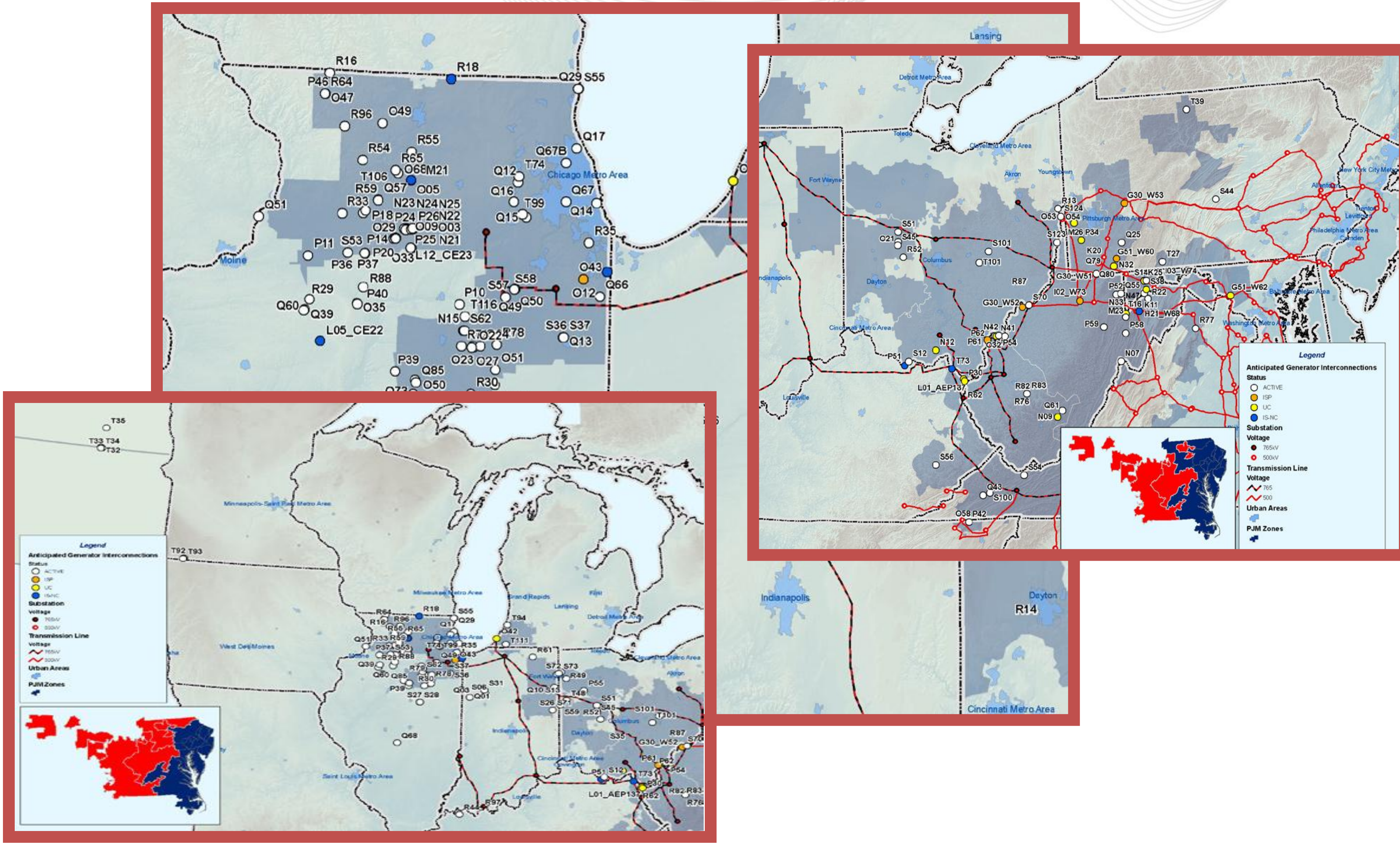
Queue Fuel Mix Through Close of X Queue



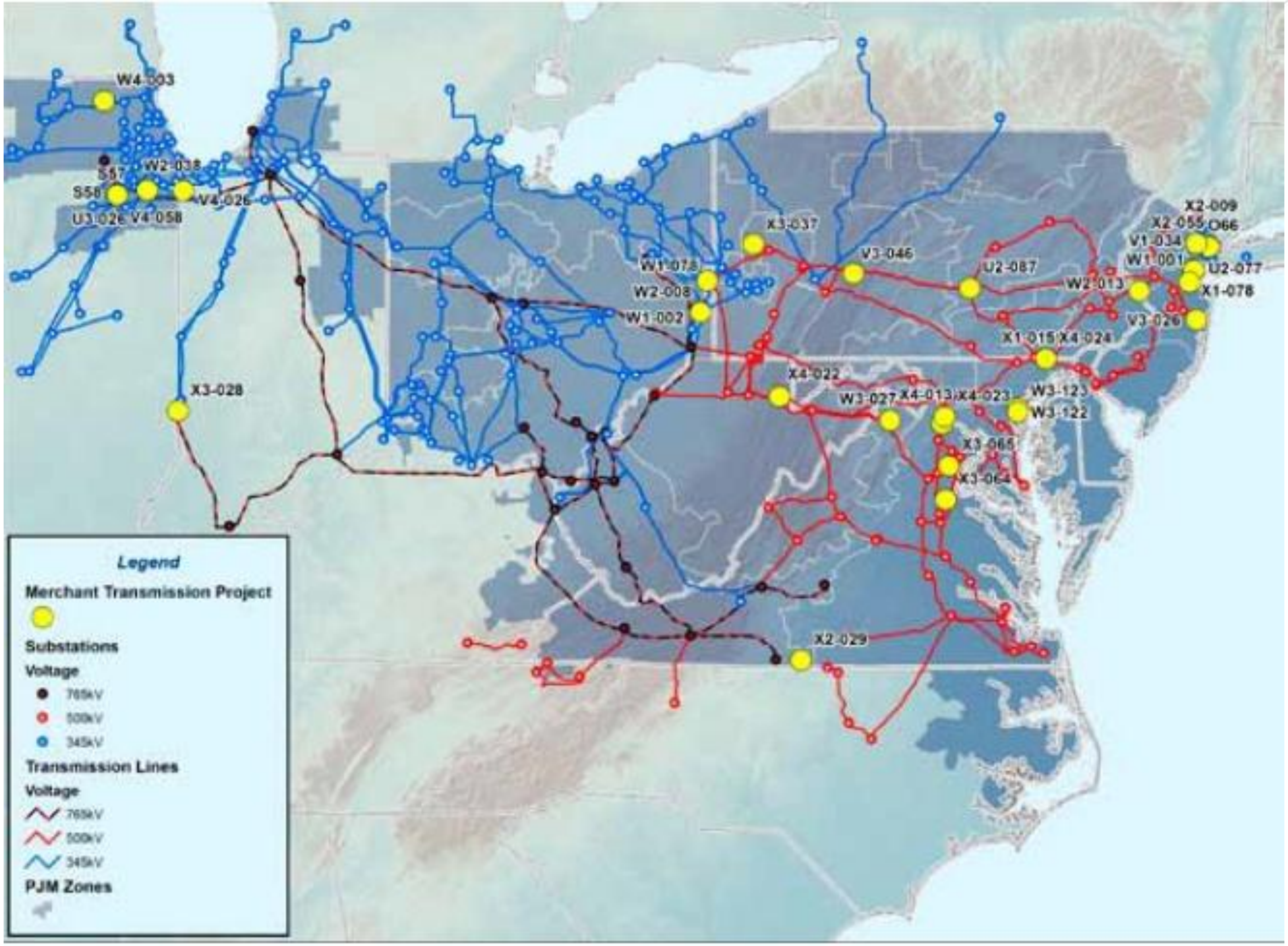
Generator Interconnection Requests: Eastern Mid-Atlantic PJM and West/Central Pennsylvania

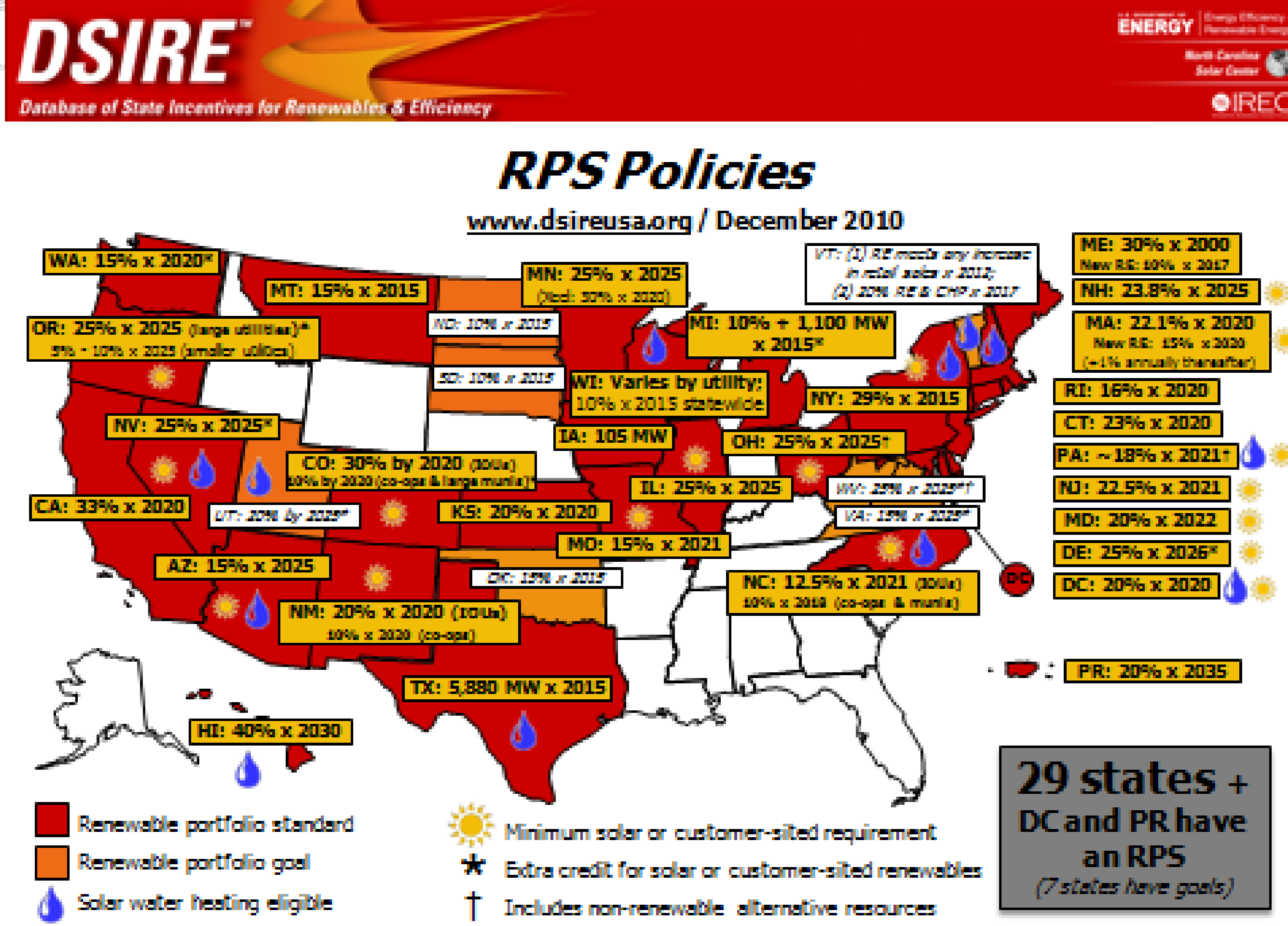


Generator Interconnection Requests: Western PJM



Merchant Transmission Interconnection Requests in PJM





PJM's 2009 CO_2 whitepaper showed 15 GW of wind reduced LMP by $5.00-$5.50/MWh on average

2026		
Target Installed Nameplate based on State Targets	Solar	11,000
	Wind	41,000
	Total	52,000
Forecast Restricted Demand** (2011 PJM Load Forecast)		172,904
Installed Reserve Margin		20%
Installed Capacity Needed		207,485
Installed Capacity Credit***	Solar	4,180
	Wind	6,150
	Total	10,330
Current Installed Capacity		185,544
Additional Non-Renewable Capacity Needed		11,611

* assuming 30% capacity factor for wind and 12% for solar

** assuming 10,000MW of DR

*** assuming capacity values at peak are 15% for wind and 38% for solar

- Large volume of needed renewables does require transmission to be deliverable
  - Case specific and costs are assigned to new resource
  - Right now “public policy” projects would only be undertaken if they passed benefit-cost test for economic reasons or reliability criteria for reliability-based projects
- Questions about cost allocation
  - “State agreement approach” whereby parties who want the project and agree to it pay for it?

Considerations for Markets and Transmission Going Forward

- Transmission may be the lowest cost contributor to wholesale costs but it is the enabling factor for vibrant, competitive wholesale markets
- Currently the biggest are for activity is reliability based projects on a more localized level
- Public policy issues under Order No. 1000 and associated cost allocation questions will remain front and center
  - Accounting for the market trends in planning process for reliability and economic based projects
  - State agreement approach vs. widespread allocation?
  - Flow-based vs. widespread allocation