PJM LMP Market Overview

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KEY STATISTICS

- PJM member companies: 600+
- Millions of people served: 51
- Peak load in megawatts: 144,644
- MWs of generating capacity: 164,905
- Miles of transmission lines: 56,250
- GWh of annual energy generation: 729,000
- Generation sources: 1,510
- Square miles of territory: 164,260
- Area served: 13 states + DC
- Internal/external tie lines: 250

26% of generation in Eastern Interconnection
23% of load in Eastern Interconnection
19% of transmission assets in Eastern Interconnection

19% of U.S. GDP produced in PJM
Day-Ahead / Real-time Market and Dispatch Functions

Day-ahead Market

1200 - Market close
Resource owners, Load Servers and Marketers submit offers / bids

1600 - Results posted
Security-constrained unit commitment and Hourly LMPs
• Generation schedules
• Purchase obligations

Reliability-based scheduling

1800 - Rebid Period
• Generation schedules adjusted
• Demand Forecast update
• Updated security analysis Transmission limitations

Real-time Market

• Hourly and Real-time operations
• 5 minute security constrained dispatch and incremental unit commitment / decommitment
• LMP-based balancing market
Generation Control Application (GCA)

AGM
realistic generator response profiles

ACM
intelligent constraint control

SCED-2
demand trajectory, generator loading strategy, CT commitment

SCED-3
final dispatch contour, pricing

Current Operating Plan (COP)
generator dispatch range & sequence solution

AGC
regulation signals
Market Results
PJM Market Expansion – A Case study

AEP / Dayton / ComEd Integration into the PJM Market

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

Dominion Integration Benefits

- Projected Benefit to Dominion Zone customers was $291 to $542 Million for Ten year period (2005-2014)
- Actual Benefit
  - $750 Million in avoided fuel costs for the four year period from May 2005 through May 2009
  - In 2008, measured benefit of $240 Million in energy cost savings and $90 Million in net FTR revenue

1. Dominion Study, Reported result in filing before VA State Corporation Commission, 2004
2. Greg Morgan, Dominion Executive, Testimony @ VA State Corporation Commission, June 2009

Prior to Integration

- PJM to DVP Transfer Capability = 2800 MW
- ECAR to DVP Transfer Capability = 2750 MW

After Integration

- Northern Market Area to DVP Proxy for Transfer Capability = 4000 MW
- Western Market Area to DVP Proxy for Transfer Capability = 3950 MW

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• **Lower energy prices across the expanded PJM region**
  - ESAI’s technical study: region-wide energy price without integration would be $0.78/MWh higher in 2005 than with integration.
  - Spreading these savings over the total PJM RTO’s energy demand of 700 terawatt-hours (TWh) per year yields aggregate savings of over $500 million per year.
Locational Price Distribution for Black Oak - Bedington 500 kV Transmission Limit (High Congestion Case)

Legend
- 110-130
- 90-110
- 70-90
- 50-70
- 30-50
- 10-30
- 0
- -10-10
- -30--10

Data taken from PJM
Real-time LMP system
System Unconstrained Marginal Price = $63.00
PJM Wholesale Cost
Full-Year 2009
($/MWh)

Energy, 39.05
Reliability, 10.79
Transmission, 3.94
Regulation, 0.33
Operating Reserve, 0.46
PJM Cost, 0.23
Reactive, 0.35
Trans. Owners Control, 0.08
Synchronized Reserve, 0.05
Black Start, 0.02

TOTAL: $55.31/MWh

* Values are PJM averages and do not reflect potential locational cost differences.
PJM Efficiencies Offer Regional Savings of $2.3 billion

Reliability Compliance –
  – from $470 million to $490 million in annual savings

Generation investment –
  – from $640 million to $1.2 billion in annual savings

Energy production cost –
  – from $340 million to $445 million in annual savings

Grid services –
  – from $134 million to $194 million in annual savings
PJM Evolution

- April 2005: Midwest ISO markets launched
- May 2004: Data exchange agreement with Midwest ISO & TVA
- October 2003: Economic planning process approved
- March 2003: Merchant transmission interconnection planning procedures approved by FERC
- April 2002: PJM West Integrated in RTEPP
- August 2000: First regional transmission plan approved by board
- June 2000: Regulation Market Day-Ahead Energy Market
- June 2002: Annual FTR and FTR Options Auction
- May 2003: Operation of ComEd
- Dec. 2002: Spinning Reserve Market
- 2001: Operation of Allegheny Power - 7-state transmission system
- Dec. 2002: Regional Transmission Organization status
- June 1999: Generation interconnection procedures approved by FERC
- June 1998: FTR Auction Market
- July 1993: PJM Independent entity status
- 1995-1996: Planning protocols developed
- June 1997: Regional transmission expansion planning process approved by FERC
- June 1999: FTR Auction Market
- July 1993: PJM Independent entity status
Proposed Renewables In PJM Footprint
Inter-Regional Coordination
Interregional Coordination in Various Market Timeframes

• Real-time Market
  – Least-cost management of transmission constraints through joint, iterative security-constrained economic dispatch

• Day-ahead Market
  – Day-ahead market will recognize flow entitlements of adjacent RTO
  – provides Day-ahead congestion relief upon request

• Reliability Scheduling
  – Transmission security analysis will recognize flow entitlements of adjacent RTO

• Financial Transmission Rights Allocations and Auctions
  – will recognize flow entitlements of adjacent RTO
• Regional Coordinated Flowgate (RCF) – a transmission facility that is impacted by generation to load delivery patterns in both markets
• The set of RCF facilities is defined annually
• RCF flow entitlement is allocated to each RTO based on historic generation delivery to Firm load customers
• Monitoring RTO – the RTO that is responsible for operation of the RCF per tariff
• When any of the pre-identified transmission constraints becomes binding in the monitoring RTO security-constrained dispatch, it is also entered in the non-monitoring RTO security-constrained dispatch.
• Monitoring RTO manages constraint based on actual facility limit
• Non-monitoring RTO manages constraint based on flow entitlement and based on the requested MW relief amount.
• RTOs share constraint shadow price information to determine least-costly dispatch alternatives
Real-Time Coordination Steps

1. Monitoring RTO informs non-monitoring RTO when RCF binds in UDS solution.

2. Monitoring and non-monitoring RTOs continue to exchange shadow price information throughout operation for constraint to ensure least-cost overall solution.

3. Monitoring RTO informs non-monitoring RTO when RCF is no longer binding and constraint is ended.