REGIONAL ENERGY RISK

SPRING 2005 PEAK LOAD
MANAGEMENT ALLIANCE CONFERENCE

Stone Mountain Park, Georgia
April 28, 2005
Susan Covino
PJM Manager - Demand Side Response
PJM Role as an RTO

• Operates the largest electric power system in the world
  – Controls a reliable transmission system
  – Administers regional wholesale electric markets
  – Provides for comprehensive regional transmission expansion planning
• Provides market monitoring coordinated with states and the FERC
• Provides an information resource for market participants and regulators
PJM is the largest centrally dispatched entity in North America (Megawatts indicate peak demand.)
## Key PJM Statistics

<table>
<thead>
<tr>
<th>Metric</th>
<th>PJM Today</th>
<th>PJM + Dominion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Millions of people served</td>
<td>45</td>
<td>51</td>
</tr>
<tr>
<td>Peak load in megawatts</td>
<td>115,000</td>
<td>130,580</td>
</tr>
<tr>
<td>Megawatts of generating capacity</td>
<td>143,420</td>
<td>166,220</td>
</tr>
<tr>
<td>Miles of transmission lines</td>
<td>49,970</td>
<td>56,070</td>
</tr>
<tr>
<td>Gigawatt-hours of annual energy</td>
<td>474,000</td>
<td>563,700</td>
</tr>
<tr>
<td>Generation sources</td>
<td>1001</td>
<td>Approx. 1,100</td>
</tr>
<tr>
<td>Area served</td>
<td>12 states + D.C.</td>
<td>13 states + D.C.</td>
</tr>
</tbody>
</table>
EMERGENCY

Designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event.

ECONOMIC

Designed to provide an incentive to customers or curtailment service providers to reduce consumption when PJM LMP prices are high

Two options:
Day-Ahead Option
Real-Time Option
<table>
<thead>
<tr>
<th>Program</th>
<th>Participation</th>
<th>Payment to Load Reducer</th>
<th>Cost to Energy Market</th>
<th>Risks to Load Reducer</th>
</tr>
</thead>
<tbody>
<tr>
<td>Emergency</td>
<td>Emergency event</td>
<td>PJM pays higher of Zonal LMP or $500/MWh</td>
<td>Costs recovered for emergency purchases in excess of LMP are allocated among PJM market buyers in proportion to their increase in net purchases</td>
<td>No Charges for Non Performance</td>
</tr>
<tr>
<td>Economic</td>
<td>Day-Ahead Market</td>
<td>If Zonal LMP &lt; $75/MWh, PJM pays LMP - Retail Rate</td>
<td>If Zonal LMP &lt; $75/MWh, PJM recovers LMP less Retail Rate from LSE</td>
<td>Charges for Non Performance:</td>
</tr>
<tr>
<td></td>
<td>Rea-Time Market dispatched by PJM</td>
<td>[Retail Rate = Generation + Transmission]</td>
<td>If Zonal LMP &gt; = $75/MWh, PJM recovers LMP less Retail Rate from LSE</td>
<td>If load reduction is committed in Day-Ahead Market and does not perform in real time</td>
</tr>
<tr>
<td></td>
<td></td>
<td>If Zonal LMP &gt; = $75/MWh, PJM pays LMP</td>
<td>PJM recovers Retail Rate from all LSE in zone</td>
<td>Real-Time LMP * Shortfall</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>+ Balancing Operating Reserves Charges</td>
</tr>
<tr>
<td>Economic</td>
<td>Real-Time Market only</td>
<td>For duration of the load reduction dispatched by PJM,</td>
<td>Costs recovered from Operating Reserves in the Real-Time Energy Market</td>
<td>No Charges for Non Performance</td>
</tr>
<tr>
<td></td>
<td>Must be dispatched by PJM</td>
<td>Actual Savings</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>[RT LMP * MW Reduction]</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>-</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Total Bid Value</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>[(Strike Price * MW Reduction) + Shutdown Costs ]</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Registration: Load Reducers

#### EMERGENCY

<table>
<thead>
<tr>
<th>Year</th>
<th>New Registered Sites</th>
<th>Additional MWs</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>61</td>
<td>548</td>
</tr>
<tr>
<td>2003</td>
<td>107</td>
<td>111</td>
</tr>
<tr>
<td>2004</td>
<td>4,147</td>
<td>1,124</td>
</tr>
</tbody>
</table>

#### ECONOMIC

<table>
<thead>
<tr>
<th>Year</th>
<th>New Registered Sites</th>
<th>Additional MWs</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>116</td>
<td>337</td>
</tr>
<tr>
<td>2003</td>
<td>129</td>
<td>387</td>
</tr>
<tr>
<td>2004</td>
<td>1,784</td>
<td>1,395</td>
</tr>
</tbody>
</table>

- Emergency program: Active sites: 4,301 / Total MWs: 1,783 MWs
- Economic program: Active sites: 2,023 / Total MWs: 2,119 MWs
- Total program: Total active sites: 6,324 / Total MWs: 3,902 MWs
- Note: Sites can switch programs, relocate out of PJM footprint, and increase load
- Last updated: 1-6-05
Total system impact is modest

<table>
<thead>
<tr>
<th>Year</th>
<th>Sites</th>
<th>MW</th>
<th>Payments</th>
<th>Year</th>
<th>Sites</th>
<th>MW</th>
<th>Payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>2002</td>
<td>61</td>
<td>548</td>
<td>$ 177,000</td>
<td>2002</td>
<td>116</td>
<td>337</td>
<td>$ 895,000</td>
</tr>
<tr>
<td>2003</td>
<td>168</td>
<td>659</td>
<td>$ 26,600</td>
<td>2003</td>
<td>245</td>
<td>724</td>
<td>$ 848,000</td>
</tr>
<tr>
<td>2004*</td>
<td>4,315</td>
<td>1,783</td>
<td>-</td>
<td>2004*</td>
<td>317</td>
<td>2,892</td>
<td>$ 1.5M</td>
</tr>
</tbody>
</table>

*Thru September 2004
• Forward Energy Reserve ("FER") product
• Emergency Load Response Enhancements
• DSR sub model – Reliability Pricing Model
• DSR as reserves (spinning and regulation markets)
• Economic Load Response – permanent market design
• Forward Energy Reserve (“FER”):
  – Denominated in 1 MW increments, for 4 hours, and 4 calls per month
  – Cleared in annual, multi-month, and/or monthly auctions
  – Paid a market clearing price consisting of a “call premium” and the “strike price”
  – Exercised in Day Ahead
Emergency Load Response Enhancements

• Require participants to indicate the price level at which they will reduce during an emergency – “minimum dispatch price”
• Incorporate the price level of an Emergency load reduction dispatched by PJM into LMP
• Create one market construct from the Emergency Load Response Program and Active Load Management with energy and capacity components.
• Allow aggregation of load response by Curtailment Service Providers as well as Load Serving Entities
• Devise penalties for failure to perform that are comparable to penalties for generation resources that get capacity payments.
DSR Sub Model Design Principles

- Elicit transparent and efficient long term regional market price signals for reliability (including locational operational features).
- Reduce barriers to entry and create opportunities for Demand Resources (DR).
- Treat demand and generation resources comparably.
- Maintain the measurement and verification processes for load reductions established for Active Load Management (ALM) resources.
Opportunities for DSR in Reserve Markets

• Spinning Reserves Market
  – Draft Business Rules developed and endorsed by DSR Working Group
  – Change name to Synchronized Reserves Market
  – Demand Resources qualify as Tier 2
  – Metering information at no less than 1 minute scan rate with daily uploads
  – Limitation on amount of Synchronized Reserve Requirement that Demand Resources can meet

• Regulation Market
  – Draft Business Rules developed and endorsed by DSR Working Group
  – Requirements for and treatment of Demand Resources are the same as Generation Resources
Transition and Permanent Market Design

- Incentives
- Measurement and Verification
Mid-Atlantic Distributed Resources Initiative (MADRI)
Many impediments to the deployment of Distributed Generation and Demand Response are outside of direct PJM control.

Early 04, PJM staff and DOE Mid-Atlantic office began planning activities for a workshop to identify barriers and solutions to further the deployment of Distributed Resource

Activities have matured into the formation of the Mid-Atlantic Distributed Resources Initiative (MADRI).

- Organized under the leadership of:
  - Public Utility Commissions (DC, DE, MD, PA, NJ)
  - PJM, DOE, EPA, FERC
- Participation of interested regional stakeholders
Initial focus areas for the working group include:

- **Distribution System Rate Making Policy**
  - Break the throughput paradigm

- **Retail Rates / Pricing Policy – Real-time pricing - in default service**
  - Customers need to see and be impacted by price
  - Default service policy

- **Encourage the development of regional policy with consistent rules**
  - Interconnection
  - Air-permitting – output based standard

- **Meter technology and data access**
  - Develop policy and incentives to install interval meters
  - Provide direct access to meter data
  - Leverage two way smart meter communication technology
Initial focus areas for the working group include:

- **Leverage DG solutions in distribution system**-
  - Develop policy and incentive rate making structure
  - DG deployment can be more cost effective than conventional distribution system upgrades
  - Deployment at customer sites or sub-stations

- **Development of straw man business models**
  - How can a single DG and DR be monetized in multiple markets
    - Wholesale
    - Distribution System
    - Behind the Meter

- **Leveraging state funding sources**
  - Technology funds established during restructuring