PJM Proposal: Reserve Market Enhancements

Adam Keech
Executive Director, Market Operations
Members Committee Meeting
January 24, 2019
The PJM Board has determined that a comprehensive package inclusive of the components outlined below, is needed to meaningfully address the reserve procurement and pricing issues.

1. Consolidation of Tier 1 and Tier 2 Synchronized Reserve products
2. Improved utilization of existing capability for locational reserve needs
3. Alignment of market-based reserve products in Day-ahead and Real-time Energy Markets
4. Operating Reserve Demand Curves (ORDC) for all reserve products
5. Increased penalty factors to ORDCs to ensure utilization of all supply prior to a reserve shortage
6. Transitional mechanism to the RPM Energy and Ancillary Services (E&AS) Revenue Offset to reflect expected changes in revenues in the determination of the Net Cost of New Entry
**Component #1: Consolidation of Tier 1 and Tier 2 and Offer Changes**

<table>
<thead>
<tr>
<th>Tier 1 Market Product</th>
<th>Vs.</th>
<th>Tier 2 Market Product</th>
</tr>
</thead>
</table>
| Remaining ramping capability on flexible dispatchable generation resources after economic dispatch | **Vs.** | • Generation resources reduced from their economic set point  
  • Synchronous condensing resources and DR |

### Tier 1 Market Product
- **10-minute response time**
- **Obligation to respond**
- **Non-compliance penalty**
- **Paid for response to an event**

### Tier 2 Market Product
- **10-minute response time**
- **Obligation to respond**
- **Non-compliance penalty**
- **Paid market clearing price regardless of deployment**
Component #1: Consolidation of Tier 1 and Tier 2 and Offer Changes

- PJM will strengthen the synchronized reserve must offer requirement
- PJM will calculate a resource’s availability and reserve offer MW using the availability and unit parameters offered in for energy, with some exceptions
  - Participants will be provided additional flexibility to update energy ramp rates intra-day and to update the Synch Reserve Maximum MW intra-hour to enable more accurate representation of their reserve capability
- The proposal reduces the maximum level of synchronized reserve offers.
  - The Variable Operations & Maintenance component will be removed from SR offers (it is already included in energy offers)
  - The $7.50/MWh offer margin will be reduced to the expected value of the penalty ($0.02 for 2018).
Component #2: Flexible Reserve Zone Modeling

- More Flexible Reserve Sub-Zone Modeling
  - Keep existing RTO reserve zone with closed loop sub-zone structure, but allow flexibility to change the location of the sub-zone on a day-ahead basis, as needed
    - Allow changes intraday on an exception basis
  - Define several reserve sub-zones, of which only one will be used at a time
Component #3: Reserve Market Alignment

ORDCs and Offer Price Caps will be consistent between DA & RT for each product
Basis for value is the cost of a reserve shortage and the uncertainty on the system that could result in falling below the reserve requirement despite procuring sufficient reserves in advance:

- Cost of a reserve shortage is based on the penalty factor
- Uncertainty is measured from historical data:
The Regulation Requirement (shown below) is used to deal with the uncertainties mentioned in the previous slides.

<table>
<thead>
<tr>
<th>Season</th>
<th>Dates</th>
<th>Non-Ramp Hours</th>
<th>Ramp Hours</th>
<th>Effective MW Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spring</td>
<td>Mar 1 – May 31</td>
<td>HE1 – HE5, HE9 – HE17</td>
<td>HE6 – HE8, HE18 – HE24</td>
<td>Non-Ramp = 525MW Ramp = 800MW</td>
</tr>
<tr>
<td>Fall</td>
<td>Sep 1 – Nov 30</td>
<td>HE1 – HE5, HE9 – HE17</td>
<td>HE6 – HE8, HE18 – HE24</td>
<td>Non-Ramp = 525MW Ramp = 800MW</td>
</tr>
</tbody>
</table>

The ORDCs can be shifted to the left by the regulation requirement

- **Update based on feedback**: PJM is studying historic regulation deployment data to determine if there is a better method to account for regulation in the ORDC.
Component #4: Implement Downward-Sloping Demand Curves

Synchronized Reserves

- $850/MWh, Current Penalty Factor
- $300/MWh, Current Penalty Factor Curve
Component #5: Implement $2,000/MWh Penalty Factors for All Products

Synchronized Reserves

- $2,000/MWh, Penalty Factor
- $850/MWh, Current Penalty Factor
- $300/MWh, Current Penalty Factor Curve
Component #5: Implement $2,000/MWh Penalty Factors for All Products

PJM dispatchers will commit high-cost generation and deploy pre-emergency and emergency load management reductions, which have a cost in excess of the existing $850 penalty factor, in order to maintain Synchronized and Primary Reserves.

- Generation offer cap (for price-setting): $2,000/MWh
- Offer cap for Pre-Emergency and Emergency Load Management Reduction Actions:

<table>
<thead>
<tr>
<th>Lead Time</th>
<th>Offer Cap Formula</th>
<th>Offer Cap</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 hours</td>
<td>$1,000 plus the Primary Reserve Penalty Factor</td>
<td>$1,100/MWh</td>
</tr>
<tr>
<td>1 hour</td>
<td>$1,000 plus (the Primary Reserve Penalty Factor * ½)</td>
<td>$1,425/MWh</td>
</tr>
<tr>
<td>30 minutes</td>
<td>$1,000 plus (the Primary Reserve Penalty Factor -$1)</td>
<td>$1,849/MWh</td>
</tr>
</tbody>
</table>

The Penalty Factor should be revised to $2,000/MWh to allow these operator actions to be reflected in market pricing.

Also need to revise Pre-Emergency and Emergency Load Management Reduction offer caps to remove circular reference.
• The goal of the E&AS adjustment is to reflect the additional E&AS revenues anticipated to be created by this proposal in the capacity market.

• PJM proposes to simulate the Energy and Reserve Market outcomes based on actual operating conditions, but with the proposed reserve market modifications, for Base Residual Auctions held after FERC approval is received.

• The revenues from these simulations will be used to scale the revenues normally used to determine the E&AS offset.

<table>
<thead>
<tr>
<th>Auction Execution Date</th>
<th>Delivery Year</th>
<th>Revenue Year</th>
<th>Revenue Calculation</th>
</tr>
</thead>
<tbody>
<tr>
<td>May 2020</td>
<td>2023/2024</td>
<td>2017</td>
<td>Scaled</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2018</td>
<td>Scaled</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2019</td>
<td>Scaled</td>
</tr>
<tr>
<td>May 2021</td>
<td>2024/2025</td>
<td>2018</td>
<td>Scaled</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2019</td>
<td>Scaled</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2020</td>
<td>Half Scaled + Half Actual</td>
</tr>
<tr>
<td>May 2022</td>
<td>2025/2026</td>
<td>2019</td>
<td>Scaled</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2020</td>
<td>Half Scaled + Half Actual</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2021</td>
<td>Actual</td>
</tr>
<tr>
<td>May 2023</td>
<td>2026/2027</td>
<td>2020</td>
<td>Half Scaled + Half Actual</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2021</td>
<td>Actual</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2022</td>
<td>Actual</td>
</tr>
<tr>
<td>May 2024</td>
<td>2027/2028</td>
<td>2021</td>
<td>Actual</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2022</td>
<td>Actual</td>
</tr>
<tr>
<td></td>
<td></td>
<td>2023</td>
<td>Actual</td>
</tr>
</tbody>
</table>

* For illustration purposes, this chart assumes May 2020 is the first Base Residual Auction held after FERC approval is received and the changes are implemented in June 2020.
Component #6: Transition

• PJM’s ideal path is to implement the following as Phase 1:
  – Tier 1/Tier 2 consolidation and offer changes
  – Enhanced locational reserve zone modeling
  – Downward-sloping demand curves with $850/MWh PFs
  – RT 30-minute reserve market
  – DA and RT reserve market alignment

• Phase 2 would be an increase in the PFs to the final state. Any further transition steps (i.e. – E&AS offset simulations) would be dependent on that final state.
Component #6: Transition

• Phase 1 would be implemented as soon as practicable following FERC approval, potentially on the first day of the Delivery Year. The E&AS offset would be adjusted in the next BRA.

• Phase 2 would be implemented June 1, 202X.
  – 202X is the first year for which the E&AS revenues using the $2,000/MWh PF can be reflected in the E&AS offset.