Unit Commitment in the PJM Day-ahead and Real-time Markets

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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: 729,000
- Generation sources: 1,210
- 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
PJM Market Timeframes

**Long Term**
- Up to 4 years ahead
- Month Ahead

**Week Ahead**
- Physical
  - Transmission reservations
    - ARR allocations
    - Annual FTR auctions
    - FTR Secondary Market
    - Monthly FTR auctions
- Financial
  - Bilateral forward contracts / Over the counter

**Day Ahead**
- Day-Ahead Market
- Reliability analysis
- Unit commitment
- Outage analysis
- Load forecast
- Forward reliability analysis

**Real Time (operating day)**
- Hours Ahead
- Minutes Ahead
- Near-term reliability analysis
- Real-Time Market
- Unit Dispatch System
• Develop financially binding hourly quantities and LMPs for next operating day based on participant bids and offers while respecting all transmission security constraints, reserve requirements and generator operating constraints.

• Requires solution of security-constrained unit commitment using full transmission model to maintain consistency with real-time market operations.
Day-ahead Market – Average Daily Volumes

- 1,210 generators, 3 part offers (startup, no load, 10 segment incremental energy offer curve)
- 10,000 - Demand bids – fixed or price sensitive
- 50,000 - Virtual bids / offers
- 8,700 - eligible bid/offer nodes (pricing nodes)
- 6,125 - monitored transmission elements
- 10,000 - transmission contingencies modeled
Day-ahead Market Data Flow

- Generation Offer Data
- Demand Schedules & Bids
- Virtual Bids / Offers
- Agg. Bus Distributions

- Network Model
- Transmission Outages
- Default Distributions
- Equipment Ratings

- PJM Load Forecast
- Hydro Schedules
- Reserve Requirements

- Energy Transactions
- External Energy Offers
- Net Tie Schedules

- Hourly LMPs
- Hourly Demand & Generation Schedules
- Transmission Limitations
- Cleared virtual bid/offer

- Energy Transaction Schedules
- External Energy Schedules
- Net Tie Schedules

- Energy Transactions
- External Energy Offers
- Net Tie Schedules

Settlements
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
## Reliability Scheduling Functions

<table>
<thead>
<tr>
<th>Time Slot</th>
<th>Description</th>
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<tbody>
<tr>
<td>8 a.m. - 12 p.m.</td>
<td><strong>Operations Technical Analysis</strong>&lt;br&gt;Assesses the technical feasibility</td>
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<tr>
<td>8 a.m. - 12 p.m.</td>
<td><strong>Market Participant Bid/Offer Period</strong>&lt;br&gt;Market participants enter bids &amp; offers in the Day-Ahead Market</td>
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<tr>
<td>Noon - 4 p.m.</td>
<td><strong>Day-ahead results posted &amp; balancing</strong>&lt;br&gt;Process all the markets requests from day-ahead bids&lt;br&gt;Clear the market</td>
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<tr>
<td>4 p.m. - 5 p.m.</td>
<td><strong>Re-bid period</strong>&lt;br&gt;Make adjustments based on the clearing results</td>
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<td>6 p.m. - 12 a.m.</td>
<td><strong>Balancing Market bid period closes</strong>&lt;br&gt;Second Commitment&lt;br&gt;Reliability analysis includes updated offers, unit availabilities and PJM load forecast information - minimizes startup and cost to run units at minimum&lt;br&gt;Supplemental Commitments&lt;br&gt;Reliability performed as needed&lt;br&gt;Minimize start-up and cost to run at minimum for additional units committed</td>
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Future Requirements

- Potential expansion of price responsive demand to many substations
- Potential to enhance Interregional Market Coordination
- Increased penetration of distributed resources, distributed energy storage devices
- Smart grid innovations
- Potential need to reduce market clearing time
Mixed Integer Programming-based Unit Commitment and Dispatch
Timeline of MIP Implementation in Production Systems

- Day Ahead Market and Reliability Commitment: December 2004
- Real Time and Ancillary Services Markets: August 2006
- RPM (Capacity Mkt): March 2007
- Perfect Dispatch Concept: March 2008
- Prototype Look-ahead Dispatch: December 2008
- Time-coupled Comprehensive RT-Dispatch: January 2010
Benefits of MIP Implementation

1. Global optimality
2. More accurate solution
3. Improved modeling of security constraints
4. Enhanced resource modeling capability
   a) Generation
   b) Demand response
   c) Transmission Devices
5. More adaptable problem definition
Market Benefits of MIP Implementation

- Lower cost to maintain operational reliability – Annual Production Cost Savings exceed $90 Million
- Lower uplift payments
Transition from Lagrangian Relaxation (LR) to MIP

1. MIP tends to solve faster with more complete transmission model, LR had significant performance issues with transmission constraints

2. Conditional constraints initially created performance problems for MIP

3. Combined cycle model, Hydro unit commitment, etc. - very difficult to implement in LR. MIP handles relatively easily

4. MIP solution speed has improved dramatically