Demand Response in PJM

February 24, 2014
• Demand Response Overview
• Emergency Operations
• Measurement & Verification
• Policy Issues
What is demand response?

• Demand response (DR)
  – reduction in electricity consumption based on PJM instructions & prices
  – Behind the meter
  – No power injections
  – PJM indifferent to method of load reduction
End Use Customer Load Reduction

- Generator: 20%
- HVAC: 26%
- Refrigeration: 3%
- Lighting: 8%
- Manufacturing: 38%
- Water Heaters: 1.5%
- Other: 3%
- Batteries: 0.01%
- Plug Load: 0.5%

2013-14 EmergencyRegs
DR Business Segments

- Industrial/Manufacturing: 50%
- Residential: 14%
- Schools: 8%
- Retail Service: 4%
- Services: 2%
- Transportation, Communications, Electric, Gas and Sanitary Services: 3%
- Agriculture, Forestry and Fishing: 2%
- Correctional Facilities: 0.4%
- Food Service: 0.1%
- Other: 2%
- Hospitals: 4%
- Office Building: 9%
- Mining: 2%

2013-14 Emergency Regs
Fuel mix for behind the meter generation

- Diesel: 87.3%
- Natural Gas: 11.2%
- Gasoline: 0.1%
- Coal: 0.2%
- Oil: 0.8%
- Kerosene: 0.2%
- Propane: 0.02%
- Other: 0.1%
- Waste Products: 0.1%

2013-14 Emergency Regs
Market Participation

• Emergency
  – Capacity (reliability pricing model - RPM)

• Economic
  – Energy
    • Day Ahead (DA)
    • Real Time (RT)
  – Ancillary Services
    • Regulation (Reg)
    • Synchronized Reserves (SR)
    • Day Ahead Scheduling Reserves (DASR)
• DR as Capacity
  – A commitment to reduce load during PJM emergency under the capped energy price
  – Must reduce load during emergency event (pre-emergency in future)
  – 3 year forward auction
  – Capacity revenues paid to committed resource whether or not energy is produced by resource
  – Daily product
Demand Side Participation in Capacity Market

- Active Load Management
- Interruptible Load for Reliability
- RPM and FRR DR
- Energy Efficiency
- Committed/Cleared DR

RPM Implemented
**Economic DR in energy market**

- **DR in energy market**
  - Day Ahead (DA) market
  - Real Time (RT) market
  - Reduce load when cleared in DA/RT market
    - Response to LMP
    - At PJM direction
  - Economic
    - Offer curve
    - Only cleared if makes economic sense
  - Only paid if LMP > Net benefits test (NBT)
• Day ahead scheduling reserves
  – Reduce load within 30 minutes if dispatched by PJM
• Synchronized Reserves
  – Reduce load within 10 minutes if dispatched
• Regulation
  – Reg A signal
  – Reg D signal
Annual DR Revenue

- Economic Energy Incentives
- Emergency Energy
- Ancillary Services
- Capacity*
- Economic Energy

Millions

$0
$100
$200
$300
$400
$500
$600

## Average DR availability by resource 2013/14

<table>
<thead>
<tr>
<th>Market</th>
<th>Available DR (MW)</th>
<th>Available DR as % of total</th>
<th>Total Locations</th>
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</thead>
<tbody>
<tr>
<td>Emergency</td>
<td>9000</td>
<td>5%</td>
<td>15,800</td>
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<tr>
<td>Energy</td>
<td>2300</td>
<td>1.5%</td>
<td>1500</td>
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<tr>
<td>Synch Reserves (MAD)</td>
<td>375</td>
<td>28%</td>
<td>161</td>
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<tr>
<td>Regulation</td>
<td>6</td>
<td>1%</td>
<td>71</td>
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</tbody>
</table>
• Demand Response Overview
• Emergency Operations
• Measurement & Verification
• Policy Issues
PECO Zone Instantaneous Load July 18, 2013

Emergency DR Event Period

- 12:40 - PECO Zone Long Lead Notified
- 14:40 - PECO Zone Long Lead Activated
- 17:00 - PECO Zone Long Lead Released
• Cold weather emergency issued – call for conservation
• Valley load forecast – 116,000 MW
  actual – 120,000 MW
• Morning peak – forecast ~140,000 MW
• Jan 6 – emergency DR, voltage reduction, large unit trips
• 02:51 – voltage reduction warning for RTO
• 04:30 – deploy all emergency DR for RTO (effective 05:30, 06:30)
  – Max gen action for RTO
• 06:00 – emergency purchases from NYISO and MISO begin to flow
• 06:21 – load all max emergency generation
• 06:27 – 100% SR for low ACE
• 08:18 – unit trips; 100% SR
• 15:00 – max emergency gen action and deploy emergency DR across RTO (effective 16:00, 17:00)
• Unanticipated interchange sinking to PJM
  – 8,000 – 10,000 MW – mostly MISO
• 18:15 – cancelled emergency DR
RTO Instantaneous Load January 7, 2014

- 4:30 - RTO Long and Short Lead Notified
- 5:30 - RTO Short Lead Activation
- 6:30 - RTO Long Lead Activation
- 11:00 - RTO Short and Long Lead Released
- 15:00 - RTO Long Lead Notified
- 16:00 - RTO Short Lead Activation
- 17:00 - RTO Long Lead Activation
- 18:16 - RTO Long and Short Lead Released

Emergency DR Event Period

MW

00:00 04:00 08:00 12:00 16:00 20:00 00:00
01/07/2014 01/07/2014 01/07/2014 01/07/2014 01/07/2014 01/07/2014 01/08/2014

RTO Instantaneous Load January 7, 2014
January 7 – LMPs reflect operations

Load Max
Emerg Gen
100% SR

Emergency Purchases

Max Gen Action
Deploy Emer DR
(RTO)

Unit Trips
100% Synch

Reserve Shortages
~7:30 to ~12:20

Voltage Reduction
Warning (RTO)
Jan 7 - Interchange

~9,000 MW of Interchange

Max Gen Action Deploy Emer DR (RTO)

Cancelled DR

Prices drop by ~$1,300
Estimated Demand Response in PJM: January 7, 2014

Notes:
Emergency DR Amounts are CSP estimated Emergency Load Reductions adjusted down based on PJM observation (from morning event).
Actual load reductions are not finalized until up to 3 months after event.
Winter events causes

• Cold!
  – High demand
  – Fuel issues
  – Forced outages
• Large units tripping
• Natural gas
• Demand Response Overview
• Emergency Operations
• Measurement & Verification
• Policy Issues
CBL (customer baseline) – forecast what resource would have used had there been no DR (demand response).
CBL certification process

- **CBL/load forecast**
  - Must be reasonably accurate for participation
  - Accurate forecast $\rightarrow$ load reductions can be quantified

- **RRMSE (relative root mean square error) test**
  - Objective way to determine accuracy of CBL to forecast load
  - $\text{RRMSE} < 20\% \rightarrow \text{accurate CBL}$
  - $\text{RRMSE} > 20\% \rightarrow \text{Variable customers}$

- **Alternative CBLs**
  - May be developed to forecast variable load more accurately
CBL breakdown for all Economic DR registrations

<table>
<thead>
<tr>
<th>CBL</th>
<th>MW</th>
<th>MW (%)</th>
<th>Registration (Count)</th>
<th>Registration (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3 Day Types with SAA (high 4 of 5)</td>
<td>1,122</td>
<td>47%</td>
<td>748</td>
<td>71%</td>
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<tr>
<td>Non-hourly metered sites DLC</td>
<td>768</td>
<td>32%</td>
<td>79</td>
<td>8%</td>
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<tr>
<td>MBL(Max Base Load)</td>
<td>270</td>
<td>11%</td>
<td>170</td>
<td>16%</td>
</tr>
<tr>
<td>Manual</td>
<td>140</td>
<td>6%</td>
<td>28</td>
<td>3%</td>
</tr>
<tr>
<td>3 Day Types (high 4 of 5)</td>
<td>107</td>
<td>4%</td>
<td>23</td>
<td>3%</td>
</tr>
<tr>
<td>7 Day Types with SAA (3 day average)</td>
<td>4</td>
<td>0%</td>
<td>3</td>
<td>0%</td>
</tr>
<tr>
<td>7 Day Types (3 day average)</td>
<td>0.1</td>
<td>0%</td>
<td>1</td>
<td>0%</td>
</tr>
<tr>
<td>3 Day Types with WSA (high 4 of 5)</td>
<td>-</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Metered Generation</td>
<td>-</td>
<td>0%</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td></td>
<td>2,411</td>
<td>100%</td>
<td>1,052</td>
<td>100%</td>
</tr>
</tbody>
</table>

“Manual” CBL represents Same Day 3+2 method used last summer which was calculated and upload by CSP
• Variable resources – RRMSE > 20%
  1. Develop CBL that reduces RRMSE with PJM approval OR
  2. MBL (Max Base Load) as CBL
     • Average of minimum load during prior days
     • Developed to ensure load reductions are not attributed to normal load fluctuations OR
  3. Cannot participate in Economic DR

• **Goal:** to develop new CBLs
  – More accurately forecast certain resources (Reduce RRMSE below 20%)
  – More resources can participate in economic DR
• Focused on all current registrations (115) that just missed accuracy threshold
  – RRMSE 20-40% using existing CBL methods
• Over 20 new CBLs tested
  – Including: moving average, median, ARIMA (autoregressive integrated moving average), 5 day type, etc., 3+2, match 3 day average
• Review of alternate CBLs from summer 2012
  – MBL (max base load)
  – 3+2
• 20 CBLs
  – Standard CBL: High 4/5 – 2/3 like days
    • 3 day type: Mean, Mean + SAA (Standard CBL)
    • 25% usage threshold
  – Past 5/5 – 3/3 like days
    • 3 day type: Mean, Median, Mean + SAA, Median + SAA
    • 5 day type: Mean, Median, Mean + SAA, Median + SAA
    • 7 day type: Mean, Median, Mean + SAA, Median + SAA
    • All hours mixed – Mean, Median
  – 3+2
  – ARIMA
  – MBL: Mean, Median

• 115 Registrations
  – RRMSE 20-40% using existing methods
### Results

<table>
<thead>
<tr>
<th>RRMSE range</th>
<th>Percent of Registrations</th>
<th>Min. across existing CBL</th>
<th>Match 3 day avg</th>
<th>3 + 2</th>
<th>Min. across variable options</th>
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</thead>
<tbody>
<tr>
<td>&lt;20%</td>
<td>&lt;20%</td>
<td>0%</td>
<td>35%</td>
<td>13%</td>
<td>42%</td>
</tr>
<tr>
<td>20%-30%</td>
<td>20%-30%</td>
<td>63%</td>
<td>39%</td>
<td>22%</td>
<td>39%</td>
</tr>
<tr>
<td>&gt;30%</td>
<td>&gt;30%</td>
<td>37%</td>
<td>25%</td>
<td>64%</td>
<td>18%</td>
</tr>
<tr>
<td>&lt;20%</td>
<td>20%-30%</td>
<td>0%</td>
<td>8%</td>
<td>32%</td>
<td>37%</td>
</tr>
<tr>
<td>20%-30%</td>
<td>&lt;20%</td>
<td>26%</td>
<td>39%</td>
<td>12%</td>
<td>19%</td>
</tr>
<tr>
<td>&gt;30%</td>
<td>20%-30%</td>
<td>74%</td>
<td>53%</td>
<td>56%</td>
<td>44%</td>
</tr>
</tbody>
</table>

Expect to move 42% (48) of registrations with RRMSE score >20% and <40% (115) to new alternative CBL with RRMSE <20%
Proposed Solution – Adopt 2 Alternative CBLs

**CBL 1 = Same Day (3 + 2)**

- Average of 3 hours before event (after skipping one hour) and 2 hours after event (after skipping one hour)
- CSP may use only if no significant pre or post change in operations that will impact CBL calculation
  - Thermal load (pre-cooling or snapback)
  - Change in typical operations (including on-site generation schedule)
- No events during HE1, 2, 3, 23, 24 (to ensure hours are available to calculate CBL)

Designed for customer with daily usage that is fairly consistent (intra-day hourly volatility)
Same Day 3+2 Example

- **Actual load**
- **3+2 CBL**

**Graph Details:**
- **Y-axis:** Load (MMW)
- **X-axis:** Hour Ending
- **Shaded Areas:**
  - 3 hours before event
  - Event
  - 2 hours after event

The graph illustrates the load variation over time, highlighting periods 3 hours before, during, and 2 hours after an event.
CBL 2 = Match Day (3 day average)

- Take average of 3 non-event days that have the most similar usage to non-event hours (exclude hour before and hour after event from non-event hours) on event day.
- Select 3 days to average. For each day in CBL basis day limit:
  - Take the difference between each comparison hour (non-event hours, excluding hour before and hour after event) from the event day and the same hour on look back day to determine the hourly difference for each comparison hour for each day.
  - Square all the hourly differences for each day and then sum the squared differences to determine the daily differences.
- Select the 3 days from the CBL Basis Day Limit with the smallest daily differences to determine the CBL Days.
- Average each of the event hours across the three CBL Days to determine the CBL for each event hour.
- First event hour to last event hour in operating day will comprise no more than 10 elapsed hours. This will ensure there are at least 12 non-event hours in the operating day to determine the selection of CBL days.

Designed for customer daily usage pattern that vary and are not based on type of day (based more on production cycle for day)
Focus on these customers
• Demand Response Overview
• Emergency Operations
• Measurement & Verification
• Policy Issues
• Operational DR
• Capacity arbitrage
• Limiting DR in RPM auction
• Must offer
• M&V
• Sampling for residential customers in ancillary services
• Normal operations
• Gas/electric coordination
• Higher penetration NG
  – Higher price volatility
  – Lower reliability
Power Day versus Gas Day

Day Ahead Set Up

Power Day 1

Off-Peak

On-Peak

Gas Day 0

Gas Day 1

Gas Day 2 Timely nominations due

Gas Day 2 Evening nominations due

Day Ahead Gas Trading

Intra-day Gas Trading

Power Day 2 Offers due

Power Day 2 Awards announced

Current Eastern Time Schedule
Potential Research Areas

- Value of fuel diversity
- Load forecasting
- Forecasting DR resource
- Measurement & verification for DR
- Electric/gas coordination
- Outage timing
- Incentives/market structure to reduce forced outages
- Interchange forecasting, market structure
Questions?
<table>
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<tr>
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<tbody>
<tr>
<td>Load Weighted Energy</td>
<td>$35.23</td>
<td>$38.66</td>
<td>9.7%</td>
<td>71.8%</td>
<td>71.7%</td>
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<tr>
<td>Capacity</td>
<td>$6.05</td>
<td>$7.13</td>
<td>17.8%</td>
<td>12.3%</td>
<td>13.2%</td>
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<tr>
<td>Transmission Service Charges</td>
<td>$4.78</td>
<td>$5.20</td>
<td>8.7%</td>
<td>9.7%</td>
<td>9.6%</td>
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<tr>
<td>Reactive</td>
<td>$0.43</td>
<td>$0.80</td>
<td>87.6%</td>
<td>0.9%</td>
<td>1.5%</td>
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<tr>
<td>Energy Uplift (Operating Reserves)</td>
<td>$0.79</td>
<td>$0.59</td>
<td>(25.5%)</td>
<td>1.6%</td>
<td>1.1%</td>
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<tr>
<td>PJM Administrative Fees</td>
<td>$0.42</td>
<td>$0.42</td>
<td>(2.1%)</td>
<td>0.9%</td>
<td>0.8%</td>
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<tr>
<td>Transmission Enhancement Cost Recovery</td>
<td>$0.34</td>
<td>$0.39</td>
<td>15.5%</td>
<td>0.7%</td>
<td>0.7%</td>
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<tr>
<td>Regulation</td>
<td>$0.26</td>
<td>$0.24</td>
<td>(5.3%)</td>
<td>0.5%</td>
<td>0.5%</td>
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<tr>
<td>Black Start</td>
<td>$0.03</td>
<td>$0.14</td>
<td>437.7%</td>
<td>0.1%</td>
<td>0.3%</td>
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<tr>
<td>Capacity (FRR)</td>
<td>$0.52</td>
<td>$0.11</td>
<td>(79.4%)</td>
<td>1.1%</td>
<td>0.2%</td>
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<tr>
<td>Transmission Owner (Schedule 1A)</td>
<td>$0.08</td>
<td>$0.08</td>
<td>(0.3%)</td>
<td>0.2%</td>
<td>0.2%</td>
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<tr>
<td>Day Ahead Scheduling Reserve (DASR)</td>
<td>$0.05</td>
<td>$0.06</td>
<td>21.9%</td>
<td>0.1%</td>
<td>0.1%</td>
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<tr>
<td>Synchronized Reserves</td>
<td>$0.04</td>
<td>$0.04</td>
<td>3.1%</td>
<td>0.1%</td>
<td>0.1%</td>
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<tr>
<td>NERC/RFC</td>
<td>$0.02</td>
<td>$0.02</td>
<td>(1.2%)</td>
<td>0.0%</td>
<td>0.0%</td>
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<tr>
<td>RTO Startup and Expansion</td>
<td>$0.01</td>
<td>$0.01</td>
<td>(1.4%)</td>
<td>0.0%</td>
<td>0.0%</td>
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<tr>
<td>Load Response</td>
<td>$0.01</td>
<td>$0.01</td>
<td>41.6%</td>
<td>0.0%</td>
<td>0.0%</td>
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<tr>
<td>Non-Synchronized Reserves</td>
<td>$0.00</td>
<td>$0.00</td>
<td>127.3%</td>
<td>0.0%</td>
<td>0.0%</td>
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<tr>
<td>Transmission Facility Charges</td>
<td>$0.00</td>
<td>$0.00</td>
<td>17.2%</td>
<td>0.0%</td>
<td>0.0%</td>
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<tr>
<td>**Total</td>
<td><strong>$49.07</strong></td>
<td><strong>$53.92</strong></td>
<td><strong>9.9%</strong></td>
<td><strong>100.0%</strong></td>
<td><strong>100.0%</strong></td>
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<tr>
<td></td>
<td>2012</td>
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<td></td>
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<td>--------------------------------</td>
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<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Load</td>
<td>775,184 GWh</td>
<td>784,515 GWh</td>
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<tr>
<td>Generation</td>
<td>790,090 GWh</td>
<td>797,100 GWh</td>
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<tr>
<td>Imports (+) / Exports (-)</td>
<td>672 GWh</td>
<td>3,104 GWh</td>
<td></td>
<td></td>
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<td>Losses</td>
<td>16,970 GWh</td>
<td>17,389 GWh</td>
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<tr>
<td>Regulation Requirement*</td>
<td>943 MW</td>
<td>784 MW</td>
<td></td>
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<tr>
<td>RTO Primary Reserve Requirement**</td>
<td>NA</td>
<td>2,085 MW</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>Total Billing</td>
<td>$29.18 Billion</td>
<td>$33.86 Billion</td>
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<td></td>
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<tr>
<td>Peak</td>
<td>Jul 17, 2012 17:00</td>
<td>Jul 18, 2013 17:00</td>
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<td></td>
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<td></td>
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<tr>
<td>Peak Load</td>
<td>154,344 MW</td>
<td>157,508 MW</td>
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<tr>
<td>Load Factor</td>
<td>0.76</td>
<td>0.76</td>
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<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Installed Capacity</td>
<td>As of 12/31/2012</td>
<td>As of 12/31/2013</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Installed Capacity</td>
<td>181,990 MW</td>
<td>183,095 MW</td>
<td></td>
<td></td>
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</tbody>
</table>

* Daily average

** Regulatory requirement remained 2,063MW throughout the year. Amount show is daily average
<table>
<thead>
<tr>
<th>Year</th>
<th>Total MWh</th>
<th>Total Credits</th>
<th>$/MWh</th>
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<tbody>
<tr>
<td>2003</td>
<td>19,518</td>
<td>$833,530</td>
<td>$42.71</td>
</tr>
<tr>
<td>2004</td>
<td>58,352</td>
<td>$1,917,202</td>
<td>$32.86</td>
</tr>
<tr>
<td>2005</td>
<td>157,421</td>
<td>$13,036,482</td>
<td>$82.81</td>
</tr>
<tr>
<td>2006</td>
<td>258,468</td>
<td>$10,213,828</td>
<td>$39.52</td>
</tr>
<tr>
<td>2007</td>
<td>714,148</td>
<td>$31,600,046</td>
<td>$44.25</td>
</tr>
<tr>
<td>2008</td>
<td>452,222</td>
<td>$27,087,495</td>
<td>$59.90</td>
</tr>
<tr>
<td>2009</td>
<td>57,157</td>
<td>$1,389,136</td>
<td>$24.30</td>
</tr>
<tr>
<td>2010</td>
<td>74,070</td>
<td>$3,088,049</td>
<td>$41.69</td>
</tr>
<tr>
<td>2011</td>
<td>17,398</td>
<td>$2,052,996</td>
<td>$118.00</td>
</tr>
<tr>
<td>2012</td>
<td>145,019</td>
<td>$9,284,118</td>
<td>$64.02</td>
</tr>
<tr>
<td>2013</td>
<td>133,071</td>
<td>$8,035,761</td>
<td>$60.39</td>
</tr>
</tbody>
</table>
DR regulation participation

- Total Payments
- Total MWh

- Dollars
- MWh


- Payments range from $- to $75,000
- MWh range from 0 to 2,500

Graph showing monthly DR regulation participation from January 2013 to December 2013.
DR SR participation

The graph illustrates the relationship between total payments and total MWh from January 2013 to December 2013. The graph shows a general trend of decreasing payments and MWh from January to June, followed by an increase in both payments and MWh from July to December. The payments range from approximately $100,000 to $600,000, while the MWh range from 0 to 150,000 MWh.
# Emergency Product Type Requirements

<table>
<thead>
<tr>
<th>Requirement</th>
<th>Limited DR</th>
<th>Extended Summer DR</th>
<th>Annual DR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Availability</td>
<td>Any weekday, other than NERC holidays, during June – Sept. period of DY</td>
<td>Any day during June-October period and following May of DY</td>
<td>Any day during DY (unless on an approved maintenance outage during Oct. - April)</td>
</tr>
<tr>
<td>Maximum Number of Interruptions</td>
<td>10 interruptions</td>
<td>Unlimited</td>
<td>Unlimited</td>
</tr>
</tbody>
</table>
| Hours of Day Required to Respond  | 12:00 PM – 8:00 PM                                                          | 10:00 AM – 10:00 PM                                                               | Jun – Oct. and following May: 10 AM – 10 PM  
Nov. – April: 6 AM- 9 PM                                                  |
| Maximum Duration of Interruption  | 6 Hours                                                                     | 10 Hours                                                                          | 10 Hours                                                                 |
| Notification                      | Must be able to reduce load within 2 hours of notification                  |                                                                                   |                                                                           |
| Event Compliance                  | Data due 45 day after end of event month                                    |                                                                                   |                                                                           |
| Test Compliance                   | Mandatory test required if no emergency event called                       |                                                                                   |                                                                           |
Emergency DR Revenue and Penalties

• Revenue
  – RPM clearing price * Capacity volume
    • $6,000 - $80,000 per year for 1 MW (based on prior auctions)
  – Energy paid at higher of LMP or offer price

• Penalties
  – Resource Capability Deficiency
    • Annual Revenue + Higher of (20% * Revenue OR $20/MW-day)
  – Event Compliance
    • On Peak: Lesser of (1/number of events or 50%) * Annual Revenue
    • Off Peak: 1/52 * Annual Revenue
• Focused on all current registrations (115) that just missed accuracy threshold
  – RRMSE 20-40% using existing CBL methods
• Over 20 new CBLs tested
  – Including: moving average, median, ARIMA (autoregressive integrated moving average), 5 day type, etc., 3+2, match 3 day average
• Review of alternate CBLs from summer 2012
  – MBL (max base load)
  – 3+2