Recent Challenges and Developments in Electricity Markets

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Outline

• Electricity Markets Overview
• Challenges from Variable Energy Resources (VER) Integration
• Market Design Enhancements
• New Risk Management Tools
• Coordination between Gas and Electricity
• Q&A
Electricity Markets Overview
Map of ISOs and RTOs in North America

6 ISOs in North America: CAISO, NYISO, ERCOT, AEISO, IESO, NBSO
4 RTOs in North America: PJM, MISO, SPP, ISO-NE
PJM

- 65,441 Miles of Transmission
- 185,600 GW of Generation
- 60+ Million Consumers
- Peak Load of 158 GW
- Network Model
  - Approx. 15 000 buses
  - Approx. 1300 units
- 500 members
  - Power Generators
  - Transmission Owners
  - Electricity Distributors
  - Power Marketers
  - Large Consumers
- Area served
  - 13 states + DC
  - 164k sq. miles.
PJMs Market Evolution Scalability:

- Market introduced with a single Marginal Cost Price in April 1997

- Serious operational problem in managing system security
  - Option of self-scheduling generation
  - Rule-based congestion management

- Nodal pricing introduced in April 1998
  - Generators are paid nodal price at injection bus
  - Load pay nodal price at withdrawal bus
  - Generators receive direct commercial signals
  - Occurrence of transmission congestion significantly reduced

- Two Settlement System: 1999
  - Day-ahead Scheduling
  - Real-time Dispatch

- Day-Ahead Regulation Market: 2000
  - Floor price determined after day-ahead market
  - Sequential method

- SPREGO: 2002
  - Initial spinning and regulation market

- SPREGO: 2006
  - MIP-based near-real-time co-optimization
  - Render co-optimization to resolve many practical operational challenges

- Day-ahead Scheduling Reserves: 2008
  - Spinning reserve and supplemental reserve

- Capacity Market (RPM): 2008

- AC2 – Advanced Control Center: 2010
  - SOA Integration

- Generation Control Applications: 2010
  - Smart Dispatch: 2010
    - Multi-period dynamic dispatch
    - Multiple time horizon scheduling

- Price Responsive Demand: 2011

- FERC Order 745 and 755: 2012
  - 1st RTO to comply in the US

- Scarcity Pricing: 2012
  - Reserve demand curves
LMP Based Market Process Overview

- **Day-Ahead Market (DA Market)**
  - DA Market Offers (Energy and Operating Reserve), Bids, Operating Reserve Requirements
  - DA Market Commitment
  - Resource and Load Meter Data

- **Reliability Unit Commitment (RUC)**
  - DA Market Commitment
  - DA Market & Net RTM Settlements

- **Real-Time Market (RTM)**
  - RT Market Offers, Load Forecast, Operating Reserve Requirements
  - RUC Commitment
  - Dispatch Instruction, cleared Operating Reserve (MW) (5 minute)
  - Dispatch Instruction, cleared Operating Reserve (MW and Price) (5 minute)

- **FTR Markets**
  - Real-time system condition

- **EMS**

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• The Day-Ahead Market outcome is a schedule that minimizes RTO total [production offer costs minus demand bid revenues], as determined based on Market Participants Offers and Bids.
DA Reliability Unit Commitment (RUC)

- The Day-Ahead RUC process outcome is a schedule that minimizes RTO total commitment costs, as determined based on generation resources (real-time) offers and system load and Operating Reserve requirement forecasts.
The Real-Time Balancing Market (RTBM) is the market mechanism by which SPP balances real-time load and generation committed by the Day-Ahead Market and RUC processes.

Its objective is to minimize the total RTO production cost based on the online resources Real-Time Offers and statuses, short-term load forecast and Operating Reserve requirements.
Market started on April 01, 2005

Visualize Large Amount of Complex Information
Market Management System Components and Architecture

- Common Source Modeler
- Market Participant Interface
- Workflow Engine
- Market Operator Interface
- Outage Scheduler

Enterprise Service Bus

- Market Database
- Network
- Commercial
- Adapter
- Adapter
- Adapter
- Adapter
- Adapter
- Adapter

- EMS
- SCUC
- SCED
- Settlements/Billing
- Transaction Scheduler
- Renewable Forecast

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Challenges From VER Integration
California ISO 2020 Net Load Profile

Load, Wind and Solar Profiles – Base Scenario
January 2020

- 6,700 MW in 3-hours
- 7,000 MW in 3-hours
- 12,700 MW in 3-hours

Net Load = Load - Wind - Solar

ERCOT Wind Generation Forecast vs. Actual

From ERCOT website
VER Integration Challenges

• Real-Time balancing risks
  – Need more flexible ramp in real-time operation

• Day-ahead and look-ahead unit commitment risks
  – Need the commitment immunized against VER uncertainty
  – Model distributed renewable resources

• Long-term resource revenue and capacity adequacy
  – Lower average energy cost (wind can offer in negative prices due to government tax credit)
  – More uncertainty for conventional generators, and hence less incentive for long term investment
Market Design Enhancements
Recent Market Design Enhancements

- FERC Order 719 – Reserve Scarcity Pricing
- FERC Order 755 – Regulation Pay For Performance
- FERC Order 765 – 15-minute scheduling
- FERC Order 745 – Allow DR to set LMP
- Ramp product – CAISO and MISO

- Capacity Markets
- Potential Energy Imbalance Market (EIM) in the West
Regulation Pay for Performance

From pjm.com
Regulation Pay for Performance

• Issues
  – No differentiation for resources that can respond more quickly and/or accurately
  – Compensation targeted to offset energy lost opportunity cost not to incent performance

• PJM Pay for Performance - The incentive payment will be based on
  – The accuracy with which a resource followed the regulation signal during the hour.
  – The quantity it moved during the hour it provided regulation.
  – The highest cleared regulation offer price during the operating hour.
  – On top of existing regulation capacity payment.
  – Facilitate growth in alternative technology resources capable of near instantaneous responses to control signals (batteries, flywheels, etc.)
Regulation Pay for Performance

105-gallon electric water heater demonstrates minimization of cost while responding to the PJM wholesale price signal and the PJM frequency regulation signal.

From pjm.com
Operational Issues and Practices in the West

• 37 Balancing Authorities (BAs) that balance within their footprints

• Variability can have greater impact in smaller footprints

• Variability (from wind and solar) is not shared across the interconnection-- each BA is on its own when balancing, which could lead to utilization of higher-cost resources

• Large unused line capacity to ensure reliability against contingencies due to not enough real-time grid information across the region
Potential EIM Footprint

• An EIM is a tool that dispatches lowest cost resources to address energy imbalances (every 5 minutes), while maintaining reliability

• Benefits of regional dispatch
  – Economic benefits
  – Reliability benefits
  – Renewable integration

• Larger footprint is better, but something less than all of the West would still work
# PacifiCorp and CAISO EIM Partnership

<table>
<thead>
<tr>
<th>TODAY</th>
<th>EIM</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAISO and PacifiCorp own/operate respective transmission assets, independently schedule for load and resource balance hour-ahead, set aside contingency reserves (for PacifiCorp, consistent with Northwest Power Pool reserve sharing pool agreement)</td>
<td>No change</td>
</tr>
<tr>
<td>PacifiCorp manually dispatches resources internal to its balancing authority to balance intra-hour load and resource changes</td>
<td>CAISO will optimize the combined PacifiCorp and CAISO EIM footprint with automated redispatch every five minutes of all generation resources that are voluntarily bid into the EIM</td>
</tr>
<tr>
<td>Diversity benefits are restricted internal to each respective balancing authority</td>
<td>Diversity benefits are captured across a much larger footprint</td>
</tr>
<tr>
<td>- Load fluctuations</td>
<td></td>
</tr>
<tr>
<td>- Wind fluctuations</td>
<td></td>
</tr>
<tr>
<td>- Natural gas prices</td>
<td></td>
</tr>
<tr>
<td>- Heat rates</td>
<td></td>
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</tbody>
</table>
New Risk Management Tools
Level of Uncertainty Varies along the Processes

- Expected difference between the actual system condition and the market clearing models

MISO Operating Reserves
- Regulating reserve
- Spinning reserve
- Supplemental reserve

RAC: Reliability Assessment Commitment
LAC: Look-ahead Unit Commitment
RT-SCED: Real-time Security Constrained Economic Dispatch
Purpose of Stochastic and Robust UC

• Determine one set of commitment that can support operations under multiple discrete scenarios or within a range of uncertainties

• The mathematical model can better formulate SCUC under uncertainties
  - Ensure adequate future actions available for uncertainties under consideration
  - Unlike reserve and headroom, the solution from stochastic UC and robust optimization can ensure future actions satisfying commitment, dispatch and transmission constraints
Stochastic Unit Commitment

- One set of commitment to cover multiple scenarios
- Minimize the total of
  - Commitment cost: startup and no load cost under the set of commitment
  - Expected dispatch cost plus violation cost
    \[ \text{Min}_x \{ c^T x + \sum_{i \in I} [p_i \times \text{Min}_{(y,s) \in \Omega(x,d_i)} (b^T y + v^T s)] \} \]
    \[ \text{s.t. } Fx \leq f, x \text{ binary} \]
    where \( \Omega(x,d_i) = \{(y, s): Hy - H_s s \leq h, Ax + By - G_s s \leq g, I_u y + D_s s = d_i \} \)
- Challenging to determine
  - Scenarios and
  - Probabilities
Robust Unit Commitment

- One set of commitment to cover a range of uncertainties
- Minimize the total of:
  - Commitment cost
  - Worst scenario dispatch plus violation cost within an uncertainty range

\[
\min_x \{c^T x + \max_{d \in \mathcal{D}} \min_{(y,s) \in \Omega(x,d)} (b^T y + v^T s)\}
\]

s.t. \(Fx \leq f, x \) binary

where \(\Omega(x,d) = \{(y,s) : Hy - H_s s \leq h, Ax + By - G_s s \leq g, I_u y + D_s s = d\}\)

- No need to generate scenarios
- Can be conservative

\text{to use the worst case scenario dispatch cost}
Unified Stochastic/Robust Optimization UC

- Combine the two approaches
- Minimize the total of:
  - Commitment cost
  - Dispatch plus violation cost under nominal scenario (or multiple predetermined scenarios)
  - Worst scenario violation cost within an uncertainty range

\[
\begin{align*}
\min_x \{ c^T x + \sum_{i \in I} [p_i \times \min_{(y,s) \in \Omega(x,d_i)} (b^T y + v^T s)] + [\max_{d \in \mathcal{D}} \min_{(y,s) \in \Omega(x,d)} v^T s] \} \\
\text{s.t. } Fx \leq f, \ x \text{ binary}
\end{align*}
\]

where \( \Omega(x, d) = \{(y, s): Hy - H_s s \leq h, Ax + By - G_s s \leq g, I_u y + D_s s = d\} \)

\( \Omega(x, d_i) = \{(y, s): Hy - H_s s \leq h, Ax + By - G_s s \leq g, I_u y + D_s s = d_i\} \)

- Benefit
  - Minimize total cost for nominal scenario (or multiple predetermined scenarios) while maintaining maximal feasibility within the uncertainty range
Coordination Between Gas and Electricity Wholesale Markets
US EIA Natural Gas Prediction

Figure 2. U.S. natural gas production, 1990-2035 (trillion cubic feet per year)

Figure 85. Natural gas consumption by sector, 1990-2040 (trillion cubic feet)
New England region is heavily dependent on the natural gas generation.

ISO NE Energy Source 2012

- Coal: 27.9%
- Gas: 38.3%
- Oil/Gas: 9.8%
- Hydro: 9.1%
- Other: 6.2%

Energy Price and Gas Price Correlation

- Day-Ahead ($/MWh)
- Real-Time ($/MWh)
- Natural Gas ($/MMBtu)
FERC Initiative

- Both Natural Gas Markets and Electricity Markets are regulated by FERC
  - Two markets are coupled
- FERC is actively pushing for more coordination between natural gas markets and electricity markets
  - 3 FERC technical conferences so far
  - Improve efficiency by sharing more information
- Many regional working group discussions
Mismatch between Gas and Electricity Markets

- **Gas Day-2**
  - Daily Initial & Evening Nomination Effective Flow at 10:00 am
  - Evening Nomination Deadline 19:00

- **Gas Day-1**
  - Daily Initial Nomination Deadline 12:30
  - Evening Nomination Deadline 19:00
  - Gas Day -1 Intra Day 1 Nomination 11:00
  - Gas Day -1 Intra Day 2 Nomination 18:00
  - Gas Day -1 Effective Flow 18:00
  - Gas Day -1 Effective Flow 22:00

- **Gas Day**
  - Daily Initial & Evening Nomination Effective Flow at 10:00 am
  - Gas Day -1 Intra Day 1 Effective Flow 18:00

- **Electric Day-2**
  - Day-ahead Market close 12:00

- **Electric Day-1**
  - Liquidity of Gas Market Dries Up 10:00
  - Day-ahead Market Complete 16:00
  - Re-offer Close 18:00
  - RAA Complete 22:00

- **Electric Day**
  - Continuous RAA and Real-time Market
Future Work

• Consider Natural Gas price and transportation’s impacts on power transmission planning

• More detailed model of gas pipelines and contracts in electricity market operation

• Potential Co-optimization between natural gas and electricity markets
Thank You!

Questions?