Electricity Market Solutions for Generator Revenue Sufficiency with Increased Variable Generation

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There is a rapid shift towards more renewable resources in the U.S. power grid:

- State and federal incentives
  - 38 states with RPS or RPG
- U.S. wind capacity: 65 GW
- U.S. solar capacity: 20 GW

Source: EIA Electric Power Monthly Table 6.2B
Characteristics of Renewables

1. Variability and uncertainty
   - Increased reserve requirements
     - More flexible capacity needed

2. Zero marginal cost of generation
   - Reduction in LMPs/wholesale electricity prices
     - Generators lose revenue
Research Questions

1. How will wind power affect prices of energy and reserves?

2. What are implications for revenue sufficiency?

3. Are new market designs needed to ensure resource adequacy?
Approach

- Model three different market policies to value reserves, energy, and capacity

1) Operating Reserves Demand Curve
   - ERCOT

2) Fixed Reserves Scarcity Pricing
   - Used in most U.S. markets
   - We assume:
     - $100/MW-h spin-up
     - $500/MW-h total reserve

3) Capacity Payments
   - $40/kW-year
   - No reserve scarcity pricing
**Approach**

- **Case study application to “ERCOT” system**
  - 4 thermal unit types (Nuclear, Coal, NGCC, NGCT)
  - 2013 ERCOT wind and load profile
  - 2024 total load projection (15% growth)
  - Wind varies from 10% to 40% of total demand

- **Cost Minimizing MIP**
  - Unit expansion
  - Commitment
  - Generation/Reserves
  - Integer unit representation
  - 8760 hourly periods

- **Sensitivities**
  - No PTC
  - No Wind Reserves
  - High Natural Gas Prices

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**Parameter**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak Load (MW)</td>
<td>77,471</td>
</tr>
<tr>
<td>Existing Generation Capacity (MW)</td>
<td>73,380</td>
</tr>
<tr>
<td>Nuclear</td>
<td>4,400</td>
</tr>
<tr>
<td>Coal</td>
<td>19,500</td>
</tr>
<tr>
<td>NGCC</td>
<td>43,600</td>
</tr>
<tr>
<td>NGCT</td>
<td>5,880</td>
</tr>
<tr>
<td>Maximum Wind Resource Capacity Factor</td>
<td>33.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Nuclear</th>
<th>Coal</th>
<th>NGCC</th>
<th>NGCT</th>
<th>Wind</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (MW)</td>
<td>2,200</td>
<td>1,300</td>
<td>400</td>
<td>210</td>
<td>-</td>
</tr>
<tr>
<td>Max. Output (MW)</td>
<td>2,046</td>
<td>1,214</td>
<td>378</td>
<td>202</td>
<td>-</td>
</tr>
<tr>
<td>Min. Output (MW)</td>
<td>2,046</td>
<td>520</td>
<td>160</td>
<td>84</td>
<td>-</td>
</tr>
<tr>
<td>Overnight Cost ($/kW)</td>
<td>5,501</td>
<td>2,925</td>
<td>1,021</td>
<td>673</td>
<td>1,630</td>
</tr>
<tr>
<td>Fixed OM ($/kW)</td>
<td>93.28</td>
<td>31.18</td>
<td>15.37</td>
<td>7.04</td>
<td>39.55</td>
</tr>
<tr>
<td>Annualized Fixed and Investment Cost ($/MW)</td>
<td>373,595</td>
<td>297,416</td>
<td>78,186</td>
<td>51,537</td>
<td>164,371</td>
</tr>
<tr>
<td>Var OM ($/MWh)</td>
<td>2.14</td>
<td>4.47</td>
<td>3.27</td>
<td>10.37</td>
<td>-</td>
</tr>
<tr>
<td>Heat Rate (btu/kWh)</td>
<td>10,464</td>
<td>8,740</td>
<td>6,333</td>
<td>10,450</td>
<td>-</td>
</tr>
<tr>
<td>Fuel Cost ($/MMbtu)</td>
<td>0.50</td>
<td>2.34</td>
<td>4.96</td>
<td>9.60</td>
<td>-</td>
</tr>
<tr>
<td>Marginal Generation Cost ($/MWh)</td>
<td>7.37</td>
<td>23.80</td>
<td>30.64</td>
<td>55.00</td>
<td>-</td>
</tr>
<tr>
<td>No Load Cost ($/MW)</td>
<td>-</td>
<td>1.10</td>
<td>4.78</td>
<td>8.86</td>
<td>-</td>
</tr>
<tr>
<td>Max Spinning-up Reserve (% of Max. Output)</td>
<td>-</td>
<td>20%</td>
<td>50%</td>
<td>80%</td>
<td>-</td>
</tr>
<tr>
<td>Ramp Up Limit (% of Max. Output/hr)</td>
<td>-</td>
<td>35%</td>
<td>50%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Ramp Down Limit (% of Max. Output/hr)</td>
<td>-</td>
<td>35%</td>
<td>50%</td>
<td>100%</td>
<td>-</td>
</tr>
<tr>
<td>Start-Up Cost ($/MW)</td>
<td>-</td>
<td>131.35</td>
<td>61.80</td>
<td>40.60</td>
<td>-</td>
</tr>
<tr>
<td>Shut-Down Cost ($/MW)</td>
<td>-</td>
<td>1.31</td>
<td>0.62</td>
<td>0.41</td>
<td>-</td>
</tr>
<tr>
<td>Forced Outage Rate</td>
<td>7.0%</td>
<td>6.6%</td>
<td>7.7%</td>
<td>7.7%</td>
<td>-</td>
</tr>
</tbody>
</table>
• ORDC derived from recent ERCOT implementation
  – 24 distinct PWL curves for month/hour pairs

\[
\begin{align*}
P_{ns} &= 0.5 \cdot (VOLL - \lambda) \cdot \left( 1 - CDF\left(\mu_{h,m,w}, \sigma_{h,m,w}, rs + rns - X\right)\right) \\
\end{align*}
\]

\[
\begin{align*}
P_{s} &= P_{ns} + 0.5 \cdot \max(VOLL - \lambda, 0) \cdot \left( 1 - CDF\left(\frac{\mu_{h,m,w}}{2} \cdot \frac{\sigma_{h,m,w}}{\sqrt{2}}, rs - X\right)\right)
\end{align*}
\]
Formulation

**ORDC**

\[
\min \sum_{i \in I} u_i \cdot (C_i + F_i) \cdot \bar{P}_i + \sum_{i \in I} \sum_{t \in T} MC_i \cdot g_{i,t} + SUC_i \cdot y_{i,t} + SDC_i \cdot x_{i,t} + NLC_i \cdot z_{i,t} \cdot \bar{P}_i \\
+ \sum_{t \in T} VOLL \cdot es_t - PTC \cdot wg_t - \sum_{t \in T} RBS_t [R_s_t] + RBNS_t [Rns_t]
\]

**FRSP/CP**

\[
\min \sum_{i \in I} u_i \cdot (C_i + F_i - CP) \cdot \bar{P}_i + \sum_{i \in I} \sum_{t \in T} MC_i \cdot g_{i,t} + SUC_i \cdot y_{i,t} + SDC_i \cdot x_{i,t} + NLC_i \cdot z_{i,t} \cdot \bar{P}_i \\
+ \sum_{t \in T} ESC \cdot es_t + SRSC \cdot srs_t + NRSC \cdot nrs_t
\]

- **Shadow Price**
  \[
  \sum_{i \in I} rs_{i,t} + wr_t + rss_t = RRs_t \quad \forall \ t \in T
  \]
  \[
  \sum_{i \in I} (rs_{i,t} + rns_{i,t}) + wr_t + rns_t = RRs_t + RRns_t \quad \forall \ t \in T
  \]

**Reserve targets are based on ORDC results.**
- **Spin**: $15/MW-h
- **Non-Spin**: $.01/MW-h

**Energy/reserve prices in each period are set equal to the marginal cost/benefit of their provision**
## Formulation

### Load Balance

\[ \sum_{i \in I} g_{i,t} + w g_t + e s_t = D_t \]

**Shadow Price**

**LMP**

### Thermal Output

\[ g_{i,t} + r s_{i,t} \leq z_{i,t} \cdot O_i \quad \forall i \in I, t \in T \]
\[ g_{i,t} \geq z_{i,t} \cdot O_i \quad \forall i \in I, t \in T \]

### Ramping

\[ g_{i,t} \leq g_{i,t-1} + z_{i,t} \cdot RU_i \quad \forall i \in I, t \in T \neq 1 \]
\[ g_{i,t} \geq g_{i,t-1} - z_{i,t-1} \cdot RD_i \quad \forall i \in I, t \in T \neq 1 \]

### Reserves

\[ r s_{i,t} \leq z_i \cdot \overline{P}_i \cdot SPR_i \quad \forall i \in I, s \in S, t \in T \]
\[ r n s_{i,t} \leq (u_i - z_i) \cdot \overline{P}_i \cdot NSR_i \quad \forall i \in I, s \in S, t \in T \]

### Wind Balance

\[ w g_t + w r_t + w c_t = W_t \quad \forall t \in T \]

### Unit Commitment

\[ z_{i,t} = z_{i,t-1} + y_{i,t} - x_{i,t} \quad \forall i \in I, t \in T \neq 1 \]
\[ z_{i,t} \leq u_i \quad \forall i \in I, t \in T \]
\[ x_{i,t}, y_{i,t}, z_{i,t} \geq 0 \quad \forall i \in I, t \in T \]

- Integer variables for expansion and commitment
- Significant reduction in computation time (up to 5000x*)
- Enables solving for full year of operations (8760 hourly periods)

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Results: Capacity Expansion

- Only new NGCT capacity is developed
  - CP results in most new capacity
  - ORDC and FRSP are comparable
Results: Prices

- Prices drop with increasing wind

- **ORDC > CP**
  - CP has no reserves pricing mechanism
  - Lower prices
  - Extra capacity developed
    - Essentially no lost load

- **FRSP > ORDC**
  - Higher reserve prices
    - Scarcity price spikes
    - Mostly non-spin
  - Less frequent lost load
    - Few hours = large price impact
Results: Exceedance Curve

- For full 8760 hour year
- ORDC -> More continuous price spectrum
### Hourly Generation and Reserves

- Summer week with 40% wind penetration
- High wind and spinning reserves at night
Results: Generator Profits

- Nuclear, Coal and Wind profits decrease with increasing wind
  - More exposed to lower off-peak prices
- Gas units receive additional revenues from providing reserves
- $40/kW-year capacity payments provide less revenue than ORDC/FRSP
  - Assumption that there is no reserve scarcity pricing
**Results: Generator Profits w/o Capital Costs**

- Most units are profitable without capital costs
Results: Policy Sensitivity

- Eliminating the PTC
  - Raises energy prices and baseload revenues
  - Reduces wind profits

- No wind reserves
  - More gas capacity is kept for reserves
  - Baseload units provide the marginal unit more often
Results: NG Price Sensitivity

- $10/MMbtu – New nuclear is developed for 10% and 20% wind
- $12/MMbtu – New coal is developed up to 40% wind
- NGCC is still never developed, NGCT expansion decreases
Results: NG Price Sensitivity

- Higher NG prices increase energy prices and wind/baseload profits
- When wind penetration is high, NGCC and NGCT profits are relatively unchanged
  - Increased revenue streams from reserves products
Conclusions

- **How will wind power affect prices of energy and reserves?**
  - Energy prices decrease
  - Reserves prices increase

- **What are implications for revenue sufficiency?**
  - Revenues decrease for nuclear, coal and wind units with more wind
  - Natural gas units are less impacted
    - Increased revenues from reserves
  - ORDC and FRSP can be structured to provide similar revenues
    - ORDC has advantage of less variable prices, fewer large spikes, less risk to investors
  - $40/kW-year capacity payments
    - Less revenue but more capacity
  - Low natural gas prices contribute to baseload revenue sufficiency issues

- **Are new market designs needed to ensure resource adequacy?**
  - Our analysis ensures resource adequacy through system cost-minimization
  - Without long term revenue sufficiency, there likely will not be resource adequacy
  - Alternative solutions
    - Hybrid CP/ORDC model
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