On the Use of Operating Parameters in Defining Marginal Cost and Minimizing Uplift

FERC Staff Technical Conference on Increasing Real-Time and Day-Ahead Market Efficiency through Improved Software

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Intuitively, it is useful to think of non-convexities as something that does not allow for a smooth or continuous representation of costs due to operational realities.

- Imagine a generator that only incurred costs when it produced energy and could produce from zero to its maximum as being smooth.

In reality, generation technologies have many non-convex operational characteristics.

- Start-up and shut-down costs
- No load (minimum run level) costs
- Minimum run and down times
- Minimum output equal to maximum output like with CTs and Demand Resources
What are equilibrium or market clearing prices with smooth and continuous cost representations?

- A set of prices such that
  1. The quantity demanded is equal to the quantity supplied...this is the energy balance constraint in SCED or the SCUC
  2. At these prices generation and load would not wish to change their respective output or consumption decision...this ensures prices are consistent with dispatch instructions and operational reliability constraints

- These are often referred to as “linear” prices and are not participant specific
- LMPs are linear prices that are not participant specific...multiple market participants at the same location face the same prices
Simple Example...Assume Smooth, Continuous Operation

<table>
<thead>
<tr>
<th>Generator</th>
<th>Min Output if Committed (MW)</th>
<th>Max Output if Committed (MW)</th>
<th>Marginal Running Cost ($/MWh)</th>
<th>Min Run/No Load Cost ($/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>0</td>
<td>100</td>
<td>50</td>
<td>n/a</td>
</tr>
<tr>
<td>B</td>
<td>0</td>
<td>100</td>
<td>52</td>
<td>n/a</td>
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<tr>
<td>C</td>
<td>0</td>
<td>100</td>
<td>55</td>
<td>n/a</td>
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<tr>
<td>D</td>
<td>0</td>
<td>20</td>
<td>65</td>
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• In the previous example, prices would increase smoothly from $50/MWh for loads between 0 MW and 100 MW up to $65/MWh for load above 300 MW.

• At a load of 250 MW, Generators A and B would be dispatched at their maximum 100 MW, Generator C would be dispatched at 50 MW. The price would be the marginal cost of C of $55/MWh.
  – Generators A and B are happy with being at their maximums since the price is greater than marginal cost.
  – Generator C is happy being dispatched anywhere in its range if the price is at least its marginal cost.
The problem is that with non-convexities, such prices may not exist that result in market clearing or an equilibrium.

- However, participant specific “uplift” payments act as a participant specific price by which a market clearing outcome can be ensured.
- The set of linear prices and participant specific prices are consistent with dispatch instructions and operational reliability needs.
- These participant specific prices can be derived solving a mixed integer program (MIP) where the optimal non-convex decision is set to equality in a linear or concave program to get linear and participant specific.

This example follows one presented in
*Extended Locational Marginal Pricing (Convex Hull Pricing)*
Paul Gribik and Li Zhang, Midwest ISO
June 2-3, 2010 FERC Technical Conference on Unit Commitment Software

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<td>D</td>
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In the previous example, at a load of 250 MW, the equilibrium price was $55/MWh…will this price clear the market with non-convexities? NO.

- Generator A is indifferent because it just covers its running cost plus its no load cost running at its maximum
- Generator B requires an additional uplift payment, or unit specific price of $200 to ensure it will follow dispatch to be run at its maximum
- Generator C requires an uplift payment or unit specific price equal to its no load cost of $500 to ensure it will follow dispatch.
• **Problem**: How to get as much of these non-convex costs into prices *AND* also ensure that equilibrium conditions can be met

• In this simple example, at a load of 250 MW, we could set the price at the average cost of Generator C at $65/MWh
  – Generator D with a running cost of $65/MWh would still not want to be dispatched given its $40 no load cost
  – Using average cost of the last unit dispatched has the property of declining prices as load increases...load of 290 MW price is $60.55/MWh...likely not a desirable property for price formation
  – At a load of 230 MW the average cost of C would be $71.66/MWh...but now generator D would want to run full out and not follow dispatch instructions.
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• With Generator C setting its min equal to max, at a load of 250 MW, the equilibrium price is now $52/MWh
  – Generator A now requires $300 in uplift to get it to run full out so that it just covers its running cost plus its no load cost running at its maximum
  – Generator B is marginal requires an uplift payment equal to its no load cost, of $500 to ensure it will follow dispatch to be run at 50 MW
  – Generator C requires an uplift payment or unit specific price equal to its no load cost of $500 plus $3/MWh or $300 to cover its running cost to ensure it will follow dispatch.
Reflecting Costs of Non-Convexities in Linear Prices as Much as Possible-3

- **Problem:** How to get as much of these non-convex costs into prices **AND** also ensure that equilibrium conditions can be met

- In this simple example, at a load of 250 MW, we could set the price assuming C is perfectly flexible, at $55/MWh
  - Generator A is indifferent because it just covers its running cost plus its no load cost running at its maximum
  - Generator B requires an additional uplift payment, or unit specific price of $500, but this must be conditioned obeying dispatch instructions, or an uplift of $200 to reflect the lost opportunity cost of being backed down to 50 MW on to ensure it will follow
  - Generator C requires an uplift payment or unit specific price equal to its no load cost of $500 to cover costs
MISO Solution: Extended LMP

• Would allow the following to set price inclusive of their non-convex costs:
  – Inflexible fast start resources on-line or off-line to set prices and include start-up, shut down, and no load costs in the offers to be reflected in price
  – Emergency Demand Resources to set price in the real-time energy market and reserves market
  – Note this does not include the use of non-convex costs, or reliability needs for steam units to be run, but often at their minimums

• Pricing problems cited
  – Block loaded CTs and associated RSG
  – Transient shortage prices that are alleviated by starting up a fast resource

• Cannot eliminate uplift payments…trying to minimize them
• Requires *ex ante* and *ex post* prices
  – *Ex ante* LMP prices and dispatch signals are sent in RT operation such that prices and dispatch signals are consistent
  – *Ex post* LMP prices are calculated to minimize uplift and are used for settlement
  – Applies to day-ahead and real-time energy markets
• Only done looking at a single interval in SCED, and not using look-ahead logic
  – No inter-temporal effects or multi-interval dispatch costs included
  – Citing complexities of trying to do this
  – Often referred to in the December 2011 filing as approximate ELMP
• Implementation timeline
  – October 2014
• Assume for price formation purposes that inflexible CTs are perfectly flexible over their operating range to set prices
  – All Fixed Block Units are treated in the same way as inflexible CTs as described above
• The NYISO also has provisions in place to “confiscate” excess energy from resources not following dispatch so that there are no gains to be had from trying to deviate from dispatch
• Still requires uplift to be paid (in the form of opportunity cost) to units being backed down to make room for inflexible units
Major Problem Areas in Uplift for PJM

- Incremental and no-load costs for units sitting at min for...steam not CTs
  - Reactive/Voltage Support
  - Thermal Constraints
  - Blackstart
- Start-up costs do not appear to be a large contributor
- Sensitive areas for reactive charges
  - BGE/PEP for APSOUTH/BED-BLA
  - Seneca area of PN when Seneca pumping
  - DPL actual high voltages in off-peak hours
  - CLVLND Interface area of ATSI
January 2014 Total Balancing Operating Reserve Credits January 2014

$ Millions

- Total Deviation Credit
- Total Reliability Credit

Winter Storm

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</thead>
<tbody>
<tr>
<td>Small Frame CT and Aero CT Units - Up to 29 MW ICAP</td>
<td>2.0 or Less</td>
<td>2.0 or Less</td>
<td>2 or More</td>
<td>14 or More</td>
<td>1.0 or More</td>
</tr>
<tr>
<td>Medium Frame CT and Aero CT Units - 30 MW to 65 MW ICAP</td>
<td>2.0 or Less</td>
<td>3.0 or Less</td>
<td>2 or More</td>
<td>14 or More</td>
<td>1.0 or More</td>
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<tr>
<td>Medium-Large Frame CT Units - 65 MW to 135 MW ICAP</td>
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<td>5.0 or Less</td>
<td>2 or More</td>
<td>14 or More</td>
<td>1.0 or More</td>
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<tr>
<td>Large Frame CT Units - 135 MW to 180 MW ICAP</td>
<td>4.0 or Less</td>
<td>5.0 or Less</td>
<td>2 or More</td>
<td>14 or More</td>
<td>1.0 or More</td>
</tr>
<tr>
<td>Combined Cycle Units</td>
<td>4.0 or Less</td>
<td>6.0 or Less</td>
<td>2 or More</td>
<td>11 or More</td>
<td>1.5 or More</td>
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<tr>
<td>Petroleum and Natural Gas Steam Units - Pre-1985</td>
<td>7.0 or Less</td>
<td>8.0 or Less</td>
<td>1 or More</td>
<td>7 or More</td>
<td>3.0 or More</td>
</tr>
<tr>
<td>Petroleum and Natural Gas Steam Units - Post-1985</td>
<td>3.5 or Less</td>
<td>5.5 or Less</td>
<td>2 or More</td>
<td>11 or More</td>
<td>2.0 or More</td>
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<tr>
<td>Sub-Critical Coal Units</td>
<td>9.0 or Less</td>
<td>15.0 or Less</td>
<td>1 or More</td>
<td>5 or More</td>
<td>2.0 or More</td>
</tr>
<tr>
<td>Super-Critical Coal Units</td>
<td>84.0</td>
<td>24.0 or Less</td>
<td>1 or More</td>
<td>2 or More</td>
<td>1.5 or More</td>
</tr>
</tbody>
</table>
Parameter Limited Schedules in PJM

- Often based on historical usage...2006 is a base year rather than the figures in the Tariff and OA
  - Steam units
  - Combined cycle units
- Temporary Exemptions (31 days or less)
- Period Exemptions (up to one year)
- Persistent Exemptions (more than one year)
- Question: What is technically feasible??
- How do gas market operations affect parameter limits and uplift?
• Some statistics 2013 through September:
  – DA OR Top 10 = 60% of total DA OR
    • Top 5 are 55% of total
  – BOR Top 10 = 58% of total BOR
    • Top 5 are 46% of total
  – Reactive Top 10 = 62% of total Reactive
Proposed and Implemented Solutions

- Extend existing logic for price-setting of inflexible units to generators sitting min for a transmission constraint (reactive/voltage or thermal) to set LMP
  - Already done for CTs that are not dispatchable
- Model and bind the constraints these generators are running for in real-time and day-ahead
  - Likely closed-loop interfaces
  - Use existing facilities but may need new interfaces
    - BC/PEPCO Interface
    - CLVLND Interface
    - DPL Interface
    - PN Interface
  - Not the complete set…just what’s been identified at PJM so far
Expected Results and Requirements of Proposed Solution

• More congestion on the system (DA and RT)
  – Ensure these facilities are modeled appropriately in FTR Auctions

• Higher prices in areas where generation is running under these circumstances
  – Closed loop interface will avoid lowering generation

• Incremental costs will be removed from uplift as long as these constraints bind
  – Reduction in uplift

• Identify and post facilities that will be bound in DA/RT for 14/15 FTR auction modeling

• PJM will need software changes to implement this
• Uplift cannot be avoided completely due to the inherent non-convexities in operations
• We already have a system of prices that are truly equilibrium prices and are consistent with dispatch needs and operation reliability.
• Do we really need more complex pricing algorithms to minimize uplift?
• Or can we find ways to chip away at this through more technical analysis of non-convexities and better gas market coordination?