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

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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-1

Generator	Min Output if Committed (MW)	Max Output if Committed (MW)	Marginal Running Cost ($/MWh)	Min Run/No Load Cost ($/hr)
A	0	100	50	n/a
B	0	100	52	n/a
C	0	100	55	n/a
D	0	20	65	n/a

Market Clearing (Equilibrium Prices)-1

- 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
  - Efficient market-clearing prices in markets with nonconvexities, Richard P. O'neill, Paul M. Sotkiewicz, Benjamin F. Hobbs, Michael H. Rothkopf, William R. Stewart, *European Journal of Operational Research - EJOR* , *vol*. 164, no. 1, pp. 269-285, 2005

Simple Example…Non-Covexities Included-2

Generator	Min Output if Committed (MW)	Max Output if Committed (MW)	Marginal Running Cost ($/MWh)	Min Run/No Load Cost ($/hr)
A	20	100	50	500
B	20	100	52	500
C	20	100	55	500
D	5	20	65	40

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

Market Clearing (Equilibrium Prices) Non-Convexities-2

- 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.

Simple Example…Non-Covexities Change

Generator	Min Output if Committed (MW)	Max Output if Committed (MW)	Marginal Running Cost ($/MWh)	Min Run/No Load Cost ($/hr)
A	20	100	50	500
B	20	100	52	500
C	100	100	55	500
D	5	20	65	40

This example follows one presented in
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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

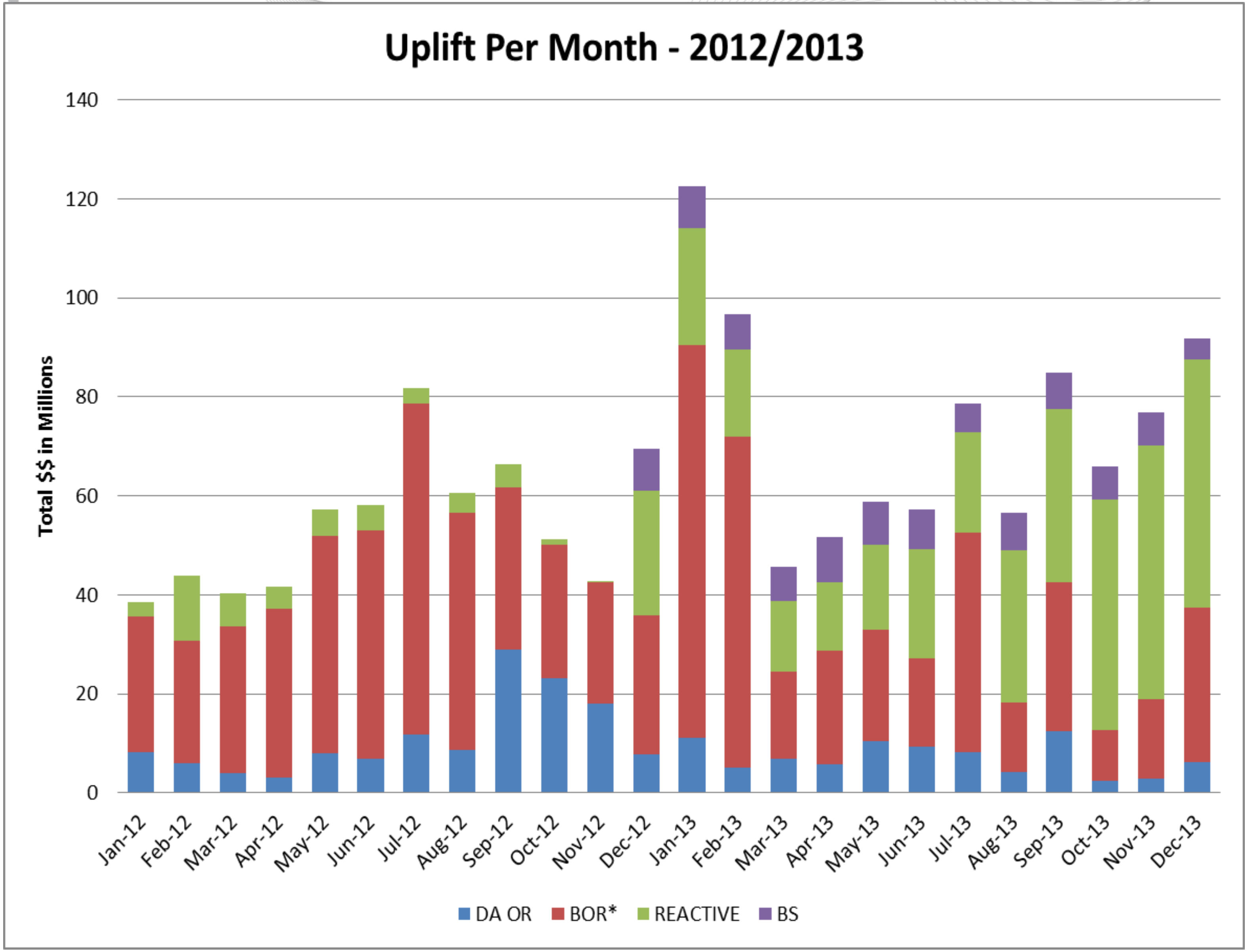
MISO Solution: Extended LMP Implementation

- 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

NYISO: Solution to Inflexible CTs

- 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

- 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



Uplift Per Month - 2012/2013
Total $$ in Millions
140
120
100
80
60
40
20
0
Jan-12
Feb-12
Mar-12
Apr-12
May-12
Jun-12
Jul-12
Aug-12
Sep-12
Oct-12
Nov-12
Dec-12
Jan-13
Feb-13
Mar-13
Apr-13
May-13
Jun-13
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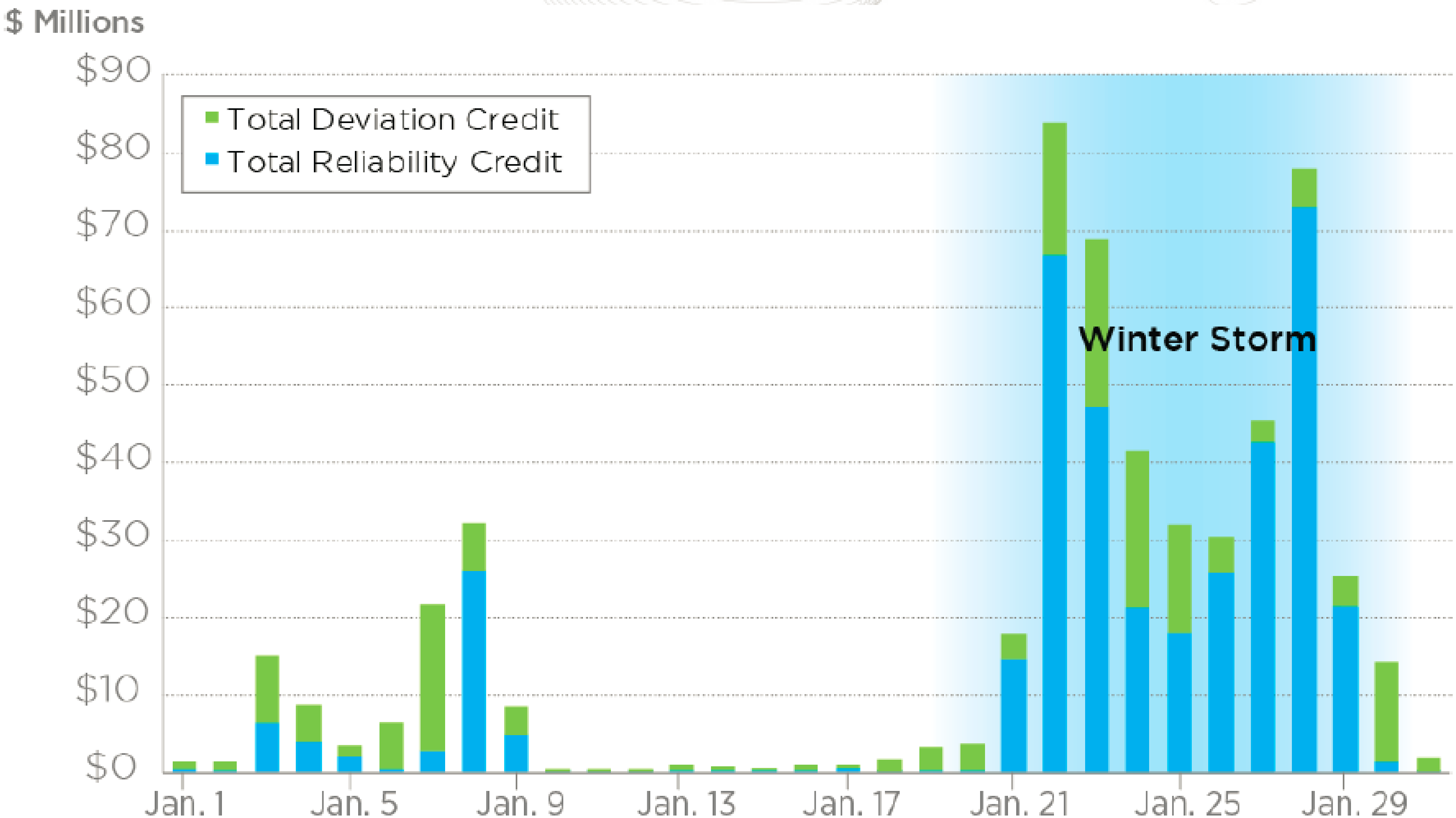
DA OR
BOR*
REACTIVE
BS

January 2014 Total Balancing Operating Reserve Credits January 2014



Parameter Limited Schedule Matrix

Parameter	Minimum Down Time (Hrs)	Minimum Run Time (Hrs)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio = Economic Maximum MW / Economic Minimum MW
Small Frame CT and Aero CT Units - Up to 29 MW ICAP	2.0 or Less	2.0 or Less	2 or More	14 or More	1.0 or More
Medium Frame CT and Aero CT Units - 30 MW to 65 MW ICAP	2.0 or Less	3.0 or Less	2 or More	14 or More	1.0 or More
Medium-Large Frame CT Units - 65 MW to 135 MW ICAP	3.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Large Frame CT Units - 135 MW to 180 MW ICAP	4.0 or Less	5.0 or Less	2 or More	14 or More	1.0 or More
Combined Cycle Units	4.0 or Less	6.0 or Less	2 or More	11 or More	1.5 or More
Petroleum and Natural Gas Steam Units - Pre-1985	7.0 or Less	8.0 or Less	1 or More	7 or More	3.0 or More
Petroleum and Natural Gas Steam Units - Post-1985	3.5 or Less	5.5 or Less	2 or More	11 or More	2.0 or More
Sub-Critical Coal Units	9.0 or Less	15.0 or Less	1 or More	5 or More	2.0 or More
Super-Critical Coal Units	84.0	24.0 or Less	1 or More	2 or More	1.5 or More

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?