Review of August 5th Market Trials Results

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DRAFT: For Discussion Purposes Only

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What Have We Reviewed?

We focused our review of this market trial on the real-time results.

- We are still in the process of developing our verification and validation tools
- We particularly focused on price spikes, high prices and low prices seeking to explain why we saw the results that we did

It is important to understand that the RT market was set up to be highly stressed due to the DAM solution that was produced the prior day and the fact that no additional commitments or SREs were called for. The difference between bid load and forecast load which was significant and the difference between forecast load and actual simulated RT load which was also significant was predominantly made up by gas turbines.

Initialization and Termination Conditions

There are high prices observed in the first couple of intervals and very low prices observed in the last interval of the day:

- These prices appear to be a function of initialization and termination conditions that are often problematic in a simulated environment
- These issues include the alignment and consistency of unit status in the simulated actual world versus the inputs being fed into RTC and RTD

Negative Prices At 1:55 and 4:55

There are significant negative prices for single intervals at 1:55 and 4:55:

- Based on the problem that was solved within the pricing dispatch the prices are explainable and derivable
- A significant loss of capacity at the top of the hour caused expensive GTs to be dispatched in the second time period of the 1:55 and 4:55 RTD runs.
- All units that were flexibly scheduled at 4:55 were ramp constrained up in the second period of the RTD solution with gas turbines at the margin at prices around $130 higher than the margin steam units at 4:55.
  - An additional MW of load at 4:55 would be met by steam (e.g. @ $50) which would then be able to ramp a MW higher in the second interval displacing a MW of GT generation that would otherwise have been dispatched (e.g. @ $180). An additional MW of load at 4:55 therefore decreases the total cost of the solution by 180 – 50 = 130 hence an LBMP of -$130

Negative Prices At 1:55 and 4:55

The significant loss of capacity at 5:00 was created by changes in quarter hourly self scheduled generators:

- Quarter hourly self schedules submitted by generators are not validated for feasibility relative to the ramp rates
- Market basepoints communicated to the units each 5 minutes ramp the unit so that it reaches the submitted self-scheduled generation level at the start of each 15 minute period
- If the difference in quarter hour schedules is less than 15 minutes of ramp the model ramps the schedule as late as possible whilst still honoring the ramp rate
- If the difference in quarter hour schedules exceeds 15 minutes of ramp the resource is straight line ramped from one schedule to the next across the 15 minutes at whatever rate is necessary to meet the next 15 minute schedule

Negative Prices At 1:55 and 4:55

The significant loss of capacity at 5:00 was created by changes in quarter hourly self scheduled generators:

- The pricing basepoints should have pulled in the actual generation at the time that each RTD run was initialized and ramped the unit towards its 15 minute schedule
- What the pricing dispatch actually did was to use the submitted self-scheduled generation level at each 15 minute point without regard to the physical ramp limitations between time periods
- A number of units submitted bids of the form that had MWs scheduled at e.g. 4:00 = 20 MW, 4:15 = 50, 4:30 = 80 and 4:45 = 110 with the cycle repeating the following hour i.e., 5:00 = 20
- The combination of these physically unachievable schedules and the pricing dispatch error immediately reduced the output from 110 to 20 in the pricing dispatch causing a capacity shortfall at 5:00 and hence the significant negative prices at 4:55.

Demand Curve Prices at 10:55

Statewide prices were approximately $2,000 at 10:55:

- During this interval all of the demand curves were violated totaling $1,750
- However the price was set by a capacity constrained unit in the east where the sum of the reserve demand curves was $1,400 ($1,750 - $25 (LI spin) - $25 (LI 10 total) - $300 (LI 30 minute total) plus an incremental energy bid of around $600
- This resource set the statewide LBMP as there were no transmission constraints at the time
- There were a number of capacity constrained LI units as well but their incremental energy bids at that time low enough that the implied price set in the east exceeded the sum of all the demand curves plus the incremental energy bid

Demand Curve Prices at 11:15

Statewide prices were approximately $2,750 at 11:15:

- During this interval all of the demand curves were violated totaling $1750
- A capacity constrained LI units with an incremental energy bids of around $1,000 set the statewide LBMP as there were no transmission constraints and all available energy on other dispatchable units had been fully dispatched

$80 to $2,500 at 17:25

Statewide prices spiked from around $80 to $2,500 between 17:20 and 17:25:

- We were able to identify marginal units setting the prices at both 17:20 and 17:25
- At 17:25 the NYCA spin, NYCA 10-minute, Eastern spin, Eastern 10-minute and LI 30 minute constraints were violated totaling $1,475 in reserve shortage costs
- The dramatic change in prices was caused by the simultaneous loss of Poletti and Ravenswood 3
- This was a result a data communication and indexing problem between RTC and RTD that has been identified and fixed
- This data communication and indexing problem affected a number of units at various times during the day and added to the general shortage of capacity available to meet energy and reserves.

RTD Prices From 7:00 to 7:55

We performed a detailed review of the entire hours prices from 7:00 to 7:55 and observed the increase in prices from less than $100 to more than $300 part way through the hour:

- We were able to identify the marginal units throughout the hour as a combination of incremental energy prices, availability bids for regulation, lost opportunity costs and reserve demand curve shortage costs
- We were able to confirm that the only ideal schedules that were generated during this period that appeared inconsistent with the posted prices belonged to uneconomic gas turbines that were likely blocked on by the hybrid dispatch
  - ✧ We do not have automatic access to the hybrid dispatch results but these results can be viewed through debug screens available when save cases are loaded
  - ✧ We are preparing a list of uneconomic GT schedules to validate against the debug screens.

Demand Curve Review

As can be seen from the prices for the day the demand curves got an extensive workout. This was a function of a number of issues:

- The DAM set up the RT to be highly dependent on GT capacity and very sensitive to loss of capacity
- A number of unit and transmission contingencies were activated during the day
- Unit status communication and indexing issues between the RTC and RTD caused other large units to drop out from time to time
- All of the demand curves including the regulation demand curve activated and functioned appropriately at some point during the day

Demand Curve Review

One element of the results produced by the demand curves that was not anticipated was the sequence of demand curve triggering:

- The additive nature of the demand curves and the generally lower constraint violation costs for the 30 minute reserves and 10 minute reserves should mean that those constraints should be violated first
- All 10 and 30 minute non-synchronous reserve at reasonable prices should be converted to energy prior to violating spinning reserve constraints
- We observed numerous instances where the system had no spinning reserve and no regulation yet there were 10 minute and 30 minute non-synchronous reserves
- This occurred because startup cost bids were submitted on these resources that raised the committed full load average cost of the units above the reserve violation cost of the spinning reserve constraints and the commitment process therefore chose to go short of spin and regulation and hold the GTs as non-synchronous reserves

Demand Curve Review

One element of the demand curves that didn't appear to work as designed was the sequence of demand curve triggering:

- The automated RTC-AMP process did not appear to mitigate these start-up costs as there was generally little congestion on the system and none of the load pocket or zonal mitigation triggers activated.
  - Mitigation outside of NYC was not available during this market trial per pending FERC ruling
  - Mitigation outside of NYC will be turned on for future market trials per recent FERC ruling
- Market monitoring is reviewing these outcomes and will determine how the existing RT mitigation procedures need to be applied such that the outcomes observed during this market trial that were a result of the high start up cost bids do not occur.