Review of August 19th Market Trials Results

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DRAFT: For Discussion Purposes Only

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What Have We Reviewed?

We extensively reviewed the results of the day-ahead market and the real-time market for the August 19th market trial. This presentation tends to focus on the real-time results and observations as that is where more of the questions arose.

- We focused on price spikes, high prices, on finding marginal units and on dispatch consistency in all intervals
- Anomalies identified by LECG have been communicated to the NYISO
- Verification continues on all Market Trials V results and will continue as the June 17th comparative day simulation is produced

External Transaction Scheduling in SCUC

We performed an extensive review of the treatment of all single hour and multi hour block imports, exports and wheels specifically focusing on the treatment of the transactions between various passes of SCUC to make sure that the outcomes of earlier passes were appropriately passed onto and respected by later passes.

- What transactions can be increased in the forecast load commitment passes?
- What dispatch limits must be honored in each pass for each type of transaction?
- Does the ultimate transaction schedule inclusive of FRED appropriately match the bid load and forecast load dispatch solutions?

Negative Early Morning RTD Prices

RTD prices of around -$300 were observed in numerous intervals in the early morning of the August 19th simulation:

- The validation of these results was complicated by a modeling problem related to regulation availability bids (described later) that once understood allowed us to explain the prices that were posted
- These situations involved low loads during the early hours of the morning. Relative the level of committed and online capacity the load was close to the total minimum generation level of the committed and online units
- The negative $300 energy prices were a function of having to violate the downward regulation range of units that would have otherwise been scheduled to carry regulation but were required to back down so that generation injections could be reduced down to the level of load to be served.
- An additional MW of energy served in one of these minimum generation stressed situations would allow an additional MW of regulation to be provided reducing the cost of the solution by the $300 shortage cost.

RTD Prices From 2:55 to 3:00

We performed a detailed review of the high prices at 2:55 and the low prices at 3:00:

- As we identify later in this presentation as an anomaly, a large unit turned on at 3:00 and immediately provided almost 1,000 MW.
- RTD saw this large schedule change coming, and began posturing the system to accommodate this by moving cheap slow ramping units down whilst increasing the output of faster ramping more expensive units. At 2:55 some expensive fast moving capacity was dispatched at $250 that could then be ramped down at 3:00 to adjust for the load schedule.
- At 3:00, units were ramped down so much that some violated the regulation constraint. Units were pushed down into their regulation range to accommodate the large output of another unit.
- The negative LBMPs at 3:00 were set by a unit that was marginal for regulation. The LBMP was set by the unit's energy bid plus its regulation availability bid, minus the regulation shortage cost.
- The down regulation range was being used by the model to create additional down ramp to cover the large schedule change.

RTD Prices From 6:55 to 7:00

We performed a detailed review of the $100+ price swing from 6:55 to 7:00:

- A large number of GTs were turning on at 7:00. At that time, all units not on Long Island were either at their mingen level or ramp constrained down.
- A load increase at 7:05 caused prices at 7:00 (-$20 across the state except on Long Island) to be set by a cheap unit that, if dispatched up 1 MW, could be up 1 MW at 7:05. This would allow a more expensive unit to be dispatched down at 7:05.
- The negative LBMP are thus set by the incremental cost of a cheap unit at 7:00 and the savings of backing down a more expensive unit at 7:05.

Demand Curve

Load levels in the August 19th trial were were nowhere near as extreme as the load from the previous market trial where every demand curve was activated.

- Two of the operating reserve demand curves and the regulation demand curve activated at various times during the day.
- The operating reserve demand curves that activated were the Long Island spinning reserve and 10 minute total reserve demand curves both of which activate at $25/MW. In each case that they did activate there was sufficient 30 minute total reserves to meet the Long Island 30 minute reserve requirement
- In each instance that the regulation demand curve activated it was a violation of the downward regulation capacity limits caused by minimum generation / low load scheduling tightness.

Problems Identified and Corrected

In reviewing the Market Trial results, we noted anomalies in SCUC, RTC and RTD that were communicated to the NYISO. Fixes are being developed for the following:

- In SCUC, some units' UOL and LOL were truncated when they included decimal points. For example, a 5.9 LOL was seen by SCUC as 5. The NYISO determined that this problem was attributable to a variable definition issue in certain program modules.

- The same variable definition problem also caused inconsistencies in the MW level of external transactions as they moved through the various SCUC passes. For example, import and wheels in the passes immediately after the bid load pass should be greater than or equal to the level set in the bid load pass. LECG found instances where this condition did not hold.

Problems Identified and Corrected

- Certain self-scheduling GT units were correctly committed in the ideal pass of SCUC because of negative mingen bids. However, they were then dispatched to 0 MW in the ideal due to the existence of bid curves that made them uneconomic. These units would therefore receive a block schedule, but no ideal schedule. NYISO has revised their bid curves to reflect the fact that these units are price-takers, and will therefore also receive an ideal schedule.
- In the Forecast Load Redispatch pass (307) of SCUC, the MW value of exports increased dramatically, well above the levels set in the Bid Load pass (304). This issue did not affect unit commitment, the final pricing or the schedules set in the Bid Load Redispatch pass (308). NYISO determined this error was caused when bid data was erroneously re-ordered in one of the data files.

Problems Identified and Corrected

- In RTC and RTD, the regulation clearing prices were in many cases inconsistent with the availability bids of marginal regulation providers. The NYISO determined that this was caused by adding an unnecessary cost to the reported regulation bids.
- In RTC and RTD, a large unit turned on and provided almost 1,000 MW within five minutes, causing price spikes. This error was traced back to a problem with the simulator that won't happen in production.
- NYISO-generated flags in RTC and RTD indicate if a unit is ramp constrained up or ramp constrained down. LECG found instances where the flag was incorrect. The NYISO has fixed the code to eliminate this problem. This problem does not affect the schedules or prices but impacts LECG's ability to easily validate the dispatch solutions.

Problems Identified and Corrected

- In RTD, the PJM proxy bus experienced -$7,000 prices in many intervals in HB2, and -$4,000 prices in HB1. The NYISO traced this issue back to a misrepresentation of transmission losses in the model.
- In RTD, the posted zonal prices from 13:55 to 14:20 were $0. LECG found marginal units in those intervals that should have correctly set price at $0.01. The NYISO has identified this as being caused by an problem in the code.
- In RTC, we identified anomalous external load schedules where schedules were not consistent over the entire hour. For example, transactions were fully scheduled at :00, :15, and :30, but received a schedule of 0 at :45. The NYISO has identified the cause as a problem in the code.

Problems Identified and Corrected

Currently, LECG is unable to verify that these problems have been corrected , since no new market trials have taken place.

However, we anticipate being able to check the solutions to these problems with the results of Market Trials VI.

Issues Identified and Outstanding

The issues below are still being investigated. It is not yet clear whether these are problems that will require process or code changes. The issues include:

- Several instances of units being flagged by the NYISO as marginal for energy in RTC and RTD, where we are unable to verify that the units are marginal (i.e., the incremental energy cost is above the LBMP).
- Non-GT units are sometimes dispatched to their UOLs in the first interval of consecutive RTD runs when doing so is uneconomic.

Additional Issues to be Verified

In addition to the issues that LECG has brought to the NYISO's attention, there are two issues that we will verify with them early next week.

- Hybrid pricing – In both RTC and RTD, there are a large number of uneconomic GTs receiving ideal schedules. LECG does not receive data to confirm that these GTs were dispatched through the hybrid pricing rule and will work with the NYISO to confirm hybrid pricing.
- Initial Conditions – There are many instances of a unit being identified as ramp constrained in the first interval of an RTC or RTD run. LECG cannot verify, without the data specifying the initial conditions of these units coming into the run, the validity of these ramp constraint flags. LECG will work with the NYISO to verify the flags.