Market Trials VI: RT Results and DA Follow-up

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DRAFT: For Discussion Purposes Only

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OVERVIEW

Today's presentation will address several of the follow-up items from the last call related to the DAM benchmarking test as well as describing the RT market results and the issues that have been identified during the review period. Issues addressed will include:

- Unit commitment summary down to a 30 MW unit UOL
- A comparison of the regulation and operating reserve prices between the June 17th SCUC and the market trial
- Review of revised bid load commitment results with the PJM bypass outage reconfigured
- Review of RT market prices, demand curve activations and RT market issues

DAY-AHEAD RESULTS: UNIT COMMITMENT

Unit Commitment, Market Trial 6 vs. SCUC

HB	Number of Generators Committed Originally but not in the Trial	Number of Generators Committed in the Trial but not Originally	Net Min Gen (MW) (SMD-SCUC)
0	0	2	103
1	0	2	103
2	0	2	103
3	0	2	103
4	0	2	103
5	0	2	103
6	0	2	105
7	0	2	105
8	0	3	143
9	3	6	-137
10	0	8	384
11	0	7	326
12	0	8	372
13	0	6	278
14	0	6	342
15	0	7	343
16	0	7	304
17	1	6	249
18	0	8	404
19	0	7	370
20	1	5	113
21	1	3	5
22	0	6	367
23	0	3	268

Internal Generators with schedules in the hour and have a UOL greater than or equal to 30 MW.

The average number of these units committed per hour in the 6/17 SCUC is 88.
The average number of these units committed per hour in the 9/28 SMD is 92.

DAY-AHEAD RESULTS: UNIT COMMITMENT

We expanded the unit commitment analysis to review the commitments of all units with UOLs greater than or equal to 30 MW.

- There is a general level of slightly higher commitment across the day
- The largest increases during the day are during the higher load periods of the day where any additional increment of energy needed would likely come from additional unit commitments
- These results are consistent with the observations related to energy prices where the incremental dispatch is due to the revised loss modeling

DAY-AHEAD RESULTS: RESERVES

Reserve Prices: Market Trial 6 minus SCUC

Regulation Prices			10 Minute Spin Prices			10 Minute Non-Spin Prices			30 Minute Operating Prices		
HOUR	NYPP	East	HOUR	NYPP	East	HOUR	NYPP	East	HOUR	NYPP	East
0	-	-	0	(0.08)	-	0	(0.08)	-	0	(0.18)	(0.18)
1	-	-	1	-	-	1	-	-	1	(0.10)	(0.10)
2	-	-	2	-	-	2	-	-	2	(0.10)	(0.10)
3	-	-	3	-	-	3	-	-	3	(0.10)	(0.10)
4	-	-	4	-	-	4	-	-	4	(0.10)	(0.10)
5	-	-	5	-	-	5	-	-	5	(0.10)	(0.10)
6	-	-	6	(0.10)	-	6	(0.10)	-	6	(0.20)	(0.20)
7	-	-	7	(0.10)	-	7	(0.10)	-	7	(0.20)	(0.20)
8	-	-	8	(0.10)	0.10	8	(0.20)	-	8	(0.20)	(0.20)
9	-	-	9	(0.10)	0.10	9	(0.20)	-	9	(0.20)	(0.20)
10	-	-	10	(0.23)	(0.03)	10	(0.33)	(0.13)	10	(0.33)	(0.33)
11	-	-	11	(0.24)	(0.04)	11	(0.34)	(0.14)	11	(0.34)	(0.34)
12	-	-	12	(0.25)	(0.05)	12	(0.35)	(0.15)	12	(0.35)	(0.35)
13	-	-	13	(0.24)	(0.04)	13	(0.34)	(0.14)	13	(0.34)	(0.34)
14	-	-	14	(0.24)	(0.04)	14	(0.34)	(0.14)	14	(0.34)	(0.34)
15	-	-	15	(2.90)	-	15	(0.34)	(0.01)	15	(0.34)	(0.34)
16	7.25	7.25	16	(2.90)	-	16	(0.34)	(0.14)	16	(0.34)	(0.34)
17	8.63	8.63	17	(0.23)	2.67	17	(0.33)	(0.13)	17	(0.33)	(0.33)
18	3.63	3.63	18	(0.10)	0.10	18	(0.20)	-	18	(0.20)	(0.20)
19	8.93	8.93	19	(0.10)	0.10	19	(0.20)	-	19	(0.20)	(0.20)
20	8.80	8.80	20	(0.10)	0.05	20	(0.20)	(0.05)	20	(0.20)	(0.20)
21	-	-	21	(0.10)	0.05	21	(0.20)	(0.05)	21	(0.20)	(0.20)
22	-	-	22	(0.10)	(0.05)	22	(0.10)	(0.05)	22	(0.20)	(0.20)
23	-	-	23	(2.90)	(2.64)	23	(1.17)	(0.91)	23	(1.27)	(1.27)

DAY-AHEAD RESULTS: RESERVES

A comparison of operating reserve and regulation clearing prices between the market trial and the original SCUC shows that:

- On the whole reserve prices were slightly lower in the market trial than in the original SCUC results with the exception of a few hours where the Eastern prices were higher in the market trial consistent with the higher energy prices
- Regulation prices were either the same or slightly higher in the market trial

DAY-AHEAD RESULTS: PJM OUTAGE

The bid load commitment pass of the SCUC was re-run to test the PJM scheduling and pricing differences related to the bypass outage problem that was identified in the 6/17 benchmarking test:

- We reviewed the shift factors associated with the constraint that caused the scheduling differentials and pricing differentials at the PJM proxy bus between the original SCUC for 6/17 and the benchmarking test
  - In the 6/17 SCUC the shift factors were zero
  - In the benchmarking test the shift factors were not zero
  - In the bid load re-run the shift factors were zero

DAY-AHEAD RESULTS: OTHER

In SCUC, we noted a few instances of external transactions having their schedules truncated in the forecast load redispatch pass (i.e., erasing the decimal point). This has been identified as an issue related to integer limits that the NYISO says has been fixed.

- This issue did not affect the binding financial schedules or prices determined by the SCUC solution

RT RESULTS

With respect to the real-time results of Market Trial VI, we performed a full examination of the results, focusing our attention on:

- Dispatch anomalies
- Large price swings in RTD
- Reserve demand curve activation
- Initial conditions
- External transaction scheduling
- GT hybrid pricing

RT RESULTS: DISPATCH ANOMALIES

LECG found only a few dispatch anomalies in the RT results in either RTC or RTD:

- In RTC, we found a few instances of units' movement exceeding their ramp capability in intervals past the first – the cause was identified by the NYISO and ABB as the approximation caused by unit loading level dependent ramp rate, which can lead to a generator schedule that violates the ramp rate limit.
- In RTD, we identified two units which erroneously turned off for one five-minute interval. This was a previously identified bug in the RTD code that has been fixed, rerun at the NYISO, and has been verified to be working correctly. These one period anomalies in unit status lead to some of the observed price swings during the day.

RT RESULTS: PRICE SWINGS

There were no large price swings observed in RTC. In RTD, however, price swings were noted at 4:30, 6:55, 16:25, 20:25, 21:25 and 22:50 EDT.

- The price swing at 16:25 was the result of a large unit erroneously turning off for one five-minute interval (previously discussed).
- Most of the rest (6:55, 20:25, 21:25 and 22:50) were the result of very large schedule changes and the inability of RTD to solve load in two simultaneous intervals given the amount of ramp capability units had at those times. – NYISO is implementing improved ramping logic to better reflect actual unit operation
- The price swing around 4:30 was caused by the erroneous solution of an external interface constraint within RTD

RT RESULTS: RESERVE DEMAND CURVES

REGULATION				
NYCA				
Reg Curve Triggered (EDT)	Reg Price	Regulation Shadow	Regulation Requirement	Regulation Provided
16:25	300	300	200	118
20:25	300	300	275	195

10-MINUTE SPIN				
EAST				
10 Spin Curve Triggered (EDT)	10 Spin Price	10 Spin Shadow Price	10 Min Spin Requirement	10 Min Spin Provided
16:25	313	25	300	265

10-MINUTE SPIN				
LI				
10 Spin Curve Triggered (EDT)	10 Spin Price	10 Spin Shadow Price	10 Min Spin Requirement	10 Min Spin Provided
0:05	25	25	60	46
21:25	25	25	60	59

RT RESULTS: RESERVE DEMAND CURVES

Unlike the first market trial, the reserve demand curves in RTD did not trigger frequently throughout the day. As the table above shows:

- The regulation curve triggered twice, setting the regulation price to $300.
- The 10-minute spin curve triggered twice on Long Island, raising prices to $25, and once in the East, raising that price to $313.
  - The $313 price comes in an interval where the regulation price is $300. The pricing is from a trade-off between reserves and regulation.

RT RESULTS: INITIAL CONDITIONS

This is the issue of a unit being identified as ramp constrained in the first interval of an RTC or RTD run. In earlier market trials LECG was not able to verify the validity of the ramp constraint flags reported to us and therefore at times was unable to confirm whether units noted as ramp constrained truly had been dispatched consistently relative to their actual generation and previous physical and ideal basepoints.

LECG chose representative intervals to evaluate with the initial condition data having identified resources we could not validate.

- In all cases reviewed we were able to confirm that the ramp rate flags we either a function of the initialization conditions or a ramp rate binding through into the next time period of the same RTC or RTD run

RT RESULTS: EXTERNAL SCHEDULING

We checked the scheduling of external transactions within the RTC 30s for economic consistency.

- All transactions were scheduled consistent with the average hourly price for the upcoming scheduling hour.
- We noted that after a schedule had been set in RTC 30, sometimes the block schedule would change as we moved up to, and through the scheduling hour. This was caused by transaction schedules within RTC being reduced to help solve for a transmission constraint, where all other flexible units capable of resolving the constraint were ramp constrained. The reductions identified by RTC are passed to the operators as advisories and may be cut as they deem necessary.

RT RESULTS: GT HYBIRD PRICING

Due to changes within the model, LECG was unable to receive the data necessary to check that uneconomic GTs were dispatched correctly under the hybrid pricing rule in Market Trial VI. We had previously verified this with the last market trial on an ad-hoc basis, and found no anomalies.

New model flexibility has been added for Market Trial VII, however, that will allow us to easily check that the hybrid pricing logic is functioning correctly. Since data has started to become available for Market Trial VII before this meeting, we started to perform some spot checking of the hybrid pricing functionality within the RTD dispatch. So far, we have confirmed that in all the periods we reviewed that the hybrid pricing logic was functioning correctly.