

PSEG: UNIT COMMITMENT AND DISPATCH IN PORTFOLIO OPTIMIZATION

May 20, 2014, Energy Market Uplift Senior Task Force

Day-Ahead

- *“develop day-ahead schedule using least-cost security constrained unit commitment and security constrained economic dispatch programs that simultaneously optimize energy and reserves” (PJM Training Materials: PJM Two Settlements, p.6)*
- *“calculate hourly LMPs for next Operating Day using generation offers, demand bids, and bilateral transaction schedules “ (Id.)*
- **Objectives:**
 - 1. Open Participation: (secure financial schedule for energy and transmission)
 - 2. Ability to hedge physical delivery
 - 3. Match DA clear with system reliability needs (Is the DA clear feasible and able to meet reliable system operations)
 - 4. Incentive for supply and demand to offer/bid; the essence of two-settlements (supply with the exception of DR has a day-ahead offer obligation)
 - 5. Incentive for supply to follow real-time dispatch instructions (financial security from the DA clear)

The DA market exists so that energy and congestion may be Bought and sold at binding prices and the DA clear can meet System reliability

DA “load” incentive

- Obtain forward price certainty
- Theoretically designed to be consistent with market trends:
- So that load is encouraged to participate because if demand is too low in the DA market participants incur higher real-time prices and/or uplift
- If a market participant believes the characteristics of their load shape is different than the rest of the market they can be rewarded if their RT load is $<$ DA buy

Several drivers undermine these incentives including Non-price setting CTs, interchange, and manual loading Of non-price setting generation

DA supply incentive; Objective #5

- Non-voluntary
- But even if you assume a voluntary offer structure:
 - generator is adequately compensated if dispatch requests generator to increase/decrease output
 - Generator is left whole if deviations are caused by following dispatch
- Generator revenue adequacy is tied to DA offer and clear

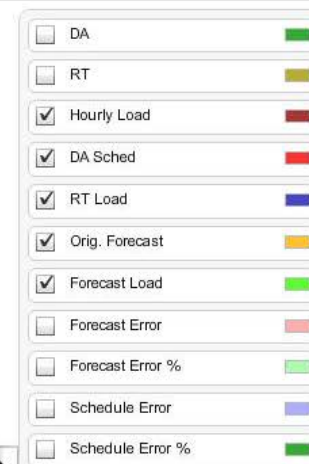
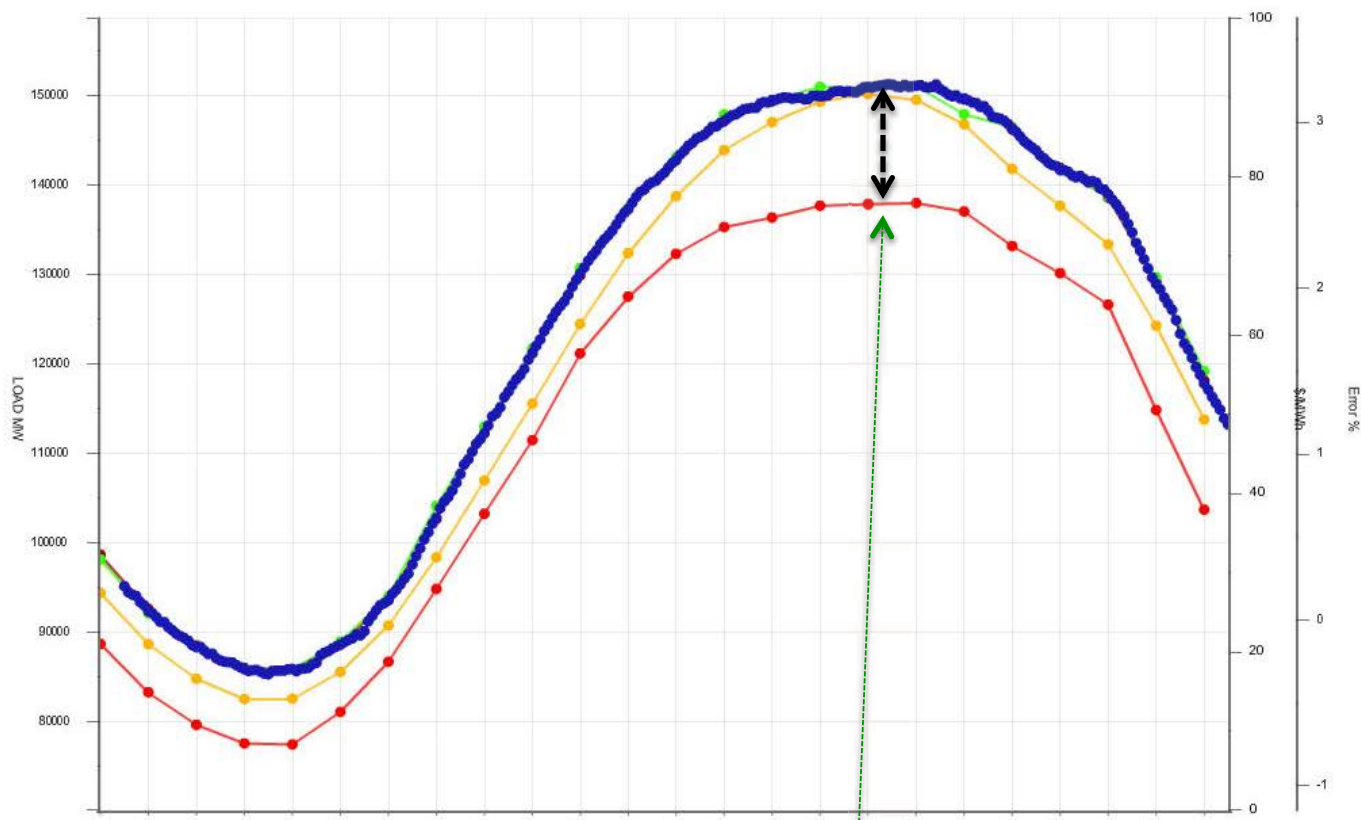
The financial security of the DA market must be preserved particularly in light of the fact that we do have a DA non-voluntary market for generation and tinkering with LOCs, Make-wholes, deviation credits... is not consistent with the current market design

Real-time

- “calculate 5 minute LMPs based on actual operating conditions as described by the PJM State Estimator” (Id.)
- actual financial settlement performed on hourly integrated LMP (Id.)
- Inputs
 - System Operating Conditions
 - Supply offer data
 - Transmission Constraints
 - Economic dispatch
 - External and dispatch-able transactions

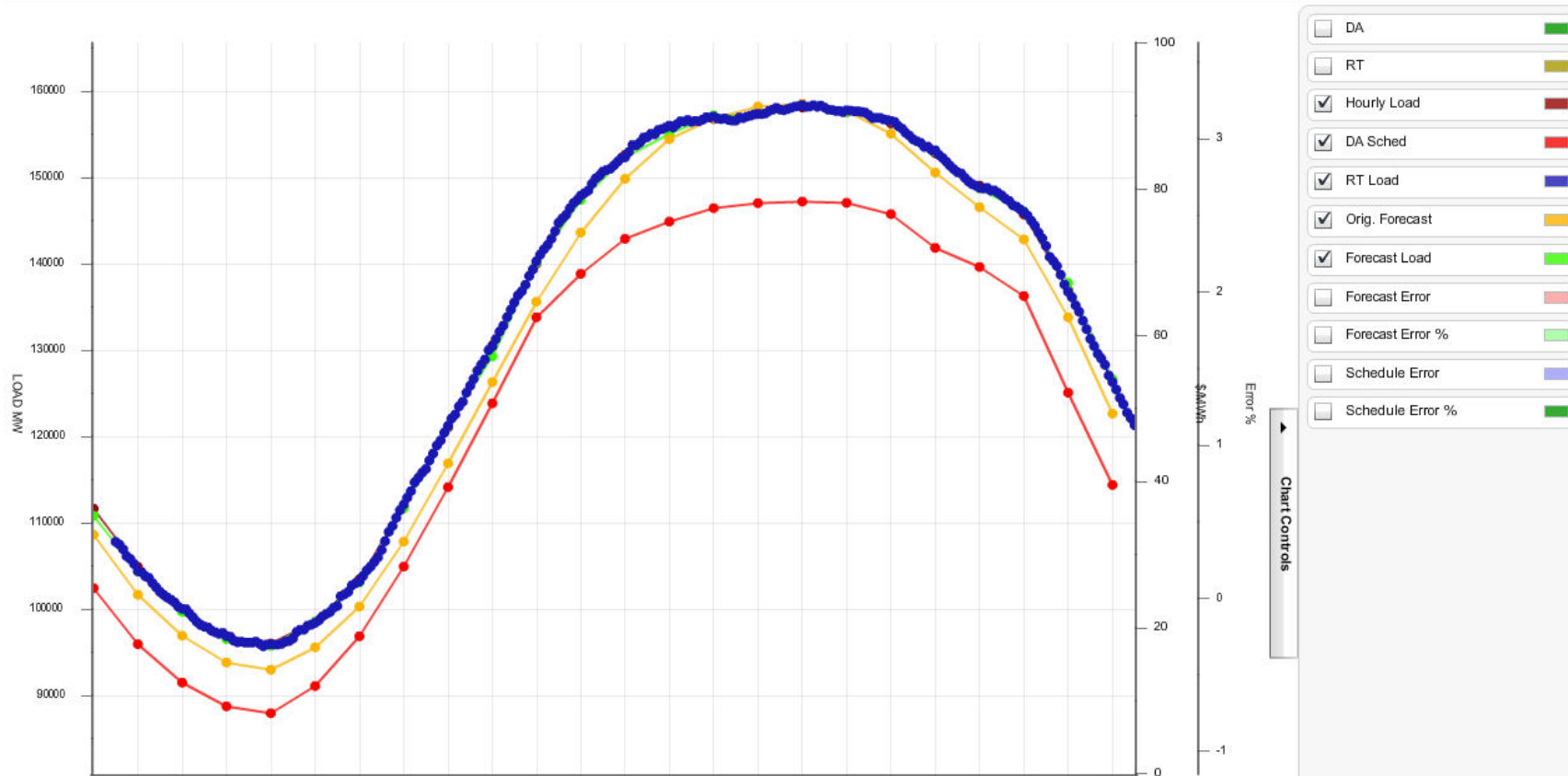
All PJM generation that is following dispatch instructions should be Eligible to set price

What we are seeing...July 15th 2013



Load Underbids in DA on near peak days; RT load tracks above forecast; but LMPs fall below \$100 and RT price is less than DA during the high on the Load curve

What we are seeing...three days later



Late in the heat wave load continues to underbid and be Rewarded with a low RT LMP; Uplift is not making up for the undermining of the DA incentives; again RT price falls below DA price during the peak of the load curve

What is happening

- DA Demand < forecast < RT load; RT price < DA price (or only slightly above it)
- PS understands what may cause this
 - Additional “non-price setting” generation scheduled by PJM to meet forecasted load
 - Interchange transactions chasing LMP
 - Self-scheduled generation
- But:
 - Additional generation manually scheduled to meet load needs to come at a cost and be reflected in price
 - Interchange transactions need to schedule in reasonable time before the operating hour like NY (75 minutes out)
 - Consider implementing less than hourly integrated pricing

***Additional generation needed to true-up underbid load
But has no effect on price and is sent to uplift***

Winter 2014 event day

- Tetco M3 gas index at ~\$71mmbtu; 13GWs of conservative ops
 - Western Hub DA: \$302.91; RT: \$491.79
 - This reflects ~4k HR and ~7k HR respectively (even a conservative ~8k dispatched HR costs ~\$575)
- **Does the price reflect what is actually on the system meeting load? NO**
- During the past year we have seen $\text{Price}(\text{RT}) < \text{Price}(\text{DA})$ consistently despite DA load being underbid (suppressed prices...increased and undue uplift)
- Again, PS understands that a virtual may be marginal...
 - but they do not displace generation MWs only its cost (or price)
- We get “perverse” price convergence from the virtuals (when we do get convergence it is at a suppressed price)
- CTs without a dispatch range need to be able to set price

Forward curves and heat rate calls are derived from the Real-time price so it is most efficient when the price reflects what is running On the system to meet load

Recommendations

- **RT LMP needs to reflect what is on the system otherwise you have less than efficient price formation and disrupt accurate formation of forward price curves**
- CTs need to be able to set price
- Generation scheduled to meet forecasted load must be reflected in price
- Off-cost operations need to run “tighter” or be better reflected in price
- Implement and adhere to closed loop interfaces
- Control interchange transactions by scheduling 75 minutes before the operating hour
- Consider less than hourly integrated pricing
- Communicate Price Bounding Threshold and updates

***Market prices that do not reflect production costs
Result in un-hedgeable uplift charges for LSEs, increasing
The risk to serve load and put upward pressure on retail prices***

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Questions