CPV Comments on Net E&AS Revenue Modeling

NYISO 2020 Demand Curve Reset

For presentation at the March 26, 2020 MIWG/ICAPWG

Competitive Power Ventures

SILVER SPRING | BRAINTREE

Topics for Discussion

1. Perfect hindsight dispatch
2. EFORd
3. Dual fuel requirement

Perfect Hindsight Dispatch

- The net E&AS model dispatches the proxy unit against historical DA and RT energy and ancillary services prices. The logic commits the plant optimally DA and allows the plant to gain/shed commitments in RT to further optimize beyond the DA schedule.
- This approach gives the theoretical maximum net E&AS revenues that can be earned. In actuality, power plants can be expected to earn much less, and this is particularly true for peaking facilities that are frequently out-of-the-money or marginal.
  - ✓ *For example, a gas-fired plant that CPV previously managed earned 71% of the theoretical, backcast day-ahead energy margin.*
- The reasons for this include, among others:
  - ✓ ***Pipeline restrictions** are typical in winter months. When an operational flow order ("OFO") is in effect,*
    - Pipeline customers are penalized for being short of their DA gas nomination ("don't be short OFO"), which forces plants to over-procure gas at high prices.
    - Gas flows are restricted to the same hourly volume all day ("ratable"), which may cause the plant to run uneconomically in some hours.
  - ✓ ***Gas/electric market disconnect** – DAM offers are due before gas prices are known. When the gas price is under-forecasted, the plant may run at a loss; when gas price is overstated, the plant may not run and may incur an economic loss.*
  - ✓ ***Price impact of supply** – the calculations do not account for the price impact of the additional generation (and gas demand), which will tend to compress spark spreads relative to an ex post review of prices. This overstates the value of the DA/RT arbitrage, because RT prices would be less volatile when SCED reflects the incremental supply of proxy plant. This is particularly true in the operating reserves market, where adding 200 MW of supply would cause a large (percentage-wise) movement along the ORDC.*
- We would like to discuss possible approaches to address these shortcomings:
  1. *Address the factors with enhancements to the dispatch logic, as outlined on the next page.*
  2. *Develop a scaling factor based on historical performance of merchant CTs in NYISO. The calculations are comparable to the "scaling factor" calculations the NYISO performs for the Net CONE assessment of Controllable (Transmission) Lines.*

Perfect Hindsight Dispatch (cont'd)

Topic	Description / Support	Possible Remedy
1. Pipeline restrictions	When an OFO is in effect, the pipeline may penalize the customer for burning more gas than the DA nomination ("don't-be-short OFO") or may control flows to the ratable volume.	- Quantify frequency of days OFO is in effect. On that proportion of days, incur a ~20% volume cost, assuming that the supplier over-procures to avoid penalties from being short. - Enforce ratable gas burns on OFO days. Add logic to check whether plant is profitable over the OFO day, assuming a fixed hourly volume of gas (i.e. fixed MW level). - There is often heat rate compression on these winter OFO days. Don't assume that gas can be purchased for just a few hours; zero out energy margin for the day.
2. Gas/electric market disconnect	DAM energy offers are due before gas prices are known. When a plant under-bids gas, it incurs an operating loss; when plant over-bids, it incurs an economic loss.	- Apply a DA gas adder to reflect the risk of under-estimating the gas price, assuming that suppliers will be biased against incurring operating losses. - Alternatively, dispatch the plant based on gas prices from GD-1 but cost gas at the GD-0 price.
3. Minimal demand in ancillary services market	Similar to #5, the ancillary services prices don't reflect the incremental supply.	- Reduce the ancillary services prices to reflect the price impact of added supply. This could be done by moving along the supply curve 200 MW during high-price events or a NYISO Ranger simulation.
4. Price impact of supply	The calculations do not account for the price impact of additional generation, which will tend to compress spark spreads versus ex post prices.	- May be more difficult to quantify. Could estimate impact of added supply, or how much price increases during a trip event.

EFORd

- The 2016 DCR assumed a 2.2% EFORd for the reference CT. The industry average for comparable assets is much higher.
  - ✓ NERC GADS data show a 9.65% EFORd for 50+ MW gas turbines calculated over 2014-2018.
- The model assumes that the cost of forced outages is equal to EFORd x net E&AS revenue; however, this understates the financial impacts.
  - ✓ Plants will be charged higher prices when buying out in real time. To estimate this, the NYISO could quantify the DA/RT spread when plants trip offline.
  - ✓ Trip events are more likely to occur when plants are starting up, e.g. during morning or evening ramp, when energy prices are higher. Therefore, the realized cost during trip events would be higher than average realized prices (which are currently being used).
- Example:
  - ✓ Assume that during a forced outage, day ahead energy must be bought back at a $2/MWh premium in the real time market. The energy premium only applies to day ahead awarded energy, not to real time dispatched power.
  - ✓ Assume that during a forced outage, day ahead gas volume must be sold back in the intraday gas markets at an average discount of 10%.
  - ✓ Based on these points, a gas plant would pay $4.70/MWh in real time energy premium and intraday gas discounts (converted to energy costs at 9.0 mmbtu/MWh heat rate and $3.00/mmbtu gas price assumption). This would be in addition to the one-for-one lost opportunity cost of the forced outage currently used in the analysis.

NERC GADS 2014-2018 Generating Unit Statistical Brochure

All Units Reporting

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	EFORd
GAS TURBINE	50 Plus	464	2,247	9.65
COMBINED CYCLE	All Sizes	333	1,401	3.94

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Dual Fuel

- System-wide dual fuel is needed to address the decreasing reliability of the natural gas delivery system
  - ✓ *Not just in constrained zones*
  - ✓ *Fuel by wire delivery in winter*
- AG's fuel security analysis highlighted importance of the existing dual fuel fleet in its projections:
  - ✓ *"**Dual fuel capability - with oil as a backup fuel to natural gas - is vital for maintaining reliability.** Taking into consideration the demand for natural gas by LDCs for serving retail needs, there simply is not enough gas available for power generation downstate under prolonged, severe cold winter conditions to ensure reliable operations, absent the ability of dual-fuel units to switch fuels. While these resources may operate economically - and to the advantage of electricity consumers - most of the year on available non-firm supplies of natural gas, under severe cold weather conditions LDC demand and other firm natural gas transportation commitments (including for deliveries to neighboring regions) reduce available natural gas for power generation to levels below that needed for reliable system operations, absent the ability to switch to oil. Maintaining adequate dual fuel and other oil-fired operating capability is critical to reliable operations during averse winter conditions, especially in the downstate region." (page 18-19)*
- AG should consider recommending to include dual fuel for the ROS reference unit, in addition to the other capacity regions.