PJM Price-Setting Changes
Reduce uplift where possible without removing consistency between LMP and dispatch signals.
Major Problem Area

- Incremental and no-load costs for units sitting at min for
  - Reactive/Voltage Support
  - Thermal Constraints
  - Blackstart
- Startup costs do not appear to be a large contributor
• Sensitive areas
  – BGE/PEP for APSOUTH/BED-BLA
  – Seneca area of PN when Seneca pumping
  – DPL actual high voltages
  – CLVLND Interface area of ATSI
Proposed Solution

- Extend existing logic for price-setting of inflexible units to generators sitting min for a transmission constraint (reactive/voltage or thermal) to set LMP
  - Already done for CTs that are not dispatchable
- Model and bind the constraints these generators are running for in real-time and day-ahead
  - Likely closed-loop interfaces
- Ensure these facilities are modeled appropriately in FTR Auctions
What happens if we do this?

• More congestion on the system (DA and RT)
• Higher prices in areas where generation is running under these circumstances
  – Closed loop interface will avoid lowering generation
• Incremental costs will be removed from uplift as long as these constraints bind
  – Reduction in uplift
How do we get there?

• Review Tariff/OA/Manual language to see if changes are required
  – Initial opinion is no. Still under review.
• Identify units and facilities to be addressed
  – Go after the heavy hitters first
• Identify and post facilities that will be bound in DA/RT for 14/15 FTR auction modeling
• PJM will need software changes to implement this
• Which facilities?
  – Use existing facilities but may need new interfaces
    • BC/PEPCO Interface
    • CLVLND Interface
    • DPL Interface
    • PN Interface
  – Not the complete set…just what’s been discussed at PJM so far
Questions on the table…

- At what point is it better to have uplift instead of increased congestion?
- Should we only bind the facilities when there is a potential issue with the unit offline?
  - Binding just due to unit being on (min run time) even if not needed
- Others?
• Further discussion
  – Now
  – Jan/Feb MIC and EMUSTF

• February
  – Announce/post facilities to be modeled in FTR auction

• June 1, 2014
  – Implementation of new logic
APPENDIX: EXAMPLES
• Line A→B
• 400 MW rating
• 400 MW of FTRs sold from A→B
In real-time, absent the commitment of generation, the line would be overloaded.

PJM must take action to alleviate...
Run Generation

400 MW of FTRs

360 MW of flow

- By running Gen A at min, it pushes back on A→B
  - 50 MW push back
    - 250 * .25 = 50 MW
  - Flow down to 90%
    - (410 – 50) / 400 = 90%

PJM does not normally bind facilities below 97%.

Today we would not bind this facility. Gen A would be made whole.

Gen A
Min = 200
Max = 400
Cost = $100/MWh
dfAx(A→B) = 25%

Energy Component of LMP = $50/MWh
• Calculate a lower rating and control to it
  – Determine a lower rating such that Gen A is needed at 200.1 MW
    • 359.999 MW
• Based on this rating, Gen A needs to be dispatched above min and can therefore set LMP
• To control another .001 MW, Gen A is dispatched to 200.004 MW
  – Flow down to 359.999 MW
• Gen A sets LMP
  – Shadow Price = ($50/MWh - $100/MWh) / .25 = $200/MWh
  – Energy Component = $50/MWh
  – Congestion Component (Bus B) = $50/MWh
  – LMP @ B = $50/MWh + $50/MWh = $100/MWh
• Gen A’s uplift related to incremental cost = $0

Gen A
Min = 200
Max = 400
Cost = $100/MWh
df.ax(A → B) = 25%

Energy Component of LMP = $50/MWh
FTR Implications – Current Allocation

- Issue: Congestion on a facility for which there are more FTRs allocated than flow on the line

- FTR Credits = 400 MW * ($100/MWh - $25/MWh) = $30,000
- Congestion Collected = 360 MW * ($100/MWh - $25/MWh) = $27,000

**REVENUE SHORTFALL = $3,000**
360 MW of FTRs

- FTR Credits = 360 MW * ($100/MWh - $25/MWh) = $27,000
- Congestion Collected = 360 MW * ($100/MWh - $25/MWh) = $27,000

REVENUE NEUTRAL