Western Energy Imbalance Market — Regional Issues Forum

Meeting Summary of June 6, 2018

Administrative:

- The RIF liaison Officers Presiding:
  - Cameron Yourkowski (Renewables Northwest), Chair
  - Therese Hampton (Public Generating Pool), Vice Chair
  - Matt Lecar (Pacific Gas & Electric), Secretary
- A quorum of liaisons was confirmed present
- EIM Governing Body Members present or listening: Fong, Prescott
- The next RIF meeting will be held on November 28th 2018, in Phoenix, Arizona
  - All meeting agendas and presentation materials may be found at https://www.westerneim.com/Pages/Governance/RegionalIssuesForum.aspx

Block 1 — Informational Overview

- Approaches to Market Power Mitigation (David Patton, Potomac Economics)
  - Market power is generally the result of transmission constraints between generation and load within a local area.
  - Mitigating the inevitable market power held by certain resources is necessary to ensure competitive pricing and "just and reasonable" outcomes.
  - Some market power will always exist, but behavioral mitigation protocols such as capping generators' supply quantity is often an effective oversight strategy.
  - Strict sanctions are always an option to address more serious offenders.
  - Market Power Mitigation strategies should keep the following 3 best practices in mind:
    - Mitigation should not create barriers for competitive markets
    - Mitigation should only target intentional attempts at securing market power
    - Mitigation should only be utilized where necessary, to avoid unnecessary costs
  - Since the marginal costs of any given resource are difficult to know, needless market power mitigation can negatively affect dispatch for both the resource and the grid
  - Potomac Economics recommends use of a 'conduct and impact' framework for mitigation, which attempts to define when market power must be addressed:
    - Conduct Test: Is a supplier acting uneconomically, such as creating scarcity?
    - Impact Test: Is a supplier's uneconomic action significantly increasing prices?
  - Under this framework, the following actions are tested:
    - Economic Withholdings: To avoid being dispatched by raising offer price, thereby raising clearing prices
    - Physical Withholding: Derating or completely withholding an otherwise economic unit, thereby raising clearing prices
    - Uneconomic Production: Oversupplying in order to overtax a system constraint
  - The following monetary sanctions can be applied based on severity of manipulation:
    - $25 per MWh for offers which create uplift

        - $10—$100 for locales of chronic constraint
        - $100 per MWh for constraints which are not chronic
    - Similar market power mitigation strategies can be developed to ensure deployment only when nontrivial deviation from competitive price offerings is occurring
        - RTO market software can be utilized to estimate supplier impact on price
        - Notably, MISO mitigates less than 1% of units which fail the conduct test
    - Reference prices vary over the output range of a unit and tend to reflect historically accepted bids and operating processes
        - This results in reference prices being based on output blocks with high marginal costs, though actual marginal costs may be low
    - Conduct Tests must use reference levels—which reflect units' marginal costs—as benchmarks.
        - Reference levels should be calculated for all categories of bid components, such as physical unit constraints, minimum generation costs, and start-up costs
    - Potomac Economics calculates reference levels using the following methodologies
        - Historical accepted bids from competitive periods
        - Lowest LMP's at the time the unit was dispatched
        - Cost data gleaned from the supplier
    - Often times market monitors utilize only the third method which risks missing useful data from supplier history
    - Potomac Economics emphasizes that reference levels should not simply internalize a generator's variable costs but also its marginal costs, including:
        - Opportunity costs stemming from limitations on output over medium term (daily and weekly), and long term (monthly and interannually) periods
            - These are critical factors for hydro resources
        - Significant maintenance expense and regular scheduling
        - Incentives influenced by contracts including power purchase agreements (PPA's)
        - Miscellaneous operational and economic risks
    - Reference levels should be automated on order to ensure that changing unit characteristics are accounted for.
- Discussion
    - Powerex commented:
        - The CAISO's default energy bid (DEB) methodology is current not sufficient to account for opportunity costs surrounding inter-seasonal hydro operation
    - Responding to Oregon Public Utilities Commission, UAMPS, Seattle City Light, Chelan, Portland General, Public Generating Pool, Tony Braun (RIF liaison) CMUA, Turlock Irrigation district, et al.
        - Dr. Patton stated:
            - When constraints exist in the absence of clear market power, an RTO can dispatch resources to address such a constraint
            - In such voluntary markets as the EIM, mitigation regimes should not scare resources away from participate for fear of needless mitigation
            - However, market monitors should be empowered to create unique mitigation techniques when necessary

- In Dr. Patton's experience, two thirds of market monitoring functions are associated with analyzing the impact of RTO actions on the market

Block 2 — ISO-NE Stakeholder Engagement Process

- Participants Agreement (Vicky VanZandt, ISO-NE Board)
  - Described working relationship between ISO-NE and New England Power Pool
  - Described organizational structure of ISO-NE
  - ISO-NE works with stakeholders to develop system-wide plan for release every 2 years

Block 3 — Enhancing Load and VER Forecasts

- CAISO Presentation
  - CAISO receives forecasts from external forecast service 11-16 minutes prior to the operational block.
  - Automated Load Forecasting System (ALFS) introduces a 5 minute delay, but the CAISO has introduced enhancements that will attenuate this to a 1 minute lag
    - This improvement was implemented in coordination with IPC on April 28. 2018
  - Gave explanation of persistence forecast methodology enhancements
    - Forecast error margins have decreased
    - EIM entities have already begun utilizing VER persistence enhancements
  - CAISO requires EIM solar resources to include the following persistence methodologies:
    - Pmax
    - Actual Metered Resources MW data for up to 3 years, if available
    - Solar Resource type (Solar thermal, tracking, etc.)
    - Latitude and Longitude of array
- IPC Informal Presentation:
  - Gave overview of VER integration across its system
    - 300-400MW of wind
    - IPC is familiar with a 25-30 minute forecast lag due to reliability issues
    - Through coordination with CAISO this lag was reduced to 15 minutes
    - Due to the uncertainty component which comprises a sizable portion of the flexibility test, VER forecast issues can increase entities' flexibility requirements
  - IPC is still operating under the flexibility cap but foresees exiting it within 2 weeks' time.
- Discussion:
  - The flexibility requirement's uncertainty component is based on forecasted movement instead of system conditions
  - Hourly base schedules typically include up to date VER forecasts
- APS Presentation
  - APS noted that it believes to be one of the EIM entities most affected by the duck curve
  - The following forecasting challenges were identified:
    - The duck curve
    - Monsoon season and aberrant cloud behavior

        - VER forecasting
        - APS 3 sub-region load pockets
        - Intraday extended forecasting
        - Next-hour forecasting improvements
    - VER latency issue between APS and CAISO systems
        - APS has improved VER forecasts from 15 minute to 5 minute intervals
        - Cloud cover has caused latency issues between APS and CAISO
    - Proposed remedies for such latency issues include:
        - CAISO persistence forecast model would help address solar ramping
        - CAISO VER enhancements previously mentioned

Block 4 — EIM Updates

- 'Go Live' Experience and Lessons Learned (Idaho Power)
    - IPC presented on its experience joining the EIM
    - Generation share includes:
        - Natural Gas (758 MW max capacity)
        - Hydro (1020 MW max capacity)
        - Coal (708 MW max capacity)
    - IPC made note of several challenges faced while joining the EIM, including:
        - Load forecasting improvements needed
        - Hydro conditions during spring
    - Joining the EIM has been mainly positive, but logistical and system implementation—such as properly setting a DEB for hydro generation—can require highly complex effort
- 'Go Live' Experience and Lessons Learned (Powerex)
    - Powerex presented on its experience joining the EIM
    - Powerex transacts at the United States-Canada border, through British Columbia
        - Transmission rights are made available to the EIM on a voluntary basis
    - Expected benefits of EIM participation include:
        - Broader regional resource diversity to offset imbalances within British Columbia
        - Removing transmission hurdles rates
        - Collecting congestion rent for transmission rights provided
    - Potential, but currently unrealized benefits of EIM participation:
        - Co-optimizing imbalance and residual imbalance reserves
        - Sales opportunities that will result from better system pricing of hydro