Helping our members work together to keep the lights on... today & in the future

RSC Training on Future Markets

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Agenda

• Benefits of Expanding the Current Markets
• SPP Future Markets Design Overview
• Transmission Congestion Rights in SPP Future Markets
  ➢ Background and Overview
  ➢ Allocation/Auction Process
• RSC Responsibility and Next Steps

Benefits of Expanding the Current Markets

Richard Ross
Today’s Market Environment

- The EIS Market has been successful; it:
  - Allows for more transparent pricing.
  - Permits increased opportunities for short-term economic trading.
  - Allows for better coordination of short-term resource plans across footprint.

- However, the current EIS Market also has its limitations, as:
  - Unit Commitment is done independently by each Member.
  - The use of a physical transmission rights process can constrain economics unnecessarily and is sometimes unwieldy.
  - There is no opportunity in the Market to gain price certainty with the current design.

Day-Ahead Market and Unit Commitment

- The major benefit from the Future Markets comes from the centralized unit commitment feature.
  - Most generators have significant lead times to get them started.
    - Therefore, unit commitment cannot be completed in real-time.

- Self-Commitment of resources and scheduling are the primary hedging instruments in current EIS market.
  - This hedge relationship has to be preserved or resources will not be offered for SPP commitment.
  - We need to make sure there is no disincentive to participants offering their resources to SPP for unit commitment.
Congestion Hedging Task Force

- The Congestion Hedging Task Force (CHTF) reviewed the current scheduling mechanism for use in Future Markets and determined that a change to a financial instrument independent from physical delivery was needed.

- Major reasons included:
  - More flexibility in trading and arranging for the congestion hedge.
  - Elimination of the need to do native load schedules.
  - Better support of the use of trading hubs.
  - No near-term curtailment of hedge so more advance certainty.

Member Objectives from Future Markets

- Increase Market Participant savings by moving from self-commitment to centralized unit commitment.
- Price assurance capability for load prior to real-time.
- Market-based Operating Reserves to support the Consolidated Balancing Authority (CBA).
RSC Role in Future Markets

• The RSC has a role in certain aspects of the Future Market design per its bylaws:
  ➢ “...determination Financial Transmission Rights (FTRs) allocations...”
  ➢ “determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customer's existing rights;”

• Both of these topics are covered later in this presentation.

• The purpose of today is to start the discussion regarding the decision making process and timeline.
SPP Future Markets – Design Overview

- **Overview of key Energy and Operating Reserve Market Functions**

  - **Day-Ahead Market (DA Market)**
  - **Reliability Unit Commitment (RUC)**
  - **Real-Time Balancing Market (RTBM)**

  ![Diagram of market functions](attachment:market_diagram.png)

  - DA Market Offers (Energy and Operating Reserve), Bids, Operating Reserve Requirements
  - RTBM Offers, Load Forecast, Operating Reserve Requirements
  - RTBM Offers, Load Forecast, Operating Reserve Requirements

  - Dispatch Instruction cleared
  - Clear in DA Market
  - Clear in EMS

  - DA Market Commitment
  - RUC Commitment
  - DA Market & Net RTBM Settlements
  - TCR Markets

  - Resource and Load Meter Data

Major Features of SPP Day-Ahead Market Design

- **Day-Ahead Market (DA Market)**
  - Voluntary participation
  - Financially binding markets using unit commitment style energy market
  - Uses security constrained unit commitment and dispatch so results are physically feasible
  - Financial transmission rights clear in DA Market
  - Settlements based on Locational Marginal Prices (LMPs) as calculated by SPP based on submitted information
  - Virtual bids and offers may be submitted
  - Reserves will be co-optimized with Energy Market
Day-Ahead Market

• Develop Day-Ahead clearing using least-cost Security Constrained Unit Commitment (SCUC) and Dispatch (SCED).
  ➢ Full transmission model used.
  ➢ Contingencies modeled and respected.
  ➢ Unit commitment constraints applied.
  ➢ Reserve requirements modeled.
• Market inputs include generation offers, demand bids, virtual bids/offers and external transaction schedules.
• DA Market clearing is performed for Energy, Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve.

Generation committed through the Day-Ahead Market is selected by the RTO in a way that results in the lowest total production cost to meet requests to serve load through the Day-Ahead Market.
Day-Ahead Market

- DA Market outputs include:
  - Locational Marginal Prices (LMPs) for Day-Ahead Energy Market Settlements.
    - Used to settle purchases and sales in the DA Market.
    - Used to settle Transmission Congestion Rights (TCRs).
  - Clearing prices and quantities for Operating Reserves.
  - Financially binding schedules for Resources.
    - Provide quantity of purchases and sales.
    - Provide estimated operating schedule for next day.

Reliability Unit Commitment (DA and RT)

- RTO performs reliability assessment after close of Day-Ahead Market:
  - Assessment looks at two main areas:
    - Capacity adequacy to meet projected load forecast.
    - Transmission reliability assessment to identify potential local security problems.
  - Participation in reliability assessment
    - Mandatory participation in the RUC.
    - Resource Offers may be updated.
  - Assessment objectives
    - Minimize amount of additional capacity required.
    - Minimize start-up costs and costs to operate at minimum capacity.
    - Energy costs above minimum capacity are not considered.
  - Costs
    - Generators guaranteed recovery of start-up and no-load costs if they are dispatched on-line by the RTO.
    - Costs are allocated to those with real-time imbalances from day-ahead schedules.
Reliability Unit Commitment

The RTO will perform a reliability assessment to compare the amount of load that cleared in the Day-Ahead Market to its load forecast.

![Graph showing RTO Load Forecast and Generation Capacity Committed in DA Market]

Self Committed Resources

RTO Load Forecast plus Operating Reserve Requirement

Generation Capacity Committed in DA Market

Major Features of Real-Time Balancing Market

- Uses security constrained economic dispatch to ensure results are physically feasible.
- Operates on a continuous 5-minute basis and calculates Dispatch Instructions for Energy and clears Operating Reserve.
- Energy and Operating Reserve will be co-optimized.
- Settlements are based on the difference between the results of the RTBM process and the DA Market clearing.
- Charges are imposed on Market Participants for failure to deploy Energy and Operating Reserve as instructed.
Real-Time Balancing Market

- RTBM inputs include:
  - Generation offers, demand bids, external transaction schedules;
  - Operating Reserve requirements;
  - RUC Resource commitment;
  - SPP Short-Term Load Forecast (STLF);
  - Intermittent Resource output forecast.
- RTBM executes every 5 minutes for the next Dispatch Interval based on the inputs.

Real-Time Balancing Market

- RTBM outputs include:
  - Resource Dispatch Instructions for Energy;
  - Cleared Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve MW amounts;
  - Locational Marginal Prices (LMPs) for each Settlement Location;
  - Market Clearing Prices (MCPs) for Operating Reserve.
Future Market Settlements – Key Features

• Day-Ahead Market
  ➢ Resources are paid Locational Marginal Price (LMP) and Market Clearing Price (MCP) for cleared amounts of Energy and Operating Reserve.
  ➢ Loads are charged LMP for cleared amounts of Energy.
  ➢ The difference between charges to Load and payments to generators (congestion cost) is used to pay holders of Transmission Congestion Rights (TCRs).
  ➢ Physical resources committed by SPP are guaranteed recovery of their offer costs via a make-whole payment.

• Reliability Unit Commitment (RUC)
  ➢ Physical resources committed by SPP are guaranteed recovery of their offers cost via a make-whole payment.

Future Market Settlements – Key Features

• Real-Time Balancing Market (RTBM)
  ➢ Resources are charged/paid real-time LMP and MCP for RT deviations from cleared DA amounts of Energy and Operating Reserve.
  ➢ Loads are charged/paid real-time LMP for RT deviations from cleared DA amounts of Energy.
  ➢ Loads are charged for DA and RT Operating Reserve procurement costs at the Reserve Zone level.

• Financial Transactions
  ➢ Bilateral trading outside of the SPP Markets will still occur in order to reduce exposure to market prices in both DA and RT.
  ➢ Accommodated through submittal of financial transactions Post-Operating Day.
  ➢ Financial transactions do not alleviate exposure to congestion charges associated with the bilateral trade.
  ➢ The location of the settlement location relative to the source and sink will determine who absorbs the congestion cost.
Transmission Congestion Rights in SPP Future Markets

Keith Sugg
Introduction and Principles for TCRs

- A TCR is a financial right that entitles the holder to a share of the congestion revenue collected in the Day-Ahead Market (DA Market).

- A basic premise is that those transmission customers who have paid for long-term transmission rights will receive a commensurate level of TCRs to serve their load with their resources.
  - There is no guarantee each TCR will be a perfect hedge
  - The amount of TCRs available must be simultaneously feasible to avoid “overselling” TCRs, which could create revenue shortfalls in settlements.
  - MPs can place a value on specific TCRs through an auction
Congestion Rights are the Rights to the Congestion Revenue

- So who gets all that money?

- Congestion hedges in the form of TCR give us the mechanism to determine which parties have the rights to get that money back, and how much.

- TCR holders get paid a portion of the excess revenue collected based upon the differences in DA Market LMP between the TCR sink point and TCR source point, multiplied by the TCR MW.

- TCR provides the holder with a congestion hedge that is equivalent to the congestion hedge provided by a physical schedule in today’s EIS.
How Will Transmission Customers obtain TCRs under the Future Market Design?

- Firm transmission

- Auction Revenue Rights (ARRs) candidate set
  - Simultaneous feasibility analysis and auction

- Transmission Congestion Rights (TCRs)

- Settlement

Annual ARR Allocation

- Candidate set of ARRs are limited to the Transmission Customer’s firm transmission entitlements.

- Transmission Customers with these candidate ARRs determine which ones to nominate and the quantity of MW (up to their firm transmission rights).
Annual ARR Allocation Process

- ARRs are allocated in a three-round process:
  - Up to 50% of the ARR Nomination Cap can be nominated in Round 1;
  - Up to 75% of the ARR Nomination Cap can be nominated in Round 2;
  - Up to 100% of the ARR Nomination Cap can be nominated in Round 3.
- NITS Transmission Customers nominate ARRs by specifying the Resource to Load path verified during the registration process.
- Firm PTP Transmission Customers nominate ARRs by specifying the sources and sinks associated with the reservation verified during the registration process.

Annual ARR Allocation Process

- Only 75% of the SPP Transmission System capability is made available during the annual allocation process.
- Transmission Customers may nominate ARRs up to their Nomination Cap for each month in the allocation period:
  - 24 separate transmission system models created for the annual allocation period
  - 12 monthly on-peak and 12 monthly off-peak models
  - Nominations are independent for each model.
A Simultaneous Feasibility Test is Completed After Each Round

- If all nominated ARRs are feasible, all nominated ARRs are awarded.
- If nominated ARRs are not feasible, the nominated ARRs will be reduced until all ARRs are feasible prior to the award.
- Reductions to nominations are based on weighted impact to the affected transmission constraints.

Annual TCR Auction

- This process is the mechanism through which MP’s may obtain annual TCRs by submitting TCR Bids and/or through direct conversion of ARRs to TCRs.
- Only 75% of the SPP Transmission capability is made available during the annual auction process.
- Any MP that has satisfied the applicable credit requirements may participate in the auction.
- For each month included in the auction period, MP’s may submit TCR Bids and Offers separately for On-Peak and Off-Peak.
**ARR and TCR Auction Processes**

TCs identify and confirm NTS and Firm PTP → MPs Submit Bids to Buy TCRs and Offers to Sell TCRs → TCR Market Settlements

TCs Nominate Annual ARRAs → Annual ARR Auction

TCs Nominate Seasonal ARRAs → Seasonal Monthly ARR Auctions

MPs Submit Bids to Buy TCRs and Offers to Sell TCRs → Monthly ARR Auction

TCs Nominate Monthly Residual ARRAs → Monthly TCR Auction

The monthly auction process follows a process similar to the annual process.

**Sample Timeline to Obtain ARRs and TCRs**

12/15 - 5/31

MP Registration of Transmission Entitlements

3/9 - 4/17

Annual TCR Auction

5/4 - 5/15

Monthly TCR Allocation for June Repeals for Each Month

6/1 - 5/31

Annual TCR Auction Awards Seasonal by Month On-Peak and Off-Peak

Seasonal Monthly On-Peak and Off-Peak TCR Auctions
Who is Eligible to Obtain ARRs/TCRs?

- It is important to distinguish between allocation of ARRs and TCR auctions.
- ARRs will be to transmission customers with long-term firm transmission service.
  - Based on existing Network or Point-to-Point service.
  - Rules set the Nomination Cap on the amount of ARRs that is linked to level of long-term transmission service.
- All Market Participants who meet credit standards may participate in the TCR auctions.
  - Participation expanded during MWG deliberations.

Summary – Differences from EIS Market

- Transmission Congestion Rights (TCRs) replace use of Energy Schedules and Native Load Schedules (NLS) as congestion hedges.
- Congestion Hedging process moves ahead of Real-Time and even Day-Ahead operations (annual and monthly ARR Allocation/TCR Auction processes).
  - Only Interchange schedules into, out of or through SPP BA would be subject to TLR.
- External Parties and those without assets in Market Footprint can participate.
RSC Responsibility and Next Steps

Sam Loudenslager

RSC Decisions related to Future Markets

- As noted earlier, the RSC has responsibility in two particular areas related to the Future Market design:
  - “...determination of Financial Transmission Rights (FTRs) allocations...”
  - “determination of the transition mechanism to be used to assure that existing firm customers receive FTRs equivalent to the customer’s existing rights;”
- This means policy decisions will be needed by the RSC regarding the following:
  - Does the RSC support the proposed mechanism for allocating ARRs/TCRs to existing transmission customers based on their existing long-term firm transmission service?
  - Is the RSC satisfied that the proposed ARR nomination process allows existing customers to obtain “equivalent” rights to what they have now?
Next Steps

- Market design being reviewed by the MOPC and Board.
- Market Working Group working towards March target date to finalize core design features.
- Important to get RSC input and approval prior to requesting final MOPC and BOD approval
  - Need time to revise design documents before final MOPC/BOD review and approval.
- Request RSC charge CAWG or other working group to review design elements related to RSC decisions and report back to RSC by end of March.
- Ideally, RSC can assess situation in April with follow-up in July, if needed.