2017 IRC Markets Committee

Market Design Executive Summary

The Market Design Executive Summary details the Independent System Operator (ISO) and Regional Transmission Operator (RTO) markets within the ISO/RTO Council (IRC), concentrating on market design, pricing and settlements.

Alberta Electric System Operator (AESO)

Located in Calgary, Alberta the Alberta Electric System Operator serves 4 million customers over 16,155 miles of transmission lines with an installed generation capacity of 16,423 MW.

Market

The Alberta Market is set up as a single zone or node with separate markets for energy and ancillary services. Supply with a maximum capability of 5 MW or above has a must offer requirement in the Energy Market up to the full capability of the unit. Supply offers are sorted by price and dispatched in the merit order to meet demand. The Energy Market is a real-time dispatched market, not day ahead. A voluntary Day Ahead Market exists for Operating Reserve procurement. Other Ancillary Services (Blackstart Service, Load Shed Service for Imports (LSSi), and Transmission Must Run (TMR) are contracted through the AESO's procurement process.To ensure the reliable operation of the grid, the AESO reserves the right to direct a unit to provide Ancillary Service beyond its contracted volumes.

Pricing

The Alberta wholesale market for electricity is energy only with a single pool price. The AESO publishes the current System Marginal Price (SMP) in real time, the highest price block dispatched in each minute. The offer price cap is $999.99 per MWh. The offer price floor is $0 per MWh. Prices are set according to energy dispatch in economic merit order. In the event of supply shortfall the system marginal price (the instantaneous price) is set at the offer cap of $999.99 per MWh, and remains at $999.99 per MWh until required to shed firm load. At that point the Market Price is administratively set at $1000 per MWh. Losses are not directly allocated within Alberta's energy only pool price. Market participants attempt to recover loss charges found on their system access service (transmission tariff) invoice through their offer strategy. Only generators and opportunity services (import, export and non-firm demand) pay for losses on the Alberta Interconnected Electrical System (AIES). Ancillary Services pricing is based on contract payment terms specific to each service.

Settlements

The energy market is based on a single settlement model. At the end of each hour a "pool price" is calculated ex-post as the average of the 60 System Marginal Prices for the hour and that price is used for the hourly market settlement. The AESO recovers the costs of operating the real-time energy market through an energy market trading charge on all electricity traded. The trading charge is intended to recover the administrative cost of running the pool plus cover costs for the Market Surveillance Administrator (MSA) and the Alberta Utilities Commission (AUC). Generators and importers are paid the pool price minus the trading charge, and loads and exporters pay the pool price plus the trading charge. All penalties for failure to provide (withholding) and deviation charges (dispatch non-compliance) are assessed by the market surveillance administrator (MSA) and settled outside of the Energy Market, with the exception of late payment penalties. The AESO recovers transmission costs through the ISO Tariff.

Market Changes

On November 23, 2016 the Government of Alberta announced its endorsement of the AESO's recommendation to transition from an energy market to a new framework that includes an energy market and a capacity market. The AESO is responsible for designing and implementing the capacity market. This process is expected to take three years and a capacity market is anticipated to be in place by 2021.

In support of the Government of Alberta's Climate Leadership Plan, the AESO has also initiated a Renewable Electricity Program (REP). The REP is intended to encourage the development of 5,000 MW of renewable electricity generation capacity connected to the Alberta grid between now and 2030. The AESO is responsible for implementing and administering the program through a series of competitions that will incent the development of renewable electricity generation through the purchase of renewable attributes. The first round of REP will procure up to 400 MW of renewable electricity capacity which must be operational in 2019. In addition, under the Climate Leadership Plan, Alberta plans to phase-out all pollution from coal-fired generation by 2030, either through asset retirements or coal to gas conversions

California Independent System Operator (CAISO)

The California Independent System Operator is located in Folsom, California and serves approximately 30 million customers across 26,000 miles of transmission lines with an installed generation capacity of 71,740 MW.

Market

Energy and Ancillary Services are co-optimized in the Day-Ahead Market and the 15-minute Real-Time Unit Commitment Market. Real-Time dispatch at the 5-minute interval is not co-optimized with Ancillary Service. The objective market function is to minimize the cost of production based on resource offers. Resources can self-schedule energy, and can self-provide ancillary services. For extra-long and long-start resources, a Day-Ahead commitment is physically binding. For other resources, the Day-Ahead Market commitment is financial. The Reliability Unit Commitment (RUC) physically commits resources for reliability based on forecasted demand, and is published simultaneously with the Day-Ahead Market which is based on bid-in demand. The Day-Ahead Market closes at 10 am on the day prior to the operating day, and posts results by 1 pm. Energy, start-up and minimum load bids are submitted into the Real-Time Market, which closes 75 minutes prior to operating hour. Real-Time bids are incremental or decremental to Day-Ahead bids. Resources can change their bid between Day-Ahead and Real-Time regardless of whether they have a schedule or not.

Western Energy Imbalance Market (EIM)

The Western Energy Imbalance Market was launched in 2014 and continues to grow annually. EIM extended the CAISO's real-time market to a wide geographical footprint enabling the use of economic dispatches to meet imbalance needs on a 5 and 15-minute basis. As of March 2017, cost savings have grossed over $170 million. Additionally, EIM Entities can economically sell excess energy resulting in increased renewable integration and reduced carbon emissions across the West. Autonomy is maintained by EIM Entities; they have operational control of their respective Balancing Area (BA) and must adhere to reliability standards.

Pricing

Energy is priced using Locational Marginal Pricing (LMP) that accounts for the system energy price, congestion and marginal losses. Each generator within the CAISO market is a pricing node and is paid at the Locational Marginal Price (LMP) for that node. Load pays a zonal price, which is a load-weighted average for the 15-minute and 5-minute prices. Real-Time prices are posted for the 15-minute market every 15 minutes using a 15-minute price; real-time market prices are posted for the 5-minute market every 5 minutes using a 5-minute price. Marginal Losses are calculated for each pricing node as part of the AC power flow solution.

The Energy bid cap is $1000/MWh, and the Energy bid floor is -$150/MWh. The Ancillary Services and Reliability Unit Commitment (RUC) bid cap is $250, and the floor is $0. There is no cap on price. Ancillary Services and Shortage Pricing is based on the scarcity demand curve which covers regulation, spinning, and non-spinning reserves. The highest scarcity price is $1000/MWh, which is the energy bid cap.

Settlements

CAISO has a multi-settlement structure as the Day-Ahead, Reliability Unit Commitment, and Real-Time Markets are settled separately. The Day-Ahead and Reliability Unit Commitment Markets are settled hourly. Real-Time Markets are settled at respective 15-minute and 5-minute prices. If the net market revenues result in shortfall, generators receive an uplift payment. CAISO also settles for Flexible Ramp Product and Uninstructed Imbalance Energy.

Electric Reliability Council of Texas (ERCOT)

The Electric Reliability Council of Texas is located in Austin, Texas and serves approximately 24 million customers across more than 46,500 miles of transmission lines with an installed generation capacity of 86,000 MW.

Market

To maximize overall system benefit, the ERCOT Day-Ahead Market simultaneously co-optimizes energy, ancillary services and congestion hedging products by maximizing bid-based revenues and minimizing offer-based costs, subject to resource and network constraints. ERCOT's Day-Ahead Market is voluntary and does not solve to meet load forecast. Energy offers in the Day-Ahead Market are financially binding and awarded hourly. The Day-Ahead Market closes at 10 am and posts results by 1:30 pm. A daily Reliability Unit Commitment (RUC) run ensures enough generation is online to meet the load forecast. The Real-Time Market uses Security Constrained Economic Dispatch (SCED) that re-dispatches current generation at least-cost. Qualified Controllable Load Resources can submit demand response bids for the Real-Time market. Load Resources may provide Ancillary Services, and regularly provide up to 50% of Responsive Reserves (hourly procurement varies). Emergency Response Service offers short-term (4 month) capacity payments to Loads and Generators for emergency Demand Response.

Pricing

Energy pricing is based on Locational Marginal Pricing (LMP) and includes congestion but does not include losses. Losses are charged to load based on a load ratio share. The offer cap is $9,000/MWh for energy offer curve and ancillary services. The offer floor is -$250/MWh for energy offer curve and $0/MWh for ancillary services respectively. There is no bid cap or floor for virtual bidding in the Day-Ahead Market. Day-Ahead prices are final at 10 am two business days after and Real-Time prices are final at 4 pm two business days after. Settlement Point Prices (SPP) are computed on a 15 minute basis based on the 15 minute weighted average of the LMPs and the value of real-time reserves. An Operating Reserve Demand Curve (ORDC) is utilized for scarcity pricing. The value of real-time reserves plus energy can reach $9,000/MWh under scarcity conditions. A Real-Time On-Line Reliability Deployment Price Adder (RTORDPA) that captures impact of reliability deployments during SCED Intervals is also added to the LMPs.

Settlements

ERCOT settles the Day-Ahead and Real-Time markets separately. Day-Ahead Market activity is settled 2 days after the Operating Day, while Real-Time Market activity is settled 5, 55, and 180 days after the Operating Day using actual meter data for true up. Over 6.6M meters are settled with Advanced Meter data and over 98% of the load in ERCOT is settled with 15-minute interval data. Settlement activity is invoiced on a daily basis. The Reliability Unit Commitment is a physical commitment and settled hourly. Day-Ahead energy offers and bids are financially binding and settled hourly. Real-Time prices are posted every 5-minutes but settled at the 15-minute interval. Financial penalties for failure to provide Ancillary Services and for failure to following dispatch instructions are imposed on market participants.

Independent Electricity System Operator (Ontario)

The Independent Electricity System Operator of Ontario is located in Toronto, Ontario and serves almost 14 million customers across 18,641 miles of transmission lines with an installed generation capacity of 36,563 MW.

Market

Ontario operates a wholesale market for Energy and Ancillary Services that is dispatched every 5-minutes in Real-Time. There is no Day-Ahead Market, although there is a Day-Ahead Commitment Process (DACP) which commits dispatchable generators and schedules imports in the day-ahead time frame for a financial guarantee. Ancillary Services are a cost based market and paid for by consumers and export transactions as an hourly market uplift charge in $ per MWh. Inter-tie transactions including imports and exports are physically committed and scheduled Hour-Ahead. Operating Reserves are a market based service that are co-optimized with Energy. Bid offers are submitted between 6 am and 10 am day-ahead, and results are published at 3 pm prior to the operating day.

Pricing

Ontario pays a uniform Real-Time price to all supply, which is paid for by load. A single Energy Market Price (EMP) is dispatched every 5-minutes ignoring transmission congestion and losses. The Maximum Market Clearing Price (MMCP) for Energy is $2000, and the Minimum Market Clearing Price (-MMCP) for Energy is -$2000. The Maximum Operating Reserve Price (MORP) is $2000 per MWh. All operating reserve offer prices must be greater than or equal to $0 per MWh and less than the Maximum Operating Reserve Price. Real-Time Market prices are published within one-hour after the dispatch hour and are finalized two-business days after the operating day. Ancillary Services are cost based and paid by Ontario consumers and export transactions as an hourly market uplift charge in $ per MWh of consumption. Marginal transmission losses are included as fixed penalty factors in evaluation of bids and offers for physical dispatch. The fixed penalty factors are established by IESO for each node.

Settlements

Ontario uses a single Settlement that uses the ex post energy price. Generators, Imports and Exports are financially penalized if they fail to meet their Day-Ahead or Hour-Ahead commitment. Day-Ahead and Real-Time commitments receive a cost guarantee to recover costs.

ISO New England (ISO-NE)

ISO New England Inc. is located in Holyoke, Massachusetts and serves approximately 14.7 million customers in the six-state New England region that has 9,000 miles of transmission lines and an installed generation capacity of approximately 30,500 MW.

Market

ISO New England operates a multi-settlement energy market. The Day-Ahead Market (DAM) produces hourly prices and financially-binding energy purchase and sale schedule based upon supply offers and demand bids of market participants. The Day-Ahead Market respects operating reserve requirements but does not co-optimize Energy and Operating Reserves. The Real-Time Market is co-optimized for Energy and Operating Reserves. The energy markets are cleared to maximize market efficiency (i.e., gains from trade), while maintaining system reliability by observing security constraints. The Forward Capacity Market (FCM) is designed to acquire qualified resources three years in advance of the commitment period to meet the resource adequacy needs of the region. There is a Forward Capacity Auction (FCA) each year where Market Participants obtain a Capacity Supply Obligation to deliver capacity by the start of a commitment period. Capacity Supply Obligations can be acquired or shed bilaterally or in reconfiguration auctions.

Pricing

ISO New England utilizes Locational Marginal Pricing (LMP) that includes marginal losses and congestion. The DAM solution produces hourly LMP for all nodal and aggregate pricing locations including external interfaces. Real-Time dispatch produces ex-ante dispatch rates and LMPs. There is a $1,000/MWh offer cap in the Energy Market. There is currently a -$150/MWh offer floor price in the Energy Market.

Settlements

ISO-NE has multi-settlement Day-Ahead and Real-Time Markets. Day-Ahead Market schedules are priced for settlement at hourly Day-Ahead Market LMP. Deviations from the Day-Ahead schedule are credited or charged at the Real-Time price. The Real-Time settlement for energy and reserve are on a 5-minute basis and regulation will be settled subhourly beginning in December 2017.

Midcontinent ISO (MISO)

Midcontinent ISO is located in Carmel, Indiana and serves approximately 48 million customers across 65,800 miles of 69kV and above transmission lines with an installed generation capacity of 190,539 MW.

Market

MISO operates an Energy Market that is co-optimized with Ancillary Service products in both the Day-Ahead and Real-Time Markets. The co-optimization is simultaneous and occurs every five minutes in Real-Time to minimize the cost of production. The Day-Ahead Market is a financial commitment. Bids and offers are submitted in the Day-Ahead Market until 10:30 am EPT and results are posted at 1:30 pm EPT, with a rebidding period from 1:30 pm to 2:30 pm EPT. Real-Time offers are submitted up to a half hour before the operating hour. The Market Participants also have the ability to update certain parameters such as limits and ramp rate within the hour to be effective immediately and up until the top of the next hour. Offers can be changed between Day-Ahead and Real-Time. Operating reserves are a market based service in the Day-Ahead and Real-Time markets that are paid for by load and exports. The Planning Resource Auction (PRA) is a voluntary annual capacity auction that allows Market Participants to achieve resource adequacy more economically and its enhanced market-based design allows for greater transparency. The location-specific approach used in the PRA provides efficient price signals to encourage the appropriate resources to participate in the locations where they provide the most benefit. This methodology creates a variety of options for Load Serving Entities (“LSEs”) to obtain the resources required to meet their Planning Reserve Margin Requirement, including Fixed Resource Adequacy Plans, bilateral transactions, self-scheduling, capacity deficiency payments and auction purchases.

Pricing

MISO operates a Nodal market where Generators are paid at the injection point and Load is paid at the withdrawal point. The Energy Offer Cap is $1000 per MWh and the Energy Offer Floor is -$500. The Price Cap is $3500 per MWh. Shortage pricing is based on Market-Wide and Zonal Regulating Reserve, Market-Wide and Zonal Regulating and Spinning Reserve, Market-Wide and Zonal Operating Reserve Demand Curves, and Ramp Capability Requirement Demand Curves. The Regulation Offer Cap is $500 per MWh and the Supplemental Offer Cap is $100. For all resources except certain fast-start resources, LMP is based on the marginal cost of serving a small increment (or decrement) of load at a particular location and considers the incremental energy offer costs for setting prices. For the fast-start resources with “notification plus start-up time” of up to 10 minutes, the start-up cost and no-load cost along with the incremental energy costs are included in setting price. Marginal losses are included as part of LMP.

Settlements

MISO uses a two-settlement process to determine financial charges and credits to Market Participants. Imports and Exports are settled at the Interface Price corresponding to the external Balancing Authority. The Interface Price is calculated as the average of LMPs determined by MISO at the specified generators within the external associated Balancing Authority. Both the Day-Ahead Market and Real-Time Market are settled on an hourly basis. Each Operating Day in the Market is settled seven calendar days after the Operating Day. Subsequent settlements occur on the 14th, 55th and 105th calendar days after the Operating Day. MISO is working to implement settlement of Generators in Real-Time on a 5 minute basis by the first quarter of 2018.

New York Independent System Operator (NYISO)

The New York Independent System Operator is located in Rensselaer, New York and serves approximately 19.5 million customers across 11,130 miles of transmission lines with an installed generation capacity of 38,777 MW.

Market

The NYISO operates a two-settlement wholesale electricity market for energy and reserves. The energy market is comprised of a financially binding Day-Ahead market and a Real-Time market which schedules resources to meet load every five minutes. Both markets use a multi-period, security constrained unit commitment process that simultaneously co-optimizes energy, operating reserves and regulation to economically schedule resources to serve load and minimize production costs while maintaining transmission system reliability. The energy market rules are designed to ensure prices reflect the value of energy at specific locations and times so that suppliers are incentivized to offer their resources competitively. The Day-Ahead market runs once a day, on the day prior to the market day, accepting bids and offers until 5 am and posting schedules by 11 am. The Day-Ahead market incorporates reliability commitments into its development of least production cost solution. The Real-Time Market accepts bids and offers 75 minutes before the operating hour, executes nominally every five minutes and establishes binding dispatch schedules for each five minute interval and advisory schedules for up to an hour. The NYISO operates a short-term capacity market to ensure sufficient physical generation is available to meet the reserve margins established by the New York State Reliability Council.

Pricing

Generators are paid the nodal Location Based Marginal Price (LBMP), while Load pays a zonal price which is the load weighted average nodal price. LBMPs for internal resources are based on Day-Ahead and Real-Time Market determined prices. Both the Day-Ahead Market and the Real-Time Market LBMP includes energy, congestion and losses, and are priced *ex ante*. The NYISO calculates losses from the power flow and are priced using Marginal Losses. The Offer and Bid Cap for Energy is $1,000 per MWh (but will transition to be up to $2,000/MWh) and transactions is +-$1000 per MWh (but will transition to be +-$2,000/MWh). There is no cap on Price. Demand Response Resources are subject to an offer floor currently set to $75 per MWh.

Settlements

NYISO uses a two settlement system where the Day-Ahead market and Real-Time markets settle separately. Day-Ahead schedules settle on an hourly basis, while balancing market transaction settle on the nominal five-minute interval schedules and LBMPs. Loads settle on zonal LBMPs, while generators settle on bus LBMPs. Bid Production Cost Guarantee (BPCGs) are available in both the Day-Ahead and Real-Time Markets, subject to specific rules and limitations. Margin preservation between the Day-Ahead and Real-Time markets is available to most generators as long as they have not increased their offers between the Day-Ahead and Real-Time. There are no settlements directly based on Real-Time Commitment. Settlements for external transactions are based on confirmed interchange schedules and a composite of Real-Time Dispatch prices with Real-Time commitment external congestion costs.

PJM Interconnection (PJM)

PJM Interconnection is located in Valley Forge, Pennsylvania and serves approximately 65 million customers across more than 81,000 miles of transmission lines with an installed generation capacity of 176,546 MW.

Market

PJM simultaneously co-optimizes the Energy, Regulation, Primary and Synchronized Reserves to minimize the cost of production. The Day-Ahead Market is a forward market in which hourly prices are calculated for the next operating day based on generation offers, demand bids and scheduled bilateral transactions. The Day-Ahead offer and bid period ends at 10:30 am EPT, results are posted by 1:30 pm EPT and rebidding is open from 1:30 pm EPT to 2:15 pm EPT. PJM operates a 24 hour market in which the market day starts at midnight. PJM performs a Reliability Assessment & Commitment (RAC) that is performed after the Day-Ahead Market closes, and as-needed until the operating day begins. The Real-Time Market is a spot market in which prices are calculated at the five minute interval based on grid conditions. PJM also operates a Day-Ahead Scheduling Reserve Market that is used to ensure energy reserves are available to deal with unexpected system conditions during the operating day. The PJM Capacity Market, called the Reliability Pricing Model (RPM) procures long term capacity resources three years ahead where committed dispatchable resources are obligated to offer into the Day-Ahead Market.

Pricing

PJM prices energy using Locational Marginal Pricing (LMP). Generators committed Day-Ahead are paid a nodal price, and load pays the zonal price calculated as the load-weighted average. During a shortage event, Reserve Shortage is priced using an Operating Reserve Demand Curve (ORDC) that sets price to serve as a “penalty factor” for being unable to meet the reserve requirement. PJM triggers shortage pricing, and utilizes a 2-step Operating Reserve Demand Curve with penalty factors of $850/MWh and $300/MWh for any interval where a shortage of energy or reserves is indicated. There is a $2,000 per MWh offer cap on cost-based energy offers. Cost-based offers greater than $1,000/MWh are verified ex-ante prior market clearing. Any offers greater than $1,000/MWh that cannot be verified before the market clearing process begins, but are verified during or after the operating hour, or verified cost-based offers greater than $2,000/MWh, will be eligible for make-whole payments. Market-based offers are capped at $1,000/MWh.

Settlements

PJM has a two-settlement process that includes deviation charges and Lost Opportunity Cost (LOC) compensation. PJM settles transactions hourly and issues invoices to market participants weekly. As a result of FERC Order 825, and effective February 1, 2018, PJM will move from hourly to 5-minute settlements. Customers may ask for nodal settlement. Operating Reserve payments are given should a unit not be made whole from Energy Market prices.

Southwest Power Pool (SPP)

Southwest Power Pool is located in Little Rock, Arkansas and serves approximately 18 million customers across 60,944 miles of transmission lines with an installed generation capacity of 83,465 MW.

Market

The SPP Energy products are simultaneously co-optimized with Regulation-Up, Regulation-Down, Spinning Reserve, and Supplemental Reserve to minimize the cost of production. The Real-Time Market is a physical commitment that solves every 5 minutes and dispatches 10 minutes ahead and produces a 5-minute price for settlement. The Day-Ahead Reliability Unit Commitment runs prior to, and commits resources for the Operating Day to minimize the cost of capacity as computed based on resource offers. Intra-Day Reliability Unit Commitment runs are performed at least every four hours to maintain system balance.

Pricing

SPP prices Energy using Locational Marginal Pricing (LMP), which includes Energy, Congestion and loss components. Generators are paid a nodal price, and Consumption generally pays the zonal price, with an option for nodal, aggregated as load-weighted. Day-Ahead prices are produced hourly and posted after the Day-Ahead Market clears. Real-Time Prices are calculated every 5 minutes and are posted as the Real-Time Market clears. Imports and Exports are calculated zonally. External busses are selected based on a powerflow analysis that represents flow on the SPP system. The external busses do not include losses from external facilities. Ex ante pricing is used for both the Real-Time and Day-Ahead Markets. There is a Safety-Net Energy Offer Cap of $1000 per MWh, and an Energy Offer Floor of -$500 per MWh. The Regulation-Up Offer Floor is -$500 per MWh and the Regulation-Down Offer Floor is $0 per MWh. The Contingency Reserve Offer Floor is -$100 per MWh. Start-Up and No-Load have an offer floor of $0. There is no cap or floor on Energy bids.

Settlements

SPP has Multi-Settlement process where the Day-Ahead Market and deviations are settled in Real-Time. SPP applies Uninstructed Deviation Charges to Resources that fail to meet Real-Time dispatch instructions within a dispatch interval. Additionally, resources that have been paid to provide regulation and do not perform are assessed a non-performance charge. Generators are made whole to their production costs using Day-Ahead and Reliability Unit Commitment Make Whole Payments. Day-Ahead prices are posted hourly, and Real-Time prices are settled every 5 minutes.