THE SECURITY-CONSTRAINED COMMITMENT AND DISPATCH FOR MIDWEST ISO DAY-AHEAD CO-OPTIMIZED ENERGY AND ANCILLARY SERVICE MARKET

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ABSTRACT – This paper reports upon the security-constrained commitment and dispatch algorithms and their implementation for Midwest ISO's day-ahead co-optimized energy and ancillary service markets. The MIP method is utilized to solve the DA market and the RA commitment problems and the LP method solves the DA market clearing problem. Demand response resources are qualified for provision of energy and ancillary services. AS demand curves are introduced to allow for efficient pricing of energy and AS capacities by location. Efficient price signals are expected to induce new generation additions, demand response participations and thus improve grid reliability.

Key words – Electricity market, LMP, Security Constrained Unit Commitment (SCUC), Security Constrained Economic Dispatch (SCED), Mixed Integer Programming (MIP), Co-optimization, Demand responses, and Reserve demand curves

I. INTRODUCTION

The Midwest ISO launched its competitive wholesale electricity markets on April 1, 2005. These markets include day-ahead (DA) and real-time (RT) energy markets and a market for Financial Transmission Rights (FTRs). The energy markets produce DA and RT locational marginal prices (LMPs) that can vary across the region to reflect local generation production marginal costs, transmission congestion, and transmission losses. The Midwest ISO energy market utilizes a two-settlement mechanism by which the DA market cleared MW quantities are settled at DA market LMPs and the deviations of actual RT supplies and consumptions from DA market scheduled quantities are settled at RT LMPs. FTRs are financial instruments that entitle their holder to a payment equal to the congestion price differences between their source and sink price nodes in the DA energy market, hence allowing participants to hedge congestion costs on the network. The incentives provided by this transparent pricing mechanism have improved operating efficiencies and overall availability of power plants in the Midwest ISO region.

While the Midwest ISO's *energy* markets have produced substantial benefits, the projected demand growth and generator retirements in the Midwest Region indicate that the current surplus of generating capacity required for grid reliability is shrinking and may disappear within the next several years. This surplus is disappearing even faster in certain load pockets in the Midwest Region, where the transmission capability is not adequate to import energy from other parts of the system and load must rely on local generation. These local load pockets also need contingency-response resources to meet reliability requirements. LMP signals from the existing *energy* markets are insufficient to retain existing efficient capacity or to attract new investment. In the *energy* market, operating reserves are supplied via ancillary service self-schedules that preserve a portion of a resource's capacity from being utilized for energy dispatch. Market price signals for ancillary service capacities are unavailable in the *energy* market.

Wholesale electricity markets require a set of integrated market products that work together to efficiently price energy and ancillary services. While the *energy* markets provides transparent and efficient pricing signals for economic and reliable grid operations in general, market prices for AS capacities are missing and the *energy* markets alone are unable to efficiently price electricity during hours of scarcity. The two most important types of ancillary services are Regulation, which balances load and generation on a moment-to-moment real-time basis, and Contingency Reserves, which provides energy for managing power flows and meeting demand on the grid if a generator trips off-line or a transmission line goes out of service. Because transmission constraints may limit the ability of the system to deliver energy to different areas on the grid, the prices for energy and ancillary services may vary by location.

The Midwest ISO is currently implementing the DA and RT co-optimized energy and ancillary service (AS, or operating reserve) markets, which is scheduled to go into production on January 6, 2009. The co-optimized energy and AS markets allows both energy and ancillary services to be priced efficiently, in particular under scarcity conditions. In addition, demand response resources are allowed for supplying energy and ancillary services for which they are qualified. These market features are expected to induce investment in new generation additions and thus assure an adequate supply of energy at all times.

Midwest ISO's co-optimized energy and AS market design has drawn much from other co-optimized markets [1,2,3]. The Midwest ISO's simultaneously co-optimized energy and AS markets consist of DA and RT markets [5]. Similar to the existing *energy* market, the two-settlement mechanism is adopted to settle energy and AS awards in the DA and RT markets in terms of the DA and RT LMPs and AS market clearing prices (AS MCPs).

This paper reports upon the security-constrained commitment and dispatch models implemented for Midwest ISO's DA co-optimized energy and ancillary service market, while Midwest ISO's RT co-optimization of energy and AS is reported in [4].

This paper is organized as follows. Midwest ISO's co-optimized energy and AS market rules are highlighted in Section II. In Section IV, the security-constrained resource commitment and dispatch formulations for Midwest ISO's day-ahead market are presented with terminology defined in Section III. Specific schemes to handle DA market clearing solution infeasibilities are described in Section V. The day-ahead market solution process is presented in Section VI. Numerical results follow in Section VII and the paper is concluded with Section VIII.

II. HIGHLIGHTS OF MIDWEST ISO DAY-AHEAD CO-OPTIMIZED ENERGY AND AS MARKET

The key market rules of the Midwest ISO's DA market are highlighted below.

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978-1-4244-4241-6/09/$25.00 ©2009 IEEE

A. Day-Ahead Market Products

- Energy offers in the form of MW and price ($/MWh) by physical resources. Participants may self-commit their resources as must-run. Further, participants may request their resources, if committed, be dispatched at least as much as the self-scheduled MW levels.
- AS offers in $/MW by qualified physical resources. Participants may provide ancillary service self-schedules which, if cleared, should be at least as much as the self scheduled MW level.
- Ancillary services include regulating reserve (REG), spinning reserve (SPIN), and supplemental reserve (SUP). Contingency reserve (CR) is made up of both spinning reserve and supplemental reserve from qualified online and offline resources. Operating reserve (OR) is made up of contingency reserve plus regulating reserve and represents the total short-term operating reserve requirement.
- Regulating reserve in the DA market is an hourly product. Regulation may be supplied in the DA market by any regulation qualified resource available to provide regulation.
- Spinning reserve in the DA market is an hourly product and equal to a specified percentage of the Midwest ISO CR requirement that must be supplied by spin qualified resources.
- Supplemental reserve in the DA market is an hourly product defined as a percentage of the Midwest ISO CR requirement that must be supplied by qualified supplemental resources.

B. Day-Ahead Market Resources

- Internal generation resources: may be qualified to provide energy and ancillary services subject to maximum/minimum emergency/economic/regulation limits, min-run/down times, max-run times, cold/intermediate/hot start/notification times and startup costs, and ramp-rate limits.
- External Asynchronous Resources (EAR): may be qualified to provide energy and ancillary services. An available EAR is dispatchable continuously from 0 to its max MW. Its ramping capability may be however restricted by the ramp-rates of its associated external system.
- Type-1 Demand Response Resources (DRR): may be qualified to supply energy at fixed target MW reduction (when committed), or to provide CR (when not committed, but qualified for CR), subject to shut-down and hourly curtailment costs, minimum interruption/non-interruption times and exclusivity of energy or AS dispatch.
- Type-2 DRRs: may be qualified to provide energy and ancillary services. Type-2 DRRs have the same commitment and dispatch model as generation resources.
- Demand bids: Demand bids include fixed demand bids that must be served, and price-responsive demands that are dispatchable continuously from 0 to its max bid MW.
- External Bilateral Transactions: are qualified to provide energy. They include wheel-in spot sales, wheel-out spot purchases, and wheel-through up-to-congestion (UTC) transactions.
- Virtual supplies (incremental offers) and virtual demands (decremental bids), are only qualified to provide energy. They can be dispatched continuously from 0 to its max MW offer.
- Intermittent Renewable Resources (IRR): are qualified to provide energy. IRRs are dispatchable in DA but in general self-committed with prescribed MW profiles and fixed in RAC.

C. Midwest ISO AS Requirements and AS Demand Curves

- Market-wide OR requirement: It is equal to the sum of REG and CR. Should available regulation capacity within the market be less than the market-wide OR requirement, additional CR, if available, is cleared to maintain total OR equal to the market-wide OR requirement. The additional CR will be available to supplement the deficient REG through manual CR deployment when required to comply with NERC control performance standards and the NERC disturbance control standard.

  The Midwest ISO market-wide OR demand curve is utilized to ensure that energy and OR are priced to reflect scarcity conditions when OR becomes scarce. The market-wide OR demand curve price is determined in terms of the Value of Lost Load (VoLL, currently set to $3,500/MW) and the estimated conditional probability of loss of load given that a single forced resource outage of 100 MW or greater will occur at the cleared market-wide OR level for which the price is being determined.

- Market-wide REG requirement is supplied from qualified regulation resources. The market-wide REG demand curve is utilized to ensure that market prices reflect scarcity conditions when regulation is scarce. However, REG availability depends on the commitment and the dispatch of regulating resources. When the market-wide REG requirement cannot be met with the committed resources due to capacity or ramping scarcities, operators may take actions such as changing the commitment of resources to make capacity available to meet REG requirements. Therefore, the market-wide REG demand curve price is the average cost per MWh of committing and running a peaking unit for an hour. REG offers are capped at $500/MW.
- Reserve zones are established to ensure proper REG dispersion and maximize the probability that contingency reserves are deliverable for loss of the largest supply resource within that reserve zone, where a minimum REG and/or CR requirement may be defined. Reserve zone configuration studies identify significant transmission constraints under projected system conditions that could occur through resource redispatches. Reserve zones are defined by grouping resource, load and interface nodes that have similar impacts on one of the identified transmission constraints. Reserve zone configuration studies are normally performed on a quarterly basis, in conjunction with the update of the network model. Under a unplanned outage condition or event resulting in an adverse reliability condition, the reserve zone can be reconfigured to ensure the reliability of the transmission system.
- Reserve zone OR demand curves: For each reserve zone, the OR demand curve is designed as follows:
  a) For cleared OR levels within a reserve zone greater than or equal to ten percent (10%), but less than one hundred percent (100%), of the reserve zone's OR Requirement, the demand curve price is the sum of the energy offer price cap ($1000/MWh) and the CR offer price cap ($100/MWh);
  b) For cleared OR levels less than ten percent (10%) of the reserve zone's OR Requirement, the demand curve price equals the VOLL less the maximum REG demand curve scarcity price for the reserve zone.
- Zonal REG demand curve: For each reserve zone, the REG demand curve price for each hour for cleared REG levels within the reserve zone that are less than the reserve zone's REG requirement is the same as for the market-wide REG demand curve price. The REG demand curve price is zero for the cleared REG levels greater than the zonal REG requirement.
- Midwest ISO good utility practice (GUP) AS requirements
  a) Minimum generation based OR requirement that must be supplied from qualified resources except Type-1 DRRs
  b) Market-wide and zonal minimum REG plus SPIN requirements to ensure that minimum amounts of frequency responsive reserves to be dispatched from qualified resources.

c) Maximum REG and REG dispatch from any single resource is limited to a given percentage of the corresponding requirements to ensure deployment performances.
d) Participant's self-schedules for energy, REG and CR are met as much as possible without significant impacts on market economics and grid reliability.

GUP constraints are modeled as soft constraints in the DA SCED algorithm to balance the needs for reliability and economics. However, the GUP constraints are enforced as hard constraints in the DA market and RAC SCUC solutions to ensure that sufficient resources are committed to meet Midwest ISO's reliability requirements.

D. Simultaneous Energy and AS Co-Optimization

The bids and offers for energy and ancillary services are cleared for all market resources for the whole DA market period via a simultaneously co-optimized, MIP-based SCUC and LP-based SCED algorithms. The simultaneously co-optimized SCUC algorithm determines the overall least cost resource commitment and dispatch schedules to meet the energy supply and demand bids, subject to transmission security constraints, the Midwest ISO AS requirements and resource operational parameters, such as economic maximum and minimum limits, regulation maximum and minimum limits, ramp-rate limits, min/max-run time and min-down time. After the resource commitments are determined by the SCUC algorithm, the SCED algorithm is performed to calculate DA market MW awards, LMPs and MCPs on an hourly basis for committed dispatchable/self-scheduled generation resources, price sensitive demand bids, external bilateral transactions, virtual supplies, virtual demands and committed demand response resources to supply the hourly fixed demand bid. The DA market clearing observes the transmission security constraints under selected contingencies and satisfies the Midwest ISO's ancillary service requirements.

E. Reliability Assessment Commitment

Reliability assessment (RA) commitment is to ensure that the Midwest ISO commits and schedules sufficient resources to meet its forecasted demands and AS requirements for each hour of the next operating day subject to transmission constraints and AS requirements, taking into account the financially binding commitments in the DA market. The RA commitment serves as a critical function to bridge the resource adequacy gap between the DA financial market-clearing and the RT physical grid operation. When the DA bid-in demands are close to actual RT loads, the DA market based resource schedules will be in higher compliance with physical grid operational needs, indicating higher market efficiency as well as better convergence of DA and RT markets. In order for spot prices to incentivize DA bidding of actual load demands, the fundamental market principle is to commit any additional capacity required to meet Midwest ISO's hourly demand forecast and AS requirements by minimizing startup and no-load costs on top of the DA market committed resources.

While this fundamental principle is also applicable to Midwest ISO's co-optimized energy and AS market design, it is by itself insufficient. One problem is that ignoring energy offer prices (typically set to 0) creates arbitrariness of energy dispatches, and thus degrading the quality of transmission network security analysis (overly optimistic). For Midwest ISO's energy and AS co-optimization, ignoring energy and AS offer prices debilitate the energy and AS co-optimization function in the RA commitment framework that determines resources to provide REG in real-time.

The basic RA principle is enhanced to minimize the overall costs of startup and minimum energy costs as well as the scaled energy and AS offer prices. The enhanced RA commitment principles solve the problems of transmission security analysis associated with arbitrariness in resource energy dispatches and the loss of co-optimization capability with zero energy and AS offer prices.

III. TERMINOLOGY

Prior to describing the SCUC and SCED algorithms, the used terminology is given below for ease of reference.

CCost: Total commitment cost for generation resources, DRRs and IRRs. It is 1) summation of startup costs and no-load costs for the DA market SCUC; or 2) summation of qualified startup costs and minimum energy (ME) costs for the RA SCUC. The ME cost of a resource is defined as the no-load cost plus the incremental energy cost up to its economic minimum limit.

ECost: Total energy dispatch cost for generation supplying resources. It is 1) summation of hourly energy dispatch costs of the DA market resources for the DA SCUC; 2) hourly summation of the DA market resources for the DA market SCED; or 3) summation of hourly energy dispatch pseudo-cost of the physical resources (excluding demand bids and virtual transactions) for the RA SCUC. Energy dispatch "pseudo-cost" of a resource is the product of its energy MW dispatch and its energy offer price scaled by a factor.

ASCost: Total AS dispatch cost for AS offers. It is 1) summation of hourly AS dispatch cost of the DA market resources for the DA SCUC; 2) hourly summation of AS dispatch cost of the DA market resources; or 3) summation of hourly AS dispatch pseudo-cost of the physical resources for the RA SCUC. AS dispatch "pseudo-cost" of a resource is the product of its AS MW dispatch and its AS offer price scaled by the same factor as above.

EValue: Total bid dispatch value for energy consuming resources. It is 1) summation of hourly dispatch values for price-responsive demand bids, virtual demands and spot purchases for the DA market SCUC, or 2) hourly summation of price-responsive and virtual demand bid and spot-purchase dispatch values for the DA market SCED. Demand bids are not allowed for the RA SCUC. The Midwest ISO net scheduled interchanges are applied in place of dispatchable external transactions in the RA SCUC.

CValue: Total UTC transaction value. It is 1) summation of hourly dispatch values for UTC transactions for the DA market SCUC, or 2) hourly summation of the UTC transaction dispatch values for the DA market SCED. It is inapplicable to RA SCUC.

ASValue: Total AS value. It is 1) summation of hourly products, or 2) hourly summation of products, of cleared MW quantities and prices on the market-wide and reserve zone OR and REG demand curves. This term applies to the DA market SCED only.

r and Nr: Index and number of energy supplying resources.

ES_{rt} : Energy dispatch of energy supplying resource r at time t.

j and Nc: Index and number of energy consuming resources.

k and Nps: Index and number of phase angle regulators *(PAR).*

EC_{jt} : Energy dispatch of energy consuming resource j at time t.

FD_t : Fixed demand bid for DA market or demand forecast for the RA commitment at time t.

θ_{kt} : Angle of PAR k at time t, bounded with its min and max regulating limits in radian.

L_t : Transmission loss at time t, nodal transmission loss sensitivity based linear function of nodal net injections.

d_j : Nodal distribution factors for transmission losses.

S_{lit} : Shift factors of constraint l w.r.t net injection at node i (j) or the angle of PAR k at time t.

LF_{lt} : Flow component from external loop flows at time t.

TSL_{lt} : Transmission security limit of constraint l at time t.

REG_{rt} : REG dispatch of committed resource r and time t.

CR_{rt} : CR dispatch of qualified resource r and time t. For online and spinning qualified resource, it represents the cleared spinning reserve MW. For online resources not qualified for spinning but qualified for on-line supplemental reserve, it represents the cleared on-line supplemental reserve MW. For offline quick start resource, it represents the cleared offline supplemental reserve MW. All cleared CR MW are expected to be deployable within 10 minutes in real time.

RF_{rt} : Binary variable to solve for regulation commitment of REG qualified resource r and time t.

RHL_{rt} : Regulation max limit of resource r and time t.

$EcHL_{rt}$: Economic max limit of resource r and time t.

CF_{rt} : Binary variable to solve for commitment status of resource r

RLL_{rt} : Regulation min limit of resource r and time t.

$EcLL_{rt}$: Economic min limit of resource r and time t.

RRL_{rt} : Ramp-rate limit (MW/hour) of resource r and time t.

α_t : CR sharing of ramp-rate limit, a configurable option to manage ramp-rate dispatches.

Q_t^{GOR} : Equal to a given percentage of OR requirement that are to be supplied by generation resources (excluding Type-1 DRRs).

Q_t^{REG} (Q_{zt}^{REG}), Q_t^{OR} (Q_{zt}^{OR}) and Q_t^{RS} (Q_{zt}^{RS}): Market-wide (zonal) REG, OR, and REG+SPIN requirements at time t.

$r \in rz$: Denote resource r is located in reserve zone z.

$r \in SPIN$: Denote resource r is a SPIN qualified resource.

$r \in GEN$: Denote resource r is a qualified generation resource.

RMx^{REG} (RMx^{CR}): Max single resource dispatch for REG (CR).

$DRR1TargetMW_{rt}$: Target curtailment MW for Type-1 DRR r.

$MaxOfflineCR_{rt}$: Max CR MW of quick-start offline resource r.

IV. THE SECURITY-CONSTRAINED COMMITMENT AND DISPATCH FORMULATION

The SCUC and SCED are formulated to clear DA market in compliance with Midwest ISO's energy and AS market business rules. For simplicity and convenience of reference, Greek symbols are used to index the pertinent constraints and denote their shadow prices as well.

- Objective function

$$\min\left[CCost + ECost + ASCost - EValue - CValue - ASValue\right]$$

- Hourly power balance Constraint

$$(\lambda_t) \quad \sum_{r=1}^{Nr} ES_{rt} = \sum_{j=1}^{Nc} EC_{jt} + FD_t + L_t$$

- Hourly transmission limit constraint

$$(\mu_t) \left\{ \begin{array}{l} \sum_{r=1}^{Nr}[S_{lrt} * ES_{rt}] + \sum_{k=1}^{Nps}[S_{lkt} * \theta_{kt}] \\ - \sum_{j=1}^{Nc}[S_{ljt}(EC_{jt} + d_j * (L_t + FD_t))] + LF_{lt} \end{array} \right\} \begin{array}{l} \le \\ = TSL_{lt} \\ \ge \end{array}$$

- Cleared ES, REG and CR constraint

$$(\sigma_{rt}^{ES}) : ES_{rt} \le CF_{rt} * EcHL_{rt}$$

$$(\sigma_{rt}^{REG}) : REG_{rt} \le RF_{rt} * 0.5 * (RHL_{rt} - RLL_{rt})$$

$$(\sigma_{rt}^{CR}) : \ CR_{rt} \le CF_{rt} * (EcHL_{rt} - EcLL_{rt}) + (1 - CF_{rt}) * MaxOfflineCR_{rt}$$

- Market resource maximum limit constraint

$$(\tau_{rt}^{\max}) \ ES_{rt} + REG_{rt} + CR_{rt} \le RF_{rt} * RHL_{rt} + (1 - RF_{rt}) EcHL_{rt}$$

- Market resource minimum limit constraint

$$(\tau_{rt}^{mn}) \ ES_{rt} - REG_{rt} \ge \left\{ \begin{array}{c} RF_{rt} \times RLL_{rt} + \\ (1 - RF_{rt}) EcLL_{rt} - (1 - CF_{rt}) EcLL_{rt} \end{array} \right\}$$

- Ramp-rate limit constraint

$$(\tau_{rt}^{RR}) \left\{ \begin{array}{l} Up - ramp : ES_{rt} + \alpha_t \times CR_{rt} \le ES_{rt-1} + RRL_{rt} \\ \quad Down - ramp : ES_{rt-1} - ES_{rt} \le RRL_{rt} \end{array} \right.$$

Note, due to the real time ramp issues discussed in [6], there is no ramp rate but only capacity assigned for REG. In the ASM production system, α_t is currently also set at 0 so that ramp rate is not assigned for CR either.

- Market-wide/zonal REG requirement constraint

$$(\gamma_t^{REG}) : \qquad \sum REG_{rt} \ge Q_t^{REG}$$

$$(\gamma_{zt}^{REG}) : \qquad \sum_{r \in rz} REG_{rt} \ge Q_{zt}^{REG}$$

To ensure sufficient capacity be committed for reliability, Q_t^{REG} (Q_{zt}^{REG}) equals 100% REG requirement for the DA market and RA SCUC. For the DA market SCED, they are based on the REG MW cleared on the REG demand curve.

- Market-wide/zonal OR requirement constraint. Note the total CR_{rt} includes cleared spinning reserve, on-line and offline supplemental reserve MW.

$$(\gamma_t^{OR}) : \qquad \sum REG_{rt} + \sum CR_{rt} \ge Q_t^{OR}$$

$$(\gamma_{zt}^{OR}) : \qquad \sum_{r \in rz} REG_{rt} + \sum_{r \in rz} CR_{rt} \ge Q_{zt}^{OR}$$

To ensure sufficient capacity be committed for reliability, Q_t^{OR} (Q_{zt}^{OR}) equals 100% OR requirement for the DA market and RA SCUC. For the DA market SCED, they are equal to the OR MW cleared on the OR demand curve.

- Market-wide min generation-based OR requirement (GUP)

$$(\gamma_t^{GOR}) : \qquad \sum REG_{rt} + \sum_{r \in GEN} CR_{rt} \ge Q_t^{GOR}$$

This GUP constraint is prioritized with lower violation penalty for the DA market SCED.

- Market-wide/zonal REG+SPIN requirement (GUP)

$$(\gamma_t^{RS}) : \qquad \sum REG_{rt} + \sum_{r \in SPIN} CR_{rt} \ge Q_t^{RS}$$

$$(\gamma_{zt}^{RS}) : \qquad \sum_{r \in rz} REG_{rt} + \sum_{r \in rz, r \in SPIN} CR_{rt} \ge Q_{zt}^{RS}$$

The GUP constraints are prioritized with lower violation penalty for the DA market SCED.

- REG and CR ramp constraint

(λ_{rt}^{REG}): $REG_{rt} \le 5 * RRL_{rt} / 60$

(λ_{rt}^{CR}): $CR_{rt} \le 10 * RRL_{rt} / 60$

- Max single resource REG or CR dispatch (GUP)

(τ_{rt}^{REG}): $REG_{rt} \le RMx^{REG}$

(τ_{rt}^{CR}): $CR_{rt} \le RMx^{CR}$

These GUP constraints are prioritized with lower violation penalty for the DA market SCED.

- Energy, REG and CR Self-schedule constraint (GUP)

$$(\tau_{rt}^{SS}) \begin{cases} ES_{rt} \ge CF_{rt} \times ESS_{rt} \\ REG_{rt} \ge RF_{rt} \times REGSS_{rt} \\ CR_{rt} \ge CRSS_{rt} \end{cases}$$

The self-schedule constraints may be prioritized with high or low violation penalties. The low penalty option may be activated when such self-schedules cannot be honored due to transmission constraints.

- Resource commitment constraints: Resources' physical and operational constraints are enforced in the SCUC algorithm. These constraints include:
  - Cold/intermediate/hot notification and startup times
  - Min-run, min-down and max-run times
  - Max daily starts
- RF and CF binary variable constraint

(δ_{rt}^{RF-CF}) $RF_{rt} \le CF_{rt}$

- Exclusive dispatch of Energy and CR for Type-1 DRRs

(δ_{rt}^{DRR1e}) $CR_{rt} \le (1 - CF_{rt}) \times DRR1TargetMW_{rt}$

- Block Energy Dispatch for Type-1 DRRs

(δ_{rt}^{DRR1b}) $ES_{rt} = CF_{rt} \times DRR1TargetMW_{rt}$

- Tie-breaking constraints for the DA market SCED: Price-tied energy offers, AS offers and energy bids are dispatched in proportion to their offer (bid) quantities. E.g., for any two energy offers *m* and *n* with MW_m and MW_n, their proportional dispatches, ES_m and ES_n are achieved with the following constraint:

$$(\omega_{mn}^{tie}) \qquad \frac{ES_m}{MW_m} - \frac{ES_n}{MW_n} = x1_{mn} - x2_{mn}$$

Where the non-negative variables $x1_{mn}$ and $x2_{mn}$ are minimized with a small penalty (e.g., 10^{-6}).

V. HANDLING SCUC AND SCED INFEASIBILITIES

The above SCUC and SCED algorithm is enhanced with addition of violation variables to the pertinent constraints to allow prioritized relaxation of infeasible constraints, thereby improving the robustness of the DA market clearing models. Infeasibilities may occur in the MIP SCUC and the LP SCED based market clearing due to conflicting constraints resulting from input data errors, capacity scarcities, or GUP constraints that are too expensive to satisfy. When an infeasible constraint exists in the solution, the penalty of the constraint's violation variable may invalidate the market clearing prices, which must be resolved to ensure feasible, optimal solution.

A. Emergency Capacity Commitment

In the SCUC solution, the given demands (fixed demand bids for the DA market and the forecasted demands for the RA commitment) and 100% of the Midwest ISO's market-wide and zonal AS requirements are to be satisfied by committing sufficient resources. When there is energy shortage, energy surplus, or capacity shortage in any hour, the DA emergency condition is declared. Under the energy or capacity shortage conditions, resources' upward capacity from max economic limits to max emergency limits may be utilized for hours with shortage and emergency resources may be committed. For energy surplus conditions, resources may be dispatched below min economic limits until min emergency limits.

As an operational practice, it is desirable to minimize the utilization of emergency capacity resources. To achieve this goal, a 2nd MIP solve is performed with emergency capacity dispatches penalized with a price adder in the 2nd-solve objective. This 2nd SCUC solution determines the emergency resource commitments and the minimum relaxation of emergency capacities.

B. Infeasibility With GUP Constraints

GUP constraints are enforced as soft constraints using high violation penalties, as described in the previous section. These constraints may be violated in the DA market and RA SCUC solutions, which requires no special handling as such constraints have no direct impacts on market clearing prices.

When GUP constraints are violated in the DA market SCED solution, a second SCED solve is required with these violated constraints relaxed to ensure that market clearing prices are not contaminated by those violation penalties. The general logic is to relax the limits of the violated constraints by the amounts of violation determined in the 1st SCED solution with a user-defined margin (e.g., 5%).

C. Scarcity Pricing

In the DA market SCED solution, available resource capacities may be scarce and deficient of meeting the fixed demand bids plus fixed spot purchase external transactions, or short of meeting 100% of the AS requirements. In the latter case, the shortage of AS capacity causes the demand curve to set market clearing prices, reflecting the market capacity scarcity conditions.

In the former case that the fixed demand bids and fixed spot purchases cannot be met, the SCED model is re-solved by applying a relaxation variable that will uniformly scale down the fixed-demand bids and fixed spot purchases. This relaxation variable is penalized with high cost factor to minimize the reduction of the fixed energy demands.

The above logic ensures that the DA market clearing solution maximize Midwest ISO's reliability needs at the least costs.

VI. DA MARKET CLEARING SOLUTION

In Midwest DA market clearing, the SCUC is based on the MIP method while the SCED is solved using the LP method. Transmission security constraints are enforced in the form of pre-defined constraint list for the SCUC and a simultaneous feasibility testing (SFT) function iterating with SCED. The DA market solution scheme is depicted in Figure 1.

LMPs at commercial pricing nodes (*cp*) and AS MCPs for reserve zones are calculated as part of the DA market SCED LP solution using the following formulae:

- LMP for Energy: $LMP_{cn,t} = \lambda_t - \lambda_t \dfrac{\partial L_t}{\partial E_{cn,t}} - \sum_{l} [\mu_{lt} \times S_{l,cn,t}]$

  where $\dfrac{\partial L_t}{\partial E_{cn,t}}$ is the sensitivity of transmission losses w.r.t. net nodal injection $E_{cp,t}$ at the distributed load reference.
- Market-wide MCP for demand SUP: $\rho_t^{DSUP} = \gamma_t^{OR}$
- Market-wide MCP for gen SUP: $\rho_t^{GSUP} = \gamma_t^{OR} + \gamma_t^{GOR}$
- Market-wide MCP for SPIN: $\rho_t^{SPIN} = \gamma_t^{OR} + \gamma_t^{GOR} + \gamma_t^{RS}$
- Market-wide MCP for REG: $\rho_t^{REG} = \rho_t^{SPIN} + \gamma_t^{REG}$
- Zonal MCP for demand SUP: $\rho_{z,t}^{DSUP} = \gamma_t^{OR} + \gamma_{z,t}^{OR}$
- Zonal MCP for gen SUP: $\rho_{z,t}^{GSUP} = \rho_{z,t}^{DSUP} + \gamma_t^{GOR}$
- Zonal MCP for SPIN: $\rho_{z,t}^{SPIN} = \rho_t^{SPIN} + \gamma_{z,t}^{OR} + \gamma_{z,t}^{RS}$
- Zonal MCP for REG: $\rho_{z,t}^{REG} = \rho_t^{REG} + \gamma_{z,t}^{OR} + \gamma_{z,t}^{RS} + \gamma_{z,t}^{REG}$

The above MCPs have the cascading effects with higher prices for higher quality products. Since REG can substitute for SPIN or SUP, and SPIN for SUP, the co-optimization solution ensures that REGMCP ≥ SpinMCP ≥ SupMCP at the market-wide and reserve zone level respectively.

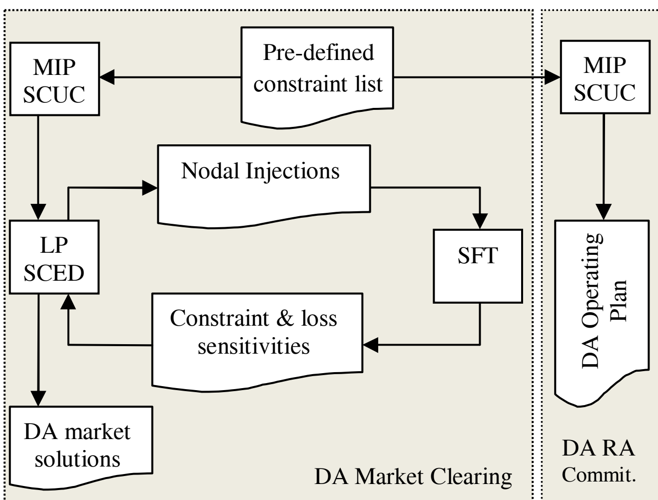


Figure 1 - DA Market and RA Commitment

In addition, the DA market SCUC and SCED algorithms generate the following key market determinants:

- Physical market resource hourly commitment statues and energy and AS dispatch schedules
- Energy dispatch schedules for demand bids, virtual supplies and demands as well as external dispatchable transactions

which forms the basis for the DA operating plan of the next operating day. The DA operating plan may be continuously updated during the operating day using the RAC process and the real-time market dispatch [3].

VII. NUMERICAL ILLUSTRATIONS

For clarity and simplicity, numerical cases based on a 5-bus example with 6 generation resources, 1 Type-1 DRR, virtual transactions and external transactions (Appendix A includes input data) are used to illustrate the primary features of Midwest ISO's DA market processes. One reserve zone, consisting of G1, G2 and G3, is constructed to model market-wide and zonal AS requirements. Market-wide REG and CR requirements are 70MW and 80MW respectively. Reserve zone REG and CR requirements are 20MW and 50MW respectively. SPIN and SUP requirements are defined as 80% and 20% of the CR requirements respectively. The REG demand curve price of $239/MW is used. For the OR demand curve, the demand curve price is $2037/MW up to the REG MW level and then $$1100/MW until the 100% requirements.

A. Co-Optimized Energy and AS Commitment

Commitment schedules are shown in Table 1 below for the energy-only and the co-optimized energy and AS day-ahead markets. In the table, the gray background "1" cells denote that the resources are not committed in the energy-only case, but are committed in the energy and AS co-optimization case. The gray background "0" cells denote that the resources are committed in the energy-only case, but not committed in the co-optimization case. For the energy-only and co-optimized energy and AS market cases, the total costs for commitment and energy dispatch are $152,372 (energy dispatch cost=$149,807) for the energy only case and $187,982 (energy dispatch cost=$158,683 and AS dispatch cost=$26,679) for the co-optimization case. The SCUC solutions for the energy-only and co-optimization cases are achieved with close to 0% MIP gap.

Because reliability requirements for AS capacities are necessary regardless of the energy-only or co-optimization market, the co-optimized energy and AS market provides a more efficient mechanism of scheduling such capacities simultaneously. The increased energy dispatch is expected due to the additional capacity needs of meeting AS requirements. Differences in commitment schedules for G2, G3 and T-1 DrrA are observed for the co-optimized energy and AS case. It is noted that, in the co-optimization case, T-1 DrrA is committed to provide contingency reserve for hours 23 and 24, as opposed to being committed to provide energy in the energy-only case. T-1 DrrA is not committed for hours 19-22 because of its 4-hour minimum non-interruption time constraint.

B. Hourly DA LMPs and MCPs

The hourly LMPs and AS MCPs for this co-optimization case without transmission constraint are presented in Figures 2 and 3. From the above mentioned figure, the following typical features of the co-optimized energy and AS market may be observed:

- The MCP results are shown in Figure 2. It illustrates the price cascading effects.
- AS MCPs may be higher than energy LMPs: The AS MCPs include two price components: 1) the AS offer price and 2) the product substitution cost (or sometimes called marginal lost opportunity cost). Product substitution cost is incurred when it is necessary to back off the dispatch of one product in order to make capacity available for another product. Depending on available capacities and the offer prices of resources participating in the product substitution, the product substitution cost may be large enough to cause AS MCPs higher than the energy LMPs. Several instances of this scenario are observed for RegMCPs higher than energy LMPs.
- Spatial property of AS MCPs: The market-wide vs. zonal MCP pairs are shown in Figure 3, indicating the zonal MCPs are always as high as market-wide MCPs for the same AS product. Zonal MCPs for a lower quality AS product (e.g., SUP or SPIN)

may greater than market-wide MCPs for a higher quality AS product (e.g., REG or SPIN).

The market price behaviors for Midwest ISO co-optimized energy and AS market are discussed in further detail in [3].

C. Midwest ISO DA Market Clearing

Midwest ISO day-ahead market clearing determines hourly commitment and dispatch schedules for ~1500 resources totaling ~130,000 MW capacity and a peak market load of 109,157 MW. The MIP based SCUC algorithm solves the day-market commitment problem within ~15 minutes for a MIP gap of 0.05%. The DA SCED and SFT iterative process calculates the bid and offer awards, LMPs for ~2000 commercial pricing nodes and MCPs for 9 local reserve zones within ~2 hours for a network model of ~36,000 buses.

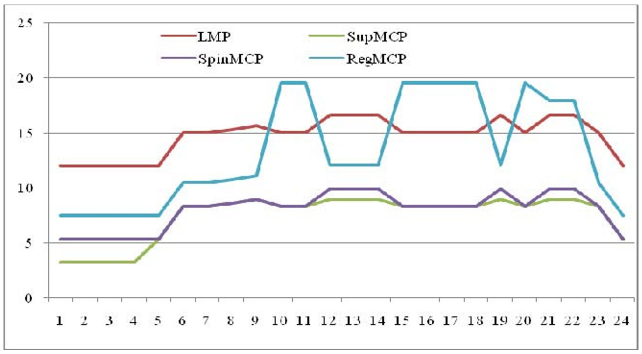


Figure 2 – Hourly LMPs and AS MCPs

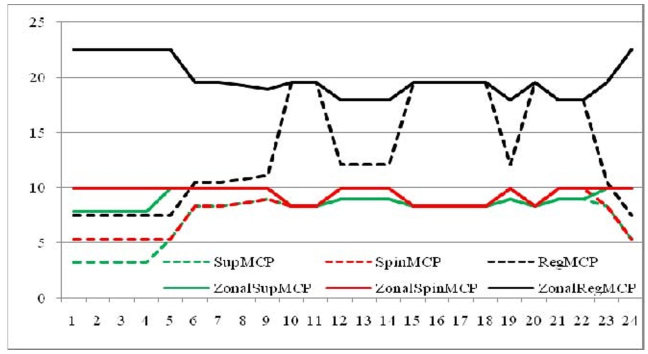


Figure 3 – Hourly market-wide and zonal MCPs

VIII. CONCLUSIONS

This paper reports on Midwest ISO's co-optimized DA energy and AS market design and the implementation of the DA market and RA SCUC and the SCED algorithms. Mechanisms to handle MIP and LP infeasibilities are designed to achieve the balance between economics and reliability as well as to avoid invalid prices. AS demand curves are introduced in the Midwest ISO's new market design to improve the efficiency of energy and AS pricing, especially under capacity scarcity conditions. The properties of Midwest ISO's DA co-optimized energy and AS market are illustrated with numerical examples.

Table 1 –Energy-only and co-optimized energy and AS commitment schedules

Resource Name	CF,RF SF	Commitment for Each Hour of DA Market																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
G1	CF	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	RF	0	0	0	1	1	1	1	1	0	1	1	0	0	0	1	1	1	1	0	1	1	0	1	1
G2	CF	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	RF	1	1	1	1	1	1	1	1	1	1	1	0	1	1	1	1	1	1	0	1	1	1	1	1
G3	CF	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	RF	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
G4	CF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	SF	1	1	1	1	0	0	0	0	1	0	0	1	1	1	0	0	0	0	1	0	1	1	0	0
G5	CF	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	RF	1	1	1	1	1	1	1	1	1	0	0	1	1	1	0	0	0	0	1	0	0	0	1	1
T-1 DrrA	CF	1	1	1	1	1	1	1	0	0	0	0	1	1	1	1	1	1	1	0	0	0	0	0	0
	SF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
IndyCT	CF	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

IX. APPENDIX

- Resource commitment parameters

Resource Name	Startup Time			Initial OnTime	Min Time		Transit Time		Startup Cost			Max Starts
	Cold	Inter	Hot		Run	Down	HtoIT	HtoCT	Cold	Inter	Hot	
G1	2	2	1	-1	4	4	2	3	800	700	600	6
G2	3	2	1	2	4	4	2	3	900	800	700	6
G3	5	3	2	2	4	4	2	3	1000	900	800	4
G4	2	2	1	-60	4	5	2	3	400	300	200	20
G5	6	4	3	3	8	6	2	3	1000	900	800	3
T-1 DrrA	0	0	0	2	4	4	0	0	300	300	300	0
IndyCT	1	1	1	-1	1	1	1	1	10	10	10	24

- Resource dispatch parameters for 24 hours

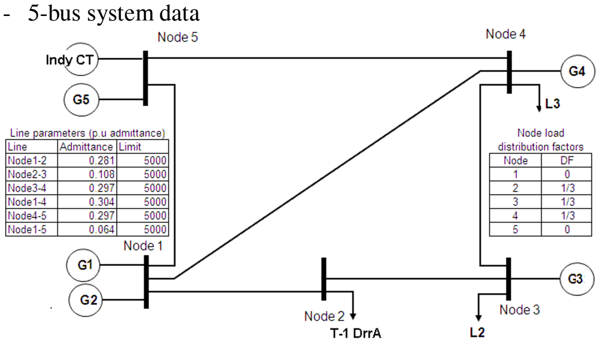
Resource Name	No Load	Minimum Limits			Maximum Limits			Qualified			Ramp Limit
		Eme	Eco	REG	REG	Eco	Eme	REG	SPIN	SUP	
G1	15	8	10	12	90	100	105	1	1	0	110
G2	10	9	11	13	99	110	115	1	1	0	120
G3	16	50	52	55	460	520	550	1	1	0	5500
G4	18	18	20	22	180	200	210	1	1	1	2200
G5	19	55	60	70	540	600	650	1	1	0	6500
T-1 DrrA	1	90	90	90	100	100	100	0	0	1	100
IndyCT	15	8	10	12	90	100	105	1	1	0	110

- Resource energy and AS offers for 24 hours

Resource	Band 1 Energy		Band 2 Energy		Target	Curtail	Loss	AS Offer Price		
Name	MW	Price	MW	Price	MW	Price ($/h)	Sens	REG	SPIN	SUP
G1	90	10	120	14	--	--	0	7.7	4.62	0
G2	95	12	120	15	--	--	0	8.25	4.95	0
G3	300	18	560	30	--	--	0	16.5	9.9	0
G4	120	23	230	30	--	--	0	16.5	3	3.2
G5	400	8	660	10	--	--	0	5.5	3.3	0
T-1 DrrA	--	--	--	--	15	8.88	0	3	0	0
IndyCT	100	300	--	--	--	--	0	1	90	90

Note: For T-1 DrrA, curtailment prices are $800/hour for hours 10 and 11, $600/hour for hours 19-22.

- 5-bus system data



X. ACKNOWLEDGMENT

The authors gratefully acknowledge the contributions of Matthew H. Tackett, Technical Manager - Market Administration for the Midwest Independent Transmission System Operator (Midwest ISO). Mr. Tackett led the market design effort for the Midwest ISO ancillary services market and provided guidance for the works described in this paper.

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XII. BIOGRAPHIES

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