Executive Summary: 
Introduction

• This State of the Market (“SOM”) report provides our annual evaluation of the Midwest ISO’s markets as the Independent Market Monitor (“IMM”).
  ✓ The report includes our assessment of the competitive performance of the markets and our recommendations for future improvements.
• The Midwest ISO operates competitive wholesale electricity markets that include:
  ✓ Day-ahead and real-time energy markets that produce transparent prices that vary by location to reflect the value of transmission congestion and losses; and
  ✓ Financial Transmission Rights (“FTRs”) that allow participants to hedge congestion between various locations.
• On January 6, 2009, the Midwest ISO began operating as a balancing authority and introduced day-ahead and real-time operating reserves and regulation markets (known as Ancillary Services Markets, or “ASM”).
  ✓ The ancillary services markets optimize the allocation of resources between the ASM and energy markets, which has increased the efficiency of the market.
  ✓ This optimization provides more flexibility from the Midwest ISO’s generating resources that is used to more efficiently manage congestion and satisfy load.
• In June 2009 the Midwest ISO began operating a Voluntary Capacity Auction (“VCA”) for loads to meet residual Module E requirements.
**Executive Summary:**

**Benefits of Midwest ISO Energy Markets**

- The Midwest ISO markets produce substantial savings in a variety of areas.

  **Daily commitment of generation:** Coordinated commitment of generation through the day-ahead market produces savings relative to the prior decentralized system by:
  
  - Reducing the quantity of generation that is committed; and
  - Ensuring that the most economic generation is committed.

- **Efficient dispatch and congestion management:** Total dispatch costs are reduced by:
  
  - Producing energy from the most economic supply and demand resources;
  - Employing the lowest cost redispatch options to manage congestion; and
  - Allowing for greater utilization of the transmission capability in the region.

- **Reliability:** Reliability is improved because the five-minute dispatch provides much more responsive and accurate control of power flows on the transmission system versus Transmission Line Loading Relief (“TLR”) procedures previously relied upon.

- **Price signals:** The prices produced by the energy market provide a transparent economic signal to guide short and long-run decisions by participants and regulators.

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**Executive Summary:**

**Competitive Performance and Prices**

- The Midwest ISO energy markets performed competitively in 2009.
  
  - Although certain suppliers in the Midwest ISO have local market power, there was very little evidence of attempts to exercise market power in 2009.
  - Hence, mitigation measures were employed infrequently to address economic withholding that would have increased energy prices or uplift costs.

- Prices in the day-ahead and real-time energy markets declined 44 and 45 percent, respectively, in 2009 due to sharp declines in fuel prices and reduced load.
  
  - Natural gas prices decreased by an average of 55 percent in 2009, oil prices decreased by 44 percent, and coal prices decreased by roughly 30 percent.
  - In a competitive market, suppliers will face strong incentives to offer their supply at prices close to their short-run marginal costs of production, the vast majority of which are fuel costs for most generators.
    
    - The continuing close correspondence of energy prices and fuel prices in the Midwest ISO demonstrates the competitiveness of Midwest ISO’s markets.
  - Real-time energy prices fell by almost 15 percent even after adjusting for lower fuel prices.

- Several other factors contributed to lower energy prices, including:
  
  - A decrease in average load of 6.6% due to mild weather and poor economic conditions;
  - Improved optimization of energy and reserves under ASM; and
  - Sharp increases in intermittent generation from wind resources that led to surplus generation in real-time and relatively low energy prices.
Executive Summary:  
Long-Term Economic Signals

• In long-run equilibrium, the market should provide “net revenues” that create efficient incentives for investment and retirement.
  ✓ The net revenue is the revenue the unit would have received in hours it would have run, less its variable production costs in those hours.
  ✓ Net revenues must be sufficient to cover a new resource’s fixed operating and maintenance costs and provide a return on the investment in order for the investment to be economic.
• We calculated the net revenue for a new combined-cycle unit and a gas turbine, which showed that Midwest ISO markets would not have supported investment in either type of unit in 2009 based on their annualized costs of new investment.
• These results are consistent with expectations because:
  ✓ The Midwest ISO footprint has a growing capacity surplus that precluded any significant periods of shortage from occurring in 2009, and
  ✓ The ASM provided scarcity pricing during shortages of regulation and operating reserves, but these shortages were relatively infrequent in 2009.
  ✓ The introduction of the voluntary capacity market and enforcement provisions of the Module E capacity requirements should also improve the long-term market signals needed to maintain adequate resources.
    – However the capacity surplus has cased the VCA to clear close to zero in all but one month.

Executive Summary:  
Day-Ahead Market Performance

• Day-ahead market outcomes are important because:
  ✓ The day-ahead market governs most of the generator commitments in the Midwest ISO – hence, efficient commitment requires efficient day-ahead market results;
  ✓ Most wholesale energy bought or sold through Midwest ISO markets is settled in the day-ahead market; and
  ✓ The entitlements of firm transmission rights are determined by the results of the day-ahead market (the payment to an FTR holder is based on day-ahead congestion).
• Our analyses indicate that price convergence in the Midwest ISO has continued to exhibit a day-ahead premium.
  ✓ The day-ahead premiums are consistent with the higher volatility, risk, and RSG cost associated with buying in the real-time market.
  ✓ The day-ahead premiums are larger in the Midwest ISO due to higher RSG allocations.
• Active virtual supply and demand participation in the day-ahead market has contributed to the price convergence exhibited in the Midwest ISO.
  ✓ However, virtual trading levels decreased substantially in late 2008 and into 2009.
  ✓ These reductions can be attributed to RSG allocation decisions made by FERC in November 2008 and tight credit conditions.
  ✓ Price convergence during this period was acceptable overall, but convergence in congested areas that are less liquid deteriorated. This should improve when the MISO implements its new RSG allocation that will reduce the costs imposed on virtual trades.
Executive Summary: Real-Time Market Performance

- This report includes a study of the real-time price volatility in the Midwest ISO, which remains greater than that of some other RTOs.
  - Volatility has decreased by 17 percent under ASM markets because the real-time market now has the flexibility to jointly optimize resources for energy and ASM needs.
- The price volatility in the Midwest ISO is largely because it runs a true five-minute real-time market, producing new dispatch instructions and prices every five minutes.
  - The short timeframe and limited ability of the real-time market to “look ahead” causes the system to frequently become “ramp-constrained”, which results in transitory sharp movements in prices up or down.
  - Ramp constraints bind when the market’s generation cannot change output quickly enough to accommodate changes in demand, net imports, etc. on a five-minute basis.
- The analysis in this report shows that:
  - Prices fluctuate most when load is ramping up or down near the peak (afternoon in the summer, and dual peaks in morning and evening in the winter); and
  - Changes in real time prices are related to changes in Net Scheduled Interchange (“NSI”) that occur at the tops of the hour, and to periods when large quantities of generators start-up or shut-down at the same time.
  - The recent integration of large quantities of wind resources, whose output can be difficult to forecast, has also contributed to the volatility.
- The report includes several recommendations to improve real-time performance.

Executive Summary: Ancillary Services Markets

- Midwest ISO introduced ancillary services markets in January 2009, which have performed as expected in the real-time with no significant issues.
  - The ASM markets have led to improved system flexibility and lower price volatility.
  - The ASM markets also set more efficient prices to reflect the economic trade-offs between reserves and energy, particularly during shortage conditions.
- The prices in the ASM markets have been consistent with expectations and with the ASM results in similar RTO markets.
  - Monthly average regulation prices dropped from $22 per MWh in January to less than $11 in November. Much of the decline in regulation prices is due to reductions in the requirements during the first half of the year.
  - Spinning reserve prices averaged roughly $3 per MWh in 2009.
- In the spring of 2009, shortages of spinning reserves and regulation occurred at a relatively high frequency.
  - The Midwest ISO has improved the consistency between the market requirements and operating requirements, which tends to reduce the frequency of such shortages.
  - However, prices do not always accurately reflect the spinning reserve shortages due to the Midwest ISO’s method of relaxing the requirement during the shortage.
  - The report includes a recommendation to improve pricing during shortages.
Executive Summary:
Revenue Sufficiency Guarantee Payments

- Revenue Sufficiency Guarantee ("RSG") payments are made to ensure that the total revenue a generator receives when its offer is accepted exceeds its as-offered costs.
  - Resources started after the day-ahead market to maintain reliability receive “real-time” RSG when their costs are not covered by the real-time market.
  - Almost 90 percent of RSG is incurred in the real-time market, which is expected because most commitments made for reliability are made in real time.
  - Peaking resources received two-thirds of the real-time RSG, although they produced less than 1 percent of the energy generated in the Midwest ISO. This is not surprising because:
    - Peaking resources are generally on the margin (i.e., the highest-cost resources) when they run and prices are frequently set by a lower-cost unit.
- RSG costs decreased by 47 percent ($97 million) in 2009 due to:
  - Lower average load and fuel prices during 2009; and
  - Reduced commitments to manage congestion.
- This report includes a study of the causes of RSG, which showed:
  - Two-thirds of the RSG was paid to units committed for system-wide capacity needs in 2009 (only one-third was committed to manage congestion).
  - More importantly, the real-time deviations that cause roughly one half (including virtual supply) of the RSG bear virtually all of the RSG costs. This mismatch between cost causation and the current allocation creates inefficient incentives.

Executive Summary:
Dispatch of Peaking Resources in Real Time

- As discussed above, the dispatch of peaking resources is important because it is a significant determinant of RSG costs and efficient energy pricing.
- The dispatch of peaking resources fell by roughly 15 percent in 2009 from 2008.
  - On average, 227 MW of peaking resources were dispatched per hour in 2009.
  - During the peaking summer months, this amount rose only slightly to 287 MW due to the mild weather in 2009.
- Our analysis shows a large share of the peaking resources are dispatched out-of-merit ("OOM"), indicating that they frequently do not set the energy price.
  - Dispatching a resource OOM occurs when the its offer price is higher than the LMP, which typically requires higher RSG payments to ensure the resource recover its as-offered costs.
  - The fact that peaking resources frequently do not set prices also contributes to under-scheduling of load in the day-ahead market:
    - Peaking resources are generally the only resources that can be committed in real time to serve the load not scheduled day-ahead – if prices are set by a lower-cost unit, the market will not provide the loads the incentive to purchase more day-ahead.
- The Midwest ISO is actively working on a pricing method that will allow inflexible units and demand response resources to set prices.
Executive Summary: Generating Capacity

- With the addition of MidAmerican and Muscatine, the generating resources in the Midwest ISO market totaled almost 140 GW in 2009.
- We estimate the planning reserve margins for summer 2010, which are sensitive to the assumptions made regarding deratings/outages and interruptible demand.
  - Capacity margins exceed 47 percent based on nameplate ratings (including interruptible load and behind the meter generation), and 34 percent based on summer capacity ratings.
  - We also adjust for temperature-sensitive capacity that likely will not be available at the extreme peak periods – this results in a capacity margin of nearly 26 percent.
  - These margins indicate a sizable surplus in the Midwest ISO region, which has resulted from decreasing load over the past two years and the rapid growth of wind resources.
- Although the system’s resources are adequate for the summer of 2010, new resources will be needed over the long-run to meet the needs of the system.
  - It therefore remains important for the market’s economic signals that govern new investment and retirement decisions to be efficient.
- More than 3 GW of new capacity is expected to enter during the 2009-2010 planning year, more than half of which is wind. Roughly 750 MW of generation is expected to retire.
  - The intermittent nature of wind causes it to provide less reliability to the system than the nameplate capacity level.
  - Although wind provides substantial environmental benefits, it also creates significant operational challenges that the Midwest ISO is working to address.

Executive Summary: Transmission Congestion

- One of the most significant benefits of the Midwest ISO energy markets is that they provide accurate and transparent price signals that reflect congestion on the network.
  - Total congestion costs in the day-ahead and real-time markets decreased 37 percent to $322 million in 2009, due primarily to lower fuel prices, lower load, and transmission upgrades that reduced congestion in the Central region and into WUMS.
  - In 2009, over 94 percent of total congestion was captured in the day-ahead market, a slight decline 98 percent in 2008 but a significant improvement from 2006 and 2007.
    - This indicates better convergence between day-ahead market assumptions and actual real-time conditions.
- There were many instances when the real-time market model was unable to reduce the flow below the transmission limit (i.e., the congestion was not manageable).
  - This generally occurs for brief periods when generation affecting the constraint lacks the flexibility or ramp capability to be redispatched.
  - Manageability is generally worse for low voltage constraints because fewer generators affect low voltage constraints.
  - Twenty-one percent of internal congestion was not manageable on a five-minute basis in 2009, which is an improvement from nearly 28 percent in 2008.
    - MISO implemented two recommendations in 2009 that improved manageability.
Executive Summary: Financial Transmission Rights

- Financial transmission rights provide a hedge for congestion because day-ahead congestion over the path that defines the FTR is rebated to the holder.
- FTRs were under-funded in 2009 – day-ahead congestion was 17 percent less than the obligations to FTR holders. Some of the factors explaining the shortfalls include:
  ✓ Continued challenges associated with accurately forecasting loop flow and non-market flows on Midwest ISO constraints in the FTR modeling; and
  ✓ Topology differences between the FTR and day-ahead models, including transmission outages that are not reflected in the FTR market.
  ✓ To address the under-funding, the Midwest ISO modified assumptions on loop flows and the transmission limits used in FTR market. However, these results indicate that improvements are still possible.
- This report identifies one type of constraint in the day-ahead that has contributed to underfunding and other issues in the day-ahead market.
- The report also evaluates FTR prices by comparing them to the actual value of congestion payable to FTRs (higher payments are “FTR profits”). FTR Profits have decreased from the start of the market through 2009.
  ✓ This trend indicates improving performance of the FTR market as it becomes more liquid and participants improve in the ability to value the FTRs.

Executive Summary: Market-to-Market and Coordination with PJM

- This report evaluates the market-to-market process under the Joint Operating Agreement (“JOA”) with PJM that is key in managing constraints affected by both RTOs.
  ✓ Roughly the same number of constraints were jointly managed on each of the RTO’s system in 2009, which is an increase for MISO and a decrease for PJM from 2008.
  ✓ In general, the market-to-market coordination has resulted in more efficient management of congestion, and more efficient LMPs in each RTO’s energy market.
  ✓ Payments from PJM to MISO decreased 12 percent, while payments from MISO to PJM decreased almost 30 percent.
    - Net payments were made by PJM to MISO in each month in 2009 even though more PJM constraints are active than Midwest ISO constraints in many months.
    - Together with other results in this section, this suggests that MISO generally provides more flow relief on PJM’s constraints than PJM does on the MISO’s.
- In April 2009 the Midwest ISO identified an issue with the PJM’s market flow calculations that understated PJM’s market flows and settlements from 2005 until June 2009.
  ✓ This is now the subject of active complaints at FERC and the RTOs are improving their auditing and validation of the market-to-market settlements to minimize future errors.
  ✓ Other JOA issues have arisen that have resulted in two referrals on PJM from us to FERC, as well as a number of disagreements between the RTOs regarding interpreting the JOA.
  ✓ We recommend that the RTOs work together to clarify the JOA in a number of areas to minimize future disagreements and ensure efficient outcomes.
Executive Summary: External Transactions

- The Midwest ISO relies heavily on imports from adjacent areas, averaging 3.8 GW in on-peak hours in 2009 and 2.4 GW in off-peak hours.
  - Although power flows in either direction depending on prevailing prices, Midwest ISO generally imports power from PJM and Manitoba and exports power to Ontario.
- Our analysis of the interchange between the Midwest ISO and adjacent markets shows that the prices at the interfaces are relatively well-arbitraged during most hours.
  - However, many hours exhibit large price differences due to uncertainty regarding price differences (transactions are scheduled in advance), which indicates that significant savings could be achieved from better use of the external interfaces.
  - To achieve better price convergence with PJM, we recommend that the RTOs consider expanding JOA to optimize net interchange between the two areas.
- Transaction scheduling and the RTOs’ dispatch around Lake Erie generate significant unscheduled power flows (i.e., loop flows).
  - The Midwest ISO had been working with the four RTOs around Lake Erie to develop market rules that would better coordinate these flows.
  - We have estimated production cost savings of almost $370 million annually for the four RTOs associated with improving coordination and interchange between the RTOs.
    - Most of these savings are from optimizing the net interchange across the external interfaces between the RTOs.

Executive Summary: Market Power and Mitigation

- This report provides an overview of the market concentration and other structural market power indicators, as well as a review of the conduct of participants and imposition of market power mitigation measures in 2009.
- The report indicates that concentration is low for the overall Midwest ISO area, although it is considerably higher in the individual regions.
- Whether a supplier is “pivotal”, which occurs when market demands cannot be satisfied without the supplier’s resources, is a more reliable indicator of potential market power.
  - 64 percent of the active “broad constrained area” (“BCA”) constraints have a pivotal supplier. BCAs are all constraints other than area defined in WUMS and SE Minnesota.
  - 69 percent of the active “narrow constrained area” (“NCA”) constraints into WUMS have a pivotal supplier, as do 75 percent of the active NCA constraints into Minnesota.
  - In addition, nearly 80 percent of all intervals in 2009 exhibited an active BCA constraint with at least one pivotal supplier.
  - Similarly, 30 percent and 6.5 percent of the intervals exhibited an active NCA constraints with a pivotal supplier in WUMS and Minnesota, respectively.
- These results indicate that:
  - Local market power exists persists with respect to both BCA and NCA constraints; and
  - The market power mitigation measures remain critical.
Executive Summary: Market Power and Mitigation

- The structural analyses summarized above indicate substantial local market power.
- However, our analyses of participants’ conduct provide little evidence of attempts to withhold resources (either physically or economically) to exercise market power.
- We calculate a “price-cost mark-up” that compares the system marginal price based on actual offers to a simulated system marginal price based on assuming suppliers had all submitted offers at their estimated marginal costs.
  - Based on this metric we found an average “mark-up” of the system marginal price of roughly one percent, indicating that the market outcomes in 2009 were very competitive.
- We calculate an “output gap” metric designed to detect economic withholding.
  - The output gap is the quantity of power not produced when suppliers’ competitive costs are significantly lower than the LMP.
  - This analysis shows that the output gap has decreased each year from 2007 to 2009. The average output gap level was 0.5 percent and fell as low as 0.2 percent.
- These results and others in this report provide little indication of significant economic or physical withholding, although we monitor these levels on an hourly basis and regularly investigate instances of potential withholding.
- Market power mitigation in the Midwest ISO’s energy market occurs pursuant to automated conduct and impact tests that utilize clearly specified criteria.
  - Because conduct has generally been competitive, market power mitigation was rare.

Executive Summary: Demand Response

- Demand response contributes to reliability in the short-term, resource adequacy in the long-term, reduces price volatility and other costs, and mitigates supplier market power.
- The Midwest ISO has more than 12,000 MW of total demand response capability, although most of it is in the form of interruptible load and behind-the-meter generation developed under regulated retail initiatives.
- Modest amounts of this demand response capability participates in the MISO’s markets:
  - 2,353 MW of non-dispatchable “Type 1” demand response resources can sell supplemental reserves and emergency energy to the Midwest ISO;
  - 111 MW of dispatchable “Type 2” demand response resources directly participate in the Midwest ISO’s energy and ancillary services; and
  - Emergency demand response can also be used to reduce LSEs’ capacity requirements under Module E.
- The Midwest ISO has been active in facilitating demand response.
  - The Midwest ISO has established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements, and has filed tariff changes to allow retail aggregators to participate in the MISO markets.
  - The Midwest ISO is considering the modifications that would be necessary to allow load interruptions and other emergency actions to set prices in energy and reserve markets.
- We recommend the Midwest ISO consider changes to allow non-dispatchable demand response resources to participate in a real-time economic demand response program.
Executive Summary: Capacity Market

- Beginning in June 2009, the Midwest ISO began running a monthly VCA to allow load-serving entities to procure capacity to meet their Module E capacity requirements.
  - The capacity cleared in the VCA is a small portion of the total designated capacity, from 0.1 percent in August to 1.2 percent in November.
  - This indicates that the VCA is serving as a balancing market with most LSEs’ needs satisfied through owned capacity or bilateral purchases.
- This report shows:
  - Capacity designations always met or exceeded requirements, at times by 5 percent;
  - The total capacity available significantly exceeded the requirements, from a minimum of 7 percent for August to a maximum of 42 percent for November; and
  - VCA clearing prices have been close to zero in most months, which is consistent with the substantial capacity surplus prevailing in the Midwest ISO.
- The high capacity prices in July were the result of the peak demand for capacity and large quantities of capacity that were not offered in the VCA or offered at high prices.
  - We attributed these results to inexperience with this new market and uncertainty regarding a retail load auction occurring in the same timeframe.
- We have concerns regarding undue barriers to participants importing and exporting capacity to and from external areas, which are addressed in the recommendations.

Summary of Recommendations

- Although the markets have performed well under the new ancillary services markets in 2009, we recommend the Midwest ISO consider the following improvements.
  1. Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.
     - This change would improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs.
     - The Midwest ISO has a project underway to develop a feasible approach.
  2. Allow non-dispatchable demand response (or interruptible load) to set real-time energy prices when they are called on in a shortage.
     - It would also improve price signals in the highest-demand hours, which is important for ensuring that the markets send efficient economic signals to maintain adequate supply resources and develop additional demand response capability.
     - It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.
Summary of Recommendations (cont’d)

3. Improve the integration of wind resources in the Midwest ISO system by allowing them to be dispatchable at a specified offer price and be eligible to set prices in the energy market.
   ✓ The Midwest ISO work underway that addresses this recommendation.

4. Develop a “look-ahead” capability in the real-time that would facilitate better management of ramp capability and commitment of peaking resources.
   ✓ The Midwest ISO’s commitment of peaking resources can be improved by using an economic model to commit and de-commit peaking units.
   ✓ This look-ahead capability could include a multi-period dispatch optimization to move slower-ramping units in anticipation of system demands over the ensuing hour.
   ✓ Better management of ramp needs and commitment of gas turbines would reduce out-of-merit quantities, reduce RSG payments, and improve energy pricing.
   ✓ We recommended this previously and the Midwest ISO has initiated a project to develop these capabilities.

5. To address the loop flows around Lake Erie, we recommend the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements.
   ✓ Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.
   ✓ The scheduling coordination being discussed by the ISOs around Lake Erie should address both efficiency and manipulation concerns with the current system.

6. Improve the real-time operation of the system by:
   ✓ Optimizing the use of the load offset to improve the Midwest ISO’s management of ramp capability in the near term.
   ✓ Improving the short-term load forecast (“STLF”) to reduce the system ramp that is consumed by the real-time market.

7. Improve congestion pricing and FTR funding by:
   ✓ Discontinue its constraint relaxation procedure and use the marginal value limits to set the LMPs when a transmission constraint is unmanageable.
   ✓ Discontinue the modeling of radial constraints in the day-ahead market.
   ✓ Allow local transmission owners to secure low voltage constraints that the Midwest ISO lacks the resources to manage.
Summary of Recommendations (cont’d)

8. Improve the performance of the spinning reserve market by:
   ✓ Improving the consistency between the reliability requirement for spinning reserves and the market requirement.
   ✓ Allowing the spinning reserve penalty price to set the price in the spinning reserve market (and be reflected in energy prices) during spinning reserve shortages by not relaxing the requirement.

9. Evaluate the formula for the regulation penalty price to ensure that it accurately reflects the costs of committing peaking resources in the Midwest ISO.

10. We recommend the following changes to improve the market to market process:
    ✓ Instituting a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly.
    ✓ Work with PJM to identify any other modeling parameters, provisions, or procedures that may be limiting PJM’s relief on Midwest ISO’s constraints.
    ✓ Clarify the JOA in areas including: 1) the use of marginal value limits, 2) pre-positioning on coordinated constraints, 3) use of proxy flowgates, 4) the obligation to activate a coordinated constraint, 5) the obligation to test new constraints, and 6) flowgate definitions and the thresholds used to identify new coordinated constraints.

11. To achieve better price convergence with PJM, we recommend that the RTOs consider expanding the JOA to optimize the interchange between the two areas.
    ✓ This could be accomplished by allowing participants to submit offers to transact within the hour if the spread in the RTOs’ real-time prices is greater the offer price.

12. Remove inefficient barriers to capacity trading with adjacent areas by:
    ✓ Modifying deliverability requirements for external resources to establish a maximum amount of capacity imports by interface that can be utilized to satisfy LSEs’ capacity requirements under Module E.
    ✓ Working with PJM to identify deliverability and must-offer requirements that may create inefficient barriers to exporting capacity to PJM.
Prices and Revenues

All-In Price

- The first figure in this section summarizes the “all-in price” for wholesale electricity in the Midwest ISO’s markets from 2007 to 2009.
- The all-in price represents the cost of serving load in the real-time market. It includes energy, ancillary services (after markets began in Jan. 2009), capacity costs (after the capacity auction began in June 2009) and uplift costs per MWh of real-time load.
  - The all-in price was $31.28 per MWh in 2009, a 40 percent decrease from 2008.
  - Real-time energy prices, the dominant component of the all-in price, decreased by 45 percent from 2008 to 2009.
  - Average uplift costs also decreased substantially, declining 16 percent from 2008. It remains a very small percentage (less than 1 percent) of the all-in price.
- The July capacity auction cleared at a high price due to large amounts of capacity that were not offered competitively. Although little capacity cleared, the spot price is used to estimate the market’s capacity costs for the month so it is sizable in July.
- The decrease in the all-in price from 2008 to 2009 is primarily due to sharply lower fuel prices (natural gas and coal) and lower load.
  - Fuel costs constitute the majority of most suppliers’ marginal costs of production.
  - Since suppliers in competitive markets offer at marginal cost, the correlation of the all-in price and fuel costs demonstrate the competitiveness of the markets.
The all-in price is computed by calculating a load-weighted average real-time energy price, plus real-time ancillary services costs, capacity costs (VCA price times requirements), and uplift cost, divided by actual load.

The next figure in this section shows average day-ahead energy prices and natural gas prices during 2009. Natural gas prices were at their lowest levels since the start of the Midwest ISO energy markets for much of the year before recovering in the fourth quarter. Low natural gas and coal prices, mild summer and winter weather, and reduced economic activity contributed to a substantial decline in day-ahead energy prices of 44 percent from 2008 to 2009.

The figure shows day-ahead prices are correlated with natural gas prices. As in prior years, the correlation was strong throughout 2009, even though natural gas was often not on the margin in 2009 due to low load levels.

Differences between hub prices show the congestion on the Midwest ISO system. During almost all months, Minnesota and WUMS exhibited lower prices than other regions, which is indicative of frequent west-to-east congestion. Congestion into the East region and Michigan resulted in higher prices at the Michigan Hub relative to all other hubs in 2009 as well as the Michigan Hub in prior years.
Day-Ahead Average Monthly Hub Prices
2009, All Hours

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<th>Month</th>
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<th>Michigan Hub</th>
<th>Minnesota Hub</th>
<th>WUMS Area</th>
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Midwest ISO Fuel Prices

- The next figure shows fuel prices from January 2007 through December 2009. Fuel prices in 2009 collectively dropped 30 to 55 percent compared to 2008.
- Oil and Natural Gas Prices:
  - While gas prices began and ended the year at approximately $6.00 per MMBtu, they averaged less than $4.00 in 2009 and were as low as $2.01. These were the lowest fuel prices since the Midwest ISO’s energy markets began in 2005.
  - Oil prices rose steadily from a monthly average of almost $10.00 per MMBtu in January to more than $13.50 in December, averaging $11.62 for 2009.
    - Under normal conditions oil use is insignificant but oil can sometimes be a significant marginal fuel in peak winter load conditions when gas supplies may be interrupted.
- Coal Prices:
  - Overall, coal prices declined substantially throughout the first quarter of 2009 and then stabilized thereafter.
  - Illinois Basin prices fell from $2.90 per MMBtu in January to $1.72 in December, averaging almost $2.00 for the year.
  - Likewise, Powder River Basin prices fell from $0.76 per MMBtu in January 2009 to $0.37 in October before rising to the 2009 average of $0.50 in December.
Midwest ISO Fuel Prices
2007 – 2009

Real Time Energy Prices

- The next figure shows a real-time price duration curve for each hub. A price duration curve shows the number of hours (x-axis) when the LMP is greater than or equal to a particular price level (y-axis).

- There was a marked downward shift in the price duration curve in 2009 caused primarily by the decrease in fuel prices.
  - Compared to prior years, the hours with prices exceeding $200 and $100 per MWh decreased sharply at all locations. This represents the combined effect of lower fuel prices and mild peak loads as well as other less significant factors.
  - At the Cinergy Hub, the real-time LMP exceeded the 2008 median LMP of roughly $37.50 in only 18 percent of hours.

- The figure also shows a sizable increase in the number of hours with pricing below zero, which is primarily caused by congestion in western areas and minimum generation events when they occur elsewhere.
  - Negative prices were most prevalent in Minnesota and WUMS, which generally occur in off-peak hours when excess generation results in west-to-east congestion.
  - Increased frequency of minimum generation events also increased negative pricing frequency in other areas from roughly 0.1 percent in prior years to close to 1 percent in 2009.
The next figure shows a subset of the real-time price duration curve spanning the 200 highest-priced hours at each hub.

- Prices in these peak hours play a critical role in sending the economic signals that govern investment and retirement of generation.

- High prices were much less prevalent in 2009 than in prior years.
  - Michigan Hub had 3 hours with prices exceeding $300 per MWh, which was more than the other locations due to congestion.
  - The decline in high-priced hours is primarily attributable to low peak hour demand associated with the mild weather experienced in 2009 and decreased economic activity.
  - Recent declines in load levels and increases in wind generation have resulted in sizable surplus generation levels, so infrequent shortages are expected.

- The decrease in peak pricing events reduces incentives to invest in new investment in generation or demand response resources.
  - This reduction in the economic signals provided by the Midwest ISO markets is further evaluated in the Net Revenue analysis later in this section of the report.
The implied heat rate duration curves on the next slide represent the average load-weighted hourly real-time energy price in each hour divided by the prevailing natural gas price.

- Real-time energy prices and gas prices are down respectively 45 and 55 percent year-over-year. The larger decline in gas prices means that the average implied heat rate for 2009 increased in comparison to 2008.
- One reason for this increase is that some of a generator’s marginal costs are not related to fuel. This causes their offers and resulting energy prices to fall less than fuel prices.
- In addition, natural gas fired resources were on the margin less frequently in 2009.

The shape of the duration curve for 2009 differs from prior years in several ways:
- The implied heat rates in the top 100 hours in 2009 are respectively 8 and 31 percent higher than in 2007 and 2008 due to a higher relative oil-to-natural gas spread in 2009.
  - The implied heat rate, which is based on natural gas prices, rises when this spread increases and oil is on the margin.
- A higher coal-to-natural gas spread in 2009 also led to a higher implied heat rate during the majority of hours in the year (creating a flatter duration curve) when coal-fired resources set the price in the market.
- The figure also shows a sharp increase in hours with negative implied heat rates associated with the negative energy prices discussed earlier in this section.
The next figure shows the frequency with which different types of units set the unconstrained energy price in the Midwest ISO.

- When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained areas).
- Therefore, the total for all the fuel types is greater than 100 percent.

Coal units set prices in 96 percent of intervals (including virtually all off-peak hours), an increase from 87 percent in 2008. The increase in coal price setting is due to:

- The substantial decrease in average load during 2009;
- The sizable increase in wind generation, which displaces higher-cost units; and
- The decrease in coal prices of roughly 30 percent during 2009.

Natural gas and oil set prices during the highest-load hours. Hence, these fuel prices have a larger effect on the load-weighted average prices than the percentages suggest.

- Gas, oil-fired, and dual-fueled resources set prices in 20.5 percent of intervals during 2009, a significant decline from 34 percent in 2008.
- However, almost 28 percent of all real-time energy costs were incurred when these resources were on the margin.
Share of Interval Price Setting by Unit Fuel Type 2007 – 2009

Long-Term Economic Signals to Maintain Adequate Resources

- In long-run equilibrium, the market should provide net revenues (revenue in excess of production costs) that create efficient incentives for investment and retirement.
- The following figure shows net revenues provided by the Midwest ISO market from 2007 through 2009 for two generic types of new units:
  - Gas combined-cycle (“CC”) unit with an assumed heat rate of 7,000 BTU/kWh; and
  - Gas combustion turbine (“CT”) unit with an assumed heat rate of 10,500 BTU/kWh.
- The introduction of jointly-optimized ASM markets in January 2009 and Voluntary Capacity Auction in June helped to improve long-term price signals.
  - Based on our estimates of the annualized costs of new investment, Midwest ISO markets would not currently support investment in gas CT or CC generation.
  - Annualized costs for constructing new capacity are similar to 2008; however, a steep decline in energy prices in 2009 resulted in large differences between net revenues and revenue requirements.
  - The Midwest ISO footprint has a sizable capacity surplus that precluded significant periods of shortage from occurring in 2009, particularly at reduced load levels.
  - When shortages did occur, the markets in 2009 did not fully price them because peaking units and interrupted load did not contribute to setting prices.
    - MISO is working on pricing changes to allow interruptible load to set price.
Capacity During Monthly Peak Load Hours

- The following figures show the generation capacity available and unavailable to the market during the peak-load hour of each month during 2009.
- The first figure shows the 2009 peak load hour occurred in late June at 96.5 GW.
  - Almost 15 GW of available generation was not committed during that hour, which indicates the sizable prevailing capacity surplus in the Midwest ISO region.
- The peak load was generally higher than the emergency maximum of all online generation, which indicates that the Midwest ISO relies on net imports to satisfy its energy demand.
  - Headroom during the peak hour was more than 2,500 MW for each of two highest monthly peaks (June and August). This raises a potential concern regarding over-commitment in the peak hours (which can suppress peak pricing), which is evaluated later.
- July was abnormally cool in 2009, which is evidenced by the fact that the peak load that month was almost 14 GW lower than in June.
- The 6-GW increase in total capacity in September was due to the addition of MidAmerican and Muscatine.
  - The differences in total monthly capacity are due to the intermittent generation in each peak hour. Unavailable intermittent capacity is not shown on the chart.
The second figure provides the same results but shows only the capacity that was unavailable.

The figure shows large quantities of uncommitted generation in every month (exceeding 30 GW on average) due to the decline in peak monthly demand in 2009.

This uncommitted generation pattern reflects the increased capacity margins detailed later in this report.

Day-ahead deratings were slightly higher on average during the summer due to high temperatures that reduce the ratings for some units and the fact that planned outages are lowest in the summer (since deratings are the sum for all units not on outage).

Roughly 7.6 GW of capacity is “permanently” derated relative to nameplate capacity and never available for dispatch. The permanent derates are attributable to:

- The fact that most units cannot produce their nameplate output under normal operation, particularly the large quantity of older baseload units in the region; and
- Increases in wind resources, which rarely operate close to their rated levels.

Permanent derates increased in September when MidAmerican joined MISO.

<table>
<thead>
<tr>
<th>Peak Load</th>
<th>Peak Hour</th>
<th>Peak Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>85,675</td>
<td>Jan 15</td>
<td></td>
</tr>
<tr>
<td>80,320</td>
<td>Feb 4</td>
<td></td>
</tr>
<tr>
<td>75,702</td>
<td>Mar 2</td>
<td></td>
</tr>
<tr>
<td>66,927</td>
<td>Apr 6</td>
<td></td>
</tr>
<tr>
<td>70,100</td>
<td>May 27</td>
<td></td>
</tr>
<tr>
<td>99,497</td>
<td>Jun 25</td>
<td></td>
</tr>
<tr>
<td>82,708</td>
<td>Jul 28</td>
<td></td>
</tr>
<tr>
<td>90,878</td>
<td>Aug 15</td>
<td></td>
</tr>
<tr>
<td>80,103</td>
<td>Sep 10</td>
<td></td>
</tr>
<tr>
<td>70,789</td>
<td>Oct 15</td>
<td></td>
</tr>
<tr>
<td>76,354</td>
<td>Nov 30</td>
<td></td>
</tr>
<tr>
<td>87,108</td>
<td>Dec 10</td>
<td></td>
</tr>
</tbody>
</table>
The following figure shows the generator outages that occurred in each month during 2009 as a percentage of total market generation.

- These values do not include partial outages or deratings.
- The figure splits the forced outages into short-term outages (less than 7 days) and long-term outages (more than 7 days).

- The annual combined outage rate was 11.4 percent for the three categories of outages, an increase over 2008 (9.3 percent) and 2007 (11.0 percent).
  - Planned outages rose 32 percent – low load levels and prices made it more attractive to schedule maintenance in 2009.
  - Long-term forced outage rates rose to almost 3 percent in 2009, particularly during off-peak load months. Forced outages are somewhat random, but the lower prevailing energy prices decreased the economic incentive to quickly return a unit from a forced outage.
  - Short-term outages, which are more likely than other outages to be physical withholding, fell slightly in 2009.

- The largest total outage levels occurred in the spring (17 percent) and fall (nearly 18 percent) because planned outages are generally scheduled during low load periods.
  - Planned outages averaged 11.2 percent during the spring and 8.3 percent in fall.

- Module E rule changes in the late summer provided more incentive for participants to report outages in the 4th quarter.
The next figure depicts load duration curves for the past three years, which show the number of hours that the load is greater than the level indicated on the vertical axis.

There was a clear downward shift in the 2009 load duration curve.

- Average load in 2009 was 61.1 GW.
- Excluding MidAmerican and Muscatine, average load dropped 6.6 percent compared to 2008 and 8.9 percent compared to 2007.
- The figure also shows the instantaneous peak load in 2009 of 96.5 GW was almost 6 percent below the predicted peak demand of 102.5 GW.

The reductions in load are attributable to both mild temperatures and reduced economic activity.

- The Midwest ISO performed an analysis suggesting that the decline in economic activity alone contributed to a 6.5 percent reduction in average load in 2009.
- The figure also shows nearly 20 percent of the energy demands occur in only the top three percent of load hours.

This indicates that a large share of the Midwest ISO’s resources are needed primarily to meet the Midwest ISO’s peak energy or operating reserve demands.

This underscores the importance of efficient pricing during peak load hours and the necessity of a capacity market to compensate these resources.

Load Duration Curves

2007 – 2009

<table>
<thead>
<tr>
<th>Hours of Load</th>
<th>&gt; 85 GW</th>
<th>&gt; 90 GW</th>
<th>&gt; 95 GW</th>
<th>&gt; 100 GW</th>
</tr>
</thead>
<tbody>
<tr>
<td>2007</td>
<td>473 (5.4%)</td>
<td>267 (3.0%)</td>
<td>122 (1.4%)</td>
<td>31 (0.4%)</td>
</tr>
<tr>
<td>2008</td>
<td>237 (2.7%)</td>
<td>103 (1.2%)</td>
<td>21 (0.2%)</td>
<td>0 (0.0%)</td>
</tr>
<tr>
<td>2009</td>
<td>76 (0.9%)</td>
<td>23 (0.3%)</td>
<td>3 (0.0%)</td>
<td>0 (0.0%)</td>
</tr>
</tbody>
</table>

Load (MW)

0 10,000 20,000 30,000 40,000 50,000 60,000 70,000 80,000 90,000 100,000 110,000

Hours

0 500 1,000 1,500 2,000 2,500 3,000 3,500 4,000 4,500 5,000 5,500 6,000 6,500 7,000 7,500 8,000 8,500
The next figure evaluates weather patterns and monthly load levels in 2007 to 2009.

- The top panel shows the monthly average and peak loads in 2009, which fell respectively 6.5 and 2.1 percent compared to 2008.
- Because a large share of the load is sensitive to weather, the figure shows weather patterns over the past three years.
  ✓ The bottom panel in the figure shows the monthly Heating Degree Days (“HDD”) and Cooling Degree Days (“CDD”) summed for four primary locations in the Midwest ISO.
  ✓ To account for the different relative impacts of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize the effects on load (based on a regression analysis).
- Reduced economic activity was a primary driver of the drop in demand. The Chicago Purchasing Manager’s Index, a leading business barometer and a broad measure of economic activity, was almost 8 percent lower in 2009 than in 2008.
- Mild summer and winter weather (excluding January) also contributed to lower load.
  ✓ Total degree days decreased by almost 11 percent year-over-year.
  ✓ The coolest July on record resulted in a 45 percent drop in CDDs and a 15 percent drop in average load in July 2009 from the prior year.
  ✓ Unusually cold January weather led to a relatively modest 1.7 percent load decline in 2009 compared to January 2008, the smallest monthly load decrease in 2009.

Heating and Cooling Degree Days

2007 – 2009
Distribution of Regional Generation Capacity
By Fuel Type

- The next two figures show the distribution of generating capacity by type and location.
- Generating resources in the Midwest ISO market footprint totaled 138.5 GW in 2009, a modest increase compared to 2008.
  - The resources in this figure are those owned by Midwest ISO market participants and exclude Midwest ISO members that are only reliability members (an additional 22 GW).
  - The addition of MidAmerican and Muscatine Power and Water in September 2009 added 6.5 GW of capacity in the West, of which 1.5 GW is wind capacity.
- The Midwest ISO continues to rely heavily on coal-fired generation – approximately 52 percent of its generation capacity is coal-fired.
  - Since coal units are generally baseloaded, coal-fired resources generate an even larger proportion (74 percent) of total energy produced.
- The next largest fuel type is natural gas-fired generation, which accounts for almost 28 percent of the generating resources in the Midwest.
  - Because these resources are higher-cost than most of the other resources in the Midwest ISO, they produce less than 18 percent of the energy in the region. This is down from over 27 percent in 2007 due to lower load and influx of new wind generation.
- Nuclear units represent under 8 percent of capacity but produce 15 percent of the energy.
- Steady growth in wind capacity (2.8 GW in additions in 2009, up 66 percent) increased wind’s share of capacity and generation to 5.1 and 2.9 percent, respectively.
The next table shows our estimates of the Midwest ISO’s reserve margins for summer 2010. These results differ from those in the Midwest ISO’s Summer Assessment.

The table shows capacity levels, internal demand, and resulting reserve margins for each region projected for 2010 given announced capacity additions and retirements.

- Internal demand is internal load less the sum of interruptible load and other demand side response capability.
- The Reserve Margin = ((Capacity plus Firm Net Imports) ÷ Internal Demand or Load) – 1

The primary differences between these results and the Midwest ISO’s Assessment are:

- We include all capacity in the Midwest ISO footprint unless it is exported on a firm basis.
  - Suppliers have incentives to offer all capacity into the Midwest ISO energy markets, whether or not it is designated under Module E. Excluding undesignated capacity understates the true surplus that currently prevails in the region.
- The Midwest ISO only includes resources designated as capacity resources under Module E, while our margins are calculated before forced outages are considered.
- The Midwest ISO applies a forced outage rate based on a three-year summer peak average. We apply a “high temperature derate” to reflect heat wave conditions when derates can be expected to greatly exceed average derates due to environmental restrictions or the effects of extreme ambient temperatures, leading to lower reserve margins than planners typically estimate.
The table shows reserve margins are highly sensitive to the assumed maximum capacity levels and to whether interruptible demand is included.

- The reserve margin for the Midwest ISO region is 31 percent when based on Internal Load and almost 40 percent when based on Internal Demand (which includes demand response capability).
- Among the regions, the reserve margin varies from 17 percent to 45 percent when based on Internal Load and from 27 percent to 54 percent when based on Internal Demand.
- These results would lead one to conclude that the Midwest ISO has a substantial surplus.

- However, using summer ratings and accounting for the temperature sensitive capacity that would not be expected to be available under peak demand conditions, we find:
  - The reserve margin projected for 2010 for the Midwest ISO region is 12 percent when based on Internal Load and 20 percent when based on Internal Demand.
  - Among the regions, the reserve margin varies from almost 5 percent to 26 percent when based on Internal Load and from 12 percent to 37 percent when based on Internal Demand.

- Given typical forced outage rates ranging from 4 to 8 percent, the existing capacity in the region should be more than adequate to satisfy the system’s demands in 2010.

- Although the system’s resources are adequate for summer 2010, new resources will be needed over the long-run to meet the needs of the system. Hence, the market’s economic signals that govern new investment and retirement decisions remain critical.
Additions and Retirements of Generation Capacity
2009 – 2010 Planning Year

- The following table shows the capacity added since summer 2009 and expected to be available for summer 2010.
- In total, 3 GW of additions and 756 MW of retirements/reclassifications are expected.
  - Although such capacity additions are substantial, much of the new capacity is wind. The intermittent nature of wind resources causes it to contribute less to reliability than conventional supply or demand response resources do.
  - For 2010, the Midwest ISO has reduced the Module E capacity credit for intermittent resources from 20 percent to 8 percent.
  - The additional coal capacity in WUMS and gas fired capacity in the East should improve the Midwest ISO’s ability to manage congestion into these areas.
- Dairyland Power Cooperative and Big Rivers Electric are expected to join in 2010, adding an additional 3 GW of capacity.

<table>
<thead>
<tr>
<th>Region</th>
<th>Coal</th>
<th>Gas</th>
<th>Oil</th>
<th>Other</th>
<th>Waste</th>
<th>Water</th>
<th>Wind</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CENTRAL</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>50</td>
<td>50</td>
</tr>
<tr>
<td>EAST</td>
<td>18</td>
<td>656</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>120</td>
<td>794</td>
</tr>
<tr>
<td>WUMS</td>
<td>640</td>
<td>60</td>
<td>37</td>
<td>2</td>
<td>7.5</td>
<td>10.4</td>
<td>99</td>
<td>809</td>
</tr>
<tr>
<td>WEST</td>
<td>0</td>
<td>6</td>
<td>37</td>
<td>2</td>
<td>7.5</td>
<td>10.4</td>
<td>1,340</td>
<td>1,392</td>
</tr>
<tr>
<td>Total</td>
<td>658</td>
<td>722</td>
<td>37</td>
<td>2</td>
<td>7.5</td>
<td>10.4</td>
<td>1,609</td>
<td>3,045</td>
</tr>
</tbody>
</table>

Voluntary Capacity Auction Results

- Beginning in June 2009, the Midwest ISO began running a monthly VCA to allow Load-Serving Entities (“LSE”) to procure capacity to meet their Module E capacity requirement.
  - The capacity cleared in the VCA is a small portion of the total designated capacity and ranged from 0.1 percent in August to 1.2 percent in November.
  - This indicates that the VCA is serving as a balancing market with most LSEs’ needs satisfied through owned capacity or bilateral purchases.
- The following figure shows the total monthly capacity requirements and how LSEs are satisfying those requirements. It shows:
  - Capacity designations always met or exceeded requirements, at times by 5 percent;
  - The total capacity available significantly exceeded the requirements, from a minimum of 12 percent for August to a maximum of 51 percent for October; and
  - The low VCA clearing prices in most months are consistent with the substantial capacity surplus prevailing in the Midwest ISO.
- The high capacity prices in July were the result of the peak demand for capacity and large quantities of capacity that were not offered in the VCA or offered at high prices.
  - We attributed these results to inexperience with this new market and uncertainty regarding a retail load auction occurring in the same timeframe.
Voluntary Capacity Auction Results
June 2009 – December 2009

Day-Ahead Market Performance
• The next figure shows daily day-ahead prices during peak hours (6am to 10pm on weekdays) and the corresponding scheduled load (including net cleared virtual demand).
• Overall, day-ahead prices in 2009 were very stable throughout the year and were consistent with changes in fuel prices and load conditions.
  ✓ Fuel prices and day-ahead prices were highest in the beginning of the year in January and at the end of the year in December.
  ✓ The load-weighted average day-ahead price in peak hours was $35.91 per MWh in 2009, a 48 percent decrease from 2008.
• Differences in prices at the Minnesota, WUMS, Michigan, and Cinergy Hubs show the prevailing congestion patterns throughout the year.
  ✓ West-to-east congestion across the Midwest ISO caused the lowest average prices in Minnesota ($33 per MWh) and the highest prices in Michigan ($38.40).
  ✓ Transmission outages and high load in late June contributed to substantial congestion out of the West and the highest day-ahead prices of the year in eastern areas.
  ✓ Seasonal patterns were less prevalent in 2009 than in prior years due to low fuel prices and mild peak load conditions that generally prevailed during summer 2009.

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Day-Ahead Hub Prices and Load
Peak Hours, 2009

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The next figure shows day-ahead prices and load during off-peak hours.

- Off-peak prices were 38 percent lower on average in 2009 than in 2008.
  - Price spreads between eastern and western hubs were more prominent in the off-peak hours, and were higher on a percentage basis than in prior years.
  - In the West, Minnesota and WUMS prices averaged $21 and almost $19 per MWh, respectively. In the East, Cinergy and Michigan both averaged close to $25 per MWh ($24.73 and $25.41).
- Day-ahead average off-peak prices were highest from January through March due to winter peaks and higher fuel prices.
  - Prices at Cinergy and Michigan Hubs were only marginally higher than prices at Minnesota and WUMS during these winter months.
  - The high loads in the winter-peaking western areas resulted in considerable congestion out of the West and some congestion into the West.
- Because coal-fired generation was almost always on the margin in off-peak hours, the steady decline in off-peak prices was almost entirely due to the decline in coal prices.
Day-Ahead and Real-Time Price Convergence

- The next series of analyses focuses on the convergence of real-time and day-ahead energy prices.
- It is important that prices in the day-ahead market converge with those in the real-time market because:
  - The day-ahead market governs most of the generator commitments in the Midwest ISO – hence, efficient commitment requires efficient day-ahead market results.
  - Most wholesale energy bought or sold through Midwest ISO markets is settled through the day-ahead market.
  - The entitlements of firm transmission rights are associated with the results of the day-ahead market.
- In general, good convergence depends on:
  - Consistent topology and modeling assumptions between the day-ahead and real-time; and
  - Price-sensitive bids and offers in the day-ahead market, including active virtual supply and demand participation.

Day-Ahead and Real-Time Prices
Cinergy Hub

- The next figure shows monthly average prices in the day-ahead and real-time markets at Cinergy Hub, which remains the most liquid forward trading point in the region.
  - The table below shows average and absolute day-ahead price premiums as a percent of the real-time price for four representative hubs.
- There were modest day-ahead premiums in most months of 2009 at the Cinergy Hub.
  - Day-ahead premiums are rational because day-ahead prices are less volatile and entities purchasing in the real-time market are subject to RSG uplift cost allocation.
  - Lower day-ahead premiums are consistent with the drop in real-time RSG costs and fuel prices in 2009. However, the monthly averages in percentage terms are similar.
- The current RSG allocation, which is discussed in detail later in the report, imposes disproportionately large costs on virtual supply transactions.
  - This has resulted in sharp declines in virtual activity and contributed to large price differences that are not quickly arbitrageda
d  
  - Average price differences were largest in WUMS (7 percent avg. day-ahead premium for the year) and in Minnesota (7 percent avg. day-ahead premium in 1st half of 2009).
- The absolute value of the hourly differences in Minnesota and WUMS continued to be higher than in other areas, which is attributable to higher price volatility in these areas.
  - Negative real-time price spikes during off-peak hours are a primary cause of the volatility.
Day-Ahead and Real-Time Prices
Cinergy Hub, 2007 – 2009

Average Price Difference (% of Real-Time Price)

<table>
<thead>
<tr>
<th>Hub</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cinergy Hub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Michigan Hub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Minnesota Hub</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WUMS Area</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Average Absolute Price Difference (% of Real-Time Price)

Day-Ahead and Real-Time Price Differences
Midwest ISO and Neighboring Markets

- The following figure compares day-ahead and real-time price differences in the Midwest ISO to other RTO markets in the Eastern Interconnect. The comparison includes:
  - Average price differences and the average of the absolute value of the hourly price differences (which shows the typical difference regardless of the direction); and
  - Prices in constrained and unconstrained areas in each market.
- The comparison of the average prices in the table shows:
  - The Midwest ISO has maintained its day-ahead premium, which is consistent with the relatively large share of RSG costs that the Midwest ISO allocates to real-time deviations.
  - Neighboring markets, which had exhibited consistent day-ahead premiums in 2008, now generally show slight real-time premiums at many locations.
  - The average absolute differences are consistent with the overall price volatility in each market. The Midwest ISO and New York ISO both run true five-minute markets and are therefore more volatile than PJM and ISO-New England, which generally run the dispatch every 15 minutes.
  - The congested locations exhibit the largest average absolute differences in each market (exceeding $15 per MWh in New York City) due to the higher volatility in these areas.
- Overall, these analyses indicate that price convergence in the Midwest ISO has been consistent with other RTO markets.
  - However, convergence in some of the Midwest ISO’s congested areas has eroded as virtual activity has diminished.
Day-Ahead to Real-Time Price Differences
Midwest ISO and Neighboring Markets, 2009

<table>
<thead>
<tr>
<th></th>
<th>Average Clearing Price</th>
<th>Average of Hourly Absolute Price Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Day-Ahead</td>
<td>Real-Time</td>
</tr>
<tr>
<td>Midwest ISO:</td>
<td></td>
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</tr>
<tr>
<td>Cinergy Hub</td>
<td>$30.77</td>
<td>$30.30</td>
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<tr>
<td>Michigan Hub</td>
<td>$32.17</td>
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<td>$26.17</td>
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<td>WUMS Area</td>
<td>$28.89</td>
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<td>New England ISO:</td>
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<td>New England Hub</td>
<td>$43.18</td>
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<td>Maine</td>
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<td>New York ISO:</td>
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<td>Zone A (West)</td>
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<td>AEP Gen Hub</td>
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<td>$43.73</td>
<td>$43.27</td>
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<tr>
<td>Western Hub</td>
<td>$40.69</td>
<td>$40.29</td>
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</table>

Day-Ahead ASM Prices and Price Convergence 2009

- Ancillary Services Markets (“ASM”) were introduced in January 2009 and have operated with no significant issues.
- The following chart shows monthly average day-ahead clearing prices for the Midwest ISO’s ancillary service products for 2009.
  - The ASM prices in the Midwest ISO have been consistent with expectations and are comparable to ASM results in similar RTO markets.
  - Spinning reserve and supplemental reserve prices converged well between the day-ahead and the real-time during 2009.
  - However, regulation prices were consistently higher in real time due to:
    - Increased energy price volatility that increases the opportunity costs of generators providing regulation; and
    - Reduced regulation availability – this is primarily due to the Midwest ISO’s regulation commitment process, which selects a subset of regulation
  - As in real time, the day-ahead regulation prices dropped in the first half of the year, due in large part to the reduction in the regulation scheduling requirements.
- The small number of shortages of supplemental reserves (occurring mostly during ARS events) have caused some divergence between the day ahead and real time.
Day-Ahead ASM Prices and Price Convergence
2009

Day-Ahead Load Scheduling

- The next figure shows the components of load cleared in the day-ahead market as a percentage of the actual real-time load.
- The net load scheduled day-ahead is a key driver of real-time RSG costs.
  - Net load is the physical load, plus virtual load minus virtual supply.
  - Supplies are committed and scheduled in the day-ahead to satisfy the net load.
  - When net load is significantly less than 100 percent of the actual load, particularly in the peak load hour of the day, the Midwest ISO will frequently commit peaking resources to satisfy the incremental increase in load, increasing real-time RSG costs.
- Participants will have incentives to schedule net load at less than 100 percent whenever day-ahead prices exceed real-time prices. This condition often results from:
  - Significant quantities of generation being committed by participants or by the Midwest ISO after the day-ahead market;
  - Under-scheduling of wind resources in the day-ahead market; or
  - High-cost units (such as peaking resources) not setting prices in the real-time market when they are needed to meet the market’s generation demand.
The figure shows the vast majority of load scheduled in the day-ahead market is fixed (i.e., will be purchased at any price).

- Day-ahead load scheduling in 2009 averaged nearly 100 percent of actual load.
- In 2009 price-sensitive and net virtual load accounted for 3.6 percent of scheduled load compared to 2.2 percent in 2008.

- The day-ahead market consistently cleared net virtual load (more virtual demand than supply) in 2009, which coincides with the allocation of RSG charges under the Interim Rate to include cleared virtual supply offers beginning in November 2008.

- Overall, the net load (total load net of virtual supply) scheduled in the day-ahead market as a percent of the real-time load increased in 2009 compared to 2008.

- 99.9 percent of the actual load was scheduled on net in 2009 in all hours, an increase from 99.2 and 98.9 percent in 2008 and 2007, respectively.
- Net load scheduling in the peak hour of each day (the hour that is most likely to require the Midwest ISO to commit additional generation) increased substantially:
  - 99.2 percent of the actual load was scheduled on net in the day-ahead market, versus 97.6 percent in 2008 and 96.8 percent in 2007.
- Higher load scheduling and lower overall load have together reduced the Midwest ISO’s reliance on peaking resources in the real-time and have lowered overall RSG costs.
Virtual Load and Supply in the Day-Ahead Market

• Virtual trades in the day-ahead market serve to facilitate convergence between day-ahead and real-time prices and suppress market power in the day-ahead market.

• FERC issued a series of Orders from April 2006 to November 2008 requiring the allocation of RSG costs to cleared virtual supply offers, among other things.
  - Although these orders should have only affected virtual supply, both virtual supply and demand quantities have decreased.
  - The current “Interim Rate” for allocating RSG costs has resulted in almost all real-time RSG costs to be allocated solely to deviations (real-time physical load increases, virtual supply, real-time import reductions, etc.), which is only one cause of RSG costs.
    - Hence, the Interim Rate over-allocates RSG costs to virtual supply, which bore roughly 24 percent of all real-time RSG costs under this rate in 2009.

• RSG allocations and tight credit conditions early in the year contributed to sharp reductions in virtual activity in 2009. The credit issues attenuated later in the year.

• Reduced virtual activity raises potential concerns regarding the performance of the day-ahead market because:
  - Active virtual trading in the day-ahead market promotes price convergence with the real-time market, which facilitates an efficient commitment of generating resources; and
  - Active virtual supply protects the market against attempts to raise day-ahead prices at a location through manipulated supply offers or demand bids.
  - While this has not been a concern to date, we continue to monitor these trends.

Virtual Load and Supply in the Day-Ahead Market
2007 – 2009

![Graph showing virtual load and supply in the day-ahead market for 2007 to 2009](image-url)
The next figure shows the monthly average profitability of virtual purchases and sales. Profitability of all cleared virtual transactions increased modestly to $0.80 per MWh in 2009 from $0.42 and $0.33 per MWh in 2007 and 2008, respectively.

- Virtual supply has been more profitable than virtual demand, primarily due to the prevailing day-ahead price premium.
- Virtual supply transactions had an average profitability was $2.03 per MWh. However, after paying RSG charges of $1.60 per MWh, those transactions netted an average profit of only $0.43 per MWh.

The table below the chart shows the percent of virtuals clearing with abnormally large profits or losses. Large sustained profits may indicate a day-ahead modeling problems while large losses may indicate an attempt to manipulate day-ahead prices.

- Attempts to create artificial congestion or other price movements in the day-ahead market will cause prices to diverge from real-time prices and be unprofitable.
- The portion of transactions generating losses greater than $50 per MWh has fallen by more than one-half.
- We screen unprofitable transactions for those participants whose losses are intentionally caused by the bid or offer. Very few transactions have raised potential concerns and none have warranted a referral to FERC.

Note: Profits do not include the cost of RSG allocations, which averaged $1.60 per MWh on virtual supply transactions in 2009.
The next figure shows the monthly average profitability of virtual purchases and sales at the Cinergy Hub, other hubs, and other nodal locations:

- Cinergy Hub is the single most liquid trading point in the Midwest ISO, with almost 30 percent of all trading volume.
- Most other virtual trading activity occurs at individual nodes – over 60 percent in 2009.
- The average gross profit per MWh of cleared virtual supply offers was $2.03 in 2009.
  - Virtual supply was generally more profitable at the nodal level ($2.46 per MWh) because larger price differences occur at locations other than Cinergy.
  - Almost $36 million of the $41 million in gross virtual supply profits in 2009 occurred at nodal locations.
  - The allocation of RSG costs offset more than half of these profits.
- The average gross profit per MWh of cleared virtual demand bids was -0.06 in 2009.
  - 37 percent of virtual load cleared at the Cinergy Hub where virtual demand lost an average of $0.87 per MWh in 2009.

Note: Profits do not include the cost of RSG allocations which averaged $1.60 per MWh on virtual supply transactions in 2009.
Virtual Transaction Volumes
Eastern Interconnect

- The next figure shows monthly average transaction volumes of virtual supply and demand for the Midwest ISO and neighboring RTOs as a percent of actual load.
- Virtual load and supply volumes declined in all three RTOs in late 2008 into 2009 due primarily to the credit market issues that occurred at that time.
  - Volumes in New York returned to normal levels by mid-year.
  - Volumes in New England increased in mid-year, but declined later in 2009 due in part to a general reduction in congestion and arbitrage opportunities.
- Virtual load share of actual load in the Midwest ISO declined by more than one-third from 2008 and 2009 and remained near 5 to 6 percent of actual load throughout 2009.
- Virtual supply declined by almost half as a share of actual load in the Midwest ISO in 2009, averaging only 3.8 percent of actual load.
- The high RSG cost allocation rate applied to virtual supply (and other deviations between the day-ahead and real-time markets) beginning in November 2008 contributed to the decline in virtual supply quantities.
  - Under the Interim Rate in 2009, this rate averaged $1.60 per MWh in 2009.

Virtual Transaction Volumes
Eastern Interconnect

- [Bar chart showing virtual load and supply as a percentage of actual load for different regions over time]
Day-Ahead Forecast Error in Daily Peak Hour

- Day-ahead forecasting is a key element of the day-ahead commitment process.
  - The accuracy of the day-ahead load forecast is particularly important for the Reliability Assessment Commitment ("RAC") process.
  - Inaccurate forecasts can cause the Midwest ISO to commit additional resources that are unnecessary or to not commit resources that are needed, both of which can be costly.
- The following figure shows the percentage difference between the day-ahead forecasted load and real-time actual load for the peak hour of each day in 2009.
  - The day-ahead forecast of peak load was 0.6 percent greater than real-time peak load on average, which indicates that the forecasting was relatively accurate.
  - The average peak load forecast error – the magnitude of the error, regardless of direction – was 1.9 percent in 2009.
    - This is slightly higher than the 1.5 percent observed in 2008, but lower than the 2.2 percent error in 2007.
    - These results are comparable to the performance of other RTOs.
  - Consistent with the prior two years, the figure shows the load tended to be over-forecasted in the summer and under-forecasted in the fall.
    - The magnitude of this seasonal bias increased in summer 2009 due to an unexpectedly cool summer, but decreased in the winter.
    - The Midwest ISO is working to identify the source of this bias.

<table>
<thead>
<tr>
<th>DA Forecast Minus RT Load (% of RT Load)</th>
<th>Jan-09</th>
<th>Feb-09</th>
<th>Mar-09</th>
<th>Apr-09</th>
<th>May-09</th>
<th>Jun-09</th>
<th>Jul-09</th>
<th>Aug-09</th>
<th>Sep-09</th>
<th>Oct-09</th>
<th>Nov-09</th>
<th>Dec-09</th>
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<table>
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<tr>
<th>Average Peak Load Forecast Error</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avg DA Forecast Minus Avg RT Load</td>
<td>-0.2%</td>
<td>0.6%</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>Average Peak Load Forecast Error</th>
<th>Avg DA Forecast Minus Avg RT Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>2008</td>
<td>1.5%</td>
<td>-0.2%</td>
</tr>
<tr>
<td>2009</td>
<td>1.9%</td>
<td>0.6%</td>
</tr>
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</table>
Real Time Market Performance

The following figure in this section shows real-time prices during peak hours and the corresponding actual load.

The figure shows a general correlation between peak load and peak prices, with some notable price separations due to congestion events.

Overall, fuel prices and load were substantially lower in 2009 than 2008, particularly during the summer months, leading to lower prices throughout the footprint.

- The load-weighted real-time energy price during peak hours in 2009 was $35.49 per MWh, down 47 percent from 2008.
- This reduction was primarily due to fuel prices that fell between 30 and 55 percent, depending on the fuel.
- Average load and peak load also decreased in 2009, which reduced the frequency of relatively high prices in the Midwest ISO.
  - Average daily peak prices rarely rose above $70 and never did so at Cinergy Hub.
  - Congestion resulted in transitory price spikes, primarily in WUMS (e.g., June 23) and in Minnesota (e.g., December 15).

As in the day-ahead market, west-to-east congestion prevailed throughout the year.

This trend is less apparent during peak hours than during off-peak hours, when high levels of wind and exports from ComEd lead to surplus generation in the West.
Real-Time Hub Prices and Load
Peak Hours

- The next figure shows real-time prices during off-peak hours and actual load.
- The figure shows energy prices were generally very low in off-peak hours due to:
  - The high percentage of off-peak hours when prices are set by coal-fired resources.
  - Higher wind generation levels in off-peak hours.
- There were consistent negative price spikes throughout the year.
  - Persistent west-to-east congestion resulted in 25 days with negative average off-peak prices at both Minnesota and WUMS Hubs.
    - Although off-peak prices were relatively volatile, there was a consistent daily price spread of $6 to $8 per MWh between western and eastern hubs.
    - Increased wind generation in the West and large exports by Commonwealth Edison and MHEB contribute to this trend.
  - Cinergy and Michigan experienced negative pricing on just 2 and 4 days, respectively. These prices are generally the result of minimum generation events.
- Congestion into eastern areas in early March were caused by several forced and planned generator outages as well as substantial volumes of wheels from Ontario to PJM, resulting in price spreads in excess of $60 per MWh.
Real-Time Hub Prices and Load Off-Peak Hours, 2009

- The following figures show average interval-level real-time prices by time of day in the summer and winter months of 2009 when loads are the highest.
- Volatility has decreased significantly in 2009 under ASM markets because the real-time market now has the flexibility to jointly optimize the use of resources for energy and ASM needs.
- To examine the drivers of the price volatility, the figures show the effective headroom on the system (the amount of generation that can be utilized in the next five minutes given ramp limitations) and the average change in NSI.
- As in prior years, these figures show that in 2009:
  - Prices fluctuate most when load is ramping up or down near the peak (afternoon in the summer, and dual peaks in the morning and evening in the winter);
  - The sharp price movements are often at times when the system is ramp-constrained, which occurs when the system’s generation is increasing or decreasing as quickly as possible to accommodate changes in NSI, load, or other needs.
  - The changes in real time prices are directly related to changes in effective headroom, which often changes significantly at the top of the hour when NSI changes and the commitment and de-commitment of units are occurring.
    - The generation commitment effects are largest late in the day, when generators are shutting down.
The following chart shows the monthly average System Marginal Price ("SMP") that prevailed in the market in 2008 and 2009, as well as the SMP after adjusting for the drop in fuel prices.

- As highlighted earlier, fuel prices (coal, oil, and natural gas) dropped 30 to 55 percent in 2009.
- Each interval’s SMP was indexed to the average two-year fuel price of the marginal fuel during the interval.
- The price-setting fuel was the fuel that was most frequently on the margin during the particular interval.
- No other adjustments, such as the switching of marginal fuels, were made.
- Average fuel-adjusted energy prices fell almost 15 percent in 2009 due to milder than average temperatures, reduced in economic demand, and residual ASM effects.
- Although the methodology does not capture several likely impacts of changing fuel prices on generation dispatch, the figure clearly demonstrates that fuel price changes account for a significant share of the year-over-year change in electricity prices.
Five-Minute Real-Time Price Volatility
Midwest ISO and Neighboring Markets

- The next figure shows the average percentage change in real-time price between five-minute intervals for several hubs in neighboring markets.
- The results indicate that the Midwest ISO, along with NYISO, has the most price volatility and ISO-NE has the least. These differences can be explained by the differences in the software and operations of the different markets.
  - MISO and NYISO are five-minute markets, with five-minute prices and dispatch. Ramp constraints are more likely in these markets due to the shorter time to move generation.
  - The NYISO’s real-time dispatch is a multi-period optimization that looks ahead one hour so it can anticipate ramp needs and begin moving generation to accommodate them.
- PJM and ISO-NE generally produce a real-time dispatch every 10 to 15 minutes, although they produce 5-minute prices using their ex-post pricing models.
  - Although this system does not alter the generation dispatch levels as frequently as the Midwest ISO or NYISO, the systems are less likely to be ramp-constrained because they have 15 minutes of ramp capability to serve the systems’ demands.
  - Because the system is redispached less frequently, these markets likely rely more heavily on regulation to satisfy intra-interval changes in load and supply.
- Of the locations shown, Cinergy Hub exhibited the least volatility interval-to-interval because it is the least affected by congestion.
- The figure also shows price volatility dropped by roughly one-quarter at Cinergy Hub since the ASM markets were implemented due to the increased system flexibility.

Five-Minute Real-Time Price Volatility
Midwest ISO and Neighboring Markets, 2009

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Real-Time ASM Prices and Shortages

- In their first year of operation, Ancillary Service Markets in 2009 performed as expected in the real-time with no significant issues.
- The following chart shows monthly average real-time clearing prices for the Midwest ISO’s ancillary service products for 2009.
  - The prices in the Midwest ISO have been consistent with expectations and with the ASM results in similar RTO markets.
  - Regulation prices dropped significantly in the first six months of operation and then rose slightly in the fourth quarter. Much of the decline in regulation prices is due to reductions in the requirements during the first half of the year.
- In spring 2009, shortages of spinning reserves and regulation occurred at a relatively high frequency.
  - The Midwest ISO has improved the consistency between the market requirements and operating requirements, which tends to reduce the frequency of such shortages.
  - Prices do not always accurately reflect the spinning reserve shortages due to the Midwest ISO’s method of relaxing the requirement during the shortage.
- A small number of shortages of total reserves (including spinning and supplemental reserves) occurred during ARS events in 2009. Overall, supplemental reserve prices have been relatively low as expected.
- Locational differences in ASM prices continue to be relatively limited.
The next two figures show the real-time offer prices and quantities of the ASM products.

Average regulation capability (1,835 MW) is less than other operating reserves because:

- It is limited to five minutes of ramp capability (spinning reserve is 10 minutes); and
- Only a limited number of resources can provide regulation.

The solid segments of the bars show the capability that is available to be scheduled on a 5-minute basis, while the hatched segments represent capability that cannot be scheduled.

Three-quarters of the unavailable regulation is due the resource not being “committed” for regulation, which is the process by which the ISO selects which available units with offers will be included in the 5-minute real-time co-optimization.

The figure shows that lower cost offers began to be marginal later in the year because:

- The requirement decreased gradually over the year; and
- The regulation resources committed increased after the first quarter of 2009.

These changes have contributed to the price reductions that occurred through the year.

We note that regulation prices averaged nearly $15 per MWh, which is higher than the typical marginal offer price because the clearing price includes opportunity costs when resources must be dispatched up or down from their economic level to provide regulation.
Spinning and Supplemental Offers and Commitments

- The next figure shows the offer prices and quantities of qualified spinning and offline supplemental reserves available in the real-time market.
  - The share of each ancillary service product cleared relative to qualified capability remained between 15 and 25 percent in every month.
  - This supports the competitive performance of the markets because individual suppliers are unlikely to be pivotal.
- As with regulation, marginal clearing prices for spinning reserves were higher than the offer price tranches indicate.
  - Clearing prices averaged approximately $3.25 per MWh, but sufficient capability was typically available each month to meet the requirement for less than $1 per MWh.
  - Actual clearing prices are higher due to the co-optimization of energy and ancillary services, which causes prices to sometimes include opportunity costs or shortage costs.
- Almost half of the spinning reserves that cannot be scheduled are due to units that are being dispatched near dispatch maximum, thereby limiting available spinning reserves.
- Cleared AS quantities slightly declined during 2009 as a result of reduced regulation and spinning reserve requirements.
- Supplemental reserve offers declined considerably after March due to technical, economic, and regulatory concerns by some of the participants, which we are investigating.
The Midwest ISO believes that it is required to have a minimum amount of spinning reserves at all times that can be deployed immediately in response to a contingency.

- However, units scheduled for spinning reserves may temporarily not be able to provide the full quantity in 10 minutes if the real-time energy market is instructing them to ramp up.

- To account for this, the Midwest ISO establishes a market requirement that exceeds its real requirement for “rampable” spinning reserves by roughly 200 MW on average.

- As a result, market shortages can occur when the Midwest ISO is not physically short or visa versa.

- The Midwest ISO should set the market requirement to make the market results as consistent with the real conditions as possible.

- The following figure shows all intervals with either a real or market shortage, indicating:

  - In roughly 19 percent of the shortage intervals, there was both a real and market shortage.

  - In almost 80 percent of the shortages, the market indicated a shortage that was not real.

- These results indicate that the consistency between the market and real requirements could be improved, which would improve the economic signals provided by the market.

- Hence, we recommend that the Midwest ISO improve the consistency of the requirements by setting the market requirement dynamically or by reducing the difference between the two requirements.

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**Market Spin Shortage vs. Real Spin Shortages**

<table>
<thead>
<tr>
<th>Intervals of Shortage</th>
<th>Market Requirement</th>
<th>Rampable Spin Requirement</th>
<th>Market and Real Shortage</th>
<th>Real Shortage Only</th>
<th>Market Shortage Only</th>
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<td>0-50</td>
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<td>1</td>
<td>0.28%</td>
<td>0.03%</td>
<td>1.15%</td>
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<tr>
<td>51-100</td>
<td>0</td>
<td>1</td>
<td>0.28%</td>
<td>0.03%</td>
<td>1.15%</td>
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<tr>
<td>101-150</td>
<td>0</td>
<td>1</td>
<td>0.28%</td>
<td>0.03%</td>
<td>1.15%</td>
</tr>
<tr>
<td>151-200</td>
<td>0</td>
<td>1</td>
<td>0.28%</td>
<td>0.03%</td>
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<tr>
<td>201-250</td>
<td>0</td>
<td>1</td>
<td>0.28%</td>
<td>0.03%</td>
<td>1.15%</td>
</tr>
</tbody>
</table>

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Regulation Pricing During Shortages

- Regulation shortages occurred in 778 intervals (less than one percent of intervals).
  - Shortages occurred most frequently during off-peak hours (three quarters of all shortage intervals were off-peak) and during spring 2009.
    - Shortages occur comparatively more often during off-peak hours partly because fewer regulation-capable units are online.
  - The shortages are generally small – one-third of regulation deficits were less than 50 MW, and 59 percent were less than 100 MW.
- The next figure shows the regulation price during shortage intervals for periods where the market met its spinning reserve requirement.
  - The regulation price during shortage intervals is equal to the monthly regulation penalty price plus the spinning reserve price.
    - The penalty price is determined formulaically each month and is intended to reflect the commitment cost of a peaking resource.
  - The figure shows the regulation price during intervals with shortage in a given month is determined consistent with the penalty price, regardless of the size of the deficit. This is good because the price reliably reflects the shortage.
  - The formula-based penalty price increased sharply in early 2010. We are reviewing the formula to determine whether it is serving its intended purpose.
There were 1,501 spin deficits in 2009, or 1.4 percent of all intervals. In general, shortages occur when the demands on the system to ramp up the online capacity cause the real-time market to have insufficient resources to satisfy both the energy requirements and the spinning reserve requirements. In these cases, the price for spinning reserve should theoretically reflect the reliability cost of being short of the required reserves.

The cost to the system of being short of spinning reserve should be reflected in the spinning reserve penalty price. This value was roughly $100 per MWh in 2009. This prevents the real-time market from taking actions more costly than $100 to maintain its spinning reserves.

Although it would be most efficient for prices to be set at the penalty price when the system is short of spinning reserves, this is not always the case because the Midwest ISO relaxes its spinning reserve requirement when it is short.

The next figure shows the shortage quantity and price for every shortage in 2009. The average spinning reserve price during these events was $77. However, the prices are widely dispersed and many of largest deficits are often priced the lowest. The second largest shortage exhibited a price of less than $10 per MWh. This suggests that the relaxation methodology is distorting spinning reserve prices – we recommend that the Midwest ISO discontinue the relaxation and set prices based on the penalty price during shortages.
The Midwest ISO began directly deploying reserves during DCS and ARS events in 2009. There were nine supplemental reserve deployments in 2009. The figure shows the amount successfully deployed within 10 minutes, within 30 minutes, and not deployed within 30 minutes during each of these events. The figure shows that the response of the supplemental reserves to deployments was not good in 2009. On average, only 39 percent of the reserves were successfully deployed within 10 minutes, with an additional deployment of 32 percent within 30 minutes. On average, 142 MW of the deployments did not respond within 30 minutes. This can have a significant impact on reliability and raises concerns that some suppliers may be selling reserves they are knowing not capable of deploying. In response to the poor response to deployments in 2009, the Midwest ISO has proposed tariff changes to add additional testing and verification requirements for offline supplemental reserves. Resources failing to deploy during events or during tests will lose bid qualification until subsequent successful testing is completed. This should help, but may not entirely address the issue. Scrutiny on this issue has led some participants to reduce their offer quantities from less reliable units, which has contributed to better performance in 2010 to date.

Non-Responsive Supplemental Reserve Deployments 2009
Day-Ahead and Real-Time Generation

- The following figure details the average monthly generation scheduled in the day-ahead and real-time markets.

- It shows generation capability is generally greater in the real-time market because:
  - Some resources are self-scheduled by participants after the day-ahead market;
  - Generation is committed after the day-ahead market when load increases from the day-ahead, when net imports decrease, or when net virtual supply must be replaced in real time;
  - Intermittent generation, particularly wind, often increases in the real-time market.

- The figure shows load was considerably lower in 2009 than in prior years, but was more fully scheduled.

- The figure also shows there is more of dispatch flexibility in the real-time market compared to prior years.
  - The dispatchable range (dispatch max less dispatch min) dropped seven percentage points on average, from 36 percent in day-ahead to 29 percent in real time.
    - This drop is the result of an increase in dispatch min or decrease in dispatch max.
    - In prior years this drop was much more substantial (approximately 10 percentage points), indicating much more available flexibility.
  - This increased flexibility is likely due to the introduction of the ASM markets and the Price Volatility Make-Whole Payment (“PVMWP”), both of which improve suppliers’ incentives to be flexible.
Changes in Supply from Day-Ahead to Real-Time

- Changes in load and imports from day-ahead can create a need to commit additional capacity in the real-time market. The next analysis details another reason for real-time commitments: changes in physical availability between day-ahead and real-time.

- On average, 3.2 GW (6 percent) of capacity scheduled in the day-ahead was unavailable for real-time market dispatch in 2009.
  - This is an increase of almost 10 percent from 2008 and is primarily attributable to increases in lost capacity from intermittent wind generation.
  - Other reasons for decreases in available capacity in real-time are forced outages, de-commitments (whether by generator owner or Midwest ISO), and decisions by schedulers to not start and buy back energy at the real-time price.

- The capability lost in real-time was partially offset by almost 1 GW of average increases in capacity from units scheduled in day-ahead increasing their dispatch max in real-time.
  - The remainder of this capacity was replaced by Midwest ISO-directed commitments or self-scheduling of resources by scheduling coordinators.

- A recent software change has been made to mimic the real-time headroom requirement in the day-ahead model. This should increase the day-ahead commitment and thereby reduce the need for additional units to be started in the real-time market.

---

Changes in Supply from Day-Ahead to Real-Time

2009

- Self-Committed in RT
- Increased RT Dispatch Max
- Committed Capacity for Congestion Management
- Derated in RT (Capacity not Cleared in DA)
- Derated in RT (Capacity Cleared in DA)
- Not Online in RT (Scheduled DA)
- Net Change in Capacity (DA minus RT)
The next two figures show the change in the dispatchable range offered by online generators between 2008 and 2009.

- The dispatch range is the range between each online unit’s economic maximum and economic minimum – and is the range in which the real-time market can dispatch the unit.

- Flexibility increased substantially across all unit types in 2009. The introduction of the ASM markets contributed to the improved flexibility in the following ways:
  - Quantity of AS products a supplier can sell is limited by the dispatch range and ramp rates.
  - Day-Ahead Margin Assurance Payment -- makes generators whole if they are harmed by responding flexibly in periods when prices are volatile.
  - Output ranges previous held out of the real-time market to provide ancillary services are now available to the real-time market and co-optimized with energy.

- The vast majority of the Midwest ISO’s flexibility is provided by steam turbines.
  - Combustion turbines were most flexible on average – flexible turbines are more likely to be committed in real time since they will have lower commitment costs.
  - Although flexibility increased significantly in 2009, it is still lower than the full physical flexibility that many generators could provide.
  - Any loss in flexibility can affect the market by limiting redispatch options for managing congestion, which this is evaluated later in the report.

### Real-Time Dispatchable Range

#### Real-Time Dispatchable Range 2008 – 2009

![Graph showing Real-Time Dispatchable Range 2008 – 2009](chart.png)
Revenue Sufficiency Guarantee Payments
Day-Ahead and Real-Time

- The next two figures show monthly RSG payments in the day-ahead and real-time markets that are made to peaking units and other units.
  - RSG payments are made to ensure that the total market revenue a generator receives when its offer is accepted is at least equal to its as-offered costs.
  - Resources that are not committed in the day-ahead market, but must be started to maintain reliability, are likely recipients of RSG payments – this is “real-time” RSG because such units receive their revenue from the real-time market.
  - Because the day-ahead market is financial, it generates very little RSG – a unit that is uneconomic will generally not be selected.
  - Peaking resources are typically the most likely to warrant an RSG payment because they are generally on the margin (i.e., the highest-cost resources) when they run and frequently do not set the energy price (i.e., the price is set by a lower-cost unit).
- To exclude the effects of fuel price changes, the figures adjust the RSG costs for changes in fuel prices based on the fuel prices prevailing at the end of the year.
- The figures show that over 90 percent of RSG is generated in the real-time market.
  - This is expected because the commitments needed for reliability occur after the day-ahead market.

Revenue Sufficiency Guarantee Payments
Day-Ahead and Real-Time

- The first figure that includes all real-time RSG shows:
  - Over 70 percent of the RSG was paid to units committed for capacity reasons in 2009. This is surprising because load was much more fully scheduled day ahead in 2009 than in prior years.
  - Two-thirds of real-time RSG payments were made for peaking resources, even though they produced less than 1 percent of total energy generated in 2009. This is not surprising because peaking resources are the highest cost units and the most available in real time.
- Nominal real-time RSG costs fell 47 percent in 2009 to $111 million. The sharp decline is attributable to:
  - Lower fuel prices in 2009 – on a fuel-adjusted basis, RSG costs were largely unchanged.
  - Fully scheduled load in the day-ahead for most months of the year.
- Reduced reserve requirements and improvements in commitment processes contributed to a decline in RSG costs after the first 3 months under ASM.
- The second figure shows day-ahead RSG, which increased 2.7 percent to almost $16 million in 2009 on a nominal basis.
  - On a fuel-adjusted basis, day-ahead RSG costs doubled.
  - However, it continues to be a small percentage (12.4 percent) of total uplift costs in the market.
The Midwest ISO introduced the Price Volatility Make Whole Payment ("PVMWP") along with ASM to ensure adequate cost recovery in the real-time.

- The PVMWP ensures that suppliers responding flexibly to the Midwest ISO’s prices and following its dispatch signals are not harmed by doing so.
- The payment should therefore eliminate a generator’s incentive to ignore dispatch signals or operator instructions when it is potentially uneconomical to do so.

- The payment consists of:
  - Day Ahead Margin Assurance Payment ("DAMAP"), paid to a qualified resource when real-time prices are insufficient to allow recovery of their incremental energy costs through the LMP; and
  - Real Time Operating Revenue Sufficiency Guarantee Payment ("RTORSGP"), paid to a qualified resource that is manually redispatched.

- Payments have increased late in 2009 as fuel prices and energy prices increased, and totaled $44.2 million. These payments consisted of:
  - $34.4 million of DAMAP; and
  - $9.8 million of RTORSGP.

- A large majority of DAMAP payments were made to selected flexible coal units during peak hours, particularly during the second half of the year.
The following figure analyzes the real-time RSG distribution data by week and region and shows more clearly when and where RSG costs were incurred.

As detailed elsewhere in this report, the summer peak was extremely mild relative to prior years and the 2009 Summer Assessment. Accordingly, the RSG costs incurred during these weeks was minimal.

- High day-ahead load scheduling and low fuel prices contributed to low RSG payments.
- RSG payments exceeded $5 million during one week in 2009, compared to 11 weeks in 2008.

Many of the highest weekly RSG costs were caused by transmission congestion.

- During the winter in early 2009, the West region incurred more RSG costs than during the rest of 2009 due to extreme winter weather and forced generation outages.
  - Overall, RSG payments in the West are 63 percent lower in 2009 than in 2008.
- The East region had the largest share of RSG costs due to:
  - Transmission outages on market-to-market flowgates;
  - Transmission outages related to upgrades projects in Michigan in the fall; and
  - The fact that a large portion of the units committed for capacity are in the East.
- Reduced congestion into WUMS due to transmission upgrades contributed to a 66 percent year-over-year reduction in RSG payments to units in WUMS.
We conducted a study of RSG cost causation and attribution, quantifying the contributions of various factors to real-time RSG costs.

The study is based on a detailed analysis of individual real-time unit commitments that resulted in RSG Make-Whole Payments.

This study intended to estimate the direct effects of various generation and load deviations on real-time RSG costs.

- These direct effects are estimated based on a detailed analysis of individual real-time commitments. Indirect effects are not included in the study.

Once all real-time commitments that result in an RSG payment are identified, the analytic process includes the following basic steps:

- Determine whether the commitment was made to satisfy the systems capacity needs or to manage a transmission constraint (and the extent to which it is needed).
- Identify all types of deviations that contributed to the need for the commitment.
- Attribute RSG costs for each commitment to a) deviations, b) other factors (non-deviations), or c) “need unknown” (need for the commitment not identified).

“Need unknown” does not indicate that the commitment should not have been made. Uncertainties regarding load, generation availability, loop flows, etc. may justify these commitments and we may not have the information the operator relied upon.

We have estimated the amount of RSG that may be attributed to 17 types of deviations and those that are not attributable to deviations.

The results of this analysis are shown by month in the following figure and are grouped into the following classes:

- RSG cost attributed to commitments whose need is not apparent (23 percent);
- RSG cost attributed to needed commitments that were not deviation-related (19 percent); and
- RSG cost attributed to deviations (58 percent), which includes:
  - the 8 types of generation and load deviations that currently incur RSG cost under the Interim Rate allocation (51 percent);
  - the 7 types of deviations that are explicitly exempt from RSG costs under the Interim Rate allocation (6 percent); and
  - the 2 types of deviations that are not explicitly exempt, but that do not incur RSG costs under the Interim Rate allocation (i.e., virtual load and wheels) (1 percent).

The figure also shows:

- Roughly two-thirds of RSG payments during the period for capacity-related commitments.
- RSG costs decreased substantially over the year as fuel prices decreased.
Attribution of RSG Costs by Factor
January 6, 2009 to December 31, 2009

$18 $16 $14 $12 $10 $8 $6 $4 $2 $0
RSG Costs ($ Millions)

Note: Due to data limitations, the “Factors Paying RSG” class includes deviations from participants that have “carve-out” rights associated with grand-fathered agreements (“GFAs”) that are not allocated RSG.

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Results of RSG Attribution Analysis

- The next figure provides a more detailed breakdown of the RSG attribution results.
- For the capacity commitments and the constraint-related commitments, this figure provides the total real-time RSG costs that we attribute to each type of deviation.
- The most important conclusion from this analysis is that the deviations that currently bear virtually all of the real-time RSG costs only cause about half of it.
  - This results in inefficient incentives for the participants responsible for those deviations.
  - The implementation of a revised RSG cost allocation should address this issue.
- This figure also shows:
  - Two of the 7 exempt factors do not contribute to a material amount of real-time RSG costs (units in testing and contingency reserve deployments).
  - Three of the remaining 7 factors taken together in the “other exemptions” contribute to significantly less than one percent of the real-time RSG costs (units following Midwest ISO instructions, tripping offline, or affected by other conditions).
  - The units starting/stopping and units covered by the deactivation of dispatch bands each contributed to approximately one percent of the real-time RSG costs.
  - Of the 7 exempt factors, the largest quantities of real-time RSG costs were caused by intermittent resources, totaling more than 4 percent of the real-time RSG costs. Most of this quantity was caused by the wind resources (approximately 3 percent).
## Attribution of RSG Costs by Factor
### January 6, 2009 to December 31, 2009

<table>
<thead>
<tr>
<th>Factor</th>
<th>Capacity</th>
<th>Constraint</th>
<th>Total</th>
<th>Share</th>
</tr>
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<tbody>
<tr>
<td>Need Unknown</td>
<td>$6.68</td>
<td>$18.29</td>
<td>$24.97</td>
<td>23%</td>
</tr>
<tr>
<td>Not Deviation Related</td>
<td>9.17</td>
<td>12.04</td>
<td>21.21</td>
<td>19%</td>
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<tr>
<td>Other Exemption</td>
<td>0.52</td>
<td>0.06</td>
<td>0.58</td>
<td>0.5%</td>
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<tr>
<td>Testing</td>
<td>0.00</td>
<td>0.02</td>
<td>0.02</td>
<td>0.0%</td>
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<tr>
<td>Start Stop</td>
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<td>0.08</td>
<td>0.52</td>
<td>0.5%</td>
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<tr>
<td>Intermittent</td>
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<td>0.20</td>
<td>1.05</td>
<td>1.0%</td>
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<td>0.68</td>
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<td>3.1%</td>
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<td>0.00</td>
<td>0.03</td>
<td>0.0%</td>
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<tr>
<td>Dispatch Bands</td>
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<td>0.11</td>
<td>1.46</td>
<td>1.3%</td>
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<tr>
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<td>0.74</td>
<td>0.74</td>
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<tr>
<td>Wheels</td>
<td>0.00</td>
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<td>0.10</td>
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<tr>
<td>Must-Run</td>
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<td>0.15</td>
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<td>0.89</td>
<td>11.12</td>
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<tr>
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</tr>
<tr>
<td>Excessive Energy</td>
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<td>0.01</td>
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</tr>
<tr>
<td>Virtual Supply</td>
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<td>12%</td>
</tr>
<tr>
<td>Exports</td>
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<tr>
<td>Imports</td>
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<tr>
<td>Load</td>
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<td>1.48</td>
<td>19.61</td>
<td>18%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$72.01</td>
<td>$37.03</td>
<td>$109.04</td>
<td>100%</td>
</tr>
</tbody>
</table>

Note: Due to data limitations, the eight types of deviations at the bottom of the table includes deviations from participants that have “carve-out” rights associated with GFAs that are not allocated RSG.

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## Dispatch of Peaking Resources

- As discussed above, the dispatch of peaking resources is important because it is a driver of RSG costs and a determinant of efficient energy pricing.
- The following figure summarizes the dispatch of peaking resources in 2009, showing the average hourly dispatch of peaking units by day.
- An average of 227 MW were dispatched per hour in 2009, down slightly from 267 MW from 2008.
  - A heat wave in late June led the Midwest ISO to commit 3,500 MW in peaking units, the highest hourly dispatch of the year.
- The reduction in dispatch of peaking resources can be attributed to a number of factors:
  - Load was more fully scheduled in the day-ahead market so less load had to be satisfied through real-time commitments;
  - A drop in peak load levels, which resulted in fewer conditions that required peaking resources; and
  - A modest decrease in congestion, which can require the commitment of peaking resources to relieve the constraint.
Dispatch of Peaking Resources

- The figure also evaluates how consistent the peaking resource dispatch is with market outcomes by showing the shares of the peaking resource output that are in-merit (LMP > offer price) and out of merit (LMP < offer price).

- Approximately 33 percent of the peaking resources were in-merit in 2009 (down from 45 percent in 2008), indicating that they continue to set the energy price infrequently.
  - This is not uncommon since gas turbines often have a very narrow operating range and therefore operate at their minimum or maximum.

- When peaking (or demand response) resources are the most economic option for meeting the markets’ demands, but do not set prices, real-time prices will be inefficiently low.
  - This affects the incentives to schedule in the day-ahead market and, ultimately, the commitment of resources that is coordinated by the day-ahead market.
  - A suboptimal commitment coming out of the day-ahead will tend to raise real-time costs.
  - Inefficiently low real-time prices when peaking resources are dispatched also distorts the incentives of participants to import and export power efficiently.

- We have recommended changes to improve real-time pricing by allowing peaking resources and demand resources to set prices.
  - The Midwest ISO has done substantial work to develop a feasible approach in this area.

Daily Peaker Dispatch and Prices
2009, All Hours
Day-Ahead Scheduling versus Real-Time Wind Generation

- Wind generation and capacity have increased rapidly in the Midwest ISO market and are expected to continue to increase due to favorable wind resource potential in the West, state renewable portfolio standards, and various state and federal subsidies.
- Wind generation promises substantial environmental benefits.
  - However, as an intermittent resource, it presents special operational challenges as it becomes a greater percentage of the market and regional generation mix.
- The following slide shows the wind generation scheduled in the day-ahead and real-time markets.
  - The intermittent nature of wind presents forecasting and scheduling challenges.
  - The chart shows the continued rapid growth of wind generation and seasonality of wind. Wind generation is higher during shoulder months.
  - The chart also shows wind generation tends to be under-scheduled in the day-ahead market.
    - This creates price convergence issues in western areas and can lead to uncertainty regarding the need to commit resource for reliability.
  - The uncertainty of wind output can cause real-time RSG costs that are not currently allocated to wind suppliers because it is an intermittent resource.
    - The Midwest ISO filed with FERC to remove this exemption on December 7, 2009.


<table>
<thead>
<tr>
<th>Month</th>
<th>Day-Ahead Wind</th>
<th>Real-Time Wind</th>
<th>Difference</th>
</tr>
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<tbody>
<tr>
<td>Jan - 08</td>
<td>3,500</td>
<td>3,000</td>
<td>-500</td>
</tr>
<tr>
<td>Feb - 08</td>
<td>3,000</td>
<td>2,500</td>
<td>-500</td>
</tr>
<tr>
<td>Mar - 08</td>
<td>2,500</td>
<td>2,000</td>
<td>-500</td>
</tr>
<tr>
<td>Apr - 08</td>
<td>2,000</td>
<td>1,500</td>
<td>-500</td>
</tr>
<tr>
<td>May - 08</td>
<td>1,500</td>
<td>1,000</td>
<td>-500</td>
</tr>
<tr>
<td>Jun - 08</td>
<td>1,000</td>
<td>500</td>
<td>-500</td>
</tr>
<tr>
<td>Jul - 08</td>
<td>500</td>
<td>0</td>
<td>-500</td>
</tr>
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<td>Sep - 08</td>
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<tr>
<td>Nov - 08</td>
<td>-1,500</td>
<td>-2,000</td>
<td>-500</td>
</tr>
<tr>
<td>Dec - 08</td>
<td>-2,000</td>
<td>-2,500</td>
<td>-500</td>
</tr>
</tbody>
</table>

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Wind Generation Capacity Factors by Load Hour Percentile

- Wind capacity factors (actual output ÷ maximum output) vary substantially across the footprint by region, hour, season, and temperature. They have been higher:
  - In the western portion of the footprint where the wind is stronger;
  - During off-peak hours than during on-peak hours;
  - During the winter and spring than during the summer and fall; and
  - When temperatures are mild.
- The following figure shows average hourly wind capacity factors by load hour percentile, season, and region.
  - The figure shows wind output (reflected in the capacity factors) is generally negatively correlated with load, particularly in the summer.
    - Capacity factors are lowest when the output is most needed.
    - The spread between western and eastern capacity factors is larger in the winter than the summer, but decreases at the highest load levels.
  - These results are consistent with the Midwest ISO’s analysis supporting the reduced capacity credits for wind resources from 20 percent to 8 percent.

Wind Generation Capacity Factors by Load Hour Percentile, 2009

- The figure shows wind output (reflected in the capacity factors) is generally negatively correlated with load, particularly in the summer.
  - Capacity factors are lowest when the output is most needed.
  - The spread between western and eastern capacity factors is larger in the winter than the summer, but decreases at the highest load levels.
  - These results are consistent with the Midwest ISO’s analysis supporting the reduced capacity credits for wind resources from 20 percent to 8 percent.
Manual Redispatch

- The following figure shows all redispatch actions performed manually by the Midwest ISO operators (rather than through the real-time market).
  - This is usually done when the output of a unit that is not dispatchable must be changed to manage congestion or address a local reliability issue.
- The figure shows that the vast majority of manual redispatches were of wind units.
  - On average, 25 MW of wind was curtailed per interval in 2009.
  - Wind units were curtailed in 36 percent of intervals, with an average of 70 MW per interval.
  - During certain intervals, as much as 600 MW was manually redispatched.
  - Since wind units are not dispatchable currently, operators have to manually redispatch them when their output is overloading a constraint.
    - The manual curtailment of wind units is often an inefficient way to relieve congestion.
    - The Midwest ISO is currently working on an initiative to allow wind units to be dispatchable and to set LMPs.
- Manual redispatch of non-wind units are exceedingly rare, averaging less than 1 MW per interval.

Manual Redispatch 2009

Average Amount Curtailed per Interval (MW)

- Negative (Non-Wind)
- Positive (Non-Wind)
- Negative (Wind)
Real-Time Market: Conclusions

- The Midwest ISO’s real-time market continues to perform relatively well.
  - The nodal market accurately reflected the value of congestion in the Midwest ISO.
  - The introduction of ancillary services markets went smoothly and operate as expected.
  - The ASM markets have led to increased dispatch flexibility and contributed to lower real-time price volatility.
- The performance of the real-time market is compromised in some cases by:
  - Reduced dispatch flexibility offered by many generators, which can make congestion more difficult to manage. This has improved substantially in 2009 but remains an issue.
  - The absence of a real-time model that optimizes the commitment and de-commitment of peaking resources.
  - Prices that do not always reflect the costs of peaking resources or demand resources when they are the marginal source of energy.
  - The current state of the integration of wind resources into Midwest ISO markets.
- These issues are addressed by the recommendations at the end of this sections.

Real-Time Market: Recommendations

- We recommend the following changes to the real-time market:
- Develop a “look-ahead” capability in the real-time that would facilitate better management of ramp capability and commitment of peaking resources.
  - The Midwest ISO’s commitment of peaking resources can be improved by using an economic model to commit and de-commit peaking units.
  - This look-ahead capability could include a multi-period dispatch optimization to move slower-ramping units in anticipation of system demands over the ensuing hour.
  - Better management of ramp needs and commitment of gas turbines would reduce out-of-merit quantities, reduce RSG payments, and improve energy pricing.
  - We recommended this previously and the Midwest ISO has initiated a project to develop these capabilities.
- Develop real-time software and market provisions that allow gas turbines running at their EcoMin or EcoMax to set the energy prices.
  - This change would improve the efficiency of the real-time prices, improve incentives to schedule load fully in the day-ahead market, and reduce RSG costs.
  - The Midwest ISO has a project underway to develop a feasible approach.
• Develop provisions that allow demand response resources to set energy prices in the real-time market when they are called upon in a shortage.
  ✓ It would also improve price signals in the highest-demand hours, which is important for ensuring that the markets send efficient economic signals to:
    – Develop and maintain adequate supply resources; and
    – Develop additional demand response capability.
  ✓ It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.

• Improve the integration of wind resources in the Midwest ISO system by allowing them to be curtailable at a specified offer price and be eligible to set prices in the energy market.

• Improve the performance of the spinning reserve and energy markets by:
  ✓ Improving the consistency between the reliability requirement for spinning reserves and the market requirement.
  ✓ Allowing the spinning reserve penalty price to set the price in the spinning reserve market (and be reflected in energy prices) during spinning reserve shortages by not relaxing the requirement.

• Evaluate the formula for the regulation penalty price to ensure that it accurately reflects the costs of committing peaking resources in the Midwest ISO.

• Improve the real-time operation of the system by:
  ✓ Optimizing the use of the load offset to improve the Midwest ISO’s management of ramp capability in the near term.
  ✓ Reducing the system ramp that is consumed by interval-to-interval changes in real-time load by improving the STLF used by the real-time market.
Transmission Congestion and FTR Results

- One primary function of Midwest ISO energy markets is to deliver lowest-cost supply to load while respecting the limitations of the transmission network.
- The locational market structure in the Midwest ISO generally ensures that the transmission capability will be fully utilized and that the marginal value of energy will be reflected in the price at each location.
- When transmission system limits require higher-cost resources to be dispatched to serve the load (i.e., a transmission constraint is binding), the prices on either side of the transmission constraint will diverge.
  - This results in congestion costs being incurred that reflect the cost of relieving the transmission constraint.
  - The congestion costs collected by the Midwest ISO in the day-ahead market are paid to holders of FTRs, who use them to hedge the congestion costs.
  - Congestion persists over the long-run because investment to relieve congestion should be made only when the marginal investment cost is lower than the marginal congestion cost.
- This section of the report evaluates the congestion costs, FTR market results, and the Midwest ISO’s management of congestion.
The first figure in this section shows total congestion costs by month in the Midwest ISO market from 2007 through 2009.

Day-ahead congestion costs declined almost 40 percent from 2008 to 2009 to $305 million. This reduction was due to reduced gas prices (which lowers redispatch costs), lower average load, and transmission improvements.

- Day-Ahead congestion costs were higher in the last four months of the year as economic conditions improved and gas prices increased.

Real-time congestion costs more than doubled compared to 2008:

- These costs are incurred when the transmission capability is:
  - Reduced from day-ahead to real time; or
  - Used by “loop flows” caused by entities outside of the Midwest ISO.

- In both cases, the Midwest ISO must often redispatch generation in real-time to reduce the flows over an interface that was scheduled in the day-ahead market.

- Normally one would expect the real-time congestion to be very low if the modeling of the network is consistent between the day-ahead and real-time markets.
  - However, unexpected loop flows, real-time transmission outages, and real-time TLRs for external constraints can all contribute to increased balancing congestion.

### Total Congestion Costs

<table>
<thead>
<tr>
<th>2007</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>DA Congestion Cost</td>
<td>632,878,942</td>
<td>500,251,809</td>
</tr>
<tr>
<td>RT Congestion Cost</td>
<td>81,862,328</td>
<td>79,777,492</td>
</tr>
</tbody>
</table>
Market participants purchase or are allocated FTR rights that entitle them to congestion costs that arise between specific locations on the network.

- Shortfalls or surpluses occur when the FTRs held by participants represent more or less transmission capacity than the physical transmission system.
  - A surplus may occur when the Midwest ISO sells fewer FTRs than the physical capability of the network;
  - A shortfall may occur when transmission outages or other factors cause the network capability to decrease relative to the capability in the FTR model used to sell FTRs.
  - “Loop flows” over the network caused by activity outside the Midwest ISO can also lead to shortfalls or surpluses if they differ from the quantities assumed in the FTR model.

The following figure compares the day-ahead congestion revenue to the FTR entitlements.

- When the revenue is insufficient to satisfy the FTR entitlements, the market will have a shortfall that is remedied by reducing the payments to all FTRs on a pro rata basis.

The figure shows the day-ahead congestion collections continued to be substantially less than FTR obligations (20 percent in 2009).

- The shortfall was 16.3 and 19.6 percent in 2008 and 2007 respectively.
- Shortfalls are undesirable because they introduce uncertainty regarding the value of the FTRs and ultimately reduce the revenues from the FTR market.

- Shortfalls occurred in most months in 2009. They were smallest in the summer months in 2009 before increasing during the fourth quarter.
- The Midwest ISO has continued to work on the FTR allocation and modeling to reduce shortfalls. Changes made in FTR modeling in June 2008 intended to:
  - Improve loop flow assumptions in the FTR market;
  - Add constraints related to market-to-market and non-market constraints; and
  - Generally reduce transmission line ratings to account for expected changes to the system due to outages.

- While the improvements introduced in 2008 contributed to lower shortfalls in 2009, we have recommended further improvements.
- The Midwest ISO has recently proposed a new initiative to enhance screening for topology discrepancies between the planning and actual system topology.
Day-Ahead Congestion and Payments to FTR Holders
2007 – 2009

The following figure shows the monthly payments and obligations to FTR holders, including payments to FTR Option B and Carve-out FTRs (which are alternative forms of FTRs made available to participants with grandfathered agreements).

The figure shows the vast majority of the payments were made to FTR holders, as opposed to payments to FTR Option B and Carve-out FTRs.

- As in prior years, approximately 95 percent of all payments were made to holders of conventional FTRs.
- The low magnitude of payments for these other types of rights is encouraging because they do not provide the same efficient incentives as FTRs do.

As discussed above, funding shortfalls declined in 2009 on an absolute basis, but increased as a percentage of obligations.

- We recommend improvements later in this section that would likely further reduce the day-ahead shortfall.
The Midwest ISO uses radial constraints to limit the day-ahead flow to selected generator locations when excessive virtual loads are submitted at them.

- Virtual load at these locations can result in infeasible day-ahead model solutions because the model reflects the low voltage facilities at the unit site (i.e., the step up transformer to bring the power onto the higher-voltage network is modeled).
- Radial constraints generally have GSF of -1 so all power sinking at the generator point flows over the constraint and no other locations affect the constraint.
- The radial constraints ensure the day-ahead market will solve, but can cause congestion that would never exist in the real-time market (because there is no physical load that could cause power to flow to the generator location).
- Because these constraints have not generally been reflected in the FTR market, it is possible more FTRs may sink at the generator locations than the radial constraints would support, which can cause FTR shortfalls and enable manipulation.

The next figure shows day-ahead congestion and FTR shortfalls for radial constraints.

- Radial constraints generated roughly one percent of the total day-ahead congestion, but accounted for almost 8 percent of the FTR shortfalls.
- The Midwest ISO is taking steps to limit shortfalls by including radial constraints in the FTR market, but we recommend it strive to remove these constraints from the day-ahead market since this congestion cannot exist in the real-time market.
Radial Constraints and FTR Underfunding
2009

<table>
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<th></th>
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<td>FTR Underfunding</td>
<td>3,571,136</td>
</tr>
<tr>
<td>FTR Obligations for Radial Constraints</td>
<td>5,788,662</td>
</tr>
</tbody>
</table>

The prior figures showed the congestion collected through the Midwest ISO markets. This can vary substantially from the congestion that occurs physically in real time.

The next figure shows the value of real-time congestion by region.

- The value of real-time congestion is equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
- Real-time congestion totaled $863 million in 2009, down 8 percent from $938 million in 2008. These values continue to be much higher than the congestion collected by the Midwest ISO due to:
  - Loop flows that use some of the network capability without paying,
  - PJM’s entitlements on the Midwest ISO system; and
  - Poor price convergence in western areas of the Midwest ISO affected by congestion.
- Over two-thirds of all real-time congestion occurs in the eastern half of the footprint.
  - Congestion is down 10 and 14 percent in the East and Central, respectively.
- Congestion in the West rose 50 percent (to $167 million) due to increasing supply.
- Transmission upgrades contributed to lower congestion into WUMS in 2009.
- The figure also shows that transmission constraints were binding more frequently (up almost 20 percent) as more low voltage constraints began binding.
The next figure shows the value of real-time congestion by type of constraint. It is computed in the same manner as in the previous analysis.

- Congestion occurs on external constraints when a TLR is called on a neighboring system that causes the Midwest ISO to re-dispatch its generation.
- As in prior years, most of the congestion in 2009 occurred on Midwest ISO internal constraints (including Midwest ISO market-to-market constraints).
  - In total, Midwest ISO constraints (internal and market-to-market) represent over 90 percent of the congestion value.
  - In 2009, the top five congested lines comprised 61 percent of all market-to-market congestion, down from 72 percent in 2008.
  - Thirty-one percent of all market-to-market congestion occurred on one constraint.
- Congestion on non-Midwest ISO constraints (PJM market-to-market and external) was modest in 2009 and remains a small portion of overall real-time congestion.
  - PJM market-to-market congestion fell 32 percent to $72 million, while external congestion fell nearly 50 percent to $10 million.
- We review market-to-market results in more detail later in this report.
The NERC TLR Procedure is an Eastern Interconnection-wide process that allows reliability coordinators to mitigate potential or actual operating security limit violations while respecting transmission service reservation priorities.

As we have detailed in prior reports, it is an inefficient and less reliable means of managing system congestion.

LMP markets help to efficiently manage most internal congestion through redispatch rather than the curtailment of scheduled transactions through the TLR process.

TLR levels include:
- Level 3 – non-firm curtailments;
- Level 4 – commitment or redispatch of specific resources or other operating procedures to manage specific constraints; and
- Level 5 – curtailment of firm transactions.

The next figure shows TLR activity by level on MISO flowgates from 2007 to 2009.
- In 2009, TLR flowgate-hours fell 46 percent compared to 2008, while GWh curtailed decreased 44 percent.
- The more severe Level 4 and 5 TLRs have been virtually eliminated since 2007.

Although significant quantities of TLRs are still called to ensure that transactions external to the Midwest ISO are curtailed when they cause congestion, the Midwest ISO relies primarily on economic redispatch to manage congestion.
Constraints are sometimes difficult to manage if the available redispatch capability of the generators that affect the flow on the constraint is limited.

- When there is insufficient redispatch capability to reduce the flow below the limit in the next five-minute interval, we consider the constraint “unmanageable”.
- The presence of an unmanageable constraint does not mean the system is unreliable – reliability standards generally require the flow to be less than the limit within 30 minutes.
- When a constraint is unmanageable, an algorithm “relaxes” the limit for the constraint for purposes of calculating a shadow price for the constraint and the associated LMPs.

The next figure shows the frequency with which constraints were unmanageable in each month in 2008 and 2009. This figure shows:

- The number of constrained hours increased significantly in 2009 compared to 2008.
- Manageability improved in 2009:
  - 21 percent of internal congestion costs were unmanageable in 2009, compared to almost 28 percent in 2008.
  - The introduction of the ASM markets and PVMWP in 2009 has led to increased generation flexibility, which improves manageability.
  - The Midwest ISO has also modified a number of real-time modeling parameters in response to prior IMM recommendations that have increased the amount of congestion relief available to the real-time market.
The next analysis examines the manageability of constraints by voltage level.

Due to the physical properties of electricity, more power tends to flow over higher-voltage lines and a wider array of generators tend to affect these flows.

- Low voltage constraints must typically be managed with a smaller set of more locals generating resources.
- This can make low voltage constraints more difficult to manage.

The figure shows that the manageability of the constraints at all but lowest voltage level improved substantially in 2009 because:

- The Midwest ISO implemented several recommendations that increased the amount of relief available to the real-time market; and
- Under ASM, more generator flexibility has been available to the real-time market.

The figure also shows that in 2009, the manageability of higher voltage constraints was much better than on lower voltage constraints.

- Nearly 40 percent of the lowest voltage facilities were unmanageable in 2009.
- This suggests that the Midwest ISO has accepted responsibility for facilities that it lacks the resources to effectively manage.
- We recommend that the Midwest ISO establish criteria for determining when it should secure these low voltage facilities.
Pricing Unmanageable Transmission Constraints

- Midwest ISO employs a “constraint relaxation algorithm” to produce a shadow price when a constraint is violated (the economic value of the constraint used to calculate LMPs).
- The next figure shows “unmanageable” constraint hours by voltage level.
  - The purpose of this figure is to determine whether the LMPs fully reflect the violated constraint – i.e., shadow prices close to 100 percent of the marginal value limit.
- The figure shows that:
  - Almost three-quarters of unmanageable constraints occur on constraints rated 138 kV or lower, and manageability is the worst on the lowest voltage constraints.
  - The constraint relaxation algorithm produces shadow prices that are substantially below the MVL for violated constraints, particularly on low voltage constraints.
    - It produces a zero shadow price for 42 percent of the violated low voltage constraints.
    - Less than 20 percent of all violated constraints have shadow prices above 90 percent of MVL.
- Based on our analysis, we conclude that this algorithm often produces inefficient shadow prices that distort the associated LMPs -- the shadow price and associated LMP should be equal to the reliability cost of violating the constraint (the MVL).
- Hence, we continue to recommend that the Midwest ISO discontinue use of the relaxation algorithm and set prices based on the constraint penalty factors.
Pricing of Unmanageable Congestion by Voltage Level

2009

<table>
<thead>
<tr>
<th>69-115kV</th>
<th>138kV</th>
<th>161-230kV</th>
<th>345kV</th>
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<tbody>
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<td>0-30</td>
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<td>90+</td>
</tr>
</tbody>
</table>

Shadow Price as Percent of Marginal Value Limit

Balancing Congestion Costs

- Like all other settlements in the real-time market, real-time balancing congestion costs should be related only to deviations from the day-ahead schedules.
  - Because the real-time settlements are only for deviations from the day-ahead schedules, real-time congestion charges should be zero as long as the transmission limits and external loop flows assumed in the day-ahead market have not changed.
  - Inconsistencies in limits, loop flows, or other modeling inputs can compel the Midwest ISO to incur real-time congestion costs to reduce the flow on constrained facilities from the day ahead to real time, which is recovered through uplift charges.
- The next figure shows the real-time congestion costs from 2007 to 2009.
  - Balancing congestion costs totaled $18 million in 2009, up from $9 million in 2008 but substantially below the $80 million incurred in 2007.
    - The lower costs in recent years are due to improvements made in the day-ahead modeling of loop flows and an overall decrease in congestion.
    - No month incurred more than $5 million in costs in 2009.
  - Occasional negative balancing congestion costs reflect payments received from PJM for market-to-market coordination, which totaled $38 million in 2009.
    - Settlement revenues are detailed in the External Transactions section of this report.
Balancing Congestion Costs
2007 – 2009

- $30
- $25
- $20
- $15
- $10
- $5
- $0
- $5
- $10
- $15
- $20
- $25
- $30

FTR Profitability

- One indicator of the liquidity of the FTR markets is the profitability of the FTR purchases.
  - FTR profits are the difference between the costs to purchase the FTR and the payout on the
    FTR based on congestion realized in the day-ahead market.
  - In well-functioning, liquid FTR markets, the FTR profits should be relatively low because
    the market clearing price for the FTR should reflect a rational expectation of the congestion
    value of the FTR.
- The next two figures show the profitability of FTRs purchased in the seasonal FTR
  auctions and the monthly FTR auctions.
- The first figure shows average FTR profitability in the seasonal auctions has declined from
  more than $1.50 per MWh in fall 2005 to a loss of approximately $0.02 per MWh in 2009.
  - Peak FTRs were considerably more profitable ($29.8 million) in 2009 than off-peak FTRs
    ($15.2 million loss).
- The second figure shows average profitability in the monthly auction has been steady,
  averaging $0.29 per MWh in 2009, versus $0.22 and $0.25 in 2008 and 2007, respectively.
  - These results indicate that the liquidity and overall performance of the FTR markets has
    been good, causing FTR prices to accurately reflect their value.
FTR Profitability
Seasonal Auctions, 2007 – 2009

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FTR Profitability

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To provide further detail on the performance of the FTR markets, our next analysis examines the monthly FTR prices compared to day-ahead congestion that are payable to the FTR holders.

- We analyze values for WUMS, the Minnesota Hub, and the Michigan Hub in peak and off-peak hours.
- All values are computed relative to Cinergy Hub, which is the most actively traded location in the Midwest ISO.

In a well-functioning market, the FTR prices should reflect a reasonable expectation of the day-ahead congestion that will occur into the area.

- The profit earned by an FTR holder is the difference between the FTR price paid and the congestion paid to the FTR holder.
- Convergence between the two is not perfect – changes in congestion patterns typically do not get reflected in the auction price until the following month’s auction.
- The results in the following figures help explain the changes in FTR profitability shown in the analyses above.

The following two figures show the results for WUMS in peak and off-peak hours.

Aside from October 2009, the value of congestion at WUMS relative to Cinergy was negative in each month in 2009.

- Convergence between auction prices and congestion has modestly improved.
- The average on-peak spread in 2009 was $1.53 per MWh, down from $2.10 in 2008 (excluding June) and $5.16 in 2007.

Starting in the middle of 2008, the direction of the congestion in WUMS switched due to transmission upgrades in the region (particularly Arrowhead-Weston 345kV) and additional upgrades in 2009.

This trend is particularly pronounced during off-peak hours, as shown in the second figure.

- Congestion averaged -$4.27 per MWh during 2009 in off-peak hours.
- Volatility is lower and convergence is generally good in off-peak hours.
- The average off-peak spread between auction prices and congestion in 2009 was $4.55 per MW, unchanged from 2008.
FTR Auction Prices and Congestion
WUMS Area: Peak Hours

FTR Auction Prices and Congestion
WUMS Area: Off-Peak Hours
FTR Auction Prices and Congestion
Minnesota Hub

- As was the case with WUMS, congestion variability at the Minnesota Hub has decreased markedly since 2007 and convergence between congestion values and FTR prices has improved significantly.
  - The monthly average peak-hour spread was $2.26 per MWh in 2009, down 42 percent compared to 2008 (excluding June) and down 68 percent compared to 2007.
  - Off-peak congestion was more uniform than peak congestion in 2009 and, as with WUMS, reversed direction in the middle of 2008.
    - Off-peak volatility was down 44 and 63 percent compared to 2008 and 2007, respectively.
    - The monthly average off-peak spread was $1.79 per MWh in 2009, down 13 percent compared to 2008 (excluding June) and down 55 percent compared to 2007.
- One difficulty in valuing the FTRs is the fact that the congestion can change directions. As shown, some months have negative congestion while congestion is positive for other months.
- Both figures reveal a tendency for a slight lag in convergence, as one would expect, because FTRs are sold prior to the month in which the congestion occurs.

FTR Auction Prices and Congestion
Minnesota Hub: Peak Hours

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The next two figures provide the same analysis of the FTR prices and congestion into Michigan from Cinergy.

The value of congestion and FTR prices from Michigan to Cinergy are relatively low.

- Congestion into Michigan increased in the fall due to transmission outages associated with a number of upgrade projects.
- This resulted in congestion that was not reflected in the FTR prices, although the divergence was modest compared to WUMS and Minnesota Hubs.

Overall, these results for the Michigan Hub indicate reasonably good convergence between FTR prices and the value of day-ahead congestion.

- Convergence can be challenging on the Michigan interface because the congestion frequently switches direction, although this was not a significant issue in 2009.
- Michigan congestion is often impacted by loop flows around Lake Erie. When the Phase Angle Regulators (“PARs”) on the Midwest ISO-IESO interface are fully operational, convergence should improve.
  - Of the four PARs designed to control the interface, one is currently in operation, two more are available but not in operation, and one is being repaired.
  - Additional agreements are still needed on the PAR operation and scheduling.
FTR Auction Prices and Congestion
Michigan Hub: Peak Hours

FTR Auction Prices and Congestion
Michigan Hub: Off-Peak Hours
Market-to-Market Activity

- The next series of analyses evaluate the “market-to-market” process between the Midwest ISO and PJM, which is specified in the JOA between the RTOs.
  - The market-to-market process is used by the Midwest ISO and PJM to coordinate the relief of transmission constraints that both systems affect.
  - A market-to-market constraint is a constraint on a Midwest ISO-PJM coordinated flowgate located in either of the RTOs.
- When a market-to-market constraint is binding, the monitoring RTO sends a shadow price and an amount of relief requested (the desired reduction in flow) to the other RTO (i.e., the “reciprocating RTO”).
  - The shadow price measures the marginal cost of relieving the constraint.
  - When the reciprocating RTO receives the shadow price and requested relief, it incorporates these values in its real-time market to provide as much of the requested relief as possible at a cost less than the shadow price.
  - From a settlement perspective, each market is entitled to a certain flow on each of the market-to-market constraints (its Firm Flow Entitlement, or “FFE”). Settlements are made between the RTOs based on its actual flow over the constraint relative to its entitlement.
- This market-to-market process is essential for ensuring that generation is efficiently re-dispatched to manage these constraints, and that prices in the two markets are consistent.

- The following figure shows the total number of market-to-market constraint-hours (instances when a market-to-market constraint is binding and activated).
- The top panel represents coordinated flowgates located in the PJM system and the bottom panel represents flowgates located in the Midwest ISO.
  - The darker shade in the stacked bars are peak hours in the month when coordinated flowgates were activated, and the lighter shade represents off-peak hours.
- The figure indicates:
  - The activity on PJM market-to-market constraints in the Midwest ISO decreased 31 percent from 2008 to 2009 to 916 hours per month.
  - However, activity on Midwest ISO market-to-market constraints increased by 44 percent in 2009 to 1,000 hours per month.
  - Midwest ISO market-to-market constraints that were coordinated most frequently were west-to-east constraints impacted by Commonwealth Edison exports.
  - PJM market-to-market constraints are generally the most frequent in the summer, when the demands on the transmission system are the greatest.
Market-to-Market Activity
2008 – 2009

The following figure shows a summary of the market-to-market settlements.

- The positive values represent payments made to the Midwest ISO on coordinated flowgates and the negative values represent payments made to PJM on coordinated flowgates.
- Settlement is based on the reciprocating RTO’s actual market flows compared to its FFE.
- The drop line shows net payments to the Midwest ISO or PJM in each month.
- If a reciprocating RTO’s market flows are below its FFE then it will receive a payment for providing relief at the cost of providing that relief.
- If its flows are above its FFE, it will make a payment at the cost of the monitoring RTO’s congestion.
- The figure shows payments from PJM to the Midwest ISO decreased 12 percent in 2009, while payments from the Midwest ISO to PJM decreased almost 30 percent.
  - As in 2008, net payments were made by PJM to the Midwest ISO in each month in 2009 even though more PJM constraints are active than Midwest ISO constraints in many months.
  - Together with other results in this section, this suggests that the Midwest ISO generally provides more flow relief on PJM’s constraints than PJM does on the Midwest ISO’s.
Market-to-Market Settlements
2008 – 2009

<table>
<thead>
<tr>
<th>Settlements ($ Millions)</th>
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<tbody>
<tr>
<td>$30</td>
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<tr>
<td>$24</td>
</tr>
<tr>
<td>$18</td>
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<td>$12</td>
</tr>
<tr>
<td>$6</td>
</tr>
<tr>
<td>$0</td>
</tr>
<tr>
<td>-$6</td>
</tr>
</tbody>
</table>

Estimated Underpayment
Actual Payment to PJM
Actual Payment to MISO
Actual Net Payment

08 09 J F M A M J J J A S O N D
Avg 2008 2009

Market-to-Market Settlement Error and Issues

- In April 2009 the Midwest ISO identified an issue with PJM’s market flow calculations that understated PJM’s market flows and affected settlements from 2005 until June 2009.
  - Unfortunately, PJM did not retain the data necessary to correct the settlements and this is now the subject of active complaints at FERC.
  - PJM and the Midwest ISO agreed on a methodology using an alternate data source to estimate the underpayment of the most recent two years, which totals $65 million.
  - The figure shows the monthly values using this methodology, which peaked at close to $15 million in June 2008.
  - The RTOs are improving their processes to provide additional auditing and validation of the market-to-market settlements to minimize future errors.
- In addition to this error, other issues regarding coordination under the JOA have arisen:
  - We have made two tariff compliance referrals to FERC regarding PJM’s implementation of the JOA – the JOA is a tariff attachment in both RTOs.
  - Additionally, the JOA lacks clarity in a number of areas that have resulted in disagreements between the RTOs on the obligations and settlements under the JOA.
  - We recommend that the RTOs work together to clarify the JOA in these areas, including: 1) use of the monitoring RTO’s marginal value limits during coordination; 2) pre-positioning on coordinated constraints; 3) use of proxy flowgates; 4) the obligation to activate a coordinated constraint; and 5) the obligation to test new constraints.
Market-to-Market Constraints
Shadow Price Convergence

- The next two figures show an analysis that examines the five most frequently activated market-to-market constraints on the PJM and Midwest ISO systems.
  - The analysis is intended to show the extent to which the shadow prices on coordinated constraints converge between the two RTOs.
  - Each figure shows the initial shadow price of the monitoring RTO on each coordinated flowgate, the average shadow prices in the post-initialization period for both the monitoring and reciprocating RTOs, and the relief requested by the monitoring RTO in both periods.
  - The figure also shows (on the horizontal axis) the percent of hours the constraint was activated that it was being coordinated (i.e., relief was being provided by the reciprocating RTO).
  - Cases in which the reciprocating RTO does not respond (where relief capability is not available) are excluded from the analysis.

- If the market-to-market process is operating well:
  - The shadow prices of the two RTOs should converge after a coordinated constraint is activated; and
  - In most cases, the shadow prices should decrease from the initial value as the two RTOs collaborate to manage the constraint.

PJM Market-to-Market Constraints
Shadow Price Convergence

- The first figure shows the results of our analysis of the PJM coordinated flowgates.
  - The shadow prices decrease and move toward convergence over the duration of the event, indicating that the market-to-market process is achieving its objective.
  - The percentage of active intervals that are coordinated (where relief is received) is lower than in prior years.
  - The relief requested varies by constraint, and over the course of the coordinated hours for each constraint.
    - In 2009, both PJM and the Midwest ISO used automated software to determine the appropriate relief request based on market conditions.
    - However, the RTOs have recognize that the software has not always provided reasonable relief values and work is underway to improve the software.
  - Even though the relief values have not always been optimal, the Midwest ISO’s response has contributed to large reductions in PJM’s shadow price in the period that the RTOs are coordinating.
PJM Market-to-Market Constraints
Relief Requested and Shadow Prices, 2009

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Midwest ISO Market-to-Market Constraints
Relief Requested and Shadow Prices

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Midwest ISO Market-to-Market Constraints
Relief Requested and Shadow Prices, 2009

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The Midwest ISO and PJM have recently responded to a number of past recommendations which should improve the performance of the process in 2010.

We recommend the following additional changes to improve the market-to-market process:

- The Midwest ISO should institute a process to more closely monitor the information being exchanged with PJM to quickly identify cases where the process is not operating correctly.
- The Midwest ISO should discontinue the constraint relaxation algorithm, even on market-to-market constraints that cannot be resolved by the monitoring RTO.
- The RTOs should work together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM’s relief.
- The RTOs should clarify the JOA in a number of specific areas.
- We continue to recommend that the RTOs expand their market-to-market process to optimize interchange between markets and coordinate export transactions.

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External Transactions

This section of the report evaluates the interchange between the Midwest ISO and adjacent areas. We summarize the magnitude of the external transactions and evaluate the efficiency with which imports and exports are scheduled.

The following figure shows the daily average hourly net imports scheduled in the day-ahead market over all interfaces in 2009. It shows:

- The Midwest ISO is a net importer of power in both peak and off-peak periods due to its reliance on large imports from the West and Canada.
- In 2009 there was no longer a discernable seasonal pattern of net imports with the highest levels of imports occurring in equally in peak and off-peak conditions.

Day-ahead imports averaged 3.4 GW over all hours in 2009, a slight decline compared to 3.6 GW in 2008.

- This indicates the degree to which the Midwest ISO relies on net imports to satisfy the demands of the market.

Given the Midwest ISO’s heavy reliance on net imports in real time, it is important for external resources to be able to fully participate in the capacity market.

- Hence, we recommend the Midwest ISO modify its deliverability requirement for external resources to establish a maximum amount of capacity imports by interface that can be utilized to satisfy LSEs’ capacity requirements under Module E.
**Daily Average Day-Ahead Imports 2009**

The next figure shows the net imports in the real-time market and the change in net imports from the day-ahead market.

In the real-time market in 2009, the Midwest ISO imported an average of 3.0 GW, a slight decline from the average of 3.1 GW in 2008.

- PJM (1.1 GW) and Manitoba Hydro (0.9 GW) were the two largest sources of imports to the Midwest ISO in the real-time market, comprising 75 percent of all imports.

As the figure shows, real-time net imports generally decreased from those scheduled in the day-ahead market.

- On 49 days the average net imports decreased by more than 1,000 MW, which can create reliability issues for the Midwest ISO that must be managed.

- Large changes in net imports can cause the Midwest ISO to have to commit additional generation and rely more heavily on peaking resources.

The figure shows changes in net imports from day-ahead to real time occurred with greater frequency in late fall and in winter.

The largest share of the reduced real-time imports are on the western interfaces with WAUE and the Manitoba Hydro Electricity Board (“MHEB”), though all the major interfaces show reduced real-time imports.
Daily Average Real-Time Imports 2009

- The following figure shows the average net imports scheduled across the Midwest ISO-PJM interface by hour of the day. The figure shows:
  - The Midwest ISO is a net importer of power on average from PJM during every hour.
  - The Midwest ISO imports track load, with imports falling during overnight hours.
  - The fluctuation in hourly imports is lower in 2009 than it was in 2008.
    - The Midwest ISO in 2009 imported more during the morning hours and less during afternoon and evening hours compared to 2008.
  - The standard deviation of the net imports declined in 2009 compared to 2008.
    - However, it remains large, indicating that the magnitude and direction of the flows between the two markets is highly variable.
    - This is due to the similarity of the generating resources in PJM and the Midwest ISO. Hence, the prices in the two areas tend to move in similar ranges.
    - Because the relative prices in the two areas govern the net interchange between them, movements in the relative prices in the two areas will cause the incentives to import and export to fluctuate.

Hourly Average Real-Time Imports from PJM
The following figure shows hourly real-time net imports across the Canadian interfaces.

- The Midwest ISO exchanges power with Canada through interfaces with MHEB and the Independent Electricity System Operator of Ontario (“IESO”).
  - The Midwest ISO is typically a net importer from MHEB through the high voltage DC connection.
    - Net imports from MHEB are generally higher in the peak hours (averaging 960 MW) and lower in the off-peak hours (averaging 712 MW).
    - Average hourly imports from MHEB were 200 MW lower in 2009 than in 2008.
  - The Midwest ISO is on the whole a net exporter to Ontario, although the direction of the power flows switch periodically.
    - Exports to IESO are generally lower in the peak and ramping hours.
    - The wide standard deviation, which averaged 636 MW in 2009, shows the Midwest ISO is an importer from IESO during many hours (particularly peak hours).
    - Average hourly exports to Ontario were approximately 300 MW less in 2009 than in 2008.
Hourly Average Real-Time Imports from Canada 2009

Wheels From IESO to PJM

- Schedules from IESO to PJM (across the Midwest ISO) increased over the past two years. The next figure shows the quantity and profitability of these transactions.
  - The relatively high volume of these transactions continued in 2009.
  - The transactions are explained by their consistent profitability.
    - Since the beginning of 2007, these transactions have netted average profits over $10 per MWh, and occasionally over $20 per MWh.
    - The profitability of these transactions has declined over time and the profitability tends to be inversely correlated with the volumes.
    - Profitability is calculated based on the prices in PJM and IESO minus the Midwest ISO’s wheeling charge. It does not include costs allocated by IESO, which would reduce the profitability.
  - These transactions may not always be efficient, even though they are generally profitable.
    - If these transactions had to pay for the congestion they cause in New York, many of them may not be profitable, which raises efficiency concerns.
    - If PJM priced the transactions at its Midwest ISO interface (instead of its current pricing method for IESO) the average profitability would drop to -$1.30 per MWh.
    - The large difference between the PJM’s IESO and Midwest ISO prices may create incentives to combine other transactions with these wheels to acquire the difference.
Loop Flows around Lake Erie

Conclusions

- The assumptions made when transactions are scheduled are often inconsistent with how the actual power flows associated with the schedules, particularly around Lake Erie.
  - These inconsistencies produce large quantities of “loop flows” that have costs that are not borne by the participants scheduling the transactions, which can lead to inefficient use of the transmission network.
  - The loop flows also create uncertainties regarding available transmission capability that must be accounted for in the real-time market, day-ahead market, and FTR markets.
  - Phase angle regulators are in the process of being placed in operation (one of four is in service) that could help improve the consistency between the schedules and flows.
  - However, this has been significantly delayed by the lack of necessary agreements between the relevant transmission owners and operators. The Midwest ISO is limited in its ability to facilitate these agreements.
- To address the loop flow issues around Lake Erie, we recommend the Midwest ISO develop a joint agreement with IESO, NYISO, and PJM to modify scheduling and settlement provisions to better align physical flows with the settlements.
  - Improved scheduling and settlement rules around Lake Erie would substantially reduce loop flows, increase efficiency, and eliminate inequitable cost transfers.
  - The scheduling coordination being discussed by the ISOs around Lake Erie should address both efficiency and manipulation concerns with the current system.
The following series of figures evaluate the price convergence and net imports between the Midwest ISO and adjacent markets.

- The left side of each figure is a scatter plot of the real-time price differences and the real-time net imports in unconstrained hours.
- The right side of each figure shows the monthly averages for hourly real-time price differences between the adjacent regions and the monthly average magnitude of the hourly price differences (average absolute differences).

In an efficient market, prices at the interface should tend to converge when the interfaces between the regions are not congested.

Like other markets, the Midwest ISO relies on participants to increase or decrease their net imports to cause prices to converge between markets.

Given the uncertainty regarding the difference in prices (because the transactions are scheduled in advance), one should not expect perfect convergence.

The right-hand panel in the following two figures shows Midwest ISO interface prices in 2009 tended to be slightly higher than PJM’s, except in the fourth quarter.

- The absolute average price difference was just over $10 per MWh in 2009, down from almost $18 per MWh in 2008.
- The left-hand-side panel in the figure shows participants have not been fully effective at arbitraging the prices between the two areas.
  - The import and export quantities remain widely scattered relative to the price differences.
  - In 59 percent of the hours, power is scheduled in the wrong direction (from the higher-priced market to the lower-priced market).

To achieve better price convergence, we continue to recommend that the RTOs consider expanding the JOA to optimize the net interchange between the two areas.

- Under this approach, participants’ transactions would be financial. The RTOs would determine the optimal physical interchange based on the relative prices in the two areas.
- This change would likely achieve the vast majority of any potential savings associated with jointly dispatching the generation in the two regions.
- The Midwest ISO has begun investigating the means to implement this recommendation.
Real-Time Prices and Interface Schedules in 2009
PJM and Midwest ISO

The next figure provides the same analysis for the Midwest ISO – IESO interface in the real-time market.

- The pattern in the left-hand side of the figure confirms that the Midwest ISO was a net exporter of power to IESO in 2009, exporting an average of 100 MW.
  - On average, Midwest ISO prices exceeded the IESO prices.
  - Absolute average price differences averaged $13.57 per MW, down from nearly $21 per MWh in 2008.
  - Average prices were more volatile during the first half of 2009.
    - IESO premiums of approximately $5 per MWh prevailed during the first two months of the year.
    - Midwest ISO premiums averaged $6.25 per MWh from March to July.
- The dispersion of prices shows the schedules over this interface are relatively slow to respond to price differences.
- Interpreting these results is complicated by the fact that IESO does not have a nodal market so the IESO price may not fully reflect the true value of power imported from the Midwest ISO.
Real-Time Prices and Interface Schedules in 2009
IESO and Midwest ISO

Participant Conduct and Mitigation
Market Concentration

- The analyses in this section of the report provide an overview of the competitive structure and performance of Midwest ISO markets in 2009.
- The first analysis is of market concentration, measured using the Herfindahl-Hirschman Index ("HHI").
  - HHI values are calculated by summing the squares of each supplier’s market share.
  - Markets with HHIs greater than 1,800 are considered highly concentrated, while markets with HHIs less than 100 are considered highly competitive.
  - The HHI provides only a general indication of market conditions and is not a definitive measure of market power because it does not consider demand, network constraints, and load obligations.
- The market concentration of the entire Midwest ISO region is relatively low.
  - However, all of the Midwest regions have HHI values close to or exceeding 1800.
    - Investment in the West has reduced the HHI from 2,089 to 1,685 there.
    - The WUMS HHI figure increased from 2,088 to 2,382.
  - The HHIs in the Midwest ISO are higher than in some other markets because the vertically-integrated utilities in the Midwest have not divested substantial amounts of generation.
A better metric than the HHI for evaluating competitive issues in electricity markets is the Residual Demand Index (\textquotedblright RDI\textquotedblright), which indicates the portion of the load in an area that can be satisfied without the largest supplier.

- An RDI less than 1 indicates that the load can be fully satisfied without the largest supplier\’s resources. An RDI greater than 1 indicates that a supplier is \textquotedblright pivotal\textquotedblright – that is, it is a monopolist over a portion of the load.
  - In general, the RDI will decrease as load increases, since increasing quantities of rivals\’ generation will be needed to satisfy the load.
  - In calculating the RDI, we include all import capability into the area, not just the imports that were actually scheduled.

- The next figure shows the portion of hours when a supplier was pivotal.
  - The analysis shows an improvement in the competitive structure of all regions.
    - The portion of hours when a supplier was pivotal decreased by 70 percent (in the East) to 100 percent (in the Central region).
    - These decreases are partly due to reduced congestion into some of these areas.
    - Although the portion of hours spiked in WUMS during the highest load hours, this only comprises 0.3\% of all hours.
  - Overall, the figure shows a modest improvement in 2009 from prior years as a result of investments in generation, transmission, and lower overall load.
Constraint-Specific Pivotal Supplier Analysis

- We conducted a pivotal supplier analysis for individual transmission constraints in periods during which the constraints were active.
  - A supplier is pivotal for a constraint when its resources are needed to manage the transmission constraint (i.e., it has the ability to overload the constraint such that other suppliers cannot unload it).
  - This is frequently the case for lower voltage constraints because the resources that significantly affect the flows over the constraint are those that are near the constraint – if they are all owned by the same supplier, it is likely to be pivotal.
    - Although overall congestion was modestly lower in 2009 compared to 2008, an increasing share of binding intervals occurred on low voltage constraints.
- The next figure shows the portion of active NCA constraints (WUMS and Minnesota) and BCA constraints (ISO-wide) that have at least one pivotal supplier.
- This figure shows, among active constraints in 2009:
  - 69 percent of those into WUMS had a pivotal supplier, down from 79 percent in 2008.
  - 75 percent of those into Minnesota had a pivotal supplier, up from 69 percent in 2008.
  - 64 percent of Midwest ISO BCA constraints had a pivotal supplier, up from 59 percent in 2008.
- These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of BCA constraints in 2009 created significant potential for local market power.
Constraint-Specific Pivotal Supplier Analysis

- The figure above showed that a supplier was frequently pivotal when a BCA constraint or NCA constraint was active.

- The next figure shows the percentage of intervals during the market’s operation in 2009 when at least one supplier was pivotal for a BCA or NCA constraint.
  - This analysis varies from the prior analysis because it incorporates how frequently BCA and NCA constraints are active.

- This analysis shows:
  - There was an active BCA constraint with at least one pivotal supplier in 79 percent of the hours during 2009, up 13 percentage points from 2008.
    - As in prior years, the regional distribution of BCA constraints varied by month, with the Central region experiencing more constraints than the other three regions.
    - The monthly frequency ranged from 62 percent to more than 90 percent.
  - There was an active NCA constraint with a pivotal supplier in only 17 and 21 percent of hours in WUMS and Minnesota, respectively, a decrease of 13 percent in 2009 for WUMS, and an increase of 15 percent for Minnesota.

- These results indicate that the BCA and NCA mitigation continues to be essential.

Constraint-Specific Pivotal Supplier Analysis 2009

[Graph showing the percentage of intervals during the market’s operation in 2009 when at least one supplier was pivotal for a BCA or NCA constraint.]
**Price-Cost Mark-Up Analysis**

- The prior analyses (pivotal supplier and market concentration) are structural analyses intended to identify potential market power concerns.
- The remainder of this section evaluates the competitive performance of the market based on the conduct of the participants. These analyses are used to detect significant economic or physical withholding.
- The first analysis estimates a “mark-up” of real-time market prices over suppliers’ competitive costs.
  - To produce a valid comparison, we estimate the system marginal price assuming that suppliers offer at prices equal to a) their reference levels, and b) their actual offers.
  - This analysis is a broad metric that does not account for physical restrictions on the units and transmission constraints, which would require re-running the market software.
  - We performed this analysis for the past two years and found average annual mark-ups of approximately 2 percent in 2008 and approximately 1.2 percent in 2009.
  - Given the many factors that can cause reference levels to vary slightly from suppliers’ true marginal costs, mark-ups this small indicate that the markets have performed very competitively over the timeframe studied.

**Economic Withholding: Output Gap Analysis**

- Economic withholding occurs when a participant offers resources above competitive levels to raise energy prices or RSG payments.
  - We use the “output gap” metric for this analysis, which shows the quantity of output that is not produced when suppliers’ marginal costs (based on reference prices) are lower than the LMPs by more than a given threshold.
- This figure shows:
  - The output gap continued to decline in 2009 compared to 2008.
  - Output gap levels were considerably lower in the second half of 2009 as a result of sustained low load levels and prices and surplus generation.
  - The output gap averaged 0.5 percent of load in 2009, down from 1.3 in 2008. These levels are extremely low and generally raise limited competitive concerns.
  - However, we monitor these levels continually and have investigated many specific output gap issues. In most cases, values can be explained by competitive factors.
Economic Withholding: Output Gap Analysis

The next figure examines the output gap by load level and size of participant.

- The incentive to economically withhold supply generally increases under high load conditions when prices are most sensitive to such withholding. Additionally, large suppliers generally have a greater ability to increase prices.
- Therefore, the following four figures show the output gap in each region by load level, separately showing the two largest suppliers in the region versus others.

These figures show:

- The output gap at both threshold levels are less than 1 percent at all load levels and locations, confirming that participants generally did not engage in anti-competitive behavior in 2009.
  - Overall surplus generation due to lower load in 2009 reduced the incentive to economically withhold supply.
- The output gap tends to rise at higher load levels because the higher prices that occur at high load levels cause a much higher share of the resources to be economic.
  - However, these low levels do not raise economic withholding concerns.
- The output gap quantities for the largest suppliers are not significantly higher than for other suppliers. Only in the East are they discernibly higher.
- Overall, these results and our ongoing monitoring and investigations of hourly results indicate that economic withholding has not been a pressing concern in 2009.
Real-Time Market Output Gap
Central Region in 2009

Real-Time Market Output Gap
East Region in 2009
Real-Time Market Output Gap
West Region in 2009

Real-Time Market Output Gap
WUMS Region in 2009
Ancillary Services Offers

- The following figure shows the monthly average quantity of regulation and operating reserves offered at prices higher than the reference price by $10 or more per MW.
  - These thresholds are below the BCA mitigation threshold, which is the lesser of 300 percent or $50 per MWh (for offer prices greater than $5 per MWh).
- The figure shows that offers for ASM were generally competitive in 2009.
  - On average 244 MW of regulation capability (or 4 percent of the online regulation capability) failed at the $10 threshold, while 148 MW also failed at the $20 threshold.
  - Similarly, 422 MW of spinning reserve capability (or 2 percent of the total capability) failed at the $10 threshold.
  - Offer prices for supplemental reserves, and in turn conduct failures, are exceedingly low.
    - In September, several units offered on average 7 MW of offline supplemental reserves at over $40 above threshold.
  - There were only two instances of ASM mitigation in 2009.
- Over the year, the quantities exceeding the reference level increased, but they remained below the levels that would raise potential competitive concerns.

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Evaluation of Outages and Partial Deratings

- While the prior analyses assessed offer patterns to identify potential economic withholding, the following analyses seek to identify potential physical withholding.
- Physical withholding occurs when a unit that would be economic at the market price is unavailable to produce some or all of its output. This is accomplished by the supplier unjustifiably claiming an outage or derating the resource.
- Our physical withholding analysis is shown in the following figures for each region:
  - The figures show short-term forced outages (less than 7 days), and other deratings (excluding permanent deratings).
  - The data is shown by load level and for the largest two suppliers compared the other suppliers.
    - The results are shown by load level because attempts to withhold would likely occur at high load levels when prices are most sensitive to withholding.
  - We focus primarily on short-term outages and partial deratings because withholding through long-term forced outages is less likely to be a profitable strategy.

Evaluation of Outages and Partial Deratings

- The results in the following figures do not raise substantial competitive concerns because:
  - In the Central and West regions, the deratings and outages are comparable across all load levels (generally ranging from 8 to 17 percent) and are lower for the top suppliers than the other suppliers.
  - In the East and WUMS, the largest suppliers exhibited outages and deratings that were slightly higher other suppliers overall and at higher levels during peak periods.
    - Derating quantities were generally higher during high load levels as expected, particularly in the East due to higher ambient temperatures.
  - In the other three regions, outages and deratings by the largest two suppliers occurred at a slightly lower rate than those by other suppliers.
- Short-term outages were much less prevalent in 2009 than in 2008.
- We continue to investigate any outages or deratings that create substantial congestion or other price effects. Audits and investigations have not uncovered any significant attempts to physically withhold generation in 2009.
Real-Time Deratings and Forced Outages
Central Region in 2009

![Chart showing percentage of capacity in category for different MISO load levels: Up to 60, 60 to 70, 70 to 80, 80 to 90, 90 to 100.]

Real-Time Deratings and Forced Outages
East Region in 2009

![Chart showing percentage of capacity in category for different MISO load levels: Up to 60, 60 to 70, 70 to 80, 80 to 90, 90 to 100.]

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The final two figures in this section show the frequency with which mitigation has been imposed in the real-time market.

As in prior years, very little mitigation was imposed in the day-ahead market, which is much less vulnerable to withholding due to the presence of virtual traders.

The first figure shows the frequency and quantity of real-time energy mitigation by month.

- Mitigation caps a unit’s offer price when it exceeds the conduct threshold and the offer raises clearing prices substantially – this process is completely automated.
- BCA and NCA mitigation was exceedingly rare in 2009, dropping 74 percent and 98 percent respectively from 2008 levels.
  - Only 5 BCA and 3 NCA unit-hours (51 BCA and 33 NCA unit-intervals) of mitigation occurred.
  - This is due to fewer high-priced opportunities to exercise market power and transmission improvements in NCAs (Minnesota in particular).
- When mitigation did occur, quantities mitigated were still substantial, averaging 193 MW and 73 MW per unit-hour of NCA and BCA mitigation respectively.

Although mitigation was infrequent during 2009, the analyses above continue to show that local market power is a significant concern.

- If exercised, local market power could have substantial economic and reliability consequences within the Midwest ISO market.
- Hence, market power mitigation measures remain essential.

Mitigation in the Real-Time Energy Market by Month 2009

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In addition to the mitigation of energy offers shown in the prior figure, mitigation is also applied to offers that result in RSG payments.

The next figure shows the frequency and amount by which RSG payments were mitigated in each month of 2008 and 2009.

The figure shows mitigation occurred for 30 unit-days in 2009, up from 7 in 2008.

However, the dollar amount mitigated dropped by 65 percent to $96,000.

Since RSG payments are a function of LMPs, lower overall prices in 2009 reduced the dollar amount that was mitigated.

These figures remain substantially below the totals for prior years.

This is likely due to the mitigation criteria that must be satisfied:
- The unit must be committed for a constraint or a local reliability issue;
- The unit’s offer must exceed the conduct threshold; and
- The effect of the inflated offer must exceed the impact threshold (i.e., to raise the unit’s RSG payment by 200 percent on a BCA constraint).

Although RSG mitigation remains minimal, this does not indicate a lack of locational market power.
Competitive Performance: Conclusions

- Our structural analyses indicate that there is substantial local market power within the Midwest ISO region.
- However, our analyses of participants’ conduct and the market outcomes indicated that the market continued to perform very competitively in 2009.
  - We found little evidence of attempts by suppliers to withhold resources economically to exercise market power.
  - Additional investigations of potential physical withholdings found no exercise of market power.
  - Hence, mitigation measures were employed infrequently to address economic withholding that would have increased energy prices or uplift costs.

Demand Response Programs
Demand Response Programs

eXisting Programs

- The Midwest ISO has more than 12,500 MW of total demand response capability.
  - The vast majority of this is in the form of interruptible load developed by LSEs under regulated retail initiatives and is beyond the control of the Midwest ISO.
- Midwest ISO-controlled demand response resources ("DRR") consist of two types:
  - "Type I" resources are capable of supplying a specific quantity of energy or reserves through physical load interruption, typically for reliability reasons.
    - These resources must be notified well in advance and are therefore not generally responsive to prices.
    - These resources are eligible to sell contingency reserves and can also be used to satisfy an LSE’s Module E capacity requirement.
    - Although 17 units are capable of providing over 2.3 GW of total Type I capacity, peak response in 2009 totaled just 340 MW due to low [peak] load conditions.
  - "Type II" resources are capable of supplying energy and operating reserves over a dispatchable range, such as through controllable load or behind-the-meter generation.
    - These resources can be dispatched on a five minute basis that is comparable to generation so it can fully participate in the markets on a price-sensitive basis.
    - Only 4 units totaling 111 MW of capacity currently participate, although peak participation in 2009 was 65 MW.
  - On average, only 0.1 MW of Type I resources and 17.6 MW of Type II resources cleared in real-time in 2009.

The following table compares the Midwest ISO’s demand response programs to the demand response programs of ISO-New England and New York ISO.

- The figure shows although the Midwest ISO has incorporated a significant amount of demand response into its resource adequacy construct, economic demand response is a very small portion of overall demand response.
- Demand response resources comprise approximately 7 to 8 percent of the resource mix in all three RTOs.
- The table shows that while the Midwest ISO has the greatest quantity of total demand response, it has the smallest amount enrolled in its ISO administered programs.
- Supply-side DRR is currently the only available means to participate in the Midwest ISO’s energy and ancillary service markets.
  - Price-responsive demand-side resources, such as Aggregators of Retail Customers ("ARC"), do not currently participate in real-time energy markets.
  - In other RTOs, ARCs comprise most of the growth in demand response capability, particularly in capacity markets.
### Comparison of ISO Demand Response Programs

<table>
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<tr>
<th>Program/Resource</th>
<th>Quantity in MW</th>
<th>Pct of Resource Mix</th>
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<tbody>
<tr>
<td><strong>MISO TOTAL</strong></td>
<td>12,550</td>
<td>6.8%</td>
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<tr>
<td>DRR Type I</td>
<td>2,353</td>
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<tr>
<td>DRR Type II</td>
<td>111</td>
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<tr>
<td>Load-Modifying Resources</td>
<td>4,860</td>
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<tr>
<td>Behind-The-Meter Generation</td>
<td>4,984</td>
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<tr>
<td>Emergency</td>
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<td><strong>ISO-NE TOTAL</strong></td>
<td>2,554</td>
<td>7.4%</td>
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<td>Real Time Demand Response</td>
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<td>Real Time Emergency Response</td>
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<td><strong>NYISO TOTAL</strong></td>
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<td>Day-Ahead Demand Response</td>
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<td>Demand Side Ancillary Services</td>
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<td>Targeted Demand Response</td>
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<tr>
<td>Installed Capacity - Special Case Resources</td>
<td>2,061</td>
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</table>

### Demand Response Programs

**Current and Future Efforts**

- In order to comply with Order 719 and 719-A to create a platform for expanded demand response participation, the Midwest ISO has:
  - Established a stakeholder process to identify and address specific barriers related to market rules, settlement provisions, and operating requirements.
  - Filed Tariff revisions on October 2, 2009 to allow ARCs to participate in all Midwest ISO markets.
    - ARCs are scheduled to be eligible to participate beginning June 1, 2010, although FERC has not yet approved the Tariff revisions.
    - They will be paid only the LMP minus the predetermined Marginal Foregone Retail Rate, which is an economically efficient payment.
    - There are several state and local regulatory barriers to their full participation.
  - Hence, we recommend that the Midwest is develop an approach for allowing demand response resources or other reliability actions to set energy and reserve prices.
  - The Midwest ISO has been evaluating alternatives for addressing this recommendation.