2010 State of the Market Report
Midwest ISO

Presented by:

Midwest ISO
Independent Market Monitor

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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 a comprehensive review of various market metrics, our assessment of the competitive performance of the markets, and our recommendations for 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;
  - ✓ Since January 2009, Ancillary Services Markets (“ASM”), including day-ahead and real-time regulating and operating reserves that are jointly optimized with energy markets;
    - – This optimization provides added flexibility from the Midwest ISO’s generating resources to more efficiently manage congestion and satisfy load.
  - ✓ Financial Transmission Rights (“FTRs”) that allow participants to hedge congestion between various locations; and
  - ✓ Since June 2009, 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 in 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. Production costs are reduced by:

- ✓ Producing energy from the most economic supply and demand resources;
- ✓ Employing the lowest-cost redispatch options to manage congestion;
- ✓ Allowing for greater utilization of the transmission capability in the region; and
- ✓ Optimizing the scheduling of ancillary service products.

•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 used before.

•Price signals. The Midwest ISO markets provide transparent economic signals to guide short- and long-run decisions by participants and regulators.

Executive Summary: Competitive Performance and Summary

- Overall, the Midwest ISO markets continued to perform competitively in 2010.
  - ✓ While substantial local market power exists, there was little evidence of attempts to exercise market power in 2010.
  - ✓ Therefore, mitigation measures were not frequently employed in 2010.
  - ✓ However, commitments for local reliability (e.g., voltage support) raised substantial competitive concerns, for which we recommend expanded mitigation authority.
- Energy prices increased by almost 20 percent in 2010 to roughly $35 per MWh. Most of this increase was related to fuel price increases.
  - ✓ Most of this increase was caused by higher fuel prices – natural gas prices increased 14 percent, oil increased 31 percent, and western coal increased 42 percent.
  - ✓ Fuel-price adjusted energy prices rose only 3 percent. The correspondence of energy prices and fuel prices demonstrates the competitiveness of Midwest ISO's markets.
  - ✓ Warmer summer temperatures and improved economic conditions led to a 6.2 percent increase in average load (adjusted for membership changes), which contributed to the higher energy prices.

Executive Summary: Competitive Performance and Summary (cont'd)

- Real-time transmission congestion increased 18 percent due to higher load, fuel prices, and wind output.
  - ✓ However, the constraint "relaxation" algorithm artificially reduced real-time congestion by 25 percent (over $300 million).
  - ✓ Lower real-time congestion will lead to lower day-ahead congestion, reducing the efficiency of the resource commitments, raising RSG costs, and reducing FTR prices and revenues.
- Ancillary services markets continued to perform well.
  - ✓ ASM prices remained stable and competitive.
  - ✓ Shortages have been infrequent and interzonal price differences have been low.
- Wind output continued to rise rapidly – average output increased 35 percent and peaked at 6.7 GW.
  - ✓ The rapid increase in wind output raises operational and market concerns that are being addressed in part by making intermittent resources dispatchable in 2011.
- The Voluntary Capacity Auction continued to clear at a price close to zero, which is consistent with the prevailing high level of surplus capacity in the region.

Executive Summary: Long-Term Economic Signals

- In long-run equilibrium, the market should provide “net revenues” that provide efficient incentives for investment when new resources are needed.
  - ✓ Net revenue is the revenue the unit would have received in hours it would have run, less its variable production costs in those hours.
  - ✓ For a new resource to be economic, net revenues must cover the resource’s fixed operating and maintenance costs and provide an adequate return on the investment.
- Improved shortage pricing under ASM and the introduction of the VCA improved the markets’ ability to produce efficient long-term price signals.
- However, net revenues in 2010 would not have supported investment in either a new combined-cycle unit or a gas turbine based on their annualized costs of entry.
- These results are consistent with expectations because the Midwest ISO region has a capacity surplus that:
  - ✓ Resulted in very infrequent shortages in 2010; and
  - ✓ Contributed to very low capacity prices in the VCA.
- Nonetheless, this report includes a number of recommendations to improve the energy and capacity markets that are designed to improve long-term price signals.

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, so 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).
- Midwest ISO energy markets continued to exhibit a day-ahead price premium.
  - ✓ These day-ahead premiums are consistent with the higher RSG costs (approximately $2 per MWh), volatility, and risk associated with buying in the real-time market.
- Active virtual supply and demand participation in the day-ahead market has contributed to the price convergence exhibited in the Midwest ISO.
  - ✓ Virtual trading levels have decreased considerably since 2008, attributable largely to tight credit conditions and RSG allocation decisions made by FERC.
    - – New allocation procedures introduced in April 2011 should reduce the costs allocated to real-time deviations, including to virtual supply.
  - ✓ Price convergence during this period was good overall but was not as good in congested areas, which are less liquid.

Executive Summary: Real-Time Market Performance

- The introduction of ASM in 2009 resulted in improved supply flexibility that allows the real-time market to satisfy the system's demands with less price volatility.
- Nonetheless, volatility in the Midwest ISO remained higher than in neighboring RTOs because the Midwest ISO runs a true five-minute real-time market (producing a new dispatch every 5 minutes rather than every 15 minutes as do most other RTOs).
- Since the real-time market software is limited in its ability to look ahead, the system is frequently "ramp-constrained" (i.e., generators are moving as quickly as they can up or down). This results in transitory spikes in prices up or down.
- The report shows that ramp constraints tend to bind and cause price volatility when:
  - ✓ Actual load is changing rapidly, including "non-conforming" load associated with industrial facilities that can change sharply and without advance notice;
  - ✓ Net Scheduled Interchange ("NSI") over one or more of the Midwest ISO's external interfaces changes significantly;
  - ✓ A large quantity of generation is either starting up or shutting down; or
  - ✓ The Midwest ISO is not setting its load offset parameter, which is used to manage anticipated ramp changes on the system, in an optimal manner.
- The report includes several recommendations to improve real-time performance and reduce price volatility.

Executive Summary: Ancillary Services Markets

- The Midwest ISO ancillary services markets, introduced in January 2009, have continued to perform as expected 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 stable and consistent with expectations.
  - ✓ Average regulation prices decreased nearly 10 percent in 2010 due to fewer shortages, a reduction in the demand curve, and slightly lower regulation requirements.
  - ✓ Spinning reserve prices averaged under $4 per MWh, up 8 percent from 2009.
    - Although the frequency of shortages declined, prices increased modestly due in part to improved shortage pricing (reduced relaxation during shortage conditions).
    - However, the spin relaxation still sometimes sets prices well below the true value of the reserves during shortages so we recommend eliminating the relaxation and implementing a spinning reserve demand curve.
  - ✓ Supplemental reserve prices rose to $1.72 per MWh due to a decrease in offer volumes that reflects participant concerns about meeting deployment obligations.
    - Midwest ISO is working with market participants to clarify the Midwest ISO Tariff's must-offer requirements and deployment obligations.
    - Deployment response improved markedly in 2010.

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 payments when their costs are not covered in the real-time market.
  - ✓ The vast majority of RSG costs are incurred in the real-time market, which is expected because most commitments made for reliability are made in real time.
  - ✓ 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).
- Total RSG costs increased 40 percent to $186 million in 2010, over 85 percent of which was incurred in real time when reliability commitments are made.
  - ✓ The increase is partly due to higher loads and higher fuel prices (which increase commitment costs).
  - ✓ The remaining increase (more than $25 million) was mainly due to payments made to units committed routinely to resolve a local voltage issue. The majority of this cost was associated with increased offer prices, which raises competitive concerns.
  - ✓ We recommend an expansion in the market power mitigation measures to more effectively address these competitive concerns.

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Executive Summary: Price Volatility Make-Whole Payment

- The Midwest ISO introduced the PVMWP in 2008 to ensure adequate cost recovery in the real-time for resources offering dispatch flexibility.
  - ✓ The payment ensures that suppliers responding flexibly in real time to the 5-minute prices and following dispatch signals are not harmed in the hourly settlement.
  - ✓ 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 two separate payments:
  - ✓ The Day Ahead Margin Assurance Payment ("DAMAP") is paid to a resource dispatched to a level *below* its day-ahead schedule in a manner that erodes its day-ahead margin because the hourly real-time price is less than its as-offered costs.
  - ✓ The Real Time Offer Revenue Sufficiency Guarantee Payment ("RTORSGP") is paid to a resource unable to recover incremental as-offered energy costs through the hourly LMP when dispatched in real-time to a level *above* its day-ahead schedule.
- PVMWP payments increased 60 percent in 2010: DAMAP payments totaled $53.2 million, while RTORSGP payments totaled over $15 million.
- While the rise in PVMWP in 2010 tracked increases in price volatility at the resource locations, we have identified some concerns with the payment formulas.
  - ✓ We recommend some changes to these formulas to address the concerns.

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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.
- Dispatching a resource out-of-merit order occurs when its offer price is higher than the LMP, which typically requires higher RSG payments to ensure the resource recovers its as-offered costs.
- The dispatch of peaking resources doubled to an average of 452 MW per hour in 2010 due largely to higher loads in 2010.
  - ✓ High summer loads caused a daily average of more than 5 GW of peaking resources to be dispatched on some days.
- The majority of peaking resources were committed in-merit (almost 60 percent) in 2010, which is explained by the large number of commitments in peak summer periods.
  - ✓ Although peaking units set prices more frequently than in prior years, 40 percent still ran out-of-merit due to their inflexibility, which can preclude them from setting prices.
- Real-time prices will be inefficiently low when peaking (or demand response) resources are the most economic option for meeting market demands, but do not set prices,.
  - ✓ It also contributes to under-scheduling of load in the day-ahead market, distorting real-time prices and compromising participant incentives.
- We support the Midwest ISO's continued work on a pricing method to allow peaking resources and Demand Response resources to set real-time energy prices.

Executive Summary: Generating Capacity

- The Midwest ISO added two additional members in 2010 – Dairyland Power Cooperative and Big Rivers Electric – increasing its reliability footprint to 157 GW.
- We estimate the planning reserve margins for summer 2011, which are sensitive to the assumptions made regarding deratings/outages and interruptible load.
  - ✓ Planning reserve margin is 56% based on nameplate ratings (including DR, interruptible load, and behind-the-meter generation) and 37% based on summer ratings.
  - ✓ We also adjust for temperature-sensitive capacity that likely will not be available at the extreme peak periods – this results in a planning reserve margin of 28%.
  - ✓ These margins indicate a sizable surplus in the Midwest ISO region, as a result of slower-than-anticipated load growth and the continued increase of wind resources.
  - ✓ The planning reserve margin is only 14% in the East region due partly to the departure of First Energy.
- Although the system's resources are adequate for the upcoming summer, new resources will be needed over the long-run to meet the needs of the system, particularly if older marginal coal units retire rather than upgrading to meet environmental rules.
  - ✓ It therefore remains important for the market's economic signals that govern new investment and retirement decisions to be efficient.
- The Midwest ISO expects nearly 3.4 GW of additions in Planning Year 2011, half of which is in the form of wind generation. Nearly 1.1 GW of retirements are expected.

Executive Summary: Transmission Congestion

- One of the most significant benefits of the Midwest ISO energy markets is providing accurate and transparent price signals that reflect congestion on the network.
  - ✓ Total congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly $500 million due to higher loads and transmission outages.
  - ✓ In 2010, the day-ahead market captured nearly all the congestion costs, indicating good convergence between day-ahead assumptions and actual real-time conditions.
  - ✓ Net real-time balancing congestion costs, which are related only to deviations from day-ahead schedules, were actually slightly negative due to market-to-market settlements.
- The value of real-time congestion increased 18 percent to $1.08 billion in 2010.
  - ✓ This is considerably higher than the amount collected by the Midwest ISO due to PJM entitlements, loop flows, and poor price convergence at certain locations.
- As in prior years, there were many instances when the real-time model was unable to reduce the flow below the transmission limit (i.e., the congestion was not manageable).
  - ✓ When this occurs a constraint relaxation algorithm is used to price the congestion, which results in extremely poor price signals – 27 percent of the unmanageable constraints were priced at zero.
  - ✓ This algorithm reduced the valued of real-time congestion by 25 percent in 2010 (more than $300 million), which adversely affects the day-ahead outcomes and FTR prices.
  - ✓ We strongly recommend the Midwest ISO discontinue use of this algorithm and price unmanageable constraints at the Marginal Value Limit.

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Executive Summary: Financial Transmission Rights

- Financial transmission rights provide a hedge for congestion because day-ahead congestion costs over the path that defines an FTR is rebated to the FTR holder.
- In a well-functioning and liquid FTR market, 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.
  - ✓ Profitability of FTRs purchased in the monthly auctions averaged just $0.19 per MWh, while seasonal profitability averaged $0.09 per MWh.
  - ✓ Although profits were higher in April and May due to unexpected congestion, convergence was generally very good.
  - ✓ The results indicate that FTR markets continue to perform as expected.
- FTRs remained underfunded by 11 percent in 2010, which occurs when less transmission capacity is available in the day-ahead market than assumed in the FTR market due primarily to transmission outages or loop flows.
- However, underfunding was substantially lower than in recent years due to improvements made by the ISO in June 2010 in constraint modeling and forecasting.
- Radial constraints to generator locations continue to contribute to underfunding, and we continue to recommend their removal from the day-ahead market.
  - ✓ Radial constraints generated over 8 percent of the total day-ahead congestion (up from 1 percent in 2009), but accounted for over one-third of the FTR shortfalls.

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Executive Summary: Market-to-Market Coordination with PJM

- The market-to-market process under the Joint Operating Agreement (“JOA”) with PJM governs the management of constraints affected by both RTOs.
  - ✓ Market-to-market coordination has resulted in more efficient management of congestion and more efficient LMPs in each RTO’s energy market.
- Market-to-market constraint hours and payments both rose considerably in 2010.
  - ✓ The frequency of congestion on Midwest ISO-coordinated constraints rose 23 percent while activity on PJM-coordinated constraints rose 16 percent.
  - ✓ Net payments to the Midwest ISO averaged approximately $3 million per month, which indicates that the Midwest ISO places less flow on PJM’s constraints relative to its entitlements than PJM does on the Midwest ISO constraints.
- In addition, shadow price convergence on Midwest ISO market-to-market constraints improved modestly in 2010, but remains substantially worse than convergence on PJM market-to-market constraints.
  - ✓ We continue to recommend that the RTOs work together to identify improvements to the relief software, modeling parameters, or other procedures that may be limiting PJM’s relief.

Executive Summary: External Transactions

- The Midwest ISO remains a net importer during all hours and seasons.
- Real-time net imports in 2010 increased 8 percent to 3.2 GW per hour.
  - ✓ Relative to 2009, imports decreased by 800 MW in January-May and increased by 700 MW in June-December due primarily to changes in interchange with PJM.
  - ✓ The Midwest ISO generally imports power from PJM, Manitoba Hydro, and Ontario (after accounting for wheel transactions scheduled through the Midwest ISO to PJM).
- Real-time net imports generally decreased from those scheduled in the day-ahead market by an average 232 MW in 2010, which is less than in prior years.
- Interchange between the Midwest ISO and adjacent markets arbitrages the price differences between markets as well as can be expected under current market rules.
  - ✓ However, many hours exhibit large price differences due to scheduling uncertainties.
  - ✓ Significant savings could be achieved from better use of the external interfaces.
- We recommend the Midwest ISO continue to work with PJM to implement new scheduling provisions to better coordinate the physical interchange between markets.
  - ✓ We estimate production cost savings of almost $300 million annually for the four RTOs around Lake Erie associated with improving coordination of interchange between the RTOs and better managing unscheduled “loop flows”.

Executive Summary: Market Power and Mitigation

- This report provides an overview of 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 2010.
  - ✓ The report indicates that concentration is low for the Midwest ISO region, although it is considerably higher in the individual regions.
- A more reliable indicator of potential market power is whether a supplier is "pivotal", which occurs when market demands cannot be satisfied without the supplier's resources.
  - ✓ This can occur when transmission constraints isolate an area of the grid.
  - ✓ 76 percent of the active "Narrow Constrained Area" ("NCA") constraints into WUMS have a pivotal supplier, as do 60 percent of the active NCA constraints into Minnesota.
  - ✓ 56 percent of the active "Broad Constrained Area" ("BCA") constraints have a pivotal supplier – BCAs are all constraints not defined as part of an NCA.
- In addition, nearly 90 percent of all intervals in 2010 exhibited an active BCA constraint with at least one pivotal supplier.
- These results indicate that:
  - ✓ Considerable market power persists with respect to both BCA and NCA constraints; and
  - ✓ The market power mitigation measures remain essential to limiting exposure.

Executive Summary: Market Power and Mitigation

- The structural analyses summarized above indicate substantial local market power.
  - ✓ However, our analyses of conduct provide little evidence of participants attempting to withhold resources (either physically or economically) to exercise market power.
- We calculate a "price-cost mark-up" of the system marginal price ("SMP") of only 1.3 percent, indicating that the market outcomes in 2010 were competitive.
  - ✓ The price-cost mark-up compares the SMP based on actual offers to a simulated SMP based on assuming suppliers had submitted all offers at competitive reference levels.
- We also 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.
  - ✓ The average output gap level in 2010 remained less than 0.5 percent of actual load in nearly all months.
- These results and others provide little indication of significant economic or physical withholding, although we monitor for and regularly investigate potential withholding.
- Market power mitigation in the Midwest ISO's energy market (and ASM) occurs pursuant to automated conduct and impact tests that utilize clearly-specified criteria.
  - ✓ Because conduct has largely been competitive, market power mitigation has been rare.
  - ✓ However, we identified a competitive concern associated with commitments to satisfy local reliability needs that warrant an expansion in the mitigation measures.

Executive Summary: Capacity Market

- The Midwest ISO in June 2009 began conducting a monthly VCA to allow load-serving entities to procure capacity to meet their Module E capacity requirements.
  - ✓ The capacity cleared in the VCA increased in 2010, but remains a very small percentage (2.6 percent) of designated capacity, indicating that the VCA is serving as a balancing market with most LSEs' needs satisfied through owned capacity or bilateral purchases.
- The VCA in each month of 2010 cleared at close to zero (less than $10 per MW-mo.). This is due to a) the surplus capacity in the Midwest ISO and b) the current market design, which attributes no value to capacity in excess of the minimum requirement.
- The total capacity available significantly exceeded the requirements, from a minimum of 3 percent for July to a maximum of 51 percent for April.
- The Midwest ISO is currently working with participants and the States to develop improvements to the capacity construct and we are providing comments.
  - ✓ Although it is not currently under consideration, we recommend that the Midwest ISO evaluate the use of a sloped demand curve for this market in its new capacity construct.
  - ✓ A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement and produce more efficient capacity prices.
- We also have concerns regarding undue barriers to participants importing and exporting capacity to and from external areas, which we address in the recommendations.

Summary of Recommendations

Although Midwest ISO markets continued to perform relatively well in 2010, we recommend the Midwest ISO make the following improvements:

<u>Energy Pricing</u>

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's Enhanced LMP initiative should provide a feasible approach.

2. Allow non-dispatchable DR (or interruptible load) to set real-time energy prices when they are called upon in a shortage.

- ✓ This would 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 DR capability.
- ✓ It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.

Summary of Recommendations (cont'd)

3. **Discontinue use of the constraint relaxation algorithm and set LMPs based on a transmission constraint's MVL when the constraint is unmanageable.**
   - ✓ The current algorithm artificially reduced real-time congestion on the Midwest ISO's system by more than $300 million, or 25 percent, in 2010.

Real-Time Market Performance and Operations

4. **Develop a "look-ahead" capability in the real-time that would facilitate better management of ramp capability and commitment of peaking resources by:**
   - ✓ Using an economic model to commit and de-commit peaking units economically to minimize the system's overall production costs; and
   - ✓ Implementing 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 these improvements previously and the Midwest ISO has initiated a project to develop these capabilities.

Summary of Recommendations (cont'd)

5. **Prior to development of the look-ahead capability, improve the use of the load offset parameter.**
   - ✓ This parameter is currently used to manage ramp capability by incrementally increasing or decreasing the load served by the real-time market.
   - ✓ Suboptimal use can reduce ramp capability and increase price volatility.
   - ✓ This recommendation likely requires improving the tool used to produce recommended offset levels and modifying the procedures to use these values.
6. **Implement tighter market power mitigation thresholds for resource commitments made for local reliability needs (including voltage support).**
   - ✓ Suppliers face little or no competition when they are needed to resolve local reliability requirements and can extract substantial market power rents.
   - ✓ This recommendation will address these competitive concerns, which are not adequately addressed under current mitigation measures.
7. **To achieve better price convergence, expand the JOA to optimize the interchange between the two areas.**
   - ✓ Changes such as allowing participants to submit offers to transact within the hour will allow the interface between the markets to be more fully utilized.
   - ✓ This would generate substantial benefits by allowing lower-cost resources in one area to displace higher-cost resources in the other area.

Summary of Recommendations (cont’d)

8. Continue working with PJM to improve the market-to-market process by:

- ✓ More closely monitoring the information being exchanged with PJM in order to quickly identify cases when the process is not operating correctly;
- ✓ Discontinuing the constraint relaxation algorithm, even on market-to-market constraints that cannot be resolved by the monitoring RTO;
- ✓ Working together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM’s relief; and
- ✓ Clarifying the JOA to avoid future disagreements.

9. Seek additional improvements to STLF used by the real-time market to reduce the amount of system ramp consumed by changes in real-time load.

- ✓ The Midwest ISO should explore potential improvements to the information it receives on non-conforming load.

10. Discontinue the modeling of radial constraints in the day-ahead market.

- ✓ This change will improve the convergence of congestion values between the day-ahead and real-time market and improve funding for FTRs affected by these constraints.

Summary of Recommendations (cont’d)

<u>**ASM Improvements**</u>

11.Eliminate RTORSGP payments to deployed operating reserves.

- ✓ This will improve the efficiency of the reserve markets by causing these expected deployment costs to be included in participants’ offers.
- ✓ There are two additional recommendations that relate to potential gaming opportunities of such side payments, which we have conveyed confidentially to the Midwest ISO.

12.Improve the performance of the spinning reserve market by:

- ✓ Improving the consistency between the reliability requirement for spinning reserves and the market requirement; and
- ✓ Allowing the spinning reserve penalty price (or reserve demand curve) to set the price in the spinning reserve market (and be reflected in energy prices) during spinning reserve shortages by not relaxing the requirement.

Summary of Recommendations (cont'd)

Capacity Market Improvements

13. Remove inefficient barriers to capacity trading with adjacent areas.

- ✓ The Midwest ISO should modify 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.
- ✓ This should allow participants to be able to more effectively arbitrage capacity price differences between markets to the extent physical transmission capability allows.
- ✓ Ultimately, this will cause both markets to send more efficient long-term price signals and improve the stability of the RTOs by reducing incentives for participants to alter RTO membership.

14. Evaluate the use of a sloped demand curve in the Resource Adequacy Construct in the future.

- ✓ A sloped demand curve would more accurately reflect the reliability value of capacity in excess of the minimum requirement.
- ✓ It also will produce more efficient and stable capacity prices, particularly as the market moves toward the minimum planning reserve requirement.

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Prices and Revenues

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All-In Price

- The first figure in this section summarizes the "all-in price" for wholesale electricity in the Midwest ISO's markets from 2008 to 2010.
  - ✓ The all-in price represents the cost of serving load in the real-time market. It includes energy, ancillary services (after markets began in January 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 $34.76 per MWh in 2010, up $3.39 (11 percent) from 2009.
- Real-time energy prices, the dominant component of the all-in price, increased by 18 percent from 2009 to 2010 due to higher load and fuel prices.
  - ✓ Natural gas prices rose 14 percent, while western coal and oil prices rose 42 and 31 percent, respectively.
  - ✓ Fuel costs constitute the majority of most suppliers' marginal costs of production.
  - ✓ Since suppliers in competitive markets offer at marginal cost, the correlation between the all-in price and fuel costs demonstrates the competitiveness of the markets.
- The capacity component of the all-in price averaged just $0.01 per MWh in 2010, consistent with surplus capacity in the region and the design of the VCA.
- Total real-time uplift costs including revenue sufficiency guarantee and price volatility make whole payments increased 46 percent in 2010 to $230 million.
  - ✓ This equates to $0.39 per MWh of actual load, roughly 1 percent of the all-in price.

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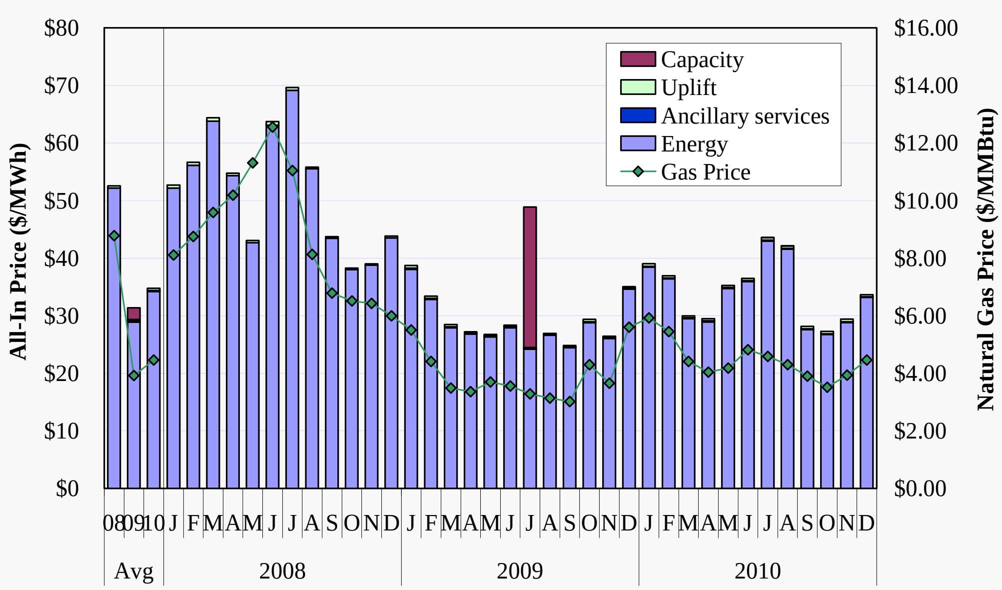
All-In Price 2008 – 2010



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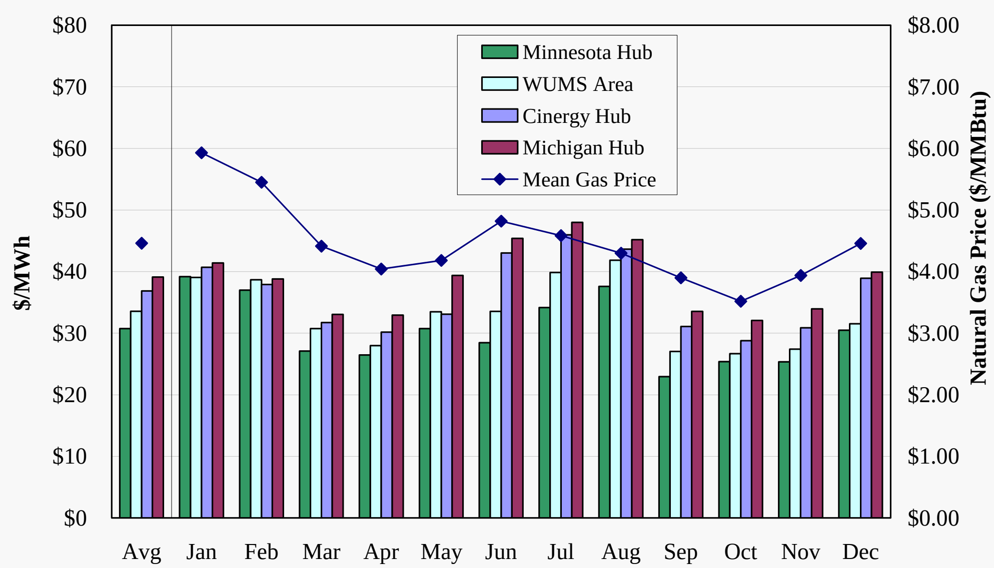
Average Energy and Fuel Prices

- The next figure in this section illustrates monthly average day-ahead energy prices by hub and their correlation with natural gas prices during 2010.
  - ✓ Day-ahead energy prices averaged $35.45 per MWh in 2010, a 19 percent increase from 2009.
  - ✓ Natural gas prices averaged $4.46 per MMBtu, a 14 percent increase from 2009.
  - ✓ Higher load due to increased economic activity and warm summer temperatures and higher fuel costs were the primary reasons for the increase in day-ahead energy prices.
- Differences among hub prices show the effect of marginal losses and congestion on the Midwest ISO system.
  - ✓ The persistent divergence between prices in the eastern and western regions widened in 2010, reflecting transmission congestion due in part to increased generation in WUMS and higher wind output in the West region.
  - ✓ Congestion into Michigan consistently produced the highest prices there.
    - – Prices often averaged over $10 per MWh more at Michigan Hub than at Minnesota Hub, particularly after the first quarter.
    - – Transmission upgrades in Michigan contributed to the congestion in 2010.
  - ✓ The west-to-east congestion was more severe in off-peak hours due to surplus generation in the West region.

Day-Ahead Average Monthly Hub Prices 2010



Midwest ISO Fuel Prices

- The next figure shows fuel prices from 2008 to 2010. With the exception of Illinois Basin Coal, all prices increased from 2009 to 2010, from 8 to 42 percent.

<u>Oil and Natural Gas Prices</u>:

- Natural gas prices averaged $4.46 per MMBtu, up 14 percent from 2009.
  - ✓ Prices in January exceeded $6 before falling to under $5 for the remainder of the year.
  - ✓ Prices averaged under $4 in fall and ended December near the annual average.
  - ✓ Natural gas prices were unusually low in 2009, averaging less than $4 per MMBtu and falling as low as $2.01 per MMBtu.
- Oil prices averaged $15.63 per MMBtu (up 31 percent), continuing a gradual increase that began in early 2009. Prices ended December near $18.
  - ✓ Oil use is typically insignificant but can become more significant during peak winter load conditions when gas supplies are interrupted.

<u>Coal Prices</u>:

- Illinois Basin prices averaged $1.84 per MMBtu (7 percent lower than in 2009) and, aside from a 13 percent rise in early September, were largely flat.
- Powder River Basin prices averaged $0.73 per MMBtu in 2010, up 42 percent from 2009. Prices rose from $0.53 per MMBtu in January to peak at $0.88 in August.

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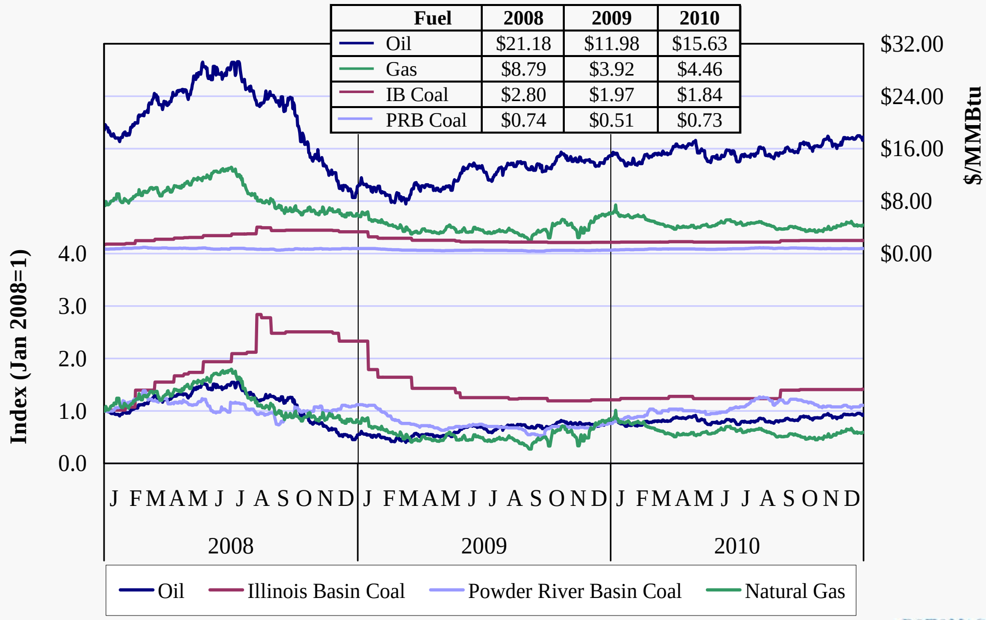
Midwest ISO Fuel Prices
2008 – 2010

Fuel	2008	2009	2010
Oil	$21.18	$11.98	$15.63
Gas	$8.79	$3.92	$4.46
IB Coal	$2.80	$1.97	$1.84
PRB Coal	$0.74	$0.51	$0.73



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Real Time Energy Prices

- The next figure shows real-time price duration curves for four representative locations in the Midwest ISO.
  - ✓ 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).
- Price duration curves at the four hub locations shifted upward modestly from last year due to higher fuel prices and load.
  - ✓ The share of hours with prices exceeding $200 and $100 per MWh increased at all locations. The largest changes were at the Cinergy and Michigan Hubs.
  - ✓ Nonetheless, less than 2 percent of all hours exceeded $100, compared to 10 percent of hours in 2008, when natural gas prices were almost twice as high.
- The figure also shows the number of hours with negative pricing decreased in 2010 compared to 2009.
  - ✓ Negative prices remain prevalent in Minnesota and WUMS, generally occurring in off-peak hours when excess generation causes west-to-east congestion.
  - ✓ This is indicated by the divergence of the duration curves at hours above 8,000.
  - ✓ The number of minimum generation alerts and events declined in 2010 relative to 2009, although they still contributed to negative prices at all hubs.

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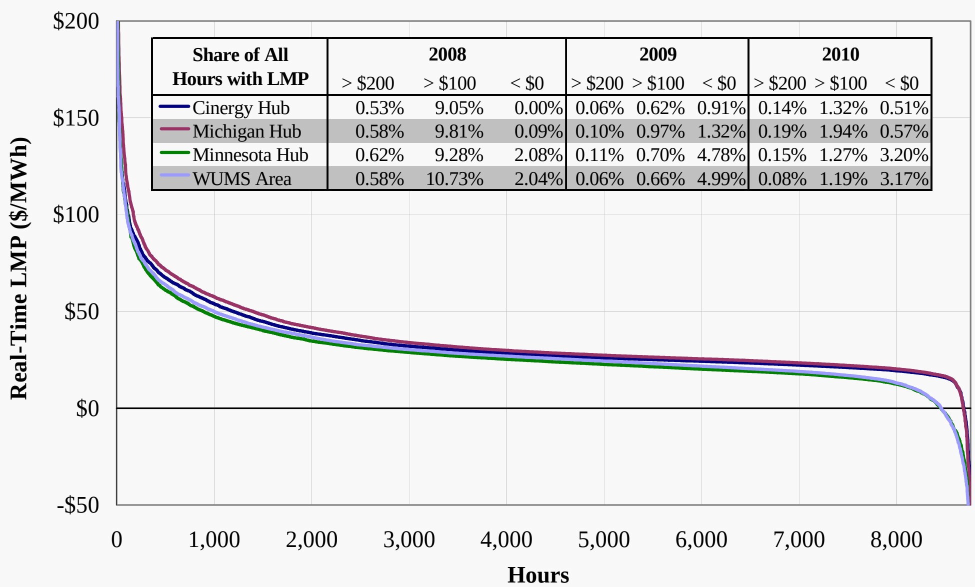
Real-Time Price Duration Curve
All Hours in 2010



Share of All Hours with LMP	2008			2009			2010		
	> $200	> $100	< $0	> $200	> $100	< $0	> $200	> $100	< $0
Cinergy Hub	0.53%	9.05%	0.00%	0.06%	0.62%	0.91%	0.14%	1.32%	0.51%
Michigan Hub	0.58%	9.81%	0.09%	0.10%	0.97%	1.32%	0.19%	1.94%	0.57%
Minnesota Hub	0.62%	9.28%	2.08%	0.11%	0.70%	4.78%	0.15%	1.27%	3.20%
WUMS Area	0.58%	10.73%	2.04%	0.06%	0.66%	4.99%	0.08%	1.19%	3.17%

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Highest-Priced Hours in the Real-Time Market

- The next figure shows the portion of the real-time price duration curve that spans the 200 highest-priced hours at each hub.
  - ✓ Energy prices during these peak hours play a critical role in sending the economic signals that govern investment and retirement of generation.
- Prices at the Michigan hub during these hours were consistently higher than at other representative locations due to higher marginal losses and congestion.
- Overall, the number of hours with prices exceeding $150 per MWh roughly doubled from 2009 lows, but remain less than 1 percent of all hours.
  - ✓ Almost all of these hours occurred during the unusually warm summer months.
  - ✓ High prices remained substantially less frequent than in 2008, primarily due to high levels of surplus supply – the result of rapid increases in wind generation and slower load growth – and lower fuel prices.
- The decrease in peak pricing events reduces incentives to invest in new generation or demand response resources.
  - ✓ The price signals that govern investment decisions are further evaluated in the Net Revenue section of this report.

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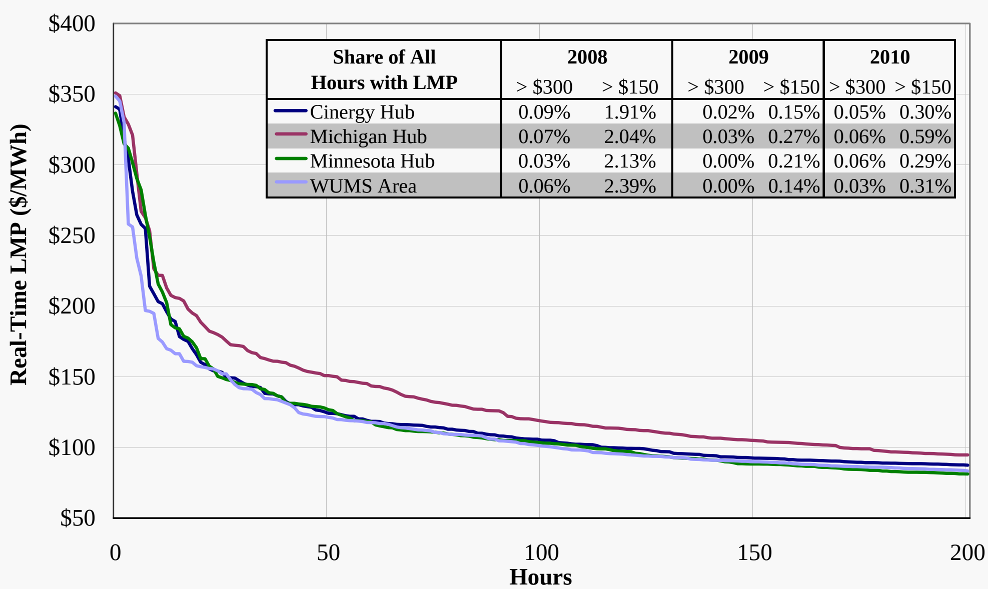
Real-Time Price Duration Curve
Highest-Priced Hours in 2010



Share of All Hours with LMP	2008 > $300	2008 > $150	2009 > $300	2009 > $150	2010 > $300	2010 > $150
Cinergy Hub	0.09%	1.91%	0.02%	0.15%	0.05%	0.30%
Michigan Hub	0.07%	2.04%	0.03%	0.27%	0.06%	0.59%
Minnesota Hub	0.03%	2.13%	0.00%	0.21%	0.06%	0.29%
WUMS Area	0.06%	2.39%	0.00%	0.14%	0.03%	0.31%

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Fuel-Adjusted System Marginal Price

- The following chart shows the monthly average System Marginal Price ("SMP") that prevailed in the market in 2009 and 2010, as well as the SMP after adjusting for changes in fuel prices.
  - ✓ Natural gas, oil and Powder River Basin coal prices increased between 14 percent (gas) and 42 percent (PRB coal) from 2009 to 2010, so fuel-adjusted prices in 2010 were lower than the nominal SMP generally.
- 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 increased 3 percent in 2010, from $29.41 to $30.28 per MWh due to increases in fuel prices and load.
  - ✓ Nominal SMP increased 18 percent in 2010.
- Although the methodology does not capture several likely impacts of changing fuel prices on generation dispatch, the figure suggests that fuel price changes account for a significant share of the year-over-year change in electricity prices.

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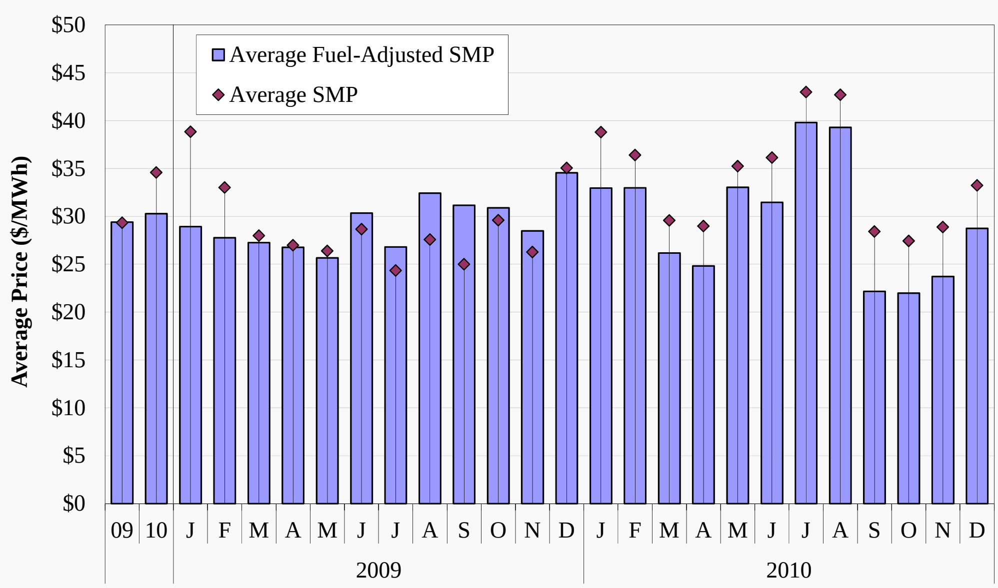
Fuel-Adjusted System Marginal Price 2009– 2010



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Price Setting Summary

- The next figure shows the frequency with which different types of units set energy prices 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 92 percent of intervals in 2010 (including nearly all off-peak hours). This is similar to 2009 but is an increase from 81 percent in 2008. The continued high levels of coal price setting compared to 2008 are due to:
  - ✓ Continued increases in wind generation that shift the supply curve outward and result in more frequent periods when coal-fired generation is on the margin; and
  - ✓ Relatively low coal prices: while Powder River Basin coal prices in 2010 returned to 2008 price levels, it remained the cheapest fossil fuel. Illinois Basin coal declined slightly in 2010.
- Natural gas and oil set prices during the highest-load hours, so they have a larger effect on load-weighted average prices than the percentages suggest.
  - ✓ Gas, oil-fired and dual-fueled resources set prices in 23 percent of intervals during 2010, a significant increase from 17 percent in 2009.
  - ✓ Over 35 percent of all real-time energy costs were incurred when these resources were on the margin.

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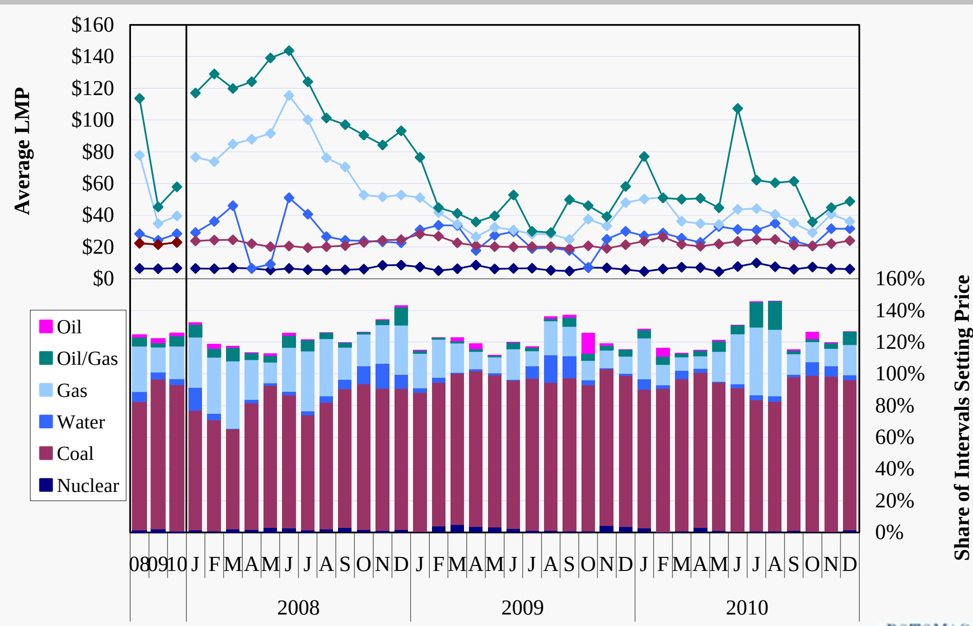
Share of Interval Price Setting by Unit Fuel Type 2008 – 2010



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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 2008 through 2010 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 in 2009 of the Voluntary Capacity Auction and Ancillary Services Markets improved long-term price signals. However, Midwest ISO markets would not currently support investment in gas CT or CC generation.
  - ✓ Annualized costs for new capacity are similar to 2009 and remain much higher than net revenues in all areas due to the prevailing surplus of capacity.
  - ✓ The large increase in ancillary services revenues for CTs is due to contingency reserve prices increasing by $1.20 per MWh on average in 2010.
- The prevailing capacity surplus precluded significant periods of shortage in 2010 and contributed to very low capacity prices.
  - ✓ When shortages did occur, the markets in 2010 did not always price them fully because peaking units and interrupted load did not contribute to setting prices.
  - ✓ MISO is working on pricing changes to allow interruptible load and peaking resources to set price.

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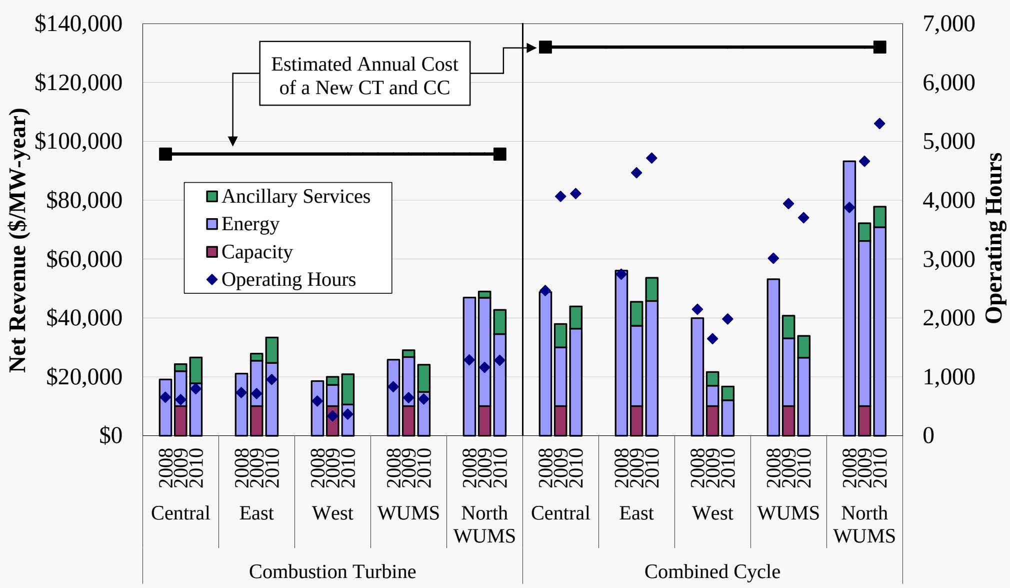
Net Revenue and Operating Hours 2008 – 2010



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Load and Resources

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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 in 2010.
- The annual peak load hour in 2010 occurred on August 10 at nearly 109 GW.
  - ✓ Even during this peak hour, over 8 GW of available generation was not committed, which demonstrates the sizable capacity surplus in the Midwest ISO region.
- Peak loads were substantially higher in 2010 than in 2009, particularly during summer.
  - ✓ In May and July, peak loads exceeded the prior year's by 18 and 17 GW, respectively.
  - ✓ The December peak of 91.4 GW on December 13 set a market winter record.
- The peak load was generally higher than the emergency maximum of all online generation, which indicates that the Midwest ISO continues to use net imports to satisfy its peak energy demands instead of committing offline resources.
  - ✓ Excess headroom, which can indicate over-commitment during peak hours and potentially suppress peak pricing, was less of a concern in 2010, except in September (nearly 3.7 GW). Peak pricing is evaluated later in the report.
- New members joining in June (DPC) and December (BREC) added 3 GW of capacity.
  - ✓ The differences in total monthly capacity are due to the intermittent generation in each peak hour. Unavailable intermittent capacity between a wind resource's permanently derated level and actual output is not shown on the chart.

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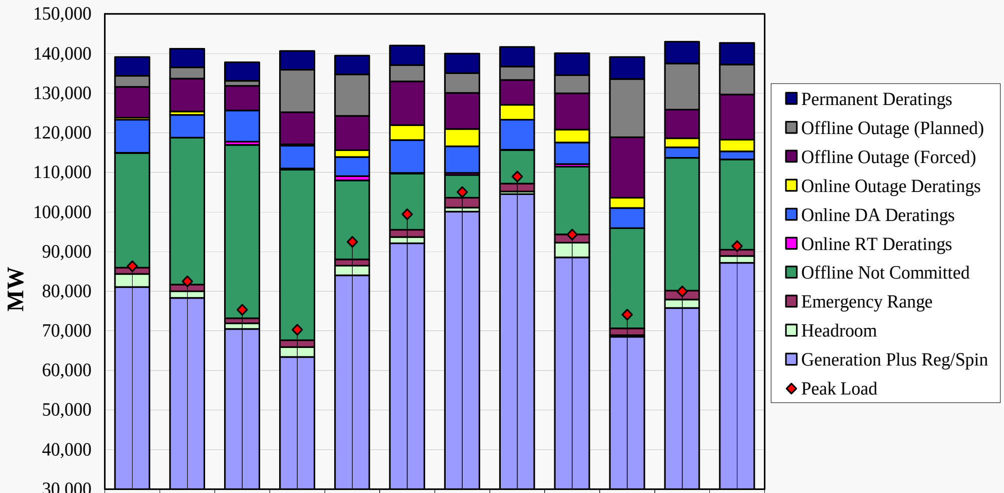
Capacity During Monthly Peak Load Hours 2010

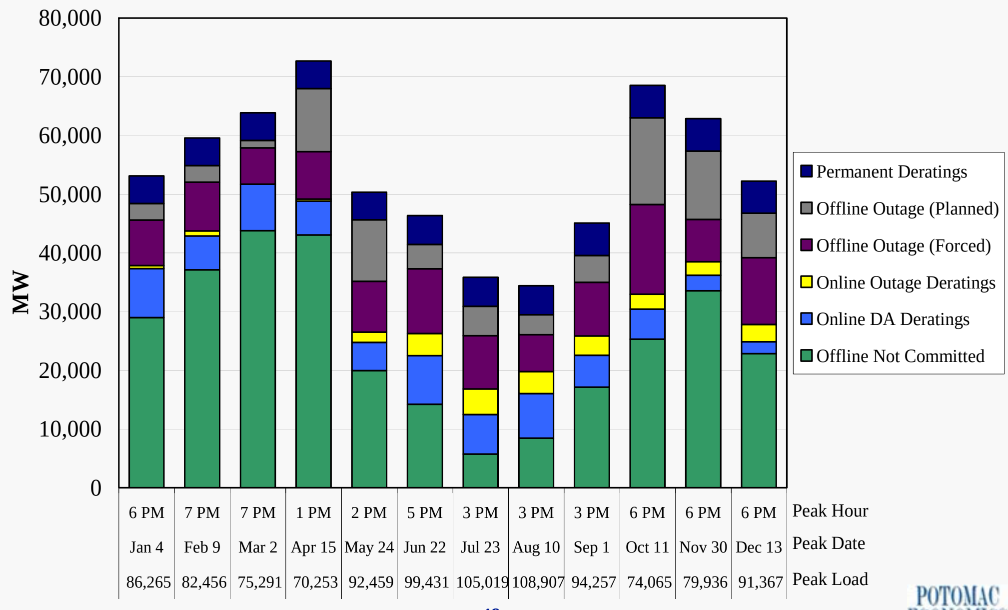


6 PM	7 PM	7 PM	1 PM	2 PM	5 PM	3 PM	3 PM	3 PM	6 PM	6 PM	6 PM	Peak Hour
Jan 4	Feb 9	Mar 2	Apr 15	May 24	Jun 22	Jul 23	Aug 10	Sep 1	Oct 11	Nov 30	Dec 13	Peak Date
86,265	82,456	75,291	70,253	92,459	99,431	105,019	108,907	94,257	74,065	79,936	91,367	Peak Load

Capacity During Monthly Peak Load Hours

- The next figure provides the same results but shows only the capacity that was unavailable or offline.
- The figure shows large quantities of uncommitted generation in most months.
  - ✓ The available uncommitted generation capacity was as low as 5.7 GW in July and 8 GW at the annual peak in August.
  - ✓ It reached as high as 44 GW in March and averaged 25 GW in monthly peak hours (down from over 30 GW in 2009).
- 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 5.5 GW of capacity is “permanently” derated relative to nameplate capacity and is never available for dispatch. 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 often have ratings in excess of available transmission.
- Peak load hours occurred in mid-afternoon in the summer and in the evening during the winter, which is typical of Midwest ISO’s shifting seasonal load pattern.

Offline and Unavailable Capacity During Monthly Peak Load Hour, 2010



POTOMAC ECONOMICS

Generation Outages

- The following figure shows the generator outages that occurred in each month during 2010 as a share of total generation capacity.
  - ✓ These values do not include partial outages or deratings.
  - ✓ The figure splits the forced outages into short-term (fewer than 7 days) and long-term outages (more than 7 days).
- The annual combined outage rate was 13.4 percent for the three categories of outages, increasing from 2008 (9.3 percent) and 2009 (11 percent).
  - ✓ Planned outages rose further in 2010 to 3.4 percent despite higher load levels and energy prices.
  - ✓ Long-term forced outage rates rose to 3.4 percent in 2010.
  - ✓ Short-term outages, which are more likely than other outages to reflect physical withholding, rose slightly to 1.9 percent of capacity in 2010.
- The largest total outage levels occurred in the spring (16 percent) and fall (17 percent) because planned outages are generally scheduled during low load periods.
  - ✓ Planned outages averaged 11 percent during each of these seasons.
- Module E rule changes in the late summer 2009 provided incentives for participants to more accurately report outages and may have contributed to the increases in total reported outage rates over the past two years.

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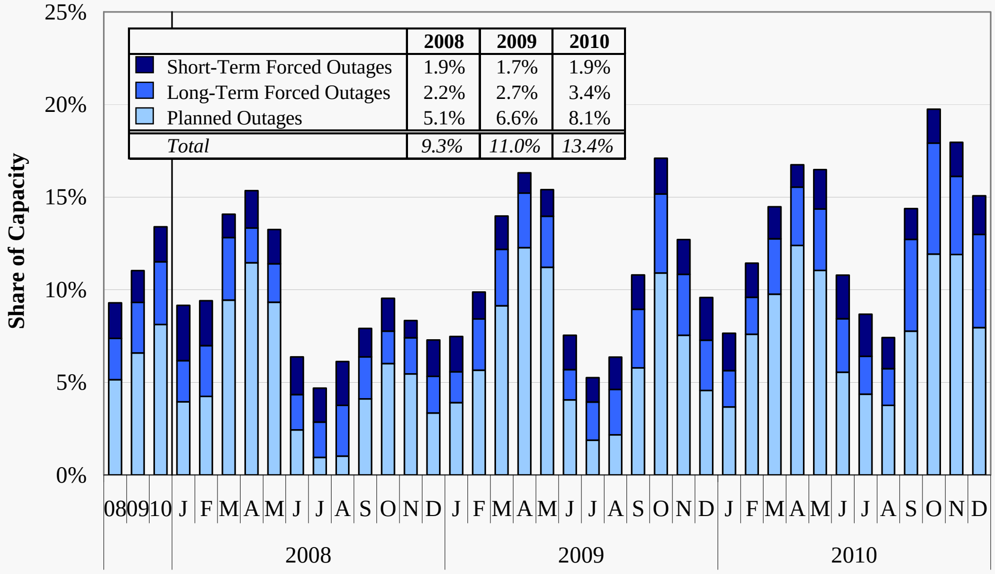
Generation Outage Rates 2008 – 2010



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Load Duration Curves

- The next figure depicts load duration curves for 2010 which show the number of hours that the load is greater than the level indicated on the vertical axis.
- There was a clear upward shift in the 2010 load duration curve from 2009 levels.
  - ✓ Average load in 2010 increased 10 percent to 67.4 GW and peaked above 100 GW for the first time since 2007.
  - ✓ After accounting for changes in membership, average load increased 6.2 percent compared to 2009, but decreased 0.8 percent compared to 2008.
  - ✓ However, load in the top 1,000 hours was considerably higher in 2010 than 2008 due to relatively hot summer conditions.
- The figure also shows the instantaneous peak load in 2010 of 109 GW was 3.3 percent below the Summer Assessment-predicted peak demand of 112.7 GW.
  - ✓ Increases in load are primarily attributable to unusually warm temperatures across the Midwest during the summer as well as an increase in economic activity from 2009.
- The figure also shows 18 percent of the energy demands occur in only the top five percent of load hours.
  - ✓ This indicates that a large share of the Midwest ISO's resources is 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.

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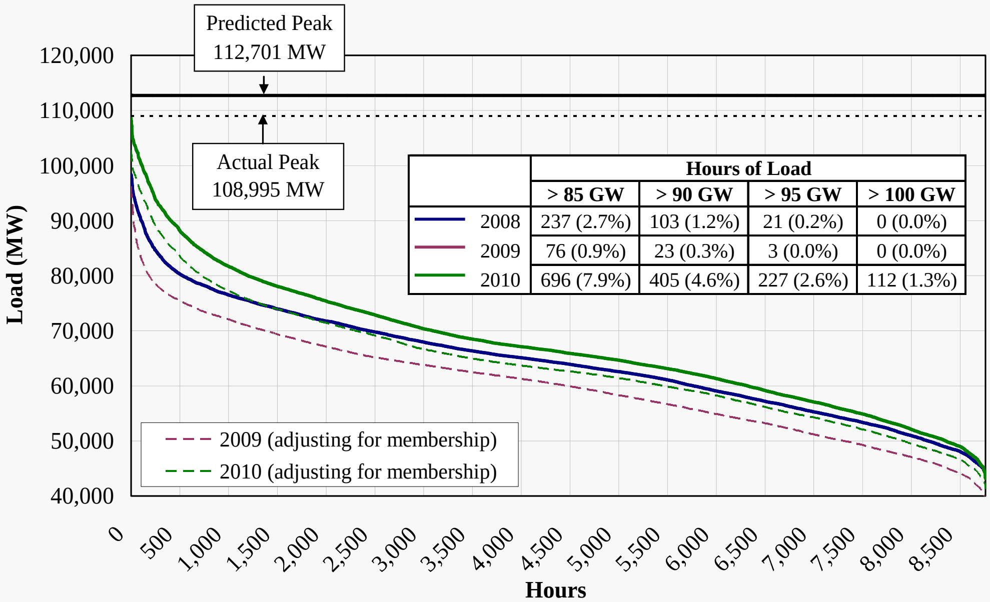
Load Duration Curves 2008 – 2010



	Hours of Load			
	> 85 GW	> 90 GW	> 95 GW	> 100 GW
2008	237 (2.7%)	103 (1.2%)	21 (0.2%)	0 (0.0%)
2009	76 (0.9%)	23 (0.3%)	3 (0.0%)	0 (0.0%)
2010	696 (7.9%)	405 (4.6%)	227 (2.6%)	112 (1.3%)

POTOMAC ECONOMICS

Heating and Cooling Degree Days

- The next figure evaluates weather patterns and monthly load levels from 2008 to 2010.
- The top panel shows loads rose throughout 2010 from 2009. Adjusted for membership changes, annual peak and average load rose 6.9 and 6.2 percent, respectively.
- Because a large share of the load is sensitive to weather, the bottom panel summarizes aggregate weather patterns over the past three years.
  - ✓ The bottom panel shows the monthly Heating Degree Days (“HDD”) and Cooling Degree Days (“CDD”) summed for four primary locations in the Midwest ISO.
  - ✓ To normalize the statistics for the relative effect on load of HDDs and CDDs, HDDs are inflated by a factor of 6.07 (based on a regression analysis).
- In all, total adjusted degree days increased nearly 25 percent in 2010.
- Near-record temperatures between May and August increased summer loads 11 to 22 percent from 2009 averages. Degree days rose by as much as 140 percent.
  - ✓ Each of these months had well above normal temperatures throughout the Midwest ISO, particularly in the East and Central regions.
  - ✓ This is in stark contrast to the summer of 2009, when the coolest July on record for most of the footprint contributed to a 15 percent drop in average load.
- Increased economic activity also contributed to higher loads. The Chicago Purchasing Manager’s Index, a leading business barometer and a broad measure of economic activity in the region, was expansionary in each month in 2010.

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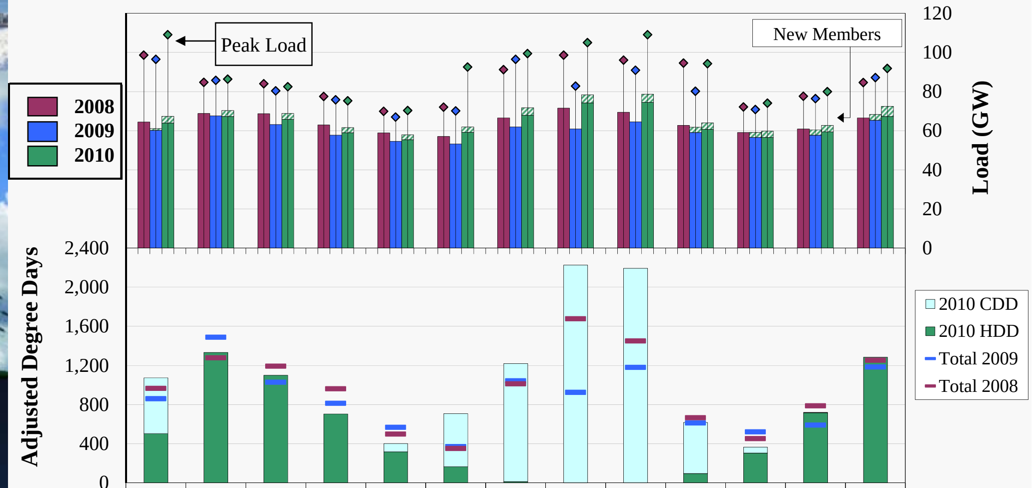
Heating and Cooling Degree Days 2008 – 2010



09-10 % Chg	2010	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Avg. Load	6.2%	-0.5%	4.2%	2.2%	1.5%	11.3%	9.6%	21.9%	15.4%	2.7%	0.0%	2.8%	3.0%
Degree Days	24.7%	-10.4%	6.9%	-13.2%	-29.4%	91.2%	16.9%	141.1%	85.8%	0.8%	-29.9%	22.2%	8.6%

POTOMAC ECONOMICS

Distribution of Regional Generation Capacity By Fuel Type

- The next two figures shows the distribution of generating capacity by location (for 2008 to 2010) and by location and type (for 2010).
- Generating resources in the Midwest ISO market footprint totaled 144.4 GW in 2010, an increase of 5.3 percent from 2009.
  - ✓ These resources include those registered by Midwest ISO market participants and exclude Midwest ISO reliability-only members (an additional 13 GW).
  - ✓ The majority of the added capacity in 2010 is newly-built, consisting primarily of wind resources in the West region (1.5 GW) and a mixture of fossil resources in the East.
  - ✓ The additions of Dairyland Power in June and Big Rivers Electric in December shifted nearly 3 GW of reliability-only capacity into the market.
- The Midwest ISO continues to rely heavily on coal-fired generation – over half of its generation capacity is coal-fired.
  - ✓ Since coal units are generally base-loaded, coal-fired resources generate over three quarters of total energy produced.
- Nuclear units are similarly base-loaded and produce 14 percent of total energy.
- The third largest fuel type is natural gas-fired generation, which accounts for over 28 percent of the supply resources in the Midwest, but less than 6 percent of the energy.
- Wind resource capacity has been steadily increasing and now accounts for 6 percent of market capacity and 3.5 percent of total energy output.

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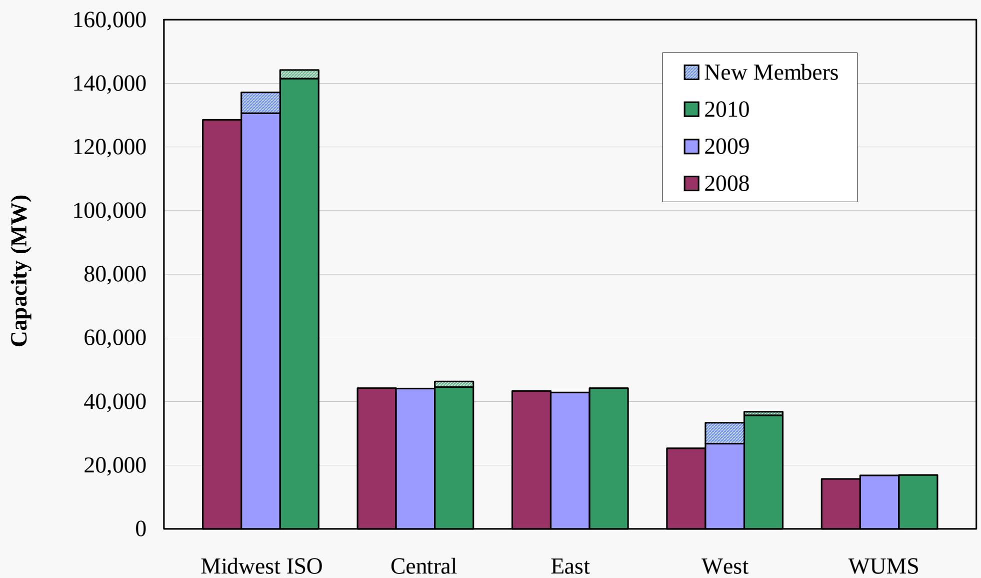
Generation Capacity by Coordination Region 2008 – 2010



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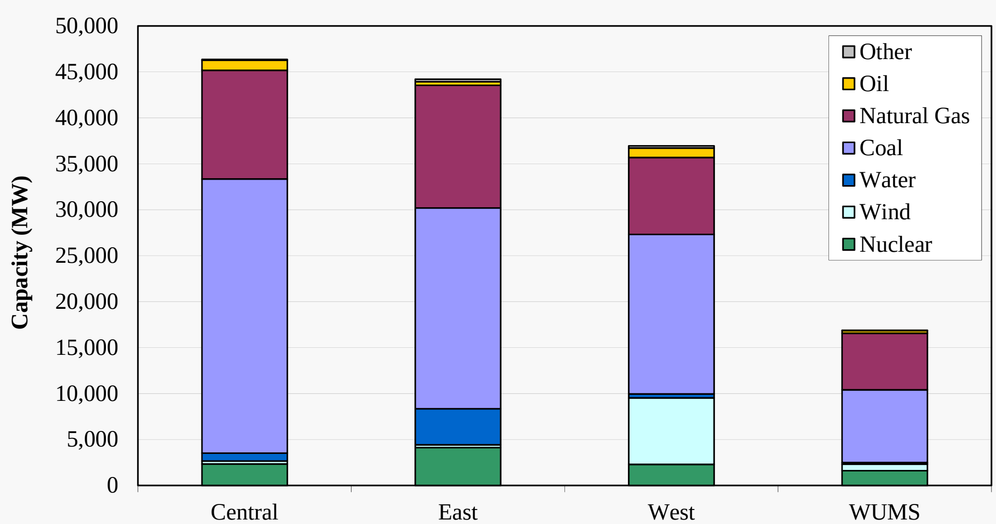
Distribution of Regional Generation Capacity By Fuel Type and Region, 2010



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Generation Capacity and Reserve Margins

- The table shows reserve margins are highly sensitive to the assumed maximum capacity levels and to whether interruptible demand is included.
- Using nameplate capacity levels and the projected levels for 2011:
  - ✓ The reserve margin for the Midwest ISO region is 43 percent when based on Internal Load and 56 percent when based on Internal Demand (which includes DR capability).
  - ✓ Among the regions, the reserve margin varies from 22 percent to 55 percent when based on Internal Load and from 34 percent to 76 percent when based on Internal Demand.
  - ✓ These results suggest 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 2011 for the Midwest ISO region is 17 percent when based on Internal Load and 28 percent when based on Internal Demand.
  - ✓ Among the regions, the reserve margin varies from less than 4 percent in the East to 19 percent in WUMS when based on Internal Load, and from 14 percent to 31 percent when based on Internal Demand.
- Given typical forced outage rates ranging from 3 to 8 percent, the existing capacity in the region should be more than adequate to satisfy the system's demands in 2011.
- However, 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.

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Generation Capacity and Planning Reserve Margins Estimates for 2011

Region	Load	Firm Net Imports	Nameplate		Available Capacity[1]		High Temp. Capacity[2]	
			Capacity	Reserve Margin	Capacity	Reserve Margin	Capacity	Reserve Margin[4]
East								
Internal Load	24,503	285	29,632	22.1%	26,659	10.0%	25,133	3.7%
Internal Demand[3]	22,232	285	29,632	34.6%	26,659	21.2%	25,133	14.3%
Central								
Internal Load	39,407	1,879	49,773	31.1%	46,587	23.0%	43,218	14.4%
Internal Demand	37,675	1,879	49,773	37.1%	46,587	28.6%	43,218	19.7%
West								
Internal Load	25,968	2,410	37,967	55.5%	28,599	19.4%	26,255	10.4%
Internal Demand	22,976	2,410	37,967	75.7%	28,599	35.0%	26,255	24.8%
WUMS								
Internal Load	12,848	320	17,478	38.5%	15,867	26.0%	15,005	19.3%
Internal Demand	11,710	320	17,478	52.0%	15,867	38.2%	15,005	30.9%
MISO								
Internal Load	98,053	5,549	134,850	43.2%	117,712	25.7%	109,610	17.4%
Internal Demand	89,919	5,549	134,850	56.1%	117,712	37.1%	109,610	28.1%

1 Midwest ISO Summer-Rated Capacity from its 2011 Summer Assessment, including undesignated capacity and wind at 8% capacity credit.
2 High Temperature capacity is based upon tempearture derates that occurred in the Day-Ahead market of August 1, 2006.
3 Net Internal Demand estimate excludes all DSM (interruptible load, DCLM, and behind the meter generation).
4 Our planning reserve margins differ from the Midwest ISO's because: a) we include temperature-related deratings (reduces our margins), b) we include all physical capacity, not only those designated as capacity (increases our margins), c) we calculate our margins based on internal load and internal demand while the Midwest ISO's is generally based on internal demand, d) we exclude estimated forced outage rates (increases our margins).

POTOMAC ECONOMICS

Additions and Retirements of Generation Capacity 2010 – 2011 Planning Year

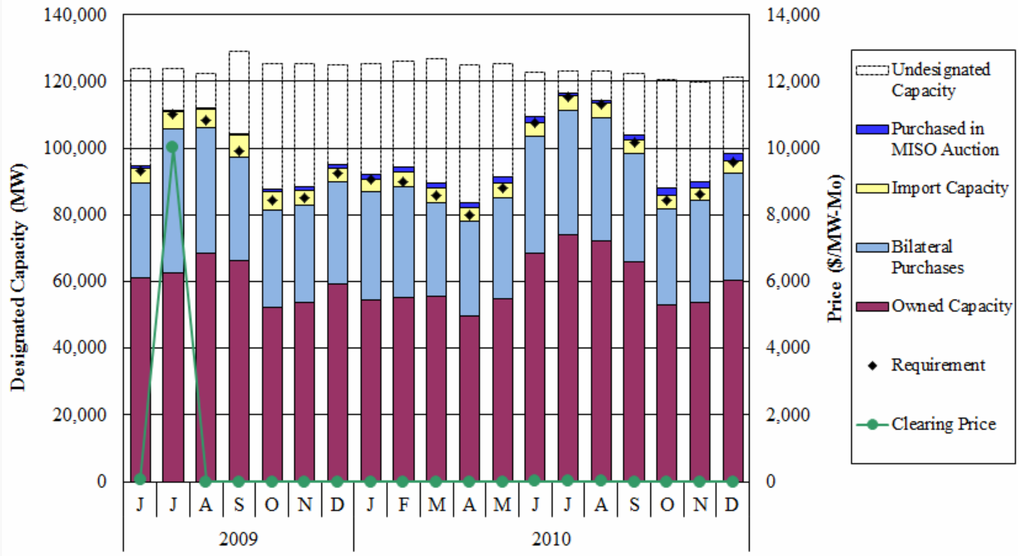
- The following table below shows the capacity added since summer 2010 and expected to be available for upcoming summer 2011.
- In all, 3.4 GW of additions and 1.1 GW of retirements are expected.
  - ✓ This excludes the anticipated exit of First Energy in June 2011, which will remove 13.6 GW from the Midwest ISO footprint.
- About half of the additional capacity is wind generation, most of which is in the West.
  - ✓ However, wind units contribute less to reliability due to their intermittent nature.
  - ✓ Their capacity credit for Module E resource adequacy will be determined on a case basis, and will range from 0 to 31 percent for Planning Year 2011.
- Nearly all other additions are coal and gas resources in the Central region.
- Over 70 percent of the retirements are coal units, most of which are in the East region.

Region	Coal	Gas	Waste	Water	Wind	Total
Central	880	795	0	0	150	1,825
East	0	0	2	0	10	12
West	0	0	0	9	1,381	1,390
WUMS	0	0	0	0	162	162
Midwest ISO	880	795	2	9	1,703	3,390

Voluntary Capacity Auction Results

- 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 average capacity cleared in the VCA rose by 1,000 MW in 2010.
  - ✓ It remains a very small percentage (2.6 percent) of total designated capacity.
  - ✓ This indicates that the VCA is serving as a balancing market with most LSEs' needs satisfied through owned capacity or bilateral purchases.
- The VCA in each month in 2010 cleared at less than $10 per MW-month (close to zero), which is indicative of the surplus capacity in the Midwest ISO.
- 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, ranging from 1 percent in summer months to nearly 5 percent in shoulder months.
  - ✓ The total capacity available significantly exceeded the requirements, from a minimum of 6 percent for July to a maximum of 52 percent for April.
- Requirements are based on the forecasted monthly peak load, so they vary monthly.
  - ✓ The clearing price will likely remain low so long as available capacity exceeds this requirement.

Voluntary Capacity Auction Results
June 2009 – December 2010



Note: Total column height represents the total designated capacity, including imports.

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Day-Ahead Market Performance

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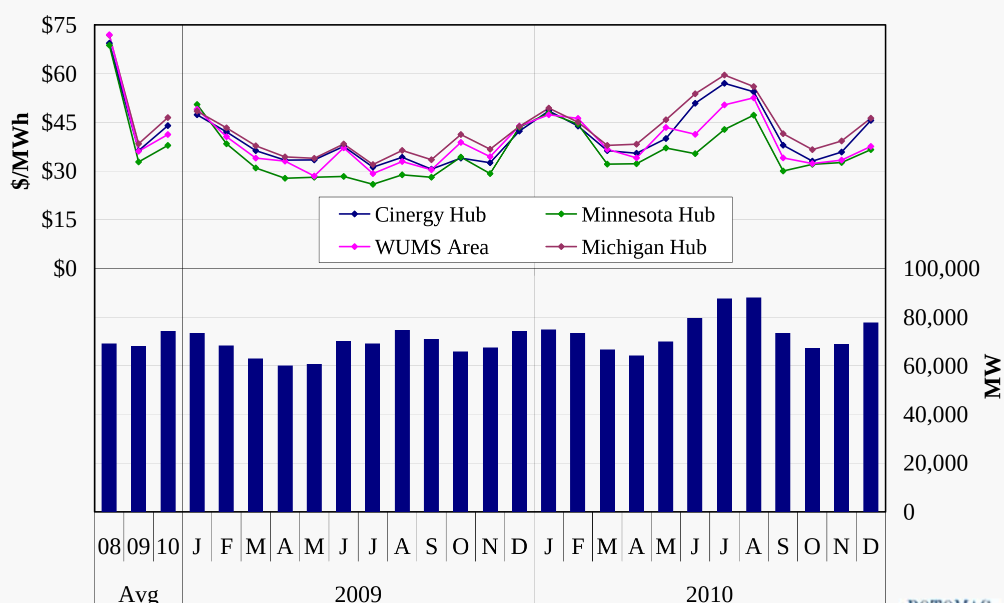
Day-Ahead Hub Prices and Load
Peak Hours

- The next figure shows average daily day-ahead prices during peak hours (6 am to 10 pm on weekdays) and the corresponding average scheduled load (including net cleared virtual demand).
- Overall, day-ahead prices in 2010 were stable throughout the year and tracked changes in fuel prices and load conditions.
  - ✓ Average prices during peak hours were highest during a sustained heat wave in the summer and in January, when natural gas prices were highest.
  - ✓ The average load-weighted day-ahead price in peak hours rose 19 percent to $42.69 per MWh in 2010.
- Differences in prices at the four representative hubs show the prevailing congestion patterns throughout the year.
  - ✓ West-to-east congestion across the Midwest ISO again caused the lowest average prices in Minnesota ($38 per MWh) and the highest prices in Michigan ($46).
    - – Price separation was most apparent in June and July, when high loads in the East, along with transmission outages and seasonal deratings, contributed to a nearly $20 price difference between Minnesota and Michigan Hubs.
  - ✓ Despite day-ahead loads often approaching 100 GW, peak prices in June through August averaged just over $50 per MWh due to moderate fuel prices.

POTOMAC ECONOMICS

Day-Ahead Hub Prices and Load
Peak Hours

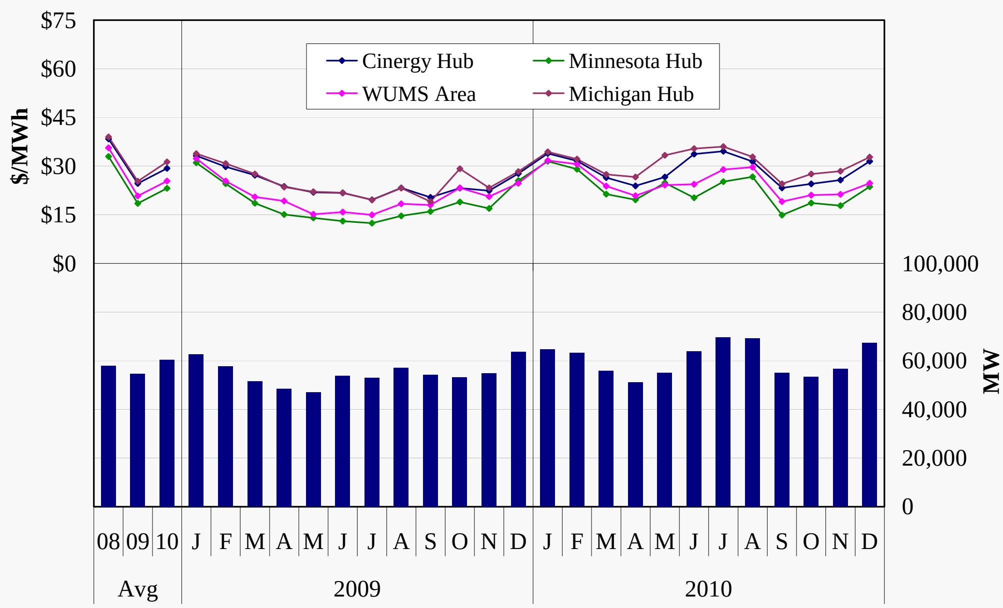


POTOMAC ECONOMICS

Day-Ahead Hub Prices and Load
Off-Peak Hours

- The next figure shows average day-ahead prices and load during off-peak hours.
- Day-ahead off-peak prices averaged $27.65 per MWh in 2010.
  - ✓ This is a 21 percent increase from 2009, but a 28 percent decrease from 2008.
- Prices rose primarily on higher day-ahead loads (up 5.6 percent, adjusted for membership) and higher coal prices.
  - ✓ Coal-fired generation was almost always on the margin in off-peak hours.
  - ✓ Off-peak prices did not rise as fast as peak prices due to less congestion.
- As in prior years, the price spread between the eastern and western halves of the footprint was more consistent during off-peak hours.
  - ✓ Prices averaged over $31 per MWh at Michigan and $29 at Cinergy Hub.
  - ✓ WUMS prices averaged $26 while Minnesota prices averaged just $23.
  - ✓ Increased day-ahead scheduled wind generation (up 46 percent), which is higher during off-peak hours, contributed to recurring congestion out of the West.
- High loads in the winter-peaking West along with modestly higher fuel prices reduced the difference between Minnesota and Michigan Hub prices in January and February to approximately $3 per MWh.
  - ✓ This price spread averaged nearly $9 between March and December.

Day-Ahead Hub Prices and Load
Off-Peak Hours, 2010



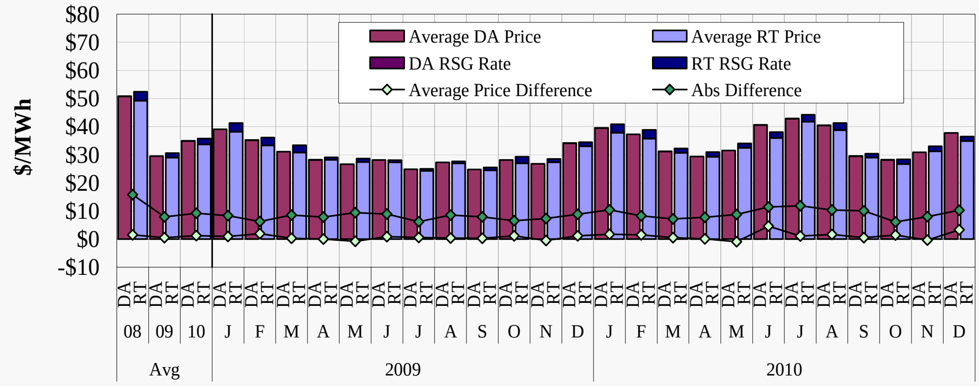
Day-Ahead and Real-Time Price Convergence

- 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 Midwest ISO's generator commitments – 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; and
  - ✓ The entitlements of firm Financial Transmission Rights ("FTRs") 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 the average and the average absolute value of the day-ahead price premiums as a share of the real-time price for four representative locations.
- There were modest day-ahead premiums at Cinergy Hub in most months of 2010.
  - ✓ Day-ahead premiums are rational because day-ahead prices are less volatile and entities purchasing in the real-time market are subject to a higher RSG uplift cost allocation ($2.04 per MWh versus just $0.04 allocated to day-ahead purchases).
  - ✓ After adding the average RSG allocations, price convergence is very good.
- Average price differences, excluding uplift charges, were largest in WUMS: the day-ahead premium in 2010 averaged 7 percent and exceeded 10 percent in several months.
  - ✓ Real-time congestion on market-to-market constraints out of WUMS contributed to lower prices there, particularly in late summer.
  - ✓ These types of differences are not quickly arbitraged due to relatively low virtual trading volumes, likely due to the real-time RSG allocations to virtual supply.
    - – The RSG allocation in 2010 imposed disproportionately large costs on virtual supply transactions, but was replaced in April 2011.
- 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 there caused partly by negative real-time price spikes during off-peak hours.

Day-Ahead and Real-Time Prices
Cinergy Hub, 2009 – 2010



Average DA-RT Price Difference (% of Real-Time Price)

	Avg 08	Avg 09	Avg 10	2009 J	F	M	A	M	J	J	A	S	O	N	D	2010 J	F	M	A	M	J	J	A	S	O	N	D
Cinergy Hub	3	2	3	2	6	1	0	-3	3	2	1	1	4	-2	3	4	4	2	0	-3	13	2	4	2	5	-1	9
Michigan Hub	3	2	4	4	5	4	0	-4	-1	0	4	3	7	-1	2	8	3	2	3	2	10	5	2	2	-5	-2	10
Minnesota Hub	3	4	2	7	8	12	3	1	11	-3	6	-5	1	4	-1	13	4	4	-2	-3	0	-5	3	5	7	-3	4
WUMS Area	3	8	7	8	12	12	6	4	13	2	8	5	8	16	5	13	9	8	1	-5	15	-2	10	21	11	4	2

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

	Avg 08	Avg 09	Avg 10	2009 J	F	M	A	M	J	J	A	S	O	N	D	2010 J	F	M	A	M	J	J	A	S	O	N	D
Cinergy Hub	32	27	27	22	19	28	28	34	33	25	32	32	24	27	27	28	23	23	26	27	32	28	27	35	23	25	29
Michigan Hub	33	32	31	22	19	29	33	34	34	27	37	47	39	34	27	30	24	24	32	39	33	31	27	40	37	26	31
Minnesota Hub	38	39	35	29	28	43	46	51	51	34	42	41	34	35	36	36	28	28	30	37	35	29	31	47	39	43	32
WUMS Area	37	39	33	25	31	38	39	55	55	33	37	39	37	41	37	35	26	28	28	35	41	30	33	50	31	32	31

ECONOMICS

Day-Ahead ASM Prices and Price Convergence

- Ancillary Services Markets were introduced in January 2009 and have operated without significant issues.
- The following chart shows monthly average day-ahead clearing prices for the Midwest ISO's ancillary service products in 2010.
  - ✓ The ASM prices in the Midwest ISO have been consistent with expectations and are comparable to ASM results in similar markets.
  - ✓ Year-over average prices for regulating and spinning reserves were nearly unchanged.
  - ✓ Supplemental reserve prices rose after February due to a reduction in offers on concerns by some participants regarding the ability to satisfy deployment obligations.
- Regulation prices were often 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 offers.
- Day-ahead spinning reserve prices diminished over 2010, in part due to the headroom commitment changes in day-ahead RSC in June 2010, which increased day-ahead spinning reserve capability.
- The small number of shortages of supplemental reserves (occurring mostly during ARS events) resulted in slightly higher real-time prices in some months.

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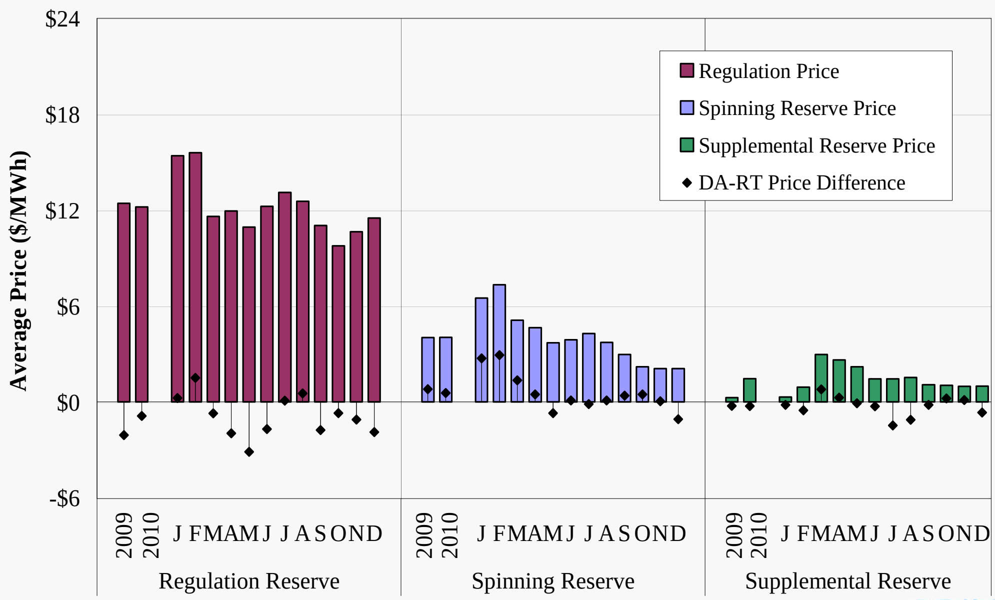
Day-Ahead ASM Prices and Price Convergence 2010



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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 in the peak hours of the day, the Midwest ISO will frequently commit peaking resources to satisfy the incremental real-time load, increasing real-time RSG costs.
- Participants will have incentives to schedule net load less than 100 percent when:
  - ✓ Significant quantities of generation are committed by participants or by the Midwest ISO after the day-ahead market;
  - ✓ Wind resources are underscheduled in the day-ahead market; or
  - ✓ High-cost units (such as peaking resources) do not set prices in the real-time market when they are needed to meet the market’s generation demand.

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Day-Ahead Load Scheduling

- 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 2010 averaged over 99 percent of actual load.
  - ✓ Full load scheduling reduces the need for the Midwest ISO to commit peaking resources in real-time, thereby lowering overall RSG costs.
- Net load scheduled in the day-ahead market as a percent of real-time load declined by 0.6 percentage points from the 99.9 percent recorded in 2009.
  - ✓ Scheduling during peak load hours similarly decreased, by 0.7 percent.
- Much of the peak-hour under-scheduling occurred in the peak load months.
  - ✓ Under-scheduling of wind generation in the day-ahead market (in January and February) and summer load forecast uncertainties (including thunderstorms) contributed to the modest under-scheduling.
- As in 2009, the day-ahead market consistently cleared net virtual load.
  - ✓ Midwest ISO began allocating RSG charges to cleared virtual supply in late 2008.

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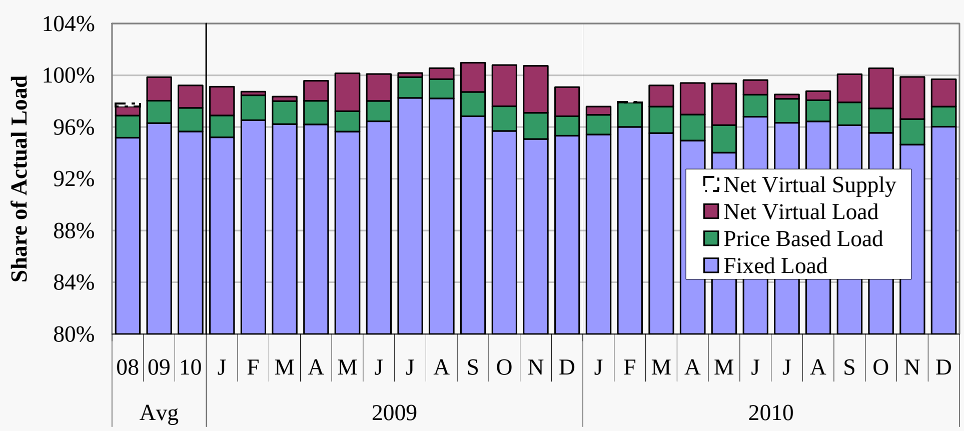
Day-Ahead Load Scheduling vs. Actual Load Daily Peak Hour, 2010



Share of Actual Load(%)

	Avg 08	Avg 09	Avg 10	2009 J	2009 F	2009 M	2009 A	2009 M	2009 J	2009 J	2009 A	2009 S	2009 O	2009 N	2009 D	2010 J	2010 F	2010 M	2010 A	2010 M	2010 J	2010 J	2010 A	2010 S	2010 O	2010 N	2010 D
All Hour	99.2	99.9	99.3	100.1	99.4	98.7	99.2	99.4	99.9	100.3	100.7	100.4	100.1	100.2	100.6	98.2	98.9	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0
Peak Hour	97.6	99.9	99.2	99.1	98.7	98.4	99.6	100.2	100.1	100.2	100.5	101.0	100.8	100.7	99.1	97.6	97.9	99.2	99.4	99.4	99.6	98.5	98.8	100.1	100.5	99.9	99.7

POTOMAC ECONOMICS

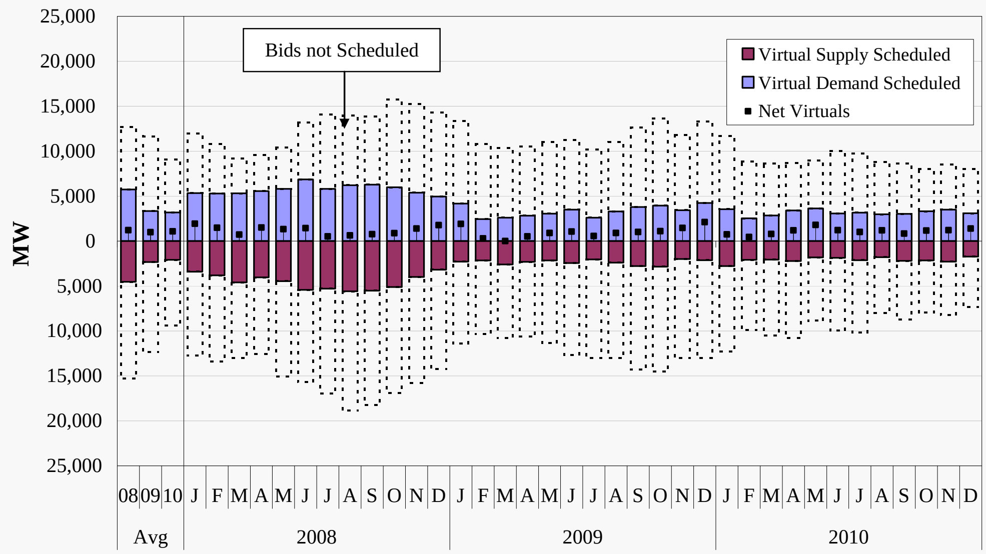
Virtual Load and Supply in the Day-Ahead Market

- Virtual trading in the day-ahead market facilitates convergence between day-ahead and real-time prices and suppresses market power in the day-ahead market.
- The Commission issued a series of Orders from April 2006 to November 2008 in part requiring the allocation of RSG costs to cleared virtual supply.
  - ✓ The average hourly rate applied to virtual supply was $2.04 per MWh in 2010 and was relatively volatile, occasionally nearing $10.
  - ✓ The "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 are just one cause of RSG costs.
  - ✓ Hence, the Interim Rate over-allocates RSG costs to virtual supply, which bore $34 million (roughly 21 percent) of real-time RSG costs under this rate in 2010.
- A revised RSG methodology addressing many of these concerns was implemented in April 2011.

Virtual Load and Supply in the Day-Ahead Market

- The following figure shows virtual demand and supply activity over the past three years.
  - ✓ Total virtual bids and offers decreased by 23 percent from 2009 to 2010.
  - ✓ Virtual supply offer volumes have declined by 39 percent since 2008.
- Cleared (scheduled) virtual demand and supply volumes declined 10 percent or less in 2010, but are down 45 and 54 percent, respectively, relative to 2008.
- Reduced virtual activity raises potential concerns regarding the performance of the day-ahead market because active virtual trading:
  - ✓ Promotes price convergence with the real-time market, which facilitates an efficient commitment of generating resources; and
  - ✓ Protects the market against attempts to raise day-ahead prices at a location through manipulated supply offers or demand bids.
- To date, very few virtual transactions have raised potential concerns and virtual trading restrictions (mitigation) have been applied only once, in early 2010.
  - ✓ The Midwest ISO made modeling changes in early 2010 which reduce the likelihood that similar virtual strategies will be attempted or profitable.

Virtual Load and Supply in the Day-Ahead Market 2008 – 2010



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Virtual Profitability in the Day-Ahead Market

- The next figure shows the monthly average profitability of virtual purchases and sales.
  - ✓ Profitability of all cleared virtual transactions decreased slightly to $0.75 per MWh.
- Virtual supply has been more profitable than virtual demand, primarily due to the prevailing day-ahead price premium.
  - ✓ In 2010, the average profitability of virtual supply transactions was $2.53 per MWh.
  - ✓ However, after average RSG cost allocations of $1.87 per MWh (74 percent of profits), those transactions netted an average profit of only $0.66 per MWh.
- The table below the chart shows the percent of virtuals clearing with abnormally large profits or losses. Large sustained profits may indicate 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 to near 1 percent and never exceeded 1.5 percent in any month in 2010.
  - ✓ We screen transactions with large or sustained losses for those that are primarily caused by the bid or offer. Only one pattern of trades warranted mitigation in 2010.

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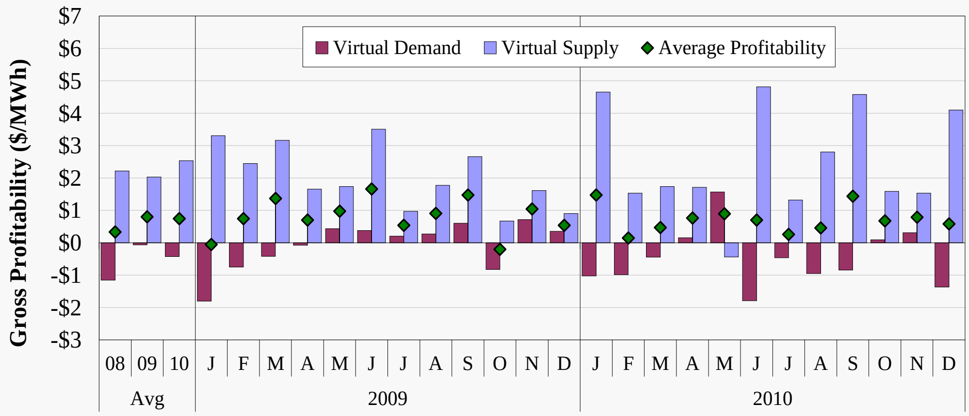
Virtual Profitability in the Day-Ahead Market 2009 – 2010



Share of Cleared Virtuals with Extreme Profitability (%)

	Avg 08	Avg 09	Avg 10	2009 J	2009 F	2009 M	2009 A	2009 M	2009 J	2009 J	2009 A	2009 S	2009 O	2009 N	2009 D	2010 J	2010 F	2010 M	2010 A	2010 M	2010 J	2010 J	2010 A	2010 S	2010 O	2010 N	2010 D
Profit> $50/MWh	2.8	1.2	2.3	0.7	1.2	1.7	0.9	2.0	1.6	0.7	1.4	1.5	0.8	0.7	1.4	2.4	1.0	1.3	2.1	3.6	2.4	2.3	1.7	2.7	2.7	2.5	2.5
Profit< -$50/MWh	3.7	1.6	1.1	0.9	1.0	1.6	1.7	1.6	1.7	0.8	1.6	1.6	1.7	2.5	2.2	1.2	0.8	0.6	1.0	1.5	0.9	1.3	1.0	1.4	1.0	1.3	1.1

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Virtual Profitability by Location

- 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 23 percent of all trading volume, down from nearly 30 percent in 2009.
  - ✓ Most other virtual trading activity occurred at non-hub locations – over 70 percent.
- The average gross profit per MWh of cleared virtual supply offers was $2.53 in 2010.
  - ✓ Virtual supply was generally more profitable at the nodal level ($2.67 per MWh) because nodal locations are more prone to congestion-related price spikes.
    - – Hub prices are an average of many nodes, which dilutes the local congestion impact there.
  - ✓ Over 85 percent (nearly $40 million) of all profits were at nodal locations.
- The average gross loss per MWh of cleared virtual demand bids was $0.43 in 2010.
  - ✓ Approximately one-third of all cleared virtual load bids in 2010 were at the Cinergy Hub, where virtual demand lost an average of $1.57 per MWh, accounting for nearly all of the average losses.
    - – Many of these transactions are physical hedges by generation-owning participants to protect against price spikes in the real-time market.
  - ✓ Virtual load at other locations was slightly profitable overall.

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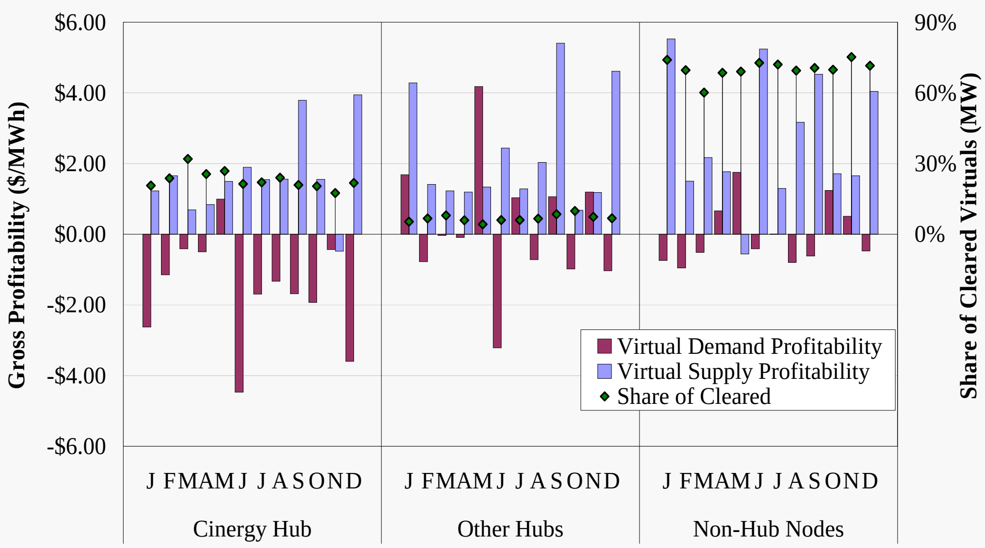
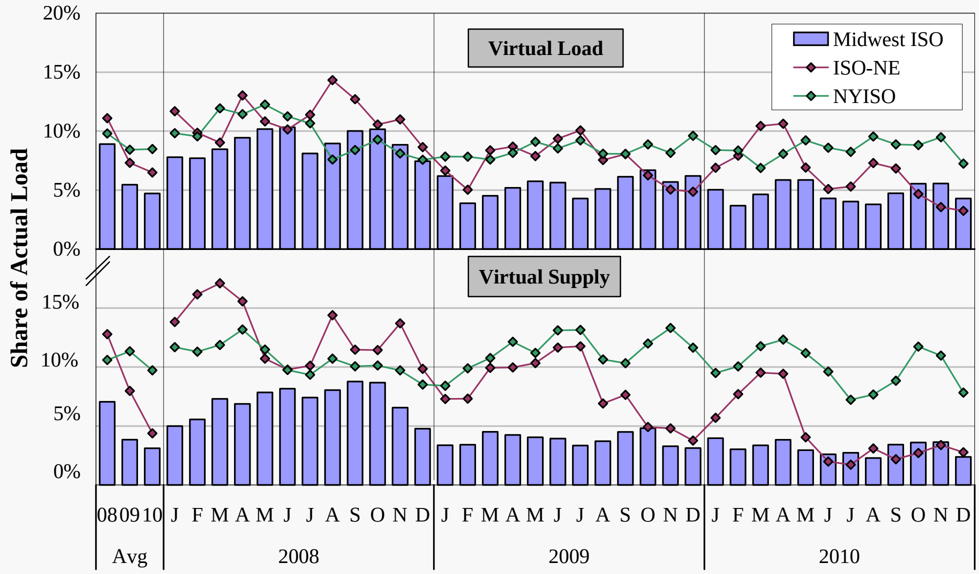
Virtual Profitability by Location
2010



Virtual Transaction Volumes
Eastern Interconnect

- The next figure shows monthly average transaction volumes of virtual supply and demand for the Midwest ISO and two other RTOs as a percent of actual load.
- Virtual demand and supply volumes declined in all three RTOs in late 2008 due primarily to the credit market issues that occurred at that time.
  - ✓ Volumes in NYISO in 2010 declined slightly but remain near 10 percent of actual load.
  - ✓ Volumes in ISO-New England declined in mid-2010 due to modeling changes deployed in May, as well as an increase in uplift charges in the second half of the year.
- Virtual volumes as a share of actual load in the Midwest ISO declined by less than one percentage point in 2010 and averaged less than 5 percent, lower than either of the other RTOs.
- 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.
  - ✓ This rate averaged $2.04 per MWh in 2010 but varied considerably – the standard deviation was $2.39.

Virtual Transaction Volumes Eastern Interconnect



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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 2010.
  - ✓ The day-ahead forecast of peak load was equal to actual real-time load, which indicates that the forecasting was very accurate overall.
  - ✓ This masks some of the substantial day-to-day variability in load forecasting accuracy.
  - ✓ The average peak load forecast error – the magnitude of the error, regardless of direction – was 1.9 percent in 2010, unchanged from 2009.
    - – 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, when weather is more volatile, and under-forecasted in the shoulder months.
  - ✓ This is partially due to load forecast errors by participants. In addition, summer storms contribute to increased volatility in real-time load due to rapid temperature changes.

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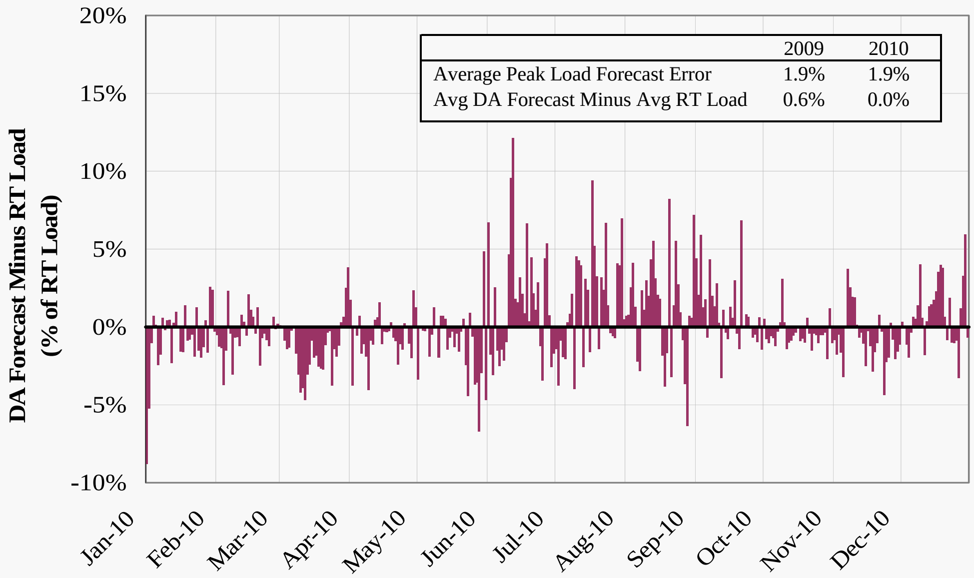
Day-Ahead Forecast Error in Daily Peak Hour 2010



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Real Time Market Performance

POTOMAC ECONOMICS

Real-Time Hub Prices and Load
Peak Hours

- The first figure in this section shows average real-time prices during peak hours and the corresponding actual load.
- The figure shows a positive correlation between peak load and peak prices, with some notable price separations due to transmission congestion.
- Increases in fuel prices and summer loads resulted in higher prices across the footprint.
  - ✓ The load-weighted real-time energy price during peak hours in 2010 was $41.43 per MWh, up 19 percent from 2009 but 38 percent lower than in 2008.
  - ✓ The price of natural gas rose 14 percent and is often the marginal fuel in peak hours.
  - ✓ Load averaged 74.5 GW during peak hours and exceeded 100 GW on 21 days.
- High loads and transmission congestion resulted in transitory price spikes, notably at Minnesota and WUMS in May and at Cinergy Hub in July.
  - ✓ However surplus conditions in the Midwest ISO limited the frequency of high-priced events – there was only one Maximum Generation Alert (and no Event) in 2010.
- As in the day-ahead market, west-to-east congestion prevailed throughout the year.
  - ✓ Prices in the East region averaged $44 per MWh while prices in the West averaged $38.
  - ✓ This trend is less apparent during peak hours than during off-peak hours, when high levels of wind contribute to excess generation conditions in the West.

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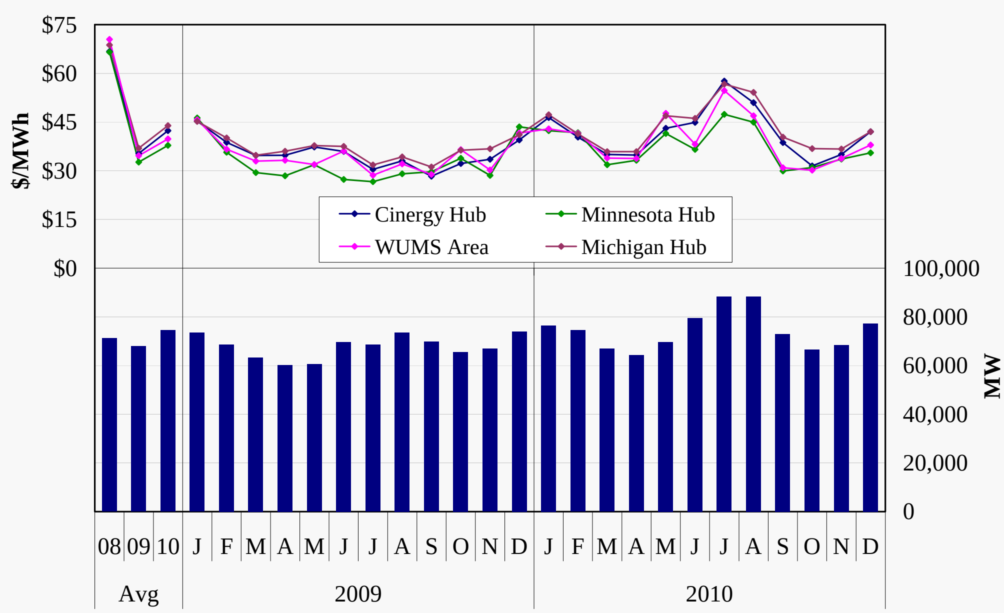
Real-Time Hub Prices and Load
Peak Hours



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Real-Time Hub Prices and Load
Off-Peak Hours

- The next figure shows average real-time prices and actual load during off-peak hours.
- 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; and
  - ✓ Higher wind generation levels in off-peak hours (up 32 percent in 2010).
- Off-peak prices averaged $26.49 per MWh, up 19 percent from 2009.
  - ✓ This increase was due to higher fuel prices and to fewer instances of negative system-wide prices.
  - ✓ There was only one Minimum Generation Event in 2010, so system-wide negative pricing was not frequent.
- Persistent west-to-east congestion resulted in lower off-peak prices in Western areas.
  - ✓ Prices averaged over $30.50 per MWh at Michigan hub and $28 at Cinergy hub.
  - ✓ Prices averaged just $22 and $23 in at Minnesota and WUMS, respectively.
  - ✓ Congestion out of the West resulted in over 260 off-peak hours with negative prices at Minnesota and WUMS in 2010.
- Transmission and generator outages affecting the Southwestern Michigan interface contributed to Michigan exhibiting the highest off-peak prices in the footprint.

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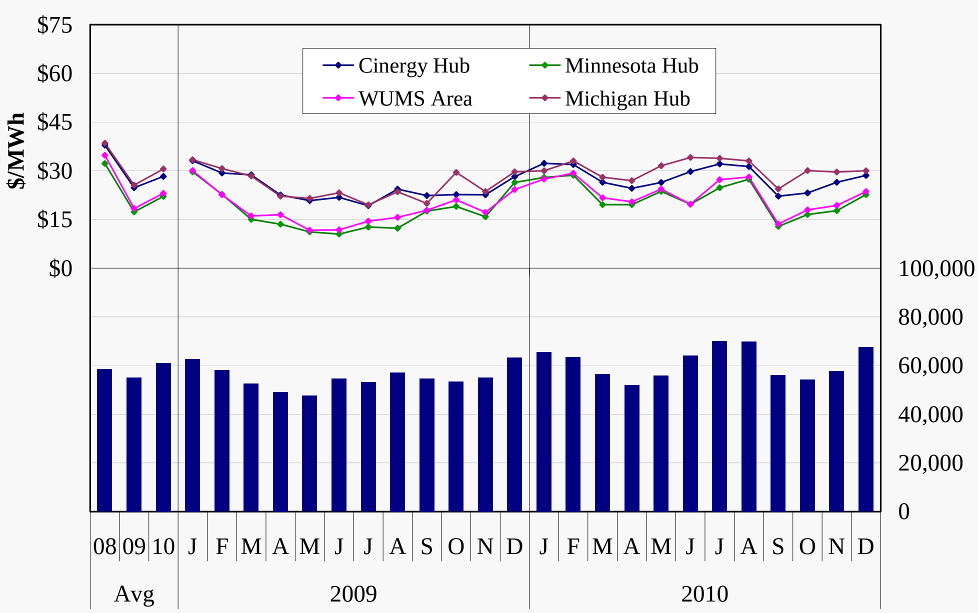
Real-Time Hub Prices and Load
Off-Peak Hours, 2010



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Real-Time Prices by Time of Day

- The following figure shows interval-level average real-time prices by time of day in the summer of 2010 when loads are the highest.
  - ✓ Price volatility has decreased substantially since the introduction in 2009 of ASM markets that are jointly optimized with the energy market.
- 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 2010:
  - ✓ 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.

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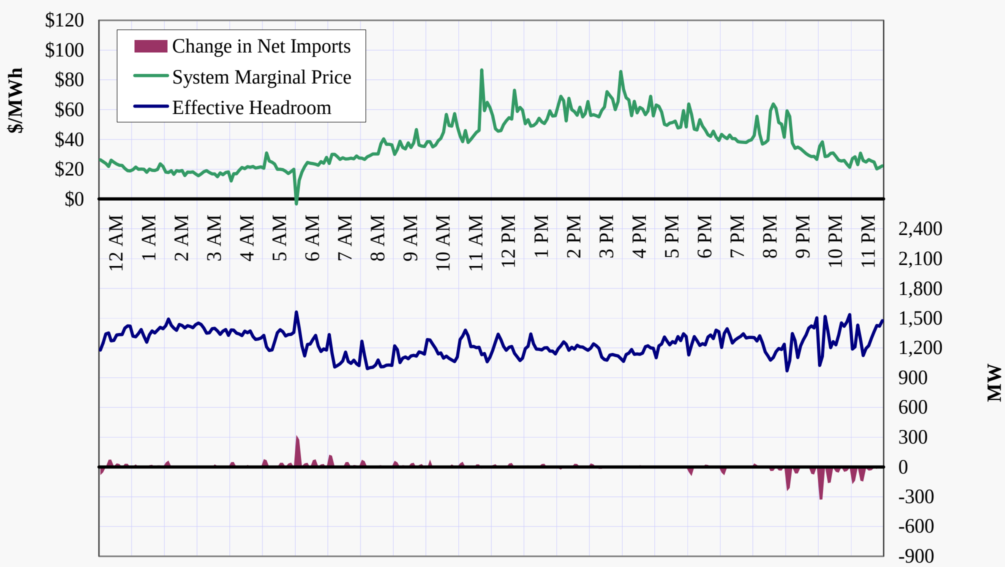
Real-Time Prices by Time of Day
Summer 2010



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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 in 2010 the Midwest ISO, along with NYISO, has the most price volatility and ISO-NE has the least. These differences can largely 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.
    - – Of the Midwest ISO locations shown, Cinergy Hub exhibited the least volatility interval-to-interval because it is the least affected by congestion.
  - ✓ 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 satisfy 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.
  - ✓ Additionally, the 5-minute prices produced between dispatch runs are not likely to change significantly.
  - ✓ Because the system is redispatched less frequently, these markets likely rely more heavily on regulation to satisfy intra-interval changes in load and supply.

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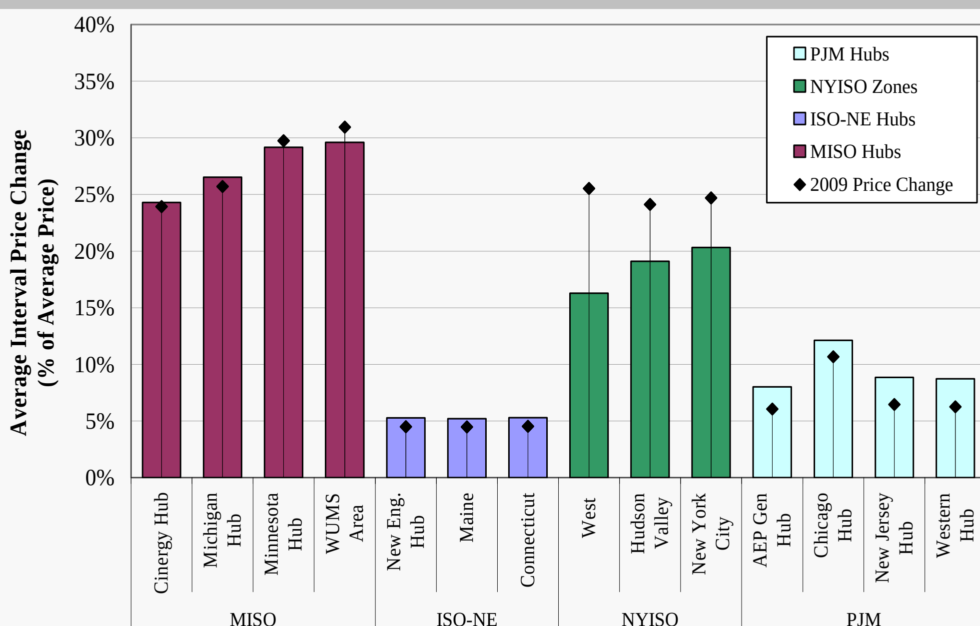
Five-Minute Real-Time Price Volatility
Midwest ISO and Neighboring Markets, 2010



POTOMAC ECONOMICS

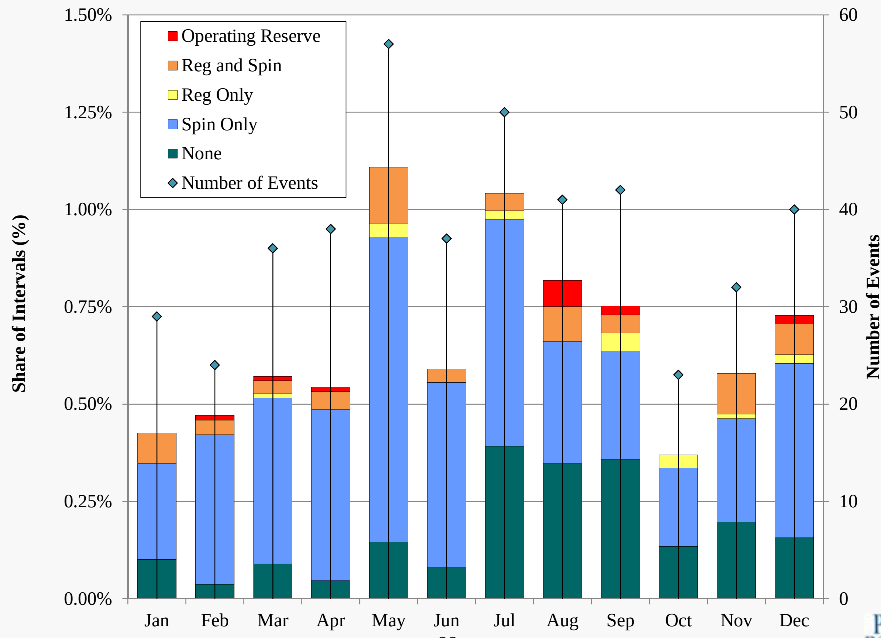
Evaluation of High-Priced Intervals

- We performed a study in 2010 analyzing the primary causes of relatively high prices in the Midwest ISO. The results are shown in the following three figures.
- The first class of events we analyzed was high system-wide prices.
  - ✓ Each event is a period characterized by a System Marginal Price (“SMP”) greater than $175 per MWh during one or more 5-minute intervals.
  - ✓ There were 449 such events in 2010, lasting on average 1.6 intervals. The longest event lasted 8 intervals (less than 1 hour).
- The second class of events was relatively high prices at specific location caused by congestion. This events were identified by:
  - ✓ An LMP greater than $175 per MWh *and* a congestion component equal to at least $50 per MWh.
  - ✓ Since these events are localized, they occur much more frequently: 6,744 such events occurred in the studied period, lasting on average 8.76 intervals.
    - – The longest constraint-specific locational price spike lasted 16 hours.

High-priced SMP Events

- The first figure shows the number of system-wide pricing events by month, along with the types of shortages that occurred during the event.
- The figure shows that high-priced events occurred in each month, ranging from 23 events in October to 57 events in May.
  - ✓ Since price spikes often lasted only one interval, the share of intervals that were high-priced was less than 1 percent during most months.
  - ✓ The number of events increased modestly during the higher-load summer months.
- The figure also shows that in more than three-quarters of high-priced intervals, the market was short of one or more ancillary service product.
  - ✓ The value of the forgone ancillary services is included in both the ASM and energy prices, so it is not surprising that most of the high prices are associated with one or more shortages of reserves or regulation.
    - – Summer is the exception as higher loads caused nearly half of the high-priced events from July to September to occur without an ASM shortage.
  - ✓ In general, the system will go into shortage in the lowest value reserve first, making trade-offs that will maintain higher-value reserves.
    - – Hence, the system will generally go short first of spinning reserves (60 percent), then regulation (12 percent) and then overall operating reserves (2 percent).

High-priced SMP Events



Causes of High System Marginal Prices

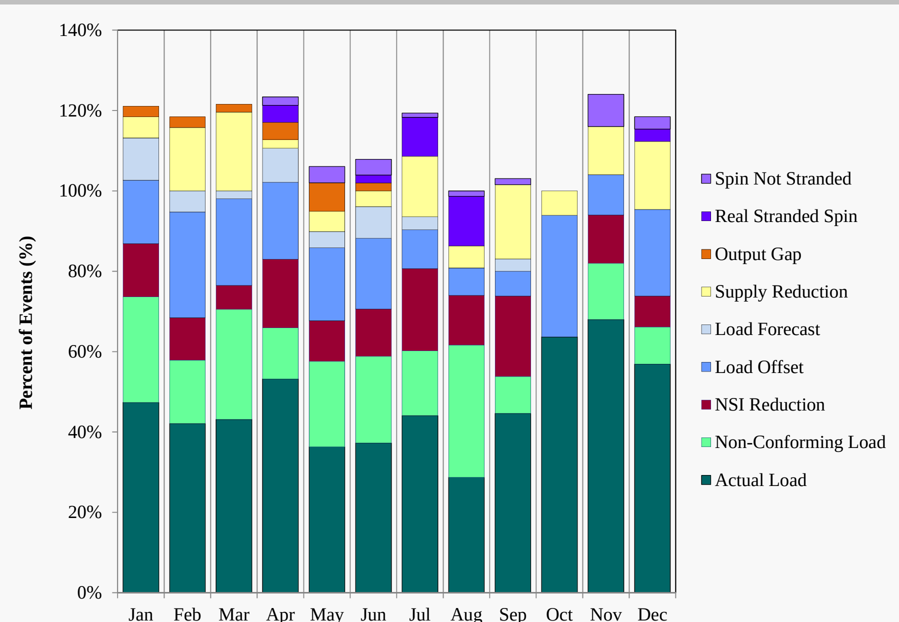
- The next figure identifies the primary causes of high SMPs during the study period.
  - ✓ The figure shows the share of the high-priced intervals in each month that each factor contributed to causing.
- In all cases, the system is limited in its ability to ramp the necessary supply to satisfy both energy and ASM requirements.
  - ✓ In some cases, the system can ramp sufficiently, but only at a cost that is higher than the spinning reserves' value so the system will not procure the entire requirement.
  - ✓ In general, the causes shown in the figure are factors that demand ramp from the system and thus contribute to the shortage and associated high price.
  - ✓ When these factors produce a ramp demand leading into the shortage greater than 300 MW, we classify the factor as a contributor to the shortage.
- The total number of causes exceeds 100 percent in each month because multiple causes may contribute materially to a single high-priced event.

Causes of High System Marginal Prices

- The most prevalent cause of high prices is sharp movements in load. Load increases (actual or non-conforming) contributed to 63 percent of all high-priced events in 2010.
  - ✓ Actual load contributed to 45 percent of all high-priced intervals, while non-conforming load contributed to an additional 18 percent of events.
- Sudden reductions in NSI contributed to 13 percent of the high-priced intervals.
  - ✓ NSI volatility has improved from the early days of the market because the MISO has adjusted its criteria for accepting substantial changes in physical imports/exports.
- Operators' use of the offset, a manual adjustment of the real-time load, contributed in 16 percent of the high-priced intervals.
  - ✓ Some offsets that increase the ramp demand on the system are justifiable if they prevent a larger shortage later.
- Supply reductions by participants contributed to 11 percent of the events. However, potential economic withholding (output gap) contributed only marginally.
- Other causes contributed to a small share of the events.
  - ✓ Errors in the short-term load forecast ("STLF") contributed to 3 percent of intervals. MISO has worked to improve the STLF and such instances decreased through the year.
  - ✓ Spinning reserves "stranded" behind transmission constraints contributed to 3 percent of the events.
- Look-ahead dispatch and commitment tools will recognize many of these factors and allow the Midwest ISO to better manage its ramp capability.

POTOMAC ECONOMICS

Causes of High System Marginal Prices



POTOMAC ECONOMICS

Real-Time ASM Prices and Shortages

- The following chart shows monthly average real-time clearing prices for ancillary service products in 2010.
- Regulation and spinning reserve prices generally declined over the course of 2010.
  - ✓ Regulating reserve prices averaged $13 per MWh, down 9 percent from 2009 due to:
    - Fewer shortages (down 79 percent);
    - A decrease in the regulation demand curve (sets the price during shortages); and
    - A slight decline in the average requirements.
  - ✓ Spinning reserve prices rose 8 percent from 2009 and averaged $3.49 per MWh.
    - The frequency of shortages decreased in the second half of 2010.
    - The price effect of the reduction in shortages was offset by more consistent pricing when shortages occurred (reduced relaxation) and the effects of higher fuel prices.
- Supplemental reserve prices rose from $0.51 per MWh in 2009 to $1.72 in 2010.
  - ✓ Prices rose in the first half of 2010 due to a decline in the offer volume caused by participant concerns over their ability to meet deployment obligations.
  - ✓ In addition higher load levels, particularly in summer, reduced the quantity of generation available for non-energy products.
- Zonal premiums for ancillary service products continue to be low.

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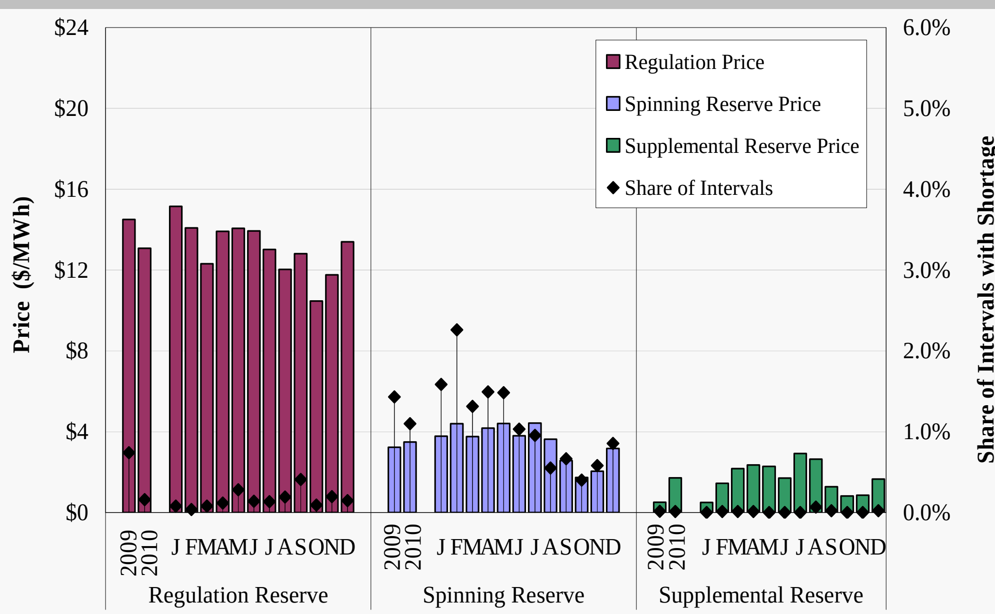
Real-Time ASM Prices and Shortages 2010



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Regulation Offers and Commitments

- The next figures show the real-time offer prices and quantities of the ASM products.
- Average regulation capability rose 16 percent in 2010 to 2,125 MW, but remained 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 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.
- Seasonal increases committed supply resulted in more lower-cost offers becoming marginal – the marginal offer price in July and August was less than $1 per MWh.
  - ✓ The average marginal clearing price for regulation was $13 per MWh, but sufficient capability was typically available to meet the requirement with offers less than $2 per MWh.
  - ✓ This is because the clearing price includes opportunity costs when resources must be dispatched up or down from their economic level to provide regulation.

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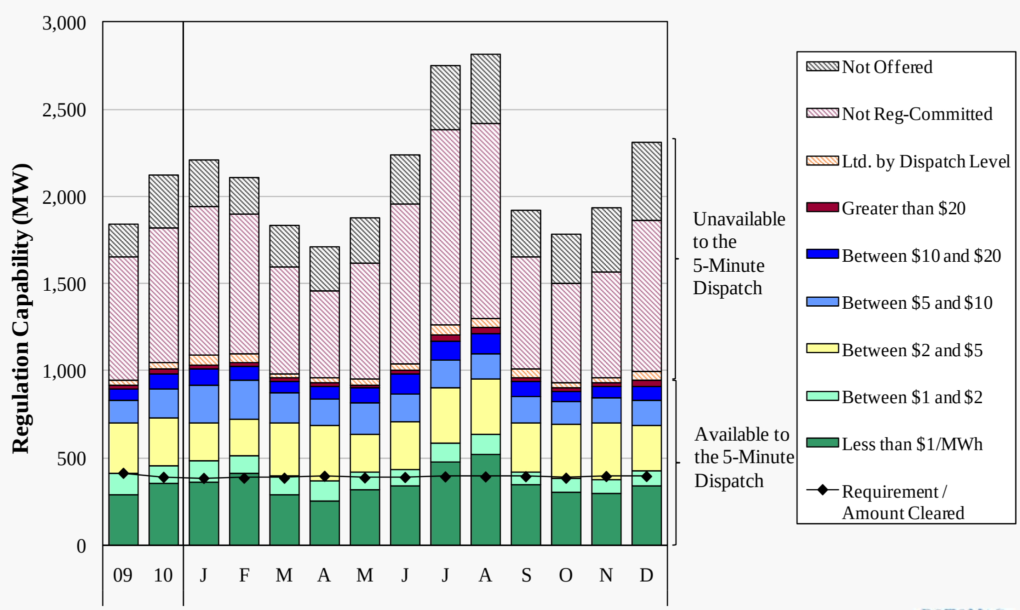
Regulation Offers and Commitments 2010



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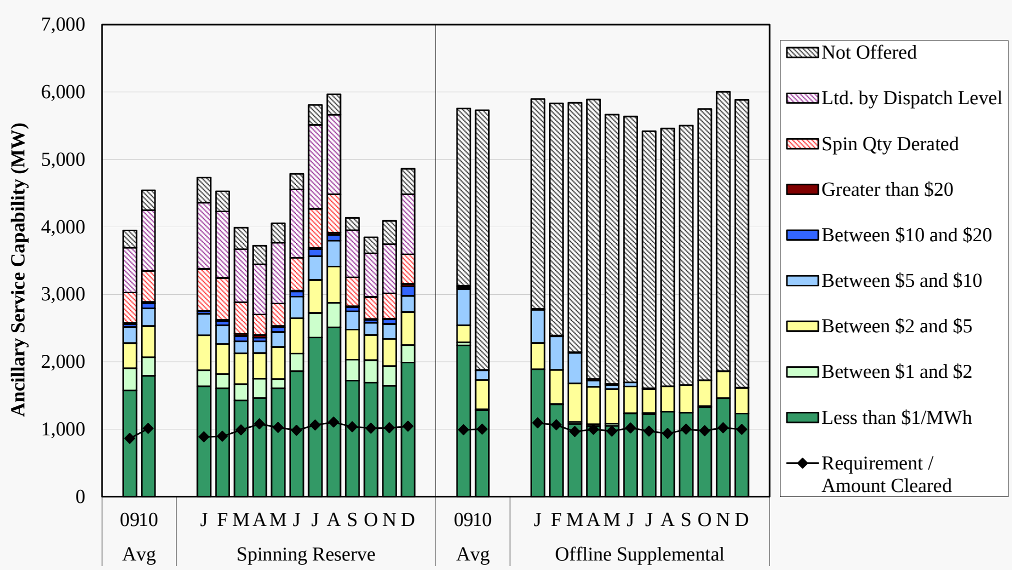
Spinning and Supplemental Offers and Commitments

- 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.
  - ✓ At these levels, suppliers are unlikely to be pivotal and market power is limited.
- As with regulation, the clearing prices for spinning reserves were higher than the offer price tranches indicate due to the contribution of opportunity costs and ramp shortages.
  - ✓ Clearing prices averaged $3.49 per MWh, but sufficient capability was typically available to meet the requirement with offers 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 is due to units that are being dispatched near dispatch maximum, thereby limiting available spinning reserves.
- Over two-thirds of supplemental reserve capacity was not offered in 2010.
  - ✓ Offers exceeded 4,000 MW per hour in March 2009, but have fallen to less than 2,000 MW due partly to participant concerns over their ability to meet deployment obligations.
  - ✓ The Midwest ISO is establishing a guideline for how reliable the deployment of a resource should be for it to be offered, which should help participants determine whether they should be offering a resource.

Spinning and Supplemental Reserve Offers 2010



Market Spin Shortage vs. Real Spin Shortages

- 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, resulting in a real spin shortage that is not reflected in the market outcome.
- To account for this, the Midwest ISO establishes a market requirement that exceeds its real requirement for "rampable" spinning reserves by nearly 200 MW.
  - ✓ Hence, market shortages can occur when MISO is not physically short, or vice versa.
  - ✓ The Midwest ISO should set the market requirement to make the market results as consistent with real conditions as possible.
- The next figure shows all intervals with either a real or market shortage, indicating:
  - ✓ Real shortages occurred in 0.16 percent of intervals, a 50 percent decrease from 2009.
  - ✓ However, market shortages occurred in more than 1 percent of all intervals, indicating that the majority of market shortages were not real shortages.
- 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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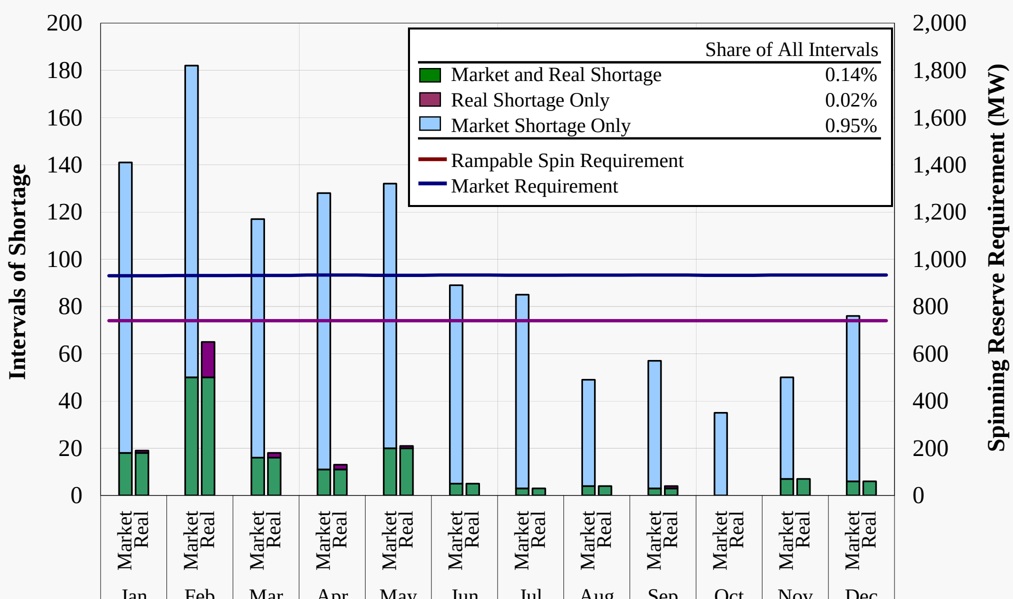
Market Spin Shortage vs. Real Spin Shortages 2010



POTOMAC ECONOMICS

Regulation Pricing During Shortages

- Regulation shortages occurred in just 166 intervals in 2010 (less than 0.2 percent of all intervals), down significantly from 778 in 2009.
  - ✓ The reduction in shortages is due to a general increase in flexibility as a result of:
    - The removal of dispatch bands in March 2010;
    - Higher regulation commitment levels; and
    - Fewer hours with very low loads in 2010, when fewer regulation-capable units are online.
  - ✓ The shortages are generally small, averaging under 100 MW.
- The next figure shows the regulation price during the shortage intervals for the 111 intervals when the market was not short of spinning reserves.
  - ✓ The regulation price during shortage intervals is equal to the monthly regulation penalty price, which averaged $226 per MWh, plus the spinning reserve price.
    - The penalty price is calculated each month and is intended to reflect the commitment cost of a peaking resource, which fell over the year.
  - ✓ The figure shows that regulation shortage prices were consistent with the penalty price regardless of the size of the deficit, which is appropriate and reflects the fact that the Midwest ISO does not relax the requirement during shortages.

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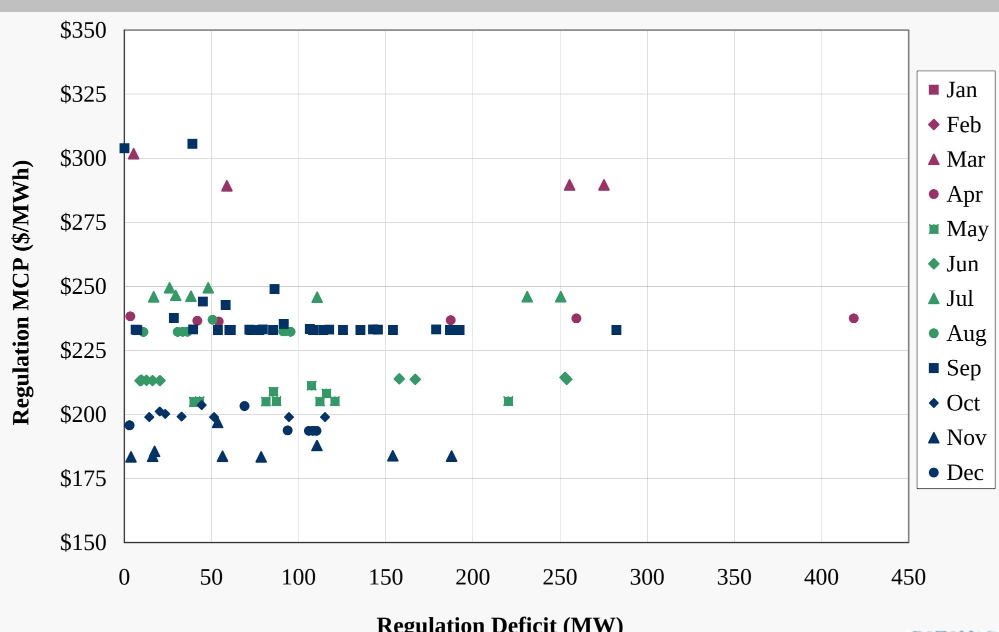
Regulation Pricing During Shortages 2010



POTOMAC ECONOMICS

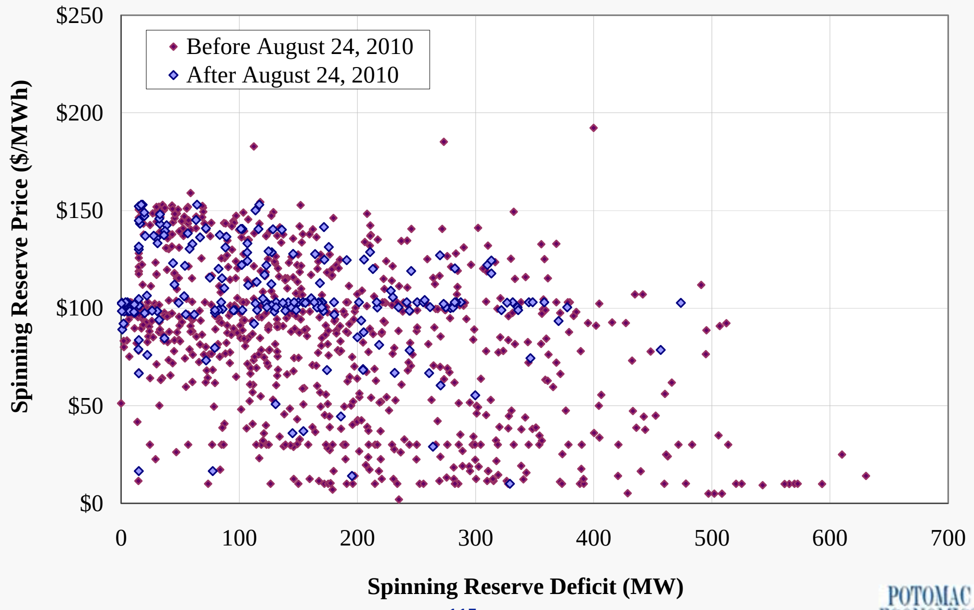
Spinning Reserve Pricing During Shortages

- 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 (administratively set at $98 per MWh in 2010).
  - ✓ Starting in February 2010, the Midwest ISO implemented an additional penalty constraint priced at $50 per MWh that required 90 percent of spinning reserve be met by generating resources (as opposed to demand response).
  - ✓ These constraints prevent the real-time market from taking actions more costly than $148 (plus the prevailing operating reserve clearing price) to maintain its spinning reserves.
- Although prices should be set at the penalty price when the system is short of spinning reserves, this was frequently not the case because the Midwest ISO relaxes the spinning reserve requirement when in deficit.
  - ✓ In August 2010, a modeling change was implemented to reduce the extent of the relaxation to improve pricing during spinning reserve shortages.

Spinning Reserve Pricing During Shortages

- There were 1,141 spinning reserve shortages in 2010, or 1.1 percent of all intervals, down from over 1,500 in 2009.
  - ✓ Almost 70 percent of shortages occurred during peak hours, when the ramp needs of the system are highest.
- The following figure shows the shortage quantity and price for the 1,068 shortages in 2010 when regulation reserves and total operating reserves were not in shortage.
  - ✓ Prices after the modeling change on August 24 clustered much more consistently around the $98 and $148 price points, indicating that the relaxation algorithm is not affecting prices as much as it had previously.
  - ✓ The prices earlier in the year were widely dispersed, and many of largest deficits were often the lowest priced.
    - – The largest of these shortages (630 MW) was priced at $14 per MWh.
    - – In all, 205 of these spinning reserve shortages were priced under $50.
  - ✓ This suggests that the relaxation methodology had been distorting the spinning reserve prices prior to the modeling change.

Spinning Reserve Pricing During Shortages 2010



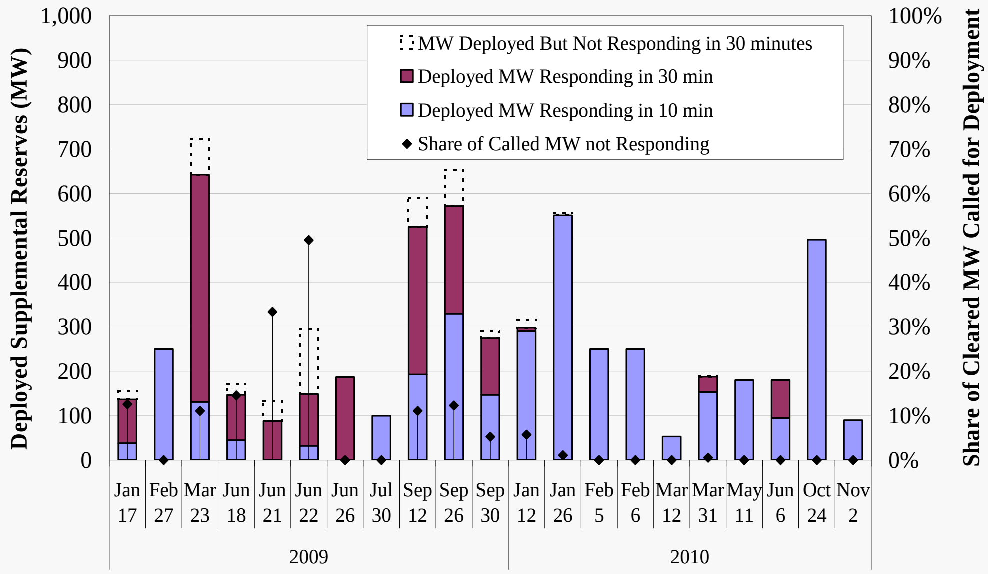
POTOMAC ECONOMICS

Supplemental Reserve Deployments

- Supplemental reserves are deployed during DCS and ARS events.
  - ✓ There were ten supplemental reserve deployments in 2010, in line with prior years.
  - ✓ 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 improved markedly in 2010.
  - ✓ On average, 94 percent of the reserves were successfully deployed within 10 minutes, up from just 36 percent in 2009.
  - ✓ In all, 99 percent were successfully deployed within the 30 minute requirement, whereas only 87 percent did so in 2009.
- Just 25 MW of the deployed capacity did not respond within 30 minutes, down from 475 MW in 2010.
  - ✓ The improvement is encouraging because a lack of response can have a significant impact on reliability and raises concerns that some suppliers may be selling reserves they are incapable of deploying.
- The Midwest ISO implemented improved measurement and verification procedures in response to last year's poor performance.
  - ✓ However, offered quantities of have decreased substantially in 2010. These results may indicate that the more reliable resources are still being offered.

POTOMAC ECONOMICS

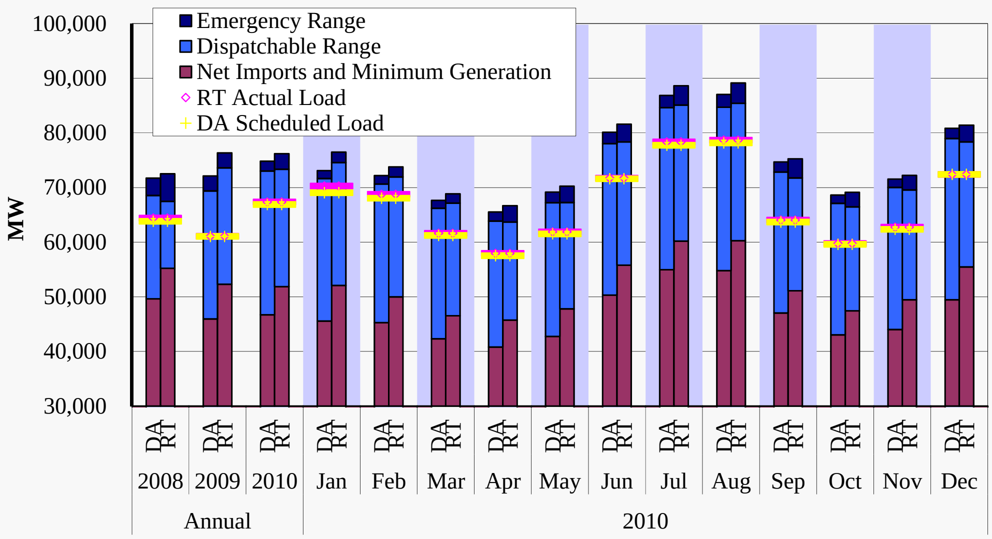
Non-Responsive Supplemental Reserve Deployments 2009 – 2010



Day-Ahead and Real-Time Generation

- The following figure details the average monthly generation scheduled in the day-ahead and real-time markets alongside the corresponding actual and scheduled load.
- Committed generation was slighter higher in real time than day ahead, which is expected due to the commitments needed for reliability and self-commitments.
- On a monthly basis, the generation committed in the real-time declined during 2010 due to the day-ahead headroom commitment logic implemented on April 21.
  - ✓ During the first three months of 2010, the average increase in real-time supply (not including emergency range above generators' economic maximum) was 2 GW per hour.
  - ✓ From May through December, 300 MW of additional supply was available in real time.
- The figure shows that the dispatchable range decreases from day ahead to real-time, which is generally is due to:
  - ✓ Wind generation, which is considered self-scheduled output in real-time, can offer a dispatchable range in the day-ahead and accounts for a difference 1.5 GW per hour; and
  - ✓ Self-scheduling by participants after the day-ahead market.
- Flexibility improved in 2009 with the introduction of the Price Volatility Make-Whole Payment and ancillary services co-optimization, both of which provide incentives for suppliers to be flexible.
  - ✓ Dispatchable generation as a share of total real-time capability remained at 30 percent on average in 2010.

Day-Ahead and Real-Time Generation 2010, All Hours



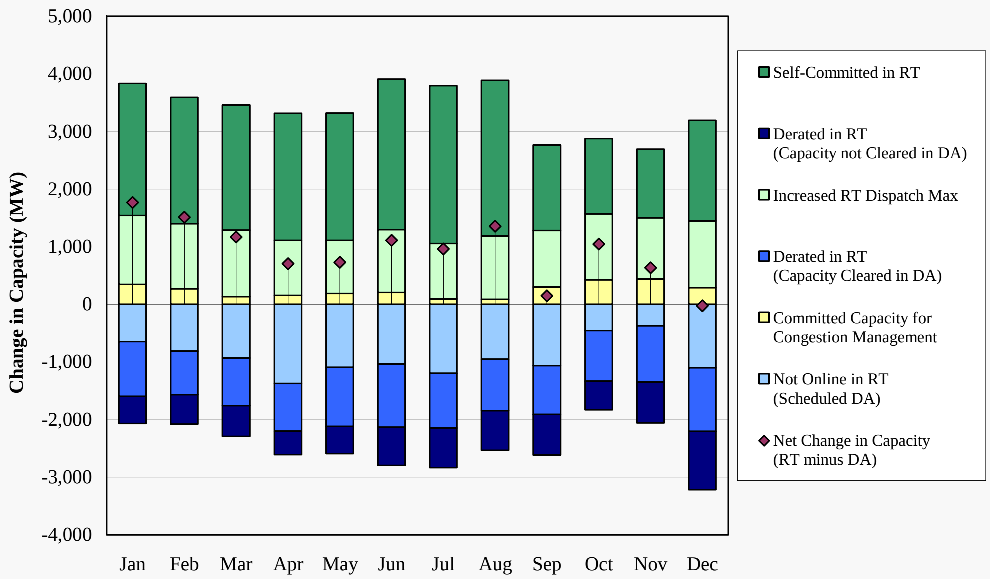
POTOMAC ECONOMICS

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 during peak hours.
- On average, 2.5 GW (4 percent) of capacity scheduled in the day-ahead was unavailable in real time in 2010. This is similar in magnitude to 2009 and is attributable to:
  - ✓ Forced outages;
  - ✓ De-commitments or deratings after the day ahead; and
  - ✓ Decisions by suppliers scheduled day-ahead to not start and buy back energy at the real-time price instead.
- The capability lost in real-time was more than offset by:
  - ✓ Almost 1 GW of average increases in capacity from units scheduled in day-ahead increasing their dispatch max in real-time; and
  - ✓ About 2 GW of self-scheduled resource capacity.
- Any remaining need would be satisfied by incremental imports or capacity committed by the Midwest ISO.

POTOMAC ECONOMICS

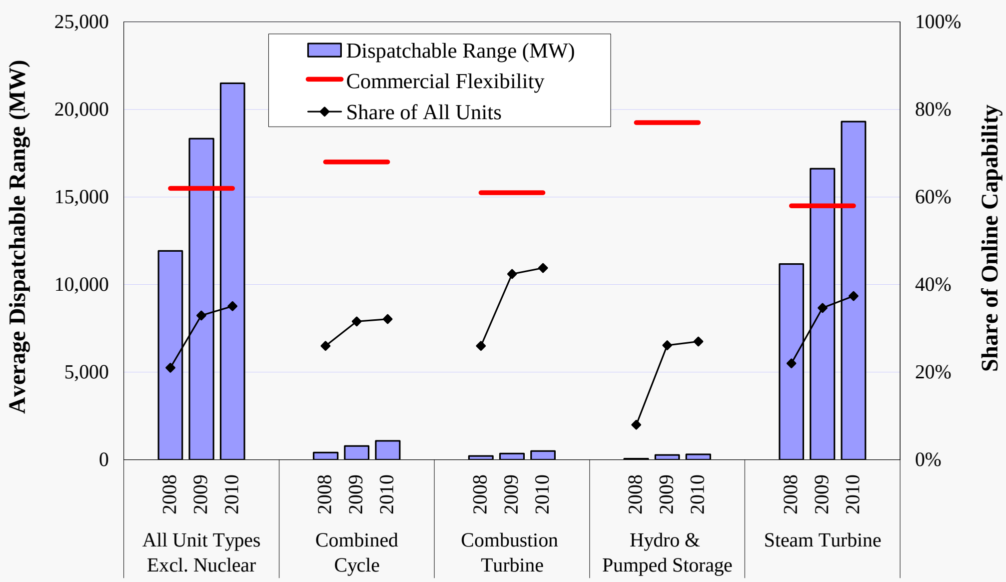
Changes in Supply from Day-Ahead to Real-Time 2010



Real-Time Dispatch Range

- The next figure shows the change in the dispatchable range (between online units' economic maximum and minimum) offered between 2008 and 2010.
  - ✓ This range is important because it provides the dispatch flexibility needed to follow load and manage congestion.
- Flexibility increased substantially across all unit types in 2009 and continued in 2010. The ASM markets contributed to the improved flexibility since:
  - ✓ The quantity of AS products a supplier can sell based on the dispatch range and ramp rates;
  - ✓ Price Volatility Make-Whole Payments ensure generators are not harmed by responding flexibly in periods when prices are volatile; and
  - ✓ 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.
- Although flexibility has increased significantly through 2010, it is still lower than the full physical flexibility that many generators could provide.
  - ✓ The effects of reductions in flexibility on the Midwest ISO's ability to manage congestion is evaluated later in the report.

Real-Time Dispatchable Range 2008 – 2010



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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 cost – a unit that is uneconomic will generally not be selected.
  - ✓ Peaking resources are 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 85 percent of RSG is generated in real time.
  - ✓ This is expected because the commitments needed for reliability occur after the day-ahead market.

POTOMAC ECONOMICS

Revenue Sufficiency Guarantee Payments Day-Ahead and Real-Time

- The first figure shows that real-time RSG costs in 2010 rose 40 percent to $162 million.
  - ✓ Higher fuel prices account for some of the increase: fuel-adjusted RSG rose 27 percent.
  - ✓ The remaining increase was largely due to: a) substantially higher costs during the summer months due to much higher weather-related loads; and b) increased costs associated with non-peaking resources committed for local reliability.
- Nearly half of real-time RSG payments in 2010 were made to non-peaking units, up from approximately one-third in 2009.
  - ✓ This is primarily due to substantial payments to non-peaking resources committed from September to December to provide localized voltage support to the system.
  - ✓ $29.6 million was paid to units committed to provide voltage support in total, which is evaluated further in Section VII.
- As in 2009, over 65 percent of fuel-adjusted, real-time RSG payments were made to units committed for capacity purposes.
  - ✓ Less than full load scheduling early in the year and high summer loads resulted in considerable commitments for capacity after the close of the day-ahead market.
- Day-ahead RSG increased by 40 percent to $23.5 million, largely due to increased commitments due to the day-ahead headroom commitment software deployed in April.
  - ✓ However, day-ahead RSG remains a small share of total uplift costs.

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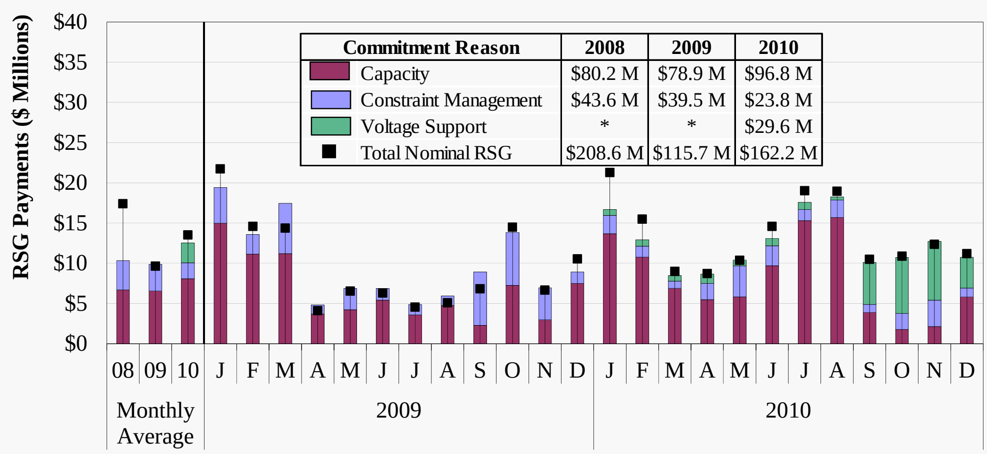
Total Real-Time RSG Distribution 2009 – 2010



Share of Real-Time RSG Costs by Unit Type (%)

Peaking Units	62	63	52	57	66	50	48	67	69	48	60	67	79	69	68	56	53	57	56	62	49	69	71	42	22	24	45
Other Units	38	37	48	43	34	50	52	33	31	52	40	33	21	31	32	44	47	43	44	38	51	31	29	58	78	76	55

* Voltage-related commitment information unavailable prior to 2010.

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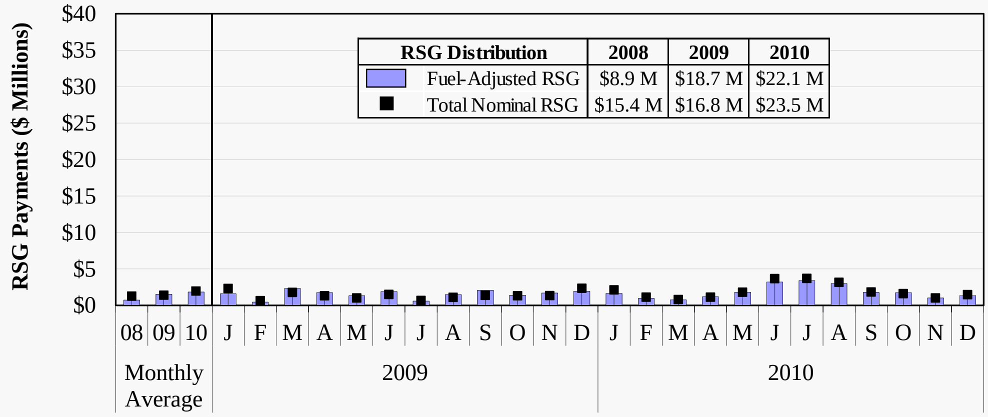
Total Day-Ahead RSG Distribution 2009 – 2010



Share of Day-Ahead RSG Costs by Unit Type

Peaking Units	13	6	14	3	2	1	1	16	14	4	11	8	5	4	3	4	0	2	3	14	11	26	35	10	3	3	9
Other Units	87	94	86	97	98	99	99	84	86	96	89	92	95	96	97	96	100	98	97	86	89	74	65	90	97	97	91

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Weekly Real-Time RSG Payments

- The following figure analyzes the real-time RSG distribution data by week and by region to more clearly show patterns in RSG payments.
  - ✓ Overall, real-time RSG payments were consistent with load patterns.
  - ✓ High summer loads combined with modest load under-scheduling required additional commitments in real-time, predominantly in the East and Central.
  - ✓ Higher fuel prices and at times substantial under-scheduling contributed to elevated RSG payments early in 2010.
    - – Congestion on constraints out of the West contributed as well.
- RSG payments were nearly unchanged in the East but increased in other regions.
  - ✓ Payments in Central and West increased 42 and 78 percent, respectively.
  - ✓ In 2010, 57 percent of payments were in the East or Central, down from 71 percent.
    - – In 2010 more RSG was paid to resources in the East than any other region due in part to continued transmission upgrades and other unplanned outages.
- RSG costs associated with commitments to provide voltage support in WUMS beginning in September contributed to the bulk of the increase in WUMS for the year.
  - ✓ As detailed earlier, this voltage issue required the commitment of non-peaking units and resulted in over $25 million in payments.
  - ✓ Market power issues related to these types of commitments are evaluated in greater detail later in Section VII.

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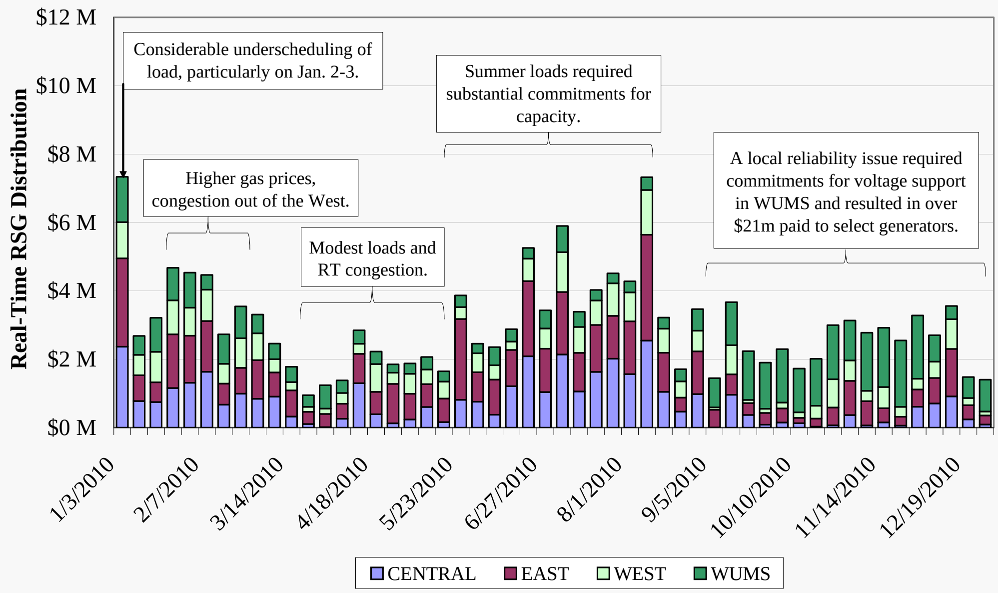
Weekly RSG Distribution by Region 2010



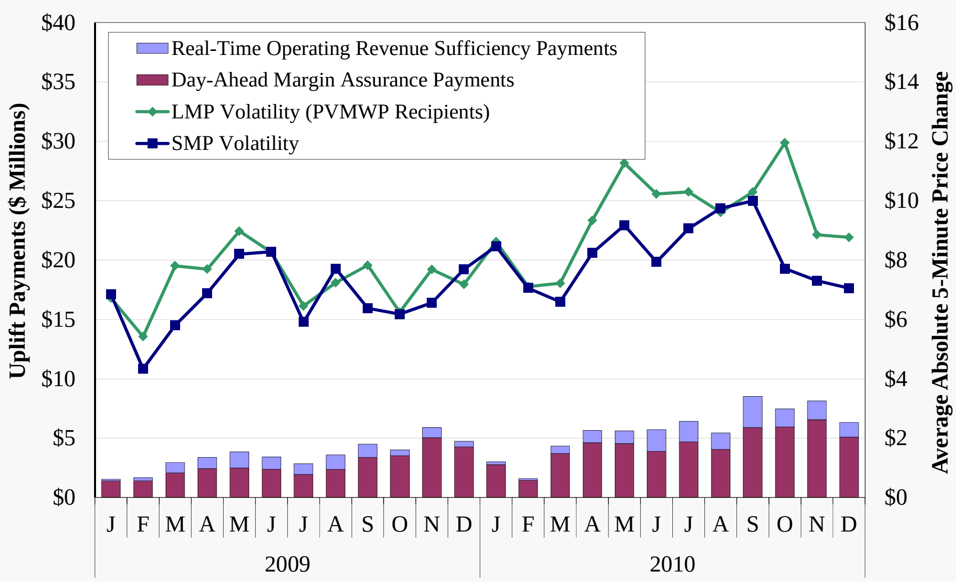
Price Volatility Make-Whole Payment

- The Midwest ISO introduced the PVMWP in 2009 along with ASM to ensure adequate cost recovery in the real-time.
  - ✓ The payment ensures that suppliers responding flexibly in real time to the Midwest ISO's prices and following 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 two separate payments:
  - ✓ The Day Ahead Margin Assurance Payment ("DAMAP") is paid to a resource dispatched to a level *below* its day-ahead schedule in a manner that erodes its day-ahead margin because the hourly real-time price is less than its as-offered costs.
  - ✓ The Real-Time Offer Revenue Sufficiency Guarantee Payment ("RTORSGP"), paid to a resource that is unable to recover its incremental energy costs through the LMP when dispatched in real-time to a level *above* its day-ahead schedule.
- Opportunity costs for avoided revenues are not included in the payment.
- PVMWP payments rose 60 percent in 2010: DAMAP payments totaled $53.2 million, while RTORSGP payments totaled over $15 million.

Price Volatility Make-Whole Payment

- The lines on the chart show two measures of price volatility: one based on the system marginal price and one based on the LMPs at generator locations receiving PVMWPs.
  - ✓ The price volatility measures are correlated with payments, which largely explain why the payments have increased – as volatility increases, the payments to flexible suppliers following dispatch will tend to increase.
  - ✓ LMP volatility is higher at recipients' locations as expected – they are generally asked to move more than other suppliers due to the larger price fluctuations.
- We have investigated these increases and the rules governing the payments, finding that there are improvements that should be made to provide better incentives and reduce opportunities for gaming. These recommended changes include:
  - ✓ Eliminating RTORSGP payments to deployed operating reserves. This will improve the efficiency of the reserve markets by causing these expected deployment costs to be included in participants' offers.
    - – The largest recipient of RTORSGP payment was a DR resource that began selling spinning reserves mid-year and was paid $0.94 million when deployed to cover energy curtailment costs of $500 per MWh.
    - – Considering these deployment costs in the selection of the spinning reserves would improve efficiency by minimizing total costs (including deployment costs).
  - ✓ The remaining two changes recommended relate to potential gaming opportunities that were not a problem in 2010. The IMM has conveyed the details of these strategies confidentially to the Midwest ISO.

Price Volatility Make-Whole Payment 2009 – 2010



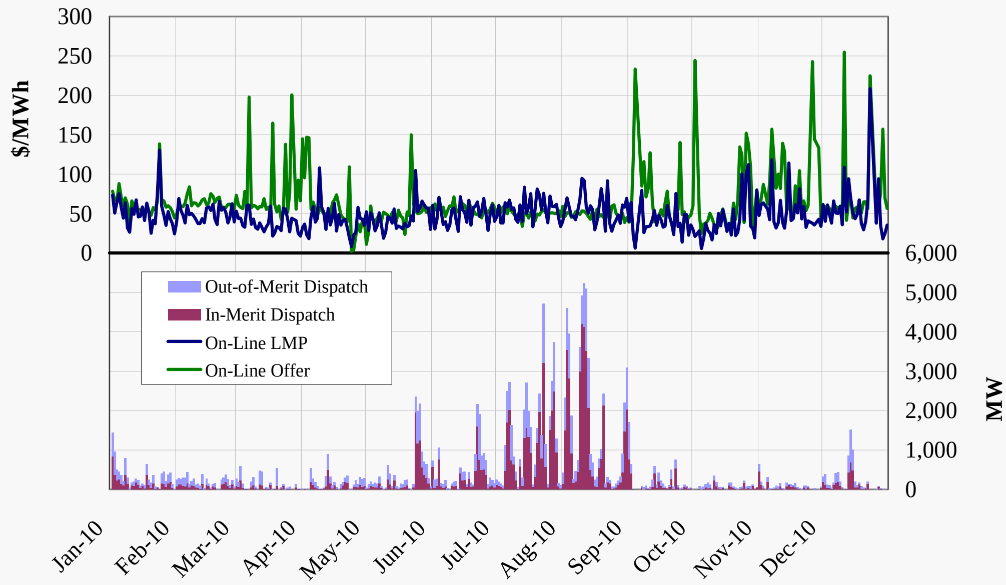
Dispatch of Peaking Resources

- 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 2010, showing the average hourly dispatch of peaking units by day.
  - ✓ An average of 465 MW was dispatched per hour in 2010, an increase of 105 percent from 2009, when 227 MW was dispatched on average.
- The main reason for this year-over-year increase was substantially higher summer loads due to relatively hot temperatures.
  - ✓ Nearly two-thirds of all peaking unit commitments occurred during the high-load summer months, when more generation capacity is needed to meet the system's needs.
    - – More than 1,200 MW was dispatched on average during the summer months.
  - ✓ For the period from August 10-12, when real-time loads peaked near 110 GW, over 5,000 MW of peaking resources were dispatched on average per hour.
    - – Daily peak hour commitments exceeded 10,000 MW on each day.
- Other factors that contributed to increased dispatch of peaking resources included:
  - ✓ Less than full load scheduling, particularly in July and August; and
  - ✓ An increase in real-time transmission congestion, which can require commitments for congestion management.

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).
- The majority of peaking resources were dispatched in-merit in 2010, which is unusual.
  - ✓ Approximately 40 percent were out-of-merit in 2010, compared to 67 percent in 2009.
  - ✓ The higher in-merit share in 2010 was due to the fact that a large portion of the peaking resource dispatch occurred during high-load periods in the summer when peaking resources are much more likely to be in-merit.
- Under the majority of conditions, however, peaking resources are typically dispatched out-of-merit because they cannot set prices when they run at their economic minimum.
- When peaking (or DR) resources are the most economic option for meeting market 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 coordinated by the day-ahead market.
  - ✓ A suboptimal commitment in the day-ahead will tend to raise real-time costs.
  - ✓ Inefficiently low real-time prices also distort the incentives to import and export power.
- Hence, we continue to recommend that the Midwest ISO develop pricing improvements to allow inflexible resources to set prices when they are needed, which the Midwest ISO has been working on as part of its ELMP initiative.

Daily Peaker Dispatch and Prices
All Hours



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Day-Ahead and Real-Time Wind Generation

- Wind generation and capacity have increased rapidly in the Midwest ISO 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.
  - ✓ As an intermittent resource, wind generation has resulted in greater operational challenges as its share of the Midwest ISO's resource generation portfolio increases.
- The following slide shows a seven-day moving average of wind generation scheduled in the day-ahead and real-time markets.
  - ✓ The chart shows the continued rapid growth of wind generation and seasonality of wind.
    - – Average wind output rose 35 percent in 2010 to 2.3 GW and peaked at 6.7 GW.
  - ✓ The chart also shows day-ahead scheduling of wind generation improved slightly in 2010, although wind remains modestly under-scheduled.
    - – Under-scheduling of wind creates price convergence issues in western areas and can lead to uncertainty regarding the need to commit resources for reliability.
- The introduction of the Dispatchable Intermittent Resource type in June 2011 will allow wind units to become dispatchable (from zero to a forecasted maximum) and set prices.
  - ✓ This should improve pricing and congestion management in the West and potentially reduce the amount of RSG incurred to manage this congestion.

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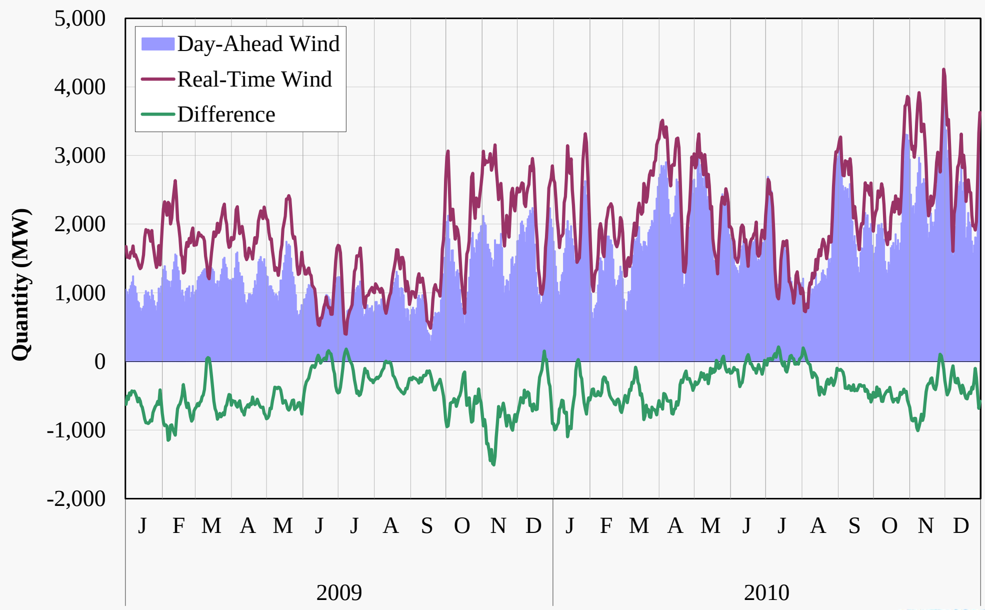
Day-Ahead and Real-Time Wind Generation 7-Day Moving Average



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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.
- The following figure shows average hourly wind capacity factors by load hour percentile, season and region. This analysis shows that:
  - ✓ Wind output (reflected in the capacity factors) is generally negatively correlated with load, particularly in the summer.
  - ✓ There is a persistent spread between western and eastern units' capacity factors due to differences in the wind profiles.
- Because the capacity factor of wind resources can vary significantly by location, the Midwest ISO is changing how it allocates capacity credits to wind resources.
  - ✓ For Planning Year 2010, all wind resources received capacity credits based on an 8 percent capacity factor.
  - ✓ For Planning Year 2011, Midwest ISO will allocate capacity credits on a per-unit basis, rather than do so evenly system-wide.
    - – Capacity credits will range from 0 to 31 percent and average 12.9 percent.
  - ✓ This will allow for a more accurate reflection of a unit's actual peak performance.

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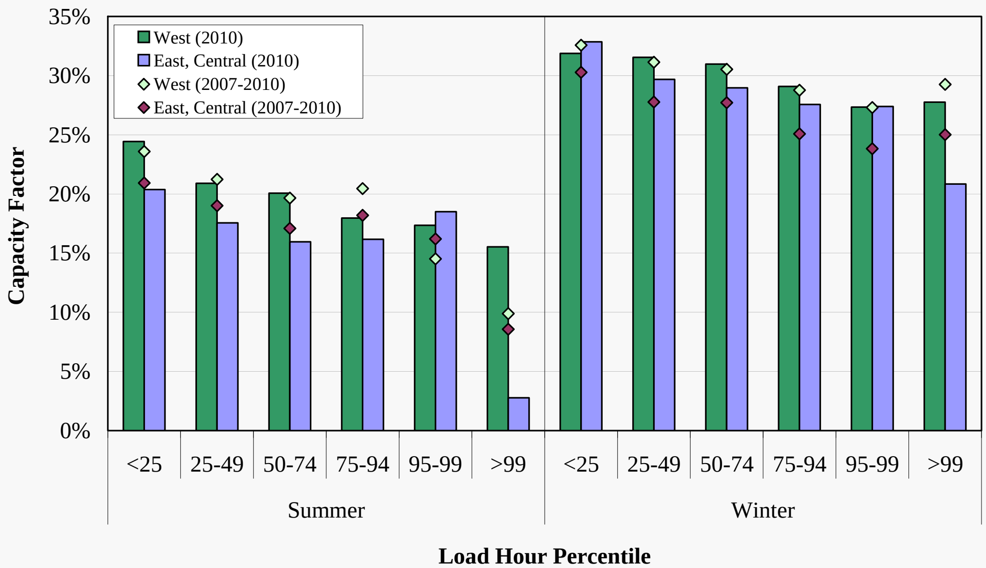
Wind Generation Capacity Factors by Load Hour Percentile, 2010



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Wind Curtailments

- Since wind units cannot currently respond to economic dispatch instructions through the real-time market, units must at times be curtailed manually by Midwest ISO operators to manage congestion or to address a local reliability issue.
  - ✓ Wind suppliers may curtail themselves in response to low prices, but these appear to the Midwest ISO as a reduction in wind output.
- Manual curtailment of wind units is often an inefficient means to relieve congestion.
  - ✓ The introduction of the Dispatchable Intermittent Resource type, scheduled for June 2011, should alleviate many of these concerns and allow for efficient redispatch.
- The following figure shows that ISO-directed wind curtailments more than tripled in 2010.
  - ✓ Curtailments occurred in nearly two-thirds of all intervals, up from 30 percent in 2009.
  - ✓ On average, over 100 MW of wind was curtailed per interval in 2010, compared to approximately 30 MW in 2009. As much as 870 MW was curtailed in one interval.
  - ✓ Curtailments are greater during shoulder months, when wind generation and penetration levels (wind as a share of online generation) are highest.
- The length of the average curtailment also increased to approximately nine hours.
  - ✓ The Midwest ISO improved its wind forecasting in July and its curtailment tools and procedures in late September.
  - ✓ The average curtailment shortened to five hours in October-December.

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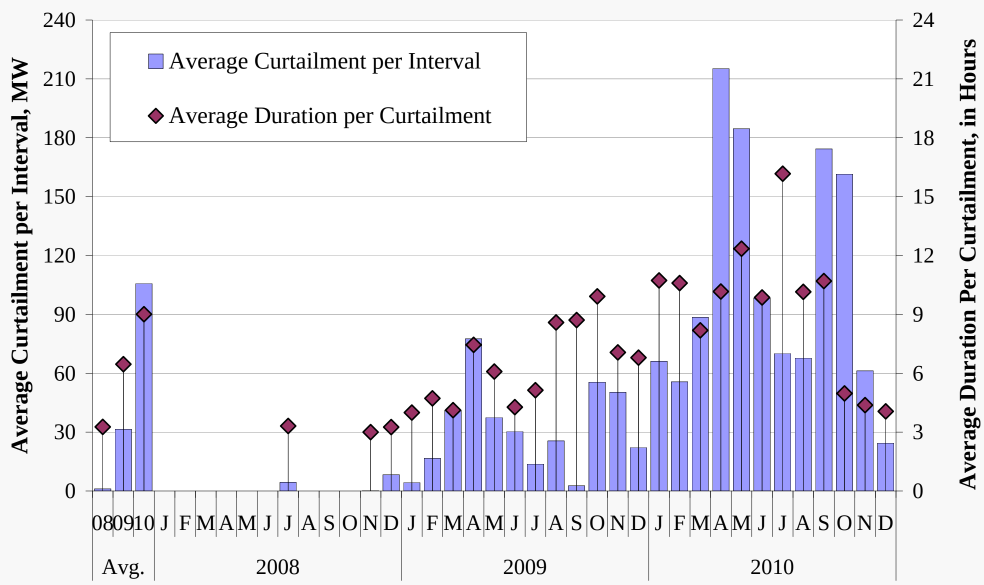
Wind Curtailments
2008 – 2010



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Wind Volatility
Average Sixty-Minute Change

- The hourly volatility of wind generation output has increased substantially over the past three years, when nameplate wind capacity doubled to 9.2 GW. These fluctuations create demands on the system that the Midwest ISO must manage.
- The following figure shows the average absolute value of the sixty-minute change in wind generation by month.
  - ✓ The average absolute change was 186 MW in 2010, up 47 percent from 2009.
  - ✓ Wind output must generally be "firmed" by other resources through redispatch or by the commitment of peaking resources.
- To show the largest changes in wind output that the Midwest ISO has had to manage, the figure also shows the 95th percentile of changes in both directions (top 5 percent).
  - ✓ These changes have grown consistently over the past three years as wind capacity has grown, and averaged more than 400 MW in both directions in 2010.
  - ✓ The maximum changes in 2010 were roughly 1,800 MW upward and 1,400 MW downward.
  - ✓ Volatility is modestly higher during spring and fall months, when loads are lower.
- As wind capacity continues to grow, the Midwest ISO will need to continue to work to accommodate these fluctuations efficiently and reliably.

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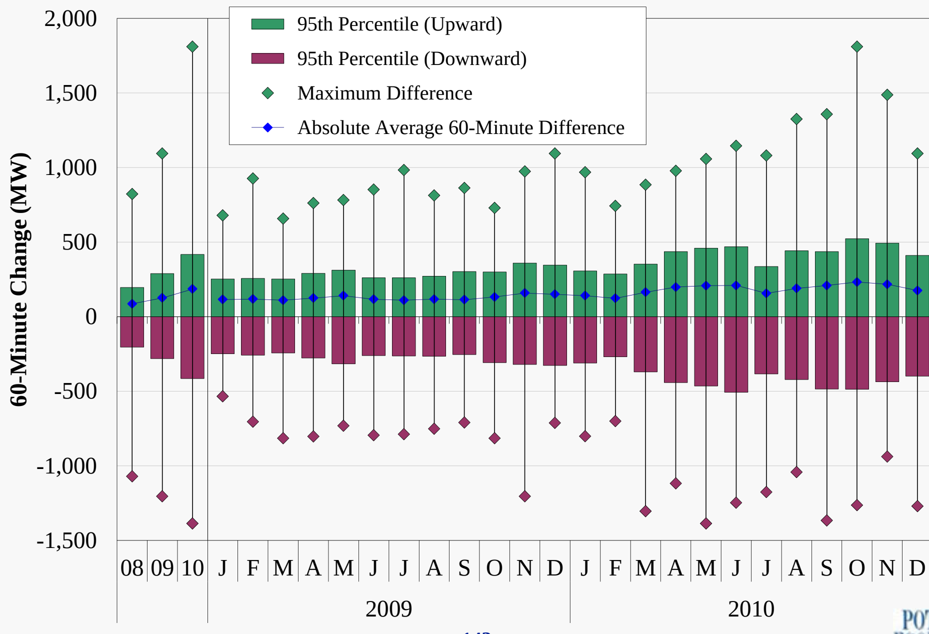
Wind Volatility
Average 60-Minute Change



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Real-Time Market: Conclusions

- The Midwest ISO's real-time market continues to perform relatively well.
  - ✓ The nodal energy market accurately reflects the marginal value of energy at each location in the Midwest ISO based on prevailing congestion and losses.
  - ✓ The ancillary services markets continue to operate smoothly.
  - ✓ The increased flexibility facilitated by the ASM markets increased further in 2010, which improves efficiency and reduces 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 under ASM.
  - ✓ The absence of a real-time model to optimize 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.
  - ✓ Shortcomings in the current processes to manage the system's ramp capability needed to accommodate movements in non-conforming load, NSI, wind and other factors that lead to increased price volatility.
  - ✓ The current state of the integration of wind resources into Midwest ISO markets.
- These issues are addressed by the following recommendations.

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Real-Time Market: Recommendations

- Develop a look-ahead commitment and dispatch capability 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 should include a multi-period dispatch to optimize the use of slower-ramping units to meet 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.
  - ✓ The Midwest ISO has initiated a project develop these capabilities.
- Prior to development of the look-ahead capability, the Midwest ISO should improve the use of its load offset parameter.
  - ✓ This parameter is used currently to manage ramp capability by incrementally increasing or decreasing the load served by the real-time market.
  - ✓ The recommendation likely requires improving the tool used to produce recommended offset levels and modifying its procedures to use these values.

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Real-Time Market: Recommendations (cont.)

- 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 DR 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 DR capability.
  - ✓ It may be possible to address this recommendation in conjunction with the pricing recommendation for gas turbines.
- Seek additional improvements to STLF used by the real-time market to reduce the amount of system ramp consumed by changes in real-time load.
  - ✓ The Midwest ISO should explore potential improvements to the information it receives on non-conforming load.

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Transmission Congestion and FTR Results

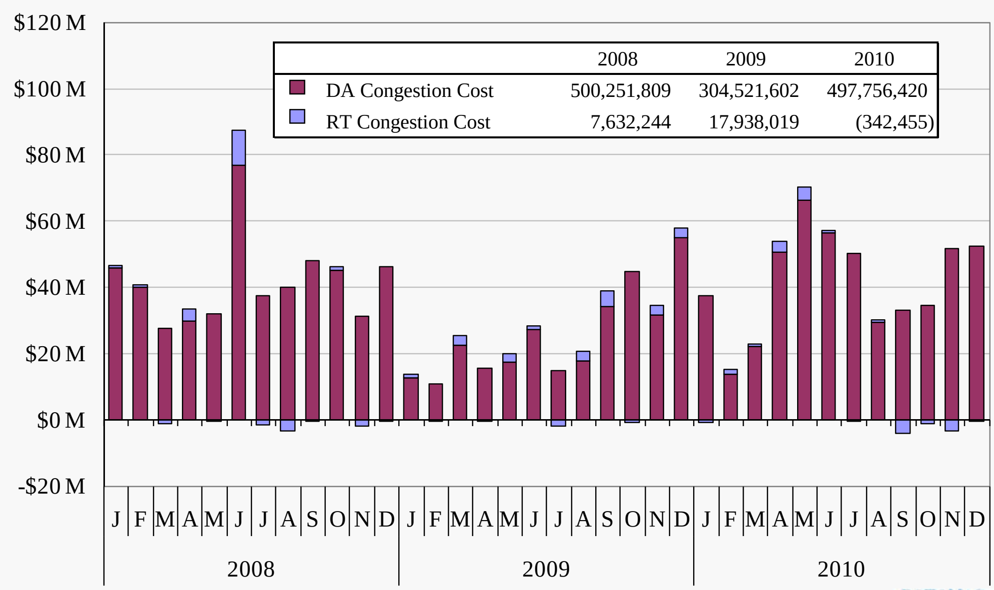
Transmission Congestion and FTRs

- One primary function of the Midwest ISO energy markets is to deliver least-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.

Total Congestion Costs

- The first figure in this section shows total congestion costs by month in the Midwest ISO market from 2008 through 2010.
- Day-ahead congestion costs increased 63 percent to near 2008 levels.
  - ✓ Costs were highest in the second quarter of 2010 due to transmission outages in the East, generation outages throughout the footprint and high loads due to unseasonably warm temperatures during the last week of May and into June.
- Real-time congestion costs, which are calculated net of market-to-market settlement payments, are incurred when the transmission capability is:
  - ✓ Reduced (de-rated) 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.
- The very low real-time congestion costs (slightly negative) show that the consistency of the day-ahead and real-time markets modeling of the network has improved.
  - ✓ However, unexpected loop flows, real-time transmission outages and real-time TLRs for external constraints can all contribute to episodes of real-time congestion.

Total Congestion Costs 2008 – 2010



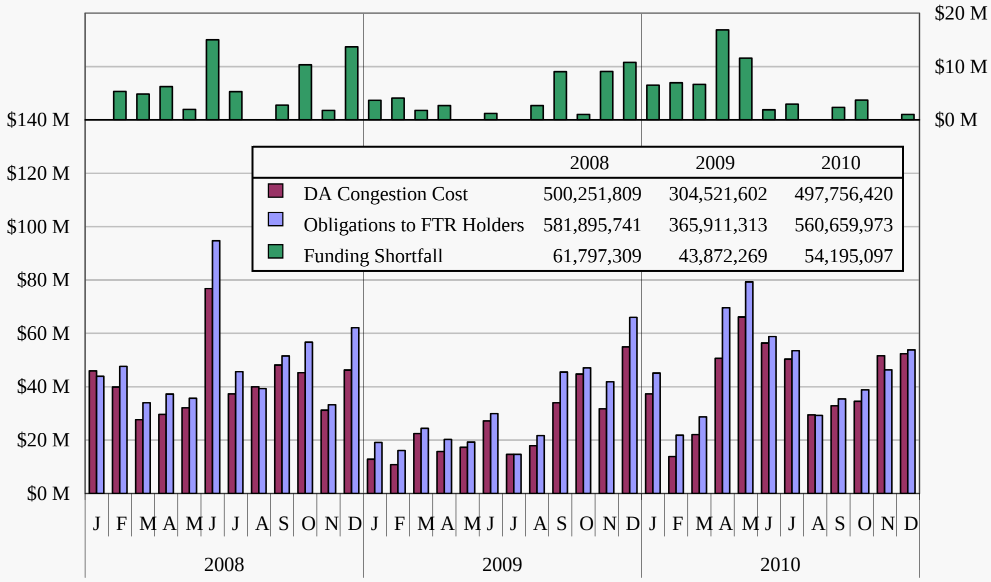
Day-Ahead Congestion and Obligations to FTR Holders

- 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 embodied in the 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.

Day-Ahead Congestion and Payments to FTR Holders

- The figure shows the day-ahead congestion collections continued to be substantially less than FTR obligations (11 percent in 2010).
  - ✓ This is less than in 2009 and 2008, when 17 and 14 percent was uncollected.
  - ✓ Shortfalls are undesirable because they introduce uncertainty regarding the value of the FTRs and ultimately reduce the revenues from the FTR market.
- Significant improvements in the monthly FTR modeling beginning in April and the seasonal auction for June resulted in dramatic improvements in FTR funding levels. Improvements included:
  - ✓ Improved constraint forecasting and identification procedures.
  - ✓ More complete modeling of lower-voltage branches of the network.
  - ✓ Improved modeling and accuracy of limits on radial constraints.
- As shown in a later figure, the Midwest ISO changes in FTR modeling has improved funding levels on radial constraints, but there continues to be significant underfunding on these constraints.
  - ✓ Therefore, we continue to recommend changes to the current modeling approach for radial constraints that should increase funding levels.

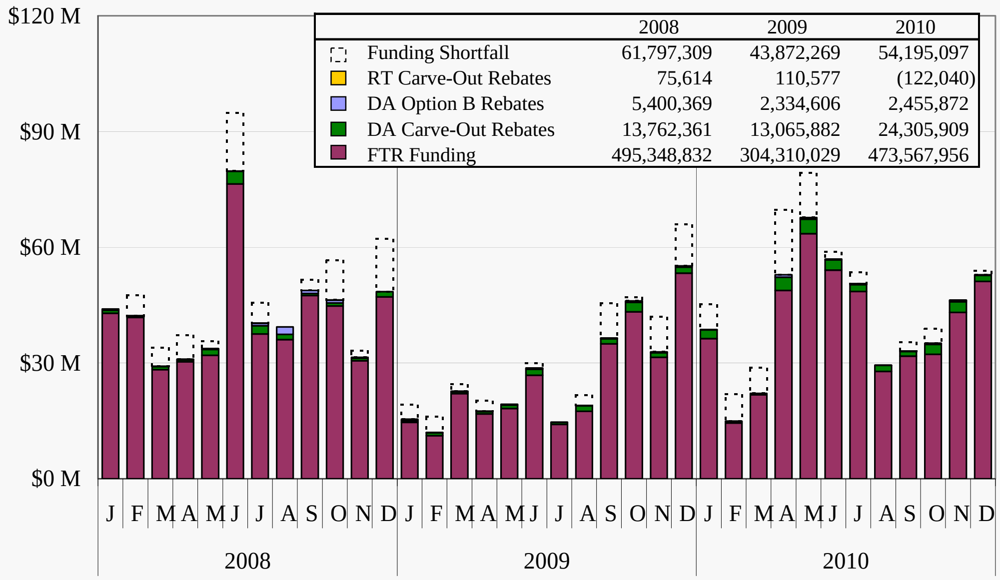
Day-Ahead Congestion and Payments to FTR Holders 2008 – 2010



Payments to FTR Holders

- The following figure shows the monthly payments and obligations to FTR holders in more detail.
  - ✓ It includes payments to FTR Option B rebates 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.
    - – Payments to day-ahead holders of Carve-Out FTRs nearly doubled to $24 million, but this amount represents less than five percent of all payments.
    - – A large portion of carve-out payments were due to increased congestion in the West and WUMS areas that augmented the value of the carve-outs.

Payments to FTR Holders 2008 – 2010

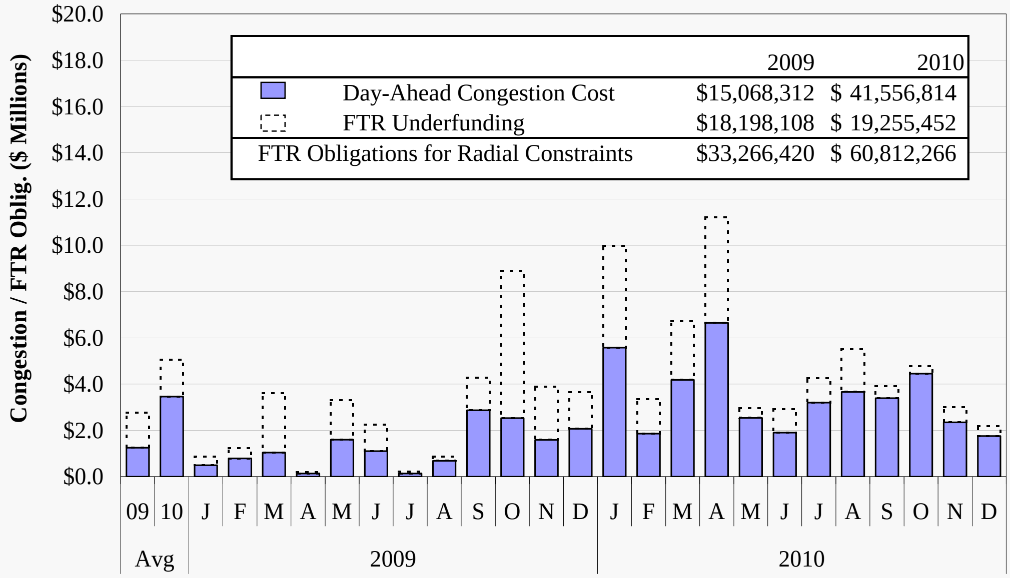


	2008	2009	2010
Funding Shortfall	61,797,309	43,872,269	54,195,097
RT Carve-Out Rebates	75,614	110,577	(122,040)
DA Option B Rebates	5,400,369	2,334,606	2,455,872
DA Carve-Out Rebates	13,762,361	13,065,882	24,305,909
FTR Funding	495,348,832	304,310,029	473,567,956

Radial Constraints and FTR Underfunding

- Midwest ISO uses fictitious radial constraints to selected generator locations to limit the quantity of virtual load that can clear at these locations in the day-ahead market.
  - ✓ 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).
  - ✓ The radial constraints ensure the day-ahead market will solve, but they 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 were not fully 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 over 8 percent of the total day-ahead congestion, up from 1 percent in 2009, and contributed to over one-third of the FTR shortfalls.
    - – Two-thirds of this underfunding occurred in January to April before the Midwest ISO made improvements to the modeling of these constraints in the FTR auctions.
    - – However, FTR underfunding remains significant on these constraints.
  - ✓ We continue to recommend that the Midwest ISO remove these facilities (step-up transformers) and the associated radial constraints from the day-ahead and FTR markets since this congestion cannot exist in the real-time market.

Radial Constraints and FTR Underfunding 2009 – 2010



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Value of Real-Time Congestion by Coordination Region

- The prior figures showed the congestion collected through the Midwest ISO markets. This can vary substantially from actual congestion that occurs physically in real time.
- The next figure shows the value of regional, real-time congestion on internal flowgates.
  - ✓ The value of real-time congestion is equal to the marginal cost of a constraint (i.e., the shadow price) multiplied by the flow over the constraint.
  - ✓ Real-time congestion totaled $1.03 billion in 2010, up 18 percent from 2009.
- These values continue to be much higher than the congestion collected by the Midwest ISO due to:
  - ✓ Loop flows that use some of the Midwest ISO network capability free of charge; and
  - ✓ PJM's entitlements on the Midwest ISO system.
- Congestion rose fastest in in the West, by $120 million (67 percent) to $299 million.
  - ✓ Nearly 30 percent of total congestion (and almost half of all constraints) occurred in the West, up from 20 percent in 2009. Much of this occurred on lower-voltage lines.
  - ✓ The average number of binding constraints per interval in 2010 rose 26 percent to 1.54.
- Very little congestion occurred in February and March due to modest loads and the return from outage of key generators and transmission lines.

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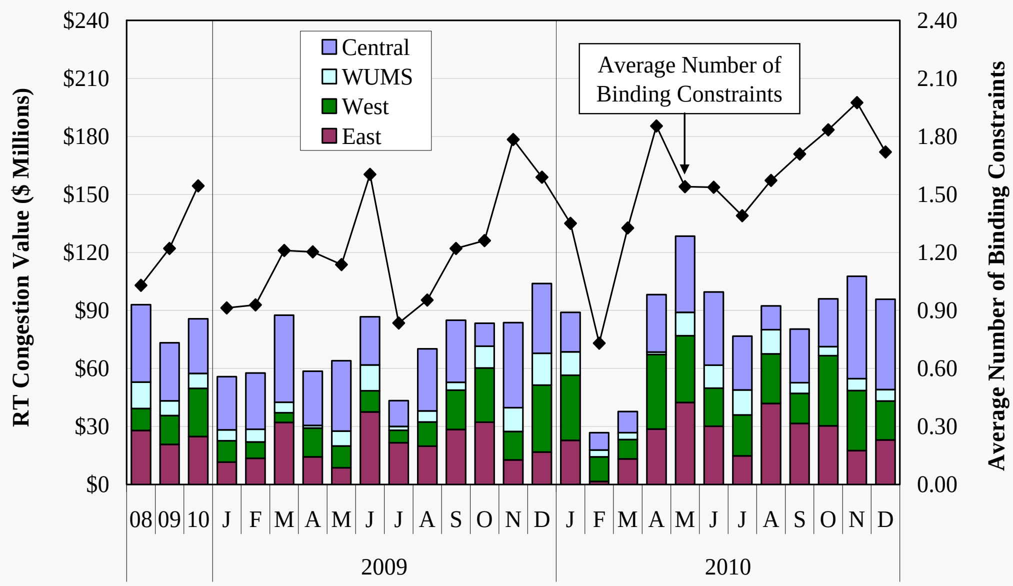
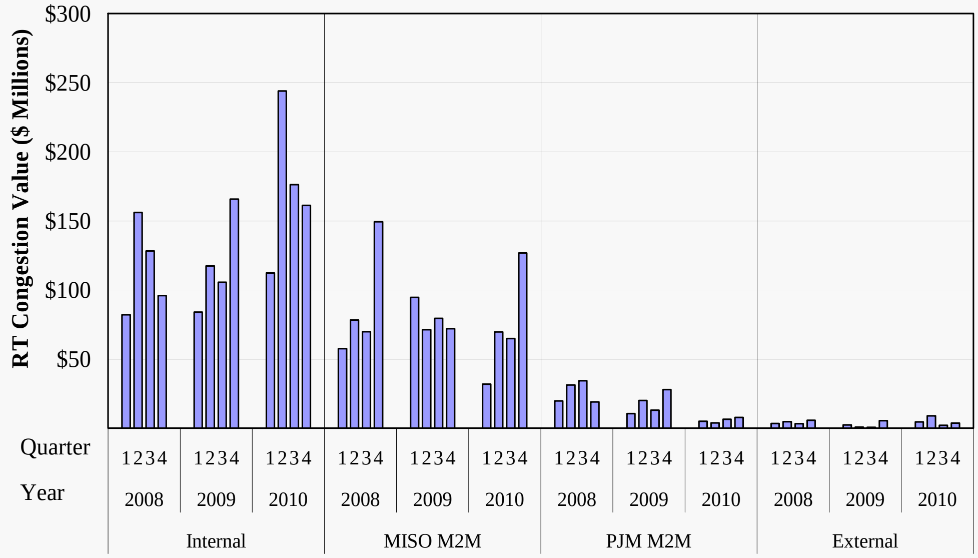
Real-Time Congestion by Coordination Region 2009 – 2010



Value of Real-Time Congestion by Type of Constraint

- 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 real-time congestion occurred on Midwest ISO internal constraints (including Midwest ISO market-to-market constraints).
  - ✓ In total, Midwest ISO constraints (internal and market-to-market) represent nearly 96 percent of the congestion value.
- Ten of the top 14 highest-value constraints were MISO market-to-market constraints, all of which are located in the eastern half of the Midwest ISO.
  - ✓ Many of these were transitory and triggered by local outages. For example, all congestion on the two highest-value constraints occurred in relatively brief periods:
    - $39 million occurred over a few weeks in the fourth quarter in the Central region.
    - $32 million occurred over a two-day period in August in the East.
  - ✓ Market-to-market congestion out of WUMS and also into Michigan persisted all year.
    - Midwest ISO took over control of a frequently binding tie line between WUMS and ComEd – a number transmission projects are underway in the area.
- PJM market-to-market constraints and external constraints continue to be a very small share of total congestion.

Value of Real-Time Congestion by Type of Constraint Q1 2008 – Q4 2010



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Transmission Line Loading Relief Events

- 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.
  - ✓ TLR Levels range from 0 to 6: TLR Level 3 involves the curtailment of non-firm transactions, whereas TLR Level 5 may result in the curtailment of firm transactions.
- LMP markets manage most internal congestion through optimal redispatch rather than pro-rata curtailment of scheduled transactions through the TLR process.
- The next figure shows TLR activity by level on MISO flowgates from 2008 to 2010.
  - ✓ TLR flowgate-hours fell 20 percent in 2010 while curtailed amounts fell 36 percent.
  - ✓ Nearly 60 percent of total curtailed GWh occurred on a set of market-to-market constraints out of WUMS, mostly during the period May-August.
  - ✓ 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.

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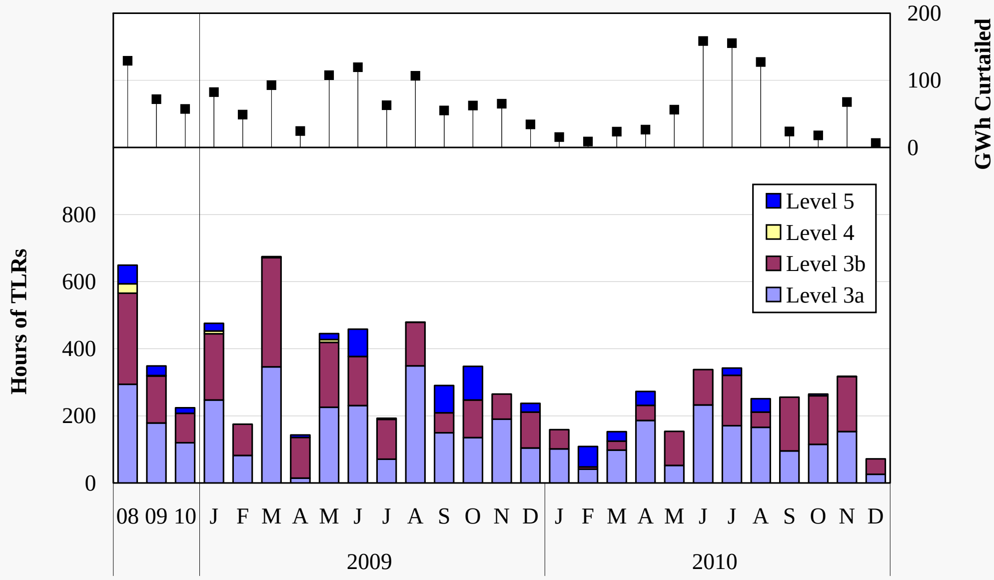
Monthly TLR Activity 2009 – 2010



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Congestion and Manageability

- 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 – NERC 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 internal constraints were unmanageable in each month in 2009 and 2010. This figure shows:
  - ✓ The share of unmanageable constraint-hours increased from 20 to 23 percent.
    - – Unmanageability was somewhat higher during the high-load summer months when there was less redispatch capability available to the real-time market.
    - – The slight increase overall was due to an increase in the frequency of binding hours for low voltage constraints, which tend to be less manageable.
- External and PJM market-to-market constraints are excluded from this analysis.

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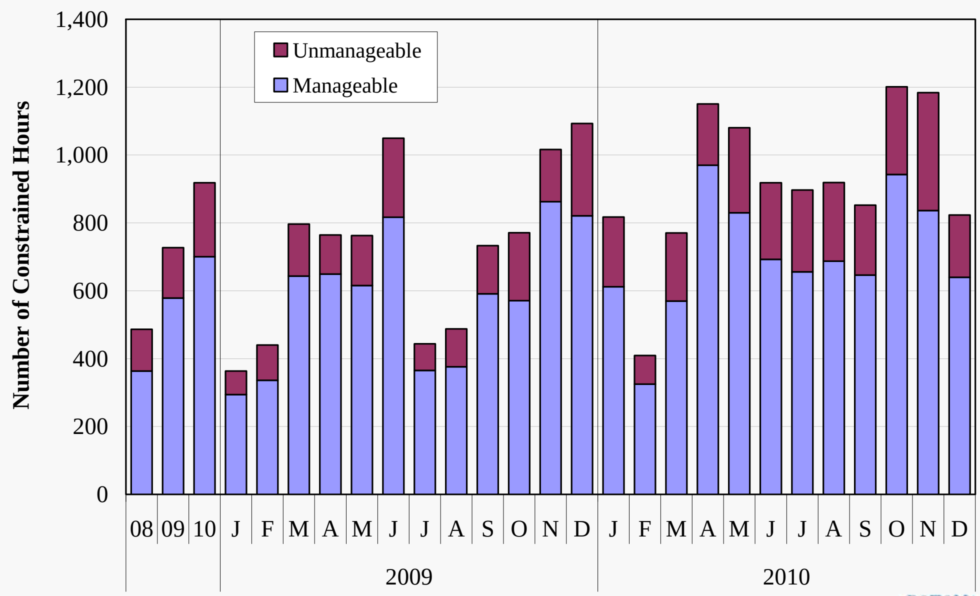
Congestion and Manageability 2009 – 2010



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Congestion and Manageability by Voltage Level

- 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 local generating resources.
  - ✓ As a result they are often more difficult to manage, as the following results confirm.
- Congestion increased by 25 percent or more on all but one voltage class of constraint.
- The largest increase was on low voltage constraints (69-115 kV), which nearly doubled in 2010.
  - ✓ Manageability on these improved slightly, to 62 percent of congestion, but they remain considerably more difficult to manage than higher voltage constraints.
  - ✓ Approximately 82 percent of the congestion on constraints rated 161 kV or higher was manageable in 2010.
- This increase suggests that the Midwest ISO is continuing to accept responsibility for low-voltage facilities that it lacks the resources to effectively manage.
  - ✓ We continue to recommend that the Midwest ISO establish criteria for determining when it should secure these low voltage facilities.
  - ✓ The Midwest ISO began developing such criteria in 2010.

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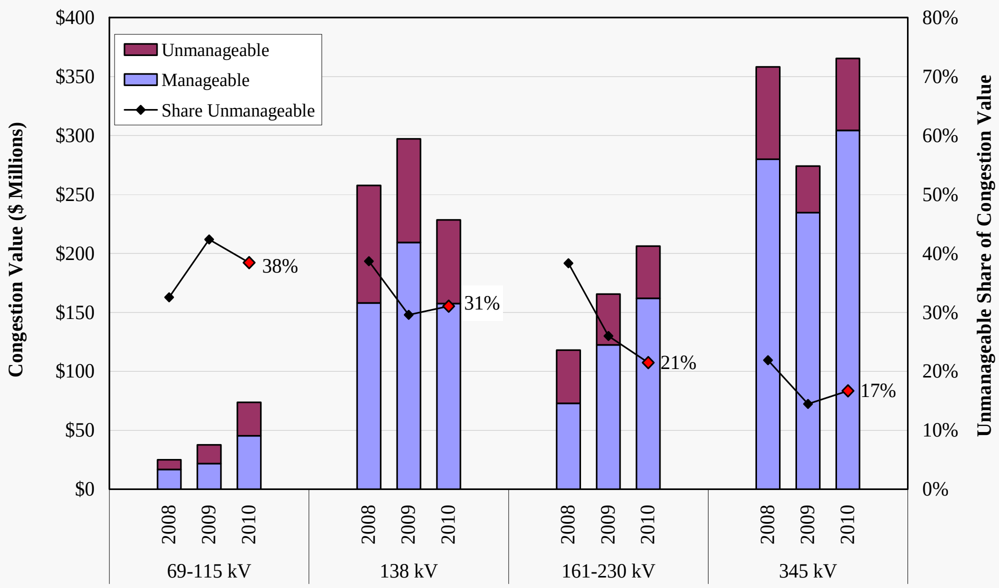
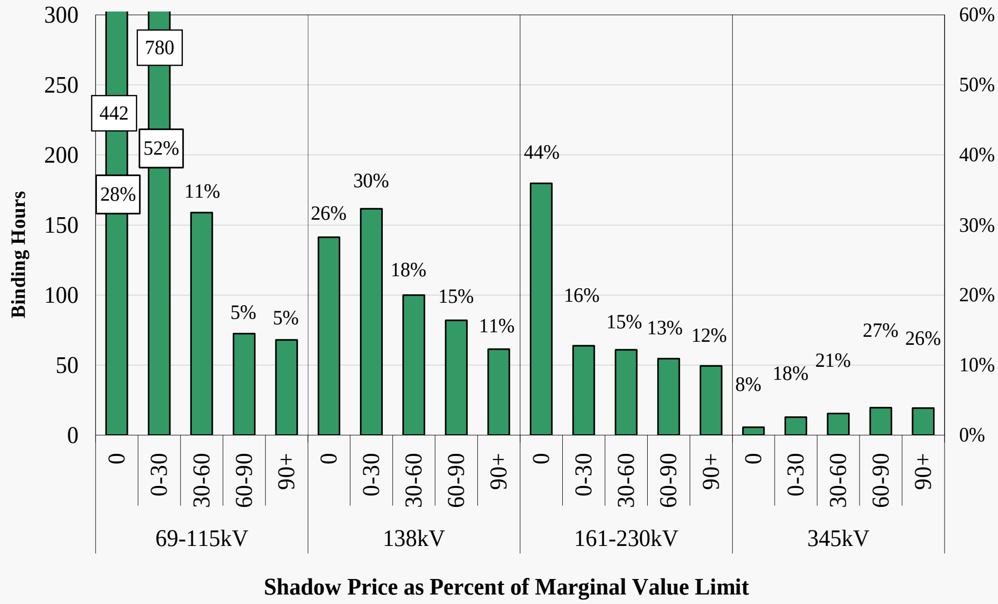
Congestion and Manageability by Voltage Level 2008 – 2010



Pricing Unmanageable Transmission Constraints

- Midwest ISO employs a "constraint relaxation algorithm" to produce a shadow price (the value of the constraint used to calculate LMPs) when a constraint is violated.
- The marginal value limit ("MVL") is the maximum cost the market will incur to manage a constraint and should, therefore, reflect the reliability cost of violating it.
  - ✓ Hence, it is efficient for the constraint to be priced at the MVL level if the constraint is violated (which will then be reflected in LMPs at locations affected by the constraint).
- The next figure shows unmanageable constraint hours by voltage level.
  - ✓ The hours are divided into tranches by the ratio of the shadow price to the constraint penalty price (marginal value limit, or "MVL").
  - ✓ The purpose of this figure is to determine whether the LMPs fully reflect the violated constraint – that is, the shadow price for the constraints are at or near the MVL.
- The figure shows that the vast majority of binding hours do not exhibit shadow prices that approach the full MVL.
  - ✓ Nearly 60 percent of unmanageable binding hours occur on low voltage constraints and over three-quarters have shadow prices less than 30 percent of their MVL.
  - ✓ Higher voltage constraints are also substantially mispriced – over half of the higher voltage constraints are priced less than 30 percent of their MVL.
  - ✓ 27 percent of all violated constraints are priced at 0 – which means that the market would not show any reflection of these constraints in the LMPs or dispatch.

Pricing of Unmanageable Congestion by Voltage Level 2010



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Pricing Unmanageable Transmission Constraints

- The results in the prior figure indicate that the relaxation algorithm generally produces inefficiently low shadow prices that distort associated LMPs.
  - ✓ The shadow price and associated LMP should be equal to the reliability cost of violating the constraint (i.e., the MVL). Instead, the relaxation algorithm produces shadow prices that bear little resemblance to the true value of the violated constraints.
- To estimate the economic effects of this problem, the next figure shows the value of the real-time congestion associated with violated constraints, separately showing
  - ✓ The portion of the congestion that was priced and reflected in market outcomes; and
  - ✓ The portion of the congestion artificially eliminated by the relaxation algorithm.
- The figure shows that the relaxation algorithm eliminated a substantial share of the congestion associated with unmanageable constraints at all voltage levels.
- Overall, almost 60 percent of the congestion on unmanageable constraints was eliminated by the relaxation algorithm.
  - ✓ The reduction in the value of this congestion was $313 million in 2010, up from $239 million in 2009.
  - ✓ This represents a reduction in the value of real-time congestion of almost one quarter, which results in corresponding reductions in day-ahead congestion and FTR revenues.
- Hence, we continue to recommend that the Midwest ISO discontinue use of the relaxation algorithm and set prices based on the constraint MVLs.

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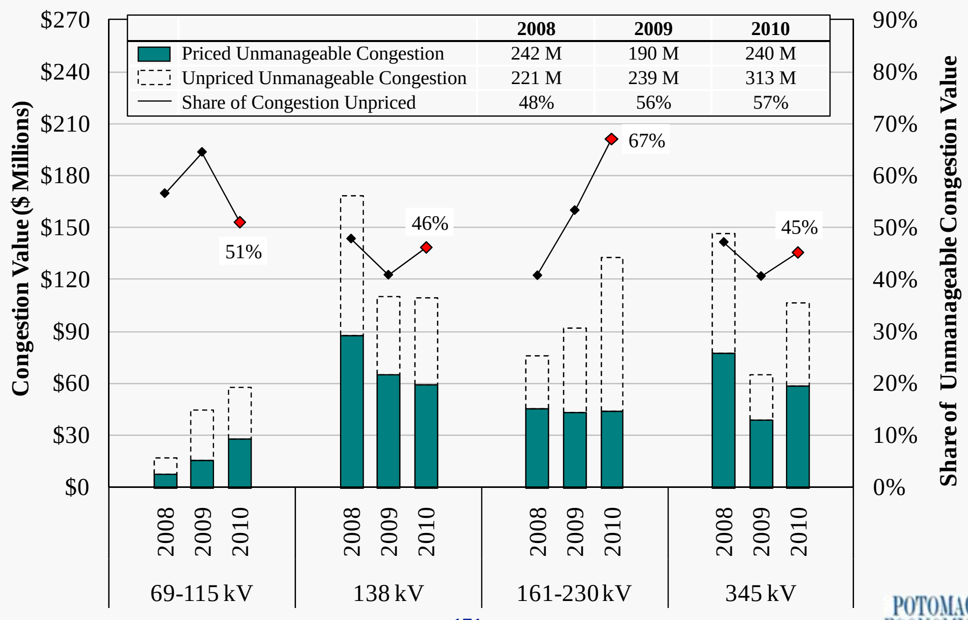
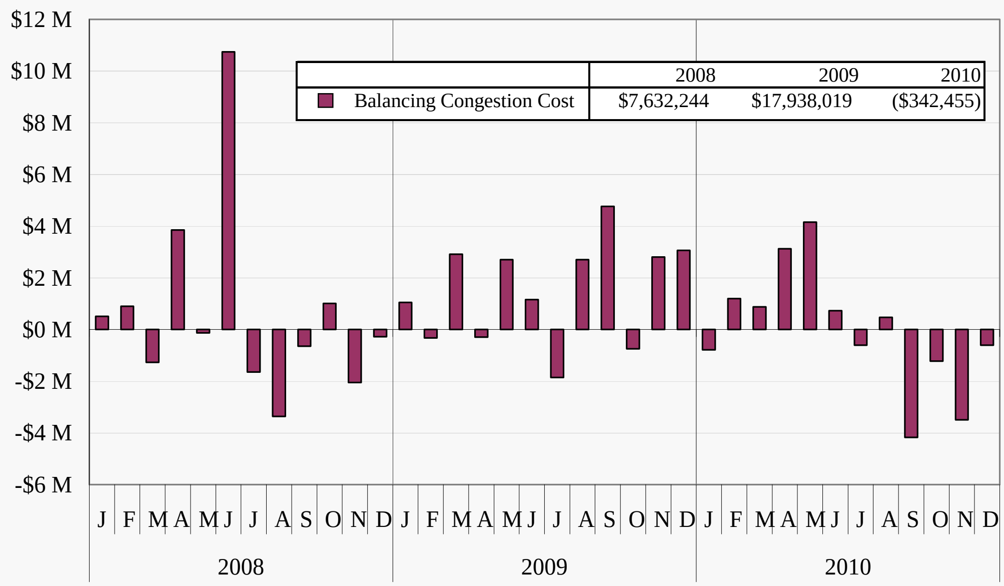
MVL Unmanageable Pricing



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 2008 to 2010 net of market-to-market settlements.
- Balancing congestion costs have fallen sharply since the markets began.
  - ✓ Costs averaged $80 million per year in 2006-2007, before declining to $7 million in 2008 and $17 million in 2009.
  - ✓ In 2010, these costs fell to -$342,000. This indicates significant improvements in the day-ahead modeling of loop flows and potential real-time congestion.

Balancing Congestion Costs
2008 – 2010



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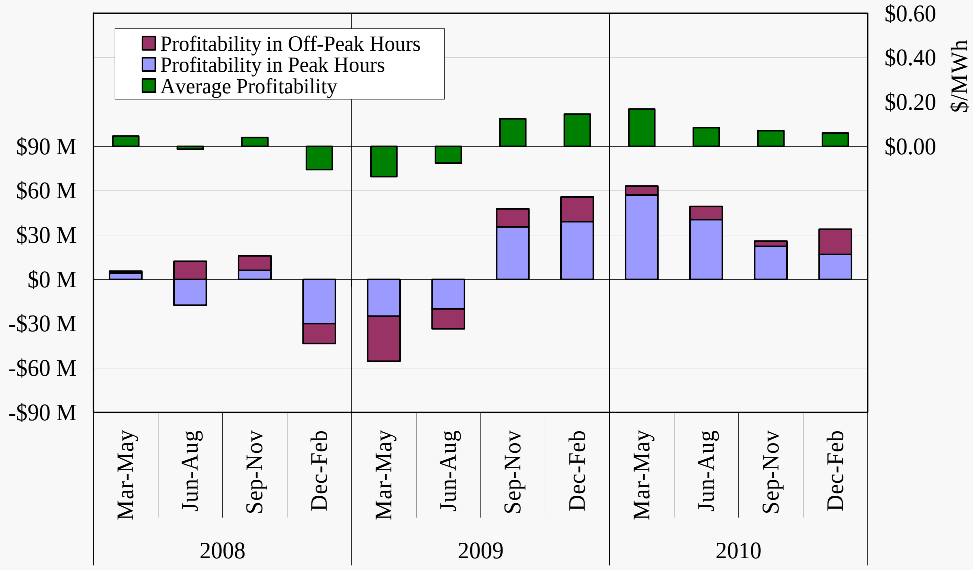
FTR Profitability

- 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 market, 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 first figure shows that profitability of FTRs purchased in the seasonal FTR auction was consistently marginally profitable in 2010, earning an average of $0.09 per MWh.
  - ✓ FTR profits during peak periods ($120 million) were over six times greater than off-peak profits.
- The second figure shows that profits for monthly FTRs averaged $0.19 per MWh in 2010, ranging from $0.64 per MWh in April and May to a loss of $0.04 in December.
  - ✓ The profitability in April and May is explained by unexpectedly high congestion.
  - ✓ As with the seasonal auction, monthly peak profits ($36.7 million) more than doubled off-peak profits ($15.4 million).
- These results indicate that the liquidity and overall performance of the FTR markets has been good, generally causing FTR prices to accurately reflect their value.

POTOMAC ECONOMICS

FTR Profitability
Seasonal Auctions, 2008 – 2010



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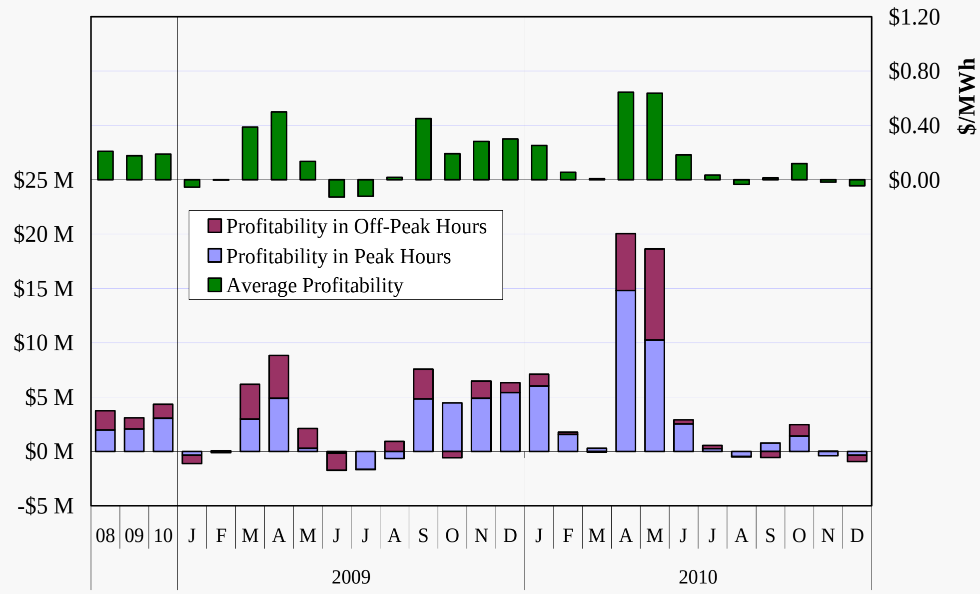
FTR Profitability
Monthly Auctions, 2009 – 2010



POTOMAC ECONOMICS

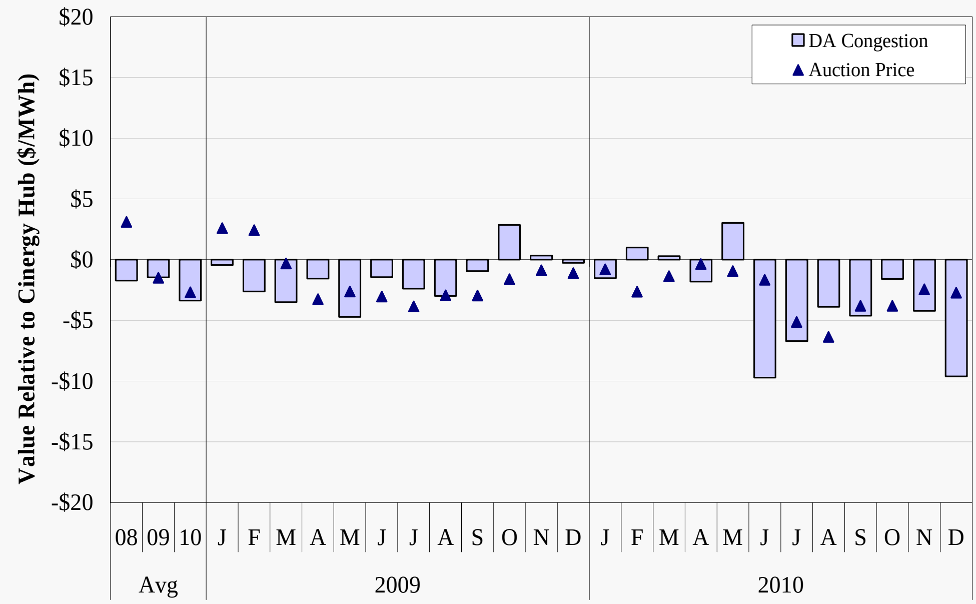
FTR Auctions

- 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 show values for WUMS Area, 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 are typically reflected in the auction prices with a lag.
  - ✓ The results in the following figures help explain the changes in FTR profitability shown in the analyses above.

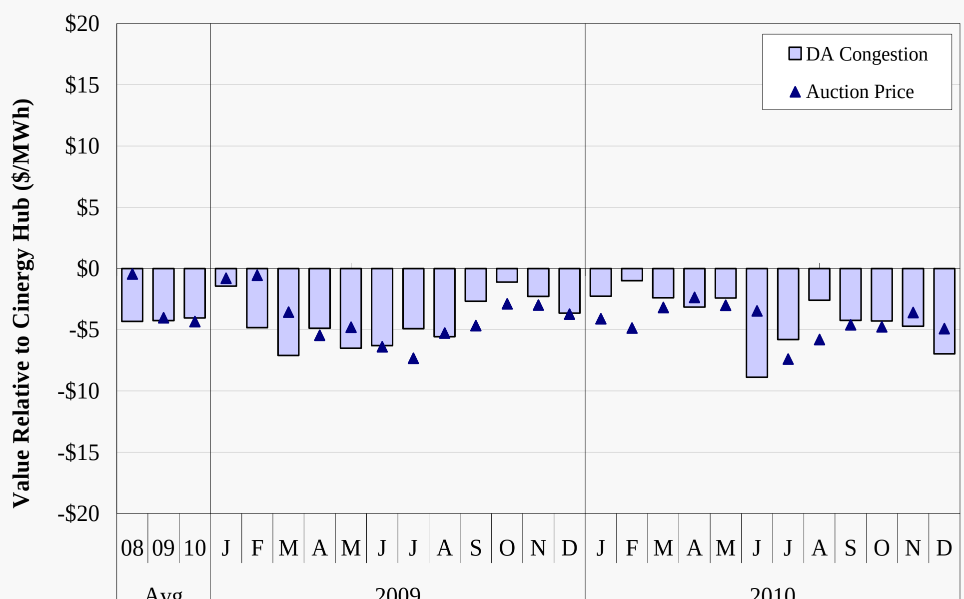
FTR Auction Prices and Congestion WUMS

- The first figure shows that the value of peak congestion at WUMS relative to Cinergy was negative in most months of 2010 (i.e., congestion from WUMS to Cinergy).
  - ✓ Convergence between auction prices and congestion values was only fair in 2010 because volatility in monthly congestion patterns increased in 2010.
  - ✓ The average monthly spread in 2009 was $2.93 per MWh, up $0.60 from 2009.
  - ✓ Auction prices generally adjusted the following month to changes in congestion patterns – adjusting for a one-month lag in convergence, the spread averaged $1.53 per MWh.
- Peak-hour congestion out of WUMS increased in June 2010 due to higher loads in the East, unit additions in WUMS and congestion on certain market-to-market flowgates.
  - ✓ Congestion averaged $0.19 per MWh from January to May and -$5.76 per MWh thereafter.
- The second figure shows that off-peak hours continued to exhibit consistent negative (export) congestion, due in part to wind generation in the West.
  - ✓ Off-peak congestion averaged -$4.04 per MWh in 2010, slightly less than the -$4.26 recorded in 2009.
  - ✓ Convergence is better during off-peak hours due to the lower volatility – the monthly average off-peak spread between auction prices and congestion in 2010 was $1.84 per MWh (up from $1.51 in 2009).

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

- Similar to WUMS, convergence between congestion values and FTR prices at the Minnesota Hub decreased modestly in 2010.
  - ✓ Peak congestion values relative to Cinergy Hub were negative during most months due to persistent west-to-east congestion.
    - – This trend was stronger in the middle of the year: in the period January to May values averaged -$0.83 per MWh and averaged -$5.65 thereafter.
  - ✓ The monthly average peak-hour spread was $2.47 per MWh in 2010, up 10 percent from the prior year.
- Off-peak congestion in 2010 was again more uniform than peak congestion.
  - ✓ The monthly off-peak spread averaged $2.21 per MWh, up from $1.79 in 2009.
  - ✓ Peak and off-peak spreads are similar to 2009 but were substantially lower than in 2007 or 2008.
- As at WUMS and other locations, the figures reveal a tendency for a one-month lag in convergence, as one would expect because FTRs are sold prior to the month in which the congestion occurs.
  - ✓ Adjusting for this lag in FTR prices, convergence improves by one-third.

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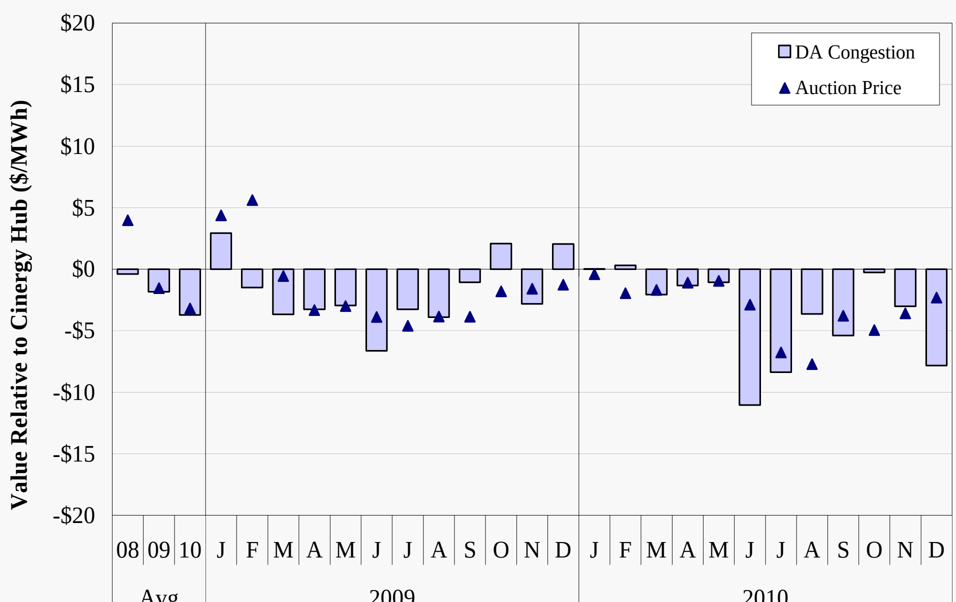
FTR Auction Prices and Congestion Minnesota Hub: Peak Hours



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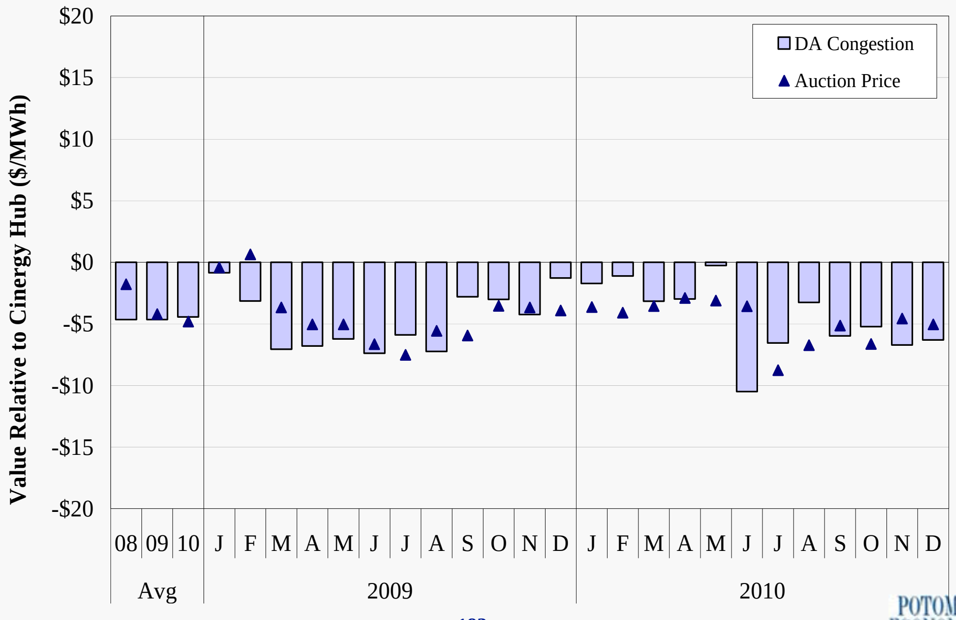
FTR Auction Prices and Congestion
Minnesota Hub: Off-Peak Hours



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FTR Auction Prices and Congestion
Michigan Hub

- 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 considerably lower than at either Minnesota Hub or WUMS Area.
  - ✓ Congestion into Michigan persisted for nearly all of 2010 due to import constraints on the Southwestern Michigan interface, as well as temporary transmission outages in the second and fourth quarters of the year.
  - ✓ The average spread between congestion values and FTR prices in 2010 was $1.16 per MWh, comparable to the $1.09 per MWh value in 2009.
- Convergence between Michigan and Cinergy Hubs is more dependent upon generator and transmission outages than upon hourly load or wind patterns.
  - ✓ Unlike at WUMS and Minnesota Hubs, peak and off-peak convergence is very similar.
- Overall, these results for the Michigan Hub indicate reasonably good convergence between FTR prices and the value of day-ahead congestion.
  - ✓ Michigan congestion is often impacted by loop flows around Lake Erie.
  - ✓ Coordinated operation of five Phase Angle Regulators (of which two are controlled by MISO) should improve flows around Lake Erie, but significant regulatory issues remain, and they are unlikely to be placed into service before the end of 2011.

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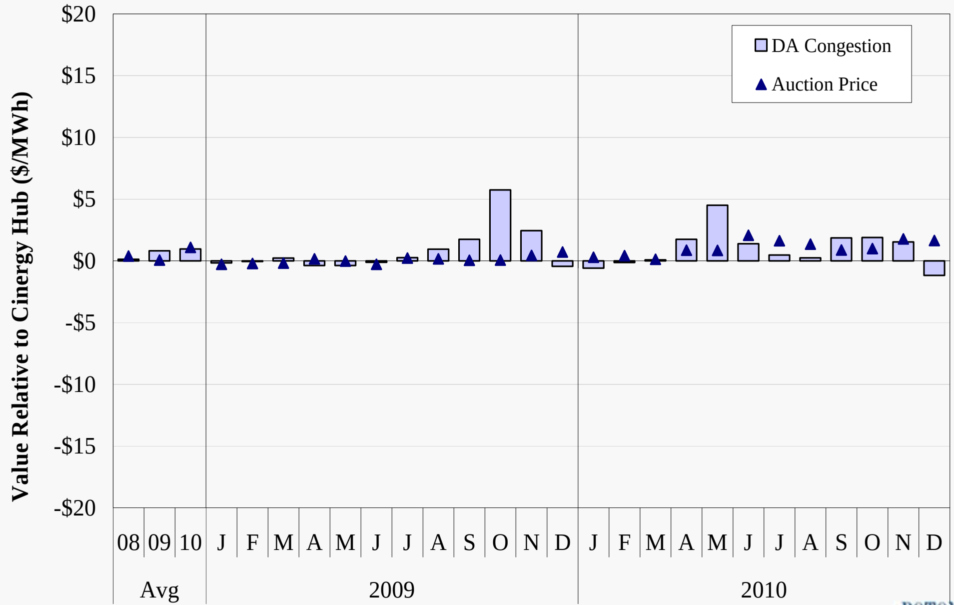
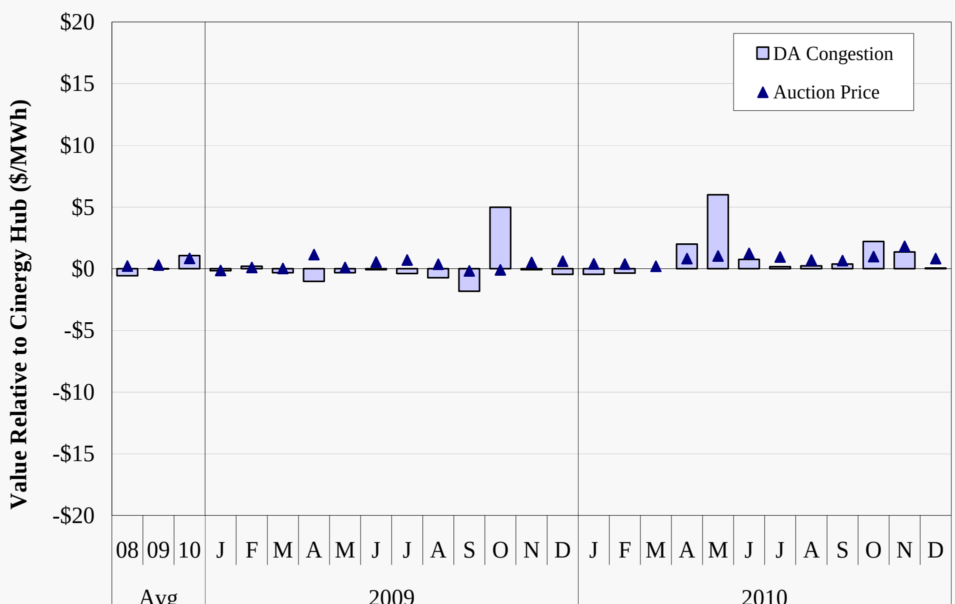
FTR Auction Prices and Congestion Michigan Hub: Peak Hours



POTOMAC ECONOMICS

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



POTOMAC ECONOMICS

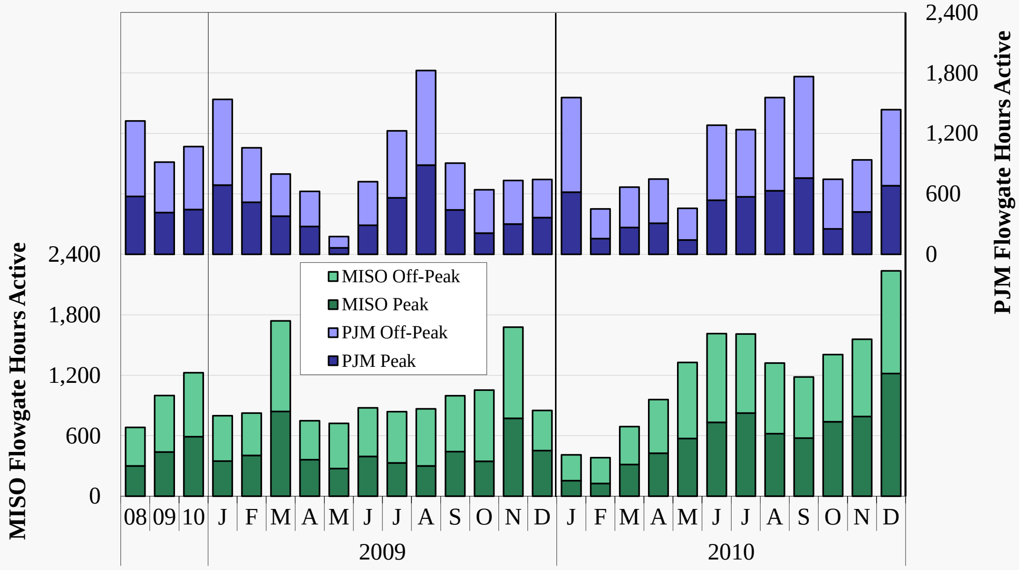
Market-to-Market Activity

- 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 two RTOs.
  - ✓ The market-to-market process is used by the Midwest ISO and PJM to coordinate the relief of congestion on transmission constraints that impact both systems.
  - ✓ 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 quantity of relief, it incorporates these values in its real-time market to provide as much of the requested relief as possible at a cost up to the shadow price of the monitoring RTO.
  - ✓ 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 occur between the RTOs based on the difference between the actual flow and the FFE.
- 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 and accurate.

Market-to-Market Activity

- The following figure shows the total number of market-to-market constraint-hours (instances when a market-to-market constraint is activated and binding).
- The top panel represents coordinated flowgates located in the PJM system and the bottom panel represents flowgates located in the Midwest ISO.
  - ✓ The panels are divided into peak hours (darker shade in the stacked bars) and off-peak hours (lighter shade).
- The figure indicates activity on all market-to-market constraints increased in 2010.
  - ✓ Activity on Midwest ISO flowgates increased by 23 percent, while activity on PJM flowgates increased by 16 percent.
- Midwest ISO activity increased most during peak hours (up 35 percent) and increased steadily over the course of 2010.
  - ✓ Activity was lowest in January and February, consistent with the very low congestion observed on internal constraints.
  - ✓ In late January, a key constraint from WUMS to PJM switched from PJM to MISO control and unit additions in WUMS have increased the binding frequency.
- Activity on PJM market-to-market constraints are generally the most frequent in the summer, when demands on the system and west-to-east flows are the greatest.
  - ✓ However, off-peak constraint hours increased faster (25 percent) than did peak constraint hours (7 percent).

Market-to-Market Activity
2008 – 2010



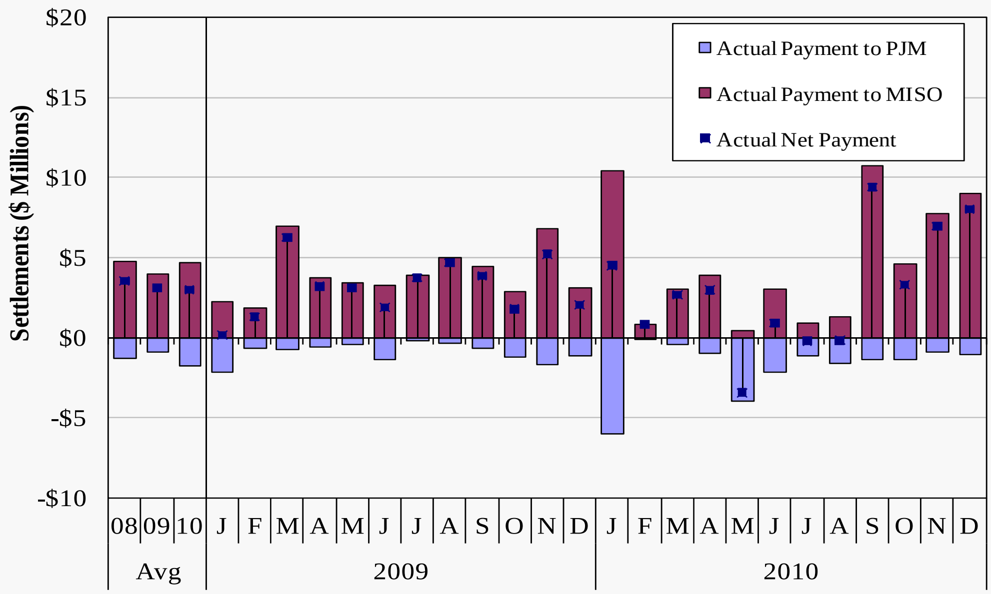
POTOMAC ECONOMICS

Market-to-Market Settlements

- 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.
  - ✓ The drop line shows net payments to the Midwest ISO or PJM in each month.
- Settlement is based on the reciprocating RTO’s actual market flows compared to its firm flow entitlement.
  - ✓ If a reciprocating RTO’s market flows are below its FFE, 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 to each RTO increased by about $1 million and remain substantially in favor of the Midwest ISO overall.
  - ✓ Net payments were largely unchanged at $3 million on average per month to the Midwest ISO. Only in May did PJM receive considerable net payments.
  - ✓ This result suggests that the Midwest ISO generally uses less of its entitlement on PJM-coordinated flowgates than PJM uses on Midwest ISO-coordinated flowgates.

POTOMAC ECONOMICS

Market-to-Market Settlements
2008 – 2010



POTOMAC ECONOMICS

Market-to-Market Constraints
Shadow Price Convergence

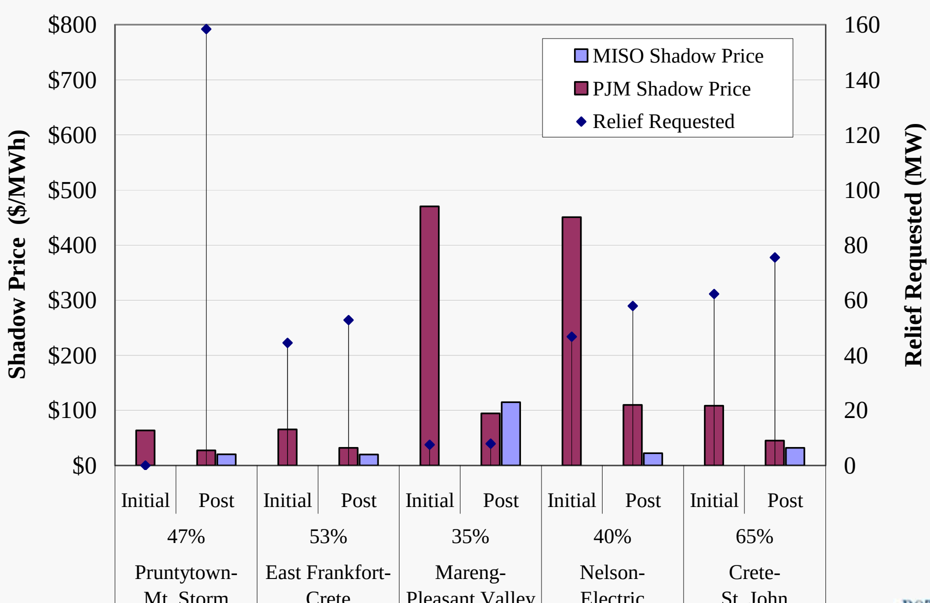
- The next two figures show an analysis that examines the five most frequently activated market-to-market constraints on the PJM and Midwest ISO systems.
  - ✓ The analysis is intended to show the extent to which the shadow prices on coordinated constraints converge between the two RTOs.
  - ✓ Each figure 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.

POTOMAC ECONOMICS

PJM Market-to-Market Constraints
Shadow Price Convergence

- The first figure shows the results of our analysis of PJM-coordinated flowgates.
- The shadow prices decrease significantly and generally 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) varies considerably by constraint.
- The relief requested varies by constraint and over the course of the coordinated hours for each constraint.
  - ✓ The process to determine the appropriate relief request is based on market conditions and is now nearly fully automated.
- However, the RTOs have recognized that the software has not always provided reasonable relief values and work is underway to improve the software.
  - ✓ Revised versions of the software were implemented in late 2010 and in addition manual fixed relief requests continue to be used on certain FGs.
- Although the relief values have not been optimal, the Midwest ISO's response has contributed to reductions in PJM's shadow price when the RTOs are coordinating.
  - ✓ In most cases, Midwest ISO and PJM shadow prices converge well.

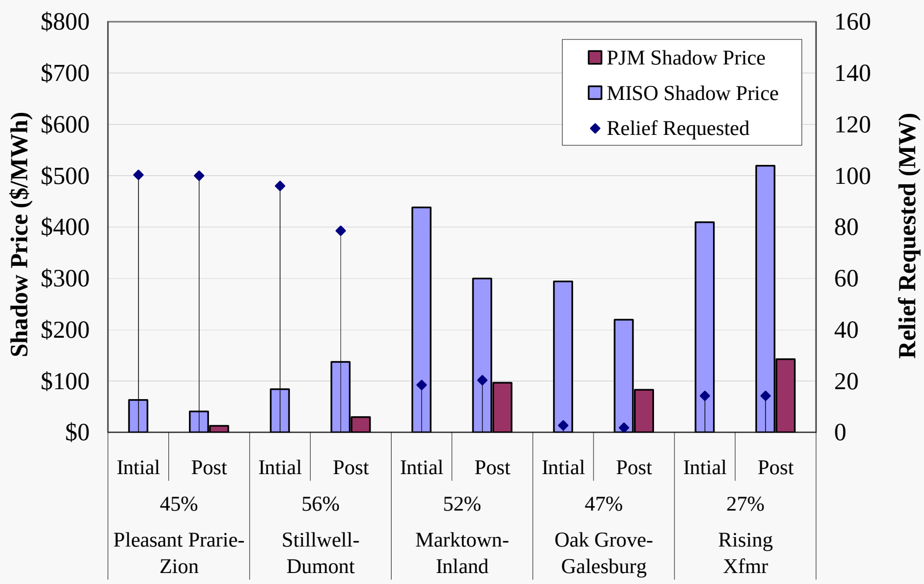
PJM Market-to-Market Constraints
Relief Requested and Shadow Prices, 2010



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

- The next figure shows the most frequently activated market-to-market constraints on the Midwest ISO system.
  - ✓ The most common flowgates for market-to-market coordination are those that limit flows from west-to-east, including Pleasant Prairie-Zion, Stillwell-Dumont and Oak Grove-Galesburg.
  - ✓ PJM made changes to allow it to provide additional relief when a Midwest ISO market-to-market constraint binds.
- Similar to the analysis of the PJM constraints, the figure shows the shadow prices tend to decrease and move toward convergence over the duration of the event.
- However, when comparing these results to those for the PJM constraints, we find:
  - ✓ While improved compared to 2009, the reduction in the Midwest ISO's shadow prices in 2010 continue to be much smaller; and
  - ✓ The shadow prices do not converge as well after the coordination is initiated.
- As a result, additional cost-effective relief may therefore be available from PJM.
  - ✓ The improvement to the relief software may improve these results.
  - ✓ We continue to recommend that the RTOs work together to identify any other modeling parameters, provisions, or procedures that may be limiting PJM's relief.

Midwest ISO Market-to-Market Constraints Relief Requested and Shadow Prices, 2010



Market-to-Market Recommendations

- The Midwest ISO and PJM have recently responded to a number of past recommendations which should further improve the performance of the process in 2011.
  - ✓ The Broader Regional Markets Initiative should produce Interconnection-wide cost savings in 2011 and provide better coordination of the interchange with PJM.
- We recommend the following additional changes to improve the market-to-market process:
  - ✓ The Midwest ISO should continue to improve its processes to more closely monitor the information being exchanged with PJM in order 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.

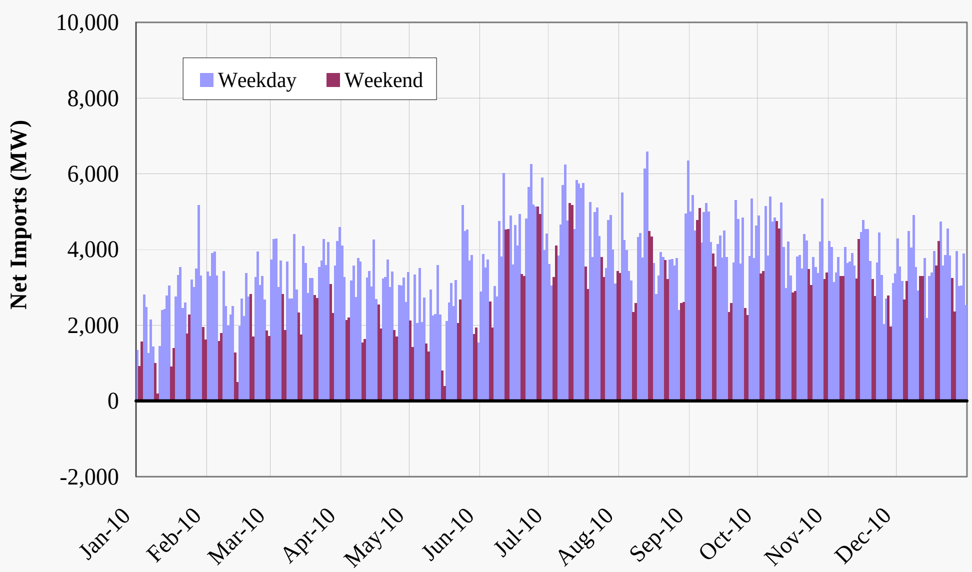
External Transactions

Daily Average Day-Ahead Imports

- This section of the report evaluates the interchange between the Midwest ISO and adjacent areas, summarizing the magnitude of the external transactions and 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 2010. It shows:
  - ✓ The Midwest ISO remains a net importer of power during all hours and seasons, and relies on them to satisfy the demands of the market.
- In all, day-ahead net imports in 2010 averaged nearly 3.5 GW per hour, down less than 2 percent from 2009.
  - ✓ As in prior years, weekday imports were nearly 1 GW higher than weekend imports.
  - ✓ In January to May 2010, net imports averaged nearly 800 MW less than over the same period in 2009, while net imports in June to December were nearly 700 MW greater.
  - ✓ Net imports from Manitoba increased by over 1,000 MW between May and July, which contributes to west-to-east congestion in the Midwest ISO.
- 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 continue to recommend the Midwest ISO modify its deliverability requirement for external resources under Module E.

POTOMAC ECONOMICS

Daily Average Day-Ahead Net Imports

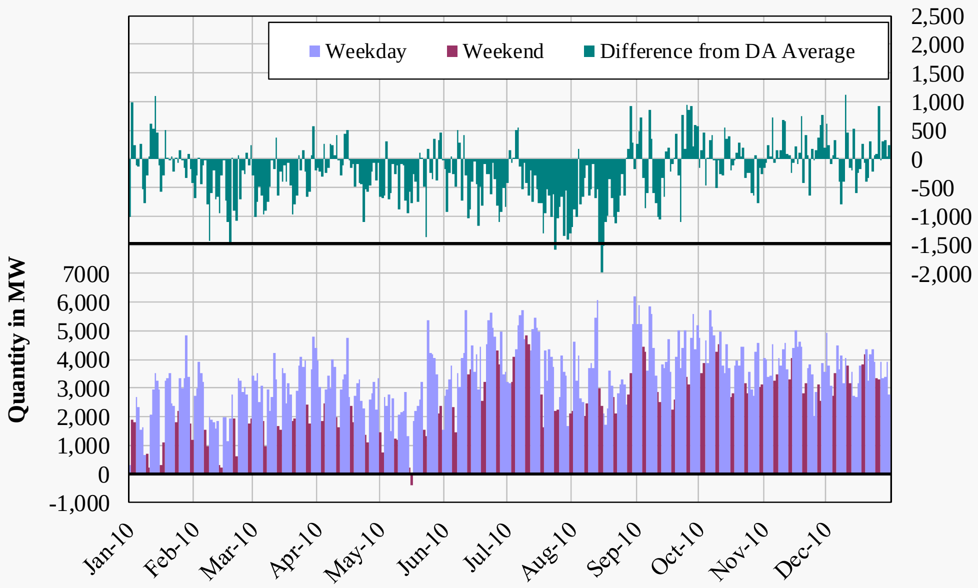


POTOMAC ECONOMICS

Daily Average Real-Time Imports

- The next figure shows the net imports in the real-time market and the change in net imports from the day-ahead market.
- Real-time net imports increased 8 percent in 2010 to an average of 3.2 GW.
  - ✓ Net imports from PJM increased by 700 MW percent to nearly 1 GW. PJM, Manitoba and Ontario comprised the majority of all net imports.
- Real-time net imports generally decreased from those scheduled in the day-ahead market by an average 230 MW in 2010, which is less than in prior years.
  - ✓ On 30 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.
- Changes between day-ahead and real-time were greatest in summer.
  - ✓ Differences in net imports over the PJM and Manitoba interfaces, which together averaged nearly -400 MW in summer, dissipated in September.
  - ✓ As in prior years, overall reductions in real-time imports are larger on the western interfaces, particularly with WAPA.

Daily Average Real-Time Imports 2010



Hourly Average Real-Time Imports from PJM

- The following figure shows the average net imports scheduled across the Midwest ISO-PJM interface by hour of the day.
- The figure shows average net imports from PJM increased by over 700 MW from 2009.
  - ✓ The Midwest ISO is on average a net importer of power during each hour.
    - – Imports increased consistently across all hours from last year.
  - ✓ Net imports from PJM are not correlated with load.
    - – This is a result of wheel transactions from Ontario, which tend to increase with load and lower the net imports at the PJM interface.
- The standard deviation of the net imports shows that imports regularly vary by as much as 2,000 MW.
  - ✓ 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.

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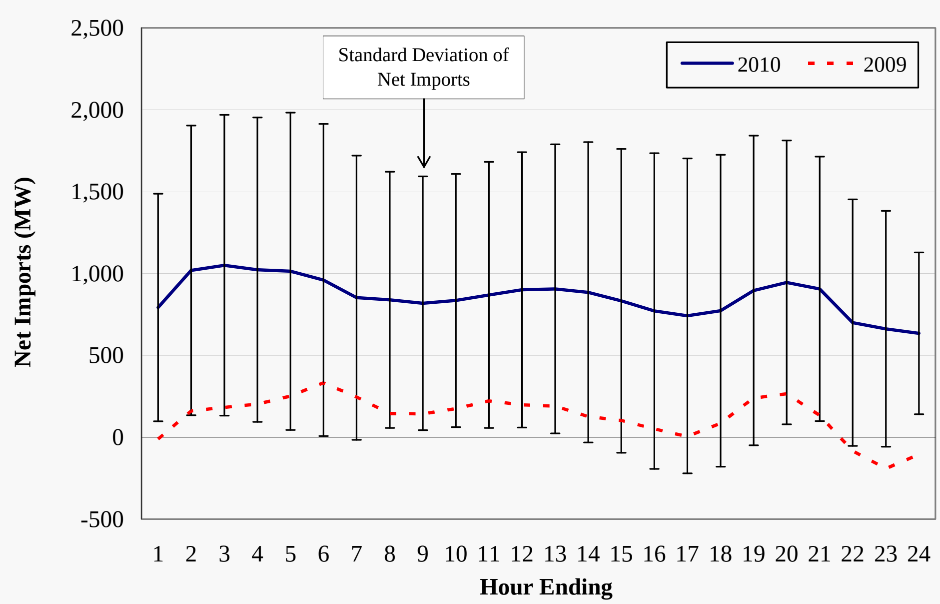
Hourly Average Real-Time Imports from PJM 2009 – 2010



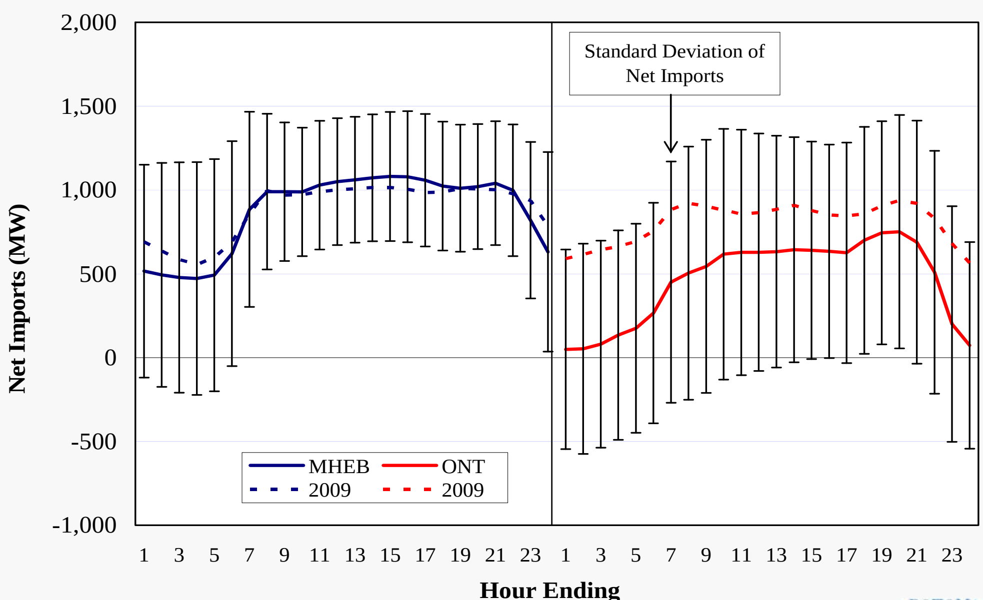
POTOMAC ECONOMICS

Hourly Average Real-Time Imports from Canada

- The following figure shows hourly real-time net imports across the Canadian interfaces with Manitoba and Ontario (IESO).
  - ✓ Similar to interfaces with PJM, power flows vary considerably in direction and magnitude, as indicated by the wide standard deviations.
- The Midwest ISO remains a net importer across the Manitoba and Ontario interfaces, although a large share of the net imports from Ontario are the result of transactions to PJM wheeling through the Midwest ISO.
- Imports across the Manitoba interface track load and increase substantially during peak hours.
  - ✓ In 2010, hourly imports were largely unchanged at approximately 500 MW during off-peak hours and 1,000 MW during peak hours.
    - – The variation in schedules are considerably wider during off-peak hours.
  - ✓ Imports also vary seasonally depending in part on water levels in Manitoba – imports averaged less than 500 MW in January but near 1,500 MW in August.
- Hourly net imports from Ontario decreased by 350 MW on average in 2010.
  - ✓ Excluding wheel transactions to PJM, Midwest ISO is a net exporter to Ontario averaging 263 MW per hour.

POTOMAC ECONOMICS

Hourly Average Real-Time Imports from Canada 2009 – 2010



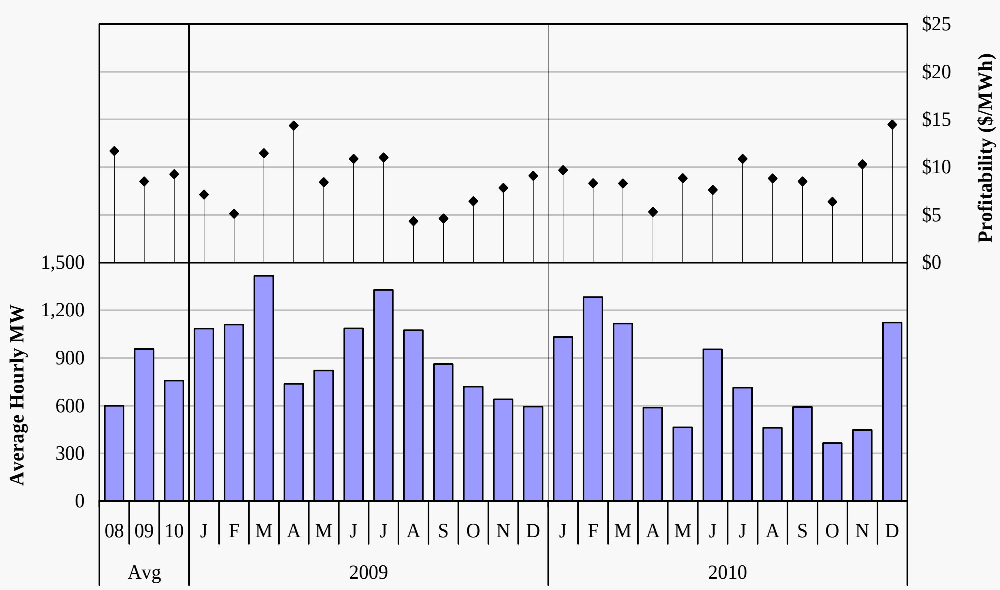
POTOMAC ECONOMICS

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 volume of these transactions decreased by 21 percent in 2010 and they remain persistently profitable.
  - ✓ These transactions netted average profits of nearly $10 per MWh in 2010, up 9 percent.
  - ✓ 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, but would not likely cause the transactions to be unprofitable.
- 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 $0.74 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.

POTOMAC ECONOMICS

Real-Time Ontario-PJM Wheels
Quantity and Profitability, 2008 – 2010



POTOMAC ECONOMICS

Loop Flows Around Lake Erie Conclusions

- The assumption made when a transactions is scheduled is often inconsistent with how the actual power flows, 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 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 IESO – MISO PARs are expected to begin operation in late 2011 and should significantly reduce unscheduled flows.
- The Broader Regional Markets Initiatives ("BRMI") developed with IESO, NYISO and PJM should also improve the utilization of the interfaces around Lake Erie.
  - ✓ We have estimated cumulative annual production cost savings of $297 million for these initiatives and strongly support them.
  - ✓ The most valuable initiative is one that would allow better coordination of the interchange with PJM, which is discussed later in this section.

POTOMAC ECONOMICS

Real-Time Prices and Interface Schedules

- The following series of figures evaluate the price convergence and net imports between the Midwest ISO and adjacent markets.
  - ✓ The left panel in the figures is a scatter plot of the real-time price differences and the real-time net imports in unconstrained hours.
  - ✓ The right panel in the figures shows the monthly averages for hourly real-time price differences between adjacent markets and the monthly average magnitude of the hourly price differences (average absolute differences).
- In an efficient market, prices at the interface should 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.
  - ✓ Because transactions are scheduled in advance, uncertainty regarding future price differences will produce less than perfect price convergence.

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Real-Time Prices and Interface Schedules
PJM and Midwest ISO

- The following figure presents results for the Midwest ISO – PJM interface.
- The right panel shows Midwest ISO and PJM prices varied by just a few dollars in either direction for most of 2010.
  - ✓ The absolute average price difference was roughly $12 per MWh in 2010, up from $10 per MWh in 2009, and were modestly higher during summer months.
- Net power flows were scheduled from PJM to Midwest ISO in 80 percent of hours in 2010, as shown in the left panel.
  - ✓ Import and export quantities remain widely scattered relative to the price differences.
  - ✓ In over 56 percent of the hours, power was scheduled in the wrong direction (from the higher-priced market to the lower-priced market), which confirms that the current structure does not allow participants to fully arbitrage the prices in the two markets.
- To achieve better price convergence, we recommend that the RTOs a) optimize the net interchange between the two areas, or b) allow participants to submit intra-hour offers to transact that would be scheduled based on forecasted price differences.
  - ✓ Under these approaches 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 economic savings associated with jointly dispatching the generation in the two regions.
  - ✓ The Midwest ISO has begun investigating the means to implement this recommendation.

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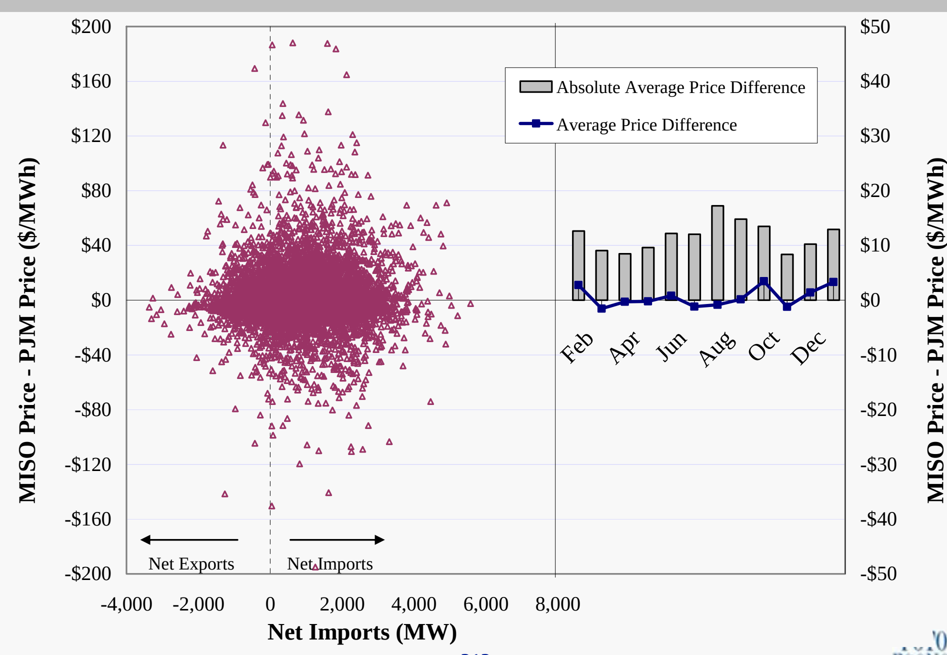
Real-Time Prices and Interface Schedules in 2010
PJM and Midwest ISO



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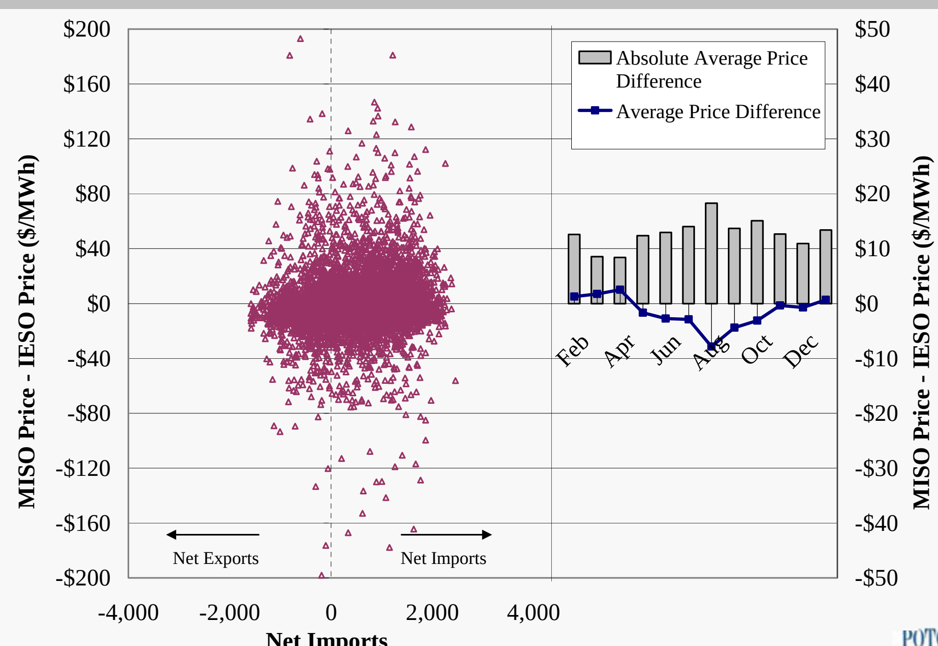
Real-Time Prices and Interface Schedules IESO and Midwest ISO

- The next figure provides the same analysis for the Midwest ISO-IESO interface in the real-time market.
- The pattern in the left side of the figure confirms that the Midwest ISO was a net importer of power from IESO in 2010, importing an average of 458 MW.
  - ✓ This is unexpected because the IESO price premium averaged $1.45 per MWh.
    - – IESO prices were considerably higher than Midwest ISO prices during the second and third quarters of 2010 – premiums there averaged $3.77 during this period and peaked near $8 in July.
  - ✓ Absolute average price differences averaged $12.74 per MWh, down from $13.57 in 2009 and nearly $21 in 2008.
- The dispersion of prices and schedules in the figure shows that transactions were relatively unresponsive to price differences.
  - ✓ Power was scheduled in the lower-priced direction in 51 percent of hours in 2010.
- 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 2010 IESO and Midwest ISO

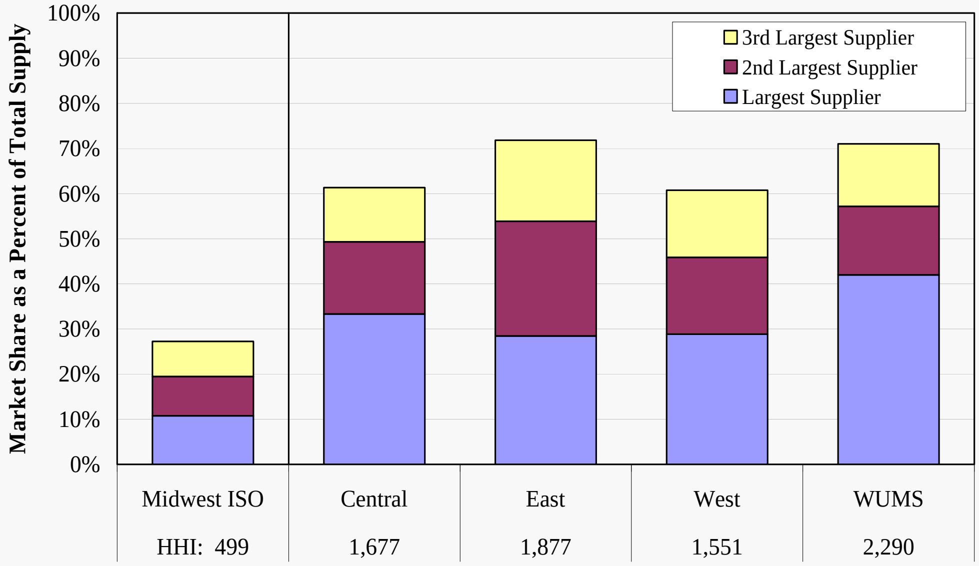


Participant Conduct and Mitigation

Market Concentration

- The analyses in this section of the report provide an overview of the competitive structure and performance of Midwest ISO markets in 2010.
- The first analysis is of market concentration, measured using the Herfindahl-Hirschman Index ("HHI").
  - ✓ HHIs are calculated by summing the squares of each supplier's market share.
  - ✓ Markets with HHIs of greater than 1,800 as 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, or load obligations.
- The market concentration of the entire Midwest ISO region is relatively low (499).
  - ✓ However, all of the Midwest regions have HHI values approaching or exceeding 1,800. WUMS remains the most concentrated region at 2290.
    - – In 2010 HHI values fell in all regions due to investment or membership additions.
  - ✓ 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.

Market Concentration 2010



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Residual Demand Index

- A better metric than the HHI for evaluating competitive issues in electricity markets is the Residual Demand Index ("RDI"), 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 "pivotal" – i.e., 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.
- Due to more high load periods, the share of all hours with pivotal suppliers increased in all Midwest ISO regions, except the West, in 2010.
  - ✓ In hours with loads greater than 90 GW, the pivotal supplier share in WUMS decreased from over 90 percent in 2009 to near 30 percent in 2010; however, there were 8 times more high-load hours in 2010.
  - ✓ The frequency of pivotal suppliers in the West declined as a result of new wind capacity built by relatively small-scale generation owners and the entry of Mid-American.
  - ✓ Pivotal suppliers continue to be less of a concern in the Central region.

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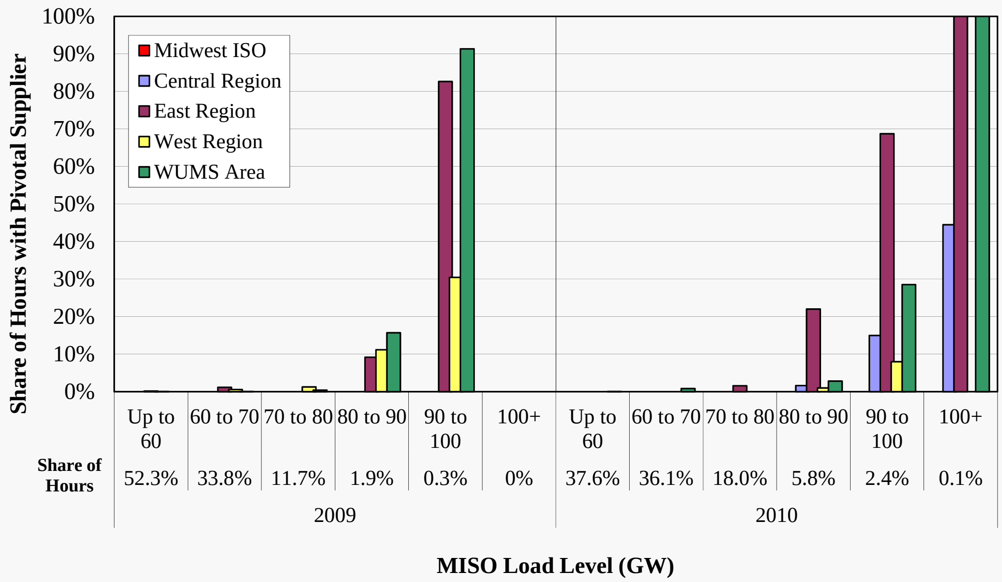
Residual Demand Index by Load Level
2009 – 2010



POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis
Share of Constraints

- 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 on the constraint are more limited than higher voltage constraints – and more likely to be owned by the same supplier.
    - – Much of the increase in congestion in 2010 was on low-voltage constraints.
- The next figure shows the portion of active NCA constraints (WUMS and Minnesota) and BCA constraints (Midwest ISO-wide) that have at least one pivotal supplier.
- This figure shows, among active constraints in 2010:
  - ✓ 76 percent of those into WUMS had a pivotal supplier, up from 69 percent in 2009.
  - ✓ 60 percent of those into Minnesota had a pivotal supplier, down from 75 percent.
  - ✓ 56 percent of all BCA constraints had a pivotal supplier, down from 64 percent.
- These results indicate that while local market power is most commonly associated with the NCA constraints, a large share of BCA constraints in 2010 created significant potential for local market power, particularly during the summer months.

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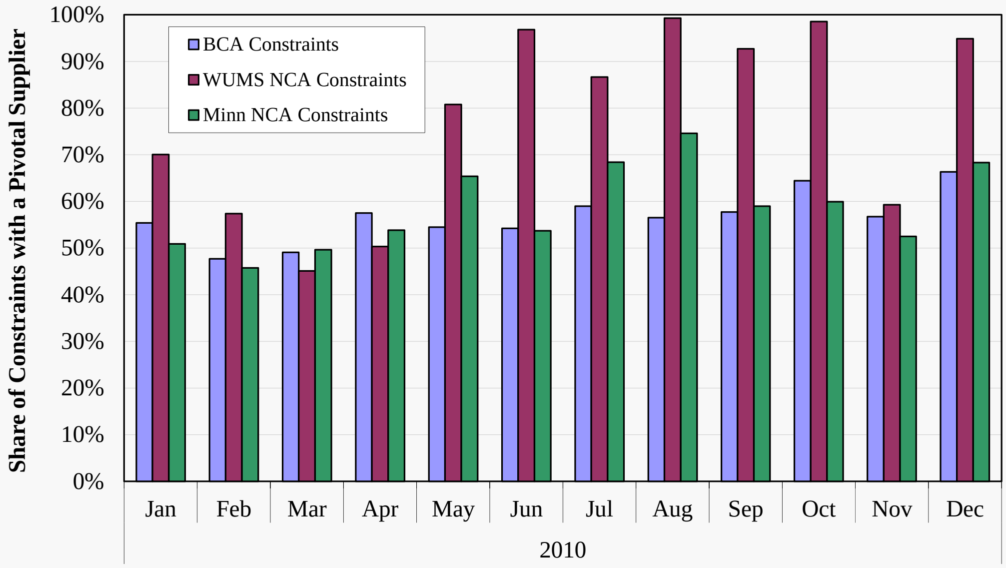
Constraint-Specific Pivotal Supplier Analysis
Share of Constraints – 2010



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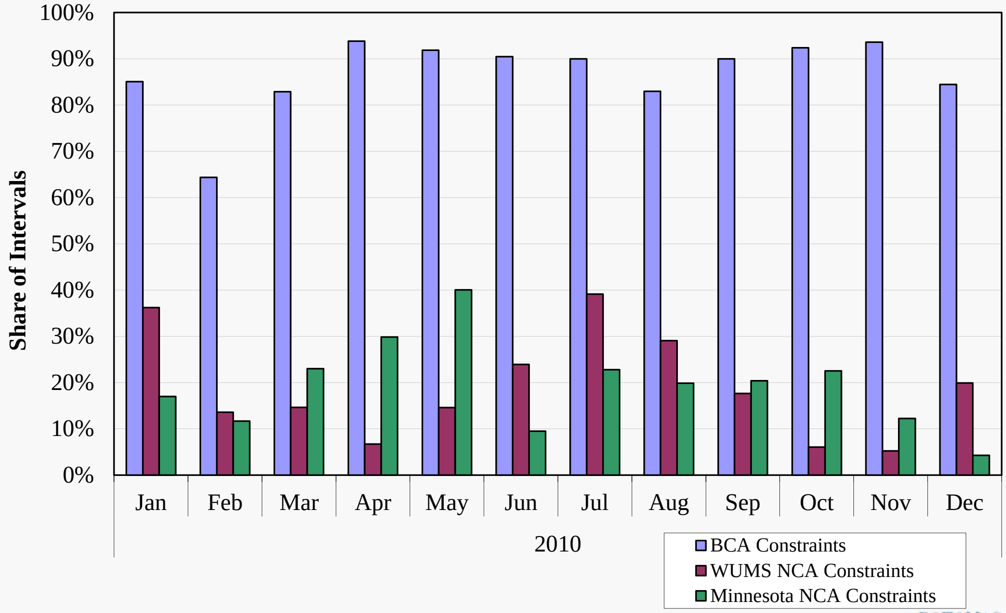
Constraint-Specific Pivotal Supplier Analysis
Share of Intervals

- 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 in 2010 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 87 percent of the hours during 2010, up from 79 percent in 2009.
  - ✓ The increase is partly a result of the Midwest ISO assuming responsibility for more lower-voltage constraints, which resulted in a higher number of binding constraints
    - – The monthly frequency ranged from 64 to 94 percent.
  - ✓ The share of active NCA constraints in 2010 with a pivotal supplier was largely unchanged at approximately 20 percent in both areas.
- These results indicate that the BCA and NCA mitigation continues to be essential.

POTOMAC ECONOMICS

Constraint-Specific Pivotal Supplier Analysis Share of Intervals – 2010



Price-Cost Mark-Up Analysis

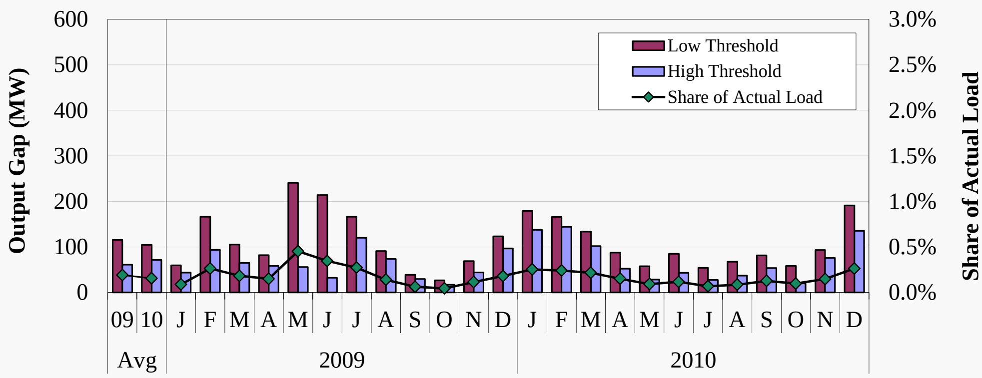
- The prior analyses (pivotal supplier and market concentration) are structural analyses intended to identify potential market power concerns.
- The remainder of this section evaluates the competitive performance of the market based on the conduct of the participants. These analyses are used to detect 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 compare an estimated system marginal price based on: a) actual offers to b) offer prices equal to suppliers' reference levels.
  - ✓ This analysis is a broad metric that does not account for physical restrictions on the units or transmission constraints, which would require re-running the market software.
  - ✓ We estimated an average annual mark-up in 2010 of 1.3 percent, compared to 1.2 and 2 percent in 2009 and 2008, respectively.
  - ✓ 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:
  - ✓ On average output gap levels at the high threshold were modestly higher in 2010 than in 2009 and they were slightly decreased at the low threshold averaging 72 MW at high threshold and 105 MW at low threshold.
    - – Levels were highest in the winter months as a result of relatively high energy prices and fuel price volatility.
  - ✓ As a share of actual load, output gap at low threshold remains less than 0.5 percent and ranged from 0.07 percent in July to 0.26 percent in December.
    - – These levels are extremely low and raise very few competitive concerns.
- We continue to monitor output gap levels continually and have investigated many specific output gap issues.
  - ✓ In most cases, values can be explained by competitive factors.

POTOMAC ECONOMICS

Economic Withholding: Output Gap Analysis Average of Daily Peak Hour, 2009 – 2010



Low Threshold Results by Unit Status (MW)

Off-Line	68	43	28	97	43	35	190	177	78	15	13	17	59	61	74	110	75	28	12	31	16	19	18	5	33	95
On-Line	48	62	32	70	63	48	51	36	89	76	26	10	10	62	105	57	59	60	46	54	39	49	64	54	61	96

High Threshold Results by Unit Status (MW)

Off-Line	22	42	25	52	9	21	8	7	46	1	5	13	41	37	67	110	73	27	12	31	16	19	18	5	33	89
On-Line	39	30	18	42	57	38	48	25	75	73	25	4	3	60	71	35	29	26	17	12	12	19	36	15	43	46

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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 as a percentage of actual load at both threshold levels are less than 1 percent at most load levels and locations, confirming that participants generally did not engage in anti-competitive behavior in 2010.
    - – Higher load levels in 2010 resulted in modest increases in output gap at the highest load levels, but never exceeded 1.5 percent in any region.
  - ✓ 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.
  - ✓ With the exception of the Central region, output gap levels were generally slightly higher for the top two suppliers in each region compared to other suppliers.
- In all, these results, coupled with our ongoing monitoring and investigations of hourly results, indicate that economic withholding has not been a significant concern in 2010.

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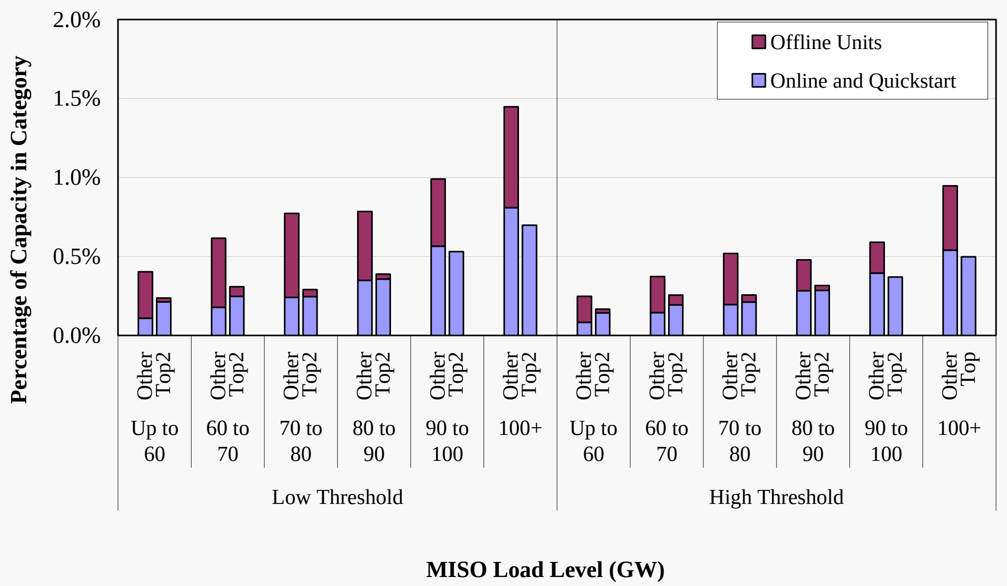
Real-Time Market Output Gap
Central Region, 2010



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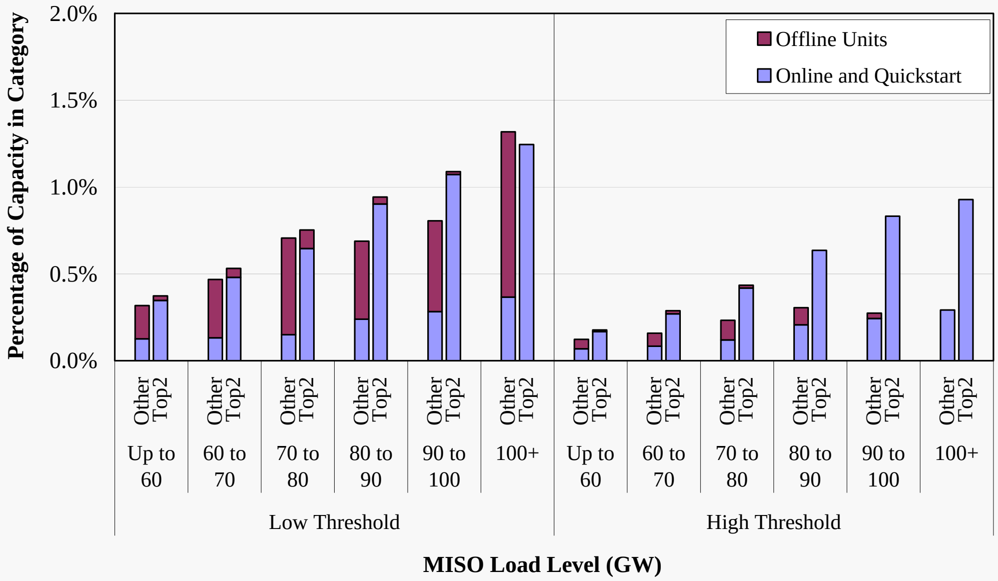
Real-Time Market Output Gap
East Region, 2010



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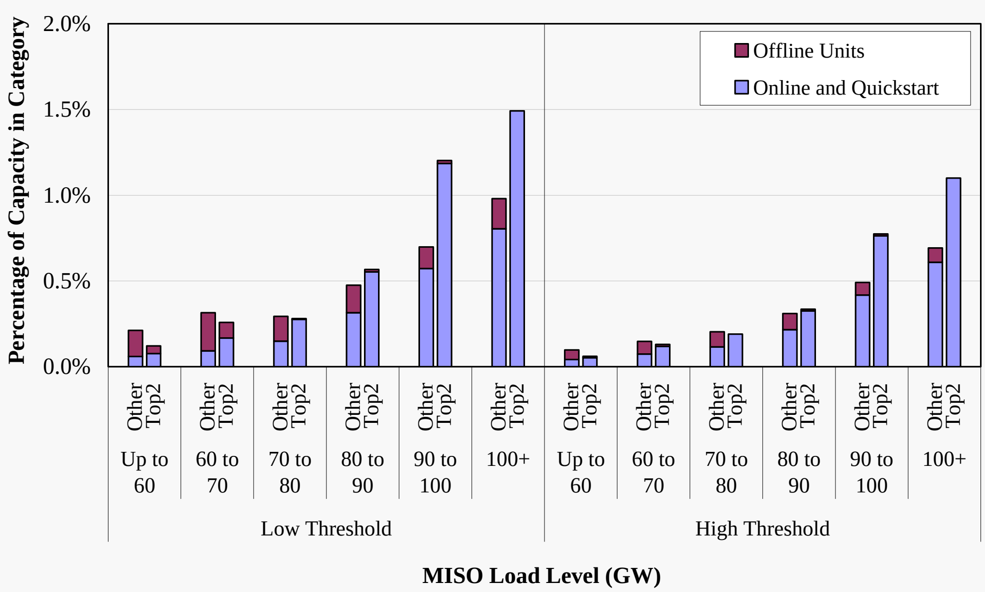
Real-Time Market Output Gap
West Region, 2010



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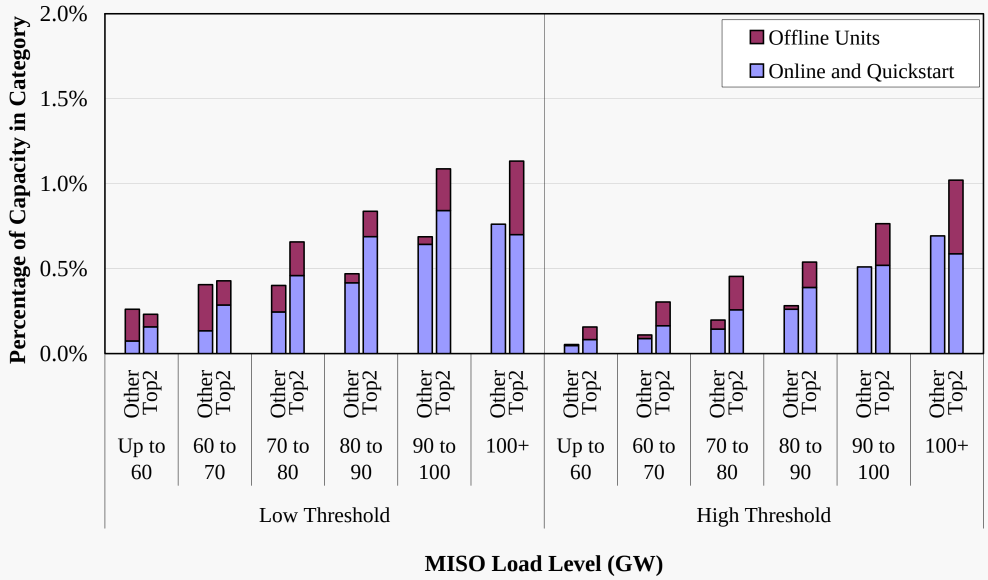
Real-Time Market Output Gap
WUMS Region, 2010



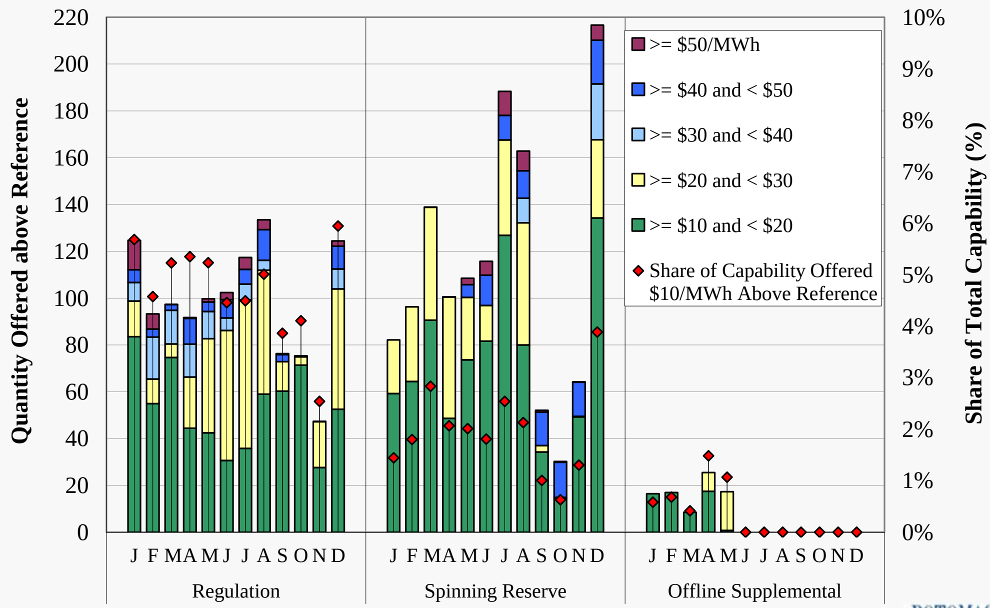
POTOMAC ECONOMICS

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 ancillary services were generally competitive in 2010, with the vast majority of AS offers within $10 per MWh of the reference price.
  - ✓ On average, 99 MW of regulation capability regulation capability (4.7 percent) was offered at more than $10 per MW above its reference level.
    - – This is largely unchanged from 2009 (4.8 percent).
    - – However, the share offered at more than $20 per MWh increased to 45 MW on average, up from 19 MW in 2009.
  - ✓ Similarly, 113 MW of spinning reserve capability (or 2.0 percent of the total capability) failed at the $10 threshold, up slightly from 105 MW in 2009.
  - ✓ Offer prices for supplemental reserves remained low, as did conduct failures.
    - – Supplemental reserve offer failures at the $10 threshold did not occur after May, which coincides with the reduction in overall offer volumes (see slide 79).
  - ✓ There were 6 ASM mitigation events in 2010 – all of which were involved mitigation of regulation offers.
- Overall, these results indicate that the offers into the Midwest ISO's ancillary services markets have been competitive and contributed to good performance.

POTOMAC ECONOMICS

Ancillary Services Offers 2010



POTOMAC ECONOMICS

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.
- 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 deratings (excluding permanent deratings).
  - ✓ The data is shown by load level and for the largest two suppliers compared to 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.

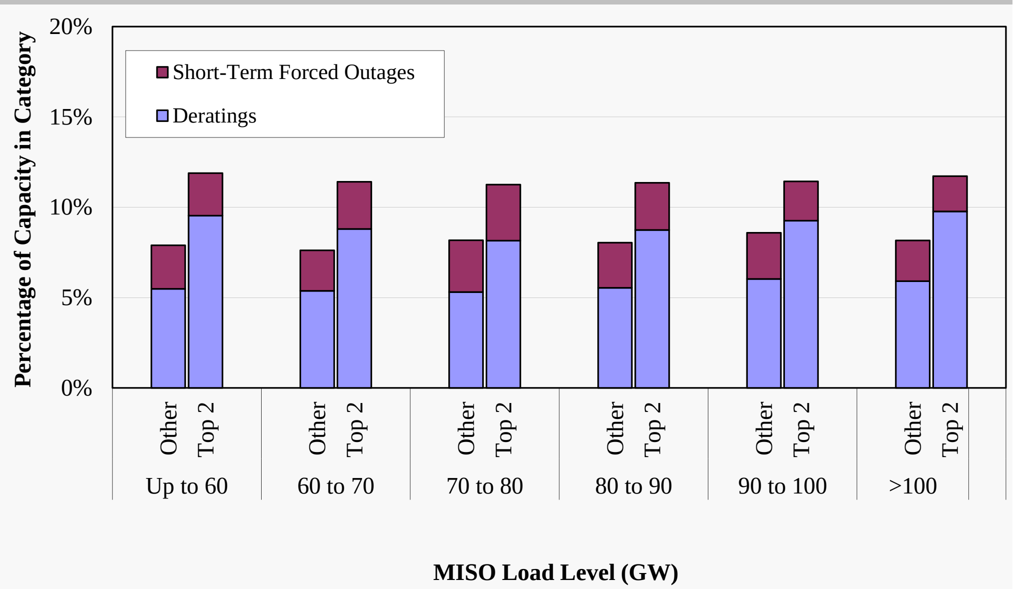
POTOMAC ECONOMICS

Evaluation of Outages and Partial Deratings

- The results in the following figures do not raise substantial competitive concerns.
  - ✓ Outages and deratings increased slightly from 2009 levels, but remain fairly low.
  - ✓ Much of this increase is in the form of deratings, in part due to higher ambient temperatures during the warmer than normal summer months.
- In the East and West regions, the deratings and outages are comparable across all load levels (generally ranging from 8 to 12 percent).
- In the Central and WUMS regions, the largest suppliers exhibited outages and deratings that were materially higher than those by other suppliers, although only in WUMS did these rise during peak periods (to over 15 percent).
  - ✓ The spike in WUMS deratings can be attributed to high temperature deratings of a number of combined cycle resources. These deratings did not contribute to an increased congestion pattern in the region.
- Short-term forced outages remain a small share of the total unavailable capacity.
  - ✓ They were highest in Central but only comprised on average about one quarter of the unavailable capacity in that area.
- We continue to investigate any outages or deratings that create substantial congestion or other price effects. Our audits and investigations have not uncovered any significant attempts to physically withhold generation in 2010.

POTOMAC ECONOMICS

Real-Time Deratings and Forced Outages Central Region, 2010



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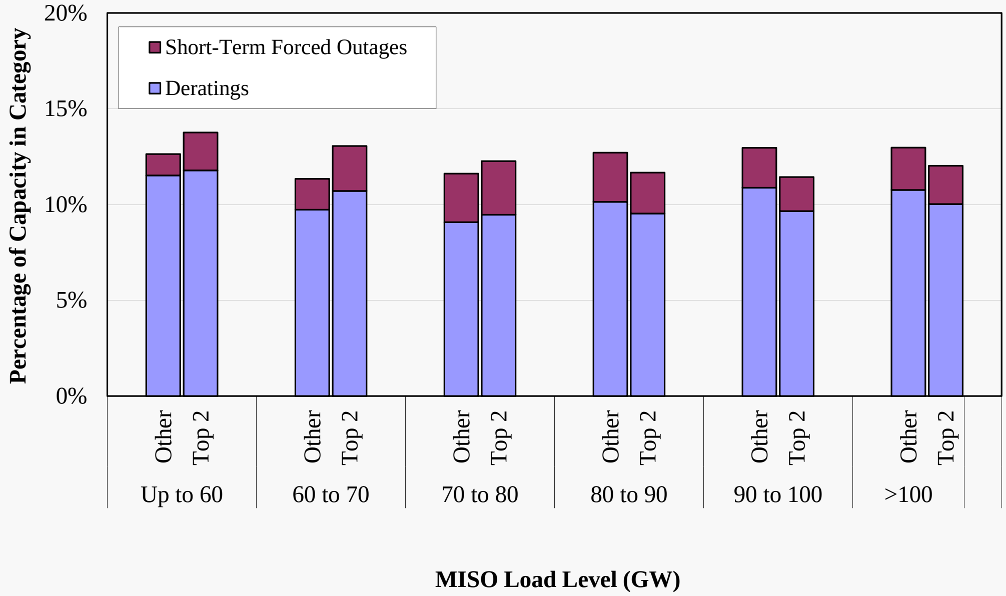
Real-Time Deratings and Forced Outages East Region, 2010



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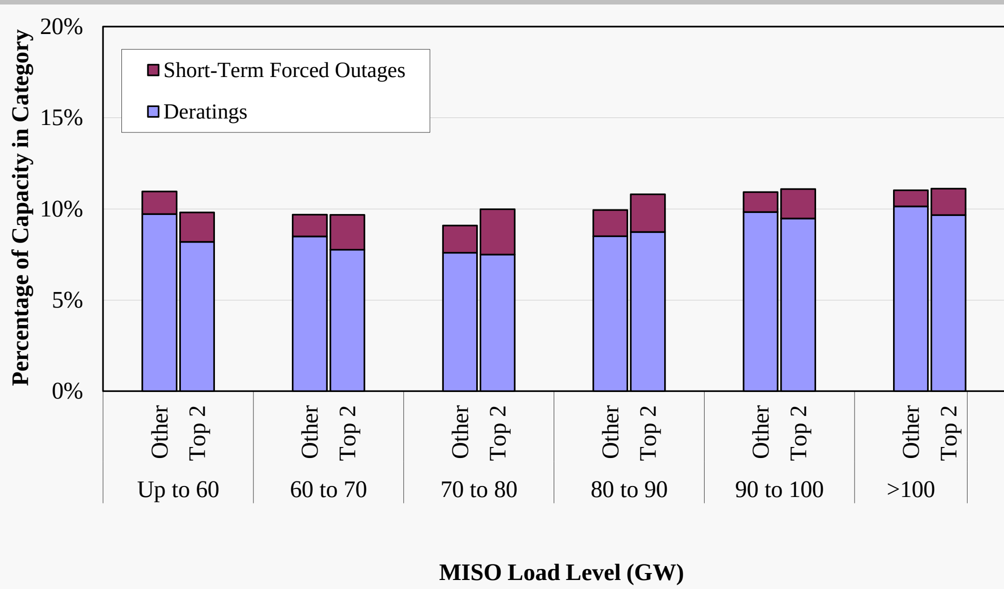
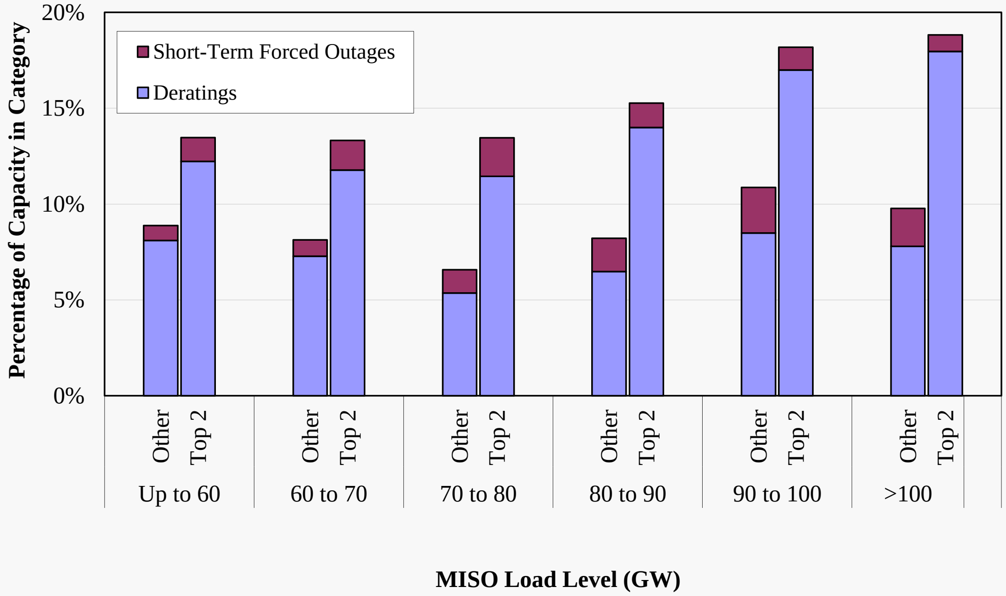
Real-Time Deratings and Forced Outages West Region, 2010



POTOMAC ECONOMICS

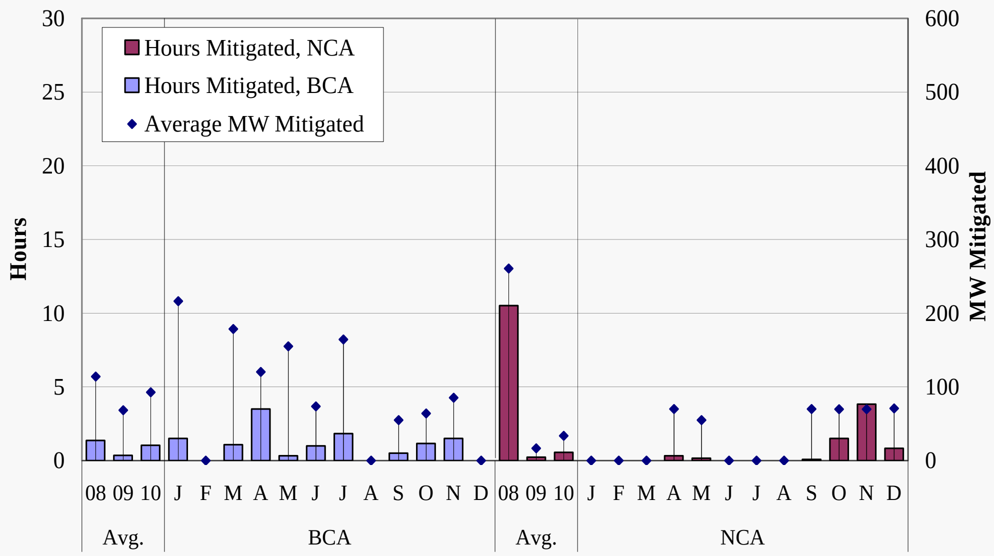
Real-Time Deratings and Forced Outages WUMS Region, 2010



Real-Time Energy Mitigation

- 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.
  - ✓ 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 for economic withholding.
  - ✓ Both BCA and NCA energy mitigation remained rare in 2010, but rose from 2009 lows.
    - Mitigated BCA unit-hours rose to over 12 hours, while mitigated NCA unit-hours rose to nearly 7 hours.
  - ✓ The average quantities mitigated, however, decreased to 89 MW per unit-hour of BCA mitigation (down from nearly 200 MW in 2009) and 60 MW per unit-hour of NCA mitigation.
- Although mitigation remained infrequent in 2010, the analyses above continue to show that local market power is a significant concern and the mitigation remains essential.
  - ✓ If exercised, local market power could have substantial economic and reliability consequences within the Midwest ISO market.

Real-Time Energy Mitigation 2010



POTOMAC ECONOMICS

Real-Time RSG Mitigation

- In addition to the mitigation of energy offers shown in the prior figure, mitigation is also applied to offers that result in RSG make-whole payments.
- The next figure shows the frequency and amount by which RSG payments were mitigated in each month of 2009 and 2010.
- The figure shows mitigation occurred for 39 unit-days in 2010, up from 30 in 2009 and just 7 in 2008.
  - ✓ The dollar amount mitigated increased to $246,000.
  - ✓ This is largely due to higher overall energy prices since RSG payments are a function of LMPs.
- The results show that mitigation remains infrequent, in part due to the three-part 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 infrequent, this does not indicate a lack of locational market power.

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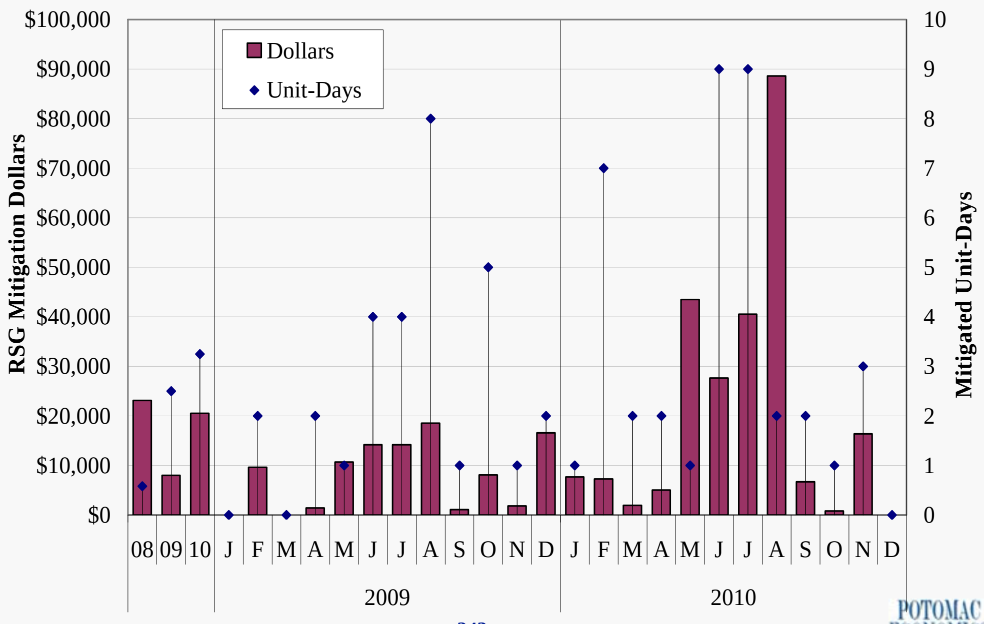
Real-Time RSG Mitigation 2009 – 2010



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Local Voltage Commitments

- The RSG mitigation is intended address market power associated with commitments that are needed to manage congestion or local reliability needs.
- Although the current mitigation rules are generally adequate, some commitments are made for extremely local needs, including most commitments for voltage support.
  - ✓ Because reactive power cannot be transported, voltage support requirements can require commitment units at a single plant whose owner will have monopoly market power.
  - ✓ Further, when these requirements arise, they often result in commitments on nearly a daily basis, which increases the potential costs of this form of market power.
- The following figure shows the costs of voltage commitments in 2010, separately showing the competitive production costs (based on reference levels) and the additional costs related to actual offer prices in excess of the suppliers' reference levels.
- The figure shows that of the $29.6 million in RSG costs for voltage support, roughly $16 million was associated with offer prices above reference levels.
  - ✓ These payments rose sharply in the fall when a supplier repeatedly committed to provide voltage support raised its offers by less than the NCA threshold.
  - ✓ The figure also shows that during this period, these payments rose to as much as 45 percent of the total RSG costs.
- Current mitigation measures are not adequate for these commitments, and we recommend the Midwest ISO implement conduct/impact thresholds equal to 10 percent of suppliers' reference levels for these commitments.

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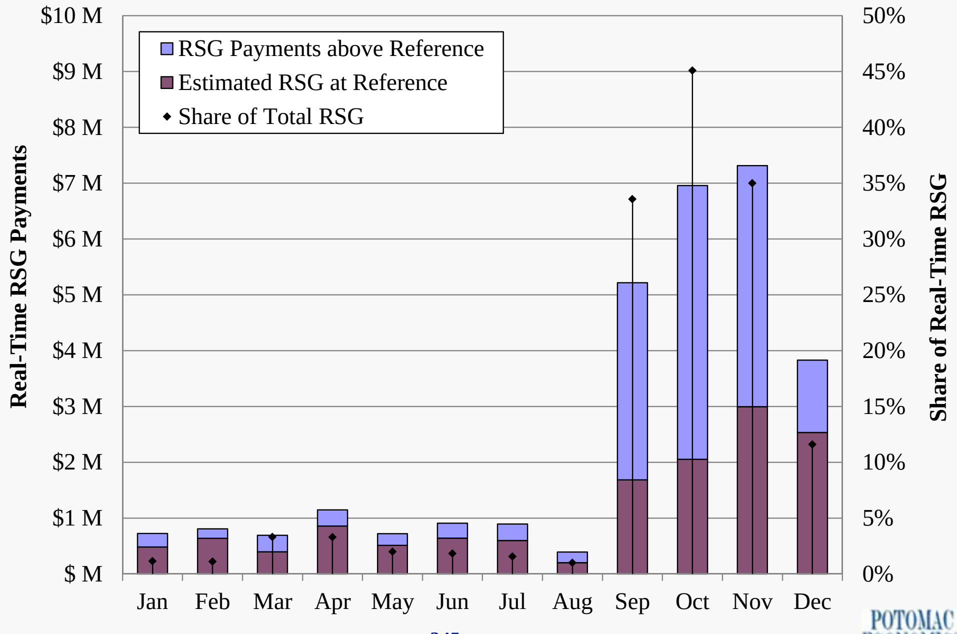
RSG for Constraint Management



POTOMAC ECONOMICS

Competitive Performance: Conclusions

- Our structural analyses indicate that there remains substantial local market power within the Midwest ISO.
  - ✓ However, these results generally indicated some improvement in 2010 as transmission and generation resulted in less frequent circumstances when one or more suppliers were pivotal.
- Our analyses of participants' conduct and the market outcomes indicated that the market continued to perform very competitively in 2010.
  - ✓ With one exception, we generally 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.
- However, we recommend that the mitigation measures be improved to more effectively mitigate commitments for voltage support and other comparable local reliability needs by lower the conduct/impact thresholds for these commitments.

POTOMAC ECONOMICS

Demand Response Programs

Demand Response Programs
Existing Programs

- The Midwest ISO has nearly 9,000 MW of total DR capability.
  - ✓ The vast majority of this is in the form of interruptible load developed by LSEs under regulated retail initiatives or behind the meter generation.
- Midwest ISO-controlled DR resources 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.
  - ✓ "Type II" resources can supply energy and 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 (comparable to generation) so it can fully participate in the markets.
- The quantity of dispatchable resources decreased considerably in 2010 because some pumped storage units de-registered as DRR resources.

Demand Response Programs

- The following table compares the Midwest ISO's DR programs to the DR programs of ISO-New England and New York ISO.
- Overall, the Midwest ISO has the largest quantity of DR resources and is comparable to the other RTOs as a percent of the total peak load.
  - ✓ The 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.
    - – DR resources totaled nearly 8.7 GW at year-end 2010 (equivalent to nearly 8 percent of the yearly peak load), down 31 percent from 2009.
  - ✓ The share of demand response that can respond actively to Midwest ISO dispatch instructions (rather than passively though curtailment) is nearly zero.
- Supply-side DRR is currently the only available means to participate in the Midwest ISO's energy and ancillary services markets.
  - ✓ Price-responsive demand-side resources, such as those owned by Aggregators of Retail Customers ("ARCs"), still do not participate in real-time energy markets.
    - – The Midwest ISO filed on October 2, 2009, to allow for ARC participation, but the revised Tariff sheets are awaiting Commission approval.
  - ✓ In other RTOs, ARCs comprise most of the growth in DR capability, particularly in capacity markets.

POTOMAC ECONOMICS

Comparison of ISO Demand Response Programs 2010

		2010	Pct. of 2010 Peak	2009	Y/Y Change
MIDWEST ISO	**TOTAL**	**8,663**	**7.9%**	**12,550**	**-31%**
	Behind-The-Meter Generation	5,077		4,984	2%
	Load Modifying Resources	3,184		4,860	-34%
	DRR Type-I	46		2,353	-98%
	DRR Type-II	0		111	-100%
	Emergency DR	357		242	47%
NYISO	**TOTAL**	**2,362**	**7.1%**	**2,384**	**-1%**
(as of Aug 31, 2010)	ICAP - Special Case Resources	2,103		2,061	2%
	Of which: Targeted DR	*489*		*531*	-8%
	Emergency DR	257		323	-20%
	Of which: Targeted DR	*77*		*117*	-34%
	DADRP	331		331	0%
ISO-NE	**TOTAL**	**2,719**	**10.0%**	**2,292**	**19%**
	Real-Time DR Resources	1,255		873	44%
	Real-Time Emerg. Generation Resources	672		875	-23%
	On-Peak Demand Resources	533		N/A	
	Seasonal Peak Demand Resources	259		N/A	

Note: Quantities in MW.

POTOMAC ECONOMICS

Demand Response Programs
Current and Future Efforts

- In order to comply with Order 719 and 719-A to create a platform for expanded DR participation, the Midwest ISO:
  - ✓ 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.
    - They were proposed to be paid only the LMP minus the predetermined Marginal Foregone Retail Rate.
    - Although this is economically efficient, it is not consistent with FERC's recent Final Rule on Demand Response Compensation, which will likely require the Midwest ISO to modify its proposal.
- In order for the market to perform efficiently when load interruptions and other emergency actions are taken by the ISO, these actions need to be reflected in the energy and reserve market prices.
  - ✓ Hence, we recommend that the Midwest develop an approach for allowing DR resources or other reliability actions to set energy and reserve prices.
  - ✓ The Midwest ISO has been evaluating alternatives for addressing this recommendation.