IMM Quarterly Report
Third Quarter 2010

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Summary of Quarterly Results

- This presentation summarizes the outcomes of the Midwest ISO energy and ancillary services markets during the third quarter of 2010.
- The markets continued to perform competitively in the third quarter, although prices rose considerably on a year-over-year basis due to higher load, fuel prices and increased congestion.
  - ✓ Energy prices averaged $39 per MWh in the real-time market and $40 per MWh in the day-ahead in the third quarter of 2010.
    - – These prices were approximately 55 percent higher than prices during the third quarter of 2009, but were 32 percent lower than in the same period in 2008.
    - – The increases are attributable to both considerably higher fuel prices (gas prices were up 36 percent year-over-year) and higher load (up 13 percent).
  - ✓ Ancillary service prices remained stable with infrequent periods of shortage or interzonal constraints.
  - ✓ Real-time transmission congestion was 24 percent higher in the third quarter of 2010 than in 2009 due to higher loads and transmission and generator outages in the East.
  - ✓ 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 footprint.

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Day-Ahead Average Monthly Hub Prices

- The first figure in this section shows average day-ahead energy prices in July through September of 2008 to 2010 at four hubs in the Midwest ISO.
  - ✓ The figure also shows natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin in peak hours.
- Day-ahead prices in the third quarter of 2010 were 15 percent higher than prices in the second quarter of 2010 and 55 percent higher than prices in the third quarter of 2009.
- The primary drivers of the year-over-year price increase were:
  - ✓ A 13 percent increase in average load (excluding the effects of membership additions since September 2009);
    - – The sharp increase in load was primarily due to unusually warm summer weather, particularly in the eastern half of the footprint.
  - ✓ Higher natural gas prices, which were up 36 percent from the third quarter of 2009;
- Prices at Cinergy and Michigan continue to be higher than prices at WUMS and Minnesota, which is indicative of the west-to-east congestion pattern.
  - ✓ Prices in the East region were nearly $10 per MWh higher than prices in the West.

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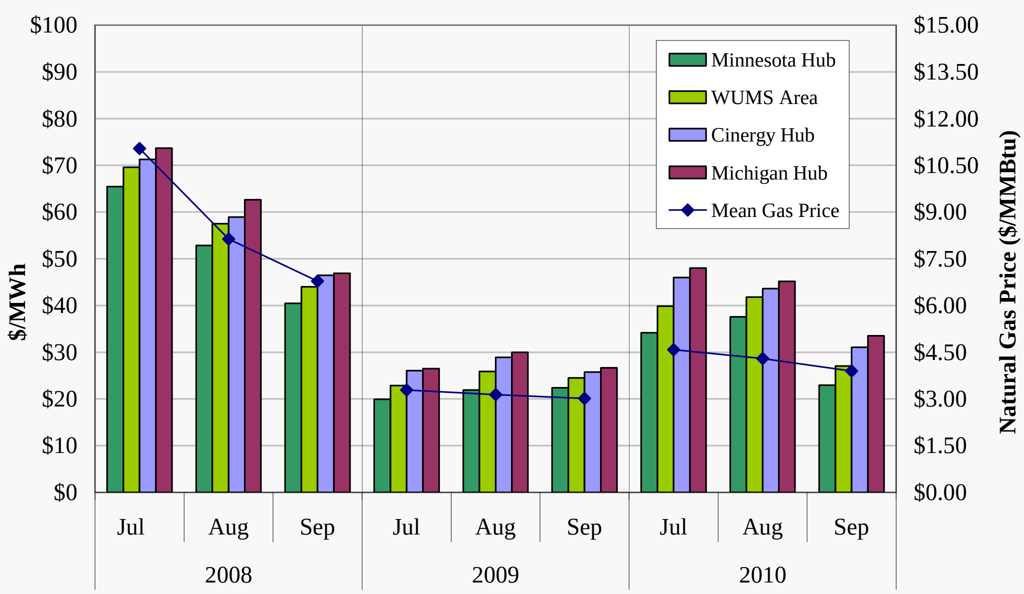
Day-Ahead Average Monthly Hub Prices
Third Quarter 2008 – 2010, All Hours



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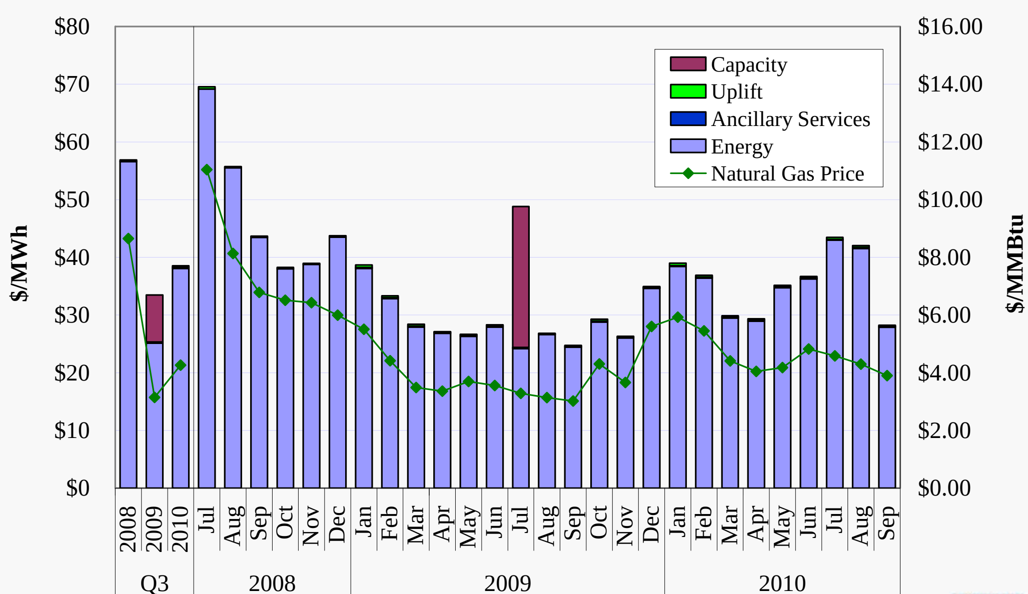
All-In Price

- The "all-in price" summarizes prices in the Midwest ISO and represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price, the average real-time uplift costs, and the costs of ancillary services and capacity.
  - ✓ The ancillary services are shown beginning in January 2009, when the Midwest ISO began operating markets for these products. Similarly, capacity costs are only included from June 2009, when the voluntary capacity auction was introduced.
- The all-in price for the third quarter of 2010 was $38.53 per MWh, a 15 percent increase from the third quarter of 2009.
  - ✓ The increase from 2009 was due to substantial increases in the energy component of the all-in prices, but was partially offset by a decline in capacity costs.
  - ✓ The all-in price was 14 percent higher than in the second quarter of 2010.
- Energy comprised 98.8 percent of the all-in price, with uplift, ancillary services and capacity collectively accounting for the remainder.
  - ✓ The voluntary capacity auction continues to clear at close to zero in each month, which is consistent with the high level of surplus capacity in the Midwest ISO.

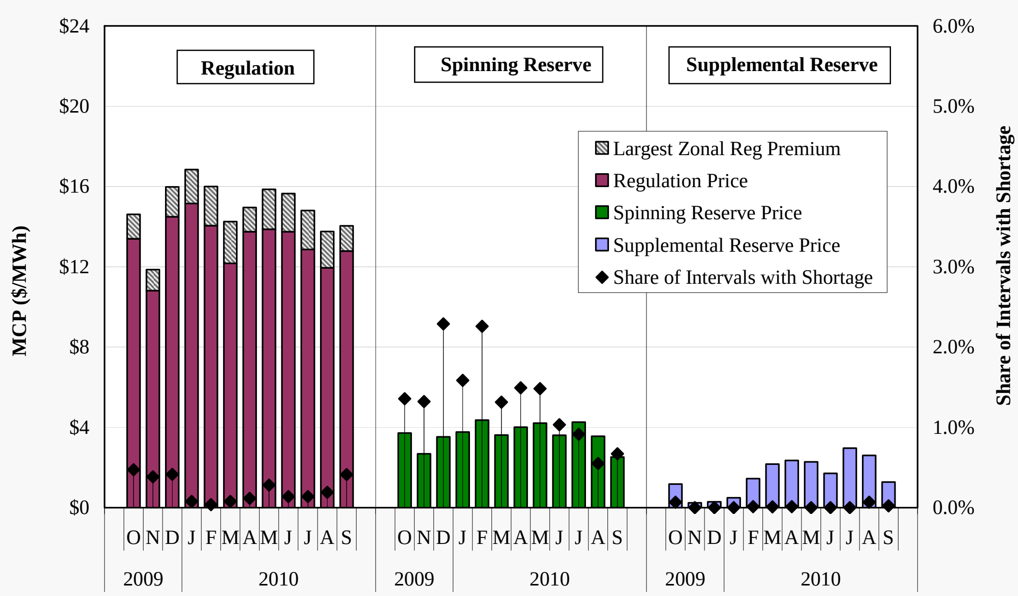
All-In Price
July 2008 – Sept 2010



Monthly Real-Time Ancillary Service Prices

- The following chart shows monthly average real-time clearing prices for the Midwest ISO's ancillary service products for the preceding twelve months.
  - ✓ ASM markets continue to operate as expected with no significant issues.
  - ✓ Regulation prices averaged $12.52 per MWh in the third quarter of 2010, up 8 percent from $11.62 in the third quarter of 2009.
    - – This is in part due to the formula-based regulation penalty price, which sets prices during shortages. It averaged $237 per MWh in the quarter.
    - – The penalty price in the third quarter of 2009 averaged under $100 per MWh.
    - – We are working with the Midwest ISO to evaluate the penalty price formula.
  - ✓ Locational differences in regulation prices continue to be relatively limited.
- Spinning reserve prices were flat, and shortages occurred in just 0.7 percent of intervals in the third quarter of 2010, down over 40 percent from the prior year.
  - ✓ The Midwest ISO has improved the consistency between the market requirements and operating requirements, which reduces the frequency of such shortages.
- Supplemental reserve prices averaged $2.29 per MWh, up nearly 200 percent from the third quarter of 2009.
  - ✓ This increase is attributable to a general decline in the offer volume due to participant concerns over their ability to meet deployment obligations.

Monthly Average Ancillary Service Prices Regulation and Spinning Reserves, 2009 – 2010



Midwest ISO Fuel Prices

- The next figure shows daily average fuel prices from January 2008 through the third quarter of 2010.
- Economic conditions contributed to substantial reductions in fuel prices from mid-2008 through 2009. Although they have recovered from their lows of summer 2009, fuel prices remain relatively low compared to earlier years.

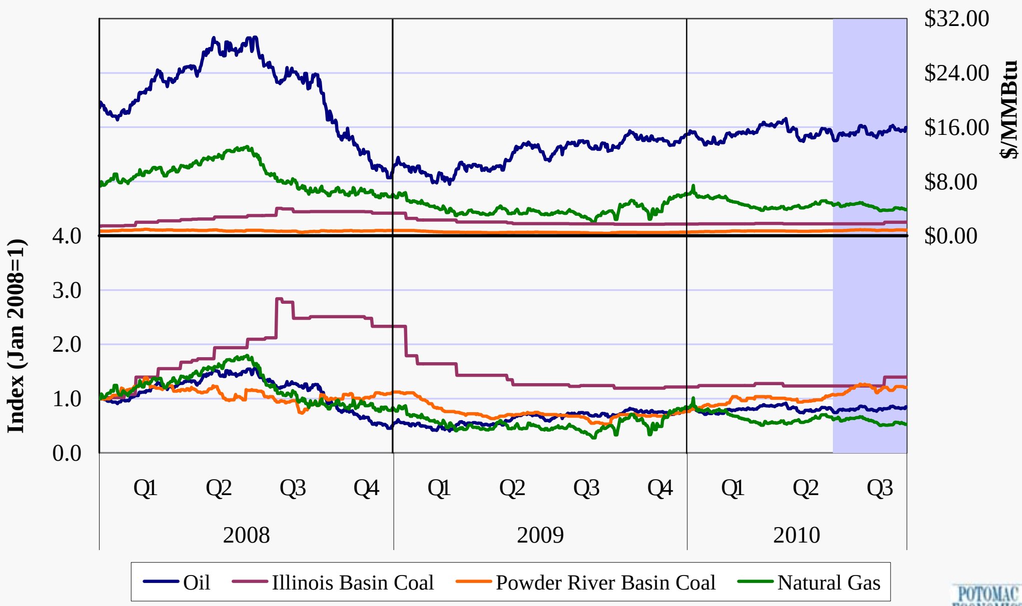
<u>Oil and Natural Gas Prices</u>

- Natural gas prices declined slightly over the quarter. Prices averaged $4.27 per MMBtu over the third quarter of 2010, down 2 percent from the second quarter.
  - ✓ Prices are 36 percent higher than in the third quarter of 2009.
- Oil prices were relatively flat over the quarter. Oil prices averaged $15.25 per MMBtu, down 5 percent from the previous quarter, but up 18 percent from the third quarter of 2009.

<u>Coal Prices</u>

- Average Illinois Basin prices during the quarter were largely unchanged, averaging $1.82 per MMBtu. Prices were 3 percent higher than in the third quarter of 2009.
- Power River Basin prices increased 18 percent in the quarter, averaging $0.82 per MMBtu. Prices have nearly doubled since the summer of 2009.

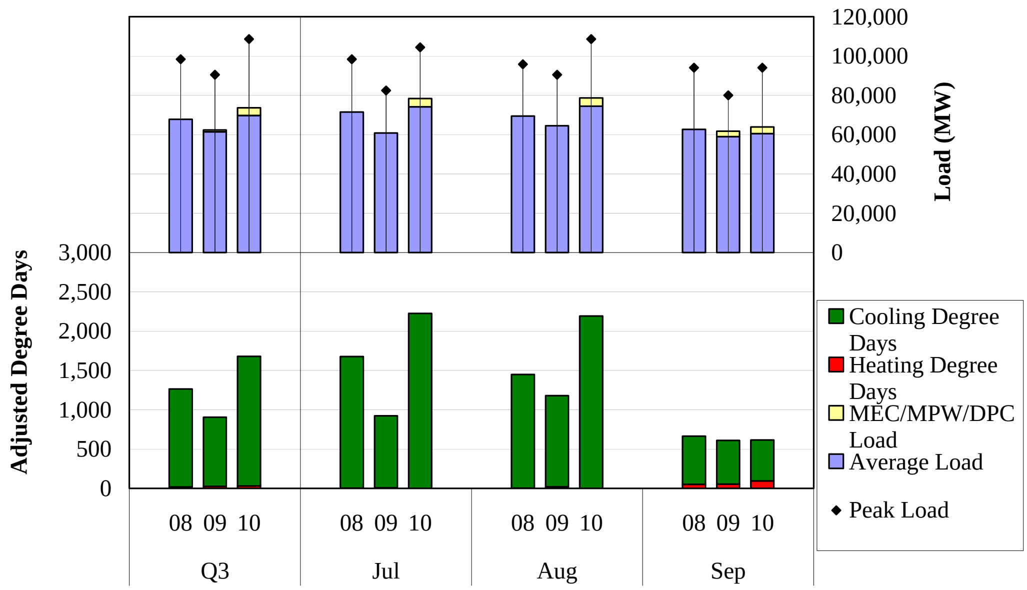
Midwest ISO Fuel Prices 2008 – 2010



Changes in Load and Weather Patterns

- The next figure shows changes in load in the third quarter over the past three years, as well as the changes in weather patterns that contributed to the load changes.
- The top panel shows the monthly average and peak loads in the third quarter from 2008 to 2010.
  - ✓ Excluding membership changes, the average load in the third quarter of 2010 was 13.4 percent higher than in the third quarter of 2009.
- Because a large share of the load is sensitive to weather, the figure shows how weather patterns have changed over time.
  - ✓ The bottom panel in the figure shows the monthly heating degree days, summed for the third quarters of 2008 to 2010, at four locations with the Midwest ISO.
  - ✓ To account for the different relative impacts of Heating Degree Days (HDDs) and Cooling Degree Days (CDDs), HDDs are inflated by a factor of 6.07 to normalize the effects on load (based on a regression analysis).
- Unseasonably warm weather in July and August, coupled with mild weather in 2009, resulted in an 87 percent year-over-year increase in cooling degree days.
  - ✓ There were 21 days in the quarter where load exceeded 100 GW, a stark contrast to the third quarter of 2009 when load exceeded 90 GW only once.

Load and Weather Patterns
Third Quarter, 2008 – 2010



Share of Interval Price Setting By Unit Fuel Type

- 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).
- Coal units set prices in approximately 93 percent of all hours in the third quarter of 2010 (including nearly all off-peak hours), down from 96 percent in 2009.
  - ✓ This figure remains considerably higher than in the third quarter of 2008, when coal set the price in 86 percent of all hours.
- Gas- and oil-fired units often set prices during the highest-load hours. Hence, these fuels have a larger effect on load-weighted average prices than the percentages would indicate.
  - ✓ Gas, oil-fired, and dual-fueled resources set energy prices in nearly 60 percent of hours in July and August, a 240 percent increase from the same period in 2009.
    - – This increase is partly due to the reliance on these higher-cost resources to satisfy the relatively high demand this quarter.
    - – In addition, the 24 percent increase in real-time congestion in the quarter resulted in more oil-fired and gas-fired units being dispatched to manage congestion.
  - ✓ In September, these resources set the energy price in only 15 percent of hours as both load and congestion decreased.

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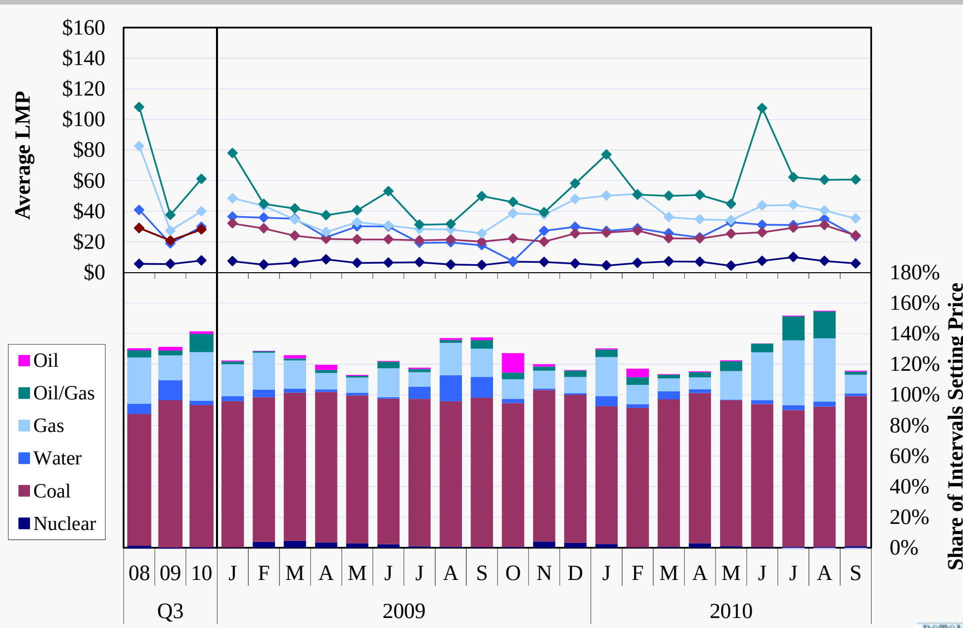
Share of Interval Price Setting By Unit Fuel Type



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Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between the day-ahead and real-time prices.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and larger RSG allocation to buyers in the real-time market.
- The next figure shows the day-ahead to real-time price convergence at the Cinergy Hub (the table shows other locations).
- Modest day-ahead premiums generally prevailed at most hubs. However, when the RSG allocations are included, the total real-time cost slightly exceeded the day-ahead cost.
- Although price convergence was generally good this quarter, real-time congestion on market-to-market constraints out of WUMS contributed to lower prices there in August and September.
  - ✓ The market response to these types of differences is limited by sustained low virtual trading volumes, likely due to the real-time RSG allocations to virtual supply.
- The absolute value of the hourly differences measures the typical magnitude of the differences, regardless of direction. This is highest in the congested areas due to:
  - ✓ Higher volatility and negative price spikes during off-peak hours; and
  - ✓ Limited flexibility offered to manage congestion in the real-time market.

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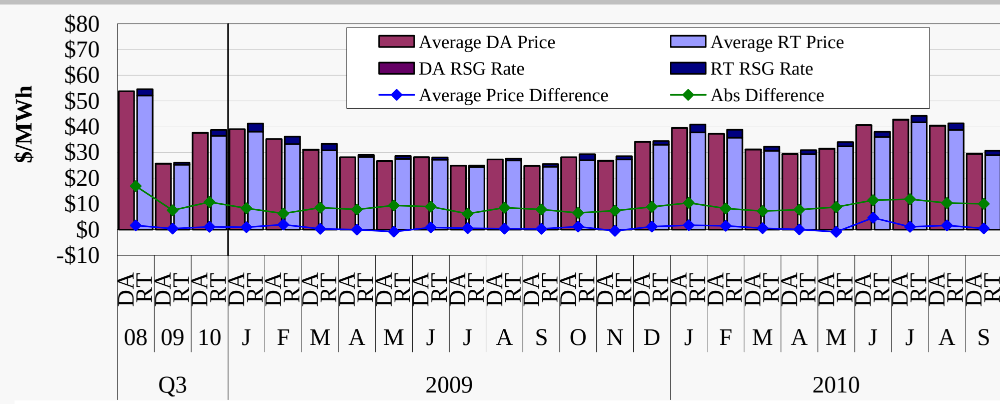
Day-Ahead and Real-Time Price Convergence
January 2009 – September 2010



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

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
Michigan Hub	4	3	3	4	5	4	0	-4	-1	0	4	3	7	-1	2	8	3	2	3	2	10	5	2	2
Minnesota Hub	1	-1	1	7	8	12	3	1	11	-3	6	-5	1	4	-1	13	4	4	-2	-3	0	-5	3	5
WUMS Area	4	5	9	8	12	12	6	4	13	2	8	5	8	16	5	13	9	8	1	-5	15	-2	10	21

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

Cinergy Hub	33	30	30	22	19	28	28	34	33	25	32	32	24	27	27	28	23	23	26	27	32	28	27	35
Michigan Hub	35	37	33	22	19	29	33	34	34	27	37	47	39	34	27	30	24	24	32	39	33	31	27	40
Minnesota Hub	38	39	36	29	28	43	46	51	51	34	42	41	34	35	36	36	28	28	30	37	35	29	31	47
WUMS Area	38	36	37	25	31	38	39	55	55	33	37	39	37	41	37	35	26	28	28	35	41	30	33	50

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Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ The net load scheduled day-ahead is a key driver of RSG because low levels of scheduling can force the Midwest ISO to commit peaking resources to satisfy higher real-time load.
  - ✓ High levels of day-ahead load scheduling reduce the need to commit peaking resources to satisfy the peak load in real time, which reduces RSG costs.
  - ✓ However, real-time commitments are still made to maintain reserves, manage congestion and resolve local reliability issues.
- Load scheduling averaged over 99 percent for all hours in each month in the quarter.
- Peak load scheduling dropped slightly to 98.5 and 98.8 percent, respectively, in July and August.
  - ✓ Load is often underscheduled in the highest load periods because peaking resources needed under these conditions frequently do not set the price, and additional supply is often committed by the Midwest ISO.
    - – These two factors tend to lower real-time prices, reducing the incentive to buy more in the day-ahead market.
  - ✓ Uncertainty regarding summer weather patterns, including thunderstorms, can lead to forecast errors that cause load scheduling to be highly variable day-to-day.
  - ✓ In September, peak load scheduling exceeded 100 percent as load decreased.

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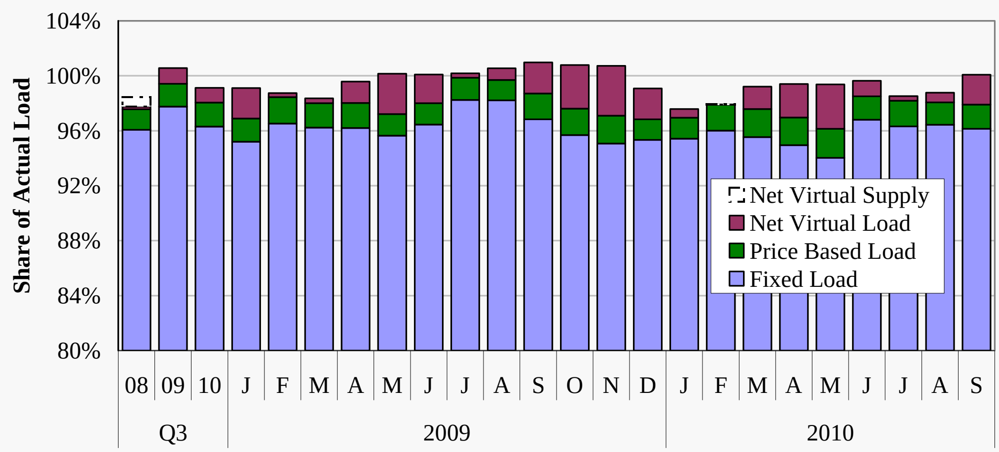
Day-Ahead Load Scheduling 2009 – 2010



Share of Actual Load(%)

All Hour	98.9	100.5	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
Peak Hour	97.8	100.6	99.1	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

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Virtual Load and Supply in the Day-Ahead Market

- Virtual trading in the day-ahead market facilitates convergence between the day-ahead and real-time prices. This serves to improve the efficiency of the day-ahead market results and mitigate market power in the day-ahead market.
- The next figure shows the average hourly virtual bids and offers, those that were scheduled, and the net virtual load scheduled (virtual load less virtual supply).
- Virtual trading volumes fell in late 2008 after FERC issued an order in November requiring the allocation of RSG costs to virtual supply and credit conditions deteriorated.
- Cleared virtual volumes were modestly lower in the third quarter of 2010 than in the third quarter of 2009, but are substantially lower than in the third quarter of 2008.
  - ✓ Cleared virtual load was 10 percent lower than in 2009 and 51 percent lower than in 2008.
  - ✓ Cleared virtual supply was down 15 percent from 2009 and down 72 percent from 2008.
- Offered volumes declined further – virtual supply offers decreased 42 percent year-over-year, while virtual load bids declined 30 percent.
  - ✓ A large share of this decrease is likely due to the current RSG allocation to virtual supply.
  - ✓ The largest concern of the low virtual level is related to convergence between day-ahead and real-time prices. This has not been a problem yet in most areas, but we continue to monitor it closely.
  - ✓ We expect activity to increase when the new RSG allocation rules are implemented.

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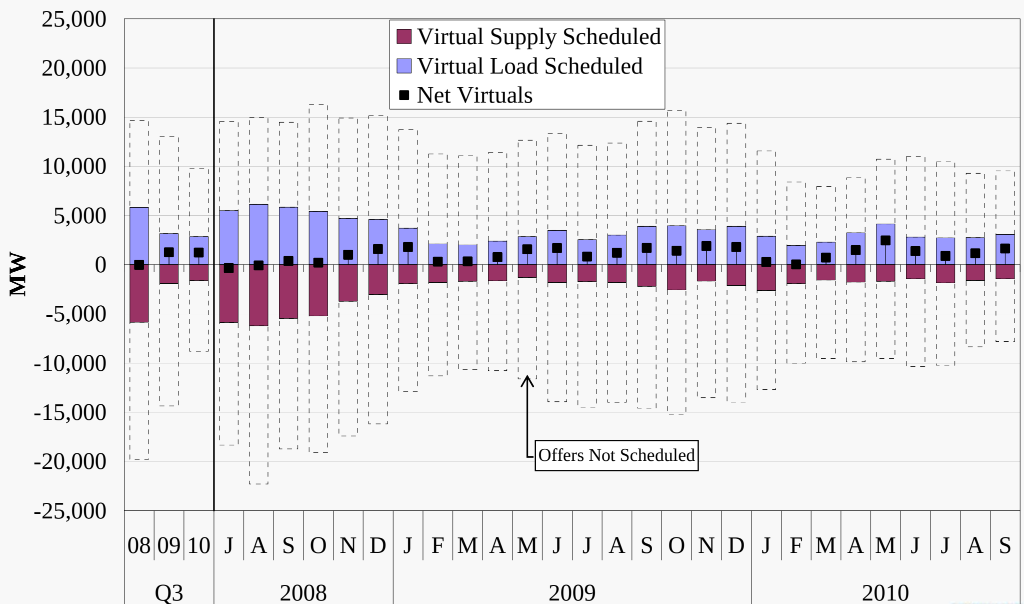
Virtual Load and Supply in the Day-Ahead Market
July 2008 – September 2010



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Virtual Profitability in the Day-Ahead Market

- The next figure shows monthly average profitability of virtual purchases and sales.
  - ✓ Moderate profits continued in the third quarter. Virtual supply was consistently more profitable than virtual demand due to the prevailing day-ahead premium at most locations.
    - – Virtual supply profit margins are reduced by RSG cost allocations.
    - – The weighted average hourly RSG Distribution Rate assessed to virtual supply averaged $2.26 per MWh in the third quarter, which reduced net profitability to just $0.66 per MWh.
- We continue to monitor for large losses on virtual transactions because they can indicate an attempt by a participant to manipulate the day-ahead market prices.
  - ✓ For example, a participant may submit a high-priced virtual bid at a constrained location that causes inflated congestion in the day-ahead market
    - – While this would cause foreseeable losses on the virtual transaction, the resultant congestion could increase FTR payments or the value of a financial position.
  - ✓ The table below the figure shows that the share of transactions incurring large losses remains low and did not raise significant competitive concerns in the third quarter.
    - – However, we mitigated one pattern of virtual purchases in early 2010.
    - – Modeling changes made in the FTR market should reduce future concerns.

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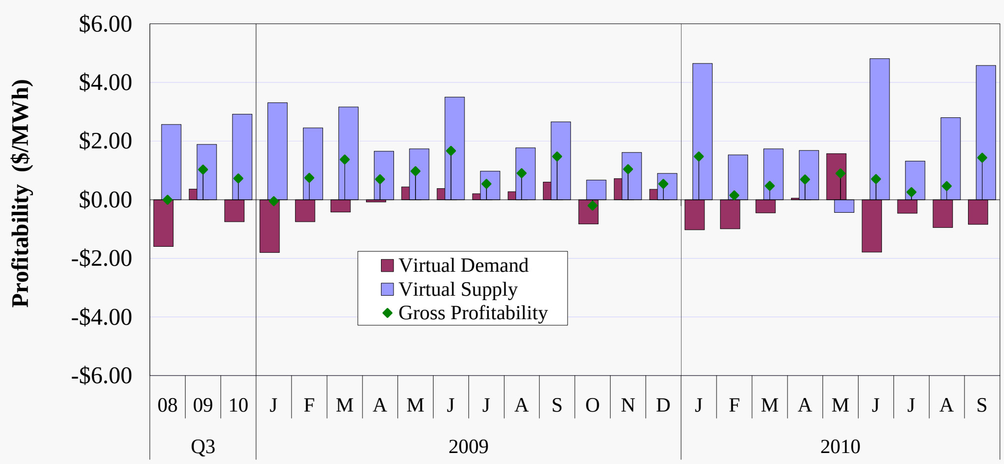
Virtual Profitability in the Day-Ahead Market 2009 – 2010



Share of Cleared Virtuals with Extreme Profitability

Profit > $50/MWh	3.9%	1.3%	2.2%	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%
Profit < -$50/MWh	4.1%	1.4%	1.3%	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%

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Peaking Unit Real-Time Dispatch

- The following figure shows the real-time dispatch of peaking resources, separately indicating the share of these peaking resources that were out-of-merit (offer price higher than the LMP).
- Dispatch of all peaking resources increased by nearly 5 times in the third quarter to nearly 1,000 MW per hour. This is primarily due to:
  - ✓ Substantially higher summer peak load levels;
  - ✓ Increased congestion that required some peaking resource commitments to manage the flows on the constraints; and
  - ✓ Lower day-ahead load scheduling, which can compel the Midwest ISO to commit peaking resources to meet the increased real-time load.
- If they do not set the energy price, a large share of the relatively high-cost resources to manage congestion or to meet capacity will be out-of-merit.
  - ✓ However, the share that is out-of-merit will decrease as more peaking resources are dispatched.
  - ✓ The Midwest ISO continues to develop pricing improvements that will allow peaking resources to set energy prices when appropriate.

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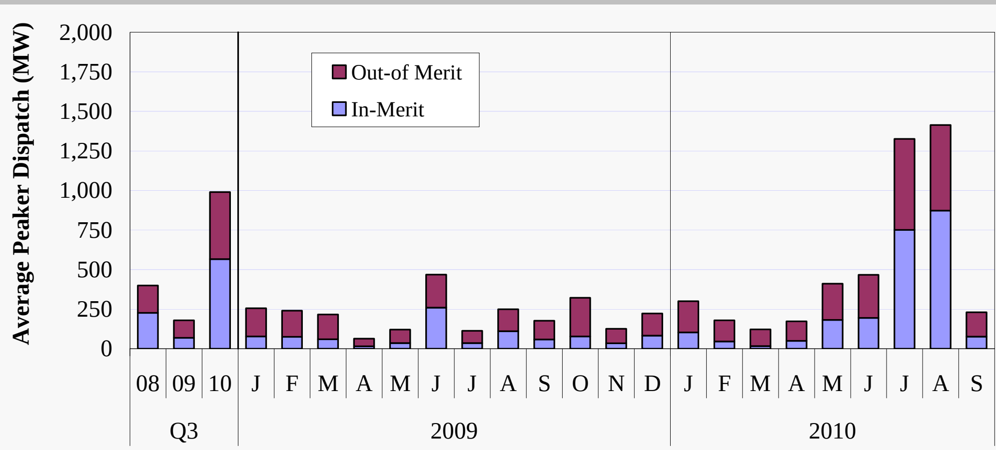
Peaking Unit Dispatch and In-Merit Status 2009 – 2010



Out-of-Merit Quantity and Share

MW	173	111	423	178	166	157	49	86	208	78	138	118	244	92	140	197	133	105	123	228	272	575	540	154
%	43%	62%	43%	70%	69%	72%	76%	71%	45%	69%	55%	67%	76%	73%	63%	66%	74%	86%	71%	56%	58%	43%	38%	67%

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Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets. To account for fuel prices, RSG costs are shown on a nominal basis and adjusted for changes in fuel prices.
- RSG costs in the real-time market in the third quarter increased 57 percent from the same period in 2009 on both a nominal basis and fuel-adjusted basis.
  - ✓ This increase was attributable to the increased use of peaking resources to satisfy the high real-time loads.
  - ✓ The increase in RSG was much lower than the increase in peaking resource dispatch because a larger share of these units were running in-merit.
- Two-thirds of the real-time RSG was paid to peaking units, which is expected because they are the highest-cost units and often do not set real-time energy prices.
  - ✓ Hence, their costs are often not recovered through the LMP and an RSG payment is made.
- The second figure shows day-ahead RSG levels, which continued to be much lower than in the real-time market. This is expected because the day-ahead market is purely financial.
  - ✓ Midwest ISO implemented a new commitment requirement in the day-ahead market in June to improve its ability to accommodate the ramp needs of the system. This should result in higher day-ahead commitments and day-ahead RSG costs.
  - ✓ This change has contributed to the $5 million quarter-over-quarter increase in day-ahead RSG costs. However, this increase should reduce real-time RSG costs.

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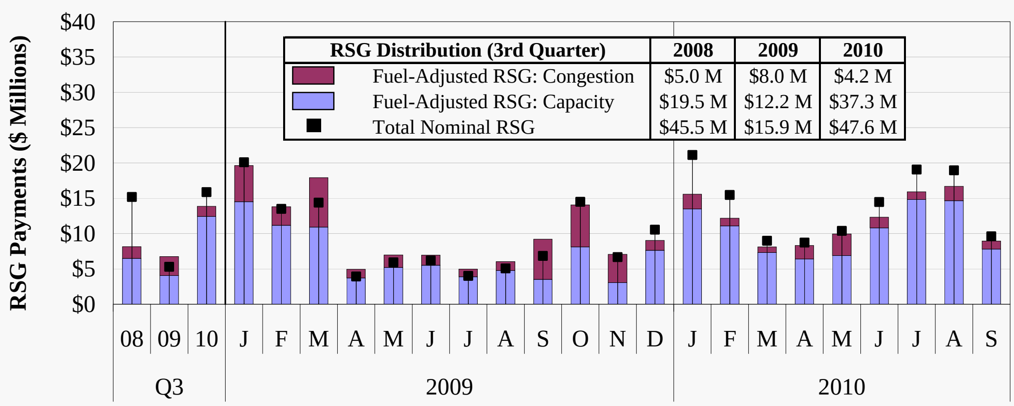
Real-Time RSG Payments 2009 – 2010



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

Peaker	56.8	63.4	65.5	57.5	65.1	50.2	46.1	66.3	68.4	48.8	61.1	73.6	80.2	69.9	71.1	58.6	53.7	59.1	59.0	64.7	50.5	70.9	72.2	41.4
Congestion	12.0	30.2	7.9	9.4	12.1	9.2	5.1	19.5	17.5	10.3	15.4	52.8	34.5	46.9	11.9	9.3	5.5	4.2	15.7	24.5	3.3	4.8	10.2	9.5
Capacity	44.8	33.2	57.6	48.1	53.1	41.0	40.9	46.8	50.9	38.5	45.8	20.8	45.7	23.0	59.3	49.3	48.2	54.9	43.3	40.2	47.2	66.1	62.0	31.8
Non-Peaker	43.2	36.6	34.5	42.5	34.9	49.8	53.9	33.7	31.6	51.2	38.9	26.4	19.8	30.1	28.9	41.4	46.3	40.9	41.0	35.3	49.5	29.1	27.8	58.6
Congestion	6.9	9.9	1.8	10.6	5.4	25.0	17.7	4.2	2.7	11.4	6.0	11.9	8.3	10.1	2.3	3.0	3.6	5.4	8.3	7.2	9.7	1.9	1.0	3.1
Capacity	36.3	26.7	32.8	31.9	29.5	24.8	36.2	29.5	28.9	39.8	32.9	14.5	11.5	20.0	26.5	38.5	42.7	35.5	32.8	28.1	39.8	27.2	26.8	55.5

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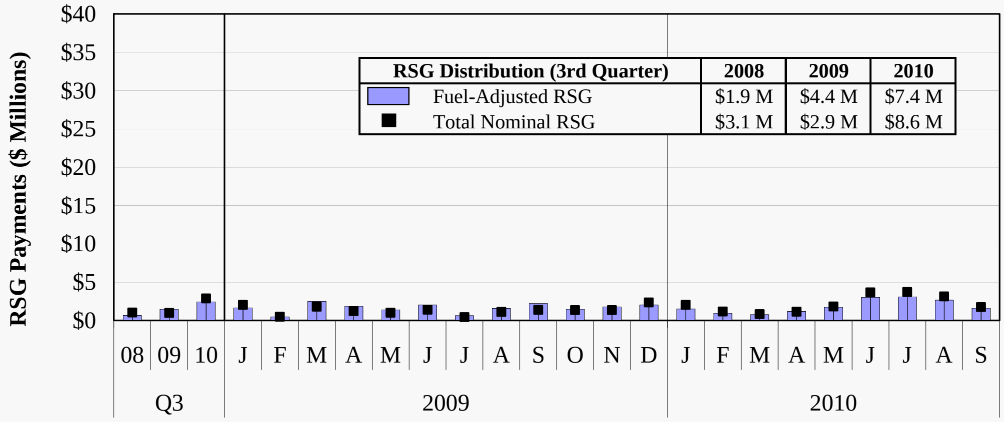
Day-Ahead RSG Payments 2009 – 2010



Share of Day-Ahead RSG Costs by Unit Type (%)

Peaker	36.7	10.1	27.1	3.8	2.6	0.9	1.4	21.5	17.2	4.2	12.6	10.0	6.0	4.3	3.6	3.8	0.2	2.3	3.2	14.3	11.1	27.1	36.5	10.3
Non-Peaker	63.3	89.9	72.9	96.2	97.4	99.1	98.6	78.5	82.8	95.8	87.4	90.0	94.0	95.7	96.4	96.2	99.8	97.7	96.8	85.7	88.9	72.9	63.5	89.7

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Scheduling of Wind Generation in Real-Time and Day-Ahead Markets

- Wind generation and capacity have grown rapidly in the Midwest ISO market. This trend is expected to continue due to attractive wind profiles in the West region, state renewable portfolio standards, and federal mandates and subsidies.
- The following figure shows wind output scheduled in the day-ahead and real-time markets.
- Wind output continues to grow in the Midwest ISO, averaging nearly 1.9 GW in the third quarter.
  - ✓ This is less than the 2.4 GW of output in the second quarter, which is not surprising because wind output is generally higher in shoulder months.
  - ✓ However, this represents a year-over-year increase of 71 percent from 2009 and nearly 100 percent from 2008.
    - – Much of this growth is due to the new members in the West region.
  - ✓ Day-ahead wind scheduling has improved in 2010 – the average difference as a percent of real-time wind output was 12 percent in the third quarter of 2010, down from 18 percent in the third quarter of 2009.
- Wind output remains volatile, underscoring the forecasting, scheduling, and reliability challenges that must be addressed by the Midwest ISO.

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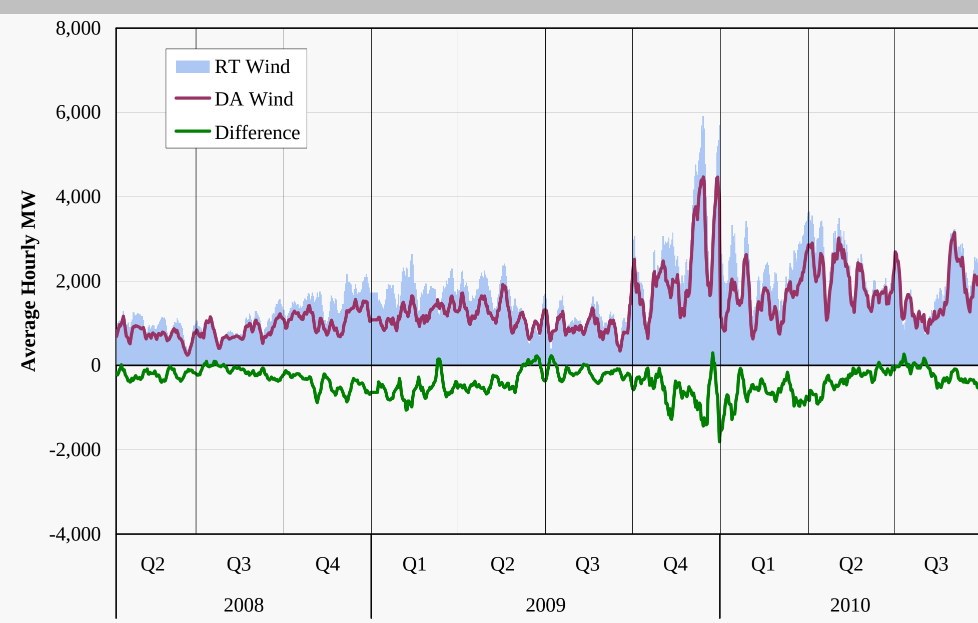
Scheduling of Wind Generation in Real-Time and Day-Ahead Markets



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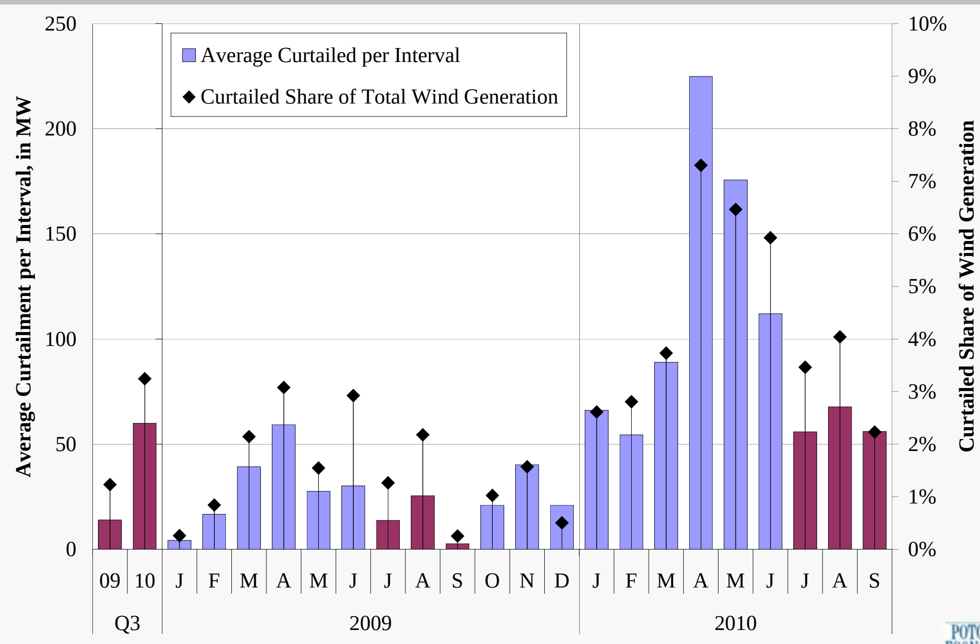
Manual Wind Curtailments

- As wind output has increased, manual curtailments of wind output to prevent transmission overloads have also increased. This has been necessary because wind resources are not currently dispatchable.
- Curtailments averaged 60 MW per interval in the third quarter of 2010, up from 14 MW per interval in the third quarter in 2009.
  - ✓ However, curtailments are lower than in the second quarter of 2010 when 170 MW was curtailed on average.
  - ✓ The reduction in curtailments from the second to third quarter of 2010 can be attributed to 500 MW reduction in average wind output.
- Curtailment quantities have risen faster than growth in wind output because transmission congestion becomes much more frequent as wind output rises.
  - ✓ On average 3.2 percent of wind generation was curtailed, less than the 6.5 percent that was curtailed in the second quarter of 2010.
  - ✓ In the third quarter of 2009, only 1.2 percent of wind generation was manually curtailed.
- The Midwest ISO plans to implement changes to allow wind units to be dispatchable, which should be more efficient than the manual curtailments.

Manual Wind Curtailments 2009 – 2010



Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows the Midwest ISO's obligation to FTR holders, which entitle them to congestion costs that arise between particular locations on the network.
  - ✓ Day-ahead congestion totaled $113 million in the third quarter of 2010, an increase of 69 percent compared to the same quarter in 2009.
  - ✓ This increase was due to higher fuel prices, increased congestion out of the West and within the East in real time.
- The figure also shows the actual FTR payments and the shortfall between the obligation and the payment.
  - ✓ Shortfalls and surpluses occur when the portfolio of FTRs represent more or less transmission capacity than the physical network.
  - ✓ "Loop flows" over the network caused by activity outside of the MISO can lead to shortfalls or surpluses if they differ from the amounts assumed in the FTR market.
- The day-ahead funding shortfall declined in the third quarter of 2010 to 4.5 percent.
  - ✓ The shortfall ratio was 14 percent during the third quarter of 2009 and 16 percent of obligations in the second quarter of 2010.
  - ✓ This reduction is primarily due to the Midwest ISO's continued work on the ARR allocation process and modeling improvements in the FTR market.

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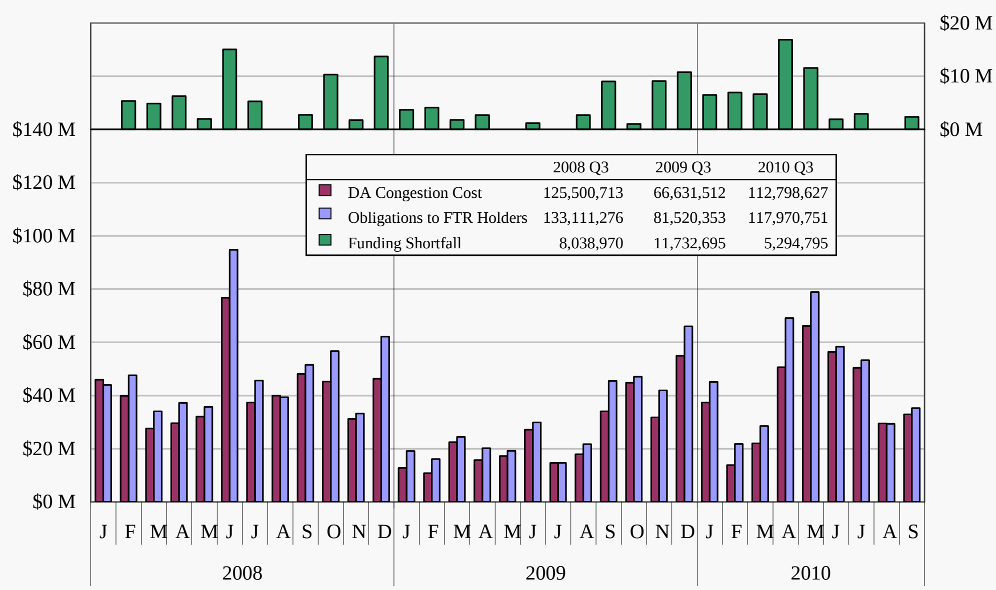
Day-Ahead Congestion and Obligations to FTR Holders



	2008 Q3	2009 Q3	2010 Q3
DA Congestion Cost	125,500,713	66,631,512	112,798,627
Obligations to FTR Holders	133,111,276	81,520,353	117,970,751
Funding Shortfall	8,038,970	11,732,695	5,294,795

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Real-time Congestion by Coordination Region

- The next figure shows the value of real-time congestion by region.
  - ✓ The value of real-time congestion equals the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
  - ✓ The total value shown is higher than the congestion costs collected by the Midwest ISO because loop flows do not settle with the Midwest ISO and PJM has entitlements to transmission capability on the Midwest ISO system.
- The value of real-time congestion in the third quarter of 2010 increased to $245 million, up 24 percent from $198 million in the third quarter of 2009.
  - ✓ Increased wind output resulted in a 61 percent increase in congestion out of the West.
  - ✓ A change of control from PJM to Midwest ISO of several market-to-market constraints, which resulted in an apparent threefold increase in real-time congestion out of WUMS.
  - ✓ Congestion in the East increased by 25 percent, while congestion in the Central region fell by 15 percent.
    - – Nearly half of the congestion in the East was on one constraint in Michigan on Aug. 30-31 due to concurrent planned transmission outages and forced generator outages.
  - ✓ The average frequency of binding constraints also increased in the third quarter to 1.53 constraints per interval, up from 1.00 in 2009. Much of this increase occurred on low-voltage constraints in the West region that are affected by increases in wind generation.

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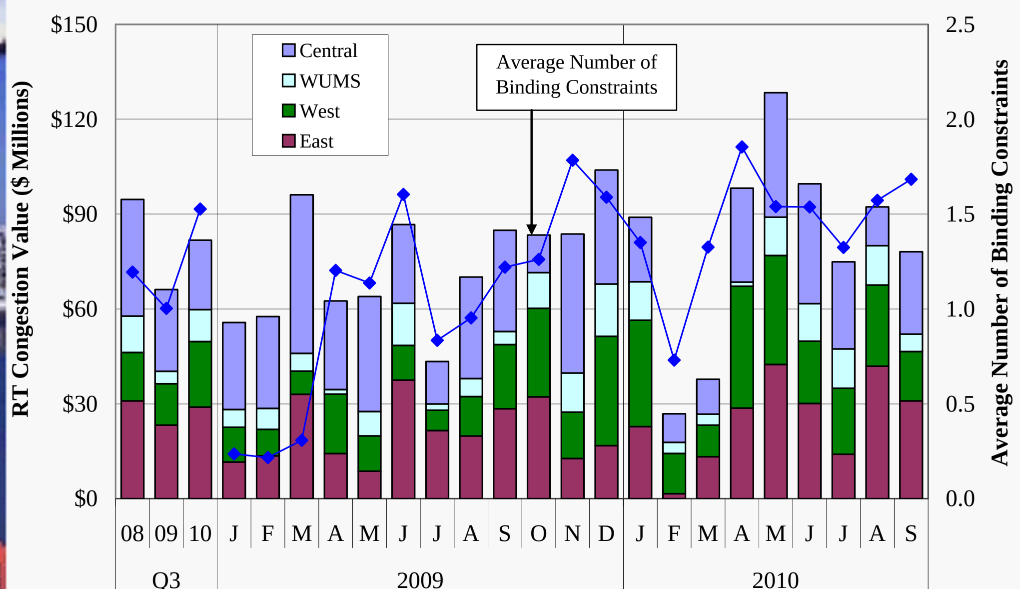
Real-time Congestion by Coordination Region 2009 – 2010



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Value of Real-Time Congestion by Type of Constraint

- The next figure shows the value of real-time congestion by the type of constraint from the third quarter of 2008 to the third quarter of 2010.
  - ✓ It includes congestion on external constraints, which occurs when a neighboring system calls a TLR that causes Midwest ISO to re-dispatch its generation.
- As in prior quarters, most of the congestion during the quarter occurred on Midwest ISO internal constraints (including Midwest ISO market-to-market constraints).
  - ✓ In total, the Midwest ISO constraints (internal and market-to-market) account for nearly 97 percent of all the congestion value, up from 93 percent in 2009.
    - – Internal congestion increased by 20 percent and 28 percent from the third quarters of 2008 and 2009, respectively.
    - – Much of the increase in congestion is on lower-voltage constraints, primarily in the West, that are affected by wind output.
  - ✓ Congestion on PJM market-to-market constraints fell by 50 percent to $6.4 million.
  - ✓ Congestion on external constraints rose to just over $2 million, a large share of which represents inefficient redispatch.
    - – We are investigating whether changes could be made to the TLR process to address these inefficiencies.

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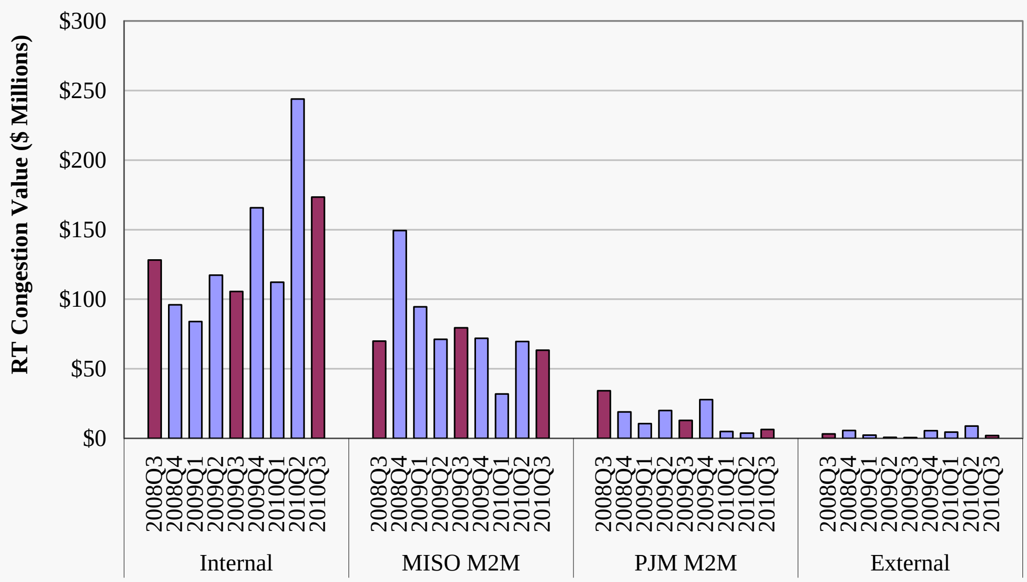
Value of Real-Time Congestion by Type of Constraint 2008 – 2010



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FTR Profitability

- FTR profits are the difference between the revenues from the FTR based on day-ahead congestion and the price of the FTR.
  - ✓ In liquid FTR markets, profits should be low over the long-term because the clearing price for FTRs should reflect a rational expectation of their congestion value.
  - ✓ However, profits and losses may be large in the short-term when fluctuations in congestion patterns cause outcomes to deviate from expectations.
- The next two figures show the profitability of FTRs purchased in the seasonal and monthly FTR auctions, respectively.
  - ✓ After modest losses in most auctions in 2009, FTRs purchased in 2010 have been consistently profitable, particularly peak-hour FTRs.
  - ✓ However, profitability averaged only $0.08 per MWh in the summer auction and $0.01 in monthly auctions.
  - ✓ This remains significantly lower than the profitability of FTRs in 2005 to 2007 (not shown), which indicates that the liquidity in the FTR market is allowing it to price the FTRs efficiently.

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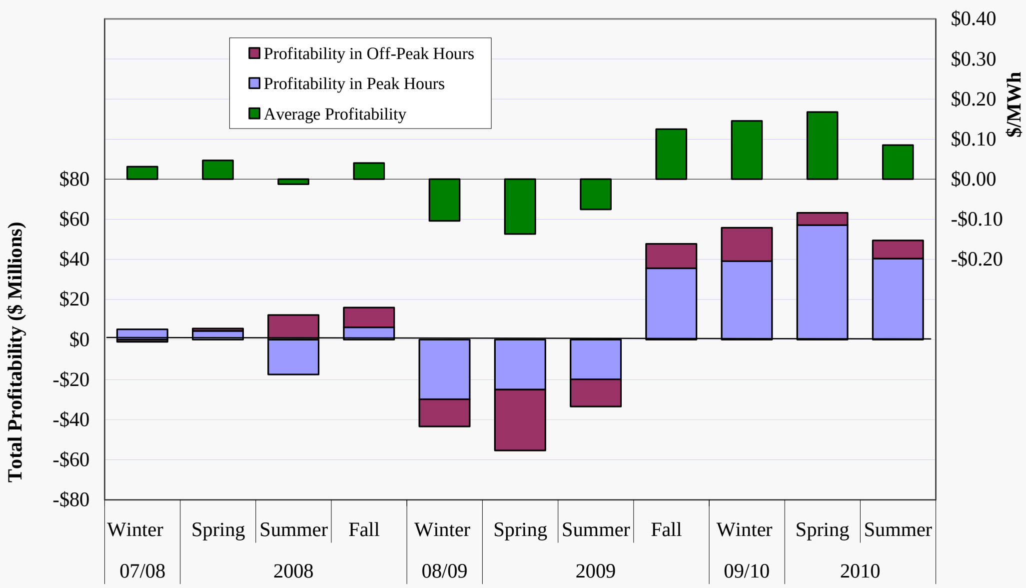
Seasonal FTR Profitability 2008 – 2010



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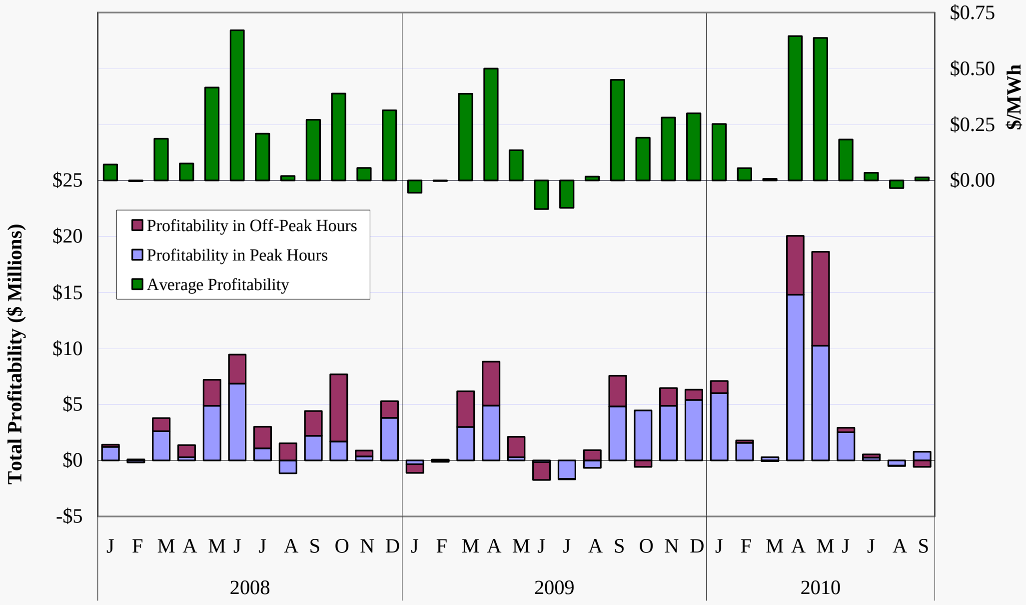
Monthly FTR Profitability
2008 – 2010



Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market during the third quarter from 2008 to 2010.
- The Midwest ISO imported nearly 3.6 GW on average in the third quarter, nearly three-quarters of which came across PJM and Manitoba Hydro interfaces.
  - ✓ High load levels and resulting higher prices made it more attractive to schedule into the Midwest ISO during the third quarter.
- In most days during the quarter, real-time net imports decreased from those scheduled in the day-ahead market.
  - ✓ Average differences between day-ahead and real-time imports were nearly 600 MW in the quarter, up from 355 MW in the second quarter.
    - – Imports were overscheduled on all but six days in July and August.
  - ✓ On 23 days during the quarter, net imports declined by more than 1,000 MW between the day-ahead market and real time.
    - – As a percentage of day-ahead net imports, this difference increased from 14.1 percent in the second quarter to 18.7 in the third quarter.

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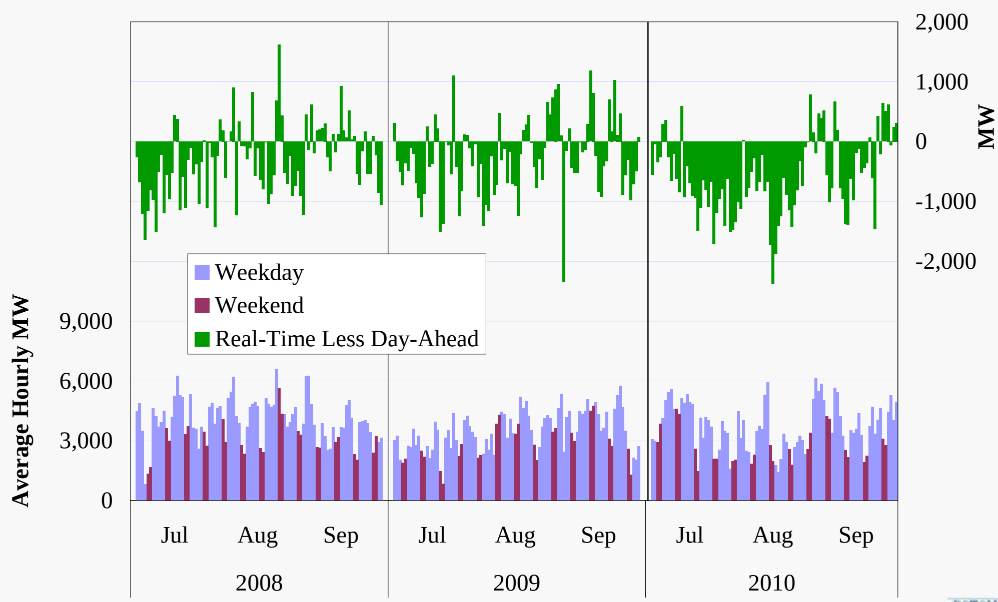
Average Hourly Real-Time Imports
Third Quarter, 2008 – 2010



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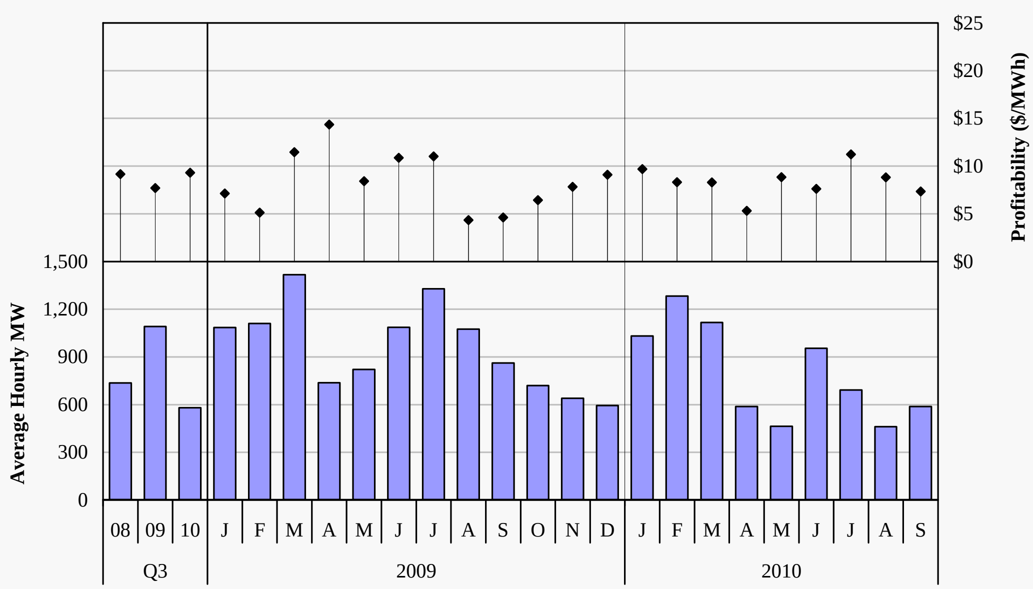
Real-Time Ontario-PJM Wheels Quantity and Profitability

- When circuitous scheduling was disallowed by NYISO, schedules from IESO to PJM (across the Midwest ISO) increased. The next figure shows the quantity and profitability of these transactions from 2008 through the third quarter of 2010.
- Year-over year volumes of these wheel transactions fell by 46 percent in the third quarter, although their profitability rose slightly.
- The transactions are explained by their profitability (62 percent of all hours).
  - ✓ Since the beginning of 2009, these transactions have netted profits between $5 and $15 per MWh nearly every month, and averaged $9.30 per MWh in the third quarter.
  - ✓ Profitability is calculated based on the prices in PJM and IESO minus the Midwest ISO's wheeling charge (it does not include costs assigned by IESO).
- If PJM instead priced these transactions at its Midwest ISO interface – prices in PJM averaged $36 per MWh in the third quarter, versus $48 per MWh at the Ontario interface – average profitability would drop to -$2.37 per MWh.
  - ✓ The large difference between the PJM's IESO and MISO prices may create incentives to combine other transactions with these wheels to acquire the difference.
- The scheduling coordination being discussed by the ISOs around Lake Erie should address both efficiency and manipulation concerns with the current system.

Real-Time Ontario-PJM Wheels Quantity and Profitability, 2009 – 2010



Generation Outage Rates

- The following figure shows the generator outages that occurred in each month from January 2009 through September 2010 as a percentage of total generation capacity.
  - ✓ These values include only full outages, not partial outages or deratings.
  - ✓ The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).
- The total outage rate for the three classes of outages was 9.9 percent in the third quarter of 2010, compared to 7.7 percent in 2009 and 6.2 percent in 2008.
  - ✓ Outage rates in all classes were higher than in prior years.
  - ✓ The higher forced outage rates can be partially explained by higher loads, which required substantially more unit commitments and therefore provided more opportunities for unit failure.
- Long-term and short-term forced outage rates increased by respectively 1.0 and 0.4 percentage points over last year, while planned outages rose by 0.9 percentage points.
  - ✓ We monitor short-term outages closely because they can indicate potential exercises of market power.
  - ✓ The increase is largely attributable to a small number of large units that were on multi-day outages during the quarter, but did not raise competitive concerns.
  - ✓ Module E must-offer compliance requirements, revised in late 2009, increased the incentive for participants to accurately report outages.

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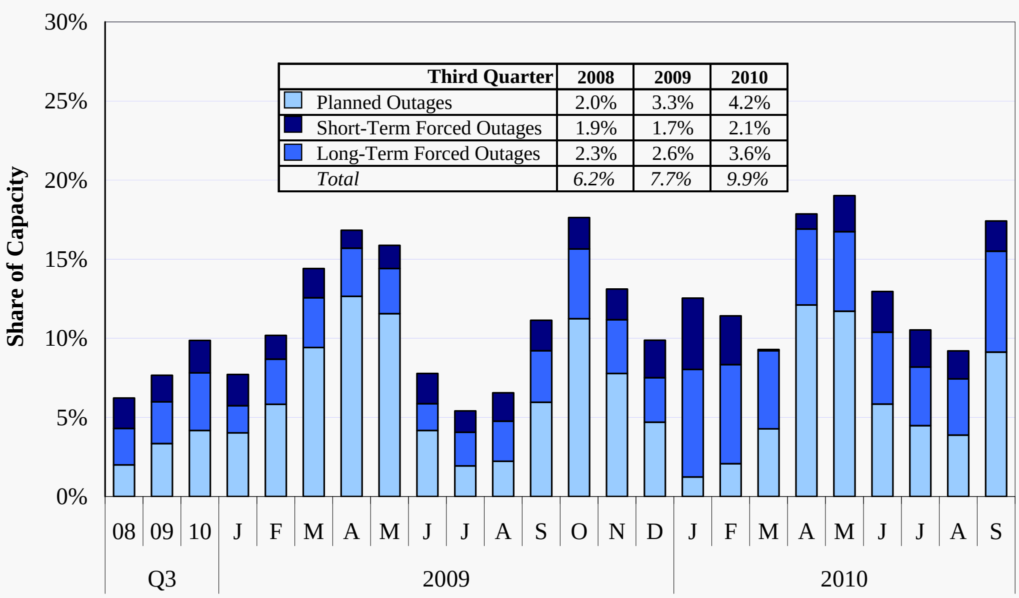
Generation Outage Rates 2009 – 2010



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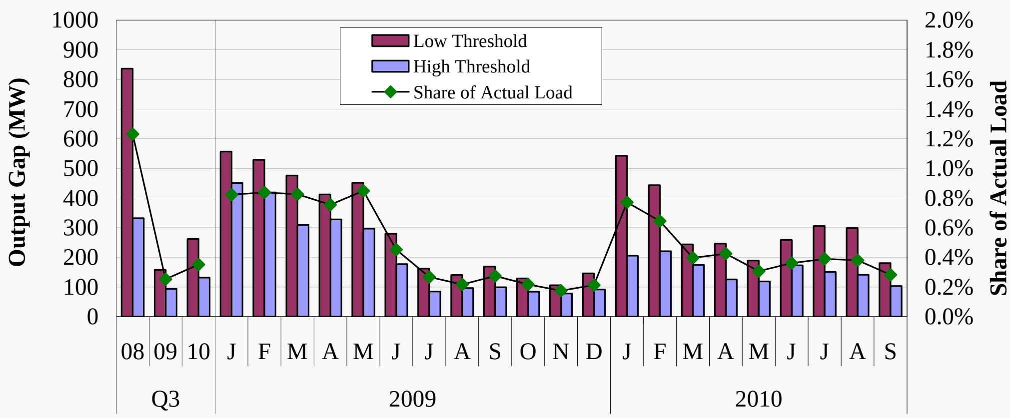
Monthly Output Gap

- The next figure shows the output gap levels used to screen for economic withholding by month for 2009 through the third quarter of 2010.
  - ✓ Output gap measures the difference between actual output and the output level that would be expected based on competitive offers.
- The figure shows the output gap under two thresholds: a “high” threshold (equal to the mitigation threshold) and a “low” threshold (one-half of mitigation threshold).
  - ✓ Output gap levels under the high and low thresholds were respectively 11 and 36 percent higher during the quarter than the exceedingly low levels observed in the summer of 2009.
  - ✓ Compared to the second quarter of 2010, the output gap was 5 percent lower at the high threshold, but 14 percent higher at the low threshold.
  - ✓ The NCA mitigation thresholds are defined to be lower than the thresholds applied in Broad Constrained Areas.
- We routinely investigate hourly increases in the output gap.
  - ✓ Three units accounted for most of the elevated output gap level early in July and August. However, these offers did not raise competitive concerns.
- As a share of overall load, the low-threshold output gap averaged less than 0.4 percent and remains consistent with competitive outcomes.

Monthly Output Gap 2009 – 2010



Low Threshold Results by Unit Status (MW)

Off-Line	105	26	107	66	57	35	6	44	41	18	4	56	16	1	26	417	347	145	137	63	86	120	135	65
On-Line	731	131	155	491	472	441	405	407	238	144	136	113	113	105	120	126	96	99	109	126	172	186	163	115

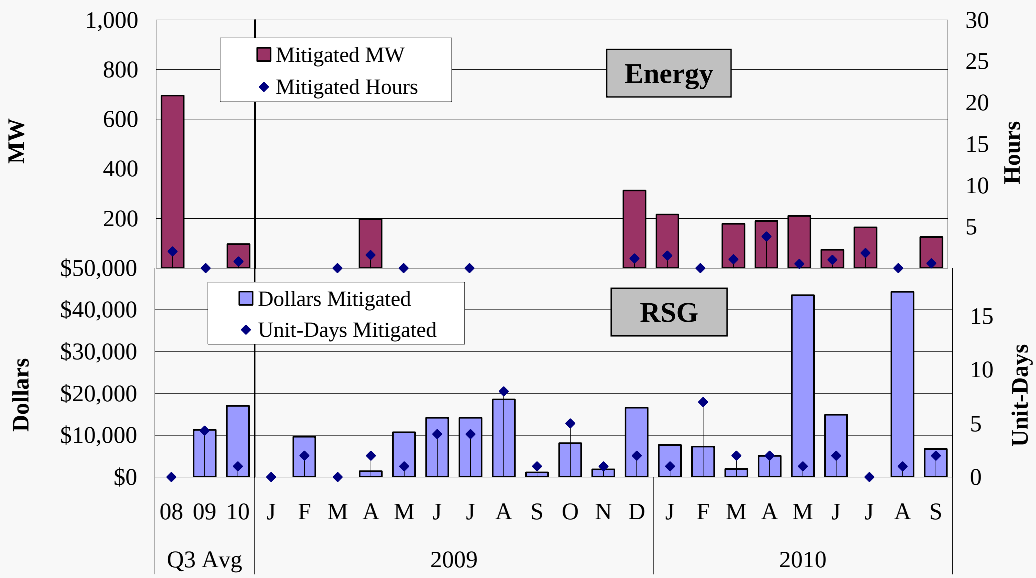
High Threshold Results by Unit Status (MW)

Off-Line	72	7	30	57	38	4	3	0	1	2	1	19	0	1	7	118	162	111	52	34	54	37	39	14
On-Line	260	87	102	394	381	305	325	296	176	84	96	81	84	77	85	87	59	64	74	85	119	114	102	90

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which mitigation has been imposed in the real-time market and for RSG payments.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the average quantity mitigated.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigated.
- Mitigation in both the day-ahead and real-time markets has been rare due to:
  - ✓ Minimal price impacts because the market has cleared in supply ranges that are highly elastic (causing withholding to have a lesser impact); and
  - ✓ The majority of resources bid competitively into the MISO markets.
- Quarter-over-quarter comparisons of mitigation levels show that these events continue to be exceedingly rare.
  - ✓ Local market power, however, continues to be a significant concern and the market power mitigation measures remain critical.
- There was only one day-ahead market mitigation event during the third quarter.
  - ✓ This is not surprising because a competitive real-time market will discipline the day-ahead market as long as the day-ahead market is liquid and well-arbitraged.

Real-Time Market Power Mitigation 2009 – 2010



Voluntary Capacity Auction

- Beginning in June 2009, the Midwest ISO began a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The capacity cleared in the VCA remains a very small portion of the total designated capacity, and averaged 1.4 percent in the third quarter 2010.
  - ✓ This is consistent with the expectation that this market would only be a balancing market with LSEs' needs satisfied through owned capacity or bilateral purchases.
- The following figure shows the total monthly capacity requirements and how LSEs are satisfying those requirements. It shows:
  - ✓ Capacity designations always met or exceeded requirements. In the third quarter of 2010, designations exceeded the requirement by 1 to 2 percent.
  - ✓ The total capacity available exceeded the requirement by 3 percent in July, 5 percent in August, and 16 percent in September.
    - – The low VCA clearing prices are consistent with the system's capacity surplus.
  - ✓ The high capacity prices in July 2009 were the result of the peak demand for capacity and large quantities of capacity that were not offered or offered at a high price.
    - – We attribute these results to inexperience with this new market and conditions occurring in this period. These issues have not arisen since July 2009.

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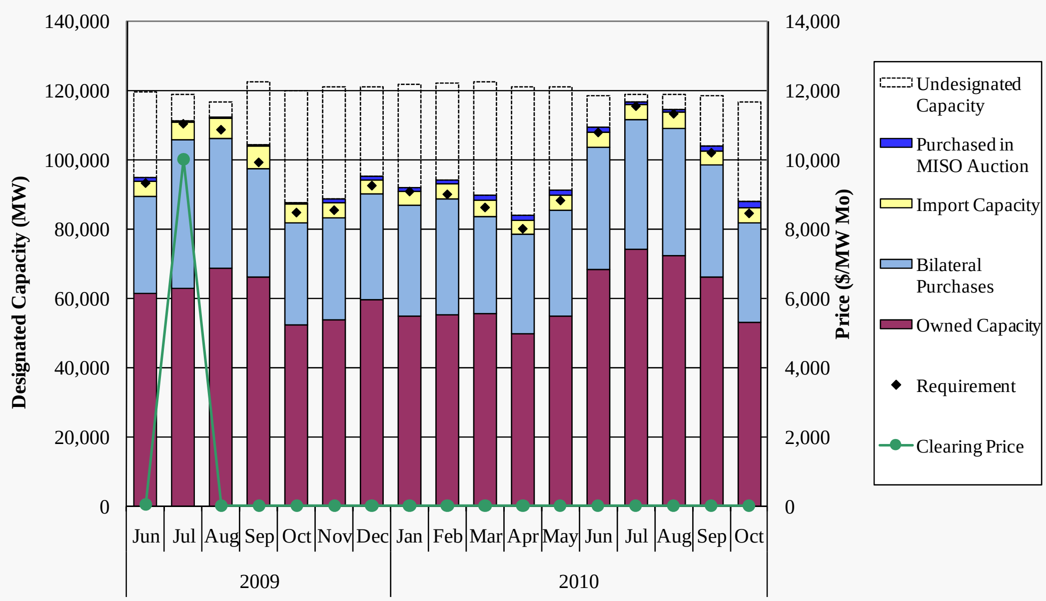
Capacity Market Results
June 2009 – Oct 2010



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

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