IMM Quarterly Report: Winter 2013
December–February

MISO Independent Market Monitor

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Potomac Economics

March 27, 2013

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Quarterly Summary

		Value	Change[1] Prior Qtr.	Prior Year
RT Energy Prices ($/MWh)	●	$28.58	*1%*	*10%*
Fuel Prices ($/MMBtu)				
Natural Gas	●	$3.46	*2%*	*18%*
Western Coal	●	$0.57	*2%*	*-9%*
Eastern Coal	●	$1.77	*-1%*	*-16%*
Load (MW)[2]				
Average Load	●	58.6	*9%*	*2%*
Peak Load	●	74.2	*-12%*	*3%*
% Scheduled DA (Peak Hour)	●	100.4%	100.2%	101.8%
Transmission Congestion ($M)				
Real-Time Congestion Value	●	$336.8	*4%*	*33%*
Day-Ahead Congestion Revenue	●	$180.3	*5%*	*53%*
Balancing Congestion[4]	●	$12.8	$11.4	$24.7
FTR Funding Shortfall	●	$28.2	$28.5	-$13.6
Ancillary Service Prices ($/MWh)				
Regulation	●	$7.63	*-19%*	*2%*
Spinning Reserves	●	$1.51	*-38%*	*24%*
Supplemental Reserves	●	$0.46	*-65%*	*-16%*

		Value	Change[1] Prior Qtr.	Prior Year
Wind Output (MW)	●	4,498	*18%*	*13%*
Guarantee Payments ($M)				
Real-Time RSG	●	$9.4	*-23%*	*68%*
Day-Ahead RSG	●	$7.0	*-20%*	*130%*
Day-Ahead Marginal Assurance	●	$5.1	*-53%*	*-40%*
RT Operating Rev. Sufficiency	●	$1.2	*-66%*	*-21%*
Price Convergence[3]				
Market-wide DA Premium	●	1.0%	-1.3%	3.8%
Virtual Trading				
Cleared Quantity (MW)	●	6,597	*-4%*	*-11%*
% Price Insensitive		41%	40%	52%
% Screened for Review	●	2%	2%	1%
Profitability ($/MW)	●	$0.33	$0.51	$0.75
Dispatch of Peaking Units (MW/hour)	●	243	349	136
Output Gap- Low Thresh. (MW/Hour)	●	47	32	15
Maximum VCA Price ($/MW-Mo.)	●	$0.19	$0.15	$0.20
Other:				

Key:
- ● Expected
- ● Monitor/Discuss
- ● Concern

Notes:
1. Values not in italics are the value for the past period rather than the change.
2. Comparisons adjusted for change in membership.
3. Values include allocation of real-time RSG (DDC rate).
4. Real-time shortfalls (which contributes to negative ECF), net of real-time surpluses. No offset for market-to-market settlements.

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Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations for December thru February for the last three years.
  - ✓ We include natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin during peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices in winter averaged $28.87 per MWh, an 8 percent increase from the prior winter.
  - ✓ This increase was due to gas prices rising nearly 20 percent from last winter, which was partly offset by coal prices dropping 9 to 16 percent.
  - ✓ Load rose by 1.7 percent (adjusted for membership changes) to average 58.9 GW.
  - ✓ Both energy prices and fuel prices were relatively flat from the Fall 2012.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ There was very little difference among hub prices this winter.
    - – There was substantial congestion in the west, but the congestion *into* the Minnesota Hub area offset the prevailing pattern of west-to-east congestion.
  - ✓ Day-ahead scheduling of wind output rose a further 24 percent from last winter to over 4.2 GW, which generally contributes to west-to-east congestion.

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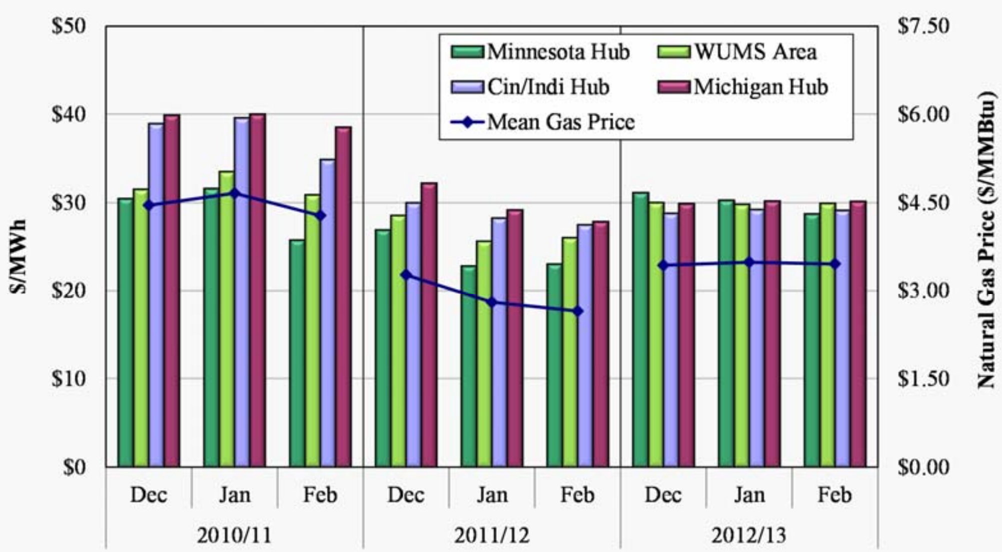
Day-Ahead Average Monthly Hub Prices Winter 2011–2013



Note: Cinergy Hub was replaced by Indiana Hub as the Central region's proxy price in 2012.

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All-In Price

- The "all-in price" 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 and real-time uplift, ancillary services, and capacity costs per MWh of load.
- The figure also includes the monthly average natural gas price and shows that energy prices generally track changes in fuel prices.
  - ✓ This is expected in a competitive market because fuel costs are the vast majority of most units' marginal costs and gas units are often setting prices.
- The all-in price rose 11 percent from last winter to $28.72 per MWh.
  - ✓ As with day-ahead energy prices, the rise in the energy component of the all-in price was due to the substantial rise in natural gas prices.
- Energy costs continue to make up over 99 percent of the all-in price.
  - ✓ Uplift costs rose slightly but made up just 7 cents to the all-in price.
  - ✓ The ancillary services component was unchanged from last winter at 9 cents.
  - ✓ The Voluntary Capacity Auction cleared near zero in each month, so capacity payments did not contribute materially to the all-in price.
    - – These prices are primarily due to certain market flaws that require attention.
    - – The new annual planning reserve auction, to be held next month, should better reflect the capacity needs in local areas.

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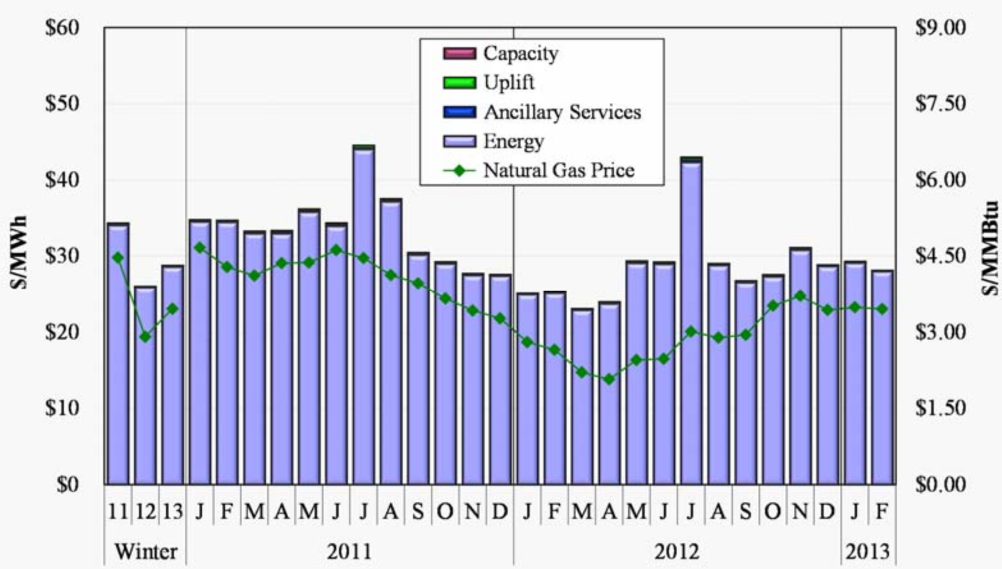
All-In Price
Winter 2011–2013



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Ancillary Services Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO's ancillary service products for the last 15 months, showing the component of each price that is due the shortage/non-shortage prices for each product (reflected in higher quality prices because they can satisfy lower quality requirements).
- Average regulation prices rose 2 percent from last winter to $7.63 per MWh.
  - ✓ The frequency of shortages declined 16 percent, however the shortage component of the average regulation prices rose 41 cents because the penalty price increased.
- On December 17, per FERC Order 755, MISO began a two-part compensation scheme for regulation resources that pays separately for capacity and for mileage.
  - ✓ Some suppliers' regulation offer prices rose sharply because they misunderstood the new market framework. This was quickly remedied after they were contacted.
  - ✓ This is likely responsible for approximately half of the difference in price between January versus December and February.
  - ✓ The regulation mileage deployment factor declined in February from 12 to 6.73 cycles per hour. The resulting reduction of the movement component accounts for most of the February regulation price decline.
- Spinning reserve clearing prices rose 24 percent to $1.51 per MWh, mostly due to an increase in spinning reserve shortages (from 60 to 95 intervals).
- Supplemental reserve prices declined 9 cents to $0.46 per MWh. There were two operating reserve shortages.

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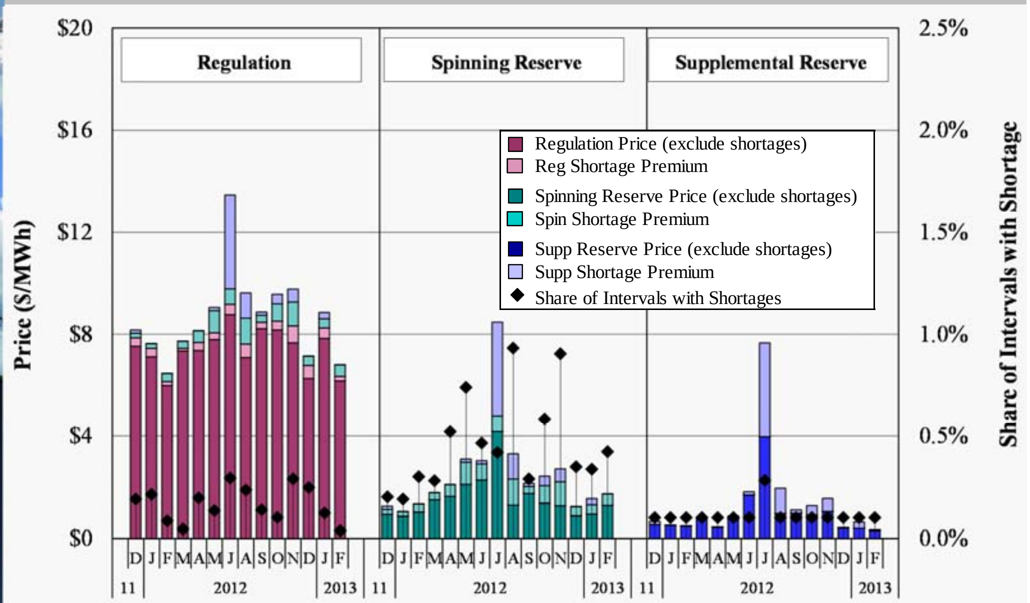
Monthly Average Ancillary Service Prices Regulation and Contingency Reserves, 2011–2013



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MISO Fuel Prices and Capacity Factors

Natural Gas and Oil Prices

- Natural gas prices averaged $3.46 per MMBtu this winter, 18 percent higher than last winter. Prices were 2 percent higher than in fall.
  - ✓ Prices rose gradually over the period and approached $4 in early March.
- Oil prices rose 8 percent from last winter to $22.07 per MMBtu. Oil is rarely marginal (even in winter), so this rise had a minimal impact on energy prices.
  - ✓ Oil units received over one-third of all real-time RSG paid this quarter, however.

Coal Prices

- Illinois Basin prices declined 16 percent from last winter to $1.77 per MMBtu.
- Western (Powder River Basin) coal prices similarly declined 10 percent to $0.57 per MMBtu. Prices for both coal types were nearly unchanged from fall averages.

Capacity Factors

- The continued rise in gas prices has resulted in a nearly complete reversion of the generation changes observed in the first half of 2012
- $2 natural gas prices in early 2012 doubled the capacity factors for gas-fired resources

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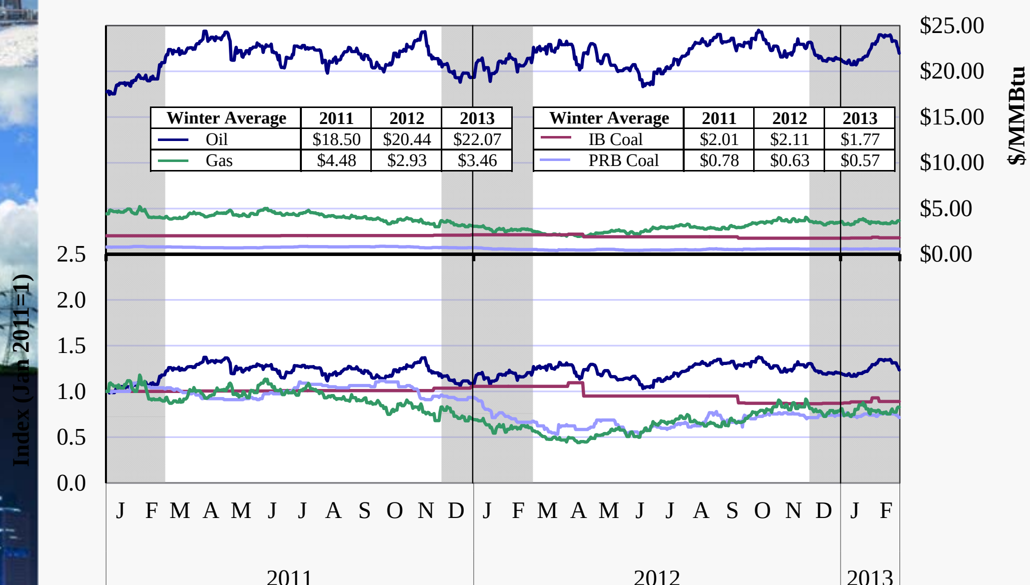
MISO Fuel Prices 2011–2013



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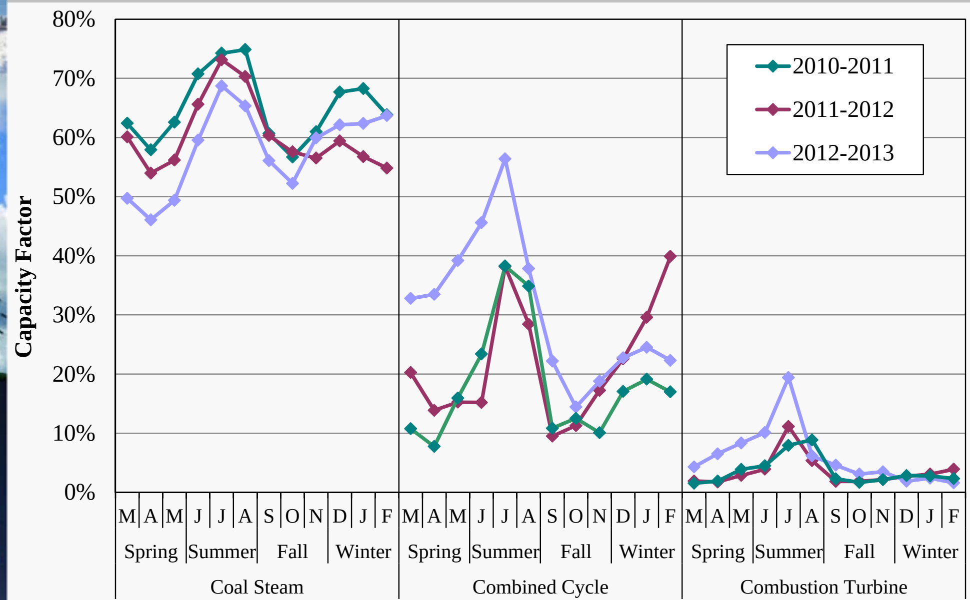
Capacity Factors by Unit Type 2011–2013



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Changes in Load and Weather Patterns

- The next figure shows changes in load in winter 2011 to 2013, as well as the changes in weather patterns that contributed to these changes.
- Because a large share of the load is sensitive to weather, the figure shows how changes in weather patterns correspond to changes in load.
  - ✓ The bottom panel in the figure shows the monthly heating and cooling degree days (“HDDs and CDDs”) at four locations in MISO since December 2010.
- The figure shows that total degree days increased 9 percent from winter 2012.
  - ✓ Total degree days remained slightly below average, indicating that temperatures were generally above normal this winter.
- These weather factors affected the monthly average and peak loads during each period shown in the top panel of the figure.
  - ✓ Load associated with membership departures since December 2010 is shown separately (FirstEnergy and portions of Duke Energy).
  - ✓ Average and peak loads respectively rose 1.7 and 2.7 percent (adjusted for membership changes) from last winter. Load peaked at 74.2 GW on January 22.

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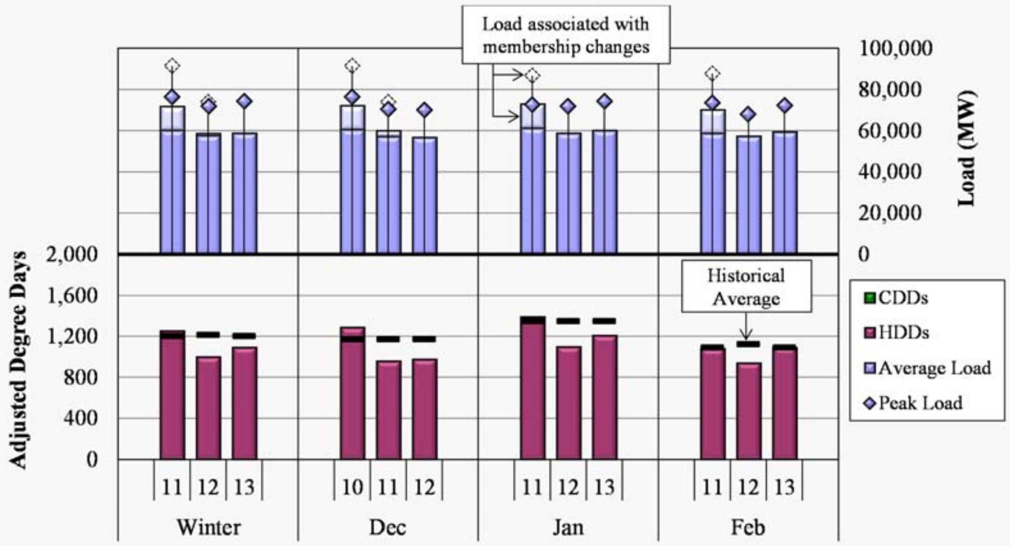
Load and Weather Patterns Winter 2011–2013



Note: Calculations are the average monthly degree days of four representative cities in MISO: Cincinnati, Detroit, Milwaukee and Minneapolis.

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Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on MISO-managed internal and market-to-market constraints (the figure excludes external constraints).
  - ✓ Real-time congestion is equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
  - ✓ This is higher than the congestion costs collected by MISO because loop flows do not settle with MISO and PJM has entitlements to MISO's transmission capability.
  - ✓ The figure separately shows congestion on those constraints that are temporarily violated (i.e., the congestion is considered "unmanageable" in the 5-minute dispatch).
- The value of real-time congestion rose 33 percent from the prior winter to $336 million.
  - ✓ By far the most expensive constraint, valued at $42 million and located in the Central Region, was due to both high and low voltage transmission outages in PJM and MISO.
  - ✓ The congestion relief is mostly available through lowering dispatch of wind resources.
- Relaxation eliminated just 1 percent of congestion costs this quarter, compared to 16 percent last winter. The practice continues to be used only on M2M constraints.
  - ✓ While much improved from last year, relaxation still adversely affects the day-ahead market, FTR market, and longer-term investment decisions.
- MISO has deactivated the transmission "deadband" on a limited set of constraints, which has reduced shadow price volatility and improved pricing efficiency.
  - ✓ We recommend MISO eliminate this provision for all constraints.

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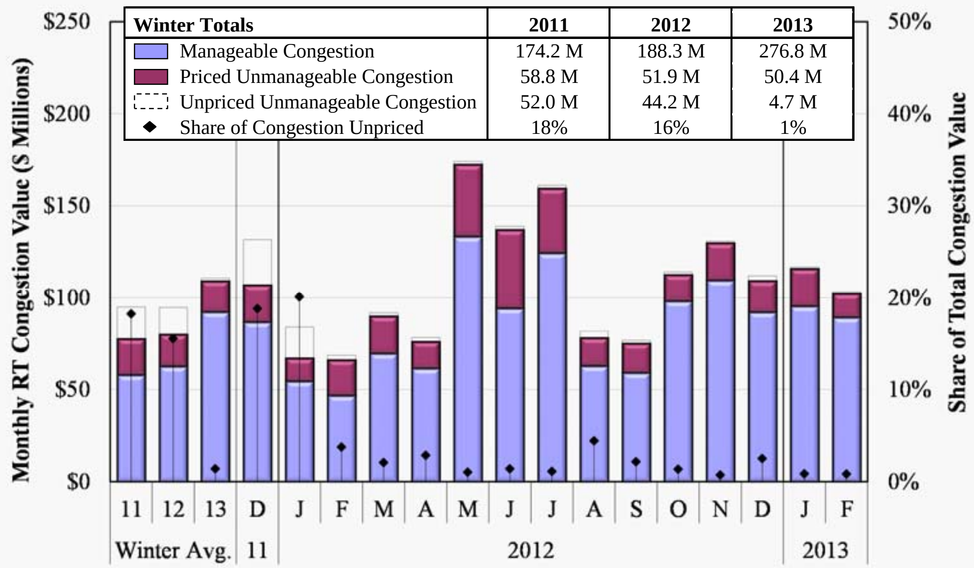
Value of Real-Time Congestion Winter 2011–2013



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Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows day-ahead congestion, FTR obligations and FTR shortfalls.
- Day-ahead congestion rose 53 percent from last winter to $180.3 million, consistent with the rise in real-time congestion described above.
- FTR holders are entitled to the day-ahead congestion costs that arise between particular locations in MISO, which allows them to manage day-ahead price risk.
  - ✓ MISO collects congestion through its settlements with loads and generation, and pays it out to FTR holders.
  - ✓ If MISO does not collect sufficient congestion revenue to cover its obligation to the FTR holders, a shortfall arises and payments to FTR holders are reduced. Shortfalls (or surpluses) occur when the portfolio of FTRs represent more (or less) transmission capacity than the capability of the network in the day-ahead market.
- FTR obligations, which were over-funded by 12.5 percent last winter, but were underfunded by almost 16 percent this quarter.
  - ✓ Prior surpluses were accrued mostly on internal market-to-market constraints and covered shortfalls on other constraints. The surpluses fell when MISO began modeling its flow entitlements, rather than typical flows, on these constraints in the FTR market.
  - ✓ Additional underfunding resulted from same-bus "zero-cost" FTRs sold in prior auctions and from unplanned transmission outages, predominantly in the West region. MISO is addressing the same-bus FTR issue in an upcoming FERC filing.

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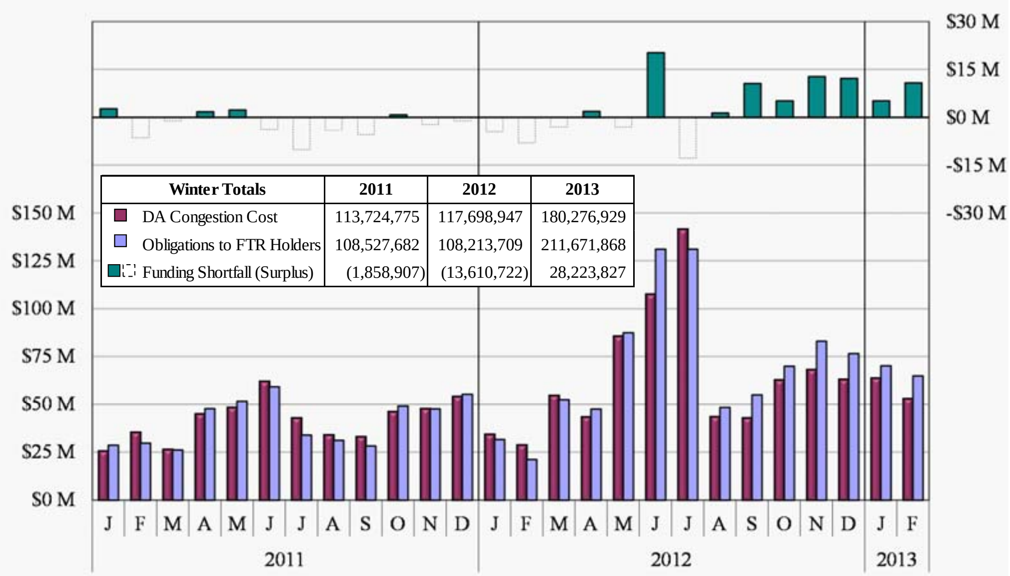
Day-Ahead Congestion and Obligations to FTR Holders, 2011–2013



Winter Totals	2011	2012	2013
DA Congestion Cost	113,724,775	117,698,947	180,276,929
Obligations to FTR Holders	108,527,682	108,213,709	211,671,868
Funding Shortfall (Surplus)	(1,858,907)	(13,610,722)	28,223,827

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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 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 Indiana Hub (the inset table shows other locations), along with average price differences.
- Overall, the figure shows that price convergence was good during the quarter.
  - ✓ There was a slight day-ahead premium at all hub locations. The highest premium was in WUMS at 2.4 percent, while the premium averaged 1 percent system-wide.
  - ✓ Substantial real-time congestion into the West region, particularly in the first half of the quarter, was not always fully reflected in the day-ahead market.
  - ✓ However, after accounting for the real-time RSG allocation, the price difference ranged from -1 percent to 1 percent at the four hub locations.

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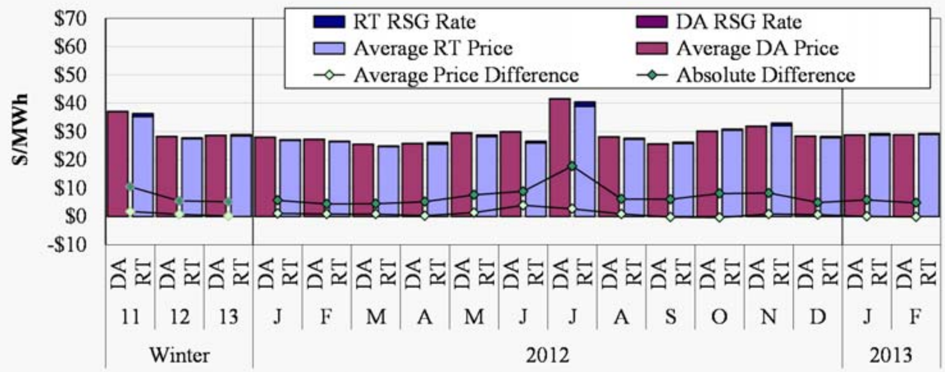
Day-Ahead and Real-Time Price Convergence 2011–2013



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

	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F
Cin/Ind Hub	5	3	0	4	3	3	1	5	15	7	3	-1	-1	3	2	0	-1
Michigan Hub	3	4	1	5	2	-1	5	5	7	7	3	4	1	3	1	1	2
Minnesota Hub	0	5	2	3	-2	2	-12	-6	0	2	2	-7	3	-8	-1	3	4
WUMS Area	0	4	2	3	0	4	0	-1	-1	2	3	-4	0	0	3	1	4

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

	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F
Cin/Ind Hub	2	2	-1	3	2	2	-2	3	13	3	1	-2	-2	0	1	-2	-1
Michigan Hub	1	3	0	4	2	-2	2	3	5	4	2	3	0	1	-1	-1	1
Minnesota Hub	-3	3	1	2	-2	1	-15	-8	-3	-2	1	-9	2	-11	-2	1	4
WUMS Area	-4	3	1	2	-1	3	-3	-3	-3	-2	1	-6	-1	-3	1	-1	3

Note: Beginning in April 2011, the RSG rate is specifically the DDC Rate charged to deviations, and excludes CMC rates.

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Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG costs because low levels compel MISO to commit peaking resources in real-time to satisfy load.
  - ✓ However, real-time commitments are still made to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- Load was scheduled at close to 100 percent on average in all hours (99.7 percent). During the peak hour each day, it was scheduled at 100.4 percent on average.
  - ✓ Under-scheduling remains most apparent during off-peak hours, which can be rational if additional supply (such as wind output or imports) is expected in real-time.
- Net virtual load consistently offset a portion of the scheduling shortfall of physical load in most hours.
  - ✓ Much of this was offered price-insensitively by load-serving entities.
- As we show in monthly reports, this broad metric can mask considerable variation in day-to-day scheduling, particularly during the December holidays.

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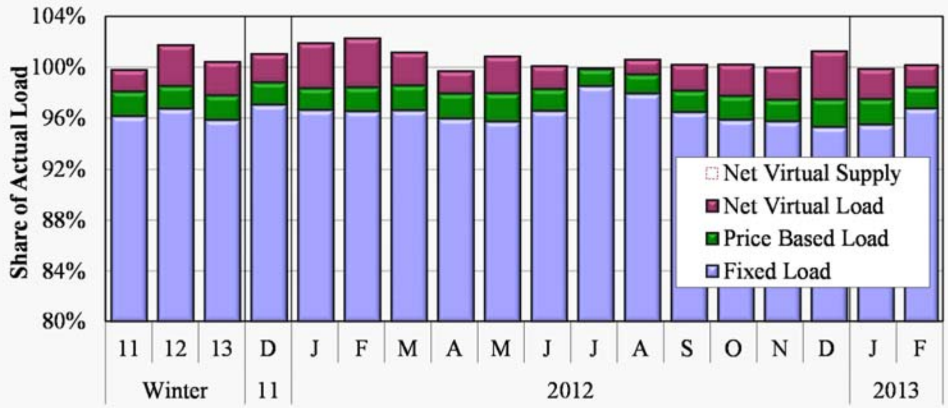
Day-Ahead Peak Hour Load Scheduling Winter 2011–2013



Share of Actual Load(%)

	Winter 11	Winter 12	Winter 13	D 11	J 2012	F 2012	M 2012	A 2012	M 2012	J 2012	J 2012	A 2012	S 2012	O 2012	N 2012	D 2012	J 2013	F 2013
All Hour	99.8	99.8	99.7	99.6	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0	98.4	98.8	99.4	100.1	99.4	99.7
Peak Hour	100.0	101.8	100.4	101.1	101.9	102.3	101.2	99.7	100.9	100.1	99.9	100.6	100.2	100.2	100.0	101.3	99.9	100.2

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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 day-ahead market results and moderates market power in the day-ahead market.
- The next figure shows the average hourly quantities of virtual demand bids and supply offers and those that were scheduled (cleared) in the day-ahead market.
- We distinguish between “price-sensitive” and “price-insensitive” bids and offers.
  - ✓ We define bids and offers as price-insensitive when they are submitted at more than $20 above and below an “expected” real-time price, respectively.
  - ✓ Price-insensitive bids and offers that then contribute to a significant difference in the congestion at a location between the day-ahead and real-time markets (labeled “Screened Transactions”) raise potential manipulation concerns.
- We have been monitoring changes in virtual trading activity patterns due to MISO’s changes in the RSG cost allocation in April 2011.
  - ✓ The change eliminates the allocation of capacity-related real-time RSG to virtual supply when it is offset by the participant by virtual load or other “helping” deviations.
  - ✓ This allocation has motivated the increase in price-insensitive virtual trading strategies.

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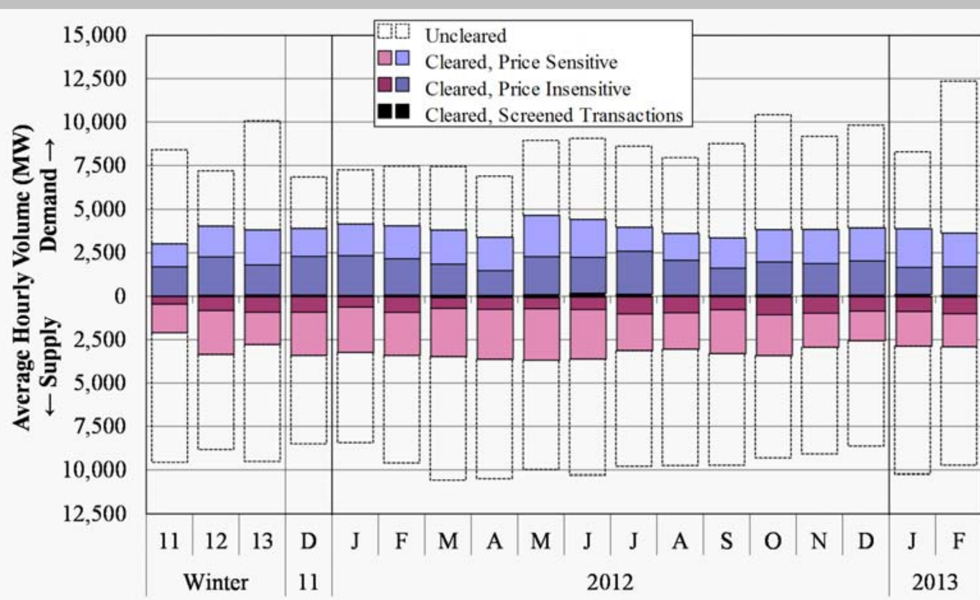
Virtual Load and Supply in the Day-Ahead Market

- The figure shows that offered volumes rose 22 percent from the prior winter to 19.6 GW, including a 40 percent rise in virtual demand.
  - ✓ Most of the increase in offered volumes, however, is a price-sensitive quantity by one participant that rare clears.
- Cleared volumes, however, declined 11 percent to an average of 6.6 GW.
  - ✓ Demand declined 5 percent to 3.8 GW, while supply declined 17 percent to 2.7 GW.
- The overall price-sensitivity of virtual volumes was unchanged at 41 percent.
  - ✓ Changes to the RSG allocation in April 2011 reduced the allocation for participants taking balanced positions, which can be ensured by offering price-insensitively.
  - ✓ A virtual spread product, which would allow participants to sensitively clear bids and offers only when their price difference exceeds a strike price, would improve arbitrage of locational price differences.
  - ✓ We will recommend such a product in our upcoming *State of the Market* report.
- MISO filed Tariff modifications on February 25 to fix the tariff error that has caused congestion-related RSG to be allocated backward to virtual transactions.
- The share of Screened Transactions rose from 1.4 percent last winter to 2.0 percent.
  - ✓ We investigate these closely and did not find any trading that raised concerns.

Virtual Volumes
Winter 2011–2013



Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by two types of market participants: physical participants and financial-only participants.
  - ✓ Physical participants generally have different incentives/reasons to trade virtually (e.g. hedging other risks) than do financial-only participants (e.g. price arbitrage).
- Financial-only participants comprised 71 percent of all virtual activity this winter, a decline from the 78 percent last winter.
  - ✓ Financial-only cleared volumes declined 19 percent to 4.7 GW on average.
  - ✓ Cleared supply volumes by physical participants doubled to 500 MW, but demand volumes still comprise nearly 75 percent of all physical participant volumes.
- The increase in uncleared offered volumes, mostly by a single subsidiary of a physical participant, began in the fall and averaged nearly 5 GW by February.
  - ✓ It bids up to 11 GW in some hours but clear almost none since they generally bid well below the LMP. This activity does not raise competitive concerns.
- The share of volumes that are price-sensitive remains much higher for financial-only participants (71 percent) than those of physical participants (30 percent).
  - ✓ Hence, the activity of the financial-only participants is important for providing liquidity to the day-ahead market.

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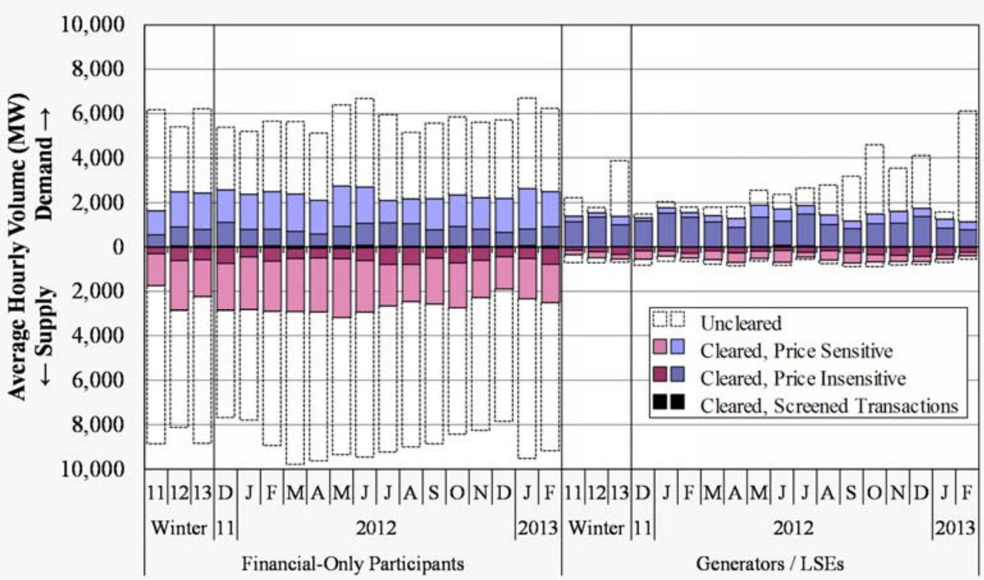
Virtual Load and Supply by Participant Type Winter 2011–2013



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Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual purchases and sales.
- Gross profits on virtual transactions totaled $4.8 million this winter ($0.33 per MW).
  - ✓ This is a decline from last winter, when it averaged $0.75 per MW.
  - ✓ Virtual supply was more profitable (at $0.93 per MW) than demand ($-0.09), which is expected when the market exhibits a modest day-ahead premium.
- These margins exclude CMC and DDC charges assessed to net harming deviations.
  - ✓ Including DDC charges to net virtual supply lowers the net profit to $0.44 per MW.
  - ✓ As previously noted, the CMC allocation to virtual transactions has been incorrect since April 2011, resulting in allocations to helping virtual transactions that reduce the need for real-time commitments. MISO filed with FERC to fix this flaw on February 25.
- Virtual transactions by financial participants continue to be profitable and generally improve price convergence overall.
  - ✓ Profitability of these transactions declined from $1.25 per MW last winter to $0.68.
- Some physical participants have consistently incurred losses on virtual demand, likely to hedge risks associated with supply uncertainty and real-time price spikes.
  - ✓ Demand remains unprofitable for these participants, although it improved from $-1.45 per MW last winter to $-0.57.

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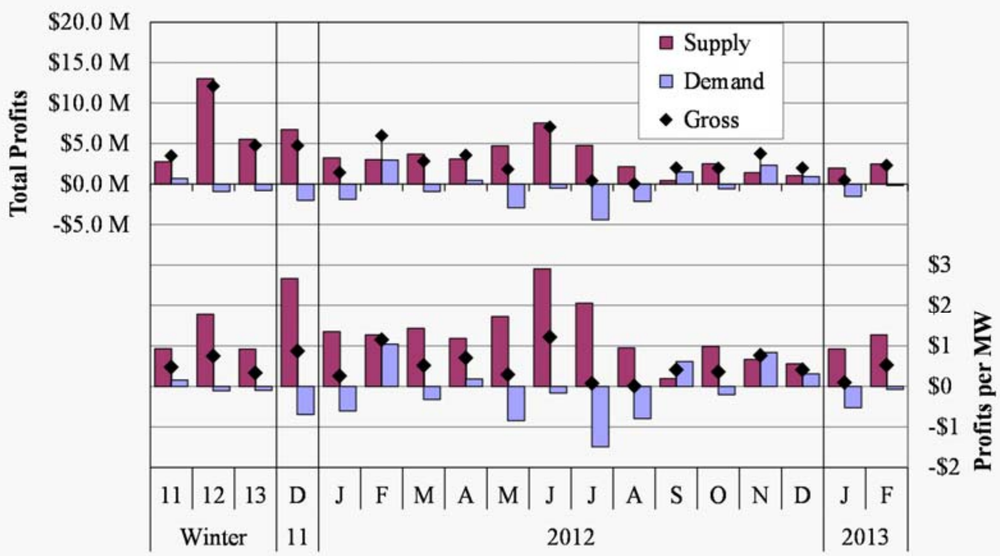
Virtual Profitability Winter 2011–2013



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Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were in-merit (offer price at or lower than the LMP).
  - ✓ The figure is categorized by the market and the reason for the commitment.
- Peaking resource dispatch quantities rose 37 percent from last winter to a monthly average of 208 MW per hour.
  - ✓ Capacity dispatches rose the most and more than doubled to 83 MW per hour.
    - – About 60 percent of these were identified by LAC, including on January 22, when extreme cold temperatures in the West region required over 2.2 GW per hour.
    - – Additionally, over 80 percent of dispatch quantities for congestion management were identified by the LAC commitment process.
  - ✓ Real-time VLR needs were minimal since most such commitments are now made in the day-ahead market.
- The share of in-merit dispatch was mostly unchanged at 57 percent.
  - ✓ Nearly 80 percent units committed day-ahead were in-merit.
  - ✓ Two-thirds of units committed in real-time, however, were dispatched out-of-merit order, and therefore could not set price.
    - – MISO's Extended LMP Initiative, expected to be put into production in early 2014, will allow peaking resources to set prices more frequently.

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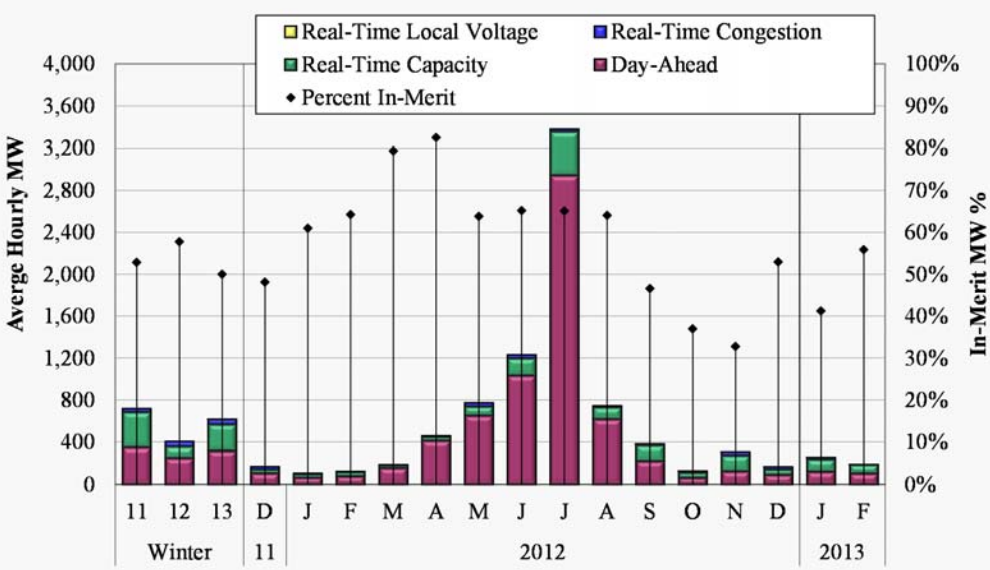
Peaking Resource Dispatch
Winter 2011–2013



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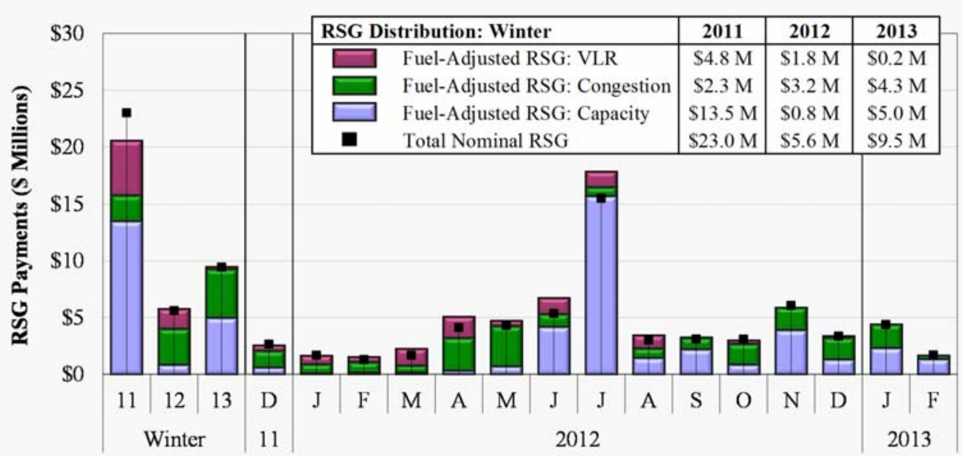
Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets, respectively.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices (adjusting values to correspond to the average fuel prices over the period shown).
- Nominal real-time RSG costs rose 68 percent from the low levels of last winter to $9.45 million. Only six percent of this rise was attributable to changes in fuel prices.
  - ✓ Commitments for capacity rose substantially from last winter to a fuel-adjusted $5 million.
    - – Payments were modest on all days except on January 22, when nearly $1 million was paid to 77 separate units committed during a cold-spell.
  - ✓ Commitments for congestion rose 35 percent to $4.3 million.
    - – Two-thirds of this accrued to units in the West region, including nearly $1 million for a set of six constraints impacted by transmission work in mid-January.
- The second figure shows that day-ahead payments more than doubled to $7.0 million.
  - ✓ This rise was entirely to payments for VLR, since such commitments are now mostly made in the day-ahead market.
  - ✓ Voltage commitments in real-time declined from 1.8 million to just $222,000.
- Peaking units received 75 percent of total payments and were mostly committed made for capacity.

POTOMAC ECONOMICS

Real-Time RSG Payments
Winter 2011–2013



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

Peaker	54	54	75	35	26	31	29	51	75	68	84	44	67	73	75	77	82	57
Non-Peaker	46	46	25	65	74	69	71	49	25	32	16	56	33	27	25	23	18	43

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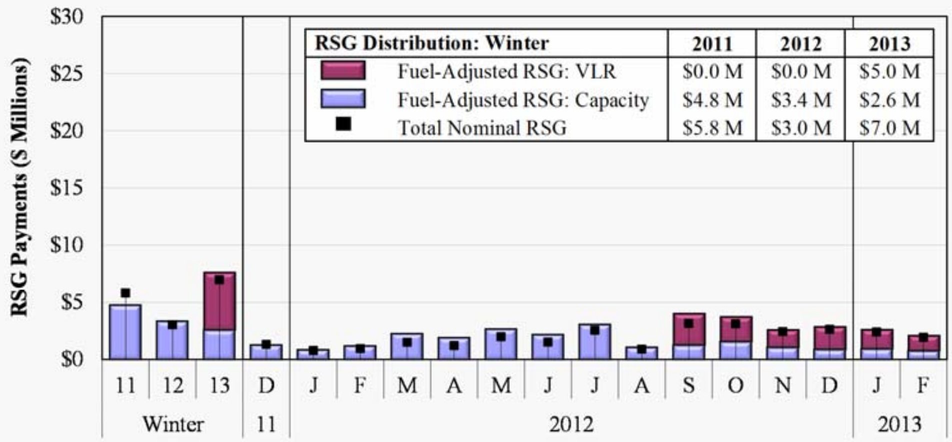
Day-Ahead RSG Payments
Winter 2011–2013



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

Peaker	2	4	1	4	2	1	2	8	21	16	62	36	9	1	2	6	1	0
Non-Peaker	98	96	99	96	98	99	98	92	79	84	38	64	91	99	98	94	99	100

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Price Volatility Make Whole Payments

- The next chart shows Price Volatility Make Whole Payments ("PVMWP") that improve incentives for suppliers to follow dispatch instructions.
- These payments totaled $11.3 million this quarter and come in two forms:
  - ✓ Day-Ahead Margin Assurance payments ("DAMAP"), which declined 39 percent from last winter to $9.1 million; and
  - ✓ Real-Time Offer Revenue Sufficiency Guarantee Payments ("RTORSGP"), which declined 28 percent to $2.2 million.
- Large coal units in the East and Central regions continue to be the largest recipients of such payments, predominantly during ramping hours.
- The lines on the chart show two measures of price volatility: one based on the System Marginal Price ("SMP") and the other on LMPs at generator locations.
  - ✓ The figure shows that the payments have been correlated with price volatility as expected—increased volatility leads to higher obligations to flexible suppliers.
  - ✓ Although SMP volatility was unchanged from last winter, LMP volatility declined nearly 30 percent.
- We will be recommending several improvements to PVMWP eligibility criteria and settlement requirements in the upcoming *2012 State of the Market Report*.

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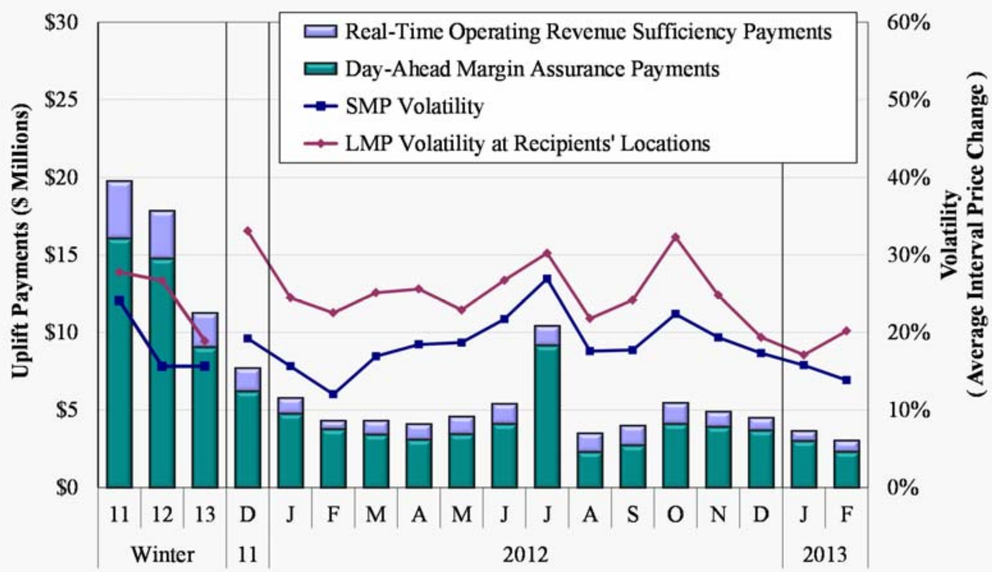
Price Volatility Make Whole Payments Winter 2011–2013



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

- The next figure shows wind output scheduled in day-ahead and real-time markets.
  - ✓ Attractive wind profiles in the West Region, along with state renewable portfolio standards and federal subsidies, continue to support investment in wind resources.
- Real-time wind output increased 13 percent from last winter to nearly 4.5 GW, and comprised 7.4 percent of total generation this quarter.
  - ✓ Nameplate capacity over the same period increased 20 percent to 12.2 GW.
- Under-scheduling of wind in the day-ahead improved considerably from last winter, declining by more than half to just 287 MW.
  - ✓ Very little of this was offset by net virtual supply at wind locations, a considerable change from last winter.
  - ✓ Changes in congestion patterns this winter made virtual supply at wind locations much less profitable than last winter, declining from $3.07 to $1.34 per MW.
  - ✓ The incentives to schedule at these locations will improve when the CMC sign error is corrected.

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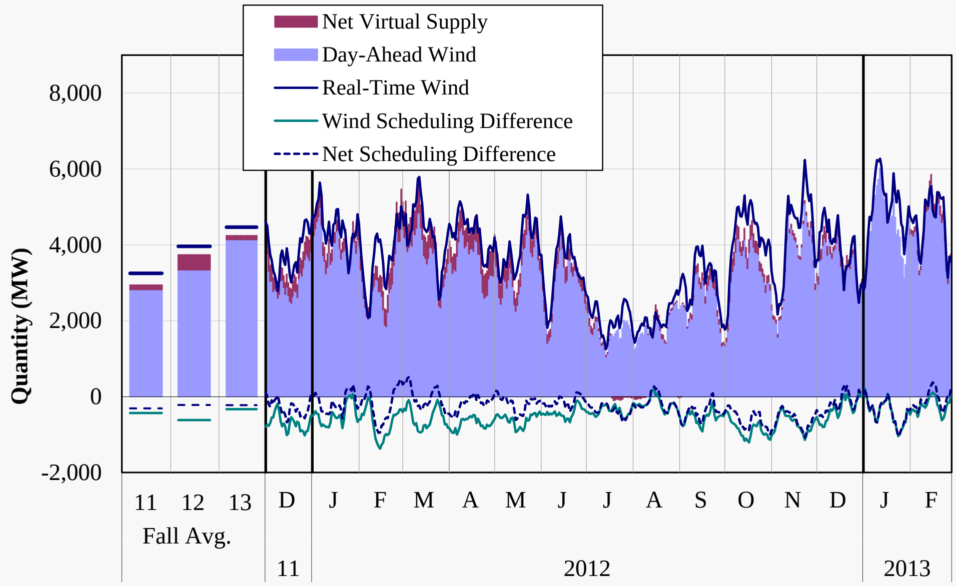
Wind Output in Real-Time and Day-Ahead Markets 7-Day Moving Average, Winter 2011–2013



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Wind Curtailment

- The majority of wind resources (52 percent) in the MISO footprint this winter were DIR and were capable of responding to MISO dispatch instructions.
  - ✓ As of the March 1 conversion deadline, 111 of the 176 wind resources (totaling nearly 10 GW, or 78 percent of total wind capacity) are DIR and able to set prices.
  - ✓ Wind resources may be exempt from DIR if they were either put into service after the April 1, 2005 exemption cutoff or have long-term transmission service.
  - ✓ We are working with MISO to evaluate DIR compliance issues.
- Wind volatility (based on units' forecasted maximums) rose 9 percent to an average of 43 MW per interval, less than the 13 percent rise in wind output.
  - ✓ DIR substantially improves the manageability of the congestion impacted by wind volatility.
  - ✓ Manual curtailments by MISO—including at times of unresponsive DIRs—remained necessary at times to prevent transmission overloads.
- The following figure shows that economic DIR curtailments have replaced manual curtailments since 2011 as the primary means of controlling wind output.
  - ✓ Manual curtailments declined 43 percent from last winter to 33 MW per hour.
  - ✓ Economic curtailment of wind resources averaged 74 MW this winter, up from 49 MW last winter, and totaled nearly 70 percent of curtailments during the quarter.

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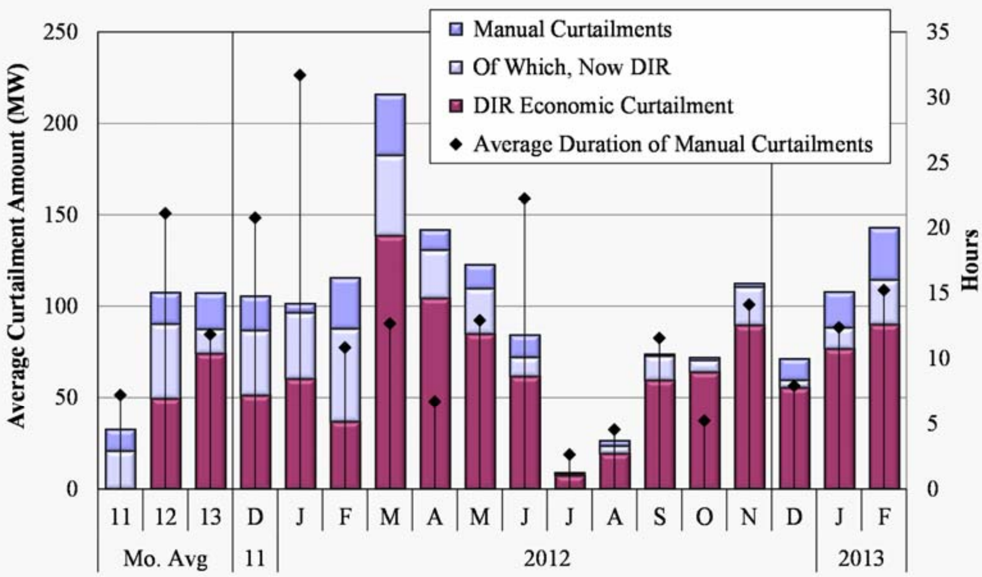
Wind Curtailment
Winter 2011–2013



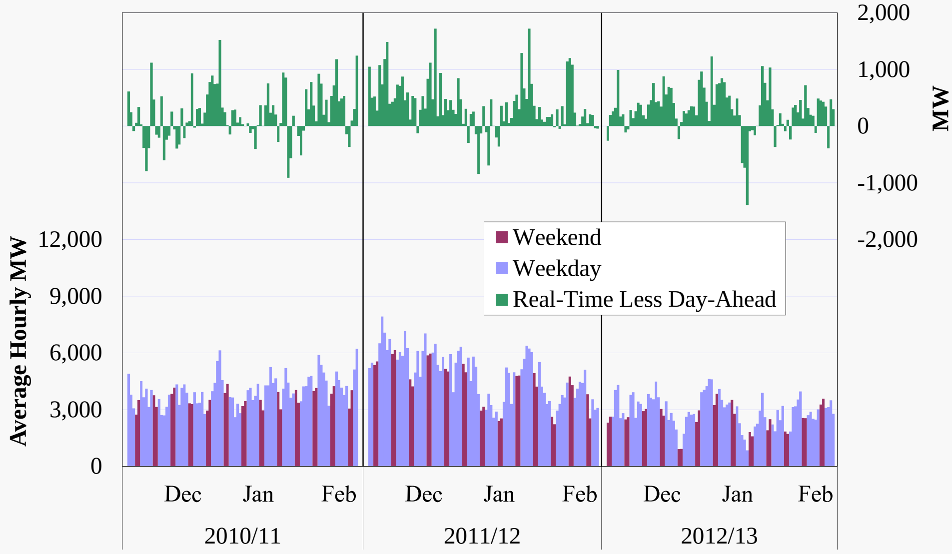
POTOMAC ECONOMICS

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 in the winter months of 2011 to 2013.
- Net imports declined by 40 percent from last winter to 2.9 GW per hour.
  - ✓ MISO remains a considerable net importer of energy during most hours.
- Nearly all of the decrease occurred on the PJM interface, where net imports declined by 53 percent to 1.4 GW.
  - ✓ Wheeled transactions to PJM declined 17 percent from last winter.
  - ✓ Net imports from Manitoba, which vary significantly by season, declined by 17 percent from last winter and by two-thirds from the fall to an average of 283 MW.
- Net imports rose from the day-ahead to real-time market by 295 MW on average.
  - ✓ This is a smaller increase than in the prior winter when it increased by an average of 384 MW.
  - ✓ Real-time net imports rose on almost all days except for several days after the cold-weather peak that occurred on January 22.
- MISO and PJM continue to discuss proposals to improve interchange in the JCM process, including interchange optimization or "Coordinated Transaction Scheduling", which would achieve substantial economic efficiencies.

POTOMAC ECONOMICS

Average Hourly Real-Time Imports Winter 2011–2013



POTOMAC ECONOMICS

Monthly Output Gap

- The output gap measure is used to screen for economic withholding by suppliers.
  - ✓ It measures the difference between actual output and the output level that would be expected based on competitive offers.
- The next figure shows the output gap since December 2011 under two thresholds:
  - ✓ A “high” threshold, equal to the mitigation threshold; and
  - ✓ A “low” threshold, equal to one-half of mitigation threshold.
  - ✓ We filed revised NCA thresholds in early February. The Minnesota threshold declined due to increased congestion into the region in the past year, while the WUMS increased to the maximum threshold equal to the BCA equivalent.
- Output gap levels in MISO increased from extremely low levels last winter, but remained very low (less than 0.01 percent of load at both thresholds).
  - ✓ At the high threshold, output gap rose from 4 to 18 MW, while at the low threshold it rose from 15 to 47 MW.
  - ✓ The rise in January was associated with unintended high regulation offers caused by a lack of participant familiarity with the new regulation mileage structure.
- We continue to routinely investigate hourly increases in output gap, and have found limited instances of competitive concern.

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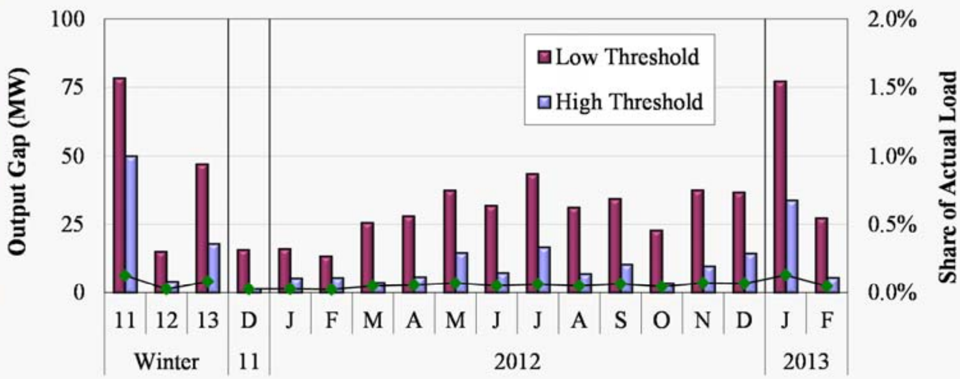
Monthly Output Gap Winter 2011–2013



Low Threshold Results by Unit Status (MW)

Off Line	110	3	5	0	4	4	1	1	9	0	11	0	8	0	2	5	8	2
On Line	61	12	42	16	12	9	24	27	29	32	33	31	26	23	36	32	69	25

High Threshold Results by Unit Status (MW)

Off Line	67	3	4	0	4	4	1	1	9	0	9	0	5	0	1	4	7	1
On Line	40	1	14	1	2	1	2	4	6	7	7	7	5	3	9	11	27	4

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Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which energy and RSG mitigation was imposed in the real-time market.
  - ✓ 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.
- Since most resources continue to be offered competitively, mitigation is infrequent.
  - ✓ We continue to evaluate each imposition of AMP mitigation and found mitigation to be appropriately applied each instance.
- Energy mitigation occurred for 27 hours and 670 MW, up from a single interval and 75 MW last winter.
  - ✓ The large majority of mitigation hours occurred on February 14, when a unit in the Minnesota NCA that offered the last 10 MW of its output range well above its conduct threshold was mitigated repeatedly.
  - ✓ Nearly two-thirds of mitigation quantities, however, occurred in BCAs.
- RSG mitigation quantities declined slightly from last winter to $122,000.
  - ✓ There were an additional five day-ahead mitigations under the tighter VLR threshold.
- Although mitigation is infrequent, considerable market power continues to persist and market power mitigation measures remain critical.

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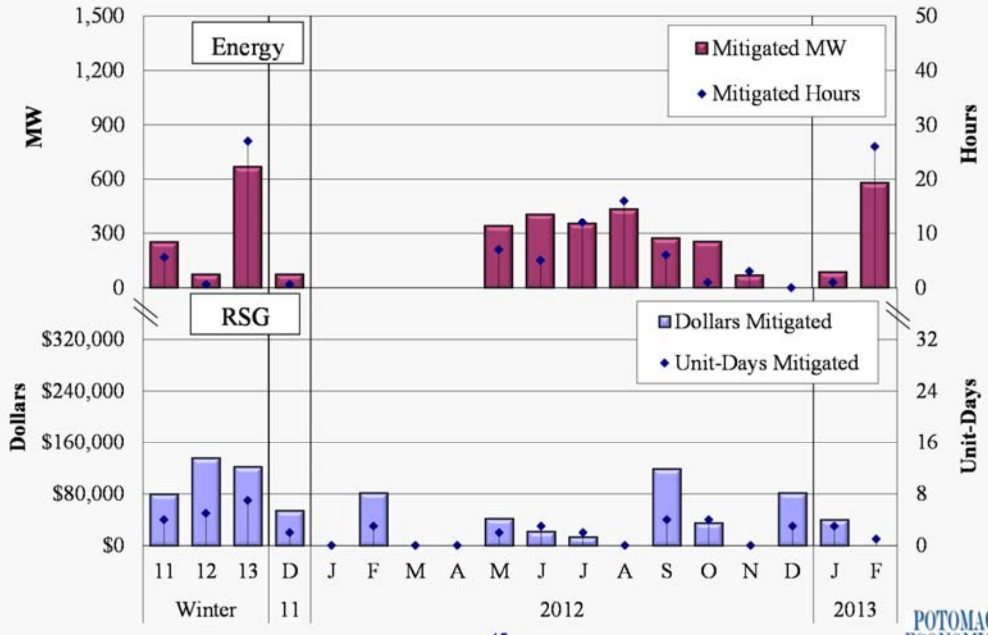
Real-Time Market Power Mitigation
Winter 2011–2013



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Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities (LSEs) to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The following figure shows the monthly capacity requirements, designated capacity, and VCA clearing price since January 2012.
- The monthly auction this winter cleared at $0.09 to $0.19 per MW-month, which is very low and reflects a sizable capacity surplus in MISO.
  - ✓ The surplus exceeded the VCA requirement, which is based on a participant-forecasted load, by at least 30 percent in each month.
  - ✓ Barriers to trading capacity with PJM and the current vertical demand curve continue to contribute to inefficiently low capacity prices, particularly in summer months.
- The capacity cleared in the VCA each month remains a very small portion of the total designated capacity (approximately 1 percent). This reflects the fact that most LSEs satisfy their needs primarily through owned capacity or bilateral purchases.
  - ✓ Monthly capacity designations by LSEs exceeded the requirement by 2 to 6 percent.
- In mid-March we participated in a mock Planning Resource Auction, which will replace the VCA in the April clearing for the upcoming Planning Year that begins in June.
  - ✓ The new auction will improve long-term economic signals by incorporating a zonal component to clearing prices.

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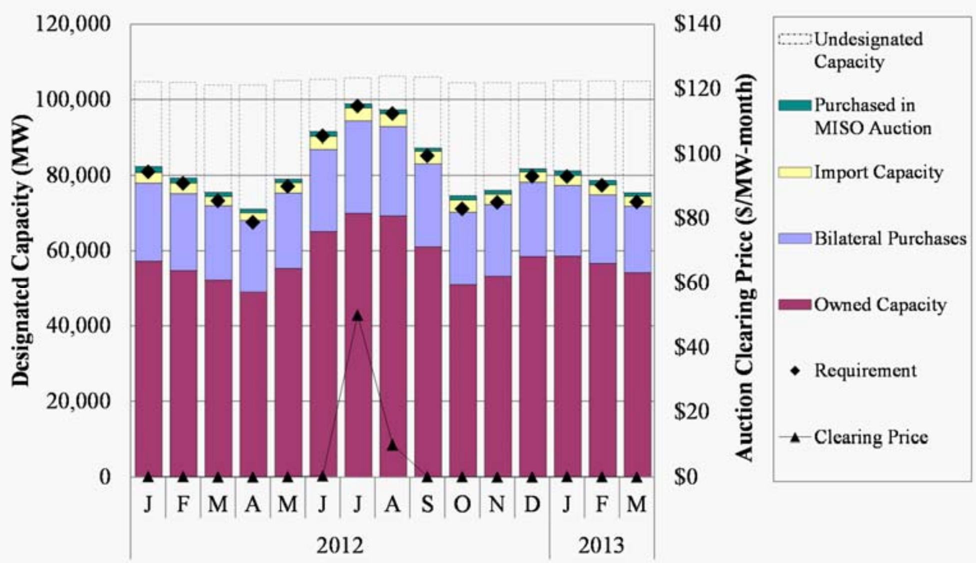
Voluntary Capacity Auction
January 2012–March 2013



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

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Submittals to External Entities and Other Issues

Submittals to External Entities:

- We continue to meet with FERC regarding market outcomes and prior referrals.
  - ✓ We continue discuss concerns regarding resources failing to update real-time offers with MISO and FERC.
- We continue to respond to inquiries and data requests, and to submit reports to FERC on virtual trading activity and on compliance with Module E must-offer requirements.
- We hosted 2 workshops/meetings with two offices within FERC to present our market monitoring software and screens and we participated in FERC Conference.
- We met with OMS to address market trends and questions.
- We made a recommendation to MISO for sanction of uneconomic production.

Other Issues:

- We responded to written and additional verbal questions from MISO stakeholders on a follow-up meeting on the $7 million market-to-market resettlement.
  - ✓ Our written response included a detailed legal review of the authority cited by MISO.
  - ✓ We also met with MISO, PJM, and the PJM IMM on the JOA re-settlement issue.
- We submitted a referral to FERC enforcement as we have concluded that this re-settlement does not comply with the MISO tariff.
- Participated in the mock Planning Resource Auction to replace the VCA.

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List of Acronyms

AMP	Automatic Mitigation Procedures
BCA	Broad Constrained Area
CDD	Cooling Degree Days
CMC	Constraint Management Charge
DAMAP	Day-Ahead Margin Assurance Payment
DDC	Day-Ahead Deviation & Headroom Charge
DIR	Dispatchable Intermittent Resource
HDD	Heating Degree Days
JCM	Joint and Common Market Initiative
LAC	Look-Ahead Commitment
LSE	Load-Serving Entities
M2M	Market-to-Market
NCA	Narrow Constrained Area
PVMWP	Price Volatility Make Whole Payment
RSG	Revenue Sufficiency Guarantee
RTORSGP	Real-Time Offer Revenue Sufficiency Guarantee Payment
VCA	Voluntary Capacity Auction
VLR	Voltage and Local Reliability
WUMS	Wisconsin Upper Michigan System

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