IMM Quarterly Report: Summer 2012
June–August

MISO Independent Market Monitor

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Potomac Economics

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Quarterly Summary

		Value	Change[1] Prior Qtr.	Change[1] Prior Year
RT Energy Prices ($/MWh)	🔵	$33.82	*34%*	*-13%*
Fuel Prices ($/MMBtu)				
Natural Gas	🟢	$2.79	*24%*	*-37%*
Western Coal	🟢	$0.48	*0%*	*-40%*
Eastern Coal	🟢	$1.91	*-6%*	*-6%*
Load (MW)[2]				
Average Load	🟢	65.7	*24%*	*2%*
Peak Load	🟢	98.6	*37%*	*0%*
% Scheduled DA (Peak Hour)	🟢	100.2%	100.6%	100.2%
Transmission Congestion ($M)				
Real-Time Congestion Value[4]	🟢	$378.3	*8%*	*26%*
Day-Ahead Congestion Revenue	🟢	$294.5	*48%*	*110%*
Balancing Congestion[5]	🟢	$8.8	$30.1	$8.8
FTR Funding Shortfall	🟢	$8.8	-$17.9	-$4.1
Ancillary Service Prices ($/MWh)				
Regulation	🟢	$10.68	*29%*	*-12%*
Spinning Reserves	🟢	$4.96	*112%*	*26%*
Supplemental Reserves	🟢	$3.83	*438%*	*37%*
Wind Output (MW)	🟢	2,477	*-40%*	*30%*

		Value	Change[1] Prior Qtr.	Change[1] Prior Year
Guarantee Payments ($M)				
Real-Time RSG	🟢	$23.4	*132%*	*-41%*
Day-Ahead RSG	🟢	$5.0	*6%*	*-43%*
Day-Ahead Marginal Assurance	🟢	$15.6	*9%*	*56%*
RT Operating Rev. Sufficiency	🟢	$3.8	*-11%*	*24%*
Interval SMP Price Volatility (%)	🔵	22.0%	18.0%	23.2%
Price Convergence[3]				
Market-wide DA Premium (%)	🟢	1.4	-0.4	0.1
Locational (Max, %)	🟢	5.1	-0.1	5.0
Virtual Trading				
Cleared Quantity (MW)	🟢	7,256	*-4%*	*-2%*
% Price Insensitive	🟢	34.7%	23.2%	47.0%
% Screened for Review	🟢	3.6%	2.7%	3.5%
Profitability ($/MW)	🟢	0.46	0.49	-0.20
Dispatch of Peaking Units (MW/h)	🟢	1,767	*311%*	*70%*
Generator Outage Rate	🔵	10.4%	21.4%	8.3%
Output Gap (MW/Hour)	🟢	36	*19%*	*-29%*
Max Cap. Market Price ($/MW-Mo.)	🟢	$50.00	$ 0.15	$ 0.40
Other: Market performance under stress: pricing and procedures.	🔴			

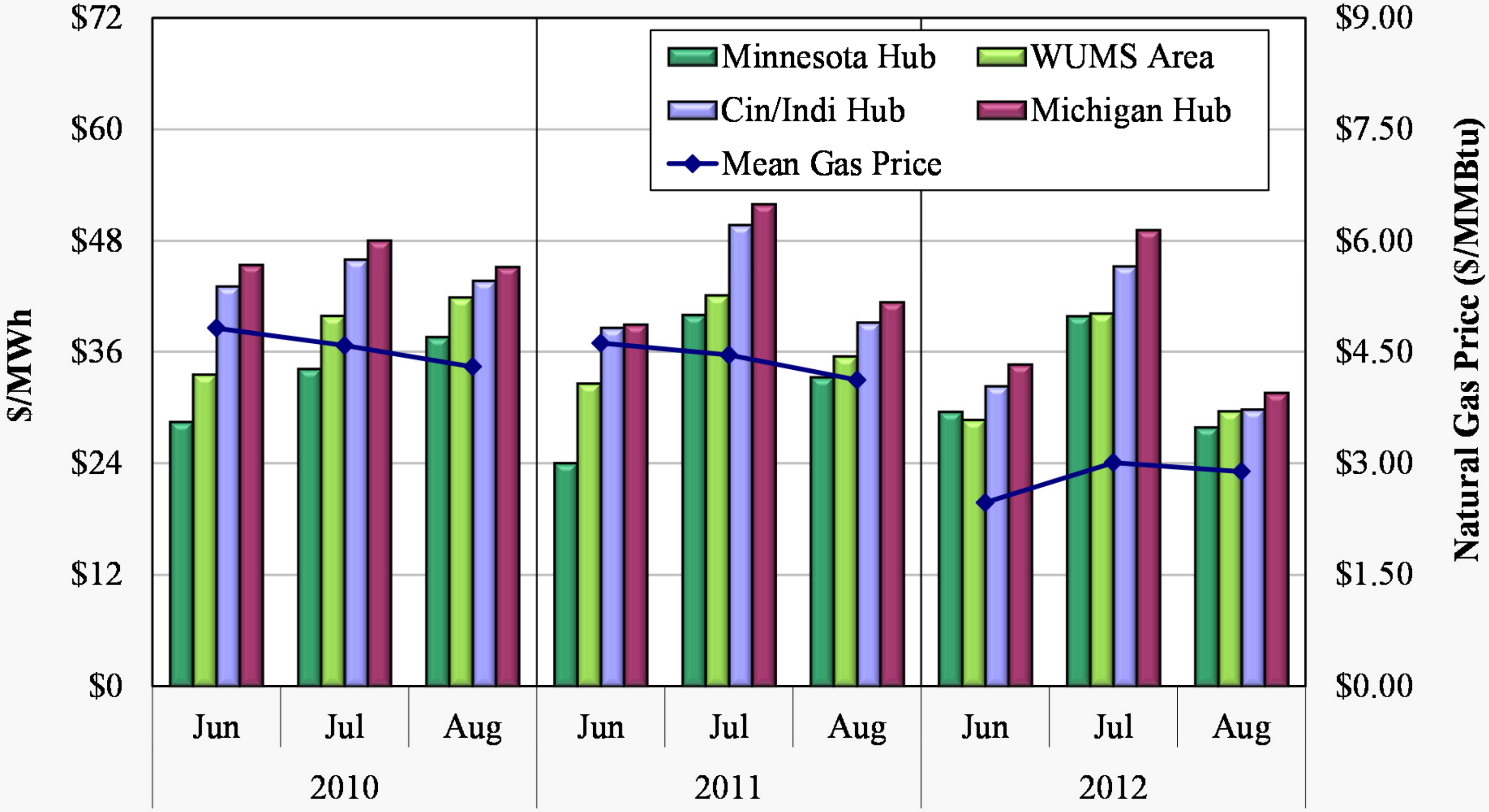
Key:
- 🟢 Expected
- 🔵 Monitor/Discuss
- 🔴 Concern

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 congestion value equals the value of each MISO constraint times the flow over the constraint. A large share of this flow is not settled with MISO because its caused by others.
5. RT shortfalls (contribute to neg. ECF), net of RT surpluses. No M2M settlement offset.

Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations hubs for June to August of 2010 to 2012.
  - ✓ We include 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.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices this summer averaged $35.20 per MWh, a 13 percent decline from the prior summer.
  - ✓ Natural gas prices again averaged below $3 per MMBtu and were 37 percent lower than last summer. Western coal prices declined comparably.
  - ✓ Unusually hot weather, including a two-week long heat wave in July, resulted in a 2 percent rise in average summer load to 65.7 GW (membership-adjusted).
    - – We examine MISO's handling of peak load days in greater detail later in this presentation.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ Prices remained highest at the Michigan Hub ($39 per MWh), more than $6 higher than prices at Minnesota Hub.
  - ✓ Day-ahead wind scheduling, which affects west-to-east power flows, rose 19 percent from last summer to 2.1 GW.

Day-Ahead Average Monthly Hub Prices Summer 2010–2012



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

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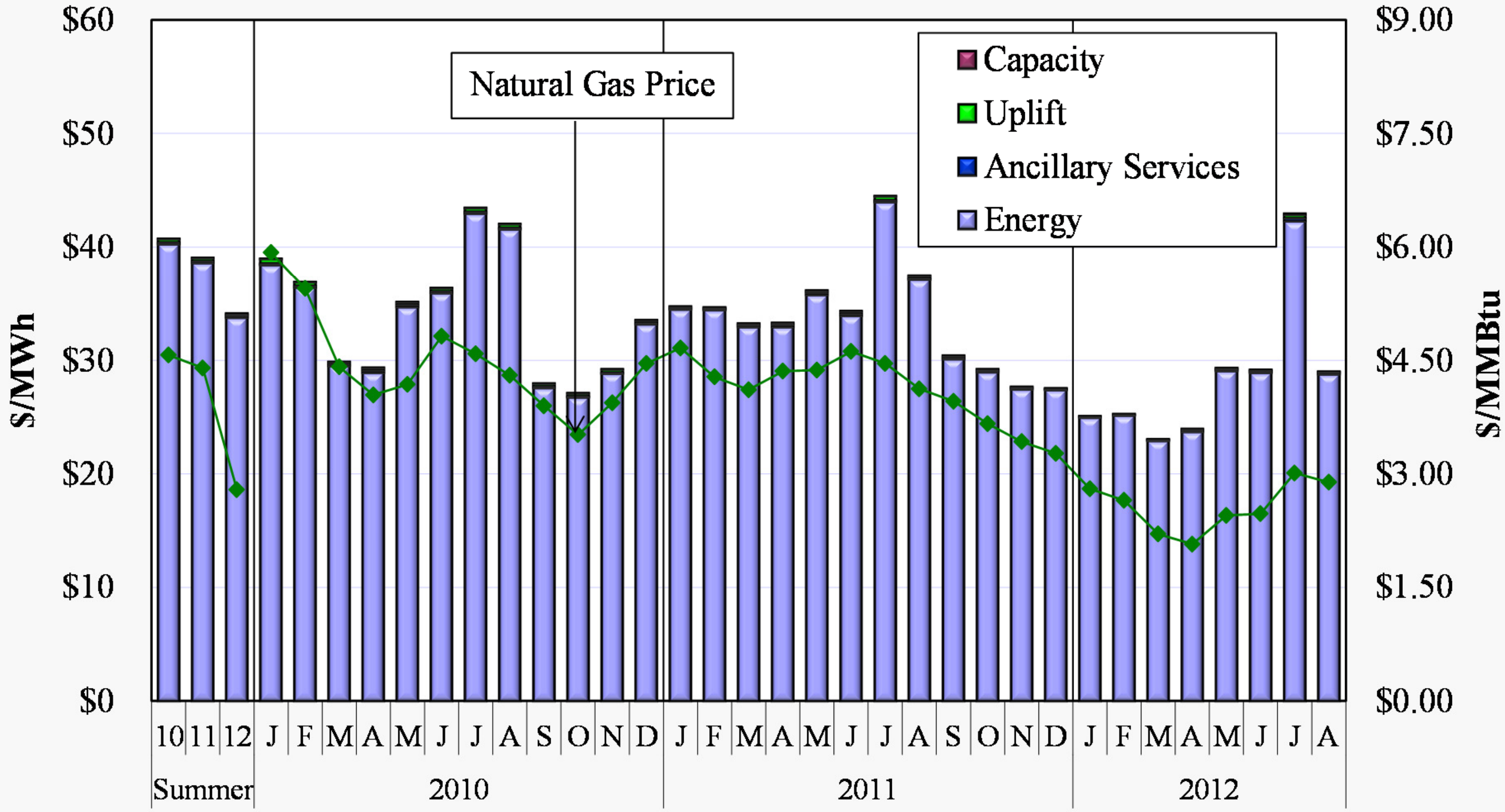
All-In Price

- 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 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 declined 13 percent from last summer to $34.14 per MWh.
  - ✓ The energy component accounted for virtually all of the decrease, which was due to considerable declines in fuel prices (natural gas fell 37 percent, western coal fell 40 percent, and other fuel prices fell 4 to 6 percent).
  - ✓ Energy prices fell less than fuel prices did because they were partially offset by the price effects of shortages that occurred in July during periods of unusually hot weather.
- Energy costs continue to make up nearly the entire all-in price (99 percent).
  - ✓ Ancillary services contributed 18 cents to the all-in price, up slightly from last summer.
  - ✓ The Voluntary Capacity Auction rose modestly in July to clear at $50 per MW-mo., but capacity payments added just 4 cents to the all-in price.
    - – The very low capacity prices in MISO are due to the capacity surplus in MISO and market design issues identified in our *2011 State of the Market* report.

All-In Price
2010–2012



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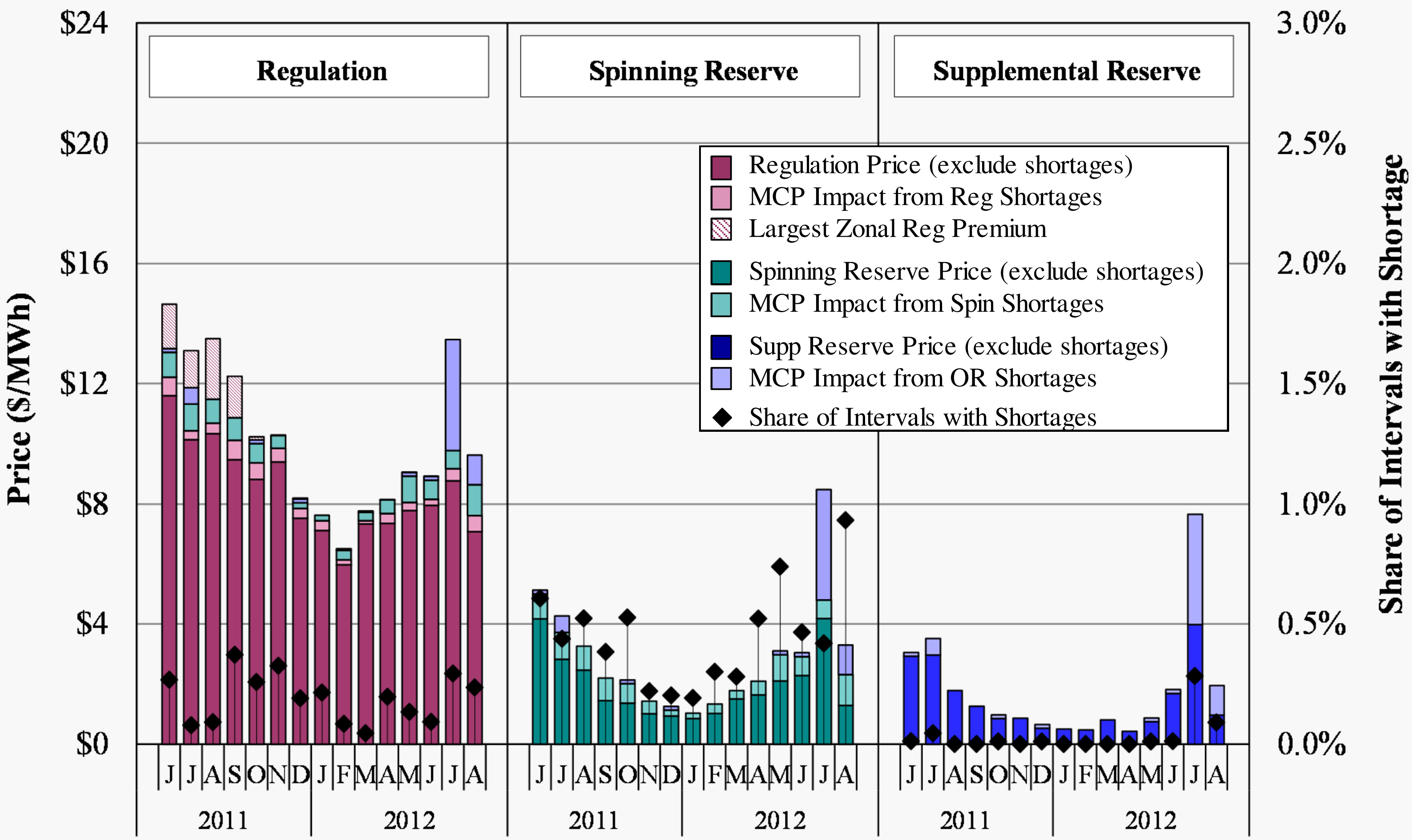
Monthly Average Ancillary Services Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO’s ancillary service products for the last 15 months.
  - ✓ We show separately the portion of each product’s price that is due to shortages of each product (shortages for lower quality products are reflected in higher quality products because they can be substituted).
- AS prices were significantly affected by 34 intervals of operating reserve shortages this summer, which result in ancillary services prices above $1,100 per MWh.
  - ✓ There were only five such shortages in each of the prior two summers.
  - ✓ The operating reserve shortages were the primary cause of the increase in the prices for spinning reserves and regulation.
  - ✓ Such shortages added roughly $1.60 to the average price for each product.
- Despite the shortages, regulation prices fell 12 percent from last year to $10.68 per MW as lower energy prices reduced the opportunity costs of providing regulation.
- Spinning reserve prices increased 26 percent to $4.96 per MWh, while supplemental reserve prices rose 37 percent to $3.83.
  - ✓ On some high load days, MISO met its contingency reserve requirements by committing offline units and holding more spinning reserves than required.

Monthly Average Ancillary Service Prices
Regulation and Contingency Reserves, 2011–2012



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MISO Fuel Prices

Natural Gas and Oil Prices

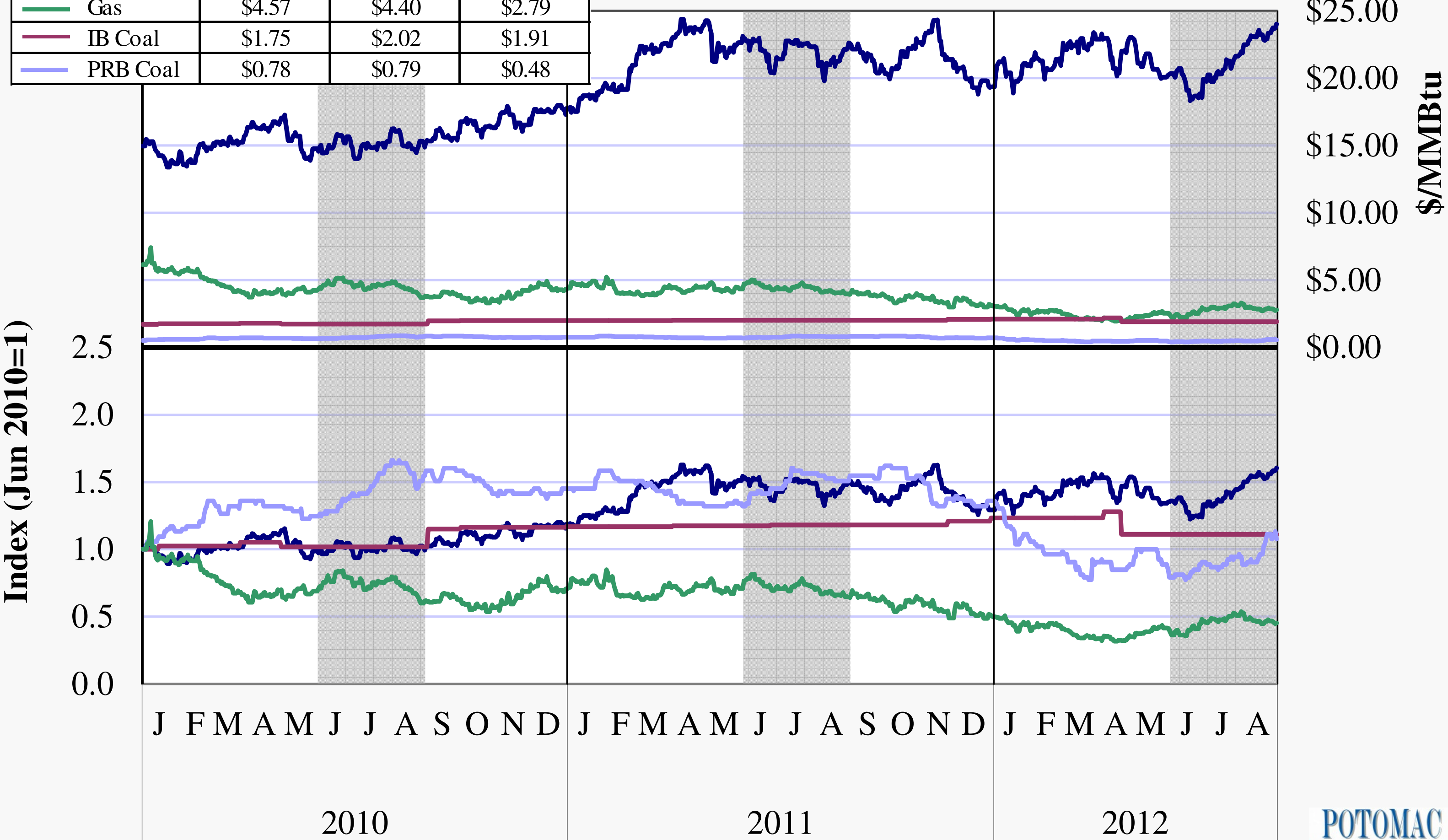
- Natural gas prices averaged $2.79 per MMBtu in the quarter, 37 percent lower than last summer. However, they have risen by 24 percent from this spring.
- Sustained low prices for natural gas have altered dispatch patterns in MISO, as some gas resources are now competitive with some of the base-load coal resources.
  - ✓ This summer the share of MISO's output produced by gas resources nearly doubled to 14 percent, while the share for coal resources declined from 74 to 66 percent (see subsequent slide).
- Oil prices declined 4 percent from last summer to $21.12 per MMBtu.
  - ✓ Oil was not frequently the marginal fuel this summer, so high oil prices had little impact on energy prices.

Coal Prices

- Illinois Basin prices declined 6 percent from last summer to $1.91 per MMBtu.
- Average Powder River Basin (western coal) prices averaged $0.48 per MMBtu, down 40 percent from last summer and unchanged from the spring.
  - ✓ This decrease allowed many of the coal resources burning PRB coal to retain a significant cost advantage over resources firing Illinois Basin coal or natural gas.

MISO Fuel Prices
2010–2012

Summer Average	2010	2011	2012
Oil	$15.08	$21.93	$21.12
Gas	$4.57	$4.40	$2.79
IB Coal	$1.75	$2.02	$1.91
PRB Coal	$0.78	$0.79	$0.48



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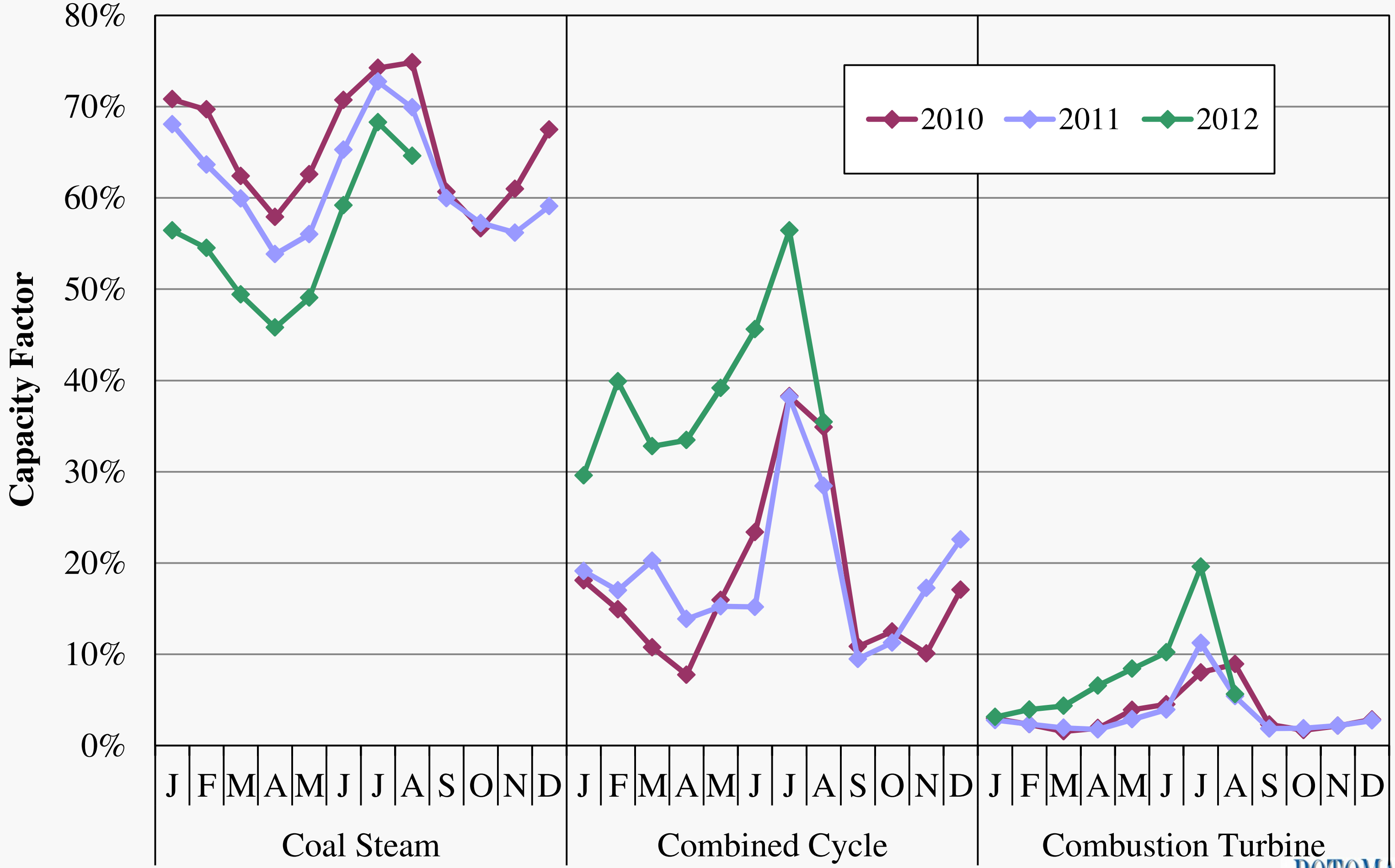
MISO Unit Type Capacity Factors

- The significant decline in natural gas prices in 2012 has resulted in notable changes in generation patterns compared to recent years.
  - ✓ At prevailing gas prices, combined-cycle resources are now competitive with a substantial share of MISO's coal resources (particularly those burning IB coal).
    - – A number gas-fired peaking units were routinely scheduled day-ahead for economics during peak hours this quarter (see slide 42).
  - ✓ A new combined cycle at a gas price of $2.79 per MMBtu (the summer 2012 average) would have incremental energy costs of less than $25 per MWh.
- The following chart shows the capacity factors of different types of resources.
  - ✓ In summer 2012, the average capacity factor for combined-cycle resources increased from 27 percent last summer to 46 percent.
  - ✓ Combustion turbine capacity factors similarly increased from 7 to 12 percent.
  - ✓ Coal-fired resource capacity factors declined from 69 to 64 percent.
    - – This is in part due to higher planned outage rates for environmental upgrades.
    - – The recent ruling on CSAPR ruling may affect the recent trends of outages and Attachment Y submissions.

MISO Unit Type Capacity Factors 2010–2012



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Changes in Load and Weather Patterns

- The next figure shows changes in load in summer 2010 to 2012, as well as the changes in weather patterns that contributed to the load 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 summer monthly heating and cooling degree days (“HDDs and CDDs”) at four locations in MISO since 2010.
- The figure shows that total degree days increased 9 percent from summer 2011.
  - ✓ Near-record temperatures throughout the footprint, particularly in late June and July, produced total degree days 50 percent above the historical average.
- These weather factors significantly affected the monthly average and peak loads during each period shown in the top panel of the figure.
  - ✓ Excluding membership changes (e.g. the departure of FirstEnergy and portions of Duke Energy), average load rose nearly 2 percent from last summer.

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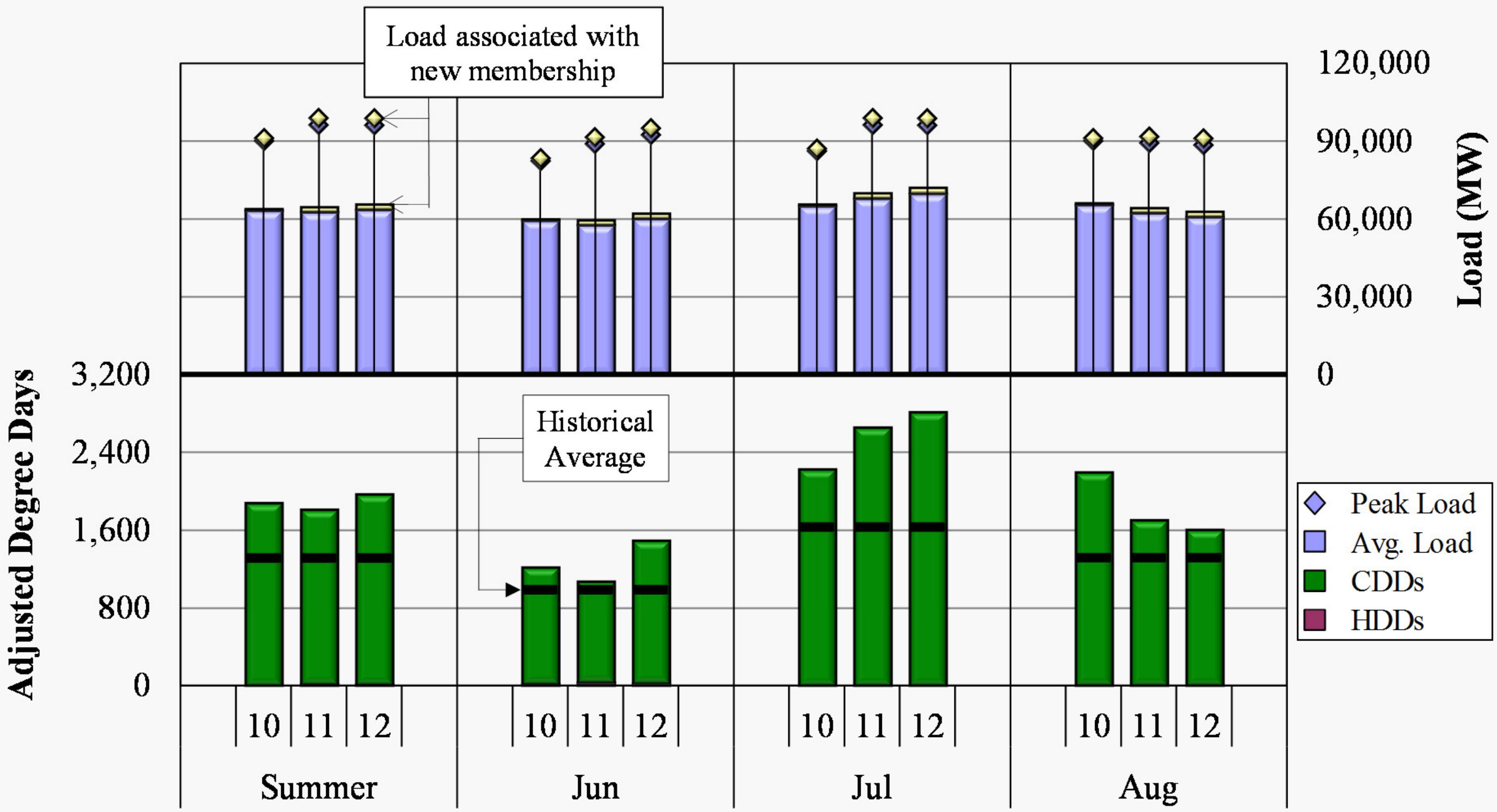
Load and Weather Patterns Summer 2010–2012



Note: Calculations are the average monthly degree days of four representative cities in MISO: Cincinnati, Detroit, Milwaukee and Minneapolis. FirstEnergy and Duke Ohio is removed from the load levels.

Evaluation of Peak Days: Summer 2012

- The next 15 slides review the performance of the MISO market during days with very hot weather that occurred in the region in late June and in July.
  - ✓ In late June and extending through the first week of July, MISO experienced record temperatures.
  - ✓ Two subsequent, shorter heat waves later in July both produced record load.
  - ✓ As shown on the following slide, most of the major MISO load centers repeatedly experienced triple-digit temperatures.
- MISO set new market peak loads on July 4 (96.7 GW), July 17 (97.7 GW) and July 23 (98.6 GW).
  - ✓ MISO's reserve margin was often reduced during the peak load periods due to several long term forced outages and low wind generation levels.
- MISO LSEs invoked voluntary load curtailments on most of the peak load days.
  - ✓ Curtailments peaked at 514 MW on July 17. There were no involuntary curtailments.
  - ✓ MISO does not call for these curtailments, nor do they include them in their reliability commitment process.

Evaluation of Peak Days: July 2012

- The table below shows the high temperatures on notable days in June and July compared to the historical average.
  - ✓ MISO issued a MaxGen Alert on June 28, 29 and July 2 (yellow), a MaxGen Warning on July 5 and 6 (orange), and a MaxGen Event on July 17 (red).
  - ✓ MISO set an all-time peak load record on July 23, but did not issue any MaxGen Alerts, Warnings or Events on this day.
  - ✓ We evaluate these days more closely in the subsequent slides.

	Hist.	June				July											x		
	Avg.	27	28	29	30	1	2	3	4	5	6	7	8	15	16	17	23	24	25
Cincinnati	85	89	102	100	102	98	95	95	99	99	102	104	100	89	97	97	95	86	95
Detroit	82	89	98	93	93	93	91	84	100	88	99	96	86	93	91	100	97	86	86
Indianapolis	85	91	104	103	97	95	98	98	102	103	105	105	96	95	98	101	102	97	103
Milwaukee	80	93	96	86	92	84	87	97	102	103	94	86	81	88	98	100	99	86	96
St. Louis	89	99	108	106	105	102	100	101	105	105	106	107	98	96	98	103	106	107	108
Minneapolis	79	91	87	89	89	93	98	93	98	91	99	84	87	90	98	94	96	82	92

x MISO set an all-time peak load of 98,556 MW.

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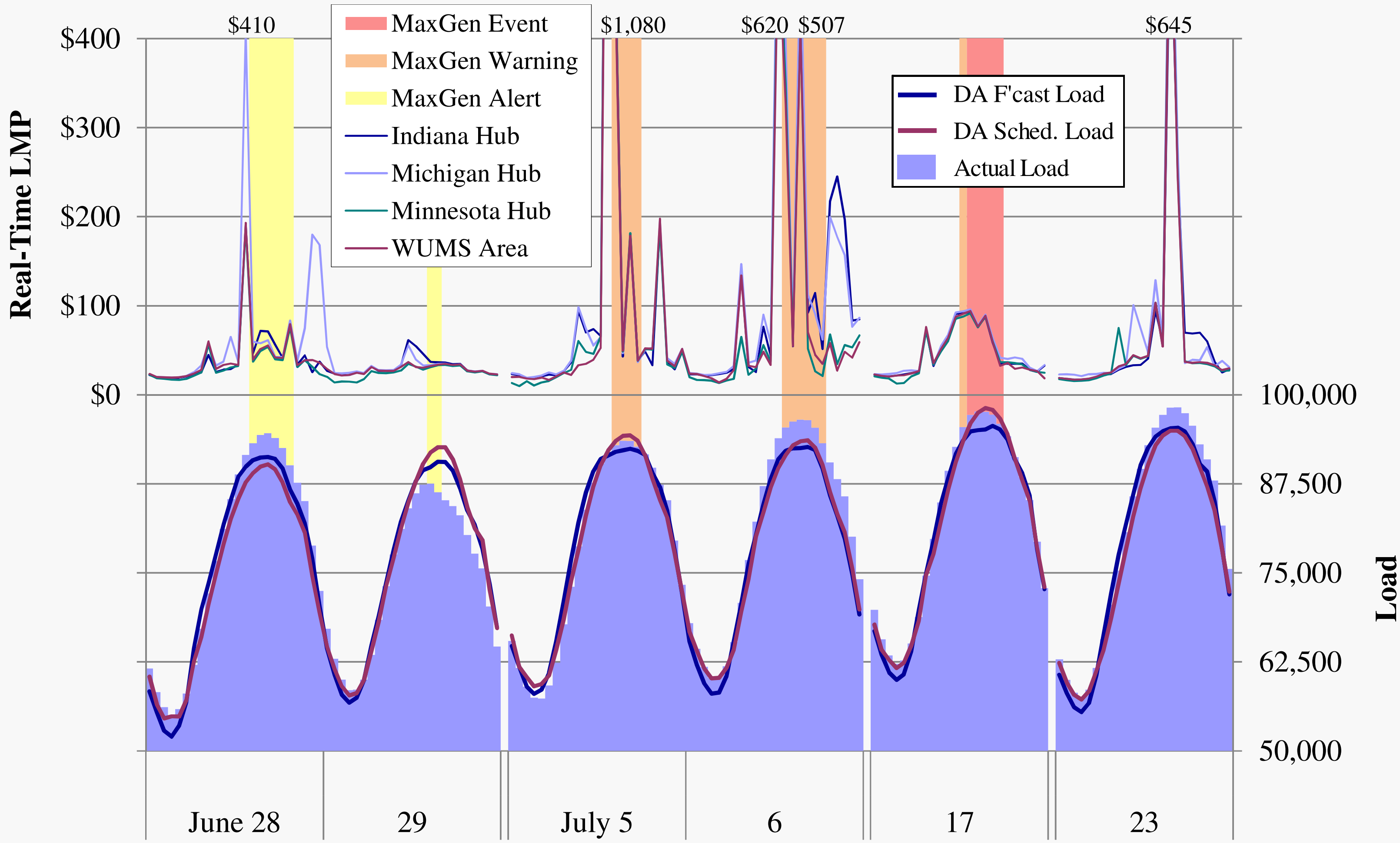
Load Scheduling and Real-Time Energy Prices Summer 2012

- The following chart shows a summary of real-time hub prices during six notable days in summer, as well as the DA forecasted load, DA scheduled load, and real-time load.
- The chart also shows, in shading, the periods when MISO declared Maximum Generation Alerts, Warnings, or Events.
  - ✓ MISO declared Conservative Operations and Hot Weather Alerts on each of these days.
- The chart shows that prices were impacted by the day-ahead market and RAC.
  - ✓ Load was significantly under-scheduled in the day-ahead on four of the six peak days, three of which were likely due to the actual load significantly exceeding the forecast.
  - ✓ Load was substantially over-scheduled on June 29 because thunderstorms reduced load unexpectedly.
- This chart only shows some of the factors that determined real-time prices. Other factors that impact price include:
  - ✓ Real-time generator forced outages/derates and transmission derates;
  - ✓ Changes in real-time wind generation and net imports; and
  - ✓ Operator actions (e.g., real-time commitments or load offsets).
- In the subsequent charts we show details of several price spike events that occurred during four peak July days that show the impacts of these factors.

DA Load Scheduling and RT Energy Prices Summer 2012



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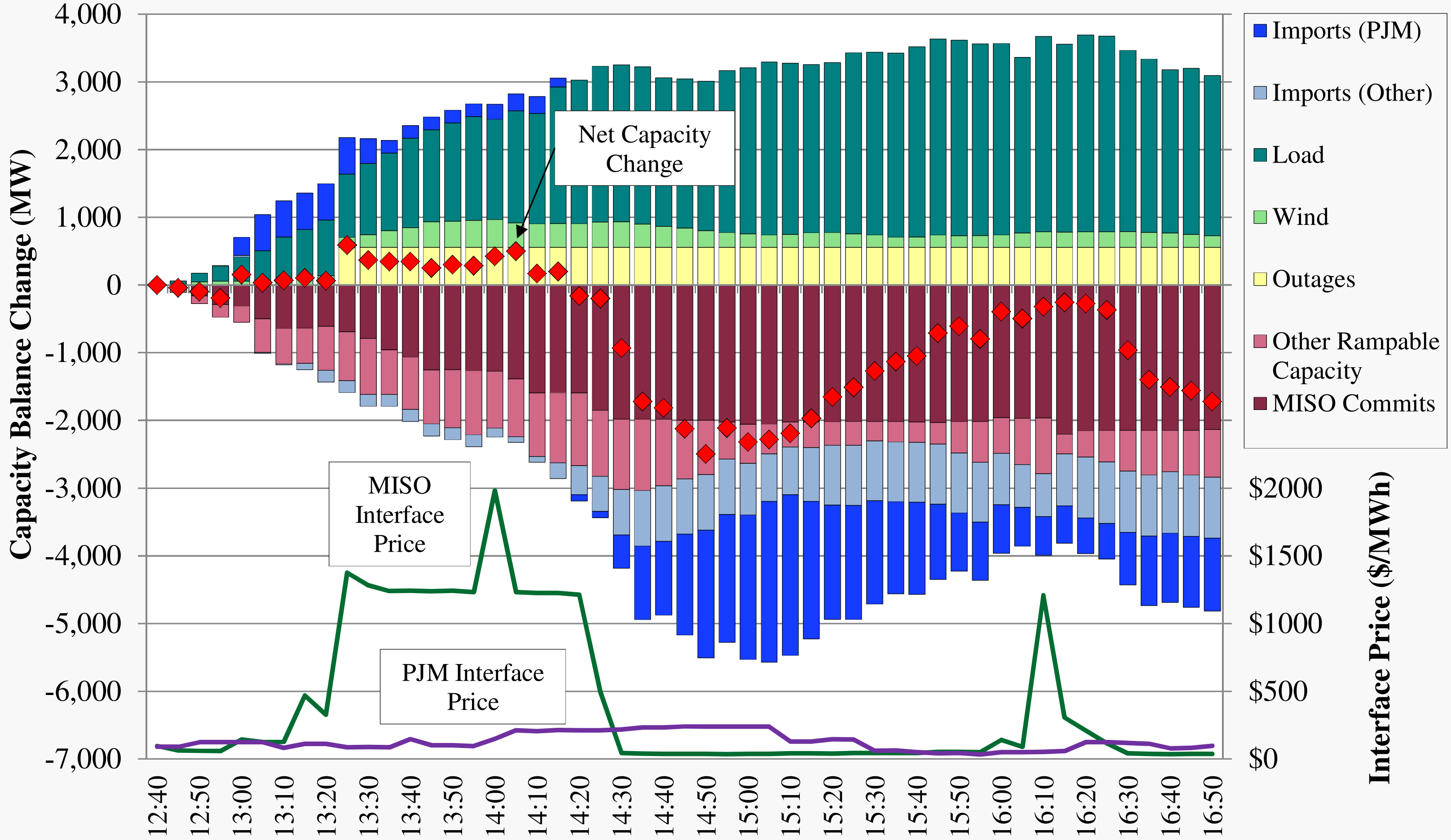
Real-Time Factors Impacting Energy Prices

- The next four charts show the real-time factors that directly impact capacity levels and energy prices on the afternoons of July 5, 6, 17 and 23.
  - ✓ "Harmful" factors that contribute to higher prices are shown as positive MW (e.g., load, outages, falling net imports) and "helpful" factors that reduce prices are shown as negative MW (e.g., increased supply, net imports, etc.).
  - ✓ The charts show the cumulative impact of supply and demand factors that affect the net capacity balance in each interval relative to start of the period shown.
- The factors shown in the charts include the changes in:
  - ✓ Real-time market load (including the application of any operator offset);
  - ✓ Real-time Net Scheduled Interchange (changes in net imports);
  - ✓ Changes in real-time wind output;
  - ✓ MISO commitments (for capacity or congestion);
  - ✓ Significant outages (real-time forced unit outages greater than 60 MW); and
  - ✓ Other Supply (e.g., additional ramping capability from resources dispatched up in the prior interval, increased output from non-dispatchable resources, or self-commitments).

Events on July 5
12:40–16:50

- The market was short of reserves twice during the peak hours on July 5, which led to transitory price spikes.
- 12:40–13:25: Net demand (net of supply changes) rose roughly 600 MW, leading to an operating reserve shortage.
  - ✓ Load was rising rapidly over the period, increasing by a total of 1100 MW.
  - ✓ A forced outage of a 558-MW unit occurred at 13:12 (reflected in the 13:25 interval).
  - ✓ Imports from PJM fell by more than 500 MW (as prices in PJM rose to over $120 per MWh) and wind declined by 200 MW in this period, both contributing to the shortage.
  - ✓ The net demands were not fully offset—MISO committed roughly 750 MW by this time and other supply rose 800 MW as output rose on ramp-constrained units.
- 13:30–14:25: MISO was in an operating reserve shortage.
  - ✓ MISO committed an additional 1,100 MW and other supply rose by another 200 MW, but load increases by a further 1,300 MW.
  - ✓ Net imports did not begin to respond materially to the price spike until 14:15 because of the 30-minute scheduling window. By 14:25, net imports increased by a cumulative 1 GW and the shortage ended.
- 14:25–16:50: Load continued to rise, but net imports continued to surge by more than 3 GW, producing very low prices. When imports fell, a brief shortage occurred.

July 5
12:40–16:50



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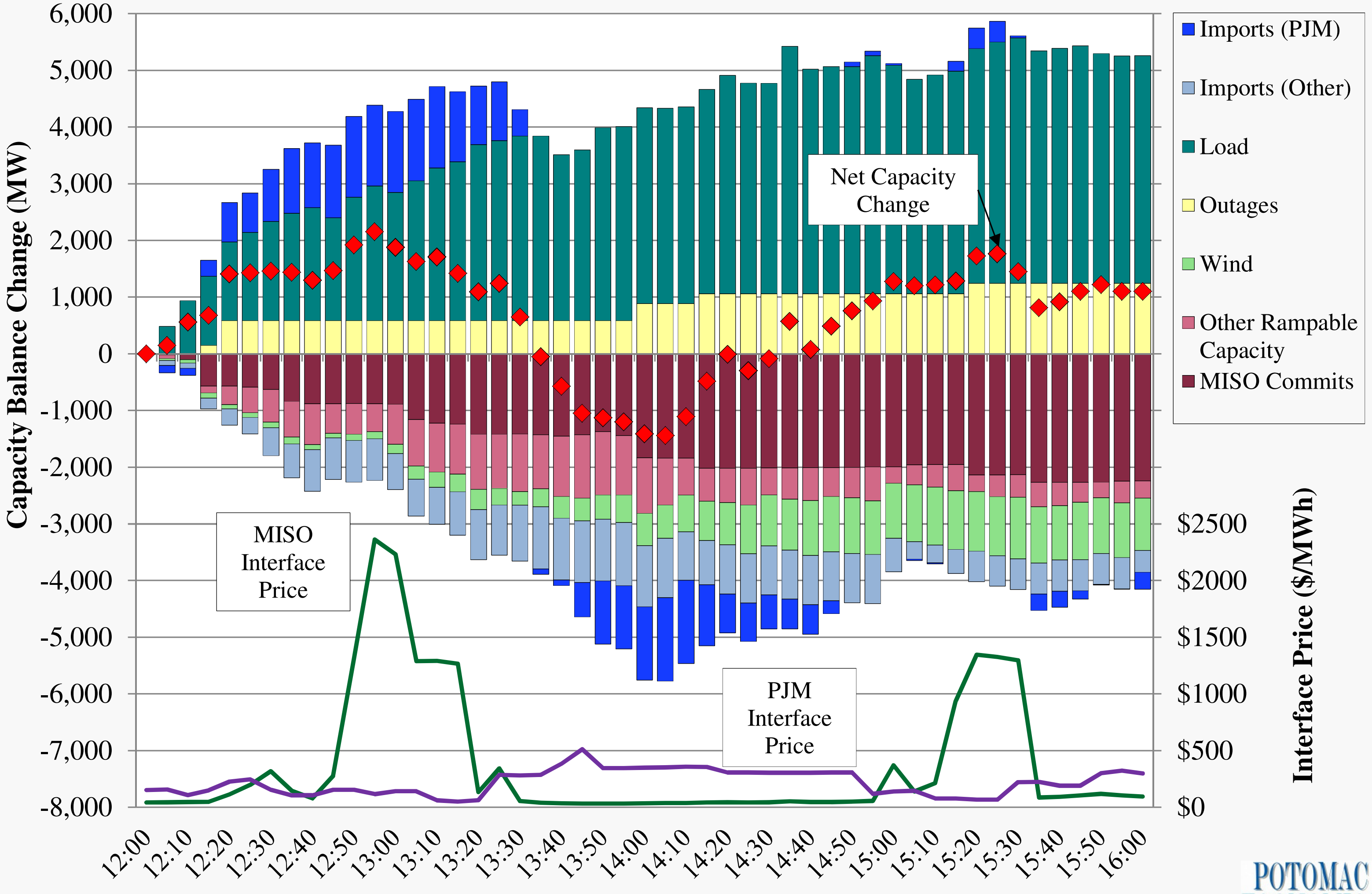
Events on July 6
12:00–16:00

- 12:00–12:50: Net demand increased nearly 1.3 GW due to rapid increases in load and falling net imports from PJM, leading to an operating reserve shortage.
  - ✓ Load increased 1.7 GW during this time period and imports declined by 800 MW.
  - ✓ In addition, a 586-MW unit tripped at 12:15 (and is fully reflected by 12:20).
  - ✓ Net imports from PJM fell by more than 1,500 MW because prices early in the hour were roughly $100 per MWh higher in PJM than in MISO.
  - ✓ MISO committed 1 GW, higher dispatch levels made 670 MW more ramp-constrained capacity available (“other supply”), and wind rose 100 MW. These were not enough to keep up with the rising net demands.
- 12:55–13:20: Reserve shortage produced prices peaking at almost $2,400 per MWh.
  - ✓ Load increased 1 GW during this period, but the shortage ends because:
  - ✓ MISO committed an additional 540 MW; other supply grows by 430 MW as dispatch rises; wind output increased 200 MW; and net imports begin to respond.
- 13:20–15:10: Net imports from PJM surged almost 3.0 GW in total after the shortage has already ended, leading to energy prices averaging $40 per MWh.
  - ✓ Low energy prices resulted in substantial real-time RSG payments to units committed by MISO and caused net imports to drop as load rises by another 1 GW.
- 15:15–15:35: Load increased slowly, but falling net imports and additional outages led to a second shortage and prices peaking over $1,300 per MWh.

July 6
12:00–16:00



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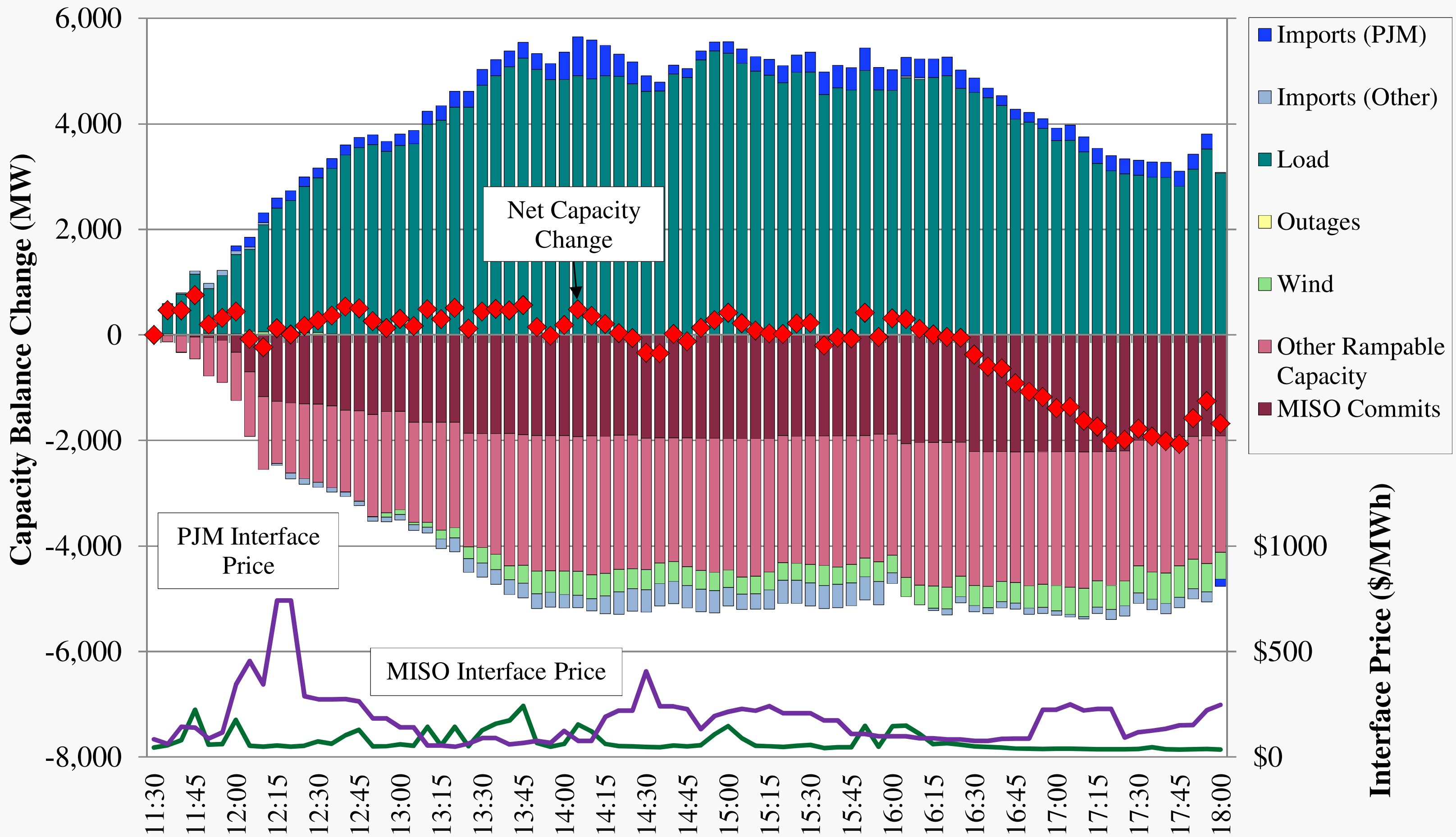
Events on July 17
11:30–18:00

- On July 17, record load was forecast and an operating reserve shortage was expected. MISO declared a Max Gen Event Step 1A from 13:00 to 19:00.
- 10:00–13:00: MISO began preparing for forecasted loads and sharp load increases by committing CTs and shifting operating reserves from offline to online resources.
  - ✓ At 10:00, MISO began committing quick start CTs.
  - ✓ From 11:30 to 13:00, load increased by nearly 4 GW.
  - ✓ When MISO declared the MaxGen Event at 13:00, it had committed more than 800 MW of fast-start CTs, carrying only 300 MW of contingency reserves on offline units.
- 13:00–18:00: MISO declared an emergency and committed all available resources.
  - ✓ At 13:07, MISO declared a Max Gen Event Step 1A, curtailing 200 MW of exports.
  - ✓ By 14:00, voluntary load curtailments of 400 MW had occurred.
  - ✓ By 16:30, MISO completed the commitment of all available resources and is meeting operating reserve requirements entirely with spinning reserves. No DR was called.
  - ✓ As load fell and wind output rose in the late afternoon, decommitments occurred slowly.
- Many of the commitments made under MISO's Max Gen Event procedures were not needed to address the forecasted shortage, which resulted in low energy prices
  - ✓ The low prices prevented net imports from responding to satisfy MISO demands and increased RSG costs to almost $3 million.
- These results point to significant potential improvements in the reliability procedures and market pricing (some of which will be addressed by ELMP).

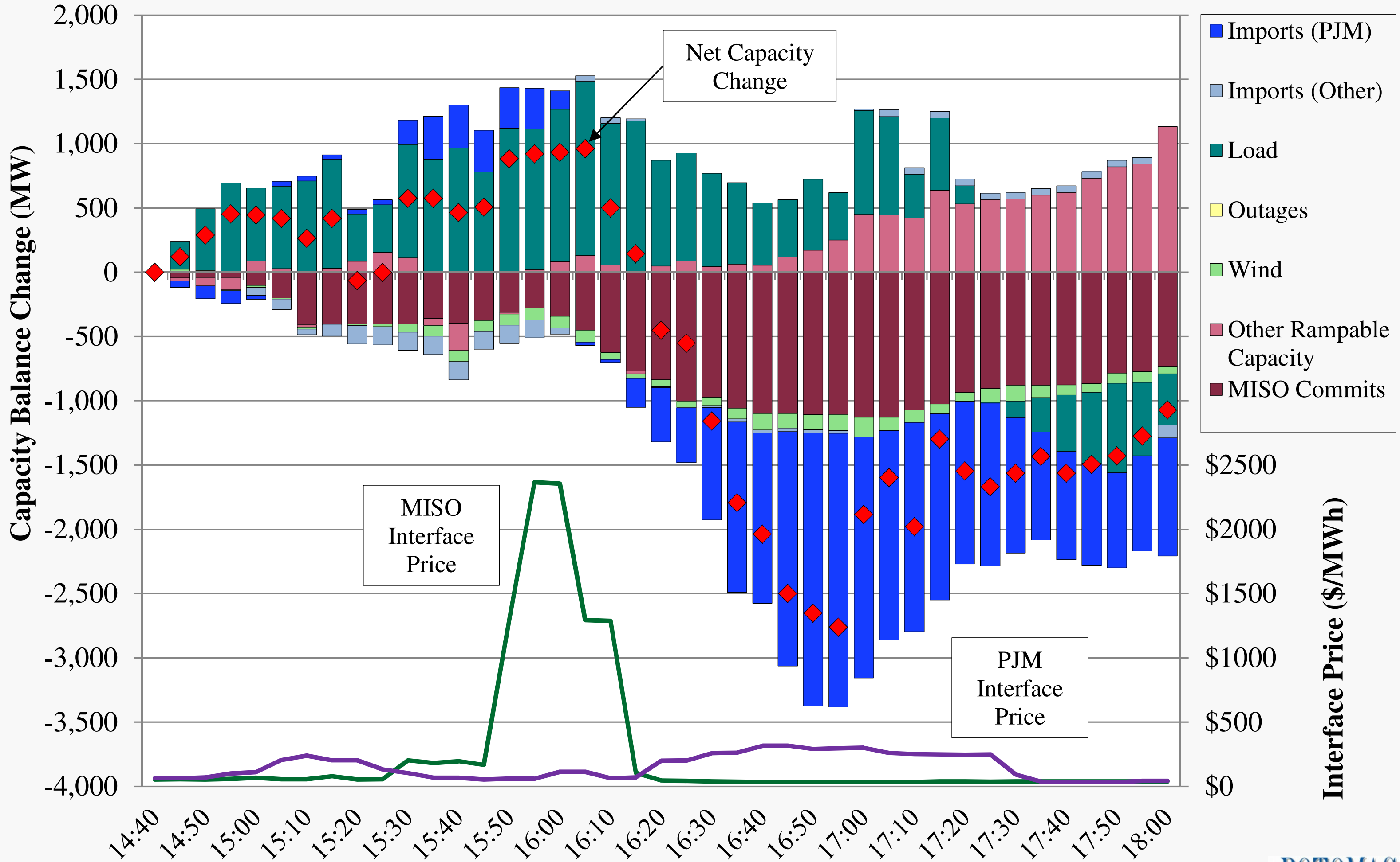
July 17
11:30–18:00



Events on July 23
14:40–18:00

- MISO's all-time peak load of 98.6 GW occurred on July 23 at 13:55 and it contributed to an operating reserve shortage lasting 25 minutes.
- 14:40-15:35: Prices rose from $54 per MWh to $202 because of a net 500 MW increase in demand.
  - ✓ Net imports from PJM fell by almost 400 MW (because prices earlier in the hour were higher in PJM by roughly $200 per MWh) and load grew by 900 MW.
  - ✓ The fluctuation in load was caused by MISO's use of its "load offset" parameter.
- 15:40-16:20: As load continued to rise, MISO had five intervals with an operating reserve shortage, two of which were priced at approximately $2,200 per MWh.
  - ✓ In response, MISO committed nearly 500 MW over six intervals, load began falling, and net imports increased, which contributed to ending the shortage.
- 16:20-17:00: As with prior events in July, net imports from PJM respond sharply -- increasing by more than 3500 MW from the peak of the shortage.
  - ✓ This excess response resulted in low energy prices (less than $45/MWh), higher RSG and the loss of available capacity as MISO ramped down internal resources.

July 23
14:40–18:00



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Peak Week Observations and Conclusions

- Tight conditions test the performance of the market and the RTO, and highlight opportunities for improvement.
  - ✓ Overall, reliability was maintained and the markets accurately signaled the actual shortages that occurred.
  - ✓ However, the markets were not well coordinated with the operating procedures to satisfy the needs of the system as efficiently as possible, resulting in:
    - Excess costs being incurred;
    - Higher RSG; and
    - Increased price volatility associated with shortages that could have been avoided.
- MISO's reliability mandate and associated operating procedures generally require it to take actions to maintain reliability and avoid shortages.
  - ✓ When they are effective, market prices may not reflect the true costs of meeting these needs and lower-cost market responses may be precluded.
  - ✓ The ELMP project will improve MISO's pricing during these conditions and mitigate this issue, particularly if it can be extended to reflect demand response and MISO's reliability actions in its energy prices.
  - ✓ However, some of MISO's operating procedures may also warrant review to determine whether reliability actions are taken in the most efficient order.

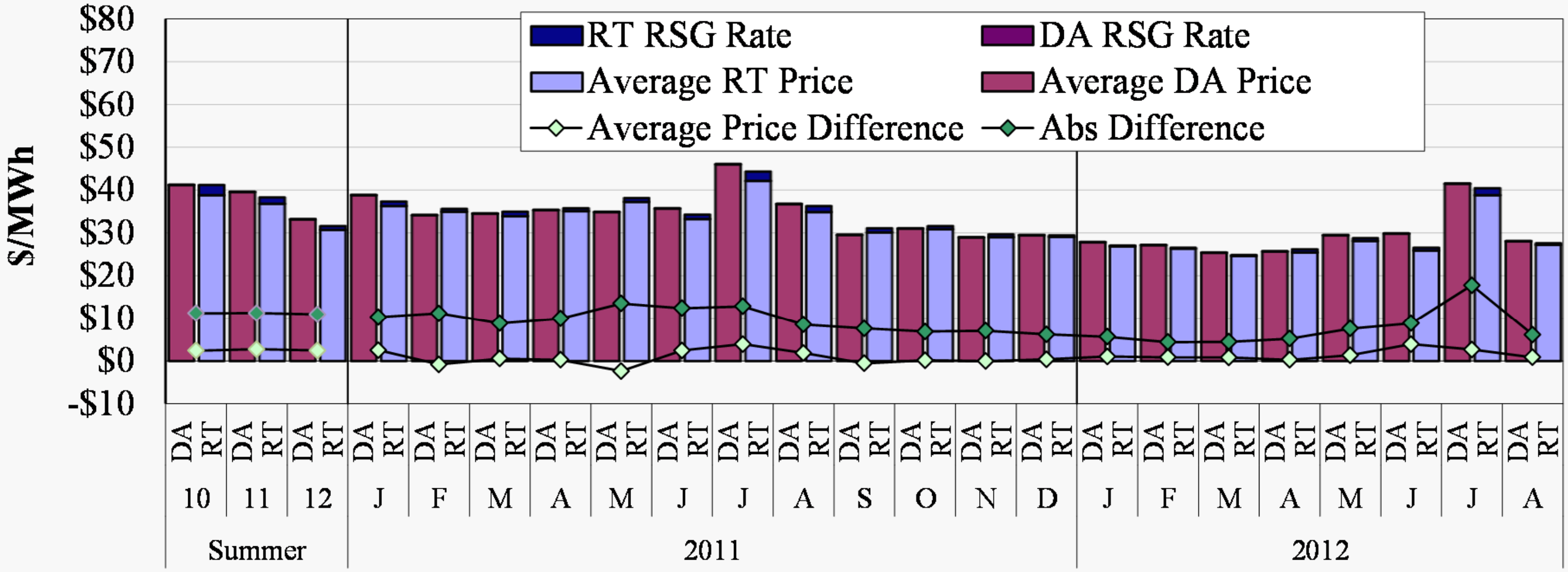
Peak Week Observations and Conclusions (continued)

- On all days except July 17, changes in net imports from PJM was one of the primary causes of the shortages and associated price volatility.
- Under today's market design the interfaces with other areas provide significant reliability to MISO, but cannot be relied upon by MISO operators because:
  - ✓ The response is necessarily lagged (currently 30 minutes or more).
  - ✓ Participants' schedules are not directly coordinated, so net import responses may vastly over or under-shoot the amount necessary to achieve efficient interchange.
- The JCM discussions with PJM include many initiatives, including interchange optimization.
  - ✓ Interchange optimization allows transactions to be struck intra-hour by the RTO's based on the projected inter-market price differences ~20 minutes ahead, which can be much better coordinated with the RTOs' decisions to commit units.
    - – Today, participants' schedules are based on what they saw 30 minutes ago.
  - ✓ Of the initiatives being considered by the RTOs, only interchange optimization would address these two underlying shortcomings of the current market design.
  - ✓ In addition to the improved efficiency and lower costs that better coordination of interchange would achieve, it would also tangibly improve reliability.
  - ✓ We have recommended that this initiative be prioritized above most others.

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.
- The markets converged reasonably well, with modest monthly day-ahead premiums at most locations.
  - ✓ On several days in June and mid-July, anticipated day-ahead congestion in the East region failed to materialize, contributing to most of the sizable premiums there.
  - ✓ Thunderstorms early in the summer at times resulted in lower than expected peak load.
- The persistent day-ahead premium in MISO is partially explained by higher price volatility in the real-time.
  - ✓ There was generally a considerable day-ahead premium during most peak hours on most days, but this was offset by periodic real-time price spikes.
- The day-ahead premiums were consistent with the DDC RSG rate applied to real-time load purchases, which averaged $0.89 per MWh this quarter.
  - ✓ We are recommending improvements that would lower the share of real-time RSG that is allocated under the DDC rate.

Day-Ahead and Real-Time Price Convergence 2010–2012



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

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

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

Cin/Ind Hub	0	3	5	4	-4	-1	-1	-9	4	4	1	-5	-2	-2	0	3	2	2	-2	3	13	3	2
Michigan Hub	0	2	4	3	-7	0	5	-7	0	4	1	-6	0	-6	2	4	2	-2	2	3	5	4	2
Minnesota Hub	-8	-5	-1	-2	-8	-13	-18	1	-13	0	-5	-8	-3	1	10	2	-2	1	-15	-8	-3	-2	1
WUMS Area	0	0	-1	0	-8	-3	-6	2	3	2	-5	-2	7	5	7	2	-1	3	-3	-3	-3	-2	1

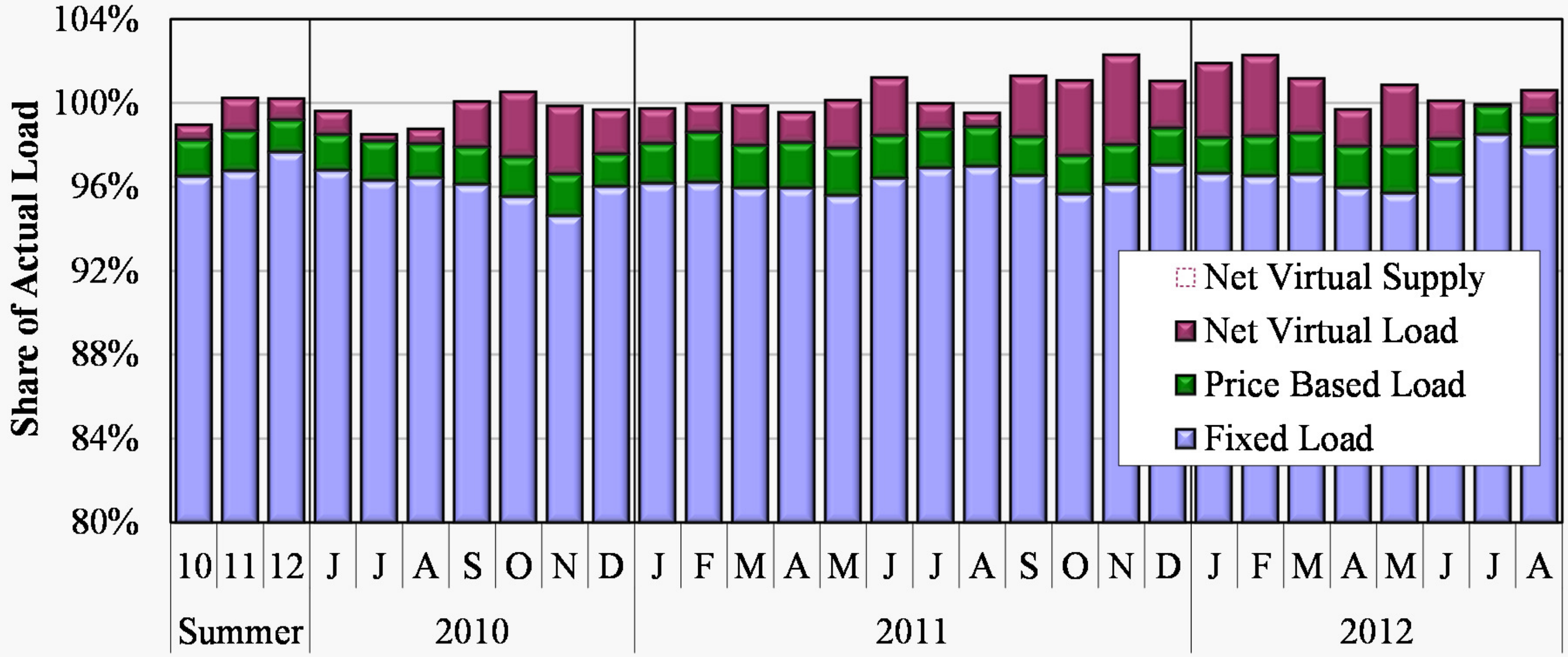
Note: Beginning in April 2011, the RSG rate is specifically the DDC Rate charged to deviations, and excludes CMC rates.

POTOMAC ECONOMICS

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 can compel MISO to commit peaking resources to satisfy higher real-time load.
  - ✓ However, real-time commitments are still made to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- Load this summer was slightly under-scheduled on average during all hours (at 99.8 percent) and slightly overscheduled during the peak daily hour (100.2 percent).
  - ✓ Net virtual load during the peak hour, much of which is offered price-insensitively by LSEs, consistently made up the scheduling shortfall of physical load.
- As we show in monthly reports, this broad metric can mask considerable variation in day-to-day scheduling.
  - ✓ Load was generally under-scheduled during the peak hour on days with peak load greater than 90 GW, particularly in July.
  - ✓ On most other days, load was accurately forecasted and scheduled by participants.

Day-Ahead Peak Hour Load Scheduling 2010–2012



Share of Actual Load(%)

All Hour	99.4	100.6	99.8	99.9	99.2	99.4	99.4	99.8	99.4	100.0	100.3	99.8	99.6	99.3	99.4	100.8	100.9	100.2	100.4	100.4	100.5	99.6	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0
Peak Hour	98.8	100.2	100.2	99.6	98.5	98.8	100.1	100.5	99.9	99.7	99.8	100.0	99.9	99.6	100.1	101.2	100.0	99.5	101.3	101.1	102.3	101.1	101.9	102.3	101.2	99.7	100.9	100.1	99.9	100.6

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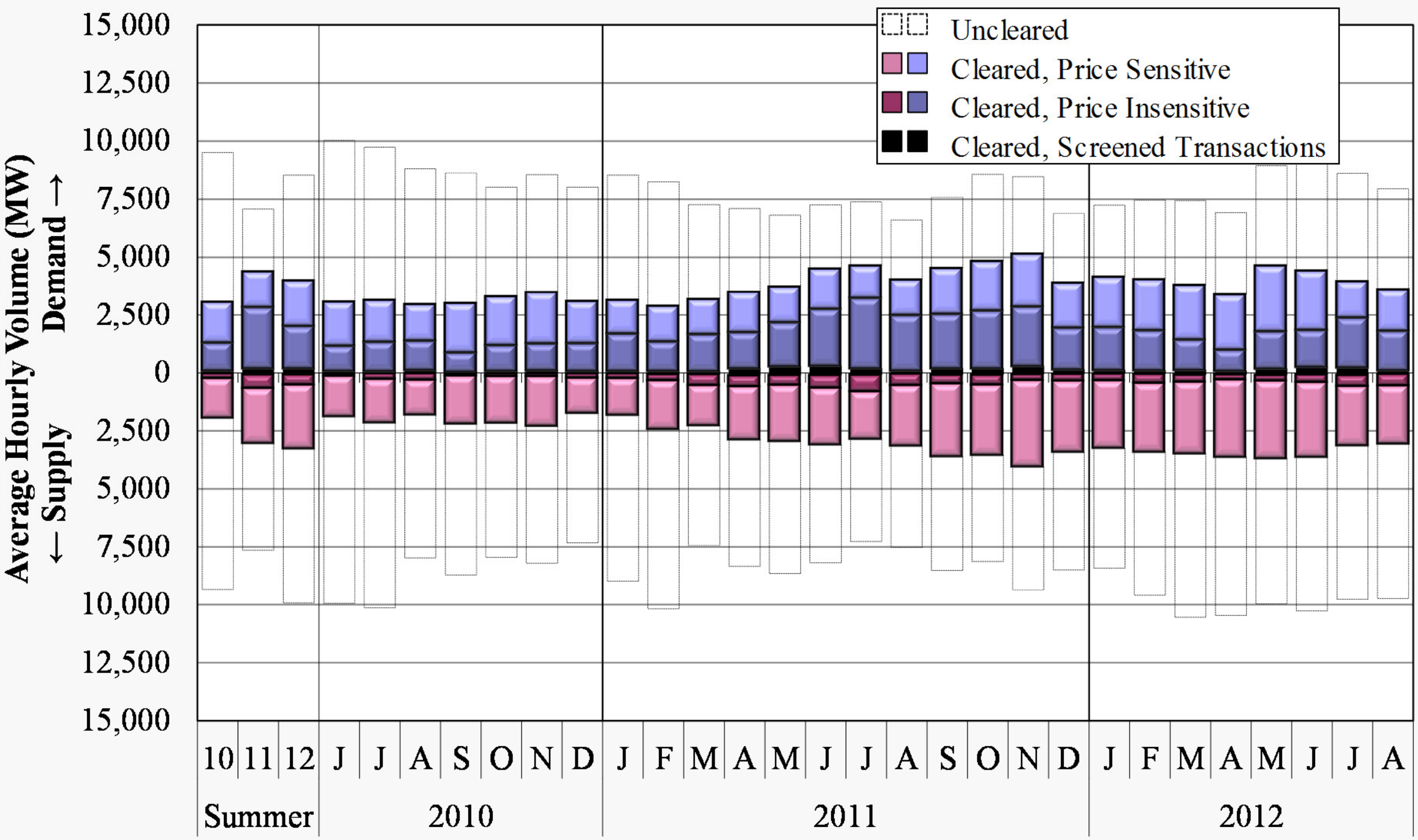
Virtual Load and Supply in the Day-Ahead Market

- 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 $30 above and below expected real-time prices, respectively.
  - ✓ Price-insensitive bids and offers that 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 any allocation of 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 as discussed below.

Virtual Load and Supply in the Day-Ahead Market

- The figure shows that offered volumes increased 25 percent from last summer.
  - ✓ Cleared volumes were flat at 7.3 GW. Virtual demand declined 9 percent to 4.4 GW, while supply increased 8 percent to 3.0 GW.
- The price-sensitivity of bids and offers has improved materially since last summer: the share of cleared volumes that were price-insensitive declined from 47 percent last summer to 34 percent.
  - ✓ The discontinuation of a price-insensitive virtual trading strategy likely motivated by marginal loss factor differences during 2011 accounts for much of this decline.
  - ✓ This share remains higher than the 30 percent in summer 2010, however, because changes to the RSG allocation in April 2011 reduced the allocation for participants taking balanced positions.
  - ✓ A balanced position can be ensured by bidding and offering price-insensitively and can be valuable to arbitrage price differences between locations from the day-ahead to the real-time market.
    - – A virtual spread product would allow participants to more effectively arbitrage such locational differences.
- The share of Screened Transactions was nearly unchanged at 3.6 percent.

Virtual Volumes
2010–2012



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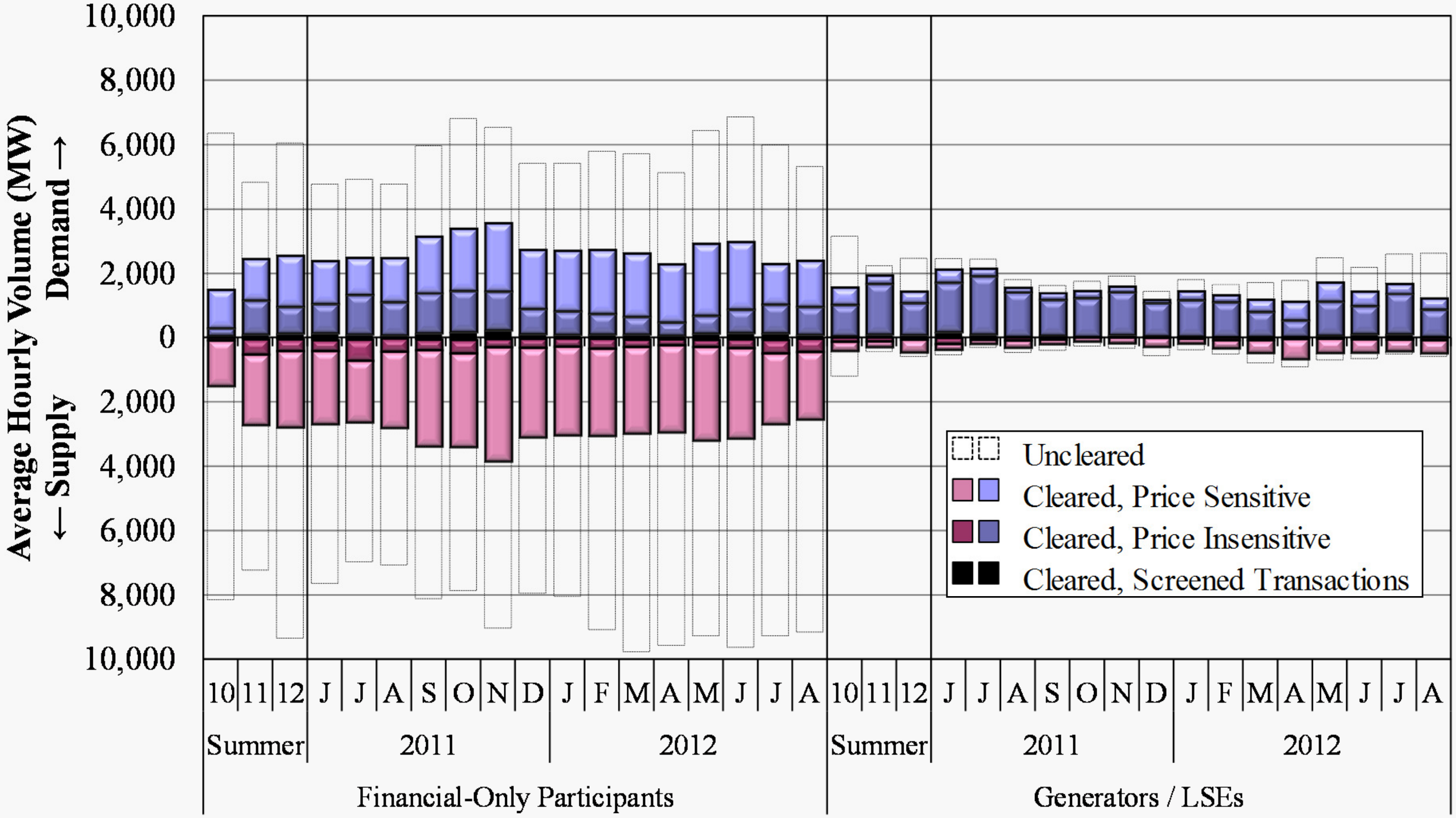
Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by type of market participant.
  - ✓ The figure distinguishes between physical participants (generation owners or LSEs) and financial-only participants.
- Most of the increase in offered volumes was by financial-only participants: such entities comprised 74 percent of cleared volumes this summer, up from 70 percent last summer.
  - ✓ Cleared supply and demand volumes by financial participants both rose 4 percent from last summer.
  - ✓ Cleared volumes by physical participants, however, declined 15 percent – demand volumes in particular fell by 26 percent.
- While financial participants' volumes were roughly divided between supply and demand, over three quarters of physical participants' volumes were demand bids.
- Physical participants generally offer less price-sensitively than financial participants do, which makes it more likely that such volumes clear.
  - ✓ Such transactions allow physical participants to hedge against load uncertainty or supply availability in order to manage price risk.

Virtual Load and Supply by Participant Type
Summer 2010–2012



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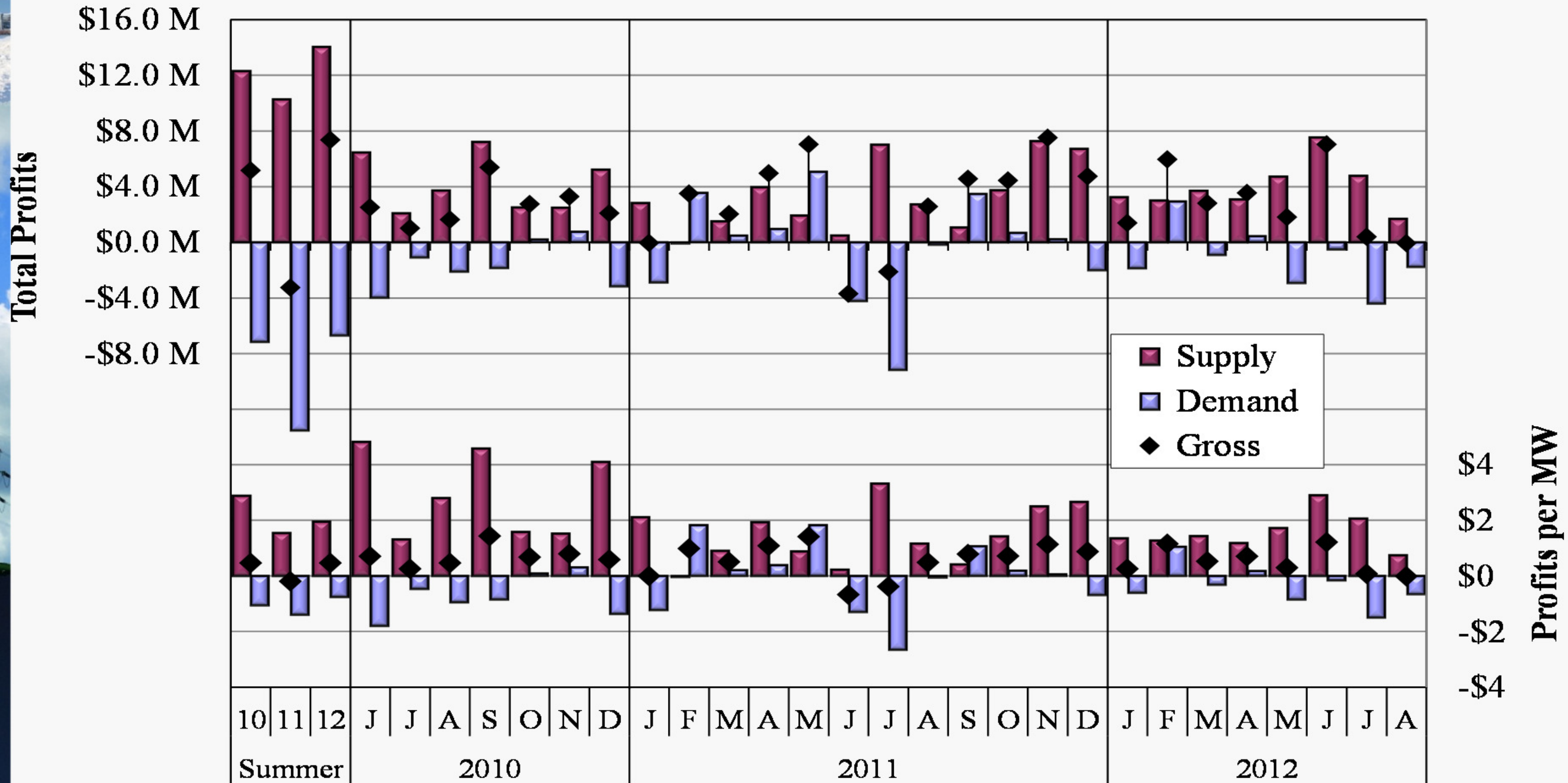
Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual purchases and sales.
- Gross profitability this summer totaled $7.4 million, or $0.46 per MW. This is a substantial improvement from last summer when participants lost $3.2 million ($-0.20).
  - ✓ Virtual supply continues to be considerably more profitable ($1.95 per MW) than demand ($-0.76). This is expected in markets with prevailing day-ahead premiums.
- These margins exclude CMC and DDC charges assessed to net harming deviations, including DDC charges to net virtual supply. DDC charges averaged $0.89 per MWh in the period, which reduced the profits for virtual supply by approximately one-half.
  - ✓ As previously noted, the CMC allocation to virtual transactions is incorrect, resulting in allocations to virtual transactions that contribute to convergence. We are working with MISO to identify the best procedural option for fixing this.
- Virtual transactions by financial participants continue to be profitable and improve convergence overall, while those by physical participants are generally unprofitable.
  - ✓ Excluding RSG allocations, financial participants' profits averaged $1.08 per MW, while physical participants' profits averaged $-1.28 (and $-1.99 for virtual demand).
  - ✓ Physical participants consistently incur losses on virtual demand, likely to hedge risks associated with supply uncertainty and real-time price spikes.

Virtual Profitability 2010–2012



Percent Screened

Demand	3.0	4.5	5.0	2.9	2.4	3.9	1.6	2.6	2.9	2.9	2.5	3.0	2.4	5.4	7.5	6.8	4.2	2.4	4.3	4.0	5.7	3.8	2.9	2.8	3.1	2.5	3.9	5.7	5.9	3.1
Supply	0.7	2.1	1.9	0.8	0.8	0.5	0.7	0.6	0.7	1.0	0.8	1.9	2.3	3.2	3.0	2.9	2.5	0.9	2.0	2.1	1.3	1.1	0.8	1.2	2.1	1.7	2.3	1.7	2.8	1.3

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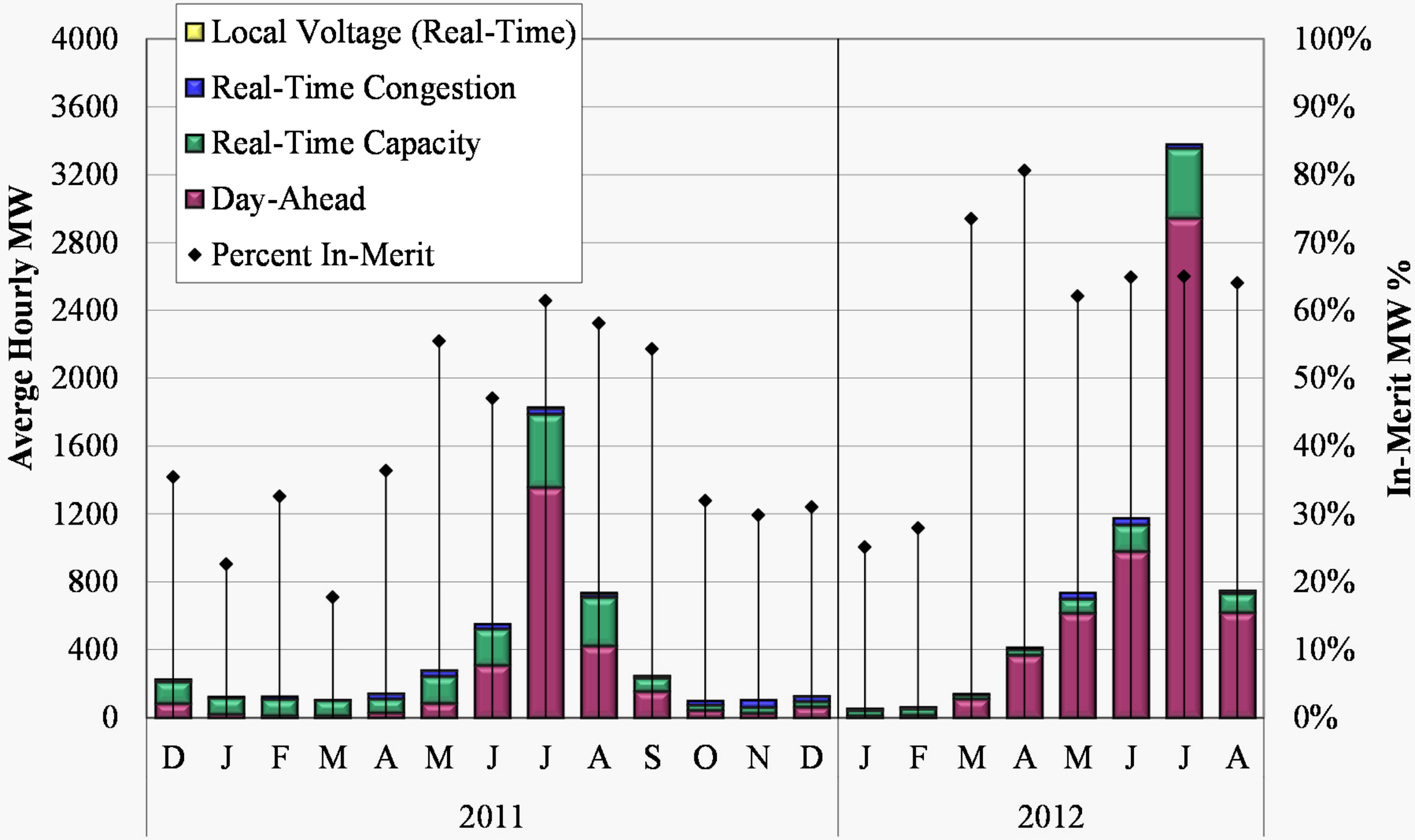
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were in-merit (offer price lower than the LMP).
  - ✓ The figure is categorized by the market and the reason for the commitment.
- Peaking resource dispatch quantities rose 70 percent from last summer to an average of nearly 1,800 MW per hour.
  - ✓ This is attributable to an increase in demand as well as the reduction in natural gas prices, which lowers the costs of most peaking resources (see slide 12).
- Over 85 percent of such resources were committed day-ahead, of which 70 percent were dispatched in-merit in real time.
  - ✓ Real-time commitments are generally made for short-term capacity needs unforeseen day-ahead, and are often out-of-merit (nearly 60 percent).
  - ✓ In all, approximately two-thirds of all peaking resources were dispatched in-merit, up from 58 percent last summer.
- When peaking resources are dispatched out-of-merit, they do not contribute to setting the energy price, even though they are needed to meet system needs.
  - ✓ MISO's ELMP initiative, filed in December 2011, will allow peaking resources to set energy prices more reliably. It is set to be introduced in late 2013.
  - ✓ This will improve MISO's price signals and lower its costs.

Peaking Resource Dispatch and In-Merit Status 2010–2012



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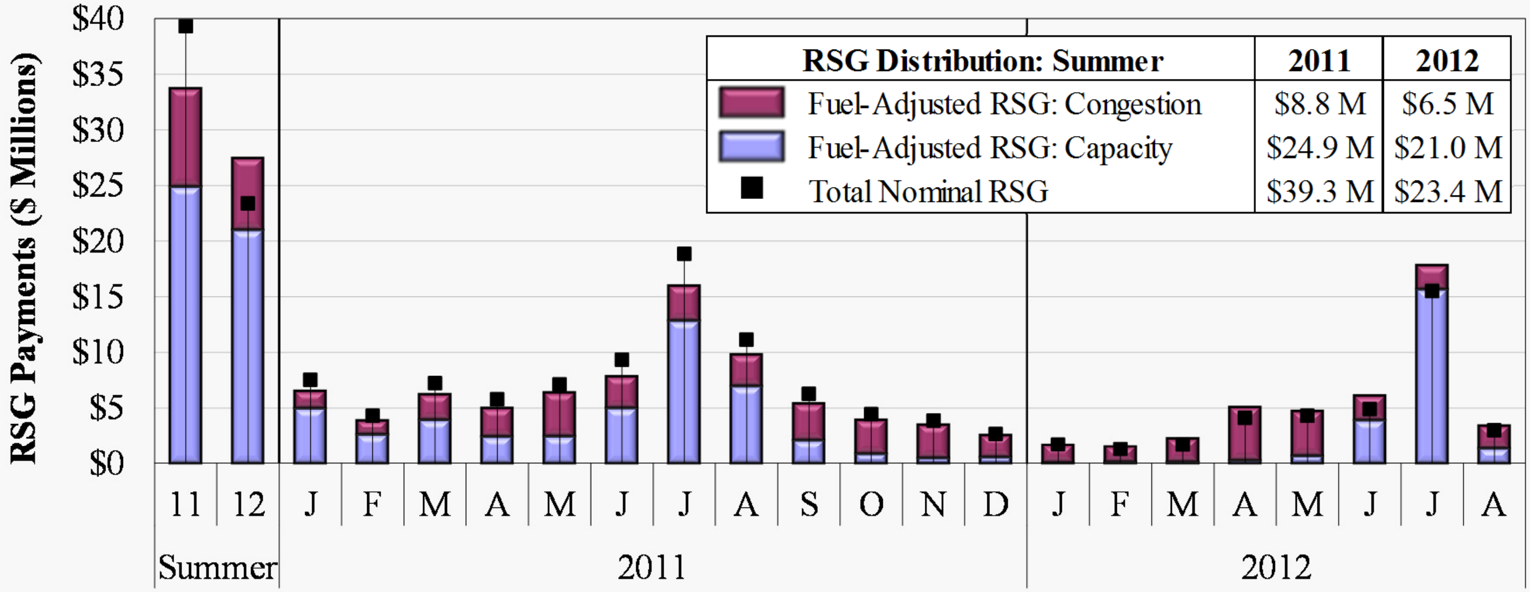
Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets.
  - ✓ 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 RSG costs declined 41 percent from last summer to $23.4 million. The decrease in fuel prices accounted for nearly two-thirds of this decline.
- As is typical in summer, approximately three-quarters of payments went to resources committed for capacity purposes.
  - ✓ Capacity payments declined 16 percent to a fuel-adjusted $21.0 million.
  - ✓ Payments were greatest on days when load was most under-scheduled (see slide 33).
- RSG payments to units committed for congestion declined 27 percent to a fuel-adjusted $6.5 million. Nearly 40 percent of this went to select units in North WUMS committed almost daily for voltage support.
- The second figure shows that nominal day-ahead RSG payments declined 43 percent from last summer (and by 11 percent in fuel-adjusted terms) to $5.0 million.
  - ✓ Day-ahead payments continue to be lower than real-time RSG payments because most reliability requirements are satisfied only in the real time.

Real-Time RSG Payments
2010–2012



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

Peaker	71	76	60	53	54	53	48	69	75	66	45	46	41	35	26	31	30	51	75	70	84	43
Constraint	14	8	7	13	6	17	16	15	14	15	16	32	35	29	26	31	28	48	67	10	5	17
Capacity	57	68	53	40	49	36	32	53	62	51	29	14	6	7	0	0	1	3	8	60	79	27
Non-Peaker	29	24	40	47	46	47	52	31	25	34	55	54	59	65	74	69	70	49	25	30	16	57
Constraint	12	13	15	21	31	34	43	19	6	14	47	48	52	50	69	59	64	47	18	22	5	42
Capacity	17	11	24	26	15	14	9	12	18	19	9	6	6	15	5	10	6	2	6	8	11	15

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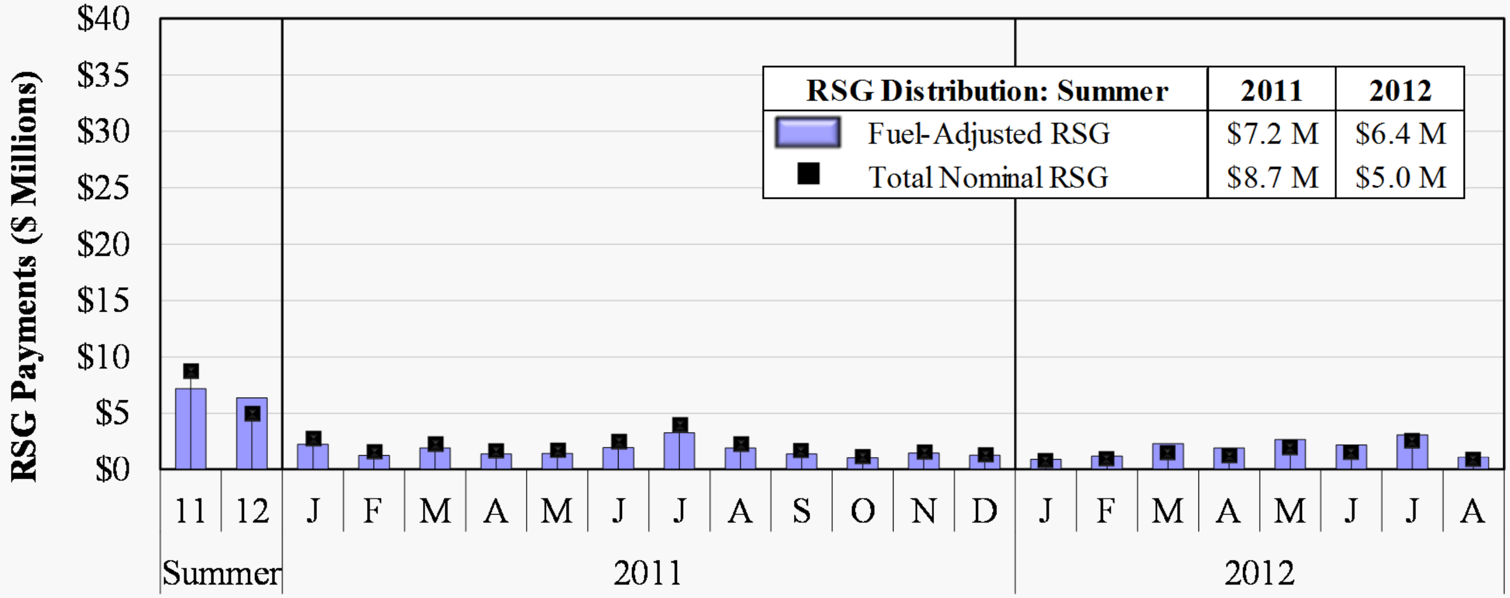
Day-Ahead RSG Payments 2010–2012



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

Peaker	28	43	1	0	2	2	7	21	41	15	19	11	6	4	2	1	2	8	21	16	62	36
Non-Peaker	72	57	99	100	98	98	93	79	59	85	81	89	94	96	98	99	98	92	79	84	38	64

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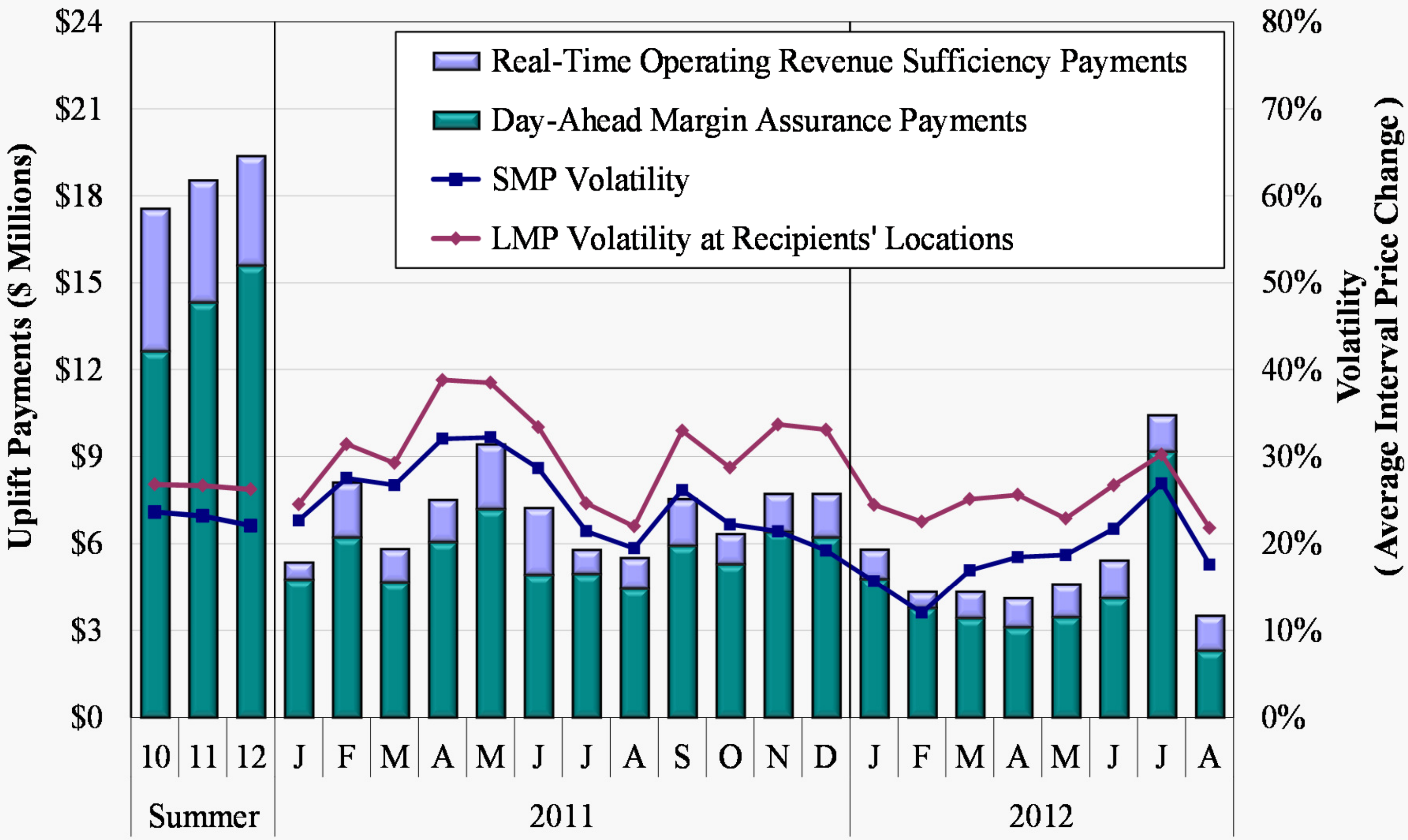
Price Volatility Make Whole Payments

- The next chart shows Price Volatility Make Whole Payments ("PVMWP") that improve incentives for suppliers to follow dispatch instructions.
  - ✓ The payments are in two forms: Day-Ahead Margin Assurance payments ("DAMAP") and Real-Time Offer Revenue Sufficiency Guarantee Payments ("RTORSGP").
- Total PVMWP increased 5 percent from last summer to $19.4 million.
  - ✓ DAMAP remains the larger of the two payments: payments totaled $15.6 million, an increase of 9 percent. RTORSGP declined by 1 percent to $3.7 million.
- 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.
    - – Total payments rose 48 percent from spring, while SMP volatility rose 22 percent.
  - ✓ It also shows that volatility is higher at recipients' locations because they are generally re-dispatched more than other suppliers are due to the larger price changes.
- We recommended in the *2011 State of the Market Report* that MISO revise eligibility criteria for PVMWP to address certain efficiency and gaming concerns. MISO is working with stakeholders to address this recommendation.

Price Volatility Make Whole Payments 2010–2012



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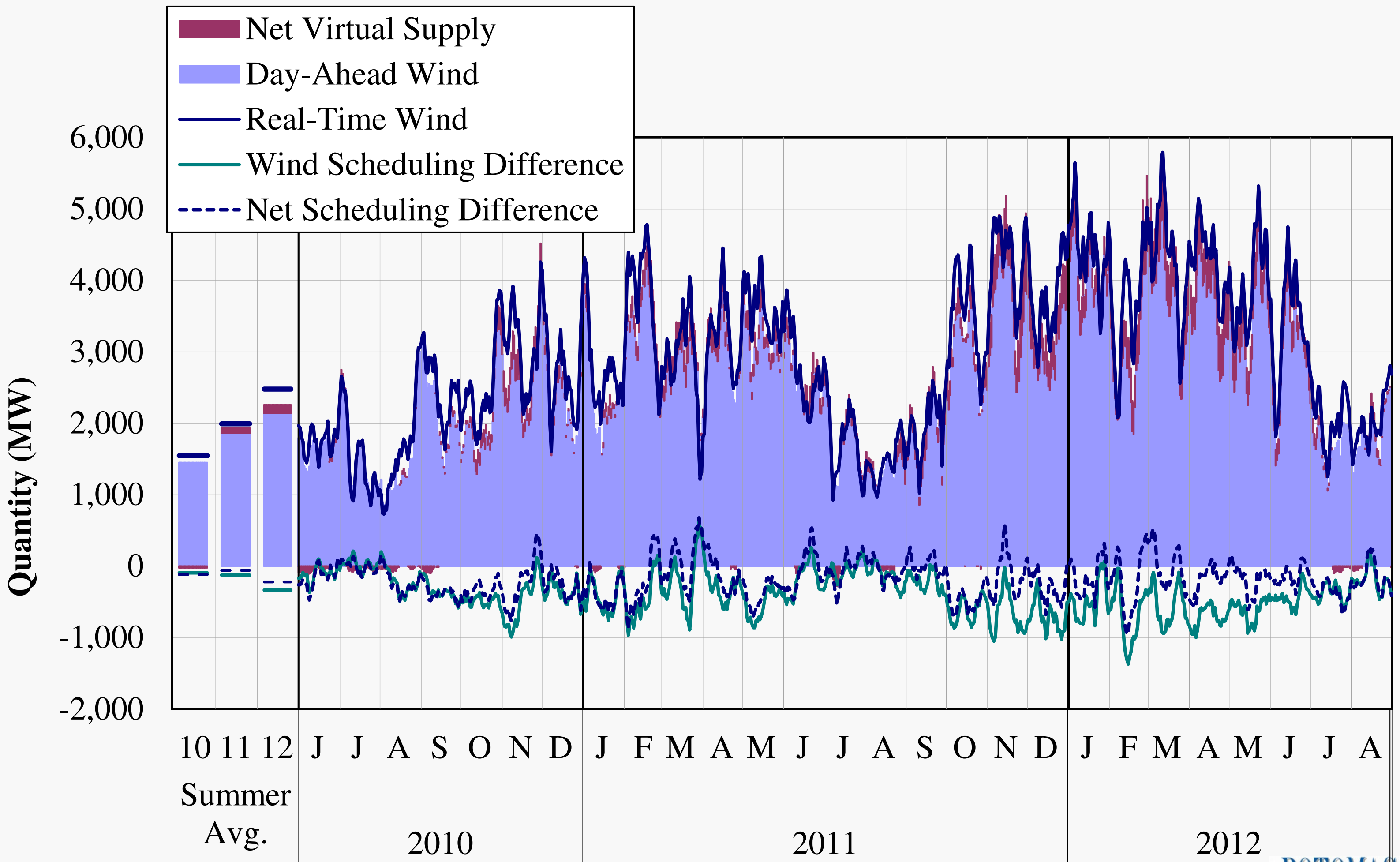
Scheduling of Wind Generation in Real-Time and Day-Ahead Markets

- 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 generation.
- Real-time wind output increased 30 percent from last summer to nearly 2.5 GW.
  - ✓ Nameplate capacity over the same period increased 22 percent to 11.8 GW.
  - ✓ Wind output made up 4 percent of total generation, up from 3 percent last summer.
- Variability in output—both in real time and deviations from the day-ahead—must be managed by MISO by modifying the commitment or dispatch of other resources.
- Under-scheduling of wind in the day-ahead market averaged 344 MW this quarter, up from 116 MW last summer.
  - ✓ Only one-third of this was offset by net virtual supply at wind locations, a decline from 55 percent last summer and nearly 80 percent in the spring.
- Manageability of the congestion caused by variable wind output should continue to improve as DIR resources expand in the MISO footprint.
  - ✓ In summer 2012, 4.8 GW (41 percent) of total wind resources were dispatchable.
  - ✓ All wind resources, unless otherwise exempt, must become DIR by June 2013.

Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average



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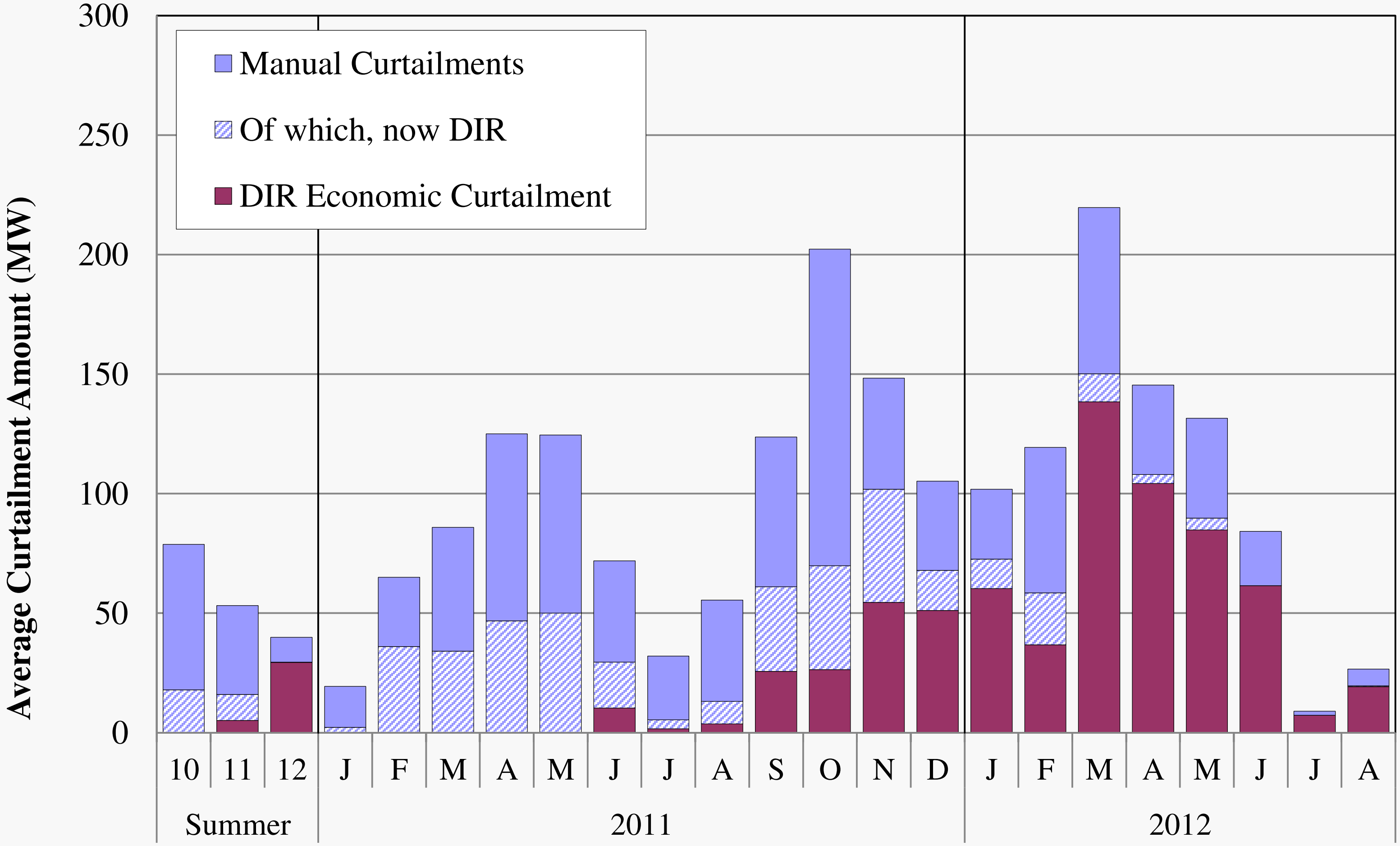
Wind Curtailments

- Manual curtailment of wind resources by MISO are at times necessary to prevent transmission overloads.
  - ✓ Since the implementation of the DIR type in June 2011, increasing amounts of wind resources have become able to respond to MISO dispatch instructions.
    - As of September 1, a majority of wind resources (6.2 GW) are now DIR.
    - DIR units provided MISO with additional flexibility to manage congestion.
- The following figure shows that economic DIR curtailments have replaced manual curtailments as the primary means of controlling wind output.
  - ✓ Economic curtailment of wind resources averaged 29 MW in summer 2012, and made up 74 percent of total wind curtailments.
  - ✓ DIR resources are being curtailed economically at a greater rate than they were being curtailed manually prior to converting to DIR.
    - Absent DIR, total wind curtailments would have been considerably higher.
- As a share of wind output, manual curtailments declined to just 0.4 percent in summer 2012, down from 2.4 and 4.5 percent in the prior two summers.

Wind Curtailments
2010–2012



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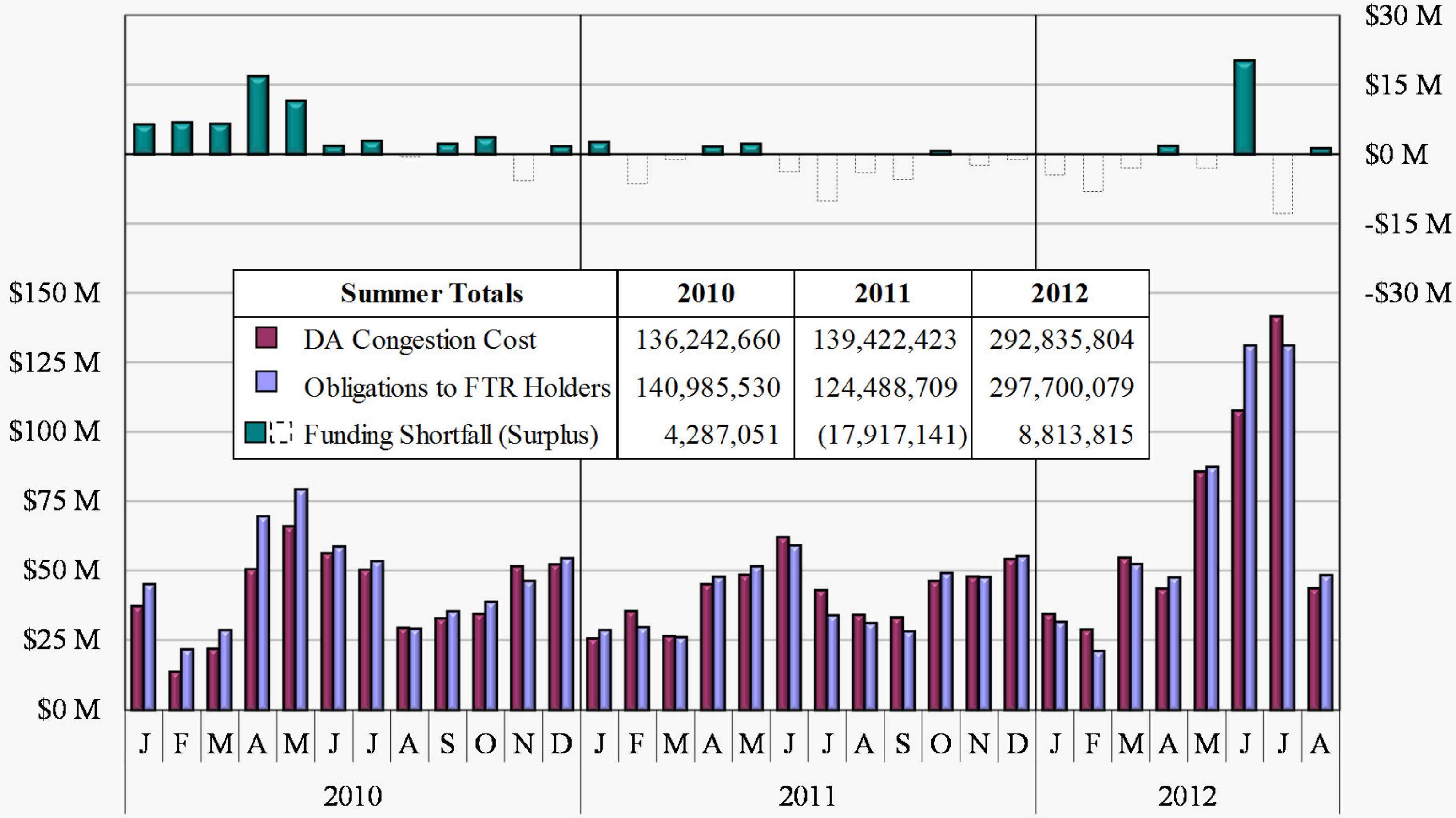
Day-Ahead Congestion and Obligations to FTR Holders

- 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 day-ahead congestion from loads and pays it out via FTRs.
    - – Day-ahead congestion this summer more than doubled from \$139 million last summer to \$293 million.
- The next figure shows day-ahead congestion, FTR obligations, and FTR shortfalls/surpluses;
  - ✓ Shortfalls and surpluses occur when the portfolio of FTRs represent more or less transmission capacity than the capability of the network in the day-ahead market.
- MISO continues work on the ARR allocation process and modeling improvements in the FTR market to increased FTR funding.
  - ✓ The day-ahead funding shortfall was \$8 million this summer, including \$20 million of underfunding in June.
  - ✓ If sustained, surpluses can indicate that MISO is not making FTRs available that fully reflect the capability of the system.
    - – Surpluses on market-to-market constraints over the prior two years appears to have been addressed in the 2012-2013 FTR year that began in June.

Day-Ahead Congestion and Obligations to FTR Holders, 2010–2012



Summer Totals	2010	2011	2012
DA Congestion Cost	136,242,660	139,422,423	292,835,804
Obligations to FTR Holders	140,985,530	124,488,709	297,700,079
Funding Shortfall (Surplus)	4,287,051	(17,917,141)	8,813,815

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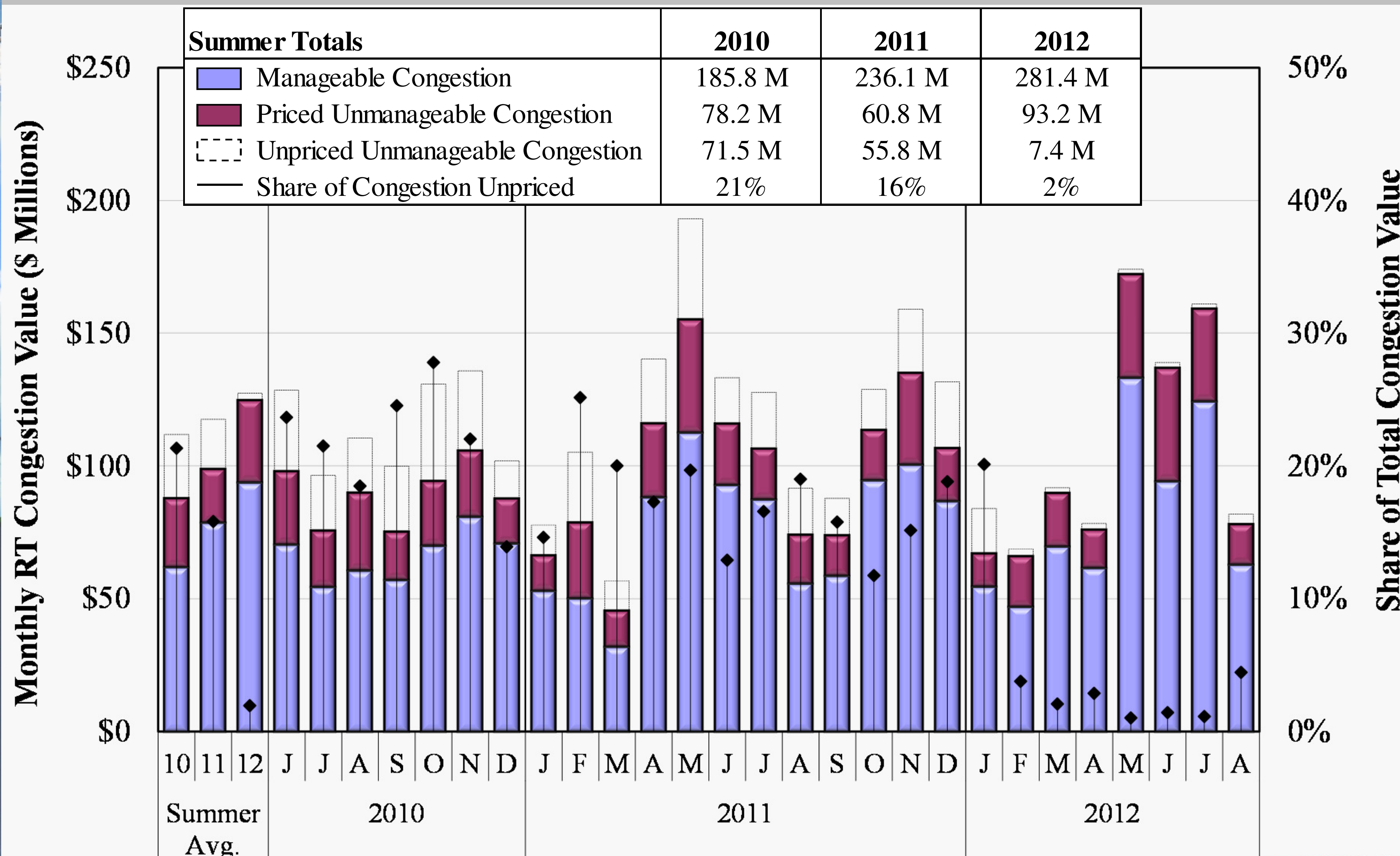
Congestion Management

- As noted previously in prior reports MISO recently made two significant changes to congestion management:
  - ✓ In late January, MISO implemented a new process to reduce the lag between observed flows on constraints and inputs into the real-time market.
  - ✓ On February 1, 2012 constraint relaxation was disabled for internal non-M2M constraints.
    - – Constraint relaxation is an algorithm that caused unmanageable constraints (whose flow exceeds its limit for at least one interval) to be underpriced.
- These two initiatives have resulted in a substantial improvement in the manageability and pricing of constraints.
  - ✓ Violated constraints are now priced at their full Marginal Value Limit (assumed cost of violating the constraint in the real-time dispatch), leading to day-ahead market results and MP actions have improved the management of the constraints.
  - ✓ MISO has also developed new post-contingency action plans with TOs, reducing the need to activate low-voltage constraints that cannot be managed.
  - ✓ We will continue to evaluate the impacts of these initiatives.

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).
- Real-time congestion rose 26 percent from last summer to $371 million.
  - ✓ Almost all of the increase was on internal constraints, as shown in the second figure, that were affected by generator and transmission outages, mainly in the West.
- Constraint relaxation continues to be used on MISO M2M and external constraints.
  - ✓ Relaxation eliminated 2 percent of congestion costs this summer, compared to 16 percent last summer.
  - ✓ While much improved from last year, relaxation still adversely affects the day-ahead market, FTR market, and longer-term investment decisions.

Value of Real-Time Congestion 2010–2012



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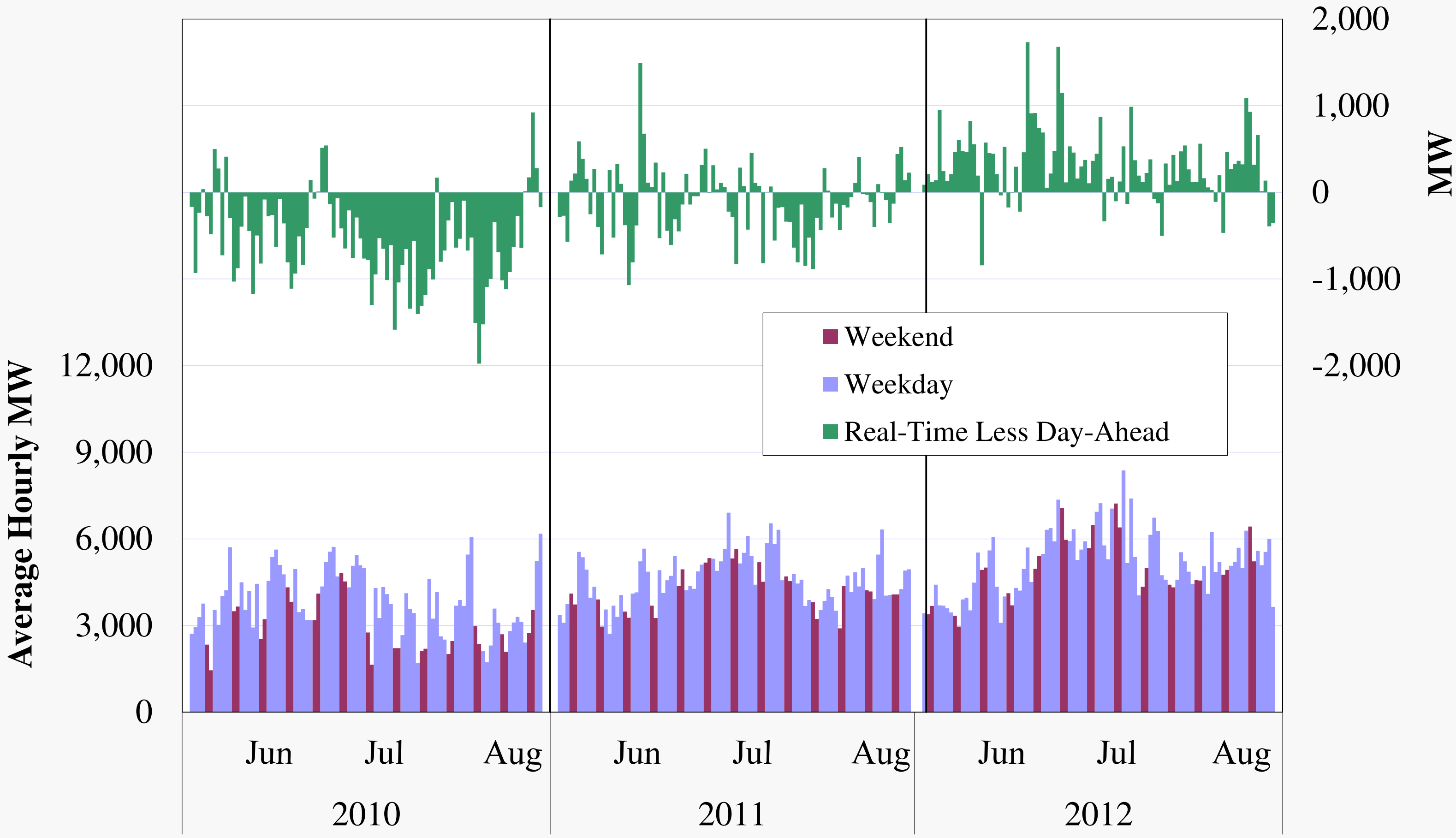
Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market during the three summer months since 2010.
- In summer 2012 MISO was a net importer of 5.2 GW per hour on average.
  - ✓ This is an increase of 14 and 40 percent from the summers of 2011 and 2010.
- Regionally, imports declined modestly on MISO’s largest two interfaces with PJM and Manitoba, but increased by more than 1 GW across western interfaces.
- Net imports were under-scheduled in day ahead by an average of 313 MW, and at times by much more, particularly on very high load days.
  - ✓ On days that MISO was in Conservative Operations, imports were under-scheduled by approximately 700 MW per hour on average.
  - ✓ In prior summers, load was generally over-scheduled by several hundred MW.
- The increase in net imports may be due in part to the updated RSG allocation.
  - ✓ Revisions made in April 2011 reduced charges to real-time imports.
  - ✓ Participants are currently assessed a deviation charge only on net negative real-time volumes.

Average Hourly Real-Time Imports Summer 2010–2012



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Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2011 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 cumulative outage rate for the three types of outages was 10.5 percent. This is a modest increase from the 8-9 percent in prior summers.
  - ✓ Long-term forced outages increased from 2.5 to 4.6 percent.
    - – Several large units were forced out of service in late June and remained so during much of the remainder of summer.
    - – Forced outage are often greatest during the high load days, since units are more likely to trip when they are starting, stopping or operating near maximum capacity.
  - ✓ Short-term forced outages declined from 2.4 to 2.0 percent.
    - – Short-term forced outages can indicate potential physical withholding.
  - ✓ Planned outages increased modestly to 3.8 percent.
    - – Lower gas prices likely contributed to increased planned outages of coal resources, some of which were associated with environmental upgrades.

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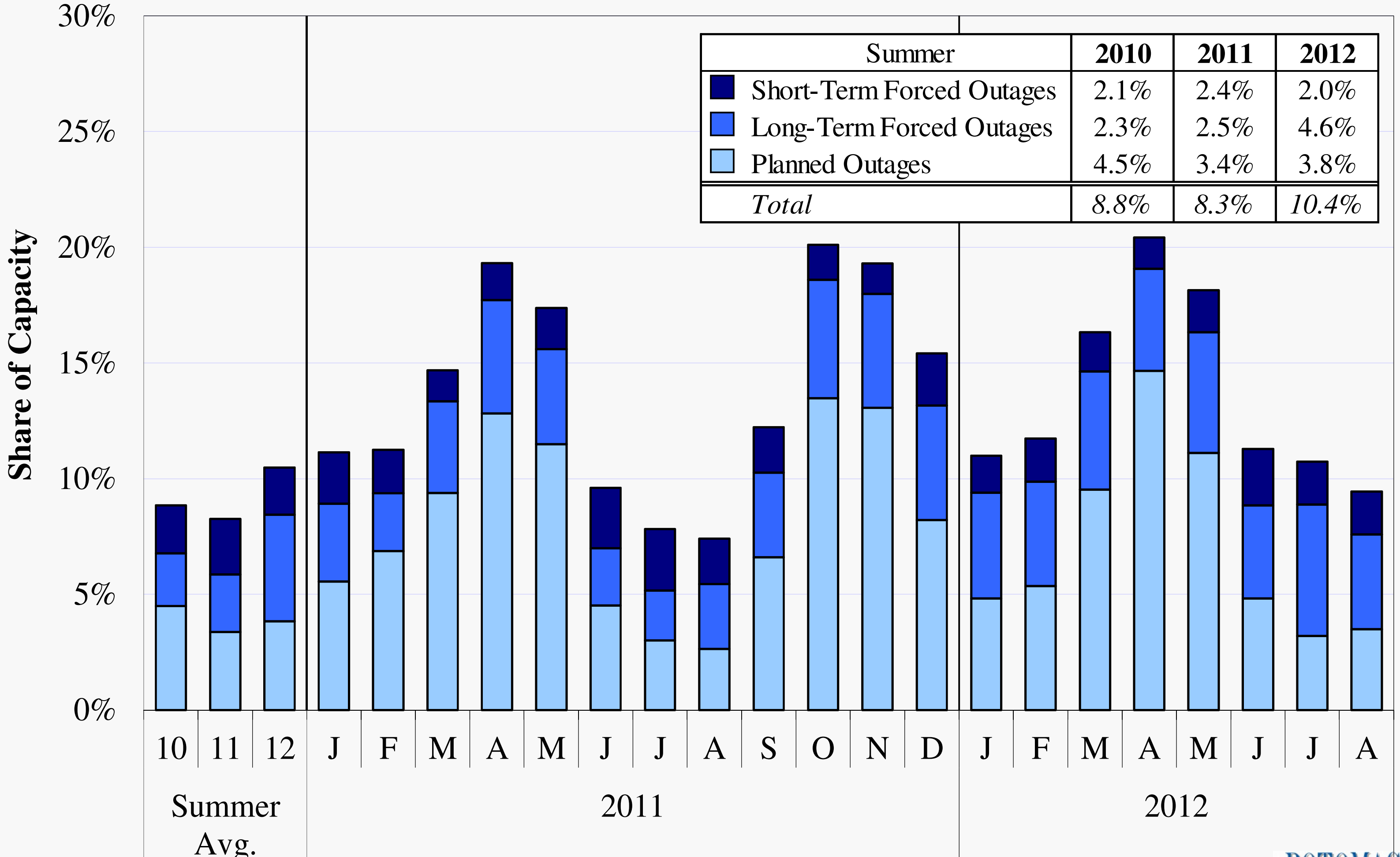
Generation Outage Rates 2011–2012

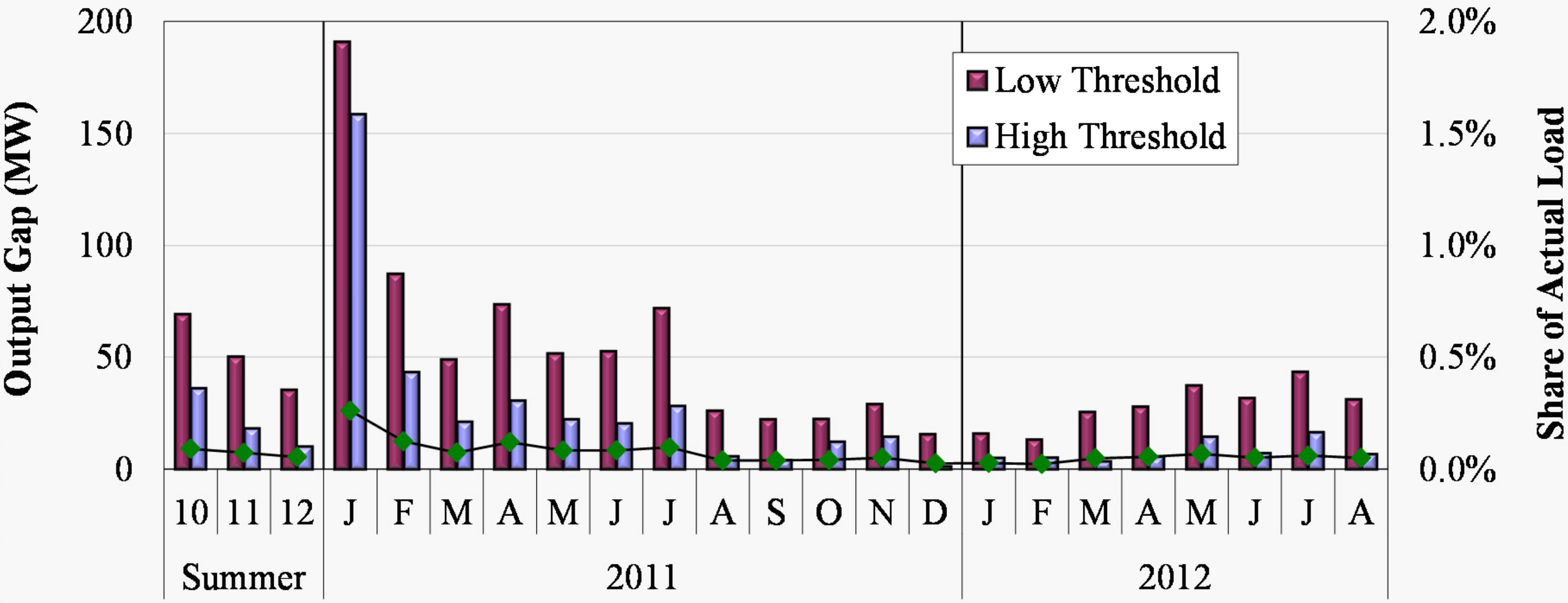


Summer	2010	2011	2012
Short-Term Forced Outages	2.1%	2.4%	2.0%
Long-Term Forced Outages	2.3%	2.5%	4.6%
Planned Outages	4.5%	3.4%	3.8%
Total	*8.8%*	*8.3%*	*10.4%*

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 January 2011 under two thresholds: a "high" threshold (equal to the mitigation threshold) and a "low" threshold (equal to one-half of mitigation threshold).
- Output gap levels under both thresholds continued to be extremely low, averaging just 36 and 10 MW this quarter under the low and high thresholds, respectively.
- As a share of overall load, the low-threshold output gap again averaged less than 0.01 percent of load.
  - ✓ The mitigation thresholds for Narrow Constrained Areas were updated in early February. The Minnesota threshold declined substantially while the WUMS threshold increased substantially. The North WUMS increased slightly.
  - ✓ These threshold changes can affect the output gap levels since they are used in this analysis.
- Overall, these results raise no competitive concerns, although we continue to routinely investigate hourly increases in the output gap.

Monthly Output Gap
2010–2012



Low Threshold Results by Unit Status (MW)

	10	11	12	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A
Off Line	22	11	4	143	44	21	14	9	11	23	0	1	11	12	0	4	4	1	1	9	0	11	0
On Line	47	39	32	48	43	29	60	43	42	49	26	22	12	17	16	12	9	24	26	29	32	33	31

High Threshold Results by Unit Status (MW)

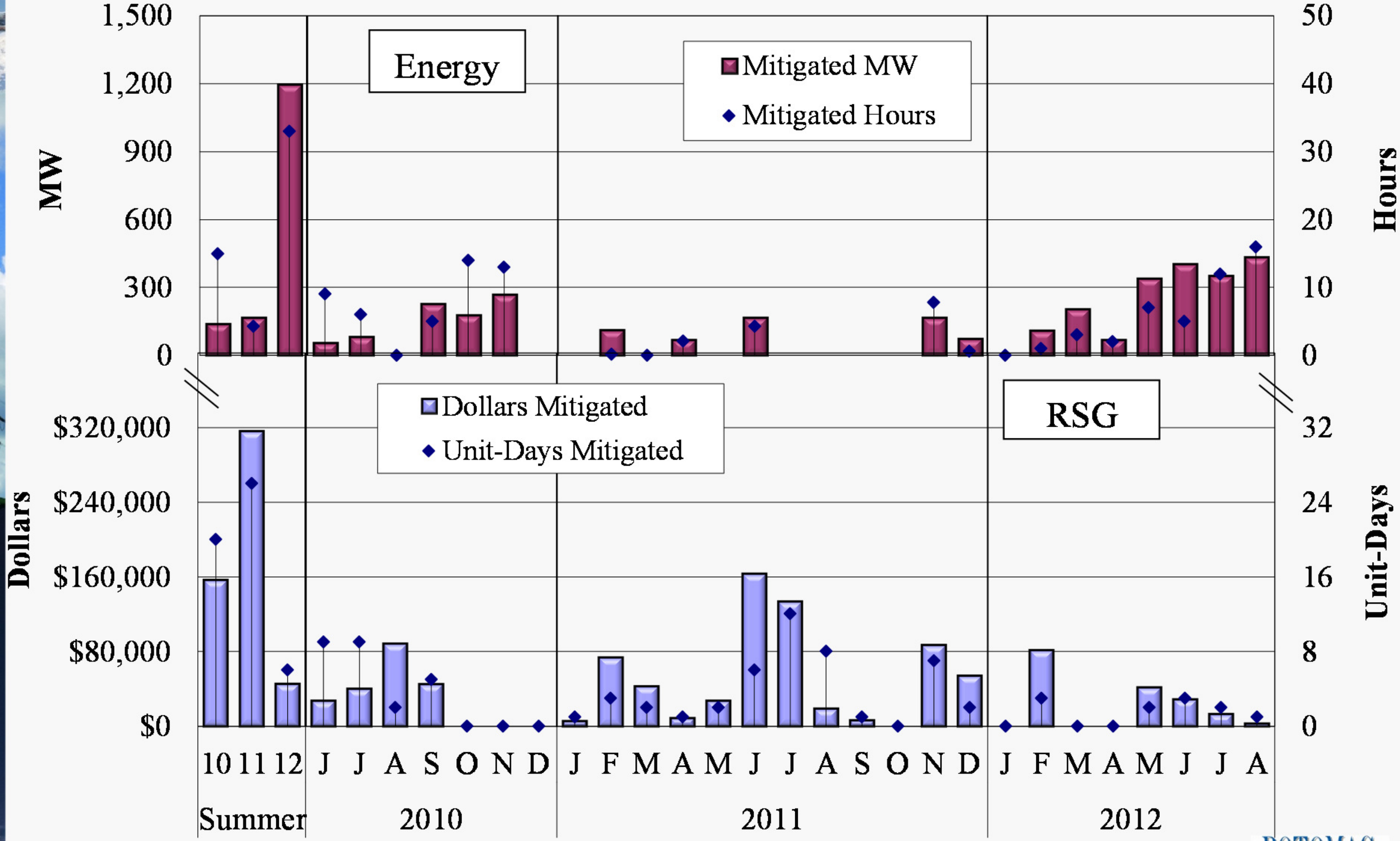
	10	11	12	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A
Off Line	42	10	3	142	29	16	14	9	10	19	0	1	11	12	0	4	4	1	1	9	0	9	0
On Line	35	8	7	17	14	5	17	13	10	9	6	4	1	3	1	2	1	2	4	6	7	7	7

POTOMAC ECONOMICS

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 increased considerably in summer 2012, but remains fairly infrequent.
  - ✓ Energy mitigation occurred for 33 hours and a total of nearly 1,200 MW.
  - ✓ Two-thirds of these occurred in Broad Constrained Areas, with the rest occurring in the Minnesota NCA, where the mitigation threshold was lowered in early 2012.
  - ✓ Some of the increase is due to participant error (i.e., incorrect offer parameters).
  - ✓ Mitigation remains infrequently because most resources are offered competitively in the MISO markets.
- RSG mitigation, conversely, declined to just 6 unit-days and $46,000.
- We continue to evaluate each instance of AMP mitigation and found mitigation to be appropriately applied in all but one instance.
  - ✓ In one hour, one unit was improperly mitigated for energy due to an incorrect reference.
  - ✓ This instance has been reported to FERC and was discussed with the affected MP.
- Although mitigation is infrequent, local market power continues to be a significant concern and market power mitigation measures remain critical.

Real-Time Market Power Mitigation 2010–2012

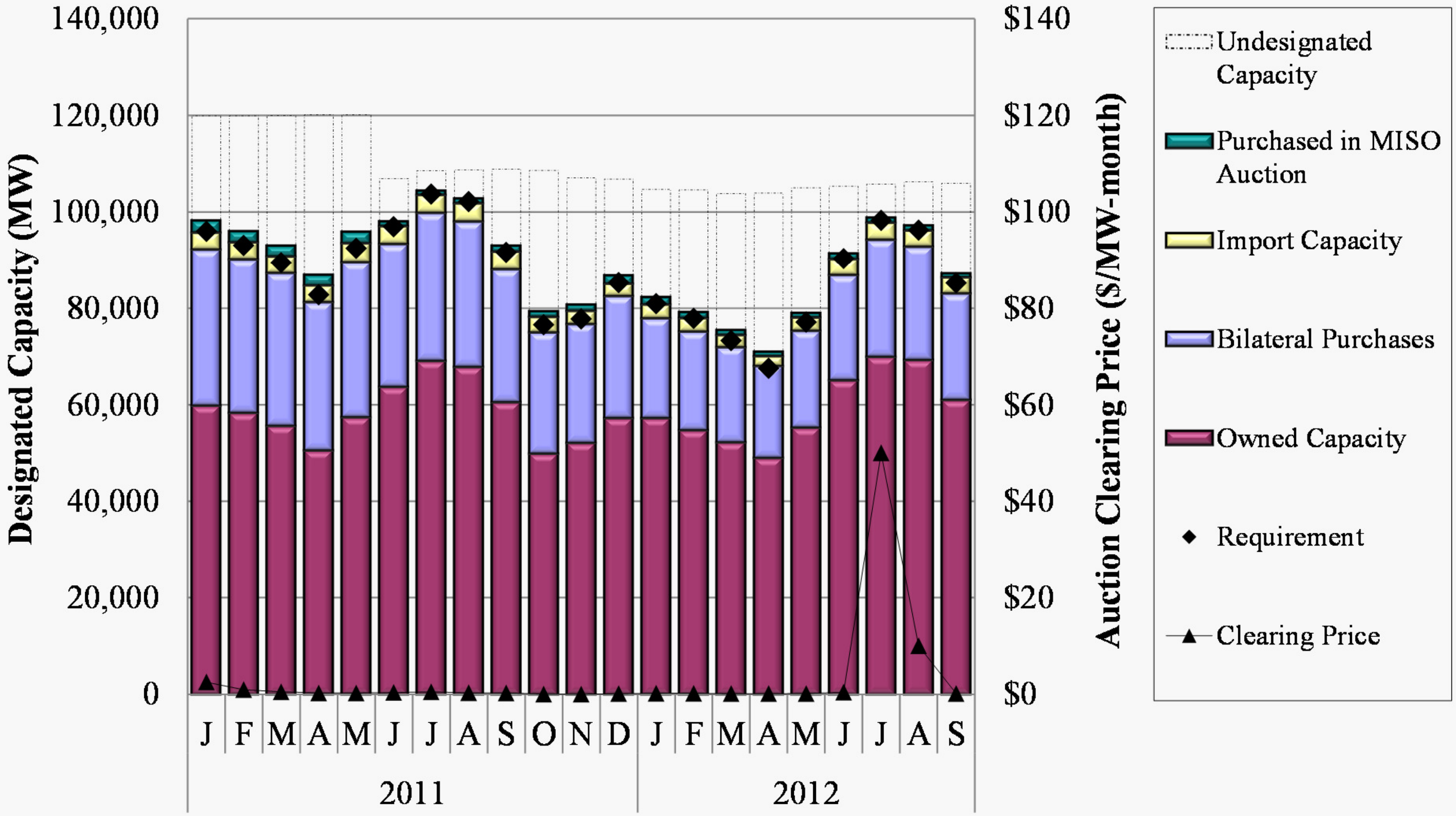


POTOMAC ECONOMICS

Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities 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 2011.
- The auction in July cleared at the highest level ($50 per MW-month) in 24 months, but even this price is extremely low.
  - ✓ The low prices in the VCA are partially due to capacity surplus in MISO (7.6 percent, up from 4.7 percent last July).
  - ✓ However, barriers to trading capacity with PJM and the current vertical demand curve are also contributing to inefficiently low capacity prices.
  - ✓ Significant changes to MISO's resource adequacy construct have been approved by FERC, but it will still be important to address these two market design issues.
- The figure also shows how LSEs met their capacity obligations.
  - ✓ The capacity cleared in the VCA each month remains a very small portion of the total designated capacity (1-2 percent). This reflects the fact that most LSEs satisfy their needs primarily through owned capacity or bilateral purchases.
  - ✓ Capacity designations exceeded the requirement by 1 to 5 percent this summer.

Voluntary Capacity Auction 2011–2012



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

POTOMAC ECONOMICS

Submittals to External Entities and Other Issues

<u>Submittals to External Entities in August:</u>

- We continue to meet regularly with FERC regarding market outcomes and responded to a number of inquiries and data requests this quarter.
  - ✓ We provided additional details to FERC related to previous referrals.
  - ✓ We submitted reports to FERC regarding participants that may have violated Module E must-offer requirements.
  - ✓ We submitted written comments and participated in the JCM workshops and discussed coordination issues with PJM and stakeholders.
  - ✓ A notification for a potential Tariff violation related to DAMAP payments has been made to FERC and a referral is being prepared.

<u>Other Issues:</u>

- We continued to coordinate with MISO staff on responses to SOM recommendations.
- We continue to work with MISO on the fall implementations of voltage/local reliability market power mitigation and Order 755 (regulation mileage product).