IMM Quarterly Report
Summer 2011

MISO Independent Market Monitor

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Summary of Summer 2011 Results

- This presentation summarizes the outcomes of the MISO energy and ancillary services markets for summer 2011 from June through August.
- Load declined 1 percent this summer compared to summer 2010, despite a substantial heat wave during the week of July 17–23.
  - ✓ MISO set a new all-time peak load on July 20 at just under 104 GW and declared a Maximum Generation Event (at the lowest level) on July 21.
  - ✓ Our evaluation of the heat wave indicates that there are potential improvements that should be considered to Module E.
- Real-time energy prices averaged $38.67 per MWh, down 4 percent from last summer.
  - ✓ Day-ahead energy prices averaged $40.27 per MWh, exhibiting a 4 percent premium.
- Real-time congestion rose 12 percent, but more than $55 million was artificially eliminated by MISO's relaxation of violated transmission constraints.
- Wind output averaged 1.9 GW, down 40 percent from last quarter. Lower output and 1.2 GW of dispatchable wind led manual wind curtailments to fall 45 percent.
- Cleared virtual volumes increased 45 percent from last summer, which is likely partly due to revisions to the RSG allocation process in April 2011.
  - ✓ These revisions have contributed to changes in the virtual trading patterns in MISO, which we evaluate in this report.

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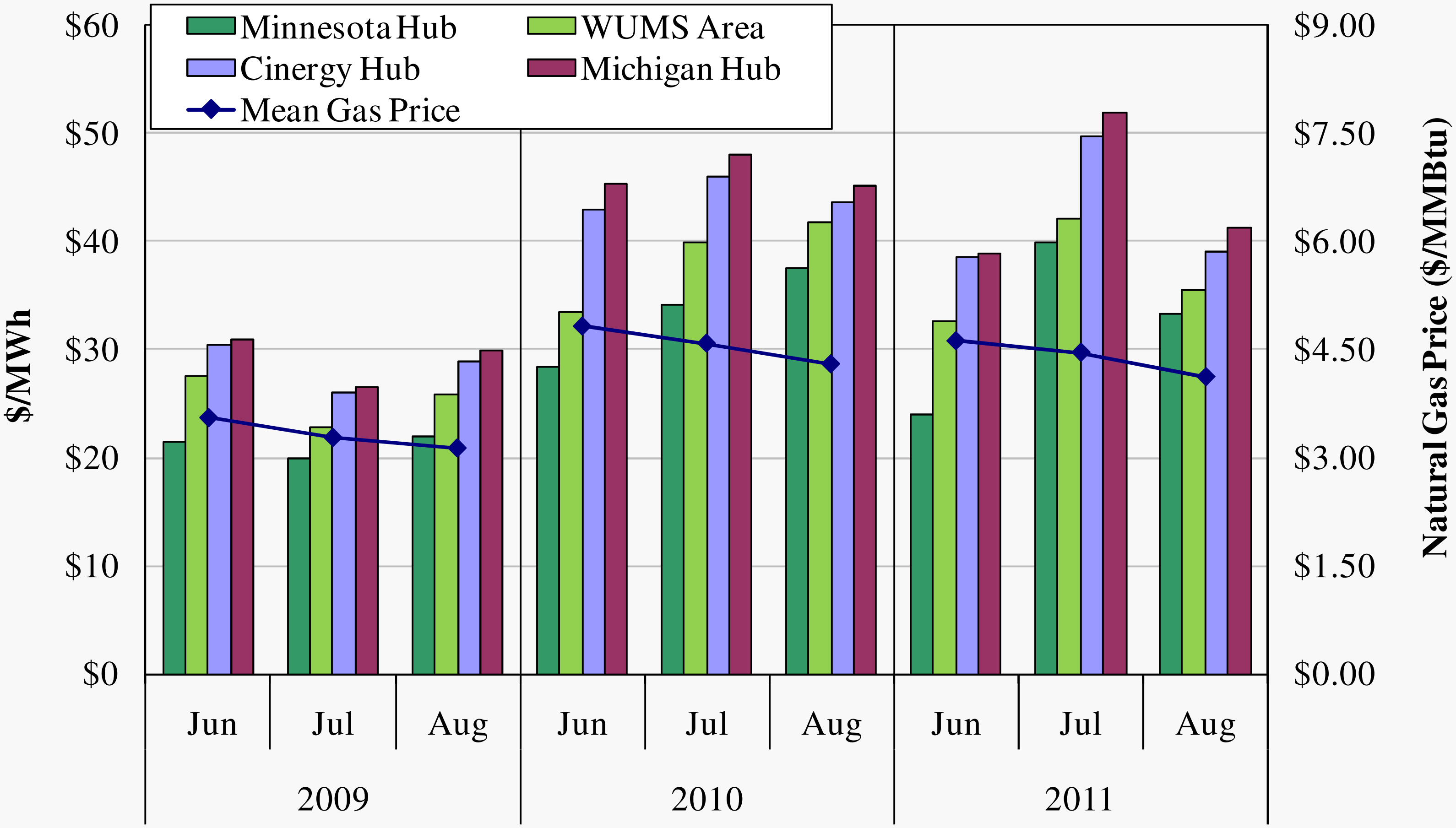
Day-Ahead Average Monthly Hub Prices

- The first figure in this section shows average day-ahead energy prices in the three summer months of 2009 to 2011 at four representative hub locations in MISO.
  - ✓ The figure shows natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin in peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead prices this summer averaged $40.27 per MWh, a decline of 4 percent from summer 2010.
  - ✓ The lower energy prices were partly due to a 4 percent drop in gas prices (to $4.41 per MMBtu). Day-ahead congestion rose 3 percent.
  - ✓ Coal prices rose modestly, while oil prices were 45 percent higher than last year.
  - ✓ Adjusted for membership changes, scheduled load was unchanged at 68.6 GW.
- Prices were highest in July ($47 per MWh) due to the heat wave in mid-July.
- Price differences between the West and East regions of MISO, reflecting west-to-east congestion, persisted throughout the summer (averaging $10).
  - ✓ Congestion eased in August as wind output fell – day-ahead scheduled wind averaged just 1.3 GW in August, down 18 percent from the prior year.

Day-Ahead Average Monthly Hub Prices
Summer 2009–2011



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All-In Price

- The "all-in price" in MISO represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price, the average real-time uplift costs, and the costs of ancillary services and capacity.
- The all-in price for the summer was $39.03 per MWh, down 4 percent from summer 2010 because of lower natural gas prices that declined 4 percent.
  - ✓ Average real-time load decreased slightly to 68.2 GW, down 1.1 percent from summer 2010.
  - ✓ Load peaked at 103,975 MW on July 20, a market record. However, supply conditions were much tighter on July 21 because of a considerable drop in wind output as well as reduced imports (see slides 7–11).
  - ✓ However, real-time congestion increased 12 percent.
- As in prior periods, energy costs comprised nearly the entire all-in price.
  - ✓ Uplift, ancillary services and capacity costs together contributed just $0.40.
  - ✓ The voluntary capacity auction continues to clear at close to zero in each month, which is consistent with surplus levels of capacity in MISO.

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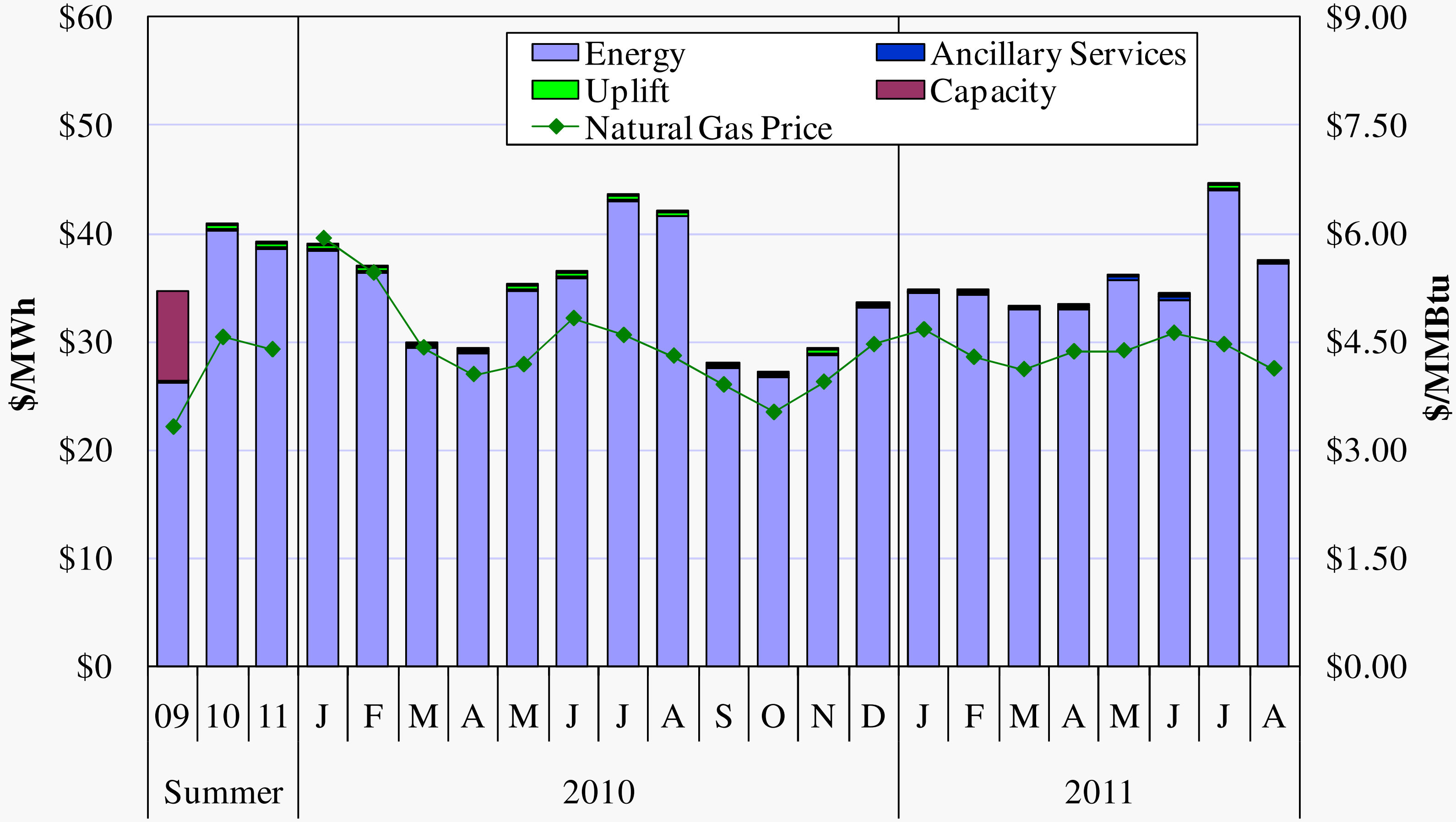
All-In Price
2009–2011



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Heat Wave in July
July 17 to 23

- The highest loads during summer 2011 occurred during a heat wave that spanned the entire MISO.
- As shown below, temperatures were significantly above the historical average across the MISO, although the heat wave broke earlier in the West Region.

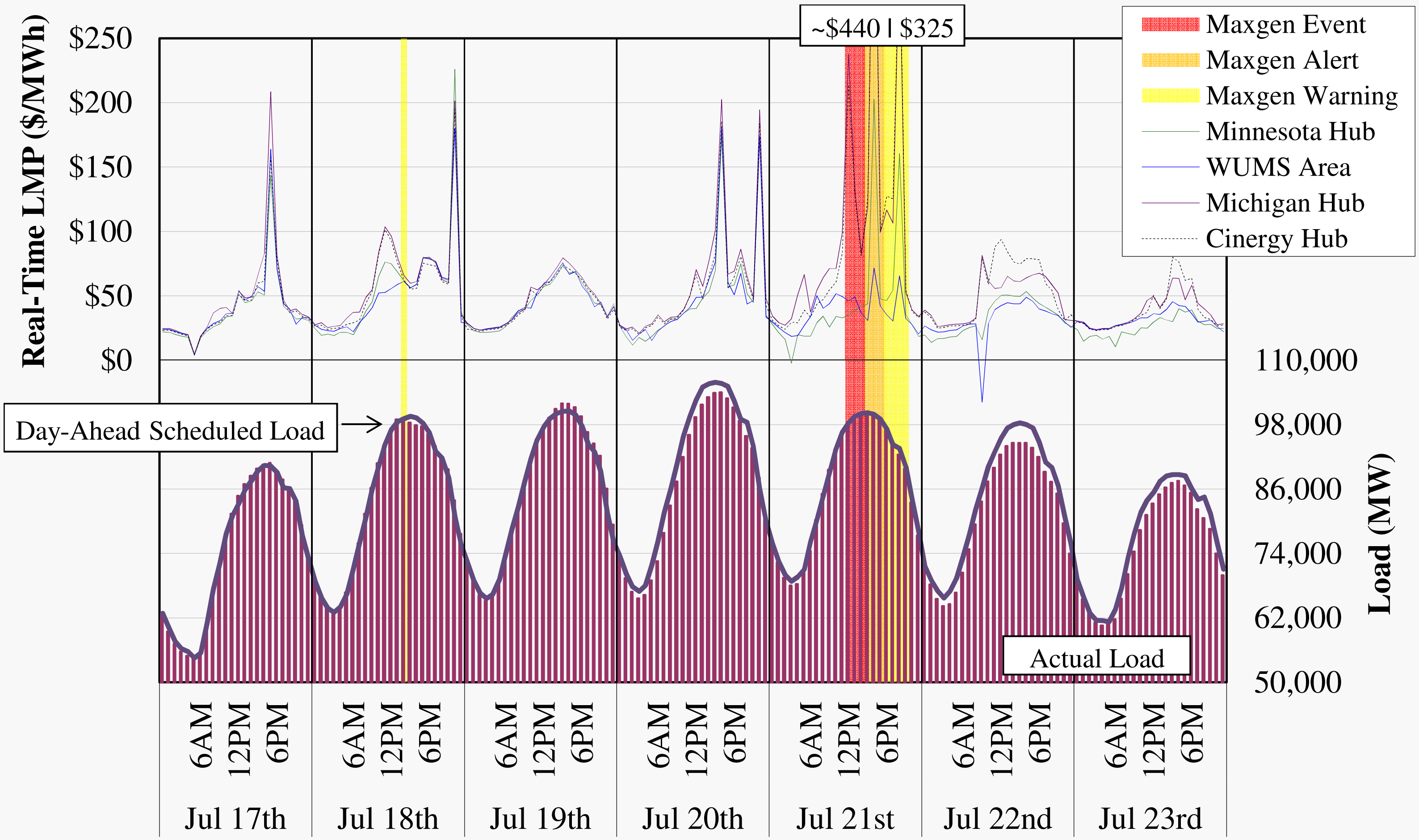
	Historical Average	July 17	July 18	July 19	July 20	July 21	July 22	July 23
Cincinnati	87	91	93	96	98	99	97	93
Detroit	84	93	96	90	96	100	95	91
Indianapolis	86	94	94	96	98	100	97	96
Milwaukee	82	95	95	85	98	94	86	86
Minneapolis	84	93	98	97	96	86	89	85
St. Louis	90	95	97	99	100	103	101	100

- MISO issued a Hot Weather Alert from July 17–23, Conservative Operations from July 18–22 and Maximum Generation Alerts on July 18 and 21.
  - ✓ A Maximum Generation Event Step 1a was declared from 1200–1500 on July 21, which triggered cuts of approximately 100 MW of non-firm exports to PJM.
  - ✓ No voluntary load reductions or emergency commitments of generators occurred.
- The next two slides show prices, load and generating capacity during the week.

Load and Prices
July 17–23

- The next figure shows the hourly load and real-time prices at four hub locations in MISO during the peak-load week. Shaded areas show various types of Maximum Generation Alerts and Events.
- Actual load peaked at 103,975 MW in Hour Ending 16 on July 20. Load scheduled in the day-ahead market for this hour was almost 2 GW higher.
  - ✓ Controlling for membership, this peak exceeded the 2006 summer load peak by 1 GW.
  - ✓ Real-time prices averaged $191 per MWh in this hour and congestion was limited.
  - ✓ Wind output of 4–5 GW helped prevent Maximum Generation conditions on July 20.
- There were few Alerts and Warnings despite load that exceeded the forecasted peak load in the Summer Assessment in 23 hours (by >5 GW in the peak hour on July 20).
  - ✓ Most MaxGen activity (8 of the 9 hours) occurred on July 21 because of a 3 GW drop in wind output from the prior day's peak hour and a reduction in imports.
  - ✓ Congestion out of WUMS on July 21 also reduced supply available to the rest of MISO and caused WUMS prices to remain low when prices in other areas rose sharply.
- Lower loads and load scheduling above 100 percent led to modest prices on July 22–23.
- Voluntary load curtailment (estimated at 500 to 900 MW) during the heat wave helped satisfy the system's needs, but was not reflected in energy prices.
- Finally, MISO had difficulty managing ramp capability during ramp down hours on the nights of July 18 and 20, which led to brief spikes in energy prices.

Load and Real-Time Prices
July 17–23



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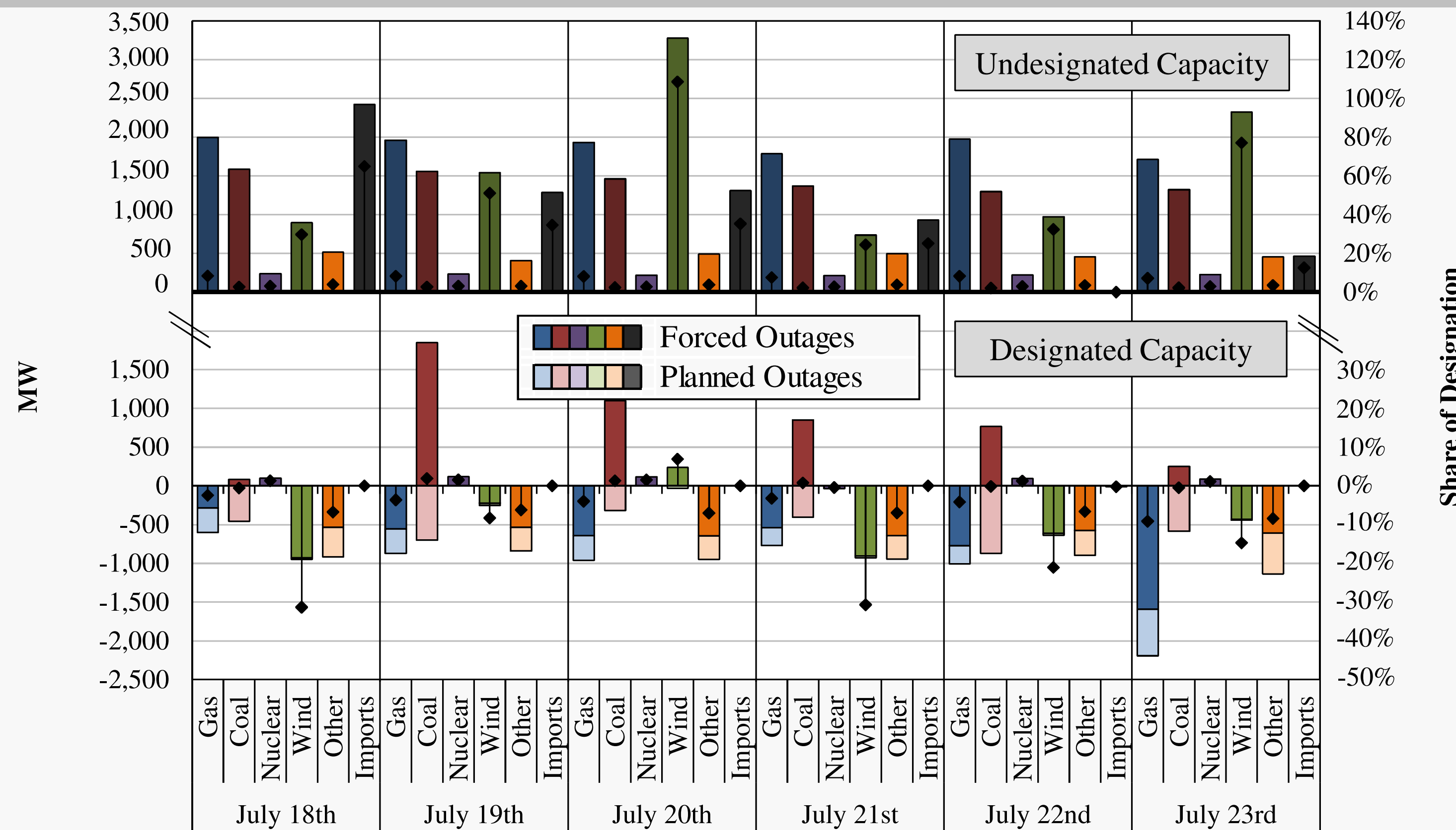
Peak Hour Capability
July 17–23

- The next chart details the real-time generation and import capability available during the daily peak hour in each day of the heat wave. The bottom and top panels summarize designated (Module E) and undesignated resources, respectively.
- Designated resources provided on average 2 percent less capacity than designated as a result of higher than anticipated forced outages.
  - ✓ Forced outages are shown as positive when anticipated outages exceeded actuals.
    - – Coal resources provided an extra 200 MW due to lower forced outages.
  - ✓ Average high temperature derates of gas-fired capacity exceeded forecasts by 700 MW.
  - ✓ Wind resources were the most variable unit type. On July 21, Module E wind resources were 31 percent below designated capacity.
- Undesignated capacity contributed the equivalent of 5.9 percent of designated capacity during the heat wave and 7.7 percent during the peak hour on July 20.
  - ✓ Over 3 GW of this capacity on July 20 was from wind resources.
  - ✓ NSI averaged 1.1 GWh (28 percent) above firm import capacity sales.
- The table at the bottom shows that in net on each day, there was at least a 2.1 percent increase in available capacity above Module E designated levels.
  - ✓ This explains the lack of load curtailment and emergency commitments during the high-load week.

Peak Hour Capability
July 17–23



Market-Wide Summary (all unit types) -- Percent Change from Module E Designations:	July 18th	July 19th	July 20th	July 21st	July 22nd	July 23rd
Undesignated Cap.	6.8%	6.2%	7.7%	4.9%	4.3%	5.7%
Designated Capacity	-2.4%	-0.6%	-0.7%	-2.0%	-2.3%	-3.5%
Total Supply Δs	4.3%	5.6%	7.0%	2.9%	2.1%	2.2%

Comparison to Actual Peak Conditions to Forecast

- The following table compares the results of two of the peak days from July week to the estimates from the IMM 2010 State of the Market Report ("SOM").
  - ✓ The purpose of the table is to compare actual supply and demand to the levels we forecasted in our 2010 SOM. It also shows the implication of a number of supply and demand factors on the reserve margins that prevailed on July 20 and 21.
- As described in the SOM, the Summer Capability case uses the summer ratings provided by MISO for all resources in MISO.
  - ✓ The "high-temperature derates" case estimates the deratings due to very high temperatures based on MISO's experience during the 2006 peak event.
  - ✓ The wind resources shown in these two SOM cases are the designated amounts plus 8 percent of any undesignated amounts.
  - ✓ Since reserve margins assume no forced outages, they are not removed from the Internal Capacity column for July 20 and 21.
- On July 20, MISO set a new all-time peak load at 103,975 MW.
  - ✓ In addition to the unusually hot temperatures, the table shows that the actual load diversity this summer was less than assumed by MISO in its Summer Assessment.
  - ✓ Conditions were not particularly tight due to low forced outages, high wind output, and smaller high-temperature deratings than predicted in the SOM.
- On July 21, load was much lower (although the forecast was significantly higher) but conditions were tighter due to much lower wind output.

Summary of Peak Supply and Demand Levels

Region	Load[1]	Load Diversity[2]	Net Imports	Wind Output[3]	DSM/IL and BTM/DRR[4]	Internal Capacity[5]	Reserve Margins: With DSM	Reserve Margins: No DSM[6]
SOM - Summer Capability								
MW	98,053	4,674	4,894	895	7,868	117,712	35.9%	25.0%
SOM - High Temperature Derates								
MW	98,053	4,674	4,894	895	7,868	109,610	27.0%	16.8%
Delta[7]	-	-	-	-	-	*(8,102)*	*-9.0%*	*-8.3%*
July 20, 2011								
MW	103,975	2,740	4,716	4,633	7,868	113,296	20.5%	11.4%
Delta[7]	*5,922*	*(1,934)*	*(178)*	*3,738*	-	*(4,416)*	*-15.5%*	*-13.7%*
July 21, 2011								
MW	100,543	2,740	4,664	810	7,868	108,593	20.1%	10.7%
Delta[7]	*2,490*	*(1,934)*	*(230)*	*(85)*	-	*(9,119)*	*-15.8%*	*-14.3%*

[1] The SOM rows reflect the estimated cooincident MISO peak for Summer 2011. For specific dates , the rows show the actual peak daily load.

[2] The SOM rows reflect estimated load diversity. For specific dates, the rows reflect actual diversity based on Summer 2011 control area 5 minute peak loads.

[3] The SOM rows reflect wind capacity designated plus undesignated at a capacity factor of 8 percent. For specific dates, the rows reflect actual wind generation at peak load.

[4] Includes all DSM (interruptible load, DCLM, and behind the meter generation and DRR).

[5] For Baseline, represents designated resources. For Adjusted row includes High Temperature Derates estimated in SOM 2011 based upon temperature derates that occurred in the Day-Ahead Market of August 1, 2006. For specific dates, includes the actual available capacity plus real-time forced outages.

[6] Reserve margin excluding forced outages and assuming no DSM.

[7] Delta values are computed relative to the SOM Baseline.

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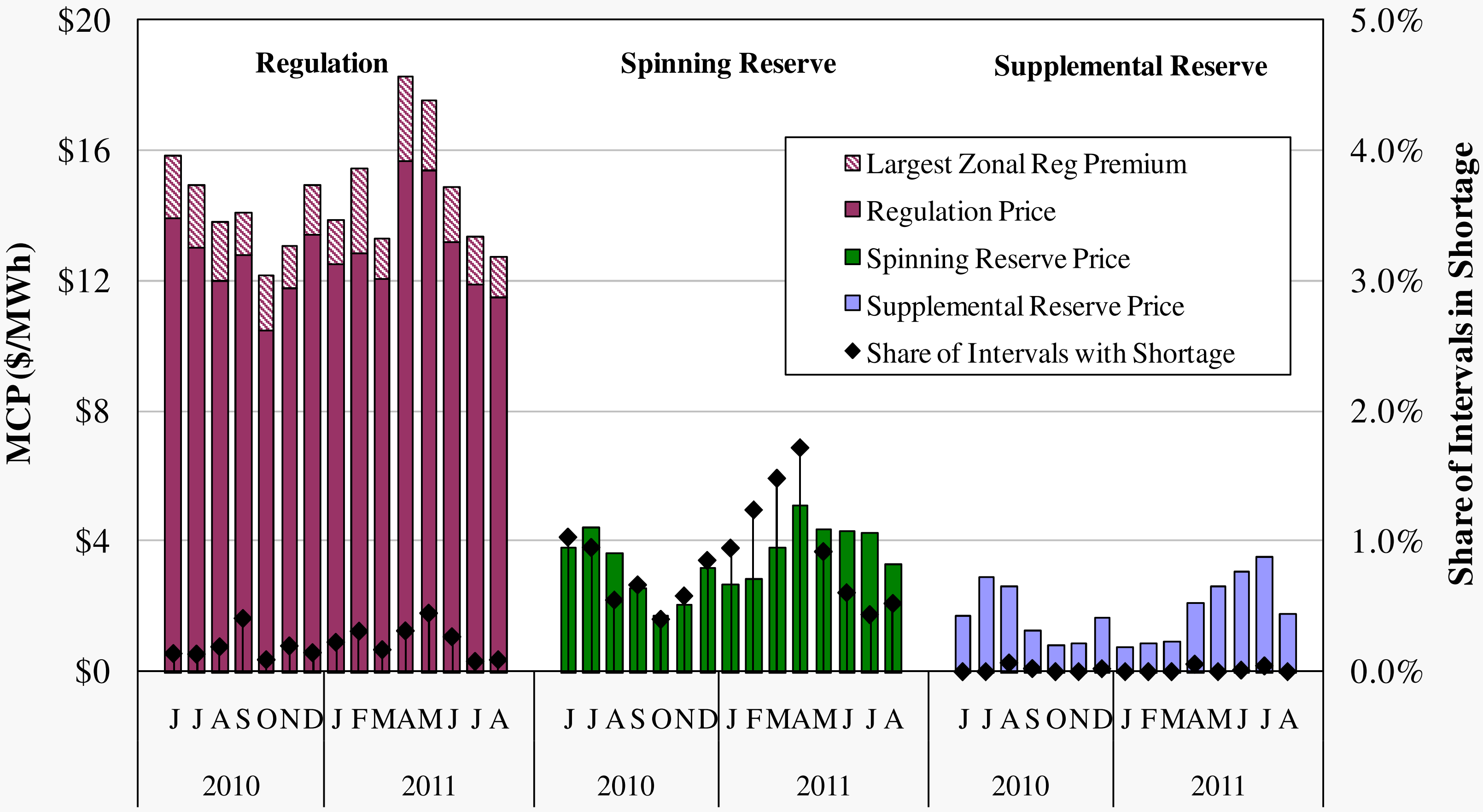
Conclusions Regarding the Peak Week in 2011

- Designated resources did not provide the full capability expected due to:
  - ✓ High-temperature deratings that are not fully accounted for in the Module E process or MISO's Summer Assessments.
  - ✓ Wind resources produced substantially less output than their designations in some of the peak hours (and substantially more in others).
  - ✓ These factors were offset by relatively low forced-outage levels for many resources.
- The actual peak substantially exceeded the forecasted peak because:
  - ✓ Temperatures were hotter than normal; and
  - ✓ Load diversity was less than assumed in the MISO Summer Assessment.
  - ✓ Planning (and procuring capacity under Module E) for a forecasted peak under normal conditions may not fully prepare the system to address unusual conditions.
- These issues, however, did not cause significant reliability issues during the peak week because MISO currently has a substantial capacity surplus.
  - ✓ Undesignated capacity more than compensated for the reduction in capability from designated resources.
  - ✓ However, these planning issues will have larger implications once the surplus dissipates.

Monthly Real-Time Ancillary Service Prices

- The following chart shows monthly average real-time clearing prices for MISO's ancillary service products for the preceding fifteen months.
- Regulation clearing prices averaged $12.16 per MWh this summer, down 6 percent from summer 2010 and 15 percent from spring 2011.
  - ✓ Prices decreased due to fewer shortages and slightly lower fuel prices.
  - ✓ There were 38 regulation shortage intervals in summer, down from 82 and 41 in spring 2011 and summer 2010, respectively.
  - ✓ In addition, the average regulating reserve demand curve price declined 28 percent from summer 2010 to $166 per MW.
  - ✓ The zonal premium was highest in Michigan (Zone 4) at over $1.40 per MWh.
- Spinning reserve prices averaged $3.94 per MWh this summer, roughly equal to those in summer 2010, and 10 percent lower than spring 2011.
  - ✓ As with regulation, there were fewer spinning reserve shortages – the percentage of shortage intervals declined to approximately one-third.
- Supplemental reserve prices rose 15 percent from summer 2010 to $2.79 per MWh.
- Real-time premiums for each product were substantial.
  - ✓ Supplemental reserves were almost twice as expensive in real time due to:
    - – Low offline contingency reserve offer volumes; and
    - – The impact of contingency reserve deployments in real time.

Monthly Average Ancillary Service Prices
Regulation and Spinning Reserves, 2010–2011



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MISO Fuel Prices

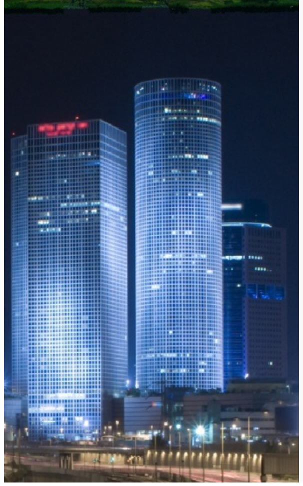
- The next figure shows daily average fuel prices from June 2009 to present.
- Fuel prices (except natural gas) were higher compared to last summer.

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

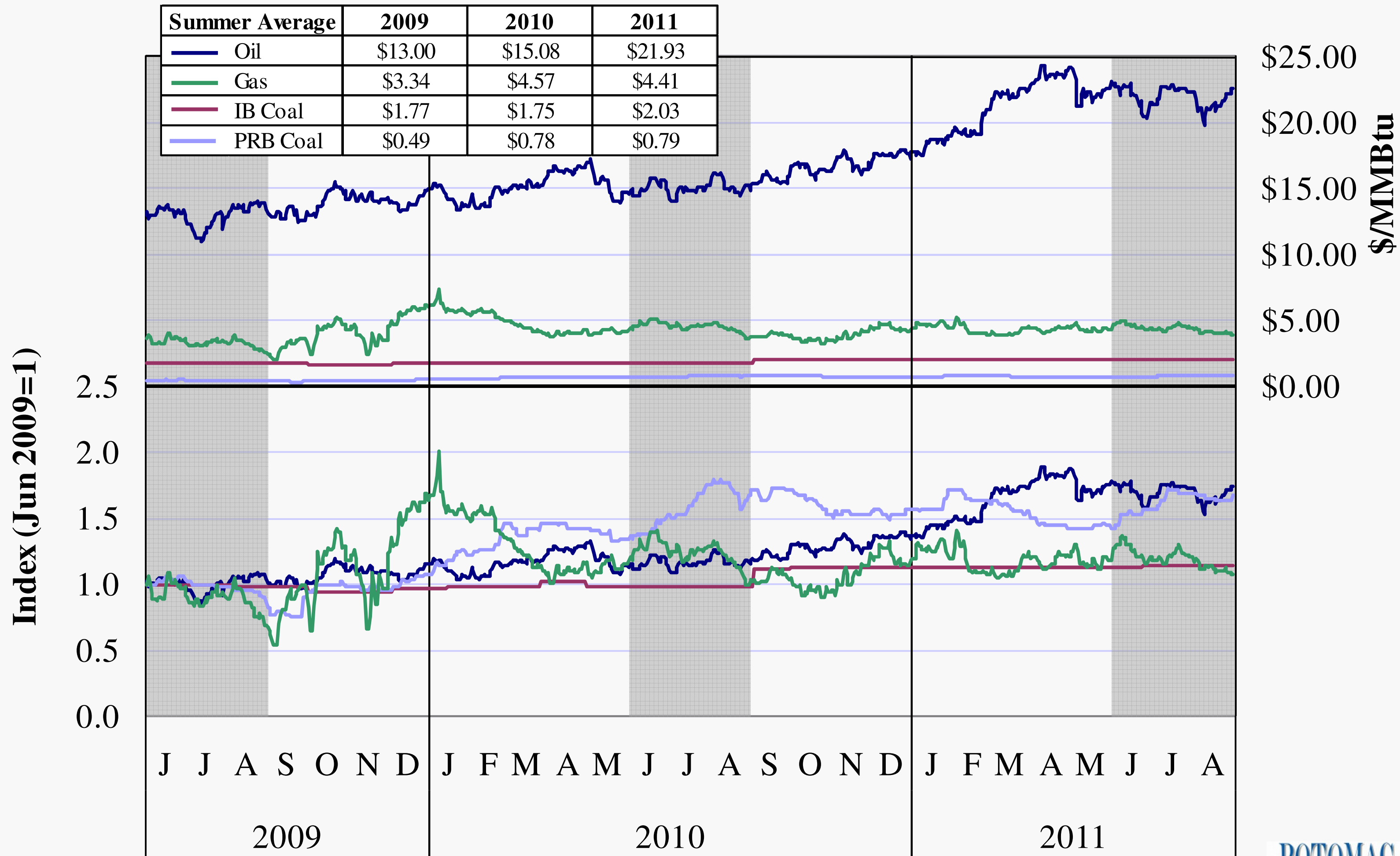
- Natural gas prices averaged $4.41 per MMBtu in the June to August period.
  - ✓ Gas prices were 4 percent lower than in summer 2010 but one-third higher than in summer 2009.
  - ✓ Gas prices declined gradually over the summer, peaking at $5.01 per MMBtu on June 10 and ending August at below $4.
- Oil prices averaged near $22 per MMBtu in the quarter, up 45 and 69 percent from the summers of 2010 and 2009, respectively.
  - ✓ This increase has not significantly affected MISO energy prices because oil resources were rarely on the margin this summer (see slide 19).

<u>Coal Prices</u>

- Illinois Basin prices again averaged near $2 per MMBtu. Prices are largely unchanged in 2011 but are 10 percent higher than in summer 2010.
- Powder River Basin prices increased 1 cent from last summer, averaging $0.79 per MMBtu. Prices are over 60 percent higher than in summer 2009.



MISO Fuel Prices
2009–2011

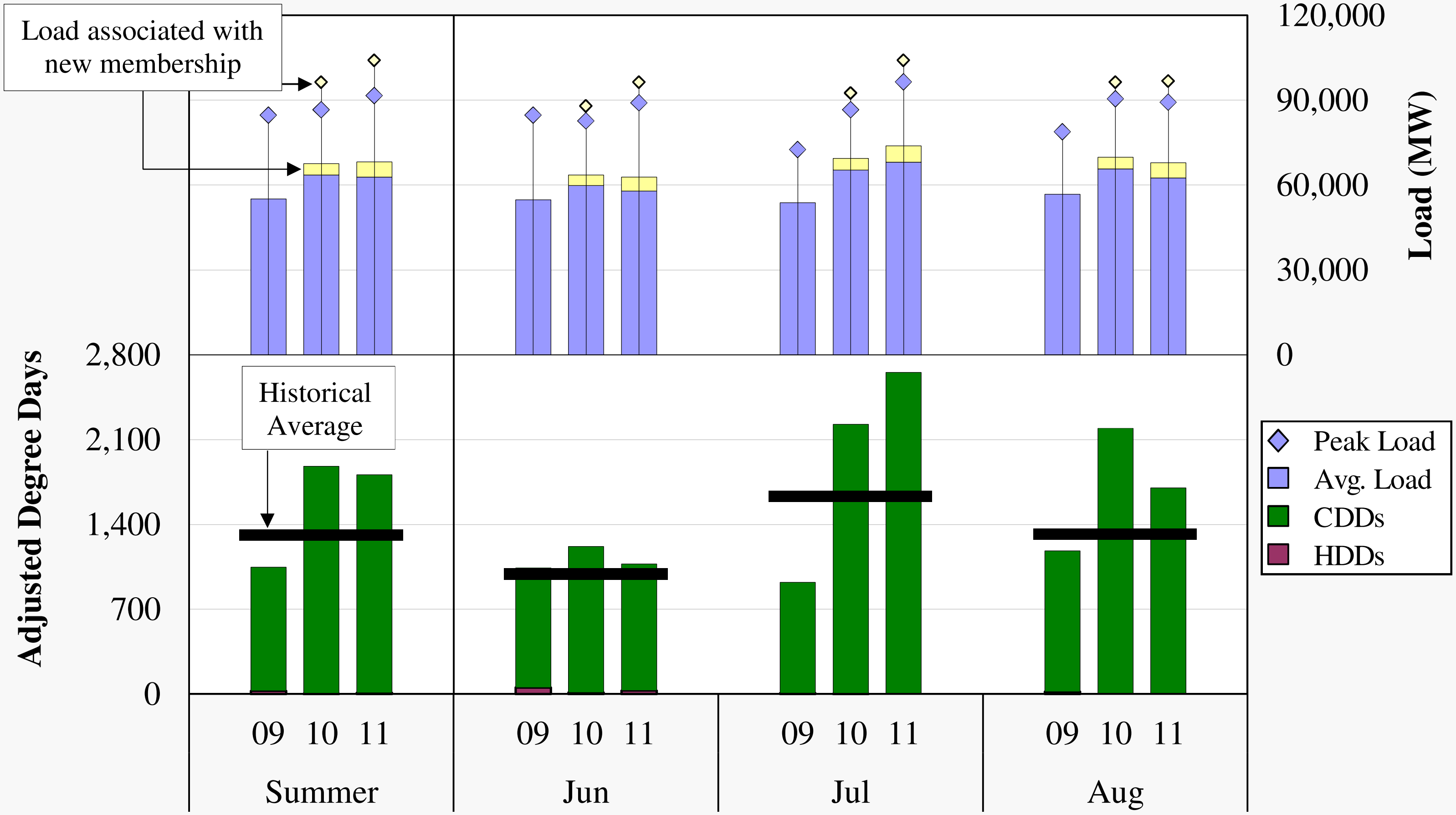


Summer Average	2009	2010	2011
Oil	$13.00	$15.08	$21.93
Gas	$3.34	$4.57	$4.41
IB Coal	$1.77	$1.75	$2.03
PRB Coal	$0.49	$0.78	$0.79

Changes in Load and Weather Patterns

- The next figure shows changes in load in summer of 2009 to 2011, as well as the changes in weather patterns that contributed to the load changes.
- The top panel shows the monthly average and peak loads in each summer.
  - ✓ Load averaged 68.2 GW in the quarter and peaked near 104 GW on July 21.
  - ✓ Excluding membership changes (FirstEnergy exited MISO on June 1), average load decreased by 1.1 percent from summer 2010 on slightly cooler weather.
- Because a large share of the load is sensitive to weather, the figure shows how changes in weather patterns contributed to changes in load.
  - ✓ The bottom panel in the figure shows the monthly heating and cooling degree days ("HDDs and CDDs") for the second quarters of 2009 to 2011 at four locations in MISO.
  - ✓ To account for the different relative impacts of HDDs and CDDs, HDDs are inflated by a factor of 6.07 to normalize the effects on load (based on a regression analysis).
- Consistent with the changes in load, degree days fell by 4 percent in summer 2011.
  - ✓ Despite the decline degree days remained 38 percent above the historical average.
  - ✓ July average temperatures across MISO were near all-time records. June and August were near normal.

Load and Weather Patterns Summer 2009–2011



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

Share of Interval Price Setting
By Unit Fuel Type

- The next figure shows the frequency that different types of units set real-time energy prices in MISO.
  - ✓ When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained area).
- Coal units set prices in approximately 92 percent of all hours in summer 2011.
  - ✓ This is a 7 percentage-point increase from last summer. This is attributable to an increase in the frequency of binding constraints, causing coal-fired resources being on the margin at some locations even during peak load conditions.
- Gas-fired resources set prices in 20 percent of all intervals, unchanged from 2010.
  - ✓ Along with oil-fueled resources, these units typically set prices during high load periods or when they are needed to manage congestion.
- The introduction of the DIR type in June allowed select wind units to set price for the first time. In summer 2011, 11 wind units offering 1.2 GW participated.
  - ✓ DIR units set price in nearly 5 percent of intervals. In almost every instance, DIR are setting price only in local areas affected by a constraint, rather than market wide.
  - ✓ The average LMP at these locations was -$16 per MWh because these units receive subsidies that result in marginal costs less than zero.
  - ✓ Beginning September 1, an additional 800 MW of wind resources qualify as DIR.

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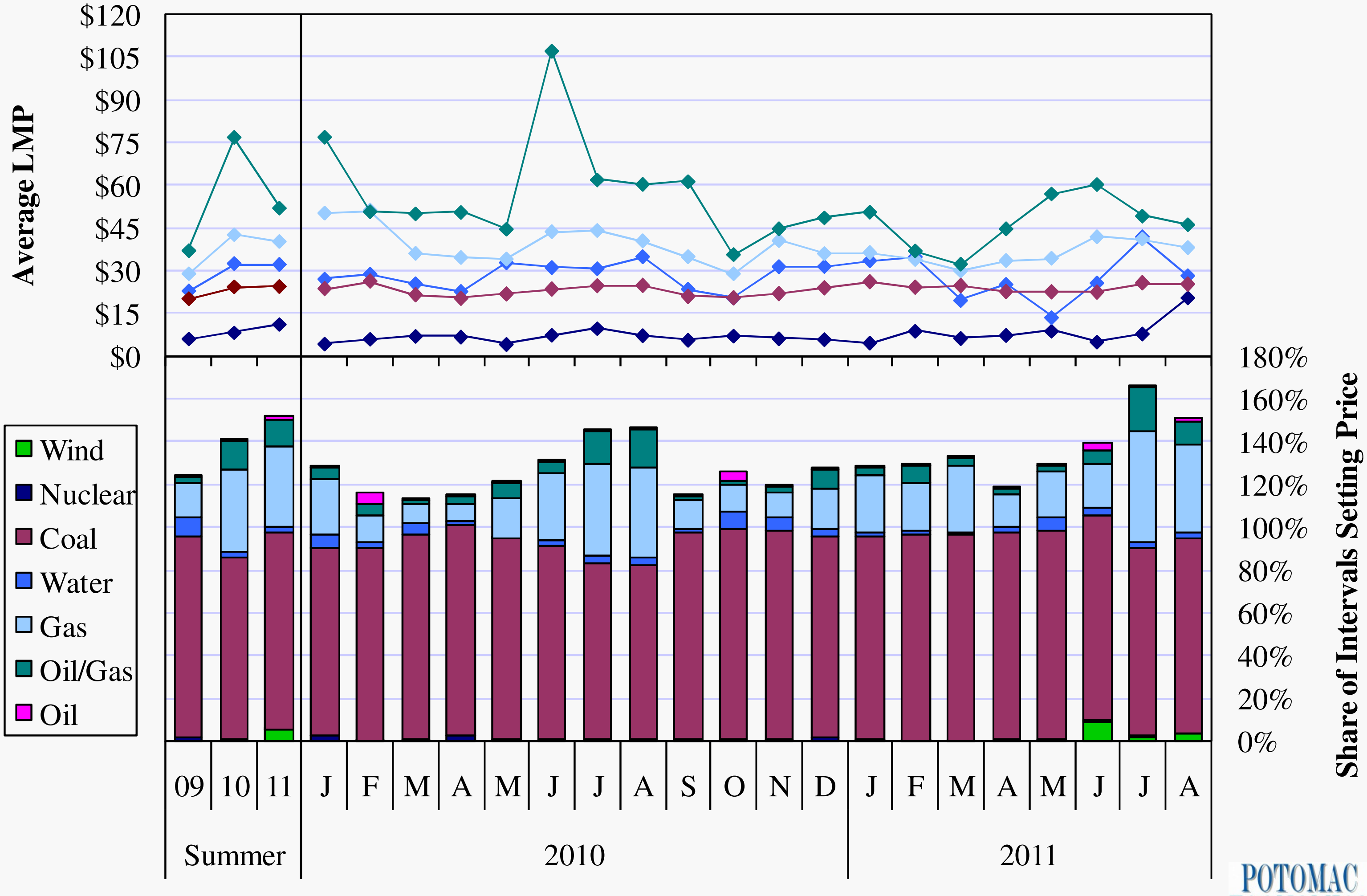
Real-Time Energy Price Setting By Unit Fuel Type 2010–2011



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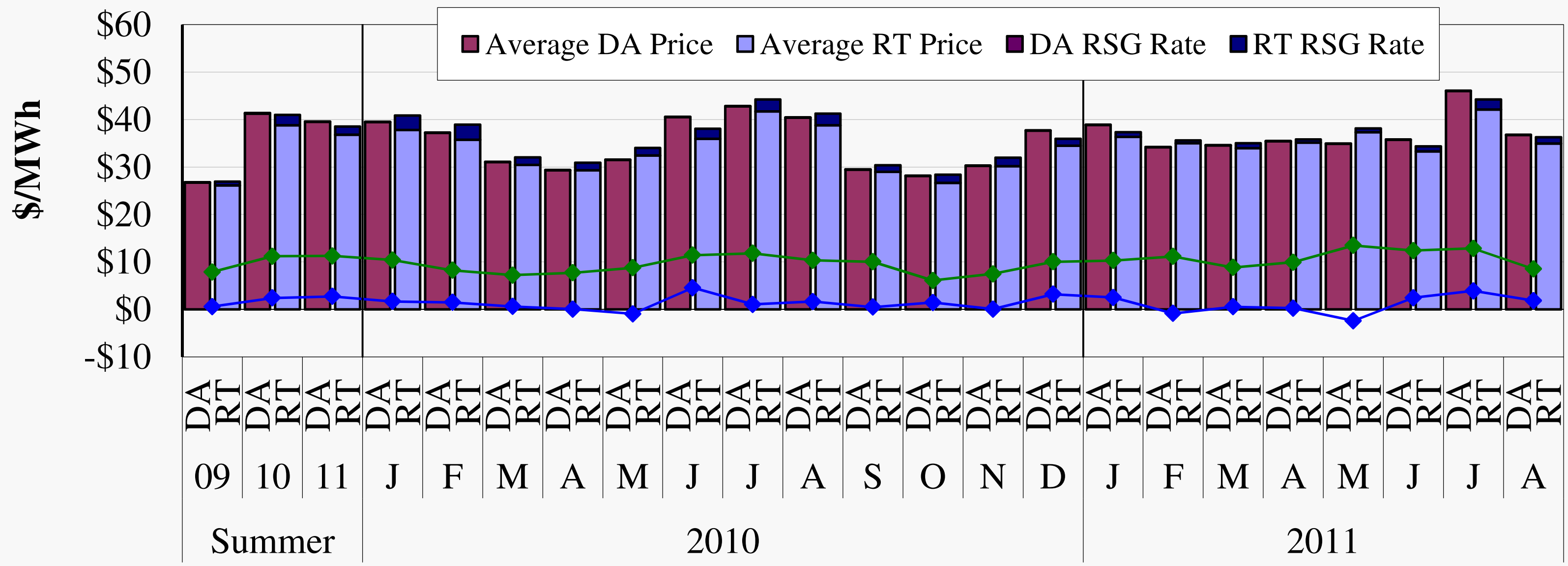
Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between the day-ahead and real-time prices.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and larger RSG allocation to buyers in the real-time market.
- The next figure shows the day-ahead to real-time price convergence at the Cinergy Hub (the table shows other locations).
- Prices convergence was fair at most locations this summer. Day-ahead premiums ranged from -1 percent at Minnesota Hub to 7 percent at Cinergy Hub and were similar to those in summer 2010.
  - ✓ Premiums were in part due to load being overscheduled in each month (see slide 23), caused in part by participant forecast errors and higher expected real-time prices.
- Premiums are often higher in summer than in other months because participants hedge against an increased risk of real-time shortages on high-load days.
  - ✓ This was particularly the case in July (premiums of 6-9 percent footprint-wide).
- In June, congestion in the West region increased real-time prices there on several days.
- The absolute value of the hourly differences measures the typical magnitude of the differences, regardless of direction. These values were consistent with prior periods.

Day-Ahead and Real-Time Price Convergence 2010–2011



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

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

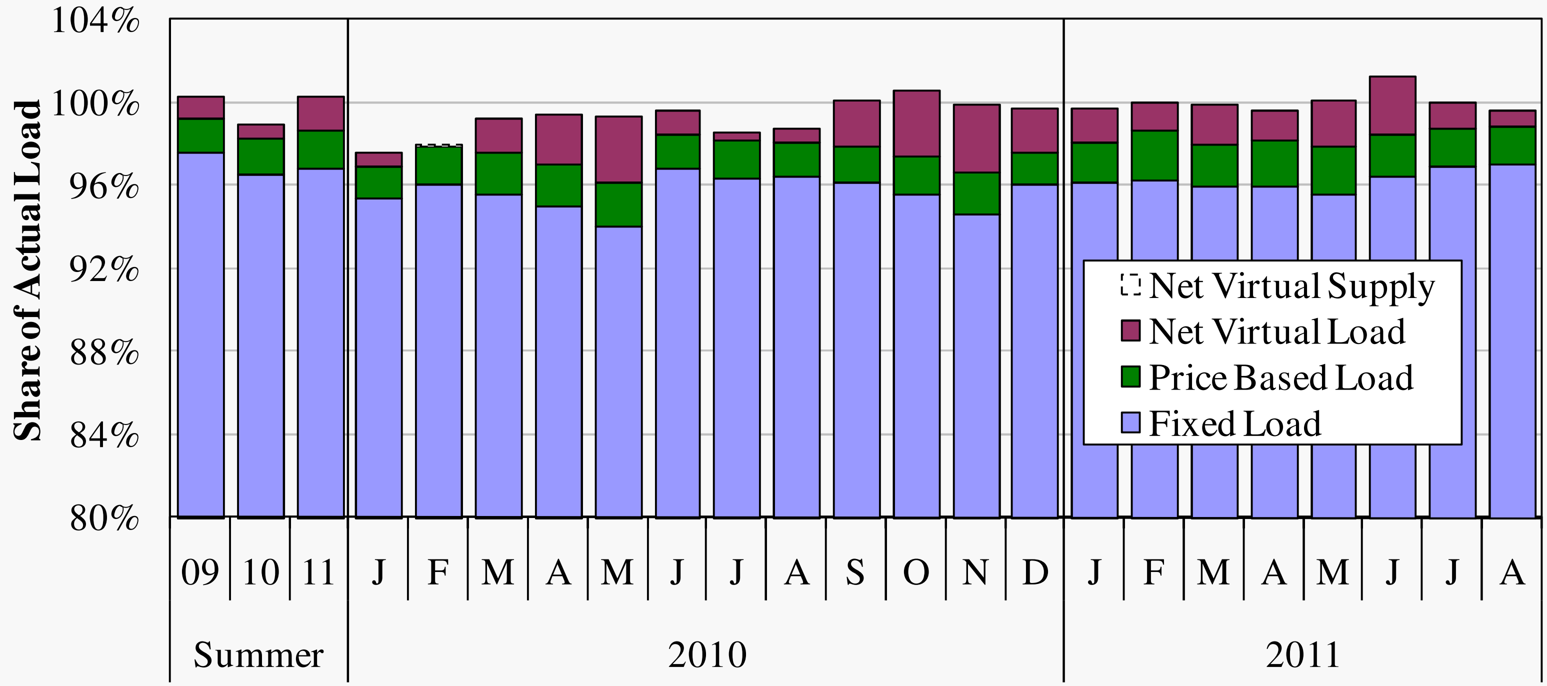
Average Absolute DA-RT Price Difference (% of Real-Time Price)

Cinergy Hub	30	29	31	28	23	24	26	27	32	28	27	35	23	25	29	28	32	26	28	36	37	30	24
Michigan Hub	33	30	32	30	24	24	32	39	33	31	27	40	37	29	31	31	36	28	39	40	37	32	26
Minnesota Hub	42	32	32	36	28	28	30	37	35	29	31	47	39	41	32	24	52	33	41	48	40	27	29
WUMS Area	42	35	30	35	26	29	28	35	41	30	33	50	31	31	31	24	34	25	31	37	39	26	26

Day-Ahead Load Scheduling

- The following figures analyze net load scheduling and related impacts.
- The first figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG because low levels can compel MISO to commit peaking resources to satisfy higher real-time load.
  - ✓ However, real-time commitments are still made to maintain reserves, manage congestion and resolve local reliability issues.
- Load was more than fully scheduled on average during all hours (100.6 percent) as well as peak hours (100.3 percent) in summer 2011.
  - ✓ Net virtual load more than made up the scheduling shortfall of fixed and price-based load.
- This broad metric masks considerable variation in day-to-day scheduling. The second figure shows that the scheduling of net load has a strong positive correlation with day-ahead price premiums.
  - ✓ Large scheduling discrepancies – particularly under-scheduling – can have disproportionately large price effects.
  - ✓ Under-scheduling of load during the peak hour, likely due to poor participant forecasting or unanticipated storms, exceeded 4 percent on 8 days in the period.
  - ✓ When this occurs, MISO often has to commit expensive real-time resources.

Day-Ahead Peak Hour Load Scheduling 2009–2011



Share of Actual Load(%)

All Hour	100.7	99.5	100.6	98.2	98.9	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0	100.3	99.8	99.6	99.3	99.4	100.8	100.9	100.2
Peak Hour	100.5	99.0	100.3	97.6	97.9	99.2	99.4	99.4	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	99.6

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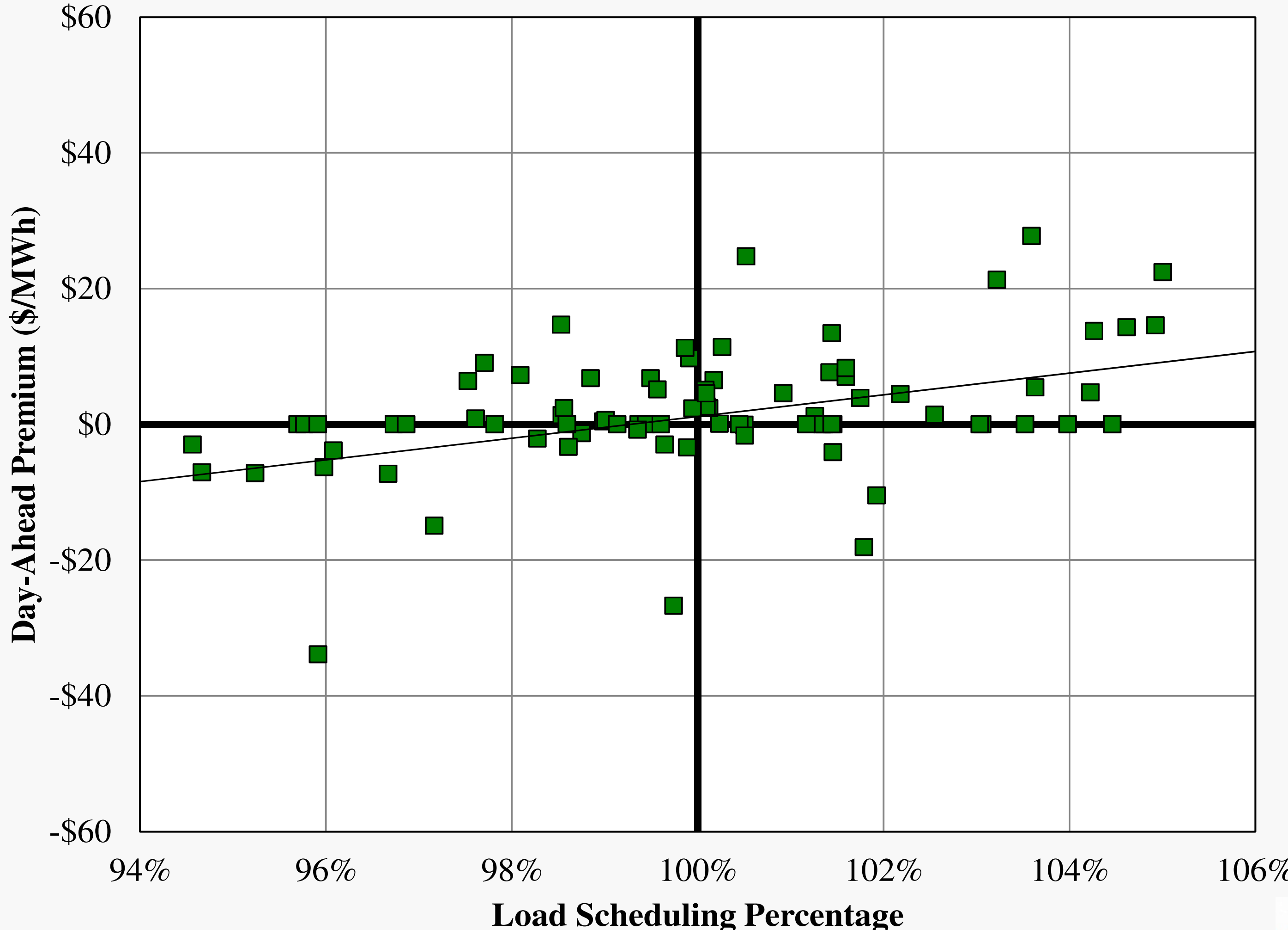
Daily Load Scheduling and Price Convergence
Peak Hours, Summer 2011



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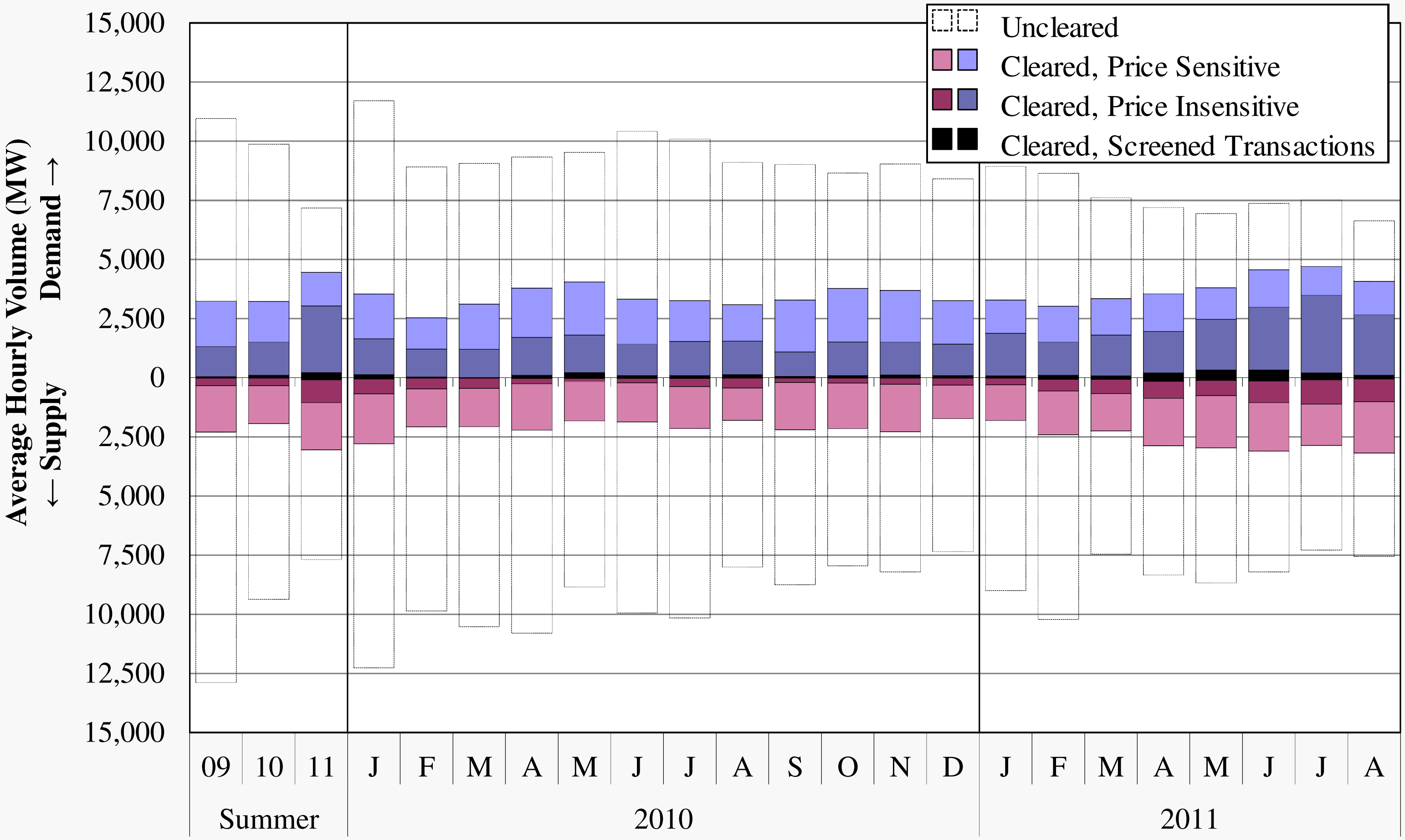
Virtual Load and Supply in the Day-Ahead Market

- 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 mitigates market power in the day-ahead market.
- The next three figures shows the average hourly quantities virtual demand bids and supply offers and those that were scheduled (cleared) in the day-ahead market.
- The figures distinguish between bids and offers that are price-sensitive and price insensitive (those that are very likely to clear).
  - ✓ Bids and offers are considered price-insensitive when they are offered at more than $30 above and below “expected” real-time prices, 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”) are investigated.
    - – These volumes are not rational and lead to price divergence.
- The table below the figures show the average number of participants in each hour.
- We have been monitoring trends in virtual trading activity closely since MISO changed the RSG cost allocation in April 2011.
  - ✓ The change generally reduces the allocation of RSG to virtual supply, and eliminates any allocation when virtual supply is netted against virtual load.

Virtual Load and Supply in the Day-Ahead Market

- The first figure shows that cleared volumes increased by 45 percent in summer 2011 compared to summer 2010.
- This rise is largely associated with price-insensitive bids and offers.
  - ✓ Approximately 68 percent of demand bids and 35 percent supply offers were price-insensitive, compared to 47 and 18 percent, respectively, in summer 2010.
  - ✓ Only 3 to 5 percent of cleared volumes were screened for further review.
- The increase in price-insensitive offers is likely due to the change in RSG allocation.
  - ✓ Some participants appear to be taking positions across constrained paths to arbitrage differences in day-ahead and real-time congestion.
  - ✓ By forcing an equal level of supply and demand transactions to clear, participants can avoid most of the RSG cost allocation.
  - ✓ Improving the netting provisions across participants could reduce the incentives to bid and offer price-insensitively.
- The number of participants has not changed significantly since the start of 2010.

Virtual Load and Supply
2009–2011

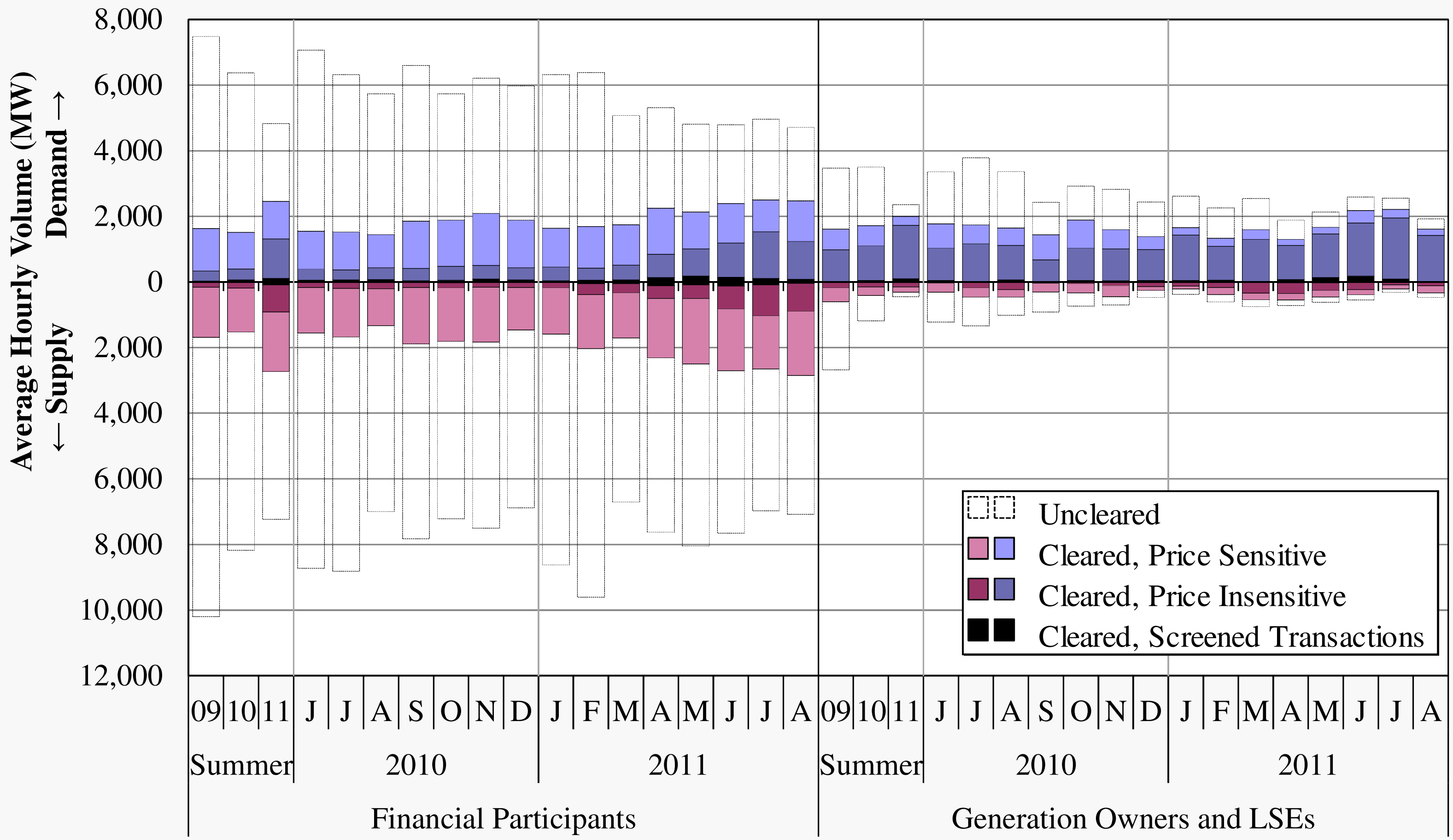


Avg. Hourly Participants																						
	66	68	72	71	72	72	71	69	67	69	67	68	72	74	67	69	70	71	75	78	76	71	67

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.
- On average 72 participants were active in each hour in summer 2011, of which three-quarters (53) were financial participants.
  - ✓ Financial-only participants comprised 81 percent of offered volumes and 69 percent of cleared volumes in summer 2011, up from 76 and 59 percent, respectively, last summer.
    - These participants offered 97 percent and cleared 92 percent of the virtual supply.
  - ✓ While financial participants’ volumes were evenly divided between supply and demand, nearly 85 percent of physical participants’ volumes were demand bids.
- Physical participants generally offer less price-sensitively than financial players do.
  - ✓ Fully 82 percent of volumes offered by physical participants cleared in summer 2011, compared to only 43 percent of those offered by financial-only participants.
    - This is an increase from 45 and 21 percent, respectively, in summer 2010, and is largely due to the increase in price-insensitive transactions (see previous slide).
  - ✓ Much of the increase in price-insensitive trading is by financial participants whose bidding patterns generally are not indicating potential competitive concerns.
  - ✓ These increases are likely due to the new RSG allocation rules and the increased incentives to arbitrage congestion differences across key paths.

Virtual Load and Supply by Participant Type 2009–2011



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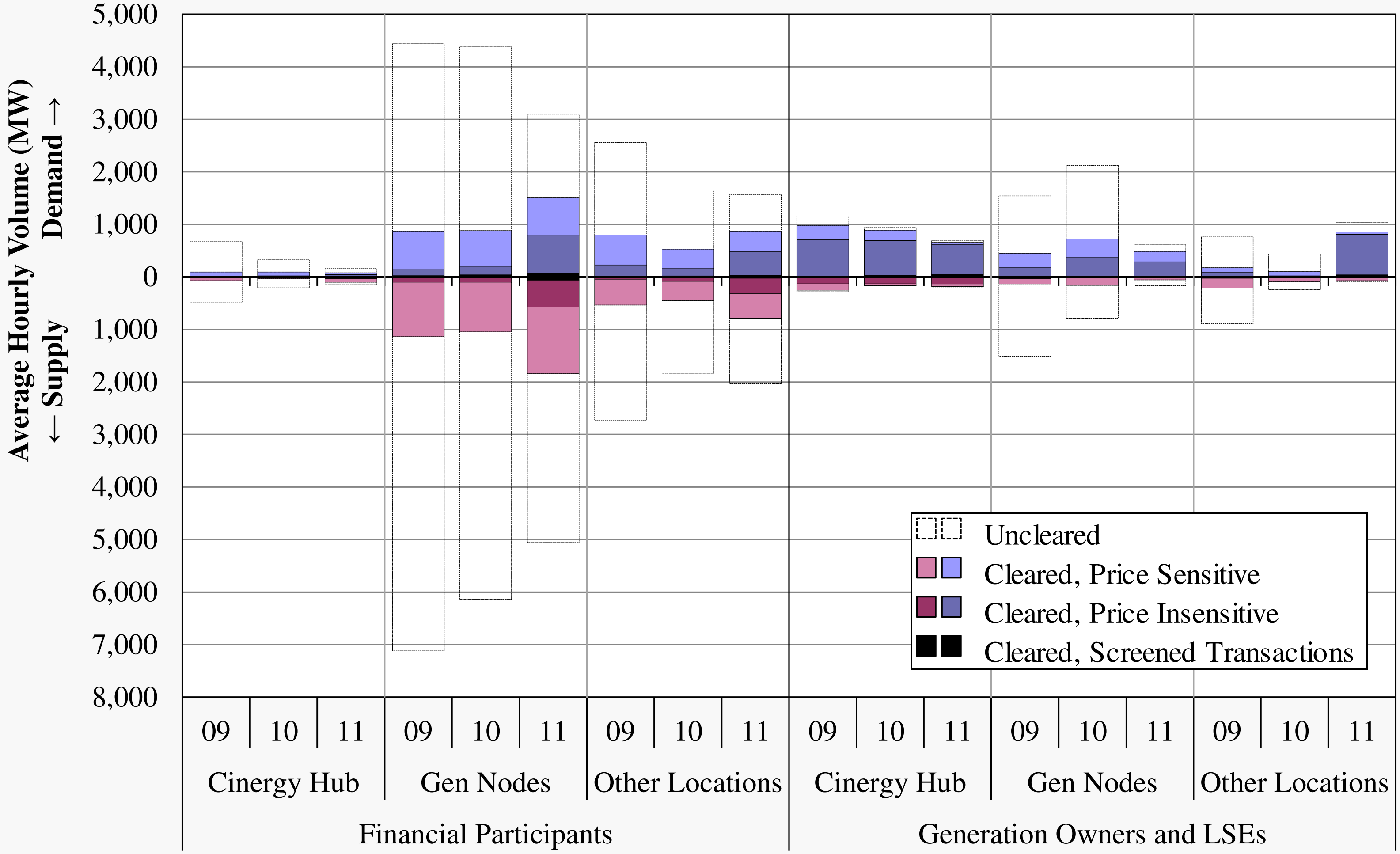
Virtual Load and Supply by Participant Type and Location

- The third figure in this set presents the same results broken down by type of market participant and location (Cinergy Hub, other hubs and zones, and nodes).
- The majority of virtual liquidity in the day-ahead market is at generator nodes.
  - ✓ 60 percent of offered volumes and 52 percent of cleared volumes occur here.
  - ✓ Roughly 90 percent of these volumes are by financial participants.
  - ✓ 88 percent of cleared volumes at Cinergy Hub are price-insensitive transactions by physical participants.
- Conversely, over three-quarters of offered volumes by physical participants are at hub locations.
- The figure shows that the increase in cleared virtual transactions are almost entirely due to increased activity by financial participants at all locations.
  - ✓ However, bid and offer volumes are lower for almost all locations and participant types.
- While these results do not raise significant concerns, they will be useful in evaluating potential improvements in the RSG allocations rules.

Virtual Load and Supply by Participant Type and Location, Summer 2009–2011



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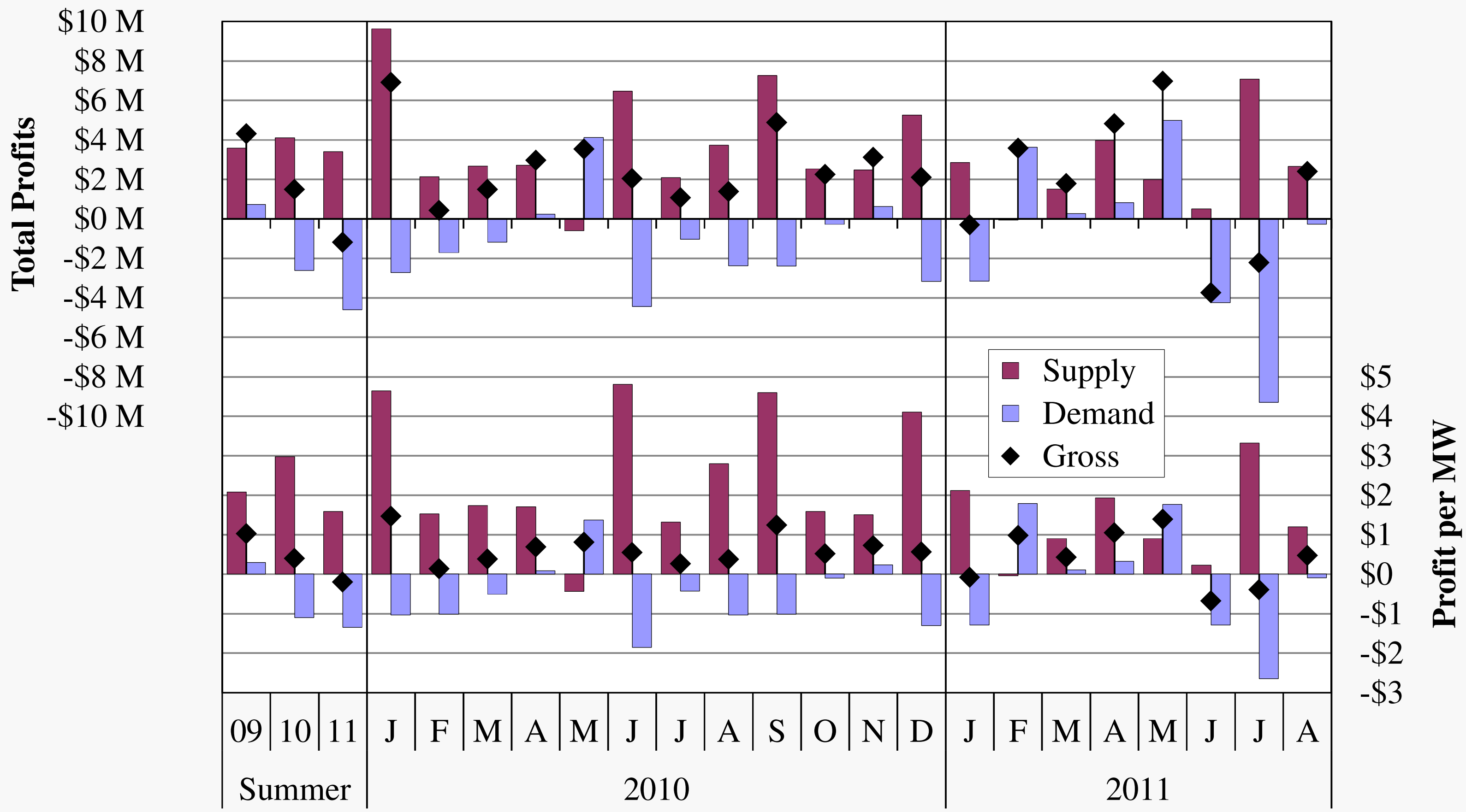
Virtual Profitability in the Day-Ahead Market

- The following two figures examine monthly profitability of virtual purchases and sales.
- In summer 2011, gross profits declined to -\$1.2 million (-\$0.20 per MW).
  - ✓ While supply has remained modestly profitable (\$1.58 per MW), demand was unprofitable in each month, losing \$1.35 per MW on average.
  - ✓ Virtual supply profitability is expected in markets with prevailing day-ahead premiums.
  - ✓ Demand losses spiked in June and July when day-ahead premiums were substantial.
  - ✓ These margins exclude CMC or DDC charges assessed to net harming deviations, including net virtual supply. DDC charges averaged \$1.53 per MWh in the period.
- The second figure shows that virtual transactions by financial participants are generally profitable and improve convergence, while those by physical participants are generally unprofitable.
  - ✓ In particular, cleared virtual supply offers by financial participants averaged \$1.69 per MW, while cleared virtual demand bids by physical participants averaged -\$3.02.
  - ✓ Physical participants may be willing to incur losses on virtual demand to hedge against the risk of real-time price spikes.
- The table below the first figure indicates that the share of cleared volumes screened for additional review have increased modestly, but remain small (3 to 5 percent).

Virtual Profitability by Location 2009–2011



Share of Cleared Virtuals Screened

	09	10	11	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A
Supply	1.0	1.2	3.0	1.7	1.0	0.9	1.3	1.4	1.4	1.2	1.0	1.0	1.1	1.1	1.3	1.2	3.0	3.1	5.0	3.8	4.5	3.2	1.5
Demand	1.3	3.4	4.9	3.8	1.3	0.5	2.8	5.3	3.1	2.9	4.3	1.7	2.8	3.3	3.2	2.7	3.6	2.6	5.9	8.4	7.2	4.5	2.7

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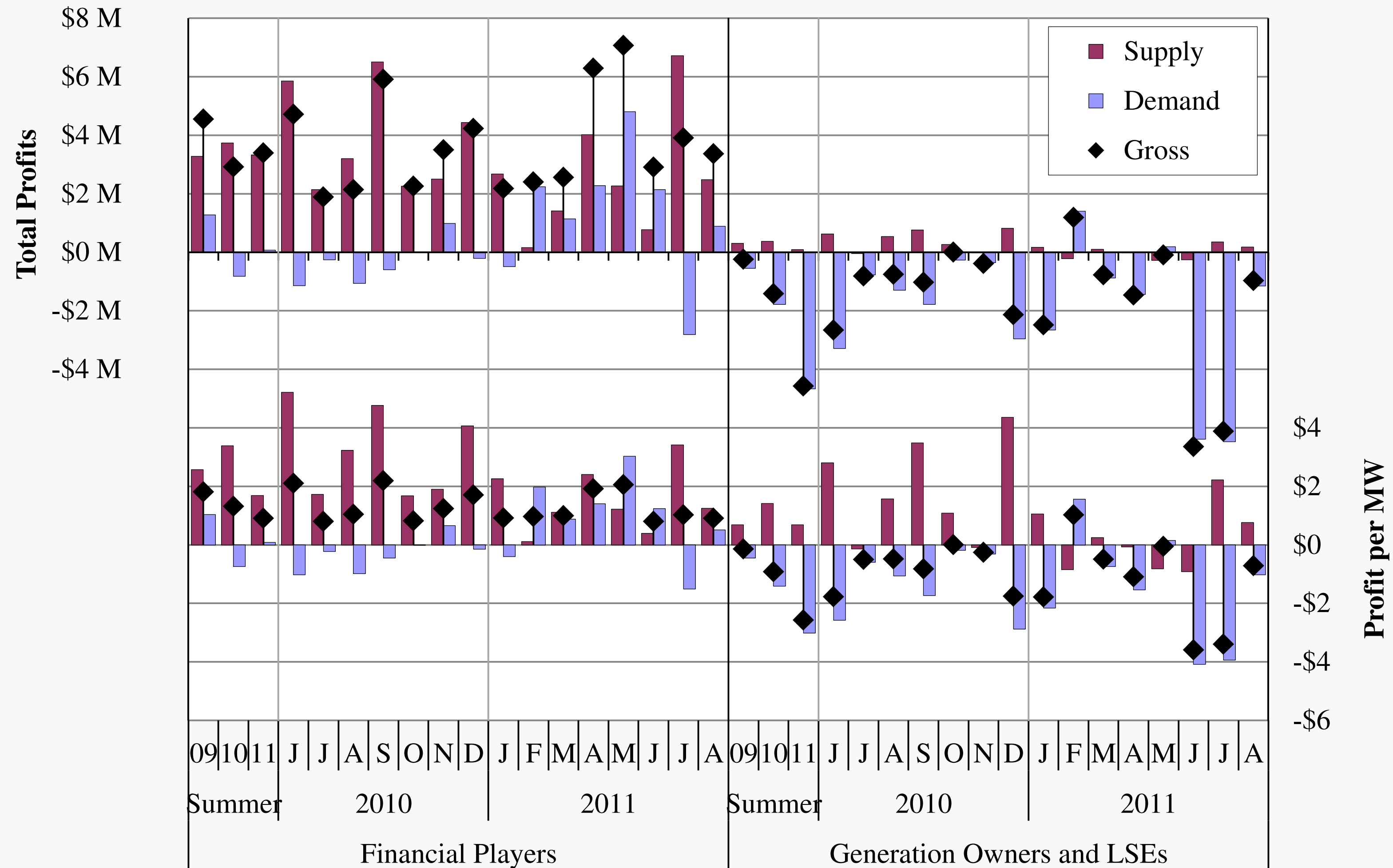
Virtual Profitability by Participant
2009–2011



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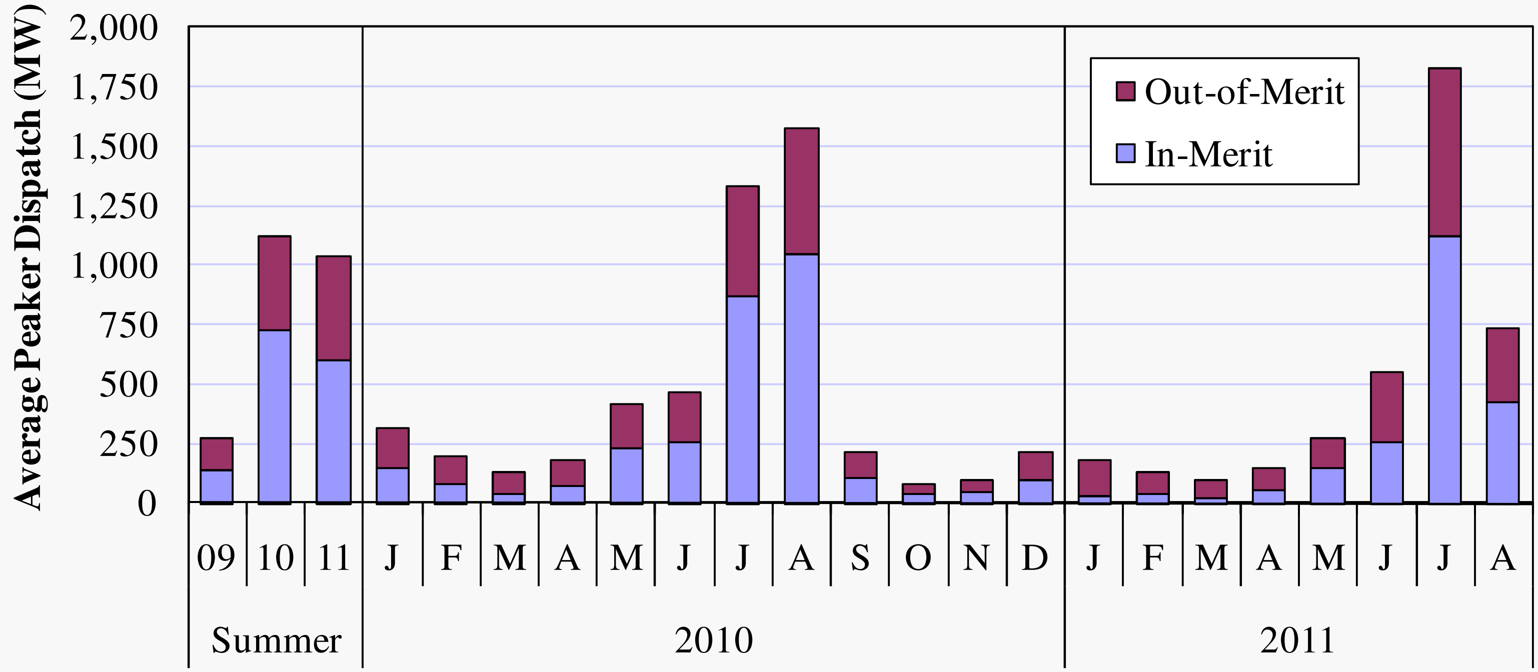
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were out-of-merit (offer price higher than the LMP).
- Peaking resource dispatch quantities averaged 1,039 MW per hour this summer, slightly less than in summer 2010.
  - ✓ Quantities were 4 times greater than during the unusually cool summer of 2009.
- The share of units dispatched out-of-merit rose 6 percentage points to 42 percent.
  - ✓ This share remains less than normal because high levels of dispatch to serve peak load tends to increase the frequency with which they set real-time energy prices.
- Dispatch quantities were highest in late July to meet load and ASM requirements.
  - ✓ Hourly dispatch quantities repeatedly exceeded 10 GW during the afternoon hours of the July 17–23 heat wave.
- Low day-ahead load scheduling on several days in the quarter also caused MISO to commit additional units in real-time to satisfy load.
- When peaking resources do not set the energy price, relatively high-cost resources committed to manage congestion or to provide capacity will be out-of-merit.
  - ✓ MISO continues to develop pricing improvements, including its Enhanced LMP initiative, that will allow peaking resources to set energy prices when appropriate.
  - ✓ This should improve MISO's price signals and reduce real-time RSG payments.

Peaking Resource Dispatch and In-Merit Status 2010–2011



Out-of-Merit Quantity and Share

MW	142	401	437	173	120	88	106	185	212	461	530	106	46	44	116	152	88	82	92	120	296	707	308
%	51	36	42	54	60	68	59	44	45	35	34	49	54	47	54	82	68	82	64	44	53	39	42

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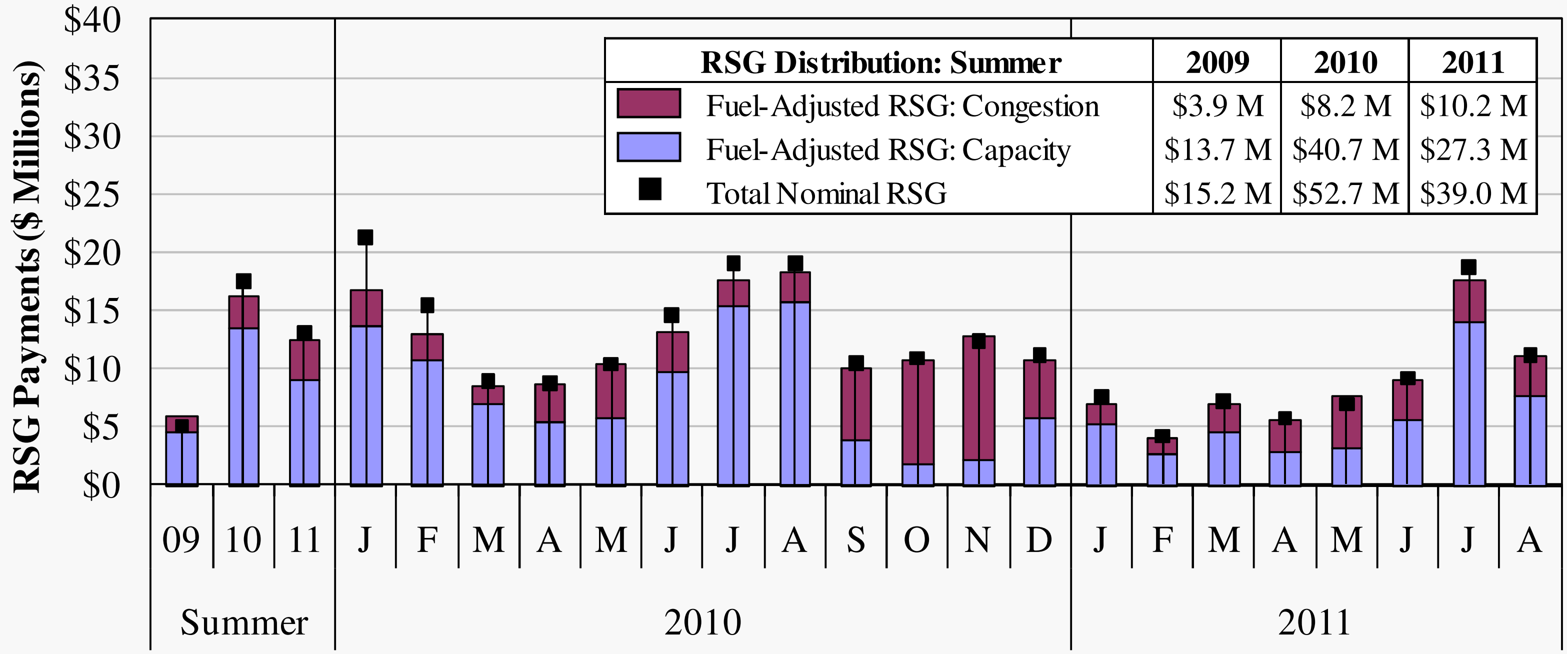
Real-Time and Day-Ahead RSG Payments

- 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.
- RSG costs in summer 2011 decreased from $53 million to $39 million.
  - ✓ Overall costs fell by roughly one-quarter on both a nominal and fuel-adjusted basis.
  - ✓ Payments for capacity decreased by approximately one-third to $27.3 million, while those for congestion rose by one-quarter to $10.2 million.
- The increase in load scheduling (to over 100 percent) reduced the amount of commitments that MISO had to make for capacity in the real time.
  - ✓ Also, changes to import and wind generation levels from day-ahead schedules did not cause MISO to have to commit peaking resources as frequently as they did in 2010.
- The second figure shows day-ahead RSG levels, which continued to be lower than real-time RSG because reliability requirements are not modeled in the day-ahead market.
  - ✓ Day-ahead RSG costs decreased 17 percent to $8.7 million. Tight capacity conditions in July resulted in over 40 percent of July payments to go to peaking units.

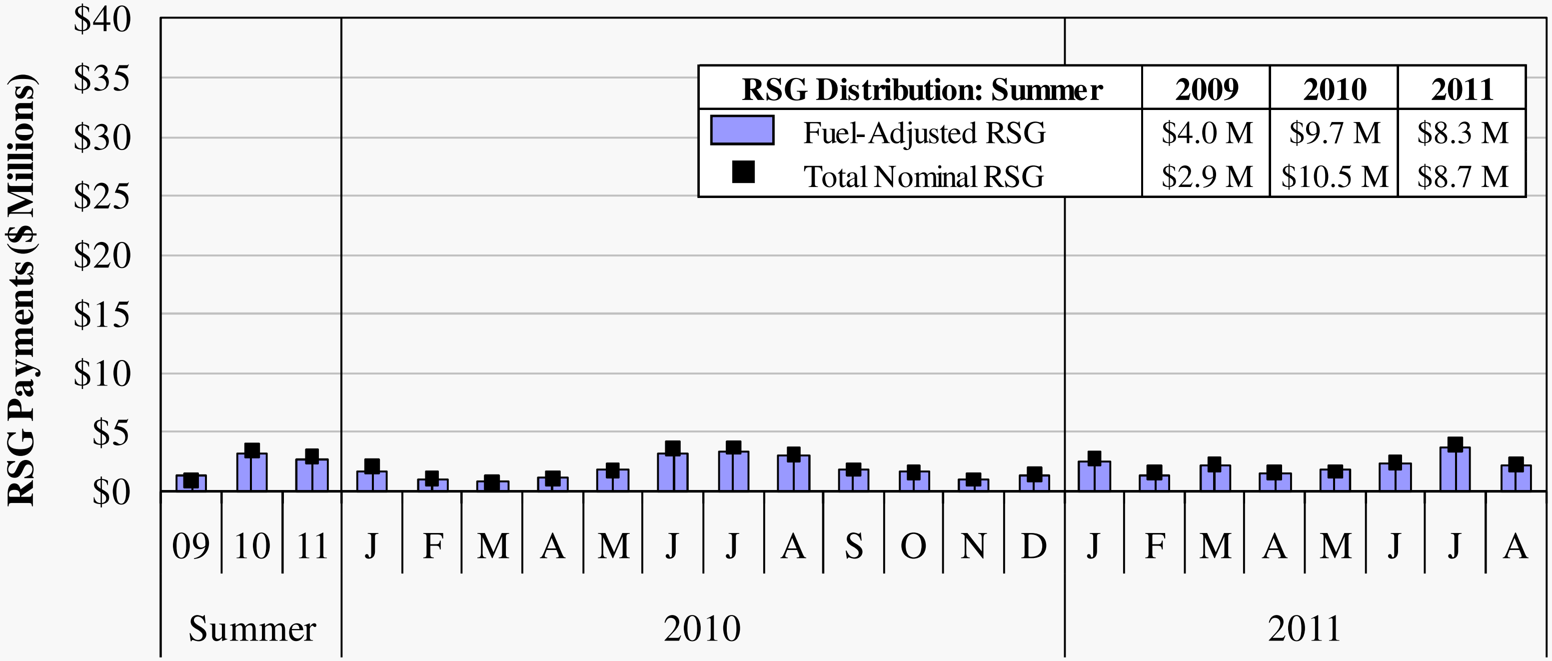
Real-Time RSG Payments 2010–2011



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

Peaker	60	64	71	58	53	59	58	64	50	69	71	39	20	23	47	61	51	54	53	47	69	75	66
Constraint	16	7	15	10	9	4	16	27	5	6	10	12	13	16	13	7	13	6	17	14	16	14	15
Capacity	44	57	56	48	44	55	43	37	45	63	60	28	8	7	34	53	38	49	36	33	53	61	51
Non-Peaker	40	36	29	42	47	41	42	36	50	31	29	61	80	77	53	39	49	46	47	53	31	25	34
Constraint	6	9	12	6	6	13	19	16	20	7	3	52	72	67	31	15	21	31	34	44	19	7	14
Capacity	34	26	17	36	40	28	22	21	30	24	26	9	8	9	22	24	28	15	13	10	12	18	19

Day-Ahead RSG Payments 2010–2011



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

Peaker	13	23	28	4	0	2	3	14	11	26	35	10	3	3	9	1	0	2	2	7	21	41	15
Non-Peaker	87	77	72	96	100	98	97	86	89	74	65	90	97	97	91	99	100	98	98	93	79	59	85

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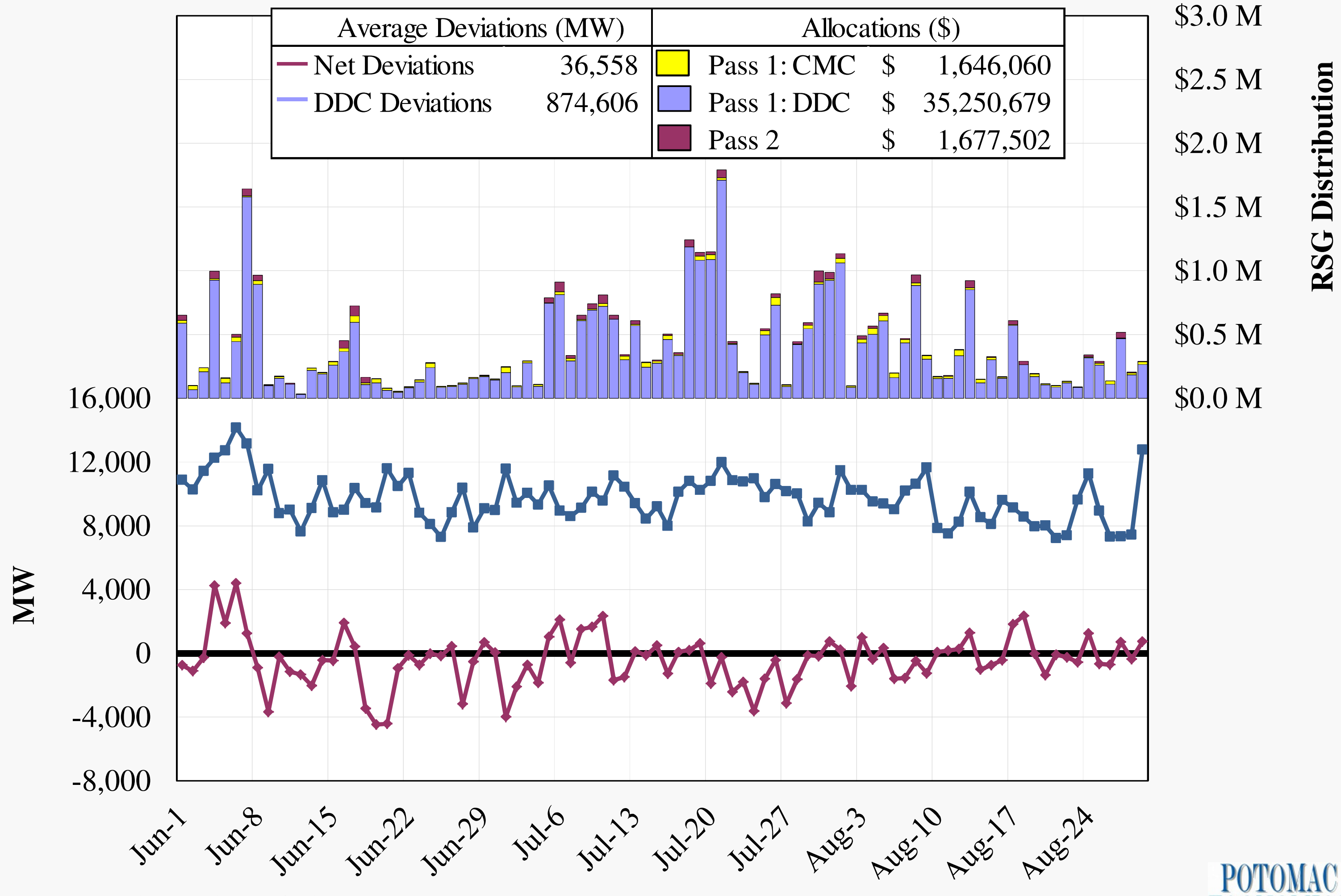
Allocation of RSG Charges

- The next figure evaluates the new RSG Cost Allocation implemented in April 2011.
  - ✓ The top panel shows the real-time RSG that was allocated to market-wide deviations (“DDC”), deviations that affect constraints (“CMC”), and real-time load (“Pass 2”).
  - ✓ The bottom panel shows net deviations from physical load, virtual supply and load.
- The figure shows that under the new allocation method over 90 percent of the real-time RSG costs are being allocated to market-wide deviations.
  - ✓ This level of allocation substantially exceeds the portion of the real-time RSG costs we had previously estimated were actually caused by deviations.
  - ✓ The excessive share of allocations to deviations is primarily due to:
    - – Most uplift costs associated with commitments for local voltage support (more than 20 percent of all RSG costs) are ultimately being charged to DDC deviations.
    - – Helping and harming deviations are not netted in the allocation, except at the participant level.
- Regarding voltage support costs, MISO is actively working to modify the allocation of these costs, which should be borne by the real-time load in the affected area.
- Regarding netting, the IMM previously filed a protest suggesting all deviations be netted automatically to cap the RSG costs allocated to deviations.

Allocation of RSG Charges
Summer 2011

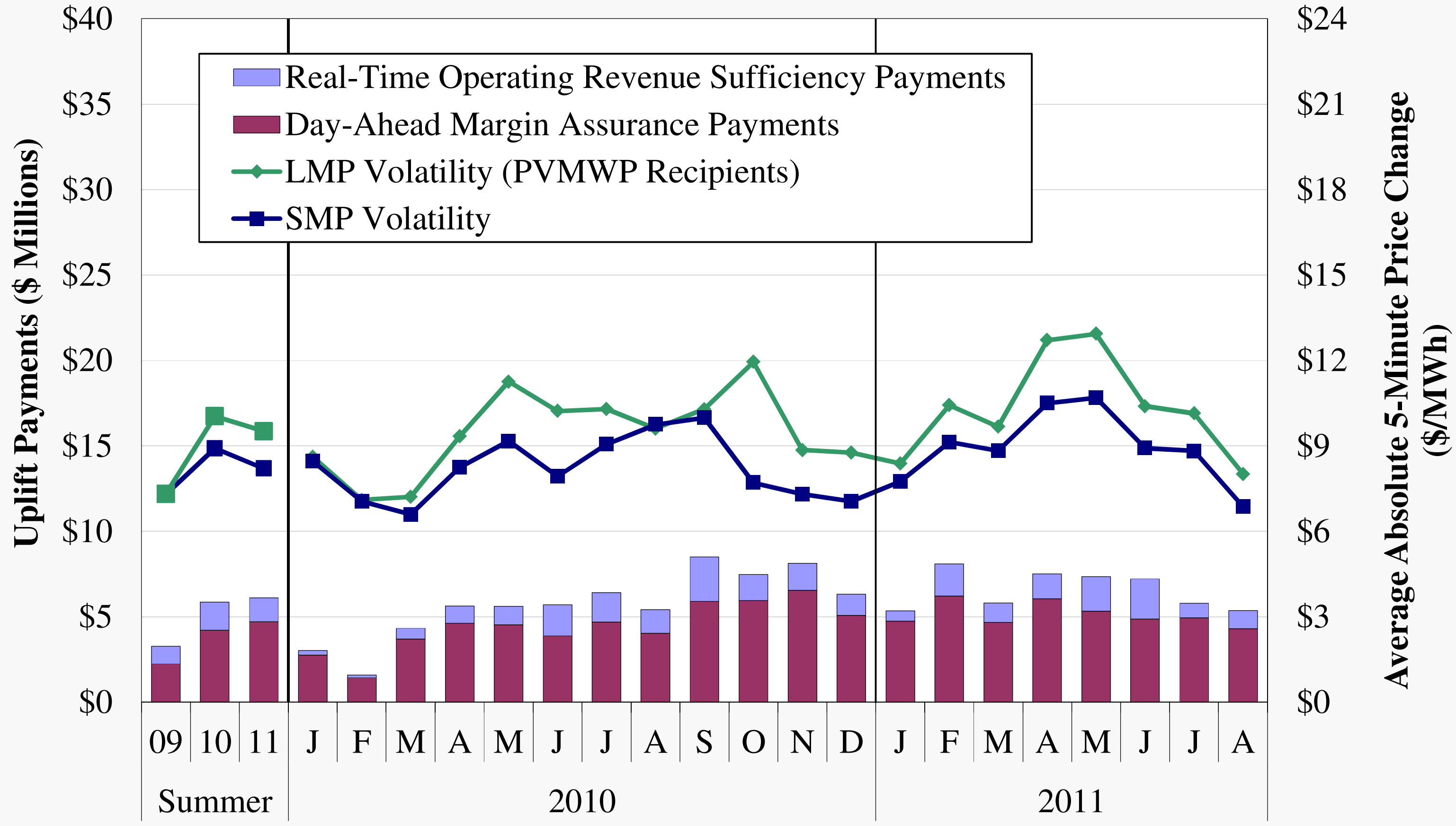


Note: Settlement data only available through August 29.

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 come in two forms: Day-Ahead Margin Assurance (“DAMAP”) and Real-Time Offer Revenue Sufficiency Guarantee Payments (“RTORSGP”).
- Payments in 2011 have fallen gradually since peaking in February at over $8 million, consistent with a general reduction in price volatility.
  - ✓ Payments averaged $6.1 million in summer 2011, up 5 percent from last summer.
  - ✓ DAMAP payments rose 12 percent, while RTORSGP payments fell 14 percent.
- The lines on the chart show two measures of price volatility: one based on the system marginal price 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.
  - ✓ It also shows that volatility is higher at recipients’ locations because they are generally redispatched more than other suppliers due to the larger price changes.
- We recommended several changes to the calculation formulas and RTORSGP eligibility criteria in the 2010 State of the Market Report to improve these payments.

Price Volatility Make Whole Payments 2010–2011



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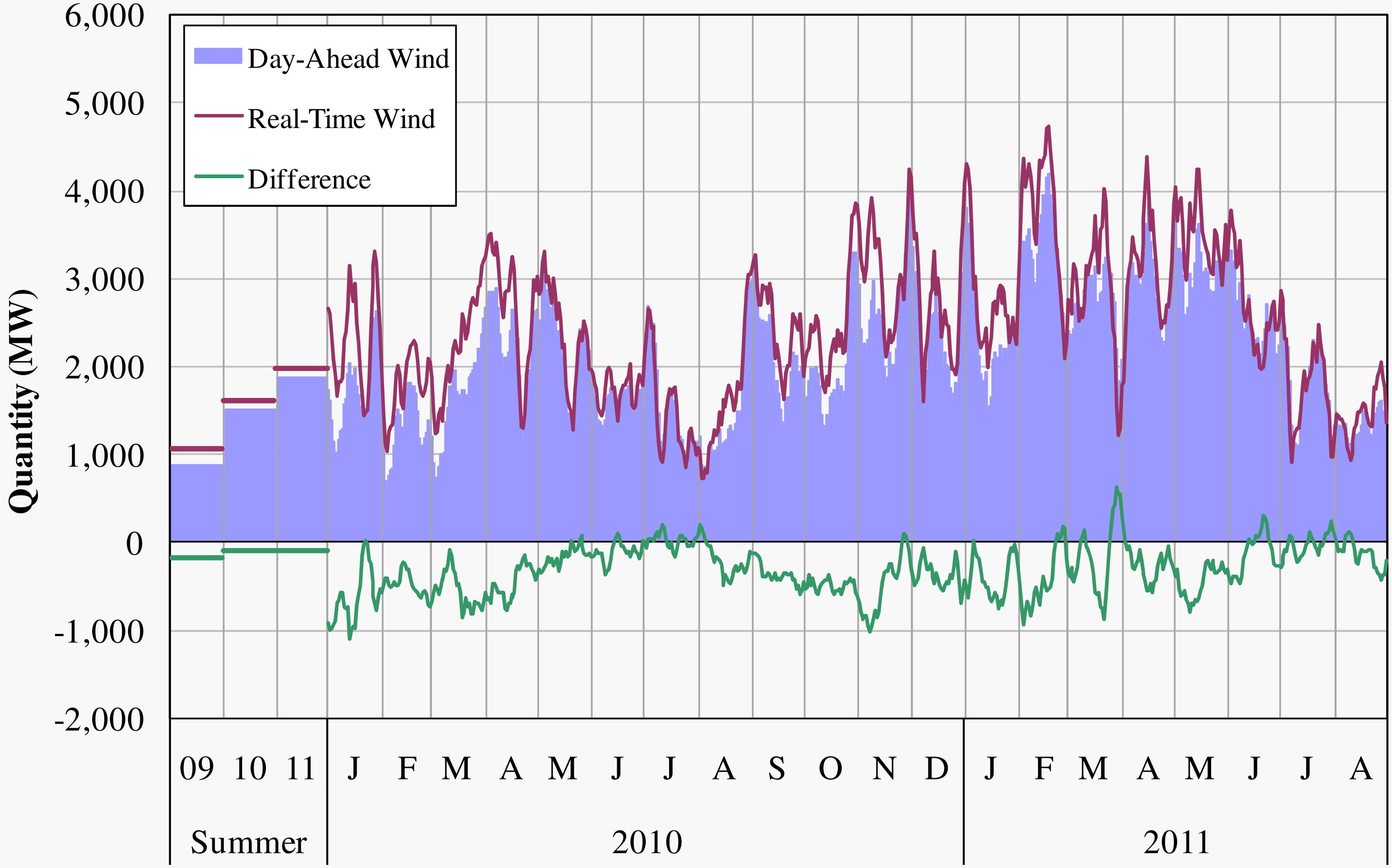
Scheduling of Wind Generation in Real-Time and Day-Ahead Markets

- The following figure shows wind output scheduled in day-ahead and real time.
  - ✓ Attractive wind profiles in the West Region, assisted by state renewable portfolio standards and federal subsidies, have increased nameplate capacity to over 10 GW.
- Wind generation in summer is typically considerably lower than in shoulder months.
  - ✓ Output averaged just 1.9 GW in June to Aug., compared to nearly 3.2 GW in the spring.
  - ✓ Wind output increased 11 percent from last summer. Nameplate capacity over the same period increased 13 percent.
- Deviations from the day-ahead, as well as real-time variability, must be managed by MISO in real-time by modifying the commitment or dispatch of other resources.
  - ✓ Under-scheduling of wind in the day-ahead was largely unchanged at 100 MW.
- Wind output remains volatile, and can present forecasting, scheduling, and reliability challenges that must be addressed by MISO.
  - ✓ Average 60-minute wind volatility fell to 200 MW due to lower generation levels.
  - ✓ The continued adoption of the Dispatchable Intermittent Resource type, first introduced in June 2011, should help address many of these challenges as participation increases.
    - – Sixteen resources totaling over 2 GW are registered as DIR as of September 1.

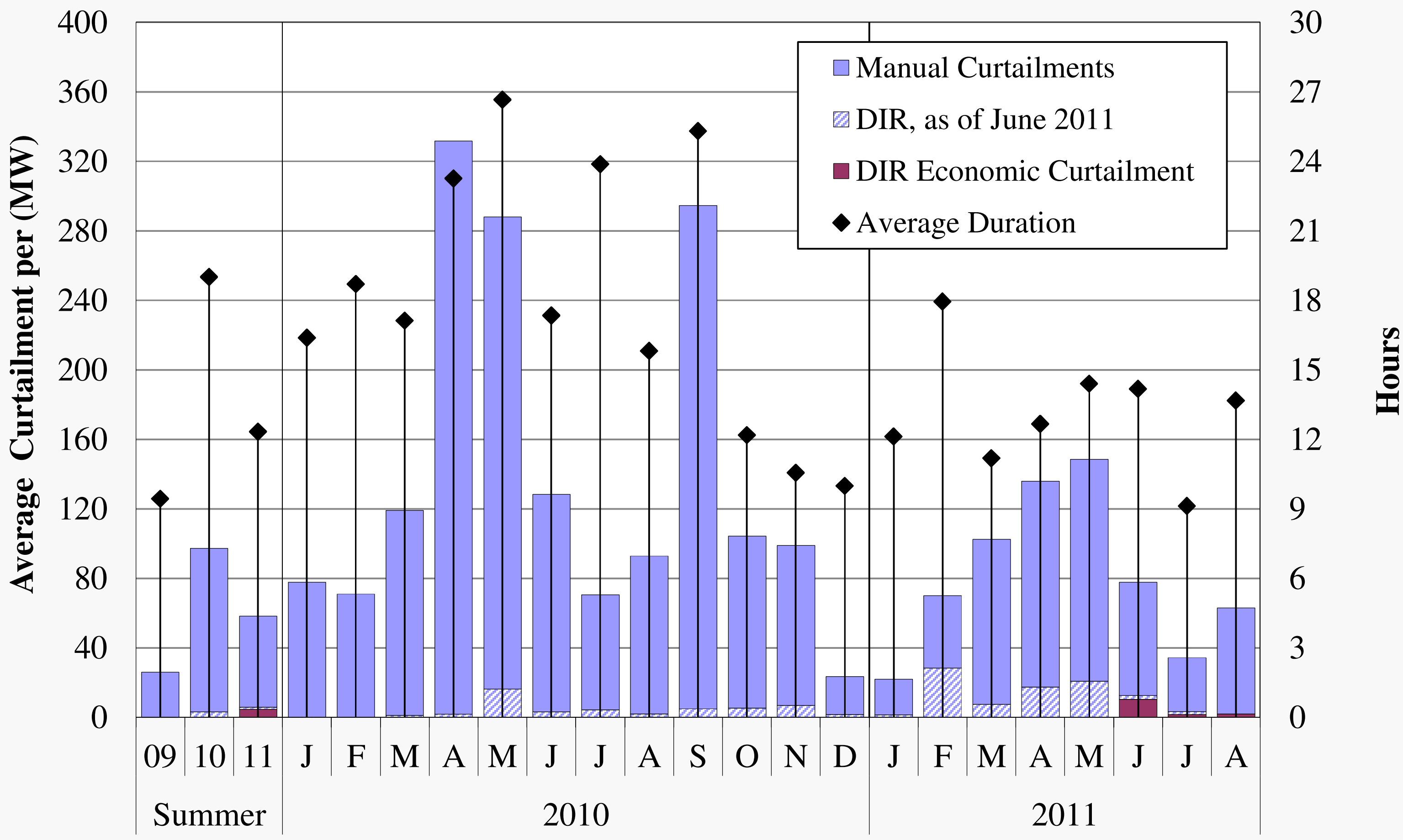
Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average, 2009–2011



Manual Wind Curtailments

- Manual curtailment of wind resources by MISO has increased with wind output.
  - ✓ This has been necessary in order to prevent transmission overloads because most wind resources are not currently dispatchable by MISO.
  - ✓ Approximately 1.2 GW of wind was dispatchable in summer (DIR was implemented June 1). Over 2 GW is DIR as of Sept. 1, but nearly 7 GW remains non-dispatchable.
- Manual wind curtailments averaged 54 MW per hour in summer 2011, down 45 percent from last summer. This was likely partly due to DIR.
  - ✓ On average 2.8 percent of wind generation was manually curtailed in summer 2011, less than the 5.8 percent that was curtailed in the same period last year.
  - ✓ Approximately one-fifth of all wind curtailments since the start of 2010 were for units currently registered as DIR, which are being curtailed less than they were before DIR.
- The average curtailment lasted approximately 12 hours during this summer, down from approximately 19 hours in summer 2010.
  - ✓ Most of this change is likely due to a reduction in the severity of congestion affected by the wind resources and improvements in the manual curtailment process.
- To date, economic DIR curtailments have averaged approximately 5 MW per hour.
  - ✓ DIR units provided MISO with additional flexibility to manage congestion.
  - ✓ Startup issues that negatively affected the initial results were encountered in early June and have since been resolved.

Manual Wind Curtailments 2009–2011



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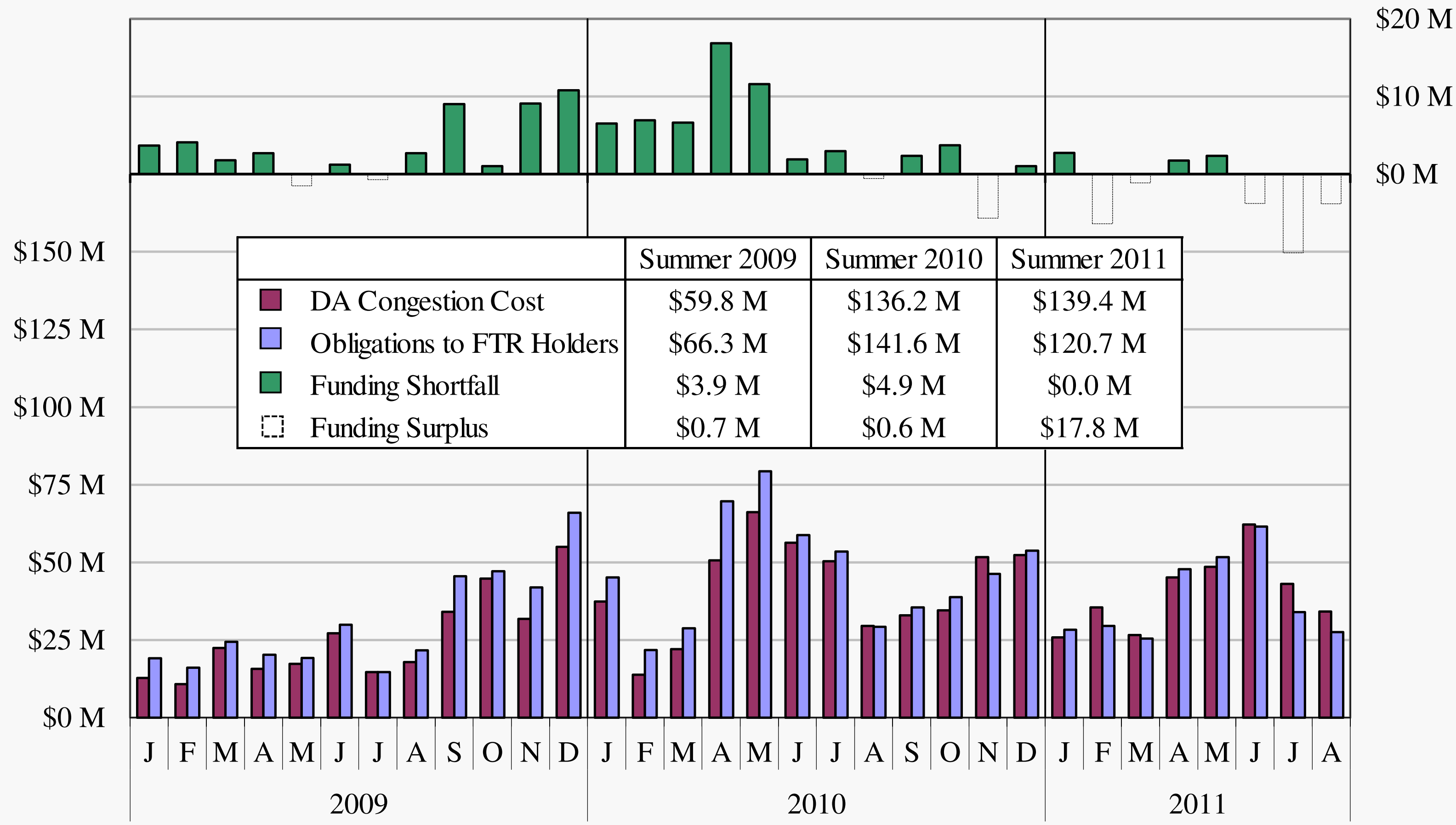
Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows MISO's obligation to FTR holders, which entitle them to the day-ahead congestion costs that arise between particular locations in MISO.
  - ✓ Day-ahead congestion totaled $139 million in summer 2011, an increase of 3 percent compared to summer 2010.
- The figure also shows the actual FTR payments and the shortfall between the obligation and the payment.
  - ✓ Shortfalls and surpluses occur when the portfolio of FTRs represent more or less transmission capacity than the capability of the network in the day-ahead market.
- MISO's continued work on the ARR allocation process and modeling improvements in the FTR market has increased FTR funding.
  - ✓ The day-ahead funding surplus was $17.8 million during the summer and is over $18.5 million year-to-date, so sufficient revenues have been collected to fully fund all FTRs in 2011.
  - ✓ However, if funding surpluses persist, it may indicate that MISO is not making FTRs available that fully reflect the capability of the system.

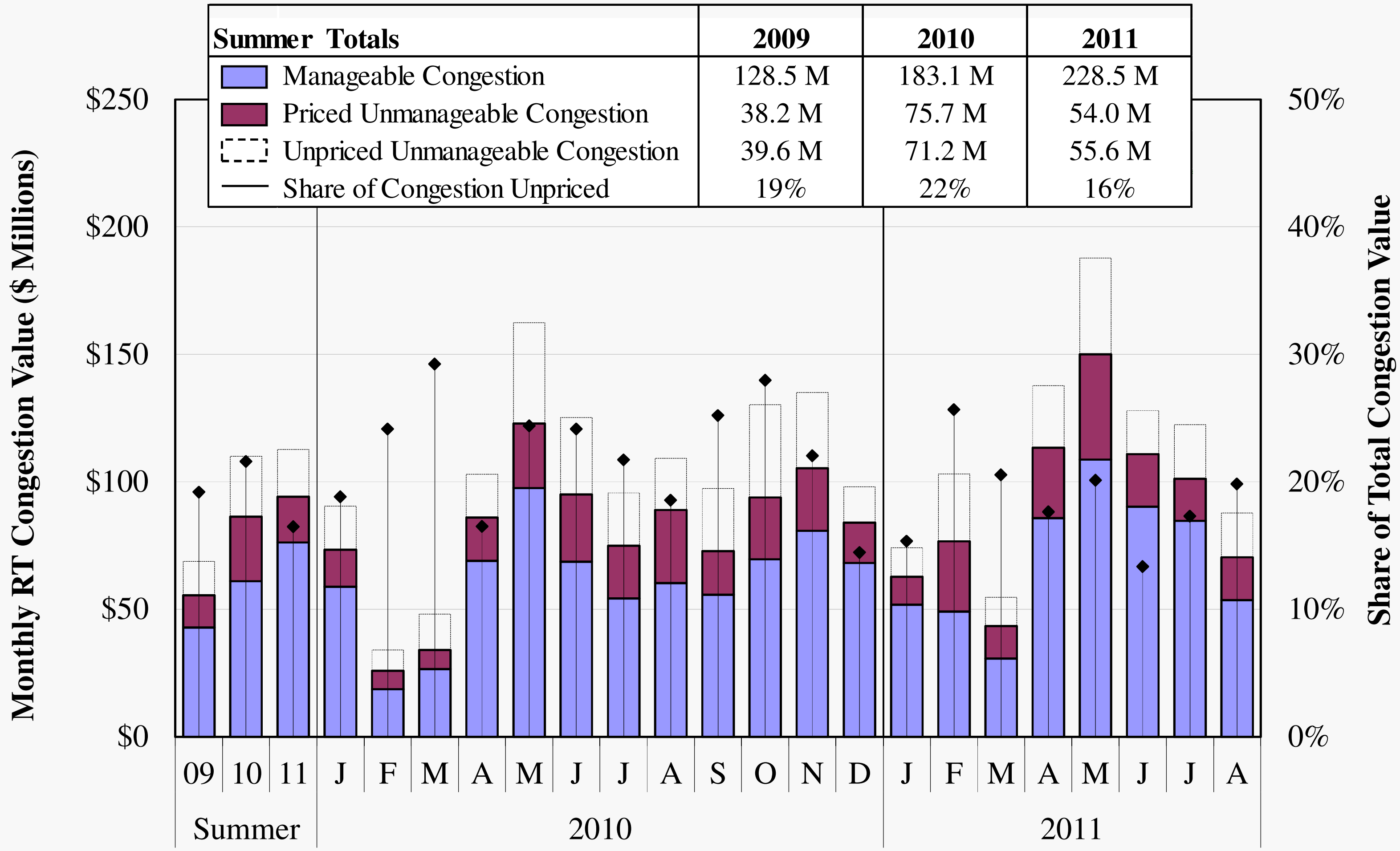
Day-Ahead Congestion and Obligations to FTR Holders, 2009–2011



Value of Real-Time Congestion

- The next 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, equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint, totaled nearly $300 million in summer 2011.
  - ✓ 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").
- Congestion was 9.2 percent higher than last summer, and was most prevalent on transmission constraints with large west-to-east flows.
  - ✓ The most expensive constraint ($30 million) was in central Iowa in June and July.
- When constraints are unmanageable, MISO employs a "constraint relaxation" algorithm that artificially reduces the value of the congestion, often to zero.
  - ✓ The figure shows that this algorithm eliminated $56 million, or 16 percent, of the real-time congestion that should have occurred in the quarter.
  - ✓ This adversely affects the day-ahead market and the revenues from the FTR market and can potentially impact reliability and investment decisions.
  - ✓ We continue to recommend MISO suspend use of this algorithm.

Value of Real-Time Congestion
2010–2011

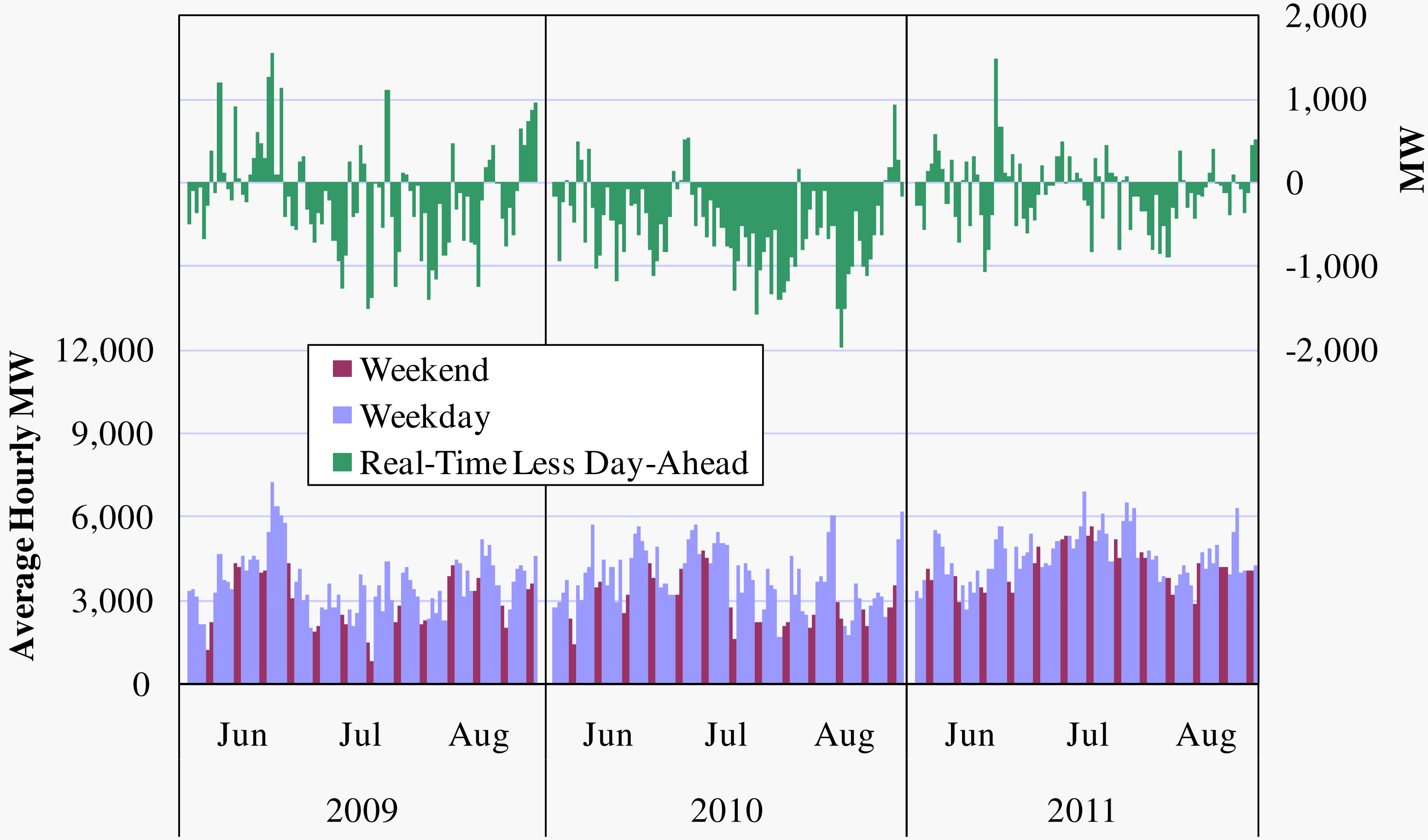


Summer Totals	2009	2010	2011
Manageable Congestion	128.5 M	183.1 M	228.5 M
Priced Unmanageable Congestion	38.2 M	75.7 M	54.0 M
Unpriced Unmanageable Congestion	39.6 M	71.2 M	55.6 M
Share of Congestion Unpriced	19%	22%	16%

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 summers of 2009 to 2011.
- MISO's net imports exceeded 4,500 MW per hour on average in summer 2011.
  - ✓ Net imports are 23 percent higher than last summer, and averaged over 6,000 MW on five days.
  - ✓ Imports were greatest in July (5.2 GW), coinciding with higher energy prices.
  - ✓ As in prior periods, approximately half of all imports flowed over the interface with PJM, while 25 percent came from Manitoba Hydro.
- Scheduling improved considerably from last summer, in part due to revisions to the RSG allocation process in April that has reduced charges to real-time imports.
  - ✓ Participants are currently assessed a deviation charge on net negative real-time volumes. Net positive real-time imports are no longer considered a deviation.
- The daily average deviation was less than 100 MW, down from 544 last summer.
  - ✓ The absolute difference (regardless of direction) improved from 630 to 324 MW.
- However, changes from day-ahead to real-time continue to be substantial at times.
  - ✓ Imports twice changed by more than 1 GW, and did so by 1.5 GW on June 22.
  - ✓ Declines in real-time imports can require unit commitments and RSG payments.

Average Hourly Real-Time Imports Summer 2009–2011



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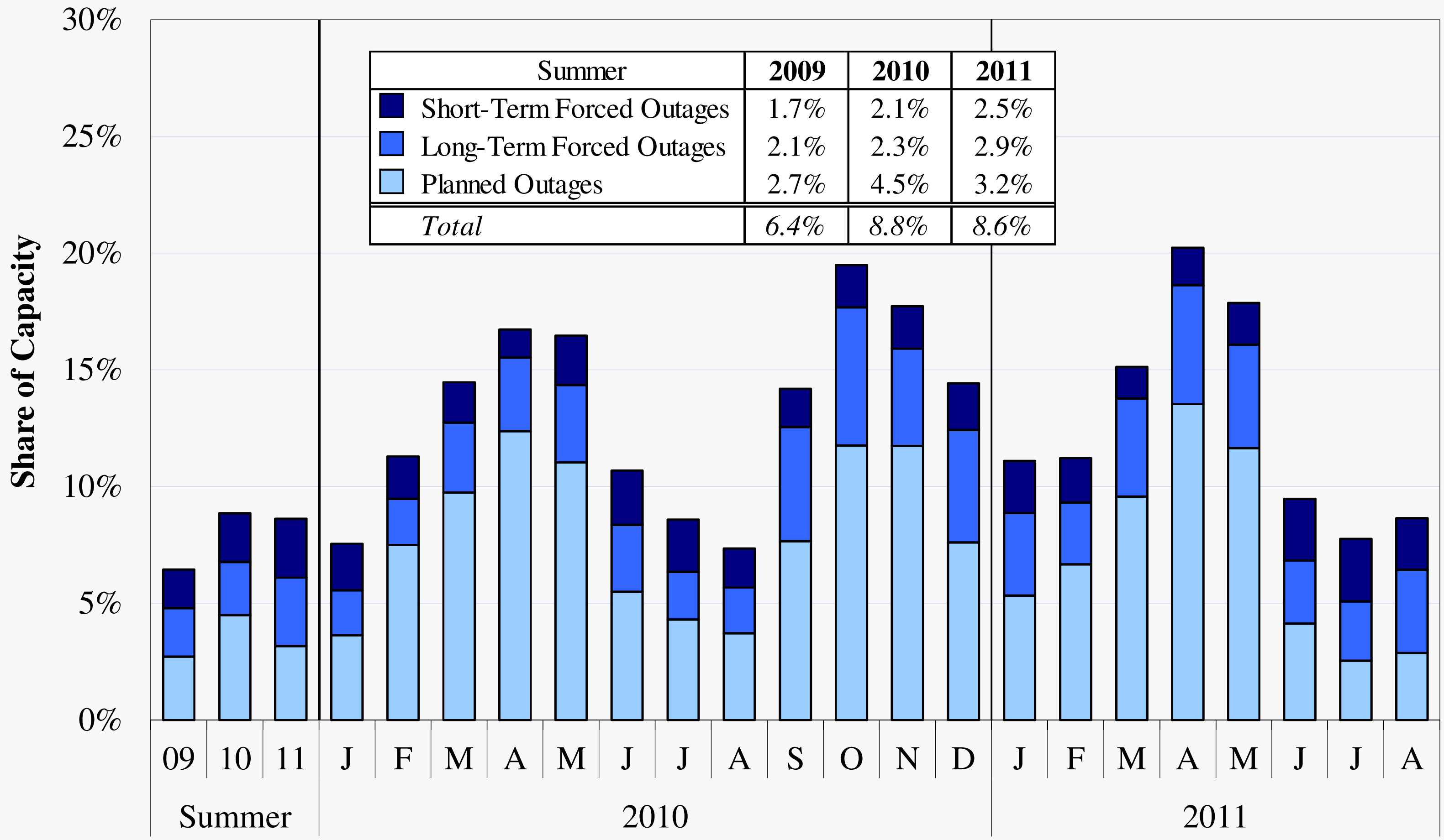
Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2010 as a percentage of total generation capacity.
  - ✓ These values include only full outages, not partial outages or deratings.
  - ✓ The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).
- The cumulative outage rate for the three types of outages was 8.6 percent in summer 2011, down from 8.8 percent in summer 2010.
  - ✓ Planned outages declined to 3.2 percent.
    - – During summer, planned outages should be minimal since high load and average prices increase the opportunity costs of scheduling maintenance.
  - ✓ Forced outages increased modestly. Short-term forced outages rose to 2.5 percent while long-term forced outages rose to 2.9 percent.
    - – Changes in monitoring of Module E requirements to outages and deratings likely resulted in an apparent increase in forced outage rates.
    - – We continue to monitor short-term outages closely because they can indicate potential physical withholding.

Generation Outage Rates
2010–2011



Summer	2009	2010	2011
Short-Term Forced Outages	1.7%	2.1%	2.5%
Long-Term Forced Outages	2.1%	2.3%	2.9%
Planned Outages	2.7%	4.5%	3.2%
Total	*6.4%*	*8.8%*	*8.6%*

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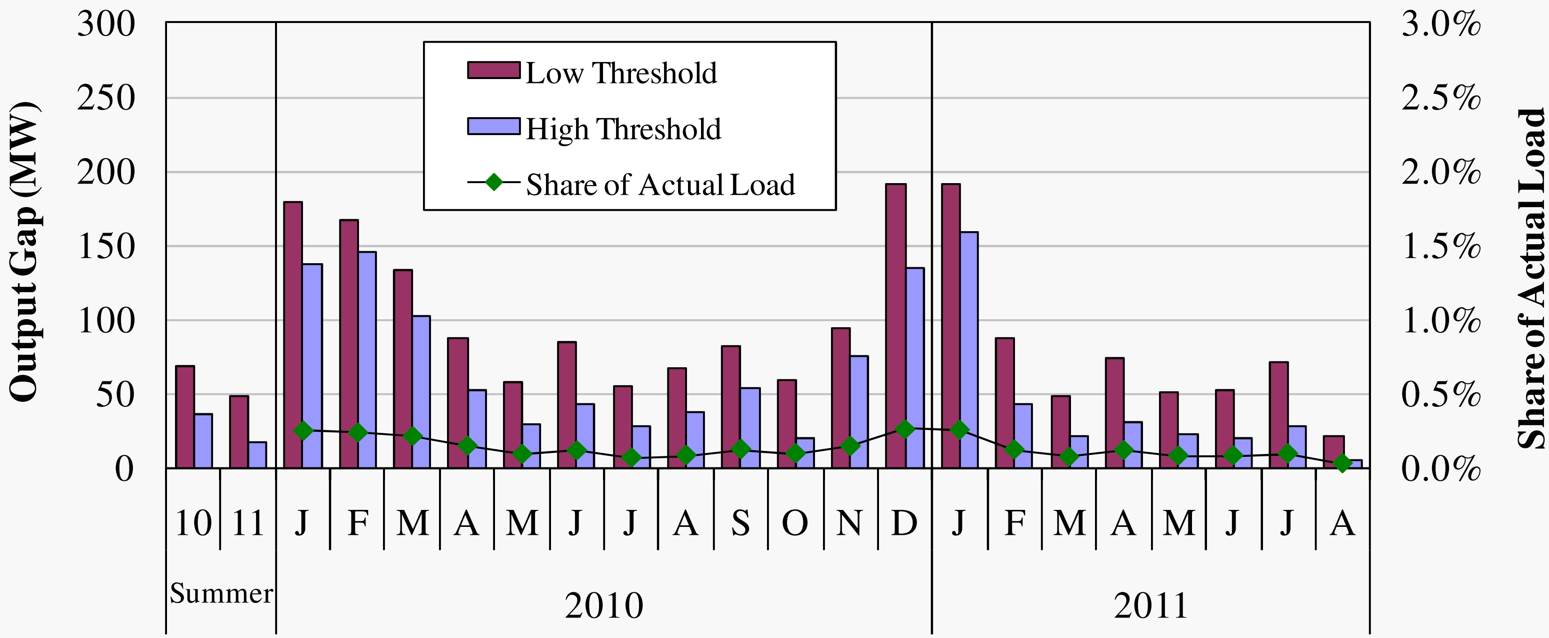
Monthly Output Gap

- The output gap measure is used to screen for economic withholding by participants.
  - ✓ 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 2010 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 continue to be extremely low.
  - ✓ This summer, output gap levels were just 50 and 18 MW under the high and low thresholds, respectively.
  - ✓ These metrics are respectively 28 and 50 percent lower than in summer 2010.
- As a share of overall load, the low-threshold output gap again averaged less than 0.1 percent of load, which is very low.
  - ✓ The mitigation thresholds for Narrow Constrained Areas (i.e. WUMS, NWUMS and Minnesota) were updated per Module D in January and the WUMS and Minnesota thresholds were increased significantly.
- These results show that there were few competitive concerns in the quarter.
  - ✓ We continue to routinely investigate hourly increases in the output gap.

Monthly Output Gap
2010–2011



Low Threshold Results by Unit Status (MW)

Off Line	22	11	74	110	75	28	12	31	16	19	18	5	33	95	143	44	21	14	9	11	23	0
On Line	47	39	105	57	59	60	46	54	38	49	64	54	61	96	48	43	29	60	43	42	49	25

High Threshold Results by Unit Status (MW)

Off Line	22	10	67	110	73	27	12	31	16	19	18	5	33	89	142	29	16	14	9	10	19	0
On Line	14	8	71	35	29	26	17	12	12	19	36	15	43	46	17	14	5	17	13	10	9	6

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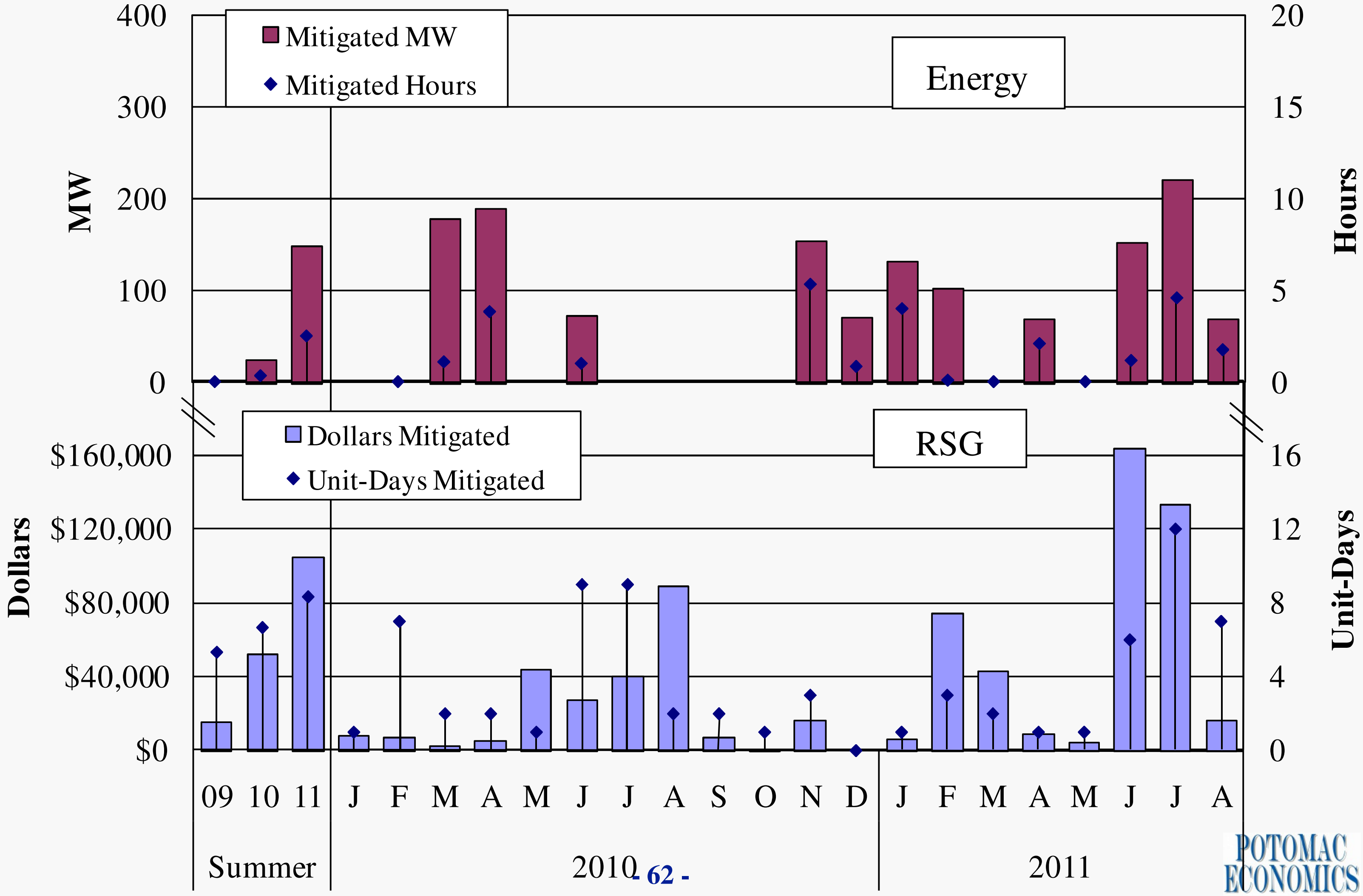
Mitigation in the Real-Time Energy Market

- 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.
- Energy mitigation in summer 2011 increased considerably from 2010 lows, to 2.5 unit-hours and 148 MW, up from 0.33 unit-hours and 25 MW in summer 2010.
  - ✓ Most of this mitigation occurred when loads exceeded 90 GW – when markets clear in in inelastic supply ranges, withholding has a higher price impact.
  - ✓ Nevertheless, mitigation continues to be extremely infrequent because the vast majority of resources are offered competitively in the MISO markets.
- RSG mitigation doubled to approximately $105,000 on average per month, nearly all of which occurred in June and July.
- Although mitigation levels indicate that these events continue to be infrequent, local market power continues to be a significant concern.
  - ✓ Market power mitigation measures therefore remain critical.
  - ✓ We continue to evaluate AMP mitigation and found all mitigation events to be appropriately applied.

Real-Time Market Power Mitigation 2009–2011



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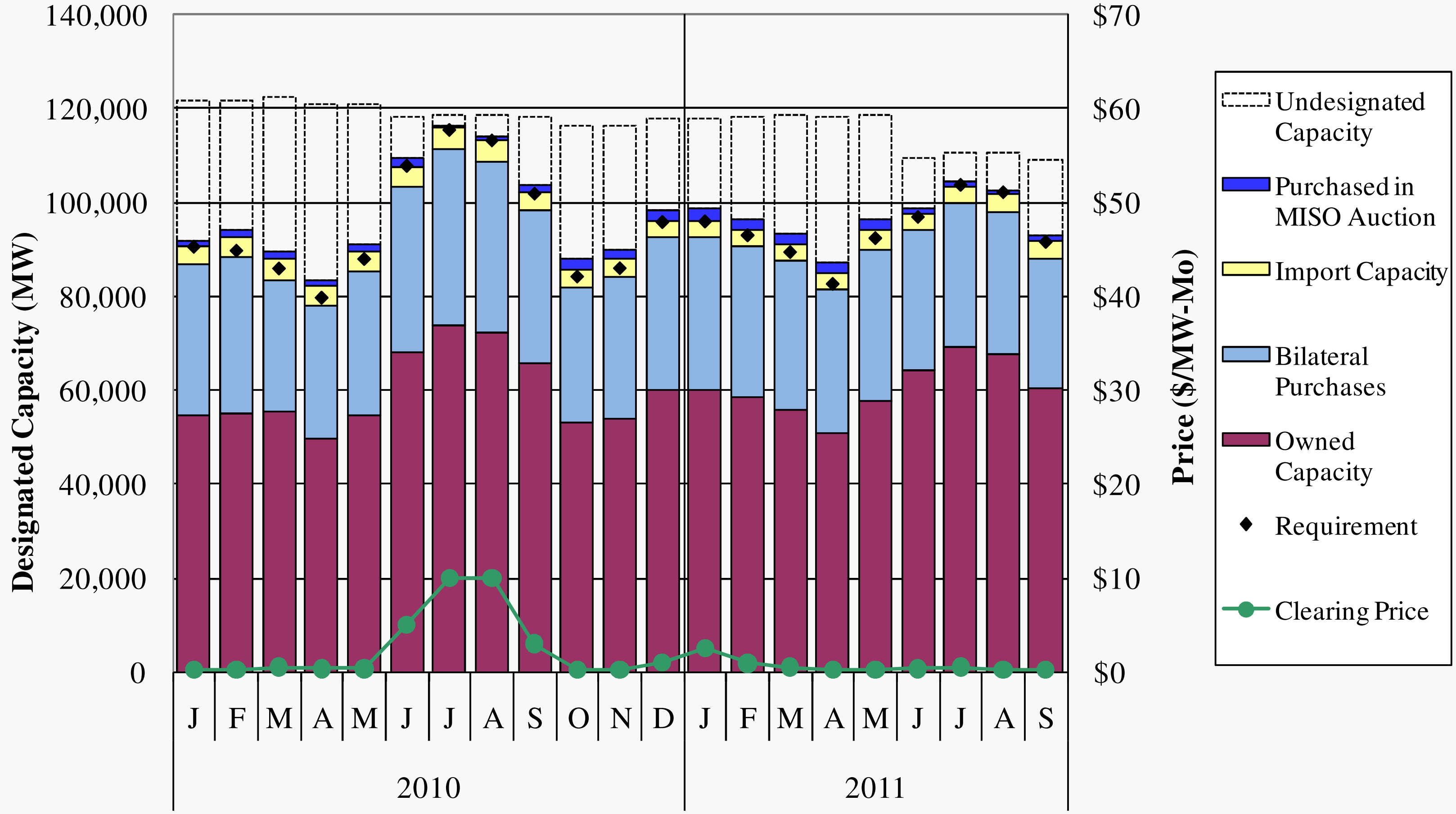
Voluntary Capacity Auction

- 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 auction has continually cleared at close to zero (less than $1 per MW-month), consistent with the surplus capacity that exists in the MISO footprint.
- The following figure shows the monthly capacity requirements, designated capacity and VCA clearing price since January 2010.
  - ✓ Capacity and requirements both fell after May 2011, when FirstEnergy departed.
  - ✓ The capacity cleared in the VCA remains a very small portion of the total designated capacity, and averaged less than 1 percent in summer 2011.
  - ✓ This is consistent with the expectation that this market would be only a balancing market, with LSEs' needs satisfied through owned capacity or bilateral purchases.
- The figure also shows how LSEs are satisfying those requirements. It shows:
  - ✓ Capacity designations continue to meet or exceed requirements – designations exceeded the requirement by an average of 1.1 percent in the period.
  - ✓ The total capacity available exceeded the requirement by 7 to 11 percent. As a result, VCA clearing prices remain extremely low.
- We are reviewing the proposed Resource Adequacy Tariff revisions and plan to file comments with the Commission.

Voluntary Capacity Auction January 2010–August 2011



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

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