IMM Quarterly Report: Spring 2013
March–May

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)	●	$33.77	*18%*	*33%*
Fuel Prices ($/MMBtu)				
Natural Gas	●	$4.13	*19%*	*84%*
Western Coal	●	$0.62	*9%*	*29%*
Eastern Coal	●	$1.80	*2%*	*-11%*
Load (MW)[2]				
Average Load	●	53.9	*-8%*	*2%*
Peak Load	●	71.9	*-4%*	*0%*
% Scheduled DA (Peak Hour)	●	98.6%	100.6%	100.6%
Transmission Congestion ($M)				
Real-Time Congestion Value	●	$391.7	*16%*	*11%*
Day-Ahead Congestion Revenue	●	$176.1	*-2%*	*-3%*
Balancing Congestion[4]	●	$19.0	$12.8	$30.1
FTR Funding Shortfall	●	$32.1	$28.2	-$4.1
Ancillary Service Prices ($/MWh)				
Regulation	●	$12.98	*70%*	*56%*
Spinning Reserves	●	$4.73	*214%*	*103%*
Supplemental Reserves	●	$2.07	*345%*	*190%*

		Value	Change[1] Prior Qtr.	Change[1] Prior Year
Wind Output (MW)	●	4,215	*-6%*	*2%*
Guarantee Payments ($M)				
Real-Time RSG	●	$25.0	*164%*	*148%*
Day-Ahead RSG	●	$4.8	*-31%*	*2%*
Day-Ahead Marginal Assurance	●	$11.3	*28%*	*13%*
RT Operating Rev. Sufficiency	●	$3.1	*49%*	*0%*
Price Convergence[3]				
Market-wide DA Premium	●	-3.0%	-2.3%	-3.4%
Virtual Trading				
Cleared Quantity (MW)	●	5,972	*-9%*	*-21%*
% Price Insensitive	●	38%	41%	34%
% Screened for Review	●	2%	2%	2%
Profitability ($/MW)	●	$0.93	$0.33	$0.49
Dispatch of Peaking Units (MW/hour)	●	437	258	475
Output Gap- Low Thresh. (MW/Hour)	●	88	47	30
Maximum VCA Price ($/MW-Mo.)	●	$0.10	$0.14	$0.12
Other:				

Key: ● Expected ● Monitor/Discuss ● Concern

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

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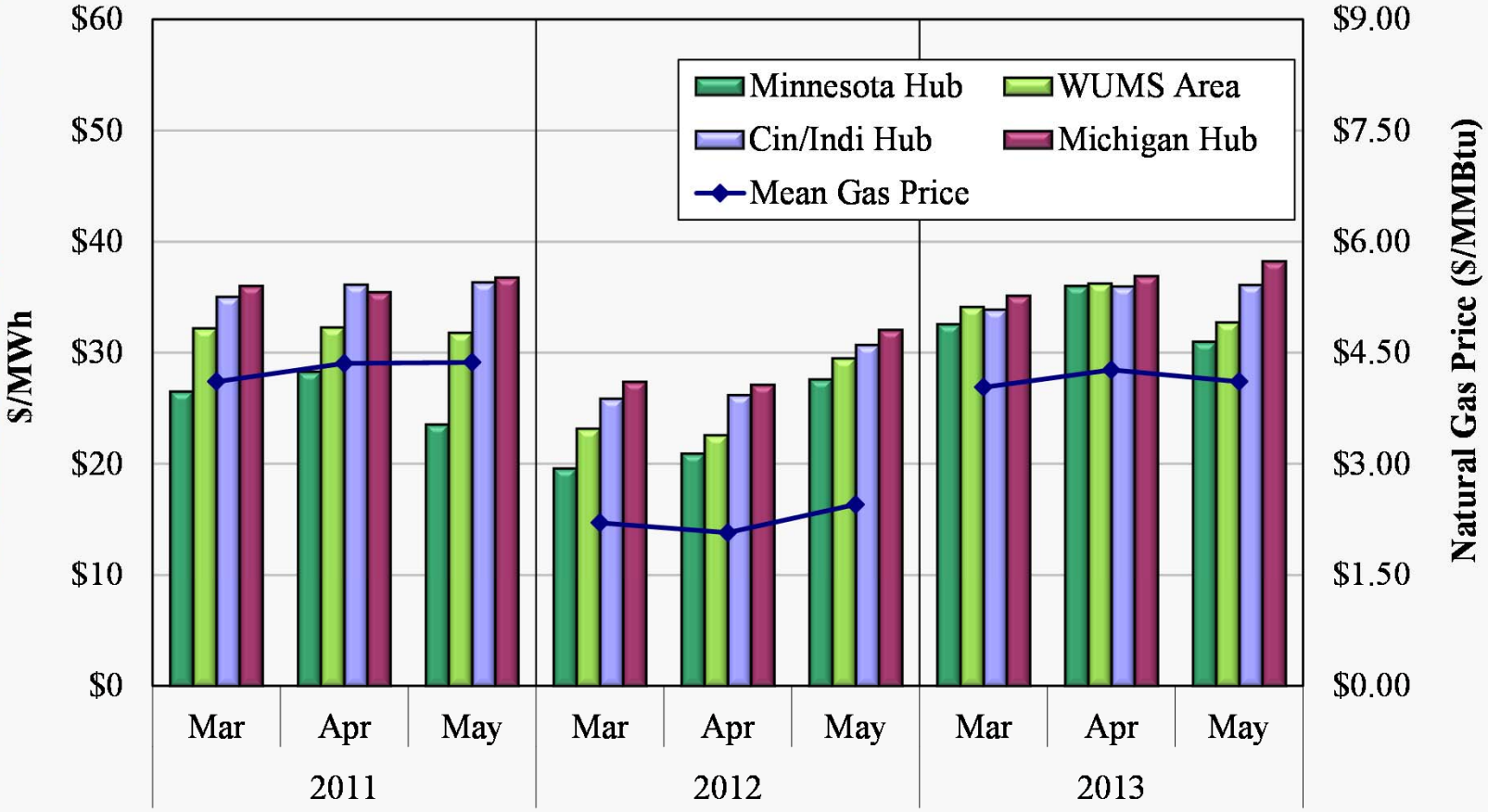
Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations in March to May for the last three years.
  - ✓ We include natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin during peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Day-ahead energy prices in spring averaged $33.51 per MWh, a 30 percent increase from last spring, mainly due to much higher natural gas prices.
  - ✓ Gas prices rose 19 percent from winter to $4.13 per MMbtu, 84 percent higher than the $2.25 averaged last spring.
  - ✓ Day-ahead scheduled load rose 1.9 percent to 53.4 GW.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ West-to-east congestion resumed, particularly in May. It added $3.35 per MWh to the average price at Michigan and subtracted $2.44 at Minnesota.
  - ✓ Day-ahead scheduling of wind output, which affects west-to-east power flows, rose 11 percent from last spring to nearly 3.9 GW.
    - – This is 8 percent lower than in winter because of reductions in the wind speed.

Day-Ahead Average Monthly Hub Prices
Spring 2011–2013



Note: Cinergy Hub was replaced by Indiana Hub as the Central region's proxy price after 2011.

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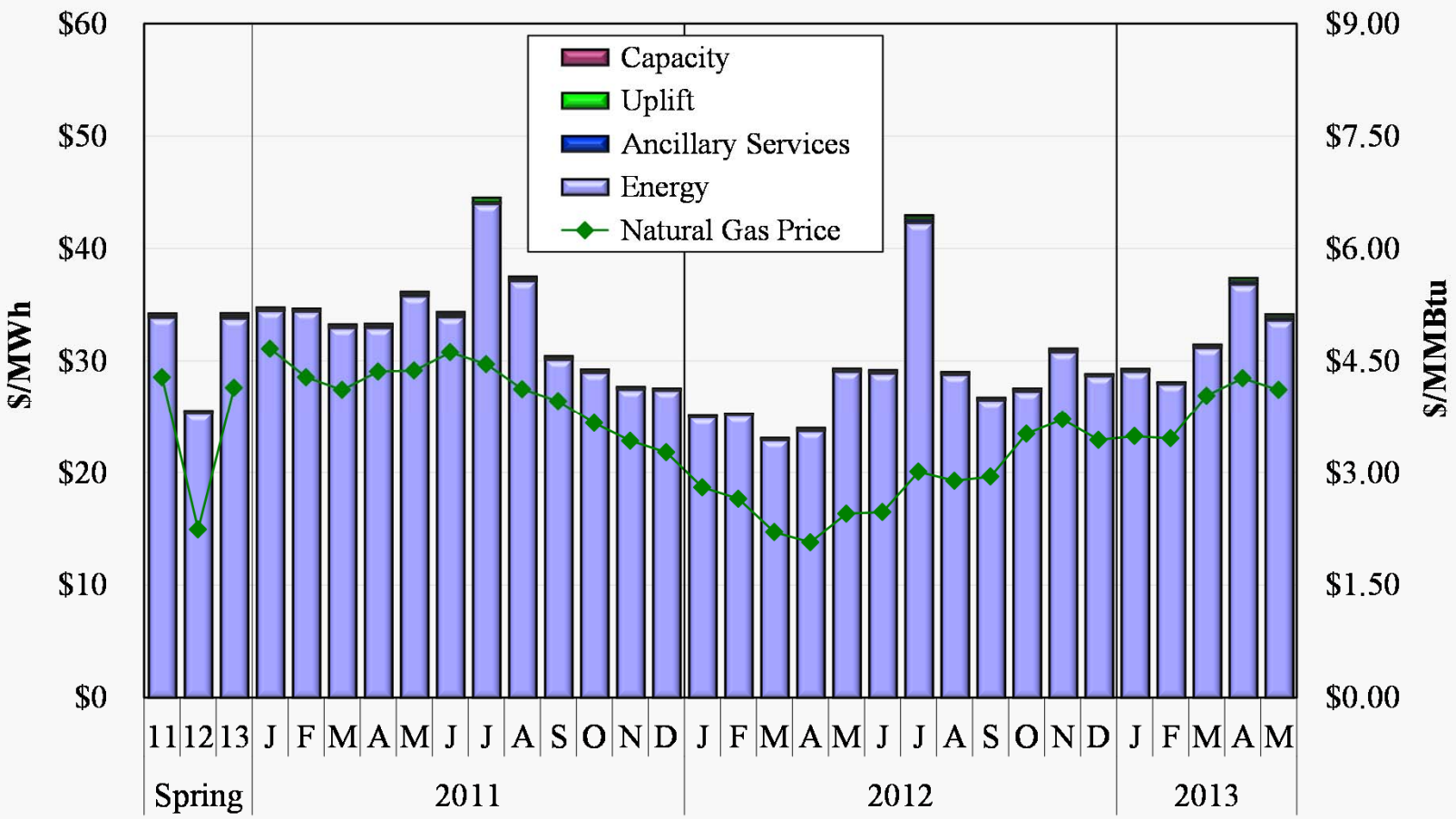
All-In Price

- The "all-in price" represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price and real-time uplift, ancillary services, and capacity costs per MWh of load.
  - ✓ The figure also includes the monthly average natural gas price and shows that, as in the day-ahead, real-time energy prices generally track changes in fuel prices.
- The all-in price rose 34 percent from last spring to $34.24 per MWh.
  - ✓ As with day-ahead energy prices, the rise in the energy component of the all-in price was primarily due to the 84-percent rise in natural gas prices.
- Energy costs continue to make up nearly all (98.7 percent) of the all-in price.
  - ✓ Uplift and ancillary services costs each more than doubled from last spring, although they still only contribute 21 and 23 cents, respectively.
  - ✓ The Voluntary Capacity Auction again cleared near zero in each month this spring, so capacity payments did not contribute materially to the all-in price.
    - – This price reflects interaction of MISO's current modest capacity surplus and the shortcoming associated with the markets' representation of demand.
    - – The new annual Planning Reserve Auction, which cleared at $1.05 per MW-day, is designed to better reflects regional capacity needs.

All-In Price
Spring 2011–2013



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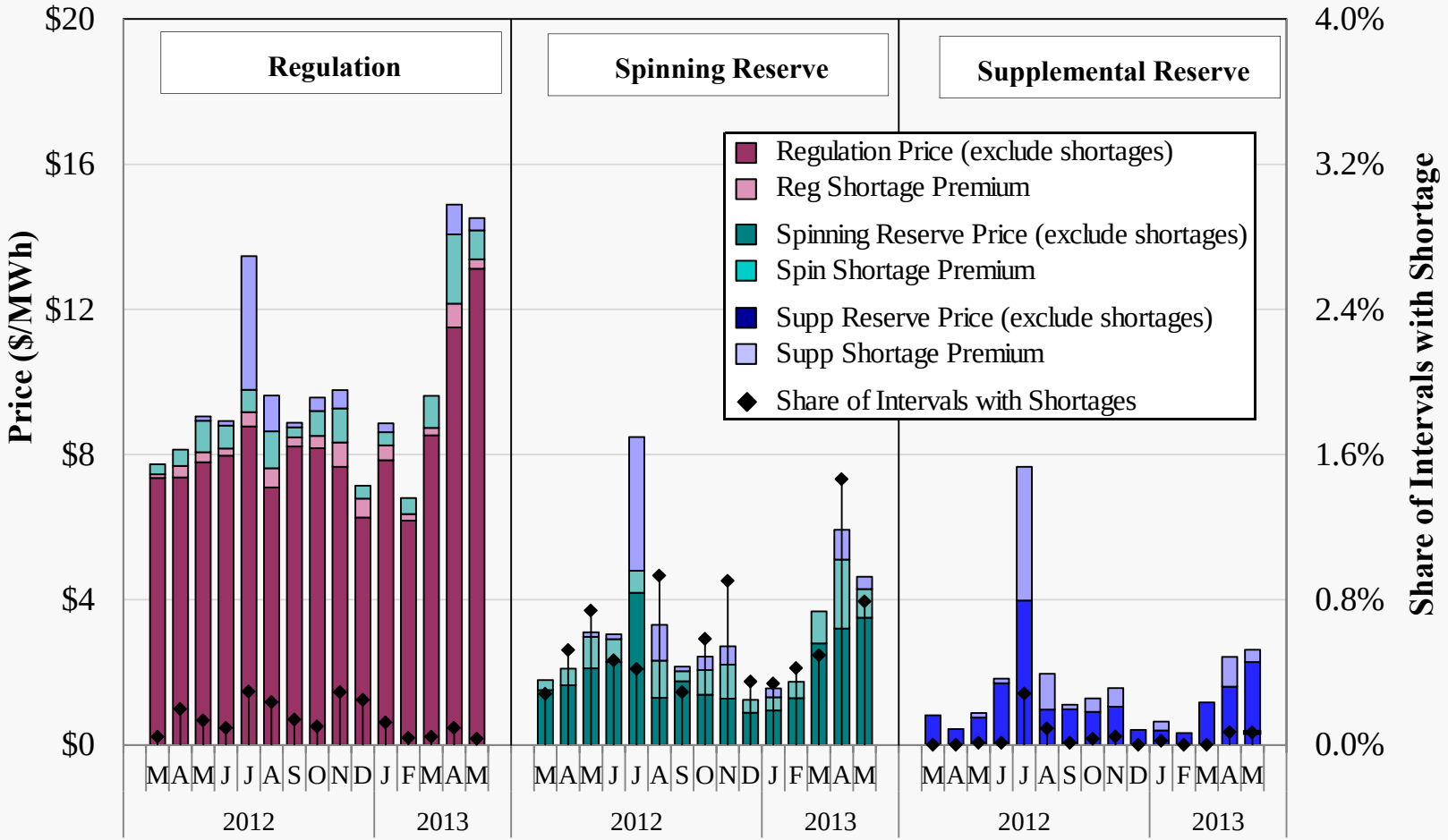
Ancillary Services Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO's ancillary service products for the last 15 months.
  - ✓ 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).
- All three ancillary service products rose considerably from last year, when gas and energy prices were lower and shortages were far fewer.
- Regulation prices averaged $12.98 per MWh, up 56 percent from last spring.
  - ✓ Although there were fewer shortages for regulation, they had a larger impact because of a rise in the fuel-indexed monthly penalty price (to $190 on average).
- Spin prices more than doubled to $4.73 per MWh, while supplemental reserve prices nearly tripled to $2.07 per MWh.
  - ✓ There were 240 spin shortages in the quarter (up from 136 last spring), along with 12 operating reserve shortages in April and May.
  - ✓ Most of these shortages would not have occurred if interchange with PJM were optimized and the flaw failure to account for reserves being provided when a quick-start unit is in the process of starting were corrected.
  - ✓ Prices of some of the shortages in May fell because on May 1, MISO began pricing the first four percent of an operating reserve shortage at $200 per MWh.

Monthly Average Ancillary Service Prices
Regulation and Contingency Reserves, 2012–2013



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MISO Fuel Prices and Capacity Factors

Natural Gas and Oil Prices

- Natural gas prices averaged $4.13 per MMBtu in spring, up 84 percent from last spring, when they averaged just $2.25.
  - ✓ Prices this quarter were 19 percent higher than the $3.46 winter average.
- Oil prices rose 1 percent from last spring to $22.02 per MMBtu.
  - ✓ Although this fuel is rarely marginal (and so has a minimal impact on energy prices), significant RSG payments can accrue to such units.

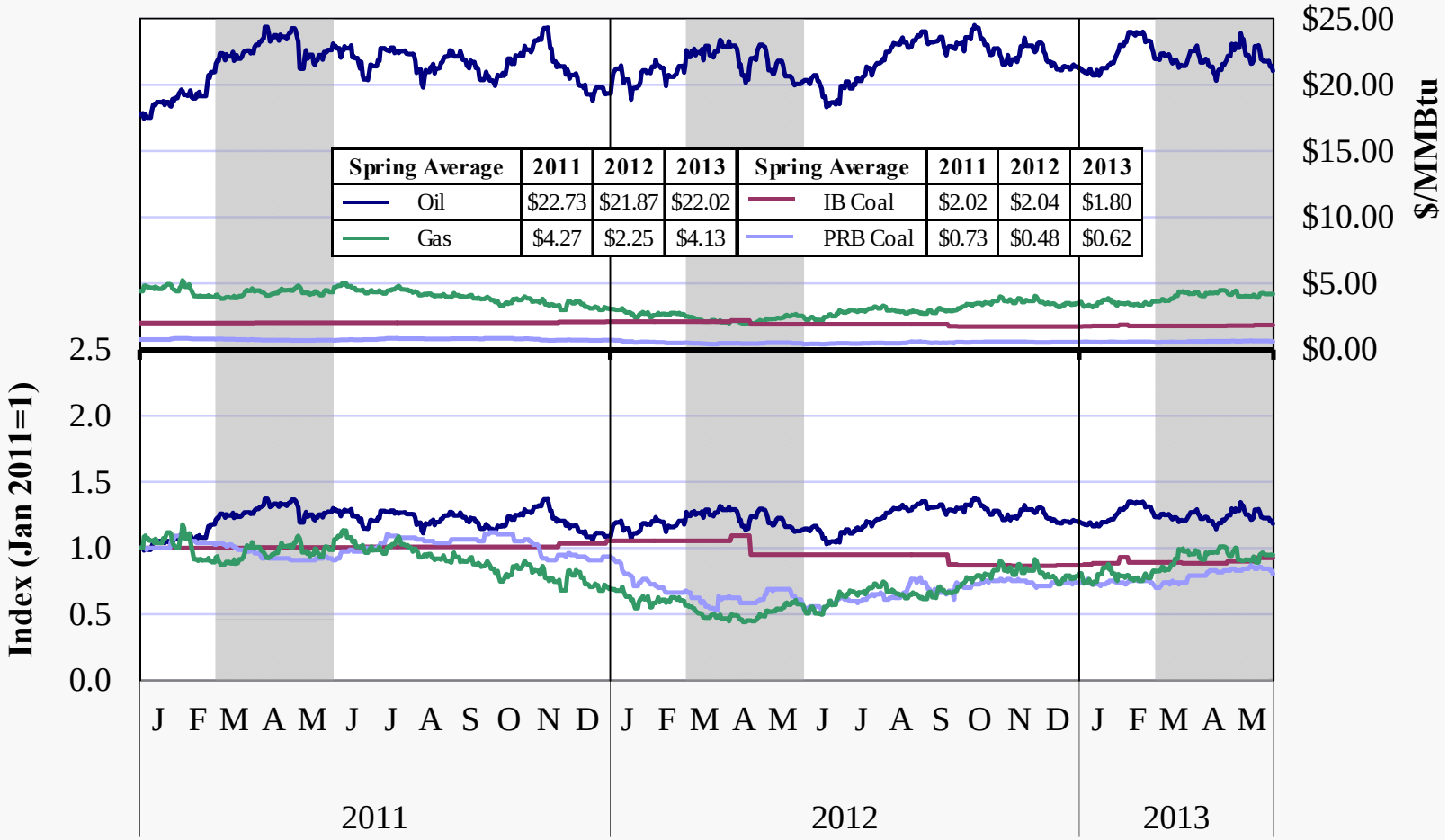
Coal Prices

- Illinois Basin prices declined 11 percent from last spring to $1.80 per MMBtu.
- Western (Powder River Basin) coal prices, however, rose another 9 percent from winter to $0.62 per MMBtu, and are 29 percent higher than last spring.

Capacity Factors

- The continued rise in gas prices has resulted in a nearly complete reversion of the generation changes observed last spring, when very low natural gas prices doubled the capacity factors for gas-fired resources from the prior year's levels.

MISO Fuel Prices
2011–2013



Spring Average	2011	2012	2013	Spring Average	2011	2012	2013
Oil	$22.73	$21.87	$22.02	IB Coal	$2.02	$2.04	$1.80
Gas	$4.27	$2.25	$4.13	PRB Coal	$0.73	$0.48	$0.62

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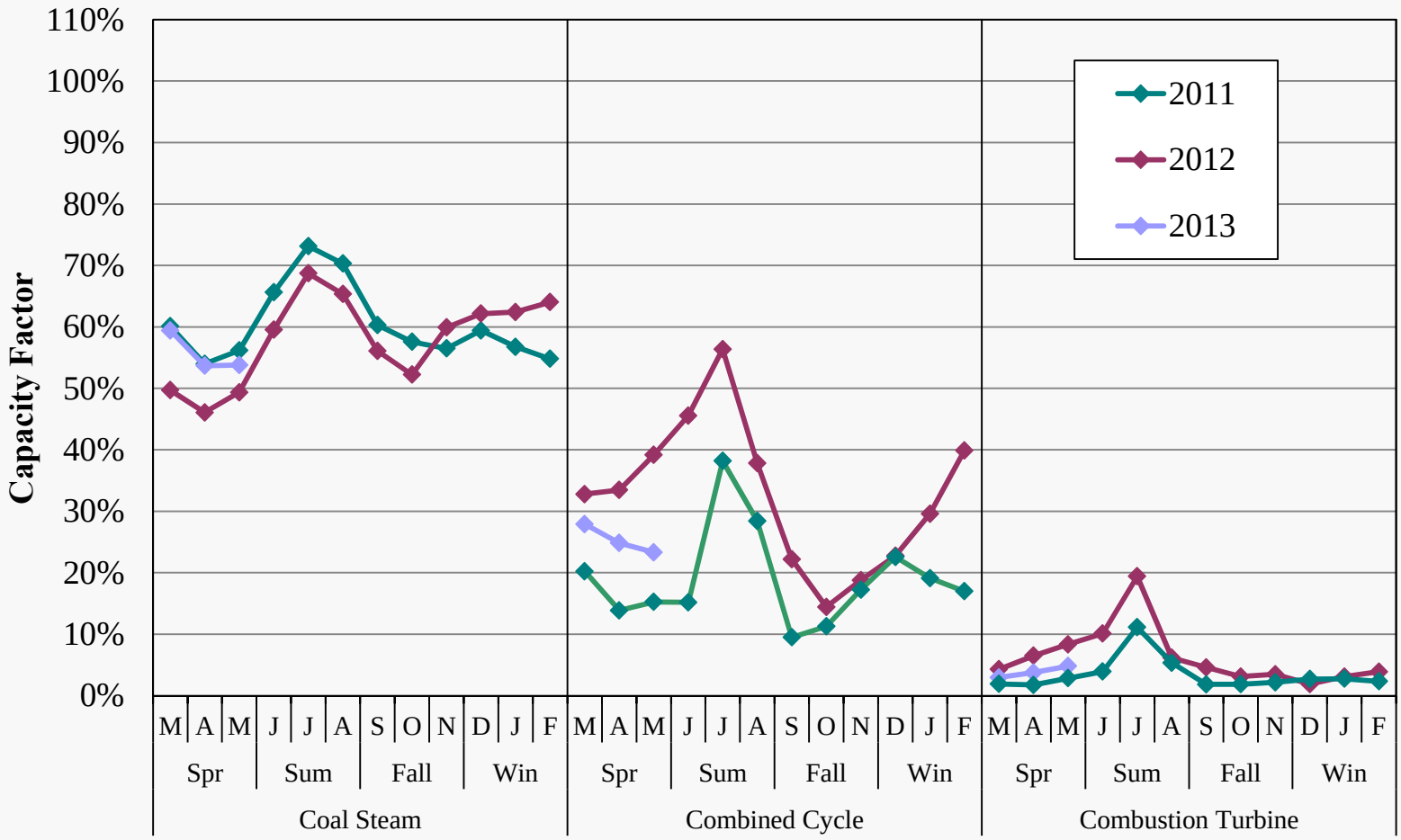
Capacity Factors by Unit Type
2011–2013



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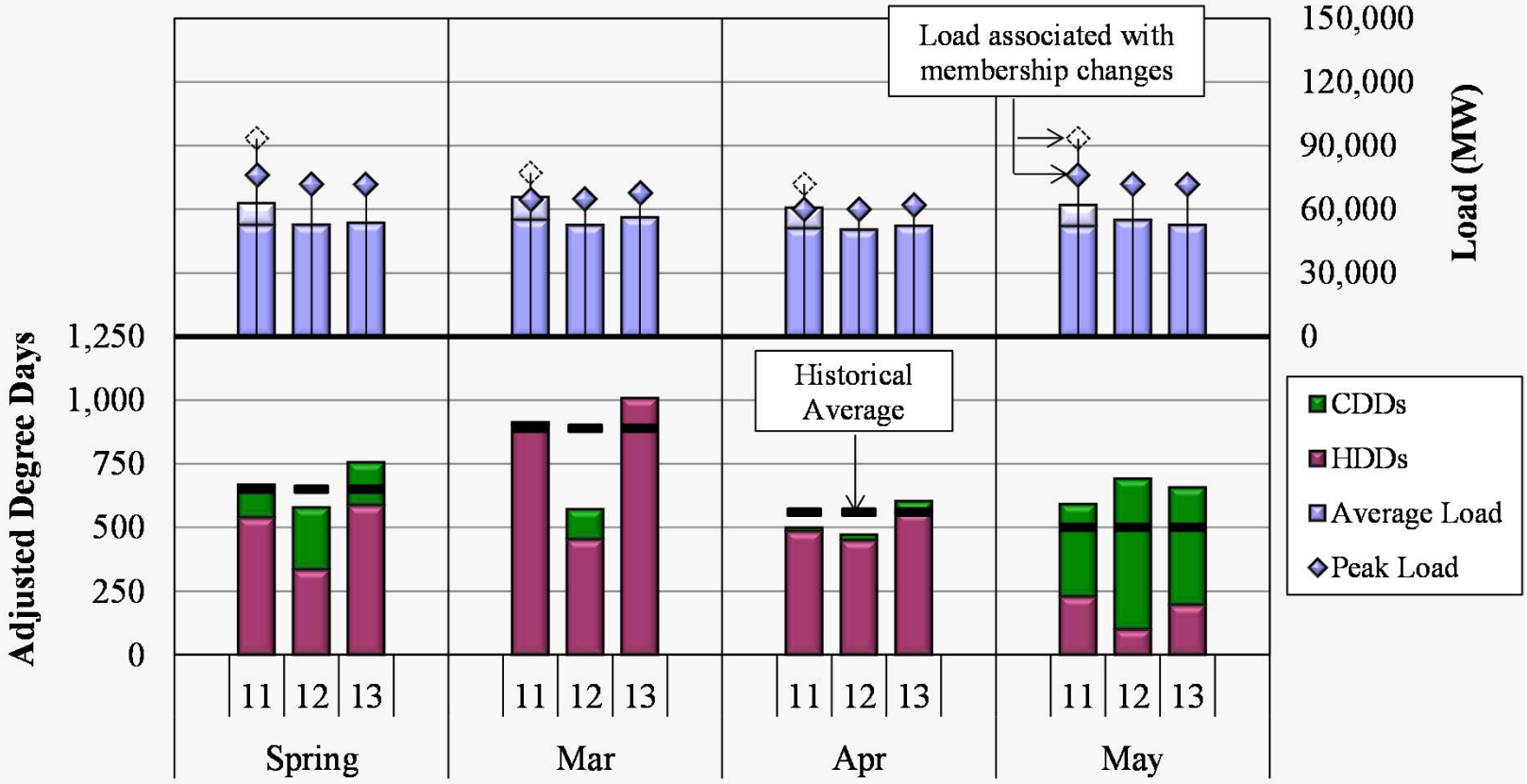
Changes in Load and Weather Patterns

- A large share of the load is sensitive to weather, so changes in weather patterns contribute directly to changes in load. This relationship is shown in the next figure.
  - ✓ The top panel shows peak and average load in the spring months of 2011 to 2013, while the bottom panel shows the average heating and cooling degree days (HDDs and CDDs, a proxy for weather).
  - ✓ Degree days are normalized (based on a regression analysis) so that heating and cooling days have an equal effect.
- The figure shows that total degree days increased 31 percent from last spring (which was unusually mild) and were 17 percent above the historical average.
  - ✓ March 2013 in particular was significantly colder than the prior March.
- This increase in degree days contributed to a 2.1 percent rise in average load in the quarter compared to the prior year.
  - ✓ Load averaged 53.9 GW in the spring and peaked at 71.9 GW on May 31.
  - ✓ Load associated with membership departures since March 2011, including FirstEnergy and portions of Duke Energy, is shown separately.

Load and Weather Patterns
Spring 2011–2013



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

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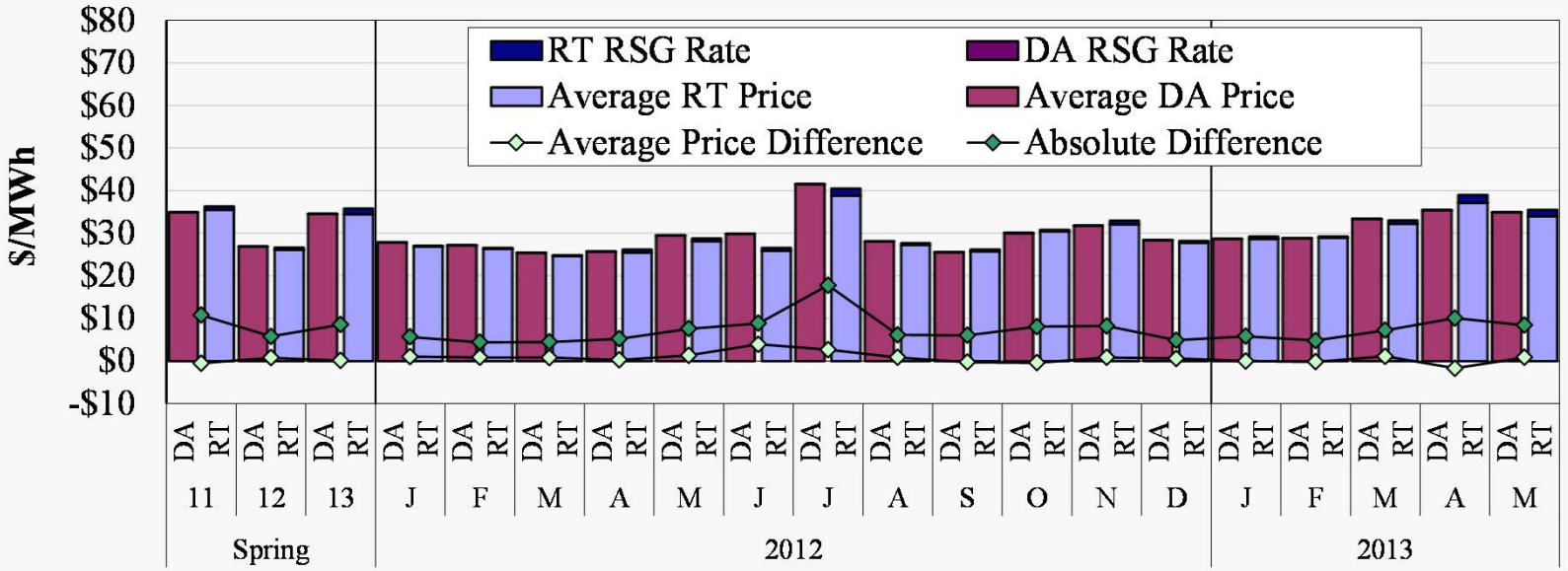
Day-Ahead and Real-Time Price Convergence

- 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 day-ahead and real-time prices were virtual equal at each of the four hubs.
  - ✓ The inclusion of real-time RSG costs, which rose from an average of $0.52 per MWh last spring to $1.34, results in effective real-time premiums of 3-4 percent.
- There were substantial real-time premiums experienced in April and May, when operating reserve shortages were not anticipated by the day-ahead market.
  - ✓ Four of the OR shortages in May had a smaller impact because they were priced at $200 per MWh, the penalty price for the first 4% of reserve shortage in the newly implemented Operating Reserve Demand Curve (ORDC).

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



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

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

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

Cin/Ind Hub	-4	1	-3	3	2	2	-2	3	13	3	1	-2	-2	0	1	-2	-2	1	-9	-1
Michigan Hub	-1	1	-3	4	2	-2	2	3	5	4	2	3	0	1	-1	-1	1	3	-10	-2
Minnesota Hub	-11	-8	-3	2	-2	1	-15	-8	-3	-2	1	-9	2	-11	-2	1	4	1	-11	2
WUMS Area	-2	-1	-4	2	-1	3	-3	-3	-3	-2	1	-6	-1	-3	1	-1	3	1	-10	-3

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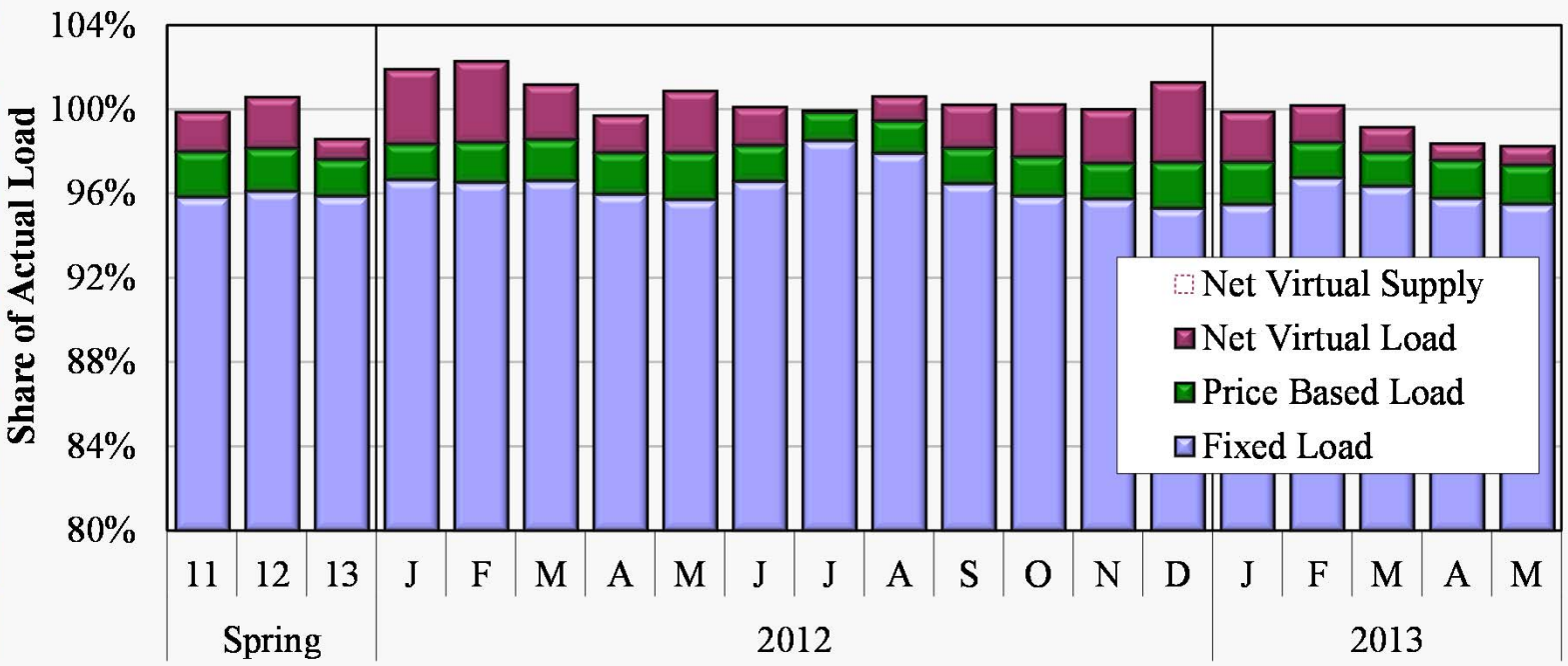
Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG costs because low levels can compel MISO to commit peaking resources in real time to satisfy load.
  - ✓ However, some real-time commitments are made regardless of load scheduling levels to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
- For the quarter, load scheduling averaged 98.6 percent, down from 100.6 percent last spring. During all hours it was nearly unchanged at 99 percent.
  - ✓ Most of the decline is attributable to reduced net virtual load, which accounted for three quarters of the decline.
  - ✓ In particular, physical participants cleared 555 MW less of price-insensitive demand, mostly at Indiana Hub and other hubs (see subsequent slides).
  - ✓ Wind and imports continue to be under-scheduled by approximately 700 MW.

Day-Ahead Peak Hour Load Scheduling
Spring 2011–2013



Share of Actual Load(%)

	11	12	13	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M
All Hour	99.4	99.1	99.0	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0	98.4	98.8	99.4	100.1	99.4	99.7	99.6	98.9	98.6
Peak Hour	100.1	100.6	98.6	101.9	102.3	101.2	99.7	100.9	100.1	99.9	100.6	100.2	100.2	100.0	101.3	99.9	100.2	99.2	98.4	98.3

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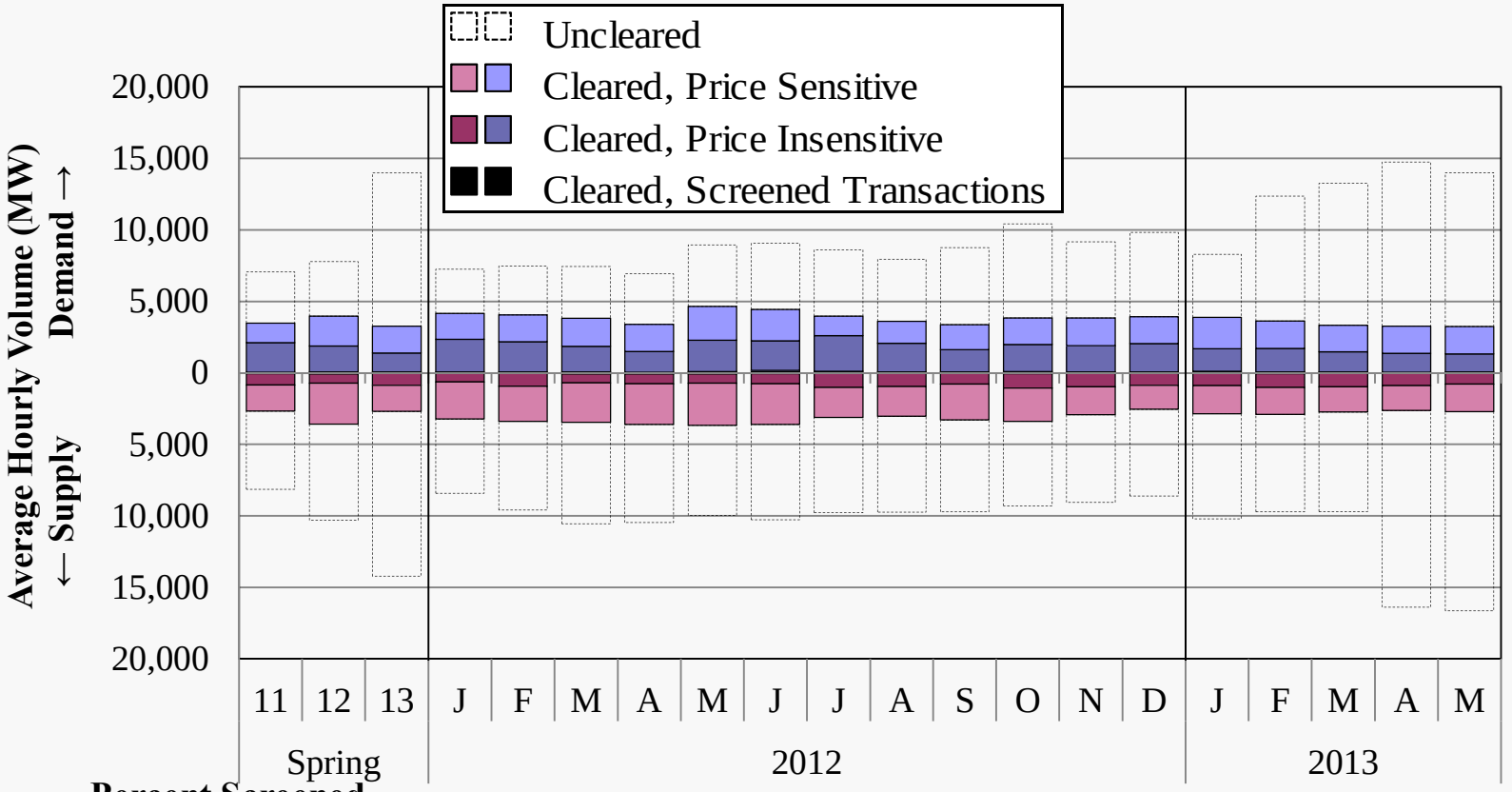
Virtual Load and Supply in the Day-Ahead Market

- Virtual trading in the day-ahead market facilitates convergence between the day-ahead and real-time prices.
  - ✓ This serves to improve the efficiency of day-ahead market results and moderates market power in the day-ahead market.
- The next figure shows the average hourly quantities of virtual demand bids and supply offers and those that were scheduled (cleared) in the day-ahead market.
- We distinguish between "price-sensitive" and "price-insensitive" bids and offers.
  - ✓ We define bids and offers as price-insensitive when they are submitted at more than $20 above and below an "expected" real-time price, respectively.
  - ✓ Price-insensitive bids and offers that then contribute to a significant difference in the congestion at a location between the day-ahead and real-time markets (labeled "Screened Transactions") raise potential manipulation concerns.
- We have been monitoring changes in virtual trading activity patterns due to MISO's changes in the RSG cost allocation in April 2011.
  - ✓ The change reduces the 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.

Virtual Load and Supply in the Day-Ahead Market

- The figure shows that cleared volumes declined 21 percent from last spring to 6.0 GW.
  - ✓ Cleared supply decreased by 25 percent to 2.7 GW, while demand declined 17 percent to 3.3 GW. Nearly all of this decline in demand occurred since winter.
- Offered volumes increased 56 percent to 28.2 GW, although most of this is limited to one participant whose price-sensitive volumes rarely clear.
- Nearly 38 percent of cleared volumes were price-insensitive, up from 34 percent last spring.
  - ✓ Changes to the RSG allocation in April 2011 reduced the allocation for participants taking balanced positions, which can be ensured by offering price-insensitively.
- Most of these price-insensitive volumes would benefit from a virtual spread product, which would allow participants to more efficiently arbitrage locational differences.
  - ✓ Bids and offers would clear only when the congestion price difference between two selected points exceeds a specific price.
  - ✓ We recommend such a product in *our 2012 State of the Market Report.*
- The share of Screened Transactions declined to 106 MW per hour, or 1.7 percent.
  - ✓ We investigate these closely and did not find any trading that raised concerns.

Virtual Volumes
Spring 2011–2013



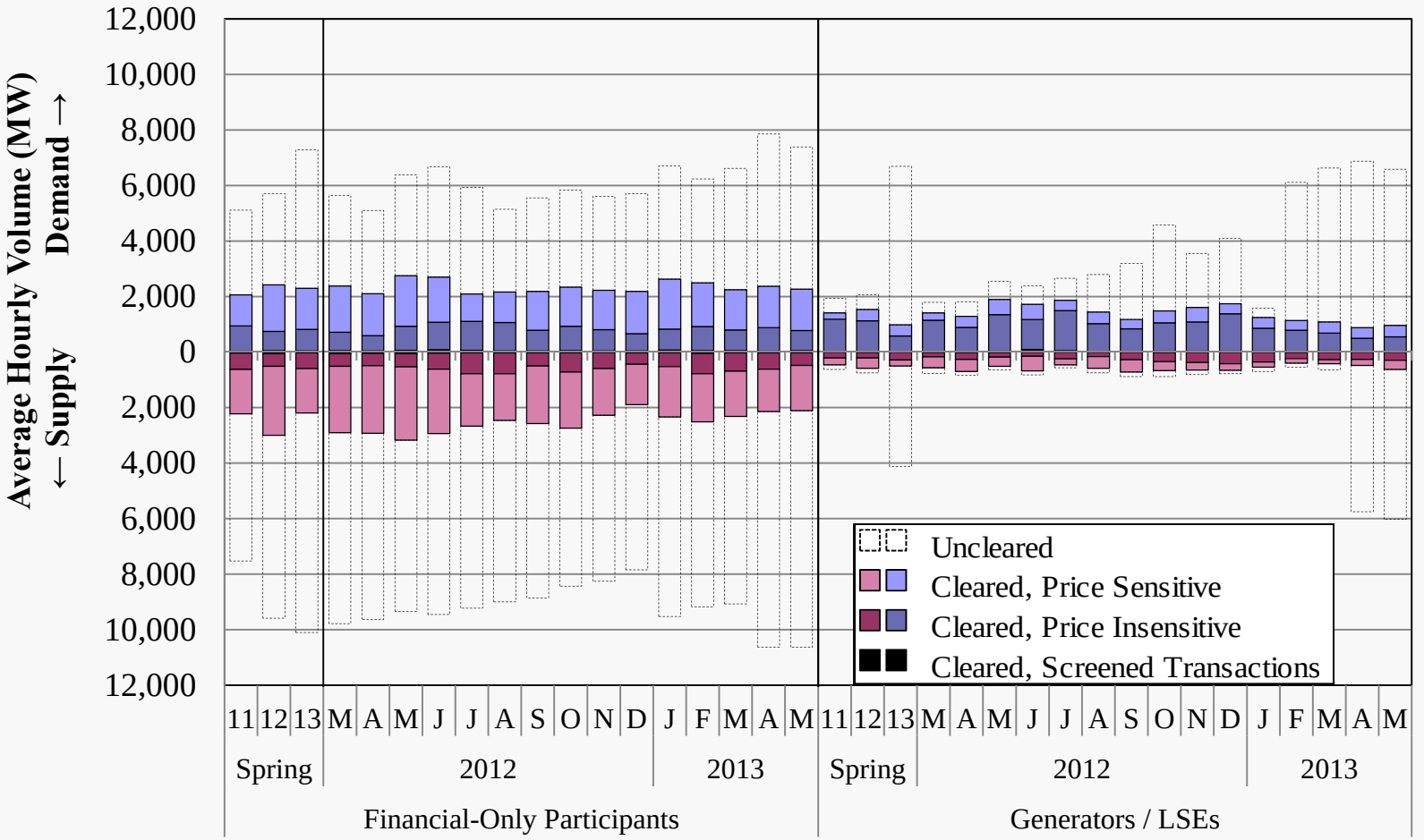
Percent Screened

Demand	1.7	1.8	2.1	1.5	2.0	1.7	1.6	2.1	4.0	3.1	1.8	2.1	2.2	2.1	2.1	2.8	2.2	2.4	1.8	2.2
Supply	1.9	2.2	1.4	0.9	1.2	2.4	1.9	2.2	1.4	1.2	1.0	1.2	1.3	1.0	1.4	1.1	2.0	1.5	1.2	1.4
Total	1.8	2.0	1.8	1.2	1.6	2.0	1.7	2.2	2.9	2.3	1.4	1.6	1.8	1.6	1.8	2.1	2.1	2.0	1.5	1.8

Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by two types of market participants: physical participants and financial-only participants.
  - ✓ Physical participants generally have different motivations to clear volumes (e.g. hedging other risks) than financial-only participants do (e.g. price arbitrage).
- Financial-only participants continue to constitute roughly 75 percent of all virtual volumes. This share is up from 72 percent last spring.
  - ✓ Financial-only cleared volumes declined 17 percent to 4.5 GW, whereas physical participant volumes declined 30 percent to 1.5 GW.
- The increase in uncleared offered volumes by a single subsidiary of a physical participant, which began with virtual demand in February, extended to supply in April.
  - ✓ They bid an average of 8300 GW, but clear just 6 MW since they generally bid at prices that are very unlikely to clear. This activity does not raise competitive concerns.
- The share of volumes that are price-sensitive remains much higher for financial-only participants (69 percent) than those of physical participants (42 percent).
  - ✓ Physical participant volumes, however, have become more price sensitive on average because price insensitive volumes fell.

Virtual Load and Supply by Participant Type
Spring 2011–2013



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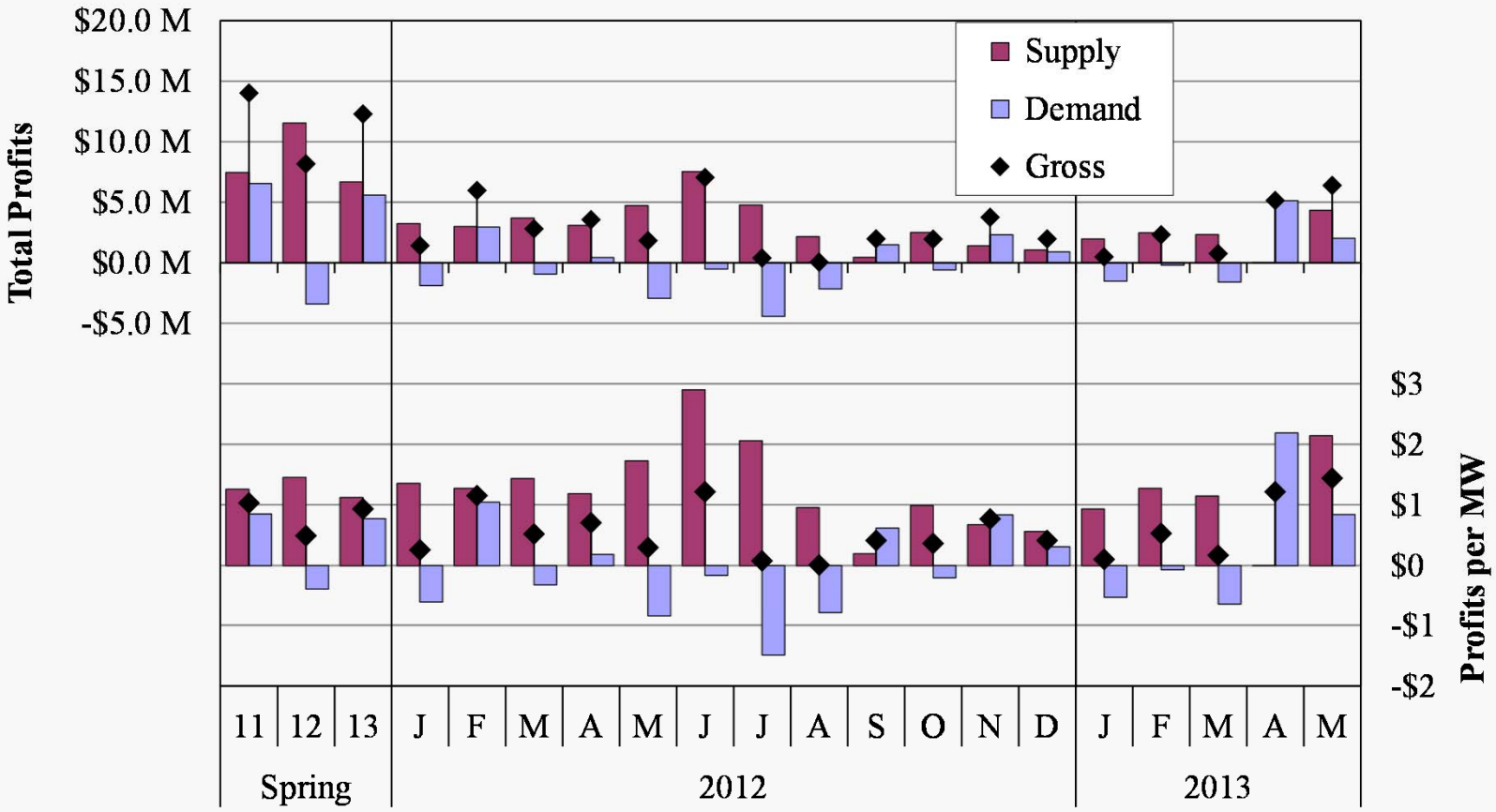
Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual supply and demand.
  - ✓ Gross virtual profits this spring totaled $12.3 million, up from $8.2 million last spring.
- Gross profitability on virtual transactions rose from $0.49 per MW last spring to $0.93.
  - ✓ Demand in particular was unusually profitable at $0.77, in part because of a greater number of real-time price spikes this quarter, particularly in April.
  - ✓ Virtual supply profitability averaged $1.12, which is expected when the market exhibits a slight day-ahead premium.
- These margins exclude CMC and DDC charges assessed to net harming deviations.
  - ✓ Including DDC charges, which averaged $1.34 per MW, to net virtual supply made supply slightly unprofitable this quarter.
  - ✓ In late April, MISO fixed the CMC allocation sign error that had been misallocating congestion-related RSG to virtual transactions. This improved incentives for participants to accurately arbitrage congestion price differences.
- Virtual transactions by financial participants continue to be profitable and generally improve price convergence overall.
  - ✓ Profitability of these transactions rose from $0.88 per MW last spring to $1.02.
  - ✓ Cleared virtuals by physical participants were also profitable at $0.54 this quarter.

Virtual Profitability
Spring 2011–2013



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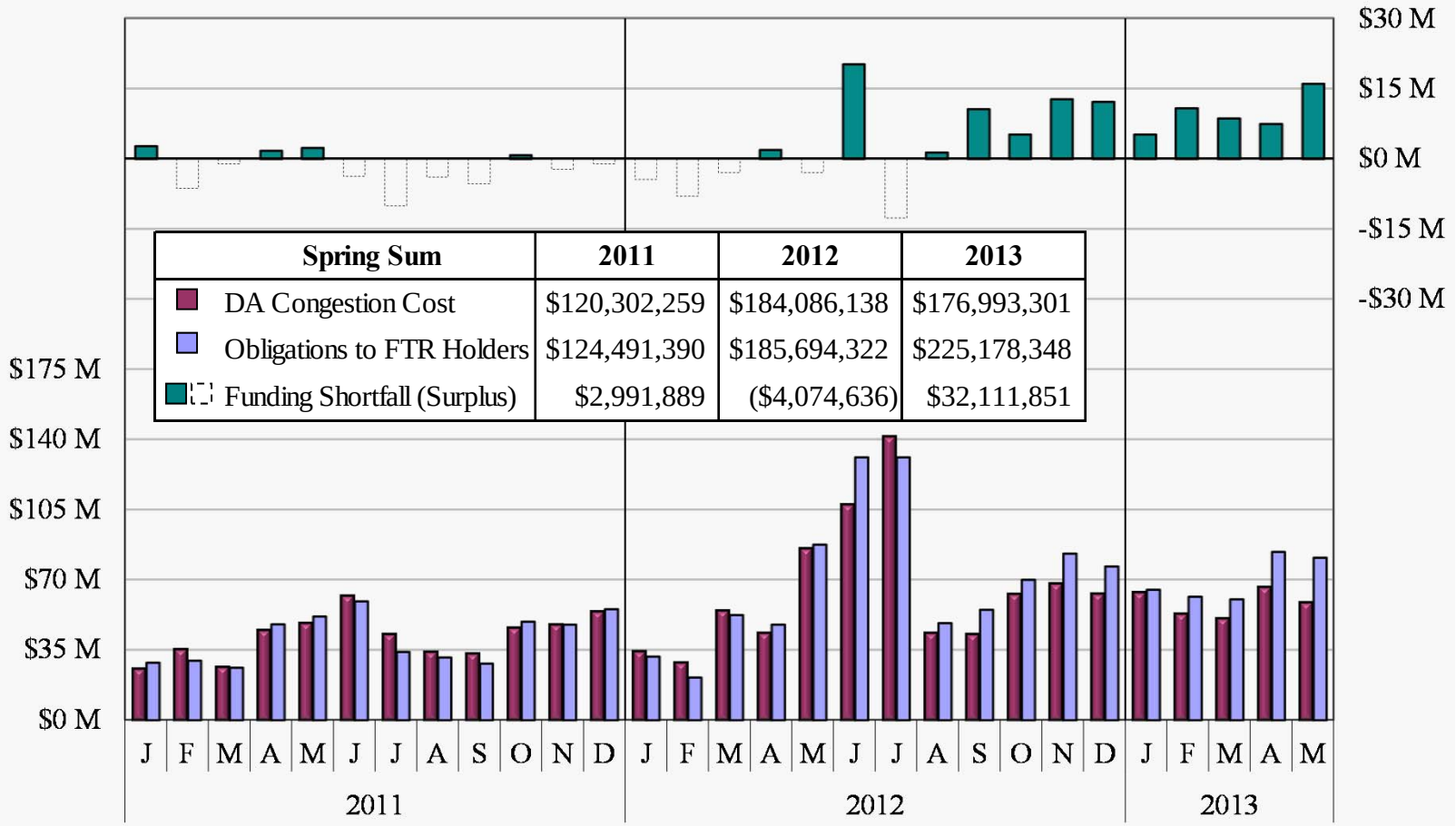
Day-Ahead Congestion and Obligations to FTR Holders

- 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 declined 3 percent from last spring to $177 million.
- The next figure shows day-ahead congestion, FTR obligations and FTR shortfalls.
  - ✓ Shortfalls (or surpluses) occur when the portfolio of FTRs represent more (or less) transmission capacity than the capability of the network in the day-ahead market.
- FTR obligations were underfunded by 9 percent ($32.1 million) this spring, unchanged from winter but down from the full funding last spring.
  - ✓ Underfunding began with the new FTR year in June and has averaged 8 percent since.
  - ✓ Surpluses the prior FTR year were accrued on internal market-to-market constraints and covered shortfalls on other constraints.
  - ✓ These surpluses disappeared during the 2012-2013 FTR year, contributing to large shortfalls and reduced FTR funding.
  - ✓ MISO is continuing the evaluate and improve FTR modeling assumptions in its annual and monthly auctions to increase funding levels.

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



Spring Sum	2011	2012	2013
DA Congestion Cost	$120,302,259	$184,086,138	$176,993,301
Obligations to FTR Holders	$124,491,390	$185,694,322	$225,178,348
Funding Shortfall (Surplus)	$2,991,889	($4,074,636)	$32,111,851

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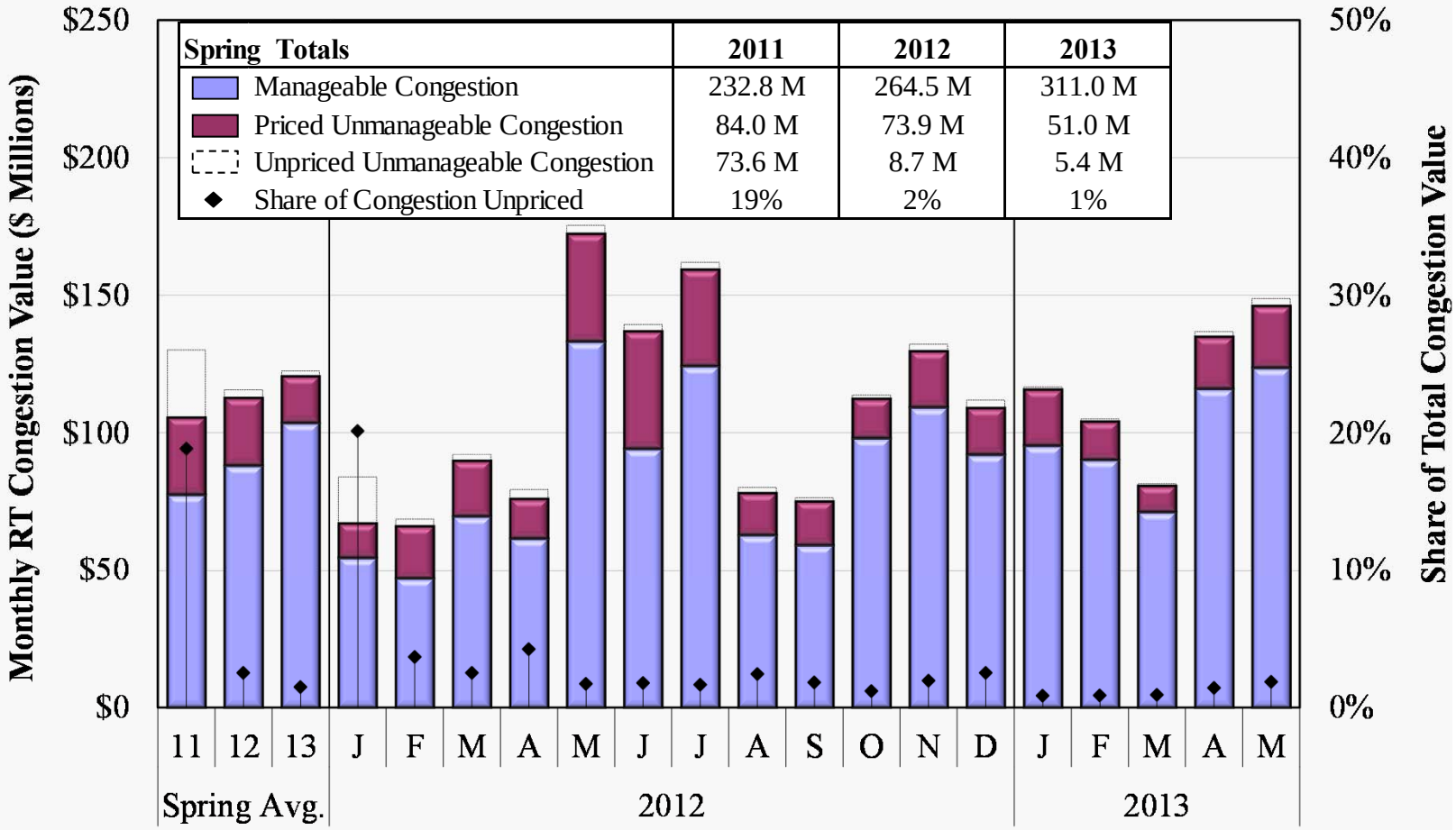
Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on MISO-managed internal and market-to-market constraints (the figure excludes external constraints).
  - ✓ Real-time congestion is equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint.
  - ✓ This is higher than the congestion costs collected by MISO because loop flows do not settle with MISO and PJM has entitlements to MISO's transmission capability.
  - ✓ The figure separately shows congestion on those constraints that are temporarily violated (i.e., the congestion is considered "unmanageable" in the 5-minute dispatch).
- The value of real-time congestion rose 7 percent from the prior spring to $362 million, which is a relatively small increase given the substantial rise in fuel prices.
  - ✓ Over $55 million accrued in the second half of May on a set of constraints in the Central region that was impacted by the planned outage of a 1,300-MW unit.
- Constraint relaxation is now only used on external and M2M constraints and it eliminated one percent of congestion value in the quarter, which is a substantial improvement compared to prior periods when it was used on all constraints.
- MISO has deactivated the transmission "deadband" on a limited set of constraints, which has reduced shadow price volatility and improved pricing efficiency.
  - ✓ Our analysis in the *State of the Market Report* shows the benefits from MISO's trial study and we continue to recommend MISO eliminate this provision for all constraints.

Value of Real-Time Congestion
Spring 2011–2013



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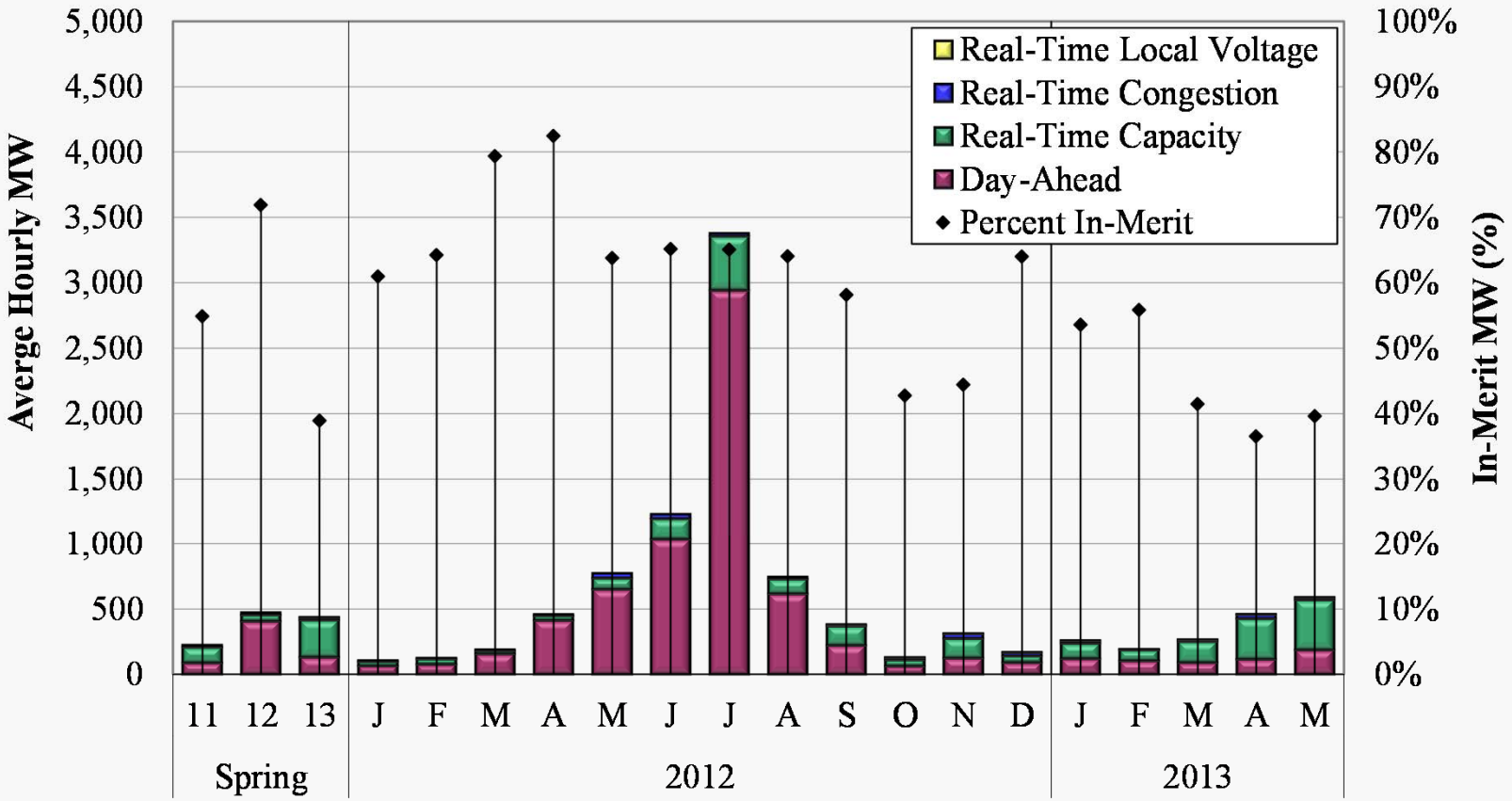
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were in-merit (offer price at or lower than the LMP).
  - ✓ The figure is categorized by the market and the reason for the commitment.
- Total peaking unit dispatch quantities decreased 9 percent from last spring to 437 MW per hour.
  - ✓ Capacity dispatches rose nearly five-fold to 285 MW. The majority of these were out-of-merit commitments identified by the LAC process.
  - ✓ Day-ahead committed peaking unit output declined by more than two-thirds.
    - – In spring 2012, very low fuel prices resulted in many peaking units being competitive with base-load generation.
  - ✓ Real-time congestion and VLR needs this quarter constituted a very small portion of total peaking quantities (4.1 and 0.2 percent, respectively).
- The share of in-merit dispatches declined from 72 percent to just 39 percent.
  - ✓ MISO's Extended LMP Initiative, expected to go-live in early 2014, will allow peaking resources to set prices more frequently.

Peaking Resource Dispatch
Spring 2011–2013



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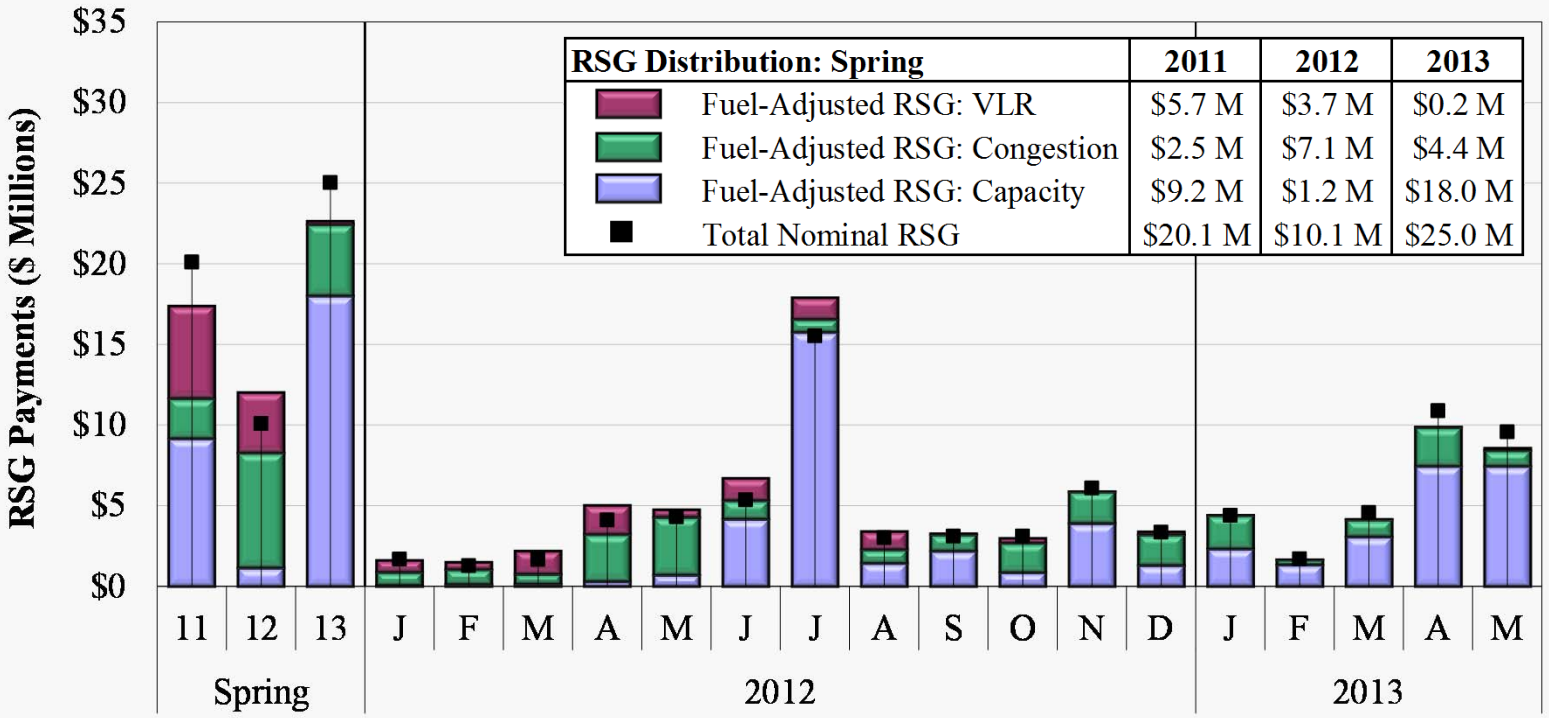
Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets, respectively.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices (adjusting values to correspond to the average fuel prices over the period shown).
- Nominal real-time RSG costs rose nearly 150 percent from last spring to $25.0 million.
  - ✓ One-third of this increase was due to increases in fuel prices.
- In fuel-adjusted terms, payments for capacity rose from $1.2 to $18 million.
  - ✓ This is in part due to a decline in load scheduling that increased MISO's need to commit resource to satisfy its capacity needs.
  - ✓ Over 90 percent were identified as necessary by LAC.
- Over sixty percent of payments (nearly $3 million) for congestion went to just three units in the Central Region committed for a nearby transmission outage.
- The second figure shows day-ahead RSG payments totaled $4.8 million and are nearly unchanged, in fuel-adjusted terms, from last spring.
  - ✓ Payments to units committed for VLR averaged nearly $1 million and are down substantially from the fall, when such commitments were first moved to the day-ahead.
  - ✓ Higher energy prices make it more likely that these units are revenue-adequate.

Real-Time RSG Payments
Spring 2011–2013



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

Peaker	35	54	75	26	31	29	51	75	68	84	44	67	73	75	77	82	57	76	82	77
Non-Peaker	65	46	25	74	69	71	49	25	32	16	56	33	27	25	23	18	43	24	18	23

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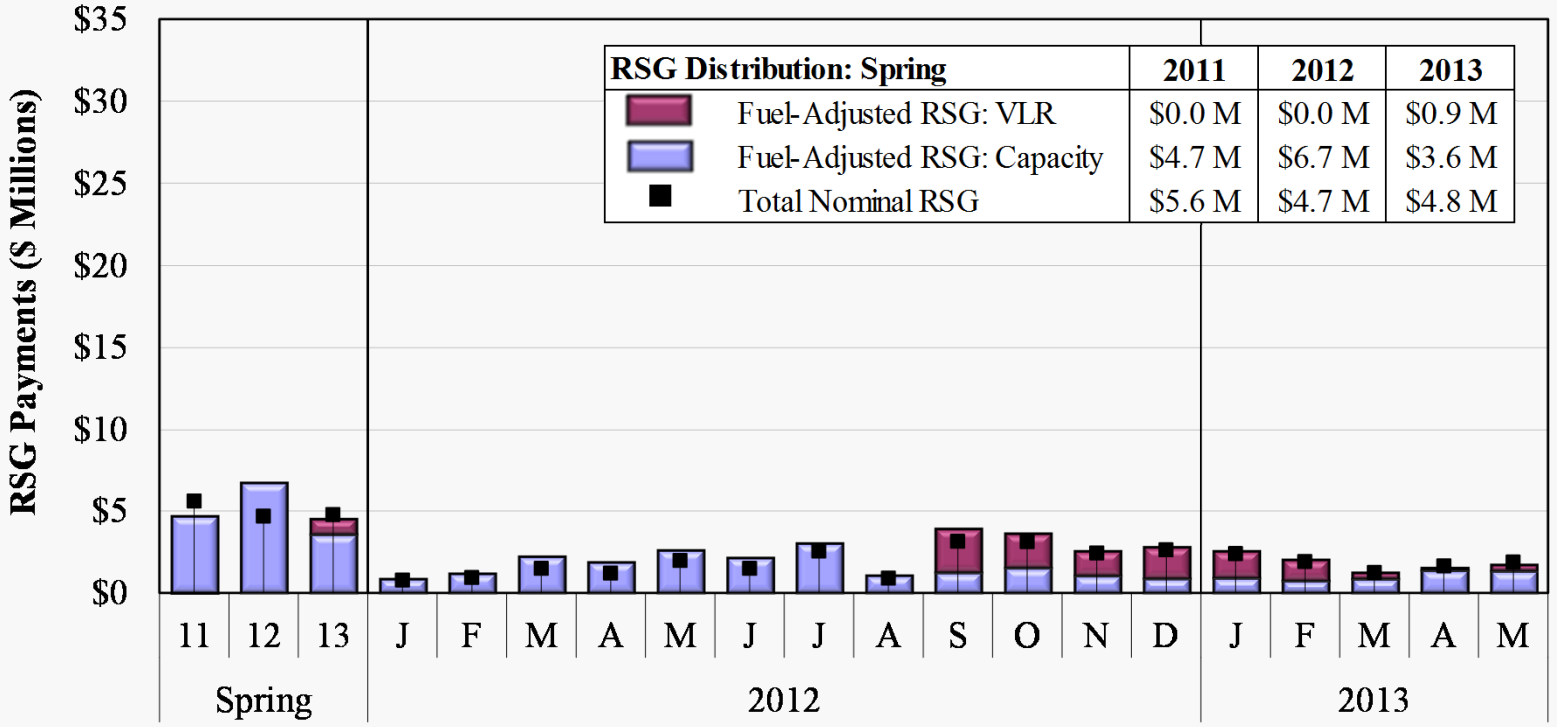
Day-Ahead RSG Payments
Spring 2011–2013



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

Peaker	4	4	1	2	1	2	8	21	16	62	36	9	1	2	6	1	0	2	11	6
Non-Peaker	96	96	99	98	99	98	92	79	84	38	64	91	99	98	94	99	100	98	89	94

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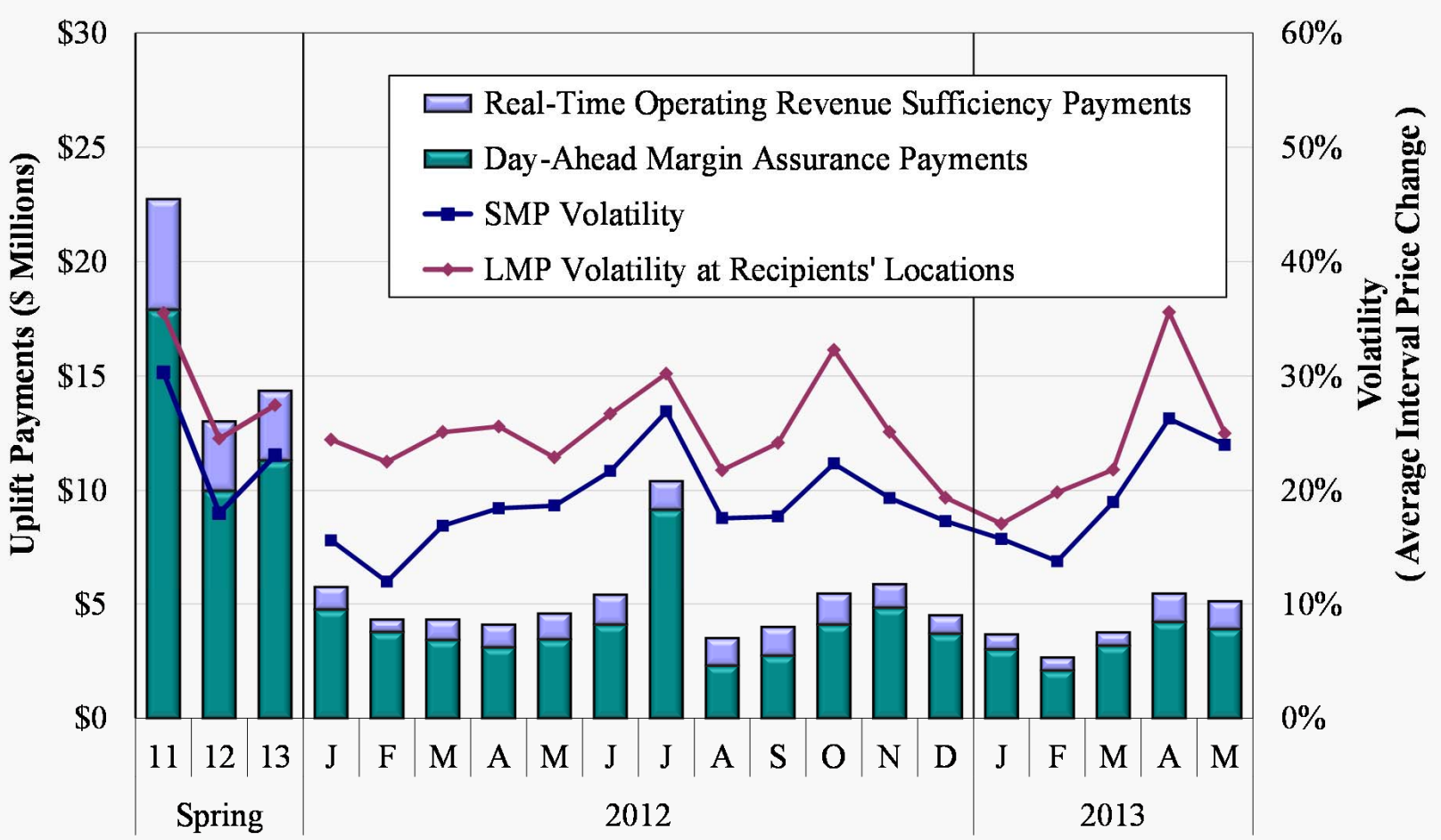
Price Volatility Make Whole Payments

- The next chart shows Price Volatility Make Whole Payments (PVMWP) that improve incentives for suppliers to follow dispatch instructions.
- The payments, which totaled $14.4 million this spring, come in two forms:
  - ✓ DAMAP, which increased 13 percent from last spring to $11.3 million; and
  - ✓ RTORSGP, which was nearly unchanged at $3.1 million.
- Large coal units in the East and Central regions continue to be the largest recipients of such payments, predominantly during ramping hours.
- The lines on the chart show two measures of price volatility: one based on the System Marginal Price (SMP) and the other on LMPs at generator locations.
  - ✓ The figure shows that the payments have been correlated with price volatility, as expected, and increased volatility leads to higher payments to flexible suppliers.
  - ✓ SMP and LMP volatility both recorded double-digit increases from last spring.
- We recommended several improvements to PVMWP settlement eligibility criteria and calculations in this year's *State of the Market Report*.

Price Volatility Make Whole Payments
Spring 2011–2013

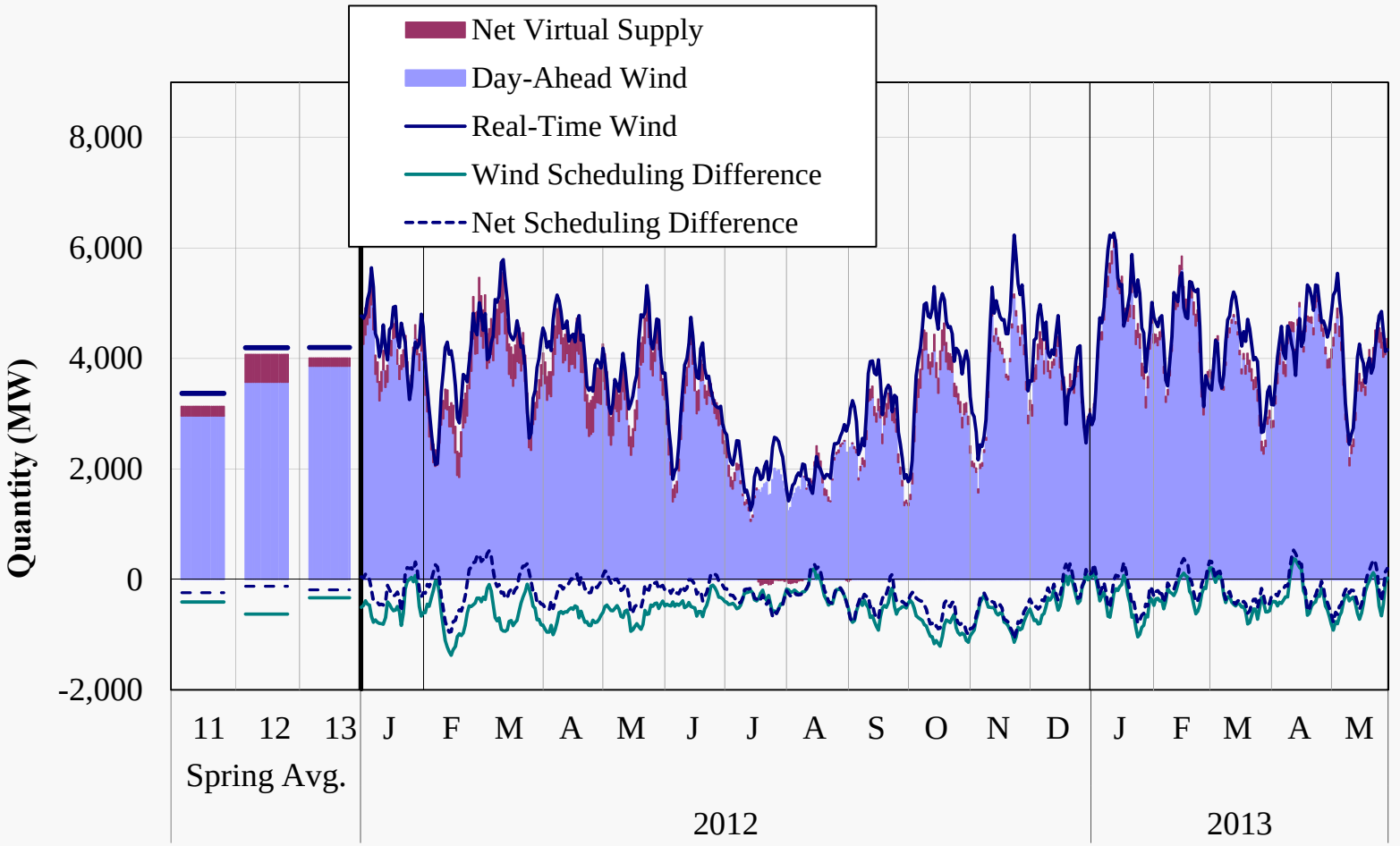


POTOMAC ECONOMICS

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 2 percent from last spring to 4.2 GW, and comprised 8.4 percent of total generation this quarter.
  - ✓ Nameplate capacity over the same period increased 9 percent to 12.2 GW, or nearly 10 percent of total capacity.
- Under-scheduling of this wind output in the day-ahead improved considerably from last spring, declining by more than half to 331 MW.
- Less than half of this was offset by net virtual supply, even though virtual supply continues to be substantially profitable at these locations.
  - ✓ Profits on virtual supply at wind locations totaled $3.3 million, or $3.37 per MW. This is up from $2.20 last spring.

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



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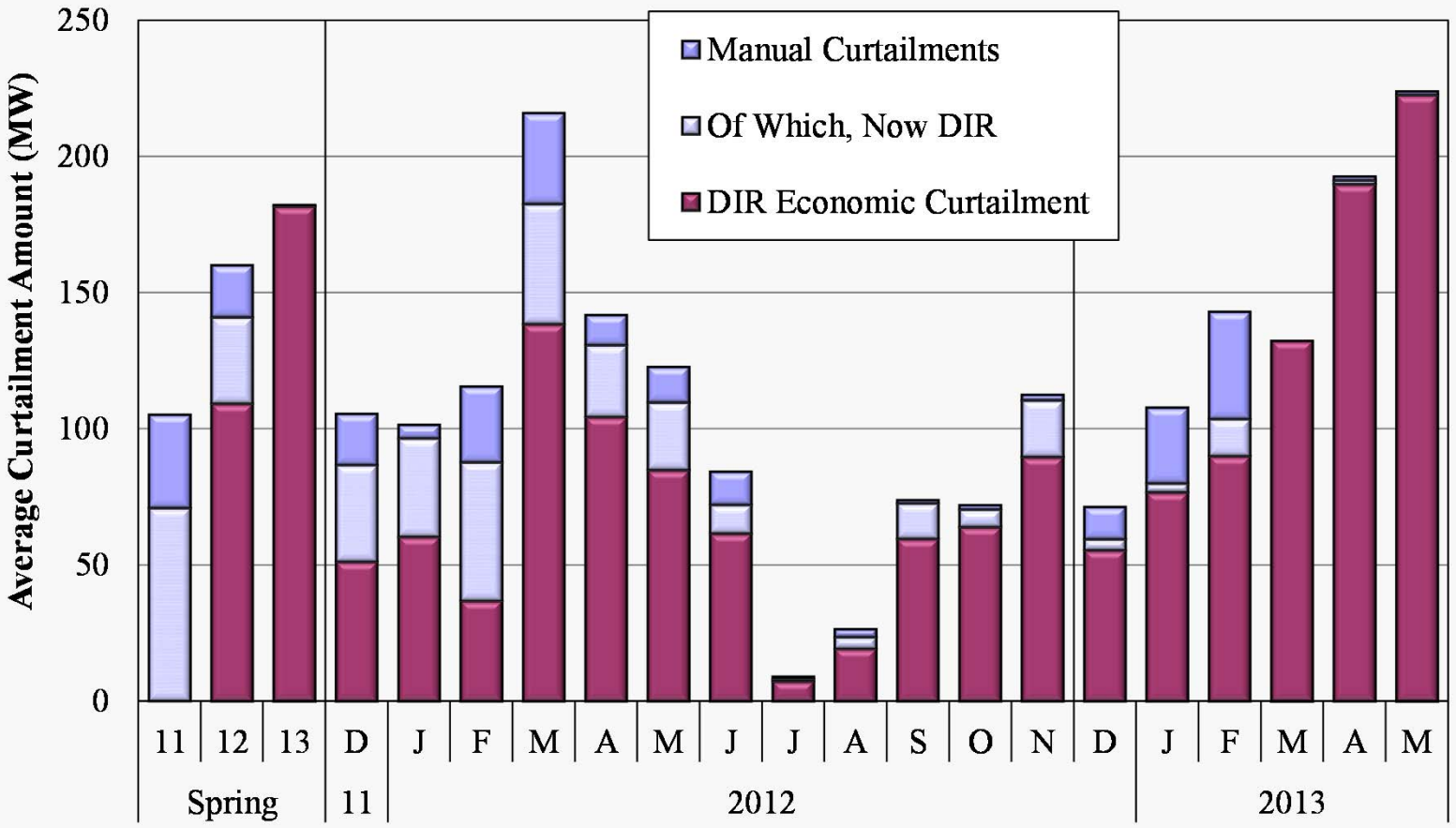
Wind Curtailments

- Nearly 80 percent of wind capacity—111 out of 176 units—in the MISO footprint is registered as DIR.
  - ✓ Although not all of these are yet able to respond to MISO dispatch instructions, they have substantially improved congestion management and pricing.
- MISO must still manage the ramp demands of related to wind volatility, which averaged 47 MW per interval (based on units' forecasted maximums).
  - ✓ In addition, DIRs this spring were cumulatively deficient (below their set point instruction) by an average of 67 MW per interval.
- The following figure shows that economic DIR curtailments have almost fully replaced manual curtailments since 2011 as the primary means of controlling wind output.
  - ✓ Manual curtailments declined 97 percent from last spring to an average of 1.4 MW per interval. There were just 10 such curtailments this quarter.
  - ✓ Economic curtailment of wind resources averaged 182 MW this spring, up 66 percent from the 109 MW averaged last spring.

Wind Curtailments
Spring 2011–2013

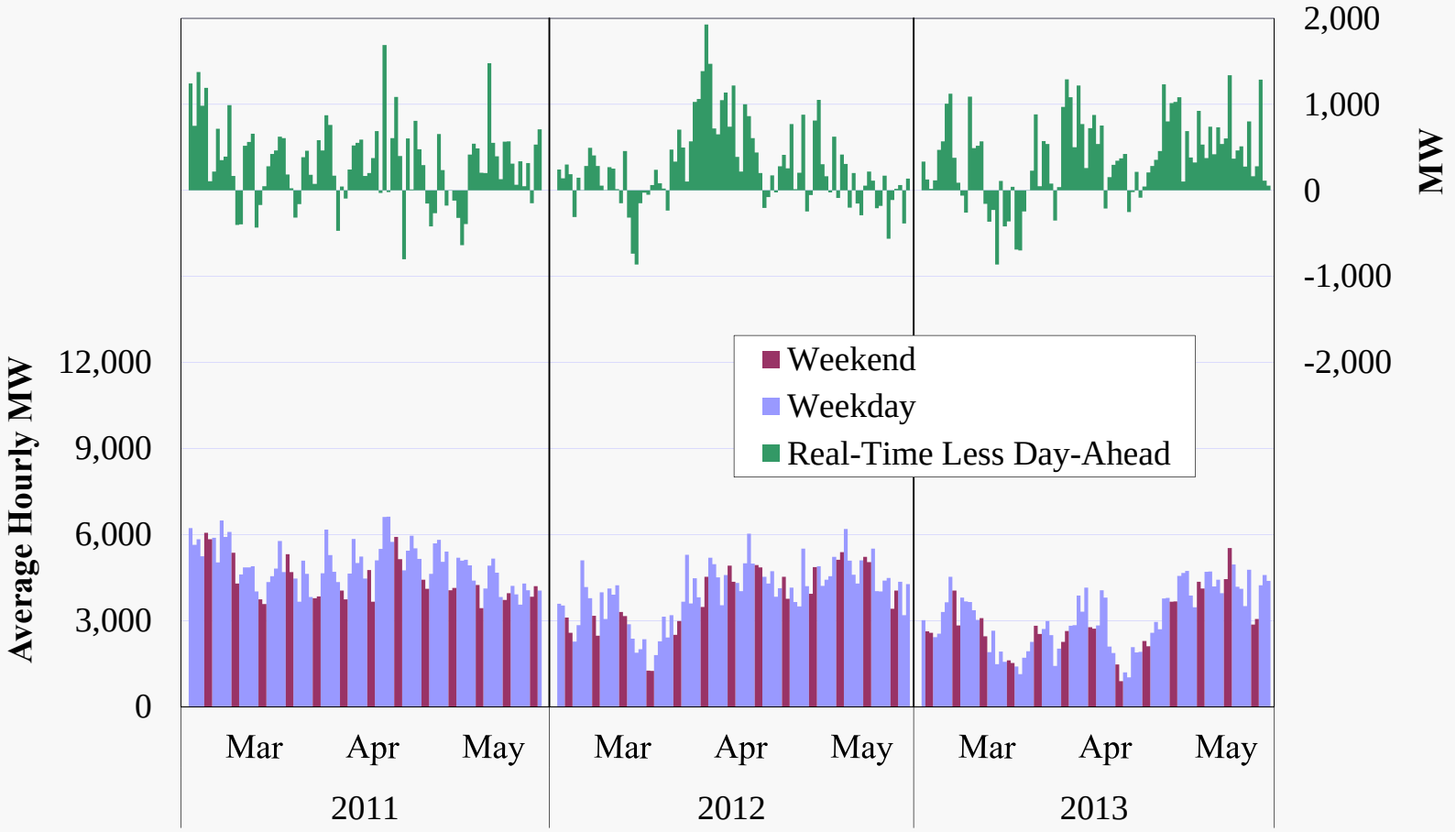


POTOMAC ECONOMICS

Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market in spring of 2011 to 2013.
- Net imports declined by 23 percent from last spring to 3.1 GW per hour.
  - ✓ MISO remains a considerable net importer of energy during most hours.
  - ✓ Imports rose by 49 percent from Manitoba to 974 MW on average, while they declined by 26 percent across the PJM interface, to 1.6 GW.
- Transactions wheeled through MISO still originate predominantly in Ontario, and are almost exclusively scheduled to PJM.
  - ✓ These averaged nearly 1.5 GW, mostly unchanged from last spring.
  - ✓ These transactions are partly motivated by substantial excess payments being made by PJM and MISO, which is discussed in detail in our 2012 SOM Report.
- MISO and PJM continue to discuss proposals to improve interchange in the JCM process, including interchange optimization and alignment of scheduling rules.
  - ✓ Our analysis of interchange continues to show that the interface with PJM is not efficiently utilized, which should be addressed by interchange optimization.
  - ✓ The JCM has made progress on alignment but this will not alleviate inefficiencies documented in our SOM.

Average Hourly Real-Time Imports
Spring 2011–2013



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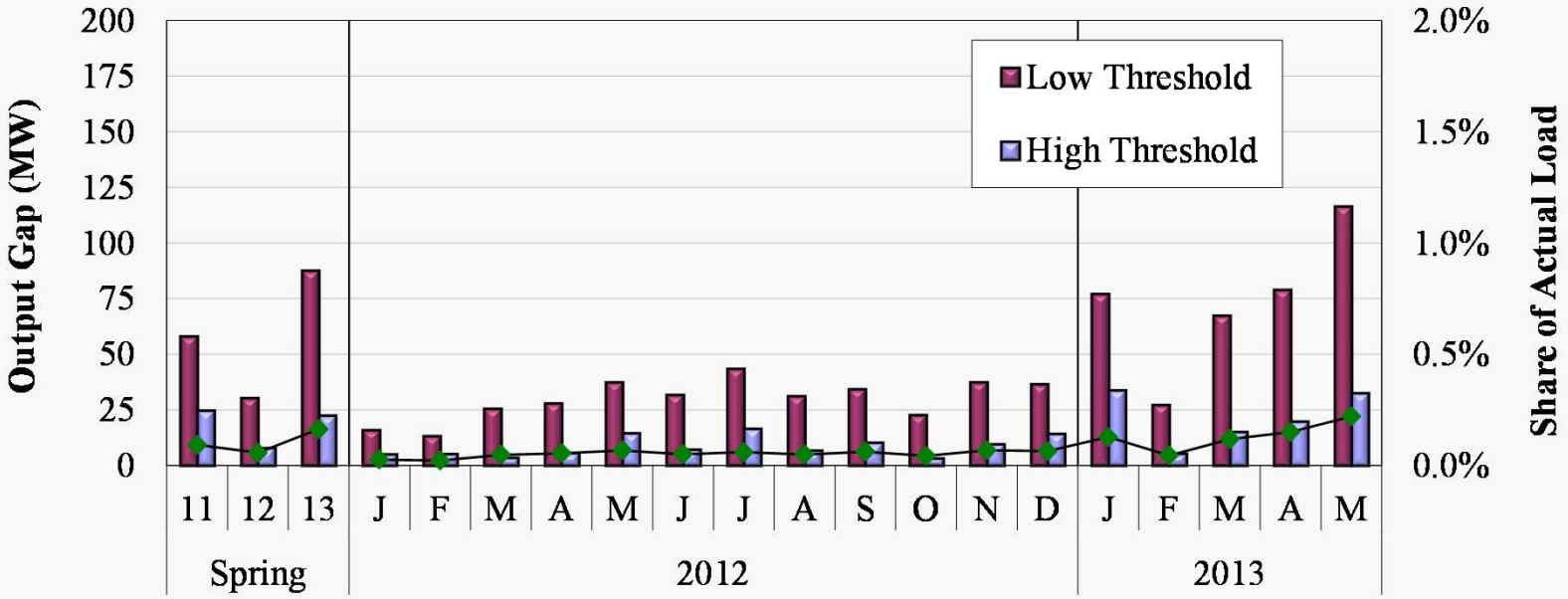
Monthly Output Gap

- 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 2012 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 in MISO increased from extremely low levels last spring, but remained very low (less than 0.01 percent of load at both thresholds).
  - ✓ At the high threshold, output gap rose from 8 to 23 MW, while at the low threshold it rose from 30 to 88 MW.
- We continue to routinely investigate hourly increases in output gap, and have found very limited instances of competitive concern.

Monthly Output Gap
Spring 2011–2013



Low Threshold Results by Unit Status (MW)

Off Line	15	4	6	4	4	1	1	9	0	11	0	8	0	2	5	8	2	6	0	12
On Line	44	27	81	12	9	24	27	29	32	33	31	26	23	36	32	69	25	62	79	104

High Threshold Results by Unit Status (MW)

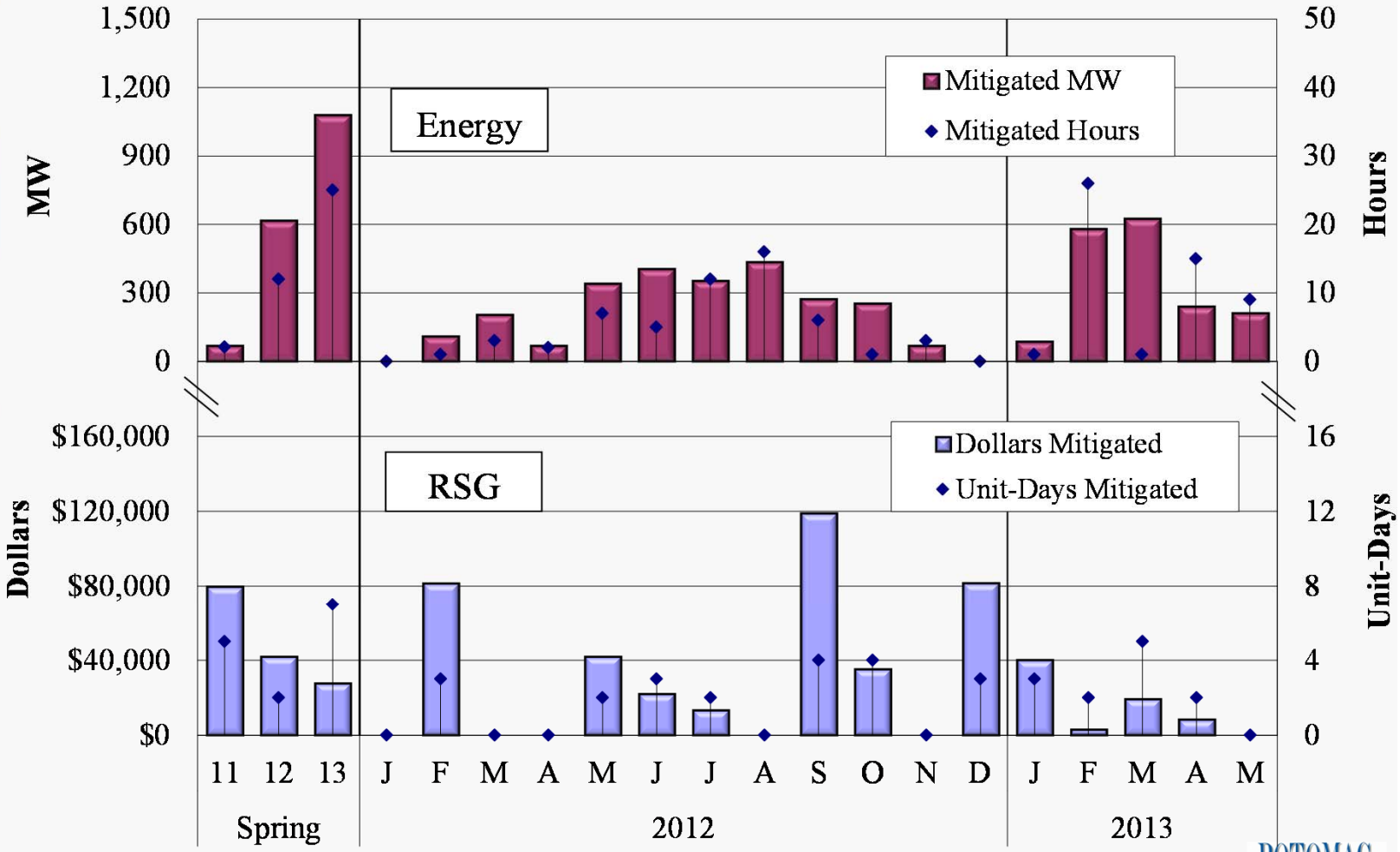
Off Line	13	4	5	4	4	1	1	9	0	9	0	5	0	1	4	7	1	4	0	10
On Line	12	4	18	2	1	2	4	6	7	7	7	5	3	9	11	27	4	11	20	22

POTOMAC ECONOMICS

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which energy and RSG mitigation was imposed in the real-time market in each month since January 2012.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the average quantity mitigated.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigated.
- Since most resources continue to be offered competitively, mitigation in MISO remains infrequent.
  - ✓ Considerable market power continues to persist, however, and market power mitigation measures remain critical.
  - ✓ We continue to evaluate each imposition of AMP mitigation and found mitigation this quarter to be appropriately applied in each instance.
- Energy mitigation occurred for 25 hours and 1,080 MW, up from 12 hours and 617 MW last spring.
  - ✓ Over 70 percent of mitigated quantities occurred in Minnesota NCA, in part because thresholds there are lower than anywhere else in the footprint.
- RSG mitigation quantities declined 34 percent from last spring to $28,000.
  - ✓ There were no day-ahead mitigations for VLR this quarter.

Real-Time Market Power Mitigation
Spring 2011–2013



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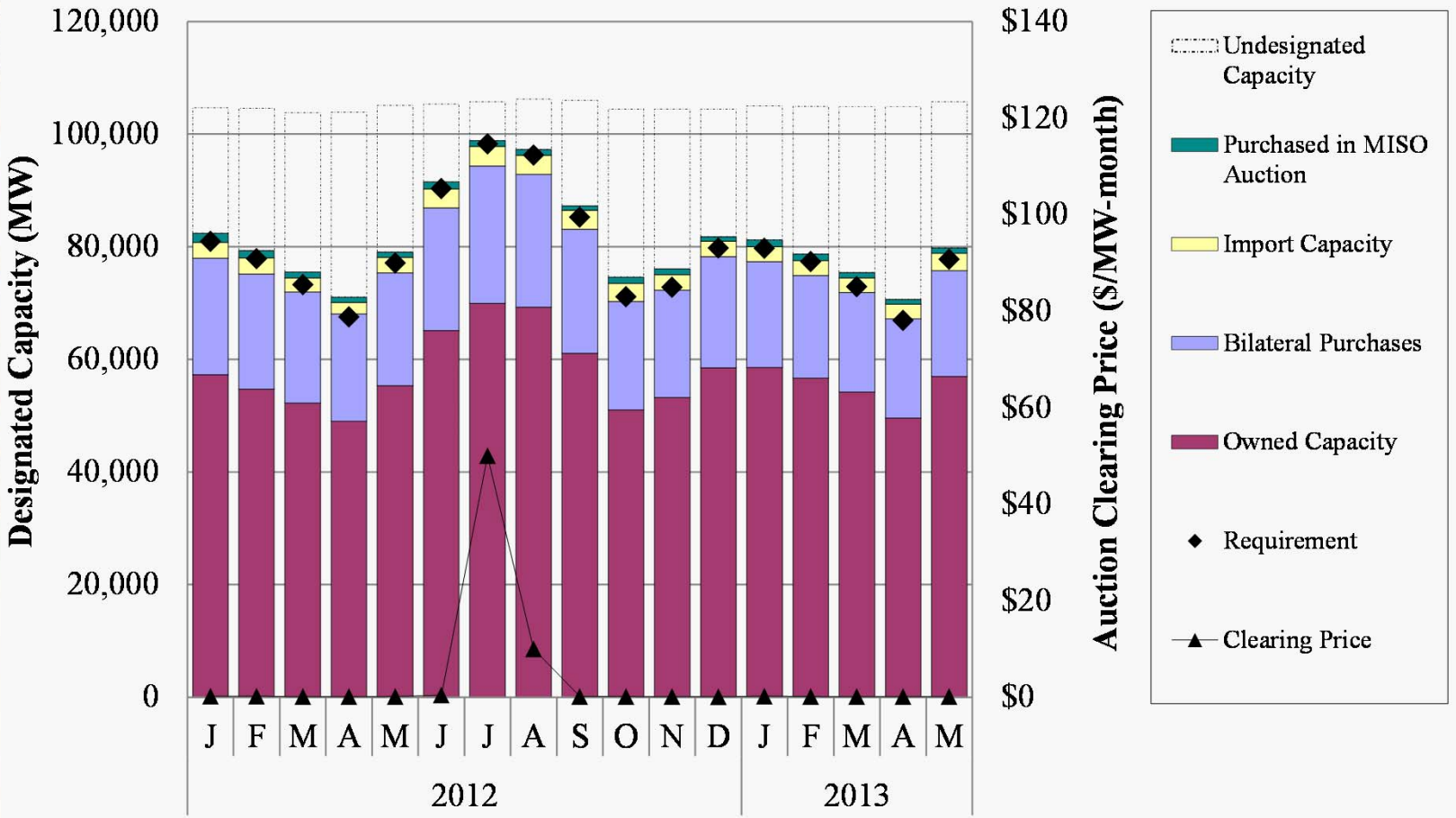
Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities (LSEs) to procure residual capacity to meet their Module E capacity requirements.
  - ✓ The following figure shows the monthly capacity requirements, designated capacity, and VCA clearing price since January 2012.
- The auction cleared at $0.10 per MW each month, which is essentially zero and reflects both the current capacity surplus and the capacity market design shortcomings.
  - ✓ Capacity levels exceeded the VCA requirement, which is based on a participant-forecasted load, by 36 to 57 percent in each month.
- The capacity cleared in the VCA each month remains a very small portion of the total designated capacity (approximately 1 percent). This reflects the fact that most LSEs satisfied their needs primarily through owned capacity or bilateral purchases.
  - ✓ Monthly capacity designations by LSEs exceeded the requirement by 3 to 6 percent.
- The VCA was replaced by a more robust PRA for the upcoming Planning Year.
  - ✓ It cleared at $31.94 per MW-month, which similarly reflects a modest surplus.
  - ✓ Barriers to trading capacity with PJM and the current vertical demand curve continue to contribute to inefficiently low capacity prices, particularly in summer months.

Voluntary Capacity Auction
January 2012–May 2013



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

POTOMAC ECONOMICS

Submittals to External Entities and Other Issues

Submittals to External Entities:

- We continue to meet with FERC regarding market outcomes and prior referrals.
  - ✓ We continue to discuss with MISO and FERC our concerns about resources that fail to accurately update real-time offers.
- We continue to respond to inquiries and data requests, and to submit reports to FERC on virtual trading activity and on compliance with Module E must-offer requirements.
- We recently participated in FERC's biannual meeting with market monitors and presented presentations on a number of issues.
- We met with OMS to address market trends and recommendations.

Other Issues:

- We are working with MISO on a number of upcoming filings related to PVMWP settlement rules including eligibility and allocations.
- We are also reviewing and providing advice on MISO's proposals for implementing demand curves for its transmission constraints.
- We are continuing to monitor the situation involving the MISO participant that lost its market-based pricing authority. FERC reconsidered its requirement that the supplier offer its resources at zero, which should address our efficiency concerns.

List of Acronyms

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