IMM Quarterly Report: Winter 2014
December–February

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)	$49.92	*59%*	*75%*
Fuel Prices ($/MMBtu)			
Natural Gas	$8.02	*114%*	*132%*
Western Coal	$0.70	*11%*	*23%*
Eastern Coal	$1.88	*1%*	*6%*
Load (MW)[2]			
Average Load	78.7	*7%*	*2%*
Peak Load	109.3	*-10%*	*9%*
% Scheduled DA (Peak Hour)	99.6%	98.3%	100.2%
Transmission Congestion ($M)			
Real-Time Congestion Value	$1,038.4	*143%*	*262%*
Day-Ahead Congestion Revenue	$631.0	*133%*	*208%*
Balancing Congestion[4]	-$0.7	$9.2	$1.2
Ancillary Service Prices ($/MWh)			
Regulation	$15.25	*38%*	*99%*
Spinning Reserves	$4.39	*33%*	*184%*
Supplemental Reserves	$3.70	*37%*	*682%*

	Value	Change[1] Prior Qtr.	Change[1] Prior Year
FTR Funding (%)	100%	97%	91%
Wind Output (MW)	5,062	*15%*	*12%*
Guarantee Payments ($M)[5]			
Real-Time RSG	$45.9	*221%*	*391%*
Day-Ahead RSG	$31.1	*314%*	*349%*
Day-Ahead Marginal Assurance	$40.3	*198%*	*356%*
RT Operating Rev. Sufficiency	$3.2	*13%*	*58%*
Price Convergence[3]			
Market-wide DA Premium	1.0%	-2.8%	-0.4%
Virtual Trading			
Cleared Quantity (MW)	7,274	*19%*	*10%*
% Price Insensitive	47%	33%	41%
% Screened for Review	5%	2%	2%
Profitability ($/MW)	$1.83	$1.32	$0.33
Dispatch of Peaking Units (MW/hr)	588	311	206
Output Gap- Low Thresh. (MW/hr)	561	63	83
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 any change in membership.
3. Values include allocation of real-time RSG (DDC rate).
4. Net real-time shortfallst that contribute to negative ECF with no offset for M2M settlements.
5. Includes effects of market power mitigation.

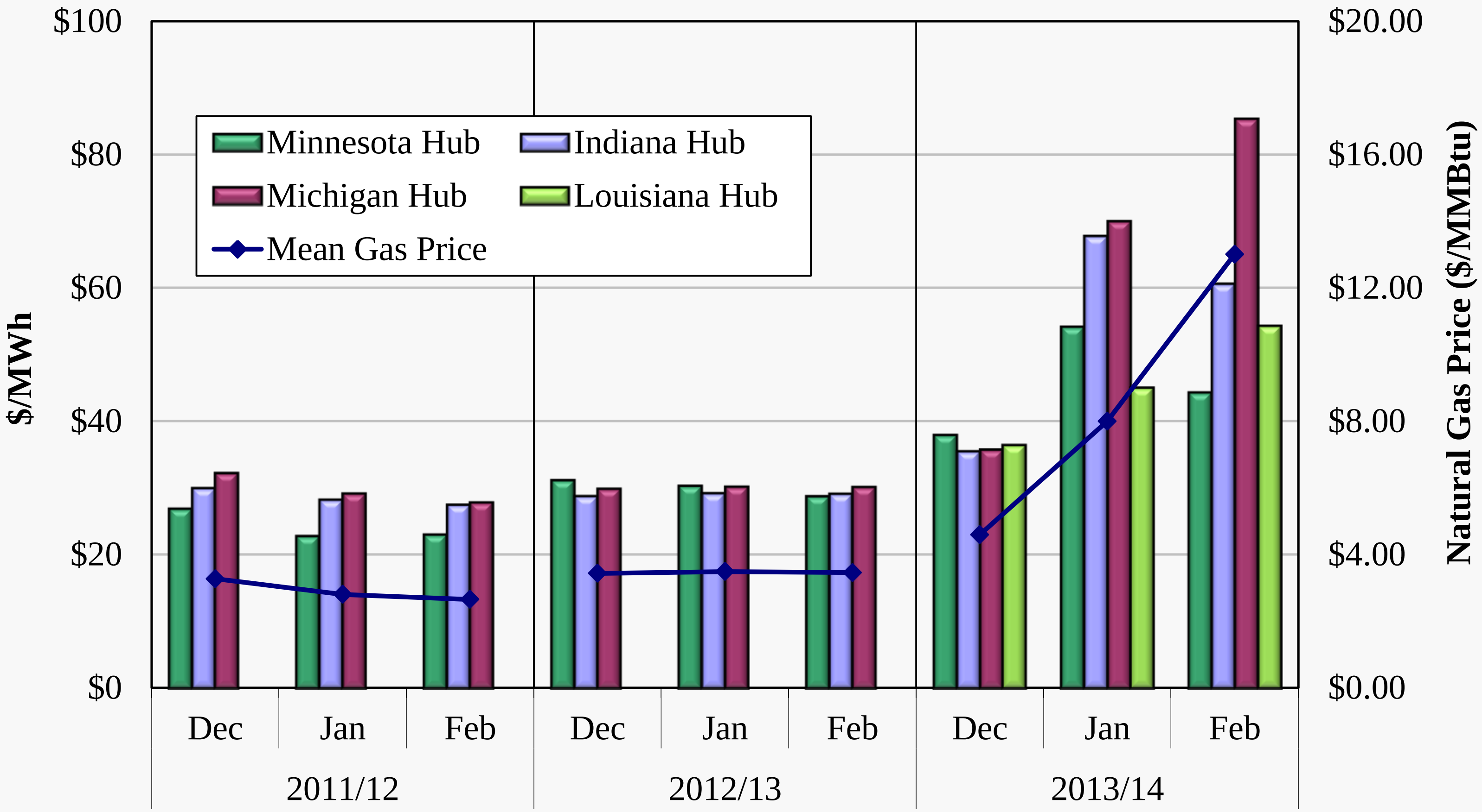
Summary of Winter 2014

- In the winter quarter, cold temperatures caused sharp increases in electricity demand, natural gas prices, energy prices and volatility throughout the Eastern Interconnect.
  - ✓ MISO set a market winter peak load record of 109.3 GW on the evening of January 6.
  - ✓ High offer prices caused by extreme gas prices and supply reductions due to gas curtailments caused energy prices to rise sharply in January and February.
- MISO also experienced record levels of congestion driven by high demand and large fuel cost differences between regions.
  - ✓ Generation costs of gas units in the Midwest Region were as much as 10 times higher than in the South Region on some days because of the regional differences in gas prices.
  - ✓ Congestion was aggravated by inter-regional transfer limitations, such as the Operations Reliability Coordination Agreement ("ORCA") constraints and TLR constraints.
  - ✓ Congestion into Michigan in February resulted in very high day-ahead average hub prices that have continued into March.
- The high energy prices, congestion, and real-time price volatility resulted in record levels of price volatility make-whole payments.
  - ✓ A disproportionate amount of PVMWP in January went to generators in MISO South and we are investigating units that did not respond to dispatch on January 6 and 7.
  - ✓ Outages and congestion in Michigan also contributed to very high uplift payments in February and early March.

Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at four representative locations in each month in the past three winters.
  - ✓ We include natural gas prices in the Midwest 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 rose 79 percent from last winter to $51.52 per MWh.
  - ✓ The primary reason for the substantial rise is a more than doubling of natural gas prices for much of MISO, which averaged $8.02 per MMBtu at Chicago.
  - ✓ An unusually cold winter resulted in a 2 percent rise in average load.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ Hub prices ranged from $43 per MWh at Arkansas to $64 at Michigan. This spread is much larger than usual and reflects the significant increase in congestion this quarter.
    - – One-third of the price separation is due to binding on external TVA constraints that limit lower-cost South generation from serving Midwest Region load.
    - – Fuel cost differences between the two regions were a significant factor.
  - ✓ Congestion was most significant into Michigan in February, where outages contributed to over $37 million of congestion on five constraints and $85 average prices.
- Day-ahead prices were highest on January 28 (see second slide), when two external constraints limiting interregional transfers were severely binding.

Day-Ahead Average Monthly Hub Prices Winter 2012–2014



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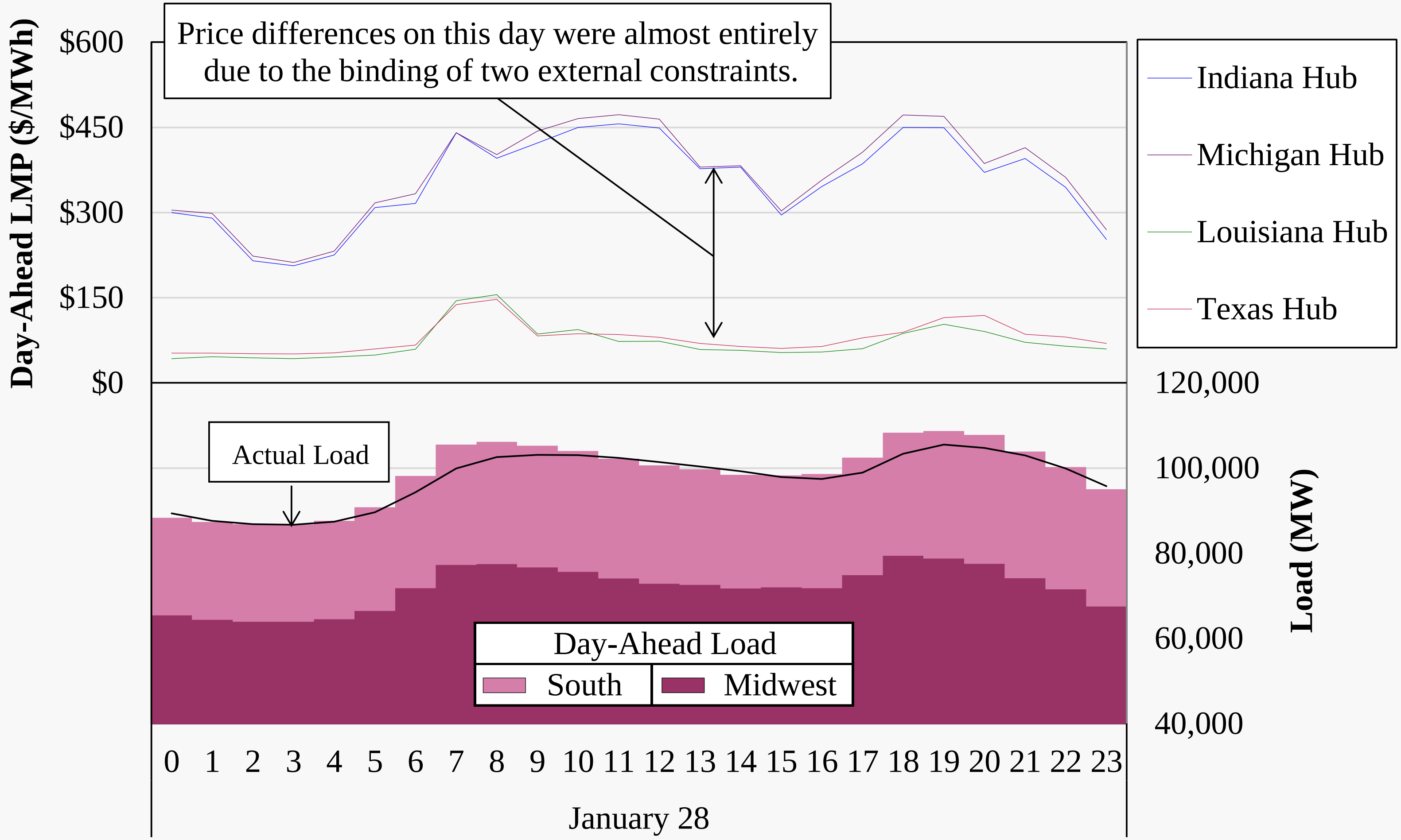
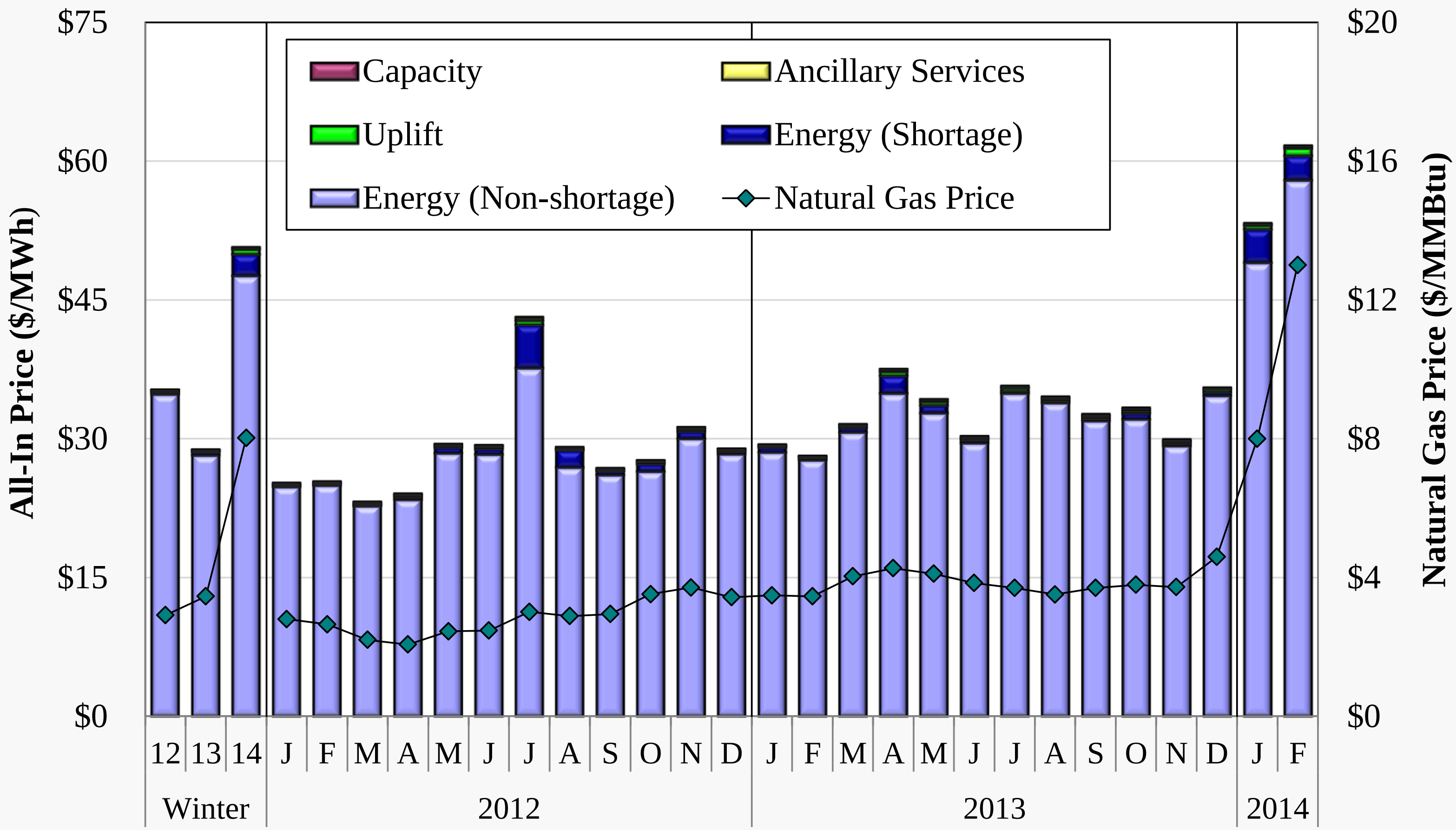
Day-Ahead Energy Prices
January 28, 2014



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.
  - ✓ We separate the energy component associated with shortages.
  - ✓ The figure includes monthly average natural gas prices at Chicago City Gate because it is a key driver of energy prices.
- The all-in price rose 76 percent from last winter to $50.68 per MWh.
- The energy component continues to make up 98.5 percent of the all-in price.
  - ✓ The extreme and volatile winter, however, resulted in the share of this component associated with shortages rising from 1.2 to 4.7 percent.
  - ✓ Shortages were largest in January during the Polar Vortex.
- Uplift costs rose 240 percent to $0.54 and made up over 1 percent of the all-in price.
  - ✓ These costs were highest in February, averaging $0.82 due to high gas prices and severe congestion into Michigan that required high-cost generator commitments.
- Ancillary service prices more than doubled from last winter and added $0.18 to the all-in price, primarily due to 46 operating reserve shortages (up from five last winter).
- The capacity component from the Planning Resource Auction added only five cents.

All-In Price
Winter 2012–2014



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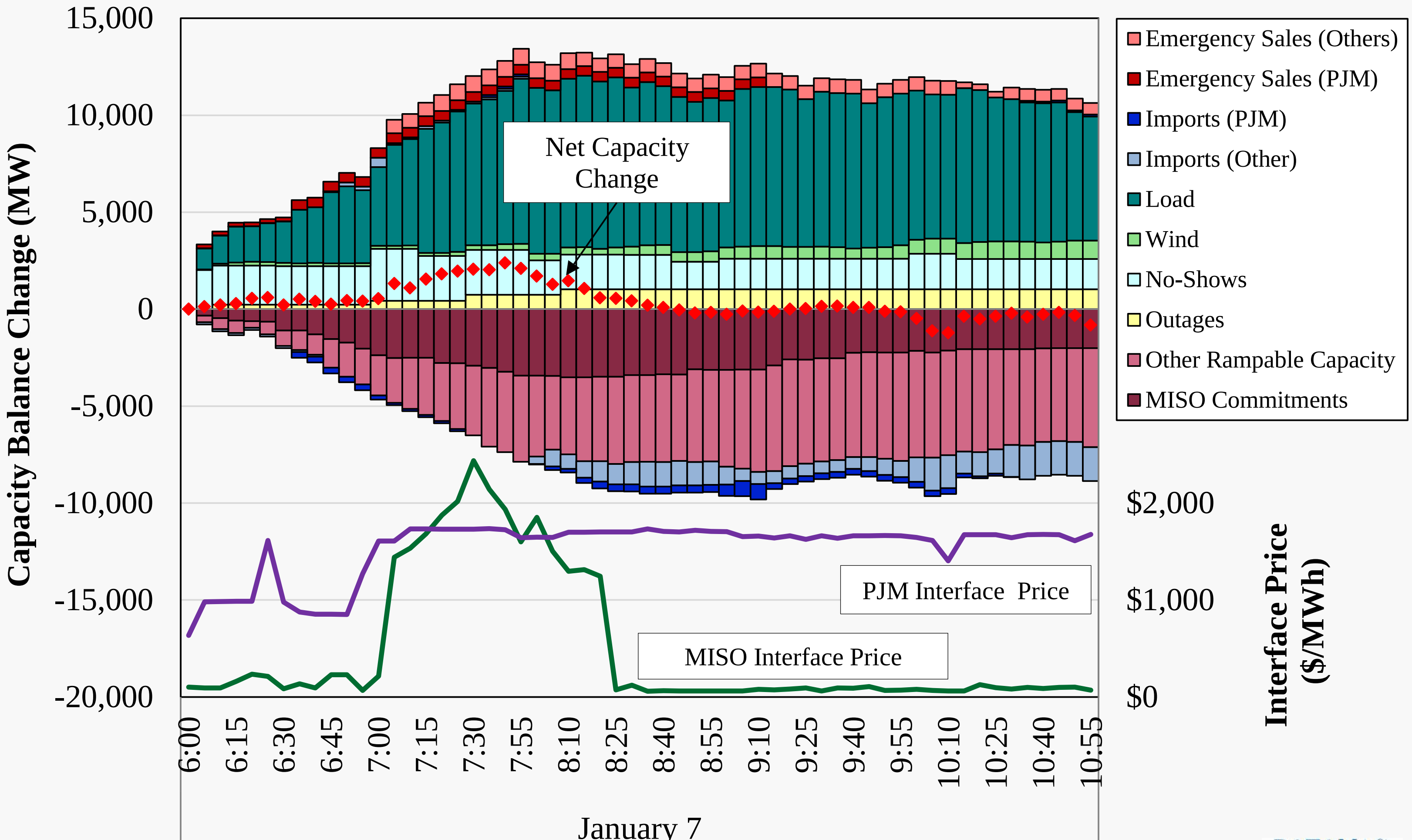
Real-Time Factors Impacting Energy Prices

- The next two figures show the real-time factors affecting capacity levels and energy prices on two notable days in the quarter: January 7 and February 11.
  - ✓ The factors shown in the charts include the changes in load, NSI with PJM and other areas, wind output, MISO commitments, outages, and other supply changes.
  - ✓ "Harmful" factors that contribute to higher prices are shown as positive MW (e.g., load, outages, falling net imports) and "helpful" factors that reduce prices are shown as negative MW (e.g., increased supply, net imports, etc.).
    - – For January 7, we separately show energy sales to PJM and others that were approved due to emergency conditions in these areas.
  - ✓ The charts show the incremental impact of supply and demand factors that affect the net capacity balance in each interval relative to start of the period shown.
- The net effect of all factors for each interval (relative to the first interval in the period) is shown by the red marker.
  - ✓ A net effect of close to zero means that MISO's commitments and supply changes offset increases in load and reductions in wind and net imports.

Real-Time Factors Impacting Energy Prices January 7

- The entire Eastern Interconnect experienced very cold temperatures on January 7.
  - ✓ 1:53 – PJM anticipates the need for emergency energy from 06:00 to 11:00 and begins accepting bids for emergency energy.
  - ✓ 6:00 – MISO begins scheduling 500 MW in emergency sales to PJM, and its prices rise accordingly. The PJM interface price for MISO is $632 per MWh.
  - ✓ 6:00 to 6:30 – Load grows sharply and over 1.5 GW of MISO generation experiences a forced outage or fails to startup.
  - ✓ 7:00 – 700 MW of additional emergency exports begin (approved at 6:30). Some additional generators fail to start.
  - ✓ 7:10 – MISO goes into an operating reserve shortage lasting over an hour.
  - ✓ 7:15 – MISO declares a Maximum Generation Alert at 07:15 and upgrades it to a Warning at 07:30. It lasts until 11:15.
- At its deepest point, MISO is roughly 1,900 MW short of operating reserves and holding only 300 MW of reserves.
- MISO attempted to commit nearly all available resources and operating reliably through this event. However, the recognition of the shortage appeared to be late and the approval of the additional 700 MW in exports at 7:00 warrants review.

Real-Time Energy Prices
January 7



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Real-Time Factors Impacting Energy Prices February 11

- February 11 featured two six-interval periods of shortages during ramp hours: from 07:30 to 07:55 and from 18:50 to 19:15.
- Leading up to the first shortage, MISO declared a Cold Weather Alert (at 06:45) and Conservative Operations (at 07:10).
- The first shortage in the morning was primarily caused by:
  - ✓ Sharply increasing load due to extremely cold weather; and
  - ✓ A limited number of outages and units that failed to start due to gas issues.
- The second shortage also appeared to be caused by load rising more rapidly than expected in the evening because of the extremely cold weather.
  - ✓ In addition, nearly 500 MW of exports to PJM contributed to MISO’s shortage.
  - ✓ A 900-MW swing in net imports from PJM after the initial shortage interval then returned MISO prices to just $52 per MWh within the hour.

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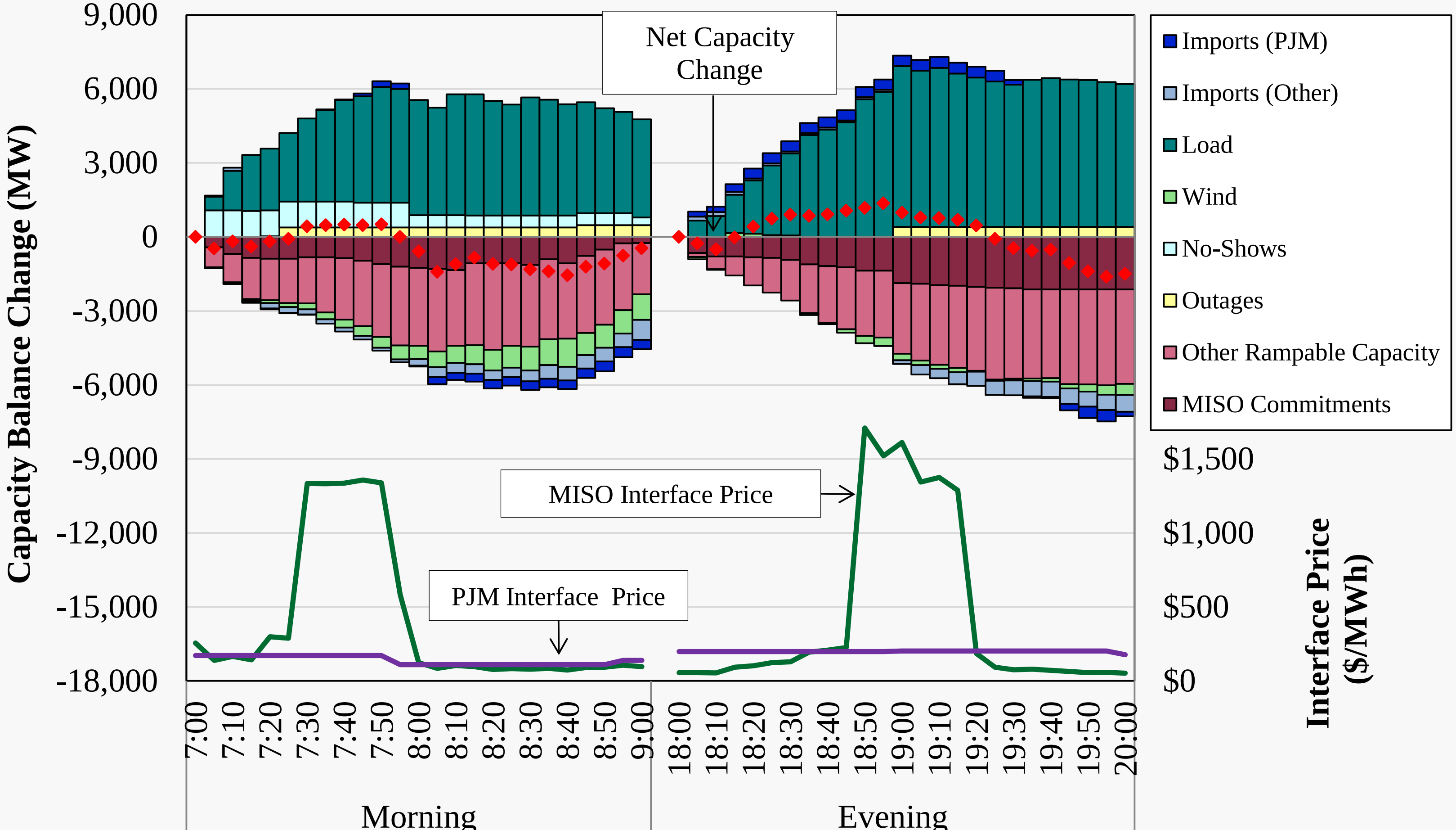
Real-Time Energy Prices
February 11, 2014



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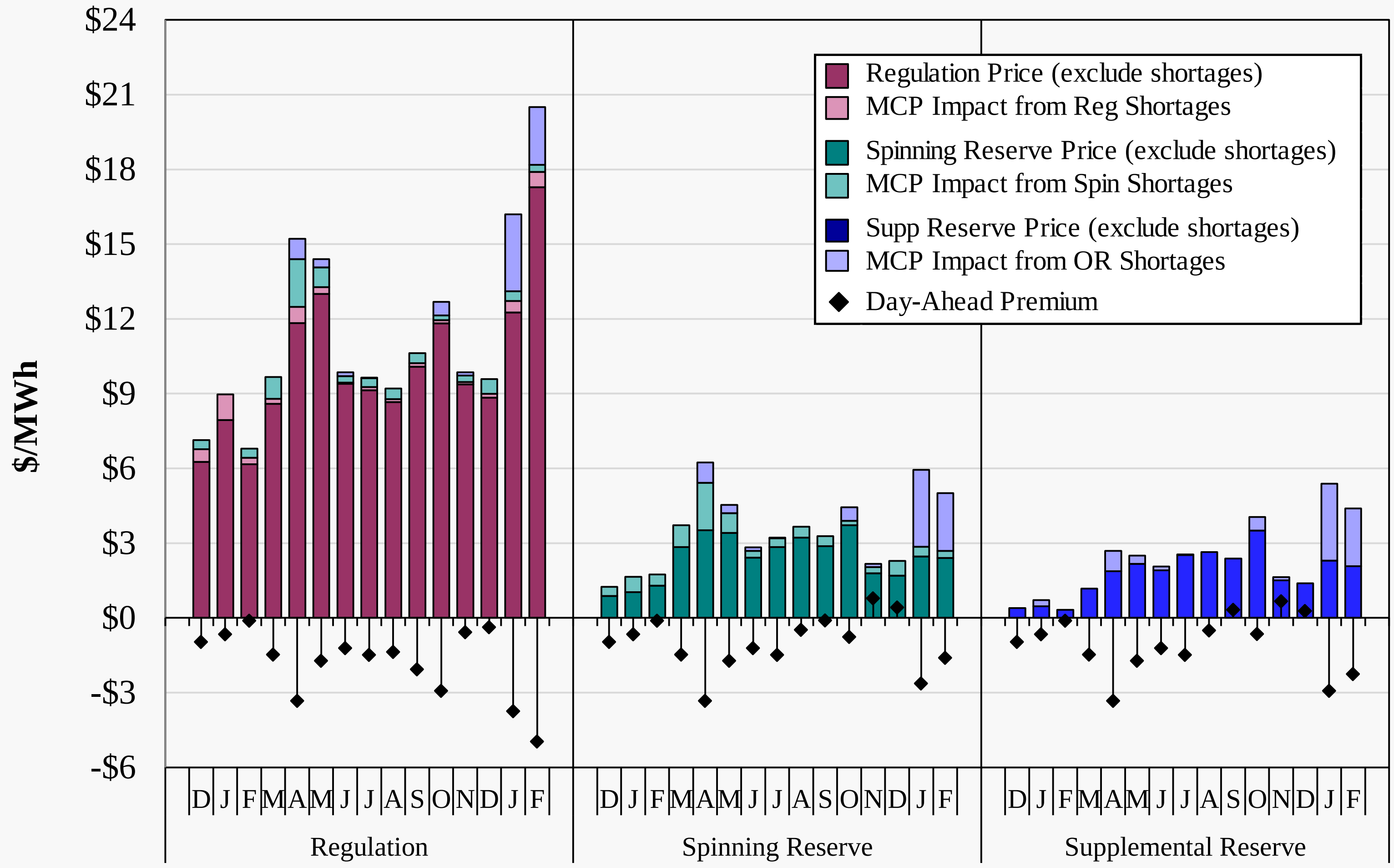
Ancillary Services Prices

- 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).
- The significant rise in energy and fuel prices similarly led to large increases from last winter in the clearing prices of all three ancillary services products.
  - ✓ In addition, the substantial rise in operating reserve shortages—46 in the quarter—added $1.78 to each product's average clearing price.
  - ✓ The significant real-time premiums for each product in January and February indicates that the shortages were not fully anticipated by the day-ahead market.
  - ✓ Prices for all three products were approximately 35 percent higher than in the fall.
- Regulation prices nearly doubled from last winter and averaged $15.25 per MWh.
  - ✓ The 22 regulation shortages this winter were lower than the 36 last winter.
- Spinning reserve prices rose from $1.55 to $4.39 per MWh, while supplemental reserve clearing prices rose from $0.47 to $3.70 per MWh.
  - ✓ The 103 spinning reserve shortage intervals were comparable to last winter.

Monthly Average Ancillary Service Prices
Regulation and Contingency Reserves, 2013–2014



MISO Fuel Prices

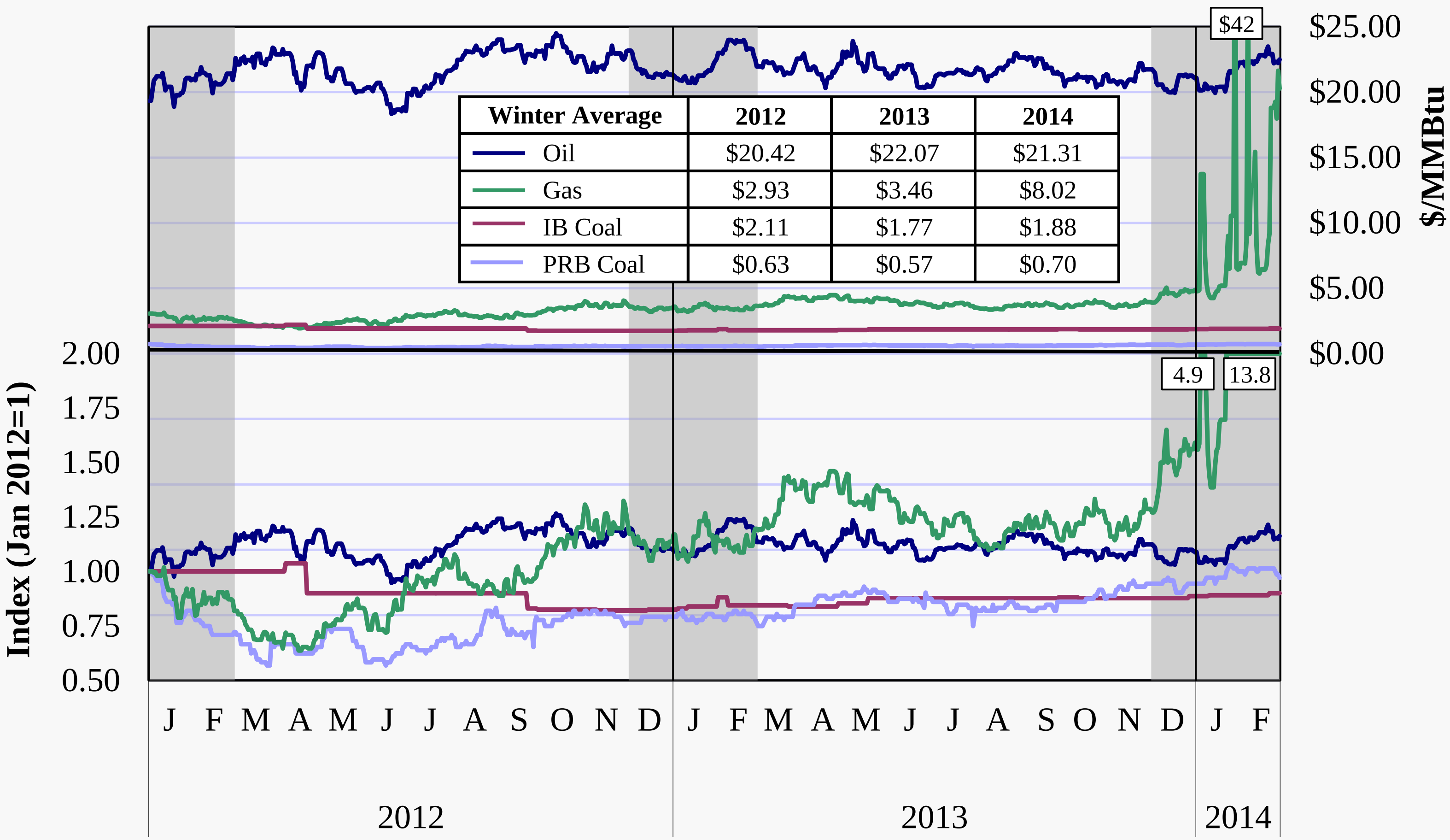
<u>Natural Gas and Oil Prices</u>

- Natural gas prices at Chicago rose 132 percent from last winter to $8.02 per MMBtu.
  - ✓ Prices were extremely volatile (see next slide) due to periodic fuel supply and delivery issues, as well as low storage levels. The cold winter has prompted record gas withdrawals from storage.
  - ✓ Periods with prices above $10 were generally short-lived except late in February, when this occurred for 12 consecutive days.
- Henry Hub (Texas) prices, which are usually lower than delivered prices in the Midwest, were much less impacted by these issues and never rose above $8.
  - ✓ Large differences in regional gas prices can substantially affect congestion patterns when demand is high and inter-area transfer limits bind.
- Oil prices averaged $21.31 per MMBtu, down 3.5 percent from last winter.
  - ✓ Many peaking units are dual-fueled and switched from natural gas to oil during the winter when it was economical to do so, which moderated the gas supply issues.

<u>Coal Prices</u>

- Illinois Basin prices rose 11 cents from last winter to $1.88 per MMBtu, while Western (Powder River Basin) coal prices rose 13 cents (23 percent) to $0.70.
  - ✓ February marked a record spread between coal and gas prices, contributing to record congestion costs due to the high opportunity cost of ramping down coal units.

MISO Fuel Prices
2012–2014



Winter Average	2012	2013	2014
Oil	$20.42	$22.07	$21.31
Gas	$2.93	$3.46	$8.02
IB Coal	$2.11	$1.77	$1.88
PRB Coal	$0.63	$0.57	$0.70

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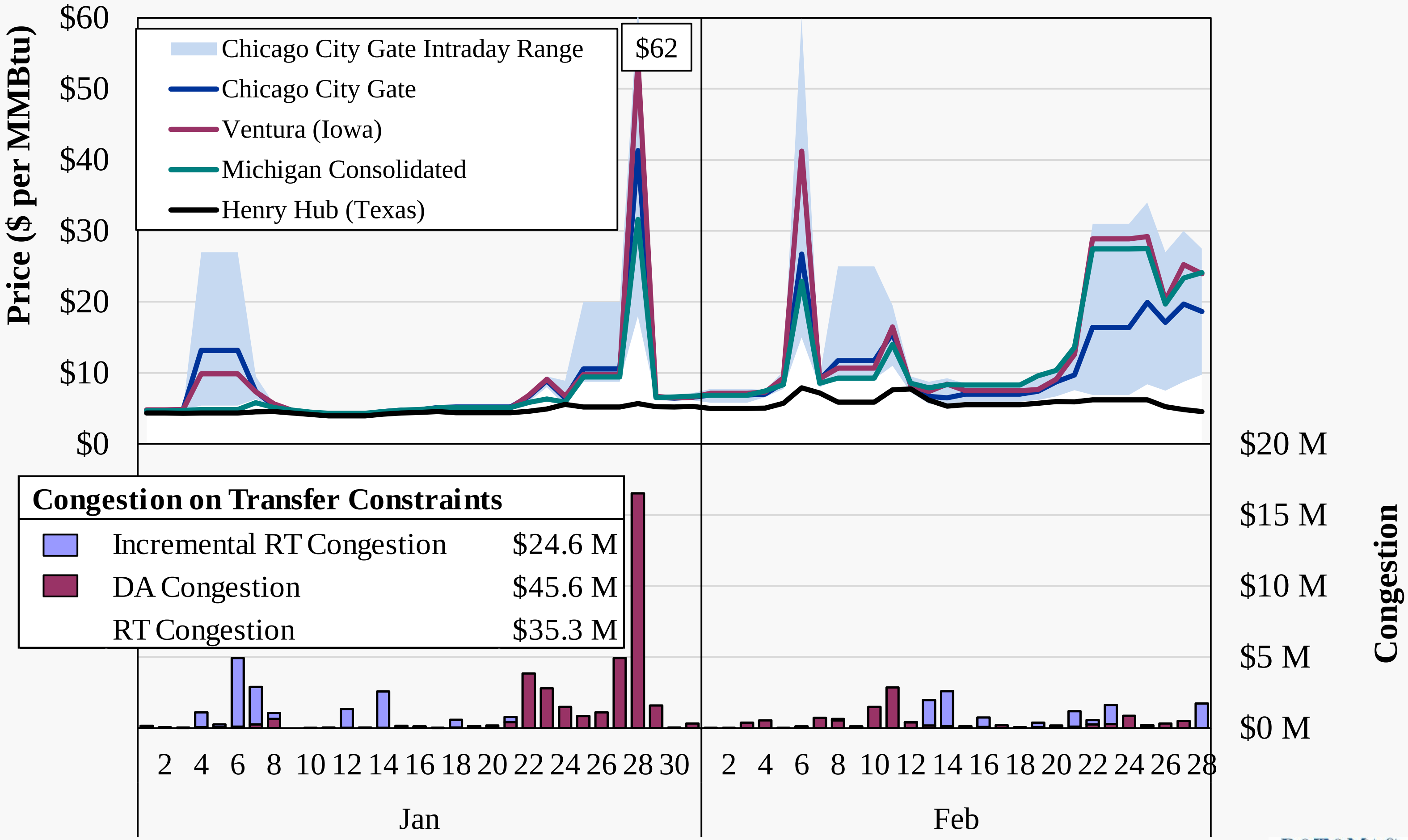
Daily Natural Gas Prices

- Because natural gas prices were unusually volatile in early 2014 and significantly affected MISO's market results, the next figure shows daily natural gas prices.
  - ✓ In addition to showing the average price at 4 locations, it shows the intraday price range at the Chicago City Gate price, a representative price for many participants.
  - ✓ This intraday price range is typically small, but can be large on "critical" days.
- The bottom panel shows day-ahead and incremental real-time congestion (visible when RT congestion value > DA congestion costs) for four constraints between the Midwest and South regions.
- There were numerous price spikes in the Midwest region, attributable to sustained high gas demand and pipeline bottlenecks that caused prices to diverge.
  - ✓ This contributes to congestion between the Midwest and South regions, where Henry Hub prices did not rise sharply.
- The highest gas prices occurred on January 28, February 6, and in late February.
  - ✓ Some participants purchasing intraday gas on these days were subject to penalties that resulted in their marginal costs exceeding the $1,000 per MWh offer cap.
  - ✓ Under these types of conditions, the cap interferes with the efficient operation of the markets and we recommend MISO consider raising it.

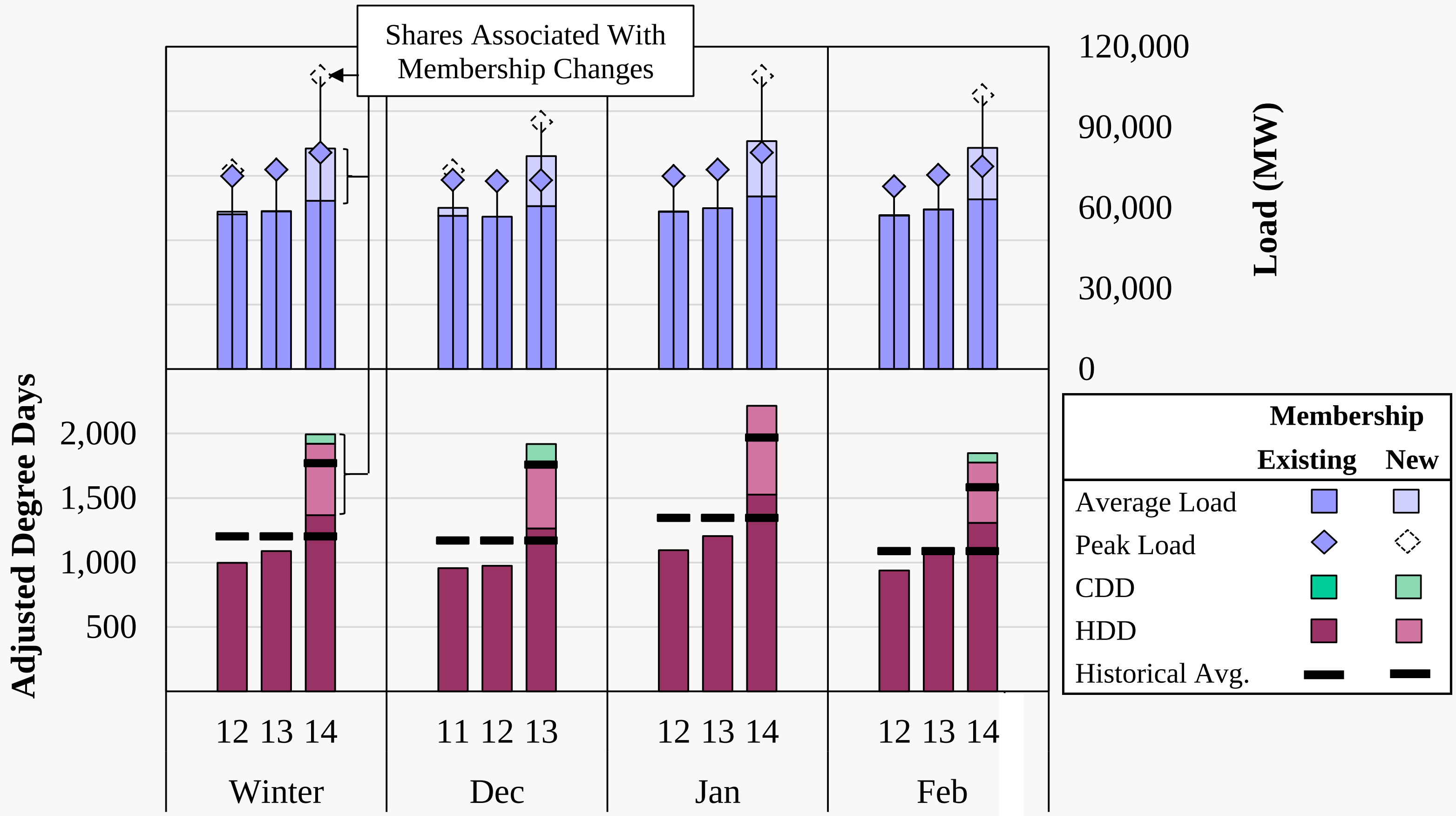
Daily Natural Gas Prices
January–February 2014



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 winter months of 2012 to 2014, while the bottom panel shows the average heating and cooling degree days (a weather metric that is highly correlated with load).
  - ✓ Degree days are normalized (based on a regression analysis) so that heating and cooling days have an equal effect on load.
  - ✓ We show the South region's contribution to load and degree days separately.
- The figure shows that degree days rose 25 percent from last winter, and were 14 percent above the historical average.
  - ✓ For most states in MISO, this winter was among the top 10 coldest on record.
  - ✓ The cold was most extreme in January (notably during the Polar Vortex), but more sustained in February.
- The higher degree days contributed to the rise in average load of 2 percent from last winter. It averaged 78.7 GW for the quarter.
  - ✓ Average load in January was nearly 9 percent higher than the prior January.
  - ✓ MISO set an all-time membership-adjusted winter peak of 109.3 GW on January 6.

Load and Weather Patterns
Winter 2012–2014

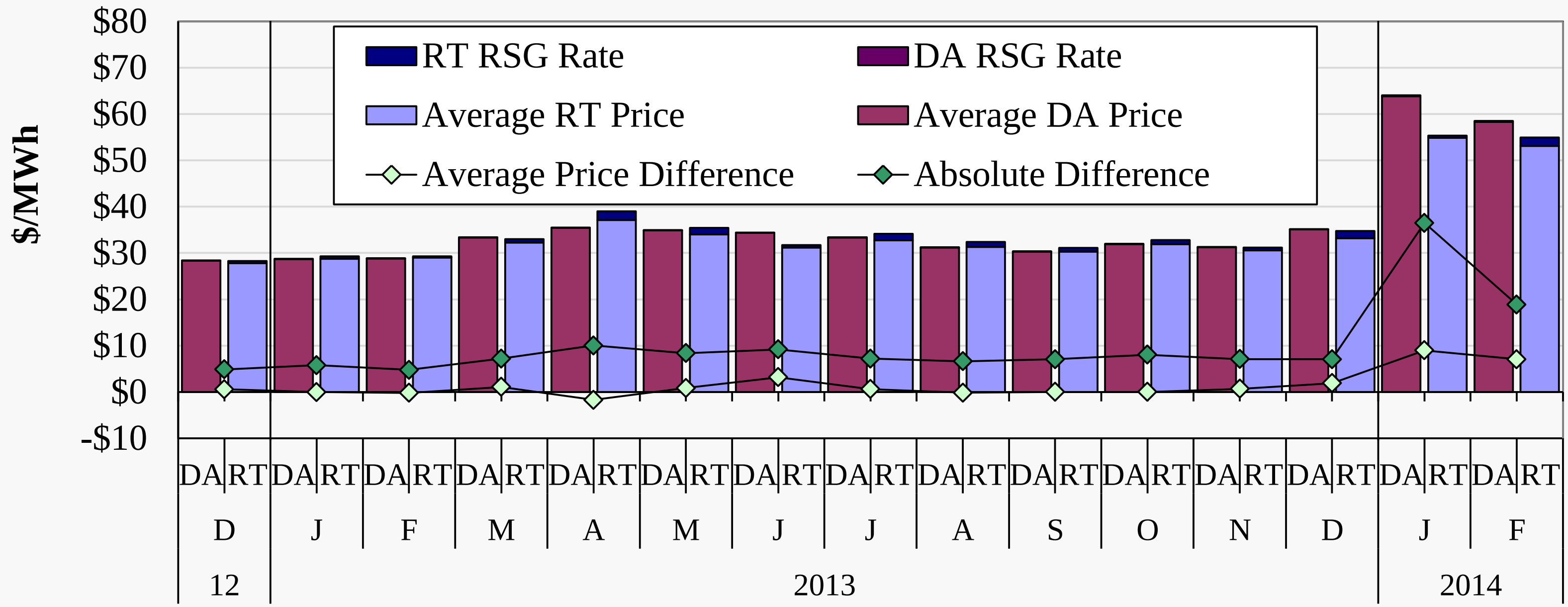


Note: Calculations are the average monthly degree days of four representative cities in MISO: Cincinnati, Detroit, Milwaukee and Minneapolis. For the South region, Little Rock and New Orleans are used.

Day-Ahead and Real-Time Price Convergence

- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub since December 2012 (the table shows other locations), along with price differences.
  - ✓ Modest day-ahead premiums are generally expected in MISO due to greater real-time price volatility and uplift charges applicable to real-time load purchases.
  - ✓ Real-time RSG costs under the DDC rate averaged $1.43 this quarter.
- Convergence was poor this winter, with significant day-ahead premiums at most hubs in the Midwest Region and real-time premiums in the South Region.
  - ✓ This is primarily attributable to significant real-time price volatility related to the inter-regional constraints (ORCA and TVA and SPP external constraints).
  - ✓ Congestion in the North region in December and in February caused price convergence there to deviate from this general pattern.
- Congestion into Michigan in February was unusually volatile.
  - ✓ This resulted in significant real-time premiums on some days and day-ahead premiums on other days. The day-ahead price premiums were often coupled with congestion management-related RSG costs which totaled $15.5 million in February.
    - – Less than one-third of these costs were allocated appropriately under the CMC charge. FERC recently approved a change to the CMC structure which would have assigned $10.3 million of these RSG costs to constraint-flow deviations.

Day-Ahead and Real-Time Price Convergence Winter 2013–2014



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

Indiana Hub	1	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1	16	11
Michigan Hub	-1	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3	25	15
Minnesota Hub	-2	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6	16	-5
WUMS Area	1	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1	19	4
Arkansas Hub													-5	-12	-13
Louisiana Hub													-6	-22	-11
Texas Hub													-2	-6	-11

Daily Price Convergence

- To more closely examine when and where convergence was poorest, the next two figures show daily price convergence in January and February.
  - ✓ Each figure shows, in the bars, the day-ahead premium at the two hubs closest to the ORCA interface between the Midwest and South regions (Arkansas and Indiana).
  - ✓ The diamonds show the premium at two hubs further away (Michigan and Louisiana).
  - ✓ Hence, differences in convergence between the two stacked bars on a particular day is generally due to inter-regional transfer constraints such as ORCA, whereas differences between a bar and a diamond is due to local congestion.
- In January, convergence was poor during the Polar Vortex and late in the month.
  - ✓ On January 6-7, the Polar Vortex resulted in real-time prices that were significantly under-anticipated by the day-ahead market.
  - ✓ On January 28, day-ahead prices were near $400 per MWh across the Midwest region because of the binding of two external constraints that did not bind as hard in real time.
- The patterns in February reveal that the most significant convergence issues were between Michigan and Indiana hubs. On most days, premiums between the two hubs varied widely.
  - ✓ The alternating day-ahead and real-time daily premiums at Michigan Hub are not apparent from the monthly metrics.

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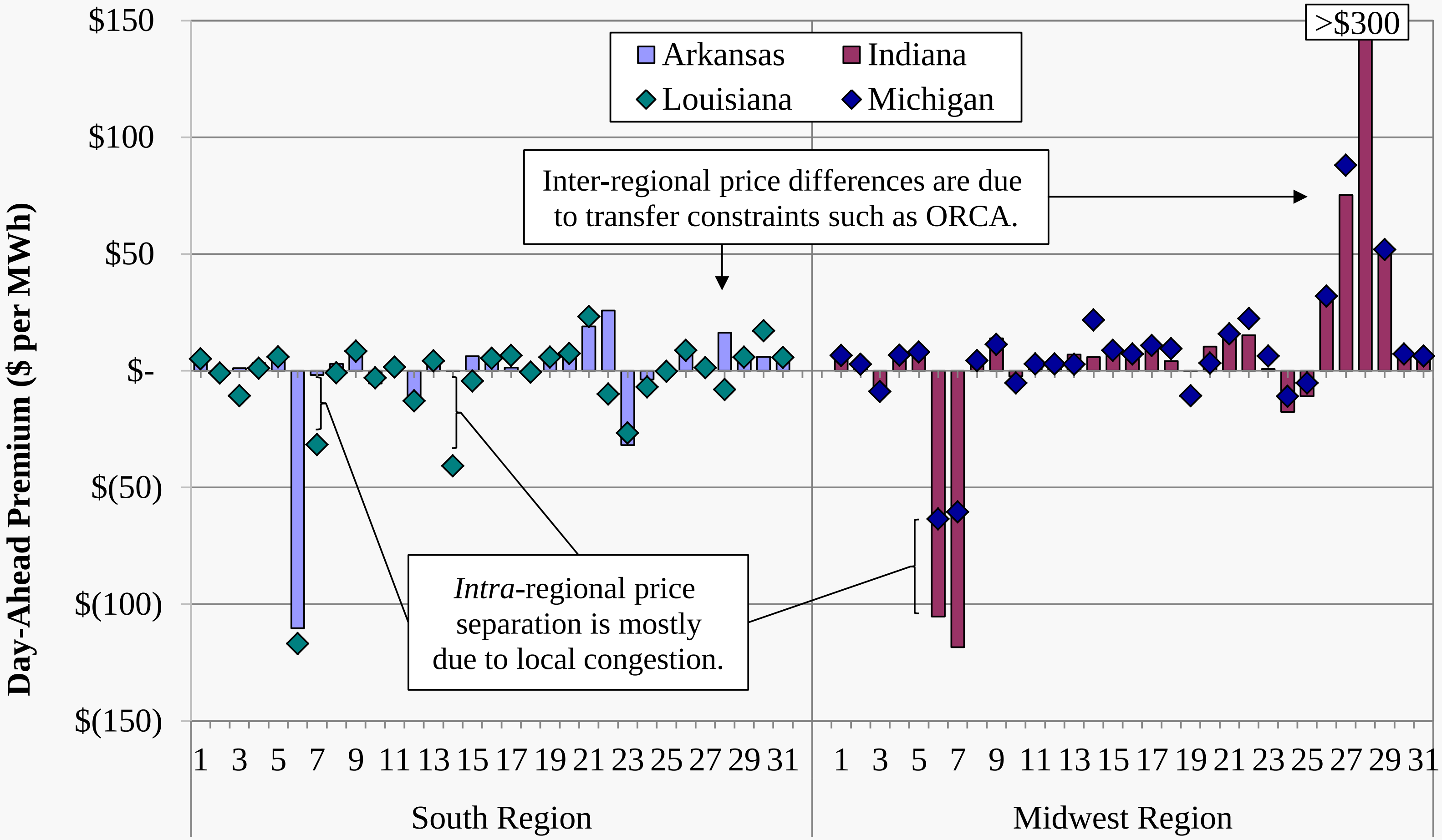
Daily Day-Ahead Premiums
January 2014



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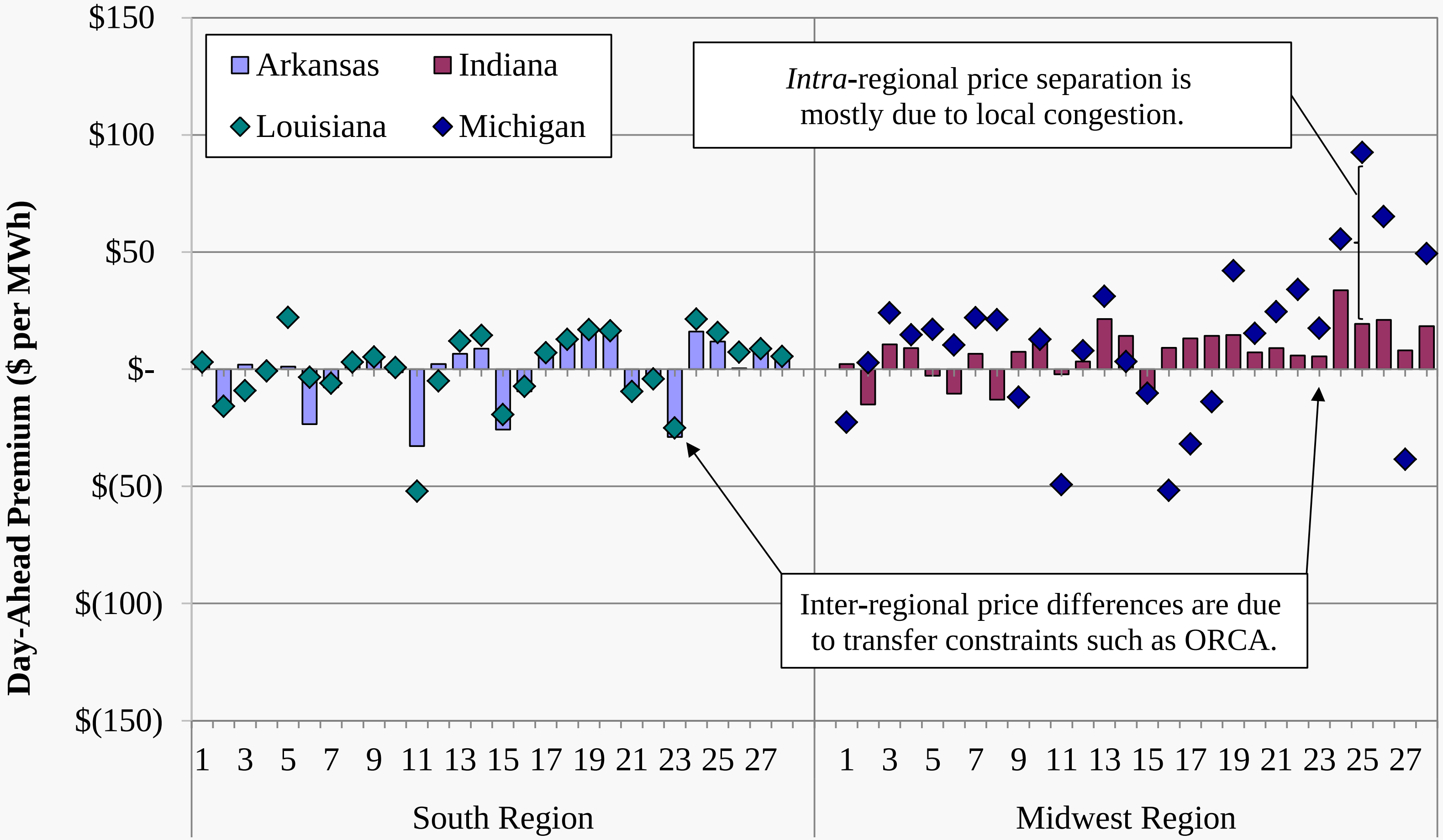
Daily Day-Ahead Premiums
February 2014



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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. These commitments include those to manage congestion, resolve local reliability issues, and accommodate short-term ramp demands.
  - ✓ Over-scheduling load day-ahead, however, can suppress real-time price signals.
- For the quarter, load scheduling averaged nearly 100 percent.
  - ✓ Net virtual demand of 819 MW offset a 2 percent shortfall in physical load.
- Load was over-scheduled in January (101.7 percent) and under-scheduled in February (98.5), mostly due to changes in price-based load.
  - ✓ Under-scheduling was most persistent early February, which may be partly due to large losses incurred by virtual load on January 28.
- During all hours, it was over-scheduled at 100.6 percent, particularly in the South region, where it averaged 103.5 percent in December to January.
  - ✓ Large quantities of day-ahead VLR commitments in the South likely contribute to the over-scheduling.

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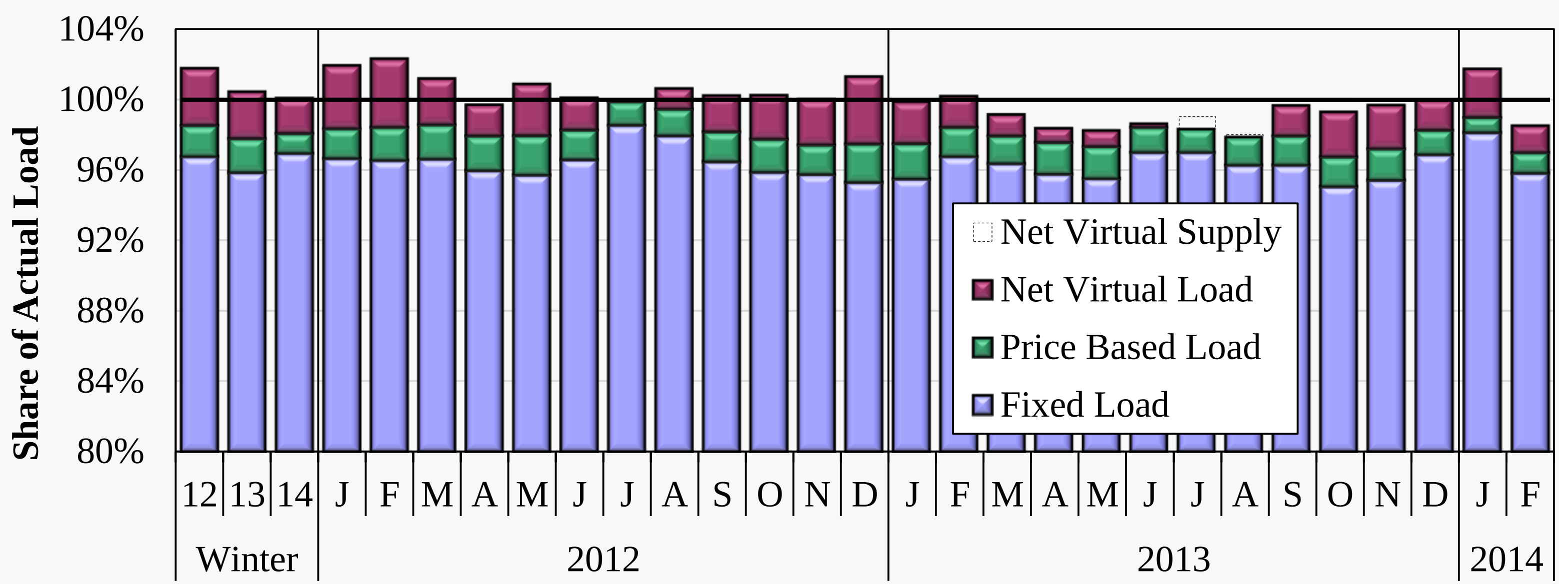
Day-Ahead Peak Hour Load Scheduling 2012–2014



Share of Actual Load (%)

	12	13	14	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F
All Hours	99.8	99.7	100.6	100.1	99.7	99.7	97.7	99.9	99.3	100.1	100.0	98.4	98.8	99.4	100.1	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9	99.1	98.8	99.0	100.9	101.7	99.3
Peak Hours Midwest	101.8	100.4	99.3	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	98.6	98.3	97.9	99.7	99.3	99.7	99.5	100.4	98.0
Peak Hours South			103.1																								104.9	104.4	99.9

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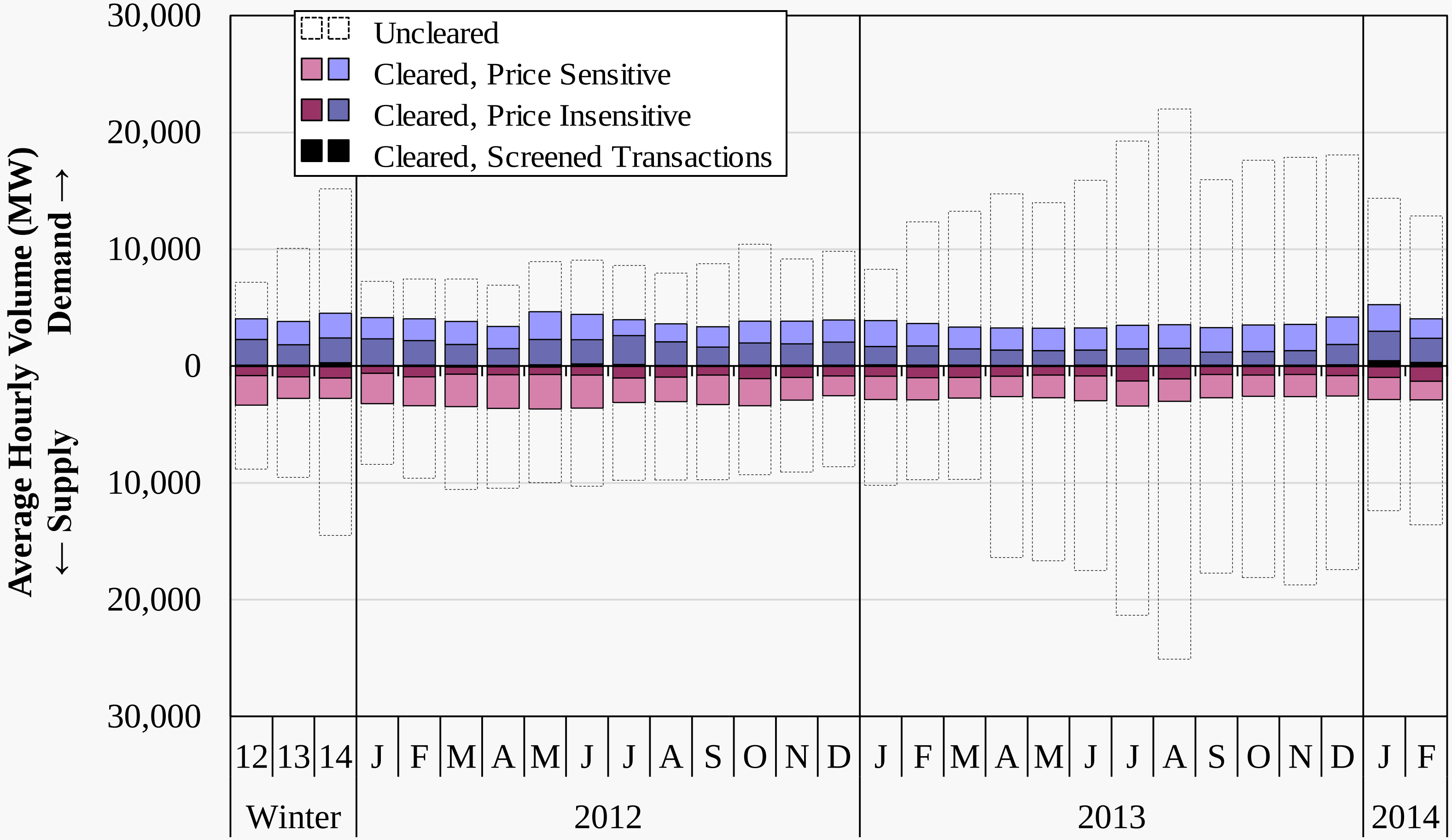
Virtual Load and Supply in the Day-Ahead Market

- 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 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 closely 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 transactions rose 10 percent from last winter to 7.3 GW.
  - ✓ Cleared demand rose much faster—by 18 percent to 4.5 GW—than did supply, which was nearly unchanged at 2.8 GW.
- Total bids and offers this quarter rose 51 percent to 29.7 GW. Most of this increase is due to participants' "backstop" bids submitted at prices that are very unlikely to clear.
  - ✓ The majority of offered volumes are not expected to clear, and do not pose a concern.
  - ✓ Several physical participants have reduced such offered volumes since the fall.
- The increase in price volatility this winter made it much riskier for participants to submit bids and offers, and impacts our expected price metric.
  - ✓ Hence, the share of cleared volumes that were price-insensitive rose from 33 to 47 percent. This increase is not due to a material change in participant behavior.
  - ✓ In addition, the current RSG allocation still provides incentives for participants to take balanced positions, which can be ensured by offering price-insensitively.
- The share of Screened Transactions rose to 4.8 percent, primarily due to the substantial increase in congestion volatility.
- Most of these price-insensitive transactions would benefit from the virtual spread product MISO is considering, which would allow participants to more efficiently arbitrage locational differences.

Virtual Transactions
2012–2014



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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 transactions (e.g., hedging physical obligations) than financial-only participants (e.g., price arbitrage), and are generally more selective in their locations.
- This winter, 85 percent of all cleared volumes were submitted by financial participants, up from 71 percent last winter.
  - ✓ Demand transactions by these participants rose 32 percent to 3.7 GW.
- Over 80 percent of physical participant transactions were price-insensitive, compared to just 40 percent of those submitted by financial participants.
- Uncleared transaction volumes by financial participants were 67 percent greater this winter than in the prior winter, while physical participants offered three times as much supply.
  - ✓ A majority of uncleared transactions are offered by a small number of participants at prices that make them very unlikely to clear (“backstop” bids and offers).
  - ✓ Although fewer than 1 percent of these transactions clear, they are substantially profitable, and contribute to convergence, when they do.

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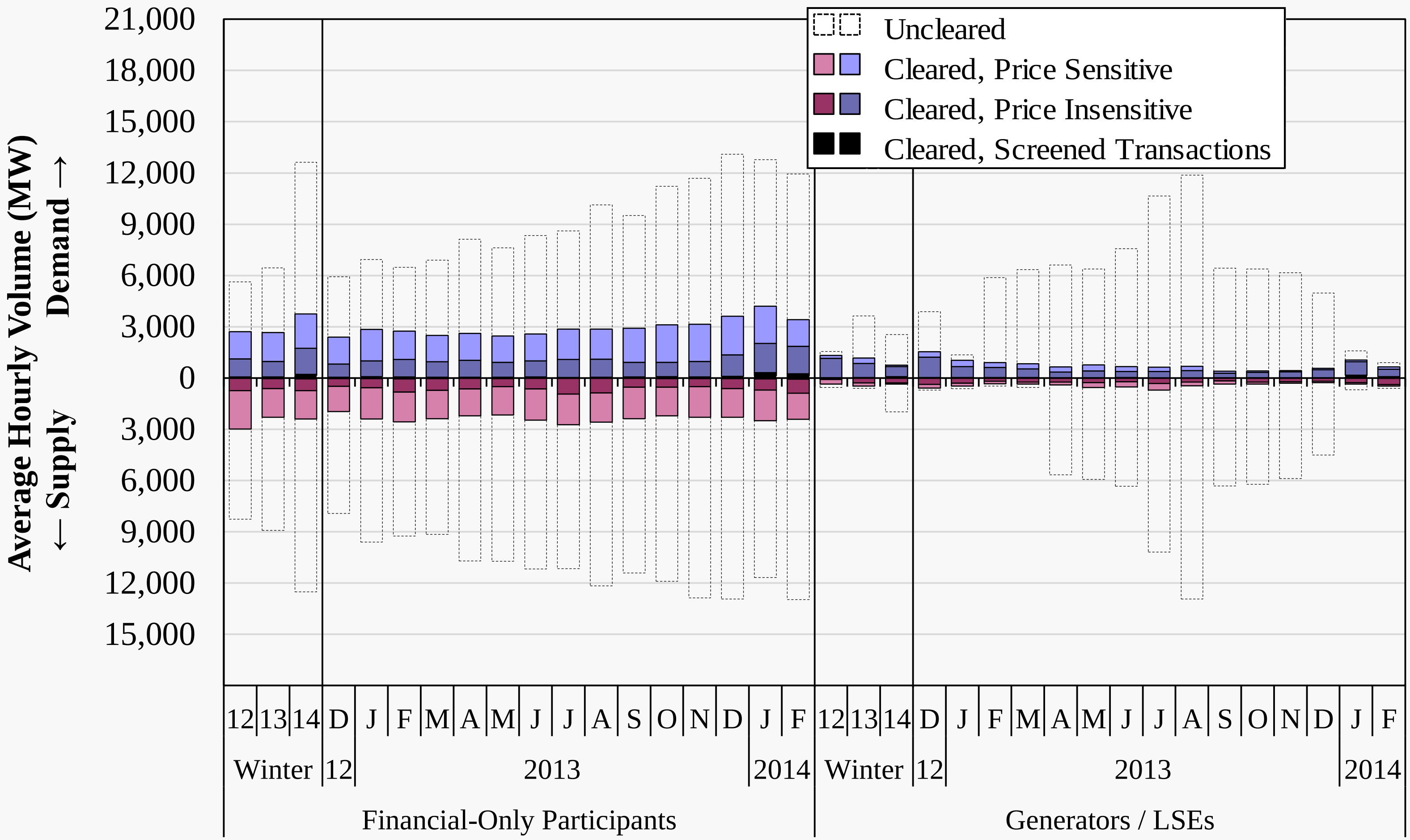
Virtual Load and Supply by Participant Type Winter 2013–2014



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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 totaled $28.7 million this winter, up from $4.7 million last winter.
- On a per-MW basis, profitability rose from $0.33 per MWh last winter to $1.83.
- Supply in particular was unusually profitable at $4.03 per MWh, while demand averaged $0.48.
  - ✓ The most profitable locations were on one side of a constraint in the Central region, where they contributed to convergence of the congestion.
  - ✓ These margins exclude CMC and DDC charges assessed to net harming deviations, including net virtual supply, which reduced its profitability by one-third.
- Virtual transactions by financial participants continue to be profitable, indicating that they generally improve price convergence overall.
  - ✓ It averaged $2.81 per MW (including $4.69 for supply), up from $0.68 last winter.
- Demand for physical participants was significantly unprofitable at $-5.08 per MW.
  - ✓ Much of this was submitted price-insensitively at hub locations in the Midwest Region, and therefore reflects the significant day-ahead premium at those locations.
- Demand losses at the Indiana Hub, the most traded location, were nearly $-9 million.

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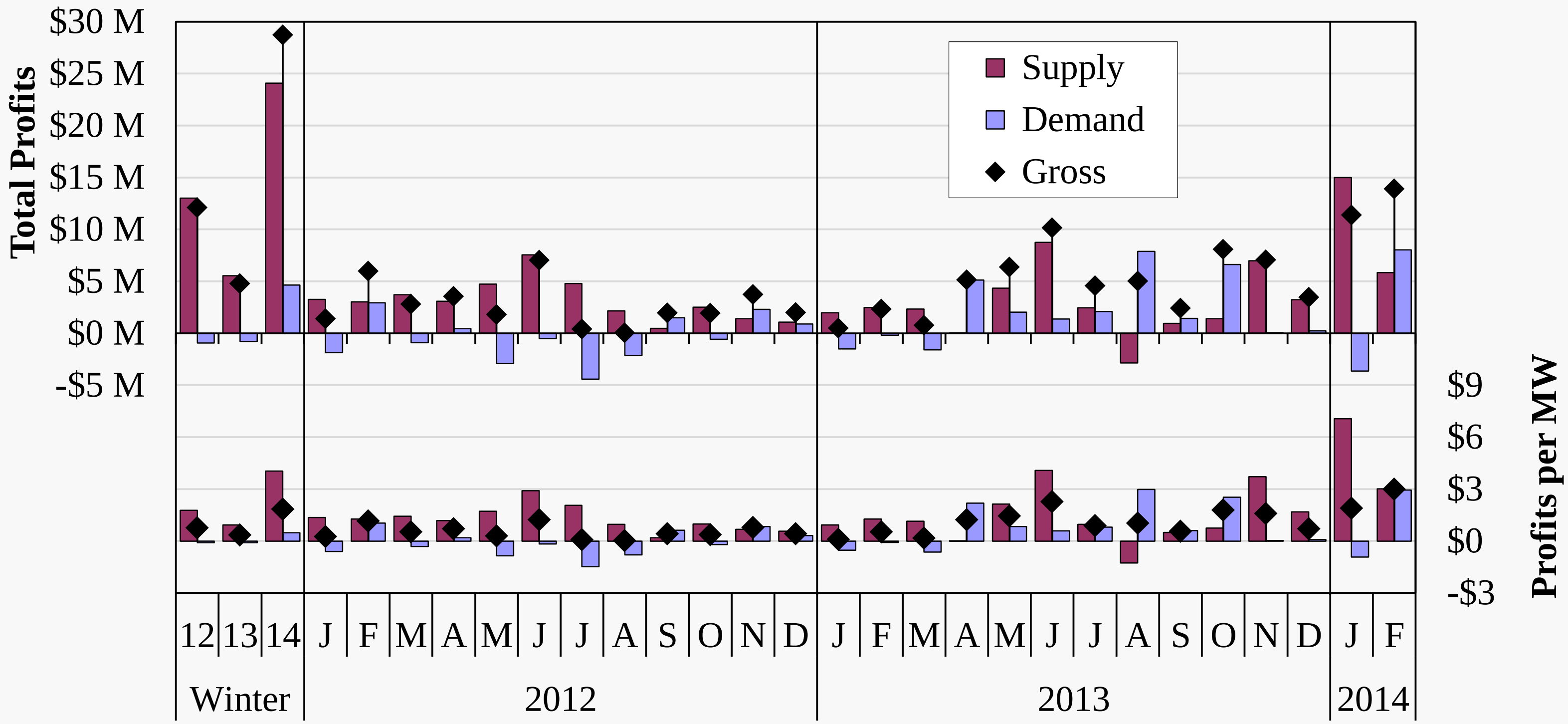
Virtual Profitability
2012–2014



Percent Screened

Demand	2	2	7	1	2	2	2	2	4	3	2	2	2	2	2	3	2	2	2	2	3	1	1	2	2	2	2	9	8
Supply	1	1	2	1	1	2	2	2	1	1	1	1	1	1	1	1	2	1	1	1	1	0	1	1	1	2	1	2	3
Total	1	2	5	1	2	2	2	2	3	2	1	2	2	2	2	2	2	2	2	2	2	1	1	2	2	2	2	7	6

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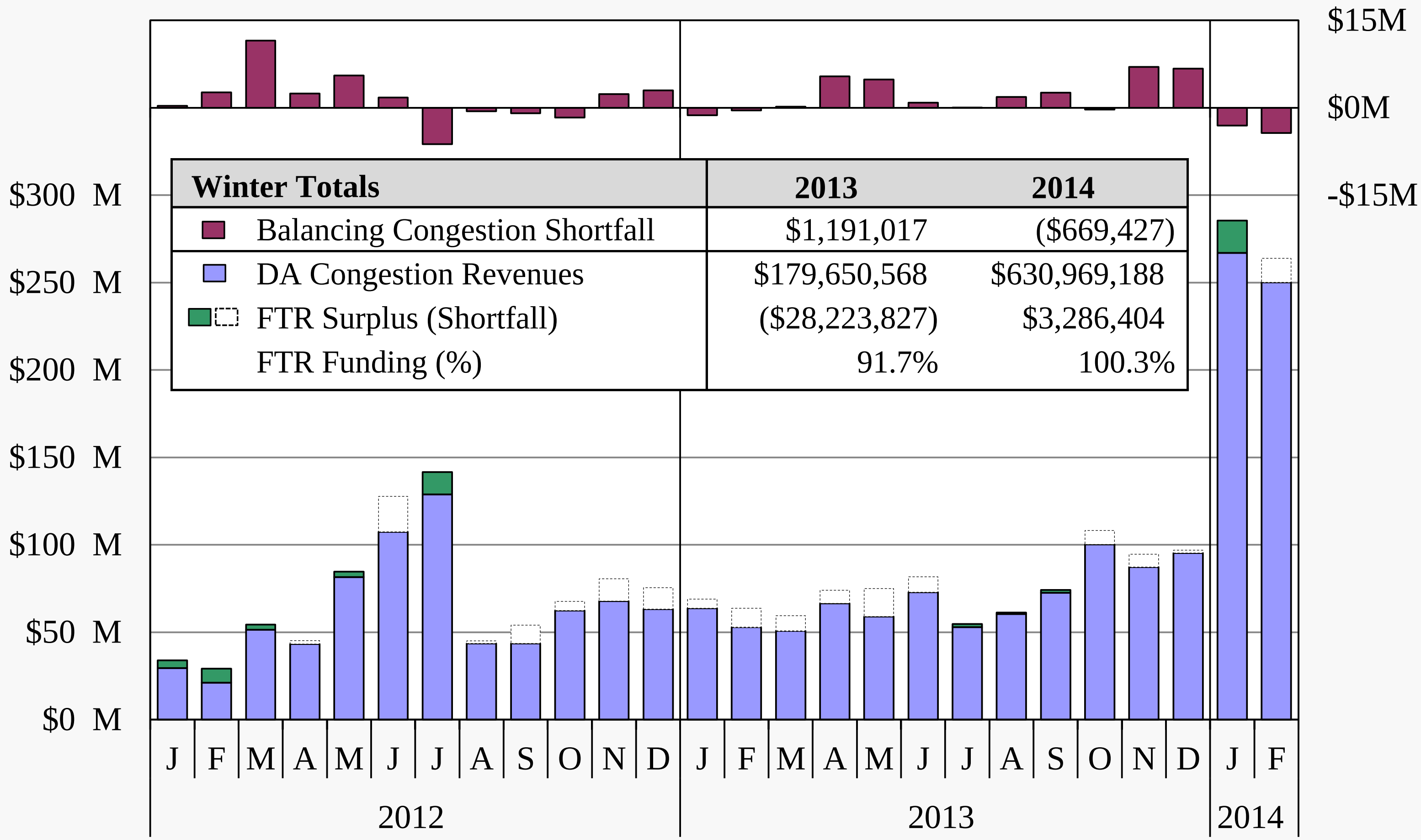
Day-Ahead Congestion and Obligations to FTR Holders

- Holders of FTRs 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 through its settlements with loads and generation, and pays it out to FTR holders.
  - ✓ If MISO does not collect sufficient congestion revenue to cover its obligation to the FTR holders, a shortfall arises and payments to FTR holders are reduced.
  - ✓ Shortfalls (or surpluses) occur when the portfolio of FTRs represent more (or less) transmission capacity than the capability of the network in the day-ahead market.
- The next figure shows monthly day-ahead and FTR surpluses or shortfalls since 2012.
  - ✓ It also shows balancing congestion, which results from modeling differences between day-ahead and real-time constraints. Net shortfalls in occur when DA scheduled flows exceed the real-time limit on a binding transmission constraint.
- Day-ahead congestion more than tripled from last winter to $631 million, which was primarily due to (a) much higher fuel prices, (b) congestion in the South and (c) congestion on the inter-area constraints.
  - ✓ Nearly $70 million of this accrued on one constraint in the Central Region impacted by a long-term transformer outage.
- FTR obligations for the quarter were fully-funded, although a 4 percent surplus in January offset a 3 percent shortfall in February.

Day-Ahead Congestion, Balancing Congestion and FTR Underfunding, 2012–2014



Winter Totals	2013	2014
Balancing Congestion Shortfall	$1,191,017	($669,427)
DA Congestion Revenues	$179,650,568	$630,969,188
FTR Surplus (Shortfall)	($28,223,827)	$3,286,404
FTR Funding (%)	91.7%	100.3%

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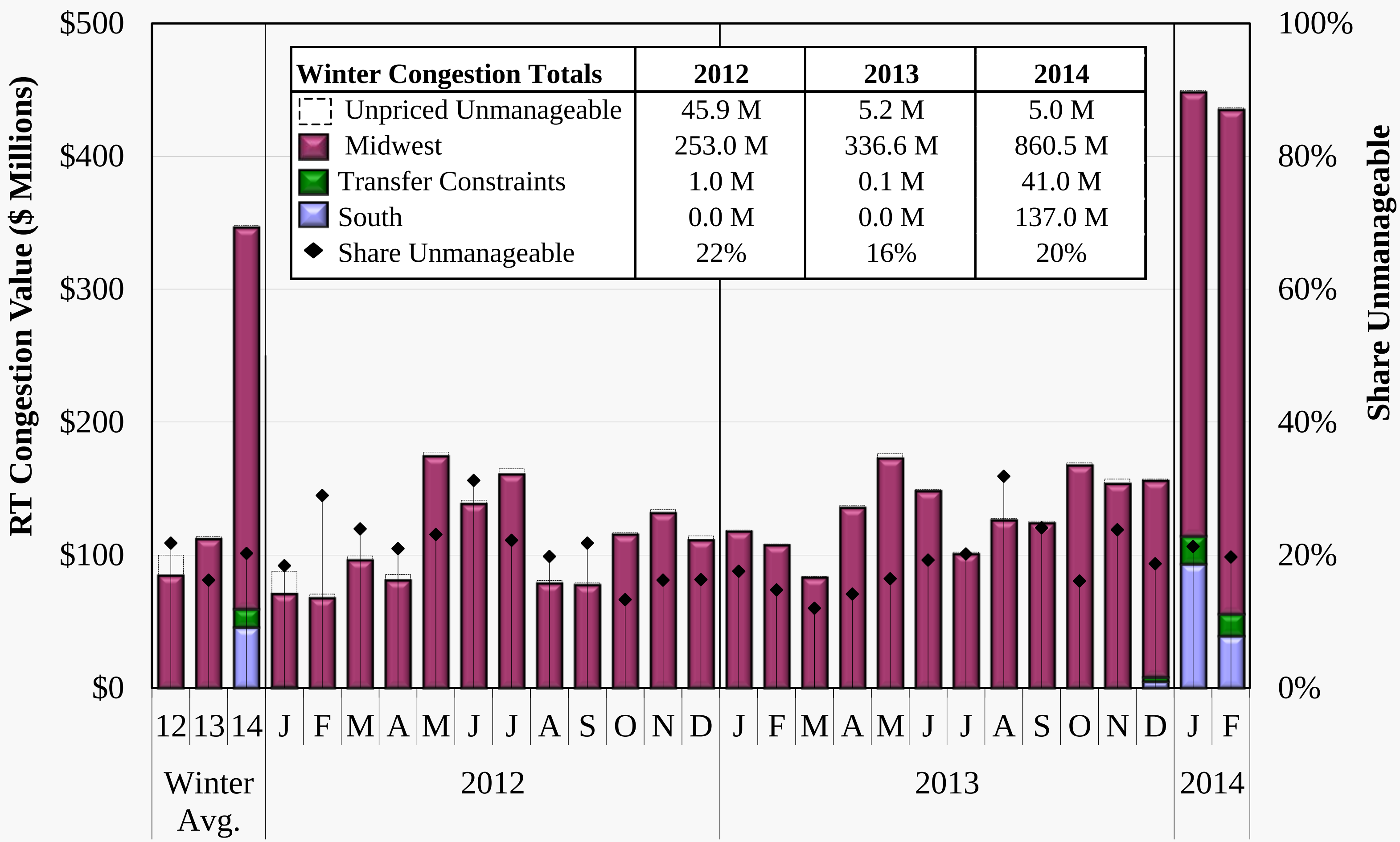
Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on the MISO system.
  - ✓ 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.
  - ✓ We distinguish between congestion in the Midwest and South regions, and also separate congestion on the set of “transfer” constraints that limit flows between the two regions.
- The value of real-time congestion more than tripled to $1.04 billion this winter, driven in part by the sharp increase in fuel prices.
- The most expensive constraint was in Michigan and accrued $90 million in congestion value, almost all of it in February (including $20 million on Feb 16-17).
  - ✓ Two other expensive constraints, valued at $39 and $28 million, were significantly impacted by wind output, which was 12 percent higher than last winter.
- The Reverse ORCA constraint, which limits flows from the Midwest region to the South region, accrued $25 million in value and in real time was three times as impactful as the South-to-Midwest ORCA.
  - ✓ MISO is currently testing a revised implementation of the ORCA constraints which should correct the intra-regional dispatch inefficiencies we have shown previously.
  - ✓ It also remains important to raise the ORCA limit.

Value of Real-Time Congestion 2012–2014



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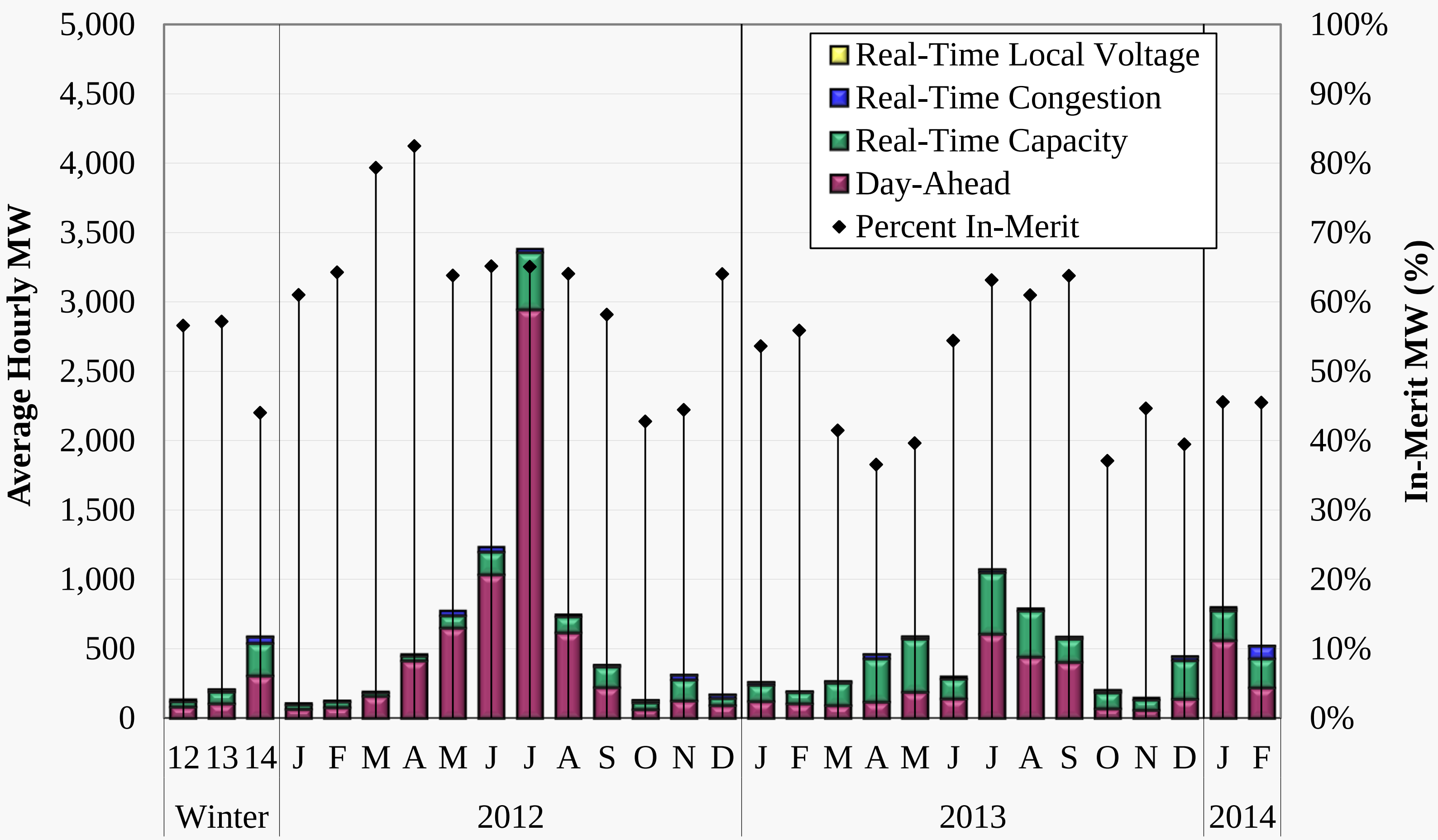
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were in-merit (offer price at or lower than the LMP).
  - ✓ The figure is categorized by the market and the reason for the commitment.
- Peaking unit dispatch quantities nearly tripled from last winter to 588 MW per hour, and rose evenly across all commitment categories.
- A slight majority of peaking resource dispatches continue to come from resources committed day-ahead. These increased to 307 MW, up from 106 MW last winter.
  - ✓ Day-ahead commitments were greatest in January, when loads were highest.
  - ✓ MISO averaged over 1,000 MW per hour on 8 days in the month, most notably during the Polar Vortex of January 6-8 and on January 28.
- Capacity needs rose to 232 MW per hour and were also highest during the Polar Vortex.
- Peaking units dispatched for congestion were most significant in February, when they accounted for almost 20 percent of the monthly total.
  - ✓ These were predominantly made for a set of constraints in Michigan, as well as for two constraints in Mississippi impacted by a 500-kV line outage.
- The share of peaking unit dispatch that was in-merit declined from 57 to 44 percent.
  - ✓ MISO's ELMP Initiative will allow peaking resources to set prices more frequently.

Peaking Resource Dispatch
2012–2014



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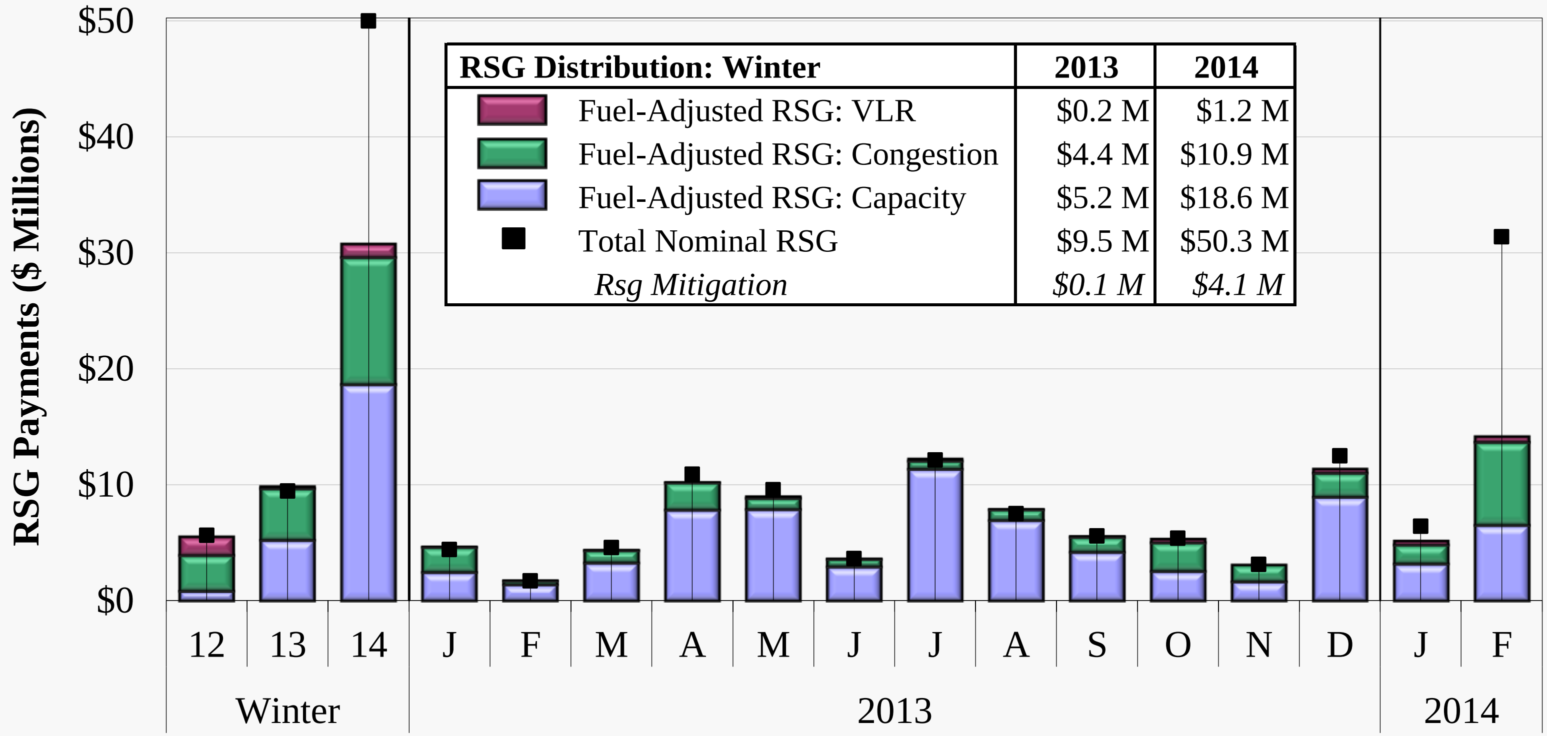
Real-Time and Day-Ahead RSG Payments

- The next two figures show *unmitigated* 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 five-fold from last winter to $50 million.
  - ✓ The considerable rise in fuel prices accounted for approximately half of this increase.
- In fuel-adjusted terms, payments for capacity rose from $5.2 to $17.7 million.
  - ✓ Cold weather led to high loads and required significant capacity needs in each month.
- Payments for congestion more than doubled to a fuel-adjusted $10.3 million.
  - ✓ Nearly 60 percent was paid to 24 units committed in February for outage-related congestion in Michigan impacted by significant generator and transmission outages.
- Payments for voltage and local reliability rose to $1.2 million, the vast majority of which were to units in the South Region.
- The second figure shows that day-ahead RSG payments similarly rose to record levels.
  - ✓ Payments rose from $7 million to $37.2 million, of which 60 percent was to satisfy local reliability needs (mostly in the South region).

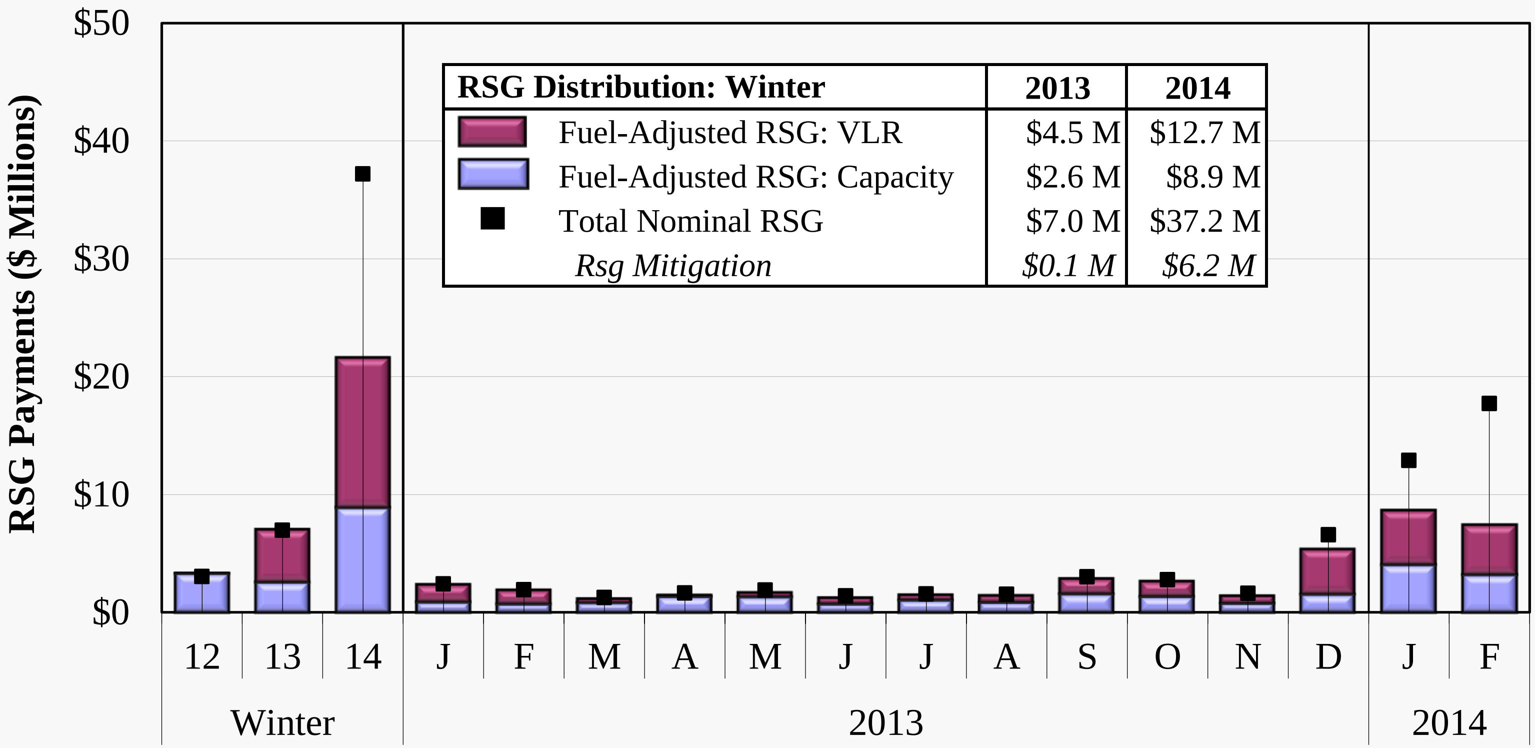
Real-Time RSG Payments 2013–2014



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

Peaker	54	78	50	82	57	76	82	77	75	85	81	74	51	62	79	61	48
Non-Peaker	46	22	50	18	43	24	18	23	25	15	19	26	49	38	21	39	52

Day-Ahead RSG Payments 2013–2014



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

Peaker	4	7	15	1	0	2	11	6	7	10	18	9	11	4	11	14	16
Non-Peaker	96	93	85	99	100	98	89	94	93	90	82	91	89	96	89	86	84

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Day-Ahead and Real-Time RSG Payments By Region

- The next figure shows total day-ahead and real-time unmitigated RSG payments on each day this winter separated by MISO Region.
- The figure shows that payments to units in the North and Central Regions were modest in December and January after the integration of the South Region.
  - ✓ Payments to these units were mostly for capacity needs, which after integration were more often satisfied with headroom on units in the South Region.
- RSG payments increased significantly in the second half of February, when congestion into Michigan resulted in commitments that cause RSG to rise sharply.
  - ✓ Much of the RSG was paid to gas-fired units on days with very high gas prices and pipeline off-take requirements that limited commitment flexibility.
    - – This pattern continued into early March.
  - ✓ We are reviewing the circumstances underlying these RSG payments and the associated concurrent outages (generation and transmission in both PJM and MISO) that resulted in the need for frequent commitments.
  - ✓ These events may suggest the need for changes in MISO's procedures and authorities related to outage scheduling.

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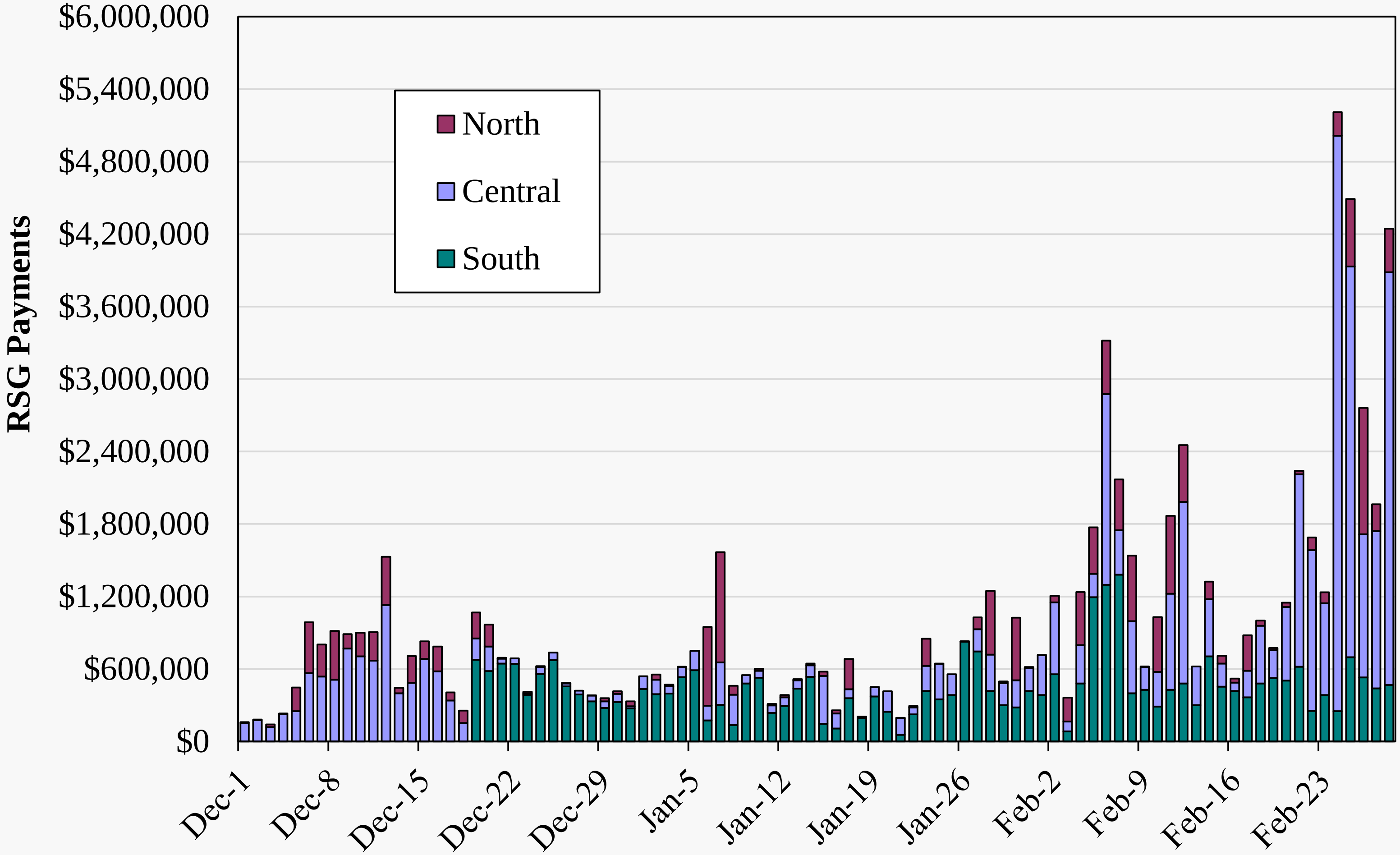
Daily RSG Payments by Region
Day-Ahead and Real-Time, Winter 2014



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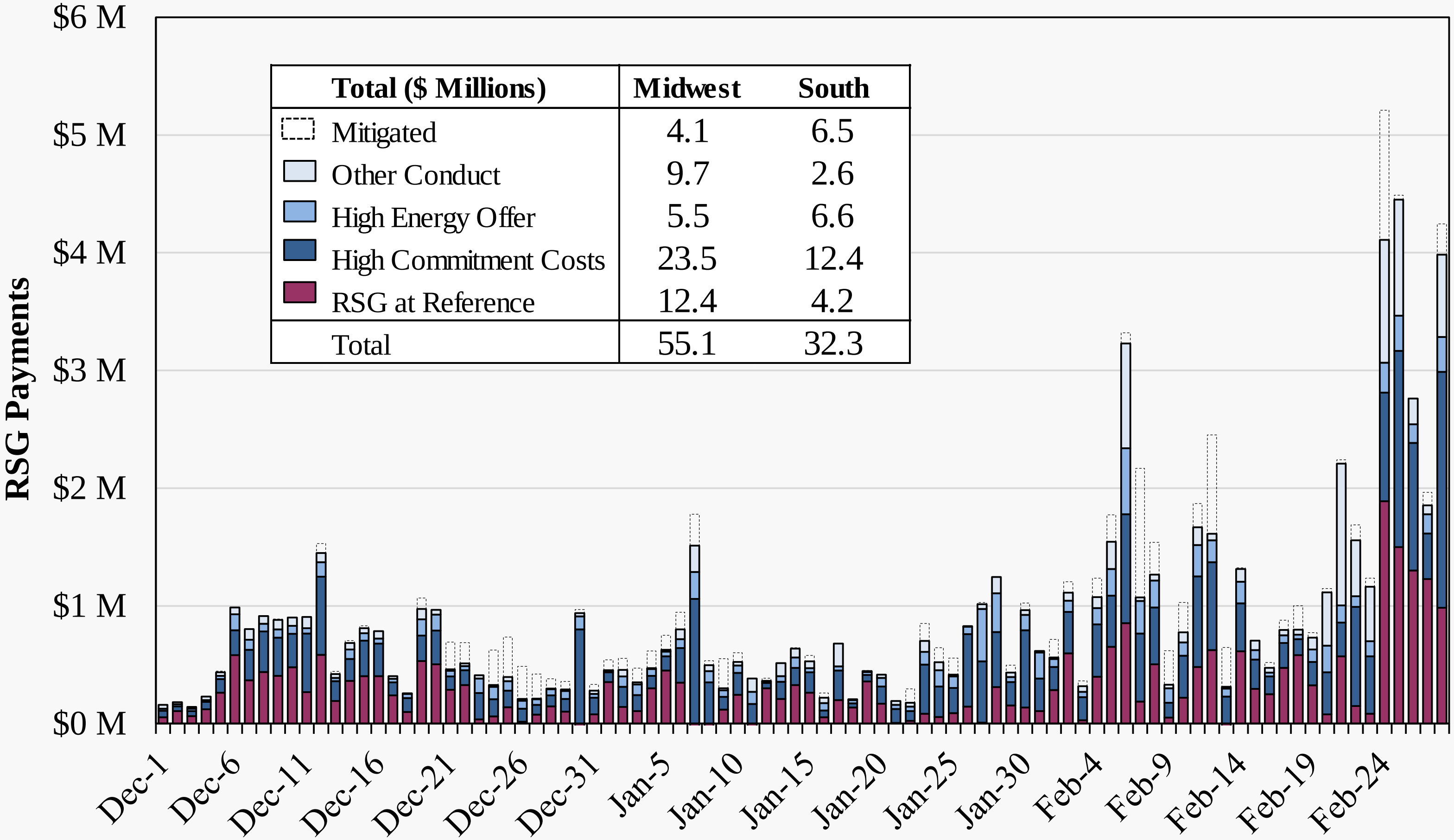
Day-Ahead and Real-Time RSG Payments By Conduct

- The next figure shows daily total RSG payments separated by conduct categories.
- The figure shows that more than 80 percent of the RSG payments this winter were associated with unit offers in excess of their reference values.
  - ✓ A majority (51 percent) of this additional cost is associated with startup and minimum generation costs that exceed reference values.
  - ✓ An additional 17 percent of RSG costs is due to increased incremental energy offers above reference offers, while a comparable share was due to other conduct such as lengthened minimum run times.
- The chart shows that over $10 million of the RSG—15 percent of the excess—will be mitigated under the current conduct and impact framework.
  - ✓ While this is the highest level of RSG mitigation for any similar period, it is still a small share of the RSG payments associated with costs above reference levels.
- These results indicate the potential need for tighter conduct and impact thresholds for congestion-related RSG payments.
  - ✓ We are developing a proposal to present in the *2013 State of the Market Report*.
  - ✓ Our initial proposal would have mitigated roughly 20 percent of the unmitigated RSG accrued on the Michigan constraint that we described earlier in this report.

Daily DA and RT RSG Payments by Conduct December–February



Price Volatility Make Whole Payments

- The next two charts shows two types of Price Volatility Make Whole Payments (PVMWP), which improve incentives for suppliers to follow dispatch instructions.
- DAMAP nearly quadrupled to $40.3 million this winter, while RTORSGP rose 58 percent to $3.24 million.
  - ✓ Large, relatively flexible coal units continue to be the largest recipients of DAMAP, predominantly during ramping hours (including $9.3 million in hour ending 7).
  - ✓ Roughly half of the DAMAP was paid to units in MISO South. As noted previously, some of these payments were due to failure to follow dispatch.
- 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 receiving payment.
  - ✓ The figure shows that the payments have been correlated with price volatility, as expected because increased volatility leads to higher payments to flexible suppliers.
  - ✓ SMP volatility more than tripled to $2.55 per interval, while LMP volatility doubled to over $9 per interval. These increases were due to the high fuel prices and cold weather.
- The second figure shows weekly DAMAP by region, and separates those payments that would not have accrued under tighter deviation rules (labeled "Eligible and IMM Deviating") that we are recommending.
  - ✓ Over $8 million, or nearly 20 percent of the $40 million paid in DAMAP, would not be eligible under the tighter deviation criteria.

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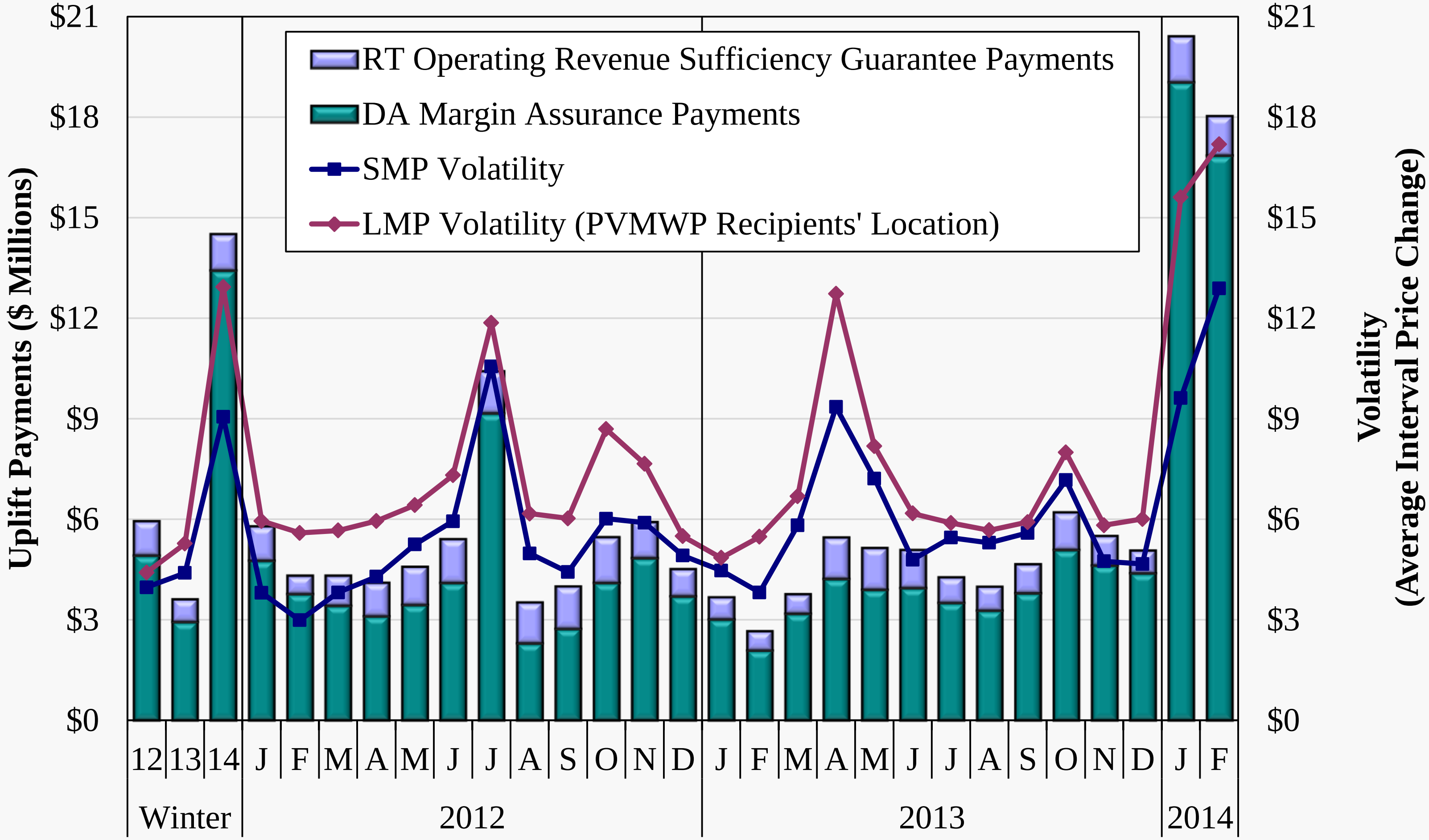
Price Volatility Make Whole Payments Winter 2012–2014



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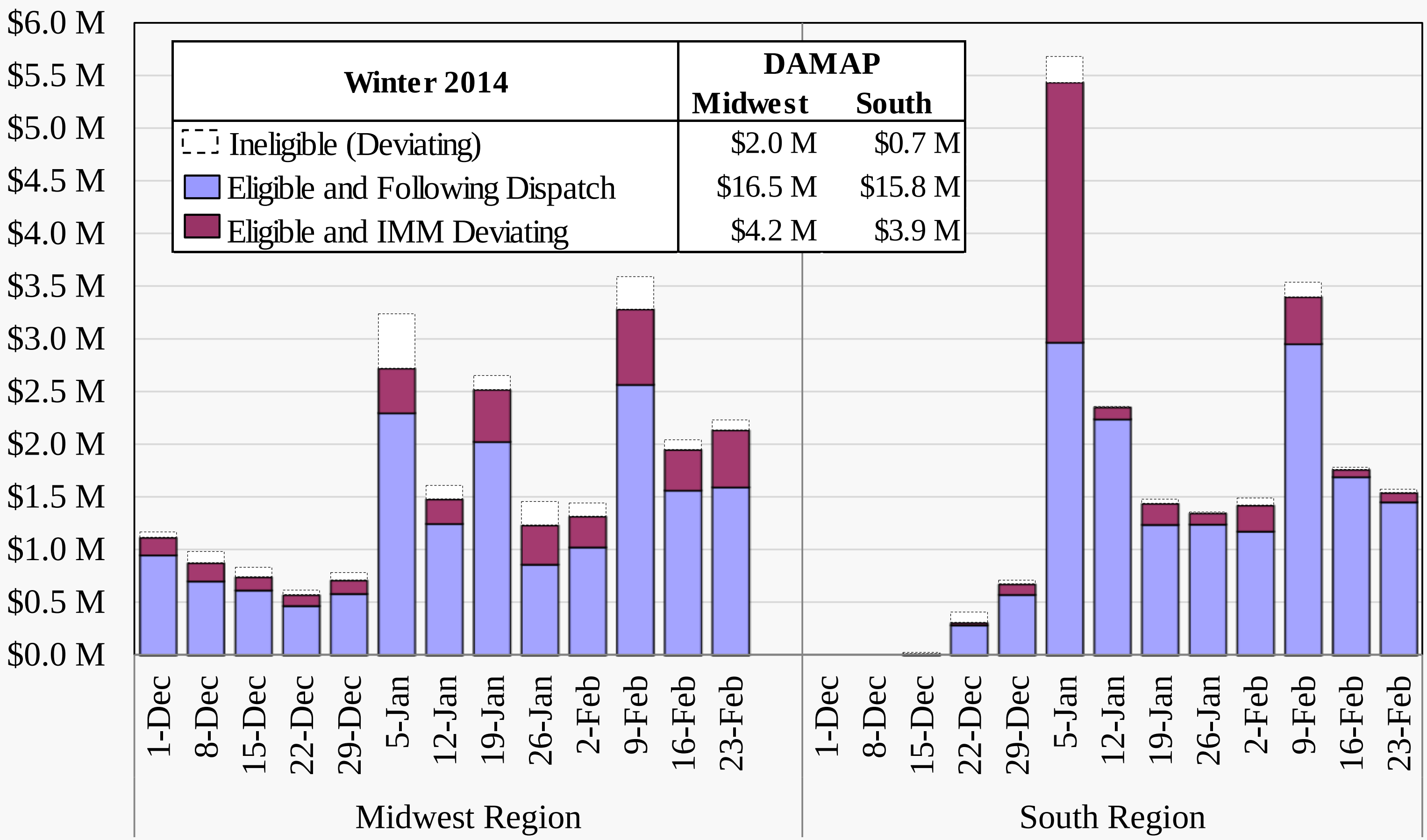
Daily Day-Ahead Margin Assurance Payments By Region, January 2014



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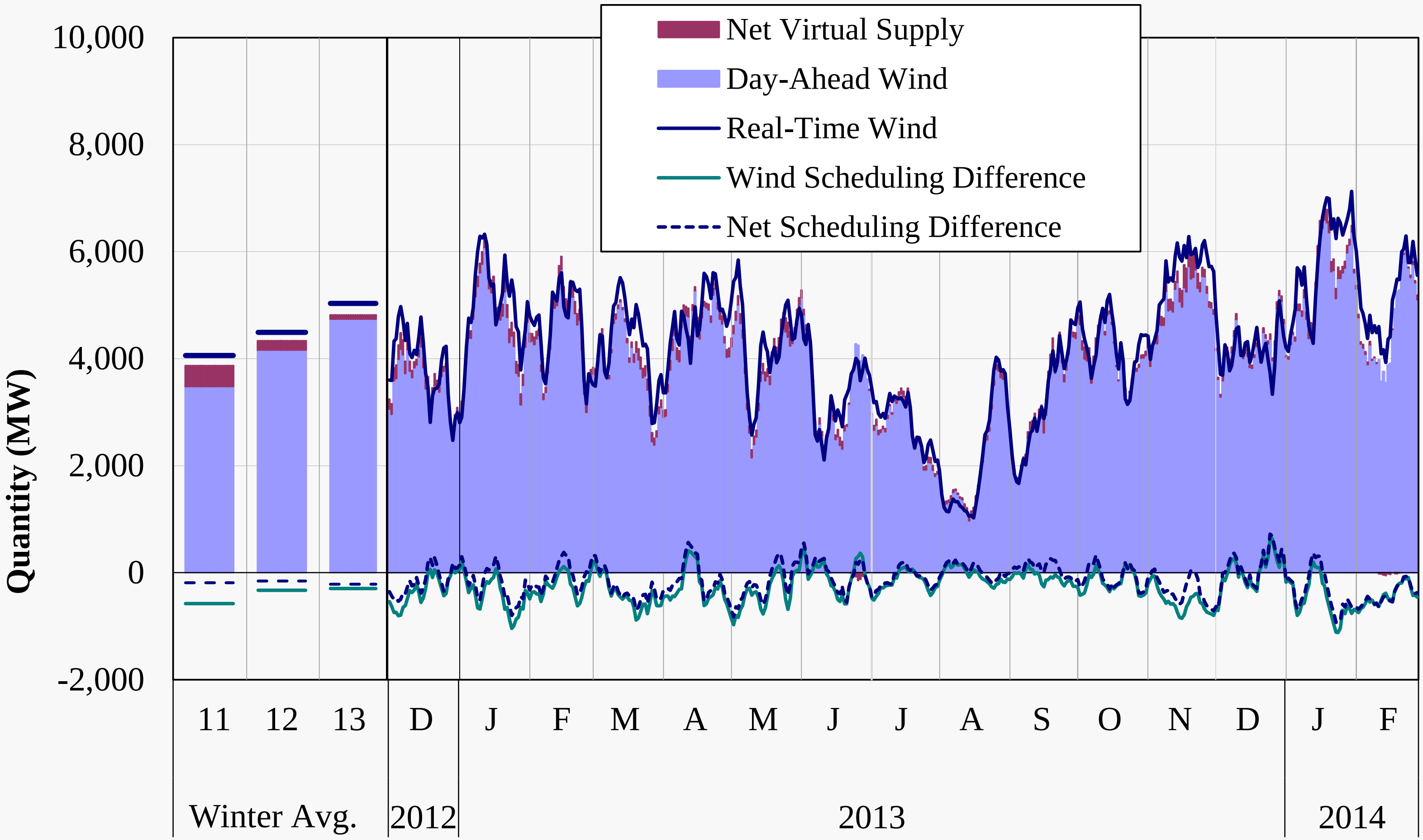
Wind Generation in Real-Time and Day-Ahead Markets

- The next figure shows wind output scheduled in day-ahead and real-time markets.
  - ✓ Attractive wind profiles in western states, along with state renewable portfolio standards and federal subsidies, continue to support investment in wind resources.
  - ✓ Approximately 80 percent of resources are now DIR, and have almost entirely replaced manual curtailments as the preferred means to manage wind output (see second slide).
- Real-time wind output rose 12 percent from last winter to 5.1 GW. When accounting for 267 MW of average DIR curtailments, output rose 16 percent.
- Under-scheduling of wind in the day-ahead market has improved since 2012.
  - ✓ It averaged 285 MW this winter, mostly unchanged from last winter, and averaged 94 percent of real-time output.
  - ✓ This is likely due to the wide-spread adoption of DIR, whereby congestion-related price effects at wind locations contributed to lower real-time prices and increased the incentive to schedule wind in the day-ahead market.
- Under-scheduling of wind produces incentives for participants to make up the difference with net virtual supply, although it declined to less than 100 MW this winter.
  - ✓ It was more profitable than usual this quarter, averaging $5.09 per MWh.
- MISO must still manage the ramp demands related to wind volatility, which averaged 49 MW per interval (based on units' forecasted maximums).

Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average, Winter 2012–2014



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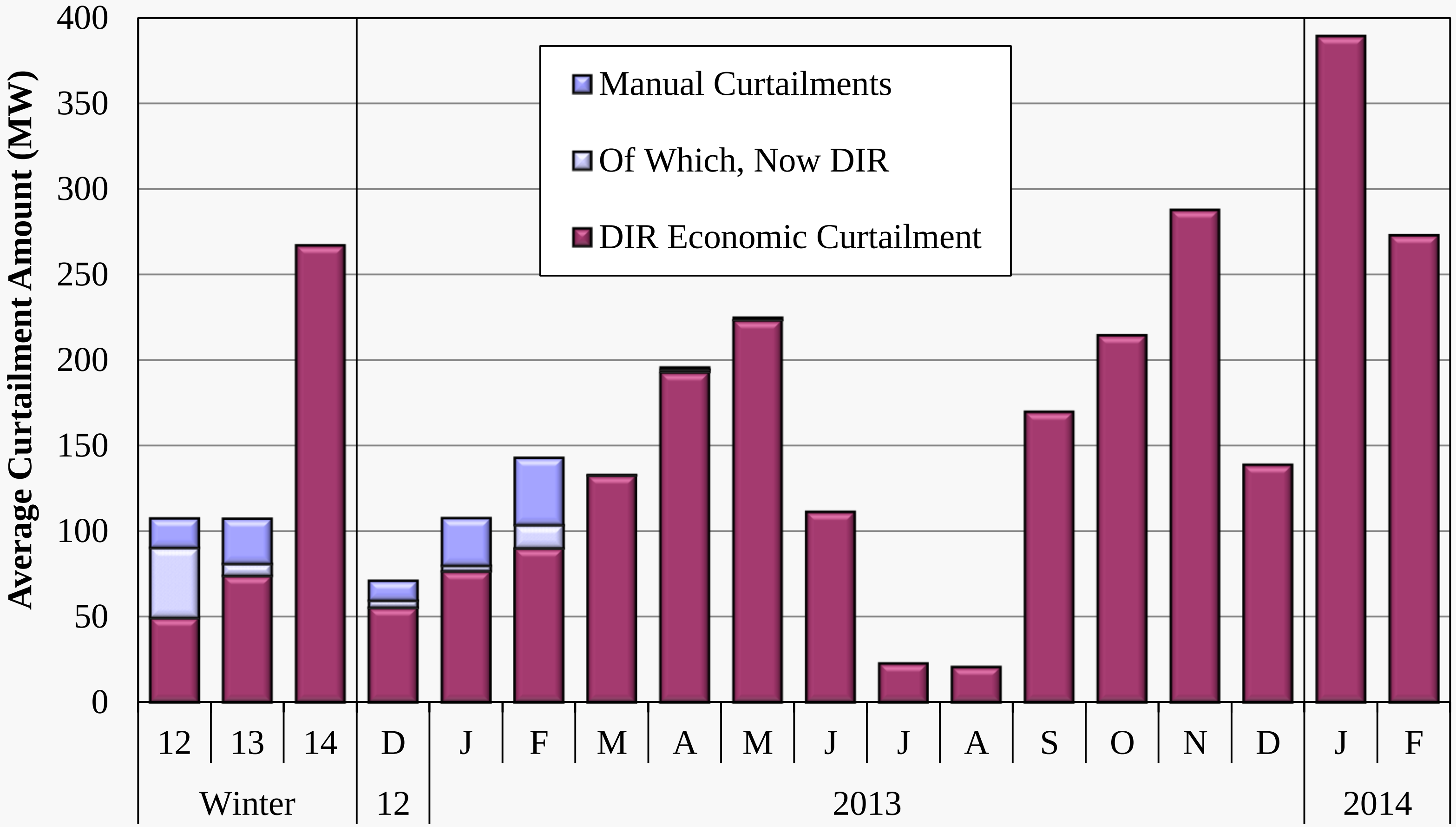
Wind Curtailments
Winter 2012–2014



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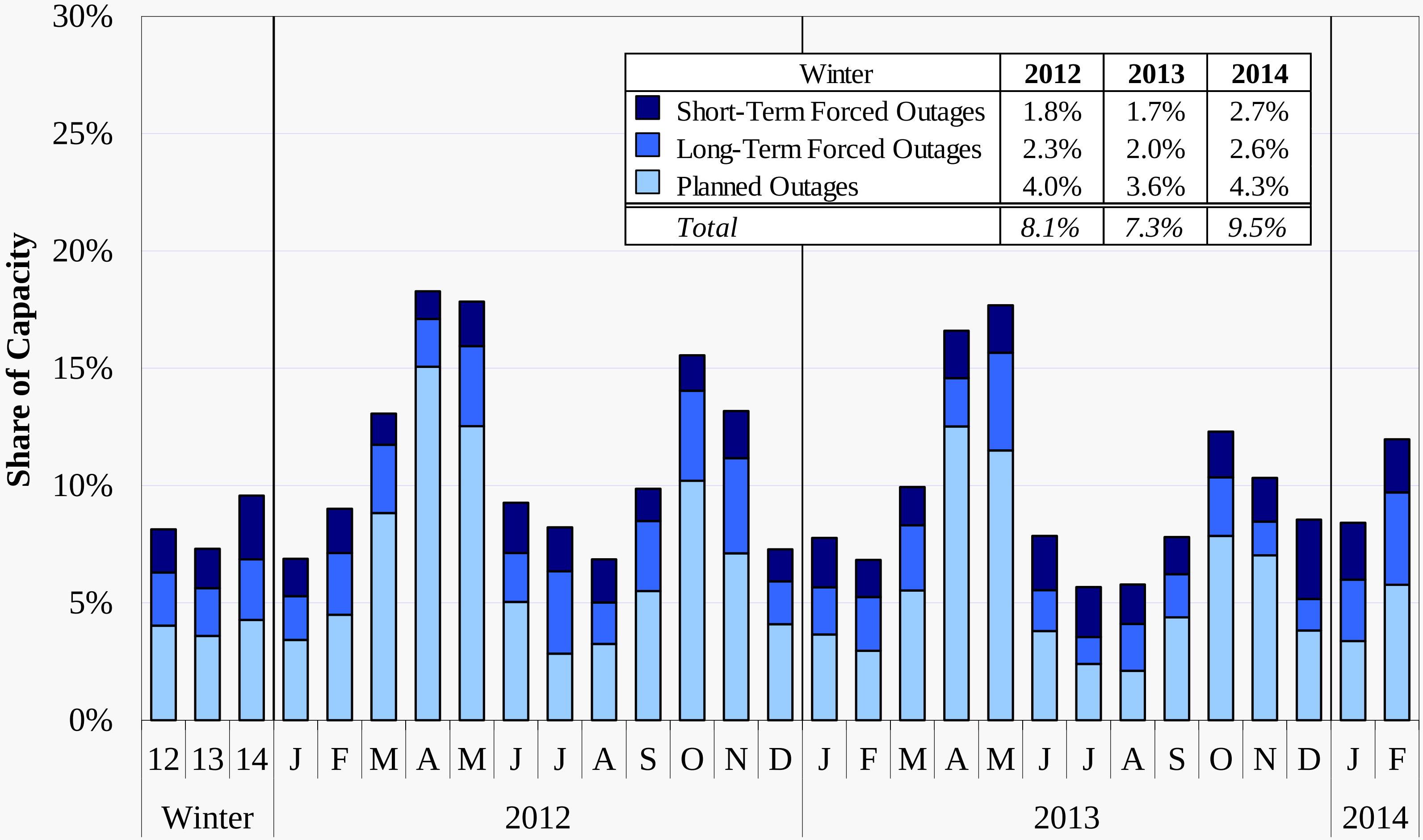
Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2012 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 9.5 percent, up from 7.3 percent last winter and 8.1 percent in the prior winter.
- Outage rates across the three categories all increased modestly this winter.
  - ✓ Long-term forced rose from 2.0 to 2.6 percent, while short-term forced outages, which can indicate potential physical withholding, rose from 1.7 to 2.7 percent.
    - – Some of the increase in forced outage reflect increased fuel supply issues this winter.
  - ✓ Planned outages rose to 4.3 percent, and exceeded 5 percent in February.
- We continue to investigate those outages that contributed to shortages or severe congestion.

Generation Outage Rates 2012–2014



Winter	2012	2013	2014
Short-Term Forced Outages	1.8%	1.7%	2.7%
Long-Term Forced Outages	2.3%	2.0%	2.6%
Planned Outages	4.0%	3.6%	4.3%
Total	*8.1%*	*7.3%*	*9.5%*

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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 2013 under two thresholds:
  - ✓ A "high" threshold, equal to the applicable tariff mitigation threshold; and
  - ✓ A "low" threshold, equal to one-half of mitigation threshold.
- Output gap levels in MISO rose this winter to nearly 0.7 percent of actual load.
  - ✓ At the high threshold, average output gap rose from 40 to 380 MW.
  - ✓ At the low threshold, it rose from 83 to 561 MW.
- The majority of the increase is due to fuel price uncertainties associated with volatile daily and intra-day gas prices. It is difficult for fuel price adjustments in reference levels to accurately reflect this volatility and uncertainty.
  - ✓ As a result, output gap was far higher on days with very high gas prices.
  - ✓ The largest contributor in February (approximately 30 percent at high threshold), was one unit that we are reviewing.
- We continue to routinely investigate hourly increases in output gap, and have found very limited instances of competitive concern.

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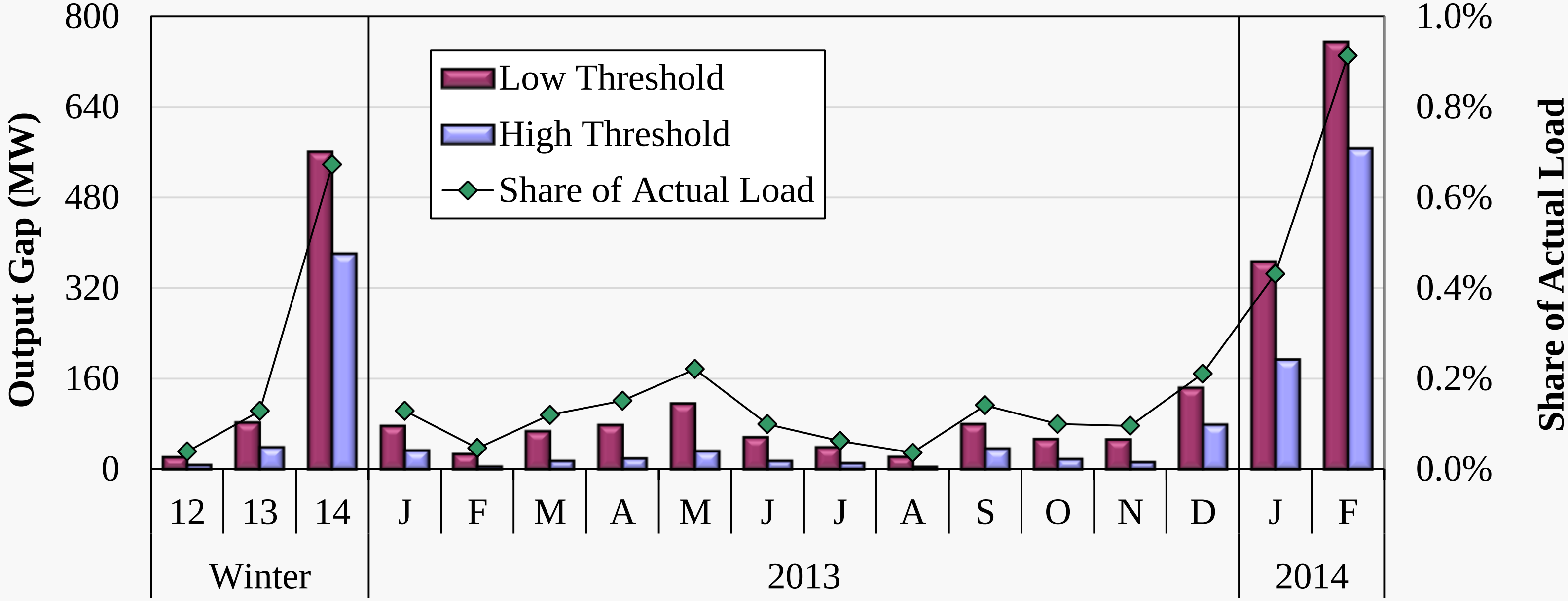
Monthly Output Gap
Winter 2013–2014



High Threshold Results by Unit Status (MW)

Offline	4	23	278	7	1	4	0	10	1	6	0	23	7	2	59	106	451
Online	4	17	102	27	4	11	20	22	15	5	5	14	11	11	20	89	116

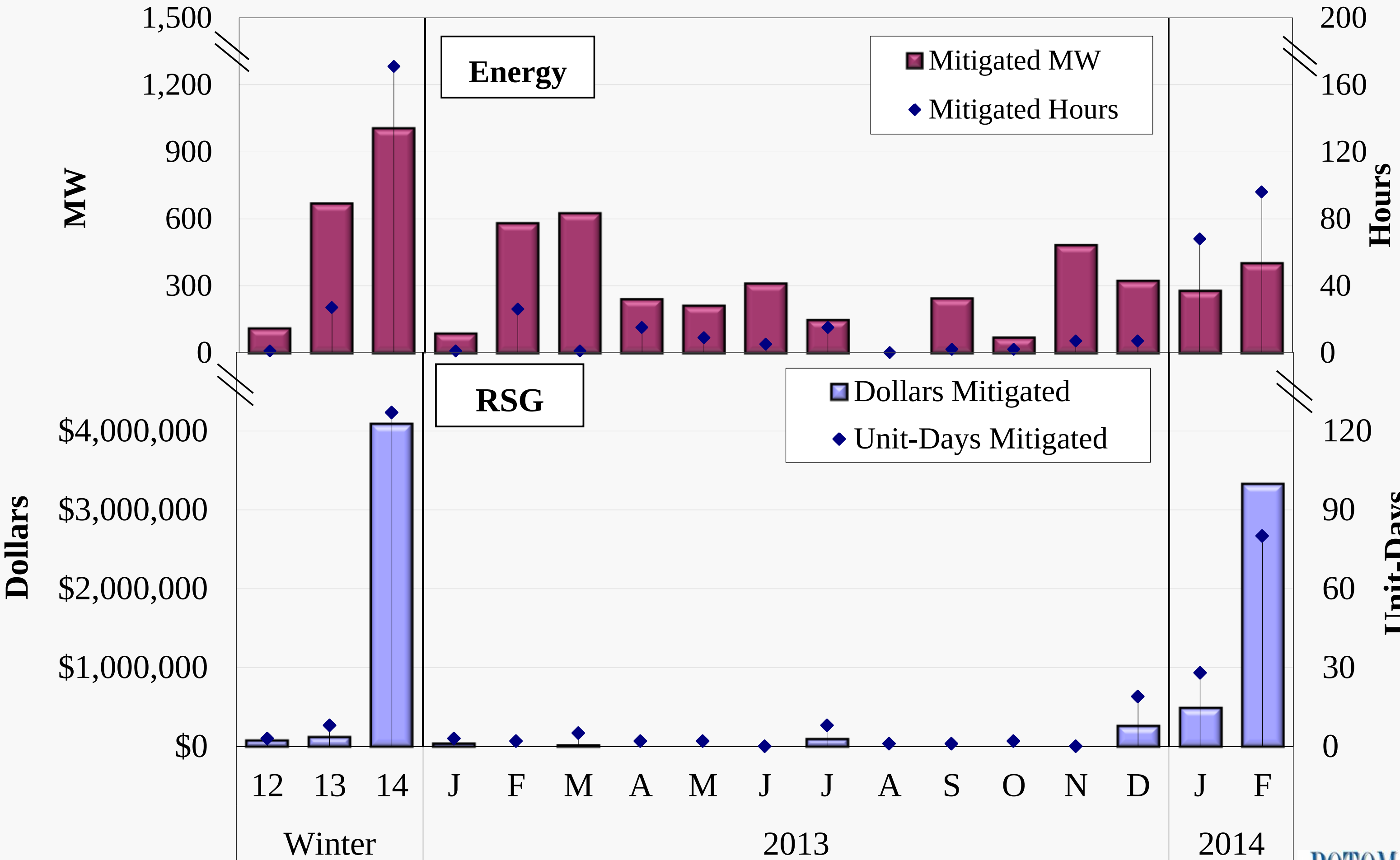
Low Threshold Results by Unit Status (MW)

Offline	4	27	329	8	2	6	0	12	2	9	0	26	11	4	70	140	519
Online	18	56	232	69	25	62	79	104	56	30	22	55	42	50	74	228	236

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 2013.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the mitigated quantity.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigation.
- In part because of the high and fluctuating fuel prices, an increased number of resources this quarter offered in excess of the applicable conduct and impact thresholds.
  - ✓ The conduct and impact thresholds are more likely exceeded during periods of high prices since they include fixed dollar thresholds that are not adjusted for fuel prices.
- The conduct and impact tests were appropriately applied. Energy mitigation rose to 171 hours and over 1 GW this winter, up from 27 hours and 670 MW last winter.
  - ✓ RSG mitigation occurred for 127 unit-days and totaled nearly $4.1 million, mostly in February.
  - ✓ In addition, there were over 1,000 mitigated unit-hours in the day-ahead market (mostly in the South Region), as well as 356 unit-days of RSG mitigation under VLR rules.
- Some participants are seeking to dispute certain instances of RSG mitigation.

Real-Time Market Power Mitigation Winter 2012–2014



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Submittals to External Entities and Other Issues

Submittals to External Entities:

- We responded to several data requests related to prior referrals of resources failing to update real-time offers.
  - ✓ We are also working with MISO on the related *2012 SOM* recommendations for changes in operations and settlements that will reduce the impact of such conduct.
- We submitted comments regarding the SPP and MISO complaints on the JOA and loop flows caused by MISO's dispatch. Our comments included the estimated efficiency loss in limiting inter-area transfers to 1000 MW, which exceeded $12 million/month.
  - ✓ This is *very* conservative and excludes the inefficiency of the current ORCA constraints.

Other Issues:

- We continue to work with MISO and PJM on the interface pricing flaw. We made additional presentations at the JCM and are working with all on alternative solutions.
- We have been reviewing MISO's proposed modification of how the ORCA constraint has been implemented.
- FERC approved most of MISO's proposed changes to the RSG allocations.
  - ✓ These changes went into effect on March 17. However, not all changes were accepted and rehearing is likely needed.
- The extreme congestion and RSG costs related to outages in Michigan in February and March underscore the need for improvements to outage scheduling and the market power mitigation measures.

Selected Conduct Investigations

- Updating Real-Time Offers
  - ✓ We continued to investigate "inferred derates" where units are not following dispatch signals without update real-time offers, which can result in unjustified DAMAP payments and allows resources to avoid RSG allocations.
  - ✓ Unreported derates can also have a significant impact on reliability and commitment decisions, resulting in delays and more expensive commitments.
  - ✓ We have recommended changes to address these issues and will continue to refer the most significant events to FERC enforcement.
- Physical Withholding
  - ✓ We have been investigating a number of cases of potential physical withholding during winter peak conditions.
- Fuel Cost/Availability Audits
  - ✓ We are auditing a number of resources' fuel cost information submitted to receive a reference level adjustment. We are also investigating fuel availability issues that may have caused selected forced outages during the quarter.
- Uneconomic Production
  - ✓ Additional cases of potential uneconomic production have occurred this quarter.
  - ✓ We have been increasing the automation of our testing to incorporate cycling costs, which is allowing us to evaluate these cases more quickly.
  - ✓ One of these investigations is likely to be recommended for sanction.

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List of Acronyms

AMP	Automated 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
ORCA	Operations Reliability Coordination Agreement
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
TLR	Transmission Line Loading Relief
TCDC	Transmission Constraint Demand Curve
VCA	Voluntary Capacity Auction
VLR	Voltage and Local Reliability
WPP	Weekly Procurement Process
WUMS	Wisconsin Upper Michigan System