IMM Quarterly Report: Spring 2014
March – May

MISO Independent Market Monitor

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Potomac Economics

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Quarterly Summary

	Status	Value	Change[1] Prior Qtr.	Change[1] Prior Year
RT Energy Prices ($/MWh)	Expected	$42.60	*-15%*	*26%*
Fuel Prices ($/MMBtu)				
Natural Gas	Monitor/Discuss	$6.24	*-22%*	*51%*
Western Coal	Expected	$0.74	*6%*	*21%*
Eastern Coal	Expected	$1.93	*3%*	*7%*
Load (MW)[2]				
Average Load	Expected	71.9	*-9%*	*-4%*
Peak Load		98.2	*-11%*	*2%*
% Scheduled DA (Peak Hour)	Expected	99.7%	100.0%	98.6%
Transmission Congestion ($M)				
Real-Time Congestion Value	Monitor/Discuss	$724.6	*-30%*	*85%*
Day-Ahead Congestion Revenue	Monitor/Discuss	$379.7	*-40%*	*116%*
Balancing Congestion[4]	Expected	$2.7	-$4.3	$10.4
Ancillary Service Prices ($/MWh)				
Regulation	Expected	$14.26	*-7%*	*9%*
Spinning Reserves	Expected	$2.63	*-40%*	*-45%*
Supplemental Reserves	Expected	$1.63	*-56%*	*-23%*

	Status	Value	Change[1] Prior Qtr.	Change[1] Prior Year
FTR Funding (%)	Expected	96%	100%	91%
Wind Output (MW)	Expected	4,961	*-2%*	*11%*
Guarantee Payments ($M)[5]				
Real-Time RSG	Monitor/Discuss	$50.2	*8%*	*95%*
Day-Ahead RSG	Monitor/Discuss	$31.1	*0%*	*490%*
Day-Ahead Marginal Assurance	Monitor/Discuss	$28.0	*-30%*	*148%*
RT Operating Rev. Sufficiency	Expected	$3.5	*6%*	*12%*
Price Convergence[3]				
Market-wide DA Premium	Expected	1.8%	3.2%	-0.8%
Virtual Trading				
Cleared Quantity (MW)	Expected	7,322	*1%*	*23%*
% Price Insensitive	Expected	48%	47%	38%
% Screened for Review	Expected	3%	5%	2%
Profitability ($/MW)	Expected	$3.07	$1.83	$0.93
Dispatch of Peaking Units (MW/hr)	Expected	459	588	437
Output Gap- Low Thresh. (MW/hr)	Expected	259	422	87
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 shortfalls that contribute to negative ECF with no offset for M2M settlements.
5. Includes effects of market power mitigation.

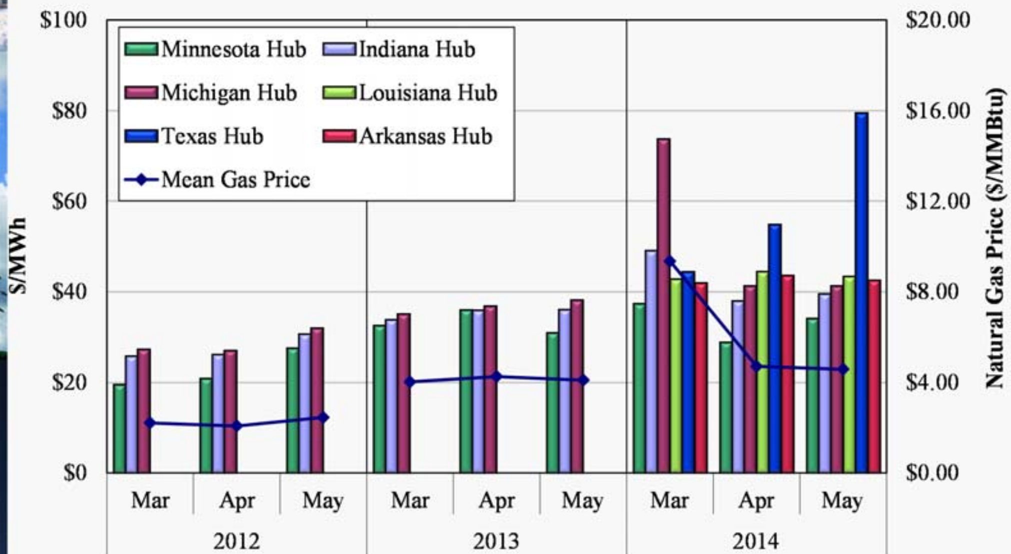
Summary of Spring 2014

- Real-time energy prices averaged $42.60 per MWh this spring, up 26 percent from last spring and 15 percent lower than in winter.
  - ✓ The increase was mostly due to higher gas prices, which averaged $6.24 per MMBtu. This winter's gas supply issues and high demand continued into early March.
    - – Prices in March averaged over $8 per MMBtu and occasionally exceeded $30.
    - – Despite the market uncertainty, there were far fewer AS shortages this spring.
  - ✓ Load averaged 71.9 GW, and in the Midwest Region was slightly lower than last spring.
  - ✓ Day-ahead prices were 2 percent higher, although a 5 percent day-ahead premium in the Midwest Region offset a 6 percent real-time premium in the South Region.
    - – In real-time, prices were 27 percent higher in the South Region.
- There was significant congestion into Michigan in March and Texas in April and May.
  - ✓ Commitments needed to manage the Michigan constraints in real-time required $14.4 million in RSG payments, much of which was associated with inflated offers.
  - ✓ The total value of real-time congestion rose 85 percent from last spring to $725 million.
  - ✓ In April and May, significant generator and transmission outages in the South resulted in sustained high prices at Texas Hub and the declaration of a number of Local Transmission Emergencies that required the commitment of emergency-only resources.
- The new version of the transfer constraint between South and Midwest (SRPBC) raised contributed significantly to the Texas congestion and degraded reliability.

Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at representative locations in each month in the spring of 2012 to 2014.
  - ✓ We include a representative natural gas price 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 29 percent from last spring to $43.38 per MWh.
  - ✓ This is mostly due to a significant rise in gas prices, particularly early in March.
  - ✓ Scheduled load averaged 71.3 GW and by 4 percent from last spring (for the Midwest Region).
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ The most significant congestion this quarter was into Michigan in March and into Texas in the second half of the quarter. S
  - ✓ Significant generator and transmission outages in both cases limited power flows into the two regions.
    - – In May, prices averaged nearly $80 per MWh at Texas Hub compared to less than $45 at all other hub locations.
  - ✓ A large share of the differences in prices between the South (outside Texas) and Midwest regions are due to transfer constraints, although these constraints had larger effects in the real-time market.

Day-Ahead Average Monthly Hub Prices Spring 2012–2014



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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.
  - ✓ We separate the energy component associated with shortages.
  - ✓ The figure includes monthly average natural gas prices at Chicago Citygate because the natural gas price is a key driver of energy prices.
- The all-in price rose 27 percent from last spring to an average of $43.54 per MWh.
- The energy component continues to make up 98 percent of the all-in price.
  - ✓ Despite the extreme weather and related gas issues in March, there were not many shortage periods. Shortages added 55 cents to the price, down from $1.06 last year.
- Ancillary service prices added 14 cents, down from the 23 cents added last year.
  - ✓ The shortage component of the energy price and ancillary services prices are closely correlated because the products are jointly optimized.
- Uplift costs were 1.2 percent ($0.52) of the all-in price. The costs were highest in March ($0.96), when significant real-time commitments were needed in Michigan.
- The capacity component from the Planning Resource Auction added five cents.

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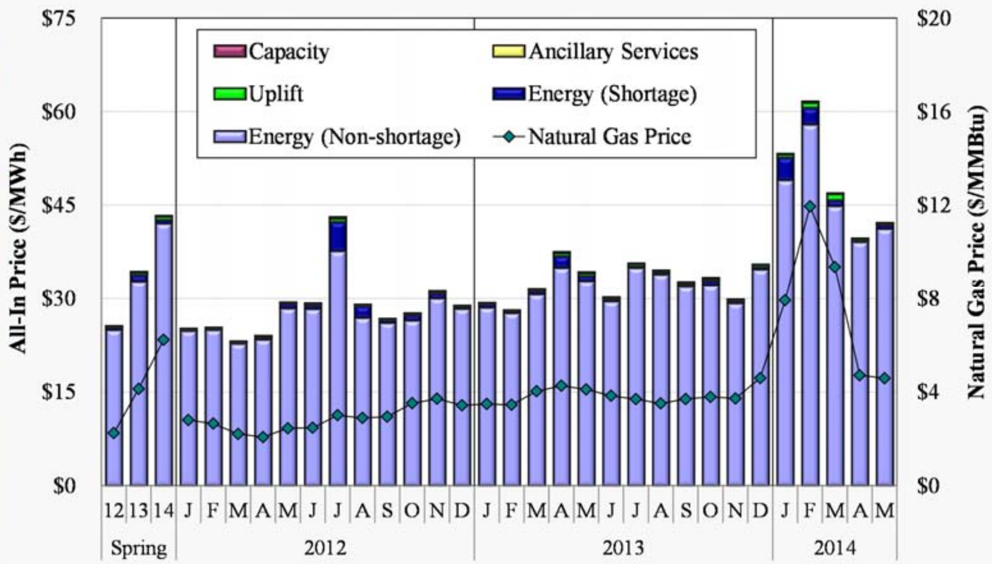
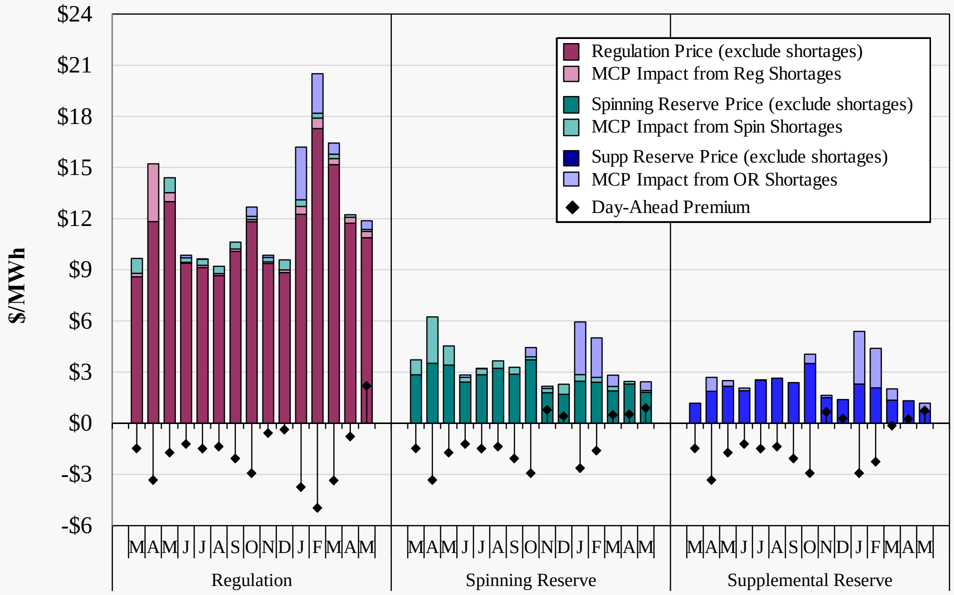
All-In Price
2012 –2014



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).
- Regulation clearing prices averaged $14.26 per MWh this spring, up 9 percent from last spring. There were 26 shortages for regulating reserves.
  - ✓ The significant rise in gas prices similarly impacted all ancillary services prices.
  - ✓ There was a modest day-ahead premium for regulation in May.
- Spinning reserve prices declined 45 percent from last spring to $2.63 per MWh.
  - ✓ The rise in gas prices was more than offset by an 84 percent decline in shortages.
    - – There were just 38 this spring, down from 240 last spring.
- Supplemental reserve prices declined 23 percent to $1.63 per MWh. Operating reserve shortages were unchanged at 12.

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



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MISO Fuel Prices

Natural Gas and Oil Prices

- Natural gas prices at Chicago rose 51 percent from last spring to $6.24 per MMBtu.
  - ✓ Prices were 22 percent lower than in winter, when they averaged $8.02 per MMBtu.
- The extremely volatile prices this winter were the result of high winter demand, low storage levels and pipeline bottlenecks that continued into early March.
  - ✓ Prices on some days averaged $36 per MMBtu and traded as high as $60 intra-day.
  - ✓ After mid-March, prices never exceeded $5 per MMBtu.
  - ✓ Prices at Henry Hub in Texas experienced much less price volatility. Significant spreads between gas hubs can lead to inter-regional congestion (see second slide).
- Oil prices averaged $21.51 per MMBtu, down 2.3 percent from last spring.
  - ✓ Many peaking units are dual-fueled and some switched from natural gas to oil when it was economical to do so, which moderated the gas supply issues in March.

Coal Prices

- Illinois Basin prices rose 7 percent from last spring to $1.93 per MMBtu, while Western (Powder River Basin) coal prices rose 13 cents (21 percent) to $0.74.
- There continue to be supply issues due to rail congestion from the PBR region but so far these have not had a significant market impact.

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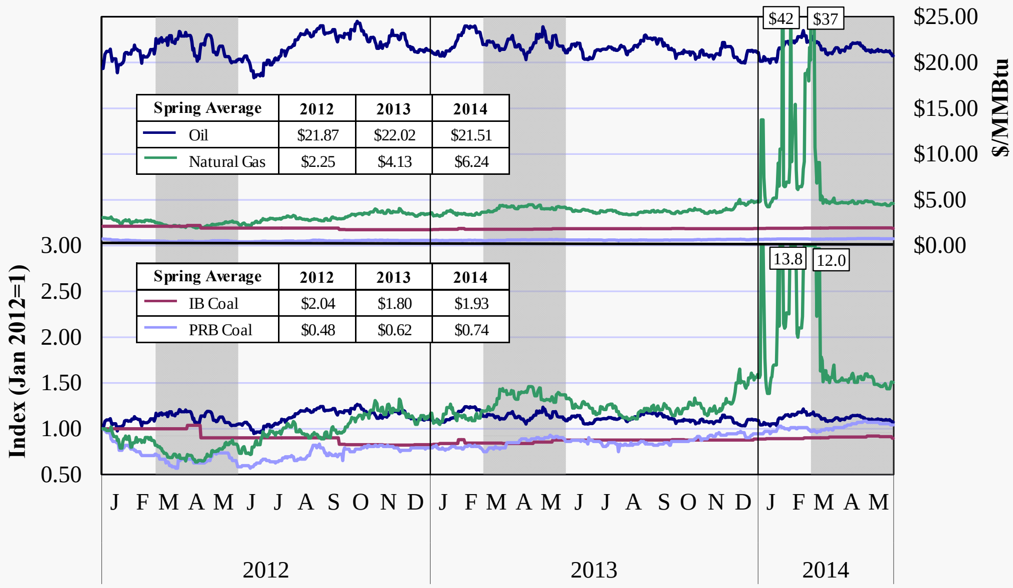
MISO Fuel Prices 2012–2014



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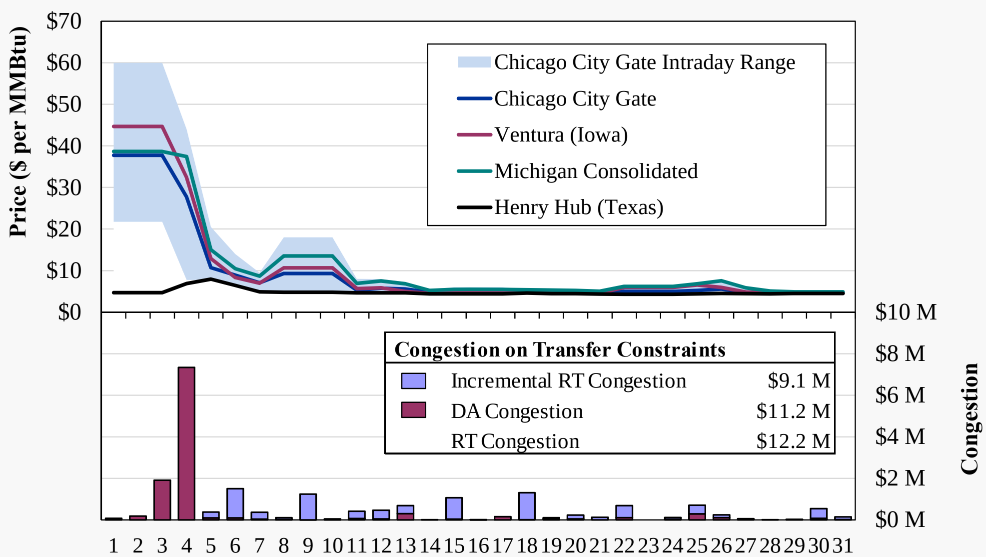
MISO Daily Gas Prices March 2014



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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 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 in MISO were 5 percent above the historical average, but declined 4 percent from last spring in the Midwest Region.
  - ✓ Degree days in the Midwest Region were nearly 20 percent above average in March and in May, but 7 percent below average in April.
    - – Temperatures in early March were far below average for the Midwest.
  - ✓ Spring degree days in the South Region were seasonal, with below average degree days in March offsetting above average degree days in April and May.
- Despite the slight decline in degree days the Midwest Region from last spring, average and peak load rose 2 percent from last spring.
  - ✓ Load averaged 71.9 GW for the quarter, and peaked on March 3 at 98.2 GW.

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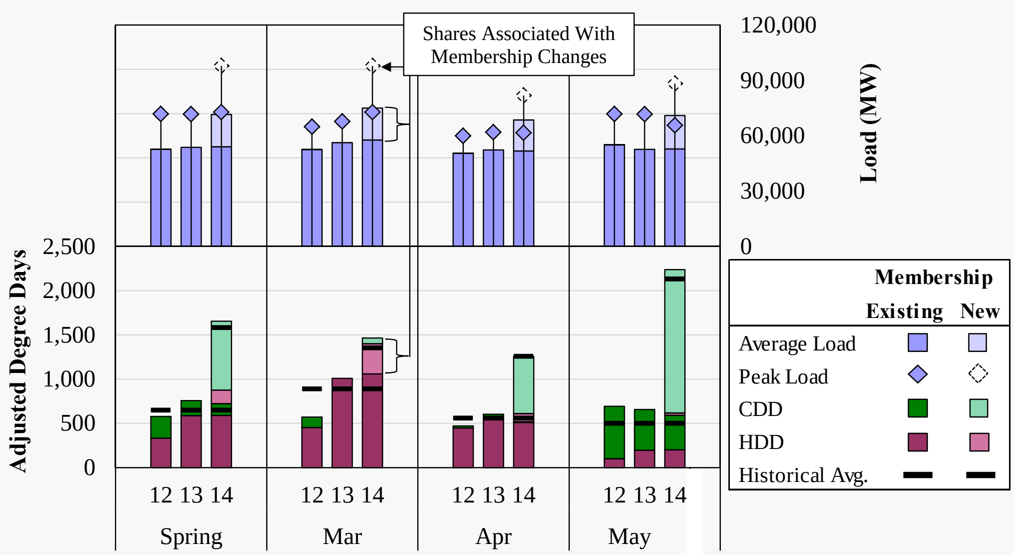
Load and Weather Patterns Spring 2012–2014



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.

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Day-Ahead and Real-Time Price Convergence

- The next figure shows the day-ahead to real-time price convergence at the Indiana Hub in 2013 and 2014 (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 $1.20 per MWh this quarter, but on some days in early March averaged as high as $32.
    - – MISO substantially revised this allocation effective March 17 to be more consistent with cost-causation. In April-May, 53 percent of real-time non-VLR RSG costs were allocated to DDC, compared to 84 percent in March.
- Convergence was again poor this spring, with premiums varying widely by region and month. This was primarily due to unusually volatile congestion.
  - ✓ In March, congestion at the Michigan Hub was priced much higher day-ahead, while severe congestion in the South was unforeseen and contributed to real-time premiums.
  - ✓ In May, there were modest day-ahead premiums across the footprint except in Texas.
    - – Day-ahead prices for many afternoons in early May were $5 to $10 higher than real-time prices because of load overscheduling and over-anticipated congestion.
    - – In Texas, this was more than offset by repeated outage-related congestion in May that resulted in real-time price spikes.
  - ✓ MISO is considering changes related to the SRPBC constraints that should result in production cost savings and reduced price volatility.

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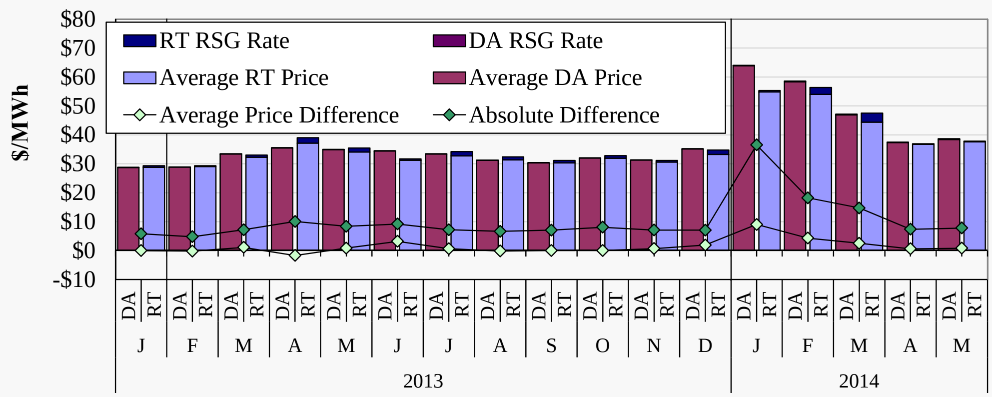
Day-Ahead and Real-Time Price Convergence 2013–2014



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

Indiana Hub	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1	16	4	-1	2	2
Michigan Hub	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3	25	7	26	-1	2
Minnesota Hub	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6	16	-9	-5	-3	3
WUMS Area	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1	19	-2	-1	-3	4
Arkansas Hub												-5	-12	-16	-20	1	5
Louisiana Hub												-6	-22	-14	-19	-12	11
Texas Hub												-2	-6	-14	-12	-4	-6

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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.
- For the quarter, load scheduling averaged 99.7 percent in the daily peak hour and 99.4 percent in all hours.
  - ✓ Net virtual demand of 1.2 GW helped offset a 3 percent shortfall in physical load.
- Scheduling in the peak hour remains considerably higher in the South region (101.2 percent) compared to the Midwest Region (98.9 percent).
  - ✓ Large quantities of day-ahead VLR commitments in the South likely contribute to the higher scheduling levels.

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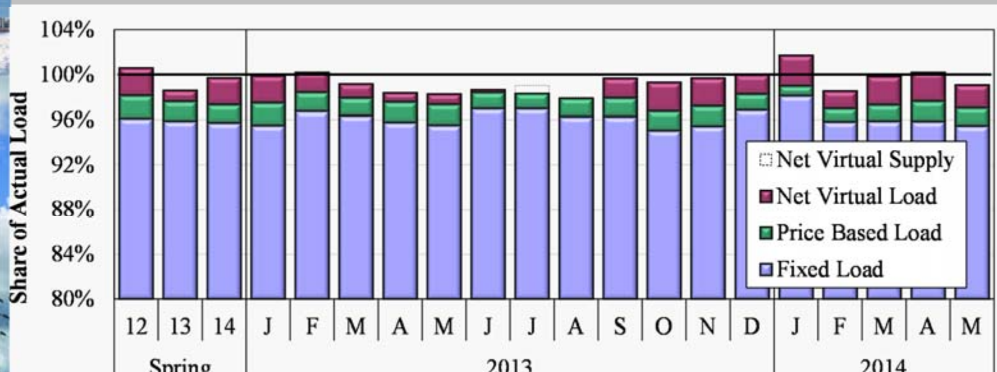
Day-Ahead Peak Hour Load Scheduling 2012–2014



Share of Actual Load (%)

	Spring 12	Spring 13	Spring 14	2013 J	F	M	A	M	J	J	A	S	O	N	D	2014 J	F	M	A	M
All Hours	99.1	99.0	99.4	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	99.2	99.8	99.1
Peak Hours Midwest	100.6	98.6	98.9	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	99.3	99.5	98.0
Peak Hours South			101.2												104.9	104.4	99.9	100.4	101.5	101.6

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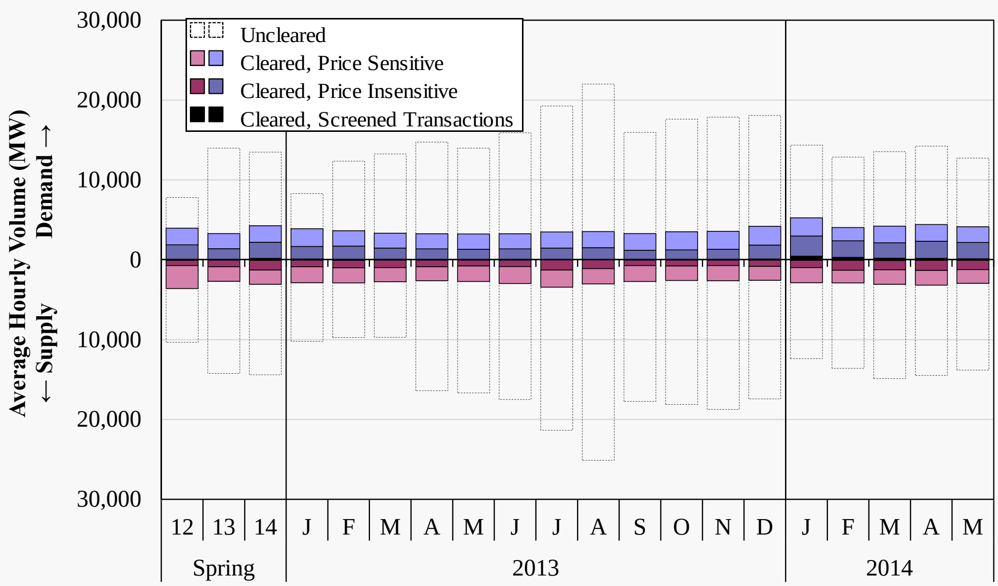
Virtual Load and Supply in the Day-Ahead Market

- The figure shows that offered transactions were mostly unchanged from last spring, despite the larger footprint, while cleared transactions rose 23 percent to 7.3 GW.
  - ✓ Demand rose by 30 percent to 4.3 GW, while supply rose 13 percent to 3.1 GW.
- Much of the increase offered volumes is due to participants' "backstop" bids submitted at prices that rarely clear (1-2 percent of the time).
  - ✓ Such bids were 35 percent of offered volumes but only 2.2 percent of cleared virtuals.
  - ✓ 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 quarter 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 38 to 48 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 from 1.8 to 3.4 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 2013–2014



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.
- Financial participants made up nearly 90 percent (6.4 GW) of all cleared volumes this quarter, up from 76 percent last spring.
  - ✓ Demand transactions by financials in particular rose 54 percent, [and is likely due to greater arbitrage opportunities from the increased price volatility].
  - ✓ Physical participant volumes averaged less than 1 GW and are 40 percent lower than in spring 2013 and nearly 60 percent lower than in spring 2012.
- Transactions cleared by financial participants were far more likely to be price-sensitive (57 percent) than those by physical participants (just 19 percent).
- Uncleared transactions by physical participants declined 95 percent from last spring because several participants stopped offering “backstop” bids and offers.

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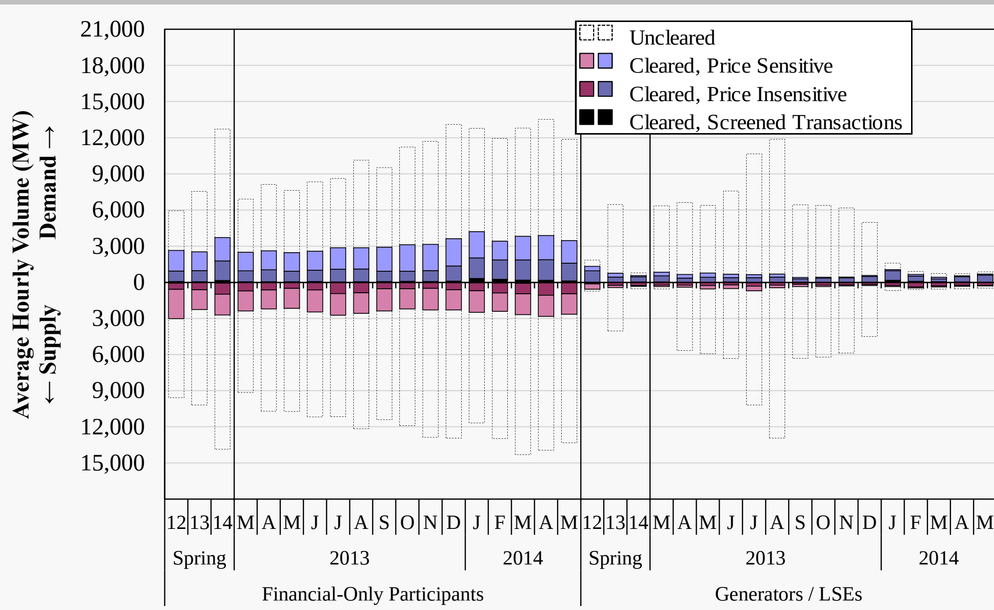
Virtual Load and Supply by Participant Type Spring 2013–2014



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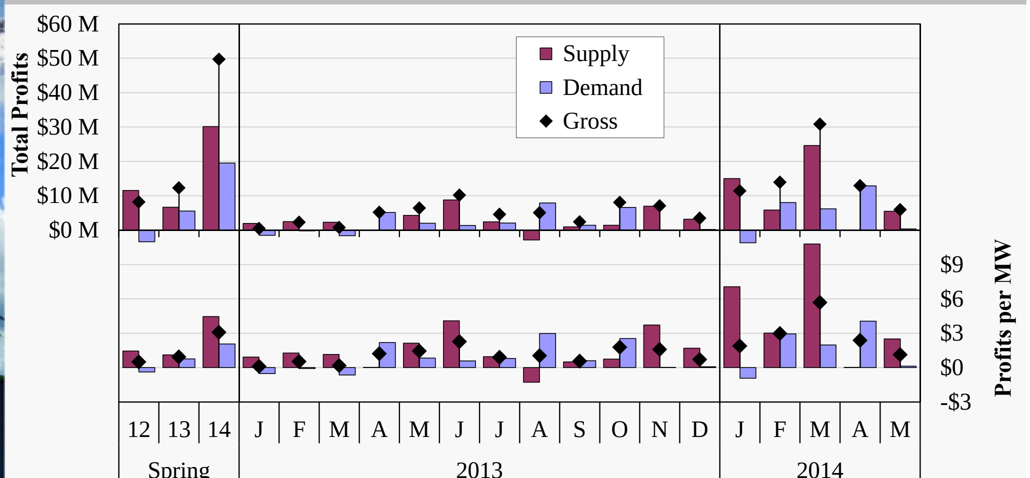
Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual supply and demand.
  - ✓ Gross virtual profits totaled nearly $50 million, up from $12.2 million last spring.
  - ✓ On a per-MW basis, profitability rose from $0.93 per MWh last spring to $3.07.
- Supply and demand were both considerably profitable at $4.46 and $2.07 per MWh.
  - ✓ The most profitable demand locations were hub locations in the South region.
  - ✓ Supply was most profitable at locations in Illinois most impacted by flows on market-to-market constraints.
  - ✓ These margins exclude CMC and DDC charges assessed to net harming deviations, including net virtual supply, which reduced its profitability by one-third.
- Supply profits were greatest in March, when price volatility and convergence issues were most significant. On March 4 alone, virtual supply earned $10.3 million, of which over $6 million was in the form of “backstop” bids that helped convergence.
  - ✓ Demand was most profitable in April and reflects the 4 percent market-wide real-time premium that month.
- Virtual transaction profitability by financial participants averaged $3.42 per MWh, while physical participant profitability averaged $0.52 per MWh.
  - ✓ This indicates that both generally improved price convergence overall.

Virtual Profitability 2013–2014



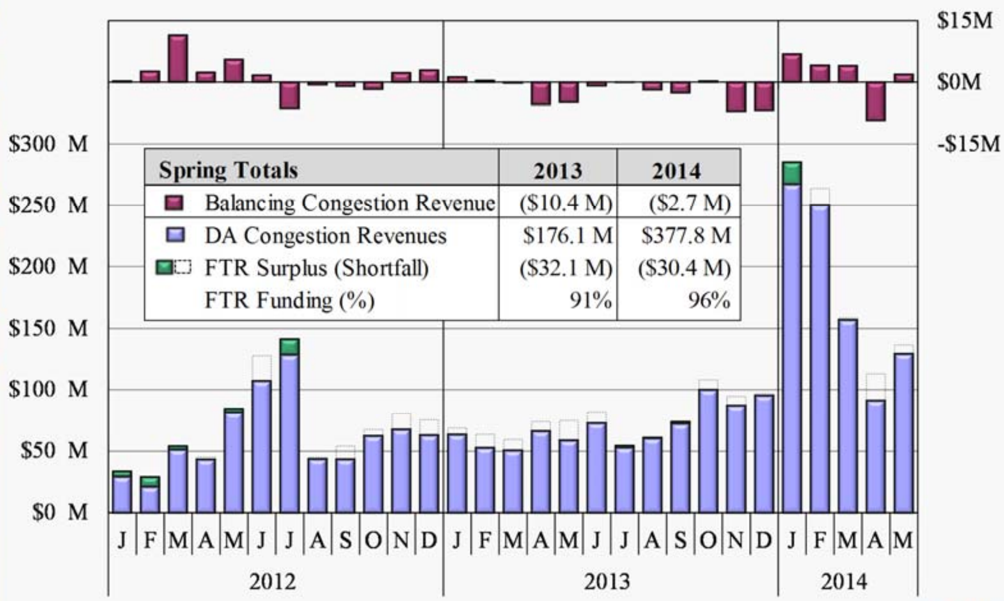
Percent Screened

Demand	1.8	2.1	4.3	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5	8.9	7.9	5.3	4.3	3.4
Supply	2.2	1.4	2.2	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3	2.1	2.7	2.7	1.9	2.0
Total	2.0	1.8	3.4	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1	6.5	5.7	4.2	3.3	2.8

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.
  - ✓ If MISO does not collect sufficient day-ahead 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.
  - ✓ Net shortfalls in occur when DA scheduled flows exceed the real-time limit on a binding transmission constraint.
- It also shows balancing congestion, which results from modeling differences between day-ahead and real-time constraints.
- Day-ahead congestion more than doubled from last spring to $378 million but was far lower than the $671 million collected in winter.
  - ✓ Although gas prices are were lower than in winter, significant congestion in the South and on inter-regional constraints continued into spring.
  - ✓ MISO collected $48 million on one constraint impacted by significant outages.
- FTR obligations were underfunded predominantly on constraints in the South. For the quarter, funding averaged 96 percent.

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

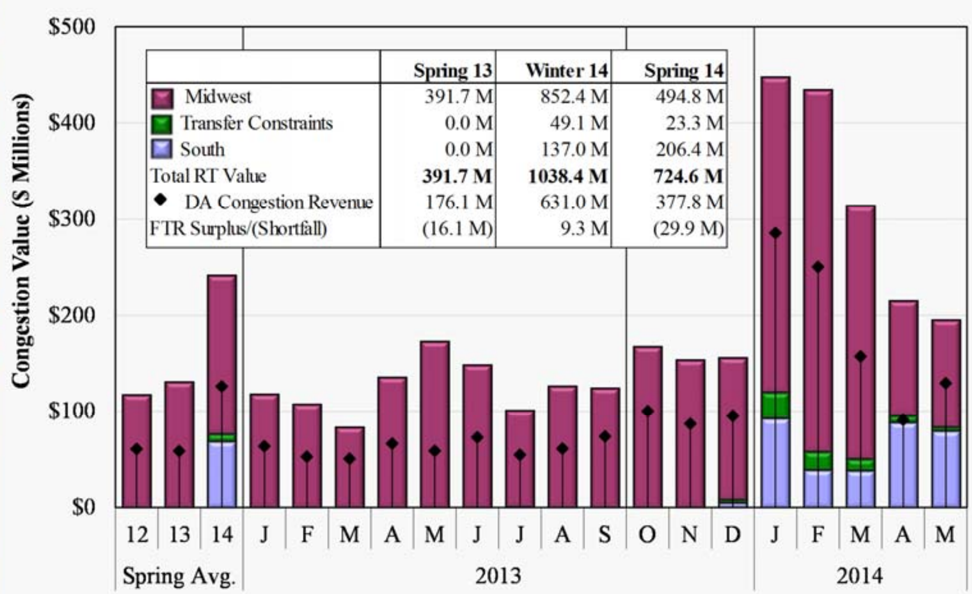


Spring Totals	2013	2014
Balancing Congestion Revenue	($10.4 M)	($2.7 M)
DA Congestion Revenues	$176.1 M	$377.8 M
FTR Surplus (Shortfall)	($32.1 M)	($30.4 M)
FTR Funding (%)	91%	96%

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. We show day-ahead congestion in the drop lines.
  - ✓ 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 rose by 85 percent from last spring to $725 million.
  - ✓ This is 30 percent less than congestion in winter, when conditions were more extreme.
- Sixty million of this accrued on the constraint in the South described earlier that was impacted by various outages.
  - ✓ Up to 700 MW of forced generator outages beginning in late April significantly reduced the available relief capability on this constraint.
  - ✓ A large portion of the high costs in the Midwest were the constraints in Michigan caused by outages that also produced significant uplift costs in March.
- Transfer constraints were valued at $23.3 million, and were three times more valuable in the Midwest-to-South direction.
  - ✓ The SRPBC continues to cause significant congestion-related inefficiencies on other constraints in MISO South when binding from North to South.

Value of Real-Time Congestion 2013–2014



	Spring 13	Winter 14	Spring 14
Midwest	391.7 M	852.4 M	494.8 M
Transfer Constraints	0.0 M	49.1 M	23.3 M
South	0.0 M	137.0 M	206.4 M
Total RT Value	**391.7 M**	**1038.4 M**	**724.6 M**
◆ DA Congestion Revenue	176.1 M	631.0 M	377.8 M
FTR Surplus/(Shortfall)	(16.1 M)	9.3 M	(29.9 M)

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 rose 5 percent from last spring to 459 MW.
- Sixty percent of dispatches were of resources committed day-ahead, which more than doubled from last spring to 272 MW.
  - ✓ Quantities were greatest in May (486 MW) and were by far highest on the afternoon of May 27, when nearly 7 GW per hour was committed during afternoon hours.
- Real-time capacity dispatches averaged 126 MW, a 56 percent decline from last spring.
- Peaking units dispatched for real-time congestion and for local voltage both rose considerably from last spring, but collectively were just 13 percent of the total.
  - ✓ Congestion dispatches averaged 50 MW, while voltage quantities averaged 11 MW.
  - ✓ The rise is entirely due to congestion on the constraint in the South discussed earlier.
- The share of peaking unit dispatch that was in-merit rose from 39 to 45 percent.
  - ✓ MISO's ELMP Initiative will allow peaking resources to set prices more frequently.

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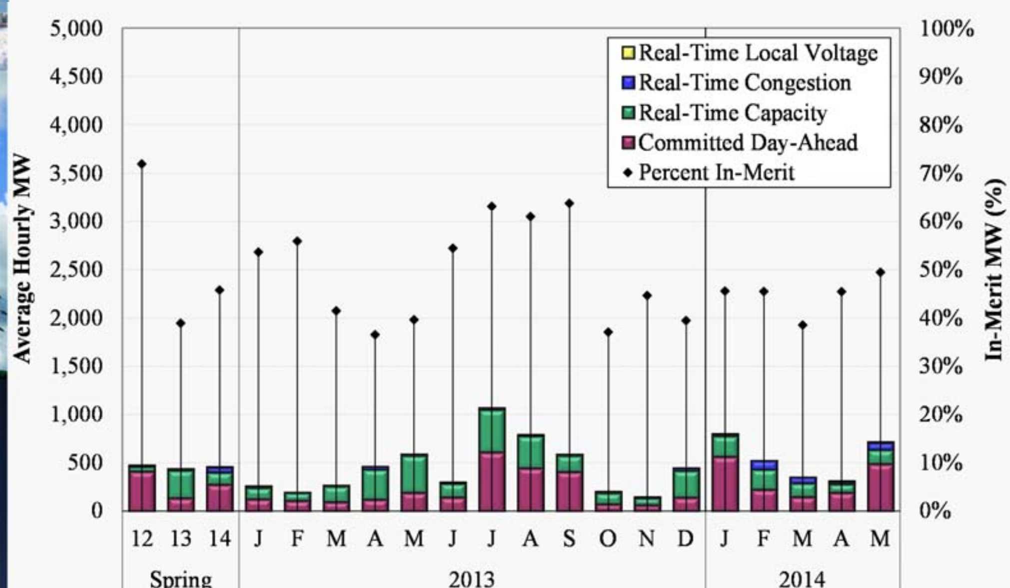
Peaking Resource Dispatch 2013–2014



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Real-Time and Day-Ahead RSG Payments

- The next 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 more than doubled from last spring to $50.2 million.
  - ✓ A large majority of this rise is due to cold weather and high fuel prices in early March.
  - ✓ Adjusting for fuel prices, RSG costs rose less than 15 percent.
- In fuel-adjusted terms, payments for capacity declined 13 percent to $18 million.
  - ✓ The decline is due to milder and less severe weather after March.
- Payments for congestion nearly doubled to a fuel-adjusted $10.6 million, the majority of which was paid to units in Michigan needed for outage-driven congestion in March.
- The second figure shows that day-ahead RSG payments have risen substantially post-integration, since VLR commitments in the South are most-often made day-ahead.
  - ✓ Payments totaled $31.1 million, of which nearly two-thirds was to units in the South.
  - ✓ Much of the day-ahead RSG categorized for capacity is actually incurred due to VLR needs. We have recommended MISO develop methods to improve the categorize these commitments as VLR for allocation and mitigation purposes.

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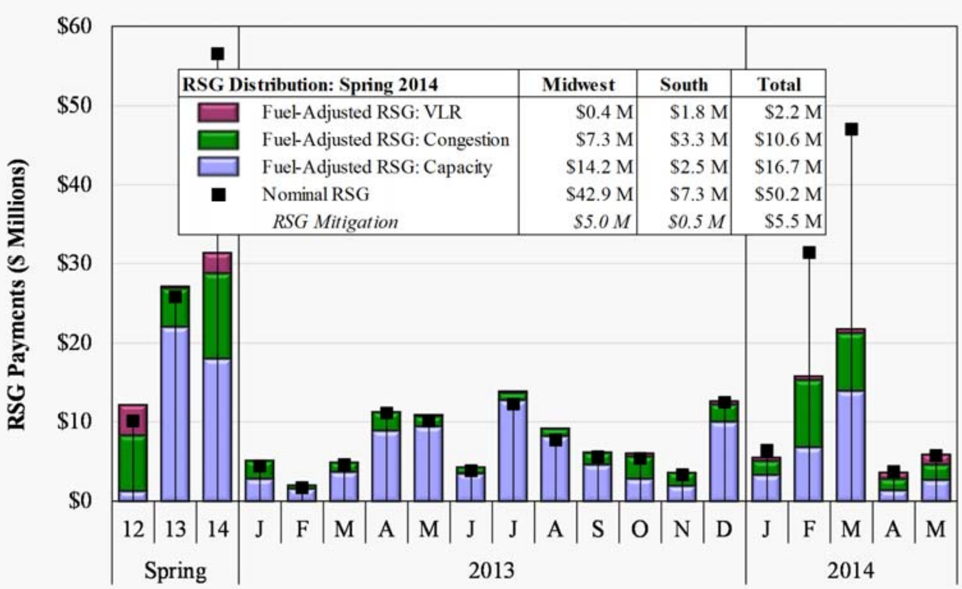
Real-Time RSG Payments 2013–2014



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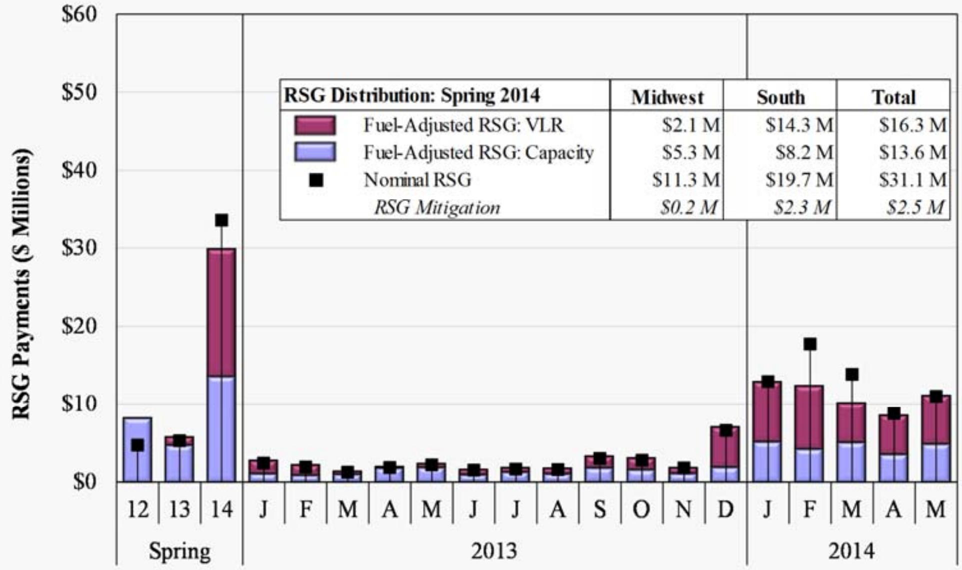
Day-Ahead RSG Payments 2013–2014



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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.
  - ✓ Payments were far larger in the first week of the quarter, when late winter weather, gas supply issues and congestion in Michigan required significant real-time commitments.
- The figure shows that more than 70 percent of the RSG payments this spring were associated with unit offers in excess of their reference values.
  - ✓ Most of this additional cost was associated with startup and minimum generation costs that exceed reference values, particularly in the Midwest Region.
  - ✓ An additional $16 million of RSG costs was due to increased incremental energy offers above reference or to other conduct such as lengthened minimum run times.
- The chart shows that approximately $9 million of the RSG—14 percent of the excess— will be mitigated under the current conduct and impact framework.
  - ✓ These results indicate the need for tighter conduct and impact thresholds for congestion-related RSG payments.
- We proposed improved RSG mitigation criteria in our *State of the Market Report*.
  - ✓ Our initial proposal would have mitigated an additional $5.7 million of the unmitigated RSG this quarter, including $3.2 million the constraints in Michigan.

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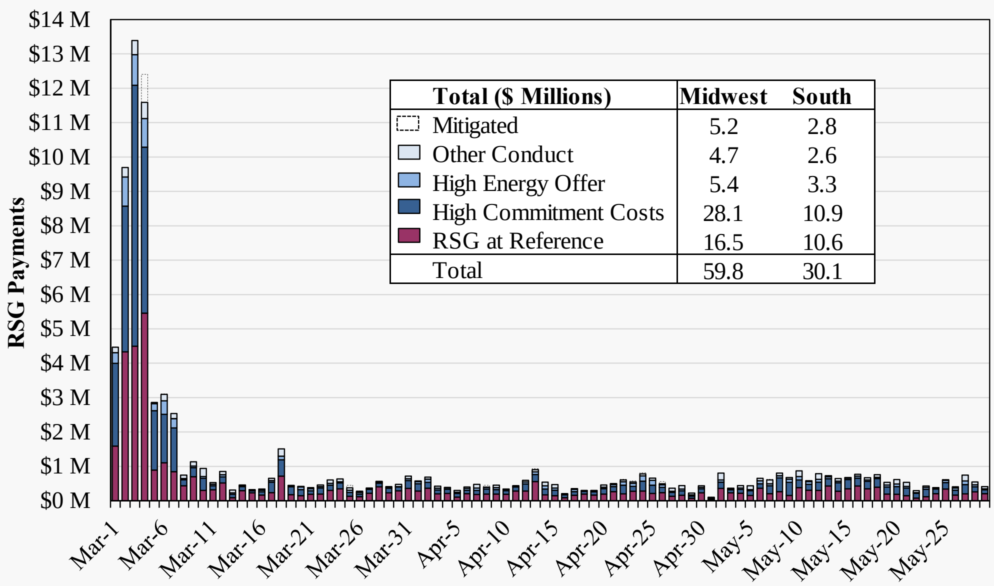
Daily DA and RT RSG Payments by Conduct
Spring 2014



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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 this quarter totaled over $28 million. Payments in the Midwest Region rose 25 percent from last spring and made up slightly more than half of DAMAP.
  - ✓ Payments accrued disproportionately to large gas-fired steam turbines in the South Region.
  - ✓ In the Midwest Region, flexible coal units received the most payments.
- RTORSGP payments rose 12 percent to $3.45 million, but declined 8 percent adjusted for South Region membership.
- 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 and LMP volatility were slightly lower in dollar terms than last spring.
  - ✓ Far fewer shortage intervals this spring offset the rise in volatility associated with higher gas prices.

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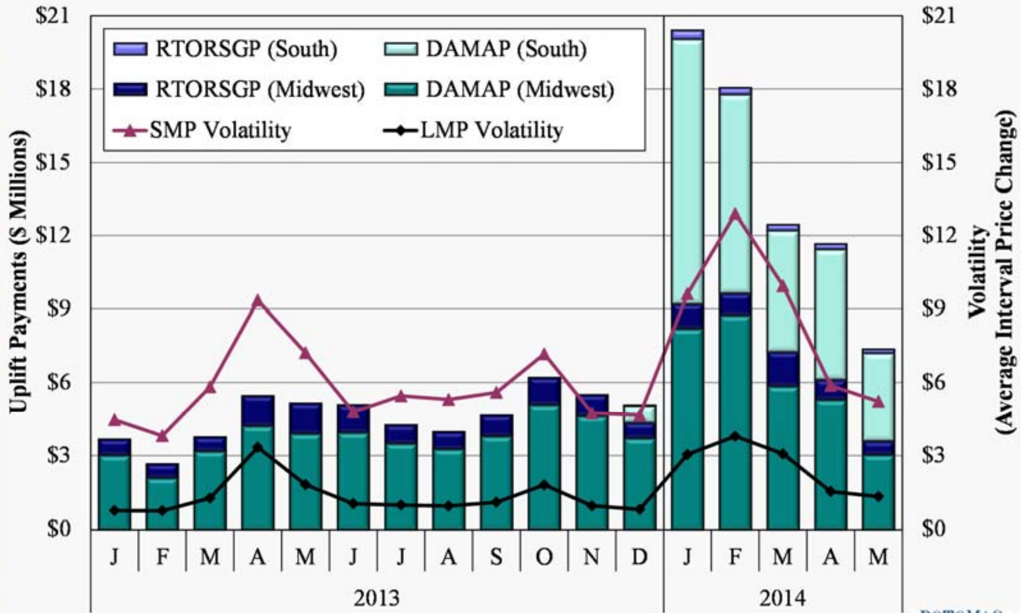
Price Volatility Make Whole Payments 2013–2014



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Wind Output 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 DIR, and have almost entirely replaced manual curtailments as the preferred means to manage wind output (see second slide).
- Real-time wind output rose 11 percent from last spring to average nearly 5.0 GW.
  - ✓ But for DIR curtailments, which rose to over 300 MW per interval this spring, wind output would have risen 14 percent.
  - ✓ The increase in output has led to more severe congestion on some lower-voltage constraints in the West.
- Under-scheduling of wind in the day-ahead market rose modestly from last spring and averaged over 400 MW, or nearly 10 percent of real-time output.
  - ✓ This produces an incentive for participants to make up the difference with net virtual supply, which was considerably profitable this quarter at $3.65 per MWh.
  - ✓ Net virtual supply only totaled 50 MW, however.
  - ✓ MISO must still manage the ramp demands related to wind volatility, which rose from 48 MW per interval last spring to 55 MW (based on units' forecasted maximums).

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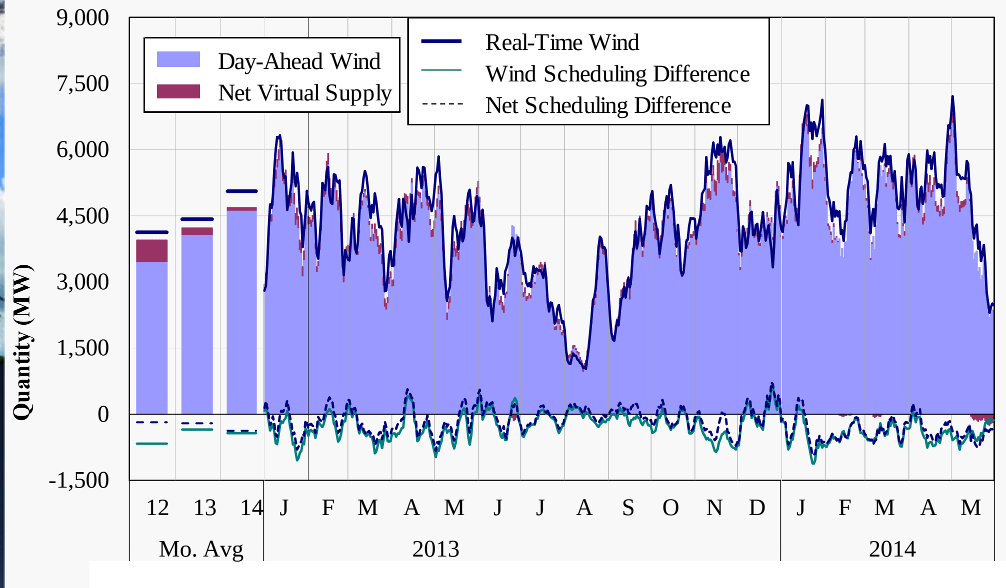
Wind Output in Real-Time and Day-Ahead Markets 7-Day Moving Average, 2013–2014



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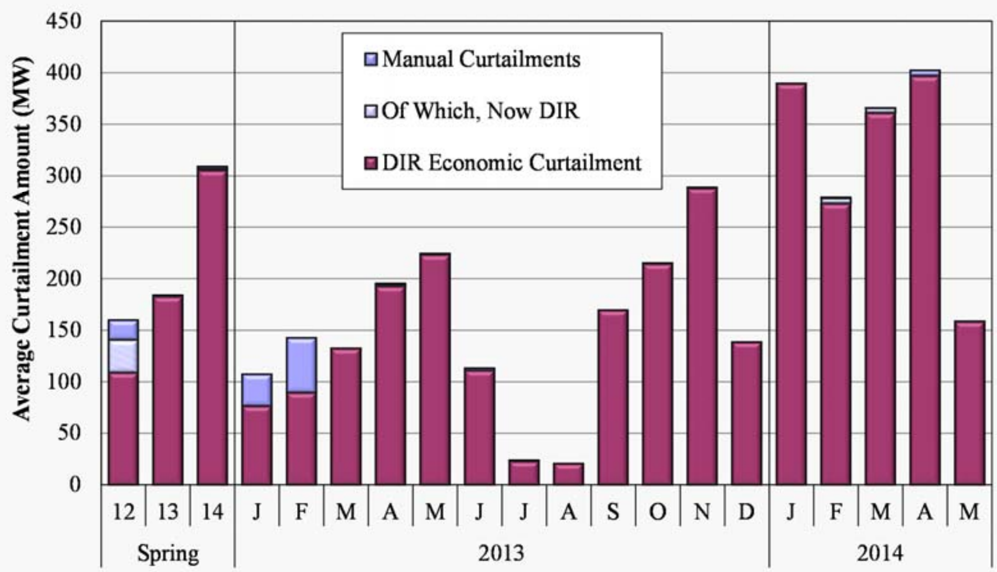
Manual and Economic Wind Curtailments 2013–2014



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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).
- Outages this spring were higher than last spring in all three categories, but were cumulatively lower (at 17.9 percent) than the outage rate in spring 2012.
  - ✓ Outages in March in particular averaged nearly 50 percent higher than last March, and likely reflect increased supply issues from this winter.
- Long-term forced rose from 3.3 to 4.4 percent, while short-term forced outages, which can indicate potential physical withholding, rose slightly to 2.0 percent.
  - ✓ Planned outages rose from 10.1 to 12.2 percent.
- We continue to investigate those outages that contributed to shortages or severe congestion.
  - ✓ Forced and planned outages have caused severe congestion into the Western and WOTAB load pockets (see slide 29).
  - ✓ We are reviewing the factors contributing to this congestion.

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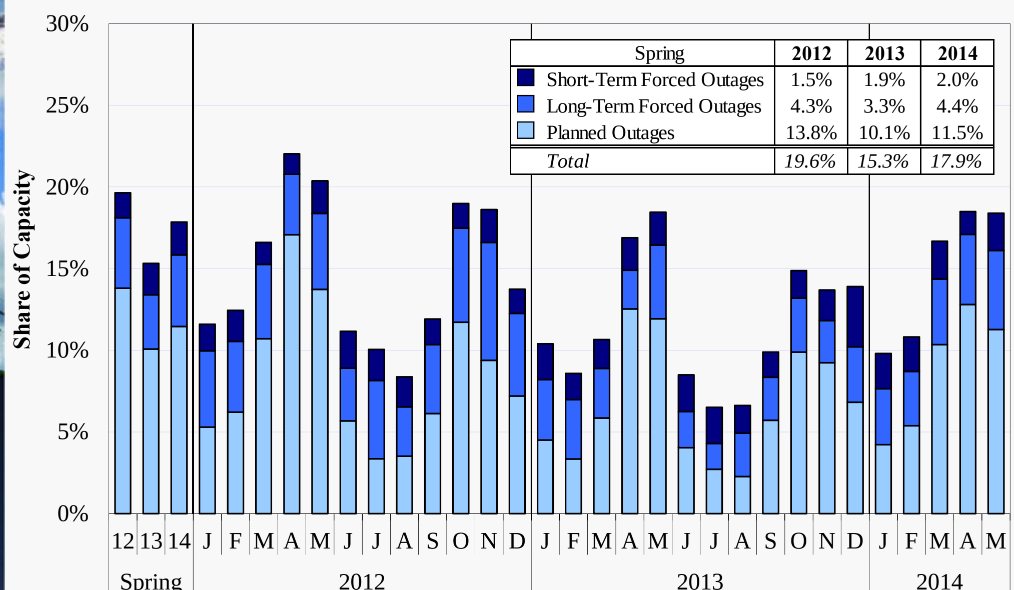
Generation Outage Rates 2012–2014



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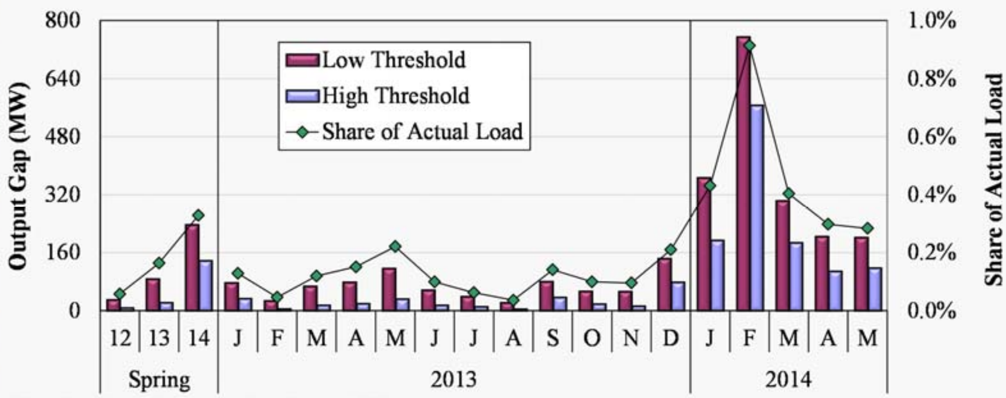
Monthly Output Gap

- 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 substantially this spring and averaged nearly 0.4 percent of actual load. Although still low, this is up from 0.16 percent last spring.
  - ✓ At the high threshold, average output gap rose from 23 to 160 MW, while at the low threshold, it rose from 87 to 259 MW.
- Much of the increase was due to fuel price uncertainties associated with volatile daily and intra-day gas prices in March. 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.
- We continue to routinely investigate hourly increases in output gap, and have found very limited instances of competitive concern.

Monthly Output Gap 2013–2014



High Threshold Results by Unit Status (MW)

	Spring 12	Spring 13	Spring 14	J 2013	F	M	A	M	J	J	A	S	O	N	D	J 2014	F	M	A	M
Offline	4	5	95	7	1	4	0	10	1	6	0	23	7	2	59	106	451	130	83	71
Online	4	18	43	27	4	11	20	22	15	5	5	14	11	11	20	89	116	57	26	46

Low Threshold Results by Unit Status (MW)

	Spring 12	Spring 13	Spring 14	J 2013	F	M	A	M	J	J	A	S	O	N	D	J 2014	F	M	A	M
Offline	4	6	112	8	2	6	0	12	2	9	0	26	11	4	70	140	519	154	99	82
Online	27	81	125	69	25	62	79	104	56	30	22	55	42	50	74	228	236	150	105	120

Mitigation in the Real-Time Energy Market

- The next two figures show the frequency with which energy and RSG mitigation was imposed in the day-ahead and real-time markets in recent months.
  - ✓ The first figure separates energy mitigation by broad and narrow constrained area.
- Energy mitigation was imposed for 501 unit-hours and 702 MW this spring, mostly day-ahead.
  - ✓ It was far higher in March because of the high and fluctuating fuel prices.
  - ✓ This resulted in an increased number of resources to offer 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 utilize fixed dollar thresholds that are not adjusted for fuel prices.
- RSG mitigation totaled nearly $9 million, most of which occurred in the real-time market in early March for the reasons described above.
  - ✓ While far higher than the $250,000 mitigated last spring, this amount significantly lower than the nearly $10 million mitigated this winter.
  - ✓ Thirty percent of this was mitigated under the VLR framework, nearly all of which was for South units in the day-ahead market.
- Some participants are disputing certain instances of RSG mitigation.

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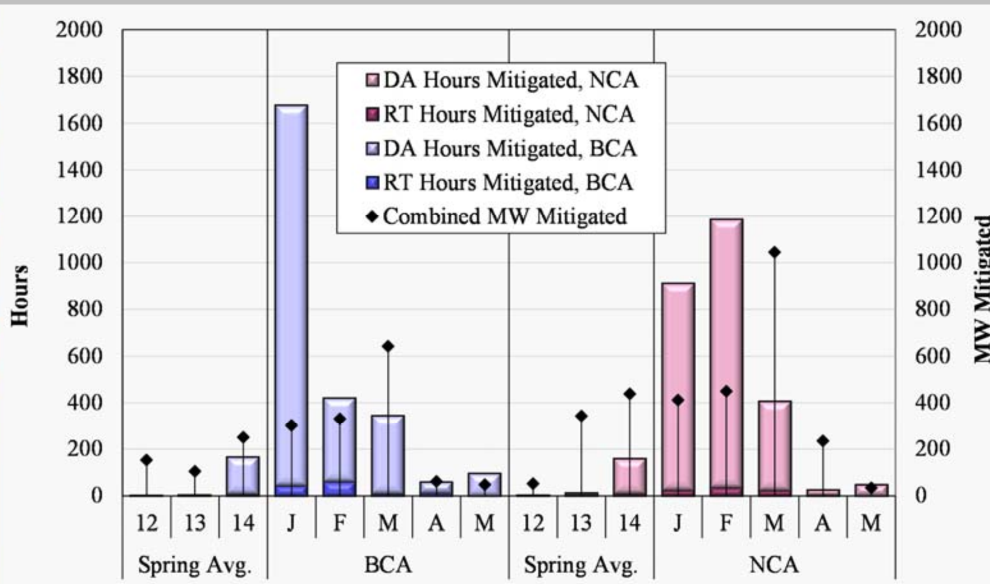
Day-Ahead and Real-Time Energy Mitigation By Constrained Area, 2014



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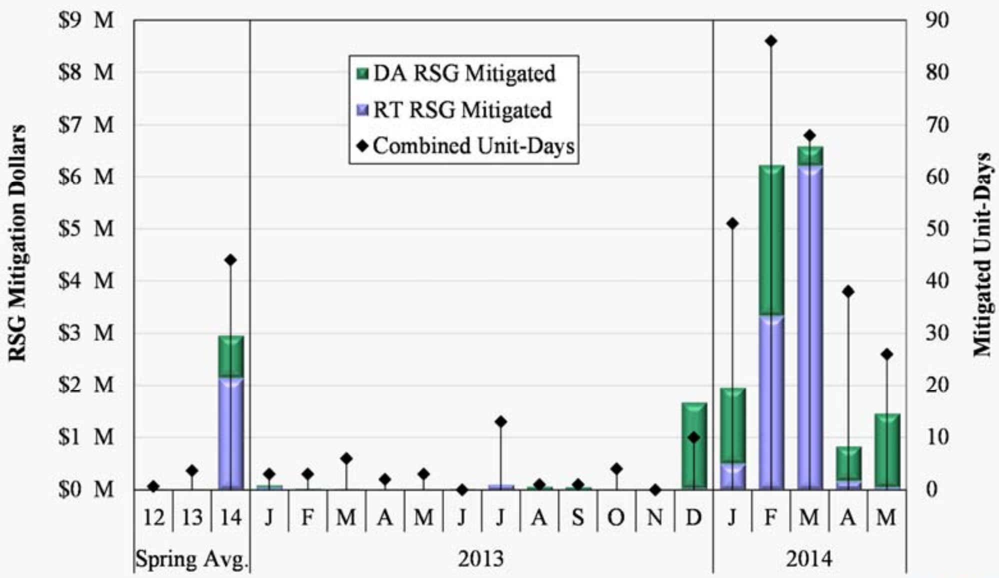
Day-Ahead and Real-Time RSG Mitigation 2013–2014



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Submittals to External Entities

- We responded to additional FERC data requests related to prior referrals of resources failing to update real-time offers and data related to conduct.
- We discussed our comments with the MSC on the SRPBC implemented by MISO in response to FERC's March 28 Order on SPP's complaint.
  - ✓ We are still concerned that MISO's decision to limit flows to 1,000 MW increases the inefficiencies and raises the costs borne by its customers.
  - ✓ Since its implementation, we believe MISO's approach has raised prices in MISO South by approximately five percent.
  - ✓ MISO is discussing with it customers our recommendation to utilize a transmission demand curve set at a price that would cover the potential liability to SPP, which would allow greater economic utilization of transfers between the Midwest and South regions.

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Other Issues

- 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 we will be working with MISO to re-file one important change.
- Coal-conservation measures continue and inventories are low at a number of coal-fired resources due to rail transportation issues. However, we do not expect significant impacts at this time.
- We are working with MISO on responses to mitigation disputes that are related to reference values
  - ✓ As noted previously, there were an unprecedented number amount of mitigation and disputes during the volatile winter period.
- We continue to work with MISO and PJM on the interface pricing flaw and improvements.
  - ✓ This is critical because the RTO's interface pricing provides the economic incentives that govern imports and exports between MISO and its neighbors.
  - ✓ We are working with stakeholders and the JCM working group on alternative solutions.
  - ✓ A separate group including the RTO's customers and FERC staff has now been formed to discuss this flaw and related interface pricing issues.

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
SRPBC	Sub-Regional Power Balance Constraint
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