IMM Quarterly Report: Summer 2014
June – August

MISO Independent Market Monitor

David B. Patton, Ph.D.
Potomac Economics

September 29, 2014

POTOMAC ECONOMICS

Quarterly Summary

		Value	*Change*[1] Prior Qtr.	Prior Year
RT Energy Prices ($/MWh)	🟢	$34.75	*-18%*	*5%*
Fuel Prices ($/MMBtu)				
Natural Gas - Chicago	🟢	$4.22	*-32%*	*14%*
Natural Gas - Henry Hub	🟢	$4.16	*-11%*	*15%*
Western Coal	🟢	$0.70	*-6%*	*15%*
Eastern Coal	🟢	$1.91	*-1%*	*2%*
Load (MW)[2]				
Average Load	🟢	82.7	*15%*	*-1%*
Peak Load	🔵	115.6	*21%*	*-6%*
% Scheduled DA (Peak Hour)	🟢	100.4%	99.7%	98.5%
Transmission Congestion ($M)				
Real-Time Congestion Value	🟢	$331.7	*-54%*	*-12%*
Day-Ahead Congestion Revenue	🟢	$210.7	*-49%*	*13%*
Balancing Congestion[4]	🟢	-$5.3	-$3.4	-$2.8
Ancillary Service Prices ($/MWh)				
Regulation	🟢	$9.01	*-33%*	*-6%*
Spinning Reserves	🟢	$1.31	*-49%*	*-59%*
Supplemental Reserves	🟢	$0.50	*-67%*	*-79%*

		Value	*Change*[1] Prior Qtr.	Prior Year
FTR Funding (%)	🟢	98%	96%	99%
Wind Output (MW)	🟢	2,750	*-45%*	*4%*
Guarantee Payments ($M)[5]				
Real-Time RSG	🟢	$10.7	*-81%*	*-55%*
Day-Ahead RSG	🔵	$34.6	*14%*	*636%*
Day-Ahead Marginal Assurance	🟢	$13.9	*-52%*	*30%*
RT Operating Rev. Sufficiency	🟢	$4.9	*32%*	*86%*
System Support Resource (SSR)	🔴	$15.1	$7.5	$2.4
Price Convergence[3]				
Market-wide DA Premium	🟢	3.4%	-0.4%	-2.6%
Virtual Trading				
Cleared Quantity (MW)	🟢	7,012	*-4%*	*6%*
% Price Insensitive	🟢	44%	48%	39%
% Screened for Review	🟢	2%	3%	1%
Profitability ($/MW)	🟢	$0.20	$3.07	$1.36
Dispatch of Peaking Units (MW/hr)	🟢	548	439	719
Output Gap- Low Thresh. (MW/hr)	🟢	130	237	39
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.

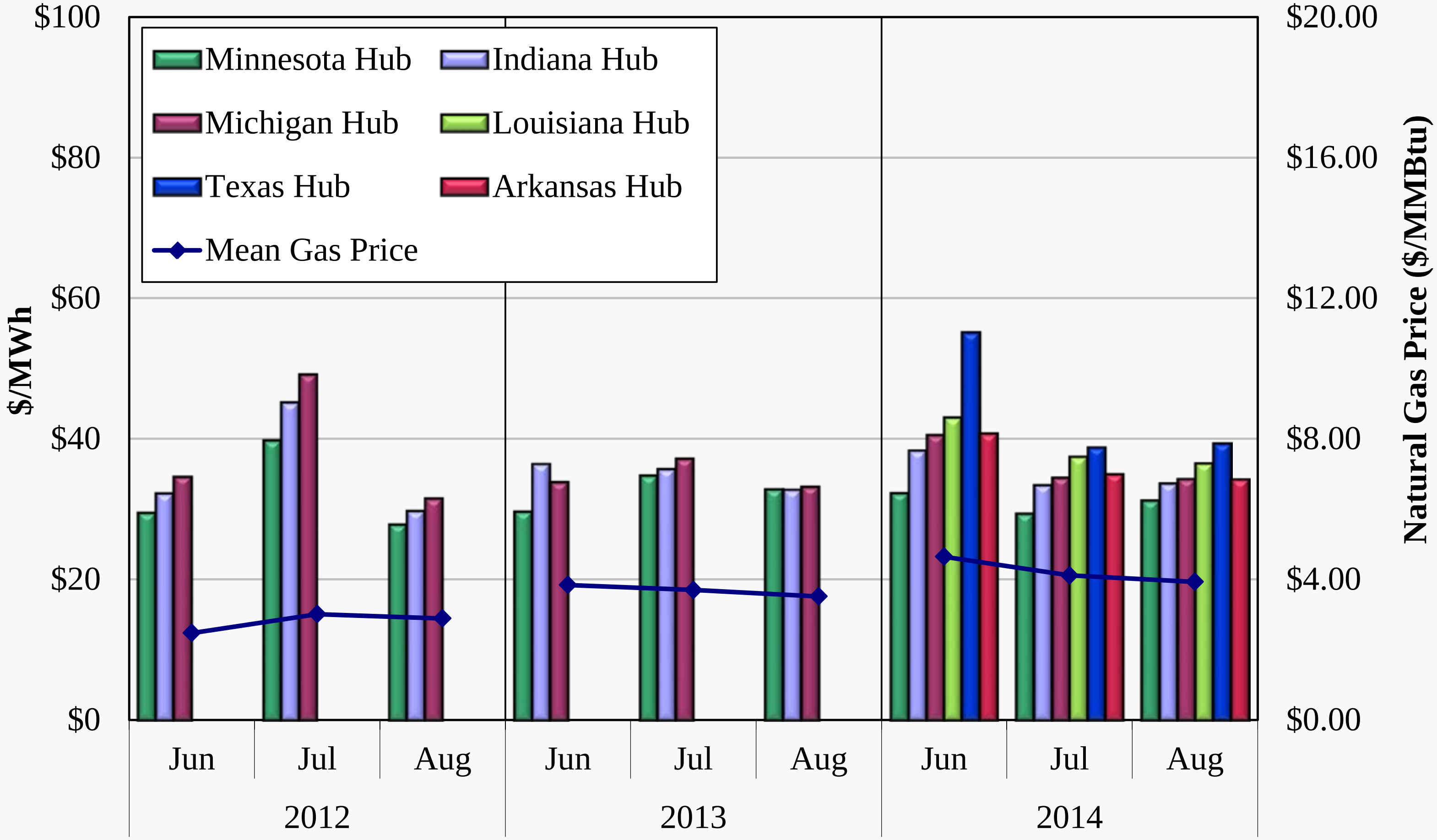
Summary of Summer 2014

- Real-time energy prices this summer averaged $34.75 per MWh. This is 5 percent higher than last summer, despite far milder conditions.
  - ✓ Natural gas prices rose 15 percent from last summer;
  - ✓ Average load declined 1 percent (adjusted for the South Region) and the peak load in the Midwest Region was 6 GW lower than last summer.
- An absence of significant of heat waves and combined with relatively low outage rates resulted in ample available capacity to meet the demands of the system this summer.
  - ✓ Most market metrics, including congestion, ancillary services clearing prices and real-time RSG payments, declined significantly from the spring and from last summer.
    - – There were almost no instances of shortages for any ancillary services product.
- DAMAP payments and day-ahead RSG payments both rose considerably since last summer, most of which is attributable to reliability requirements in the South Region.
  - ✓ DAMAP was lower than in early in 2014 because of improved generator performance.
  - ✓ Additionally, some of the apparent dragging at certain locations in MISO South that contributed to DAMAP in 2014 was due to a modeling issue that is being fixed.

Day-Ahead Average Monthly Hub Prices

- The first figure shows monthly average day-ahead energy prices at six locations in the MISO footprint for each month in the summer 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 8 percent from last summer to $35.99 per MWh.
  - ✓ This is mostly due to 14 and 15 percent rises in natural gas and western coal prices, respectively, which were partly offset by reduced demand and good generator availability.
- Price differences among areas in MISO reflect transmission congestion and losses.
  - ✓ Day-ahead congestion was most notable into Texas early in summer, and was the result of continued severe real-time outage-related congestion at the end of May.
    - – Even absent this specific congestion, Texas Hub prices were still the highest in MISO in each month, averaging over $44 per MWh for the summer.
    - – Prices at Minnesota remained the lowest at $31 per MWh.
  - ✓ Price differences between the Midwest Region, which averaged $34.20 per MWh, and the South Region, where prices averaged $40.23, are due to transfer constraints including the SRPBC.

Day-Ahead Average Monthly Hub Prices Summer 2012–2014



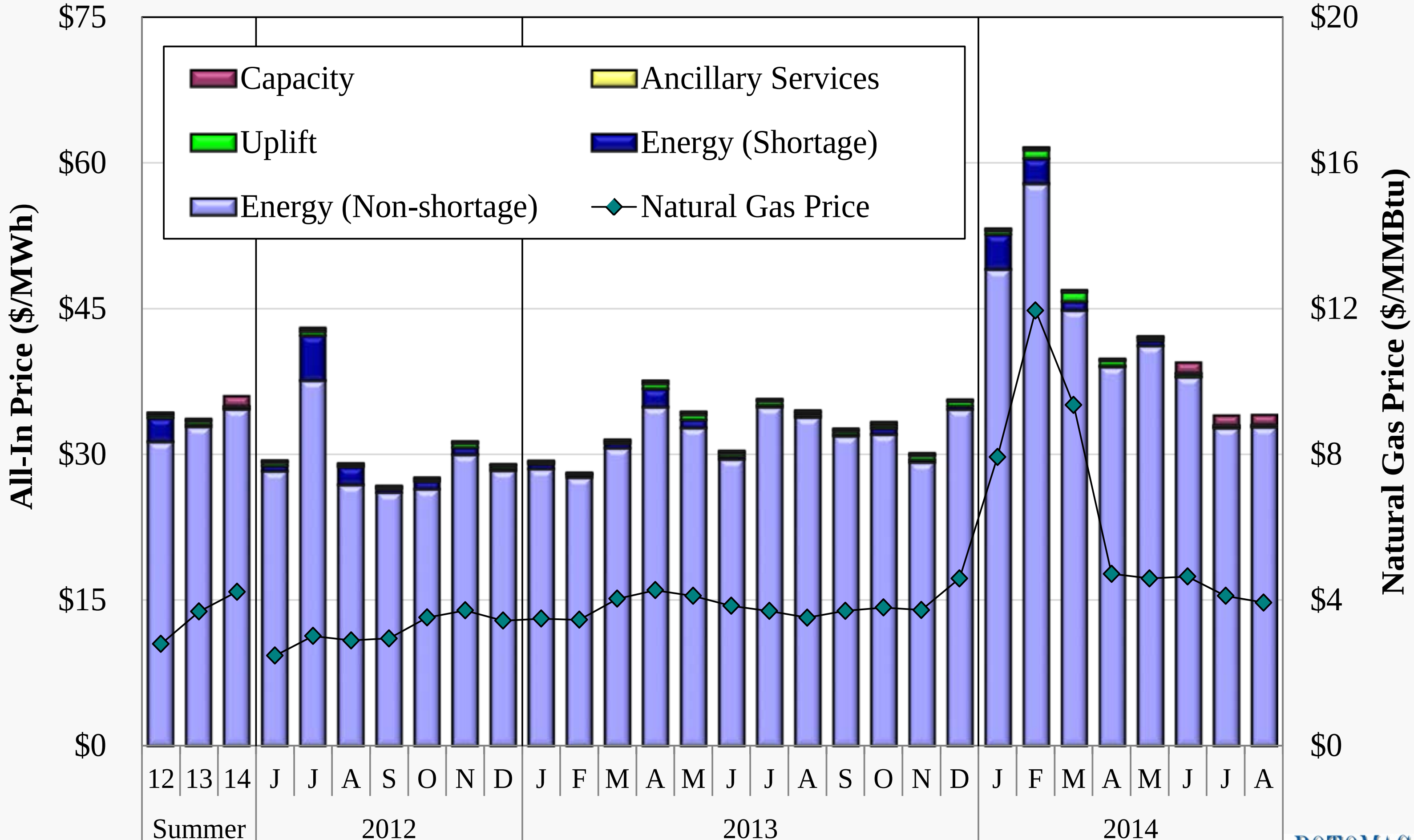
POTOMAC ECONOMICS

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 8 percent from last summer to an average of $36.29 per MWh.
- The energy component continues to make up over 96 percent of the all-in price.
  - ✓ Energy prices rose from last summer because of the increase in natural gas prices.
  - ✓ An absence of peak conditions this summer resulted in notable decline (from 26 cents to 4 cents) in the share of the energy component associated with shortages.
- Ancillary service prices added just 7 cents, while uplift costs added 22 cents. Both are down substantially from last summer.
- Capacity costs from the 2014-2015 Planning Resource Auction, which cleared at $16.75 per MW-day, accounted for $1 (3 percent) of the all-in price.
  - ✓ Capacity market revenues will likely become a more significant component of the all-in price as MISO's capacity surplus declines in the future.
- The all-in price does not include SSR payments that have doubled to $10 million per month due to a recent FERC decision to allow for the inclusion of fixed costs.

POTOMAC ECONOMICS

All-In Price
2012 –2014

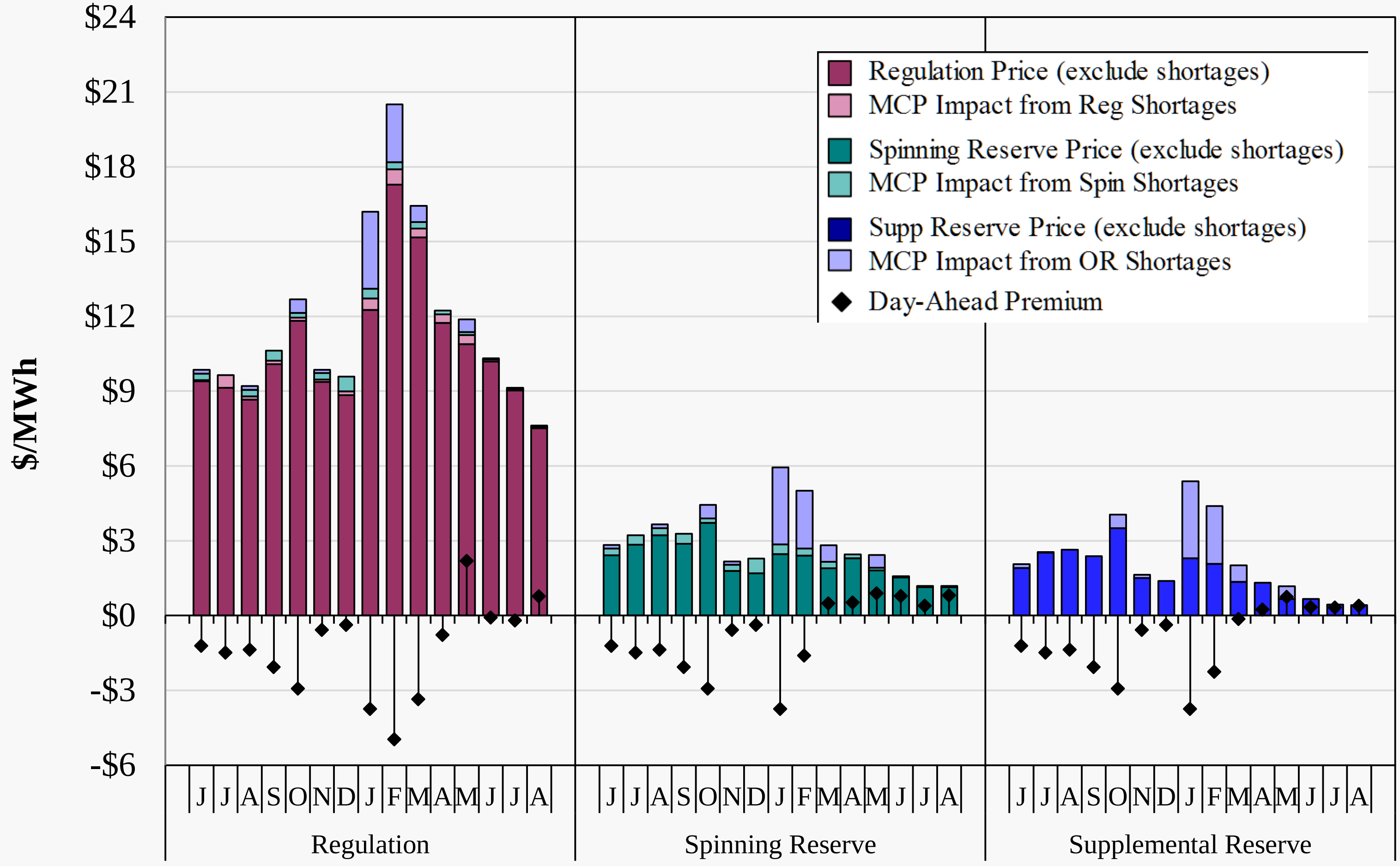


Ancillary Services Prices

- The following chart shows monthly average real-time marginal clearing prices for MISO's ancillary service products for the prior 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.
- A near absence of shortages for all products resulted in significant declines in all ASM prices from the spring and from last summer.
  - ✓ Regulation clearing prices averaged $9.01 per MWh this summer, down 6 percent from last summer and more than one-third less than in spring.
    - Most of this decline is due to MISO recording only 7 periods of regulation shortage.
    - Shortage pricing for all products added just 11 cents to the average regulation price.
  - ✓ Spinning reserve prices declined by nearly 60 percent from last summer to an average of $1.31 per MWh, while supplemental prices averaged just $0.50.
    - Spinning reserve shortages declined from 81 to 12, and there were no Operating Reserve shortages.

POTOMAC ECONOMICS

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



POTOMAC ECONOMICS

MISO Fuel Prices

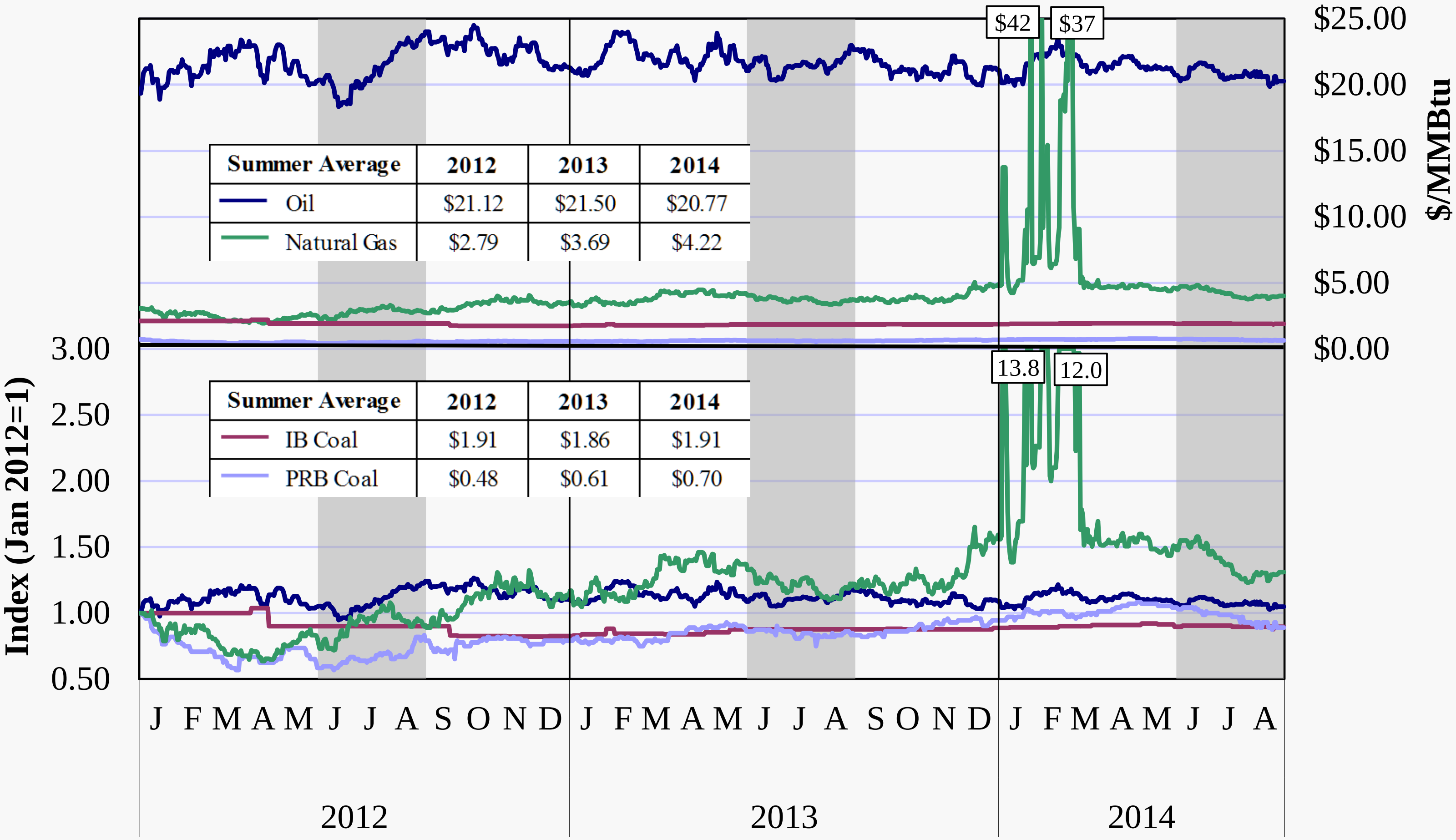
Natural Gas and Oil Prices

- Natural gas prices rose 14 percent from last summer to $4.22 per MMBtu.
  - ✓ Prices averaged 30 percent less than in the spring, when winter demand and various supply issues caused high and volatile natural gas prices that extended into March.
  - ✓ Prices declined gradually over the quarter and have remained below $4 since mid-July.
- Natural gas prices between the Midwest and South did not diverge significantly this summer. Such divergence can create congestion between these areas.
- Oil prices declined to $20.77 per MMBtu, a 3.4 percent decline from both the spring and from last summer.

Coal Prices

- Illinois Basin prices were mostly unchanged at $1.91 per MMBtu. This is 5 cents greater than last summer but 2 cents lower than the average in spring.
- Powder River Basin coal prices declined 6 percent from spring to average $0.70 per MWh, but remain 9 cents higher than last summer.
  - ✓ Supply issues due to rail congestion from the Powder River Basin continue, but so far these have had a very limited market impact.

MISO Fuel Prices
2012–2014



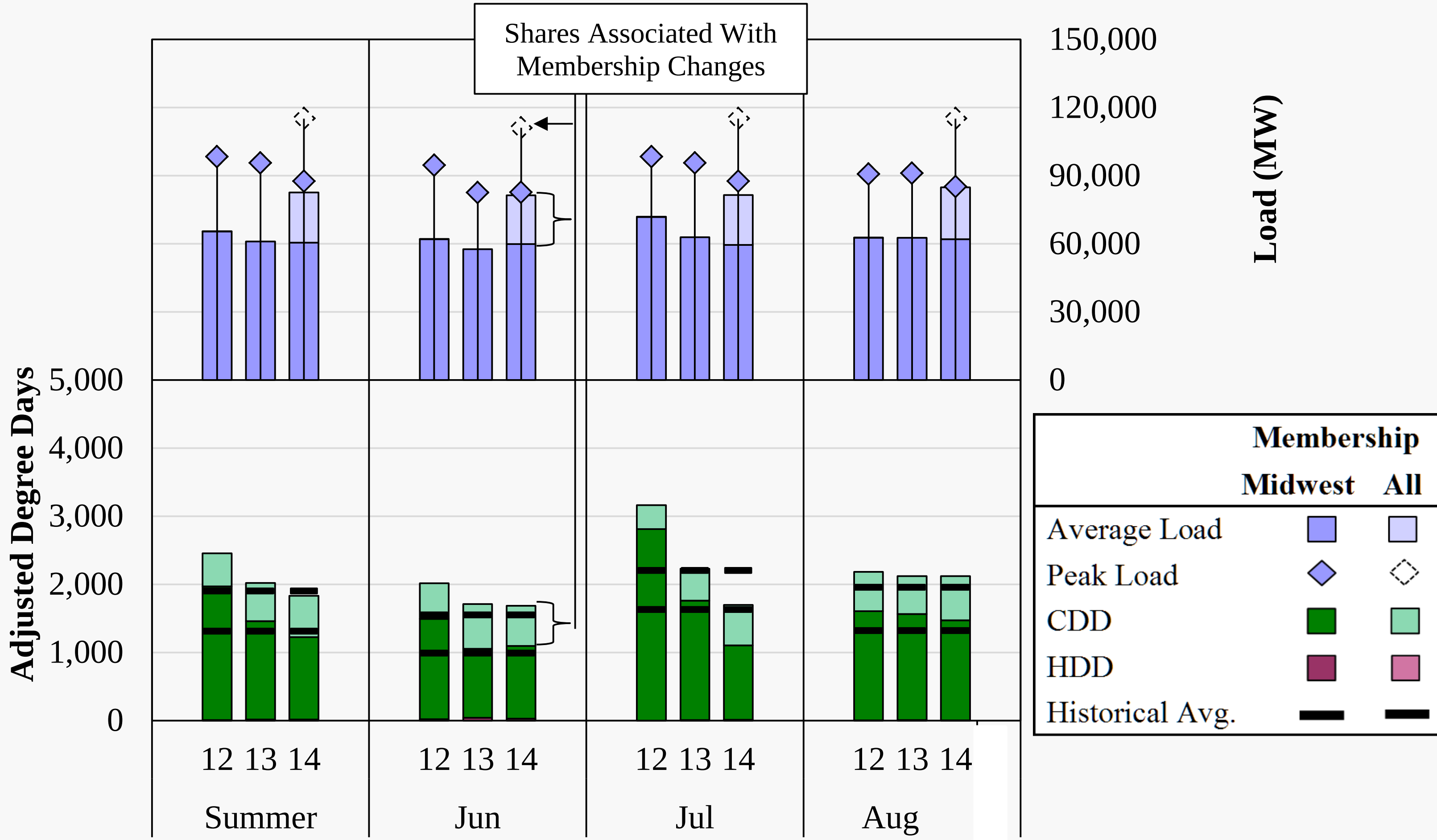
POTOMAC ECONOMICS

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 summer 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).
  - ✓ We show the South Region's contribution to load separately and include two South cities in the degree-day metric.
- The figure shows that degree days in MISO this summer declined 9 percent from last summer, and were 4 percent below the historical average.
  - ✓ Most of the decline this year was attributable to abnormally cool weather in July.
  - ✓ In the Midwest Region, degree days declined 16 percent from last year and 38 percent from summer 2012, both of which resulted in substantially higher loads.
- As a result, average load declined 1.1 percent in the Midwest Region.
  - ✓ Due to a lack of extreme conditions this summer, peak load declined by more than 6 percent, adjusted for membership additions.

POTOMAC ECONOMICS

Load and Weather Patterns Summer 2012–2014



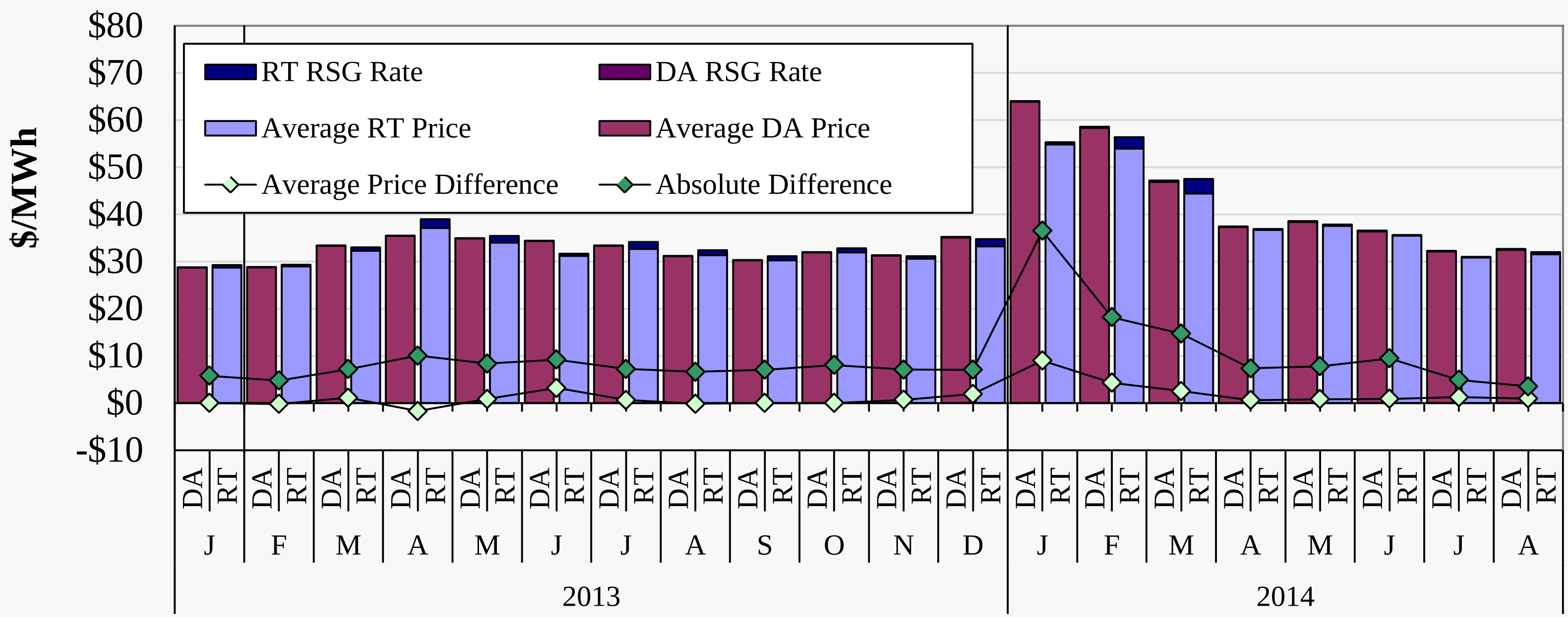
Note: Midwest degree day calculations include four representative cities in Midwest: Cincinnati, Detroit, Milwaukee and Minneapolis. The MISO region includes Little Rock and New Orleans in the six-city average.

POTOMAC ECONOMICS

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.
- Convergence was improved this summer, particularly after June. There was a 3 percent day-ahead premium MISO-wide.
  - ✓ Much of the volatile day-ahead congestion in the South Region (notably at Texas Hub) in early June was a response to severe real-time congestion in late May.
  - ✓ Outage-related real-time congestion in June into Michigan also occurred in the day-ahead market with a lag.
- Part of the improvement is due to relatively low price volatility, particularly in July and August. There were very few price spikes because of a near absence of AS shortages.
- Real-time RSG costs under the DDC rate averaged only $0.25 per MWh this summer.
  - ✓ This decline is in part due to MISO's revisions of the allocation in March to be more consistent with cost causation.
  - ✓ The share of non-VLR RSG borne by deviations this summer was 72 percent, down from 95 percent last summer.

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



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

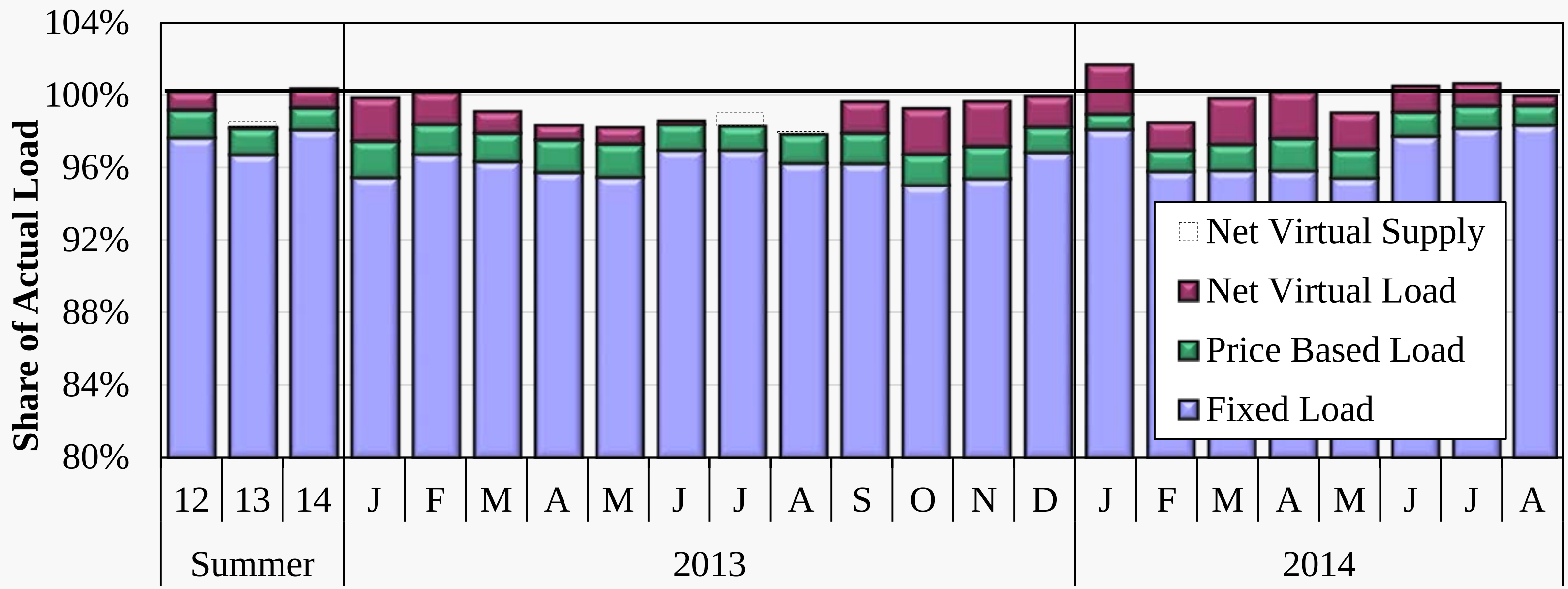
Indiana Hub	-2	-2	1	-9	-1	9	-2	-4	-3	-2	0	1	16	4	-1	2	2	3	4	2
Michigan Hub	-1	1	3	-10	-3	5	-5	-3	-4	-2	3	3	25	7	26	-1	2	-5	4	3
Minnesota Hub	1	3	1	-11	2	0	-6	-8	-4	-6	-10	-6	16	-9	-5	-3	3	4	1	3
WUMS Area	-1	3	1	-9	-3	4	-2	-6	0	-1	5	-1	19	-2	-1	-3	3	0	2	2
Arkansas Hub												-5	-12	-16	-20	1	4	10	5	2
Louisiana Hub												-6	-22	-14	-19	-12	11	1	4	3
Texas Hub												-2	-6	-14	-13	-4	-6	31	3	5

POTOMAC ECONOMICS

Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG costs because low levels can compel MISO to commit peaking resources 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 100.4 percent in the daily peak hour, and exactly 100 percent in all hours.
  - ✓ Fixed and price-based load scheduling this summer was considerably higher than in prior months.
  - ✓ It typically averages 97-98 percent, with 1-2 GW of net virtual demand making up the difference. Net virtual demand was down to 0.5 percent of the scheduled load.
- Scheduling in the peak hour remains higher in the South region (102 percent) compared to the Midwest Region (99.6 percent).

Day-Ahead Peak Hour Load Scheduling 2012–2014



Share of Actual Load (%)

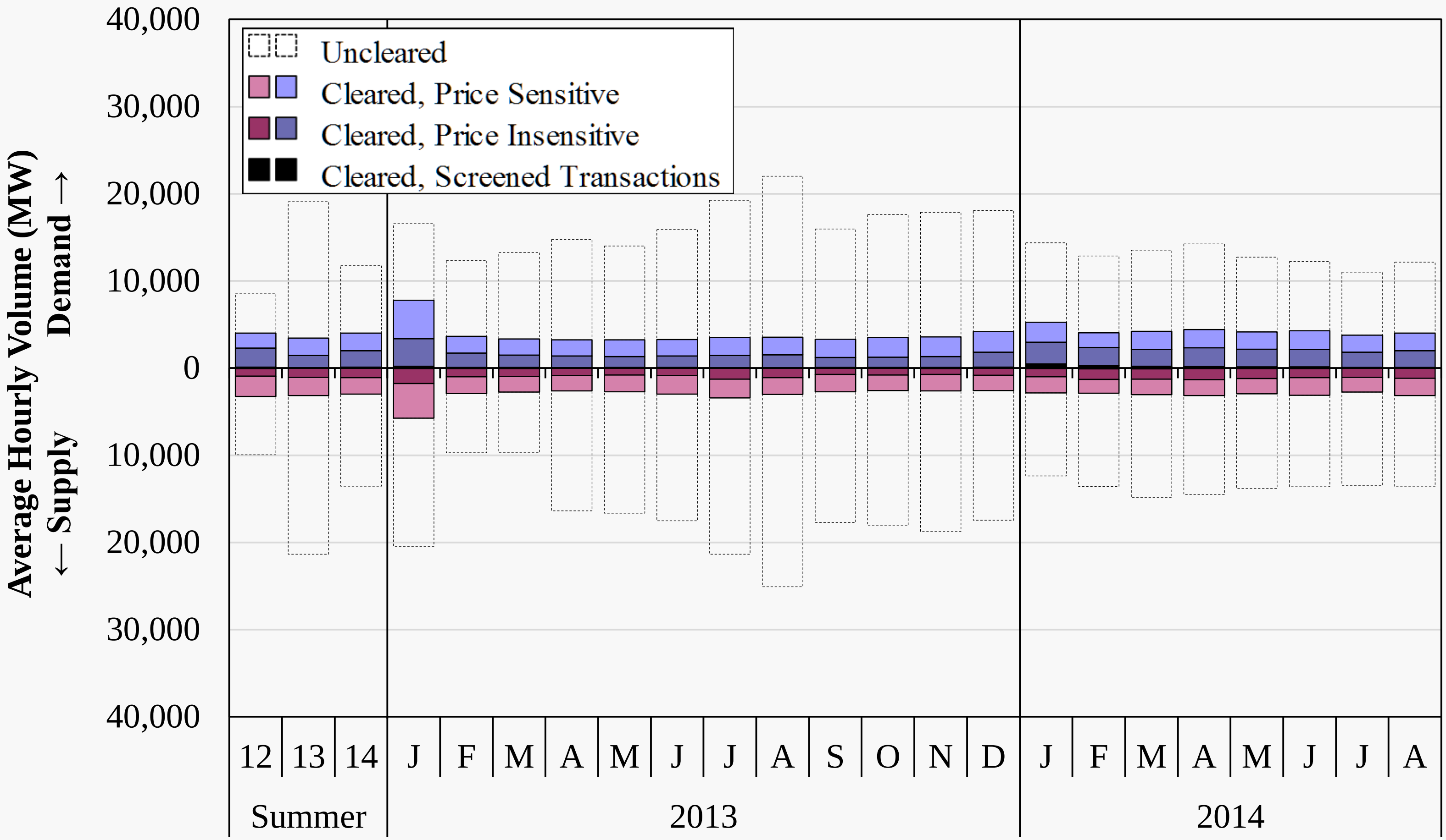
	Summer 12	Summer 13	Summer 14	2013 J	2013 F	2013 M	2013 A	2013 M	2013 J	2013 J	2013 A	2013 S	2013 O	2013 N	2013 D	2014 J	2014 F	2014 M	2014 A	2014 M	2014 J	2014 J	2014 A
All Hours	99.8	98.9	100.0	99.4	99.7	99.6	98.9	98.6	99.0	98.8	98.9	99.1	98.8	99.0	100.9	101.7	99.3	99.2	99.8	99.1	100.1	100.2	99.8
Peak Hours Midwest	100.2	98.3	99.6	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	99.5	99.8	99.5
Peak Hours South			102.0												104.9	104.4	99.9	100.4	101.5	101.6	102.7	102.5	100.7

POTOMAC ECONOMICS

Virtual Load and Supply in the Day-Ahead Market

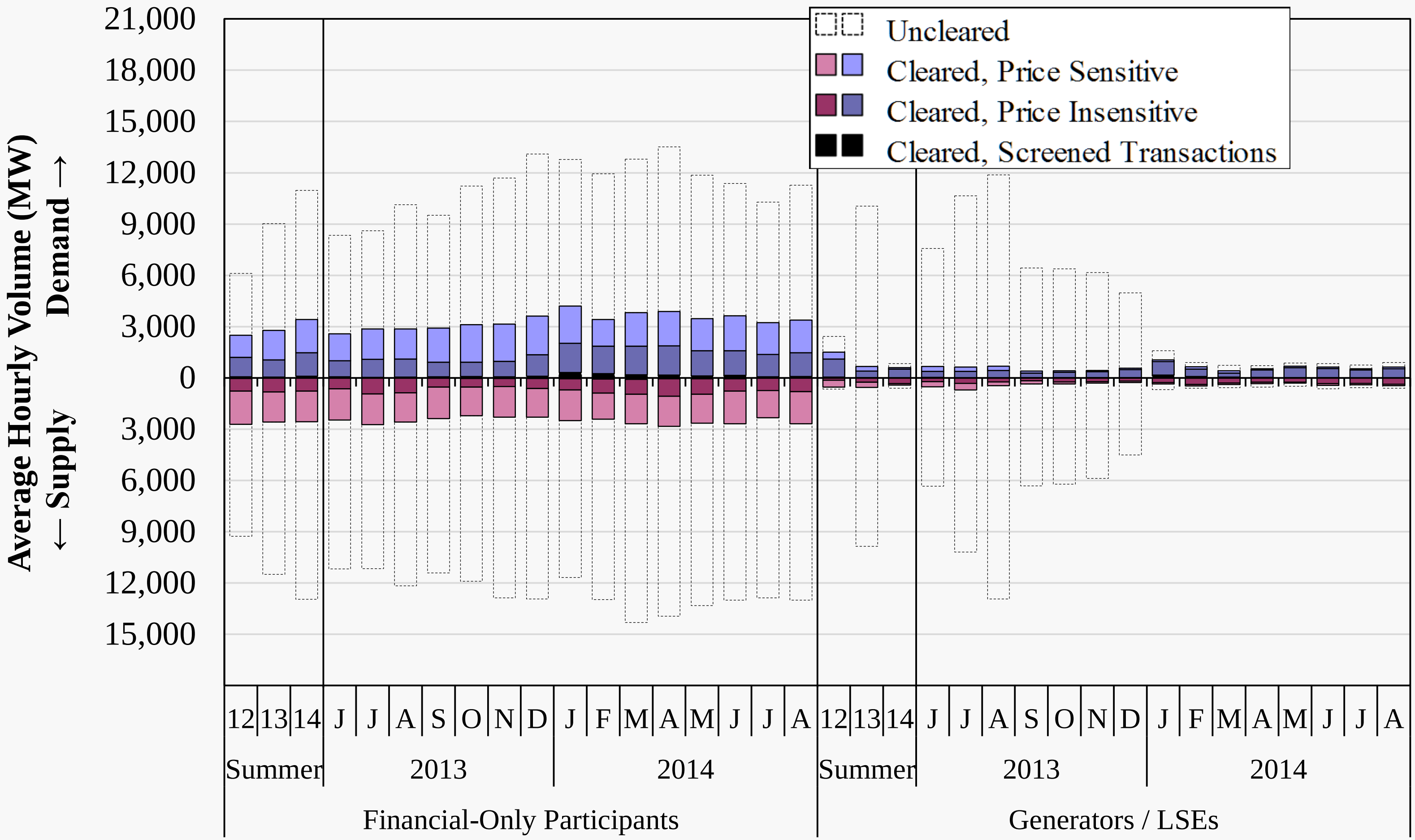
- The next two figures shows the monthly average quantity of offered and cleared virtual supply and demand transactions since January 2013.
  - ✓ We separately identify the share that are price-insensitive, as well as those that are “screened” as also contributing to (or preventing the relief of) congestion.
  - ✓ The second figure separates these volumes by participant type.
- Offered transactions declined 37 percent from last summer because several physical participants discontinued a strategy of offering bids at prices that rarely clear.
  - ✓ Such “backstop” bids are profitable and contribute to convergence when they do clear.
- Cleared transactions rose from 6.6 GW to 7.0 GW per hour. Demand transactions rose 16 percent to 4.0 GW per hour, while supply declined 5 percent to 3.0 GW.
  - ✓ Financial participants continue to clear over 85 percent of all virtual transactions.
- The share of transactions that were price-insensitive rose from 39 percent to 44 percent, although this is lower than the 48 percent level in the spring.
  - ✓ Most of this rise is associated with demand volumes that continue to be submitted by a participant at two locations in the South region.
  - ✓ We investigated this pattern earlier this year and deemed it consistent with a legitimate risk management strategy.
- The share of screened transactions declined to 1.7 percent. This is expected during times of lower congestion and price volatility.

Virtual Load and Supply
2013–2014



POTOMAC ECONOMICS

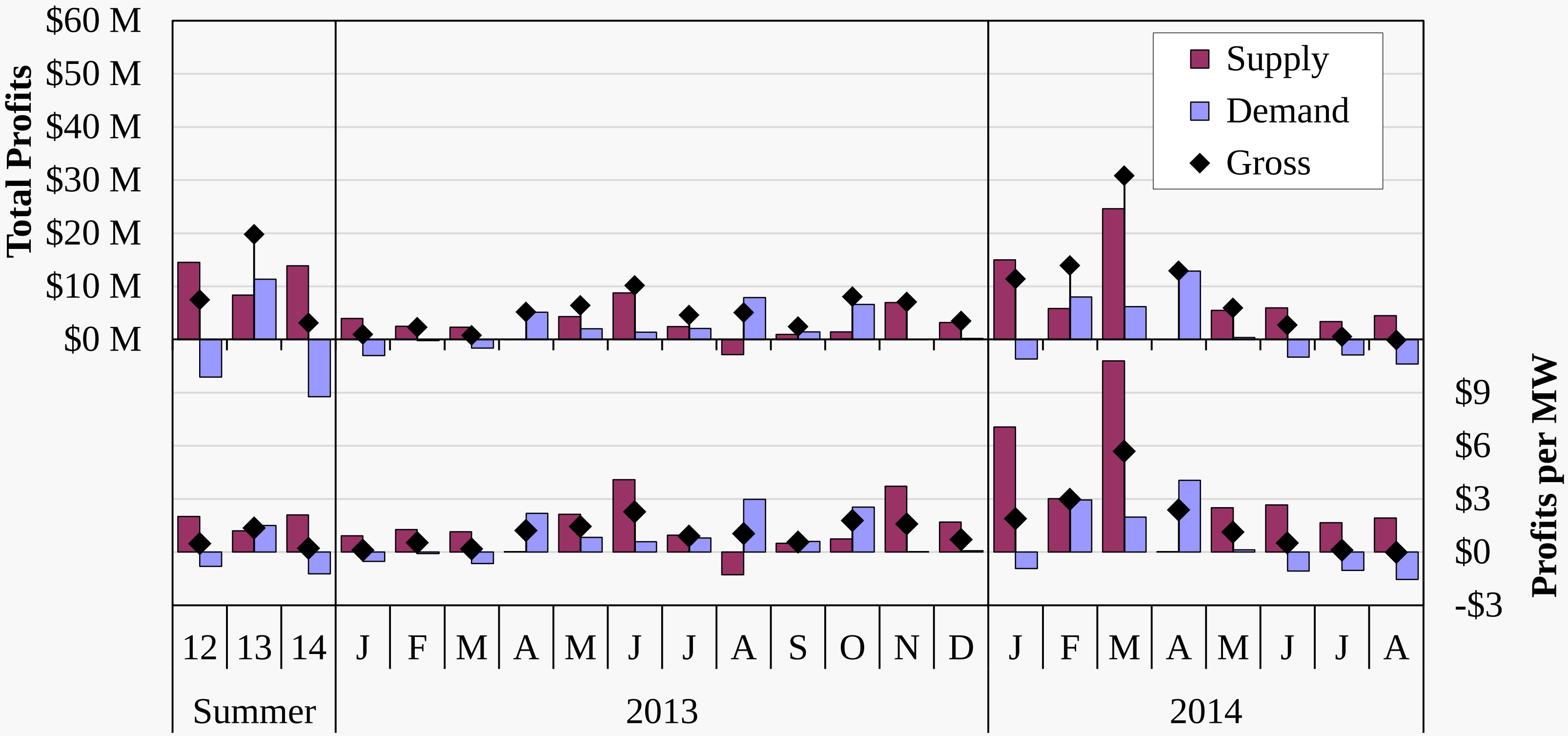
Virtual Load and Supply by Participant Type
Summer 2013–2014



Virtual Profitability in the Day-Ahead Market

- The next figure summarizes the monthly profitability of virtual supply and demand.
  - ✓ Gross profits totaled $3.1 million this summer. This is much lower than the $19.7 million earned last summer, and far lower than the nearly $50 million earned in spring.
  - ✓ On a per-MW basis, profitability declined from $1.36 per MWh to just $0.20 per MWh.
  - ✓ Low levels of profitability are expected with price convergence is good.
- Supply was moderately profitable at $2.10 per MWh, while demand lost -$1.21. This pattern held for every month this summer.
  - ✓ This is consistent with the modest day-ahead premium this quarter.
- The most profitable locations continue to be near volatile constraints, particularly some in Illinois and Indiana that are significantly impacted by market-to-market flows.
  - ✓ The most unprofitable locations were all hub locations (particularly Indiana and Texas Hubs), where significant quantities of demand cleared.
- Profitability was nearly the same for financial participants ($0.21 per MWh) as it was for physical participants ($0.16 per MWh).
  - ✓ This indicates that both generally improved price convergence, which is typically true of the financial participants and less frequently so for physical participants.
- These margins exclude CMC and DDC charges assessed to net harming deviations, including net virtual supply, although this was not very significant this summer.

Virtual Profitability 2013–2014



Percent Screened

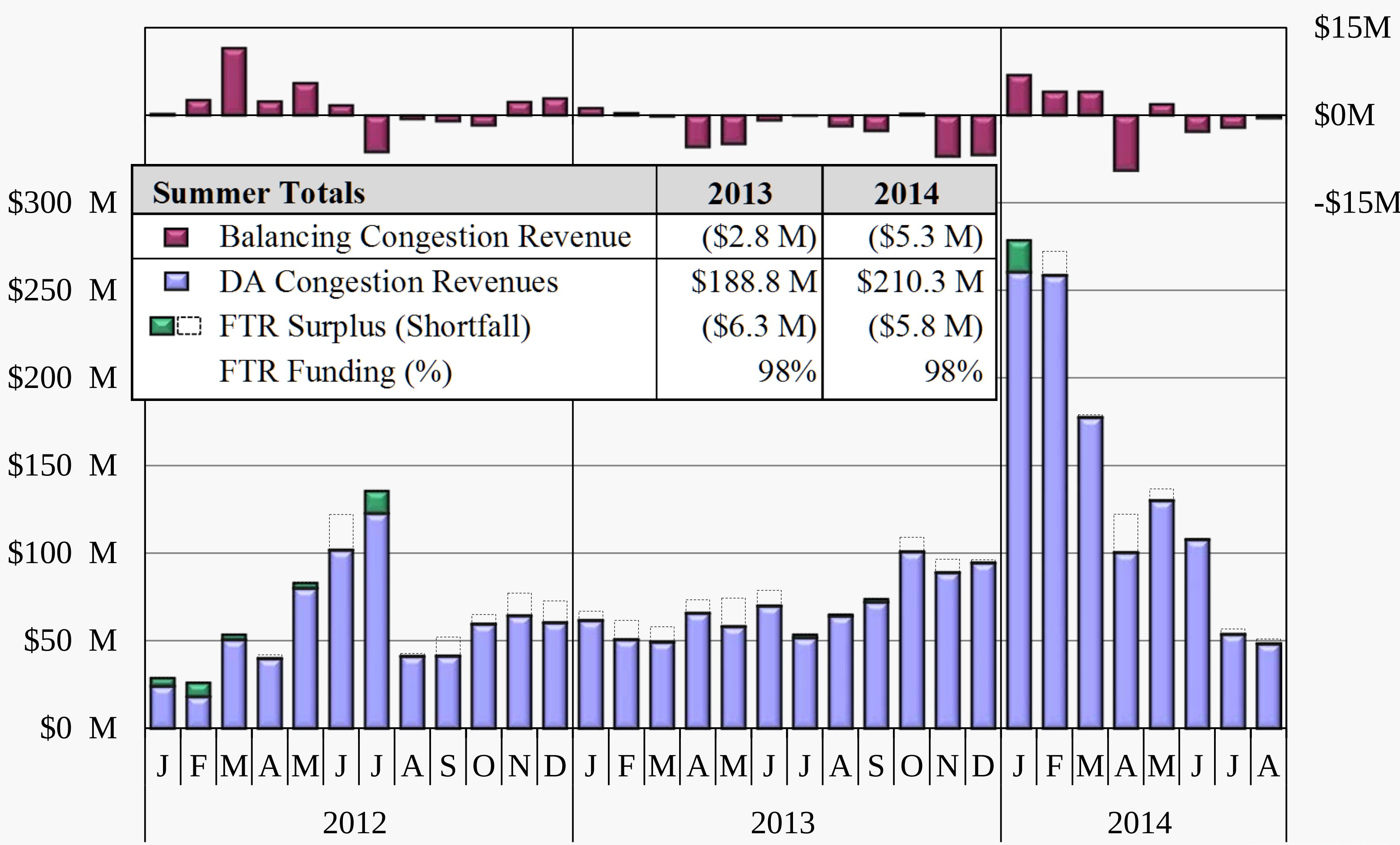
Demand	3.0	1.7	2.4	2.8	2.2	2.4	1.8	2.2	2.7	1.0	1.5	2.3	2.4	2.3	2.5	8.9	7.9	5.3	4.3	3.4	3.5	1.8	2.0
Supply	1.2	0.7	0.9	1.1	2.0	1.5	1.2	1.4	1.2	0.4	0.5	1.2	1.4	1.8	1.3	2.1	2.7	2.7	1.9	2.0	1.6	0.9	0.2
Total	2.2	1.2	1.8	2.1	2.1	2.0	1.5	1.8	2.0	0.7	1.0	1.8	2.0	2.1	2.1	6.5	5.7	4.2	3.3	2.8	2.7	1.4	1.2

POTOMAC ECONOMICS

Day-Ahead Congestion and Obligations to FTR Holders

- The next figure shows monthly day-ahead congestion and FTR funding since 2012.
- Day-ahead congestion rose 13 percent from last summer to $210 million, although it declined considerably when accounting for the expanded footprint.
  - ✓ Over $15 million of this accrued on one constraint in the South Region early in June.
  - ✓ As discussed earlier, this was the result of congestion that began in late May, and resulted in very high day-ahead prices at the Texas Hub.
- If MISO does not collect sufficient day-ahead congestion revenue to cover its obligation to the FTR holders, the shortfall results in lower payments to FTR holders.
  - ✓ Shortfalls (or surpluses) occur when the portfolio of FTRs represent more (or less) transmission capacity than the capability of the network in the day-ahead market.
- FTR were nearly fully funded this quarter. The largest shortfalls were on constraints impacted by significant transmission outages.
  - ✓ The largest shortfalls were on the N-to-S SRPBC during off-peak.
- Balancing congestion was relatively low this quarter.
  - ✓ Balancing congestion results from constraint modeling differences (when day-ahead scheduled flows exceed the real-time limit on a binding transmission constraint).
  - ✓ The low levels of balancing congestion indicate good consistency between the day-ahead and real-time markets.

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



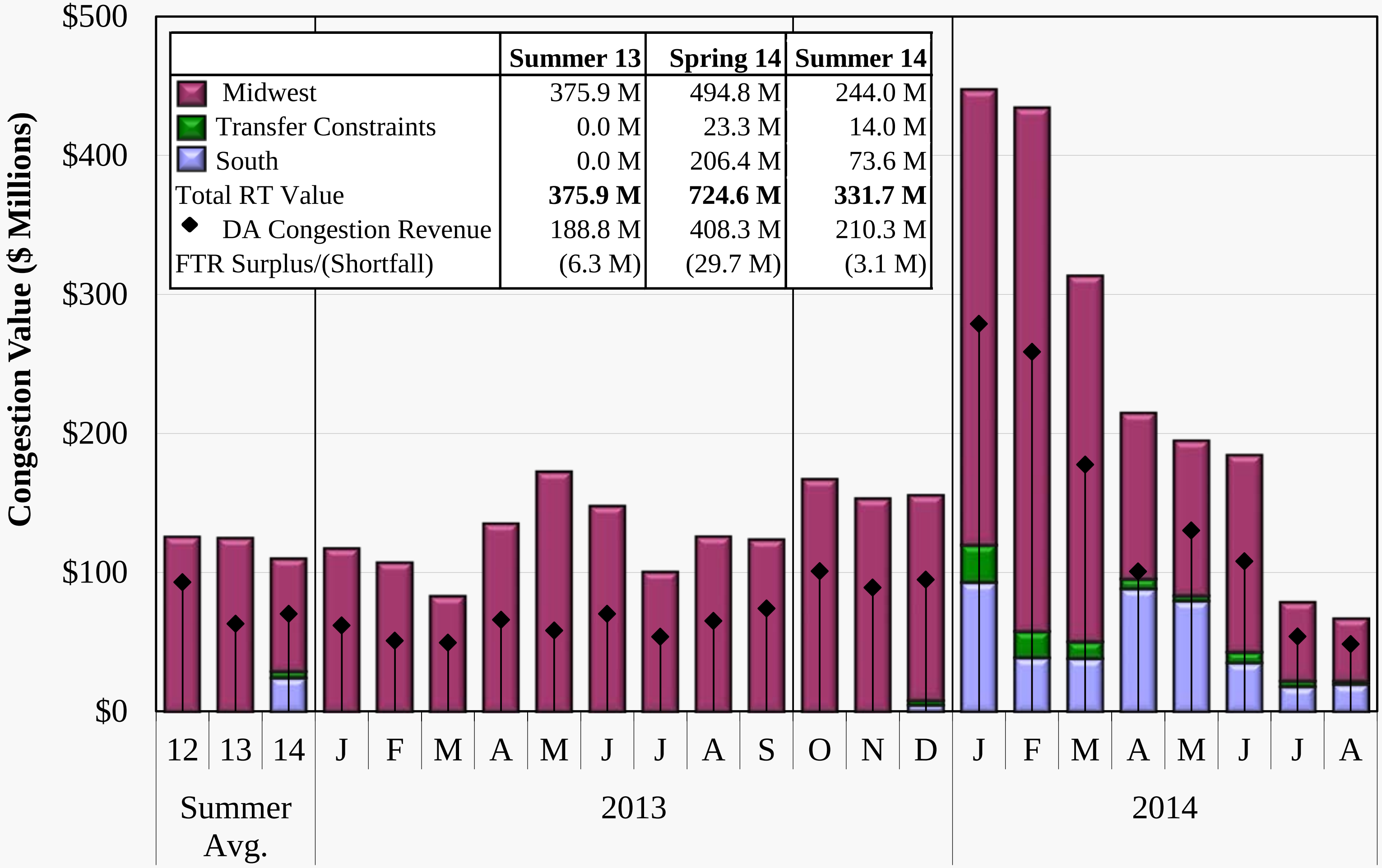
Summer Totals	2013	2014
Balancing Congestion Revenue	($2.8 M)	($5.3 M)
DA Congestion Revenues	$188.8 M	$210.3 M
FTR Surplus (Shortfall)	($6.3 M)	($5.8 M)
FTR Funding (%)	98%	98%

POTOMAC ECONOMICS

Value of Real-Time Congestion

- The following figure shows the value of real-time congestion on the MISO system.
  - ✓ Real-time congestion value is the marginal cost of a constraint (the shadow price) times the flow on the constraint. Day-ahead congestion revenues are shown in drop lines.
  - ✓ The congestion values are higher than the congestion costs collected by MISO because loop flows do not settle with MISO and PJM has entitlements to MISO's 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 declined 12 percent from last summer to $332 million, and nearly 60 percent from the $724 million recorded this spring.
  - ✓ In the Midwest region, it declined 35 from last summer and 51 percent from the Spring.
  - ✓ The large reduction from the Spring was largely due to much lower gas prices.
  - ✓ Mild summer conditions reduce network loadings and low seasonal outages increased the amount of available capacity to serve load and manage constraints.
- Transfer constraints were valued at $14 million, down 40 percent from the spring. This was due in part to the lower gas prices and in part to improved modeling of the SRPBC.
- Nearly two-thirds of the real-time congestion was collected day-ahead, a substantial increase from previous months.

Value of Real-Time Congestion 2013–2014



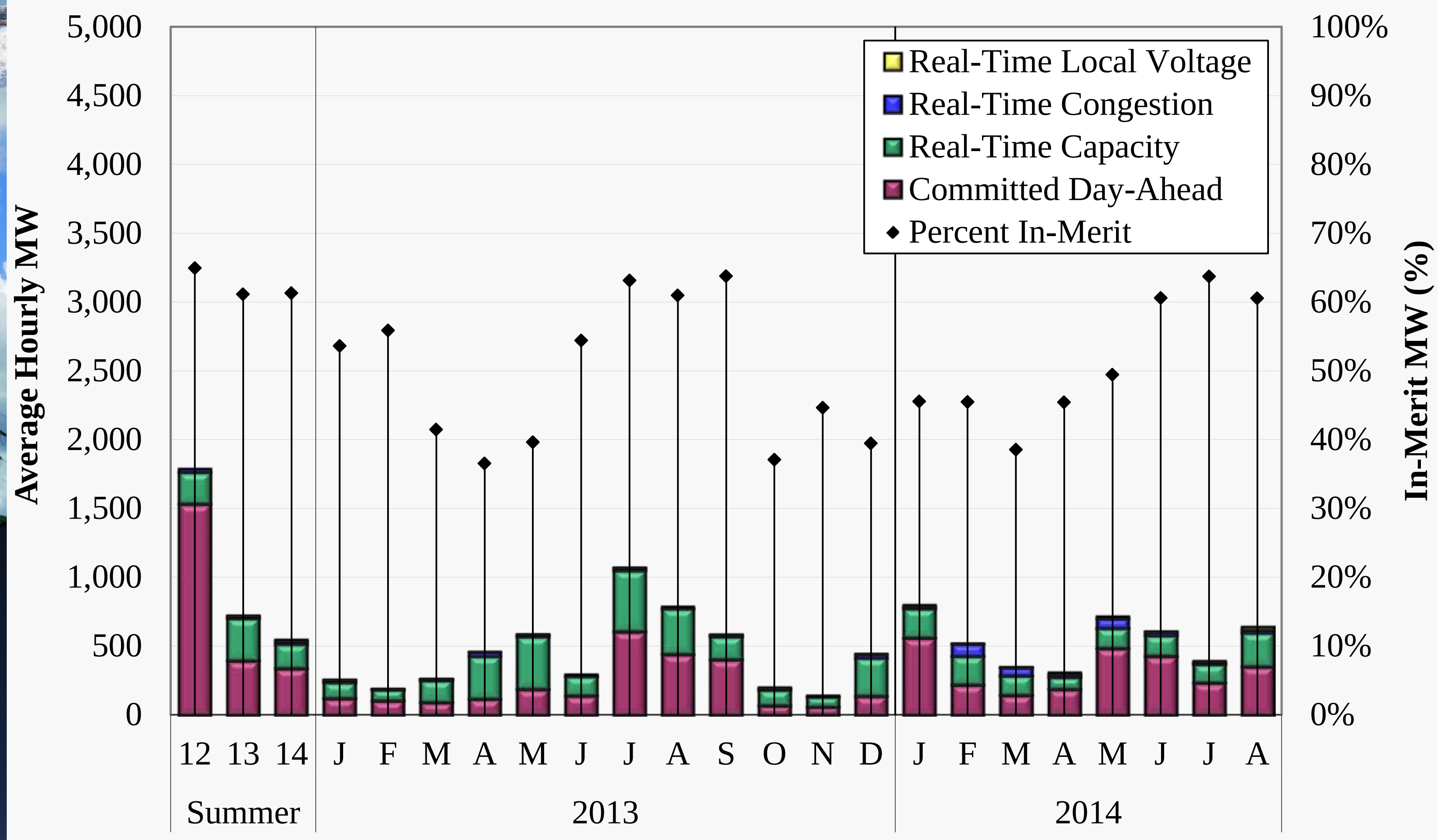
	Summer 13	Spring 14	Summer 14
Midwest	375.9 M	494.8 M	244.0 M
Transfer Constraints	0.0 M	23.3 M	14.0 M
South	0.0 M	206.4 M	73.6 M
Total RT Value	**375.9 M**	**724.6 M**	**331.7 M**
◆ DA Congestion Revenue	188.8 M	408.3 M	210.3 M
FTR Surplus/(Shortfall)	(6.3 M)	(29.7 M)	(3.1 M)

POTOMAC ECONOMICS

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 averaged 548 MW this summer, a 24 percent decline from last summer and down nearly 70 percent from the 1,800 MW in summer 2012.
  - ✓ Daily quantities rarely exceeded 1,000 MW, except on the highest-load days.
  - ✓ Commitments for capacity declined most, by 42 percent, because the mild load conditions this summer reduced MISO's real-time need for peaking resources.
  - ✓ Day-ahead commitments similarly declined 15 percent to 338 MW.
- Commitments of peaking resources needed for voltage rose to 11 MW, up from nearly none last summer. Almost all were located in load pockets in the South region.
  - ✓ Congestion-related commitments rose slightly to 21 MW, but remain a small portion of the total.
- The share of peaking unit dispatch that was in-merit was unchanged at 61 percent.
  - ✓ MISO's ELMP Initiative will allow peaking resources to set prices more frequently.
  - ✓ ELMP implementation is being delayed to address concerns regarding the methodology for allowing offline units to set prices.

Peaking Resource Dispatch
2013–2014

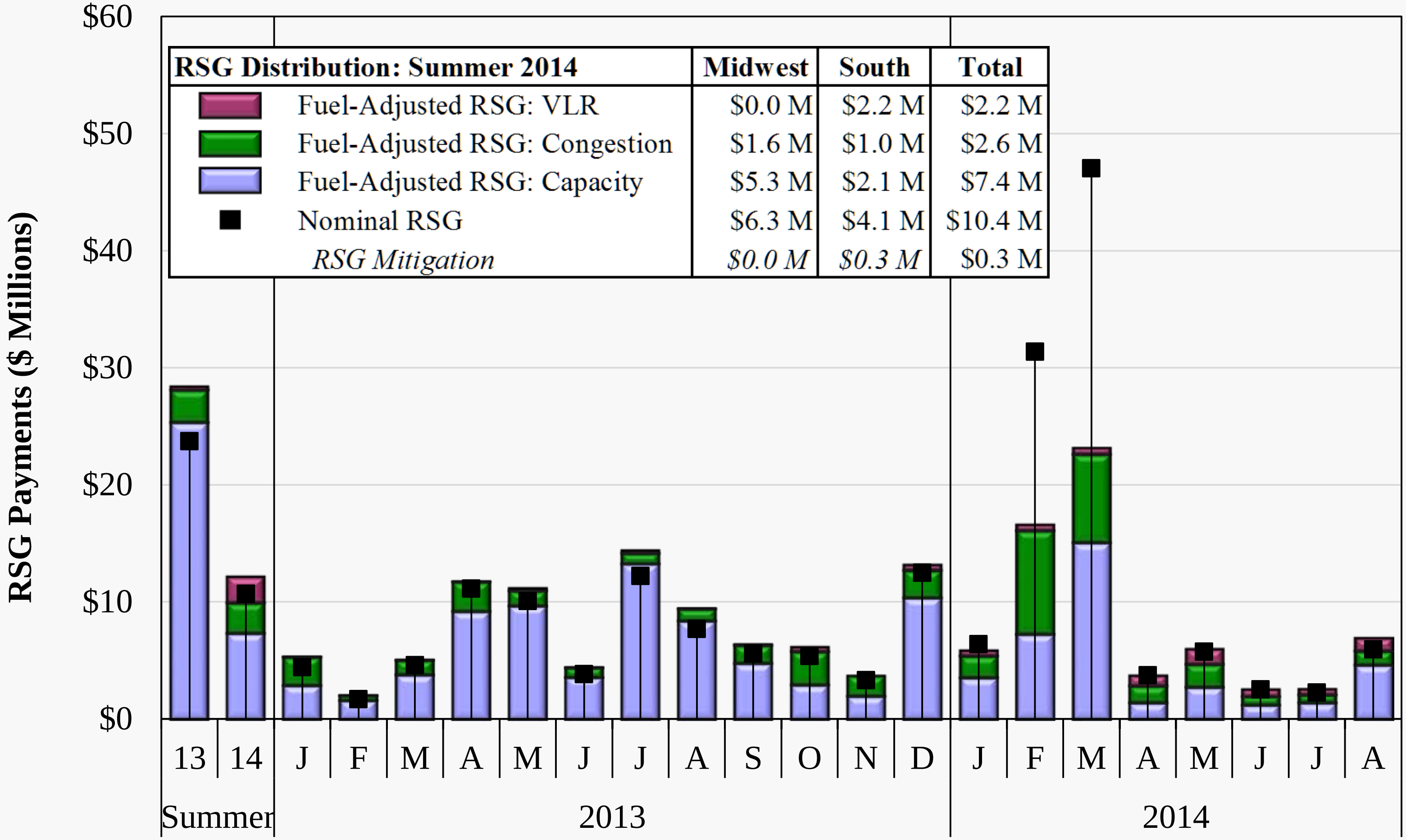


POTOMAC ECONOMICS

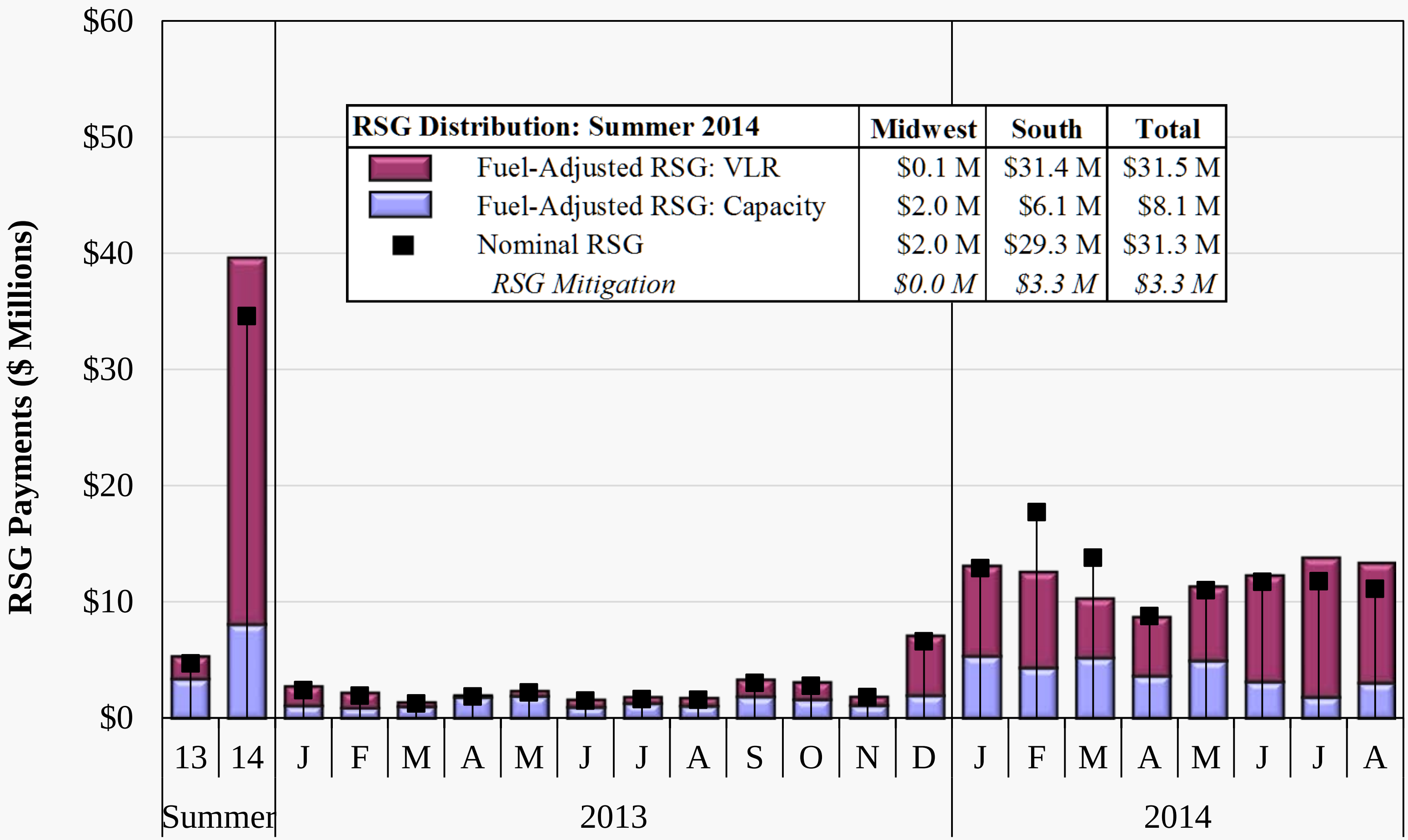
Real-Time and Day-Ahead RSG Payments

- The next 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).
- Day-ahead RSG costs totaled $34.6 million, up 30 percent from the Spring in fuel adjusted terms.
  - ✓ 80 percent of the day-ahead RSG was paid to units in the South region, where out-of-market units are committed day ahead each day for voltage support.
  - ✓ Since most of these units are offered competitively, only 4 percent of dollars were mitigated.
  - ✓ In the Midwest region, day-ahead RSG payments declined 58 percent from last summer to $1.97 million, nearly all of which was for capacity. This reduction was primarily due to the mild conditions this summer.
- Nominal real-time RSG costs declined by 55 percent to $10.7 million. In fuel-adjusted terms they declined 57 percent from last summer to $12.2 million.
  - ✓ Payments for capacity declined nearly 70 percent to $7.4 million (fuel-adjusted) due to the milder conditions this summer, while payments for congestion-related commitments rose to $1.7 million.

Real-Time RSG Payments 2013–2014



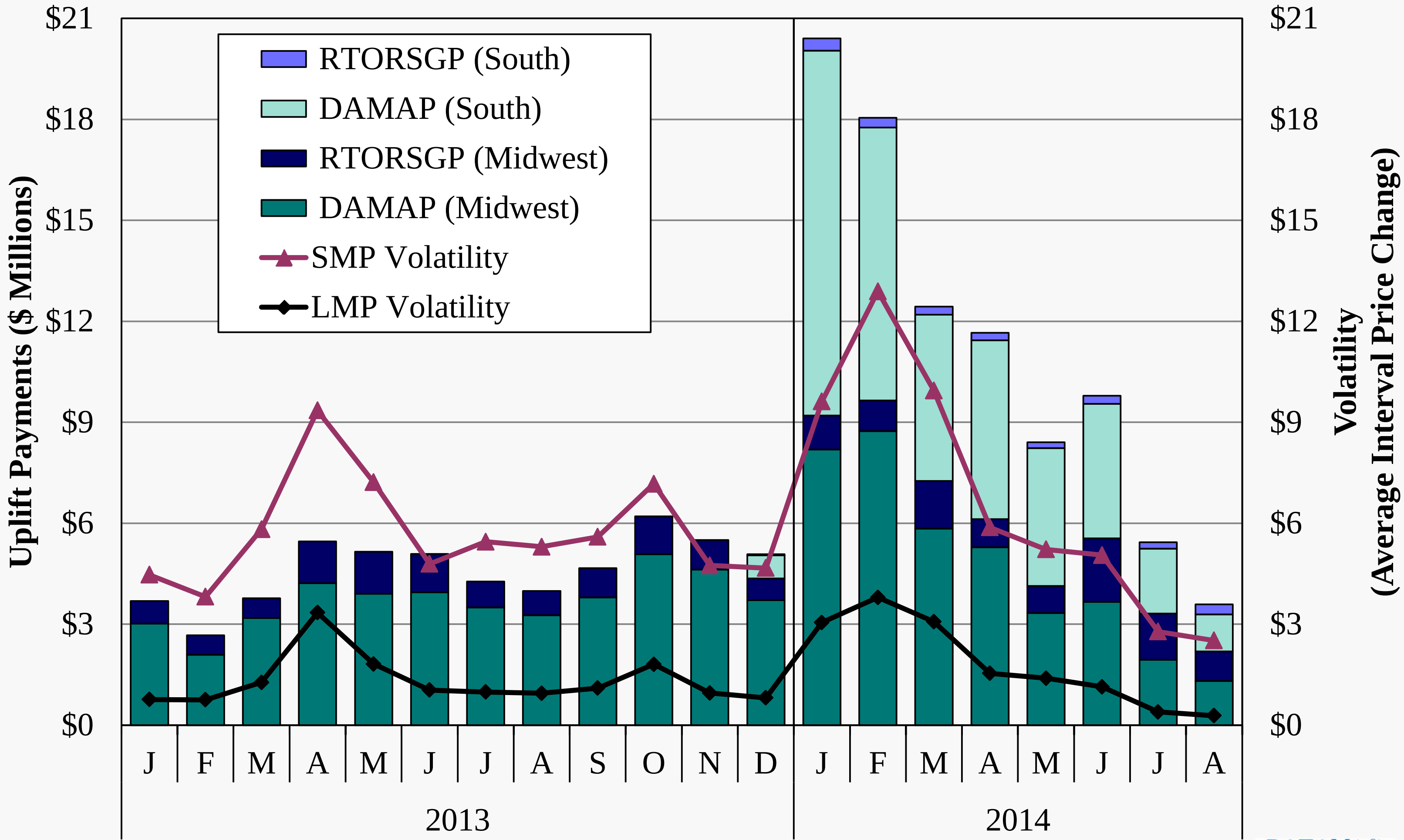
Day-Ahead RSG Payments 2013–2014



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.
  - ✓ 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.
- Total PVMWP this summer totaled $18.8 million, 42 percent lower than in the Spring.
  - ✓ The $11 million paid to units in the Midwest was 21 percent lower than last summer because of substantially lower price volatility.
  - ✓ The payments are strongly correlated with price volatility because it leads to higher payments to flexible units. Volatility were very low this summer due to very few shortages, good resource availability, and mild summer loads.
- DAMAP totaled nearly $14 million, down from $28.8 million this spring, and was paid evenly to resources in the Midwest and South regions.
  - ✓ Payments accrued disproportionately to large gas-fired steam turbines in the South Region. In the Midwest, flexible coal units received the most payments.
  - ✓ DAMAP in the South has fallen as generator performance has improved. MISO has addressed a State Estimator modeling issue that had contributed to apparent dragging for some units and increased DAMAP costs in the Spring.
- RTORSGP rose 32 percent to nearly $5 million, of which nearly $1 million went to two units situated near a volatile constraint in Iowa (mostly in June).

Price Volatility Make Whole Payments 2013–2014



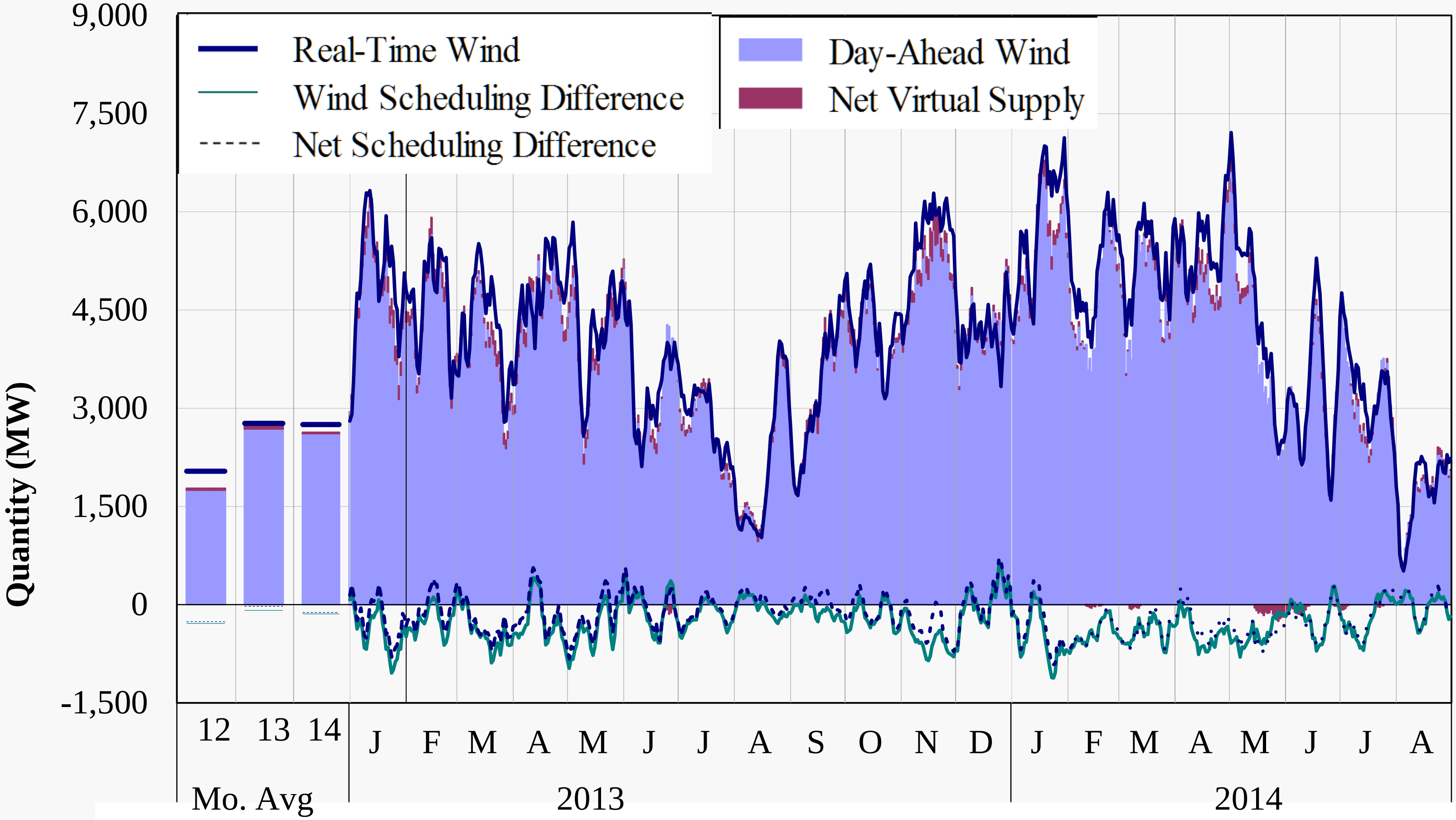
POTOMAC ECONOMICS

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 wind units are DIR, and have almost entirely replaced manual curtailments as the preferred means to manage wind output (see second slide).
- Real-time wind output was mostly unchanged from last summer at 2.7 GW.
  - ✓ Wind output is seasonal, and its output and aggregate volatility is far lower in summer than it is during shoulder seasons.
  - ✓ The total ramp demand per interval this summer was 29 percent lower than in spring.
- Under-scheduling of wind in the day-ahead market improved from the spring, but rose modestly from last summer to 134 MW, or 5 percent of real-time output.
  - ✓ This produces an incentive for participants to make up the difference with net virtual supply, which remained considerably profitable this summer at $2.92 per MWh at these locations

POTOMAC ECONOMICS

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

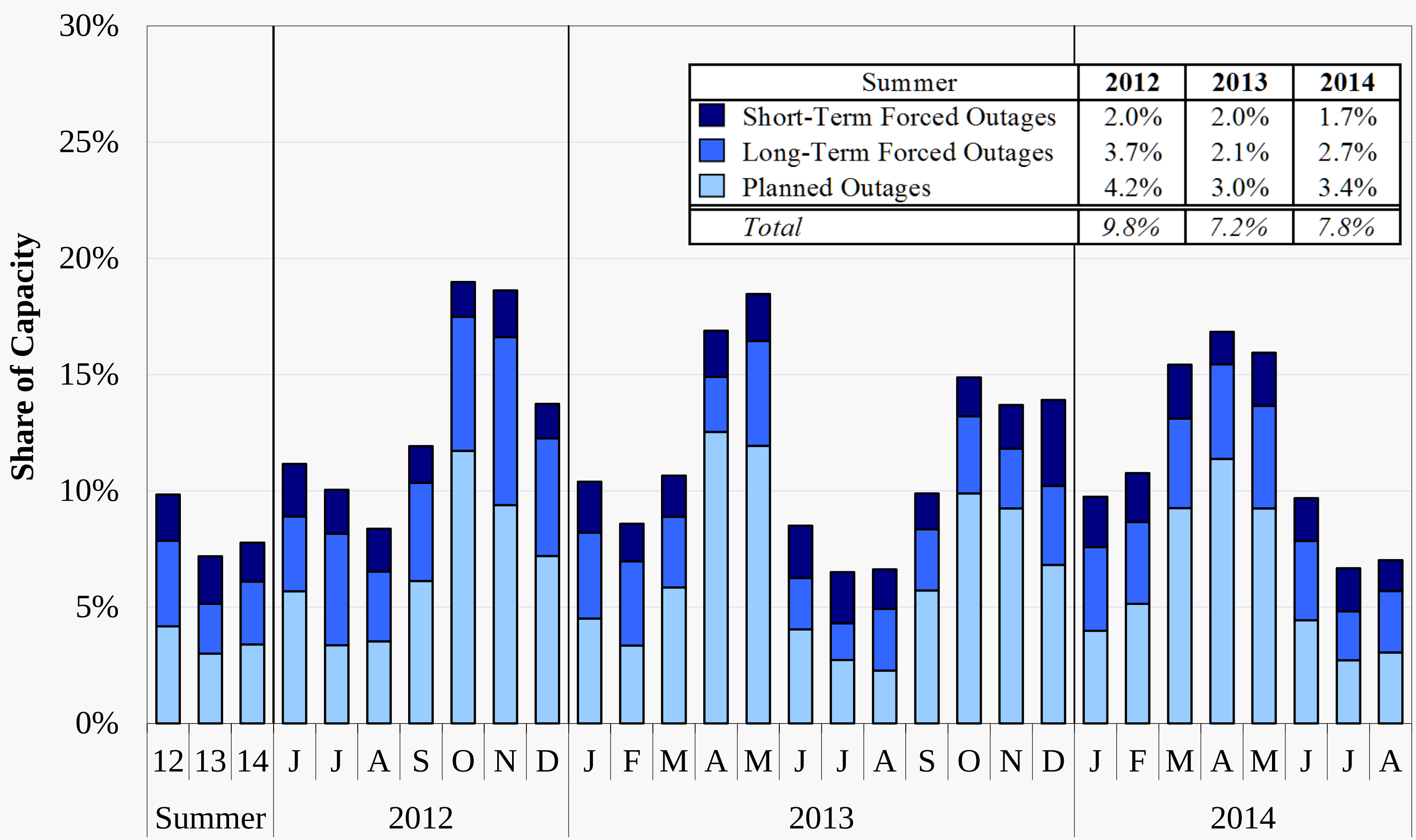


ECONOMICS

Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since June 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 summer rose slightly from 7.2 percent last summer to 7.8 percent.
  - ✓ Short-term forced outages declined to just 1.7 percent, which likely contributed to the lower price volatility this summer.
  - ✓ Long-term forced outages rose to 2.7 percent, while planned outages averaged 3.4 percent.
  - ✓ Several outages in South region load pockets that had the potential to be problematic during peak conditions did not continue past June.
- We continue to investigate those outages that contributed to shortages or severe congestion, none of which raise concerns this quarter.

Generation Outage Rates 2012–2014



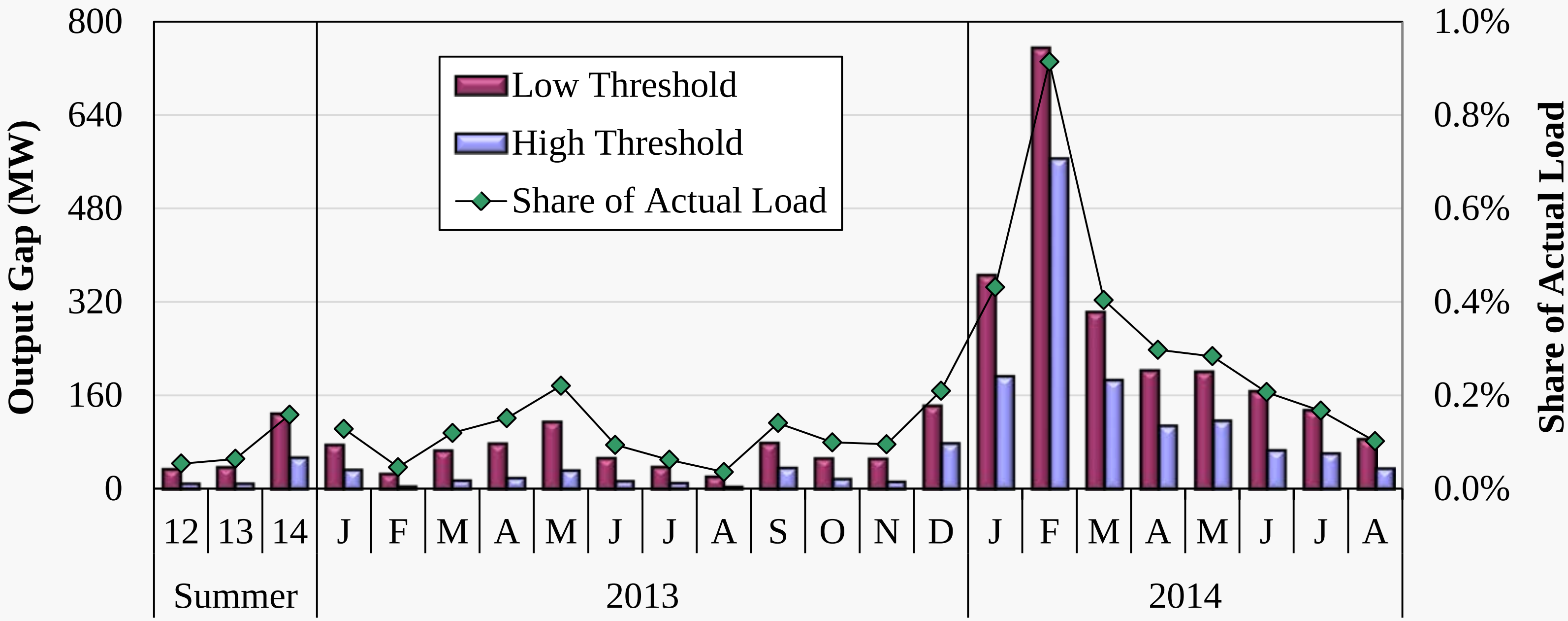
Summer	2012	2013	2014
Short-Term Forced Outages	2.0%	2.0%	1.7%
Long-Term Forced Outages	3.7%	2.1%	2.7%
Planned Outages	4.2%	3.0%	3.4%
Total	*9.8%*	*7.2%*	*7.8%*

POTOMAC ECONOMICS

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 from the very low levels recorded last summer, but remains very low at 0.16 percent of actual load.
  - ✓ At low threshold, it rose from 39 MW to 130 MW, while at the mitigation threshold it rose from 10 to 56 MW.
  - ✓ Since peaking in February, output gap has declined in each subsequent month.
- 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)

Offline	3	2	17	7	1	4	0	10	1	6	0	23	7	2	59	106	451	130	83	71	13	21	15
Online	7	8	39	27	4	11	20	22	14	5	5	14	11	11	20	89	116	57	26	46	54	41	21

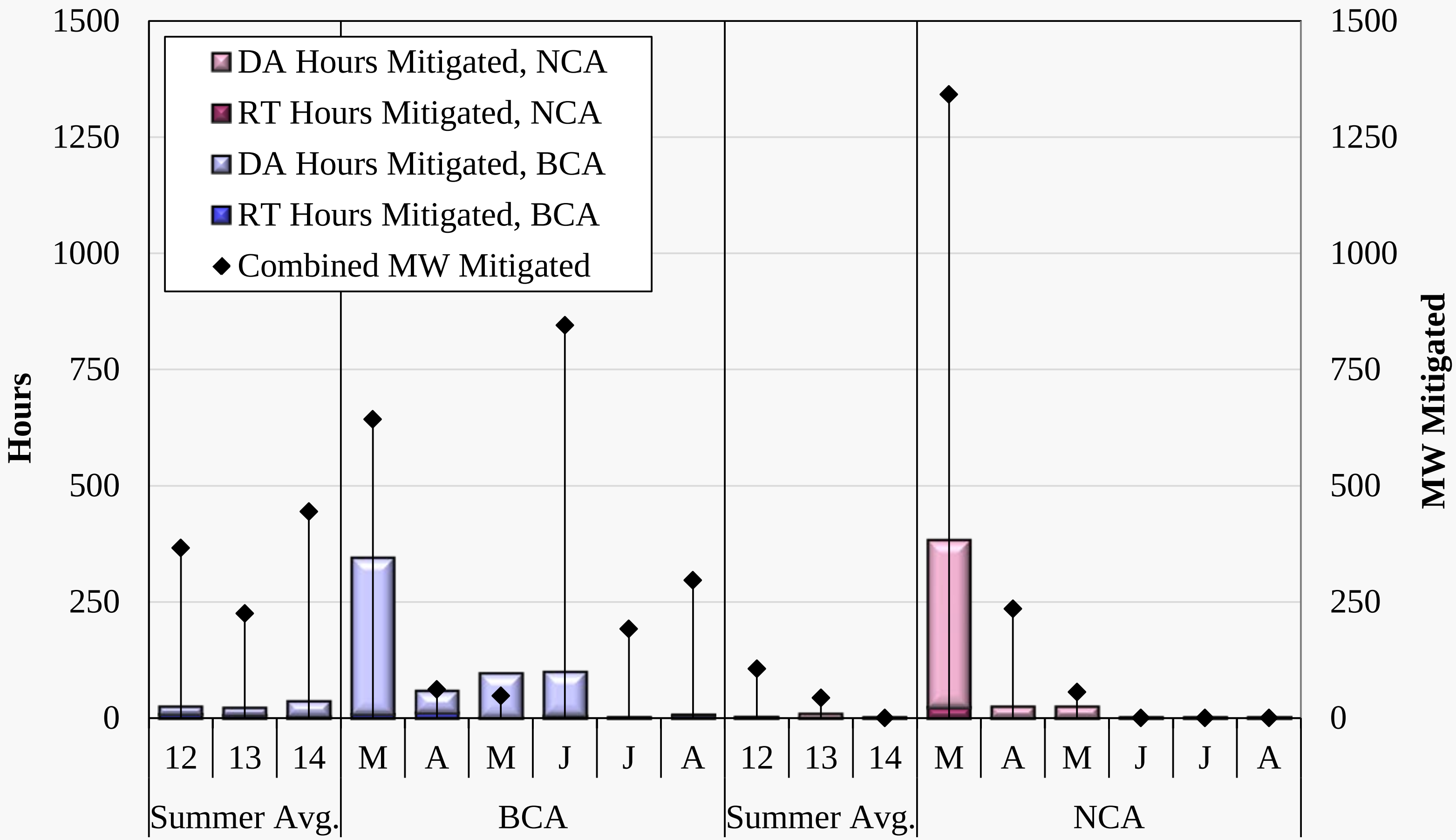
Low Threshold Results by Unit Status (MW)

Offline	4	4	23	8	2	6	0	12	1	9	0	26	11	4	70	140	519	154	99	82	18	29	22
Online	32	35	107	69	25	62	79	104	53	30	22	55	42	50	74	228	236	150	105	120	150	107	65

Mitigation in the Real-Time Energy Market

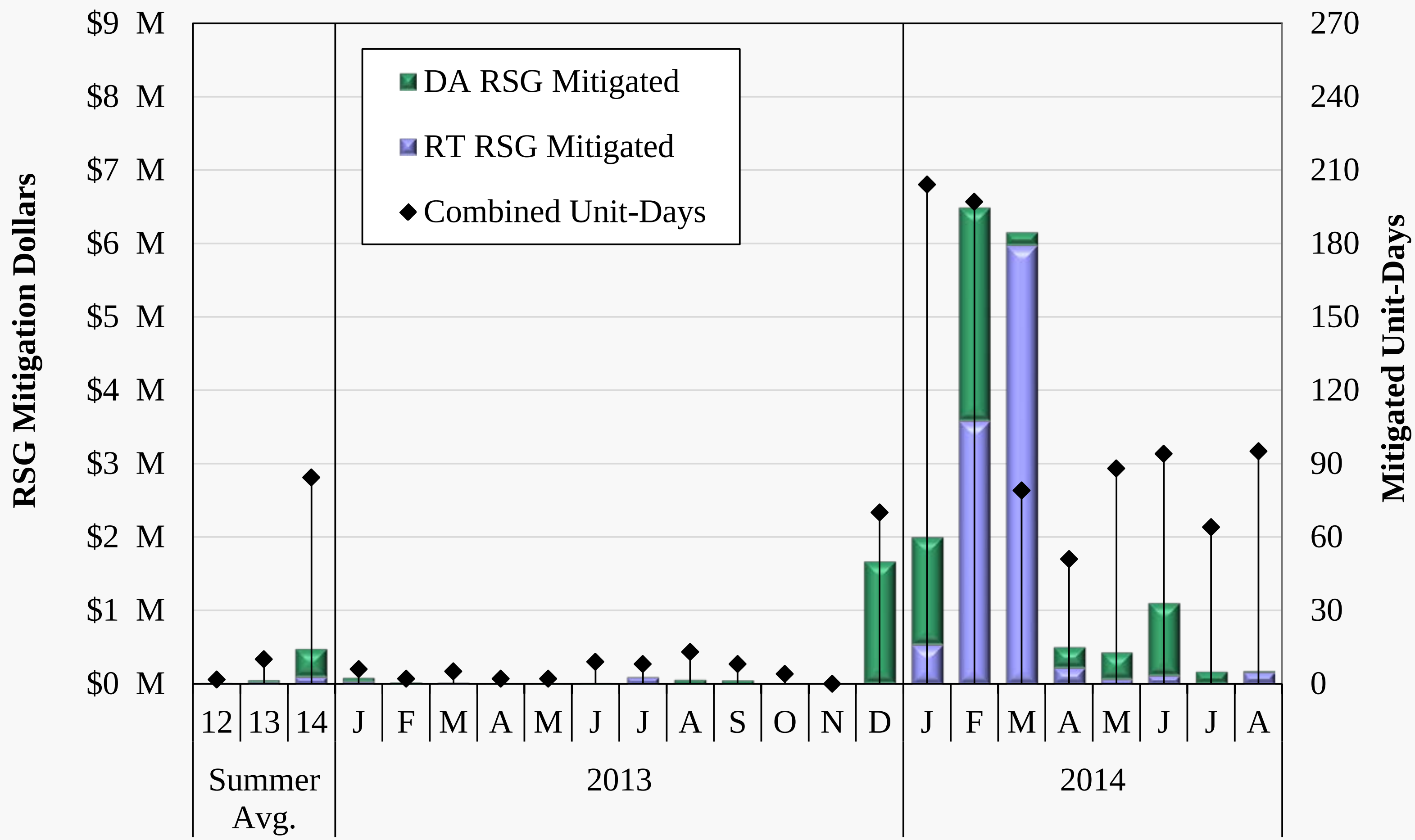
- The next two figures show the frequency with which energy and RSG mitigation was imposed in the day-ahead and real-time markets in recent months.
  - ✓ The first figure separates energy mitigation by broad and narrow constrained area.
- Energy mitigation was imposed for 33 unit-hours and 445 MW this summer.
  - ✓ Most of the MW quantities were implemented in the day-ahead market in June and were located in BCAs.
  - ✓ Several of the real-time mitigations were due to participant error, whereby a unit's reference levels were based on an indication for an operation mode that was different than the mode in which the participant was actually offering.
- RSG mitigation totaled $1.46 million, 80 percent of which occurred day-ahead.
  - ✓ This is up substantially from last summer, when $185,000 was mitigated.
  - ✓ Most day-ahead mitigation was under the tighter VLR framework. Nearly all of this mitigation were of units in the South region.
  - ✓ Unit-hours of mitigation similarly rose from 10 to 84.
- Some participants are disputing certain instances of RSG mitigation and we are assisting MISO in responding to the disputes.

Day-Ahead And Real-Time Energy Mitigation 2013–2014



POTOMAC ECONOMICS

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



POTOMAC ECONOMICS

Submittals to External Entities and Other Issues

- 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 participated in a FERC technical conference on real-time price formation and uplift.
- We presented a summary of our review of ELMP parallel operations to the MSC.
  - ✓ MISO has agreed with most of our recommendations and has filed to delay the ELMP implementation to implement these changes. We filed in support of the postponement.
- We participated in the FERC Settlement Conference on JOA resettlement payments to PJM disputed by MISO Customers.
- We participated in the FERC Settlement Conference on the SPP transmission charges.
- We continue to work with MISO and PJM on improving their interface pricing, which is critical because it provides the economic incentives that govern imports and exports.
  - ✓ We presented proposals and participated in a working group of the JCM, and presented a case study of how one constraint in MISO affected interface and PJM FTR funding.
- We conducted a half-day workshop on capacity market design issues for state commissioners and commission technical staff.
- We presented a summary of market integration results and issues to the Entergy Regional State Committee.

POTOMAC ECONOMICS

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

POTOMAC ECONOMICS