IMM Quarterly Report: Fall 2011
September-November

MISO Independent Market Monitor

David B. Patton, Ph.D.
Potomac Economics

December 2011

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Summary of Fall 2011 Results

- Real-time prices in the quarter averaged $28.86 per MWh, a 4 percent increase from last fall. Day-ahead prices rose 2 percent and averaged $29.19.
  - ✓ Prices rose evenly across MISO. Prevailing congestion patterns continue to produce real-time price differences of $10 per MWh from the west to east.
- Prices were not significantly changed due to similarities in load and fuel prices.
  - ✓ Load averaged 56.4 GW in the quarter, an increase of less than 1 percent.
  - ✓ Natural gas prices fell 2 percent to $3.69 per MMBtu, while coal prices rose slightly.
- Wind generation averaged over 3.3 GW and set a new record at 7.8 GW.
  - ✓ Congestion manageability in the West improved in part due to increased availability of DIR wind units. Manual wind curtailments fell by 32 percent compared to fall 2010.
- RSG costs fell by more than 50 percent from fall 2010 due to high day-ahead load scheduling (decreasing the need for peaking resources) and lower voltage support costs.
  - ✓ Voltage support still accounts for more than 30 percent of the real-time RSG cost. Important changes to the allocation of these costs will be filed in December by MISO.
- Cleared virtual transactions continue to rise due to price-insensitive virtual transactions that appear to have primarily been arbitraging transitory differences in loss factors.
  - ✓ MISO is improving the methods for producing day-ahead loss factors, which should reduce predictable differences at individual locations.

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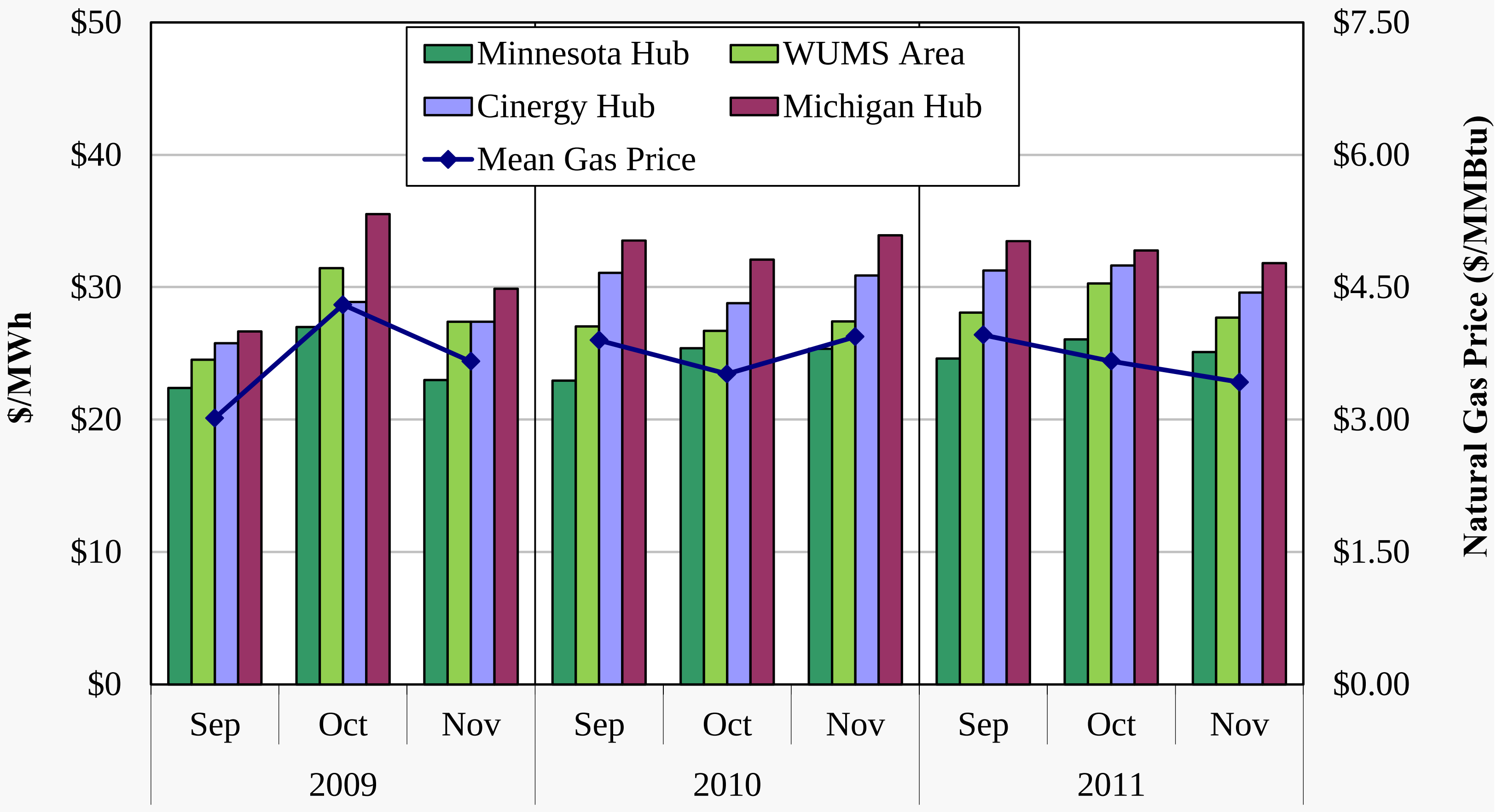
Day-Ahead Average Monthly Hub Prices

- The first figure in this section shows monthly average day-ahead energy prices at selected hubs in fall 2009 to 2011.
  - ✓ The figure shows natural gas prices because fuel costs are the majority of most suppliers' marginal costs and gas units are often on the margin in peak hours.
  - ✓ In a workably competitive market, energy and fuel prices should be correlated.
- Average day-ahead energy prices this quarter rose 2 percent from fall 2010 to $29.19 per MWh.
  - ✓ The slight price increase is consistent with higher day-ahead load (up 1.3 percent, adjusted for membership changes) and higher coal prices (up 1-2 percent).
  - ✓ Natural gas prices decreased 2 percent to $3.69 per MMBtu.
- Price differences reflecting the value of transmission congestion and losses persist between the western and eastern areas in MISO.
  - ✓ Day-ahead congestion rose 2 percent from fall 2010. Prices at Michigan ($33 per MWh) in the quarter averaged nearly $8 higher than those at Minnesota.
  - ✓ Wind output continues to increase and contributes to this pattern.
    - – Day-ahead wind scheduling rose by 25 percent to 2.8 GW this quarter.

Day-Ahead Average Monthly Hub Prices
Fall 2009–2011



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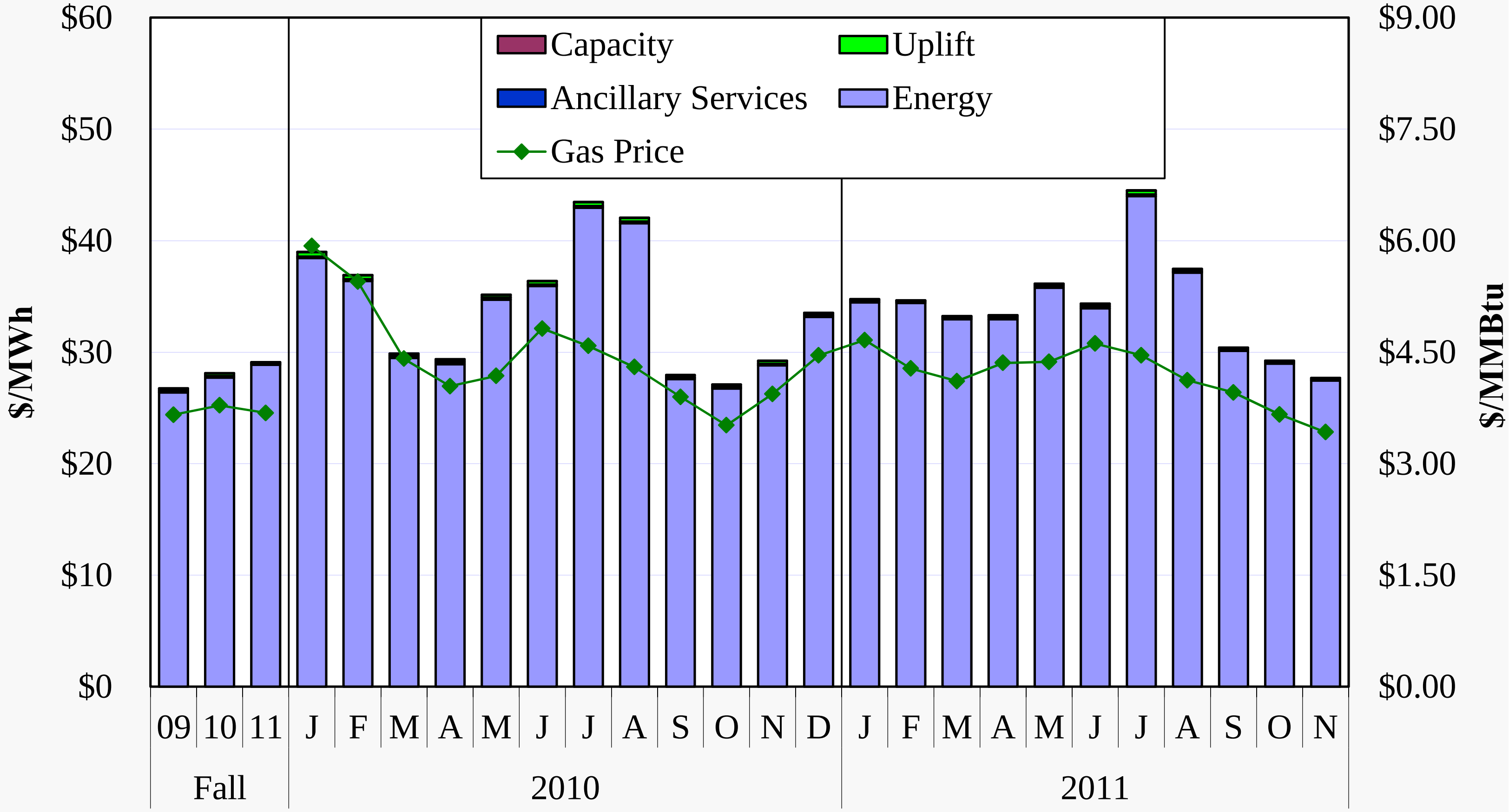
All-In Price

- The “all-in price” represents the total cost of serving load in the real-time market.
  - ✓ The all-in price is equal to the sum of the average real-time energy price, the average real-time uplift costs, and the costs of ancillary services and capacity.
- The all-in price in fall 2011 was $29.10 per MWh, an increase of 4 percent over last fall.
  - ✓ As with day-ahead energy prices, the all-in price rose on a modest increase in coal prices, loads and real-time congestion. Gas prices were nearly unchanged.
- The figure also shows the average natural gas price in each month.
  - ✓ Energy prices generally continue to move with changes in fuel prices, as expected in a workably competitive market.
- As in prior quarters, energy costs comprised nearly the entire all-in price.
  - ✓ Uplift, ancillary services and capacity costs together contributed just 24 cents.
  - ✓ The Voluntary Capacity Auction continues to clear at close to zero in each month, which is consistent with surplus levels of capacity in MISO.

All-In Price
2009–2011



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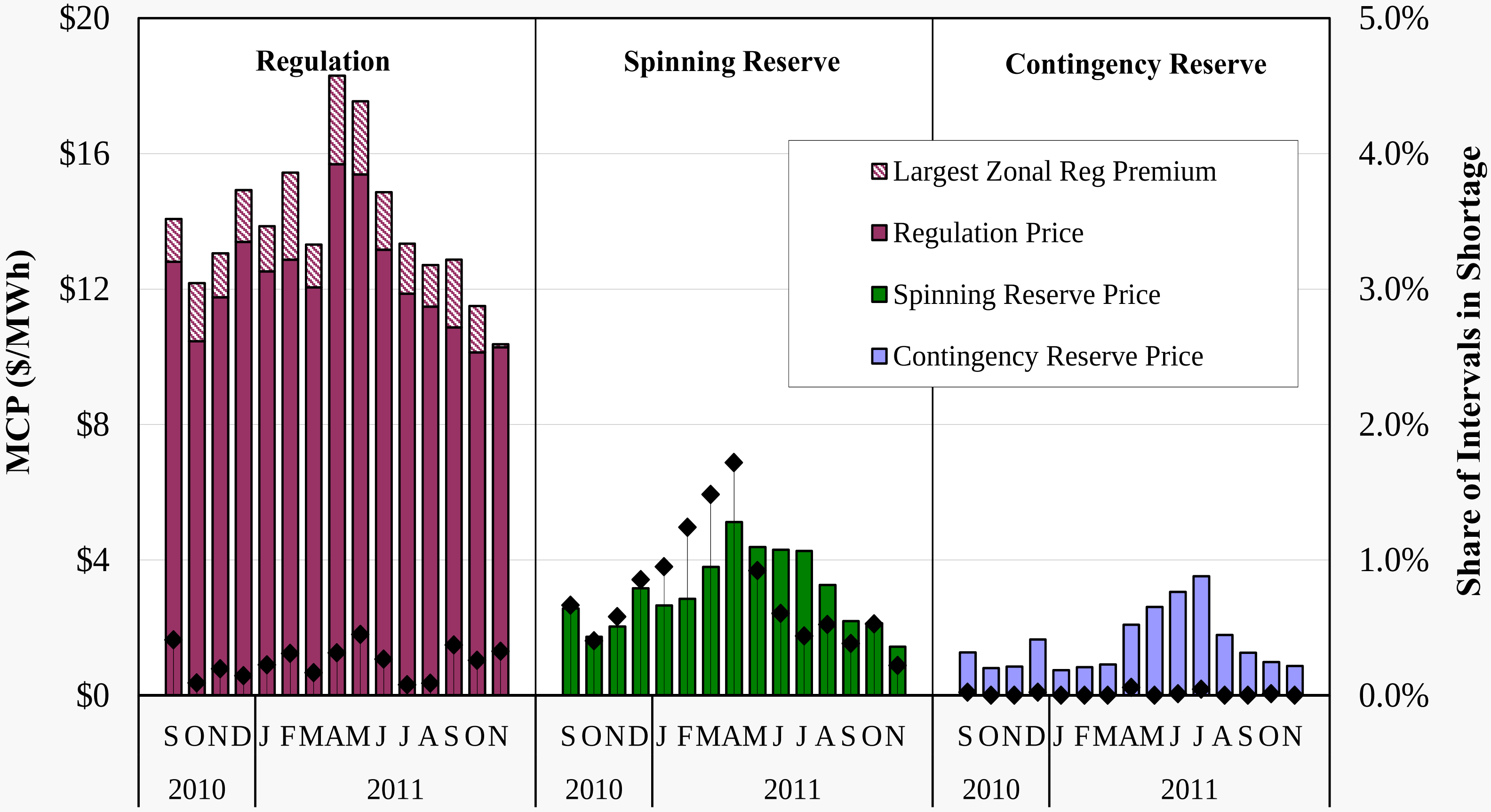
Monthly Real-Time Ancillary Service Prices

- The following chart shows monthly average real-time clearing prices for MISO’s ancillary service products since September 2010.
- Regulating reserve prices averaged $10.43 per MWh in the quarter, a decrease of 11 percent from last fall.
  - ✓ Monthly prices have fallen by one-third since peaking near $16 in April.
  - ✓ Since regulating reserves can be used to fulfill requirements for lower-quality reserves, a considerable reduction in spinning reserve shortages (to less than 0.5 percent of intervals) has resulted in lower clearing prices for regulation.
  - ✓ The average regulating reserve demand curve price, which sets price during intervals of shortage, declined nearly 30 percent from last fall to $145.
- Spinning reserve clearing prices declined by 9 percent to $1.93 per MWh.
  - ✓ There were 99 spinning reserve shortages in the quarter, down from 142 last fall.
- Contingency reserve prices rose six cents to average $1.04 per MWh in the quarter.
  - ✓ There was one interval (on October 24) with an operating reserve shortage.
- A slight real-time price premium persisted for regulating and contingency reserves.

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



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MISO Fuel Prices

- The next figure shows daily average fuel prices from June 2009 to present.
- Fuel prices (except oil) were mostly unchanged from fall 2010.

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

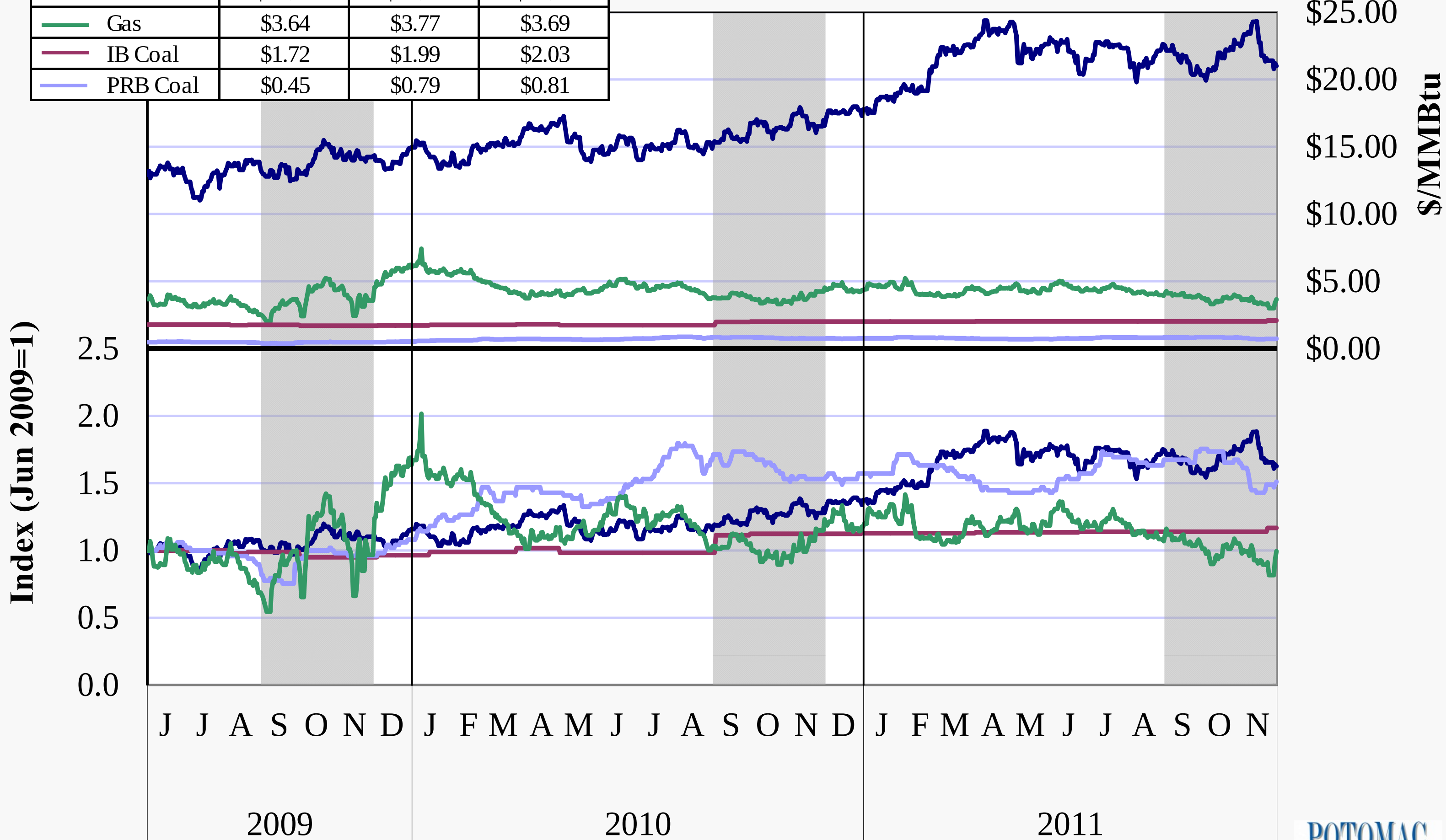
- Natural gas prices averaged $3.69 per MMBtu in the quarter, largely unchanged from the fall quarters in both 2009 and 2010.
  - ✓ Prices rose briefly above $4 in early September before falling to $3.01 late in November.
- Oil prices averaged near $22 per MMBtu in the quarter, up by one-third from fall 2010 and by nearly sixty percent from fall 2009.
  - ✓ This rise has not materially impacted MISO energy prices because oil resources are rarely a marginal fuel (see slide 14).

<u>Coal Prices</u>

- Illinois Basin prices rose 4 cents to $2.03 per MMBtu.
- Powder River Basin prices rose 2 cents from last fall to $0.81 per MMBtu.
  - ✓ Prices fell from $0.86 per MMBtu in October to $0.70 by quarter’s end.

MISO Fuel Prices
2009–2011

Fall Average	2009	2010	2011
Oil	$13.84	$16.36	$21.85
Gas	$3.64	$3.77	$3.69
IB Coal	$1.72	$1.99	$2.03
PRB Coal	$0.45	$0.79	$0.81



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Changes in Load and Weather Patterns

- The next figure shows changes in load in fall 2009 to 2011, as well as the changes in weather patterns that contributed to the load changes.
- The top panel shows the monthly average and peak loads during each fall.
  - ✓ Load averaged 56.4 GW in the period and peaked at 97.3 GW in early September.
  - ✓ Excluding membership changes (e.g. FirstEnergy's exit on June 1), average load increased 0.3 percent from fall 2010.
- Because a large share of the load is sensitive to weather, the figure shows how changes in weather patterns contributed to changes in load.
  - ✓ The bottom panel in the figure shows the monthly heating and cooling degree days ("HDDs and CDDs") for the fall of 2009 to 2011 at four locations in MISO.
  - ✓ To account for the different relative impacts of HDDs and CDDs on load, HDDs are inflated by a factor of 6.07 (based on a regression analysis).
- Consistent with the changes in load, degree days rose 2.4 percent in fall 2011.
  - ✓ Temperatures were mild throughout the quarter – September temperatures were below normal for much of the footprint, while in November they were much above normal in the East and Central regions.
  - ✓ Degree days remained roughly 7 percent below the historical average.

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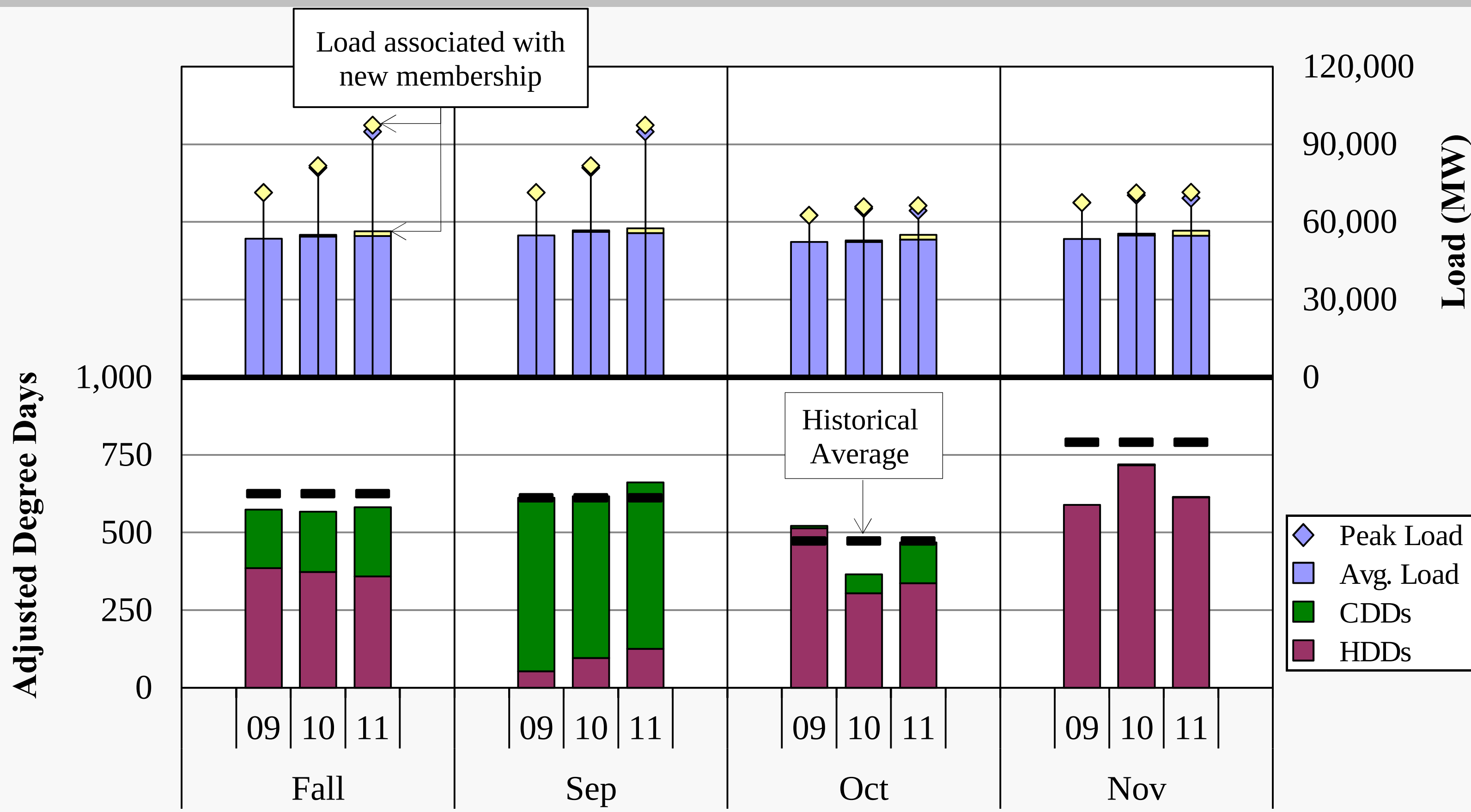
Load and Weather Patterns
Fall 2009–2011



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

Share of Interval Price Setting By Unit Fuel Type

- The next figure shows the frequency with which different types of units set real-time energy prices in MISO.
  - ✓ When a constraint is binding, more than one type of unit may be setting prices (one in the constrained area and one in the unconstrained area).
- As in prior years, coal units in fall 2011 set prices in nearly all hours (96.3 percent).
- Gas-fired resources set prices in 26.5 percent of all intervals, up from 15.3 percent last year. This is mostly due to an increase in the frequency of binding constraints.
  - ✓ Gas units along with oil-fired resources are typically needed during periods of high or unanticipated increases in load, or to manage congestion.
- Intervals with prices set by wind (DIR) units increased sharply to nearly 25 percent.
  - ✓ The DIR type was introduced in June. In fall 2011, 16 units representing 2 GW of capacity were registered, but only 14 units comprising 1.5 GW were active.
  - ✓ In almost every instance when these units were setting prices, they did so only in local areas affected by a constraint, rather than market-wide.
  - ✓ The average LMP at these locations when on the margin was -$18 per MWh because these units receive subsidies that often result in marginal costs, and in turn energy offers, below zero.
  - ✓ In January 2012, an additional 8 wind resources will become DIR-type units.

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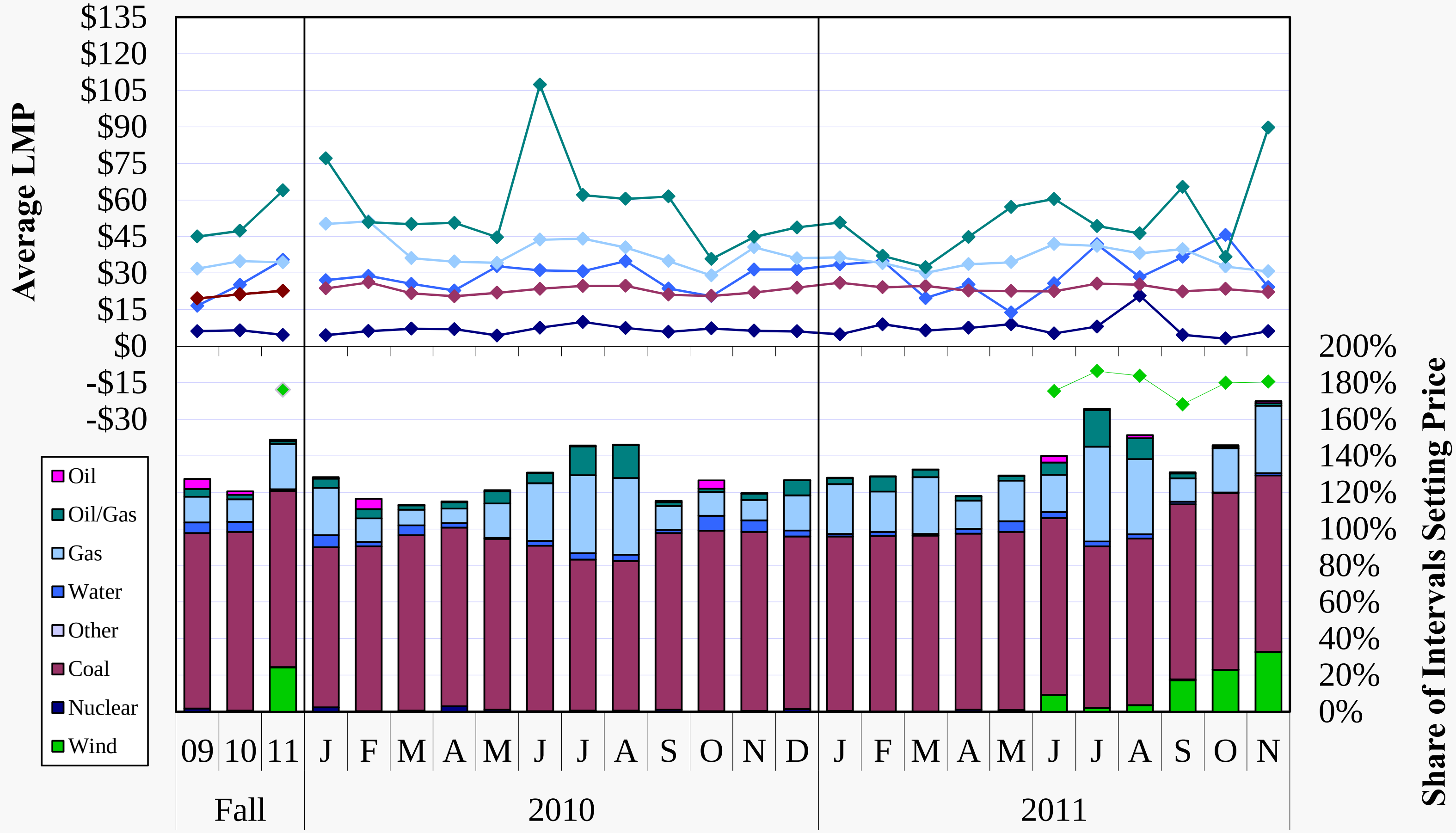
Real-Time Energy Price Setting By Unit Fuel Type 2010–2011



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Day-Ahead and Real-Time Price Convergence

- A well-functioning and liquid day-ahead market should result in good convergence between day-ahead and real-time prices.
  - ✓ Day-ahead premiums are generally expected due to the higher price volatility in the real-time market and larger RSG allocation to buyers in the real-time market.
- The next figure shows the day-ahead to real-time price convergence at the Cinergy Hub (the table shows other locations).
  - ✓ On the whole, price convergence in MISO was fair: there were slight real-time premiums of approximately 1 percent at most locations.
  - ✓ Only WUMS exhibited a day-ahead premium (6 percent).
- Slight real-time premiums prevailed despite full day-ahead load scheduling, under-scheduling of wind by an average of 520 MW, and an average increase in real-time imports by nearly 380 MW.
  - ✓ Unexpected load contributed to modest real-time premiums in early September.
  - ✓ The small real-time premiums during the quarter do not raise significant concerns.
- The absolute value of the hourly differences measures the typical magnitude of the differences, regardless of direction.

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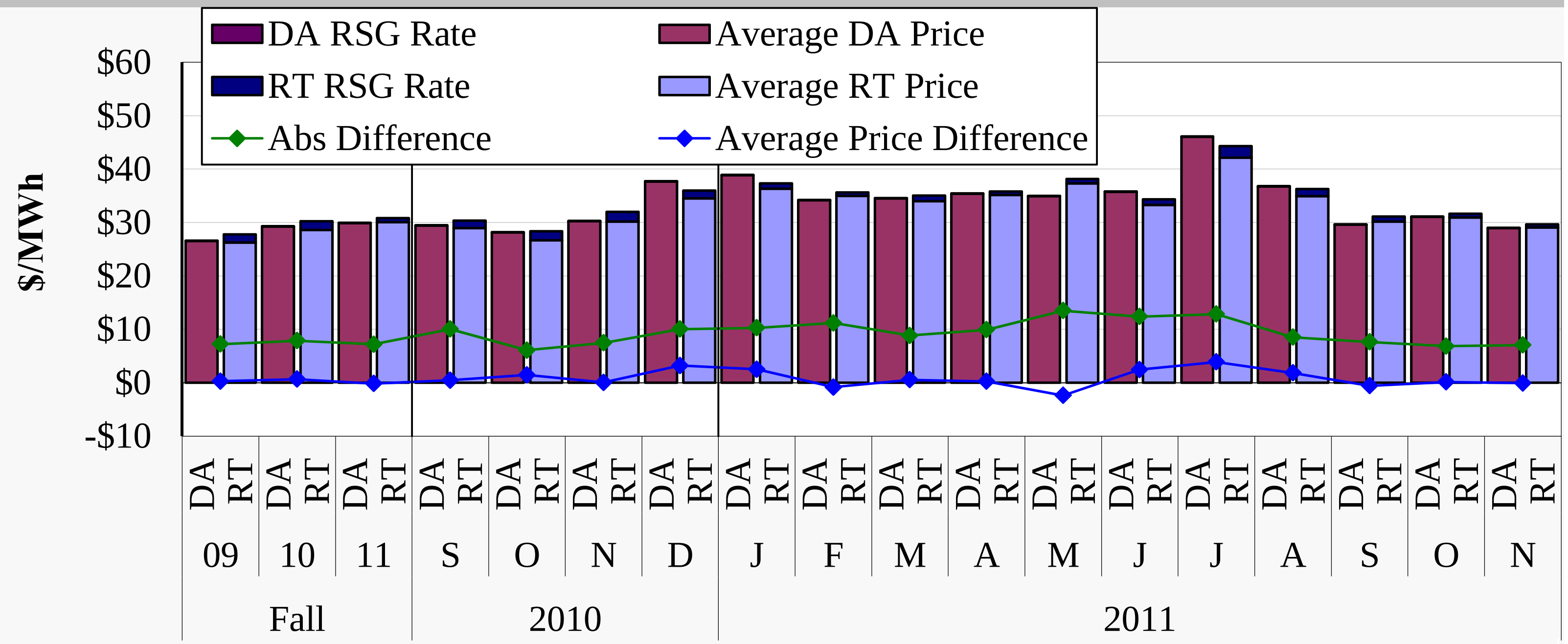
Day-Ahead and Real-Time Price Convergence 2009–2011



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

Cinergy Hub	1	2	-1	2	5	0	9	7	-2	2	1	-6	7	9	5	-2	0	0
Michigan Hub	3	0	-1	2	-5	2	10	6	-5	3	7	-5	2	8	4	-3	2	-4
Minnesota Hub	0	4	0	5	7	-1	4	1	-6	-10	-16	5	-9	6	-1	-4	0	4
WUMS Area	10	12	6	21	11	4	2	3	-6	0	-4	5	6	8	-1	1	9	8

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

Cinergy Hub	28	27	24	35	23	25	29	28	32	26	28	36	37	30	24	25	22	24
Michigan Hub	40	36	26	40	37	29	31	31	36	28	39	40	37	32	26	29	23	28
Minnesota Hub	37	42	38	47	39	41	32	24	52	33	41	48	40	27	29	37	32	44
WUMS Area	39	37	30	50	31	31	31	24	34	25	31	37	39	26	26	32	29	30

Note: Beginning in April 2011, the RSG rate is specifically the DDC Rate charged to deviations, and excludes CMC rates.

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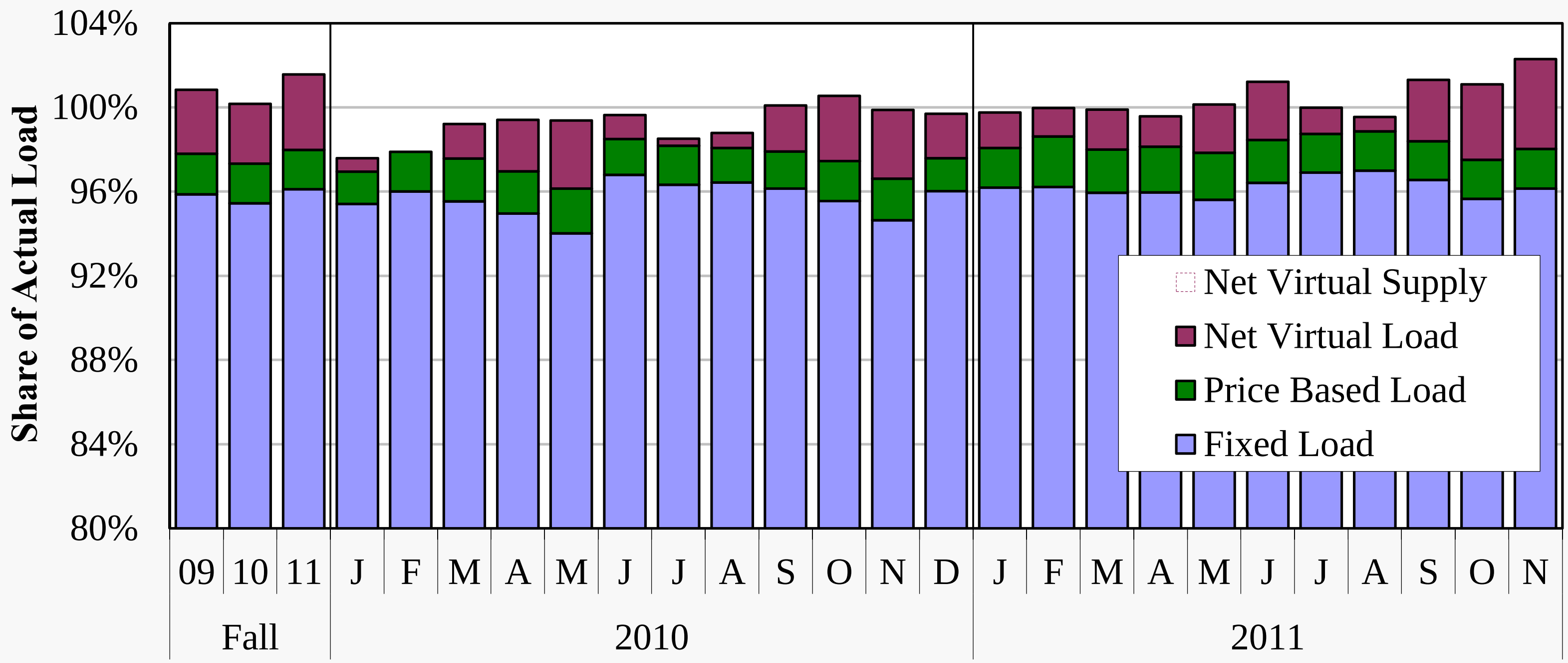
Day-Ahead Load Scheduling

- The following figure shows net load scheduling during the daily peak hour.
  - ✓ Net day-ahead load scheduling is a key driver of RSG because low levels can compel MISO to commit peaking resources to satisfy higher real-time load.
  - ✓ However, real-time commitments are still made to manage congestion, resolve local reliability issues and accommodate short-term ramp demands.
- Load was fully scheduled on average during all hours (100.4 percent) as well as peak hours (101.6 percent) in fall 2011.
  - ✓ Net virtual load more than made up the scheduling shortfall of fixed and price-based load.
- This broad metric masks considerable variation in day-to-day scheduling and the correlation with day-ahead price premiums.
  - ✓ Large scheduling discrepancies – particularly under-scheduling – can have disproportionately large price effects.
  - ✓ Forecasting errors by participants, particularly in September, contributed to large under and over-scheduling on some days (by over 10 percent on Sept. 4).
  - ✓ However, these events tend to be relatively infrequent and did not raise substantial concerns this quarter.

Day-Ahead Peak Hour Load Scheduling 2009–2011



Share of Actual Load(%)

All Hour	100.2	99.5	100.4	98.2	98.9	99.3	99.2	99.4	99.9	99.2	99.4	99.4	99.8	99.4	100.0	100.3	99.8	99.6	99.3	99.4	100.8	100.9	100.2	100.4	100.4	100.5
Peak Hour	100.7	100.2	101.6	97.6	97.9	99.2	99.4	99.4	99.6	98.5	98.8	100.1	100.5	99.9	99.7	99.8	100.0	99.9	99.6	100.1	101.2	100.0	99.5	101.3	101.1	102.3

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Virtual Load and Supply in the Day-Ahead Market

- Virtual trading in the day-ahead market facilitates convergence between the day-ahead and real-time prices.
  - ✓ This serves to improve the efficiency of day-ahead market results and mitigates market power in the day-ahead market.
- The next three figures show the average hourly quantities virtual demand bids and supply offers and those that were scheduled (cleared) in the day-ahead market.
- The figures distinguish between bids and offers that are "price-sensitive" and "price insensitive" (those that are very likely to clear).
  - ✓ Bids and offers are considered price-insensitive when they are offered at more than $30 above and below "expected" real-time prices, respectively.
  - ✓ Price-insensitive bids and offers that then contribute to a significant difference in the congestion at a location between the day-ahead and real-time markets (labeled "Screened Transactions") are investigated.
    - – These transactions are not rational and lead to price divergence.
- We have been monitoring changes in virtual trading activity since MISO changed the RSG cost allocation in April 2011.
  - ✓ The change generally reduces the allocation of RSG to virtual supply, and eliminates any allocation when virtual supply is netted against virtual load.

Virtual Load and Supply in the Day-Ahead Market

- The first figure shows that cleared volumes in fall 2011 increased by 56 percent from the prior fall. Offered volumes, however, increased by just 1 percent.
  - ✓ Cleared virtual supply volumes rose by 68 percent to 3.7 GW per hour on average, while cleared virtual demand rose 48 percent to 4.8 GW.
- This rise is largely associated with price-insensitive bids and offers.
  - ✓ Approximately 57 percent of cleared demand bids were price-insensitive, up from 34 percent in fall 2010. Similarly 13 percent of virtual supply was offered price-insensitively, up from six percent last fall.
  - ✓ Less than 5 percent of cleared volumes were screened for further review.
- These increases coincides with the April 2011 RSG allocation change.
  - ✓ The change has generally reduced the transaction cost of submitting virtual bids and offers. By forcing an equal level of supply and demand to clear, participants can avoid most of the RSG cost allocation.
- The RSG rule change has made it favorable for certain participants to take balanced positions to arbitrage basis differences (price differences between locations).
  - ✓ A large share of these appear to be intended to arbitrage loss factors differences.
  - ✓ Such arbitrage provides little benefit and MISO is taking steps to reduce such discrepancies.

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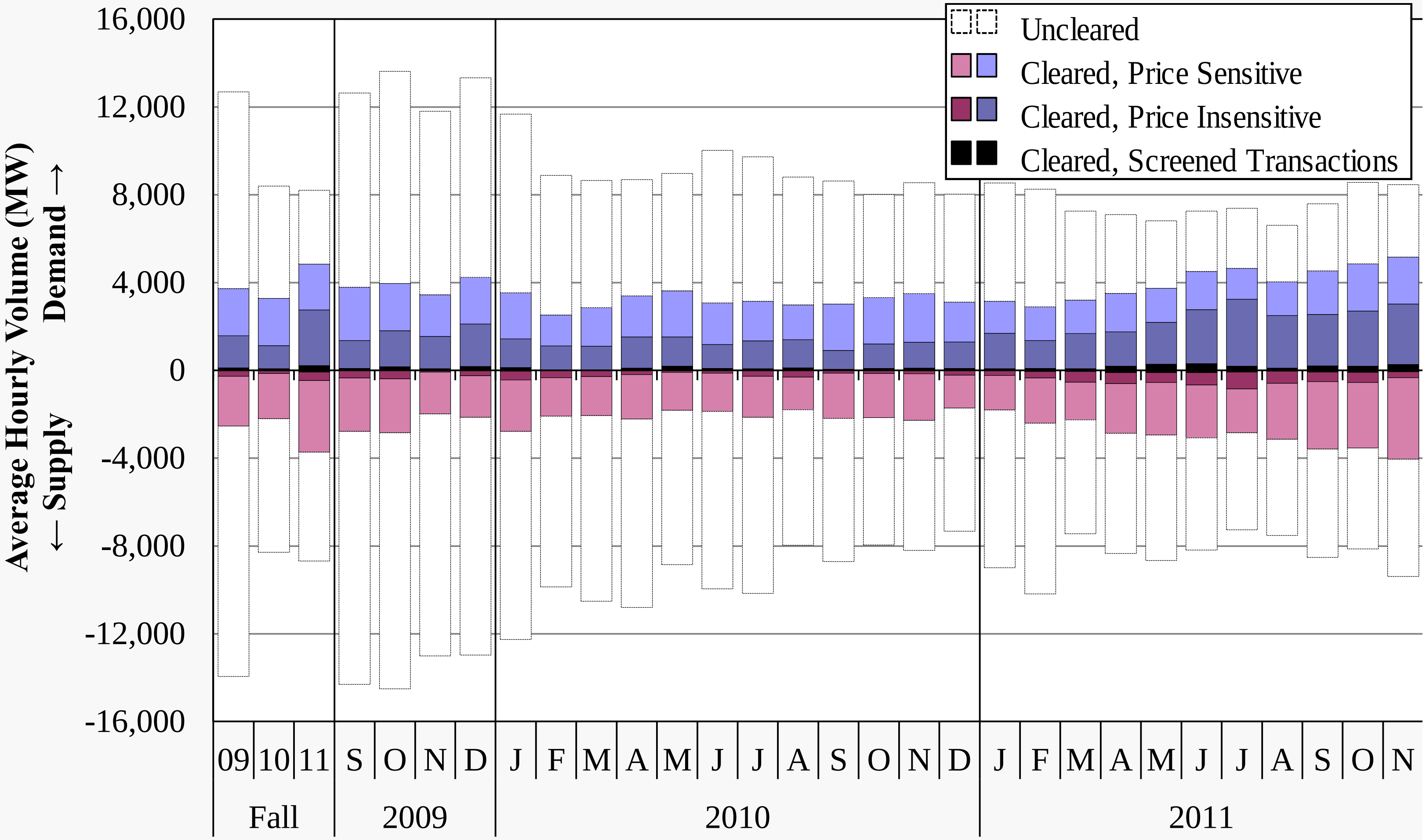
Virtual Volumes 2009–2011



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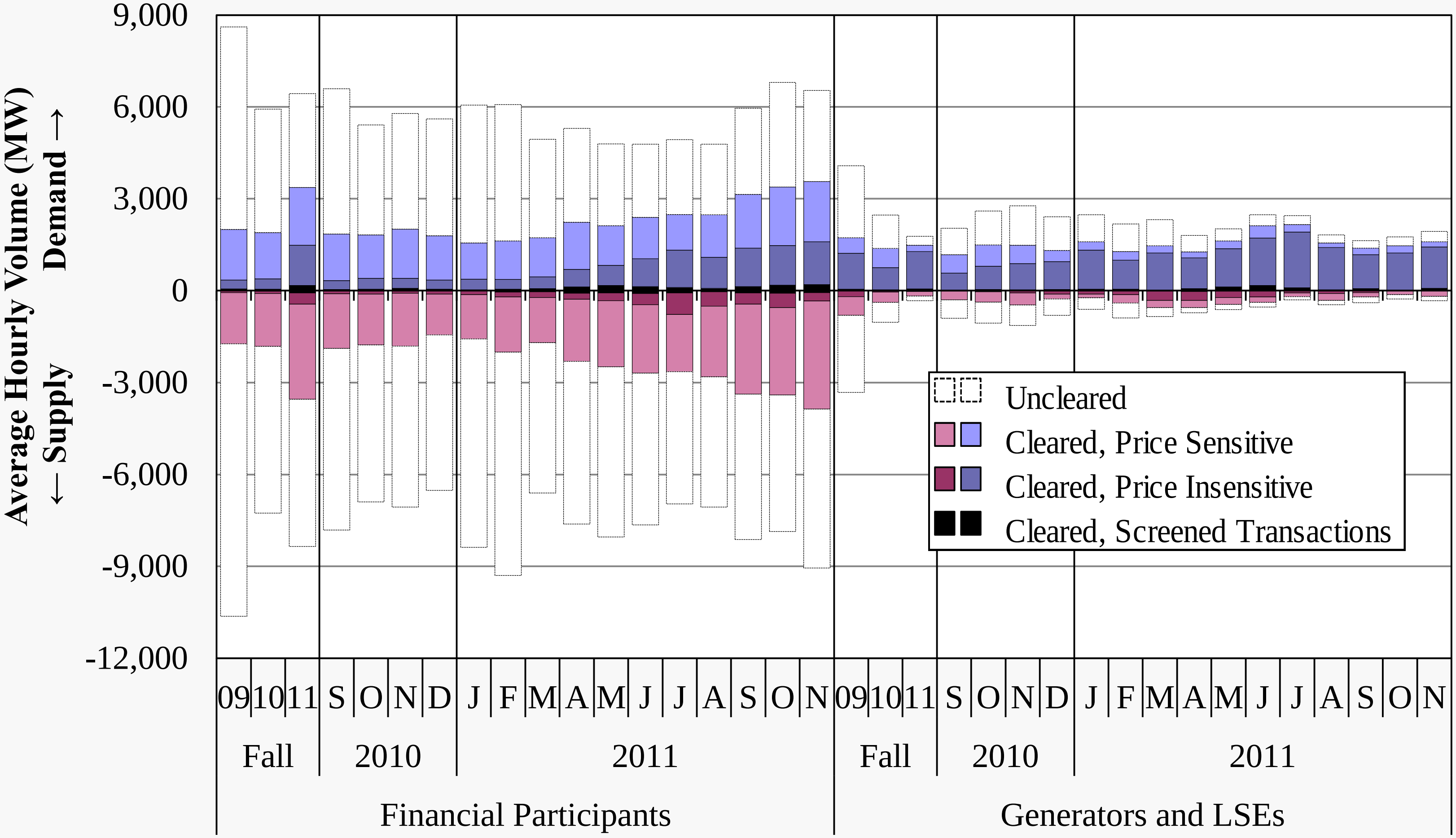
Virtual Load and Supply by Participant Type

- The next figure shows the same results disaggregated by type of market participant.
  - ✓ The figure distinguishes between physical participants (generation owners or LSEs) and financial-only participants.
- The increase in volumes is confined to financial-only participants: such participants comprised 81 percent of cleared volumes in fall 2011, up from 68 percent in fall 2010.
  - ✓ Financial participants cleared approximately 3.5 GW each of supply and demand in fall 2011, up from approximately 1.9 GW in the prior fall.
- While financial participants' volumes were evenly divided between supply and demand, nearly 90 percent of physical participants' volumes were demand bids.
  - ✓ Physical participants provided just 5 percent of cleared virtual supply.
- Physical participants generally offer less price-sensitively than financial participants.
  - ✓ Such transactions provide physical participants with a hedge against load uncertainty or supply availability.
  - ✓ Nearly 80 percent of volumes offered by physical participants in fall 2011 cleared, compared to 47 percent of those offered by financial-only participants.
  - ✓ This is a substantial increase from prior years: just 34 percent of volumes offered by physical participants in fall 2009 cleared, while 50 percent did so in fall 2010.

Virtual Volumes by Participant Type 2009–2011



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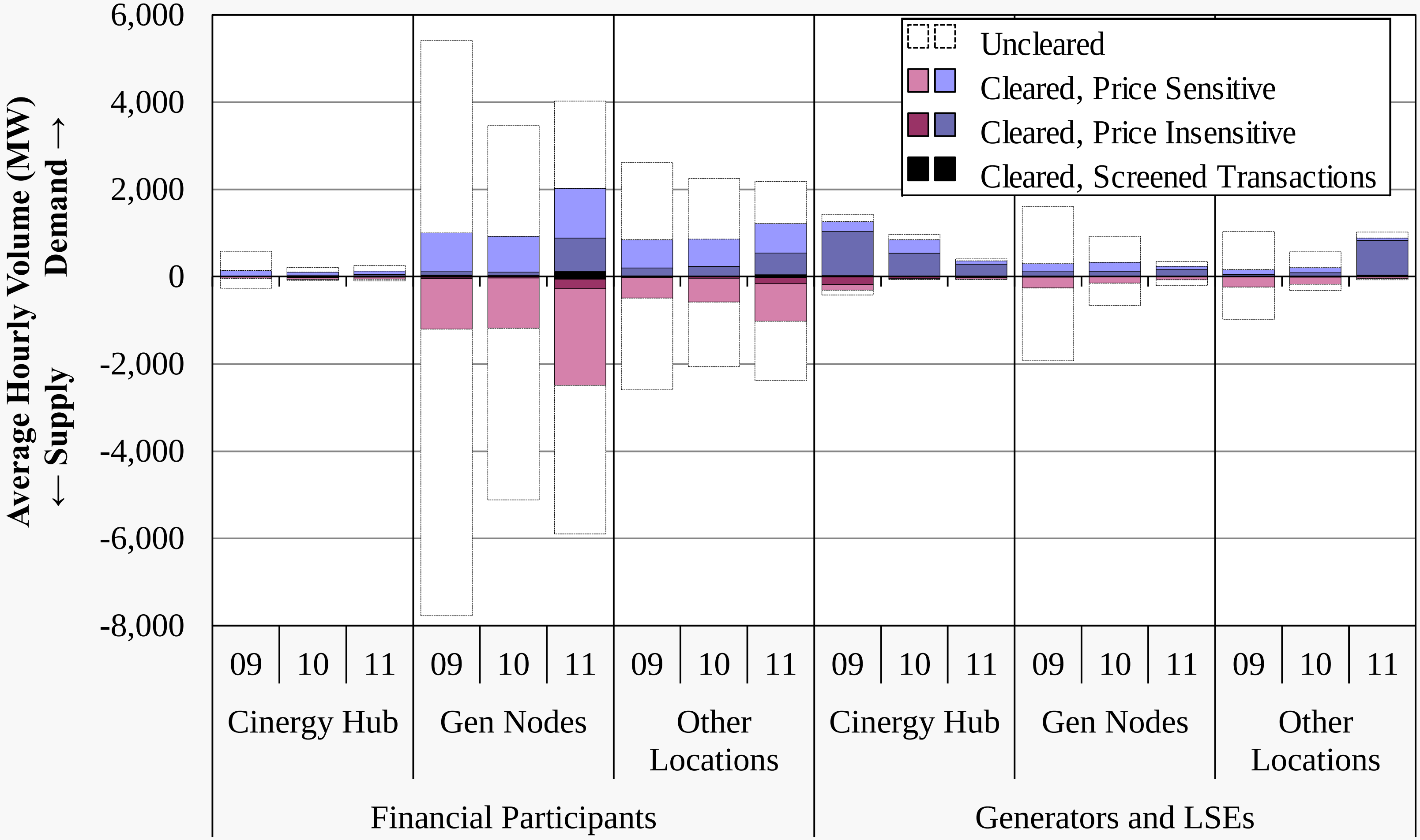
Virtual Load and Supply by Participant Type and Location

- The third figure in this set presents the same results broken down by type of market participant and location (Cinergy Hub, other hubs and zones, and nodes).
  - ✓ Cinergy Hub remains the single most liquid trading point, although offered and cleared volumes there have dropped by two-thirds there since fall 2009.
- The majority of virtual liquidity in the day-ahead market is at generator nodes.
  - ✓ Over 60 percent of offered volumes and 56 percent of cleared volumes occur here.
  - ✓ As in prior quarters, the vast majority of these – 95 percent in fall 2011 – are by financial-only participants.
  - ✓ Conversely, three-quarters of offered volumes by physical participants are in the form of demand bids at hub locations, including Cinergy Hub.
- The figure shows that the increase in cleared virtual transactions are almost entirely due to increased activity by financial participants. Much of the increase is associated with the price-insensitive trading strategies we discussed above.
- Similarly, the year-over drop in offered volumes is almost entirely confined to physical participants at all locations.
  - ✓ One participant began offering substantial price-insensitive demand quantities at a load zone in January 2011, which has not raised significant concerns.

Virtual Volumes by Participant Type and Location
Fall 2009–2011



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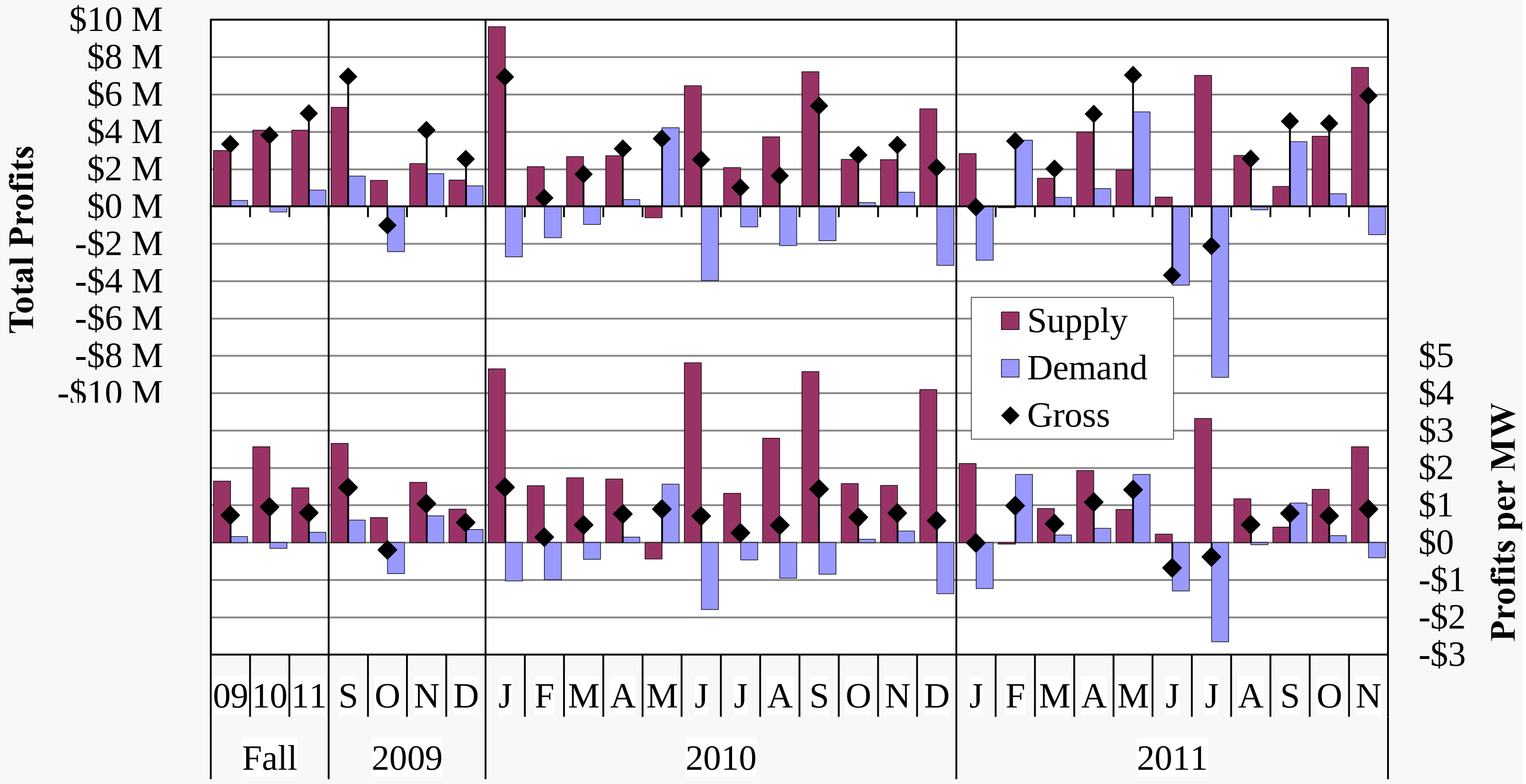
Virtual Profitability in the Day-Ahead Market

- The following two figures examine monthly profitability of virtual purchases and sales.
- Gross profitability in fall 2011 totaled nearly $15 million, or $0.80 per MW.
  - ✓ This result is consistent with the modest profitability recorded in prior quarters.
- Virtual supply continues to be considerably more profitable ($1.47 per MW) than virtual demand ($0.28).
  - ✓ Virtual supply profitability is expected in markets with prevailing day-ahead premiums.
  - ✓ These margins exclude CMC or DDC charges assessed to net harming deviations, including net virtual supply. DDC charges averaged $0.76 per MWh in the quarter, down from $1.53 in the third quarter of 2011.
- The second figure shows that virtual transactions by financial participants are generally profitable and improve convergence, while those by physical participants are generally unprofitable.
  - ✓ Cleared virtual supply by financial participants remained persistently profitable at $1.53 per MW. Cleared demand was also profitable at $0.54.
  - ✓ Demand losses by physical participants, which averaged $-0.41 per MW in fall 2011, were not as great as in summer, when they lost on average near $3 per MW.
  - ✓ Physical participants have consistently been willing to incur losses on virtual demand to hedge against the risk of real-time price spikes.

Virtual Profitability
2009–2011



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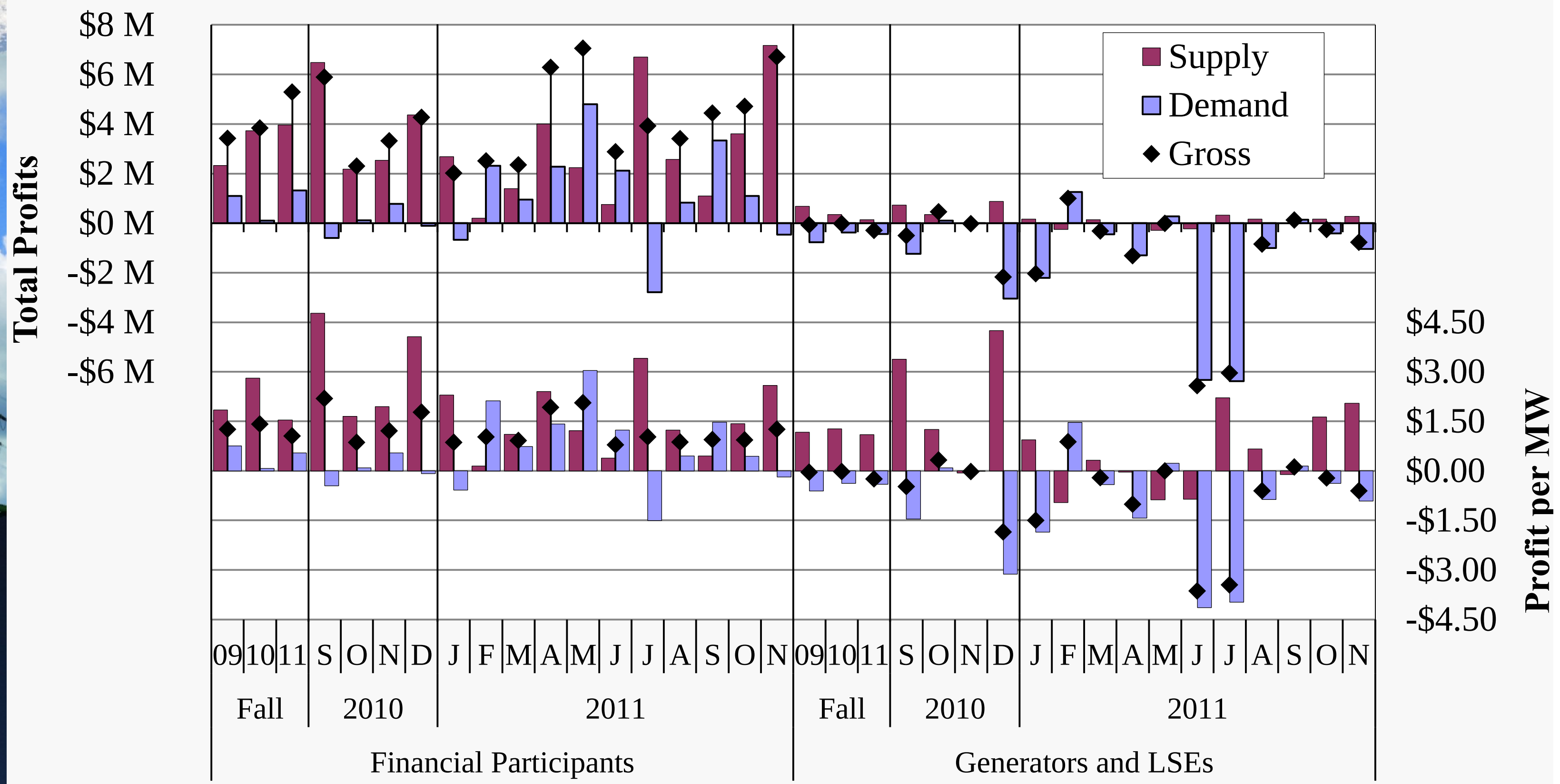
Virtual Profitability by Participant Type 2009–2011



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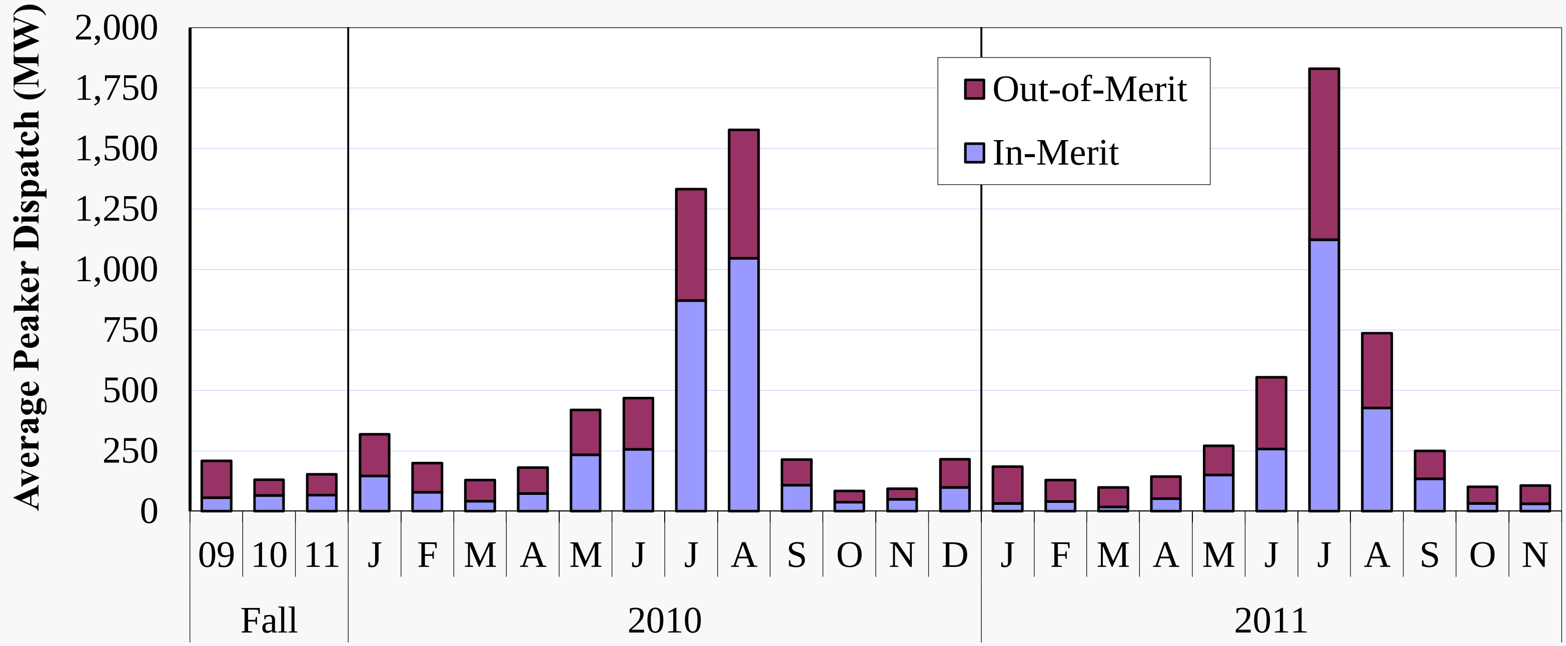
Peaking Resource Real-Time Dispatch

- The following figure shows the dispatch of peaking resources, indicating the share of the peaking resources that were out-of-merit (offer price higher than the LMP).
- Peaking resource dispatch quantities averaged 152 MW per hour in fall 2011.
  - ✓ This is comparable to prior fall seasons and is substantially below summer totals, when large quantities of peaking resources are sometimes committed for the system's capacity needs.
- The share of units dispatched out-of-merit increased to 57 percent, which is typical for periods that do not require the dispatch of large quantities of peaking resources.
  - ✓ This continues to indicate that peaking resources frequently do not set the energy price, even when they are needed to meet the system's needs.
- When peaking resources do not set the energy price, relatively high-cost resources committed to manage congestion or to provide capacity will be out-of-merit.
  - ✓ MISO continues to develop pricing improvements, including its Enhanced LMP initiative, which will allow peaking resources to set energy prices when appropriate.
  - ✓ This will improve MISO's price signals and reduce real-time RSG payments.

Peaking Resource Dispatch and In-Merit Status 2010–2011



Out-of-Merit Quantity and Share

MW	152	65	86	173	120	88	106	185	212	461	530	106	46	44	116	152	88	82	92	120	296	707	311	115	69	75
%	73	50	57	54	60	68	59	44	45	35	34	49	54	47	54	82	68	82	64	44	53	39	42	46	68	70

Real-Time and Day-Ahead RSG Payments

- The next two figures show RSG payments made to peaking units and other units in the real-time and day-ahead markets.
  - ✓ RSG costs are shown on both a nominal basis and adjusted for changes in fuel prices.
  - ✓ Fuel prices are indexed to the average price over the period shown. Hence, the adjustment is greatest for periods when fuel prices were highest (in January 2010).
- RSG costs decreased substantially in fall 2011. Overall costs fell by more than 50 percent on both a nominal and fuel-adjusted basis (fuel prices were unchanged).
- Payments for capacity decreased to just $4 million, down 51 percent from fall 2010.
  - ✓ More than full load scheduling (averaging 102.3 percent during the peak hour, see slide 18) limited the need for MISO to commit additional resources in real time.
- Payments for congestion decreased nearly 60 percent to $10.5 million.
  - ✓ In fall 2010, the majority of payments for congestion ($18.4 million) were made to units in WUMS committed for voltage support. These commitments continued into fall 2011 but totaled just $5 million.
- The second figure shows day-ahead RSG payments, which were comparable to RSG payments during the same quarter in 2009 and 2010.
  - ✓ Day-ahead RSG payments continue to be lower than real-time RSG payments because most reliability requirements are satisfied only in the real time.

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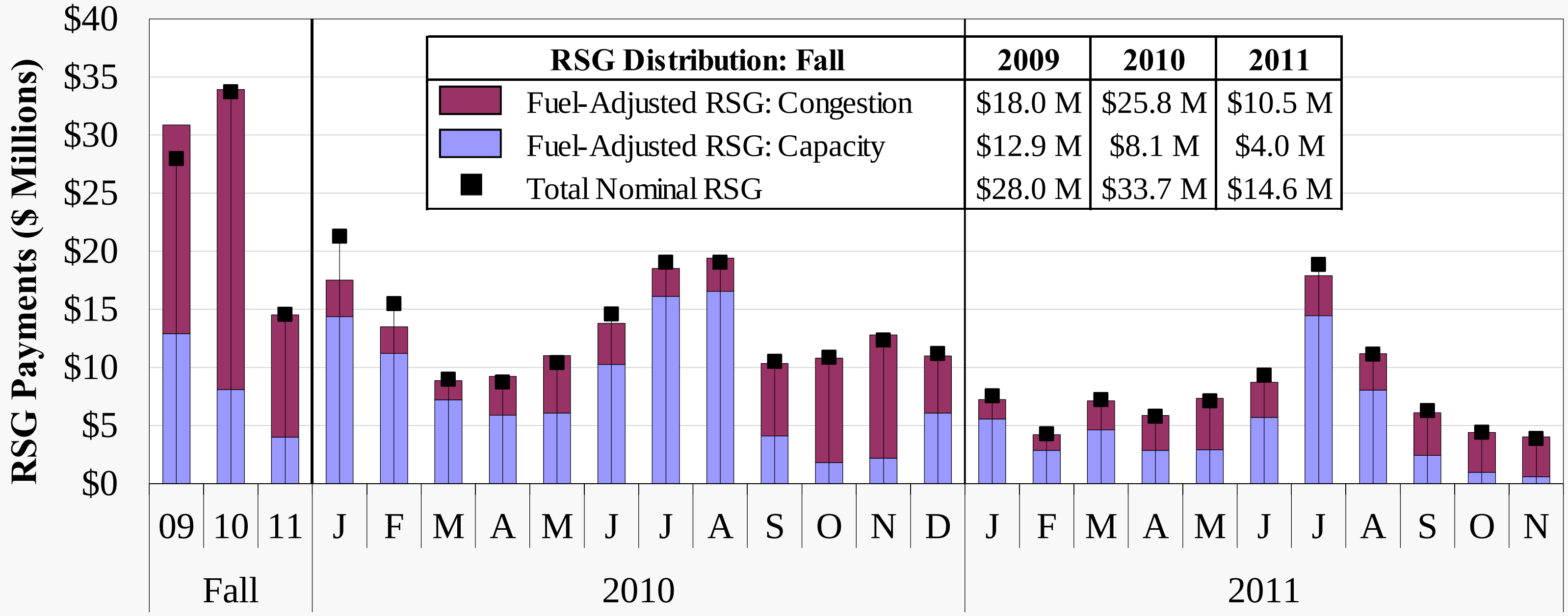
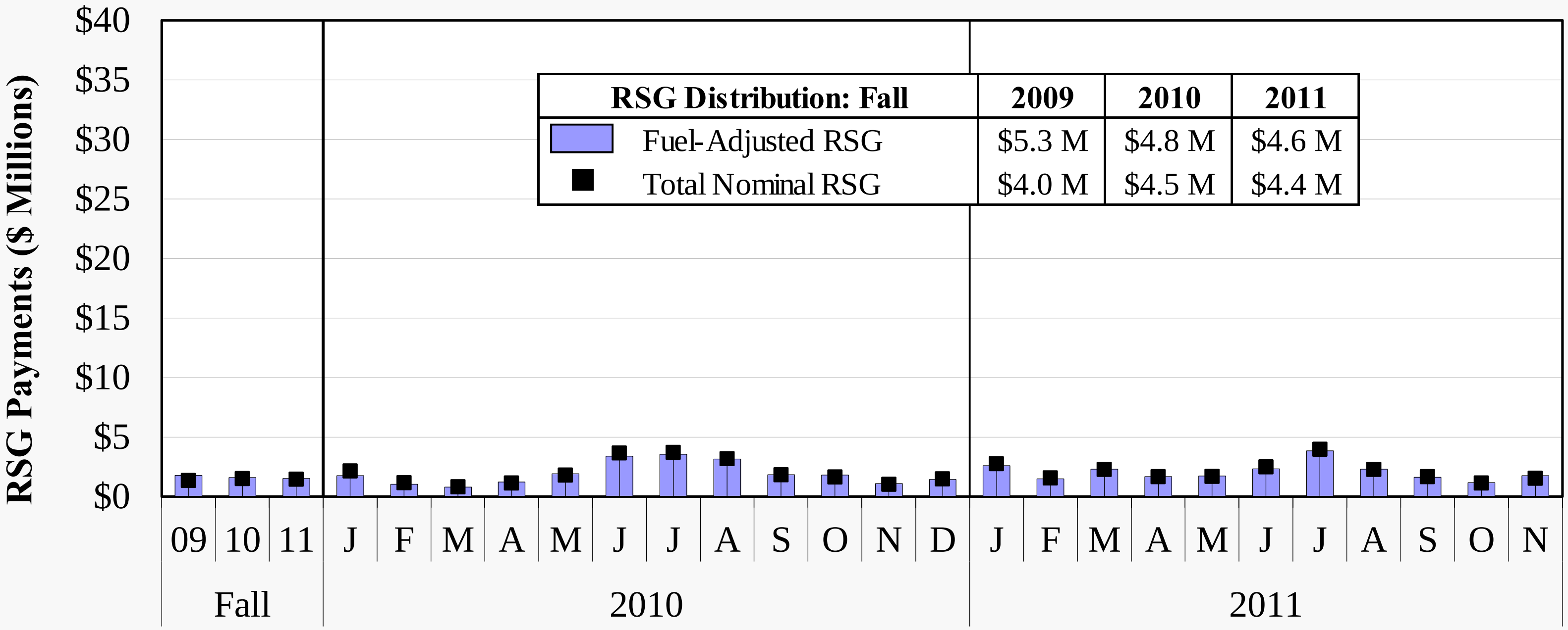
Real-Time RSG Payments 2010–2011



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

Peaker	76	27	44	58	53	59	58	64	50	69	71	39	20	23	47	60	53	54	53	48	69	75	66	45	46	41
Constraint	45	14	26	10	9	4	16	27	5	6	10	12	13	16	13	7	13	6	17	16	15	14	15	16	32	35
Capacity	31	14	19	48	44	55	43	37	45	63	60	28	8	7	34	53	40	49	36	32	53	62	51	29	14	6
Non-Peaker	24	73	56	42	47	41	42	36	50	31	29	61	80	77	53	40	47	46	47	52	31	25	34	55	54	59
Constraint	12	64	48	6	6	13	19	16	20	7	3	52	72	67	31	15	21	31	34	43	19	6	14	47	48	52
Capacity	13	9	7	36	40	28	22	21	30	24	26	9	8	9	22	24	26	15	14	9	12	18	19	9	6	6

Day-Ahead RSG Payments 2010–2011



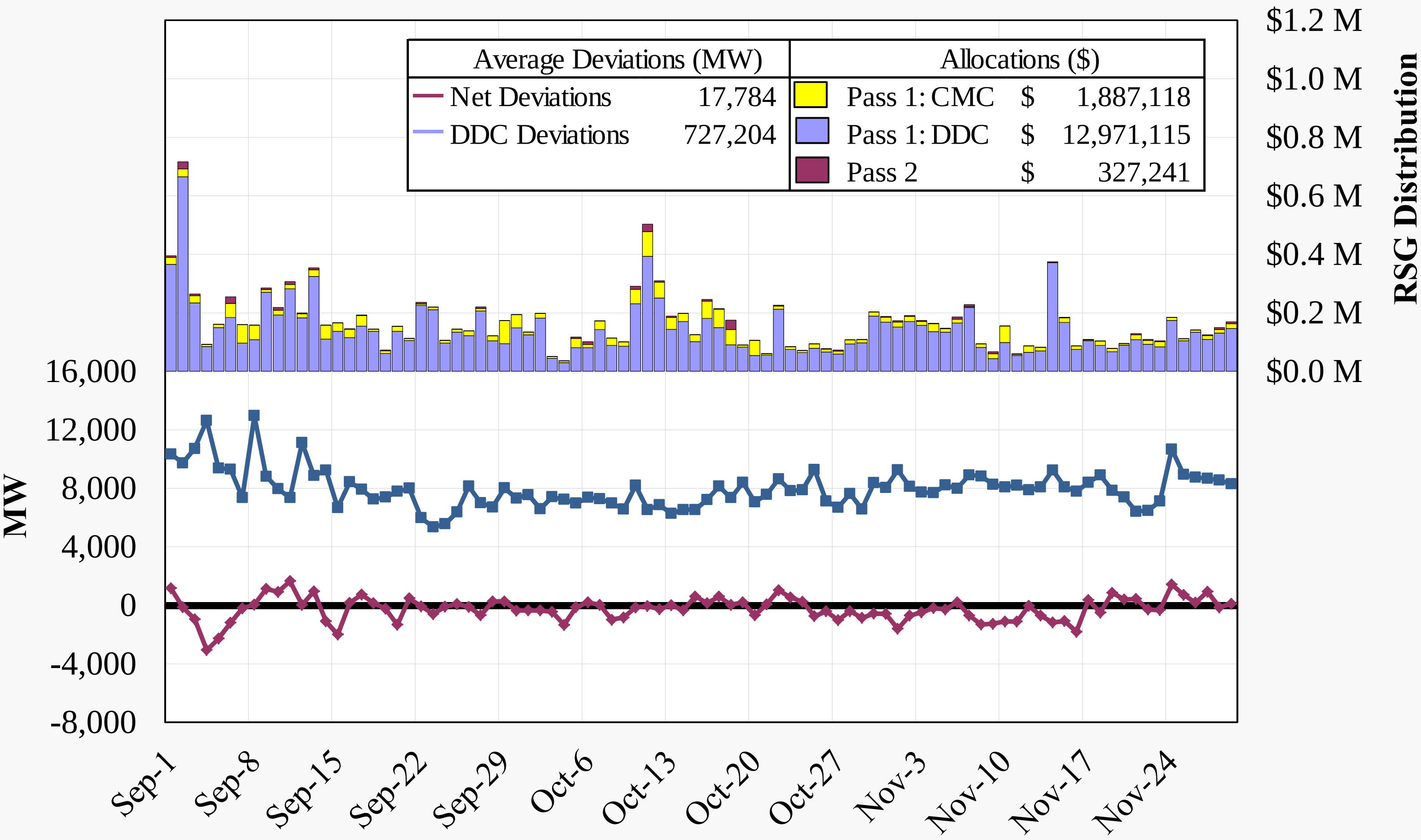
Share of Day-Ahead RSG Costs by Unit Type (%)

Peaker	7	6	12	4	0	2	3	14	11	26	35	10	3	3	9	1	0	2	2	7	21	41	15	19	11	6
Non-Peaker	93	94	88	96	100	98	97	86	89	74	65	90	97	97	91	99	100	98	98	93	79	59	85	81	89	94

Allocation of RSG Charges

- The next figure evaluates the allocation of RSG costs in fall 2011. The process was substantively revised in April 2011 to better reflect cost causation.
  - ✓ The top panel shows the real-time RSG that was allocated to market-wide deviations (“DDC”), deviations that affect constraints (“CMC”), and real-time load (“Pass 2”).
  - ✓ The bottom panel shows net deviations from physical load, virtual supply and load.
- The figure shows that under the new allocation method, over 85 percent of the real-time RSG costs incurred in fall 2011 are being allocated to market-wide deviations.
  - ✓ This level of allocation substantially exceeds the portion of the real-time RSG costs we had previously estimated were actually caused by deviations.
  - ✓ The excessive share of allocations to market-wide deviations is primarily due to:
    - – Over 80 percent of uplift costs associated with commitments for constraint management are ultimately being charged to DDC deviations.
    - – Helping and harming deviations are not netted in the allocation, except at the participant level.
  - ✓ We have been working with MISO and stakeholders on one key improvement to modify the allocation of voltage support costs, which should be borne by the real-time load in the affected area rather than deviations. This change should be filed in December.
    - – We will be providing additional recommended improvements to the allocation process in our *2011 State of the Market Report*.

Allocation of RSG Charges
Fall 2011



POTOMAC ECONOMICS

Price Volatility Make Whole Payments

- The next chart shows Price Volatility Make Whole Payments ("PVMWP") that improve incentives for suppliers to follow dispatch instructions.
  - ✓ These payments come in two forms: Day-Ahead Margin Assurance ("DAMAP") and Real-Time Offer Revenue Sufficiency Guarantee Payments ("RTORSGP").
- Payments in fall 2011 totaled $18.3 million, a 24 percent decline from fall 2010. This is consistent with a general reduction in price volatility.
- DAMAP continues to be the larger of the two payments at $14.9 million, which is 19 percent lower than in fall 2010.
  - ✓ RTORSGP payments declined by more than 40 percent, to $3.4 million.
- The lines on the chart show two measures of price volatility: one based on the system marginal price and the other on LMPs at generator locations.
  - ✓ The figure shows that the payments have been correlated with price volatility as expected – increased volatility leads to higher obligations to flexible suppliers.
  - ✓ It also shows that volatility is higher at recipients' locations because they are generally redispatched more than other suppliers due to the larger price changes.
- We recommended several changes to the calculation formulas and RTORSGP eligibility criteria in the *2010 State of the Market Report* to improve these payments and MISO is working on these changes.

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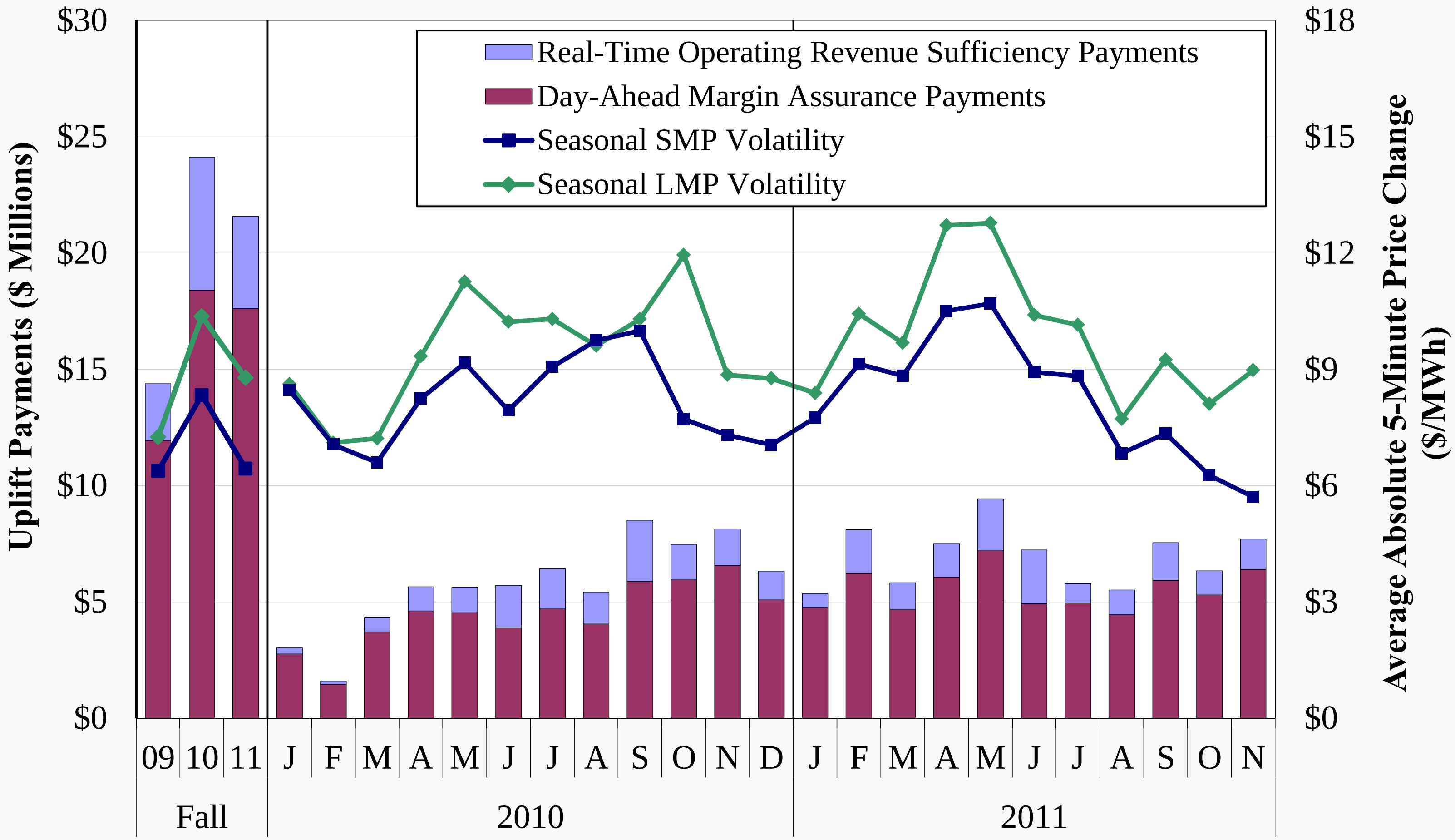
Price Volatility Make Whole Payments 2010–2011



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

- The next figure shows wind output scheduled in day-ahead and real time.
  - ✓ Attractive wind profiles in the West Region, along with state renewable portfolio standards and federal subsidies, continue to support investment in wind generation.
- Real-time wind output averaged 3.3 GW in fall 2011, a 21 percent increase from 2010.
  - ✓ Nameplate capacity over the same period rose 22 percent to 10.6 GW.
  - ✓ Wind generation remains distinctly seasonal – output in fall 2011 was nearly twice as high as during the summer 2011.
- Wind output was exceptionally high in November, averaging 4.4 GW and peaking at a new record of almost 7.8 GW on November 5.
- Variability in output – both in real-time and deviations from the day-ahead – must be managed by MISO by modifying the commitment or dispatch of other resources.
  - ✓ Average sixty minute volatility of non-DIR wind resources was 216 MW, a slight decrease from fall 2010. As a share of wind output it remained near 8 percent.
  - ✓ Underscheduling of wind in the day-ahead resumed this quarter and averaged 520 MW.
- Manageability of the congestion caused by wind should continue to improve as DIR resources expand in the MISO footprint.
  - ✓ Sixteen resources totaling over 2 GW were registered as DIR in the quarter.
  - ✓ Beginning in January, an additional eight resources will participate.

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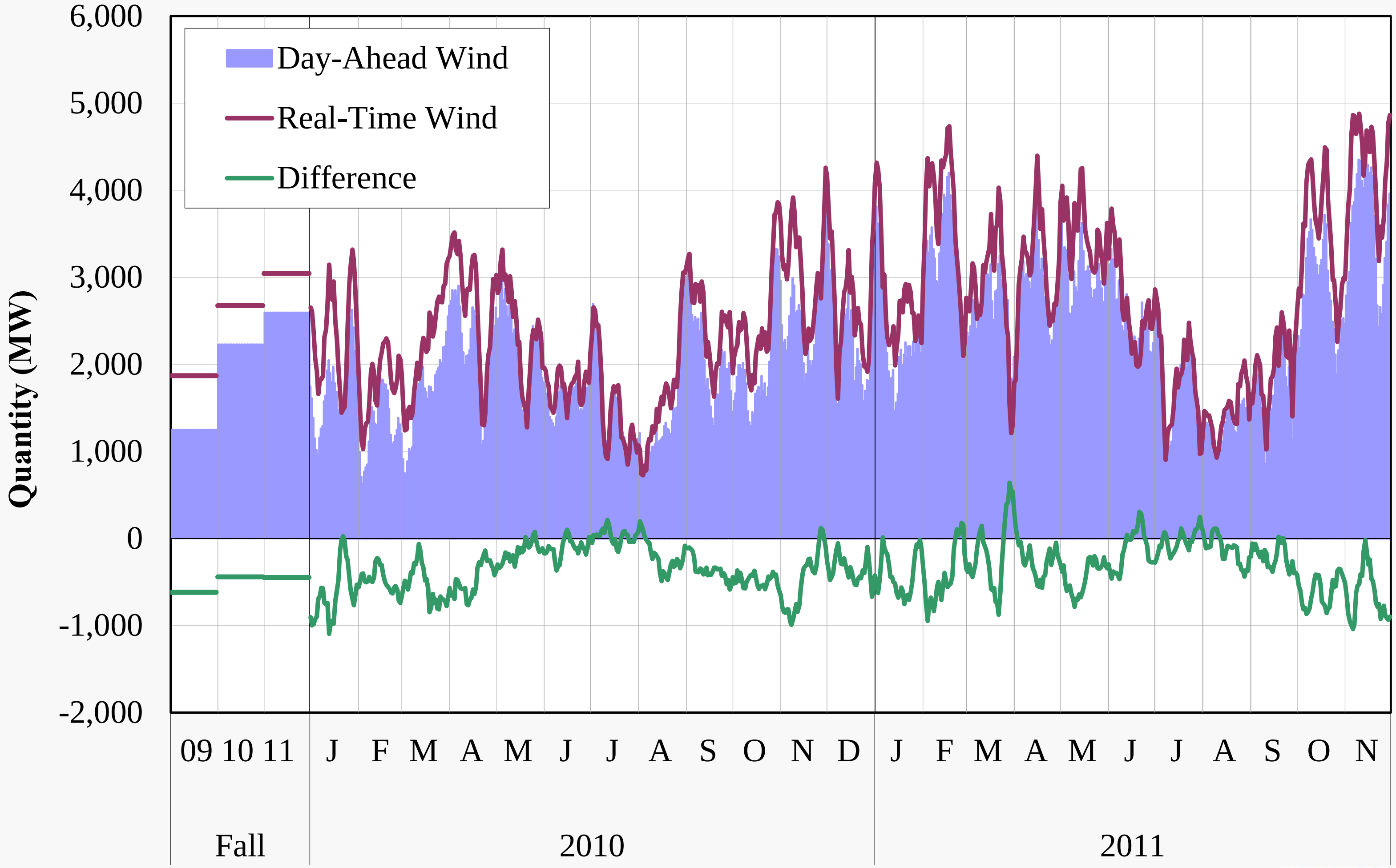
Wind Output in Real-Time and Day-Ahead Markets
7-Day Moving Average, 2009–2011

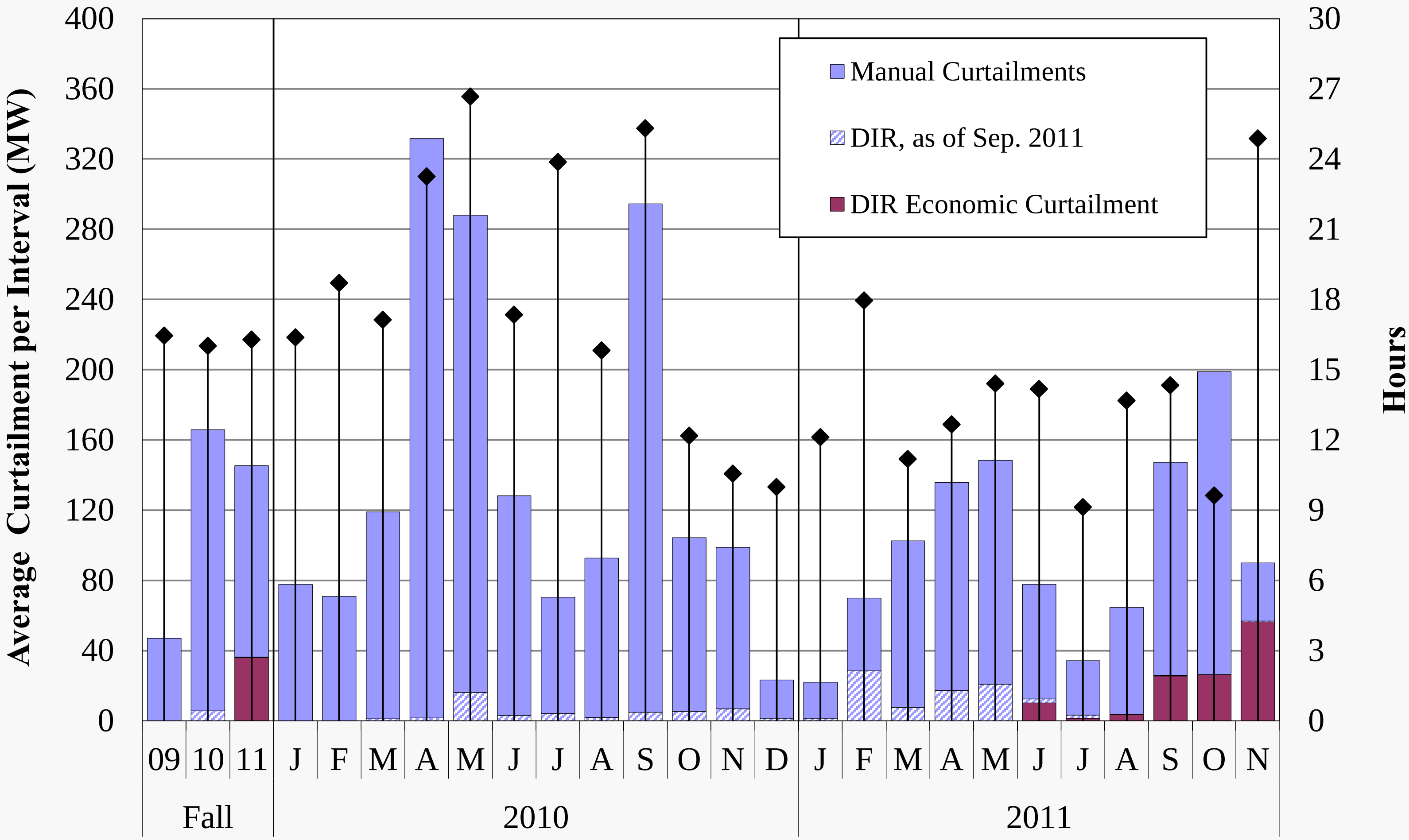


POTOMAC ECONOMICS

Manual Wind Curtailments

- Manual curtailment of wind resources by MISO has increased with wind output.
  - ✓ This has been necessary to prevent transmission overloads because most wind resources are not currently dispatchable by MISO.
- As noted, sixteen wind resources providing 2 GW of capacity were registered as DIR in fall 2011, although only 14 of these units were active.
  - ✓ Over 8.6 GW of wind generation remains non-dispatchable.
- Manual wind curtailments totaled 109 MW in fall 2011, a 34 percent decline from fall 2010 even though wind output rose by 21 percent.
  - ✓ The reduction in manual curtailments can be attributed to the increased use of DIR.
  - ✓ The share of wind generation that was manually curtailed declined from 5.7 percent in fall 2010 to 3.2 percent in fall 2011.
  - ✓ However, the average manual curtailment still lasted over 16 hours.
- Economic DIR curtailments have increased steadily since their introduction in June.
  - ✓ In fall 2011, an average of 36 MW was economically curtailed per interval. Economic DIR curtailments in November outpaced manual wind curtailments for the first time.
  - ✓ Less than 5 percent of all curtailments since the start of 2010 were of units currently registered as DIR, indicating that DIR units are not in the most congested locations.
  - ✓ Expanded adoption of the DIR type should therefore significantly improve congestion manageability and energy pricing.

Manual Wind Curtailments 2009–2011

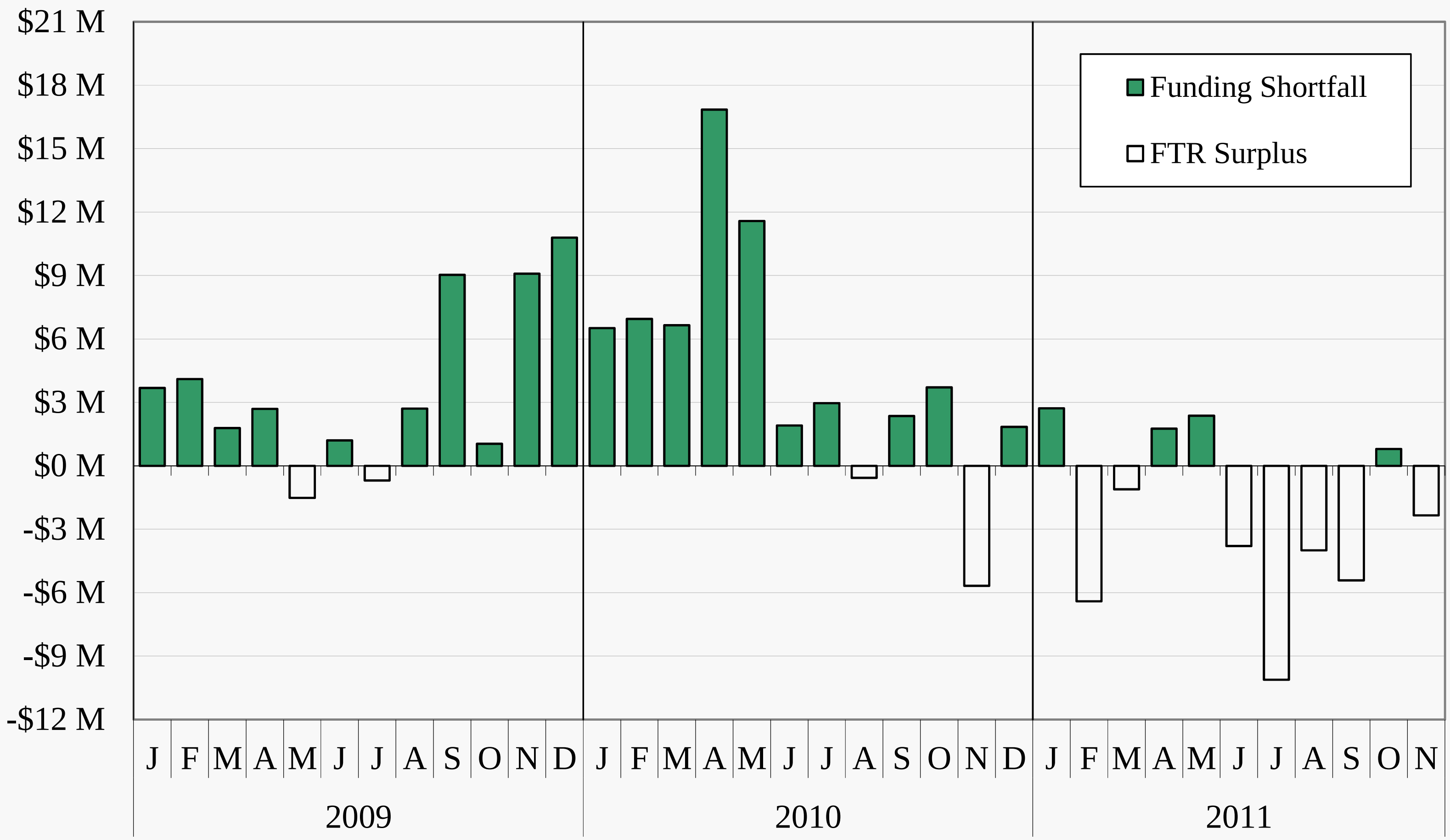


POTOMAC ECONOMICS

Day-Ahead FTR Funding

- FTR holders are entitled to the day-ahead congestion costs that arise between particular locations in MISO.
  - ✓ MISO collects congestion costs and pays them out via FTR payments.
  - ✓ Shortfalls and surpluses can 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 the monthly shortfalls or surpluses since January 2009.
- MISO’s continued work on the ARR allocation process and modeling improvements in the FTR market has increased FTR funding levels.
  - ✓ FTR surpluses occurred in most months of 2011, and totaled nearly $7 million in fall 2011. They have totaled nearly $26 million year-to-date.
  - ✓ Hence, sufficient revenues have been collected to fully fund all FTRs in 2011.
- However, the persistent funding surpluses in 2011 suggests that MISO may not be making FTRs available that fully reflect the capability of the system.
  - ✓ Like under-funding, surpluses should be monitored and adjustments should be made to minimize these funding discrepancies.

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



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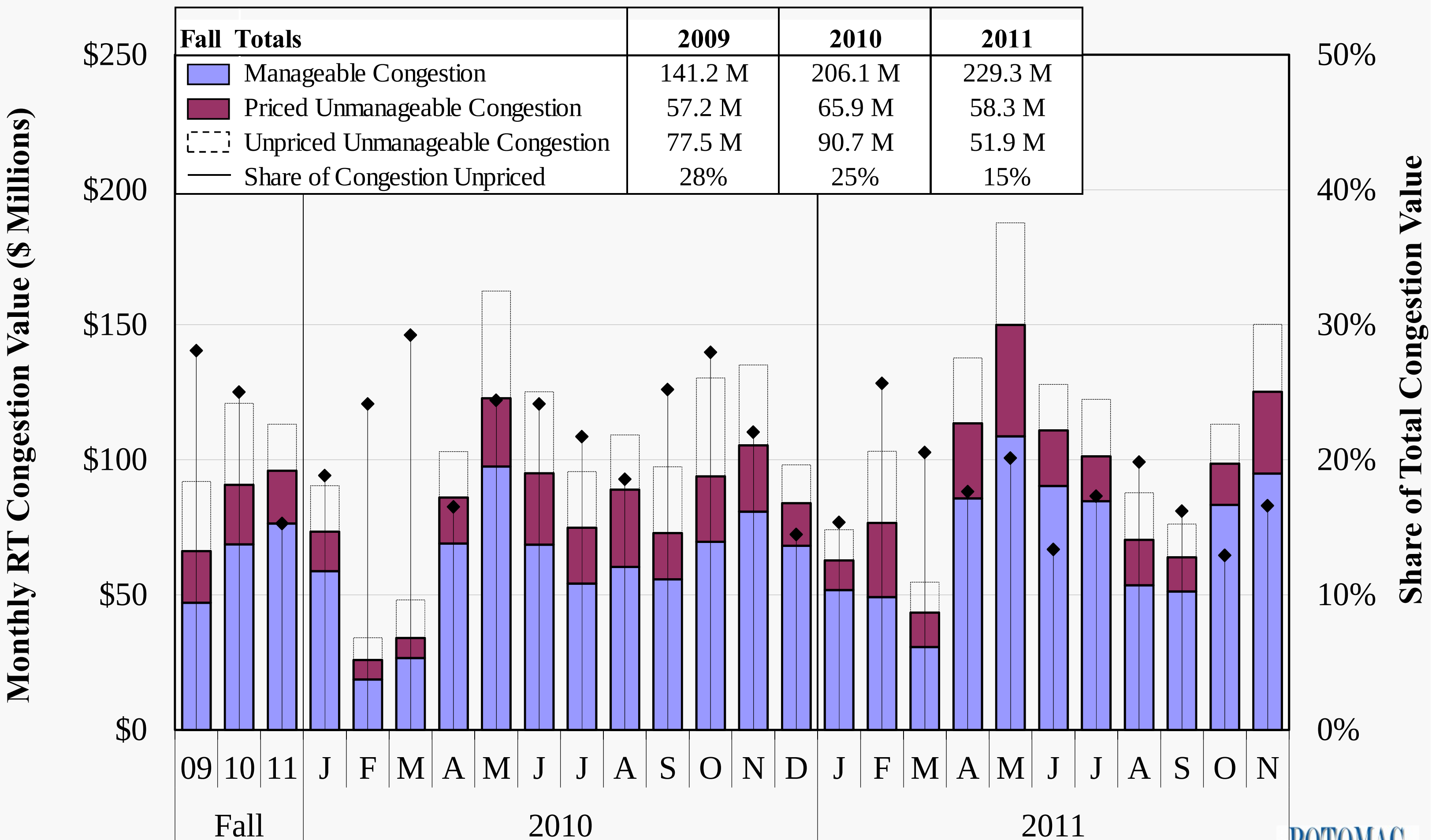
Value of Real-Time Congestion

- The next figure shows the value of real-time congestion on MISO-managed internal and market-to-market constraints (the figure excludes external constraints).
  - ✓ Real-time congestion, equal to the marginal cost of a constraint (i.e., the shadow price) times the flow over the constraint, rose modestly in fall 2011 to $287 million.
  - ✓ This is higher than the congestion costs collected by MISO because loop flows do not settle with MISO, and PJM has entitlements to MISO's transmission capability.
  - ✓ The figure separately shows congestion on those constraints that are temporarily violated (i.e., the congestion is considered "unmanageable" in the 5 minute dispatch).
- Congestion decreased in the West, but rose in the East and Central regions.
  - ✓ Manageability improved in the West, which may be due to the introduction of the DIR type, as well as changes in the management and pricing of low-voltage facilities.
- When constraints are unmanageable, MISO employs a "constraint relaxation" algorithm that artificially reduces the value of the congestion, often to zero.
  - ✓ MISO has announced that it will discontinue the use of this algorithm on February 1, 2012 for internal constraints that are not coordinated with PJM or SPP.
  - ✓ The figure shows that this algorithm eliminated $52 million (15 percent) of the real-time congestion that should have occurred in the quarter.
    - – This adversely affects the day-ahead market and the revenues from the FTR market and can potentially impact reliability and investment decisions.

Value of Real-Time Congestion 2010–2011

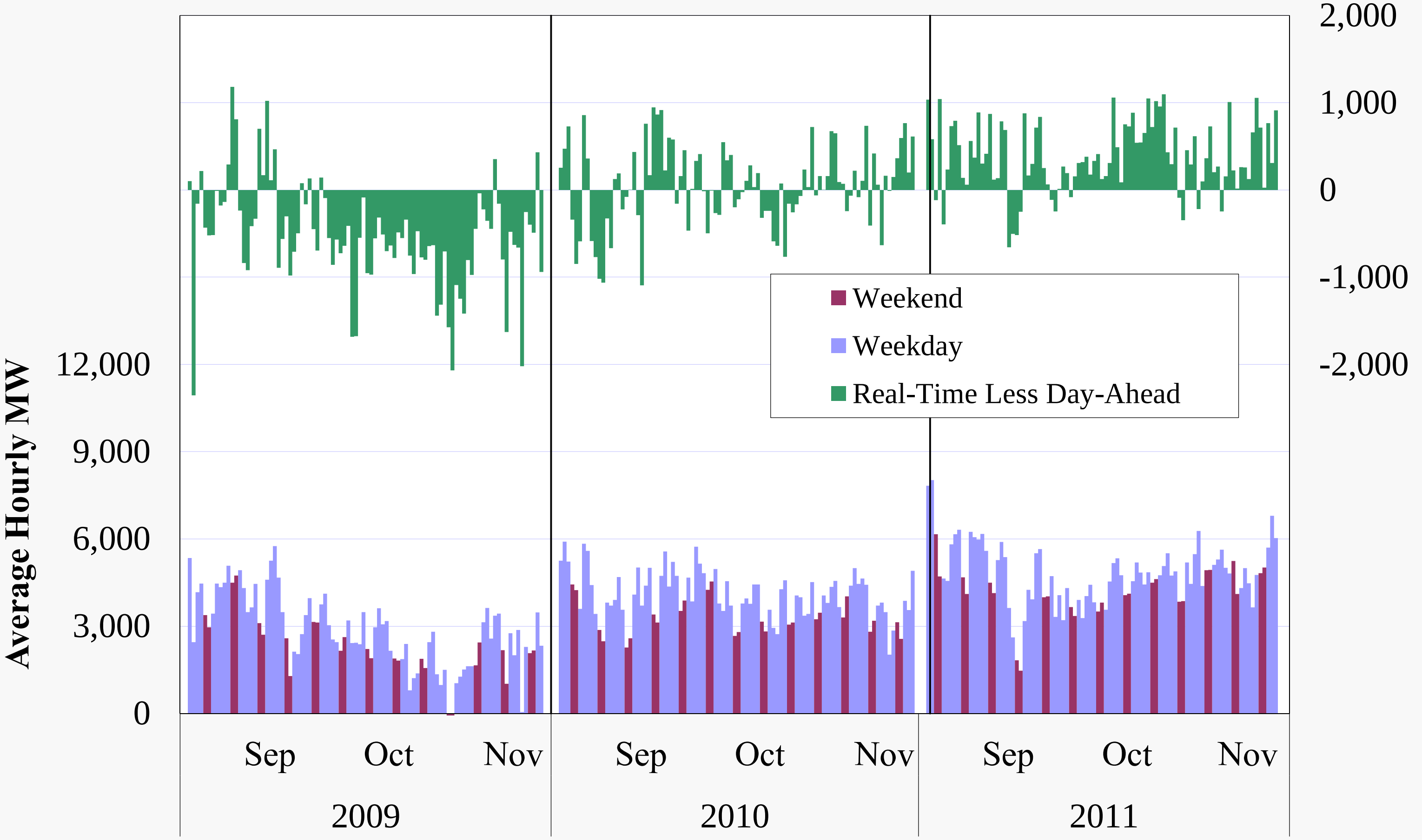


Fall Totals	2009	2010	2011
Manageable Congestion	141.2 M	206.1 M	229.3 M
Priced Unmanageable Congestion	57.2 M	65.9 M	58.3 M
Unpriced Unmanageable Congestion	77.5 M	90.7 M	51.9 M
Share of Congestion Unpriced	28%	25%	15%

Average Hourly Real-Time Imports

- The next figure shows net imports in the real-time market and the change in net imports from the day-ahead market during the fall of 2009 to 2011.
- MISO remains a substantial net importer in all hours, averaging 4.7 GW per hour in fall 2011. Net imports were nearly 20 percent higher than in fall 2010.
  - ✓ Imports exceeded 3 GW in almost all hours and peaked at over 8 GW in early September when prices were highest.
  - ✓ Much of the increase occurred over the interface with PJM, where net imports rose 25 percent to 2.9 GW. Imports from Manitoba fell 21 percent to 853 MW.
- Net imports increased in real time on most days in the quarter, averaging 378 MW.
  - ✓ In general, additional imports in real-time are beneficial and reduce the potential need for MISO to commit additional resources to meet the system's needs.
  - ✓ This is why the RSG allocation process was revised to eliminate any allocation of capacity-related RSG to this class of deviations.
- Changes from day-ahead to real-time continue to be substantial at times.
  - ✓ Net imports increased by more than 1 GW on eight days in the quarter.
  - ✓ MISO manages such changes through its real-time dispatch.

Average Hourly Real-Time Imports
Fall 2009–2011

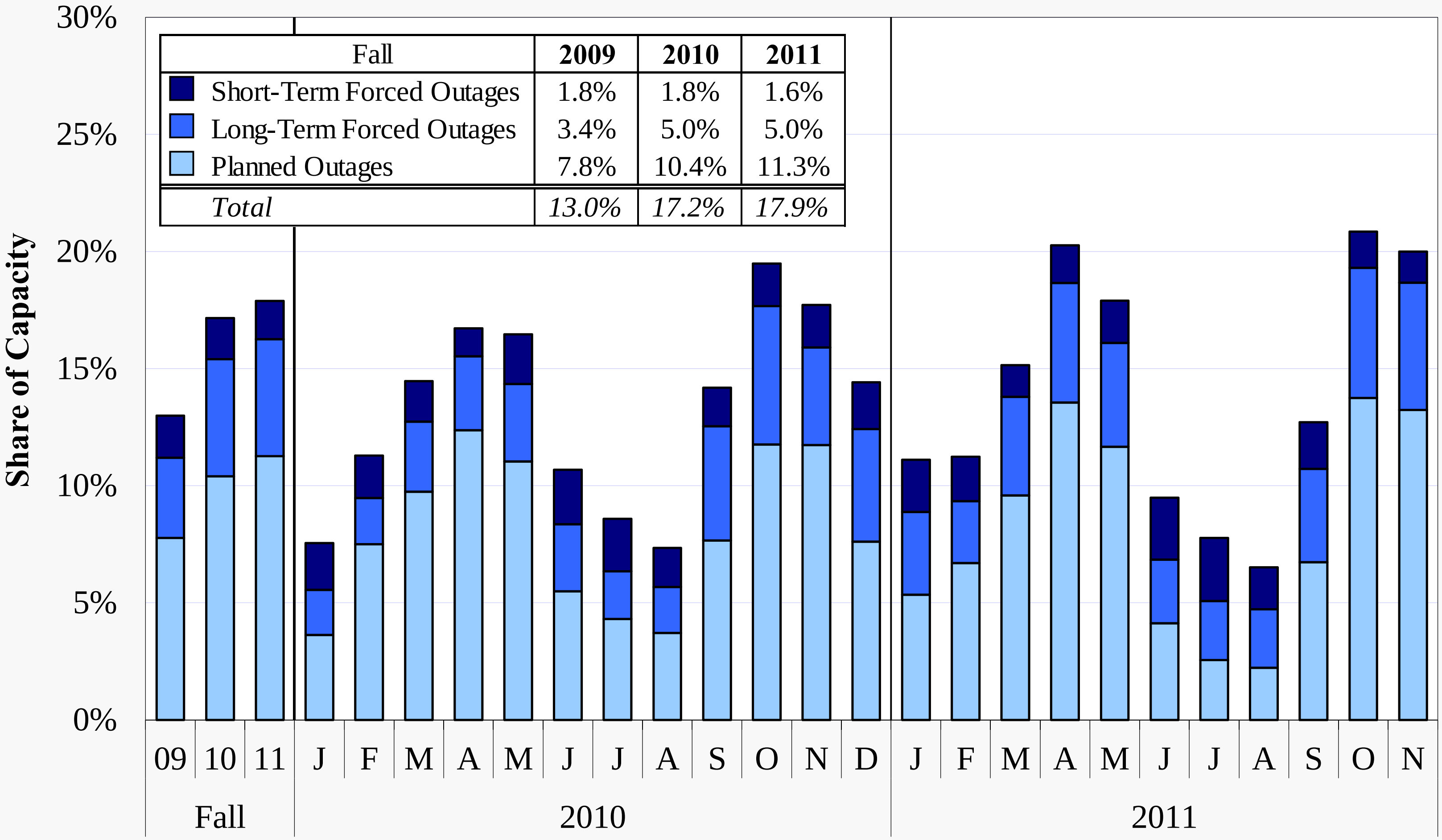


POTOMAC ECONOMICS

Generation Outage Rates

- The following figure shows the generator outages that occurred in each month since January 2010 as a percentage of total generation capacity.
  - ✓ These values include only full outages, not partial outages or deratings.
  - ✓ The figure divides the forced outages between short-term (less than 7 days) and long-term (longer than 7 days).
- The cumulative outage rate for the three types of outages was 17.9 percent in the quarter, up from 17.2 percent in fall 2010.
  - ✓ The increase was almost entirely in planned outages, which increased to 11.3 percent. Some of the increase is due to resources scheduling outages in preparation for new environmental rules.
- Short-term forced outages decreased slightly from 1.8 to 1.6 percent, while long-term forced outages were unchanged at 5.0 percent.
  - ✓ We monitor forced outages for indications of potential physical withholding. Although there were several notable outages, withholding was not a concern in fall 2011.
  - ✓ Changes in monitoring of Module E requirements to outages and deratings likely resulted in an apparent increase in forced outage rates since mid-2010.

Generation Outage Rates 2010–2011



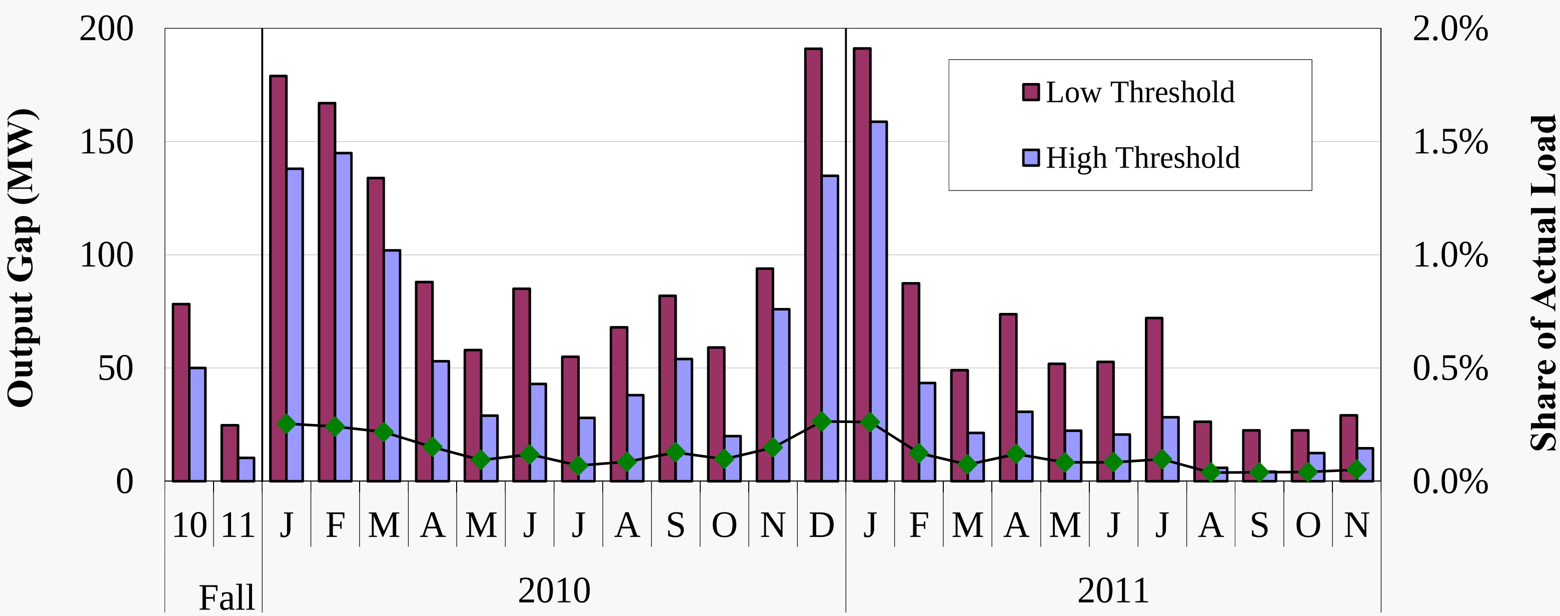
Fall	2009	2010	2011
Short-Term Forced Outages	1.8%	1.8%	1.6%
Long-Term Forced Outages	3.4%	5.0%	5.0%
Planned Outages	7.8%	10.4%	11.3%
Total	*13.0%*	*17.2%*	*17.9%*

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 2010 under two thresholds: a “high” threshold (equal to the mitigation threshold) and a “low” threshold (equal to one-half of mitigation threshold).
- Output gap levels under both thresholds continued to be extremely low.
  - ✓ Levels averaged just 25 and 11 MW this quarter under the high and low thresholds, respectively.
  - ✓ These levels represent a decrease of 68 and 78 percent from fall 2010.
- As a share of overall load, the low-threshold output gap again averaged less than 0.1 percent of load.
  - ✓ The mitigation thresholds for Narrow Constrained Areas (i.e. WUMS, North WUMS and Minnesota) were updated per Module D in January and the WUMS and Minnesota thresholds were increased significantly.
- These results show that there were few competitive concerns in the quarter.
  - ✓ We continue to routinely investigate hourly increases in the output gap.

POTOMAC ECONOMICS

Monthly Output Gap
2010–2011



Low Threshold Results by Unit Status (MW)

Off Line	19	8	74	110	75	28	12	31	16	19	18	5	33	95	143	44	21	14	9	11	23	0	1	11	12
On Line	60	17	105	57	59	60	46	54	38	49	64	54	61	96	48	43	29	60	43	42	49	26	22	12	17

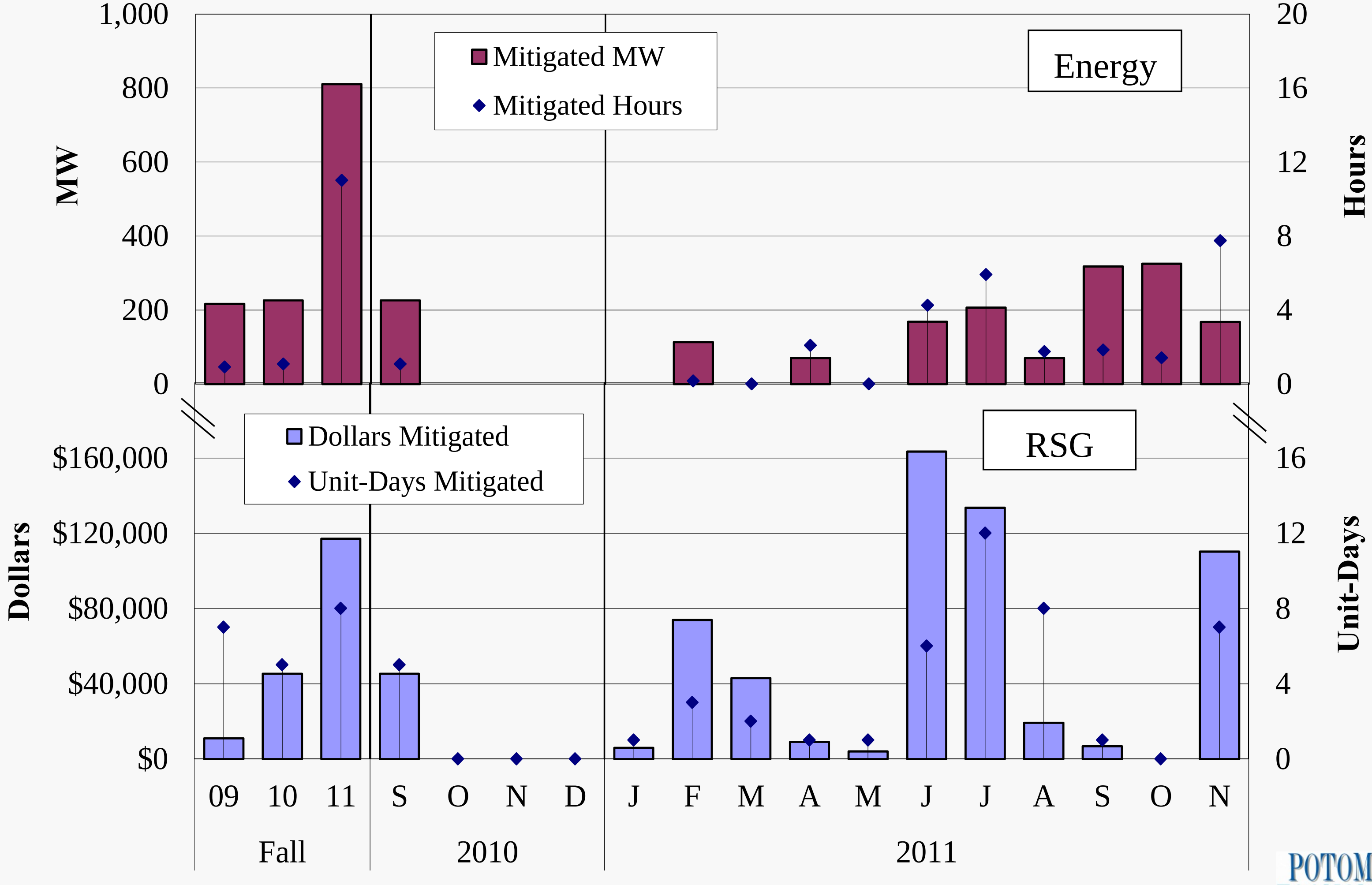
High Threshold Results by Unit Status (MW)

Off Line	19	8	67	110	73	27	12	31	16	19	18	5	33	89	142	29	16	14	9	10	19	0	1	11	12
On Line	31	3	71	35	29	26	17	12	12	19	36	15	43	46	17	14	5	17	13	10	9	6	4	1	3

Mitigation in the Real-Time Energy Market

- The next figure shows the frequency with which mitigation has been imposed in the real-time market and for RSG payments.
  - ✓ The top panel shows the frequency of mitigation in the energy market, including the number of hours in which mitigation took place and the average quantity mitigated.
  - ✓ The bottom panel shows the frequency and quantity of RSG mitigated.
- Energy mitigation in fall 2011 rose considerably from 2010 levels.
  - ✓ Mitigation quantities rose more than three-fold to a total of 800 MW.
    - – The majority of these quantities occurred in Broadly Constrained Areas.
  - ✓ Mitigation unit-hours increased to 11 unit-hours, which remains very low.
    - – Roughly 70 percent these unit-hours were of a WUMS unit in early November.
- Despite this increase, mitigation continues to be extremely infrequent because the vast majority of resources are offered competitively in the MISO markets.
- Although mitigation levels indicate that these events continue to be infrequent, local market power continues to be a significant concern.
  - ✓ Market power mitigation measures therefore remain critical.
  - ✓ We continue to evaluate AMP mitigation and found all mitigation events to be appropriately applied.

Real-Time Market Power Mitigation 2009–2011

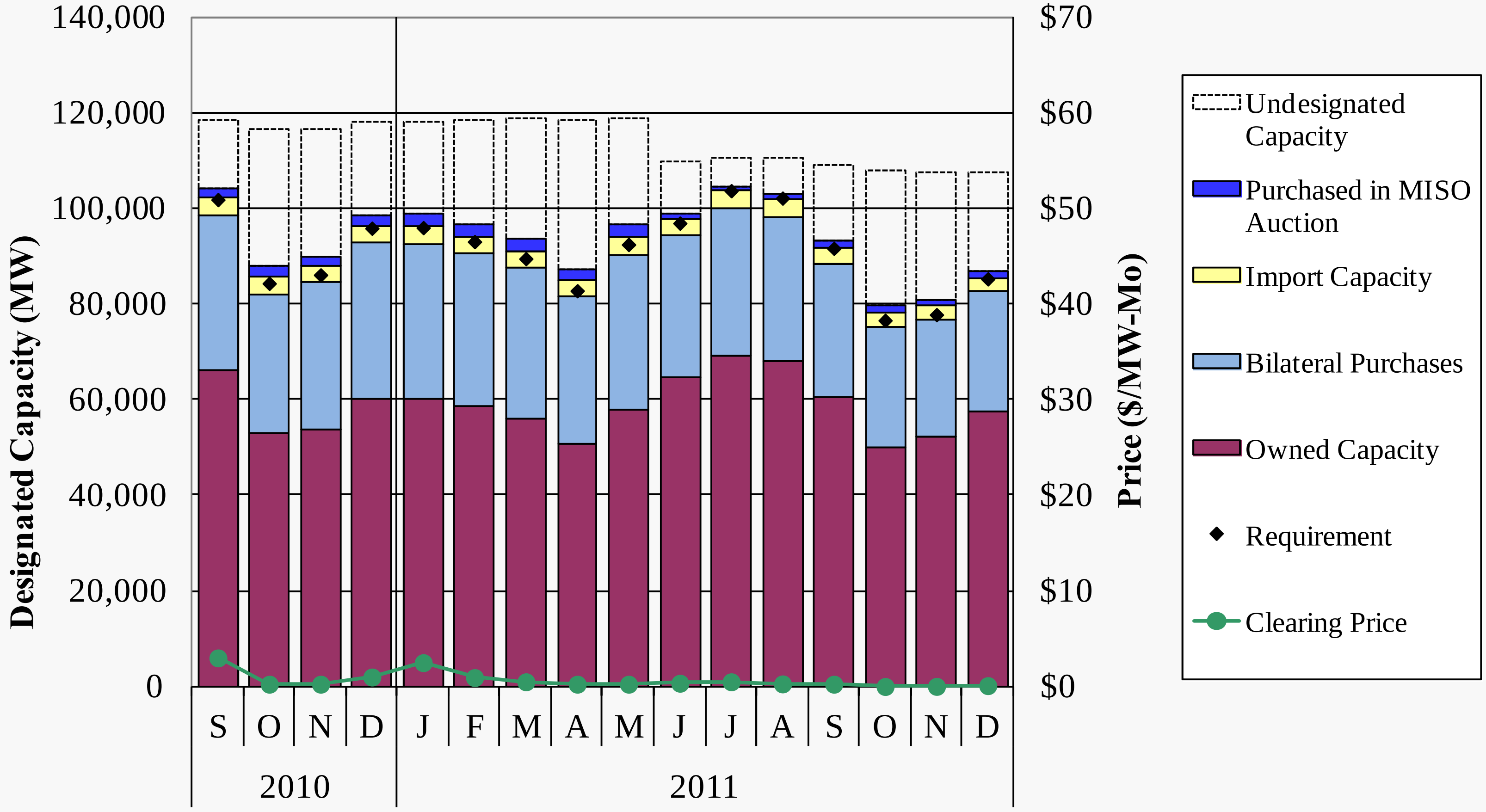


POTOMAC ECONOMICS

Voluntary Capacity Auction

- MISO runs a monthly Voluntary Capacity Auction (VCA) to allow load-serving entities to procure residual capacity to meet their Module E capacity requirements.
  - ✓ In fall 2011, the auction continued to clear at close to zero (less than $1 per MW-month), consistent with the surplus capacity that exists in the MISO footprint.
- The following figure shows the monthly capacity requirements, designated capacity and VCA clearing price for the preceding fifteen months.
  - ✓ Capacity and requirements both fell after May 2011 when FirstEnergy departed.
  - ✓ The capacity cleared in the VCA each month remains a very small portion (1-2 percent) of the total designated capacity.
  - ✓ This outcome is consistent with the expectation that most LSEs satisfy their capacity needs primarily through owned capacity or bilateral purchases.
- The figure also shows the total supply and designations for resources in MISO.
  - ✓ The total capacity available exceeded the requirement by at times over 40 percent (in October). As a result, VCA clearing prices remain extremely low.
  - ✓ Requirements vary by month, so undesignated capacity is greater in shoulder periods.
  - ✓ Capacity designations continue to meet or exceed requirements – designations exceeded the requirement by 2 to 4 percent.
- We filed Comments with the Commission on MISO's proposed Resource Adequacy Tariff revisions.

Voluntary Capacity Auction
October 2010–November 2011



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