SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance in the first six months of 2011. As part of the review of market performance, the MMU analyzed the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Highlights

- Operating reserve charges increased $24,826,194, or 10.1 percent, from $270,734,409 in the first six months of 2011 compared to $245,908,215 in the first six months of 2010. Reliability credits decreased $9,827,203, or 18.2 percent, in the first six months of 2011 compared to the first six months of 2010, and deviation credits increased $10,216,220, or 11.8 percent.

- Reliability charges were $44,230,427, 31.3 percent of all balancing operating reserve charges for the first six months 2011, and deviation charges were $97,092,749, or 68.7 percent.

- The Western reliability rate in the first six months of 2011 is the highest balancing operating reserve rate, averaging $.9802/MWh. The average daily RTO deviation rate of $.1619/MWh decreased in the first six months of 2011 when compared to the rate of $.7360/MWh in the first six months of 2010.

- Operating reserve credits for dispatchable transactions, which are a subset of pool-scheduled spot market import transactions, or balancing transaction operating reserve credits, for the months January through June 2011, were $1,252,846. The year with the next highest first half total balancing transaction operating reserve credits was in 2008, when credits were $818,778.

- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 34.3 percent of total operating reserve credits in the first six months of 2011, compared to 42.3 percent in the first six months of 2010. In the first six months of 2011, the top generation owner received 30.9 percent of the total operating reserve credits paid.

- The regional concentration of balancing operating reserves for the first six months of 2011 is slightly lower than the first six months of 2010, with 31.1 percent of the credits being paid to units operating in the PSEG zone, 24.7 percent in the Dominion zone, and 11.2 percent in the AEP zone.

- In the first six months of 2011, coal units provided 47.6 percent, nuclear units 34.8 percent and gas units 12.8 percent of total generation. Compared to the first six months of 2010, generation from coal units decreased 5.6 percent, and generation from nuclear units decreased 1.6 percent. Generation from natural gas units increased 42.4 percent, and generation from oil units increased 1.8 percent.

- At the end of June 2011, 80,787 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 167,000 MW in 2011. Wind projects account for approximately 39,656 MW of capacity, 49.1 percent of the capacity in the queues and combined-cycle projects account for 20,304 MW, 25.1 percent, of the capacity in the queues.

- Three large plants (over 550 MW) have started generating in PJM since January 1, 2011. This is the first time since 2006 that a plant rated at more than 500 MW has come online in PJM. Overall, 3,409 MW of nameplate capacity has been added in PJM in 2011 (excluding the ATSI zone additions), the most since 2003.

Recommendations

- In this *2011 Quarterly State of the Market Report for PJM: January through June*, the recommendations from the *2010 State of the Market Report for PJM* remain MMU recommendations.

Overview

Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through June 30, 2011, PJM installed capacity resources increased from 166,410.2 MW on January 1 to 179,813.1 as a result of the integration of American Transmission Systems, Inc. (ATSI) into the PJM footprint.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of June 30, 2011, 41.9 percent was coal; 28.2 percent was gas; 18.4 percent was nuclear; 6.2 percent was oil; 4.5 percent was hydroelectric; 0.4 percent was solid waste, 0.4 percent was wind, and 0.0 percent was solar.

- **Generation Fuel Mix.** In January through June 2011, coal provided 47.6 percent, nuclear 34.8 percent, gas 12.8 percent, oil 0.2 percent, hydroelectric 2.2 percent, solid waste 0.7 percent and wind 1.7 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Environmental Impact and Renewables

- **Cross-State Air Pollution Rule.** On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), a rule that requires 28 states, including all of the PJM states except Delaware, and also excepting the District of Columbia, to reduce certain power plant emissions that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle National Ambient Air Quality Standards (NAAQS). This rule replaces a 2005 rule known as the Clean Air Interstate Rule (CAIR), which has been in effect temporarily while the EPA developed a successor rule responding to an order of the U.S. Court of Appeals for District of Columbia Circuit directing revisions compliant with the requirements of the Clean Air Act. The CSAPR becomes effective January 1, 2012, replacing CAIR.

  The CSAPR requires 21 states, including all of the PJM states except Delaware, and also excepting D.C., to reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual PM2.5 NAAQS and to reduce ozone season NOX emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS. Emission reductions are effective starting January 1, 2012 for SO_2 and annual NO_X reductions and May 1, 2012 for ozone season NO_X reductions. Significant additional SO_2 emission reductions are required in 2014 from certain states, including all of the PJM states except Delaware, and also excepting D.C. EPA estimates that by 2014 this rule and other federal rules will lower power plant annual emissions of SO_2, NO_X from 2005 levels in the CSAPR region, respectively, by 73 percent (6.4 million tons/year) and 54 percent (1.4 million tons/year).

  The rule implements an air quality-assured trading program for states in the CSAPR region. Each of the states covered by this rule has pollution limits set by the EPA. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states, subject to provisions intended to assure that each state will meet its individual obligations.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole payments, operating reserve credits are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying the operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in the first six months of 2011.** Operating reserve charges increased 10.1 percent in the first six months of 2011 compared to the first six months of 2010. Reliability credits decreased $9,827,203, or 18.2 percent, in the first six months of 2011 compared to the first six months of 2010, and deviation credits increased $10,216,220, or 11.8 percent.

  The overall increase in operating reserve charges in 2011 is comprised of a 2.4 percent increase in day-ahead operating reserve charges, a 15.6 percent decrease in synchronous condensing charges and a 12.0 percent increase in balancing operating reserve charges.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

Existing and Planned Generation

Installed Capacity and Fuel Mix

Installed Capacity

Table 3-1 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2011 (See 2010 SOM, Table 3-42)

	1-Jan-11		31-May-11		1-Jun-11		30-Jun-11	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,986.0	40.9%	67,879.4	40.7%	76,968.3	42.4%	75,308.3	41.9%
Gas	47,736.6	28.7%	47,831.1	28.7%	50,729.0	28.0%	50,733.5	28.2%
Hydroelectric	7,954.5	4.8%	7,991.8	4.8%	8,029.6	4.4%	8,047.0	4.5%
Nuclear	30,552.2	18.4%	30,822.2	18.5%	33,145.6	18.3%	33,145.6	18.4%
Oil	10,949.5	6.6%	10,854.1	6.5%	11,212.3	6.2%	11,212.3	6.2%
Solar	0.0	0.0%	1.9	0.0%	15.3	0.0%	15.3	0.0%
Solid Waste	680.1	0.4%	680.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	551.3	0.3%	551.3	0.3%	633.5	0.3%	646.0	0.4%
Total	166,410.2	100.0%	166,611.9	100.0%	181,438.7	100.0%	179,813.1	100.0%

Energy Production by Fuel Source

Table 3-2 PJM generation (By fuel source (GWh)): January through June 2010 and 2011[1] (See 2010 SOM, Table 3-43)

	2010 (Jan-Jun)		2011 (Jan-Jun)		Change in Output
	GWh	Percent	GWh	Percent	
Coal	180,693.4	50.8%	170,495.9	47.6%	(5.6%)
Standard Coal	175,212.6	49.3%	164,911.8	46.0%	0.0%
Waste Coal	5,480.9	1.5%	5,584.1	1.6%	0.0%
Nuclear	126,789.7	35.7%	124,708.7	34.8%	(1.6%)
Gas	32,252.9	9.1%	45,921.7	12.8%	42.4%
Natural Gas	31,456.6	8.8%	45,081.2	12.6%	43.3%
Landfill Gas	796.1	0.2%	840.5	0.2%	5.6%
Biomass Gas	0.2	0.0%	0.1	0.0%	(64.9%)
Hydroelectric	8,146.2	2.3%	7,726.9	2.2%	(5.1%)
Wind	4,183.0	1.2%	6,084.5	1.7%	45.5%
Waste	2,573.7	0.7%	2,596.4	0.7%	0.9%
Solid Waste	2,024.9	0.6%	1,981.4	0.6%	(2.1%)
Miscellaneous	548.8	0.2%	614.9	0.2%	12.1%
Oil	875.5	0.2%	891.7	0.2%	1.8%
Heavy Oil	687.0	0.2%	750.1	0.2%	9.2%
Light Oil	175.0	0.0%	129.7	0.0%	(25.9%)
Diesel	10.3	0.0%	7.8	0.0%	(24.3%)
Kerosene	3.2	0.0%	4.0	0.0%	26.8%
Jet Oil	0.1	0.0%	0.0	0.0%	(51.1%)
Solar	2.1	0.0%	21.6	0.0%	919.1%
Battery	0.2	0.0%	0.1	0.0%	(26.6%)
Total	355,516.8	100.0%	358,447.4	100.0%	0.8%

1 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water.

Table 3-3 PJM capacity factor (By unit type (GWh)); January through June 2010 and 2011[2] [3] (New table)

	2010 (Jan-Jun)		2011 (Jan-Jun)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	4.6%	0.1	3.4%
Combined Cycle	28,041.9	28.8%	42,100.8	41.9%
Combustion Turbine	2,278.1	1.9%	2,002.7	1.6%
Diesel	216.4	12.7%	233.1	13.5%
Diesel (Landfill gas)	508.2	37.7%	509.4	36.6%
Nuclear	126,789.7	92.7%	124,708.7	90.8%
Pumped Storage Hydro	3,850.5	16.1%	3,390.8	14.2%
Run of River Hydro	4,295.7	42.2%	4,336.1	42.6%
Solar	2.1	14.9%	21.6	14.4%
Steam	185,296.8	53.1%	175,326.9	49.0%
Wind	4,183.0	28.9%	6,084.5	32.1%

Planned Generation Additions

Table 3-4 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through June 30, 2011[4] (See 2010 SOM, Table 3-44)

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516
2010	2,097
2011 (Jan-Jun)	3,409

2 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values.
3 The capacity factor for solar units in 2010 contains a significantly smaller sample of units than 2011.
4 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

PJM Generation Queues

Table 3-5 Queue comparison (MW): June 30, 2011 vs. December 31, 2010 (See 2010 SOM, Table 3-44)

	MW in the Queue 2010	MW in the Queue 2011	Year-to-Year Change (MW)	Year-to-Year Change
2011	25,378	17,935	(7,443)	(29%)
2012	13,261	15,827	2,567	19%
2013	11,244	12,614	1,370	12%
2014	13,888	14,788	900	6%
2015	5,960	11,419	5,459	92%
2016	1,350	2,850	1,500	111%
2017	2,140	2,160	20	1%
2018	3,194	3,194	0	0%
Total	76,415	80,787	4,372	6%

Table 3-6 Capacity in PJM queues (MW): At June 30, 2011[5, 6] (See 2010 SOM, Table 3-46)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,086	555	17,409	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	148	160	2,335	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	150	3,828	4,482
N Expired 31-Jan-05	1,377	2,143	173	6,713	10,407
O Expired 31-Jul-05	1,678	1,470	362	4,083	7,592
P Expired 31-Jan-06	513	2,625	655	4,908	8,701
Q Expired 31-Jul-06	1,759	1,384	2,778	8,693	14,614
R Expired 31-Jan-07	4,687	691	1,183	16,194	22,755
S Expired 31-Jul-07	2,357	2,507	1,055	11,475	17,393
T Expired 31-Jan-08	11,399	801	573	14,845	27,617
U Expired 31-Jan-09	6,505	222	575	26,106	33,407
V Expired 31-Jan-10	12,388	99	411	4,253	17,150
W Expired 31-Jan-11	17,849	3	446	6,198	24,496
X Expires 31-Jan-12	11,121	0	60	37	11,218
Total	71,652	29,763	9,135	198,156	308,706

Table 3-7 Average project queue times (days): At June 30, 2011 (See 2010 SOM, Table 3-47)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	789	645	0	4,420
In-Service	776	653	0	3,602
Suspended	2,435	791	890	3,849
Under Construction	1,207	847	0	4,370
Withdrawn	507	496	0	3,186

Distribution of Units in the Queues

Table 3-8 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2011 (See 2010 SOM, Table 3-48)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	1,255	762	17	0	0	961	665	0	2,159	5,818
AEP	2,545	580	10	170	0	161	2,397	0	14,097	19,960
AP	958	0	6	98	0	372	597	32	1,065	3,129
ATSI	268	72	22	0	0	0	135	0	947	1,444
BGE	0	0	29	0	1,640	0	132	0	0	1,801
ComEd	1,080	398	103	23	613	55	1,366	20	15,412	19,069
DAY	0	0	2	112	0	60	12	0	1,440	1,626
DLCO	0	0	0	0	91	0	0	0	0	91
Dominion	2,095	615	18	0	1,774	154	322	32	1,634	6,644
DPL	600	96	0	0	0	159	20	50	855	1,780
JCPL	1,995	27	30	0	0	1,284	0	0	0	3,336
Met-Ed	1,760	7	18	0	24	110	0	3	0	1,922
PECO	663	7	17	0	490	26	0	2	0	1,206
PENELEC	905	0	12	0	0	136	50	0	1,530	2,632
Pepco	2,309	0	6	0	0	10	0	0	0	2,325
PPL	1,354	139	14	3	1,600	166	33	20	498	3,826
PSEG	2,518	1,083	4	0	50	397	105	2	20	4,178
Total	20,304	3,786	308	406	6,282	4,051	5,833	161	39,656	80,787

5 The *2011 Quarterly State of the Market Report for PJM: January through June* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 3-9 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2011[7] (See 2010 SOM, Table 3-49)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	7,030	1,975	68	0	540	2,827	790	54	3,034	16,318
SWMAAC	2,309	0	35	0	1,640	10	132	0	0	4,126
WMAAC	4,019	146	43	3	1,624	412	83	23	2,028	8,380
Non-MAAC	6,946	1,665	162	403	2,478	802	4,829	84	34,594	51,963
Total	20,304	3,786	308	406	6,282	4,051	5,833	161	39,656	80,787

Table 3-10 Existing PJM capacity: At June 30, 2011[8] (By zone and unit type (MW)) (See 2010 SOM, Table 3-50)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	0	661	21	0	0	0	1,264	0	8	1,953
AEP	4,367	3,676	59	1,002	2,094	0	21,574	0	1,203	33,976
AP	1,129	1,180	36	80	0	0	8,451	0	691	11,566
ATSI	0	1,661	52	0	2,134	0	8,029	0	0	11,876
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,738	7,178	111	0	10,421	0	6,790	0	1,945	28,183
DAY	0	1,369	52	0	0	1	3,572	0	0	4,993
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	3,173	3,761	161	3,589	3,558	0	8,545	0	0	22,787
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	1,590	0	66	439	0	9,470	0	185	12,724
JCPL	1,390	1,225	33	400	615	0	318	0	0	3,980
Met-Ed	2,000	406	42	20	805	0	885	0	0	4,157
PECO	2,644	836	7	1,642	4,541	3	1,649	1	0	11,322
PENELEC	0	344	39	513	0	0	6,834	0	555	8,284
Pepco	230	1,327	12	0	0	0	4,679	0	0	6,248
PPL	1,810	618	49	581	2,470	0	5,527	0	220	11,274
PSEG	2,878	2,863	0	5	3,493	34	2,529	0	0	11,802
Total	23,702	31,315	775	7,904	34,051	39	96,190	1	4,806	198,784

7 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.
8 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-11 PJM capacity (MW) by age: at June 30, 2011 (See 2010 SOM, Table 3-51)

Age (years)	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,467	16,177	425	11	0	39	1,887	1	4,796	41,802
11 to 20	3,936	6,323	114	48	0	0	5,632	0	10	16,062
21 to 30	857	1,162	37	3,382	16,517	0	7,216	0	0	29,171
31 to 40	244	4,401	43	105	16,053	0	35,467	0	0	56,313
41 to 50	198	3,253	153	2,915	1,482	0	27,353	0	0	35,353
51 to 60	0	0	4	379	0	0	16,409	0	0	16,792
61 to 70	0	0	0	0	0	0	2,078	0	0	2,078
71 to 80	0	0	0	344	0	0	95	0	0	439
81 to 90	0	0	0	488	0	0	54	0	0	542
91 to 100	0	0	0	194	0	0	0	0	0	194
101 and over	0	0	0	37	0	0	0	0	0	37
Total	23,702	31,315	775	7,904	34,051	39	96,190	1	4,806	198,784

Table 3-12 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[9] (See 2010 SOM, Table 3-52)

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Combined Cycle	198	2.5%	8,037	23.7%	7,030	14,870	34.8%
	Combustion Turbine	1,375	17.0%	7,358	21.7%	1,975	7,958	18.6%
	Diesel	53	0.7%	157	0.5%	68	171	0.4%
	Hydroelectric	2,042	25.3%	2,047	6.0%	0	5	0.0%
	Nuclear	615	7.6%	8,648	25.5%	540	9,188	21.5%
	Solar	0	0.0%	37	0.1%	2,827	2,864	6.7%
	Steam	3,784	46.9%	7,584	22.4%	790	4,589	10.7%
	Storage	0	0.0%	1	0.0%	54	55	0.1%
	Wind	0	0.0%	8	0.0%	3,034	3,042	7.1%
	EMAAC Total	8,067	100.0%	33,877	100.0%	16,318	42,742	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	2,309	2,539	22.4%
	Combustion Turbine	761	16.5%	2,162	18.3%	0	1,400	12.4%
	Diesel	0	0.0%	19	0.2%	35	54	0.5%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	29.5%
	Solar	0	0.0%	0	0.0%	10	10	0.1%
	Steam	3,840	83.5%	7,686	65.1%	132	3,978	35.1%
	SWMAAC Total	4,601	100.0%	11,801	100.0%	4,126	11,327	100.0%

Table 3-12 continued next page.

9 Percents shown in Table 3-12 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 3-12, continued from previous page.

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
WMAAC	Combined Cycle	0	0.0%	3,810	16.1%	4,019	7,829	48.5%
	Combustion Turbine	312	3.8%	1,367	5.8%	146	1,201	7.4%
	Diesel	46	0.6%	129	0.5%	43	126	0.8%
	Hydroelectric	887	10.9%	1,113	4.7%	3	229	1.4%
	Nuclear	0	0.0%	3,275	13.8%	1,624	4,899	30.4%
	Solar	0	0.0%	0	0.0%	412	412	2.6%
	Steam	6,887	84.7%	13,246	55.9%	83	6,441	39.9%
	Storage	0	0.0%	0	0.0%	23	23	0.1%
	Wind	0	0.0%	775	3.3%	2,028	2,803	17.4%
	WMAAC Total	8,132	100.0%	23,715	100.0%	8,380	16,134	100.0%
Non-MAAC	Combined Cycle	0	0.0%	11,624	9.0%	6,946	18,570	12.7%
	Combustion Turbine	805	2.3%	20,429	15.8%	1,665	21,289	14.5%
	Diesel	57	0.2%	470	0.4%	162	575	0.4%
	Hydroelectric	1,429	4.1%	4,744	3.7%	403	3,718	2.5%
	Nuclear	867	2.5%	20,423	15.8%	2,478	22,034	15.0%
	Solar	0	0.0%	1	0.0%	802	803	0.5%
	Steam	31,478	90.9%	67,675	52.3%	4,829	41,026	28.0%
	Storage	0	0.0%	0	0.0%	84	84	0.1%
	Wind	0	0.0%	4,024	3.1%	34,594	38,618	26.3%
	Non-MAAC Total	34,636	100.0%	129,390	100.0%	51,963	146,718	100.0%
All Areas	Total	55,436		198,784		80,787	216,921	

Environmental Impact and Renewables

Characteristics of Wind Units

Table 3-13 Capacity factor[10] of wind units in PJM, January through June 2011 (See 2010 SOM, Table 3-53)

Type of Resource	Capacity Factor	Capacity Factor by Cleared MW	Total Hours	Installed Capacity (MW)
Energy-Only Resource	30.2%	NA	54,947	849
Capacity Resource	32.3%	207.8%	174,272	3,957
All Units	32.1%	207.8%	229,219	4,806

10 Capacity factor by cleared MW refers to cleared RPM MW in peak periods (peak hours during January, February, June, July, and August).

Table 3-14 Wind resources in real time offering at a negative price in PJM, January through June 2011 (See 2010 SOM, Table 3-54)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	1,062.0	1,466	2.81%
All Wind	2,407.6	2,757	5.29%

Figure 3-1 Average hourly real-time generation of wind units in PJM, January through June 2011 (See 2010 SOM, Figure 3-13)

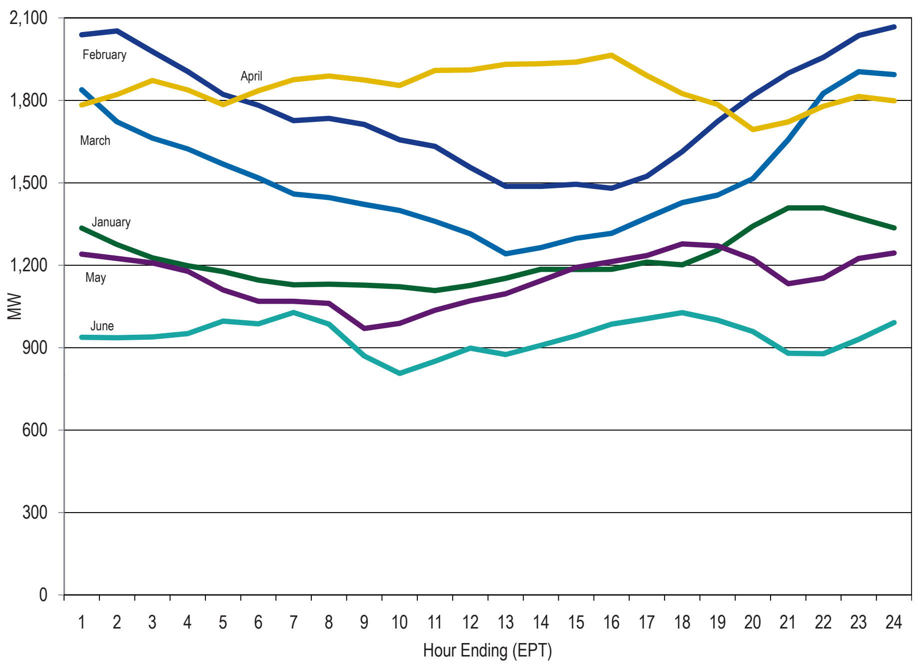


Table 3-15 Capacity factor of wind units in PJM by month, 2010 and 2011[11] (See 2010 SOM, Table 3-55)

	2010		2011	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	818,423.9	35.7%	909,690.8	29.1%
February	612,044.4	28.6%	1,181,192.0	40.5%
March	727,819.1	29.5%	1,130,037.9	35.0%
April	881,317.4	35.5%	1,329,713.7	42.5%
May	670,571.5	26.2%	856,656.7	26.5%
June	472,775.6	18.6%	677,215.5	20.7%
July	380,114.8	14.4%		
August	330,818.7	12.1%		
September	705,289.0	24.0%		
October	1,006,233.1	32.5%		
November	1,088,610.5	35.5%		
December	1,118,789.3	35.3%		
Annual	8,812,807.2	27.4%	6,084,506.5	32.1%

Table 3-16 Peak and off-peak seasonal capacity factor, average wind generation (MWh), and PJM load (MWh): January through June 2011 (See 2010 SOM, Table 3-56)

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	32.5%	41.0%	23.9%		31.0%
	Average Wind Generation	1,407.3	1,782.5	1,063.1		1,443.6
	Average Load	86,939.1	75,551.5	91,635.1		86,648.4
Off-Peak	Capacity Factor	36.2%	43.8%	23.3%		33.0%
	Average Wind Generation	1,568.1	1,903.1	1,034.1		1,353.3
	Average Load	75,243.8	62,156.7	70,626.9		71,493.0

11 Capacity factor shown in Table 3-15 is based on all hours in January through April, 2011.

Figure 3-2 Average hourly day-ahead generation of wind units in PJM, January through June 2011 (See 2010 SOM, Figure 3-14)

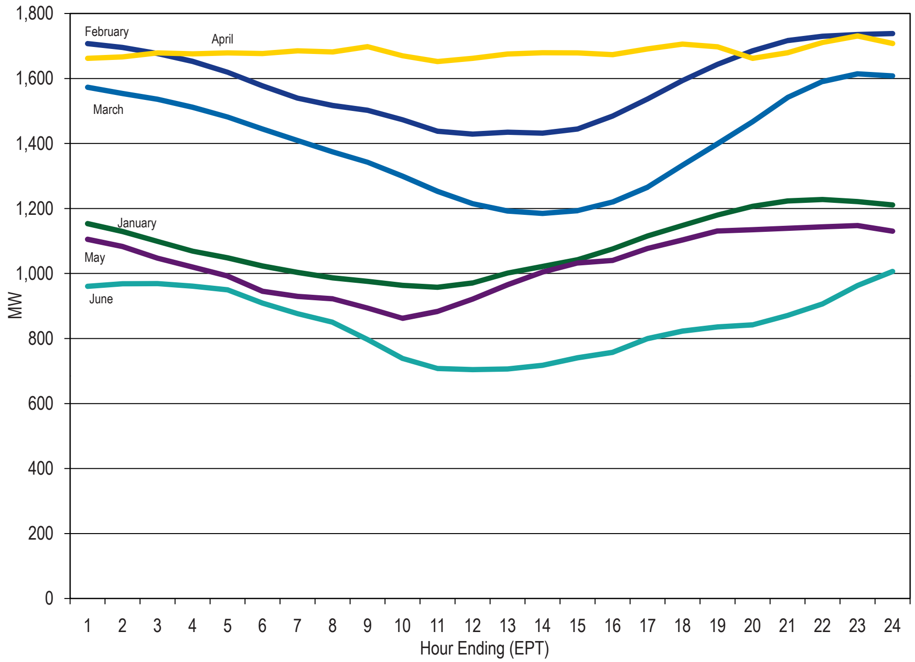
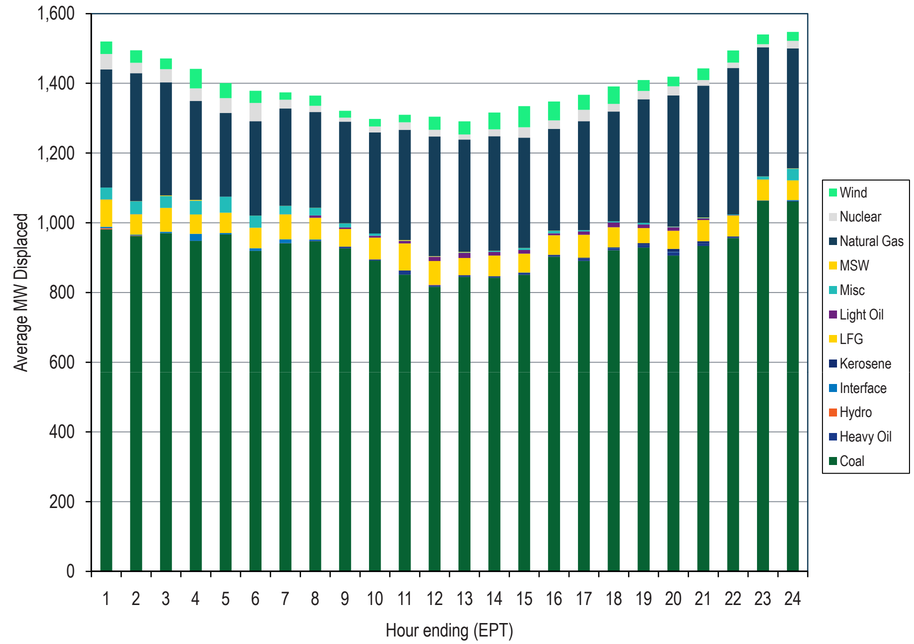


Figure 3-3 Marginal fuel at time of wind generation in PJM, January through June 2011 (See 2010 SOM, Figure 3-15)



Environmental Regulatory Impacts

Emission Allowances Trading

Figure 3-4 Spot monthly average emission price comparison: 2010 and 2011 (See 2010 SOM, Figure 3-16)

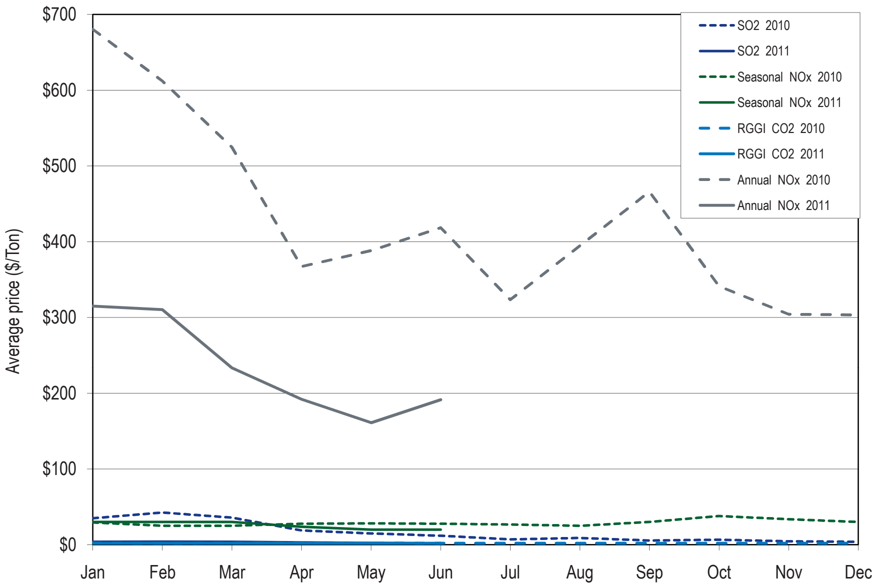


Table 3-17 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period (See 2010 SOM, Table 3-57)[12]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000

Emission Controlled Capacity in the PJM Region

Table 3-18 SO_2 emission controls (FGD) by unit type (MW), as of June 30, 2011 (See 2010 SOM, Table 3-58)

	SO2 Controlled	No SO2 Controls	Total	Percent Controlled
Coal Steam	54,741.7	30,117.0	84,858.7	64.5%
Combined Cycle	0.0	23,723.4	23,723.4	0.0%
Combustion Turbine	0.0	30,509.2	30,509.2	0.0%
Diesel	0.0	371.2	371.2	0.0%
Non-Coal Steam	0.0	10,837.0	10,837.0	0.0%
Total	54,741.7	95,557.8	150,299.5	36.4%

Table 3-19 NO_x emission controls by unit type (MW), as of June 30, 2011 (See 2010 SOM, Table 3-59)

	NOx Controlled	No NOx Controls	Total	Percent Controlled
Coal Steam	82,075.9	2,782.8	84,858.7	96.7%
Combined Cycle	23,573.4	150.0	23,723.4	99.4%
Combustion Turbine	24,818.5	5,690.7	30,509.2	81.3%
Diesel	0.0	371.2	371.2	0.0%
Non-Coal Steam	5,808.1	5,028.9	10,837.0	53.6%
Total	136,275.9	14,023.6	150,299.5	90.7%

Table 3-20 Particulate emission controls by unit type (MW), as of June 30, 2011 (See 2010 SOM, Table 3-60)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	83,099.7	1,759.0	84,858.7	97.9%
Combined Cycle	0.0	23,723.4	23,723.4	0.0%
Combustion Turbine	0.0	30,509.2	30,509.2	0.0%
Diesel	0.0	371.2	371.2	0.0%
Non-Coal Steam	3,047.0	7,790.0	10,837.0	28.1%
Total	86,146.7	64,152.8	150,299.5	57.3%

12 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed July 1, 2011).

Renewable Portfolio Standards

Table 3-21 Renewable standards of PJM jurisdictions to 2021[13,14] (See 2010 SOM, Table 3-61)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	7.00%	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%
Indiana	No Standard										
Illinois	6.00%	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%
Kentucky	No Standard										
Maryland	7.50%	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%
Michigan		<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	8.30%	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%
North Carolina	0.02%	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%
Ohio	1.00%	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%
Pennsylvania	9.20%	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Washington, D.C.	6.54%	7.57%	9.10%	10.63%	12.17%	13.71%	15.25%	16.80%	18.35%	20.40%	20.40%
West Virginia					10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%

Table 3-22 Solar renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-62)

Jurisdiction	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Delaware	0.20%	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%
Indiana	No Standard										
Illinois		0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%
Kentucky	No Standard										
Maryland	0.05%	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%
Michigan	No Solar Standard										
New Jersey	0.31%	0.39%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%
North Carolina	0.07%	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
Ohio	0.03%	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%
Pennsylvania	0.02%	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.04%	0.07%	0.10%	0.13%	0.17%	0.21%	0.25%	0.30%	0.35%	0.40%	0.40%
West Virginia	No Solar Standard										

13 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

14 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.

Table 3-23 Additional renewable standards of PJM jurisdictions to 2021 (See 2010 SOM, Table 3-63)

Jurisdiction		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Illinois	Wind Requirement	3.75%	4.50%	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)		306	442	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518
North Carolina	Swine Waste			0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)			170	700	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	4.20%	6.20%	6.20%	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%

Table 3-24 Renewable alternative compliance payments in PJM jurisdictions: 2011 (See 2010 SOM, Table 3-64)

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Indiana	No standard		
Illinois	$12.73		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$675.00
North Carolina	No specific penalties		
Ohio	$45.00		$400.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 3-25 Renewable generation by jurisdiction and renewable resource type (GWh): January through June 2011 (See 2010 SOM, Table 3-65)

Jurisdiction	Battery	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	0.0	29.9	0.0	0.0	0.0	0.0	0.0	0.0	29.9	59.7
Indiana	0.0	0.0	0.0	24.4	0.0	0.0	0.0	1,525.5	1,549.9	1,549.9
Illinois	0.0	74.9	0.0	0.0	0.0	3.2	0.0	2,819.4	2,894.2	2,897.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	0.0	42.9	0.0	1,369.4	0.0	292.3	0.0	166.1	1,578.3	1,870.6
Michigan	0.0	14.2	0.0	33.5	0.0	0.0	0.0	0.0	47.7	47.7
New Jersey	0.0	140.1	275.5	17.6	19.2	674.8	0.0	5.9	182.7	1,133.1
North Carolina	0.0	0.0	0.0	231.2	0.0	0.0	0.0	0.0	231.2	231.2
Ohio	0.0	27.6	0.0	50.3	0.6	0.0	0.0	3.6	82.2	82.2
Pennsylvania	0.1	424.7	851.8	1,598.7	1.9	1,113.5	4,992.7	1,007.7	3,033.0	9,991.1
Tennessee	0.0	0.0	0.0	0.0	0.0	172.5	0.0	0.0	0.0	172.5
Virginia	0.0	85.4	2,263.5	428.7	0.0	596.2	0.0	0.0	514.2	3,373.9
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.9	0.0	582.2	0.0	0.0	552.9	556.4	1,139.5	1,692.4
Total	0.1	840.5	3,390.8	4,336.1	21.6	2,852.6	5,545.6	6,084.5	11,282.7	23,071.8

Table 3-26 PJM renewable capacity by jurisdiction (MW), on June 30, 2011 (See 2010 SOM, Table 3-66)

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	15.0	0.0	0.0	0.0	0.0	0.0	0.0	1,858.4
Illinois	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	1,944.9	2,029.8
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Maryland	60.0	24.5	129.0	97.9	0.0	1,162.0	0.0	109.0	0.0	120.0	1,702.4
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
North Carolina	0.0	80.4	0.0	0.0	400.0	5.0	34.5	191.1	0.0	7.5	718.5
Ohio	3,339.7	25.8	25.0	27.2	0.0	112.0	1.1	0.0	0.0	150.0	3,680.8
Pennsylvania	35.0	215.5	2,370.7	0.0	2,575.0	672.6	3.0	263.0	1,418.9	790.0	8,343.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	108.5	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,465.5
West Virginia	500.0	2.0	0.0	0.0	0.0	239.6	0.0	0.0	130.0	555.5	1,427.1
PJM Total	3,934.7	534.5	4,440.0	157.0	6,563.0	2,983.3	38.6	943.1	1,548.9	4,806.1	25,949.2

Table 3-27 Renewable capacity by jurisdiction, non-PJM units registered in GATS[15,16] (MW), on June 30, 2011 (See 2010 SOM, Table 3-67)

Jurisdiction	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	9.3	0.0	0.1	9.4
Illinois	4.0	97.8	0.0	0.0	0.0	10.6	0.0	302.5	414.9
Indiana	0.0	26.4	0.0	679.1	0.0	0.4	0.0	0.0	705.9
Kentucky	2.0	16.0	0.0	0.0	0.0	0.2	88.0	0.0	106.3
Maryland	0.0	5.0	0.0	0.0	0.0	21.4	0.0	0.0	26.4
Michigan	0.0	1.6	0.0	0.0	0.0	0.1	0.0	0.0	1.7
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	225.0	0.0	0.0	0.0	0.0	2.3	0.0	0.0	227.3
New York	0.0	36.5	0.0	0.0	23.3	293.3	0.0	0.2	353.2
North Carolina	179.9	0.0	0.0	0.0	0.0	0.4	0.0	0.0	180.4
Ohio	1.0	49.5	52.6	45.0	0.0	23.1	109.3	9.7	290.2
Pennsylvania	0.2	5.4	4.8	85.5	0.3	80.0	0.0	3.2	179.4
Virginia	12.5	14.8	0.0	0.0	0.0	4.7	318.1	0.0	350.2
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	1.9	0.0	0.0	1.9
West Virginia	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.3
Wisconsin	9.0	0.0	0.0	0.0	0.0	0.6	44.6	0.0	54.2
Total	433.7	253.0	57.4	809.6	23.6	448.8	560.0	461.8	3,047.9

15 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
16 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed July 01, 2011).

Operating Reserve[17]

Credit and Charge Results

Overall Results

Table 3-28 Monthly operating reserve charges: Calendar years 2010 and 2011 (See SOM 2010, Table 3-72)

	2010 Charges				2011 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$10,281,351	$50,022	$40,472,496	$50,803,869	$12,373,099	$110,095	$47,862,223	$60,345,417
Feb	$11,425,494	$14,715	$22,346,529	$33,786,738	$8,940,203	$139,287	$26,361,087	$35,440,577
Mar	$8,836,886	$122,817	$16,823,288	$25,782,991	$6,837,719	$66,032	$24,219,868	$31,123,619
Apr	$7,633,141	$93,253	$22,870,495	$30,596,889	$4,405,102	$13,011	$18,453,276	$22,871,388
May	$5,127,307	$131,600	$39,144,404	$44,403,311	$7,064,934	$39,417	$44,579,042	$51,683,393
Jun	$3,511,264	$33,923	$56,989,229	$60,534,415	$8,303,391	$9,056	$60,957,566	$69,270,014
Jul	$4,601,788	$88,136	$63,190,853	$67,880,778				
Aug	$3,622,670	$66,535	$41,690,612	$45,379,817				
Sep	$8,433,892	$27,971	$40,637,086	$49,098,949				
Oct	$7,719,744	$1,543	$30,433,986	$38,155,273				
Nov	$6,556,715	$29,674	$20,020,310	$26,606,698				
Dec	$12,951,879	$59,954	$83,021,125	$96,032,958				
Total	$46,815,443	$446,330	$198,646,441	$245,908,215	$47,924,448	$376,898	$222,433,063	$270,734,409
Share of Annual Charges	19.0%	0.2%	80.8%	100.0%	17.7%	0.1%	82.2%	100.0%

17 See the *2010 State of the Market Report for PJM* Volume II, Section 3, "Energy Market, Part 2", Table 3-68 *Operating reserve credit and charges* and Table 3-69 *Operating reserve deviations* for details regarding operating reserve structure.

Table 3-29 Regional balancing operating reserve charges allocation: January through June 2011[18] (See SOM 2010, Table 3-73)

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$28,732,141 20.3%	$1,159,813 0.8%	$29,891,954 21.2%	$51,525,893 36.5%	$16,397,206 11.6%	$17,921,911 12.7%	$85,845,010 60.7%	$115,736,964 81.9%
East	$2,987,646 2.1%	$93,096 0.1%	$3,080,743 2.2%	$5,636,070 4.0%	$1,462,329 1.0%	$1,477,305 1.0%	$8,575,704 6.1%	$11,656,447 8.2%
West	$10,703,266 7.6%	$554,465 0.4%	$11,257,730 8.0%	$1,436,871 1.0%	$609,733 0.4%	$625,431 0.4%	$2,672,035 1.9%	$13,929,766 9.9%
Total	$42,423,052 30.0%	$1,807,375 1.3%	$44,230,427 31.3%	$58,598,834 41.5%	$18,469,268 13.1%	$20,024,647 14.2%	$97,092,749 68.7%	$141,323,176 100%

Deviations

Allocation

Table 3-30 Monthly balancing operating reserve deviations (MWh): Calendar years 2010 and 2011 (See SOM 2010, Table 3-74)

	2010 Deviations				2011 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,439,465	5,707,965	2,698,568	17,845,998	9,795,075	3,263,461	3,189,885	16,248,420
Feb	7,675,656	5,332,236	2,456,048	15,463,940	7,196,554	2,809,384	2,712,419	12,718,358
Mar	8,101,950	5,138,264	2,264,951	15,505,165	7,510,358	2,467,175	2,777,797	12,755,330
Apr	7,006,983	4,668,407	2,132,045	13,807,435	6,622,271	2,027,200	2,714,483	11,363,954
May	9,004,034	4,228,004	2,416,103	15,648,141	7,148,336	2,381,985	2,930,319	12,460,640
Jun	10,936,989	3,964,478	3,174,230	18,075,697	9,846,329	2,558,367	3,035,163	15,439,859
Jul	10,928,408	3,847,011	3,412,498	18,187,917				
Aug	9,747,045	3,417,328	3,188,437	16,352,810				
Sep	9,480,237	3,587,356	2,524,213	15,591,806				
Oct	7,170,712	2,913,554	2,368,303	12,452,569				
Nov	7,606,971	2,860,054	2,485,153	12,952,178				
Dec	10,069,627	4,027,236	3,513,489	17,610,352				
Total	107,168,077	49,691,893	32,634,038	189,494,008	48,118,923	15,507,572	17,360,066	80,986,561
Share of Annual Deviations	56.6%	26.2%	17.2%	100.0%	59.4%	19.1%	21.4%	100.0%

18 The total charges shown in Table 3-29 do not equal the total balancing charges shown in Table 3-28 because the totals in Table 3-28 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-29 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

Table 3-31 Regional operating reserve charges determinants (MWh): January through June 2011 (See SOM 2010, Table 3-75)

	Reliability Charge Determinants			Deviation Charge Determinants				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	342,314,644	14,602,809	356,917,452	48,118,923	15,507,572	17,360,066	80,986,561	437,904,013
East	182,993,605	6,816,309	189,809,914	29,066,619	8,324,158	8,469,894	45,860,671	235,670,585
West	159,321,038	7,786,500	167,107,538	18,883,992	7,093,775	8,718,421	34,696,188	201,803,727

Table 3-32 Monthly impacts on netting deviations: January through June 2011 (See SOM 2010, Table 3-76)

Month	Demand Deviations (MWh) Old Rules	Demand Deviations (MWh) New Rules	Difference	Supply Deviations (MWh) Old Rules	Supply Deviations (MWh) New Rules	Difference	Generator Deviations (MWh) Old Rules	Generator Deviations (MWh) New Rules	Difference
Jan	8,956,331	9,795,075	838,743	3,137,527	3,263,461	125,934	3,197,210	3,190,656	(6,554)
Feb	6,694,980	7,196,554	501,574	2,738,472	2,809,384	70,912	2,727,242	2,712,446	(14,796)
Mar	7,007,409	7,510,358	502,950	2,386,348	2,467,172	80,824	2,787,110	2,777,995	(9,115)
Apr	6,114,800	6,622,271	507,471	1,974,093	2,027,200	53,106	2,719,625	2,714,483	(5,142)
May	6,682,928	7,148,336	465,407	2,342,384	2,381,985	39,601	2,945,222	2,939,608	(5,614)
Jun	8,916,182	9,846,329	930,147	2,580,099	2,558,367	(21,733)	3,067,764	3,034,875	(32,888)
Total	44,372,631	48,118,923	3,746,293	15,158,924	15,507,569	348,645	17,444,173	17,370,063	(74,109)

Table 3-33 Summary of impact on netting deviations: January through June 2011 (See SOM 2010, Table 3-77)

	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Total Deviations (MWh)
Old Rules (No Netting)	44,372,631	15,158,924	17,444,173	76,975,727
New Rules (Netting)	48,118,923	15,507,569	17,370,063	80,996,555
Difference	3,746,293	348,645	(74,109)	4,020,828

Balancing Operating Reserve Charge Rate

Figure 3-5 Daily RTO reliability and deviation balancing operating reserve rates ($/MWh): January through June 2011 (See SOM 2010, Figure 3-20)

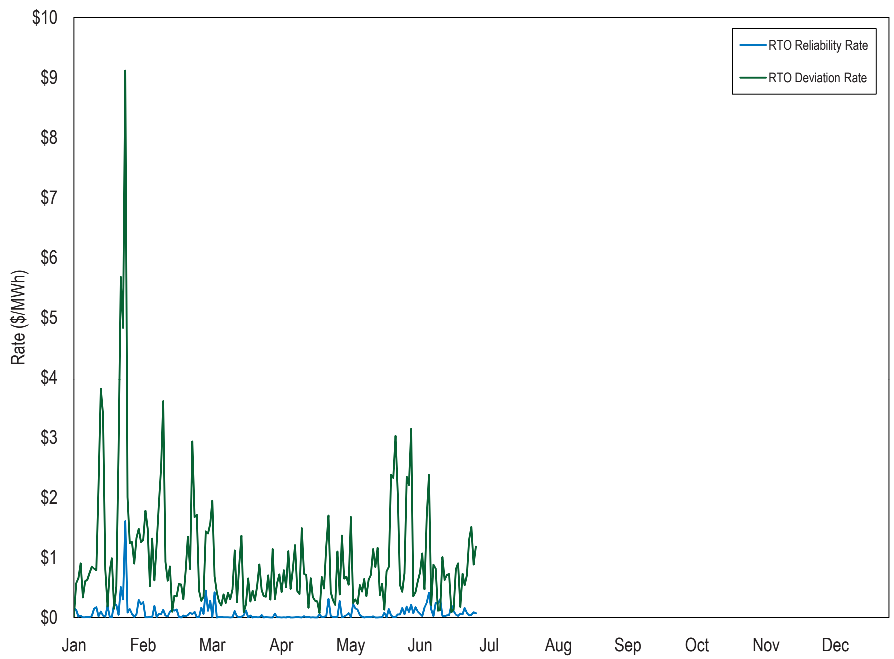


Figure 3-6 Daily regional reliability and deviation rates ($/MWh): January through June 2011 (See SOM 2010, Figure 3-21)

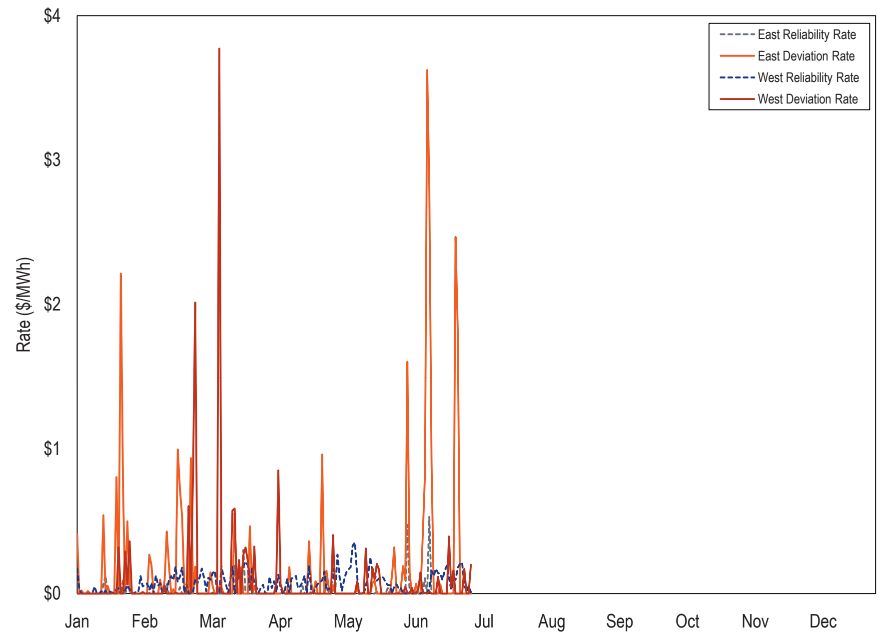


Table 3-34 Regional balancing operating reserve rates ($/MWh): January through June 2011 (See SOM 2010, Table 3-78)

	Reliability ($/MWh)	Deviations ($/MWh)
RTO	0.015	0.162
East	0.033	0.082
West	0.980	0.000

Operating Reserve Credits by Category

Figure 3-7 Operating reserve credits: January through June 2011 (See SOM 2010, Figure 3-22)

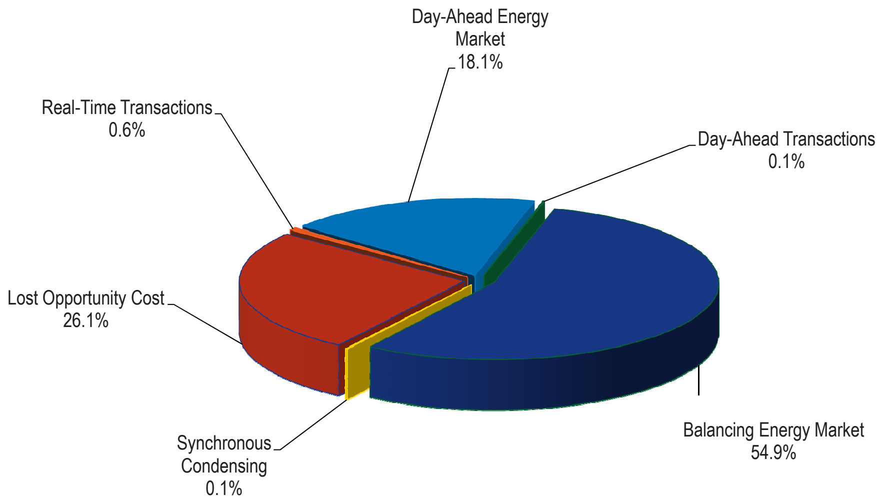


Table 3-35 Credits by month (By operating reserve market): Calendar year 2011[19] (See SOM 2010, Table 3-79)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$12,352,611	$20,488	$110,095	$42,162,945	$473,317	$2,940,640	$58,060,095
Feb	$8,844,162	$96,041	$139,287	$22,796,574	$378,056	$3,186,458	$35,440,578
Mar	$6,830,696	$7,024	$66,032	$15,720,534	$421,862	$7,085,716	$30,131,863
Apr	$4,395,461	$9,641	$13,011	$11,007,237	$215,816	$7,230,224	$22,871,389
May	$7,057,377	$7,557	$39,417	$21,636,684	$13,365	$20,245,034	$48,999,434
Jun	$8,158,879	$144,512	$9,056	$30,752,084	$20,077	$27,948,556	$67,033,165
Total	$47,639,185	$285,263	$376,898	$144,076,058	$1,522,493	$68,636,627	$262,536,524
Share of Credits	18.1%	0.1%	0.1%	54.9%	0.6%	26.1%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-36 Operating reserve credits by unit types (By operating reserve market): January through June 2011 (See SOM 2010, Table 3-80)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	31.1%	0.0%	66.9%	2.0%	$75,656,593
Combustion Turbine	1.1%	0.4%	45.5%	52.9%	$92,057,522
Diesel	3.3%	0.0%	72.8%	23.9%	$175,429
Hydro	13.0%	0.0%	87.0%	0.0%	$930,452
Landfill	0.0%	0.0%	0.0%	100.0%	$11,033,044
Nuclear	0.0%	0.0%	0.0%	100.0%	$289,427
Steam	29.9%	0.0%	63.3%	6.8%	$75,980,516
Wind Farm	0.0%	0.0%	99.6%	0.4%	$1,808,379

19 Credits may not equal charges due to adjustments made by PJM Settlements that are only reflected on participants' final bills.

Table 3-37 Operating reserve credits by operating reserve market (By unit type): January through June 2011 (See SOM 2010, Table 3-81)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	49.6%	0.0%	35.3%	2.2%
Combustion Turbine	2.2%	100.0%	29.2%	73.0%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.3%	0.0%	0.6%	0.0%
Landfill	0.0%	0.0%	0.0%	16.5%
Nuclear	0.0%	0.0%	0.0%	0.4%
Steam	48.0%	0.0%	33.5%	7.7%
Wind Farm	0.0%	0.0%	1.3%	0.0%
Total	$47,421,160	$376,898	$143,393,719	$66,739,586

Economic and Noneconomic Generation

Table 3-38 Economic vs. noneconomic hours: January through June 2011 (See SOM 2010, Table 3-82)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	10,458	62.2%	6,363	37.8%	16,821
Combustion Turbine	3,674	34.0%	7,125	66.0%	10,799
Diesel	117	25.6%	340	74.4%	457
Steam	26,550	79.9%	6,668	20.1%	33,218

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

Table 3-39 Regional balancing operating reserve credits: January through June 2011 (See SOM 2010, Table 3-86)

	Reliability Credits	Deviation Credits	Total Credits
RTO	$29,891,954	$85,845,010	$115,736,964
East	$3,080,743	$8,575,704	$11,656,447
West	$11,257,730	$2,672,035	$13,929,766
Total	$44,230,427	$97,092,749	$141,323,176

Table 3-40 Total deviations: January through June 2011 (See SOM 2010, Table 3-87)

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	48,118,923	15,507,572	17,360,066	80,986,561

Table 3-41 Charge allocation under old operating reserve construct: January through June 2011 (See SOM 2010, Table 3-88)

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	48,118,923	15,507,572	17,360,066	80,986,561
Balancing Rate ($/MWh)	1.745	1.745	1.745	1.745
Charges ($)	$83,968,488	$27,061,024	$30,293,664	$141,323,176

Table 3-42 Actual regional credits, charges, rates and charge allocation (MWh): January through June 2011 (See SOM 2010, Table 3-89)

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$29,891,954	356,917,452	0.084	$29,891,954	$85,845,010	80,986,561	1.060	$85,845,010	$115,736,964
East	$3,080,743	189,809,914	0.016	$3,080,743	$8,575,704	45,860,671	0.187	$8,575,704	$11,656,447
West	$11,257,730	167,107,538	0.067	$11,257,730	$2,672,035	34,696,188	0.077	$2,672,035	$13,929,766
Total	$44,230,427	356,917,452	NA	$44,230,427	$97,092,749	80,986,561	NA	$97,092,749	$141,323,176

Table 3-43 Difference in total operating reserve charges between old rules and new rules: January through June 2011 (See SOM 2010, Table 3-90)

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$83,968,488	$27,061,024	$30,293,664	$141,323,176
Charges (Current)	$42,423,052	$1,807,375	$44,230,427	$58,598,834	$18,469,268	$20,024,647	$97,092,749
Difference	$42,423,052	$1,807,375	$44,230,427	($25,369,654)	($8,591,757)	($10,269,017)	($44,230,427)

Impact on Decrement Bids and Incremental Offers

Table 3-44 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): Calendar years, 2010 and 2011 (See SOM 2010, Table 3-91)

	2010				2011			
Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	8,291,432	13,029,516	2,463,852	3,452,047	6,054,214	8,284,810	1,548,295	3,162,842
Feb	8,323,844	11,828,781	2,004,162	2,234,045	5,732,202	7,440,032	1,376,811	2,271,323
Mar	8,032,429	11,159,303	2,150,898	2,594,826	5,372,006	7,753,370	1,152,806	2,548,787
Apr	7,568,471	9,989,951	2,214,314	2,066,270	5,200,154	7,351,597	956,132	2,049,879
May	8,306,597	11,573,314	2,250,271	3,437,786	5,537,880	7,609,897	1,105,325	2,148,071
Jun	8,304,139	12,735,819	2,223,204	4,058,044	6,367,269	8,938,210	1,200,432	2,709,247
Jul	8,389,094	12,813,573	1,840,017	3,503,722				
Aug	7,862,123	11,648,289	1,465,333	2,676,901				
Sep	8,188,967	11,532,284	2,103,152	3,105,498				
Oct	7,777,616	10,423,935	1,564,871	2,163,717				
Nov	8,027,852	11,041,950	1,408,786	2,467,942				
Dec	9,416,187	12,320,592	1,920,956	3,451,929				
Total	98,488,750	140,097,307	23,609,817	35,212,727	34,263,725	47,377,915	7,339,801	14,890,148

Table 3-45 Comparison of balancing operating reserve charges to virtual bids: Calendar years, 2010 and 2011 (See SOM 2010, Table 3-92)

	2010			2011		
Month	Charges Under Old Rules	Charges Under Current Rules	Difference	Charges Under Old Rules	Charges Under Current Rules	Difference
Jan	$12,525,384	$10,190,867	($2,334,517)	$13,891,398	$10,165,699	($3,725,698)
Feb	$5,319,874	$3,936,420	($1,383,454)	$7,483,306	$5,767,494	($1,715,812)
Mar	$4,797,076	$3,468,829	($1,328,248)	$6,669,083	$4,947,154	($1,721,929)
Apr	$6,480,725	$5,301,308	($1,179,417)	$4,942,221	$4,056,663	($885,558)
May	$13,658,944	$10,158,307	($3,500,637)	$11,228,667	$9,896,693	($1,331,974)
Jun	$18,021,960	$10,673,612	($7,348,348)	$14,781,112	$11,756,752	($3,024,360)
Jul	$17,068,724	$14,327,987	($2,740,737)			
Aug	$9,394,993	$7,575,980	($1,819,013)			
Sep	$13,065,704	$10,820,010	($2,245,694)			
Oct	$9,019,721	$6,456,368	($2,563,353)			
Nov	$5,817,780	$3,925,450	($1,892,330)			
Dec	$17,570,579	$19,884,462	$2,313,884			
Total	$132,741,464	$106,719,600	($26,021,864)	$58,995,787	$46,590,455	($12,405,332)

Table 3-46 Summary of impact on virtual bids under balancing operating reserve allocation: January through June, 2010 and 2011 (See SOM 2010, Table 3-93)

Jan - Jun	Region	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)	Total Adjusted Virtual Deviations (MWh)	Balancing Rate Under Current Rules ($/MWh)	Balancing Rate Under Old Rules ($/MWh)	Charges Under Current Rules	Charges Under Old Rules	Differerence
2010	RTO	13,306,701	17,843,017	31,149,718	1.868	1.194	$61,402,213	$39,270,576	($22,131,638)
	East	8,947,802	11,120,832	20,068,635	0.000	0.113	$0	$1,181,245	$2,843,731
	West	4,309,184	6,577,952	10,887,136	0.000	0.000	$0	$0	$1,181,245
2011	RTO	7,339,801	14,890,148	22,229,949	1.836	2.498	$43,709,241	$58,995,787	($15,286,545)
	East	3,840,936	7,470,872	11,311,807	0.175	0.000	$2,027,106	$0	$2,027,106
	West	3,409,227	7,250,964	10,660,191	0.078	0.000	$854,107	$0	$854,107

Segmented Make Whole Payments

Table 3-47 Impact of segmented make whole payments: Calendar years, 2010 and 2011 (See SOM 2010, Table 3-94)

	2010			2011		
Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
Jan	$32,982,105	$33,924,489	$942,385	$40,766,342	$41,957,597	$1,191,255
Feb	$17,321,317	$17,609,133	$287,815	$21,621,511	$22,774,422	$1,152,911
Mar	$13,458,120	$13,672,172	$214,052	$14,872,573	$15,695,526	$822,954
Apr	$16,441,644	$17,036,058	$594,414	$10,202,172	$10,884,948	$682,776
May	$21,854,306	$23,455,721	$1,601,415	$18,606,188	$20,402,476	$1,796,288
Jun	$36,297,521	$38,885,349	$2,587,828	$27,575,556	$31,046,441	$3,470,886
Jul	$32,251,623	$37,053,630	$4,802,007			
Aug	$21,867,024	$24,335,171	$2,468,147			
Sep	$24,293,196	$25,686,790	$1,393,593			
Oct	$21,839,101	$22,478,455	$639,354			
Nov	$15,795,391	$16,238,383	$442,991			
Dec	$49,180,164	$51,293,810	$2,113,646			
Total	$303,581,512	$321,669,160	$18,087,648	$133,644,341	$142,761,411	$9,117,069

Table 3-48 Share of balancing operating reserve increases for segmented make whole payments (By unit type): January through June 2011 (See SOM 2010, Table 3-96)

Unit Type	Share of Increase
Combined-Cycle	48.6%
Combustion Turbines	33.2%
Steam	18.1%
Diesel	0.1%

Unit Operating Parameters[20]

Table 3-49 Units receiving credits from a parameter limited schedule: January through June 2011 (See SOM 2010, Table 3-98)

Unit Type	Number of Units	Observations
Combined-Cycle	1	4
Large Frame Combustion Turbine (135 - 180 MW)	5	11
Medium-Large Frame Combustion Turbine (65 - 125 MW)	9	44
Petroleum/Gas Steam (Pre-1985)	2	2
Sub-Critical Coal	20	107

Issues in Operating Reserves

Concentration of Operating Reserve Credits

Table 3-50 Unit operating reserve credits (By zone): January through June 2011 (See SOM 2010, Table 3-100)

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$274,894	$0	$2,199,633	$2,007,460	$4,481,987	1.7%
AEP	$1,235,203	$368	$22,906,738	$4,944,754	$29,087,062	11.2%
AP	$893,398	$0	$4,852,097	$3,901,669	$9,647,164	3.7%
ATSI	$205,519	$0	$193,350	$1,894,992	$2,293,862	0.9%
BGE	$4,967,552	$0	$3,944,432	$361,172	$9,273,156	3.6%
ComEd	$425,869	$0	$2,291,135	$7,802,345	$10,519,348	4.0%
DAY	$78,783	$0	$437,577	$130,359	$646,719	0.2%
Dominion	$2,838,549	$0	$23,431,639	$38,150,077	$64,420,264	24.7%
DLCO	$161,831	$0	$1,110,820	$5,239	$1,277,890	0.5%
DPL	$727,090	$0	$6,908,735	$749,387	$8,385,213	3.2%
JCPL	$1,355,222	$0	$4,431,998	$625,010	$6,412,229	2.5%
Met-Ed	$120,577	$0	$1,404,692	$337,577	$1,862,846	0.7%
PECO	$607,154	$4,692	$3,906,967	$1,412,073	$5,930,885	2.3%
PENELEC	$295,112	$0	$1,501,303	$318,057	$2,114,472	0.8%
Pepco	$2,160,314	$0	$11,440,864	$3,662,251	$17,263,430	6.6%
PPL	$362,546	$0	$4,769,857	$959,946	$6,092,349	2.3%
PSEG	$30,929,572	$371,838	$48,344,221	$1,374,261	$81,019,892	31.1%
External	$0	$0	$0	$0	$0	0.0%
Total	$47,639,185	$376,898	$144,076,058	$68,636,627	$260,728,769	100.0%

20 See the *2010 State of the Market Report for PJM*, Volume 2, Section 3, "Energy Market, Part 2," Table 3-97 *Unit Parameter Limited Schedule Matrix* for details regarding default unit operating parameters.

Table 3-51 Top 10 units and organizations receiving total operating reserve credits: January through June 2011 (See SOM 2010, Table 3-101)

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$25,079,394	9.6%	9.6%	$80,499,792	30.9%	30.9%
2	$20,266,194	7.8%	17.4%	$48,591,684	18.6%	49.5%
3	$14,737,524	5.7%	23.0%	$19,347,376	7.4%	56.9%
4	$6,152,848	2.4%	25.4%	$11,936,834	4.6%	61.5%
5	$5,105,132	2.0%	27.4%	$11,013,317	4.2%	65.7%
6	$4,459,407	1.7%	29.1%	$10,594,807	4.1%	69.8%
7	$3,722,211	1.4%	30.5%	$7,490,078	2.9%	72.7%
8	$3,459,683	1.3%	31.8%	$6,687,352	2.6%	75.2%
9	$3,287,786	1.3%	33.1%	$5,745,703	2.2%	77.4%
10	$3,218,698	1.2%	34.3%	$5,745,477	2.2%	79.6%

Table 3-52 Top 10 units and organizations receiving day-ahead generator credits: January through June 2011 (See SOM 2010, Table 3-102)

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$11,590,529	24.3%	24.3%	$30,810,681	64.7%	64.7%
2	$9,677,411	20.3%	44.6%	$5,049,931	10.6%	75.3%
3	$5,381,825	11.3%	55.9%	$2,772,387	5.8%	81.1%
4	$2,059,315	4.3%	60.3%	$1,824,719	3.8%	84.9%
5	$1,937,566	4.1%	64.3%	$1,095,566	2.3%	87.2%
6	$1,776,698	3.7%	68.1%	$976,591	2.0%	89.3%
7	$1,459,626	3.1%	71.1%	$649,814	1.4%	90.6%
8	$1,095,566	2.3%	73.4%	$551,011	1.2%	91.8%
9	$455,192	1.0%	74.4%	$519,792	1.1%	92.9%
10	$382,258	0.8%	75.2%	$468,225	1.0%	93.9%

Table 3-53 Top 10 units and organizations receiving synchronous condensing credits: January through June 2011 (See SOM 2010, Table 3-103)

	Units			Organizations		
Rank	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution	Synchronous Condensing Credit	Synchronous Condensing Credit Share	Synchronous Condensing Credit Cumulative Distribution
1	$35,887	9.5%	9.5%	$371,838	98.7%	98.7%
2	$33,192	8.8%	18.3%	$4,692	1.2%	99.9%
3	$31,995	8.5%	26.8%	$368	0.1%	100.0%
4	$31,793	8.4%	35.3%			
5	$25,729	6.8%	42.1%			
6	$23,986	6.4%	48.4%			
7	$23,039	6.1%	54.6%			
8	$15,433	4.1%	58.7%			
9	$13,620	3.6%	62.3%			
10	$13,089	3.5%	65.7%			

Table 3-54 Top 10 units and organizations receiving balancing generator credits: January through June 2011 (See SOM 2010, Table 3-104)

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$19,685,413	13.7%	13.7%	$47,943,012	33.3%	33.3%
2	$8,653,852	6.0%	19.7%	$20,074,030	13.9%	47.2%
3	$5,056,441	3.5%	23.2%	$15,690,653	10.9%	58.1%
4	$4,649,940	3.2%	26.4%	$10,477,906	7.3%	65.4%
5	$4,091,759	2.8%	29.2%	$5,395,108	3.7%	69.1%
6	$3,197,086	2.2%	31.5%	$4,917,553	3.4%	72.5%
7	$2,997,047	2.1%	33.5%	$4,682,426	3.2%	75.8%
8	$2,526,301	1.8%	35.3%	$3,893,635	2.7%	78.5%
9	$2,469,064	1.7%	37.0%	$3,516,216	2.4%	80.9%
10	$2,208,298	1.5%	38.5%	$3,109,125	2.2%	83.1%

Table 3-55 Top 10 units and organizations receiving lost opportunity cost credits: January through June 2011 (See SOM 2010, Table 3-105)

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$3,708,849	5.4%	5.4%	$25,745,266	37.5%	37.5%
2	$3,442,108	5.0%	10.4%	$10,555,653	15.4%	52.9%
3	$2,322,305	3.4%	13.8%	$3,442,108	5.0%	57.9%
4	$2,053,327	3.0%	16.8%	$3,359,135	4.9%	62.8%
5	$2,041,305	3.0%	19.8%	$2,998,092	4.4%	67.2%
6	$1,865,391	2.7%	22.5%	$2,733,470	4.0%	71.1%
7	$1,787,465	2.6%	25.1%	$2,680,133	3.9%	75.1%
8	$1,705,513	2.5%	27.6%	$1,700,722	2.5%	77.5%
9	$1,641,311	2.4%	30.0%	$1,374,261	2.0%	79.5%
10	$1,567,090	2.3%	32.2%	$1,286,619	1.9%	81.4%

PLS (Parameter Limited Schedules) Recommendations

Startup and Notification Times

Startup and notification times are offer parameters that should, like other parameters, reflect the physical limitations of the units. There are currently no limits on startup and notification time parameters, and as a result these parameters could be used to exercise market power through economic withholding under both cost based and price based offers.

Table 3-56 is based on calculating notification and startup times independently, then adding together. Table 3-57 is based on adding notification and startup times together first, then calculating distribution. All data are based on historical cost-based offers within one standard deviation of the mean since November 2007.

Table 3-56 Cold notification and cold startup hours (By percentile): Since November 2007 (New table)

	Cold Notification Time			Cold Startup Time			CS + CN		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	4	8.5	18	12.5	14	18	16.5	22.5	36
Petroleum/Gas Steam (Post-1985)	1	1	2	6	12	14	7	13	16
Combined-Cycle	2	5	7	5	6.2	8	7	11.2	15
Sub-Critical Coal	2	2	4	15	16	20	17	18	24
Super-Critical Coal	2	2	8	19	20	22	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	0.25	1	2	0.5	0.5	0.8	0.75	1.5	2.8
Medium Frame Combustion Turbine (30 - 65 MW)	0.2	0.3	1.4	0.3	0.5	0.5	0.5	0.8	1.9
Medium-Large Frame Combustion Turbine (65 - 135 MW)	1	2	2	0.5	0.7	1	1.5	2.7	3
Large Frame Combustion Turbine (135 - 180 MW)	2	5	6	0.5	0.7	1	2.5	5.7	7

Table 3-57 Time-To-Start hours (By percentile): Since November 2007 (New table)

	All Months			Peak Months			Off-Peak Months		
Parameter Class	70th	80th	90th	70th	80th	90th	70th	80th	90th
Petroleum/Gas Steam (Pre-1985)	18	20	32	18	20	30	17	19	32
Petroleum/Gas Steam (Post-1985)	9	13	14	9	13	14	9	13	14
Combined-Cycle	9	11	14	8.5	10	13.5	9	11	14
Sub-Critical Coal	16.5	18	22	16.5	18	22.5	16	18	22
Super-Critical Coal	21	22	30	21	22	30	21	22	30
Small Frame Combustion Turbine (0 - 30 MW)	1	1.5	2.2	1	1.5	2.2	1	1.5	2.2
Medium Frame Combustion Turbine (30 - 65 MW)	0.5	0.8	1.7	0.5	0.7	1.7	0.5	1	2
Medium-Large Frame Combustion Turbine (65 - 135 MW)	2	2	3.3	2	2	3.3	2	2.3	3.4
Large Frame Combustion Turbine (135 - 180 MW)	3	5	6.6	2.5	4.3	6.6	4	5	6.8

Parameter Limited Schedules

Currently, parameter limited schedules are only enforced for cost-based schedules, except for emergencies, permitting the use of price-based schedule parameters as a possible method to exercise market power. For example, a unit may temporarily extend a minimum down time parameter to avoid being turned off when not economic, and not based on a physical change at the unit. This will increase operating reserve credits to the unit and operating reserve charges paid by other participants. As another example, a unit may offer more flexible operating parameters on a price-based schedule than on a cost-based schedule. The result is higher market prices when the price-based schedule is taken in place of the cost-based schedule when offer capping is implemented and the potential for increased operating reserve credits to the unit and operating reserve charges paid by other participants when the cost-based schedule is used. The MMU recommends that the PJM dispatch become more forward looking in order to better capture the operation of baseload units that were not designed to cycle daily and that the most flexible parameter offered be used as the parameter limited schedule.