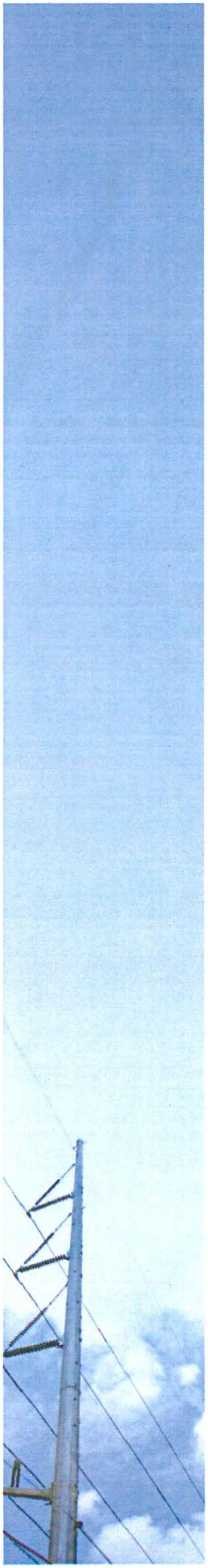

Monthly State of the Market Report

May 2009

Staff BK 11

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SPP Market Monitoring Unit

SPP Southwest Power Pool

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Executive Summary

The SPP Energy Imbalance Services (EIS) market performance continues to be robust. The market price for electricity remains very low with a system average of $23.67/MWh for the month (Figure 11). This is the second lowest monthly value for the EIS market. The very low prices are primarily the result of low natural gas prices and coal providing almost 50% of the marginal fuel. SPP price volatility continues to be very low, slightly lower than MISO and about half the value for ERCOT.

The new Nebraska Market Participants are experiencing slightly lower prices than the system average which is not unexpected given the large number of coal and nuclear units. Last month this report included several supplemental figures breaking out market results with and without Nebraska MPs. The supplemental metrics for May showed very similar patterns and are not included in this report.

This report contains several new supplemental figures that will only be shown occasionally: price duration curves, Figures 5a (May) and Figure 6a (last 12 months); and annual wind capacity additions to the SPP market, Figure 9a. The price duration curves show the relative price stability for electricity in the SPP market. The annual wind capacity chart shows the growth in wind generation over the last nine years, with dramatic growth occurring in the past five years.

One metric of concern this month is the ramp rate deficiency value (Figure 16). The number of up ramp deficiencies was at an all time low (nine intervals) while the number of down ramp deficiency intervals were at an all time high (80 intervals). The number of intervals when the system experienced a down ramp deficiency was almost 7 times higher in May than the average over the last 12 months. The increase in the number of base load units participating in the market with the addition of Nebraska could be a contributing factor. A high number of base load units could force intermediate and peaking units to their minimums, thus limiting down ramp capability. The MMU and SPP Operations are continuing to assess this issue.

Temporary flowgates are again the predominate congestion issue in May with four of the top five and six of the top ten congested flowgates being temporaries (Figure 2). Two temporary flowgates that experienced significant congestion over the last few months were retired in May. This is a positive factor for SPP markets.

One final noteworthy issue is fuel on the margin (Figure 10). Coal generation was setting market price 48 percent of the time in May; this is the highest since EIS Market startup. This appears to be driven by the significant base load capacity additions from Nebraska, specifically nuclear plants replacing natural gas generation resulting in more coal units on the margin.

Figures

Figure 1 – SPP EIS Price Contour Map
May 2009

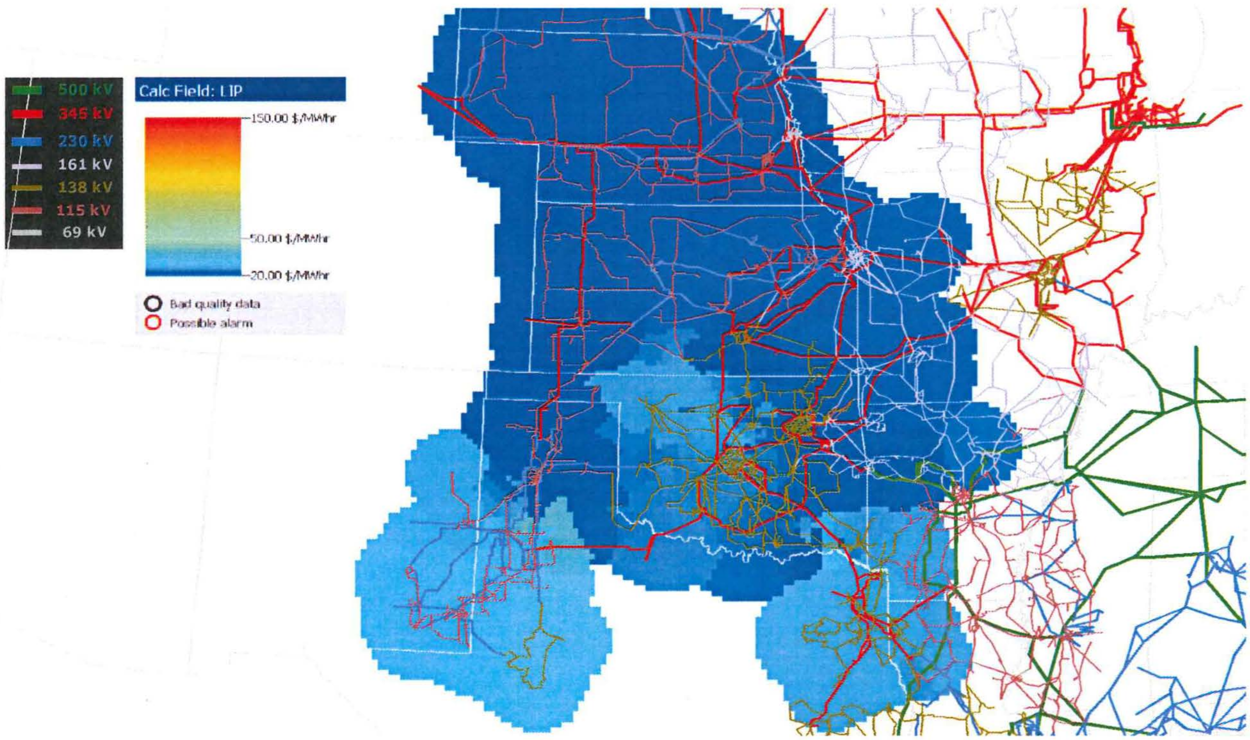
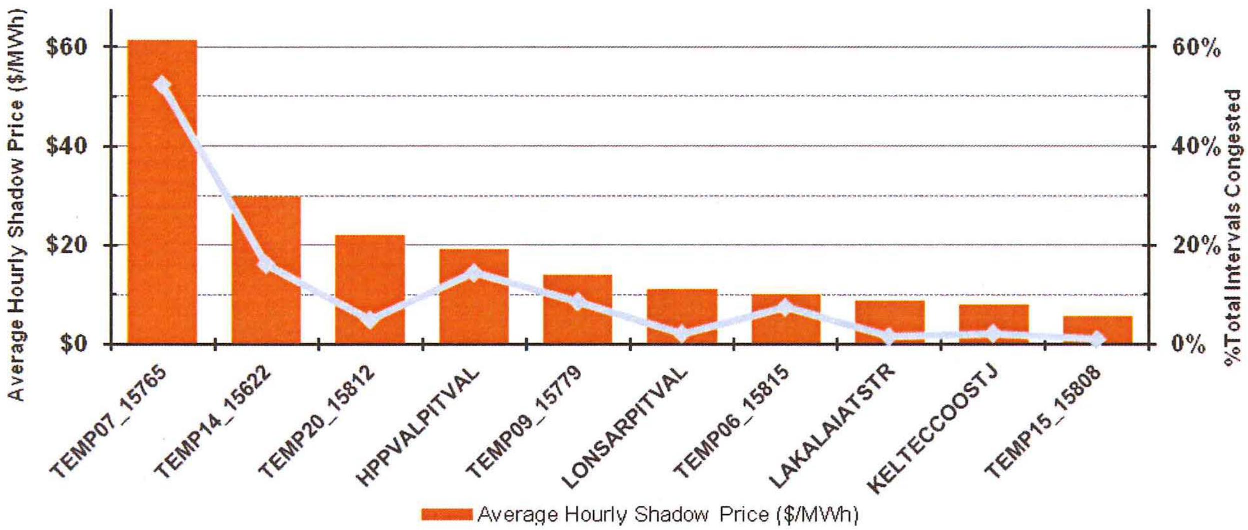
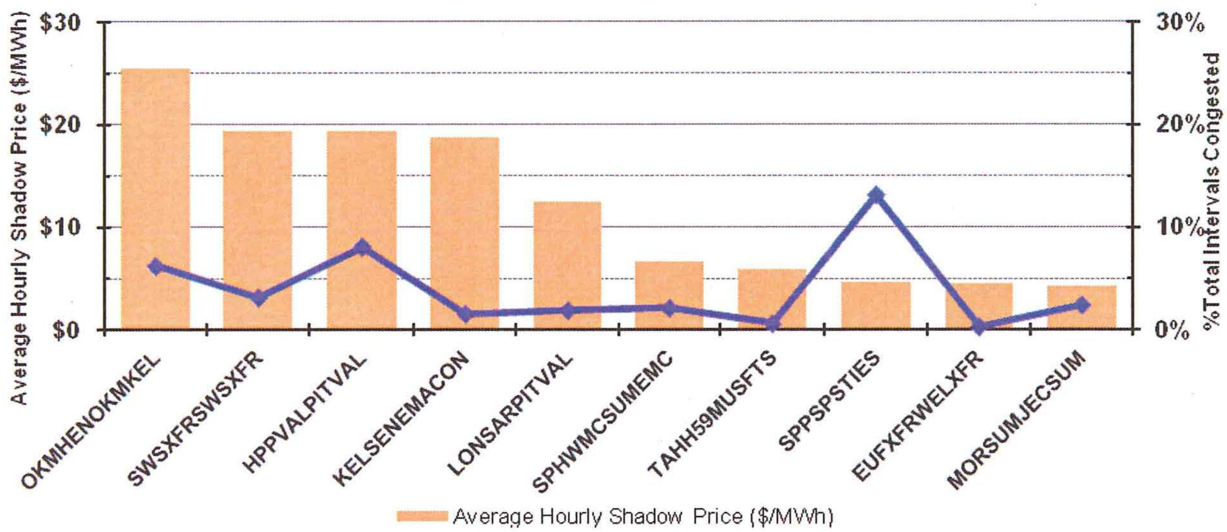


Figure 2 – Congestion by Shadow Price impact – May 2009



Flowgate Name	Flowgate Location (kV)	Control Area	Average Hourly Shadow Price ($/MWh)	Total % Intervals (Breached or Binding)	Detailed Description
TEMP07_15765	Kress – Hale Co. (115) ftlo Swisher – Tuco (230)	SPS	$ 61.35	52.4%	Modeled 05/01/09 to reflect derate of flowgate capacity. Additionally, a generator was lost that led to the increase in flow on this flowgate.
TEMP14_15622	Randall County Int - Palo Duro (115) ftlo Amarillo-Swisher (230)	SPS	$ 29.67	16.0%	Modeled 02/16/09 to reflect derate of flowgate capacity. Related to outage of second circuit Tolksub - Roosevelt 230 kV. Attempt to control high North to South flow.
TEMP20_15812	Arcadia Transformer (345/138)	OKGE	$ 21.98	4.7%	Modeled 5/16/09 to monitor Arcadia XFMR 345/138 kV #2 during the outage of Arcadia – Northwest 345 kV. Retired 06/09/09.
HPPVALPITVAL	Hugo Power Plant -Valliant (138)	WFEC-CSWS	$ 19.17	14.3%	Insufficient MW available for redispatch on both sides of the flowgate.
TEMP09_15779	Medicine Lodge (138/115) XFR ftlo Red Willow – Mingo (345)	SECI-NPPD	$ 13.86	8.5%	There are no increment units for this flowgate, thus leaving SPP with little control on its flow.
LONSARPITVAL	Lone Oak to Sardis (138)	CSWS	$ 11.02	2.0%	Insufficient available MW south of the flowgate. Same area as Hugo Power Plant.
TEMP06_15815	Woodring (345/138) XFR ftlo Woodring - Cimarron (345)	OKGE	$ 10.01	7.4%	Modeled 05/28/09 to monitor high North-South flows when flowgate appeared in RTCA (Real Time Congestion Analysis) Additionaly, outage of Spring Creek - Northwestern 345kkV line caused breaches. Retired 06/11/09
LAKALAIATSTR	Lake Road - Nashua (161) ftlo Iatan - Stranger Creek (345)	SECI	$ 8.73	1.4%	Due to St. Joe - Hawthorne 345kv outage
KELTECCOOSTJ	Kelly - Tecumseh (161) ftlo Cooper – St Joe (230)	WR-NPPD	$ 7.99	2.0%	Heavy north south flow combined with no ramp availability of decremental units.
TEMP15_15808	McElroy – Kinze 138 kV ftlo Sooner – Woodring 345 kV	OKGE	$ 5.50	0.9%	Modeled 05/25/09 to monitor outage of Spring Creek – Northwestern 345 kV. Retired 6/11/09.

Figure 3 – Congestion by Shadow Price impact – Previous 12 months

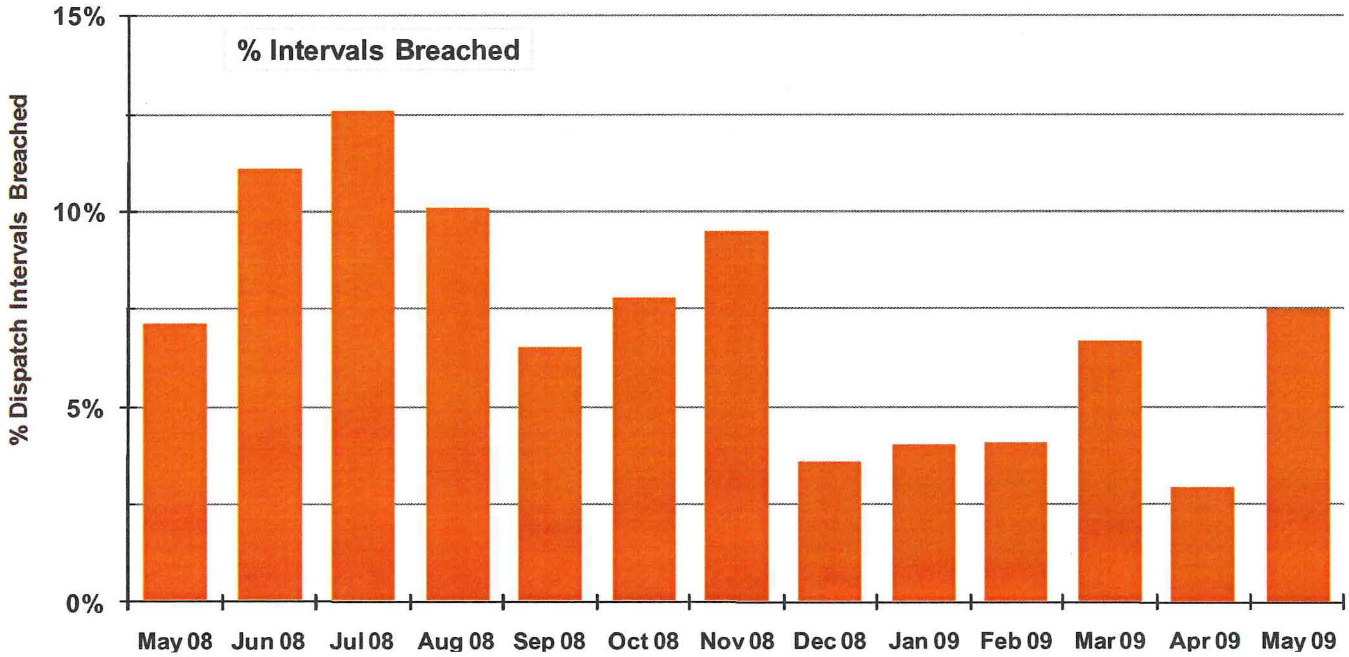


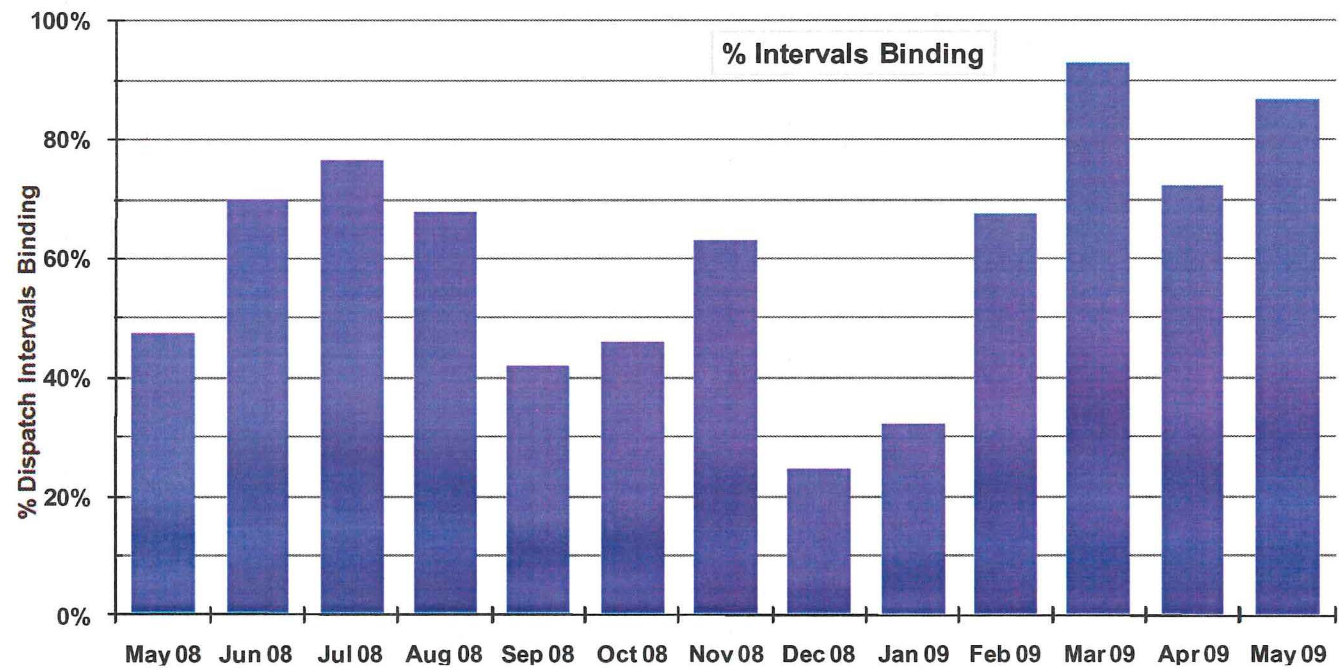
Flowgate Name	Flowgate Location (kV)	Control Area	Average Hourly Shadow Price ($/MWh)	Total % Intervals (Breached or Binding)	Proposed Solution [estimated completion date]
OKMHENOKMKEL	Okmulgee to Henryetta (138)	CSWS	$ 25.46	6.3%	Mitigated in part (~32%) by construction of the Seminole to Muskogee 345kV line in southeastern Oklahoma. [4/1/2012] *
SWSXFRSWSXFR	SW Shreveport Transformer (345/138)	CSWS	$ 19.40	3.2%	Ongoing upgrades to SW Shreveport Transformer will address this constraint in northwest LA. [Summer 2009]
HPPVALPITVAL	Hugo Power Plant to Valliant (138)	WFEC-CSWS	$ 19.29	8.1%	New 19 mile Hugo to Valliant 345 kV line with 138/345 kV XF at Hugo PP will address these constraints in southeastern OK. [4/1/2012]
KELSENEMACON	Kelly to South Seneca (115)	WR	$ 18.78	1.6%	Project work for Trans-Canada Pipeline will help alleviate this situation in Northern Kansas. **
LONSARPITVAL	Lone Oak to Sardis (138)	CSWS	$ 12.48	1.9%	New 19 mile Hugo to Valliant 345 kV line as stated above.
SPHWMCSUMEMC	South Phillips to West McPherson (115)	WR	$ 6.65	2.2%	Wichita-Reno Co-Summit 345 kV will address this constraint in central KS. [4/1/2012]
TAHH59MUSFTS	Tahlequah – Highway 59 (161)	GRDA-OGE	$ 5.96	0.6%	No current solution has been proposed for this flowgate
SPPSPSTIES	Texas Panhandle (5 various ties)	SPS	$ 4.64	13.1%	Tuco – Woodward 345 kV line will address this constraint. Estimated in-service date is [5/1/2014]*
EUFXFRWELXFR	Eufaula Transformer (138/138)	SPA	$ 4.51	0.3%	SWPA has a planned upgrade of the Eufaula Transformer from 100 to 200 MVA in 2010.
MORSUMJECSUM	Morris – Summit (230)	WR	$ 4.27	2.5%	Wichita-Reno Co-Summit 345 kV will address this constraint in central KS. [4/1/2012]

* Part of the Balanced Portfolio P3-E adjusted approved in 2009.

** Project includes new 32 mile 115 kV line from Knob Hill to Steele City, new 15 mile 115 kV line from Steele City to Harbine, and rebuild of 10.3 mile 115 kV line between Kelly and South Seneca in northern Kansas. [6/1/2010]

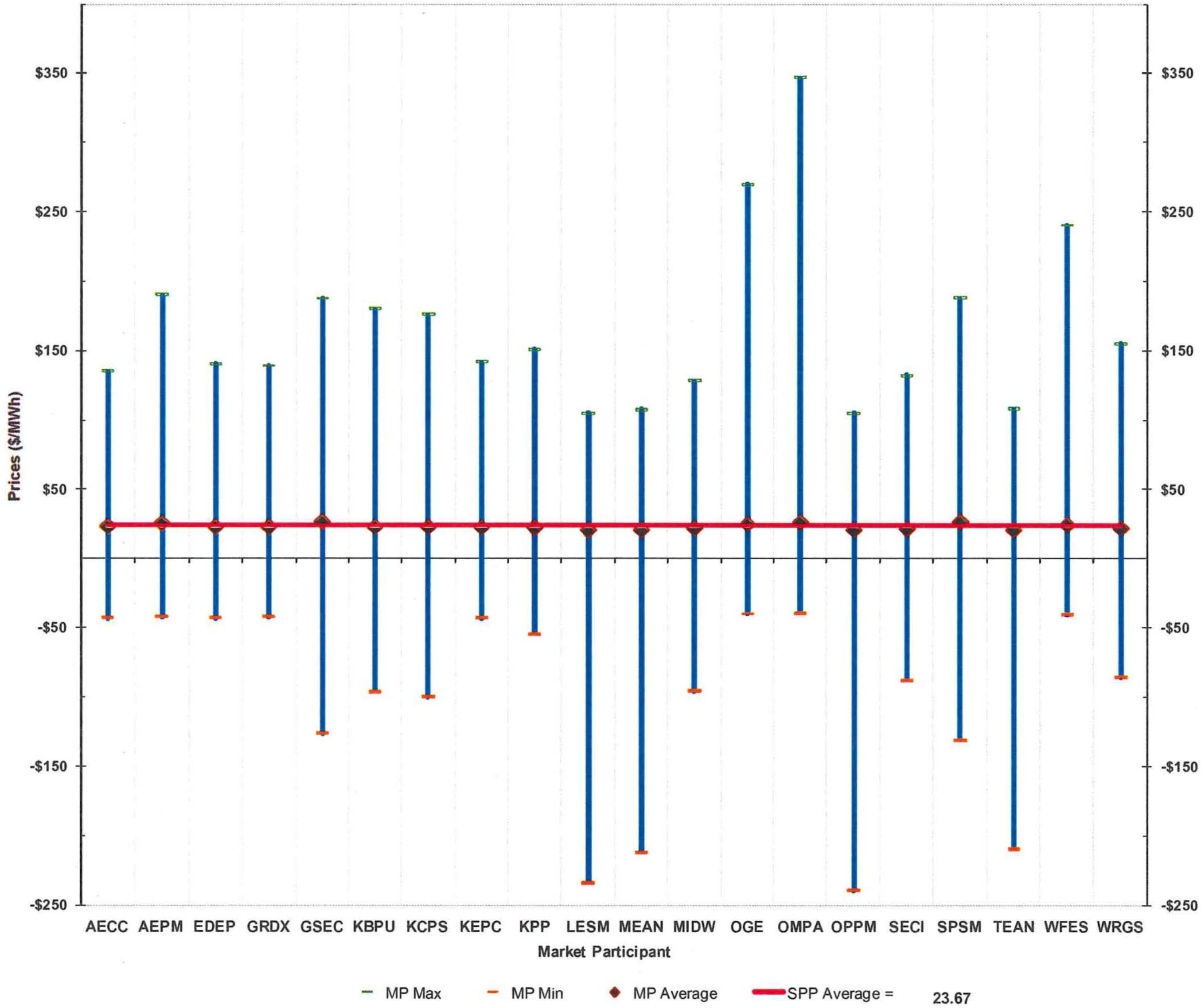
Figure 4 – Breached and Binding Flowgates by Interval





intervals	MAY 2008	JUN 2008	JUL 2008	AUG 2008	SEP 2008	OCT 2008	NOV 2008	DEC 2008	JAN 2009	FEB 2009	MAR 2009	APR 2009	MAY 2009	last 12 months
% Breached	7.1%	11.1%	12.6%	10.1%	6.5%	7.8%	9.5%	3.6%	4.2%	4.1%	6.7%	2.9%	7.5%	7.2%
% Binding	47.6%	69.9%	76.7%	67.9%	42.1%	46.1%	63.3%	24.4%	32.1%	67.4%	92.9%	72.1%	86.9%	61.8%

Figure 5 – Hourly Price Ranges by Market Participant – May 2009



in $	AECC	AEPM	EDEP	GRDX	GSEC	KBPU	KCPS	KEPC	KPP	LESM	MEAN	MIDW	OGE	OMPA	OPPM	SECI	SPSM	TEAN	WFES	WRGS
Max	135	191	140	139	188	180	176	142	151	105	107	128	270	347	105	132	188	108	240	155
Avg	23	25	22	23	26	22	22	22	22	20	20	21	24	26	20	21	26	20	24	22
Min	-43	-42	-43	-43	-126	-97	-100	-43	-55	-234	-212	-96	-40	-40	-240	-88	-131	-210	-41	-86

Figure 5a – Price Duration Curve – May 2009

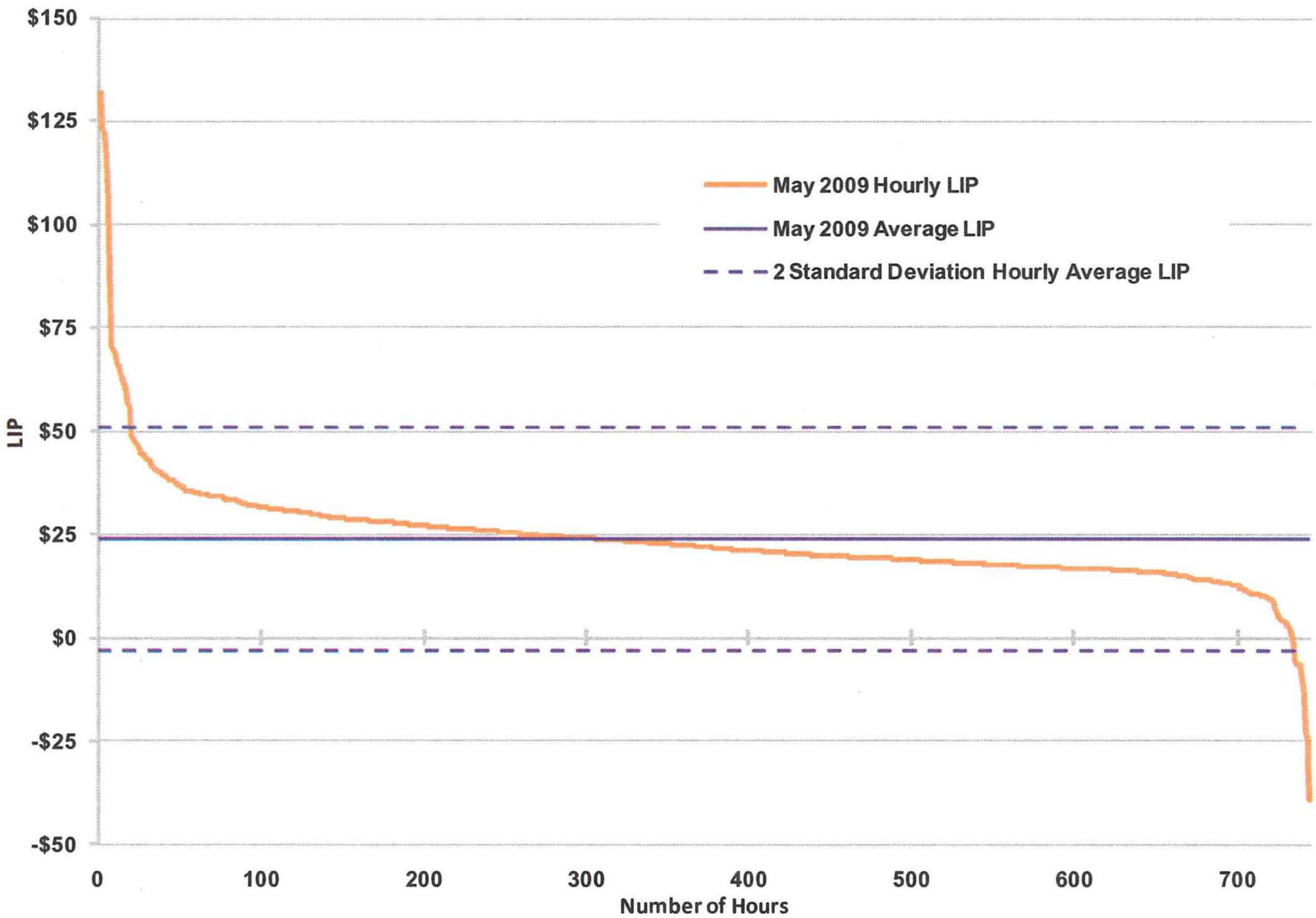
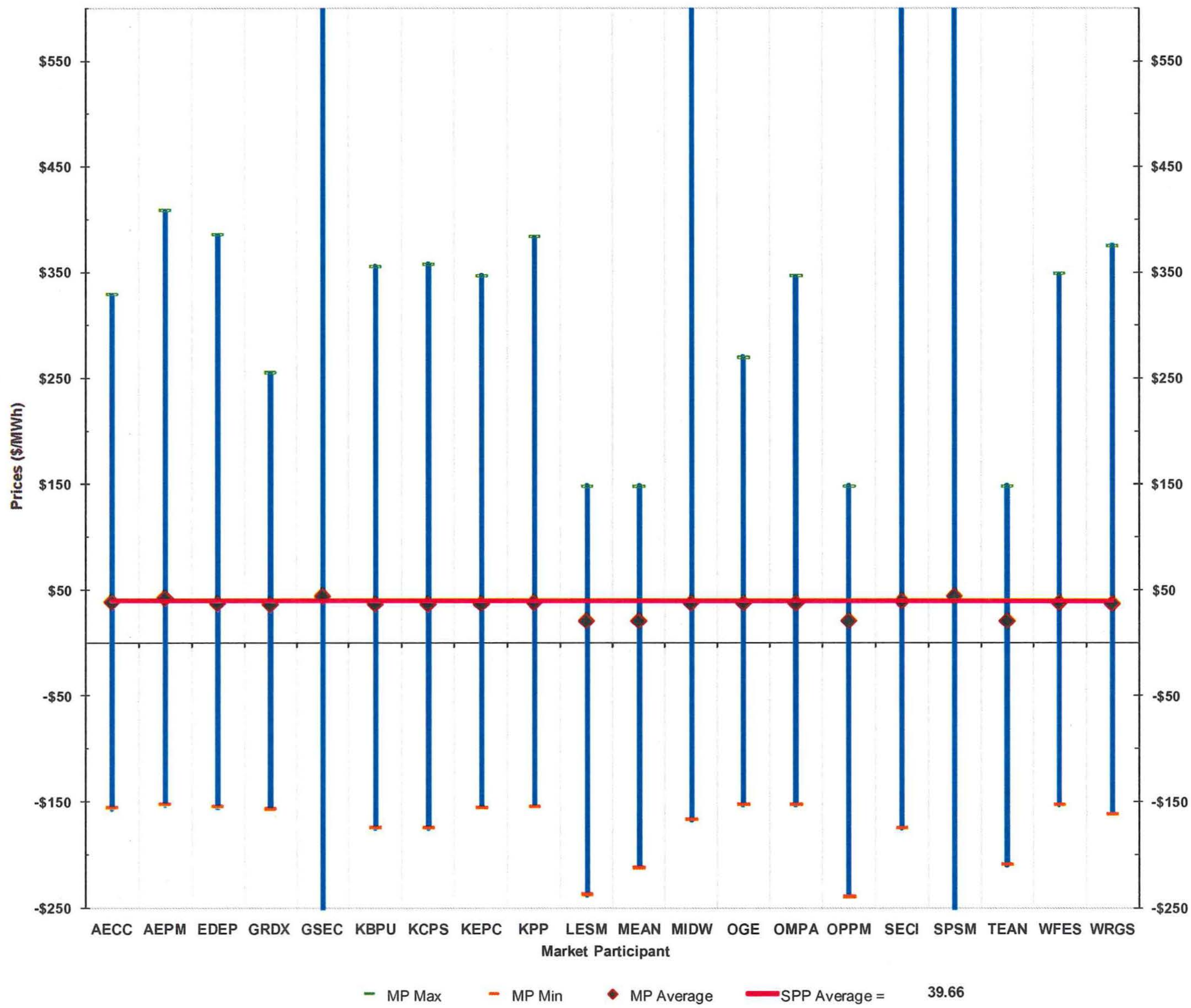


Figure 6 – Hourly Price Ranges by Market Participant – Previous 12 months



in $	AECC	AEPM	EDEP	GRDX	GSEC	KBPU	KCPS	KEPC	KPP	LESM	MEAN	MIDW	OGE	OMPA	OPPM	SECI	SPSM	TEAN	WFES	WRGS
Max	329	409	386	255	1,647	356	358	347	384	148	148	971	270	347	148	833	1,685	148	349	375
Avg	38	42	37	36	44	36	36	37	38	20	20	37	38	37	20	39	44	20	38	37
Min	-156	-153	-155	-157	-409	-175	-175	-156	-155	-238	-212	-167	-153	-153	-240	-175	-418	-210	-153	-161

Figure 6a – Price Duration Curve – Previous 12 months

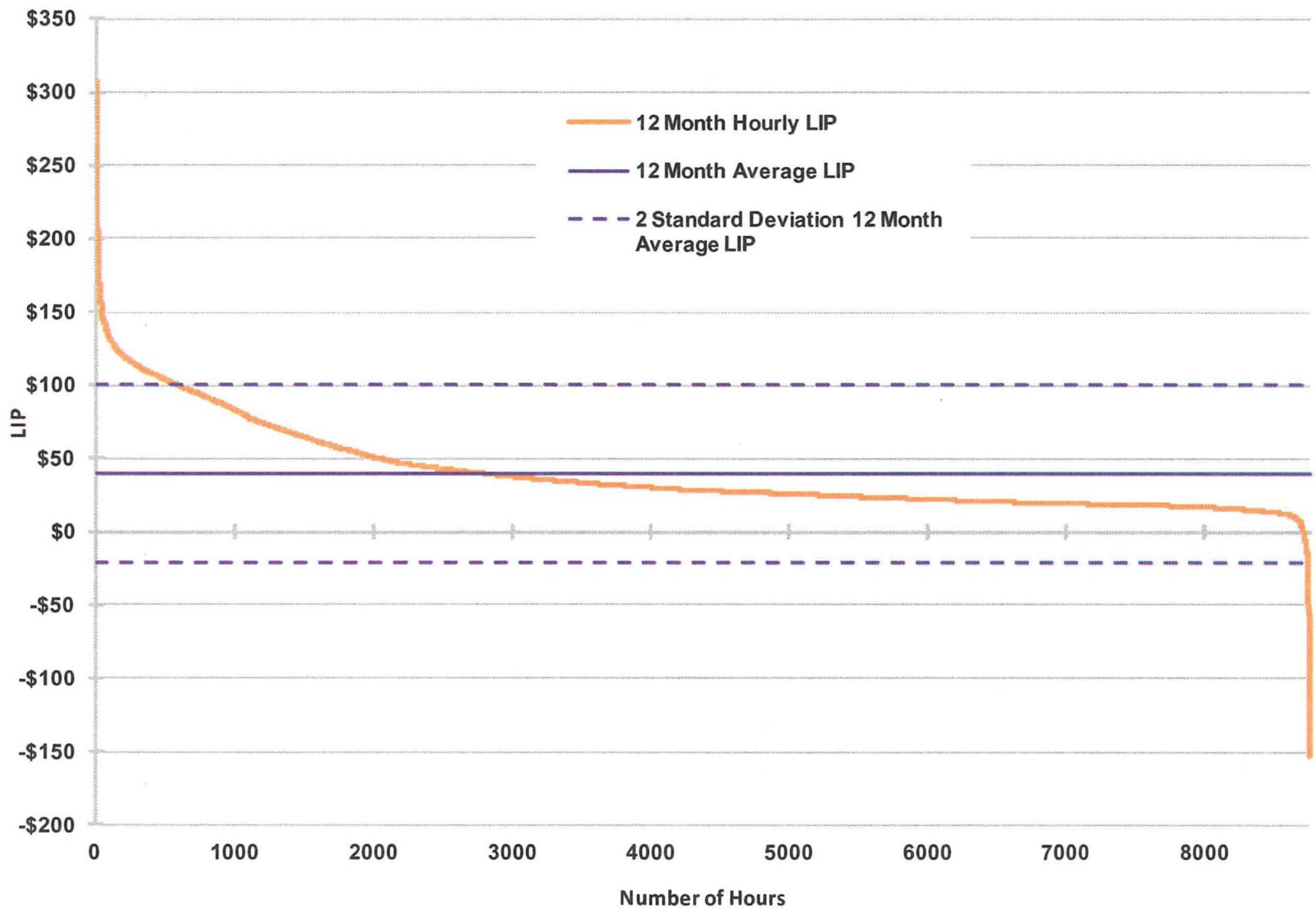
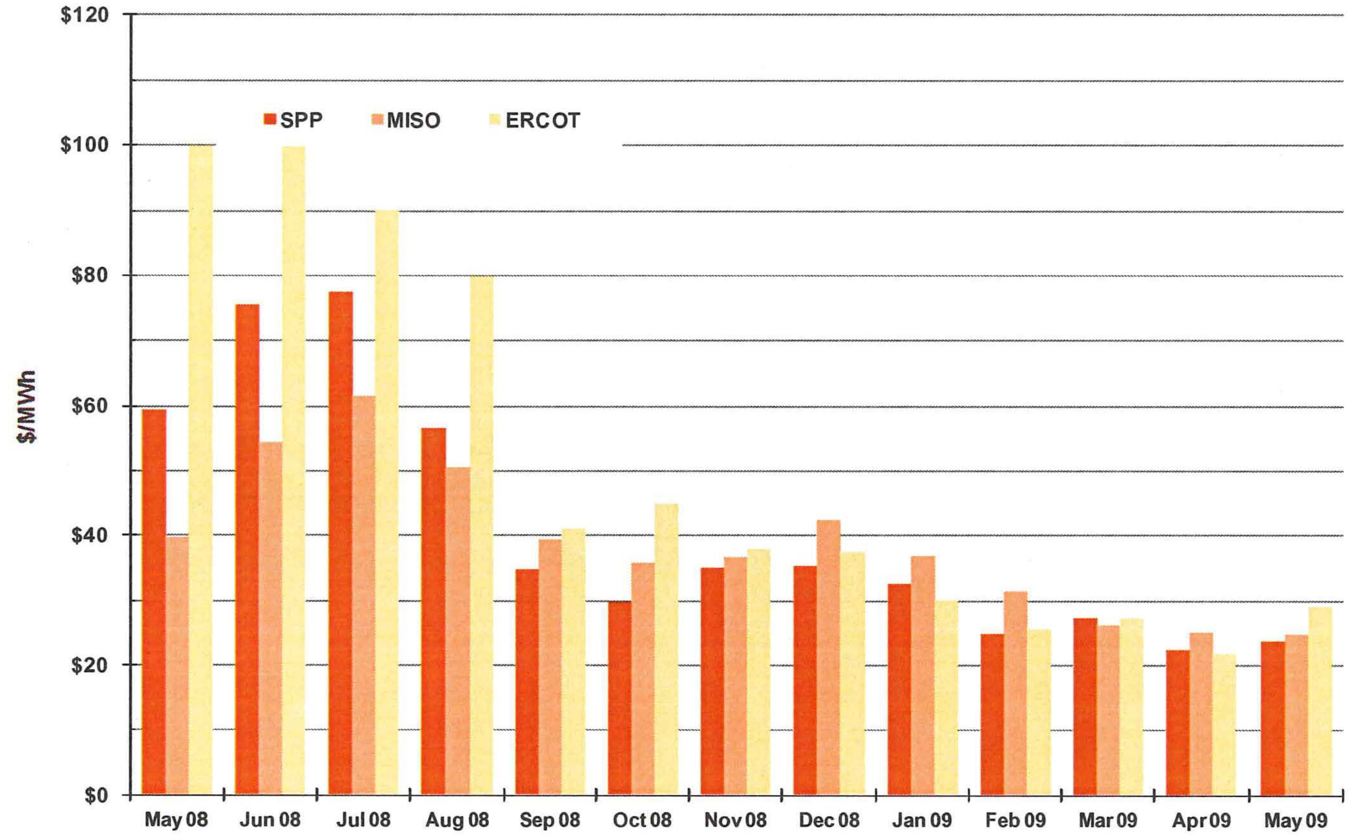


Figure 7 – Regional Monthly Prices



Region	Average Price	Maximum Price	Minimum Price	Volatility	Average On-Peak Price	Average Off-Peak Price
SPP	$ 23.67	$ 132.11	$ - 39.27	57%	$ 28.10	$ 18.74
MISO	$ 24.67	$ 146.54	$ - 91.27	69%	$ 30.26	$ 20.06
ERCOT	$ 29.24	$ 472.41	$ -3.90	111%	$ 33.52	$ 25.71

Note: This table is a "rough comparison" because of inherent differences in the structure of the three markets and also because of the differences in how prices for SPP, MISO, and ERCOT are calculated. For SPP, load weighted averages are used, while the data from MISO and ERCOT are not load weighted. Volatility is measured by the Coefficient of Variation, which is the standard deviation across all hours divided by the average of all hours.

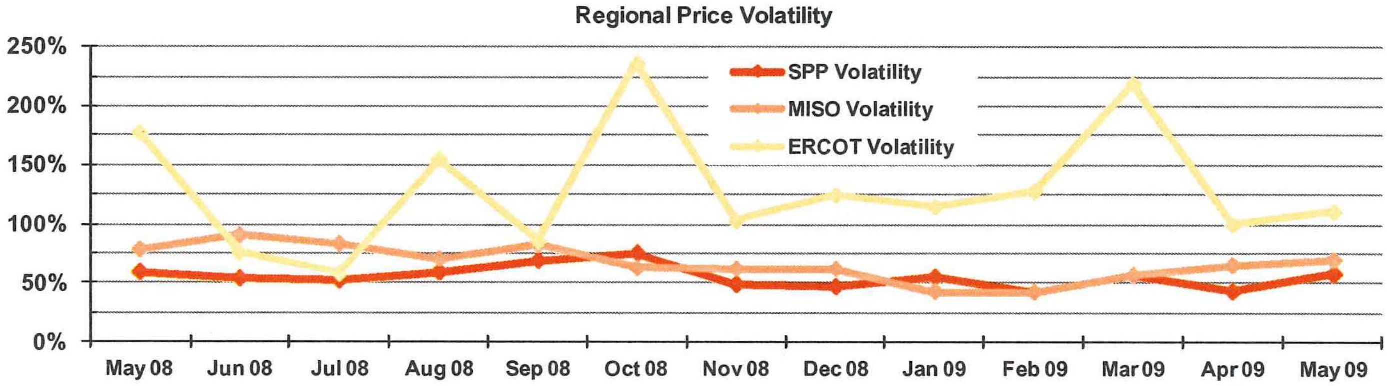
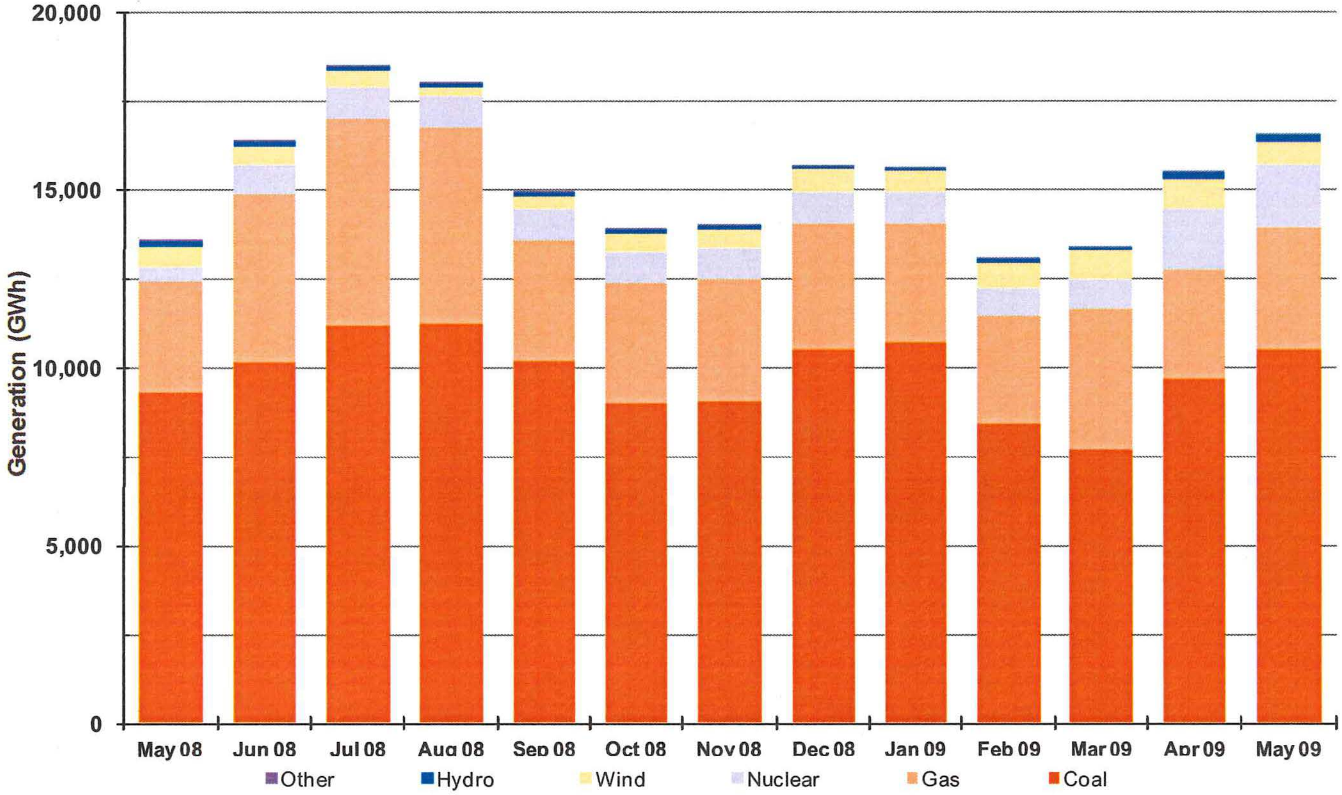


Figure 8 – Energy Generation by Fuel Type

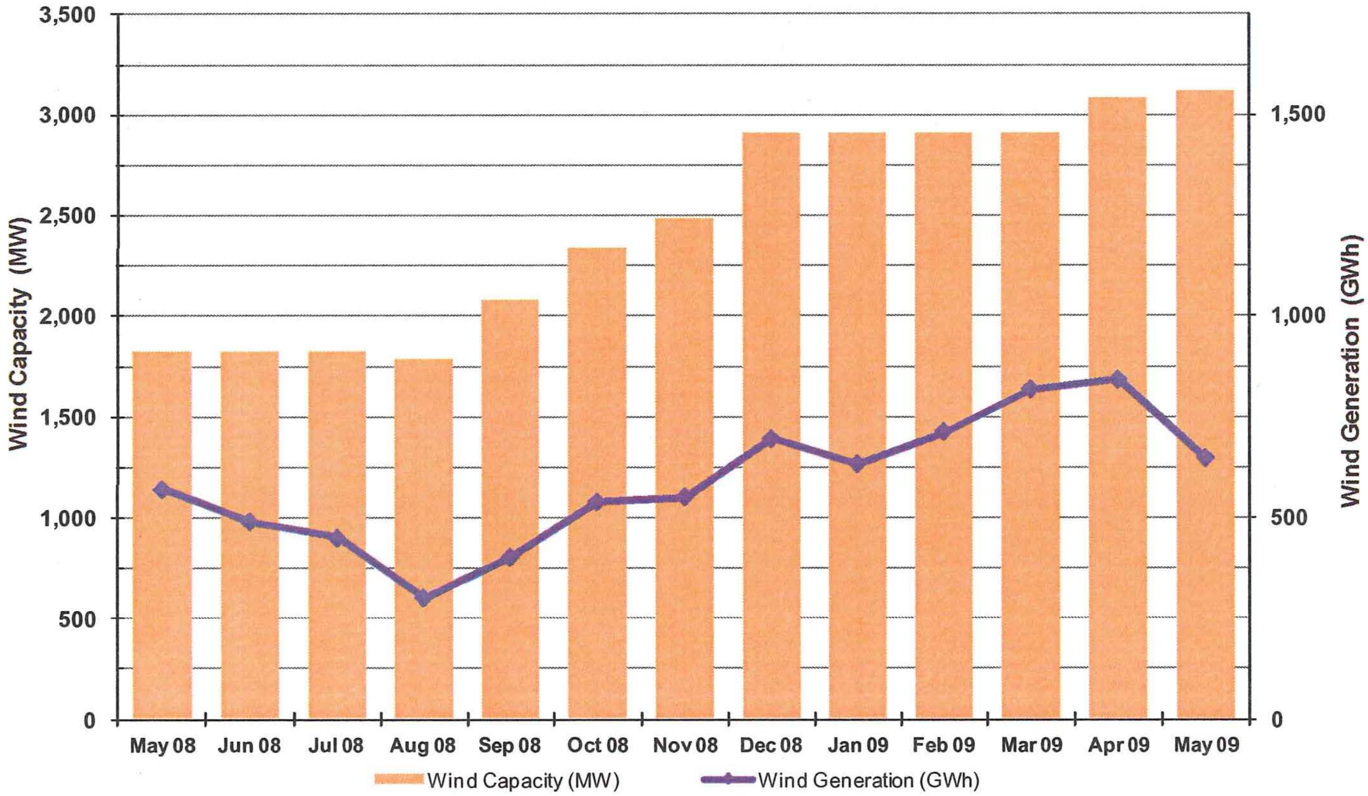


in GWh	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09
Coal	9,280	10,114	11,149	11,222	10,199	9,000	9,056	10,486	10,731	8,385	7,668	9,656	10,504
Gas	3,143	4,771	5,891	5,538	3,404	3,367	3,437	3,551	3,306	3,048	3,960	3,073	3,449
Nuclear	436	846	871	868	843	880	865	893	892	799	875	1,720	1,769
Wind	570	490	449	301	402	538	550	694	632	711	817	841	646
Hydro	163	153	151	92	109	109	63	37	59	95	74	222	211
Other	34	41	40	40	41	43	33	31	14	4	6	6	4
Total	13,626	16,416	18,551	18,062	14,997	13,937	14,004	15,692	15,634	13,042	13,400	15,518	16,584

by %	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09
Coal	68%	62%	60%	62%	68%	65%	65%	67%	69%	64%	57%	62%	63%
Gas	23%	29%	32%	31%	23%	24%	25%	23%	21%	23%	30%	20%	21%
Nuclear	3%	5%	5%	5%	6%	6%	6%	6%	6%	6%	7%	11%	11%
Wind	4%	3%	2%	2%	3%	4%	4%	4%	4%	5%	6%	5%	4%
Hydro	1%	1%	1%	1%	1%	1%	0%	0%	0%	1%	1%	1%	1%
Other	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Source: MOS

Figure 9 – Wind Generation & Capacity

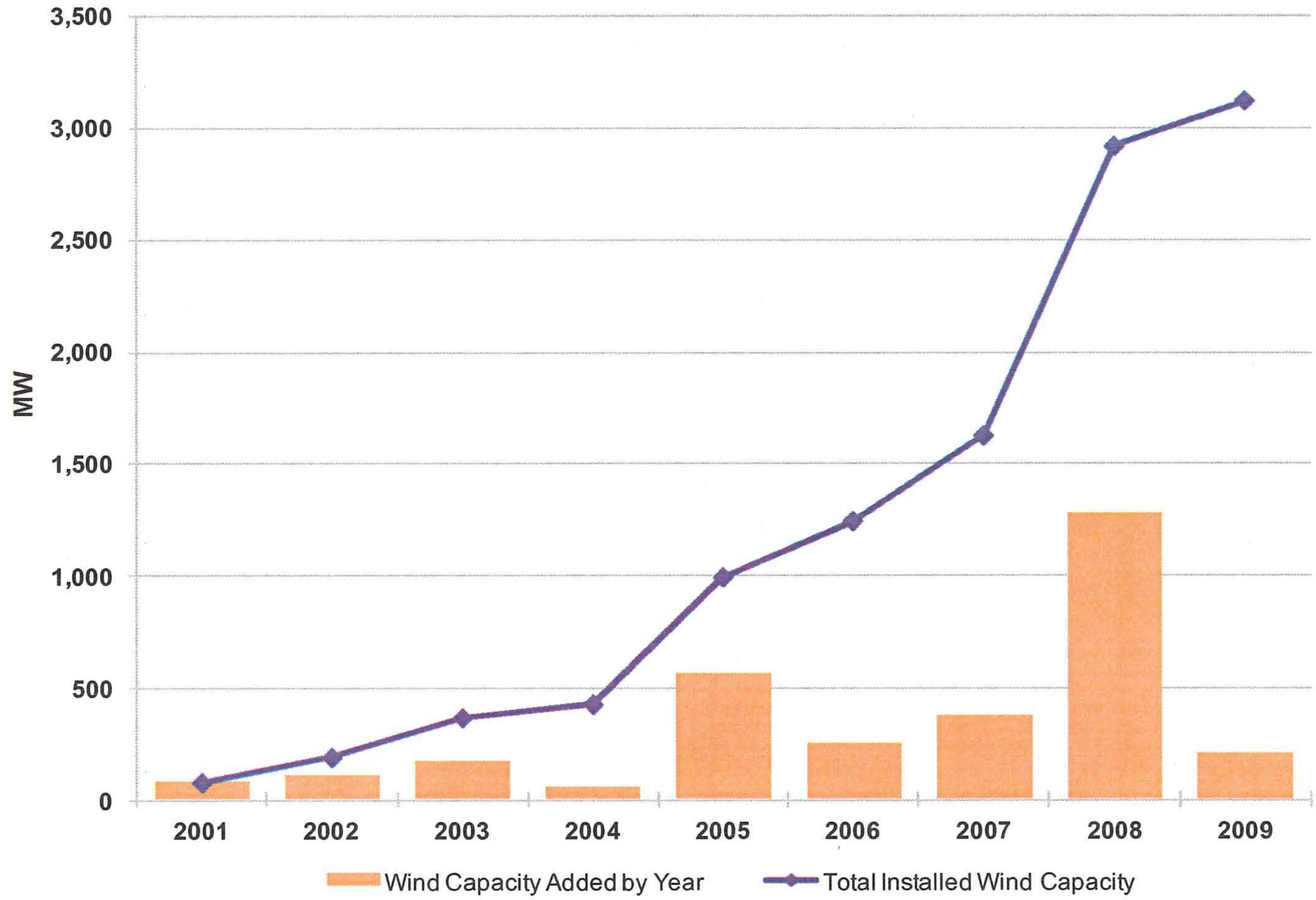


	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09
Capacity (MW)	1,823	1,823	1,823	1,788	2,083	2,337	2,486	2,915	2,915	2,915	2,915	3,089	3,119
Generation (GWh)	569.7	490.0	449.2	301.3	401.8	538.0	550.4	694.2	632.1	711.5	816.5	840.9	646.2
Capacity Factor	42%	37%	33%	23%	26%	31%	31%	32%	29%	36%	38%	38%	28%
# of Resources	25	25	25	25	29	32	33	37	37	37	38	42	45

__Notes:__

1. *In August 2008, a 95 MW resource was terminated, but a 60 MW resource was added, accounting for the reduction of capacity of 35 MW.*
2. *Four new wind resources came online in December 2008, accounting for 429 MW of additional capacity.*
3. *In March 2009, one resource was split into 2 distinct resources, therefore the number of resources increased by one, but the capacity remains unchanged.*
4. *In April 2009, with the addition of the Nebraska entities, four additional wind resources were added accounting for an additional 174 MW of capacity.*
5. *In May 2009, three resources were added accounting for 30MW of capacity.*

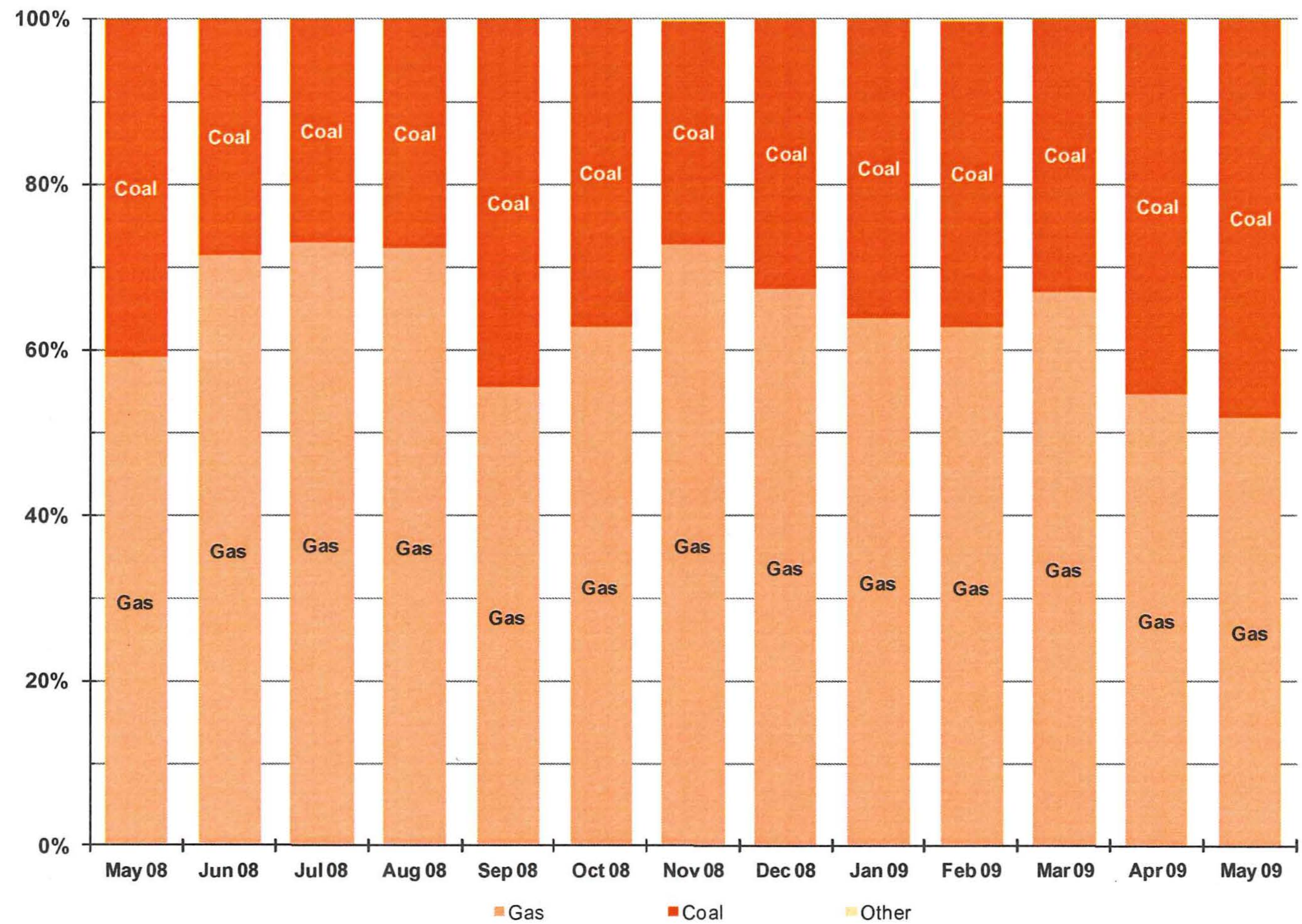
Figure 9a – Wind Capacity – Annual



in MW	2001	2002	2003	2004	2005	2006	2007	2008	2009*
Wind Capacity Added	80	112	176	60	568	250	381	1288	204
Total Wind Capacity	80	192	368	428	996	1,246	1,627	2,915	3,120

** 2009 figures are through May 31, 2009*

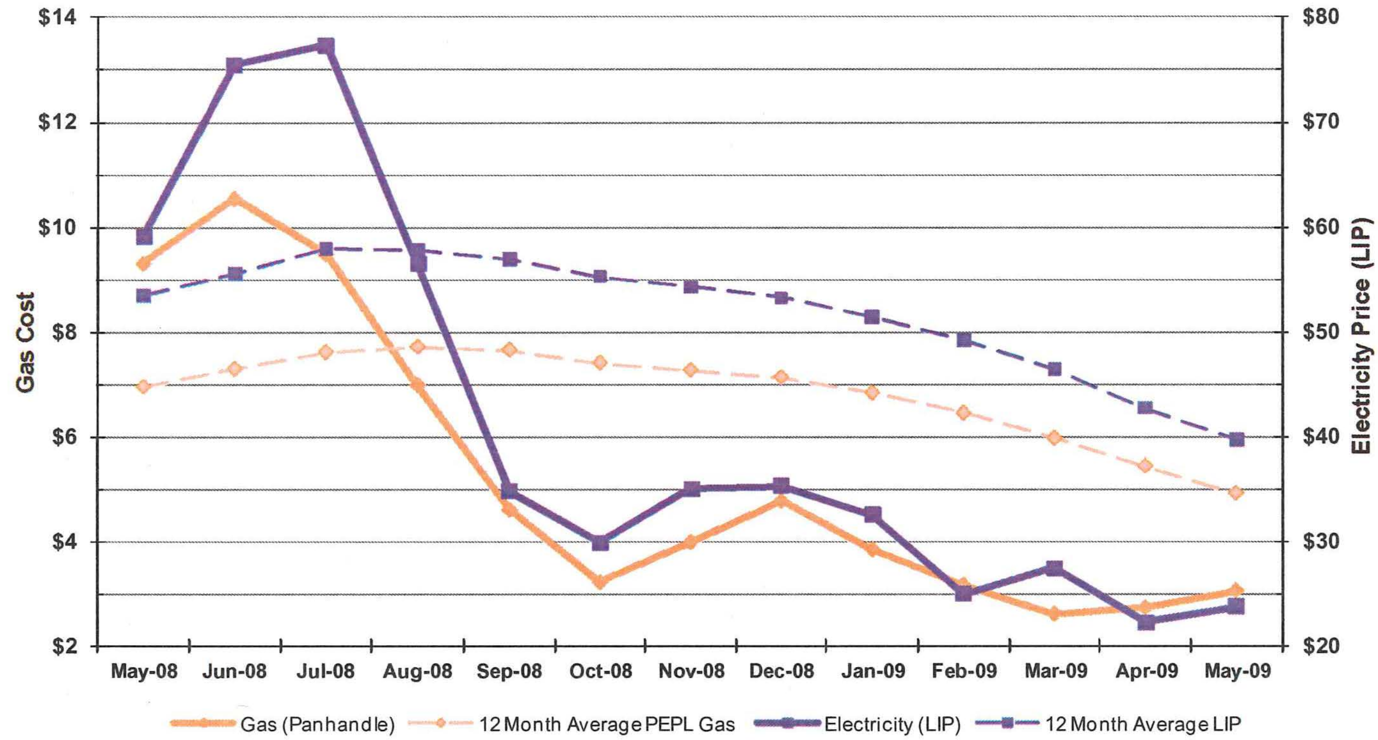
Figure 10 – Fuel on the Margin



	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	last 12 months
Other	0.0%	0.0%	0.1%	0.1%	0.0%	0.0%	0.2%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%
Coal	40.9%	28.5%	27.0%	27.6%	44.5%	37.2%	27.2%	32.6%	36.1%	37.2%	33.0%	45.3%	48.2%	35.4%
Gas	59.1%	71.5%	72.9%	72.3%	55.5%	62.7%	72.7%	67.4%	63.9%	62.6%	67.0%	54.6%	51.8%	64.6%

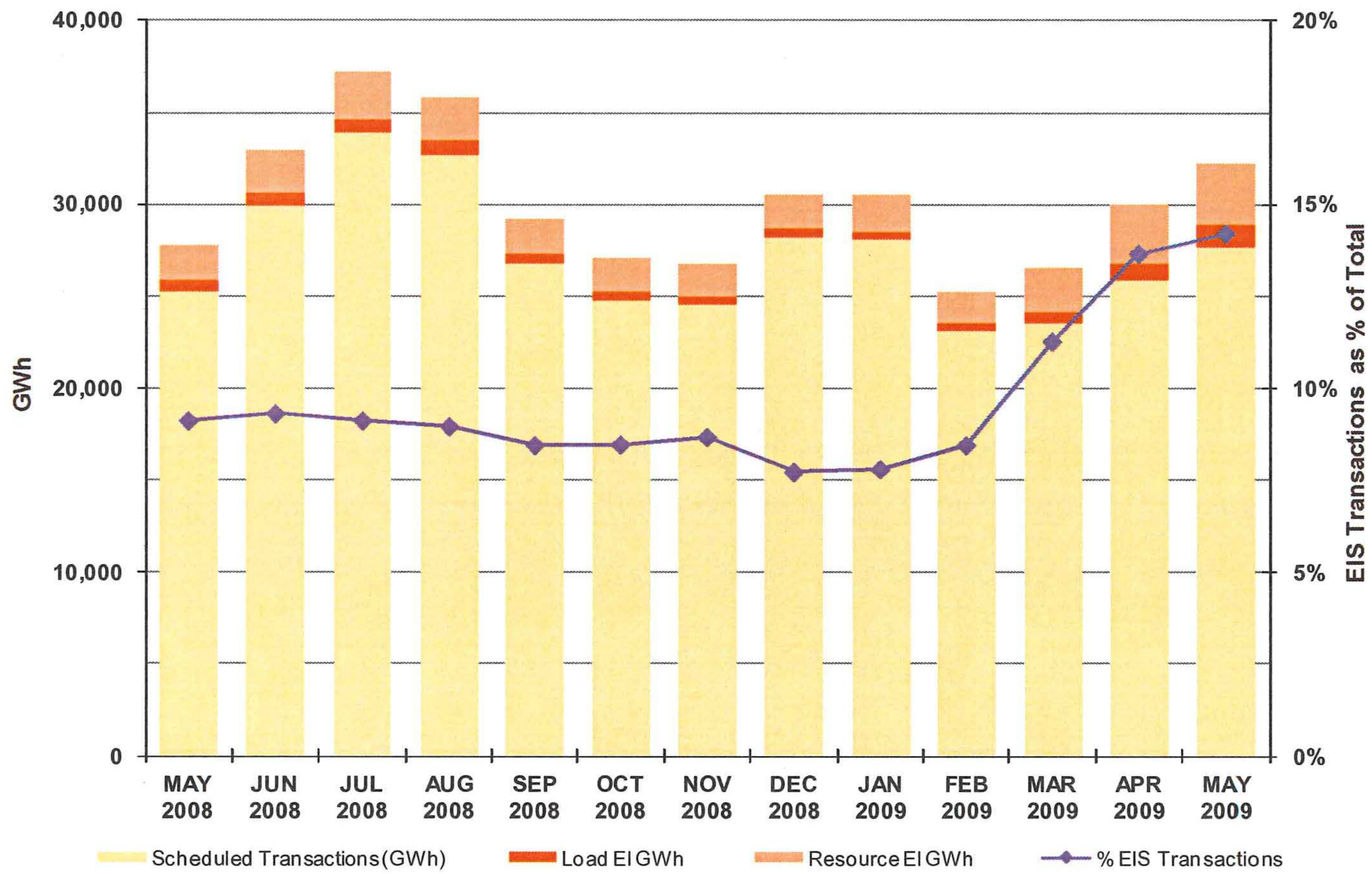
__Note:__
During non-congested periods, one resource sets the price for the entire market. During congested periods, the market is effectively segmented into several sub-areas, each with its own marginal resource. All congested intervals count the same as a non-congested period, but the marginal fuel type for each sub-area is represented proportionally in the congested period.

Figure 11 – Gas Cost / LIP Comparison



	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	12 month average
Electricity (LIP) [$/MWh]	59.05	75.52	77.36	56.46	34.74	29.82	34.98	35.21	32.47	24.88	27.38	22.21	23.67	39.66
Gas Panhandle [$/MMBtu]	9.29	10.54	9.48	6.97	4.58	3.19	3.96	4.76	3.83	3.15	2.60	2.72	3.05	4.90

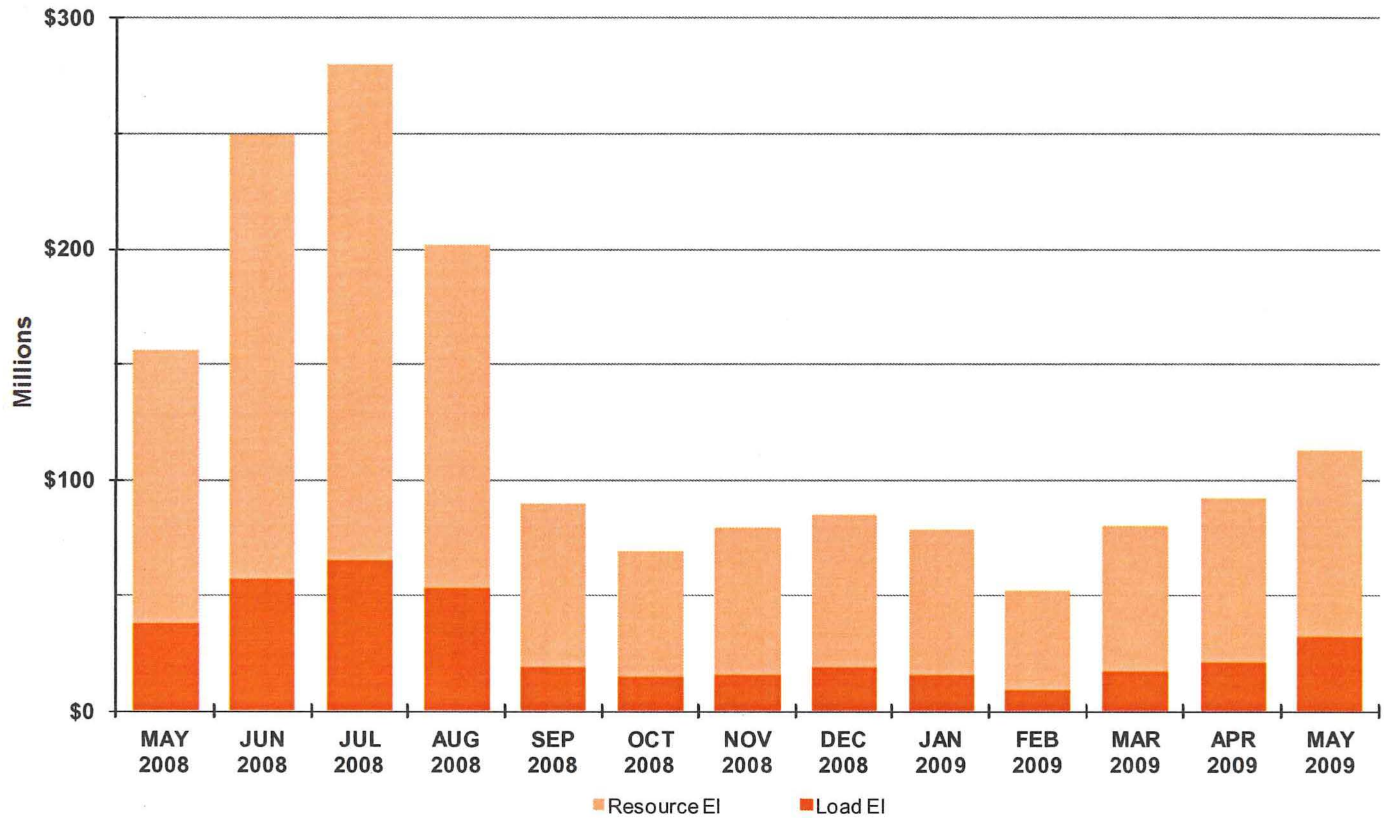
Figure 12 – EIS Settlements - GWh



in GWh	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	Last 12 Months
Resource EI	1,947	2,395	2,649	2,424	1,956	1,838	1,888	1,850	1,937	1,768	2,396	3,204	3,327	27,633
Load EI	579	671	747	784	508	449	433	503	436	362	588	888	1,245	7,615
Scheduled Transaction	25,230	29,925	33,891	32,665	26,719	24,762	24,479	28,170	28,112	23,116	23,548	25,892	27,646	328,925
Total Energy	27,757	32,991	37,286	35,874	29,183	27,048	26,800	30,524	30,486	25,246	26,533	29,983	32,217	364,172

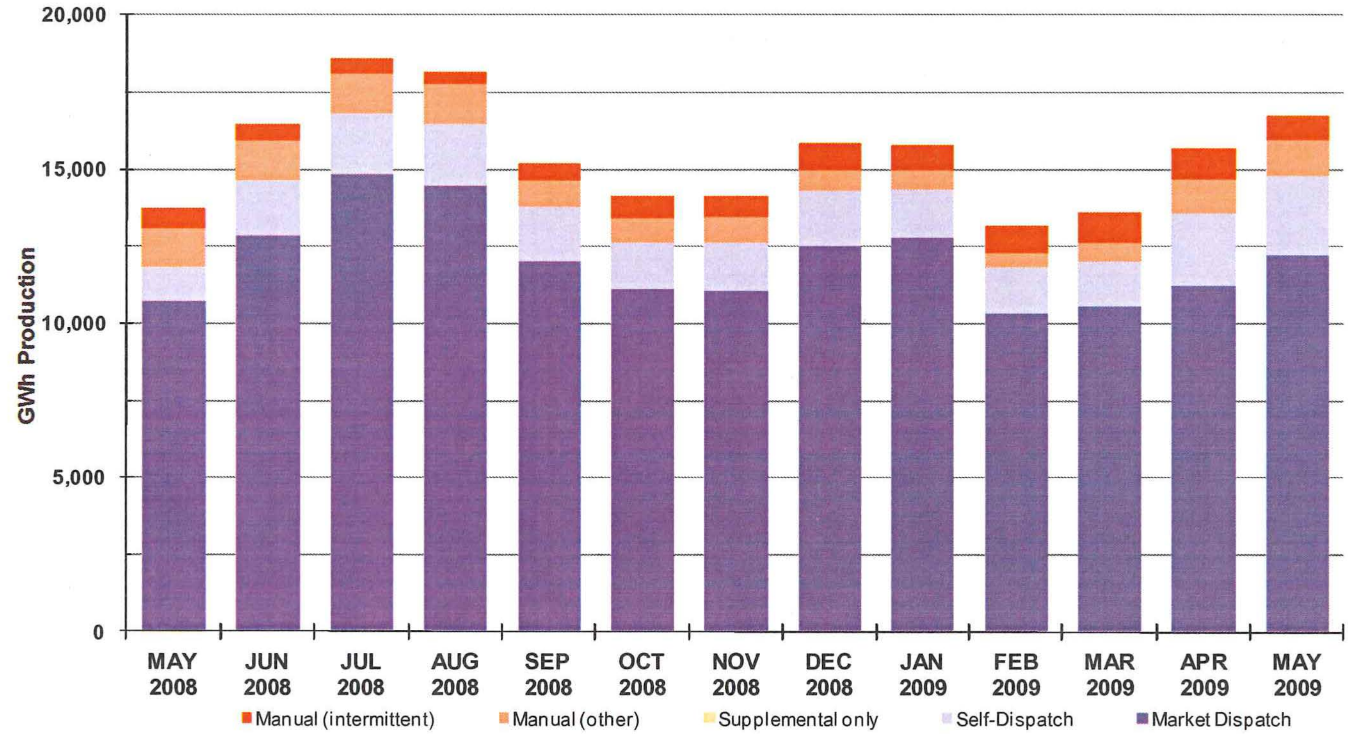
by %	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	Last 12 Months
Resource EI	7.0%	7.3%	7.1%	6.8%	6.7%	6.8%	7.0%	6.1%	6.4%	7.0%	9.0%	10.7%	10.3%	7.6%
Load EI	2.1%	2.0%	2.0%	2.2%	1.7%	1.7%	1.6%	1.6%	1.4%	1.4%	2.2%	3.0%	3.9%	2.1%
Scheduled Transactions	90.9%	90.7%	90.9%	91.1%	91.6%	91.5%	91.3%	92.3%	92.2%	91.6%	88.8%	86.4%	85.8%	90.3%

Figure 13 – EIS Settlements - $



in million $	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	Last 12 Months
Resource EI	118	193	215	148	71	55	64	66	63	43	64	71	81	1,133
Load EI	38	57	65	53	19	14	15	19	15	9	17	20	32	335
Total EI	156	249	280	201	90	69	79	85	78	52	80	92	112	1,467

Figure 14 – Depth of Energy Market for Resources Only – by Status

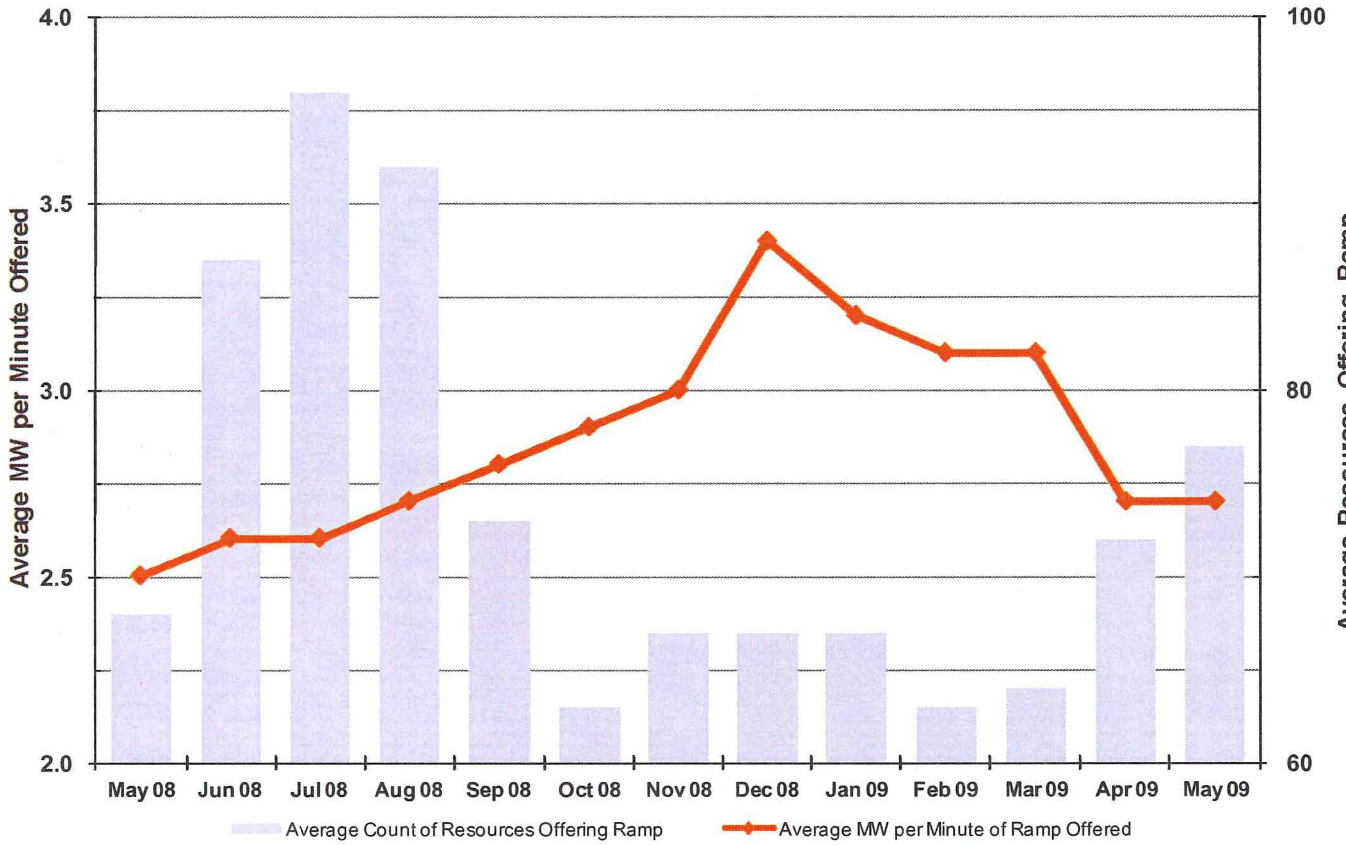


in GWh	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	Last 12 Months
Market Dispatch	10,678	12,857	14,856	14,436	11,978	11,118	11,048	12,493	12,778	10,325	10,533	11,178	12,190	145,790
Self-Dispatch	1,135	1,775	1,977	2,011	1,777	1,499	1,538	1,786	1,590	1,468	1,436	2,386	2,601	21,845
Supplemental only	0	1	1	1	1	0	2	1	1	1	1	0	0	9
Manual (other)	1,268	1,279	1,242	1,288	855	761	831	680	614	499	616	1,095	1,162	10,920
Manual (intermittent)	626	540	513	436	560	720	724	867	797	882	1,022	1,040	796	8,897
TOTAL	13,706	16,451	18,589	18,173	15,171	14,098	14,143	15,827	15,780	13,174	13,609	15,698	16,749	187,461

by % of total	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	Last 12 Months
Market Dispatch	78%	78%	80%	79%	79%	79%	78%	79%	81%	78%	77%	71%	73%	78%
Self-Dispatch	8%	11%	11%	11%	12%	11%	11%	11%	10%	11%	11%	15%	16%	12%
Supplemental only	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Manual (other)	9%	8%	7%	7%	6%	5%	6%	4%	4%	4%	5%	7%	7%	6%
Manual (intermittent)	5%	3%	3%	2%	4%	5%	5%	5%	5%	7%	8%	7%	5%	5%

Note: May not total to 100% due to rounding.
Source: Metered Settlement data

Figure 15 – Resource Five Minute Ramp Rates Offered and Available to the EIS Market

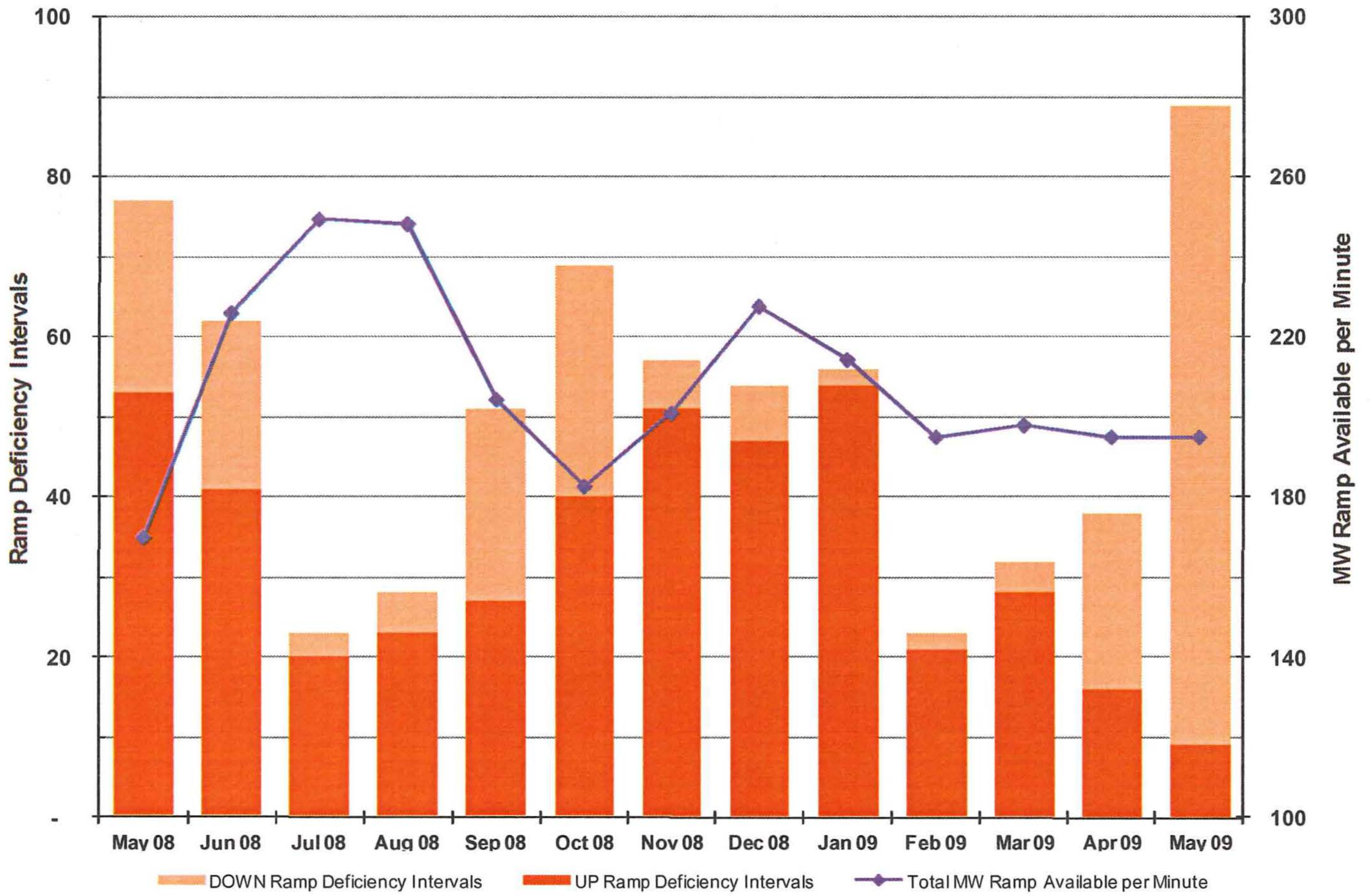


	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	12 month average
Average MW per Minute Ramp Offered	2.5	2.6	2.6	2.7	2.8	2.9	3.0	3.4	3.2	3.1	3.1	2.7	2.7	2.9
Average Count of Resources Offering Ramp	68	87	96	92	73	63	67	67	67	63	64	72	77	74

__Notes:__

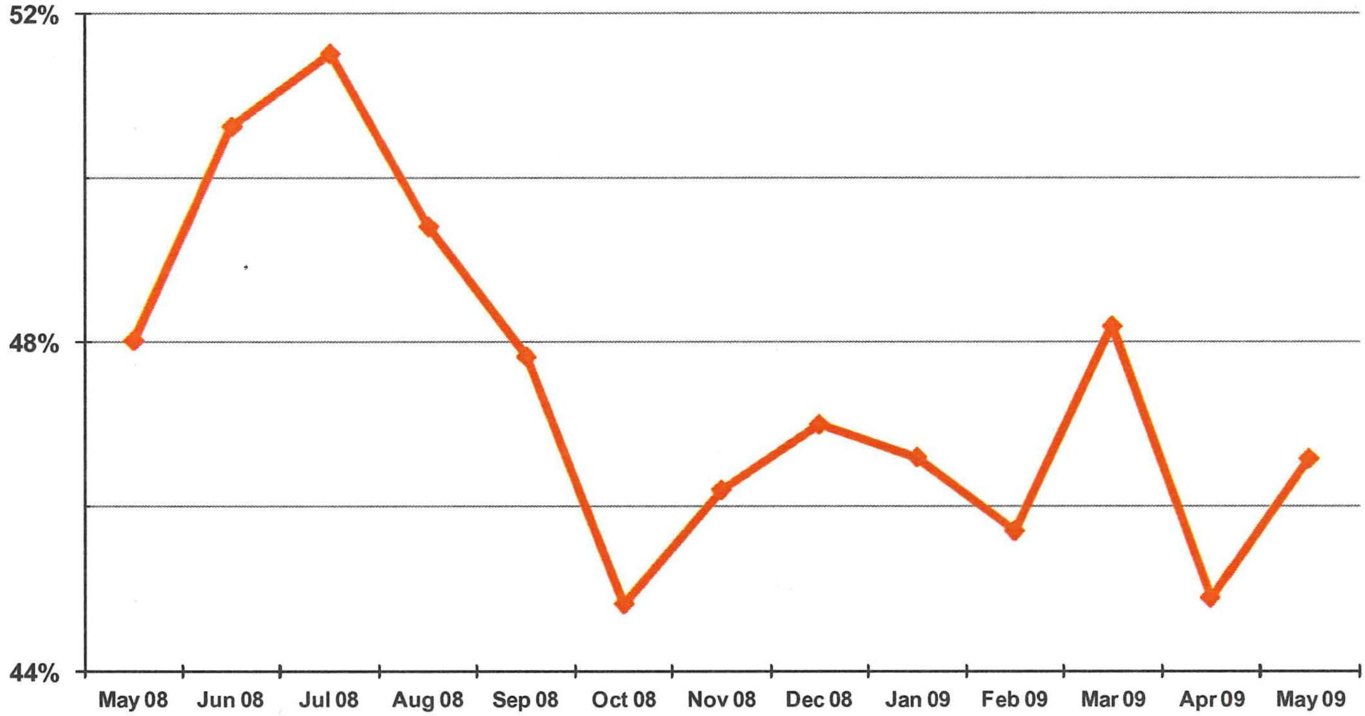
1. *Resource 5-minute ramp rates offered and available to the EIS market are calculated by averaging the resource's up and down offered ramp rates across the dispatchable range to give a single offered ramp rate that is consistent both before and after the implementation of PRR113. When multiplied by five, this represents the 5-minute ramp range. If this 5-minute ramp range is less than the dispatchable range, the 5-minute ramp range is reduced to the dispatchable range. Finally, this 5-minute ramp range is divided by five to come up with the 5-minute ramp rate offered and available to the EIS market. This number is expressed in MW per minute.*

Figure 16 – Monthly Summary of Market Ramp Rate Deficiency



	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	12 month average
UP Ramp Deficiency Intervals	53	41	20	23	27	40	51	47	54	21	28	16	9	31
DOWN Ramp Deficiency Intervals	24	21	3	5	24	29	6	7	2	2	4	22	80	17
Total Ramp Deficiency Intervals	77	62	23	28	51	69	57	54	56	23	32	38	89	49
% of Total Market Dispatch Intervals	0.9%	0.7%	0.3%	0.3%	0.6%	0.8%	0.7%	0.7%	0.6%	0.3%	0.4%	0.5%	1.0%	0.6%
MW Ramp Available per Minute	170	226	250	248	204	183	201	228	214	195	198	195	208	211

Figure 17 – Dispatchable Range



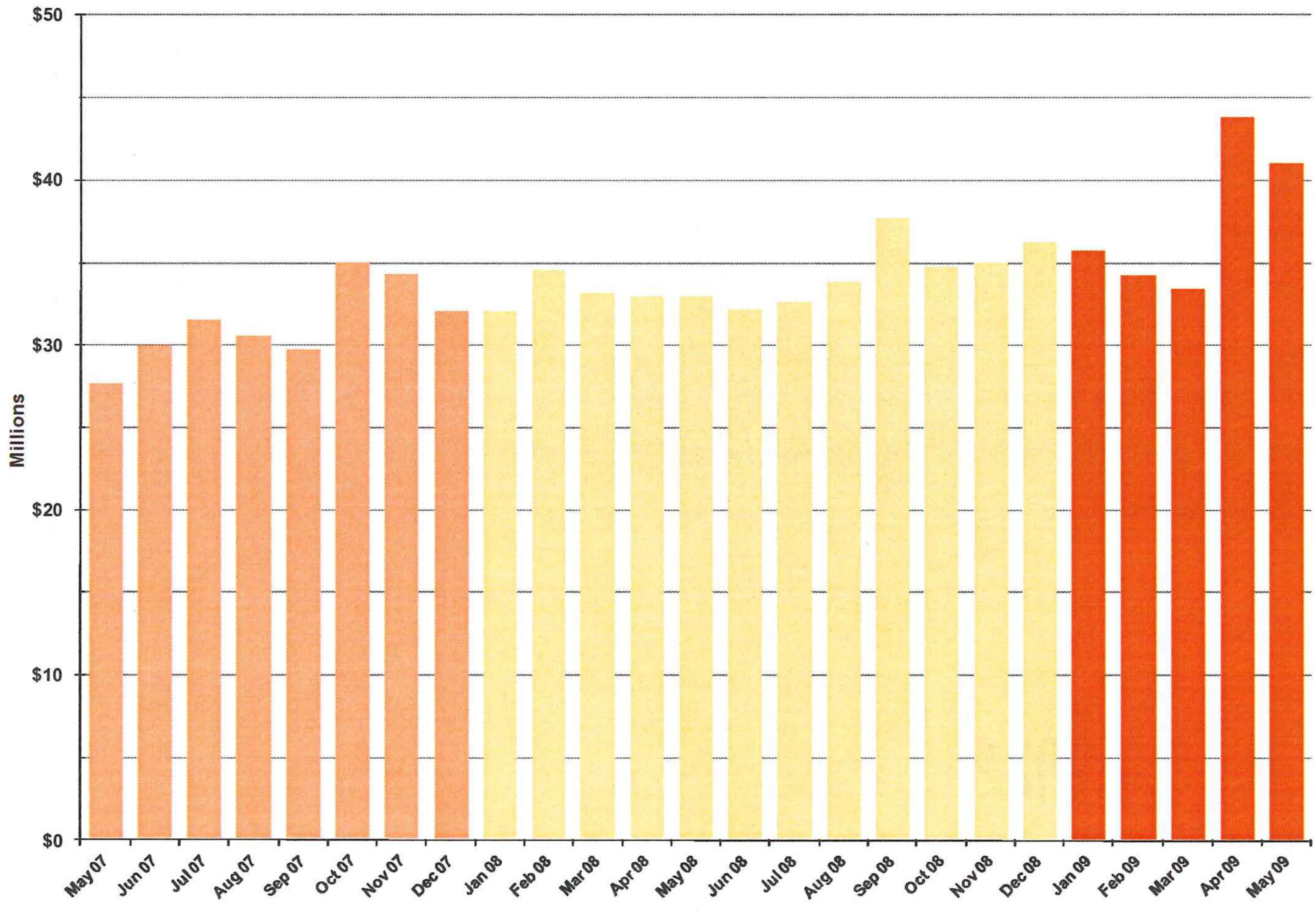
	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	last 12 mo
Average	48.0%	50.6%	51.5%	49.4%	47.8%	44.8%	46.2%	47.0%	46.6%	45.7%	48.2%	44.9%	46.6%	47.4%

AdjMax = Resource Plan Max, adjusted for ancillary service.
AdjMin = Resource Plan Min, adjusted for ancillary service.
Resource Plan Range = (AdjMax – AdjMin) / AdjMax for a particular resource.

For example:

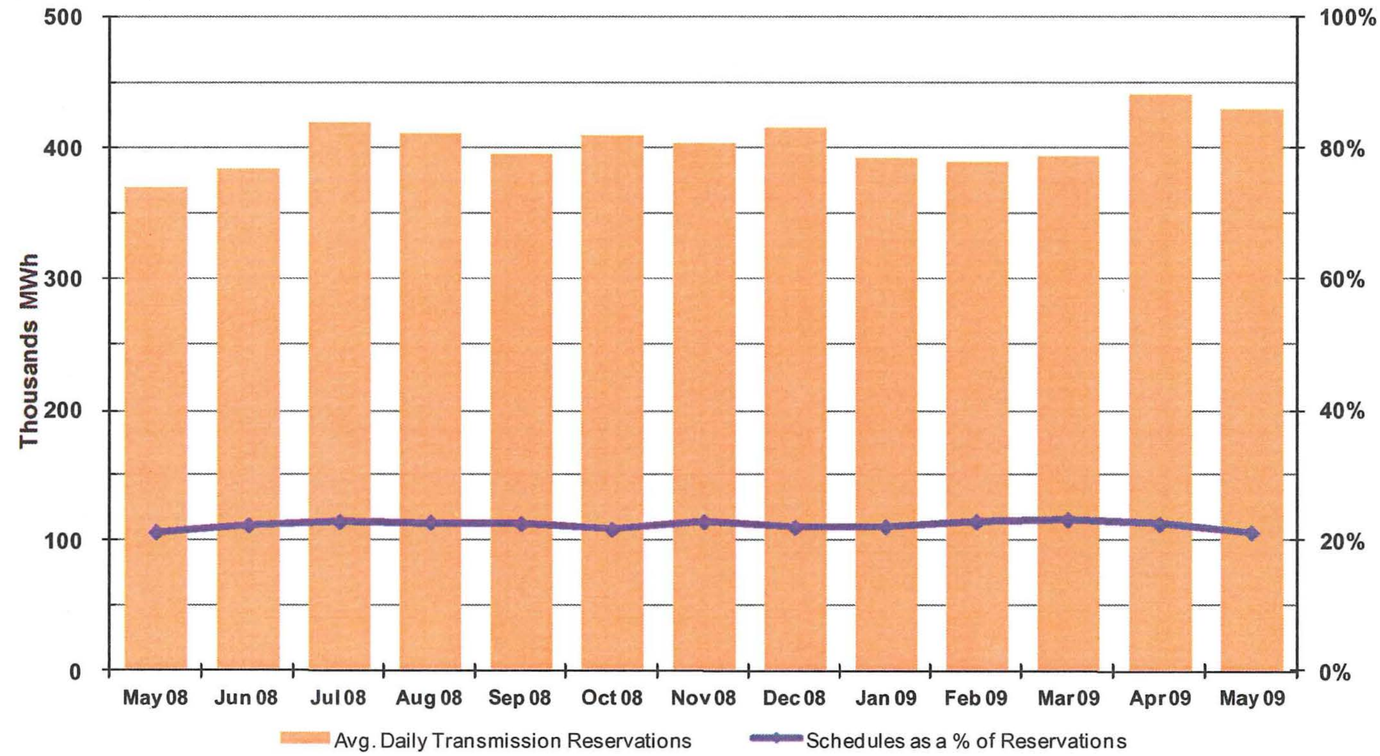
Resource A: AdjMax = 200, AdjMin = 100; (200 – 100) / 200 = 50% Range
Resource B: AdjMax = 200, AdjMin = 180; (200 – 180) / 200 = 10% Range

Figure 18 – Transmission Owner Revenue



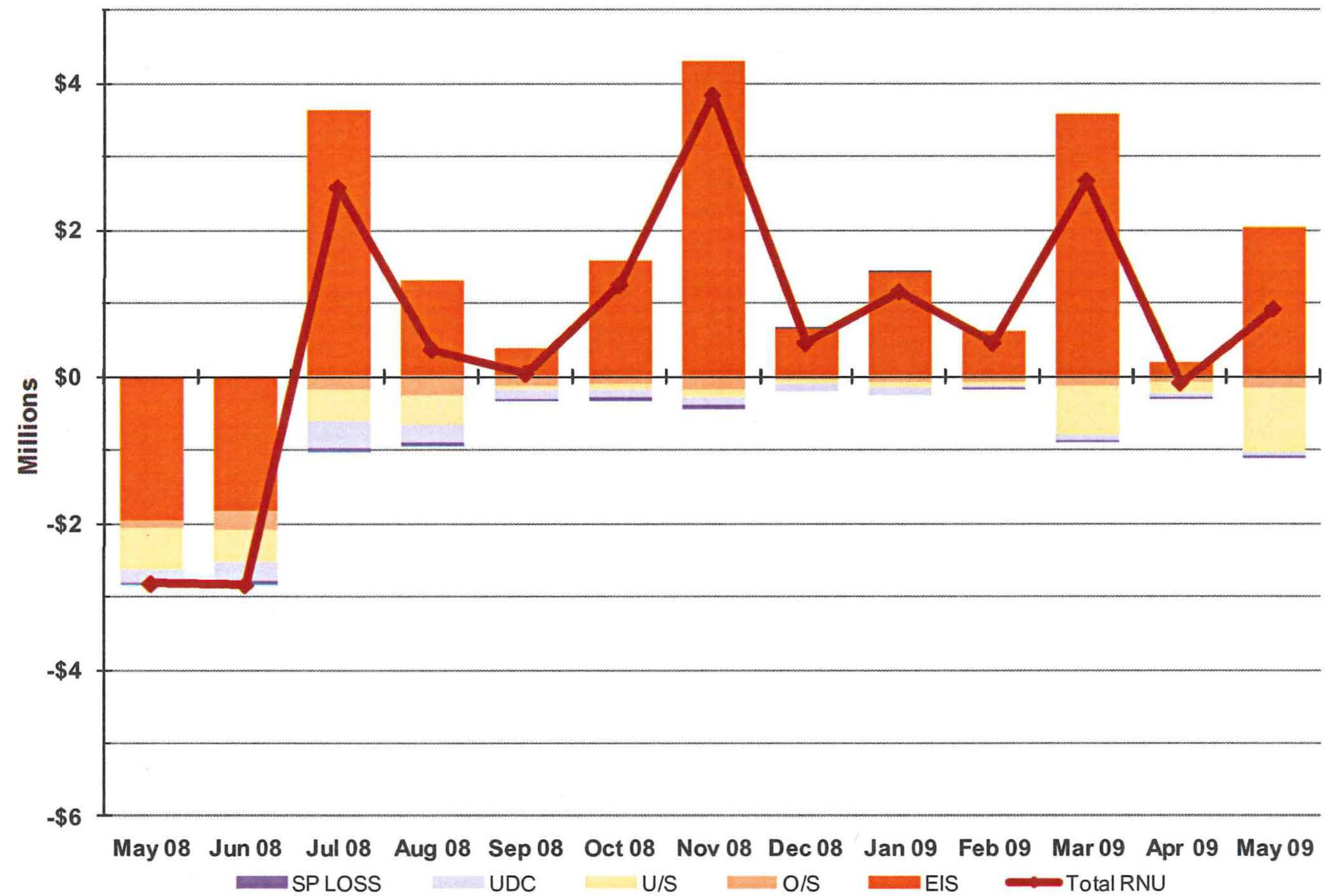
in millions $	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
2007	27.0	29.0	26.8	27.4	27.6	29.9	31.5	30.5	29.7	35.0	34.3	32.0
2008	32.1	34.6	33.1	33.0	32.9	32.1	32.6	33.8	37.7	34.7	35.0	36.3
2009	35.7	34.2	33.4	43.8	41.0							

Figure 19 – Average Transmission Reservations and Schedules



in thousands MWh	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09	12 month average
Average Daily Reservations	370	384	420	412	396	410	404	415	393	390	394	441	430	408
Average Daily Schedules	78	86	96	94	89	89	92	91	87	89	91	99	91	91
%	21%	22%	23%	23%	23%	22%	23%	22%	22%	23%	23%	22%	21%	22%

Figure 20 – RNU Components



$ (thousands)	May 08	Jun 08	Jul 08	Aug 08	Sep 08	Oct 08	Nov 08	Dec 08	Jan 09	Feb 09	Mar 09	Apr 09	May 09
EIS	-1,961	-1,834	3,625	1,309	370	1,593	4,294	652	1,421	628	3,574	188	2,036
O/S	-119	-272	-183	-247	-139	-105	-167	-42	-83	-62	-139	-80	-147
U/S	-560	-435	-428	-417	-42	-80	-107	-50	-75	-53	-645	-155	-886
UDC	-175	-266	-363	-235	-137	-108	-111	-109	-103	-48	-79	-40	-61
SP Loss	-14	-45	-69	-44	-15	-45	-67	5	3	-7	-33	0	-15
Total RNU	-2,829	-2,852	2,582	366	36	1,255	3,843	456	1,163	459	2,678	-87	928

EIS (Energy Imbalance Charge/Credit) – All energy deviations between actual generation or load and schedules are settled as (EIS).

O/S (Over-Scheduling Charge) - During any hour, if Locational Imbalance Prices diverge and a Market Participant's Load imbalance is more than 4% (but at least 2 MW) at an applicable Settlement Location in that hour, that MP may be subject to an Over-Scheduling Charge.

U/S (Under-Scheduling Charge) - During any hour, if Locational Imbalance Prices diverge and a Market Participant's Load imbalance is more than 4% (but at least 2 MW) at an applicable Settlement Location in that hour, that MP may be subject to an Under-Scheduling Charge.

UDC (Uninstructed Resource Deviation) – the difference between the dispatch instructions and the actual performance of a Resource.

SP Loss - Self-Provided Losses