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Thursday, May 2, 2013

Merchant generator challenges may be systemic

ANALYSIS Merchant generators have been working against the challenging headwinds in wholesale power markets for a couple of years, but separate reports from two analysts now posit that the challenges could be more systemic than cyclical.

Power markets are “troubled” and even though some people think that the climate will improve when more states open up, things are going in the opposite direction, Julien Dumoulin-Smith at UBS Securities said.

In his report, Evaluating the Competitive Landscape, Dumoulin-Smith wrote that the landscape is shifting and that there is a “fundamental re-evaluation” of the merits of restructuring taking place in many regions.

The markets where investors can expect a return of and on investment are limited to the PJM Interconnection and the

(continued on page 19)

ERCOT expects tight summer power supplies

MARKETS The Electric Reliability Council of Texas may declare an energy emergency alert this summer, as demand is expected to top its all-time peak and generation capacity growth remains relatively slow.

But in the longer term, the planning reserve margin is expected to slightly exceed the current target of 13.75% in 2014, and the reserve margins in the following years, while tight, are forecast to be higher than they were in previous reports.

This summer's final Seasonal Assessment of Resource Adequacy and the longer-term Capacity, Demand, and Reserves Report, which covers the period from 2014 through 2023, were released Wednesday.

"We are expecting above-normal temperatures throughout the summer in most areas of the ERCOT region," said Kent Saathoff,

(continued on page 20)

San Onofre may be retired, boost gas demand

GENERATION Southern California could continue to see some heavier reliance on natural gas for power generation after Edison International's CEO raised the possibility that San Onofre Nuclear Generation Station could be retired if Unit 2 cannot be restarted.

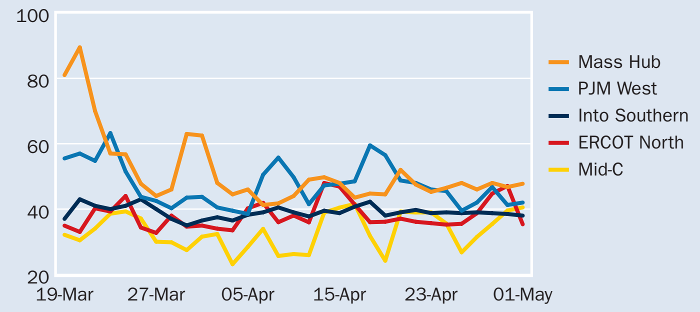
The utility likely will decide before the end of the year whether to retire one or both of the 1,127-MW San Onofre reactors in California, said Ted Craver, chairman and CEO of Southern California Edison parent Edison International during an earnings call.

Platts unit Bentek Energy showed that gas consumed due to the San Onofre nuclear outages on Wednesday was 315,000 Mcf for Unit 2 and 318,000 Mcf for Unit 3. Both units at the plant have been shut since early 2012 because of unusual wear on steam tubes.

SoCal Edison disclosed that its share of outage costs at San

(continued on page 20)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for May 2 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	47.90	56.33	33.72	41.10
NYISO	34.64	58.24	29.58	39.35
PJM	36.68	44.94	24.33	31.05
MISO	36.34	40.93	23.94	34.06
ERCOT	24.80	43.80	11.40	41.68
CAISO	45.52	57.67	35.34	40.55

Note: Lows and highs for each ISO are for various hubs and zones. A full listing of average LMPs are availible for the hubs and zones inside this issue.

Day-ahead bilateral indexes and spark spreads for May 2

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	47.75	10403	15.62	11.03	1.85	-7.33	-21.10
N.Y. Zone-A	39.50	8886	8.39	3.94	-4.95	-13.84	-27.18
PJM/MISO							
PJM West	42.00	9786	11.96	7.67	-0.92	-9.50	-22.38
Indiana Hub	40.50	9289	9.98	5.62	-3.10	-11.82	-24.90
Southeast & Central							
Southern, Into	38.00	8832	7.88	3.58	-5.03	-13.63	-26.54
ERCOT, North	35.34	8455	6.08	1.90	-6.46	-14.82	-27.36
West							
Mid-C	40.51	9744	11.41	7.25	-1.07	-9.38	-21.85
SP15	62.50	14484	32.30	27.98	19.35	10.72	-2.23

Note: All indexes are on-peak. Spark spreads are reported in ($) and Marginal heat rates in (Btu/kWh). A full listing of bilateral indexes and marginal heat rates are inside this issue.

Inside this Issue

NORTHEAST MARKETS

Dailies mixed, with demand expected to rise

Daily power prices in the Northeast were mixed Wednesday, while forward prices did not see big changes and the NYMEX June natural gas settled at $4.326/MMBtu, down 1.7 cents.

Northeast dailies were mixed Wednesday as demand in the region is expected to rise slightly Thursday.

ISO New England projected peak load on Wednesday around 15,100 MW and 15,130 MW for Thursday.

Algonquin city-gates spot natural gas traded around $4.60/MMBtu, down about 5 cents, while Tennesee Zone 6 was at $4.57/MMBtu, about flat, and Transco Zone 6 New York was around $4.47/MMBtu, nearly unchanged.

Boston was forecast to have high temperatures in mid-60s Thursday, with lows in upper 40s.

Mass Hub on-peak was up about 75 cents, in the upper $40s/MWh. Mass Hub off-peak was up slightly in mid-$30s/MWh.

New York State was forecast to have high temperatures in the 70s, with lows ranging from the mid-40s to low 50s.

The New York ISO projected peak load Wednesday around 17,817 MW and 18,066 MW Thursday.

New York Zone A on-peak was down about $3 in the low $40s/MWh. Zone G on-peak stayed firm in the upper $40s/MWh.

Day-ahead auction prices in ISO-NE were mostly down Wednesday. Internal Hub peak lost over $6, clearing just under $48/MWh and off-peak gaveup over $3, clearing above $34/MWh.

Rhode Island peak and off-peak saw gains, with peak climbing $3.67 to about $56.33/MWh and off-peak up $2.19 to about $41.10/MWh.

Maine peak lost the most on the day, giving up about $6.80 and clearing just above $48/MWh, while off-peak was down $3.74 to about $33.72/MWh.

SE Mass peak gave up over $4, clearing at about $49.39/MWh and off-peak was off about $2, to about $35.31/MWh.

Day-ahead auction prices in NYISO on Wednesday were mixed, with most zonal prices in the Western part of the state giving back some of the previous day's gains while eastern zones saw some gains.

West Zone peak tumbled the most on the day, falling $6.71 to clear at $38.21/MWh and off-peak edged down 41 cents, to about $30.91/MWh.

Genesee Zone peak lost nearly $3, going to about $37.86/MWh and off-peak was down 43 cents to about $30.78/MWh.

Central Zone peak lost about $3.69, going to about $39.09/MWh and off-peak slipped 47 cents, to about $31.39/MWh.

The lowest-priced zone on the day was North Zone peak, which fell over $3 to about $34.64/MWh and off-peak was down 42 cents to about $29.58/MWh.

Capital Zone peak tacked on $1.54, clearing at $48.03/MWh and off-peak edged down 88 cents, to about $32.70/MWh.

New York City Zone jumped $4, to about $53/MWh and off-peak slipped 45 cents, to about $33.90/MWh.

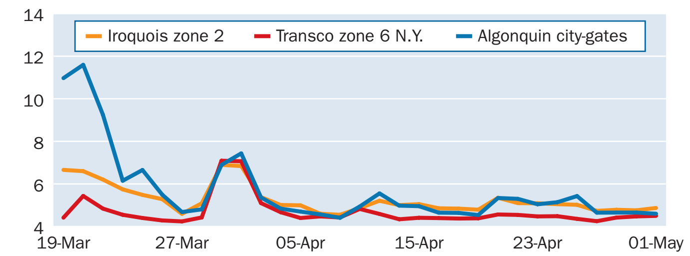
(continued on page 10)

Northeast day-ahead bilateral indexes for May 2 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	47.75	1.00	47.25	10403
N.Y. Zone-G	48.75	0.25	48.63	10406
N.Y. Zone-J	53.00	4.00	51.00	11313
N.Y. Zone-A	39.50	-4.00	41.50	8886
Ontario*	26.25	-3.00	27.75	5504
Off-Peak				
Mass Hub	35.00	-0.50	35.25	7625
N.Y. Zone-G	34.00	-0.50	34.25	7257
N.Y. Zone-J	34.25	-0.25	34.38	7311
N.Y. Zone-A	31.00	-0.25	31.13	6974
Ontario*	18.00	-1.00	18.50	3774

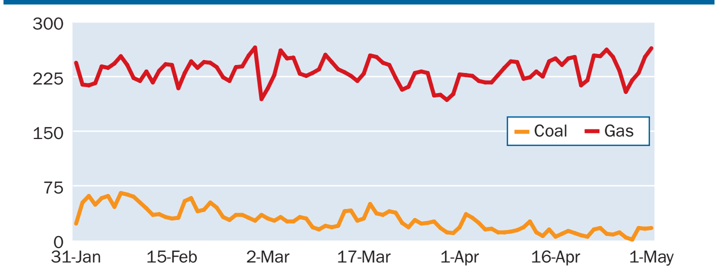
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO gas and coal generation (GWh)



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 30-Apr	%Chg	% Chg Year-ago	Forecast 01-May	02-May	03-May	04-May	05-May
ISONE								
Load	313	0	3	333	327	314	287	283
Generation								
Coal	4	0	40	6	3	3	2	2
Gas	135	4	-13	151	144	131	125	127
Nuclear	65	0	-5	65	65	65	65	65
NYISO								
Load	394	0	3	395	401	397	365	362
Generation								
Coal	11	-12	83	11	7	5	4	4
Gas	117	17	-10	114	119	117	108	110
Nuclear	119	0	6	119	119	119	119	119

Source: Bentek

ISONE day-ahead LMP for May 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	47.97	-0.90	-0.10	-6.13	51.04	10444
Connecticut	48.50	-0.90	0.43	-6.02	51.51	10280
NE Mass-Boston	47.90	-0.90	-0.17	-5.93	50.87	10428
SE Mass	49.39	0.93	-0.51	-4.08	51.43	10755
West-Central Mass	48.33	-0.90	0.26	-6.16	51.41	10524
Rhode Island	56.33	8.54	-1.17	3.67	54.50	12265
Maine	48.04	-0.71	-0.22	-6.80	51.44	9998
New Hampshire	48.73	-0.90	0.66	-5.98	51.72	10142
Vermont	47.99	-0.90	-0.08	-6.02	51.00	9987
Off-Peak						
Internal Hub	34.08	-0.72	0.08	-3.04	35.60	7393
Connecticut	34.02	-0.72	0.02	-3.01	35.53	7281
NE Mass-Boston	34.06	-0.72	0.06	-2.98	35.55	7389
SE Mass	35.31	0.76	-0.17	-2.00	36.31	7659
West-Central Mass	34.25	-0.72	0.25	-3.04	35.77	7430
Rhode Island	41.10	6.89	-0.51	2.18	40.01	8917
Maine	33.72	-0.72	-0.28	-3.75	35.60	7107
New Hampshire	34.35	-0.72	0.35	-2.97	35.84	7238
Vermont	33.84	-0.72	-0.16	-2.95	35.32	7131

NYISO day-ahead LMP for May 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	48.03	-8.83	2.33	1.54	47.26	10315
Central Zone	39.09	-1.25	0.97	-3.69	40.94	8799
Dunwoodie Zone	48.61	-7.26	4.49	0.48	48.37	10394
Genesee Zone	37.86	-0.95	0.05	-2.98	39.35	8522
Hudson Valley Zone	48.70	-7.21	4.61	0.45	48.48	10412
Long Island Zone	58.24	-16.12	5.25	0.91	57.79	12453
Millwood Zone	48.58	-7.29	4.43	0.52	48.32	10388
Mohawk Valley Zone	39.66	-1.17	1.62	-3.69	41.51	8705
N.Y.C. Zone	53.01	-11.35	4.79	4.06	50.98	11335
North Zone	34.64	0.00	-2.23	-3.07	36.18	7210
West Zone	38.21	-1.40	-0.05	-6.71	41.57	8602
Off-Peak						
Capital Zone	32.70	-0.03	1.75	-0.88	33.14	7104
Central Zone	31.39	0.00	0.46	-0.47	31.63	7092
Dunwoodie Zone	33.65	-0.02	2.70	-0.53	33.92	7270
Genesee Zone	30.78	0.00	-0.15	-0.43	31.00	6954
Hudson Valley Zone	33.92	-0.02	2.97	-0.51	34.18	7329
Long Island Zone	39.35	-4.95	3.48	-0.65	39.68	8503
Millwood Zone	33.63	-0.02	2.67	-0.53	33.90	7265
Mohawk Valley Zone	31.82	0.00	0.89	-0.57	32.11	7045
N.Y.C. Zone	33.90	-0.02	2.95	-0.45	34.13	7325
North Zone	29.58	0.00	-1.34	-0.43	29.80	6235
West Zone	30.91	0.00	-0.02	-0.41	31.12	6984

Generation unit outage report

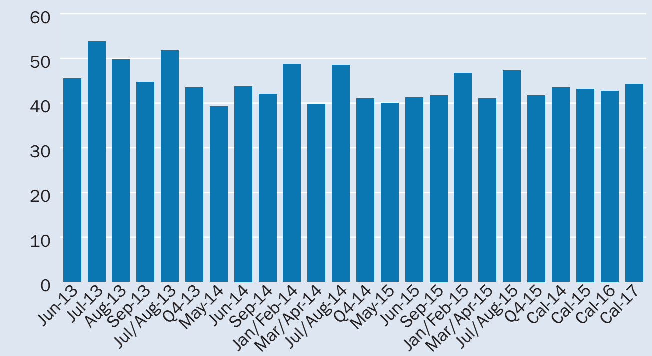
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-1/Bruce Power	750	n	Ont.	PMO	Unk	04/28/13
Bruce-8/Bruce Power	820	n	Ont.	Unk	Unk	05/01/13
Darlington-4/OPG	878	n	Ont.	PMO	Unk	02/04/13
Millstone-3/Dominion	1203	n	Conn.	RF	05/24/13	04/13/13
Nine Mile Point-1/CENG	640	n	N.Y.	RF	05/14/13	04/15/13
Pickering-4/OPG	500	n	Ont.	PMO	Unk	04/28/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13
Pilgrim/Entergy	670	n	Mass.	RF	05/21/13	04/14/13
Salem-1/PSEG	1254	n	N.J.	PMO	05/13/13	04/14/13

Northeast Platts-ICE Forward Curve, May 1 ($/MWh)

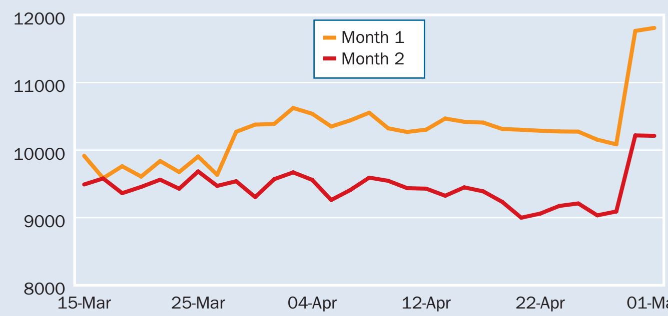
Prompt month: Jun 13	On-peak	Off-peak
Mass Hub	59.50	41.50
N.Y. Zone G	61.00	38.25
N.Y. Zone J	65.00	41.00
N.Y. Zone A	45.50	32.50
Ontario*	38.25	23.25

*Ontario prices are in Canadian dollars

N.Y. Zone A: Forward curve on-peak ($/MWh)



N.Y. Zone A: Marginal heat rate on-peak (Btu/kWh)



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
N.Y. Zone-A		
Next-week	04/30	39.50-40.50

*Ontario prices are in Canadian dollars.

Daily generation outage references

MO	unplanned maintenance outage	RF	refueling outage
PMO	planned maintenance outage	Unk	unknown
OA	offline/available		

Fuels: Nuclear=n; Coal=c; Natural gas=g; Hydro=h ; Wind=w

Sources: Generation owners, public information and other market sources.

SOUTHEAST MARKETS

Dailies move lower; terms mixed

Power prices for Thursday delivery in the Southeast turned lower Wednesday, while forwards in the region were mixed. The NYMEX June natural gas settled Wednesday at $4.326/MMBtu, down 1.7 cents.

Electric Reliability Council of Texas dailies for Thursday delivery were weaker on the IntercontinentalExchange Wednesday morning with peak load forecast decreasing as temperatures were expected to plummet below seasonal norms.

Spot natural gas at Houston Ship Channel was steady around $4.315/MMBtu.

ERCOT North Hub next-day on-peak physical power shed about $11.75 to trade around $35.25/MWh on ICE, while off-peak fell about $1 to trade around $26/MWh. South Hub on-peak dropped $12 to trade around $35/MWh. Off-peak was offered at $26/MWh, steady with Tuesday prices.

High temperatures across ERCOT's footprint were forecast to fall to the low to upper 70s Thursday, with lows in the mid-40s to upper 50s. The average May high temperature across ERCOT is in the mid-80s, with the average low in the mid-to upper 60s.

System load in ERCOT was forecast to peak at 45,700 MW Wednesday and 36,650 MW Thursday, compared with an actual peak of 44,319 MW Tuesday.

With the exception of the west, real-time prices for ERCOT averaged $20/MWh from 12:15 a.m. to 6 a.m. CDT Wednesday, while West Hub averaged $9.50/MWh.

Wind generation was forecast to peak at 7,725 MW at 1 a.m. CDT Wednesday when it actually reached 6,975 MW at 5 a.m. Wind output was expected to peak at 8,275 MW at 7 p.m. CDT Thursday.

North Hub on-peak balance-of-the-week packages were bid at $36.75 and offered at $37.25/MWh. Next-week on-peak was bid at $37.25 and offered at $38.25/MWh. Balance-of-the-month was bid at $38/MWh.

In the Southeast, dailies for Thursday delivery were weaker Wednesday morning with temperatures forecast falling below seasonal norms. Into Southern next-day on-peak power market was in the upper $30s/MWh, a slight drop from Tuesday prices.

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for May 2 ($/MWh)

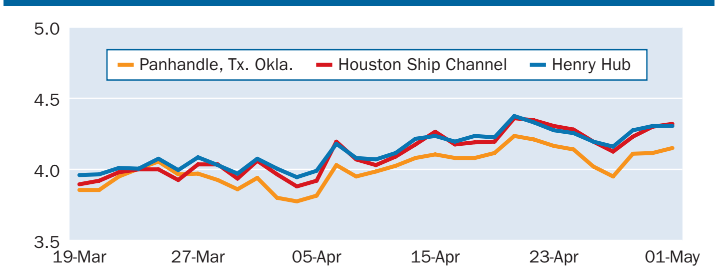
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	39.00	-0.25	39.13	8735
Southern, Into	38.00	-0.50	38.25	8832
Florida	38.75	-0.25	38.88	9012
TVA, Into	38.75	-0.50	39.00	8903
Entergy, Into	35.75	-1.00	36.25	8422
Southeast Off-Peak				
VACAR	28.25	0.25	28.13	6327
Southern, Into	27.75	0.25	27.63	6450
Florida	27.50	0.25	27.38	6395
TVA, Into	28.00	0.50	27.75	6433
Entergy, Into	24.50	2.00	23.50	5771
ERCOT On-peak				
ERCOT, North	35.34	-11.75	41.22	8455
ERCOT, Houston	35.25	-11.50	41.00	8164
ERCOT, South	35.00	-12.00	41.00	8206
ERCOT, West	26.00	-11.50	31.75	6205
ERCOT Off-Peak				
ERCOT, North	26.30	-0.79	26.70	6292
ERCOT, Houston	25.50	-0.25	25.63	5906
ERCOT, South	25.25	-0.75	25.63	5920
ERCOT, West	11.75	0.00	11.75	2804
SPP/MRO On-peak				
MAPP, Soth	37.00	-1.25	37.63	8477
SPP, North	36.50	-1.00	37.00	8795
SPP/MRO Off-Peak				
MAPP, Soth	25.00	0.75	24.63	5727
SPP, North	24.50	1.00	24.00	5904

Southeast load and generation mix forecast (GWh)

	Actual 30-Apr	%Chg	% Chg Year-ago	Forecast 01-May	02-May	03-May	04-May	05-May
ERCOT								
Load	859	2	1	880	779	751	705	666
Generation								
Coal	349	1	22	347	336	337	331	324
Gas	356	3	-15	382	301	273	274	282
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	692	7	-2	617	598	582	572	574
Generation								
Coal	416	2	17	388	385	388	384	379
Gas	180	27	-27	140	105	95	101	110
Nuclear	22	-45	1	22	22	22	22	22

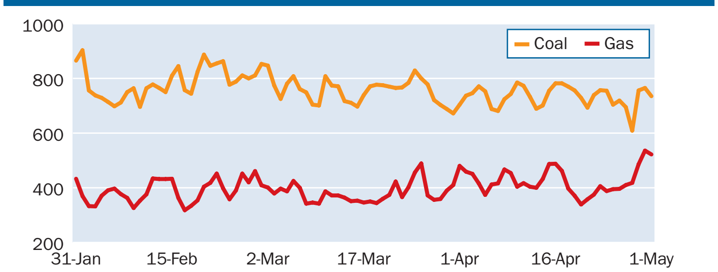
Source: Bentek

Southeast & Central spot natural gas prices ($/MMBtu)



Source: Platts

ERCOT & SPP gas and coal generation (GWh)



Source: Bentek

ERCOT average day-ahead LMP for May 2 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	32.77	-14.89	40.22	7724
Hub Average	31.70	-14.51	38.96	7474
Houston Hub	34.13	-14.51	41.39	7899
North Hub	33.80	-15.52	41.56	8088
South Hub	34.08	-14.00	41.08	7991
West Hub	24.80	-13.99	31.80	5916
AEN Zone	32.41	-15.33	40.08	7732
CPS Zone	35.78	-13.11	42.34	8436
LCRA Zone	33.46	-14.42	40.67	7889
Rayburn Zone	43.80	-15.98	51.79	10481
Houston Zone	34.14	-14.57	41.43	7901
North Zone	37.80	-16.35	45.98	9045
South Zone	35.18	-14.25	42.31	8250
West Zone	27.31	-46.48	50.55	6513
Off-Peak				
Bus Average	22.98	-1.38	23.67	5426
Hub Average	21.20	-0.79	21.60	5005
Houston Hub	24.68	-1.15	25.26	5727
North Hub	24.95	-2.23	26.07	5973
South Hub	23.77	-0.90	24.22	5574
West Hub	11.40	1.13	10.84	2728
AEN Zone	23.32	-0.83	23.74	5581
CPS Zone	23.70	-0.97	24.19	5585
LCRA Zone	23.41	-0.87	23.85	5516
Rayburn Zone	41.68	-3.39	43.38	9979
Houston Zone	24.64	-1.14	25.21	5718
North Zone	31.82	-2.82	33.23	7619
South Zone	23.95	-0.78	24.34	5616
West Zone	12.77	0.24	12.65	3056

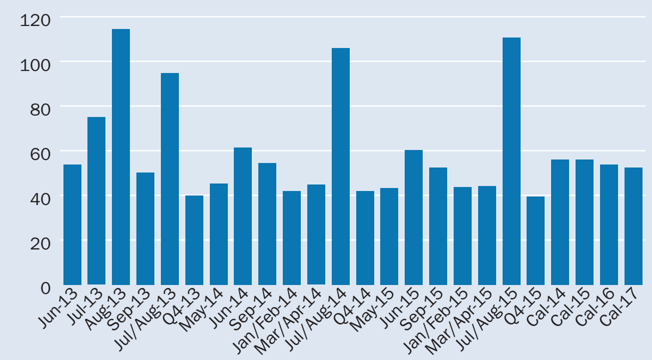
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	05/01	36.75-37.25
Bal-week	04/30	38.00-38.50
Bal-week	04/29	38.75-39.25
Bal-month	05/01	37.50-38.00
Bal-month	04/26	39.25-39.75
Bal-month	04/25	38.25-38.75
Next-week	05/01	37.00-37.50
Next-week	04/30	36.50-37.00
Next-week	04/29	38.00-38.50
Next-week	04/26	39.75-40.25
Next-week	04/25	38.00-38.50
Entergy, Into		
Bal-week	05/01	35.00-35.50
Bal-week	04/30	36.50-37.00
Bal-week	04/29	36.25-36.75
Bal-month	05/01	35.75-36.25
Bal-month	04/26	37.50-38.00
Bal-month	04/25	36.75-37.25
Next-week	05/01	35.00-35.50
Next-week	04/30	37.00-37.50
Next-week	04/29	36.75-37.25
Next-week	04/26	38.50-39.00
Next-week	04/25	36.75-37.25
ERCOT, North		
Bal-week	05/01	37.25-37.75
Next-week	04/25	36.50-37.00
ERCOT, West		
Next-week	04/25	36.75-37.25

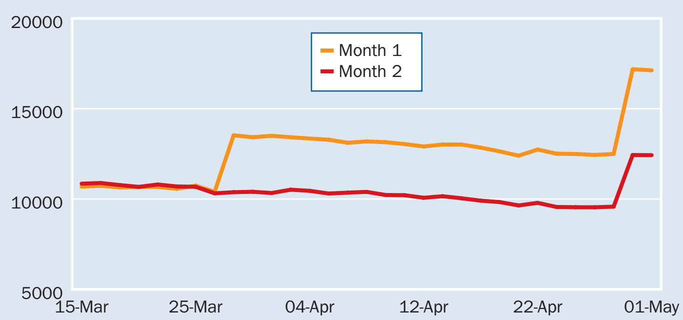
Southeast & Central Platts-ICE Forward Curve, May 1 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
Southern Into	41.25	30.50
Entergy Into	39.00	27.75
ERCOT North	52.75	33.00
ERCOT Houston	53.75	34.00
ERCOT West	52.50	32.25
ERCOT South	53.00	32.75

ERCOT Houston: Forward curve on-peak ($/MWh)



ERCOT Houston: Marginal heat rate on-peak (Btu/kWh)



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Arkansas-1/Entergy	903	n	Ark.	PMO	05/03/13	03/25/13
Bowen/Georgia Power	3160	c	Ga.	PMO	Unk	04/04/13
Browns Ferry-2/TVA	1155	n	Ala.	PMO	Unk	03/14/13
Brunswick-2/CP&L	953	n	NC	MO	Unk	03/03/13
Crystal Rver-3/Progress	838	n	Fla.	MO	Retired	09/26/09
Farley-2/Southern	928	n	Ala.	RF	05/19/13	04/14/13
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Waterford-3/Entergy	1222	n	La.	PMO	Unk	04/26/13

Market coverage

Platts provides a detailed methodology related to its coverage of North American electricity markets at: http://platts.com/MethodologyAndSpecifications/ElectricPower. Questions can be directed to Mike Wilczek, Market Editor, (202) 383-2246, Mike_Wilczek@platts.com.

WEST MARKETS

Dailies go mostly higher; most terms slide

Western dailies were mostly up Wednesday morning with higher peak demand forecast in California and higher spot natural gas prices in the region. Most terms fell, and the NYMEX June natural gas settled Wednesday at $4.326/MMBtu, down 1.7 cents.

In the Northwest, Mid-Columbia day-ahead on-peak gained about $1 to trade between $39.50 and $42/MWh for Thursday delivery. Mid-C day-ahead off-peak prices added more than 75 cents to trade between $28.50 and $30.75/MWh. The Mid-C on-peak balance-of-the-month packages were bid at $32 and offered at $32.75/MWh, about $1.25 higher than on Wednesday.

Portland, Oregon, forecast highs were in the low 70s Thursday, up about 5 degrees. Projected lows also up from the mid-40s to around 50.

The Bonneville Power Administration's wind generation at 7 a.m. PDT Wednesday was 84 MW and its hydropower was 11,314 MW.

In California, SP15 next-day on-peak gained more than $3.50 to trade between $61 and $64/MWh. SP15 day-ahead off-peak rose $2.25 to about $41.50/MWh. SP bal-month was bid at $57.25 and offered at $57.45/MWh on IntercontinentalExchange, down more than $1. NP15 day-ahead on-peak was up $1.75 to about $50.75/MWh. NP15 day-ahead off-peak added nearly $1.75 to about $37.50/MWh. NP15 bal-month was offered at $47.75 and offered at $48/MWh.

Sacramento, California, expected highs around 95 through Thursday. Lows were projected in the high 50s to around 60. Burbank forecast highs in the low 90s Thursday, an increase of around 10 degrees, and steady lows near 60.

The California Independent System Operator projected peak demand to hit 30,272 MW Wednesday and 33,051 MW Thursday.

Renewables were 3,214 MW and wind was about 33,051 MW around 7 a.m. PDT Wednesday.\

In the desert Southwest, Palo Verde next-day on-peak was up almost $1 to trade between $42.50 and $43.75/MWh. Palo Verde day-ahead off-peak was near flat, to trade between $30.25 and $31/MWh. Palo Verde bal-month was bid at $40.25 and offered at $41/MWh, about 75 cents lower.

Phoenix forecast highs near 100 through Thursday and lows in the low to mid-60s.

Next-day natural gas rose in the Rockies and California. Opal was up 4.2 cents to $4.152/MMBtu, PG&E city-gate added 5.9 cents to $4.444/MMBtu, and SoCal city-gate gained 8.1 cents to $4.526/MMBtu.

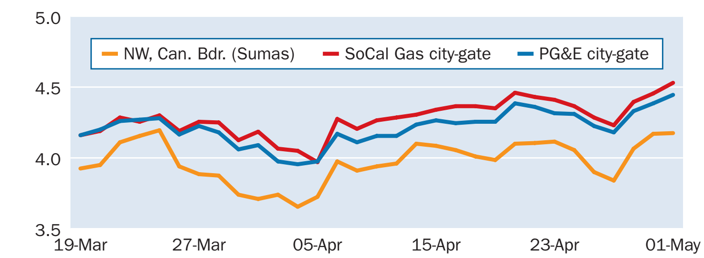
Day-ahead prices in the California ISO auction were mostly up Wednesday afternoon with the higher peak demand forecast. SP15 on-peak rose $6.79 to $57.67/MWh and SP15 off-peak climbed $2.17 to $40.55/MWh. NP15 on-peak added $1.64 to $48.41/MWh as NP15 off-peak gained $2.29 to $38.64/MWh. ZP26 on-peak was down 43 cents to $45.52/MWh while ZP26 off-peak increased 10 cents to $35.34/MWh.

(continued on page 11)

Western day-ahead bilateral indexes for May 2 ($/MWh)

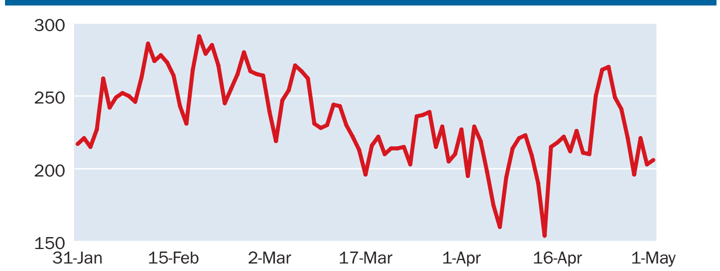
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	42.95	1.59	42.16	10300
Mid-C	40.51	0.95	40.04	9744
Palo Verde	43.39	0.87	42.96	10258
Mead	43.75	-0.50	44.00	10139
Mona	37.75	0.25	37.63	9264
Four Corners	41.00	2.50	39.75	9891
NP15	50.75	1.75	49.88	11417
SP15	62.50	3.50	60.75	14484
Off-Peak				
COB	30.87	0.62	30.56	7403
Mid-C	29.71	0.57	29.43	7146
Palo Verde	30.88	0.09	30.84	7300
Mead	32.25	0.75	31.88	7474
Mona	26.75	2.00	25.75	6564
Four Corners	26.75	-0.75	27.13	6454
NP15	37.75	2.00	36.75	8493
SP15	41.75	2.50	40.50	9676

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO gas generation (GWh)



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 30-Apr	%Chg	% Chg Year-ago	Forecast 01-May	02-May	03-May	04-May	05-May
CAISO								
Load	651	-2	2	641	667	686	634	588
Generation								
Gas	203	-8	5	206	264	316	301	253
Nuclear	56	0	-27	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for May 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	48.41	-5.69	-2.58	1.64	47.59	10879
SP15 Gen Hub	57.67	2.06	-1.08	6.79	54.28	13365
ZP26 Gen Hub	45.52	-7.40	-3.77	-0.43	45.74	10548
Off-Peak						
NP15 Gen Hub	38.64	-1.12	-0.43	2.29	37.50	8779
SP15 Gen Hub	40.55	1.52	-1.16	2.17	39.47	9454
ZP26 Gen Hub	35.34	-2.92	-1.93	0.10	35.29	8240

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	05/01	31.50-32.50
Bal-month	04/30	30.25-30.75
Bal-month (off-peak)	05/01	12.75-13.25
Bal-month (off-peak)	04/25	22.00-23.00

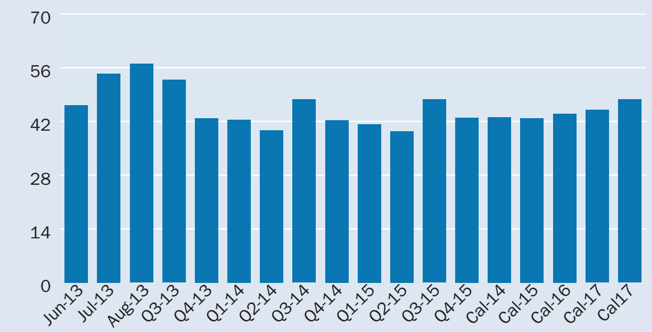
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
ACE Cogen/Constellation	118	g	Calif.	MO	Unk	04/28/13
Catalina Solar-1&2/EDF	110	s	Calif.	MO	Unk	04/01/13
Desert Star/SDG&E	495	g	Calif.	PMO	Unk	03/24/13
Empire-1/Inland Empire	376	g	Calif.	PMO	Unk	04/01/13
Encina-5/Cabrillo	330	g	Calif.	PMO	Unk	04/29/13
Gilroy Cogen/Calpine	120	g	Calif.	PMO	Unk	04/01/13
Helms-2/PG&E	407	h	Calif.	PMO	Unk	12/02/12
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
Los Esteros/Calpine	188	g	Calif.	PMO	Unk	01/02/13
Mandalay-1/NRG	215	g	Calif.	PMO	Unk	02/10/13
Mandalay-3/NRG	130	g	Calif.	PMO	Unk	04/29/13
Mexicali/Sempra	180	g	Calif.	MO	Unk	04/25/13
Morro Bay-4/Dynergy	325	g	Calif.	PMO	Unk	04/29/13
Mountanview-4	525	g	Calif.	PMO	Unk	04/23/13
Panoche/Panoche Energy	400	g	Calif.	PMO	Unk	04/29/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12
Sunrise/Edison	586	g	Calif.	PMO	Unk	04/30/13
Topaz/MidAmerican	130	s	Calif.	MO	Unk	04/29/13
Walnut Creek-5/Edison	100	g	Calif.	MO	Unk	04/30/13

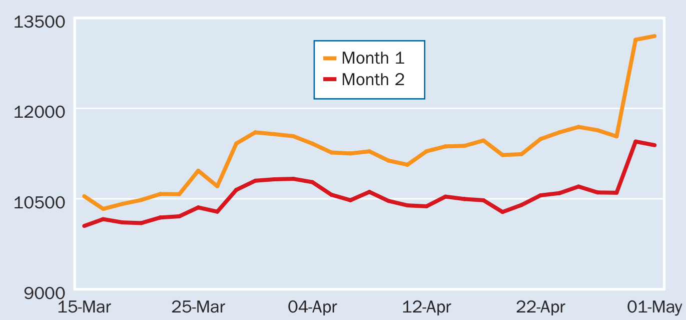
Western Platts-ICE Forward Curve, May 1 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
Mid-C	28.00	10.00
Palo Verde	43.75	27.25
Mead	46.25	31.75
NP15	46.50	34.00
SP15	52.75	36.75

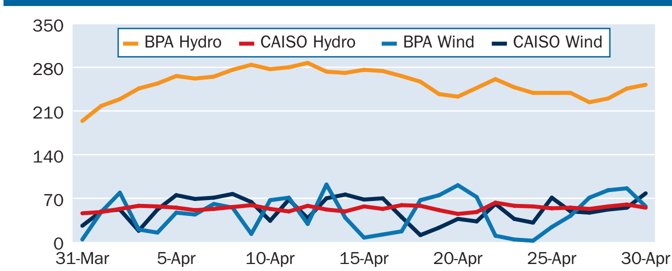
Mead: Forward curve on-peak ($/MWh)



Mead: Marginal heat rate on-peak (Btu/kWh)



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

Additional information on data and analysis:

For more information on data and analysis from Bentek Analytics, including five-day load and generation mix forecasts and relative load normalized by temperature, email power@bentekenergy.com, or call 303-988-1320. Average on-peak and off-peak LMP and marginal heat-rate data is available via Platts Market Data. More detailed, hourly LMP and marginal heat-rate data is available from Bentek Analytics.

PJM & MISO MARKETS

Mid-Atlantic dailies edge up as demand drops

Daily power prices in the Mid-Atlantic were up Wednesday, while Midwest dailies saw mixed activity and the NYMEX June natural gas contract settled at $4.326/MMBtu, down 1.7 cents.

Mid-Atlantic dailies were up slightly Wednesday, with steady spot gas prices and lower expected electricity demand.

Temperatures across the PJM Interconnection were forecast in the low 60s to low 70s.

PJM forecasted peak demand for Wednesday around 90,599 MW and 88,037 MW for Thursday.

Texas Eastern M-3 spot natural gas was around $4.43/MMBtu on the IntercontinentalExchange Wednesday, steady with Tuesday.

PJM West Hub on-peak packages for Thursday were up about $1, in the low $40s/MWh on ICE. Off-peak next-day packages were about 25 cents higher, in the upper $20s/MWh.

Midwest dailies were steady, as Chicago city gates spot gas was up about 6 cents, around $4.42/MMBtu.

Indiana Hub on-peak packages for Thursday were holding in low $40s/MWh. Off-peak packages rose about 50 cents, in the upper $20s/MWh.

Dailies in the Midwestern portion of PJM were mixed. AEP-Dayton Hub on-peak was up about 25 cents in the low $40s/MWh. AD Hub off-peak were gained about $1 in the upper $20s/MWh. Northern Illinois Hub on-peak slipped about 25 cents, to around $40/MWh and off-peak was down about $2 in the mid-$20s/MWh.

Day-ahead auction prices in PJM were mostly lower Wednesday. Western Hub peak dropped $4.19 to about $38.91/MWh and off-peak edged up 50 cents to about $29.57/MWh.

Chicago Hub peak lost the most on the day, falling over $5 to about $37.24/MWh and off-peak was 82 cents lower at about $24.79/MWh.

PSEG Zone peak fell over $2, clearing at about $42.84/MWh and off-peak was up about 69 cents, to about $30.93/MWh.

New Jersey Hub peak lost about $3.24, going to about $41.32/MWh and off-peak was up 54 cents, to about $30.68/MWh.

BG&E Zone peak was down about $4.15, to about $40.55/MWh and off-peak edged up 64 cents to about $30.55/MWh.

Rockland Electric Zone peak and off-peak bucked the losing trend on the day, as peak added $2.12, clearing at about $45/MWh and off-peak added about $1.50, clearing just over $31/MWh.

MISO day-ahead auction prices cleared mostly weaker Wednesday afternoon.

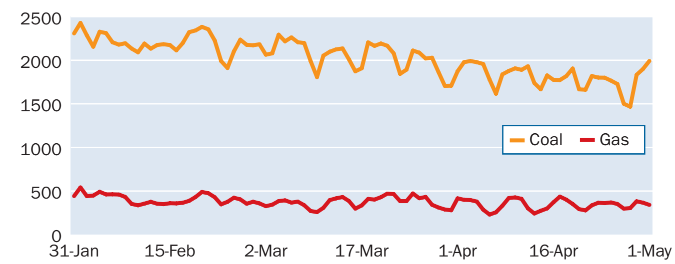
Michigan Hub maintained is position as the highest-priced hub, with an on-peak clearing price of $40.93/MWh, a drop of $3.50, while off-peak cleared at $34.06/MWh, up $4.88.

Minnesota Hub on-peak cleared at $37.98/MWh, up $2.97, while off-peak cleared at $23.94/MWh, a gain of $3.66. Indiana Hub on-peak cleared at $36.68/MWh, falling $6.23. Off-peak

PJM & MISO day-ahead bilateral indexes for May 2 ($/MWh)

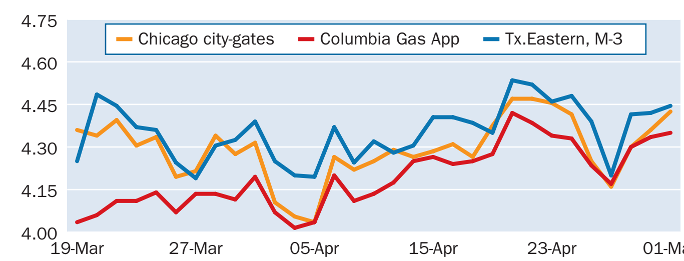
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	42.00	0.75	41.63	9786
Dominion Hub	42.00	0.50	41.75	9529
AD Hub	41.75	0.50	41.50	9676
NI Hub	40.00	-0.25	40.13	9040
PJM Off-Peak				
PJM West	29.50	0.25	29.38	6874
Dominion Hub	29.75	0.75	29.38	6750
AD Hub	29.00	1.00	28.50	6721
NI Hub	25.25	-0.75	25.63	5706
MISO On-peak				
Indiana Hub	40.50	-0.50	40.75	9289
Michigan Hub	42.00	0.50	41.75	9292
Minnesota Hub	32.25	0.00	32.25	7376
Illinois Hub	38.50	-1.50	39.25	8676
MISO Off-Peak				
Indiana Hub	28.25	0.50	28.00	6479
Michigan Hub	30.25	1.75	29.38	6692
Minnesota Hub	22.00	3.75	20.13	5031
Illinois Hub	25.50	-1.00	26.00	5746

PJM & MISO gas and coal generation (GWh)



Source: Bentek

PJM & MISO spot natural gas prices ($/MMBtu)



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 30-Apr	%Chg	% Chg Year-ago	Forecast 01-May	02-May	03-May	04-May	05-May
PJM								
Load	1911	1	5	1961	1961	1930	1762	1708
Generation								
Coal	817	4	16	846	812	783	746	715
Gas	290	-2	-19	300	289	277	269	268
Nuclear	630	0	2	632	632	632	632	632
MISO								
Load	1296	3	4	1346	1324	1290	1180	1146
Generation								
Coal	1084	3	13	1146	1081	1011	943	921
Gas	76	-12	-36	42	49	57	54	54
Nuclear	92	8	-8	131	132	138	147	156

Source: Bentek

MISO average day-ahead LMP for May 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	36.68	-0.19	0.69	-6.23	39.80	8419
Michigan Hub	40.93	3.11	1.64	-3.50	42.68	9042
Minnesota Hub	37.98	2.40	-0.60	2.97	36.50	8696
Illinois Hub	36.34	0.90	-0.74	-4.60	38.64	8206
Off-Peak						
Indiana Hub	27.71	1.35	0.78	0.61	27.41	6388
Michigan Hub	34.06	6.99	1.50	4.88	31.62	7481
Minnesota Hub	23.94	-0.57	-1.07	3.66	22.11	5541
Illinois Hub	26.36	1.26	-0.48	2.37	25.18	6021

PJM & MISO near-term bilateral markets ($/MWh)

Package	Trade date	Range
PJM West		
Bal-week	05/01	37.50-39.50
Bal-week	04/30	39.50-40.25
Bal-week	04/29	43.50-44.00
Bal-month	04/25	42.50-43.00
Next-week	05/01	43.00-44.25
Next-week	04/30	43.25-44.50
Next-week	04/25	41.75-43.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Callaway/Ameren	1235	n	Mo.	PMO	05/08/13	04/09/13
DC Cook-1/I&M	1152	n	Mich	RF	05/18/13	03/27/13
Fermi-2/DTE Energy	1555	n	Mich.	MO	07/19/13	04/27/13
Monticello/Xcel	666	n	Minn.	PMO	05/19/13	03/02/13
North Anna/Dominion	903	n	Va.	PMO	05/07/13	04/06/13
Perry/FirstEnergy	1260	n	Ohio	PMO	05/05/13	03/18/13
Susquehanna-2/PPL	1330	n	Penn.	PMO	05/22/13	04/13/13

PJM average day-ahead LMP for May 2 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	36.80	-0.36	-1.68	-4.72	39.16	8428
AEP-Dayton Hub	38.20	-0.15	-0.49	-4.66	40.53	8748
ATSI Gen Hub	38.52	-0.24	-0.08	-4.55	40.80	8783
Chicago Gen Hub	36.68	-0.79	-1.38	-4.94	39.15	8304
Chicago Hub	37.24	-0.75	-0.85	-5.08	39.78	8431
Dominion Hub	38.98	0.34	-0.20	-4.42	41.19	8841
Eastern Hub	40.09	-0.32	1.56	-4.28	42.23	9007
New Jersy Hub	41.32	1.47	1.01	-3.24	42.94	9284
Northern Illinios Hub	37.00	-0.75	-1.09	-5.02	39.51	8378
Ohio Hub	38.54	-0.09	-0.21	-4.57	40.83	8745
West Internal Hub	38.42	0.08	-0.50	-4.67	40.76	8950
Western Hub	38.91	-0.05	0.12	-4.19	41.01	9063
AEP Zone	38.08	-0.19	-0.58	-4.68	40.42	8719
Allegheny Power Zone	38.28	-0.15	-0.41	-4.66	40.61	8873
Atlantic Elec Zone	38.91	-1.19	1.25	-4.65	41.24	8743
ATSI Zone	38.95	-0.18	0.29	-4.66	41.28	8882
BG&E Zone	40.55	0.54	1.17	-4.15	42.63	9283
ComEd Zone	37.23	-0.73	-0.88	-5.02	39.74	8428
Dayton P&L Zone	39.09	-0.28	0.52	-4.86	41.52	8971
Delmarva P&L Zone	40.49	0.23	1.41	-4.10	42.54	9097
Dominion Zone	39.27	0.37	0.06	-4.41	41.48	8906
Duke Zone	37.84	-0.21	-0.79	-4.77	40.23	8685
Duquesne Light Zone	36.74	-0.38	-1.72	-4.76	39.12	8499
JCPL Zone	39.66	-0.11	0.93	-4.67	42.00	8912
MetEd Zone	38.20	-0.77	0.13	-4.65	40.53	8647
PECO Zone	38.04	-1.17	0.36	-4.69	40.39	8610
Pennsylvania Elec Zone	39.79	0.08	0.87	-3.79	41.69	9190
PEPCO Zone	40.16	0.45	0.86	-4.22	42.27	9193
PPL Zone	38.28	-0.70	0.13	-4.55	40.56	8664
PSEG Zone	42.84	2.98	1.02	-2.05	43.87	9626
Rockland Elec Zone	44.94	5.20	0.90	2.12	43.88	10099
Off-Peak						
AEP Gen Hub	27.95	0.26	-1.24	0.28	27.81	6412
AEP-Dayton Hub	28.67	0.43	-0.69	0.38	28.48	6578
ATSI Gen Hub	29.01	0.30	-0.21	0.33	28.85	6625
Chicago Gen Hub	24.33	-2.90	-1.70	-0.73	24.70	5570
Chicago Hub	24.79	-2.74	-1.40	-0.82	25.20	5676
Dominion Hub	29.76	0.59	0.24	0.56	29.48	6759
Eastern Hub	30.73	0.24	1.56	0.50	30.48	6926
New Jersy Hub	30.68	0.59	1.17	0.54	30.41	6915
Northern Illinios Hub	24.51	-2.90	-1.52	-0.94	24.98	5610
Ohio Hub	28.81	0.48	-0.60	0.41	28.61	6550
West Internal Hub	29.05	0.36	-0.24	0.32	28.89	6785
Western Hub	29.57	0.33	0.31	0.50	29.32	6906
AEP Zone	28.64	0.35	-0.64	0.28	28.50	6572
Allegheny Power Zone	29.18	0.34	-0.08	0.31	29.03	6785
Atlantic Elec Zone	30.28	0.06	1.30	0.37	30.10	6824
ATSI Zone	29.24	0.29	0.02	0.34	29.07	6676
BG&E Zone	30.55	0.46	1.16	0.64	30.23	7009
ComEd Zone	24.70	-2.81	-1.42	-0.82	25.11	5655
Dayton P&L Zone	28.97	0.27	-0.22	0.33	28.81	6677
Delmarva P&L Zone	30.83	0.35	1.56	0.49	30.59	6948
Dominion Zone	29.85	0.54	0.39	0.48	29.61	6779
Duke Zone	28.08	0.25	-1.10	0.33	27.92	6472
Duquesne Light Zone	27.97	0.26	-1.22	0.29	27.83	6486
JCPL Zone	30.41	0.33	1.15	0.30	30.26	6853
MetEd Zone	29.98	0.19	0.86	0.44	29.76	6805
PECO Zone	29.90	0.08	0.89	0.41	29.70	6787
Pennsylvania Elec Zone	29.94	0.31	0.71	0.59	29.65	6939
PEPCO Zone	30.27	0.48	0.86	0.53	30.01	6945
PPL Zone	29.86	0.20	0.74	0.42	29.65	6778
PSEG Zone	30.93	0.85	1.16	0.69	30.59	6971
Rockland Elec Zone	31.05	1.19	0.93	1.50	30.30	6998

cleared at $27.71/MWh, adding 61 cents.

The lowest-priced hub became Illinois Hub, with on-peak clearing the auction at $36.34MWh, a loss of $4.60. Off-peak cleared at $26.36/MWh, rising $2.37.

Congestion costs at the hubs ranged from negative 19 cents to $3.11 for peak, and from negative 57 cents to $6.99 for off-peak.

Mid-Atlantic forwards were flat to up Wednesday, despite a dip in gas futures. June NYMEX gas futures shed 1.3 cents, trading at about $4.33/MMBtu.

PJM West on-peak June financial futures were unchanged with bids at $52.40/MWh and offers at $52.50/MWh on ICE at about 2:30 p.m. EDT Wednesday. PJM West on-peak July-August stood still at about $62/MWh, while on-peak fourth-quarter held steady at about $46.25/MWh. PJM West off-peak May rose 25 cents to about $32.50/MWh.

Midwest June forwards were steady to up Wednesday. AD Hub on-peak June financial futures were unchanged at about $47.50/MWh. Indiana Hub on-peak June took on 50 cents, rising to about $43.25/MWh. NI Hub on-peak June stood still at about $45.50/MWh.

Northeast markets *... from page 2*

Long Island Zone moved up nearly $1 to about $58.24/MWh and off-peak edged down 65 cents to about $39.35/MWh.

Northeast term power was tame Wednesday as June NYMEX gas futures shed 1.3 cents, trading at about $4.33/MMBtu.

In New England, Mass Hub on-peak June financial futures fell 25 cents, with bids at $59.25/MWh and offers at $60/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT Wednesday. Mass Hub on-peak July-August was unchanged at about $60.50/MWh. Mass Hub off-peak June stood still at about $41.50/MWh.

New York Zone G on-peak June lost 25 cents to about $61/MWh. New York Zone G on-peak July-August moved up 75 cents, to about $68.75/MWh. New York Zone A on-peak June fell 25 cents to about $45.50/MWh, while Zone A on-peak July-August was unchanged at about $51.75/MWh.

Southeast markets *... from page 4*

Spot natural gas at Transco Zone-3 was steady around $4.301/MMBtu.

High temperatures in Atlanta were forecast to drop to the low 70s Thursday, below the average May high temperature in Atlanta of 80. The low was forecast in the upper 50s, below the average low of 60.

The ERCOT day-ahead auction for Thursday delivery cleared weaker Wednesday afternoon as peak load was forecast to fall sharply.

Houston Hub jumped into the highest-priced hub position while West Hub remained the lowest-priced hub. Houston Hub on-peak cleared in the ERCOT auction at $34.13/MWh, falling around $12.50, while off-peak cleared at $24.68/MWh, down almost $1.25.

South Hub on-peak cleared at $34.08/MWh, a drop of $14, while off-peak cleared at $23.77/MWh, losing nearly $1. North Hub on-peak cleared the auction at $33.80/MWh, a loss of more than $15.50 from Tuesday's clearing price, while off-peak cleared at $24.95/MWh, falling about $2.25.

West Hub on-peak cleared in the ERCOT auction $24.80/MWh, down about $14, while off-peak cleared at $11.40/MWh, adding roughly $1.25. Rayburn Zone on-peak led the load zones at $43.80/MWh, falling almost $16 from Tuesday.

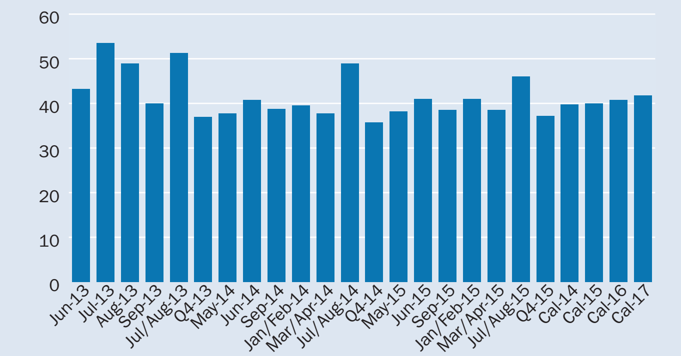
The highest hourly day-ahead price occurred at 9 p.m. CDT in the North Hub at $45.76/MWh and in the Rayburn Zone at $58.20/MWh.

ERCOT system load was forecast to peak at 36,650 MW Thursday, down 20% from Wednesday's expected peak of 45,700 MW.

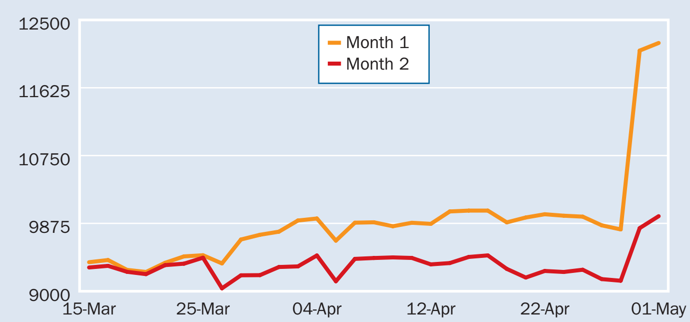
PJM & MISO Platts-ICE Forward Curve, May 1 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
PJM West	52.50	32.50
AD Hub	47.50	30.00
NI Hub	45.50	26.25
Indiana Hub	43.25	26.50

Indiana Hub: Forward curve on-peak ($/MWh)



Indiana Hub: Marginal heat rate on-peak (Btu/kWh)



South Central US June terms were mixed Wednesday. ERCOT Houston on-peak June fell 25 cents to about $53.75/MWh, and July-August slid 65 cents to about $95/MWh. Heat rates were up about 20 Btu/kWh on the IntercontinentalExchange at about 2:30 p.m. EDT. ERCOT North June fell 25 cents to about $52.75/MWh, July-August dropped 65 cents to about $95.75/MWh, and September stayed at about $49/MWh. Into Entergy June surged 75 cents to about $39/MWh, and July-August rose 25 cents to about $42/MWh.

Southeast US on-peak June went up Wednesday, even as June NYMEX gas futures went down. Into Southern June jumped 75 cents to about $41.25/MWh, July-August rose 25 cents to about $43.75/MWh, and September rose 25 cents to about $43.75/MWh.

West markets

... from page 6

In the Northwest, Mid-Columbia on-peak June was unchanged with bids at $27.75 and offers at $28.25/MWh on ICE around 2:30 p.m. EDT. July rose 25 cents to about $44.50/MWh, and the third quarter rose 25 cents to about $45.90/MWh. In California, SP15 on-peak June financial terms slipped down 75 cents with bids at $52.50 and offers at $52.75/MWh. July lost 50 cents to about $62/MWh, and Q3 fell 25 cents to about $62.85/MWh. NP15 June fell 25 cents to about $46.50/MWh, and Q3 crept down 20 cents to about $55.90/MWh. Palo Verde June fell 25 cents to about $43.75/MWh, July rose 25 cents to about $53/MWh, and Q3 climbed 45 cents to about $51.35/MWh.

NEWS

IP&L to retire coal plant, build gas plant

Indianapolis Power & Light said Wednesday it will retire its 341-MW Eagle Valley coal-fired power plant and convert four coal units totaling 260 MW to natural gas at its Harding Street coal plant and construct a 650-MW natural gas-fired plant by 2017.

The twin moves are aimed at reducing the coal portion of the AES subsidiary's generation portfolio to 55% by 2017. Coal accounted for 86% of the utility's generation mix in 2007. Gas will make up 33% of the portfolio in 2017.

The estimated $36 million conversion of Units 3, 4, 5 and 6 at Harding Street, located in Indianapolis, should be completed in 2016, according to Brandi Davis-Handy, a company spokeswoman. Unit 7, the baseload plant's remaining 500-MW coal unit, will remain in operation.

Also unaffected by the latest decision is IP&L's largest coal plant, 1,760-MW Petersburg in Pike County, Indiana, she said. IP&L expects to spend about $631 million to construct the combined-cycle gas plant at the Eagle Valley site north of Martinsville in Morgan County.

The company said the planned gas plant will lower sulfur dioxide, nitrogen oxide and particulate emissions by more than 98%. Virtually all mercury, lead and fluoride emissions will be eliminated, and water use will be decreased by 97%.

Both the planned plant and Harding Street conversion must be approved by the Indiana Utility Regulatory Commission. IP&L has been weighing an Eagle Valley retirement for some time and has been under pressure from environmentalists to shutter or repower Harding Street, just a few blocks from downtown Indianapolis.

The utility currently has 3,353 MW of generation capacity. The IURC also is reviewing IP&L's plans to spend $511 million to install pollution controls at Petersburg and Harding Street 7 so they can continue to burn coal for many years to come.

As part of the planned expenditure, the utility has signed a $420 million contract with Indiana Environmental Partners for engineering, procurement and construction of the controls. IEP is a joint venture between Chicago-based Sargent & Lundy and Kiewit Corp. of Omaha, Nebraska.

IP&L burns 6.5 million to 7 million short tons of coal annually from several US coal basins, Davis-Handy said.

— Bob Matyi

Gas-fired projects get OK from Ohio regulators

Ohio is set to add about 1,400 MW of natural gas-fired combined cycle capacity over the next few years after the state Power Siting Board on Wednesday approved separate projects for North America Project Development and Tenaska.

The board endorsed North America's plans to construct a 800-MW plant, Oregon Clean Energy Center, on a 30.5-acre site near the Toledo suburb of Oregon in northwest Ohio. North America is a development company co-owned by veteran independent power developers William Martin and William Siderewicz.

Tenaska, an Omaha, Nebraska-based power developer, won approval to convert its existing 815-MW Rolling Hills natural gas-fired peaking plant near Wilkesville in Vinton County into a 1,414-MW combined-cycle/peaking facility to serve as many as 1.4 million households in the region.

Tenaska acquired Rolling Hills from Dynegy in 2008.

Oregon Clean Energy "will add much-needed generating capacity to northern Ohio," siting board chairman Todd Snitchler, who also chairs the Public Utilities Commission, said in a statement. "The facility will take advantage of cleaner-burning natural gas, at today's affordable prices, further enhancing Ohio's diversified energy portfolio."

The project is expected to create about 532 construction and 25 permanent jobs.

Coal still is the leading fuel source in Ohio, accounting for more than 60% of electric generation in the Midwestern state.

Martin, in an interview after the meeting, said his company is reviewing power purchase proposals "from creditworthy offtakers who are interested in buying our energy, all 800 megawatts. So, we're in a good position there."

North America, he added, is "negotiating some bilateral capacity agreements."

The plant is estimated to cost about $860 million.

With the project still requiring an air permit from the Ohio Environmental Protection Agency, Martin said it is doubtful construction can get under way in 2013. More likely, it will begin in 2014, with the plant up and running in late 2016 or early 2017.

Oregon Clean Energy is intended to replace some of the roughly 1,611 MW of older coal capacity expected to be retired in the region in the next few years because of new Environmental Protection Agency rules.

"We're excited about the project and the path it's taking," Martin said.

The board also endorsed Tenaska's plan to convert four of Rolling Hills' five existing combustion turbines from simple-cycle to combined-cycle mode.

Once completed, Rolling Hills would use the upgraded turbines to serve intermediate or baseload power demands and continue to use the remaining simple-cycle turbine to provide peaking power to the wholesale power market.

Construction is expected to get under way in 2014.

Jeff James, Tenaska's project manager for Rolling Hills, called the board's approval "a major milestone" for the project. The company is on track to begin construction "as early as 2014 and begin operations as early as 2016, great timing to meet the PJM market's need for capacity."

The board's decision comes on the heels of a PJM Interconnection system impact study that found no negative impacts of linking the converted plant to the regional transmission system, he said. The project's application now is proceeding through a PJM interconnection facilities study.

The twin projects mean more power supply "in what has been a relatively weak demand environment," said Paul Patterson, a Glenrock Associates analyst in New York. "So I don't see it exactly warming the hearts of incumbent generators."

He added: "It's like these merchant generators have all these challenges to their profitability: energy efficiency, demand response, subsidized renewables; and with the prospect of new highly efficient gas-fired power plants on the horizon, it is like they are being attacked on multiple fronts."

— Bob Matyi

Texas 925-MW unit set for summer availability

While the new, 925-MW Sandy Creek coal unit — which is expected to begin commercial operation later this month, nearly a year behind schedule — may face headwinds economically in an Electric Reliability Council of Texas market dominated by lower-cost power from natural gas-fired units, the unit may also benefit at least short term from what is expected to be an unusually tight reserve margin environment in ERCOT this summer.

LS Power holds a roughly 64% — or 591-MW — ownership interest in the $1 billion-plus supercritical pulverized coal unit in McLellan County, while Brazos Electric Power Cooperative owns a 25% stake and the Lower Colorado River Authority owns the remaining 11%.

The Brazos co-op also holds a 30-year power purchase agreement for 150 MW of LS Power's share of the unit, and LCRA holds a 30-year PPA for 100 MW, again from LS's share.

The Sandy Creek unit, which was initially planned when natural gas prices were high, had been expected to begin commercial operation in June 2012. However, during test-firing of the unit in October several tubes overheated, badly damaging the boiler and delaying the unit's commercial start-up.

Last year, both Moody's Investors Service and Standard & Poor's downgraded the project's construction-related debt. Moody's cited the project's delayed online date, as well as "the deterioration in the wholesale energy markets in ERCOT and an increase in projected fuel costs." It said that while the Brazos and LCRA PPAs increased the contracted portion of the project's output, "the lower market prices for power and higher prices for coal have squeezed the merchant margin."

S&P, which like Platts is part of The McGraw-Hill Cos., took a similar view. It noted, "The project faces around-the-clock merchant power prices for about 56% of its capacity starting in 2015 following a two-year restructured hedge period."

The positive news, S&P said, is that the Brazos and LCRA PPAs "provide contractual payments for about 44% of capacity," and ERCOT's northern region, where Sandy Creek is located, "could face higher electricity prices in the future due to decreasing capacity margin, particularly if economic growth and load demand were to increase."

Not much has changed since those assessments, said Elias Hinckley, an energy finance attorney at Kilpatrick Townsend who follows the ERCOT market and the factors that affect it. Energy prices in ERCOT "remain pretty soft" due to still-low natural gas prices, he said, and even newer coal-fired units have found it difficult to compete. Market dynamics also have challenged the coal units Luminant Energy brought online in 2010, he said.

Daily CSAPR allowance assessments, May 1

CSAPR ($/st)	2013 Range	Mid	2014 Range	Mid
SO_2 Group 1	5.00-35.00	20.00	5.00-25.00	15.00
SO_2 Group 2	25.00-75.00	50.00	25.00-65.00	45.00
NOx Annual	40.00-70.00	55.00	30.00-70.00	50.00
NOx Seasonal	20.00-90.00	55.00	20.00-80.00	50.00

All prices in $/st

Daily CAIR allowance assessments, May 1

	$/allowance	Change	$/st
SO2 2013	0.72	0.00	1.44

For methodology, visit www.emissions.platts.com. Full coverage of SO2 and NOx emissions markets now appears in Platts Coal Trader. For information on Coal Trader, contact support@platts.com or call 1-800-PLATTS-8.

RGGI carbon allowance futures, Apr 30 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.52	0	Dec13	1.97	0
Dec13 V11	3.45	0	Dec14	1.97	0
Dec13 V12	3.42	0			
Dec13 V13	3.55	245			
Dec14 V10	3.52	0			
Dec14 V11	3.45	0			
Dec14 V12	3.45	0			
Dec14 V13	3.55	0			
Dec15 V10	3.52	0			
Dec15 V11	3.45	0			
Dec15 V12	3.45	0			
Dec15 V13	3.55	0			

The Regional Greenhouse Gas Initiative is a carbon cap-and-trade program for power generators in nine Northeast and Mid-Atlantic US states. One RGGI allowance is equivalent to one short ton of CO2. The volume listed is the number of futures contracts traded. Each futures contract represents 1,000 RGGI allowances.

Hinckley noted, however, that the "tight" economics facing Sandy Creek and other coal units would ease considerable if gas prices continue rising.

Sandy Creek is joining the ERCOT market as the region faces a supply-challenged summer. ERCOT said in the Seasonal Assessment of Resource Adequacy report it released Wednesday that it expects "tight reserves this summer" and that there is "a significant chance that ERCOT will need to declare an Energy Emergency Alert … and issue corresponding public appeals for conservation." It noted that Sandy Creek is the only fossil-fired addition to the grid for the summer season.

Spokesmen for LS Power and Brazos did not respond to several requests for comment. LCRA spokeswoman Jennifer Glynn Schattle confirmed that Sandy Creek will be online soon, and noted that last summer LCRA purchased "short-term power last summer to cover the gap" created by Sandy Creek's start-up delay.

— Housley Carr

Exelon nuclear fleet sets Q1 generation record

Exelon's 17-unit nuclear fleet, the largest in the US, set a fleet record for first-quarter generation, President and CEO Christopher Crane said in an earnings call Wednesday.

Nuclear generation output of 36,031 GWh exceeded its previous high in first-quarter 2007 by about 575 GWh, Crane said.

First-quarter 2012 nuclear generation was 35,262 GWh, Exelon said in its earnings release Wednesday.

The fleet also achieved an "excellent" capacity factor of 96.4% in the first quarter, the fourth-best quarterly capacity factor in Exelon's history, Crane said. That compares with a 93.6% capacity factor in first-quarter 2012, he said.

Crane did not say why output and capacity factor were so high, but much of it was due to 28 fewer outage days than in the same period last year. The fleet had 49 refueling outage days and 6 non-refueling outage days during the quarter, compared with 67 refueling outage days and 16 non-refueling outage days a year ago, Exelon said.

Exelon also said the dispatch match rate for its generation business' fossil and hydro fleet was 98.4% in the first quarter, compared with 87.8% in the year-ago period. The 2013 results include former Constellation Energy plants and Exelon hydro plants, while the 2012 data includes only legacy Exelon fossil plants.

The performance in 2012 was driven by an outage at one of the peaking units in Texas. Energy capture for the wind and solar fleet was 94.9% in the first quarter, compared with 94.4% in Q1 2012, the company added.

Exelon said "forward power [prices] increased during the [first] quarter in nearly all regions. The Midwest and Mid-Atlantic saw increases of $2 per MWh or more, driven by expanding heat rates and increasing natural gas prices."

Capital expenditures for nuclear units are expected to be $150 million lower than prior estimates in 2013, due in part to cancellation of power uprate projects for Dresden and Quad Cities facilities, the company said.

Exelon said it is "projecting to end the year in a strong cash position with $1.35 billion, the majority of which will be held" at Exelon Generation, which operates the nuclear fleet.

— Steven Dolley

Cal-ISO pegs EIM implementation at $18.3 million

The total cost estimate for implementing the energy imbalance market proposed by the California Independent System Operator and PacifiCorp is $18.3 million, the ISO told the Federal Energy Regulatory Commission on Tuesday.

That cost will be borne by EIM participants, the ISO said, asking FERC to "accept the implementation agreement effective July 1, 2013, so the extension of the real-time energy market to include PacifiCorp's participation in the energy imbalance market may proceed without delay" (Docket No. ER13-1372.)

PacifiCorp agreed in a February 12 memorandum of understanding with the ISO to pay a fixed implementation fee, which the filing at FERC reiterates is $2.1 million.

"The implementation fee is based on the ISO's estimate of the costs it will incur to configure its real-time energy market to function as an energy imbalance market available to all balancing authority areas" in the Western Electricity Coordinating Council," according to the filing.

"Using this estimate, the ISO derived a rate that allocates the $18.3 million to potential entrants into the energy imbalance market according to their proportionate share of the total WECC load," the ISO said.

The fee "is based on the ISO's estimate of the start-up cost of implementing an energy imbalance market that could ultimately accommodate the entire [WECC] should the WECC utilities all choose to participate," said Michael Epstein, the ISO's director of financial planning, in the filing to FERC.

The $18.3 million would be incurred incrementally, rather than upfront, "as the imbalance energy activity from additional balancing authority areas is incorporated into the market," Epstein explained.

The annual estimated benefits of the EIM is $21 million to $129 million, according to a report commissioned for the ISO and the utility. The market is scheduled to launch in October 2014, according to the MOU.

Included in the estimated $18.3 million in EIM implementation costs are ISO system improvements, hardware and software upgrades, licenses and training.

The $2.1 million fee is "is just and reasonable because it allocates a portion of the overall cost to PacifiCorp in an amount proportionate to PacifiCorp's share of the benefits that will ensue from the energy imbalance market," the ISO said.

Comments to FERC on the EIM agreement are due on May 21.

— Martin Coyne

PJM, JP Morgan clash over compensation

JP Morgan Ventures Energy and PJM Interconnection are clashing over how the company will be compensated after losing its authority to sell power at market-based rates for six months. .

That includes whether the Federal Energy Regulatory Commission should require ISOs to amend their tariffs to address the issue.

The dispute centers on the level of compensation JP Morgan should receive after its suspension began April 1. FERC suspended JP Morgan's authority in November after determining that the company submitted false information to the California Independent System Operator and FERC during an investigation of the company's activities.

In the November order, FERC said JP Morgan could only participate in wholesale electricity markets by "either scheduling quantities of energy products without an associated price or by specifying a zero-price in their offer," and that the rate the company would receive "will be capped at the higher of the applicable locational marginal price or its default energy bid." FERC at the time said that it had "previously accepted the default energy bid as a reasonable opportunity to recover costs."

FERC on March 19 approved changes to Cal-ISO's tariff, outlining how JP Morgan and other entities that lose market-based rate authority but that want to participate in the region's markets would operate during such time (Docket No. ER13-872). It also approved JP Morgan's plan for handling the suspension.

But in an April 10 filing with FERC (Docket Nos. ER13-830, EL13-58), JP Morgan argued broadly that PJM and the Midcontinent Independent System Operator "have failed to make any changes to implement the commission's orders. Consequently, if their current tariffs prohibit them from complying with the commission's orders, those tariffs are unjust and unreasonable and must be modified to be made just and reasonable." MISO on April 26 changed its name to reflect its broader membership.

JP Morgan said PJM's suggestion in previous filings that the company's "offers be capped at $0/MWh and its payments capped at the applicable LMP" is inconsistent with FERC's orders and confiscatory. "Under the approach advocated by PJM and the PJM Market Monitor, [JP Morgan] could be dispatched at any LMP of $0/MWh or above. This makes it significantly more likely that [JP Morgan] could be required to supply energy at a price below its marginal costs. It therefore significantly increases the potential amount of losses that [JP Morgan] could be required to incur," the company said.

PJM contended that JP Morgan "mischaracterized" FERC's March 19 order. While JP Morgan said that FERC's order provides that payments "would be capped at the higher of the applicable LMP or the cost-based equivalent of the default energy bid," PJM noted that FERC's suspension order contained no mention of a "cost-based equivalent," but instead referred specifically to the "default energy bid."

"The distinction is important because, unlike the [Cal-ISO] tariff, PJM's tariff does not have a 'default energy bid' construct, and [JP Morgan's] wordplay does not create such a construct out of thin air," PJM said in the April 26 filing.

PJM called its tariff just and reasonable, reiterating that JP Morgan was required to respond to the suspension order and that JP Morgan "cannot unilaterally force a compliance obligation on PJM where none exists."

Said PJM, "More importantly, just as the tariff was just and reasonable prior to the suspension order, it remains just and reasonable now." going on to say that if JP Morgan or another market participant "were to submit a $0 offer, and yet be compensated at the higher of LMP or costs, other market participants would be forced to pay uplift charges when costs are higher than LMP. That result would be unjust and unreasonable, and PJM will not act for the benefit of [JP Morgan] at the expense of other PJM market participants."

MISO apparently did not file a response to JP Morgan's filing by the April 26 deadline. A spokesman for MISO did not respond to a request to comment by press time.

— Bobby McMahon

Coal could gain from rising gas prices: Barclays

Coal prices, which have been resilient despite power generators switching to natural gas, could be poised to rally as gas prices strengthen and power demand grows, according to a Tuesday report from Barclays Commodities Research.

Aggregate coal shipments sank by a heat-rate-adjusted gas equivalent volume of 6.4 Bcf/d last year, and the delivered cost of coal dropped 3% from 2011 to 2012, the report said. However, average coal prices were actually 7% higher than in 2008.

While coal displacement responds to prices, it does so "with a slight lag," the report explained.

With gas prices having more than doubled from a year ago to trade well above $4/MMBtu, "there is a large amount of coal demand to be gained and gas demand to be lost," Barclays said.

Multiple cold snaps covering wide swaths of the US toward the end of the 2012-13 winter drove gas storage inventories sharply lower and prices sharply higher.

Barclays asserted that for gas inventories to rebuild comfortably by October, prices would need to rise enough to reduce gas consumption in power generation during the peak cooling season.

"If temperatures average in line with historical norms for the rest of the injection season, current forward prices may have run ahead of fundamentals," the report said.

Barclays noted that power plant data shows coal-fired generation flexibility is more limited than it had expected. For instance, some plants were forced to operate despite negative economics due to transmission and reliability constraints.

Also, many power generators were unable to reduce coal deliveries to match a drop in economically viable coal-fired generation requirements, and coal inventories swelled beyond comfortable levels, forcing some units to operate at negative margins, the report said. These factors could be providing price support for coal.

Delivered coal prices "appear to be exceptionally resilient" to the drop in consumption at power plants, Barclays said.

"One might expect coal deliveries priced at $3/MMBtu equivalent or more to drop the most as coal-to-gas displacement eats into the coal supply stack. However, the data show that the largest declines took place for coal deliveries priced below $2/MMBtu," the report said.

Barclays said this shows the declines in coal consumption are not a reflection of coal-to-gas displacement dynamics but are instead a reflection of structural coal price trends.

Over the past four years, coal shipments have dropped by a gas equivalent volume of 13.6 Bcf/d (heat-rate adjusted), with nearly half of that decline taking place in 2012.

Compared with a 1.1% drop in overall power loads between 2011 and 2012, coal-fired generation fell 12.5% during that time, a decline comparable to the one seen during the economic slowdown of 2009.

Between 2011 and 2012, Appalachian coal saw the largest declines with deliveries dropping 3.4 Bcf/d in heat-rate adjusted gas equivalent volume. Within that region, Central Appalachian coal took the largest hit, dropping 2.7 Bcf/d year-over-year.

Southern and Northern Powder River Basin coal saw an unprecedented drop in deliveries of about 2.2 Bcf/d year-on-year during the same time, Barclays said.

Given current gas prices, the analysts expect Power River Basin coal-fired generation could return to 2011 levels, effectively a 2.2 Bcf/d gas equivalent. Similarly, Appalachian coal could see a boost of 3.4 Bcf/d equivalent compared with last year.

"We believe that the full effect of prices recovering from the Q1 average of $3.48[/MMBtu] to the current levels of $4.26[/MMBtu] for Q2 and $4.42[/MMBtu] for Q3 on coal-to-gas displacement has not yet been felt in the balances."

— *T.L. Hamilton*

Few dealers prepared for cleared swaps: Analyst

Few brokers appear ready to manage real-time cleared commodity swaps just over a month before mandatory clearing takes effect for most dealers, a Tabb Group analyst said Wednesday.

"As clearinghouses become the counterparties to standardized derivatives from here on, the buy side will have to adopt a new workflow for managing swaps portfolios," Will Rhode said in a report.

The need to transfer trades across multiple parties including executing brokers, futures commission merchants and derivatives clearing organizations is a "booking and communication exercise that requires efficient systems and infrastructure," Rhode said.

As a result of the changes, buy-side firms "will put down the phone, close their Excel spreadsheets and start thinking in terms of systems that can communicate FIXml and FpML files containing detailed, machine-readable trade and position information," he said, adding that "that is the reality of trading swaps in the new world of central clearing."

As part of the Dodd-Frank Wall Street Reform and Consumer Protection Act, the Commodity Futures Trading Commission issued final rules for mandatory clearing of previously over-the-counter traded swaps. Some categories of dealers had to comply by March 11 while others, including commodity pools and private funds, must comply beginning June 10.

Readiness for managing cleared swaps has direct financial implications, Rhode said, and "a single mistake in coding or trade detail could mean that the clearinghouse fails to recognize a trade that has been placed to offset another.

"As a result, the clearinghouse will demand an additional margin charge for the new trade in addition to the charge for the trade that should have netted out," Rhode said. "This entirely negates the benefits of portfolio margining at the clearinghouse."

Many dealers may not have the operational capacity to deal with multiple client requests to transition bilateral swaps as Phase 2 of the clearing mandate goes into effect on June 10, Rhode said. According to the Dodd-Frank rules, Phase 2 mandates that commodity pools and private funds must comply with the clearing requirement.

Through the Dodd-Frank mandates, the CFTC aimed to eliminate dealer counterparty risk via the central clearing mandate. "In truth, buy-side firms will nevertheless face some level of credit risk to their clearing brokers, since they will manage margin on their client's behalf into the clearinghouse," Rhode said.

"In the event of an FCM default, a buy-side firm may not be able to recoup margin balances," he said. "To minimize this, a fund will spread its portfolio across multiple FCMs and, in the process, 'rebalance' or port its swap positions from one FCM to another in order to diversify the risk of rejected trades or unexpected margin calls."

Such need to transfer trades across multiple parties is a major challenge, Rhode said, adding that another hurdle involves the real-time regime of clearing.

"Once the buy-side clearing mandate goes live in June, DCOs, FCMs and clearing brokers must be able to accept trades for clearing within one minute of execution," Rhode said.

Clearing members are required to "pre-screen orders and to accept or reject trades on the firm's behalf within the 60-second window and mandates merchants and clearing organizations to quickly communicate information about accepted or rejected trades," Rhode said.

Both Dodd-Frank and International Organization of Securities Commissions (IOSCO) mandates, as well as matter of convenience "will push buy side firms to transfer all swaps into cleared space," Rhode said.

"It is only a matter of time before today's universe of clearable swaps cease to trade bilaterally altogether," he said. "The buy side will quickly tire of running two books on two systems and will look to migrate its clearable swaps portfolios, with both old and new trades, entirely into clearing."

— *Anastasia Gnezditskaia*

RFP winners expected to be unveiled in July: PGE

Portland General Electric expects to announce the winning bidders of several pending solicitations by July, Jim Piro, PGE president and CEO, said Wednesday during an earnings conference call with analysts.

“Negotiations are going well and we should be able to announce the winning bidders [in the second quarter],” Piro said. The negotiations could result in power purchase agreements or utility-owned projects, Piro said.

Last year, PGE, based in Portland, Oregon, issued requests for proposals for various types of resources. The utility is in negotiations for 300 MW to 500 MW of baseload energy resources. Also, PGE is negotiating PPAs for seasonal peaking resources and proposals for 100 average MW of renewable resources.

An independent evaluator hired by the Oregon Public Utility Commission is overseeing the solicitation process.

“We're pleased the [IE] ... confirmed the RFPs were conducted in a fair, unbiased and transparent manner,” Piro said. Some power developers, however, believe that the utility has tilted the process in favor of self-build projects.

PGE named itself as the winning bidder for peaking capacity. As a result, the utility expects to break ground this month on a 220-MW, natural gas-fired peaking unit, Piro said. PGE expects the Port Westward Unit Unit 2 to start operating in early 2015, Piro said.

One issue that may weigh against PGE taking on PPAs is “imputed debt,” the practice of ratings agencies to count purchased power contracts as a form of debt. The issue is a concern, Piro said, noting that the utility may need to increase its equity ratios if PPAs are added. “We're looking at that pretty closely.”

PGE's short-term outlook for power sales is not as strong as expected. The company expects sales growth to be at the low end of its 0.5% to 1% 2013 growth forecast offered three months ago.

PGE's total electric sales fell 1.3% in the first quarter to 5.04 million MWh from 5.1 million MWh a year ago. Residential sales fell 1.3% to 2.23 million MWh and commercial sales dropped 2.8% to 1.79 million MWh. Industrial sales increased 1.8% to 1.02 million MWh in the first quarter. After adjusting the results for weather and Leap Year, sales were flat in in the quarter, according to Piro.

Piro said he sees the weak sales results as “a small blip on the curve.” In general, PGE expects growth to increase across the Northwest in the coming years, he said.

Various factors weigh on sales, according to Piro. “The economy is still relatively fragile,” he said. “People are being relatively conservative. People have instituted efficiency measures.”

The sluggish sales do not affect PGE long-range need for increased transmission capacity to serve customers, according to Piro. “Our current view is it's better to [build transmission] now than wait until the last minute,” Piro said, noting that power line projects take years to develop.

PGE and the Bonneville Power Administration are studying iterations for a modified Cascades Crossing project, which would have about 2,600 MW of capacity. PGE expects the scope of the project, which is subject to working out an agreement with BPA, to be clearer by year’s end.

— Ethan Howland

Virginia AG concerned about AEP transfer

The Virginia attorney general and others are not convinced that the transfer of coal-fired generation owned by Ohio Power to Appalachian Power, a sister utility owned by American Electric Power, is the lowest cost alternative to meet utility’s energy and capacity demands.

The Federal Energy Regulatory Commission this week determined that the transfer of two-thirds ownership, or 867 MW, of the John Amos Unit 3, to Appalachian Power, and an equal split in ownership of the 1,600 MW Mitchell plant located in West Virginia between Appalachian Power and Kentucky Power would have no effect on wholesale rates or transmission rates.

The proposed transfers would cost Appalachian Power $1.2 billion or about $700/kW, Jeri Matheney, an Appalachian Power spokeswoman, said.

The utility has not solicited offers or attempted to identify possible market based alternatives to the purchase of the Ohio Power assets, Scott Norwood, president of Norwood Energy Consulting, said in testimony filed last week at the State Corporation Commission on behalf of the consumer counsel, which is part of the Virginia attorney general's office.

“So [Appalachian Power] does not really know whether there may have been other suppliers who were willing to sell power from existing or new generation projects at a lower cost than the proposed asset transfers from Appalachian Power’s affiliate,” Norwood said.

Appalachian Power’s analysis of the transfer includes a number of unreasonable assumptions, including overly optimistic performance assumptions, a very long assumed life for the coal units and assumptions regarding the sale of excess coal-fired energy and capacity from the units that may not materialize, Norwood said.

Norwood also had concerns about the ownership risks associated with older coal plants, the reduction in the company’s fuel diversity and the lack of evidence regarding the market value of the generation units.

“I have serious unresolved questions as to whether the generating assets transfers represent the best alternative for supplying Appalachian Power’s future capacity and energy requirements,” Norwood said.

More alternatives should have been analyzed to assess the effect of lower natural gas price forecasts, Stephen Baron, president of Kennedy and Associates, a utility consultant, said in testimony submitted on behalf of the Old Dominion Committee for Fair Utility Rates.

Appalachian Power looked at the benefit of the generation transfer under high and low natural gas expectations, but the analysis was based on the 2011 price forecast from the US Energy Information Administration’s Annual Energy Outlook, Baron said. The agency’s 2013 natural gas price forecast is much lower than the 2011 forecast, he said. “Clearly, there is a substantial risk that the economic benefits claimed by Appalachian power from the asset transfer may not materialize,” Baron said.

The utility also has presented little analysis of the potential effect additional clean air or climate change regulations would have on the generation transfer, Baron said.

Appalachian Power’s generating capacity is nearly 70% coal-fired, which puts it at significant risk from new environmental or climate regulations, Baron said. The utility modeled for the implementation of a carbon dioxide tax beginning in 2022, but whether the assumptions were too low is a risk, he said.

Competitive Power Ventures, which has plans to build a 700 MW gas-fired plant in Smyth County, Virginia, recommended that the SCC require Appalachian Power to purchase capacity and energy from the PJM Interconnection market over the next three years while it further studies its long-term resource options.

CPV also recommended that the SCC require the utility to issue a request for proposals to identify market-based alternatives and have the solicitation overseen by the SCC staff since Appalachian Power and AEP “likely have a preference” for transferring the units rather than choosing a lower-cost option.

The utility will file its rebuttal testimony on May 21 and the SCC will hold a hearing on the issue beginning June 4, Ken Schrad, an SCC spokesman, said.

Todd Burns, an Appalachian Power spokesman in Virginia, said the company would respond to the testimony from CPV, the consumer counsel and the committee for fair utility rates in its rebuttal.

FERC on Tuesday also approved the transfer of about 9,000 MW owned by Ohio Power to a new competitive generation company, AEP Generation Resources. It also approved the merger of Wheeling Power in West Virginia and Appalachian Power as well.

“We will continue to work with regulators in Kentucky, Virginia and West Virginia to seek the additional approvals necessary to transfer ownership of the Mitchell plant and the AEP Ohio-owned share of the Amos plant to Appalachian Power and Kentucky Power to help satisfy their existing and long-term generation requirements,” Nicholas Akins, AEP’s president and CEO said in a statement.

Testimony in the West Virginia proceeding on the transfers is due June 18 and the Public Service Commission has scheduled a hearing beginning July 16.

— Mary Powers

MISO, stakeholders discuss futures development

The Midcontinent Independent System Operator is collaborating with stakeholders in its Southern footprint to create long-range forecasts for future grid design scenarios.

MISO on April 26 changed its name to reflect its broader membership.

MISO representatives met with its Southern footprint entities, including representatives from Entergy, the Public Utility Commission of Texas, Cleco, Mississippi Public Service Commission, Excel Energy and others during an all-day transmission planning workshop in New Orleans Tuesday.

"We want to develop these futures … with all of the stakeholders in the Southern region," said MISO Manager of Resource Forecasting Digaunto Chatterjee, adding the scenarios should encompass different futures. " We just want to make sure we're all on the same page."

The scenarios should look at where power flows, where load is growing and where generation is added in order to help with power grid "robustness," Chatterjee said.

"The objective of value-based planning is to develop the most robust plan under a variety of scenarios, not the least-cost plan under a single scenario," according to Chatterjee's presentation.

Planners do not want to "put all our eggs in one area," Chatterjee said. The goal is to achieve minimum total costs for energy, capacity and transmission.

"If you know where your generation is going you can build your transmission and if you know where your transmission is going you can build your generation," Chatterjee said.

Unlike its Midwest footprint, which is heavy on coal-fired power (47%), MISO's Southern footprint has mostly natural gas-fired generation.

"There's a lot of gas issues in the South we didn't have in the Midwest," said John Lawhorn, a senior director of regulatory and economic studies.

Natural gas makes up 69% (32,624 MW) of the MISO Southern footprint's generation mix, followed by coal at 18% (8,622 MW), nuclear with 11% (5,304 MW) and hydro at 2% (731 MW).

"I don't care where the unit is located, specifically. I'm concerned with the overall economic impact on the fleet," said MISO's Jameson Smith, a manager of regulatory studies.

The planning reserve margin for the MISO Southern region is 14.2%, the same as its Midwest region.

"We want to make sure we are at least considering the extremes," Smith said.

The goal is to identify near-term congestion issues and longer-term economic opportunities along with developing transmission solutions from a holistic viewpoint.

Tuesday's workshop was the first step in a seven-step process for the Southern part of the MISO Transmission Extension Plan 2014. The analysis will cover a 20-year period through 2032. Models will be developed for five-year increments, and all models will be used to perform multi-year cost/benefit calculations, according to the presentation.

Stakeholder meetings to develop additional future scenarios will take place through May. In May and June, MISO will perform regional resource forecasts so that in July and August it can develop economic models. Economic studies will take place from August through May 2014.

The analyses may lead to transmission project recommendations for MISO board of directors' approval in December 2014, Chatterjee said, as well as the determination of economic opportunities or ideas for further analyses.

— Kassia Micek

EIA seen estimating 28-32 Bcf storage build

A consensus of analysts expect the Energy Information Administration Thursday to estimate a natural gas storage injection between 28 and 32 Bcf for the reporting week that ended Friday.

A stock build within those expectations would be roughly equal to a 31-Bcf injection seen during the comparable week last year, yet below the five-year-average injection of 67 Bcf, according to EIA data. As a result, the 804-Bcf deficit to last year should stay about the same while the 94-Bcf deficit to the five-year average should expand.

The wider range of analyst expectations spanned from injections of between 24 and 36 Bcf.

EIA estimated a 30-Bcf build for the week that ended April 19, increasing overall stocks to 1.734 Bcf.

Bentek Energy's supply/demand model predicts an injection of 32 Bcf for the week that ended Friday, while its pipeline flow model anticipates an addition to stocks of 31 Bcf. Bentek is a unit of Platts.

Jefferies & Co. analyst Subash Chandra, whose estimate of a 32-Bcf injection is near the higher end of the range, said heating degree-days "were once again unseasonably high at 104, which is 27 above normal" and "gas prices are likely to remain supported on this week's injection number."

Yet for next week, Chandra said a much bigger injection, 95 Bcf, is expected as heating degree-days will fall to 36, which is 26 below normal. Such an injection "could break the gas rally," Chandra added.

Analysts with PIRA Energy Group said "the still-stubbornly large year-on-year gas storage deficit has propelled Henry Hub cash prices markedly higher over the last month or so."

Going forward, there is an upside price risk on "protracted net

US supply declines, coupled with non-electricity generation demand growth," PIRA said.

— Anastasia Gnezditskaia

Coal's share of PJM fuel mix remains strong

Coal-fired generation is continuing to claw back its market share in the PJM Interconnection in 2013, recent data from the grid operator shows.

Coal-fired generation supplied about 45% of the PJM Interconnection's generation fuel mix in March, about flat to its contribution in February.

However, coal's share of PJM's fuel mix is up compared with March 2012 when it was around 37%.

PJM's fuel mix for March is the most recent data available.

Natural gas-fired generation was down slightly month to month, contributing about 15% in March, compared with about 16% in February.

However, this amount is down about five percentage points compared with March of last year.

Nuclear generation contributed about 36% in the generation mix, about one percentage point higher than last month, but about one percentage point lower than March 2012.

Wind generation within PJM was steady around 2% of the fuel mix in March, flat to February 2013 and March 2012.

Hydro generation was also holding nearly flat around 1%.

Other sources of generation, which include sources such as biomass and solid waste, contributed around 1% in March 2013, about flat to February, but down about one percentage point compared with same time last year.

— Eric Wieser

Utility output falls 1.7% on year in week: EEI

US utilities generated 67,629 GWh in the week that ended Saturday, down 1.7% from 68,831 GWh generated in the corresponding week of 2012, the Edison Electric Institute said Wednesday.

The weekly total was 2,083 GWh below the 69,712 GWh total posted in the week that ended April 20, EEI said.

Output fell in just four of the nine regions EEI assesses, but three of the five increases in generation were of less than 0.6%, it said.

In contrast, the largest percentage decrease — in the South Central region — was 8.6% to 11,062 GWh. The second-largest percentage slide was in the Rocky Mountain region, where output fell 4.9% to 4,387 GWh, according to EEI data.

In five regions where output climbed, the largest percentage increase was in the Pacific Northwest, where output rose 4.4% to 2,694 GWh.

Utility generation in the year-to-date was 1.26 million GWh, up 2.6% from 1.23 million GWh in the same period of 2012, EEI said.

The numbers are based on generation from investor-owned utilities, cooperatives and government-owned utilities.

— Keiron Greenhalgh

Generator challenges may be systemic

...from page 1

Electric Reliability Council of Texas, Dumoulin-Smith said.

Merchants in those markets warrant premium cash flow multiples, while generators in regions and states such as California, New York and New England face more regulatory risk given the uncertainty over how to procure new generation.

The issue of new procurement centers on capacity payments, and there is a wide variety of approaches to incentivizing the building of new generation.

PJM has a fairly well established capacity market. ERCOT has no capacity market but allows prices to move more in step with market forces. But the other the wholesale power markets — California, New York, New England and the Midwest Independent Transmission System Operator — are either looking at adopting or adjusting some form of capacity payment. MISO on April 26 changed its name to Midcontinent Independent System Operator to reflect its broader membership.

Eventually Dumoulin-Smith expects states like New York to pursue a more formulaic approach to procurement along the lines of a traditional integrated resource plan. He sees the current "ad hoc" approach to procurement in New York as less than ideal and argues that a more formal IRP approach could foster wider participation and more regulatory clarity.

That said, Dumoulin-Smith sees a growing problem in contradictory policies from the Federal Energy Regulatory Commission regarding capacity markets. Specifically FERC's denial last year of MISO's request to implement a minimum offer price rule while accepting various "different flavors" of MOPRs in New England, PJM and New York.

But while capacity prices are important, they are not a panacea, Dumoulin-Smith said. They can serve to dampen the volatility associated with power and gas prices and support a break-even cash flow for marginal generators, but they are not necessarily sufficient to provide a return on and of capital.

Hugh Wynne at Bernstein Research, in his report, Seven Reasons Why Competitive Power Generation is an Awful Business, makes a similar point.

"Competitive markets make it clear that you can get capacity more cheaply, but it is still tough to get an adequate return on investment, if you are a merchant generator," he said.

In addition, competition in capacity markets is not limited to the jurisdiction of an RTO, creating an uneven situation where regulated generators in neighboring jurisdictions receive both a regulated rate of return and capacity payments for their electricity. Both Wynne and Dumoulin-Smith say that those capacity exports suppress capacity prices for merchant generators.

To make matters worse, capacity markets have also called forth alternatives to new generation such as demand response that compete with generation for a share of the capacity market, Wynne said.

The status of demand response resources in PJM's capacity auction has become a controversial topic, but it is only one example of the market distortions that are taking place in wholesale markets.

Regulatory goals such as increased penetration of renewable generation have resulted in incentives and subsidies, such as state level renewable portfolio standards, that have suppressed wholesale prices. And new, stricter environmental regulations are imposing capital costs on merchant generators for which they have no recovery mechanism, Wynne said.

In addition, Wynne argued that the planning of investments in competitive generation is more difficult than in other industries. Most other industries have a single production technology, but electricity is produced by a wide range of inputs and technologies, from nuclear and hydroelectric power to wind and solar power. And, because the shape of the power supply curve derives from the cost of three different fuels – uranium, coal and natural gas – as well as capital cost of renewable resources, power price forecasts tend to be wrong.

The UBS and Bernstein reports should be a “wake up call,” for regulators at both the state and federal level, John Shelk, president and CEO of the Electric Power Supply Association, said.

Among the many goals that regulators are weighing, Shelk said the one concern that no one seems to have in mind is whether or not merchant generators are able to earn a sufficient return on investment to provide a sustainable business model.

“I keep asking FERC: Who is the score keeper? We need a system that is consistent with putting private capital to work,” Shelk said.

— Peter Maloney

ERCOT expects tight summer supplies ...from page 1

ERCOT executive advisor who has overseen various aspects of grid operations and system planning for several decades, in a prepared statement.

"To help ensure there is enough generation to serve consumer needs, we likely will ask people to conserve power during the hottest hours of the hottest days," he continued. "If generation outages exceed expected conditions during peak demand periods, or if we see a return of record-breaking conditions like those in 2011, ERCOT also may need to implement energy emergency alert actions, with the possibility of rotating outages if needed to protect the grid."

ERCOT came within 500 MW of declaring an energy emergency alert around 2:30 p.m. Monday, as a large generator tripped offline, bringing the physical reserves capacity below 3,000 MW and causing real-time prices to climb past $300/MWh – topping $480/MWh in the Rayburn Load Zone.

"It wasn't an emergency situation," Saathoff said in a conference call Wednesday. "As reserves decline, prices will go up."

ERCOT expects power demand this summer to peak at 68,383 MW, slightly more than the 68,305 MW all-time record set August 3, 2011.

The amount of generation available is forecast to be 74,438 MW, which is just 8.9% more than the expected peak demand.

The previous summer 2013 SARA, issued March 1, forecasted peak demand at 67,998 MW and total resources at 73,708 MW. The generation capacity expanded partly because of the inclusion of 925 MW of coal-fired generation at the Sandy Creek Energy Station in McLennan County and about 700 MW of new wind generation, while about 256 MW of capacity was derated, mothballed or retired.

These assessments assumed that wind generation could only be depended upon for 8.7% of its nameplate capacity, but a recent Loss-of-Load Expectation Study indicated that a more appropriate number may be 32.9% for coastal wind generation and 14.2% for non-coastal wind generation.

Drought conditions are not expected to create problems for power plants this summer, but some plants may have problems later in the year.

In Wednesday's conference call, ERCOT meteorologist Chris Coleman said the weather forecast for the latest SARA was for slightly less extreme heat, especially in the coastal area, and slightly more precipitation, in comparison with the March 1 SARA.

For the longer term, the CDR forecasts a 13.8% reserve margin for the summer of 2014, up from 10.9% in the previous CDR, issued in December, as the historical average summer weather would result in peak demand of less than 69,800 MW, and generation capacity is expected to hit 77,600 MW, compared with 74,943 MW in the December CDR.

For the following years, the CDR forecasts the reserve margin at 11.6% in 2015, 10.4% in 2016, 10.5% in 2017, 9.4% in 2018, 7.4% in 2019, 6.5% in 2020, 6% in 2021, 5.2% in 2022 and 4.5% in 2023.

In the December CDR, the forecasts were 10.5% in 2015, 8.5% in 2016, 8.4% in 2017, 7.1% in 2018, 5% in 2019, 4.1% in 2020, 3.6% in 2021 and 2.8% in 2022. The December CDR included the summer of 2013 but not the summer of 2023.

"Load growth forecasts become less certain in the longer term," an ERCOT press release states. "Also, available generation capacity only includes resources that have interconnection agreements and any necessary air quality permits in place."

On Thursday, ERCOT's Technical Advisory Committee will consider recommending a change in the target reserve margin from 13.75% to about 16%, and Robbie Searcy, ERCOT spokeswoman, said that recommendation may be forwarded to the ERCOT board of directors for their May 14 meeting.

— Mark Watson

San Onofre could be retired, ...from page 1

Onofre during the first quarter exceeded $500 million. "We're trying to signal it is difficult for us to continue to underwrite cost without clarity on rates and clarity on restart. There's a practical limit to how much we can underwrite," Craver said. San Onofre-1 permanently shut in 1992.

In early April, SoCal Edison voluntarily submitted a license amendment request to the Nuclear Regulatory Commission to support restarting Unit 2 in time for the upcoming summer.

SoCal Edison's plan is to initially operate Unit 2 at 70% for five months. Following that, it would shut down Unit 2 for steam generator tube inspections.

Based on inspection data, Unit 2 would resume operation at 70% for an additional period during the remainder of the 18 – to 24-month fuel cycle while the company updates its analysis to determine the appropriate long-term power level, the utility said.

Meanwhile, the San Onofre outage has contributed to higher gas demand and prices in California.

SoCal Gas spot prices averaged around $4.35/MMBtu Wednesday, up 6 cents from Tuesday, while the SoCal Gas city-gate averaged around $4.53/MMBtu, up about 7 cents from Tuesday.

A regional trader said San Onofre uncertainty likely has already been priced into the spot market, and that with renewables flooding the market in California, the gas forwards may not be as volatile.

Platts forward curve assessments support that notion. The SoCal calendar year 2014, 2015 and 2016 forwards packages did not see basis changes day-over-day, but some skepticism about whether the units will return seems to be baked into the back of the curve.

SoCal's basis package rises from plus 8.5 cents/MMBtu for calendar 2014 to plus 20 cents/MMBtu for calendar 2016, according to Platts forward assessments.

Additionally, SoCal summer package is already averaging some 85 cents higher than the corresponding package last year, indicating market players are already expecting increased gas consumption and higher prices thanks to the outage.

Bentek data shows California and Southwest inflows rising from an average of about 5.23 Bcf/d in 2011 to 6.31 Bcf/d in 2012 and averaging 5.96 Bcf/d year-to-date.

Additionally, the nuclear outage blunted a drop in gas prices in 2012 so that wholesale power prices in the state were only down about 2%, the California Independent System Operator's internal market monitor said in a report in April.

The loss of San Onofre, a key source of grid stability and voltage support in southern California, also boosted transmission constraints, according to the report.

SoCal Edison owns 78.2% of San Onofre, which it operates. San Diego Gas & Electric owns 20% and the city of Riverside, California, utilities the remaining 1.8%.

— Patrick Badgley

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