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Wednesday, May 8, 2013

Companies see benefit in plant refueling option

ANALYSIS

As many as 3,500 MW of coal plants are going to be refueled to burn natural gas instead of being retired, reflecting a decision on the part of the owners to trade off less efficiency for lower costs.

There is generally a loss of efficiency in refueling a plant, but given that the refueled units would be run mostly to meet peak demand, owners are looking for the loss of efficiency and cost of conversion to be offset by higher power prices during peak periods or by a bigger window in which the converted plant could operate.

In some locations, the refueled units could also earn revenues from capacity payments. In those instances, the availability of those units could dampen expectations of higher capacity prices as a result of coal units being retired.

The bottom line is that coal plants refueled to burn natural gas

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FERC approves PJM, MISO congestion plan

MARKETS

Federal energy regulators have approved changes to the PJM Interconnection and Midcontinent Independent System Operator's joint operating agreement aimed at improving how the two grid operators calculate congestion settlements between their regions.

The Federal Energy Regulatory Commission, in separate Monday orders (Docket Nos. ER13-1054, ER13-1052), approved proposals by PJM and MISO, formerly known as the Midwest Independent Transmission System Operator, to change the methodology with which market-to-market settlements are calculated and to include energy imports when calculating market flows. The orders have an effective date of June 18, 2013.

PJM and MISO in filings said that the changes will improve

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Solicitation for line gets strong response

TRANSMISSION

The developer of the Grand Isle Intertie, a 400-MW transmission line proposed between New York and New England, has received responses in excess of the line's capacity from its April 12 solicitation.

Both energy suppliers and load-serving entities in New England responded to the solicitation, according to Anbaric Transmission, project developer. Anbaric did not name the bidders that responded to the solicitation.

With phase 1 of the solicitation now finished, Anbaric is moving to phase 2 — allocation of the line's Transmission Scheduling Rights or TSRs.

The solicitation follows new guidance released earlier this year by the Federal Energy Regulatory Commission for open solicitations by new merchant and participant-funded

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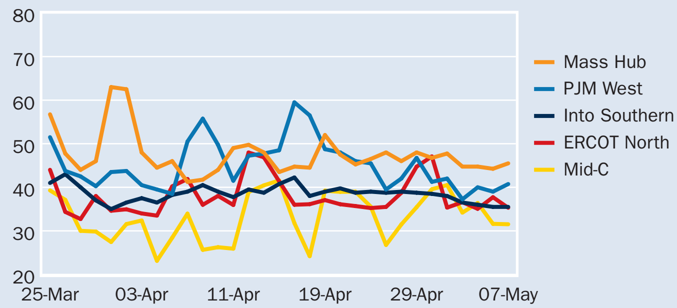
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for May 8 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	46.14	50.33	32.01	32.79
NYISO	42.50	62.72	30.16	35.27
PJM	37.66	52.58	23.02	30.27
MISO	42.85	43.82	25.40	30.50
ERCOT	33.24	48.23	19.14	24.86
CAISO	36.58	42.41	27.48	31.91

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 8

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	45.50	10866	16.19	12.00	3.63	-4.75	-17.31
N.Y. Zone-A	50.00	12320	21.59	17.53	9.42	1.30	-10.88
PJM/MISO							
PJM West	40.75	10435	13.42	9.51	1.70	-6.11	-17.83
Indiana Hub	44.00	11097	16.25	12.28	4.35	-3.58	-15.48
Southeast & Central							
Southern, Into	35.50	9091	8.17	4.26	-3.55	-11.36	-23.08
ERCOT, North	35.30	9235	8.54	4.72	-2.93	-10.57	-22.04
West							
Mid-C	31.52	8439	5.38	1.64	-5.83	-13.30	-24.51
SP15	47.75	12181	20.31	16.39	8.55	0.71	-11.05

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 as spot gas dips

Daily power prices in the Northeast were mixed Tuesday as spot natural gas prices dipped. Forward power prices also were mixed, while the NYMEX June natural gas futures contract settled 9.1 cents lower on Tuesday, at $3.920/MMBtu.

In the spot natural gas market, Algonquin city-gates traded around $4.20/MMBtu, down about 4 cents, while Tennessee Zone 6 gave up about 2 cents, settling around $4.19/MMBtu and Transco Zone 6 New York shed about 2 cents, to around $4.04/MMBtu.

Boston was expected to see high temperatures on Wednesday around 64, with lows around 55.

ISO New England projected peak load on Tuesday around 15,160 MW and 15,290 MW for Wednesday.

Mass Hub on-peak gained about $1 in the mid-$40s/MWh. Mass Hub off-peak climbed about $1 to the low $30s/MWh.

New York State was forecasted to see high temperatures on Wednesday in the mid-60s to low 70s, and lows in the 50s.

The New York Independent System Operator projected peak load on Tuesday around 18,742 MW and 18,519 MW for Wednesday.

New York Zone A on-peak for Wednesday fell about $5, to the upper $40s/MWh, while Zone G on-peak increased by about $2, to upper $40s/MWh.

Day-ahead prices in the ISO-NE auction were mosty down Tuesday, even as demand was expected higher Wednesday, with Internal Hub peak prices falling nearly $2.50 to about $47.10/MWh and off-peak edging down 65 cents to about $32.49/MWh.

Coming in as the highest price was Rhode Island peak, which bucked the losing trend and edged up about 36 cents to about $50.33/MWh, while off-peak slipped about $1 to around $32.35/MWh. Connecticut peak, which previously was the highest, fell $2.86 to about $47.85/MWh and off-peak was off 78 cents to about $32.75/MWh.

Maine peak came in as the lowest price, at around $46.14/MWh, a decrease of about $1.83, while off-peak lost 31 cents to about $32/MWh.

Day-ahead auction prices for Wednesday in NYISO were mostly higher Tuesday. West peak prices were down about $1.42, but remained strong in the low $50s/MWh as loads in the West were above forecast levels on Monday and Tuesday.

Long Island peak jumped the most on the day, gaining $7.83 to about $62.72/MWh, while off-peak edged down 16 cents to about $35.27/MWh.

North peak moved up almost $5.50, to about $42.50/MWh and off-peak added over $1 to about $30.30/MWh. Hudson Valley peak was up about $1.88, to around $49.50/MWh and off-peak climbed nearly $1 to about $33.50/MWh.

New York City peak and off-peak both added over $1 to about $50/MWh and about $33.50/MWh, respectively.

Northeast term power was mixed Tuesday as June NYMEX gas futures fell 7.7 cents, trading at about $3.934/MMBtu.

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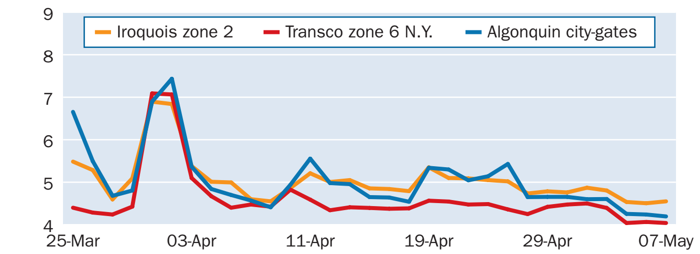
Northeast day-ahead bilateral indexes for May 8 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	45.50	1.25	45.63	10866
N.Y. Zone-G	49.50	2.00	47.08	11525
N.Y. Zone-J	50.00	1.00	49.29	11641
N.Y. Zone-A	50.00	-3.25	44.54	12320
Ontario*	30.00	3.00	28.29	6861
Off-Peak				
Mass Hub	33.00	1.00	33.88	7881
N.Y. Zone-G	33.50	1.00	33.79	7800
N.Y. Zone-J	33.50	1.00	33.88	7800
N.Y. Zone-A	30.25	0.75	30.75	7454
Ontario*	16.50	-1.00	17.96	3773

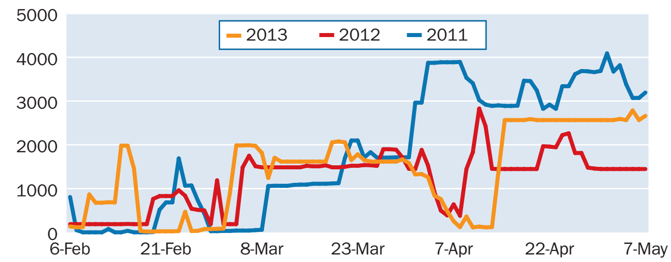
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO nuclear generation outages (GW)



Source: NRC

Northeast load and generation mix forecast (GWh)

	Actual 06-May	%Chg	% Chg Year-ago	Forecast 07-May	08-May	09-May	10-May	11-May
ISONE								
Load	313	14	3	348	335	325	326	296
Generation								
Coal	5	93	39	6	3	2	3	2
Gas	137	4	-12	167	161	155	151	145
Nuclear	65	0	-7	65	65	65	65	65
NYISO								
Load	396	13	3	436	421	417	416	378
Generation								
Coal	9	41	82	12	8	5	5	5
Gas	126	23	-11	151	144	134	128	123
Nuclear	119	5	7	117	119	119	119	119

Source: Bentek

ISONE day-ahead LMP for May 8 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	47.10	-0.39	-0.03	-2.49	45.54	11228
Connecticut	47.85	-0.39	0.72	-2.86	46.11	10958
NE Mass-Boston	46.90	-0.39	-0.23	-2.61	45.45	11180
SE Mass	47.23	0.44	-0.73	-1.96	45.77	11258
West-Central Mass	47.52	-0.39	0.39	-2.50	45.87	11326
Rhode Island	50.33	3.88	-1.07	0.36	48.12	11997
Maine	46.14	-0.39	-0.99	-1.83	45.06	10278
New Hampshire	47.86	-0.39	0.73	-2.42	46.13	10661
Vermont	47.51	-0.39	0.38	-2.48	45.62	10584
Off-Peak						
Internal Hub	32.49	-0.03	0.00	-0.65	32.00	7685
Connecticut	32.75	-0.03	0.26	-0.78	32.15	7506
NE Mass-Boston	32.44	-0.03	-0.05	-0.62	31.95	7674
SE Mass	32.20	0.04	-0.35	-0.80	32.09	7618
West-Central Mass	32.79	-0.03	0.30	-0.58	32.19	7757
Rhode Island	32.35	0.32	-0.49	-0.99	33.16	7653
Maine	32.01	-0.03	-0.48	-0.31	31.54	7143
New Hampshire	32.72	-0.03	0.24	-0.58	32.14	7302
Vermont	32.62	-0.03	0.14	-0.58	31.88	7279

NYISO day-ahead LMP for May 8 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	47.08	0.07	2.59	1.69	43.87	10911
Central Zone	45.95	-0.78	0.61	1.57	40.56	11331
Dunwoodie Zone	49.31	0.06	4.81	1.78	45.38	11484
Genesee Zone	43.87	-0.10	-0.79	1.58	38.99	10818
Hudson Valley Zone	49.49	0.06	4.98	1.88	45.53	11525
Long Island Zone	62.72	-12.43	5.73	7.83	55.30	14606
Millwood Zone	49.37	0.06	4.87	1.80	45.37	11498
Mohawk Valley Zone	46.02	-0.12	1.35	2.12	40.86	10958
N.Y.C. Zone	49.90	-0.02	5.32	1.01	47.36	11622
North Zone	42.50	0.03	-2.03	5.47	36.49	9469
West Zone	51.87	-8.34	-1.02	-1.42	43.57	12791
Off-Peak						
Capital Zone	32.46	0.00	1.55	0.99	32.29	7577
Central Zone	30.93	-0.04	-0.02	0.94	30.85	7659
Dunwoodie Zone	33.22	0.00	2.32	1.01	33.05	7751
Genesee Zone	30.20	-0.03	-0.74	0.89	30.22	7478
Hudson Valley Zone	33.49	0.00	2.59	0.92	33.38	7813
Long Island Zone	35.27	-1.29	3.08	-0.16	36.65	8229
Millwood Zone	33.25	0.00	2.35	1.00	33.05	7758
Mohawk Valley Zone	31.74	-0.02	0.81	1.05	31.43	7610
N.Y.C. Zone	33.55	0.00	2.64	1.07	33.30	7827
North Zone	30.30	0.00	-0.60	1.15	29.64	6762
West Zone	30.16	-0.03	-0.77	0.78	30.18	7470

Generation unit outage report

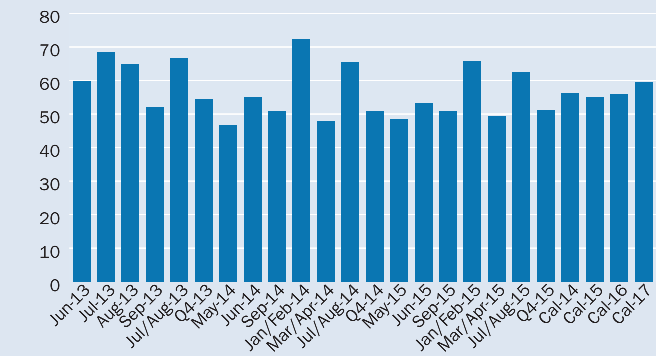
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-1/Bruce Power	750	n	Ont.	PMO	Unk	04/28/13
Bruce-8/Bruce Power	820	n	Ont.	Unk	Unk	05/01/13
Darlington-4/OPG	878	n	Ont.	MO	Unk	05/04/13
Millstone-3/Dominion	1203	n	Conn.	RF	05/24/13	04/13/13
Nine Mile Point-1/CENG	640	n	N.Y.	RF	05/14/13	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	05/11/13	04/14/13
Salem-1/PSEG	1254	n	N.J.	PMO	05/13/13	04/14/13

Northeast Platts-ICE Forward Curve, May 7 ($/MWh)

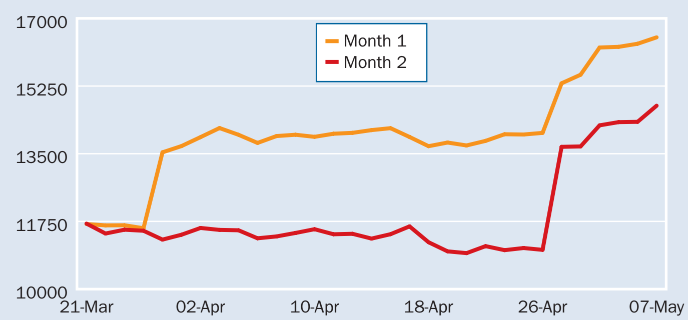
Prompt month: Jun 13	On-peak	Off-peak
Mass Hub	58.25	40.00
N.Y. Zone G	59.75	37.50
N.Y. Zone J	63.75	40.50
N.Y. Zone A	44.75	31.00
Ontario*	37.00	22.00

*Ontario prices are in Canadian dollars

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



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



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Bal-week	05/03	43.25-43.75

*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 weaker despite demand jump

Daily power prices in the Electric Reliability Council of Texas for Wednesday delivery were weaker Tuesday morning, with peak load forecasted to increase and steady spot natural gas prices. The NYMEX June natural gas futures contract settled 9.1 cents lower Tuesday, at $3.920/MMBtu.

ERCOT dailies for Wednesday delivery were down on the IntercontinentalExchange Tuesday, while steady temperatures are forecast. High temperatures across ERCOT's footprint were forecast in the mid-80s Wednesday, with lows in the low 60s. The average May high temperature across ERCOT is in the mid-80s, with the average low in the mid- to upper 60s.

Spot natural gas at Houston Ship Channel was holding around $3.973/MMBtu.

ERCOT North Hub next-day on-peak physical power was bid at $35.25/MWh and offered at $35.50/MWh on ICE, down about $2.25. Off-peak lost nearly $2.50 to trade around $22.75/MWh.

South Hub on-peak was bid at $35/MWh and offered at $37/MWh, a loss of about $2.50.

System load in ERCOT was forecast to peak at 41,600 MW Tuesday and 44,175 MW Wednesday, compared with an actual peak of 36,138 MW Monday.

Real-time prices for ERCOT averaged $22/MWh from 12:15 a.m. to 6 a.m. CDT Tuesday.

Wind generation was forecast to peak at 8,250 MW at midnight CDT Tuesday and 8,425 MW at 1 a.m. CDT Wednesday.

North Hub on-peak balance-of-the-week packages were bid at $36.50/MWh and offered at $37/MWh. Next-week on-peak was bid at $36.30/MWh and offered at $37.50/MWh. Balance-of-the-month on-peak packages were bid at $36.75/MWh and offered at $37.85/MWh.

In the Southeast, dailies for Wednesday delivery were weaker Tuesday morning, with temperatures forecasted to rise. Into Southern next-day on-peak power was bid at $34/MWh and offered at $36.50/MWh, a loss of about 25 cents from Monday prices. Off-peak was steady at $26.50/MWh on ICE.

Spot natural gas at Transco Zone 3 was steady, at about $3.906/MMBtu.

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Southeast & Central day-ahead bilateral indexes for May 8 ($/MWh)

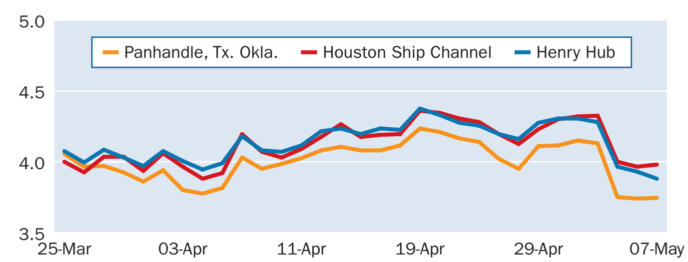
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	36.75	0.25	37.54	9063
Southern, Into	35.50	0.00	36.67	9091
Florida	36.50	0.25	37.54	9335
TVA, Into	37.75	1.00	37.58	9539
Entergy, Into	34.50	0.50	34.96	8990
Southeast Off-Peak				
VACAR	27.50	0.00	27.66	6782
Southern, Into	27.00	0.50	26.91	6914
Florida	27.00	0.50	26.72	6905
TVA, Into	27.00	0.50	27.13	6822
Entergy, Into	23.75	0.50	23.44	6189
ERCOT On-peak				
ERCOT, North	35.30	-2.42	37.85	9235
ERCOT, Houston	36.50	-2.00	38.08	9177
ERCOT, South	36.75	-1.75	38.21	9500
ERCOT, West	35.25	-2.50	34.50	9222
ERCOT Off-Peak				
ERCOT, North	22.79	-2.46	25.96	5962
ERCOT, Houston	23.00	-2.25	25.44	5783
ERCOT, South	23.25	-2.25	25.84	6010
ERCOT, West	19.50	-2.25	17.09	5101
SPP/MRO On-peak				
MAPP, Soth	38.25	0.75	36.88	9808
SPP, North	36.75	0.75	36.08	9813
SPP/MRO Off-Peak				
MAPP, Soth	24.75	0.50	24.22	6346
SPP, North	24.25	0.50	23.81	6475

Southeast load and generation mix forecast (GWh)

	Actual 06-May	%Chg	% Chg Year-ago	Forecast 07-May	08-May	09-May	10-May	11-May
ERCOT								
Load	752	10	-1	827	869	885	907	822
Generation								
Coal	322	12	22	341	352	363	376	371
Gas	294	3	-16	335	351	342	354	330
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	613	3	-3	621	636	646	631	607
Generation								
Coal	386	-1	17	393	392	395	395	391
Gas	139	8	-29	138	142	144	142	134
Nuclear	49	0	-1	19	20	24	30	36

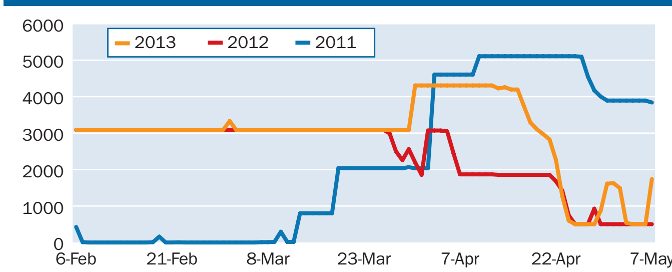
Source: Bentek

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



Source: Platts

ERCOT & SPP nuclear generation outages (GW)



Source: NRC

ERCOT average day-ahead LMP for May 8 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	33.97	-1.75	36.13	8764
Hub Average	34.32	-1.79	35.99	8855
Houston Hub	35.27	-1.06	36.80	8873
North Hub	33.41	-1.84	36.22	8726
South Hub	35.33	-0.96	36.85	9125
West Hub	33.24	-3.34	34.10	8681
AEN Zone	33.35	-2.21	35.87	8712
CPS Zone	37.47	-0.37	37.96	9730
LCRA Zone	34.49	-2.48	36.63	8957
Rayburn Zone	33.56	-1.83	38.89	8764
Houston Zone	36.23	-0.59	37.04	9114
North Zone	33.58	-1.80	37.43	8768
South Zone	37.67	0.05	38.15	9728
West Zone	48.23	-16.76	57.03	12597
Off-Peak				
Bus Average	21.87	-0.38	25.21	5623
Hub Average	21.59	-0.45	24.59	5551
Houston Hub	22.47	-0.02	25.76	5670
North Hub	22.10	-0.34	25.92	5722
South Hub	22.65	0.14	25.50	5820
West Hub	19.14	-1.57	21.17	4991
AEN Zone	22.14	-0.30	25.30	5774
CPS Zone	23.13	0.58	25.59	6004
LCRA Zone	22.50	0.01	25.38	5841
Rayburn Zone	24.86	1.64	31.03	6438
Houston Zone	22.48	-0.01	25.74	5672
North Zone	23.02	0.31	28.00	5960
South Zone	22.98	0.38	25.61	5905
West Zone	19.37	-4.93	22.75	5051

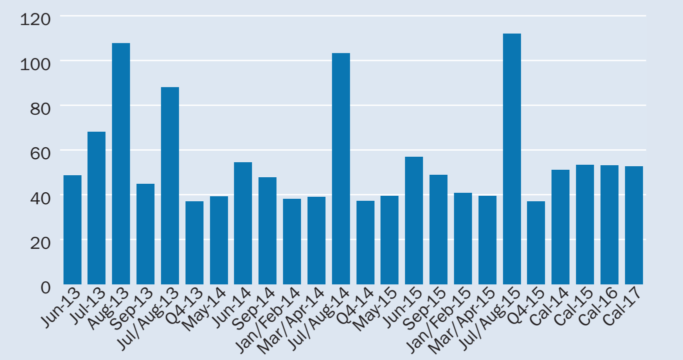
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	05/07	35.25-35.75
Bal-week	05/06	36.25-36.75
Bal-week	05/01	36.75-37.25
Bal-month	05/06	35.75-36.25
Bal-month	05/03	36.25-36.75
Bal-month	05/02	36.25-37.75
Bal-month	05/01	37.50-38.00
Next-week	05/06	35.50-36.00
Next-week	05/03	36.50-37.00
Next-week	05/01	37.00-37.50
Entergy, Into		
Bal-week	05/07	34.50-35.00
Bal-week	05/01	35.00-35.50
Bal-month	05/06	34.00-34.50
Bal-month	05/03	35.25-35.75
Bal-month	05/01	35.75-36.25
Next-week	05/06	33.50-34.00
Next-week	05/03	35.25-35.75
Next-week	05/01	35.00-35.50
ERCOT, North		
Bal-week	05/06	38.50-39.00
Bal-week	05/01	37.25-37.75
Bal-month	05/06	37.75-38.50
Next-week	05/06	37.00-37.50
ERCOT, West		
Next-week	05/02	37.75-38.25

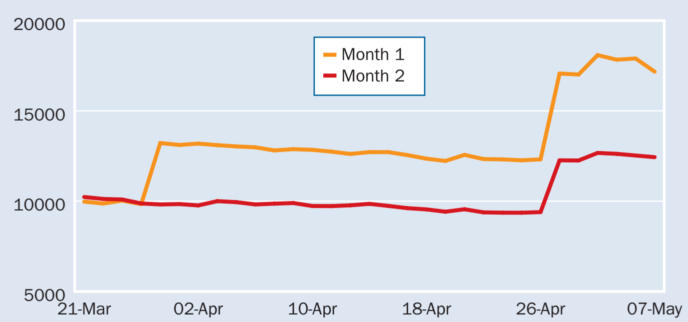
Southeast & Central Platts-ICE Forward Curve, May 7 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
Southern Into	39.50	30.75
Entergy Into	37.25	28.00
ERCOT North	48.50	30.50
ERCOT Houston	49.00	31.50
ERCOT West	48.25	29.75
ERCOT South	48.75	30.25

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



ERCOT South: 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	06/08/13	03/25/13
Bowen-1/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
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
Wolf Creek/WCNOC	1249	n	Kan.	MO	Unk	05/07/13

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 and terms finish mostly lower

Western dailies were mostly down Tuesday with lower demand expected in California and mostly lower spot natural gas prices in the region. Most terms slipped, and the NYMEX June natural gas futures contract settled 9.1 cents lower at $3.920/MMBtu.

In the Northwest, Mid-Columbia day-ahead on-peak fell slightly to trade between $28.50 and $32.75/MWh for delivery on Wednesday. Mid-C day-ahead off-peak prices dropped more than $5.25 to trade between $7 and $15.50/MWh. The Mid-C on-peak balance-of-the-month package was bid at $25.75/MWh and offered at $26.50/MWh.

Portland forecast highs were for the upper 70s through Wednesday. Projected lows were in the low 50s.

The Bonneville Power Administration's wind generation at 7 a.m. PDT Tuesday was 2,068 MW and hydropower was 11,092 MW.

In California, SP15 next-day on-peak was up more than 25 cents to trade between $47.25 and $49/MWh. SP15 day-ahead off-peak was down 75 cents to around $36.50/MWh. SP15 on-peak bal-month traded at $51.50/MWh. NP15 day-ahead on-peak fell slightly to trade between $40.25 and $41/MWh. NP15 day-ahead off-peak was down more than $1.50 to trade between $32 and $32.25/MWh. NP15 on-peak bal-month was bid at $42.50 and offered at $43.50/MWh. Sacramento, California, expected highs in the upper 70s Wednesday. Forecast lows were for the low 50s. Projected highs in Burbank were for the low 70s, and expected lows were for the upper 50s.

The California Independent System Operator projected peak demand to hit 29,650 MW on Tuesday and 29,396 MW on Wednesday.

Renewable generation was 3,317 MW and wind was about 1,500 MW at 7 a.m. PDT on Tuesday in the Cal-ISO.

In the desert Southwest, Palo Verde next-day on-peak was down more than $1.75 to trade between $34/MWh and $35.50/MWh. Palo Verde day-ahead off-peak fell about $3.25 to trade between $23.25 and $23.75/MWh. Palo Verde on-peak bal-month was bid at $36 offered at $42/MWh.

Phoenix highs were forecast for the low 80s Wednesday and expected lows were the mid-60s.

Next day natural gas was mixed in the Rockies and California. Opal was near flat $3.762/MMBtu, PG&E city-gate lost 3.2 cents to $4.043/MMBtu, and SoCal city-gate dropped 3 cents to $4.105/MMBtu.

Day-ahead prices in the California ISO auction were down Tuesday afternoon following the projection of lower peak demand Wednesday. SP15 on-peak fell $4.93 to $42.41/MWh and SP15 off-peak lost $5.03 to $31.91/MWh. NP15 on-peak dropped $1.49 to $38.73/MWh as NP15 off-peak dropped $5.04 to $28.73/MWh. ZP26 on-peak was down $2.15 to $36.58/MWh and ZP26 off-peak slipped $2.17 to $27.48/MWh.

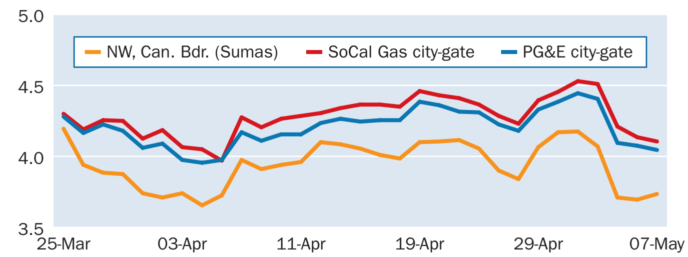
In the Northwest term markets, Mid-C on-peak June gained 50 cents with bids at $27.25 and offers at $28/MWh on ICE around

(continued on page 11)

Western day-ahead bilateral indexes for May 8 ($/MWh)

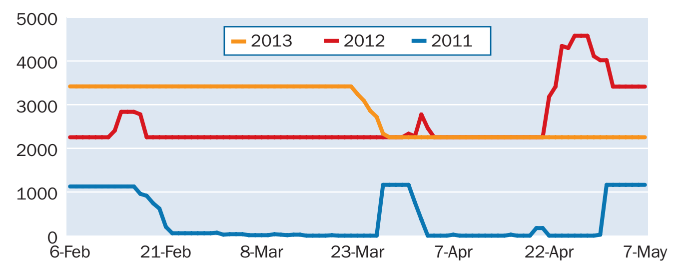
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	34.00	-0.09	37.64	8912
Mid-C	31.52	-0.09	35.43	8439
Palo Verde	34.94	-1.57	39.11	9093
Mead	36.00	-1.38	40.38	9184
Mona	33.75	-1.50	36.25	9000
Four Corners	34.00	-2.00	37.96	9031
NP15	40.25	-0.75	45.96	9951
SP15	47.75	0.25	55.32	12181
Off-Peak				
COB	12.75	-8.97	26.51	3342
Mid-C	10.93	-6.17	24.92	2926
Palo Verde	23.44	-3.28	29.25	6100
Mead	24.50	-3.25	30.38	6250
Mona	20.25	-2.75	24.47	5400
Four Corners	23.00	-3.75	28.25	6109
NP15	32.25	-1.50	35.88	7973
SP15	35.75	-1.50	39.88	9120

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO nuclear generation outages (GW)



Source: NRC

Western load and generation mix forecast (GWh)

	Actual 06-May	%Chg	% Chg Year-ago	Forecast 07-May	08-May	09-May	10-May	11-May
CAISO								
Load	617	10	2	621	621	625	623	594
Generation								
Gas	192	7	6	181	199	217	232	240
Nuclear	56	0	-24	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for May 8 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	38.73	-2.14	-1.69	-1.49	41.76	9575
SP15 Gen Hub	42.41	0.82	-0.98	-4.93	50.27	10818
ZP26 Gen Hub	36.58	-3.36	-2.62	-2.15	40.07	9333
Off-Peak						
NP15 Gen Hub	28.73	-1.59	-0.62	-5.04	35.04	7063
SP15 Gen Hub	31.91	1.73	-0.76	-5.03	38.15	8078
ZP26 Gen Hub	27.48	-1.86	-1.60	-2.17	31.64	6958

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	05/02	28.50-29.00
Bal-month	05/01	31.50-32.50
Bal-month (off-peak)	05/06	6.00-7.50
Bal-month (off-peak)	05/03	8.00-8.75
Bal-month (off-peak)	05/02	10.00-10.75
Bal-month (off-peak)	05/01	12.75-13.25

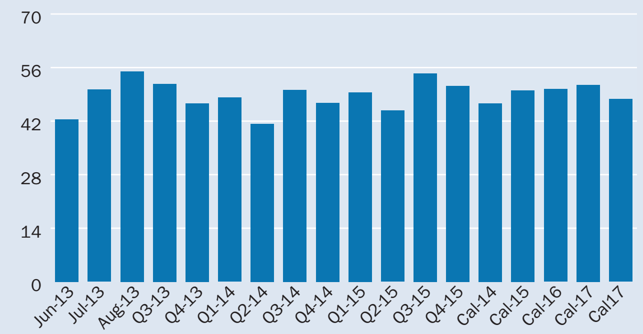
Generation unit outage report

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
Contra Costa-6/NRG	337	g	Calif.	MO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
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
Hatchet Ridge/Pattern	102	w	Calif.	MO	Unk	05/06/13
Helms-2/PG&E	407	h	Calif.	PMO	Unk	12/02/12
High Desert/High Desert	830	g	Calif.	PMO	Unk	05/05/13
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
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
Sentinel/CPV	728	g	Calif.	MO	Unk	05/02/13
Sunrise/Edison	586	g	Calif.	PMO	Unk	04/30/13
Walnut Creek/Edison	100	w	Calif.	MO	Unk	05/06/13

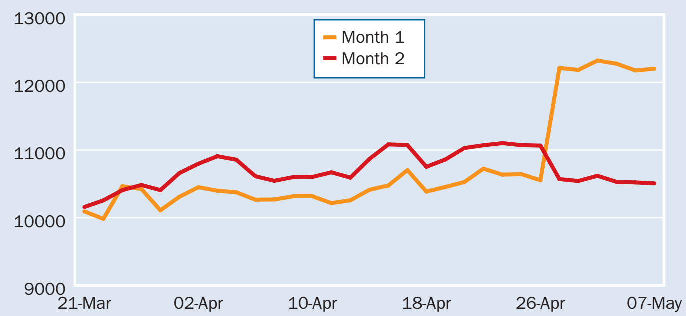
Western Platts-ICE Forward Curve, May 7 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
Mid-C	27.50	11.00
Palo Verde	39.75	25.00
Mead	42.25	29.50
NP15	42.50	31.50
SP15	48.75	34.25

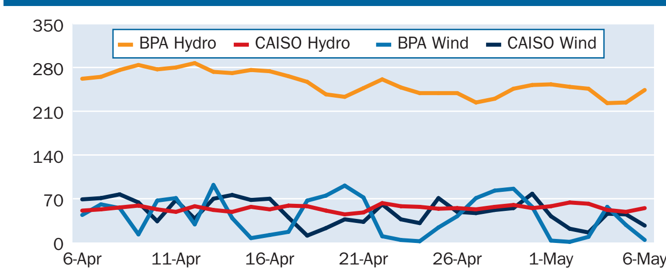
NP15: Forward curve on-peak ($/MWh)



NP15: 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

Dailies stronger on steady demand

Daily power prices in the Mid-Atlantica and Midwest were up on Tuesday, as power demand is expected to be steady on Wednesday. Forward power prices on Tuesday were flat to down, while the NYMEX June natural gas futures contract settled 9.1 cents lower, at $3.920/MMBtu.

Temperatures across the PJM Interconnection footprint are expected in the mid-60s to mid-70s on Wednesday.

PJM forecasted peak demand for Tuesday around 87,760 MW and 87,752 MW for Wednesday.

Texas Eastern M-3 spot natural gas was down slightly, by about 1 cent, to around $4.05/MMBtu on the IntercontinentalExchange early Tuesday.

PJM West Hub on-peak packages for Wednesday gained about $1, to around $40.25/MWh on ICE. PJM West Hub off-peak slipped about $1 to the upper $20s/MWh.

Midwest dailies climbed with strong demand expected Wednesday. Chicago city gates spot gas was about flat with Tuesday, at around $4/MMBtu.

Indiana Hub on-peak packages for Wednesday climbed about $3 to the low $40s/MWh. Indiana Hub off-peak tacked on about $1 in the mid-$20s/MWh.

Dailies in the Midwestern portion of PJM were stronger, as AEP-Dayton Hub peak gained about $2.50, in the low $40s/MWh while AD Hub off-peak was steady in the upper $20s/MWh.

Northern Illinois Hub peak gained over $2 in the mid- to upper $30s/MWh and off-peak climbed about $2 in the low $20s/MWh.

Day-ahead auction prices in PJM were mostly down Tuesday, with steady demand forecasted for midweek. Rockland Electric zone peak stayed at the top and peeled back about $4.83 to around $52.58/MWh, while off-peak was down $2.11 to about $30.27/MWh.

PSEG zone peak lost about $4.17, clearing around $47.27/MWh and off-peak was about $2.61 down to about $29.40/MWh. BG&E zone peak was down 84 cents to about $42.46/MWh and off-peak shed $2.32 to about $28.32/MWh.

Western hub peak fell nealry $1 to about $40.78/MWh and off-peak dropped over $2 to about $27.40/MWh. Prices in the Chicago and Illinois region edged higher after taking some losses Monday. Chicago Hub peak added about 58 cents to about $38.69/MWh and off-peak added 77 cents, going to just over $23/MWh.

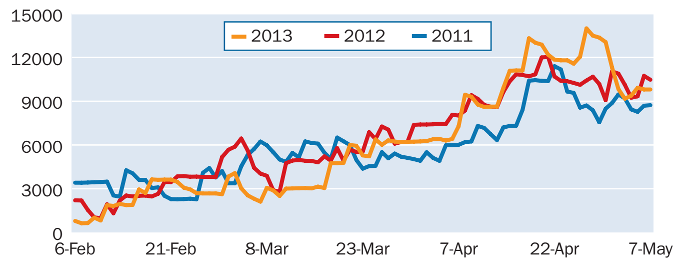
ComEd Zone peak moved up nearly 50 cents, to about $38.65/MWh and off-peak ws up 66 cents, to around $23/MWh. Northern Illinois Hub peak edged up 26 cents to about $38.62/MWh and off-peak moved up 36 cents to about $23.06/MWh.

Day-ahead auction prices in Midcontinent Independent System Operator, formerly Midwest Independent Transmission System Operator, cleared mostly firmer Tuesday afternoon. Michigan Hub became the highest-price hub, with on-peak clearing at $43.82/MWh, a jump of 38 cents, while off-peak cleared at $30.50/MWh, up $2.57.

PJM & MISO day-ahead bilateral indexes for May 8 ($/MWh)

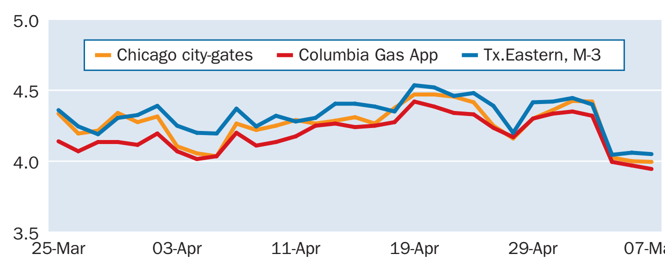
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	40.75	1.75	40.04	10435
Dominion Hub	41.25	1.75	40.25	10313
AD Hub	40.25	2.50	39.33	10268
NI Hub	37.50	2.25	37.17	9387
PJM Off-Peak				
PJM West	29.25	-0.75	29.50	7490
Dominion Hub	29.50	-0.75	29.67	7375
AD Hub	28.00	-1.00	28.58	7143
NI Hub	22.50	2.50	22.42	5632
MISO On-peak				
Indiana Hub	44.00	3.25	40.04	11097
Michigan Hub	44.25	2.50	41.71	10637
Minnesota Hub	44.50	-0.75	37.96	11309
Illinois Hub	43.00	1.00	39.25	10730
MISO Off-Peak				
Indiana Hub	27.25	1.25	27.33	6873
Michigan Hub	27.00	-3.25	30.42	6490
Minnesota Hub	27.50	4.00	23.29	6989
Illinois Hub	26.00	0.75	25.46	6488

PJM & MISO nuclear generation outages (GW)



Source: NRC

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 06-May	%Chg	% Chg Year-ago	Forecast 07-May	08-May	09-May	10-May	11-May
PJM								
Load	1872	15	5	1922	1976	1998	1993	1817
Generation								
Coal	819	22	15	830	811	794	786	757
Gas	248	17	-20	284	304	300	287	274
Nuclear	640	-1	2	640	640	640	640	640
MISO								
Load	1257	14	3	1348	1359	1359	1322	1188
Generation								
Coal	1064	10	12	1137	1134	1107	1059	986
Gas	66	124	-39	68	66	60	50	38
Nuclear	159	6	-8	159	159	159	159	159

Source: Bentek

MISO average day-ahead LMP for May 8 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	43.31	0.55	-0.37	0.13	38.51	10924
Michigan Hub	43.82	0.35	0.34	0.38	40.02	10537
Minnesota Hub	43.44	-0.55	0.86	-0.92	39.15	11037
Illinois Hub	42.85	1.07	-1.34	1.10	37.91	10689
Off-Peak						
Indiana Hub	27.80	0.86	0.11	0.46	26.88	7020
Michigan Hub	30.50	2.94	0.72	2.57	29.66	7346
Minnesota Hub	25.40	-1.64	0.21	-0.94	24.20	6447
Illinois Hub	27.27	1.03	-0.60	-0.92	25.10	6810

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

Package	Trade date	Range
PJM West		
Bal-week	05/06	41.00-41.50
Bal-week	05/03	40.75-41.25
Bal-week	05/01	37.50-39.50
Bal-month	05/02	45.25-46.00
Next-week	05/03	42.25-43.00
Next-week	05/02	41.25-42.25
Next-week	05/01	43.00-44.25

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	Unk	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
Palisades/Entergy	778	n	Mich.	MO	Unk	05/05/13
Perry/FirstEnergy	1260	n	Ohio	MO	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 8 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	39.05	0.02	-1.57	-0.91	37.03	9778
AEP-Dayton Hub	40.51	0.27	-0.37	-0.87	38.34	10142
ATSI Gen Hub	40.89	0.21	0.08	-1.25	38.73	10216
Chicago Gen Hub	38.21	-0.88	-1.51	0.57	34.80	9563
Chicago Hub	38.69	-0.90	-1.01	0.58	35.23	9684
Dominion Hub	41.15	0.43	0.11	-1.18	39.17	10273
Eastern Hub	40.32	-1.39	1.11	-1.90	39.59	9960
New Jersy Hub	43.01	2.00	0.41	-3.27	41.30	10625
Northern Illinios Hub	38.62	-0.76	-1.22	0.26	34.96	9665
Ohio Hub	40.81	0.37	-0.17	-0.88	38.63	10146
West Internal Hub	40.53	0.22	-0.29	-1.15	38.51	10368
Western Hub	40.78	0.14	0.04	-0.97	39.01	10433
AEP Zone	40.34	0.19	-0.45	-0.99	38.24	10101
Allegheny Power Zone	40.53	0.04	-0.11	-1.31	38.55	10316
Atlantic Elec Zone	38.52	-2.54	0.45	-1.88	38.53	9515
ATSI Zone	41.12	0.15	0.37	-1.26	39.07	10273
BG&E Zone	42.46	0.36	1.50	-0.84	40.51	10701
ComEd Zone	38.65	-0.87	-1.08	0.46	35.10	9673
Dayton P&L Zone	41.15	0.09	0.46	-0.70	38.87	10379
Delmarva P&L Zone	39.97	-1.56	0.93	-1.79	39.46	9875
Dominion Zone	41.45	0.41	0.44	-1.16	39.44	10348
Duke Zone	39.83	0.03	-0.80	-0.67	37.66	10047
Duquesne Light Zone	38.94	-0.06	-1.61	-1.12	36.90	9909
JCPL Zone	37.66	-3.20	0.25	-2.16	38.53	9302
MetEd Zone	38.28	-2.20	-0.12	-1.92	38.08	9532
PECO Zone	37.88	-2.55	-0.18	-1.79	37.72	9431
Pennsylvania Elec Zone	42.21	0.74	0.87	-1.42	40.08	10736
PEPCO Zone	42.09	0.26	1.22	-1.04	40.14	10607
PPL Zone	38.32	-2.08	-0.21	-1.92	38.03	9540
PSEG Zone	47.27	6.13	0.54	-4.17	43.56	11677
Rockland Elec Zone	52.58	11.30	0.68	-4.83	46.09	12988
Off-Peak						
AEP Gen Hub	26.48	0.30	-0.91	-1.86	27.52	6624
AEP-Dayton Hub	27.69	0.86	-0.27	-1.73	28.57	6925
ATSI Gen Hub	27.46	0.33	0.03	-1.98	28.51	6849
Chicago Gen Hub	23.09	-2.92	-1.08	0.72	20.98	5774
Chicago Hub	23.04	-3.25	-0.81	0.77	21.00	5761
Dominion Hub	28.01	0.66	0.26	-2.00	29.10	6964
Eastern Hub	28.06	0.17	0.80	-2.34	29.76	6901
New Jersy Hub	28.44	0.96	0.39	-2.69	29.87	6994
Northern Illinios Hub	23.06	-3.11	-0.93	0.36	20.73	5766
Ohio Hub	27.96	1.03	-0.17	-1.73	28.81	6947
West Internal Hub	27.40	0.42	-0.11	-1.92	28.48	6986
Western Hub	27.65	0.42	0.13	-2.03	28.89	7049
AEP Zone	27.41	0.62	-0.30	-1.94	28.44	6858
Allegheny Power Zone	27.41	0.37	-0.06	-2.05	28.60	6959
Atlantic Elec Zone	27.53	0.03	0.41	-2.35	29.44	6770
ATSI Zone	27.57	0.32	0.16	-1.99	28.67	6877
BG&E Zone	28.32	0.37	0.86	-2.32	29.75	7107
ComEd Zone	23.02	-3.23	-0.85	0.66	20.82	5755
Dayton P&L Zone	27.48	0.31	0.08	-1.75	28.42	6938
Delmarva P&L Zone	27.99	0.16	0.73	-2.30	29.75	6881
Dominion Zone	28.12	0.63	0.39	-2.05	29.22	6992
Duke Zone	26.80	0.34	-0.63	-1.66	27.66	6767
Duquesne Light Zone	26.28	0.27	-1.08	-1.87	27.43	6670
JCPL Zone	27.28	-0.18	0.36	-2.85	29.49	6707
MetEd Zone	27.37	0.08	0.20	-2.42	29.15	6786
PECO Zone	27.28	0.03	0.15	-2.32	29.07	6762
Pennsylvania Elec Zone	28.27	0.53	0.64	-1.96	29.32	7224
PEPCO Zone	28.27	0.48	0.69	-2.21	29.53	7092
PPL Zone	27.29	0.08	0.12	-2.38	29.04	6766
PSEG Zone	29.40	1.89	0.41	-2.61	30.22	7229
Rockland Elec Zone	30.27	2.74	0.43	-2.11	30.27	7442

Minnesota on-peak cleared at $43.44/MWh, a drop of 92 cents from Monday. Off-peak cleared the auction at $25.40/MWh, down 94 cents.

Indiana Hub on-peak cleared at $43.31/MWh, adding 13 cents, while off-peak cleared at $27.80/MWh, a gain of 46 cents.

The lowest-priced hub remained Illinois Hub, with on-peak clearing the auction at $42.85/MWh, up $1.10. Off-peak cleared at $27.27/MWh, a loss of 92 cents.

Congestion costs at the hubs ranged from negative 55 cents to $1.07 for peak, and from negative $1.64 to $2.94 for off-peak.

Mid-Atlantic forwards were down Tuesday amid falling gas futures. June NYMEX gas futures came down 7.7 cents, trading at about $3.934/MMBtu.

PJM West on-peak June financial futures were 50 cents weaker, with bids at $50.40/MWh and offers at $50.70/MWh on ICE at about 2:30 p.m. EDT Tuesday. PJM West on-peak July-August shed 40 cents, to about $59.85/MWh, while on-peak fourth quarter fell 50 cents, to about $44.25/MWh. PJM West off-peak June peeled back 50 cents, moving down to about $31.75/MWh.

Midwest forwards were flat to down Tuesday as gas futures fell. AD Hub on-peak June financial futures shed 35 cents to about $46/MWh. AD Hub on-peak July-August was 35 cents weaker at about $54.15/MWh.

Indiana Hub on-peak June was unchanged at about $42.25/MWh, while Indiana Hub on-peak July-August stood still at about $50/MWh.

NI Hub on-peak June dropped 50 cents to about $44/MWh. NI Hub on-peak July-August eased down 25 cents to about $52/MWh.

Northeast markets *... from page 2*

In New England, Mass Hub on-peak June financial futures dropped 75 cents, with bids at $57.75/MWh and offers at $58.50/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT Tuesday. Mass Hub on-peak July-August came down 50 cents to about $59/MWh. Mass Hub off-peak June lost 50 cents to about $40/MWh.

New York Zone G on-peak June rose 50 cents, to about $59.75/MWh. New York Zone G on-peak July-August fell 75 cents to about $66.75/MWh. New York Zone A on-peak June was unchanged at about $44.75/MWh, while Zone A on-peak July-August edged up 15 cents to about $50.75/MWh.

Southeast markets *... from page 4*

High temperatures in Atlanta were forecast moving up into the mid-70s Wednesday, below the average May high temperature in Atlanta of 80. The low was forecast in the mid-50s, below the average low of 60.

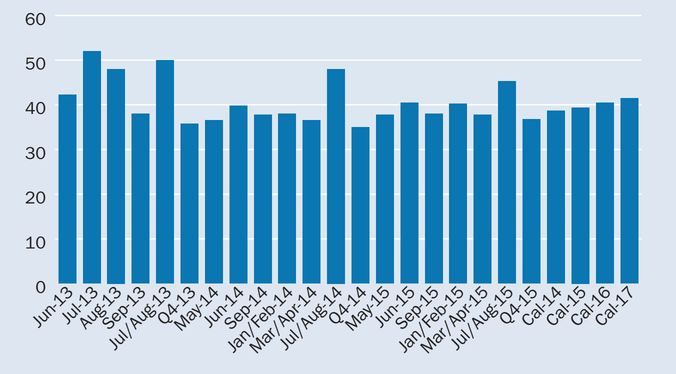
The ERCOT day-ahead auction cleared weaker Tuesday afternoon, even with peak load forecasted to increase Wednesday.

South Hub became the highest-priced hub, as West Hub returned to the lowest-priced hub. South Hub on-peak cleared at $35.33/MWh, a drop of about $1, while off-peak cleared at $22.65/MWh, up about 25 cents.

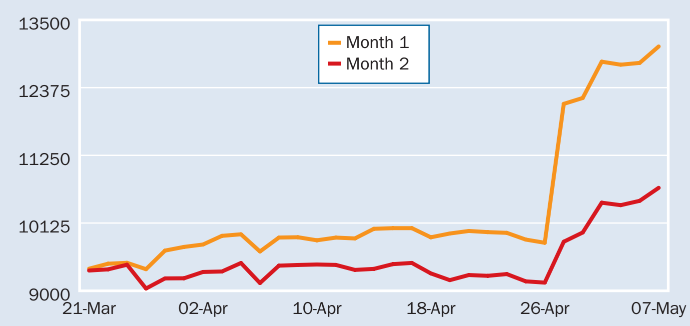
PJM & MISO Platts-ICE Forward Curve, May 7 ($/MWh)

Prompt month: Jun 13	On-peak	Off-peak
PJM West	50.50	31.75
AD Hub	46.00	29.75
NI Hub	44.00	26.50
Indiana Hub	42.25	28.00

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



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



Houston Hub on-peak cleared in the auction at $35.27/MWh, falling almost $1, while off-peak cleared at $22.47/MWh, nearly unchanged.

North Hub on-peak cleared the auction at $33.41/MWh, a loss of more than $1.75 from Monday's clearing price, while off-peak cleared at $22.10/MWh, down almost 25 cents.

West Hub on-peak cleared in the ERCOT auction at $33.24/MWh, a drop of roughly $3.25, while off-peak cleared at $19.14/MWh, down about $1.50.

West Zone on-peak led the load zones at $48.23MWh, falling about $16.75 from Monday.

The highest hourly day-ahead price occurred at 5 p.m. CDT in the Houston Hub, at $57.66/MWh and in the West Zone at $84.03/MWh.

Most South Central US terms fell at the front of the curve Tuesday, as June NYMEX gas lost 7.7 cents to about $3.934/MMBtu in late trading.

ERCOT Houston on-peak June dropped $1.50, to about $49.50/MWh, and July-August tumbled $3.25 to about $89.25/MWh.

Heat rates were down about 110 Btu/kWh on ICE at about 2:30 p.m. EDT Tuesday.

ERCOT North June slid $1.50 to about $48.50/MWh, July-August plunged $3.25 to about $90/MWh, and September fell $1.50 to about $44.75/MWh.

Into Entergy June stayed at about $37.25/MWh, and July-August edged down 10 cents to about $40.40/MWh.

Southeast US on-peak June was unmoved Tuesday, even as June NYMEX gas futures moved down. Into Southern June stayed at about $39.50/MWh, July-August inched down 10 cents to about $42.15/MWh, and September fell 25 cents to about $36.75/MWh.

West markets *... from page 6*

2:30 p.m. EDT. July fell 25 cents to about $41.50/MWh, and the third quarter fell 35 cents to about $42.75/MWh. In California, SP15 on-peak June financial terms lost 50 cents with bids at $48.50 and offers at $49/MWh. July fell 50 cents to about $57.50/MWh, and Q3 fell 40 cents to about $58.60/MWh. NP15 June shed 75 cents to about $42.50/MWh, and Q3 fell 75 cents to about $51.75/MWh. Palo Verde June dropped $1 to about $39.75/MWh, July slid 75 cents to about $49/MWh, and Q3 fell 60 cents to about $47.65/MWh.

NEWS

AMP/FirstEnergy plant project scuttled

FirstEnergy will not go forward with an 873-MW natural gas-fired peaking project in northeast Ohio, the company said Tuesday, after receiving notification from the utility’s joint venture partner, American Municipal Power, that it was pulling out of the project.

The Akron-based company has retained an independent investment advisor with a goal of selling its roughly 1,240 MW of hydroelectric power assets in the second half of 2013, Anthony Alexander, FirstEnergy president and CEO, told analysts during a conference call to discuss first-quarter earnings.

Lower capacity revenue, primarily as a result of lower capacity prices, trimmed earnings by 19 cents/share in the quarter, the company said.

Capacity prices are expected to average from $16 to 28-MW/day through May 2014, FirstEnergy said, then rise to around $100-MW/day from June 2014 to May 2016.

FirstEnergy's total generation output climbed by 902,000 MWh to 24.3 million MWh in the latest quarter, up from 23.4 million MWh in the comparable period of 2012.

Alexander said FirstEnergy Solutions' sales book targeting 104 million MWh of generation sales for 2013 is "essentially filled." FES is the competitive arm of FirstEnergy.

He predicted power markets would see "an upside" over the next couple of years as more older coal-fired generating capacity is retired in the Midwest.

"I think there will be a lot more generation removed from energy and capacity markets going forward to bring the supply side more in balance over time," he said. "I'm not sure that's fully reflected in the forward prices we're seeing out there."

Financial uncertainty, meanwhile, doomed the gas plant project announced last November by FirstEnergy and American Municipal Power, a Columbus, Ohio-based wholesale power supplier that serves about 130 cities in six states.

The companies had planned to jointly construct and operate the gas plant in northeast Ohio by early 2016.

Although the estimated price tag of the project was never publicly disclosed, it presumably would have cost several hundred million dollars to build the four combustion turbines at the site of FirstEnergy's 1,257-MW Eastlake baseload coal plant.

Construction was to have started in the latter half of 2014.

Under the joint venture arrangement, AMP would have provided construction financing and owned 75% of the generation with FirstEnergy controlling the remaining 25%, or about 220 MW.

Alexander said FirstEnergy recently was notified by AMP it was pulling out of the project. Alexander did not cite reasons for AMP's decision.

Later in the day, however, AMP said in a statement that "uncertainty regarding a number of issues, several of which could affect AMP's financing for the project" doomed the plant.

As an example, AMP said, "The future of tax-exempt and tax-advantaged financing is in question and some of AMP's projects have already seen increased interest costs because of the federal 'sequester.'"

With the project dead, Alexander said his company plans to continue working with PJM Interconnection, an independent system operator based in Pennsylvania, on additional projects aimed at supporting and bolstering system reliability in the northeast Ohio region.

Alexander also said the Environmental Protection Agency has granted the company a one-year extension, through April 2016, to comply with the new Mercury and Air Toxics Standards rule at five FirstEnergy coal plants: Hatfield's Ferry and Bruce Mansfield in Pennsylvania, and Fort Martin, Harrison and Pleasants in West Virginia.

Altogether, FirstEnergy owns about 20,000 MW of generation capacity, of which 9,700 MW is supercritical coal and 2,500 MW is subcritical coal. The remainder consists of 4,000 MW of nuclear and about 1,700 MW of gas and oil. Renewables comprise the remainder.

— Bob Matyi

Lawyers challenge EPA climate rules in court

Attorneys representing coal-fired electric utilities and the oil-rich states of Texas and Wyoming told a federal appeals court Tuesday that the Obama administration broke the law in implementing its controversial greenhouse-gas regulations for energy-related facilities and other smokestack industries.

But in a potentially bad sign for the power and oil sectors, two of the three judges who heard the oral arguments appeared to be very skeptical of the industry and the states’ claims that the Environmental Protection Agency erred in implementing its climate-change regulations.

The issues played out before a three-judge panel of the US Court of Appeals for the District of Columbia Circuit, which is considering two separate but related lawsuits over EPA’s process of ensuring that states take GHG emissions into account when issuing construction permits for new power plants, refineries and other major carbon emitters.

David Rifkin, an attorney representing Texas, told the court that EPA illegally “coerced” the Lone Star State into adding a carbon-control element to its state implementation plan, or SIP, under an inadequately short timeline. Texas ultimately refused to take that step, which prompted EPA to take control of the state’s permitting process as far as carbon regulations are concerned.

Rifkin said EPA’s action was illegal on procedural grounds, and that it also violated Texas’ rights as a sovereign state. Rifkin denounced EPA’s move as “federal blackmail,” and argued that it was illegal because the federal Clean Air Act “prohibits EPA from putting a gun to the head of states.”

But Judge David Tatel, who has sided with EPA in previous climate-change lawsuits before the DC Circuit, sharply questioned Rifkin’s argument. Tatel, who was appointed to the federal bench by President Bill Clinton, noted that Texas previously announced with great fanfare that it had no intention of regulating GHG emissions from the energy sector and other industries. Tatel also noted that many other states did not object when EPA directed them to revise their SIPS, a process known as a "SIP call."

"Tell me where the coercion comes from," Tatel asked Rifkin. "Texas in this case has done nothing" to regulate industrial carbon emissions.

Judge Judith Rogers, another Clinton appointee, also hit Rifkin on that point, saying Texas "had no intention of doing anything" on GHG emissions because the state objected on such an approach on policy grounds.

"Other states were in similar situations, and didn't do what Texas did," said Rogers, who also questioned whether Texas and Wyoming were actually hurt by the process that EPA used implement its carbon regulations.

But Mark DeLaquil, another attorney who represented Texas, argued that his state was indeed harmed by the manner in which EPA required his state to add a carbon element to its SIP.

"Process matters," DeLaquil said.

DeLaquil also pushed back against Tatel and Rogers' claims that Texas' beef with EPA's process was essentially moot because the state's attorney general announced long ago that Texas had no intention of regulating carbon emissions. DeLaquil said the state's attorney general made that announcement "a long time ago," before EPA even issued its SIP call.

DeLaquil said that shouldn't detract from his argument against EPA's process, because the state could always "revisit its views" on the subject of carbon regulations. But according to DeLaquil, the process that EPA used to implement its GHG rules was akin to "forcing a state to buy a pig in a poke."

Henry Nickel, a Washington-based attorney at Hunton & Williams' Washington office, represented a number of large coal-fired electric utilities in the case. Nickel also faulted EPA's process, saying the agency should have given Texas and other states upwards of three years to add carbon elements to their SIPS because "this is a brand new regulatory program of real complexity."

Judge Brett Kavanaugh, who was appointed to the federal bench by President George W. Bush, appeared to side with the industry's view that EPA didn't give states enough time to revise their SIPs.

"They wanted three years" and to avoid facing a "construction moratorium," Kavanaugh said. "That sounds like injury to me."

It was not clear Tuesday when the DC Circuit might rule on the case. Separately, a host of states and industry trade groups have also asked the US Supreme Court to consider their challenge to another aspect of EPA's climate-change regime, but it is unlikely that the high court will agree to hear that case.

— Brian Hansen

Correction

An article Tuesday about the Electric Reliability Council of Texas' additional analysis on a scarcity pricing proposal misstated the additional peaker net margin values. The total additional peaker net margin is measured in $/MW not $/MWh as the peaker net margin relates to the capacity of a generation unit rather than the energy it produces over time. Therefore, the total additional peaker net margin under "interim solution B+," using a minimum contingency level of 1,375 MW, ranges from $38,544/MW with the systemwide offer cap at $5,000/MWh to $85,773/MW with the systemwide offer cap at $9,000/MWh in 2011; In 2012, those numbers range from $7,740/MW to $14,643/MW. With a minimum contingency level of 1,750 MW, the additional peaker net margin ranges from $67,892 to $146,795/MW in 2011 and from $17,267 to $32,362/MW in 2012. The new analysis adds a minimum contingency level of 2,300 MW with the additional peaker net margin ranging from $192,728 to $400,361/MW in 2011 and from $53,194 to $99,568/MW in 2012.

Daily CSAPR allowance assessments, May 7

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 7

	$/allowance	Change	$/st
S02 2013	0.73	0.00	1.46

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, May 6 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.49	0	Dec13	1.97	0
Dec13 V11	3.42	0	Dec14	1.97	0
Dec13 V12	3.39	0			
Dec13 V13	3.45	0			
Dec14 V10	3.49	0			
Dec14 V11	3.42	0			
Dec14 V12	3.42	0			
Dec14 V13	3.50	0			
Dec15 V10	3.49	0			
Dec15 V11	3.42	0			
Dec15 V12	3.42	0			
Dec15 V13	3.50	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.

Georgia Power solar RFP gets PSC OK

The Georgia Public Service Commission on Tuesday unanimously approved the final version of Georgia Power's planned request for proposals for 60 MW of utility-scale solar photovoltaic capacity, clearing the way for the RFP's official release on Friday. Bids are due June 4.

Georgia Power planned to issue the first of two planned 60-MW utility-scale solar RFPs on April 12, but that schedule was set back due to the significant number of questions raised and suggestions made regarding the first draft of the solicitation.

The final version of the solicitation approved by the PSC on

Tuesday makes clearer that the winners of the RFP will be responsible for the cost of connecting their solar facilities to the Georgia Power grid.

It also states that the utility will figure into each bid the cost of any enhancements Georgia Power would need to make to its transmission system able to deliver the solar power to its customers. The total cost of a solar developer's bid plus any cost of upgrading the grid cannot exceed $120/MWh on a levelized basis, the RFP says.

"The revisions are consistent with the methodology used for evaluating and selecting the winning bids in Georgia Power's traditional RFPs and ensures that the proposals selected do not exceed the company's identified avoided costs," Accion Group, the PSC independent monitor for the solicitation, said in a "summary of changes" statement at the RFP website, https://gpscim.accionpower.com/_solar_1301/.

"After detailed discussions and review with the commission staff and independent monitor, Georgia Power has revised the evaluation process as it relates to the costs of interconnection" so that interconnection costs up to the point where new facilities connect to the existing transmission or distribution system are the responsibility of the bidder, Accion said.

It added, "Based on the information contained in each bid proposal selected for the competitive tier, [Georgia Power] will develop a cost estimate for grid improvements, if any, to the existing transmission and distribution system necessary to deliver the solar energy to the company's customers," and those estimated costs "will be imputed to the bid in the bid evaluation."

The final version of the RFP was revised to include a provision requiring bidders to submit an affidavit affirming site control of the project location.

Georgia Power expects a short list of finalists will be determined by September 13; power purchase agreement negotiations will occur between October 1 and November 6, and the utility will file the resulting PPAs at the PSC on November 15.

In the RFP, Georgia Power will consider solar projects of 1 to 20 MW each. Bidders will submit priced proposals with per-kWh price offers not to exceed $120/MWh, again including the cost of any necessary grid improvements. The winners will enter into 20-year power purchase agreements. All winning projects must begin commercial operation by January 1, 2015.

Georgia Power expects to issue a similar RFP for 60 MW of utility-scale solar in spring 2014, utility spokesman John Kraft said. Projects proposed under that RFP will need to come online by January 1, 2016. Seeking 60 MW of solar capacity now and 60 MW in a year "allows us to take advantage of any technological advances that might affect the price" of solar power, he said, noting that the price of solar photovoltaic panels has fallen sharply in recent years.

The 210-MW Georgia Power "advanced solar initiative" approved by the PSC in November includes 120 MW of utility-scale solar and 90 MW of small- and medium distribution-scale projects of up to 1 MW each. Of the 90 MW in the latter part of the plan, 45 MW will be selected this year and 45 MW in 2014.

Georgia Power said last month that it received nearly 1,000 distinct small- and medium-scale proposals totaling about 600 MW during the March 1-11 submission period, and conducted an April 5 lottery to select 129 proposals totaling 45 MW. A similar process is planned for March and April 2014.

Participants in the small- and medium-scale programs will be paid a flat $130/MWh for the power they provide during their 20-year PPAs. Participants in the medium-scale program can opt to receive an escalating price for power that begins at about 8.5 cents/kWh in 2013 and rises to more than 17 cents/kWh by the end of their 20-year agreements.

— Housley Carr

BGE wants to build 230-kV transmission line

Baltimore Gas & Electric wants approval from Maryland regulators to build a double-circuit 230-kV transmission line around the northern section of its service territory to minimize risks associated with generation retirements.

The PJM Interconnection had requested the project be online as soon as possible, but BGE said it would be unlikely to have it completed before June 1, 2017.

"In the event that generation retirements occur prior to the completion of the project BGE may be forced to implement extraordinary measures to maintain the integrity of the system during peak load periods. Such extraordinary measures could include rotating load shedding," BGE said in the filing made Monday.

Delays could result in system congestion, BGE said.

The project primarily consists of replacing 28.5 miles of a single-circuit 230-kV line with a double-circuit 230-kV transmission line in Harford and Baltimore counties.

The project is needed to mitigate potential overloads and help ensure BGE is able to import sufficient power to support the forecasted 7,649 MW summer peak load for 2017.

Allowing more imports into the region, which includes BGE and Pepco service areas, will lessen congestion during peak periods, the filing said.

The $73.5 million upgrades will provide system reinforcement for load growth, BGE said.

The upgrades will improve operations and maintenance flexibility by allowing supply to continue to the northeast side of BGE service territory during maintenance and repair work, BGE said. Without the upgrades, it will be much more difficult for BGE to properly maintain and repair this portion of the utility's 230-kV transmission system, BGE said in the filing.

The new double-circuit line will enhance the reliability and supply of energy to Harford County north of Baltimore and eliminate the risk that an equipment failure at the Bagley substation located on the Baltimore County-Harford County line could interrupt service on the 230-kV line, BGE said.

The project will be built in three phases beginning in January.

— Mary Powers

Black Hills in deal to sell gas-fired unit to city

Black Hills Wyoming, an independent power producer, has agreed to sell a 40-MW natural gas-fired unit to the city of Gillette, Wyoming, for $22 million, Black Hills, the company's parent, said Tuesday.

As part of the deal, Black Hills Wyoming will sell power for 20 years to Gillette when it is cheaper to buy power from the wholesale market instead of operating the unit.

Gillette's municipal utility, with a peak load of about 70 MW, gets its power from a mix of sources, Kendall Glover, utilities director, said Tuesday. The utility buys power on the wholesale market through the Municipal Energy Agency of Nebraska and gets some power from the Western Area Power Administration, Glover said. Also, Gillette has a 23% stake in the 110-MW, coal-fired Wygen III plant in Gillette.

The unit the city plans to buy currently operates at a roughly 5% rate, Glover said. If the price of wholesale power rises, Gillette will likely run the unit more often, he said. The unit came online in 2001.

Black Hills Wyoming currently sells power from the unit to Cheyenne Light, Fuel and Power, another Black Hills subsidiary. Black Hills expects the sale to close in August 2014 when the power sales agreement with Cheyenne Light, Fuel and Power expires. The Federal Energy Regulatory Commission must approve the sale.

"This agreement demonstrates our ability to propose creative solutions to meet our customers' energy needs while enhancing the value of our power generation business for our shareholders," David Emery, Black Hills chairman, president and CEO, said.

Black Hills Wyoming had been considering various options for the unit in preparation of the expiration of the power supply contract. One option had been extending the power purchase agreement with Cheyenne Light, Fuel and Power.

The unit is part of a power plant complex in Gillette, which includes Black Hills' coal mine, six coal-fired generating units and two natural gas-fired units totaling about 800 MW. The generating units are owned by various equity partners, including several Black Hills affiliates and other third parties. Black Hills Power, a regulated utility, owns 52% of the plant and Montana-Dakota Utilities owns 25%.

Black Hills Wyoming owns 309 MW of unregulated generation, including about 68 MW in a coal-fired unit in Gillette and 200 MW of natural gas-fired generation in Colorado.

— Ethan Howland

Flow estimates higher for Northwest rivers: NOAA

Columbia River flows from April through September at The Dalles Dam on the border between Washington and Oregon likely will be 95% of normal, the Northwest River Forecast Center said late Monday in its Ensemble Streamflow Prediction Report.

The projection is 1 percentage point above the April 29 ESP report, which forecast The Dalles flows at 94% of normal, the National Oceanic and Atmospheric Administration unit said.

Upstream, flows at Grand Coulee Dam during the same period likely will be 101% of normal, also up 1 percentage point from the prior forecast, the NWRFC said.

ESP forecasts compare historical and current data and run the information through model scenarios to project what water supplies could look like. Power market participants closely watch the reports as an indication of upcoming water supplies for hydroelectric generation in the Pacific Northwest.

Forward electricity prices at the hydro-rich Mid-Columbia hub were mostly down after the NOAA report of higher river levels.

The Mid-C on-peak price for the third quarter of 2013 was $43.10/MWh following the issuance of the ESP report, down $2.55 from last week. The on-peak Q3 price this week is $18/MWh higher than it was during the same period in 2012.

The Mid-C off-peak Q3 price was down $2 from last week to $31.35/MWh, $13.75 higher than the Mid-C off-peak Q3 price for the same period in 2012.

The on-peak June forward price was $27/MWh, down from $28/MWh last week and $11.50 more than it was for the same period of 2012. The off-peak June forward price was $10.50/MWh, compared with $9.75/MWh last week and up from $4/MWh for the same time in 2012.

On Monday, the elevation level at The Dalles was about 159 feet, slightly above the 10-year average. Its inflows and outflows were roughly 205,000 cubic feet per second.

At Grand Coulee, the elevation was near 1,260 feet near the 10-year average. Inflows were around 128,000 cubic feet per second. Outflows were about 135,000 cubic feet per second.

The Bureau of Reclamation expects to meet its target of 1,255.5 to 1,258.5 feet at Grand Coulee while it awaits new hydro supply. "Currently Grand Coulee Dam is being operated to not exceed the flood control elevation of 1258.5 [feet] and for power demand," the bureau said on its website Tuesday, noting that unforseen power outages or weather may change the dam's levels.

— Martin Coyne

Companies see benefit

...from page 1

could introduce a new, cheap source of capacity into the market.

The top end of the cost to refuel a coal plant is about $100/kW and could be substantially less, depending on what needs to be replaced, Mark Dittus, head of Black & Veatch’s steam generation section, said. By comparison a new gas-fired plant can cost upward of $1,000/kW.

In a regulatory filing, Dominion Resources, whose Dominion Virginia Power unit is refueling its 227-MW Bremo Bluff plant in Fluvanna, Virginia, put the cost of conversion at $53.4 million, excluding financing costs.

In the filing Dominion noted that the cost of conversion is $32 million cheaper than the comparable cost of building a new plant, $123 million cheaper than acquiring a plant, and $155 million cheaper than continuing operation of the coal plant.

While Dominion only plans to refuel the Bremo plant, other utilities have larger plans. American Electric Power has proposed refuelings at four plants. That would enable the company to retain

1,800 MW of capacity that would otherwise be retired.

All of those refueled units would run as peaking plants and would sell power into the PJM Interconnection capacity market. "We expect them to run at a 5% to 10% capacity factor," AEP spokeswoman Melissa McHenry said. "It is reasonably priced and inexpensive capacity, but it can't cycle as fast as a gas turbine," she said.

McHenry was not able to provide the capacity factors of the retiring coal plants by press time.

AEP plans to refuel two units totaling 470 MW at its Clinch River plant in Virginia, a 482-MW unit at its Tanners Creek station in Indiana, a 570-MW unit at its Muskingum River station in Ohio, and is awaiting a final decision on refueling a 278-MW unit at its Big Sandy plant in Kentucky.

Several other utilities also have said they plan to refuel some of the coal-fired units they have scheduled for retirement, among them Allete, Duke Energy, MidAmerican Energy Holdings, SCANA, and Xcel Energy. Integrys is evaluating whether or not to refuel two coal units, and MidAmerican has other two other coal units it is evaluating for refueling other than the 137-MW Riverside plant that is scheduled to switch to gas in 2016.

Dittus said Black & Veatch is doing three in-house studies on refueling right now. "A lot of people are studying this." Some have yet to pull the trigger, but he said he expects to see more refuel-or-retire decisions as the year-end 2015 compliance deadline for the Environmental Protection Agency's Mercury and Air Toxics Standards rule draws closer.

Among the trade-offs to consider in making the decision to refuel is the fact that a refueled plant will suffer a loss of efficiency. The actual efficiency loss depends on the exact mix of coal the unit burns, but usually there is a 200 Btu/kW hit to a plant's heat rate, Dittus said. An older coal plant typically has a heat rate of about 11,000 Btu/kW.

The heat rate rises in a refueling, reflecting a loss of efficiency, because the hydrogen in the natural gas turns to water during combustion so some of the thermal energy is needed to evaporate the moisture. In addition, sometimes the gas-fired boiler will produce about 5% less steam. There are also other technical problems. For instance, because gas burns cleaner than coal, the heat transfer pipes get hotter and have to be adapted so they do not burn out.

Part of the equation is that the drop in efficiency if offset by the fact that the plant will be used for peaking capacity. But the potential problem is start-up time. Combustion turbines generally start up in 15 to 30 minutes. A gas-fired steam plant would require six to eight hours of warm-up. So in order to compete with a combustion turbine, a refueled plant would need to be in a hot standby status, which is more costly than a cold start, Steve Dean, managing principal at DAI Management Consultants, said.

But switching from coal to gas adds "a little more flexibility" in being able to cycle the plant on and off to meet fluctuating demand, Dittus said. The ramp up time may not improve in a refueling, but a plant refueled with gas can run with a lower load than a plant fueled by coal. A coal plant can run at about 50% of load, but the same plant converted to burn gas can run at about 25% of load, Dittus said.

Despite the loss of efficiency and the capital expenditures required to refuel, "the economics can make sense because you can save on capex, as well as other items such as water interconnections, steam turbines and pollution controls," Dean said.

And a refueled plant with access to a wholesale market can earn capacity payments as well as revenues when it runs to meet peak demand. Plants in regulated markets may not have access to capacity payments, so for them refueling offers a lower cost way to meet demand while keeping rates low.

It is harder to calculate the trade-off in lower efficiency, which puts a plant higher in the dispatch stack, against the possibility that the plant can operate at lower loads, enabling it to dispatch across a broader swath of the demand curve. Several companies seem to be betting that the trade-off will be in their favor.

— Peter Maloney

FERC OKs plan

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the accuracy of their market-to-market settlements to reduce congestion through certain transmission facilities called flowgates. The ISOs in 2011 reached a settlement to address MISO's claim that PJM erroneously calculated some market-to-market settlements and had underpaid MISO.

In the case of changes to the methodology, PJM and MISO proposed to use the same process to calculate firm flow entitlements as they do market flows – the difference between the two provides the "megawatt quantity" used in settlements, FERC said.

Using a different calculation process for market flows and firm flow entitlements, FERC said, "meant that firm entitlement rights to market-to-market flowgates were systematically predisposed to being lower than the calculated market flows. By aligning the calculation of market flows to use the same methodology currently used to calculate firm flow entitlements, these revisions will help correct a mismatch in calculation methodologies that result in inaccurate market-to-market settlements."

Likewise, FERC in approving inclusion of imports in the calculation of market flows stated that the change "will improve overall accuracy and efficiency of the congestion management process."

FERC approved the revisions despite protests by the Indiana Utility Regulatory Commission, which argued that MISO and PJM did not provide enough information to demonstrate what impact the changes would have on Indiana ratepayers and others and did not adequately involve the public in the process.

But FERC in both orders said that it is not persuaded by such arguments, saying that "The Indiana Commission has not identified any specific problems that may arise as a result of the proposed revisions. We also recognize that, although a stakeholder process is not required for the proposed revisions, PJM and MISO have provided detailed discussions of the proposed revisions at various meetings held in advance of the initial filings."

MISO and PJM believe that modifications to their JOA "as reflected in the filings maintain an efficient and transparent seams coordination process between the two RTOs," said Ron Arness, Senior Manager, Seams Administration, at MISO. "Further, the changes to the JOA improve the accuracy of the market flow calculation and efforts toward achieving greater consistency in market-to-market settlement calculations. The filings represent part of our ongoing effort to improve seams management, in this case we are addressing inconsistent treatment of jointly owned units in the market flow calculations and firm flow entitlement calculations."

— Bobby McMahon

Solicitation gets strong response

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transmission projects.

The policy sets rules for the transmission developers to select customers and negotiate rates, terms, and conditions. Under the policy, the developer must broadly solicit interest in the project and satisfy FERC criteria for selection and negotiation.

"We had expected to attract substantial interest in the capacity of the line, but this response certainly exceeded our expectations," said Bryan Sanderson, a principal of Anbaric Transmission.

The solicitation sought contracts with off-takers for the transmission scheduling rights for energy, capacity, or renewable energy credits across the line from New York to New England.

Anbaric timed the solicitation to coincide with supply needs in Vermont and Massachusetts. Utilities in Massachusetts issued a joint request for proposals in early April that was expected to result in 10 to 20-year contracts for at least 850,000 MWh of renewable energy. Utilities must submit contracts to the DPU for approval in October.

The Massachusetts renewables RFP calls for projects to be in commercial operation by December 31, 2016. Or, bidders may propose an alternative schedule, with an explanation for the delay, that puts them in operation no later than December 31, 2018.

In its solicitation, Anbaric requested 20-year terms, but said it would consider shorter contracts if the off-taker was likely to strike a supply deal of less than 20 years from a New England RFP.

The 230-kV merchant line creates a pathway to move power from upstate New York into demand-heavy New England. Upstate New York is considered fertile territory for wind power development, but it lacks transmission to move the power to load centers. Meanwhile, New England states have aggressive renewable energy goals and older power plants nearing retirement age.

GII will be an alternating current line, planned for 34 miles between Plattsburgh, New York and Essex, Vermont, predominantly along existing transmission line corridors. Anbaric plans to bury most of the line, and run part of it under Lake Champlain.

The GII solicitation schedule calls for Anbaric to short list transmission customers for negotiation by May 31. Anbaric expects the line to be service in the summer of 2016. Permitting is scheduled to begin this summer.

Anbaric Transmission is an active developer of independent transmission. The company's projects include the 65-mile Neptune Regional Transmission System, a high-voltage direct current undersea and underground power cable finished in 2007. The 660-MW line links PJM to New York and serves Long Island. Anbaric also developed the 660-MW Hudson Transmission Project, an underground and underwater line between New Jersey and New York City, scheduled to be complete this year.

— Lisa Wood

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