PLATTS
McGRAW HILL FINANCIAL
www.platts.com
[ELECTRIC POWER]
MEGAWATT DAILY
www.twitter.com/plattspower
Thursday, June 27, 2013

Imports into PJM auction may be close to limits

ANALYSIS

The capacity imports that cleared the PJM Interconnection's recent capacity auction represented a record that could be approaching the upper limit of imports.

PJM's recent capacity auction saw a 90% increase in imports from outside PJM that pushed down prices and caught several analysts by surprise. In the auction's wake, many market observers are struggling to understand if the high level of imports can be sustained or increased and why exports were so much higher in this auction than in previous auctions.

In the reliability pricing model, as the PJM capacity auction is called, that closed in late May for delivery of resources in 2016-2017, a total of 7,483 MW of imports cleared, of which 4,723 MW were from the Midcontinent Independent System Operator.

(continued on page 15)

Cal-ISO unveils reliability initiative with CPUC

RESOURCE ADEQUACY

The California grid operator and utilities regulator next month plan to launch a dialogue with electricity market participants about how to improve reliability with rule changes on the adequacy and capacity of the state's power system.

Calling the effort the "Multi-Year Reliability Framework" in a market notice Wednesday, the California Independent System Operator said it and the California Public Utilities Commission "have scheduled a joint stakeholder workshop on July 17" to discuss "revisions to the CPUC's resource adequacy program and the ISO's capacity procurement mechanism tariff provisions."

Currently, the capacity mechanism allows the Cal-ISO to procure generation needed to offset sudden changes in resource adequacy as reported monthly and annually by utilities in the state.

(continued on page 17)

MISO net flow from PJM drops in scenario

MARKETS

The net average amount of power imported into the Midcontinent Independent System Operator from the PJM Interconnection would fall by 46% by 2017 and by 65% by 2022 in one of the scenarios being studied by MISO, a key panel learned Wednesday.

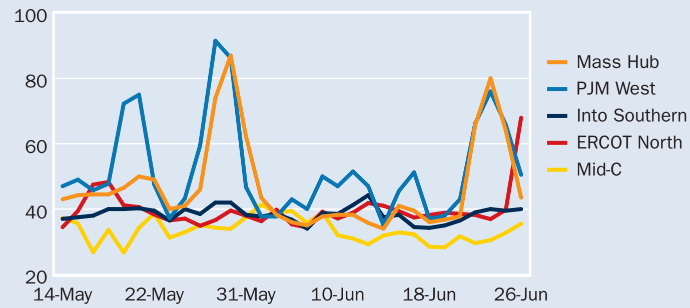
In a report to MISO's Planning Advisory Committee, Lynn Hecker, MISO economic studies manager, presented three scenarios being reviewed the MISO-PJM Interregional Planning Stakeholder Advisory Committee.

The purpose of these scenarios is to help evaluate cross-seam transmission issues and identify opportunities for transmission expansion.

The first scenario includes MISO state renewable portfolio standards and PJM's queue-based generation development remaining

(continued on page 17)

Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Jun 27 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	38.29	41.33	28.24	29.70
NYISO	41.40	166.44	27.51	49.78
PJM	36.47	53.96	22.68	29.39
MISO	42.69	51.20	23.31	25.09
ERCOT	65.05	103.07	24.71	25.18
CAISO	50.93	54.80	33.25	33.63

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 Jun 27

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	43.50	10469	14.42	10.26	1.95	-6.36	-18.83
N.Y. Zone-A	42.75	12139	18.10	14.58	7.53	0.49	-10.08
PJM/MISO							
PJM West	50.50	14518	26.15	22.67	15.72	8.76	-1.68
Indiana Hub	53.75	14507	27.82	24.11	16.70	9.29	-1.83
Southeast & Central							
Southern, Into	40.00	10731	13.91	10.18	2.73	-4.73	-15.91
ERCOT, North	67.94	18550	42.30	38.64	31.32	23.99	13.00
West							
Mid-C	35.53	20508	23.40	21.67	18.21	14.74	9.54
SP15	56.50	15047	30.22	26.46	18.95	11.44	0.18

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 down as demand declines

Daily power prices in the Northeast were down Wednesday as demand is expected to weaken on Thursday. Forward prices increased as the NYMEX July natural gas futures contract settled at $3.707/MMBtu Wednesday, up 6 cents.

ISO New England forecasted peak load for Wednesday around 23,500 MW, falling to 21,160 MW for Thursday. High temperatures for the Boston area are expected in the low 70s Thursday.

Algonquin city gates spot natural gas tumbled nearly $1 to $4.20/MMBtu, as Transco Zone 6 New York was down 41 cents to $4.18/MMBtu.

Mass Hub on-peak for Thursday lost about $20, going to the mid-$40s/MWh, while off-peak moved down more than $6 to the low $30s/MWh.

The New York ISO forecasted peak load for Wednesday at 29,540 MW and 27,399 MW for Thursday. High temperatures in New York state are expected to be around 80 on Thursday.

New York Zone A peak for Thursday went down about $5 to the low $40s/MWh. NY Zone G peak plunged about $20 to the mid-$50s/MWh.

Day-ahead auction prices in ISONE tumbled Wednesday, with lower demand in the forecast and weaker regional spot gas prices. Internal Hub peak was down $21.37 to reach $40.35/MWh. Connecticut peak lost $21.45 to clear at $41.33/MWh. Maine peak decreased $17.87 to $38.29/MWh, while Vermont peak came off $20.83 to $41.15/MWh.

Off-peak prices were down an average of less than $6, to around $29/MWh.

Day-ahead auction prices in NYISO fell midweek with lower expected demand. Dunwoodie peak fell the most on the day, losing $19.16 and going to $56.72/MWh. New York City peak was down $14.74 to $63.22/MWh. Long Island peak only fell $6.17 to $166.44/MWh. West zone peak was $4.86 lower at $42.52/MWh. Hudson Valley peak tumbled $17.22 to $54.79/MWh.

Northeast term power prices increased Wednesday as July NYMEX gas futures rose. Mass Hub on-peak July financial futures climbed $2.25, with bids at $53.75/MWh and offers at $54.40/MWh on the IntercontinentalExchange at about 2:30 p.m. EDT. Mass Hub on-peak August gained $1.50 to reach $52.25/MWh, while on-peak September added 50 cents to $53.10/MWh. Mass Hub off-peak July picked up 50 cents to $36.50/MWh.

New York Zone G on-peak July rose $2 to $63/MWh. NY Zone A on-peak July was $1 stronger at $48.75/MWh.

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

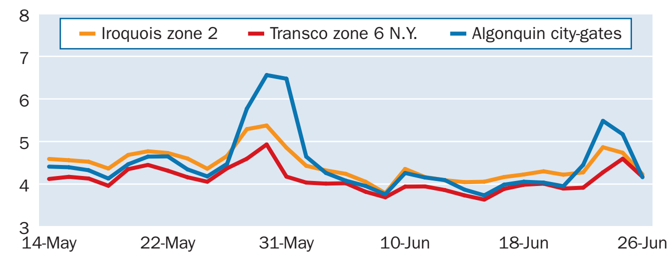
Sources: Generation owners, public information and other market sources.

Northeast day-ahead bilateral indexes for Jun 27 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	43.50	-20.50	44.38	10469
N.Y. Zone-G	54.75	-19.75	50.29	13036
N.Y. Zone-J	63.25	-13.75	53.76	15060
N.Y. Zone-A	42.75	-5.75	40.12	12139
Ontario*	32.00	-6.25	30.37	7566
Off-Peak				
Mass Hub	30.00	-6.75	29.66	7220
N.Y. Zone-G	31.75	-5.25	30.25	7560
N.Y. Zone-J	32.25	-5.25	30.88	7679
N.Y. Zone-A	28.25	-6.75	27.74	8022
Ontario*	20.00	-5.00	20.12	4729

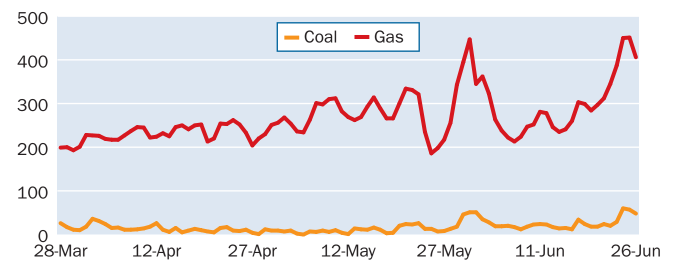
*Ontario prices are in Canadian dollars

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 25-Jun	%Chg	% Chg Year-ago	Forecast 26-Jun	27-Jun	28-Jun	29-Jun	30-Jun
ISONE								
Load	479	-1	2	409	398	399	384	374
Generation								
Coal	28	-4	41	20	15	14	15	16
Gas	209	-1	-9	184	160	153	161	168
Nuclear	111	0	-7	110	111	111	111	111
NYISO								
Load	581	0	1	564	539	522	488	467
Generation								
Coal	29	-7	86	28	25	22	22	22
Gas	242	1	-11	222	201	188	192	192
Nuclear	124	1	9	127	127	128	130	133

Source: Bentek

ISONE day-ahead LMP for Jun 27 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	40.35	0.00	0.02	-21.37	41.87	9441
Connecticut	41.33	0.00	0.99	-21.45	42.06	9667
NE Mass-Boston	40.16	0.00	-0.18	-20.79	41.51	9394
SE Mass	39.99	0.00	-0.35	-20.89	41.52	9356
West-Central Mass	40.69	0.00	0.35	-21.30	41.80	9520
Rhode Island	39.60	0.00	-0.73	-20.97	41.42	9265
Maine	38.29	0.00	-2.05	-17.87	39.19	9163
New Hampshire	40.20	0.00	-0.14	-20.10	41.08	9619
Vermont	41.15	0.00	0.81	-20.83	41.52	9848
Off-Peak						
Internal Hub	29.41	0.00	0.06	-5.91	29.02	5928
Connecticut	29.70	0.00	0.35	-5.98	29.30	6223
NE Mass-Boston	29.35	0.00	0.00	-5.99	28.94	5916
SE Mass	29.28	0.00	-0.07	-5.99	29.13	5903
West-Central Mass	29.55	0.00	0.20	-5.99	29.17	5956
Rhode Island	29.40	0.00	0.05	-5.93	29.34	5926
Maine	28.24	0.00	-1.11	-5.30	27.21	6316
New Hampshire	29.07	0.00	-0.28	-5.90	28.54	6502
Vermont	29.27	0.00	-0.08	-5.87	28.81	6545

NYISO day-ahead LMP for Jun 27 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	47.03	-0.53	2.84	-9.99	43.48	11984
Central Zone	43.96	-0.16	0.14	-7.83	38.13	12396
Dunwoodie Zone	56.72	-7.64	5.42	-19.16	48.16	13308
Genesee Zone	42.42	-0.02	-1.27	-6.52	36.94	11959
Hudson Valley Zone	54.79	-5.82	5.31	-17.21	47.36	12854
Long Island Zone	166.44	-116.26	6.52	-6.17	76.62	39050
Millwood Zone	56.77	-7.60	5.51	-18.91	48.14	13318
Mohawk Valley Zone	45.29	-0.42	1.20	-8.69	38.81	12116
N.Y.C. Zone	63.22	-13.83	5.73	-14.74	50.80	14834
North Zone	41.40	0.00	-2.26	-6.69	34.43	9907
West Zone	42.52	-1.55	-2.70	-4.86	36.70	11988
Off-Peak						
Capital Zone	30.89	-0.31	1.90	-3.38	30.10	7340
Central Zone	28.80	-0.04	0.08	-3.25	26.63	7790
Dunwoodie Zone	31.91	-0.24	2.99	-3.32	30.21	6929
Genesee Zone	28.51	-0.03	-0.20	-3.10	26.15	7713
Hudson Valley Zone	31.85	-0.23	2.94	-3.42	30.17	6916
Long Island Zone	49.78	-17.28	3.81	2.11	34.05	10808
Millwood Zone	31.90	-0.24	2.98	-3.34	30.19	6928
Mohawk Valley Zone	29.43	-0.03	0.71	-3.25	26.94	7394
N.Y.C. Zone	32.27	-0.25	3.33	-3.68	30.66	7007
North Zone	27.51	0.00	-1.17	-2.76	25.03	6153
West Zone	28.36	-0.04	-0.36	-2.98	26.18	7673

Generation unit outage report

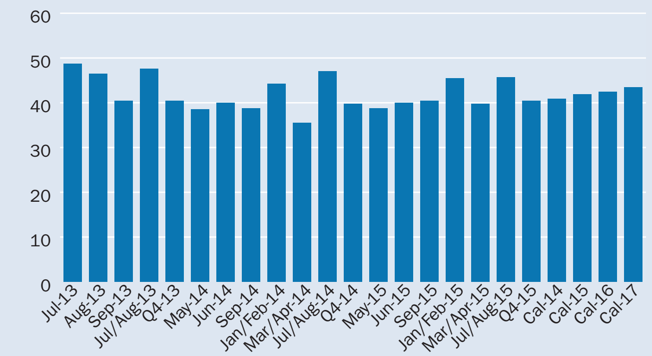
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Pickering-1/OPG	500	n	Ont	MO	Unk	06/07/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, Jun 26 ($/MWh)

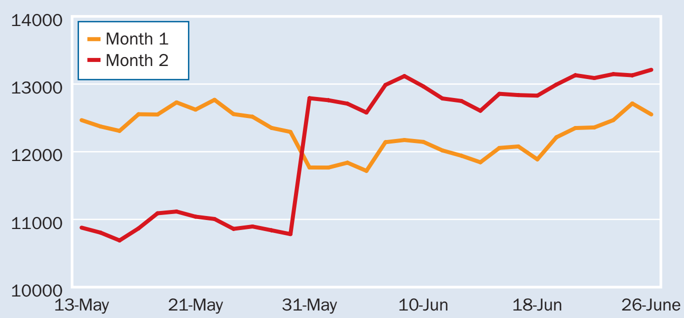
Prompt month: Jul 13	On-peak	Off-peak
Mass Hub	54.00	36.50
N.Y. Zone G	63.00	40.00
N.Y. Zone J	69.00	43.50
N.Y. Zone A	48.75	34.25
Ontario*	36.75	25.25

*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
Mass Hub		
Next-week	06/21	45.75-49.75
Next-week	06/20	59.00-63.00
N.Y. Zone-G		
Next-week	06/20	75.00-79.00
N.Y. Zone-A		
Bal-week	06/21	50.75-54.75
Next-week	06/20	58.00-62.00

*Ontario prices are in Canadian dollars.

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.

SOUTHEAST MARKETS

Temperatures push ERCOT dailies higher

Daily power prices in the Electric Reliability Council of Texas shot up Wednesday, with peak demand expected to be steady and temperatures reaching 100. Forward prices increased as the NYMEX July natural gas futures contract settled at $3.707/MMBtu Wednesday, up 6 cents.

ERCOT North Hub next-day on-peak physical power jumped about $27.75 to trade around $67.50/MWh on the IntercontinentalExchange, while off-peak was steady around $23.75/MWh.

High temperatures across ERCOT were forecast climbing into the mid-90s to low 100s Thursday, with lows in the upper 70s. The average June high temperature across ERCOT is in the low 90s, with the average low in the low to mid-70s.

Spot natural gas at the Houston Ship Channel shed 8.8 cents to $3.657/MMBtu.

System load in ERCOT was forecast to peak at 64,350 MW Wednesday and 64,175 MW Thursday, compared with an actual peak of 61,764 MW Tuesday.

Real-time prices for ERCOT averaged $22.50/MWh from 12:15 to 6 a.m. CDT Wednesday. Wind generation was forecast to peak at 7,825 MW at 2 CDT Wednesday and 6,875 MW at 1 a.m. CDT Thursday.

North Hub on-peak balance-of-the-week packages were bid at $133/MWh and offered at $140/MWh. Next-week on-peak was bid at $39.50 and offered at $41/MWh. Houston Hub bal-week on-peak was bid at $123 and offered at $142/MWh. West Hub bal-week on-peak was offered at $143/MWh.

In other South Central markets, Into Entergy on-peak for Thursday delivery was bid at $40/MWh and offered at $47/MWh, a gain of about $4 from prices for Wednesday delivery.

High temperatures across Entergy's footprint were forecast in the low to upper 90s Monday, with lows expected in the mid- to upper 70s. The average June high temperatures across the Entergy region are in the upper 80s to low 90s, with upper 60s to mid-70s.

In the Southeast, dailies for Thursday delivery were firmer Wednesday, with temperatures expected to drop. Into Southern next-day on-peak power market was in the upper $30s/MWh, a

(continued on page 10)

Southeast & Central day-ahead bilateral indexes for Jun 27 ($/MWh)

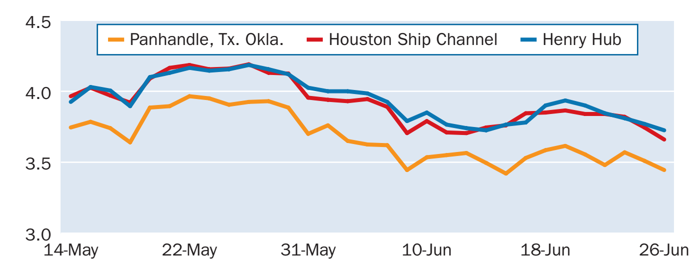
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	43.00	-3.00	40.51	11111
Southern, Into	40.00	0.50	38.03	10731
Florida	38.75	0.25	39.34	9474
TVA, Into	44.00	-1.25	39.24	11726
Entergy, Into	41.00	1.50	36.63	11225
Southeast Off-Peak				
VACAR	28.00	-0.50	26.26	7235
Southern, Into	27.50	-0.25	25.76	7378
Florida	27.00	-0.50	27.89	6601
TVA, Into	27.50	-0.25	25.17	7328
Entergy, Into	25.00	0.50	22.07	6845
ERCOT On-peak				
ERCOT, North	67.94	28.14	39.85	18550
ERCOT, Houston	73.00	29.75	42.78	19905
ERCOT, South	72.00	29.50	41.42	19789
ERCOT, West	67.00	27.75	39.49	18676
ERCOT Off-Peak				
ERCOT, North	23.76	0.01	24.35	6487
ERCOT, Houston	24.00	-0.25	24.80	6544
ERCOT, South	24.25	-0.25	24.58	6665
ERCOT, West	23.00	0.50	23.84	6411
SPP/MRO On-peak				
MAPP, South	42.00	-1.50	37.47	11491
SPP, North	43.50	1.50	36.70	12627
SPP/MRO Off-Peak				
MAPP, South	24.00	-0.75	22.30	6566
SPP, North	25.00	0.50	21.93	7257

Southeast load and generation mix forecast (GWh)

	Actual		% Chg	Forecast				
	25-Jun	%Chg	Year-ago	26-Jun	27-Jun	28-Jun	29-Jun	30-Jun
ERCOT								
Load	1178	2	0	1106	1176	1210	1169	1111
Generation								
Coal	501	5	19	432	450	468	474	467
Gas	446	-2	-14	487	507	526	529	503
Nuclear	123	0	-3	123	123	123	123	123
SPP								
Load	788	3	-4	815	825	805	758	718
Generation								
Coal	470	1	14	487	492	492	481	466
Gas	218	8	-29	228	236	230	212	188
Nuclear	49	0	-4	49	49	49	49	49

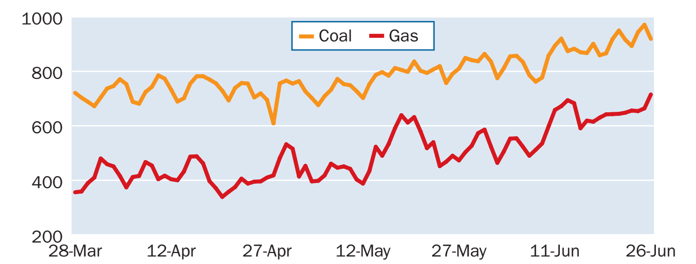
Source: Bentek

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



Source: Platts

ERCOT & SPP gas and coal generation (GWh)



Source: Bentek

ERCOT average day-ahead LMP for Jun 27 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	65.72	28.40	38.29	18023
Hub Average	65.67	27.79	38.71	18009
Houston Hub	66.06	26.23	40.77	17967
North Hub	65.91	29.41	37.52	17953
South Hub	65.05	25.81	39.38	17843
West Hub	65.56	29.64	37.13	18252
AEN Zone	72.60	24.62	44.22	20212
CPS Zone	70.79	28.28	41.97	19531
LCRA Zone	67.85	24.55	41.08	18719
Rayburn Zone	66.26	29.74	37.65	18050
Houston Zone	66.29	26.22	41.17	18030
North Zone	66.31	29.42	37.88	18063
South Zone	67.57	26.16	41.47	18534
West Zone	103.07	50.43	48.29	28692
Off-Peak				
Bus Average	24.76	1.63	23.67	6731
Hub Average	24.75	1.63	23.65	6730
Houston Hub	24.79	1.17	23.95	6660
North Hub	24.76	1.71	23.66	6691
South Hub	24.74	0.74	23.87	6718
West Hub	24.71	2.87	23.10	6857
AEN Zone	24.95	1.10	23.96	6926
CPS Zone	25.18	0.41	24.41	6878
LCRA Zone	24.85	0.97	23.89	6788
Rayburn Zone	24.76	1.74	23.68	6691
Houston Zone	24.79	1.15	24.01	6660
North Zone	24.76	1.74	23.66	6691
South Zone	24.91	0.28	24.12	6763
West Zone	24.84	3.59	23.33	6895

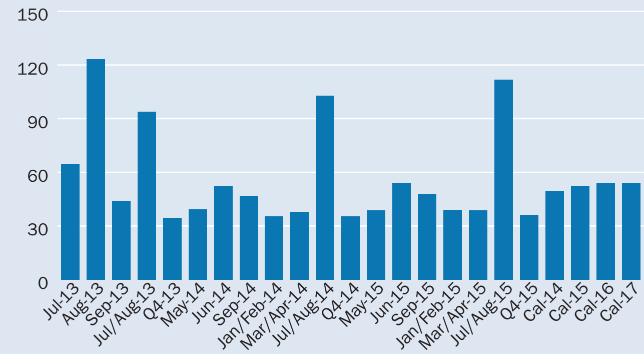
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	06/25	38.00-38.50
Bal-month	06/25	38.00-38.50
Bal-month	06/20	39.50-40.00
Next-week	06/25	39.00-39.50
Next-week	06/20	41.00-41.50
ERCOT, North		
Bal-week	06/25	78.00-80.00
Bal-week	06/21	45.75-46.25
Bal-month (off-peak)	06/26	23.50-24.50
Next-week	06/20	44.75-45.50
ERCOT, Houston		
Bal-week	06/25	80.50-83.00

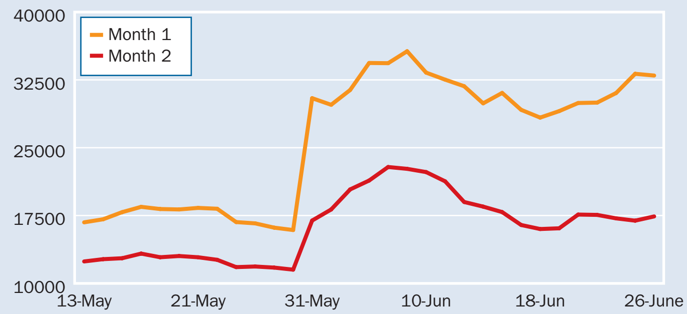
Southeast & Central Platts-ICE Forward Curve, Jun 26 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
Southern Into	40.25	30.00
Entergy Into	39.50	27.75
ERCOT North	65.25	31.50
ERCOT Houston	64.50	31.50
ERCOT West	69.25	31.50
ERCOT South	64.50	33.00

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	08/01/13	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 River-3/Progress	838	n	Fla.		Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

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.

WEST MARKETS

Dailies go mostly higher; terms finish mixed

Most Western dailies were up Wednesday as expected California demand and regional temperatures rose. Terms posted mixed results.

The NYMEX July natural gas futures contract on Wednesday posted a preliminary expiration price of $3.707/MMBtu, up 6 cents. The August contract, which takes the prompt-month position Thursday, settled at $3.737/MMBtu, up 6.7 cents.

Pacific Gas and Electric started shutting down the 1,073-MW unit 1 at the Diablo Canyon nuclear plant to repair a leak inside the reactor's containment vessel.

In California, SP15 next-day on-peak added around $9 to trade between $56 and $57.25/MWh. SP15 day-ahead off-peak was up nearly $1.75 to trade between $32.75 and $33/MWh. SP15 bal-month was bid at $50 and offered at $57.75/MWh, down about 25 cents. NP15 day-ahead on-peak was up around $7.75 to trade between $50.75 and $54.75/MWh. NP15 day-ahead off-peak gained $1.50 to about $33.50/MWh. NP15 bal-month was bid at $46 and offered at $56/MWh, about $1.50 higher. Diablo Canyon Unit-1 was at 50% capacity at press time.

Sacramento, California, expected above-normal highs around 100 on Friday, up in the upper 80s on Wednesday, up about 15 degrees from Tuesday. Forecasts for Burbank had highs around 90 through Friday.

The California Independent System Operator projected peak demand to hit 38,078 MW on Wednesday, 40,653 MW on Thursday, and 42,400 MW on Friday. Renewables were 4,264 MW and wind was more than 2,300 MW at 7 a.m. PDT on Wednesday.

In the desert Southwest, Palo Verde next-day on-peak was up almost $6 to trade between $42 and $43.50/MWh. Palo Verde day-ahead off-peak was about flat, trading between $24.75 and $25/MWh.

Phoenix expected highs to reach about 115 by Friday, more than 5 degrees above normal, and lows close to the five-day norm of 82.

In the Northwest, Mid-Columbia day-ahead on-peak was up more than $2.50 to trade between $36.25 and $37/MWh for delivery on Thursday and Friday. Mid-C day-ahead off-peak was down slightly to trade between $14 and $20/MWh on IntercontinentalExchange. The Mid-C on-peak balance-of-the-month package was bid at $33 and offered at $38.50/MWh, down about $1.25.

Portland, Oregon's forecast highs were around 90 on Friday, a gradual increase of more than 15 degrees from projections for Wednesday. Expected lows were steady in the low 60s.

The Bonneville Power Administration's wind at 7 a.m. PDT Wednesday was 8 MW and its hydropower was 11,782 MW.

Next day natural gas prices were mixed. Opal was down 1.7 cents to $3.555/MMBtu, PG&E city-gate fell to $3.824/MMBtu, and SoCal city-gate rose 1.4 cents to $3.929/MMBtu.

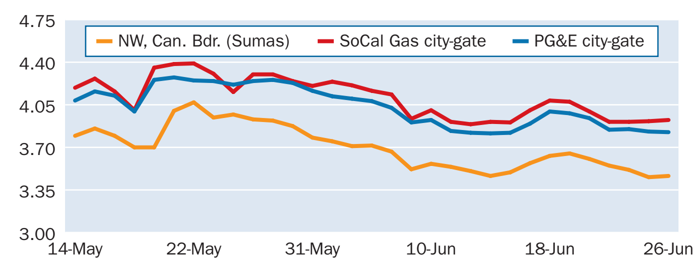
The higher demand forecast and anticipated nuclear outage in

(continued on page 10)

Western day-ahead bilateral indexes for Jun 27-28 ($/MWh)

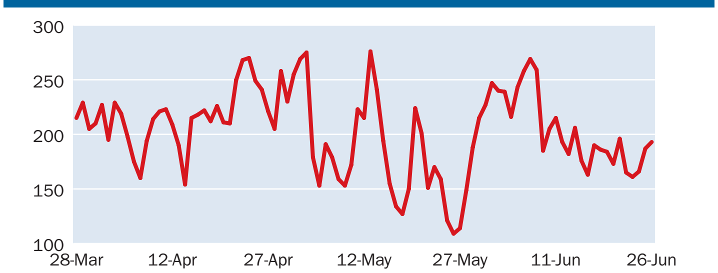
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	38.50	4.25	35.83	10754
Mid-C	35.53	2.78	33.62	20508
Palo Verde	42.60	6.01	38.18	11631
Mead	46.10	6.62	41.09	12277
Mona	44.50	7.50	38.34	12787
Four Corners	45.75	8.25	40.69	12815
NP15	51.50	7.75	42.95	13464
SP15	56.50	9.00	47.38	15047
Off-Peak				
COB	18.90	-0.12	22.24	5279
Mid-C	15.83	-0.06	20.16	9137
Palo Verde	24.75	-0.04	27.00	6758
Mead	26.16	0.41	27.72	6967
Mona	20.00	0.00	21.09	5747
Four Corners	24.00	0.25	25.40	6723
NP15	33.25	1.25	32.44	8693
SP15	33.00	1.75	34.36	8788

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO gas generation (GWh)



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 25-Jun	%Chg	% Chg Year-ago	Forecast 26-Jun	27-Jun	28-Jun	29-Jun	30-Jun
CAISO								
Load	688	5	2	706	760	797	788	783
Generation								
Gas	187	13	2	193	255	326	369	391
Nuclear	56	0	-6	42	42	45	48	52

Source: Bentek

CAISO average day-ahead LMP for Jun 27 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	50.93	-1.96	-2.88	8.81	41.72	13298
SP15 Gen Hub	54.80	0.25	-1.21	8.24	45.08	14595
ZP26 Gen Hub	50.97	-1.74	-3.06	9.32	40.46	13575
Off-Peak						
NP15 Gen Hub	33.49	-0.37	-0.82	1.86	32.28	8735
SP15 Gen Hub	33.63	0.00	-1.04	4.30	32.12	8983
ZP26 Gen Hub	33.25	0.00	-1.42	4.69	30.76	8881

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	06/25	36.75-37.25
Bal-month	06/24	34.00-34.50
Bal-month	06/21	31.00-32.50
Bal-month (off-peak)	06/25	21.50-23.00
Bal-month (off-peak)	06/24	16.50-17.75
Bal-month (off-peak)	06/21	17.00-22.00
Bal-month (off-peak)	06/20	21.75-22.25
Next-week	06/26	46.00-47.00

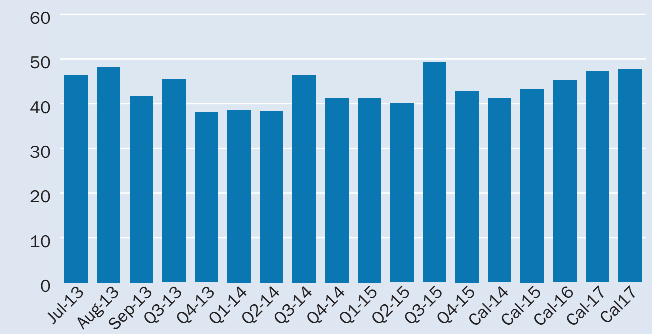
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	MO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
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	05/27/13
Mexcali/Sempra	180	g	Calif.	MO	Unk	05/02/13
Morro Bay-3/Dynegy	325	g	Calif.	PMO	Unk	06/24/13
Morro Bay-4/Dynegy	325	g	Calif.	MO	Unk	06/24/13
Ocotillo/Pattern	265	w	Calif.	MO	Unk	05/16/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12

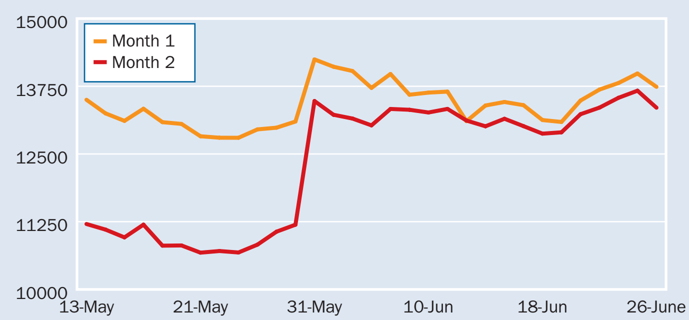
Western Platts-ICE Forward Curve, Jun 26 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
Mid-C	41.50	26.00
Palo Verde	44.50	28.25
Mead	46.50	30.25
NP15	50.50	36.75
SP15	55.50	38.50

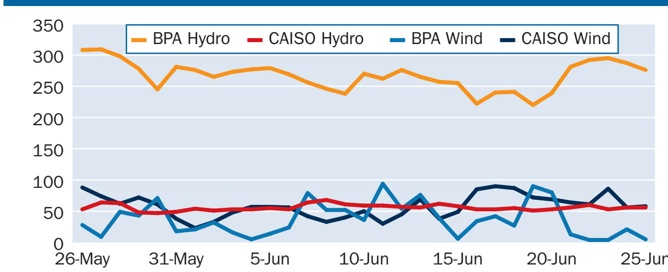
Mead: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

Dailies decline despite steady demand

Daily power prices in the Mid-Atlantic and Midwest declined Wednesday as demand was expected to be steady and spot natural gas prices weakened. Forward prices increased as the NYMEX July natural gas futures contract settled at $3.707/MMBtu Wednesday, up 6 cents.

PJM Interconnection forecasted peak demand for Wednesday at 135,720 MW and 135,734 MW for Thursday. High temperatures across the PJM footprint are forecast to be in the upper 70s to low 90s on Thursday.

Spot gas in the region was off, with Texas Eastern M-3 decreasing 15 cents to $3.72/MMBtu on the IntercontinentalExchange.

PJM West Hub on-peak packages for Thursday were down about $15 to the low $50s/MWh, while off-peak was nearly unchanged at about $30/MWh.

Daily prices in the Midcontinent ISO were down with nearby power markets and spot gas. Chicago city gates spot gas eased about 6 cents to $3.75/MMBtu.

Indiana Hub peak fell about $8 to the low $50s/MWh, while off-peak was nearly flat in the upper $20s/MWh.

Dailies in the Midwestern portion of PJM also moved down. AEP-Dayton Hub peak gave up about $14, going to the low $40s/MWh, as off-peak stayed in the upper $20s/MWh. Northern Illinois Hub peak fell $12 to $40/MWh, as off-peak moved down about $2 to the low $20s/MWh.

Day-ahead auction prices for PJM were down across the board Wednesday, even as demand was expected to remain steady. Eastern Hub peak lost $13.08, going to $52.80/MWh and Western Hub peak was down $18.19 to $42.57/MWh.

PSEG peak came down $15.16 to $52.76/MWh and JCPL lost nearly $17, going to just under $54/MWh. BG&E peak tumbled more than $23, going to slightly more than $51/MWh, while Pepco peak fell $17.60 to $48.19/MWh. In the Western part of PJM, Chicago Hub peak lost $8.56, going to $37.83/MWh and ComEd peak decreased $8.58 to $37.55/MWh.

MISO day-ahead auction clearing prices for on-peak hours increased for all hubs, with the exception of Indiana Hub Wednesday. The Indiana Hub on-peak average fell $4.80 to $51.20/MWh for Thursday delivery, but remained the highest-priced hub during on-peak hours. The Indiana Hub off-peak average slipped $2.65 to $25.08/MWh.

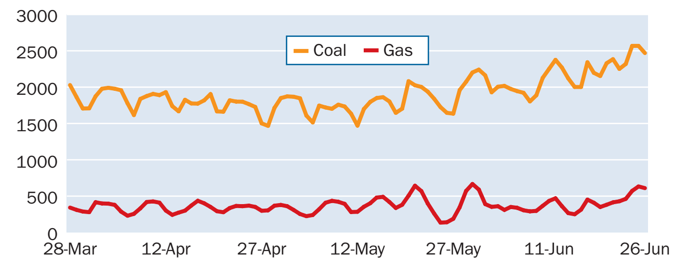
Illinois Hub on-peak average rose $1.98 to $42.69/MWh and the Michigan Hub on-peak average moved up 23 cents to $43.01/MWh. The Minnesota Hub on-peak average, with limited congestion that stayed in line with other hubs, increased $1.49 to $42.85/MWh, while Minnesota Hub off-peak average was up $1.99 to $23.31/MWh.

Mid-Atlantic forward prices rose Wednesday with firmer natural gas futures. PJM West on-peak July financial futures were $1.50 stronger, with bids at $56.60/MWh and offers at $57/MWh

PJM & MISO day-ahead bilateral indexes for Jun 27 ($/MWh)

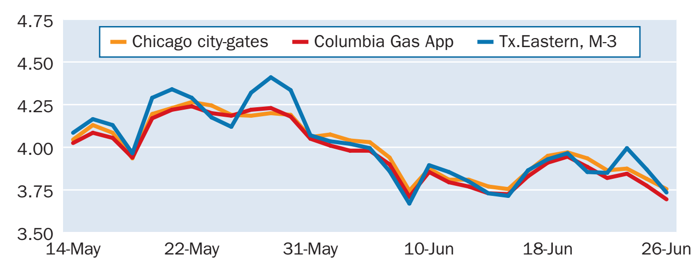
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	50.50	-15.25	47.84	14518
Dominion Hub	51.25	-11.75	47.26	13549
AD Hub	42.75	-14.25	42.34	11385
NI Hub	40.00	-12.50	39.45	10652
PJM Off-Peak				
PJM West	29.50	-0.75	27.28	8481
Dominion Hub	29.00	-1.00	27.01	7667
AD Hub	29.00	0.00	26.24	7723
NI Hub	21.00	-2.50	20.76	5593
MISO On-peak				
Indiana Hub	53.75	-8.25	42.62	14507
Michigan Hub	42.00	-5.50	38.97	10776
Minnesota Hub	41.25	-0.50	36.11	11209
Illinois Hub	41.00	-6.25	36.30	10933
MISO Off-Peak				
Indiana Hub	28.50	0.75	23.49	7692
Michigan Hub	25.50	0.50	25.28	6543
Minnesota Hub	23.75	7.25	18.68	6454
Illinois Hub	24.75	0.00	21.13	6600

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 25-Jun	%Chg	% Chg Year-ago	Forecast 26-Jun	27-Jun	28-Jun	29-Jun	30-Jun
PJM								
Load	2669	1	2	2527	2555	2479	2225	2068
Generation								
Coal	1237	-2	13	1175	1106	1067	1039	1034
Gas	484	14	-22	442	402	371	362	348
Nuclear	800	1	1	801	801	801	801	801
MISO								
Load	1656	2	1	1622	1620	1565	1366	1272
Generation								
Coal	1331	2	9	1294	1272	1253	1204	1168
Gas	149	2	-44	167	170	157	120	97
Nuclear	193	0	-12	193	193	193	193	193

Source: Bentek

MISO average day-ahead LMP for Jun 27 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	51.20	7.96	0.31	-4.80	40.86	13781
Michigan Hub	43.01	-0.73	0.82	0.23	36.97	11005
Minnesota Hub	42.85	-0.17	0.10	1.49	33.83	11629
Illinois Hub	42.69	0.69	-0.92	1.98	34.76	11350
Off-Peak						
Indiana Hub	25.08	1.19	0.01	-2.65	23.56	6643
Michigan Hub	25.09	0.37	0.84	0.09	25.72	6336
Minnesota Hub	23.31	-0.60	0.04	1.99	17.90	6276
Illinois Hub	23.73	0.55	-0.70	-0.24	21.47	6223

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

Package	Trade date	Range
PJM West		
Bal-week	06/25	51.25-52.25
Bal-week	06/24	65.00-67.00
Bal-week	06/21	62.00-63.50
Next-week	06/25	44.00-45.00
Next-week	06/24	46.50-47.50
Next-week	06/21	47.50-51.00
Next-week	06/20	60.50-65.50
AD Hub		
Next-week	06/21	43.75-45.75
NI Hub		
Next-week	06/20	48.00-54.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Kewaunee/Dominion	581	n	Wis.		Retired	05/07/13
Monticello/Xcel	666	n	Minn.	PMO	07/03/13	03/02/13

PJM average day-ahead LMP for Jun 27 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	37.08	-3.92	-2.79	-9.24	38.12	10011
AEP-Dayton Hub	39.07	-3.54	-1.17	-10.26	39.80	10550
ATSI Gen Hub	40.72	-3.13	0.07	-13.26	41.23	11208
Chicago Gen Hub	36.47	-5.25	-2.06	-8.20	35.92	9692
Chicago Hub	37.83	-4.63	-1.32	-8.56	36.98	10052
Dominion Hub	43.20	0.27	-0.85	-14.72	42.69	11390
Eastern Hub	52.80	6.14	2.87	-13.08	49.20	13818
New Jersy Hub	53.01	7.09	2.13	-15.55	44.70	13873
Northern Illinios Hub	37.26	-4.89	-1.63	-8.41	36.48	9901
Ohio Hub	39.34	-3.52	-0.92	-9.69	40.03	10430
West Internal Hub	41.70	-1.27	-0.82	-15.03	41.71	11900
Western Hub	42.57	-0.16	-1.05	-18.19	43.36	12150
AEP Zone	39.13	-3.49	-1.17	-10.48	39.93	10565
Allegheny Power Zone	40.44	-2.68	-0.67	-14.33	41.32	11101
Atlantic Elec Zone	52.15	5.96	2.40	-13.75	44.17	13648
ATSI Zone	41.09	-3.12	0.43	-14.53	41.60	11309
BG&E Zone	51.02	5.27	1.97	-23.12	48.48	14046
ComEd Zone	37.55	-4.84	-1.40	-8.58	36.77	9978
Dayton P&L Zone	39.95	-3.79	-0.05	-9.80	40.39	10754
Delmarva P&L Zone	52.25	6.17	2.30	-12.88	47.61	13675
Dominion Zone	43.85	0.43	-0.37	-14.94	43.30	11559
Duke Zone	38.64	-2.98	-2.17	-8.94	39.00	10400
Duquesne Light Zone	38.28	-4.07	-1.44	-12.94	39.60	10924
JCPL Zone	53.96	8.12	2.06	-16.97	44.23	14123
MetEd Zone	52.46	7.95	0.73	-10.67	42.83	13865
PECO Zone	51.02	5.74	1.49	-12.60	43.50	13482
Pennsylvania Elec Zone	42.73	-0.91	-0.14	-18.05	42.68	12197
PEPCO Zone	48.19	3.67	0.73	-17.60	46.23	13265
PPL Zone	51.18	6.99	0.41	-12.38	42.88	13526
PSEG Zone	52.76	6.80	2.17	-15.16	45.17	13808
Rockland Elec Zone	51.98	6.04	2.16	-15.89	44.97	13604
Off-Peak						
AEP Gen Hub	25.67	0.02	-1.38	-1.15	24.92	6782
AEP-Dayton Hub	26.87	0.57	-0.73	-1.58	25.90	7100
ATSI Gen Hub	26.96	0.07	-0.13	-1.57	26.37	7203
Chicago Gen Hub	22.68	-3.02	-1.33	-0.33	20.77	5950
Chicago Hub	23.23	-2.82	-0.97	-0.49	21.32	6094
Dominion Hub	27.50	0.61	-0.13	-1.39	26.36	7157
Eastern Hub	29.28	0.85	1.40	-1.17	29.25	7504
New Jersy Hub	29.31	0.91	1.38	-1.82	27.60	7512
Northern Illinios Hub	22.95	-2.97	-1.10	-0.43	20.88	6022
Ohio Hub	27.13	0.74	-0.63	-1.71	26.12	7092
West Internal Hub	26.93	0.26	-0.35	-1.41	26.15	7384
Western Hub	27.47	0.29	0.16	-1.50	26.59	7531
AEP Zone	26.70	0.34	-0.67	-1.42	25.81	7055
Allegheny Power Zone	27.01	0.23	-0.24	-1.29	26.18	7240
Atlantic Elec Zone	29.06	0.79	1.24	-1.31	27.48	7448
ATSI Zone	27.11	0.06	0.02	-1.53	26.49	7241
BG&E Zone	28.73	0.75	0.95	-1.37	27.47	7662
ComEd Zone	23.07	-2.94	-1.01	-0.44	21.08	6053
Dayton P&L Zone	26.84	0.10	-0.28	-1.32	25.83	7110
Delmarva P&L Zone	29.11	0.84	1.24	-1.18	28.66	7460
Dominion Zone	27.70	0.59	0.08	-1.49	26.60	7210
Duke Zone	25.72	0.05	-1.36	-1.25	24.97	6813
Duquesne Light Zone	26.07	0.02	-0.97	-1.17	25.50	7147
JCPL Zone	29.37	0.97	1.37	-2.06	27.55	7528
MetEd Zone	28.66	1.00	0.64	-1.29	27.06	7430
PECO Zone	28.76	0.78	0.95	-1.18	27.20	7456
Pennsylvania Elec Zone	27.86	0.16	0.68	-1.44	26.96	7678
PEPCO Zone	28.35	0.71	0.62	-1.50	27.18	7562
PPL Zone	28.03	0.52	0.49	-1.42	27.00	7265
PSEG Zone	29.39	0.91	1.45	-1.81	27.71	7532
Rockland Elec Zone	29.25	0.79	1.44	-2.06	27.61	7498

on ICE. PJM West on-peak August gained $1 to $55/MWh, while on-peak fourth quarter picked up 25 cents to $42.10/MWh. PJM West off-peak July took on 50 cents, rising to $33.25/MWh.

Midwest July forwards were up Wednesday amid stronger gas futures. AEP Dayton Hub on-peak July rose $1 to $50.75/MWh. Indiana Hub on-peak July gained $1.25 to $49.25/MWh. Northern Illinois Hub on-peak July climbed $1.25 to $48.75/MWh.

Southeast markets ... *from page 4*

slight gain from Tuesday.

Spot natural gas at Transco Zone 3 fell 5.1 cents to trade around $3.714/MMBtu. High temperatures in Atlanta were forecast falling to the low 80s Thursday, with lows in the low 70s. The average June high temperature in Atlanta is 86. The average low is 68.

ERCOT day-ahead auction clearing prices climbed an average of $29 for on-peak hours across all delivery locations Wednesday with load expected to rise on higher temperatures. Clearing prices for off-peak hours averaged increases of less than $2.

The West Zone was the highest price on-peak settlement point, moving up more than $50 to $103.07/MWh for Thursday delivery. Congestion was high, with the West Hub clearing at an average of $65.56/MWh for on-peak hours.

The North Hub on-peak average rose $29.41 to $65.91/MWh and the North Zone on-peak average was rose $29.42 to $66.31/MWh. Houston Hub on-peak average rose $26.23 to $66.06/MWh, and the Houston Zone on-peak average was up $26.22 to $66.29/MWh.

The highest hourly day-ahead price was for the hour ending 5 p.m. CDT for the West Zone at $333.55/MWh, an increase nearly double the same hour for Wednesday delivery. The lowest hourly day-ahead price was for the hour ending 4 a.m. CDT for the West Hub at $19.70/MWh, an increase of $1.88 from the same hour for Wednesday delivery.

South Central on-peak July terms went up Wednesday, as July NYMEX gas futures increased. ERCOT North on-peak July jumped $2.75 to about $65.25/MWh, August added $1.50 going to about $123.50/MWh, September rose 50 cents to about $43/MWh, and the fourth quarter rose 50 cents to about $34/MWh. Heat rates were down about 10 Btu/kWh on ICE.

Into Entergy on-peak July gained 50 cents to about $39.50/MWh, August moved up 50 cents to about $37.75/MWh, and September fell 25 cents to about $34.25/MWh.

Southeast on-peak July rose Wednesday, as did July NYMEX gas futures. Into Southern July surged 75 cents to about $40.25/MWh, August climbed 75 cents to about $38.50/MWh, September fell 25 cents to about $35.50/MWh, and Q4 crept down 10 cents to about $34.65/MWh.

West markets ... *from page 6*

California appeared to carry into day-ahead prices in the California Independent System Operator auction Wednesday afternoon. SP15 on-peak added $8.24 to $54.80/MWh and SP15 off-peak climbed $4.30 to $33.63/MWh. NP15 on-peak gained $8.81 to $50.93/MWh while NP15 off-peak was up $1.86 to $33.49/MWh. ZP26 on-peak jumped $9.32 to $50.97/MWh as ZP26 off-peak rose $4.69 to $33.25/MWh.

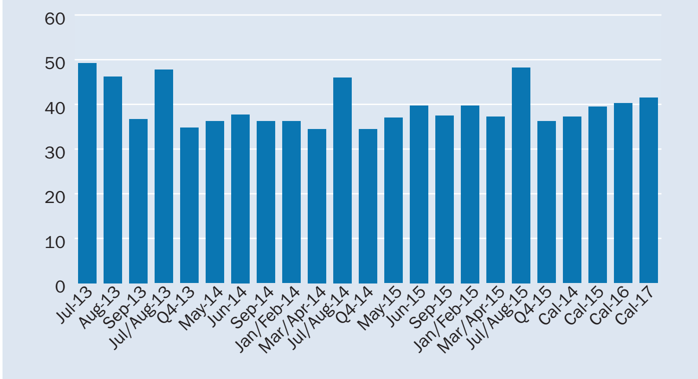
Laura Uselding, a Nuclear Regulatory Commission spokeswoman, said the PG&E plans to overlay a weld on the problem weld inside the reactor. "It is not a safety issue but more of a maintenance issue. The repair work will not take long," she said. NRC inspectors will oversee the repairs, she said.

In the Northwest term markets, Mid-Columbia on-peak July added 75 cents with bids at $41 and offers at $41.75/MWh on ICE around 2:30 p.m. EDT. The third quarter rose 40 cents to about $42.15/MWh, and the fourth quarter rose 35 cents to about $36.85/MWh. In California, SP15 on-peak July financial terms were constant with bids at $55.25 and offers at $55.50/MWh. Q3 crept down 10 cents to about $55/MWh, and Q4 stayed at about $47.35/MWh. NP15 July rose 25 cents to about $50.50/MWh, and Q3 rose 25 cents to about $49.85/MWh. Palo Verde July shed 75 cents to about $44.50/MWh, Q3 fell 30 cents to about $43.35/MWh, and Q4 climbed 60 cents to about $36.10/MWh.

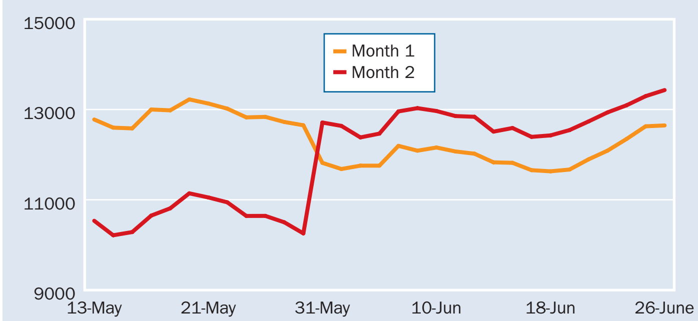
PJM & MISO Platts-ICE Forward Curve, Jun 26 ($/MWh)

Prompt month: Jul 13	On-peak	Off-peak
PJM West	56.75	33.25
AD Hub	50.75	30.75
NI Hub	48.75	27.50
Indiana Hub	49.25	28.50

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



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



NEWS

Calif. renewables market may be in lull: IPP official

California's renewable electricity market may be in a lull with the state's utilities on track for meeting the next bump in the state's renewable portfolio standard, according to an official with an independent power producer trade group.

“There's been a slowing of contracts [utilities] have been signing,” said Jan Smutny-Jones, Independent Energy Producers Association executive director. The utilities believe they have bought enough renewables to meet the second tranche of California's RPS, which hits 25% by 2016, he said.

The recent cancellation of a major solar project hints at a changing market. Last week, K Road Power canceled its 618-MW photovoltaic Calico project in Southern California. "Due to changed market conditions, we will not be able to move this project forward, either as licensed or as proposed to be amended," the New York City-based solar developer said in a California Energy Commission filing released Friday.

The market has changed, Sean Gallagher, K Road managing director for government and regulatory affairs, said Wednesday, declining to elaborate.

K Road's decision to halt the project follows BrightSource Energy's move to suspend or cancel two other projects. In April, BrightSource suspended its 500-MW Hidden Hills project, which was under contract to Pacific Gas and Electric.

The project in Inyo County on the Nevada border was put on hold because of challenges around the timing of transmission upgrades, Keely Wachs, a company spokesman, said at the time. Also, changes in the California energy markets point to the need for more flexible resources, like concentrating solar thermal power with storage, he said.

In January, BrightSource canceled its 500-MW solar thermal Rio Mesa project in Southern California.

While the renewables market may have had a role in the moves to shelve the projects, project-specific issues may also have been a factor, according to Smutny-Jones. “I think these projects had significant siting/environmental issues with them,” he said.

Longer term, California's renewable market appears healthy, Smutny-Jones said. Even when the RPS hits its 33% target, the market will continue to expand because of growing retail sales, which form the basis for the RPS goals, he said.

Also, there are discussions about expanding the 33% RPS, according to Smutny-Jones. Assembly Bill 177 was amended earlier this month to require the state's investor-owned utilities to get 51% of their energy from renewables by 2031. The bill is on track for hearings this year and a vote in 2014.

Ultimately, California's renewable market will be driven by its climate change policies, with the RPS playing a role in a broader effort to cut greenhouse gas emissions, according to Smutny-Jones. Coal-fired imports are down by about 50% from six years ago, he noted.

At the same time, once-through-cooling plants and the San Onofre nuclear plant will need to be replaced, likely with a mix of natural gas, renewables and other resources, Smutny-Jones said.

Timely procurement of all resource types will be a major issue for the state, Smutny-Jones said, pointing to three power projects that are coming online this summer. The projects – NRG Energy's 550-MW El Segundo repowering, Edison Mission Energy's 479-MW Walnut Creek project and Competitive PowerVenture's 800-MW Sentinel project – grew out of a 2006 solicitation and were “ready to go” at the time.

Some of the difficulties in bringing projects to fruition in California can be seen in K Road's Calico project. The project was originally developed by Stirling Energy Systems, which in 2005 landed an 850-MW PPA with Southern California Edison. However, the utility canceled the PPA in late 2010 just before the California Energy Commission approved the facility.

K Road bought the project near Barstow, California, in late 2010 and in June 2012 asked the CEC for permission to switch technologies to PV and build it in stages, starting with a 294-MW phase.

The CEC plans to hold a hearing August 14 to consider K Road's request that the license for the project be terminated, the state agency said Monday.

Defenders of Wildlife, the Natural Resources Defense Council and the Sierra Club sued several federal agencies last year to halt the project. The groups argued that the government had not adequately considered how the project would affect the desert tortoise and other threatened species.

— Ethan Howland

TransAlta cleared to sell power to PSE

Washington regulators have cleared the way for TransAlta to begin selling power to Puget Sound Energy under an 11-year power purchase agreement from the company's Centralia power plant.

"The approval of the contract has now been confirmed and ensures PSE customers will benefit from competitive power and the power plant" will continue to serve Washington's power needs to the end of 2025, Dawn Farrell, TransAlta president and CEO, said Wednesday in a statement.

“The approved contract agreement continues Washington state’s transition from coal to cleaner energy and enables PSE to provide customers with an affordable source of electricity,” Ray Lane, a spokesman for the Bellevue, Washington-based utility, said.

In early January, the Washington Utilities and Transportation Commission approved a PPA that would allow PSE to buy 346 MW on average of "coal transition power" from the 1,340 MW coal-fired Centralia power plant.

However, PSE balked at certain conditions imposed by the UTC, which the utility said created too much uncertainty around recovering PPA-related costs. The utility asked the UTC to reconsider its decision, saying that the utility would terminate the contract if the commission did not amend its order. In its order issued Tuesday, the UTC clarified that PSE may recover its costs for coal transition power starting in 2014.

The commission also approved an amendment to the PPA that requires TransAlta to regularly report to the UTC on how the plant is operating and information on energy deliveries under the contract.

The UTC rejected PSE's request for an increased “equity adder” as part of its cost recovery. In its original order, the commission approved a $1.49/MWh adder for all deliveries of power under the contract. The adder was designed to offset any financial advantages PSE would have had building its own plant instead of entering into the PPA.

Under the PPA, PSE will buy 180 MW of firm, baseload power starting in December 2014. A year later, the contract increases to 280 MW and from December 2016 to December 2024 the contract is for 380 MW. In 2025, the last year of the contract, PSE will buy 300 MW. TransAlta will retire the plant when the contract ends.

The contract grew out of a 2010 agreement with then-Governor Christine Gregoire. Under the agreement, Washington's greenhouse gas rules were waived for the Centralia plant. In exchange, TransAlta agreed to invest $55 million in the area. The Washington Legislature passed a “coal transition” bill that included incentives for utilities to contract for power from the plant.

With the contract and existing hedges, about 35% of Centralia's total available production will be contracted from 2014 until the end of 2020, and about 65% will be contracted from 2021 through 2025, the company said.

At least one environmental group supported the UTC's decision. “Not only is this power contract good for people and the environment in the long term, it turned out to be the most competitive generation resource choice for PSE,” Nancy Hirsh, NW Energy Coalition policy director, said Wednesday.

Meanwhile, one potential market for power from the Centralia plant was formerly shut Tuesday when Oregon Governor John Kitzhaber signed Senate Bill 242, which bars imports of new sources of conventional coal-fired generation into the state. TransAlta asked Oregon legislators to grant the Centralia power plant an exemption so the company could sell power to Oregon utilities. TransAlta argued that it plans to retire the plant so should be able to sell its power in the meantime into Oregon. The Legislature rejected the proposal.

— Ethan Howland

Daily CSAPR allowance assessments, Jun 26

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, Jun 26

	$/allowance	Change	$/st
S02 2013	0.67	0.00	1.34

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, Jun 25 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.53	0	Dec13	1.97	0
Dec13 V11	3.53	0	Dec14	1.97	0
Dec13 V12	3.53	0			
Dec13 V13	3.40	0			
Dec14 V10	3.53	0			
Dec14 V11	3.53	0			
Dec14 V12	3.53	0			
Dec14 V13	3.40	0			
Dec15 V10	3.53	0			
Dec15 V11	3.53	0			
Dec15 V12	3.53	0			
Dec15 V13	3.40	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.

AEP Ohio sees flat load growth over decade

Relatively flat load growth punctuated by a dearth of new generation projects highlights AEP Ohio's forecast for the next 10 years filed this week with the Ohio Public Utilities Commission.

“Change” is the byword for AEP Ohio, an American Electric Power subsidiary that includes Ohio Power and Columbus Southern Power. AEP Ohio is transitioning to competitive generation rates by mid-2015 and intends to transfer its 11,825

MW of mostly coal-fired capacity to an independent generation company, or genco, this year.

In its new long-term forecast, AEP Ohio said it expects electric deliveries to total 50.5 million MWh this year, rising to 50.9 million MWh in 2018 and to 51 million MWh in 2023.

Energy efficiency programs drive the minimal growth projections, AEP spokeswoman Vikki Michalski said Wednesday.

"Without the state energy efficiency program load, we could expect it to grow annually by 0.9% from 2013 to 2018," she said. "With the programs, it's pretty much flat."

Plus, she added, "The economy in Ohio just isn't as robust as it was prior to the recession" that began at the end of 2007. "Overall, the outlook is indeed for growth to be relatively flat through the whole period through 2023."

Under S.B. 221, Ohio's 2008 electric restructuring law that is under review in the General Assembly, utilities must reduce loads by 22.1% through energy efficiency programs by 2025. FirstEnergy, based in Akron, Ohio, is pushing lawmakers to roll back some of the requirements.

AEP Ohio expects its summer peak demand to increase from 10,777 MW this year to 11,157 MW in 2023, while the winter peak demand grows from 9,279 MW this year to 9,499 MW in 2023.

AEP Ohio plans a modest 30-MW turbine update this fall at its 2,600 Gavin coal-fired power plant on the Ohio River at Cheshire, Ohio, according to the report. Gavin is the largest power plant in Ohio and second-largest plant on the AEP system.

Tammy Rideout, another AEP spokeswoman, termed that a "potential investment."

Columbus, Ohio-based AEP has announced plans to retire almost 6,000 MW of older coal-fired generation, mostly in the Midwest, over the next few years to comply with Environmental Protection Agency rules.

In addition to its heavy reliance on coal-fired generation, AEP Ohio owns small amounts of natural gas and hydroelectric capacity, Rideout said.

She said AEP Ohio anticipates a decision this year from the Federal Energy Regulatory Commission on the company's application to transfer the generation assets to a genco.

Ohio Power awaits a Kentucky Public Service Commission order on its request to sell 50% of its 1,560-MW Mitchell coal plant near Moundsville, West Virginia, to Kentucky Power, another AEP subsidiary.

A PSC order is expected late this summer.

AEP Ohio's long-term outlook is similar to that of Duke Energy Ohio, which told state regulators last month it expects total energy growth of 0.4% annually from 2013 to 2023.

Without energy efficiency, Duke said the figure would be higher, with residential load projected to grow 2.1% annually.

— Bob Matyi

EIA seen estimating 88-92 Bcf storage injection

A consensus of analysts expect the Energy Information Administration on Thursday will estimate a natural gas storage injection of 88 Bcf-92 Bcf for the reporting week ended last Friday.

Addition to stocks within those expectations would be higher than a 58 Bcf injection seen during the comparable week last year and roughly the same as the five-year-average injection of 79 Bcf, according to EIA data. As a result, both the 559 Bcf deficit to last year's average and the 47 Bcf deficit to the five-year average should shrink.

The wider range of analyst expectations spanned from injections of between 75 and 95 Bcf.

EIA estimated a 95 Bcf build for the week that ended June 14, increasing the overall stocks to 2.438 Tcf.

Bentek Energy's supply/demand model predicts an injection of 90 Bcf for the week that ended Friday, while its pipeline flow model anticipates an addition to stocks of 88 Bcf. Bentek is a unit of Platts.

Jefferies & Co. analyst Subash Chandra, whose estimate of a 89 Bcf injection is at the lower end of the range, said power demand climbed 3% last week compared to previous week, but was still down 4% compared to last year. The weather was slightly milder than a year ago, with 50 cooling degree days compared to last year's 54. Last week's nuclear output was flat week-on-week and comparable with prior year levels, he added.

Given above-average injections for the last several weeks, "year-on-year storage surplus [is] disappearing faster than we expected," Chandra said. "Hopes for exit inventories of lower than 3.5 Tcf may be evaporating quickly."

Barclays Capital analysts said they expected storage at the end of October of 3.8 Tcf.

— Anastasia Gnezditskaia

Duke Fla. unit eyes RFP for 2016-20 supplies

Duke Energy's Florida utility subsidiary as soon as this summer may issue a solicitation for power the utility would need in the 2016-20 period if it determines its Crystal River-1 and -2 coal units cannot comply with the Mercury & Air Toxics Standards rule, Duke said Wednesday.

The Florida utility — formerly called Progress Energy Florida but now known as Duke Energy, like its corporate parent — has been studying whether, by switching to a different blend of cleaner coals, it could continue the operation of Crystal River's 372-MW Unit 1 and 503-MW Unit 2 for another three years or so after MATS becomes effective in April 2015, said Duke spokesman Sterling Ivey.

Doing so, Ivey said, would "allow us to keep [the coal units] in service until 2018 when we expect to bring a new [natural] gas-fired, combined-cycle unit online."

He added, "If we are not able to keep CR-1 and -2 in service, we most likely will have to consider purchasing power or building some peaker-type units to help meet customer needs" through the latter half of the decade.

Ivey noted that in the 10-year site plan Duke submitted to Florida regulators in April, the utility said it plans "to replace power due to the retirement of our nuclear plant, Crystal River-3, and the anticipated closing of [CR-1 and -2]…. We are currently evaluating our options and the next steps we will take."

Asked when Duke would likely issue a request for proposals for power, Ivey said, "I expect if we issue an RFP it will be later this summer."

Florida Public Service Commission rules require utilities that need more power to issue RFPs to help them compare the costs of purchased power with the cost of building utility-owned capacity. Utilities can ask for exemptions from the RFP rule, and the PSC grants them if the utilities make a convincing case that soliciting supply alternatives is not necessary.

In the meantime, Ivey said, Duke is reviewing the results of a test burn of "low-sulfur/low-chloride coal from Colorado" the utility completed at Crystal River last week. "We have a lot of data to review, and it will probably be several weeks before we have a final report from last week's test burn," he said, adding that based on the data, "we might conduct a second test burn later this summer or in the early fall."

Ivey said the aim of the recent test burn was to "see what kind of operational constraints we would have and to take extensive environmental compliance readings at various loads."

Duke announced in February that it will retire its 890-MW CR-3 nuclear unit, whose reinforced concrete containment building was damaged during a September 2009 steam generator replacement project.

Duke's 10-year site plan calls for the utility to begin commercial operation of a 1,307-MW, gas-fired combined-cycle facility at a yet-to-be-determined site in June 2018, and to bring online another very similar facility in June 2020. Duke is considering the possibility of building two new, 1,100-MW nuclear units at a greenfield site in Levy County, Florida. The units could come online as soon as 2024-25 if Duke commits to building them.

— Housley Carr

AEP unit details plans for W.Va. grid upgrade

Appalachian Power will spend more than $337 million to upgrade to its 138-kV transmission system near Charleston, West Virginia by 2017, the company said Wednesday.

Power plant retirements in the Kanawha and Ohio valleys will change the way electric power flows on the grid, the company said. The upgrades to the grid will address those changes and other issues identified by the PJM Interconnection, Appalachian Power said. Most of the upgrades will be in the Kanawha Valley.

Appalachian Power is a unit of American Electric Power. AEP in February 2012 retired the 600-MW Philip Sporn coal-fired plant in New Haven, West Virginia. It plans to retire the 400-MW Kanawha River coal-fired plant in Glasgow, West Virginia by June 1, 2015.

The retirements change "the dynamic of the transmission system and we have to put systems in place to adjust for that," Philip Moye, a company spokesman, said. No new generation will be added to make up for the loss of the power from the two retiring plants, he said, noting that the company has asked for approval to buy two-thirds of Unit 3 at the John Amos coal-fired plant near Charleston. The purchase would give the company 100% ownership of the plant.

PJM identified reliability issues that need to be addressed because of plant retirements, Ray Dotter, a spokesman for PJM, said. While the upgrades will have other benefits, plant retirements are the primary driver for the upgrades, he said.

PJM in its regional transmission expansion plan said other coal-fired retirements were also driving the need for the upgrades, including Appalachian Power's decision to retire units 5 and 6 at Glen Lyn and Unit 3 at Clinch River in Virginia and the Kammer plant near Moundsville, West Virginia. Others AEP retiring units cited by PJM as driving the Appalachian Power grid upgrades were at Pickway, Conesville and Muskingum in Ohio, Big Sandy in Kentucky and Tanner Creek in Indiana.

"These upgrades not only meet the immediate need to strengthen the grid, but position the region well for growth in the future," Charles Patton, the company's president and COO, said in a statement.

The company plans to rebuild about 52 miles of existing transmission lines and to upgrade substations.

Most of the work will be between the 2,933-MW John Amos coal-fired plant and the Turner and Cabin creek substations. Key loops in the Cross Lanes area and the Kanawha City area also will be upgraded along with the backbone transmission line that runs from Poca to Cabin Creek, the company said.

Existing transmission lines will be replaced with similar but sturdier conductor of the same voltage, the company said. Many of the 138-kV lines to be replaced were built as early as the 1920s through the 1940s. The towers holding the lines will be replaced with taller units of heavier construction that can carry more current, Moye said. In certain areas parallel high voltage transmission lines will be consolidated onto one tower, he said.

About 80% of the rebuilt line will be on existing right of way, but the other 20% will be moved to areas with more stable soils, Moye said.

Routing and construction details will be determined after additional fieldwork is done. At that point, AEP West Virginia Transmission Company will file requests for approval with the West Virginia Public Service Commission.

Construction is scheduled to begin this fall and be completed in 2017.

— Mary Powers

ISO-NE, NEPOOL seek time for market changes

ISO New England and the New England Power Pool asked federal regulators to provide more time to comply with an order to expand the conditions under which generators can seek cost recovery when they are ordered to run for reliability reasons.

ISO-NE and NEPOOL in a Tuesday filing said that the extra time would "permit the compliance filing to reflect the results of full stakeholder consideration of ISO-NE's proposed compliance changes, including consideration of those changes at the [NEPOOL] Participants Committee's regularly-scheduled August meeting."

The Federal Energy Regulatory Commission June 14 ordered ISO-NE to add two specific cases for when generators can obtain cost recovery through Federal Power Act section 205 filings when ordered to run for reliability reasons: when the unit is ordered to run "beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs" and "after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule."

FERC's action was in response to a petition from Dominion (Docket No. EL13-72, ER13-1291) that argued that ISO-NE's rules were flawed by not allowing Dominion's Manchester Street Station units to receive cost recovery for fuel and other expenses despite being ordered to operate for reliability reasons on February 8 and 9.

In the order, FERC required ISO-NE to submit tariff revisions by July 29, but ISO-NE and NEPOOL asked for an additional 15 days, pushing the due date for the compliance filing to August 13.

"If the requested extension were not granted, the compliance filing may not reflect full and meaningful stakeholder input through the Commission approved stakeholder process. The short extension requested would allow full stakeholder input on the proposed revisions, with some additional time for counsel to prepare and finalize a compliance filing reflecting such input," the parties said.

The filing also argued that the extension "will not adversely impact the implementation of the required market rule changes, particularly their effectiveness and implementation prior to the commencement of the 2013/2014 winter period."

— Bobby McMahon

FERC to discuss EPA rules at July event

The Federal Energy Regulatory Commission announced Tuesday that its upcoming conference on reliability will feature discussion on changes to the power sector's resource mix, pulling together views from the Environmental Protection Agency, grid operators, utilities and others.

The July 9 technical conference on the reliability of the bulk-power system will feature discussion on "what approaches are being taken by the industry, ISOs, and other system planners to address the continued changes in projected resource mix" from EPA rules for power plants, natural gas prices and other factors.

The discussion will also address how stakeholders are "identifying and responding to potential changes in the generation resource mix or in capacity reserve levels due to retirement of aging or other non-economically viable plants," which regions could be most impacted by retirements of coal plants and how regions are accommodating outages to install pollution control equipment.

Many in the utility industry have warned that recently finalized and forthcoming EPA rules for the power sector could cause reliability issues due to retirements and installation-related outages. But FERC Chairman Jon Wellinghoff and EPA officials have said relevant stakeholders are in regular communication on potential challenges.

Panelists for the discussion include representatives from the PJM Interconnection, the Midcontinent Independent System Operator, Southern Company, EPA's Office of Air and Radiation, the North American Electric Reliability Corporation and the Western Electricity Coordinating Council. This panel will discuss the status of "lessons learned" from the September 2011 blackout in California and the Southwest and cold weather outages from February 2011, according to the agenda.

Elsewhere at the conference, FERC commissioners and others are set to discuss the state of reliability on the bulk power system as well as NERC's process for standards and development and compliance activities.

— Bobby McMahon

Utility output falls 5.3% on year in week: EEI

Utilities generated 81,695 GWh in the week that ended Saturday, down 5.3% from the 86,302 GWh generated in the corresponding week of 2012, the Edison Electric Institute said Wednesday.

The weekly total was 758 GWh above the 80,937 GWh produced in the week that ended June 15, EEI said.

Output fell in eight of the nine regions EEI tracks, with the largest percentage decrease in the Mid-Atlantic region, where output tumbled 13.3% year on year to 8,741 GWh, followed by New England, which fell 12.9% to 2,467 GWh. Output in the South Central region was up 3.8% to 15,723 GWh.

Year-to-date utility generation was about 1.86 million GWh, 0.5% above the nearly 1.85 million GWh in the same period of 2012, EEI said.

— Paul Ciampoli

Record imports may be close to limits

...from page 1

In the previous auction (2015-2016), 3,935 MW of imports cleared, but only 1,539 MW from MISO. The cleared imports from MISO in the 2016-2017 auction represented a 208% jump and were by far the highest level in the auction's history. Cleared non-MISO imports, on the other hand, were higher than previous years, but were nearly 1,000 MW behind the 3,557 MW of imports that cleared in the 2011-2012 auction.

PJM, in a report written prior to the 2013 RPM, said that the amount of imports offered into the RPM from the West matched "fairly closely" the firm transmission capacity available for imports, after accounting for capacity benefit margin.

The CBM is transmission capacity that PJM leaves in reserve in the case of an emergency. PJM's total CBM is 3,500 MW and to the West it is 2,000 MW.

In that 2011 report, PJM also disputed a conclusion in a report by The Brattle Group that capacity imports could substantially reduce PJM capacity prices, as imports were already accounted for in previous auctions.

In fact, imports did depress capacity prices in the 2013 RPM. A sensitivity analysis by Monitoring Analytics, PJM's independent market monitor, shows that without imports, the auction would have cleared at $90.23/MW-day, rather than its actual clearing price of $59.37/MW-day. Even reducing imports by just 25% would have resulted in a RTO clearing price of $77.82/MW-day, according to Monitoring Analytics.

In an interview, Joseph Bowring, president of Monitoring Analytics, said the upper limit of transfer capability between the RTOs is not clear, but “my sense is that we are at the limit now,” unless companies invest in transmission upgrades.

Estimates of the limits of transfer capability are clouded by the level of transmission upgrades that will take place by next May when the next RPM takes place. It is unclear, for instance, how many of the cleared bids will require transmission upgrades, but some observers say it could be a fairly high number.

Eligible bids need only be confirmed in PJM’s firm transmission queue, not approved.

“Our concern is that one-third of the bids do not have firm transmission rights,” Glen Thomas, president of PJM Power Providers Group, said.

Andy Ott, executive vice president, markets, at PJM, said that 36% of the cleared import bids do not have firm transmission agreements, but that is a normal process, the same as a developer bidding in plant that is not built but expected to be completed by the auction’s delivery date. He added that many of the cleared bids awaiting firm agreements have “almost all” of their agreements confirmed, so that 84% are “pretty close” to having firm agreements.

If transmission upgrades are completed in order to secure firm capacity agreements that, in turn, could add to the MISO’s export capability.

But Ott cautioned that there is no single number for transfer capability viewed in terms of the pathways that lead into PJM. But there is a limit to how much energy PJM’s grid could handle and that is somewhere between 6 GW and 8 GW, he said.

Another limit on the future bidding of MISO resources into PJM’s capacity auction is the pending retirement of coal plants as a result of tighter emissions limits. MISO has identified as much as 13,000 MW of its coal plants that are at risk and has said that its currently robust reserve margin, now over 20%, could drop to single digits as a result of retirements by 2016.

Adding to the murkiness of the upper limits of transfer capability is the fact that MISO and PJM have very different views on how the reliability of capacity imports should be viewed. That became clear last week during a Federal Energy Regulatory Commission open meeting.

Ott argued at the meeting in favor of a unit specific analysis to determine if the output from a particular power plant would be deliverable. Internal and external resources should be treated equally, Ott said.

David Patton, president of Potomac Economics, MISO’s independent market monitor, says that if the cleared capacity were to be called on, the energy would not come from a particular resource, but from the MISO system as a whole.

MISO would see PJM’s need as a single load and turn up its dispatch level to serve that load while PJM would turn down its dispatch by a commensurate amount. “You can’t control the [exact path over which] electricity will flow,” he said.

The only question for the planning horizon is “how confidently you can turn up and turn down dispatch,” Patton said, adding, “we think the limit is 6 GW, or much higher under certain circumstances.”

Ott disputed Patton’s view, saying that approach would violate reliability criteria. In several different rulings FERC has already rejected that “slice of the system” approach, he said.

If, in fact, some of the cleared bids are called on and cannot deliver, they could face stiff penalties. The penalties are 125% of the clearing price settlement and is in terms of MW-days, so it adds up quickly, Ott said. But a bidder that cannot deliver has another option that they would probably go to first. They can enter PJM’s incremental auction and buy replacement capacity to fulfill their obligation, Ott said.

That could be part of some bidders’ strategy. “The risk could be very low, if they can’t deliver,” George Katsigiannakis, principal with ICF International, said in an interview. Himali Parmar, senior manager with ICF, noted that prices in the three previous incremental auctions have been lower than in the RPM. “We don’t see that happening again,” Katsigiannakis said.

Even taking into account speculative bids, there remains the question of why import bids were so high in this auction.

Several market observers have suggested that that one of the critical differences in the recent auction was the imminent incorporation of Entergy into the southern part of the MISO system. But Ott noted that only about 25% of the cleared bids from MISO came from the southern areas of the RTO. About 50% of the bids were from the middle swath of MISO, which includes Indiana, Illinois and Missouri. Ameren is one of the generators operating in that area.

Even before the auction, Ameren had said that, as a result of new transmission studies it has conducted, it planned to increase its export bids to 900 MW from 150 MW previously.

That could be a boon to Dynegy, which in March said that it had reached an agreement to buy Ameren’s Illinois generation portfolio.

That deal hit a hurdle earlier this month when the Illinois Pollution Control Board denied the transfer of pollution variances from Ameren to Dynegy. Dynegy said it remains committed to the deal and expects the matter to be favorably resolved soon.

With respect to the jump in imports, Katsigiannakis said RTOs are under increasing pressure to comply with FERC’s Order 1000 requiring tighter coordination and integration of transmission systems. In fact, reviving discussions about a joint and common market between MISO and PJM was one of the main topics at FERC’s open meeting last week.

As noted, PJM and MISO do not see eye to eye on how external resources should be analyzed. That, in part, reflects their different constituencies.

In PJM's stakeholder structure, merchant generators, which rely on both energy and capacity revenues to sustain their operations, have had a stronger say than they have had in the MISO stakeholder process, where regulated utilities have had a more dominant position. Typically, regulated utilities view mechanisms such as capacity auctions as placing an extra burden on ratepayers.

In addition, MISO, in a FERC filing, has argued in favor of ready access to capacity exports as a means of keeping companies from leaving MISO to join PJM, as has happened with Duke Energy and FirstEnergy.

Ott, however, offered his own explanation. This was the first RPM to occur after MISO's newly instituted capacity auction. MISO's capacity auction looks a year ahead and cleared at $1.05/MW-day in early April, a small fraction of the $59/MW-day clearing price of PJM's RPM. Bidders followed their economic interest, Ott said.

Unless the economics change, capacity bids are likely to flow along that path in the next RPM, even if the flow of electricity is not as predictable.

— Peter Maloney

Cal-ISO unveils reliability initiative

...from page 1

The July 17 meeting "will kick-off discussions on setting multi-year resource adequacy obligations backed by a market-based ISO backstop capacity procurement mechanism," the ISO said.

The ISO is integrating more renewables into the California grid and expects to lose roughly 2,000 MW of coastal generation this decade due to the state's requirement that power plants install "once-through cooling systems" if they use ocean water to protect turbines from overheating.

With these developments, reconsidering medium- to longer-term incentives for new generation has been a priority for Steve Berberich, the ISO's president and CEO.

Prior to July 17, the ISO expects to post on its website a proposal by its staff and staff at the CPUC for discussion at the meeting.

— Martin Coyne

MISO net power flow drops in scenario

...from page 1

in place. The second scenario includes MISO and PJM state RPS mandates with each meeting those standards with internal wind generation. The third scenario includes MISO and PJM meeting RPS standards, and PJM meets 40% of its RPS targets with MISO wind.

All of the scenarios included 12.6 GW of coal-fired generation retired in MISO and 14 GW of coal-fired generation retired in PJM.

In 2012, the maximum transfer from PJM to MISO totaled 6,217 MW and the maximum transfer from MISO to PJM was 3,326. The average transfer over the course of the year was 876 MW from PJM to MISO.

In the first scenario – which was the only one analyzed for Wednesday's meeting – the maximum transfer from PJM to MISO in 2017 would be 9,616 MW, the maximum transfer from MISO to PJM would be 6,513 MW, and the average would be 473 MW, down 46% from 2012.

In 2022, the maximum transfer from PJM to MISO would be 9,392 MW, the maximum transfer from MISO to PJM would be 7,650 MW, and the average would be 303 MW, down 65% from 2012.

In 2027, the maximum transfer from PJM to MISO would be 10,579 MW, the maximum transfer from MISO to PJM would be 7,543 MW, and the average would be 780 MW, down about 11% from 2012.

The MISO-PJM Interregional Planning Stakeholder Advisory Committee is to meet again Friday to discuss the full set of congestion analyses for the three scenarios.

By the end of July, the transmission seams congestion solutions will be submitted to each ISO's planning committees.

"By the end of November, we should have a pretty good idea of the cross-border projects that are justified by the joint operating agreement," Hecker said.

By May-June 2014, cross-border project recommendations may be made, she said.

— Mark Watson

PLATTS
McGRAW HILL FINANCIAL
MEGAWATT DAILY
Volume 18 / Issue 123 / Thursday, June 27, 2013
ISSN # 1088-4319

Managing Editor
Paul Ciampoli
News Desk
202-383-2254
electric@platts.com
Editor
Michael Fox
Market Reporters
Juliana Brint, Martin Coyne, Geoffrey Craig, Kassia Micek, Mark Watson, Eric Wieser
Market Editor
Mike Wilczek
Staff Reporters
Peter Maloney, Jeffrey Ryser, Tom Tiernan
Correspondents
Housley Carr, Lyn Corum, Ethan Howland, Bob Matyi, Mary Powers, Lisa Wood
Editorial Director, U.S. Market Reporting
Brian Jordan
Global Editorial Director, Power
Sarah Cottle
Vice President, Editorial
Dan Tanz
Platts President
Larry Neal

Megawatt Daily is published daily by Platts, a division of McGraw Hill Financial. Registered office Two Penn Plaza, 25th Floor, New York, NY 10121-2298

Officers of the Corporation: Harold McGraw III, Chairman, President and Chief Executive Officer; Kenneth Vittor, Executive Vice President and General Counsel; Jack F. Callahan, Jr., Executive Vice President and Chief Financial Officer; Elizabeth O'Melia, Senior Vice President, Treasury Operations.

To reach Platts
E-mail:support@platts.com
North America
Tel:800-PLATTS-8 (toll-free)
+1-212-904-3070 (direct)
Latin America
Tel:+54-11-4121-4810
Europe & Middle East
Tel:+44-20-7176-6111
Asia Pacific
Tel:+65-6530-6430

Manager, Advertisement Sales
Kacey Comstock

Advertising
Tel : +1-720-548-5508

UDI WORLD ELECTRIC POWER PLANTS DATABASE

NEW 2013 EDITION

UDI World Electric Power Plants Database (WEPP) is a global inventory of electric power generating units. It contains design data for plants of all sizes and technologies operated by regulated utilities, private power companies, and industrial autoproducers (captive power).

UNIQUE DATABASE IS THE LARGEST INFORMATION RESOURCE AVAILABLE

- Design information for more than 167,000 units at nearly 75,000 plant sites in 230+ countries — every country is represented
- Coverage of installed and projected steam and gas turbines, combined-cycle plants, IC engines, hydro units, wind turbines, and renewable energy units
- Details on plant operators, geographic location, capacity (MW), age, technology, fuels, and boiler, turbine, and generator manufacturers, emissions control equipment, and more

PURCHASE OPTIONS

All files can be opened directly in Excel or imported into Access or other database management software. Purchase the entire **World Electric Power Plants Database** or just select regions.

- All Units (CD-ROM)
- Asia (CD-ROM) — 44,000+ units
- Europe (CD-ROM) — 48,000+ units
- North America (CD-ROM) — 38,000+ units
- All Other (CD-ROM) —34,000+ units
- New Global Units (CD-ROM)
  - **new data subset** — this file pulls together all new and planned units of all technologies and fuels with in-service dates of 2010 and later at more than 4,000 plants worldwide

FOR MORE INFORMATION OR TO ORDER, VISIT WWW.UDIDATA.COM OR CALL YOUR NEAREST PLATTS OFFICE:

North America
1-800-PLATTS8 (toll-free)

Europe/Middle East/Africa
+44-20-7176-6111

Latin America
+54-11-4804-1890

Asia-Pacific
+65-6530-6430

For more information on Platts UDI databases and directories visit

WWW.UDIDATA.COM

PLATTS
McGRAW HILL FINANCIAL