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Tuesday, August 13, 2013

NRG Yield heralds new IPP business model

ANALYSIS The current earnings season is again highlighting the commodity risks associated with merchant generators, but new structures are emerging designed to bypass or mitigate those risks and offer a new business model for the power industry.

The new model takes advantage of the industry trend in which new, unregulated generation is increasingly being built on a contracted basis, with NRG Energy's new subsidiary, NRG Yield, providing an example.

The use of contracted assets differs from the traditional merchant generation model of building a power plant and living with the commodity risk of power prices.

Contracts for generation output include renewable power plants with a utility offtake contract to meet a renewable portfolio standard, a thermal plant contracted under a utility's long-term

(continued on page 15)

MidAmerican gains OK for more wind power

GENERATION MidAmerican Energy on Monday released the Iowa counties where it will build 1,050 MW of wind generation after state regulators on Friday approved a settlement enabling the project to move forward without a certificate of need.

MidAmerican did not need a certificate for the project, dubbed Wind VIII, because it is configured so that no more than 25 MW will be connected to each gathering line. The utility only needed approval of its ratemaking principles, the Iowa Utilities Board said.

The project met the two requirements for approval of the ratemaking principles by considering alternative sources of supply and by having an energy efficiency plan, the IUB said.

The company said it has secured development and interconnection rights for wind power sites planned for Grundy,

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FERC seeks more data on UTC transactions in PJM

MARKET OVERSIGHT The Federal Energy Regulatory Commission last week ordered PJM Interconnection to analyze how operating reserve charges are impacted by up-to congestion transactions, while also approving changes to the transactions.

FERC conditionally approved PJM's proposed changes to the UTC transactions (Docket No. ER13-1654) on Friday, saying the changes "improve market rule transparency and reflect the evolution of the UTC product from a day-ahead financial hedge of a real-time physical transaction to its present primary use as a purely virtual product."

UTC bids allow market participants to say how much they are willing to pay for congestion between two nodes by specifying a spread limit between the locational marginal price at both points. If the day-ahead congestion between those two price points is less

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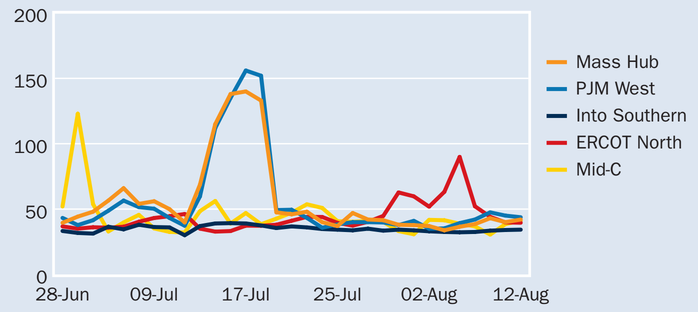
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Aug 13 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	43.23	46.21	25.87	27.88
NYISO	36.48	53.59	25.10	30.09
PJM	30.41	43.26	12.09	27.68
MISO	30.20	32.08	19.42	24.55
ERCOT	38.92	67.53	22.99	23.32
CAISO	39.06	41.99	30.86	33.75

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 Aug 13

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	42.00	11756	16.99	13.42	6.28	-0.87	-11.59
N.Y. Zone-A	37.00	11292	14.06	10.79	4.23	-2.32	-12.15
PJM/MISO							
PJM West	43.75	13715	21.42	18.23	11.85	5.47	-4.10
Indiana Hub	33.00	9807	9.45	6.08	-0.65	-7.38	-17.48
Southeast & Central							
Southern, Into	34.25	10232	10.82	7.47	0.78	-5.92	-15.96
ERCOT, North	39.56	12043	16.57	13.28	6.71	0.14	-9.72
West							
Mid-C	41.09	13024	19.01	15.85	9.54	3.23	-6.24
SP15	43.75	12792	19.81	16.39	9.55	2.71	-7.55

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

Northeast dailies climb, as do forwards

Daily power prices in the Northeast were mostly higher Monday, with spot natural gas prices up and electricity demand expected to be at its highest for the week on Tuesday. Forward prices also were higher as the NYMEX September natural gas futures contract settled at $3.31/MMBtu Monday, up 8 cents from its close on Friday.

Mass Hub on-peak power for Tuesday delivery climbed $2 to trade between $41.50/MWh and $42/MWh on the IntercontinentalExchange.

Mass Hub balance-of-the-week on-peak futures were bid at $33/MWh to $36.85/MWh on ICE, a solid discount to the dailies as loads are expected to fall later in the week. Mass Hub next-week on-peak futures were bid at $46/MWh and offered at $53/MWh on ICE.

ISO New England forecasted peak load at 19,060 MW for Monday. The peak load forecast was 19,660 MW for Tuesday and 17,330 MW for Wednesday. Temperatures for Boston are expected to fall about 5 degrees into the low 70s Tuesday.

Algonquin city-gates spot natural gas jumped about 23 cents to $3.561 /MMBtu on ICE.

New York Zone G on-peak for Tuesday delivery moved up $5.50 to the high-$40s/MWh on ICE. Zone G on-peak weekend futures were in the low-$40s/MWh. NY Zone A day-ahead on-peak prices slipped $1.50 to the mid $30s/MWh.

The New York ISO forecasted peak load at 24,187 MW for Monday. The forecast for Tuesday was 23,569 MW and Wednesday was 21,806 MW. Temperatures in New York are forecast drop about 5 degrees by Tuesday, to about 5 degrees below normal.

Transco Zone 6 New York spot gas rose 8.2 cents to $3.487/ MMBtu on ICE.

Day-ahead auction clearing prices in ISO-NE are down Monday for on-peak hours, even with steady loads expected on Tuesday and spot natural gas prices in the region moving up. Internal Hub on-peak for Tuesday delivery fell $4.77 to clear at $45.13/ MWh, while off-peak was up $2.03 to $27.32/MWh. Connecticut on-peak moved down $5 to $46.21/MWh and off-peak increased $1.83 to $27.88/MWh. NE-Mass Boston on-peak moved down $4.75 to $45.10/MWh and offpeak rose $1.90 to $27.12/MWh. Maine on-peak dropped $4.37 to $43.23/MWh and off-peak increased $2.01 to $25.87/MWh.

Day-ahead auction clearing prices in NYISO were mixed for on-peak and off-peak hours Monday, with demand expected to decrease Tuesday. New York City Zone on-peak rose $2.06 to $53.59/MWh. New York City off-peak rose $1.32 to $30.09/MWh. Hudson Valley Zone on-peak increased $1.74 to $48.61/MWh and off-peak was up $1.09 to $28.64/MWh. West Zone on-peak fell $3.82 to $36.48/MWh and off-peak rose $1.15 to $26.30/MWh.

Northeast term power prices climbed Monday with stronger natural gas futures. Mass Hub on-peak September financial futures

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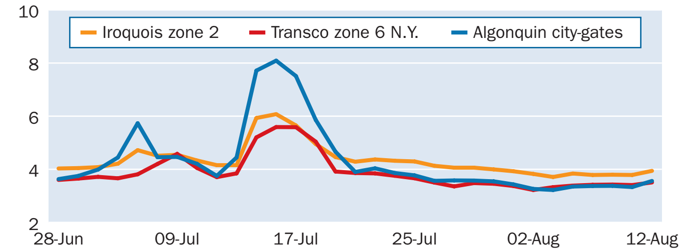
Northeast day-ahead bilateral indexes for Aug 13 ($/MWh)

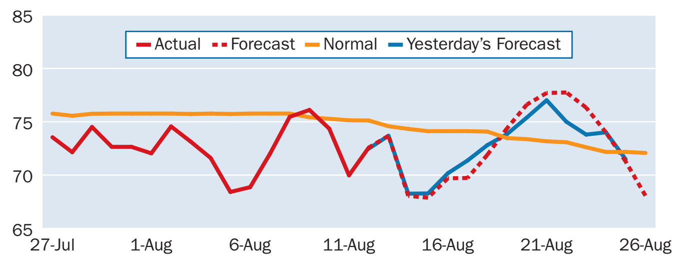
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	42.00	2.00	38.50	11756
N.Y. Zone-G	48.50	5.50	43.56	13029
N.Y. Zone-J	53.00	4.75	48.78	14238
N.Y. Zone-A	37.00	-1.00	36.92	11292
Ontario*	29.00	-1.50	29.72	7354
Off-Peak				
Mass Hub	27.50	1.50	24.86	7698
N.Y. Zone-G	28.75	0.75	27.00	7723
N.Y. Zone-J	34.00	4.00	28.75	9134
N.Y. Zone-A	26.00	1.50	24.19	7935
Ontario*	17.25	-2.00	17.58	4374

*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



ISONE & NYISO average temperature (°F)



Source: Custom Weather

Northeast load and generation mix forecast (GWh)

	Actual 11-Aug	%Chg	% Chg Year-ago	Forecast 12-Aug	13-Aug	14-Aug	15-Aug	16-Aug
ISONE								
Load	336	-11	3	370	395	378	364	368
Generation								
Coal	11	-51	81	18	18	15	14	16
Gas	154	-2	-12	161	161	150	146	151
Nuclear	81	0	-5	81	82	87	95	103
NYISO								
Load	436	-9	0	498	508	471	454	456
Generation								
Coal	16	-31	74	26	24	17	15	16
Gas	159	-8	-5	180	185	167	159	162
Nuclear	135	0	7	135	135	135	135	135

Source: Bentek

ISONE day-ahead LMP for Aug 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	45.13	0.00	-0.14	-4.77	37.89	12707
Connecticut	46.21	0.00	0.95	-5.00	38.60	12343
NE Mass-Boston	45.10	0.00	-0.17	-4.75	37.87	12699
SE Mass	45.10	0.00	-0.16	-4.53	37.97	12699
West-Central Mass	45.43	0.00	0.17	-4.85	38.16	12792
Rhode Island	44.66	0.00	-0.60	-4.37	38.37	12577
Maine	43.23	0.00	-2.03	-4.37	36.45	11176
New Hampshire	45.06	0.00	-0.20	-4.98	37.91	11650
Vermont	45.33	0.00	0.07	-5.12	38.19	11720
Off-Peak						
Internal Hub	27.32	0.00	0.03	2.02	24.08	8016
Connecticut	27.88	0.00	0.58	1.83	24.50	7674
NE Mass-Boston	27.12	0.00	-0.18	1.91	23.96	7955
SE Mass	27.11	0.00	-0.19	1.95	24.16	7952
West-Central Mass	27.52	0.00	0.22	2.02	24.24	8073
Rhode Island	27.39	0.00	0.09	2.10	25.21	8036
Maine	25.87	0.00	-1.43	2.02	22.96	6812
New Hampshire	27.06	0.00	-0.24	2.03	23.86	7128
Vermont	27.34	0.00	0.04	2.00	24.17	7200

NYISO day-ahead LMP for Aug 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	41.32	-0.44	2.31	-0.11	36.60	11563
Central Zone	38.90	-0.01	0.32	-0.86	34.95	11899
Dunwoodie Zone	50.43	-7.14	4.72	2.34	41.86	13605
Genesee Zone	37.56	-0.01	-1.02	-0.58	34.00	11487
Hudson Valley Zone	48.61	-5.48	4.56	1.73	40.97	13114
Long Island Zone	51.36	-7.15	5.64	1.98	45.52	13855
Millwood Zone	50.32	-6.98	4.76	2.30	41.79	13575
Mohawk Valley Zone	40.28	-0.43	1.27	-0.35	35.88	11848
N.Y.C. Zone	53.59	-10.06	4.96	2.06	45.98	14456
North Zone	36.81	0.00	-1.76	-0.10	32.44	9517
West Zone	36.48	-0.01	-2.11	-3.82	34.15	11157
Off-Peak						
Capital Zone	27.81	0.00	1.70	0.94	24.84	7961
Central Zone	26.44	0.00	0.32	1.09	23.54	8217
Dunwoodie Zone	28.73	0.00	2.62	1.02	25.64	7952
Genesee Zone	26.14	0.00	0.03	1.09	23.30	8126
Hudson Valley Zone	28.64	0.00	2.53	1.09	25.53	7927
Long Island Zone	29.31	-0.01	3.19	0.87	26.96	8112
Millwood Zone	28.69	0.00	2.57	1.03	25.61	7940
Mohawk Valley Zone	26.79	0.00	0.68	1.01	23.93	8027
N.Y.C. Zone	30.09	-1.09	2.89	1.32	26.82	8327
North Zone	25.10	0.00	-1.01	1.08	22.41	6611
West Zone	26.30	0.00	0.19	1.15	23.42	8176

Generation unit outage report

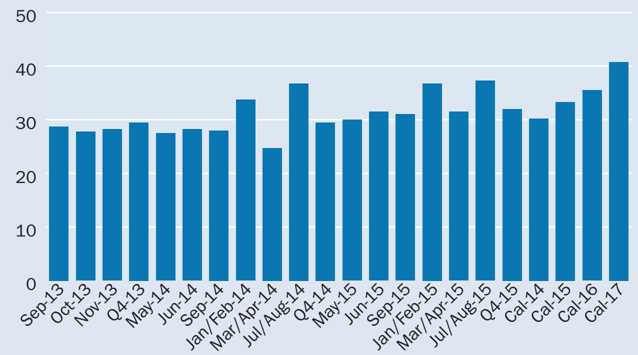
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	09/11/12
Bruce-1/Bruce Power	735	n	Ont.	Unk	Unk	07/31/13
Lambton-3/OPG	326	c	Ont.	Mo	Unk	07/31/13
Millstone-3/Dominion	1206	n	Conn.	MO	Unk	08/12/13
Nagagami	19	h	Ont.	Unk	Unk	08/08/13
Pickering-8/OPG	500	n	Ont.	Unk	Unk	08/12/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13

Northeast Platts-ICE Forward Curve, Aug 12 ($/MWh)

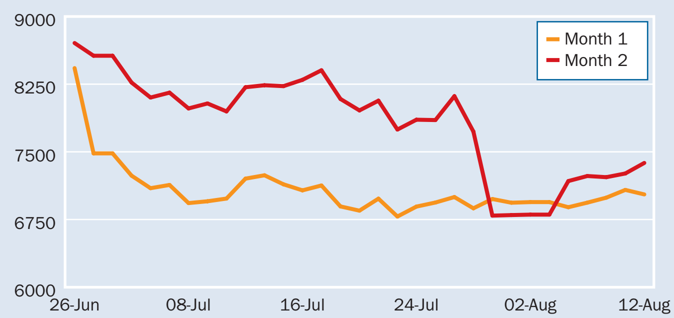
Prompt month: Sep 13	On-peak	Off-peak
Mass Hub	38.50	28.50
N.Y. Zone G	45.00	33.50
N.Y. Zone J	48.75	35.25
N.Y. Zone A	38.75	29.50
Ontario*	28.75	20.00

*Ontario prices are in Canadian dollars

Ontario*: Forward curve on-peak ($/MWh)



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



Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Next-week	08/12	48.00-52.00
Next-week	08/06	36.00-37.00
N.Y. Zone-G		
Next-week	08/12	53.00-57.00
N.Y. Zone-A		
Next-week	08/12	46.00-49.00

*Ontario prices are in Canadian dollars.

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.

SOUTHEAST MARKETS

Southeast dailies higher as ERCOT dailies dip

Power for Tuesday delivery in the Electric Reliability Council of Texas was priced lower on IntercontinentalExchange Monday, even with a peak load forecast slightly stronger and higher temperatures. Forward prices were higher as the NYMEX September natural gas futures contract settled at $3.31/MMBtu Monday, up 8 cents from its close on Friday.

Spot natural gas at Houston Ship Channel rose 4.6 cents to trade around $3.306/MMBtu.

ERCOT North Hub next-day on-peak physical power shed about 25 cents to trade around $39.50/MWh. Off-peak lost 25 cents to trade around $23/MWh.

High temperatures across ERCOT were forecast in the mid- to upper 90s Tuesday, with lows expected in the upper 70s to low 80s. The average August high temperature across the ERCOT region is in the mid-90s, with the average low in the mid-70s.

System load in ERCOT was forecast to peak at 62,850 MW Monday and 64,675 MW Tuesday, compared with an actual peak of 58,817 MW Sunday.

Real-time prices averaged $21.75/MWh and were flat from 12:15 to 6 am CDT Monday. Wind generation was forecast to peak at 3,375 MW at midnight CDT Monday and 3,900 MW at 2 a.m. CDT Tuesday.

North Hub balance-of-the-week on-peak packages were bid at $35.50 and offered at $37.50/MWh. Next-week on-peak was bid at $38.50 and offered at $40/MWh.

In the Southeast, power for Tuesday delivery was stronger Monday higher spot gas prices and temperatures forecast to be steady. Into Southern next-day on-peak power market was bid at $31.50 and offered at $37/MWh, a gain of about 25 cents from Sunday. Off-peak was bid at $24 and offered at $26/MWh, a jump of around $1.

Spot natural gas at Transco Zone-3 rose 5.9 cents to trade around $3.334/MMBtu.

High temperatures in Atlanta were forecast in the mid-80s Monday, with lows expected in the low 70s. The city's average August high temperature is 88. Its average low is 71.

The ERCOT day-ahead auction cleared stronger Monday. West

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Southeast & Central day-ahead bilateral indexes for Aug 13 ($/MWh)

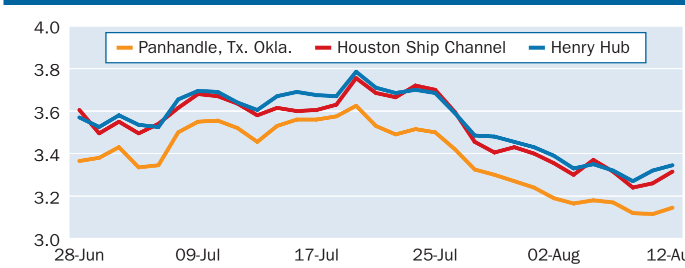
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	36.75	0.00	35.22	10545
Southern, Into	34.25	0.25	33.33	10232
Florida	37.00	-0.25	36.03	9933
TVA, Into	34.00	-0.25	31.86	10067
Entergy, Into	32.50	0.25	33.03	9819
Southeast Off-Peak				
VACAR	25.50	1.25	22.83	7317
Southern, Into	24.50	0.50	22.71	7319
Florida	28.00	2.25	25.73	7517
TVA, Into	24.00	0.50	22.50	7106
Entergy, Into	23.00	-3.50	24.13	6949
ERCOT On-peak				
ERCOT, North	39.56	-0.23	55.89	12043
ERCOT, Houston	39.50	0.00	56.11	11898
ERCOT, South	39.50	-0.75	56.33	12070
ERCOT, West	43.25	0.75	58.72	13369
ERCOT Off-Peak				
ERCOT, North	23.00	-0.25	23.13	7002
ERCOT, Houston	23.00	-0.25	23.38	6928
ERCOT, South	23.00	-0.25	23.35	7028
ERCOT, West	23.25	-0.25	23.52	7187
SPP/MRO On-peak				
MAPP, South	37.00	-2.00	39.67	11012
SPP, North	32.75	-0.75	34.81	10413
SPP/MRO Off-Peak				
MAPP, South	22.75	-3.50	24.37	6771
SPP, North	22.50	-3.25	23.96	7154

Southeast load and generation mix forecast (GWh)

	Actual 11-Aug	%Chg	% Chg Year-ago	Forecast 12-Aug	13-Aug	14-Aug	15-Aug	16-Aug
ERCOT								
Load	1110	-2	-1	1106	1159	1148	1087	1049
Generation								
Coal	424	-5	13	426	442	444	432	422
Gas	524	2	-11	515	537	515	461	430
Nuclear	123	0	-2	123	123	123	123	123
SPP								
Load	710	2	-5	686	708	701	667	656
Generation								
Coal	430	2	4	420	427	415	400	396
Gas	179	2	-26	185	192	178	164	159
Nuclear	49	0	-3	49	49	49	49	49

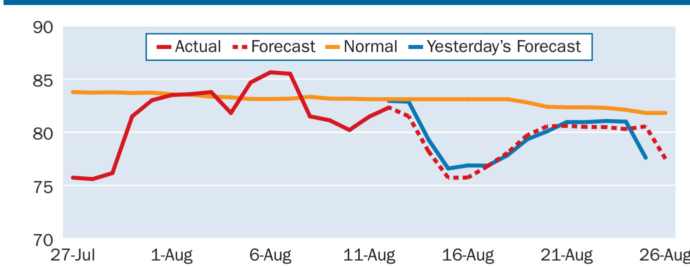
Source: Bentek

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



Source: Platts

ERCOT & SPP average temperature (°F)



Source: Custom Weather

ERCOT average day-ahead LMP for Aug 13 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	39.78	1.31	49.13	12163
Hub Average	40.36	1.43	49.50	12338
Houston Hub	39.32	1.17	48.95	11866
North Hub	39.34	1.29	48.83	12010
South Hub	38.92	0.91	48.61	11909
West Hub	43.83	2.32	51.59	13594
AEN Zone	40.86	2.12	49.87	12673
CPS Zone	41.05	1.72	49.59	12576
LCRA Zone	40.15	1.63	49.66	12301
Rayburn Zone	39.18	1.26	48.68	11961
Houston Zone	39.52	1.26	49.32	11925
North Zone	39.51	1.33	49.10	12060
South Zone	41.28	0.83	51.21	12631
West Zone	67.53	3.23	78.48	20946
Off-Peak				
Bus Average	23.07	0.30	23.19	7132
Hub Average	23.07	0.30	23.22	7131
Houston Hub	23.08	0.31	23.26	7032
North Hub	23.09	0.32	23.14	7147
South Hub	22.99	0.26	23.20	7078
West Hub	23.10	0.29	23.29	7290
AEN Zone	23.10	0.33	23.26	7287
CPS Zone	23.32	0.52	23.53	7237
LCRA Zone	23.11	0.33	23.30	7173
Rayburn Zone	23.09	0.32	23.26	7147
Houston Zone	23.08	0.31	23.26	7032
North Zone	23.09	0.32	23.26	7147
South Zone	23.10	0.31	23.30	7113
West Zone	23.27	0.21	23.51	7341

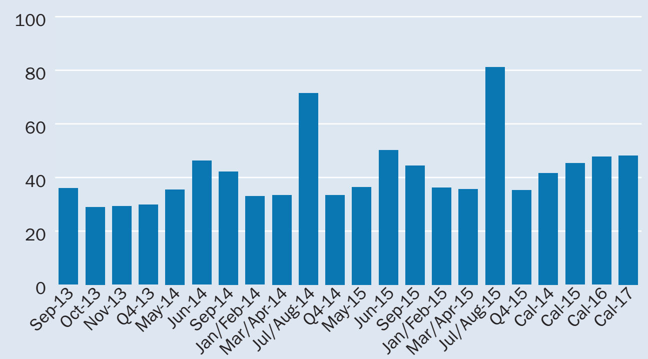
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	08/12	33.00-33.50
Bal-week	08/06	32.50-33.00
Bal-month	08/12	33.50-34.00
Bal-month	08/06	32.50-33.00
Next-week	08/12	33.00-33.50
Next-week	08/06	33.00-33.50
Entergy, Into		
Bal-week	08/12	30.25-30.75
Bal-week	08/09	32.00-32.50
Bal-week	08/06	33.00-33.50
Bal-month	08/12	32.50-33.00
Bal-month	08/09	34.00-34.50
Bal-month	08/06	32.75-33.25
Next-week	08/12	32.00-32.50
Next-week	08/09	32.50-33.00
Next-week	08/06	34.00-34.50
ERCOT, North		
Bal-week	08/06	64.75-65.25
Next-week	08/09	42.75-43.25
Next-week	08/06	55.00-57.00
ERCOT, South		
Bal-week	08/06	64.25-64.75

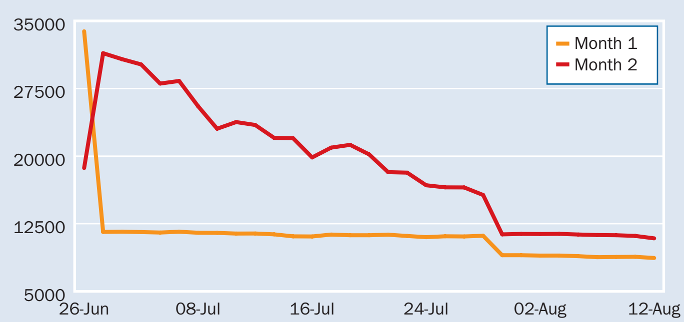
Southeast & Central Platts-ICE Forward Curve, Aug 12 ($/MWh)

Prompt month: Sep 13	On-peak	Off-peak
Southern Into	32.75	26.25
Entergy Into	32.00	23.75
ERCOT North	35.50	25.00
ERCOT Houston	38.25	25.75
ERCOT West	36.00	24.50
ERCOT South	37.00	24.00

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
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.	NA	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

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.

WEST MARKETS

Western dailies finish mixed; terms move up

Western power dailies were mixed Monday with about a 1,500-MW increase in California's expected demand and the move away from peak hours in the off-peak Sunday package. Terms gained ground, and the NYMEX September natural gas futures contract posted a preliminary settlement Monday of $3.31/MMBtu, up 8 cents from its close on Friday.

In the Northwest, Mid-Columbia day-ahead on-peak was up more than $2.50 to trade between $39.25 and $42/MWh for delivery on Tuesday. Mid-C day-ahead off-peak prices lost about $1.75 to trade between $25 and $25.95/MWh on IntercontinentalExchange. The Mid-C on-peak balance-of-the month package traded at $40.50/MWh, up around $2.75.

Portland, Oregon's forecast highs were in the high 70s to the low 80s through Tuesday. Expected lows were from the high 50s to around 60.

The Bonneville Power Administration's wind at 7 a.m. PDT Monday was 797 MW, and its hydropower was 6,312 MW.

In California, SP15 next-day on-peak declined more than 25 cents to trade between $43.50 and $44/MWh on ICE. SP15 day-ahead off-peak shed $6 to about $32.50/MWh. SP15 bal-month was bid at $46 and offered at $46.75/MWh, up more than 75 cents. NP15 day-ahead on-peak was down $1.50 to about $40.75/MWh. NP15 day-ahead off-peak dropped $3.75 to around $32.75/MWh. NP15 bal-month was bid at $42 and offered at $45/MWh, up $1.

Sacramento, California, expected highs around 90 and lows in the high 50s. Forecast highs for Burbank were in the low to high 80s and anticipated lows were in the low 60s.

The California Independent System Operator projected peak demand to hit 34,867 MW on Monday and 36,388 MW on Tuesday.

California renewables were 4,043 MW, and wind power was less than 2,200 MW at 7 a.m. PDT on Monday.

In the desert Southwest, Palo Verde next-day on-peak was up about $1 to trade between $35 and $37.50/MWh. Palo Verde day-ahead off-peak declined more than $3.75 to trade between $23.25 and $24/MWh.

Phoenix expected slightly above-normal-highs around 108 and lows in the high 80s.

Next-day natural gas prices rose in the Rockies and California. Opal was up 6.8 cents to $3.183/MMBtu, PG&E city-gate added 9.4 cents to $3.629/MMBtu, and SoCal city-gate climbed 10.9 cents to $3.504/MMBtu.

Day-ahead prices were up in the Cal-ISO auction Monday afternoon following the higher peak load forecast. SP15 on-peak rose $1.08 to $41.99/MWh, as SP15 off-peak added $1.13 to $32.04/MWh. NP15 on-peak added 29 cents to $39.56/MWh, and NP15 off-peak was up $1.29 to $33.75/MWh. ZP26 on-peak increased 38 cents to $39.06, while ZP26 off-peak climbed $1.11 to $30.86/MWh.

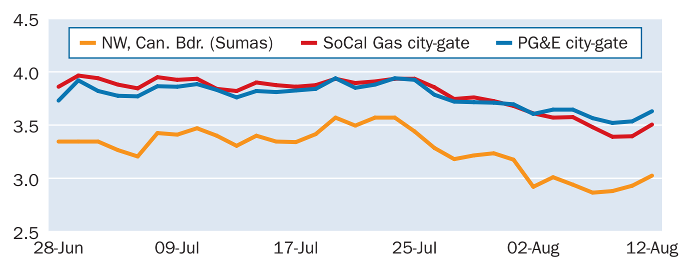
In the Northwest, Mid-Columbia on-peak September added $1 with bids at $36 and offers at $36.40/MWh on ICE around

(continued on page 10)

Western day-ahead bilateral indexes for Aug 13 ($/MWh)

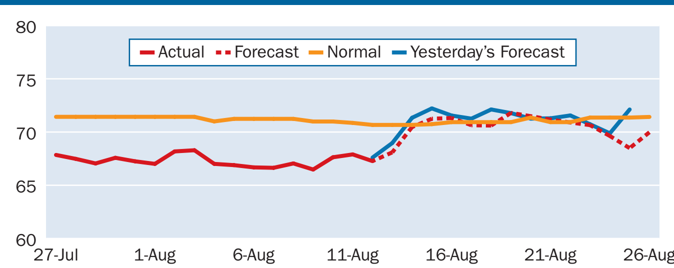
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	41.93	1.51	36.93	12405
Mid-C	41.09	2.59	35.83	13024
Palo Verde	36.10	0.75	36.02	10898
Mead	41.00	1.75	40.31	11988
Mona	41.50	-3.25	41.07	13323
Four Corners	38.50	-1.75	40.07	12012
NP15	41.00	-1.25	39.50	11295
SP15	43.75	-0.50	42.02	12792
Off-Peak				
COB	27.00	-1.00	25.60	7988
Mid-C	25.60	-1.82	24.33	8114
Palo Verde	23.53	-3.86	25.28	7103
Mead	25.25	-7.75	28.54	7383
Mona	23.75	-3.00	24.81	7624
Four Corners	23.50	-4.25	25.67	7332
NP15	32.75	-3.75	33.69	9022
SP15	32.50	-6.00	34.15	9503

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO average temperature (°F)



Source: Custom Weather

Western load and generation mix forecast (GWh)

	Actual 11-Aug	%Chg	% Chg Year-ago	Forecast 12-Aug	13-Aug	14-Aug	15-Aug	16-Aug
CAISO								
Load	632	-1	1	681	702	741	774	792
Generation								
Gas	238	-1	1	243	248	277	305	322
Nuclear	56	0	-8	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Aug 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	39.56	-0.80	-1.90	0.29	39.13	10898
SP15 Gen Hub	41.99	0.23	-0.49	1.08	40.76	12279
ZP26 Gen Hub	39.06	-0.21	-2.99	0.38	38.69	11421
Off-Peak						
NP15 Gen Hub	33.75	1.49	-0.26	1.29	33.65	9473
SP15 Gen Hub	32.04	0.26	-0.74	1.13	32.16	9622
ZP26 Gen Hub	30.86	0.00	-1.65	1.11	31.34	9267

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	08/09	43.75-44.25
Bal-month	08/09	37.50-38.00
Bal-month	08/07	37.75-38.25
Bal-month	08/06	38.25-38.75
SP15		
Bal-month	08/06	45.00-45.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Contra Costa-6/NRG	337	g	Calif.	PMO	Unk	05/01/13
Contra Costa-7/NRG	337	g	Calif.	PMO	Unk	05/01/13
El Segundo-3/NRG	335	g	Calif.	MO	Unk	07/23/13
Huntington Beach-3/AES	225	g	Calif.	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif.	PMO	Unk	04/14/13
Mexicali/Sempra	180	g	Calif.	PMO	Unk	07/22/13
Pine Flat/USACE	210	h	Calif.	PMO	Unk	08/11/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Retired	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Retired	01/31/12

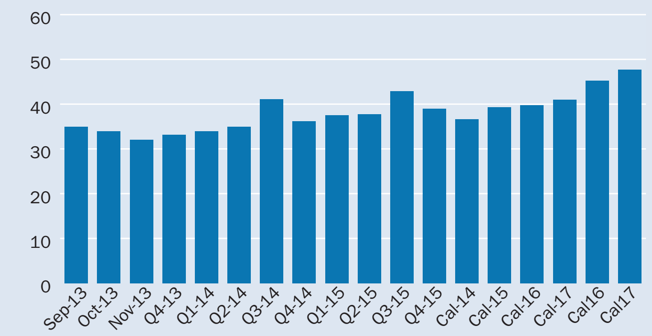
Market coverage

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.

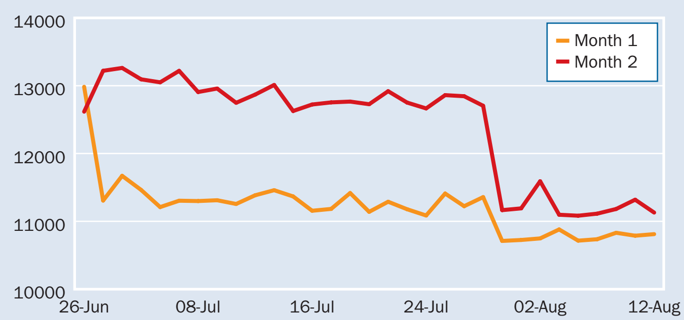
Western Platts-ICE Forward Curve, Aug 12 ($/MWh)

Prompt month: Sep 13	On-peak	Off-peak
Mid-C	36.25	28.50
Palo Verde	35.00	26.25
Mead	37.00	28.00
NP15	42.25	34.25
SP15	45.65	35.00

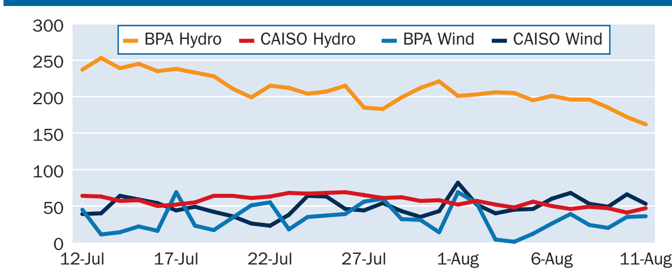
Palo Verde: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

PJM dailies stronger on spot gas gains

As daily power prices showed little activity in the Midwest Monday, Mid-Atlantic dailies gained strength, with higher spot natural gas prices countering the impact of lower electricity demand. Forward prices climbed as the NYMEX September natural gas futures contract settled at $3.31/MMBtu Monday, up 8 cents from its close on Friday.

PJM Interconnection forecasted peak demand for Monday at 129,138 MW. Demand was forecast at 115,363 MW for Tuesday and 105,719 MW for Wednesday. Temperatures in the eastern portion of PJM are forecast to drop into the 70s by Wednesday.

PJM West Hub day-ahead on-peak prices rose about $6.50 to trade between $43.50/MWh and $48/MWh on the IntercontinentalExchange. PJM West on-peak balance-of-the-week futures traded between $34.25/MWh and $35/MWh on ICE, a discount to dailies.

PJM West on-peak next-week futures traded from $50.75/MWh to $52.50/MWh on ICE.

Spot natural gas rose, with Texas Eastern M-3 gaining 13.4 cents to $3.344/MMBtu on ICE.

Midcontinent ISO daily prices moved little Monday, with mild weather ratcheting temperatures down, while prices remained firm in the eastern part of the US. Indiana Hub day-ahead on-peak prices were mostly unchanged in the low-$30s/MWh. Indiana Hub on-peak balance-of-the-week futures were at about $30/MWh on ICE, a slight dscount to daillies.

Dailies in the Midwestern portion of PJM were mixed as prices stayed firm in the east. AEP-Dayton Hub day-ahead on-peak climbed $1.75 to about $37/MWh. Northern Illinois Hub day-ahead on-peak was mostly unchanged at about $32/MWh.

Day-ahead auction clearing prices in PJM came down Monday for on-peak hours at most zones and hubs where load is expected to drop within PJM's footprint. Western Hub on-peak for Tuesday delivery fell $11.44 to $38.93/MWh, while off-peak rose 17 cents to $26.84/MWh. PJM Eastern Hub saw on-peak fall $10.54 to $41.24/MWh and off-peak moved up 13 cents to $27.38/MWh. PSEG on-peak was down $9.85 to $40.44/MWh and off-peak rose 10 cents to $27.26/MWh. Chicago Hub on-peak came down $9.32 to $31.14/MWh and off-peak was down $5.95 to $12.17/MWh.

MISO day-ahead auction prices cleared weaker Monday. Michigan Hub remained the highest-priced hub, with on-peak clearing at $32.08/MWh, a loss of $3.54. Off-peak cleared at $23.22/MWh, a drop of 39 cents.

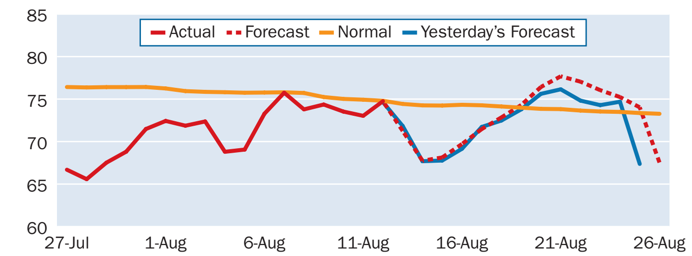
Indiana Hub on-peak cleared at $31.91/MWh, falling $4.20. Off-peak cleared at $22.91/MWh, losing 9 cents. Illinois Hub on-peak cleared at $31.78/MWh, down $1.76. Off-peak cleared at $24.55/MWh, up $3.14. Minnesota Hub remained the lowest-priced hub, with on-peak at $30.20/MWh, shedding $2.79 Off-peak cleared at $19.42/MWh, rising 24 cents.

Congestion costs at the hubs ranged from negative 84 cents to 88 cents for on-peak, and from negative $1.93 to $3.11 for off-peak.

PJM & MISO day-ahead bilateral indexes for Aug 13 ($/MWh)

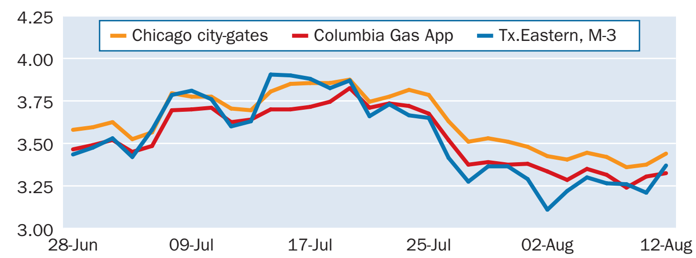
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	43.75	-1.25	40.72	13715
Dominion Hub	43.25	-2.50	40.19	12702
AD Hub	37.25	-0.75	35.97	10892
NI Hub	34.00	-1.00	34.08	9884
PJM Off-Peak				
PJM West	28.25	3.50	24.50	8856
Dominion Hub	28.75	4.00	24.58	8443
AD Hub	25.00	0.00	23.31	7310
NI Hub	18.00	-0.50	19.28	5233
MISO On-peak				
Indiana Hub	33.00	-2.00	34.00	9807
Michigan Hub	32.75	-3.00	34.64	9245
Minnesota Hub	31.00	1.00	32.58	9038
Illinois Hub	32.50	-1.75	33.25	9448
MISO Off-Peak				
Indiana Hub	22.50	1.00	22.56	6686
Michigan Hub	23.00	1.00	23.14	6493
Minnesota Hub	19.00	2.50	19.08	5539
Illinois Hub	21.00	-2.25	22.56	6105

PJM & MISO average temperature (°F)



Source: Custom Weather

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 11-Aug	%Chg	% Chg Year-ago	Forecast 12-Aug	13-Aug	14-Aug	15-Aug	16-Aug
PJM								
Load	2145	-5	1	2326	2364	2203	2117	2134
Generation								
Coal	999	-9	11	1106	1119	1126	1139	1161
Gas	376	5	-20	388	351	286	261	272
Nuclear	800	0	1	800	800	800	800	800
MISO								
Load	1323	-3	-2	1460	1452	1407	1401	1397
Generation								
Coal	1159	-2	6	1279	1205	1122	1102	1130
Gas	58	-5	-46	31	52	62	65	69
Nuclear	178	0	-11	178	178	178	178	178

Source: Bentek

MISO average day-ahead LMP for Aug 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	31.91	0.47	-0.09	-4.20	32.38	9497
Michigan Hub	32.08	0.09	0.46	-3.54	32.75	9071
Minnesota Hub	30.20	-0.84	-0.49	-2.79	30.03	8804
Illinois Hub	31.78	0.88	-0.63	-1.76	31.13	9254
Off-Peak						
Indiana Hub	22.91	0.58	0.28	-0.09	22.19	6880
Michigan Hub	23.22	0.33	0.85	-0.39	22.72	6629
Minnesota Hub	19.42	-1.93	-0.69	0.24	18.10	5712
Illinois Hub	24.55	3.11	-0.61	3.14	21.95	7250

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

Package	Trade date	Range
PJM West		
Bal-week	08/09	36.50-37.50
Next-week	08/12	49.00-52.00
Next-week	08/07	37.75-38.75
NI Hub		
Next-week	08/12	40.50-44.50
Indiana Hub		
Next-week	08/12	38.50-42.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Callaway/Ameran	1279	n	Mo.	MO	Unk	07/27/13
Kewaunee/Dominion	581	n	Wis.	NA	Retired	05/07/13

PJM average day-ahead LMP for Aug 13 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	32.32	-2.49	-2.06	-9.55	33.23	9645
AEP-Dayton Hub	33.73	-2.14	-1.01	-9.53	34.50	10066
ATSI Gen Hub	35.31	-1.55	-0.02	-9.88	36.08	10701
Chicago Gen Hub	30.41	-4.29	-2.17	-9.33	32.64	8850
Chicago Hub	31.14	-4.12	-1.62	-9.32	33.39	9063
Dominion Hub	38.84	1.86	0.10	-12.60	38.97	11418
Eastern Hub	41.24	2.43	1.93	-10.54	41.40	12064
New Jersy Hub	40.46	2.17	1.41	-9.91	40.68	11836
Northern Illinios Hub	30.82	-4.19	-1.87	-9.30	33.08	8968
Ohio Hub	33.85	-2.14	-0.89	-9.44	34.62	9947
West Internal Hub	36.16	-0.35	-0.37	-11.28	36.82	11361
Western Hub	38.93	1.57	0.48	-11.44	39.11	12232
AEP Zone	33.98	-1.97	-0.92	-9.71	34.63	10140
Allegheny Power Zone	36.08	-0.57	-0.23	-10.58	36.60	10978
Atlantic Elec Zone	40.79	2.24	1.68	-10.25	41.00	11932
ATSI Zone	35.68	-1.51	0.32	-10.38	36.52	10815
BG&E Zone	43.26	4.63	1.75	-12.23	42.87	13157
ComEd Zone	31.02	-4.17	-1.68	-9.35	33.30	9028
Dayton P&L Zone	34.61	-1.86	-0.41	-9.62	35.19	10300
Delmarva P&L Zone	40.93	2.43	1.63	-10.58	41.09	11973
Dominion Zone	39.24	1.96	0.40	-12.58	39.37	11536
Duke Zone	33.18	-1.66	-2.03	-9.93	33.91	9875
Duquesne Light Zone	34.10	-1.73	-1.04	-10.13	34.86	10697
JCPL Zone	40.51	2.28	1.36	-9.87	40.49	11851
MetEd Zone	39.47	2.17	0.42	-9.59	39.48	11649
PECO Zone	39.89	2.11	0.90	-9.99	39.85	11772
Pennsylvania Elec Zone	37.38	-0.27	0.77	-10.91	38.16	11944
PEPCO Zone	42.74	4.64	1.22	-11.89	42.12	13002
PPL Zone	39.69	2.43	0.39	-10.15	39.35	11715
PSEG Zone	40.44	2.14	1.43	-9.85	40.86	11831
Rockland Elec Zone	39.94	1.67	1.39	-9.98	40.48	11682
Off-Peak						
AEP Gen Hub	25.35	1.51	-0.96	0.02	23.20	7709
AEP-Dayton Hub	26.01	1.73	-0.53	0.02	23.89	7907
ATSI Gen Hub	26.30	1.58	-0.09	0.16	24.17	8077
Chicago Gen Hub	12.35	-11.15	-1.30	-5.89	19.74	3650
Chicago Hub	12.17	-11.61	-1.02	-5.95	19.97	3596
Dominion Hub	27.35	2.13	0.42	0.23	24.51	8120
Eastern Hub	27.38	1.76	0.82	0.13	25.12	8250
New Jersy Hub	27.21	1.73	0.68	0.11	25.06	8199
Northern Illinios Hub	12.21	-11.44	-1.15	-5.88	19.90	3608
Ohio Hub	26.11	1.78	-0.47	0.02	24.02	7742
West Internal Hub	26.47	1.69	-0.02	0.17	24.10	8488
Western Hub	26.84	1.72	0.31	0.17	24.39	8604
AEP Zone	26.03	1.67	-0.45	0.04	23.84	7914
Allegheny Power Zone	26.55	1.67	0.07	0.17	24.19	8208
Atlantic Elec Zone	27.28	1.72	0.75	0.11	25.05	8218
ATSI Zone	26.45	1.58	0.07	0.18	24.29	8126
BG&E Zone	27.68	1.84	1.04	0.23	25.18	8565
ComEd Zone	12.09	-11.64	-1.07	-5.94	19.92	3574
Dayton P&L Zone	26.26	1.70	-0.25	0.04	24.05	7886
Delmarva P&L Zone	27.32	1.76	0.76	0.16	25.04	8233
Dominion Zone	27.38	2.05	0.53	0.22	24.62	8129
Duke Zone	25.52	1.78	-1.07	-0.07	23.34	7662
Duquesne Light Zone	25.75	1.56	-0.62	0.15	23.57	8183
JCPL Zone	27.16	1.71	0.65	0.13	24.97	8184
MetEd Zone	26.70	1.71	0.18	0.19	24.58	8050
PECO Zone	26.94	1.73	0.40	0.14	24.72	8121
Pennsylvania Elec Zone	26.89	1.60	0.49	0.12	24.67	8688
PEPCO Zone	27.50	1.88	0.81	0.24	24.91	8508
PPL Zone	26.55	1.66	0.09	0.14	24.41	8006
PSEG Zone	27.26	1.75	0.71	0.10	25.19	8215
Rockland Elec Zone	27.17	1.70	0.67	0.07	25.03	8186

Mid-Atlantic forward prices rose Monday as gas futures moved up. PJM West on-peak September financial futures increased $1.25, with bids at $41.75/MWh and offers at $42/MWh on ICE in the afternoon. PJM West on-peak fourth-quarter rose 75 cents to $39.90/MWh. PJM West on-peak January-February 2014 financial futures increased 50 cents to $43.75/MWh on ICE.

Midwest forwards rose Monday with higher gas futures and power prices to the east. AD Hub on-peak September financial futures increased $1, with bids at $37.10/MWh and offers at $38/MWh on ICE. Indiana Hub on-peak September financial futures rose 75 cents, with bids at $34.10/MWh and offers at $34.50/MWh on ICE.

Northeast markets ... *from page 2*

jumped $1, with bids at $37.50/MWh and offers at $39.50/MWh on ICE at about 2:30 p.m. EDT. The prompt-month package moved up as much as $3 in morning trading. Mass Hub on-peak fourth-quarter packages rose $1.50 to $52.85/MWh and on-peak January-February packages climbed $3.50 to about $93.50/MWh.

New York Zone A on-peak September financial futures rose $1, with bids at $38.50/MWh and offers at $39/MWh on ICE. New York Zone G on-peak September financial futures climbed $2.50, with bids at $43.50/MWh and offers at $46.50/MWh on ICE.

Southeast markets ... *from page 4*

Hub remained the highest-priced hub, and South Hub remained the lowest. West Hub on-peak cleared in the ERCOT auction at $43.83/MWh, a gain of more than $2.25, while off-peak cleared at $23.10/MWh, a gain of nearly 25 cents.

North Hub on-peak cleared the auction at $39.34/MWh, up around $1.25 from Sunday's clearing price, while off-peak cleared at $23.09/MWh, an increase of around 25 cents. Houston Hub on-peak cleared in the auction at $39.32/MWh, adding almost $1.25, while off-peak cleared at $23.08/MWh, rising about 25 cents. South Hub on-peak cleared at $38.92/MWh, an increase of almost $1, while off-peak cleared at $22.99/MWh, up about 25 cents.

West Zone on-peak led the load zones at $67.53/MWh, gaining around $3.25 from Sunday.

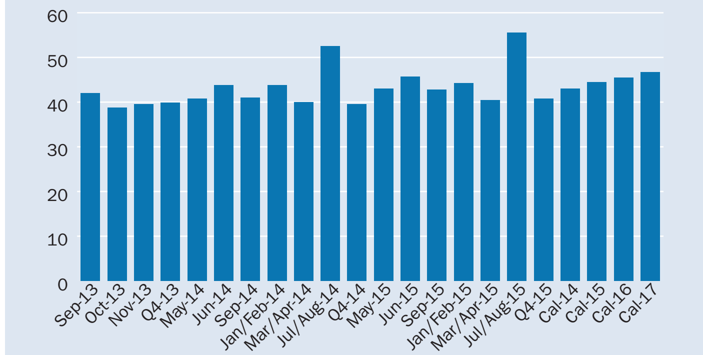
The highest hourly day-ahead price occurred at 5 p.m. CDT in the West Hub at $82.84/MWh and in the West Zone at $138.56/MWh. ERCOT system load was forecast to peak at 64,675 MW Tuesday, up 3% from Monday's expected peak of 62,850 MW.

Most South Central on-peak terms moved up at the front of the curve Monday. ERCOT North on-peak September stayed at about $35.50/MWh, October edged up 20 cents to about $30.70/MWh, and the fourth quarter climbed 40 cents to about $30.80/MWh. Heat rates were down about 260 Btu/kWh on ICE. Into Entergy on-peak September rose 50 cents to about $32/MWh, and Q4 surged 60 cents to about $31.75/MWh.

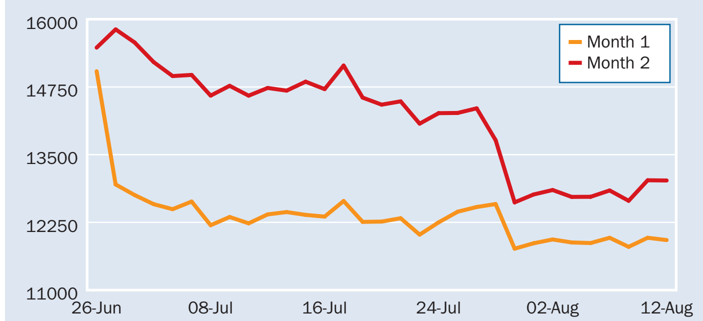
PJM & MISO Platts-ICE Forward Curve, Aug 12 ($/MWh)

Prompt month: Sep 13	On-peak	Off-peak
PJM West	42.00	29.00
AD Hub	37.75	26.75
NI Hub	34.75	21.50
Indiana Hub	34.25	24.25

PJM West: Forward curve on-peak ($/MWh)



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



Southeast on-peak September was up Monday, as were September NYMEX gas futures. Into Southern September rose 50 cents to about $32.75/MWh, October advanced 75 cents to about $32.25/MWh, and Q4 ascended 60 cents to about $32.75/MWh.

West markets ... *from page 6*

2:30 p.m. EDT. October advanced 75 cents to about $33.25/MWh, and the fourth quarter rose 65 cents to about $35/MWh. In California, SP15 on-peak September financial terms inched up 15 cents with bids at $45.60 and offers at $45.70/MWh. October stayed at about $43.50/MWh, and Q4 stayed at about $43.10/MWh. NP15 September rose 25 cents to about $42.25/MWh, and Q4 climbed 35 cents to about $40.60/MWh. Palo Verde September rose 25 cents to about $35/MWh, October surged 75 cents to about $34/MWh, and Q4 was up 40 cents to about $33.15/MWh.

NEWS

PJM opens solicitation on market efficiency

The PJM Interconnection is accepting proposals for projects that will help relieve transmission constraints identified in the grid operator's market efficiency analysis, PJM said Monday.

Proposals should address constraints that have been identified as one of the top 25 congestion events in PJM's market efficiency analysis for study years 2017, 2020 or 2023, PJM said in a presentation. PJM will also accept proposals to address market-to-market congestion or to relieve other congested facilities identified in PJM and the Midcontinent Independent System Operator's joint operating agreement planning study, according to the presentation.

Some of the constraints identified in the market efficiency analysis as having the highest expected congestion costs were the Breed to Wheatland Power Facility 345-kV line, the AP South loss of Bedington-Black Oak interface and the Pawnee 345-kV to Pawnee 138-kV transformer, according to the presentation.

This process marks the second instance in which PJM is using the competitive transmission proposal solicitation process mandated by the Federal Energy Regulatory Commission's Order 1000.

Order 1000 established a number of requirements regarding transmission planning and cost allocation, including a requirement that utilities give up their right to build regional power lines without competing with other developers. However, Order 1000 also allowed right of first refusal (ROFR) for local transmission projects, including facility upgrades, and for transmission projects on utilities' existing rights of way.

FERC allowed PJM to retain ROFR for short-term projects and for those that would address an immediate reliability need, but directed PJM to use a competitive solicitation process in other instances.

In late April, PJM began accepting proposals to address potential transmission grid needs in an area of southern New Jersey known as Artificial Island. The grid operator announced in July that it had received 26 proposals from eight companies in response to that solicitation.

Proposals under the market efficiency analysis competitive solicitation process will be accepted until September 26, according to PJM. The grid operator will run market simulations to establish benefit/cost ratios for the proposals and provide updates about the competitive solicitation process in Transmission Expansion Advisory Committee meetings, PJM said.

— Juliana Brint

BPA advancing 500-kV transmission line

After a few years of delay, the Bonneville Power Administration is moving forward with a 500-kV transmission line that will have about 1,500 MW of transfer capacity to deliver wind power and hydroelectric generation in southeastern Washington.

The roughly $90 million project includes about 38 miles of power lines that would run between the Central Ferry substation in Garfield County and the Lower Monumental substation in Walla Walla County.

The line was planned in response to transmission service requests, mainly from wind power developers who wanted to deliver energy from the Lower Snake River area to west of the Cascade Mountains, and to major transmission lines in the region like the California-Oregon AC Intertie and the Pacific DC Intertie.

After finishing an environmental review in early 2011, BPA put the project on hold because some wind power developers were withdrawing service requests. Iberdrola Renewables, for example, terminated an agreement to take service on the line.

However, a recent agreement between Puget Sound Energy, which asked for service on the line, and Portland General Electric gives BPA confidence to move forward, the federal power marketer said Friday. This month, PGE bought the development rights from Puget Sound Energy for a 267-MW wind farm that will be built north of Walla Walla. PGE expects the Tucannon River wind farm to be operational in 2015. PGE will receive energy from the wind farm over the planned transmission project.

"With this [transmission] project, we are able to help PGE meet its renewable resource needs at minimal cost to existing network customers," said Elliot Mainzer, BPA acting administrator.

BPA plans to start building the Central Ferry-Lower Monumental project in the spring and bring the project into service in December 2015.

The Central Ferry project affects other transmission efforts in the Northwest. BPA and NorthWestern Energy are preparing for a possible upgrade to the 500-kV Colstrip transmission line, which runs between Montana and Washington. The upgrade requires that the Central Ferry-Lower Monumental project is built.

The Colstrip upgrade would add 550 MW to 900 MW of capacity to the line, mainly for the benefit of renewable generators. NorthWestern and the other Colstrip line owners – Avista, PacifiCorp, PGE and Puget Sound Energy – aim to finish the upgrades to the Colstrip line by 2018.

BPA intends to release a draft environmental impact statement for its portion of the project in fall 2014, with a final EIS one year later.

NorthWestern is taking a cautious approach to the project, Robert Rowe, NorthWestern president and CEO, said July 25 during an earnings conference call, noting that the EIS process could take up to three years. "As a result of this long lead time and transmission market uncertainties that we have discussed before, we don't plan to continue quarterly updates on this project at least until the EIS results are known and the market need is reassessed," he said.

— Ethan Howland

ISO-NE seeks changes to winter reliability plan

ISO New England is asking the Federal Energy Regulatory Commission to approve changes to its program to bolster grid reliability for the coming winter, following the program's failure to secure sufficient bids to meet its objectives.

In a filing Friday (Docket No. ER13-1851), ISO-NE proposed to weaken penalties for the oil inventory aspect of the program. At the same time, it pressed FERC to accelerate review of the program and its changes to provide time for generators and demand response providers to be prepared for the program's launch this December.

ISO-NE in June proposed the program to help ensure reliability during the winter, specifically challenges the natural-gas-dependent region faces during extended cold weather periods. Last winter, the grid operator was forced to commit additional generating resources during a January cold snap and a February blizzard due to the inadequacy of generator fuel arrangements and the uncertainty created.

Under the program, ISO-NE proposed to create a winter demand-response program, pay oil and dual-fuel generators to maintain oil inventories, pay for tests to see if dual-fuel units with oil inventories are able to switch fuel sources in five hours or less and allow dual-fuel generators to bid using their higher-cost energy during the winter.

But in recent filings with FERC, ISO-NE said that it received insufficient bids to support the program's aims, specifically receiving only about 1.4 million MWh or the 2.4 million MWh sought. ISO-NE in the Friday filing with FERC said that oil-fired generators in recent discussions with the grid operator "identified a number of reasons for their low levels of participation in the oil inventory program," including the program's penalties and the time they would have to comply before the December 1 launch.

Under the initial proposal, oil-fired generators would face penalties for failing "to have committed inventory at the beginning of the program, for selling or transferring any of the program oil, for failing to successfully test dual fuel units, and for failing to replenish." In several cases, generators would face a daily penalty but could also lose all their compensation for the entire program.

But ISO-NE in the filing said that "participants indicated that these penalties were too harsh and that the 'cliffs,' pursuant to which the entire amounts were lost or came due, as applicable, approached too quickly. Participants argued that these penalties didn't recognize the tightness of the oil supply chain and the difficulty presented by numerous generators seeking to procure oil in the same timeframe."

As such, ISO-NE proposed to remove these "cliffs" for those units which fail to have enough oil at the launch of the program, those units which sell or transfer oil and those units which fail to test their units. Even with these and other changes to the penalties, ISO-NE said it "believes that these penalties will continue to provide sufficient incentives for performance under the Winter Reliability Program, and that the modifications will encourage increased participation in the program."

Regarding timing concerns, ISO-NE said in the filing that oil-fired generators said that "they would not make purchase

Daily CSAPR allowance assessments, Aug 12

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, Aug 12

	$/allowance	Change	$/st
S02 2013	0.64	0.00	1.28

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, Aug 9 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.09	0	Dec13	1.97	0
Dec13 V11	3.09	0	Dec14	1.97	0
Dec13 V12	3.09	0			
Dec13 V13	3.09	0			
Dec14 V10	3.09	0			
Dec14 V11	3.09	0			
Dec14 V12	3.09	0			
Dec14 V13	3.09	0			
Dec15 V10	3.09	0			
Dec15 V11	3.09	0			
Dec15 V12	3.09	0			
Dec15 V13	3.09	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.

commitments until the regulatory process was resolved, and that this would be more challenging to achieve both physically and financially as the winter approached for reasons that include the limitations of the oil supply chain." As such, ISO-NE asked FERC to speed review and action on the program.

ISO-NE in the filing also said that it will reopen bidding Monday for a week.

And while making several changes to the oil inventory aspect of the program, ISO-NE said it will not make several requested changes to the demand response program even though participation in that program was "disappointing," according to the ISO.

According to the filing, demand response providers said the requirements of the program – specifically, being available "for dispatch up to ten times during the winter on all days during hours ending 0600 and 2300" – raised concerns about potentially failing to perform and being subject to penalties, and that those penalties may be greater than their revenues from the program.

"The ISO acknowledges that this is a possibility, but believes that such penalties are necessary.

Without them – if there were only upside and no downside – there would be inadequate incentives to perform. The ISO considered other alternatives to changing the scope or penalty structure. In addition to implementation concerns, ISO-NE did not find any alternatives that preserved the integrity of the program design," the ISO said.

— Bobby McMahon

Natural gas' share in ERCOT rises

Natural gas' share of the Electric Reliability Council of Texas generation mix rose month on month in July for the second consecutive month, but was down when compared to 12 months earlier, according to data released late Friday by the grid operator.

ERCOT's 2013 Demand and Energy by Month report shows energy consumption across the grid operator's footprint totaled 33.6 million MWh in July, compared with 33.8 million MWh in July 2012, a 0.7% decrease.

National Weather Service data shows that Austin, which lies near the center of ERCOT's footprint, had 2.7% more cooling-degree days this July than in July 2012, but was consistent with a normal year.

Gas-fired plants provided 43.9% of the power consumed in ERCOT in July, an increase from 39.6% in June, according to the data. But gas made up 49.1% of ERCOT's generation mix in July 2012. This is the third month in this calendar year that natural gas' share of the market made gains after starting the year at 41.3% in January.

Houston Ship Channel natural gas prices averaged $3.596/MMBtu in July, starting the month at $3.495/MMBtu and falling to end at $3.430/MMBtu.

Coal-fired facilities generated 37.8% of the energy needed in July, down from 38.1% in June, but up from 33.7% in July 2012.

Nuclear plants provided 11.1% of the electricity consumed in July, down from 11.5% in June, but steady with the 11.1% used in July 2012.

Wind farms provided 6.2% in July, a drop from the 9.9% in June, but up from 5.8% in July 2012.

Other sources provided 1% of July's energy, up from 0.8% in June and 0.3% in July 2012.

ERCOT North Hub on-peak prices averaged $40.25/MWh in July, while off-peak averaged $24/MWh. Houston Hub on-peak averaged $41.50/MWh, while off-peak averaged $24.25/MWh. South Hub on-peak averaged $41/MWh and off-peak averaged $24.25/MWh. West Hub on-peak prices averaged $41.75/MWh and off-peak averaged $24.25/MWh.

ERCOT's peak demand in July was 64,814 MW on July 31, a 1.5% decrease compared with peak demand of 65,808 MW that took place on July 31, 2012.

— Kassia Micek

FERC enforcement staff defends BP analysis

In an effort to delay its response to Federal Energy Regulatory Commission accusations of manipulating the Houston Ship Channel gas market, BP was given a reluctant reprieve by Office of Enforcement staff, which said they would not disagree with the commission if they grant BP more time to reply to the staff's report.

BP requested more time to respond to the FERC on August 6, so the company could put together its defense and identify legal errors in the staff report. BP also said more time was necessary because of "new theories" related to its trading practices in the report and a lack of access to transcripts that were conducted in conjunction with the Commodity Futures Trading Commission in 2010.

FERC staff vigorously defended their more-robust analysis of BP's alleged manipulative trading strategy in their report. That came after BP claimed that enforcement staff "made a tactical decision not to give BP a chance to address its new theories before seeking a show cause order."

BP requested an additional 30 days, until October 4, to respond to FERC's claims.

Staff strongly denied that any additional analysis in their report compared with an earlier preliminary findings letter was reason enough to extend the BP response time.

"Although [Office of Enforcement] was not required to provide BP with an opportunity to respond to these refinements before the Report was issues, staff nonetheless allowed BP's counsel to review and take notes on a substantially similar draft of the Report in December 2012. Thus, BP has been on notice since at least the end of 2012 of the sum and substance of [Office of Enforcement's] analysis of the trading data that appears in the report."

Although FERC staff did not agree with the majority of BP's assertions, they did take into account that BP had only recently received full CFTC transcripts of depositions that were highlighted in FERC's report, notwithstanding the fact that "BP was allowed to read and take notes from these transcripts at FERC in October 2010," according to Office of Enforcement staff.

"As a matter of policy, the CFTC does not provide transcripts of its depositions while an investigation is ongoing, so it did not release the transcripts to BP… On August 5, [Office of

Enforcement] staff contacted the CFTC and obtained consent to release the transcripts and provided BP's counsel with them on August 8," OE Staff said.

The depositions were arranged by the CFTC when the FERC and the CFTC were jointly investigating BP's conduct, according to OE staff.

"Because BP only recently obtained transcripts of the CFTC depositions, staff does not object to a short extension of time for BP to file its Answer to the Order to Show Cause," OE staff said.

FERC enforcement staff alleged on August 5 that traders on BP's Southeast Gas Trading desk traded physical natural gas at Houston Ship Channel to increase the value of BP's swaps and financial spreads positions involving Houston Ship Channel.

FERC proposed that BP pay a civil penalty of $28 million and disgorge $800,000 plus interest in unjust profits.

— Christopher Tremulis

AEP utility defends biomass deal without RFP

Kentucky Power is defending a decision not to issue a request for proposals for what would be Kentucky's largest biomass power plant, a controversial 58-MW facility that critics claim would not generate enough sales of renewable energy credits to justify its development.

Responding to criticism from an industrial group, Kentucky Power, an American Electric Power subsidiary, said in a Friday filing with the Public Service Commission that it entered into a 20-year power purchase agreement to buy the entire output from the ecoPower Generation LLC biomass plant in southeastern Kentucky because the deal essentially was too good to pass up.

"The ecoPower (agreement) presented a unique opportunity for Kentucky Power to meet its capacity and energy obligations while, at the same time, diversifying its fuel portfolio and supporting a potential economic development engine in its service territory," said Gregory Pauley, president and COO of the utility.

Pauley said the terms of the PPA "are the result of extensive negotiations between Kentucky Power and ecoPower and represent a reasonable deal for renewable energy based in Kentucky."

The General Assembly's passage earlier this year of S.B. 46 is believed to have paved the way for Kentucky Power to reach the deal with ecoPower, a privately held company that has been searching for several years for an off-take arrangement for its estimated $150 million project. S.B. 46 authorizes the PSC to allow utilities to recover costs not collected in existing utility rates for the purchase of power from a biomass energy facility.

The PSC is expected to rule on the Kentucky Power/ecoPower contract later this year.

The Kentucky Industrial Utility Customers wants the transaction rejected, however, arguing that it could cost the utility's 175,000 ratepayers about $1 billion over the next two decades. Testifying on behalf of KIUC, Alan Taylor, president of Sedway Consulting of Boulder, Colorado, said Kentucky Power should be required to issue a competitive solicitation for renewable power.

Taylor said he believes there still is time for Kentucky Power "to conduct a solicitation for resources where it could gauge whether or not the costs of the ecoPower" contract are fair, just and reasonable. As the ecoPower project currently is structured, Taylor said he does not believe it can be defended from an economics standpoint.

The cost of the ecoPower RECs "are likely to be much higher than the REC market prices," he said. Kentucky Power has told KIUC it is seeing current REC market values in the range of $2/REC to $6/REC and did not perform an assessment of the value of the ecoPower RECs.

According to an assessment Taylor said he performed, RECs from the biomass power project "would cost the company an average of over $50/REC over the life" of the agreement. For the highest market energy and capacity price scenario, the average cost was was about $38/REC.

Given those figures, Taylor said, "Clearly, generating RECs at these prices is unlikely to result in cost-effective sales if the market price of RECs remains in the range of $2/REC-$6/REC. Indeed, such sales would yield a signficant loss."

Taylor conceded REC prices might increase in the future, but given that other renewable technologies can provide renewable energy and associated RECs at prices "that are so much lower than the ecoPower project, the long-term market price for RECs is unlikely to climb anywhere near the ecoPower cost range."

Using an annual generation estimate of 450,000 MWh from the ecoPower plant, a $38/REC cost and a $6/REC sales price, the above-market loss for Kentucky Power customers would be $288 million, Taylor said. At a $50/REC cost and a $2/REC price, the above-market loss would be $432 million.

— Bob Matyi

National Grid seeks supply for Massachusetts

National Grid is seeking supply for its residential, commercial and industrial default service customers in Massachusetts beginning November 1.

The utility posted a request for proposals Monday that sets an August 23 deadline for bidder information and contract modifications. Indicative pricing is due September 4 and final pricing a week later.

The utility seeks bids for 50% of its default service residential load from November 1, 2013, to October 31, 2014; 50% of commercial load from November 1, 2013, to October 31, 2014; and 100% of industrial load from November 1, 2013, to January 31, 2014.

Because Massachusetts is a restructured state, customers can come and go from utility supplied default service, so National Grid cannot precisely predict how much power it will need. However, the utility provides historical load information to help bidders gauge future energy use at http://www.nationalgridus.com/energysupply/.

For bidding purposes, the utility divided the supply need into 15 different blocks, which differ by load zone, customer type, load share or contract period. Bidders may offer proposals for any or all supply blocks, but cannot offer partial service to a supply block.

Prices must be made on a fixed $/MWh basis. Price may vary by load zone, calendar month and by customer group, but must be uniform for an entire calendar month and cover the entire term.

The utility will conduct its bid review in three stages. First, it will review qualifications and notify any bidders that fail to make the cut. To move forward from this stage, bidders also must execute a Master Power Agreement. Also, the utility will evaluate pricing and may seek clarification from bidders.

The utility will execute contracts no more than three days after final bids are due and submit them for approval, along with new rates, to the Massachusetts Department of Public Utilities. The DPU then has five days to review the results. If the DPU takes no action, the contracts go into effect. If it rules against the contracts, they become void.

National Grid will set its default service retail rates based on the winning bids from the RFP and power secured from earlier solicitations.

National Grid also asked bidders to separately offer proposals to meet the utility's renewable portfolio standard requirement, which is 18.1% of sales in 2013 and 19.6% of sales in 2014. More specifically, in 2013 the utility must supply 8% from Class I renewables; 3.6% from Class II; 3.5% from Class II waste; and 3.5% from alternative energy, such as combined heat and power and flywheel storage. For 2014, the utility must supply 9% from Class I; 3.6% Class II; 3.5% waste and 3.5% alternative energy.

The contact is Jorge Ayala, Wholesale Electric Supply/National Grid, (516) 545-3228; (516) 545-2464 (fax); electric.electricsupply@us.ngrid.com. The RFP is available at http://www.nationalgridus.com/energysupply/current_procurement.asp.

— Lisa Wood

NRG Yield heralds new IPP business model

...from page 1

procurement plan or under state procurement programs recently put in place in New Jersey and Maryland.

NRG Yield, "speaks to this new business model," UBS analyst Julien Dumoulin-Smith said in an interview.

NRG closed on the initial public offering for NRG Yield late last month, selling 22.5 million shares at prices ranging from $22 to almost $28 per share, netting about $468 million.

NRG Yield plans to use the proceeds from the offering to buy 1,447 MW of contracted power plants from NRG Energy. The cash flow from those plants would be used to pay dividends to NRG Yield shareholders. At the offering price, that represents a yield of about 4%.

NRG says it aims for NRG Yield to pursue an annual average dividend growth rate of 10% to 15% over the next five years. That growth, the company said, would come mainly through acquisitions, buying projects as they come online from NRG Energy, as well as from other companies.

Beyond the first set of assets the parent company is selling to NRG Yield, NRG Energy has identified another 1,039 MW of projects it could sell to NRG Yield. They are identified in a right of first refusal offer and include three solar power projects and the 550-MW El Segundo natural gas-fired plant in California.

Beyond the ROFO projects, Dumoulin-Smith says NRG's Astoria, Bowline and Dunkirk repowering projects in New York could be acquisition targets for NRG Yield, as could NRG Energy's Encina repowering project in California and its Old Bridge project in New Jersey.

During the NRG earning call on Friday, NRG CEO David Crane highlighted that NRG would use NRG Yield to acquire and build not only renewable projects but brownfield fossil-fuel projects, as well. Most of the fossil-fuel capacity that is going to be built is going to be replacement power, Crane said.

In addition, he said that with some of the strategic players "awakening from their long slumber" and becoming active in contracted solar projects, NRG will be better able to compete because NRG Yield would eliminate NRG Energy's cost of capital disadvantage.

The creation of NRG Yield "heralds the latest evolution of the IPP business model," Dumoulin-Smith wrote in an August 5 research report. The focus of that model is on contracted assets rather than merchant plants with their associated risk, he said.

As a first mover, Dumoulin-Smith sees "a plethora of both thermal (gas) and renewable (solar) acquisition targets to drive accretive growth" of NRG Yield's dividend.

Specifically he mentioned California assets owned by Edison Mission Energy, such as Walnut Creek and its cogeneration portfolio and its contracted wind assets. But primarily, he said, NRG Yield will compete for projects with private equity firms and could also be an acquistion target for private equity firms seeking exit strategies.

Dumoulin-Smith also said that other companies, such as Competitive Power Ventures, are likely to pursue a similar "MLP-like business model."

While NRG has been the first generator to pursue the structure, others are following suit. Another "yieldco" came to the market in Canada, with the transaction cloing August 9. TransAlta has spun off TransAlta Renewables in a C$200 million initial public offering.

TransAlta retains about 80% of the new company, which has acquired from the parent, interests in 28 wind and hydroelectric plants in Canada totaling 1,234 MW. TransAlta Renewables will have a net ownership interest in those plants of about 1,112 MW.

"TransAlta Renewables provides us with another effective source of capital for funding growth in renewables which will benefit the shareholders of both companies," TransAlta CEO Dawn Farrell said in a statement.

In its prospectus, TransAlta Renewables identifies "a significant need" for investment in both renewable and natural gas-fired plants in the US and Canada, driven by the replacement of aging facilities and the anticipated increase in in industrial activity and population growth.

As with NRG, the new company could buy additional assets from the parent company, and it has identified 813 MW of hydroelectric plants, 99 MW of wind farms in Quebec, and 164 MW of geothermal assets in California.

AES and its partner private equity firm, Riverstone Holdings, was planning a similar offering for the assets owned by AES Solar Energy, a joint venture of AES and Riverstone that was formed in March 2008. AES/Riverstone cancelled plans for the proposed $148 million offering of Silver Ridge Power in May, citing market conditions, but the company is expected to try to launch the offering again later this year.

The plan, according to a prospectus issued in April, was to sell 51 solar power facilities that would have had a total capacity of 522 MW.

Unlike NRG and TransAlta, however, Silver Ridge's assets are global, including projects in the US, Bulgaria, France, India, Greece and Italy and Spain, where government subsidies for solar power are under fire or have been reduced.

And, as with the NRG and TransAlta deals, Silver Ridge would have a right of first refusal to acquire projects developed by Juniper Point, a company set up by AES and Riverstone to develop utility-scale solar projects.

Another offering, for units — not common shares like the deals from NRG, TransAlta and AES/Riverstone — could price and possibly come to market later this month. Threshold Power Trust is seeking to raise about $140 million with an IPO of a foreign asset investment trust in Canada.

Threshold would use about $120 million of theproceeds to buy interests in nine wind farms in the US totaling 805 MW from J.P. Morgan affiliate JPM Capital, KEF Equity Investment (a subsidiary of KeyCorp), and EDP Renewables North America.

As with the other deals, growth would come from a right of first refusal offer. In Threshold's case it would enter into a ROFO with JMP Capital for the tax equity interests in any proposed sale by JPM of the 90-plus wind farms in which it has invested. Those wind farms have an aggregate capacity of more than 10,000 MW, according to the Threshold prospectus.

In the prospectus, Threshold says that there have been $13 billion in tax equity investments in US renewable energy projects since the end of 2008. Threshold estimates that most of those projects have already entered or are close to entering stage two of their partnership flip structure, the financial vehicle used for most wind projects that claim production tax credits.

In stage two, tax equity investors shift from receiving tax attributes to receiving cash distributions. When stage two ends – usually after about 10 years – the tax equity investors receive between 5% and about 22% of the cash distributions.

Threshold argues that tax equity investors in stage two projects are motivated to sell their interest so they can invest in new projects.

In the prospectus, Threshold estimates that by 2017 tax equity interests in US renewable energy projects originally representing investments of $9.8 billion from January 1, 2009 to December 31, 2011 could provide acquisition opportunities as the projects enter stage two. Cumulatively Threshold says there have been $23 billion of tax equity investments in US renewable energy projects from 2005 and 2011.

Threshold says that when its IPO closes, it expects to enter into a credit agreement with Union Bank and KeyBank for a $100 million credit facility that can be used for further acquisitions.

— Peter Maloney

MidAmerican gains OK for 1,050 MW ...from page 1

Madison, Marshall, O'Brien and Webster counties. The project in Marshall County is an expansion of the company's existing Vienna II wind farm. The others are new developments, said Abby Bottenfield, MidAmerican spokeswoman.

Construction on the $1.9 billion project is expected to begin in September and should be completed by the end of 2015, Bottenfield said.

The wind project likely will displace coal-fired generation, since that is often the marginal generation in the Midcontinent Independent System Operator, IUB staff said in a report accompanying the order.

"MidAmerican's analysis of future generation by fuel in its fleet indicates that Wind VIII will primarily displace generation outside of MidAmerican's territory. MidAmerican estimated no change in coal generation within its own fleet in 2016 and a small drop in coal generation due to Wind VIII in 2020. The drop in MidAmerican coal generation is made up with an increase in natural gas generation," the staff report said.

The IUB order said the settlement resolved issues raised by the consumer advocate and it set the return on equity at a compromise rate of 11.625% and 10% for funds used during construction.

MidAmerican compared the wind project to alternatives and found it to be the most favorable primarily because it has no pollution, no fuel price volatility and it provides economic benefits. The criteria where wind was not favorable were system reliability and flexibility, IUB staff said in the report.

MidAmerican compared wind power with other renewable resources based on availability, economics, and maturity of technology. It determined that wind is the most cost-effective renewable energy option in Iowa, the report said.

Energy generated from the wind turbines will be sent through collector lines connected to substations, which in turn will be connected to the transmission system, the staff report said. Collector lines will be constructed so that each line transmits 25 MW or less of wind power, because the IUB in 2003 issued an order saying that MidAmerican was not required under Iowa law to obtain a generating certificate. "MidAmerican believes that all the relevant facts and law with respect to the Wind VIII project are indistinguishable from those on which the declaratory order was based. MidAmerican was not required to obtain siting certificates for any of its prior seven wind projects," staff said.

MidAmerican estimates that the Wind VIII sites will have an average capacity factor of approximately 36%, but based on information provided by turbine suppliers, MidAmerican believes that capacity factors in excess of 40% are possible.

MidAmerican asked the board to make a decision on Wind VIII by August 5 because it would like to begin the project soon, noting that it is important to Facebook and its planned data center facility in Altoona, Iowa, and that Google has expressed interests in Wind VIII as part of its plans for expansion in Council Bluffs, Iowa.

Most information regarding MidAmerican's association with

Facebook was redacted from the staff report that accompanied the IUB order, except that there would be no purchased power contracts between the two. A portion of the renewable attributes from Wind VIII will be associated with Facebook's new data center to be built in Altoona, the staff report said.

MidAmerican will obtain all appropriate transmission interconnection, service and other related authorizations required prior to operating Wind VIII regardless of the sites selected, the staff report said.

— Mary Powers

FERC seeks more data on UTC transactions ...from page 1

than the bid, the transaction will clear and the bidder will be charged the day-ahead price of congestion between the two nodes.

FERC noted in the order that UTC transactions have "increasingly been used by financial market participants as virtual transactions and less by physical market participants as a congestion management tool." It noted that PJM reported that the number of UTC transactions has risen significantly since January 2010. According to FERC, PJM attributed this increase to the fact that these transactions are not assigned operating reserve charges.

PJM proposed several changes to the UTC transactions, including formally defining it as consisting of "a paired source and sink designation, as well as a price and megawatt quantity." The definition would limit the spread between the two nodes and "limit the eligible source-sink paths to those listed on PJM's website."

PJM also proposed to apply the forfeiture rules for financial transmission rights to UTC transactions, among several changes.

And while FERC said that the altered definition is "reasonable," it rejected PJM's proposal "to only specify on its website and in its manuals the eligible source-sink paths on which UTC transactions may be submitted and the maximum spread for UTC transactions."

Said FERC, "such practices significantly affect the ability to use UTC transactions and therefore are not provisions PJM should have unilateral discretion to adopt or modify. These terms and conditions, or the criteria by which they are to be determined, instead must be included in the PJM tariff."

FERC ordered PJM to submit a tariff revision outlining criteria for those paths and the maximum spread allowed when making UTC bids.

The commission in the order also noted that Monitoring Analytics, PJM's independent market monitor, objected to the ISO's use of not allocating operating reserve charges for UTC transactions while doing so for other virtual transactions. While FERC agreed with PJM that the issue "is beyond the scope of this proceeding," it noted that "whether and the extent to which UTC transactions should be subject to an allocation of operating reserve charges remains at issue."

In turn, FERC ordered PJM to within six months submit a filing that shows the impacts of UTC transactions, increment offers and decrement bids "on unit commitment, dispatch and operating reserve charges. The analysis should be based on the most current data available."

— Bobby McMahon

PLATTS
McGRAW HILL FINANCIAL

MEGAWATT DAILY

Volume 18 / Issue 155 / Tuesday, August 13, 2013

ISSN # 1088-4319

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

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