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Friday, April 12, 2013

Projects in PJM expected to reduce congestion

ANALYSIS The PJM Interconnection is bracing for record retirements of coal-fired generation brought on by low natural gas prices that would ordinarily challenge the grid. But, as a result of about $5 billion in mostly localized reliability projects, congestion forecasts are plummeting, indicating smoother transmission flows for the nation's largest power market.

Requests to retire more than 14,000 MW in the PJM region were made by the end of 2012 and early 2013, prompting the grid operator to authorize 777 transmission upgrades to the bulk electric system.

Yet, overall, PJM's rapid switch from coal to natural gas is likely to go off with few grid issues.

"PJM had seen this one coming," said Christopher Russo, vice president, practice leader of energy at Charles River Associates.

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PJM to impose new rules for financial traders

MARKETS The PJM Interconnection will institute new minimum participation standards for financial traders in order to avoid potential regulation by the Commodity Futures Trading Commission, PJM officials said at a Thursday meeting.

PJM and five other independent system operators in February 2012 requested exemption from CFTC oversight for four categories of wholesale electricity market transactions: financial transmission rights, energy transactions, forward capacity transactions and reserve or regulation transactions.

The CFTC granted the exemption request on March 28, subject to certain conditions. One of the conditions is that in order to qualify as exempt from CFTC oversight when transacting in any of the four categories specified by the ISOs in their original

(continued on page 24)

Dynegy CEO details strategy for Ameren plants

GENERATION When Dynegy announced its agreement to acquire Ameren's fleet of coal-fired merchant plants in Illinois last month, President and CEO Robert Flexon said one of Dynegy's objectives for its new plants would be to expand capacity sales.

But that process is going to begin before the expected close of the acquisition in the fourth quarter, Flexon said in an interview.

Ameren is going to sell 900 MW of capacity from those plants, which sit in the Midwest Independent Transmission System Operator region, into the PJM Interconnection's upcoming May capacity auction for the 2016-17 delivery year.

In the past, Ameren only sold 150 MW of capacity from its Edwards plant into PJM.

There are no regulatory restrictions to selling capacity from

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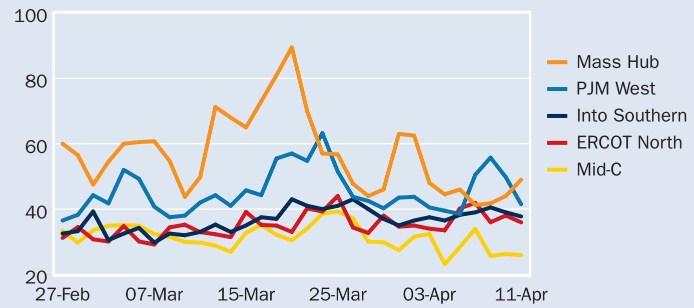
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Apr 12 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	47.68	54.90	34.77	46.04
NYISO	35.13	57.83	28.70	40.50
PJM	39.47	50.27	29.51	34.74
MISO	31.75	41.47	27.57	30.83
ERCOT	34.50	42.91	21.97	30.00
CAISO	43.94	59.90	34.44	38.17

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 Apr 12

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	49.00	9007	10.92	5.48	-5.40	-16.28	-32.60
N.Y. Zone-A	40.00	9339	10.02	5.73	-2.83	-11.40	-24.25
PJM/MISO							
PJM West	41.50	9996	12.44	8.29	-0.02	-8.32	-20.78
Indiana Hub	39.00	9264	9.53	5.32	-3.10	-11.52	-24.15
Southeast & Central							
Southern, Into	37.75	9185	8.98	4.87	-3.35	-11.57	-23.90
ERCOT, North	35.94	8902	7.68	3.64	-4.44	-12.51	-24.62
West							
Mid-C	25.91	6564	-1.72	-5.67	-13.57	-21.46	-33.30
SP15	54.50	13244	25.70	21.58	13.35	5.12	-7.23

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

Inside this Issue

NORTHEAST MARKETS

Dailies mixed as spot gas inches up

Daily power prices in the Northeast were mixed Thursday as spot natural gas prices moved up and the NYMEX May natural gas futures contract settled 5.4 cents higher, at $4.139/MMBtu.

Northeast dailies were mixed in for-Friday trading on the IntercontinentalExchange Thursday morning as spot gas traded higher on ICE and temperatures were forecast mostly lower.

Algonquin city-gates spot natural gas traded around $5.75/MMBtu on ICE, up 81 cents, while Tennessee Zone 6 traded around $5.40/MMBtu, a gain of 51 cents. Transco Zone 6 New York spot natural gas traded around $4.70/MMBtu, up 13 cents.

Temperatures in New England were forecast to decrease Friday, with highs ranging from the upper 30s to mid-40s and lows in mid-30s to around 40 degrees. Boston was expected to see a high of 41, down from a projected high of 50 on Thursday.

ISO New England forecasted peak load for Friday at 15,760 MW, up 140 MW from Thursday's projected peak load. The projected peak load for Saturday and Sunday was 14,130 MW and 14,540 MW, respectively.

Mass Hub day-ahead peak for Friday delivery traded around $50/MWh, up $6. Day-ahead off-peak was bid at $34.50/MWh and offered at $43/MWh, up about $6.50. Weekend peak packages were bid at $38 and offered at $52/MWh. Weekend off-peak was bid at $30/MWh and offered at $40/MWh.

At 10:30 a.m. EDT, the real-time price for Mass Hub power was $37.60/MWh.

In New York state, temperatures for Friday were seen as mixed, with New York City forecast to see a high of 51, down from a projected high of 63 on Thursday, while Rochester was expected to see a high of 55, up 14 degrees from Thursday's forecast.

The New York ISO forecasted peak load for Friday at 18,577 MW, down 310 MW from Thursday's projected peak load. The projected peak load for Saturday and Sunday was 17,149 MW and 16,966 MW, respectively.

NYISO Zone G day-ahead peak was bid at $45/MWh and offered at $47/MWh, down about $2.75. Zone G weekend peak was bid at $34/MWh.

NYISO Zone A day-ahead peak was bid at $39 and offered at $41/MWh, down about $2.25. Zone A weekend peak was bid at $35 and offered at $37/MWh.

Day-ahead prices for Friday cleared higher across the Internal Hub and zones in the ISO New England auction Thursday. Internal Hub peak cleared at $48.76/MWh, up $6.08, while off-peak cleared at $37.69/MWh, up $5.97. NE Mass Boston Zone peak cleared at $48.73/MWh, up $6.33, and off-peak cleared at $39.36/MWh, an increase of $7.61.

Connecticut Zone peak came in at $48.49/MWh, up $5.56, while off-peak came in at $35.48/MWh, up $3.54. Rhode Island peak cleared at $48.76/MWh, a gain of $6.37, while off-peak cleared at $37.69/MWh, a gain of $5.72.

The highest hourly price was $72.96/MWh at the Rhode

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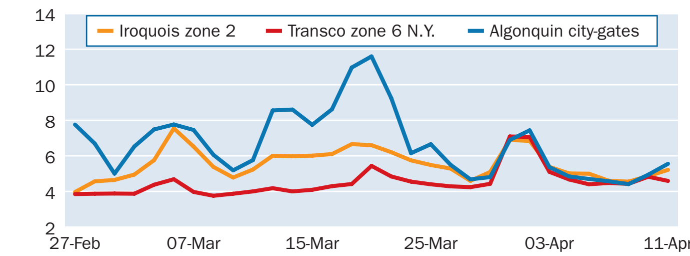
Northeast day-ahead bilateral indexes for Apr 12 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	49.00	5.00	48.60	9007
N.Y. Zone-G	46.00	-2.75	48.68	9388
N.Y. Zone-J	46.25	-3.00	49.38	9439
N.Y. Zone-A	40.00	-2.25	39.68	9339
Ontario*	33.75	-0.75	32.23	7421
Off-Peak				
Mass Hub	37.00	4.75	37.80	6801
N.Y. Zone-G	33.50	1.50	36.90	6837
N.Y. Zone-J	33.75	1.50	37.15	6888
N.Y. Zone-A	30.75	0.50	32.90	7179
Ontario*	28.25	1.25	26.65	6211

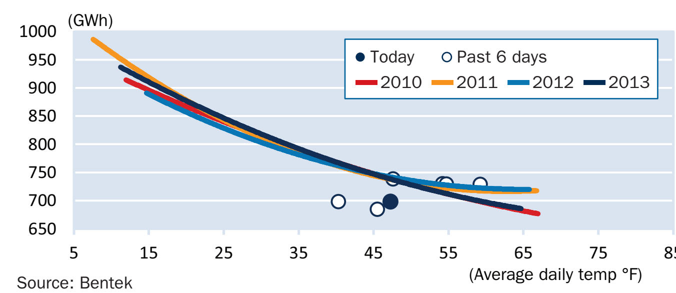
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO load per degree



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 10-Apr	%Chg	% Chg Year-ago	Forecast 11-Apr	12-Apr	13-Apr	14-Apr	15-Apr
ISONE								
Load	320	0	4	298	307	290	283	313
Generation								
Coal	7	10	39	9	11	8	7	7
Gas	111	5	-16	102	103	108	111	111
Nuclear	109	6	-1	109	109	109	109	109
NYISO								
Load	409	0	4	400	400	372	362	403
Generation								
Coal	10	-2	73	9	8	6	5	5
Gas	135	-4	-8	123	114	107	108	116
Nuclear	134	0	4	134	134	134	134	134

Source: Bentek

ISONE day-ahead LMP for Apr 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	48.76	-0.58	0.10	6.13	46.74	9117
Connecticut	48.49	-0.58	-0.17	5.56	46.96	9334
NE Mass-Boston	48.73	-0.58	0.07	6.33	46.69	9111
SE Mass	49.96	0.59	0.13	7.84	46.73	9341
West-Central Mass	48.91	-0.58	0.26	6.02	47.05	9146
Rhode Island	54.90	5.41	0.27	12.51	47.38	10266
Maine	47.92	-0.58	-0.72	5.57	45.14	9317
New Hampshire	48.91	-0.58	0.25	5.95	47.06	9508
Vermont	47.68	-0.58	-0.98	5.40	46.30	9269
Off-Peak						
Internal Hub	37.69	-0.97	0.03	5.97	37.20	7574
Connecticut	35.48	-3.00	-0.16	3.54	36.80	7204
NE Mass-Boston	39.36	0.66	0.06	7.61	37.36	7908
SE Mass	40.63	1.91	0.09	8.84	37.57	8164
West-Central Mass	37.51	-1.21	0.08	5.65	37.30	7536
Rhode Island	46.04	7.08	0.32	14.07	38.18	9250
Maine	39.06	0.68	-0.25	7.61	35.65	7930
New Hampshire	38.74	0.05	0.06	6.88	37.38	7864
Vermont	34.77	-3.05	-0.82	3.27	36.72	7057

NYISO day-ahead LMP for Apr 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	43.41	0.00	2.42	-1.87	47.48	8989
Central Zone	41.67	0.00	0.68	-2.55	41.36	9738
Dunwoodie Zone	45.59	0.00	4.59	-1.97	47.85	9312
Genesee Zone	40.86	0.00	-0.14	-2.25	40.15	9547
Hudson Valley Zone	46.16	0.00	5.16	-1.84	48.14	9429
Long Island Zone	57.83	-11.34	5.49	-3.21	60.36	11812
Millwood Zone	45.49	0.00	4.50	-1.99	47.83	9293
Mohawk Valley Zone	42.36	0.00	1.37	-2.54	42.49	9095
N.Y.C. Zone	45.97	0.00	4.97	-2.44	48.59	9389
North Zone	35.13	3.82	-2.04	-5.01	37.63	6830
West Zone	39.80	0.00	-1.20	-2.49	39.12	9300
Off-Peak						
Capital Zone	32.33	0.00	1.86	1.27	36.36	6944
Central Zone	30.90	0.00	0.43	0.81	32.64	7275
Dunwoodie Zone	32.85	0.00	2.38	1.24	36.08	6766
Genesee Zone	30.78	0.00	0.32	0.70	32.23	7248
Hudson Valley Zone	33.50	0.00	3.04	1.59	36.59	6902
Long Island Zone	40.50	-6.92	3.12	-2.94	43.05	8343
Millwood Zone	32.79	0.00	2.33	1.23	36.08	6755
Mohawk Valley Zone	31.25	0.00	0.79	0.88	33.33	6904
N.Y.C. Zone	33.00	0.00	2.54	1.23	36.28	6798
North Zone	28.70	0.60	-1.16	0.69	30.98	5826
West Zone	30.81	0.00	0.34	0.48	32.22	7253

Generation unit outage report

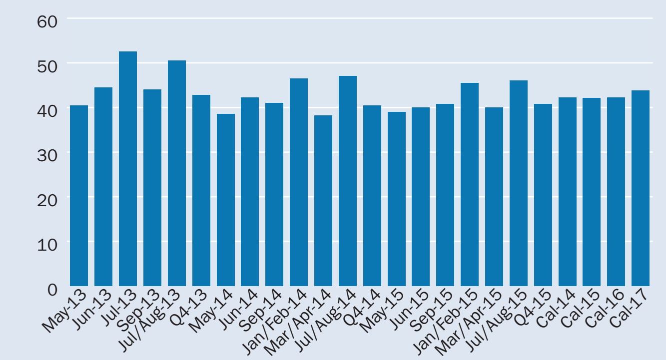
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-4/Bruce	740	n	Ont.	MO	Unk	08/02/12
Bruce-6/Bruce	825	n	Ont.	PMO	Unk	02/15/13
Darlington-4/OPG	878	n	Ont.	PMO	Unk	02/04/13
Pickering-1/OPG	452	n	Ont.	PMO	Unk	09/26/12
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13

Northeast Platts-ICE Forward Curve, Apr 11 ($/MWh)

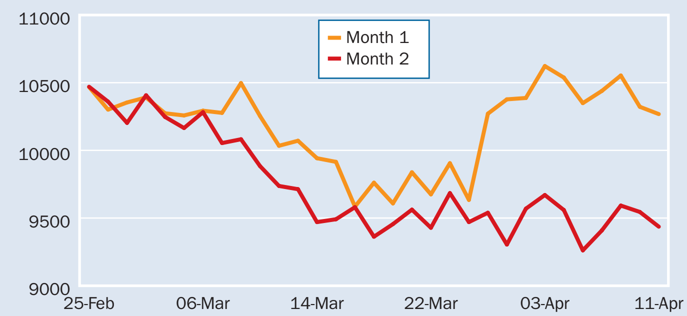
Prompt month: May 13	On-peak	Off-peak
Mass Hub	47.75	35.75
N.Y. Zone G	49.00	36.50
N.Y. Zone J	52.25	37.50
N.Y. Zone A	40.50	32.00
Ontario*	33.75	23.00

*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		
Bal-week	04/01	57.75-58.25

*Ontario prices are in Canadian dollars.

Daily generation outage references

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

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

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

SOUTHEAST MARKETS

Dailies drop as temperatures increase

Daily power prices in the Southeast dropped Thursday as temperatures were generally projected to rise. Forward prices moved up, with the the NYMEX May natural gas futures contract settling 5.4 cents higher Thursday, at $4.139/MMBtu,

Electric Reliability Council of Texas dailies for Friday delivery were weaker on the IntercontinentalExchange Thursday morning with peak load forecasted to decrease and temperatures expected to rise.

Spot natural gas at Houston Ship Channel rose 5.6 cents to trade around $4.086/MMBtu.

ERCOT North Hub next-day on-peak physical power lost about $2 to trade around $36/MWh on ICE. Off-peak dropped roughly $3.25 to trade around $26.75/MWh. South Hub on-peak fell $2.50 to trade around $36/MWh. Off-peak was offered at $27/MWh, $2.75 below Wednesday prices.

High temperatures across ERCOT were expected to rise to the low to upper 70s Friday. The average April high temperature across ERCOT ranges from the mid-70s to the low 80s, with the average low ranging from the mid-50s to the low 60s.

System load in ERCOT was forecast to peak at 37,575 MW Thursday and 34,625 MW Friday, compared with an actual peak of 37,383 MW Wednesday.

Real-time prices averaged $27.50/MWh from 12:15 a.m. to 6 a.m. CST Wednesday.

Wind generation was forecast to peak at 3,550 MW at 1 a.m. CDT Thursday, when it actually reached 2,450 MW. Wind output was forecast to peak at 6,975 MW at midnight CDT Friday.

North Hub on-peak next-week packages were bid at $40.75 and offered at $41.50/MWh.

In the Southeast, dailies for Friday delivery were weaker Thursday as temperatures were forecast decreasing.

Into Southern next-day on-peak power market was in the upper $30s/MWh, down about $1. Off-peak was bid at $28 and offered at $31/MWh on ICE, up about $2.50.

Spot natural gas at Transco Zone 3 was steady, near $4.108/MMBtu.

(continued on page 11)

Southeast & Central day-ahead bilateral indexes for Apr 12 ($/MWh)

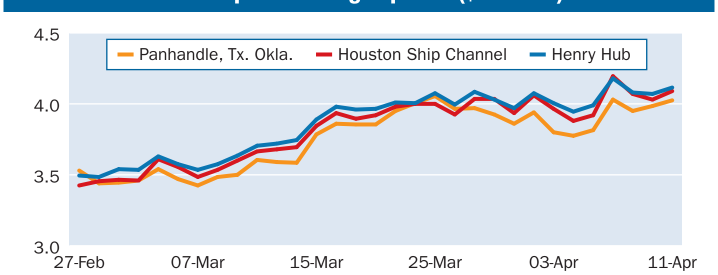
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	38.75	-3.00	39.30	9064
Southern, Into	37.75	-1.25	37.70	9185
Florida	39.50	-1.50	39.13	9122
TVA, Into	38.00	-1.00	37.50	9102
Entergy, Into	36.75	0.75	35.65	8996
Southeast Off-Peak				
VACAR	29.00	1.00	28.73	6784
Southern, Into	29.00	2.00	27.81	7056
Florida	31.50	1.75	29.44	7275
TVA, Into	29.25	2.00	28.06	7006
Entergy, Into	27.50	2.00	26.04	6732
ERCOT On-peak				
ERCOT, North	35.94	-2.09	36.72	8902
ERCOT, Houston	36.00	-1.00	36.85	8807
ERCOT, South	36.00	-2.50	37.28	8862
ERCOT, West	36.00	-1.00	36.23	8961
ERCOT Off-Peak				
ERCOT, North	26.91	-3.09	26.17	6665
ERCOT, Houston	26.50	-3.25	26.08	6483
ERCOT, South	26.50	-3.25	26.08	6523
ERCOT, West	23.25	-4.25	23.17	5787
SPP/MRO On-peak				
MAPP, Soth	39.00	0.75	37.75	9220
SPP, North	38.50	1.50	36.60	9565
SPP/MRO Off-Peak				
MAPP, Soth	30.00	0.50	26.90	7092
SPP, North	27.50	0.50	25.58	6832

Southeast load and generation mix forecast (GWh)

	Actual 10-Apr	%Chg	% Chg Year-ago	Forecast 11-Apr	12-Apr	13-Apr	14-Apr	15-Apr
ERCOT								
Load	811	-4	2	750	726	702	720	866
Generation								
Coal	381	8	18	337	333	325	321	328
Gas	267	-19	-13	279	265	270	284	319
Nuclear	62	0	0	62	63	67	75	83
SPP								
Load	611	2	-1	617	588	566	587	601
Generation								
Coal	404	4	16	408	400	390	384	383
Gas	135	12	-25	139	125	113	116	125
Nuclear	19	0	9	19	19	19	19	19

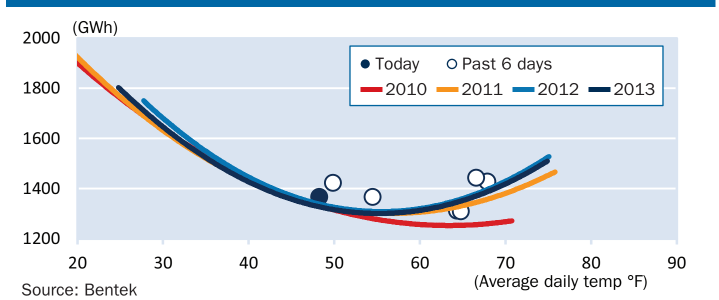
Source: Bentek

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



Source: Platts

ERCOT & SPP load per degree



Source: Bentek

ERCOT average day-ahead LMP for Apr 12 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	34.55	-5.38	36.23	8535
Hub Average	34.58	-5.48	36.22	8543
Houston Hub	34.61	-5.13	36.43	8476
North Hub	34.50	-5.28	36.21	8556
South Hub	34.59	-5.15	36.37	8512
West Hub	34.62	-6.28	35.87	8635
AEN Zone	35.85	-4.65	36.54	8940
CPS Zone	34.77	-5.17	36.61	8566
LCRA Zone	34.92	-5.05	36.44	8602
Rayburn Zone	34.80	-5.01	36.47	8631
Houston Zone	34.61	-5.16	36.43	8474
North Zone	34.65	-5.14	36.36	8592
South Zone	35.06	-4.93	36.90	8630
West Zone	42.91	-22.99	50.36	10701
Off-Peak				
Bus Average	26.02	-6.36	26.49	6467
Hub Average	25.34	-6.95	26.10	6297
Houston Hub	26.44	-5.99	26.78	6525
North Hub	26.80	-5.70	26.90	6687
South Hub	26.14	-6.24	26.68	6451
West Hub	21.97	-9.88	24.03	5533
AEN Zone	26.15	-6.34	26.64	6585
CPS Zone	26.10	-6.30	26.69	6473
LCRA Zone	26.08	-6.30	26.65	6470
Rayburn Zone	30.00	-2.96	28.42	7485
Houston Zone	26.43	-5.99	26.77	6522
North Zone	28.18	-4.52	27.65	7031
South Zone	26.15	-6.26	26.72	6453
West Zone	22.74	-12.59	26.23	5728

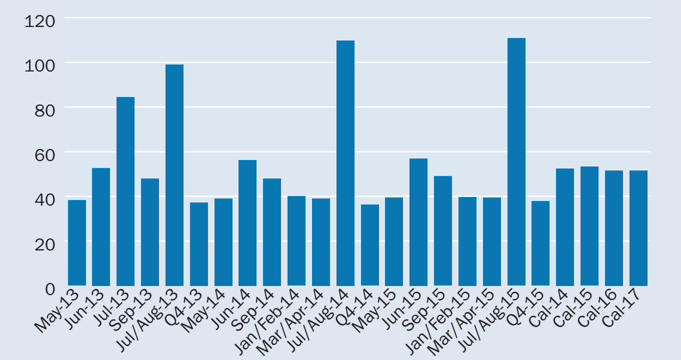
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	04/10	37.50-38.00
Bal-week	04/09	38.75-39.25
Bal-week	04/08	36.75-37.25
Bal-month	04/11	36.50-37.00
Bal-month	04/10	36.50-37.00
Bal-month	04/09	37.75-38.25
Bal-month	04/08	38.75-39.25
Next-week	04/11	36.50-37.00
Next-week	04/10	35.50-36.00
Next-week	04/09	37.75-38.25
Next-week	04/08	37.75-38.25
Next-week	04/05	35.75-36.25
Entergy, Into		
Bal-week	04/10	35.00-35.50
Bal-week	04/08	35.75-36.25
Bal-week	04/05	33.75-34.25
Bal-month	04/11	34.50-35.00
Bal-month	04/10	35.00-35.50
Bal-month	04/08	37.75-38.25
Next-week	04/11	34.00-34.50
Next-week	04/10	34.50-35.00
Next-week	04/08	37.75-38.25
ERCOT, North		
Bal-week	04/10	34.75-35.25
Bal-week	04/09	34.50-35.25
Bal-month	04/09	37.50-39.50
Next-week	04/09	39.75-40.50
ERCOT, West		
Bal-week	04/09	34.75-35.25

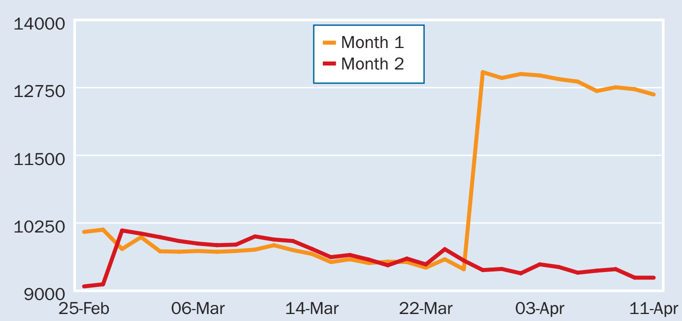
Southeast & Central Platts-ICE Forward Curve, Apr 11 ($/MWh)

Prompt month: May 13	On-peak	Off-peak
Southern Into	37.75	28.75
Entergy Into	35.50	26.25
ERCOT North	39.75	29.00
ERCOT Houston	42.25	29.75
ERCOT West	38.25	27.25
ERCOT South	40.25	29.50

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						
Arkansas Nuclear-1/Entergy	903	n	Ark.	PMO	05/03/13	03/25/13
Arkansas Nuclear-2/Entergy	1065	n	Ark.	MO	05/03/13	03/31/13
Bowen/Georgia Power	3160	c	Ga.	PMO	Unk	04/04/13
Browns Ferry-2/TVA	1155	n	Ala.	PMO	04/19/13	03/14/13
Brunswick-2/CP&L	953	n	NC	PMO	04/17/13	03/03/13
Comanche Pk-1/Luminant	1250	n	Tex.	MO	04/19/13	03/30/13
Crystal River-3/Progress	838	n	Fla.	MO	Retired	09/26/09
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
McGuire-1/Duke	1156	n	NC	PMO	04/14/13	03/17/13
South Texas-2/NRG	1413	n	Tex.	MO	Unk	01/08/13
Wolf Creek-1/Wolf Creek	1226	n	Kan.	PMO	04/10/13	02/04/13

Market coverage

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

WEST MARKETS

Dailies finish mostly lower; terms surge

Western on-peak dailies were mostly down Thursday amid lower peak load forecasts in California and mixed natural gas prices in the region. Terms rose, and the NYMEX May natural gas futures contract settled 5.4 cents higher at $4.139/MMBtu.

Western on-peak dailies were mostly down Thursday amid lower peak load forecasts in California and mixed natural gas prices in the region. Terms rose, and the NYMEX May natural gas futures contract settled 5.4 cents higher at $4.139/MMBtu.

In the Northwest, Mid-Columbia day-ahead on-peak fell about 25 cents in trades between $24.75 and $30/MWh for delivery on Friday and Saturday. Mid-C day-ahead off-peak prices dropped more than $1 to trade between $1 and $4/MWh. The Mid-C on-peak balance-of-the-month package traded at $31/MWh, up around $3, on IntercontinentalExchange.

Portland, Oregon, highs were projected to drop from the mid- to upper 50s to upper 40s by Saturday. Expected lows were dropping from the upper 30s to low 30s.

The Bonneville Power Administration's wind generation at 7 a.m. PDT Thursday was 2,808 MW and hydropower was 12,210 MW.

In California, SP15 next-day on-peak lost $3.75 to about $55/MWh. SP15 day-ahead off-peak fell more than $1.50 to around $36.50/MWh. SP15 on-peak bal-month was bid at $53 and offered at $54. NP15 day-ahead on-peak was about flat around $45/MWh. NP15 day-ahead off-peak dropped 25 cents to about $33/MWh.

Sacramento, California, highs were forecast higher around 80 to near 85 Friday and Saturday. Forecast lows were from the upper 40s to the low 50s. In Burbank, forecasts highs were for the low- to mid-70s while lows were forecast lower from near 55 to the upper 40s by Saturday. The California Independent System Operator projected peak demand would hit 29,325 MW on Thursday, 28,477 on Friday, and 26,989 on Saturday. Renewable generation was 3,633 MW and wind was about 2,000 MW at 7 a.m. PDT on Thursday.

In the desert Southwest, Palo Verde next-day on-peak was down more than $1 in trades between $34.25 and $35.50/MWh. Palo Verde day-ahead off-peak dropped more than 25 cents, trading between $23 and $25.50/MWh. Palo Verde on-peak bal-month was bid at $36.25/MWh.

High temperatures in Phoenix were forecast higher from mid- to upper 80s to around 90 Saturday. Projected lows were steady in the low 60s.

Next-day natural gas was mixed in the Rockies and California. Opal added 2.6 cents to $3.971/MMBtu and SoCal city-gate was up 1.2 cents $4.265/MMBtu. PG&E city-gate lost 1.2 cents to $4.155/MMBtu.

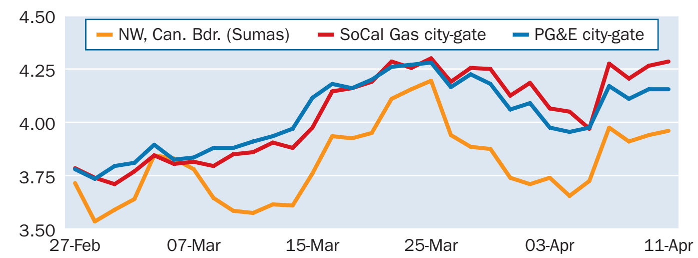
Day-ahead prices in the California ISO auction were mostly up Thursday afternoon even with lower expected demand. In Southern California, SP15 on-peak added $1.87 clearing at $59.90/MWh and SP15 off-peak increased $4.08 at $38.17/MWh. NP15

(continued on page 11)

Western day-ahead bilateral indexes for Apr 12-13 ($/MWh)

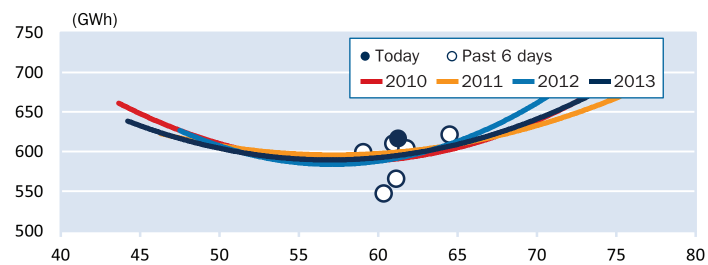
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	34.75	3.63	33.14	8709
Mid-C	25.91	-0.34	27.80	6564
Palo Verde	34.89	-1.19	36.14	8636
Mead	36.00	-1.75	37.62	8748
Mona	30.00	-1.25	31.63	7653
Four Corners	34.00	-2.25	36.10	8575
NP15	45.50	0.50	44.27	10951
SP15	54.50	-4.25	53.44	13244
Off-Peak				
COB	14.25	3.16	20.46	3571
Mid-C	1.17	-1.21	14.23	296
Palo Verde	25.23	0.41	27.83	6245
Mead	26.00	0.50	28.48	6318
Mona	20.00	1.75	20.42	5102
Four Corners	20.25	-1.75	24.52	5107
NP15	33.00	-0.25	34.27	7942
SP15	36.50	-1.50	37.79	8870

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO load per degree



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 10-Apr	%Chg	% Chg Year-ago	Forecast 11-Apr	12-Apr	13-Apr	14-Apr	15-Apr
CAISO								
Load	621	3	2	617	610	565	540	597
Generation								
Gas	189	7	4	191	196	194	183	178
Nuclear	56	0	-36	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Apr 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	47.76	-6.13	-1.35	0.56	44.08	11494
SP15 Gen Hub	59.90	6.16	-1.49	1.87	53.00	14540
ZP26 Gen Hub	43.94	-7.59	-3.71	-1.95	42.24	10665
Off-Peak						
NP15 Gen Hub	35.46	-1.25	-0.76	2.24	34.71	8534
SP15 Gen Hub	38.17	1.26	-0.56	4.08	37.05	9341
ZP26 Gen Hub	34.44	-1.25	-1.77	2.53	33.40	8429

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	04/11	31.00-31.75
Bal-month	04/09	25.00-26.00
Bal-month	04/08	27.75-30.75
Bal-month	04/05	29.00-29.50
Bal-month (off-peak)	04/11	9.00-14.50
Bal-month (off-peak)	04/10	8.50-9.25
Bal-month (off-peak)	04/09	8.00-10.00
Bal-month (off-peak)	04/08	13.25-14.25
Bal-month (off-peak)	04/05	16.00-17.00
SP15		
Bal-month	04/11	54.00-54.50

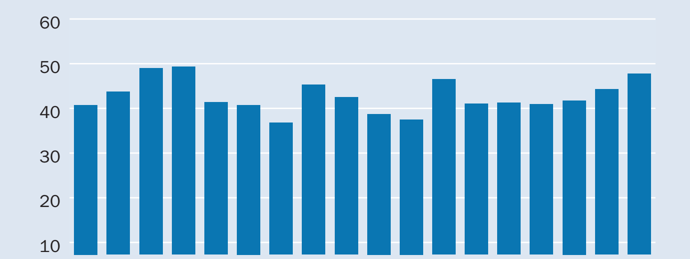
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Alamitos-3/AES	332	g	Calif.	MO	Unk	03/20/13
Alamitos-4/AES	336	g	Calif.	PMO	Unk	02/03/13
Alamitos-5/AES	498	g	Calif	PMO	Unk	03/20/13
Alamitos-6/AES	495	g	Calif.	PMO	Unk	03/17/13
Catalina Solar-1&2/EDF	110	s	Calif.	PMO	Unk	04/01/13
Coolwater-4/NRG	246	g	Calif.	PMO	Unk	03/13/13
Crockett Cogen/EIF	240	g	Calif.	PMO	Unk	03/21/13
Desert Star/SDG&E	495	g	Calif.	PMO	Unk	03/24/13
Empire-1/Inland Empire	376	g	Calif.	PMO	Unk	04/01/13
Encina-1/NRG	106	g	Calif.	PMO	Unk	03/24/13
Etiwanda-3/NRG	320	g	Calif.	MO	Unk	03/10/13
Gilroy Cogen/Calpine	120	g	Calif.	PMO	Unk	04/01/13
Helms-2/PG&E	407	h	Calif.	PMO	Unk	12/02/12
Huntington Beach-2/AES	226	g	Calif.	PMO	Unk	03/31/13
Intermountain Power-1	900	c	Calif.	PMO	Unk	04/07/13
Intermountain Power-2	900	c	Calif.	MO	Unk	03/17/13
Los Esteros/Calpine	188	g	Calif.	PMO	Unk	01/02/13
Malburg/City of Vernon	134	g	Calif.	PMO	Unk	04/01/13
Mandalay-1/NRG	215	g	Calif.	PMO	Unk	02/10/13
Mexicali-1/Sempra	625	g	Calif.	PMO	Unk	04/01/13
Mountainview-4/SCE	525	g	Calif.	PMO	Unk	02/26/13
Palomar Center/SDG&E	595	g	Calif.	PMO	Unk	04/07/13
Raesfeld/Silicon Valley	148	g	Calif.	PMO	Unk	04/07/13
Redondo-6/AES	175	g	Calif.	PMO	Unk	03/24/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12
Sunrise/Edison	586	g	Calif.	PMO	Unk	01/23/13

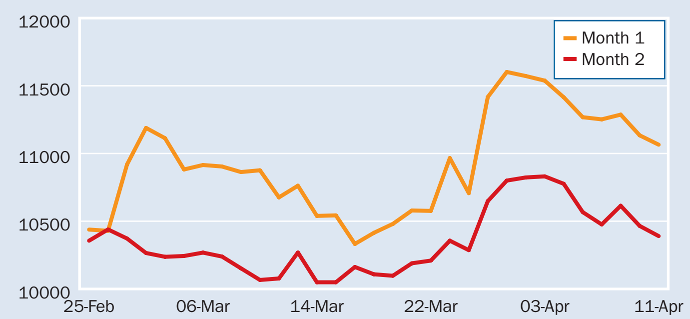
Western Platts-ICE Forward Curve, Apr 11 ($/MWh)

Prompt month: May 13	On-peak	Off-peak
Mid-C	25.50	9.50
Palo Verde	38.50	25.25
Mead	40.75	29.75
NP15	44.75	32.25
SP15	53.50	36.50

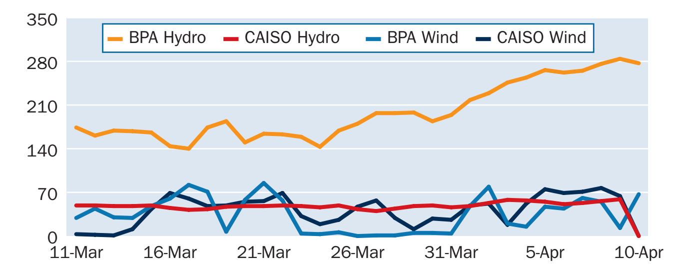
Mead: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

Additional information on data and analysis:

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

PJM & MISO MARKETS

Dailies end mostly lower; forwards rise

Most power dailies in the PJM Interconnection and Midwest Independent Transmission System Operator footprints were lower, and forwards moved up on Thursday. The NYMEX May natural gas futures contract settled 5.4 cents higher at $4.139/MMBtu.

Mid-Atlantic dailies were lower in for-Friday trading on the Intercontinental Exchange as temperatures and demand were forecast to fall. Texas Eastern M-3 spot natural gas traded around $4.33/MMBtu on ICE, up a penny.

The PJM Interconnection projected peak load at 88,361 MW for Friday, down 5,597 MW from Thursday.

Forecasts called for highs in the mid-70s and lows in the mid-50s. PJM West Hub day-ahead peak traded around $41.25/MWh, down $8.50. Day-ahead off-peak was bid at $25/MWh, $6 below Wednesday prices. Weekend peak packages were bid at $33 and offered at $35/MWh. Weekend off-peak was bid at $28/MWh.

Midwestern dailies were mostly flat as Chicago city-gates spot natural gas traded around $4.29/MMBtu on ICE, up about 4 cents. Real-time wind generation in the Midwest Independent Transmission System Operator footprint was about 2.870 MW around 10 a.m. EDT. Temperatures were forecast mostly lower for Friday with highs ranging from the mid-30s to mid-50s. Indiana Hub peak traded around $39/MWh, even with Wednesday prices. Day-ahead off-peak power traded around 29.50/MWh, up 25 cents. Weekend peak was bid at $30.50 and offered at $39.25/MWh.

Dailies were lower in the Midwestern portion of the PJM Interconnection. AEP-Dayton Hub day-ahead peak traded around $37.75/MWh, down $2.25. Weekend peak was bid at $30 and offered at $33.25/MWh. Northern Illinois Hub day-ahead peak was bid at $34.50 and offered at $39/MWh, down about $1.75. Day-ahead off-peak was bid at $23 and offered at $28/MWh, up about 75 cents.

PJM Interconnection day-ahead prices for Friday cleared the auction mixed with PJM projecting peak demand for Friday to be near 88,361 MW, down about 6% from Thursday.

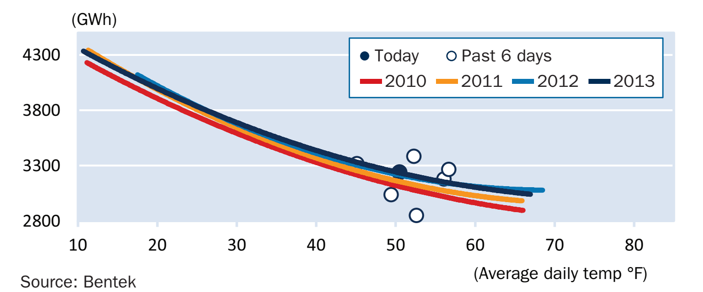
Day-ahead prices in the PJM footprint cleared at $42.96/MWh for peak, down $2 from the day prior. The off-peak price cleared at $32.80/MWh, up $2.83. The PJM Western Hub day-ahead price cleared at $43.86/MWh, down $4.08. PJM Western Hub off-peak cleared at $33.42/MWh, up $2.71. The New Jersey Hub had the highest day-ahead price, clearing at $45.12/MWh, down $3.26. Dominion Hub peak cleared at $44.92/MWh, down $4.27. Dominion Hub off-peak price cleared at $33.94/MWh, up $2.36. AEP-Dayton Hub peak price cleared at $41.24/MWh, up $1.45. AEP-Dayton Hub off-peak price cleared at $32.33/MWh, up $3.29. The day-ahead price for the Northern Illinois Hub cleared at $39.94/MWh, up $2.51. Northern Illinois off-peak price cleared at $29.89/MWh, up $3.97. The Rockland Electric Zone cleared with the highest day-ahead price at $50.27/MWh, down 34 cents.

MISO day-ahead auction prices cleared weaker Thursday

PJM & MISO day-ahead bilateral indexes for Apr 12 ($/MWh)

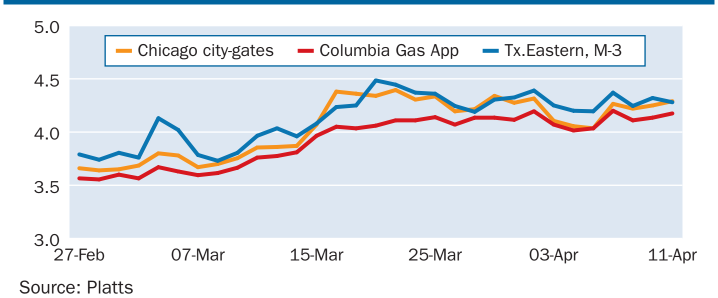
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	41.50	-8.25	44.35	9996
Dominion Hub	42.50	-8.50	44.90	10059
AD Hub	37.75	-2.25	40.13	9174
NI Hub	36.50	-2.00	38.18	8508
PJM Off-Peak				
PJM West	28.75	-2.25	32.18	6925
Dominion Hub	29.25	-2.50	32.53	6923
AD Hub	28.00	0.25	29.98	6804
NI Hub	25.75	1.00	26.73	6002
MISO On-peak				
Indiana Hub	39.00	0.00	37.08	9264
Michigan Hub	39.75	0.00	38.30	9122
Minnesota Hub	42.75	-2.75	40.55	10154
Illinois Hub	37.00	-2.00	34.90	8640
MISO Off-Peak				
Indiana Hub	29.50	0.25	28.95	7007
Michigan Hub	31.00	1.50	29.45	7114
Minnesota Hub	27.00	-5.50	26.73	6413
Illinois Hub	30.50	0.50	26.18	7122

PJM & MISO load per degree



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 10-Apr	%Chg	% Chg Year-ago	Forecast 11-Apr	12-Apr	13-Apr	14-Apr	15-Apr
PJM								
Load	2054	5	6	1916	1878	1759	1694	1915
Generation								
Coal	893	6	18	821	832	825	789	798
Gas	328	8	-16	285	248	219	210	226
Nuclear	658	2	2	662	663	668	676	684
MISO								
Load	1328	2	4	1321	1297	1195	1142	1299
Generation								
Coal	1124	3	13	1126	1083	1017	950	971
Gas	105	-15	-32	90	65	50	49	61
Nuclear	166	0	-5	166	167	171	179	186

Source: Bentek

MISO average day-ahead LMP for Apr 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	34.31	-1.80	0.63	-5.90	35.60	8152
Michigan Hub	36.25	-1.11	1.89	-4.47	36.53	8326
Minnesota Hub	41.47	6.75	-0.75	-2.30	39.12	9834
Illinois Hub	31.75	-3.15	-0.57	-6.53	33.59	7420
Off-Peak						
Indiana Hub	29.04	0.95	0.33	-1.26	29.35	6970
Michigan Hub	30.83	1.91	1.15	-1.14	30.33	7110
Minnesota Hub	27.57	-0.47	0.28	-0.78	27.15	6517
Illinois Hub	29.26	2.17	-0.67	-2.02	26.30	6868

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

Package	Trade date	Range
PJM West		
Bal-week	04/08	51.25-55.75
Bal-week	04/05	43.25-43.75
Bal-month	04/08	48.50-49.50
Bal-month (off-peak)	04/05	32.00-32.50
Next-week	04/11	51.00-56.50
Next-week	04/10	49.50-52.75
Next-week	04/09	47.50-48.75
Next-week	04/08	46.00-49.50
AD Hub		
Bal-week	04/08	47.25-47.75
Bal-month	04/08	42.50-43.50
Next-week	04/11	46.50-47.50
Next-week	04/08	42.50-43.00

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Byron-2/Exelon	1211	n	Ill.	PMO	05/01/13	04/07/13
Callaway/Ameren	1235	n	Mo.	PMO	05/08/13	04/09/13
DC Cook-1/I&M	1152	n	Mich	RF	04/25/13	03/27/13
Limerick-2/Exelon	1138	n	Penn.	RF	04/19/13	03/25/13
Monticello/Xcel	666	n	Minn.	PMO	05/19/13	03/02/13
North Anna/Dominion	903	n	Va.	PMO	05/07/13	04/06/13
Perry/FirstEnergy	1260	n	Ohio	PMO	04/21/13	03/18/13
Point Beach-1/NextEra	562	n	Wis.	PMO	04/16/13	03/18/13

PJM average day-ahead LMP for Apr 12 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	40.12	-0.66	-2.21	1.65	36.03	9527
AEP-Dayton Hub	41.24	-0.52	-1.23	1.45	37.14	9794
ATSI Gen Hub	41.75	-0.75	-0.49	1.96	37.84	9906
Chicago Gen Hub	39.47	-0.67	-2.85	2.57	35.21	9211
Chicago Hub	40.13	-0.62	-2.24	2.62	35.79	9365
Dominion Hub	44.92	0.99	0.95	-4.27	40.58	10634
Eastern Hub	43.48	-1.22	1.72	-2.74	40.45	10196
New Jersy Hub	45.12	0.54	1.59	-3.26	44.20	10580
Northern Illinios Hub	39.94	-0.62	-2.43	2.51	35.66	9320
Ohio Hub	41.34	-0.49	-1.16	1.45	37.26	9772
West Internal Hub	42.39	-0.19	-0.41	-0.41	38.32	10219
Western Hub	43.86	0.39	0.48	-4.08	40.55	10574
AEP Zone	41.43	-0.48	-1.08	1.16	37.33	9840
Allegheny Power Zone	42.81	0.29	-0.46	-4.79	39.52	10283
Atlantic Elec Zone	42.78	-1.41	1.20	-2.37	39.41	10031
ATSI Zone	42.08	-0.79	-0.12	1.96	38.12	9984
BG&E Zone	47.38	2.31	2.08	-11.06	43.76	11307
ComEd Zone	40.03	-0.62	-2.34	2.56	35.74	9341
Dayton P&L Zone	42.31	-0.50	-0.18	1.28	38.00	10054
Delmarva P&L Zone	43.04	-1.31	1.36	-2.88	40.21	10093
Dominion Zone	45.30	1.21	1.10	-5.60	41.12	10723
Duke Zone	40.91	-0.47	-1.61	1.37	36.66	9721
Duquesne Light Zone	39.60	-1.18	-2.20	2.99	35.60	9506
JCPL Zone	42.12	-2.39	1.52	-3.76	41.47	9875
MetEd Zone	42.70	-1.22	0.93	-3.83	40.60	10086
PECO Zone	42.69	-1.43	1.13	-2.30	39.53	10084
Pennsylvania Elec Zone	43.54	-0.10	0.65	-0.93	40.75	10438
PEPCO Zone	46.66	1.98	1.69	-10.62	43.32	11134
PPL Zone	42.35	-1.40	0.76	-2.72	40.44	10003
PSEG Zone	47.90	3.14	1.77	-2.39	46.82	11232
Rockland Elec Zone	50.27	5.70	1.58	-0.34	49.70	11788
Off-Peak						
AEP Gen Hub	31.63	0.20	-1.39	3.01	29.99	7540
AEP-Dayton Hub	32.33	0.20	-0.70	3.29	30.63	7706
ATSI Gen Hub	32.55	0.16	-0.43	2.95	31.13	7782
Chicago Gen Hub	29.51	-1.48	-1.83	4.02	26.91	6936
Chicago Hub	30.01	-1.41	-1.40	4.06	27.33	7054
Dominion Hub	33.94	0.36	0.76	2.36	32.13	8067
Eastern Hub	34.03	0.00	1.20	2.64	32.42	7926
New Jersy Hub	33.96	0.09	1.05	2.31	33.03	7912
Northern Illinios Hub	29.89	-1.40	-1.53	3.97	27.18	7025
Ohio Hub	32.41	0.21	-0.64	3.37	30.69	7711
West Internal Hub	32.72	0.24	-0.35	2.61	31.18	7932
Western Hub	33.42	0.28	0.32	2.71	31.92	8102
AEP Zone	32.45	0.21	-0.59	3.08	30.76	7734
Allegheny Power Zone	32.70	0.25	-0.38	2.51	31.32	7889
Atlantic Elec Zone	33.57	-0.02	0.75	2.64	31.86	7819
ATSI Zone	32.75	0.16	-0.23	2.94	31.31	7828
BG&E Zone	34.74	0.54	1.37	2.11	33.31	8321
ComEd Zone	29.94	-1.40	-1.49	4.01	27.26	7036
Dayton P&L Zone	33.00	0.27	-0.10	3.41	31.18	7919
Delmarva P&L Zone	33.86	-0.01	1.04	2.65	32.32	7887
Dominion Zone	34.07	0.38	0.86	2.37	32.29	8097
Duke Zone	32.19	0.34	-0.97	3.31	30.30	7725
Duquesne Light Zone	31.03	0.14	-1.94	2.66	29.79	7519
JCPL Zone	33.68	-0.09	0.94	2.18	32.46	7845
MetEd Zone	33.39	0.01	0.56	2.62	31.96	7870
PECO Zone	33.65	-0.01	0.84	2.65	31.84	7931
Pennsylvania Elec Zone	33.55	0.14	0.59	2.93	32.18	8113
PEPCO Zone	34.44	0.46	1.15	2.26	32.91	8249
PPL Zone	33.27	0.02	0.42	2.62	31.87	7840
PSEG Zone	34.36	0.33	1.21	2.38	33.69	8004
Rockland Elec Zone	34.11	0.15	1.13	2.35	34.02	7945

afternoon. Minnesota Hub remained the highest-priced hub, clearing at $41.47/MWh, down $2.30, while its off-peak price remained the lowest at $27.57/MWh, falling 78 cents. Michigan Hub cleared at $36.25/MWh, a loss of $4.47. Michigan Hub off-peak price cleared at $30.83/MWh, falling $1.14. The Indiana Hub day-ahead price cleared at $34.31/MWh, dropping $5.90, with off-peak at $29.04/MWh, a loss of $1.26. The lowest-priced hub was again Illinois Hub at $31.75/MWh, down $6.53. Off-peak cleared at $29.26/MWh, down $2.02.

Congestion costs at the hubs ranged from negative $3.15 to $6.75 for peak, and from negative 47 cents to $2.17 for off-peak.

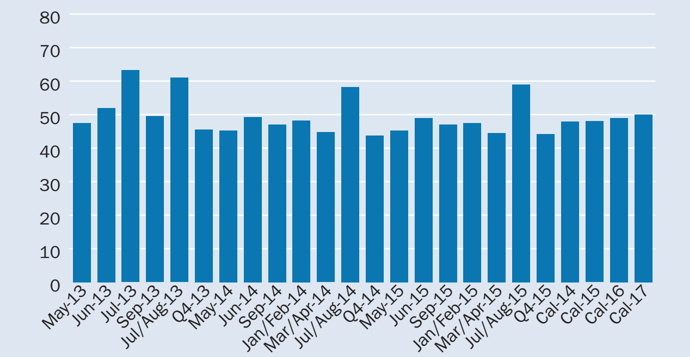
Mid-Atlantic forwards were up Thursday with the rising NYMEX contract. PJM West on-peak May financial futures were 50 cents stronger with bids at $47.35 and offers at $47.80/MWh on ICE around 2:30 p.m. EDT. PJM West on-peak June rose 50 cents to about $52/MWh, while on-peak July-August picked up 40 cents to about $61/MWh. PJM West off-peak May added 25 cents to about $32.25/MWh.

Midwest forwards rose Thursday with firmer gas futures. AD Hub on-peak May financial futures added 25 cents to about $42.75/MWh. AD Hub on-peak July-August packages gained 75 cents to about $54.75/MWh. Indiana Hub on-peak May gained 50 cents to about $39.50/MWh, while Indiana Hub on-peak July-August climbed 60 cents to about $49.75/MWh. NI Hub on-peak May edged up 25 cents to about $40/MWh. NI Hub on-peak July-August was 50 cents stronger at about $52.50/MWh.

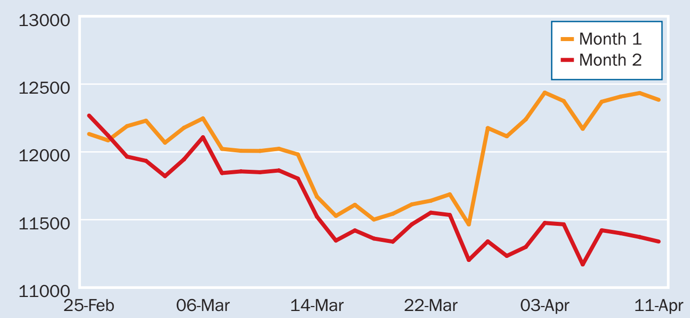
PJM & MISO Platts-ICE Forward Curve, Apr 11 ($/MWh)

Prompt month: May 13	On-peak	Off-peak
PJM West	47.50	32.25
AD Hub	42.75	30.25
NI Hub	40.00	26.00
Indiana Hub	39.50	26.50

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



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



Northeast markets *... from page 2*

Island Zone, while the lowest hourly price was $29.90/MWh at the Vermont Zone. The average day-ahead price was $45.84/MWh, up $6.89.

Day-ahead peak prices for Friday were lower across the zones in the NYISO auction Thursday, while off-peak prices were mostly higher. The NYISO projected peak load for Friday to drop by 1.6% to 18,577 MW.

New York City Zone peak cleared at $45.97/MWh, down $2.44, while off-peak cleared at $33/MWh, up $1.23. Long Island Zone peak cleared at $57.83/MWh, down $3.21, and off-peak cleared at $40.50/MWh, down $2.94. Hudson Valley Zone peak cleared at $46.16/MWh, down $1.84, and off-peak cleared at $33.50/MWh, up $1.59.

NYISO Central Zone peak came in at $41.67/MWh, down $2.55, and off-peak came in at $30.90/MWh, up 81 cents. West Zone peak cleared at $39.80/MWh, a drop of $2.49, while off-peak cleared at $30.81/MWh, a gain of 48 cents.

The highest hourly day-ahead price was $76.57/MWh at the Long Island Zone. The lowest hourly price was $26.37/MWh at the North Zone. Hourly congestion costs ranged from negative $25.21/MWh to $10.79. The average zonal price was $40.18/MWh, down $1.49.

Northeast term power mostly rose Thursday as May NYMEX gas futures gained 4.6 cents, trading at about $4.131/MMBtu after the release of the Energy Information Administration's weekly gas storage estimate.

In New England, Mass Hub on-peak May financial futures picked up 75 cents with bids at $47.35 and offers at $48.05/MWh on ICE at about 2:30 p.m. EDT.

Mass Hub on-peak June climbed $1.25 to about $59/MWh, while on-peak July-August rose $1 to about $60.25/MWh. Mass Hub off-peak May was 25 cents stronger at about $35.75/MWh.

New York Zone G on-peak May was unchanged at about $49/MWh. New York Zone A on-peak May stood still at about $40.50/MWh.

Southeast markets *... from page 4*

High temperatures in Atlanta were forecast to fall to the low 70s, with lows expected in the mid-50s. The average April high temperature in Atlanta is 73, while the average low is 52.

The ERCOT day-ahead auction for Thursday delivery cleared weaker Wednesday afternoon as peak load was forecast to decrease. ERCOT system load was forecast to peak at 34,625 MW Friday, down 8% from Thursday's expected peak of 37,575 MW.

West Hub remained the highest-priced hub for a second day as North Hub moved into position as the lowest-priced. West Hub on-peak cleared in the ERCOT auction $34.62/MWh, a loss of about $6.25 from Wednesday's prices, while off-peak cleared at $21.97/MWh, moving down almost $10.

Houston Hub on-peak cleared in the ERCOT auction at $34.61/MWh, about $5.25 weaker, while off-peak cleared at $26.44/MWh, down nearly $6.

South Hub on-peak cleared at $34.59/MWh, a decrease of roughly $5.25, while off-peak cleared at $26.14/MWh, falling about $6.25.

North Hub on-peak cleared the auction at $34.50/MWh, losing about $5.25, while off-peak cleared at $26.80/MWh, a drop of almost $5.75.

West Zone on-peak led the load zones at $42.91/MWh, a drop of about $23 from Wednesday.

The highest hourly day-ahead price occurred at 7 a.m. CDT in the Houston Hub at $40.36/MWh and at noon in the West Zone at $51.92/MWh.

Most South Central May terms moved up Thursday as May NYMEX gas gained 4.6 cents to about $4.131/MMBtu in late trading.

ERCOT Houston on-peak May rose 25 cents to about $42/MWh, but July-August dropped $1.25 to about $95.75/MWh. Heat rates were steady on ICE at about 2:30 p.m. EDT.

ERCOT North May rose 25 cents to about $39.50/MWh, June stayed at about $52.75/MWh, and July-August slid $1.25 to about $96.50/MWh. Into Entergy May climbed 50 cents to about $35.50/MWh, and July-August rose 25 cents to about $41.65/MWh.

Southeast on-peak May was unmoved Thursday, even as May NYMEX gas futures moved up. Into Southern May stayed at about $37.75/MWh, June was up 50 cents to about $40.25/MWh, and July-August rose 25 cents to about $43.25/MWh.

West markets *... from page 6*

on-peak added 56 cents clearing the auction at $47.76/MWh and NP15 off-peak rose $2.24 cents to $35.46/MWh. Meanwhile, ZP26 on-peak shed $1.95 cents at $43.94/MWh while ZP26 off-peak was up $2.53 at $34.44/MWh.

In the Northwest, Mid-C on-peak May moved up 75 cents with bids at $25.50 and offers at $25.75/MWh on ICE around 2:30 p.m. EDT. June rose 50 cents to about $22.75/MWh, and the third quarter rose 25 cents to about $42.35/MWh. In California, SP15 on-peak May financial terms jumped $1.25 with bids at $53.25 and offers at $53.75/MWh. June gained 50 cents to about $50.50/MWh, but Q3 crept down 20 cents to about $57.40/MWh. NP15 May surged up 75 cents to about $44.75/MWh, and Q3 stayed constant at about $51.15/MWh. Palo Verde May rose 25 cents to about $38.50/MWh, June rose 25 cents to about $41.25/MWh, and Q3 inched up 10 cents to about $47.85/MWh.

EMISSIONS MARKETS

Calif. GHG allowances up after linkage debate

California greenhouse gas allowance prices rose 20 cents this week in the wake of a debate over a California Air Resources Board plan to allowing trading with Quebec starting on January 1.

Contracts for end-of-year delivery on IntercontinentalExchange recovered losses from last week.

The main futures contract on ICE – vintage 2013 for delivery in December 2013 – settled at $14.35/mt. About 60 contracts representing more than 1 million allowances for delivery in December 2013 were traded on the ICE.

In the East, seven RGGIs contracts were struck for in excess of 600,000 short tons for delivery in December 2013.

The liquidity of the carbon markets has not appeared to suffer from the controversy over the California Air Resources Board's plan to allowing trading between the state and Quebec starting January 1. The ARB took comment last week on the matter.

While Governor Jerry Brown filed a letter of support, Pacific Gas & Electric and Southern California Edison raised concerns with linking the two GHG programs.

"Given the ARB's responsibility to carefully design a cap-and-trade program and establish a fair and transparent market, the ARB should monitor the success of the market it has created, before trying to expand it," SCE said April 5.

SCE and PG&E also said the board should draft language that would allow the state and province to "de-link" their programs. "The integration of multiple jurisdictions introduces challenges in assessing the cause of market stress or failure and implementing regulatory remedies," PG&E said April 5.

— Martin Coyne

Midwest plants retire 60,000-plus SO2 allowances

No trades were heard in the US emissions market for sulfur for the week ending April 11 and prices were assessed unchanged, as several Midwest plants retired allowances in line with their emissions under the Clean Air Interstate Rule.

Under that rule, power plants submit two post-2009 allowances for every one ton of SO2 emitted.

Dynegy Midwest Generation retired 18,475 allowances under the CAIR SO2 program. The Hennepin Power Station in Illinois turned in 4,070 vintage 2012 allowances, 1,723 vintage 2011 allowances and 113 vintage 2010 allowances. The Wood River Power Station in Illinois retired 4,513 vintage 2012 SO2 allowances and 2,242 vintage 2011 SO2 allowances. The Havana Station in Illinois retired 5,814 SO2 allowances, including vintages from 2010, 2011 and 2012.

The Baldwin Energy Complex in Illinois retired 10,204 vintage 2012 SO2 allowances.

Indianapolis Power & Light retired 33,830 allowances under the CAIR SO2 program. Its Eagle Valley Generating Station retired 1,844 vintage 2012 allowances. Harding Street Station turned in 16,523 vintage 2012 SO2 allowances. The Petersburg Generating Station retired 15,463 vintage 2012 SO2 allowances.

CAIR SO2 were assesses unchanged, with vintage 2013 allowances at 74 cents/allowance and vintage 2014 allowances at 60 cents/allowance.

Platts assessed all CSAPR 2012 allowances unchanged, with Group 1 SO2 at $20/st, Group 2 SO2 at $50/st, and both annual and seasonal NOx allowances at $55/st.

— Henry Clay Webster

Daily CSAPR allowance assessments, Apr 11

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, Apr 11

	$/allowance	Change	$/st
SO2 2013	0.74	0.00	1.48

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

RGGI carbon allowance futures, Apr 10 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.37	0	Dec13	1.97	0
Dec13 V11	3.30	0	Dec14	1.97	0
Dec13 V12	3.30	0			
Dec13 V13	3.30	25000			
Dec14 V10	3.37	0			
Dec14 V11	3.30	0			
Dec14 V12	3.30	0			
Dec14 V13	3.30	0			
Dec15 V10	3.37	0			
Dec15 V11	3.30	0			
Dec15 V12	3.30	0			
Dec15 V13	3.30	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.

REC MARKETS

Price influence of N.J. SREC auction lingers

In what appeared to be another quiet week in renewable energy credit trading, New Jersey SRECs showed some evidence of testing the price ceiling set by a recent auction.

Meanwhile, Massachusetts continued to contemplate changes to its SRECs market to incentive even more solar capacity.

In the latest New Jersey auction results, the market cleared between $112 and $113 per SREC, a broker noted, adding that SRECs in the state were steadily trading around $120 prior to the auction.

That said, there was trading this week at the $118-$119 per-SREC level, two brokers confirmed.

"The story this week appears to be an uptick in New Jersey SRECs," said the first broker.

"I heard that too and it appears to be a market player that was looking for some size and had to pay for it," the second broker said. "I don't think it's indicative of where the market is overall."

The price-ceiling effect of the auction is still in the forefront of market's psyche, the second broker said. "It looks like the bulk of market participants won't pay above the auction's clearing price."

On the lower end of the price spectrum, New Jersey SRECs sold for $102.50 each this week.

The New Jersey SREC market is also seeing a lack of liquidity, which may be contributing to price volatility, the second broker said. "For more normal liquidity to return, I think prices need to be at the $115-$120 level to attract more market participants."

The brokers said short term SREC supply fundamentals appear to favor upward price pressure. One cited data from the PJM Interconnection's Generation Attribute Tracking System or GATS showing a slowing of new solar capacity. The other noted that the state has seen new installed capacity figures drop from about 35 MW to roughly 17 MW.

Pulling from the supply represented in GATS, the four major New Jersey utilities — Public Service Gas & Electric, Atlantic City Electric, Jersey Central Power & Light and Rockland Electric Company — announced last week that on May 9 they will auction between "16,000 and 21,000 SRECs created in GATS as generation between June 1, 2012 and April 30, 2013."

Bids for the auction are due April 30.

North of New Jersey, market participants have started to weigh in with written comments on a post-400-MW solar program being developed at the Massachusetts Department of Energy Resources.

National Grid expressed general support for potential changes to the SREC program, including reducing the SREC alternative compliance payment which is supposed to act as a price floor.

"Likewise, lowering the level of SREC [ACP] by 5% per year will help to contain the cost of shortfalls in the supply of solar generation in future years," the utility said.

SRECTrade, the largest aggregator of solar facilities in Massachusetts, said DOER's consideration of buying SRECs in the future to create more price certainty was an innovative idea that merits more information.

The aggregator "would like to see more details on how and from whom the DOER plans to purchase these SRECs."

SRECTrade reiterated that "the market currently believes that energy year 2013 will be oversupplied based on 2013 vintage SRECs trading at prices significantly below both the alternate compliance payment and the clearinghouse auction level."

While some market participants may question investing in more solar capacity in a market thought to be oversupplied, the Solar Energy Industries Association strongly supports the state's move.

"The Commonwealth chose the best time to invest in the support of new solar generation and a local solar industry, because in this period of transition to a new, lower cost environment, the national solar industry is in the process of sinking deep roots in the states with viable markets," SEIA said.

— Martin Coyne

Renewable Energy Certificate Markets Apr 11 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	56.00	57.00	56.500
Maryland	4.75	5.00	4.875
Massachusetts	63.25	64.00	63.625
New Jersey	4.70	4.90	4.800
Ohio In-State	2.40	2.60	2.500
Pennsylvania	4.65	4.75	4.700
Texas	2.10	2.40	2.250
Solar RECs*			
Maryland	122.50	132.50	127.500
Massachusetts	220.00	230.00	225.000
New Jersey	103.00	118.00	110.500
Ohio In-State	35.00	45.00	40.000
Pennsylvania	10.00	14.00	12.000
California RPS*			
California Bundled REC (Bucket 1)	33.00	37.00	35.000
California Bundled REC (Bucket 2)	4.00	8.00	6.000
California Tradable REC (Bucket 3)	0.70	1.10	0.900
Voluntary RECs*			
National voluntary, any technology	0.70	0.80	0.750
National voluntary, wind	0.80	0.90	0.850

*Prices are for the value of the environment attribute of the renewable energy certificate only and do not include energy. Bundled transactions are normalized by subtracting the market price of electricity.

NEWS

Ruling keeps market manipulation suits alive

An appeals court ruling handed down Wednesday keeps alive a group of lawsuits filed by natural gas consumers against a host of trading companies accused of market manipulation dating back to the early 2000s.

The ruling by a three-judge panel of the US 9th Circuit Court of Appeals in San Francisco found that end-users of gas can continue to pursue their claims arising out of state laws.

The claims, which grew out of the 2001-02 energy crisis, allege that gas traders manipulated markets through false price reporting and "wash" trades, causing an artificial spike in gas — and consequently power — prices.

The decision reverses a ruling by a US district court in Nevada, which had issued a summary judgment in favor of the gas marketing companies.

In that decision, the judge ruled that under the Natural Gas Act of 1938, state market manipulation claims were pre-empted under the jurisdiction of the Federal Energy Regulatory Commission.

However, the appellate panel found that the trial judge relied on an overly broad interpretation of FERC's powers under NGA and remanded the case to the Nevada trial court, in which a number of related state and federal lawsuits originating in Missouri, Kansas, Wisconsin and Colorado had been consolidated.

In an interview Thursday, Jennifer Gille Bacon, an attorney for the plaintiffs, said the appeals court decision (*Lear Jet Inc., et al. v. Oneok Inc., et al.,* 11-16786, *et. al.*) keeps alive the claims, which the end-users — including manufacturers, hospitals and schools — began bringing in 2005.

"Had the district court decision been upheld, we'd be out of court," she said, noting that most of the federal claims raised by the plaintiffs have been dismissed.

The class certification for the plaintiffs remains in force and their consolidated case against the marketers can proceed under the laws of the different states, Bacon said, adding that the litigation is unlikely to be resolved anytime soon.

She noted that around 2000, several manipulation schemes began to skew the gas market and the price consumers paid for gas and electricity. These included reporting false price data to private index publishers, including Platts, and engaging in wash trades, in which near-simultaneous purchases and sales of the same volume of gas at the same price canceled each other out while artificially expanding market activity.

"In some parts of the country, the price of natural gas trebled and quintupled," Bacon said.

As a result of all the bad market behavior, the Commodity Futures Trading Commission levied hundreds of millions of dollars in fines against gas marketing companies, while a handful of individual gas traders from several companies were charged criminally, resulting in fines and jail time.

"Eventually FERC and the CFTC tumbled to the fact that the natural gas market was being manipulated," Bacon said.

Civil suits followed, filed by large commercial and industrial gas purchasers such as LearJet, Northwest Missouri State University, Briggs and Stratton and Sargento Foods.

The defendants include a veritable "Who's Who" of the biggest gas marketers of the time, many of which have since scaled back their marketing operations or gotten out of the business altogether. They include Northern States Power, American Electric Power, CMS Energy, Coral Energy Resources, Duke Energy, Dynegy, El Paso, Oneok and The Williams Companies.

In reaching the decision, the appellate judges relied in part on a ruling in the case of *E. & J. Gallo Winery v. Encana Corp.* That case found that "first sales" of gas "that are not preceded by a sale to an interstate pipeline, intrastate pipeline, local distribution company, or retail customer," are exempt from FERC regulation.

The defendants have 14 days to file a motion for rehearing of the decision by the three-judge panel, or an *en banc* motion for a rehearing before the full appeals court.

— *Jim Magill*

Testimony questions Entergy grid assumptions

There is no evidence that Entergy's plan to spin off its transmission assets and merge them into a new subsidiary of ITC Holdings would increase the efficiency of the regional transmission system or give Entergy's Louisiana utilities access to lower-cost power, financial experts testifying for the Louisiana Public Service Commission staff said in Wednesday filings to the PSC.

Claims by Entergy Louisiana and Entergy Gulf States Louisiana that the Entergy/ITC "spin-merge" plan would enhance transmission planning, make the Entergy-area grid more robust, and thereby give the two utilities access to less expensive power "are too speculative to provide adequate evidence that the proposed transaction will be beneficial to consumers," said Stephen Hill, principal at Hill Associates, a financial consulting firm based in Hurricane, West Virginia.

Hill, testifying on behalf of the PSC staff, said that moving Entergy's transmission assets to Federal Energy Regulatory Commission regulation "via a transfer to ITC would raise transmission rates to Entergy's Louisiana customers by approximately 30%."

Entergy has asserted that any increase in transmission rates would be more than offset by benefits such as "improved transmission grid reliability and lower energy costs due to improved access to power markets," Hill said. "However … these other touted benefits are largely speculative … and are based on what are termed 'lllustrative analyses'" rather than real-world examples.

Hill also said it is "only logical … to believe" that the Department of Justice's ongoing investigation into whether Entergy has been providing fair access to its transmission system to independent power producers is "a motivation for Entergy's proposed transfer of its transmission assets to ITC."

Hill noted that the DOJ last November issued a statement that if Entergy followed through on its plans to buy two natural gas-fired IPPs from KGen Power, to join the Midwest Independent Transmission System Operator, and to undertake the spin-merge with ITC, the DOJ Antitrust Division's concerns "will be resolved."

John Mayeaux, an investment banker and senior vice president at The Sisung Group, a New Orleans-based financial consulting firm, said in his newly filed testimony — again submitted on behalf of the PSC staff — that the Entergy/ITC spin-merge would provide "a substantial windfall" to Entergy shareholders as "the direct result" of the higher transmission rates customers would be charged once the transmission system is regulated by FERC and not state regulators in Louisiana, Texas, Arkansas and Mississippi.

Mayeaux called the alleged windfall "unfair and unjust to ratepayers." He also said the spin-merge "will likely have no impact" on the credit ratings of Entergy Louisiana and Entergy Gulf States. Entergy has asserted that transmission-investment needs would put increasing pressure on the company's finances, and that the spin-merge would eliminate that pressure and boost the ratings of Entergy and its utility subsidiaries.

Entergy spokesman Checky Herrington said Thursday, "Based upon our review, the concerns [by Hill and Mayeaux] appear to rest on the unfounded assumption that ITC and Entergy would manage the transmission system in an identical manner, that is, using the same dollars to make the same investments and engaging in the same operations and management practices.

"In fact, ITC today employs transmission practices that differ from Entergy's," Herrington said. "Through its larger size and singular focus, ITC will continue to lead in the evolution and enhancement of transmission practices as well as to bring efficiencies in the cost of managing the transmission system that simply will not be available to Entergy."

He added, "ITC also has a history of regional planning and years of experience planning transmission in the MISO markets and of working with merchant generators in the siting of their facilities. This experience will add value in terms of identifying economic projects that will lower the delivered cost of energy to customers."

Herrington concluded, "The good news from our perspective is that we now understand the parties' concerns in detail and are confident that we will be able to address them in a meaningful way."

Paul Patterson, energy analyst at Glenrock Associates of New York City, said that Entergy's proposed spin-merge with ITC presented some major regulatory challenges right up front, and that regulators in several states "have been voicing concern about FERC's transmission regulation."

Patterson said the Entergy-ITC proposal "really needs state regulators to get comfortable with the idea of handing over state-regulated assets to FERC … And it just may not be that easy for all these guys to completely let go."

In a related development, the Arkansas Public Service Commission earlier this week issued an order giving Entergy Arkansas final approval to join MISO. In a statement, Entergy Arkansas said the PSC's April 8 order "provides a clear path for the company to continue its efforts to integrate into the large regional grid operator in December 2013."

In its order, the PSC said Entergy Arkansas and MISO have "either complied or substantially complied with" each of the 19 conditions that the commission laid out in the conditional approval to join MISO the PSC issued last August.

The PSC noted in its order that if Entergy Arkansas or MISO were to later renege on any of the commitments they made to secure the commission's final approval, the PSC could order the utility to leave the regional transmission organization.

In the Entergy Arkansas statement, the utility said it anticipates that joining MISO will provide some $267 million in net benefits to its customers over the first 10 years of MISO membership.

Entergy Arkansas's sister utilities in Louisiana, Texas and Mississippi already have secured either conditional or final approvals to join MISO from their regulators.

— Housley Carr

PJM works on gas/electricity coordination

Joining other groups examining the need for increased coordination among the natural gas and electric power industries, the PJM Interconnection formed a task force on the issue, Gary Helm of PJM said Thursday.

The task force will report to the markets and reliability committee of PJM, said Helm, senior market strategist at PJM.

Helm made the remarks during a meeting of the Electric and Natural Gas Coordination Task Force of the Midwest Independent Transmission System Operator.

MISO and PJM, along with ISOs in other regions, the Tennessee Valley Authority, the North American Electric Reliability Corp., and the Federal Energy Regulatory Commission have been examining the issues of increased gas-fired generation, the natural gas infrastructure to meet increased generation needs and the scheduling and market rules associated with the gas and power sectors.

The different time lines for pipeline nomination schedules compared with the generation dispatch rules of the power industry have been examined many times, with the lack of alignment creating significant debate at the meeting Thursday. "When the composition of the generating fleet changes to a larger percentage of gas-fired generation, the misalignment of the two industries' days becomes more important and it can have increased risk of financial harm for stakeholders," said a draft document that was discussed.

The natural gas industry has added pipeline nomination cycles and made other services available to owners of gas-fired power plants, and there is a certain amount of frustration within the industry to continued examination of gas scheduling issues, said Andrew Soto, senior managing counsel for regulatory affairs at the American Gas Association. "We've been down this road several times," he said, quoting a FERC order in 2009 that found the differences in the two industries "does not suggest that revising gas scheduling procedures is the most effective means to improve coordination."

FERC last year held a series of regional meetings on gas-electric coordination and in November directed FERC staff to report on coordination efforts, along with scheduling a meeting for May 16 where grid operators will provide details on their coordination activities. At the FERC meeting in St. Louis, one factor that hit home for Soto was the tremendous amount of gas infrastructure in the region. "I understand the looming demand for gas-fired generation, but there is an awful lot of infrastructure to support that," he said Thursday.

The MISO task force is trying to compile a list of services and options available to generators in different parts of the country to show how regions are addressing increased coordination, other speakers said. The group also is trying to develop a list of changes within MISO that could mitigate any financial problems facing generators, according to the draft document.

PJM will issue a request for proposals for a study that will examine natural gas industry infrastructure within the ISO and its ability to meet the needs of more gas-fired generators, Helm said. The study will receive some funding from the Department of Energy, and "we're going to have a meeting with DOE [Thursday] afternoon" on what can be included in the RFP, Helm said. He hopes the study will include a look at retirements of coal-fired power plants in the PJM region, and that the work can be done before the middle of 2015.

The PJM effort with some level of DOE funding is similar to grid planning initiatives supported by DOE for the entire Eastern Interconnection and at the Western Electricity Coordinating Council, Helm pointed out.

— Tom Tiernan

Dominion rebuts generators on plant proposal

Requests by merchant generators for Dominion to seek market alternatives to its plan to build a 1,358-MW natural gas-fired plant are driven by the economic interest of generators as market participants in the wholesale power sector, Fred Wood, senior vice president for Dominion said in testimony filed Wednesday with regulators.

"Their recommendations should be considered against that backdrop," Wood said in the filing made at the State Corporation Commission in the proceeding underway for the approval of the project planned for Brunswick County.

Dominion does not consider the wholesale power market a bad thing, and, in fact, makes purchases from it, but when the company evaluated the use of market alternatives as supply options it determined that the best investment would be to build the $1.27 billion Brunswick plant, Wood said.

The Virginia attorney general, LS Power and other merchant suppliers questioned whether the utility's evaluation of market alternatives was appropriate. "The company did not broadly solicit offers for capacity and energy and failed to fully evaluate extensions of existing non-utility generator contracts and other short term market purchase alternatives to the Brunswick project," Scott Norwood, the AG's energy consultant, said in previously submitted testimony.

Dominion is not required to issue a request for proposals to evaluate market purchases with an option to build a new plant, Wood said. "We believe that our planning process has been reasonable and appropriate and do not believe that a broad-based RFP process was either required or necessary," Wood said.

The company used modeling to determine the best alternative and included a variety of market options into the model, Wood said.

Dominion compared the project with forecasts of wholesale market prices for capacity and energy from the PJM wholesale market, which showed the construction project had superior value, Wood said.

The company also solicited offers for the extension of its existing NUG agreements that expire within the next three to five years, Wood said. "None of the NUG offers, individually or in combination, presented a lower cost option to meet our customers' needs," Wood said.

Extending the NUGs collectively on the terms offered would have cost Dominion's customers about $226 million more than the cost of the new plant, Wood said.

Load continues to grow in Dominion's territory and with the retirement of 918 MW of coal generation in 2015 the company needs new capacity in 2016, Glen Kelly, director of generation system planning, said in testimony filed Wednesday.

While Dominion has forecast a need for more than 1,300 MW by 2016, PJM's forecast is about 500 MW higher, Kelly said.

The proposed Brunswick plant would meet Dominion's capacity needs, but the company will continue to purchase energy from the market, Kelly said.

The Brunswick project was specifically compared with market purchases, simple cycle combustion turbines and coal retrofits at Yorktown and Chesapeake stations, Kelly said.

To confirm the project's value using actual market prices, Dominion performed a backcast analysis that compares the project with actual historical market prices in addition to its forward forecast and NUG evaluations, Kelly said. "It shows that the capacity and energy benefits of the project would have exceeded its levelized fixed costs over the past five years using real, actual market data," he said.

When evaluating the option of deferring the project by relying on short-term PJM market purchases, Dominion found a one-year delay would cost $149 million and a two-year delay would cost $187 million more than building a plant, Kelly said.

Dominion projects that the weather-normalized peak load of the DOM Zone in PJM will increase 5,320 MW, or 1.7% a year, over the next 15 years, Robert Thomas, director of energy market analysis and integrated resource planning, said in testimony filed on Wednesday.

If Brunswick is not built, the company's capacity gap is expected to grow from 582 MW in 2016 to 4,056 MW in 2027, Thomas said. If the project is built, the gap would be 2,681 MW by 2027, he said.

Maria Scheller, vice president and director of energy and resources and head of ICF's modeling practice, disagreed with the merchant generators' premise that there is no need for new capacity in PJM.

She cited the outlook for retirements, the uncertainty of construction of new facilities that have cleared prior capacity market auctions, the slowing potential for demand resources and the potential for demand growth as clear indicators for the need for new generation in PJM.

— Mary Powers

CPV CEO rails against PJM capacity auction

Doug Egan, CEO of Competitive Power Ventures, earlier this week railed against the PJM Interconnection’s capacity auction, saying, “We are told this is a deregulated market. It is not a deregulated market at all; it is highly regulated.”

Egan made his remarks during a panel on the outlook for capacity markets at Platts Global Power Markets conference in Las Vegas.

As an example, Egan cited PJM’s minimum offer price rule, or MOPR, which is used to adjust downward – or “mitigate” in PJM’s language — the minimum price at which a generator can bid resources into the capacity auction.

Holding up a section of PJM’s rules, Egan read from the text: “The MOPR applies to all generation technology types except for nuclear, coal, integrated gasification combined cycle, hydroelectric, wind or solar.”

In other words, Egan said, the MOPR "only applies to new gas-fired generation. Why do we have to mitigate the best type of project? That eludes me.”

CPV is building a 725-MW gas plant in Waldorf, Charles County, Maryland. To build the plant, CPV successfully petitioned Maryland to hold a solicitation for in-state generation resources. CPV then bid and won a long-term power purchase agreement for the output of its project.

New Jersey had earlier adopted a similar, and equally controversial, measure calling for the state to subsidize 2,000 MW of in-state generation. Three plants are planned as a result of that legislation, though progress has been delayed by court challenges.

Egan defended CPV’s strategy of securing a state-backed PPA outside PJM’s capacity auction, saying, “We are not going to spend $1 billion on a project based on a price for one year. That is not a sensible approach.”

PJM holds its capacity auction every May for a single delivery year that is three years in the future. For instance, the upcoming May auction will secure capacity resources for 2016-2017.

Joe Kerecman, head of government and regulatory affairs at Calpine, questioned how CPV could offer “an out-of-market solution” and claim to be participating in a competitive market.

Egan shot back, “It is not out-of-market. There was a competitive solicitation, and we bid and won.”

Kerecman asked Egan what price CPV is being paid under its PPA. Egan said he did not have those numbers at hand.

Tamara Linde, vice president of regulatory affairs at PSEG Services, who was also on the panel, stepped in and cited the prices awarded in New Jersey’s capacity solicitation. They ranged from $286/MW-day to $432/MW-day and compare with PJM’s capacity price of about $136/MW-day.

New Jersey pays winners of the solicitation the difference in price, if the PJM capacity price is lower than New Jersey’s capacity price. If the New Jersey price is lower than PJM’s capacity price, the generators pay the state the difference.

Kerecman said that the New Jersey case was yet another example of an out-of-market solution that distorts the results of PJM’s capacity auction. PJM’s auction is not perfect, he said. The organization’s treatment of demand response resources is “discriminatory and needs to be fixed” for instance, he argued. But PJM’s auction works and that is proved by the fact that merchant projects cleared the auction last year, Kerecman said.

To bolster his case on the need for long-term contracts, Egan then cited a statement Jack Fusco, Calpine’s CEO, made at a recent conference to the effect that the only way to build a power plant is to build or buy one at a discount to replacement cost or to build one at replacement cost with a long-term contract.

Badar Khan, president and CEO of Direct Energy, who also participated on the panel, said that when New Jersey and Maryland stepped into the capacity auction process it was “a step backwards.” State officials and regulators should “let the wholesale market work,” he said.

Egan argued that states lost a lot of jurisdiction when they agreed to join PJM. “They have learned to regret that, and they want back in the game. And I think they will get back in the game. It’s only fair.”

— Peter Maloney

ISONE files plan for day-ahead credit

In accordance with their desire to move up the day-ahead energy market time line, ISO New England and NEPOOL want federal energy regulators to allow advancing the time-of-day deadlines for market participants to cure a financial assurance default or payment default, or face a market suspension.

On February 7, ISONE and NEPOOL submitted alternative versions to the Federal Energy Regulatory Commission for changing the day-ahead energy market time line. The ISO’s version would close at 9 a.m. EDT, while under the NEPOOL plan the market would close an hour later. The market currently closes at noon.

The ISO and NEPOOL joined in asking FERC to choose between the alternatives and to permit the change to take effect on or after May 1, 2013, with two weeks' notice of the actual effective date to be provided by the ISO.

On Wednesday, the ISO submitted revisions involving its financial assurance and billing policies to FERC that would move the timing of suspension of market participants to 8:30 a.m. EDT from 10 a.m. to accommodate the modified day-ahead energy market schedule pending before the commission. The ISO said in its filing that the 8:30 a.m. suspension time will accommodate either a 9 or 10 a.m. market close and "will provide the ISO with sufficient time to recognize any overnight market activities, bill payments, late-received wires or late-received amendments to letters of credit." NEPOOL joined the ISO in its filing.

Under the proposed revisions, a market participant who receives a notice of a financial assurance default will be suspended if the default is not cured by 8:30 a.m. on the next business day. Similarly, a market participant will be suspended upon failure to cure a payment default by 8:30 a.m. on the second business day.

The ISO said in its filing that a greater number of suspensions could arise under that time line, which could be highly disruptive to markets. Therefore, "it will become more critical for market participants to manage their collateral requirements consistent with financial assurance management best practices to avoid suspension," the filing states.

To drive this home, the ISO added proposed language to its financial assurance policy that lays out a suspension process for participants who repeatedly receive notice that one of its credit test percentages exceeds 100%.

The ISO believes moving up the day-ahead market timing will help address reliability needs associated with the region's growing dependence on natural gas. However, the initiative has drawn opposition from some market participants who say the gas market doesn't become liquid until after 9 a.m. Others say that by moving up the process it will be harder to accurately schedule load. The wide difference of opinion among market participants led to the separate filings.

— Allan Schilling

San Onofre-2 restart hinges on several NRC steps

Even if the Nuclear Regulatory Commission approved it, a Southern California Edison request to amend the license of its San Onofre-2 nuclear power reactor would not, in itself, authorize the unit’s restart, the NRC and SoCal Ed said Thursday.

Both San Onofre-2 and -3 have been shut since January 2012, when an unusual amount of wear was found in the tubes of their replacement steam generators, which began operating in 2010 and 2011, respectively. NRC must approve the restart of either unit.

The amendment request would change the technical specifications for unit 2 to limit the reactor to 70% capacity for one operating cycle, which would last about two years. The reactor would operate at 70% power for five months and then be shut for steam generator tube inspections, SoCal Ed said.

On Wednesday, NRC issued what it calls its "proposed determination that the license amendment request involves no significant hazards consideration."

But that determination is not final and, even if the amendment is approved, additional authorization must be received from the agency before unit 2 could restart, NRC spokesman Victor Dricks said Thursday.

The proposed determination will be published soon in the Federal Register, at which time the public will have 30 days to comment and 60 days to request a hearing, Dricks said.

In order for unit 2 to restart, NRC must also complete its review of actions SoCal Ed has taken in response to a confirmatory action letter on steam generator wear, and its technical evaluation of the utility's restart plan, Dricks said.

Even after those hurdles are cleared, NRC senior managers "must make a determination that [San Onofre-2] can be restarted safely," he said. NRC hopes to complete its inspection of SoCal Ed's responses to the confirmatory action letter and its evaluation of the restart plan in May, Dricks said.

SoCal Ed has said it wants to restart the reactor in June, so it will be online during the summer months of highest electricity demand.

The utility is pleased with the preliminary determination, but the license amendment review is a "separate process" from the other reviews, which are also proceeding in a "very transparent and open" manner, SoCal Ed spokeswoman Jennifer Manfre said Thursday.

Senator Barbara Boxer, a California Democrat who heads the Environment and Public Works Committee that oversees NRC, said in a statement Wednesday that NRC's proposed determination is "dangerous and premature," and "could pave the way" for restart of unit 2 "before the investigations of the crippled plant are completed."

"It makes absolutely no sense to even consider taking any steps to reopen San Onofre until these investigations look at every aspect of reopening the plant given the failure of the tubes that carry radioactive water," Boxer said. "In addition, the damaged plant is located in an area at risk of earthquake and tsunami."

Manfre said safety is SoCal Ed's "top priority" and the reactors will not be restarted until their safe operation is assured.

— Steven Dolley

Power producers switching back to coal: EIA

US generators used 16% less natural gas, or around 3.5 Bcf/d, to generate electricity in March compared with March 2012 levels, when prices were at 10-year lows, the Energy Information Administration said Thursday.

"This lower volume will likely be maintained for the remainder of the shoulder season, and it may indicate a shift back to more coal-fired generation," EIA analyst Michael Kopalek said.

While the NYMEX price for gas rose above $4/MMBtu in March, cash prices in markets downstream of Transco Zone 6-non New York spiked into the double digits because of pipeline constraints, according to the EIA and Platts data.

According to the EIA, Central Appalachian coal prices rose to about $30/MWh in March while Transco Zone 6-non New York prices were $5/MWh higher throughout the month and earlier in the winter prices spiked as high as January 24's $86.14/MWh.

"In Pennsylvania, for example, the spot price of Northern Appalachian Basin coal, when adjusted for delivery to electric power producers now appears competitively priced compared to natural gas," EIA said.

Wisconsin Electric Power, a We Energies subsidiary and the state's largest electric utility, last month said it expects to generate more electricity from coal this year as natural gas prices continue to trend upward.

With natural gas prices at historically low levels in 2012, coal accounted for only 43% of the utility's electricity generation, compared with 54.2% in 2011.

But coal power is forecasted to make a strong resurgence to 56% of total capacity in 2013, the company said.

— Bill Holland

ERCOT resource adequacy debated by senators

A cost-benefit analysis for a capacity market in the Electric Reliability Council of Texas and a demand-response reserve to shore up ERCOT's resource adequacy were discussed this week during a Texas Senate panel meeting.

State Senator Troy Fraser, a Republican from Central Texas, has proposed an amendment to a bill to continue the authorization for the Public Utility Commission of Texas, known as the PUC Sunset Bill, which would require a cost-benefit analysis before implementing "a significant market change that would add more than $1 billion to the annual cost to customers of the state."

At Tuesday's Senate Business and Commerce Committee meeting, Fraser pointed out that he was involved in the original legislation restructuring the Texas electricity market, and "we made very clear at that time that it was going to be an energy-only market."

Fraser said he thinks his amendment is a matter of "transparency," not policy, as it would ensure the public knows the costs and benefits of such a change. This amendment had not been posted to the Texas Legislative website as of Thursday morning.

"We're very much encouraged by Sen. Fraser's proposal to require a cost-benefit analysis for substantial market changes," said Randy Moravec, executive director of the Texas Coalition for Affordable Power.

"A capacity market, by its very design, will increase costs — perhaps significantly. But we've yet to see an in-depth examination of the potential impact of such a market change on residential customers, business customers or retail electric providers. Such a study is needed and Sen. Fraser's fiscally responsible amendment is a step in the right direction," he added.

Other legislation, S.B. 1280, would make ERCOT determine by June 1 of each year whether enough generation would be available the following year to prevent no more than one rolling blackout every 10 years. If not enough resources were available, ERCOT would have to obtain enough demand-response resources to make up the difference, and at least 20% of those demand resources would have to be obtained from each of the following groups of customers: residential, commercial and industrial.

ERCOT's most recent Seasonal Assessment of Resource Adequacy projects that generation and firm reserves are likely to exceed demand this summer by less than 8.4%.

ERCOT's most recent Capacity, Demand, and Reserves Report, issued in December, forecast that the planning reserve margin would be below the target 13.75% this summer and continue to decline thereafter. That 13.75% target was set as a goal to ensure a lack of capacity causes no more than one rolling blackout every 10 years under normal circumstances. The December CDR forecasts the reserve margin (calculated differently from the SARA) would be 13.2% this summer, 10.9% the following summer, 10.5% in the summer of 2015n and fall below 10% in the following years.

A recent Loss of Load Study projects that in order to ensure enough capacity is available to prevent no more than one rolling blackout every 10 years, a reserve margin of about 16% is required.

State Senator Kirk Watson, a Democrat from Austin, Texas, expressed frustration at the slowness of the PUC's response to the state's resource adequacy problem.

But Bill Peacock, vice president of research at the Texas Public Policy Foundation, a conservative think tank, said, "One of the big problems we have is that market interventions are actually causing less investment here in Texas."

"If generators know that they would have to compete with mandated demand response, that would reduce their incentive to invest, in the long run," Peacock said.

In contrast, Bob King, consulting firm Good Company Associates president and an advocate for demand response, said generation-oriented stakeholders "have kind of been reluctant to let new participants into the market, when they're already short on money for generation, which you can understand."

Boosting demand-response therefore requires "top-down direction from the PUC and from [the Legislature] to get it done," King said.

State Senator John Carona, a Dallas Republican, said Fraser's proposed amendment to the PUC continuation legislation may be voted upon on the Senate floor. No action was taken this week on Watson's S.B. 1280.

— Mark Watson

Reviews mixed on scarcity pricing plan

While several observers in the Electric Reliability Council of Texas agree that the scarcity pricing proposal being considered by Texas officials is the best option available, they also said it is not perfect.

William Hogan, Harvard University professor and research director of the Harvard Electricity Policy Group, said his recommendation is that Texas adopt what is being referred to as "interim solution B+" as soon as possible.

Then, once it is in motion and results are published, officials can work on the strategy needed for full blown implementation.

"I think knowing where we're going would help," Hogan said about the interim solution leading to the full blown strategy of his proposal on scarcity pricing.

The idea started when Hogan filed a paper in November with the Public Utility Commission of Texas that emphasized the importance of an operating reserve demand curve in improving real-time scarcity pricing in the ERCOT market. His proposal involved real-time co-optimization of energy and ancillary services.

Since the initial proposal could not be implemented in time for the summer peak season, ERCOT worked with Hogan to determine the validity of modifying the existing energy offer floors as an interim solution, which became "interim solution A."

"Interim solution B" was a collaboration that produced a calculation based on loss of load probability, value of lost load and the level of available reserves in real time.

Both interim solutions were presented at a January PUCT workshop, where concerns were raised regarding negative market behavior that "interim solution B" could incentivize. That's when "interim solution B+" was created by adding an ancillary service imbalance settlement.

Even though it is April, it would not be an issue to have the interim solution in place for the summer season, Hogan said.

"If the commission decides it wants to do this … and puts the resources behind this, I think it could be implemented quickly," Hogan said.

What people are saying

The obstacle standing in the way of implementing "interim solution B+" is a change to the status quo, Hogan said. Some people like change, some people do not, he added.

"As with policy decisions, it's not the execution that's hard, it's the decision to execute that's hard," Hogan said.

Critics of "interim solution B+" don't think it can be put in place in time for the summer peak season and are pushing for "interim solution A," Hogan said. However, that option is not consistent with the operating reserve demand curve idea, Hogan said.

"It's not a natural transition to what everyone thinks needs to be done in the long term," Hogan said. "I'm always nervous with adopting interim solutions that are not consistent with the long term."

Bill Hieronymus, a vice president in the energy practice at Charles River Associates, said the proposal is a huge improvement on the status quo. The two things wrong with the existing system are that it is not revenue adequate and it is unpredictable, he said.

"Interim solution B+" fixes the core problems with resource adequacy, Hieronymus said. However, the reserve margin target for ERCOT (13.75%) is not consistent with the revenues that would be achieved if based on loss of load probability, he added.

"It still doesn't solve the problem," Hieronymus said. "There's got to be something more appropriate than just this."

He would like to see ERCOT move to a capacity market, which would directly address what officials are trying to accomplish and provide more revenue stability.

"Texas is reluctant to abandon the energy-only market," Hieronymus said. "If this continues, a larger and more broadly based version of interim solution B+ will be necessary."

Some generators he has talked with support a capacity market and see this proposal as a half-way solution, while others see this proposal as the best solution within the confines available.

Tony Grasso, a market consultant and former PUCT economist, said the market needs a real evaluation on how well it is working for the money being invested.

"We ought to ask ourselves every so many years 'are we really better off or should we go back to a regulated market? Are the consumers being treated fairly?'" Grasso said.

The current electric market is trying to emulating a competitive market, Grasso said, adding that if the market is left to itself if won't work.

"It's not that it's not working," Grasso said. "It's that it needs continual tweaking. How much can the consumer still bear?

"It's like trying to make something grow in the desert. It needs continued care or it will die. … At what point would they like to see the fixes stopped?"

While Randy Moravec, executive director of Texas Coalition for Affordable Power, prefers the proposal to a capacity market, TCAP hasn't endorsed implementing "interim solution B+" because it's still in the early phase of discussions. Moravec said the proposal shows some promise of ensuring reliability without significantly increasing costs.

He'd prefer to wait and see the impact of changes made by ERCOT and the PUCT since last summer.

"Let's see if what they've done so far works or not" before adding more fixes, Moravec said.

Hogan said it comes down to the two voices that really matter: PUCT Chairwoman Donna Nelson and Commissioner Kenneth Anderson.

"I'd be interested in what they think," Hogan said.

Hogan's proposal is nothing new to Texas. About five years ago, he made a similar proposal regarding resource adequacy in Texas.

"I've been beating the same drum for four years," Hogan said when asked about his previous proposal. " … Time goes on and time goes on, because it's not politically painless."

At the time of the previous proposal, ERCOT was focused on preparing for the transition to the nodal market as designed, ERCOT spokeswoman Robbie Searcy said when asked why ERCOT did not take action previously.

"I think this is a good idea no matter what," Hogan said about Texas implementing the proposal, adding it's not an either or situation.

PUCT stakeholder comments

The PUCT has requested stakeholder comments on the whitepaper ERCOT filed March 22 that reports what the results would have been if the "interim solution B+" had been in place in 2011 and 2012. The comment deadline is May 31. It will be followed by a workshop this summer.

While the PUCT did not discuss "interim solution B+" at its Thursday meeting, comments have continued to come in from the solar energy industry and its supporters.

OCI Solar Power said in a filing that it is concerned that the PUCT has undervalued the feasibility for solar energy to serve as a solution to threatened resource inadequacy in ERCOT. The company would like the PUCT to have a workshop for stakeholders and solar industry leaders to discuss solutions regarding solar technology for ERCOT generation resources.

"We urge the commission to give more attention to solar generation as a source of cost-competitive electricity that is available during periods of peak electric demand," OCI Solar Power President Anthony Dorazio said in the filing, adding that those same sunny afternoons that result in maximum customer demand are also when solar produces its maximum capacity. Solar generating resources can also be built more quickly than other generation and don't suffer from potential fuel price increases, impact of water scarcity, or any carbon controls or taxes, Dorazio said.

SolarBridge Technologies President and CEO Ron Van Dell agreed in his filing submitted last month.

"Solar generation can reasonably be constructed and deployed more swiftly than other generation resources, and fill in resource gaps during the wait for other generation that requires a greater lead time to get online," Van Dell said.

Several others, both individuals and organizations, have echoed those comments regarding solar power in their filings and want the PUCT to have a workshop involving solar resources.

— Kassia Micek

IPA looks to use funds for RECs, DG promotion

The Illinois Power Agency is looking for a way to free up a projected $150 million pot of money to promote the development of distributed generation in the state and procure wind renewable energy credits.

Established in 2007 by power procurement and rate relief legislation passed by the General Assembly, the tiny IPA's primary mission has been to buy power on behalf of Commonwealth Edison and Ameren Illinois, the state's two largest electric utilities.

But as the utilities' load decreases because more customers migrate to competitive suppliers, the need for IPA to purchase power has diminished.

Under current plans, IPA will not buy any additional power to serve nonshopping customers of ComEd and Ameren for at least a couple of years, possibly longer.

Meanwhile, more competitive power suppliers continue to pay fees to IPA as required by state law. The Legislature's intent was for the agency to set up a fund to promote the growth of renewable energy resources in Illinois.

That clean energy fund is expected to swell from the existing $15 million to perhaps $55 million by September and to as much as $150 million in a year or so.

The problem, IPA acting director Anthony Star said in an interview, is that the law is unclear on how the agency can spend that money.

The money is supposed to be used to buy electricity. "In our view, there [are] some technical views about that that keeps us from spending it right now," he said. "We need the existing legislation amended to give us clear authority to spend the money quickly from alternative suppliers in years when we don't buy power."

That is why IPA is seeking a political solution from the General Assembly.

"There is some legislation out there now and we have been talking with legislative staff now," Star said. "I'm hoping something will happen," this year, preferably, instead of next year.

If the agency gets the go-ahead to spend the money, Star said at least some probably would be allocated for the procurement of wind RECs.

But a more ambitious plan centers around distributed generation. Several Midwestern states, including Illinois, want to increase the development of on-site, cleaner energy by manufacturers and other electricity users.

If the law is amended, "there is a clear program to aggregate distributed generation," Star said. "This would be new ground for us. The model would be contracting with aggregators to get us up to the necessary block of distributed generation we would procure."

How much that would be is yet to be determined.

As Star indicated, that could provide an entirely new reason for being for the four-person IPA.

With its decline in power procurement plans, some officials are questioning whether the IPA still serves a useful purpose.

If the agency was much larger and had a multimillion-dollar budget, said an official with the Illinois Chamber of Commerce, there likely would be a more serious push to eliminate it.

— Bob Matyi

Storage injections to erase deficit: Analysts

Even as the storage deficit continued to grow with another withdrawal reported Thursday, some analysts predict that strong injections will wipe out the year-over-year deficit by November 1.

Storage stocks fell 14 Bcf to 1.673 Tcf for the week ending April 5, the Energy Information said Thursday, below consensus estimates between 20 and 24 Bcf.

Last year at this time EIA reported an 11-Bcf injection, while the five-year average is a 15-Bcf build. As a result, the 779-Bcf deficit to the year-ago level grew to 804 Bcf, while the 37-Bcf deficit to the five-year average of 1.739 Tcf expanded to 66 Bcf.

The draw was smaller than expectations in part due to the Easter holiday weekend, when demand typically drops, said Gelber & Associates analyst Aaron Calder.

And despite April starting off with two consecutive withdrawals, the traditional injection season is still beginning with the second highest inventory on record, Calder noted.

Moreover, some analysts anticipate storage additions this spring and summer to be higher than normal, lifting inventories to around 3.8 Tcf to 3.9 Tcf by November 1 — on par with last year and above the five-year average.

According to EIA, the highest inventory at the end of injection season was in 2012 at 3.96 Tcf, followed by 3.81 Tcf in 2009.

“We anticipate that the industry will significantly trim the current [year-on-year] storage deficit by mid-season, resulting in a significant setback in prices during the second quarter,” said BNP Paribas analyst Teri Viswanath.

Bentek Energy, a unit of Platts, expects storage inventories to refill to 3.8 Tcf at the end of the injection season for a total build of 2.1 Tcf. That would be above the five-year average of 2 Tcf.

Barclays Capital analysts expect injections to average 4 Bcf/d greater than last year and inventories to rebuild to 3.9 Tcf by November 1.

Jefferies and Company analyst Subash Chandra provided a lower season-ending estimate of 3.67 Tcf, but said he expects gas prices to fall from the current $4/MMBtu level back to low $3.00s/ MMBtu. "The recent gas rally was caused by a deliverability crisis, and gas should fade back to the coal displacement orbit when withdrawal season ends," Chandra said.

Jefferies' base case assumes only a fractional recovery in coal-market share for the generation of power, but "if coal shares recovered more vigorously, say another 1%, inventories could near 3.9 Tcf," Chandra said. He noted that there is plenty of baseload generation available this summer as nuclear, hydro and wind power should be ample compared with last year, he noted.

Canaccord Genuity analysts have a different outlook, estimating that gas in storage will be only around 3.1 Tcf by November, assuming steady onshore gas production during the year.

And November 2014 gas storage inventories, assuming normal winter weather, "could fall solidly below 3 Tcf" even with a recovery in the gas rig count to around 575 rigs by the second half of 2014, they said.

— Anastasia Gnezditskaia, Stephanie Seay

Brookfield wins bid for 15 MW TSRs at Linden

Brookfield Energy Marketing offered the winning bid for 15 MW of transmission scheduling rights at the Linden Variable Frequency Transformer facility for the July 1, 2013, to October 31, 2014, term, according to an open season report filed with the Federal Energy Regulatory Commission.

Brookfield Energy Marketing was identified in the April 10 open season report (Docket No. ER07-543) as the bid with the highest price net of PJM's regional transmission expansion plan and reliability-must-run costs for the single 15-MW block that offers bi-directional transfer capability of 315 MW between the PJM Interconnection and New York City's NYISO, Zone J.

The amount of the winning bid will not be disclosed, GE Energy Financial Services spokesman Andy Katell said Thursday. Linden VFT is located in New Jersey and is an affiliate of GE EFS.

Brookfield Energy Marketing is based in Gatineau, Canada, and operates as a subsidiary of Brookfield Renewable Power and distributes hydroelectric power.

Bidders had the option of submitting offers with and without reliability costs allocated to Linden VFT related to the RTEP or the reliability-must-run costs provisions of the PJM Open Access Transmission Tariff. Bids were due April 1.

More open-season auctions involving TSRs from the merchant Linden VFT facility are expected to be held next year.

Brookfield Energy Marketing can use the scheduling rights to sell capacity and energy from PJM into the NYISO between the Linden VFT switching station and the pricing node near ConEd's Goethals substation.

The Linden VFT connects to NYISO Zone J through an upgraded 345 kV underground cable transmission system linking its 900-MW cogeneration unit to the Goethals Substation.

PSEG Energy Resources & Trade provided the winning bid in the second open season held last summer at the Linden VFT for 225 MW of TSRs with a term of five years and seven months beginning November 1, 2012.

— Cathy Cash

Projects in PJM to trim congestion

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PJM had already taken into account the need to address large-scale reliability issues and authorized upgrades under its 2012 Regional Transmission Expansion Plan that have the effect of reducing congestion.

PJM's control area spreads through 13 states and covers major load centers, including Chicago, northern New Jersey, Philadelphia, Richmond and Washington, D.C., with more than 185,000 MW and 65,000 miles of transmission lines.

If transmission congestion emerges from the massive loss of MW, it will largely be at the local, low-voltage level, Russo said. A trend in plummeting transmission congestion costs further bears that out.

The PJM market's actual congestion costs racked up to $998 million in 2011. Yet as RTEP upgrades were approved and impacts assessed, a significant drop in PJM constraints emerged in 2012 when congestion costs totaled $529 million — a 47% decrease from the previous year.

Market simulation studies for 2015 show more dramatic drops in congestion are in store stemming from the approved grid upgrades.

An 82% reduction in annual congestion costs is forecast from $980 million "as is" 2012 baseline to $173 million "as planned" with the PJM 2016 RTEP that includes the high-voltage backbone projects, Susquehanna-Roseland and Mount Storm-Doubs.

Public Service Electric and Gas is beginning construction of 45 miles of the 500 kV Susquehanna-Roseland line in New Jersey that includes two new 500 kV switching stations. PPL Electric Utilities will build the 100-mile Pennsylvania portion of the line. The $1.3 billion project is expected to be in service in June 2015. PJM has determined that the line will improve grid reliability and, developers note, congestion relief estimates of up to $200 million a year.

Dominion reports that its 96-mile 500 kV line from Mt. Storm Substation to the Douds Substation is ahead of schedule this month. The project rebuilds the 1966 line on existing right-of-way that runs from West Virginia, through parts of northern Virginia and into Maryland.

Specifically, more than 70% of the line is done, about 70% of the aging steel structures have been erected and all structure foundations have been completed, according to the utility, which has approval for the Mt. Storm-Douds project from the Virginia State Corporation Commission and the West Virginia Public Utility Commission.

Yet, localized grid reliability projects aimed at hardening the system against the brunt of the coal retirements make up the majority of the 2012 RTEP. Reactive upgrades on the high-voltage system also play a big role in reducing congestion costs by boosting the power transfer capability allowed.

Most of these projects are slated in Western PJM for completion by June 2015 to the tune of nearly $2.5 billion.

They include American Transmission Systems' conversion of FirstEnergy's five Eastlake units and one Lakeshore unit to synchronous condensers at $20 million each to provide voltage support as the coal plants shutdown.

In the American Electric Power Transmission Zone, approved projects include a lot of transformer work, such as installing a 765/345 kV transformer at the Mountaineer power plant and building a ¾-mile 345 kV line to the Sporn substation for $65 million. AEP is also expected to rebuild the Sporn-Waterford-Muskingum River 345 kV line at a cost of $200 million and the Amos-Kanawah River 138 kV corridor for $150 million.

Among the scores of other Western PJM transmission improvements include construction of a new Byron to Wayne 345 kV circuit at $109 million in the Commonwealth Edison Transmission Zone.

Local projects to get done

PJM officials say the majority of these zone-based projects to reinforce the grid in the face of record coal generation loss will get done. Congestion relief will be a by-product.

PJM in 2012 authorized about 777 transmission improvements estimated to cost more than $5 billion.

"The vast majority will go forward," said Steve Herling, PJM vice president of transmission planning. "The bulk are needed quickly."

That contrasts with the backbone power projects approved by PJM in 2007 that promised huge waves of capacity to de-bottleneck market snarls and shore up the grid during periods of increased demand.

Both the Potomac-Appalachian Transmission Highline, or PATH, and the Mid-Atlantic Power Pathway, know as MAPP, were removed from the RTEP last August 24 after the PJM board found that updated analysis showed grid conditions had changed and these large lines are no longer necessary for grid reliability.

PATH would have stretched 275 miles of new 765 kV line from AEP's Amos Substation in West Virginia to a new Kemptown Substation in Maryland. FirstEnergy had partnered with AEP in the $2.1 billion project but the companies withdrew their application in 2011 when PJM suspended it.

MAPP was a 230-mile line proposed by Pepco Holdings to run 500 kV and 640 kV DC from Possum Point, Virginia, to Hope Creek, New Jersey. PJM accepted the line after it had projected increased electricity demand in the Mid-Atlantic region that could lead to serious reliability problems in the region by 2012.

Cleveland, ground-zero for the blackout of 2003, still experiences significant constraints because of voltage criteria limits. Large generator deactivations slated for the area, including Eastlake and Avon Lake, add up to almost 2 GW and are likely to worsen this situation, notes ICF Vice President Ken Collison.

Still, PJM's remedies in response to these retirements are largely to address the voltage limits, and it is possible the situation may improve, he said.

West versus East flow of gas-fired power

Growing reliance on natural gas may highlight differences between Western and Eastern PJM delivered-gas prices. And that eventually could stand to influence the dispatch of the units and the flow of power. Still, some market-watchers foresee little change in generation patterns.

For now, the cheap available natural gas has eased the West-East flow of electricity in PJM's major lines.

"Historically, gas prices have been lower in Western PJM, giving those units an advantage," Collison said.

The recent year's drop in gas prices, he said, "has increased the competitiveness of the Eastern gas units relative to the Western coal plants. This has had the effect of reducing congestion on the interfaces linking Eastern to Western PJM."

Available gas pipeline capacity, however, may become an issue as more gas units are connected to the system, he noted.

More inexpensive gas, in the meantime, will lead to "lower differentials between the up- and down-stream points of congested elements, reducing the overall cost of congestion," Collison said.

"An increase in gas prices may reverse this trend, though the final outcome would depend on the impact on the system of the coal retirements," he said.

As coal retirements in the region are completed by 2020, it is difficult to forecast how much of the proposed gas generation will be built in the Western half of the system. Although, in the near-term, 2013-2015, Eastern PJM, home to a number of gas units, is expected to welcome a number of new large combined-cycle plants.

PJM's Herling pointed to new federal regulations to slash emissions of mercury and other air toxics from coal-fired units for many early shutdowns. But he conceded "gas prices were a big, big part of [coal plant retirement] decisions as well."

Russo of CRA points out that more expensive coal plays a role in boosting gas generation as well. "If you look at coal prices now, they're as high as they've ever been," he said.

PJM said it received a record 104 retirement requests totaling 13,868 MW — enough to meet Indiana's power needs for nearly a year—between November 1, 2011, and December 31, 2012, and another 1,697 MW were noticed for retirement in January.

An additional 6,300 MW has been identified as "at-risk" of retiring in the years ahead. The retirements are expected to stagger out to 2015, when compliance with the federal Mercury and Air Toxics Standards by the power sector is expected.

"We've never had to cope with generation retirements or fuel shifts on this scale," Herling said.

Some major grid projects will not be completed by the time a large chunk of coal retires, and that might result in operating procedures for managing reliability that will come at a cost, Herling said. PJM has been operating that way with the delay of the Susquehanna-Roseland line by running more expensive generation in northern New Jersey to retain reliability, he said.

"The deck is stacked against [aging coal units] with the EPA regulation kind of the last straw," said Herling. The amount of capital that must be sunk into coal plants to meet the emissions limit "does not paint a good picture for their economic future," he said.

— Cathy Cash

PJM to impose new rules for traders

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exemption request, market participants must either hold physical positions, maintain a net worth of at least $1 million or have assets of at least $5 million, PJM vice president and general counsel Vincent Duane said at Thursday Markets and Reliability Committee teleconference.

Duane said the eligibility requirement creates uncertainties for PJM.

"It doesn't say that if you don't meet that standard you can't trade, just that you're not entitled to that exemption," Duane said. "So we're back to square one with respect to those market participants. We haven't resolved whether those are swaps, whether PJM is a swap execution dealer."

Duane said that PJM, in consultation with the other ISOs, has decided that it will exclude companies that do not meet the CFTC exemption eligibility requirements from participating in the FTR, energy, capacity and reserve and regulation markets.

This would effectively make the $1 million in net worth or $5 million in assets standard a minimum participation requirement for financial traders in PJM. Physical market participants — defined by the CFTC as any entity "in the business of generating, transmitting or distributing electric energy or providing electric energy services that are necessary to support the reliable operation of the transmission system" — would not have to meet the financial eligibility requirements.

"We're approaching this the same way, which is to say it would not be appropriate to expose the RTO and its members to the risks of transacting with a member who is not able to satisfy the exemption criteria," Duane said. "We will seek the [Federal Energy Regulatory] Commission's consent to allow us not to transact with entities that are not able to demonstrate that they meet one of those standards."

CFTC staff issued a "no action" letter on March 29, recommending that the agency give the ISOs until September 30 to comply with the conditions of the exemption. In order to meet the September 30 deadline, PJM officials said they plan to draft tariff language instituting the minimum participation requirement and present it to stakeholder committees in April and May, with the goal of submitting it to FERC for approval in late May.

Suzanne Daugherty, PJM's vice president, CFO and treasurer, said she expects that roughly 10% of existing PJM market participants will need to demonstrate that they either hold physical positions or meet the financial eligibility requirements. Daugherty said the credit department will work with those companies to get documentation in place by September 30. New PJM members will need to show that they meet the exemption eligibility requirements when they apply for membership, Daugherty said.

— Juliana Brint

Dynegy CEO details strategy for Ameren plants

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MISO into PJM. There are only the physical limits of the transmission lines connecting the two regions.

"There is only so much transmission capacity, and they found it," Flexon said in an interview.

The ability to shift capacity from MISO to PJM is an obvious attraction for generators, given the wide gap in capacity prices, and it is something that Flexon said Dynegy intended to look into after the acquisition closed, but "Ameren beat us to the punch."

The result, Flexon said, is that Dynegy will get "almost 1,000 MW of PJM capacity at no cost."

The capacity that Ameren will sell into PJM is only about a fifth of the roughly 5,000 MW that Ameren is selling to Dynegy, but if those plants clear the auction, it could provide a boost for Dynegy's revenues and help improve the economics of the fleet.

MISO on April 5 conducted its first annual capacity auction, which cleared at $1.05/MW-day. The clearing price for PJM's most recent auction was $136/MW-day.

Despite the prospects of higher revenues from PJM capacity payments, Dynegy faces a steep challenge in making the Ameren plants profitable.

As it is, Ameren's coal plants are not generating enough revenue to support their debt obligations. That is why Ameren has been trying to sell them for some time and was even facing the possibility of having to restructure them.

Flexon said one of the strengths of Dynegy's offer to Ameren was their view of the assets as a "going entity."

"Our goal was never to take the plants into restructuring," he said.

That goal would appear to be a hard one to achieve. Even though Dynegy is not putting cash into the deal, the subsidiary Dynegy is creating to house the Ameren plants will assume their $825 million of non-recourse debt.

Those obligations will still have to be met and Dynegy will have to run them in the same environment as did Ameren, at least until 2016 when capacity payments from PJM could provide a boost.

Flexon acknowledged the challenge that Dynegy will face, but noted that part of the deal calls for Ameren to hive off three gas-fired plants from its merchant fleet, sell them and give the proceeds to Dynegy.

Including payments for the gas plants, as well as other items, Dynegy expects to receive $226 million in payments from Ameren as part of the deal.

In addition the deal includes $160 million in working capital, mostly the value of coal inventories and transport contracts, and Flexon expects to reap $60 million in annual synergies once Ameren's Illinois fleet is combined with Dynegy's existing 4,180-MW fleet of Illinois coal plants.

Flexon views those payments as a bridge to 2016, which is when the PJM capacity payments could begin to kick in. That is also around the time when the 12 GW of slated coal plant retirements in MISO will be to take hold.

Flexon said that on a fleetwide basis both the Ameren coal fleet and Dynegy's existing coal fleet will be compliant with pending Environmental Protection Agency emissions standards and with Illinois' tough pollution control standards.

In that environment, Flexon expects Dynegy's coal fleet to be well positioned. The retirement of other coal plants will put pressure on gas and capacity prices and will require Illinois' existing gas plants, which are predominantly peakers, to run as mid-merit or baseload plants. And the increased run-time of the peakers, which typically have not contracted for firm gas supplies, will also put upward pressure on gas prices.

In addition the nature of the gas producers active in the shale plays is changing. Larger companies have been entering the market, and they will bring more price discipline and higher cost structures, which would also put upward pressure on gas prices, Flexon said. The result, he said, could be higher gas prices which in turn could lead to higher power prices.

Flexon said Dynegy's October 2012 exit from bankruptcy was designed with an assumption of a gas price of $3.50/MMBtu, which is more or less in line with current prices of around $4/MMBtu.

With the Ameren acquisition, Dynegy has essentially doubled down on coal. And if the forces that Flexon sees at work come into play and gas prices rise, Dynegy will be well positioned to benefit, he said.

With its existing fleet every $1/MMBtu rise in gas prices would result in a $130 million increase in EBITDA. At year-end 2012 Dynegy had $57 million in EBITDA. With the addition of the Ameren fleet, a $1 increase in gas prices could increase Dynegy's EITDA by $330 million, he said.

— Peter Maloney

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