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Thursday, April 25, 2013

Gap from retirements may be less than thought

ANALYSIS

With the numbers so large, one can rightly wonder: How big a gap will retiring coal plants leave in the US generation fleet?

The number are high, ranging to as much as nearly 62 GW, but the gap may not be anywhere near as large.

According to an analysis of Platts data, 40% of the 30,510 MW of scheduled coal plant retirements will be replaced by the companies that are retiring those plants, either by building a new gas-fired plant or switching over a coal plant to burn gas.

The scheduled retirements fall between now and 2021, with the overwhelming majority scheduled to retire in 2015. Most of the conversions or new plants are scheduled to come online as the coal plants cease generating.

Of the total 30,510 MW of planned coal retirements, the

(continued on page 17)

MISO looks to enhance `forward transparency'

MARKETS

The Midwest Independent Transmission System Operator would like to work on improving the "forward transparency" of its resource adequacy framework, MISO staff told the grid operator's board of directors at a Wednesday meeting.

With the region facing a wave of coal plant retirements driven by Environmental Protection Agency regulation and greater reliance on natural gas, MISO believes there is a need to consider enhancements to its resource adequacy system "to increase transparency [and] enable more efficient and effective resource planning decisions," according to a presentation delivered by MISO representatives on Wednesday.

Based on member surveys, MISO expects about 10 GW of coal generation to retire by 2016. While those retirements are expected

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DR may cause 'downward bias' for RPM prices

CAPACITY AUCTIONS

Demand response resources are likely to penetrate more deeply into the PJM Interconnection's upcoming capacity auction, leading to a "downward bias" for clearing prices for generators, according to a report released April 24 by UBS Securities.

The Federal Energy Regulatory Commission on April 19 sided with providers of demand response resources in a proceeding involving PJM. FERC said that PJM should have filed changes that the grid operator made to its manual related to requiring additional information from demand response providers with FERC.

Such a filing would need to be made under Section of 205 of the Federal Power Act and the process would require a more time consuming decision involving a review under the FPA.

While that may happen at a later date, it is not going to

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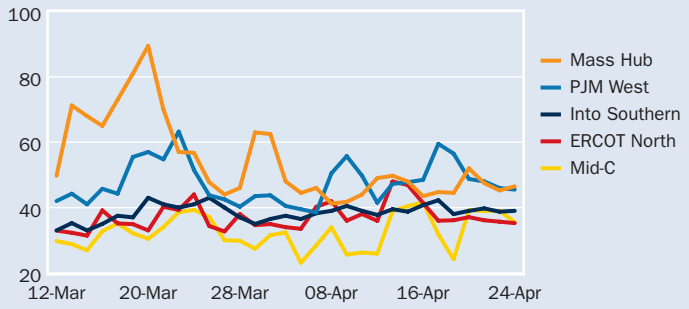
Price trends at key trading points ($/MWh)



Source: Platts

Low and high average day-ahead LMP for Apr 25 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	45.95	55.07	34.86	45.99
NYISO	34.23	59.24	26.75	42.87
PJM	43.64	50.77	31.66	36.37
MISO	39.83	46.35	28.65	33.89
ERCOT	28.56	41.59	18.78	39.37
CAISO	43.36	53.67	34.78	39.79

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 25

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	46.50	9203	11.13	6.08	-4.03	-14.13	-29.29
N.Y. Zone-A	37.00	8422	6.25	1.85	-6.93	-15.72	-28.90
PJM/MISO							
PJM West	45.50	10598	15.45	11.15	2.57	-6.02	-18.90
Indiana Hub	39.25	9033	8.84	4.49	-4.20	-12.89	-25.93
Southeast & Central							
Southern, Into	39.00	9144	9.15	4.88	-3.65	-12.18	-24.98
ERCOT, North	35.24	8416	5.93	1.74	-6.64	-15.01	-27.57
West							
Mid-C	35.56	8775	7.19	3.14	-4.97	-13.07	-25.23
SP15	55.50	13121	25.89	21.66	13.20	4.74	-7.95

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 amid spot gas gains

Daily power prices in the Northeast were mixed Wednesday, while the NYMEX May natural gas futures contract settled 7.2 cents lower at $4.166/MMBtu.

Northeast dailies were mixed in for-Thursday trading on the IntercontinentalExchange Wednesday morning as spot gas traded mostly stronger on ICE, while electricity demand was forecast to decline.

Algonquin city-gates spot natural gas was trading around $5.23/MMBtu on ICE, up 23 cents, while Tennessee Zone 6 was trading around $5.14/MMBtu, a gain of 20 cents. Transco Zone 6 New York spot natural gas was trading flat at around $4.48/MMBtu.

High temperatures in New England were forecast lower, ranging from the mid-50s to lower 60s. Boston was expected to see a high of 61 Thursday, down 5 degrees from Wednesday's projected high. Lows across the region were expected in the 40s.

ISO New England forecasted peak load for Thursday at 14,920 MW, down 300 MW from Wednesday's projected peak load. The projected peak load for Friday is 14,590 MW.

Mass Hub day-ahead peak for Thursday delivery was bid at $46.65 and offered at $47.50/MWh, up about $1.75. Day-ahead off-peak was trading around $35.50/MWh, down 25 cents. Balance-of-the-week peak financial packages were bid at $40/MWh.

At 10:30 a.m. EDT Wednesday, the price for Mass Hub power was $47.44/MWh.

In New York state, high temperatures for Thursday were expected to range from the lower 50s to lower 60s. New York City was forecast to see high of 62, compared with a projected high of 68 on Wednesday. Lows across the state were forecast to range from the mid-40s down to the md-30s.

The New York ISO forecasted peak load for Thursday at 17,983 MW, down 222 MW from Wednesday's projected peak load. The projected peak load for Friday is 17,658.

NYISO Zone G day-ahead peak was bid at $43.50 and offered at $47/MWh, up about 50 cents. Zone G balance-of-the-week peak was bid at $40 and offered at $41/MWh.

NYISO Zone A day-ahead peak was bid at $38 and offered at $41/MWh, up $1.50. Zone A bal-week peak also was bid at $38 and offered at $41/MWh.

Day-ahead auction prices for Thursday cleared mixed across the Internal Hub and zones in the ISO-NE Wednesday, with peak prices higher and off-peak lower. Internal Hub peak cleared at $46.44/MWh, up 22 cents, while off-peak cleared at $35.89/MWh, down 36 cents.

NE Mass-Boston Zone peak cleared at $46.37/MWh, up 14 cents, and off-peak cleared at $35.81/MWh, a drop of 41 cents. Connecticut Zone peak came in at $46.74/MWh, up 25 cents, while off-peak came in at $35.90/MWh, a decrease of 58 cents. Rhode Island Zone peak cleared at $55.07/MWh, up 32 cents, while off-peak cleared at $45.99, a drop of $6.46.

The Rhode Island Zone had the highest hourly price at $65.47/

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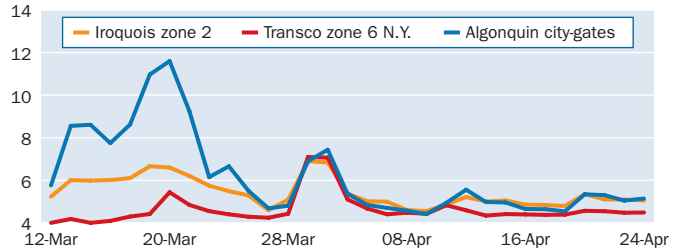
Northeast day-ahead bilateral indexes for Apr 25 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	46.50	1.25	47.78	9203
N.Y. Zone-G	46.00	1.25	48.47	9649
N.Y. Zone-J	48.25	1.00	49.50	10121
N.Y. Zone-A	37.00	-1.00	39.70	8422
Ontario*	29.75	0.25	32.18	6263
Off-Peak				
Mass Hub	35.50	-0.25	37.18	7026
N.Y. Zone-G	33.00	2.00	35.25	6922
N.Y. Zone-J	33.25	2.00	35.50	6974
N.Y. Zone-A	27.50	-0.25	31.12	6259
Ontario*	23.50	0.50	24.93	4947

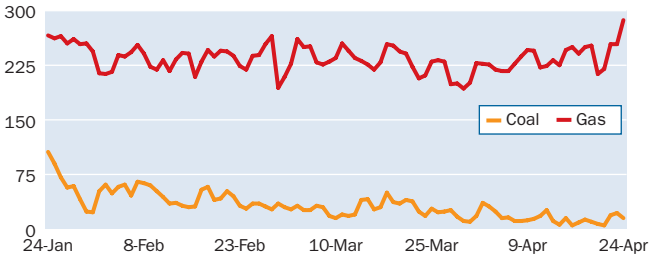
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO gas and coal generation (GWh)



Source: Bentek

Northeast load and generation mix forecast (GWh)

	Actual 23-Apr	%Chg	% Chg Year-ago	Forecast 24-Apr	25-Apr	26-Apr	27-Apr	28-Apr
ISONE								
Load	337	5	4	335	324	318	291	283
Generation								
Coal	12	19	41	6	3	4	4	3
Gas	133	2	-14	153	140	128	121	120
Nuclear	65	0	-4	65	66	71	79	87
NYISO								
Load	406	2	3	412	405	399	364	356
Generation								
Coal	10	14	79	10	7	6	5	3
Gas	121	-3	-10	134	129	121	110	110
Nuclear	119	0	6	119	119	119	119	119

Source: Bentek

ISONE day-ahead LMP for Apr 25 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	46.44	-0.90	0.02	0.22	45.87	9199
Connecticut	46.74	-0.90	0.32	0.25	46.56	9330
NE Mass-Boston	46.37	-0.90	-0.05	0.14	45.86	9184
SE Mass	47.91	0.93	-0.35	0.18	46.00	9489
West-Central Mass	46.68	-0.90	0.26	0.22	46.18	9247
Rhode Island	55.07	8.43	-0.68	0.32	47.53	10907
Maine	46.04	-0.87	-0.42	-7.50	49.97	9156
New Hampshire	46.86	-0.90	0.43	-0.04	46.25	9319
Vermont	45.95	-0.90	-0.48	0.25	45.51	9138
Off-Peak						
Internal Hub	35.89	-0.96	0.12	-0.36	36.36	7183
Connecticut	35.90	-0.96	0.13	-0.58	36.37	7165
NE Mass-Boston	35.81	-0.96	0.04	-0.41	36.41	7167
SE Mass	37.76	1.06	-0.02	-1.62	37.51	7558
West-Central Mass	36.02	-0.96	0.25	-0.38	36.51	7210
Rhode Island	45.99	9.33	-0.07	-6.46	42.19	9205
Maine	34.86	-1.03	-0.84	-2.26	36.17	6908
New Hampshire	35.82	-0.96	0.05	-0.48	36.40	7097
Vermont	35.32	-0.96	-0.45	-0.30	35.97	6998

NYISO day-ahead LMP for Apr 25 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	44.57	-5.69	2.53	2.69	46.35	9307
Central Zone	38.11	-0.78	0.99	-0.53	40.86	8670
Dunwoodie Zone	46.01	-4.67	4.99	1.85	47.19	9642
Genesee Zone	36.67	-0.61	-0.29	-0.83	39.73	8342
Hudson Valley Zone	46.10	-4.65	5.10	1.84	47.39	9661
Long Island Zone	59.24	-16.66	6.22	1.45	59.37	12413
Millwood Zone	45.94	-4.70	4.89	1.90	47.13	9627
Mohawk Valley Zone	38.62	-0.74	1.53	-0.48	41.72	8296
N.Y.C. Zone	48.46	-6.75	5.36	0.61	48.78	10155
North Zone	34.23	0.00	-2.12	-1.33	37.28	6808
West Zone	36.88	-0.79	-0.27	0.04	38.94	8389
Off-Peak						
Capital Zone	32.64	-3.14	1.69	2.44	34.62	6799
Central Zone	28.55	-0.43	0.32	0.03	31.59	6488
Dunwoodie Zone	32.97	-2.57	2.59	1.98	34.82	6893
Genesee Zone	27.80	-0.34	-0.35	-0.16	31.13	6318
Hudson Valley Zone	33.20	-2.56	2.83	1.95	35.22	6941
Long Island Zone	42.87	-11.55	3.51	0.17	42.26	8963
Millwood Zone	32.94	-2.59	2.55	2.00	34.80	6887
Mohawk Valley Zone	29.06	-0.44	0.81	0.16	32.16	6241
N.Y.C. Zone	33.09	-2.57	2.71	1.96	35.03	6918
North Zone	26.75	0.00	-1.06	-0.68	30.05	5300
West Zone	27.71	-0.44	-0.54	0.02	31.03	6296

Generation unit outage report

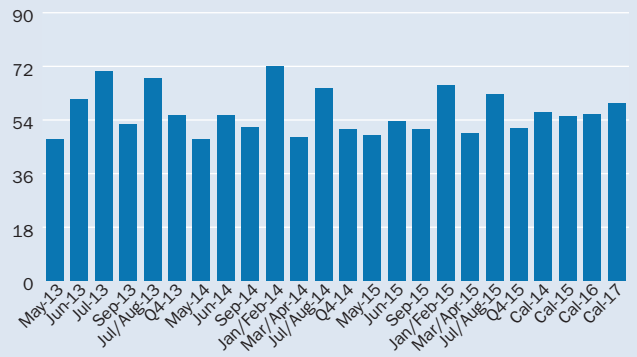
Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Darlington-4/OPG	878	n	Ont.	PMO	Unk	02/04/13
Millstone-3/Dominion	1203	n	Conn.	RF	05/24/13	04/13/13
Nine Mile Point-1/CENG	640	n	N.Y.	RF	05/14/13	04/15/13
Pickering-5/OPG	500	n	Ont.	PMO	Unk	03/18/13
Pilgrim/Entergy	670	n	Mass.	RF	05/21/13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

Northeast Platts-ICE Forward Curve, Apr 24 ($/MWh)

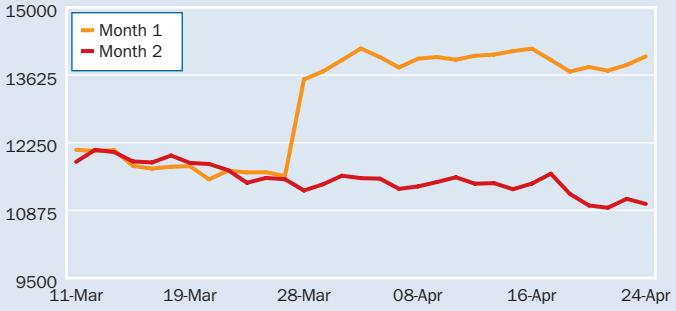
Prompt month: May 13	On-peak	Off-peak
Mass Hub	45.50	35.50
N.Y. Zone G	47.50	35.75
N.Y. Zone J	50.75	36.75
N.Y. Zone A	39.75	30.25
Ontario*	31.75	20.50

*Ontario prices are in Canadian dollars

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



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



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.

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 and terms move lower

Power prices for Thursday delivery in the Southeast region were lower Wednesday, as were forwards in the region as the NYMEX May natural gas futures contract settled 7.2 cents lower at $4.166/MMBtu Wednesday as traders tried to evaluate shoulder-season demand going forward, sources said

Electric Reliability Council of Texas dailies for Thursday delivery were weaker on the IntercontinentalExchange Wednesday morning with peak load forecast decreasing but temperatures expected to rise.

Spot natural gas at Houston Ship Channel fell 2.4 cents to trade around $4.281/MMBtu.

ERCOT North Hub next-day on-peak physical power lost about 25 cents to trade around $35.25/MWh on ICE, while off-peak added about $1 to trade around $28.25/MWh. Houston Hub on-peak was bid at $34.50/MWh, $1.50 below Tuesday prices.

South Hub on-peak was bid at $34 and offered at $37.50/MWh, a loss of about 25 cents. Off-peak rose $1.25 to trade around $28.50/MWh.

High temperatures across ERCOT's footprint were forecast rising to the low to mid-70s Thursday, with lows in the mid-40s to mid-50s. 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 34,950 MW Wednesday and 33,950 MW Thursday, compared with an actual peak of 37,776 MW Tuesday.

With the exception of the west, real-time prices for ERCOT averaged $28.75/MWh from 12:15 a.m. to 6 a.m. CDT Wednesday, while West Hub averaged $15.50/MWh.

Wind generation was forecast to peak at 6,250 MW at 1 a.m. CDT Wednesday when it actually reached 6,325 MW at 3 a.m. Wind output was expected to peak at 7,675 MW at midnight CDT Thursday.

North Hub on-peak balance-of-the-week packages were bid at $35.25 and offered at $36.25/MWh. Next-week on-peak was bid at $35.75 and offered at $37.50/MWh.

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Southeast & Central day-ahead bilateral indexes for Apr 25 ($/MWh)

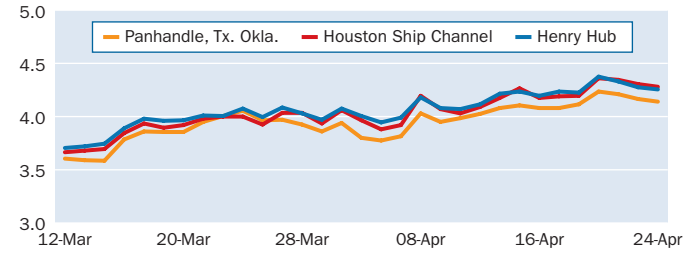
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	40.75	0.25	40.63	9168
Southern, Into	39.00	0.25	38.57	9144
Florida	41.75	0.25	40.70	9743
TVA, Into	39.00	0.00	38.70	9023
Entergy, Into	36.75	0.25	36.43	8724
Southeast Off-Peak				
VACAR	30.25	2.50	29.22	6805
Southern, Into	29.50	3.50	28.31	6917
Florida	31.25	1.25	30.56	7293
TVA, Into	29.75	3.00	28.56	6883
Entergy, Into	28.25	3.50	26.70	6706
ERCOT On-peak				
ERCOT, North	35.24	-0.45	37.87	8416
ERCOT, Houston	35.75	-0.25	38.08	8372
ERCOT, South	35.25	-0.75	38.33	8291
ERCOT, West	31.50	-3.25	36.79	7627
ERCOT Off-Peak				
ERCOT, North	28.11	0.94	26.47	6713
ERCOT, Houston	27.75	0.50	26.41	6499
ERCOT, South	28.50	1.25	26.44	6703
ERCOT, West	20.50	-1.25	22.42	4964
SPP/MRO On-peak				
MAPP, Soth	38.25	-0.75	38.89	8864
SPP, North	37.50	-0.25	37.66	9058
SPP/MRO Off-Peak				
MAPP, Soth	29.50	3.00	27.74	6837
SPP, North	28.75	3.25	26.41	6944

Southeast load and generation mix forecast (GWh)

	Actual 23-Apr	%Chg	% Chg Year-ago	Forecast 24-Apr	25-Apr	26-Apr	27-Apr	28-Apr
ERCOT								
Load	788	1	1	752	745	780	785	791
Generation								
Coal	350	-1	22	336	329	332	341	350
Gas	294	9	-14	284	262	273	289	301
Nuclear	105	30	-3	121	121	121	121	121
SPP								
Load	590	2	-1	578	584	587	592	611
Generation								
Coal	408	6	17	403	393	386	384	385
Gas	113	3	-26	104	109	117	124	132
Nuclear	49	0	2	49	49	49	49	49

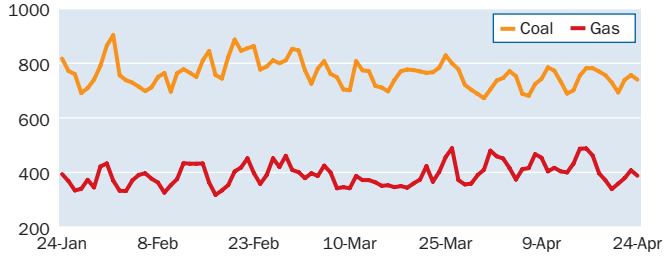
Source: Bentek

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



Source: Platts

ERCOT & SPP gas and coal generation (GWh)



Source: Bentek

ERCOT average day-ahead LMP for Apr 25 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	34.03	-1.44	36.60	8070
Hub Average	33.20	-2.30	36.50	7872
Houston Hub	35.38	-1.54	37.03	8279
North Hub	35.00	-0.49	36.69	8357
South Hub	33.82	-1.55	36.78	7953
West Hub	28.56	-5.61	35.48	6903
AEN Zone	33.77	-1.53	36.83	8164
CPS Zone	38.13	-6.36	38.19	8999
LCRA Zone	33.94	-1.77	36.83	8010
Rayburn Zone	41.59	5.14	37.51	9929
Houston Zone	35.83	-1.71	37.10	8384
North Zone	39.24	3.19	37.14	9367
South Zone	34.42	-3.10	37.71	8093
West Zone	33.26	-15.46	46.12	8039
Off-Peak				
Bus Average	27.16	0.34	26.60	6424
Hub Average	25.75	-0.38	26.05	6091
Houston Hub	28.12	0.75	27.05	6555
North Hub	28.68	1.21	27.15	6839
South Hub	27.43	0.15	26.93	6452
West Hub	18.78	-3.62	23.09	4501
AEN Zone	27.21	0.08	26.85	6524
CPS Zone	27.31	-0.01	26.95	6430
LCRA Zone	27.22	0.06	26.87	6409
Rayburn Zone	39.37	8.28	29.40	9389
Houston Zone	28.10	0.73	27.04	6548
North Zone	34.86	5.42	28.23	8313
South Zone	27.54	0.06	26.99	6478
West Zone	21.61	-1.63	24.53	5181

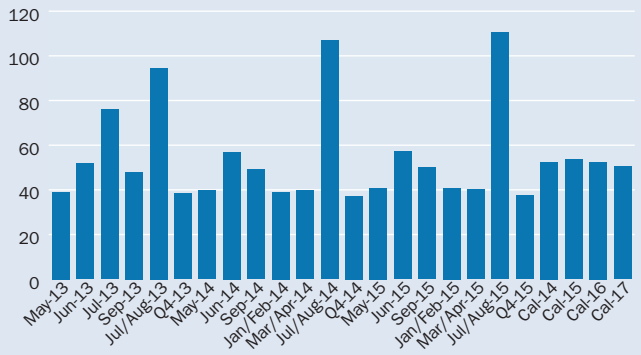
Southeast & Central near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, Into		
Bal-week	04/24	38.75-39.25
Bal-week	04/23	38.75-39.25
Bal-week	04/22	39.50-40.00
Bal-month	04/24	38.25-38.75
Bal-month	04/23	38.25-38.75
Bal-month	04/22	39.00-39.50
Bal-month	04/18	37.50-38.00
Next-week	04/24	38.00-38.50
Next-week	04/23	38.00-38.50
Next-week	04/22	39.50-40.00
Next-week	04/18	38.00-38.50
Entergy, Into		
Bal-week	04/24	36.75-37.25
Bal-week	04/23	36.75-37.25
Bal-week	04/22	36.75-37.25
Bal-month	04/24	36.75-37.25
Bal-month	04/23	36.75-37.25
Bal-month	04/22	36.75-37.25
Bal-month	04/18	36.00-36.50
Next-week	04/24	36.75-37.25
Next-week	04/23	36.75-37.25
Next-week	04/22	36.75-37.25
Next-week	04/18	35.00-35.50
ERCOT, North		
Bal-week	04/22	35.75-36.25
Next-week	04/22	37.25-37.75

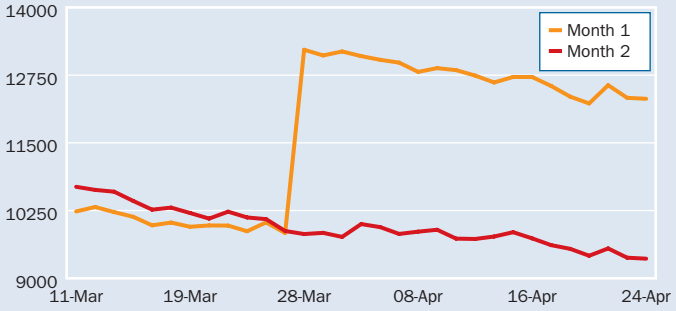
Southeast & Central Platts-ICE Forward Curve, Apr 24 ($/MWh)

Prompt month: May 13	On-peak	Off-peak
Southern Into	37.25	29.00
Entergy Into	35.15	26.50
ERCOT North	38.00	29.00
ERCOT Houston	39.75	29.75
ERCOT West	37.00	27.25
ERCOT South	39.00	29.50

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Arkansas-1/Entergy	903	n	Ark.	PMO	05/03/13	03/25/13
Arkansas-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	04/29/13	03/14/13
Brunswick-2/CP&L	953	n	NC	PMO	04/30/13	03/03/13
Crystal Rver-3/Progress	838	n	Fla.	MO	Retired	09/26/09
Farley-2/Southern	928	n	Ala.	RF	05/19/13	04/14/13
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11

Additional information on data and analysis:

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

WEST MARKETS

Dailies, terms both lose some ground

Western dailies were down Wednesday with lower spot natural gas prices, mostly cooler weather forecasts and lower peak demand forecast in California. Terms also fell, and the NYMEX May natural gas futures contract settled 7.2 cents lower at $4.166/MMBtu Wednesday.

In the Northwest, Mid-Columbia day-ahead on-peak fell more than $3.25 to trade between $33 and $38/MWh for delivery on Thursday. Mid-C day-ahead off-peak prices dropped more than $1.25 in trades between $24 and $25.25/MWh. The Mid-C on-peak balance-of-the-month package was bid at $29 and offered at $32/MWh, down about 75 cents.

Portland, Oregon, temperature forecasts had steady highs around 72 and lows from the mid- to upper 40s through Thursday.

The Bonneville Power Administration's wind generation at 7 a.m. PDT Wednesday was 46 MW and its hydropower was 10,887 MW.

In California, SP15 next-day on-peak shed nearly $6 to trade between $55.50 and $56.50/MWh. SP15 day-ahead off-peak slid about $4, trading between $40.50 and $41.50/MWh. SP15 on-peak bal-month was bid at $55 and offered at $60/MWh, about $1 lower than on Tuesday. NP15 day-ahead on-peak fell about $1.25 to around $50.25/MWh. NP15 day-ahead off-peak dropped $1.50 to about $38/MWh. NP15 on-peak bal-month was offered at $57/MWh.

Sacramento, California, expected highs inching up to around 90 on Wednesday before falling to the low 80s on Thursday. Lows were projected in the low 50s to upper 40s. Projected highs in Burbank were in the upper 60s through Thursday with lows between the mid-40s and 50.

The California Independent System Operator projected peak demand to hit 29,708 MW on Wednesday and 29,483 MW on Thursday.

In the desert Southwest, Palo Verde next-day on-peak retreated almost $2.25 to trade between $35 and $38/MWh. Palo Verde day-ahead off-peak fell more than $1.50 with trades between $30 and $31/MWh.

Phoenix forecasts had a high of about 90 on Thursday, a five-degree drop. Lows were projected steady in the mid-60s.

Next day natural gas retreated in the Rockies and California. Opal fell 5.9 cents to $4.086/MMBtu, Pacific Gas and Electric city-gate lost more than a half cent to $4.309/MMBtu, and SoCal city-gate dropped 4 cents to $4.370/MMBtu.

Day-ahead auction prices in the California ISO were mostly down Wednesday afternoon. SP15 on-peak inched up 39 cents to $53.67/MWh while SP15 off-peak fell $5.14 to $39.79/MWh. NP15 on-peak dropped $7.15 to $44.47/MWh and NP15 off-peak lost $3.61 to $35.60/MWh. ZP26 on-peak shed $7.36 cents to $43.36/MWh as ZP26 off-peak retreated $3.03 to $34.78/MWh.

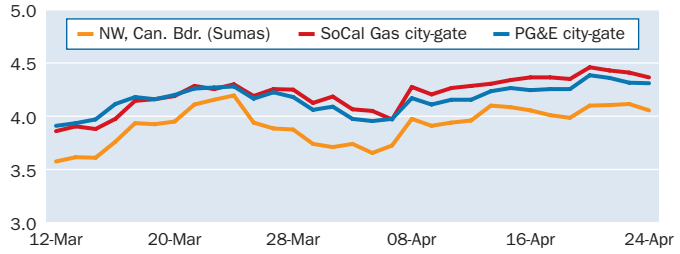
In the Northwest term markets, Mid-C on-peak May moved down 50 cents with bids at $28.25 and offers at $29/MWh on ICE around 2:30 p.m. EDT. June fell 25 cents to about $25.50/MWh,

(continued on page 11)

Western day-ahead bilateral indexes for Apr 25 ($/MWh)

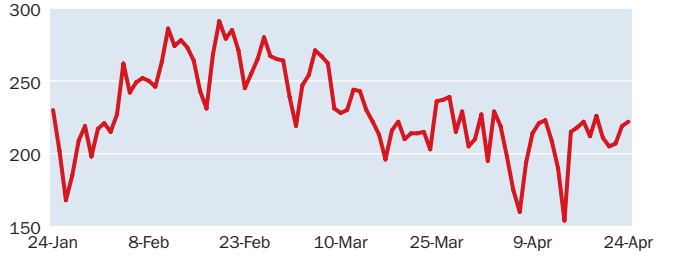
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	38.93	-4.56	36.49	9484
Mid-C	35.56	-3.43	31.25	8775
Palo Verde	37.08	-2.48	37.03	8924
Mead	39.04	-2.71	38.70	9229
Mona	35.00	-3.25	33.06	8642
Four Corners	37.50	-2.75	37.07	9191
NP15	50.25	-1.25	46.82	11659
SP15	55.50	-6.00	55.72	13121
Off-Peak				
COB	26.50	-5.75	23.97	6456
Mid-C	24.43	-4.19	18.09	6028
Palo Verde	30.30	-1.67	28.93	7292
Mead	30.25	-2.50	29.52	7151
Mona	27.00	-1.00	22.21	6667
Four Corners	30.25	-2.00	27.57	7414
NP15	38.25	-1.25	36.15	8875
SP15	40.75	-4.25	40.20	9634

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO gas generation (GWh)



Source: Bentek

Western load and generation mix forecast (GWh)

	Actual 23-Apr	%Chg	% Chg Year-ago	Forecast 24-Apr	25-Apr	26-Apr	27-Apr	28-Apr
CAISO								
Load	636	-1	2	627	615	604	558	542
Generation								
Gas	219	6	4	222	214	211	210	210
Nuclear	56	0	-32	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Apr 25 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	44.47	-2.95	-1.61	-7.15	45.54	10306
SP15 Gen Hub	53.67	5.95	-1.31	0.39	54.18	12689
ZP26 Gen Hub	43.36	-2.75	-2.92	-7.36	43.31	10251
Off-Peak						
NP15 Gen Hub	35.60	-1.71	-0.89	-3.61	35.43	8244
SP15 Gen Hub	39.79	2.22	-0.64	-5.14	38.64	9323
ZP26 Gen Hub	34.78	-1.59	-1.83	-3.03	33.94	8151

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	04/19	32.00-32.50
Bal-month	04/18	32.75-33.25
Bal-month (off-peak)	04/24	20.25-20.75
Bal-month (off-peak)	04/19	17.50-18.00
Bal-month (off-peak)	04/18	17.00-19.50

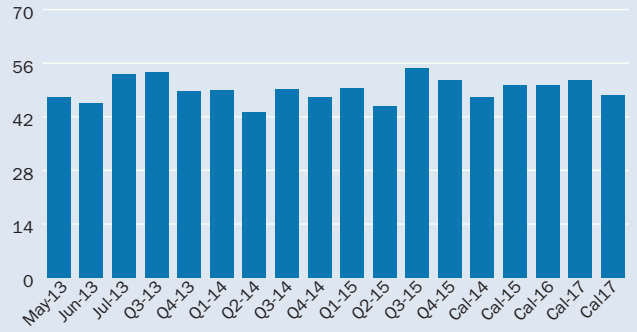
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Alamitos-4/AES	336	g	Calif.	PMO	Unk	02/03/13
Blythe Center/LS Power	493	g	Calif.	PMO	Unk	04/21/13
Catalina Solar-1&2/EDF	110	s	Calif.	MO	Unk	04/01/13
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
Gilroy Cogen/Calpine	120	g	Calif.	PMO	Unk	04/01/13
Helms-2/PG&E	407	h	Calif.	PMO	Unk	12/02/12
Huntington Beach-3/AES	225	g	Calif	PMO	Unk	04/14/13
Huntington Beach-4/AES	215	g	Calif	PMO	Unk	04/14/13
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
Mountanview-4	525	g	Calif.	PMO	Unk	04/23/13
Ormond Beach-2/RRI	775	g	Calif.	MO	Unk	04/22/13
Raesfeld/Silicon Valley	148	g	Calif.	PMO	Unk	04/07/13
Redondo-5/AES	179	g	Calif.	PMO	Unk	04/16/13
San Onofre-2/SCE	1124	n	Calif.	PMO	Unk	01/09/12
San Onofre-3/SCE	1126	n	Calif.	MO	Unk	01/31/12
Sunrise/Edison	586	g	Calif.	PMO	Unk	01/23/13
Sutter/Calpine	525	g	Calif.	PMO	Unk	04/14/13
Topaz/MidAmerican	130	s	Calif.	MO	Unk	04/21/13

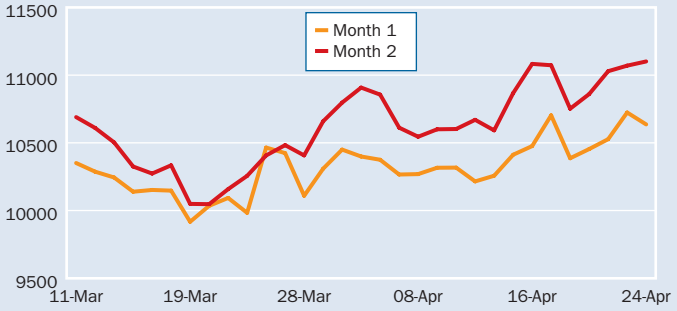
Western Platts-ICE Forward Curve, Apr 24 ($/MWh)

Prompt month: May 13	On-peak	Off-peak
Mid-C	28.50	14.00
Palo Verde	39.75	28.00
Mead	42.00	32.50
NP15	47.00	35.50
SP15	57.25	41.75

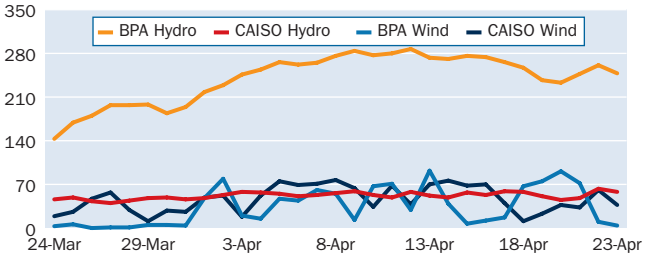
NP15: Forward curve on-peak ($/MWh)



NP15: Marginal heat rate on-peak (Btu/kWh)



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

Dailies dip on lower demand, MISO dailies mixed

Daily power prices in the Mid-Atlantic were down Wednesday, similar to forward prices and natural gas futures, with the NYMEX May natural gas futures contract settling 7.2 cents lower at $4.166/MMBtu.

Mid-Atlantic dailies were weaker in for-Thursday trading on Intercontinental Exchange as temperatures and demand were forecast to decrease.

Texas Eastern M-3 spot natural gas was trading around $4.47/MMBtu on ICE, up a penny.

PJM Interconnection projected peak load at 87,397 MW for Thursday, down 1,944 MW from Wednesday's projected peak load.

Temperatures were forecast dropping Thursday, with highs in the lower 60s.

PJM West Hub day-ahead peak was bid at $44.60 and offered at $46/MWh, down about 75 cents. Day-ahead off-peak was bid at $32 and offered at $32.50/MWh, down about $1. Balance-of-the-week financial packages were bid at $42.25 and offered at $44.25/MWh.

Dailies in the Midwest Independent Transmission System Operator were mixed as Chicago city-gates spot natural traded around $4.42/MMBtu on ICE, down 4 cents.

Wind generation in the MISO region was about 2,550 MW around 10 a.m. EDT Wednesday.

Temperatures in MISO were forecast mixed for Thursday, with highs ranging from around 47 in Minneapolis to around 59 in Cincinnati.

Indiana Hub peak was bid at $38.25 and offered at $40/MWh, down about 25 cents. Day-ahead off-peak was trading around $30.75/MWh, up $1.75. Bal-week peak was bid at $36 and offered at $41.50/MWh.

Dailies were mixed in the Midwestern portion of PJM. AEP-Dayton Hub day-ahead peak was bid at $43.10 and offered at $44.75/MWh, up about 25 cents. Day-ahead off-peak was bid at $31.55 and offered at $31.75/MWh, down about 75 cents. Bal-week peak was bid at $40 and offered at $43.50/MWh.

Northern Illinois Hub day-ahead peak was bid at $41.50/MWh and offered at 43/MWh, even with Tuesday prices. Day-ahead off-peak was bid at $29.75 and offered at $30.50/MWh, also even with Tuesday prices.

PJM day-ahead auction prices were higher for Thursday. Day-ahead prices in PJM cleared at $47.29/MWh for peak, up 66 cents from the day prior. The off-peak price cleared at $34.53/MWh, up $2.99.

The PJM Western Hub day-ahead price cleared at $48.24/MWh, up 46 cents. PJM Western Hub off-peak cleared at $34.91/MWh, up $2.96.

The Eastern Hub had the highest day-ahead Hub price, clearing at $48.64, up $1.61.

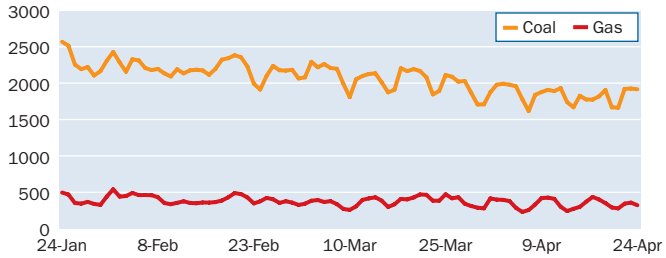
The BG&E Zone cleared with the highest day-ahead zonal price at $50.77/MWh.

Dominion Hub peak cleared at $47.68/MWh, up 89 cents.

PJM & MISO day-ahead bilateral indexes for Apr 25 ($/MWh)

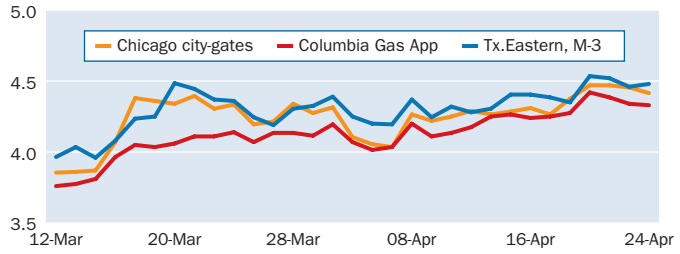
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	45.50	-0.50	46.91	10598
Dominion Hub	45.25	-0.25	47.11	10313
AD Hub	44.25	0.50	42.95	10461
NI Hub	42.50	0.25	40.82	9626
PJM Off-Peak				
PJM West	32.25	-1.00	32.37	7512
Dominion Hub	33.00	-0.25	32.67	7521
AD Hub	31.75	-0.75	30.71	7506
NI Hub	30.00	-0.25	27.58	6795
MISO On-peak				
Indiana Hub	39.25	-0.25	39.49	9033
Michigan Hub	41.00	1.25	40.55	9036
Minnesota Hub	40.25	-3.00	43.12	9258
Illinois Hub	40.25	-2.25	38.71	9122
MISO Off-Peak				
Indiana Hub	30.75	1.75	29.39	7077
Michigan Hub	31.50	2.00	30.05	6942
Minnesota Hub	26.75	-0.75	26.55	6153
Illinois Hub	31.50	2.25	27.61	7139

PJM & MISO gas and coal generation (GWh)



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 23-Apr	%Chg	% Chg Year-ago	Forecast 24-Apr	25-Apr	26-Apr	27-Apr	28-Apr
PJM								
Load	1946	0	6	1903	1936	1915	1742	1685
Generation								
Coal	824	-1	17	785	770	779	753	728
Gas	280	6	-18	292	276	256	245	248
Nuclear	629	0	2	629	630	635	644	653
MISO								
Load	1291	1	4	1284	1306	1287	1182	1160
Generation								
Coal	1101	1	13	1130	1084	1053	1019	1021
Gas	78	-1	-35	30	44	67	71	66
Nuclear	122	0	-6	122	124	131	143	154

Source: Bentek

MISO average day-ahead LMP for Apr 25 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	39.86	-1.23	-0.16	2.18	37.83	9168
Michigan Hub	40.83	-1.42	1.00	1.53	38.74	8988
Minnesota Hub	46.35	3.77	1.35	7.67	40.64	10648
Illinois Hub	39.83	-0.01	-1.40	0.92	37.20	9006
Off-Peak						
Indiana Hub	32.74	1.87	0.51	2.86	29.93	7505
Michigan Hub	33.89	2.18	1.36	3.28	30.86	7440
Minnesota Hub	28.65	-1.49	-0.21	1.74	26.72	6554
Illinois Hub	29.84	0.14	-0.65	-0.33	27.87	6682

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

Package	Trade date	Range
PJM West		
Bal-week	04/23	43.50-44.50
Bal-week	04/19	46.00-47.25
Next-week	04/24	44.00-44.75
Next-week	04/23	44.75-45.50
Next-week	04/22	45.25-46.75
AD Hub		
Bal-week	04/23	42.00-42.50

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	04/30/13	03/27/13
La Salle-1/Exelon	1207	n	Ill.	MO	Unk	04/18/13
La Salle-2/Exelon	1207	n	Ill.	MO	Unk	04/18/13
Monticello/Xcel	666	n	Minn.	PMO	05/19/13	03/02/13
North Anna/Dominion	903	n	Va.	PMO	05/07/13	04/06/13
Perry/FirstEnergy	1260	n	Ohio	PMO	05/04/13	03/18/13
Susquehanna-2/PPL	1330	n	Penn.	PMO	05/22/13	04/13/13

PJM average day-ahead LMP for Apr 25 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	44.79	0.02	-2.50	0.57	39.78	10240
AEP-Dayton Hub	45.90	0.05	-1.42	0.39	40.90	10493
ATSI Gen Hub	47.51	0.06	0.19	1.69	41.39	10874
Chicago Gen Hub	43.64	0.07	-3.69	-0.87	38.81	9862
Chicago Hub	44.50	0.06	-2.82	-0.63	39.45	10057
Dominion Hub	47.68	0.04	0.38	0.89	43.71	10864
Eastern Hub	48.64	-0.56	1.94	1.61	44.06	10857
New Jersy Hub	48.54	-0.06	1.34	1.10	46.38	10835
Northern Illinios Hub	44.17	0.06	-3.16	-0.76	39.25	9981
Ohio Hub	45.86	0.07	-1.47	0.13	41.03	10437
West Internal Hub	47.38	0.02	0.10	1.55	41.79	11039
Western Hub	48.24	0.00	0.98	0.46	43.87	11239
AEP Zone	46.27	0.04	-1.04	0.76	41.05	10577
Allegheny Power Zone	47.84	-0.01	0.58	2.02	42.47	11081
Atlantic Elec Zone	46.94	-1.54	1.21	1.86	42.92	10478
ATSI Zone	48.27	0.06	0.94	2.01	41.76	11048
BG&E Zone	50.77	0.13	3.38	-0.99	47.52	11638
ComEd Zone	44.37	0.07	-2.96	-0.70	39.36	10027
Dayton P&L Zone	46.82	0.05	-0.50	0.10	41.87	10769
Delmarva P&L Zone	47.95	-0.89	1.58	1.64	43.62	10703
Dominion Zone	48.17	0.03	0.87	0.43	44.32	10976
Duke Zone	44.27	0.07	-3.07	-0.82	40.42	10183
Duquesne Light Zone	46.72	-0.04	-0.50	2.66	39.43	10858
JCPL Zone	48.64	-0.31	1.69	1.84	44.70	10857
MetEd Zone	48.20	-0.26	1.19	1.97	43.71	10878
PECO Zone	47.67	-0.28	0.68	1.25	42.92	10759
Pennsylvania Elec Zone	48.03	0.02	0.75	1.32	43.63	11152
PEPCO Zone	49.62	0.07	2.28	-1.41	46.71	11373
PPL Zone	47.69	-0.24	0.66	1.59	43.41	10764
PSEG Zone	49.01	0.51	1.23	0.43	48.16	10938
Rockland Elec Zone	48.60	1.01	0.32	-0.44	48.60	10847
Off-Peak						
AEP Gen Hub	33.01	-0.16	-1.36	2.95	30.85	7537
AEP-Dayton Hub	33.72	-0.04	-0.76	3.00	31.46	7701
ATSI Gen Hub	35.23	0.01	0.70	4.00	31.91	8049
Chicago Gen Hub	31.66	-0.08	-2.79	2.20	28.12	7106
Chicago Hub	32.21	-0.08	-2.23	2.38	28.58	7231
Dominion Hub	35.76	0.06	1.17	3.83	32.81	8134
Eastern Hub	34.75	-0.19	0.41	1.87	33.26	7778
New Jersy Hub	35.10	0.10	0.48	2.18	33.79	7858
Northern Illinios Hub	32.01	-0.09	-2.43	2.29	28.41	7186
Ohio Hub	33.63	-0.01	-0.89	2.84	31.51	7631
West Internal Hub	35.17	-0.01	0.65	3.89	31.97	8202
Western Hub	34.91	0.01	0.37	2.96	32.58	8142
AEP Zone	34.08	-0.04	-0.41	3.21	31.60	7783
Allegheny Power Zone	35.12	-0.05	0.64	3.77	32.05	8133
Atlantic Elec Zone	34.50	-0.30	0.27	2.06	32.86	7723
ATSI Zone	35.70	0.02	1.16	4.22	32.13	8156
BG&E Zone	36.37	0.13	1.71	3.15	33.91	8343
ComEd Zone	32.13	-0.08	-2.32	2.34	28.50	7212
Dayton P&L Zone	34.67	-0.02	0.16	3.36	32.05	7946
Delmarva P&L Zone	34.69	-0.24	0.40	1.94	33.11	7765
Dominion Zone	35.85	0.05	1.27	3.72	32.98	8155
Duke Zone	32.43	0.02	-2.12	2.12	31.11	7433
Duquesne Light Zone	34.45	-0.06	-0.02	4.38	30.69	8004
JCPL Zone	35.63	0.45	0.65	2.69	33.40	7976
MetEd Zone	34.94	-0.02	0.42	2.61	32.81	7896
PECO Zone	34.45	-0.18	0.11	2.13	32.75	7787
Pennsylvania Elec Zone	34.49	0.08	-0.12	2.31	32.86	8015
PEPCO Zone	35.95	0.08	1.35	3.05	33.52	8248
PPL Zone	34.55	0.06	-0.03	2.34	32.69	7810
PSEG Zone	35.06	0.06	0.47	1.88	34.30	7849
Rockland Elec Zone	34.39	-0.13	-0.01	1.64	34.04	7698

Dominion Hub off-peak price cleared at $35.76/MWh, up $3.83. AEP-Dayton Hub peak price cleared at $45.90/MWh, up 39 cents. AEP-Dayton Hub off-peak price cleared at $33.72/MWh, up $1.

The day-ahead price for the Northern Illinois Hub cleared at $44.17/MWh, down 76 cents. Northern Illinois off-peak cleared at $32.01/MWh, up $2.29.

Peak congestion prices at the hubs ranged from negative 56 cents/MWh to 7 cents/MWh. Peak zone congestion prices ranged from negative $1.54/MWh to $1.01/MWh.

MISO day-ahead auction prices cleared stronger Wednesday afternoon. Minnesota Hub returned to the highest-priced hub position, with on-peak clearing the auction at $46.35/MWh, a jump of $7.67, while off-peak cleared at $28.65/MWh, up $1.74.

Michigan Hub on-peak clear the auction at $40.83/MWh, a gain of $1.53, while off-peak cleared at $33.89/MWh, adding $3.28. Indiana Hub on-peak cleared at $39.86/MWh, rising $2.18. Off-peak cleared at $32.74/MWh, up $2.86.

The lowest-priced hub became Illinois Hub, with on-peak at $39.83/MWh, adding 92 cents. Off-peak cleared at $29.84/MWh, falling 33 cents.

Congestion costs at the hubs ranged from negative $1.42 to $3.77 for peak, and from negative $1.49 to $2.18 for off-peak.

Mid-Atlantic forwards were mostly down Wednesday with softer gas futures. May NYMEX gas futures fell 6.7 cents, trading at about $4.171/MMBtu.

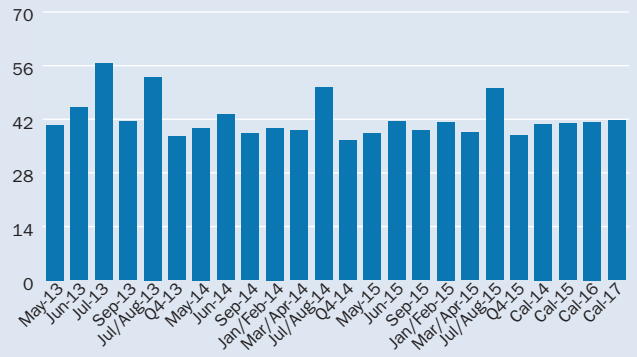
PJM West on-peak May financial futures were 75 cents weaker, with bids at $46.35 and offers at $46.75/MWh on ICE at about 2:30 p.m. EDT Wednesday. PJM West on-peak June dropped 85 cents to about $52.25/MWh, while on-peak July-August lost 90 cents, to about $61.75/MWh. PJM West off-peak May was unchanged at about $32.25/MWh.

Midwest May forwards were mixed Wednesday as gas futures fell. AD Hub on-peak May financial futures rose 25 cents to about $43/MWh. Indiana Hub on-peak May came down 50 cents to about $39/MWh. NI Hub on-peak May fell 25 cents to about $40.50/MWh.

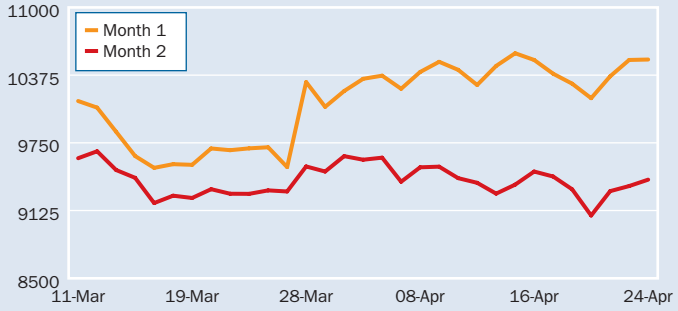
PJM & MISO Platts-ICE Forward Curve, Apr 24 ($/MWh)

Prompt month: May 13	On-peak	Off-peak
PJM West	46.50	32.25
AD Hub	43.00	30.50
NI Hub	40.50	26.50
Indiana Hub	39.00	26.25

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



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



Northeast markets ... *from page 2*

MWh. The Maine Zone had the lowest hourly price at $31.88/MWh. The average day-ahead price was $44.05/MWh, down 92 cents from the day prior.

Day-ahead auction prices for Thursday cleared mixed across the zones in the NYISO Wednesday, when the ISO projected peak load for Thursday to drop by 1.2% to 17,983 MW.

New York City Zone peak cleared at $48.46/MWh, up 61 cents, while off-peak cleared at $33.09/MWh, up $1.96. Long Island Zone peak cleared at $59.24/MWh, up $1.45, and off-peak cleared at $42.87/MWh, up 17 cents. Hudson Valley Zone peak cleared at $46.10/MWh, a gain of $1.84, and off-peak cleared at $33.20/MWh, a gain of $1.95.

Central Zone peak came in at $38.11/MWh, down 53 cents, and off-peak came in at $28.55/MWh, up 3 cents. West Zone peak cleared at $36.88/MWh, up 4 cents, while off-peak cleared at $27.71/MWh, a gain of 2 cents.

The highest hourly day-ahead price was $85/MWh at the Long Island Zone, which also included the highest hourly congestion cost at negative $35.79/MWh. The lowest hourly price was $23.21/MWh at the West Zone. The average zonal price was $39.31/MWh, up 74 cents from the day prior.

Northeast term power was tame Wednesday as May NYMEX gas futures fell 6.7 cents, trading at about $4.171/MMBtu.

In New England, Mass Hub on-peak May financial futures shed 25 cents, with bids at $45.25/MWh and offers at $45.85/MWh on ICE at about 2:30 p.m. EDT. Mass Hub on-peak June was unchanged at about $59.25/MWh, while on-peak July-August dropped 75 cents to about $59.50/MWh. Mass Hub off-peak May stood still at about $35.50/MWh.

New York Zone G on-peak May tumbled $1.25 to about $47.50/MWh. New York Zone A on-peak May came down 50 cents to about $39.75/MWh.

Southeast markets ... *from page 4*

In the Southeast, dailies for Thursday delivery were firmer Wednesday morning with temperatures forecast falling.

Into Southern next-day on-peak power market was in the upper $30s/MWh, a slight gain from Tuesday prices.

Spot natural gas at Transco Zone-3 lost 2.3 cents to trade around $4.277/MMBtu.

High temperatures in Atlanta were forecast dropping to the low-70s Thursday, below the average April high temperature in Atlanta of 73. The low was forecast falling to the upper 40s, below the average low of 52.

The ERCOT day-ahead auction for Thursday delivery cleared weaker Wednesday afternoon for on-peak as off-peak cleared mostly stronger with demand forecast to decrease.

Houston Hub maintained its position as the highest-priced hub, although it's spread with the north narrowed, and West Hub remained the lowest-priced hub.

Houston Hub on-peak cleared in the ERCOT auction at $35.38/MWh, roughly $1.50 weaker, while off-peak cleared at $27.37/MWh, up 75 cents.

North Hub on-peak cleared in the auction at $35/MWh, a loss of 50 cents from Tuesday's clearing price, while off-peak cleared at $28.68/MWh, climbing nearly $1.25.

South Hub on-peak cleared at $33.82/MWh, a decrease of about $1.50, while off-peak cleared at $27.43/MWh, adding almost 25. West Hub on-peak cleared in the ERCOT auction $28.56/MWh, falling more than $5.50, while off-peak cleared at $18.78/MWh, losing roughly $3.50.

Rayburn Zone on-peak led the load zones at $41.59/MWh, a gain of about $5.25 from Tuesday. The highest hourly day-ahead price occurred at 8 a.m. CDT in the North Hub at $43.53/MWh and at 7 a.m. in the Rayburn Zone at $50.74/MWh.

ERCOT system load was forecast to peak at 33,950 MW Thursday, down 3% from Wednesday's expected peak of 34,950 MW.

South Central May terms went down Wednesday. ERCOT Houston on-peak May fell 75 cents to about $39.75/MWh, and July-August dropped $1.90 to about $95/MWh. Heat rates were steady on the IntercontinentalExchange at about 2:30 p.m. EDT. ERCOT North May fell 75 cents to about $38/MWh, June fell 75 cents to about $51.75/MWh, and July-August slipped down $1.90 to about $95.75/MWh. Into Entergy May fell 25 cents to about $35.25/MWh, and July-August dipped 85 cents to about $41.50/MWh.

Southeast on-peak May moved down Wednesday, as did May NYMEX gas futures. Into Southern May fell 25 cents to about $37.25/MWh, June tumbled $1.25 to about $40/MWh, and July-August dropped 85 cents to about $43.25/MWh.

West markets ... *from page 6*

and the third quarter fell 50 cents to about $44/MWh. In California, SP15 on-peak May financial terms dropped $1 with bids at $57.15 and offers at $57.50/MWh. June dipped $1 to about $52.25/MWh, and Q3 fell 25 cents to about $60.85/MWh. NP15 May lost 50 cents to about $47/MWh, and Q3 fell 40 cents to about $53.75/MWh. Palo Verde May fell 25 cents to about $39.75/MWh, June slipped down 50 cents to about $43.25/MWh, and Q3 fell 50 cents to about $49.35/MWh.

NEWS

Prices, RSG charges rose in MISO in March

Higher natural gas prices and cold weather led to stronger wholesale electricity prices and a jump in revenue sufficiency guarantee charges in the Midwest Independent Transmission System Operator this March, according to MISO's independent market monitor.

The average real-time price of electricity in MISO in March was $31.20/MWh, a 12% increase over February and a 36% increase over March 2012, MISO's market monitor David Patton said at a Wednesday Board of Directors meeting.

"Last March gas prices were unusually low," Patton said. "We're in a more normal range right now, but that's resulted in higher energy prices."

Natural gas prices in the region averaged about $4/MMBtu in March, 16% higher than February and 80% higher than March 2012, according to Patton.

Real-time RSG charges also jumped up in March, rising to $4.6 million, a 171% increase over February and at 175% increase over March 2012. Real-time RSG charges occur when generating units not dispatched in the day-ahead market are called upon for real-time reliability purposes. These units are paid RSG charges credit if the real-time energy revenue is insufficient to cover their full production costs.

Patton said the increase in RSG charges was mostly due to reliance on gas-fired peaking units during cold snaps. On March 21, for example, gas supply issues and winter storms forced MISO to commit about 1,000 MW of peaking units in real-time to meet demand, according to Patton.

"Our winter weather continued into March this year, which caused several events that contributed to higher energy prices and [led us] to commit additional peaking resources," Patton said. "And because we were committing additional peaking resources, we did see higher RSG this month."

By contrast, Patton explained, last year's low gas prices helped keep RSG charges low because many peaking units were able to be dispatched economically in the day-ahead market.

"During 2012 when gas prices fell, a lot of our peaking resources became economic to commit," Patton said. "When we use those units economically they set prices and we have less RSG."

This March only about a third of peaking unit commitments were made in economic merit in the day-ahead market, down from 84% in March 2012.

Patton also highlighted changes to MISO's voluntary capacity auction and handling of wind generators.

At the beginning of April, MISO held its first annual voluntary capacity auction, a transition from its previous monthly voluntary capacity auctions. The annual auction also marked the first time the MISO modeled separate zones in its capacity market, a change Patton commended.

"[Locational requirements are] extremely important to the extent you have planning needs in local areas," Patton said. "In this auction the prices didn't separate by location, but having that framework in place is valuable."

MISO's dispatchable intermittent resources program — which allows wind generation to participate in the real-time market by submitting offers and receiving dispatch instructions rather than facing manual curtailments during periods of excess generation — became mandatory for most existing wind resources and all new wind resources.

Now roughly 80% of wind capacity is registered as a dispatchable intermittent resource, but some wind generators that recently entered program did not respond to MISO dispatch instructions, according to Patton. Both Patton and MISO staff said wind generators have been more responsive to dispatch instructions as they get used to the change.

— Juliana Brint

ISO confident on renewables integration: official

The California grid operator is confident it can reliably integrate growing amounts of renewable generation into its system, Brad Bouillon, Cal-ISO director of day-ahead market and real-time operations support, said Wednesday.

“The ISO has high confidence in the integration of renewables,” Bouillon said during a California Energy Commission workshop on natural gas issues. The CEC is holding a series of workshops as the commission prepares its 2013 Integrated Energy Policy Report, due out in October.

California's natural gas-fired power plant fleet is becoming more efficient through plant construction and rebuilding old plants, which will help handle the fluctuating output of renewable resources, Bouillon said.

In part, the ISO's confidence in its ability to integrate renewables stems from “tremendous” improvements in wind forecasting in the last few years, according to Bouillon. “If we have good forecasting, you can pull a lot of [renewable generation] into the day-ahead market ... getting you out of the spot market,” he said.

In general, the day-ahead market is roughly 15% less expensive than the spot market, Bouillon said.

Also, the state's renewable fleet is coming online in stages, giving the grid operator and others time to gain experience in managing the state's evolving generation mix, Bouillon said. California has roughly 5,000 MW of wind and 2,000 MW of solar online, he said. The renewable capacity will grow as California's investor-owned utilities respond to the state's 33%-by-2020 renewable portfolio standard.

Cal-ISO has protocols in place that allow for detailed sharing of information between power generators and natural gas suppliers, according to Bouillon. Based on day-ahead information, the ISO sends daily estimates of gas burns to natural gas suppliers, Bouillon said. The ISO also holds quarterly meetings to discuss anticipated power plant and natural gas supply outages, he said.

“In general, California is well ahead of the country,” in terms of electric and natural gas coordination, Bouillon said.

The state also appears to have plentiful natural gas storage,

which can be used to support renewables, according to Pacific Gas and Electric and Southern California Gas officials. “There is ample storage in Northern California,” said Roger Graham, PG&E director of wholesale marketing, gas systems operations.

PG&E has about 5.8 Bcf of storage, but its customers use about 3.4 Bcf on average and 4.8 Bcf on an “abnormal” peak, which represents the coldest day in the last 90 years, he said. The utility sees no need for additional storage in the medium term. “It's unlikely we'll add any storage in [the 3-5 year] time frame,” Graham said. “The forward curve is quite flat now and doesn't support the construction of new storage projects.”

The outlook is similar for Southern California Gas, a Sempra Energy subsidiary. The utility does not see the need for new storage in Southern California over the next 30 years, a company official said.

Currently, natural gas is used most in California to meet winter heating needs, officials said. PG&E is not seeing coincident ramp peaks combining heating and renewables that would be worrisome for the natural gas supply system, according to Graham.

Natural gas prices are expected to increase in California because of the state's greenhouse gas cap-and-trade program, according to Greg Mayeur, California Air Resources Board manager for compliance calculation. The cap-and-trade program is slated to include residential and commercial natural gas use in 2015. CARB expects residential natural gas rates to climb 7%, commercial rates to increase 8% and industrial rates to jump 6%, Mayeur said.

— Ethan Howland

Daily CAIR allowance assessments, Apr 24

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

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

Daily CSAPR allowance assessments, Apr 24

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

RGGI carbon allowance futures, Apr 23 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.49	0	Dec13	1.97	0
Dec13 V11	3.42	0	Dec14	1.97	0
Dec13 V12	3.39	0			
Dec13 V13	3.44	0			
Dec14 V10	3.49	0			
Dec14 V11	3.42	0			
Dec14 V12	3.42	0			
Dec14 V13	3.44	0			
Dec15 V10	3.49	0			
Dec15 V11	3.42	0			
Dec15 V12	3.42	0			
Dec15 V13	3.44	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.

Parties seek new details on EIM proposal

Boundaries and implementation milestones are among the new details sought by potential participants in the energy imbalance market proposed in late February by the California Independent System Operator and utility PacifiCorp.

An EIM, the subject of a long-standing western debate pitting advocates of ISO-type markets against more traditional bilateral market proponents, allows changes in supply and demand in one grid operating area to be netted out with opposite changes in other grid operating areas at frequent intervals.

In comments released by the ISO Tuesday, the Western Power Trading Forum called on Cal-ISO to "provide generally the high-level topography associated with the PacifiCorp EIM, including the boundaries" of the two PacifiCorp balancing authority areas involved "and the paths over which there would be transfer capacity available for EIM/ISO transfers."

Based on information from the ISO, "WPTF understands there to be about 100 MW of transfer capacity. It would be helpful in judging the tradeoffs of accuracy versus simplicity on some of the outstanding policy issues to know on which paths the capacity resides and what other capacity on which paths might become available on what schedule," WPTF said.

Interties and how they are affected by the proposed EIM is also a key concern for WPTF. It wants "futher information about what the new intertie points would be with the PacifiCorp EIM and to explain generally how transactions at these ties would work." For example, "would a market participant outside of the EIM and ISO footprint be able to bid to sell into or out of the EIM/ISO [real-time] market? If not, what options are available for participants on the other side of the traditional intertie but not located within the EIM boundary?"

The ISO also should work with the California Air Resources Board to let market participants know how the ISO "intends to determine the appropriate" greenhouse gas emissions rate under the EIM to comply with the state's GHG cap-and-trade program, WPTF said.

If the ISO wants participation in the EIM to extend beyond PacifiCorp, the grid operator should "give strong consideration to other potential EIM entities' perspectives," WPTF said.

Xcel Energy suggested "a detailed project plan showing dates related to additional entities joining the initial EIM and major deliverables and other important milestones, such as market trials."

Load forecasting for the EIM is also of particular concern to Xcel. The company fears "that anyone using the ISO forecast will avoid the over and under-scheduling charges." Cal-ISO "needs to show an example" in its next straw proposal "of how this methodology will not result in uplift charges to other EIM participants," Xcel said.

Regarding transmission constraints, Xcel said the ISO should

explain how it "might differentiate congestion management related schedules that source and sink within the EIM footprint compared to those that pass through and source and sink outside the EIM."

The Transmission Agency of Northern California sought the ISO's assurance "that non-participating transmission systems," such as the California Oregon Transmission Project, "will not be adversely impacted or that the ISO will enter into a mitigation agreement to resolve all impacts with adversely impacted parties."

Southern California Edison said it wants more details from the ISO on how it would treat EIM participants with respect to the cap-and-trade program. For example, would resources located in California be assumed to include a "GHG adder in their bid, or would they be treated the same as any other generator."

SoCal Ed also asked the ISO whether the cost of GHGs will "be included in bids, prices, and market signals."

The investor-owned utility also pressed the ISO for more details on how over-or under-scheduling by PacifiCorp could create market uplift charges.

The Sacramento Municipal Utility District took issue with the ISO's claim that an EIM "enhances reliability through real-time visibility and situational awareness of resources and transmission" across the balancing areas involved. "EIM is primarily an economic, not a reliability, tool," SMUD said. "Indeed, should participants fail to come to the market fully resourced (lean on the market), the results could be quite the opposite" of improving reliability.

While the ISO has said the EIM would not entail any new transmission charges, SMUD asserted that "it is important to establish some form of transmission service charge for EIM use of transmission."

Deciding how to address GHG costs requires considerably more deliberation among stakeholders, Arizona Public Service said. "APS recommends separate technical conferences that would include representatives from [Cal-ISO], California Air Resources Board, load serving entities," generators and electricity importers. "This issue is complex enough that all affected parties should have a voice in providing solutions to this challenge," APS said.

Because the EIM would extend beyond the Cal-ISO footprint, the ISO should not rely solely on its board for governance, APS said. "Despite the potential impact to cost structures, APS believes that an independent body from the ISO board would be necessary in order to gain maximum participation and, therefore, maximum benefits."

— Martin Coyne

Ohio law mandating usage cuts stirs debate

Armed with a new report, energy efficiency advocates are trying to convince Ohio lawmakers to leave intact a state mandate they say could save customers billions of dollars by 2020 in part by driving down wholesale energy and capacity prices.

But not everyone is buying the estimates in the report prepared by the American Council for an Energy Efficient Economy, a trade group. They are also not sold on the notion that S.B. 221, Ohio's 2008 electric restructuring law that requires utilities cut energy use by 22% by 2025, is good for the state's economy.

After the Ohio Senate Public Utilities Committee heard conflicting testimony on the controversial law Tuesday, Republican state Senator Bill Seitz, who chairs the panel, is expected to introduce legislation next month that could change the law.

Legislators listened to R. Neal Elliot, ACEEE's associate director for research, discuss findings in the report, sponsored on behalf of the Ohio Manufacturers' Association.

FirstEnergy, whose FirstEnergy Solutions unregulated subsidiary is a major player in the state's deregulating electric market, took some criticism from Rob Kelter, senior attorney for the Chicago-based Environmental Law and Policy Center. FirstEnergy, Kelter claimed, is more concerned about selling more power than reducing prices for customers.

FirstEnergy opposes the energy efficiency mandate.

Elliot said the energy efficiency standard could save Ohio customers almost $5.6 billion by 2020 in avoided expenditures and reduced wholesale energy and capacity prices. Of that amount, a $3.7 billion reduction would come from customers' spending for power, $800 million from wholesale energy price mitigation impacts, and $1.3 billion from wholesale capacity price mitigation impacts from the 2017/2018 through 2020/2021 PJM Interconnection capacity auctions.

Last year, FirstEnergy decided to retire several of its older, coal-fired power plants that represented about 2,000 MW of capacity. PJM realized import capacity in FirstEnergy's service territory would be constrained as a result, and carved out an independent zone — the American Transmission System, or ATSI zone — for its May 2012 capacity auction for 2015/2016, Elliot said.

The clearing price for the ATSI zone in that auction "was three times higher than the price that cleared for the rest of the RTO," he added.

ACEEE's analysis determined that had greater energy efficiency resources been bid into that market last year, "the auction clearing prices would have been suppressed, particularly in the ATSI zone, by 35%."

Suppressing prices is not in FirstEnergy's best interest, Kelter told the committee. "As FirstEnergy tells the SEC [Securities and Exchange Commission], the energy efficiency programs in Ohio lower the demand for FirstEnergy Solutions' product," he said. "Not only does the company sell less power, but when the demand goes down so does the price it can charge for that power.

"I believe the technical term for this is double whammy. FirstEnergy wants to sell more power, not less, so it wants to get rid of the programs."

FirstEnergy spokesman Doug Colafella said Wednesday that it is no secret his company "has been vocal on the mandates. The truth is, we are in compliance with the mandates. We're making good progress toward meeting the goals and we have an approved plan through which we're achieving the benchmarks through 2015."

Colafella said his company "supports the concept" of energy efficiency. It just is against government mandates.

FirstEnergy is not alone. In a Wednesday interview, Samuel Randazzo, a veteran energy attorney who represents the Industrial

Energy Users of Ohio trade group, questioned the accuracy of ACEEE's estimates.

Dismissing the report as "bogus," Randazzo claimed it is "a product of contributions by the Ohio Environmental Council, Sierra Club and the National Resource Defense Council."

Implicitly, he said, the report assumes that except for a state mandate, "customers will not do energy efficiency and peak demand reduction programs or bring the effects of these programs into the PJM market."

Randazzo contends nothing could be farther from the truth.

He summed up: "If the OMA/ACEEE guesstimate is correct, if Ohio customers can really save more than $5 billion by 2020, why should we assume that customers will not participate in the PJM market without the heavy and expensive hand of government forcing them to do so?"

— Bob Matyi

Energy transactions up in SPP in 2012

Energy bought and sold through Southwest Power Pool's energy imbalance service market jumped 23% from 2011 to 2012, but lower wholesale prices drove dollar volumes down by about 6.6% from 2011 to 2012, a report states.

"The overall market performance was strong in 2012, continuing a long stretch of increasingly effective market rules, vigorous participation by resource owners and substantial market benefits," states the annual State of the Market Report for 2012, prepared by SPP's internal market monitoring unit.

The draft report was included in materials for the SPP board of directors meeting April 30 in Kansas City, Missouri. Posted on the SPP website Tuesday, the report states that about 27 million MWh of electricity was sold in the SPP market in 2012, up from 20.8 million MWh in 2011.

But the regional average wholesale electricity price fell almost 24% from $29.28/MWh in 2011 to $22.29/MWh in 2012, largely because of lower natural gas prices. For 2012, the average natural gas price at the benchmark Panhandle hub was $2.63/MMBtu, compared with $3.88/MMBtu in 2011, a 32.2% decrease.

Lower wholesale power prices caused the dollar volume of trades through the energy imbalance service market to fall from $1.3 billion in 2011 to about $1.2 billion in 2012.

"The SPP EIS market price would not have supported new power plant investments in 2012," the report states. "This is as expected, given the high reserve margin and very low gas prices."

The capacity reserve margin – generation capacity in excess of expected peak load – rose from 24.3% in 2011 to 26.4% in 2012, the report states.

SPP's energy imbalance service market includes utilities in Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma and Texas.

The system consumed 228 million MWh of electricity in 2012, down from 229.2 million MWh in 2011. Both the winter and the summer were milder in 2012 than they were in 2011, judging from the number of heating and cooling degree days in five geographically dispersed cities sampled in the report. Cooling degree days were down 2%, and heating degree days were down 3.5%, collectively, at Topeka, Kansas; Lincoln, Nebraska; Oklahoma City; Tulsa Oklahoma; and Amarillo, Texas. These numbers were recorded by the National Weather Service.

SPP's 2012 average power price of $22.29/MWh was less than average prices in adjacent markets. The Electric Reliability Council of Texas 2012 average was $24.60/MWh, and the Midwest Independent Transmission System Operator 2012 average was $27.50/MWh.

Within SPP, 2012 average prices ranged from a low of $19.94/MWh in Nebraska's Basin Electric Power Cooperative to a high of $23.75/MWh in the Texas Panhandle's Southwestern Public Service. Transmission congestion drove these cost differentials, the report states.

The grid was at or near capacity 85.5% of 2012, compared with 78.8% of 2011.

Wind supplied 7.5% of the generation in 2012, compared with 6.2% in 2011. Wind farms added 3,091 MW of nameplate capacity in 2012, the largest amount of any generation type. Next was natural gas with 2,367 MW, coal with 713MW, oil with 58 MW and hydro with 7 MW.

"This magnitude of wind generation added operational difficulties in managing transmission congestion," the report states. "A significant amount of new wind capacity was concentrated in the Texas/Oklahoma Panhandle area, which could make the north-to-south congestion harder to manage."

Loop flows along SPP's eastern seam also contributed to congestion, the report states, "which will likely intensify with Entergy joining MISO in late 2013."

Coal-fired generation fell from 64% in 2011 to 60.1% in 2012. Gas-fired generation rose from 24% in 2011 to 25.6% in 2012. Nuclear generation was steady from 2011 to 2012 at about 6%. Hydro and other generation fell from 1% in 2011 to .5% in 2012.

— Mark Watson

Customer group opposes Dominion plant plan

A group of Dominion's large customers wants the State Corporation Commission to reject Dominion's request to build a 1,358-MW natural gas-fired power plant in Brunswick County, Virginia, until the utility has tested the project against market alternatives.

"Compete wants them to do their homework. The Legislature said that Dominion should look at alternative sources. Why that was not applied to this case is of concern," Joel Malina, Compete's executive director said Wednesday in an interview. Compete Coalition members include large customers and others who support competitive electricity markets.

A law passed in February said that Dominion should adequately consider third-party market alternatives as capacity resources. "We are confident that cheaper alternatives exist. Dominion owes it to their rate base to check," Malina said.

The SCC began hearing arguments on the controversial $1.3 billion project on Wednesday but opted not to webcast it.

The Electric Power Supply Association and others were disappointed in the decision not to make the proceedings available to listen to through a webcast.

"We are disappointed this important hearing is not being webcast. We were told the commission makes these decisions on a case-by-case basis," John Shelk, president and CEO, said Wednesday.

Glen Thomas, president and CEO of PJM Power Providers, which also called for a market test, said he found out Tuesday that the hearing could not be watched online.

Andy Farmer, a spokesman for the State Corporation Commission, said he does not know why the commission decided against webcasting the hearing. "We have not webcast every power plant hearing in the past," he said.

Dominion's plan to build the Brunswick plant has drawn the ire of merchant generators, the attorney general, large users and citizens alike.

Without a market test ratepayers, including large users, have no assurances that the Brunswick plant is the least-cost way to meet Dominion's future capacity needs, an April 16 letter to the SCC from Compete said.

Malina noted that many utilities are using market approaches to ensure that least cost resources are acquired to keep electricity prices down. The group cited American Electric Power, Indianapolis Power & Light, Kentucky Utilities and other utilities that have issued requests for proposals to test market options.

"Competitive procurements are a well-accepted means of acquiring electricity resources and there is no reason Dominion should not test its Brunswick plant proposal against alternatives to ensure that it's the best deal for customers," the letter said.

Merchant generators in the PJM region, including the PJM Power Providers, also have asked for a competitive market test.

Others have questioned the need for the plant.

David Schlissel, president of Schlissel Technical Consulting, said in testimony submitted to the SCC last month on behalf of the Sierra Club that Dominion's peak load and energy sales forecasting methodologies have not been accurate.

"The company has not provided any analysis explaining why its recent peak load and energy sales forecasts have been so consistently wrong on the high side and why its forecasting methodologies failed to accurately predict its short-term peak and energy sales," Schlissel said.

Dominion's peak load did not increase between 2006 and 2012, and in fact, was 308 MW lower in 2012 than in 2006, Schlissel said.

"The company's preferred resource plan that includes the Brunswick project is predicated on robust load growth continuing almost indefinitely. Lower peak loads and energy sales would reduce the need for and the relative economics of the new gas-fired and nuclear capacity included in that preferred resource plan," Schlissel said.

Dominion's peak load in 2016 would be 693 MW below its 2012 integrated resource plan forecast and annual energy sales will be 5.4 million MWh lower if peak load grows by 1% rather than 1.7% expected by Dominion, Schlissel said. Its peak load in 2020 would be 1,351 MW below its 2012 IRP forecast and annual sales would be 8.9 million MWh lower, he said.

Schlissel said that PJM also has significantly over-forecasted the actual 2012 Dominion peak loads and energy sales.

PJM's forecast issued in 2013 was 500 MW higher for the Dominion zone in 2016 that Dominion used in its modeling for the Brunswick plant, Glenn Kelly, Dominion's director of generation planning, said in testimony submitted to the SCC last month.

The company uses its own internal forecasts for planning, but it is obligated to buy capacity to meet the PJM load requirements, Kelly said. "Whether that forecast is too high or too load is debatable, but the fact remains that the PJM forecast is used in the reliability pricing model to determine the company's capacity requirements," he said.

The company used modeling to determine the best alternative and included a variety of market options into the model, Fred Wood, senior vice president for Dominion said in testimony filed earlier this month with regulators.

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

— Mary Powers

EIA seen estimating 27-31 Bcf storage injection

A consensus of analysts expects the Energy Information Administration on Thursday will estimate a natural gas storage injection of between 27 and 31 Bcf for the reporting week that ended Friday.

A stock build within those expectations would be below both the 43-Bcf injection seen during the comparable week in 2012, and the five-year-average injection of 50 Bcf, according to EIA data.

As a result, both the 794-Bcf deficit to last year and the 74-Bcf deficit to the five-year average would expand.

The wider range of analyst expectations spans injections of between 19 Bcf and 35 Bcf.

EIA estimated a 31-Bcf build for the week that ended April 12, increasing the overall stocks total to 1.704 Bcf.

Bentek Energy's supply/demand model predicts an injection of 28 Bcf for the week that ended Friday, while its pipeline flow model anticipates an addition to stocks of 30 Bcf. Bentek is a unit of Platts.

UBS Investment Research Director William Featherston, whose estimate of an about 30-Bcf injection is in the middle of the range of expectations, said weather last week was 52% cooler than in 2012 and 3% cooler than the five-year average.

Jefferies & Co. analyst Subash Chandra, whose estimate of a 21 Bcf injection is closer to the lower end of the range, said this week and next "we expect injections to trail historical averages," which will provide support for April gas prices.

— Anastasia Gnezditskaia

AEP unit defends move to buy stake in plant

American Electric Power subsidiary Kentucky Power, defending its proposed acquisition of 50% of the 1,560-MW Mitchell coal-fired power plant in West Virginia, told Kentucky regulators the deal offers several potential advantages including lower fuel costs.

In a filing this week with the Public Service Commission, Kentucky Power said Mitchell's fuel costs averaged 11-12% lower in 2011 and 2012 than fuel costs at the utility's 1,078-MW Big Sandy coal plant near Louisa in Lawrence County, Kentucky.

"That's because Mitchell is already scrubbed" and is able to burn less expensive, higher-sulfur coal, Ranie Wohnhas, Kentucky Power managing director of regulatory and finance, said in a Tuesday interview.

Big Sandy, which is not scrubbed, burns lower-sulfur coal mainly from Central Appalachia, according to company spokesman Ronn Robinson.

Kentucky Power is seeking PSC approval to recover approximately $530 million from its 175,000 ratepayers in 22 eastern Kentucky counties as part of the Mitchell transaction. Mitchell, located near Moundsville, West Virginia, is owned by Ohio Power, another AEP subsidiary.

Wohnhas said the utility hopes to receive PSC approval for the transaction by late June. "We're hoping for FERC approval before that," he added, referring to the Federal Energy Regulatory Commission.

Several intervenors in the case, including Kentucky Attorney General Jack Conway, the Kentucky Industrial Utility Customers trade group, the PSC staff and Sierra Club national environmental group, have fired off volleys of data requests to Kentucky Power.

Kentucky Power says it will need additional generating capacity from Mitchell, built in 1971, to replace capacity lost when it retires 800-MW Unit 2 at Big Sandy in 2015 because of new Environmental Protection Agency rules.

On March 28 the utility released a request for proposals seeking up to 250 MW to possibly offset the loss of 278-MW Unit 1 at Big Sandy as well. The utility is considering converting Unit 1 to natural gas or shutting it down. A final decision on the RFP probably will be made in September, according to Wohnhas.

In its most recent data request response, Kentucky Power said Big Sandy 1 most likely would operate for 15 years — until 2030 — as a gas-fired facility. The utility had been asked whether such a relatively short lifespan was "normal" for a plant converted to gas.

Wohnhas, in the interview, said Kentucky Power is not really comfortable projecting a longer life than 15 years for a gas-burning Unit 1.

"We were saying, taking the condition of Big Sandy Unit 1 under consideration, converting that, we felt like it would last another 15 years," he said. "It's not about the conversion as much as the existing plant property that has been there since 1963."

On another issue, Wohnhas said Kentucky Power's estimated $85,000 in market energy sales revenue in October 2014 essentially represents a one-month aberration. The utility was asked in the data request to explain why that month's sales revenue would be so low.

Scheduled maintenance outages at both Big Sandy and Mitchell in October 2014 are to blame for the lower estimate, Wohnhas said.

Conway recently asked the PSC to assert jurisdiction over Kentucky Power's proposed power coordination agreement with other AEP affiliates so the state will not lose authority over the utility's generation resources.

A power coordination accord pending before FERC by Kentucky Power, Appalachian Power, Indiana Michigan Power and AEP Service Corp. essentially would replace a longstanding power pooling arrangement among AEP entities that is set to end on January 1, 2014.

The PSC has not yet ruled on the AG's request.

— Bob Matyi

Utility output rises 1.7% on year in week: EEI

Utilities generated 69,712 GWh in the week that ended Saturday, up 1.7% from 68,566 GWh generated in the corresponding week of 2012, the Edison Electric Institute said Wednesday.

The weekly total was 879 GWh above the 68,833 GWh total posted the week that ended April 13, EEI said.

Output rose in five of the nine regions EEI assesses, with the largest percentage increase in the Pacific Northwest, where output rose 5.5% to 2,901 GWh. The second-largest percentage increase was in the South Central region, where output rose 5.3% to 11,809 GWh, EEI data showed.

Output fell in the remaining four regions, with the largest percentage decrease in the Mid-Atlantic, where output fell 3.1% to 7,366 GWh. The second-largest percentage decrease was in the Rocky Mountain region, where output fell 3% to 4,317 GWh.

Utility generation year-to-date was 1.19 million GWh, up 2.9% from 1.16 million GWh in the same period of 2012, EEI said.

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

— Valarie Jackson

Gap may not be dramatic ...from page 1

companies planning those retirements also plan to switch 8,626 MW from coal to gas, in many cases by using the same equipment and simply switching fuels. If refueling and building new plants at other sites in included in those plans, the total rises to 12,356 MW.

The retirements, which are seismic for the US generation fleet, are being propelled in large part by new, tighter emissions standards, in particular the Environmental Protection Agency's Mercury and Air Toxics Standards rule that take effect in 2015, as well as low cost natural gas, which has driven coal-fired generation out of the money in many markets, and slack demand for power.

The companies implementing these plans come at their decisions from a variety of perspectives and display a wide range

of strategies. Some have well developed plans. Others are still in the process of making a decision.

Southern Company, which operates four utilities in the Southeast and has 45,740 MW of capacity of which 16,466 MW is coal fired, is in the latter category. It has identified six coal plants for retirement totaling 2,961 MW or about 18% of its coal fleet.

Three of those plants will be retired this year or in 2015 with two going offline in 2016 and one in 2019. The company said it has not yet made a decision about what to do on any of those sites.

That could have to do with the fact that Southern, in a consortium with other power companies, is adding two 1,000-MW reactors to its Vogtle nuclear plant that it expects to have online in 2017 and 2018.

The only other new nuclear generation on the horizon in the United States is in South Carolina, where SCANA's South Carolina Electric & Gas, in partnership with Santee Cooper, is building two 1,100-MW reactors at the V.C. Summer plant that also are expected online in 2017 and 2018.

SCANA is planning on shutting two coal-fired plants, units #2 and #3 at its Canadys plant (totaling 295 MW) and units #1 and #2 at its McMeekin plant (250 MW). All four units will be converted to burn natural gas when they stop burning coal in 2015. But when the new units at Summer begin generating, SCANA plans to retire the converted gas units at Canadys and McMeekin.

AEP has highest amount of planned closures

American Electric Power has the highest amount of planned coal plant closures with 7,708 MW of planned retirements. AEP has also sketched out a plan for how it plans to handle those retirements.

Of the 11 plants affected by retirements, units at four of those plants will likely be switched to burn gas and continue running with an aggregate capacity of 1,814 MW.

Unit #4 at the Tanners Creek plant in Indiana (145 MW) will switch from coal to gas in the second quarter of 2015.

Three units at the Muskingum River plant in Ohio will retire, but the 570-MW unit #5 will convert from coal to gas in the second quarter of 2017.

Units #1 and #2 (242 MW each) at the Clinch River plant in Virginia will also be switched to burn gas, but AEP has yet to make a regulatory filing, so there is not yet an in-service date. AEP is also looking at refueling the 278-MW unit #1 at its Big Sandy plant in Kentucky, but has yet to make a final decision.

The driving factor in that decision is what happens to demand for electricity, which has been flat lately. "Right now we don't have the demand, so there are no plans to build new generation, except for the plants that are going to be refueled," AEP spokeswoman Melissa McHenry said.

Duke Energy is also high on the list of planned coal retirements. It has also embraced converting to gas more readily than many of its peers. Duke's overall plan is to retire 6,800 MW or 20% of its coal fleet. Some of those plants have already been retired, leaving nearly 3,000 MW of retirements still to come, most by 2015. But 795 MW of those remaining retirements will be offset either by new plants or refueling.

Duke plans to retire the 575-MW unit #2 at its Sutton plant in North Carolina by year end. There is already a 625-MW combined cycle gas turbine under construction at the site that is due online by year-end 2013. Duke is also converting the 170-MW unit #3 at its W.S. Lee plant in South Carolina to burn gas by 2015.

Duke says unit #6 at Duke's Wabash plant, a 318-MW coal-fired plant in Indiana, will either be converted to burn gas or be retired. And Duke is weighing the options for the 163-MW unit #6 at its Miami Fort plant in Ohio, including using a different blend of coal to extend the unit's life.

And at the Crystal River facility in Florida, which is also the site of the troubled nuclear unit that will be shut, two coal-fired units are being retired, and the company is considering building a combined cycle gas turbine to replace the nuclear capacity that will be lost. One way or the other, "There is new generation on the horizon in Florida," spokeswoman Erin Culbert said.

Among its already retired coal plants, Duke brought a 920-MW CCGT online in 2012 at its shuttered H.F. Lee coal plant in North Carolina. It commissioned another CCGT, this one 620 MW, in 2012, at its retired Dan River coal plant, and replaced 440-MW of oil-fired capacity at its Bartow plant in Florida with a 1,133-MW gas plant that came online in 2009.

Duke also is in the process of completing a 618-MW integrated gasification combined cycle plant in Indiana to replace the 160-MW of coal capacity at its Edwardsport plant.

Dominion Resources is retiring a total of 1,145 MW of coal capacity, with plans right now to refuel 227 MW at its Bremo Bluff plant in Virginia.

Dominion has yet to make a decision on what to do at its Chesapeake plant in Virginia where it plans to retire four coal units totaling 595 MW. It is also retiring two coal units, totaling 323 MW at its Yorktown plant, also in Virginia, and keep an 818-MW oil-fired unit running as a peaker.

PPL is retiring three coal units at its Cane Run plant in Kentucky and has begun construction of a 640-MW CCGT at the site.

FirstEnergy is retiring three coal plants totaling 914 MW and at one of those plants, the 425-MW Eastlake plant in Ohio, FirstEnergy is building an 873-MW CCGT with AMP Ohio.

Alliant Energy is retiring four smaller coal plants in Wisconsin and Iowa totaling 334 MW and plans to replace the lost capacity at the Iowa plants (154 MW) with a 600-MW new CCGT in Marshalltown, Iowa, that would come online in 2017.

Also in Iowa, MidAmerican Energy Holdings is closing its 137-MW Bettandorf coal plant in 2016 and switching it to burn gas. MidAmerican has four other coal units in Iowa, totaling 536 MW, where it is still evaluating the use of other fuels such as natural gas.

Allete is converting its converting its 110-MW Laskin plant in Minnesota to burn gas.

CMS Energy is closing its 325-MW J.R. Whiting coal plant in Michigan, but that is being offset by a 750-MW gas plant it is building in Genesee County.

In Colorado the decision whether to shut or refuel a gas plant has been hastened by legislation that requires coal plants to retire or refuel.

Xcel Energy is shutting 44-MW and 109-MW units at its

Arapahoe station and converting the larger unit to burn gas. At its Cherokee plant the 152-MW unit #3 is being replaced by 569-MW CCGT and the 352-MW unit #4 is being switched to coal.

At its Northern States Power utility Xcel is shutting two units totaling 260 MW at its Black Dog coal plant and building a 215-MW gas plant at the site for service in 2017.

Black Hills has already shut two coal plants totaling 60 MW and is shutting a 22-MW coal plant in 2014. The capacity of those three plants will be replaced by a 132-MW gas plant being built in Wyoming that is due online in the fourth quarter of 2014.

Other utilities are trying to keep their options open. The Holland Board of Public Works in Minnesota is building a 114-MW CCGT that would come online by the end of 2016 and replace the coal-fired capacity at its James De Young plant, but that plant has two units that can run on gas, which the company said they would do, selling capacity into the wholesale market for as long as it is economic.

Portland General Electric has reached an agreement with regulators to keep its 585-MW Boardman plant in Oregon running on coal until 2020. The utility is researching a conversion of that plant to burn biomass through a torrefaction process.

Also in the West, NV Energy has reached an agreement with regulators to replace 567-MW of coal-fired capacity at its Gardner plant in Nevada with 500 MW to 550 MW of gas-fired capacity when the Gardner plant is shut in 2014 (units #1-3) and 2017 (one unit #4).

Under current legislation NV Energy would also replace a divested portion of a jointly owned coal plant with up to 250 MW of new gas capacity and would have to build 150 MW of renewable capacity between 2017 and 2021.

— Peter Maloney

MISO looks to enhance transparency ...from page 1

to be partially offset by about 2 GW of new gas resources, MISO projects that it could be as much as 4 GW below its resource adequacy requirements by 2016.

Given expectations for tighter supply, MISO representatives said they see "forward transparency" as an area where the resource adequacy system needs improvement.

"The lack of forward transparency creates substantial reliability and economic efficiency concerns in resource adequacy," MISO's presentation said. "MISO has limited information about which plants will retire, retrofit, repower or be replaced. Potential lack of investment in restructured states could result in overall supply shortages. … Lack of certainty regarding available supply (and at what cost in each capacity zone) make it difficult to determine what retrofit and build investments are economic."

MISO currently sets mandatory reserve margin requirements, which load serving entities can meet through self-supply or by purchasing supply in its annual voluntary capacity auction.

MISO's presentation identified several potential ways it could improve forward transparency: providing more information about its interconnection queue and network upgrades; coordinating utilities' integrated resource plans; standardizing forward capacity products; extending the voluntary forward capacity auctions or over-the-counter market farther forward; and extending resource adequacy requirements into future periods.

"Part of MISO's job is to provide the mechanisms for efficient decisions," a MISO representative said. "We're interested in having economic decisions made. … Our market structure has to produce efficient price signals such that those decisions can be made based on the price signals that are out there. We want to make sure market information is available to inform those decisions."

MISO representatives said that studying the resource adequacy systems of other grid operators showed advantages and drawbacks associated with forward capacity markets, such as the three-year forward capacity markets in the PJM Interconnection and ISO New England. While these forward capacity markets had advantages like being able to attract demand response and other nontraditional supply and allowing for efficient retirements and retrofits, according to MISO's presentation, they have also seen frequent market design changes and disputes around market power mitigation rules.

However, MISO representatives were quick to point out that with such a high portion of regulated utilities in its footprint, its role in the resource adequacy process may differ significantly from that of other ISOs.

MISO's independent market monitor David Patton took no official position on the initiative during the meeting but stressed the importance of the capacity market in sending price signals. In the past, Patton has recommended that MISO move away from its vertical demand curve, which he sees as causing price volatility and unpredictability. Vertical demand curves can result in very high clearing prices if resources are needed to meet capacity requirements but places no value on surplus capacity.

Patton said during the meeting that the lack of price signals from the capacity market may be impacting how generators — such as the 581-MW Kewaunee nuclear power plant that will shut down this year — evaluate the economics of retirement decisions.

"If we had a functional capacity market that sends price signals, maybe Kewaunee doesn't retire, maybe people make retrofits [to coal generators to meet EPA requirements]," Patton said. "The market serves an important role that benefits customers because … it takes some of the risk off the retail customers having to bear those costs."

But some stakeholders pushed back on Patton's characterization of the importance of the capacity market.

"[Focusing on] the impact of a capacity market and capacity payments on the future viability of Kewaunee I think makes no sense," said Eric Callisto, a commissioner on the Public Service Commission of Wisconsin. "What killed Kewaunee is three and four dollar gas. We did a back of the envelope calculation and it wasn't even close."

Callisto argued that even under MISO's worst case projections for generation shortfall, enough generation will still be available to meet demand.

"It's just impacting the reserve margin, but load is being served. The sky isn't necessarily falling," Callisto said. "I think it's

premature to suggest that we need to pursue official changes to the capacity market. … What is the evidence that a longer term construct gets needed generation built more quickly and more cheaply than what we do now?"

MISO staff plans to hold a series of stakeholder workshops, beginning in June, to discuss next steps for the initiative.

— *Juliana Brint*

DR may cause 'downward bias'

...from page 1

happen before the scheduled launch of PJM's reliability pricing model auction in mid-May.

FERC's ruling, combined with a recent Environmental Protection Agency ruling on emissions from back-up generation used for DR, will likely accelerate DR participation in the upcoming auction, UBS analyst Julien Dumoulin-Smith said.

Dumoulin-Smith expects a 2.2-GW uptick in DR in PJM's 2016-17 RPM, bringing total cleared resources to about 17 GW and putting a "downside bias" on both his RTO and MAAC price expectations.

In February, Dumoulin-Smith lowered his estimates for 2016-17 RPM prices to $124/MW-day for RTO and $157/MW-day for MAAC.

The previous auction cleared at $136/MW-day for RTO and $167.46/MW-day for MAAC.

The current auction could represent a "high water mark" in the pace of DR growth, Dumoulin-Smith said. He said he is not revising his estimates for the upcoming RPM.

Many participants in the RPM have expressed concerns that DR has been saturating the auctions. PJM proposed tightening the rules on DR resources by requiring additional information from DR providers to provide greater assurance that DR resources would be available if called upon.

Looking further out, Dumoulin-Smith said concerns over the level of DR saturation may fade as generators turn their focus on growing levels of generation bid into the capacity market from outside of PJM.

Dynegy CEO Robert Flexon recently outlined a strategy for the Ameren coal assets that his company is acquiring that includes selling much higher levels of capacity into PJM.

— *Peter Maloney*

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