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Friday, April 17, 2015

FERC keeps 9 am gas day in power rule

REGULATION

The natural gas industry breathed a sigh of relief on Thursday as federal regulators issued a key gas-electric coordination rule that abandoned the controversial idea of moving the start of the gas shipping schedule into the wee hours of the morning.

"We applaud the commission for listening to the voices of the entire natural gas industry and keeping the current gas day start time of 9 am central rather than making sweeping, national changes to address limited issues occurring in regional power markets." Pat Jagtiani, executive vice president of the Natural Gas Supply Association said in a statement Thursday.

FERC last year proposed to move the start of the gas day from 9 am (all times central time unless otherwise noted) to 4 am to prevent gas supply problems during the morning electric ramp

(continued on page 17)

Efficiency cut N.E. prices by 24% this winter

ENERGY EFFICIENCY

Energy efficiency savings lowered New England's wholesale electricity prices by 24% in the winter of 2014, according to a report released Thursday by the Acadia Center, an energy advocacy group.

Efficiency programs suppressed electric demand by 13.7% from January through March 2014, lowering payments to generators by $1.49 billion, the report said.

With New England looking for ways to cut its power prices, the group said the region's states should prioritize energy efficiency investments, which cost about 4 cents/kWh.

But efficiency is not a one-size "cure-all" for the region's electricity needs, said Jamie Howland, Acadia Center director for energy efficiency and demand-side initiative.

(continued on page 18)

The battle between utilities and IPPs: a Q&A

UTILITIES

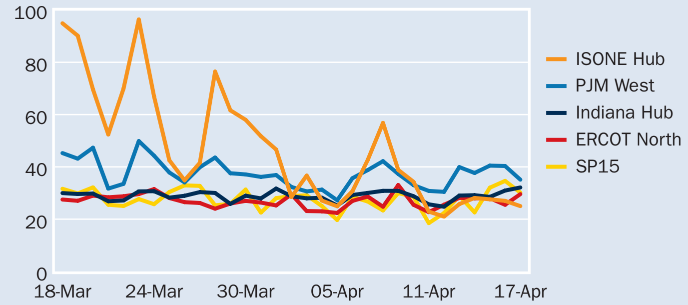
Larry Kellerman, a veteran in the power sector's world of asset acquisition and contract negotiation, spoke his mind about utilities and independent power producers, during a session at the Platts Global Power Markets Conference in Las Vegas on Wednesday,

The focus of the Q&A was on what Kellerman called the "resurgence of the integrated utility model." His primary argument was that there are today two diametrically opposed business models—regulated utility and IPP— and those two models are in running battles in virtually all of the 51 jurisdictions across the country.

Kellerman began his career negotiating qualifying facility, or QF contracts for Southern California Edison in the late 1970's. He was president of Citizens Power, and led North American power

(continued on page 18)

Price trends at key trading points ($/MWh)



Source: Average on-peak prices from various ISOs

Low and high average day-ahead LMP for Apr 17 ($/MWh)

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	24.57	25.19	15.81	16.25
NYISO	22.02	33.77	13.71	19.44
PJM	26.72	44.25	17.70	37.80
MISO	24.62	32.14	17.86	25.03
ERCOT	29.24	36.53	19.70	19.86
SPP	26.56	28.94	14.02	22.19
CAISO	28.44	38.05	26.25	27.35

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 17

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Southeast							
Southern, Into	26.00	10226	8.20	5.66	0.58	-4.51	-12.14
Florida	32.50	11207	12.20	9.30	3.50	-2.30	-11.00
Northwest							
Mid-C	20.03	9002	4.46	2.23	-2.22	-6.67	-13.35
COB	25.13	10809	8.86	6.53	1.88	-2.77	-9.75
Southwest							
Palo Verde	23.83	10173	7.43	5.09	0.41	-4.28	-11.31
Mead	25.00	10395	8.17	5.76	0.95	-3.86	-11.08

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

Soft demand weakens dailies

Northeast dailies were mostly down Thursday, pressured by lower demand projections and mild weather forecasts.

Mass Hub day-ahead on-peak futures bucked the regional trend, gaining $2 to about $28/MWh for Friday delivery on the IntercontinentalExchange. Mass Hub off-peak, however, slipped 75 cents to around $17.25/MWh.

Algonquin city-gate natural gas gained 7 cents to around $2.663/MMBtu on ICE, helping to support prices.

ISO New England expected demand to dip, peaking at about 14,600 MW Thursday, 14,400 MW Friday and 13,225 MW Saturday.

Temperature highs in Boston were forecast to rise, with highs of 64 degrees Friday and 71 degrees Saturday, more than 10 degrees over normal.

In New York state, day-ahead prices fell, pressured by bearish spot gas.

New York ISO Zone G Hudson Valley day-ahead on-peak locational marginal prices dropped 50 cents to around $28.75/MWh. New York Zone A West on-peak was about $24.75/MWh after losing nearly $5.25. New York City Zone J on-peak was 50 cents lower at around $29/MWh.

Transco Zone 6 New York spot natural gas slipped 25 cents to about $2.013/MMBtu.

New York ISO expected demand to rise slightly, peaking at about 17,450 MW Thursday, 17,675 MW Friday and 15,850 MW Saturday.

New York temperatures were forecast in line with expected averages, with highs in the lower 60s expected Friday.

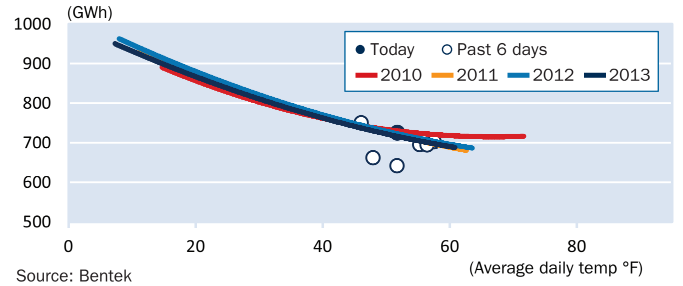
Northeast term power prices were flat to higher Thursday following an uptick in NYMEX natural gas future prices.

In New York, Zone A on-peak May held steady at around $33/MWh on ICE around 2:30 pm EDT. Zone G climbed around 25 cents to about $35.50/MWh on ICE.

In New England, Mass Hub on-peak June was up 25 cents to around $39.75/MWh, while Mass Hub on-peak July-August was flat at about $50.25/MWh on ICE.

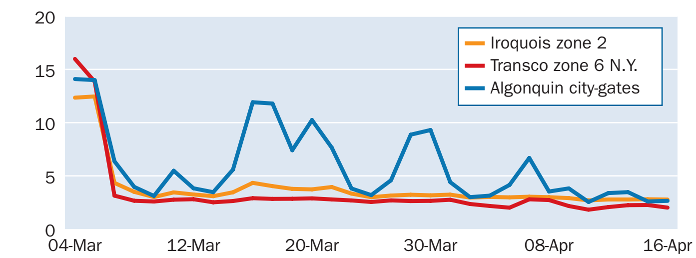
NYMEX May gas futures added 7.4 cents to around $2.684/MMBtu. Algonquin city-gate May financial basis lost 4 cents to about negative 21 cents/MMBtu on ICE, while Transco Zone 6 New York basis was down 1 cent at around negative 21 cents/MMBtu on ICE.

ISONE & NYISO load per degree



Source: Bentek

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

Northeast load and generation mix forecast (GWh)

	Actual 15-Apr	%Chg	% Chg Year-ago	Forecast 16-Apr	17-Apr	18-Apr	19-Apr	20-Apr
ISONE								
Load	305	-3	0	336	325	297	287	318
Generation								
Coal	9	3	7	6	7	5	6	7
Gas	120	-7	15	157	153	142	133	129
Nuclear	98	0	-10	98	98	98	98	98
NYISO								
Load	389	0	0	389	392	368	359	395
Generation								
Coal	8	3	-2	10	10	9	8	9
Gas	108	-1	15	107	105	95	88	86
Nuclear	135	0	5	135	135	135	135	135

Source: Bentek

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.

ISONE day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	24.99	0.01	0.00	-2.00	32.02	9680
Connecticut	24.85	0.01	-0.14	-2.02	31.50	9373
NE Mass-Boston	25.19	0.01	0.20	-2.09	32.34	9756
SE Mass	25.09	0.01	0.10	-2.16	32.22	9717
West-Central Mass	25.07	0.01	0.08	-2.02	32.04	9712
Rhode Island	25.08	0.01	0.09	-1.98	32.85	9714
Maine	24.71	0.01	-0.28	-1.99	31.94	8859
New Hampshire	24.79	-0.06	-0.14	-2.08	32.03	8888
Vermont	24.57	0.01	-0.42	-2.10	37.39	8810
Off-Peak						
Internal Hub	16.08	0.01	0.00	-5.35	22.61	6309
Connecticut	16.01	0.01	-0.07	-5.33	22.27	6057
NE Mass-Boston	16.16	0.01	0.08	-5.36	22.76	6340
SE Mass	16.21	0.01	0.13	-5.40	22.95	6360
West-Central Mass	16.14	0.01	0.07	-5.36	22.62	6336
Rhode Island	16.25	0.01	0.17	-5.40	23.84	6376
Maine	15.81	0.01	-0.27	-5.25	22.45	5613
New Hampshire	15.82	-0.07	-0.18	-5.32	22.42	5620
Vermont	15.98	0.01	-0.10	-5.33	23.62	5677

NYISO day-ahead LMP for Apr 17 ($/MWh)

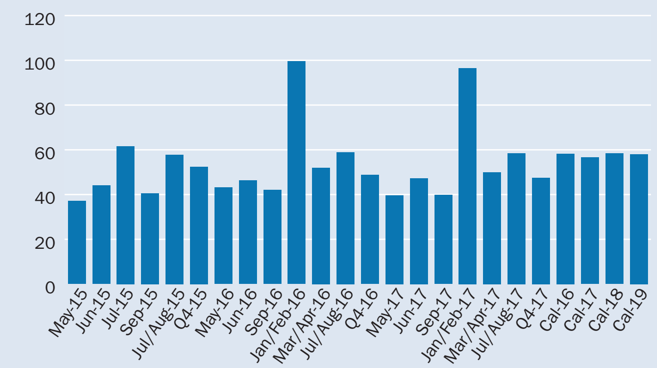
Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	27.94	-2.61	1.64	-0.12	29.95	11980
Central Zone	24.63	-0.41	0.54	-1.03	26.95	12989
Dunwoodie Zone	28.90	-2.12	3.09	-0.48	30.92	11970
Genesee Zone	23.64	-0.28	-0.33	-0.66	25.71	12466
Hudson Valley Zone	28.70	-2.08	2.93	-0.46	30.69	11885
Long Island Zone	33.77	-6.34	3.74	-0.03	33.18	13983
Millwood Zone	28.92	-2.15	3.08	-0.47	30.94	11976
Mohawk Valley Zone	24.73	-0.36	0.68	-0.61	27.12	11734
N.Y.C. Zone	29.12	-2.12	3.30	-0.58	31.34	12058
North Zone	22.02	0.00	-1.67	-0.85	24.48	7895
West Zone	24.71	-1.35	-0.34	-5.21	28.44	13027
Off-Peak						
Capital Zone	16.09	-0.83	0.84	-1.07	19.42	6825
Central Zone	14.85	-0.11	0.31	-0.84	17.78	7712
Dunwoodie Zone	16.73	-0.67	1.63	-1.07	19.90	6646
Genesee Zone	14.41	-0.09	-0.11	-0.68	17.12	7485
Hudson Valley Zone	16.66	-0.66	1.57	-1.04	19.79	6615
Long Island Zone	19.44	-2.96	2.05	1.06	22.23	7720
Millwood Zone	16.72	-0.68	1.61	-1.06	19.90	6640
Mohawk Valley Zone	14.93	-0.12	0.38	-0.91	18.01	6984
N.Y.C. Zone	16.84	-0.67	1.74	-1.09	20.02	6687
North Zone	13.71	0.00	-0.72	-1.02	16.71	4870
West Zone	14.72	-0.11	0.17	-0.75	17.44	7643

Northeast Platts M2MS Forward Curve, Apr 16 ($/MWh)

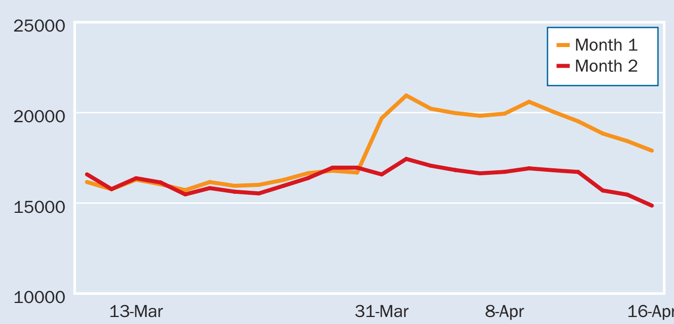
Prompt month: May 15	On-peak	Off-peak
Mass Hub	33.05	23.65
N.Y. Zone G	35.30	24.65
N.Y. Zone J	37.10	25.75
N.Y. Zone A	32.90	22.70
Ontario*	21.40	12.95

*Ontario prices are in Canadian dollars

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Bruce-6/Bruce Power	872	n	Ont.	MO	Unk	04/09/15
Cardinal/Capstone	184	g	Ont.	MO	Unk	04/14/15
Darlington-1/OPG	887	n	Ont.	MO	Unk	04/15/15
Lake Superior/Brookfield	120	g	Ont.	PMO	Unk	11/04/14
Lennox-1/OPG	525	g	Ont.	MO	Unk	04/09/15
Lennox-3/OPG	525	g	Ont.	MO	Unk	09/12/14
Pickering-5/OPG	516	n	Ont.	MO	Unk	01/13/15
Thunder Bay/Resolute	116	bio	Ont.	MO	Unk	04/14/15
Thunderbay-3/OPG	153	bio	Ont.	MO	Unk	04/16/15

SOUTHEAST MARKETS

ERCOT dailies move up to high $20s/MWh

ERCOT day-ahead power prices climbed Thursday despite demand forecasts showing some weakness.

ERCOT North Hub day-ahead on-peak futures moved up $1.25 to around $27.75/MWh for Friday delivery on the IntercontinentalExchange. North Hub off-peak prices also gained nearly $2.50 to about $19.25/MWh. ERCOT North Hub next-week futures added 50 cents to about $27/MWh on ICE.

Houston Ship Channel spot gas was nearly flat at around $2.53/MMBtu on ICE.

ERCOT forecast peak demand for Thursday at 41,003 MW, a 998 MW uptick from Wednesday's actual peak. Friday's peak was forecast at 40,311 MW, and Saturday's was expected to decrease to 39,308 MW. The high temperature for Dallas was forecast at 83 Friday, 6 degrees above normal, with the low at 66, 9 degrees above normal. In Houston, highs were expected at 81, with lows at 68, 8 degrees above normal.

Real-time prices across all hubs and zones showed no congestion at around 11 am Thursday, as wind levels tracked in line with ERCOT forecasts.

Current wind forecasts for Friday estimated wind levels to slowly subside during the day, after a projected a peak of 7,164 MW during hour ending 1 am.

Southeast dailies edged up Thursday as regional natural gas prices strengthened.

Into Southern day-ahead on-peak physical power added 75 cents to about $27.50/MWh on ICE for Friday delivery, and off-peak futures climbed $2.50 to about $21/MWh on ICE.

Spot natural gas at Transco Zone 3 moved up 3.5 cents to $2.57/MMBtu on ICE.

The high temperature in Atlanta was forecast at 73 on Friday, 2 degrees below normal, with the low expected at 57, 4 degrees above normal.

ERCOT forward prices made gains Thursday amid rising NYMEX gas futures contract prices.

ERCOT North Hub May on-peak futures added 75 cents to about $27.75/MWh on ICE at around 2:30 pm EDT. May on-peak heat rates decreased 50 Btu/kWh on ICE.

North Hub June on-peak futures moved up 75 cents to about $35/MWh. September on-peak rose 75 cents to around $31.75/MWh. Fourth quarter on-peak futures gained 25 cents to about $27.75/MWh on ICE.

May NYMEX gas future prices advanced 7.4 cents to $2.684/MMBtu.

Market coverage

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

Southeast & Central day-ahead bilateral indexes for Apr 17 ($/MWh)

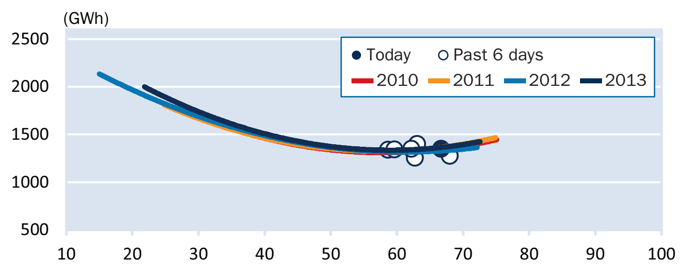
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	29.00	-0.50	31.29	11417
Southern, Into	26.00	-0.75	29.37	10226
GTC, Into	27.00	-1.00	30.40	8456
Florida	32.50	-0.25	32.46	11207
TVA, Into	27.50	-0.25	29.60	10618
Southeast Off-Peak				
VACAR	22.75	1.75	22.22	8957
Southern, Into	21.00	2.50	20.68	8260
GTC, Into	21.50	2.50	21.16	8456
Florida	25.50	3.00	23.56	8793
TVA, Into	21.75	1.75	21.47	8398

Southeast load and generation mix forecast (GWh)

	Actual 15-Apr	%Chg	% Chg Year-ago	Forecast 16-Apr	17-Apr	18-Apr	19-Apr	20-Apr
ERCOT								
Load	817	2	2	814	821	781	761	809
Generation								
Coal	348	3	-1	342	350	353	354	349
Gas	321	-1	10	350	307	291	294	283
Nuclear	91	0	9	91	91	91	91	91
SPP								
Load	533	-2	-2	534	547	520	508	543
Generation								
Coal	282	8	-8	282	295	290	283	280
Gas	105	-12	6	103	111	109	106	108
Nuclear	19	22	-2	19	20	22	25	28

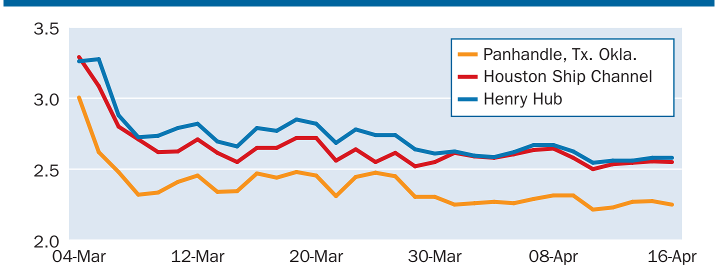
Source: Bentek

ERCOT & SPP load per degree



Source: Bentek

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



Source: Platts

ERCOT average day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	29.63	3.85	26.59	12010
Hub Average	29.63	3.74	26.64	12008
Houston Hub	29.82	3.50	27.00	11659
North Hub	29.58	4.08	26.44	11856
South Hub	29.85	3.53	26.87	11976
West Hub	29.24	3.83	26.23	12586
AEN Zone	31.09	2.13	28.89	13383
CPS Zone	29.89	3.47	28.41	12010
LCRA Zone	29.92	2.76	27.78	12019
Rayburn Zone	29.73	4.03	26.62	11915
Houston Zone	29.83	3.47	27.20	11665
North Zone	29.71	4.03	26.68	11907
South Zone	30.18	3.21	27.35	12111
West Zone	36.53	6.51	29.91	15722
Off-Peak				
Bus Average	19.71	2.50	17.86	7954
Hub Average	19.71	2.50	17.87	7954
Houston Hub	19.72	2.48	17.92	7711
North Hub	19.70	2.51	17.84	7897
South Hub	19.72	2.48	17.91	7877
West Hub	19.70	2.53	17.81	8377
AEN Zone	19.86	2.45	18.23	8445
CPS Zone	19.73	2.49	17.93	7940
LCRA Zone	19.75	2.47	18.07	7951
Rayburn Zone	19.71	2.51	17.86	7898
Houston Zone	19.72	2.48	17.93	7711
North Zone	19.70	2.49	17.85	7897
South Zone	19.84	2.49	17.94	7924
West Zone	19.72	2.77	17.78	8387

MISO South average day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Arkansas Hub	25.77	-2.92	-1.20	-0.99	25.90	10423
Louisiana Hub	32.14	1.73	0.51	-0.33	31.15	12742
Texas Hub	24.62	-4.81	-0.47	-0.73	25.99	9627
Off-Peak						
Arkansas Hub	17.86	-3.32	-0.82	-1.36	19.68	7263
Louisiana Hub	20.53	-1.58	0.09	0.09	20.79	8144
Texas Hub	19.37	-2.82	0.18	-0.85	20.58	7573

SPP average day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
SPP North Hub	26.56	-0.38	-0.43	2.70	17.95	10944
SPP South Hub	28.94	1.24	0.32	-1.53	29.08	12518
Off-Peak						
SPP North Hub	14.02	-4.23	-0.93	7.60	10.58	5788
SPP South Hub	22.19	2.82	0.19	-0.07	21.39	9569

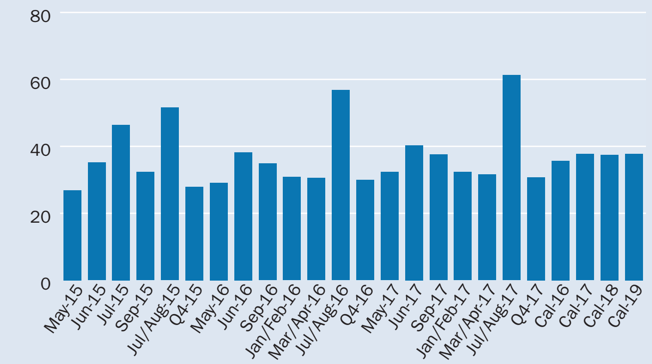
Southeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Southern, into		
Bal-week	04/15	25.75-26.75
Bal-week	04/14	25.75-26.50
Bal-week	04/13	27.50-28.25
Bal-week	04/10	29.00-29.50
Bal-week (off-peak)	04/10	19.75-20.25
Next-week	04/16	27.50-28.00

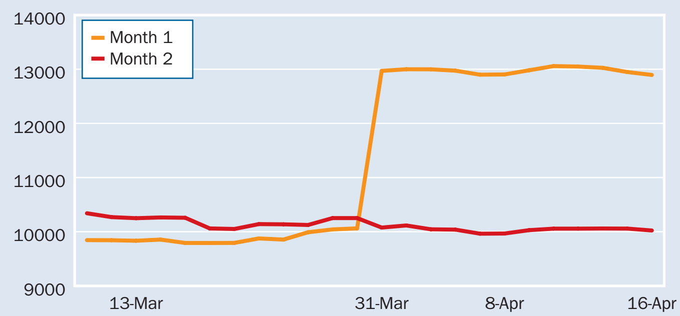
Southeast & Central Platts M2MS Forward Curve, Apr 16 ($/MWh)

Prompt month: May 15	On-peak	Off-peak
Southern Into	29.80	24.50
Entergy Into	35.35	27.35
ERCOT North	27.70	19.25
ERCOT Houston	29.75	20.70
ERCOT West	26.90	18.25
ERCOT South	29.30	20.05

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Big Brown/Luminant	575	c	Texas	MO	Unk	04/13/15
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Farley-1/Southern	918	n	Ala.	RF	Unk	03/29/15
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/15
Harris/CP&L	916	n	N.C.	MO	Unk	04/01/15
Limestone-2/NRG	860	c	Texas	MO	Unk	08/09/14
Martin Lake-2/Luminant	750	c	Texas	MO	Unk	02/01/15
Monticello/Xcel	691	n	Minn.	RF	Unk	04/12/15
Monticello-1/Luminant	565	c	Texas	MO	Unk	06/11/14
Monticello-2/Luminant	565	c	Texas	MO	Unk	06/11/14
Saint Lucie-1/FPL	982	n	Fla.	MO	Unk	03/22/15
Saint Lucie-2/FPL	1002	n	Fla	MO	Unk	04/13/15
Sequoyah-1/TVA	1186	n	Tenn	RF	Unk	04/11/15
South Texas-2/STP	1413	n	Texas	RF	Unk	03/28/15
Welsh-3/Sewpco	528	c	Texas	MO	Unk	03/30/15
Wolf Creek/WCNOC	1184	n	Kan.	RF	Unk	02/28/15

WEST MARKETS

SP15 weakens, while Palo Verde rises

West day-ahead power prices were mixed Thursday with demand projected to move down amid higher temperatures forecasts.

In California, SP15 day-ahead on-peak sank 50 cents to about $30.75/MWh on the IntercontinentalExchange for Friday-Saturday delivery. Off-peak added 25 cents to around $28/MWh.

The California Independent System Operator projected demand to decrease Friday and Saturday, peaking at about 28,950 MW Thursday, 28,875 MW Friday and 27,550 MW Saturday.

High temperatures in Sacramento were forecast in the mid-80s for Friday and Saturday with lows in the mid to upper 40s.

Spot natural gas in the California was down with Socal Citygate shedding 3.8 cents to about $2.572/MMBtu.

In the Southwest, Palo Verde day-ahead on-peak added 25 cents to around $23.75/MWh. Off-peak was up 75 cents to around $21.75/MWh.

Phoenix high temperatures were expected rising to the 80s Friday and Saturday with lows in the mid-50s to low 60s.

In the Northwest, Mid-Columbia day-ahead on-peak was down $1.75 to around $20/MWh. Off-peak eased $1.50 to about $18.75/MWh.

Portland's high temperature was forecast in the low 70s for Friday and Saturday, as much as 11 degrees above normal, with lows in the upper 40s, 5 degrees above normal.

Western US forwards were mostly stronger Thursday as the NYMEX front-month gas contract added 7.4 cents to around $2.684/MMBtu.

In the Northwest, Mid-Columbia on-peak May was steady at about $21.75/MWh on ICE around 2:30 pm EDT. Mid-C off-peak May fell 25 cents to around $16.75/MWh. On-peak June rose 25 cents to around $24.25/MWh. Mid-C on-peak third quarter jumped 50 cents to about $31.75/MWh.

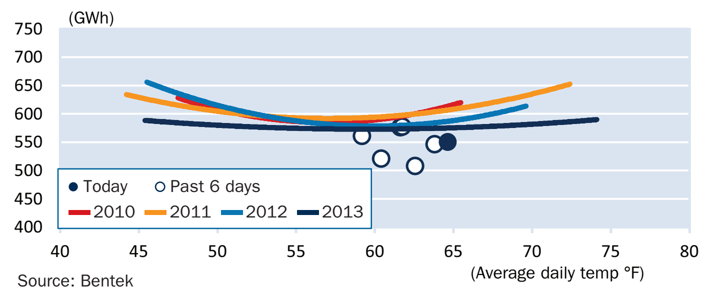
In California, SP15 on-peak May added 25 cents to about $30.50/MWh. On-peak Q3 moved up 50 cents to around $37.75/MWh.

Palo Verde on-peak May financial terms advanced 50 cents to about $25.50/MWh.

Western day-ahead bilateral indexes for Apr 17-18 ($/MWh)

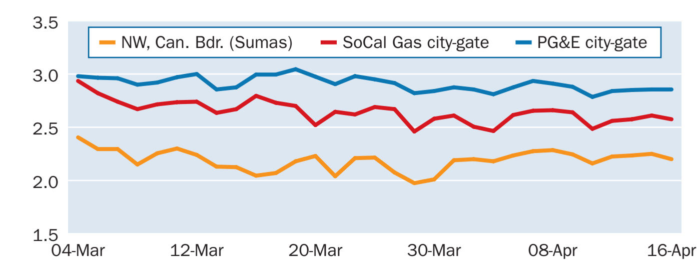
	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mid-C	20.03	-1.69	19.20	9002
John Day	21.00	-1.75	20.20	9438
COB	25.13	-0.44	23.94	10809
NOB	23.50	-1.50	22.73	10562
Palo Verde	23.83	0.15	23.78	10173
Westwing	24.25	0.00	24.16	10352
Pinnacle Peak	24.50	0.25	24.41	10459
Mead	25.00	0.25	24.14	10395
Mona	20.75	-0.50	21.02	9305
Four Corners	22.25	-0.25	23.42	9759
Off-Peak				
Mid-C	18.73	-1.36	15.70	8418
John Day	19.75	-1.50	16.68	8876
COB	21.84	-1.16	19.43	9394
NOB	21.25	-1.25	18.74	9551
Palo Verde	21.75	0.75	21.01	9285
Westwing	22.25	1.00	21.43	9498
Pinnacle Peak	22.00	1.00	20.81	9392
Mead	23.00	0.75	22.25	9563
Mona	19.50	1.00	18.74	8744
Four Corners	20.00	-0.25	20.61	8772

CAISO load per degree



Source: Bentek

Western spot natural gas prices ($/MMBtu)



Source: Platts

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.

Western load and generation mix forecast (GWh)

	Actual 15-Apr	%Chg	% Chg Year-ago	Forecast 16-Apr	17-Apr	18-Apr	19-Apr	20-Apr
CAISO								
Load	546	-5	-1	551	584	528	490	559
Generation								
Gas	206	4	-18	207	197	185	181	182
Nuclear	56	0	32	56	56	56	56	56

Source: Bentek

CAISO average day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	38.05	4.42	-0.63	0.55	32.88	13302
SP15 Gen Hub	30.15	-2.96	-1.14	-4.49	26.88	12537
ZP26 Gen Hub	28.44	-3.65	-2.16	-4.76	25.23	11827
Off-Peak						
NP15 Gen Hub	27.35	0.11	-0.47	-1.65	27.09	9576
SP15 Gen Hub	26.93	-0.07	-0.71	-1.76	26.81	11094
ZP26 Gen Hub	26.25	-0.09	-1.37	-1.75	26.06	10815

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	04/15	19.50-20.00
Bal-week	04/14	20.00-20.50
Bal-month	04/16	18.75-20.00
Bal-month	04/15	20.25-20.75
Bal-month	04/13	20.50-22.00
Bal-month	04/10	19.50-20.50
Bal-month (off-peak)	04/16	16.25-17.50
Bal-month (off-peak)	04/14	17.50-18.25
Bal-month (off-peak)	04/13	17.50-18.25
Bal-month (off-peak)	04/10	16.25-17.00
Next-week	04/15	20.50-21.00
Next-week	04/14	19.75-20.25

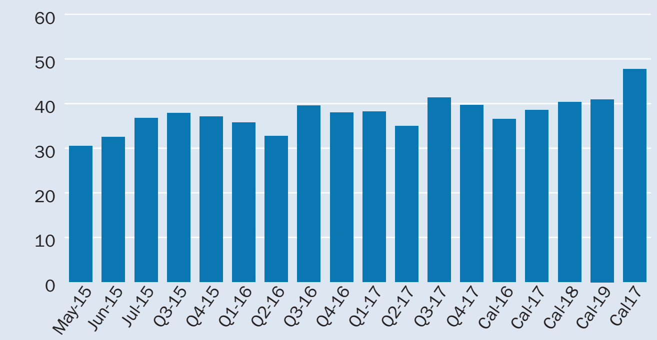
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
Alamitos-4/AES	336	g	Calif.	PMO	Unk	03/29/15
Blythe/Solar Millennium	493	s	Calif.	PMO	Unk	04/07/15
Colgate-1/YCWA	177	h	Calif.	PMO	Unk	04/06/15
Desert Star/SDG&E	495	g	Calif.	MO	Unk	04/13/15
Donald/SVP	148	g	Calif.	PMO	Unk	04/12/15
Encina-2/NRG	104	g	Calif.	PMO	Unk	04/12/15
ESJ Wind Energy/Sempra	155	w	Calif.	PMO	Unk	03/05/15
Helms-3/PG&E	404	h	Calif.	PMO	Unk	03/01/15
Imperial Valley/CalEnergy	150	st	Calif.	MO	Unk	03/30/15
Los Medanos/Calpine	561	g	Calif.	PMO	Unk	02/01/15
Moss Landing-2/Dynegy	510	g	Calif.	PMO	Unk	04/06/15
Palo Verde-3/APS	1428	n	Ariz.	RF	Unk	04/04/15
Palomar/Palomar	575	g	Calif.	PMO	Unk	04/09/15
Redondo-6/AES	175	g	Calif.	PMO	Unk	03/29/15
Solar Star-2/BHE Solar	270	s	Calif.	MO	Unk	04/16/15
Sunrise II/Sunrise	586	g	Calif.	MO	Unk	02/01/15
Sutter/Calpine	525	g	Calif.	MO	Unk	04/09/15

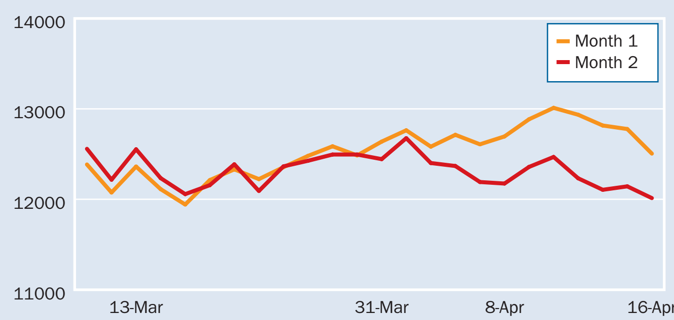
Western Platts M2MS Forward Curve, Apr 16 ($/MWh)

Prompt month: May 15	On-peak	Off-peak
Mid-C	21.80	16.65
Palo Verde	25.45	22.95
Mead	26.50	24.15
NP15	34.25	28.40
SP15	30.50	27.05

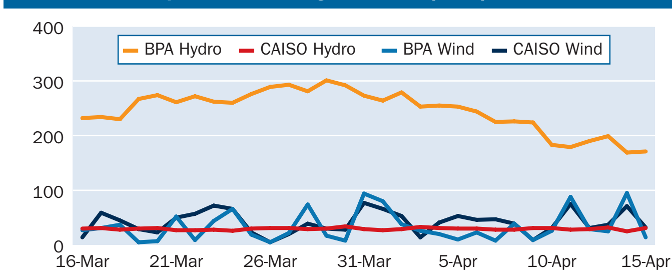
SP15: Forward curve on-peak ($/MWh)



SP15: Marginal heat rate on-peak (Btu/kWh)



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

PJM & MISO MARKETS

PJM West edges up despite weak demand

Mid-Atlantic dailies were mostly higher Thursday despite bearish spot natural gas, higher-than-average temperature forecasts and lower demand projections.

PJM West Hub day-ahead on-peak futures gained 75 cents to around $37.25/MWh for Friday delivery on the IntercontinentalExchange.

Texas Eastern M-3 natural gas, however, fell 12 cents to about $1.552/MMBtu.

The PJM Interconnection expected load to fall, peaking at around 86,075 MW Thursday, 85,250 MW Friday and 79,575 MW Saturday.

Temperatures were forecast as much as 10 degrees above normal in the PJM region, with highs ranging from the upper 60s to mid-70s Thursday and Friday.

Midcontinent day-ahead power prices showed gains despite falling demand.

Indiana Hub day-ahead on-peak futures gained nearly $1 to around $31.75/MWh for Friday delivery on ICE.

The Midcontinent ISO expected peak demand near 75,500 MW Thursday, 75,175 MW Friday and 69,075 MW Saturday.

Temperatures in MISO were forecast at or above five-day norms, with highs in the region averaging from the high 60s to upper 70s through Sunday.

Dailies in the Midwestern portion of PJM were mixed amid strength in nearby markets and bearish demand.

AD Hub on-peak fell 50 cents to about $32.25/MWh, while NI Hub on-peak gained 50 cents to around $30/MWh.

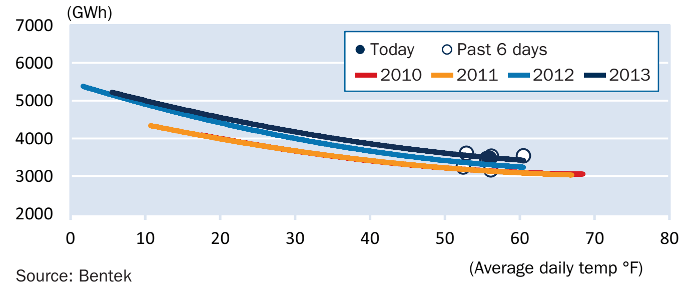
Mid-Atlantic term power prices were flat to higher Thursday amid strengthening NYMEX gas futures.

PJM West Hub on-peak May financial futures were unchanged at about $41.25/MWh on the IntercontinentalExchange around 2:30 pm EDT. PJM West Hub on-peak July-August financial futures were around $55/MWh, after gaining nearly 25 cents.

May NYMEX natural gas futures were up 7.4 cents to around $2.684/MMBtu, while May Texas Eastern M-3 gas basis slipped 2 cents to around negative 96 cents/MMBtu on ICE.

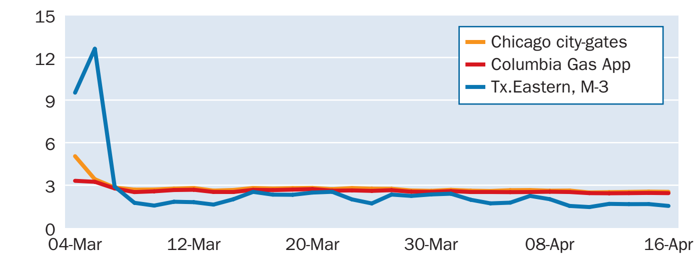
Midwest forwards were flat to lower despite an uptick in NYMEX gas future prices.

PJM & MISO load per degree



Source: Bentek

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 15-Apr	%Chg	% Chg Year-ago	Forecast 16-Apr	17-Apr	18-Apr	19-Apr	20-Apr
PJM								
Load	1843	-1	-1	1847	1879	1765	1705	1908
Generation								
Coal	702	-3	-11	713	708	672	634	628
Gas	392	3	27	372	386	390	378	380
Nuclear	622	0	2	600	604	616	638	660
MISO								
Load	1618	-2	-3	1623	1649	1541	1504	1669
Generation								
Coal	795	-6	-18	793	816	802	776	789
Gas	250	-21	51	250	269	255	229	244
Nuclear	285	-1	85	153	159	179	213	247

Source: Bentek

AD Hub on peak May financial futures were down over 25 cents to about $37.25/MWh on ICE. Indiana Hub on-peak May terms were near flat at around $34.50/MWh, while NI Hub on-peak May futures moved down 25 cents to around $34/MWh on ICE.

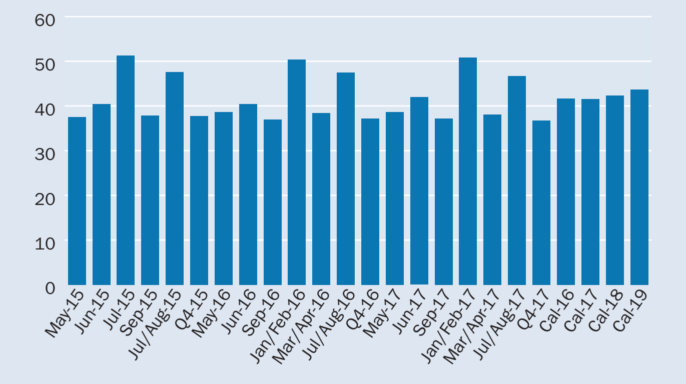
PJM average day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	31.05	-0.82	-1.06	-2.20	30.25	14028
AEP-Dayton Hub	31.96	-0.84	-0.13	-2.27	31.14	14438
ATSI Gen Hub	35.77	1.82	1.02	-2.84	33.53	16129
Chicago Gen Hub	30.17	-1.76	-1.00	-2.06	28.30	11893
Chicago Hub	30.70	-1.74	-0.49	-2.14	29.42	12101
Dominion Hub	36.59	3.32	0.33	-4.13	35.41	14674
Eastern Hub	27.88	-5.19	0.14	-4.98	28.87	15242
New Jersy Hub	27.95	-4.60	-0.38	-3.95	29.60	15280
Northern Illinios Hub	30.46	-1.75	-0.72	-2.12	28.93	12006
Ohio Hub	32.07	-0.93	0.07	-2.42	31.23	12545
West Internal Hub	34.40	1.30	0.17	-2.97	33.08	19441
Western Hub	35.10	2.47	-0.30	-5.23	35.29	19834
AEP Zone	32.24	-0.58	-0.11	-2.59	31.52	14565
Allegheny Power Zone	34.32	1.35	0.04	-3.83	34.24	16281
Atlantic Elec Zone	28.29	-4.27	-0.37	-3.96	27.85	15469
ATSI Zone	35.87	1.68	1.26	-2.95	33.82	16173
BG&E Zone	44.25	10.73	0.58	-4.01	43.15	22139
ComEd Zone	30.59	-1.75	-0.59	-2.11	29.18	12060
Dayton P&L Zone	33.19	-0.61	0.86	-2.61	31.87	13520
Delmarva P&L Zone	27.85	-5.08	-0.01	-5.31	28.69	15225
Dominion Zone	37.07	3.68	0.46	-4.01	36.10	14868
Duke Zone	31.23	-0.98	-0.72	-2.15	30.43	12723
Duquesne Light Zone	33.71	0.81	-0.03	-3.13	32.96	17311
EKPC Zone	30.64	-1.09	-1.21	-2.05	29.95	15784
JCPL Zone	27.74	-4.72	-0.47	-4.03	29.02	15169
MetEd Zone	26.94	-5.31	-0.67	-3.53	27.87	13251
PECO Zone	26.76	-5.57	-0.59	-3.44	26.88	13163
Pennsylvania Elec Zone	31.19	-1.81	0.07	-4.72	31.71	16130
PEPCO Zone	40.42	7.12	0.36	-3.97	39.98	20223
PPL Zone	26.72	-5.48	-0.73	-3.49	27.69	13140
PSEG Zone	28.13	-4.51	-0.29	-4.04	30.49	15377
Rockland Elec Zone	28.16	-4.52	-0.25	-3.80	30.10	15394
Off-Peak						
AEP Gen Hub	24.96	-0.08	-0.42	-1.58	24.08	11112
AEP-Dayton Hub	25.49	-0.20	0.22	-1.92	24.75	11346
ATSI Gen Hub	28.87	2.54	0.86	-0.77	25.78	12913
Chicago Gen Hub	22.33	-2.77	-0.37	-0.62	19.28	8764
Chicago Hub	22.61	-2.85	-0.01	-0.63	19.89	8874
Dominion Hub	29.36	3.57	0.32	-2.22	27.74	11680
Eastern Hub	18.54	-6.47	-0.46	-2.59	20.33	9467
New Jersy Hub	18.67	-6.07	-0.72	-2.69	21.03	9534
Northern Illinios Hub	22.49	-2.82	-0.16	-0.63	19.60	8824
Ohio Hub	25.53	-0.31	0.37	-2.08	24.86	9996
West Internal Hub	28.07	2.34	0.27	-1.22	26.08	15365
Western Hub	27.75	2.67	-0.38	-2.78	27.07	15190
AEP Zone	25.98	0.27	0.24	-1.76	25.02	11564
Allegheny Power Zone	27.17	1.69	0.02	-2.45	26.37	12666
Atlantic Elec Zone	18.55	-6.19	-0.73	-2.54	20.15	9470
ATSI Zone	28.72	2.26	0.99	-1.01	25.96	12847
BG&E Zone	37.80	12.26	0.07	-3.08	34.71	18261
ComEd Zone	22.54	-2.84	-0.08	-0.63	19.76	8845
Dayton P&L Zone	26.36	0.10	0.79	-1.66	25.01	10747
Delmarva P&L Zone	18.42	-6.52	-0.54	-2.56	20.23	9403
Dominion Zone	29.90	4.07	0.37	-2.26	28.25	11895
Duke Zone	24.87	-0.41	-0.19	-1.77	24.05	10139
Duquesne Light Zone	26.55	1.14	-0.06	-1.90	25.12	13439
EKPC Zone	24.34	-0.59	-0.54	-1.71	23.60	12220
JCPL Zone	18.65	-6.06	-0.75	-2.72	20.72	9525
MetEd Zone	17.88	-6.70	-0.89	-2.46	19.79	8422
PECO Zone	17.81	-6.75	-0.91	-2.60	19.61	8387
Pennsylvania Elec Zone	22.99	-2.51	0.02	-2.82	23.65	11750
PEPCO Zone	33.82	8.38	-0.03	-2.62	31.59	16339
PPL Zone	17.70	-6.91	-0.86	-2.46	19.92	8334
PSEG Zone	18.76	-6.03	-0.68	-2.80	21.52	9579
Rockland Elec Zone	18.88	-5.99	-0.60	-3.00	21.48	9640

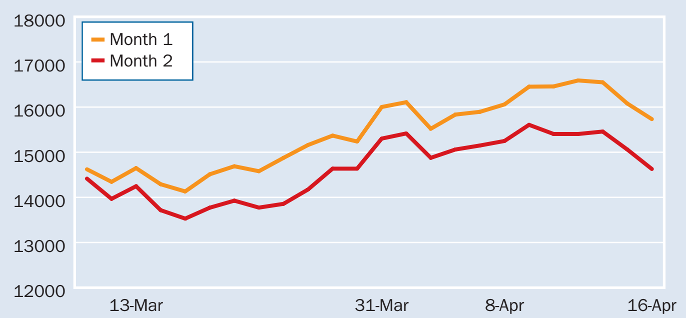
PJM & MISO Platts M2MS Forward Curve, Apr 16 ($/MWh)

Prompt month: May 15	On-peak	Off-peak
PJM West	41.30	27.65
AD Hub	37.55	26.40
NI Hub	34.15	22.15
Indiana Hub	34.55	25.25

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



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



MISO average day-ahead LMP for Apr 17 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	32.12	1.57	0.66	1.18	28.92	16548
Michigan Hub	31.19	-0.06	1.36	0.98	28.56	11205
Minnesota Hub	28.01	0.28	-2.16	-0.23	21.73	11080
Illinois Hub	31.98	2.34	-0.25	0.41	27.47	12611
Off-Peak						
Indiana Hub	25.03	2.43	0.59	1.29	24.48	12567
Michigan Hub	23.85	1.23	0.61	0.56	23.49	8598
Minnesota Hub	20.95	0.21	-1.27	1.31	14.94	8183
Illinois Hub	22.69	1.00	-0.31	-0.77	20.42	8929

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Beaver Vlly-1/FirstEnergy	1011	n	Pa	MO	Unk	04/15/15
Braidwood-1/Exelon	1242	n	Ill.	RF	Unk	03/30/15
DC Cook-2/AEP	1151	n	Mich.	RF	Unk	03/24/15
Hope Creek-1/PSEG	1233	n	N.J.	RF	Unk	04/10/15
Limerick-2/Exelon	1246	n	Pa	RF	Unk	04/13/15
Perry/FirstEnegy	1260	n	Ohio	MO	Unk	03/09/15
Prairie Island-1/Xcel	590	n	Minn.	MO	Unk	04/07/15
Susquehanna-2/PPL	1330	n	Pa	RF	Unk	04/10/15

EMISSIONS MARKETS

RGGI prices make a move higher

The Regional Greenhouse Gas Initiative allowance prices moved higher during the week, even after seeing some weakness later in the week.

The RGGI vintage 2015 contracts for December 2015 delivery moved up to as high as $5.54/st on the IntercontinentalExchange before coming back down to $5.51/st.

The RGGI vintage 2016 contract for December 2016 saw similar movement, moving up to as high as $5.72/st, a rise of about 11 cents compared with the previous week, before dropping down to $5.70/st on April 15.

There were a total of about 8 contracts cleared or traded on the ICE from April 10-14 representing about 1,125 contracts, a drop of about 1,950 from the previous week.

Four of the contracts traded or cleared on the ICE were for RGGI vintage 2015 for April 2015 with prices ranging from $5.40/st to $5.45/st.

California carbon allowances also firmed up over the week with the vintage 2015 contracts for December 2015 adding 5 cents to $12.70/metric ton on ICE.

California vintage 2016 contracts for December 2016 also found some upward momentum adding close to 4 cents to $13.12/metric ton on ICE.

Overall, there were about 16 transactions representing about 1,230 California Carbon allowance contracts cleared or traded on ICE, an increase of about 262 contracts from the previous week.

— Eric Wieser

Little movement in 'dead' CSAPR market

Brokers were again practicing their patience this week in the federal US emissions market as inactivity persisted.

"It's been so dead," one broker said, adding he expects nothing to change anytime soon.

Uncertainty continues as the courts weigh the validity of proposed tougher federal emissions programs. Utilities still don't know what rules will be approved and when they will be enforced, and it's too early in the year to know if allowances need to be bought or sold, brokers said.

"I think once the court ruling is all finalized, and if we get through the summer with some hot weather, that'll spur some activity," another broker said.

In another quiet week, a fluctuation in bids for Vintage 2015 CSAPR Group 1 SO2 allowances was the highlight of the emissions market. Brokers reported low bids of $25/st on Monday, down from $50/st at the end of last week. Offers responded to the drop, falling $5 to $75/st, then bids rose to $40/st, tightening a still-wide gap.

Platts assessed the Vintage 2015 CSAPR Group 1 SO2 allowance price at $57.50/st, down from $65/st last week, based on the midpoint between the bid/offer range.

Broker marks submitted for the Vintage 2015 CSAPR Group 2 SO2 allowance varied from bids at $100/st and $150/st, with offers at $300/st. Platts assessed the price at $200/st, unchanged from last week, based on the midpoint between the bid/offer range.

Broker marks submitted to Platts for Seasonal NOx allowances and Annual NOx allowances included bids at $115/st and $120/st, with offers at $130/st and $140/st. Platts assessed the price for both allowances at $127.50/st, unchanged from last week, based on the midpoint between the bid/offer range.

— Jim Levesque

Daily CSAPR allowance assessments, Apr 16

CSAPR ($/st)	2015 Range	Mid	2016 Range	Mid
SO_2 Group 1	40.00-75.00	57.50	35.00-70.00	52.50
SO_2 Group 2	100.00-300.00	200.00	95.00-295.00	195.00
NOx Annual	115.00-140.00	127.50	110.00-135.00	122.50
NOx Seasonal	115.00-140.00	127.50	110.00-135.00	122.50

All prices in $/st

RGGI carbon allowance futures, Apr 15 ($/allowance)

ICE	Settlement	Volume
Dec15 V14	5.51	0
Dec16 V14	5.70	0
Dec17 V14	5.90	0
Dec18 V14	6.11	0
Dec15 V15	5.51	0
Dec16 V15	5.70	0
Dec17 V15	5.90	0
Dec18 V15	6.11	0
Dec15 V16	5.51	0
Dec16 V16	5.70	0
Dec17 V16	5.90	0
Dec18 V16	6.11	0

The Regional Greenhouse Gas Initiative is a carbon cap-and-trade program for power generators in nine Northeast and Mid-Atlantic US states. One RGGI allowance is equivalent to one short ton of CO2. The volume listed is the number of futures contracts traded. Each futures contract represents 1,000 RGGI allowances.

REC MARKETS

Texas Legislature move weakens RECs

Texas REC prices peeled back this week in the wake of the Texas Senate passing a bill Tuesday that would repeal the state's renewable portfolio standard at the end of the year.

In 1999, the Texas legislature set the renewable standard at 2,000 MW by 2009, then to 5,880 MW by 2015, and set out a non-binding goal of 10,000 MW of renewable generation by 2025.

Currently, the state has over 14,000 MW of installed wind capacity, and the Electric Reliability Council of Texas reported that wind produced more than 9% of the energy needed in March and close to 12% in February.

The bill, which was sponsored in the Sen. Troy Fraser, will now head to the Texas House State Affairs Committee.

Texas RECs came off after the Senate's bill passage, with the bid side losing 10 cents to 60 cents/REC and the offer side dropping 15 cents to 75 cents/REC.

New Jersey Solar RECs made a move higher with the bid side adding $12.50 to $200/SREC and offer side going to $205/SREC, an increase of about $10.

Maryland SRECs also saw some firmness, moving up $5 to $167.50/SREC.

New Jersey SREC futures on the IntercontinentalExchange also jumped, with packages across most of the curve seeing some gains.

New Jersey SREC futures for Energy Year 2015 gained $14 over the past week to $205/SREC, while Energy Year 2016 also saw a bump, climbing $12.50 to $205/SREC, and Energy Year 2021 added $10 to $140/SREC.

Trading or clearing activity of RECs on ICE was thin over the week with less than a handful of deals for Massachusetts and Connecticut showing up.

— Eric Wieser

Renewable Energy Certificate Markets Apr 16 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	48.00	50.00	49.000
Maryland	14.75	15.50	15.125
Massachusetts	47.50	50.50	49.000
New Jersey	15.75	16.50	16.125
Ohio	3.00	5.00	4.000
Pennsylvania	14.75	15.25	15.000
Texas	0.60	0.75	0.675
Solar RECs*			
Maryland	160.00	175.00	167.500
Massachusetts	280.00	285.00	282.500
New Jersey	200.00	205.00	202.500
Ohio	35.00	45.00	40.000
Pennsylvania	37.00	45.00	41.000
California RPS*			
California Bundled REC (Bucket 1)	12.00	15.50	13.750
California Bundled REC (Bucket 2)	3.75	5.00	4.375
California Tradable REC (Bucket 3)	0.60	1.00	0.800
Voluntary RECs*			
National voluntary, any technology	0.60	0.70	0.650
National voluntary, wind	0.60	0.75	0.675

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

ISONE average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
Internal Hub	21.62	-3.39	29.31	7015	5.97	3.52
Connecticut	21.63	-3.36	29.04	7647	5.82	3.20
NE Mass-Boston	21.77	-3.46	29.61	7063	6.03	3.55
SE Mass	21.65	-3.44	29.35	7024	6.02	3.68
West-Central Mass	21.64	-3.40	29.30	7022	6.02	3.54
Rhode Island	21.89	-3.33	29.48	7102	6.01	4.28
Maine	21.30	-3.39	29.45	7708	5.98	3.32
New Hampshire	21.41	-3.39	29.34	7750	5.99	3.51
Vermont	21.02	-3.27	28.61	7608	6.13	10.35
Off-Peak						
Internal Hub	15.23	5.31	22.10	5758	-0.41	1.02
Connecticut	15.20	5.23	21.72	5684	-0.42	1.04
NE Mass-Boston	15.29	5.38	22.22	5780	-0.40	1.06
SE Mass	15.32	5.43	22.22	5790	-0.40	1.26
West-Central Mass	15.27	5.30	22.18	5773	-0.40	0.95
Rhode Island	15.42	5.41	22.45	5829	-0.40	2.04
Maine	15.04	5.32	22.07	5587	-0.44	0.92
New Hampshire	15.05	5.29	21.97	5591	-0.38	0.98
Vermont	15.10	5.21	21.55	5608	-0.31	2.73

NYISO average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
Capital Zone	27.51	2.00	28.99	11880	3.78	1.22
Central Zone	26.39	6.71	25.02	14127	-0.41	2.17
Dunwoodie Zone	28.85	3.42	29.08	12019	3.00	2.07
Genesee Zone	25.46	6.86	23.64	13634	-0.93	2.31
Hudson Valley Zone	28.78	3.55	28.96	11982	2.78	1.97
Long Island Zone	30.63	-3.33	31.49	12749	1.95	1.61
Millwood Zone	28.81	3.34	29.14	11993	3.14	2.04
Mohawk Valley Zone	26.75	6.55	25.13	12807	-0.64	2.27
N.Y.C. Zone	28.97	3.42	29.19	12062	3.24	2.41
North Zone	24.52	10.98	22.49	8874	-1.57	2.25
West Zone	25.06	6.71	28.16	13418	0.71	0.43
Off-Peak						
Capital Zone	12.94	-0.76	20.53	5744	8.13	-0.73
Central Zone	12.21	3.79	17.70	6792	4.86	0.41
Dunwoodie Zone	13.21	0.48	20.39	5791	7.95	-0.14
Genesee Zone	12.23	4.18	17.13	6798	4.01	0.31
Hudson Valley Zone	13.32	0.71	20.37	5842	7.70	-0.23
Long Island Zone	13.49	0.69	24.08	5916	8.08	-1.40
Millwood Zone	13.19	0.36	20.46	5785	8.01	-0.21
Mohawk Valley Zone	12.36	3.86	18.08	6104	4.95	0.28
N.Y.C. Zone	13.06	0.08	20.44	5728	8.23	-0.07
North Zone	11.54	4.48	16.65	4284	4.06	0.40
West Zone	11.89	3.67	17.44	6608	4.84	0.31

Ontario average hourly prices for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
IESO	32.31	-4.09	16.75	11867
Off-Peak				
IESO	8.11	6.59	6.27	3000

PJM average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
AEP Gen Hub	27.83	-5.13	30.51	12539	2.05	-0.51
AEP-Dayton Hub	28.33	-5.33	31.15	12763	2.50	-0.27
ATSI Gen Hub	29.42	-4.75	32.81	13416	6.49	0.23
Chicago Gen Hub	24.52	-7.42	28.20	9761	2.79	-0.28
Chicago Hub	24.78	-7.75	28.79	9864	3.28	0.32
Dominion Hub	32.06	-9.99	35.97	12887	4.46	-1.00
Eastern Hub	24.12	-6.45	27.67	12972	5.55	1.00
New Jersy Hub	24.53	-9.44	29.94	13197	6.16	-0.38
Northern Illinios Hub	24.64	-7.66	28.62	9809	3.22	-0.04
Ohio Hub	28.27	-5.36	31.13	11207	2.51	-0.18
West Internal Hub	29.84	-6.05	33.13	16576	4.41	-0.42
Western Hub	31.50	-40.20	37.80	17494	8.97	-2.83
AEP Zone	28.61	-5.22	31.43	12889	2.69	-0.17
Allegheny Power Zone	30.21	-7.43	34.68	14183	4.98	-0.70
Atlantic Elec Zone	27.64	-35.86	29.66	14865	2.61	-2.13
ATSI Zone	29.94	-4.76	33.40	13656	6.12	-0.05
BG&E Zone	40.35	-8.25	45.49	20389	2.96	-2.75
ComEd Zone	24.69	-7.73	28.83	9831	3.34	0.02
Dayton P&L Zone	29.13	-5.57	31.78	11966	2.72	-0.26
Delmarva P&L Zone	23.85	-6.98	27.42	12829	5.78	1.03
Dominion Zone	32.58	-9.42	36.84	13095	4.55	-1.14
Duke Zone	27.67	-5.24	30.20	11368	2.00	-0.02
Duquesne Light Zone	29.27	-4.21	33.06	15088	5.01	-0.41
EKPC Zone	27.52	-5.26	29.95	13900	1.40	-0.23
JCPL Zone	24.01	-5.90	27.66	12915	5.86	1.26
MetEd Zone	23.22	-7.04	26.82	11328	5.93	0.93
PECO Zone	23.44	-6.13	26.46	11435	5.02	0.20
Pennsylvania Elec Zone	28.02	-27.66	33.13	14573	7.26	-1.66
PEPCO Zone	36.53	-8.30	41.29	18461	3.56	-1.63
PPL Zone	23.01	-6.63	26.89	11225	5.76	0.70
PSEG Zone	24.22	-6.08	32.04	13027	7.13	-1.50
Rockland Elec Zone	24.55	-5.36	29.43	13208	6.32	0.67
Off-Peak						
AEP Gen Hub	24.11	3.16	24.01	11185	0.17	-0.15
AEP-Dayton Hub	24.81	3.64	24.77	11509	0.30	-0.25
ATSI Gen Hub	25.82	4.44	25.25	12016	2.40	0.07
Chicago Gen Hub	8.44	-10.32	17.68	3387	11.03	1.15
Chicago Hub	7.56	-11.56	18.02	3032	12.36	1.47
Dominion Hub	27.08	2.13	27.89	10866	1.54	-0.51
Eastern Hub	17.87	6.39	19.01	10677	2.68	1.39
New Jersy Hub	17.89	6.16	20.03	10693	2.87	1.14
Northern Illinios Hub	7.71	-11.33	18.00	3091	12.12	1.18
Ohio Hub	24.93	3.84	24.89	9870	0.29	-0.26
West Internal Hub	25.94	3.29	26.02	15322	1.51	-0.29
Western Hub	26.52	3.55	27.59	15668	2.59	-0.80
AEP Zone	24.87	3.48	24.89	11536	0.46	-0.11
Allegheny Power Zone	25.44	3.73	26.87	12290	1.75	-0.77
Atlantic Elec Zone	17.69	6.32	18.89	10570	2.82	1.31
ATSI Zone	25.94	4.45	25.54	12072	2.30	-0.02
BG&E Zone	35.53	0.00	37.57	18990	0.69	-3.48
ComEd Zone	7.60	-11.51	18.05	3048	12.30	1.30
Dayton P&L Zone	25.01	3.33	24.74	10237	0.39	-0.02
Delmarva P&L Zone	17.71	6.47	18.81	10580	2.75	1.49
Dominion Zone	27.60	2.06	28.69	11078	1.57	-0.81
Duke Zone	23.75	2.90	23.74	9718	0.11	0.08
Duquesne Light Zone	24.69	4.44	25.26	13150	1.96	-0.46
EKPC Zone	23.08	2.39	23.54	12224	0.20	-0.15
JCPL Zone	17.85	6.18	19.08	10667	2.74	1.74
MetEd Zone	17.22	6.44	18.24	8937	2.68	1.64
PECO Zone	17.30	6.39	18.37	8975	2.60	1.30
Pennsylvania Elec Zone	22.68	5.88	23.33	11972	2.08	0.22
PEPCO Zone	31.70	1.15	33.28	16940	0.86	-2.17
PPL Zone	17.08	6.56	18.46	8865	2.64	1.59
PSEG Zone	17.99	6.10	21.20	10749	3.01	0.50
Rockland Elec Zone	18.34	5.97	20.29	10958	2.53	1.33

MISO average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
Indiana Hub	29.09	1.80	27.77	14693	-0.57	0.80
Michigan Hub	27.74	0.57	26.64	10241	0.86	1.64
Minnesota Hub	20.93	-1.83	21.38	8327	0.73	-0.50
Illinois Hub	29.93	-2.00	25.69	11940	-0.11	1.21
Off-Peak						
Indiana Hub	24.84	-1.63	24.43	13158	0.11	0.06
Michigan Hub	23.10	1.54	22.22	8564	2.35	1.26
Minnesota Hub	7.36	-9.67	15.82	2941	5.78	-1.60
Illinois Hub	21.80	1.77	18.10	8725	-0.41	1.97

MISO South average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
Arkansas Hub	25.51	0.67	25.56	10595	0.42	0.30
Louisiana Hub	27.00	1.21	26.95	10942	6.01	4.05
Texas Hub	23.69	-0.96	26.17	9372	1.41	-0.06
Off-Peak						
Arkansas Hub	17.40	-2.28	17.85	7265	2.25	1.98
Louisiana Hub	18.74	-1.34	19.20	7643	2.29	1.64
Texas Hub	18.24	-1.98	19.06	7291	2.08	1.63

SPP average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
SPP North Hub	12.79	-1.33	11.55	5402	2.63	5.44
SPP South Hub	24.30	-2.14	31.01	10823	6.38	-2.01
Off-Peak						
SPP North Hub	-19.34	-17.66	0.67	-8169	29.30	9.96
SPP South Hub	22.71	0.95	22.22	10141	0.23	-0.95

Alberta average hourly prices for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
AESO	20.29	1.62	21.87	8389
Off-Peak				
AESO	13.33	-2.00	17.63	5542

ERCOT average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
Bus Average	23.29	-2.59	24.71	9571	5.20	1.73
Hub Average	23.29	-2.60	24.83	9570	5.39	1.65
Houston Hub	23.29	-2.60	24.96	9213	6.21	1.89
North Hub	23.29	-2.58	24.40	9526	4.71	1.90
South Hub	23.29	-2.60	25.32	9556	6.29	1.39
West Hub	23.28	-2.60	24.64	10021	4.43	1.44
AEN Zone	23.30	-2.62	32.47	10030	10.98	-3.73
CPS Zone	23.29	-2.59	25.33	9556	6.59	3.11
LCRA Zone	23.29	-2.59	26.50	9556	7.86	1.17
Rayburn Zone	23.30	-2.59	24.44	9528	4.98	2.04
Houston Zone	23.29	-2.60	24.98	9213	6.32	2.10
North Zone	23.31	-2.57	24.42	9531	5.02	2.12
South Zone	23.29	-2.60	25.92	9556	10.39	1.26
West Zone	23.19	-2.69	28.09	9981	6.36	1.38
Off-Peak						
Bus Average	17.65	-2.07	18.12	7304	2.13	-0.33
Hub Average	17.64	-2.08	18.16	7303	2.16	-0.37
Houston Hub	17.65	-2.07	18.26	7041	2.27	-0.41
North Hub	17.65	-2.07	17.97	7212	2.06	-0.21
South Hub	17.65	-2.07	18.46	7245	2.32	-0.63
West Hub	17.64	-2.08	17.97	7755	1.98	-0.25
AEN Zone	17.64	-2.09	20.81	7758	2.97	-2.63
CPS Zone	17.65	-2.07	18.40	7245	2.29	-0.55
LCRA Zone	17.65	-2.07	19.27	7245	2.55	-1.26
Rayburn Zone	17.65	-2.07	17.97	7215	2.09	-0.19
Houston Zone	17.65	-2.07	18.27	7041	2.28	-0.41
North Zone	17.66	-2.06	17.97	7218	2.11	-0.20
South Zone	17.65	-2.07	18.58	7245	2.59	-0.73
West Zone	17.46	-2.20	17.62	7676	2.16	0.08

CAISO average real-time LMP for Apr 15 ($/MWh)

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate	DA/RT spread	Avg Mo DA/RT
On-peak						
NP15 Gen Hub	30.19	-8.32	33.42	10632	5.63	-1.19
SP15 Gen Hub	14.08	-12.27	17.26	5843	17.95	8.88
ZP26 Gen Hub	15.46	-12.04	18.26	6413	15.16	6.22
Off-Peak						
NP15 Gen Hub	59.10	39.99	32.02	21147	-30.53	-5.07
SP15 Gen Hub	58.69	44.83	30.02	24854	-30.01	-3.34
ZP26 Gen Hub	57.62	43.53	29.50	24404	-29.60	-3.59

NEWS

California sees jump in flexible capacity need

California's need for flexible capacity to integrate renewables is growing, especially in non-summer months, according to a preliminary analysis by the California Independent System Operator.

The jump in need is nearly exclusively caused by 3-hour ramp and not an increase in peak load, the Cal-ISO said in a summary of its analysis.

Last year, the California Public Utilities Commission decided to start requiring load-serving entities to acquire flexible capacity as a first step in handling renewable generation in the state. The decision set local capacity procurement obligations as part of the PUC's resource adequacy program, which aims to ensure that the state has adequate electric supply to meet its needs.

The PUC defined "flexible capacity need" as the amount of resources needed by the ISO to manage grid reliability during the greatest three-hour continuous ramp in each month. The steepest ramp typically occurs at the end of the day when solar production falls off and other resources must fill in for solar to meet electric demand.

The Cal-ISO will use the flexible capacity needs assessment to allocate flexible capacity requirements for next year to load-serving entities under its flexible resource adequacy criteria must-offer obligation, or FRAC-MOO, which was conditionally approved last year by the Federal Energy Regulatory Commission.

The Cal-ISO estimates a need for 12,817 MW of flexible capacity in December next year, the month with the highest flexible requirements. The grid operator forecasts that the need will jump to 13,132 MW a year later, according to the preliminary analysis.

In the month with the lowest need, Cal-ISO expects the state will require 7,244 MW of flexible capacity in June 2016 and 7,478 a year later.

The Cal-ISO said the results for the non-summer months are higher than forecast last year, probably because the grid operator included 2,181 MW of behind-the-meter solar capacity in its analysis.

California requires three types of flexible capacity: base, peak and super-peak. The Cal-ISO estimates that the minimum amount of flexible capacity needed from the base flexibility category is 87% of the total amount of flexible capacity in the summer months, which run from May through September, and 54% of the total amount of flexible capacity for the rest of the year.

Mainly driven by new photovoltaic solar capacity, the Cal-ISO expects renewable generation in its footprint to grow from 12,110 MW this year to 13,867 MW next year, 15,198 MW in 2016 and 15,567 MW in 2018.

California's renewable portfolio standard climbs to 33% by 2020. The state also has policies supporting rooftop solar and is considering increasing its RPS to 50% by 2030.

The Cal-ISO is taking comments until April 22 on its draft assessment and intends to release a final analysis by May 1.

— Ethan Howland

Entergy Arkansas sees savings from solar PPA

An 81-MW power purchase agreement that Entergy Arkansas has entered into with the developer of a utility-scale solar project would reduce — not increase — the utility's power costs and retail rates, the Entergy Corp. subsidiary said Wednesday.

Matt Wolf, Entergy Arkansas's manager of resource planning, said in newly filed testimony to the Arkansas Public Service Commission that the utility has entered into a 20-year, fixed-price PPA with a subsidiary of NextEra Energy Resources, which plans to build the 81-MW solar photovoltaic project in east-central Arkansas's Arkansas County by the end of 2016.

The project was proposed by NextEra Energy's independent power subsidiary in response to Entergy Arkansas's May 2014 solicitation for up to 200 MW of renewable energy.

Because of falling solar panel prices and the federal investment tax credit for solar power, Wolf said, the projected net present value of the project's benefits are $25 million, but could be as high as $91 million if natural gas prices increase more than currently expected, or if generation sources that emit carbon dioxide are directed to pay a carbon tax.

Wolf noted that, "absent the current tax incentives that are available for solar projects, the projected savings under this PPA would not be available and the proposal would not show benefits."

Wolf and other Entergy Arkansas managers providing testimony on the PPA to the PSC discussed the fixed price the utility will pay NextEra Energy Resources for the project's power, but those comments were redacted.

Solar power prices from projects now under construction in areas with the best solar resources in the desert Southwest are frequently below $50/MWh; for example, a 150-MW solar PPA that Austin Energy entered into last year features a fixed power price of $47/MWh.

However, in areas like Arkansas with less ideal solar resources, solar power prices would be expected to be somewhat higher. For example, Georgia Power has said that the prices in several recent PPAs for utility-scale solar have averaged less than $65/MWh.

Wolf said that the solar project would cover about 500 acres, and that on a sunny summer day the facility will typically reach its maximum output at around 10 am and maintain that output until about 3 pm.

In addition to reducing the utility's overall power costs, the solar PPA will further diversify the utility's generation mix, Wolf said.

Solar PPA likely to displace fossil generation

"In 2014, Entergy Arkansas customers received about 71% of their energy requirements from nuclear generation," Wolf said, adding that fossil-fired units provided about 24% and hydroelectric facilities less than 1%. "This solar PPA would provide about 0.8% of [utility] customers' current total energy needs and would likely displace fossil-based generation."

Entergy Arkansas spokeswoman Sally Graham said on Wednesday that while the utility had been seeking "up to 200

MW" in last year's request for proposals for renewable power, that "did not commit Entergy Arkansas to acquire 200 MW or for that matter any megawatts." She said the utility "is evaluating other proposals from the RFP and expects to make a decision whether or not to pursue any of them in the next few weeks."

— Housley Carr

FERC backs plant seeking time on MATS

The Federal Energy Regulatory Commission Thursday issued only its second order finding that a power plant should have more time to comply with an environmental rule limiting emissions of mercury and air toxics.

FERC at its monthly meeting agreed that the Grand River Dam Authority's 490 MW coal-fired Unit 1 in Oklahoma is needed to maintain grid reliability beyond April 16, 2016, the deadline for most coal- and oil-fired plants to comply with the Environmental Protection Agency's Mercury and Air Toxics Standards (AD15-6).

Noting that Southwest Power Pool requires GRDA to maintain a 12% capacity reserve, FERC said that "based on our review of GRDA's submission, we find that the loss of GRDA's Unit No. 1 would result in GRDA falling below the 12 percent capacity reserve requirement . . . unless GRDA is able to procure replacement capacity for the unit and associated firm transmission service. Absent a significant change in future circumstances, our view is that GRDA's Unit No. 1 is needed as requested by GRDA to maintain electric reliability."

GRDA said it needed more time to comply with MATS, which requires reductions in emissions of mercury, acid gases and other toxic emissions, as a combined-cycle plant it is currently constructing will not be operational until April 16, 2017. GRDA said that it would not be able to meet its reserve requirement if its coal plant is retired before the gas plant comes online, according to the order, with SPP concurring with GRDA's assessment.

MATS requires plants to comply within three years, but provides states with broad authority to grant a fourth year of compliance, extending compliance to 2016. But under a policy issued with the final rule, the Obama administration provided an avenue for plants to obtain a fifth year for compliance if they could show that they are needed to ensure reliability.

FERC, NERC to be consulted

Under that process, EPA would consider requests for additional time and would consult with FERC, North American Electric Reliability Corp., state regulators and others to identify and address potential reliability issues.

FERC noted in Thursday's order that its comments on reliability matters "provide advice to the EPA on whether, based on the commission's review of the informational filing, there might be a violation of a commission-approved reliability standard, and may also identify issues within its jurisdiction other than a potential violation of a commission-approved reliability standard."

EPA retains the final say on whether plants receive more time. An EPA spokeswoman said Thursday that an order regarding the fifth year cannot be issued "prior to the relevant compliance date."

Despite expectations in the run-up to MATS' finalization that many plants would need the fifth year, FERC thus far has only issued two orders finding that particular plants are needed for reliability. In November, FERC said that Kansas City Board of Public Utilities' Nearman 1 unit would likely be necessary to ensure sufficient reserve margins past the 2016 deadline, supporting the utility's request for six additional months to complete installation of emissions control technologies (AD14-16).

— Bobby McMahon

DP&L has no plans for new generation

Dayton Power & Light is forecasting flat to modest load growth through 2025 and has no plans to add any capacity or retire any portion of its predominantly coal-fired generating fleet, according to the AES subsidiary's new long-term forecast.

In a filing Wednesday with the Ohio Public Utilities Commission, the utility also said it believes the two largest baseload coal plants it co-owns — 2,400-MW Stuart and 600-MW Killen — comply with the Environmental Protection Agency's new Mercury and Air Toxics Standards rule that took effect on Thursday.

But EPA's proposed Clean Power Plan, aimed at reducing carbon dioxide emissions, may prove more problematic for Ohio's smallest investor-owned electric utility.

If the CPP as proposed becomes law, DP&L's net income, cash flows and financial condition could be "adversely affected," the utility warned in the report.

For years, DP&L's more than 2,000 MW of relatively low-cost baseload coal generation was viewed as one of the company's strengths, but government pollution control edicts and lower natural gas prices have altered that equation.

Two years ago, AES, a global power generator based in Arlington, Virginia, planned to place DP&L's power plants on the selling block, though it eventually changed its mind.

As its latest forecast indicates, DP&L is experiencing the same load growth-suppressing impacts from energy efficiency as many other utilities in the Midwest. The company's 10-year growth rate is approximately 1.2% annually before energy efficiency reductions and about 0.2% afterwards, DP&L confirmed in a Thursday email.

DP&L's summer peak load demand, including the effects of energy efficiency, is expected to increase from 2,919 MW this year to 2,997 MW in 2020 and 3,109 MW in 2025. The corresponding winter peak load demand is projected to rise from 2,478 MW this year to 2,480 MW in 2020 and 2,539 MW in 2025.

Total energy consumption, meanwhile, is forecasted to only climb from 14.3 million MWh in 2015 to 14.4 million MWh in 2020 and just below 14.6 million MWh in 2025.

Under Ohio's alternative energy portfolio standard, utilities are required to get at least 25% of their power by 2025 from "green" energy sources such as wind and alternative sources such as clean coal and nuclear. Ohio also has a separate, smaller solar power requirement and annual benchmarks to meet.

DP&L said it intends to comply with the requirements during the near term by purchasing renewable energy credits, in conjunction with the 1.1-MW Yankee solar facility it built in Ohio in 2013.

In the mid-term, DP&L said its plan may include the combination of power purchase agreements and RECs, depending on the relative economics and the level of customer switching.

— Bob Matyi

Energy use expected to fall in 2015: NYISO

The forecast for New York's energy use for 2015 is lower than last year, with summer peakload expected to be slightly higher, the New York Independent System Operator said in its draft Gold Book.

NYISO will review the draft next week and release the 2015 Gold Book by the end of the month, Ken Klapp, a spokesman, said Thursday.

Energy use for the New York Capacity Area in 2015 is expected to be 160,121 GWh, 0.3% lower than what was forecast in 2014 for the weather-normalized energy use in 2015. The baseline forecast for 2015 summer peak is 33,567 MW, 0.8% higher than what was forecast in 2014 for the weather-normalized summer peak in 2015, the report said.

"By all accounts, the economic health of the state continues to be robust with growth and strength reported broadly across all sectors. However, we no longer observe a close linkage between the economy and energy use," NYISO said.

The lower forecast growth in energy use can largely be attributed to the effect of statewide energy efficiency programs and the growing effect of distributed behind-the-meter energy resources, the report said.

"The overall growth of distributed energy resources at the local distribution level is expected to be facilitated by New York State's Reforming Energy Vision initiative," the report said.

While wholesale electric load overall in the state has been nearly flat, there are regional differences, the report said. The mid-state region has shown strong growth and the downstate region has shown a persistent decline, the report said. The western region has been relatively flat.

Summer peak demand is expected to increase to 33,636 MW in 2016 and 33,779 MW in 2017, rising to 35,219 MW in 2025. Winter peak demand is expected to be 24,515 MW in 2015-16, rising to 25,020 MW in 2025-26, the report said.

Total resource capability in the New York Control area for summer 2015 is 41,617 MW, an increase of 320 MW from 2014. The total includes 38,673 MW of existing generation, 1,446 MW in long-term purchases with neighboring control areas, 374 MW of additions and uprates and 1,124 MW of special-case resources. Special-case resources include end-use loads capable of being interrupted on demand and local generators with a rating of 100 kW or more that are not visible on the NYISO information system.

33 MW of capacity mothballed

Since the 2014 edition of the Gold Book, 33 MW of summer capacity has been retired or mothballed, compared with 123 MW the previous year.

Generating capacity is trending toward returning to service in the southeast and other parts of the New York Control Area, the report said. Some generators have withdrawn their notices of intent to mothball and others are operating under reliability support services agreements, the report said. Others have or are expected to convert coal-fired units to burn natural gas.

"These actions reflect the increasing reliance of New York's generator fleet on natural gas. Currently there are 17,683 MW of dual-fueled capacity with the capability of burning natural gas or fuel oil," the report said.

Capacity resources include 17,683 MW of combined gas- and oil-fired generation, 5,400 MW of nuclear, 4,291 MW of hydropower, 3,781 MW of natural gas, 2,660 MW of oil, 1,469 MW of coal, 1,461 MW of wind, 1,407 MW of pumped storage and 521 MW of other generation.

Winter 2015-16 installed generating capacity is expected to be 41,021 MW, 799 MW more than winter 2014-15 due to retirements, additions and rating changes. The largest change is in gas generation, with 567 MW of additions, 33 MW of retirements and 50 MW that were reclassified, the report said.

In 2014, 143,738 GWh were generated in New York, an increase of 2.4% above 2013's 140,338 GWh.

Renewable generation was 35,756 GWh in 2014, or 25% of the total New York Control are generation, compared with 23% the year before.

— Mary Powers

FERC denies effort to avoid solar purchases

The Federal Energy Regulatory Commission Thursday rejected a utility's bid to terminate its obligation to purchase power from nine solar facilities in North Carolina, finding that the utility was grandfathered into its obligation to buy that power.

The order found that Virginia Electric and Power was obligated to purchase 44.91 MW of power from Community Energy's facilities as required by the Public Utility Regulatory Policies Act, under which utilities must buy power from renewable energy providers and other small generators known as qualifying facilities under certain rates (QM15-1).

While the Energy Policy Act of 2005 said that utilities could be relieved of that obligation if the generators have access to competitive wholesale markets, FERC in Order 688 created a rebuttable presumption that QFs of 20 MW or less "do not have nondiscriminatory access to markets," saying that utilities must show that such generators do have such access in order for the utility to be relieved of its obligation to buy that power.

VEPCO in its application sought to terminate its obligation, claiming that affiliates of the QFs are "sophisticated market participants" in PJM Interconnection and that each QF has nondiscriminatory access to PJM markets.

But FERC in the order noted that QFs can create an obligation for a utility to buy their power by committing to sell their power to the utility, even if the utility refuses to sign a contract. FERC also noted that a utility's efforts to terminate its PURPA obligations can only apply to new contracts or obligations, rather than those that already exist.

In this case, FERC agreed "that the Community Energy QFs have established legally enforceable obligations requiring VEPCO to purchase the output of the Community Energy QFs and that these obligations are grandfathered" under FERC rules implementing PURPA.

"Based on the record before us, Community Energy availed itself of the right to establish contracts under a state tariff to sell the output of its QFs to VEPCO prior to VEPCO's October 31, 2014, application at the Commission to terminate its purchase obligation from the Community Energy QFs," FERC said.

— Bobby McMahon

FERC keeps 9 am gas day in power rule *...from page 1*

period. Some gas-fired generators said that a 4 am start time would better match gas shipments with peak power demand.

Gas groups urged FERC to maintain the 9 am start time, arguing that infrastructure improvements were the real solution to electric generators' challenges. Gas producers also had concerns about the 4 am start time because it could require workers to make physical changes to the pipeline and production system in the middle of the night.

The proposal was one of the main policy outcomes of the commission's efforts, launched in 2012, to improve coordination between the gas and electric industries as power plants increasingly rely on gas for fuel.

FERC on Thursday decided to keep the current gas day start time. "There has not been a showing that the benefits of changing the nationwide gas day from 9 am to 4 am sufficiently outweigh the potential adverse operational safety impacts and costs of making such a change," said Caroline Wozniak of FERC's Office of Energy Policy and Innovation.

The rule does make other changes to the gas schedule, including moving the nationwide timely nomination cycle for scheduling gas transportation from 11:30 am to 1 pm, and adding an additional intraday scheduling opportunity during the gas day, Wozniak said at the commission's monthly meeting. The regulation also provides flexibility by allowing firm gas shippers to use multiparty transportation contracts, she said.

The rule makes these changes by incorporating by reference a set of standards floated by the North American Energy Standards Board to revise the rule FERC proposed last year. FERC had originally proposed to increase intraday scheduling from two to four cycles, but the rule adopted NAESB's recommendation for three cycles with nomination deadlines at 10 am, 2:30 pm, and 7 pm.

New standards begin April 2016

Interstate natural gas pipelines will begin operating under the new business practice standards on April, 1 2016. The Independent System Operators and Regional Transmission Organizations will have ninety days after publication of the final rule in the Federal Register to propose tariff revisions to coordinate its day-ahead market with the new rule or to show cause why its existing scheduling practices need not be changed.

At his first meeting as FERC Chairman, Norman Bay backed the rule, but urged the gas and electric industries to keep working on aligning the sectors and addressing regional issues. "It is my hope that the gas and electric industries will continue to work together to explore mechanisms that will enhance overall system reliability for both industries," Bay said.

Speaking to reporters after the meeting, Bay said FERC, based on the record, decided not to change the gas day, which would have enacted a national policy change even as entities in some parts of the country did not support the change. FERC had to determine if the costs of putting in place this national change were outweighed by the benefit that could be achieved, he said.

"Ultimately the record wasn't there, and the commission based on that analysis decided not to change the day," he said.

Bay also highlighted the work FERC has already done on the matter, including Order 787 on communication between the gas and electric sectors, which Bay said is particularly helpful during times of system stress. He also noted other steps FERC is taking in the rule issued Thursday as well as the directive to RTOs to better coordinate their day-ahead markets with the changes adopted in the rule.

In aggregate, progress has been made

"You have to look at the suite of the steps that have been taken. In the aggregate, some good progress has been made," Bay said, going on to say that more progress will be helpful given the importance of gas to the power sector.

In terms of next steps, Bay also noted that the rule directs NAESB to consider whether computerized scheduling of gas could help reduce pipeline processing times and allow for more intraday scheduling opportunities. Apart from that, Bay said "I would certainly encourage the gas and electric industries to continue to have discussions and to see whether or not there might be market-based proposals or services that would help improve or enhance fuel assurance."

Commissioner Philip Moeller noted that the gas sector really united to oppose moving the gas day. "In one sense, we should be congratulated as an agency for unifying the gas industry. I saw the smiles of relief from some of them out there," Moeller said at the commission meeting.

In her first meeting since handing the gavel to Bay, Commissioner Cheryl LaFleur said the regulation showed that rule making is a collaborative process with stakeholders. "I am happy to support the rule because I think it strikes a good balance between offering more flexibility to shippers and supporting conforming changes in the electric markets and offering a new nomination cycle, but leaves other things alone that we decided not to change."

Regional gas-electric work underway

FERC realizes that a lot of gas-electric work has to happen at the regional level, LaFluer said, noting that both ISO New England and PJM Interconnection are working on market reforms to promote fuel assurance. "There are also regional efforts underway in New England … working to assess and address regional needs for more natural gas infrastructure, and I am closely following those efforts as they go forward."

Commissioner Tony Clark said he was glad the commission changed its mind on the gas day because moving the start of the gas day would have just shifted regional issues. "Some of the problems that we saw in the East, that hopefully are being corrected in market tariff reforms that are being done on the electric side, were just shifted in some ways further West," he said.

Gas producers in very colds parts of the country were worried that moving up the gas day would require them to send workers out more frequently in cold conditions, in the middle of the night on roads that had not been cleared, Clark explained. "So you are even buying an additional set of problems that you may not have today," he said.

Commissioner Colette Honorable also said she was happy that the rule left regional issues to be resolved at regional levels. "We were willing to be open to what works best throughout the country and so I am very pleased about that."

Gas groups praise ruling

The gas industry praised rule, with Interstate Natural Gas Association of America president Don Santa saying the group was "gratified" that FERC retained the 9 am start of the gas day.

Dena Wiggins, the president of NGSA, also backed FERC's decision. "On the gas day, we're very happy that the commission stuck with 9 am. I think that the commissioners were right that there wasn't sufficient record support to move," Wiggins said. "So that was a victory for us, we're very happy with the outcome," she said in an interview after the meeting.

Dave McCurdy, the president of the American Gas Association, said the later timely nomination deadline and the addition of a third intraday nomination cycle were welcome changes. But FERC was right to maintain the 9 am start of the gas day, he said.

"We appreciate FERC's attention to the coordination between gas and electric systems, and believe this is a critical issue that needs attention, but changing the gas day was not a step that would have ultimately improved this coordination," McCurdy said in a statement.

— Bobby McMahon, Maya Weber

Efficiency cut N.E. prices by 24%*...from page 1*

Wholesale electric prices soared in New England in the year-ago winter on bitterly cold weather and natural gas pipeline constraints. New England's power plant fleet has become increasingly reliant on natural gas.

In preparation for the winter that just ended, ISO New England made changes to its winter reliability program by providing incentives for power plants that use several types of fuel, paying generators for unused fuel and paying for demand-response resources.

Despite colder temperatures in the most recent winter than the year before, the average cost of wholesale electric energy in New England from December through February was \$76.64/MWh, down from \$137.60/MWh a year ago, ISO New England said.

Various factors, including energy efficiency, led to the lower wholesale prices, the ISO said last week. Energy efficiency measures reduced peak demand by an additional 265 MW compared with a year ago, the grid operator said.

Partly reflecting the region's high wholesale power prices, New England states generally have aggressive energy efficiency programs, with Massachusetts and Rhode Island efficiency budgets at levels that aim to capture all cost-effective savings over 10 years, Howland said.

Led by Massachusetts, New England's efficiency investments climbed to \$900 million last year, up from \$475 million in 2010. ISO New England expects energy efficiency programs will keep load growth essentially flat over the coming years.

Massachusetts saved about 1.3 million MWh last year, reducing electric use by 2.7%, according to preliminary analysis of statewide data. The state reduced sales by about 1.1 million MWh in 2013.

Since 2002, electric efficiency programs have reduced electricity demand in New England by almost 2.2 GW, according to the Acadia Center.

— Ethan Howland

The battle between utilities and IPPs*...from page 1*

generation at El Paso Energy. He was a partner and managing director at Goldman Sachs, where he built an on-balance-sheet power generation business within Goldman's commodities division. He then headed up Cogentrix Energy, which Goldman purchased in 2004, thus adding 26 co-generation facilities and 3,300 MW of capacity to Goldman's power portfolio.

In September 2010 Kellerman founded and became CEO of private equity fund Quantum Utility Generation. Kellerman's latest venture, Twenty-First Century Utilities, was established in January and is focused on "owning and optimizing" regulated electric and integrated utilities in North America.

Kellerman noted at the outset of the question-and-answer session that over the past three decades, independent power producers, or IPPs, have had a hand in negotiating long-term contracts for renewable and alternative generation under the Public Utility Regulatory Policies Act, or PURPA, which was enacted in late 1978, as well as "other types of set-aside contracts." The IPPs have also contracted conventional generation under competitive market constructs, and, as merchant generators, they have been active in many regions of the country operating under "competitive market constructs."

"The characteristics that enabled IPPs to gain market share, create value and flourish in these three market segments were operational and financial efficiency, engineering optimization and commercial innovation," Kellerman said.

However, over time, and particularly as utility revenue models have become more constrained over the past decade, Kellerman said, utilities have learned from the innovations and have "utilized their leverage" to attempt to "rejuvenate their own commercial models."

"That has meant that utilities are taking back ground lost to the IPP industry and using their competitive strengths as well as their regulatory moats to promote rate-based self-build options," Kellerman said.

"Utilities, in a slow- to no-load-growth environment, are hungry for new capital investments to deploy in their rate base," he said. "And as a result of this emerging hunger for new rate base, the place that utilities are increasingly focusing on is new build generation, as well as the acquisition of existing orphaned, or non-contracted generation to place into rate base. We are additionally seeing acquisitions of existing power contracts and the underlying IPP generation assets behind those PPAs in order to convert PPAs that do not create value for utility shareholders."

Said Kellerman, "Utilities, the once supposedly sleeping giants in the generation space, have woken up and they are hungry."

The IPPs

It used to be, Kellerman continued, "that IPPs brought something new and different and better to the power industry. They took real risks with their own money, created or deployed engineering and technical innovations, were more efficient and were able to produce at lower total costs than the incumbents."

He named a handful of individuals, such as Bob McNair, Roger Sant, Jacek Makowski, and George Lewis, who, he said, had been key IPP leaders in the early days. He credited this group with building and operating plants "better and cheaper and more reliably and cleaner than anyone else."

"I don't know that the industry's track record in this type of leadership is nearly as strong over the better part of the past decade," he said.

Do state public utility commissions want to see the most competitive, lowest cost of power supply 'win,' and how are the regulators factoring into this new equilibrium?

"Regulators absolutely want to assure, to the maximum extent practical, that the lower lifecycle cost of new power supplies are being built, or acquired, on behalf of the customers, the ratepayers," he said.

What he said has been seen in a number of jurisdictions where there have been requests for proposals, or RFPs, is that "somehow, someway the incumbent utility always seems to win with a new build option when competing against not only IPP greenfield options, but existing plants that should be much more cost effective because they have already been built and have a lower cost basis." He noted that in a few, "relatively rare cases, we've seen IPPs able to successfully challenge the outcomes of these RFPs, but in most cases the utilities have won fair and square."

Kellerman argued that utilities have "natural advantages" over IPPs, "advantages they have always had but are increasingly taking advantage of." He said these advantages include a lower cost of capital, in-house technical and engineering expertise, existing expansion-ready sites and significant negotiating leverage with original equipment manufacturers and vendors.

"Frankly, utilities as a whole are viewed as [more] trusted owners and operators of generators than the IPP sector, given the fact that they are regulated, and [IPPs] are not," Kellerman said.

Utilities are winning their own RFPs "with full transparency, not because they are tipping the scales, but because they actually are providing a better and cheaper product."

In the competitive markets

In the competitive markets such as the PJM Interconnection, the New York Independent System Operator, ISO New England and the Electric Reliability Council of Texas, how are the regulated utilities engaged in ownership and operation of power generation?

In ERCOT, in one of the more deregulated states, Kellerman noted that unlike the broken up utilities in Dallas and Houston, municipal utilities in Austin and San Antonio have been acquiring renewable generation.

But, he said, "It is important for the IPP industry to seriously consider the situation in Virginia, because I can guarantee that the surrounding states are looking at Virginia and thinking about what is different in that state than the remainder of the PJM seaboard."

Kellerman points to Energy Information Administration data that says average retail electricity rates in Virginia last year "were 9.25 cents/kWh, while neighboring Maryland clocked in at 12.12 cents, Delaware was 11.33, New Jersey was over 14 cents and even Pennsylvania was 10.3."

While Virginia is part of the PJM footprint, generation in the state is "predominately owned and operated by the incumbent utilities, mainly Dominion, but also including the state's cooperative utilities. And this generation is rate-based and sold as a packaged product to consumers at regulated, cost-of-service based rates," Kellerman said.

When Dominion sees a need for new power supplies in its service territory, "it doesn't rely on the invisible hand of the market to motivate new supplies to show up, it doesn't hire consultants to divine where RPM capacity prices will be," Kellerman said. "The utility works with its regulators and either decides upon a generation expansion program or issues an RFP—which it typically wins— to build, own and operate the generation under a regulated ratemaking paradigm."

Kellerman argued that "lackluster forward capacity markets, low energy prices and uncertain environmental regulations are not the greatest competitive threats facing the merchant model embraced by the IPP sector in the mid-Atlantic to Northeast. "

No lower costs for ratepayers

He said that despite proclamations to the contrary, "Virginia's success story means that regulators and political leaders believe that the competitive merchant model has failed to provide ratepayers with lower costs. And what matters most in shaping the policies that this industry must live with and adapt to is what the regulators and political leaders believe. "

"While they have thus far failed in the courts, New Jersey's and Maryland's drive to craft programs designed to require contracted new generation as a stabilizing factor against high regional capacity and energy prices underscore these states' thinking that perhaps the utility-owned or utility-contracted generation can be a rational ballast against the consumer price volatility that every regulator wishes to avoid."

But why do utilities even want to build and own generation?

The simple answer, Kellerman said, is that the "the core regulatory math that exists for utility ratemaking has been fundamentally unchanged over the past 110 years."

The approach used throughout the country in all 51 regulatory jurisdictions as well as the Federal Energy Regulatory Commission, he said, "is that utilities are allowed to recover operating expenses such as people costs, fuel, purchased power and other costs without a markup, and that capital investments are able to earn an authorized, regulated rate of return. You get to recover your ongoing operating costs but you make all of your profits on the capital that you invest. If someone else invests capital and you pay them for a product, you don't lose money when you buy their product, you get to recover your costs, but you don't make money, you don't earn a profit margin on what you buy."

Should this model be changed to help encourage utilities be friendlier to low-cost IPP contract options, to level the playing field?

"Absolutely," Kellerman said. "In fact, there are some examples of states that recognize the value associated with utilities contracting for power supplies rather than owning everything, and provide certain profit incentives for utilities to engage in such contracting, including Georgia and, to a more limited extent, California."

Artificially created markets

Should utilities be viewed as competitors to the IPP industry?

The IPP industry began in the very early 1980's viewing itself as a value-added supplier to the utility industry, Kellerman said.

The IPPs that fared best for the first couple of decades "were those that best positioned themselves to provide the best and most reliable supplies of efficient power to utilities at prices that were at worst equal to and at best better than the prices at which utilities could supply power. "

"The whole PURPA construct of 'avoided cost' was premised on the notion that the only way you got to receive a power contract in the IPP space is if you could build, finance, own and operate an efficient plant at a total cost at worst equal to and hopefully cheaper than the cost that a utility would have incurred," Kellerman explained.

"That ethic still has a place in the IPP industry, though it has been largely diluted," Kellerman said. "If you are a merchant power producer in a competitive market, who is your customer? The 'market' is not a customer, it is an artificially constructed mechanism to clear products based on specified rules. "

There are very few industries that are able to sustain growth, profitability and corporate direction in an environment "where they don't have a clear understanding of, or connection to their customers," Kellerman said. "And those few industries who are disconnected from their customers in this fashion are commodity suppliers of undifferentiated commodity products who are able to compete solely on the basis of price and cost."

"I don't believe that the leaders of the IPP industry aspire to be commodity suppliers competing solely on the basis of price and cost," Kellerman said.

Options for IPPs

So how can the IPPs reconnect?

"The IPP industry was born out of innovation, technical and commercial creativity and accepting risks that utilities did not want to accept and frankly aren't paid for accepting," Kellerman said. "It is, though, a business model that is premised on encouraging greater regional power volatility, shortage-based pricing and driving the average cost of power to the marginal cost of the highest cost new generation ... on the grid, which is not consistent with the public interest."

He argued that a business model that is "focused on delivering a better, more reliable, cleaner product at a better price point than one's competitors, while being more intellectually and commercially difficult to implement, is a more robust and vastly more sustainable business proposition. Not all utilities will want to work with you, but many, I would say most, will be willing to commercially interact if you actually offer them a better mousetrap."

Kellerman said that by adding some additional options into a utility-facing power supply proposal, "such as enabling the utility to buy in as a rate-based co-owner after the project has been in commercial operation for a couple of years, or enabling the utility to have a fixed-price asset acquisition option at or near the end of the base PPA term, one can potentially provide an interesting, if not compelling value proposition both to utility consumers and to their shareholders."

"I am firmly convinced that the McNairs and Makowskis, the Sants and Lewises, would be doing those sorts of things if transported into this market environment," Kellerman said.

The EPA and retirements

On Thursday, the US Environmental Protection Agency's Mercury and Air Toxic Standards rule went into effect. Soon the EPA's Clean Power Plan will be implemented. There is much discussion throughout the power industry about coal-plant retirements. How do you view what the impact of these EPA programs will ultimately be? How intrusive or domineering is the government becoming?

"With or without MATS, CPP and related EPA environmental initiatives, there is no doubt in my mind that there will be significant coal plant retirements driven much more by the fundamental economics of coal generation than by the fear or reality of required compliance [capital expenditures]," Kellerman said.

"Looking at today's NYMEX forward gas settlements as far as the eye can see, out over 12 years, pricing never gets beyond a $4-handle, yet the delivered cost of Central Appalachian Basin compliance coal in today's market is coal is over $4/MMBTU to most eastern markets," Kellerman said. "The heat-rate adjusted fuel costs, the variable [operations and maintenance] costs, the fixed O&M costs, the annual capex budgets, are all much higher for eastern coal-fired plants than for their gas-fired equivalents, even without taking into consideration the new MATS and CPP burdens."

"When considering the materially more robust operational flexibility afforded by gas-fired units in a market that is increasingly valuing ramping and quick start/stop capabilities, the future of coal generation in, at a minimum, the eastern half of this country is highly challenged, not because of government intrusion but because of the changing needs of the power system and the fuel-on-fuel/technology-on-technology disadvantageous position that the coal generation sector finds itself in."

— Jeffrey Ryser

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