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Short list of possible coal plants shrinks

ANALYSIS The short list of new coal-fired power projects has gotten shorter.

The Environmental Protection Agency designated 15 proposed coal projects as "transitional" in April 2012 when it issued its New Source Performance Standards for limiting greenhouse gases from new power plants.

An analysis of those projects shows that only three projects on the list have any hope of moving forward. And, depending on who is counting, that list could be even shorter.

When the EPA issued its proposed NSPS rules in April 2012, the potential transitional projects were granted an exemption; those projects would be treated as existing sources and would not be subject to the new, more restrictive standards. But the EPA failed to finalize the 2012 rules, and they were superseded on September 20

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MISO, PJM and monitors work on interface pricing

MARKETS The Midcontinent Independent System Operator, the PJM Interconnection and their respective independent market monitors all agree that the pricing of certain interface transactions is problematic, but they have not yet formed a consensus on how to fix the issue, according to presentations at Friday's Joint and Common Market Initiative meeting.

Potomac Economics, MISO's independent market monitor, has raised concerns that the grid operators' pricing rules are resulting in double payment and double charges for certain interface transactions. In a presentation at Friday's meeting, Potomac Economics said the problem arises when a transaction involving both ISOs helps resolve or exacerbates congestion on a constraint that is binding in both markets and is being managed through

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Cal-ISO/PUC plan covers several initiatives

MARKETS The California Public Utilities Commission and the California Independent System Operator have developed a plan to jointly tackle three related initiatives that could change key elements of California's electric power market.

"The CPUC and ISO will use the Joint Reliability Plan to give their efforts direction, focus, and precision to ensure that proposed changes to procurement requirements and processes satisfy their shared guiding principles," according to the plan, which was released Friday by PUC staff ahead of a Thursday vote by the commission.

The plan includes key principles that will guide the PUC and ISO in developing multi-year resource adequacy requirements, a unified long-term reliability planning assessment, and a market-based mechanism to replace the ISO's capacity procurement

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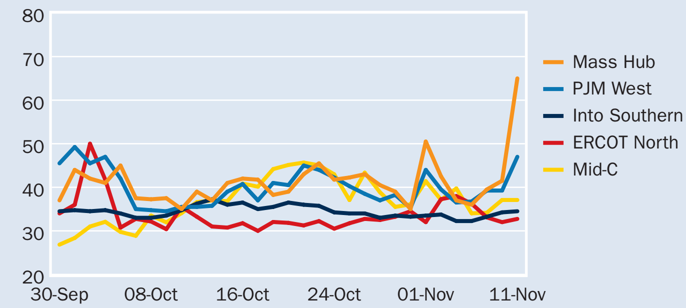
Price trends at key trading points ($/MWh)



Source: Platts

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

	On-peak low	On-peak high	Off-peak low	Off-peak high
ISONE	54.92	62.67	45.50	48.08
NYISO	24.54	68.46	17.38	36.49
PJM	38.22	54.69	25.36	32.69
MISO	36.64	40.50	24.33	28.68
ERCOT	28.79	30.57	21.01	21.93
CAISO	44.73	46.62	37.22	38.45

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 Nov 12

	Index	Marginal heat rate	Spark spreads @7k	@8k	@10k	@12k	@15k
Northeast							
Mass Hub	65.00	7985	8.02	-0.12	-16.40	-32.68	-57.10
N.Y. Zone-A	66.00	19103	41.82	38.36	31.45	24.54	14.18
PJM/MISO							
PJM West	47.00	13636	22.87	19.43	12.53	5.64	-4.70
Indiana Hub	38.00	10383	12.38	8.72	1.40	-5.92	-16.90
Southeast & Central							
Southern, Into	34.50	9524	9.14	5.52	-1.73	-8.97	-19.84
ERCOT, North	32.75	9384	8.32	4.83	-2.15	-9.13	-19.60
West							
Mid-C	37.09	10045	11.24	7.55	0.17	-7.22	-18.30
SP15	43.75	11729	17.64	13.91	6.45	-1.01	-12.20

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

Inside this Issue

NORTHEAST MARKETS

Northeast dailies up with cold weather

Northeast dailies rose sharply Monday with forecasts of colder weather, rising loads and strong spot gas.Terms in the region wre mostly higher. NYMEX December natural gas futures settled 1.5 cents higher at $3.574/MMBtu Monday as forecasts for mild temperatures across most of the US prevented the market from gaining too much on the colder-than-average temperatures in the Northeast.

Mass Hub on-peak day-ahead futures climbed $23 to the mid-$60s for Tuesday delivery on the IntercontinentalExchange. Algonquin city-gate spot natural gas jumped $3.90 to about $7.82/MMBtu on ICE. Mass Hub balance-of-the-week on-peak futures were at a discount to dailies with bids at $54 and offers at $64/MWh on ICE. Mass Hub next-week on-peak futures were bid at $38 and offered at $67/MWh on ICE.

ISO New England forecast peak load for Monday at 16,970 MW, for Tuesday at 17,850 MW and for Wednesday at 18,030 MW.

Low temperatures for Boston are expected drop below freezing Tuesday, with the mercury dropping further on Wednesday.

In New York spot prices were boosted by cold, but the market was exceptionally strong in the West of the state. New York Zone A day-ahead on-peak futures climbed $22.50 to the mid- $60s/MWh for Tuesday delivery on ICE.

Zone A balance-of-the-week on-peak futures were nearly inline with dailies, but wide with bids at $52 and offers at $74/MWh on ICE. Zone A next-week on-peak futures were bid at $46 and offered at $47.50/MWh on ICE.

Movement was more moderate in the Hudson Valley. New York Zone G day-ahead on-peak futures rose $9.50 to the low-$50s/MWh on ICE. Zone G balance-of-the-week on-peak futures were nearly inline with dailies, with bids at $50 and offers at $58/MWh on ICE. Zone A next-week on-peak futures were bid at $41 and offered at $53/MWh on ICE.

New York ISO forecast peak load for Monday at 20,378 MW, for Tuesday at 20,823 MW and for Wednesday at 20,945 MW. Temperatures in New York are forecast to fall with lows reaching below freezing in much of the state by Tuesday. Transco Zone 6 New York spot gas rose 47.2 cents to about $3.827/MMBtu on ICE.

Day-ahead auction prices in the ISO New England climbed Monday with temperatures forecast to drop. Internal Hub on-peak moved up $22.59 to $61.10/MWh for Tuesday delivery. Connecticut on-peak jumped $23.34 to $62.67/MWh and West-Central Mass on-peak increased $22.58 to $61.43/MWh. Maine on-peak rose $16.86 to $54.92/MWh.

Day-ahead auction prices in the New York ISO climbed Monday with colder weather moving into the region. New York City on-peak rose $4.87 to $51.86/MWh for Tuesday delivery. Hudson Valley on-peak climbed $5.41 to $52.28/MWh and Long Island on-peak increased $6.34 to $55.39/MWh.

West Zone on-peak rose $3.18 to $68.46/MWh, keeping the premium over zones in the east of the state.

Northeast term power prices were mostly stronger Monday,

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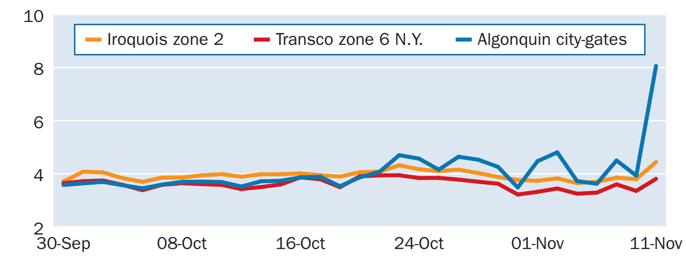
Northeast day-ahead bilateral indexes for Nov 12 ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
Mass Hub	65.00	23.50	43.38	7985
N.Y. Zone-G	54.00	10.50	42.72	13091
N.Y. Zone-J	56.50	11.00	44.94	13697
N.Y. Zone-A	66.00	23.50	42.28	19103
Ontario*	38.50	3.00	32.88	9700
Off-Peak				
Mass Hub	41.50	12.50	31.19	5098
N.Y. Zone-G	38.50	5.00	29.22	9333
N.Y. Zone-J	41.00	6.25	29.78	9939
N.Y. Zone-A	39.50	12.00	26.06	11433
Ontario*	26.50	2.00	22.75	6676

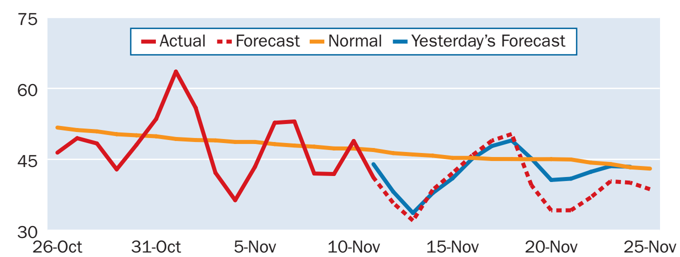
*Ontario prices are in Canadian dollars

Northeast spot natural gas prices ($/MMBtu)



Source: Platts

ISONE & NYISO average temperature (°F)



Source: Custom Weather

Northeast load and generation mix forecast (GWh)

	Actual 10-Nov	%Chg	% Chg Year-ago	Forecast 11-Nov	12-Nov	13-Nov	14-Nov	15-Nov
ISONE								
Load	311	-3	2	325	338	363	359	341
Generation								
Coal	8	-44	81	14	19	23	18	15
Gas	130	4	-13	130	128	129	129	127
Nuclear	107	0	3	107	111	111	111	111
NYISO								
Load	385	-3	0	376	402	437	433	421
Generation								
Coal	9	-26	55	9	14	19	17	14
Gas	94	11	-10	89	98	110	112	107
Nuclear	134	0	9	134	135	135	135	135

Source: Bentek

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Internal Hub	61.10	0.45	-0.13	22.59	38.93	8028
Connecticut	62.67	1.09	0.80	23.34	39.28	10412
NE Mass-Boston	60.95	0.79	-0.62	22.78	38.96	8162
SE Mass	61.49	0.81	-0.10	23.49	39.41	8079
West-Central Mass	61.43	0.34	0.31	22.58	39.16	8071
Rhode Island	61.09	0.58	-0.27	22.90	38.88	8027
Maine	54.92	-4.65	-1.22	16.87	37.88	9728
New Hampshire	57.86	-3.16	0.24	19.13	38.77	10250
Vermont	59.95	-0.96	0.13	21.42	38.70	14527
Off-Peak						
Internal Hub	47.49	0.00	0.06	14.66	29.69	10698
Connecticut	48.08	0.00	0.65	14.95	29.82	11570
NE Mass-Boston	47.18	0.00	-0.25	14.59	29.61	10677
SE Mass	47.39	0.00	-0.03	14.80	29.73	10677
West-Central Mass	47.91	0.00	0.48	14.80	29.89	10793
Rhode Island	47.39	0.00	-0.04	14.48	29.85	10675
Maine	45.50	0.00	-1.92	14.05	28.68	11305
New Hampshire	47.28	0.00	-0.15	14.75	29.49	11745
Vermont	47.11	0.00	-0.31	14.63	29.40	12372

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Capital Zone	50.25	-1.85	3.48	5.84	39.62	12827
Central Zone	48.01	-2.45	0.63	3.74	36.55	13940
Dunwoodie Zone	51.55	-1.46	5.17	4.91	40.78	12709
Genesee Zone	44.30	-0.18	-0.80	2.13	35.11	12864
Hudson Valley Zone	52.28	-1.44	5.91	5.41	41.04	12887
Long Island Zone	55.39	-4.05	6.42	6.34	46.54	13653
Millwood Zone	51.64	-1.47	5.25	5.00	40.78	12729
Mohawk Valley Zone	46.90	-0.21	1.77	3.73	36.90	12691
N.Y.C. Zone	51.86	-1.46	5.48	4.86	41.58	12785
North Zone	24.54	17.63	-2.75	0.18	30.41	5947
West Zone	68.46	-24.76	-1.22	3.18	39.97	19879
Off-Peak						
Capital Zone	36.49	-13.12	1.80	5.43	28.31	10052
Central Zone	23.71	-1.76	0.38	1.72	22.38	7043
Dunwoodie Zone	33.84	-10.12	2.15	4.20	27.61	9282
Genesee Zone	22.90	-1.35	-0.02	1.66	21.74	6803
Hudson Valley Zone	34.06	-10.02	2.47	4.37	27.75	9342
Long Island Zone	34.91	-10.70	2.64	4.48	28.84	9574
Millwood Zone	33.91	-10.17	2.16	4.25	27.62	9299
Mohawk Valley Zone	23.76	-1.57	0.63	1.46	22.72	6780
N.Y.C. Zone	34.06	-10.13	2.36	4.18	27.78	9342
North Zone	17.38	2.95	-1.24	-0.16	20.03	4564
West Zone	24.90	-3.26	0.07	2.86	22.12	7398

Northeast near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mass Hub		
Bal-week	11/05	38.00-39.00
N.Y. Zone-A		
Next-week	11/11	45.00-47.00

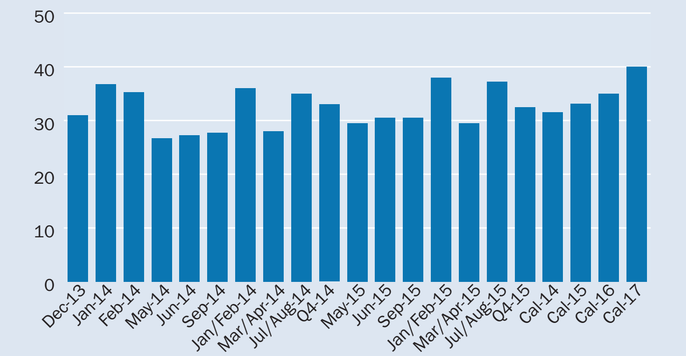
*Ontario prices are in Canadian dollars.

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

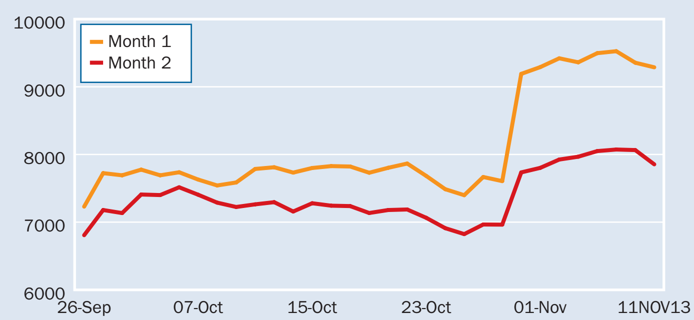
Prompt month: Dec 13	On-peak	Off-peak
Mass Hub	77.75	63.00
N.Y. Zone G	58.50	45.75
N.Y. Zone J	60.50	46.00
N.Y. Zone A	46.00	33.00
Ontario*	31.00	21.00

*Ontario prices are in Canadian dollars

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Atikokan/OPG	200	c	Ont.	PMO	Unk	10/16/13
Darlington-2/OPG	868	n	Ont.	PMO	Unk	08/27/13
Fort Frances/Fort Frances	99	w	Ont.	MO	Unk	09/20/13
Goreway-11/Goreway	195	g	Ont.	MO	Unk	11/01/13
Goreway-12/Goreway	195	g	Ont.	MO	Unk	01/01/13
Goreway-13/Goreway	195	g	Ont.	MO	Unk	11/01/13
Goreway-15/Goreway	357	g	Ont.	MO	Unk	11/01/13
Greenfield-1/Calpine	212	g	Ont.	PMO	11/18/13	10/04/13
Lambton-3/OPG	326	c	Ont.	MO	Unk	09/06/13
Lambton-4/OPG	320	c	Ont.	MO	Unk	09/27/13
Lennox-3/OPG	525	bio	Ont.	MO	Unk	09/05/13
Littleong-2/OPG	70	h	Ont.	MO	Unk	11/06/13
Nanticoke-7/Brookfield	90	c	Ont.	MO	Unk	10/25/13
Nanticoke-8/Brookfield	90	c	Ont	MO	Unk	10/31/13
Pickering-6/OPG	510	n	Ont.	MO	Unk	09/03/13
Portlands-1/Portlands	197	g	Ont.	MO	Unk	11/11/13
Portlands-2/Portlands	197	g	Ont.	MO	Unk	11/11/13
Portlands-3/Portlands	245	g	Ont.	MO	Unk	11/11/13
Taohsc/TransAlta	78	g	“Ont,”	MO	Unk	10/31/13
Thorold/Northland	265	g	Ont.	MO	Unk	11/11/13
Thunderbay-2/OPG	150	c	Ont.	PMO	Unk	03/01/13
Thunderbay-3/OPG	153	c	Ont.	MO	Unk	10/11/13

SOUTHEAST MARKETS

ERCOT dailies jump with weather, load

Electric Reliability Council of Texas dailies for Tuesday delivery were stronger on IntercontinentalExchange Monday morning with peak load and temperatures forecast to drop. South Central on-peak terms were mixed at the front of the curve Monday, while Southeast on-peak December moved down Monday. NYMEX December natural gas futures settled 1.5 cents higher at $3.574/MMBtu Monday as forecasts for mild temperatures across most of the US prevented the market from gaining too much on the colder-than-average temperatures in the Northeast.

Spot natural gas at Houston Ship Channel rose 10.5 cents to trade around $3.575/MMBtu.

ERCOT North Hub next-day on-peak physical power rose about 50 cents to trade around $32.50/MWh. Off-peak added more than 25 cents to trade around $22.50/MWh.

High temperatures across ERCOT's footprint were forecast in the low to upper 50s to low 70s Tuesday, with lows expected in the upper 30s to mid-40s. The average November high temperature across the ERCOT region is in the upper 60s to low 70s, with the average low in the upper 40s to mid-50s.

System load in ERCOT was forecast to peak at 35,325 MW Monday and 37,525 MW Tuesday, compared with an actual peak of 33,666 MW Sunday. Real-time prices averaged $22/MWh and were flat from 12:15 to 6 am CST Monday.

Wind generation was forecast to peak at 3,975 MW at 2 am CST Monday and 6,075 MW at 10 am CST Tuesday.

North Hub balance-of-the-week was bid at $38.25 and offered at $39/MWh, Next-week on-peak was bid at $32.50 and offered at $33.50/MWh.

In the Southeast, dailies for Tuesday delivery were weaker Monday morning with temperatures forecast to decrease. Into Southern next-day on-peak power lost about $1.25 to trade around $33/MWh on ICE. Off-peak gained about $2.50 to trade around $28MWh. Spot natural gas at Transco Zone-3 added 12.2 cents to trade around $3.622/MMBtu.

High temperatures in Atlanta were forecast dropping to the upper 50s Tuesday, with lows expected in the upper 30s. The average

(continued on page 10)

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

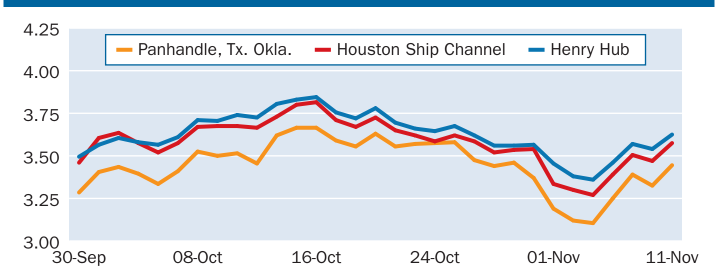
	Index	Change	Avg $/Mo	Marginal heat rate
Southeast On-peak				
VACAR	37.75	2.25	35.00	10027
Southern, Into	34.50	0.25	33.38	9524
Florida	39.25	0.25	37.22	10828
TVA, Into	35.50	1.00	33.81	9753
Entergy, Into	33.50	-0.25	31.47	9430
Southeast Off-Peak				
VACAR	29.50	2.25	26.19	7835
Southern, Into	28.00	2.50	25.46	7729
Florida	29.75	2.50	27.38	8207
TVA, Into	28.50	2.50	25.69	7830
Entergy, Into	26.00	1.00	23.83	7319
ERCOT On-peak				
ERCOT, North	32.75	0.75	34.48	9384
ERCOT, Houston	33.00	0.75	34.97	9224
ERCOT, South	33.25	-0.25	34.88	9357
ERCOT, West	32.50	0.50	34.50	9174
ERCOT Off-Peak				
ERCOT, North	22.75	0.50	22.85	6519
ERCOT, Houston	22.50	0.50	22.75	6289
ERCOT, South	22.50	0.50	22.75	6332
ERCOT, West	22.25	0.50	22.50	6281
SPP/MRO On-peak				
MAPP, South	38.00	3.75	33.06	10188
SPP, North	37.75	3.75	32.56	10958
SPP/MRO Off-Peak				
MAPP, South	27.25	1.00	24.19	7306
SPP, North	26.75	1.00	23.96	7765

Southeast load and generation mix forecast (GWh)

	Actual 10-Nov	%Chg	% Chg Year-ago	Forecast 11-Nov	12-Nov	13-Nov	14-Nov	15-Nov
ERCOT								
Load	688	-2	0	763	792	858	860	798
Generation								
Coal	272	-3	9	318	323	338	336	326
Gas	307	3	-6	307	318	377	376	325
Nuclear	111	0	2	111	112	114	117	120
SPP								
Load	516	-2	-4	525	569	609	604	575
Generation								
Coal	350	-1	2	358	402	417	401	377
Gas	98	0	-21	99	112	119	117	111
Nuclear	34	0	-5	34	34	37	41	45

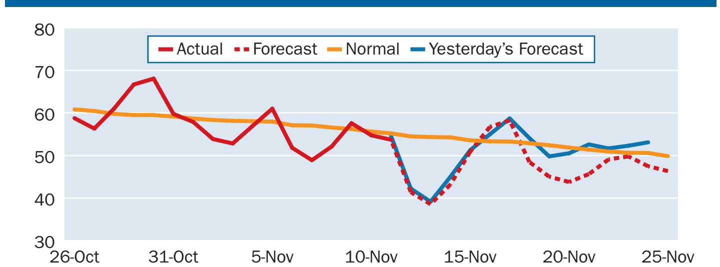
Source: Bentek

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



Source: Platts

ERCOT & SPP average temperature (°F)



Source: Custom Weather

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

Hub/Zone	Average	Change	Avg $/Mo	Marginal heat rate
On-peak				
Bus Average	30.04	-2.30	34.15	8514
Hub Average	29.95	-2.54	34.15	8491
Houston Hub	30.31	-2.37	34.30	8500
North Hub	30.20	-1.87	34.15	8679
South Hub	29.46	-3.46	34.08	8323
West Hub	29.84	-2.43	34.05	8480
AEN Zone	30.47	-2.95	34.62	8657
CPS Zone	30.27	-2.94	34.30	8583
LCRA Zone	30.31	-2.64	34.33	8595
Rayburn Zone	30.57	-1.60	34.23	8784
Houston Zone	30.31	-2.40	34.32	8501
North Zone	30.40	-1.76	34.22	8734
South Zone	28.79	-4.80	34.04	8133
West Zone	29.87	-3.69	35.21	8487
Off-Peak				
Bus Average	21.69	0.28	22.78	6279
Hub Average	21.62	0.21	22.76	6257
Houston Hub	21.73	0.32	22.80	6200
North Hub	21.79	0.38	22.82	6352
South Hub	21.65	0.23	22.76	6235
West Hub	21.29	-0.12	22.64	6256
AEN Zone	21.67	0.26	22.78	6366
CPS Zone	21.66	0.25	22.78	6261
LCRA Zone	21.66	0.25	22.78	6262
Rayburn Zone	21.93	0.52	22.86	6393
Houston Zone	21.71	0.32	22.79	6196
North Zone	21.79	0.38	22.82	6354
South Zone	21.66	0.21	22.74	6239
West Zone	21.01	-0.41	22.75	6173

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

Package	Trade date	Range
Southern, Into		
Bal-week	11/08	35.75-36.25
Bal-week	11/06	32.00-32.50
Bal-month	11/07	33.00-33.50
Next-week	11/08	34.50-35.00
Next-week	11/07	32.50-33.00
Entergy, Into		
Bal-week	11/05	32.25-32.75
Bal-month	11/05	32.00-32.50
Next-week	11/05	33.75-34.25
ERCOT, North		
Bal-month	11/07	32.25-32.75
Next-week	11/07	34.50-35.00
ERCOT, Houston		
Next-week	11/07	34.75-35.25
ERCOT, South		
Next-week	11/07	35.25-35.75

Daily generation outage references

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

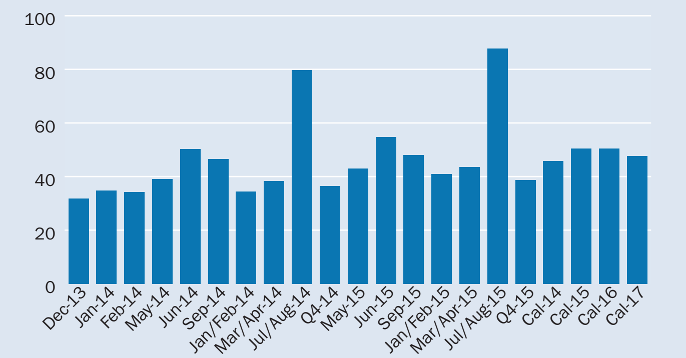
Fuels: Nuclear=n; Coal=c; Natural gas=g; Hydro=h ; Wind=w

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

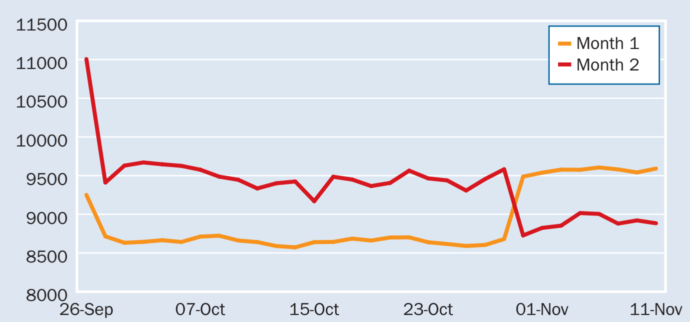
Southeast & Central Platts-ICE Forward Curve, Nov 11 ($/MWh)

Prompt month: Dec 13	On-peak	Off-peak
Southern Into	34.50	29.00
Entergy Into	32.75	26.25
ERCOT North	31.50	25.75
ERCOT Houston	31.75	25.75
ERCOT West	31.00	24.50
ERCOT South	31.50	25.25

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



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



Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Southeast & Central						
Big Brown-2/Luminant	575	c	Texas	MO	Unk	10/01/13
Bowen-2/Georgia Power	800	c	Ga.	PMO	Unk	04/04/13
Deepwater/AES	138	c	Texas	PMO	Unk	10/01/13
Fort Calhoun/OPPD	526	n	Neb.	RF	Unk	04/11/11
Martin Lake-1/Luminant	750	c	Texas	PMO	Unk	09/25/13
Monticello-1/Luminant	565	c	Texas	PMO	Unk	09/08/13
Monticello-2/Luminant	565	c	Texas	PMO	Unk	08/25/13
Oconee-2/Duke	934	n	S.C.	RF	12/09/13	10/11/13
Sequoyah-1/TVA	1186	n	Tenn.	RF	11/12/13	10/10/13
South Texas-1/STP	1413	n	Texas	MO	Unk	10/02/13
SR Berton/NRG	765	g	Texas	PMO	Unk	10/01/13
Surry-1/Dominion	861	n	Va.	RF	11/18/13	10/21/13
Welsh-3/SWEPCO	528	c	Texas	MO	Unk	06/21/13

WEST MARKETS

Dailies see light trading; most terms rise

Western power dailies experienced lighter trading volume on Veterans Day as the market had scheduled electricity delivery through Tuesday. Most terms advanced, and the NYMEX December natural gas contract settled 1.5 cents higher at $3.574/MMBtu.

The heaviest volumes appeared to be in balance-of-the-month packages, but there was day-ahead on-peak activity at the California hubs.

SP15 next-day on-peak climbed about $2.50 to trade between $45 and $47/MWh. SP15 bal-month traded between at $42.50 and $43/MWh, up nearly 50 cents. NP15 day-ahead on-peak added $2.75 to around $46/MWh. NP15 bal-month traded between $42 and $42.25/MWh, up more than 25 cents.

Sacramento, California, expected highs from 70 the low 70s and lows from the low to high 40s. Burbank's forecasts had highs in the low 80s and lows near 55.

The California Independent System Operator projected peak demand to be 29,984 MW on Monday and 30,947 MW on Tuesday. Renewables were 2,364 MW, and wind was less than 100 MW at 7:30 am PDT on Monday.

In the Northwest, Mid-Columbia bal-month was bid at $36.25 and offered at $36.50/MWh, down about 25 cents. Portland, Oregon's forecasts had highs in the upper 50s and lows from mid- to high 40s through Tuesday.

The Bonneville Power Administration's wind output was 68 MW, and its hydro output was 7,614 MW at 7:30 am PST.

In the desert Southwest, Phoenix expected highs in the upper 80s and lows in the low 60s. Unit 1 at Arizona Public Service's Palo Verde nuclear plant was back at full capacity following the repair of the main steam isolation valve. APS had been operating the unit at 60% capacity since Thursday.

Next-day natural gas prices in the Rockies and California were firmer. Opal gained 18 cents to $3.555/MMBtu, Pacific Gas and Electric city-gate rose 8.8 cents to $3.853/MMBtu, and SoCal city-gate declined 17.3 cents to $3.888/MMBtu.

Day-ahead prices were up in the California Independent System Operator auction following the higher peak demand forecast.

SP15 on-peak added 84 cents to $46.62/MWh, as SP15 off-peak rose $1.64 to $38.45/MWh. NP15 on-peak gained 77 cents to $46.53/MWh, and NP15 off-peak climbed $1.88 to $37.97/MWh. ZP26 on-peak increased 58 cents to $44.73/MWh, while ZP26 off-peak was up $1.61 to $37.22/MWh.

In the Northwest, Mid-Columbia on-peak December rose 25 cents with bids at $39.25 and offers at $39.75/MWh on ICE around 2:30 pm EST. January slid 50 cents to about $35.25/MWh, and the first quarter dipped 35 cents to about $34.65/MWh. In California, SP15 on-peak December financial terms rose 25 cents with bids at $41 and offers at $41.85/MWh. January skidded 50 cents to about $41.25/MWh, but Q1 2014 crept up 15 cents to

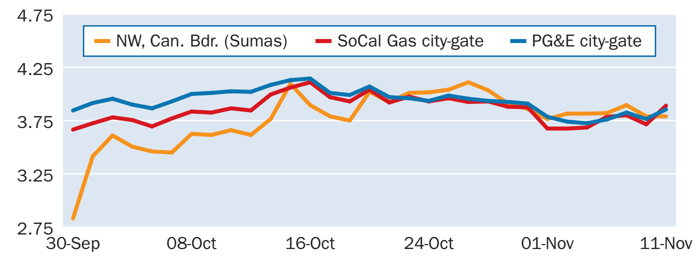
(continued on page 10)

Western day-ahead bilateral indexes for Nov 11-12* ($/MWh)

	Index	Change	Avg $/Mo	Marginal heat rate
On-peak				
COB	41.00	4.25	40.20	11833
Mid-C	37.09	2.94	36.68	10267
Palo Verde	32.87	1.87	31.76	9425
Mead	34.25	0.75	33.35	9474
Mona	34.00	1.00	33.10	10134
Four Corners	34.50	2.75	33.20	10268
NP15	43.25	2.00	42.48	11487
SP15	43.75	1.75	44.30	12102
Off-Peak				
COB	32.00	-1.00	31.36	9235
Mid-C	29.03	-1.75	28.30	8036
Palo Verde	28.00	-1.50	27.56	8029
Mead	28.25	-1.25	28.17	7815
Mona	25.00	-1.50	24.81	7452
Four Corners	24.50	-2.00	25.58	7292
NP15	34.75	-2.75	35.02	9230
SP15	35.00	-3.00	35.48	9682

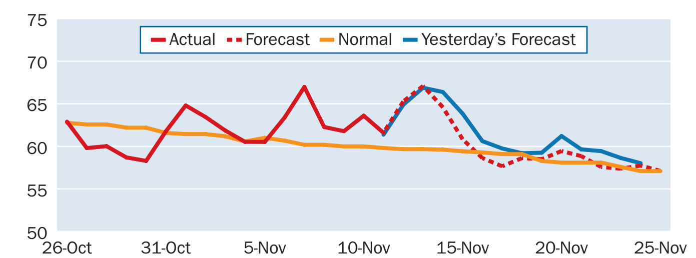
*West markets traded Friday for Monday-Tuesday delivery

Western spot natural gas prices ($/MMBtu)



Source: Platts

CAISO average temperature (°F)



Source: Custom Weather

Western load and generation mix forecast (GWh)

	Actual 10-Nov	%Chg	% Chg Year-ago	Forecast 11-Nov	12-Nov	13-Nov	14-Nov	15-Nov
CAISO								
Load	534	-3	-1	636	640	631	616	607
Generation								
Gas	247	-1	1	243	257	273	278	266
Nuclear	54	0	-6	54	56	56	56	56

Source: Bentek

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
NP15 Gen Hub	46.53	-0.18	-1.27	0.77	43.53	12055
SP15 Gen Hub	46.62	0.01	-1.37	0.84	43.54	12500
ZP26 Gen Hub	44.73	-0.18	-3.07	0.58	42.13	11992
Off-Peak						
NP15 Gen Hub	37.97	0.00	-1.19	1.88	35.87	10022
SP15 Gen Hub	38.45	-0.01	-0.69	1.64	35.93	10552
ZP26 Gen Hub	37.22	0.00	-1.94	1.61	35.17	10214

Western near-term bilateral markets ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	11/06	36.00-36.50
Bal-month	11/05	36.25-37.50

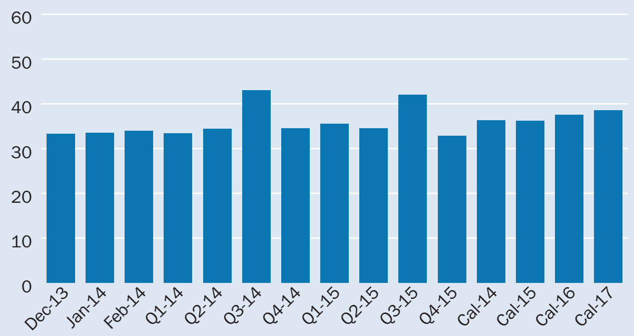
Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
West						
ACE Cogen/Constellation	118	g	Calif.	MO	Unk	09/29/13
Alamitos-2/AES	175	g	Calif.	MO	Unk	11/04/13
Alamitos-5/AES	498	g	Calif.	PMO	Unk	11/06/13
Belden/PG&E	119	h	Calif.	MO	Unk	11/07/13
Colgate/PCWA	177	h	Calif.	PMO	Unk	11/03/13
Colusa/PG&E	668	g	Calif.	PMO	Unk	11/10/13
Desert Star/Desert Star	495	g	Calif.	PMO	Unk	11/04/13
Encina-1/Cabrillo	106	g	Calif.	PMO	Unk	11/04/13
Genesis/NextEra	250	s	Calif.	PMO	Unk	10/10/13
High Desert/Tenaska	830	g	Calif.	PMO	Unk	11/03/13
Ivanpah-1/NRG	123	s	Calif.	PMO	Unk	10/10/13
Ivanpah-3/NRG	133	s	Calif.	PMO	Unk	10/10/13
La Paloma-2/Rockland	260	g	Calif.	PMO	Unk	11/10/13
Lodi/NCPA	303	g	Calif.	MO	Unk	11/04/13
Mexical/Sempra	625	g	Calif.	PMO	Unk	11/10/13
Mountain View-3/Iberdrola	525	w	Calif.	PMO	Unk	10/01/13
North Sky/NextEra	160	w	Calif.	PMO	Unk	11/04/13
Ormond Beach/NRG	775	g	Calif.	MO	Unk	11/10/13
Pine Flat/USACE	210	h	Calif.	PMO	Unk	10/02/13
Pittsburg-5/NRG	312	g	Calif.	MO	Unk	11/04/13
Pittsburg-6/NRG	317	g	Calif.	MO	Unk	11/04/13
Pittsburg-7/NRG	682	g	Calif.	MO	Unk	11/04/13
Solar Star-1/MidAmerican	310	s	Calif.	MO	Unk	10/01/13
Solar Star-2/MidAmerican	270	s	Calif.	MO	Unk	10/01/13
Sutter/Calpine	525	g	Calif.	PMO	Unk	11/03/13

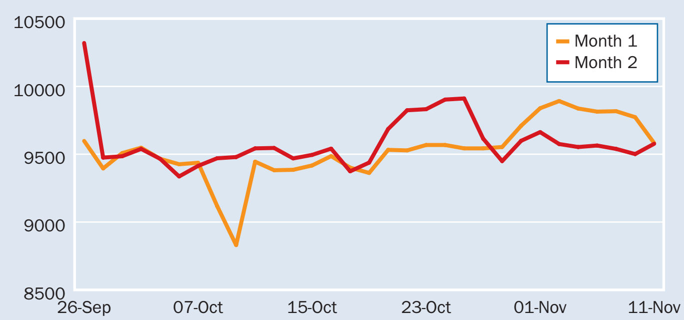
Western Platts-ICE Forward Curve, Nov 11 ($/MWh)

Prompt month: Dec 13	On-peak	Off-peak
Mid-C	39.50	31.50
Palo Verde	33.25	26.75
Mead	34.75	28.25
NP15	40.75	35.25
SP15	41.50	34.75

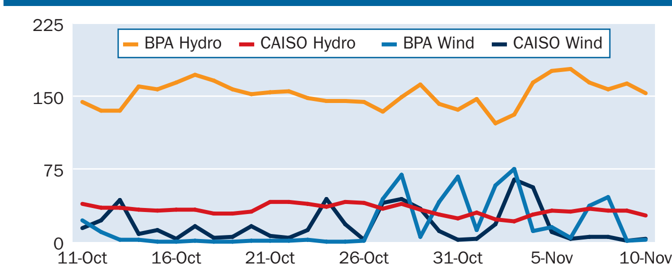
Palo Verde: Forward curve on-peak ($/MWh)



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



BPA & CAISO hydro and wind generation (GWh)



Source: BPA and CAISO

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.

PJM & MISO MARKETS

PJM & MISO dailies advance; terms flat

Mid-Atlantic dailies climbed Monday with loads expected to rise with temperatures dropping across the region. Dailies in the Midwest also advanced. Terms in the two regions were flat. NYMEX December natural gas futures settled 1.5 cents higher at $3.574/MMBtu Monday as forecasts for mild temperatures across most of the US prevented the market from gaining too much on the colder-than-average temperatures in the Northeast.

PJM West Hub day-ahead on-peak futures moved up about $8.75 to trade in the high-$40s/MWh for Tuesday delivery on the IntercontinentalExchange.

PJM West on-peak balance-of-the-week futures were bid at $45.15/MWh and offered at $46/MWh on ICE, as discount to dailies. PJM West on-peak next-week futures were bid at $40.75 to $48.50/MWh on ICE.

PJM Interconnection forecast peak load for Monday at 99,038 MW, for Tuesday at 107,607 MW and for Wednesday at 108,462 MW. On Wednesday the peak is expected to switch from the evening to the morning as early hour temperatures continue to drop.

Midwest dailies rose Monday with colder temperatures and higher demand to the east. Indiana Hub day-ahead on-peak futures were up about $2.75 to the high-$30s/MWh for Tuesday delivery. Indiana Hub on-peak bal-week futures were bid at $34.50 and offered at $38/MWh on ICE.

Dailies in the Midwestern portion of PJM Interconnection were also higher. AEP-Dayton Hub day-ahead on-peak increased $7 to the low-$40s/MWh. Northern Illinois Hub day-ahead on-peak rose $7 to the low-$40s/MWh.

Day-ahead auction prices in the PJM Interconnection climbed Monday with temperatures falling across the region. Western Hub on-peak jumped $9.56 to $47.22/MWh and Eastern Hub on-peak rose $11.48 to $54.69/MWh for Tuesday delivery.

JCPL on-peak increased $8.28 to $45.72/MWh and PSEG on-peak was up $11.24 to $49.52/MWh. BG&E on-peak climbed $10.77 to $50.30/MWh and Pepco on-peak rose $10.90 to $50.38/MWh. Locational marginal prices in the west of the grid operator's footprint saw smaller gains. Comed on-peak moved up $5.54 to $38.70/MWh and Chicago Hub on-peak increased $5.53 to $38.74/MWh.

MISO day-ahead auction prices for Tuesday delivery cleared stronger Monday afternoon. Minnesota Hub became the highest priced hub with on-peak clearing at $40.50/MWh, rising $4.56. Off-peak cleared at $24.33/MWh, gaining $6.74.

Indiana Hub on-peak cleared at $38.80/MWh, an increase of $5.73. Off-peak cleared at $28.68/MWh, up $3.57.

Michigan Hub on-peak cleared at $38.06/MWh, adding $4.74. Off-peak cleared at $28.68/MWh, rising $3.02. Illinois Hub became the lowest priced hub with on-peak clearing $36.64/MWh, climbing $4.54. Off-peak cleared at $25.94/MWh, moving up $1.36.

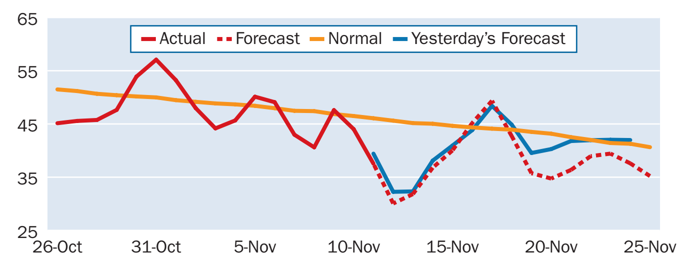
Congestion costs at the hubs ranged from negative 91 cents to $1.43 for on-peak, and from negative $2.15 to $2.03 for off-peak.

Mid-Atlantic forward prices moved little Monday. PJM West

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

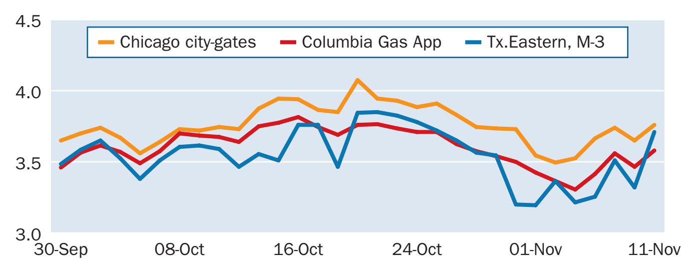
	Index	Change	Avg $/Mo	Marginal heat rate
PJM On-peak				
PJM West	47.00	7.75	39.69	13636
Dominion Hub	48.50	7.75	40.78	13206
AD Hub	42.00	5.75	36.44	11260
NI Hub	40.00	5.50	34.34	10638
PJM Off-Peak				
PJM West	33.00	1.75	30.56	9574
Dominion Hub	34.25	1.75	31.44	9326
AD Hub	32.00	2.25	28.84	8579
NI Hub	27.50	3.50	23.59	7314
MISO On-peak				
Indiana Hub	38.00	2.75	34.91	10383
Michigan Hub	38.25	2.75	34.91	10248
Minnesota Hub	43.00	2.00	38.41	11505
Illinois Hub	37.00	2.00	34.16	9847
MISO Off-Peak				
Indiana Hub	29.50	2.50	26.00	8060
Michigan Hub	29.75	2.75	26.09	7971
Minnesota Hub	24.00	1.75	21.88	6421
Illinois Hub	29.00	1.00	26.16	7718

PJM & MISO average temperature (°F)



Source: Custom Weather

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



Source: Platts

PJM & MISO load and generation mix forecast (GWh)

	Actual 10-Nov	%Chg	% Chg Year-ago	Forecast 11-Nov	12-Nov	13-Nov	14-Nov	15-Nov
PJM								
Load	1827	-6	1	1928	2106	2327	2293	2141
Generation								
Coal	749	-8	13	802	839	847	851	861
Gas	267	0	-19	272	317	357	349	313
Nuclear	685	0	1	685	685	685	685	685
MISO								
Load	1207	-3	-1	1343	1394	1431	1424	1378
Generation								
Coal	1052	-1	24	1162	1202	1180	1138	1116
Gas	56	13	-37	68	94	109	106	92
Nuclear	189	0	-10	189	189	189	189	189

Source: Bentek

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
Indiana Hub	38.80	0.31	-0.26	5.73	32.71	10647
Michigan Hub	38.06	-0.91	0.22	4.74	32.71	10231
Minnesota Hub	40.50	1.43	0.32	4.56	34.24	10879
Illinois Hub	36.64	-0.90	-1.20	4.54	32.04	9787
Off-Peak						
Indiana Hub	28.68	2.03	0.13	3.57	25.26	8088
Michigan Hub	28.68	1.94	0.22	3.02	25.14	7862
Minnesota Hub	24.33	-2.15	-0.04	6.74	17.90	6697
Illinois Hub	25.94	0.06	-0.64	1.36	25.83	7081

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

Package	Trade date	Range
PJM West		
Bal-week	11/08	47.00-48.00
Bal-week	11/06	38.25-39.50
Bal-week	11/05	37.50-38.50
Bal-month	11/07	42.00-43.00
Bal-month	11/05	38.00-39.00
Next-week	11/11	41.00-42.00
Next-week	11/07	46.25-48.00
Next-week	11/05	40.00-41.00
AD Hub		
Bal-week	11/08	42.25-43.25
Next-week	11/07	42.50-43.50

Generation unit outage report

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
PJM & MISO						
Beaver Valley-1/Fenoc	959	n	Penn.	MO	Unk	11/06/13
DC Cook-2/IMP	1151	n	Mich.	RF	Unk	10/02/13
Hope Creek/PSEG	1240	n	N.J.	RF	Unk	10/11/13
Prarie Island-2/Scel	585	n	Minn.	RF	12/13/13	09/21/13
Three Mile Island/Exelon	890	n	Penn.	RF	11/24/13	10/28/13

Additional information on data and analysis:

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

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

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
On-peak						
AEP Gen Hub	39.43	-2.75	-2.40	6.06	33.61	10982
AEP-Dayton Hub	40.84	-2.67	-1.07	6.30	34.63	11374
ATSI Gen Hub	43.96	-1.59	0.97	7.12	36.57	12472
Chicago Gen Hub	38.22	-3.49	-2.88	5.42	32.00	10201
Chicago Hub	38.74	-3.48	-2.36	5.53	32.53	10341
Dominion Hub	47.70	3.47	-0.35	8.97	38.75	13039
Eastern Hub	54.69	7.35	2.76	11.48	39.96	14683
New Jersy Hub	47.85	1.80	1.47	9.92	38.81	12846
Northern Illinios Hub	38.57	-3.47	-2.54	5.51	32.37	10294
Ohio Hub	40.90	-2.74	-0.94	6.20	34.76	11229
West Internal Hub	45.33	0.88	-0.13	8.32	36.49	13230
Western Hub	47.22	1.57	1.07	9.56	37.82	13781
AEP Zone	41.42	-2.12	-1.04	6.71	34.80	11535
Allegheny Power Zone	45.02	0.50	-0.05	8.81	36.65	12706
Atlantic Elec Zone	46.71	0.83	1.29	9.03	38.20	12539
ATSI Zone	45.03	-1.03	1.48	7.39	37.04	12774
BG&E Zone	50.30	3.67	2.05	10.77	39.75	14168
ComEd Zone	38.70	-3.47	-2.41	5.54	32.47	10330
Dayton P&L Zone	41.85	-2.56	-0.17	6.61	35.34	11602
Delmarva P&L Zone	53.71	6.49	2.64	11.03	39.66	14420
Dominion Zone	48.05	3.52	-0.05	9.39	38.72	13136
Duke Zone	39.61	-2.47	-2.50	5.83	33.59	10980
Duquesne Light Zone	42.45	-1.26	-0.87	8.24	35.46	12369
JCPL Zone	45.72	-0.24	1.39	8.28	37.79	12275
MetEd Zone	46.48	1.07	0.83	9.20	37.72	12653
PECO Zone	46.07	0.82	0.67	8.88	37.82	12541
Pennsylvania Elec Zone	48.75	1.92	2.25	8.22	39.69	14262
PEPCO Zone	50.38	4.30	1.49	10.90	39.57	14190
PPL Zone	46.39	0.93	0.88	9.11	37.54	12629
PSEG Zone	49.52	3.35	1.59	11.24	39.59	13295
Rockland Elec Zone	50.09	3.73	1.78	11.75	39.37	13448
Off-Peak						
AEP Gen Hub	28.61	-0.37	-1.09	1.85	27.12	8262
AEP-Dayton Hub	29.48	-0.19	-0.40	2.11	27.90	8514
ATSI Gen Hub	30.20	-0.20	0.32	2.10	28.64	8765
Chicago Gen Hub	25.36	-2.98	-1.74	2.00	22.44	6921
Chicago Hub	25.90	-2.77	-1.41	2.04	23.11	7070
Dominion Hub	32.61	2.09	0.45	1.65	30.58	9169
Eastern Hub	31.36	0.40	0.88	2.17	29.69	9163
New Jersy Hub	30.66	0.19	0.40	1.96	29.43	8959
Northern Illinios Hub	25.84	-2.71	-1.52	2.05	23.04	7054
Ohio Hub	29.55	-0.17	-0.35	2.17	27.98	8287
West Internal Hub	30.71	0.69	-0.05	1.85	28.89	9352
Western Hub	31.28	0.65	0.56	1.95	29.54	9527
AEP Zone	29.74	0.00	-0.33	2.14	27.99	8587
Allegheny Power Zone	30.56	0.35	0.14	1.77	28.98	8976
Atlantic Elec Zone	30.48	0.04	0.37	1.72	29.37	8904
ATSI Zone	30.45	-0.15	0.53	2.15	28.84	8840
BG&E Zone	32.69	1.44	1.18	1.76	30.94	9667
ComEd Zone	25.88	-2.73	-1.46	2.12	23.01	7064
Dayton P&L Zone	29.93	-0.24	0.10	2.16	28.24	8509
Delmarva P&L Zone	31.35	0.38	0.90	2.07	29.65	9161
Dominion Zone	32.59	1.99	0.53	1.62	30.58	9163
Duke Zone	28.62	-0.26	-1.20	1.76	27.18	8135
Duquesne Light Zone	29.41	-0.22	-0.44	1.79	28.12	8817
JCPL Zone	30.19	-0.24	0.35	1.54	29.22	8819
MetEd Zone	30.21	-0.05	0.18	1.94	28.95	8770
PECO Zone	30.22	0.04	0.11	1.72	29.03	8773
Pennsylvania Elec Zone	30.86	-0.07	0.86	2.25	29.33	9226
PEPCO Zone	32.54	1.52	0.95	1.64	30.74	9624
PPL Zone	30.13	-0.07	0.12	1.89	28.81	8746
PSEG Zone	31.04	0.50	0.46	2.31	29.59	9067
Rockland Elec Zone	31.06	0.51	0.47	2.41	29.44	9075

on-peak December financial futures held steady, with bids at $41.30/MWh and offers at $41.50/MWh at about 2:30 pm EST on the IntercontinentalExchange. PJM West on-peak January-February 2014 financial futures slipped 25 cents to $42.75/MWh on ICE.

Midwest forwards moved little Monday, even with firmer gas futures. AD Hub on-peak December financial futures were steady, with bids at $37.95/MWh and offers at $38.05/MWh on ICE. Indiana Hub on-peak December financial futures slipped 25 cents, with bids at $35.30/MWh and offers at $36.50/MWh on ICE. Northern Illinois Hub on-peak December financial futures were unchanged, with bids at $35.50/MWh and offers at $35.95/MWh on ICE.

Northeast markets *... from page 2*

with rising gas futures and strong spot power. Algonquin city-gates basis rose 2.5 cents to about $5.45/MMBtu.

In New England, Mass Hub on-peak December financial futures dropped were unchanged at about $77.75/MWh at about 2:30 pm EST on the IntercontinentalExchange. The prompt-month package was down about $1 in the morning. Mass Hub on-peak January-February 2014 financial futures rose 50 to $109.50/MWh on ICE. New York Zone A on-peak December financial futures climbed $1.75 to $46/MWh with exceptionally strong spot pricing for the zone. Zone A on-peak January-February 2014 financial futures Jumped $3.25 to $49/MWh on ICE.

New York Zone G on-peak December financial futures were unchanged at about $58.50/MWh. Bids and offers were as much as $20 wide for some New York markets on ICE.

Southeast markets *... from page 4*

November high temperature in the city is 64; its average low is 45.

The ERCOT day-ahead auction for Tuesday delivery cleared weaker Monday afternoon with peak load forecast to rise.

Houston Hub became the highest-priced hub position, and West Hub remained the lowest-priced. Houston Hub on-peak cleared in the auction at $30.31/MWh, falling $2.37, while off-peak cleared at $21.73/MWh, rising 32 cents.

North Hub on-peak cleared the auction at $30.20/MWh, down $1.87 from Sunday's clearing price, while off-peak cleared at $21.79/MWh, an increase of 38 cents.

West Hub on-peak cleared in the ERCOT auction at $29.84/MWh, a loss of $2.43, while off-peak cleared at $21.29/MWh, a drop of 12 cents.

South Hub on-peak cleared at $29.46/MWh, falling $3.46, while off-peak cleared at $21.65/MWh, adding 23 cents. Austin Energy Zone on-peak led the load zones at $30.47/MWh, adding $2.95 from Sunday. The highest hourly day-ahead price occurred at 7 pm CST in the North Hub at $46.32/MWh and in the Austin Energy Zone at $47.43/MWh.

ERCOT system load was forecast to peak at 37,525 MW Tuesday, up 6% from Monday's expected peak of 35,325 MW.

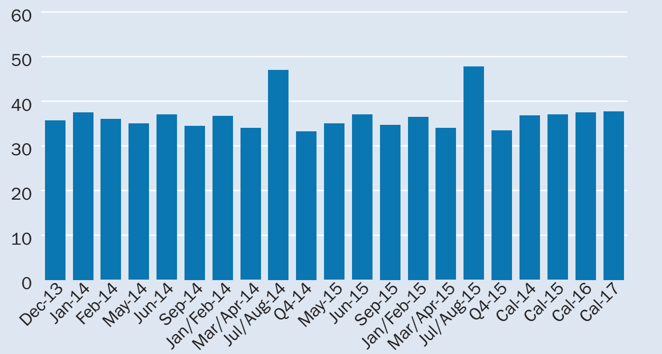
South Central on-peak terms were mixed at the front of the curve Monday. ERCOT North on-peak December stayed at about $31.50/MWh, January rose 25 cents to about $34.50/MWh, and February rose 25 cents to about $34/MWh. Heat rates were steady on the IntercontinentalExchange around 2:30 pm EST. Into Entergy on-peak December fell 25 cents to about $32.75/MWh, but January rose 25 cents to about $31/MWh.

Southeast on-peak December moved down Monday, even as December NYMEX gas futures moved up. Into Southern December fell 25 cents to about $34.50/MWh, January dipped 50 cents to about $34.75/MWh, and February slid 50 cents to about $34.50/MWh.

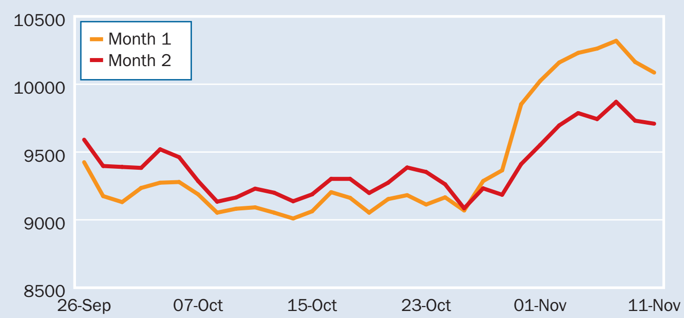
PJM & MISO Platts-ICE Forward Curve, Nov 11 ($/MWh)

Prompt month: Dec 13	On-peak	Off-peak
PJM West	41.50	33.75
AD Hub	38.00	31.00
NI Hub	35.75	26.75
Indiana Hub	36.00	28.00

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



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



West markets *... from page 6*

about $42.15/MWh. NP15 December stayed around $40.75/MWh, but January lost 50 cents to about $40.25/MWh. Palo Verde December gained 50 cents to about $33.25/MWh, January slipped down 50 cents to about $33.50/MWh, and first quarter was virtually unchanged at about $33.40/MWh.

NEWS

Duke subsidiaries get OK for joint planning

The South Carolina Public Service Commission late Friday posted an order clearing the way for Duke Energy Carolinas and Duke Energy Progress to jointly plan for generation and transmission needs.

DEC and DEP, each of which serves parts of North Carolina and South Carolina, had asked the PSC to approve joint generation and transmission planning as part of the 2013 integrated resource plans they filed in mid-October.

"According to the applicants, the purpose of this request is to determine whether such planning would result in cost savings for retail customers" of DEC and DEP, the PSC said in its order. "After review, we find that it is a logical step in the integration of the two companies, and if implemented, joint planning should improve efficiencies and have a positive impact on ratepayers."

DEC and DEP will still need to file individual IRPs. They also must secure separate regulatory approvals for any new generation units or transmission lines they plan to joint develop, or power purchase agreements they plan to jointly sign, the PSC said.

"We are supportive" of what DEC and DEP asked for and what the PSC approved, said Dukes Scott, executive director of the South Carolina Office of Regulatory Staff. Scott said he believes that jointly planning for their power needs "makes sense" for the two utilities, whose service territories adjoin each other.

Duke Energy acquired Progress Energy in July 2012 to form the nation's largest utility holding company. DEC, once known as Duke Power, serves about 2.4 million in the Carolinas, while DEP, known until the Duke-Progress merger as Progress Energy Carolinas, serves about 1.5 million. Duke also owns utilities in Ohio, Indiana, Kentucky and Florida that will continue to plan their power needs individually.

DEC and DEP in mid-October filed separate IRPs, but including in each of their plans an analysis of how their needs for incremental power would change if DEC and DEP were to jointly plan for their needs.

DEC and DEP said in the IRPs that under a "joint planning scenario," they would be able to delay two planned combined-cycle units and one planned CT by one year each; delay another combined-cycle unit by two years; replace yet another combined-cycle unit with a CT and delay its need for two years; and have DEC and DEP share ownership of two planned 1,117-MW nuclear units at DEC's planned William States Lee III station in Cherokee County, South Carolina, when they come online in the mid-2020s.

DEC's standard IRP, in which the utility planned for its own needs individually, calls for the utility to own 100% of the two Lee units, which DEC currently expects to begin commercial operation in 2024 and 2026. Under the joint planning scenario, however, DEC would own a 659-MW stake in each of the two units, and DEP would own the remaining 458 MW of each unit. The 59%/41% Lee ownership split in the joint planning scenario reflects the relative sizes and power needs of DEC and DEP.

Duke spokesman Tom Shiel said Monday that the North Carolina Utilities Commission has given DEC and DEP "its approval to jointly plan. But before implementing a capacity transaction between utilities, further approvals are required. These approvals can be either state or federal approvals depending upon the transaction. This means we can begin to examine the potential benefits that would accrue to customers once DEC and DEP coordinate new resource additions between the companies."

Shiel noted that sharing capacity between DEC and DEP "could mean any of the following: jointly owning new generation assets, one company selling excess system capacity to the other for a period of time, [and/or] sharing a third-party capacity purchase."

Since Duke and Progress closed on their merger 16 month ago, DEC and DEP have been jointly dispatching their existing units and jointly purchasing their power plant fuels. As part of their effort to secure merger-agreement approval from the NCUC and PSC, DEC and DEP committed to provide at least $687 million in savings to their customers through joint dispatch and joint fuel purchasing by the end of 2017.

Asked for an update on joint dispatch between DEC and DEP, Duke's Shiel provided the comments that Duke CFO Steve Young made during the company's third-quarter earnings conference call on Wednesday.

Young said then, "We continue to make progress on our commitment to deliver fuel and joint dispatch savings to our customers in the Carolinas. To date, we are ahead of our target, and have generated $145 million of cumulative fuel and joint dispatch savings since the inception of the merger We have contractually locked in, or generated, approximately 50% of the guaranteed fuel and joint dispatch savings. As a result, we are on track to deliver the guaranteed savings of $687 million."

— Housley Carr

IP&L plans to rely heavily on wholesale market

Indianapolis Power & Light plans to rely heavily on the wholesale power market, including a 100-MW bilateral capacity agreement it hopes to wrap up around Christmas, to trim a forecasted 544-MW capacity shortfall in 2016.

The Indiana Utility Regulatory Commission, in a recent data request, asked the AES Corp. subsidiary how it intends to deal with the capacity deficit the utility says it is facing in less than three years.

Last week, the commission got its answers.

An initially projected 744-MW capacity deficit is expected to be reduced by 200 MW in 2016 with the conversion of two older coal units, Nos. 5 and 6, at IP&L's Harding Street power plant in downtown Indianapolis to natural gas, the utility said.

Of the remaining 544 MW capacity deficiency, IP&L said it plans to secure capacity via bilateral capacity transactions well in advance of the Midcontintent Independent System Operator's capacity auction in 2016.

IP&L "is currently pursuing a 100-MW capacity-only transaction for 2016 with the goal of completing that transaction" before December 31, the utility said. Additional capacity-only or capacity and energy bilateral purchase contracts may be required, it added.

IP&L did not identify in the filing who it is negotiating with, and company spokeswoman Brandi Davis-Handy declined Monday to comment on IP&L's market purchases.

IP&L told the commission it also continues to work with MISO, a Carmel, Indiana-based independent system operator, to seek capacity credit for at least a portion of its existing 300 MW in wind power purchase ageements.

If successful, IP&L said it anticipates receiving no more than 10 MW of capacity credit for its 100-MW Hoosier Wind Park PPA, which is located in MISO Zone 6. IP&L's 200-MW Lakefield Wind Park PPA is not within MISO Zone 6, "and will not receive any MISO Zone 6 capacity credit," the utility said.

And, according to Davis-Handy, IP&L has sought and received an extension from the Environmental Protection Agency to keep the 341-MW Eagle Valley coal-fired power plant running for an additional year, before it is retired in 2016.

Eagle Valley is located near Martinsville in Morgan County, Indiana.

IP&L announced plans earlier this year to close Eagle Valley and convert the Harding Street units to gas. The utility intends to keep open its 1,760-MW Petersburg baseload coal plant in Pike County, Indiana, and a 500-MW coal unit at Harding Street, despite calls from environmental groups to shutter the facility.

IP&L, in response to an IURC question, blamed EPA and the federal government for its decision to rely largely on the market to address its capacity shortfall in 2016.

"Simply put, the federal government, with its aggressive timing on environmental rules, puts us in a position where it may be necessary to rely on the market in 2016," the company said. "Long-term reliance on the capacity market is not consistent with what IP&L views as sound resource planning practices."

Ordinarily, IP&L added, it would "seek to avoid reliance on the wholesale capacity market for purchases of this magnitude. Short-term reliance on the capacity market may be appropriate or necessary depending on the circumstances."

That is why, the utility said, it wants to construct a 650-MW combined-cycle gas plant near the Eagle Valley site. The plant, currently before the commission for final review, would go into commercial operation in 2017.

— Bob Matyi

Daily CSAPR allowance assessments, Nov 11

CSAPR ($/st)	2013 Range	Mid	2014 Range	Mid
SO_2 Group 1	5.00-35.00	20.00	5.00-25.00	15.00
SO_2 Group 2	25.00-75.00	50.00	25.00-65.00	45.00
NOx Annual	40.00-70.00	55.00	30.00-70.00	50.00
NOx Seasonal	20.00-90.00	55.00	20.00-80.00	50.00

All prices in $/st

Daily CAIR allowance assessments, Nov 11

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

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

RGGI carbon allowance futures, Nov 8 ($/allowance)

ICE	Settlement	Volume	NYMEX GE	Settlement	Volume
Dec13 V10	3.15	0	Dec13	1.97	0
Dec13 V11	3.15	0	Dec14	1.97	0
Dec13 V12	3.15	0			
Dec13 V13	3.15	50			
Dec14 V10	3.26	0			
Dec14 V11	3.26	0			
Dec14 V12	3.26	0			
Dec14 V13	3.26	0			
Dec15 V10	3.37	0			
Dec15 V11	3.37	0			
Dec15 V12	3.37	0			
Dec15 V13	3.37	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.

Exxon challenges MISO mitigation proposal

ExxonMobil Oil is asking the Federal Energy Regulatory Commission to require the Midcontinent Independent System Operator to not subject its generation assets at a Texas refinery to price caps, arguing that FERC rules implementing the Public Utilities Regulatory Policy Act are inconsistent with such caps.

At the same time, Exxon is asking FERC to provide more information on why its gas turbine generators, which are certified as qualifying facilities under PURPA, were included among generation assets that could be subject to mitigation.

Exxon's November 8 protest (ER14-136) responded to MISO's proposal last month to create two "narrow constrained areas" within the new "MISO South" area, which is the area of the grid that is being added as a result of Entergy's integration into the MISO system. In an October 16 filing, MISO explained that NCAs "are chronically constrained areas that can generate considerable market power concerns and thresholds that depend on the frequency of binding constraints."

Said MISO, "the NCA designations proposed by [Potomac Economics, MISO's independent market monitor] will establish enhanced market monitoring and mitigation measures in those areas that exhibit localized market power due to binding transmission constraints or binding reserve constraints."

MISO as well in its filing identified Exxon's Beaumont refinery complex, located in Beaumont, Texas, as one of the resources included in the NCAs. But in its protest, Exxon argued that Potomac Economics' analysis supporting the creation of the two new NCAs "may over estimate Beaumont's effect on the NCA for several reasons," including because the refinery uses a portion of the turbines' nameplate capacity of 478 MW for its "refining and chemical processes."

Exxon argued that using its nameplate capacity "would overstate the effect that the Beaumont turbines can have on the NCA," going on to say that when the refinery complex "is not operating at full capacity, the NCA will experience both reduced load and reduced generation, which should be reflected in the market power analysis. "

And in expressing a willingness to provide additional information on the issue to Potomac Economics, Exxon said that FERC "should not determine that Beaumont is an NCA resource" until refinery officials, Potomac Economics and FERC staff if willing have reviewed the underlying assumptions that led to the plant's inclusion.

Exxon also asked FERC to "clarify that the NCA portion of MISO's tariff does not apply to a Qualifying Facility's sales at avoided cost," arguing that FERC rules for QFs under PURPA do not allow the price caps in question to be applied for QF sales at avoided costs rates. The company as such asked FERC to require MISO to revise the tariff provisions in question.

Exxon argued that QFs selling at avoided cost rates under FERC rules cannot have their payment be capped "based on a transmission provider's tariff," and that applying NCAs to QFs' sales "would have the effect of forcing a Qualifying Facility to be a market participant in MISO's markets," which Exxon argued that FERC has declined to do under similar circumstances.

— Bobby McMahon

FERC OKs Western energy crisis settlement

The Federal Energy Regulatory Commission late last week approved a settlement between Arizona Electric Power Cooperative and entities in California over issues stemming from the Western energy crisis of the early 2000s.

Under the settlement approved Friday (EL00-95), AEPCO will pay the California Public Utilities Commission, several investor-owned utilities and others roughly $9.5 million, which includes a cash payment, recievables held by the California Independent System Operator and California Power Exchange and interest on those funds.

"The settlement appears to be fair and reasonable and in the public interest, and is hereby approved," FERC said in the order. In doing so, FERC said it would hold harmless CalPX and Cal-ISO in implementing the settlement.

The commission in the order said that the settlement "resolves all claims between the California Parties on the one hand and AEPCO on the other, relating to transactions in the Western energy markets during the settlement period for damages, refunds, disgorgement of profits, costs and attorneys' fees, or other remedies." For the purpose of the settlement, the settlement period was January 2000 through June 20, 2001.

The California crisis was characterized by high power prices that followed the deregulation of the state's wholesale power markets, while retail power prices remained frozen.

The AEPCO settlement is just the latest in a series of settlements struck to resolve issues from the energy crisis. Last month, FERC approved a $750 million settlement between BC Hydro's trading firm Powerex and California entities, which California PUC called "one of the largest remaining claims of overcharges arising from" the energy crisis.

FERC Chairman Jon Wellinghoff did not participate in the decision.

— Bobby McMahon

Dominion aims to build 39-mile transmission line

Dominion is seeking approval to build a 39-mile 230-kV transmission line in the western portion of Virginia near Staunton.

The transmission line would run between the Dooms switching station in Augusta County and Lexington switching station in Rockbridge County. The two stations would be expanded, Dominion said.

The Lexington station and interconnected transmission network provide service to the company's transmission system located in the western region of Virginia, Dominion said in a filing made Friday at the State Corporation Commission.

The needs for the line and upgrades to the substation are driven by load growth, the company said. Load in the region is projected to decline in the short-term, but return to 2012 levels and increase thereafter, Dominion said.

Summer peak load in the area around the Lexington substation grew to 287.33 MW in 2011 from 280.39 MW in 2010. It grew to 303.67 MW in 2012 but dropped slightly to 300.41 in 2013 and is expected to fall 1.15% to 296.96 MW in 2014, the company said.

Load growth is projected to increase 2.32% in 2014 and 2.65% in 2015 and expected to reach 333.76 MW in 2022, the company said.

The PJM Interconnection's 2013 regional transmission expansion plan included the project as needed to address excessive loading at the Lexington substation, the company said.

Power flow studies show load growth causing the Lexington station and transmission system to exceed 300 MW planning criteria as early as this winter, Dominion said.

The Lexington station is the intersection of three major transmission lines that head west, south and north and is the sole source of the region's 230-kV, 138-kV and 115-kV transmission system, Dominion said.

Relieving the excess demand on the substation also will allow Dominion to comply with mandatory North American Electric Reliability Cooperation reliability standards and maintain the reliability of its transmission system, the company said. The project is expected to be online by June 1, 2016.

The addition of the 230-kV line also will accommodate load growth in the western region of Virginia, Dominion said.

The project will be coordinated with the reconstruction of the 500-kV transmission line between the two substations, Dominion said. The SCC approved the 500-kV rebuild in May, and it also has a June 1, 2016 in service date.

The 500-kV rebuild will include towers that can accommodate the 230-kV line, Dominion said.

Coordination of the two projects will save about $26.9 million for the construction of the 230-kV line when compared to the cost of the two projects built separately, Dominion said. The project as proposed would cost $35 million, the company said.

— Mary Powers

Short list of possible coal plants shrinks ...from page 1

when the agency announced its new proposed NSPS rules.

Under its new NSPS, EPA did not continue its transitional source distinction, but included the proviso that any transitional sources that began construction prior to the publication of the rules in the Federal Register would be considered an existing source.

The proposed NSPS rules, announced September 20, have not yet been published in the Federal Register.

The proposed NSPS rules set an emissions standard of 1,100 lbs CO_2/MWh, a level that even advanced supercritical coal plants cannot meet. Of course that means that any new coal plants, such as those that were on the transitional list, would be doomed because it would not be able to comply with federal emissions standards.

As it is, the EPA views Wolverine Power Cooperative's proposed 600-MW coal project proposed for Rogers City, Michigan, as the only solid fossil fuel project under development that has an active permit. It would thus be covered by the new rules, even though it has not been designed to meet the 1,100 lbs CO_2/MWh standard.

EPA is now taking comments on whether the Wolverine project should be subject to the new rules or covered by an alternate standard. EPA will address that issue in a later proposal.

Wolverine's Rogers City project remains "an option, but it is not at the forefront," Nancy Tanner, director of communications for the co-op, said. In part, the time that has elapsed since the project was announced in 2006 has worked against it.

During that time, Wolverine has had to seek other energy sources, such as buying baseload supplies from the Ohio Valley Electric Cooperative, and now it is exploring taking a stake in We Energies' 431-MW Presque Isle coal plant in Marquette, Michigan, as well as building a gas-fired plant that would meet some of the needs that the coal plant would serve.

We Energies wants to shut Presque Isle, but the plant received a reprieve in October when the Midcontinent Independent System Operator said that the plant is needed for reliability until at least 2014.

Wolverine is weighing the possible purchase of all of Presque Isle from We Energies, Kimberly Molitor, Wolverine vice president of external affairs, said in October.

Two other projects that were on the transitional list indicated to EPA that they were under construction. If they are not, however, EPA has proposed that they will be treated the same way as Wolverine.

Those projects are Sunflower Electric Cooperative's 895-MW Holcomb-2 project and Plant Washington, an 850-MW station being developed by POWER4Georgians.

The EPA has not determined whether any of the transitional projects have begun construction, but the agency has indicated that "events may occur with these units that may result in a separate rulemaking for GHG for them at some time in the future," Cindy Hertel, manager of communications at Sunflower Electric wrote in an email response. "In the meantime," she wrote, "Sunflower will continue to take the steps necessary to preserve the viability and to advance the project."

Holcomb-2 has a long and controversial history. The project holds the distinction of being the first to be denied a permit application because of CO_2 emissions.

However Sunflower did eventually win an air permit from the Kansas Department of Health and Environment, but on October 7, 2013, the Kansas Supreme Court reversed KDHE's decision.

Sunflower says it is still pursuing the project, but Bruce Nilles, director of the Sierra Club's Beyond Coal campaign, said that to revive the project the cooperative would have to go back and re-apply for an air permit. "Once they open up that process, they fall under the new NSPS rules," he said.

Dean Alford, a spokesman for POWER4Georgians, developer of the 850-MW supercritical Plant Washington in Sandersville, Georgia, said the group's project is moving forward. The project has commenced construction to the requirements of the Clean Air Act, and therefore is exempt under the old transitional designation from the newly proposed NSPS, he said.

In August 2012, POWER4Georgians retained Black & Veatch as the project's EPC contractor and said that groundbreaking was less than a year away. And on April 15, POWER4Georgians executed a contract with IHI Corp. for the manufacture of the project's boiler. At the time, POWER4Georgians said it expected to execute a construction contract for the balance of the facility by September 2013.

Meanwhile, the project has an extension on securing its air permit from Georgia and is in the process of securing power purchase agreements.

Originally, four Georgia electric cooperatives were in line to purchase the project's output, but on April 26, 2013, POWER4Georgians announced a planned restructuring under which the four electric cooperatives would no longer be members of POWER4Georgians and would be relieved of all future

The fate of the transitional coal projects

Developer	Project	Size (MW)	Location	Planned mitigation	Status
Tenaska Energy	Trailblazer	600	Texas	CCS-EOR	cancelled
Tenaska Energy	Taylorville	602	Illinois	CCS-EOR	cancelled
Summit Power Group	Texas Clean Energy	400	Texas	CCS-EOR	in development
Erora Group	Cash Creek	761	Kentucky	CCS-IGCC	converted to gas
Southeast Idaho Energy	Power County	520	Idaho	CCS-EOR	converted to gas
EmberClear	Good Spring	270	Pennsylvania	CCS-IGCC	converted to gas
NRG Energy	Limestone 3	750	Texas	CCS ready	cancelled
Sunflower Electric Power	Holcomb-2	895	Kansas	supercritical PC	air permit invalidated
White Stallion LLC	White Stallion	1,320	Texas	none (CFB)	cancelled
Holland Board of Public Works	James DeYoung	78	Michigan	none (CFB)	cancelled
Wolverine Power Cooperative	Wolverine	600	Michigan	none-CCS ready	in development
GDF Suez	Coleto Creek	650	Texas	none-CCS ready	cancelled
Power4Georgians	Plant Washington	850	Georgia	supercritical PC	in development
Deseret G&T	Bonanza	110	Utah	none	not permitted
North American Power Group	Two Elk	250	Wyoming	none-CCS ready	not permitted
Total		**8,656**			

Sources: Environmental Protection Agency, company data

obligations and responsibilities.

POWER4Georgians is now owned by Taylor Energy Fund, which is managed by Tim Taylor, former president and CEO of Public Service Company of Colorado.

Nilles dismissed the projects on the transitional list as “done” or “toast,” meaning the Sierra Club campaign had succeeded in stopping them, except for Plant Washington. “We’d call it one half.”

If he is right, Plant Washington could be the last traditional coal plant built for a long time, probably at least a generation, if not more. But, Nilles said, “We’re putting a lot of effort to make sure it never sees the light of day.”

Aside from the three projects already mentioned, only one other project on the transitional list looks as if it could move forward, but it is not a conventional coal project.

Summit Power Group’s 400-MW Texas Clean Energy Project in Odessa calls for the CO2 from the plant to be captured and injected underground to facilitate enhanced oil recovery operations at a nearby oil field.

The project is not yet under construction, but carbon capture and storage is one of the few technological options that would enable a coal plant to comply with the EPA’s proposed NSPS rules.

“We are hoping for a financial closing by the end of next month with construction beginning at the end of first quarter 2014,” Laura Miller, Summit’s director of projects, said.

Overall, a Platts review of the status of the transitional projects found that six developers have canceled their coal projects. Tenaska Energy canceled its Trailblazer project in Texas and its Taylorville project in Illinois. NRG Energy canceled its 750-MW Limestone-3 project in Texas. White Stallion canceled a 1,320-MW coal project in Texas, and GDF Suez said it is not pursuing a 650-MW coal-fired expansion at its Coleto Creek site.

The Holland Board of Public Works in Michigan has canceled plans to build a 78-MW coal plant at its De Young site and instead plans to build a 114-MW gas plant in downtown Holland that could also provide district heating. The project is expected to secure its air permit by year end and is due online in late 2016, said spokeswoman Anne Saliers.

Three other developers have switched from coal to gas projects: Erora Group’s Cash Creek project in Kentucky, Southeast Idaho Energy’s Power County project in Idaho, and EmberClear’s Good Springs project in Pennsylvania.

Two other developers, Deseret Generation & Transmission Cooperative and North American Power Group, did not reply by press time for repeated calls for comment on their projects, the 110-MW Bonanza in Utah and the 250-MW Two Elk in Wyoming, respectively. But from EPA statements it appears those projects do not have active air permits.

That leaves four potential projects — Summit Power’s Texas CCS project, Sunflower’s Holcomb-2, Wolverine’s Rogers City, and POWER4Georgians’ Plant Washington – that could still see the light of day. They all face substantial challenges, but the successful projects would very likely represent the last coal plants that are built for the foreseeable future.

— Peter Maloney

MISO, PJM work on interface pricing

...from page 1

market-to-market coordination.

“The problem is that the payment by the [regional transmission operator in charge of monitoring the market-to-market flowgate] fully and efficiently compensates the transaction for the flow relief it provides,” Potomac Economics said in its presentation. “Therefore, every dollar paid by the non-monitoring RTO for the same relief is redundant with the payment made by the monitoring RTO. There is no justification for the non-monitoring RTO to make an additional payment or impose an additional charge on the transaction.”

In its presentation, Potomac Economics said the interface pricing problem is causing market inefficiencies by skewing incentives for some interface transactions and that the costs of double payments could be contributing to the underfunding of financial transmission rights.

Potomac Economics suggested that for transactions scheduled with both grid operators that help relieve or contribute to congestion on a market-to-market constraint, the non-monitoring ISO should remove the congestion component from its interface price.

For transactions that are only scheduled with the non-monitoring ISO, Potomac Economics said the best long-term solution would be to keep the congestion component and give the non-monitoring ISO market flow credit. As a short-term solution for these types of transactions, though, Potomac Economics suggested that the non-monitoring RTO could also remove the congestion component from its interface price.

PJM agrees that steps need to be taken to address the issue of interface pricing, a PJM official said during Friday's meeting, but PJM does not believe that the congestion component of interface prices should be removed.

"Historic experience has shown that doing this can lead to unintended consequences," the PJM official said.

Removing the congestion component just for interface prices would create inconsistencies in how PJM calculates location marginal prices and could have implications for other types of transactions that use interface prices, such as FTRs, up-to congestion transactions and futures contracts, according to the PJM official.

Instead of removing the congestion component from interface prices, PJM said in its presentation that it believes "it would be beneficial to adjust the market flow calculation to accurately account for the impact of transactions."

Monitoring Analytics, PJM's independent market operator, said in a presentation at Friday's meeting that "the current interface pricing rules do not reflect how an LMP market should operate, when a non-contiguous interface is used" and that "market participants may double pay for congestion through MISO."

In its presentation, Monitoring Analytics said it agrees with PJM's proposed solution and does not support eliminating the congestion component for certain interface prices, as proposed by Potomac Economics.

MISO agrees with Potomac Economics that the current pricing rules are problematic, a MISO official said at Friday's meeting. The MISO official also said during his presentation that MISO does not believe that PJM's proposal would address the double charges and double payments at issue and thus would not solve the problem.

MISO agrees with Potomac Economics' proposed solution for the non-monitoring ISO's congestion component for transactions scheduled with both grid operators and its long-term approach to dealing with transactions that are only scheduled with the non-monitoring ISO through market flow credits, Joseph Gardner, MISO's vice president of forward markets and operations services, said in a Friday interview. However, MISO does not support Potomac Economics' suggested short-term solution of removing the congestion component for interface transactions that are scheduled only by the non-monitoring RTO, Gardner said.

In addition to the proposals put forward by Potomac Economics and PJM, WPPI Energy has proposed that MISO and PJM should consider using the same set of nodes and node weightings to calculate their interface prices in order to provide economically efficient price signals. WPPI's proposal was presented at a MISO Seams Working Group meeting on October 28 and was mentioned but not formally presented at Friday's meeting.

Officials from the grid operators said they will continue to work on the issue and will discuss it further at future Joint and Common Market Initiative meetings.

Gardner said MISO is actively working on the issue, but does not current have a set time table for addressing the problem. Because the grid operators and their market monitors have not yet reached a consensus on how to resolve the issue, Gardner said, it is difficult to know how long it will take to develop and implement a solution.

During the meeting, the grid operators also discussed the impact of short-lead market-to-market flowgate creation on FTR underfunding, efforts to improve coordination and modeling for forward markets including FTR markets, and analysis of issues related to capacity deliverability.

— Juliana Brint

Cal-ISO/PUC plan covers several initiatives ...from page 1

mechanism, or CPM, backstop procurement authority. The plan builds on a multi-year reliability "framework" that was released in July.

The PUC will consider expanding current resource adequacy requirements to include two- and three-year forward resource adequacy requirements for system, flexible and local capacity under a rulemaking process set to start in January. At the same time, the ISO will explore developing forward resource adequacy requirements for local regulatory authorities.

Under the second initiative, the PUC and ISO will develop a joint, long-term reliability assessment to identify local, flexible, and system needs and evaluate them against installed and procured resources. "A unified assessment of load and resources in California has never been produced on a forward basis across all three capacity parameters, on a regular schedule, or using standardized methodologies for assessing data," the plan said.

The assessment will help system resource planners and market participants understand what resources will be needed to meet emerging operational needs, the plan said.

Through the third initiative, the ISO, with PUC collaboration, will consider developing a market-based backstop procurement mechanism to replace or augment the existing CPM mechanism, which compensates resources using an administrative price.

Starting this year, the ISO will conduct a stakeholder process to consider design elements for a CPM replacement, like a reliability services auction, to be the primary backstop procurement mechanism that the ISO can use to deal with deficiencies in the resource adequacy program, the plan said. The ISO board is slated to vote on a new tariff design in the third quarter next year.

While the ISO and PUC intend to work closely in developing a new backstop mechanism, the PUC reserves the right to oppose an ISO filing seeking Federal Energy Regulatory Commission authority to institute a reliability services auction, the plan said. "The ISO and CPUC staff will seek to engage FERC staff early and often throughout the development of this mechanism, especially in light of the unique nature of the proposals under consideration," the plan said.

The PUC intends to launch a proceeding in January to lay out the scope and schedule for working on the three initiatives. After holding workshops, the PUC expects to make a decision on a multi-year resource adequacy program by early 2015.

"The plan envisions assiduous inter-organizational cooperation to develop an adequate informational record upon which decision-makers can choose to act," the plan said. "Both organizations recognize that the changes under consideration to California's approach to energy policy are significant and require thorough vetting—with significant stakeholder input and analyses—prior to adopting decisions on policy outcomes that would bring these initiatives to a conclusion."

Under the plan, the PUC and ISO will use four guiding principles in weighing possible policy changes. The organizations, for example, agree to boost participation by preferred resources in energy and capacity markets.

"This principle emphasizes that achieving California's ambitious environmental goals while maintaining grid reliability should provide an opportunity that allows for greater participation by demand response, storage, and other preferred resources in both capacity markets for resource adequacy (for reliability planning purposes in advance of the delivery year) and in energy markets (to meet daily energy and operational needs)," the plan said.

Also, the organizations want to try to reduce the chance that existing generating resources will be shut early because of poor market design. "The CPUC and ISO are particularly concerned with mitigating the risk of unexpected retirements by resources that the ISO anticipates California will need in the future for local or flexible capacity attributes," the plan said.

— Ethan Howland

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