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MEGAWATT DAILY

Wednesday, January 11, 2017

NEWS HEADLINES

Cuomo calls for big NY offshore wind effort

- Asks LIPA to OK 90-MW project
- Master plan to be done by end of 2017

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ERCOT coal power share jumps in December

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- Fuel-cost ratio favored coal for 2016's second half

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ISO New England changes benchmark gas hub

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- On a bigger scale than Alabama plant

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- 'Punitive budget cap' to be imposed: ranking Dem
- Proposal would make position limits discretionary

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KEY DRIVERS/MARKET HIGHLIGHTS

- **Northeast spot prices fall, forwards rebound**
- **Central dailies mixed; most of region to be warm**
- **ERCOT dailies ease on more wind generation**
- **West power dailies up with gas prices**

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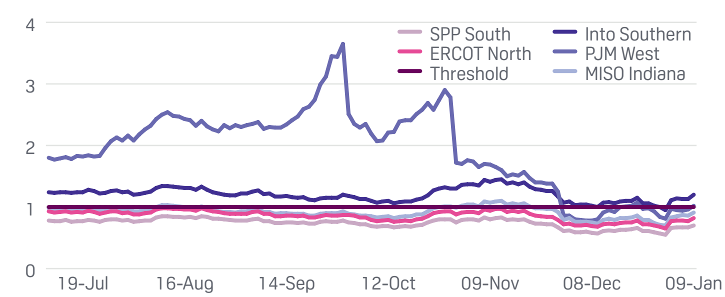
REGIONAL DAY-AHEAD PRICE CHANGES

	Day-ahead peak prices			Regional weather trends		
	11-Jan	Daily chg	Prior 7-day avg	11-Jan	Daily chg	7-day forecast
ISO Price Locations						
CAISO NP 15	37.43	-0.90 ▼	38.48	54.9	-0.6 ▼	54.5
ERCOT North Hub	20.45	-1.54 ▼	28.34	66.5	1.6 ▲	54.7
ISONE Internal Hub	32.86	-21.94 ▼	64.37	42.4	14.9 ▲	38.0
MISO Indiana Hub	27.71	-0.92 ▼	37.06	32.3	-2.0 ▼	26.4
NYISO Zone G	36.18	-21.08 ▼	62.67	40.6	13.3 ▲	39.4
PJM West Hub	28.81	-4.18 ▼	43.13	42.6	10.7 ▲	41.8
SPP South Hub	25.54	-3.69 ▼	34.81	46.8	0.6 ▲	31.3
Bilateral indexes						
Into Southern	26.00	-3.50 ▼	31.00	59.4	10.5 ▲	61.1
Palo Verde	27.75	1.75 ▲	27.54	54.5	-0.7 ▼	53.6
COB	34.82	3.16 ▲	39.04	27.3	-7.1 ▼	35.6
Mid-C	35.38	4.63 ▲	38.31	27.3	-7.1 ▼	35.6

Source: Platts

COAL-VS-GAS $/MWH FUEL COST RATIOS



The Platts coal-vs-gas fuel cost ratios indicate the regional competitiveness of gas versus coal for power generation. The ratio is calculated by dividing the $/MWh fuel cost for coal by that of gas. Gas generation is cheaper than coal generation when the ratio is greater than one. All price data reflects prompt month fuel contracts.

Source: Platts daily OTC coal prices and M2MS gas prices

PLATTS PEAK DAILY DEMAND (GW)

						Daily change		Five day forecast					Season		Season average			
ISO	07-Jan	08-Jan	09-Jan	10-Jan	11-Jan	Chg	% Chg	12-Jan	13-Jan	14-Jan	15-Jan	16-Jan	Min	Max	2017	2016	Chg	% Chg
BPA-Puget	9.94	9.31	9.03	8.83	9.76	0.93	10.53	9.78	9.65	8.51	7.72	8.03	7.09	10.97	9.54	7.99	1.55	19.40
IESO	22.29	22.46	22.34	21.59	20.90	-0.69	-3.20	20.05	21.78	21.71	21.06	20.81	19.17	22.82	21.67	21.60	0.07	0.32
CAISO	27.55	27.07	29.66	29.14	29.10	-0.04	-0.14	29.53	29.11	26.46	26.62	29.43	22.79	30.53	28.17	28.57	-0.40	-1.40
ERCOT	58.86	53.47	46.58	38.95	40.15	1.20	3.08	39.17	37.20	34.79	34.47	38.63	31.47	59.65	45.60	41.36	4.24	10.25
SPP	32.25	30.16	31.71	25.72	25.60	-0.12	-0.47	27.41	32.87	30.54	27.98	29.10	28.26	37.66	31.93	32.25	-0.32	-0.99
MISO	94.05	91.49	93.85	80.75	81.77	1.02	1.26	82.98	94.45	83.64	79.01	81.90	73.85	99.80	88.15	85.01	3.14	3.69
PJM	121.78	124.09	128.85	114.05	99.84	14.21	-12.46	93.83	100.17	101.45	98.66	96.01	89.37	128.85	113.12	107.11	6.01	5.61
NYISO	21.84	22.25	23.63	21.58	20.12	-1.46	-6.77	19.53	19.51	20.40	20.17	19.83	18.67	23.63	21.27	21.08	0.19	0.90
NEISO	18.51	18.47	19.58	17.39	16.23	-1.16	-6.67	16.02	15.88	17.46	16.51	16.43	14.87	19.58	17.46	17.30	0.16	0.92
AESO	11.16	11.33	11.44	10.75	10.68	-0.07	-0.65	10.79	10.66	9.86	9.44	10.01	10.67	11.44	11.22	10.64	0.58	5.45

Seasons are defined as: Summer (June – August), Fall (September – November), Winter (December – February), and Spring (March – May).

Source: Platts

NEWS

Cuomo calls for big NY offshore wind effort

New York Gov. Andrew Cuomo on Tuesday called on the Long Island Power Authority to approve a 90-MW offshore wind project 30 miles southeast of Montauk, and proposed an offshore "master plan" for 2,400 MW of offshore wind by 2030.

Cuomo, in a statement, said that offshore wind is "critical" to the state meeting its 50% by 2030 clean energy standard. He also called on state agencies to ensure that a potential area off Rockaway Peninsula won by Norway's Statoil in a December federal lease auction is developed "cost-effectively and responsibly."

Cuomo, a Democrat, is in his second year of his second term as governor. He has been active on the energy front and has already said he expects to run for a third term in 2018.

Cuomo has stuck with the state's ban on fracking. He pushed the Clean Energy Standard that includes zero emission credits for three upstate nuclear facilities while he opposed the license extension of the two-unit Indian Point nuclear facility just north of New York City that Entergy said Monday it would close starting in 2021.

Also on Monday Cuomo announced a state initiative to install 500 electric vehicle charging stations in order to expand the use of the zero-emission vehicles.

Master plan to be done by end of 2017

In his statement released late Tuesday Cuomo said the state's Offshore Wind Master Plan will be completed by the end of 2017. He said offshore wind projects "will be developed out of view from the coast and in close collaboration with local communities and stakeholders."

He called for LIPA to develop its 90-MW project southeast of Montauk in the Atlantic Ocean as a "first step toward developing an area that can host up to 1,000 megawatts of offshore wind power."

"In an indication of offshore wind's growing attractiveness as a power source, the proposed project is the most innovative and least cost way to meet the growing power needs of the South Fork and to provide cleaner energy for Long Island," Cuomo said.

He said LIPA has indicated that contract negotiations are close to final, and that the project will be voted on at an upcoming January meeting.

Cuomo also called upon the New York State Energy Research and Development Authority to work with Statoil, fishermen and local residents to help smooth the development of an offshore project slated for an area 17 miles south of the Rockaway Peninsula.

The Norwegian oil and gas exploration company won a federal Bureau of Ocean Energy Management lease auction of 79,000 acres with a bid of $42.5 million. The area could hold an offshore wind farm as large as 800 MW.

— *Jeffrey Ryser*

ERCOT coal power share jumps in December

ANALYSIS Coal-fired generation's share of the Electric Reliability Council of Texas' energy supply surged past the natural gas-fired fleet in December, and coal's total output for 2016 increased 3.5% from 2015, while natural gas-fired plants' total dipped by 8.6%, a new report shows.

S&P Global
Platts

MEGAWATT DAILY

Volume 22 / Issue 7 / Wednesday, January 11, 2017

ISSN: 1088-4319

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Megawatt Daily is published daily by Platts, a division of S&P Global, registered office: Two Penn Plaza, 25th Floor, New York, N.Y. 10121-2298.

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ERCOT's Demand and Energy Report for December, which was posted on the grid operator's website late Monday, showed energy supplied by ERCOT generators totaled 27.7 TWh in December, up from 25.8 TWh in December 2015.

The major components of those totals break down as follows:

- Natural gas, 8.2 TWh this December, versus almost 9 TWh in November and 12.1 TWh in December 2015;
- Coal, 10.6 TWh this December, versus 7.9 TWh in November and 6 TWh in December 2015;
- Nuclear, 3.8 TWh this December, versus 3.3 TWh in November and less than 3 TWh in December 2015; and
- Wind, almost 5 TWh this December, versus 4.2 TWh in November and 4.5 TWh in December 2015.

As a percentage of all power supplied in ERCOT, natural gas fell to 29.6% in December from 36.6% in November and 46.9% in December 2015. Coal jumped to 38.3% in December from 32.3% in November and 23.3% in December 2015. Nuclear was 13.7% in December, 13.5% in November and 11.6% in December 2015. Wind was 18% in December, 17.3% in November and 17.5% in December 2015.

Total energy up 1.2% for the year

For the 12 months of 2016, the Demand and Energy Report shows energy usage totaled 351.5 TWh, compared with 347.3 TWh in the 12 months of 2015.

"I think that a robust economy is behind some of this along with a somewhat hotter summer," said Neil McAndrews, an energy market consultant based in Austin, Texas. "I think weather will be the most impactful variable next year."

The major components of those totals break down as follows:

- Natural gas, 153.5 TWh in 2016, down from 167.9 TWh in 2015;
- Coal, 101.1 TWh in 2016, up from 97.7 TWh in 2015;
- Nuclear, 42.1 TWh in 2016, up from 39.4 TWh in 2015; and
- Wind, 53.1 TWh in 2016, up from 40.8 TWh in 2015.

McAndrews attributed the surge in coal generation, compared with natural gas generation's decrease, to relative fuel costs.

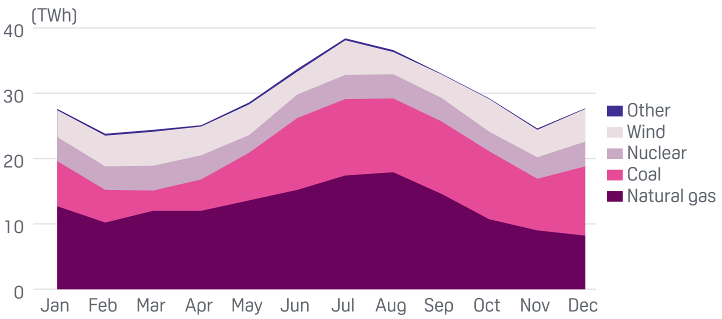
"During 2015 natural gas would substitute for coal and gain share when natural gas prices were around $3," McAndrews said in an email Tuesday. "But in 2016, coal would remain at a much higher level percent of use at $3.00 natural gas prices. I would suggest that coal prices declined and that its marginal dispatch costs were lower at the end of 2016 when compared to the beginning of 2015. So it is a combination of lower coal prices in 2016 and higher natural gas prices in 2016."

The Platts fuel-cost ratio, comparing the economics of natural gas to Powder River Basin Coal as an electricity generating fuel at the ERCOT North Hub, has been less than 1 almost every day since June, indicating that coal has been a more profitable fuel. For all of 2015, that ratio had averaged just above 1, and it had remained above 1 — indicating more favorable economics for natural gas-fired generation — from January through the end of May.

Looking to 2017, McAndrews said he expects coal, wind and solar are likely to gain market share while natural gas is likely to "decline somewhat."

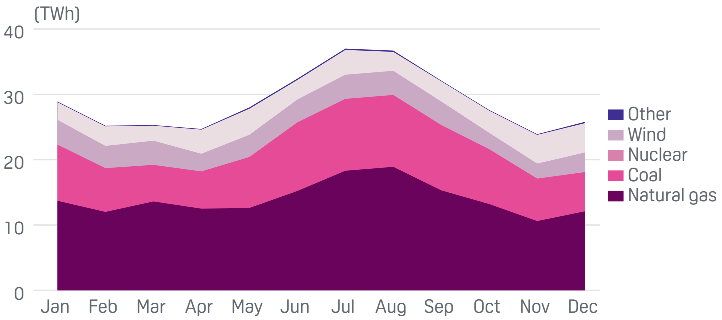
— *Mark Watson*

SOURCE OF ELECTRICITY GENERATED IN ERCOT IN 2016



Source: Electric Reliability Council of Texas

SOURCE OF ELECTRICITY GENERATED IN ERCOT IN 2015



Source: Electric Reliability Council of Texas

ISO New England changes benchmark gas hub

Tariff changes approved by the US Federal Energy Regulatory Commission Monday will allow ISO New England to base certain price thresholds in its tariff on a natural gas price index from a new, more liquid trading hub.

The market price of natural gas is a key input in ISO New England's calculation of the daily energy market offer threshold for import capacity resources, the forward reserve threshold price and the peak energy rent strike price.

The grid operator had relied on the daily Algonquin Gas Transmission city-gates natural gas price index as a good representation of the cost to acquire gas in New England, but told FERC in November that trading at this location declined in 2016, failing to form a daily price index value for 55% of the days between April and September.

ISO New England contended that trading on the Algonquin pipeline had mostly shifted to a new trading hub introduced by the Intercontinental Exchange in January 2016, and sought commission approval of tariff revisions that would allow it to instead use the price index from this new location to calculate the price thresholds at issue (ER17-337).

The new so-called AGT-CG (Non-G) hub excludes transactions that would require gas to flow on the Algonquin pipeline's G lateral, which is prone to transportation difficulties on peak winter days.

The price index formed at this hub, according to ISO New England, met FERC's availability and liquidity standards for indices used in jurisdictional tariffs. Further, a review of trading activity from August 3 to October 31 demonstrated that a daily price index was calculated on each of those days at the hub, ISO New England said.

Basing thresholds on new hub 'just and reasonable'

FERC, in an order issued Monday, found the proposed change to the source of ISO New England's gas price data to be "just and reasonable because it changes the natural gas price index used for these three tariff mechanisms from one that is rarely liquid to one that is reliably liquid and satisfies the commission's minimum criteria for indices used in jurisdictional tariffs."

The commission made the tariff changes effective Tuesday, rejecting arguments made by Dominion in a protest over one aspect of the proposal.

Dominion had argued that using the AGT-CG (Non-G) index in the calculation of the PER strike price was unjust, unreasonable and unduly discriminatory because it did not conform to existing PER requirements in ISO New England'stariff.

A PER strike price is calculated each day at a value "slightly higher than the marginal operating cost of the most expensive resource in New England" to aid in developing the PER adjustment, FERC said. That adjustment "is designed to approximate the additional revenues that a hypothetical proxy peaking unit would earn in the real-time energy market during the highest-priced hours reflecting scarcity, and to return those revenues to load." Its purpose is "to act as a hedge for load against price spikes in the energy market," FERC explained.

Dominion asserted that a PER strike price that fails to "approximate the cost of the marginal resource as the system approaches a scarcity condition … would subject capacity resources to unwarranted PER penalties."

The company contended that ISO New England provided no analysis or evidence that the price at the AGT-CG (Non-G) hub would lead to a PER strike price that appropriately approximates the fuel costs of the marginal resource. Failing to do so, Dominion said, "could have a discriminatory effect on generators that must purchase higher priced natural gas, i.e., if the real-time price exceeds the PER strike price but remains below the price of the higher priced generators." Dominion added that "these higher priced generators would be penalized more because they would not be dispatched for energy but still subject to the PER penalties."

Dominion alternative for PER strike price rejected

Dominion recommended that FERC require ISO New England to use the higher of the AGT-CG and AGT-CG (Non-G) location prices to calculate the PER strike price to "ensure that when natural gas prices exceed oil prices, the natural gas price used in the PER strike price calculation would approximate the cost of the PER proxy unit in accordance with the tariff."

FERC noted that because it deemed ISO New England's proposal just and reasonable, there was no need to entertain Dominion's alternative.

But, the commission offered that Dominion's proposal lacked "evidence that the continued use of the AGT-CG index would meet the commission's minimum index conditions."

Those conditions are "average daily volume traded of a least 25,000 MMBtus/day for gas or 2,000 MWh/day for power; average daily number of transactions of five, eight, 10, or more (depending on whether it is a daily, weekly, or monthly index); and average daily number of counterparties of five, eight, 10, or more (depending on whether it is a daily, weekly, or monthly index)."

FERC explained that an index location must meet at least one of those conditions for minimum levels of activity at a trading location to be used in a jurisdictional tariff, and "Dominion has failed to explain how the continued use of the AGT-CG price index" would meet any of these criteria.

— Jasmin Melvin

'Largest' CO2 capture project starts up

After years of discussion and construction, the US' two most prominent clean coal projects are coming online in the same month.

On Tuesday, NRG Energy and its joint venture partner JX Nippon Oil & Gas said their $1 billion Petra Nova post-combustion project that will capture 1.6 million tons of CO2 per year at NRG's Powder River Basin coal-burning WA Parish power plant outside of Houston has begun operations. The project took just over two years to build.

On January 6, Mississippi Power told the Securities and Exchange Commission that it will officially bring online by January 31 its new, 582-MW combined-cycle Kemper County power plant that will be fueled by gasified lignite in a pre-combustion process that will allow the capture of 3 million tons of CO2 per year. Construction of the Kemper plant began in February 2010. The rate payer's share of the cost of the facility is $2.88 billion, while its total cost has run to approximately $7 billion.

Both projects will pipe their captured CO2 to nearby oil fields for use in enhanced oil recovery.

NRG project the largest of its kind

On Tuesday, NRG and JX Nippon said their project is "the world's largest" post-combustion carbon capture facility, and that it was brought online "on-budget and on-schedule."

The project captures 90% of the carbon dioxide from a 240-MW slipstream of flue gas off of the facility's 610-MW Unit 8, which burns PRB coal. It captures the CO2 using an amine process developed by Mitsubishi Heavy Industries and Kansai Electric Power, and pipes the captured CO2 to enhance recovery at an oil field 82 miles away that the joint venture owns along with Hilcorp Energy.

According to David Greeson, vice president of development at NRG, the facility is now moving 220 tons of CO2 via the pipeline per hour, or roughly 5,000 tons per day. The system is designed to capture 1.6 million tons of CO2 per year.

Sale of the crude oil that is recovered is to pay for the Petra Nova project. The revenue stream for the project is equal to 50% of the oil sales, with NRG and JX Nippon each holding a 25% interest in the oil field, with Hilcorp owning 50%.

When it comes to the economics of the CO2 capture project, "oil price movements are the number 1 driver," Greeson said.

The price of oil was in the $90 to $100/barrel at the time construction on the project began in July 2014. By Christmas 2015 the price of crude hit $37.50/b. On Monday, however, the price of crude was in the $53/b range, leaving the project's developers feeling a bit more at ease.

While production at the West Ranch oilfield is currently only 300 barrels per day, Greeson said that Petra Nova and Hilcorp are anticipating that over the next ten years the field's production will be steady at between 10,000 and 15,000 b/d.

On a bigger scale than Alabama plant

Petra Nova is using an amine capture process that Mitsubishi Heavy Industries and Kansai Electric began testing on a 25-MW slip of flue gas at Alabama Power's Barry Plant in 2010. By 2011 the project was capturing and by 2012 it was burying carbon. That project captured 500 tons of carbon per day.

Geeson said that Petra Nova "stood on the shoulders" of the Barry plant project. He says that NRG was not looking to do R&D. The project just completed was a "ten times" upscaling of the Barry project that is capturing 5,000 tons of CO2 per day.

Another, smaller post-combustion project is in Canada, where capture began at the Boundary Dam facility in Saskatchewan in 2014.

On January 5, SaskPower, the utility in Saskatchewan, said the Shell Global amine process built at the 139-MW Unit 3 of the coal-fired facility captured 58,569 metric tonnes of CO2 in the month of December, and just under 800,000 mt for the full year 2016.

— Jeffrey Ryser

House weighs CFTC bill, position limits measure

As US House Republicans sounded themes of sweeping back regulation in their first weeks of the 115th Congress, legislation to reauthorize the US Commodity Futures Trading Commission took a surprise spot among the early bills poised for action this week.

And an amendment that would make it clear that a contentious position limits regulation is discretionary, rather than required action, by the CFTC under the Dodd-Frank Act is up for a vote when the bill comes to the floor. The amendment is to be offered by House Agriculture Committee Chairman Michael Conaway, Republican-Texas, whose committee has jurisdiction over the agency.

The House passed legislation similar to the underlying bill in June 2015, and the updated five-year reauthorization closely tracks that. One notable change is a provision flatlining CFTC spending at $250-million, the agency's most recent funding level, for the next five years.

The House Rules Committee Tuesday voted to approve a rule that would allow for votes and debate on nine amendments on the floor, including the position limits measure.

Democrats, upset that the bill had not moved through committees of jurisdiction this Congress, argued that an open rule, allowing unlimited amendments should be permitted. But their attempt to recommit the rule to committee failed by a 4-8 vote.

House Agriculture Committee Ranking Member Collin Peterson, Democrat-Minnesota, opposed the bill, H.R. 238, and the process of bringing it forward so early in the session. The measure will slap a "punitive budget cap on an agency that has been underfunded for years" while imposing "heavy administrative hurdles and new litigation risks" by imposing new cost-benefit analysis requirements on the agency, he contended in a "dear colleague" letter Wednesday.

Conaway on the other hand stressed that the funding for the agency is now listed as a specific sum, rather than giving a "blank check" to appropriators. The measure, largely developed in the last Congress after dozens of hearings, does not roll back any key financial reforms, he said, but keeps Congress' promise to "Main Street America" that did not cause the financial crisis.

The pending amendment on position limits comes as the CFTC recently re-proposed the long-delayed regulation, setting position limits meant to head off excessive speculation in 25 physical commodity futures and swaps markets. The re-proposal effectively put off a final decision until next administration amid expectations that a Republican-led commission or Congress might revamp if not scrap a final rule issued in the waning days of the Obama administration.

Proposal would make position limits discretionary

Conaway's amendment would strike several clauses from the Commodity Exchange Act addressing position limits. According to the Rules Committee description, the amendment "makes clear Congress's intent that the commission may impose and implement position limits as it finds necessary, provided the commission makes a finding prior to imposing such limits."

The commission, in its recent rule, stated that statutory language requires it to issue a rule without first finding that a rule would reduce excessive speculation.

Tyson Slocum of Public Citizen said the amendment would remove position limits mandates in the CEA. "The purpose of this amendment is to gut and remove the position limits mandate," he said.

The House is expected to vote on the rule Wednesday and move to final passage as early as Thursday.

The precursor to the bill passed the House June 2015 with narrow Democratic support, after CFTC Chairman Timothy Massad wrote the agriculture panel laying out a long list of reasons to his opposition to the measure.

— Maya Weber

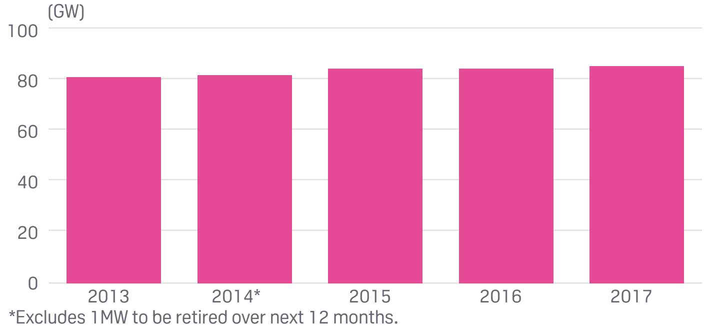
Taxes, tech and growth boost Texas capacity

ANALYSIS The Electric Reliability Council of Texas' "installed generation capacity," as counted by state regulators, surged by 9.4 GW between 2013 and 2017, mostly because of low barriers to entry, renewable tax credits, tech improvements and demand growth, observers said.

The Public Utility Commission of Texas annually produces a report counting all of ERCOT's generation capacity as a way to calculate two market power thresholds, and the report released Friday showed the state is expected to have 93.1 GW of generation capacity, which includes mothballed generation and capacity that is expected to be completed during the current calendar year.

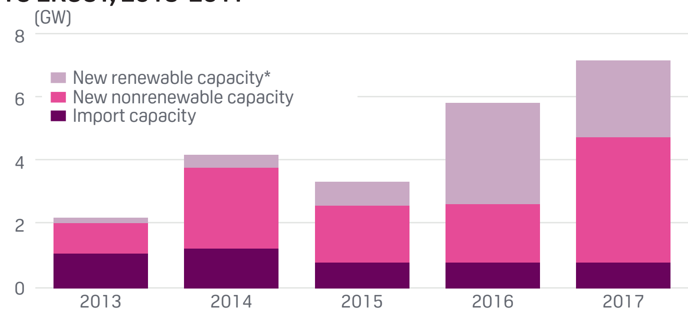
That is up from 90.8 GW in 2016 and 83.7 GW in 2013, for example.

ERCOT INSTALLED CAPACITY, 2013-2017



*Excludes 1MW to be retired over next 12 months.
Source: Public Utility Commission of Texas

CAPACITY NOT CURRENTLY INSTALLED BUT AVAILABLE TO ERCOT, 2013-2017



*For 2013-14, new renewable capacity was counted as 8.7% of nameplate capacity. For 2015, noncoastal wind capacity was 12% of nameplate, and coastal wind capacity was 56% of nameplate. For 2016, noncoastal wind was 12% of nameplate, and coastal wind was 55% of nameplate. For 2017, noncoastal wind was 14% of nameplate, coastal wind was 58% of nameplate, and solar was 77% of nameplate.
Source: Public Utility Commission of Texas

Under state law, no company can own more than 20% of ERCOT's installed generation capacity, including uncontrollable renewable resources. Therefore, according to the PUC's latest installed generation capacity report, no one company can own more than 18.6 GW of ERCOT's capacity.

Also, a PUC rule provides a "small fish swim free" exemption for owners of less than 5% of ERCOT's installed generation capacity, excluding uncontrollable renewable resources. Such a small market participant "is deemed not to have ERCOT-wide market power," according to Substantive Rule 25.504(c). Therefore, such market participants have more freedom to participate in the market without being penalized for anti-competitive behavior.

Therefore, any owner of generation totaling less than 4.3 GW of ERCOT's capacity cannot be deemed to have "ERCOT-wide market power."

How wind capacity is counted affects total

The PUC's installed generation capacity report includes estimated load carrying capacities for uncontrollable renewables that have varied over time. For 2013-14, wind capacity was counted as 8.7% of nameplate capacity. For 2015, noncoastal wind capacity was counted as 12% of nameplate, and coastal wind capacity was counted as 56% of nameplate. For 2016, noncoastal wind was counted as 12% of nameplate, and coastal wind was counted as 55% of nameplate.

For 2017, solar capacity became large enough for the first time to be counted separately, as 77% of nameplate. Noncoastal wind was counted as 14% of nameplate in the report released Friday, whereas coastal wind was counted as 58% of nameplate.

"The jump in operational capacity from 2014 to 2015 has certainly something to do with the [accounting] treatment of wind," said Gurcan Gulen, senior energy economist at the University of Texas Bureau of Economic Geology's Center for Energy Economics.

However, Jeff Schroeter, a Dallas-based managing director of Genova Power Advisors, a generation development and consulting company, said "the primary driver" in the new report's capacity growth is "new assets."

"Adjusting renewable capacity benefit on peak is secondary," Schroeter said in an email Tuesday. "I think this PUCT update of installed capacity can be summed up in three phases: low barrier to entry for generation development in the ERCOT market; renewable tax credits; ... and the march of technology improvement."

Schroeter cited ERCOT's low barrier to entry as a factor in the development of Exelon Generation's new 1,000-MW Colorado Bend II Generating Station in Wharton, Texas, which is slated to begin operating in July. Another example cited by Schroeter was Panda Power's investments in ERCOT generation, which total $2.2 billion to build 2,274 MW of capacity in ERCOT over the past few years.

Tax credit eligibility deadline extended 5 years

Regarding renewable tax credits, Schroeter cited Congress' extension, in December 2015, of the 10-year production tax credit eligibility date for wind projects until January 1, 2020, as encouraging new wind generation in the state, which added 1.3 GW in nameplate capacity in 2016 alone.

The same law extended the eligibility date for solar power investment tax credits, and UT's Gulen said he expects it "will likely induce more [investment] going forward."

"There is a long list of projects in various stages of development," Gulen said in an email Tuesday.

Schroeter noted that new renewable capacity expected to be added in the 2016 PUC installed capacity report exceeded the total for new nonrenewable capacity by a wide margin – 3.2 GW to 1.8 GW. The situation flipped in the latest PUC report, with new renewable capacity expected to be added in 2017 to total 2.5 GW, compared with almost 4 GW of new nonrenewable capacity.

"Further enhancements in wind turbine heights and efficiencies" have also enhanced wind and solar developments, Schroeter said, while improvements in "ultra-low heat rate" generation have contributed to nonrenewable generation development.

Gulen said load growth is another factor in the growth of installed generation capacity counted in the PUC report.

"Summer 2016 peak was larger than predicted," Gulen said. "[The] 2017 peak forecast has been raised. Texas' economy has been growing despite low oil and gas prices. With the recent OPEC decision injecting some life into oil prices, drilling activity might pick up. Even before the OPEC announcement, Permian drilling was increasing."

Demand growth has not only been limited to summer months, as ERCOT set a new winter peak demand record on Friday, at 59,650 MW, driven by cold temperatures throughout the region, ERCOT announced Monday. This was also a new January record.

In its seasonal assessment report on resource adequacy for winter 2016-17, the grid operator had predicted power demand would peak at 58,591 MW, around 1,050 MW below the actual new record.

The previous winter peakload record was marked at 57,924 MW on December 19, 2016, and the previous January record was set at 57,256 MW on January 7, 2014. The all-time demand record for ERCOT, a summer peaking footprint, is 71,110 MW, set on August 11, 2016.

— *Mark Watson and Jeff Zhou*

Great River Energy inks 300-MW wind deal

Minnesota's second-largest electricity supplier, Great River Energy, has taken a major step in complying with the state's renewable energy standard by purchasing the entire 300-MW output of a NextEra Energy Resources wind farm planned for neighboring North Dakota.

The long-term wind power purchase agreement is expected to almost double Great River's wind generation capacity to more than 700 MW. The Maple Grove-based generation and transmission co-op currently gets about 17% of its 2,883 MW of generation capacity from renewables, Lyndon Anderson, a spokesman for the co-op, said in a Tuesday email.

Anderson said Florida-based NextEra will own the new Emmons-Logan wind farm in south-central North Dakota on which construction is scheduled to commence in 2019. Great River expects to start receiving the power in 2020.

"This project will help ensure that GRE continues to meet the requirements of the Minnesota renewable energy standards," he added. Under the RES, utilities must get at least 25% of their electricity sales from renewable sources such as wind and solar by 2025.

However, Anderson said his co-op also secured "good prices" for the electricity to be produced by the new wind farm, although he declined to reveal them.

Wind energy prices continue to fall across the US and in some cases already are lower than comparable coal-fired generation.

Co-op mainly relies on fossil fuels

Great River continues to rely primarily on fossil fuels — coal and natural gas — for its generation. Coal accounts for 1,434 MW of its total portfolio, with gas and/or fuel providing most of the remainder.

The co-op gets another 29 MW from refuse-derived fuel.

Great River's largest power plant is the 1,146-MW Coal Creek baseload coal plant in North Dakota. Last year, the co-op announced plans to retire its 50-year-old, 189-MW Stanton coal plant in North Dakota by May 2017.

At the time, Great River said Stanton no longer was economic to operate given the low power prices in the regional energy market.

The co-op also operates the 99-MW Spiritwood station in South Dakota.

Spiritwood, a combined heat and power plant, burns lignite coal to also produce steam.

Altogether, Great River serves about 1.7 million customers in Minnesota.

Minneapolis-based Xcel Energy is the state's largest electric utility.

— Bob Matyi

AEP, First Energy Ohio rate cases diverge

Discussions over billion-dollar electricity rate cases in Ohio involving two of the nation's largest electric utilities, FirstEnergy and American Electric, appear to be headed in different directions.

The Ohio Office of Consumers' Counsel is appealing an October 12 order by the Ohio Public Utilities Commission that approved a new customer charge for FirstEnergy that could allow the Akron-based company to recoup just over $1 billion over five years, ostensibly for grid modernization.

But the OCC and other parties, including the PUC staff, have reached a "global" settlement with AEP Ohio, a subsidiary of Columbus-based AEP, that could resolve 14 cases pending before the commission and lead to a $100 million refund to standard service offer, or shopping, customers who were overcharged from August 2012 to May 2015.

DAILY CSAPR ALLOWANCE ASSESSMENTS, JAN 10 ($/st)

	$/st	2016 Range	$/st	2017 Range
NOx Annual	5.75	3.00-8.00	5.75	3.00-8.00
NOx Seasonal	140.00	125.00-175.00	475.00	400.00-650.00
SO_2 Group 1	2.50	0.50-10.00	2.50	0.50-10.00
SO_2 Group 2	4.25	0.50-10.00	4.25	0.50-10.00

RGGI CARBON ALLOWANCE FUTURES, JAN 9 ($/allowance)

ICE	Settlement	Volume
Dec17 V16	3.63	450
Dec18 V16	3.75	0
Dec19 V16	3.88	0
Dec17 V17	3.63	0
Dec18 V17	3.75	0
Dec19 V17	3.88	0
Dec17 V18	3.63	0
Dec18 V18	3.75	0
Dec19 V18	3.88	0
Dec17 V19	3.63	0
Dec18 V19	3.75	0
Dec19 V19	3.88	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.

'No tangible benefit' from FirstEnergy charge: OCC

In its rehearing application, the OCC said FirstEnergy's nearly 2 million customers in northern Ohio would pay at least $612 million and perhaps more than $1 billion, "but not for the electricity that they use" under the grid modernization charge in FirstEnergy's electric security plan.

"It was not reasonable or lawful for the PUCO to approve FirstEnergy's electric security plan that included a credit support provision charged to customers who may see no tangible benefit from the charge," the OCC, the state's residential utility consumer watchdog, asserted. "The PUCO's approval of the credit support rider constituted an unlawful subsidy that may benefit FirstEnergy's parent or unregulated generation affiliates."

The commission authorized the company to recover $132.5 million a year, to be "grossed up" to around $204 million annually, to pay FirstEnergy's taxes on the new money. The initial term is three years, but FirstEnergy can request a two-year extension which is seen as likely.

According to the OCC, the special charge authorized by state regulators is "akin to the bailout" proposed by FirstEnergy early last year covering more than 3,000 MW of "at risk" coal and nuclear generation in Ohio.

After the commission approved the credit support charge in late March, it was blocked by the Federal Energy Regulatory Commission which rescinded affiliate agreements for both FirstEnergy and AEP.

FirstEnergy, which wants to become a fully regulated utility in 12 to 18 months, defended the controversial charge as necessary to protect its credit rating.

It is unclear when the PUC will rule on the OCC appeal. An unfavorable decision could result in an appeal to the courts.

AEP global settlement ruling expected soon

The PUC is expected to rule soon on the proposed global settlement involving AEP.

Under the proposed deal, AEP Ohio customers would pay $388 million to the company starting this month under a retail stability rider for the remaining months of its rate plan.

Residential customers would pay about $43.7 million of that amount, with non-residential customers providing the balance.

AEP said it will refund a total of $100 million "as a remedy to return a portion of amounts that were paid by standard service offer customers from August 2012 through May 2015" for power purchases from the Ohio Valley Electric Corp. and a natural gas-fired plant in Lawrenceburg, Indiana.

"Residential customers were primarily served under the SSO during the period and as such it is estimated that approximately $62 million of the refund will be provided to residential customers," AEP said in a new filing with the PUC.

Over the next two years, the bills of AEP Ohio customers would be reduced by an average of $4.25/month as a result of an Ohio Supreme Court ruling last year that said AEP should not have been charging customers for its transition to electric competition.

Bruce Weston, Ohio's consumer counsel, said in a Tuesday statement that as a result of negotiations with AEP, consumers also will save more than $100 million for the costs of AEP's energy efficiency programs.

Weston commended the company "for wanting to get to 'yes' with consumers in both settlements."

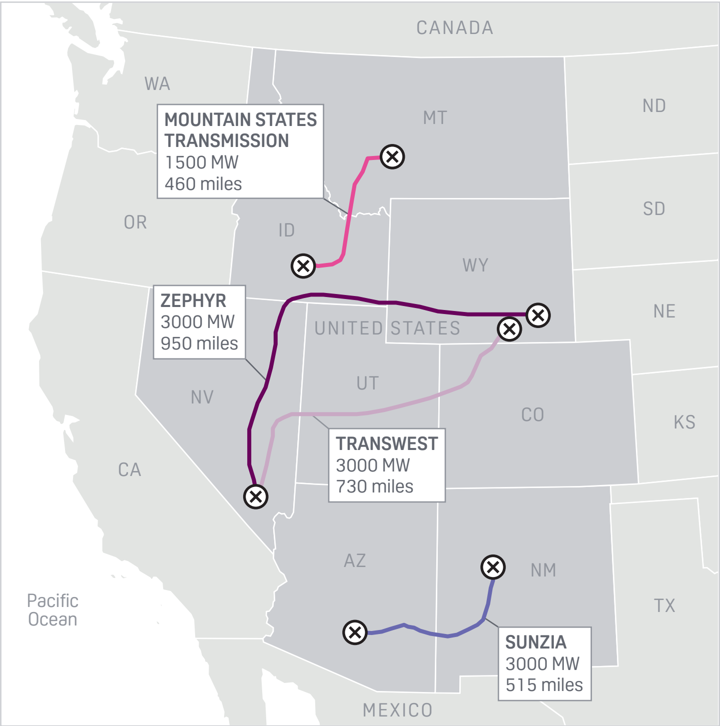
— Bob Matyi

Wires may reduce renewable curtailment: NREL

While the grid can handle renewable penetration levels close to 50%, some additional transmission would likely be needed to avoid large curtailments of the resources, according to a study released Monday by the US Energy Department's National Renewable Energy Laboratory.

"Although our analysis identifies no reliability issues in any of the

PROPOSED INTERSTATE TRANSMISSION PROJECTS



Source: NREL

OUTAGES

GENERATION UNIT OUTAGE REPORT

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Beck-2 PGS/OPG	103	h	Ont.	MO	Unk	04/11/16
Darlington-2/OPG	887	n	Ont.	MO	Unk	10/14/16
Lake Superior/Brookfield	120	g	Ont.	PMO	Unk	11/04/14
Lennox-4/OPG	525	g	Ont.	MO	Unk	12/30/16
Npiroqfalls/Iroquois	131	g	Ont.	MO	Unk	01/03/17
Pickering-4/OPG	515	n	Ont.	MO	Unk	01/05/17
Pickering-7/OPG	520	n	Ont.	MO	Unk	09/02/16
Ta Douglas/TransAlta	122	g	Ont.	MO	Unk	12/07/16
Thunderbay-3/OPG	153	bio	Ont.	MO	Unk	12/05/16
Southeast & Central						
Grand Gulf/Entergy	1443	n	Miss.	MO	Unk	09/08/16
West						
Agua Caliente/First Solar	290	s	Ariz.	PMO	Unk	01/08/17
Alamitos-5/AES	498	g	Calif.	PMO	Unk	01/08/17
Belden/PG&E	119	h	Calif.	PMO	Unk	10/24/16
Caribou 4-5/PG&E	120	h	Calif.	PMO	Unk	01/09/17
Colagte-2/YCWA	176	h	Calif.	MO	Unk	01/08/17
Colgate-1/YCWA	177	h	Calif.	MO	Unk	01/08/17
El Segundo 5-6/NRG	263	g	Calif.	MO	Unk	01/05/17
Electra 1-2/PG&E	102	h	Calif.	MO	Unk	01/09/17
Encina-4/NRG	300	g	Calif.	PMO	Unk	01/08/17
Etiwanda-3/NRG	320	g	Calif.	PMO	Unk	12/21/16
Hetch Hetchy-3/SFPUC	405	h	Calif.	PMO	Unk	01/08/17
La Paloma-3/La Paloma	256	g	Calif.	MO	Unk	01/08/17
Luz Solar 3-7/Luz Solar	175	s	Calif.	PMO	Unk	01/03/16
Luz Solar 8-9/Luz Solar	184	s	Calif.	PMO	Unk	01/03/16
Middle Fork/PCWA	218	h	Calif.	MO	Unk	01/09/17
Pio Pico-2/Apex	106	g	Calif.	MO	Unk	01/02/17
Redondo-6/AES	175	g	Calif.	PMO	Unk	01/08/17
Sutter/Calpine	525	g	Calif.	MO	Unk	06/06/16

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; Solar=s

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

SUBSCRIBER NOTE

S&P Global Platts and ICE Natural Gas Agreement

■ S&P Global Platts (Platts), the leading independent provider of information and benchmark prices for the commodities and energy markets, and Intercontinental Exchange (ICE), a leading operator of global exchanges and clearing houses, announced they have entered into a strategic agreement to strengthen North America's natural gas benchmarks, streamline the reporting process, and further improve transparency in over-the-counter (OTC) pricing. Under this agreement, ICE data regarding daily and monthly physical natural gas transactions will be anonymized and included as inputs into the Platts physical market price assessment processes. Not only will the addition of ICE data increase the volumes of natural gas underpinning the Platts natural gas benchmarks, it will expand the number of trades and market participants reflected in the Platts price assessment processes. After a transitional period, Platts will grant ICE exclusive rights to use Platts North American physical natural gas benchmarks in the settling and clearing of natural gas derivatives contracts. A key benefit of this agreement is that market participants will be able to use ICE exchange transactions and ICE eConfirm, an industry-leading electronic trade confirmation service, as a means of having their transactions data used in the Platts price assessment process. This brings additional data and efficiency to the assessment process, which traditionally comprises emailing trades to Platts. A transition period will apply before Platts incorporates the ICE data into its assessments and before ICE eConfirm can be used for submitting trades, and is targeted for mid-first half 2017. Visit the online resource www.platts.com/ice or contact Mark Callahan, Editorial Director Global Natural Gas and Power Pricing, at mark.callahan@spglobal.com or 713-658-3211 for additional information high-wind scenarios, we find that transmission expansion is likely to be critical," the report said. "Absent significant upgrades to the western transmission network, we find that a substantial amount of renewable energy cannot be utilized by the system, and therefore is curtailed."

The NREL study focuses on the Western Interconnection, which includes 11 states, two Canadian provinces, and parts of northern Mexico.

Adding 10,500 MW of transmission capacity through four proposed projects would cut the potential annual curtailment in half, from 15.5% to 7.8%, a "significant" amount given the relatively little additional transmission capacity, the report said.

Reducing the curtailment helps lower power costs and greenhouse gas emissions, according to the report. Curtailment can also be lowered by increased regional coordination, diversifying the resource mix, improving the existing power plant fleet's flexibility, or adding demand response or storage, NREL said.

The four proposed interstate transmission projects that NREL used in its study include: the Mountain States intertie, the Zephyr power transmission project, the TransWest Express project and the SunZia Southwest project. At least a dozen other major transmission projects are being proposed in the West.

Projects transport power to West Coast demand centers

The projects are generally designed to deliver low-cost wind from Montana, New Mexico and Wyoming to West Coast markets.

The projects, expected to cost about $10.1 billion, would produce annual savings of $1.8 billion to $2.8 billion by displacing more expensive electricity, according to NREL's estimates.

NREL found that the power lines would lead to increased imports across the West. "This indicates that the new transmission builds are enabling better use of wind energy in every state, not just the states in which each line begins and terminates," the report said.

Adding an additional 8,000 MW of transmission capacity would help cut curtailment and generation costs more, but would only reduce curtailment by about 20%, the report said.

Retiring large coal-fired power plants only reduces wind farm curtailment "marginally," according to the report.

NREL's study comes amid a surge in renewable generation being added to the grid. In 2015, wind generation made up 4.7% of total U.S. electricity production from nearly 74 GW of installed capacity.

The U.S. Energy Information Administration said Tuesday that it expects renewable generation to make up 63% of the 24 GW of total nameplate generating capacity that came online last year, the third year in a row that renewables have accounted for at least half of the new generating capacity.

The report noted that recent renewable grid integration research shows that integrating high shares of wind power is technically feasible but will require changes to operating practices.

Inefficient scheduling practices, for example, can reduce operating flexibility, the report said, noting that the inefficient practices could include fixed bilateral contracts or the inability to adjust schedules in real-time operations.

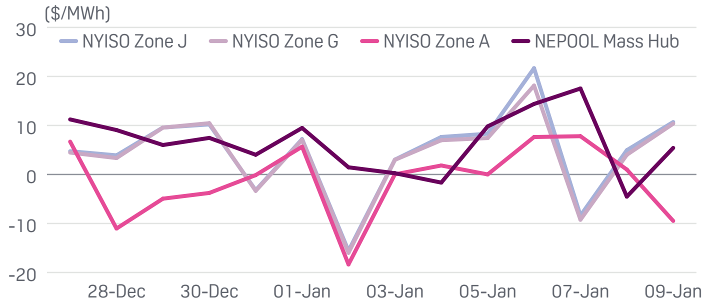
— *Ethan Howland*

NORTHEAST POWER MARKETS

NORTHEAST DAY AHEAD POWER PRICES ($/MWh)

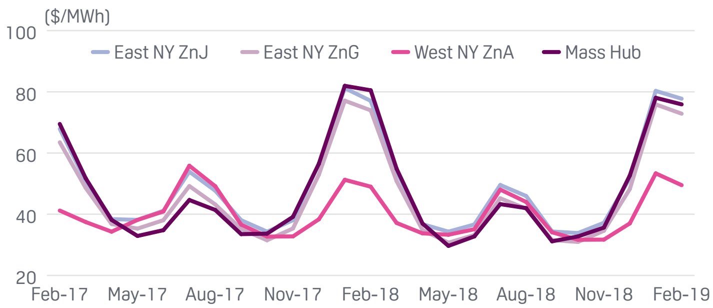
Hub/Index	Symbol	11-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-17	Yearly change Jan-16	Yearly change Chg	Yearly change % Chg
On-Peak														
ISONE Internal Hub	IINIM00	32.86	7771	3.26	-17.88	-21.94	-40.0	64.37	32.86	80.72	56.34	41.76	14.58	34.9
ISONE NE Mass-Boston	IINNM00	32.72	7737	3.12	-18.03	-21.94	-40.1	64.26	32.72	79.88	56.25	41.78	14.47	34.6
ISONE Connecticut	IINCM00	32.53	8037	4.20	-16.04	-21.92	-40.3	63.95	32.53	80.93	55.88	41.55	14.33	34.5
NYISO Zone G	INYHM00	36.18	10448	11.94	-5.37	-21.08	-36.8	62.67	33.75	90.35	53.80	38.15	15.65	41.0
NYISO Zone J	INYNM00	38.47	11111	14.23	-3.08	-28.36	-42.4	66.11	33.96	96.20	56.27	38.96	17.31	44.4
NYISO Zone A	INYWM00	31.01	10247	9.83	-5.31	-7.86	-20.2	39.09	24.37	48.95	35.53	23.43	12.10	51.6
NYISO Zone F	INYCM00	36.43	10800	12.82	-4.05	-30.81	-45.8	72.32	36.19	110.85	60.66	40.82	19.84	48.6
Off-Peak														
ISONE Internal Hub	IINIP00	33.85	6486	-2.68	-28.78	-25.79	-43.2	51.24	26.33	74.59	44.84	32.28	12.56	38.9
ISONE NE Mass-Boston	IINNP00	33.63	6444	-2.90	-29.00	-25.83	-43.4	51.04	26.18	73.98	44.65	32.32	12.33	38.2
ISONE Connecticut	IINCP00	33.63	7006	0.03	-23.97	-25.14	-42.8	50.71	26.15	74.11	44.39	31.95	12.44	38.9
NYISO Zone G	INYHP00	31.69	8386	5.24	-13.66	-25.50	-44.6	48.09	28.30	70.72	41.58	26.98	14.60	54.1
NYISO NYC Zone	INYNP00	31.90	8441	5.45	-13.45	-25.62	-44.5	48.38	28.29	71.23	41.79	27.19	14.60	53.7
NYISO West Zone	INYWP00	16.72	5622	-4.10	-18.97	-10.17	-37.8	27.58	13.22	34.07	23.97	16.72	7.25	43.4
NYISO Capital Zone	INYCP00	38.51	10522	12.89	-5.41	-33.64	-46.6	56.98	34.01	87.63	49.21	29.67	19.54	65.9

NORTHEAST AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



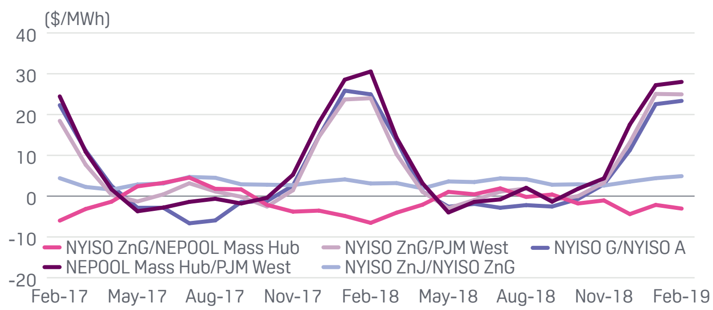
Source: Platts

NORTHEAST PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

NORTHEAST PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Northeast spot prices fall, forwards rebound

Northeast day-ahead power prices Tuesday dropped for a second straight day as high temperatures were expected to rise above seasonable levels, while some prompt-month power prices were boosted by the rally in NYMEX gas futures.

Mass Hub day-ahead on-peak for Wednesday delivery traded in the high $30s/MWh on Intercontinental Exchange, down about $13.75 from Monday's day-ahead settlement.

Algonquin Gas Transmission city-gates spot natural gas for Wednesday delivery traded near $4.021/MMBtu on ICE, down $1.24 from Monday's day-ahead price.

ISO New England predicted peakload of 19,100 MW Tuesday. Wednesday peakload is planned at 17,160 MW.

ISO New England generation fuel mix as of 2:40 pm EST Tuesday was 49% gas, 30% nuclear, 10% renewables and 7% coal. Coal burn, which surpassed 1,950 MW on Saturday, has fallen to 1,022 MW amid the sharp drop in spot gas prices.

West of the New England region, New York Independent System Operator day-ahead on-peak locational marginal prices fell across the state, with some of the largest declines in eastern NY.

NYISO New York City Zone J on-peak fell about $28.25 to the high $30s/MWh for Wednesday delivery.

Transco, Zone 6 New York spot natural gas traded 11 cents lower near $3.207/MMBtu on ICE.

The New York ISO expected peak demand of 20,549 MW Wednesday, down 1,138 MW from Tuesday.

In the Mid-Atlantic region, PJM West Hub day-ahead on-peak traded in the low $30s/MWh on ICE, down about $2.50 from Monday's day-ahead settlement.

The Mid-Atlantic region of the PJM Interconnection forecast peakload of 43,695 MW Tuesday and 38,025 MW Wednesday.

In the forward power markets, Mass Hub mini on-peak February traded in the high $60s/MWh on ICE, up about $5.25 from Monday's daily settlement.

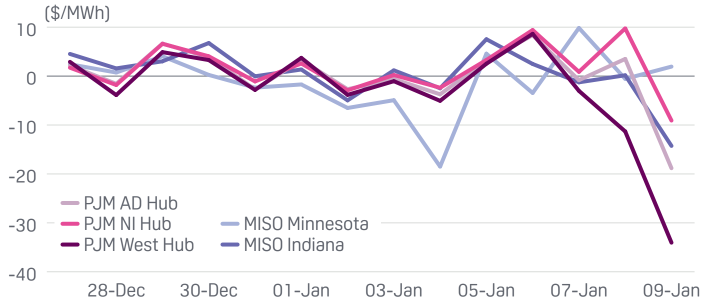
NYISO Zone G mini on-peak February traded in the mid-$60s/MWh, up $4.75, and PJM West Hub mini on-peak February traded near the mid-$40s/MWh, up $3.

PJM/MISO POWER MARKETS

PJM/MISO DAY AHEAD POWER PRICES ($/MWh)

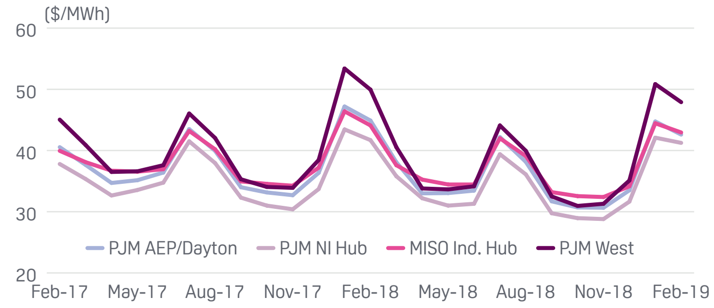
Hub/Index	Symbol	11-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly Change Jan-17	Yearly Change Jan-16	Yearly Change Chg	Yearly Change % Chg
On-Peak														
PJM AEP Dayton Hub	IPADM00	27.17	8869	5.73	-9.59	-1.94	-6.7	38.43	27.17	43.73	35.02	29.16	5.86	20.1
PJM Dominion Hub	IPDMM00	29.59	9512	7.81	-7.74	-7.81	-20.9	46.30	29.59	62.83	40.62	36.61	4.01	11.0
PJM Eastern Hub	IPEHM00	28.88	9236	6.99	-8.64	-10.98	-27.5	48.28	28.88	73.50	41.99	36.49	5.50	15.1
PJM Northern Illinois Hub	IPNIM00	26.15	8241	3.94	-11.93	-0.05	-0.2	36.06	26.15	41.78	33.08	27.09	5.99	22.1
PJM Western Hub	IPWHM00	28.81	9847	8.33	-6.30	-4.18	-12.7	43.13	28.81	52.56	38.37	32.83	5.54	16.9
MISO Indiana Hub	IMIDM00	27.71	9259	6.76	-8.20	-0.92	-3.2	37.06	25.72	43.19	33.87	25.49	8.38	32.9
MISO Minnesota Hub	IMINM00	32.08	10331	10.34	-5.18	3.76	13.3	36.49	21.03	48.27	32.33	23.17	9.16	39.5
Off-Peak														
PJM AEP Dayton Hub	IPADP00	23.70	7898	2.69	-12.31	-1.98	-7.7	30.29	22.76	34.79	27.94	23.86	4.08	17.1
PJM Dominion Hub	IPDMP00	26.09	8476	4.54	-10.85	-16.04	-38.1	39.50	22.94	69.48	34.21	32.09	2.12	6.6
PJM Eastern Hub	IPEHP00	25.15	7922	2.93	-12.95	-19.88	-44.1	41.93	22.75	79.95	35.60	31.61	3.99	12.6
PJM Northern Illinois Hub	IPNIP00	21.88	7049	0.15	-15.37	2.27	11.6	26.23	19.61	30.78	24.43	19.32	5.11	26.4
PJM Western Hub	IPWHP00	25.62	8903	5.48	-8.91	-10.07	-28.2	35.44	22.39	52.51	31.41	27.31	4.10	15.0
MISO Indiana Hub	IMIDP00	22.09	7474	1.40	-13.38	-1.04	-4.5	28.33	21.98	33.86	26.13	20.91	5.22	25.0
MISO Minnesota Hub	IMINP00	21.74	7194	0.59	-14.52	-0.39	-1.8	26.62	15.94	37.03	23.54	18.57	4.97	26.8

PJM/MISO AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



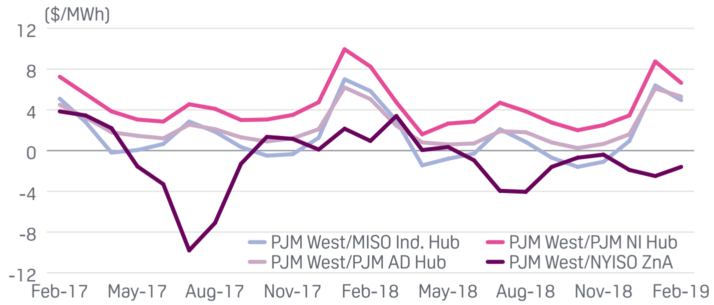
Source: Platts

PJM/MISO PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

PJM/MISO PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Central dailies mixed; most of region to be warm

Central US day-ahead on-peak power prices were mixed Tuesday, as unseasonable warm temperatures were expected for most of the region, except in Minnesota, where temperatures were forecast to drop to 9 degrees in Minneapolis.

The Midcontinent ISO projected peakload of 86,510 MW Tuesday and 84,620 MW Wednesday. MISO North is expected to decrease by 50 MW to 20,490 MW.

Coal accounted for 46.9% of Tuesday's generation mix at 3:35 pm EST, followed by natural gas (16.8%), nuclear (15.7%) and wind generation (18.3%).

Northern Natural Gas, demarcation spot gas traded 19 cents higher near $3.267/MMBtu on IntercontinentalExchange, turning to a premium to the Henry Hub spot price, which shed 9 cents near $3.210/MMBtu.

Downstream of the demarcation point, highs in Minneapolis are expected to fall to 9 degrees Wednesday, 19 degrees cooler from Tuesday and 16 degrees below the norm.

On Tuesday, NNG issued an operation alert for the Minnesota market zone, with 50% firm transportation/SMS service for gas day Wednesday due to lower-than-normal system-weighted temperatures.

In the power market, Indiana Hub day-ahead on-peak traded in the high $20s/MWh on ICE, about $1.25 below Monday's day-ahead settlement. Balance-of-the-week on-peak traded in low $30s/MWh, down about 50 cents.

In the nearby PJM Western region, peakload was estimated at 58,303 MW Tuesday and 53,242 MW Tuesday.

Highs in Chicago are forecast at 47 degrees Wednesday, 2 degrees warmer from Tuesday, and 14 degrees above the norm.

Chicago city-gates spot gas prices were trading around $3.187/ MMBtu on ICE, up 10 cents from Monday.

West of the MISO footprint, Southwest Power Pool predicted peak demand of 30,540 MW 9 pm Tuesday and 30,813 MW 9 pm Wednesday.

Wind generation in the SPP footprint is expected at 6,402 MW 9 pm Tuesday and at 8,106 MW at 9 pm Tuesday.

In the forward power markets, February prices rose as NYMEX prompt gas futures settled 17.5 cents higher near $3.278/MMBtu.

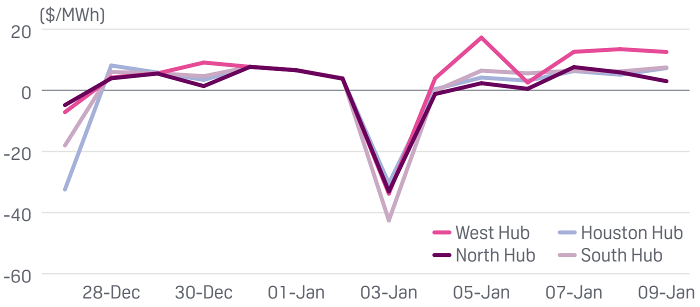
Indiana Hub on-peak February was framed in the high $30s/MWh, up $1.75 from Monday.

SOUTHEAST POWER MARKETS

SOUTHEAST & CENTRAL DAY-AHEAD POWER PRICES ($/MWh)

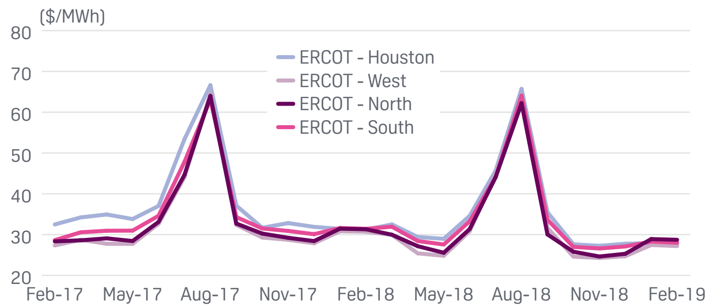
			Marginal	Spark spread		Price change		Prior 7-day	Month	Month	Yearly change			
Hub/Index	Symbol	11-Jan	heat rate	@7K	@12K	Chg	% Chg	Average	Min	Max	Jan-17	Jan-16	Chg	% Chg
On-Peak														
MISO Texas Hub	IMTXM00	26.43	8516	4.71	-10.81	-2.72	-9.3	34.98	26.43	40.36	32.52	23.54	8.98	38.2
MISO Louisiana	IMLAM00	27.72	8911	5.94	-9.61	-0.75	-2.6	37.41	27.05	41.48	34.56	24.23	10.33	42.6
SPP North Hub	ISNOM00	18.36	5663	-4.33	-20.55	-1.18	-6.0	28.02	15.71	42.80	25.60	19.33	6.27	32.4
SPP South Hub	ISSOM00	25.54	8495	4.49	-10.54	-3.69	-12.6	34.81	25.54	43.20	33.43	23.33	10.10	43.3
ERCOT Houston Hub	IERHM00	27.28	8766	5.50	-10.06	-5.40	-16.5	30.03	24.57	38.75	28.65	21.37	7.28	34.1
ERCOT North Hub	IERNM00	20.45	6687	-0.96	-16.25	-1.54	-7.0	28.34	20.45	39.39	26.92	20.82	6.10	29.3
ERCOT South Hub	IERSM00	22.00	7128	0.40	-15.04	-3.61	-14.1	28.97	22.00	39.94	27.51	20.94	6.57	31.4
ERCOT West Hub	IERWM00	16.37	5423	-4.76	-19.85	-3.97	-19.5	25.76	13.59	39.01	24.91	20.85	4.06	19.5
Off-Peak														
MISO Texas Hub	IMTXP00	21.19	7004	0.01	-15.11	-3.81	-15.2	29.27	21.19	35.05	26.58	20.24	6.34	31.3
MISO Louisiana	IMLAP00	22.09	7175	0.54	-14.85	-2.23	-9.2	29.81	22.09	35.58	27.20	20.13	7.07	35.1
SPP North Hub	ISNOP00	8.42	2698	-13.43	-29.03	2.65	45.9	19.65	5.77	30.80	16.45	15.42	1.03	6.7
SPP South Hub	ISSOP00	17.48	5959	-3.05	-17.72	-1.39	-7.4	28.00	17.48	32.70	26.36	20.24	6.12	30.2
ERCOT Houston Hub	IERHP00	6.64	2196	-14.53	-29.64	-5.79	-46.6	20.56	6.64	27.07	18.53	15.96	2.57	16.1
ERCOT North Hub	IERNP00	6.06	2006	-15.09	-30.19	-5.62	-48.1	20.58	6.06	27.14	18.48	15.76	2.72	17.3
ERCOT South Hub	IERSP00	5.56	1827	-15.74	-30.96	-4.66	-45.6	20.13	5.56	26.94	18.15	15.75	2.40	15.2
ERCOT West Hub	IERWP00	3.63	1235	-16.94	-31.64	-0.14	-3.7	17.55	3.63	26.76	16.32	15.68	0.64	4.1

ERCOT AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



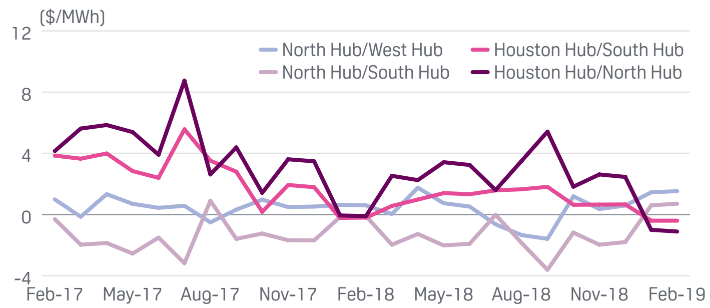
Source: Platts

ERCOT PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

ERCOT PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

ERCOT dailies ease on more wind generation

Electric Reliability Council of Texas day-ahead power prices fell on Tuesday as wind generation was set to rise amid warm weather expected ahead.

ERCOT North Hub day-ahead on-peak eased around $2.25 in the low $20s/MWh for Wednesday delivery on Intercontinental Exchange. Balance-of-the-week real-time on-peak traded in the mid-$20s/MWh, while next-week real-time on-peak was in the mid-$20s/MWh.

The real-time price average across all hubs and load zones dropped to negative $6.25/MWh from midnight to 5:30 am CST Tuesday, as wind generation climbed to a peak of around 16,300 MW at 1 am.

Wind output was forecast to peak at around 14,675 MW at 7 am CST Wednesday.

Wednesday is likely to be the warmest day of the week for the ERCOT system as a whole, with highs in the 70s and some 80s across Texas, before shower and thunderstorms expected from Friday through the weekend.

The grid operator's footprint was expected to see peak demand rise from near 39,975 MW Tuesday to about 40,900 MW Wednesday.

Gas heating demand across Texas was expected to fall from 2.36 Bcf/d Tuesday to 2.23 Bcf/d Wednesday, data from Platts Analytics' Bentek Energy showed.

In the Southeast, day-ahead markets were quiet despite the rebound in spot gas prices and warming temperatures.

High temperatures in Atlanta were expected around 65 degrees Wednesday, rising from Tuesday's 52 degrees, with lows at 46 degrees, higher than Tuesday's low of 30 degrees.

Spot gas at Florida Gas Transmission Zone-3 gained 7.8 cents to $3.188/MMBtu on ICE.

In the term markets, the ERCOT North Hub contracts strip surged Tuesday, as the NYMEX natural gas futures prompt month contract settled 17.5 cents higher at $3.278/MMBtu at 2:30 pm EST.

On ICE, the North Hub February implied power price gained around 25 cents in the upper $20s/MWh.

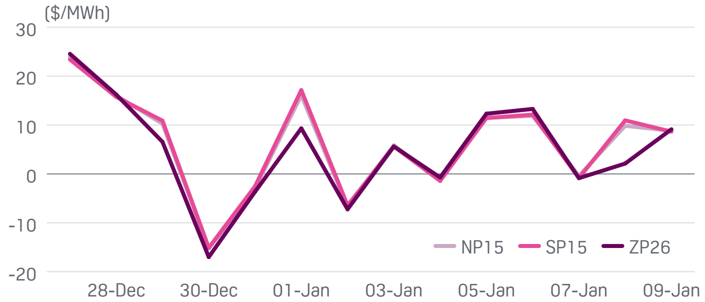
Farther out, the North Hub July-August package jumped nearly $3.75 in the mid-$50s/MWh.

WEST POWER MARKETS

WESTERN DAY-AHEAD POWER PRICES ($/MWh)

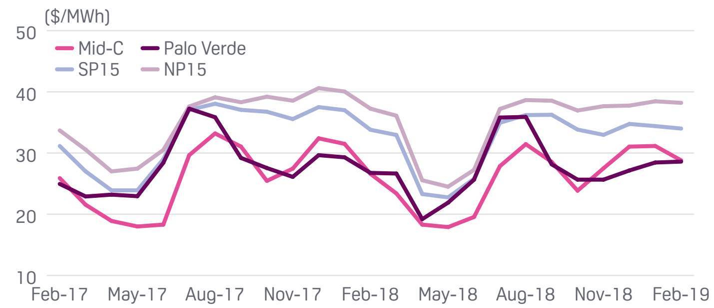
Hub/Index	Symbol	11-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-17	Yearly change Jan-16	Yearly change Chg	Yearly change % Chg
On-Peak														
NP15	ICNGM00	37.43	10809	13.19	-4.12	-0.90	-2.3	38.48	33.67	46.47	38.87	30.36	8.51	28.0
SP15	ICSGM00	35.61	11069	13.09	-3.00	-0.09	-0.3	36.80	26.88	45.12	36.60	29.80	6.80	22.8
ZP26	ICZGM00	35.93	11167	13.41	-2.68	0.21	0.6	37.01	27.49	45.51	36.90	28.33	8.57	30.3
COB	WEABE20	34.82	10932	12.52	-3.40	3.16	10.0	39.04	30.13	61.91	38.51	23.52	14.99	63.7
MEAD	AAMBW20	29.75	9253	7.24	-8.83	1.50	5.3	29.64	26.75	36.00	29.66	23.13	6.53	28.2
MID-C	WEABF20	35.38	11091	13.05	-2.90	4.63	15.1	38.31	27.51	62.01	37.95	22.75	15.20	66.8
Palo Verde	WEACC20	27.75	8852	5.81	-9.87	1.75	6.7	27.54	25.75	33.50	27.56	21.39	6.17	28.8
Off-Peak														
NP15	ICNGP00	26.35	7809	2.73	-14.14	1.17	4.6	29.11	25.18	33.17	29.88	24.89	4.99	20.0
SP15	ICSGP00	25.68	8290	4.00	-11.49	1.25	5.1	28.61	24.43	32.57	29.27	24.96	4.31	17.3
ZP26	ICZGP00	25.68	8289	3.99	-11.50	1.19	4.9	28.58	24.49	32.61	29.28	24.41	4.87	20.0
COB	WEACJ20	22.25	6986	-0.04	-15.97	-1.25	-5.3	27.25	22.25	33.00	28.36	22.34	6.02	26.9
MEAD	AAMBQ20	24.25	7543	1.75	-14.33	0.00	0.0	25.21	24.00	29.25	26.23	20.41	5.82	28.5
MID-C	WEACL20	22.78	7141	0.45	-15.50	-1.30	-5.4	25.81	22.78	30.45	26.42	21.49	4.93	22.9
Palo Verde	WEACT20	23.00	7337	1.06	-14.62	-0.75	-3.2	23.89	22.50	27.25	24.73	19.47	5.26	27.0

CAISO AVG. DAY-AHEAD/REAL-TIME PEAK PRICE SPREAD



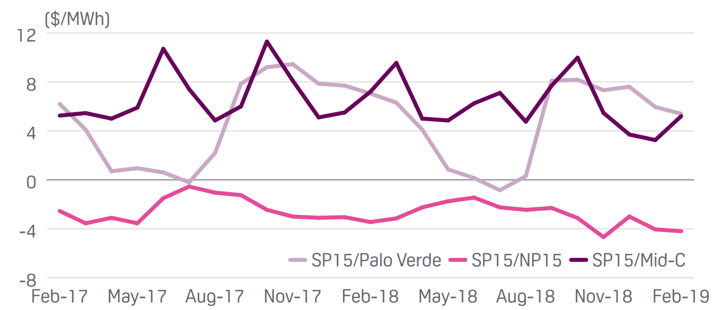
Source: Platts

WESTERN PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

WESTERN PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

West power dailies up with gas prices

West power dailies were stronger Tuesday with higher spot gas prices as temperatures were forecast to drop in California and the Northwest.

In the Northwest, Mid-Columbia on-peak rose $4.75 to the mid-$30s/MWh for Wednesday delivery on Intercontinental Exchange. Portland high temperatures were forecast dropping to 32 Wednesday, 14 degrees below normal.

A winter storm warning and winter weather advisory were issued across part of the Northwest for heavy snow, according to the National Weather Service.

Mid-C on-peak balance-of-the-week advanced $2.75 to the upper $30s/MWh. On-peak next-week gained $1.50 in the mid-$20s/MWh with as much as 3 inches of precipitation forecast for January 17 and 18 across parts of the Northwest.

The Bonneville Power Administration territory has exported an average of 150,188 MWh/d January to date, up nearly 24% from the January 2016 average.

In California, SP15 on-peak day-ahead rose $2 to the mid-$30s/MWh on ICE as California ISO forecast peakload increasing to 29,600 MW Thursday.

SoCal city-gates added 5.9 cents to around $3.369/MMBtu for Wednesday delivery.

Los Angeles high temperatures were forecast easing near 61 Wednesday, 5 degrees below normal.

On-peak balance-week jumped $5.75 to the low $30s/MWh. On-peak balance-month increased $1.50 in the low $30s/MWh as off-peak rose $1.75 to the low $30s/MWh.

Cal-ISO has imported an average of 160,855 MWh/d January to date, down 1% from the January 2016 average.

In the Southwest, Palo Verde on-peak moved up $2 to the upper $20s/MWh on ICE. Off-peak lost $1.25 to the low $20s/MWh.

High temperatures across the Southwest were forecast from the upper 50s to upper 60s Wednesday, as much as 8 degrees above normal.

West power forwards were stronger Tuesday as the NYMEX February natural gas contract rebounded 17.5 cents near $3.278/MMBtu around 2:30 pm EST.

Mid-C on-peak February added $1.25 in the mid-$20s/MWh. Palo Verde on-peak February advanced $1.75 to the mid-$20s/MWh. SP15 on-peak February climbed $2 to the low $30s/MWh.

BILATERALS

SOUTHEAST & CENTRAL DAY-AHEAD BILATERAL INDEXES ($/MWh)

Hub/Index	Symbol	11-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-17	Yearly change Jan-16	Yearly change Chg	Yearly change % Chg
On-Peak														
Florida	AAMAV20	25.25	7915	2.92	-13.03	-3.50	-12.2	31.75	25.25	41.00	30.50	24.50	6.00	24.5
GTC, Into	WAMCJ20	27.00	8558	4.92	-10.86	-4.00	-12.9	32.57	27.00	43.00	31.50	27.05	4.45	16.4
Southern, Into	AAMBJ20	26.00	8241	3.92	-11.86	-3.50	-11.9	31.00	26.00	40.00	30.00	25.86	4.14	16.0
TVA, Into	WEBAB20	26.75	8353	4.33	-11.68	-3.50	-11.6	32.39	26.75	39.50	31.46	26.29	5.17	19.7
VACAR	AAMCI20	27.25	8450	4.68	-11.45	-4.50	-14.2	32.82	27.25	43.00	32.00	28.33	3.67	13.0
Off-Peak														
Florida	AAMAO20	21.00	6583	-1.33	-17.28	-6.00	-22.2	29.29	20.75	36.75	26.61	20.24	6.37	31.5
GTC, Into	WAMCC20	22.50	7132	0.42	-15.36	-6.00	-21.1	30.75	22.00	38.25	28.09	24.44	3.65	14.9
Southern, Into	AAMBC20	21.50	6815	-0.58	-16.36	-6.00	-21.8	29.79	21.25	37.25	27.11	23.08	4.03	17.5
TVA, Into	AAJER20	22.25	6948	-0.17	-16.18	-5.50	-19.8	30.07	22.25	36.00	27.43	22.85	4.58	20.0
VACAR	AAMCB20	22.75	7054	0.17	-15.95	-8.25	-26.6	31.43	22.75	38.00	28.34	24.14	4.20	17.4

WESTERN DAY-AHEAD BILATERAL INDEXES ($/MWh)

Hub/Index	Symbol	11-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-17	Yearly change Jan-16	Yearly change Chg	Yearly change % Chg
On-Peak														
Mid-C	WEABF20	35.38	11091	13.05	-2.90	4.63	15.1	38.31	27.51	62.01	37.95	22.75	15.20	66.8
John Day	WEAHF20	36.50	11442	14.17	-1.78	4.75	15.0	39.29	28.50	63.00	38.94	23.77	15.17	63.8
COB	WEABE20	34.82	10932	12.52	-3.40	3.16	10.0	39.04	30.13	61.91	38.51	23.52	14.99	63.7
NOB	WEAIF20	35.50	11129	13.17	-2.78	4.75	15.4	39.36	27.50	64.50	38.88	23.42	15.46	66.0
Palo Verde	WEACC20	27.75	8852	5.81	-9.87	1.75	6.7	27.54	25.75	33.50	27.56	21.39	6.17	28.8
Mona	AARLQ20	29.50	9672	8.15	-7.10	1.75	6.3	34.39	26.75	44.75	33.78	21.55	12.23	56.8
Four Corners	WEABI20	27.50	9002	6.12	-9.16	0.75	2.8	29.71	25.25	38.50	29.44	21.49	7.95	37.0
Pinnacle Peak	WEAKF20	27.75	8852	5.81	-9.87	1.25	4.7	28.04	26.25	34.25	28.00	21.58	6.42	29.7
Westwing	WEAJF20	27.25	8692	5.30	-10.37	1.75	6.9	27.93	25.50	34.00	27.84	21.84	6.00	27.5
MEAD	AAMBW20	29.75	9253	7.24	-8.83	1.50	5.3	29.64	26.75	36.00	29.66	23.13	6.53	28.2
Off-Peak														
Mid-C	WEACL20	22.78	7141	0.45	-15.50	-1.30	-5.4	25.81	22.78	30.45	26.42	21.49	4.93	22.9
John Day	WEAHL20	23.75	7445	1.42	-14.53	-1.25	-5.0	26.82	23.75	31.50	27.41	22.51	4.90	21.8
COB	WEACJ20	22.25	6986	-0.04	-15.97	-1.25	-5.3	27.25	22.25	33.00	28.36	22.34	6.02	26.9
NOB	WEAIL20	23.25	7288	0.92	-15.03	-1.25	-5.1	27.39	23.25	32.50	28.14	22.04	6.10	27.7
Palo Verde	WEACT20	23.00	7337	1.06	-14.62	-0.75	-3.2	23.89	22.50	27.25	24.73	19.47	5.26	27.0
Mona	AARLO20	24.00	7869	2.65	-12.60	-0.50	-2.0	26.36	24.00	29.50	27.00	19.51	7.49	38.4
Four Corners	WEACR20	23.50	7692	2.11	-13.16	0.00	0.0	25.57	23.50	27.25	25.84	19.23	6.61	34.4
Pinnacle Peak	WEAKL20	23.75	7576	1.81	-13.87	0.25	1.1	24.11	22.75	27.50	25.00	19.85	5.15	25.9
Westwing	WEAJL20	23.00	7337	1.06	-14.62	-0.75	-3.2	24.11	22.75	27.50	24.93	19.81	5.12	25.8
MEAD	AAMBQ20	24.25	7543	1.75	-14.33	0.00	0.0	25.21	24.00	29.25	26.23	20.41	5.82	28.5

WESTERN NEAR-TERM BILATERAL MARKETS ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	01/10	38.25-39.00
Bal-month	01/09	27.25-27.75
Bal-month	01/06	25.75-26.25

PLATTS M2MS FORWARD CURVE, JAN 10 ($/MWh)

Prompt month: Feb 17

	On-peak	Off-peak
Northeast		
Mass Hub	69.50	55.75
N.Y. Zone G	63.50	45.90
N.Y. Zone J	67.90	47.80
N.Y. Zone A	41.20	29.40
Ontario*	30.25	19.10
PJM & MISO		
PJM West	45.05	35.70
AD Hub	40.55	32.30
NI Hub	37.80	28.75
Indiana Hub	39.95	30.30

*Ontario prices are in Canadian dollars

	On-peak	Off-peak
Southeast & Central		
Southern Into	36.85	29.95
ERCOT North	28.35	22.90
ERCOT Houston	32.50	23.00
ERCOT West	27.35	21.50
ERCOT South	28.65	23.10
Western		
Mid-C	25.90	20.95
Palo Verde	24.95	22.05
Mead	26.65	23.40
NP15	33.70	28.40
SP15	31.15	26.70

ISO DAY-AHEAD LMP BREAKDOWN FOR JAN 11 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
Northeast						
On-peak						
ISONE Internal Hub	32.86	0.00	0.24	-21.94	56.34	7771
ISONE Connecticut	32.53	0.00	-0.10	-21.92	55.88	8037
ISONE NE Mass-Boston	32.72	0.00	0.10	-21.94	56.25	7737
NYISO Capital Zone	36.43	-3.82	2.22	-30.81	60.66	10800
NYISO Hudson Valley Zone	36.18	-2.64	3.15	-21.08	53.80	10448
NYISO N.Y.C. Zone	38.47	-4.25	3.84	-28.36	56.27	11111
NYISO West Zone	31.01	-0.40	0.22	-7.86	35.53	10247
Off-Peak						
ISONE Internal Hub	33.85	0.00	0.31	-25.79	44.84	6486
ISONE Connecticut	33.63	0.00	0.09	-25.14	44.39	7006
ISONE NE Mass-Boston	33.63	0.00	0.10	-25.83	44.65	6444
NYISO Capital Zone	38.51	-23.54	0.87	-33.64	49.21	10522
NYISO Hudson Valley Zone	31.69	-16.40	1.19	-25.50	41.58	8386
NYISO N.Y.C. Zone	31.90	-16.53	1.26	-25.62	41.79	8441
NYISO West Zone	16.72	-2.46	0.16	-10.17	23.97	5622
PJM & MISO						
On-peak						
PJM AEP-Dayton Hub	27.17	-0.43	-0.99	-1.94	35.02	8869
PJM Dominion Hub	29.59	0.63	0.37	-7.81	40.62	9512
PJM Eastern Hub	28.88	-0.09	0.38	-10.98	41.99	9236
PJM Northern Illinois Hub	26.15	-1.25	-1.18	-0.05	33.08	8241
PJM Western Hub	28.81	0.33	-0.10	-4.18	38.37	9847
MISO Indiana Hub	27.71	-1.98	0.01	-0.92	33.87	9259
MISO Minnesota Hub	32.08	2.98	-0.58	3.76	32.33	10331
MISO Louisiana Hub	27.72	-1.64	-0.31	-0.75	34.56	8911
MISO Texas Hub	26.43	-2.60	-0.64	-2.72	32.52	8516
Off-Peak						
PJM AEP-Dayton Hub	23.70	0.09	-1.13	-1.98	27.94	7898
PJM Dominion Hub	26.09	0.77	0.58	-16.04	34.21	8476
PJM Eastern Hub	25.15	-0.35	0.76	-19.88	35.60	7922
PJM Northern Illinois Hub	21.88	-1.20	-1.66	2.27	24.43	7049
PJM Western Hub	25.62	0.31	0.57	-10.07	31.41	8903
MISO Indiana Hub	22.09	-0.79	0.38	-1.04	26.13	7474
MISO Minnesota Hub	21.74	0.52	-1.28	-0.39	23.54	7194
MISO Louisiana Hub	22.09	-0.33	-0.09	-2.23	27.20	7175
MISO Texas Hub	21.19	-1.18	-0.14	-3.81	26.58	7004
Southeast & Central						
On-peak						
SPP North Hub	18.36	-2.37	-1.03	-1.18	25.60	5663
SPP South Hub	25.54	3.76	0.03	-3.69	33.43	8495
ERCOT Houston Hub	27.28	–	–	-5.40	28.65	8766
ERCOT North Hub	20.45	–	–	-1.54	26.92	6687
ERCOT South Hub	22.00	–	–	-3.61	27.51	7128
ERCOT West Hub	16.37	–	–	-3.97	24.91	5423
Off-Peak						
SPP North Hub	8.42	-3.14	-0.26	2.65	16.45	2698
SPP South Hub	17.48	5.86	-0.19	-1.39	26.36	5959
ERCOT Houston Hub	6.64	–	–	-5.79	18.53	2196
ERCOT North Hub	6.06	–	–	-5.62	18.48	2006
ERCOT South Hub	5.56	–	–	-4.66	18.15	1827
ERCOT West Hub	3.63	–	–	-0.14	16.32	1235
Western						
On-peak						
CAISO NP15 Gen Hub	37.43	-0.29	0.03	-0.90	38.87	10809
CAISO SP15 Gen Hub	35.61	-0.10	-1.97	-0.09	36.60	11069
CAISO ZP26 Gen Hub	35.93	-0.03	-1.73	0.21	36.90	11167
Off-Peak						
CAISO NP15 Gen Hub	26.35	-0.02	-0.22	1.17	29.88	7809
CAISO SP15 Gen Hub	25.68	0.00	-0.91	1.25	29.27	8290
CAISO ZP26 Gen Hub	25.68	0.00	-0.90	1.19	29.28	8289

NORTHEAST POWER MARKETS

NYISO SUPPLY MIX (GWh/d)

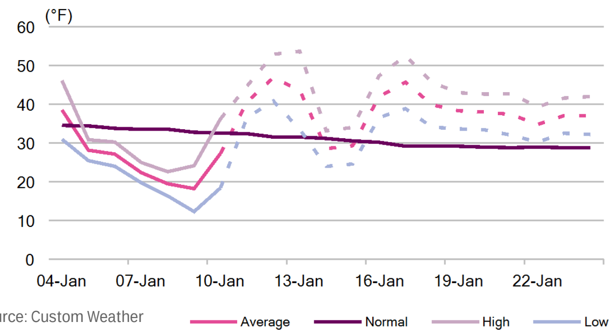
Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2017	Season average 2016	Season average Chg	Season average % Chg
Total Generation	386.61	376.83	352.89	379.47	368.98	82%	-10.49	-3.0%	300.04	422.52	360.87	360.49	0.38	0.0%
Gas	157.37	148.15	143.71	161.48	169.19	38%	7.71	5.0%	63.65	169.19	123.79	124.71	-0.92	-1.0%
Coal	27.52	27.18	26.75	30.3	30.96	7%	0.66	2.0%	9.51	31.45	20.71	19.24	1.47	8.0%
Nuclear	124.58	124.53	124.22	124.22	124.22	28%	0	0.0%	96.61	126.84	121.32	129.45	-8.13	-6.0%
Other	149.76	160.29	161.11	141.44	123.44	28%	-18	-13.0%	101.57	217.12	168.25	154.11	14.14	9.0%

ISONE SUPPLY MIX (GWh/d)

Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2017	Season average 2016	Season average Chg	Season average % Chg
Total Generation	297.53	299.32	297.73	292.88	320.64	78%	27.76	9.0%	257.58	321.67	292.57	286.54	6.03	2.0%
Gas	87.71	89.1	105.04	114.76	120.22	29%	5.46	5.0%	68.07	120.22	91.34	115.76	-24.42	-21.0%
Nuclear	97.8	97.8	97.8	97.8	97.8	24%	0	0.0%	79.95	97.8	93.76	93.34	0.42	0.0%
Coal	39.15	43.87	50.62	53.08	63.45	16%	10.37	20.0%	23.23	65.96	36.58	26.92	9.66	36.0%
Wind	21.89	7.8	4.26	12.06	13.33	3%	1.27	11.0%	2.64	24.68	11.29	7.77	3.52	45.0%
Other	117.84	131.19	116.75	94.09	114.43	28%	20.34	22.0%	93.42	154.45	124.15	103.35	20.8	20.0%

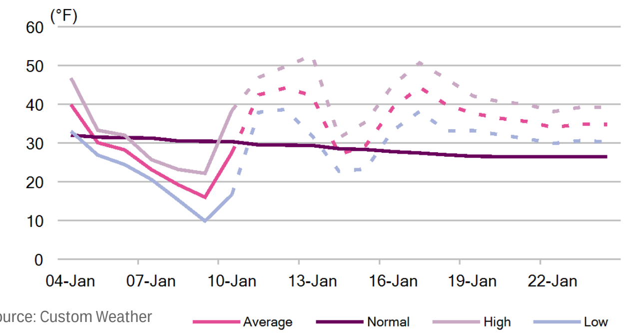
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

NYISO TEMPERATURE



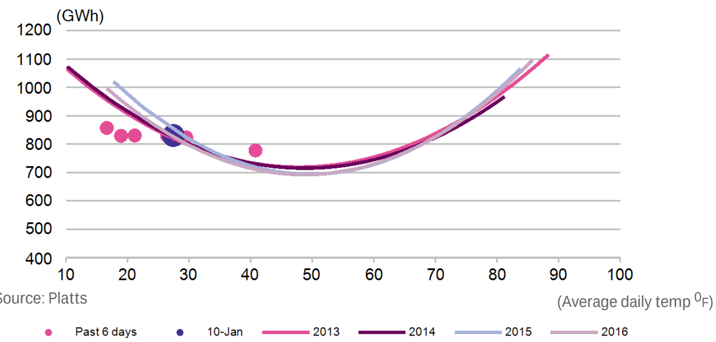
Source: Custom Weather

ISONE TEMPERATURE



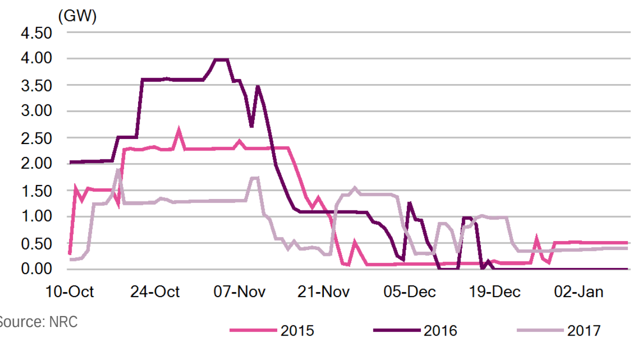
Source: Custom Weather

ISONE & NYISO LOAD PER DEGREE



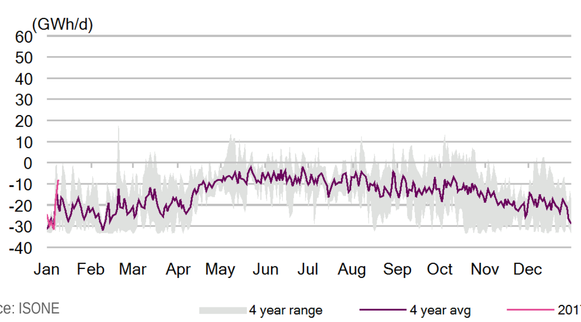
Source: Platts

ISONE & NYISO NUCLEAR GENERATION OUTAGES



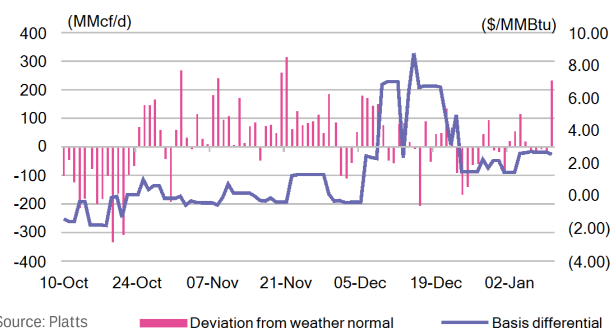
Source: NRC

ISONE-NYISO INTERTIE TRANSMISSION E-W



Source: ISONE

ISONE POWER BURN VS. GAS BASIS



Source: Platts

PJM/MISO POWER MARKETS

PJM SUPPLY MIX (GWh/d)

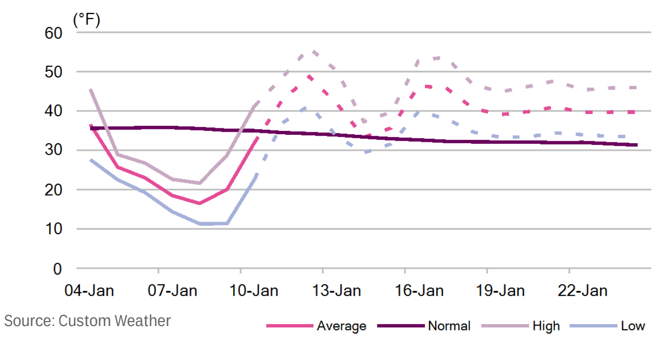
							Daily change		Season		Season average			
Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Chg	% Chg	Min	Max	2017	2016	Chg	% Chg
Total Generation	2,475.43	2,524.77	2,586.41	2,635.96	2,386.14	100%	-249.82	-9.0%	1,894.54	2,799.45	2,314.63	2,153.06	161.57	8.0%
Gas	558.26	547.02	548.27	566.91	573.2	24%	6.29	1.0%	170.6	643.12	418.71	522.12	-103.41	-20.0%
Coal	983.93	1,057.07	1,127.72	1,150.84	925.65	39%	-225.19	-20.0%	732.91	1,291.71	996.15	746.12	250.03	34.0%
Nuclear	791.79	788.95	783.91	793.87	796.86	33%	2.99	0.0%	729.66	796.86	765.02	773.18	-8.16	-1.0%
Other	155.2	146.2	141.86	141.39	98.09	4%	-43.3	-31.0%	-45.5	192.3	76.98	145.89	-68.91	-47.0%

MISO SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Chg	% Chg	Min	Max	2017	2016	Chg	% Chg
Total Generation	2,114.24	2,221.36	2,168.71	2,102.6	2,034.16	99%	-68.44	-3.0%	1,620.66	2,230.17	1,913.96	1,854.69	59.27	3.0%
Gas	364.65	495.17	465.48	397.72	438.62	21%	40.9	10.0%	132.48	495.17	292.84	376.83	-83.99	-22.0%
Coal	1,069.6	1,158.4	1,148.86	1,094.49	1,016.25	50%	-78.24	-7.0%	691.69	1,158.4	931.74	884.47	47.27	5.0%
Nuclear	283.71	283.98	265.55	261.01	266.71	13%	5.7	2.0%	179.59	295.16	274.71	283.76	-9.05	-3.0%
Wind	143.53	68.48	93.11	196.35	144.5	7%	-51.85	-26.0%	49.48	311.6	175.38	137.94	37.44	27.0%
Other	223.97	196.91	182.53	137.97	179.67	9%	41.7	30.0%	137.97	381.31	215.88	146.29	69.59	48.0%

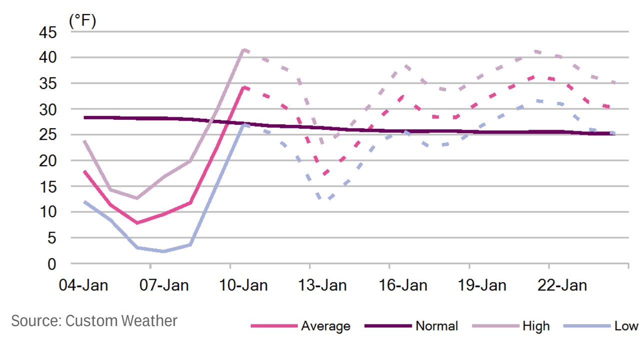
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

PJM TEMPERATURE



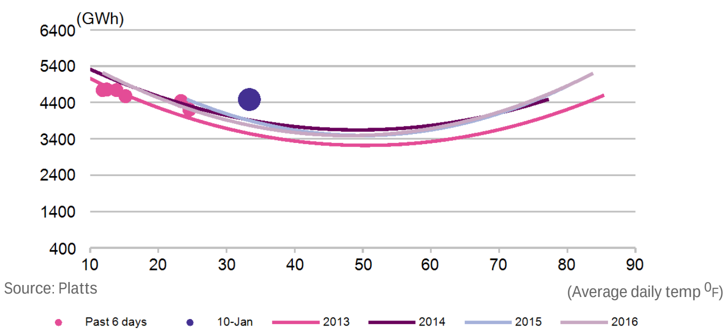
Source: Custom Weather

MISO TEMPERATURE



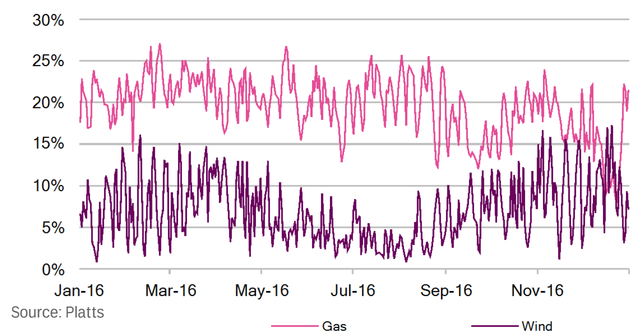
Source: Custom Weather

PJM & MISO LOAD PER DEGREE



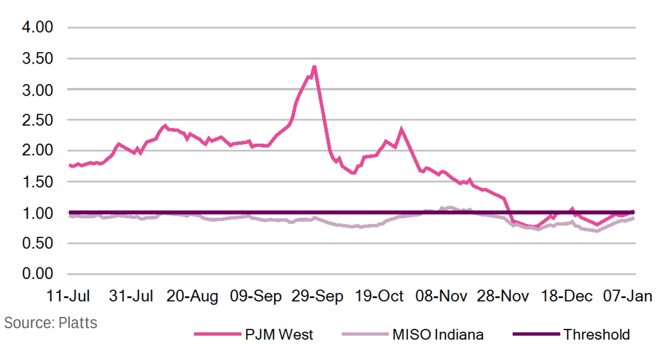
Source: Platts

MISO GENERATION MARKET SHARE - GAS VS. WIND



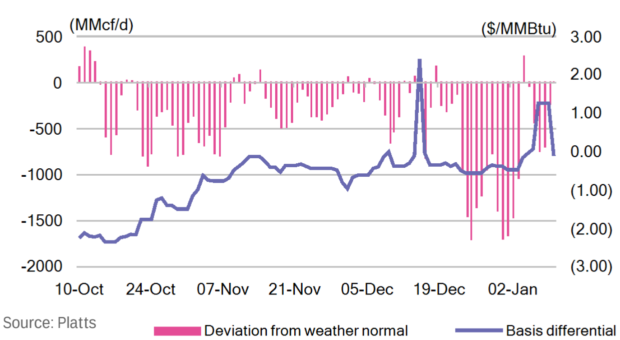
Source: Platts

PJM/MISO COAL-VS-GAS $/MWh FUEL COST RATIO



Source: Platts

PJM POWER BURN VS. GAS BASIS



Source: Platts

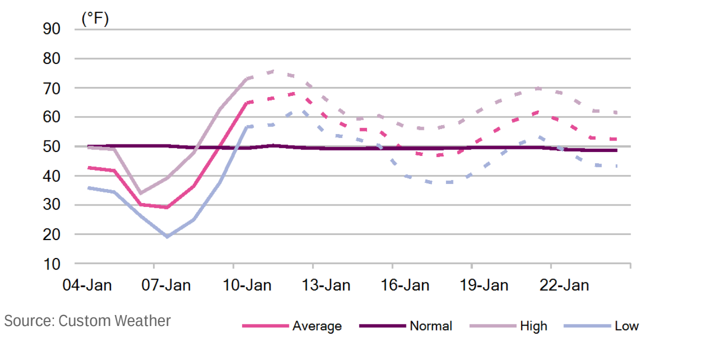
SOUTHEAST POWER MARKETS

ERCOT SUPPLY MIX (GWh/d)

Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2017	Season average 2016	Season average Chg	Season average % Chg
Total Generation	996.52	1,249.91	1,240.64	1,117.58	1,057.41	100%	-60.17	-5.0%	744.42	1,249.91	920.41	845.36	75.05	9.0%
Gas	459.7	633.48	569.99	398.32	301.08	28%	-97.24	-24.0%	194.68	633.48	321.2	362.23	-41.03	-11.0%
Coal	316.84	407.14	445.68	452.47	409.91	39%	-42.56	-9.0%	250.61	457.91	360.92	253.38	107.54	42.0%
Nuclear	123.33	123.33	123.33	123.33	123.33	12%	0	0.0%	123.03	123.33	123.32	112.94	10.38	9.0%
Wind	212.56	176.39	91.98	250.95	296.24	28%	45.29	18.0%	76.94	315.28	167.24	145.71	21.53	15.0%
Other	-115.91	-90.43	9.67	-107.49	-73.14	-7%	34.35	-32.0%	-212.8	49.31	-52.27	-28.9	-23.37	81.0%

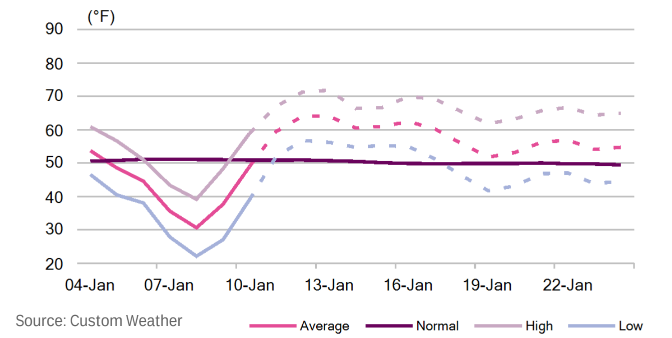
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

ERCOT TEMPERATURE



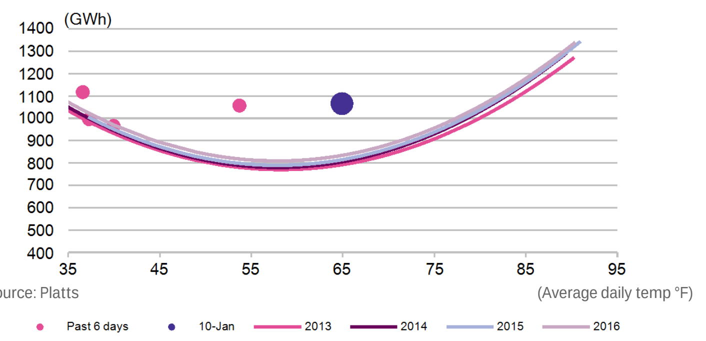
Source: Custom Weather

SOUTHEAST TEMPERATURE



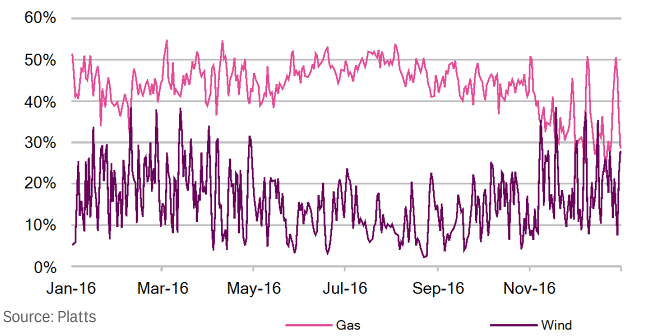
Source: Custom Weather

ERCOT LOAD PER DEGREE



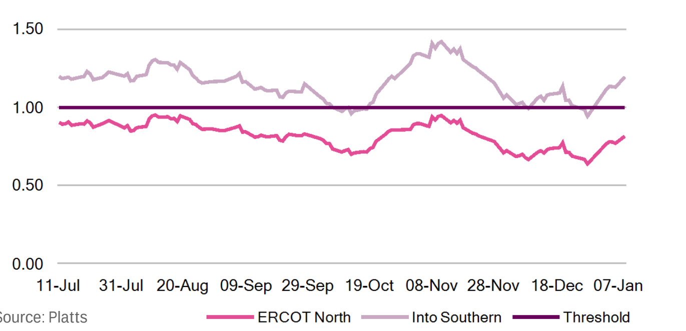
Source: Platts

ERCOT GENERATION MARKET SHARE - GAS VS. WIND



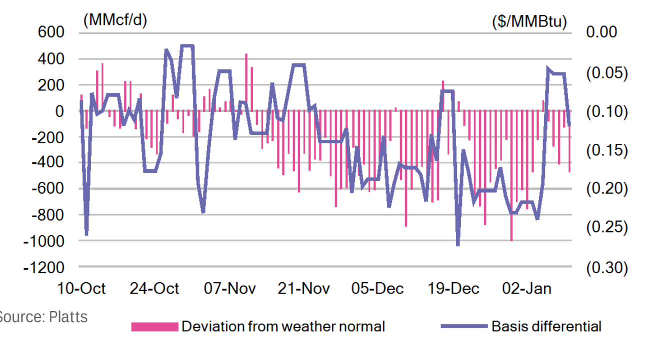
Source: Platts

SOUTHEAST COAL-VS-GAS $/MWh FUEL COST RATIO



Source: Platts

ERCOT POWER BURN VS. GAS BASIS



Source: Platts

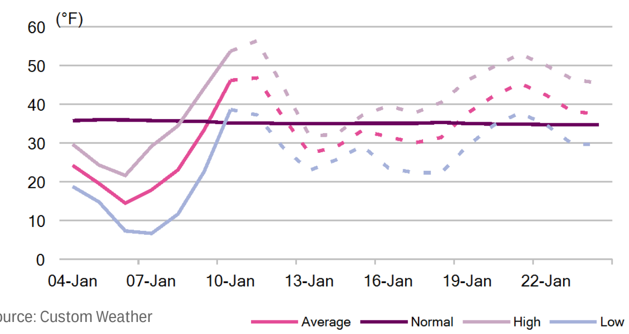
SPP POWER MARKETS

SPP GENERATION MIX (GWh/d)

							Daily change		Season		Season average			
Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Chg	% Chg	Min	Max	2017	2016	Chg	% Chg
Total Generation	855.06	861.86	852.14	810.32	790.08	--	-20.24	-2.0%	55.27	867.17	710.09	675.03	35.06	5.0%
Coal	437	467.52	470.91	372.88	367.43	47%	-5.45	-1.0%	21.94	479.26	372.48	330.5	41.98	13.0%
Natural Gas	163.86	275.71	228.83	125.59	100.57	13%	-25.02	-20.0%	5.82	275.71	123.81	139.23	-15.42	-11.0%
Wind	182.82	45.14	82.34	243.19	250.67	32%	7.48	3.0%	21.13	252.02	146.17	117.78	28.39	24.0%
Nuclear Power	50.38	50.38	50.37	50.35	50.39	6%	0.04	0.0%	4.19	50.41	48.07	62.17	-14.1	-23.0%
Hydro	21.01	22.6	19.7	18.3	21.03	3%	2.73	15.0%	0.57	22.95	19.54	25.15	-5.61	-22.0%
Diesel	0	0.52	0	0	0	--	0	0.0%	0	0.52	0.02	0.19	-0.17	-89.0%

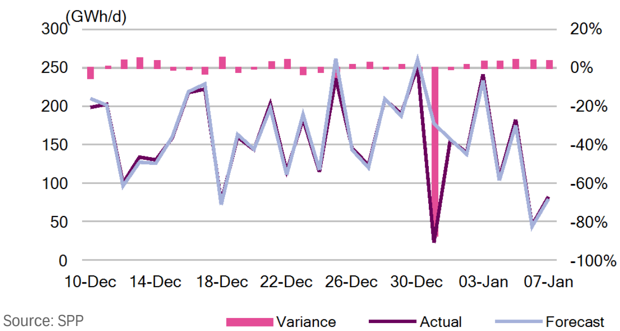
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: SPP

SPP TEMPERATURE



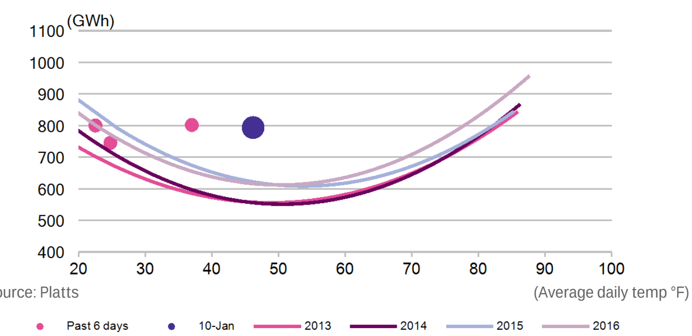
Source: Custom Weather

SPP ACTUAL WIND GENERATION VS. FORECAST



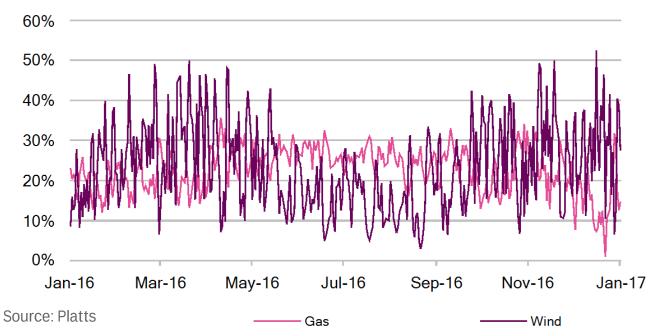
Source: SPP

SPP LOAD PER DEGREE



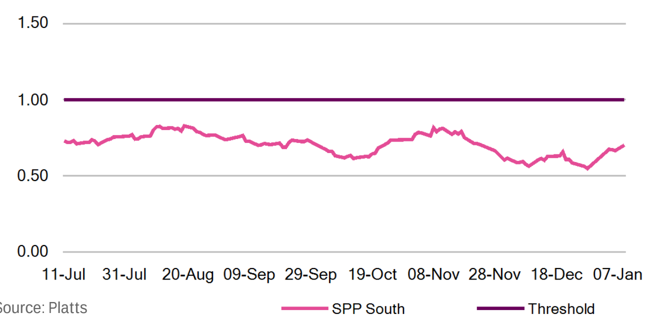
Source: Platts

SPP GENERATION MARKET SHARE - GAS VS. WIND



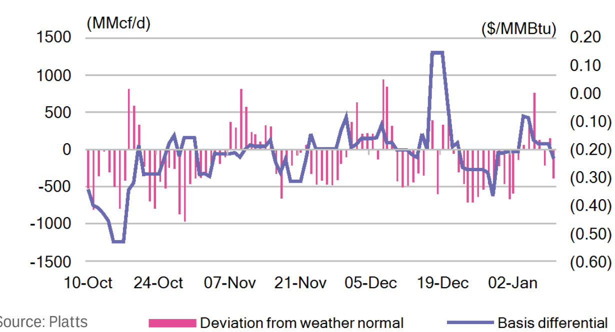
Source: Platts

SPP COAL-VS-GAS $/MWh FUEL COST RATIO



Source: Platts

SPP POWER BURN VS. GAS BASIS



Source: Platts

WEST POWER MARKETS

CAISO GENERATION MIX (GWh/d)

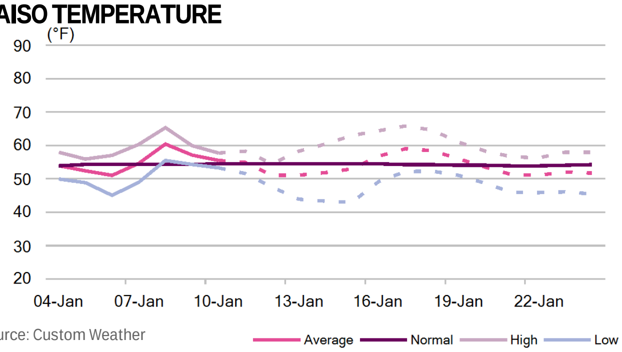
							Daily change		Season		Season average			
Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Chg	% Chg	Min	Max	2017	2016	Chg	% Chg
Total Generation	603.9	609.08	577.9	544.72	600.96	--	56.24	10.0%	537.66	627.09	591.88	583.31	8.57	1.0%
Thermal Power	250.44	233.15	201.86	161.09	216.66	36%	55.57	34.0%	107.38	271.52	201.48	229.12	-27.64	-12.0%
Nuclear Power	54.45	54.34	54.33	54.48	54.51	9%	0.03	0.0%	54.33	54.74	54.55	53.43	1.12	2.0%
Hydro	81	82.53	84.24	70.85	56.87	9%	-13.98	-20.0%	54.34	84.24	65.46	40.95	24.51	60.0%
Power Imports	103.3	145	177.12	166.78	177.12	29%	10.34	6.0%	103.3	212.57	176.94	165.85	11.09	7.0%
Solar PV	28.14	47.22	15.73	36.42	21.52	4%	-14.9	-41.0%	11.91	49.15	32.88	32.42	0.46	1.0%
Solar Thermal	0	1.6	0	0.48	0	--	-0.48	-100.0%	0	3.49	1.23	1.96	-0.73	-37.0%
Wind	52.13	12.3	14.36	23.24	41.78	7%	18.54	80.0%	2.77	63.04	25.94	24.69	1.25	5.0%
Bio + Geo	34.44	32.92	30.25	31.38	32.49	5%	1.11	4.0%	30.25	34.94	33.4	34.89	-1.49	-4.0%

BPA GENERATION, LOAD, and TRANSMISSION (GWh/d)

							Daily change		Season		Season average			
Category	5-Jan	6-Jan	7-Jan	8-Jan	9-Jan	% Share	Chg	% Chg	Min	Max	2017	2016	Chg	% Chg
Total Generation	348.48	361.17	364.65	343.23	351.85	--	8.62	3.0%	46.07	383.11	327.52	296.61	30.91	10.0%
Hydro	270.31	269.36	263.1	248.13	248.23	71%	0.1	0.0%	34.77	270.31	228.75	200.6	28.15	14.0%
Thermal Power	73.88	88.42	96.95	84.27	83.5	24%	-0.77	-1.0%	11.09	97.86	74.07	72.54	1.53	2.0%
Wind power	4.29	3.4	4.6	10.83	20.12	6%	9.29	86.0%	0.21	81.91	24.71	23.47	1.24	5.0%
Load	222.8	220.83	216.08	200.77	195.23	--	-5.54	-3.0%	27.85	222.8	185.18	162.59	22.59	14.0%
Net Exports	125.7	140.36	148.58	142.48	156.63	--	14.15	10.0%	18.22	189.82	142.32	133.94	8.38	6.0%

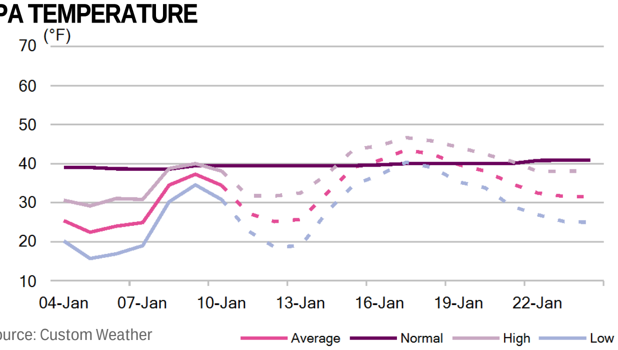
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: CAISO & BPA

CAISO TEMPERATURE



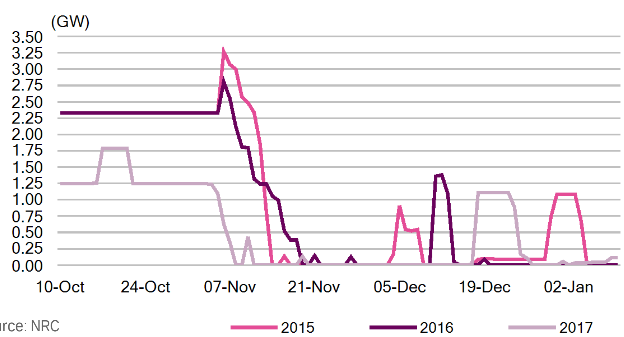
Source: Custom Weather

BPA TEMPERATURE



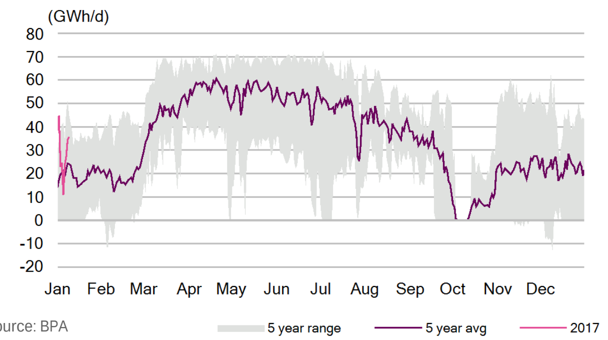
Source: Custom Weather

WESTERN NUCLEAR GENERATION OUTAGES



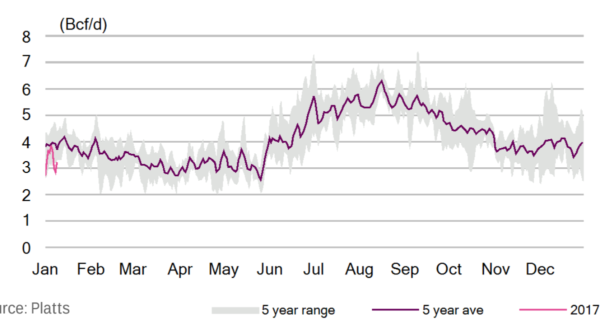
Source: NRC

BPA DC LINE TRANSMISSION FLOWS N-S



Source: BPA

YEAR-TO-DATE WEST POWER BURN



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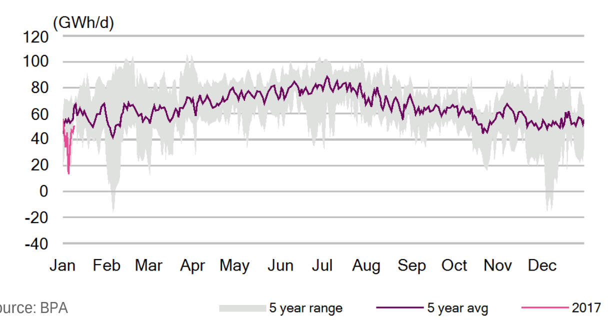
BPA AC LINE TRANSMISSION FLOWS N-S



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