PLATTS
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MEGAWATT DAILY

Friday, January 15, 2016

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- **SP15 dailies sink to upper $20s/MWh on demand**

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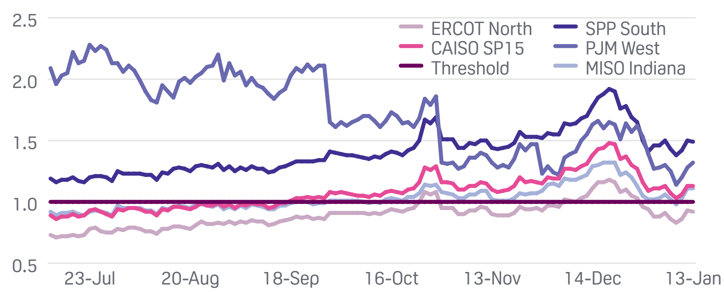
REGIONAL DAY-AHEAD PRICE CHANGES

	Day-ahead peak prices			Regional weather trends		
	15-Jan	Daily chg	Prior 7-day avg	15-Jan	Daily chg	7-day forecast
ISO Price Locations						
CAISO NP 15	31.67	1.28 ▲	32.91	54.2	1.7 ▲	55.5
ERCOT North Hub	20.78	2.08 ▲	20.93	52.6	-1.9 ▼	47.0
ISONE Internal Hub	31.67	-13.72 ▼	38.40	32.5	7.0 ▲	29.6
MISO Indiana Hub	22.18	-2.34 ▼	25.89	31.2	0.2 ▲	18.2
NYISO Zone G	31.95	-15.47 ▼	38.85	37.3	9.5 ▲	30.3
PJM West Hub	24.46	-2.88 ▼	30.80	40.0	7.6 ▲	28.9
SPP South Hub	21.49	-0.10 ▼	25.61	35.0	-9.3 ▼	27.8
Bilateral indexes						
Into Southern	20.50	-4.50 ▼	27.11	53.6	3.0 ▲	46.2
Palo Verde	20.50	0.00 —	22.18	52.5	1.8 ▲	54.0
COB	22.46	0.00 —	24.62	42.5	1.6 ▲	43.2
Mid-C	21.70	0.00 —	23.79	42.5	1.6 ▲	43.2

Source: Platts

COAL-TO-GAS POWER PRICE RATIOS AT MAJOR TRADING HUBS



The Platts coal-to-gas power price ratios are used to asses the regional competitiveness between coal and gas generation at the major power trading hubs. The ratio is defined as the coal $/MWh dispatch price divided by the gas $/MWh dispatch price; gas generation is more competitive than coal when the ratio is a ratio greater than one and vice versa. All price data is for 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	11-Jan	12-Jan	13-Jan	14-Jan	15-Jan	Chg	% Chg	16-Jan	17-Jan	18-Jan	19-Jan	20-Jan	Min	Max	2016	2015	Chg	% Chg
BPA-Puget	8.64	8.11	7.92	8.09	7.92	-0.17	-2.10	7.28	7.33	7.71	7.95	8.00	6.11	9.40	8.36	7.68	0.68	8.85
IESO	22.81	23.62	23.71	22.84	21.78	-1.06	-4.64	20.00	21.46	23.50	23.48	23.55	20.10	24.01	22.09	22.26	-0.17	-0.76
CAISO	29.68	29.51	29.24	29.08	29.08	0.00	0.00	26.48	26.76	29.23	29.07	29.08	22.89	30.71	28.46	28.73	-0.27	-0.94
ERCOT	49.28	48.11	45.29	37.15	37.42	0.27	0.73	39.74	37.71	41.76	38.26	37.24	32.79	49.28	42.57	42.20	0.37	0.88
SPP	34.21	35.49	36.09	25.66	28.11	2.45	9.55	30.73	35.51	37.90	30.78	27.36	29.70	37.52	33.11	30.43	2.68	8.81
MISO	97.45	93.42	96.14	82.19	83.32	1.13	1.37	84.06	101.59	111.86	99.80	86.37	79.04	97.45	86.77	87.09	-0.32	-0.37
PJM	116.78	116.24	121.90	113.58	102.77	10.81	-9.52	98.50	112.28	125.02	125.85	115.82	91.93	122.82	108.60	110.05	-1.45	-1.32
NYISO	22.26	22.23	22.94	22.09	20.23	-1.86	-8.42	18.51	19.88	24.17	24.01	22.58	17.95	23.29	20.94	21.71	-0.77	-3.55
NEISO	18.10	18.10	18.83	18.98	17.20	-1.78	-9.38	15.44	16.50	19.95	20.05	18.86	14.05	19.22	17.21	17.99	-0.78	-4.34
AESO	10.88	10.79	10.79	10.26	10.64	0.38	3.70	10.36	10.37	10.60	10.50	10.69	10.01	10.96	10.71	10.60	0.11	1.04

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

Source: Platts

NEWS

FERC shoots down call to pull surveillance rule

January 22 is the deadline for comments to be filed with federal regulators on a proposal for new reporting requirements designed to help detect energy market manipulation, and calls for suspension of the comment period have been denied.

Industry groups had hoped that the Federal Energy Regulatory Commission would put delay the proposed market surveillance rule given outstanding questions on the scope of the rulemaking and a general lack of clarity on how market participants would be expected to comply.

The rule (RM15-23) proposed in September would require market participants to obtain a common alpha-numeric identifier, list connected entities with which they have ownership, employment, debt or contractual relationships and briefly describe the nature of those relationships. The connected entity data, through mandated tariff revisions, would be collected by the independent system operators and regional transmission organizations and then electronically furnished to the commission.

FERC asserted that the information would add context to market data it already receives from the ISOs and RTOs, including insight into the incentives underlying market participants' trading activities so staff may better differentiate between seemingly anomalous trading patterns for legitimate business reasons and for potentially manipulative reasons warranting investigation, according to the notice of proposed rulemaking.

Electric, gas and commodities trading groups and companies, however, raised concerns about the potentially heavy burden and high compliance costs associated with the proposed new reporting regime. Further, they said the NOPR was rife with ambiguity and lacked detail.

Industry groups argued in a filing with the commission December 30 that while FERC staff voiced major clarifications and substantive changes to the proposed rulemaking during a December 8 technical conference, those developments were not reflected in the official NOPR, nor were additional questions staff and commissioners posed during the conference or the commission's intent to take "comments on a proposal that is substantively different from the NOPR as published in the Federal Register."

The December 30 filing was submitted by the American Forest & Paper Association, Canadian Electricity Association, Commercial Energy Working Group, Edison Electric Institute, Electricity Consumers Resource Council, Electric Power Supply Association, Independent Power Producers of New York, Industrial Energy Consumers Group, International Energy Credit Association and Retail Energy Supply Association.

Industry sought revised NOPR

On behalf of their members, the industry groups asked FERC to suspend the current January 22 comment deadline; either withdraw the NOPR and issue a revised proposal or issue a supplement to the existing NOPR; and open a new comment window.

This would facilitate creation of an official document that takes into consideration industry's concerns, codifies the clarifications made during the technical conference and specifies any new questions FERC would like industry and other stakeholders to address, the groups contended.

Their request was backed by Ares EIF Management, the National Rural Electric Cooperative Association and the American Public Power Association in subsequent filings with FERC.

But the commission said in an order issued Wednesday that it had not been persuaded to take such actions, and upheld the January 22 deadline.

The commission did clarify that it would accept comments on the NOPR itself as well as the guidance staff provided at the technical conference and companies' positions on whether the NOPR should be withdrawn, supplemented or revised.

"While the technical conference provided a useful forum for interested entities to raise their concerns with the proposal and to ask questions of commission staff, it remains necessary for the commission to receive written comments on the NOPR prior to determining what revisions are necessary, or whether issuing a supplemental or revised NOPR is appropriate or necessary, or whether issuing a final rule in this docket is appropriate," the FERC order said.

A well-informed decision on next steps for the rulemaking will first require detailed, specific comments, FERC said, adding that "interested entities can seek additional clarifications and urge the commission to reconsider aspects of the proposal in their comments."

Order keeps option to revise or terminate NOPR

Meghan Gruebner, an attorney with Sutherland Asbill & Brennan who represents clients that could be impacted by the proposed rule, including one of the signatories to the joint motion, said Thursday that FERC's decision, while unfortunate, was not the end of the road, especially since FERC's order indicated that terminating the NOPR or issuing a revised or supplemental NOPR were still on the table.

"I am sure several commenters will address jurisdictional and definitional issues related to the NOPR, as well as the cost-benefit analysis presented under the NOPR," Gruebner said. "Once the commission sees that there are still many outstanding issues notwithstanding staff guidance provided at the technical conference [in December], I think it likely the commission will withdraw the NOPR and issue a revised or supplemental NOPR."

However, FERC's refusal to do so at this juncture and before the comment window closes does pose some challenges, she said.

Among the uncertainties surrounding the rulemaking are lingering questions on "the intent and objectives of the commission under the connected entity NOPR" and whether FERC has narrowly tailored the requirements under the NOPR to achieve its objectives, Gruebner said.

While the NOPR frames the purpose around detecting market fraud, authorized under section 222 of the Federal Power Act, Gruebner said, "statements made by staff during the technical

MLK HOLIDAY NOTICE

■ *Megawatt Daily* will not publish Monday, January 18, because of the Martin Luther King Jr. Day holiday. Wholesale power assessments based on trading Friday, January 15, will be published in the Tuesday, January 19 issue. Flow dates for power traded Friday vary among markets, and will be specified in published tables.

conference suggest that the connected entity data is intended to aid market power assessments and pivotal supplier tests."

Gruebner added that if the latter is the real purpose of the NOPR, then "the rule must be further refined." Moreover, "this purpose is beyond the scope of the current rulemaking and affected market participants must be put on notice if this is the real purpose," she said.

Ambiguity also still exists on certain definitions and on the commission's intent to prevent gas markets from being swallowed up by the rulemaking, Gruebner said.

— Jasmin Melvin

NYISO reports capacity auction, power prices

New York Independent System Operator power prices set record lows in December, and NYISO's capacity auction performed solidly, grid officials reported this week.

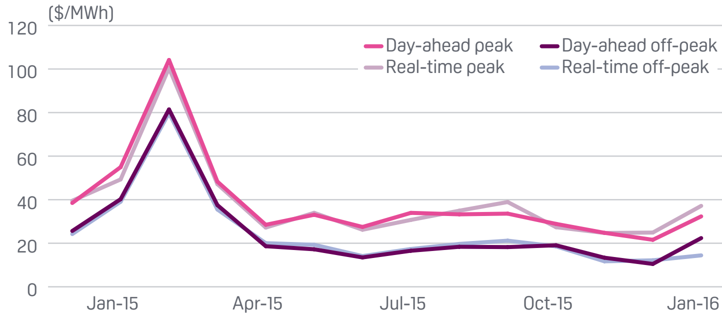
NYISO's average Locational Based Marginal Price for December was $20.90/MWh, lower than the $24.80/MWh price for November, which was the previous lowest price for any month during NYISO's operation. The LBMP for December 2014 was $38.08/MWh.

The average year-to-date monthly cost in December was $44.09/MWh, a 36% decrease from the $69.31/MWh year-to-date monthly cost in December 2014.

The highest peak demand in December was 21,254 MW on December 28. The all-time winter capability period peak load of 25,738 MW occurred on January 7, 2014, NYISO said.

The average daily sendout in December was 408 GWh/day in December, higher than the 396 GWh/day in November but lower than the 433 GWh/day in December 2014. Day-ahead market MWh sales totaled 13.62 million MWh.

MONTHLY AVERAGE NYISO POWER PRICES



Note: Prices are calculated as a simple average across all LMP locations each month
Source: New York ISO

Natural gas and distillate prices were lower compared to the previous month, the report said. Natural gas at Transco Zone 6 NY was $1.60/MMBtu, down from $1.80/MMBtu in November. "Natural gas prices are down 51% year-over-year," NYISO said. Jet kerosene Gulf Coast was $8.01/MMBtu, down from $9.80/MMBtu in November. Distillate prices were down 42% year-over year.

2015 capacity auction performed well: NYISO

The 2015 market clearing prices in NYISO's installed capacity spot market auctions support the conclusion that the auctions continue to be attractive to suppliers, the grid operator also said this week in its

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2015 Installed Capacity report.

The report reviewed the outcomes of the installed capacity market and the effectiveness of the ICAP demand curves in attracting investment in new generation. Capacity market outcomes are reviewed to ensure market signals are aligned with reliability needs, the report said.

Capacity prices during the 2014/2015 winter were lower on average than the previous winter. The average ICAP spot market auction prices were $2.03/kW-month for the New York Control Area compared with $3.10/KW-month the year before.

Prices in the winter 2014-2015 in the Lower Hudson Valley capacity zone were $4.04/kW-month. The zone was created in May 2014.

New York City's average price in the 2014-2015 winter was $8.36/kW-month compared with $9.73/kW-month the previous winter. The average winter price on Long Island was $3.14/kW-month in winter 2014-2015 compared with $3.35/kW-month during the previous winter, the report said.

The average spot market auction prices for the 2015 summer were lower than the previous summer by $2.14/kW-month in the New York Control Area, $3.07/kW-month lower in the Lower Hudson Valley, $3.12/kW-month lower in New York City and 79 cents/kW-month in Long Island.

About 41% of the load was met through bilateral transactions in the winter of 2014-2015 compared with 46% during the previous winter. The remainder was met through auction purchases, the report said. During the summer of 2015, 43.3% of the load was met through bilateral transactions compared with 44% during the previous summer.

Capacity committed through bilateral transactions, auctions and self-supply remained above the New York Control Area minimum installed capacity requirement and above each locality's minimum installed capacity requirement, the report said.

"The amount of capacity committed to the NYCA, including imports, continues to be high compared with minimum requirements," the report said.

The average monthly import levels into New York were about 2,000 MW in the winter of 2014-2015, about 250 MW more than the previous winter and about 200 MW less than the summer of 2015.

The report also looked at the amount of power that was withheld from sale during the review periods by analyzing the difference between available capacity and the amount committed through auctions, bilateral transactions and self supply. The average amount of power withheld across the state in the 2014-2015 winter was 24 MW compared with 2 MW during the previous winter. About 3 MW were withheld on average during the summer of 2015.

NYISO determined that none of the instances of withholding power for sale in the Rest of State, which excludes the Lower Hudson Valley, was intended to artificially raise prices. "There were seven market participants with at lease 15 MW of unoffered capacity in any given month in ROS," the report said.

The effect on price by the unoffered capacity was 24-cents/kW-month in the winter 2014-2015 and 80-cents/kW-month during the summer of 2015.

In the past, it has been difficult to relate the investment in new generation to the ICAP demand curves, the report said. But since the new Lower Hudson Valley Zone was implemented along with its ICAP demand curves, there has been investment in resources in the zone and a sharp decrease in generation outside the new zone, the report said.

The new zone is providing the market signals for resources to return to service, the report said.

Demand response up 9.5% from 2014 levels

NYISO also this week reported a 9.5% increase in the number of megawatts enrolled in demand response programs compared with 2014, the grid operator said in its 2015 annual report on demand response programs.

As of July 31, 2015, 3,896 users were enrolled in the emergency demand response program and a special installed capacity program.

About 97% of the total users enrolled in the state's reliability-based demand response programs are enrolled in the special installed capacity program, the report said. Those users can offer unforced capacity into the NYISO installed capacity market as a capacity supply resources.

Those enrolled in installed capacity program are capable of providing 1,325.4 MW of demand response, or 4.3% of the 2015 summer peak period demand of 31,138 MW.

The New York City load zone is the only load zone with resources participating in NYISO's targeted demand response program, meant to solve local reliability programs.

NYISO also offers a day-ahead demand response program in which offers are structured like those of generation resources by specifying the hours they are available. Enrollment in the day-ahead program has been static for several years.

NYISO's demand-side ancillary service program represents 126.5 MW of capability and had an average performance of 144% from May 2015 through October 2015, the report said.

— Mary Powers

Minn. PUC official backs 500-kV line project

After clearing a major route hurdle, Minnesota Power aims this year to begin acquiring right-of-way for a proposed 500-kV transmission line to carry 883 MW of hydropower from Manitoba Hydro into the northern US, strengthening regional reliability.

Ann O'Reilly, an administrative law judge for the Minnesota Public Utilities Commission, ended uncertainty over the path of the 220-mile Great Northern Transmission Line late last week by recommending approval of the Allete subsidiary's preferred "blue" route, which includes an international border crossing northwest of Roseau, Minnesota, just south of the US border with Manitoba.

ALJ recommendations carry considerable weight with the PUC, which is expected to issue a final decision by spring.

"Once we receive approval on the route permit and a presidential permit, we'd start acquiring right-of-way in 2016, but construction won't start until 2017 because we still need final engineering, and there are other approvals to obtain such as a wetlands permit from the Army Corps of Engineers and a license to cross state land" from the Minnesota Department of Natural Resources, Minnesota Power spokeswoman Amy Rutledge said Thursday in an email.

The Duluth-based utility applied for a certificate of need for the project on October 22, 2013, and the commission granted it in June 2015. The line is targeted for commercial operation by June 1, 2020.

Cost estimate: $557.9 million to $710.1 million

In her report, O'Reilly noted the project is estimated to cost between $557.9 million and $710.1 million in 2013 dollars.

Manitoba Hydro will build and be sole owner of the Canadian portion of the new interconnection. For the Minnesota portion of the project, Manitoba Hydro will own 49%, with Minnesota Power controlling 51%.

An unusual feature of their power purchase agreement allows Minnesota Power to use Manitoba Power's hydropower system to store wind energy the Minnesota utility produces at its nearly 500 MW Bison Wind Energy Center in south-central North Dakota.

Minnesota Power will be able to deliver electricity from Bison to Manitoba Hydro when wind production is high and demand on Minnesota Power's electric system is low. As a result, Manitoba Power's system will serve as a de facto battery for energy produced from Bison.

Under their financing arrangement, Minnesota Power will only be responsible for 28.3% of the project's capital costs and only 33% of the operation and maintenance costs of the facilities, according to the report.

Aside from reliability issues, Minnesota Power says the new line is needed to help the utility diversify its generation portfolio, which still relies heavily on coal, by adding more renewable energy.

Line expected to help renewables shift

Under its "Energy Forward" strategy to reduce carbon emissions and assure continued reliability and affordable rates, Minnesota Power eventually aspires to reach a generation mix of one-third coal, one-third natural gas and one-third renewables. Currently, coal accounts for about 70% of the portfolio, with renewables contributing about 30%. A decade ago, coal generated 95% of the utility's power.

"Minnesota Power believes the Great Northern is a critical component of our Energy Forward strategy to diversify our energy mix while providing reliable and competitively-priced power to our customers," Rutledge said. "We do feel this is a competitive resource and is an excellent complement to our nearly 500 MW of wind energy."

Minnesota Power serves 144,000 customers, including several large industrial customers, in northeastern Minnesota.

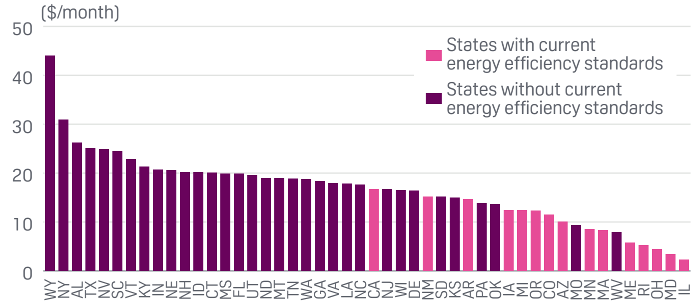
— *Bob Matyi*

Energy efficiency, CPP can cut power bills: study

By using an aggressive energy efficiency standard to comply with the Clean Power Plan, the average residential customers' monthly bills in the Lower 48 states could decrease by $17, a study released Thursday shows.

Synapse Energy Economics, a Cambridge, Massachusetts-based consultancy focused on the economic impact of energy and environmental policy, on Thursday released a study entitled "Cutting Electric Bills with the Clean Power Plan." The Clean Power Plan calls for cutting carbon dioxide emissions at existing power plants by 32% by 2030, with interim targets before that date.

2030 BILL SAVINGS WITH HIGH ENERGY EFFICIENCY AND CPP



Source: Synapse Energy Economics

"Synapse examined the comparative cost associated with state implementation plans that maximize available energy efficiency strategies versus a future in which states are not Clean Power Plan-compliant," the study states. "We found that if states comply with the Clean Power Plan through strategies that encourage cost-effective energy efficiency, households can expect to save an average of $17 per month on their electric bills in 2030 compared to a reference case that does not comply with the rule. … Monthly savings range from a high of $44 per month in Wyoming to a minimum of $2 per month in Illinois."

All of these dollar amounts are in 2013 dollars.

States that do not now have energy efficiency standards stand to have the sharpest decrease in monthly residential power bills by 2030, said Elizabeth Stanton, a study co-author. "The largest bill savings were also found in states with higher poverty rates," she said.

Synapse also studied the effect on monthly bills of complying with the CPP by methods such as renewable power, but "with far lower efficiency savings."

"We found that, on average, bills were $21 per month lower in the scenario that employs strong investments in energy efficiency than in the scenario that achieves compliance through other strategies," the study states.

Average savings by state ranged from a high of $33 a month in Wyoming to a low of $5 a month in Maryland.

Patrick Knight, the study's lead author, said, "Our analysis confirms that energy efficiency is one of the most cost-effective ways to reduce and avoid emissions from power generators."

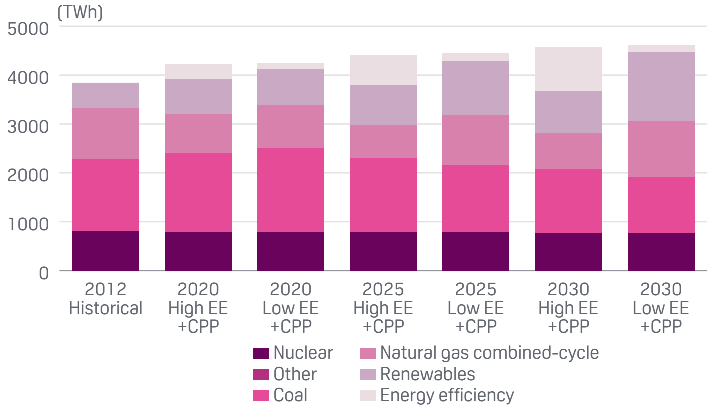
'Compliance ... will be a lot less painful': King

Robert King, president of Good Company Associates, an Austin, Texas-based energy business consultancy, said he "would generally agree with" the Synapse study's findings, that "compliance with the CPP will be a lot less painful than people are being led to believe by political dialogue meant to ideologically differentiate party positions."

However, the study does contain a mistake, King said, because it assumes Texas has no efficiency standard, but Texas adopted an energy efficiency standard in 1999.

"When it was first adopted we were ranked 11th in energy efficiency programs among the states by the American Center for an Energy Efficiency Economy (ACEEE) in Washington," King said in an email. "Still, in part because our efficiency goal is tied to the rate of growth in demand and Texas demand growth has slowed substantially, Texas had slid to 34th in the national rankings until we adopted a more up-to-

ENERGY EFFICIENCY EFFECTS ON LOWER 48 GENERATION MIX



Source: Synapse Energy Economics

date building code this last [legislative] session."

Knight explained that the Texas standard is based on peak demand, while the Synapse study only modeled states as having an energy efficiency standard that had a set energy efficiency requirement in terms of annual retail sales.

King is incoming president of the Gulf Coast Power Association and CEO of the Southcentral Partnership for Energy Efficiency as a Resource.

Joshua Rhodes, a postdoctoral fellow at the University of Texas Energy Institute, said the study's conclusions were not surprising.

"There are a lot of cost-effective energy efficiency measures that are rather simple to do and can have a big impact," Rhodes said in an email. "However, getting this information to people and then having them act on it is nontrivial."

Rhodes noted that wholesale power markets typically operate by dispatching the least-expensive power first, so "reductions in demand will typically reduce wholesale market prices for electric power."

"If prices in the wholesale markets can remain lower, it is harder for utilities to raise rates," Rhodes said.

More coal in high-EE scenario generation mix

The study reaches what may be a counterintuitive conclusion about how the employment of an aggressive energy efficiency effort to comply with the CPP would affect the generation mix, compared with complying with the CPP with little energy efficiency. With the aggressive energy efficiency effort, coal-fired generation would provide a larger share of the total, at 34%, compared with 29.7% with little energy efficiency.

"If you have a lot of energy efficiency, what that means is that in order to fill the rest of capacity, you can call on more coal," Knight said in a media conference call.

Tennessee Valley Authority spokesman Scott Fiedler said the TVA, which serves public power and co-operative customers in Alabama, Georgia, Kentucky, Mississippi, North Carolina and Virginia, has already reduced its CO2 emissions by more than 30% since 2005.

And the TVA's integrated resource plan is "very clear on the important role energy efficiency will play in continuing to achieve those goals," Fiedler said.

"TVA plans to achieve energy efficiency savings between 900 and 1,300 megawatts by 2023 and between 2,000 and 2,800 megawatts by 2033," Fiedler said.

Nora Mead Brownell, a founding partner in the Espy Energy Solutions consultancy and a former Federal Energy Regulatory Commission member, said, "State policy makers should remove barriers to entry, create standards for metrics on performance, ... harmonize rules for protocols over states and even regions."

"To protect old, inefficient power plants is about politics and money, not customers," Brownell said in an email. "Gas is cheaper than coal – that is what hurts coal more than policy."

The Synapse study was funded by a grant from the Energy Foundation, a "pragmatic and nonpartisan" philanthropic organization that promotes "the transition to a sustainable energy future by advancing energy efficiency and renewable energy," according to the Energy Foundation website.

— Mark Watson

Need for fossil fuels, nukes likely to stay: expert

The affordability, availability and reliability of conventional energy sources, such as oil, natural gas, nuclear power and coal, mean they are unlikely to be displaced by renewable energy in the global economy, according to a University of Texas researcher.

"Energy security drives everything," said Scott Tinker, director of UT's Bureau of Economic Geology. "Energy lifts humans from poverty … Good intentions don't always produce good outcomes."

After the Kyoto protocols were largely ratified in 2002, developing nations' carbon dioxide emissions soared from about 13 gigatons a year to about 22 gigatons a year, according to Tinker, speaking Tuesday at the UT Energy Journalism Workshop. In contrast, the developed nations' emissions fell from about 12 gigatons a year to about 11 gigatons a year.

On Monday at the same workshop, Michael Webber, UT Energy Institute deputy director, noted that for Third World nations where electricity is relatively uncommon, coal may represent a rational choice, just as it was when the United States was a predominately agrarian society.

"Coal was cleaner, cheaper and more abundant than wood," Webber said. "The shortage of one resource causes the development of alternatives."

Nuclear power growing in China

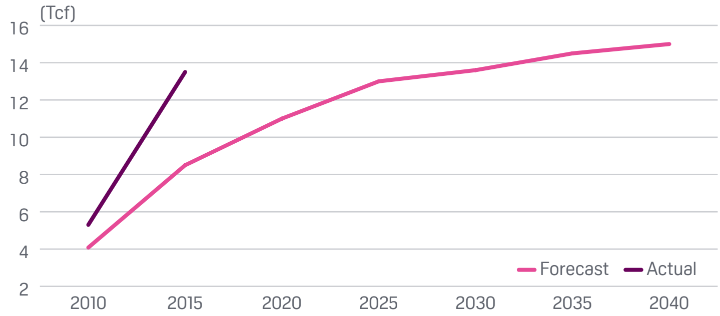
Developing nations have been rationally choosing to maximize their energy value by opting for the least expensive, most widely available and most reliable power, perhaps while accepting limits on the sustainability of those choices. For example, China is building 29 nuclear plants in an attempt to slow down its consumption of coal for electricity, which is widely blamed for severe pollution in Chinese cities.

"If we fight nuclear, they're going to keep burning coal," Tinker said.

Tinker noted that after the Fukushima nuclear plant disaster prompted Japan to shut down all of its nuclear plants in 2011, the share of Japan's electricity generation fueled by coal, natural gas and oil jumped from about 61% to about 87% in 2013, while hydro and other renewable power's share stayed constant at around 12%.

"They switched to coal, natural gas and oil, not renewables — it wasn't secure for them," Tinker said.

US SHALE NATURAL GAS FORECAST VS. ACTUAL



Source: University of Texas Bureau of Economic Geology, Rice University, US Energy Information Administration

Developed nations' global investment in renewable energy peaked at $190 billion in 2011, easing down to $139 billion in 2014, he noted. Developing nations' renewable power investment hit $107 billion in 2012, before falling to $97 billion in 2013, then resurging to $131 billion in 2014.

Webber said, "As technology improves, an economy tends to decarbonize and clean up."

Mineral value chain important for renewables

But Gurcan Gulen, UT Bureau of Economic Geology senior energy economist, on Monday pointed out that a switch to renewables has other consequences, some of them geopolitical. For example, minerals used in batteries include cobalt and lithium. The world's largest cobalt reserves are in the Democratic Republic of Congo, and the world's largest lithium reserves are in Bolivia, and both of these nations pose political and logistical problems for acquiring those resources. Cadmium is a mineral important for solar panels, and China is the world's leading producer.

The shale gas boom has relieved pressure on the global economy to use less sustainable energy resources, Tinker said, with actual US production outstripping forecasts by more than 50%, reaching a level not expected until around 2030, according to a 2012 Rice University study.

"How long is that going to last?" Tinker asked. "That's unknowable, but there are some fundamentals."

With natural gas prices languishing near $2/MMBtu, most shale resources are out of the money, he said. US production has not yet significantly declined, he said, because producers are concentrating on the most productive, efficient wells.

On Tuesday, when the NYMEX February WTI crude and the IntercontinentalExchange February Brent crude settled below $32/b, Tinker said, "I don't know how it will play out."

Saudi 'pain is getting very real': Tinker

However, Tinker noted that "the pain is getting very real" for Saudi Arabia.

"The economy in Saudi Arabia is awful, and they haven't seen that before," Tinker said.

Saudi Arabia's budget fell from a surplus equal to 5.8% of gross domestic product in 2013 to a 3.4% deficit in 2014, and the deficit was expected to have grown to 21.6% of GDP in 2015, according to Tinker's presentation materials.

But for the US, the future is more appealing, Webber said, as oil production set a new record in 2014, at 8.7 million b/d, which topped the nation's previous peak oil year in the late 1960s.

"I think it's pretty exciting that we're setting new records," Webber said. "The US became the world's largest oil producer in 2014."

This was the result of effective government policy, functional technology and properly aligned markets, Webber said. Among the relevant government policies was research and development at the US Department of Energy, he said.

Meanwhile, energy use has become more efficient, Tinker said. If the US had continued using energy at the same rate it had in the early 1970s, by 2014, energy use would be 80% larger than it was, or about 180 quadrillion Btu/year, versus actual use of about 100 quadrillion Btu/year.

Webber said, "Perhaps we've had our peak energy obesity event."

— Mark Watson

PJM warned of Ohio subsidizing at-risk plants

New generation in Ohio is difficult to justify if state regulators approve what amounts to a "special subsidy" for American Electric Power and FirstEnergy, the head of a company developing 1,800 MW of natural-gas fired generation in Ohio has said.

AEP and FirstEnergy are seeking Ohio Public Utilities Commission approval for separate power purchase agreements totaling more than 6,000 MW of at-risk coal and nuclear generation. The controversial proposals have sparked the most vociferous stakeholder response in years, with varied groups dividing into supporting and opposing camps.

Boston-based Advanced Power Management definitely is in the latter category.

In a Wednesday letter to PJM Interconnection's board of managers, Advanced Power president Chuck Davis implored the Pennsylvania-based regional grid operator to "act now" to prevent the PPAs from becoming reality.

If the PPAs win the PUC's endorsement, "the results will be that pricing for capacity and energy received by other market participants, who do not benefit from the subsidy, will be significantly lower than expected," Davis said. "This negatively impacts the investment returns of parties invested in the PJM market as a result of lower energy margins and capacity revenues."

Generation investment impacts expected

Likewise, those that have contemplated investment in new generation "will face lower returns and, as a result, either find it more challenging to raise capital or not make the investment at all."

The end result will be "antiquated and uneconomic power generation facilities will be kept on line," he added, at a time when they otherwise would be replaced by newer, lower-cost and cleaner facilities with a far smaller carbon footprint.

AEP and FirstEnergy argue the PPAs would ensure continued diversity in Ohio's generation mix while providing reliability. AEP, for instance, has pointed to the January 2014 "polar vortex" when virtually all of its coal-fired generation in Ohio was needed to keep the lights on.

Davis, though, suggested generation developers like his company might find more investment avenues closed to them if the PPAs are approved.

The 700-MW, $899-million Carroll County Energy combined-cycle gas plant, under construction in Carroll County, is co-owned by Advanced, TIAA-CREF, Prudential Capital Group and Chuba Electric. The equity investors have committed $411 million in funds and a syndicate of 10 commercial banks provided an additional $488 million in credit facilities support the construction and financing of the project, according to Davis.

"The development and financing of the project was predicated on the PJM market mechanism which is the largest and most liquid competitive capacity and energy market in the US," he noted.

That investment was made, he said, "because of the robust capacity and energy markets in PJM, and the value of the price signals they send to the market participants for new entry."

Such market signals also would serve as the basis for Advanced's further investment in the 1,100-MW, $1.1-billion South Fork Energy LLC combined-cycle gas plant in Columbiana County, scheduled for commercial operation in 2020.

Davis said he agreed with previous statements to PJM by the PJM Power Providers Group and Electric Power Supply Association. They maintained that PJM's market benefits will evaporate "if the market is corrupted by state actions that subsidize otherwise uneconomic units." They, like Advanced Power, want PJM to "articulate this fact" to Ohio regulators and take appropriate actions at both the independent system operator and the Federal Energy Regulatory Commission "to limit any damage."

PJM has not yet voiced an opinion on PPAs

PJM spokesman Ray Dotter declined to comment Thursday on Davis' letter "because it is to the board and we don't speak to it."

To this point, PJM has neither supported nor opposed the PPAs, on which the PUC is expected to rule in the next couple of months.

The PUC has denied formal intervenor status to PJM in both the AEP and FirstEnergy cases. However, it will allow the grid operator to file "amicus briefs" as an entity that is not a party to the cases but has information to offer.

Dotter said PJM will make such a filing in the coming weeks.

Merchant generators Exelon and Dynegy, meanwhile, have weighed in with unsolicited offers to effectively replace the generation covered by the PPAs with their own generation. In Exelon's case, it would be non-polluting nuclear generation.

— *Bob Matyi*

OUTAGES

GENERATION UNIT OUTAGE REPORT

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Lake Superior/Brookfield	120	g	Ont.	PMO	Unk	11/04/14
Lennox-2/OPG	525	g	Ont.	MO	Unk	01/13/16
Lennox-3/OPG	525	g	Ont.	MO	Unk	09/04/15
Pickering-4/OPG	515	n	Ont.	MO	Unk	01/08/16
Pickering-6/OPG	520	n	Ont.	MO	Unk	09/21/15
Pickering-7/OPG	520	n	Ont.	MO	Unk	01/07/16
PJM & MISO						
Prairie Island-2/NMC	604	n	Minn.	MO	Unk	12/18/15
Southeast & Central						
Limestone-1/NRG	830	c	Texas	MO	Unk	11/30/15
Martin Lake-2/Luminant	750	c	Texas	MO	Unk	02/01/15
Martin Lake-3/Luminant	750	c	Texas	MO	Unk	06/18/15
River Bend-1/Entergy	979	n	La.	MO	Unk	01/11/16
Sequoyah-1/TVA	1152	n	Tenn.	MO	Unk	12/26/15
Watts Bar-2/TVA	1179	n	Tenn.	MO	Unk	01/04/15
West						
Alamitos-5/AES	498	g	Calif.	PMO	Unk	01/11/16
Belden Hydro/PG&E	119	h	Calif.	PMO	Unk	10/28/15
Encina-4/Cabrillo Power	300	g	Calif.	PMO	Unk	01/03/16
Etiwanda-3/Reliant	320	g	Calif.	PMO	Unk	01/11/16
Gilroy/Calpine	120	g	Calif.	PMO	Unk	01/10/16
Kerckhoff-1/PG&E	153	h	Calif	PMO	Unk	11/02/15
Luz-8&9/NextEra	184	s	Calif.	MO	Unk	01/05/16
Mojave/Abengoa	275	s	Calif.	PMO	Unk	01/10/16
Redondo-6/AES	175	g	Calif	PMO	Unk	01/04/16
Sutter Agg/Calpine	525	g	Calif.	MO	Unk	12/20/15
Redondo-6/AES	175	g	Calif	PMO	Unk	01/04/16
Sutter Agg/Calpine	525	g	Calif.	MO	Unk	12/20/15

Daily generation outage references: O=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.

Full power cost varies by region, type: UT panel

After accounting for various costs of electricity generation technologies, the generation type that would have the lowest full production cost varies substantially across the contiguous US, University of Texas researchers have found.

Carey King, assistant director of the UT Energy Institute, in an email Wednesday said that the levelized cost of energy is commonly used to determine the relative cost/kWh of various types of electricity generation.

Lazard, the Bermuda-based financial advisory firm, regularly publishes a report on a range of unsubsidized LCOEs for various technologies. The latest such report, issued in November, shows that onshore wind had the lowest minimum cost, at $32/MWh, but this ranged up to a maximum of $77/MWh.

Thin-film photovoltaic solar had the next-lowest minimum, at $50/MWh, ranging up to $60/MWh.

Natural gas combined-cycle generation had the lowest minimum for non-intermittent generation, at $52/MWh, ranging up to $78/MWh.

Jim Dyer, a professor of information, risk and operations management at UT's McCombs School of Business, said at Monday's UT Energy Journalism Workshop that the LCOE "is certainly a reasonable place to start in terms of alternatives you might consider."

But King said Wednesday that "the conventional LCOE has several shortcomings that render it spatially and temporally static."

"From the spatial variability perspective, costs of building and operating an identical plant across different geographies will be different," King said. "Moreover, fuel costs, capacity factors and financing terms differ across regions as well. Thus, given these cost variations, any given technology might have the lowest LCOE in any given county. UT researchers continue to investigate additional factors that form the 'full cost of electricity' via estimation of [transmission and distribution] costs and dispatch modeling of different generation portfolios."

This "full cost of electricity" model would also take into account costs for land, capital, operations and maintenance, regulations, taxes, the environment and human health.

Human health costs higher in some places

Sheila Olmstead, an environmental economist and professor at UT's Lyndon Baines Johnson School of Public Affairs, said human health costs can vary significantly by location. For example, in a recent year Santa Monica, on the California coast, had one day above the federal ozone limit, while Pasadena, California, which is about 25 miles inland, had 28 days above the ozone limit, she said.

The UT study excludes subsidies, decommissioning costs and water supplies, said Olmstead, who is one of the researchers.

The study may not be published for months, but at Monday's workshop, the team presented a map with striking geographic variations regarding which technology provided the least-expensive FCE across the more than 3,000 counties of the contiguous US. This particular map did not include transmission and distribution costs.

Wind power would have the lowest FCE for new generation for most of the Great Plains, the western Rockies, the Great Lakes area and the Northeast, including most of New York, according to the map, which the research team would not release to Platts for publication before it is published in a peer-reviewed journal.

Natural gas-fired generation would have the lowest FCE in the Southeast and much of the West. Nuclear power would provide the lowest FCE in north-central California, much of Minnesota and Wisconsin, and much of North Carolina.

In certain urban areas — notably Cobb County (Atlanta), Georgia; Dade County (Miami), Florida; Harris County (Houston), Texas; and Ventura County (Los Angeles-area), California — rooftop solar PV had the lowest FCE for new generation.

Dyer, who is on the research team, said business decision makers would like to know the best type of generation to add to a particular location.

The team hopes to develop a website that enables visitors to adjust certain parameters to make projections about what an area's "eventual portfolio of plants would be 10 years from now," Dyer said.

— Mark Watson

Cuomo plans to eliminate coal from N.Y. by 2020

New York Governor Andrew Cuomo said Wednesday that he intends to eliminate the use of coal in the state by 2020 while making the goal of having 50% of state's power from renewable sources by 2030 a requirement.

The measures are part of making New York a leader in the fight against climate change, Cuomo said during his state of the state address.

"We will help coal plants transition, but clean air is our first priority," he said.

The fate of one of four coal-fired plants in the state has already been decided.

NRG Energy will close the two-unit, 380-MW Huntley coal-fired plant on March 1, David Gaier, a company spokesman, said Wednesday in an interview.

NRG had plans to convert the 530-MW Dunkirk plant to burn natural gas, but those plans were put on hold and the units there were closed January 1.

Entergy Nuclear last year asked a federal court to overturn a Public Service Commission order approving a 10-year contract that requires National Grid to pay NRG $20.4 million a year for the output of the Dunkirk conversion. Entergy said the payment would lead to the suppression of power prices.

"The Entergy lawsuit against the PSC created significant uncertainty for NRG in moving forward with the Dunkirk project. Under the circumstances, that project to add natural gas fueling capability to units 2, 3 and 4, remains on hold," Gaier said Wednesday.

NRG in late December submitted Dunkirk to the PSC as an option for a public policy need identified by the PSC in July.

"Under the New York Independent System Operator Public Policy Planning Process, the NYISO solicited both transmission and non-transmission projects, including generation and so-called hybrid projects proposals, for the public policy requirement identified by the PSC," Gaier said.

Cayuga plant's switch to gas in PSC hands

The fate of the conversion of the 310-MW Cayuga plant to burn natural gas has been in the hands of the Public Service Commission since the plant's owner and New York State Electric and Gas filed competing plans for its future early last year.

In the meantime, Upstate New York Power Producers, owner of Cayuga and the 675-MW Somerset unit, in September asked the Federal Energy Regulatory Commission for approval to sell the units to Bicent Power. On December 30 the company asked FERC to approve the transaction as soon as possible.

New York's 2015 energy plan issued in June set a target for the state to procure 50% of its power from renewable sources by 2030. "That target is now a requirement," Cuomo said in his state-of-the-state address. The requirement needs regulatory approval, however.

The energy plan also calls for a 40% reduction in greenhouse gas emissions from 1990 levels and a 23% decrease in energy consumption by buildings. Cuomo did not mention those goals in Wednesday's address.

— Mary Powers

EMISSIONS MARKETS

RGGI, CCA prices make gains

The Regional Greenhouse Gas Initiative and California Carbon Allowance markets saw less trading activity on the IntercontinentalExchange this past week although prices made gains.

CCA Vintage 2016 December 2016 delivery added 8 cents to $13.24/metric ton, while Vintage 2017 December 2017 futures also moved up 8 cents to $13.82/mt.

CCA had 11,201 contracts on ICE with the majority for V15 January 2016 delivery ranging from $12.76/mt to $12.84/mt between at 2,945 contracts.

In line with CCA activity, RGGIs were stronger week-on-week.

RGGI Vintage 2016 December 2016 delivery futures moved up 13 cents to end the week at $8.18/short ton as Vintage 2017 December 2017 futures headed up 10 cents to $8.46/st on ICE.

RGGIs saw 1,998 contracts from 32 deals for vintage 2015 and vintage 2016 on ICE. V16 for January delivery totaled 380 contracts and ranged from $7.85/st to $8/st, while V16 for December delivery totaled 950 contracts that ranged from $8.05/st to $8.20/st.

The 31st quarterly carbon dioxide allowance Regional Greenhouse Gas Initiative auction will take place March 9. State participating in the RGGI auction will offer for sale 14.839 CO2 allowance, according to the auction notice. The states will use a reserve price of $2.10/st in 2016.

There is also a 10 million CO2 allowance cost containments reserve available for this auction, according to the auction notice. This reserve will be assessed if the interim clearing prices exceeds the CRR trigger prices of $8.00/st.

In Virginia, the state's General Assembly 2016 session started January 13 and includes House Bill 351, also known as the Virginia Alternative Energy and Coastal Protection Act. It would establish a statewide funding source to affected localities for flood resilience by joining the Regional Greenhouse Gas Initiative.

— Kassia Micek

DAILY CSAPR ALLOWANCE ASSESSMENTS, JAN 14 ($/st)

	$/st	2015 Range	$/st	2016 Range
Nox Annual	95.00	80.00-100.00	95.00	80.00-100.00
NOx Seasonal	200.00	180.00-215.00	200.00	180.00-215.00
SO_2 Group 1	2.00	1.00-5.00	2.00	1.00-5.00
SO_2 Group 2	5.00	3.00-7.00	5.00	3.00-7.00

RGGI CARBON ALLOWANCE FUTURES, JAN 13 ($/allowance)

ICE	Settlement	Volume
Dec16 V15	8.18	500
Dec17 V15	8.46	0
Dec18 V15	8.74	0
Dec16 V16	8.18	0
Dec17 V16	8.46	0
Dec18 V16	8.74	0
Dec16 V17	8.18	0
Dec17 V17	8.46	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.

NOX allowance trades move CSAPR market

Deals this week for Seasonal NOX and Annual NOX allowances brought slight price changes in the Cross-State Air Pollution Rule Market.

Brokers on Thursday reported trades for both NOX allowances. Deals for Annual NOX allowances were heard at $90/st then $95/st, and deals for Seasonal NOX allowances were heard at $190/st then $200/st. Brokers also said they saw Annual NOX trades earlier in the week at the same prices.

Platts on Thursday assessed Seasonal NOX allowances at $200/st, up $10/st from last week, based on the last reported trade.

Annual NOX allowances were assessed Thursday at $95/st, down $5 from last week, based on the last reported trade.

Market players reported no deals in Group 1 SO2 or Group 2 SO2 allowances. Platts pushed up the price of both allowances this week based on broker marks. Platts on Thursday assessed Group 1 SO2 allowances at $2/st, up $1 from last week, and Group 2 SO2 allowances at $5/st, up $1 from last week.

— Jim Levesque

REC MARKETS

REC, SREC activity picks up for New Year

Renewable energy credits markets trading picked up on IntercontinentalExchange for the first full week of the New Year.

RECs had 4,250 MW in volume trade or clear on ICE last week between 19 deals, compared with 3,100 MW in volume and 16 deals the previous week. Solar RECs had 4,120 MW in volume clear or trade on ICE between 16 deals, compared with 3,600 MW in volume and 27 deals the previous week.

The majority of REC activity came in the form of Pennsylvania RECs V18 for June 2018 with 1,700 MW in volume.

Most SREC activity was New Jersey SREC energy year 2016 July 2016 delivery with 2,750 MW between 8 deals and averaged nearly $287.50/SREC.

The New Jersey SREC futures curve on ICE was mixed this past week.

Energy year 2016 July 2016 delivery slipped $3 to $289/SREC, while energy year 2017 July 2017 delivery lost $2.50 to $287.50/SREC.

Energy year 2018 July 2018 delivery remained at $260/SREC, while energy year 2019 July 2019 delivery moved up $4 to $210/SREC.

Packaged further out on the curve were flat on the week.

New Jersey SRECs jumped $4.25 this week to $284.25/SREC.

Maryland SRECs fell $1.25 to $131.75/SREC as Massachusetts SRECs slipped 50 cents to $476.75/SREC.

REC markets were unchanged.

As of November 30, the cumulative weighted average trading price for NJ-SRECs for EY16 was $203.95/SREC, according to the New Jersey Clean Energy Program. Prices traded as high as $485/SREC in November, compared with $488/SREC in October. There were 141,713 SRECs for EY16 issued in November, down 10% from October. There were 145,921 SRECs traded in November, down 53% from October.

As of November 30, the cumulative weighted average trading price for NJ-SRECs for EY15 was $192.64/SREC, according to the New Jersey Clean Energy Program. Prices traded as high as $373.50/SREC in November, compared with $400/SREC in October. There were 8,353 SRECs for EY15 issued in November, up 6.7% from October. There were 468,351 SRECs traded in November, up 26% from October.

New Jersey has had three solar installations this year as of November 30, according to the NJCEP.

— Kassia Micek

RENEWABLE ENERGY CERTIFICATE MARKETS JAN 14 ($/MWh)

	Low	High	Mid
Class I/Tier I RECs*			
Connecticut	48.00	50.00	49.000
Maryland	14.50	16.50	15.500
Massachusetts	49.00	50.00	49.500
New Jersey	15.75	16.75	16.250
Ohio	1.75	2.25	2.000
Pennsylvania	15.25	16.75	16.000
Texas	0.35	0.45	0.400
Solar RECs*			
Maryland	126.75	136.75	131.750
Massachusetts	473.75	479.75	476.750
New Jersey	281.25	287.25	284.250
Ohio	15.25	18.75	17.000
Pennsylvania	16.00	19.00	17.500
California RPS*			
California Bundled REC (Bucket 1)	11.50	14.50	13.000
California Bundled REC (Bucket 2)	3.50	5.50	4.500
California Tradable REC (Bucket 3)	0.40	0.80	0.600
Voluntary RECs*			
National voluntary, any technology	0.38	0.43	0.405
National voluntary, wind	0.38	0.43	0.405

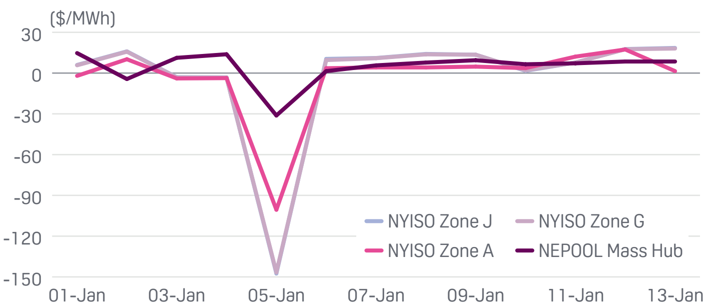
*Prices are for the value of the environment attribute of the renewable energy certificate only and do not include energy. Bundled transactions are normalized by subtracting the market price of electricity.

NORTHEAST POWER MARKETS

NORTHEAST DAY AHEAD POWER PRICES ($/MWh)

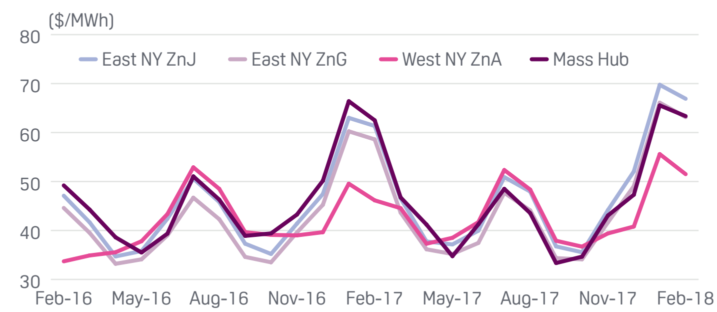
Hub/Index	Symbol	15-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-16	Yearly change Jan-15	Yearly change Chg	Yearly change % Chg
On-Peak														
ISONE Internal Hub	IINIM00	31.67	9138	7.41	-9.92	-13.72	-30.2	38.40	23.36	66.06	43.75	77.52	-33.77	-43.6
ISONE NE Mass-Boston	IINNM00	31.59	8992	7.00	-10.57	-13.55	-30.0	38.40	23.42	66.55	43.93	78.05	-34.12	-43.7
ISONE Connecticut	IINCM00	31.43	10636	10.74	-4.03	-13.98	-30.8	38.27	23.26	65.39	43.27	76.19	-32.92	-43.2
NYISO Zone G	INYHM00	31.95	13259	15.08	3.03	-15.47	-32.6	38.85	23.66	51.08	38.37	61.38	-23.01	-37.5
NYISO NYC Zone	INYNM00	32.96	13677	16.09	4.04	-14.97	-31.2	39.20	23.88	52.50	38.83	62.72	-23.89	-38.1
NYISO West Zone	INYWM00	20.23	10971	7.32	-1.90	-5.75	-22.1	23.95	11.72	38.01	23.29	38.82	-15.53	-40.0
NYISO Capital Zone	INYCM00	35.25	14259	17.95	5.58	-18.20	-34.1	43.11	26.84	58.38	41.48	66.44	-24.96	-37.6
Off-Peak														
ISONE Internal Hub	IINIP00	21.81	5152	-7.82	-28.99	-14.54	-40.0	23.19	8.18	68.68	34.84	58.38	-23.54	-40.3
ISONE NE Mass-Boston	IINNP00	21.76	4768	-10.19	-33.01	-14.46	-39.9	23.17	8.15	68.96	34.97	58.53	-23.56	-40.3
ISONE Connecticut	IINCP00	21.59	5952	-3.80	-21.94	-14.52	-40.2	23.00	8.18	67.85	34.33	57.32	-22.99	-40.1
NYISO Zone G	INYHP00	24.65	8449	4.23	-10.36	-5.33	-17.8	25.56	14.25	41.73	27.42	46.42	-19.00	-40.9
NYISO NYC Zone	INYNP00	24.86	8521	4.44	-10.15	-5.35	-17.7	25.75	14.35	42.05	27.63	46.58	-18.95	-40.7
NYISO West Zone	INYWP00	12.40	7178	0.31	-8.33	-5.08	-29.1	12.57	5.08	25.16	14.42	29.41	-14.99	-51.0
NYISO Capital Zone	INYCP00	28.26	11480	11.03	-1.28	-4.82	-14.6	29.35	17.18	49.84	31.37	51.61	-20.24	-39.2

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



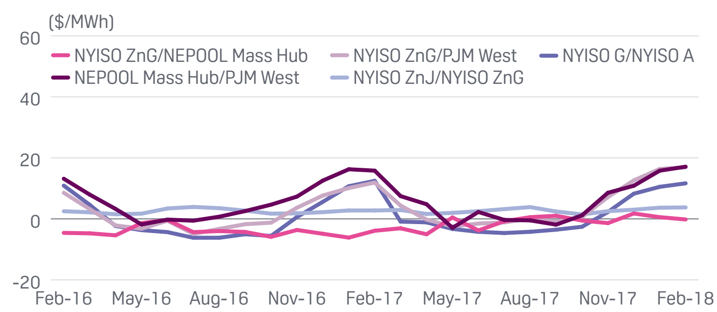
Source: Platts

NORTHEAST PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

NORTHEAST PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Mass Hub in low $30s/MWh as demand wanes

Northeast day-ahead power prices fell Thursday with a pullback in expected demand and lower regional spot gas prices.

Mass Hub on-peak sank $9.75 to about $33.50/MWh for Friday delivery on the IntercontinentalExchange. Off-peak lost $6.25 to nearly $23.75/MWh. Next-week on-peak lost 75 cents to around $57/MWh with off-peak down $1.50 to $44.50/MWh.

Algonquin Gas Transmission city-gate eased 64.9 cents to about $3.751/MMBtu for Friday delivery on ICE.

The ISO New England expected peakload around 17,500 MW Friday, down 6.2% from Thursday's predicted peak.

New York ISO day-ahead locational marginal prices plummeted with weaker spot gas and lower predicted demand.

NYISO Zone G Hudson Valley on-peak shed nearly $15.50 near $32/MWh for Friday delivery. NYISO Zone A West fell close to $20.25 to about $20.25/MWh. NYISO Zone J New York City on-peak lost $15 to around $33/MWh.

Transco Zone 6 New York spot natural gas dropped 67.3 cents to $2.172/MMBtu.

NYISO projected peakload around 20,325 MW Friday, down 5.3% from Thursday's predicted peak.

Northeast forward power prices were weaker Thursday as NYMEX gas futures fell.

In New England, Mass Hub on-peak February had a wide bid-offer spread with the bid at $46/MWh and the offer at $67/MWh around 2:30 pm EST on the IntercontinentalExchange. March on-peak lost $1 to about $44/MWh. April on-peak fell $1 to around $38.75/MWh with off-peak down 50 cents to $26/MWh. July-August on-peak sank $1.25 to about $48.50/MWh. July-August off-peak added $2 to around $30.50/MWh.

In New York, Zone A on-peak February shed $1.75 to about $33.50/MWh while off-peak February was at $18.50/MWh. Zone G February on-peak dropped $3 to about $44/MWh.

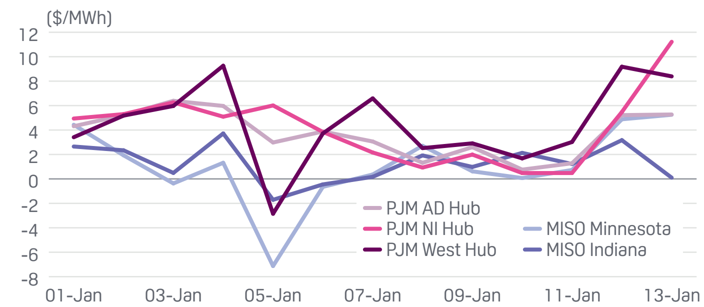
NYMEX February gas futures moved down 13 cents to around $2.139/MMBtu. Algonquin city-gate February gas basis fell 6.6 cents to $3.140/MMBtu. Transco Zone 6 NY February gas basis lost 19.3 cents to around $2.688/MMBtu.

PJM/MISO POWER MARKETS

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

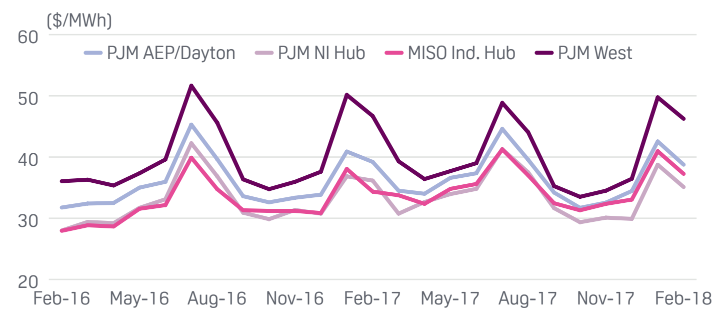
Hub/Index	Symbol	15-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly Change Jan-16	Yearly Change Jan-15	Yearly Change Chg	Yearly Change % Chg
On-Peak														
PJM AEP Dayton Hub	IPADM00	24.09	12175	10.24	0.35	-0.98	-3.9	27.96	22.43	37.28	28.13	34.91	-6.78	-19.4
PJM Dominion Hub	IPDMM00	25.61	11794	10.41	-0.45	-3.07	-10.7	32.62	23.98	47.79	33.65	43.43	-9.78	-22.5
PJM Eastern Hub	IPEHM00	23.99	12389	10.44	0.75	-4.80	-16.7	32.47	19.91	53.51	32.29	50.73	-18.44	-36.3
PJM Northern Illinois Hub	IPNIM00	22.59	9827	6.50	-5.00	-0.48	-2.1	26.59	21.52	35.26	26.82	31.42	-4.60	-14.6
PJM Western Hub	IPWHM00	24.46	14902	12.97	4.76	-2.88	-10.5	30.80	23.17	44.31	31.32	41.13	-9.81	-23.9
MISO Indiana Hub	IMIDM00	22.18	12193	9.45	0.35	-2.34	-9.5	25.89	22.18	29.83	25.62	33.37	-7.75	-23.2
MISO Minnesota Hub	IMINM00	20.09	8660	3.85	-7.75	-3.19	-13.7	24.85	18.76	28.37	23.06	27.18	-4.12	-15.2
Off-Peak														
PJM AEP Dayton Hub	IPADP00	19.78	9897	5.79	-4.20	-3.51	-15.1	22.01	13.41	28.69	22.73	28.64	-5.91	-20.6
PJM Dominion Hub	IPDMP00	22.33	9906	6.55	-4.72	-8.57	-27.7	27.73	14.45	54.04	29.76	36.26	-6.50	-17.9
PJM Eastern Hub	IPEHP00	19.01	8832	3.94	-6.82	-12.09	-38.9	28.30	13.44	59.63	28.98	40.19	-11.21	-27.9
PJM Northern Illinois Hub	IPNIP00	15.44	6650	-0.81	-12.42	-2.69	-14.8	18.61	11.06	26.47	19.45	23.69	-4.24	-17.9
PJM Western Hub	IPWHP00	21.01	12737	9.46	1.22	-5.68	-21.3	24.24	13.50	41.80	25.96	33.60	-7.64	-22.7
MISO Indiana Hub	IMIDP00	18.43	10071	5.62	-3.53	-2.15	-10.4	21.13	18.43	23.25	20.96	25.57	-4.61	-18.0
MISO Minnesota Hub	IMINP00	16.60	7154	0.36	-11.24	-3.09	-15.7	20.07	13.66	22.62	18.49	20.10	-1.61	-8.0

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



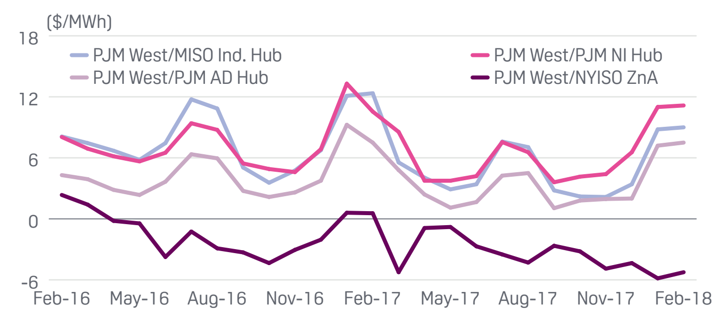
Source: Platts

PJM/MISO PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

PJM/MISO PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

PJM load slips 11%, helps soften spot prices

Mid-Atlantic day-ahead power prices fell Thursday with lower expected demand as temperatures across the region were forecast above normal.

PJM West Hub on-peak dropped $6.50 to around $24.50/MWh for Friday delivery on the IntercontinentalExchange. Off-peak shed $10.50 to about $20/MWh. Next-week on-peak lost $2 to around $41/MWh with off-peak around $34.50/MWh.

Texas Eastern M-3 day-ahead natural gas sank 27.9 cents to $1.691/MMBtu.

The PJM Interconnection predicted peakload to reach 101,300 MW Friday, down 11% from Thursday's predicted peak.

Midwest spot power prices fell Thursday with temperatures and demand expected lower with forecasts calling for above normal temperatures.

Indiana Hub on-peak dropped $2.25 about $23.25/MWh for Friday delivery on ICE. Off-peak lost $2.75 to roughly $19.75/MWh. Next-week on-peak lost 25 cents to about $30.25/MWh.

The Midcontinent ISO forecast peak demand to hit 83,950 MW Friday, down 4.7% from Thursday's predicted peak of 93,400 MW.

Spot power prices in the western portion of the PJM were weaker with temperatures forecast to remain above seasonal norms, following the trend in nearby markets.

AD Hub on-peak was down $4.75 to about $23.25/MWh and off-peak lost $6.50 to roughly $19/MWh. Next-week on-peak was around $34/MWh with off-peak near $28.50/MWh.

NI Hub on-peak sank $4 to around $21.75/MWh and off-peak shed $1.50 to $19/MWh. Next-week on-peak lost $1.75 to nearly $32.25/MWh.

Mid-Atlantic forwards were weaker Thursday as NYMEX gas futures and regional gas basis were down.

PJM West Hub on-peak February financial futures shed $1.75 to about $36.25/MWh on the IntercontinentalExchange around 2:30 pm EST. Off-peak February lost $1 to around $30/MWh. On-peak March fell $1 near $36.50/MWh with off-peak down 75 cents to $28.75MWh. July-August on-peak eased 75 cents to around $48.75/MWh and off-peak eased 25 cents to near $26.75/MWh.

NYMEX February gas futures dropped 13 cents to around $2.139/MMBtu. Texas Eastern M-3 February gas basis lost 16.6 cents to 50.4 cents/MMBtu.

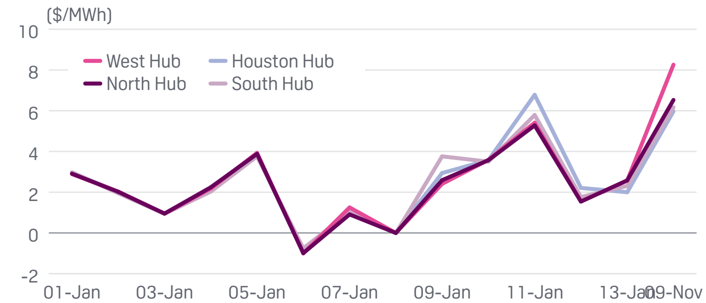
AD Hub on-peak February shed $1 to around $32.25/MWh on ICE. Indiana Hub on-peak February fell 75 cents to about $28.25/MWh. NI Hub on-peak sank $1.50 to about $28/MWh.

SOUTHEAST POWER MARKETS

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

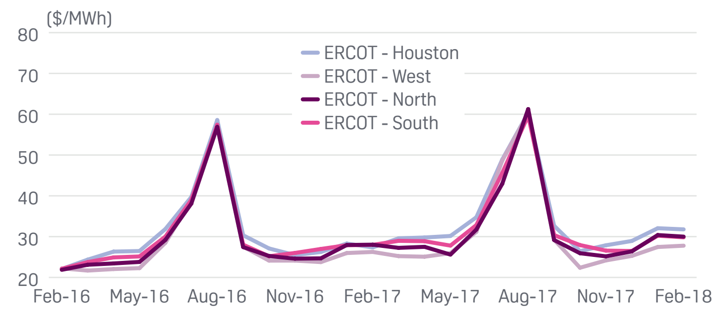
Hub/Index	Symbol	15-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-16	Yearly change Jan-15	Yearly change Chg	Yearly change % Chg
On-Peak														
MISO Texas Hub	IMTXM00	20.93	9650	5.75	-5.10	-0.29	-1.4	23.58	20.93	28.18	23.61	29.99	-6.38	-21.3
MISO Louisiana	IMLAM00	22.35	10247	7.08	-3.82	-4.89	-18.0	25.35	20.96	32.25	24.50	30.03	-5.53	-18.4
SPP North Hub	ISNOM00	18.66	8070	2.47	-9.09	2.09	12.6	20.42	15.66	22.79	19.75	25.26	-5.51	-21.8
SPP South Hub	ISSOM00	21.49	10150	6.67	-3.92	-0.10	-0.5	25.61	21.49	28.93	24.85	28.57	-3.72	-13.0
ERCOT Houston Hub	IERHM00	20.79	9609	5.64	-5.17	0.01	0.0	21.76	18.98	25.94	21.39	27.37	-5.98	-21.9
ERCOT North Hub	IERNM00	20.78	9729	5.83	-4.85	2.08	11.1	20.93	18.70	24.44	21.01	27.11	-6.10	-22.5
ERCOT South Hub	IERSM00	20.76	9622	5.66	-5.13	1.04	5.3	21.28	18.97	24.95	21.13	27.21	-6.08	-22.3
ERCOT West Hub	IERWM00	20.78	9623	5.66	-5.13	1.94	10.3	21.00	18.84	24.57	21.06	27.17	-6.11	-22.5
Off-Peak														
MISO Texas Hub	IMTXP00	18.06	8160	2.57	-8.50	-1.63	-8.3	20.63	17.84	23.46	20.51	27.27	-6.76	-24.8
MISO Louisiana	IMLAP00	17.96	8055	2.35	-8.80	-2.56	-12.5	20.72	17.90	23.19	20.49	26.52	-6.03	-22.7
SPP North Hub	ISNOP00	11.83	5124	-4.33	-15.87	0.28	2.4	15.83	11.55	18.38	15.39	18.70	-3.31	-17.7
SPP South Hub	ISSOP00	16.10	7529	1.13	-9.56	-4.05	-20.1	22.25	16.10	24.80	21.65	24.53	-2.88	-11.7
ERCOT Houston Hub	IERHP00	14.31	6469	-1.17	-12.24	-0.02	-0.1	16.76	13.21	18.73	16.48	20.79	-4.31	-20.7
ERCOT North Hub	IERNP00	14.35	6553	-0.98	-11.93	0.23	1.6	16.55	13.20	18.73	16.39	20.78	-4.39	-21.1
ERCOT South Hub	IERSP00	14.26	6453	-1.21	-12.26	-0.05	-0.3	16.62	13.21	18.70	16.40	20.85	-4.45	-21.3
ERCOT West Hub	IERWP00	14.35	6592	-0.89	-11.77	0.25	1.8	16.56	13.20	18.73	16.40	20.86	-4.46	-21.4

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



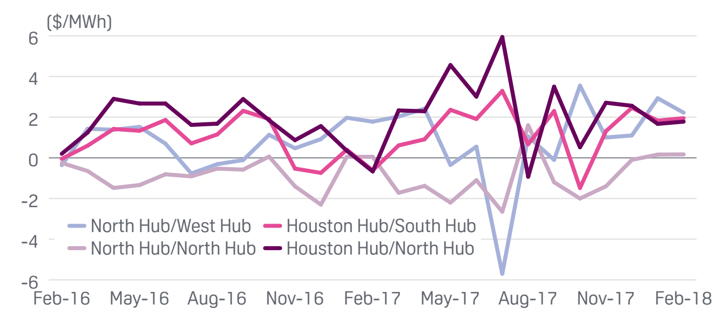
Source: Platts

ERCOT PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

ERCOT PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

ERCOT dailies move up near $20/MWh

Electric Reliability Council of Texas dailies were mixed Thursday with on-peak prices edging higher while off-peak prices eased.

ERCOT North Hub on-peak rose $1 to around $20/MWh for Friday delivery on IntercontinentalExchange. Off-peak fell 50 cents to about $13.50/MWh. Spot natural gas at Houston Ship Channel fell 9.5 cents to $2.150/MMBtu on ICE.

ERCOT forecast system load to peak 39,700 MW at 8 am Friday.

Wind generation averaged 10,151 MW at 3 am CST, before dropping to a low of 6,877 MW at 11 am. On Friday, wind generation was expected to average about 8,125 MW at 1 am.

Temperatures were expected to remain above normal levels Friday.

North Hub balance-of-the-day on-peak for Thursday traded 1,450 MW at about $18.50/MWh, down about 50 cents from Wednesday's day-ahead price. Real-time day-ahead on-peak was up $1 to about $19.75/MWh and 2,750 MW traded on-screen and 1,050 MW in block volume was cleared on the exchange.

In the Southeast, spot power prices declined Thursday as gas prices fell.

Into Southern on-peak was down about $5 to the low $20s/MWh for Friday delivery. Georgia Transmission Company on-peak was down about $3 to the mid-$20s/MWh.

Spot natural gas at Transco Zone-3 fell 10.3 cents to about $2.177/MMBtu on ICE.

ERCOT forward power prices pressed lower Thursday as NYMEX February gas futures settled 13 cents down at $2.139/MMBtu.

ERCOT North Hub February on-peak was down $1.25 to about $21.75/MWh on IntercontinentalExchange at around 2:30 pm EST and on-peak heat rate traded 200 MW at 10.255 MMBtu/MWh. March-April on-peak fell 75 cents to about $23.25/MWh. May on-peak was down 75 cents to about $23.75/MWh. June on-peak was down 75 cents to about $29.25/MWh. In the back-half, July-August on peak fell $2 to about $48.25/MWh and on-peak heat rates traded for 275 MW at 19.913/MMBtu/MWh.

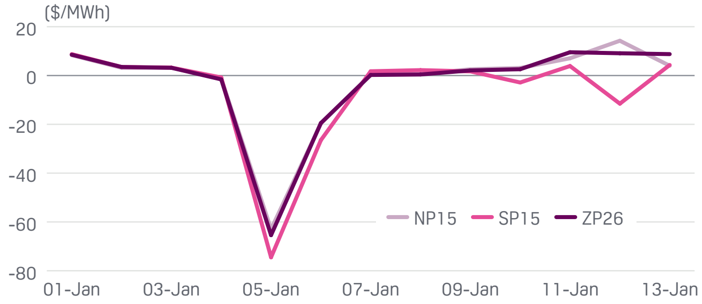
In other Midwest regions, the Southwest Power Pool South Hub July-August on-peak was down 25 cents to about $33.25/MWh.

WEST POWER MARKETS

WESTERN DAY-AHEAD POWER PRICES ($/MWh)

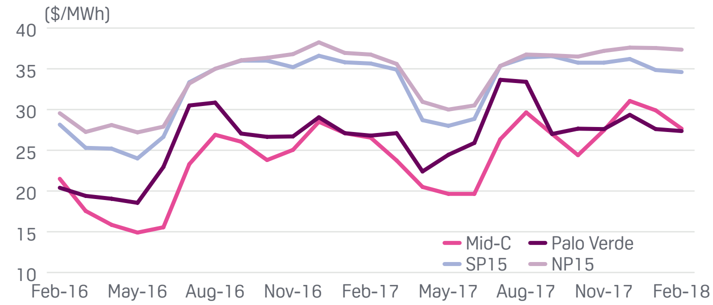
Hub/Index	Symbol	15-Jan	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Jan-16	Yearly change Jan-15	Yearly change Chg	Yearly change % Chg
On-Peak														
NP15	ICNGM00	31.67	12544	14.00	1.37	1.28	4.2	32.91	29.82	36.47	32.35	35.22	-2.87	-8.1
SP15	ICSGM00	28.16	12310	12.15	0.71	-4.38	-13.5	32.62	28.16	34.00	31.96	35.41	-3.45	-9.7
ZP26	ICZGM00	25.58	11182	9.57	-1.87	-3.87	-13.1	30.56	25.58	33.19	30.46	34.29	-3.83	-11.2
COB	WEABE20	22.46	10163	6.99	-4.06	0.00	0.0	24.62	22.46	29.46	25.39	26.77	-1.38	-5.2
MEAD	AAMBW20	22.50	9847	6.51	-4.92	0.00	0.0	24.32	22.50	26.50	24.46	27.28	-2.82	-10.3
MID-C	WEABF20	21.70	9841	6.26	-4.76	0.00	0.0	23.79	20.54	28.43	24.60	23.07	1.53	6.6
Palo Verde	WEACC20	20.50	9203	4.91	-6.23	0.00	0.0	22.18	20.50	24.00	22.46	25.84	-3.38	-13.1
Off-Peak														
NP15	ICNGP00	24.19	9495	6.36	-6.38	-0.19	-0.8	26.85	24.19	29.49	26.67	29.75	-3.08	-10.4
SP15	ICSGP00	23.53	10185	7.36	-4.19	-0.28	-1.2	27.08	23.53	30.34	26.83	29.70	-2.87	-9.7
ZP26	ICZGP00	22.92	9921	6.75	-4.80	-0.17	-0.7	26.41	22.92	29.47	26.23	29.13	-2.90	-10.0
COB	WEACJ20	21.25	9615	5.78	-5.27	0.00	0.0	22.79	21.25	29.00	24.14	24.16	-0.02	-0.1
MEAD	AAMBQ20	20.50	8972	4.51	-6.92	0.00	0.0	21.07	19.50	24.50	21.65	26.66	-5.01	-18.8
MID-C	WEACL20	20.55	9320	5.12	-5.91	0.00	0.0	22.45	19.90	27.10	23.39	19.74	3.65	18.5
Palo Verde	WEACT20	19.00	8530	3.41	-7.73	0.00	0.0	20.00	18.50	22.75	20.42	24.21	-3.79	-15.7

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



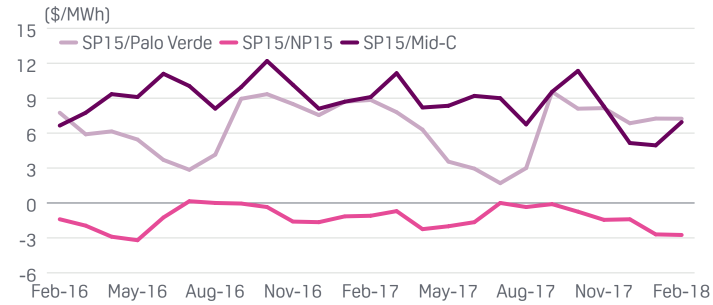
Source: Platts

WESTERN PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

WESTERN PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

SP15 dailies sink to upper $20s/MWh on demand

West day-ahead power prices were mixed Thursday amid lower demand projections.

Dailies traded on an altered schedule ahead of the holiday weekend, with day-ahead on-peak scheduled for Saturday delivery, while off-peak included all-day Sunday.

In California, SP15 on-peak dropped nearly $1.75 to $29/MWh and off-peak jumped $2 to $27.25/MWh.

PG&E city-gate spot gas fell 3.1 cents to $2.524/MMBtu for Friday delivery and SoCal city-gate gas declined 5.3 cents to $2.457/MMBtu.

California ISO projected demand to peak near 26,750 MW Saturday and 27,025 MW Sunday, down from Friday's expected peakload of around 28,550 MW.

In the Southwest, Palo Verde on-peak gave up $1 to around $19.50/MWh, while off-peak slipped 25 cents to about $18.75/MWh.

Spot gas prices at Opal were 3 cents below the previous day at $2.524/MMBtu.

In the Northwest, Mid-Columbia prices rose. Day-ahead on-peak added 50 cents to nearly $22.25/MWh, while off-peak gained $1 to around $21.50/MWh.

West forward prices tracked NYMEX gas futures lower Thursday afternoon, despite higher regional gas basis.

In the Northwest, Mid-Columbia February on-peak shed 50 cents to $21.50/MWh on the IntercontinentalExchange around 2:30 pm EST. February off-peak and March on-peak shed 25 cents each to around $19.25/MWh and $17.75/MWh, respectively.

In the Southwest, Palo Verde February on-peak sank $1 to about $20.25/MWh, $9 below where the February 2015 package was valued this time last year. Second quarter on-peak fell 50 cents to near $20/MWh.

In California, SP15 February and March on-peak financial futures lost 50 cents each, trading near $28.25/MWh and $25.50/MWh, respectively.

NYMEX February gas futures gave up 13 cents to $2.139/MMBtu, weighing on prices. PG&E city-gate February gas basis jumped 3.6 cents to 30.1 cents/MMBtu, while SoCal February gas basis added 3 cents to 9 cents/MMBtu.

BILATERALS

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

Hub/Index	Symbol	15-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-16	Jan-15	Chg	% Chg
On-Peak														
Florida	AAMAV20	19.50	8744	3.89	-7.26	-4.50	-18.8	26.11	19.50	32.00	26.58	35.02	-8.44	-24.1
GTC, Into	WAMCJ20	22.50	10297	7.20	-3.72	-3.00	-11.8	28.07	21.50	32.50	28.00	36.48	-8.48	-23.2
Southern, Into	AAMBJ20	20.50	9382	5.20	-5.72	-4.50	-18.0	27.11	20.50	32.00	26.98	35.82	-8.84	-24.7
TVA, Into	WEBAB20	21.25	9529	5.64	-5.51	-3.75	-15.0	27.50	21.25	31.75	27.38	35.88	-8.50	-23.7
VACAR	AAMCI20	21.50	9598	5.82	-5.38	-5.00	-18.9	29.25	21.50	35.00	29.20	38.68	-9.48	-24.5
Off-Peak														
Florida	AAMAO20	17.25	7735	1.64	-9.51	-5.00	-22.5	20.39	15.75	26.75	21.22	27.56	-6.34	-23.0
GTC, Into	WAMCC20	20.00	9153	4.70	-6.22	-5.00	-20.0	23.57	19.00	30.00	23.23	28.38	-5.15	-18.1
Southern, Into	AAMBC20	19.50	8924	4.20	-6.72	-5.00	-20.4	22.64	18.00	29.00	22.27	27.93	-5.66	-20.3
TVA, Into	AAJER20	19.50	8744	3.89	-7.26	-4.75	-19.6	22.71	18.75	28.00	22.28	27.77	-5.49	-19.8
VACAR	AAMCB20	19.50	8705	3.82	-7.38	-6.50	-25.0	23.61	19.50	31.00	23.50	29.48	-5.98	-20.3

WESTERN DAY-AHEAD BILATERAL INDEXES ($/MWh)

Hub/Index	Symbol	16-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-16	Jan-15	Chg	% Chg
On-Peak														
Mid-C	WEABF20	22.16	--	--	--	0.46	2.1	23.38	20.54	28.43	24.41	23.07	1.35	5.8
John Day	WEAHF20	23.3	--	--	--	0.5	2.2	24.42	21.50	29.50	25.44	24.02	1.42	5.9
COB	WEABE20	22.00	--	--	--	-0.46	-2.0	24.09	22.00	29.46	25.13	26.77	-1.64	-6.1
NOB	WEAIF20	21.50	--	--	--	-0.50	-2.3	23.67	21.50	29.25	24.77	25.70	-0.93	-3.6
Palo Verde	WEACC20	19.50	--	--	--	-1.00	-4.9	21.69	19.50	24.00	22.23	25.84	-3.61	-14.0
Mona	AARLQ20	20.50	--	--	--	-1.00	-4.7	22.06	20.50	25.25	22.67	25.82	-3.14	-12.2
Four Corners	WEABI20	19.25	--	--	--	-0.75	-3.8	21.58	19.25	25.00	22.29	26.30	-4.01	-15.2
Pinnacle Peak	WEAKF20	19.75	--	--	--	-1.25	-6.0	22.06	19.75	24.50	22.63	26.65	-4.02	-15.1
Westwing	WEAJF20	20.5	--	--	--	-0.75	-3.5	22.33	20.50	24.50	22.85	26.28	-3.43	-13.1
MEAD	AAMBW20	21.75	--	--	--	-0.75	-3.3	23.83	21.75	26.50	24.25	27.28	-3.03	-11.1
Off-Peak														
Mid-C	WEACL20	21.31	--	--	--	0.76	3.7	22.08	19.90	27.10	23.26	19.74	3.52	17.8
John Day	WEAHL20	22.25	--	--	--	0.75	3.5	23.08	21.00	28.00	24.27	20.67	3.60	17.4
COB	WEACJ20	21.75	--	--	--	0.5	2.4	22.44	21.25	29.00	23.99	24.16	-0.17	-0.7
NOB	WEAIL20	21.25	--	--	--	0.25	1.2	22.18	21.00	29.25	23.80	22.40	1.39	6.2
Palo Verde	WEACT20	18.75	--	--	--	-0.25	-1.3	19.68	18.50	22.75	20.31	24.21	-3.90	-16.1
Mona	AARLO20	19.00	--	--	--	0.5	2.7	19.43	18.50	23.50	20.39	22.65	-2.25	-10.0
Four Corners	WEACR20	18.75	--	--	--	0.75	4.2	18.78	18.00	23.00	19.88	24.54	-4.67	-19.0
Pinnacle Peak	WEAKL20	19.25	--	--	--	-1.25	-6.1	20.35	19.25	23.00	20.91	24.58	-3.67	-14.9
Westwing	WEAJL20	19.25	--	--	--	-0.25	-1.3	20.13	19.00	23.25	20.77	24.50	-3.73	-15.2
MEAD	AAMBQ20	19.75	--	--	--	-0.75	-3.7	20.75	19.50	24.50	21.53	26.66	-5.13	-19.2

Note: Western bilateral off-peak indexes include all day Sunday.

WESTERN NEAR-TERM BILATERAL MARKETS ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-week	01/12	20.75-21.25
Bal-week	01/11	20.25-20.75
Bal-week	01/08	24.00-24.50
Bal-month	01/14	21.75-22.50
Bal-month	01/13	21.50-22.00
Bal-month	01/12	20.75-21.50
Bal-month	01/11	21.75-22.75
Bal-month	01/08	23.75-24.25
Bal-month (off-peak)	01/14	19.75-20.25
Bal-month (off-peak)	01/13	19.75-20.25
Bal-month (off-peak)	01/12	19.50-20.00
Bal-month (off-peak)	01/11	20.00-20.50
Next-week	01/12	22.75-23.25
Next-week	01/11	22.50-23.00
Next-week	01/08	23.50-24.00

Package	Trade date	Range
Palo Verde		
Bal-week	01/12	22.25-22.75
Bal-week	01/11	22.25-22.75
Bal-week	01/08	21.75-22.25
Bal-month	01/14	21.00-21.50
Bal-month	01/13	20.75-21.25
Bal-month	01/12	21.50-22.00
Bal-month	01/11	22.25-22.75
Bal-month	01/08	22.50-23.00

SOUTHEAST NEAR-TERM BILATERAL MARKETS ($/MWh)

Package	Trade date	Range
Southern, into		
Bal-week	01/12	26.25-26.75
Bal-week	01/11	28.75-29.25
Bal-week	01/08	31.25-31.75
Next-week	01/14	29.25-29.75
Next-week	01/13	30.25-30.75
Next-week	01/12	29.50-30.00
Next-week	01/11	30.50-31.00
Next-week	01/08	29.00-29.50

PLATTS M2MS FORWARD CURVE, JAN 14 ($/MWh)

Prompt month: Feb 16

	On-peak	Off-peak
Northeast		
Mass Hub	49.20	37.15
N.Y. Zone G	44.60	32.00
N.Y. Zone J	47.10	33.10
N.Y. Zone A	33.70	17.50
Ontario*	17.65	11.20

*Ontario prices are in Canadian dollars

	On-peak	Off-peak
PJM & MISO		
PJM West	36.05	29.55
AD Hub	31.75	25.40
NI Hub	28.00	21.20
Indiana Hub	27.95	23.65

	On-peak	Off-peak
Southeast & Central		
Southern Into	26.00	23.75
ERCOT North	21.85	17.45
ERCOT Houston	22.05	17.75
ERCOT West	22.25	16.70
ERCOT South	22.10	17.70
Western		
Mid-C	21.50	19.05
Palo Verde	20.40	19.25
Mead	20.60	20.35
NP15	29.55	25.20
SP15	28.15	24.50

ISO DAY-AHEAD LMP BREAKDOWN FOR JAN 15 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
Northeast						
On-peak						
ISONE Internal Hub	31.67	0.00	0.17	-13.72	43.75	9138
ISONE Connecticut	31.43	0.00	-0.07	-13.98	43.27	10636
ISONE NE Mass-Boston	31.59	0.00	0.10	-13.55	43.93	8992
NYISO Capital Zone	35.25	-17.33	1.22	-18.20	41.48	14259
NYISO Hudson Valley Zone	31.95	-13.43	1.82	-15.47	38.37	13259
NYISO N.Y.C. Zone	32.96	-14.16	2.10	-14.97	38.83	13677
NYISO West Zone	20.23	-4.46	-0.93	-5.75	23.29	10971
Off-Peak						
ISONE Internal Hub	21.81	0.00	0.11	-14.54	34.84	5152
ISONE Connecticut	21.59	0.00	-0.11	-14.52	34.33	5952
ISONE NE Mass-Boston	21.76	0.00	0.07	-14.46	34.97	4768
NYISO Capital Zone	28.26	-16.89	0.84	-4.82	31.37	11480
NYISO Hudson Valley Zone	24.65	-13.09	1.03	-5.33	27.42	8449
NYISO N.Y.C. Zone	24.86	-13.17	1.16	-5.35	27.63	8521
NYISO West Zone	12.40	-2.25	-0.38	-5.08	14.42	7178
PJM & MISO						
On-peak						
PJM AEP-Dayton Hub	24.09	0.28	-0.43	-0.98	28.13	12175
PJM Dominion Hub	25.61	1.39	-0.02	-3.07	33.65	11794
PJM Eastern Hub	23.99	-1.26	1.00	-4.80	32.29	12389
PJM Northern Illinois Hub	22.59	-0.40	-1.25	-0.48	26.82	9827
PJM Western Hub	24.46	0.41	-0.19	-2.88	31.32	14902
MISO Indiana Hub	22.18	-0.30	0.82	-2.34	25.62	12193
MISO Minnesota Hub	20.09	-0.52	-1.06	-3.19	23.06	8660
MISO Louisiana Hub	22.35	1.65	-0.96	-4.89	24.50	10247
MISO Texas Hub	20.93	0.04	-0.78	-0.29	23.61	9650
Off-Peak						
PJM AEP-Dayton Hub	19.78	0.73	-0.54	-3.51	22.73	9897
PJM Dominion Hub	22.33	2.50	0.24	-8.57	29.76	9906
PJM Eastern Hub	19.01	-1.54	0.97	-12.09	28.98	8832
PJM Northern Illinois Hub	15.44	-2.69	-1.46	-2.69	19.45	6650
PJM Western Hub	21.01	1.13	0.29	-5.68	25.96	12737
MISO Indiana Hub	18.43	0.03	0.71	-2.15	20.96	10071
MISO Minnesota Hub	16.60	-0.24	-0.86	-3.09	18.49	7154
MISO Louisiana Hub	17.96	0.70	-0.43	-2.56	20.49	8055
MISO Texas Hub	18.06	0.63	-0.26	-1.63	20.51	8160
Southeast & Central						
On-peak						
SPP North Hub	18.66	-0.52	-0.95	2.09	19.75	8070
SPP South Hub	21.49	0.76	0.61	-0.10	24.85	10150
ERCOT Houston Hub	20.79	–	–	0.01	21.39	9609
ERCOT North Hub	20.78	–	–	2.08	21.01	9729
ERCOT South Hub	20.76	–	–	1.04	21.13	9622
ERCOT West Hub	20.78	–	–	1.94	21.06	9623
Off-Peak						
SPP North Hub	11.83	-1.51	-0.71	0.28	15.39	5124
SPP South Hub	16.10	1.89	0.16	-4.05	21.65	7529
ERCOT Houston Hub	14.31	–	–	-0.02	16.48	6469
ERCOT North Hub	14.35	–	–	0.23	16.39	6553
ERCOT South Hub	14.26	–	–	-0.05	16.40	6453
ERCOT West Hub	14.35	–	–	0.25	16.40	6592
Western						
On-peak						
CAISO NP15 Gen Hub	31.67	1.26	-1.04	1.28	32.35	12544
CAISO SP15 Gen Hub	28.16	-2.46	-0.84	-4.38	31.96	12310
CAISO ZP26 Gen Hub	25.58	-4.11	-1.76	-3.87	30.46	11182
Off-Peak						
CAISO NP15 Gen Hub	24.19	0.41	-0.65	-0.19	26.67	9495
CAISO SP15 Gen Hub	23.53	-0.28	-0.62	-0.28	26.83	10185
CAISO ZP26 Gen Hub	22.92	-0.35	-1.16	-0.17	26.23	9921

NORTHEAST POWER MARKETS

NYISO SUPPLY MIX (GWh/d)

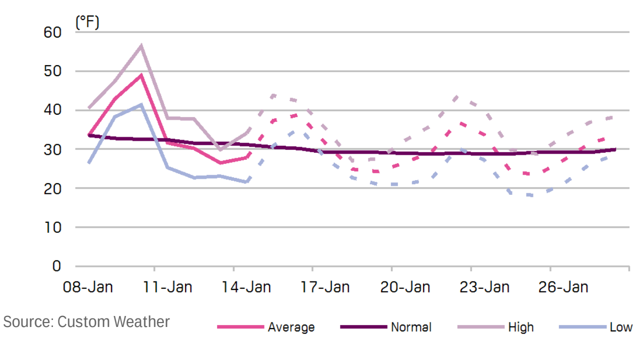
							Daily change		Season		Season average			
Category	9-Jan	10-Jan	11-Jan	12-Jan	13-Jan	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	347.04	341.03	381.26	392.2	353.33	83%	-38.87	-10.0%	311.78	411.65	356.47	388.17	-31.7	-8.0%
Gas	114.83	124.4	131.2	141.09	132.2	31%	-8.89	-6.0%	82.53	168.75	118.71	144.01	-25.3	-18.0%
Coal	15.71	14.07	24.07	25.4	24.99	6%	-0.41	-2.0%	5.69	32.84	16.66	26.62	-9.96	-37.0%
Nuclear	134.67	134.67	134.67	134.67	134.67	32%	0	0.0%	94.43	134.67	130.12	132.83	-2.71	-2.0%
Other	132.82	115.65	156.54	161.23	132.77	31%	-28.46	-18.0%	107.34	203.64	149.7	188.56	-38.86	-21.0%

ISONE SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	9-Jan	10-Jan	11-Jan	12-Jan	13-Jan	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	276.71	271.58	290.85	303.8	306.15	81%	2.35	1.0%	242.61	314.26	283.44	305.36	-21.92	-7.0%
Gas	97.7	96.37	114.45	124.93	121.94	32%	-2.99	-2.0%	85.39	152.29	118.36	113.03	5.33	5.0%
Nuclear	97.8	97.8	97.8	97.8	97.8	26%	0	0.0%	90.83	97.8	96.61	97.24	-0.63	-1.0%
Coal	23.53	17.56	25.84	34.17	39.72	10%	5.55	16.0%	11.76	51.22	21.36	31.62	-10.26	-32.0%
Wind	6.03	10.73	17.93	6.96	16.31	4%	9.35	134.0%	1.42	17.93	7.41	6.34	1.07	17.0%
Other	106.74	97.19	95.93	109.92	103.77	27%	-6.15	-6.0%	76.34	112.95	96.29	123.98	-27.69	-22.0%

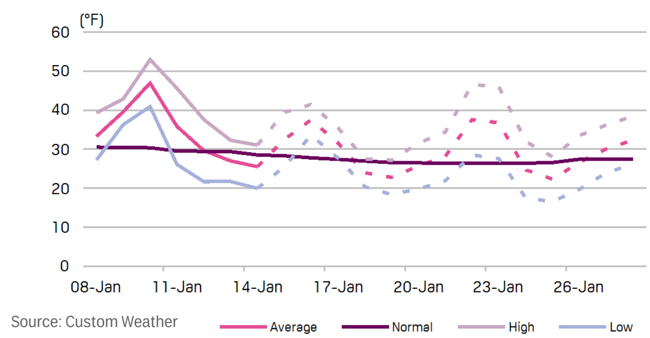
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

NYISO TEMPERATURE



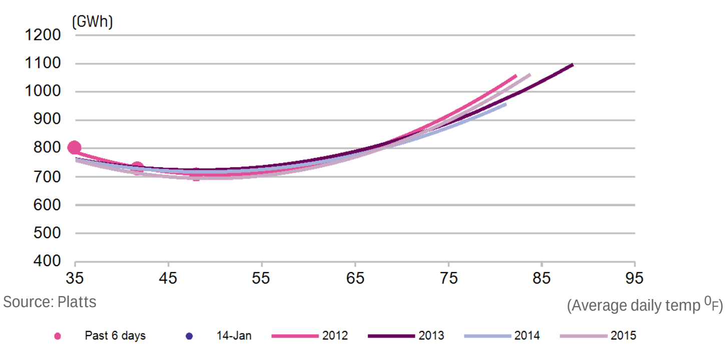
Source: Custom Weather

ISONE TEMPERATURE



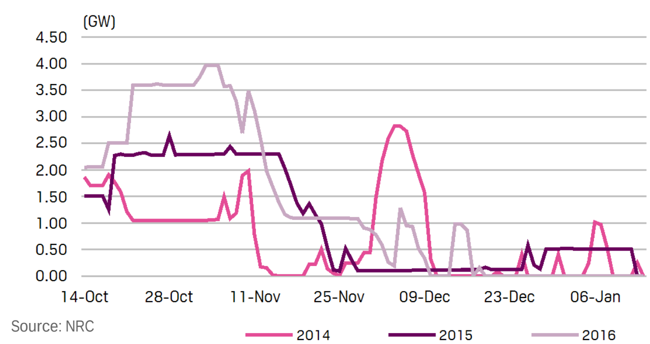
Source: Custom Weather

ISONE & NYISO LOAD PER DEGREE



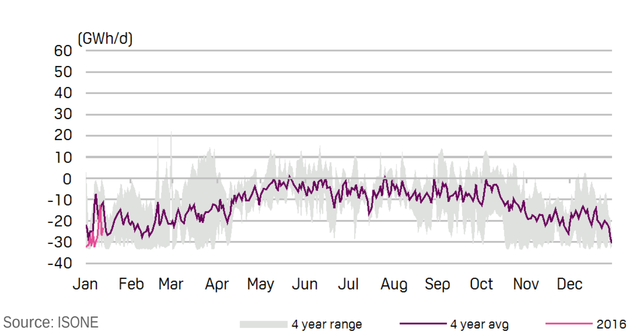
Source: Platts

ISONE & NYISO NUCLEAR GENERATION OUTAGES



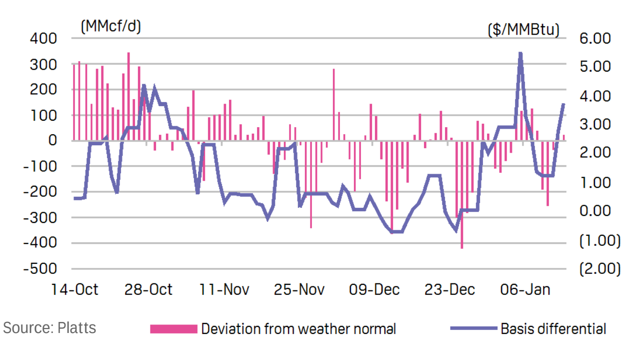
Source: NRC

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)

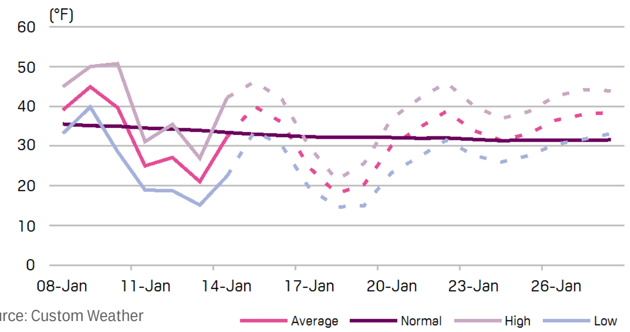
							Daily change		Season		Season average			
Category	9-Jan	10-Jan	11-Jan	12-Jan	13-Jan	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
ISO_TotalLoad_Actual_PJM	1,960.95	1,949.19	2,435.89	2,492.32	2,175.41	100%	-316.91	-13.0%	0	0	0	0	0	0.0%
Gas	424.1	454.73	498.7	478.74	486.18	22%	7.44	2.0%	374.44	498.7	432.96	376.02	56.94	15.0%
Coal	766.23	780.99	995.02	1,053.42	873.23	40%	-180.19	-17.0%	574.61	1,080	807.28	1,035.03	-227.75	-22.0%
Nuclear	798.65	800.83	800.83	801.11	801.11	37%	0	0.0%	715.98	801.11	778.83	780.96	-2.13	0.0%
Other	-28.03	-87.36	141.33	159.05	14.89	1%	-144.16	-91.0%	-109.27	204.66	51.37	218.17	-166.8	-76.0%

MISO SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	9-Jan	10-Jan	11-Jan	12-Jan	13-Jan	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	1,771.28	1,954.41	2,128.08	2,078.5	1,927.61	102%	-150.89	-7.0%	1,601.6	2,128.08	1,828.91	1,958.37	-129.46	-7.0%
Gas	262.94	343.13	486.38	442.18	372.75	20%	-69.43	-16.0%	262.94	486.38	360.44	311.18	49.26	16.0%
Coal	801.72	949.59	1,093.62	1,050	906.65	48%	-143.35	-14.0%	700.66	1,093.62	859.44	1,078.24	-218.8	-20.0%
Nuclear	283.05	287.75	290.23	288.61	281.88	15%	-6.73	-2.0%	169.98	310.07	288.88	288.63	0.25	0.0%
Wind	208.66	130.19	105.31	169.07	135.5	7%	-33.57	-20.0%	23.75	253.95	137.57	124.35	13.22	11.0%
Other	174.72	205.43	150.29	119	188.91	10%	69.91	59.0%	113.3	329.63	155.51	140.15	15.36	11.0%

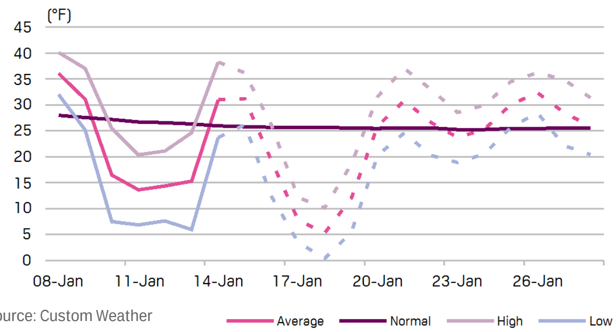
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

PJM TEMPERATURE



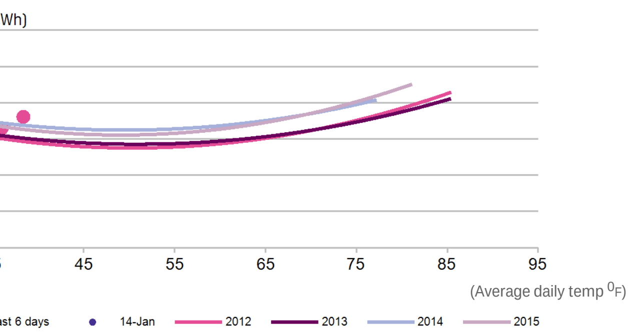
Source: Custom Weather

MISO TEMPERATURE



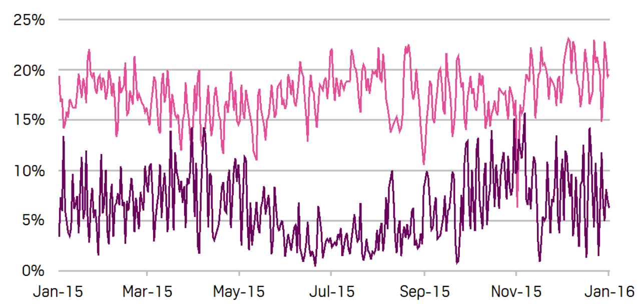
Source: Custom Weather

PJM & MISO LOAD PER DEGREE



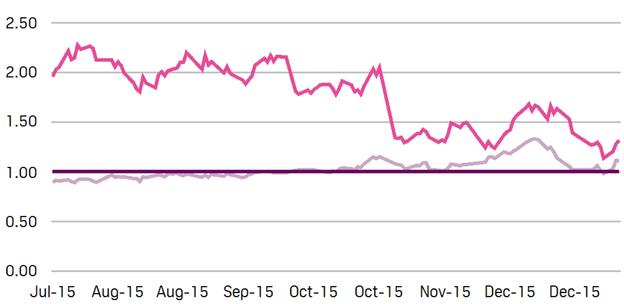
Source: Platts

MISO GENERATION MARKET SHARE - GAS VS. WIND



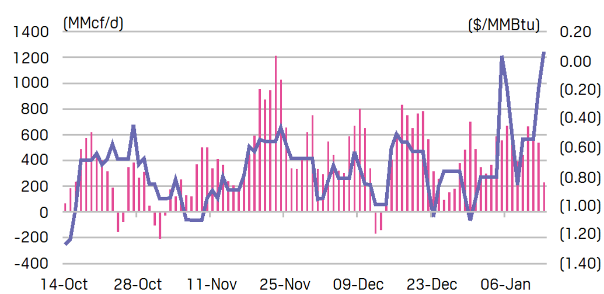
Source: Platts

PJM/MISO COAL-TO-GAS DISPATCH PRICE RATIOS



Source: Platts

PJM POWER BURN VS. GAS BASIS



Source: Platts

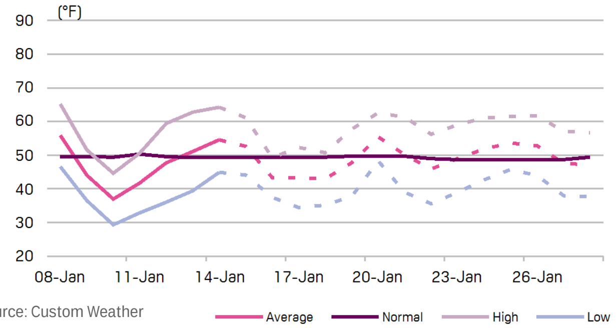
SOUTHEAST POWER MARKETS

ERCOT SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	9-Jan	10-Jan	11-Jan	12-Jan	13-Jan	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	884.07	977.74	1,005.05	934.93	903.85	100%	-31.08	-3.0%	762.15	1,005.05	856.8	886.08	-29.28	-3.0%
Gas	397.98	465.3	423.66	336.44	320.84	35%	-15.6	-5.0%	258.26	465.3	324.71	331.62	-6.91	-2.0%
Coal	370.63	403.88	412.84	395.14	383.93	42%	-11.21	-3.0%	335.42	413.59	369.36	384.76	-15.4	-4.0%
Nuclear	120.7	123.33	123.33	123.33	123.33	14%	0	0.0%	87.57	123.33	105.15	123.25	-18.1	-15.0%
Wind	159.98	50.4	51.42	54.31	140.49	16%	86.18	159.0%	30.87	300.07	130.21	94.58	35.63	38.0%
Other	-165.23	-65.17	-6.2	25.71	-64.74	-7%	-90.45	-352.0%	-242.3	45.82	-72.62	-60.24	-12.38	21.0%

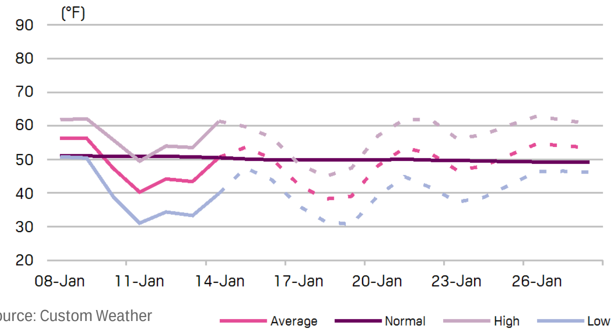
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

ERCOT TEMPERATURE



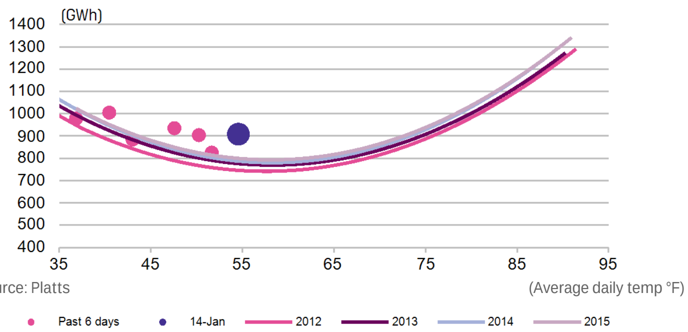
Source: Custom Weather

SOUTHEAST TEMPERATURE



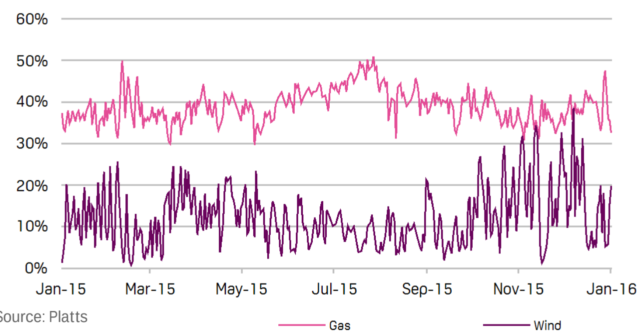
Source: Custom Weather

ERCOT LOAD PER DEGREE



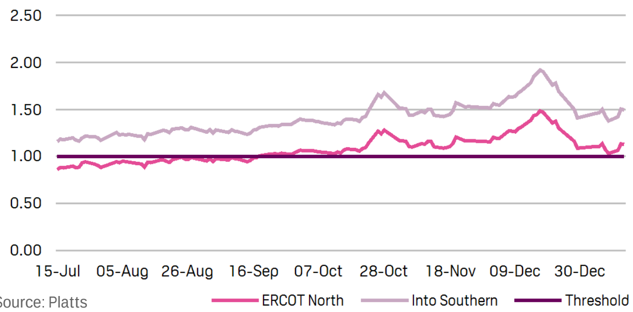
Source: Platts

ERCOT GENERATION MARKET SHARE - GAS VS. WIND



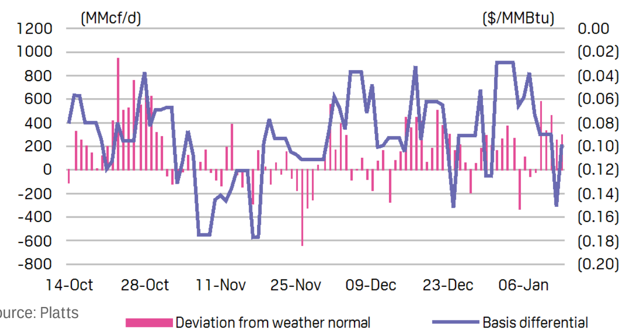
Source: Platts

SOUTHEAST COAL-TO-GAS DISPATCH PRICE RATIOS



Source: Platts

ERCOT POWER BURN VS. GAS BASIS



Source: Platts

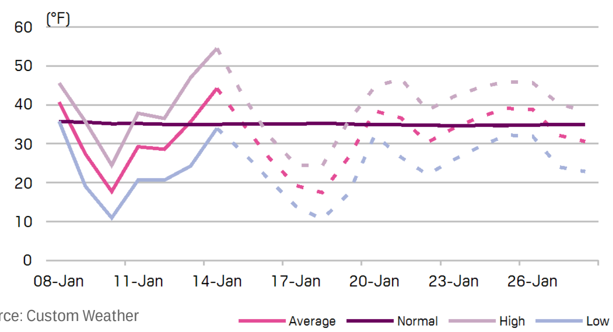
SPP POWER MARKETS

SPP GENERATION MIX (GWh/d)

Category	9-Jan	10-Jan	11-Jan	12-Jan	13-Jan	% Share	Daily change Chg	Daily change % Chg	Season Min	Season Max	Season average 2016	Season average 2015	Season average Chg	Season average % Chg
Total Generation	741.09	777.14	774.04	745.17	723.16	--	-22.01	-3.0%	54.61	777.14	673.1	645.06	28.04	4.0%
Coal	363.81	449.54	421.77	411.83	395	55%	-16.83	-4.0%	23.38	449.54	337.85	375.28	-37.43	-10.0%
Natural Gas	135.48	182.13	158.54	161.62	150.38	21%	-11.24	-7.0%	10.09	241.62	140.58	127.21	13.37	11.0%
Wind	149.95	54.37	99.93	77.86	82.91	11%	5.05	6.0%	12.24	205.52	108.92	79.73	29.19	37.0%
Nuclear Power	62.37	62.36	62.4	62.39	62.41	9%	0.02	0.0%	5.21	62.52	60.98	60.01	0.97	2.0%
Hydro	29.47	28.74	31.38	31.46	32.47	4%	1.01	3.0%	1.88	32.68	24.42	2.79	21.63	775.0%
Diesel	0	0	0.02	0	0	--	0	0.0%	0	0.77	0.35	0.05	0.3	600.0%

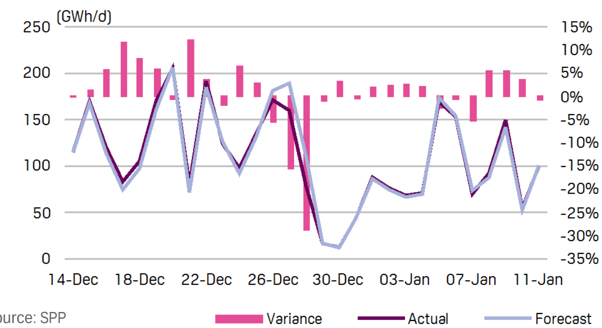
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: SPP

SPP TEMPERATURE



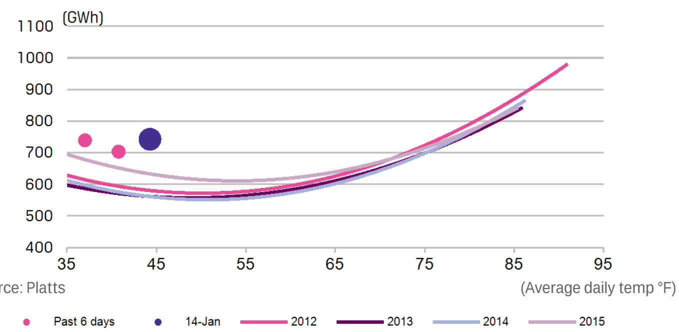
Source: Custom Weather

SPP ACTUAL WIND GENERATION VS. FORECAST



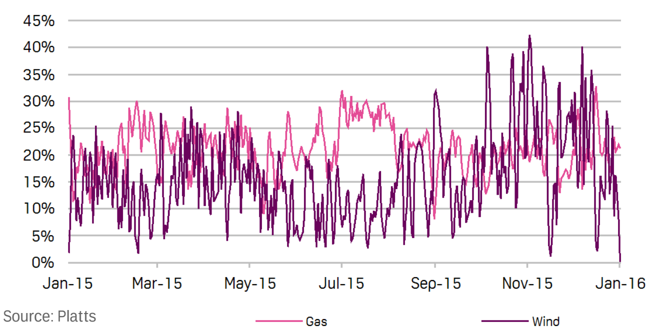
Source: SPP

SPP LOAD PER DEGREE



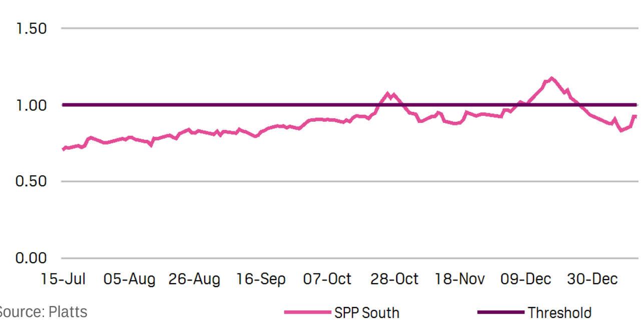
Source: Platts

SPP GENERATION MARKET SHARE - GAS VS. WIND



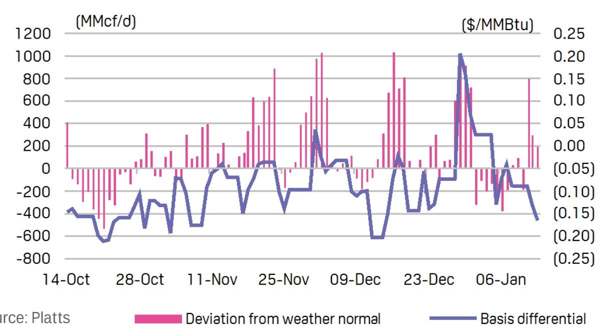
Source: Platts

SPP COAL-TO-GAS DISPATCH PRICE RATIOS



Source: Platts

SPP POWER BURN VS. GAS BASIS



Source: Platts

WEST POWER MARKETS

CAISO GENERATION MIX (GWh/d)

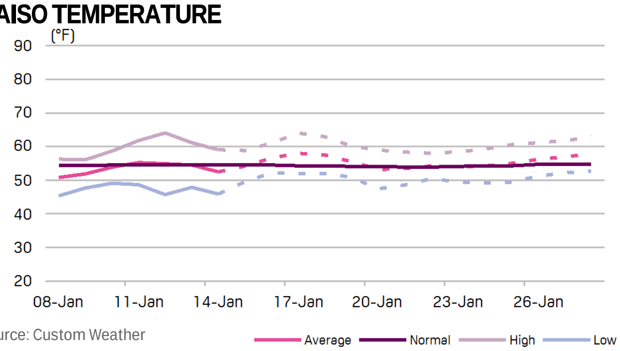
							Daily change		Season		Season average			
Category	**9-Jan**	**10-Jan**	**11-Jan**	**12-Jan**	**13-Jan**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2016**	**2015**	**Chg**	**% Chg**
Total Generation	568.62	544.26	597.25	601.2	603.23	--	2.03	0.0%	542.2	651.87	600.03	581.1	18.93	3.0%
Thermal Power	240.91	229.53	281.91	279.97	261.8	43%	-18.17	-6.0%	178.42	315.07	255.02	239.49	15.53	6.0%
Nuclear Power	54.59	54.58	54.58	54.57	54.57	9%	0	0.0%	10.67	54.76	52.17	51.45	0.72	1.0%
Hydro	38.67	37.51	34.95	34.92	37.14	6%	2.22	6.0%	26.39	44.78	34.74	32.82	1.92	6.0%
Power Imports	170.27	166.88	158.89	158.8	151.68	25%	-7.12	-4.0%	141.29	201.13	167.35	181.34	-13.99	-8.0%
Solar PV	22.16	16.58	27.75	32.15	26.24	4%	-5.91	-18.0%	6.72	35.3	26.65	23.79	2.86	12.0%
Solar Thermal	0.02	0	2.26	2.09	0.2	--	-1.89	-90.0%	0	3.29	1.5	1.22	0.28	23.0%
Wind	6.42	5.11	3.04	5.16	37.73	6%	32.57	631.0%	2.62	70.96	27.19	14.86	12.33	83.0%
Bio + Geo	35.58	34.07	33.86	33.55	33.87	6%	0.32	1.0%	33.55	37.19	35.41	36.13	-0.72	-2.0%

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

							Daily change		Season		Season average			
Category	**9-Jan**	**10-Jan**	**11-Jan**	**12-Jan**	**13-Jan**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2016**	**2015**	**Chg**	**% Chg**
Total Generation	272.3	261.99	292.22	283.19	298.45	--	15.26	5.0%	44.74	359.55	295.34	333.88	-38.54	-12.0%
Hydro	192.76	186.1	210.72	204.02	183.66	62%	-20.36	-10.0%	23.73	221.9	188.58	259.08	-70.5	-27.0%
Thermal Power	79.42	73.34	80.41	73.52	67.36	23%	-6.16	-8.0%	10.39	101.89	84.12	55.57	28.55	51.0%
Wind power	0.12	2.55	1.1	5.64	47.43	16%	41.79	741.0%	0.03	94.39	22.63	19.23	3.4	18.0%
Load	169.6	166.19	179.08	173.26	165.97	--	-7.29	-4.0%	23.86	203.27	169.07	158.54	10.53	7.0%
Net Exports	102.71	95.81	114.31	109.94	132.51	--	22.57	21.0%	20.1	180.26	126.27	175.07	-48.8	-28.0%

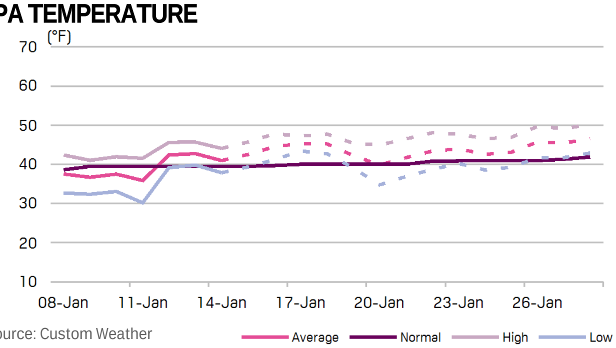
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: CAISO & BPA

CAISO TEMPERATURE



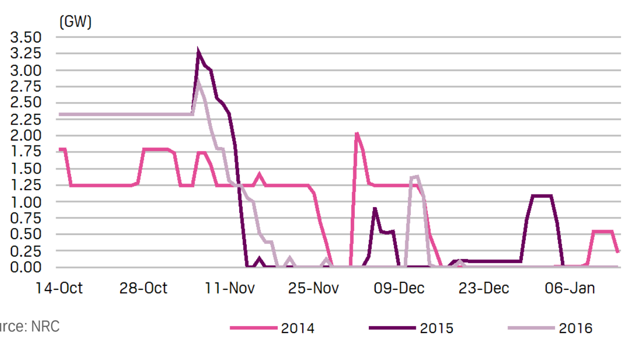
Source: Custom Weather

BPA TEMPERATURE



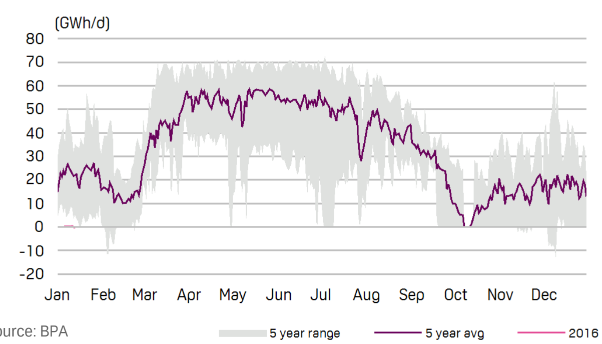
Source: Custom Weather

WESTERN NUCLEAR GENERATION OUTAGES



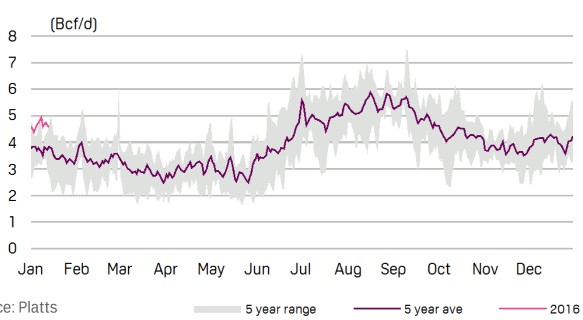
Source: NRC

BPA DC LINE TRANSMISSION FLOWS N-S



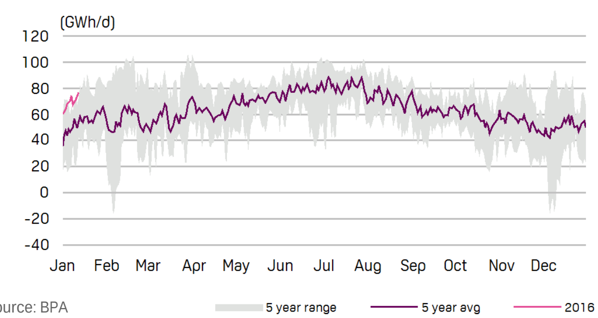
Source: BPA

YEAR-TO-DATE WEST POWER BURN



Source: Platts

BPA AC LINE TRANSMISSION FLOWS N-S



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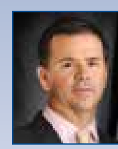

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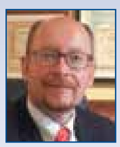

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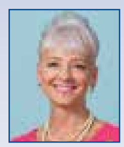
InterEnergy Holdings



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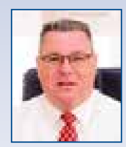

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