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MEGAWATT DAILY

Wednesday, September 21, 2016

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- **Central spot prices mixed on varied temperatures**
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- **West spot dailies mostly rise with gas cash prices**

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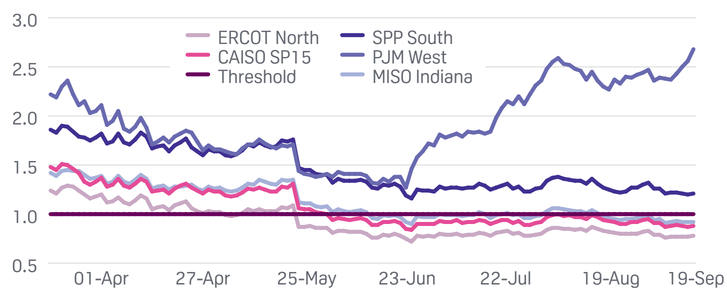
REGIONAL DAY-AHEAD PRICE CHANGES

	Day-ahead peak prices			Regional weather trends		
	21-Sep	Daily chg	Prior 7-day avg	21-Sep	Daily chg	7-day forecast
ISO Price Locations						
CAISO NP 15	39.42	-2.11 ▼	37.53	70.0	-3.7 ▼	69.8
ERCOT North Hub	35.93	-7.02 ▼	39.80	83.0	-2.5 ▼	79.7
ISONE Internal Hub	41.59	-13.77 ▼	36.52	72.7	-1.5 ▼	63.4
MISO Indiana Hub	50.69	1.64 ▲	39.43	74.1	1.3 ▲	66.6
NYISO Zone G	40.43	1.43 ▲	31.08	73.0	-1.4 ▼	64.6
PJM West Hub	44.60	-9.53 ▼	39.87	74.6	0.5 ▲	68.2
SPP South Hub	50.45	7.43 ▲	37.33	80.7	-0.2 ▼	74.1
Bilateral indexes						
Into Southern	34.50	1.50 ▲	32.54	79.3	-0.7 ▼	78.2
Palo Verde	27.14	0.39 ▲	26.10	72.1	-3.2 ▼	71.0
COB	33.25	1.25 ▲	29.86	58.8	0.3 ▲	63.6
Mid-C	29.51	0.61 ▲	28.19	58.8	0.3 ▲	63.6

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)

ISO	17-Sep	18-Sep	19-Sep	20-Sep	21-Sep	Daily change Chg	Daily change % Chg	Five day forecast 22-Sep	23-Sep	24-Sep	25-Sep	26-Sep	Season Min	Season Max	Season average 2016	2015	Chg	% Chg
BPA-Puget	6.01	6.04	6.14	6.65	6.62	-0.03	-0.45	6.65	6.71	6.20	6.19	6.73	4.91	6.33	6.04	6.69	-0.65	-9.72
IESO	18.75	20.06	22.12	21.12	20.49	-0.63	-2.98	20.49	19.69	17.27	17.04	18.76	18.07	25.09	20.78	19.38	1.40	7.22
CAISO	33.01	36.91	38.65	36.44	33.45	-2.99	-8.21	31.35	32.76	34.30	37.37	39.33	27.60	38.65	32.89	33.04	-0.15	-0.45
ERCOT	61.19	62.37	66.89	58.49	55.80	-2.69	-4.60	54.95	52.32	47.59	44.10	48.75	47.56	66.89	58.89	46.64	12.25	26.27
SPP	31.87	31.03	34.02	39.01	37.13	-1.88	-4.82	35.85	35.78	32.94	29.94	31.80	29.64	44.08	36.65	30.86	5.79	18.76
MISO	85.50	87.91	101.82	98.10	98.26	0.16	0.16	96.41	95.24	82.38	82.36	88.54	75.08	114.75	93.80	82.39	11.41	13.85
PJM	101.31	109.16	113.75	116.53	117.67	1.14	0.98	115.81	116.29	99.14	88.25	97.25	93.22	143.07	116.52	95.81	20.71	21.62
NYISO	19.52	22.50	23.30	24.05	23.82	-0.23	-0.96	24.25	23.76	19.26	18.48	21.12	17.79	29.71	23.20	20.49	2.71	13.23
NEISO	14.71	17.53	17.86	19.17	19.13	-0.04	-0.21	19.24	18.38	15.02	14.77	16.81	13.48	23.03	17.09	16.28	0.81	4.98
AESO	8.96	9.08	9.46	9.32	9.30	-0.02	-0.21	9.27	9.33	8.76	8.79	9.23	8.86	9.85	9.31	9.67	-0.36	-3.72

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

Source: Platts

NEWS

ERCOT reliability-risk conclusion draws doubts

A consultancy's analysis concluding that the Electric Reliability Council of Texas faces the risk of rolling blackouts without "immediate reforms" for the state's power markets has drawn skepticism from power industry observers.

On Friday, PA Consulting Group, a global consultancy focusing on energy and utilities, announced that it had completed a study indicating that "unless the Texas Public Utility Commission acts soon to introduce new reforms to the electricity market's structure, Texans could be subject to rolling blackouts and high electricity prices in the near future."

"One of the fundamental principles of any competitive market is that producers should have a reasonable opportunity to recover their costs and make a fair market return, otherwise existing producers could go bankrupt and new producers will not enter the market," according to the media release.

The independent analysis, by David Cherney, Ethan Paterno and Ryan Hardy, PA Consulting energy and utility experts, which was not commissioned by a client, states that the Operating Reserve Demand Curve, a price adder introduced in 2014 to reflect scarcity in high-demand conditions, is "not working."

"Over the past two summers, Texas has seen record highs in electricity demand, but 2015 and 2016 were among the least profitable years for power plants in recent memory," the media release states. "If this continues, it’s doubtful that new power plants will be built."

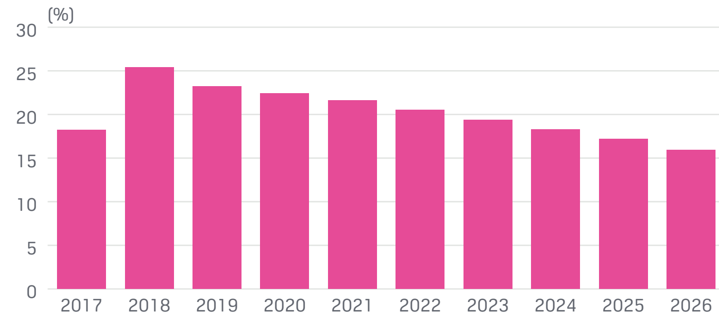
ORDC too new to judge efficacy: UT economist

But Gurcan Gulen, senior energy economist at the University of Texas Bureau of Economic Geology's Center for Energy Economics, said, that with only two years of ORDC performance history, it is "probably too early to say 'it's not working.'"

"Having said that, the higher price cap and ORDC have not been generating enough price signals probably because summers have been milder; weather-normalized load growth has not been as high as in the past; new capacity came online, including a lot of wind and some gas; wind generation increased; and natural gas remaining very cheap," Gulen said in an email Sunday.

ERCOT is a summer peaking market, and its most recent "Report on the Capacity, Demand and Reserves in the ERCOT Region, 2017-2026," issued in May, shows reserve margins ranging above the system's target rate of 13.75% for the entire period.

ERCOT PROJECTED SUMMER RESERVE MARGIN



Source: Electric Reliability Council of Texas

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But PA Consulting's media release states that ERCOT's "actual reserve margin" this past summer was 11.5%, while other US markets had reserve margins above 20%.

"Over the next several years, with increasing demand for electricity and potential power plant retirements due to poor profitability, ERCOT's reserve margin will decline absent the development of new power plants," the media release states. "As a result, the 24 million customers thant ERCOT provides power to could face sustained rolling blackouts and high electricity prices."

But Neil McAndrews, an Austin, Texas-based electricity market consultant, said ERCOT faces no serious risk of rolling blackouts without market changes.

"We have had very few problems with supply shortages," McAndrews said in an email Sunday. "Low power prices due to low natural gas prices have been the major worry especially to higher cost coal generation. This may lead to premature retirements of coal generation. Eventually the glut of natural gas supply will decline and power prices should rise above these very low levels."

Asked why other stakeholders have not generally been calling for substantial reforms, PA Consulting's Paterno said, "As our analysis suggests, this is not ncessarily a current problem, but one that needs to be addressed given the lead time to build new power plants."

Shifting the ORDC to the right so as "to yield higher prices at higher reserve levels ... is the best path forward at this time," Paterno said.

Weather, heavy winds limit scarcity prices: consultant

McAndrews said the existing ORDC has not generated much scarcity pricing revenue partly because "sudden large deviations in weather have been missing these last couple of years."

"This year, we saw a very windy summer, and that lessened the frequency of higher demand spikes and price adders even when temperatures were high," McAndrews said.

But that is the nub of ERCOT's "missing money" problem, according to Jeff Schroeter, managing director of Genova Power Advisors, a consultancy that focuses on generation development.

"I think looking at the PUCT and market design is looking in the wrong place," Schroeter said in an email Friday. "Too much federally subsidized renewables and a flat economy are the causation elements. I do think ORDC actually works pretty well."

ERCOT's merchant market is "ultra efficient and has too much renewable subsidy in the form of wind [production tax credit] hours," Schroeter said.

The 2015 value of a gas peaker with a heat rate of 10 MMBTu/MWh was just about $300/kW, and the value of a natural gas combined-cycle plant with a 7 MMBtu/MWh heat rate was about $450/kW, but the cost of a new-build peaker would be about $450-600/kW, and a new-build combined-cycle plant would cost about $650-900/kW, Schroeter said.

"We have too many hours per year when wind can bid below gas due to the ... $25/MWh production tax credit – and it is going to get worse before it gets better with another ... 6,000 MW of wind still coming down the pipeline," Schroeter said.

— Mark Watson

CEQ under attack as some see project delays

A White House guidance on how agencies should consider climate change when reviewing infrastructure projects is likely to spawn litigation, creating delays for pipelines and other energy projects, a policy analyst and energy industry attorney said Tuesday.

At a briefing arranged by the House Natural Resources Committee, Kevin Book, managing director at ClearView Energy Partners, and Scott Segal, partner at Bracewell, tore into the logic of the guidance, made final by the White House Council on Environmental Quality August 2, and said that the additional analysis and inevitable legal challenges will lead to delays.

Not all observers, however, are expecting a huge impact on the natural gas pipeline permitting process, as some see the US Federal Energy Regulatory Commission as likely to keep to its approach. The committee also plans a hearing Wednesday on the guidance, where CEQ Managing Director Christy Goldfuss is likely to come under fire from the panel's chairman.

"This guidance looks like it slows things down, creates headwinds to ongoing project approvals, and potentially creates cost and investment barriers, with the effect of keeping oil and gas and other mineral resources [such as] coal in the ground," Book said.

Segal agreed. "Irrespective of changes [from CEQ's earlier draft], which I regard as running the gamut from cosmetic to confusing within the final guidance, they will not expedite. They will result in project delays, because they require administrative agencies to do things that they have not done before," said Segal.

The guidance describes how agencies should consider impacts of their actions on climate change as part of National Environmental Policy Act reviews, for instance, advising agencies to quantify projected greenhouse gas emissions "whenever the necessary tools, methodologies, and data inputs are available."

Legal hooks for public interest groups

Book acknowledged that the guidance does not have the binding force of a rulemaking, but said it has the "legal hook that a challenger can [use to] say an agency did not fulfill its obligation as instructed by the agency that promulgates rules for NEPA," namely CEQ.

For instance, he pointed out that three weeks after the guidance was issued, Physicians for Social Responsibility and WildEarth Guardians filed suit, challenging the Bureau of Land Management's environmental reviews under its oil and gas permitting program. "BLM may have trouble moving ahead with leases" until it has clarity, he said.

Asked whether there was a difference thus far in the environmental reviews or orders on natural gas pipelines coming out of FERC in weeks since the guidance, Book said no yet, although he expects a change in the future.

While FERC's role has been as an "enabling agency" tasked with getting energy projects built with minimal environmental impact, once they are asked to play a "limiting role," the core project team must meet added requirements, which slows things down, he said.

FERC thus far has pressed back against those urging it consider upstream and downstream impacts of building pipelines, saying that is not its charge, but the guidance changes the balance, Book said. "Now we have guidance that says that is potentially what you have to do, which means that they're going to have to have an answer. They probably only need to have one answer, really well crafted, before they can find ways to get back to doing what they do, but that takes time," he added.

Segal added that CEQ "listened in a very peculiar way" to FERC's objection to the words upstream and downstream, which were in an earlier draft; it drew a line through those words, he said, and replaced them with words like "forseeable" and "causal relationship."

FERC in 'same bad situation'

"It puts FERC in the same bad situation, only rather than drawing bright-line distinctions as they did in the draft, they said we'll leave it up to the agency," Segal said. FERC now has an obligation under the draft to examine climate change impacts that implies a life-cycle analysis, he said, while it is up to the agency to determine how to apply that to individual projects.

"Here's the rub on that," he said. "I am certain that the public interest groups will not agree with any interpretation which allows the construction of future pipelines," and they will sue FERC over the administrative process. "This document is so amorphous it will not assist FERC," Segal added.

However, Howard Nelson, DC shareholder with Greenberg Traurig, said, "I'm still of the view that this doesn't change the game," predicting in an interview that FERC will rebut any claims that the guidance requires or suggests expanded reviews, just as it has battled legal challenges based on the draft guidance. He emphasized instead that the final guidance appears less prescriptive than the draft, which had specific language pointing to consideration of upstream and downstream impacts. While environmental groups will likely argue the contrary, CEQ appears to have adhered to the concerns expressed by FERC in comments and given deference to the agency to decide if there is a close causal connection between a pipeline and a source of production, he said.

Segal also took on other aspects of the logic of the guidance.

Segal said it may impede three key aspects of the administration's climate change plan: increasing use of natural gas, improving efficiency of power plants and adding renewable energy. Each individual action along those lines may need an assessment of whether it increases climate impacts, for instance a transmission line that connects renewables could be reviewed on whether it could add to power transmitted from fossil fuel sources.

Three critical assumptions of the CPP are "implicated and potentially delayed" by CEQ guidance, Segal said. "Ironic, ain't it, it since it's the cornerstone of the administration's climate change strategy, encumbered by the goo which is the CEQ guidance," Segal said.

Segal also called determining the environmental impacts of a particular project on global climate "an impossible task" that would violate the rule of reason that the US uses as a key element of environmental law and jurisprudence of NEPA. For instance, he said a project could offset emissions elsewhere that are not taken into account, or it may affect climate change in a way that is not linear and may lack an actual exacerbation end point.

Similarly, he said, the guidance calls for estimates of how global warming would affect a pipeline project, without considering how alternatives to pipelines might instead be less resilient. "The first time CEQ says you know you've got a point there, we think climate change makes a pipeline a good idea,' I'll eat my hat. This is unidirectional."

Finally, he took on an aspect of the guidance that asks agencies to consider the "recognizable frame of reference" such as state climate change goals. "In Anglo-American jurisprudence, if you are doing the same thing, you generally get the same response at law, … but not under this NEPA guidance. If it's in one political jurisdiction that has adopted a different law, it will literally come up with a different outcome, if I'm reading this document the way I think I'm reading it," he said.

— Maya Weber

CFE names directors for new spin-off gencos

Mexico's long-time electricity monopoly announced Monday that it has named director generals for 11 new subsidiaries that it has created as part of the reforms of the power sector launched in December 2013.

The director generals named Monday by the Comisión Federal de Electricidad, or CFE, will oversee six generation subsidiaries, a distribution and a transmission subsidiary, a basic and a qualified retail service subsidiary, and an affiliate that will oversee legacy interconnection contracts.

The new subsidiaries are broken off from CFE and are to be separate legal entities with separate offices, boards of directors and director generals, or CEOs.

"This horizontal separation of CFE has the objective to guarantee the open access and the efficient and competent operation of the wholesale electricity market," the CFE said in a statement. "This separation will strengthen CFE in its objective to generate value and to provide better quality service at more competitive prices and in a more friendly way toward the environment."

Earlier this month the CFE released details on the six new generation companies it is creating. It calls them Empresas Productivas Subsidiarias, or EPSs.

Five of the six new EPSs have been stocked with between 7,900 MW and 9,000 MW of capacity, dividing roughly 42,500 MW of capacity that CFE owns. The sixth EPS will manage roughly 16,100 MW of legacy contracts.

Generation companies are not regionally divided

The gencos are not regionally based, but rather will operate a mix of assets located in all regions of the country.

EPS 1, as designated by CFE, will operate just over 8,000 MW of capacity, including the 900-MW converted gas-fired Manzanillo I facility on the Pacific Coast in the state of Colima, and the 616-MW Mazatlán facility also on the coast in the state of Sinloa.

This subsidiary, whose new director general is Manuel Pérez Topete, previously a CFE regional superintendent of operations and production, will have a total of 19 facilities, seven of which are located in Baja California, seven along the country's western Pacific coast, and three on the border with Texas. Three of the 19 facilities are hydroelectric, with most of the rest thermal generators.

EPS 2 is the largest of the five, with 15 facilities with 9,000 MW of combined capacity. This subsidiary will manage the 700-MW

Samalayuca II CCGT facility located 40 miles south of the US border in the northern state of Chihuahua, and the 2,100 MW Petacalco coal-fired facility located on the Pacific Coast near Alcapulco in the state of Guerrero.

It has two facilities in Baja and the big Chicoasen hydro facility on the Grijalva River in Chiapas that has an installed capacity of 2,430 MW. Its new director general is Ignacio Carrizales Martínez.

With 8,500 MW of capacity, EPS 3 will own and operate the Carbon II facility and the Altamira, as well as the Rio Santiago hydro facility. It will also operate the 550-MW Tula and 615-MW Valle de Mexico combined cycle facilities located near Mexico City.

The subsidiary's new director general is Guillermo Virgen González, who was previously CFE's production director in its northeast region.

EPS 4's new director general is Juan Antonio Fernández Correa. He will oversee a subsidiary with 23 facilities with 7,900 MW of combined capacity. EPS 4 has eleven facilities located in the central region of Mexico that supply Mexico City and its area's south of the country's capital. It also owns five hydro facilities on its northwest coast, as well as the 1,080 MW Malpaso y Penitas hydro facility in Chiapas.

The fifth genco, which CFE designates EPS 6, has been given 18 facilities with 9,000 MW of combined capacity, with almost all located in the eastern half of the country, with seven thermal facilities located in the Yucatan.

It will own the 495-MW Tuxpan V CCGT Power Station located in Tuxpan in the state of Veracruz, near the coast of the Gulf of Mexico. It will own the 1,200 MW Carbon I Rio Escondido coal-fired facility located in Nava in the state of Coahuila, near the border with Texas. Victor Manuel Cárdenas Marin is the subsidiary's new director general.

CFE continues to oversee transmission

CFE will continue to manage the country's electricity transmission system through its Empresa Subsidaria de Transmission. It has eight regional grid operations and 30 sub-transmission areas within those regions, and operates almost 15,000 miles of 400kV lines and roughly the same amount of 230 kV lines.

According to Prodesen, the Secretaria de Energia's National Electric System Development Program, a 17,000-mile network expansion is planned for 2016 through 2030.

On Monday, Noé Peña Silva, the former coordinator of transmission at CFE was named the new transmission subsidiary director general.

— *Jeffrey Ryser*

Gas plant development spreads across Midwest

In an era of coal plant closings, the development of natural gas-fired generation is showing no signs of abating or reaching a saturation point in the Midwest and nearby regions.

For example, a new Alliant Energy natural gas-fired plant is under construction in Wisconsin. A second new Panda Power Funds' gas plant is up and running in Pennsylvania. Meanwhile, a veteran power plant developer is targeting a year from now for the start of work on a second large gas plant in northwestern Ohio.

Alliant recently commenced construction on a 700-MW combined-cycle gas plant expansion at its existing 675-MW Riverside Energy Center gas plant site in Beloit, Wisconsin, company spokesman Scott Reigstad said in a Tuesday email.

Riverside is operated by Alliant's Wisconsin Power & Light subsidiary.

The $700 million expansion is scheduled for commercial operation in early 2020.

Alliant/WPL are holding a formal groundbreaking at the site on Thursday, according to Reigstad.

"We're primarily doing pre-construction activities at this time that include items affiliated with the new facility," he said. "The heavier construction will kick in more early next year."

Next year also is when Alliant's new 650-MW Marshalltown combined-cycle plant is scheduled for commercial operation in Iowa.

"Our Marshalltown Generating Station is progressing well and is approximately 90% complete," Reigstad said. "The project is on time and on budget and is expected to go in-service in the spring of 2017." That project also carries an estimated price tag of $700 million.

Panda adding 3 plants in Pennsylvania

Panda, based in Dallas, Texas, has placed its new 829-MW Patriot gas plant in Williamsport, Pennsylvania, in commercial operation, according to company spokesman Bill Pentak. A sister, 829-MW plant in Towanda, Pennsylvania, began running earlier this summer.

Panda's 1,124-MW Panda Hummel gas plant remains under construction in Snyder County, Pennsylvania.

One of the first of several new combined-cycle gas plants under construction or development in Ohio is pushing toward a May 31, 2017, completion date, William Martin, president of Boston-based CME Energy, said in a Tuesday interview.

The 800-MW Oregon Clean Energy Center must be operating by June 1 because it cleared a previous PJM Interconnection capacity auction.

Martin said "the pipe has all been laid" to connect the plant with planned gas suppliers ANR Pipeline and Panhandle Eastern.

FirstEnergy's American Transmission Systems Inc. subsidiary has finished the $2.4 million construction of two 0.2-mile 345-kV transmission lines to connect Oregon to the grid, according to FirstEnergy spokesman Doug Colafella.

Martin already is planning a second gas plant in the same area, this one exceeding 900 MW.

"I think in the fall of 2017 we should have a closing and shovel in the ground" for the new plant, which will be called Clean Energy Future-Oregon because it has a different ownership structure, he said. It is slated for commercial operation in 2020.

Martin, who has built plants in the US and around the globe, believes neither Ohio nor the region is in any immediate danger of a natural gas overload.

"We think there will be more [gas] plants yet in PJM and Ohio," he said.

In all, at least eight gas plants totaling more than 7,000 MW of generation are planned for Ohio, home of the Utica and Marcellus shale gas plays.

Alliant's plants are located in the Carmel, Indiana-based Midcontinent Independent System Operator, like PJM, a regional grid operator.

So, too, is Tenaska's proposed 900-MW Blue River Generating Station gas plant in Indiana.

Delette Olberg, spokeswoman for the Omaha, Nebraska-based independent power developer, said in an email that Blue River

Generating "remains under development, and will move forward when market conditions allow."

In August, Tenaska started construction on its long-delayed, 925-MW Tenaska Westmoreland combined-cycle plant near Smithton in Westmoreland County, Pennsylvania. It is set for completion in 2018.

Tenaska also is heavily invested in solar energy development.

On Tuesday, the 150-MW Tenaska Imperial Solar Energy Center West became fully operational in Southern California. Tenaska's second-largest solar project, near Seeley, has a 25-year power purchase agreement with San Diego Gas & Electric.

— Bob Matyi

PROPOSED NATURAL GAS FIRED POWER GENERATION

(MW)

State	Plant Name	2016	2017	2018	2019	2020	2021
Iowa							
	Marshalltown Generating Station CC		645				
	University of Iowa UI West Campus Plant		20				
Ohio							
	Carroll County Energy Center			700			
	Clean Energy Future Lordstown			800			
	Columbiana County Power Plant					1,100	
	Guernsey Power Station					1,100	
	Middletown Energy Center			540			
	Oregon Clean Energy Project		800			800	
	Pickaway Energy Center						1,000
	Rolling Hills		621				
Pennsylvania							
	Bayles Energy Greene County Gas Plant	9					
	Berks Hollow Energy Station		855				
	CPV Fairview (Jackson)				600		
	Fairview Energy Center				980		
	Good Spring NGCC I	330					
	Hickory Run Energy Station		900				
	Hummel Station		1,064				
	Jessup Lackawanna Energy Center			1,300			
	Oxbow Creek Energy Plant		20				
	Penn State West Campus Steam Plant		3				
	Red Glen Energy Plant	4					
	Tenaska Lebanon Valley Generating Station				955		
	Tenaska Westmoreland Project			925			
	York Energy Center		760				
Wisconsin							
	Riverside Energy Center					700	

Source: Platts Power Plant Databank

LADWP to explore 100% renewable supply

Under a directive from the Los Angeles City Council, the city's municipal utility will study what it would take to get all of its electricity from renewable resources.

LADWP will work with the California Independent System Operator, the Southern California Public Power Authority, other utilities and stakeholders to craft a plan for getting all its power from renewable resources.

"This legislation will make sure that our transition to 100% clean energy happens as quickly and as strategically as possible and serves as a road map for other cities that want to join the clean energy future," City Councilmember Mike Bonin, a sponsor of the measure, said Friday.

LADWP is California's third largest utility with about 23 million MWh in annual sales. The municipal utility has a record peak load of 6,396 MW and has 7,628 MW in installed capacity.

Forty percent of LADWP's electricity came from coal-fired resources last year, according to the utility's most recent integrated resource plan, released in December.

However, as part of a plan to stop using coal-fired electricity, LADWP in July sold its 477-MW stake in the Navajo Generating Station in northeast Arizona to Salt River Project. LADWP's remaining coal-fired generation comes from the 1,800-MW Intermountain Power Project near Delta, Utah.

The Intermountain Power Project has 29 Utah municipal and cooperative utility participants. About 75% of the plant's output is under contract through 2027 to LADWP and five other California municipal utilities. LADWP takes up to 1,200 MW from the plant.

The utilities plan to convert the Utah plant to up to 1,200 MW of natural gas by July 2025.

Utility faces challenges just getting to 50% by 2030

It is unclear how LADWP would get all its power from renewable resources. The utility faces "significant challenges" in meeting its current plan to get half of its power supply from renewables by 2030, according to the IRP.

LADWP estimates that as it adds more renewable generation to its system, by 2025 it will face a late afternoon ramp of 2,500 MW to 3,500 MW as solar generation drops with the setting sun, according to the resource plan. The utility can take various steps to help it meet the late afternoon ramp, including building quick starting natural gas-fired units, the IRP said.

The utility's resource plan calls for adding 800 MW of distributed solar by 2023 plus 4,228 MW of renewables by 2035. Currently, LADWP has 1,874 MW of renewables and 1,009 MW under construction, according to an update presented Tuesday by staff to the board. The utility has 98 MW of planned renewable projects and 1,344 MW of potential projects, the update said.

By 2030, LADWP expects to get half its power supply from renewables, 25% from natural gas, 16% from energy efficiency, 6% from nuclear and 3% from hydroelectric resources, according to the resource plan.

Seventeen U.S. cities have committed to getting all their electricity from renewable resources, including Salt Lake City, Boulder, San Diego and San Francisco, according to the Sierra Club. Denver is exploring the option.

— Ethan Howland

ERCOT finds no alternative to NRG RMR contract

The Electric Reliability Council of Texas found no alternatives to the $60 million reliability-must-run agreement with NRG Texas' 371 MW gas-fired Greens Bayou-5.

ERCOT in June contracted to keep Greens Bayou-5, located in Houston, Texas, operating on an RMR basis for the summer months through June 2018, at an estimated cost of about $60 million, in case it is needed to support transmission system reliability under certain critical operating conditions.

The contract was in response to a March 29 NRG Texas filing with ERCOT of the generator's intent to suspend operations at the 43-year-old steam boiler generator starting June 27.

As required by protocol, ERCOT evaluated the availability of cost-effective alternatives to the Greens Bayou RMR agreement.

ERCOT issued a request for proposal July 13 to procure one or more potential must-run alternative resources with the prospect of eliminating the need for the existing RMR agreement with NRG Texas Power LLC.

"During the review of must-run alternatives, ERCOT did not receive offers that would adequately meet the reliability need served by the Greens Bayou 5 unit," ERCOT wrote in a news release. "Of the eligible offers received, there was insufficient capacity offered to fulfill the criteria set forth in the request for proposals."

ERCOT received eight alternative offers

ERCOT received eight offers from four qualified scheduling entities, representing a combined capacity total of 385.9 MW for four of the five contract months and 300.9 MW for the other contract month, according to ERCOT.

Upon review of the offers, ERCOT determined that several of the offers did not qualify as eligible MRA resources, according to ERCOT. In its evaluation of the remaining eligible offers, ERCOT determined that they did not provide an acceptable solution to the reliability concern necessary to replace the need for the RMR unit.

The RMR agreement with ERCOT requires NRG to make Greens Bayou-5 available for use upon request by ERCOT for all hours during the months of July through September 2016, June through September 2017, and June 2018. Per the agreement, ERCOT will pay NRG a standby payment of $3,185 per hour during the term of the agreement.

The RMR agreement with Greens Bayou-5 addresses specific reliability concerns on the Singleton-to-Zenith transmission line serving the Houston area, according to ERCOT. Under the agreement, the unit will remain available during summer peak demand periods in case the unavailability of other transmission and generation facilities in that area result in a critical reliability concern. When the Houston Import Project is energized in summer 2018, ERCOT does not anticipate this issue to continue to be a concern.

A request for comment from NRG was not returned by deadline.

— *Kassia Micek*

DAILY CSAPR ALLOWANCE ASSESSMENTS, SEP 20 ($/st)

	$/st	2016 Range	$/st	2017 Range
NOx Annual	8.50	5.00-15.00	8.50	5.00-15.00
NOx Seasonal	350.00	300.00-400.00	1300.00	500.00-2000.00
SO_2 Group 1	1.75	0.50-3.00	1.75	0.50-3.00
SO_2 Group 2	3.50	1.00-6.00	3.50	1.00-6.00

RGGI CARBON ALLOWANCE FUTURES, SEP 19 ($/allowance)

ICE	Settlement	Volume
Dec16 V15	4.65	0
Dec17 V15	4.80	0
Dec18 V15	4.98	0
Dec16 V16	4.65	0
Dec17 V16	4.80	0
Dec18 V16	4.98	0
Dec16 V17	4.65	0
Dec17 V17	4.80	0
Dec16 V18	4.60	0
Dec17 V18	4.75	0
Dec18 V18	4.93	0
Dec19 V18	5.13	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.

SPP panel advances renewables rule changes

Southwest Power Pool would require all nonwind intermittent energy resources to register as dispatchable beginning January 1 under a rule approved Tuesday by SPP's Market Working Group.

Market Protocol Revision Request 193 focuses on solar generation rules, but this aspect of the proposed rule change would also affect weather-dependent generation such as run-of-river hydro. All such resources would be eligible to provide regulation down, but not regulation-up, spinning reserve or supplemental reserve services.

Any resources that are registered with SPP and have an interconnection agreement before January 1 would be exempt from the requirement to be dispatchable by SPP.

MPRR 193 also requires SPP to produce a solar-powered generation output forecast featuring "a rolling 48-hour probability distribution of the hourly production potential from all" solar generators in SPP.

The initial MPRR submission by SPP staff noted that SPP would have 280 MW of utility-scale solar installed by the end of 2016 and has about 3,000 MW of utility-scale solar in the interconnection queue.

Storage market concepts also discussed

The Market Working Group also discussed at length how SPP should handle short-term stored energy resources, such as batteries, and generators moved compressed air, pumped hydro and flywheels. Although "short term," such resources would be required to sustain output for at least 15 minutes.

SPP staff proposes that such resources only be used for regulation ancillary services, unless the owner chooses to opt out of the regulation market. Such "very high performing resources" could reduce SPP's day-ahead market requirement for total regulation services.

SPP would manage such resources "state of charge," so that SPP calls on the battery, for example, to discharge into the grid when the grid's frequency is low or charges up from the grid when the grid's frequency is high. SPP would maintain such a stored energy's charge at 50%, so that it could provide both regulation-up and regulation-down services.

Erin Cathey, SPP senior market design analyst, said incorporating these features in SPP's systems would cost about $400,000, and management hopes to present a Market Protocol Revision Request containing these features to the Market Working Group "in the next month or two."

A teleconference listener who did not identify himself, said, "As a developer, I think going forward is the best thing to do."

SPP wants stakeholders to offer feedback about the concept, and Richard Ross, Market Working Group chairman, said that feedback could be in the form in a separate Market Protocol Revision Request.

— *Mark Watson*

PJM objects to Dominion fuel reimbursement

PJM Interconnection does not have authority to reimburse Dominion Virginia Power for switching from gas to oil fuel because the generator failed to use the available procedures for such situations, the grid operator said Monday in response to a recent complaint from the generator.

“Dominion had a full and fair opportunity to submit a cost-based offer using the fuel source in question here but did not avail itself of that opportunity, leaving PJM with no cost-based offer on file to utilize in real-time to close the market,” the grid operator argued.

“Therefore, PJM is unable to compensate Dominion for its actual costs without a commission order requiring it to do so,” PJM said in its response Monday.

At issue is Dominion's August 29 complaint (EL16-109) arguing that PJM unfairly denied its request for a fuel cost adjustment when it ran a power plant for reliability on back-up fuel oil instead of less expensive natural gas. The generator asked the US Federal Energy Regulatory Commission to direct PJM to pay Dominion the $387,587 in additional fuel costs it incurred to follow PJM's dispatch.

In June, PJM directed Dominion to operate several units at its gas-fired power station in Ladysmith, Virginia, to maintain system reliability during a transmission constraint, even though the plant did not have a day-ahead commitment to run, according to the complaint. At that time, Dominion told PJM that due to a constraint on Virginia Natural Gas pipeline, it would need to run on back-up fuel oil instead of natural gas, and PJM reaffirmed its dispatch directive, the complaint said.

No oil cost schedule available

Dominion requested a cost adjustment for its fuel costs but PJM denied the request, saying that Dominion did not have an oil offer in the market. In its complaint, Dominion argued that PJM's rules do not require multiple cost-based offers for different fuels to be on file for resources to be eligible for a cost adjustment.

Dominion urged FERC to reject PJM's interpretation of its market rules, or waive any PJM rules needed to compensate Dominion for its fuel costs when dispatched by PJM for reliability.

On Monday, PJM fired back that it is not required, nor authorized, to compensate Dominion for its oil costs. PJM can only dispatch resources and set prices on the basis of the cost schedules that are on file and listed as available in its Markets Gateway system, and Dominion did not have an oil cost schedule in the system at all.

“Had Dominion made a cost schedule to operate the resources using oil as a fuel source ‘available’ in Markets Gateway at the time, PJM would have been able to pay Dominion for its oil costs,” PJM said.

Generators can have up to 99 offer schedules in the Markets Gateway at any one time and can make any one or more of them available on a particular operating day to account for contingencies including fuel type, PJM said. “Dual-fuel units are allowed, and in fact expected, to have multiple cost schedules in the Markets Gateway every day — at least one for each fuel on which the unit is capable of operating,” the answer said.

As such, Dominion should always have both a natural gas and oil cost schedule available in case it needs to change its fuel source, the grid operator explained. But Dominion “intentionally chose not to submit a cost-based schedule to operate the units on oil in the Markets Gateway because it thought it was administratively burdensome to do so.”

Dominion’s complaint noted that PJM has accepted downward cost adjustments when Dominion submitted a cost-based offer assuming use of fuel oil, but later ran on gas. “In this respect, PJM’s treatment of cost adjustments is heads I win, tails you lose,” Dominion said.

PJM cautions against 'sweeping directive'

PJM acknowledged that it will reduce its payments at the market seller’s request, but noted that sellers are under no obligation to receive reduced compensation. “If PJM dispatches a resource in its energy markets based on the market-based offer for the resource to operate using a more expensive fuel, but the resource actually operates on lower cost fuel, there is no prohibition under the PJM market rules from doing so and retaining the excess compensation,” the answer said in a footnote.

OUTAGES

GENERATION UNIT OUTAGE REPORT

Plant/Operator	Cap	Fuel	State	Status	Return	Shut
Northeast						
Beck-2 PGS/OPG	103	h	Ont.	MO	Unk	04/11/16
Bruce-5/BrucePower	828	n	Ont.	MO	Unk	09/20/16
Darlington-3/OPG	876	n	Ont.	MO	Unk	09/09/16
Halton Hills/TransCanada	226	g	Ont.	MO	Unk	09/20/16
Lake Superior/Brookfield	120	g	Ont.	PMO	Unk	11/04/14
Lennox-3/OPG	525	g	Ont.	MO	Unk	09/14/16
Lennox-4/OPG	525	g	Ont.	MO	Unk	08/29/16
Littlelong/OPG	137	h	Ont.	MO	Unk	08/16/16
NP Kirkland1-5/Algonquin	117	g	Ont.	MO	Unk	09/01/16
Pickering-7/OPG	520	n	Ont.	MO	Unk	09/02/16
Thunder Bay/Resolute	116	bio	Ont.	MO	Unk	09/19/16
Thunderbay-3/OPG	153	bio	Ont.	MO	Unk	09/15/16
PJM & MISO						
Davis-Besse/FirstEnergy	1003	n	Ohio	MO	Unk	09/10/16
North Anna-1/Dominion	903	n	Va.	MO	Unk	09/11/16
Oyster Creek/AmerGen	637	n	N.J.	MO	Unk	09/18/16
Southeast & Central						
Catawba-2/Duke	1180	n	S.C.	MO	Unk	09/10/16
Grand Gulf/Entergy	1443	n	Miss.	MO	Unk	09/08/16
Watts Bar-2/TVA	1164	n	Tenn.	MO	Unk	08/31/16
Wolf Creek/Wolf Creek	1184	n	Kan.	MO	Unk	09/02/16
West						
AV Solar Ranch-1/Exelon	242	s	Calif.	PMO	Unk	09/20/16
Encina-4/NRG	300	g	Calif.	MO	Unk	09/20/16
Encina-5/NRG	330	g	Calif.	MO	Unk	09/20/16
Henrietta Solar/SunPower	100	s	Calif.	MO	Unk	09/08/16
LaRosita-1/Intergen	180	g	Mex.	PMO	Unk	05/30/16
Mesquite Solar-3/Sempra	152	s	Ariz.	MO	Unk	09/08/16
Palo Verde-3/APS	1146	n	Ariz.	MO	Unk	09/20/16
Pio Pico-1/Apex	103	g	Calif.	PMO	Unk	08/18/16
Pio Pico-2/Apex	103	g	Calif.	MO	Unk	08/05/16
Pio Pico-3/Apex	103	g	Calif.	PMO	Unk	07/22/16
Sutter/Calpine	525	g	Calif.	MO	Unk	06/06/16

Daily generation outage references: MO=unplanned maintenance outage; RF=refueling outage; PMO=planned maintenance outage; Unk=unknown; OA=offline/available. Fuels: Nuclear=n; Coal=c; Natural gas=g; Hydro=h ; Wind=w; Solar=s

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

The grid operator also rejected Dominion's claims that its fuel reimbursement problem stems from PJM's tariff, which does not allow market participants to update their offers in real-time. Even after FERC approves PJM's proposed real-time offer revisions, Dominion will still have to have an oil cost schedule in the system if it wants to recover its oil costs, PJM explained.

PJM objected to granting a waiver in this type of case, noting it could give sellers without accurate cost schedules an "out," and allow sellers to have a risk-free ability to offer units on a lower cost fuel in order to clear the markets, but then later request payment based on a higher cost fuel. "As a result, the commission should move carefully should it seek to impose a sweeping directive coming out of this proceeding."

— *Kate Winston*

Solar QF rate suspension violates PURPA: groups

The suspension of a standard power purchase rate for small solar projects by Montana utility regulators lacks any legal basis, violates a 1978 law and will have a chilling effect on solar development in the state, two clean energy advocacy groups told FERC Monday.

Vote Solar, a nonprofit grassroots organization, and Montana Environmental Information Center, a nonprofit environmental advocacy group, are calling out the Montana Public Service Commission for acquiescing to a plea by the state's largest utility that effectively exempts it from its obligation to buy power from qualifying facilities. The groups argue that the June 16 decision by the PSC and subsequent July 25 order backing that decision violate the Public Utility Regulatory Policies Act.

The 1978 law requires utilities to purchase power from small renewable power plants and other qualifying facilities at the full avoided cost of replacing that power with other generation.

Vote Solar and MEIC contend that the Montana PSC applied an unlawful standard, impermissibly freeing NorthWestern Energy of its legally enforceable obligations.

"Far from advancing PURPA's mandate, the Montana Commission's decision pulls the rug out from small solar energy producers with advanced projects in Montana and stalls future solar development in the state," Vote Solar and MEIC said in their complaint (EL16-117). "Not only does the Montana Commission's decision violate PURPA by effectively eliminating market access for small solar energy producers with a nameplate capacity between 100 kW and 3 MW, but it also exceeds the Montana Commission's authority to suspend PURPA's application in certain extraordinary situations, none of which are present here."

PSC granted emergency motion in split decision

NorthWestern on May 3 filed an application with the PSC to significantly lower the standard rates it pays to QFs of 3 MW or less. The utility argued that existing rates approved by the PSC were higher than its current estimated avoided costs and sought a 35% drop in the 24-year levelized avoided cost used to set the rates for 3 MW and smaller QFs.

The utility then filed a motion on May 17 for an emergency suspension of the standard rate for new solar QFs between 100 kV and 3 MW until the PSC acts on its rate application, asserting that its ratepayers would otherwise be subjected to unnecessarily high costs as the utility faced "the immediate execution" of a high volume of power purchase agreements for solar QFs that would create long-term obligations at the current standard rates.

A split PSC granted the motion in a 3-2 decision, carving out a narrow exemption for solar QFs between 100 kV and 3 MW that had sent a signed PPA to NorthWestern and executed an interconnection agreement prior to the June 16 decision.

Vote Solar and MEIC argue that this decision and the order that followed violated PURPA and applied "an overly restrictive legally enforceable obligation standard that nullifies significant investments by small solar developers, thus bringing solar development in Montana to a standstill."

The rate suspension means that small solar producers would have to engage in "good faith negotiation" to obtain long-term contracts with NorthWestern. But PSC Commissioner Travis Kavulla, who voted against the emergency motion, said in his dissent that such negotiations would be pointless as it would be foolish for NorthWestern to negotiate a contract rate above what is proposed in its rate application, the groups noted.

Rate challenges should not nullify current rates

The emergency suspension of the standard rate, the groups said, effectively allows NorthWestern to set the standard rate until its rate application is ruled on, violating PURPA and putting solar developers in an untenable position.

Vote Solar and MEIC said the proper response to an allegedly outdated avoided-cost estimate would be to go through the formal process of requesting a rate change with the PSC, during which time the current rate previously deemed just and reasonable by the PSC would remain in effect.

None of the three circumstances that lawfully permit a utility to be relieved of its PURPA obligations to purchase power from QFs are present in this situation, the groups contended.

The groups also argued that the PSC imposed "an illegally high bar to creating a legally enforceable obligation" through the exemption granted to solar QFs with signed PPAs and executed interconnection agreements.

"The Montana Commission's application of its overly restrictive legally enforceable obligation standard violates PURPA by extinguishing legally enforceable obligations to which QFs are entitled and discouraging future solar development in Montana," Vote Solar and MEIC said.

Under PURPA, FERC has the authority to enforce the statute's requirements on state commissions when requested by generators, and can even take state commissions to federal district court to enforce those requirements. But enforcement actions are rare as the commission generally relies on voluntary compliance or has let the parties themselves engage in the litigation, even when a violation of PURPA was found.

Groups seek FERC action to invalidate rate suspension

Vote Solar and MEIC urged immediate action by FERC in this case to enforce PURPA and invalidate the PSC's suspension of the standard rate for small solar QFs, saying that such "blatant violations of PURPA [would] have devastating consequences for clean energy in Montana."

In addition to invalidating the rate suspension, the groups asked FERC to reinstate the standard rate, which was last approved by the PSC in 2015; rule that the PSC's legally enforceable obligation standard violated PURPA; and entitle the legally enforceable obligations present at the time of the suspension to the pre-existing standard rate.

FERC, in a notice issued Tuesday, opened the petition for enforcement to public comment through October 11. Per typical procedure, FERC will review the petition and any comments or protests filed, and issue a notice of intent either to act or not to act within 60 days of the petition being filed.

A notice of intent not to act would clear the way for Vote Solar and MEIC to initiate litigation if they so choose, while a notice of intent to act means that at some point FERC would go to court to enforce PURPA.

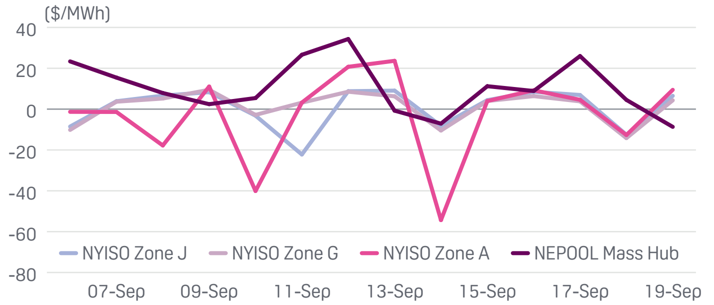
— *Jasmin Melvin*

NORTHEAST POWER MARKETS

NORTHEAST DAY AHEAD POWER PRICES ($/MWh)

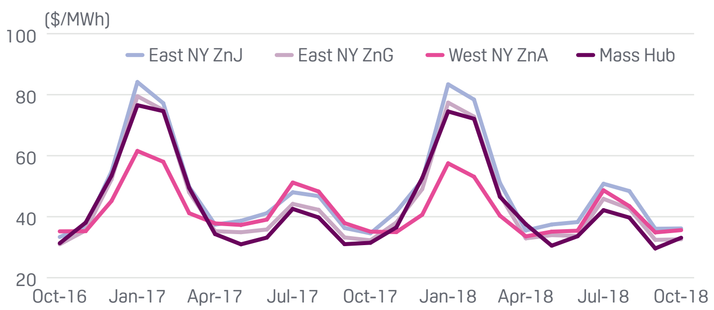
Hub/Index	Symbol	21-Sep	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Sep-16	Yearly change Sep-15	Yearly change Chg	Yearly change % Chg
On-Peak														
ISONE Internal Hub	IINIM00	41.59	12781	18.81	2.54	-13.77	-24.9	36.52	17.19	63.50	35.12	36.08	-0.96	-2.7
ISONE NE Mass-Boston	IINNM00	49.38	15174	26.60	10.33	-6.10	-11.0	45.45	17.34	85.61	47.21	39.89	7.32	18.4
ISONE Connecticut	IINCM00	48.80	15337	26.53	10.62	-8.56	-14.9	38.60	17.26	62.93	36.17	36.08	0.09	0.2
NYISO Zone G	INYHM00	40.43	16318	23.09	10.70	1.43	3.7	31.08	19.94	52.00	32.84	36.96	-4.12	-11.1
NYISO NYC Zone	INYNM00	40.88	16498	23.53	11.15	1.44	3.7	33.06	20.15	55.57	34.28	38.59	-4.31	-11.2
NYISO West Zone	INYWM00	43.88	24315	31.25	22.22	5.65	14.8	30.03	18.04	52.71	33.41	31.44	1.97	6.3
NYISO Capital Zone	INYCM00	40.58	16175	23.02	10.47	2.58	6.8	29.93	19.53	45.83	31.18	31.07	0.11	0.4
Off-Peak														
ISONE Internal Hub	IINIP00	20.70	6732	-0.82	-16.20	-7.24	-25.9	21.02	10.13	30.53	20.45	20.31	0.14	0.7
ISONE NE Mass-Boston	IINNP00	20.71	6734	-0.82	-16.20	-7.27	-26.0	21.08	10.17	33.10	21.10	20.84	0.26	1.2
ISONE Connecticut	IINCP00	20.80	6863	-0.42	-15.57	-7.11	-25.5	21.22	10.12	30.54	20.49	20.18	0.31	1.5
NYISO Zone G	INYHP00	23.40	9946	6.93	-4.83	2.40	11.4	17.97	12.39	27.67	19.15	19.55	-0.40	-2.0
NYISO NYC Zone	INYNP00	24.21	10293	7.75	-4.02	2.98	14.0	18.65	12.52	28.25	19.65	20.19	-0.54	-2.7
NYISO West Zone	INYWP00	21.69	12635	9.67	1.09	2.25	11.6	16.45	10.01	22.46	16.72	16.82	-0.10	-0.6
NYISO Capital Zone	INYCP00	23.04	9440	5.96	-6.25	2.78	13.7	17.69	12.30	27.92	18.85	18.21	0.64	3.5

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



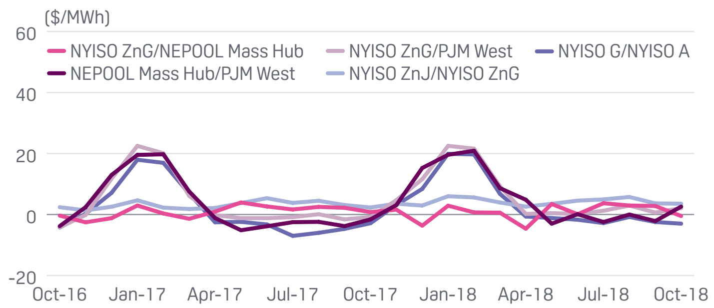
Source: Platts

NORTHEAST PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

NORTHEAST PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Northeast prices mixed amid higher gas demand

Northeast spot power prices were mixed as natural gas-fired power demand is expected to decline modestly from Tuesday's high levels.

Gas-fired power demand in the Northeast jumped sharply from the weekend, rising to an average of 7.6 Bcf/d on Tuesday from Saturday's level of 6 Bcf/d, according to flow data from Platts Analytics' Bentek Energy. Demand on Wednesday is expected to be slightly below Tuesday's average.

Mass Hub on-peak fell $11.50 to the mid-$40s/MWh for Wednesday delivery on IntercontinentalExchange.

Algonquin Gas Transmission city-gate rose 25.5 cents to around $3.450/MMBtu for Wednesday delivery on ICE.

On-peak balance-of-the-week traded at a weighted average price of $38/MWh for 100 MW on ICE, as more seasonable temperatures were expected by Friday.

ISO New England predicted peakload of 19.20 GW Tuesday and 18.10 GW Wednesday.

New York ISO locational marginal prices were up from Tuesday as high temperatures are expected to remain in the 80s across New York City, Albany and Rochester, 10-13 degrees above the norm. High temperatures are expected to drop to the mid-60s to high 70s by Friday.

NYISO West Zone A on-peak rose $5.75 to $44/MWh for Wednesday delivery. New York City Zone J on-peak was up $1.50 to $41/MWh, while Hudson Valley Zone G on-peak rose $1.50 to $40.50/MWh.

NYISO Zone G on-peak bal-week was bid at $35/MWh and offered at $38.75/MWh on ICE. Zone A on-peak bal-week traded at a WAP of $40/MWh for 50 MW.

In the Mid-Atlantic region, PJM West Hub on-peak day-ahead was down $2.50 to the high $40s/MWh for Wednesday delivery.

On-peak balance-of-the-week traded at a WAP of $46.63/MWh for 300 MW on ICE.

The Mid-Atlantic region of the PJM Interconnection forecast peakload around 41.33 GW Tuesday and 41.99 GW Wednesday.

In the forward power markets, Mass Hub mini on-peak October rose 75 cents to about $31.75/MWh on ICE.

NYISO Zone G on-peak November was bid at $35.35/MWh and offered at $36.25/MWh on ICE.

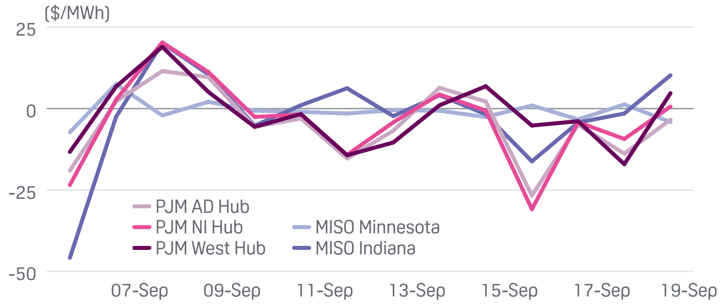
PJM West Hub mini on-peak October was up 50 cents to around $35/MWh.

PJM/MISO POWER MARKETS

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

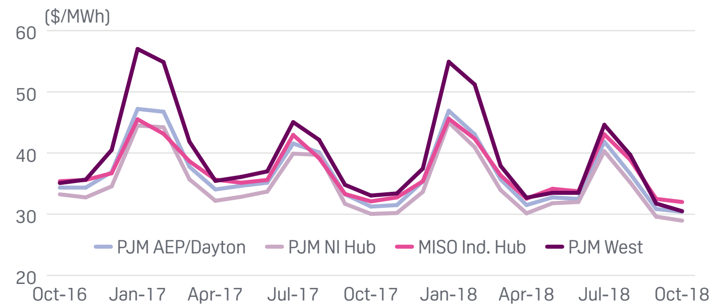
Hub/Index	Symbol	21-Sep	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly Change Sep-16	Yearly Change Sep-15	Yearly Change Chg	Yearly Change % Chg
On-Peak														
PJM AEP Dayton Hub	IPADM00	42.52	17585	25.59	13.50	-8.86	-17.2	37.65	21.38	51.38	34.86	33.59	1.27	3.8
PJM Dominion Hub	IPDMM00	42.19	13796	20.78	5.49	-10.36	-19.7	40.97	22.90	53.10	37.57	35.76	1.81	5.1
PJM Eastern Hub	IPEHM00	39.06	23582	27.47	19.18	-12.59	-24.4	37.87	15.56	59.61	35.82	38.54	-2.72	-7.1
PJM Northern Illinois Hub	IPNIM00	45.54	14818	24.03	8.66	-6.04	-11.7	37.29	21.45	51.58	35.16	32.43	2.73	8.4
PJM Western Hub	IPWHM00	44.60	25269	32.24	23.42	-9.53	-17.6	39.87	21.64	60.14	37.40	35.52	1.88	5.3
MISO Indiana Hub	IMIDM00	50.69	24240	36.05	25.60	1.64	3.3	39.43	25.10	56.04	38.19	32.09	6.10	19.0
MISO Minnesota Hub	IMINM00	28.45	9732	7.99	-6.63	-2.50	-8.1	24.88	16.69	33.65	24.43	27.67	-3.24	-11.7
Off-Peak														
PJM AEP Dayton Hub	IPADP00	21.05	9028	4.73	-6.93	-1.93	-8.4	20.81	9.01	22.98	18.95	19.47	-0.52	-2.7
PJM Dominion Hub	IPDMP00	23.53	7896	2.67	-12.23	-1.01	-4.1	22.68	9.98	24.54	20.31	20.49	-0.18	-0.9
PJM Eastern Hub	IPEHP00	21.60	13924	10.74	2.98	-4.54	-17.4	22.33	5.50	26.14	17.95	18.89	-0.94	-5.0
PJM Northern Illinois Hub	IPNIP00	21.73	7269	0.80	-14.14	-0.76	-3.4	20.34	8.33	22.49	18.40	19.17	-0.77	-4.0
PJM Western Hub	IPWHP00	22.41	13382	10.69	2.31	-1.61	-6.7	21.26	8.99	24.02	19.35	19.71	-0.36	-1.8
MISO Indiana Hub	IMIDP00	21.96	10850	7.79	-2.33	-0.75	-3.3	21.70	10.83	24.11	19.98	19.72	0.26	1.3
MISO Minnesota Hub	IMINP00	15.81	5559	-4.10	-18.32	-2.05	-11.5	15.47	6.66	18.95	13.73	15.38	-1.65	-10.7

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



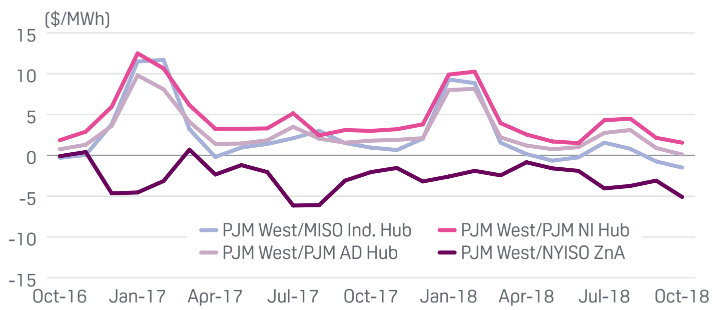
Source: Platts

PJM/MISO PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

PJM/MISO PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

Central spot prices mixed on varied temperatures

Central spot power prices were mixed Tuesday on mixed weather forecasts across the region.

Indiana Hub on-peak was down $2.50 to the high $40s/MWh for Wednesday delivery on IntercontinentalExchange. On-peak balance-of-the-week traded at a weighted average price of $49.63/MWh for 200 MW on ICE.

On-peak next week was bid at $32/MWh and offered at $36.75/MWh.

The Midcontinent Independent System Operator projected peakload of 103.49 GW Tuesday and 104.25 GW Wednesday.

Highs in Indianapolis are expected to reach 84 degrees Wednesday, 1 degree above Tuesday, and 10 degrees above the norm. High temperatures in St. Louis are expected to reach 87 degrees, flat with Tuesday and 10 degrees above the norm.

MISO peakload averaged 94,459 MW September 12-16, down about 10.5% from the previous week.

Southwest Power Pool predicted peak demand around 43.88 GW 5 pm CDT Tuesday and 43.10 GW 5 pm Wednesday. Wind generation in the SPP footprint is projected at 5.39 GW during Tuesday's peakload and at 6.48 MW during Wednesday's peakload.

Peakload averaged 36.79 GW September 12-16, down 11.7% from the previous week, according to data from Platts Analytics' Bentek Energy.

AD Hub on-peak was down $2.75 to the high $40s/MWh for Wednesday delivery on ICE. On-peak balance-of-the-week was bid at $42/MWh and offered at $47.25/MWh, while on-peak next-week was bid at $29.25/MWh and offered at $34.45/MWh.

NI Hub on-peak rose $2.25 to the low $50s/MWh for Wednesday delivery.

PJM Western region predicted peak load at 64.42 GW 5 pm Tuesday and 66.52 GW 5 pm Wednesday.

In the forward power markets, nearby prices were framed higher. NYMEX October gas futures settled 11.3 cents up to $3.047/MMBtu.

Indiana Hub on-peak October was bid at $35/MWh and offered at $35.60/MWh, while on-peak November was bid at $34.90/MWh and offered at $36/MWh.

AD Hub on-peak October was bid at $34.15/MWh and offered at $34.50/MWh. On-peak November was bid at $34.20/MWh and offered at $34.85/MWh.

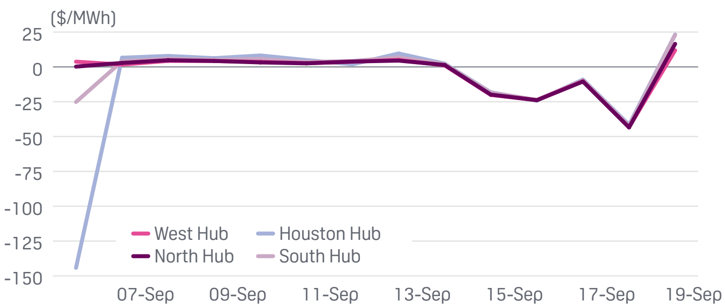
NI Hub on-peak October was bid at $33/MWh and offered at $33.40/MWh.

SOUTHEAST POWER MARKETS

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

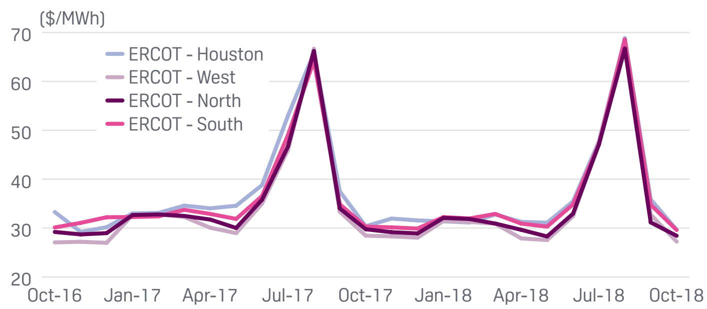
Hub/Index	Symbol	21-Sep	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Sep-16	Yearly change Sep-15	Yearly change Chg	Yearly change % Chg
On-Peak														
MISO Texas Hub	IMTXM00	42.54	13931	21.16	5.90	-0.53	-1.2	37.58	27.72	43.07	34.16	30.69	3.47	11.3
MISO Louisiana	IMLAM00	43.07	14180	21.81	6.62	-4.33	-9.1	40.27	28.10	47.40	36.55	31.14	5.41	17.4
SPP North Hub	ISNOM00	19.64	6532	-1.41	-16.44	-5.46	-21.8	24.42	13.72	29.17	21.93	22.28	-0.35	-1.6
SPP South Hub	ISSOM00	50.45	17632	30.42	16.11	7.43	17.3	37.33	24.61	50.45	34.27	29.26	5.01	17.1
ERCOT Houston Hub	IERHM00	38.78	12675	17.36	2.07	-10.02	-20.5	42.22	27.40	68.72	35.19	28.00	7.19	25.7
ERCOT North Hub	IERNM00	35.93	12001	14.97	0.00	-7.02	-16.3	39.80	24.53	65.00	32.02	27.93	4.09	14.6
ERCOT South Hub	IERSM00	37.26	12211	15.90	0.64	-5.72	-13.3	40.62	26.08	66.53	33.43	28.16	5.27	18.7
ERCOT West Hub	IERWM00	36.47	12538	16.11	1.56	-6.50	-15.1	40.01	23.80	65.41	32.07	27.94	4.13	14.8
Off-Peak														
MISO Texas Hub	IMTXP00	23.25	7740	2.22	-12.80	-0.87	-3.6	22.66	18.43	24.12	22.03	21.10	0.93	4.4
MISO Louisiana	IMLAP00	23.17	7803	2.38	-12.46	-0.85	-3.5	22.68	15.86	24.02	21.55	20.82	0.73	3.5
SPP North Hub	ISNOP00	6.79	2322	-13.68	-28.30	-4.14	-37.9	12.52	0.40	15.89	10.57	12.39	-1.82	-14.7
SPP South Hub	ISSOP00	22.95	8276	3.54	-10.33	1.68	7.9	22.10	15.06	25.65	20.55	19.24	1.31	6.8
ERCOT Houston Hub	IERHP00	19.34	6436	-1.69	-16.72	0.04	0.2	19.73	16.84	20.25	18.73	17.92	0.81	4.5
ERCOT North Hub	IERNP00	18.45	6295	-2.07	-16.72	0.08	0.4	19.42	15.77	20.24	18.22	17.89	0.33	1.8
ERCOT South Hub	IERSP00	19.17	6419	-1.74	-16.67	0.03	0.2	19.65	16.54	20.25	18.49	17.97	0.52	2.9
ERCOT West Hub	IERWP00	18.54	6539	-1.31	-15.48	0.07	0.4	19.46	15.85	20.24	18.24	17.89	0.35	2.0

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



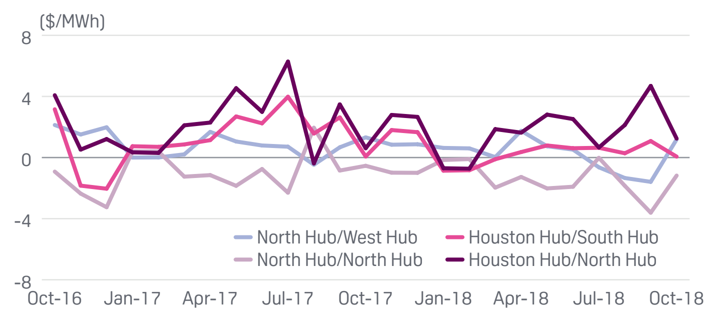
Source: Platts

ERCOT PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

ERCOT PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

ERCOT dailies drop on lower demand forecast

Electric Reliability Council of Texas daily power prices halved Tuesday with demand forecast falling.

ERCOT North Hub day-ahead on-peak plummeted $34.50 to the mid-$30s/MWh for Wednesday delivery on IntercontinentalExchange. Off-peak was down 50 cents near $18.75/MWh. Balance-of-the-week on-peak eased $5 to almost $32/MWh as on-peak next-week remained in the upper $20s/MWh.

North Hub bal-day on-peak was around $40/MWh, dropping about $31 from where the Tuesday package traded Monday.

ERCOT forecast peakload dropping from around 66,225 MW Tuesday to about 64,300 MW Wednesday, down nearly 3% day on day.

Wind generation was forecast to reach 7,350 MW at midnight Wednesday, after dropping as low as 2,600 MW around 11 am.

Texas high temperatures were forecast around 94-96 Wednesday, as much as 7 degrees above normal. Parts of Texas expected a heat index as high as 109.

In the Southeast, power dailies fell Tuesday despite higher spot gas prices and above normal temperatures forecast.

In the Southeast, Into Southern day-ahead on-peak was down $2.50 to the mid-$30s/MWh for Wednesday delivery. Into GTC day-ahead on-peak was down $2 to the mid-$30s/MWh.

The high temperature in Atlanta was forecast near 87 Wednesday, 5 degrees above normal.

In the Southeast, demand in Southern Company's footprint was about 31,700 MW around 1 pm EDT Tuesday, compared with the forecast of 34,600 MW for that hour, according to the US Energy Information Administration's Electric System Operating Data. The service territory exported as much as 2,075 MW Monday, 150 MW less than the previous day.

ERCOT North Hub term prices were stronger Tuesday morning as NYMEX October natural gas futures added 11.3 cents to around $3.047/MMBtu.

On ICE, ERCOT North Hub October on-peak futures rose 50 cents to nearly $28.75/MWh around 2:30 pm EDT as on-peak heat rates were bid at 9.45 MMBtu/MWh and offered at 9.55 MMBtu/MWh.

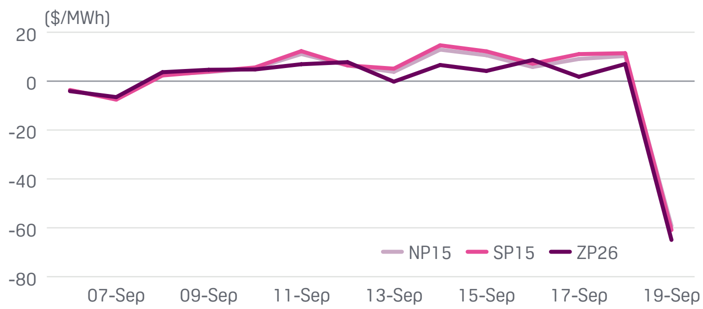
In the Midcontinent Independent System Operator South Region, Arkansas Hub on-peak October moved up less than 25 cents to nearly $30/MWh.

WEST POWER MARKETS

WESTERN DAY-AHEAD POWER PRICES ($/MWh)

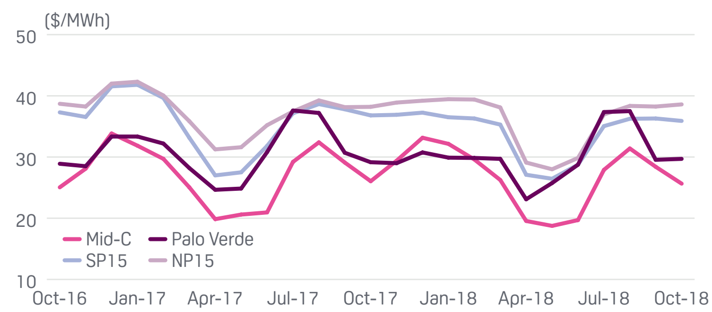
Hub/Index	Symbol	21-Sep	Marginal heat rate	Spark spread @7K	Spark spread @12K	Price change Chg	Price change % Chg	Prior 7-day Average	Month Min	Month Max	Yearly change Sep-16	Yearly change Sep-15	Yearly change Chg	Yearly change % Chg
On-Peak														
NP15	ICNGM00	39.42	11223	14.83	-2.73	-2.11	-5.1	37.53	30.34	41.74	35.81	37.29	-1.48	-4.0
SP15	ICSGM00	38.37	13049	17.79	3.08	-1.77	-4.4	35.03	22.87	40.14	33.08	37.50	-4.42	-11.8
ZP26	ICZGM00	37.88	12885	17.30	2.60	-2.52	-6.2	34.41	23.78	40.40	32.75	36.54	-3.79	-10.4
COB	WEABE20	33.25	11348	12.74	-1.91	1.25	3.9	29.86	27.75	33.41	30.44	30.90	-0.46	-1.5
MEAD	AAMBW20	29.00	9864	8.42	-6.28	0.00	0.0	27.61	25.50	31.50	27.69	31.33	-3.64	-11.6
MID-C	WEABF20	29.51	10391	9.63	-4.57	0.61	2.1	28.19	24.53	29.64	27.92	27.00	0.92	3.4
Palo Verde	WEACC20	27.14	9326	6.77	-7.78	0.39	1.5	26.10	23.03	29.23	26.12	29.80	-3.68	-12.3
Off-Peak														
NP15	ICNGP00	30.72	8926	6.63	-10.58	1.47	5.0	29.80	27.64	32.02	30.05	29.01	1.04	3.6
SP15	ICSGP00	29.84	10214	9.39	-5.22	1.47	5.2	28.77	26.79	31.07	29.08	29.24	-0.16	-0.5
ZP26	ICZGP00	29.82	10207	9.37	-5.24	1.45	5.1	28.72	26.62	30.95	29.04	28.86	0.18	0.6
COB	WEACJ20	24.00	8191	3.49	-11.16	0.00	0.0	24.43	22.00	28.25	24.81	23.33	1.48	6.3
MEAD	AAMBQ20	23.25	7908	2.67	-12.03	0.00	0.0	24.18	21.50	25.75	23.32	24.67	-1.35	-5.5
MID-C	WEACL20	23.78	8373	3.90	-10.30	0.58	2.5	23.54	20.62	27.11	23.59	23.09	0.50	2.2
Palo Verde	WEACT20	22.00	7560	1.63	-12.92	0.00	0.0	22.96	20.36	24.50	22.07	23.25	-1.18	-5.1

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



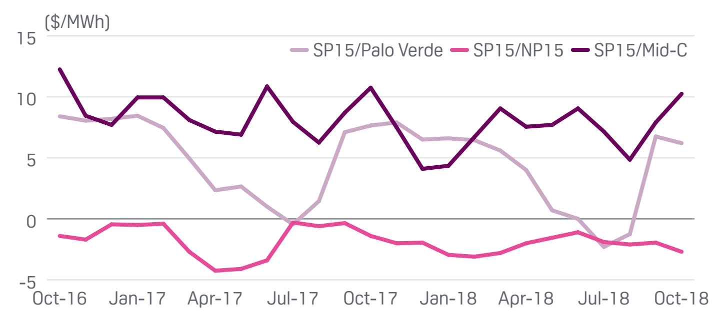
Source: Platts

WESTERN PLATTS M2MS FORWARD CURVE: ON-PEAK



Source: Platts

WESTERN PLATTS M2MS LOCATIONAL SPREADS: ON-PEAK



Source: Platts

West spot dailies mostly rise with gas cash prices

West spot power prices were mostly stronger Tuesday. California prices edged up as regional spot gas prices firmed, while Southwest prices ticked higher as a nuclear generating unit in the region tripped, taking 1,346 MW off the grid.

SP15 day-ahead on-peak gained 25 cents to the upper $30s/MWh on IntercontinentalExchange for Wednesday delivery. Off-peak dropped 50 cents to the upper $20s/MWh. Balance-of-the-month traded near mid-$30s/MWh.

Spot gas prices at Pacific Gas and Electric city-gate and Southern California Gas city-gates improved for Wednesday delivery 9.5 cents to near $3.510/MMBtu and 1.2 cents to about $3.047/MMBtu, respectively.

California Independent System Operator projected peak demand decreases from 38,250 MW Tuesday to 35,075 MW Wednesday.

Mid-Columbia day-ahead on-peak added 50 cents to the upper $20s/MWh. Off-peak increased 50 cents to the lower $20s/MWh.

Wind speeds are forecast to remain low from Tuesday to Wednesday, which could keep wind generation weak. BPA wind generation was 36 MW around 11:00 am PDT Tuesday. Wind generation share in the BPA footprint was 16.9% for Monday, according to Platts Megawatt Daily Market Fundamentals Data.

Palo Verde day-ahead on-peak rose 25 cents to around upper $20s/MWh. Off-peak was unchanged at the lower $20s/MWh.

Arizona Public Service's 1,346 MW Palo Verde 3 nuclear reactor tripped Monday afternoon and is operating at zero Tuesday.

West forward power prices were stronger Tuesday as NYMEX October gas futures jumped 11.3 cents to $3.047/MMBtu.

SP15 October on-peak climbed 75 cents to about $37.25/MWh on ICE by 2:30 pm EDT. The prompt month had the highest volume of trading activity. SP15 traded as far along the curve as Q1 2017.

Palo Verde October on-peak rose 50 cents to about $28.75/MWh. Trading activity extended out as far along the curve as June 2017 packages.

Mid-Columbia October on-peak added 50 cents to about $25/MWh. The prompt month had the highest volume of trading activity while Q3 2017 packages were the limit on the curve for trading activity.

BILATERALS

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

Hub/Index	Symbol	21-Sep	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 Sep-16	Yearly change Sep-15	Yearly change Chg	Yearly change % Chg
On-Peak														
Florida	AAMAV20	37.75	11152	14.05	-2.87	1.00	2.7	36.75	32.00	43.25	37.86	35.37	2.49	7.0
GTC, Into	WAMCJ20	35.00	11419	13.54	-1.78	1.25	3.7	33.39	29.00	37.50	33.91	31.24	2.67	8.5
Southern, Into	AAMBJ20	34.50	11256	13.04	-2.28	1.50	4.5	32.54	28.50	37.00	32.66	30.07	2.59	8.6
TVA, Into	WEBAB20	38.25	12250	16.39	0.78	0.75	2.0	34.25	28.75	41.25	35.23	30.57	4.66	15.2
VACAR	AAMCI20	37.50	11924	15.49	-0.24	0.75	2.0	34.46	28.25	38.25	34.64	32.12	2.52	7.8
Off-Peak														
Florida	AAMAO20	24.00	7090	0.30	-16.62	0.00	0.0	25.82	19.50	27.25	22.55	23.09	-0.54	-2.3
GTC, Into	WAMCC20	20.25	6607	-1.20	-16.53	0.00	0.0	22.07	17.00	23.50	19.58	19.88	-0.30	-1.5
Southern, Into	AAMBC20	18.00	5873	-3.45	-18.78	0.00	0.0	20.04	15.75	21.25	17.73	19.11	-1.38	-7.2
TVA, Into	AAJER20	19.50	6245	-2.36	-17.97	0.00	0.0	20.21	15.50	21.00	18.25	18.98	-0.73	-3.8
VACAR	AAMCB20	21.25	6757	-0.76	-16.49	1.50	7.6	20.32	14.50	21.25	18.06	18.76	-0.70	-3.7

WESTERN DAY-AHEAD BILATERAL INDEXES ($/MWh)

Hub/Index	Symbol	21-Sep	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 Sep-16	Yearly change Sep-15	Yearly change Chg	Yearly change % Chg
On-Peak														
Mid-C	WEABF20	29.51	10391	9.63	-4.57	0.61	2.1	28.19	24.53	29.64	27.92	27.00	0.92	3.4
John Day	WEAHF20	30.50	10739	10.62	-3.58	0.50	1.7	29.25	25.50	30.75	28.97	28.00	0.97	3.5
COB	WEABE20	33.25	11348	12.74	-1.91	1.25	3.9	29.86	27.75	33.41	30.44	30.90	-0.46	-1.5
NOB	WEAIF20	31.50	11092	11.62	-2.58	0.00	0.0	29.93	26.75	32.00	29.76	29.26	0.50	1.7
Palo Verde	WEACC20	27.14	9326	6.77	-7.78	0.39	1.5	26.10	23.03	29.23	26.12	29.80	-3.68	-12.3
Mona	AARLQ20	29.50	10461	9.76	-4.34	-0.25	-0.8	27.43	24.00	30.75	27.26	29.77	-2.51	-8.4
Four Corners	WEABI20	29.00	10069	8.84	-5.56	1.00	3.6	26.96	24.75	30.00	26.97	29.42	-2.45	-8.3
Pinnacle Peak	WEAKF20	27.75	9536	7.38	-7.17	0.50	1.8	26.54	22.75	29.50	26.41	30.16	-3.75	-12.4
Westwing	WEAJF20	27.00	9278	6.63	-7.92	-0.25	-0.9	26.29	24.50	29.75	26.50	30.28	-3.78	-12.5
MEAD	AAMBW20	29.00	9864	8.42	-6.28	0.00	0.0	27.61	25.50	31.50	27.69	31.33	-3.64	-11.6
Off-Peak														
Mid-C	WEACL20	23.78	8373	3.90	-10.30	0.58	2.5	23.54	20.62	27.11	23.59	23.09	0.50	2.2
John Day	WEAHL20	24.75	8715	4.87	-9.33	0.50	2.1	24.46	21.50	28.00	24.54	24.07	0.47	2.0
COB	WEACJ20	24.00	8191	3.49	-11.16	0.00	0.0	24.43	22.00	28.25	24.81	23.33	1.48	6.3
NOB	WEAIL20	24.75	8715	4.87	-9.33	0.00	0.0	24.11	22.50	28.00	24.70	24.37	0.33	1.4
Palo Verde	WEACT20	22.00	7560	1.63	-12.92	0.00	0.0	22.96	20.36	24.50	22.07	23.25	-1.18	-5.1
Mona	AARLO20	21.25	7535	1.51	-12.59	-0.25	-1.2	21.14	19.00	22.00	20.55	22.65	-2.10	-9.3
Four Corners	WEACR20	22.50	7813	2.34	-12.06	0.00	0.0	23.07	20.00	24.75	22.24	21.99	0.25	1.1
Pinnacle Peak	WEAKL20	22.25	7646	1.88	-12.67	0.00	0.0	22.96	20.25	24.75	21.94	23.38	-1.44	-6.2
Westwing	WEAJL20	22.75	7818	2.38	-12.17	0.50	2.2	23.21	20.50	24.75	22.32	23.39	-1.07	-4.6
MEAD	AAMBQ20	23.25	7908	2.67	-12.03	0.00	0.0	24.18	21.50	25.75	23.32	24.67	-1.35	-5.5

SOUTHEAST NEAR-TERM BILATERAL MARKETS ($/MWh)

Package	Trade date	Range
GTC, into		
Bal-week	09/20	33.75-34.25
Bal-week	09/19	34.25-34.75

WESTERN NEAR-TERM BILATERAL MARKETS ($/MWh)

Package	Trade date	Range
Mid-C		
Bal-month	09/20	27.50-28.50
Bal-month	09/19	26.25-27.75
Bal-month	09/14	27.50-28.50
Bal-month (off-peak)	09/19	23.00-24.00
Bal-month (off-peak)	09/15	24.00-25.00
Bal-month (off-peak)	09/14	24.25-25.25

BILATERALS

PLATTS M2MS FORWARD CURVE, SEP 20 ($/MWh)

Prompt month: Oct 16

	On-peak	Off-peak
Northeast		
Mass Hub	31.30	21.30
N.Y. Zone G	30.95	20.90
N.Y. Zone J	33.35	21.45
N.Y. Zone A	35.20	18.00
Ontario*	15.15	7.95
PJM & MISO		
PJM West	35.10	24.00
AD Hub	34.35	23.70
NI Hub	33.25	21.00
Indiana Hub	35.40	24.20

*Ontario prices are in Canadian dollars

	On-peak	Off-peak
Southeast & Central		
Southern Into	33.05	24.05
ERCOT North	29.20	21.90
ERCOT Houston	33.30	22.90
ERCOT West	27.05	20.30
ERCOT South	30.10	21.95
Western		
Mid-C	25.05	22.70
Palo Verde	28.90	24.05
Mead	31.15	25.55
NP15	38.70	31.80
SP15	37.30	31.00

ISO DAY-AHEAD LMP BREAKDOWN FOR SEP 21 ($/MWh)

Hub/Zone	Average	Cong	Loss	Change	Avg $/Mo	Marginal heat rate
Northeast						
On-peak						
ISONE Internal Hub	41.59	-3.57	0.12	-13.77	35.12	12781
ISONE Connecticut	48.80	3.50	0.27	-8.56	36.17	15337
ISONE NE Mass-Boston	49.38	4.13	0.21	-6.10	47.21	15174
NYISO Capital Zone	40.58	-2.09	2.54	2.58	31.18	16175
NYISO Hudson Valley Zone	40.43	-0.78	3.70	1.43	32.84	16318
NYISO N.Y.C. Zone	40.88	-0.76	4.17	1.44	34.28	16498
NYISO West Zone	43.88	-7.02	0.91	5.65	33.41	24315
Off-Peak						
ISONE Internal Hub	20.70	0.00	-0.03	-7.24	20.45	6732
ISONE Connecticut	20.80	0.00	0.07	-7.11	20.49	6863
ISONE NE Mass-Boston	20.71	0.00	-0.02	-7.27	21.10	6734
NYISO Capital Zone	23.04	-0.58	1.44	2.78	18.85	9440
NYISO Hudson Valley Zone	23.40	-0.22	2.16	2.40	19.15	9946
NYISO N.Y.C. Zone	24.21	-0.72	2.47	2.98	19.65	10293
NYISO West Zone	21.69	0.00	0.66	2.25	16.72	12635
PJM & MISO						
On-peak						
PJM AEP-Dayton Hub	42.52	1.35	-0.68	-8.86	34.86	17585
PJM Dominion Hub	42.19	0.90	-0.56	-10.36	37.57	13796
PJM Eastern Hub	39.06	-3.90	1.11	-12.59	35.82	23582
PJM Northern Illinois Hub	45.54	5.76	-2.08	-6.04	35.16	14818
PJM Western Hub	44.60	2.29	0.45	-9.53	37.40	25269
MISO Indiana Hub	50.69	7.27	1.00	1.64	38.19	24240
MISO Minnesota Hub	28.45	-10.21	-3.77	-2.50	24.43	9732
MISO Louisiana Hub	43.07	0.02	0.62	-4.33	36.55	14180
MISO Texas Hub	42.54	0.50	-0.39	-0.53	34.16	13931
Off-Peak						
PJM AEP-Dayton Hub	21.05	0.68	0.00	-1.93	18.95	9028
PJM Dominion Hub	23.53	3.05	0.11	-1.01	20.31	7896
PJM Eastern Hub	21.60	1.24	-0.01	-4.54	17.95	13924
PJM Northern Illinois Hub	21.73	1.77	-0.41	-0.76	18.40	7269
PJM Western Hub	22.41	1.98	0.06	-1.61	19.35	13382
MISO Indiana Hub	21.96	0.60	0.59	-0.75	19.98	10850
MISO Minnesota Hub	15.81	-2.78	-2.18	-2.05	13.73	5559
MISO Louisiana Hub	23.17	1.65	0.75	-0.85	21.55	7803
MISO Texas Hub	23.25	1.85	0.63	-0.87	22.03	7740
Southeast & Central						
On-peak						
SPP North Hub	19.64	-19.71	-0.85	-5.46	21.93	6532
SPP South Hub	50.45	10.18	0.07	7.43	34.27	17632
ERCOT Houston Hub	38.78	–	–	-10.02	35.19	12675
ERCOT North Hub	35.93	–	–	-7.02	32.02	12001
ERCOT South Hub	37.26	–	–	-5.72	33.43	12211
ERCOT West Hub	36.47	–	–	-6.50	32.07	12538
Off-Peak						
SPP North Hub	6.79	-8.82	-0.41	-4.14	10.57	2322
SPP South Hub	22.95	6.99	-0.05	1.68	20.55	8276
ERCOT Houston Hub	19.34	–	–	0.04	18.73	6436
ERCOT North Hub	18.45	–	–	0.08	18.22	6295
ERCOT South Hub	19.17	–	–	0.03	18.49	6419
ERCOT West Hub	18.54	–	–	0.07	18.24	6539
Western						
On-peak						
CAISO NP15 Gen Hub	39.42	-0.06	-0.53	-2.11	35.81	11223
CAISO SP15 Gen Hub	38.37	-0.04	-1.61	-1.77	33.08	13049
CAISO ZP26 Gen Hub	37.88	-0.05	-2.09	-2.52	32.75	12885
Off-Peak						
CAISO NP15 Gen Hub	30.72	-0.01	-0.27	1.47	30.05	8926
CAISO SP15 Gen Hub	29.84	0.00	-1.16	1.47	29.08	10214
CAISO ZP26 Gen Hub	29.82	0.00	-1.18	1.45	29.04	10207

WEEKEND BILATERAL INDEXES FOR SEP 17-18 ($/MWh)

	Saturday Index	Sunday Index
Southeast On-peak		
VACAR	33.50	33.50
Southern, into	34.25	34.25
GTC, into	34.75	34.75
Florida	37.50	37.50
TVA, into	33.25	33.25
Southeast Off-Peak*		
VACAR	20.75	20.75
Southern, into	21.25	21.25
GTC, into	23.50	23.50
Florida	27.25	27.25
TVA, into	20.75	20.75
West On-peak**		
Mid-C	26.42	24.19
John Day	27.50	25.25
COB	27.83	26.75
NOB	28.00	27.00
Palo Verde	25.25	26.75
Westwing	25.50	27.25
Pinnacle Peak	25.50	27.00
Mead	26.50	29.00
Mona	25.75	28.25
Four Corners	25.50	27.50
West Off-Peak**		
Mid-C	23.70	17.50
John Day	24.75	18.25
COB	23.75	20.25
NOB	23.25	19.50
Palo Verde	22.50	22.25
Westwing	22.75	22.25
Pinnacle Peak	22.00	22.50
Mead	23.50	22.50
Mona	20.00	15.75
Four Corners	22.50	22.00

*Southeast off-peak prices are for a Saturday-Monday package.
**West Saturday prices are for a Friday-Saturday package and Sunday prices are for Sunday only.

WEEKLY BILATERAL INDEXES FOR WEEK ENDING SEP 17 ($/MWh)

	Index	Change	Low	High
Southeast On-peak				
VACAR	33.35	-3.28	31.00	36.00
Southern, into	31.55	-2.08	30.00	34.00
GTC, into	32.50	-3.63	30.00	35.50
Florida	36.05	-5.83	34.25	37.50
TVA, into	32.60	-6.15	30.50	34.50
Southeast Off-Peak				
VACAR	18.29	1.90	16.50	21.00
Southern, into	17.93	1.50	16.25	20.75
GTC, into	---	---	---	---
Florida	23.29	3.11	21.50	26.00
TVA, into	18.57	1.61	17.25	21.00
West On-peak				
Mid-C	27.90	-0.38	25.50	30.50
John Day	28.96	-0.39	27.50	30.75
COB	29.08	-2.81	27.00	31.00
NOB	29.13	-1.32	28.00	30.75
Palo Verde	25.29	-0.19	24.00	26.50
Westwing	25.42	-0.68	24.75	26.25
Pinnacle Peak	25.71	0.21	25.00	26.50
Mead	26.42	-0.73	25.50	28.00
Mona	26.25	-0.10	25.50	28.75
Four Corners	26.29	0.14	25.00	27.50
West Off-Peak				
Mid-C	25.53	1.90	23.00	27.25
John Day	26.50	1.89	24.75	27.50
COB	26.07	0.86	23.75	27.75
NOB	25.54	0.43	23.25	27.25
Palo Verde	22.27	0.52	21.50	23.25
Westwing	22.71	0.89	22.25	23.00
Pinnacle Peak	22.18	0.93	22.00	22.75
Mead	23.54	0.61	23.25	24.00
Mona	20.21	0.25	19.50	21.50
Four Corners	22.79	1.36	22.00	24.00

NORTHEAST POWER MARKETS

NYISO SUPPLY MIX (GWh/d)

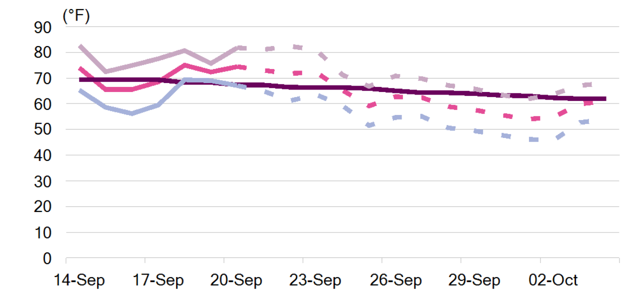
							Daily change		Season		Season average			
Category	**15-Sep**	**16-Sep**	**17-Sep**	**18-Sep**	**19-Sep**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2016**	**2015**	**Chg**	**% Chg**
Total Generation	380.24	370.69	348.24	377.59	378.41	85%	0.82	0.0%	328.06	526.39	404.37	379.9	24.47	6.0%
Gas	162.8	142.57	140.37	166.24	183.51	41%	17.27	10.0%	135.33	255.76	185.98	152.98	33	22.0%
Coal	11.6	8.62	5.31	5.45	8.38	2%	2.93	54.0%	3.36	18.09	10.21	13.17	-2.96	-22.0%
Nuclear	124.93	124.93	125.14	124.93	124.93	28%	0	0.0%	124.93	132.34	129.87	128.24	1.63	1.0%
Other	137.72	147.21	131.13	149.23	128.3	29%	-20.93	-14.0%	82.33	199.75	147.19	124.29	22.9	18.0%

ISONE SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	**15-Sep**	**16-Sep**	**17-Sep**	**18-Sep**	**19-Sep**	**% Share**	**Chg**	**% Chg**	**Min**	**Max**	**2016**	**2015**	**Chg**	**% Chg**
Total Generation	283.69	274.24	259.25	296.13	328.24	86%	32.11	11.0%	257.97	386.59	308.36	282.34	26.02	9.0%
Gas	93.29	85.42	88.86	123.51	131.57	35%	8.06	7.0%	85.42	175.8	124.09	143.99	-19.9	-14.0%
Nuclear	81.72	81.72	84.93	97.64	97.8	26%	0.16	0.0%	79.06	97.8	86.68	71.4	15.28	21.0%
Coal	20.27	19.93	16.91	22.62	26.39	7%	3.77	17.0%	15.38	39.4	23.31	10.43	12.88	123.0%
Wind	2.78	1.63	7.56	8.95	1.59	--	-7.36	-82.0%	1.45	10.63	4.62	6.7	-2.08	-31.0%
Other	129.66	127.23	97.57	86.57	122.56	32%	35.99	42.0%	83.02	147.86	116.91	96.84	20.07	21.0%

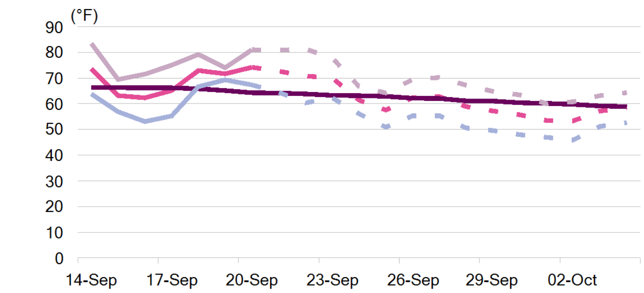
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

NYISO TEMPERATURE



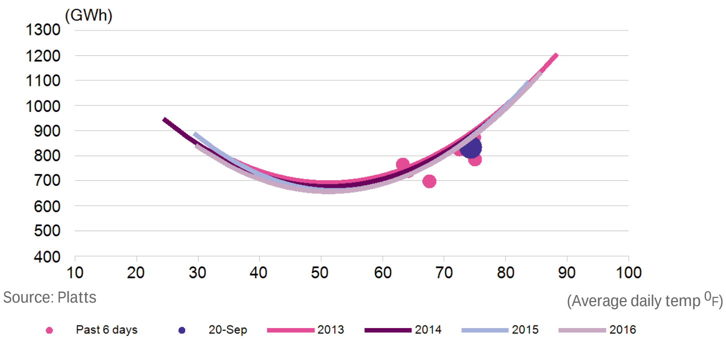
Source: Custom Weather

ISONE TEMPERATURE



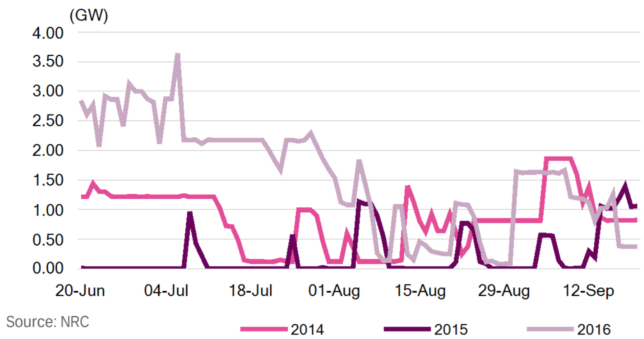
Source: Custom Weather

ISONE & NYISO LOAD PER DEGREE



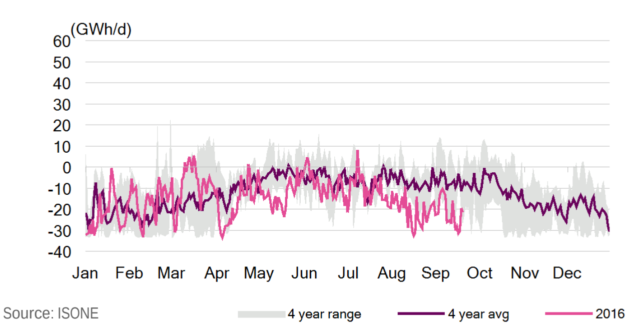
Source: Platts

ISONE & NYISO NUCLEAR GENERATION OUTAGES



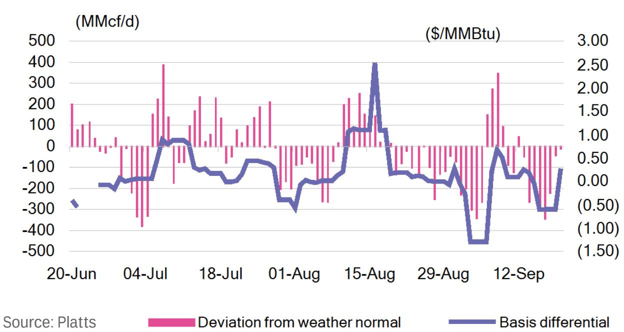
Source: NRC

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)

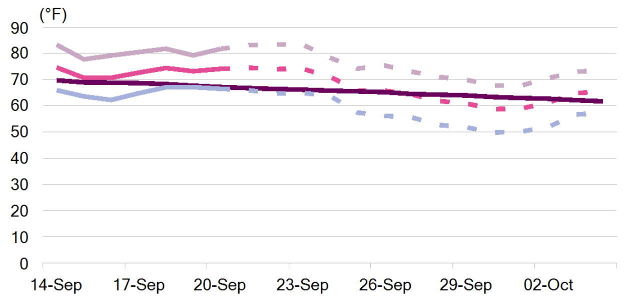
							Daily change		Season		Season average			
Category	15-Sep	16-Sep	17-Sep	18-Sep	19-Sep	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	2,173.24	2,145.08	2,065.29	2,131.36	2,211.47	101%	80.11	4.0%	2,013.9	2,806.89	2,331.24	1,974.42	356.82	18.0%
Gas	584.03	574.01	508.42	580	668.41	30%	88.41	15.0%	507.13	806.36	621.92	480.75	141.17	29.0%
Coal	719.37	713.08	746.32	725.73	671.79	31%	-53.94	-7.0%	671.79	1,053.64	821.11	665.73	155.38	23.0%
Nuclear	738.32	740.62	724.78	745.18	730.57	33%	-14.61	-2.0%	724.78	773.25	749.47	704.51	44.96	6.0%
Other	116.67	100.56	62.05	57.28	123.26	6%	65.98	115.0%	-86.39	185.71	70.75	116.48	-45.73	-39.0%

MISO SUPPLY MIX (GWh/d)

							Daily change		Season		Season average			
Category	15-Sep	16-Sep	17-Sep	18-Sep	19-Sep	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	2,003.26	1,982.83	1,883.94	1,855.7	1,985.96	103%	130.26	7.0%	1,763.98	2,307.97	1,989.48	1,804.57	184.91	10.0%
Gas	351.82	362.4	312.43	275.19	440.34	23%	165.15	60.0%	222.98	562.63	359.97	315.24	44.73	14.0%
Coal	971.27	927.34	902.69	839.58	936.66	48%	97.08	12.0%	783.04	1,102.81	931.96	881.07	50.89	6.0%
Nuclear	281.11	279.46	277.27	269.8	268.33	14%	-1.47	-1.0%	177.43	318.67	283.9	239.11	44.79	19.0%
Wind	100.43	90.34	68.79	156.45	98.28	5%	-58.17	-37.0%	51.05	177.56	109.41	129.22	-19.81	-15.0%
Other	267.8	281.59	252.6	241.14	189.72	10%	-51.42	-21.0%	189.72	371.65	259.15	188.36	70.79	38.0%

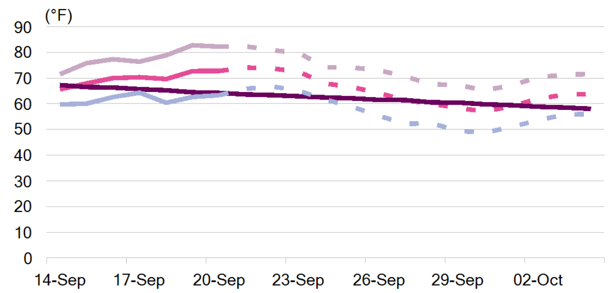
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

PJM TEMPERATURE



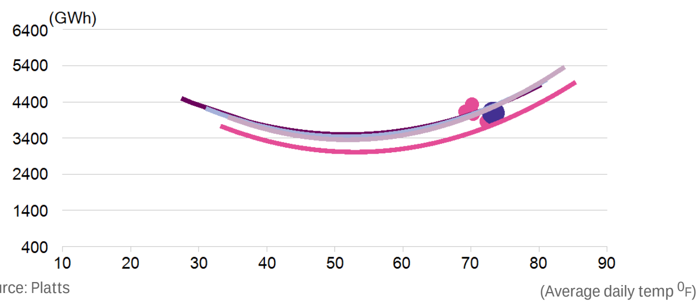
Source: Custom Weather
Average Normal High Low

MISO TEMPERATURE



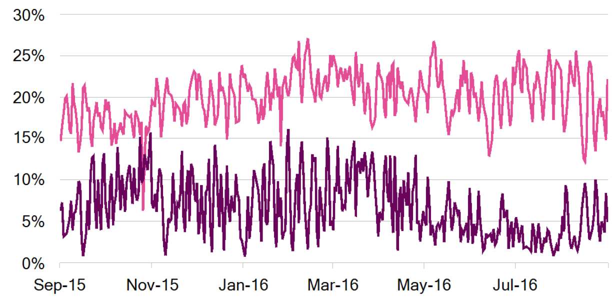
Source: Custom Weather
Average Normal High Low

PJM & MISO LOAD PER DEGREE



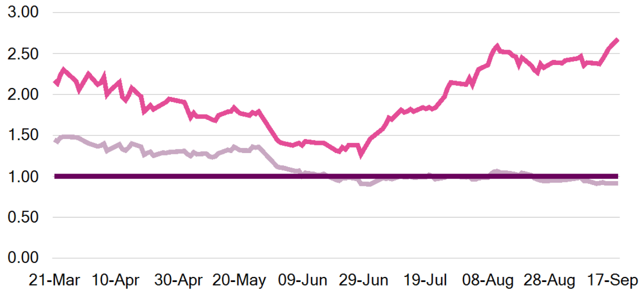
Source: Platts
(Average daily temp ^{0}F)
Past 6 days 20-Sep 2013 2014 2015 2016

MISO GENERATION MARKET SHARE - GAS VS. WIND



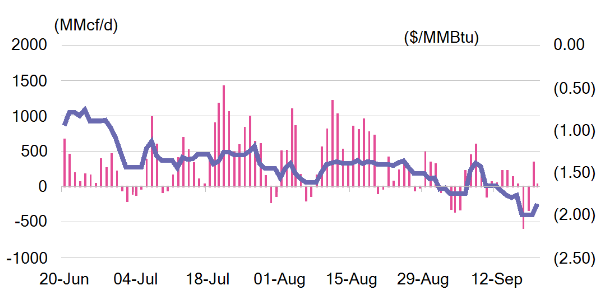
Source: Platts
Gas Wind

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



Source: Platts
PJM West MISO Indiana Threshold

PJM POWER BURN VS. GAS BASIS



Source: Platts
Deviation from weather normal Basis differential

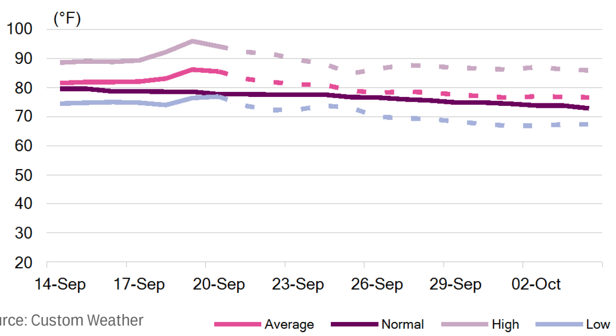
SOUTHEAST POWER MARKETS

ERCOT SUPPLY MIX (GWh/d)

Category	15-Sep	16-Sep	17-Sep	18-Sep	19-Sep	% 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	1,154.35	1,161.51	1,145.13	1,153.73	1,146.25	100%	-7.48	-1.0%	1,008.68	1,216.41	1,129.23	919.01	210.22	23.0%
Gas	550.47	536.57	559.36	565.48	610.07	53%	44.59	8.0%	431.52	610.07	514.83	388.03	126.8	33.0%
Coal	325.92	336.77	314.79	318.29	299.23	26%	-19.06	-6.0%	297.96	424.4	343.48	294.24	49.24	17.0%
Nuclear	123.33	123.33	123.33	123.33	123.33	11%	0	0.0%	123.33	123.33	123.33	94.12	29.21	31.0%
Wind	71.81	93.06	71.16	91.9	112.1	10%	20.2	22.0%	25.99	250.24	122.46	117.59	4.87	4.0%
Other	82.84	71.79	76.49	54.74	1.52	--	-53.22	-97.0%	-130.17	135.83	25.14	25.02	0.12	0.0%

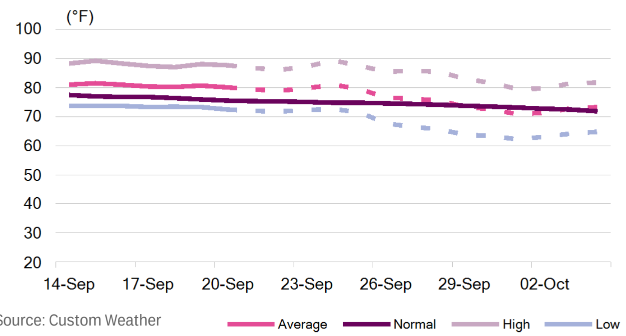
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: Platts

ERCOT TEMPERATURE



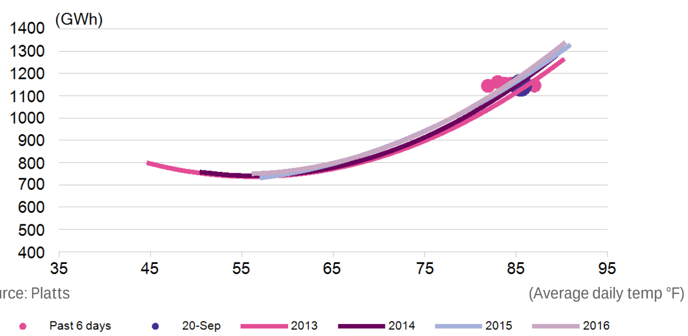
Source: Custom Weather

SOUTHEAST TEMPERATURE



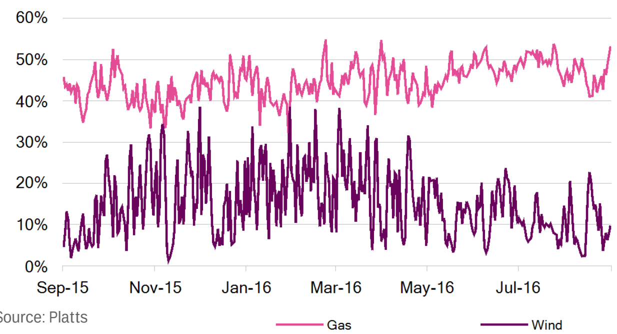
Source: Custom Weather

ERCOT LOAD PER DEGREE



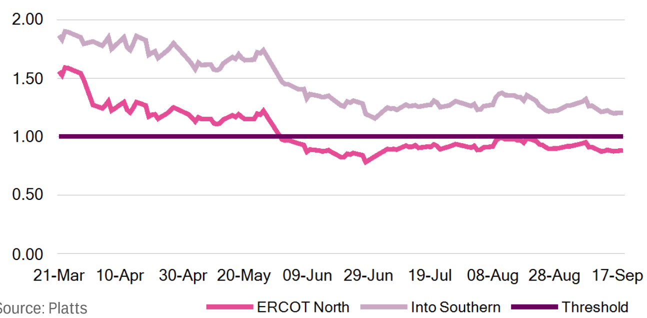
Source: Platts

ERCOT GENERATION MARKET SHARE - GAS VS. WIND



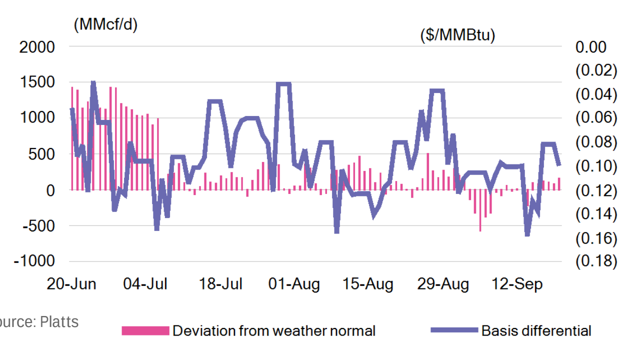
Source: Platts

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



Source: Platts

ERCOT POWER BURN VS. GAS BASIS



Source: Platts

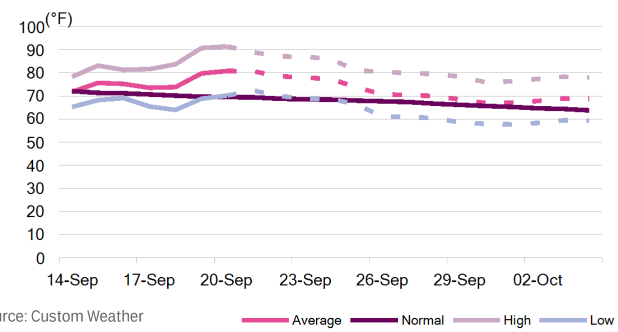
SPP POWER MARKETS

SPP GENERATION MIX (GWh/d)

Category	15-Sep	16-Sep	17-Sep	18-Sep	19-Sep	% 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	738.53	708.87	674.78	688.7	799	--	110.3	16.0%	60.71	848.9	705.7	646.88	58.82	9.0%
Coal	382	403.06	404.71	369.64	390.67	49%	21.03	6.0%	30.72	464.76	370.37	338.09	32.28	10.0%
Natural Gas	199.15	176.04	176.13	177.64	261.82	33%	84.18	47.0%	15.03	261.82	169.15	129.3	39.85	31.0%
Wind	97.54	68.58	34.65	84.28	85.5	11%	1.22	1.0%	11.17	182.87	105.46	101.59	3.87	4.0%
Nuclear Power	27.22	29.94	29.63	29.57	29.45	4%	-0.12	0.0%	2.45	59.29	30.67	61.26	-30.59	-50.0%
Hydro	30.66	29.33	27.03	25.65	27.42	3%	1.77	7.0%	1.18	32.35	28.04	16.51	11.53	70.0%
Diesel	1.96	1.92	2.64	1.92	4.14	1%	2.22	116.0%	0.16	4.14	2.02	0.13	1.89	1454.0%

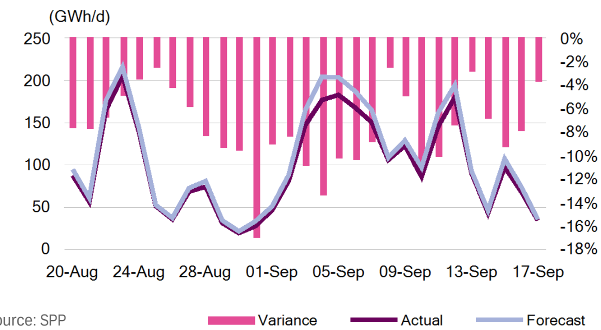
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: SPP

SPP TEMPERATURE



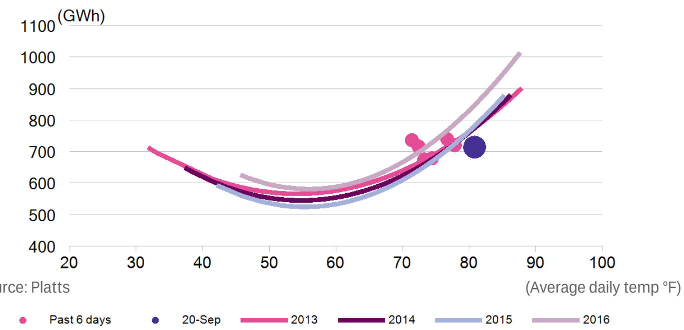
Source: Custom Weather

SPP ACTUAL WIND GENERATION VS. FORECAST



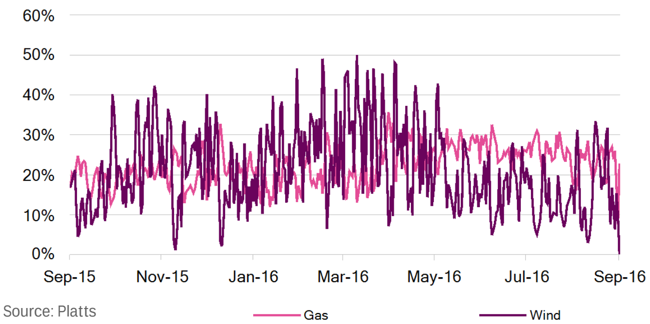
Source: SPP

SPP LOAD PER DEGREE



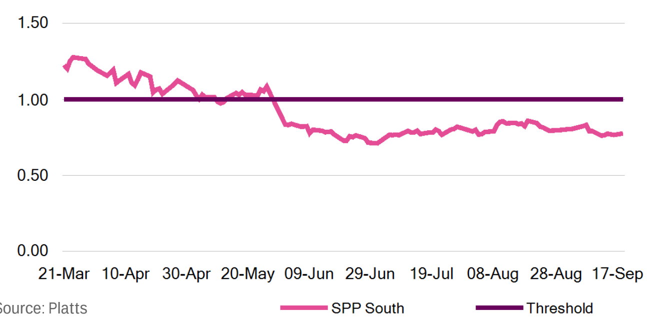
Source: Platts

SPP GENERATION MARKET SHARE - GAS VS. WIND



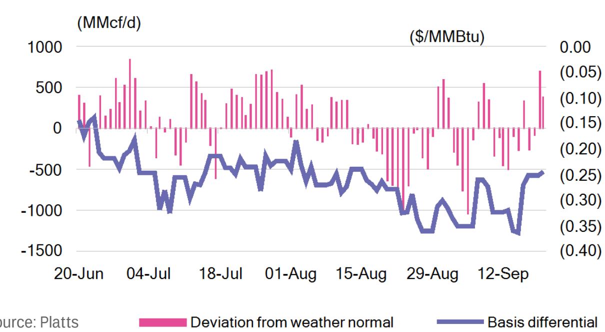
Source: Platts

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



Source: Platts

SPP POWER BURN VS. GAS BASIS



Source: Platts

WEST POWER MARKETS

CAISO GENERATION MIX (GWh/d)

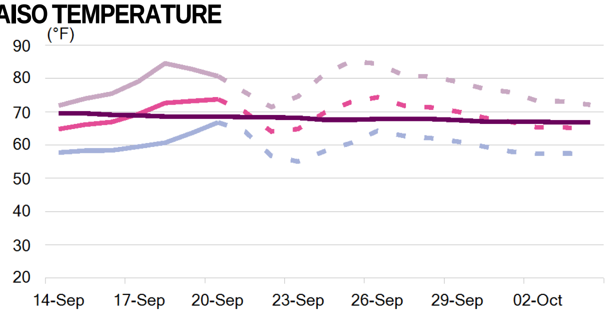
							Daily change		Season		Season average			
Category	15-Sep	16-Sep	17-Sep	18-Sep	19-Sep	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	645.87	657.92	642.33	667.8	745.67	--	77.87	12.0%	576.7	745.67	664.72	652.51	12.21	2.0%
Thermal Power	212.56	215.99	201.38	239.67	311.47	42%	71.8	30.0%	127.77	311.47	221.49	298.26	-76.77	-26.0%
Nuclear Power	54.29	54.23	54.28	54.22	54.14	7%	-0.08	0.0%	54.14	54.66	54.41	41.9	12.51	30.0%
Hydro	65.27	69.13	61.65	65.92	77.86	10%	11.94	18.0%	56.56	77.86	66.06	34.04	32.02	94.0%
Power Imports	175.96	185.97	200.43	196.43	204.94	27%	8.51	4.0%	155.12	210.85	179.49	176.43	3.06	2.0%
Solar PV	71.32	69.18	65.92	62.86	44.77	6%	-18.09	-29.0%	44.77	72.29	67.26	38.47	28.79	75.0%
Solar Thermal	5.72	6.64	5.76	5.34	3.87	1%	-1.47	-28.0%	3.87	6.92	5.96	3.18	2.78	87.0%
Wind	28.23	24.4	19.23	9.82	14.92	2%	5.1	52.0%	9.82	71.75	37.05	24.02	13.03	54.0%
Bio + Geo	32.52	32.39	33.68	33.53	33.69	5%	0.16	0.0%	32.23	33.69	33.01	36.2	-3.19	-9.0%

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

							Daily change		Season		Season average			
Category	15-Sep	16-Sep	17-Sep	18-Sep	19-Sep	% Share	Chg	% Chg	Min	Max	2016	2015	Chg	% Chg
Total Generation	253.59	271.89	286.51	259.35	272.96	--	13.61	5.0%	34.08	295.64	250.02	257.97	-7.95	-3.0%
Hydro	143.35	150.11	122.63	121.17	134.95	49%	13.78	11.0%	17.44	150.11	124.52	145.76	-21.24	-15.0%
Thermal Power	97.43	97.31	85.5	87.47	91.86	34%	4.39	5.0%	15.5	98.57	88.13	85.4	2.73	3.0%
Wind power	12.81	24.47	78.38	50.71	46.15	17%	-4.56	-9.0%	1.13	78.38	37.38	26.81	10.57	39.0%
Load	134.13	135.76	130.81	127.21	130.12	--	2.91	2.0%	18.97	136.94	125.81	140.51	-14.7	-10.0%
Net Exports	122.51	137.45	156.61	129.86	143.34	--	13.48	10.0%	15.12	161.97	124.52	117.58	6.94	6.0%

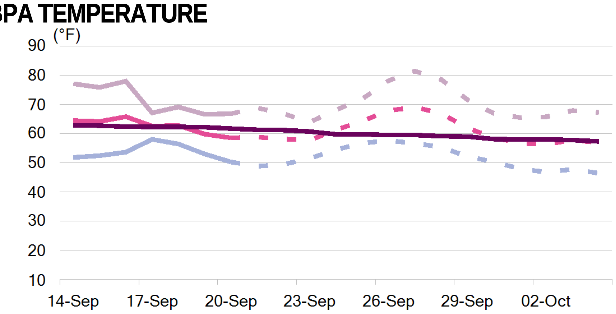
Seasons are defined as: Summer (June - August), Fall (September - November), Winter (December - February), and Spring (March - May). Source: CAISO & BPA

CAISO TEMPERATURE



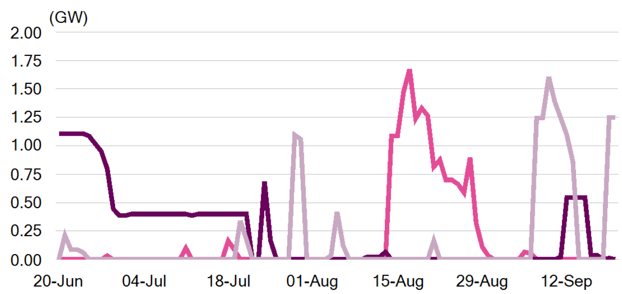
Source: Custom Weather — Average, Normal, High, Low

BPA TEMPERATURE



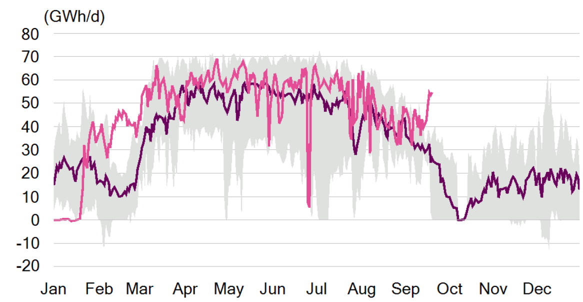
Source: Custom Weather — Average, Normal, High, Low

WESTERN NUCLEAR GENERATION OUTAGES



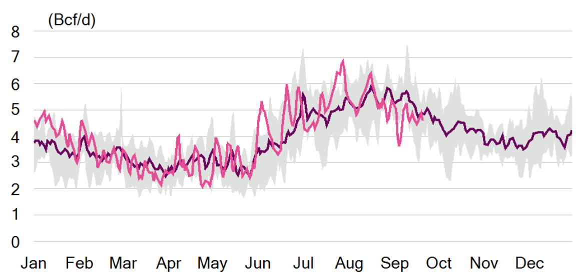
Source: NRC — 2014, 2015, 2016

BPA DC LINE TRANSMISSION FLOWS N-S



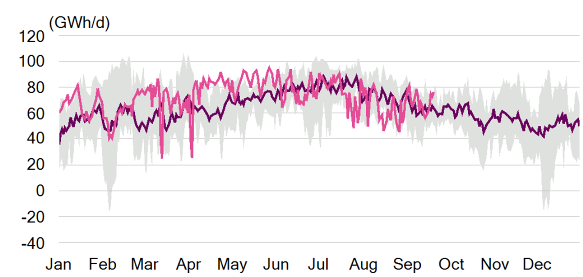
Source: BPA — 5 year range, 5 year avg, 2016

YEAR-TO-DATE WEST POWER BURN



Source: Platts — 5 year range, 5 year ave, 2016

BPA AC LINE TRANSMISSION FLOWS N-S



Source: BPA — 5 year range, 5 year avg, 2016

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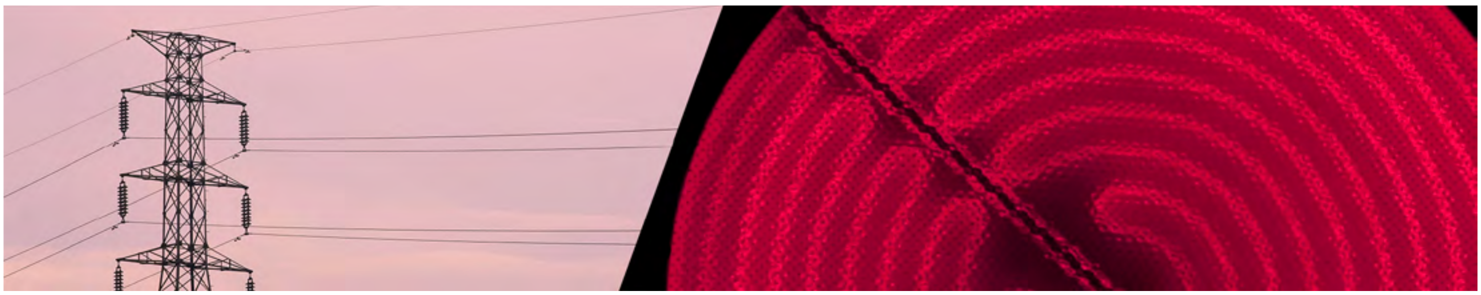

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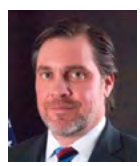

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Director, Office of Enforcement
Federal Energy Regulatory Commission

Patrick J. McCormick III
Committee on Energy and Natural Resources
US Senate

William W. Hogan
JFK School of Government
Harvard University

KEY NODAL TOPICS COVERED THIS YEAR INCLUDE:

- Whether new restrictions on virtuals would harm or help the efficiency of the market
- The role for which anti-trust laws can be used to bring liability for manipulation
- Individual market assessments including the newest participant—Mexico

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