Electricity Price Outlook for December 2018

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The Office of Technical and Regulatory Analysis presents the outlook for wholesale electricity prices each month. This assessment considers trends in electricity futures markets as ***well as forecasted weather, economic growth, and input fuel prices.***

Key Points in this Month's Outlook

- On June 1st, new, lower Standard Offer Service ("SOS") electric rates took effect: A 5.3 percent average decrease for residential customers and 4.3 percent average decrease for small commercial customers.

- Plentiful natural gas in the PJM region is keeping wholesale electricity prices stable.

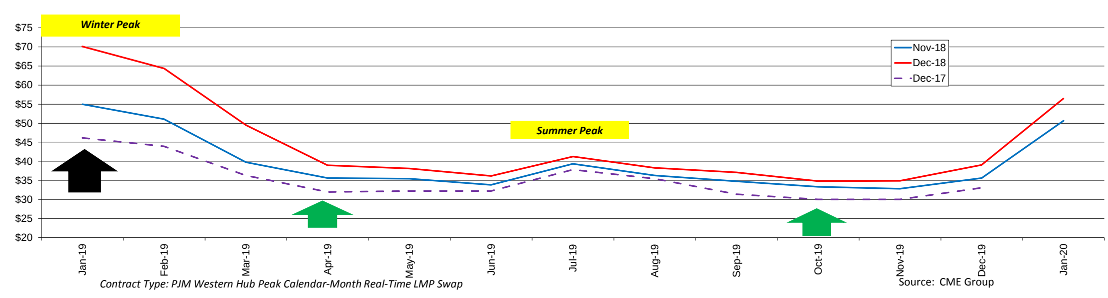
- Natural gas now exceeds coal as a generation fuel source in the PJM region.

Wholesale Electricity Futures Market

Contracts to deliver electricity in future months are traded for the multi-state region that is served by regional transmission operator PJM Interconnection and includes the District of Columbia. Figure 1 below shows the futures contract "price strips" through November 2019 as settled on November 23, 2018 (blue line), and on December 12, 2018 (red line).[1]

Because electricity cannot be easily stored, the effect of seasonal temperature changes on the price of future delivery contracts stands out sharply, with yearly peaks in the hot summer months and cold winter ones. Wholesale prices rise to incentivize high-cost generators to turn on their power plants to meet the high demand for electricity to run air conditioning on hot summer days and heating systems on cold winter days.

Figure 1: Wholesale Electricity Futures Prices ($/MWh)



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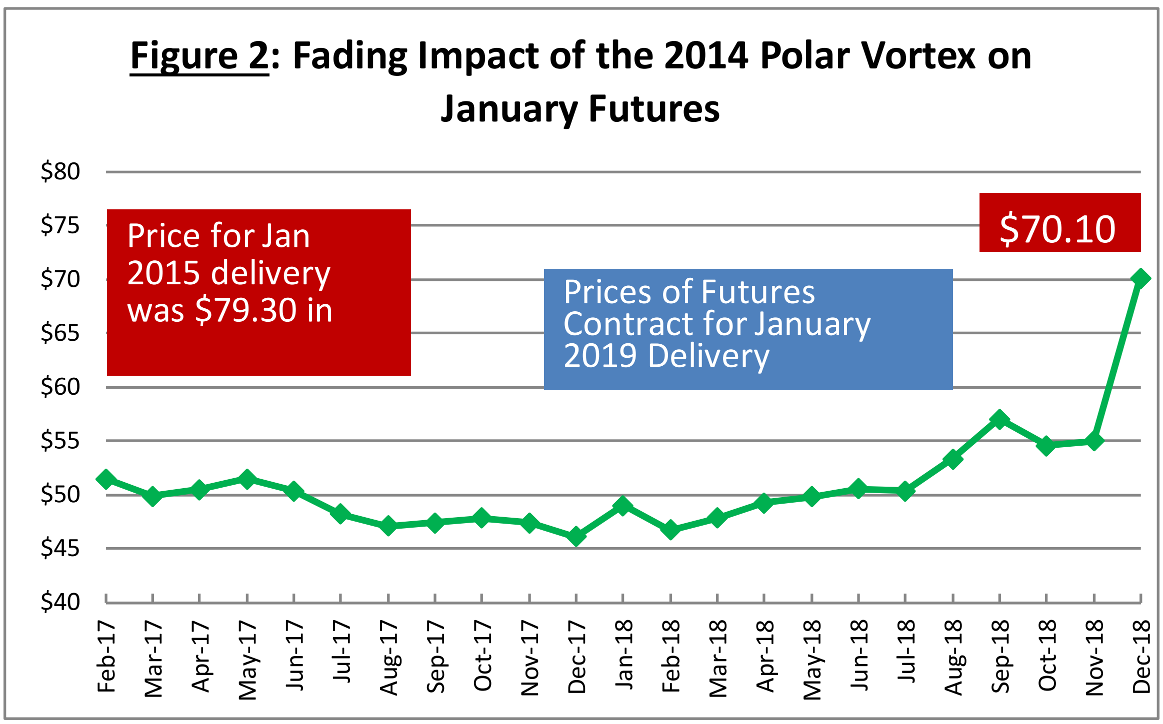
1 See PJM Western Hub Peak Calendar-Month Real-Time LMP Swap Futures; CME Group.

In Figure 1 above, the dashed purple line shows the trading values for the “price strip” from one year ago (December 10, 2017). Price expectations for all months are well above last year’s levels. However, near-term investor expectations of future electricity prices are higher than last month (red and blue lines). The futures price for January 2019 has increased by nearly 27.5 percent since last month (see black arrow). As can be seen in Figure 1, the trend of January (winter) prices exceeding July (summer) prices continues.

Price expectations during the “shoulder months” are above where they were a year ago. The green arrows (see Figure 1 above) point to the “shoulder months” of April 2019 and October 2019. During these months, temperatures are moderate and demand can be met from less expensive generation like nuclear and wind.

The green line in Figure 2 (below) illustrates how investors have responded to the unusually cold winter weather experienced during the “Polar Vortex” of January 2014 -- and the February 2015 cold snap -- as they form expectations about the price of electricity in coming winter months. In May 2014, the price of a MWh for delivery in January 2015 closed at $79.30. Investors’ fears about the risk of January generation outages seem to be moderating and have returned to pre-Polar Vortex levels.[2] However, the near-term weather outlook (see below) seems to driving the January contract price upwards. The most recent price for January 2019 delivery is $70.10 – a increase of 27.5 percent from the previous month. *This price jump may be related to the near certainty of El Niño conditions (see below) which can cause temperature volitility*.



Behind these price movements lie the extraordinary demands for electricity during January 2014 when eight of the 10 highest winter demands for electricity ever recorded in the

[2] The Federal Energy Regulatory Commission held a hearing about the January 2014 cold snap. The FERC Staff presentation can be found at this link: http://ferc.gov/legal/staff-reports/2014/04-01-14.pdf.

PJM region occurred. PJM set a new, all-time winter peak demand during the evening of January 7, 2014.[3] PJM reports that these January 2014 cold-weather events resulted in an unusually high level of "forced outages" of generators serving the PJM system; this created a "shortage effect" that drove wholesale prices temporarily higher.[4]

Progress made by PJM in managing extreme winter peak demand was demonstrated during the most recent January when usage achieved levels within the "PJM Top Ten Winter Peaks" (see figure below). PJM President Andy Ott told the U.S. Senate Committee on Energy and Natural Resources on January 23, 2018, that "Preliminary data (Figure 5) shows that overall forced outages during the peak demand hour of the recent cold snap were about half what they were during the Polar Vortex."[5]

Jan. 5 Cold Weather Update

Retail Residential Electricity Prices

The U.S. Energy Information Administration's (EIA) *Short-Term Energy Outlook (STEO)* reports that retail residential electricity prices are expected to remain flat in 2018 nationwide and a 3.2 percent increase is projected in 2019.[6] Factors other than generation costs are included in the prices reported by EIA, including the cost of continued investment in transmission and distribution infrastructure.

On March 7, 2018, the Public Service Commission of the District of Columbia approved the results of the annual competitive auction for new electric generation rates for default service, called Standard Offer Service or SOS, which went into effect on June 1, 2018. As a result of a competitive auction overseen by the Commission, on average, the rate for SOS (which consists of the generation and transmission price) for a residential SOS customer will decrease by about

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3 PJM's previous, all-time winter peak demand was 136,675 MW, on February 5, 2007. PJM GRID MEETS MONTH-LONG CHALLENGES OF COLD JANUARY; January 31, 2014; http://pjm.com/~/media/about-pjm/newsroom/2014-releases/20140131-pjm-grid-meets-month-long-challenges.ashx.

4 See PJM; "Generation Forced Outages for January 6-8, 2014"; http://www.pjm.com/~/media/documents/reports/20140109-january-2014-cold-weather-peaks-and-generator-outages.ashx.

5 http://www.pjm.com/-/media/library/reports-notices/special-reports/2018/20180123-testimony-andrew-ott-to-us-senate.ashx.

6 *December 2018 Short-Term Energy Outlook (STEO)*; Table 7c; http://205.254.135.24/forecasts/steo/.

$2.74 per month for the average user of 644 kWh (kilowatt hour) per month. The residential SOS customer's rate during the summer will decrease from 7.7 cents per kWh to 7.2 cents per kWh, while the winter rate will decrease from 8.2 cents per kWh to 7.9 cents per kWh. On average, the rate for small commercial SOS customers will decrease about $5.59 per month for the average user of 1,763 kWh per month. Overall, residential customers will be subject to an average SOS rate decrease of 5.3 percent, while small commercial SOS customers will be subject to an average rate decrease of 4.3 percent.[7]

The following sections provide a brief discussion of some of the factors affecting this month's outlook, including the three-month weather forecast, the overall economic outlook, and the prices of fuels used in power generation.

Weather Outlook

Sea-surface temperatures in the equatorial Pacific Ocean influence weather patterns across North America; these so-called *La Niña/El Niño* conditions are the primary factor in the three-month temperature outlook which, in turn, impacts investor expectations about future electricity prices.

The National Oceanic and Atmospheric Administration's December 13th *El Niño* watch indicates that *El Niño* is expected to form and continue through the Northern Hemisphere winter 2018-19 (~90% chance) and through spring (~60% chance).[8] NOAA notes that, with a potential *El Niño* condition, above-normal average temperatures are expected in the mid-Atlantic region through the December-January-February period.[9] The arrival of *El Niño* conditions means that greater-than-normal precipitation this winter is more likely. *El Niño* conditions are also associated with greater variability in both temperature and precipitation which implies increased chances of extreme weather events in our region.

Heating-degree days measure the demand for heating during the winter. EIA reports that heating degree days in our region are projected to be lower in 2019 than in 2018. Projected heating degree days for 2019 are one percent above the ten-year average.[10]

Cooling-degree days measure the demand for air conditioning during the summer. EIA projects cooling-degree days in the Census region that includes the District of Columbia will be four percent fewer in 2019 compared to the ten-year average. The projection for summer 2019 is eleven percent lower than 2018.[11] The long-term warming trend continues.[12]

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7 Formal Case No. 1017; Order No. 19290; March 7, 2018.

8 http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/enso_advisory/ensodisc.html. "ENSO" means *El Niño* Southern Oscillation; "ENSO-neutral" means that neither *El Niño* nor *La Niña* conditions are present.

9 http://www.cpc.ncep.noaa.gov/products/predictions/90day/fxus05.html.

10 *STEO*, Table 9c.

11 *STEO*; Table 9c.

12 NOAA National Climatic Data Center; Contiguous U.S. Temperature 1896 – 2018.

Economic Growth and Electricity Consumption

The outlook for economic activity in 2018 remains one of moderate growth. Real (inflation-adjusted) gross domestic product (GDP) is expected to increase and to continue bringing down the unemployment rate gradually. Real GDP grew by 2.2 percent in 2017 and and is projected to grow by 2.9 percent in 2018 and by 2.9 percent in 2019.[13] Economic growth is unlikely to affect electricity price trends unless it is sustained above three percent.

EIA forecasts that nationwide residential electricity sales (measured in kWh) will increase by six percent in 2018, followed by a three percent decrease in in 2019. Nationwide electricity sales for all sectors will increase by 2.3 percent in 2018 with a one percent decrease projected in 2019.[14]

Fuel Prices

In recent years, the cost of fuels for electricity generation has been restrained, with the exception of petroleum-based fuels where the market remains volatile in both directions. This moderate trend is driven by historically low natural gas prices and moderate economic growth. *The cost of natural gas for generation is projected to remain below the $4 level in 2018 and 2019.*[15]

Petroleum

OPEC and allied exporters have been unable to contain the drop in crude oil prices.[16] North Sea Brent crude averaged $65 per barrel in November, a decrease of $16 from the October average. Brent crude is forecast to average $61 per barrel in 2019 compared with an average of $71.40 per barrel in 2018.[17] EIA expects retail gasoline to average $2.73 in 2018 and and $2.50 in 2019.[18]

U.S. shale oil producers continue to raise their production, acting as a countervailing force to OPEC. EIA estimates that U.S. crude oil production averaged 11.5 million barrels per day (b/d) in November, an increase of 150,000 b/d from October. EIA reports that domestic crude oil production averaged 9.4 million b/d in 2017 and projects an average of 10.9 million b/d in 2018 – up from 8.9 million b/d in 2016 and surpassing the 1970 record of 9.6 million b/d. EIA forecasts that 2019 crude oil production will average 12.1 million b/d.[19] The latest Monthly *Drilling Productivity Report* from the EIA shows oil and natural gas output increasing in the U.S. shale-producing basins surveyed (see Figure 3 below).[20]

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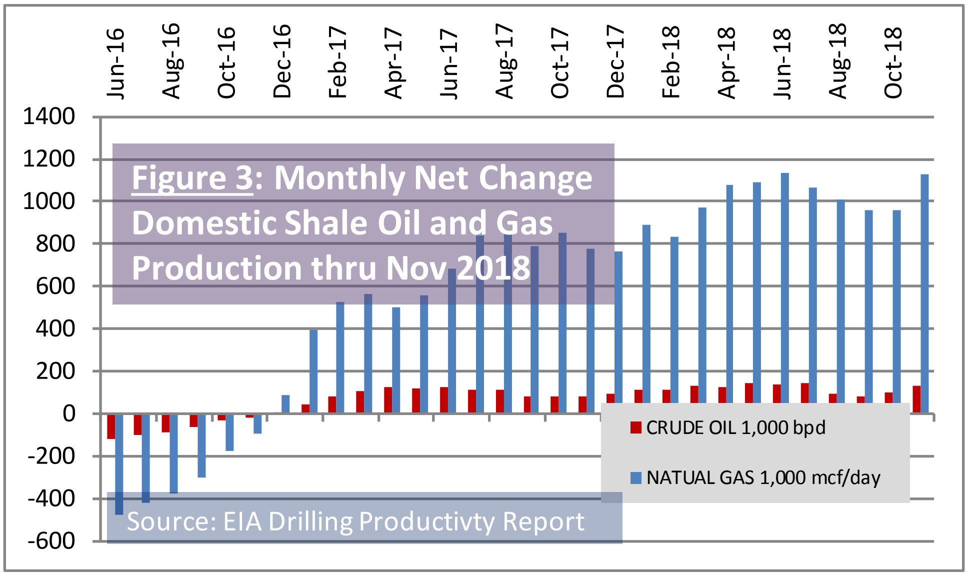
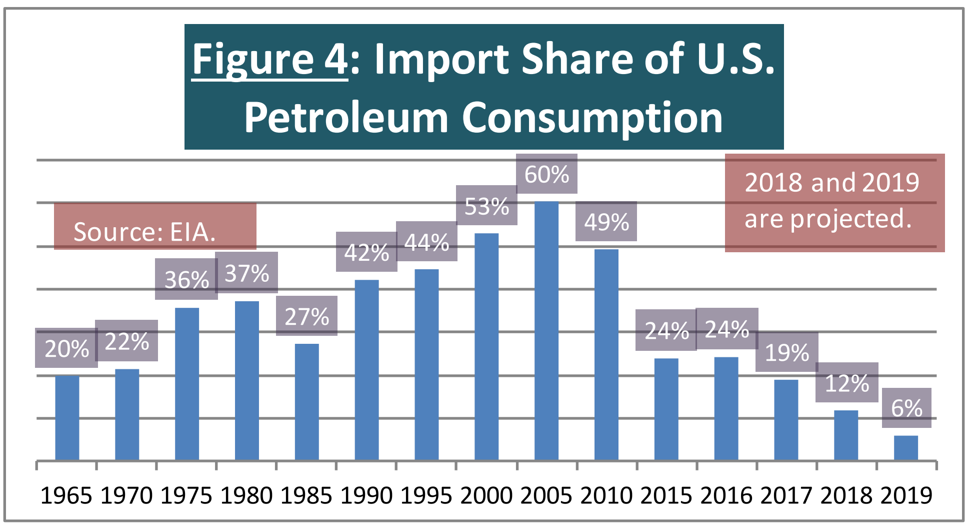
13 *STEO*; Table 1.
14 *STEO*; Table 7b.
15 *STEO*, Table 7a.
16 "U.S. Oil Prices Down Almost 40% From High;" *Wall Street Journal*; December 18, 2018.
17 *STEO*, page 1. The "North Sea Brent Crude" is the key contract for setting the price of crude oil in international markets.
18 *STEO*, Table 2.
19 *STEO*, page 1 and Table 4a.
20 See EIA's monthly *Drilling Productivity Report*; http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf.



Net liquid fuel imports to the United States peaked at over 60 percent of domestic supply in 2005 and then fell to 19 percent in 2017 – the lowest level since 1970; this represents a major shift in the structure of world oil markets.[21] EIA projects the import share to fall even further -- to 12 percent in 2018 and six percent in 2019.[22] See Figure 4 below.



Only time will tell whether the recent increase in domestic output will continue to moderate the price of crude oil. Russia is already pumping 10.8 million barrels a day of crude, a level unseen since the Soviet Union. Saudi Arabia, currently at 10.4 million barrels a day, is headed toward record-level output.[23]

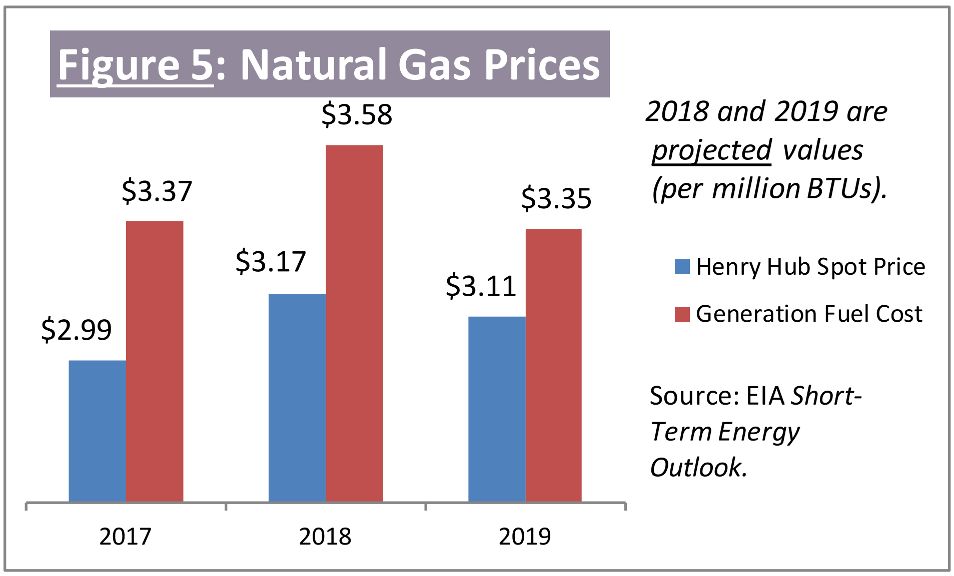
21 *STEO*; Table 4a. *EIA Monthly Energy Report*; July 2018; Table 3.1; http://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf.
22 *STEO*, Table 4a.
23 *Wall Street Journal*, October 26, 2018.

Petroleum fuels made up 0.2 percent of the PJM fuel mix during the twelve months ending in October 2018.[24] (See Figure 6 on page 10 below.)

Natural Gas

Natural gas prices are significantly below 2008 levels when the Henry Hub price averaged $8.94 per one million British Thermal Units (MMBtu).[25] Recently, the spot price has recovered from the lows reached in early 2012 when it briefly touched $2 per MMBtu.

Natural gas prices in the spot market result from the interaction of trends in domestic production, growing gas-fired generation, and expected winter heating needs; growing natural gas exports may impact prices in the future. Record domestic production offset rising exports and above-average usage. EIA expects Henry Hub spot prices to average $3.17/MMBtu for all of 2018 and $3.11 in 2019.[26]



The Henry Hub spot price is more volatile than the cost of natural gas actually paid by electricity generators where long-term contracts and hedging are typically involved. EIA projects that the cost of natural gas for power generation will rise in 2018 and fall in 2019.[27]

U.S. liquefied natural gas (LNG) export capcity is growing. Sabine Pass LNG (Texas) began export operations in February 2016; and commercial exports from Dominion Energy's Cove Point LNG in Maryland have begun.[28] EIA reports that Cove Point utilized 94 percent of

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24 See PJM System Mix by Fuel; https://gats.pjm-eis.com/gats2/PublicReports/PJMSystemMix/Filter.

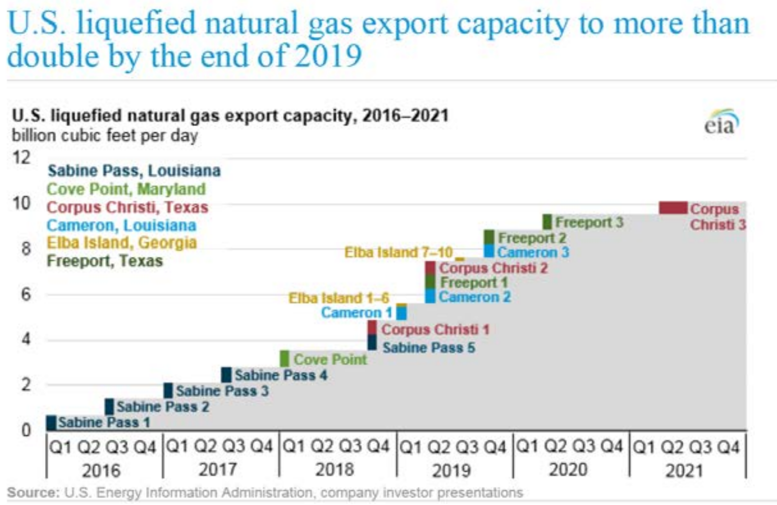
25 EIA; *2011 Annual Energy Outlook*; page 115.

26 *STEO*; page 2.

27 *STEO*; Table 7a.

28 U.S. Cove Point LNG terminal begins commercial LNG deliveries; *Reuters*; April 16, 2018. https://www.reuters.com/article/us-dominion-covepoint-lng/u-s-cove-point-lng-terminal-begins-commercial-lng-deliveries-data-idUSKBN1HN1JX.

its capacity in May. Natural gas liquefaction capacity from all projects currently under construction is projected to expand rapidly. EIA expects exports to grow faster than domestic production, possibly putting modest upward pressure on natural-gas prices; EIA expects LNG export capacity to more than double by the end of 2019.[29]



Regional variations in natural-gas prices also impact regional wholesale electricity markets like PJM – influenced by local gas production and the availability of gas pipeline transportation capacity. The *Wall Street Journal* reports that plentiful natural gas in the Appalachian region has fueled an expansion of gas-fired generation and depressed electricity prices in the PJM wholesale market.[30] This is confirmed in a brief analysis from EIA: *Natural-gas fired plants are being added and used more in PJM Interconnection*. EIA explains that gas-fired capacity has being growing in the region and that gas-fired generation has a rising "capacity factor" which combine to increase megawatthours generated by natural gas.[31]

The long-term impact of inexpensive natural gas can be seen easily in PJM price trends. "Figure 3.47" (below) shows the monthly and annual average load-weighted LMP for 1999 through September 2018.[32] Annual average LMP has declined since natural-gas prices peaked in 2008. Note the January price spike in 2018, the result of extreme winter cold.

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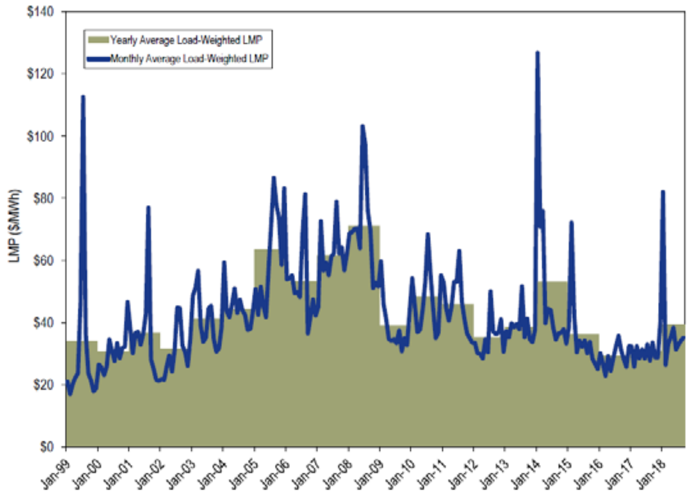
[29] See Table 5a and https://www.eia.gov/todayinenergy/detail.php?id=37732. "Bcf/d" is billion cubic feet per day.

[30] "Power Plants Bloom Even as Electricity Prices Wilt," *Wall Street Journal*, December 28, 2017.

[31] U.S. EIA; *Natural-gas fired plants are being added and used more in PJM Interconnection*; October 17, 2018. https://www.eia.gov/todayinenergy/detail.php?id=37293.

[32] Independent Market Monitor*; Q3 2018 State of the Market Report for PJM January through September (November 8, 2018);* page 179. LMP means "locational marginal price" which refers to the price-setting methodology used in PJM's wholsesale electricity market.

Figure 3-47 Real-time, monthly and annual, load-weighted, average LMP: January 1999 through September 2018



Natural gas accounted for 30.4 percent of the PJM fuel mix during the twelve months ending in October 2018, a significant increase from 16.4 percent in June 2014.[33] (See Figure 6 below.)

<u>Coal</u>

Coal has been displaced by natural gas, wind, and nuclear in electricity generation. Nationwide, coal consumption in electric power generation has not returned to the peak level of 2007. EIA estimates that coal production was 774 million short tons (MMst) in 2017, six percent higher than in 2016. EIA expects that coal production will decline by 1.6 percent in 2018 followed by a further 2.6 percent decrease in 2019.[34]

EIA reports that the delivered price of coal for power generation peaked at $2.39 in 2011. EIA estimates the delivered price of coal averaged $2.06 per MMBtu in 2017 and forecasts $2.07 per MMBtu in 2018 and $2.08 in 2019.[35]

In the PJM wholesale market that serves the District of Columbia, the cost of natural gas is a more important factor than coal in setting the overall level of wholesale market prices for electricity.[36] Coal represented 29.4 percent of the PJM fuel mix during the twelve months ending in October 2018, down from a recent high of 45.2 percent in June 2014.[37] As noted above, the natural gas share of PJM generation is rising, in line with national trends. Coal has

33 See PJM.

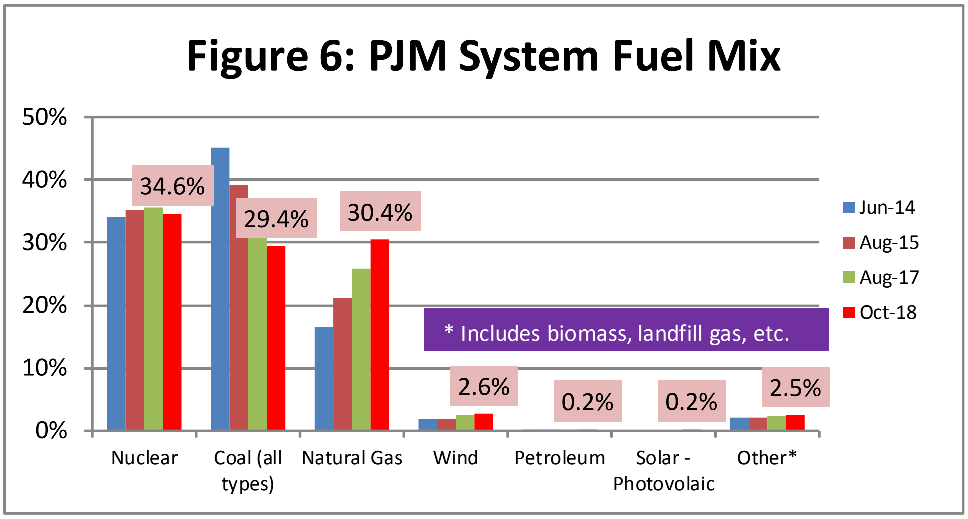
34 *STEO*; Table 6. Historical data can be found at http://www.eia.gov/totalenergy/data/annual/pdf/sec7_9.pdf. See also The Brattle Group; Coal Plant Retirements: Feedback Effects on Wholesale Electricity Prices; November 2013; http://www.brattle.com/system/news/pdfs/000/000/584/original/Coal_Plant_Retirements_-_Feedback_Effects_on_Wholesale_Electricity_Prices.pdf.

35 *STEO*; Table 7a.

36 EIA reports prices for coal as delivered under long-term contracts that are less volatile than the spot prices reported for other fossil fuels. See Table 6, *STEO*.

37 See PJM.

fallen to third place behind nuclear and natural gas a share of the PJM fuel mix. (See Figure 6 below.)



Across the United States, coal generation plants are being retired and new natural gas-fired generation plants are being built, mirroring trends in the PJM region. EIA projects that the natural gas share of electricity generation nationwide will rise from 24 percent in 2010 to 32 percent in 2017, rising to 35 percent in 2018 and 2019. Coal's share of generation averaged 30 percent in 2017, down from 45 percent in 2010, and will fall to 26 percent in 2019.[38] EIA's forecasted generation shares for coal and natural gas are very sensitive to the natural-gas price forecast.

<u>Renewables</u>

EIA reports that solar capacity is growing rapidly nationwide, with utility-scale solar expected to grow by 68 percent from 2016 to 2019. At that rate, utility-scale solar will be more than one percent of electricity generation capacity in 2018. Wind capacity is growing rapidly across the country as well, increasing by 30 percent during 2016-2019.[39]

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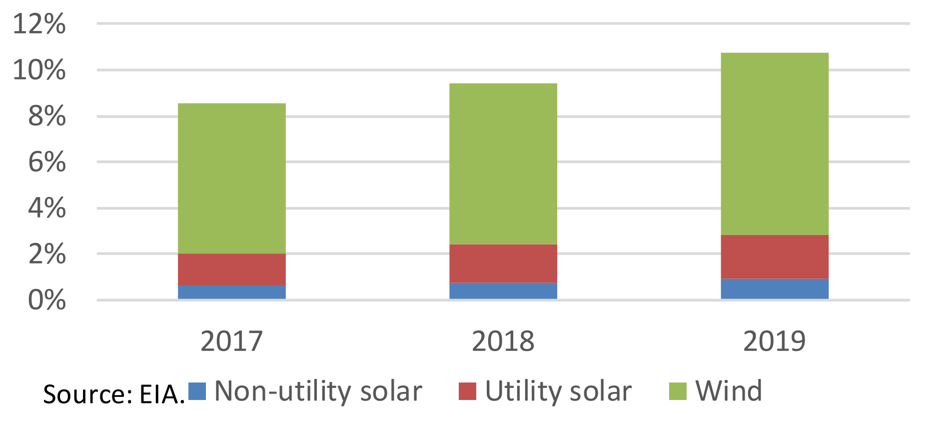
38 *STEO;* page 14.

39 *STEO*; Table 8b.

Figure 7: Wind and Solar are a Growing Share of U.S. Electricity Generation



Nationwide, EIA projects that generation of electricity from all nonhydropower renewables will provide nearly 10 percent in 2018 and reach 11 percent in 2019.[40] Wind may generate more electricity than hydropower source for the first time in 2019. Generation from utility-scale solar is projected to rise by 31 percent between 2017 and 2019.[41]

Renewable Portfolio Standards ("RPS") enacted by many states are stimulating the rapid growth of solar in the PJM market. This stimulus will intensify as scheduled increases will raise the RPS for solar in coming years, as shown in "Table 8-6" below.[42]

Table 8-6 Solar renewable standards by percent of electric load for PJM jurisdictions: 2018 to 2030

Jurisdiction with RPS	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Delaware	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%
Illinois	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%	1.50%	1.50%
Maryland	1.50%	1.95%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Michigan	No Minimum Solar Requirement												
New Jersey	4.30%	4.90%	5.10%	5.10%	5.10%	4.90%	4.80%	4.50%	4.35%	3.74%	3.07%	2.21%	1.58%
North Carolina	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%	0.50%	0.50%
Pennsylvania	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%	4.10%	4.50%
Jurisdiction with Voluntary Standard													
Indiana	No Minimum Solar Requirement												
Virginia	No Minimum Solar Requirement												
Jurisdiction with No Standard													
Kentucky	No Renewable Portfolio Standard												
Tennessee	No Renewable Portfolio Standard												
West Virginia	No Renewable Portfolio Standard												

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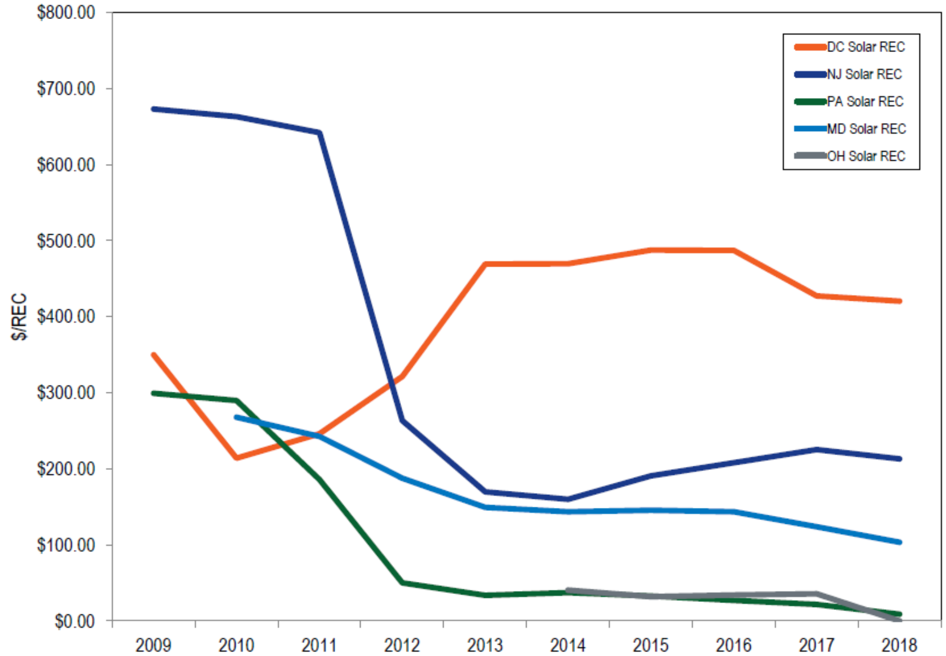
40 *STEO* at page 2.

41 *STEO* at Table 8b.

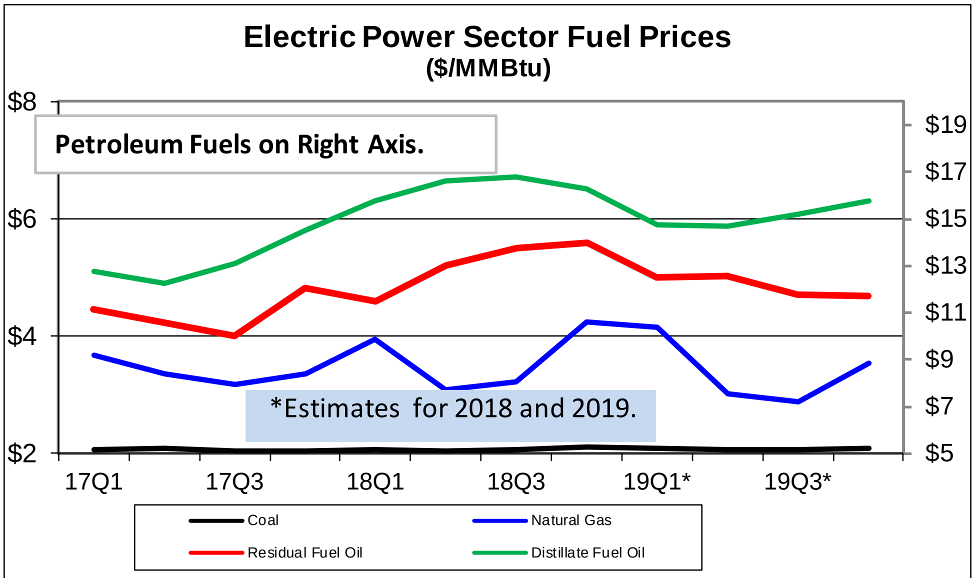
42 Independent Market Monitor; *Q3 2018 State of the Market Report for PJM* (November 8, 2018); page 351.

Prices for Solar Renewable Energy Credits ("SRECs") are much higher in the District of Columbia than in neighboring jurisdictions, as can be seen in "Figure 8-7" below.[43]

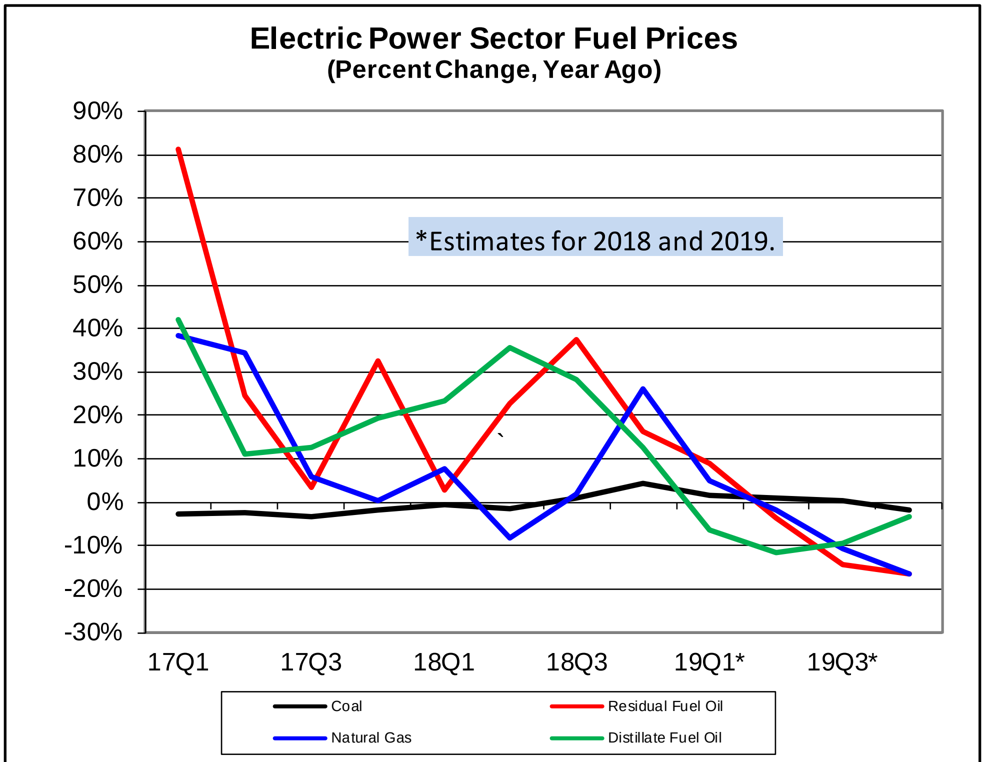
Figure 8-7 Average SREC price by jurisdiction: January 2009 through September 2018



43 Independent Market Monitor; *Q3 2018 State of the Market Report for PJM* (November 8, 2018); page 352.



Source: EIA, *Short-Term Energy Outlook*, Table 7a, Dec 2018.



.Source: EIA, Short-Term Energy Outlook, Table 7a, Dec 2018.

Wholesale Electric Market Assessment Information

Price of Electricity Futures Contracts for November 23 and December 12, 2018

Twelve Month NYMEX Strip Components[44]

$/MWh (for $/kWh, divide by 1000)

	Nov-18	Dec-18
Jan-19	$ 54.97	$ 70.10
Feb-19	$ 51.03	$ 64.40
Mar-19	$ 39.80	$ 49.50
Apr-19	$ 35.57	$ 39.00
May-19	$ 35.43	$ 38.15
Jun-19	$ 33.87	$ 36.15
Jul-19	$ 39.38	$ 41.25
Aug-19	$ 36.32	$ 38.25
Sep-19	$ 34.72	$ 37.10
Oct-19	$ 33.35	$ 34.80
Nov-19	$ 32.80	$ 34.85
Dec-19	$ 35.63	$ 39.05
Jan-20	$ 50.68	$ 56.50

PEPCO DC Zone Locational Marginal Price (Hourly Integrated LMP for the hour ending 1500)[45]

December 12, 2018: **$30.20**

The above are wholesale energy prices only. Transmission and distribution rates are not included.

Weather Forecast

1. Current for next few days to one week:

   http://www.cnn.com/Weather/

   http://home.accuweather.com/

2. National Oceanic and Atmospheric Administration, Climate Prediction Center Outlook:

   http://www.cpc.ncep.noaa.gov/

[44] http://www.cmegroup.com/trading/energy/electricity/pjm-western-hub-peak-calendar-month-real-time-lmp.html.

[45] http:// http://oasis.pjm.com/system.html.