Electricity Price Outlook for April 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

- The DC PSC announced lower Standard Offer Service ("SOS") electric rates: 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.

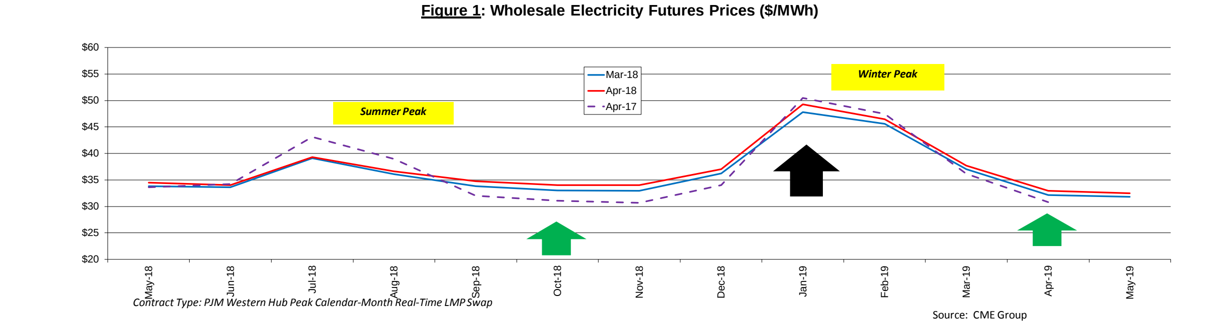
- Utility investments in solar generating capacity are projected to accelerate nationwide.

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 May 2019 as settled on March 26, 2018 (blue line), and on April 24, 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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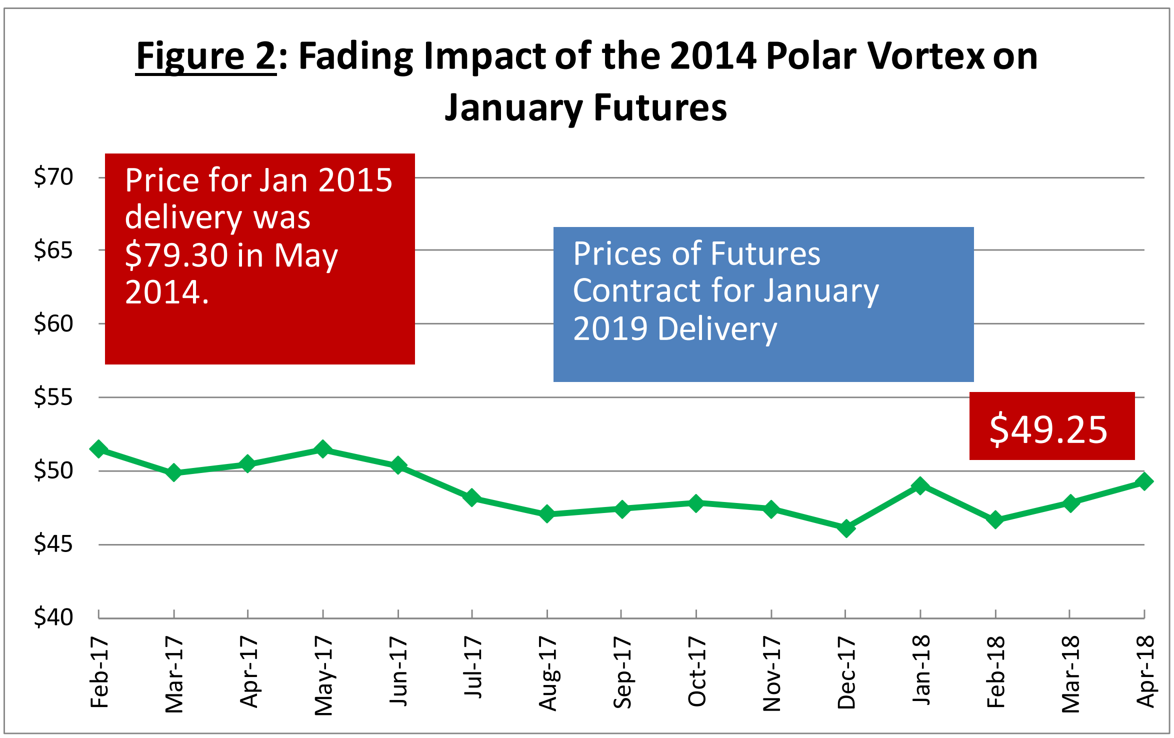
[1] See PJM Western Hub Peak Calendar-Month Real-Time LMP Swap Futures; CME Group.

In Figure 1 above, the dashed purple line shows the trading values for the "price strip" from one year ago (April 20, 2017). Price expectations for summer and winter months are below last year's levels. Near-term investor expectations of future electricity prices are similar to last month (blue line). The futures price for January 2019 has increased 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 October 2018 and April 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] The most recent price for January 2019 delivery is $49.25 – a 3 percent increase from the previous month.



[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.

Behind these price movements are the extraordinary demands for electricity during January 2014 when eight of the 10 highest winter demands for electricity ever recorded in the PJM region occurred. PJM set a new, all-time winter peak demand of 141,312 megawatts 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]

On February 20, 2015, PJM set another new peak for winter demand -- 143,826 MW -- when PJM's "forced outage" rate peaked at 13.3 percent. It is notable that this reduced rate of forced outage is well below the "forced outage" rate of 22.2 percent experienced by PJM generators on January 7, 2014.[5] This shows that PJM has learned some lessons since the "Polar Vortex." Investor anxiety about PJM's capacity to meet extreme demand in the future seems to have largely abated.

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."[6] Futures markets registered a brief uptick for the winter months that has since abated.

Jan. 5 Cold Weather Update

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 *PJM weathered 2015 winter demand better than 2014: staff;"* Platts; 20 April 2015; http://www.platts.com/latest-news/electric-power/houston/pjm-weathered-2015-winter-demand-better-than-21320423.

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

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 increase by 2.2 percent in 2018 nationwide and a further 3.3 percent increase is projected in 2019.[7] Factors other than generation costs play a role, including the need for 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 will go 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 $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.[8]

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 April 12th *El Niño* watch indicates that *La Niña* is expected to transition to ENSO-neutral during April-May, with ENSO-neutral then likely (greater than 50% chance) to continue through the Northern Hemisphere summer 2018.[9] NOAA notes that, with ENSO-neutral conditions developing, above-normal temperatures are expected in the mid-Atlantic region through the May-June-July period.[10]

Heating-degree days measure the demand for heating during the winter. EIA reports that heating degree days in our region are projected to be about 16 percent higher in 2018 than in 2017. Projected heating degree days for 2018 are slightly below the ten-year average.[11]

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

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

9 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.

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

11 *STEO*, Table 9c.

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 three percent fewer in 2018 compared to 2017. The projection for summer 2018 is equal to the 10-year average.[12] The long-term warming trend continues.[13]

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 2.3 percent in 2017 and and is projected to grow by 2.7 percent in 2018 and by 2.8 percent in 2019.[14] Restrained economic growth depresses the growth of electricity sales and moderates prices of generation fuels.

EIA forecasts that residential electricity sales (measured in kWh) will increase by 3.8 percent in 2018, followed by no increase in 2019. Nationwide electricity sales for all sectors will increase by 2.2 percent in 2018 with a slight increase projected in 2019.[15]

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 2017 and 2018.[16]

<u>Petroleum</u>

The Organization of Petroleum Exporting Countries ("OPEC"), led by Saudi Arabia, are poised to extend output cuts agreed least year with allied, non-OPEC producers, and Russia has agreed to support the extension through the end of 2018.[17] OPEC and Russia are reported to be discussing an unprecedented 10- to 20-year agreement on output restraint.[18] North Sea Brent crude averaged $66 per barrel in March, a $1 increase from the February average. Brent crude is forecast to average $63 per barrel in 2018 and 2019 compared with an average of $54 per barrel in 2017.[19]

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12 *STEO*; Table 9c.

13 NOAA National Climatic Data Center; Contiguous U.S. Temperature 1896 – 2016; https://www.ncdc.noaa.gov/cag/time-series/us/110/0/tavg/1/2/1895-2017?trend=true&trend_base=100&firsttrendyear=1895&lasttrendyear=2017.

14 *STEO*; Table 1.

15 *STEO*; Table 7b.

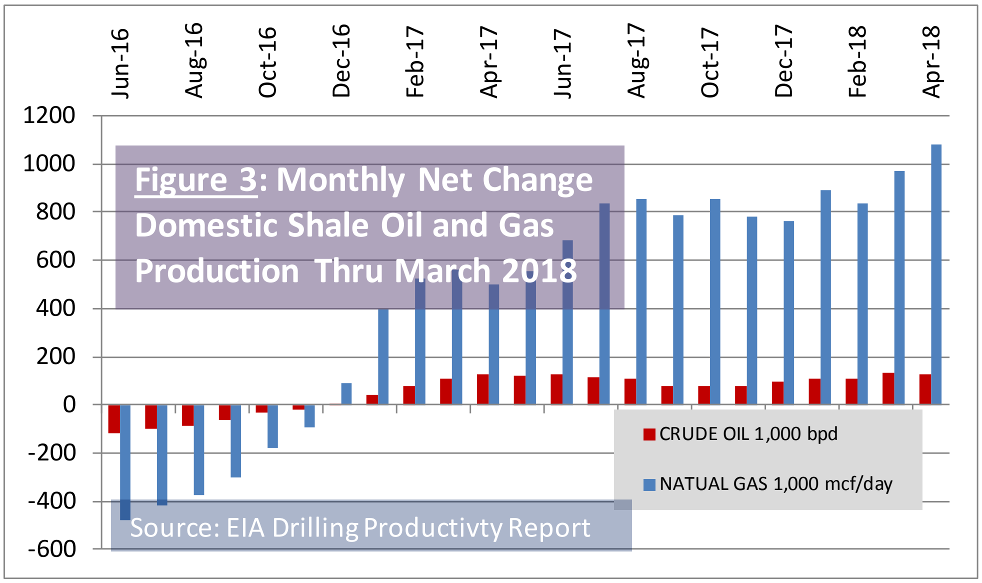
16 *STEO*, Table 7a.

17 "OPEC, Russia agree oil cut extension to end of 2018," Reuters; November 30, 2017.

18 "Exclusive: OPEC, Russia consider 10- to 20-year oil alliance - Saudi Crown Prince," Reuters; March 27, 2018.

19 *STEO*, page 1. The "North Sea Brent Crude" is the key contract for setting the price of crude oil in international markets.

U.S. shale oil producers continue to raise their production, acting as a countervailing force to OPEC's output restraint. EIA estimates that U.S. crude oil production averaged 10.4 million barrels per day (b/d) in March, an increase of 260,000 b/d from February. EIA reports that domestic crude oil production averaged 9.3 million b/d in 2017 and projects 10.7 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 11.4 million b/d. [20] The latest *Monthly Drilling Report* from the EIA shows oil and natural gas output increasing in the U.S. shale-producing basins surveyed (see Figure 3).[21]



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.[22] EIA projects the import share to fall even further -- to 13 percent in 2018 and 9 percent in 2019.[23] See Figure 4 below.

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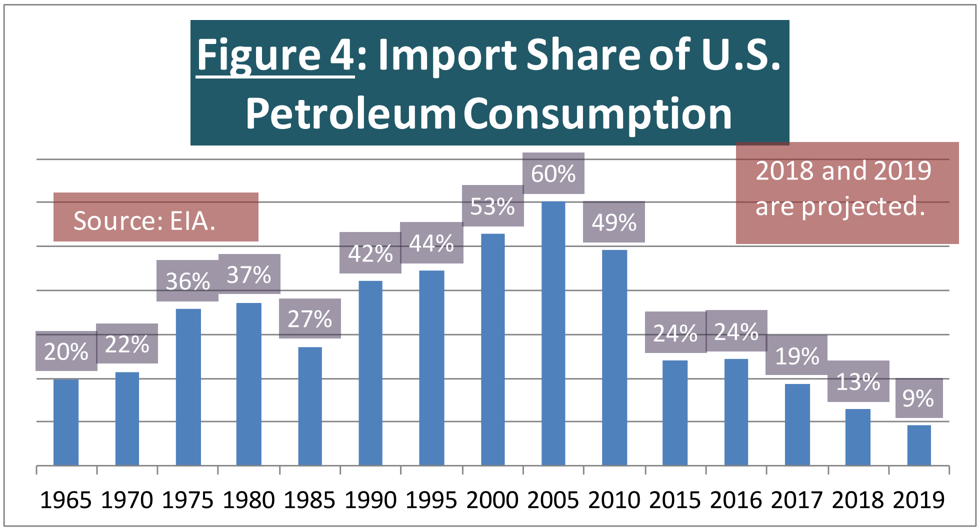
20 *STEO*, page 1 and Table 4a.

21 See EIA's monthly *Drilling Productivity Report*; http://www.eia.gov/petroleum/drilling/pdf/dpr-full.pdf.

22 *EIA Monthly Energy Report*; June 2016; Table 3.1; page 49; http://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf. *STEO*; Table 4a.

23 *STEO*, Table 4a.



Regular gasoline averaged $2.15 per gallon in 2016. EIA reports that retail gasoline prices averaged $2.42 in 2017 and will average $2.64 in 2018 and $2.61 in 2019.[24]

Despite extension of the OPEC-Russia agreement, EIA expects output from non-OPEC sources to increase in 2018. Oil price increases will continue to be moderated by continuing growth in domestic production.[25]

Petroleum fuels made up 0.2 percent of the PJM fuel mix during the twelve months ending in February 2018.[26] (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).[27] 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 winter heating needs.

In March, the average Henry Hub natural gas spot price was $2.69 per MMBtu, up only three cents from February.[28] Record domestic production offset rising exports and above-average usage. EIA expects Henry Hub spot prices to average $3.10/MMBtu for all of 2018.[29]

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24 *STEO*; Table 2.

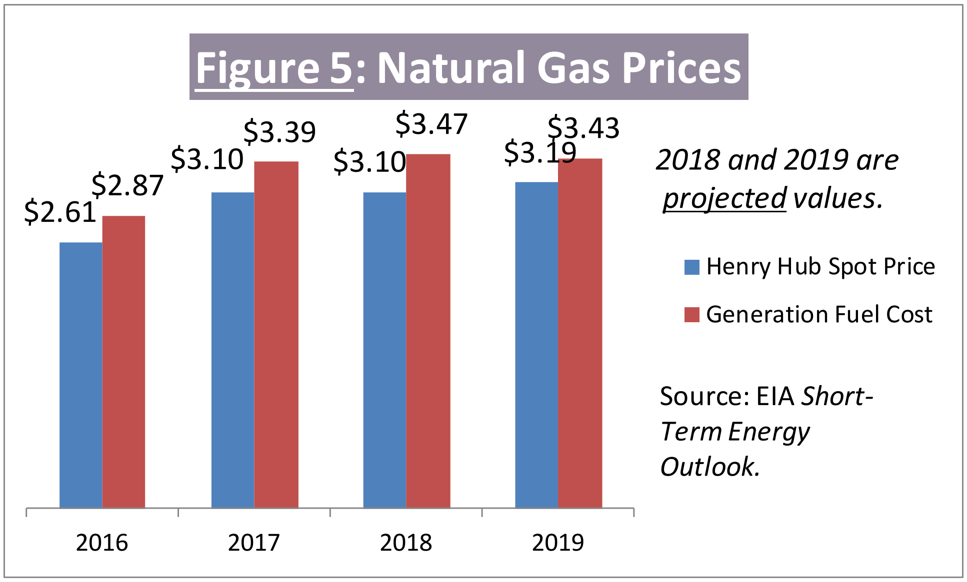
25 *STEO*, Tables 3b and 3c; page 4.

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

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

28 *STEO*; page 8. "Henry Hub" refers to a distribution hub on the natural gas pipeline system in Erath, Louisiana. It is used as the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange.

29 *STEO*; page 2.



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 increase by two percent in 2018 followed by a decrease of one percent in 2019.[30]

U.S. liquefied natural gas (LNG) export capcity is growing. Sabine Pass LNG (Texas) began export operations in February 2016; and commercial exports from Cove Point LNG in Maryland have begun.[31] 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 projects 1.94 billion cubic feet of LNG exports in 2017, 2.95 in 2018, and 4.83 in 2019.[32]

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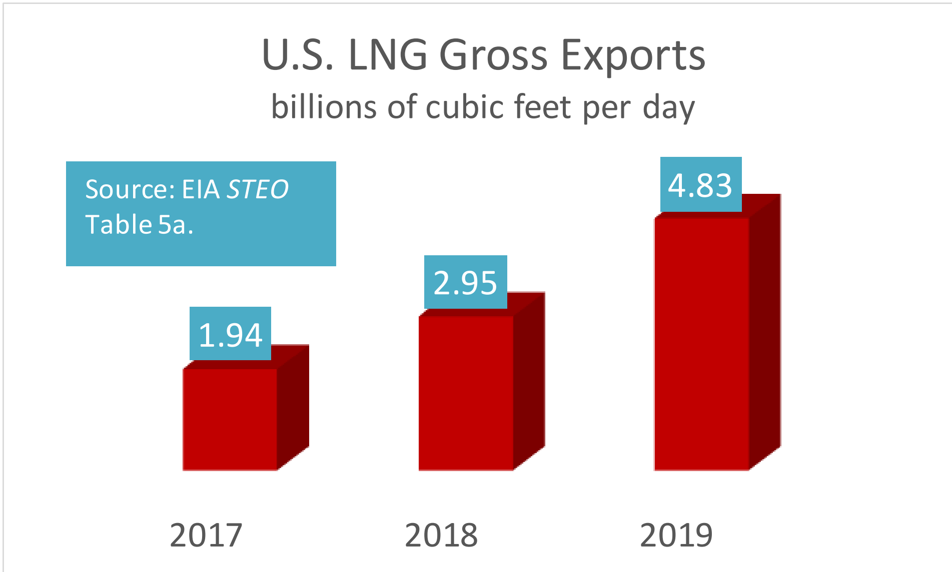
30 *STEO*; Table 7a.

31 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.

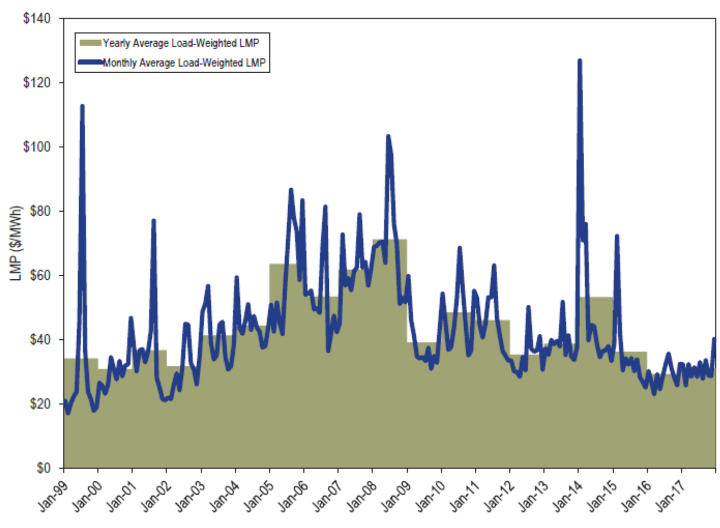
32 See Table 5a and https://www.eia.gov/naturalgas/weekly/#jm-trends. "Bcf/d" is billion cubic feet per day.



Regional variations in natural-gas prices are also a factor that influences 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.[33]

The impact of inexpensive natural gas can be seen easily in PJM price trends. "Figure 7" (below) shows the monthly and annual average load-weighted LMP for 1999 through 2017.[34] Annual averages LMP has declined since natural-gas prices peaked in 2008. January price spikes have not recurred since 2015, despite extreme winter cold in 2018.

Figure 7 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through 2017



33 "Power Plants Bloom Even as Electricity Prices Wilt," *Wall Street Journal*, ecember 28, 2017.

34 Independent Market Monitor*; 2017 State of the Market Report for PJM Volume One;* page 24.

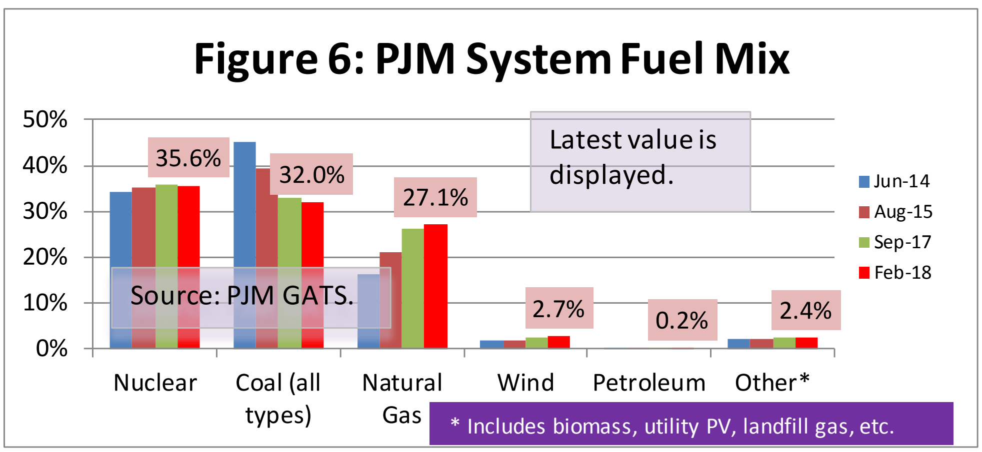
Natural gas accounted for 27.1 percent of the PJM fuel mix during the twelve months ending in February 2018, a significant increase from 16.4 percent in June 2014.[35] (See Figure 6 below.)

Coal

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 declined to 774 million short tons (MMst) in 2017, six percent higher than in 2016. EIA expects that coal production will decrease by 4.6 percent in 2018 followed by a slight rebound in 2019.[36]

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 $2.08 per MMBtu in 2017 and forecasts $2.19 per MMBtu in 2018 and $2.21 in 2019.[37]

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.[38] Coal represented 32 percent of the PJM fuel mix during the twelve months ending in February 2018, down from a recent high of 45.2 percent in June 2014.[39] As noted above, the natural gas share of PJM generation is rising, in line with national trends. Furthermore, coal remains just behind nuclear as a share of the PJM fuel mix. (See Figure 6 below.)



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35 See PJM.

36 *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.

37 *STEO*; Table 7a.

38 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*.

39 See PJM.

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 32 percent in 2017 to 34 percent in 2018 and 2019. Coal's share of generation averaged 30 percent in 2017, falling to 29 percent in 2018 and 2019.[40] EIA's forecasted generation shares for coal and natural gas are very sensitive to the natural-gas price forecast.

Renewables

Utility-scale solar still accounts for only 0.2 percent of installed capacity on the PJM system; however, it is growing at a rapid pace. During 2016, this capacity grew from 128 MW on January 1 to 262.3 MW by December 31.[41] This represents a growth rate of 105 percent for a single year. For comparison, wind represents 0.6 percent of PJM installed capacity and grew by 12 percent during 2016.

In line with capacity, generation from from solar (net metered and utility scale) is also growing quickly on the PJM system. In the first three quarters of 2016, solar generated 799.2 GWh which rose to 1,156.6 GWh in the same period of 2017. While the latter amount represents only 0.2 percent of total PJM generation, the rate of growth was substantial: 44.7 percent.[42]

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 8-7" below.[43]

Table 8-7 Solar renewable standards by percent of electric load for PJM jurisdictions: 2017 to 2028

Jurisdiction with RPS	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%
Illinois	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%
Maryland	1.15%	1.50%	1.95%	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	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%	3.83%	3.92%	4.01%	4.10%
North Carolina	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%
Pennsylvania	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Washington, D.C.	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.60%	2.85%	3.15%	3.45%	3.75%
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											

40 *STEO;*page 2.

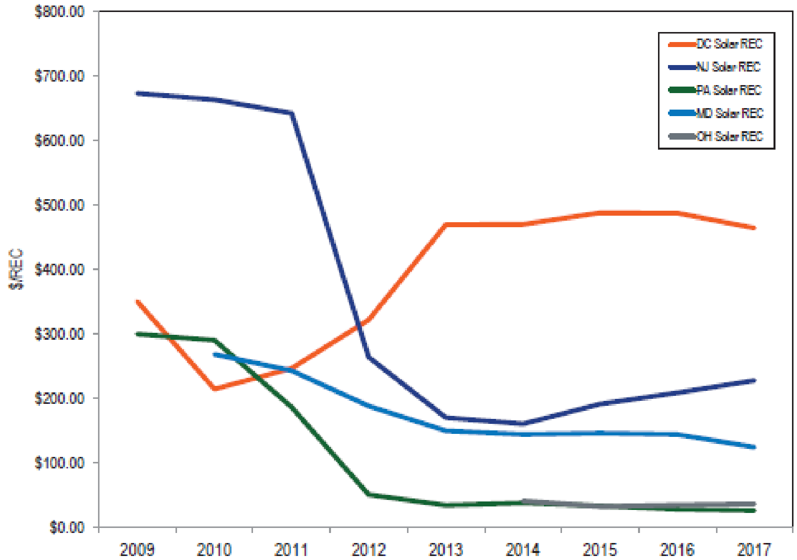
41 Independent Market Monitor 2017 Quarterly State of the Market Report for PJM: January through September; page 36.

42 IMM 2017 Quarterly State of the Market Report for PJM: January through September; Table 3-9; page 109.

43 IMM 2017 Quarterly State of the Market Report for PJM: January through September; page 322.

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.[44]

Figure 8-7 Average SREC price by jurisdiction: 2009 through 2017



EIA reports that solar capacity is also growing rapidly nationwide, with utility-scale solar expected to grow by 95 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 as well, increasing by 27 percent during 2016-2019.[45]

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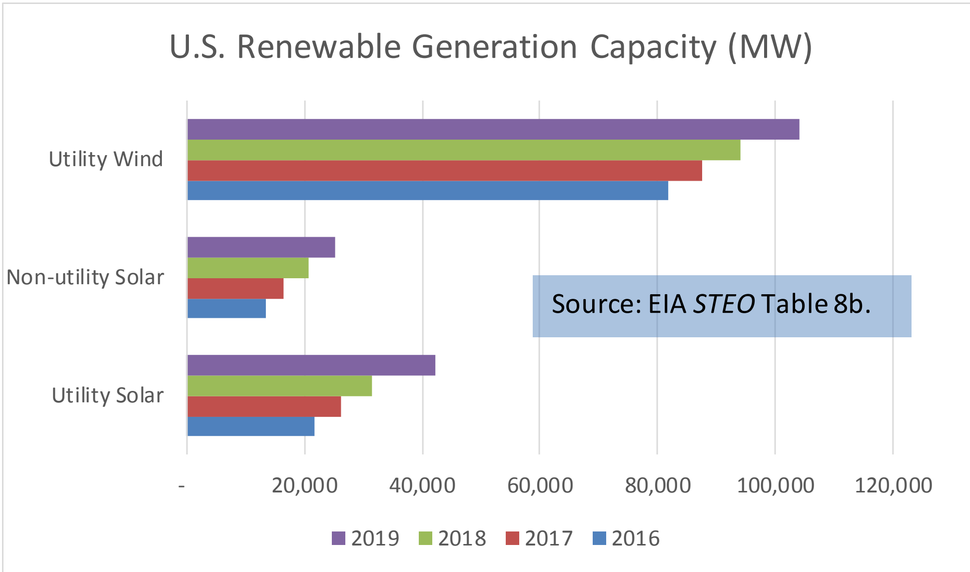
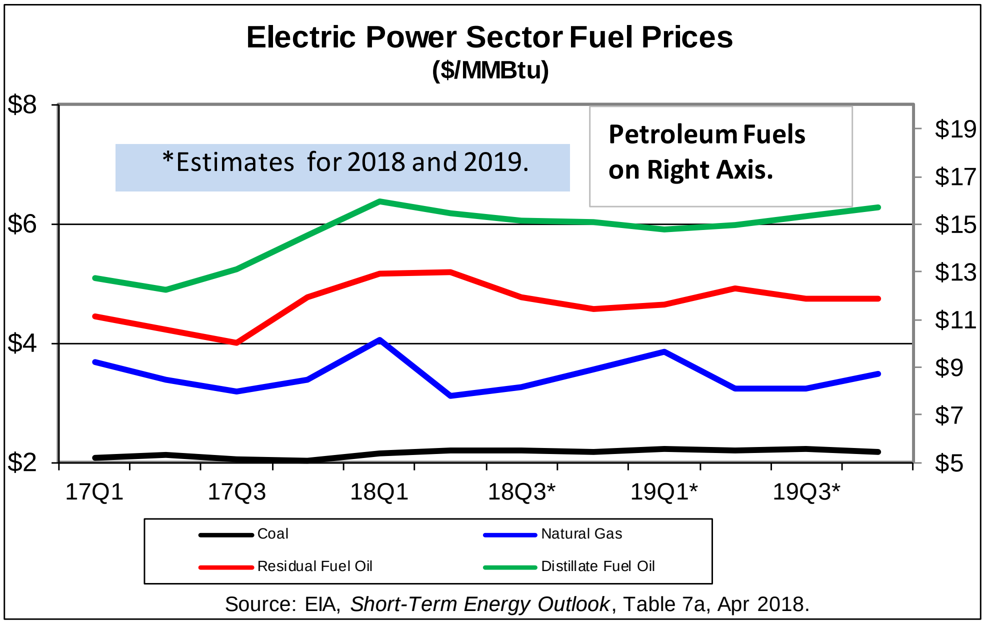
44 Independent Market Monitor*; 2017 State of the Market Report for PJM Volume Two;* page 353.

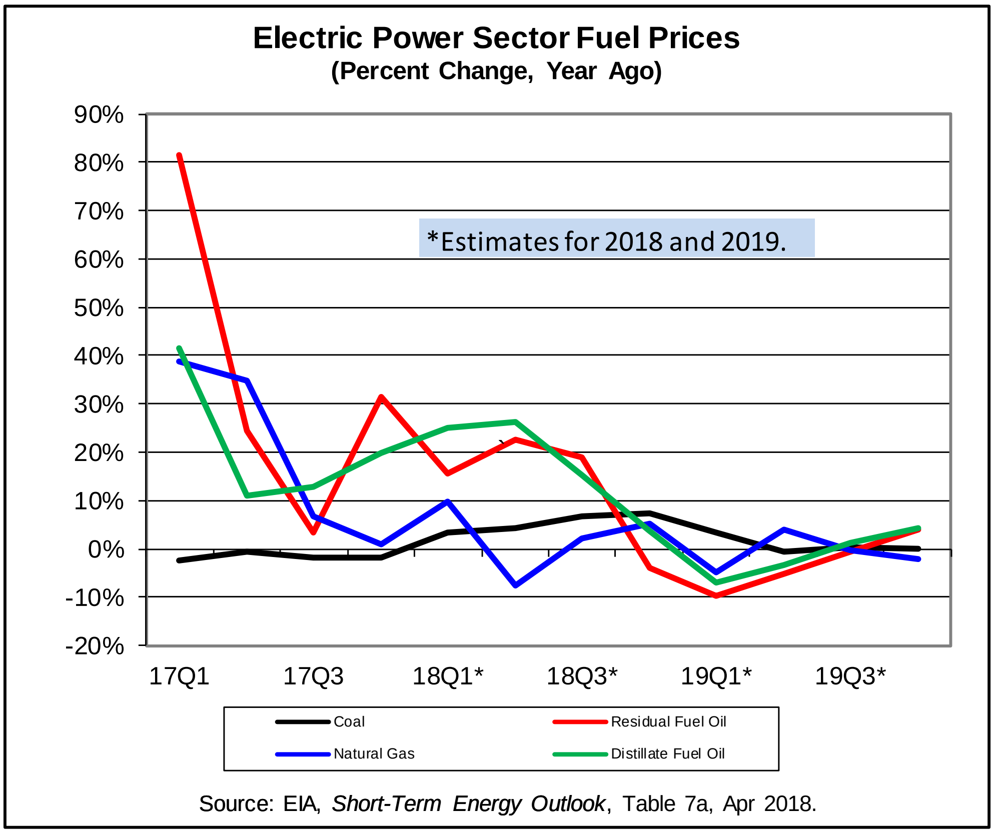
45 *STEO*; Table 8b.



Nationwide, EIA projects that generation of electricity from wind will grow by 12 percent from 2017 to 2019, when it will exceed generation from hydropower for the first time. Generation from solar will rise by 40 percent between 2017 and 2019.[46]

[46] *STEO* at page 2.


Electric Power Sector Fuel Prices
($/MMBtu)
*Estimates for 2018 and 2019.
Petroleum Fuels on Right Axis.
$8
$6
$4
$2
$19
$17
$15
$13
$11
$9
$7
$5
17Q1
17Q3
18Q1
18Q3*
19Q1*
19Q3*
Coal
Natural Gas
Residual Fuel Oil
Distillate Fuel Oil
Source: EIA, Short-Term Energy Outlook, Table 7a, Apr 2018.


Electric Power Sector Fuel Prices
(Percent Change, Year Ago)
*Estimates for 2018 and 2019.
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
-10%
-20%
17Q1
17Q3
18Q1*
18Q3*
19Q1*
19Q3*
Coal
Residual Fuel Oil
Natural Gas
Distillate Fuel Oil
Source: EIA, Short-Term Energy Outlook, Table 7a, Apr 2018.

Wholesale Electric Market Assessment Information

Price of Electricity Futures Contracts for March 26 and April 24, 2018

Twelve Month NYMEX Strip Components[47]

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

	Mar-18	Apr-18
May-18	$ 33.80	$ 34.50
Jun-18	$ 33.65	$ 34.00
Jul-18	$ 39.10	$ 39.30
Aug-18	$ 36.08	$ 36.60
Sep-18	$ 33.83	$ 34.75
Oct-18	$ 33.03	$ 34.00
Nov-18	$ 32.95	$ 34.00
Dec-18	$ 36.22	$ 37.05
Jan-19	$ 47.81	$ 49.25
Feb-19	$ 45.60	$ 46.45
Mar-19	$ 37.00	$ 37.70
Apr-19	$ 32.13	$ 32.95
May-19	$ 31.81	$ 32.45

PEPCO DC Zone Locational Marginal Price (Hourly Integrated LMP for the hour ending 1000[48]

April 24, 2018: **\$32.50**

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/

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

[48] http://ftp.pjm.com/pub/account/lmpgen/lmppost.html.