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PRICES AND SPENDING

Trends in electricity prices during the transition away from coal

By William B. McClain

The electric power sector of the United States has undergone several major shifts since the deregulation of wholesale electricity markets began in the 1990s. One interesting shift is the transition away from coal-powered plants toward a greater mix of natural gas and renewable sources. This transition has been spurred by three major factors: rising costs of prepared coal for use in power generation, a significant expansion of economical domestic natural gas production coupled with a corresponding decline in prices, and rapid advances in technology for renewable power generation.[1] The transition from coal, which included the early retirement of coal plants, has affected major price-determining factors within the electric power sector such as operation and maintenance costs, capital investment, and fuel costs. Through these effects, the decline of coal as the primary fuel source in American electricity production has affected both wholesale and retail electricity prices.

Identifying specific price effects from the transition away from coal is challenging; however the producer price indexes (PPIs) for electric power can be used to compare general trends in price development across generator types and regions, and can be used to learn valuable insights into the early effects of fuel switching in the electric power sector from coal to natural gas and renewable sources. The PPI program measures the average change in prices for industries based on the North American Industry Classification System (NAICS). This article uses industry indexes for NAICS 221110, electric power generation, and NAICS 221122, electric power distribution.[2] For tracking changes in prices for power generation, the PPI distinguishes between prices received by power distribution utilities that also generate electric power and non-utility electric power generators. Utility and non-utility generators differ in scale, integration with electric transmission and distribution networks, and fuel mix. For distribution to end-users, the PPI publishes indexes by end-user and census region.[3]

This **Beyond the Numbers** article looks at both generation and distribution prices for electricity, from 2004 to 2019. To examine price trends for electricity generation, this article compares utility and non-utility generation price movements. To analyze price trends for electricity distribution, this article compares price movements for different aggregations of regional residential electric power distribution. The article also discusses how prices have varied during the decline of coal, rise of natural gas, and early growth of renewable power as a share of electricity production.

How are electricity prices set?

As with many sectors, it is useful to consider price changes in both wholesale and retail markets. Wholesale prices are received by generators of electric power (e.g., power plants), which may be owned by large utilities that also distribute power or may be independent power producers at stand-alone power plants. Retail prices are received by utilities, cooperatives, and municipalities that purchase the wholesale power for distribution to residential, commercial, and industrial end-users.

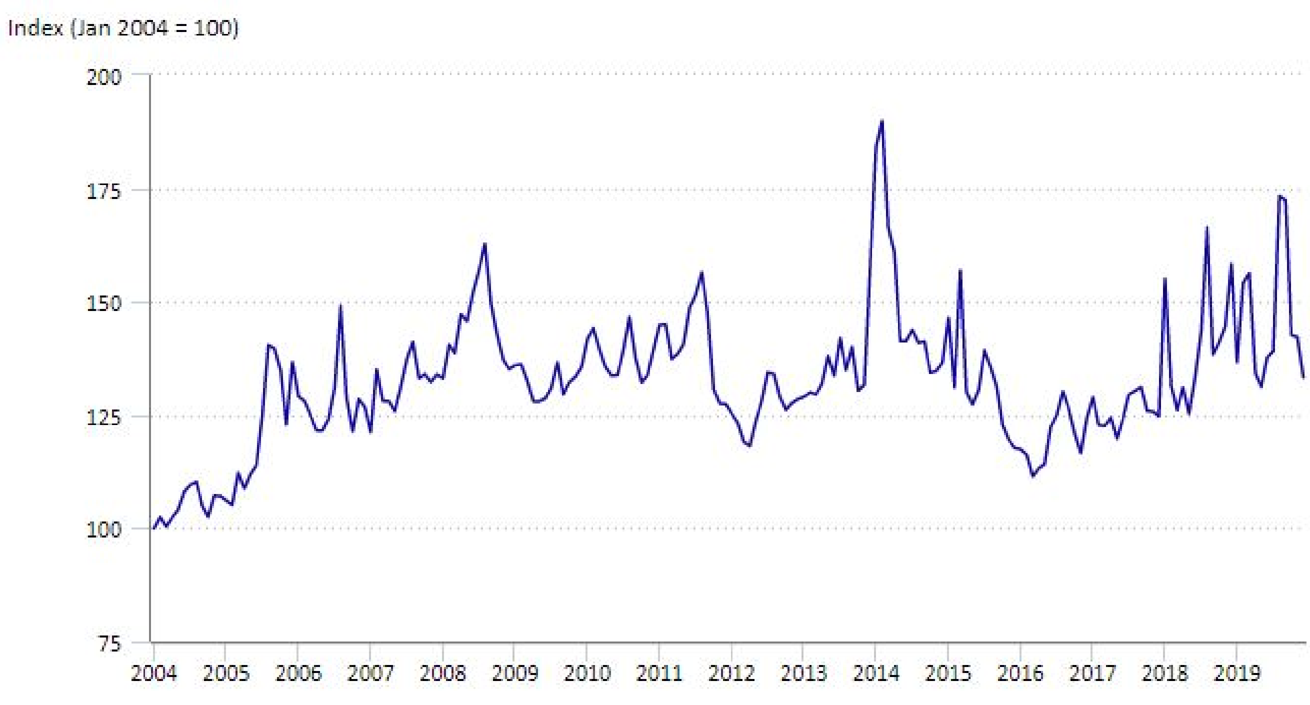
Price setting differs significantly across markets, although wholesale price movements typically will pass through to retail prices.[4] The majority of wholesale transactions in the United States take place in deregulated markets. Prices are set by frequent and active auctions designed to balance supply and demand subject to the physical constraints of power transmission. Generators of electric power submit selling bids equal to their marginal cost to produce a specific quantity of energy, and distributors (chiefly utilities) submit demand levels. Generator bids are then ordered from lowest to highest until energy supplied is equal to demand.[5] Prices are then set by the *marginal producer*—the generator with the lowest bid that equilibrates supply and demand at a specific pricing *node* or physical location where bulk power is transformed for distribution to end-users. All suppliers will receive this price, even if they submitted a lower bid. Wholesale prices not set in competitive auctions are taken from long-term bilateral contracts or internal transfer pricing. Most retail prices are set through regulatory proceedings that evaluate a utility's total asset base and operating costs in order to determine the rates that earn the utility a target rate of return on generation and distribution assets. Rates are frequently set for a year or longer and are a combination of fixed and variable per-unit charges.

For both wholesale and retail markets, frequent drivers of short- and medium-term price changes include demand shifters (e.g., variation in temperature or economic activity), fuel price changes, and unexpected supply shocks (e.g., unplanned maintenance on a power plant or downed power lines). Long-term price changes are primarily driven by long-term trends in demand (e.g., population growth, economic development, or shifting energy conservation preferences), shifts in fuel mix and the corresponding capital investment in generating capacity, and shifts in the policy environment (e.g., introducing or removing subsidies for a particular fuel source).

Changes in electricity prices

Prices used for PPIs in the generation sector reflect the full range of wholesale prices, including prices set by competitive auctions in deregulated wholesale markets, prices from bilateral contracts, and internal transfer prices. As seen in chart 1, wholesale prices for electric power generation first experienced larger annual increases through the mid- and late-2000s, before increasing at slower rates (with significant volatility) since 2010. From 2004 to 2010, generation prices rose 31.7 percent, with 5 of 6 years exhibiting annual increases. Between 2010 and 2019, prices only rose 5.8 percent. (The index also exhibits seasonal volatility, as prices spike in the summer due to high demand for cooling purposes.) During heatwaves, demand can surge to such a point that it strains generation capacity, causing significant price spikes. Smaller peaks occur in the winter, as some regions also use electric power for heating purposes. Prices are typically lowest in spring and fall, when cooling and heating demand are low. Month-over-month volatility is not only a result of shifts in demand; but can also reflect plant retirements or the introduction of new capacity, planned and unplanned shutdowns that reduce capacity, and changes in fuel prices.

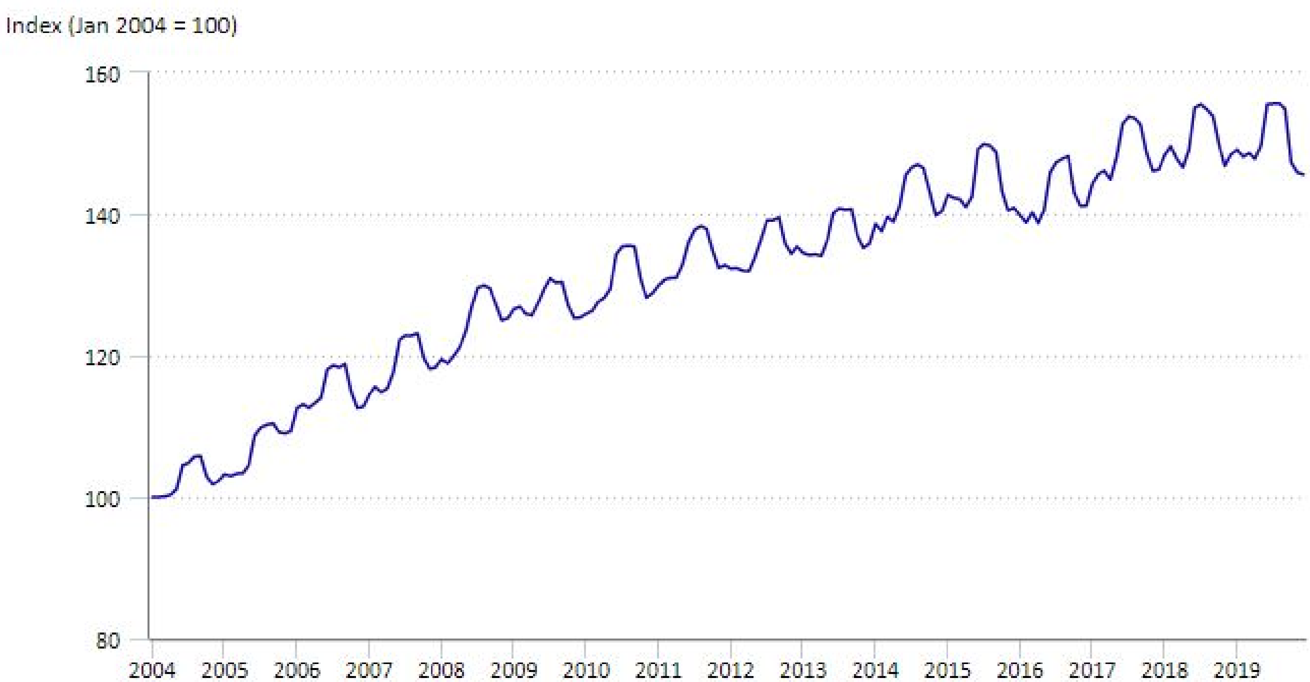
Chart 1. Producer Price Index (PPI) for NAICS 221110, electric power generation, January 2004–December 2019, not seasonally adjusted



Hover over chart to view data.
Source: U.S. Bureau of Labor Statistics.

BLS calculates the set of industry PPIs for electric power distribution using sample bills that replicate the monthly charges end-users pay for power. The rates in these bills are overwhelmingly set by regulatory price-setting cases filed with state-level utility commissions. Often at least half of a bill is determined by charges that remain the same for 6 months or longer. Chart 2 shows the monthly industry PPI for electric power distribution from 2004 to 2019.[6] In general, there has been a significant upward trend in the prices approved by regulators for distribution companies through this period; although, as with prices for electric power generation, the trend flattened out beginning in 2010. Annual average prices for electric power distribution increased 27.3 percent from 2004 to 2010. Between 2010 and 2019, prices only increased by 17.5 percent. Compared to generation prices, distribution prices demonstrate stronger seasonality. This is due to many distributors having different rates for winter and summer, causing the regular cyclical jump from May to October. This approach to rate-setting has been in place for some time, but the index for electric power distribution suggests that the regularity and magnitude of seasonal pricing has increased over time. There are several possible explanations for this dynamic, such as more distributors introducing seasonal rates over time, regulators being more willing to approve higher seasonal costs, and shifts in the fuel mix in effect during periods of high demand affecting peak prices.

Chart 2. Producer Price Index for NAICS 221122, electric power distribution, January 2004–December 2019, not seasonally adjusted



Hover over chart to view data.
Source: U.S. Bureau of Labor Statistics.

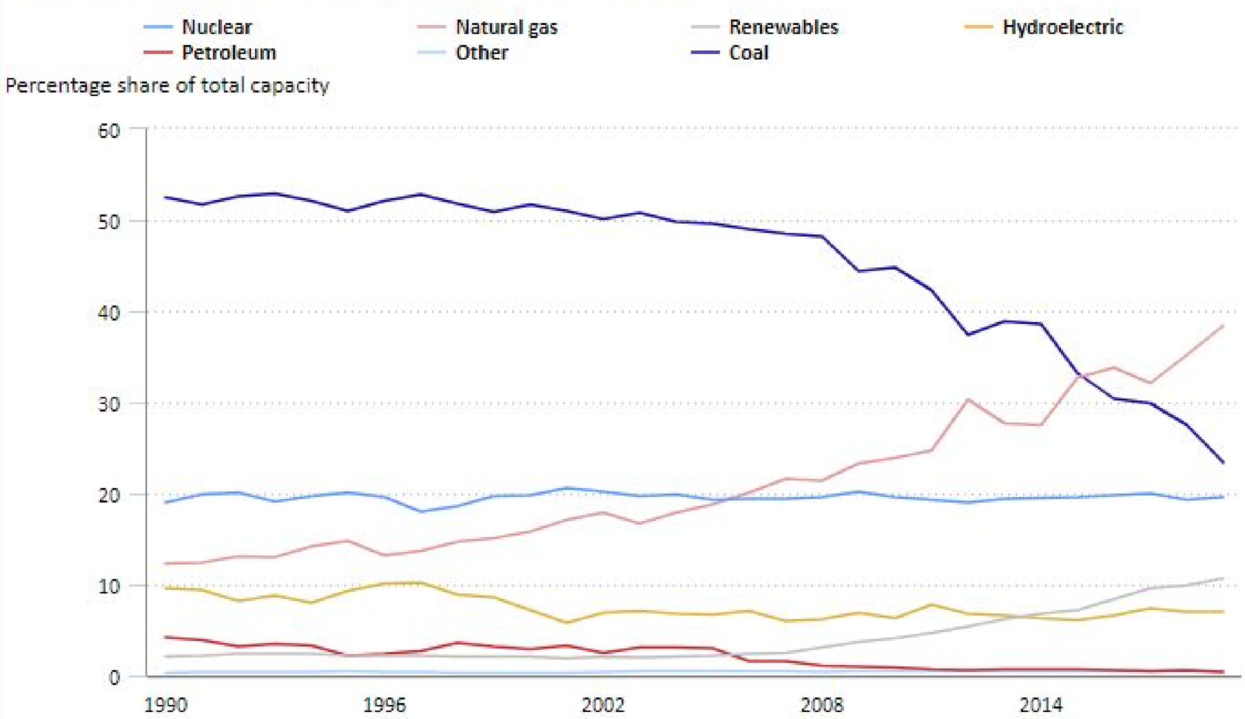
The upward trend of regular rate increases for electric power distribution reflects several dynamics.[7] Distribution rates typically depend on the value of a utility's return-generating assets, annual operating and maintenance expenses, and a desired rate of return. These price trends therefore reflect: (1) capital investment intended to maintain, replace, and expand generation capacity, and (2) overall changes in operating and maintenance costs.

Variation in distribution prices also reflect changes in generation power prices, which pass through to distribution prices in the form of variable fuel cost adjustments that measure average prices paid for power.

Shifts in fuel mix over time

In the United States, the generation of *baseload* electricity, defined by the Energy Information Administration as the minimum amount of electric power required to maintain mechanical and thermal efficiency of the grid system, historically was met through large coal-powered plants. Starting in the early 2000s, there was rapid growth in domestically produced natural gas from shale formations and other nonconventional sources.[8] As a result, natural gas prices declined 60.1 percent between 2003 and 2019. This, combined with rapid advances in technology for renewable generation, supported a shift away from coal. In addition to being a source of baseload power itself, natural gas has the ability to quickly ramp up, which helps handle intermittency from renewable power sources like the sun or wind. Chart 3 illustrates the share of total U.S. electric power generation from 1990 to 2019, by fuel source. The chart shows the stark decline of coal and the growth in natural gas and renewable power. Relative fuel-mix contributions from nuclear and hydroelectric power sources have both remained relatively flat over the period.

Chart 3. U.S. fuel mix for electric power generation, 1990–2019



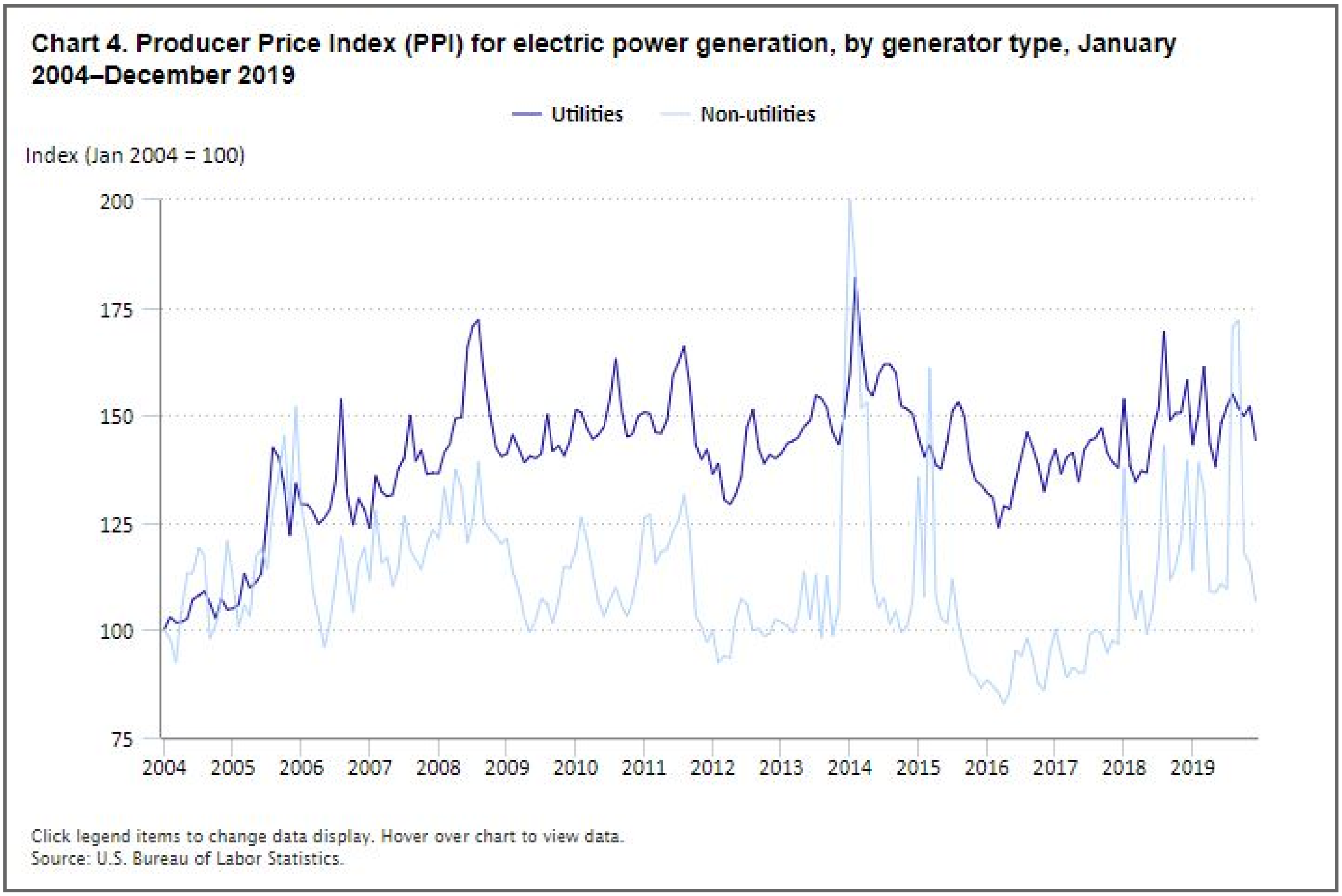
Click legend items to change data display. Hover over chart to view data.
Source: U.S. Energy Information Administration.

Changes in fuel types used to generate electricity are only one of several forces shaping price trends in wholesale and retail electric power prices. Shifts in demand, technological development, changes to market structure, and policy are all relevant drivers of power prices. Comparing medium- and long-term trends across generator types and regions with different fuel mixes helps demonstrate how price development has varied during the transition away from coal.

Price development by generator type

As described earlier, within the industry PPI for NAICS 221110 there exist two detailed indexes that independently track changes in prices for electric power generation—one for power generation by utilities and the other for power generation by non-utilities. These two PPIs for electric power generation reflect differences in prices by generator type. Utility generators represent legacy firms that operate as vertically integrated utilities that generate, transmit, and distribute electricity. Utilities remain major players in the market, owning many of the large coal, nuclear, and hydroelectric power plants and are still primarily responsible for electric power distribution. That said, expansion of open access to transmission in 1996, which required utilities to charge fair-market rates to competing generators seeking to move energy over the utilities' high voltage transmission networks, has led to growth in the share of energy produced by non-utility generators. Many non-utility generators are independent power producers, which are usually smaller and are more likely to produce power using natural gas and non-hydroelectric renewable energy sources. Both utilities and non-utilities have experienced significant declines in their use of coal to generate electric power, with usage by utilities dropping from 60.4 percent in 2004 to 32.1 percent in 2019; while coal usage by independent power producers declined from 34.0 percent in 2004 to 13.9 percent in 2019. As discussed earlier, coal has been replaced with natural gas and renewable energy, with independent power producers more likely to switch towards renewable energy sources. Independent power producers produced 61.7 percent of their power in 2019 from natural gas and non-hydroelectric renewable energy; compared to 37.3 percent for utilities. In the same year, non-hydroelectric renewable energy sources accounted for 20.1 percent of net generation for independent power producers, compared with 2.5 percent for utilities.[9]

Chart 4 plots the two detailed indexes for electric power generation from 2004 to 2019. Over this period, non-utility generators did not raise prices as much as utility generators—although they exhibited greater price volatility. Using annual average index data, the non-utility index rose 17.2 percent from 2004 to 2019, while the utility index rose 41.8 percent. Over this period, the utility index never fell below its January 2004 index value, while the non-utility index declined below its January 2004 index value in more than a fifth of the months between January 2004 and December 2019. This difference points to the impact that large quantities of existing coal plants have had on utility-based power generation, while independent power producers with fuel mixes that combine natural gas and renewable energy have been able to take advantage of falling gas prices and improving renewable technology.



Price development by regional fuel mix

The electric power system remains regionalized. State-based utilities generally approve rates, while most power consumed in a region comes from the generating capacity in that region. Using Energy Information Administration (EIA) data and aggregating states into their census regions, the PPI program can compare price trends across the regions, by fuel mix.[10] The figures in this section compare average price changes in residential electric power between regions with high or low capacity shares of the specific fuel types: coal, natural gas, renewables (excluding hydropower), and total renewables (including hydropower).[11] In contrast, within the main PPI structure for NAICS 221122, regional PPIs for residential electric power are combined to create and aggregate indexes for overall residential electric power.

Exhibit 1 categorizes each Census region's sources of electric power by type of power source, assigning a descriptor of either *low* or *high*. Regions are grouped as *low* or *high* based on whether they are in the upper or lower half of all regions for share of each fuel type, using the average share from 2004 to 2019.

Exhibit 1. Use of electric power generation sources, by region, 2004–19

Region	Coal	Natural gas	Total renewables	Renewables (excluding hydropower)
New England	Low	High	High	High
Middle Atlantic	Low	High	High	Low

See footnotes at end of table.

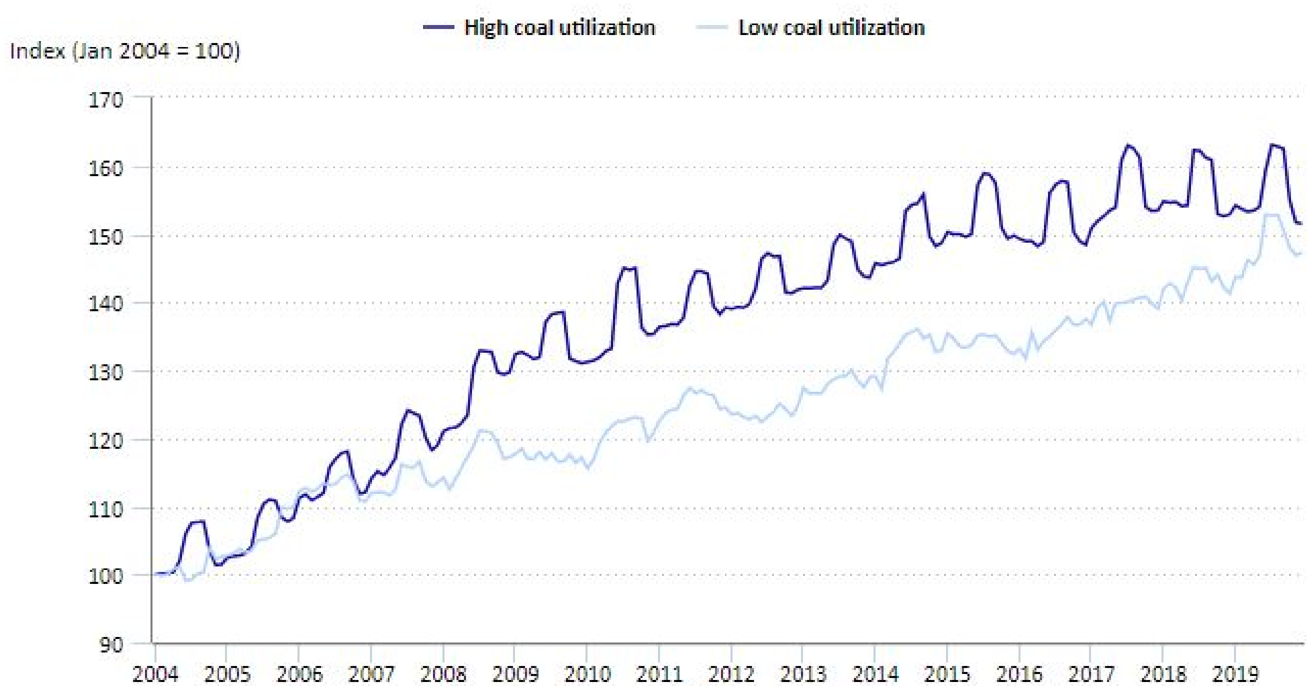
Exhibit 1. Use of electric power generation sources, by region, 2004–19

Region	Coal	Natural gas	Total renewables	Renewables (excluding hydropower)
South Atlantic	High	High	Low	Low
East North Central	High	Low	Low	Low
East South Central	High	Low	Low	Low
West North Central	High	Low	High	High
West South Central	Low	High	Low	High
Mountain	High	High	High	High
Pacific	Low	Low	High	High

Source: U.S. Energy Information Administration.

As shown in chart 5, regions with high and low shares of capacity in coal plants have seen prices diverge significantly since 2010. Prices have risen at a faster rate and remained at higher levels in regions with higher shares of coal. This is not surprising given the 93.4 percent increase in the price for prepared bituminous coal from 2004 to 2019.[12] Most of that increase happened between 2004 and 2010, when prices rose 79.8 percent.

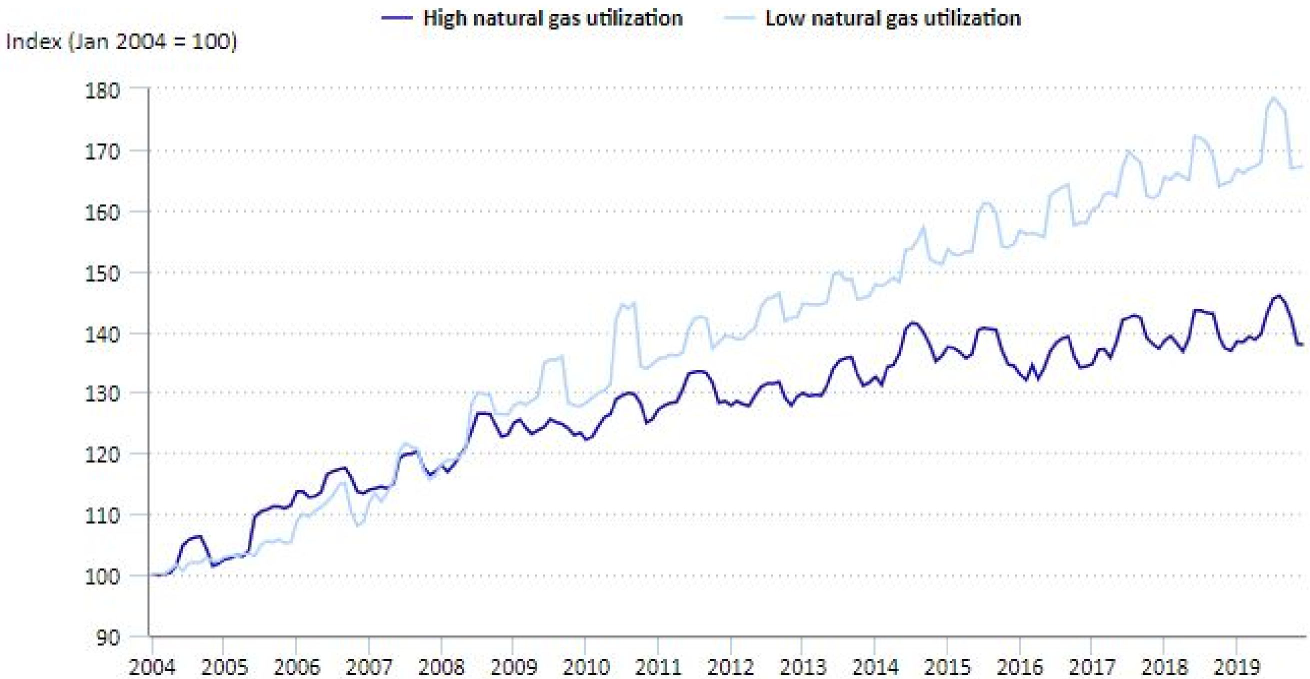
Chart 5. Producer Price Index (PPI) for residential electric power based on degree of coal utilization by region, January 2004–December 2019



Click legend items to change data display. Hover over chart to view data.
Source: U.S. Bureau of Labor Statistics.

Chart 6 compares the high and low groups by share of natural gas utilization for electric power generation, and indicates that regions with high penetration of natural gas saw prices rise at a slower rate since 2008. Regions with a low share of natural gas saw steeper price increases and exhibited sharper seasonal differences. This coincides with the overall downward trend in prices for natural gas, and its rise as an input to generation as compared to nuclear power and coal.[13]

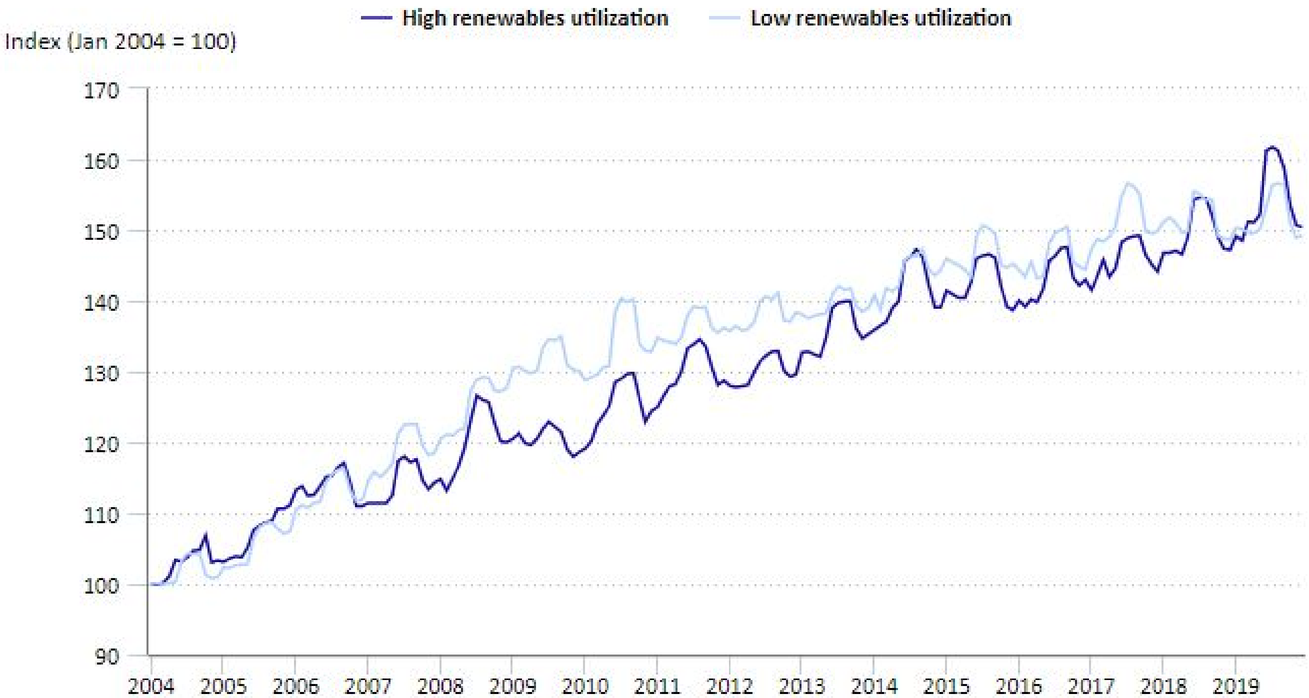
Chart 6. Producer Price Index (PPI) for residential electric power based on degree of natural gas utilization, January 2004–December 2019



Click legend items to change data display. Hover over chart to view data.
Source: U.S. Bureau of Labor Statistics.

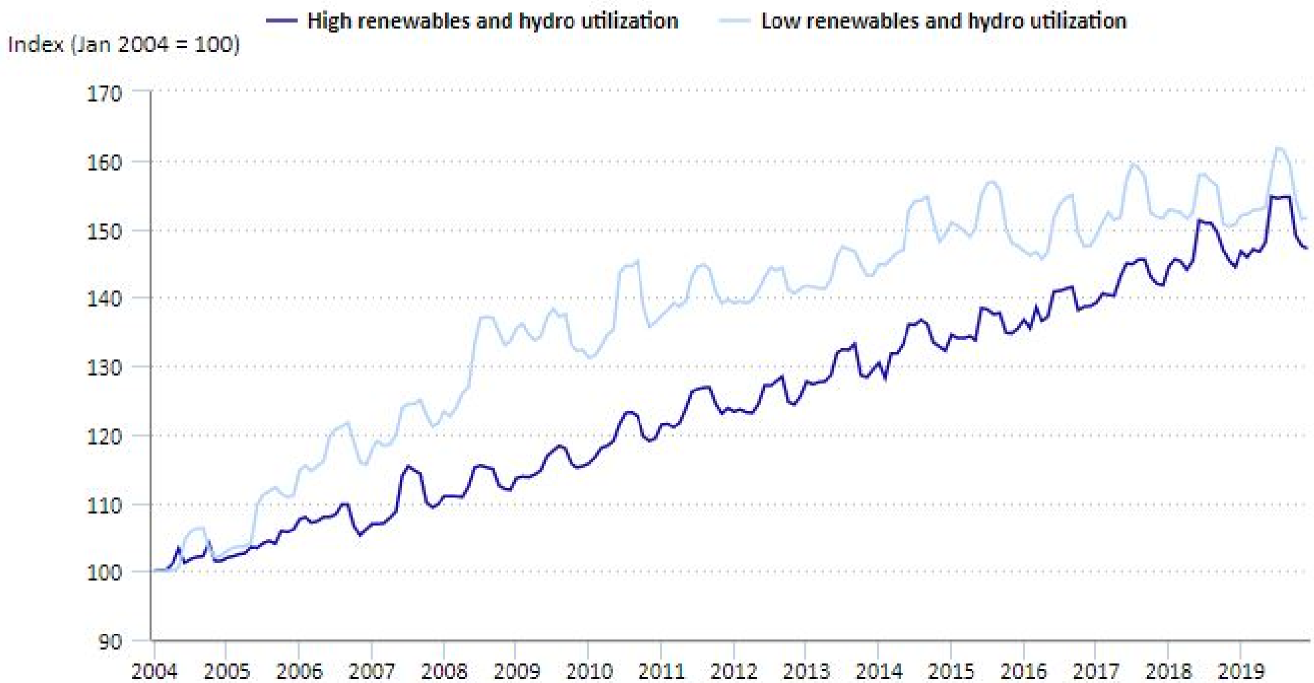
Reflected in chart 7, regions with higher penetration of renewable fuel (excluding hydroelectric power) saw slower price increases from 2004 to 2019. Electric power prices in regions with high shares of renewable fuel (excluding hydropower) experienced slower price growth and lower overall price levels from 2005 to 2015. Since 2015, the gap has closed and all regions have seen more similar price levels. For total renewable fuel, including hydropower, electric power prices in regions with high consumption of total renewable fuel did not rise as much from 2005 to 2019. (See chart 8.)

Chart 7. Producer Price Index (PPI) for residential electric power based on degree of non-hydroelectric renewable utilization, by region, January 2004–December 2019



Click legend items to change data display. Hover over chart to view data.
Source: U.S. Bureau of Labor Statistics.

Chart 8. Producer Price Index (PPI) for residential electric power based on degree of total renewable utilization, by region, January 2004–December2019



Click legend items to change data display. Hover over chart to view data.
Source: U.S. Bureau of Labor Statistics.

It is worth noting that the regions defined as high renewable fuel areas also are areas with substantial populations and high demand for electric power. Intermittency and location-specific availability of renewable fuel for electric power generation means that as the share of generating capacity from sources such as solar and wind rise, the degree of price volatility more heavily depends on the ability of transmission systems to cope with swings in availability. Given that marginal producers determine prices in deregulated energy auctions, a grid ill-prepared for a sudden drop in renewable fuel power generating capacity could see generators with the highest fuel costs (e.g., peaking oil generators) driving price changes. Prices for residential electric power in regions with high utilization of renewable power depend on non-renewable power-generating capacity to a higher degree than do regions with low usage of renewables fuel. The greater price stability linked to hydropower generation, and the smaller spikes during peak demand seasons, help demonstrate how intermittency can combine with existing grid characteristics to push prices higher in periods of high demand and low excess capacity.

Conclusion

In general, prices received by the electric power generation industry have seen only modest increases since the PPI for this industry was introduced in late 2003. Price increases for power generation have moderated in large part due to increasing competition, including growth in smaller-scale independent power producers that use more natural gas and renewable fuel, rather than coal, to generate electricity. The wholesale electricity market has benefited from low natural gas prices, as well as, falling capital costs for renewable energy from wind and solar sources (which have zero fuel cost and often only modest operating and maintenance costs). Over the same period, coal prices surged 93.4 percent from 2004 to 2019, while wholesale electricity prices increased 39.2 percent and retail electricity prices advanced 49.4 percent. Most of the increase in wholesale electricity prices occurred from 2004 to 2010, when coal was still the dominant fuel in the U.S. electricity sector.

Wholesale and retail power prices have been buffered from the effect of higher prices for coal by fuel-switching to natural gas and renewable fuel. Identifying the different price trends for residential electric power by regional fuel mix shows broad differences in how price trends by fuel source have varied between 2004 and 2019. Regions with higher use of natural gas and renewable fuel for electric power generation, in particular hydroelectric power, have seen prices rise more slowly than prices in regions that have predominantly used coal. Although it is not possible to attribute the differences in the retail price development solely to fuel mix, the significant role that capacity investment and fuel costs play in determining distribution rates suggests that at least part of the variation between these regions is explained by capacity shifts in the industry.

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NOTES

[1] "U.S. coal consumption continues to decline across all sectors," *Today in Energy* (U.S. Energy Information Administration, June 2020), https://www.eia.gov/todayinenergy/detail.php?id=44115; "U.S. coal-fired electricity generation in 2019 falls to 42-year low," *Today in Energy* (U.S. Energy Information Administration, May 2020), https://www.eia.gov/todayinenergy/detail.php?id=43675; and Fred Pearce, "As Investors and Insurers Back Away, the Economics of Coal Turn Toxic," *Yale Environment 360* (March 10, 2020), https://e360.yale.edu/features/as-investors-and-insurers-back-away-the-economics-of-coal-turn-toxic.

[2] For more information about the structure and introduction of the PPI for NAICS 221110 (Electric power generation) and NAICS 221121 (Electric bulk power transmission and control), see "New Producer Price Indexes for Electric Power Generation, NAICS 221110, and Electric Bulk Power Transmission and Control, NAICS 221121" (U.S. Bureau of Labor Statistics, October 2005), https://www.bls.gov/ppi/ppipower.htm.

[3] The United States Census Bureau designates nine census regions: New England, Middle Atlantic, South Atlantic, East North Central, East South Central, West North Central, West South Central, Mountain, and Pacific. For a map and more information, see "Census Regions and Divisions of the United States" (U.S. Census Bureau), https://www2.census.gov/geo/pdfs/maps-data/maps/reference/us_regdiv.pdf.

[4] For more information on U.S. electricity markets, see “U.S. Electricity Grid & Markets” (U.S. Environmental Protection Agency), https://www.epa.gov/greenpower/us-electricity-grid-markets; and “Electric Power Markets,” (Federal Energy Regulatory Commission, October 2020), https://www.ferc.gov/industries-data/market-assessments/overview/electric-power-markets.

[5] The two primary energy auctions are the day-ahead futures market that ensures enough capacity is available to meet expected future demand and a real-time market that balances supply to address deviations of demand from the day-ahead schedule. A large quantity of energy in deregulated markets is sold on the day-ahead market. For more detailed information on the structure of wholesale auctions, see “Lesson 8: Day-ahead and Real-time Energy Markets” from “EBF 483: introduction to electricity markets,” Penn State College of Earth and Mineral Sciences, https://www.e-education.psu.edu/ebf483/node/527.

[6] The PPI program also publishes a commodity index for electric power (PPI 054) using the same microdata employed to calculate the PPI for NAICS 221122, electric power distribution. This commodity index is available unadjusted (WPU054) and seasonally adjusted (WPS054). The seasonally adjusted version of this index accounts for identifiable, historical seasonal variations in the index. Long-term trends (12-month and annual rates of change) are comparable between the not-seasonally-adjusted and seasonally-adjusted commodity indexes, as well as to the industry index.

[7] Distribution prices are the result of complicated regulatory proceedings that require a full accounting of a utility’s rate base and expenses. A utility’s rate base includes the full set of assets that will earn a return, meaning changes in rate bases will reflect capital investment and plant retirement. Inclusion of operating and maintenance costs results in a pass-through of general inflation, as well as fuel- and plant-specific inflation. In addition to long-term trend components that drive prices up, short-term fluctuations in fuel costs will also pass through to distribution prices.

[8] Stephen York, “Drilling deep into PPI indexes to understand regional variations in natural gas price movements,” *Beyond the Numbers: Prices and Spending*, vol. 7, no 1 (U.S. Bureau of Labor Statistics, February 2018), https://www.bls.gov/opub/btn/volume-7/drilling-deep-into-ppi-indexes-to-understand-regional-variations-in-natural-gas-price-movements.htm?view_full.

[9] For more information, see tables 3.2 and 3.3 from the U.S. Energy Information Administration, Electricity: Electric Power Annual, https://www.eia.gov/electricity/annual/.

[10] The Energy Information Administration collects detailed generator data at the state-level on Form EIA-860 and makes these data publicly available; see “Form EIA-860 detailed data with previous form data (EIA-860A/860B)” (U.S. Energy Information Administration, September 2020), https://www.eia.gov/electricity/data/eia860/.

[11] Residential prices are used because the PPI disaggregates by region and end-user at the same time. Residential end-users typically account for a plurality of electricity sales. From 2008 to 2018, they were responsible for 37.6 percent of total sales of electricity in the United States, compared with 35.9 percent for commercial users and 26.3 percent for industrial users. (See table 2.5 in the EIA’s Electric Power Annual.) Residential consumers had the largest share of sales in each year in that time period. In general, the price trends for residential consumers presented in this article are similar for commercial and industrial end-users. One notable difference is that commercial and industrial users, due to higher average usage levels and lighter regulation, often display greater month-over-month variability in rates.

[12] To obtain PPI data for prepared bituminous coal and lignite, not seasonally adjusted, see https://data.bls.gov/timeseries/WPU051209?from_year=2001.

[13] To obtain PPI data for natural gas, not seasonally adjusted, see https://data.bls.gov/timeseries/WPU0531?from_year=2001.

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