The Impact of the Energy Transition on Wholesale Power Pricing and Market Risk

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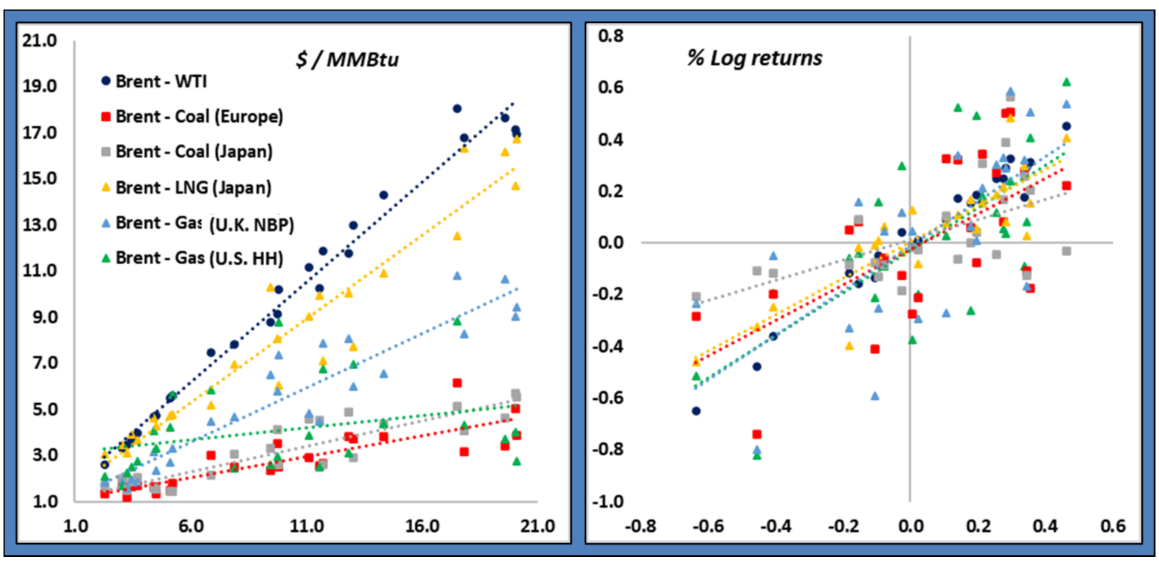
Low carbon power generation is gaining market share in many key markets around the world. Underpinned by displacing traditional thermal power generation with renewables like wind and solar, this trend introduces supply intermittency that drives new pricing patterns and changes the profile of risk. The scale and complexity of the intermittency challenge will increase as the share of renewable generation rises in energy systems. Understanding these challenges are key to investment, strategy, and policy decisions. This article explores these trends using evidence from the U.K. power market, followed by a discussion on future implications and recommendations.

Background

For decades, key energy commodities - crude oil, natural gas, coal, electricity - were interlinked. As globally traded energy commodities, crude oil and liquid fuels like heavy fuel oil (HFO) and gasoil were generally the dominant driver of other energy commodity prices. They drove gas and Liquefied Natural Gas (LNG) prices via contractual linkage, by influencing upstream costs for gas exploration, as competing feedstock into petrochemicals, and as competing fuels in power generation. They also influenced traded coal prices via mining and shipping costs. These historical relationships are illustrated in Figure 1.

Figure 1

Historical Relationship Between Oil, Gas, and Coal Prices and Returns (Annual Average, 1995-2019)[1]

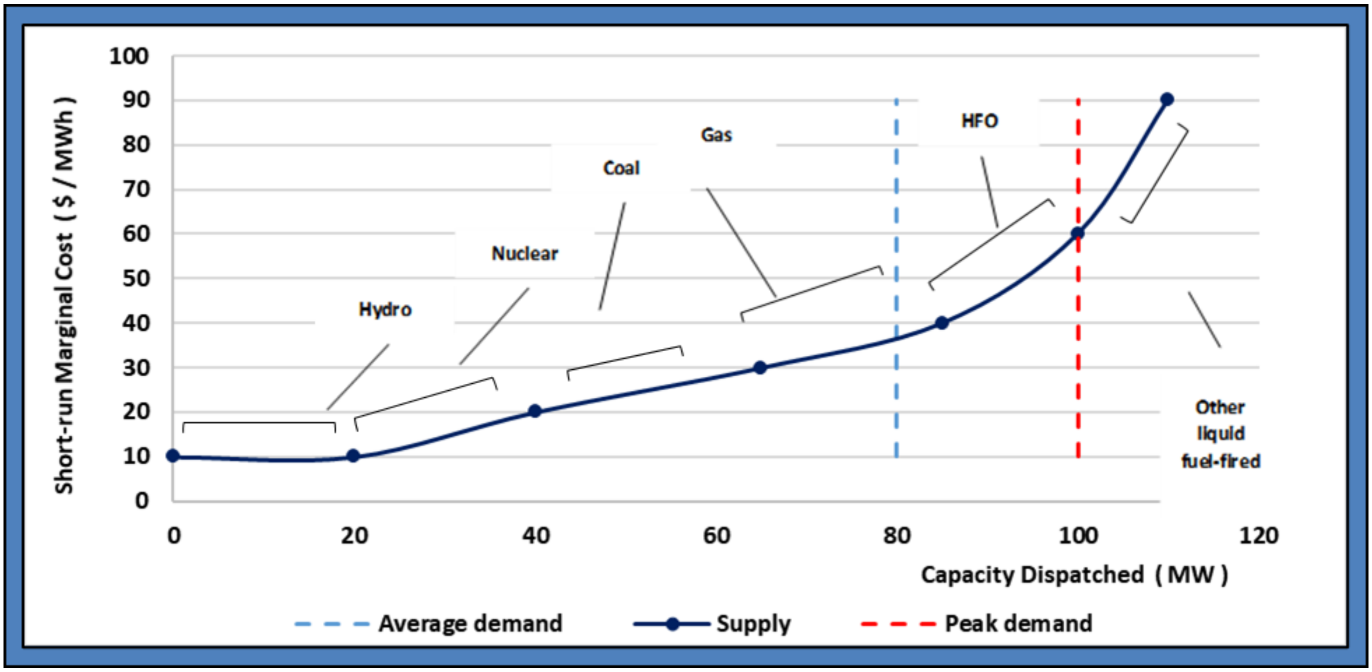


Abbreviations: MMBtu stands for million British thermal units (Btu). A Btu is a measure of heat energy and is a common unit for comparing fuels. U.K. NBP stands for the U.K. National Balancing Point while U.S. HH stands for the U.S. Henry Hub in Louisiana.

Notes: In the left-hand-side graph, the y-axis displays Brent crude oil prices, converted to $/MMBtu, while the x-axis displays six comparison fuels that are identified in the graph's color-coded legend. The right-hand-side graph uses the same color-coded legend to show % log returns of Brent versus the six comparison fuels.

These relationships underpinned power generation costs and price formation in traded markets across the world, which typically were in equilibrium with a fossil fuel-fired power plant setting the power price at the margin. See Figure 2.

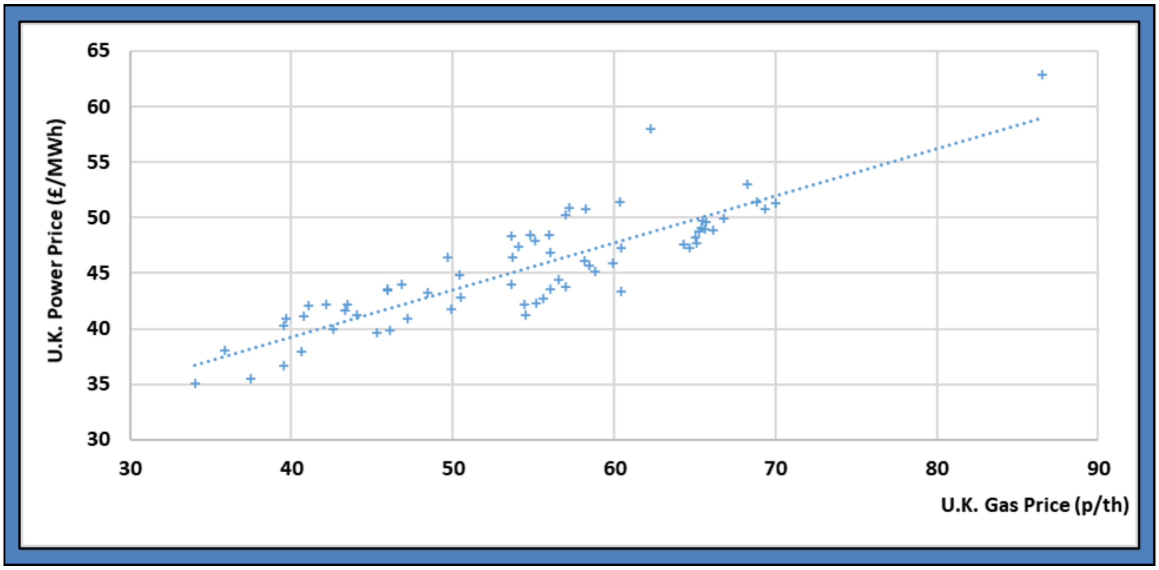
Figure 2
Make up of a Typical "Traditional" Power Supply Stack at a Given Point in Time



Abbreviations: MW stands for Megawatts, a unit of power, while MWh stands for a Megawatt of electricity used continuously for one hour.

The influence of fuel prices on power prices could be seen in the strong association between prices of power and fuels, especially gas, which were only broken for short periods of time due to localized shocks to demand and supply, *e.g.*, cold weather inducing high demand or outages removing supply. See Figure 3 on the next page.

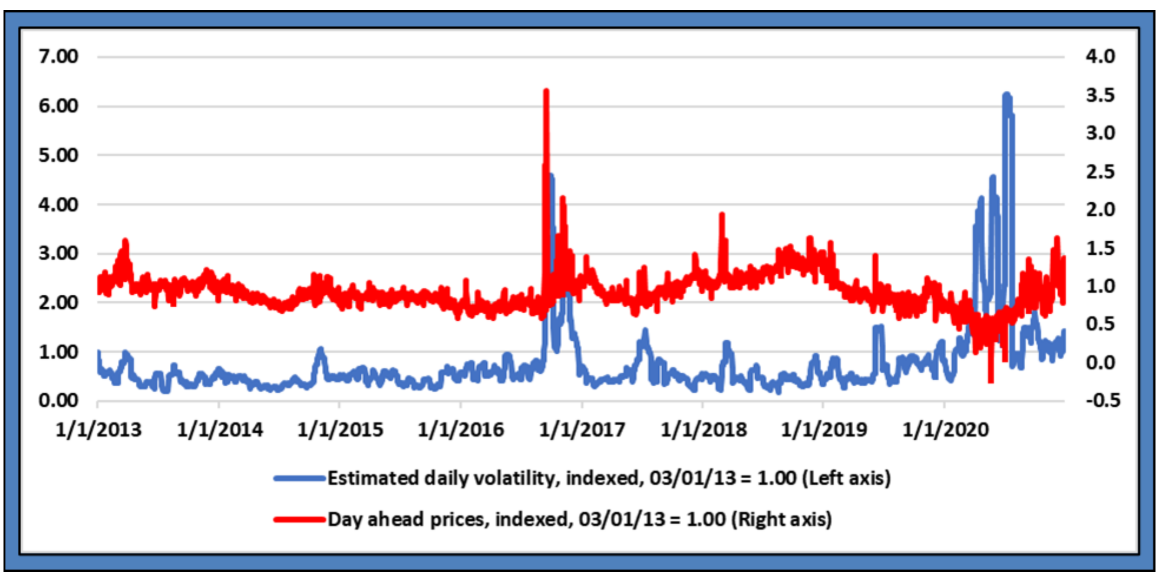
Figure 3
Historical Relationship Between U.K. Gas and Power (Monthly Average Spot Prices, 2010-2015)[2]



Abbreviation: p/th stands for pence per therm (in the U.K.).

It was also the case especially in electricity markets that price dislocations tended to be biased to the upside rather than downside; as during periods where supply relative to demand was limited, the probability of being short in a costly blackout event drove up prices much faster compared to how prices reacted during periods of oversupply. See Figure 4. On the supply side, plants could always turn off temporarily when they were "out of money," restoring balance while they would always be limited by their maximum capacity.

Figure 4
U.K. Power Spot Price and Volatility Trends (Daily, 2013-2020)[3]



Unhedged generation assets had the opportunity to recover higher profits during these periods of positive price spikes, which, if sustained, would signal the need for investment on the supply side. Conversely, downstream suppliers needed to be good at demand forecasting and hedge price risk typically via forward purchasing, and also via direct investment in generation assets, in the absence of liquid markets.

Effects of Low Carbon Renewable Generation in the Power System

As the transition towards a low carbon energy system progresses, renewables are displacing fossil fuels in the power generation sector. Oil and coal fired power plants are disappearing from the fuel mix altogether in many of the key markets.

The intermittent nature of the incoming renewable generation technologies, which are largely wind and photovoltaic solar, is changing how power markets function. Photovoltaic solar and wind generation technologies do not provide a controllable form of capacity due to their dependence on weather and other environmental conditions. This introduces new patterns and high levels of intraday as well as seasonal variability, which naturally also differ by location.

In addition to this, over a year, on average, these generation technologies typically provide a lot less than their maximum potential output compared to a traditional fuel-fired or nuclear power plant.[4] Therefore, in the absence of large-scale power storage, they need to be built in much larger quantities to ensure there is enough supply around when needed. The key challenge from a market risk point-of-view is that these plants sometimes do generate at or close to their maximum capacity. When that happens, there can be excess supply that is difficult to curtail, leading to strong downward swings in prices.

In sizeable power markets which experienced a quick buildout of wind and solar generation,[5] we have indeed started to observe changes in market pricing especially within-day where downside shocks, and in some cases even negative prices, are realized. Table 1 on the next page presents evidence from the U.K. power market where the ratio of the five highest and lowest hourly prices to the annual average price are compared across the years 2013, 2017, and 2019. These years were selected as they have similar average price and volatility characteristics and exclude periods of very high volatility as shown in Figure 4 on the previous page.

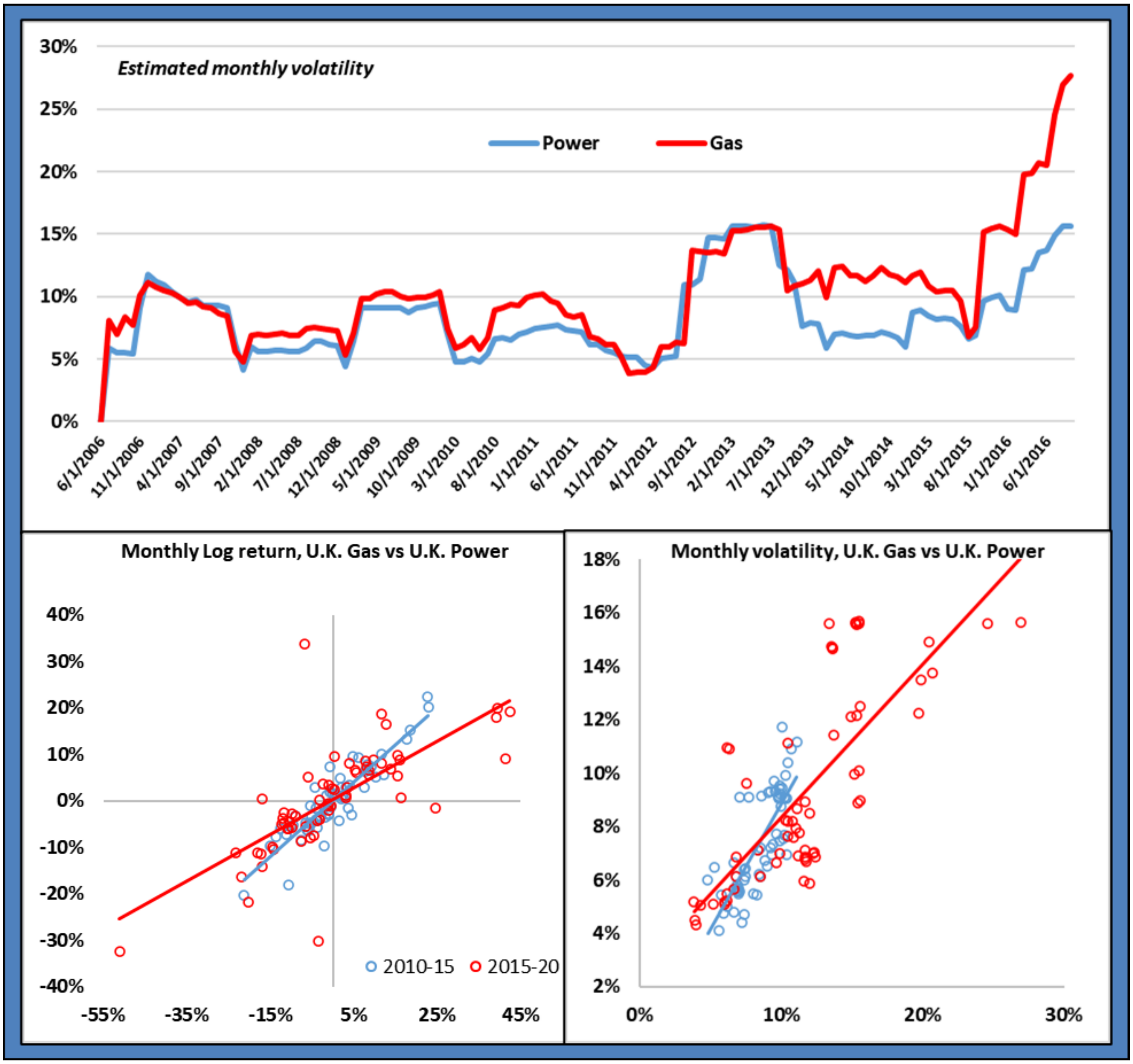
Table 1
Ratio of Highest and Lowest Hourly Power Prices to the Average Price within the Respective Year

		2013	2017	2019
	Highest			
	1	309.1%	330.8%	643.9%
	2	271.0%	322.4%	510.8%
	3	259.3%	308.8%	313.5%
	4	259.2%	299.2%	279.5%
	5	259.1%	293.0%	279.5%
	Lowest			
	1	29.9%	3.5%	-6.6%
	2	30.0%	4.2%	0.0%
	3	30.0%	10.1%	0.0%
	4	30.0%	10.3%	0.0%
	5	30.1%	11.0%	0.0%
Average day-ahead power and gas price (indexed to 2013=100%)				
Power		100.0%	90.4%	85.6%
Gas		100.0%	66.2%	51.0%
Ratio of Installed Wind and Solar to Total Installed Capacity				
		15%	31%	36%

It is immediately noticeable in Table 1 that despite similar price and volatility levels, we are seeing more extreme price movements as the ratio of wind and solar capacity in the power system increases.[7]

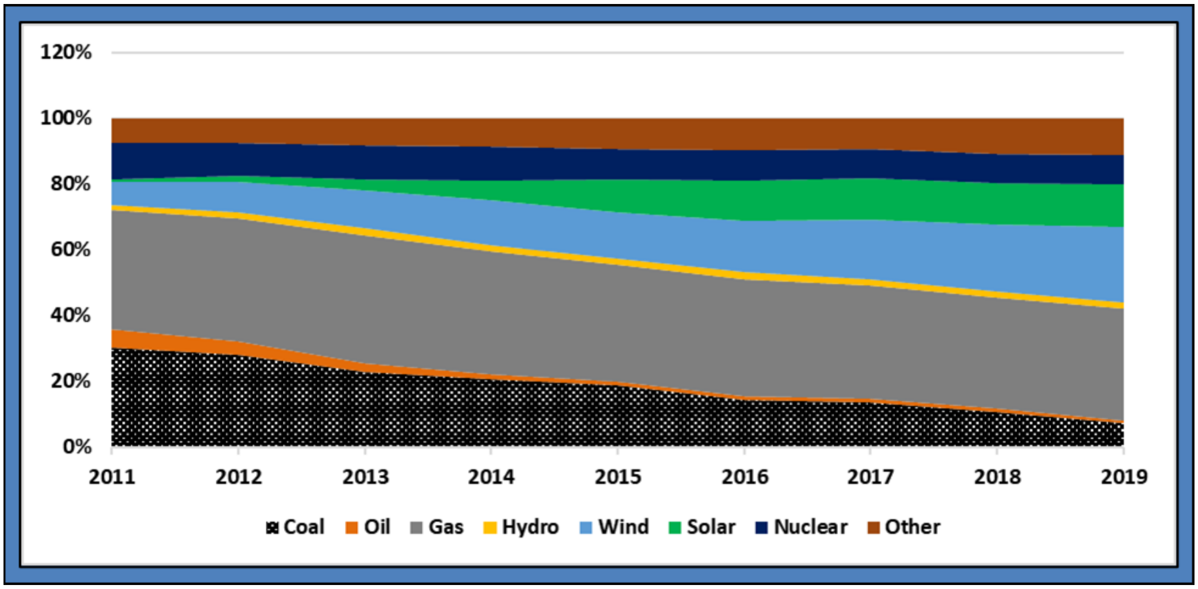
In addition to this, although a considerable amount of the variation in U.K. power prices is still driven by gas prices (as the marginal generator is still predominantly gas-fired), we are starting to see this relationship weakening with the relationship between renewable generation volumes and market price response strengthening. Figure 5 on the next page shows that during the earlier part of the last decade, U.K. gas and power price volatilities were highly correlated; however, the relationship became weaker in the second half of the decade, as evidenced by the flatter linear regression line as well as the dispersion of the data.

Figure 5
U.K. Gas and Power Returns and Volatility Trends (Monthly Data, 2010-2020)[8]



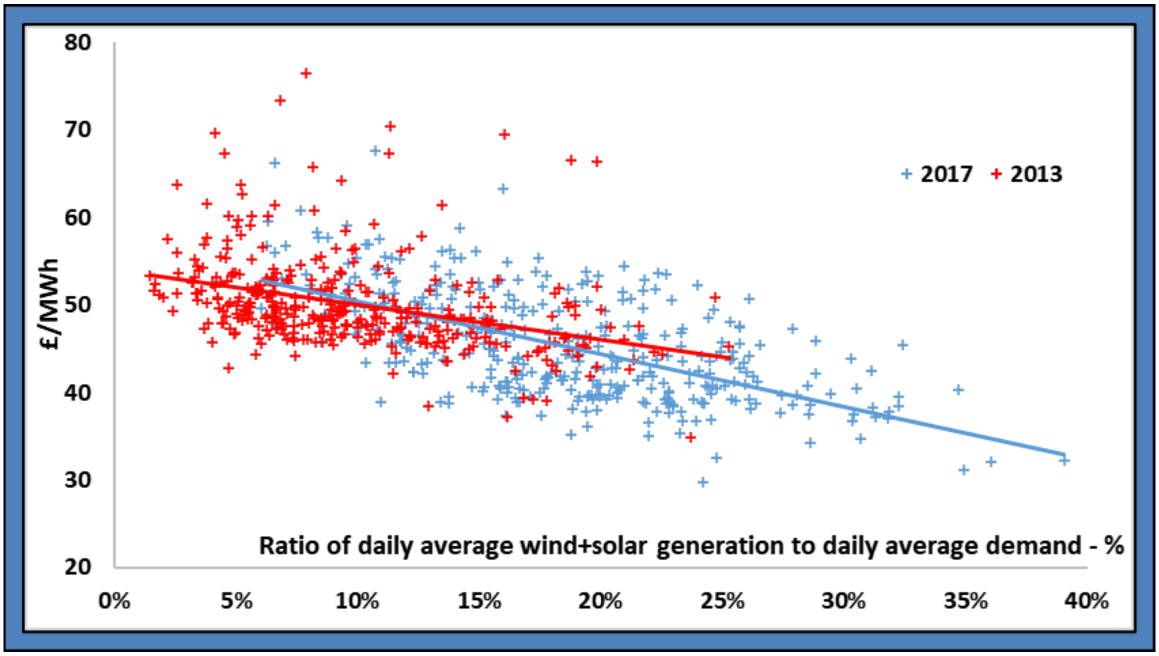
This is notable as gas-fired plants became the dominant thermal capacity over the same period as coal plants came off the system as new gas fired plants were built, which is illustrated in Figure 6 on the next page.

Figure 6
Installed Capacity in the Great Britain (GB) Power System, % of Total[9]



Intuitively, the consequence of this trend should be a stronger relationship between the price of gas and power. However, a combination of factors, including changes to plant efficiency as old plants retired and new plants came online, new interconnection capacity, and in particular, a substantial increase in the capacity of near-zero marginal cost plants (wind and solar), changed the market pricing dynamics. The impact of wind and solar generation on market prices is further examined in Figure 7 on the next page where the evolution of the relationship between day-ahead market prices and daily wind and solar generation as a percentage of daily average demand between 2013 and 2017 is shown.

Figure 7
Impact of Wind and Solar Generation on Power Prices in the U.K.



The data indicate that wind and solar generation became a stronger driver of power prices in 2017 vs. 2013, evidenced by a steeper regression line and less dispersion in 2017 vs. 2013. This is consistent with how the capacity mix evolved. Nameplate capacity of wind and solar in the Great Britain (GB) system increased from about 14 gigawatts (GW) to 31GW while peak demand fell in the same timeframe.

Transitioning to "Net Zero" and Implications for the Future

While the future evolution of the energy supply mix in a given geography is uncertain, on trend, power systems will include growing levels of renewable generation, in particular wind and photovoltaic solar. This will mean an amplification of the patterns driven by the intermittent nature of these technologies that we have briefly analyzed in this article.

An increasing share of these technologies will lead to the displacement of gas and other traditional thermal power plants as the marginal price setter. Initially this will increase short-term price volatility – a trend that has already started in some markets. In the longer term, in markets where the majority of generation comes from renewable sources, power prices could trend lower, leading to lower revenues captured by assets exposed to market prices. The impact of this on the wider market can range from lower returns for market participants to a slowing down of new investment. This impact could continue until or unless the market pricing regime evolves to reflect the long-run cost of investment in renewable generation or energy storage technologies (*e.g.*, lithium-ion (Li-Ion) batteries or hydrogen as an energy vector), which would need to become economic at large scale to take over as the marginal price setter.

In theory, energy storage presents a solution to the physical balancing challenges and hence a substantial commercial opportunity depending on future costs and other operational characteristics. In practice however, there are challenges to making storage work at large scale in competitive markets, as the "last" incremental new capacity has the potential to arbitrage away the profits for all incumbents. Adjustments to energy policy and regulation may be required to ensure different storage technologies have the chance to develop and become viable as a long-term solution to intermittency.

Conclusion

Low carbon power generation is gaining market share in many key markets around the world. Underpinned by displacing traditional fuel-fired power generation with renewables like wind and solar, this is introducing supply intermittency, the scale and complexity of which will increase as the trend advances. Based on an extrapolation of the impacts we see today we can predict that the magnitude of market (price) risk will increase in the coming years in the markets where low carbon generation gains market share.

Investors and market participants will need to build the skills to manage the changing risks as well as the analytical capabilities to stress test their portfolios against long-term directional shifts in market pricing. Policymakers will need to ensure markets continue to function as intended since markets will continue to play an instrumental role in meeting customers' energy needs as well as the decarbonization of economies in a commercially sustainable manner.

Endnotes

The *GCARD* previously covered the transition to next generation energy sources in an article based on a J.P. Morgan Center for Commodities' Research Council meeting that was summarized by the *GCARD*'s Contributing Editor, Hilary Till, and which is available at the following link:
http://www.jpmcc-gcard.com/wp-content/uploads/2018/10/JPMCC-Research-Council-Report-120415.pdf.

1 Source: BP Statistical Review.

2 Sources: U.K. Office of Gas and Electricity Markets (OFGEM) and Author's calculations.

3 Sources: Nordpool and Author's calculations.

4 Exact yields vary greatly by generation technology and specific location. For example, photovoltaic solar could be generating power throughout the entire day almost every day of the year in places with a sunny climate like in the Mediterranean region, reaching annual capacity factors close to 40-50% while they can be close to 10% in Northern Europe. Similarly, wind turbines can have higher yield when deployed offshore and at an elevation where wind speeds are more stable, promising yields above 40% while many onshore locations yield significantly less. It is also important to note that advances in both wind and solar technologies, including how they are deployed (*e.g.*, floating vs. fixed offshore wind), are improving yields.

5 For example, Germany, U.K., and California markets.

6 Sources: Nordpool, the U.K. Government Digest of United Kingdom Energy Statistics (DUKES) 5.12, and Author's calculations.

7 We can also see the confirmation of this trend in the distributional characteristics of the daily returns where we see an excess kurtosis of 2.9 in 2013 which rises to 5.9 and 7.4 in 2017 and 2019, respectively.

8 Sources: U.K. OFGEM and Author's calculations. Volatility estimated by 12-month rolling standard deviation of logarithmic returns.

9 Sources: U.K. Government DUKES 5.12 and Author's calculations.

Author Biography

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Mr. Nazim Osmancik is a senior executive with extensive experience in macro research, strategy, market analysis, trading and risk management gained in the energy sector and professional services. His professional experience includes leading risk, treasury, foreign exchange and cash management operations as Chief Risk Officer of Centrica Energy Marketing & Trading, as well as leading the global market analysis and price forecasting functions within Centrica Plc, U.K. Prior to Centrica, he held various posts in consulting firms including IPA, PwC, and ICFi. Mr. Osmancik studied Economics and Mathematics at Macalester College and has a Master's degree in Finance from the London School of Economics. His research interests include market pricing in fully decarbonized energy systems, non-linear interactions between energy commodity markets, forecast evaluation and enhancement, and developing systematic trading strategies. Mr. Osmancik had last contributed an article to the *GCARD* on "Evaluating Forecasts for Better Decision-Making in Energy Trading and Risk Management: An Industry Practitioner's View on How to Enhance the Usefulness of Forecasts Including Potential Applications of Machine Learning."

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