Merchant risk for wind and solar projects: towards a revenue-weighted energy yield

Wind and solar farms are commonly described as intermittent generators. Unlike their conventional fossil fuel counterparts, they cannot be switched on whenever the market price and/or demand is most suitable. This is one of the major challenges of renewable energy generators, and one of the key reasons that they needed secure, long-term support mechanisms to grow the solar and wind industry in the UK and other markets.

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Support mechanisms such as feed-in tariffs and Renewable Obligations Certificates (ROCs) gave investors confidence that their assets would secure a healthy revenue despite their intermittency.

The outlook for renewables in the UK today is very different, and we are seeing the installation of more and more projects without the financial safety blanket that support mechanisms offered. Power Purchase Agreements (PPAs) with a significant merchant component are becoming commonplace across Europe, and it is crucial for investors and developers to understand and mitigate merchant risk.

As technical advisors, we typically focus on predicting the long-term average energy yield of a wind or solar farm (the net P50 yield). However, this analysis traditionally does not take into account how seasonal, daily and hourly variations in wind or solar generation align with dynamic electricity market prices. In a merchant world, a megawatt hour of electricity generated during a time of low demand (and therefore low electricity prices) is worth less than a megawatt hour generated during a demand spike.

In this article, we explain how to combine electricity price and energy generation data to form a revenue-weighted P50 energy yield. Using UK electricity market data since 2015, we explore how wind and solar farms may have fared if they were trading their energy on the Day-ahead market and how this picture may evolve in the future.

METHODOLOGY

For the purpose of this analysis, we assume that the wind and solar generators would have to export their power to the grid regardless of the price, and that there would be no opportunities for curtailment or energy storage. We have focused on the UK's wind and solar fleet as a whole, rather than considering individual generators, although in reality the wind and solar resource profile will vary across the country.

A key input to the revenue-weighted energy yield is the Price Capture Ratio (PCR). The PCR is the ratio of the price achieved by the renewable asset at the time of generation against the average price over the given period:

- If PCR > 1, the renewable asset has achieved a higher price for the generated electricity than it would have achieved by taking the average price on the market.
- If PCR < 1, the asset would have been better off taking the average price of the market over the period.

Why is this important? The average price on the market is a major factor for setting the price that many of these renewable assets would be paid if they were to opt for longer-term PPAs. Opting for the safety of long-term agreements may lower the risk, but does it offer the best financial return in the long run?

The PCR can then be used to inform a revenue-weighted P50 energy yield. The table below shows a comparison between a conventional revenue calculation and the PCR-adjusted calculation.

Conventional financial model	Merchant financial model
Annual revenue = P50 energy yield (MWh/year) x Fixed PPA price (£/MWh)	Annual revenue = Revenue-weighted P50 energy yield (MWh/year) x average Day-ahead price (£/MWh) where: Revenue-weighted P50 energy yield = P50 energy yield x PCR (%)

*N.B. Both models have been simplified for illustrative purposes.

We have used the Day-ahead market as the basis of our study. We chose this market as it is the largest market in the UK in terms of traded volume of electricity. In 2019, 30 to 40% of all UK energy consumption was traded on the Day-ahead market.[1] A typical wind or solar merchant PPA will have a certain percentage of generation bought by the offtaker at a fixed price, and the remaining percentage is then paid based on trading the project's output on the Day-ahead market.

RESULTS

Quarterly average day-ahead price

Figure 1 shows the average Day-ahead price on a quarterly basis. The error bar in Figure 1 represents the highest and lowest half-hourly prices seen during each quarter. During quarter 1, 3 and 4 of 2016, the highest prices on the Day-ahead market were 245, 1174 and 796 £/MWh respectively.

A combination of low wind generation; unseasonably high demand as a result of weather conditions; planned and unplanned outages of nuclear power plants; and planned maintenance on the Irish interconnector caused the spikes in the Day-ahead prices.

Following a spike in electricity prices in Q3/Q4 2018, the average Day-ahead price has been on a downward trajectory. Of course, half-hourly spot prices vary considerably more than quarterly averages. While the positive volatility has also decreased in the market since 2019 — as shown by the error bars — the negative volatility has increased, with half-hourly prices going negative for the first time in Q4 2019. The negative prices, low volatility and downward trends in average prices represent an increase in risk for renewables operating in merchant contracts.

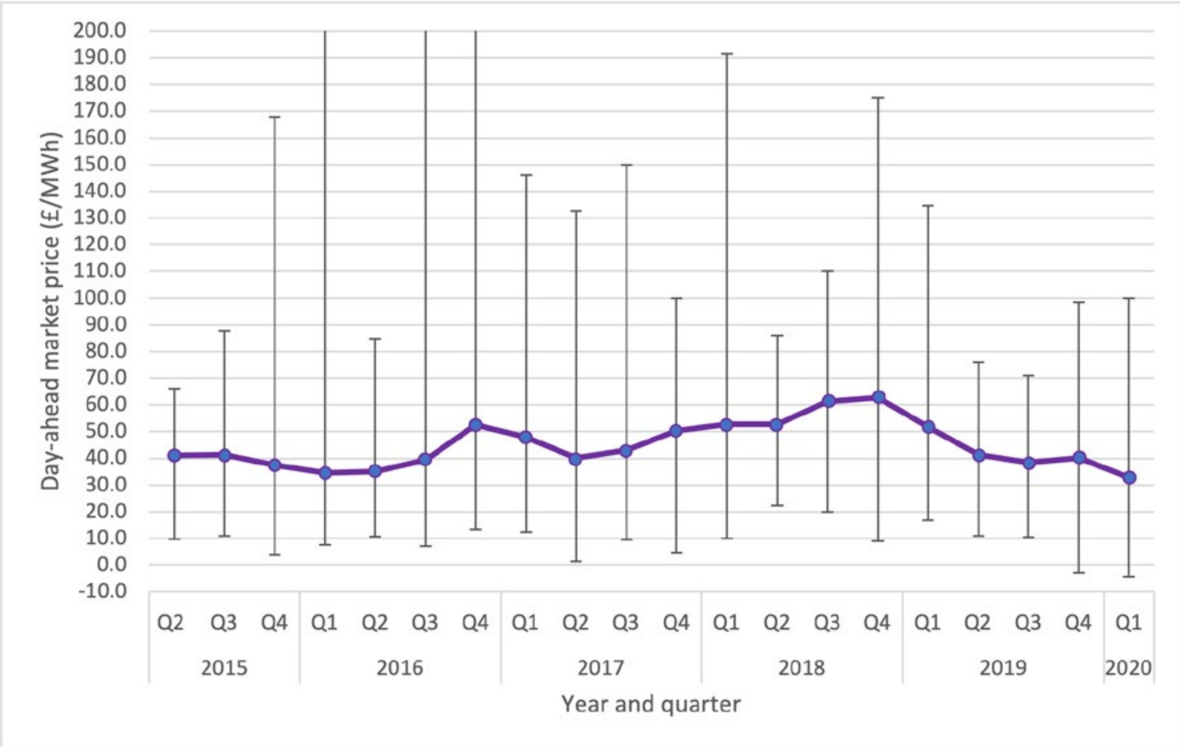

Figure 1: Average market price of each quarter.[2]

1 Nord Pool Group, (2020), Day-ahead prices. Available from https://www.nordpoolgroup.com/Market-data1/Dayahead/Area-Prices/ALL1/Hourly/?view=table [Accessed: 19/05/2020].

2 Entsoe, (2020) Day-ahead prices. Available from https://transparency.entsoe.eu/transmission-domain/r2/dayAheadPrices/show [Accessed: 19/05/2020].

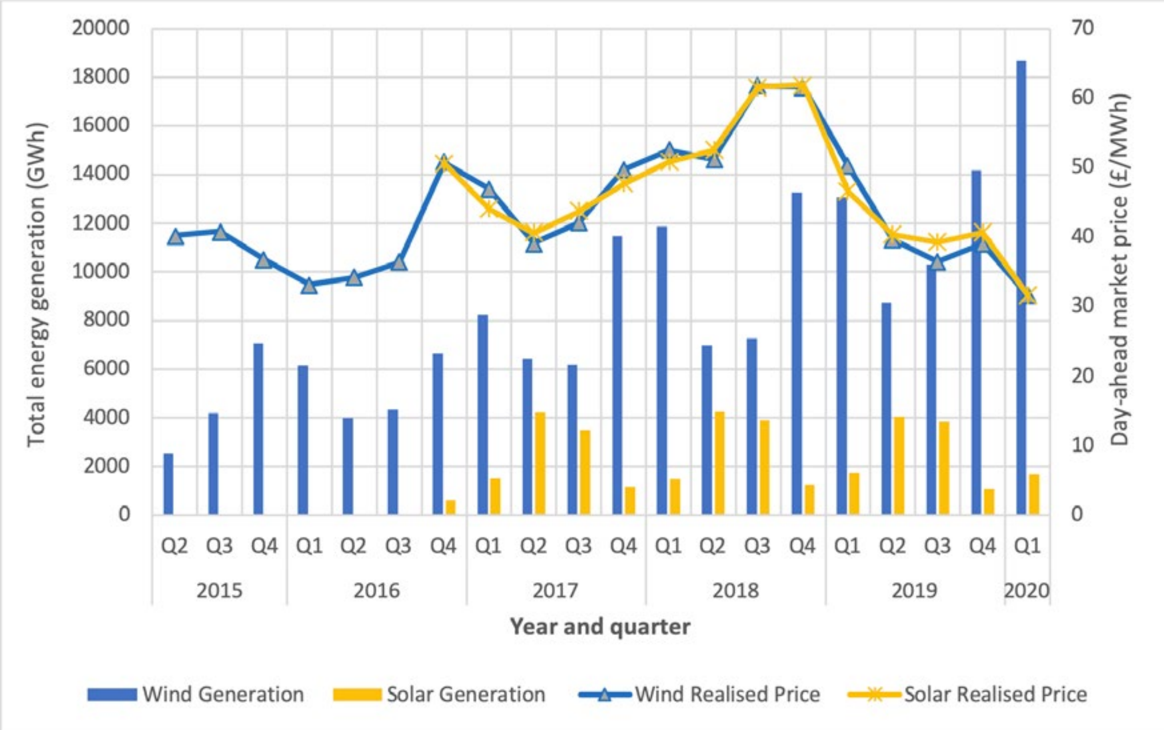

Figure 2: Total wind and solar energy generation and realised price on the Day-ahead market.

Figure 2 shows the total UK wind and solar generation for each quarter and the price that wind and solar would have been able to achieve if all their generation was traded on the Day-ahead market, as shown by the realised price for wind and solar. Unsurprisingly, solar generation is considerably higher in summer than in winter, whereas wind generation tends to be higher in the winter months when demand, and as a result electricity prices, is typically higher.

Figure 2 shows a clear increase in the total amount of wind generation since 2015 (as more projects have come online in recent years); however, solar generation is relatively stable since data was made available in late 2016. This reflects the slowdown in UK solar installations since its peak in 2015/16.

An interesting observation from Figure 2 is the significantly high wind generation in Q1 2020. While this can be partly attributed to increased wind capacity in the UK, the main cause of this high generation is due to unusually high wind resource during this quarter. **Figure 3** shows the extent of the increased wind resource in the UK.

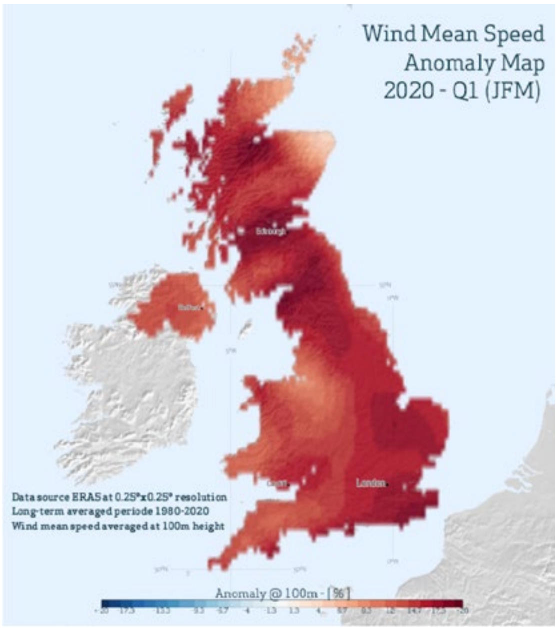

Figure 3: Mean wind speed anomaly map of the UK showing that most of the UK experienced wind speeds 10% higher than usual in Q1 2020, with some regions being over 18% windier than usual[3].

3 Vortex (2020), Wind Mean Speed Anomaly Map 2020 – Q1. Available from https://vortexfdc.com/knowledge/1q-2020-anomaly-wind-map-uk/ [Accessed: 19/05/2020].

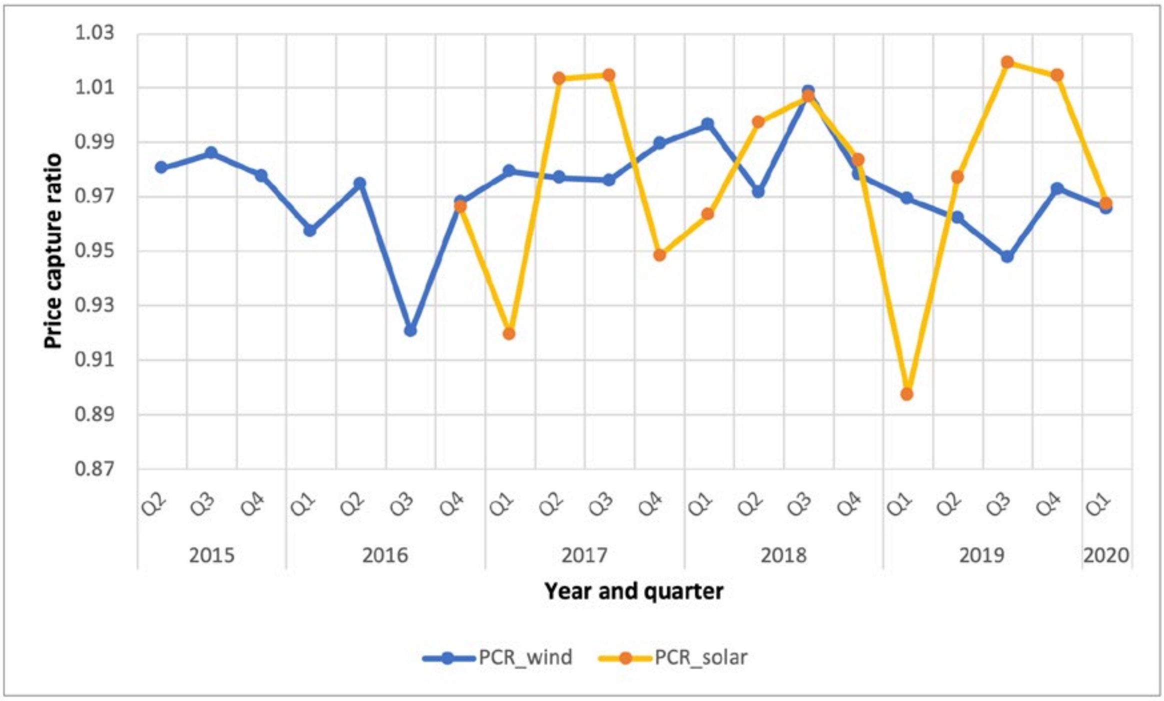

Figure 4: Capture price ratio of wind and solar generation using the moving average price across each quarter.

Up to this point, the realised price achieved by both wind and solar is mainly driven by the average Day-ahead market price, and it is difficult to isolate any trends caused by the wind and solar resource profiles themselves. This is where the PCR helps us to evaluate how the technology types have performed, independent of the broader market price trends. **Figure 4** shows the wind and solar PCR for each quarter. Please note that solar generation data was unavailable prior to Q4 2016. The results in Figure 4 find that the solar PCR is lower in the winter months compared with the summer months, with the realised price in Q1 2019 falling to around 90% of the average Day-ahead price, but Q2 and Q3 typically achieve a PCR slightly above 1. This shows that merchant solar projects achieve a better PCR during months they are able to produce more electricity during the morning and evening demand peaks.

The wind PCR follows a less predictable seasonal pattern and overall lower volatility compared with solar. We can observe a notable downward trend since Q3 2018. As wind already represents a significant fraction of the UK's total electricity generation, high volume of wind generation in the winter months may cause the Day-ahead price to decrease overall and lower the PCR. This cannibalisation effect is likely to increase in the future as more on and offshore wind farms come online.

This analysis clearly shows that while the impact of price cannibalisation is currently limited, it would be overly simplistic to assume that wind and solar can achieve average Day-ahead prices in a merchant context. It is important to account for the seasonal and intra-day variation of the wind and solar generation profiles to assess what percentage of the average market price a project will be able to realise.

Is this the shape of things to come?

As the penetration of wind and solar generation on the UK grid increases, we can expect to see more volatility on the Day-ahead market. As a result, individual generators will be more exposed to price cannibalisation effects, where particularly windy and/or sunny periods coinciding with low demand lead to low or even negative electricity prices.

You can see an example in **Figure 5**, which shows the demand and supply on the GB transmission network on the 13 April 2020.

The Day-ahead prices showed negative values for five hours from 03:00 to 08:00. This was a result of high levels of wind generation on the grid and a flattening of the typical morning demand peak because of the Covid-19 lockdown in the UK. However, with no solar generation on the GB transmission network, this graph does not allow us to see the effect that solar generation has on the Day-ahead market price.

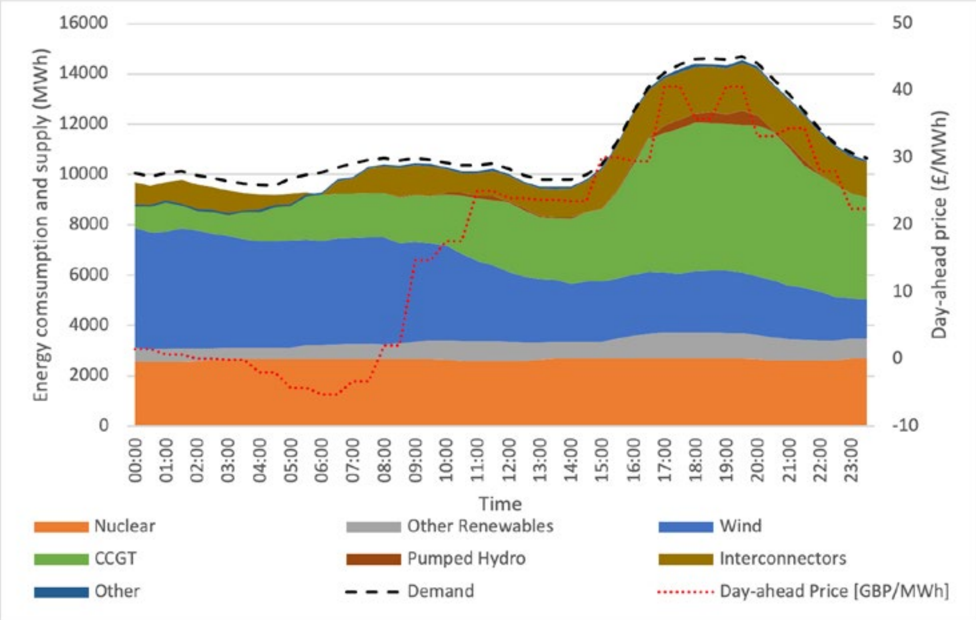

Figure 5: UK wind output against Day-ahead market prices on 13 April 2020.[4]

Figure 6 shows demand and supply on the transmission network, including solar generation. Note that real demand is higher than the demand shown in Figure 6, as some of the demand is met by embedded generation that is not captured in the transmission network metering.

Figure 6 shows that the peak of solar generation (coinciding with typically low demand during mid-day) led to another dip in the Day-ahead price, but the impact was less severe as wind generation had already fallen or had been curtailed by this point.

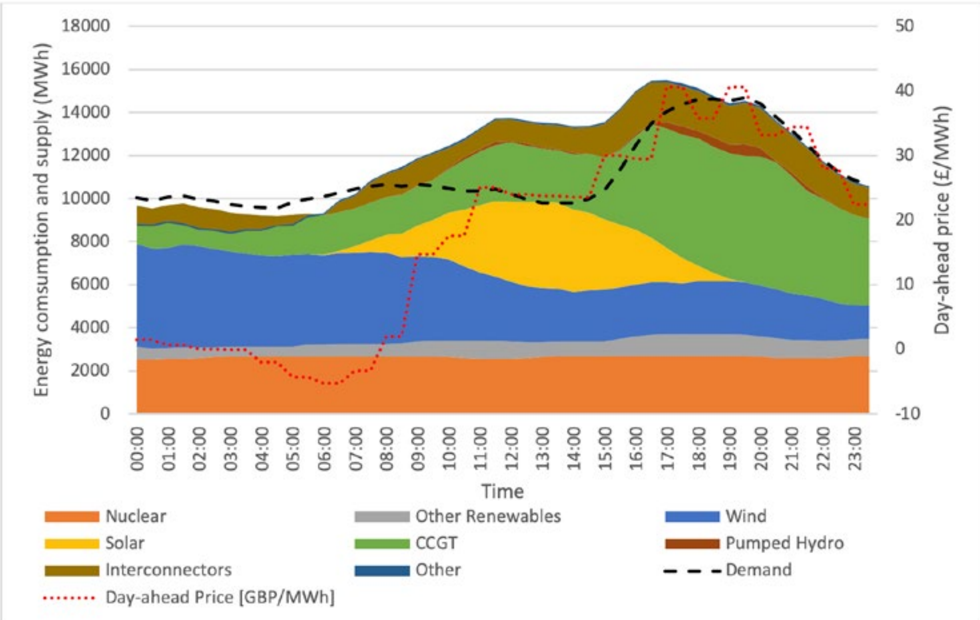

Figure 6: UK wind output against Day-Ahead market prices on 13 April 2020, including solar generation. N.B.: The solar generation is prediction of potential output given the weather conditions and may vary to actual output. The demand curve is for indicative purposes and may be higher or lower depending how much of the demand is being met by embedded services.

4 GridWatch (2020), G.B National Grid Status. Available from https://www.gridwatch.templar.co.uk/download.php [Accessed: 19/05/2020].

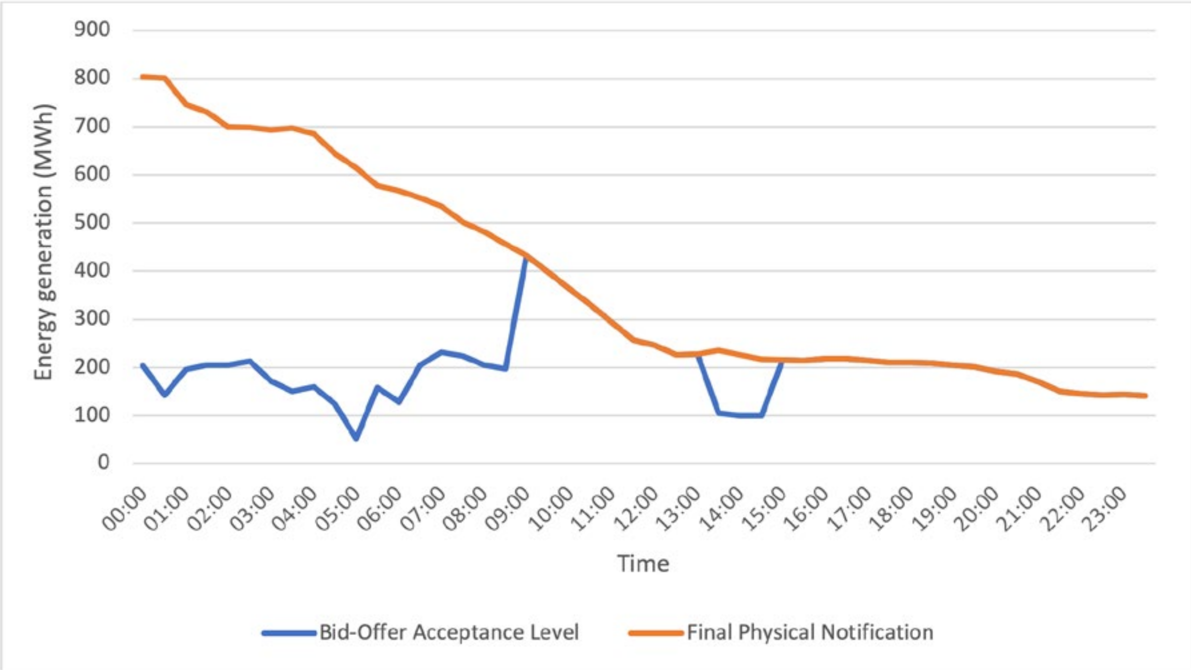

Figure 7: A snapshot of the wind generation on the 13 April 2020 from some of the largest wind farms in the UK. The orange line represents the power output available, and the blue line shows curtailed output from the wind farms. All four wind farms were curtailed during periods of high theoretical power output.[5]

The price recovery on the Day-ahead market was largely a result of the wind speeds in the UK reducing. However, **Figure 7**, which shows the output of four of the UK's biggest wind farms (Gwynt y Môr, Hornsea 1, Whitelee and Clyde), highlights that wind farms in the UK were also heavily curtailed during this period to help balance the system. The Balancing Mechanism (BM) tool manages this form of curtailment, and generators are paid to reduce their output.

The above analysis shows that negative price risk is becoming a key factor for merchant projects to consider. Under proposed rules for the upcoming CFD AR4 auction, even subsidised projects will not be paid for generation during negative price periods.

5 Elexon (2020), BM Reports Accessible from https://www.bmreports.com/bmrs/?q=balancing/physicaldata [Accessed: 19/05/2020].

OUTLOOK

The first step to mitigating merchant risk is to understand current trends. In this article, we have proposed a methodology for calculating a revenue-weighted P50 energy yield that takes into account wind and solar capture prices on the Day-ahead market.

Over the coming months, we will publish a series of articles exploring the following topics:

- Capture price trends for individual wind and solar generators across the UK and how owning a portfolio of geographically and technologically diverse assets may help to mitigate against merchant risk.
- Trends in the Balancing Mechanism and volume of curtailment.
- Pricing trends on the intra-day market.
- Continued impact of Covid-19 on the UK electricity market.
- Opportunities for battery storage co-location to reduce the need for curtailment and manage negative price risk.
- Trends in other countries with a strong merchant focus, such as Sweden and Spain.

To find out more and discuss how we can help you evaluate merchant risk for your projects, contact:

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