Call for Input

Power Market Liquidity

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Contents

Executive summary

We monitor liquidity levels in Great Britain's (GB) wholesale energy markets to ensure they do not adversely affect market efficiency and competition to the detriment of consumers. In this Call for Input we analysed liquidity levels in the GB wholesale electricity market and particularly looked at developments since the suspension of the Market Making Obligation (MMO) under the Secure and Promote licence condition in November 2019.[1]

We measured liquidity as total volume traded over the counter (OTC) and on power exchanges, as well as in terms of end-of-day OTC bid-offer spreads available to traders. Our analysis covered the years 2016-2023 and found that:

- Both total traded volumes and bid-offer spreads have worsened since the suspension of the MMO, reaching a trough in 2022 before rebounding somewhat in 2023 towards 2020-2021 levels
- The drop in liquidity has mostly affected curve products traded OTC.[2] The volume traded on exchanges on the day-ahead has been relatively steady and exchange-based curve trading has increased
- Similar trends have occurred in the other major European power markets (Germany, France, Italy, Netherlands)

We considered that at least four factors might have contributed to the observed reduction in liquidity on the GB power market curve contracts in recent years.

Firstly, record high prices and volatility following Russia's invasion of Ukraine and Europe's subsequent shift away from Russian gas has made trading power considerably more capital intensive. Traders are required to post more collateral and need larger credit lines to operate in a riskier market environment.

Secondly, the growth in renewable generation might be fostering a structural reduction in liquidity on forward contracts with longer-term delivery periods (far-curve contracts). Volumes of intermittent generation are more difficult to predict compared with firm generation and this might discourage selling on the far curve. At the same time, producers of firm electricity might prefer to market more of their future generation closer to delivery to take advantage of short-term price spikes on the spot or on the balancing mechanism when intermittent generation is low. A steep increase in

[1] Decision to suspend the Secure and Promote Market Making Obligation with effect on 18 November 2019

[2] Forward contracts that cover a minimum delivery span of one month make up the curve. We consider monthly forwards and the quarterly contract closest to delivery (front quarter) as near-curve products, while contracts with delivery from quarter+2 onwards as far curve.

intermittent generation capacity coming online through contract-for-difference subsidies indexed to day-ahead prices might also drain liquidity on the curve in future.

Thirdly, the vast majority of current domestic tariffs, which account for approximately one-third of GB's power consumption, are standard variable tariffs covered by Ofgem's default tariff cap. The methodology behind the cap calculation is linked to trading over the next four quarters. This might reduce the incentive to hedge on the far curve, especially on contracts beyond one year ahead of delivery.

Finally, these trends are compounded by GB power market's historical difficulty to attract the same level of speculative trading from international traders and financial institutions compared with the more liquid GB National Balancing Point (NBP) gas hub or German power market.

We are seeking views and supporting evidence from industry on the trends and drivers of liquidity in the GB wholesale electricity market; whether there is sufficient liquidity to meet the needs of market participants; and whether there is a need and scope for a regulatory intervention to support liquidity in the short-medium term.

We are also asking for views on what an intervention could look like, if evidence suggests that it may be required.

We welcome stakeholders' responses to the questions set out in chapter 6 of this document.

1. Introduction

Background

1.1 Ofgem defines liquidity as a measure of the ability to buy or sell a product without causing a major change in its price and incurring significant transaction costs.[3]

1.2 A liquid wholesale market has several buyers and sellers willing to transact frequently. This makes markets more efficient and price discovery easier and more transparent.

1.3 A liquid market also allows participants to more easily manage their exposure to future changes to commodity prices and avoid unwillingly taking on excessive volatility risk. This is because prices formed in liquid markets typically reflect demand and supply fundamentals better, increasing confidence in the price signals created in the market. Liquid markets may therefore reduce the costs of risk management.

1.4 Ofgem has set three liquidity objectives for wholesale energy markets. The energy markets must:

A. Ensure the availability of a range of longer-term products – this supports the hedging of risk of exposure to large changes in prices

B. Support robust reference prices that are widely available to market participants

C. Promote an effective near-term market which enables all companies to buy the energy they need for their customers

1.5 We have been monitoring levels of liquidity in Great Britain's (GB) wholesale energy markets to ensure they are adequate for markets to be competitive and efficient and are meeting our objectives.

1.6 Previous reports produced by Ofgem have found liquidity to be satisfactory in the GB gas market, but considerably lower in the GB power market.[4] In light of this, in 2014 we decided to develop regulatory interventions in the form of Secure and Promote.[5]

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[3] Electricity wholesale market liquidity | Ofgem
[4] For a brief history of liquidity in the GB power market and the publications prior to the introduction of Secure and Promote, see appendix 2.
[5] Wholesale power market liquidity: decision letter

Secure and Promote

1.7 Secure and Promote was designed to address three distinct objectives. These were to ensure the availability of products that support hedging, robust reference prices along the curve and an effective near-term market. The three elements designed to meet these targets were the Supplier Market Access Rules, the Market Making Obligation (MMO) and new Reporting Requirements.

1.8 The Supplier Market Access Rules sought to reduce barriers for independent suppliers to trade by making it easier for independent suppliers to access trading agreements and to trade smaller clip sizes.[6]

1.9 The MMO applied to the six largest vertically integrated companies in the electricity market – Centrica, EDF Energy, E.On, RWE npower, SSE and Scottish Power. It mandated that they post regulated bid-offer spreads for a number of forward products on an accessible trading platform during two one-hour windows. The MMO requirements are detailed in appendix 3.

1.10 The Reporting Requirements obligated licensees to submit a quarterly report to Ofgem containing information on their activities under Secure and Promote.

1.11 We monitored the effects of Secure and Promote on liquidity through yearly reports. We found that the MMO had a positive effect in reducing bid-offer spreads on the targeted forward contracts. However, its effects on total traded volumes were mixed. Total volume was the highest in 2016, when price volatility was also higher than usual. Once volatility declined the following year, total traded volume also dipped, suggesting the boost in liquidity was mostly driven by market fundamentals rather than market making requirements.[7]

End of the Market Making Obligation

1.12 The structure of the GB wholesale electricity market changed dramatically during the period that Secure and Promote was in place. By the end of 2019, there were no longer six large, vertically integrated, suppliers.[8]

1.13 As a result the MMO, which applied to companies meeting a set number of criteria in terms of vertical integration of their business and market share, fell on fewer

[6] Clip size refers to the size – usually in megawatt – of the contract to be traded.
[7] Secure and Promote Review: Consultation
[8] This was the result of a number of corporate transactions reducing the number of vertically integrated companies. The domestic market share of the original 'Big Six' suppliers (British Gas, EDF Energy, E,ON, npower, Scottish Power and SSE) shrank from 70% to 50% once SSE sold its supply business to OVO Energy in 2020. This has then crept up to 58% as of Q2 2023. For more information, see Electricity supply market shares by company: Domestic (GB) | Ofgem.

market participants over the years, ultimately applying to only two market participants by the end of 2019.

1.14 We therefore suspended the MMO in November 2019. At the same time, we committed to continue monitoring market liquidity with a view to assessing the impact of the MMO suspension on liquidity, while also considering alternatives to the MMO in the event we believed intervention was still necessary.

1.15 The Supplier Market Access Rules and the Reporting Requirements of Secure and Promote were not suspended in November 2019 and are still in place.

2. Case for review

Purpose and scope of review

2.1 The suspension of the Secure and Promote Market Making Obligation (MMO) provided us, and market participants, with an opportunity to observe liquidity in the absence of intervention and assess whether further Ofgem involvement would result in more efficient market outcomes.

2.2 In 2019 we commissioned NERA Economic Consulting as part of our ongoing assessment on whether interventions to support liquidity in Great Britain's (GB) wholesale electricity market were needed. In a report published shortly after the suspension of the MMO NERA concluded that, although the GB power market was less liquid than others in continental Europe, there was no clear market failure leading to a lack of liquidity in the GB wholesale electricity market.[9]

2.3 In December 2020 we concluded that liquidity had not fallen to a level whereby the liquidity objectives were not being met by market conditions.[10] We stated that intervention was therefore not justified at that point in time.

2.4 Since then we have continued to monitor liquidity in the wholesale electricity market, along with reviewing stakeholder feedback on liquidity levels, to assess if our liquidity objectives are being met. Our latest analysis, detailed in appendix 4, shows that:

- Total traded volumes on the curve have declined since 2020, although levels are increasing again and are higher in 2023 than they were in 2022
- Bid-offer spreads during 2023 remain significantly higher than historic averages prior to 2021. However, weekly averages this year have been consistently below the equivalent weeks in 2022
- Liquidity on day-ahead contracts has stayed broadly consistent since 2016, with traded volumes on spot market and exchanges increasing during 2022

2.5 We note that stakeholder feedback on liquidity has been mixed since the suspension of the MMO. For example, some stakeholders noted increased hedging difficulties following the removal of the MMO and the need for new intervention. However, other feedback has noted the need for caution and further evidence and

[9] Update - Liquidity Policy Review: Publication of NERA Economic Consulting Options Assessment Report
[10] Update on the future of liquidity policy

data gathering before making any fundamental new interventions in the short-to-medium term.[11]

2.6 We recognise that there are multiple factors which may be impacting power market liquidity and we are keen to hear wider views on what might be driving these trends.

2.7 We are also seeking views and supporting evidence from industry on whether liquidity in the GB wholesale electricity market is sufficient to meet the needs of market participants, or whether any intervention may be required in the short-medium term. We are also asking for suggestions on what intervention could look like, if evidence suggests that it may be required. In the longer-term, we will need to consider how any potential interventions could be affected by reforms introduced under the UK government's Review of Electricity Market Arrangements.[12] We will work closely with UK government to ensure liquidity is maintained in the transition to future market arrangements.

2.8 We would like to obtain data that could feed into any future impact assessment that may need to be undertaken. These could relate to any monetary costs or benefits that participants have faced, or expect to face, due to developments in electricity market liquidity over time.

2.9 When responding to the questions in this document, where possible, please outline any impacts on your business and provide evidence to support your answer.

Data collection

2.10 We have utilised data available under our licence with price reporting agency ICIS to continually monitor liquidity under the metrics that we describe above. These summarise liquidity in the over-the-counter (OTC) market and they are retrospective, reporting trends observed in previous days, weeks, months, etc.

2.11 We have also monitored how liquidity on power exchanges compares with OTC, since the former is increasing in prominence. Liquidity data from ICE and Nord Pool exchanges are available under subscription, while data from the EPEX exchange is available under our licence.

2.12 To determine churn, we have used the government's publicly available data on consumption from the Department of Energy Security and Net Zero in

[11] Feedback has been collected and summarised as part of bilateral discussions with stakeholders.
[12] Review of electricity market arrangements

collaboration with the Office for National Statistics. These values are published on the Ofgem website.[13]

2.13 The OTC data we used covers trades with physical delivery of the commodity (OTC Physical) and does not include financial trades (OTC Financial), which do not entail physical deliveries and work as a hedge against spot prices.

2.14 Historically, the number of OTC Financial transactions has been negligible when compared with OTC Physical ones both in GB market and in most of Europe. However, trading on OTC Financial deals has increased considerably in recent years, especially in certain markets such as Italy. We welcome feedback from stakeholders on the role played by OTC Financial deals in the GB power market.

2.15 Throughout our analysis we refer to spot trading as trading for deliveries on the same day (intraday) or on the next day (day-ahead).

2.16 We consider prompt trading as trading for delivery after day-ahead and up to the next month (front month), ie trading on day+2 onwards, next weekend, next week's weekdays, the remaining days of a week (balance of the week) or month (balance of the month) for which deliveries have begun.

2.17 Forward contracts that cover a minimum delivery span of one month make up the curve. We consider monthly forwards and the quarterly contract closest to delivery (front quarter) as near-curve products, while contracts with delivery from quarter+2 onwards as far curve.

[13] Dataset from Ofgem Wholesale Market Indicators, available at: Wholesale market indicators | Ofgem – Electricity trading volumes and churn ratio by month and platform (GB)

3. Market monitoring

3.1 In this section we show the main findings from our analysis of the current liquidity levels in Great Britain's (GB) wholesale electricity market. The full analysis can be found in appendix 4. In section 4 we discuss the potential factors behind our findings.

3.2 In our analysis we focused on two main indicators of liquidity: total traded volume and bid-offer spreads.

3.3 The total traded volume is how many megawatt-hours market participants exchange across all venues – through exchanges and over-the-counter (OTC) bilateral trading – and products. It gives a picture of how much trading market participants were able or willing to undertake ahead of delivery, and can be broken down by trading venue and product.

3.4 Bid-offer spreads are the price difference between the highest bid to buy and the lowest offer to sell wholesale electricity that market participants were happy to submit for a given forward contract on the market. In other words, the bid-offer spread shows the premium buyers need to pay to meet an offer and the discount sellers have to accept if they are willing to meet a bid.

Main findings

1. Total traded volumes for all contracts and products have dropped since 2016, but most notably since 2020. Traded volume reached its lowest total in 2022, following the price volatility caused by Russia's invasion of Ukraine, but has since recovered in 2023. However, traded volumes remain below 2016-2019 levels, when the Market Making Obligation (MMO) was in place. See appendix 4 section 1.1.

2. In particular, traded volumes of monthly and seasonal contracts have declined. However, traded volume on quarterly contracts has increased since Q4 2022, which may be linked to the change in indexation of the standard variable tariff price cap methodology. See appendix 4 section 1.2.

3. The share of total trading conducted on exchange-based spot markets has risen. This trend was particularly prominent in 2022 when prices increased dramatically and made longer-term prompt and curve delivery products significantly more costly, due to increased credit requirements. This increase in costs likely forced

some market participants to reduce their forward hedging and move to spot markets. See appendix 4 section 1.2.

4. Bid-offer spreads on curve contracts widened since the end of the MMO in November 2019 and reached consistently high levels in 2022, although reducing somewhat in 2023. However, bid-offer spreads on the day-ahead contract have remained broadly consistent since 2016. See appendix 4 section 2.1.

5. The trend of declining liquidity seen on the GB market is not unique to GB and is replicated in Germany, France, Italy and the Netherlands.[14] The GB market has consistently been the second most liquid northwest European power market behind Germany but above France, and in 2023 average GB bid-offer spreads have been wider than Germany's but comparable to France's. See appendix 4 section 1.3 and 2.2.

6. Since the suspension of the MMO in November 2019, traded volumes within the traditional 10.30-11.30am market making window have been substantially lower, but trading has been occurring more regularly throughout the day. See appendix 4 section 1.4.

7. Liquidity may have been too low for market participants to buy the necessary volumes of the contracts indexed against in the standard variable tariff price cap during two observation windows.[15] OTC traded volumes during the 9a and 9b observation windows were below the level of assumed supplier forward hedging specified under the standard variable tariff price cap.[16] See appendix 4 section 1.5.

8. It is unclear if bid-offer spreads are consistently at NERA's "low liquidity" threshold, due to the nature of the metrics used. The percentage bid-offer spread becomes lower when wholesale prices are high, as seen in 2022. See appendix 4 section 2.3.

[14] These countries do not have any liquidity interventions in place in their OTC markets.
[15] The dates for the observation windows are detailed in appendix 4, table 1.
[16] Cap periods refer to the period in which the cap on standard variable tariffs is set for. This was for a period of six months until cap period 8. The cap applied quarterly from period 9a (for Q4 2022). Each cap period has an observation window during which the notional SVT supplier is assumed to forward hedge their expected customer demand for the cap period and pay an indexed wholesale price for this volume of energy.

4. Potential factors behind liquidity trends

4.1 In this section we consider four factors which we believe might currently be constraining liquidity on Great Britain's (GB) power market, especially on curve contracts. These are:

i. Increased credit requirements caused by higher wholesale prices and market volatility

ii. Increase of renewables in the electricity generation mix

iii. Structure of retail contracts, with an increase in regulated variable tariffs in the domestic segment of the market

iv. Lower presence of financial and international traders compared with the GB gas market

4.2 This list of potential factors is not exhaustive and, as part of this Call for Input, we are seeking views from industry on what factors could be constraining liquidity at present or in future (see chapter 6).

Credit risk and price volatility

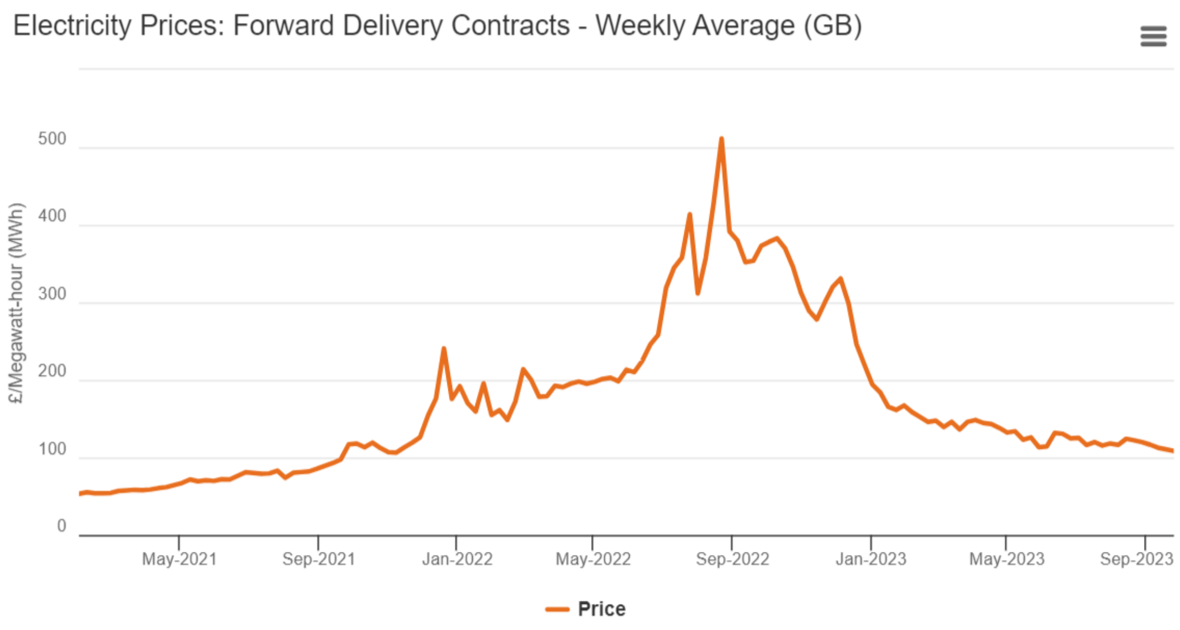
4.3 As shown in figure 1, energy traders have been facing highly volatile wholesale prices recently, on the back of the Covid-19 pandemic in 2020, rising tensions between Russia and Ukraine in the second half of 2021 and Russia's invasion of Ukraine in 2022.

4.4 An environment of price shocks and record volatility has made the financial architecture of credit lines and collaterals needed to support trading activities onerous to maintain and likely hindered traders' ability to operate on the market.

4.5 When wholesale prices increase, the amount of collateral that market participants are required to post to maintain credit margins rises to keep up with the higher financial value of trades. High volatility has a similar effect in draining credit lines and inflating collateral requirements, since it increases the mark-to-market exposure of trades.[17] This is particularly the case with far-curve products, which cover a larger period of delivery and are therefore more financially onerous.

[17] Marking to market is a way to measure how profitable or loss-making a trade is compared with the latest market price for the traded contract. Mark-to-market metrics are used by exchanges, brokers and market participants to gauge whether traders have the necessary amount of collateral to mitigate the impact of a market participant defaulting on the contract.

Figure 1 – Weekly average prices for electricity forward delivery contracts[18]



4.6 The increase in credit lines and collaterals for trading is likely to have been particularly detrimental to suppliers that did not have generation assets to back their credit needs. However, generators too faced credit pressures, and we are aware collateral requirements for some generators may have quadrupled in 2022.

4.7 Volatile prices might also make generators more cautious about the amount of future generation they are willing to sell in advance through forward contracts. Hedging only part of future generation reduces the risk of having to potentially buy back at scarcity prices on the spot in case of unplanned outages or delayed returns to service. This further lowers liquidity on curve contracts.

4.8 Data showing a pick-up in market activity in 2023 amid falling prices and volatility, as shown in the liquidity metrics in appendix 4, might indicate credit conditions for traders are improving.

Effects of rising renewable generation

4.9 Our data shows that the growth in renewable generation may also be a factor behind draining liquidity on far-curve forward contracts.

4.10 Renewable producers face a higher risk when selling volumes on the curve compared with thermal generators, as they have less certainty about the actual

[18] Chart from Ofgem Wholesale Market Indicators, available at: [Wholesale market indicators | Ofgem]

volume their assets will produce in future periods. The intermittent nature of wind and solar might therefore inherently discourage far-curve hedging to a certain degree. The subsidy structure that supports some of the installed intermittent generation is also likely to discourage market activity on the curve (see the next section on Contracts for Difference).

4.11 Producers of firm generation such as gas-fired, coal-fired and nuclear power plants have more of an incentive to sell at least part of their generation on the curve to lock in revenues and profit margins. In the past, it was not unusual for this class of generators to start selling part of their future production 18-24 months in advance.

4.12 However, the rapid growth of intermittent renewable energy has affected the running time of firm generation assets. The proportion of firm generation in GB's power generation mix dropped 18 percentage points to 62% between 2016 and 2022.[19]

4.13 Despite the decline, firm generation remains key to meeting demand needs when unfavourable weather restricts renewable output. During these periods, firm assets might reap much higher profits on spot markets and on the balancing mechanism than through forward hedging. This might make thermal producers less inclined to sell their future production on the forward market, even when curve prices are profitable.

4.14 If fewer generators have an incentive to sell their future production on the forward market, fewer buyers might be able to find the volumes they need to hedge their retail portfolios. This, in turn, would increase their exposure to price volatility and potentially undermine their financial stability, which could ultimately result in fewer market participants and a less competitive market for consumers. Alternatively, lower liquidity on the curve might lead to suppliers not offering fixed price tariffs and passing on short-term volatility to consumers through variable tariffs.

4.15 The relationship between rising renewable installed capacity and declining curve liquidity since 2016 is shown in figure 2a.

[19] See tables 5.6 in Digest of UK Energy Statistics (DUKES): electricity - GOV.UK (www.gov.uk)

Figure 2a – Annual trends in total GB power products traded and installed renewable capacity

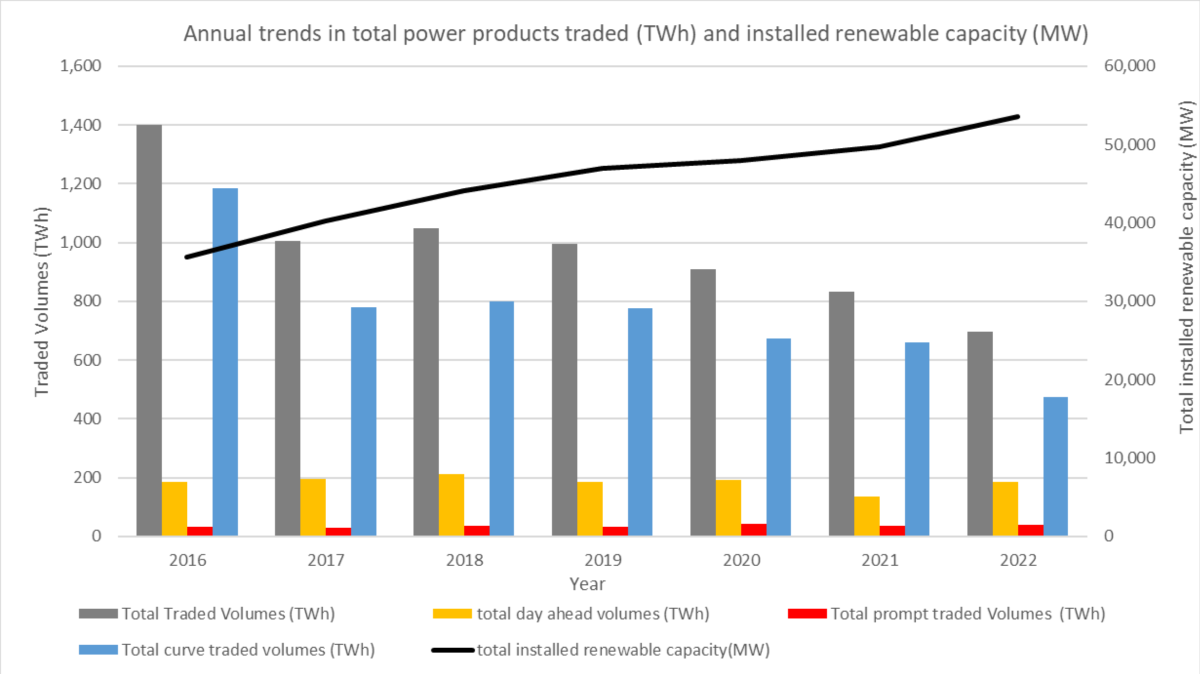
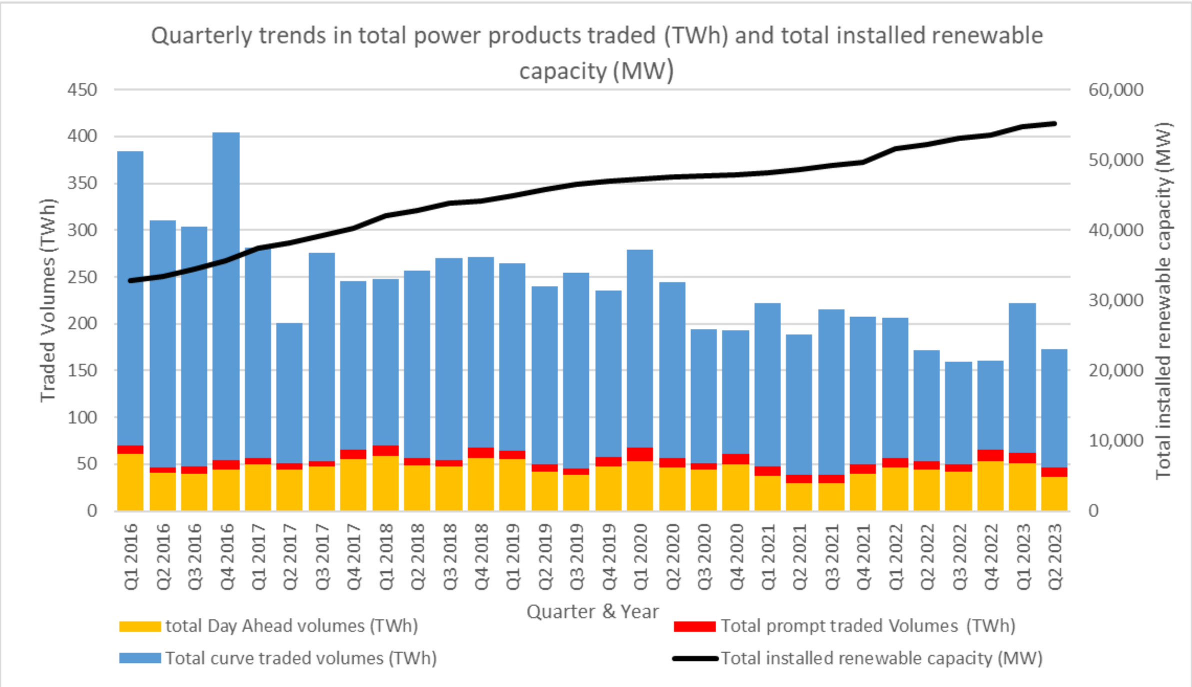


Figure 2b – Quarterly trends in total GB power products traded and installed renewable capacity[20]



[20] Data on renewable capacity from table 6.1 of the September 2023 edition of the Department for Energy Security and Net Zero's Energy Trends, available at Energy Trends: UK renewables - GOV.UK (www.gov.uk). Additionally, traded volumes are Ofgem analysis of data provided under licence from ICIS.

4.16 However, it is important to note that the correlation between these two variables is far from perfect, as shown in figure 2b. The drop in volumes traded on the curve accelerated since 2020 compared with 2017-2019, despite the rate of growth in installed renewables being slower. Day-ahead and prompt traded volumes have remained fairly steady since 2016, despite quarterly variation.

4.17 This suggests other factors have also likely driven the observed fall in volumes traded on the curve. These include, but are not limited to, reduced end-user demand caused by Covid-19, wholesale price increases and market volatility since 2021, and potentially the suspension of the Secure and Promote Market Making Obligation in 2019.

Impact of the Contracts for Difference scheme on liquidity

4.18 Contracts for Difference (CfDs) are GB's leading subsidy scheme in place for prospective renewable projects.[21] At present, CfD-backed installed renewable capacity stands at 6.7GW, or 15% of total renewable capacity.[22] However, projects which have secured CfDs with the Low Carbon Contracts Company (LCCC) have a combined capacity of 29.4GW, the vast majority of which are wind and solar projects which are set to come online in future.[23] As the energy system accelerates its path towards full decarbonisation, an increasing share of national power demand is likely to be met by CfD-backed renewable generation.

4.19 Since day-ahead prices are the market reference for CfDs, some market participants have raised concerns that the growth of CfD-backed renewables could result in an increasing share of generation being sold on the spot rather than hedged with curve forwards. Selling on the spot ensures that CfD generators receive the contractual strike price, as well as minimising the volumetric risk of hedging intermittent, weather-driven generation ahead of delivery.

4.20 In our analysis we looked at traded volumes and CfD-backed renewable generation to assess if there are any signs of this potential trend driving liquidity patterns on the GB power market.

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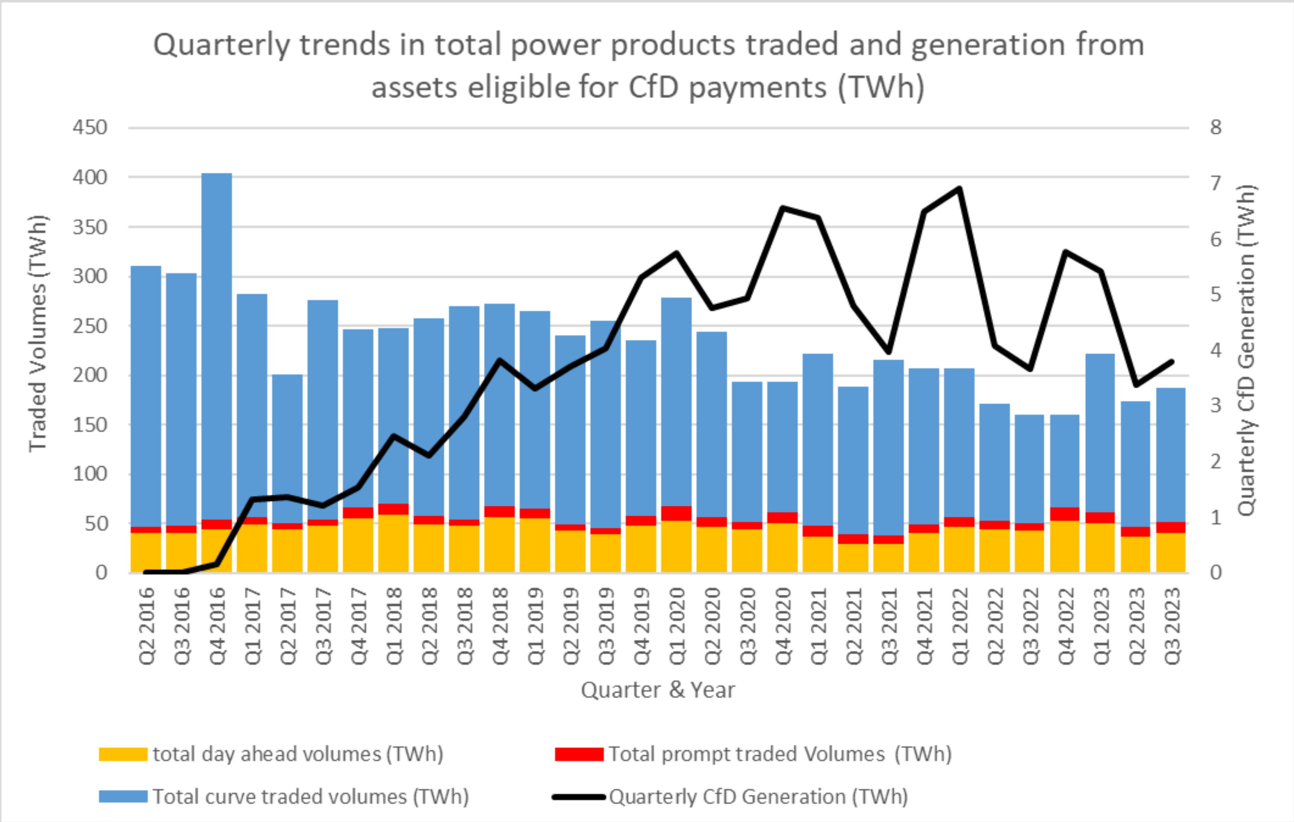
[21] A CfD is a contract between an electricity generator and the Low Carbon Contracts Company (LCCC) that enables the generator to stabilise its revenue at a pre-agreed price, referred to as the strike price. Each time wholesale market prices drop below the strike price, LCCC tops up the difference to ensure the generator receives the strike price. Equally, when wholesale prices ramp up above the strike price, the generator will reimburse LCCC for the extra profit.

[22] CfD Contract Portfolio Status - CfD Contract Portfolio Status - LCCC Data Portal (lowcarboncontracts.uk)

[23] CfD auction results can be found here: Auction Outcomes - Dataset - LCCC Data Portal (lowcarboncontracts.uk)

Figure 3a – Quarterly trends in total GB power products traded and generation from assets eligible for CfD payments[24]



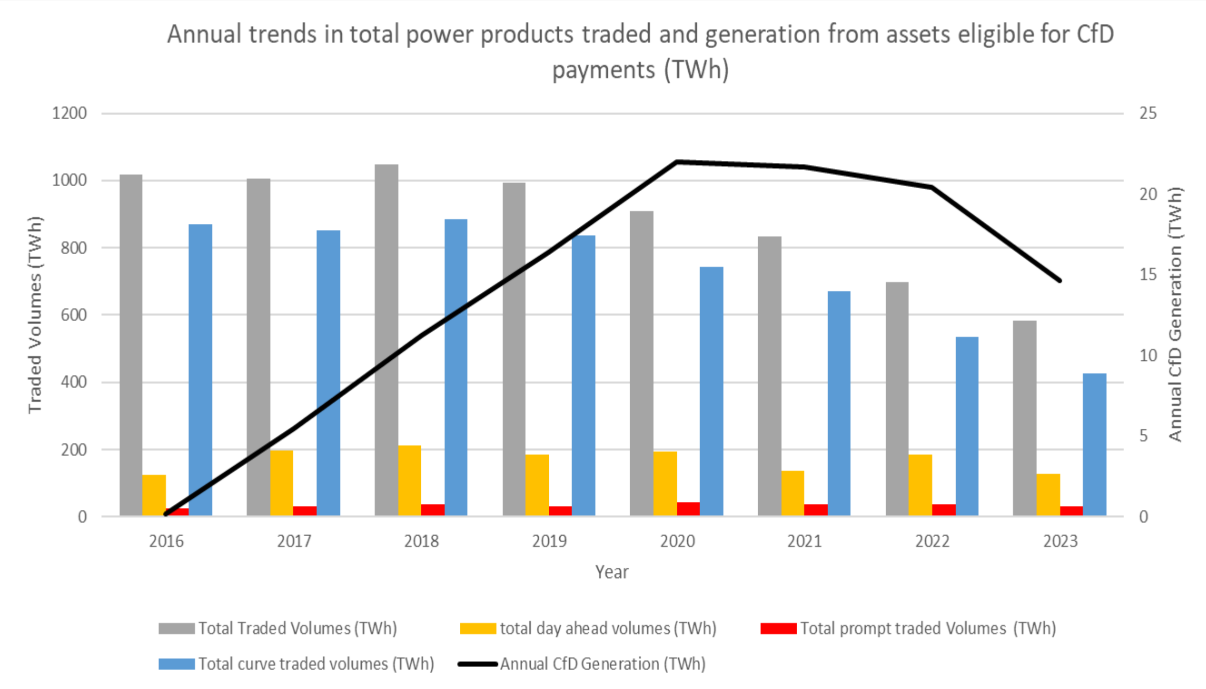
4.21 Figure 3a shows changes in traded volumes and CfD-backed generation in the GB market on a quarterly basis. The data shows no obvious correlation between changes in CfD generation and traded volumes for spot and prompt contracts from Q2 2016 onwards.

4.22 However, figure 3b aggregates the data year by year and does show a fall in total trading for curve contracts since 2018 – bearing in mind that 2023 is missing data for the fourth quarter.

4.23 While total trading of curve contracts has trended proportionately lower year-on-year, annual CfD generation has fallen since 2020, which points to other drivers behind these observed liquidity trends.

[24] Figures 3a and 3b use data on actual CfD generation from assets eligible for CfD payments from Actual CfD Generation and avoided GHG emissions - Dataset - LCCC Data Portal (lowcarboncontracts.uk) as updated on 7 October 2023. Data on traded volumes is Ofgem analysis of data provided under licence from ICIS.

Figure 3b – Annual trends in total GB power products traded and generation from assets eligible for CfD payments[25]



4.24 These findings suggest that the rise in CfDs is unlikely to be behind a meaningful shift of trading from longer-dated forwards to the spot for the time being. However, this might be because CfDs underpin a low proportion of total generation at the moment. Therefore, in the coming years, the scheduled rise of CfD-backed renewable generation might shift a considerable share of liquidity away from the curve.

Structure of retail contracts

4.25 The current structure of the domestic retail market might reduce the incentive to hedge on the far curve, especially on contracts beyond one year ahead of delivery.

4.26 Domestic consumers account for around one-third of GB's national power consumption. Suppliers offer households either a tariff fixing the price rate of their power consumption or a tariff that allows the price rate to track shorter-term wholesale market movements. Fixed tariffs typically last for one or two

[25] Total traded volumes during 2016 are only calculated from Q2 2016 to concur with the timeseries in the actual CfD generation dataset.

years, which means suppliers could be more interested in hedging their volumes further out on curve forwards.

4.27 Our data shows that the amount of households on variable tariffs rose from 50% to 87% in the year to July 2023,[26] as high wholesale price volatility meant suppliers removed fixed tariffs from the market.[27]

4.28 Variable tariffs are subject to Ofgem's default tariff cap methodology, which caps the rates that suppliers can charge households for the electricity and gas they use. Suppliers are incentivised to follow the price cap methodology to reduce their price exposure.[28] Since October 2022, the cap includes a backwardation allowance that incentivises suppliers to focus their purchases on the front quarter. A larger share of domestic variable contracts linked to Ofgem's cap might make suppliers less interested in hedging their customers' volume on longer-date forwards, such as the seasons.

4.29 Since March 2023, we have started to see more fixed tariffs being offered again, so this trend may change in the future. Lower wholesale prices and the expiration of the Market Stabilisation Charge in March 2024 could lead to fixed tariffs covering a higher number of consumers.[29]

4.30 When it comes to industrial consumers, the tariff picture is more nuanced. Industrial consumption makes up two-thirds of GB's power consumption. Industrial consumers can negotiate supply contracts with varying degrees of market exposures and contract lengths covering several years of supply. For this reason, drawing conclusions on how industrial contracts may affect hedging is more complicated.

4.31 The structure of retail contracts has knock-on effects on market participants' willingness to trade on the wholesale market. The higher share of households on variable tariffs could be reducing the involvement of traders on far-curve forwards. If this trend continues, it could structurally reduce the presence of buyers on the far curve at a time when producers could also withdraw their involvement on the back of growing subsidised renewable generation.

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[26] See 'Number of domestic electricity customer accounts by supplier (excluding pre-payment customers): Standard variable, fixed and other tariffs (GB)'; available in Retail market indicators | Ofgem

[27] The number of fixed tariffs available on the market dropped from 1220 in 2021 to 337 in 2022, according to our analysis of Cornwall Insights data. Zero fixed tariffs were available between November 2022 and February 2023.

[28] Suppliers are still responsible for managing their wholesale procurement, including considering what commercial decisions to make.

[29] For more information on the effect of the Market Stabilisation Charge on fixed tariffs, see Future of Market Stabilisation Charge after March 2024 | Ofgem

Low market participation of financial and international traders

4.32 The GB power market is historically less liquid than its gas equivalent. One of the reasons for this is the higher number of financial institutions active on the gas market compared with power, and the different stance GB markets hold in the continental (and global) arena.

4.33 As the trading hub of Europe's first liberalised gas market and – until the mid-2000s – the largest gas producer, the NBP hub was for decades the go-to market for gas in the continent as well as a price reference for gas forwards.

4.34 This attracted liquidity and trading interest from abroad to the NBP, with market participants joining the hub not just to secure physical deliveries of gas but also for speculative trading. Although the NBP is now second to the Dutch TTF hub in terms of liquidity, the market continues to see good metrics in terms of volume liquidity and trading churn rates.

4.35 The GB electricity market has seen international financial traders lower their participation over the past two decades on the back of the Enron scandal of 2001-02 and the effects of the 2008-09 financial crisis.[30] At the same time, a historically low degree of interconnectedness with other northwest European markets capped the international reach of the GB power market compared with the NBP.

4.36 Our data on over-the-counter (OTC) trading activity on GB power and NBP front-month products in 2023 shows that the number of international companies,[31] financial institutions and trading houses active on GB's power market is considerably lower than on the NBP.[32]

4.37 The liquidity picture of the GB power market improves when comparing it with other European power markets rather than the NBP, although it considerably lags behind Germany's. The German power market has attracted more activity thanks to its deeper volume pool – based on higher industrial and residential demand – as well as its geographical position and high interconnectedness with other large markets such as France, the Nordics and Italy via Switzerland and Austria.

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[30] For a discussion on changes in liquidity after the Enron scandal, [Liquidity in the GB wholesale energy markets (ofgem.gov.uk)](https://www.ofgem.gov.uk).
[31] For the purpose of this analysis, we considered 'international' a market participant that either does not have a retail presence or does not own power generation assets in GB.
[32] Ofgem analysis of OTC data for gas and power in 2023.

4.38 Although the factors determining the lower participation of international and financial traders in GB's power markets compared with the NBP or Germany might be structural, we welcome views on how this could be improved.

5. Potential intervention

5.1 The purpose of this Call for Input is to gain stakeholder views on the current levels of power market liquidity, to inform our assessment of whether market conditions are resulting in insufficient levels of liquidity, and therefore whether policy options for intervention may be justified. Until this evidence has been provided and assessed, we are not suggesting that intervention is necessary. In the longer-term, we will need to consider how any potential interventions could be affected by reforms introduced under the UK government's Review of Electricity Market Arrangements. We will work closely with UK government to ensure liquidity is maintained in the transition to future market arrangements.

5.2 In 2019, Ofgem held a Liquidity Policy Options Assessment Stakeholder Workshop. The feedback from industry participants widely accepted that, should further intervention to support liquidity in the wholesale market be required, the intervention should be in the form of a tendered or voluntary market making obligation. This workshop was attended by over 30 market participants and included a range of generators, suppliers and energy traders. Stakeholders argued that a competitively designed tendered approach should be the preferred method of intervention because:

- It would ensure that costs are transparently and equitably borne by market participants
- It would ensure that the obligation is fulfilled at the lowest cost to consumers
- It would introduce an element of price discovery of the costs of market making
- It would not require the specification of an eligibility threshold which may distort competition and may not be future-proof

5.3 However, given the changes in market fundamentals that have occurred since 2019, as well as known and potential future changes, we welcome views from stakeholders on whether a tendered market making obligation still represents the preferred option should intervention be required, or whether alternatives should be considered.

6. Responding to the Call for Input

Questions:

Please provide answers to as many of the following questions that you feel are relevant to your business. When answering these questions, please outline any impacts on your business and provide quantified evidence to support your answer.

Power market liquidity trends

1. How do you consider Great Britain's power market liquidity to have changed between the suspension of the Market Making Obligation and today? What do you consider to be the main drivers of this?
2. How do you consider that trading on the spot, prompt and forward markets has changed since the suspension of the Market Making Obligation?
3. How does your assessment of current liquidity levels change when considering trading on financial products (excluded in our analysis) in addition to physical products (included)?

How liquidity is impacting trading

4. How has your trading behaviour changed since the suspension of the Market Making Obligation? What are your reasons for this?
5. How do you consider that liquidity for the price cap indexed products has changed since the implementation of the default tariff cap?
6. How easily do you consider you are able to trade the products that you need to? Which products would you like to trade that you are currently not able to, where this can be directly attributed to the liquidity of the product?
7. What has been the cost to your business of any illiquidity that you have encountered?

The future of liquidity

8. Do you consider that liquidity will improve or decline in the short-medium term? What do you consider will be the drivers of this?

Potential intervention options

9. Given the levels and drivers of liquidity, do you consider that liquidity intervention in Great Britain's power market would be justified in the short-medium term?
10. What market-led approaches could be used to improve liquidity?
11. What regulatory interventions do you think could be appropriate to improve liquidity?

12. If intervention was required, what would your preferred option be? What benefits would this bring to your business? Where possible, please quantify these benefits.

General

13. Are there any other considerations that you would like us to be aware of?

Please send responses to WholesaleMarketPolicy@ofgem.gov.uk by Friday 2 February 2024, including detail and supporting evidence wherever possible. As part of your comments, please explain how any suggested approaches would be deliverable in practice. We will publish non-confidential responses on our website at www.ofgem.gov.uk/consultations.

If you have any questions, please contact us at the above email address.

Your response, data and confidentiality

You can ask us to keep your response, or parts of your response, confidential. We'll respect this, subject to obligations to disclose information, for example, under the Freedom of Information Act 2000, the Environmental Information Regulations 2004, statutory directions, court orders, government regulations or where you give us explicit permission to disclose. If you do want us to keep your response confidential, please clearly mark this on your response and explain why.

If you wish us to keep part of your response confidential, please clearly mark those parts of your response that you do wish to be kept confidential and those that you do not wish to be kept confidential. Please put the confidential material in a separate appendix to your response. If necessary, we'll get in touch with you to discuss which parts of the information in your response should be kept confidential, and which can be published. We might ask for reasons why.

If the information you give in your response contains personal data under the General Data Protection Regulation (Regulation (EU) 2016/679) as retained in domestic law following the UK's withdrawal from the European Union ("UK GDPR"), the Gas and Electricity Markets Authority will be the data controller for the purposes of GDPR. Ofgem uses the information in responses in performing its statutory functions and in accordance with section 105 of the Utilities Act 2000. Please refer to our Privacy Notice on Call for Inputs, see Appendix 1.

If you wish to respond confidentially, we'll keep your response itself confidential, but we will publish the number (but not the names) of confidential responses we receive. We won't link responses to respondents if we publish a summary of responses, and we will evaluate each response on its own merits without undermining your right to confidentiality.

7. Next steps

7.1 Following this Call for Input, we will assess stakeholder feedback and evidence to consider whether current wholesale power market liquidity is sufficient to meet market participant requirements and enable the effective management of risk. We will also assess this evidence against Ofgem's liquidity objectives for wholesale energy markets.

7.2 We will then determine whether we should further consider policy options for intervention. If this is required, we will engage with industry on these options and next steps.

7.3 We welcome stakeholders' responses to the questions set out in this document and, as far as possible, ask that responses are supported with appropriate evidence.

Appendix 1: Privacy notice on Call for Inputs

Personal data

The following explains your rights and gives you the information you are entitled to under the General Data Protection Regulation (GDPR).

Note that this section only refers to your personal data (your name address and anything that could be used to identify you personally) not the content of your response to the call for input.

1. The identity of the controller and contact details of our Data Protection Officer

The Gas and Electricity Markets Authority is the controller (for ease of reference, "Ofgem"). The Data Protection Officer can be contacted at dpo@ofgem.gov.uk

2. Why we are collecting your personal data

Your personal data is being collected as an essential part of the call for input process, so that we can contact you regarding your response and for statistical purposes. We may also use it to contact you about related matters.

3. Our legal basis for processing your personal data

As a public authority, the GDPR makes provision for Ofgem to process personal data as necessary for the effective performance of a task carried out in the public interest, ie a call for input.

4. With whom we will be sharing your personal data

We will not share your personal data with any other organisation.

5. For how long we will keep your personal data, or criteria used to determine the retention period.

Your personal data will be held for six months after the project is closed.

6. Your rights

The data we are collecting is your personal data, and you have considerable say over what happens to it. You have the right to:

- know how we use your personal data
- access your personal data
- have personal data corrected if it is inaccurate or incomplete
- ask us to delete personal data when we no longer need it
- ask us to restrict how we process your data
- get your data from us and re-use it across other services
- object to certain ways we use your data

- be safeguarded against risks where decisions based on your data are taken entirely automatically
- tell us if we can share your information with 3rd parties
- tell us your preferred frequency, content and format of our communications with you
- to lodge a complaint with the independent Information Commissioner (ICO) if you think we are not handling your data fairly or in accordance with the law. You can contact the ICO at https://ico.org.uk/, or telephone 0303 123 1113.

7. Your personal data will not be sent overseas

8. Your personal data will not be used for any automated decision making.

9. Your personal data will be stored in a secure government IT system.

10. More information

For more information on how Ofgem processes your data, click on the link to our "Ofgem privacy promise".

Appendix 2: Ofgem publications on power market liquidity before Secure and Promote

- October 2008: Energy Supply Probe - Initial Findings Report. This investigation found that the level of wholesale market liquidity in the electricity market was of concern, especially to smaller market participants and suppliers, and constituted a potential barrier to entry limiting competition.
- June 2009: Liquidity in the GB wholesale energy markets (ofgem.gov.uk). We investigated liquidity in the GB wholesale energy markets and examined suggested reasons as to why liquidity is low, particularly in the electricity market. We also outlined possible measures to improve GB electricity market liquidity.
- February 2010: Liquidity Proposals for the Great Britian (GB) wholesale electricity market. We examined why liquidity was low in the GB electricity market and considered market initiatives to increase liquidity.
- July 2010: Great Britain (GB) wholesale electricity market liquidity: summer 2010 assessment. We set out a new framework for assessing the market's performance in respect of liquidity in the power market. The evidence suggested that there were weaknesses in longer-term liquidity, that price transparency had not improved and that independent market participants found it difficult to hedge their customers' demand or generation output over a longer period.
- December 2012: Wholesale power market liquidity: consultation on a 'Secure and Promote' licence condition. We consulted on a 'Secure and Promote' licence condition to improve liquidity.
- January 2014: Wholesale power market liquidity: decision letter. We published our decision on Secure and Promote in January 2014, with the licence condition taking effect from 31 March 2014.

Appendix 3: Market Making Obligation requirements

Summary of the main market making requirements under Secure and Promote[33]

- **Licensees affected**

  Centrica, EDF Energy, E.On, RWE npower, Scottish Power, SSE

- **Forward contracts covered by Market Making Obligation**

  - Baseload and peakload: Month+1, Month+2, Quarter+1, Season+1, Season+2, Season+3

  - Baseload only: Season+4

- **Minimum availability window**

  Working days from 10.30am to 11.30am and from 3.30pm to 4.30pm

- **Maximum bid-offer spread allowed**

  - 0.5% for following baseload products: Month+1, Month+2, Quarter+1, Season+1, Season+2

  - 0.6% for following baseload products: Season+3, Season+4

  - 0.7% for following peakload products: Month+1, Month+2, Quarter+1, Season+1, Season+2

  - 1% for Season+3 Peakload

- **Size of bid and offers per product**

  5MW, 10MW[34]

- **Maximum time allowed to reinstate bids or offers hit or lifted by counterparties during Market Making Obligation windows**

  5 minutes

- **Allowed exemptions from posting bids and offers during Market Making Obligation windows**

  - When a Market Making Obligation licensee trades a net volume of 30MW of a single product in the same direction during the window

  - If product price changes by more than 4% in a single direction

[33] Liquidity in the Wholesale Electricity Market (Special Condition AA of the electricity generation licence): Guidance

[34] 5MW, 10MW, 15MW and 20MW if the licensee nominated as Nominee a person who or whose affiliate was itself a Relevant Licensee or was appointed as Nominee by another Relevant Licensee.

Appendix 4: Liquidity metrics

1. Total traded volumes

Our analysis presented here is based on over-the-counter (OTC) data from price-reporting agency ICIS and exchange data from the exchanges EPEX, ICE and Nord Pool.

It is important to note that the OTC data we used here covers trades with physical delivery of the commodity (OTC Physical) and does not include financial trades (OTC Financial), which do not entail physical deliveries and work as a hedge against spot prices.

Historically, the number of OTC Financial transactions has been negligible when compared with OTC Physical ones both in Great Britain's (GB) market and in most of Europe. However, trading on OTC Financial deals has increased considerably in recent years, especially in certain markets such as Italy.

We welcome feedback from stakeholders on the role played by OTC Financial deals in the GB power market.

1.1 Total traded volume has been falling, most notably since 2020

Figure 4 shows a general decline in volumes traded across all contract types between Q1 2016 and Q3 2023.

Liquidity was highest towards the end of 2016, after which total trading fell to a monthly average of around 255 terawatt-hours (TWh) until Q2 2020, despite the Market Making Obligation under the Secure and Promote licence condition being in operation until November 2019. Volumes reached a low of around 160TWh in Q3 and Q4 2022, at the heights of wholesale market price volatility.

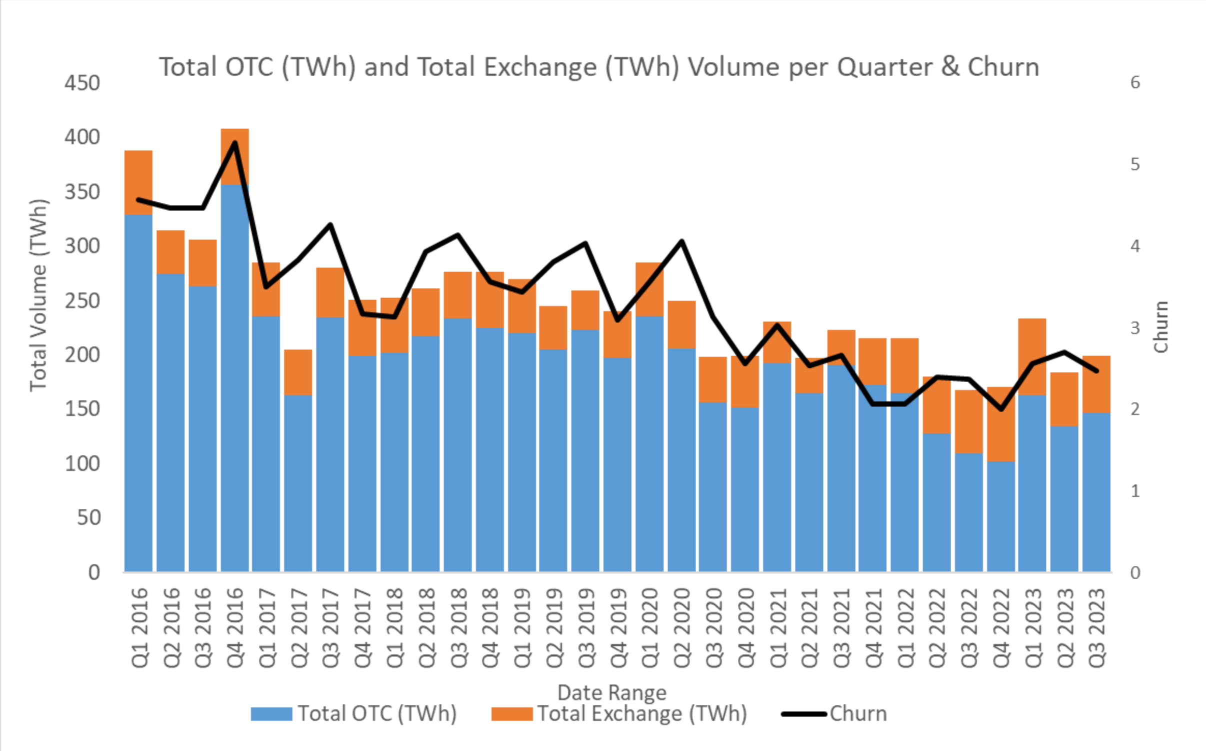
It is worth noting that total trading for all contracts has increased during 2023 compared to 2022 as price volatility has eased, peaking at around 222TWh in Q1 2023.

In figure 4 we have included the overall churn rate seen in the OTC market. Churn rates show the number of times that a product is traded before delivery to the end consumer. The higher the rate of churn, the greater the trading activity and liquidity of a market.[35]

The general trend for churn rates is a decrease, caused by the overall drop in traded volumes and the rise of exchange-based trading.

[35] Churn rates vary depending on the time of year. Typically rates are higher during the summer and lower during the winter. This is associated with increases in demand during winter months, but is also linked to the tendency for a significant proportion of forward hedging to be done by late summer, ahead of the delivery of the Q4 and Winter season contracts.

Figure 4 – Total GB power OTC and exchange traded volume and churn rates per quarter[36]



1.2 Trading of curve contract products has fallen the most

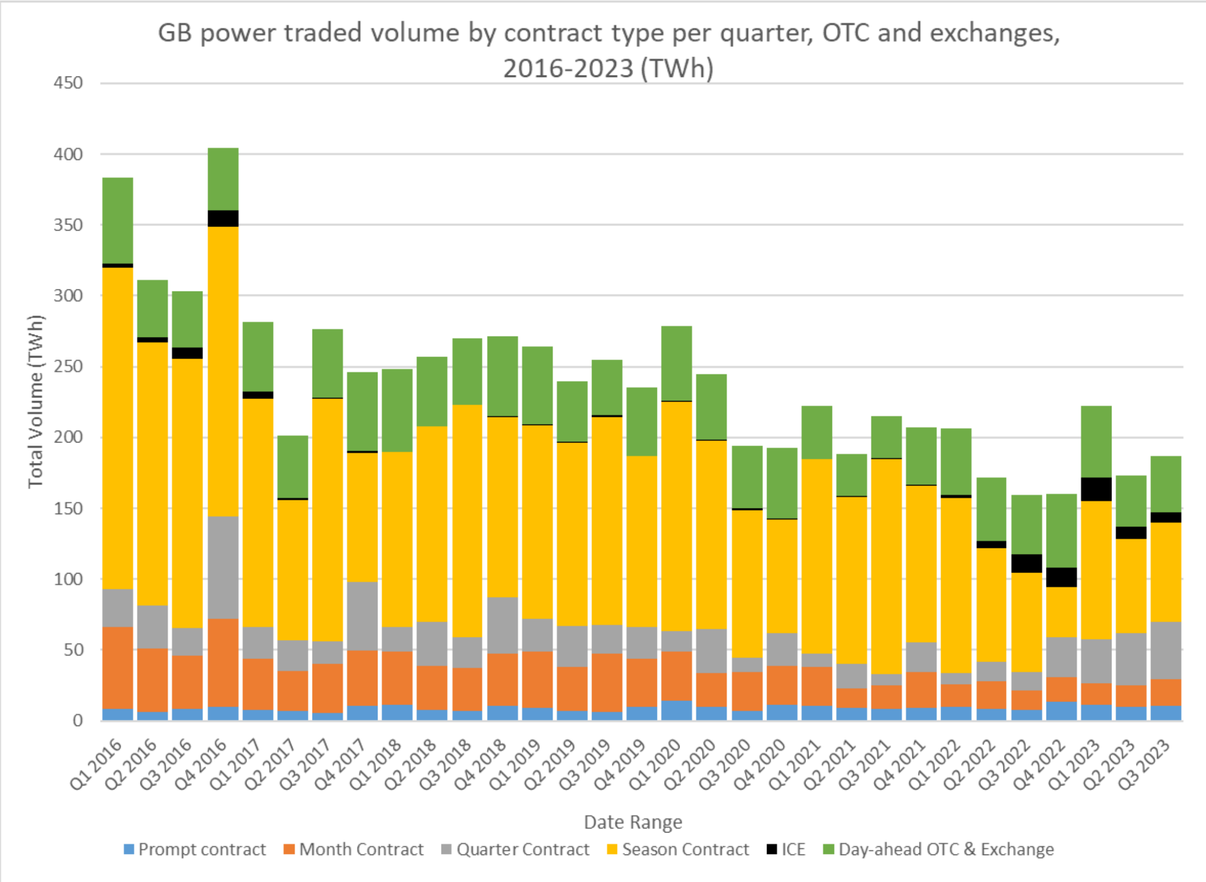
We understand that recent trends in liquidity might affect market participants' ability to hedge their future power needs ahead of time using curve contracts.

Figure 5 shows a breakdown of GB power traded volume by type of contract. This allows us to see where liquidity has shrunk the most and where it has held up better.

The data shows that the downward trend in liquidity has mostly affected monthly and seasonal contracts. Quarterly contracts have instead seen a pick-up in traded volumes, especially since Q4 2022, compared to relative volumes traded before this. This is likely linked to the shift in the indexation of the standard variable tariff price cap from seasonal to quarterly contracts. More detail on this change is documented in section 1.5 of this appendix.

[36] Source: Ofgem analysis of OTC Data from ICIS and exchange data from ICE, Nord Pool and EPEX. The ICE and Nord Pool data is publicly available, while the EPEX data is provided to Ofgem under licence. The churn rate is derived from the total OTC and exchange volumes divided by the power consumption, with the latter data publicly available on the government's website.

Figure 5 – GB power traded volume by contract type per quarter, OTC and exchanges[37]



The graph also shows that while OTC curve trading declined in 2022, the volume transacted on spot markets on exchanges increased. Data suggests that this trend might have been reversing recently, with prompt and curve volumes increasing year on year in Q2 and Q3 2023 while spot volumes decreased.

This increase in exchange-based trading may be linked to the reassurance offered by exchanges' clearing functions to mitigate against counterparty default risk amid periods of price volatility, as well as to a lack of credit facilities available to some participants to continue trading OTC.

As high prices and volatility strained credit lines and required market participants to post more collateral to back their forward trading, some market participants might have been forced to reduce their forward hedging and resort more to spot markets to meet their needs.

[37] Source: Ofgem analysis of OTC data provided under licence from ICIS and exchange data from ICE. Day-ahead exchange data are spot auction volumes from Nord Pool and EPEX.

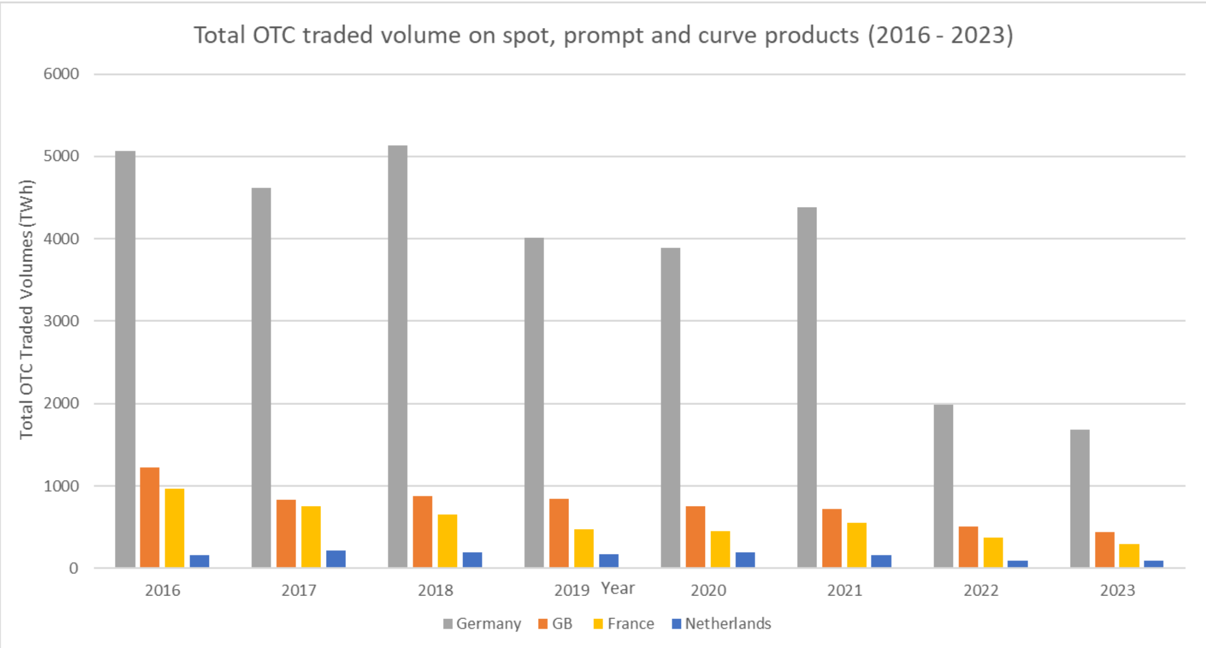
Lower wholesale prices in 2023 might be behind the year-on-year decline in spot volumes and increase in prompt and curve trading seen in Q2 and Q3 2023.[38]

1.3 OTC traded volumes are falling across northwest Europe

Figure 6 shows a comparison of OTC physical volumes traded in northwest Europe's main wholesale electricity markets.[39]

The general trend of declining OTC liquidity seen on the GB power market is replicated also in Germany, France and the Netherlands, with varying degrees of magnitude. All four markets reached a trough in 2022. However, 2023 traded volumes appear on track to stay well below 2021 levels, although we note that 2023 trading is still ongoing.

Figure 6 – Total OTC traded volume on day-ahead, prompt and curve power products



[38] We are not able to show a breakdown of ICE futures trading by contract, as we do not possess the necessary disaggregated data.
[39] We do not own data on futures trading concluded on exchanges for international markets, so the graph is likely to underreport market liquidity. However, we consider OTC to provide a credible representation of overall liquidity trends.

1.4 Trading is now less constrained to the market making times

Figure 7 shows that when the Secure and Promote Market Making Obligation (MMO) was in place, traded volumes were constrained to the market making windows between 10.30-11.30am and 3.30-4.30pm. Stakeholder feedback has previously suggested that liquidity has been very low outside of these windows, making it very difficult to trade.

Since the suspension of the MMO, traded volumes within the traditional 10.30-11.30am market making window have been substantially lower. However, since 2021 traded volumes have proportionately increased in the periods between the two traditional windows and continue to rise throughout the day. This suggests that trading now occurs more regularly throughout the day.

Figure 7 – Evolution of OTC-traded front-quarter GB power contract volumes by time of day

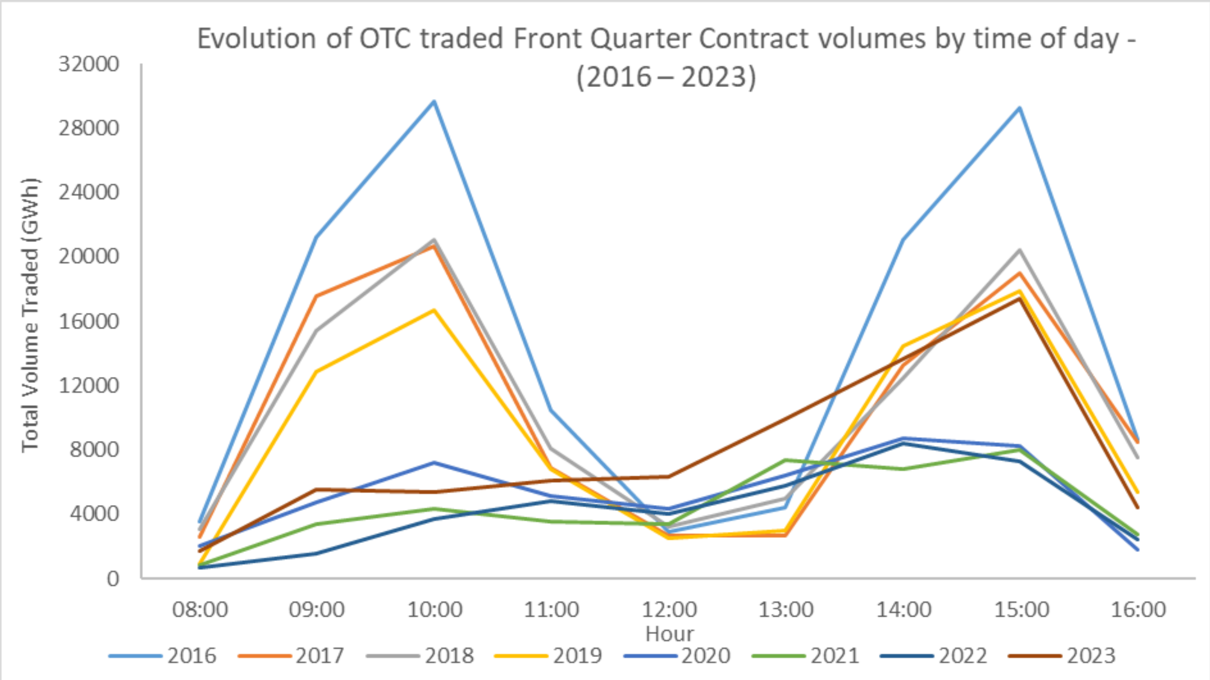


Figure 7 - Caveats and limitations to note:

The data granularity in figure 7 is limited to hourly intervals whereas electricity market settlement is half-hourly. It also means that we cannot show how trading differs between 16:00-16:30 and 16:30-17:00, which is relevant to the extent that participants can/cannot bid/offer to match the ICIS price assessment.

ICIS assessments of power prices are based on bid-offer information picturing the market at 4.30pm, unless the last point of market liquidity can be traced back to an earlier point in time.

These end-of-day price assessments are used as a contractual price index by participants throughout the wholesale market. However, in volatile markets even representing the last point of liquidity might give a benchmark that is quite far from the actual bid-offer spreads traders faced earlier in the day, potentially impacting their bottom line.

1.5 Hedging the standard variable tariff price cap contracts

The standard variable tariff (SVT) price cap was indexed against seasonal wholesale electricity contract prices up until June 2022, part way through the observation window for cap period 9 (hence the combined 9a & 9b bar in figure 8 to show trading of the winter contract until then).[40] Thereafter, the direct fuel cost allowance transitioned to indexation against quarterly products (shown with separate 9a and 9b bars in figure 8). Suppliers were also more incentivised to hedge the first quarter of the 12-month forward view after the introduction of the backwardation allowance for cap period 9a.[41]

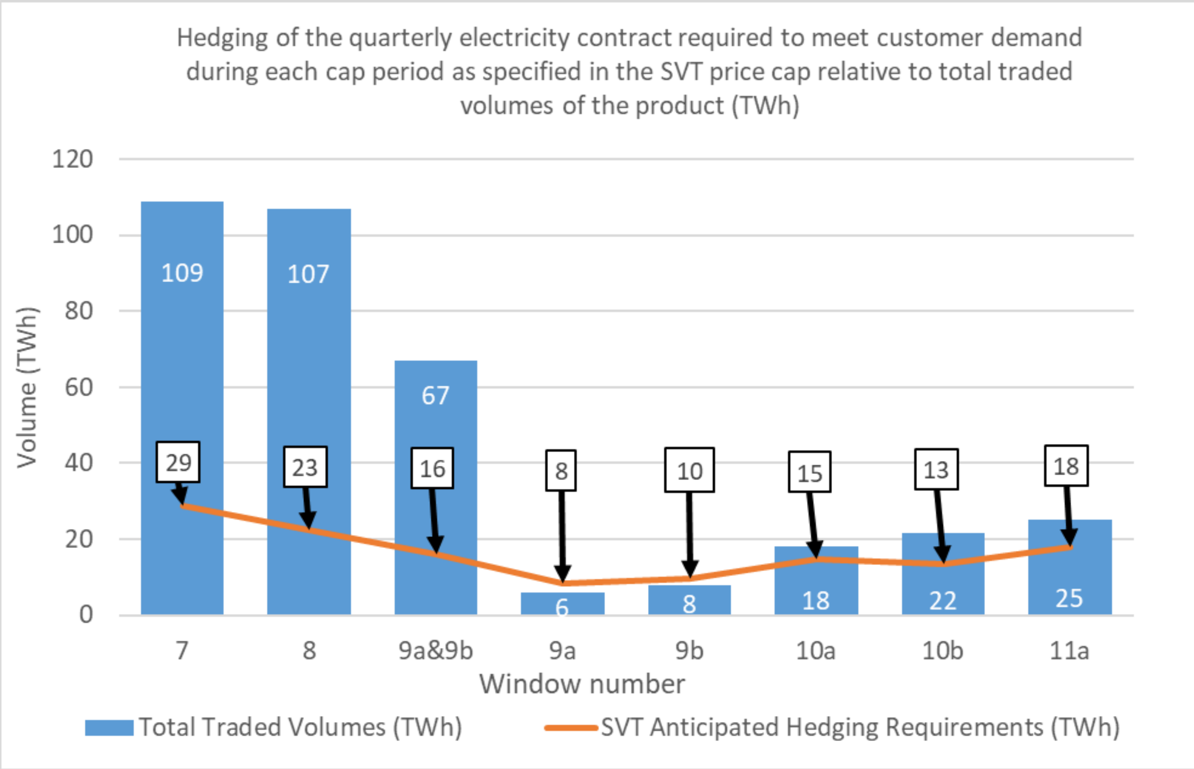
Our analysis suggests that total OTC traded volumes of the indexed first quarter product during each of the 9a and 9b observation windows were below the levels of forward hedging required under the price cap by SVT suppliers (figure 8).

In other words, SVT suppliers might not have been able to forward purchase the volumes of quarterly electricity products that they were incentivised to under the price cap during these observation windows, which coincided with some of the peaks in wholesale energy prices in 2022.

If suppliers bought some of their wholesale energy in a different way from the cap indexation methodology, this could potentially lead to a cost difference compared to the allowance that they received.

[40] See footnote 16.
[41] Backwardation costs are a result of the difference between the index used to set the cap level and the way suppliers are able to purchase energy for their cap customers. When the market is in backwardation, the forward prices in the later nine months are lower than in the first quarter (the actual cap period). It brings the cap level below the cost to suppliers of purchasing that energy for customers (for that cap period); see: [Price cap - Decision on changes to the wholesale methodology (ofgem.gov.uk)](). The allowance attempts to reimburse suppliers for this cost difference.

Figure 8 – Anticipated supplier hedging of the quarterly[42] electricity contract volumes required to meet customer demand during each cap period as specified in the SVT price cap, relative to total traded volumes of the product[43]



Liquidity improved from the observation window for cap period 10a to the extent that total traded volumes of the first quarter product exceeded the totals required for SVT supplier forward hedging under the direct fuel cost allowance. However, there is a risk that suppliers may not have been able to hedge their demand using quarterly products in line with the cap indexation methodology because they are not the only buyers in the market.

Financial intermediaries and brokers, as well as non-domestic suppliers, for example, account for a proportion of total trading activity. Whilst we cannot directly quantify this, we note that traded volumes for quarterly electricity products averaged around 24TWh per quarter up until Q2 2022 (when quarterly product cap indexation commenced), compared to an average of around 30TWh since Q3 2022.

[42] Note that bars 7 to 9a&9b show the traded volumes of the relevant seasonal contract that was indexed under the SVT price cap at that time before the move to quarterly contract indexation.
[43] Source: Ofgem analysis of data provided under licence from ICIS and Ofgem's forecast of contract buying volumes required to hedge SVT customer demand in the price cap. Volumes are based on those traded during the observation windows.

Table 1 – Observation window date ranges

Price cap delivery period name	Observation window date range
7	01/02/2021 to 30/07/2021
8	02/08/2021 to 31/01/2022
9a&9b	01/02/2022 to 01/06/2022
9a	06/06/2022 to 18/08/2022
9b	19/08/2022 to 16/11/2022
10a	17/11/2022 to 17/02/2023
10b	20/02/2023 to 18/05/2023
11a	19/05/2023 to 17/08/2023

This shows that although trading in quarterly products has increased since price cap indexation, there is still likely to be a strong proportion of non-domestic suppliers purchasing these.

This leaves open the possibility that the first quarter product continues to be traded below the volumes assumed for SVT suppliers to fully hedge their end-user demand according to the price cap wholesale cost allowance indexation methodology. However, it should be noted that the amount that suppliers forward trade also depends on their commercial decisions and suppliers may choose to hedge different products during this period.

It should also be noted that figures 11 and 12 below show the bid-offer spreads for the peakload front-quarter contract. Peak quarterly contracts are less frequently traded, but still form part of the indexed direct fuel costs that form the wholesale allowance that suppliers can recover through the default tariff cap.

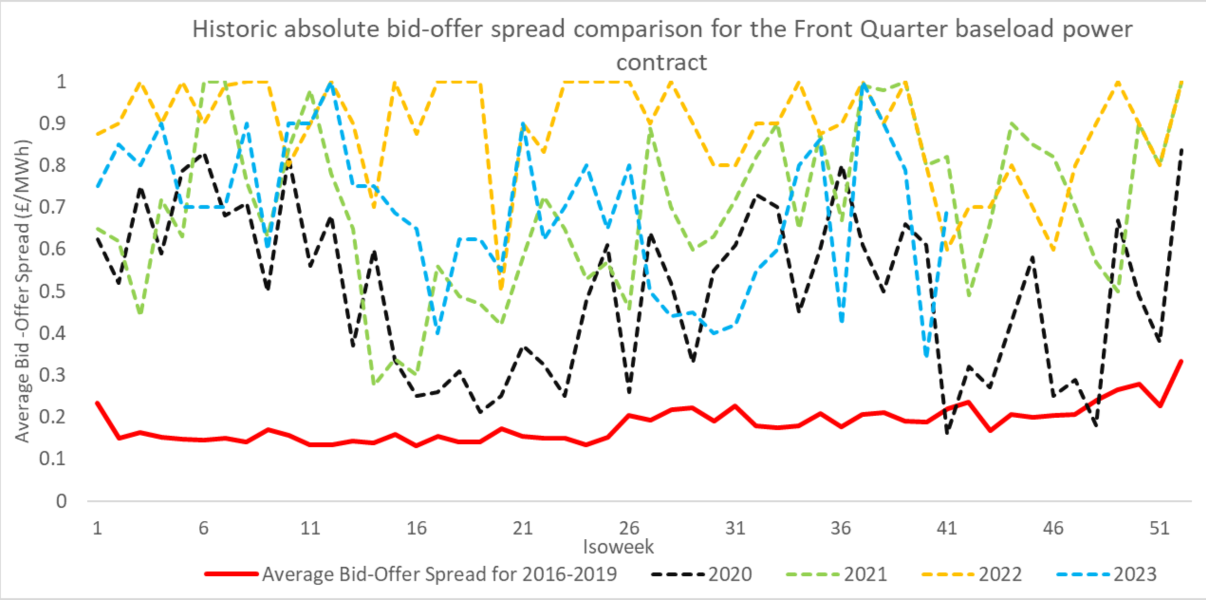
Bid-offer spreads are discussed below; however, peakload front-quarter spreads have typically been wider than baseload, which suggests that suppliers offering SVT products (and other market participants) might have had to forward hedge using alternative products as imperfect proxies for the wholesale cost allowance.

2. Bid-offer spreads

2.1 Bid-offer spreads have increased since the suspension of the MMO

Figure 9 shows the bid-offer spreads for the baseload front-quarter contract, which is often indexed in the SVT price cap. The influence of the MMO on bid-offer spreads is shown in the 2016-2019 average below.

Figure 9 – Historic absolute bid-offer spread comparison for the front-quarter GB power baseload contract[44]



Since the suspension of the MMO, the spread between the best bid to buy and the best offer to sell has grown. This suggests that liquidity has declined. However, the trend since the suspension of the MMO in 2019 is consistent with other liquidity metrics, where bid-offer spreads reach consistently high levels in 2022 before reducing in 2023. Lower wholesale prices and market volatility in 2023 have likely reduced the credit requirements needed to trade, increasing competition and liquidity in the market.

Figure 10 demonstrates a similar picture, with average bid-offer spreads on the curve increasing following the MMO suspension in 2019, reaching their highest levels in 2022 amid spiking energy prices, before decreasing in 2023.

Despite the decline, bid-offer spreads on the front month and front season in 2023 are still higher than they were in 2020 and 2021. On the other hand, bid-offer spreads on the front quarter, although higher than they were under the MMO, are lower in 2023 than in 2021. This could be due to increased buying interest on this contract caused by the price cap methodology change. This may also account for the decrease in liquidity on the front season contract, in comparison to 2021.

Bid-offer spreads on the day-ahead contract have remained broadly consistent since 2016, demonstrating stable levels of liquidity on this product.

[44] Ofgem analysis of data provided under licence from ICIS.

Figure 10 – Yearly average bid-offer spreads for day-ahead, front-month, front-quarter and front-season GB power baseload contracts

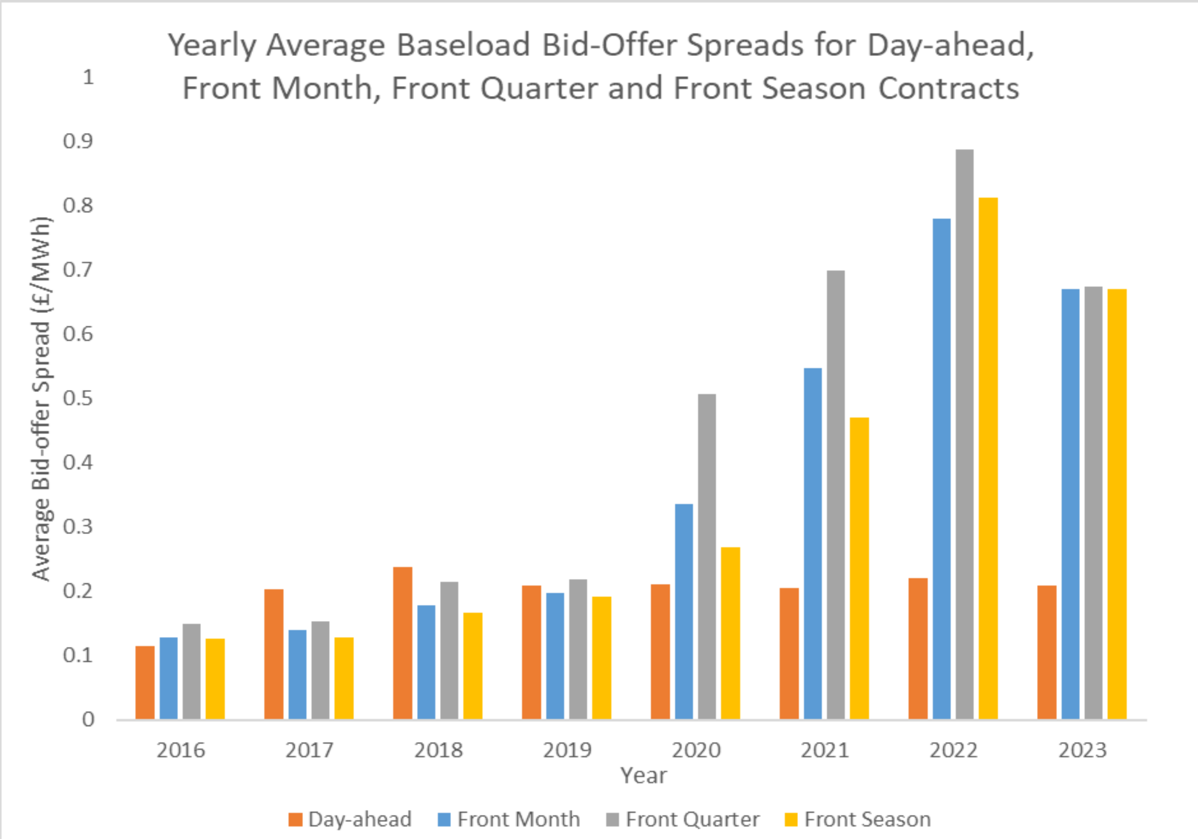


Figure 11 – Historic absolute bid-offer spread comparison for the front-quarter GB power peakload contract

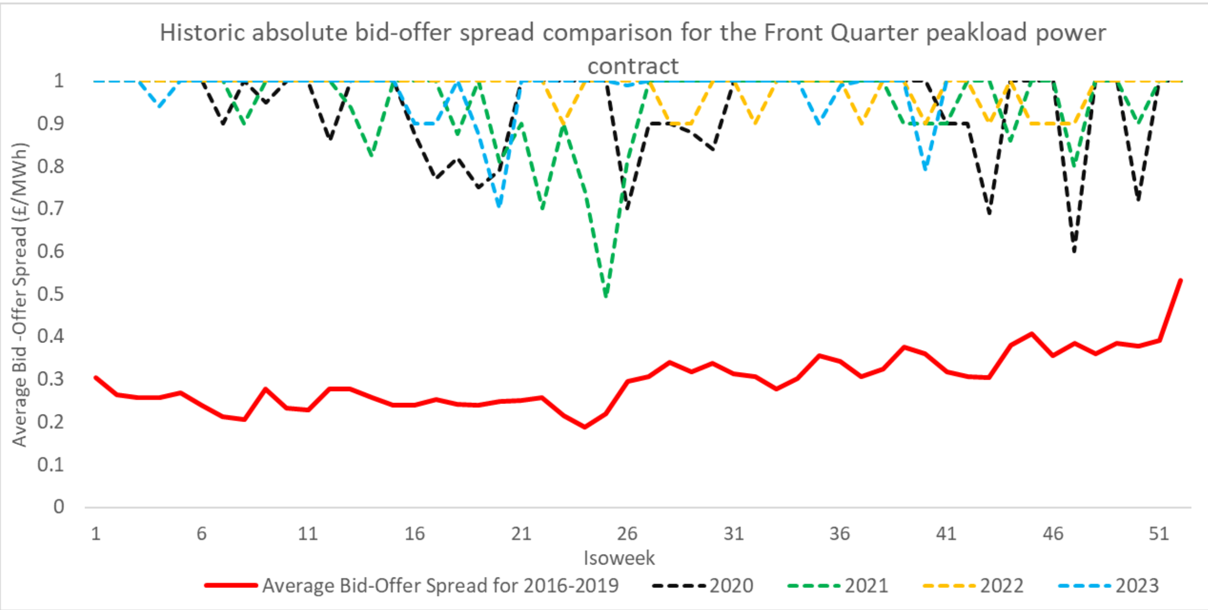
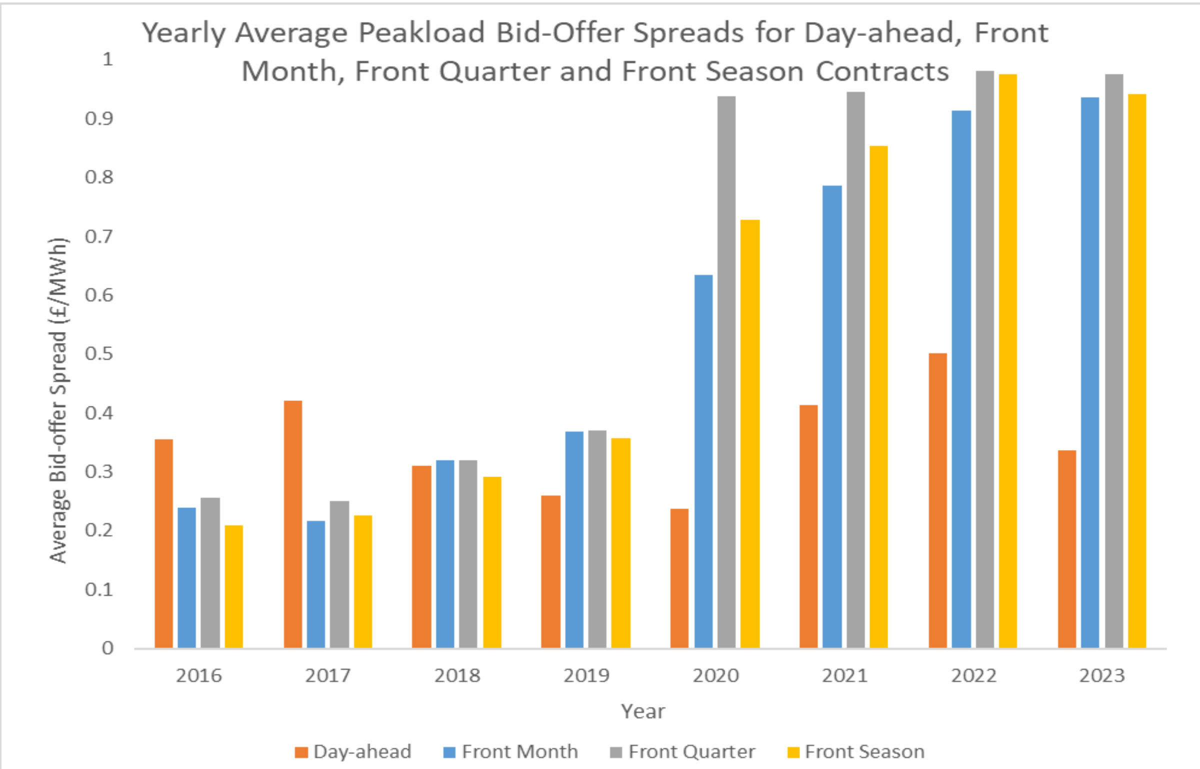


Figure 11 shows that bid-offer spreads for the front-quarter peakload contract have increased considerably since the suspension of the MMO and are consistently above the average for 2016-2019, when the scheme was in operation. ICIS caps its bid-offer spread assessments at £1/MWh and this level has been regularly hit since 2020. This suggests that liquidity on the front-quarter peakload contract has declined, and could even be lower than shown on this graph due to the cap.

Figure 12 shows a similar trend, with average bid-offer spreads on curve contracts rising significantly following the MMO suspension in 2019. The front-quarter contract has average bid-offer spreads very close to the £1/MWh maximum, suggesting poor liquidity in this contract. In the peakload day-ahead contract, bid-offer spreads increased in 2022 but recovered in 2023 to a lower level than in 2016 and 2017.

<u>Figure 12 – Yearly average peakload bid-offer spreads for day-ahead, front-month, front-quarter and front-season GB power contracts</u>



<u>Figures 9, 10, 11 & 12 - Caveats and limitations to note</u>

The bid-offer spread in figures 9, 10, 11 and 12 are calculated by subtracting the end of day bid price from the offer price and averaging for each week.

The analysis in these figures takes the ICIS end-of-day price assessment, which caps the bid-offer spread at a maximum of £1.00/MWh. There might have been days, particularly during the height of price volatility, when the spread between the maximum bid and the minimum offer exceeded this amount. This is not captured and the figure, therefore, potentially does not show the full extent of illiquidity over the last years.

2.2 Bid-offer spreads rise and fall at a similar rate across Europe

Figure 13 shows the average bid-offer spreads for the GB front-quarter baseload product relative to some of the largest EU markets. It shows that bid-offer spreads were highest across Europe in 2022, demonstrating that the decline in liquidity was not unique to GB. Similarly, bid-offer spreads decreased across Europe in 2023 as price volatility stabilised.

GB bid-offer spreads were consistently lower than the French and Italian equivalent while GB had the MMO in place. However, GB bid-offer spreads rose following the MMO suspension and have mostly been higher than France, Germany and Italy's since 2020, especially between 2020 and 2022.

Figure 14 shows the bid-offer spreads for the GB front-quarter baseload product relative to some of the largest EU markets up until 5 November 2023. The German market had the lowest bid-offer spreads, and highest liquidity, during 2023. However, GB's bid-offer spreads are at a very similar level to France and Italy's, with an average bid-offer spread of £0.68/MWh compared to €0.69/MWh for France and €0.67/MWh for Italy.

Figure 13 – Bid-offer spreads in the French, German, Italian and GB power markets for the front-quarter baseload contract

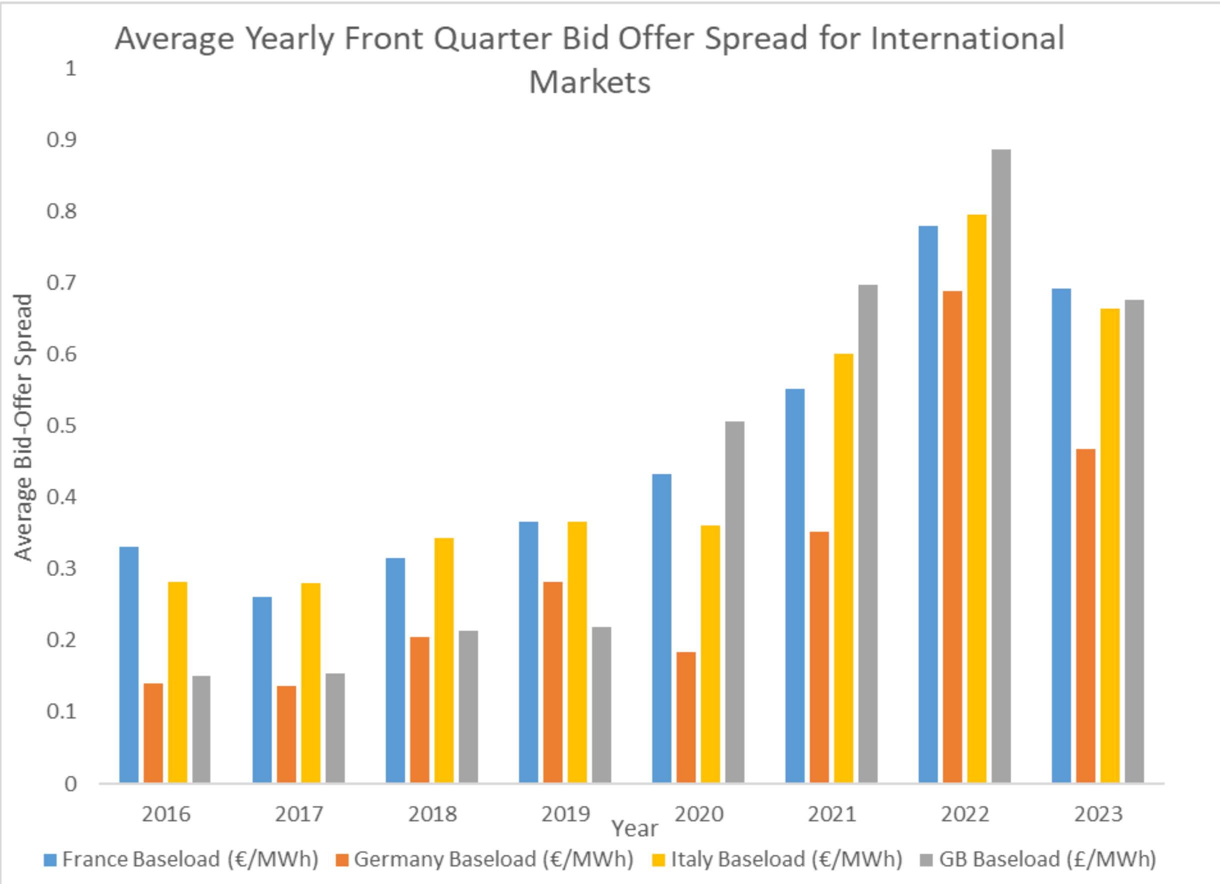
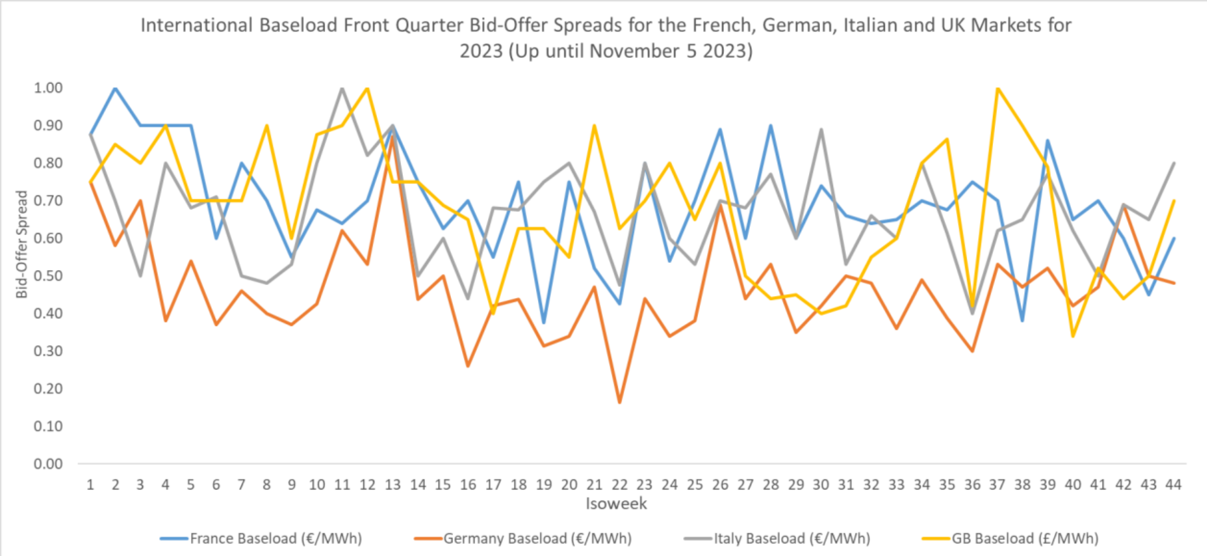


Figure 14 – Bid-offer spreads for the front-quarter baseload contract in the French, German, Italian and GB power markets in 2023 (up until 5 November 2023)[45]



Figures 13 & 14 - Caveats and limitations to note

The analysis in figures 13 and 14 take the ICIS end-of-day price assessment, which caps the bid-offer spread at a maximum of €1.00/MWh for non-GB Markets (approx. £0.87/MWh) and £1.00/MWh for the GB market.[46] They have been displayed without conversion here to remove the impact of currency fluctuations. There might have been days, particularly during the height of price volatility, when the spread between the maximum bid and minimum offer exceeded this amount. This is not captured and the figure, therefore, potentially does not show the full extent of illiquidity over the year in all European markets.

2.3 It is unclear if bid-offer spreads are consistently at NERA's "low liquidity" threshold given the constraint of the £1/MWh spread cap

In its liquidity options assessment, which was conducted as part of our liquidity review, NERA assessed the net benefits of a tendered market maker that would deliver the same levels of liquidity as the MMO did. NERA's analysis found that net benefits would be achieved by a tendered MMO if bid-offer spreads fell close to their "low liquidity" counterfactual.

This "low liquidity" counterfactual had average bid-offer spreads at 1.98% for baseload and 2.80% for peakload contracts, and these benchmarks are highlighted in red in figures 15 and 16.

[45] Ofgem analysis of data provided under licence from ICIS.
[46] ICIS' pricing methodology can be found here: [European Daily Electricity Markets (EDEM) Methodology – 15 August 2023 | Compliance and Methodology (icis.com)]

Figure 15 – Relative bid-offer spreads for the front-quarter GB power baseload contract[47]

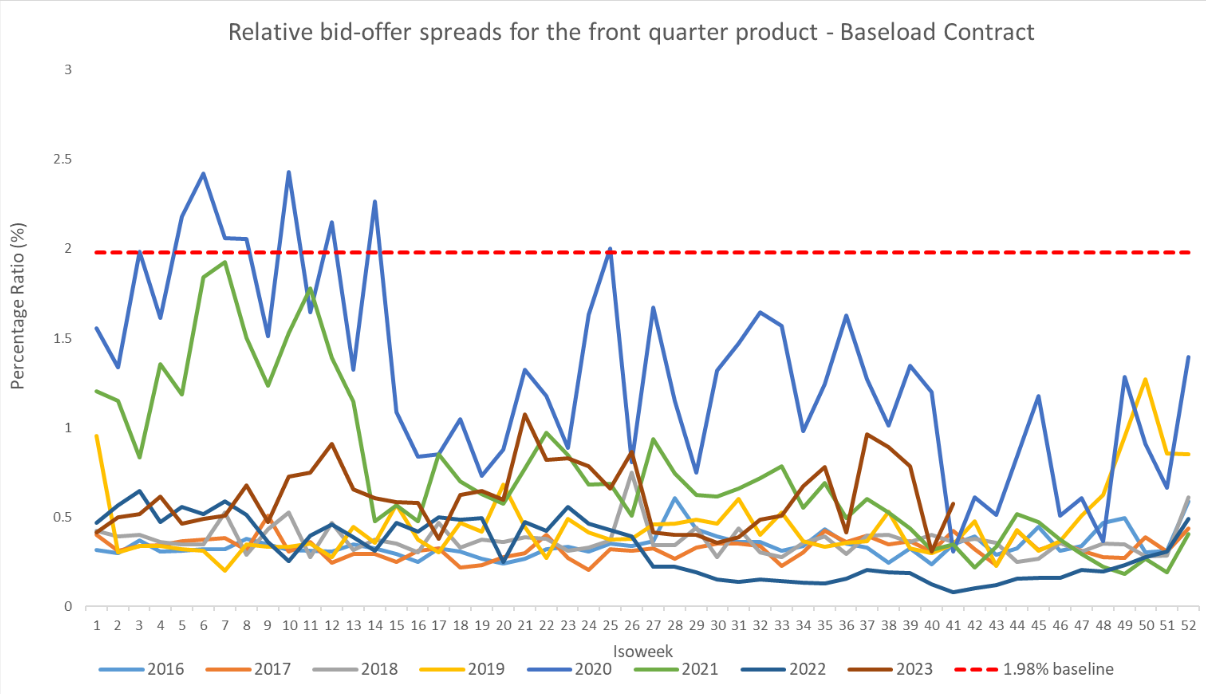
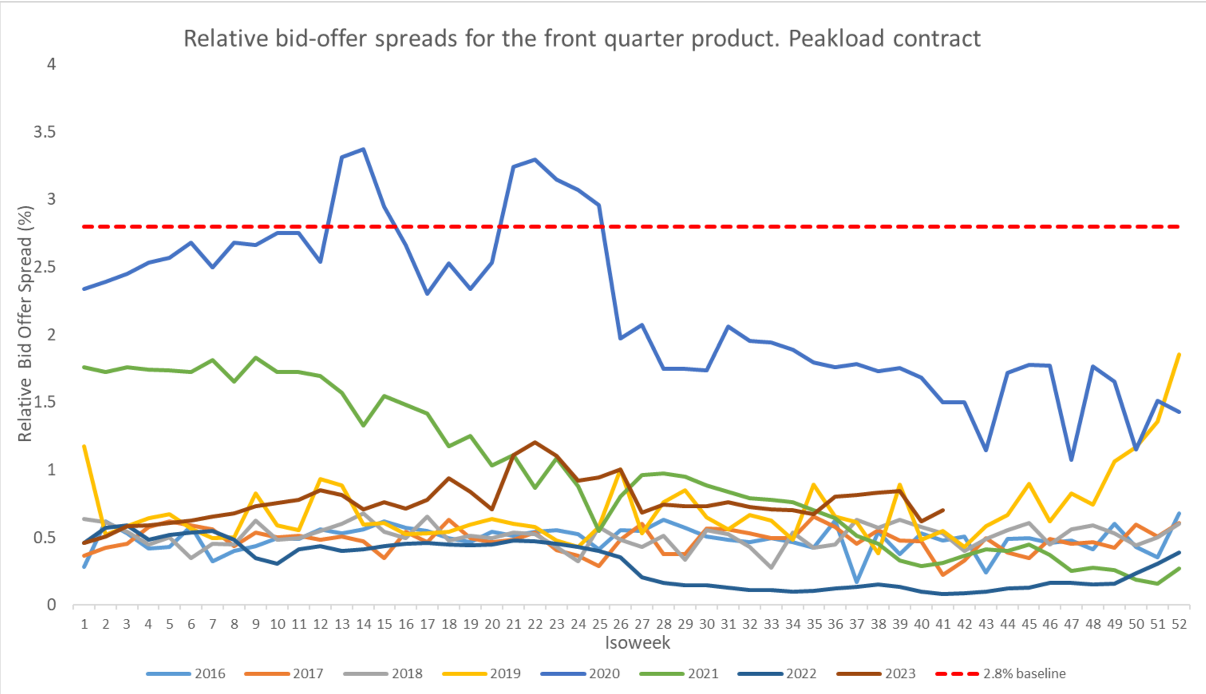


Figure 16 – Relative bid-offer spreads for the front-quarter GB power peakload contract[48]



[47] Ofgem analysis of data provided under licence from ICIS.
[48] Ofgem analysis of data provided under licence from ICIS.

The graphs show that this threshold was breached during the first half of 2020 for both baseload and peakload front-quarter contracts, but then returned under this level for the second half of 2020 and has been consistently under this level to date. This suggests that bid-offer spreads are not consistently at a level which would benefit from a tendered market maker.

However, this may not be a correct conclusion because, as shown in figure 9, absolute pound bid-offer spreads were at their highest in 2022, far higher than in 2020.

We explained above that ICIS caps its bid-offer spread assessment at £1/MWh. This spread as a percentage of the bid/offer price becomes lower when wholesale prices are higher. For example, a £1 spread is 1.54% of £65/MWh, which was the highest front-quarter price in 2020. However, a £1 spread is only 0.12% of a £840/MWh bid, which was the highest front-quarter price in 2022. This 0.12% figure would suggest that spreads were low, and liquidity high, in 2022.

Appendix 5: Glossary

Bid-offer spread

The price difference between the highest bid to buy and the lowest offer to sell posted by market participants for a given forward contract.

Contracts for Difference (CfD)

UK government's main mechanism for supporting low-carbon electricity generation. A CfD is a contract between an electricity generator and the Low Carbon Contracts Company (LCCC) that enables the generator to stabilise its revenue at a pre-agreed price, referred to as the strike price. Each time wholesale market prices drop below the strike price, LCCC tops up the difference to ensure the generator receives the strike price. Equally, when wholesale prices ramp up above the strike price, the generator will reimburse LCCC for the extra profit.

Churn rate

The churn rate is the number of times a forward product is traded before delivery to the end-consumer. It is calculated as total volume traded on a product divided by total demand during the product's delivery period.

Curve

Forward power contracts for deliveries in the next month ahead (front month) or later. Curve products typically have a monthly, quarterly, seasonal or yearly granularity. Contracts covering deliveries up to the next quarter included are often referred to as 'near curve', while contracts for deliveries from Q+2 onwards as 'far curve'.

Default tariff

See 'Standard variable tariff (SVT)'.

EPEX

A French-based spot power exchange operating in most European markets. It is part of Germany-headquartered energy exchange EEX. In Great Britain, EPEX operates one of the two main exchanges for spot power trading.

Fixed tariff

A retail tariff in which the electricity rate and standing charge are fixed for the duration of the contract.

Forwards

Contracts for wholesale electricity to be delivered in the future beyond the next day only, ie from day+2 onwards. When traded in organised exchanges, forward contracts are standardised and referred to as 'futures'.

Futures

See 'Forwards'.

ICE

A US-headquartered financial company that operates several exchanges and clearing houses around the world. In the UK, ICE operates in both Great Britain's power and NBP gas futures markets.

ICIS

One of the main international price reporting agencies for energy commodities. At its London offices, ICIS produces price assessments and market indexes for several European over-the-counter power and gas wholesale markets.

Low Carbon Contracts Company (LCCC)

LCCC is a UK government-owned company which manages contracts and financial transactions with low-carbon electricity generators as part of the CfD scheme and with capacity providers as part of the Capacity Market scheme.

Market Making Obligation (MMO)

The MMO was introduced by Ofgem in 2014 through the Secure and Promote policy. Details on the market making requirements can be found in appendix 3.

National Balancing Point (NBP)

Great Britain’s virtual location for trading wholesale gas.

Nord Pool

A Norway-headquartered power exchange operating in most European markets. In Great Britain, it operates one of the two main exchanges for spot power trading.

Over the counter (OTC)

Trading of commodities, financial instruments and derivatives that takes place between two market participants directly or through a broker. This is in contrast to exchange-based trading where the exchange acts as a central counterparty to all traders.

Prompt

Trading for delivery after day-ahead and up to the next month (front month), ie trading on day+2 onwards, next weekend, next week’s weekdays, the remaining days of a week (balance of the week) or month (balance of the month) for which deliveries have begun.

Spot

Trading for delivery on the same day (intraday) or on the next day (day-ahead).

Standard variable tariff (SVT)

Also referred to as ‘default tariff’, SVT is a retail tariff in which the electricity rate and standing charge paid by the consumer can change during the duration of the contract. SVTs are regulated by Ofgem, which sets a maximum cap to the tariff. The cap is revised every three months.

Title Transfer Facility (TTF)

The Netherlands’ virtual location for trading wholesale gas.

Vertically integrated energy company

An energy company that owns both electricity generation assets and a retail business.