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Where does the money go? An analysis of revenues in the GB power sector during the energy crisis

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ABSTRACT

The gas crisis has fed through to a huge impact on wholesale electricity prices in Britain. We use hourly price and generation data to estimate the impact on associated revenues to different types of generators. Given the extent of forward contracting, we complement simple results based on the day-ahead prices ("Case 1") with a more realistic case based on a representative, technology-specific assumptions on forward contracts ("Case 2"). We estimate that revenues to GB generators rose by almost £30bn, from about £20.5bn/yr (pre-Covid) to £49.5bn in 2022. About 70% of this accrued to gas generators (from about £6bn/yr to £19bn) and renewable generators with Renewable Obligation Certification (from £7.7bn to £15.5bn). There are various indications that the increase in revenues to gas plants significantly exceeded the rise in their input costs, and no reason to think the generating cost

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of these renewables significantly increased. Nuclear, and some other biomass and renewables also benefited. We find that the Electricity Generation Levy, introduced in Jan 2023, would have had limited impact on these numbers if it had existed in 2022 and is likely to have less impact in 2023. Finally, we discuss reasons and potential implications of the findings.

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Keywords: Electricity market design; energy crisis; renewable energy; CfD; long-run contracts; energy transition; energy poverty.

Contents

Introduction: the energy context in 2022

The price surges of the European energy crisis (which have largely driven a wider cost-of-living crisis) have hugely increased the money that consumers have had to spend on energy – and correspondingly, much higher revenues flowing into the energy sector. The profits made by the major oil and gas companies in 2022 – almost US$70bn globally from Shell and BP alone - have attracted the main headlines.[1]

The impact on the electricity sector has received less attention. Nevertheless, as documented in the first working paper in this series,[2] fossil fuel generators largely set the price in Europe's competitive electricity wholesale market – and nowhere more than the UK. Natural gas is used to generate around 40% of UK electricity, but set the price 98% of the time in 2021 in the pivotal wholesale electricity market, setting the clearing price paid to all generators selling into the day-ahead market. Consequently, as gas prices soared in 2022, following the Russian invasion of Ukraine, electricity bills followed.

As a result, the overall electricity bill to UK consumers in 2022 (households and businesses combined) rose by over £30bn – i.e., by around £500 per head of the UK population. This working paper explores "where did the money go" in terms of the revenues associated with different types of generators and discusses some of the possible implications.

Our analysis does not directly consider costs, which are generally not publicly available, and hence cannot be used directly to evaluate profits, though some inferences can be drawn.

In Autumn 2022, in response to concerns about the unexpected levels of profits in the electricity sector, the UK government announced the Electricity Generator Levy (EGL) – popularly, if inaccurately, called a windfall tax, on electricity sales from non-fossil sources above a given price. We also explore how much difference this would have made, if it had applied during 2022, as a guide to its possible significance (or not) subsequently. It is not our purpose to focus on nor criticize any specific technology or company – their behaviour and revenues reflect the rules and incentives set by the current market structure - but to present an objective assessment based on the data available. Our results are intended to contribute to debates about the implications of current market design in an era of fuel price volatility, whether it is fit for purpose in a system with rapidly growing volumes of renewable generators - and the level of uncertainty and intransparency arising from its complexity, and the lack of publicly available data about the actual terms of trade within the sector.

Our approach

At first glance, estimating the revenues going to generators in GB[3] would seem straightforward: data on day-ahead wholesale prices are publicly available, as are the general statistics of how much different generators produced. In fact, getting a robust answer turns out to be anything

[1] BP reported $28bn profits for 2022 (Bousso *et al.*, 2023) whilst Shell reported $39.9bn profits (Bousso and Nasralla, 2023)

[2] (Zakeri and Staffell, 2022)

[3] We focus on Great Britain, rather than UK for our analysis, as from an electricity system perspective generation in Northern Ireland does not operate in the same market.

but simple. We start by summarising the main assumptions we used to calculate the average revenues of generators disaggregated by generation technology. The detailed methods and sources used for the analysis are expanded in Appendix A.

Our analysis is based on publicly available data of electricity generation and prices in GB. For estimating the revenues associated with selling power from different generators, we aggregated them by technology and analysed four main revenue streams:

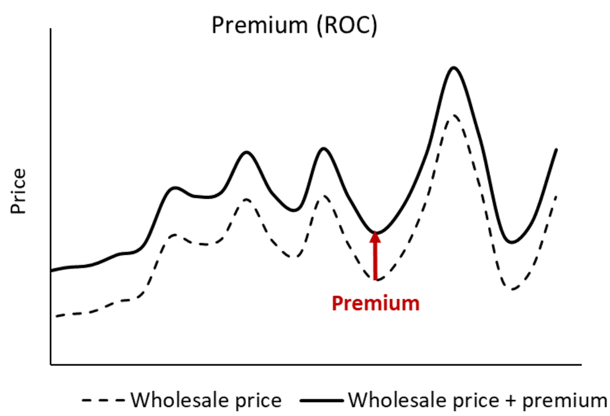
- selling electricity in the wholesale market,
- payments for rebalancing the system through the intra-day balancing mechanism (for flexible generators to cover deviations from projected supply-demand balance),
- payments for constrained generation (which occur when constraints in transmission prevent generators from being able to sell their output),
- and, for renewable generators accredited under the system 'renewable obligation certificates (ROCs), the revenues from selling the corresponding ROCs to suppliers, who have to meet obligations for renewables procurement.

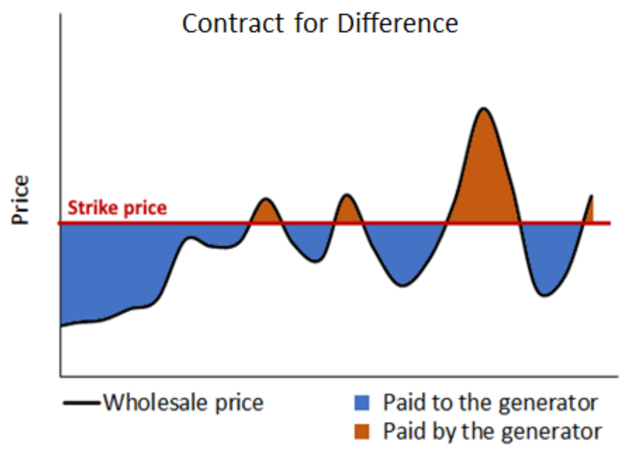
Box 1 indicates in a stylised way the difference between major types of generator participation in the GB generation market.

Box: Three routes for generator revenues from electricity sales through the wholesale market*

Fossil fuel generators bid into the wholesale market (including forward contracts over varied durations); bids in the day-ahead market receive the clearing price of the most expensive generator required to meet projected demand, which thereby also set expectations for the likely value of forward contracts. They may enhance revenues if some generation is held back and sold at higher price through the 'balancing mechanism' (BM) to cover short term variations in the supply-demand balance.

Renewable generators with contacts for Renewables Obligation Certificates sell electricity through normal market channels and gain additional revenues from selling their ROCs to suppliers, at a price which has (by design) come to be relatively stable at around £50/MWh. The number of ROCs allocated depends on the generating technology.
The system started in 2000 and was phased out over 2014-2017. The ROC contracts issued last for 20 years.



Renewable generators with contacts for difference bid for contracts based on a strike-price, which effectively guarantees a price for all generation sold. Operationally, they still sell into the wholesale market (and can contract their sales in any way they choose, for example with forward contracts). However, relative to a "reference price", they either receive supplement, or pay back money (which goes through to suppliers).	
*This excludes bilateral Power Purchase Agreements, and feed-in tariffs for small scale renewables like PV, and some other arrangements for small scale / local generation. Generators may also receive revenues from the balancing mechanism, and constraint payments if they are unable to generate due to transmission constraints.	

The ROCs system was initiated in 2000, with growing numbers of contracts being issued until the system was phased out over 2014-17; however the contracts last 20 years, so almost all ROC contracts were still active in 2022.

Starting from 2013, the ROCs system was largely replaced by contracts-for-difference (CfD), offering a fixed price for larger renewable generators. For generators producing electricity under a CfD contract, the revenue from selling electricity corresponds to the volume produced multiplied by the strike price defined in the contract. For all other cases it depends on the price negotiated between the buyer and the generator (in the case of bilateral agreements), or on the price reached on trading platforms.

These revenue streams are presented schematically in Figure 1.

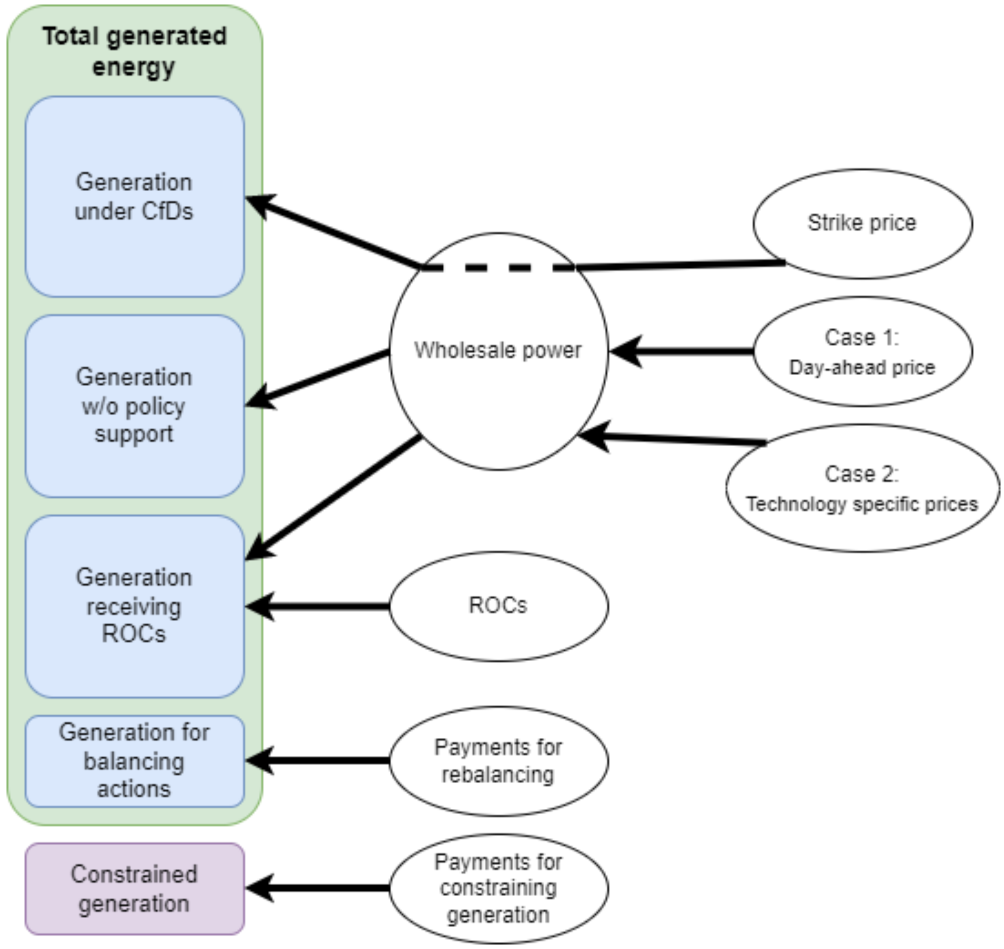


Figure 1: Revenue streams included in the analysis.

Methodology and data sources

To calculate the revenue from selling electricity, we obtained and aggregated by technology the actual amount of electricity produced by each generator using data provided by the LCCC[4] for the CfD generators and from Elexon[5] for generators that are part of the national Balancing Mechanism (BM).

As some CfD generators are part of the BM, we remove them from the Elexon data to avoid double counting. As shown in Figure 2, these data, for which we have hourly generation per each generator accounts for 76% of the total GB generation. These data exclude solar generation, as these generators are all embedded in the distribution network and their generation is difficult to measure for the system operator. For the same reason, it also excludes oil generation (mostly small, distributed diesel generators) and most of onshore wind in England and Wales (Scottish wind is usually connected on the transmission network, therefore it is easy to measure and thus participates in the BM). In addition, we use the data of total volumes of generation by all renewables receiving Renewable Obligation Certificates (ROC), provided by the government (BEIS, now DESNEZ)[6] to include ROC generation outside the BM, reaching a coverage of 85% of GB generation. The remaining generation to reach the total

[4] (LCCC, 2023)
[5] (Elexon, 2023a)
[6]Renewables obligation: certificates and generation (monthly – Excel) (DESNZ, 2023b)

annual energy generation according to DUKES[7] is assumed to be generation with no support and selling to the wholesale market. As the data for the generation outside BM and CfD contracts (two lightest colours on Figure 2) is not available at an hourly level, we assume they operate in the same way as generators of the same technology in the BM. Considering the different coverage of generation volumes just described, our analysis covers in detail a 75% of GB generation and extrapolates that behaviour to a remaining 20%, leaving less than 5% of generation not included in our analysis (namely, solar and oil).

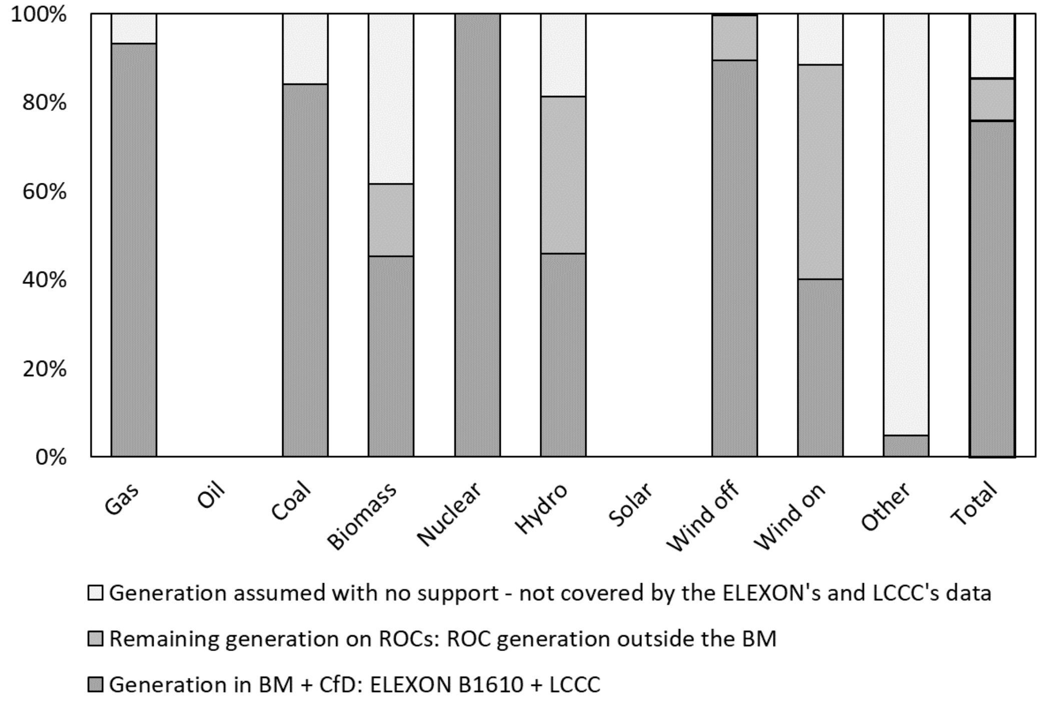


Figure 2: Generation included in our analysis as a fraction of GB generation 2022

Source: Produced by the authors with data from ET 5.1[8]

Note: 2022 generation was obtained from ET 5.1 for the UK. Northern Ireland is discounted using the relative capacities by technology for 2021 from DUKES 5.8 and the self-consumption of each technology was discounted using values form DUKES 5.6J.

A fraction of the electricity generated is produced to 're-balance' supply and demand near to real time, and is paid through the BM arrangements at a different rate than the energy sold in the wholesale market. Therefore, the volume of electricity generated for balancing is identified using a different dataset provided by Elexon and discounted from wholesale electricity revenues calculations.

The electricity generated (after discounting the fraction sold in the BM) is multiplied on an hourly basis by the price to calculate revenues. Estimating the exact price at which each generator sells the energy it produces is extremely difficult, as each generator may decide to sell its energy on the day ahead market or on forward contracts (with the average agreed

[7] DUKES 5.6 (DESNZ, 2022) and ET 5.1 for 2022 (DESNZ, 2023a)

[8] Fuel used in electricity generation and electricity supplied (ET 5.1 - quarterly) (DESNZ, 2023a)

forward price following closer the spot price on the date the contract was agreed rather than the spot price on the delivery date). Most generators opt for a diversified strategy, selling part of their generation through wholesale markets on the day ahead market and part of it in forward contracts, with the actual spread depending largely on the technical characteristics of the generation technology and individual companies' hedging strategies. In addition, some of the renewable generators sell all or part of their energy through long term power purchase agreements (PPAs), which have prices that are set in a contract for several years of electricity delivery.

To address this issue, we examine two cases for the prices at which an average generator of each technology is selling its electricity. For the first case we assumed that all the energy is sold in the day ahead market, using the intermittent market reference price (IMRP) provided by the Low Carbon Contracts Company (LCCC). This approach follows a common approximation, but it fails to consider that most of the produced electricity is traded in bilateral agreements with prices set months or years before the actual generation of the electricity.

In a second case we assume that generators sell their electricity through different timeframes forward contracts of different maturities, varied by generation technology. Table 1 presents brief descriptions of the two cases. **Error! Reference source not found.** presents the prices we used for the energy sold on different forward timeframes. We present further details on how we reached these prices, and the division of contract maturities between generators of different technologies, in the Appendices.

Table 1: Definition of the main assumptions of the two cases being assessed in our study

Case 1	Day-ahead price construction	Standard assumption where the price of the energy sold in the wholesale market is based on the day-ahead price.
Case 2	Inferred representative contract price construction	The price of a unt of energy sold in the wholesale market depends on when it was sold (as per **Error! Reference source not found.**). The proportions of energy sold in the day-ahead and forward markets depend on each generation technology (as per Table 2, in the Appendix).

We emphasise that we did not account for individual companies' hedging strategies, which depend on commercial decisions of each company, but aimed to represent an expected average behaviour based on our analysis of each technology.

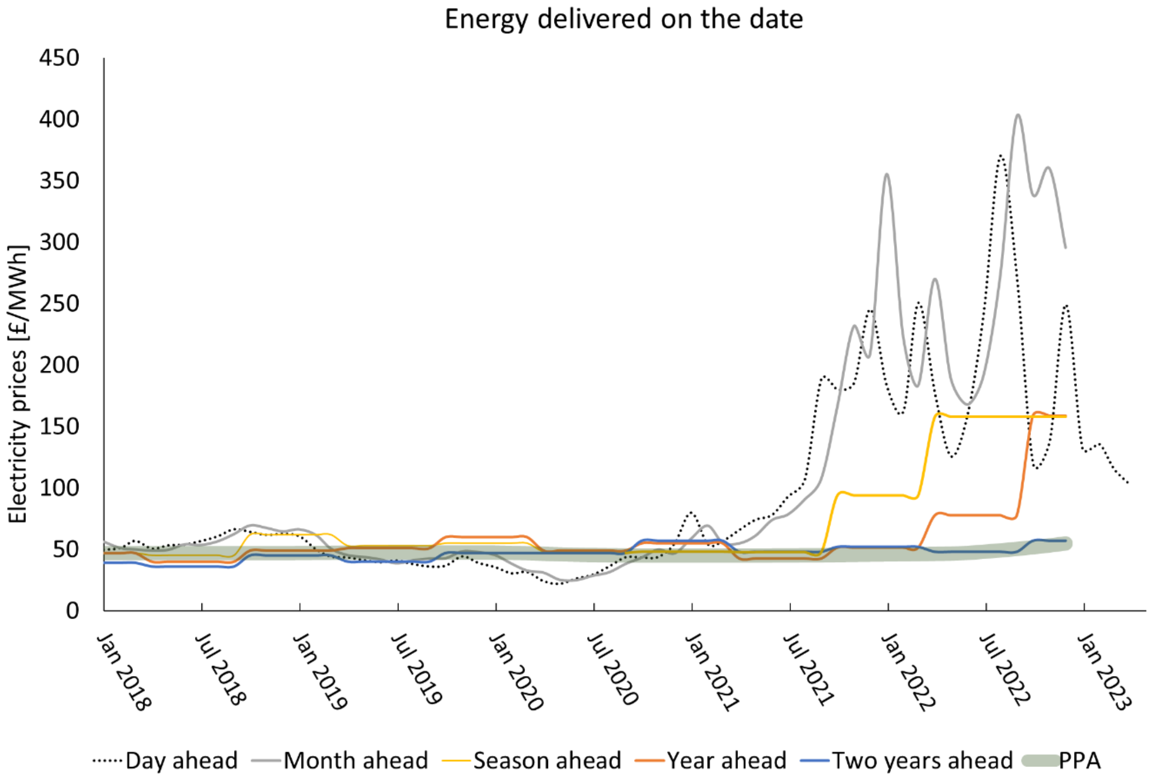


Figure 3: Prices of forward traded energy delivered on specific dates.
Source: Produced by the authors from multiple sources, as per Appendix A.3

For calculating the revenues from selling ROCs, we identified the generators operating in the BM that are under a RO contract using Ofgem's RO database.[9] The revenues from ROCs were calculated multiplying the ROCs sold times the price of a ROC.

For calculating the number of ROCs issued to each generator, we considered the technology and the year of accreditation and that all issued ROCs are sold. As the value that each generator got for the ROCs is unknown because it is set in trading platforms or in bilateral agreements, the annual "buy out price" plus "recycle payment" was used as a market approximation of the ROC's value to suppliers. This value represents the equilibrium price that a ROC should reach in a competitive market.

To estimate the payments from the constraints and re-balancing services in the BM, we used National Grid's monthly balancing reports (National Grid, 2023), which presents payments to and from generators disaggregated by technology. These payments are added to the total revenues.

After comparing the results from both cases, we focus our analysis on Case 2, as it represents a more realistic approximation of how average generators behave in the market. For this case we also (p.16) explore the effect that implementing a cap on the "windfall" revenues would have had if applied in 2022.[10]

[9] (Ofgem, 2020)
[10] The "Electricity Generator Levy on Exceptional Electricity Generation Receipts" started applying on generators whose costs have not been impacted by the increase in price of fuels in January 2023.

Aggregate prices, generation and revenues during the last five years

The relative contribution of different technologies has not changed massively over the past 5 years. After a decrease of gas generation in 2020 due to a lower demand driven by the COVID-19 lockdowns, it recovered to pre-pandemic levels and the main changes have been an increase in generation from offshore wind and a decrease in generation from nuclear and coal, as shown in Figure 4.

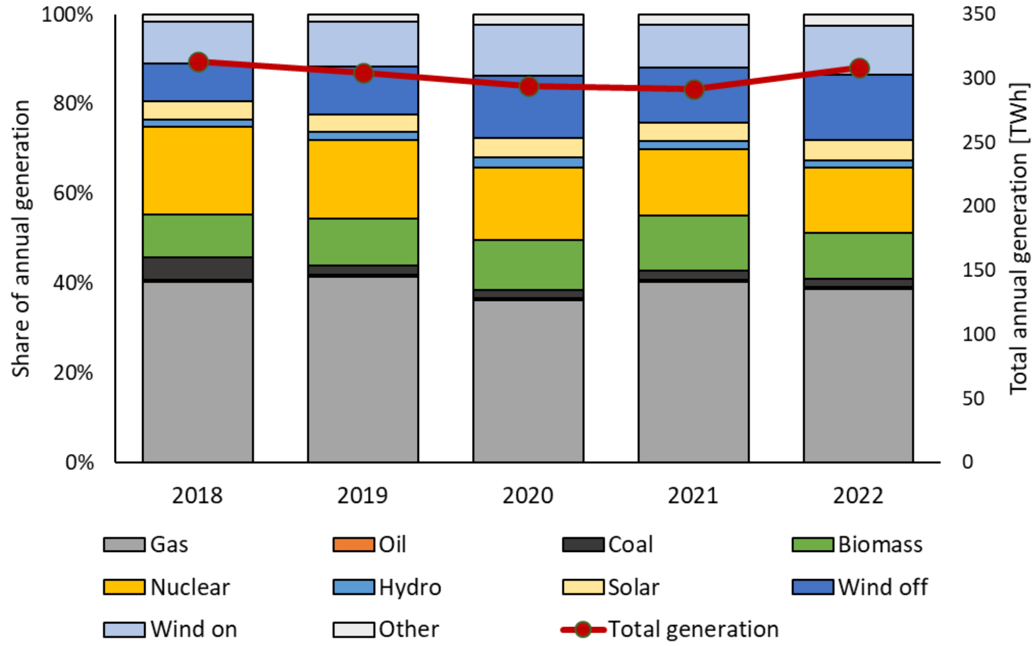


Figure 4: Relative contribution to the total electricity generated per each technology. Source: Produced by the authors with data from ELEXON B1610[11]

Although, according to Figure 4, close to 50% of the energy generated is produced by technologies whose average generation costs should not have increased markedly, the market design based on marginal pricing has driven the revenues upwards for all generators (except those on CfDs), as shown in Figure 5, which presents the evolution of revenues of all the generators included in our analysis.

However, it also shows that this growth has not been even among the different generators. Technologies that, according to our assumptions, sell most of their energy in the forward markets, such as biomass and nuclear, experience a lower increase, while wind, gas and coal experienced the highest increases. For instance, when comparing the average revenue from before covid (2019-2019) with 2022, our analysis shows that biomass and nuclear, increased their revenues by 89% and 66% respectively. On the other hand, gas increased its revenues by 205%, coal by 93%, offshore wind by 111% and onshore wind by 143% in the same period.

[11] (Elexon, 2023a)

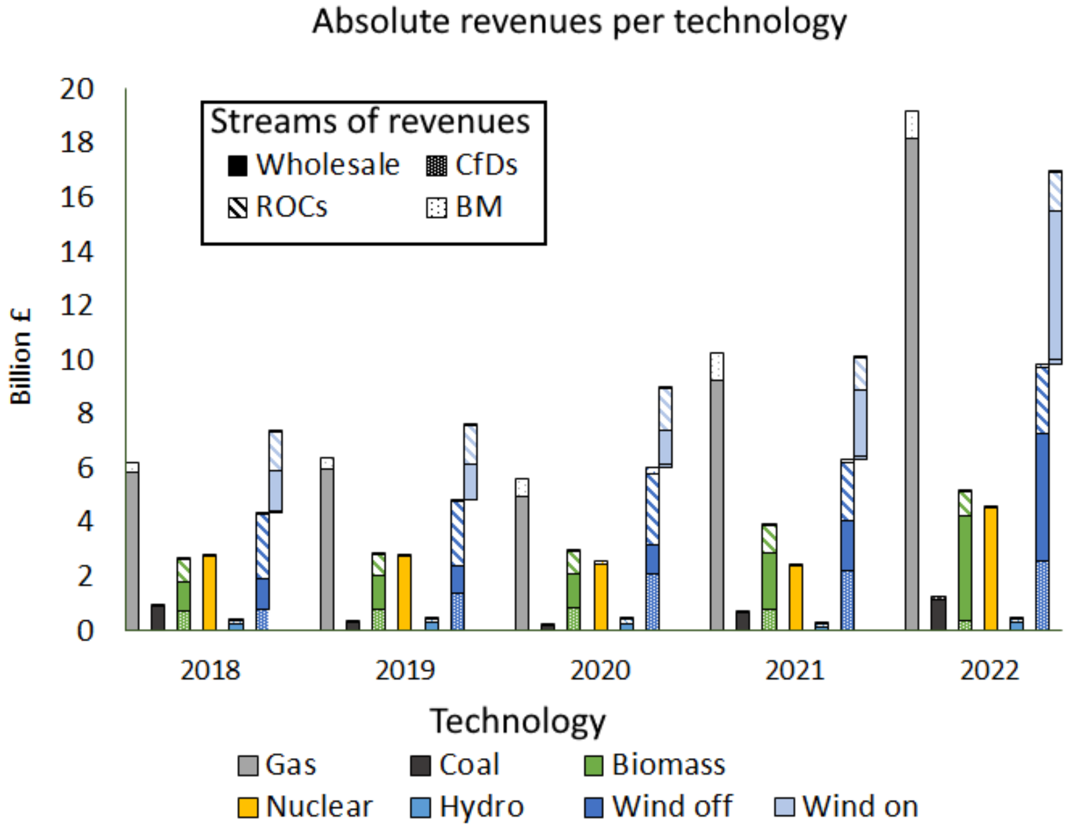


Figure 5: Evolution of revenues of all generators in absolute terms per technology under the assumptions in Case 2.
Source: Produced by the authors with data from various sources
Note: The colours in this figure represent the different technologies, while the variations in pattern represent the source of the revenue.

As the absolute revenue figures presented in Figure 5 do not account for the difference in volume produced by each technology (Figure 4), the following section presents relative revenues per unit of energy generated, encompassing all the revenue streams presented in Figure 1.

Current revenues depend on contracting & hedging strategies

In Figure 6 we present the spread of revenues captured across all generators over time under each case.

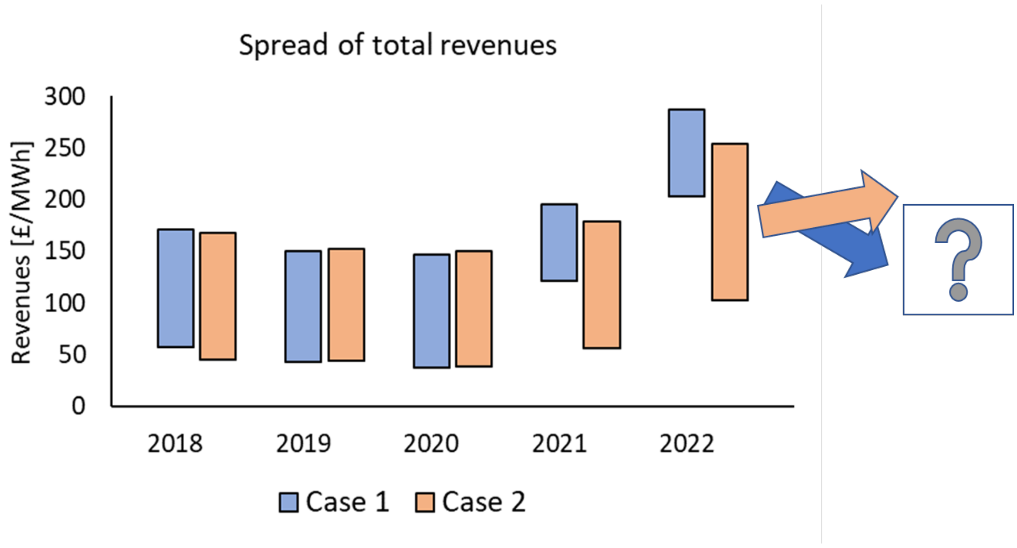


Figure 6: Spread of revenues per MWh captured by different generation technologies for the different cases.
Source: Produced by the authors with data from various sources

The range of revenues per unit of electricity sold were relatively similar in each case before 2021, but with the surge in the spot prices of electricity, Case 2 has the price range increasing in value more slowly than Case 1, as some generators (like nuclear) have large portions on forward contracts at prices as set 1 to 3 years ahead. This also explains the higher spread of revenues among generators in Case 2, in 2021 and 2022 in particular.

However, this may also mean that in the future the average revenues for generators may go down slower than the spot price, because higher spot prices would affect contracts signed in 2022 for delivery over 2023/24/25 (as suggested by the arrows), although the overall effect would be much attenuated.

In Figure 7 we present a similar result, but in this case the revenues per unit of energy of each technology are weighted by their total annual generation and averaged. It also illustrates the division of revenues between selling electricity in the wholesale market, revenues from selling ROCs, and from operations in the BM.

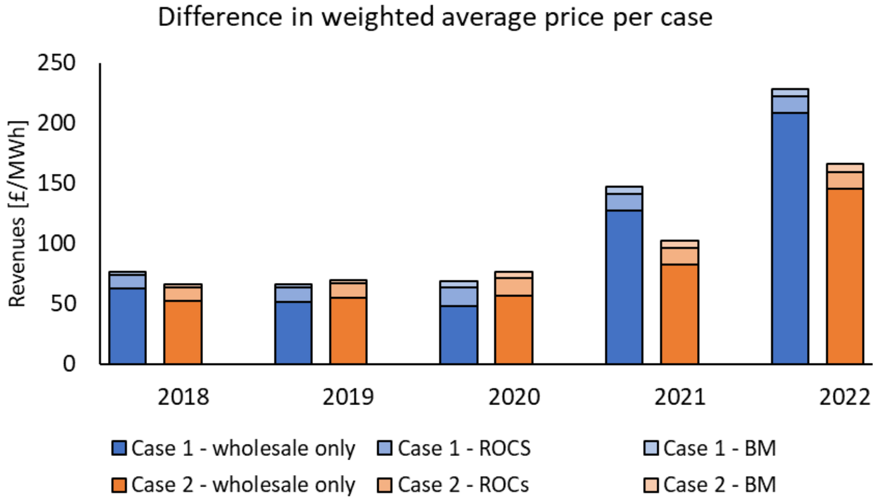


Figure 7: Average revenues of all generators per case and their disaggregation per source of revenue
Source: Produced by the authors with data from various sources

This indicates that revenues from ROCs have remained relatively constant, and the increase in total revenues is largely due to wholesale price rises and the operation in the BM. In rough numbers, ROCs moved from representing 20% of total revenues across all generators in 2018 to less than 10% in 2022, while the balancing actions represent a relatively steady 3-5% of revenues, as their price is set in a parallel market which is tied to the spot price of electricity.

Figure 8 presents the revenues by technologies under the assumptions of Case 2. Before 2021 the situation was relatively stable, with direct revenues per unit of electricity sold through wholesale markets being similar among different technologies. the exceptions are biomass and offshore wind, which increased their revenue from selling electricity thanks to the CfD support (more of this discussed next).

However, under our assumptions for Case 2, after the large increase in spot prices of electricity since 2021, the differences between the revenues from wholesale electricity among technologies have accentuated. In particular, technologies such as hydro and nuclear, that are assumed to sell more of their generation years in advance, have experienced a slower increase in their revenues. In contrast, technologies that sell most of their generation in the day ahead market saw their revenues per unit of energy rise more quickly. In particular, coal has experienced the highest increase in revenues per unit of generated electricity, as it has operated in times when the system requires additional generation, and the prices of electricity are high.

In addition, mostly coal, but also gas have increased their revenues from operations in the balancing market, given their ability to change their generation level within their operational constraints. There is clear evidence that some generators constrained volumes offered on a short-term basis, so as to be called upon to make up shortfalls at much higher prices in the balancing mechanism (which is particularly valuable at times of system stress), a practice exposed by Bloomberg in March.[12]

[12] Certain gas generators used an on-off manoeuvre to sell part of their generation at higher price into the Balancing Mechanism instead of the main day-ahead market (Finch, Grotto and Gillespie, 2023)

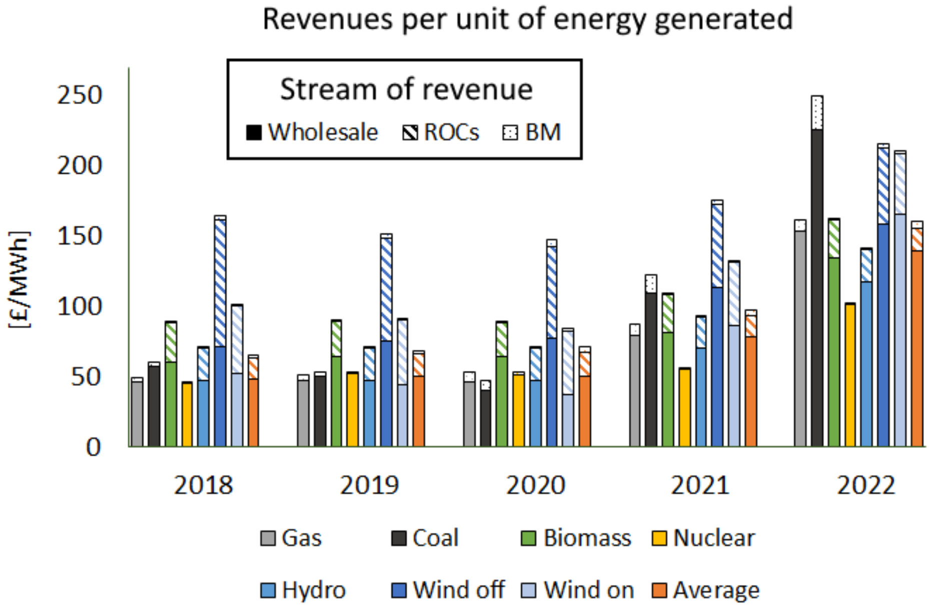


Figure 8: Evolution of revenues per unit of generated electricity by technology disaggregated by source of revenue for Case 2.
Source: Produced by the authors with data from various sources

Relationship to costs

As noted, this study has not directly examined generating costs, in large part because of the confidentiality and complexity of cost structures; as a consequence, we make no attempt to quantify potential profits. Ultimately, profits will become apparent in company reports, though interpreting these in terms of different technologies and contracts may remain somewhat impenetrable. Moreover, as observed clearly in the ability of oil and gas companies to avoid paying the UK windfall profits tax on North-Sea production through investment, profits will to an extent depend on investment strategies.

We do however offer two general observations.

First, gas generation is the sector for which both costs and revenues have increased by far the most – and though these are related, they are by no means in lockstep. We estimated that revenues associated with gas generation may have soared from about £6bn/yr, to almost £20bn in 2022 (Figure 5), along with the unit price rising from average around £50/MWh to about £160/MWh (Figure 8).

An important published measure, the 'clean spark spread' offers an indexof the gap between the electricity price and the fuel cost of gas-generated electricity, which is taken as a rough measure of the profitability of gas power generation.[13] As shown in Figure 5, over 2018-2020

[13] 'Clean Spark spreads' are based on day-ahead power baseload and day-ahead gas prices, so are meant to represent the day-ahead spark spread, taking into account also the carbon price as a cost, based on: [Day-ahead power price] – [(day-ahead gas price * p/therm to £/MWh)/ 50% fuel efficiency] – [(carbon price + carbon price support) * metric tonne of carbon to MWh*emission intensity factor/ 50% fuel efficiency factor]. Ofgem publish spark spreads with price assessments from ICIS. (Ofgem, 2023)

the spark spread was about £5/MWh (which was also the average since 2010). In 2021 it jumped to an average of £23/MWh; in 2022, it almost doubled to average £42/MWh. This indicates that the margins increased – the price paid to 'typical' gas generators for their electricity increased more than the increase in generating costs, a conclusion supported by our own estimate of total cost trends.[14] We touch upon possible reasons why in the conclusions.

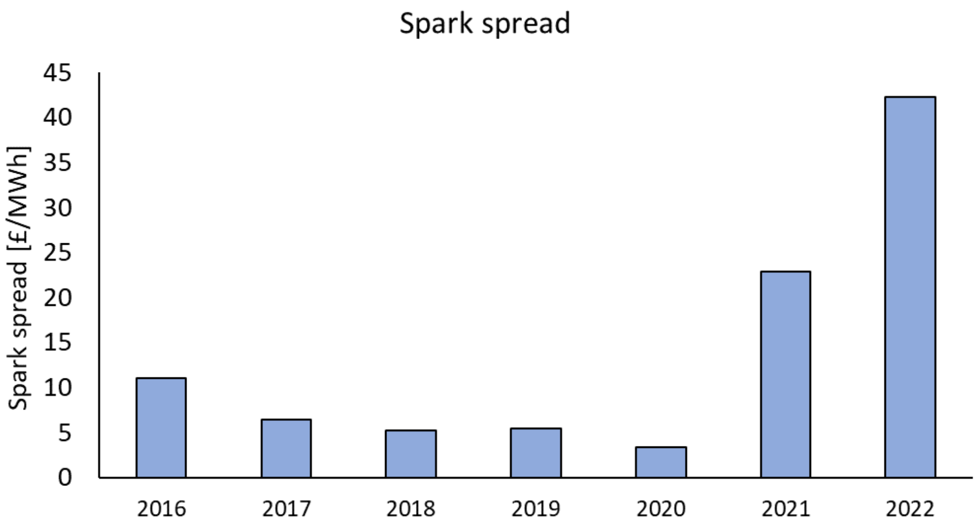


Figure 9: Change in spark spread and day-ahead gas prices in the last years
Source: Ofgem[13]

Second, there is no reason to think that the cost of operating renewables increased significantly to 2022. The increase in revenues to wind generators (other than CfDs) from wholesale – the solid components in Figure 5 - is driven almost entirely by the increase in wholesale price (Figure 8).[15] These revenues overall increased by £7.6bn from 2020 to 2022 – more than doubling, from £6.4bn to £14bn.[16]

The early investors in renewables did face many challenges and risks to help launch the industry, at a time when renewables were much more expensive and it was harder to attract capital. In the same way that the gas industry points to lean years of extremely low gas prices, they argue that for years they had to survive with wholesale power prices lower than expected.

The volatility of profits overall in the energy industry has always been one of its features; it remains highly debateable whether it was (or is) necessarily healthy for that to be extended to renewables, with income linked to the vagaries of fossil fuel price fluctuations, topped up by guaranteed income from ROCs. Contracting renewables: from ROCs to CfDs.

[14] If we compare both gas and electricity prices on a "day ahead" basis, the cost of gas increased by £14bn from pre-Covid times while the revenues in our Case 1 raised by £21bn. This is unrealistic given forward contracting. Alternately: if gas generators in 2022 bought 60% of their gas at 2022 prices, and had 30% hedged one year in advance and 10% two years in advance (at the corresponding historical prices: an arbitrary, but probably conservative hedging strategy), we estimate that the costs of the gas for generation in 2022 would have been £10bn, while their revenues in our Case 2 are £13bn. Both cases indicate revenues much greater than costs.
[15] The capacity of wind generation on ROCs – onshore and offshore - had stopped growing by 2020; and the price of ROCs barely changed.
[16] Onshore, from 2.7 to £6.9bn; offshore, from 3.7 to £7.12bn. As indicated, this excludes CfDs whose earnings above their strike price are returned to suppliers.

Contracting renewables: from ROCs to CfDs

As much of the discussion on revenues for electricity generation has focused on renewable generation, we have analysed in more detail the revenues of wind generation and how they have been affected by the supporting policies (RO and CfD). This analysis is reflected in Figure 10, where the capture revenues are differentiated for wind generators on CfDs and on ROCs.

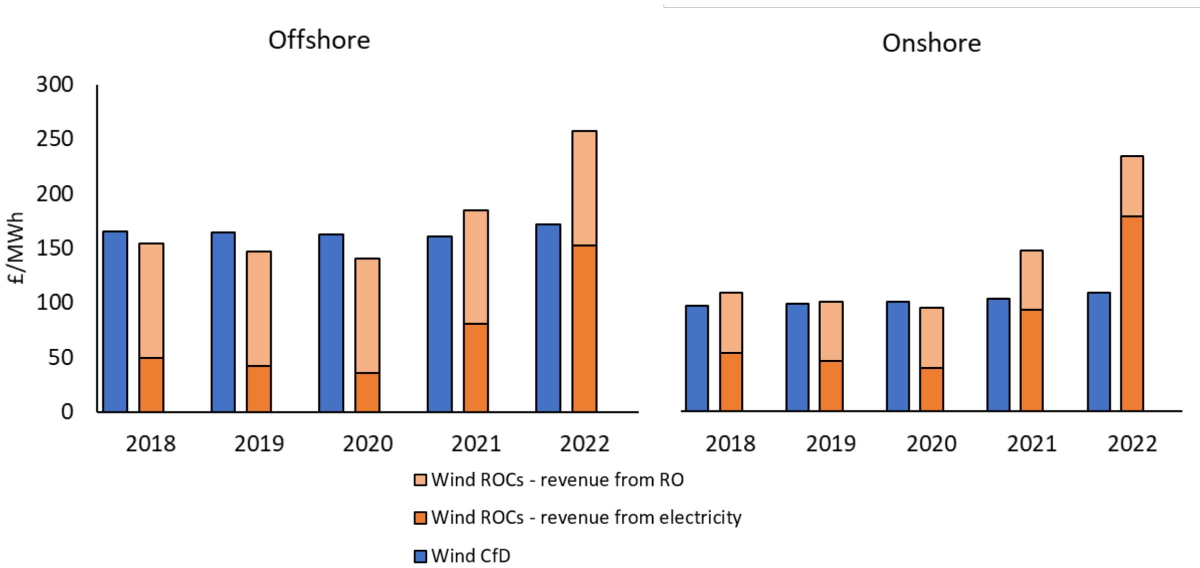


Figure 10: Comparison of revenues for Offshore wind (left) and Onshore wind (right) on CfDs and in ROCs
Source: Produced by the authors with data from various sources

Introduced to support the growth of the nascent renewable energy industry, the ROCs system started with a uniform 'one ROC for each MWh', alike for almost all renewables. It became apparent that onshore wind energy - the easiest, quickest, and cheapest renewable – would dominate, and offshore wind would barely get a look-in. In 2008 the government introduced 'banding' - in particular, offering two ROCs per unit for offshore wind. The aim was to attract investment into offshore wind despite the greater scale of investment and risks involved, given its relative immaturity alongside its far greater potential (and growing opposition to onshore wind).

The data in Figure 10 suggest that – at least up until 2020 - this was pitched well. The total revenues to the offshore wind plants on these 'doubled' ROC contracts were dominated by the value of ROCs, rather than wholesale electricity sales, whilst slightly less than the cost of the first round of offshore wind on CfDs. Onshore wind plants, meanwhile, gained about half their revenues from ROC sales; and again, the overall price per unit for wind generation supported by both policies were relatively similar.

However, in the last two years, the revenues per unit of energy to ROCs-based generators has exceeded that supported by CfDs, driven by wholesale market revenues. Meanwhile generators on CfDs, which for some years were receiving payments from the LCCC to match their strike price, have started paying money back, as wholesale market prices surpassed strike price. As shown in Figure 11, onshore wind (with lower strike prices) started paying money back from mid 2021, but by 2022 even the relatively expensive first rounds of offshore CfDs were paying money back. Overall, the system has worked to stabilise revenues to renewables on CfD contracts, whilst renewables on ROCs earned well over £200/MWh (gross) during 2022.

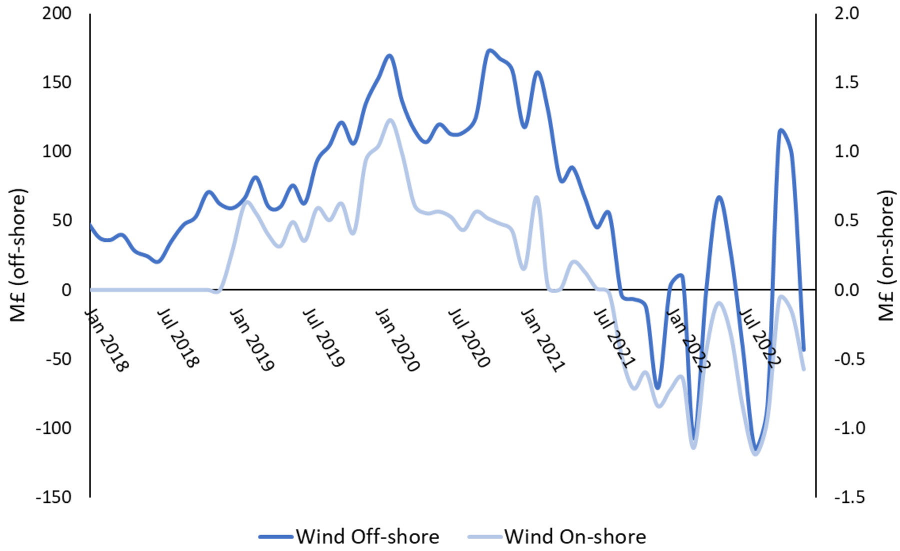


Figure 11: Payments from LCCC to wind generators on CfDs
Source: Produced by the authors with data from the LCCC[17]

In aggregate, although the overall cash flow in the CfD system has been towards generators, the main benefit of CfDs is that they provide clarity of future revenues to investors and to the market, securing a long-term supply of clean power at a predictable and affordable price (at least for the recent auctions). Figure 12: Average wholesale prices of electricity produced by existing and contracted CfDs.

, previously included in our Working Paper 4, shows the price that electricity delivered by already auctioned projects under CfDs should reach after their construction, which is only around 20% higher than the average wholesale market price before 2021 (Figure 8), including the more expensive contracts allocated in Round 1 on a non-competitive basis (and less if only auctioned CfDs are included).

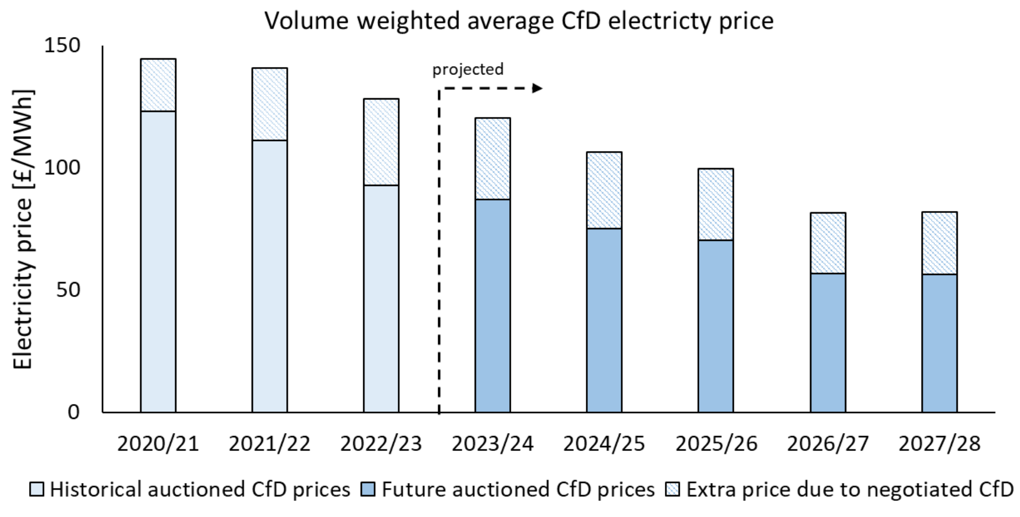


Figure 12: Average wholesale prices of electricity produced by existing and contracted CfDs.

[17] (LCCC, 2023)

Source: Navigating the Energy-Climate Crises: Working Paper 4[18]

Effect of the Electricity Generator Levy

Considering the adoption of the Electricity Generator Levy on exceptional electricity generation receipts, also known as the windfall tax from January 2023, we assessed how its earlier implementation would have impacted the revenues of the generators affected by them and how much it would have represented for the Treasury. Figure 13 show the impact a tax designed in the same way as the one designed as of April 2023 would have had on the generators (for more details see the Appendix).

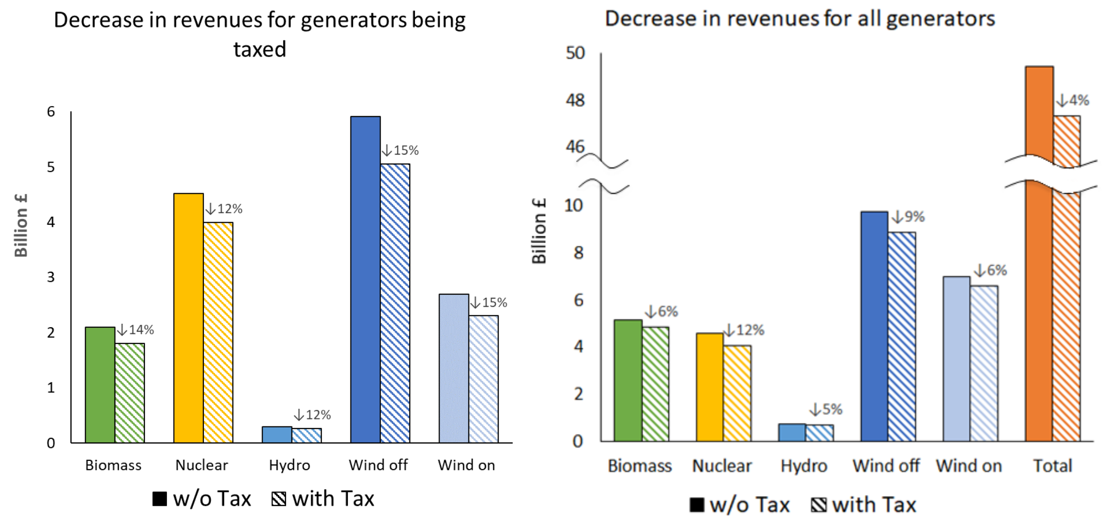


Figure 13: Effect of the 'revenue cap' if applied in 2022.
Source: Produced by the authors with data from various sources

The figure on the left shows the effect the cap would have had on the companies it covers[19], while the figure on the right presents the effect distributed among the revenues of all the generators of each specific technology, considering those not affected, due to their small size or being under a CfD contract and on the total generation (in orange). From the figure, it is clear that the most affected by the cap are qualifying wind and biomass generators, which would have seen their revenues decrease by around 15%. Nuclear and hydro generators would have seen their revenues decrease by around 12%. The main difference between the technologies is due to the proportion of the energy produced in 2022 sold through forward contracts at prices below the spot price and the proportion of the generation receiving ROCs, thus the revenues from this stream are not affected by the cap.

This transfer of revenues from the generators to the Treasury would have amounted to £2.1 billion, representing 4% of the total revenues of all generators in 2022. However, it would not have translated into a decrease in the electricity bills unless converted in direct subsidies to the final consumers. If spread evenly across all the electricity consumers (including large industry)

[18] (Grubb, Drummond and Maximov, 2022)
[19] Companies owning generators in the BM that fit the description detailed in Appendix A.6. We assumed that generators outside the BM do not fit the definition and therefore are excluded from the cap.

and passed through the electricity suppliers, it would have represented close to £2 decrease in the monthly bill for an average household[20].

Interestingly, if looking back at Figure 10, the effect of the cap would bring the revenues per unit of energy of wind generators of ROCs to around 200 £/MWh, still above the level of CfD generators, reaffirming the value of CfDs as a policy that stabilises prices while fostering investment in clean power.

The effect that this cap would have in 2023 is uncertain, as it would require estimating future prices of electricity. However, it is safe to say that under a scenario of comparatively lower wholesale prices in 2023, the effect will reduce.

Conclusions and implications

Electricity is a fundamental need in modern society. In a time of gas crisis, the way the market works has amplified the impact on consumers – though the complexity and confidentiality of contracts in the market makes establishing exactly by how much fraught with difficulty. These conclusions outline what may be drawn from our analysis.

We have derived best estimates of the impact of the energy crisis on revenues associated with different generation sources in GB during the energy crisis, focusing particularly on gas and renewables. Given the complexity of contracting structures, we derived estimates not only based on the published day-ahead prices, but using a more realistic, estimated representation of the typical structure of 'forward contracts.' Our numbers cannot be assumed to be representative of any particular facility or company. We accounted for Power Purchase Agreements although the data on volumes and prices is patchy and probably incomplete. Feed-in-tariffs (which are generally for smaller generators on fixed prices, often at distribution level) were excluded from our analysis, which also means we have not covered solar.

1. **Gas generation: profiting from its own crisis?**

Revenues associated with gas generation in 2022 rose by about £13bn (200%) compared to the pre-Covid average (2018-2019), to £19bn. Predominantly this reflected the increase in gas prices, passed through directly into wholesale prices. However, two factors show there was more than this.

First, the operating margin estimated by Ofgem (the 'clean spark spread' - the extent to which the electricity price exceeded the estimated generating cost of a typical gas generator), also jumped (Figure 9). After averaging around £5/MWh pre-Covid, it increased sharply from 2021 and in 2022 averaged £42/MWh. Our own comparison of overall costs (note 14) point to a similar basic conclusion, that profits increased substantially. Gas generation also increased revenues from the balancing mechanism, to around £1bn, which may just reflect their fuel cost increase, but resonates with warnings about market manipulation.[21]

In part, this points to a paradox of the UK's highly liberalised electricity system: there is not really any fuel-on-fuel competition. Renewables generate when they can, subject only to installed capacity and the intensity of wind and sunshine. Nor do high gas prices stimulate

[20] Assuming 33% of demand from domestic consumers (DESNZ, 2022) and 27.5 million households in GB (ONS, 2022)
[21] (Finch, Grotto and Gillespie, 2023)

meaningful competition even for investment, given the planning hurdles and construction times (along with the higher risks that purely renewable investments based purely on the wholesale market face, given the market structure)[22]. So there is negligible price-based competition in wholesale generation between gas and renewables, and indeed limited competition with nuclear or biomass either, for similar reasons.

Aside from regulatory monitoring, the constraint on pricing from gas plants is competition between different gas generators in Britain, and from interconnectors flows with the continent. Through 2015-19, imports of cheaper electricity set the price for more than 10% of the time and would have constrained prices at other times. Multiple factors including post-Brexit frictions in trading, and low hydro (Norway) and nuclear (France) generation, as well as the growing gas crisis, changed this so that interconnectors ceased to play any measurable role in constraining electricity prices in Britain.[23] There was therefore no effective external constraint to gas plants substantially increasing their operating margins. It appears that gas generation was itself a major beneficiary of the gas crisis.

Nuclear plants were a more 'passive' beneficiary from the crisis; our analysis suggests, proportionately somewhat less than gas due to the greater prevalence of long-term contracts for its outputs reflecting pre-crisis gas prices. Overall, our "Case 2" estimates suggest a 66% increase in their revenues from pre-covid levels in 2022.

2. Renewables on Renewables Obligation Certificates (ROCs): windfall gains?

Revenues associated with generation from renewables with ROCs in 2022 rose by about £7.7bn (100%) compared to the pre-Covid average (2018-2019), to £15.5 bn. They were hence also major beneficiaries of the crisis. The renewables industry argues that they – particularly the early investors – invested when renewables were much more expensive and had to take large risks (including subsequently, presumably increasing wastage from developments stalled or blocked in planning), and endured several years in which wholesale electricity prices were lower than expected (which we have not explored).

Nevertheless, £7.7 bn is a huge increase in revenues for sources that represented 23% of GB generation in 2022 – more than doubling the pre-Covid average, for sources whose costs (or debt repayments) would have barely changed. We also find that the energy generation levy would have only moderated this increase to a limited degree. The ROCs system may have spurred the rapid expansion of renewables, but the sheer scale and volatility of revenues shows the wisdom of ending that system in 2017, compared to the stability and predictability of fixed price contracts.

It remains a live debate whether and if so how the generators with ROCs could be persuaded to move away from their 20-year contracts towards cost-reflective fixed-price contracts. The attraction of price security, compared to the uncertainties of wholesale prices and the future of the generation levy, may persuade some to do so.

At the same time, meeting our decarbonisation goals will require tens of £billions of new investment in renewables. The companies do need cash reserves and the possibilities for rates

[22] As explained in Grubb and Newbery (2018): "Gas generation can be [self-]hedged by passing through fuel prices into the market; zero-carbon investments in contrast would take all the price risk of both fossil fuel and carbon price uncertainties." For a more detailed explanation see Newbery (2012)
[23] See our NECC Working Paper #1, Zakeri et al (2022).

of return that attract such large volumes of capital. We have not explored the extent to which the renewable energy companies are reinvesting the profits accumulated in the energy crisis and it is unclear why the government's EGL does not allow an investment offset (of the kind associated with the windfall profits tax on oil and gas companies).

3. Renewables on Contracts-for-Difference: not as simple as it seems

Finally, the situation for the rapidly rising volume of renewables on contracts-for-difference is simpler. In general, they have not profited from the energy crisis in the way that other generators have – that was the deal, the security of government underwriting in return for an obligation to return revenues received at prices above the agreed 'strike price'.

Nevertheless, these are not quite fixed price contracts – with implications. The CfDs generators sell into the wholesale market, and subsequently returned their 'surplus' revenues to suppliers. In the short term, suppliers gained that benefit. To try and ensure that suppliers pass these revenues on to their final customers, Ofgem moved to include the CfD recycling revenues in the price cap that limits what suppliers can charge.[24]

This in turn means that the price cap is no longer a mechanism simply for protecting vulnerable customers, but has become the channel through which any recycled payments from CfDs flow to customers, with implications for the retail market.[25] It also means that although CfDs do help to isolate those renewable generators from the gas-driven wholesale price, consumers have no direct access to this 'pool' of CfD-backed electricity. The benefit is only transmitted, in general, through the recycled payments merged into the default tariff price cap.

It is a measure of the complexity of the system that in general, during the energy crisis, customers with so-called '100% renewable' or other green tariffs saw their prices rise just as much as other customers. Many green suppliers (except for those with direct 'Power Purchase Agreement' bilateral contracts) were buying renewables in terms of ROCs or 'guarantees of origin' – but still had to purchase the associated electricity from, and at the cost of, the gas-driven wholesale market.

As the volume of renewables grows, these limitations will only become more apparent. The CfDs are unquestionably an improvement on previous mechanisms, but they do not remove the need to consider more fundamental market reforms for a decarbonising and increasingly renewables-intensive GB electricity system.

[24] Without this, suppliers could in theory price their customer tariffs based on their own marginal cost of purchase from the wholesale market, for example, and thereby profit from the CfD revenues as a 'lump sum' revenue.

[25] This is beyond the scope of this study, but it presumably limits the prospect for other tariffs to compete with the 'standard variable tariff' – which may hugely constrain the realistic scope for retail competition. It also means that consumers outside the scope of the price-cap – including most industry, public and commercial sectors – see no benefit from the recycled CfD payments, and only see the price derived from the gas-driven wholesale market (unless they enter into direct, bilateral PPA contracts – for which CfD generators have little financial incentive)

The energy crisis overall resulted in about £30bn of enhanced revenues flowing to GB electricity generators overall. This extraordinary increase of revenues, along with consumer hardship, the opacity of the system, and the complex but indisputable scale of profits, underlines the case for reform of the system: to reduce the wholesale dependence on fossil fuel price volatility, and better reflect the known and more stable economics of a rapidly growing volume of renewable generation.

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Appendix A. Detailed Methods

Table 2: Assumed proportions of electricity sold on different timeframes and contracts by technology for Case 2.

	Fraction of generation traded on wholesale markets	Wind		Biomass	Hydro	Nuclear	Gas	Coal
		Onshore	Offshore					
Generators on CfD	N/A (accounted separately)	Revenues calculated based on strike price, so actual hedging structure is not required			N/A			
% from remaining generation								
50% of total PPA are onshore wind, 30% of total PPA are offshore, remaining 20% of PPA are solar (not included in the analysis as it is not part of the BM)								
% energy sold on PPA	1% in 2018 growing to 5% in 2022	8% in 2018 growing to 17% in 2022	10% in 2018 growing to 16% in 2022	N/A				
% from remaining generation (excluding generation on CfDs and PPAs)								
% energy sold on day-ahead	20-30% *	40%	40%	10-30% *	15%	10%	20-40% *	70%
% energy sold on month-ahead	20%	30%	30%	10-5% *	10%		10%	20%
% season ahead	20%	15%	15%	10-5% *	10%		10%	10%
% year ahead	29-27% *	10%	10%	50-45% *	25%	90%	25-15% *	
% 2 years ahead	11-3% *	5%	5%	20-15% *	40%		35-25% *	

* The first value corresponds to the fraction assumed from 2018 to 2020 and the second value to the value assumed in 2022 with a linear transition in 2021

Appendix A.1 Renewables with CfDs

For CfDs, the revenue calculation is relatively straightforward as the LCCC offers both volumes and strike prices on its website (LCCC, 2023) for each CfD contract and data for daily generation and the payment from/to the contract holder to the LCCC. It is likely that wind generators on CfD sell their electricity mostly on a day ahead basis and that biomass CfD generators would sell a larger proportion a season or year ahead. However, this information is not used in the calculation and therefore, any difference in revenues that CfD generators may achieve by selling under different conditions than the references assumed in their contracts (intermittent and baseload market reference prices for wind and biomass respectively) are excluded from our analysis.

Appendix A.2 All generation without CfDs

For the generators outside CfDs, the method is based on the Elexon-B1610 database (Elexon, 2023a), which has the half hourly generation of all the units in the balancing mechanisms (BM). The generation units that are part of the BM can have their generation measured from the grid and are in most of the cases connected on a transmission level. Renewable generation under Feed-in Tariffs are thus mostly, if not entirely, excluded. In total, these generators represent 74% of all electricity generation in GB[26] (when compared to data at DUKES 5.6b) and close to 90% of all major power producers (from the same source).

Every BM unit that generated energy in the period from January 2018 to December 2022 was identified by name, generation technology and policy support (ROC or CfD).

Subtracting the generation of units under CfDs and the energy produced due to balancing actions (described in the next section) gives the generation of the units that would be producing revenues from selling in the wholesale market. The price at which they sell their energy in our Case 1 has been approximated by the intermittent market reference price (IMRP) published by the LCCC, which is a weighted average of the day ahead prices reported by the different trading platforms. The remaining volume of generation produced by generators on ROCs according to DESNZ[27] and remaining non-supported generation to reach the total GB generation by technology[28] are assumed to sell at the same average price as generators of the same technology.

Appendix A.3 Allocating and pricing generation sold outside day-ahead markets in Case 2

The majority of electricity generation is sold outside the day-ahead market, mostly through bilateral 'forward' contracts between generators and suppliers/off-takers, for delivery typically 1-3 years in the future. Figure 14 presents the fraction of the total energy traded in GB that has been traded "over the counter" (OTC), which is done through brokers on bilateral contracts on forward deliveries. The remaining power is traded in platforms on spot (day ahead or intraday markets).

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[26] It increases to 76% after adding the CfD generators that are outside the BM

[27] Energy generated from ROCs outside the BM is obtained by subtracting the generation on ROCs in the BM from the total generation from generators on ROCs per technology presented in (DESNZ, 2023b)

[28] The total GB generation is obtained from (DESNZ, 2022))for 2018-2021 and from (DESNZ, 2023a) for 2022, after removing Northern Ireland based on its share of the total installed capacity by technology.

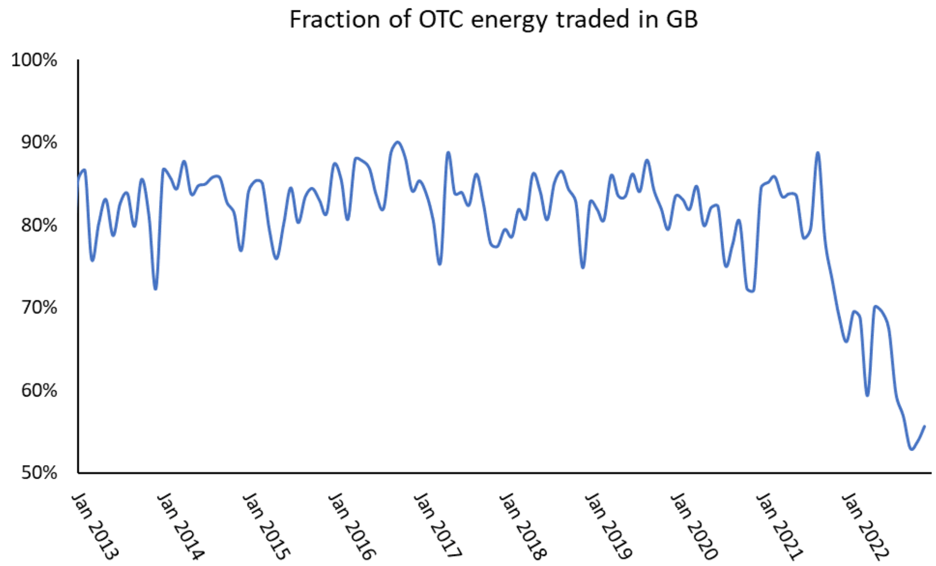

Figure 14: Fraction of the energy traded Over the Counter in GB. Source: (Ofgem, 2023)

Specific volumes and prices of forward traded energy, and the specific technology or technology mix concerned, are generally not made public (with aggregated price indices generally only available through subscription services). Ofgem data, presented in Figure 14, suggests that forward trades have typically been well above 80% of total volumes exchanged through brokers and platforms, but since autumn 2021, the proportion of electricity delivered through forward contracts has reduced below 70%, with the proportion traded on day-ahead markets increasing. Around 2% of the total energy trade is done in intra-day markets, but in the absence of specific volumes and prices we assume that on average prices are close enough to the day-ahead price to assume parity for our purposes.

We understand that between 70% and 80% of electricity is sold in forward markets (rather than day ahead or intraday). As such, it is important to understand how the forward traded electricity approximately spreads across timeframes and how this spread varies from one generation technology to other, and how this may have changed during the period analysed.

In this approach, the spread of energy traded in different time frames has been derived from data in publicly available resources and it is summarised in Table 1.

For generation under CfDs, it has been assumed that all of it is sold in the day-ahead market, or otherwise receives the strike price stipulated.

The volume of contracted renewable PPAs and their average price evolution have been reconstructed based on data published by different sources, such as LevelTen Energy[29] , Zeigo[30], Pexapark[31], BNEF[32] and SP Global[33]. It was assumed that the price of the PPA would remain constant in time after the contract had been signed. This is not necessarily true, as each

[29] (PV-tech, 2022)
[30] (Zeigo, 2021)
[31] (Pexapark, 2022)
[32] (BNEF, 2022)
[33] (S&P, 2020)

PPA contract can specify different clauses and prices may be indexed to inflation and even to spot.

The spread between day-ahead and forward 'over-the-counter' traded energy was obtained from Ofgem[34] and LEBA[35]. This was corroborated with information published by Energy UK in its Wholesale Market Report[36]. This report also provided a spread between month ahead forward trading and longer time ahead trading. The detail of time spreads for each technology was performed based on the researchers' and advisors' inference.

The prices of the different period ahead forward contracts are estimated based on the information published by LEBA in its monthly reports[35] for the month ahead price and from Energy UK[36] for the season ahead, one year ahead and two years ahead contracts. We assume no technology specific variation for energy prices contracted on the same date and with the same forward timeframe.

Figure 3: Prices of forward traded energy delivered on specific dates.presents a plot of the prices of the energy delivered on each day, depending on when it was contracted. This is the data that is used in the calculation as it is the approximated average prices that generators got for the energy they are generating on that date.

Figure 15, on the other hand, presents a different take on the same data, as it presents the approximated average prices of the contracts for electricity supply signed on the same date. This figure is for illustration only, as it helps to appreciate how the prices of forward contracts tend to follow the day-ahead price at the time of the agreement.

Appendix A.4 Revenue from Constraint payment and Balancing Actions

Revenues from Constraint and Balancing Actions paid to different technologies were obtained from National Grid's Monthly Balancing Services Summary (National Grid, 2023). Volumes of balancing actions were gathered from Elexon's Balancing Services Volume Data (Elexon, 2023b).

The constraint payments are supposed to be entirely additive to the revenues from other sources and are added on a monthly basis to each generation technology. Balancing actions money transfers are also added to the total revenues. However, when a balancing action requires a generator to increase its energy production, the generator gets paid the balancing action price instead of the wholesale market price (or whichever contract is it selling the energy through). As this energy has been produced, it is accounted in the generation data (Elexon B1610) and, as has been noted before it is subtracted in our analysis from the generation sold in the wholesale market.

As the data for constraint and balancing payments is provided disaggregated as Gas, Coal, Wind and Other generators (including Biomass, Nuclear, Solar and Hydro), the payments to Other generators is disaggregated among the remaining technologies proportional to their generation. The same approach is used when disaggregating payments to wind among onshore and offshore technologies.

[34] (Ofgem, 2023)
[35] (LEBA, 2022)
[36] (Energy UK, 2019)

Appendix A.5 Revenue from selling ROCs

The ROCs issued to each unit supported by this policy were calculated considering the technology and the year of accreditation, according to Table 3. This considered that the "ROC year" is accounted from April to May.

Table 3: ROCs allocated to technologies in across time

	Fuelled*	Hydro 20MW DNC	Hydro > 20MW	Off-shore Wind	On-shore Wind
2001-2008	1	1	1	1	1
2009	1.35	1	1	1.5	1
2010-2013	1.35	1	1	2	1
2014	1.35	1	1	2	0.9
2015	1.35	1	1	1.9	0.9
2016-2018	1.35	1	1	1.8	0.9

* Note: Drax unit 4 has been capped on ROCs allocations at 125,000 ROCs per year.

For calculating the revenues from selling ROCs it was assumed that all ROCs granted were sold. As the value that each generator got for the ROCs is unknown because it is set in trading platforms or in bilateral agreements, the annual "buy out price" plus "recycle payment" was used as a market approximation of the ROC's value. It is worth noting that in a perfectly competitive market the price of ROCs should tend to this value, as at this point it is economically indifferent to buy ROCs and get the recycle payments or to pay the buyout price.

The revenues from ROCs were added to the revenues from selling electricity for the generators in the BM that are supported by ROCs. The generation supported by ROCs of generators outside the BM was identified as the difference between the total generation supported by ROCs[37] and the generation supported by ROCs in the BM. It was assumed that these generators followed the same trend of ROCs adjudication and selling.

[37] (DESNZ, 2023b)

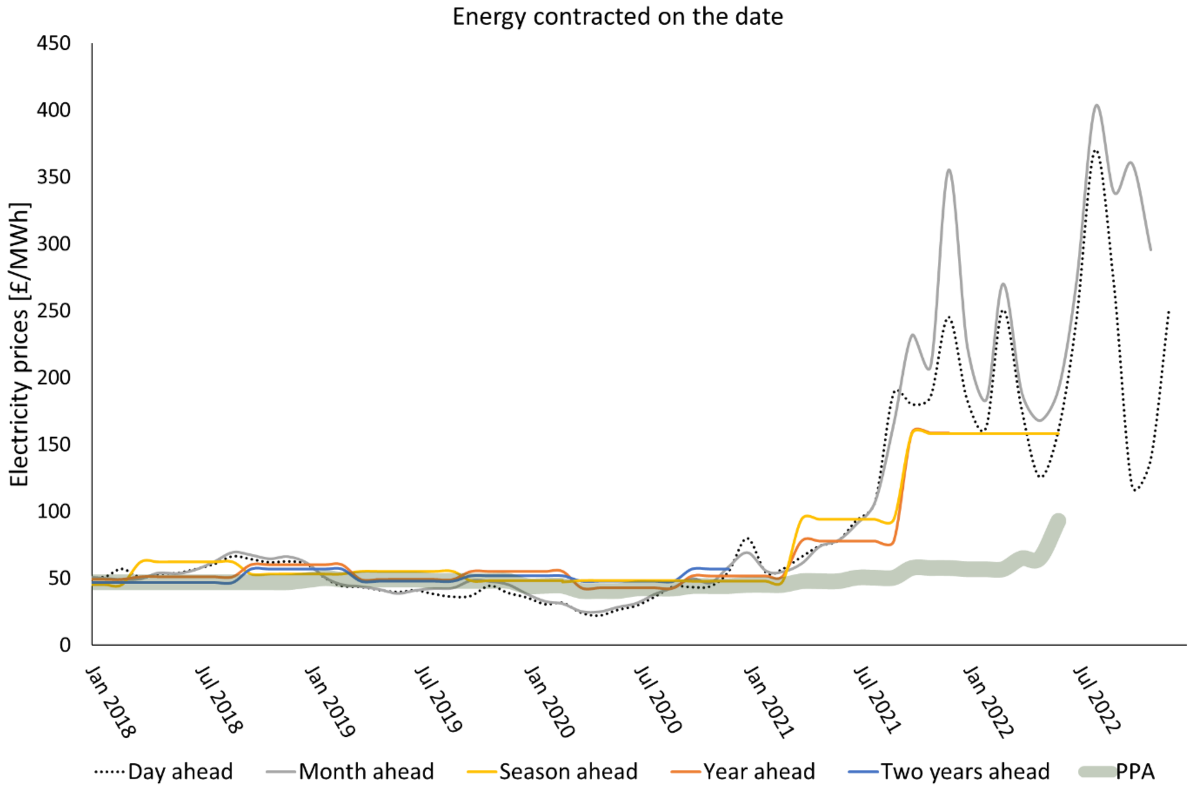

Figure 15: Prices of energy contracted on the date depending on the period of the contract.

Appendix A.6 Cap on exceptional revenues

The Electricity Generator Levy on exceptional electricity generation receipts, which effectively operates as a revenue cap, operates on generation technology that has increased its revenues due to the high wholesale electricity prices, but that has not seen a proportional increase in its costs. From the technologies included in our analysis, this includes, biomass, nuclear, hydro, and wind generation.

This cap is applied to groups or companies that generate more than 50 GWh/yr and represents a 45% charge on all the generation that exceeds 75 £/MWh on an annual basis and is calculated as following per each group/company (HM Treasury, 2022):

$$0.45 \cdot (GR - EG \cdot BP - A)$$

, where GR are the generation receipts (revenues from selling electricity in the year), EG is the electricity generated in the year, BP is the Benchmark Price (£75 /MWh) and A the cap-free allowance of £10 m/yr.

To assess the eligible generation subject to the cap, all generators of the technologies subjected to the cap are matched to their parent company, according to Elexon's data, and the parent companies grouped when appropriate. The generation of the grouped companies is compared with the 50 GW/yr threshold. Generation outside the BM (not included in the Elexon data) are assumed to be small and therefore excluded from being capped.