Institute for Sustainable Resources
Centre for Net Zero Market Design

Evaluation of aggregate profits of GB gas power stations

Aleksei Egorov, Chrysanthi Rapti, Margaux Daly, and Michael Grubb

Overview

This study estimates the aggregate profits of GB gas-fired power stations during 2019–2024 to assess whether generators earned elevated profits during the 2021–2022 energy crisis. Aggregate revenues from wholesale electricity markets, balancing services, the Capacity Market and ancillary services are compared with fuel, carbon and operating costs to estimate sector-wide profitability. The results show that aggregate profits increased from around £0.5 billion per year in 2019–2020 to approximately £2.9 billion in 2021 and £4.7 billion 2022, before moderating to around £1.2 billion per year in 2023–2024. Compared with a benchmark "normal" profit margin, profits were substantially elevated during the crisis, increasing electricity costs for consumers under GB's marginal pricing mechanism. The analysis finds no evidence of market abuse but suggests that elevated risk premia, and the influence of electricity interconnectors on GB price formation during exceptional conditions, contributed to the observed increase in generator profitability during the crisis.

Keywords: Gas-fired generation; Energy crisis, Aggregate profits; Marginal pricing; Interconnectors.

Acknowledgements

This working paper presents research conducted under UCL Institute for Sustainable Resources' 'Energy systems, policy and markets' area.

This paper was commissioned by E3G and their support is gratefully acknowledged. The findings and conclusions expressed remain those of the named authors.

It is available as Working Paper #10 in the Working Paper series of the UCL Centre for Net Zero Market Design. Papers in this series investigate a broad range of applied research topics related to the evolution of our electricity systems, policies and markets under the mandate for power sector decarbonisation.

Lead researcher and corresponding author

Dr Aleksei Egorov, Research Fellow in Econometric Modelling for Energy and the Environment, University College London Institute for Sustainable Resources.*

Email: aleksei.egorov@ucl.ac.uk

Co-authors

Dr Chrysanthi Rapti, Senior Research Fellow, UCL Institute for Sustainable Resources.*

Margaux Daly, Research Fellow, UCL Institute for Sustainable Resources / Centre for Net Zero Market Design.*

Professor Michael Grubb, Professor of Energy and Climate Change, UCL Institute for Sustainable Resources / Centre for Net Zero Market Design.*

* UCL Central House, 14 Upper Woburn Place, London WC1H 0NN. The work was led by ISR's Econometrics team, and ISR hosts the UCL Centre for Net Zero Market Design.

Executive summary

It is generally assumed that the wholesale cost of electricity in Great Britain is set mainly by the cost of gas power generation, with a modest operating profit margin. This study assesses the actual aggregate profits[1] of GB gas-fired power stations over the period 2019–2024 and considers explanations for the observed profit dynamics. Profits are assessed by calculating:

- aggregated revenues - comprising wholesale market revenues, revenues from balancing and constraint management services provided through the Balancing Mechanism, Capacity Market revenues, and ancillary services revenues; compared to
- aggregated costs, including fuel (gas) costs, carbon costs (ETS & Carbon Price Support), Balancing Services (BSUoS) charges, and other operating and maintenance costs.

Primary Results: Immediately prior to the gas crisis (2019–2020), aggregate profits of GB gas power stations were relatively low, at around £0.5 billion per year with profit margins between 5% and 9%. During the gas crisis, profitability increased substantially, reaching £2.9 billion (19% profit margin) in 2021 and £4.7 billion (18% profit margin) in 2022. Thus in the crisis, electricity prices increased by substantially *more* than the input costs, which included the impact of gas prices also increasing carbon prices - but other factors drove up profit margins as well.

Profits subsequently declined in 2023 and 2024, falling to £1.2 billion (9% margin) and £1.3 billion (12% margin), respectively. Although the major spike in profitability was limited to 2021–2022, profitability has remained at levels significantly higher than pre-crisis 2019–2020.

Profit benchmarks suggest that the 'normal' level of profits for gas-fired power generators is expected to lie in the range of 7% to 10%; as power stations profits during the crisis were thus elevated to more than twice the "normal" level of profitability. In the crisis, and apparently subsequently, elevated profits for gas-fired power stations (and other types of generators, given the marginal pricing mechanism) translated directly into additional costs for electricity consumers, beyond those attributable to higher gas and carbon costs. We estimate that the excess profits earned by gas-fired power generators - defined as profits above the 'normal' profitability range of 7%–10% - resulted in additional electricity costs of approximately £4.1 billion in 2021 and £6.6 billion in 2022 for all electricity consumers. For households, the corresponding additional costs were estimated at £1.4 billion (approximately £49 per household) in 2021 and £1.9 billion (approximately £68 per household) in 2022.

[1] Our analysis thus treats the fixed costs associated with power station construction as being recovered through the generating asset's profit margin. Given our focus on annual profits, the analysis uses day-ahead prices as a proxy for the actual, more complex trading structure which includes forward contracting for both input costs and electricity sales.

What drove elevated profits?

Factors which could explain the elevated profits include increased bidding by gas-fired power stations in the wholesale market, more frequent use of relatively less efficient generating assets, and the role of interconnectors in electricity price setting.

Gas-fired power stations likely increased their bids due to higher risk premia during periods of high volatility in 2021-2022, given increased risks in gas procurement and related non-delivery risks to forward electricity contracts, given a tight and volatile global gas market (section 3.1.3). There have been concerns that gas-fired power generators may engage in strategic bidding behaviour in the Balancing Mechanism,[2] although we have seen no evidence of such behaviour in the wholesale market.

Potentially most significant, in 2022 GB electricity prices decoupled from GB gas prices and tracked higher wholesale electricity prices predominantly in France. The dominant factors were higher gas prices in the EU (as supplies from eastern Europe were heavily restricted, and gas exports from GB to the continent were constrained by gas pipeline capacity); and much reduced nuclear (and hydro) output, leading to significant net electricity exports from GB, at higher prices. GB gas generators could thus raise their prices substantially above costs, and whereas in previous years, interconnectors had contributed to lower GB prices (with cheaper power from the continent competing against GB generators), this reversed during the crisis.

In addition, other studies of the EU energy market have highlighted concerns of limited liquidity, counterparty risk, weak transparency and bargaining imbalances in electricity contracting.

Whilst our study provides estimates of total sector-level profits, it does not allow for an assessment of individual gas-fired power stations or companies. Also, our simplifying assumptions separate profits attributable to electricity generation from those arising from electricity trading and the various hedging strategies used by gas generators for both electricity sales and input procurement, primarily natural gas. Thus, the estimated profits may not reflect total corporate profits, which also capture various trading activities.

Note that levels of profit during 2021-22, and (to lesser degree) since, contrast with low margins in previous years, and it is too early for our approach to evaluate profits in the current crisis. Our results may not translate for projections and do not necessarily equate to long-run profitability. Rather, the results suggest that the GB electricity market is *pro-cyclical;* bidding behaviour did not only pass through costs in times of crisis, but enhanced profits and thus substantially amplified, rather than moderated, the overall impact on energy consumers.

[2] Inflexible Offers Licence Conditions introduced by Ofgem in 2023 to limit such behaviour.

Contents

Table of Figures

Table of Tables

1. Introduction

The primary objective of this study is to examine the dynamics of aggregate profits earned by GB gas-fired power stations immediately before, during and after the 2021-2022 energy crisis. The analysis covers the period 2019-2024, providing two years of observations before the crisis and two years following it, and assesses whether the profitability increased during this exceptional period. The analysis therefore focuses on changes in profitability around the energy crisis rather then on assessing returns to investment over the full economic life of gas-fired generating assets.

The methodology of the analysis involves estimating total revenues and total costs for the sector. Revenues comprise wholesale electricity market revenues, payments received through the Balancing Mechanism for re-balancing and constraint management services, Capacity Market revenues, and revenues from ancillary services. Costs include fuel (natural gas) costs, carbon costs, Carbon Price Support (CPS), Balancing Services Use of System (BSUoS) charges, and other operating and maintenance costs. These components are calculated using high-frequency data (up to hourly resolution) on generation volumes, electricity prices, and input prices.

In many markets, it might be expected that profits decline when input prices increase. However, in the case of GB gas power generation we find the opposite: the results of the analysis show that aggregate profits increased substantially during the gas price crisis in 2021–2022. Although costs, particularly gas and carbon costs, rose sharply during this period, revenues increased by a greater margin:

- Aggregate profits rose from around £500 million per year in 2019–2020 to £2.9 billion in 2021 and £4.7 billion in 2022, corresponding to profit margins of 19% and 18%, respectively. This translates into profits per MWh generated of £27 in 2021 and £42 in 2022.
- In 2023 and 2024, profits declined relative to the peak crisis years but remained above pre-crisis levels. Total profits were £1.2 billion in 2023 (9% margin, £14 per MWh) and £1.3 billion in 2024 (12% margin, £17 per MWh).

The report also discusses potential factors that could explain the estimated increase in gas-fired power generators' profits in 2021–2022. In particular, we consider three possible drivers (in addition to higher input prices) that may have affected electricity prices and, consequently, the profits of gas power stations: higher margins in gas power stations bids; more frequent use of relatively less efficient gas-fired generating assets during periods of high electricity market volatility; and the role of interconnectors in setting electricity prices. The analysis of these potential factors shows that:

- Higher bidding by gas-fired power stations, potentially driven by increased risk premia, may have contributed to the disproportionate increase in electricity prices relative to input costs.

- There is no evidence that less efficient gas-fired generating assets were dispatched more frequently during the energy crisis (2021–2022).
- Electricity trading through interconnectors may have contributed significantly to higher electricity prices relative to input costs. Prior to the energy crises, interconnectors lowered wholesale electricity prices by enabling imports from continental Europe, where electricity prices were generally lower. However, in 2022, GB became a net exporter of electricity due to high electricity prices in continental Europe[3], leading to GB electricity prices becoming linked to the higher electricity prices in France, allowing all generators to benefit from higher market prices and, consequently, higher profits. The analysis shows that while electricity prices in GB and France were broadly similar during 2022 (with prices slightly higher in France), natural gas prices were significantly lower in GB due to substantial LNG inflows combined with limited storage and export capacity. As a result, GB generators were able to produce electricity at relatively low input costs and sell it at prices determined by the higher-cost markets of continental Europe, particularly France.

This paper partially builds on the analysis of Maximov et al. (2023), which estimated the aggregate revenues of different types of electricity generators over a similar period. It extends that study in two main ways. First, we estimate the aggregate cost base in addition to aggregate revenues, allowing us to analyse aggregate profits. Second, we examine a range of factors that may explain the observed dynamics of these estimated profits. However, unlike Maximov et al. (2023), which considered a broader set of generator technologies, our analysis focuses exclusively on gas-fired power generators.[4] The revenue estimates presented in this report broadly corroborate those of Maximov et al. (2023). However, it is worth noting that our analysis employs a slightly different approach to revenues evaluation. Specifically, we account for Capacity Market revenues and revenues from ancillary services, which were not included in Maximov et al. (2023)

The report consists of two main parts. Section 2 discusses the methodology used to assess gas power station profits, the underlying assumptions of the analysis, and the main results. Section 3 focuses on potential explanations for the estimated increase in gas power station profits, specifically examining factors that may have driven higher bids by gas-fired generators, whether relatively less efficient gas-fired generating assets were used more frequently during periods of high profits, and whether interconnectors played a significant role in setting electricity prices in GB over the period considered in the study.

Section 4 summarises and discusses the main findings of the study, with one broad observation that GB market design, in context of the 2021–2022 energy crisis, served to amplify rather than dampen the impact of price volatility.

[3] In Europe, the spike in natural gas prices was amplified by outages in the French nuclear fleet.

[4] https://www.ucl.ac.uk/bartlett/sites/bartlett/files/necc_working_paper_2_final_pdf_with_cover40.pdf.

Due to the aggregated nature of this analysis, it is not possible to assess the performance of individual power stations or to draw conclusions about how the estimated profits were distributed. In addition, the simplifying assumptions used in this analysis separate the revenues and costs associated with electricity generation from those associated with trading and the various hedging strategies employed by gas-fired generators. As a result, the estimated profits reflect only those associated with electricity generation and do not include profits or losses arising from trading or hedging activities. Consequently, the estimated profits may differ from total corporate profits, which also incorporate the financial effects of trading and hedging strategies.

2. Profits Assessment

This section presents our empirical analysis of the aggregate profits of gas power generators in GB. We begin by describing the datasets used in the analysis, the assumptions underlying the analysis, and the algorithm used to calculate aggregate revenues, costs, and profits in Section 2.1. Section 2.2 then presents the results, and Section 2.3 discusses whether the estimated profits can be considered excess profits.

2.1. Methodology and Data

2.1.1. Datasets Used for the Analysis

The analytical model used to estimate aggregate profits suggests that gas power stations have four main sources of revenue:

- Electricity sales on the wholesale market[5]
- Payments for balancing and constraint management services through the Balancing Mechanism[6]
- Capacity Market revenues[7]
- Revenues from ancillary services[8]

[5] Electricity traded between generators, suppliers, and other market participants before it is sold to end consumers.

[6] The Balancing Mechanism is the real-time market through which the system operator balances the electricity system and manages network constraints.

[7] Payments to electricity providers for making generation capacity available to support security of supply.

[8] Payments for services that help maintain the stability, reliability, and security of the electricity system.

To generate electricity, power stations incur a range of costs, including:

- Fuel (natural gas) cost
- Carbon cost[9]
- Carbon Price Support (CPS)[10]
- Balancing Services Use of System (BSUoS) charges[11]
- Fixed and variable operating costs, insurance, connection and use of system charges.

Multiple data sources were combined to obtain the data for all cost and revenue components listed above. These sources are summarised in Table 1.

Table 1. Data sources used for the profit evaluation.

Data	Frequency	Source
Electricity generation, MWh	Hourly	ELEXON
Generation for the Balancing Mechanism (BM), MWh	Hourly data for each Balancing Mechanism Unit (BMU)	ELEXON
Revenues from constraint and re-balancing services (Balancing Mechanism), £ million	Monthly	NESO Monthly Balancing Services Summary (MBSS)
Electricity prices, £/MWh	Day-ahead prices, hourly	Low Carbon Contracts Company (LCCC)
Gas prices, p/therm	Daily	LSEG
Carbon prices, £/tCO2e	Daily	LSEG
Carbon Price Support (CPS), £/tCO2e	Constant, £18/tCO2e	DESNZ
Balancing Services Use of System (BSUoS) prices	Half-hourly	NESO
Capacity Market revenues, £ million	Reports for all auctions with delivery between 2019 and 2024	NESO Capacity Market Auctions Reports

[9] Costs incurred by electricity generators for purchasing or surrendering emissions allowances under the UK Emissions Trading Scheme (UK ETS).

[10] A UK carbon tax levied on fossil fuels used for electricity generation to strengthen the carbon price signal and encourage lower-carbon generation.

[11] BSUoS is a fee collected by the NESO to cover the real-time costs of balancing electricity supply and demand. Until 1 April 2023, the fee was paid equally by generators and suppliers (50% each), after which generators were exempted from the charge.

Revenues from ancillary services, £ million	Monthly	NESO Monthly Balancing Services Summary (MBSS)
Assumptions for calculating other costs	Annual	DESNZ, DUKES

2.1.2. Assumptions/Approximations Underlying the Analysis

In addition to the data sources listed in Section 2.1.1, the analysis requires the introduction of several simplifying assumptions.

We estimate generator revenues using publicly available day-ahead electricity price data (*Assumption 1*). A similar approach is adopted to estimate costs, which are based on day-ahead gas and carbon prices (*Assumption 2*). Although gas-fired power stations neither sell most of their electricity nor procure most of their natural gas on the day-ahead market, we consider these assumptions to provide reasonable approximations for the following reasons:

- First, while these assumptions enable the analysis to be conducted using publicly available data, they are not expected to introduce a material bias into the profit estimates. Their main implication is that both revenues and fuel costs may be overstated during periods of high day-ahead price volatility, particularly in 2021 and 2022. However, because revenues and fuel costs are estimated using the same pricing assumption, any upward bias is expected to largely offset when calculating profits. As a result, the estimated profit figures are unlikely to be materially affected.
- Second, the use of day-ahead gas prices is economically justified because it reflects the opportunity cost of fuel consumption. Even when generators hold gas under longer-term supply contracts, the relevant cost for generation decisions is its current market value - that is, the price at which the gas could be sold on the day. Using the gas for electricity generation therefore entails foregoing the opportunity to sell it on the market. From this perspective, valuing gas consumption at the prevailing day-ahead market price provides a reasonable measure of the economic cost of generation.
- Finally, Assumptions 1 and 2 distinguish the profitability of electricity generation from the financial effects of trading and hedging strategies. Assumption 1 excludes the gains or losses associated with selling electricity under longer-term contracts (e.g. month-ahead or season-ahead), while Assumption 2 excludes the effects of procuring natural gas under longer-term supply contracts or other hedging arrangements. Consequently, the estimated profits reflect generation margins rather than total corporate profits, which also depend on firms' commercial trading and hedging strategies. Focusing on generation margins is more appropriate in the context of this study, as they capture the profitability of generators' core activity.

Another important assumption *(Assumption 3)* relates to the average thermal efficiency used to calculate aggregate costs and profits. The thermal efficiency of gas-fired generation is an important input into the estimation of fuel costs, but the specific thermal efficiency applicable to the generation represented in the ELEXON data cannot be observed directly.

For this analysis, we assume an average thermal efficiency based on DUKES data, which reports annual average efficiencies for generators classified as major power producers. According to DUKES, the average thermal efficiency was approximately 48-49%, depending on the year, over the period considered in the analysis. Although the GB gas-fired generation fleet is heterogeneous in terms of plant age, configuration, technical condition, and other factors affecting thermal efficiency, DUKES data provides the most robust benchmark for an aggregate-level cost assessment.

2.1.3. Methodology of Revenues, Costs and Profits Assessment

To evaluate revenues - including revenues from electricity sales on the wholesale market, payments for balancing and constraint management services (Balancing Mechanism), revenues from Capacity Market and revenues from ancillary services – the following algorithm was used:

- We use hourly generation data from ELEXON[12] to determine the volume of electricity produced by gas-fired power stations in each hour over the period 2019–2024.
- We use a separate ELEXON dataset[13] to identify the volumes of electricity generated for re-balancing purposes through the Balancing Mechanism. This data is available at hourly frequency for each individual gas-fired generator. We then calculate the volume of electricity sold on the wholesale market as the difference between total generation and generation allocated to re-balancing services in each hour.
- Hourly day-ahead electricity price data from LCCC[14] is used to calculate wholesale market revenues. For each hour, wholesale market revenues are computed as the product of the volume of electricity sold on the wholesale market and the corresponding day-ahead price.
- Hourly wholesale market revenues are aggregated to the annual level by summing revenues across all hours within each year.
- Revenues from re-balancing and constraint management services (Balancing Mechanism) are derived using data from NESO's Market Balancing Services Summary (MBSS)[15]. As these data is available at a monthly frequency, annual revenues are calculated by summing payments across all months within each year.
- Ancillary services revenues are also derived from NESO MBSS reports, which provide data on payments received by gas-fired power generators for the provision of ancillary services. This data provides only the total value of ancillary services procured by NESO

[12] https://bmrs.elexon.co.uk/generation-by-fuel-type.

[13] https://bmrs.elexon.co.uk/balancing-mechanism-bmu-view.

[14] https://dp.lowcarboncontracts.uk/dataset/imrp-actuals.

[15] https://www.neso.energy/industry-information/industry-data-and-reports/system-balancing-reports.

- and is not disaggregated by generator type. For the purposes of these calculations, we assume that 40% of total ancillary services payments accrue to gas-fired generators[16].
- Capacity Market revenues are derived from NESO Capacity Market Auction Reports. Specifically, we use reports for all auctions with delivery between 2019 and 2024 and extract data on the clearing price, total awarded capacity, and the share of awarded capacity allocated to gas-fired power generators[17]. This information is then used to calculate the total Capacity Market revenues received by gas-fired power generators from each auction.
- Total annual revenue is calculated as the sum of annual wholesale market revenues, annual revenues from re-balancing and constraint management services (Balancing Mechanism), annual Capacity Market revenues, and annual revenues from ancillary services.

The total costs of gas power generators are estimated in two steps. First, we estimate the variable costs, which include fuel (gas) costs, carbon costs[18], the Carbon Price Support (CPS), and Balancing Services Use of System (BSUoS) charges. Total annual variable costs are calculated following the steps outlined below:

- We begin by estimating the volume of gas required to generate the observed electricity output, assuming an average efficiency of 48% (or 49%, depending on the year), based on DUKES data for GB gas-fired power stations: $Gas_t(MWh) = \frac{1}{efficiency} \times Electricity_t(MWh)$, where t is the day because gas price data is available at a daily frequency.
- The total annual gas cost is calculated by multiplying the estimated volume of gas (derived in the previous step) by the corresponding daily gas price obtained from LSEG[19]. The costs are then aggregated across all days within each year.
- Total carbon emissions are then calculated by multiplying gas fuel consumption by the fuel emission factor of of 0.184 tCO2e per MWh.

[16] Although the share of renewables in total electricity generation was significant over the period covered by the analysis, gas generators continue to play an important role in providing system flexibility, including a range of ancillary services. Therefore, the assumption of 40% is likely to be conservative and may underestimate the actual payments that gas generators receive for providing ancillary services.

[17] NESO Capacity Market Auction Reports provide information by delivery year, with each delivery year running from 1 October to 30 September. To convert Capacity Market revenues from delivery years to calendar years, we assume that revenues are distributed evenly throughout each delivery year. Thus, when calculating Capacity Market revenues, for example, for the 2019 calendar year, we allocate 9/12 of the revenues from delivery year 2018/2019 and 3/12 of the revenues from delivery year 2019/2020.

[18] This refers to the costs incurred under the UK Emissions Trading Scheme (UK ETS).

[19] https://www.lseg.com/en/data-analytics.

- The total carbon cost is calculated on a daily basis by multiplying total carbon emissions by the carbon price observed on that day. Daily carbon costs are then aggregated to obtain annual carbon costs.
- The total annual CPS cost is calculated by multiplying total annual emissions by the fixed CPS rate of £18 per tCO_2e.
- BSUoS charges are estimated for each settlement period by multiplying the generation volume by the corresponding BSUoS price. We account for the fact that generators were responsible for only 50% of the BSUoS charge; therefore, the BSUoS price for each settlement period is divided by two. BSUoS charges are calculated only for the period from January 2019 to April 2023, after which generators were exempted from this charge.
- Total variable costs are calculated as the sum of gas costs, carbon costs (UK ETS), CPS costs and BSUoS costs.

Second, we consider other costs which include four main components: fixed operating and maintenance (O&M) costs, variable O&M costs, insurance costs, and connection and use of system charges. The assumptions for these costs were sourced from Electricity Generation Costs 2025 report (DESNZ, 2026)[20]. These assumptions are summarised in Table 2.

Table 2. Assumptions for other cost components.

	Note	Unit	Value, 2024 £
Fixed O&M	Staffing and site cost, routine maintenance, IT systems and monitoring, site overheads, etc.	£/MW/year	16,000
Variable O&M	Incremental maintenance due to operation, consumables (excluding fuel), waste handling, etc.	£/MWh	5
Insurance	-	£/MW/year	2,500
Connection and use of system charges	-	£/MW/year	4,400

Source: DESNZ, 2026.

The assumptions for fixed O&M, insurance, and connection and use of system charges are expressed on a per-MW capacity basis and do not depend on generation levels. To estimate total annual fixed O&M, insurance, and connection costs, we multiply the unit values presented in Table 2 by the total installed gas-fired capacity in GB[21].

[20] https://www.gov.uk/government/publications/electricity-generation-costs-2025.

[21] This is based on data from DUKES Table 5.7.

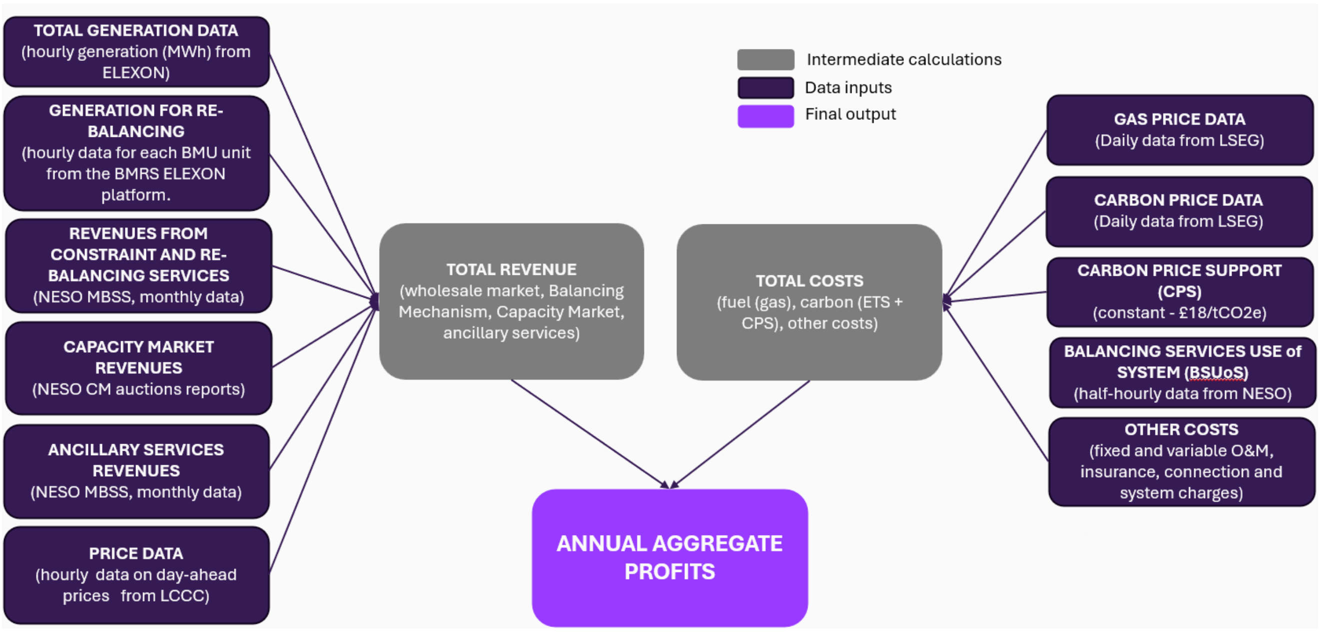
Variable O&M costs are expressed on a per-MWh basis. Accordingly, total annual variable O&M costs are calculated by multiplying the unit value reported in Table 2 by total annual electricity generation.

The cost assumptions in Table 2 are reported in real 2024 prices. To estimate costs for other years, we adjust these values for inflation using the Consumer Price Index (CPI)[22]. For example, when calculating costs for 2019, the 2024 figures are deflated by cumulative CPI inflation over the period 2019-2024.

We do not account for the cost of constructing the power stations in this analysis, as we assume that these costs should be recovered through profit margins over a lifetime of the generating asset.

Figure 1 below provides a graphical representation of the algorithms described above for estimating the aggregate costs, revenues, and profits of gas power stations.

Figure 1. Analytical framework for assessing aggregate profits of gas power stations.



2.2. Results of the Profits Assessment

This section presents the main findings of the analysis. It begins with a descriptive overview of price and generation data (Section 2.2.1), followed by the results of the revenue evaluation (Section 2.2.2), cost evaluation (Section 2.2.3), and profit analysis (Section 2.2.4). This section

[22] https://www.ons.gov.uk/economy/inflationandpriceindices.

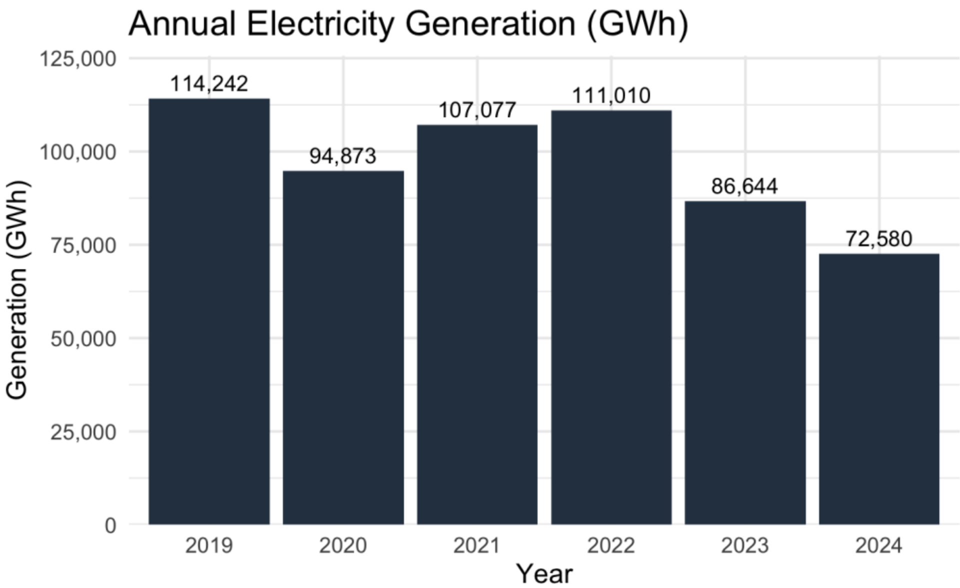
also includes the results of the estimation of the overall price impact of gas power station profits (2.2.5).

2.2.1. Descriptive Analysis of the Available Data

The share of gas generation in GB has increased considerably over the past decades, alongside the gradual phase-out of coal generation. During the period considered in this analysis (2019–2024), the share of gas generation in total electricity generation declined from 44% in 2019 to 31% in 2024, primarily due to the increasing share of wind generation and higher electricity imports via interconnectors after 2022[23]. Total electricity production in GB also declined from 323 TWh in 2019 to 285 TWh in 2024 (a 12% decrease)[24].

Figure 2 presents the total annual generation of gas power stations over the period 2019–2024, calculated using ELEXON hourly generation data used in the analysis. Consistent with the decline in both the share of gas generation and total electricity generation, absolute gas generation decreased from 114,242 GWh in 2019 to 72,580 GWh in 2024.

Figure 2. Total annual generation of gas power stations.



Source: calculations are based on ELEXON generation data - hourly generation aggregated to the annual level.

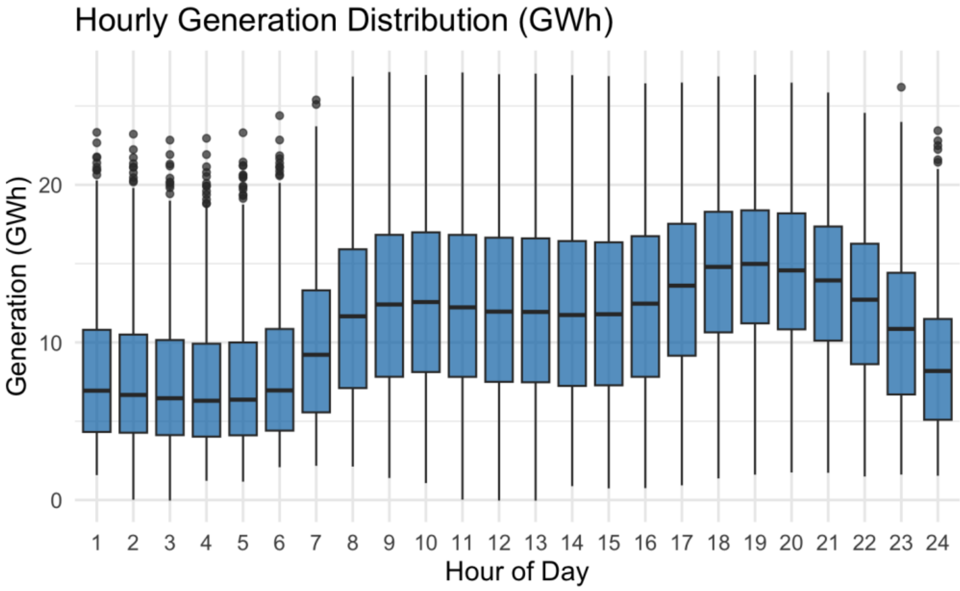
However, despite the decline in the overall share of gas generation in total electricity generation, gas generators remain a key provider of flexibility in the electricity system. Figure 3 shows the average generation of gas power stations across different hours of a typical day. Specifically, it

23 https://www.elexon.co.uk/2025/08/26/how-the-uks-fuel-mix-has-changed-over-the-past-nine-years/.

24 https://www.iea.org/countries/united-kingdom/electricity.

indicates that gas generation is significantly higher during peak periods compared to off-peak periods.

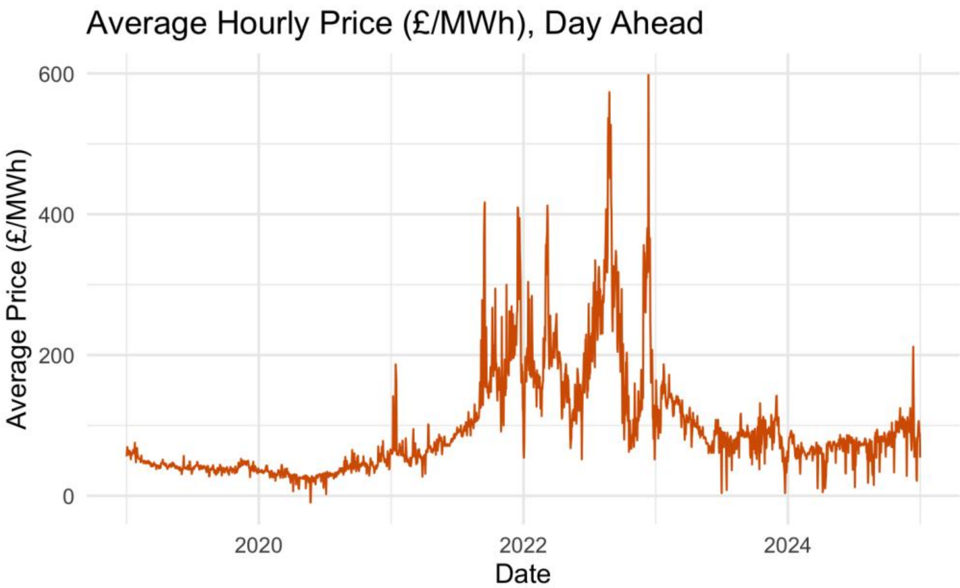
Figure 3. Average generation during different hours of the day.



Source: calculations are based on ELEXON generation data (hourly data averaged across days).

Figure 4 presents the evolution of day-ahead wholesale electricity prices used in the revenue calculations. Three broad patterns can be observed over the period 2019–2024. First, prices were relatively low and stable in 2019–2020. This can primarily be explained by relatively low demand during those years due to the COVID-19 pandemic and reduced levels of economic activity. Second, during 2021–2022 (the period of the gas price crises) prices increased sharply, with substantial spikes and significantly higher volatility. Third, in 2023-2024 prices moderated compared to the crisis peak but remained above pre-2021 levels and continued to exhibit elevated volatility.

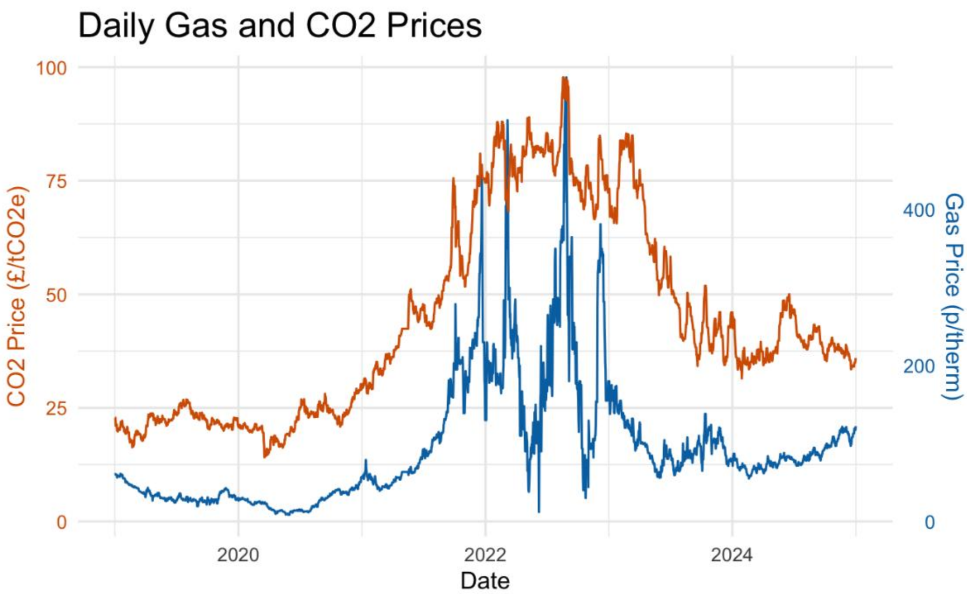
Figure 4. The dynamics of day-ahead electricity prices.



Source: LCCC.

One of the key contributors to the spike in electricity prices in 2021-2022 is the increase in both gas and carbon prices, which are the two main components of the short-run marginal cost (SRMC) of gas power stations. Figure 5 shows the evolution of gas and carbon prices over the period 2019-2024.

Figure 5. Dynamics of gas and carbon prices used in cost calculations.



Source: LSEG.

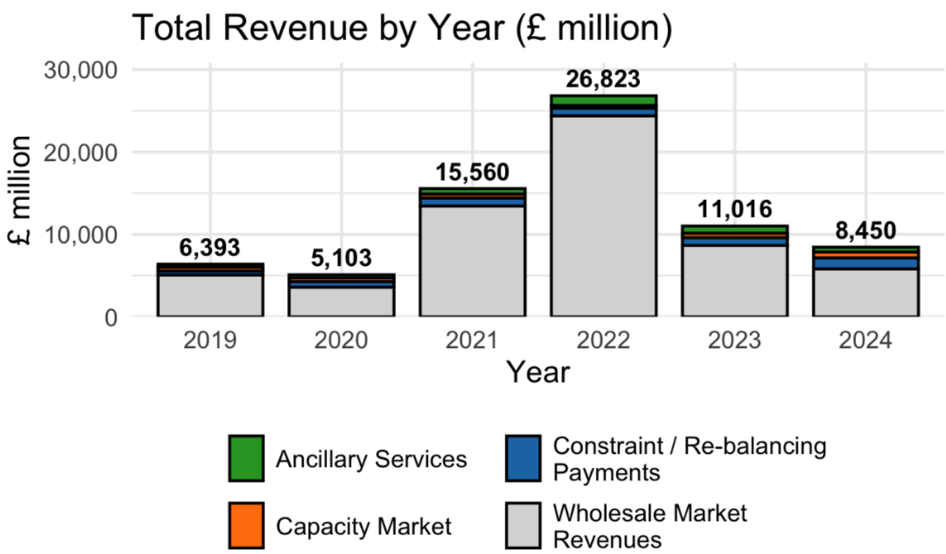
Both gas and carbon prices increased markedly in 2021–2022 compared to 2019–2020. While the overall trends in gas and carbon prices are broadly similar, gas prices exhibited substantially higher volatility after 2021. After 2022, both gas and carbon prices declined but remained higher than pre-2021 levels.

While the trends in electricity, gas, and carbon prices are broadly similar over the period, from this descriptive analysis it is not clear whether the increase in electricity prices can be fully explained by the increase in the SRMC of generators. The results presented in the following sections address this question by analysing whether gas power stations earned additional profits during the period of high market volatility.

2.2.2. Evaluation of Revenues

The results of the revenue evaluation using the algorithm described in Section 2.1 are presented in Figure 6 and Table 3.

Figure 6. Results of the total annual revenues evaluation.



Source: calculations based on ELEXON (generation data), LCCC (electricity prices), and NESO (constraint and balancing payments, Capacity Market revenues, revenues from ancillary services).

Table 3. Results of the total annual revenues evaluation.

	2019	2020	2021	2022	2023	2024
Wholesale market revenues, £ million *(% of total revenues)*	5,293 *(83%)*	3,828 *(75%)*	13,848 *(89%)*	25,098 *(94%)*	9,177 *(83%)*	6,174 *(73%)*
Constraint/Re-balancing payments, £ million (% of total revenues)	487 *(8%)*	670 *(13%)*	966 *(6%)*	935 *(3%)*	952 *(9%)*	1,341 *(16%)*

Capacity Market revenues, £ million *(% of total revenues)*	466 *(7%)*	452 *(9%)*	481 *(3%)*	321 *(1%)*	539 *(5%)*	696 *(8%)*
Ancillary services revenues, £ million *(% of total revenues)*	147 *(2%)*	153 *(3%)*	265 *(2%)*	469 *(2%)*	348 *(3%)*	239 *(3%)*
Total revenues, £ million	**6,393**	**5,103**	**15,560**	**26,823**	**11,016**	**8,450**

Source: calculations based on ELEXON (generation data), LCCC (electricity prices), and NESO (constraint and balancing payments, Capacity Market revenues, revenues from ancillary services).

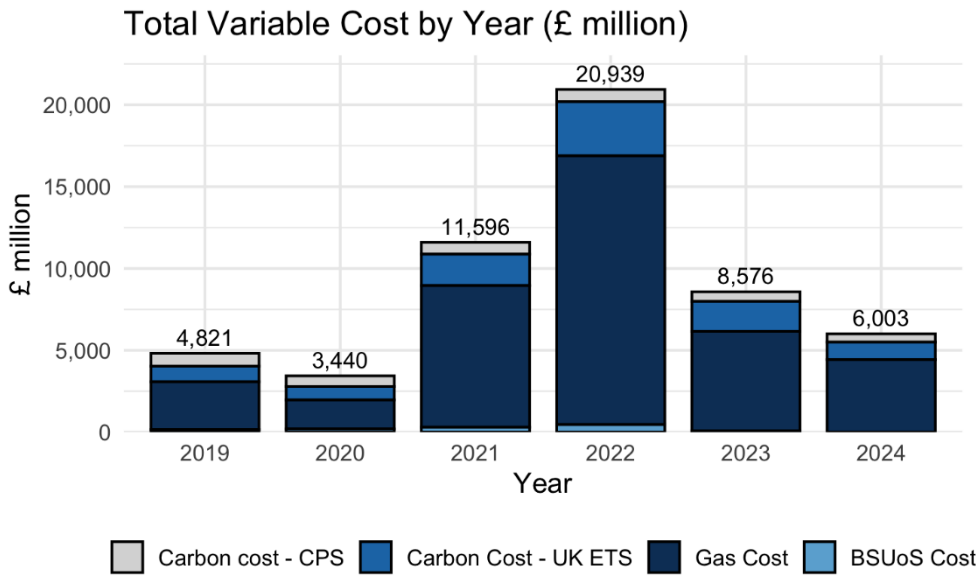
Annual revenues ranged between £5.1 billion and £6.4 billion in 2019–2020. During the gas price crisis, revenues increased sharply, reaching £15.6 billion in 2021 and £26.8 billion in 2022. In 2023 and 2024, revenues declined but stabilised at £8.5–£11.0 billion - approximately twice the levels observed in 2019–2020.

In all years, most revenues were derived from wholesale electricity market sales (73%–94%, depending on the year). The share of revenues from balancing and constraint management services ranged from 3% to 16%, while Capacity Market revenues accounted for 1% to 9%, and ancillary service revenues for 2% to 3%. However, these shares should be interpreted in the context of substantial variation in total revenues over the period. In absolute terms, revenues from balancing and constraint services increased steadily throughout the period, reaching their highest level in 2024. Capacity Market payments also increased in 2023–2024 relative to previous years. Ancillary service revenues peaked in 2022 and subsequently declined, although levels in 2023–2024 remained significantly higher than in 2019–2020. Overall, the share of non-wholesale revenues for gas power generators was around 20% in 2019–2020. It declined to 9% in 2021–2022, as wholesale revenues increased more significantly than other revenue components, before rising again to 22% in 2023–2024, broadly returning to the level observed before the crisis.

2.2.3. Evaluation of Costs

The results of the evaluation of the main variable costs, which include fuel (gas) costs, carbon costs, the CPS, and BSUoS are presented in Figure 7 and Table 4.

Figure 7. The results of the main variable costs evaluation.



Source: calculations based on ELEXON (generation data), LSEG (carbon prices and gas prices) and NESO (BSUoS price data).

Table 4. The results of the main variable costs evaluation.

	2019	2020	2021	2022	2023	2024
Gas cost, £ million *(% of total main variable costs)*	2,923 *(61%)*	1,777 *(52%)*	8,654 *(75%)*	16,422 *(78%)*	6,074 *(71%)*	4,433 *(72%)*
Carbon cost – UK ETS, £ million *(% of total main variable costs)*	953 *(20%)*	819 *(24%)*	1,920 *(17%)*	3,304 *(16%)*	1,836 *(21%)*	1,069 *(19%)*
Carbon cost - CPS, £ million *(% of total main variable costs)*	788 *(16%)*	655 *(19%)*	722 *(6%)*	749 *(4%)*	586 *(7%)*	501 *(9%)*
BSUoS cost. £ million *(% of total main variable costs)*	157 (3%)	189 (5%)	300 (3%)	464 (2%)	80[25] (1%)	0 (0%)
Total main variable costs, £ million	**4,821**	**3,440**	**11,596**	**20,939**	**8,576**	**6,003**

Source: calculations based on ELEXON (generation data), LSEG (carbon prices and gas prices) and NESO (BSUoS price data).

Total annual costs follow a pattern similar to that observed for revenues. Variable costs were relatively low in 2019 and 2020 (£4.8 billion and £3.4 billion, respectively), before increasing sharply in 2021–2022 and reaching a peak of £20.9 billion in 2022. This surge was primarily driven by higher gas costs, reflecting the substantial rise in gas prices during this period.

[25] Power generators became exempt from BSUoS charges on April 1, 2023.

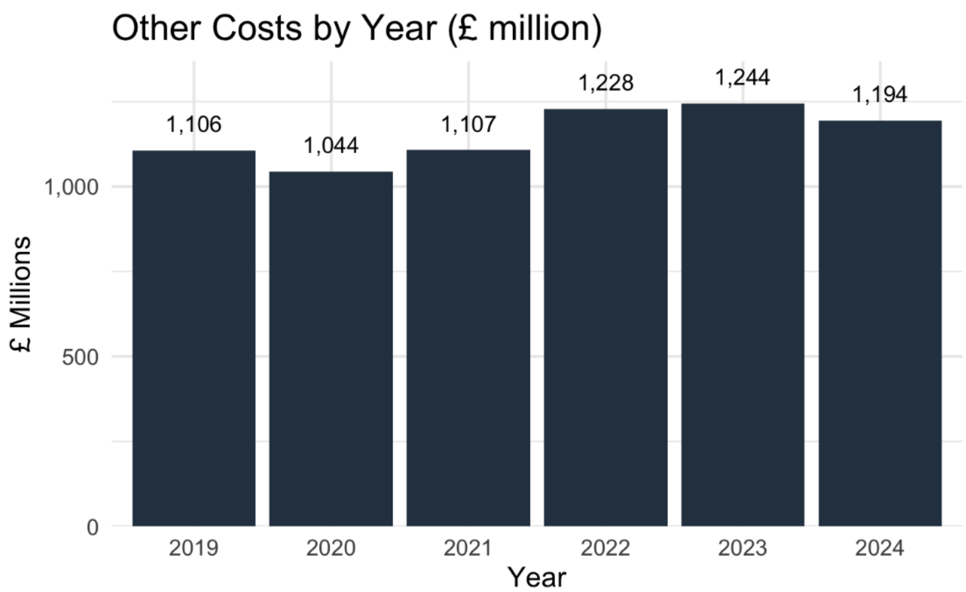
Carbon costs (including UK ETS cost and CPC cost) also increased significantly, rising from approximately £1.6 billion in 2019–2020 to £2.6 billion in 2021 and almost £4.1 billion in 2022. In 2023, both gas and carbon costs declined, with a further reduction observed in 2024. However, cost levels in 2023-2024 remained above those in 2019-2020.

In relative terms, before the energy crisis, gas and carbon costs accounted for the majority of variable costs, with gas accounting for around 60%. During the crisis, the share of gas costs increased to 75%–78% before declining to around 71%, which remains significantly above pre-crisis levels.

BSUoS costs remained relatively marginal throughout the period and did not significantly affect total costs.

The main variable costs per MWh can be considered the short-run marginal cost (SRMC) of electricity generation; that is, they reflect the cost of producing one additional MWh of electricity and do not include fixed costs such as plant maintenance, salaries, insurance, and other overheads. To account for this additional cost, we use assumptions set out in the Electricity Generation Costs 2025 report (DESNZ, 2026)[26]. These assumptions are summarised in Section 2.1 (Table 2). The estimated other costs are presented in Figure 8 and Table 5.

Figure 8. The results of other costs evaluation.



Source: calculations based on ELEXON data and assumptions from DESNZ (2026).

[26] https://www.gov.uk/government/publications/electricity-generation-costs-2025.

Table 5. The results of other costs evaluation.

	2019	2020	2021	2022	2023	2024
Fixed O&M, £ million *(% of total other costs)*	451 *(41%)*	458 *(44%)*	467 *(42%)*	509 *(41%)*	570 *(46%)*	581 *(49%)*
Variable O&M, £ million *(% of total other costs)*	460 *(42%)*	389 *(37%)*	439 *(40%)*	500 *(41%)*	428 *(34%)*	363 *(30%)*
Insurance, £ million *(% of total other costs)*	71 *(6%)*	71 *(7%)*	73 *(7%)*	80 *(7%)*	89 *(7%)*	91 *(8%)*
Connection and use of system charges, £ million *(% of total other costs)*	124 *(11%)*	126 *(12%)*	128 *(12%)*	140 *(11%)*	157 *(13%)*	160 *(13%)*
Other costs, total, £ million	**1,106**	**1,044**	**1,107**	**1,228**	**1,244**	**1,194**

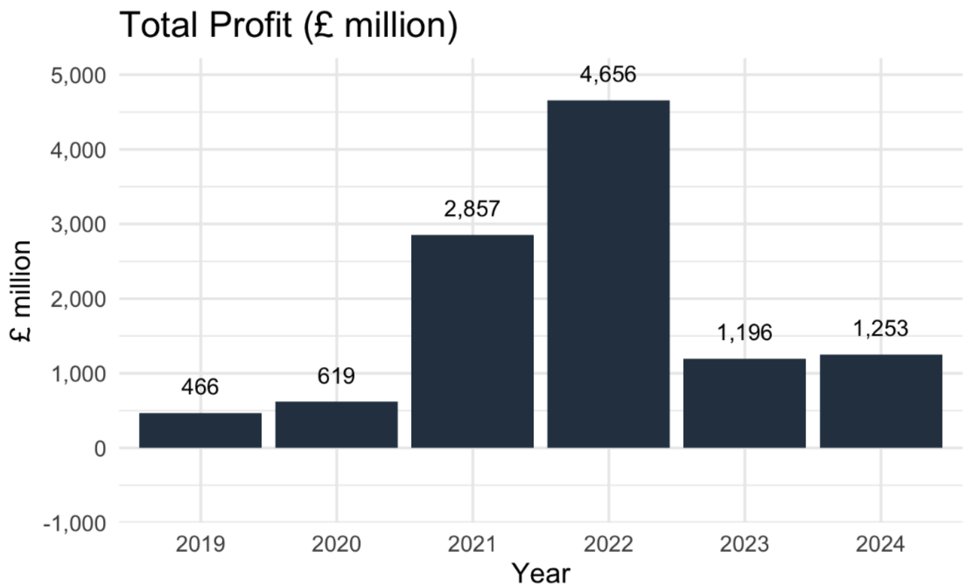
Source: calculations based on ELEXON data and assumptions from DESNZ (2026).

Fixed other costs - including fixed O&M, insurance, and connection and use of system charges - which do not depend on generation levels, increased steadily over time, largely reflecting general inflation. Variable O&M costs followed the pattern of total annual generation. The structure of other costs did not change to the same extent as the structure of the main variable costs, as other costs are less affected by fluctuations in gas and carbon prices. Overall, total other costs remained relatively stable over the period, averaging around £1.1 billion per year.

2.2.4. Evaluation of Profits

Once aggregate revenues and costs have been estimated, profit is calculated as the difference between the two. The results of the total profit evaluation are presented in Figure 9.

Figure 9. The results of the total profits evaluation.

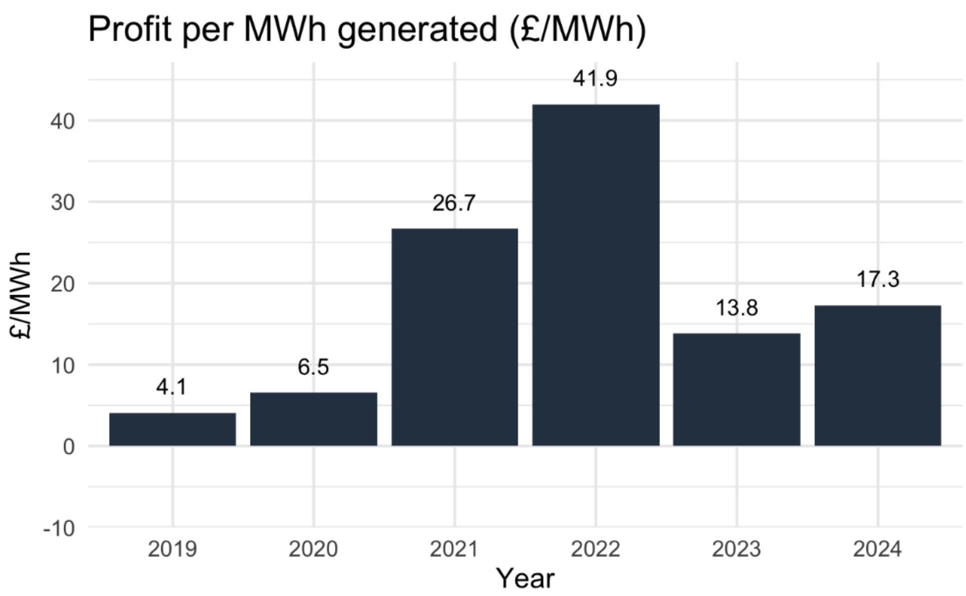


Source: calculations based on the estimates of total revenues (Section 2.2.2) and total costs (Section 2.2.3).

The profit estimates shown in Figure 9 indicate that, in 2019–2020, aggregate profits of GB gas-fired power stations were relatively low, at around £0.5 billion. In 2021, profits increased sharply to £2.9 billion and rose further to £4.7 billion in 2022. However, this surge was not sustained, as profits declined in 2023 and 2024, reaching £1.2 billion and £1.3 billion respectively. The relatively low profits can be primarily attributed to relatively low wholesale electricity prices in those years (Figure 4). Additionally, profits in 2020 may have been affected by a significant decline in the average load factor of gas-fired power stations (35.6% compared to 41.5% in 2019[27]) due to the impact of the COVID-19 pandemic and reduced levels of economic activity.

Figures 10 and 11 show profits per MWh generated and profit margins, respectively.

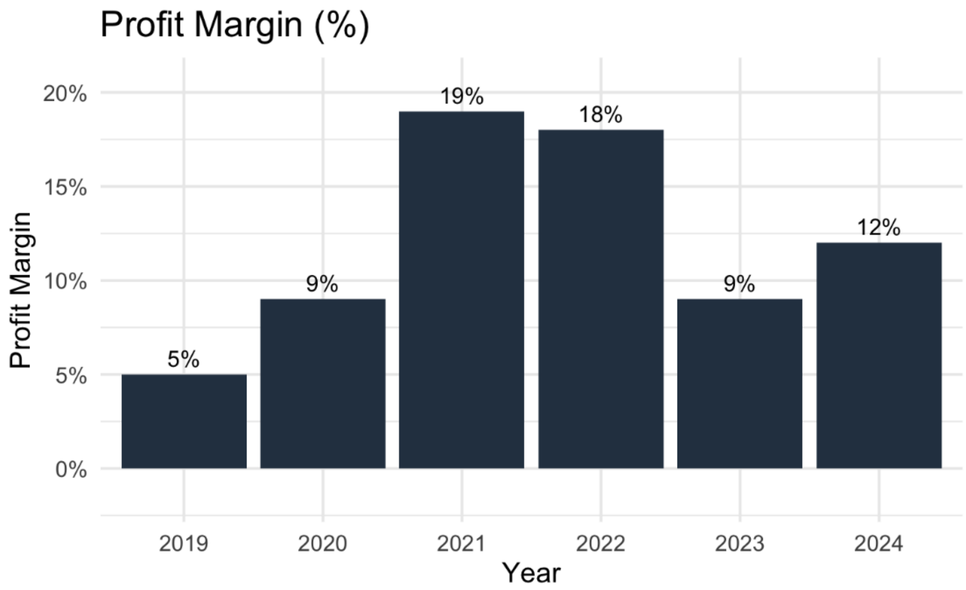
Figure 10. Profits per MWh generated.



Source: calculations based on the estimates of total revenues (Section 2.2.2) and total costs (Section 2.2.3).

[27] Source: Digest of UK Energy Statistics (DUKES).

Figure 11. Estimated profit margins.



Source: calculations based on the estimates of total revenues (Section 2.2.2) and total costs (Section 2.2.3).

Profit margins, defined as total profit relative to total revenue, increased from 5% in 2019 and 9% in 2020, to 19% in 2021 and 18% in 2022. Margins subsequently declined to 9% in 2023 and 12% in 2024. Profit margins should be interpreted with some caution in the context of the sharp increase in energy prices in 2021–2022. As the margin is expressed as a share of revenues, a relatively modest change in the percentage margin can mask a substantial increase in absolute profits. This can be seen when considering Figure 9 (total profits) and Figure 11 (profit margins) together.

Thus, the spikes in profits observed in 2021–2022 appear to have been a transitory phenomenon, although some ongoing impacts may persist compared with 2019–2020 levels, as profitability stabilised at levels above those observed during 2019–2020.

2.2.5 Additional Electricity Costs for the Economy and Households

Given the marginal pricing mechanism in the GB electricity market, under which all generators receive the price set by the most expensive unit required to balance supply and demand, high prices set by gas generators or interconnector trades (as discussed in Section 3.3[28]) were

[28] As discussed in Section 3.3, interconnector trades could also have played a role in setting electricity prices in GB, particularly in 2022, when GB became a net exporter of electricity. As we do not separately estimate the impact of interconnector trades on electricity price setting, throughout this section we refer to "prices set by gas generators and interconnectors" for accuracy. Accordingly, the additional electricity costs estimated in this section should be interpreted as the combined effect of high prices set by gas-fired generators and interconnectors, together with the operation of the marginal pricing mechanism.

transmitted across the market. As a result, electricity generators with relatively low short-run marginal costs (such as renewable generators[29]) also captured these high electricity prices, leading to higher profits.

This mechanism created a multiplier effect on consumer electricity costs. This section presents estimates of the overall price impact resulting from the combination of high electricity prices set by gas power generators and interconnector trades, together with the marginal pricing mechanism, on the economy as a whole and on households. These impacts are calculated for two years - 2021 and 2022 - when estimated profits of gas power stations were at their highest.

The starting point for this calculation is the estimated profit earned by gas-fired power generators per MWh of electricity generated (Figure 10). We treat the estimated profits of gas power stations per MWh of generation as a markup attributable to gas generators. This markup can be applied to the volume of generation over which it is assumed to have been passed through because of the marginal pricing, calculated as total electricity generation for the wholesale market excluding generation covered by Contracts for Difference, multiplied by the share of time during which electricity prices were set by gas-fired generators.

The estimated profits per MWh presented in Section 2.2.4 are £26.7/MWh for 2021 and £41.9/MWh for 2022. However, it cannot be assumed that all of these profits per MWh should be used to calculate additional electricity costs for the economy, as gas power stations are expected to earn a certain level of profit to recover capital costs and to compensate for investment risk in gas-fired power generation. As discussed in Section 2.3, the "normal" level of profits for gas power generators during the period 2019–2024 is assumed to be between 7% and 10% based on different benchmarks. Accordingly, we assume a normal profit margin of 8.5% (the midpoint of this range), with earnings above this level considered to contribute to additional electricity costs for the economy. The profits per MWh of generation corresponding to profit margins above the 8.5% threshold are £14.6/MWh in 2021 and £22.1/MWh in 2022. These values are used in the calculations reported in Table 6.

One of the key assumptions required to estimate the volume of electricity to which the gas generators' markup applies is the proportion of time during which electricity prices were set by gas-fired power generators or interconnector trades. According to Zakeri et al. (2023)[30], natural gas accounted for 98% of wholesale electricity price-setting events in 2021, implying that wholesale electricity prices were set by gas-fired power generators for the vast majority of the time.

---

[29] Except those operating under Contracts for Difference (CfD). CfD guarantees eligible renewable energy developers a fixed, agreed-upon price for electricity over a 15-year period, protecting them from volatile wholesale market prices. Given that they receive a fixed price, changes in electricity prices resulting from gas-fired generators setting the market price are not passed through to them.

[30] https://www.sciencedirect.com/science/article/pii/S23524847230130.

For the calculations presented in Table 6, we assume that the estimate reported by Zakeri et al. (2023) (98%) captures the frequency with which electricity prices were set by both gas generators and interconnectors, as interconnectors were the main competitors to gas generating assets in setting the marginal price during 2021-2022. We also assume that this share remained unchanged in 2022, as 2021 is the most recent year for which an estimate is available in Zakeri et al. (2023).

Table 6. Estimated additional electricity costs.

	2021	2022
Profits of gas power stations per MWh of electricity generated above the 8.5% profit margin, £/MWh (A)	14.60	22.10
Share of periods when electricity prices were set by gas generators (Zakeri et al, 2023) (B)[31]	0.98	0.98
Total electricity generation, TWh (DUKES Table 5.6) (C)	307.88	324.80
Generation by CfD generators, TWh (LCCC) (D)	21.66	20.45
Electricity generation volume to which gas power station markups applies ((C-D)*B), TWh (E)	280.50	298.26
Overall markup (A)*(E), £ million (F)	**4,095**	**6,592**
Electricity consumed by the households, TWh (G)	93.40	86.47
Total markup for households (A)*(G), £ million (H)	**1,364**	**1,911**
Total number of households, million (ONS) (I)	28.12	28.24
Markup per household (H)/(I), £ (J)	**48.50**	**67.66**

Source: calculations based on the profit estimates (Section 2.2.4), Zakeri et al. (2023), DUKES, LCCC, ONS.

As shown in Table 6, the marginal pricing mechanism, in combination with the high profits of gas power stations (above the "normal" level) and their significant role in setting electricity prices, resulted in substantial additional electricity costs for the economy. It is estimated that these additional costs amounted to £4.1 billion in 2021 and £6.6 billion in 2022. For households, the corresponding additional costs were estimated at £1.4 billion in 2021 and £1.9 billion in 2022, equivalent to approximately £49 and £68 per household in 2021 and 2022, respectively. These figures represent additional costs paid by GB electricity consumers, on top of the increase in electricity costs attributable to higher input (natural gas and carbon) prices.

The estimates presented in Table 6 represent the overall additional electricity costs to the economy and households. However, this analysis does not examine how these additional

[31] The most recent estimate available in Zakeri et al. (2023) is for 2021. We assume that the share of times when the price was set by gas power generators did not change materially in 2022 compared to 2021.

revenues were distributed across different types of electricity generators. In particular, some generators, such as renewable and nuclear generators[32] (except those operating under Contracts for Difference), had lower short-run marginal costs than gas-fired generators during 2021-2022 and may therefore have earned higher profit margins than those estimated for gas-fired generators. In addition, there is likely to have been substantial variation in profit margins among gas-fired power generators themselves, reflecting differences in thermal efficiency and load factors. Analysing the distribution of these additional revenues across different generator types would require a separate analysis and is therefore beyond the scope of this study.

2.3. Can Estimated Profits for 2021 and 2022 be Considered as Excess Profits?

The results of the profit evaluation indicate that profits of gas power generators increased sharply in 2021-2022 compared to the levels observed in 2019-2020. To determine whether the profits observed in 2021-2022 can be considered excessive, these estimates need to be compared against an appropriate benchmark. One possible approach is to use hurdle rates for gas power generation projects as such a benchmark.

The hurdle rate represents the minimum rate of return required by investors to commit capital to the construction, upgrade, or acquisition of a plant. It is typically calculated as the sum of the weighted average cost of capital (WACC)[33] and a risk premium reflecting the specific risks associated with gas power generation projects. Estimates of hurdle rates for gas generation projects in GB can be found in previous studies. For example, a study by Europe Economics estimated the hurdle rate for CCGT plants at 7.5% in 2018[34]. More recent estimates by CEPA for 2024 suggest a hurdle rate for new CCGT investment between 8.9% and 10.1% (real, so c.11-12% nominal if 2% inflation)[35] .

An alternative approach, used in the Unite the Union report[36], suggests benchmarking profitability against the national average profit margin. The report uses a 7% national average profit margin for 2024 as the benchmark level.

---

[32] Except those operating under Contracts for Difference.

[33] The baseline cost to the company for borrowing money.

[34] https://assets.publishing.service.gov.uk/media/5f3e797bd3bf7f3927d4a235/Cost_of_Capital_Update_for_Electricity_Generation_Storage_and_Demand_Side_Response_Technologies.pdf.

[35] https://assets.publishing.service.gov.uk/media/68cd1d818c44a661b4995d9f/cepa-desnz-hurdle-rates-electricity.pdf.

[36] https://www.unitetheunion.org/media/b2kldhmg/profiteering-doc-october-30-fv.pdf.

One more approach to defining a normal level of profitability would be to assess whether the profits earned by gas-fired generators provide a return above the required return on the capital employed. Under this approach, the value of the existing asset base could be estimated using the replacement cost of a modern equivalent asset, adjusted for depreciation, and the resulting capital employed compared with an appropriate required rate of return. This approach has the advantage of linking normal profits directly to the amount of capital that investors need to remunerate, rather than to generators' annual revenues. However, applying this approach accurately to the existing GB gas-fired generation fleet is challenging. In particular, it requires assumptions about the appropriate replacement cost of generating capacity, the economic life and remaining life of existing assets, depreciation, expenditure on refurbishment and life extension, and the appropriate required return on capital. As a result, estimates of the economic capital employed and the corresponding level of normal profits are subject to considerable uncertainty. Nevertheless, Indicative calculations suggest that the level of normal profits implied by a capital-based approach is of a similar order of magnitude to that implied by the benchmarks discussed above and does not suggest that the 2021–2022 profit estimates would cease to be considered unusually high.

Thus, we can assume that a reasonable estimate of the "normal" profit level for gas power generators lies in the range of 7% to 10%. Given these possible benchmarks, the aggregate profits recorded in 2021 and 2022 can be considered elevated, approximately 9.5–10.5% above the benchmark representing the "normal" level of profitability. This indicates that the increases in gas and carbon costs in 2021–2022 alone do not fully account for the magnitude of the rise in electricity prices. Part of the price increase appears to have translated into higher profits.

Earning high (super-normal) profits becomes potentially problematic when these result from factors such as external circumstances beyond firms' control or the abuse of a dominant market position, which may impose significant social costs and could be considered "windfalls". Nevertheless, this can also be considered problematic if the current market structure and design make it too easy to earn such profits and if they are not required to support investment. The aggregate nature of this analysis does not allow us to determine how these profits were ultimately distributed across the sector, or whether specific market participants captured a disproportionate share of those profits. In addition, it is worth noting that aggregate profit margins of gas-fired power generators exhibit significant year-to-year variation, even over the relatively short period covered by this analysis (2019–2024), with the late 2010s having lower margins in both gas and electricity generation business.

We acknowledge that profitability may have been lower in the years preceding 2019. However, the purpose of this study is not to assess the cumulative returns earned by gas-fired generators over their full economic life, but to examine how their profitability changed during the 2021–2022 energy crisis relative to the periods immediately before and after it.

3. Why Did Profits Increase in 2021-2022?

The most notable finding of the profit evaluation presented in the previous section is the significant increase in the profits of gas power stations in 2021-2022. In this section, we examine the possible factors that may have contributed to this increase in profitability. Specifically, we discuss three potential factors: (1) an increase in gas power station bids above their underlying costs, (2) more frequent use of relatively less efficient gas power stations due to heightened market volatility, and (3) the role of interconnectors in setting electricity prices during this period.

The discussion of possible reasons for the increase in profits of gas power generators during 2021-2022 presented in this section is based, among other sources of evidence, on engagement with industry experts and stress-testing the findings based on these engagements.

3.1. Increase in Gas Power Station Bids in the Wholesale Market

The GB electricity market is highly liberalised, with electricity generators independently deciding how much electricity to generate and at what price to offer it to the market. At the same time, the electricity market differs from classical markets in several important respects. In conventional markets, sellers can raise prices in line with demand and selling opportunities. However, two key factors usually prevent prices from rising to excessive levels. First, consumers are generally unwilling to pay prices above the value they place on the product. Second, sellers compete to gain market share by offering lower prices than their competitors.

These market dynamics do not always apply to electricity trading. The systems are not designed to enable consumers to express the value they place on electricity, particularly at the minute-by-minute level required to balance supply and demand. In addition, there are periods when the combination of location, timing, or the specific nature of the service required means that only a limited number of sellers are available, resulting in weak competition. Under such circumstances, there may be few effective external constraints on price increases.

However, this does not imply that there are no factors limiting prices. Most electricity generators operate internal compliance processes that ensure that higher offer prices can be justified on the basis of long-run cost recovery. Without such safeguards, firms could be exposed to potential scrutiny under competition law for abuse of a dominant market position.

In the following subsections, we examine three potential factors that could have led gas-fired power generators to price electricity significantly above underlying generation costs: (1) changes in the level of competition, (2) the willingness to exploit tight market conditions to maximise profits, and (3) increased risk premia.

3.1.1. The Role of Competition

Limited competition can lead to companies being able to charge higher prices, but only if the level of competition decreased significantly in 2021-2022 (when the profit spikes were observed) compared with 2019-2020, when profit margins were lower. Table 7 below presents the ownership structure of GB gas-fired generation capacity over the period 2019-2024 and its changes.

Table 7. Ownership structure of GB gas-fired generation capacity and its changes.

	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)	2023 MW)	2024 (MW)	Change (MW)
Vitol	1,252	1,252	3,252	3,252	3,268	3,252	2,000
UK Transition Ltd.				1,332	1,332	1,332	1,332
Cheung Kong & SSE			1,234	1,234	1,234	1,234	1,234
SSE (group)	2,790	2,790	2,790	2,781	3,610	3,610	820
River Nene				245	634	634	634
EPUKI	2,270	2,886	2,886	2,886	2,886	2,886	616
RWE (Npower)	6,564	6,564	7,118	7,118	7,139	7,160	596
Intergen	2,560	2,560	2,560	2,560	2,860	2,860	300
PX Group			155	155	105		0
Energy Capital Partners	1,200		1,200	1,200	1,200	1,200	0
Triton Power		1,200					0
Marchwood Power	898	898	898	898	898	898	0
Sembcorp Utilities	120	120	120	120	120	120	0
Uniper UK	2,970	2,970	2,970	2,970	2,818	2,970	0
ESB	1,730	1,730	1,730	1,730	1,730	1,704	-26
Fellside Heat & Power	155	155					-155

E.On UK	162	162					-162
Centrica	344	344	459	99			-344
AES	616						-616
Seabank Power	1,234	1,234					-1,234
Calon Energy	2,189	2,189	2,189	2,189	850	850	-1,339
EDF	1,342	1,342	1,342				-1,342
Drax Power	2,000	2,000					-2,000
TOTAL (MW)	**30,396**	**30,396**	**30,903**	**30,769**	**30,684**	**30,710**	**314**

Source: DUKES.

Table 7 indicates that the overall installed capacity did not change significantly in 2024 compared with 2019. At the same time, seven companies exited the market over the period. The most significant exit was that of Drax Power, with a total capacity of 2,000 MW. Its assets were subsequently acquired by Vitol in 2021. Three new companies also entered the market during the period, resulting in a net reduction of four in the total number of companies.

To assess how these market entries and exits affected the level of competition, we calculated the Herfindahl-Hirschman Index (HHI), a commonly used measure of market concentration that helps assess the level of competitiveness in an industry. It is calculated as the sum of the squares of the market shares of each firm operating in the market[37]. The HHI values calculated for each year from 2019 to 2024 are presented in Table 8.

Table 8. Herfindahl-Hirschman Index (HHI) for companies owning GB gas power generation assets.

	2019	2020	2021	2022	2023	2024
HHI	984	1,014	1,113	1,121	1,156	1,164

Source: calculations based on the data presented in Table 7.

The average value of the HHI index over the period 2019–2024 was 1,092, indicating a relatively competitive market. The HHI ranges from 0, corresponding to perfect competition, to 10,000, corresponding to a pure monopoly. Although the index increased slightly in 2021, reflecting a modest reduction in competition following the exit of several companies from the market, the

[37] The exact formula is $HHI = \sum_{i=1}^{n} S_i^2$, where n is the number of companies in the market, and S_i is the market share (in %) of the company i.

change was not substantial. Overall, there is no evidence to suggest that the level of competition declined significantly in 2021–2022 in a way that could explain the increase in gas power station profits.

3.1.2. Existing Evidence on the Strategic Bidding Behaviour of Gas Power Generators

Despite a reasonable level of competition, previous analyses provide evidence that, during the period considered, gas power generators may have engaged in strategic bidding behaviour that contributed to excess returns. However, this evidence mostly relates to bidding behaviour in the Balancing Mechanism rather than in the wholesale electricity market.

Ofgem's response to balancing costs (2025)[38] analysed bids in the Balancing Mechanism and found that spark spreads (the difference between electricity prices and the cost of gas and carbon) reached £421/MWh in winter 2022–23. The report notes that these levels are significantly above typical competitive returns, indicating potential scarcity exploitation and strategic bidding behaviour. This suggests that gas-fired generators could have earned excess profits from the Balancing Mechanism during periods of system stress.

Ofgem identifies two types of behaviour by gas-fired generators that may be used to earn additional profits in the Balancing Mechanism. First, generators may reduce output to zero close to delivery and then re-enter the Balancing Mechanism at higher prices within the same day. Second, generators may choose not to commit generation day-ahead and instead bid high prices into the Balancing Mechanism.

In October 2023, Ofgem introduced the Inflexible Offers Licence Condition (IOLC) to address the first type of behaviour (within-day repositioning). This intervention led to an approximately 80% decline in clean spark spreads compared with 2022-23 levels, with an estimated consumer benefit of £17 million in avoided costs.

However, the second type of behaviour (day-ahead non-commitment) does not formally breach the IOLC. Evidence suggests that on more than 90% of tight market days, at least one gas-fired generator chose not to commit any generation, rising to 100% of such days in 2024-25. This may indicate systematic withholding behaviour aimed at capturing higher returns in the Balancing Mechanism.

Another study focusing on Balancing Mechanism costs is the Review of the Balancing Market by Frontier Economics (2022)[39]. The report analyses the drivers of high balancing costs, with

[38] https://www.ofgem.gov.uk/sites/default/files/2025-11/Ofgem%E2%80%99s-response-to-balancing-costs-in-winter-2024-to-2025.pdf.

[39] https://www.frontier-economics.com/media/l43dzwca/frontier-lcp-cornwall-review-of-the-balancing-market-v2.pdf

particular attention to system conditions, bidding behaviour, and the design of the Balancing Mechanism.

It finds that high balancing costs were concentrated in a small number of "tight system" days, with the top 10 cost days coinciding with very low system margins, indicating scarcity conditions. Gas-fired generators were the dominant recipients of balancing payments, with around 65% of balancing costs on high-cost days going to CCGT units. Very high prices (up to £4,000/MWh) were repeatedly observed, and CCGT units consistently submitted very high offers.

Overall, the evidence suggests that prices were driven by both scarcity and bidding behaviour. High prices were not solely explained by fuel costs but also reflected pricing strategies under tight system conditions. The report also notes that the Electricity System Operator did not always accept lower-priced offers that were available in the market, indicating that system conditions and operational constraints also contributed to elevated balancing costs.

It is worth noting that both the Ofgem and Frontier Economics reports provide evidence relating to bidding behaviour in the Balancing Mechanism, not in the wholesale electricity market, where gas-fired power plants generate most of their revenues (Figure 6).

The report by Unite the Union (2025)[40] focuses on the profitability of the UK energy sector and therefore has a much broader scope than gas-fired generators alone. According to the analysis, UK energy companies reported very high profits during the energy crisis, with total gains estimated in the tens of billions of pounds. A key point highlighted in the report is the presence of significant inframarginal profits. Generators with lower short-run marginal costs (in particular non-gas generators) received electricity prices set by high-cost gas-fired plants. The report argues that this outcome is a direct consequence of the market design based on marginal pricing, whereby the marginal (typically gas) unit sets the wholesale electricity price for all generators. As a result, increases in gas prices were transmitted into higher electricity prices across the entire generation stack, not only affecting gas-fired generation but also significantly increasing revenues for other technologies.

3.1.3. Increased Risk Premiums as a Cause of Higher Bid Prices

The key factor that may have incentivised gas-fired generators to consistently submit higher-priced bids is the increase in risk premia during periods of system stress. The most significant risk in such periods was related to gas supply constraints - namely, the possibility that generators might not secure sufficient gas to deliver the electricity they had committed to produce.

In the wholesale market, this risk meant that if a generator had traded forward but subsequently faced a gas shortage, it might be unable to generate the contracted electricity and would then

[40] https://www.unitetheunion.org/media/b2kldhmg/profiteering-doc-october-30-fv.pdf

have to purchase the missing volume in the market, likely at extremely high prices, or face high imbalance cost. In the Balancing Mechanism, insufficient gas supply could prevent a generator from fulfilling its contracted output, potentially triggering substantial financial non-delivery penalties under the Balancing and Settlement Code (BSC).

The BSC modification P448, introduced in 2022, was aimed at reducing such risks for gas generators by clarifying that if a gas plant was forced to shut down due to a system-wide gas shortage, it would not be penalised under the Balancing and Settlement Code. It created a framework to manage cross-market impacts so that a gas supply crisis would not automatically translate into a systemic electricity market failure. Another amendment intended to reduce this risk was the Grid Code modification GC0160, which updated technical rules and parameters around emergency instructions. It ensured that generators could prioritise asset safety, fuel conservation, and coordinated emergency operations without facing regulatory breach proceedings. Both amendments were introduced in late 2022, and profits of gas-fired power stations declined in 2023 compared to 2022 (Figure 9). However, it is not possible to assess the role of these measures in reducing electricity prices and profits of gas-fired power stations, as natural gas prices (and their volatility) also declined significantly in 2023 relative to 2022.

The introduction of changes to the Balancing and Settlement Code and the Grid Code itself highlights the importance of these risks for gas generators during this period and therefore supports the view that increased risk premia were incorporated into the prices submitted by gas-fired plants. However, these amendments did not fully eliminate risks associated with electricity trading in the wholesale market. A significant proportion of electricity is traded through forward contracts agreed in advance of delivery, and these contracts can have relatively long durations (season-ahead, one-year ahead, two-year ahead) (Maximov et al., 2023)[41]. It is therefore plausible that, at the onset of the gas crisis in 2021, gas generators had already taken on substantial forward commitments for the following one to two years, alongside a high degree of uncertainty regarding their ability to fulfil these obligations. This logic coincides with the feedback collected during stakeholder engagement.

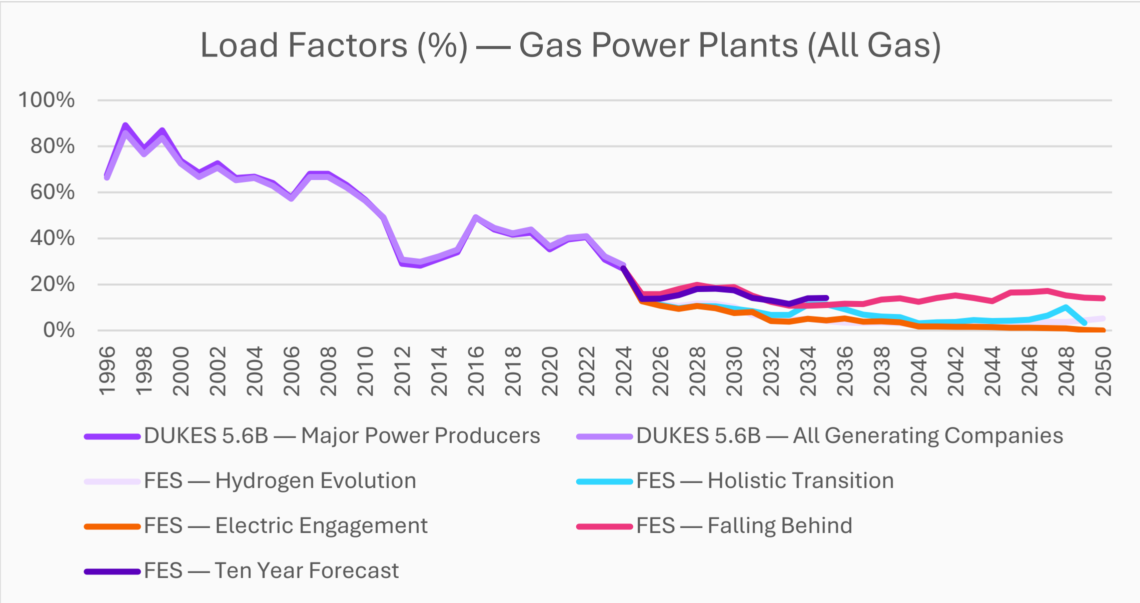
3.2 More Frequent Use of Less Efficient Power Stations

High market volatility and increased demand from continental Europe through interconnectors in 2022 could potentially have led to situations in which relatively less efficient gas-fired power stations were required to ramp up more frequently. Due to their lower efficiency, these assets have higher short-run marginal costs and therefore tend to submit higher-priced offers into the market.

[41] https://www.ucl.ac.uk/bartlett/sites/bartlett/files/necc_working_paper_2_final_pdf_with_cover40.pdf.

To test this hypothesis, we analysed data on the average load factors of gas-fired power stations. This is presented in Figure 12.

Figure 12. Historical and projected average load factors of gas-fired power plants.



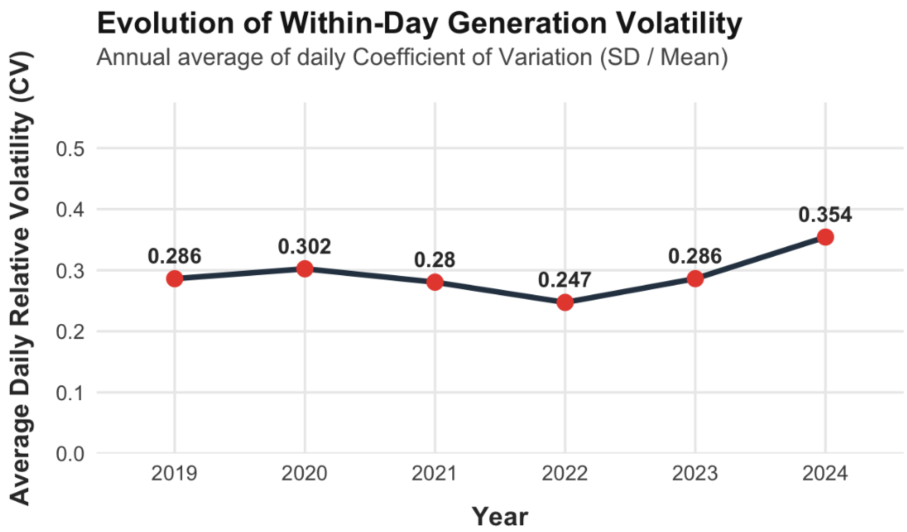
Source: calculations based on the data from DUKES and FES.

Figure 12 shows both observed load factors and projected values based on the Future Energy Scenarios (FES). If less efficient power stations had been used more frequently during ramp-ups, we would expect an increase in average load factors in 2021–2022 compared with previous years. However, changes in average load factors over this period are not material, suggesting no evidence of a more frequent use of less efficient assets.

Another indicator that may provide insight into whether less efficient gas power stations were used more frequently is the variation in gas-fired power generation over the course of the year. This variation would be expected to increase if additional generating assets - particularly those that were previously used less often - began operating more intensively to meet demand. Relatively less efficient assets that start to be used more frequently incorporate relatively high short-run marginal costs in their bids, as well as ramping costs. The effect is likely to be more pronounced within a day, as less efficient assets are typically dispatched during periods of peak demand. To capture this pattern, we calculated the daily coefficient of variation[42] in gas-fired generation and then averaged these values across each year. The results are presented in Figure 13.

[42] The coefficient of variation is defined as the ratio of the daily standard deviation to the mean daily generation.

Figure 13. Yearly averages of the within day generation volatility.



Source: calculations based on the ELEXON generation data.

The volatility dynamics show no evidence of increased volatility in 2021–2022. In fact, volatility declined slightly during these years compared with the levels observed in 2019–2020.

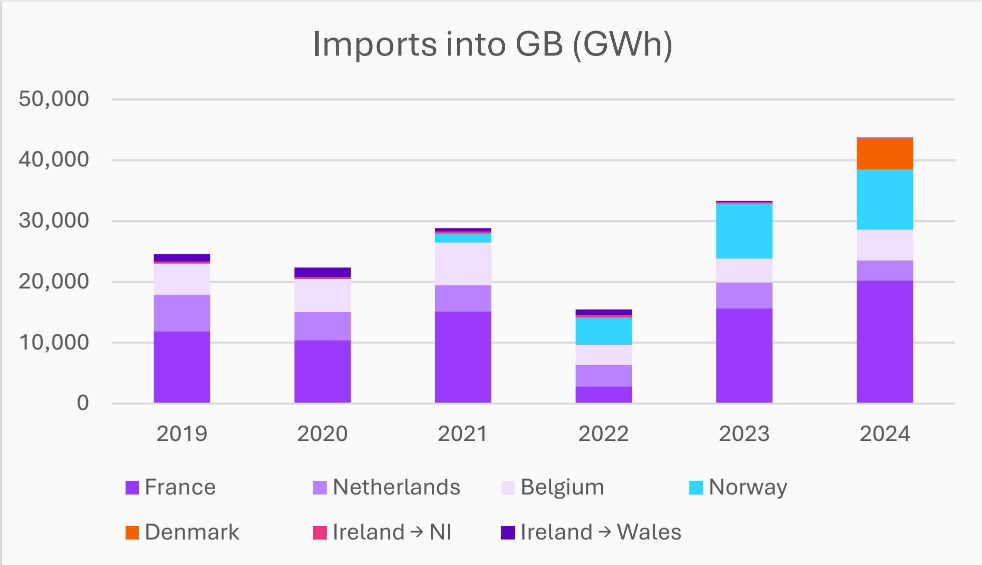
Thus, the descriptive analysis of average load factors and the volatility of gas-fired power generation provide no evidence that relatively less efficient generating assets were used more frequently in 2021–2022. Consequently, there is no indication that changes in the utilisation of such assets contributed to an increase in the average short-run marginal costs of gas power stations and, therefore, their bidding behaviour.

3.3 The Role of Interconnectors in Setting Electricity Prices

GB is not an isolated electricity market, as it is connected to continental Europe via interconnectors. On the one hand, interconnectors can provide additional electricity supply during peak hours and therefore compete with domestic gas-fired generators. On the other hand, they can also create additional demand for GB electricity and shift the balancing point in GB generation stack, potentially leading to a situation in which electricity prices are set by relatively less efficient generating assets.

Electricity imports into GB increased steadily over the period, with the exception of 2022, when imports declined compared with previous years (Figure 14).

Figure 14. Electricity imports into GB.

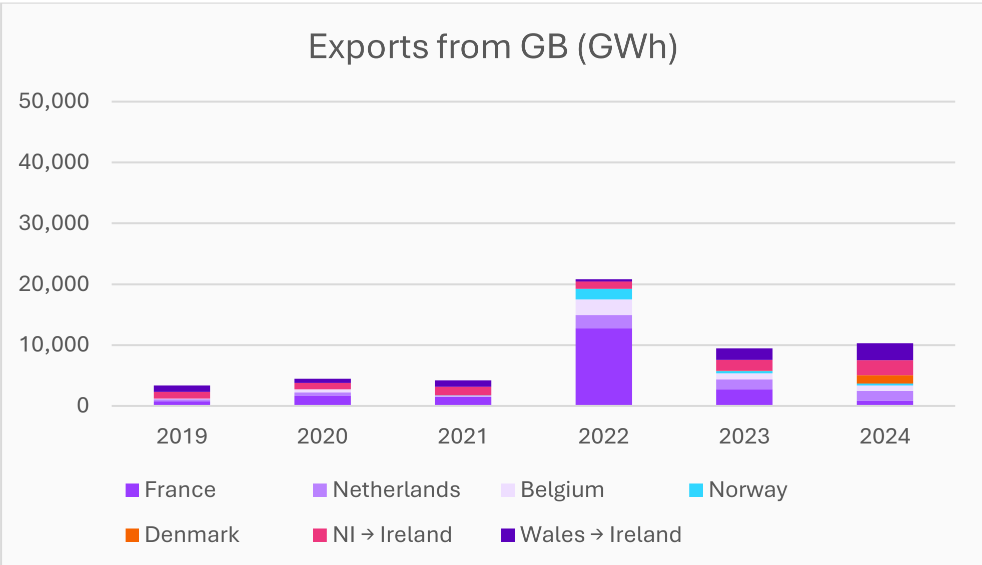


Source: ELEXON.

As shown in Figure 14, most of the electricity imported into GB is transmitted via the interconnector with France. Significant shares of imports also originate from Belgium, Netherlands, and, from 2022 onwards, from Norway.

Electricity exports from GB have historically been lower than imports (Figure 15). However, exports also increased steadily over the period, with a notable spike in 2022.

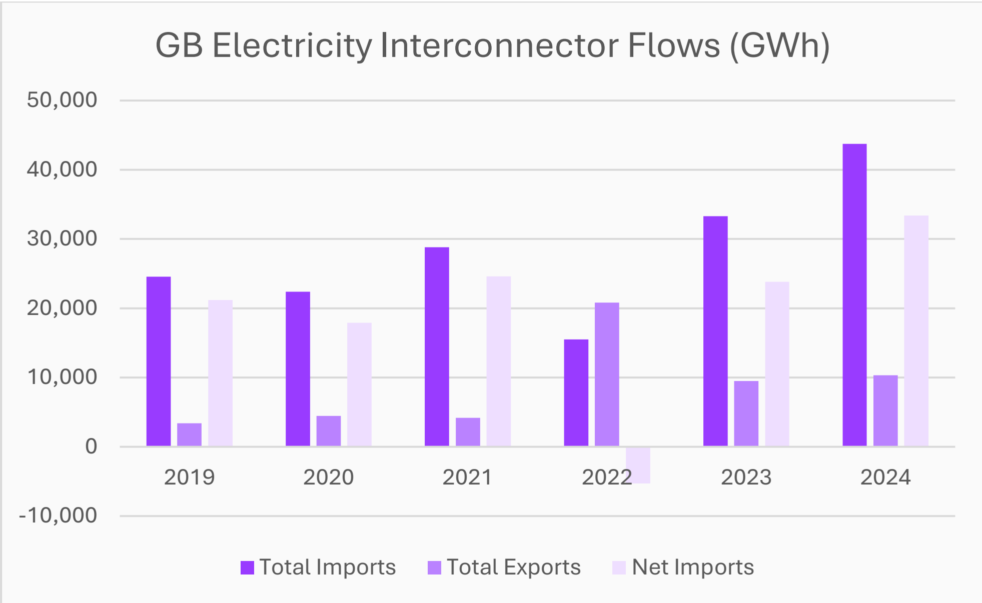
Figure 15. Electricity exports from GB.



Source: ELEXON.

The increase in electricity exports observed in 2022 was primarily driven by significantly higher demand from France, where the nuclear fleet experienced record-low availability, with more than half of its 56 reactors taken offline at certain points. This spike in exports to France led to GB becoming a net exporter of electricity in 2022 (Figure 16). However, in 2023 and 2024, GB returned to being a net importer of electricity.

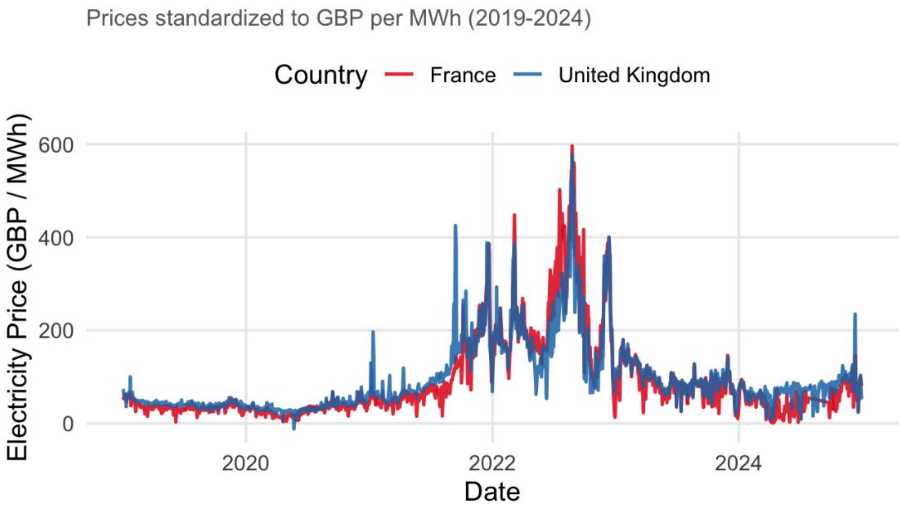
Figure 16. Net electricity imports to GB.



Source: ELEXON.

The increase in electricity exports from GB to France in 2022 coincides with the dynamics of electricity prices in two countries (Figure 17).

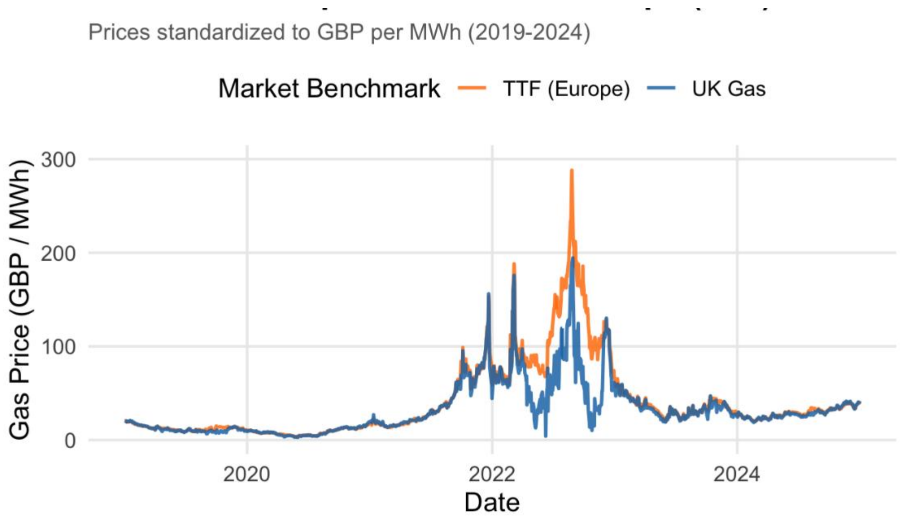
Figure 17. Dynamics of electricity prices in GB and France.



Source: LSEG (GB data), EEX (French data), and the Bank of England (exchange rate data).

As shown on Figure 17, the wholesale electricity prices in France were slightly higher than in GB during the most of the 2022. This could lead to the situation when exporting of GB-generated electricity to France was more profitable than selling it on the domestic wholesale market. This could have led to a situation in which domestic electricity prices in GB became partially decoupled from GB gas prices and instead more closely reflected electricity prices in France. To test this hypothesis further, it is necessary to analyse the differences in gas prices faced by GB and French gas-fired generators over this period. Specifically, we use National Balancing Point (NBP) gas prices as a benchmark for GB and Title Transfer Facility (TTF) gas prices as a benchmark for France. This data is presented in Figure 18.

Figure 18. Gas prices faced by GB and French gas-fired power generators.



Source: LSEG (UK NBP), ICE (TTF), and the Bank of England (exchange rate data).

Figure 18 shows that, prior to 2021, UK natural gas prices closely tracked those in continental Europe. However, in 2022 the two prices diverged, with gas becoming significantly cheaper in the UK than in continental Europe.

The discount in UK natural gas prices relative to continental Europe in 2022 was primarily driven by an infrastructure-related crisis rather than global supply shortages. Following the reduction in Russian pipeline imports, the UK became an important entry point for LNG into Europe due to its substantial regasification capacity, which enabled global LNG cargoes to be delivered into UK terminals. However, the UK's limited gas storage capacity, following the closure of the Rough storage facility, constrained its ability to absorb the resulting influx during periods of high arrivals. When the UK attempted to re-export surplus volumes to continental Europe, cross-Channel interconnector capacity constraints limited the flow of gas to the continent. As a result, domestic supply exceeded local summer demand, placing downward pressure on UK prices and leading to a significant discount of UK NBP prices relative to European benchmarks, at times exceeding €30/MWh[43].

This created a situation in which GB gas-fired power generators had access to relatively cheap natural gas in 2022, yet this did not translate into lower or stabilised GB electricity prices. Instead, GB generators were incentivised to export electricity to continental Europe, where electricity prices were higher due to gas supply constraints. This contributed to a significant widening of spark spreads for GB gas generators and, consequently, to elevated profits. This helps explain the finding that profits were above normal levels in both 2021 and 2022, with profits in 2022 being almost twice as high as those observed in 2021.

Overall, the evidence presented in this section suggests that interconnectors are unlikely to explain the high profits of GB gas-fired power generators in 2021. However, their impact in 2022 appears to have been significant. In particular, in 2022 interconnectors had a material influence on electricity price formation in GB and acted as an additional factor contributing to gas-fired generation profitability, alongside the factors that had already driven elevated profits in 2021.

4. Conclusions

This report estimates the aggregate profits of GB gas-fired power stations over the period 2019–2024 using an accounting framework that combines observed electricity generation, wholesale electricity prices, balancing market revenues, fuel costs, carbon costs, and operating costs. The results indicate that aggregate profits were around £0.5 billion in 2019–2020, increased sharply during the gas crisis to £2.9 billion in 2021 and £4.7 billion in 2022, and subsequently declined

[43] https://timera-energy.com/blog/prices-across-europes-gas-hubs-diverge/#:~:text=Constraints%20on%20pipelines%20from%20the,the%20use%20of%20interruptible%20capacity.

to approximately £1.2 billion per year in 2023–2024. Relative to a range of benchmark profitability measures, the evidence suggests that profits in 2021–2022 were above levels that might be considered normal for the sector.

The findings contribute to an important debate surrounding the energy crisis. The substantial increase in profits observed during 2021–2022 does not appear to have been driven by increased electricity demand or a sustained improvement in the underlying economics of gas-fired generation. Rather, it reflects the interaction between exceptional market conditions and an electricity market design in which gas-fired generators frequently set the wholesale electricity price. In addition, this is complemented by the GB's linkage with European electricity markets via interconnectors, which can lead to situations in which high electricity prices in Europe are transmitted to GB, resulting in higher GB electricity prices even when domestic generation costs remain unchanged.

The analysis suggests that the increase in profitability of gas power generation cannot be fully explained by rising gas and carbon costs alone. While these costs were the primary trigger of higher electricity prices, the magnitude of the increase in wholesale prices exceeded what would be required simply to preserve historical profit margins. This finding is consistent with evidence from previous studies and regulatory investigations indicating that periods of system stress can create opportunities for generators to earn returns significantly above normal levels. At the same time, the evidence reviewed in this report does not support a simple interpretation that high profits were solely the result of deliberate strategic behaviour. Elevated risk premia, concerns regarding fuel availability and uncertainty surrounding future market conditions are all likely to have contributed to higher offer prices.

Electricity systems require flexible generation capacity to remain available during periods of system stress, and generators must earn sufficient returns over time to justify investment and continued operation. Some increase in profitability during periods of scarcity is therefore both expected and economically efficient under the current electricity market design. The key question is not whether profits increased during the crisis, but whether the magnitude of those profits was proportionate to the risks borne. The results suggest that profits exceeded normal benchmarks by a considerable margin, however, the available evidence is insufficient to determine what proportion represented justified scarcity rents, compensation for heightened risk, or economic rents arising from market conditions.

In 2022, when estimated profits of gas-fired generators reached their highest levels, the energy market environment was particularly complex. In addition to increased risks for gas-fired power generators, which contributed to higher risk premia and therefore higher electricity prices, the GB's integration into European electricity markets via interconnectors led to a situation in which European electricity prices (primarily in France) became a driver of GB electricity prices, rather than domestic input cost dynamics. Under these exceptional conditions, GB gas-fired power generators were rationally responding to economic incentives by using relatively cheap natural gas available in the UK to generate electricity and selling it into European markets at higher prices.

An important implication of the results is that high profitability of gas power generators should be viewed as a feature of the broader market environment. The marginal pricing mechanism transmits the costs and bidding behaviour of the marginal generating units across the entire market. Consequently, even modest increases in markups by price-setting generators could have significant economy-wide effects on electricity costs.

Several limitations should be considered when interpreting the findings. Most importantly, the analysis is conducted at an aggregate sector level and therefore cannot identify the profitability of individual generating assets or companies. The analysis also relies on simplifying assumptions regarding trading strategies, fuel procurement arrangements, and plant efficiencies. While sensitivity testing suggests that the central conclusions are robust to reasonable changes in these assumptions, the reported profit estimates should be interpreted as indicative rather than exact measures of realised profitability.

Overall, the results indicate that the gas crisis generated a temporary but exceptional increase in the profitability of GB gas-fired power generation. Although these elevated profits partially disappeared as market conditions normalised, the findings raise broader questions regarding the interaction between marginal pricing, market volatility, risk allocation, and consumer outcomes during periods of energy system stress.