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Research article

Examining the drivers of the imbalance price: Insights from the balancing mechanism in the United Kingdom

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ABSTRACT

The increasing integration of renewable energy sources in the UK electricity sector has posed challenges to the stability of the system, leading to a sharp rise in the costs of balancing services. This study analyses half-hourly data from January 2017 to December 2023 to examine the factors determining the imbalance price in the UK's balancing mechanism, with particular focus on the sharp price increases in 2021–2022. Employing a Generalised Additive Model (GAM) to account for non-linear relationships, the analysis finds that the imbalance price is positively affected by the net imbalance volume (demand-side factor) and negatively impacted by the de-rated margin (supply-side factor). The wholesale electricity price, however, is identified as the dominant factor driving both the mean and volatility of the imbalance price during 2021–2022. These findings suggest that the balancing mechanism is functioning effectively and that a reduction in the wholesale price would lead to a lower imbalance price and thus lower costs of balancing services.

1. Introduction

The past few decades have witnessed a dramatic increase in the adoption of renewable energy. According to the IEA (2023), renewable electricity capacity additions amounted to an estimated 507 GW in 2023, representing an increase of almost 50% compared to 2022. Global cumulative electricity capacity from renewable sources increased from 1224.7 GW in 2010 to 3864.5 GW in 2023. Of this, variable renewable sources, including solar, increased from 41.5 GW to 1418.0 GW, and wind capacity rose from 181.1 GW to 1017.4 GW (IRENA, 2024). Nevertheless, the ongoing expansion of renewable electricity generation, particularly from unpredictable and intermittent sources, poses challenges to the stability of the electricity system, as higher shares of variable renewable energy increase the need for balancing supply and demand (IRENA, 2019; IEA, 2020).

Stimulated by support schemes such as the Renewables Obligation (Li et al., 2020; Shao et al., 2021; Pashakolaie et al., 2024; Wang et al., 2024b) and the Contracts for Difference (Bunn and Yusupov, 2015; Nelson and Dodd, 2023; Schlecht et al., 2024), the UK has experienced a transition away from carbon-intensive fuels, aligning with its commitment to achieving net zero emissions by 2050. Between 2012 and 2023, the share of coal in the electricity generation mix fell from its recent peak at 39.24% to 1.29%, a decline that was largely offset by renewable energy, which grew from 12.15% to 47.03% (DESNZ, 2024b).

Despite this progress, the growing share of renewable electricity generation, particularly from unpredictable and intermittent sources like wind and solar (which accounted for 32.86% in 2023), continues to present challenges to the stability of the electricity system (DESNZ, 2024b). The primary role of the National Grid Electricity System Operator (ESO) is to maintain a real-time balance between supply and demand within the UK electricity system through its balancing services.[1] The costs associated with balancing services have increased

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[1] The National Energy System Operator (NESO) was launched on 1st October 2024, after the UK government acquired the Electricity System Operator (ESO) from National Grid and transferring it into public ownership. As this study focuses on the period before 2024, it continues to refer to the term National Grid ESO for convenience.

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significantly, rising from an average of £1.5 billion annually between 2017 and 2020 to £3.9 billion between 2021 and 2022 (National Grid ESO, 2023a).

As a major component of balancing services, the balancing mechanism addresses system imbalances using a market-based approach and operates from gate closure (1 h before delivery) to real-time within each half-hour settlement period.[2] Parties (generators and suppliers) voluntarily submit offers and bids to either increase generation or reduce demand. Specifically, an offer represents a proposal to increase energy in the system (by increasing generation or reducing demand), while a bid is a proposal to decrease energy in the system (by reducing generation or increasing demand). In the event of a discrepancy between supply and demand, the ESO accepts the most cost-effective bids or offers to manage the system imbalance through bid-offer acceptance, accepting offers when additional energy is required or accepting bids when excess energy needs to be removed.

The imbalance price represents the price of marginal accepted offers or bids used by the ESO to balance the electricity system and serves as a penalty for imbalance. The imbalance price reflects the cost of balancing services and has sharply increased in recent years, rising from an average annual value of £44.61/MWh between 2017 and 2020 to £156.20/MWh between 2021 and 2022 (Elexon, 2023a). This sharp rise in the imbalance price necessitates investigation, as it may indicate dysfunction in the balancing mechanism and the potential for increased consumer utility bills.

Quantitative studies on balancing costs and imbalance prices remain limited and inconclusive in the context of the UK (Swinand and Godel, 2012; Lucas et al., 2020; Bunn et al., 2021). Quantitative studies on balancing costs and imbalance prices remain limited and inconclusive in the context of the UK (Swinand and Godel, 2012; Lucas et al., 2020; Bunn et al., 2021). This study is the first to analyse the factors contributing to the rising imbalance prices in the balancing mechanism in 2021 and 2022. In the model specification, the first factor is the net imbalance volume, defined as the remaining volume after netting accepted offers and bids, which can be considered the demand-side factor. The second factor is the de-rated margin, defined as the surplus of generation capacity over demand, which serves as the supply-side factor. The third factor is the wholesale electricity price from the intraday market, which is used in the computation of the imbalance price.

Based on half-hourly data from 1 January 2017 to 31 December 2023, a Generalised Additive Model (GAM) is employed to capture the non-linear relationships among the variables in the model specification. This approach offers a more robust understanding of the effects of these three factors. However, multicollinearity arises between the wholesale price and the de-rated margin, compromising the accuracy of the estimated effects of these variables on the imbalance price and potentially leading to misleading conclusions. To resolve this multicollinearity issue, a partialling out technique is used to isolate the impact of the wholesale price from the influence of the de-rated margin, thereby capturing the effects of both on the imbalance price more accurately. This crucial step improves the statistical validity of the model and provides sounder theoretical insights into the relationships among these factors. Additionally, this study investigates the period of 2021 and 2022, when the imbalance price exhibited higher mean and volatility, and assesses the relative importance of these factors on the imbalance price based on the analysis of predicted values and incremental goodness of fit.

The remainder of this paper is organised as follows. Section 2 provides the literature review, and Section 3 describes the background of the balancing mechanism. Section 4 details the data, methodology, and model specification. Section 5 presents the empirical results, and Section 6 examines the periods of rising imbalance prices and compares these findings with those from earlier studies. Finally, Section 7 offers concluding remarks.

2. Literature review

Electricity from variable renewable sources has grown significantly worldwide, including in European countries and major polluters, but the rising trend imposes challenges to the electricity grid as the system needs to be balanced at all times.

2.1. Increasing variable renewable energy

The dramatic increase in the adoption of renewable energy over the last two decades has been driven by a combination of favourable policies, falling technology costs, and global commitments to reduce carbon emissions (Aguirre and Ibikunle, 2014; Carley et al., 2016; Bashir et al., 2024; Energy Institute, 2024; Gupta and Guha, 2024b). Following the oil price shocks of the 1970s, European countries began exploring alternatives to fossil fuels to reduce their reliance on external energy sources, and since then renewable energy, particularly wind and solar, has undergone remarkable growth. Denmark was an early pioneer in wind energy development beginning in the 1970s and 1980s, and now has one of the highest shares of wind power in its electricity generation mix globally, contributing about 57.72% of electricity in 2023, while solar contributed about 9.28% (Johansen, 2021; Carlini et al., 2023). Germany is widely regarded as a global leader in renewable energy development through its renewable energy transition policy (Energiewende), which aims to shift away from fossil fuels and nuclear energy toward cleaner, sustainable sources. It held the highest installed capacity of wind power globally until being surpassed by the United States in 2008. As of 2023, wind power accounted for around 27.20% of the country's electricity consumption, with 12.2% from solar (Eising et al., 2020; Kolb et al., 2020). The United Kingdom was relatively late in developing renewable energy compared to some European countries due to its historical reliance on North Sea oil and gas, which provided a level of energy security and reduced the urgency to develop alternatives. However, once the UK committed to renewable energy, it quickly became a global leader, particularly as the world's largest market for offshore wind energy, with projects such as Hornsea One and Dogger Bank setting global benchmarks in scale and capacity. In 2023, wind contributed 28.1% and solar contributed 4.6% of electricity generation (Shao et al., 2022, 2023; Newbery, 2023a; Wang et al., 2024a).

Outside Europe, as the country with the highest cumulative carbon dioxide emissions and the second-largest annual emissions, the United States has seen significant growth in wind and solar energy, driven by federal incentives and state-level renewable portfolio standards. In 2023, wind and solar contributed 10.01% and 5.60%, respectively, to the total electricity generation (Joshi, 2021; Qin et al., 2022). As the world's largest annual emitter, China has experienced explosive growth in both wind and solar energy, emerging as the global leader in installed capacity for both technologies. The rapid expansion has been driven by ambitious renewable energy targets and strong government policies, aimed at reducing the country's reliance on coal and addressing air pollution. As of 2023, wind energy contributed around 9.36% of total electricity generation, while solar contributed 6.18%. Looking ahead, China aims to achieve 1200 GW of combined wind and solar capacity by 2030, playing a pivotal role in its broader goal of reaching carbon neutrality by 2060 (Chen et al., 2020; Lin and Chen, 2023; Xu and Lin, 2024). Another major polluter, India, has seen substantial growth in both wind and solar energy over the past decade, driven by government incentives for solar and wind energy development. As of 2023, wind contributed 4.17% and solar 5.16% to its electricity generation, and India also plans to expand renewable energy projects to achieve 500 GW

[2] Another major component of balancing services is ancillary services, which are essential for maintaining the technical stability (e.g., frequency and voltage) of the electricity grid on a second-by-second basis and are typically pre-contracted by the ESO. This is not the focus of this study but will be briefly explained in Section 3.1.1.

of renewable energy capacity by 2030 (Jain et al., 2021; Nibedita and Irfan, 2022; Gupta and Guha, 2024a).

2.2. Increasing balancing costs

The intermittency of renewable energy sources has long been recognised as a challenge for the stability of power systems (Joskow, 2011; Gowrisankaran et al., 2016; Newbery, 2023b). Studies have explored the impacts of this variability on balancing costs. In relation to Germany's balancing market, Hirth et al. (2015) suggest that integrating wind and solar generators into power systems causes integration costs, including balancing costs due to forecast errors, and profile costs, arising from the deviation between renewable generation and load. Hirth and Ziegenhagen (2015) propose a paradox as balancing costs have been reduced by half while wind and solar capacity has tripled since 2008. Ocker and Ehrhart (2017) further examine the paradox and suggest that the reduced balancing costs were the results of flexible trading of electricity from renewable energy sources and efficiency savings from national and international grid control cooperation. In Spain, González-Aparicio and Zucker (2015) suggest that wind power forecast errors are positively related to balancing costs. Batalla-Bejerano and Trujillo-Baute (2016) indicate that the increasing presence of intermittent renewable production leads to higher balancing costs and greater fluctuation in reserve requirements. Moving to Italy, Gianfreda et al. (2018) note that, as renewable production increased, balancing volume decreased while balancing costs surged significantly. In Portugal, Frade et al. (2019) find that increased wind generation led to a rise in balancing costs and suggest that wind generators should be made responsible for the economic cost of their imbalance. For Ireland, Di Cosmo and Valeri (2018) find that balancing payments increased as a result of wind generation and forecast errors of demand and wind. In Denmark, Soini (2021) examines the relationship between wind power generation and the price of the balancing power market and finds that balancing power prices are consistently higher during lower-than-expected wind power production.

Focusing on the UK, Dale et al. (2004) indicate that extra balancing costs would be incurred due to uncertainties in wind output. Gross et al. (2006) suggest that increased intermittent renewable generation pushes up both short-run balancing costs and longer-term costs of maintaining a higher system margin. Based on the assessment of costs and benefits of wind generation on the electricity system, Strbac et al. (2007) argue that it is feasible and cost-effective to integrate wind generation for 20% of power production, but balancing costs would increase. In a more recent study, Joos and Staffell (2018) indicate that system operation costs have increased by 62% in Britain since 2010, while there has been a five-fold increase in variable renewable capacity. The study reveals that the bulk of rising costs were due to the dispatch of gas plants because of the variability of renewable energy sources and suggests shorter product lengths and more frequent auctions in the balancing system to improve functioning and transparency.

Among econometric studies on the UK, Swinand and Godel (2012) found a positive marginal impact of wind generation on system balancing costs based on half-hourly data from November 2008 to November 2011 and conclude that the impacts of wind on the balancing system are not likely to be high for 5–10 GW of installed capacity. Lucas et al. (2020) develop a regression model using a machine learning algorithm with 19 predictors based on half-hourly data from 1 January to 31 December 2019 and find that the largest impacts were from the net imbalance volume, the loss of load probability, and de-rated margins. Bunn et al. (2021) consider a Markov regime-switching model based on half-hourly data from 1 July 2016 to 30 June 2019 and find that the imbalance price reflects fundamental drivers like demand forecast errors, scarcity variables, and generation from wind and solar.

2.3. The research gap

Studies have examined the integration of renewable energy and its impact on balancing costs in other countries, such as Germany (Hirth et al., 2015; Hirth and Ziegenhagen, 2015; Ocker and Ehrhart, 2017) and Spain (González-Aparicio and Zucker, 2015; Batalla-Bejerano and Trujillo-Baute, 2016). However, research on imbalance prices in the UK remains limited. For example, econometric studies (Swinand and Godel, 2012; Lucas et al., 2020; Bunn et al., 2021) have explored the effects of wind generation and market variables on balancing costs and prices, but their findings are inconclusive.

This study contributes to the research in three ways. First, previous analyses were based on earlier periods when renewable penetration was lower and imbalance prices were more stable, so they do not capture the unprecedented price volatility seen in 2021–2022. Second, the role of wholesale prices remains underexplored. This variable was included in Swinand and Godel (2012), but the negative relationship to the imbalance price was unexplained. Lucas et al. (2020) considers this variable, but its role is minor compared with other variables highlighted. Bunn et al. (2021) did not consider the wholesale price. Third, the non-linear relationships between these variables and imbalance prices have not been explored, particularly under conditions of high price volatility.

3. Background

On 1 April 2019, the ESO became a legally independent company within the National Grid Group, separated from the Electricity Transmission Operator (ETO). The status of independence allows the ESO greater flexibility to adapt to evolving market demands, eliminate conflicts of interest, and promote fair competition, ensuring no bias towards the infrastructure division of the organisation (National Grid ESO, 2021). Through balancing services, the ESO is responsible for maintaining a real-time balance between supply and demand in the UK electricity system. The Electricity National Control Centre (ENCC) of the ESO is the central hub for electricity system operation, which continuously monitors the system and facilitates the distribution of electricity nationwide from generation points to demand areas.

3.1. Balancing services

Balancing services are crucial for ensuring the stability and reliability of the grid. In 2021 and 2022, the costs of balancing services increased sharply and raised concerns from the regulator (Ofgem, 2021; National Grid ESO, 2022). Fig. 1 shows that the total costs of balancing services, which represent the comprehensive financial expenses dedicated to system stabilisation, increased by over four-fold from £1.20 billion in 2019 to £5.12 billion in 2022.[3] According to National Audit Office (2020), the costs of balancing services were £10 of the average household annual electricity bill in 2019, which approximately increased to around £40 in 2022.[4] Although these costs have remained a relatively minor component of overall electricity bills, the role of balancing services is increasingly critical in ensuring that the electricity grid operates at the standard frequency (50Hz) and avoids blackouts, especially with the growing integration of variable renewable energy

[3] The total costs of balancing services are categorised into several segments, including Balancing Mechanism operations, Trades, Ancillary Services, and System Operator to System Operator (SO-to-SO) transactions, along with costs arising from system losses, non-delivery, and reconciliation processes (National Grid ESO, 2023b).

[4] According to National Audit Office (2020), the average household annual electricity bill was £639 in 2019, including wholesale costs (£125), social and environmental obligation costs (£132), energy supplier costs (£121), network costs (£140, of which £37 for transmission, £93 for distribution, and £10 for balancing services), and VAT (£30).

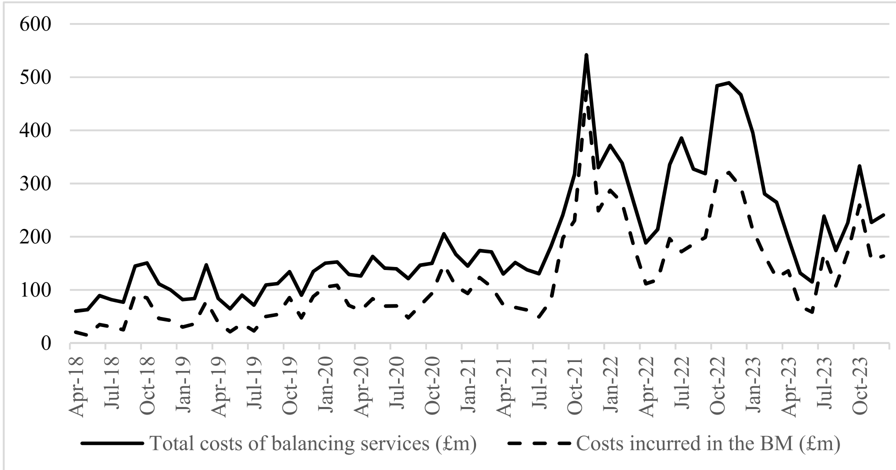

Fig. 1. Monthly total costs of balancing services (£million) and costs incurred in the balancing mechanism (£million) from April 2018 to December 2023. Source: Monthly Balancing Services Summary, ESO.

sources.

3.1.1. Ancillary services

The total costs of balancing services include two main components, ancillary services and the balancing mechanism. For example, in March 2023, the total costs of balancing services were £263.87 million, with ancillary services accounted for £119.11 million (44%) and the balancing mechanism accounted for £122.87 (45%) (National Grid ESO, 2023b).

The first component, ancillary services, is essential for maintaining the technical stability of the electricity grid. These services are pre-contracted by the ESO and run automatically (automatically detecting and responding without human intervention) to ensure the grid operates within technical parameters, particularly to maintain the system's frequency at 50Hz, on a second-by-second basis. It includes three service types: tendered services such as firm frequency response, fast reserve and short-term operating reserve; mandatory services such as reactive power (voltage control); and commercial services such as restoration (National Grid ESO, 2023b).

The second component, the balancing mechanism, comes into play when there are supply-demand imbalances that the ESO requires additional adjustments beyond what ancillary services can manage. The balancing mechanism is the focus of this study and will be elaborated in Section 3.2, as it is more related to managing the volatility of wind and solar and the resulting imbalances in supply and demand caused by the unpredictable nature of these energy sources.

3.1.2. Capacity market

Another relevant concept is the Capacity Market. The prevalence of low marginal cost renewable electricity and governmental support for these renewable sources have undermined traditional fossil fuel-based plants and posed a threat to the constant availability of dispatchable electricity. To secure a stable long-term electricity supply, the government introduced the Capacity Market in 2013, which aims to incentivise investments in new capacities of reliable energy or for existing capacity to remain operational (DECC, 2012).

If a generator is awarded a contract through the auction, they receive regular payments (e.g., £/kW per year) for being available during the delivery year, based on the clearing price set in the auction. The main requirement is that capacity providers (i.e., contract holders) must be available to supply electricity or reduce demand when a Capacity Market Notice is issued by the system operator (DESNZ, 2024a). This usually happens when the grid is under stress, i.e., electricity demand is high and supply is tight. However, if a Capacity Market Notice is not issued, contract holders are free to participate in ancillary services and the balancing mechanism. For example, they can submit bids and offers in the balancing mechanism to adjust their generation or demand.

3.2. Balancing mechanism and actions of the ESO

The balancing mechanism is employed by the ESO as the main tool for balancing supply and demand, and it operates as a continuous auction from gate closure (1 h before delivery) to real-time. Fig. 1 shows that the costs incurred in the balancing mechanism exhibited sharp rises in 2021 and 2022. For example, the costs incurred in the balancing mechanism increased by over four-fold from £0.59 billion in 2019 to £2.64 billion in 2022.

3.2.1. Party's initial imbalance in the balancing mechanism

For each settlement period (a half-hour period), all parties (generators and suppliers) must inform the ESO of their positions by submitting Final Physical Notifications (FPNs) at gate closure. FPN represents the expected metered volume of generation or demand from a party in a settlement period. After gate closure, parties are required to comply with their FPNs and may only deviate from their FPNs following the instruction of the ESO. The information provided through FPNs enables the ESO to identify potential system imbalances and take the corresponding balancing actions. Meanwhile, parties also submit their Energy Contract Volume Notifications (ECVNs), which inform the ESO about their contracted volumes with other parties.

For each settlement period t, the initial imbalance (IM_t^i) of a party is calculated as the difference between the FPN (which indicates expected metered volumes) and the ECVN (which indicates contracted volumes),

$$IM_t^i = FPN_t - ECVN_t \tag{1}$$

At this stage, parties have three possible positions. First, in a *short* position, parties have a shortage of energy - this means under-generation by generators or over-consumption by suppliers.[5] Second, in a *long* position, parties have a surplus of energy – this means over-generation by generators or under-consumption by suppliers. Third, the party is in a *balanced* position. These initial positions are determined at gate closure based on their FPNs and ECVNs, but parties can participate in the balancing mechanism to change the positions of their final imbalance at the end of the settlement period.

[5] Specifically, a generator with a short position has an initial imbalance below zero but a supplier with a short position has an initial imbalance above zero.

3.2.2. Offers and bids

Participation in the balancing mechanism is voluntary, and parties can submit up to ten options (offers and bids). The price and volume of each offer/bid indicate the value participants have placed on being requested to deviate from the FPN declared at gate closure. An offer is a proposal to increase energy in the system (increase generation or reduce demand), with the offer price (£/MWh) being the amount a party expects to be paid by the ESO. In contrast, a bid is a proposal to reduce energy in the system (reduce generation or increase demand), with the bid price (£/MWh) being what a party agrees to pay to the ESO, as a reduction in generation can lead to lower costs for the party making the bid.[6]

For example, consider a generator with an expected volume, or Final Physical Notification (FPN), of 150 MW. The generator may submit an offer to increase its volume by 25 MW, raising its output to 175 MW at an offer price of £20/MWh. Additionally, it can submit another offer to further increase its volume by an additional 25 MW to 200 MW at an offer price of £25/MWh. Conversely, the generator may submit a bid to reduce its volume by 25 MW, lowering its output to 125 MW at a bid price of £20/MWh. A further bid can be submitted to decrease its volume by another 25 MW to 100 MW at a bid price of £15/MWh.

3.2.3. The ESO's actions in the balancing mechanism

After receiving bids and offers from parties, the ESO acts to balance the system through bid-offer acceptance, that is, accepting offers when more energy is required (buy balancing actions) or accepting bids when energy needs to be removed (sell balancing actions). Parties participating in the balancing mechanism adjust their generation or consumption according to the instructions provided by the ESO. The ESO is obligated to accept offers and bids economically and compensate parties on a pay-as-bid basis.

The system has two states. First, the system is short when there is not enough energy. Therefore, the ESO needs to increase energy in the system by accepting more offers than bids, so the net imbalance volume (NIV) is greater than zero ($NIV > 0$). A positive offer price implies that the ESO pays these parties for their extra energy, and the cashflow of an offer is calculated by multiplying the offer price (£/MWh) by its increased volume (MWh) indicated in their offers. Among the offers accepted, most are from gas-fired generators, followed by pumped storage and coal-fired generators on a much smaller scale. For example, in April 2023, the total offer cashflow (i.e., aggregated offer cashflow from all accepted offers) was £122.24 million, of which £104.81 million (85.74%) was paid to gas-fired generators (Elexon, 2023b). This positive offer cashflow indicates payment from ESO to parties whose offers are accepted.

Second, the system is long when there is excess energy. Therefore, the ESO needs to remove energy from the system by accepting more bids than offers, so the net imbalance volume is less than zero ($NIV < 0$). A positive bid price implies that parties pay the ESO to reduce their generation. For example, when gas generators reduce electricity supplied to the grid, they save on fuel costs, so they agree to make payments to the ESO. However, bids work differently for renewable generators. For example, when wind generators reduce their generation, they do not make savings since there are near-zero marginal costs but lose out on subsidies from support schemes. Therefore, wind generators are only willing to reduce their generation if they are compensated in terms of negative bid prices, which represent a payment from the ESO to a generator for reducing generation. In terms of payment, the cashflow of a bid is calculated by multiplying the bid price (£/MWh) by the decreased (negative) volume (MWh) indicated in the bid. The negative bid cashflow indicates payments made from parties to the ESO. Conversely, a positive bid cashflow, resulting from negative bid prices, indicates payments made from the ESO to parties. For example, in April 2023, the total bid cashflow (i.e., aggregated bid cashflow from all accepted bids) was £3.68 million received by the ESO, but this is the net value mainly comprising £31.09 million paid by gas-fired generators and £28.49 million paid to wind generators (Elexon, 2023b).

3.3. Imbalance settlement

While the ESO balances the system through bid-offer acceptance in the balancing mechanism in each settlement period, Elexon, a subsidiary of the ESO, is responsible for conducting the financial settlement of imbalances after the settlement period. For simplicity, this study refers to the financial settlement as 'payment to/from the ESO'.

3.3.1. Party's final imbalance

The financial settlement is conducted after the balancing mechanism closes for each settlement period. The amount of the financial settlement depends on the final imbalance, which is the difference between a party's actual metered volume and contracted volume.

If a party does not participate in the balancing mechanism, its final imbalance volume (IM_t^f) is the same as its initial imbalance (IM_t^i),

$$IM_t^f = IM_t^i = FPN_t - EVCN_t \tag{2}$$

In contrast, if a party participates in the balancing mechanism, its final imbalance is adjusted by any accepted offers and bids, i.e., the delivery of balancing services, and is written as

$$IM_t^f = FPN_t + BOA_t - EVCN_t \tag{3}$$

where BOA_t represents accepted offers or bids in the balancing mechanism, and ($FPN_t + BOA_t$) is the final metered volume.

Similar to initial imbalances, final imbalances can be either short (i.e., shortage) or long (i.e., surplus), or zero (i.e., balanced). Parties with final imbalances face financial settlement after the balancing mechanism, and this settlement depends on the imbalance price, which is derived from prices on accepted offers and bids.

3.3.2. Imbalance price

The imbalance price is defined as the price of marginal offers or bids that the ESO uses to balance the system, which reflects the costs of balancing services (Elexon, 2020).[7] The imbalance price is used to settle a party's final imbalance volumes in each half-hour settlement period.

The calculation of the imbalance price is simplified in Fig. 2.[8] In a half-hour interval, the system can fluctuate between short or long states, so there are both accepted offers and bids. Accepted offers are stacked from the highest price to the lowest above the horizontal line. A lower offer price is preferable to the ESO as it pays less to parties to increase energy in the system, so the offer with the lowest price is positioned closest to the horizontal line. Meanwhile, accepted bids are stacked from the highest price to the lowest below the horizontal line. A higher bid price is preferable to the ESO as it receives a higher payment for removing energy from the system, so the bid with the highest price is positioned closest to the horizontal line.

The netting process in the balancing mechanism begins by matching the volume of the accepted offers and bids that are furthest from the

[6] Technically, offers and bids are submitted in pairs (up to ten pairs), providing an undo option for acceptance. For example, if the ESO has already accepted an offer, the corresponding bid price in this pair represents the price the ESO would need to pay to reverse the acceptance (Elexon, 2020).

[7] The P305 reform in 2015 shifted dual imbalance prices to a single imbalance price, with the purpose of providing more cost-reflective incentives and thereby improving overall system efficiency (Elexon, 2018).

[8] The detailed calculation of the imbalance price is set out in (Elexon, 2020). There are several minor adjustments made in the calculation of the imbalance price, but the results of this study should not be affected.

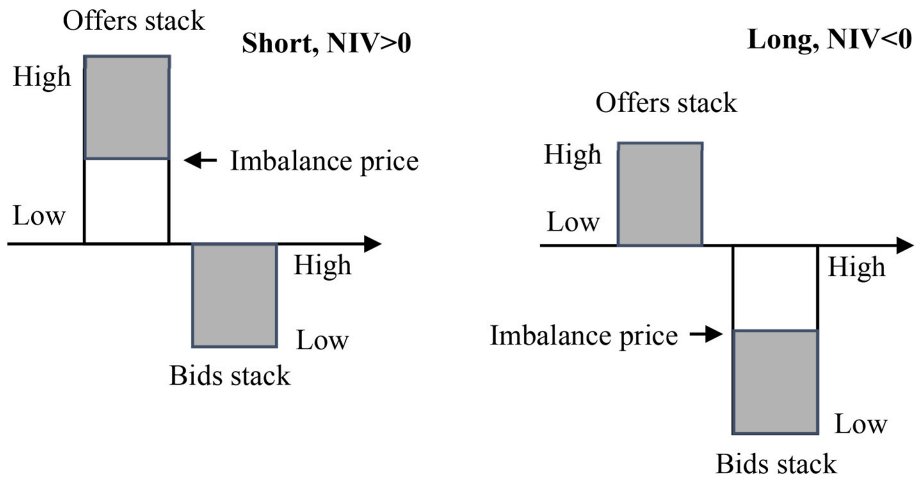

Fig. 2. The determination of the imbalance price via the netting process.

horizontal line, and continues until the smaller stack is fully netted by the far end of the larger stack. When one stack is fully netted, the volume of the remaining stack is referred to as the net imbalance volume, which serves as a measure of the overall system imbalance. If the stack of accepted offers remains, the net imbalance volume is positive, indicating that the system is short and the ESO has accepted more offers than bids to increase energy. In contrast, if the stack of accepted bids remains, the net imbalance volume is negative, indicating that the system is long and the ESO has accepted fewer offers than bids to remove energy.

The imbalance price is also determined in this process. When the system is short, the imbalance price is the price of the marginal accepted offer, i.e., the remaining accepted offer with the highest price. When the system is long, the imbalance price is the price of the marginal accepted bid, i.e., the remaining accepted bid with the lowest price. When the system is balanced, i.e., the net imbalance volume is zero, the imbalance price is set at the value of the wholesale price.

3.3.3. Imbalance charge and imbalance cashflow

The financial settlement proceeds after the imbalance price for each settlement period is determined, and the direction of payment depends on the final imbalance of each party.[9] If the party's final imbalance is in a short position, it makes a payment to the ESO to compensate for its shortage, referred to as the imbalance charge. In contrast, if the party's final imbalance is in a long position, it receives payment from the ESO for its surplus, referred to as the imbalance cashflow.[10]

It is important to distinguish payments for actions taken in the balancing mechanism and payments for the imbalance after the balancing mechanism. First, the party receives the offer cashflow or pays the bid cashflow for their actions in the balancing mechanism on a pay-as-bid basis, without involving the imbalance price. Second, the party receives the imbalance cashflow or pays the imbalance charge based on its final imbalance and the imbalance price.

4. Data, methodology, and model specification

This section explains the data, methodology, and model specification used in the analysis of this study.

4.1. Data

This study analyses data from 1 January 2017 to 31 December 2023 at the half-hour frequency (i.e., settlement periods), collected from Elexon and the National Grid ESO. The imbalance price, as the variable of interest, is calculated from netting accepted offers and bids in the balancing mechanism, as explained in Section 3.3.2. For illustration, Fig. 3 depicts the monthly average imbalance price, which fluctuated around £40/MWh between 2017 and 2020 and then surged sharply in 2021 and 2022. Recent months, up to 2024, show a decline in the imbalance price. As suggested by Elexon (2020), the imbalance price reflects the costs of balancing services, and its movement mirrors the costs of balancing services depicted in Fig. 1.

The net imbalance volume, which is the remaining volume after netting accepted offers and bids in the balancing mechanism, can be considered the demand-side factor affecting the imbalance price. For each settlement period, the system can be categorised into two states depending on the sign of the net imbalance volume. Fig. 4 depicts the relationship between the imbalance price and the net imbalance volume, showing distinct patterns between short and long states.

The de-rated (capacity) margin, which is defined as the anticipated surplus of generation capacity over demand, can be regarded as the supply-side factor affecting the imbalance price (Ofgem, 2011). For each settlement t, the de-rated margin, drm, is written as

$$drm_t = TC_t + w_t^f - d_t^f \tag{4}$$

where TC_t is the capacity of convention fuel generation, w_t^f is the forecasted wind generation, and d_t^f is forecasted demand.[11] To make the de-rated margin more relevant to the balancing mechanism and more accurately measure the tightness of the real-time market, forecasted values are replaced with actual values,

$$drm_t^{rt} = TC_t + w_t - d_t \tag{5}$$

where drm_t^{rt} is real-time de-rated margin, w_t is the actual wind generation, and d_t is the actual demand. This more accurate measurement of the system tightness helps understand the decision-making in the balancing mechanism. In the analysis below, the term de-rated margin refers to this real-time version. In addition, the real-time de-rated

[9] Although it is uncommon, a negative imbalance price occurs when it is determined by the marginal bid with a negative price. This typically happens in scenarios of large excess supply and low demand. When the imbalance price is negative, the usual directions of cashflows and charges are reversed. In such cases, parties with long positions make payments to the ESO, while parties with short positions receive payments from the ESO.

[10] Both imbalance charge and imbalance cashflow are collectively termed cashflow on imbalance volumes.

[11] The detailed calculation of the de-rated margin is documented in Elexon (2019a).

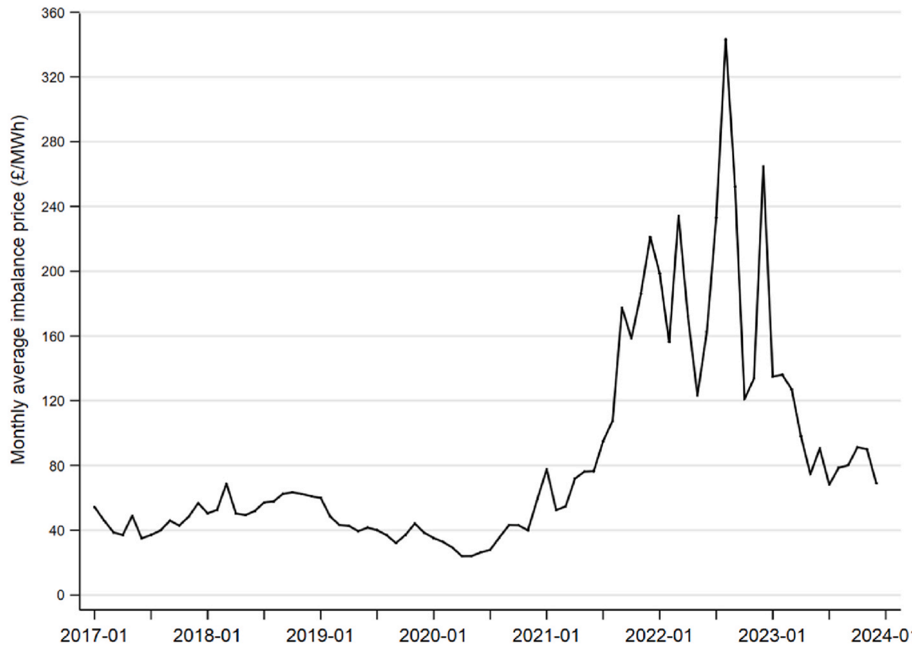

Fig. 3. Monthly average imbalance price (£/MWh) from January 2017 to December 2023.
Source: Authors' own calculations based on data from Elexon.

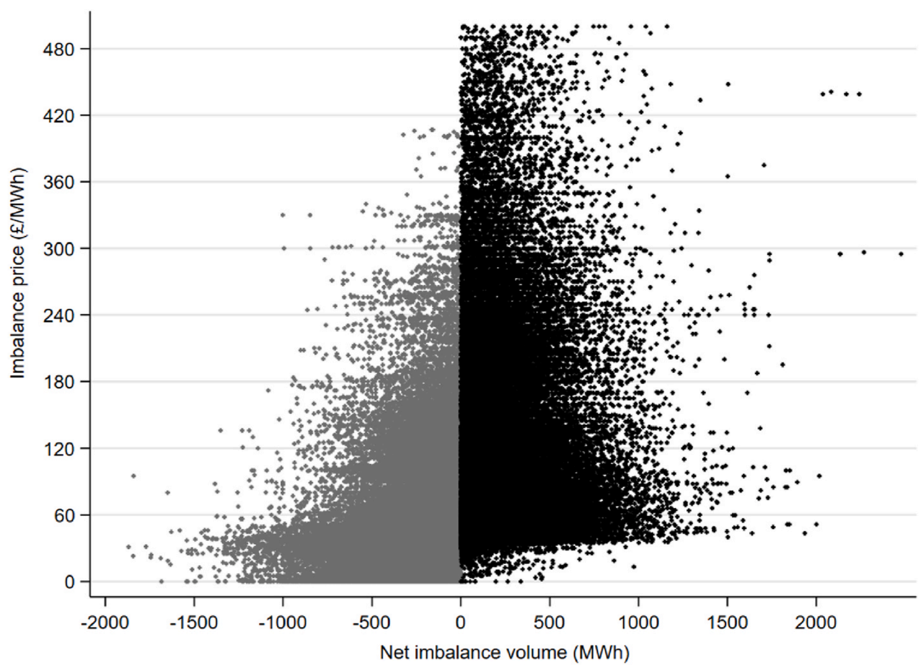

Fig. 4. Imbalance price (£/MWh) against net imbalance volume (MWh) from January 2017 to December 2023.
Source: Authors' own calculation based on the data from Elexon.

margin can be written as

$$drm_t^{rt} = drm_t + \left(w_t - w_t^f\right) - \left(d_t - d_t^f\right) \tag{6}$$

which shows that the real-time de-rated margin is adjusted by forecast errors in wind and demand.

Another explanatory variable is the wholesale electricity price, which is measured by the market index price at half-hour intervals from the intraday market operating prior to the balancing mechanism.[12] The wholesale price is relevant to the imbalance price for two reasons. First, in computing the imbalance price, the wholesale price is set as the default value for the imbalance price when the net imbalance volume is

[12] The intraday market is mainly facilitated by power exchanges to allow continuous trading within 24-h intervals before the gate closure. The continuous intraday market operates on a pay-as-bid basis, and the market price index is the weighted average from intraday trading on products of various lengths (Elexon, 2019b).

Table 1
Descriptive statistics of variables for the full sample, the short state, and the long state.

Variable	Mean	Std. Dev.	Min	Max
Short state (n = 49,751)				
Imbalance price (£/MWh)	113.19	74.30	35.75	415.00
Net imbalance volume (MWh)	228.91	176.50	7.67	814.66
De-rated margin (MW)	9681.90	5334.67	−181.24	22,351.21
Wholesale price (£/MWh)	88.84	61.95	23.53	345.20
Long state (n = 54,785)				
Imbalance price (£/MWh)	45.51	33.78	−7.07	188.00
Net imbalance volume (MWh)	−251.41	189.06	−853.44	−8.70
De-rated margin (MW)	10,897.57	5805.98	109.04	23,576.17
Wholesale price (£/MWh)	65.95	45.51	5.24	274.62

Source: Elexon, National Grid ESO.

zero, so parties may consider the wholesale price as a reference point when submitting offers and bids in the balancing mechanism. Second, the wholesale price is collected from the intraday market prior to the balancing mechanism, so the market condition may persist across these two adjacent markets.

The descriptive statistics are summarised in Table 1 for the short state (needs more energy) and the long state (needs to remove energy).[13] The short and long states are considered separately for two reasons. First, comparing the two subsamples, the imbalance price shows different patterns as depicted in Fig. 4, tending to be higher in the short state compared to the long state, possibly because marginal costs of generation increase when reaching full capacity. Second, the opposite signs of the net imbalance volume indicate distinct conditions between the short and long states. A higher value in the short state implies that the system requires more energy, whereas a higher value in the long state indicates that a greater surplus of energy needs to be removed.

4.2. Methodology

Given the non-linear relationships and complex interactions, the Generalised Additive Model (GAM) has been utilised in various studies focusing on electricity prices (Serinaldi, 2011; Nazifi, 2016; Bernardi and Lisi, 2020; Narajewski and Ziel, 2020; Soini, 2021), electricity consumption (Gaillard et al., 2016; Amato et al., 2021), and wider issues related to energy and environment (Pitt et al., 2020; Hua et al., 2021; Pourkhanali et al., 2024).

Developed by Hastie and Tibshirani (1986), the Generalised Additive Model (GAM) is a generalised linear model in which the dependent variable depends linearly on unknown smooth functions of independent variables in an interpretable additive form, expressed as

$$g(y) = \beta_0 + f_1(x_1) + f_2(x_2) + f_3(x_3) + \ldots + f_m(x_m) \tag{7}$$

where g is the link function and β_0 is the intercept. The smooth functions of each independent variable, $f_i(x_i)$, are estimated by non-parametric methods. This structure allows GAMs to model non-linear relationships between dependent and independent variables while retaining the interpretability of linear models.

Therefore, unlike linear models that presume a fixed relationship and risk oversimplification, GAMs employ smooth functions for each independent variable to effectively manage non-linear dependencies, intricate supply-demand dynamics, and varying market conditions. In the balancing markets, it has been suggested that non-linear relationships present as high prices are more likely to appear when demand or supply reaches the boundary (Mureddu and Meyer-Ortmanns, 2018; Soini, 2021). Therefore, this analysis employs the GAM due to its flexibility in exploring non-linear relationships in the balancing mechanism in the UK.

4.3. Model specification

In the analysis, the dependent variable is the imbalance price, p_t^{ib}, and the model specification is illustrated as

$$p_t^{ib} = \beta_0 + f_1(drm_t^{rt}) + f_2(niv_t) + f_3(p_t^{w}) + \gamma D_t + \varepsilon_t \tag{8}$$

where t represents half-hourly intervals, niv_t is the net imbalance volume indicating the demand-side effect, drm_t^{rt} is the real-time de-rated margin measuring the supply-side effect, p_t^{w} is the wholesale electricity prices capturing the dynamics of the intraday market, D_t is a vector of time dummies including three quarter-dummies, and ε_t is the error term.

However, the issue of multicollinearity may arise between the de-rated margin and the wholesale price because the former partially measures the tightness of the intraday market and thus affects the latter. Therefore, to address the issue of multicollinearity, the partialling out technique is used to allow for a more accurate estimation of their relationships with the imbalance price. The partialling out technique first estimates the relationship between the wholesale price and the de-rated margin as

$$p_t^{w} = \beta_0 + f_1(drm_t^{rt}) + \varepsilon_t \tag{9}$$

After the estimation, the fitted value is written as

$$\widehat{p}_t^{w} = \widehat{\beta}_0 + \widehat{f}_1(drm_t^{rt}) \tag{10}$$

The residual $\widehat{\varepsilon}_t$ measures the deviation between the actual value and the fitted value, indicating the variation of the wholesale price caused by all factors except the de-rated margin. Then the revised wholesale price is written as

$$p_t^{rw} = \widehat{\beta}_0 + \widehat{\varepsilon}_t = p_t^{w} - \widehat{f}_1(drm_t^{rt}) \tag{11}$$

which reflects the level of the wholesale price after removing the estimated impact from the de-rated margin.

Therefore, in the model specification, this revised version is considered to be the wholesale price. This approach isolates the impact of the wholesale price on the imbalance price from the influence of the de-rated margin, and provides a more accurate representation of the impact of both on the imbalance price,

$$p_t^{ib} = \beta_0 + f_1(drm_t^{rt}) + f_2(niv_t) + f_3(p_t^{rw}) + \gamma D_t + \varepsilon_t \tag{12}$$

which is the specification for the analysis and will be estimated for the short and long states, respectively.

5. Empirical results

The results of the GAM analysis based on Eq. (12) are presented for the short and long states, respectively. In the analysis, the constant and time dummies are treated parametrically, indicating linear relationships with the dependent variable.

5.1. The short state

Table 2 shows the estimation results for the short state, where more energy is needed. The intercept term represents the average imbalance price in the short state since the normalisation of the methodology ensures that the effects of independent variables have a mean equal to zero. The approximate significance of smooth terms evaluates the relevance of each variable in affecting the dependent variable in the model. The *edf* stands for effective degrees of freedom, which represents the complexity

[13] While other studies use a daily hourly average to remove excessive noise (Gelabert et al., 2011; Clò et al., 2015; Shao et al., 2022), the top and bottom 2.5% of the imbalance price are excluded to mitigate the problem of outliers with extreme values.

Table 2
Results from the Generalised Additive Model for the short state.

Parametric coefficients			
	Estimate	Std. Error	p-value
Intercept	134.20	0.41	0.0000***
Approximate significance of smooth terms:			
	edf	F-statistics	p-value
De-rated margin	6.81	768.45	0.0000***
Net imbalance volume	4.42	28.12	0.0000***
Wholesale price	9.70	15,704.02	0.0000***
Other statistics			
R-sq.(adj)	0.92	Deviance explained	92.20%
-REML	221,500	Scale estimate	430.59
Observations	49,751		

of the smooth term.[14] The F-statistics and associated p-values indicate that the impacts of all three independent variables on the imbalance price are statistically significant at the 1% level, and they should not be excluded from the specification.

Among other statistics, the value of the adjusted R-square suggests that the model explains 92.2% of the variation in the imbalance price in the short state, highlighting the model's explanatory power. The REML score strikes the best balance between data explanation and complexity, and a smaller score is typically preferred. The scale estimate represents the standard deviation of the residuals, and a lower scale estimate is desirable as it implies smaller average residuals, indicating a closer alignment of the model predictions with the observed data. As such, the REML scores and the scale estimate suggest that the specification in Eq. (12) has a better fit than specifications excluding any one of the independent variables.

The relationships between independent variables and the imbalance price are depicted as the partial effect plots in Fig. 5 for the short state. The X-axis represents the values of the independent variable, and the Y-axis represents the estimated partial effect of the independent variable on the dependent variable after accounting for the effect of the other independent variables. The solid line represents the estimated effect and the dashed line represents the 95% confidence intervals surrounding the estimated effect. An upward-sloping (downward-sloping) curve indicates a positive (negative) relationship between two variables.

First, the net imbalance volume has a positive impact on the imbalance price. In the short state, a positive net imbalance volume indicates that the volume of accepted offers exceeds the volume of accepted bids. The net imbalance volume increases when more offers are accepted and/or fewer bids are accepted, so the volume of remaining accepted offers is larger, leading to a higher imbalance price. This positive impact of the net imbalance volume aligns with expectations, as the imbalance price should rise when there is greater demand for additional energy to balance the system.

Second, the de-rated margin has a negative impact on the imbalance price. In the short state which needs more energy, a higher de-rated margin indicates more spare generators and thus stronger competition among them to increase energy, so they are incentivised to submit lower prices in their offers (paid by the ESO) and leads to a lower imbalance price. This negative impact from the de-rated margin also aligns with expectations, as the imbalance price should be higher when the system is in a tighter condition due to less available capacity. In addition, as Eq. (6) suggests, the de-rated margin considered in this study reflects the real-time market conditions, including the impacts of forecast errors. For instance, under negative wind forecast errors (actual volumes being less than expected) or positive demand forecast errors (actual volumes being greater than expected), the de-rated margin is reduced, and this consequently drives up the imbalance price.

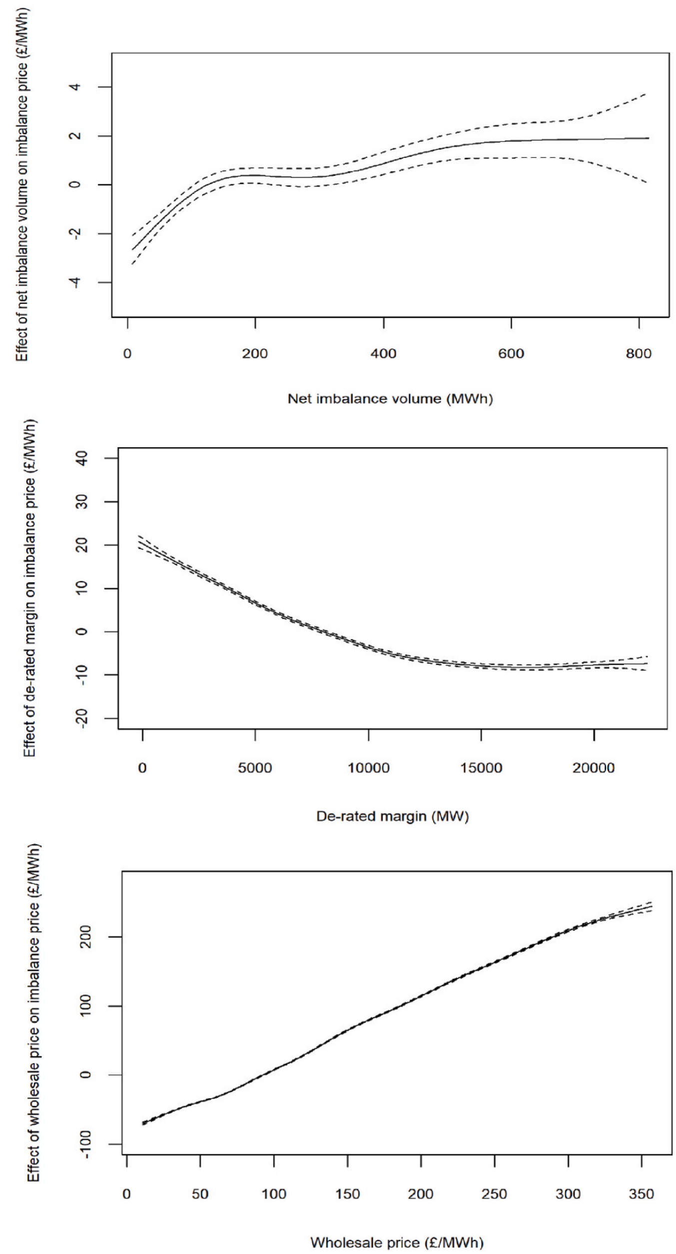

Fig. 5. Non-parametric estimation for the short state.[115].

Third, there is a positive relationship between the wholesale price and the imbalance price because (i) the former is used as the reference point for the latter and (ii) these prices reflect supply and demand conditions of two adjacent markets, i.e., the wholesale price reflects the market condition up to gate closure and the imbalance price reflects the market condition from gate closure to real-time.

5.2. *The long state*

Table 3 shows the estimation results for the long state, where energy needs to be removed. The approximate significance of smooth terms indicates that all the independent variables have statistically significant impacts on the imbalance price at the 1% significance level. Additionally, the adjusted R-square value suggests that the model explains 77.8% of the variation in the imbalance price, and the combination of the REML scores and the scale estimate metrics demonstrates the model's

[14] For example, an edf of one indicates a straight line, while higher edf values describe more complex relationships.

Table 3
Results of the Generalised Additive Model for the long state.

Parametric coefficients			
	Estimate	Std. Error	p-value
Intercept	40.63	0.29	0.0000***
Approximate significance of smooth terms:	edf	F-statistics	p-value
De-rated margin	8.99	210	0.0000***
Net imbalance volume	1.04	129.10	0.0000***
Wholesale price	9.25	6618.10	0.0000***
Other statistics			
R-sq.(adj)	0.78	Deviance explained	77.80%
-REML	229,350	Scale estimate	253.1
Observations	54,785		

adequacy in capturing the dynamics of the imbalance price.

The partial effect plots for the long state are provided in Fig. 6. First, the positive impact of the net imbalance volume on the imbalance price holds, but the interpretation is different. The net imbalance volume is presented as negative values in the long state, indicating that the volume of accepted offers is less than that of accepted bids. The negative net imbalance volume decreases further when there are fewer accepted offers and/or more accepted bids, resulting in a larger volume of remaining accepted bids, leading to a lower imbalance price. Second, the negative impact of the de-rated margin on the imbalance price also holds in the long state, where energy needs to be removed. A higher de-rated margin indicates fewer operational generators and thus weaker competition among them to reduce generation, which incentivises them to submit lower prices in their bids to reduce generation (pay to the ESO). These results resolve the puzzling positive relationship between these two variables detected in Soini (2021). Third, the positive relationship between the wholesale price and the imbalance price remains in the long state.

5.3. Residual analysis

Diagnostic checks are employed to ensure that well-fitted models are constructed, as shown in Figs. 7 and 8. The top-left panel presents a quantile-quantile plot, which compares the model residuals to a normal distribution. The model fits well across the domain but loses accuracy at the extremes due to outliers caused by extreme events. The top-right panel shows a histogram of residuals, which displays a roughly symmetrical bell shape, suggesting that the residuals are normally distributed. The slight deviations from the bell shape could be due to random variations, especially in cases where the sample size is large. The bottom-left panel presents a scatter plot of residuals against linear predictors, which should be randomly dispersed around zero. Upon observation, this cloud of points lacks a distinct pattern, indicating that the model is appropriate. Finally, the bottom-right panel shows the plot comparing the model's responses (i.e., observed dependent values) versus the fitted (predicted) values. This cloud of points approximately forms a diagonal line, indicating that the model almost captures all the systematic changes in the data.

6. Discussion

This section explores the drivers behind the rising imbalance price during 2021–2022. Additionally, it compares the results of this study with previous research to highlight the contributions made by this analysis.

6.1. Investigating the sub-period with high and volatile imbalance price

The estimated results from the GAM analysis show that all three independent variables have statistically significant impacts on the imbalance price over the sample period from January 2017 to December 2023. However, due to concerns about the increasing costs of balancing services and imbalance price in 2021 and 2022, the sample is divided into three sub-periods: 2017–2020, 2021–2022, and 2023 to facilitate further investigation.

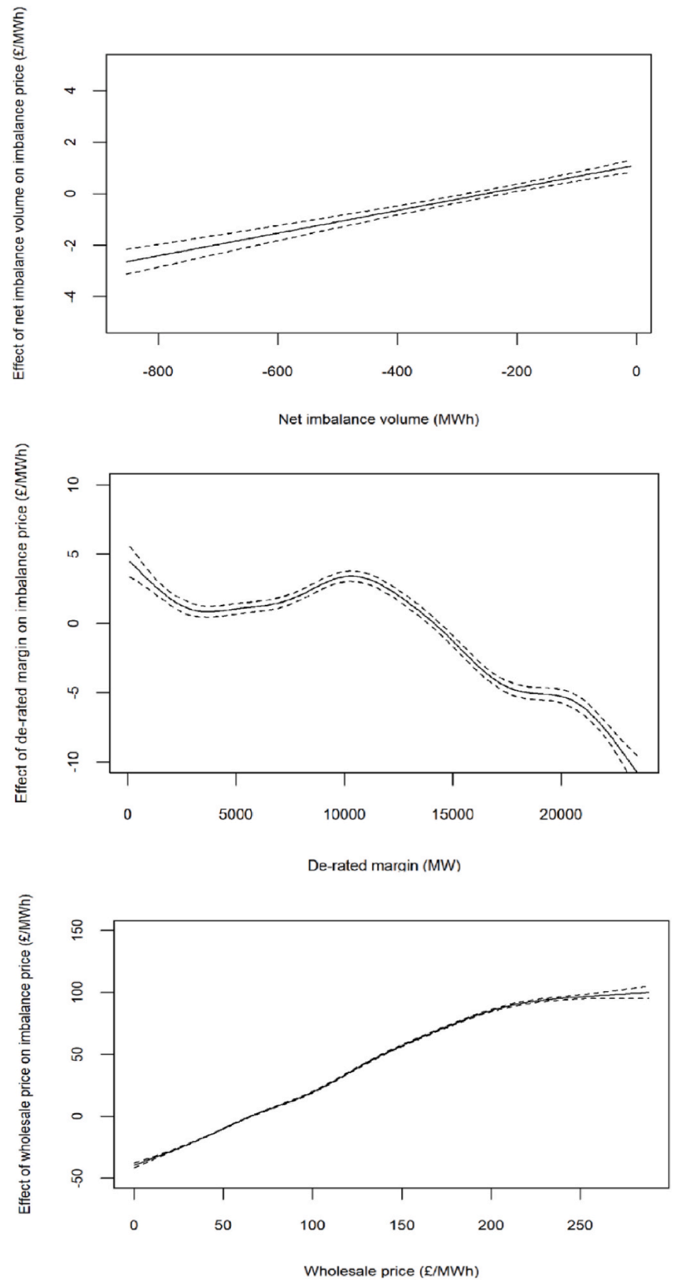

Fig. 6. Non-parametric estimation for the long state.

Table 4 summarises the statistics across the three sub-periods. First, compared to 2017-20, the imbalance price in both short and long states shows a higher mean in 2021–2022. For example, in the short state, the mean increased from £64.97/MWh in 2017–2020 to £179.98/MWh in 2021–2022. Meanwhile, for comparison, the coefficient of variation (the ratio of the standard deviation to the mean) increased from 0.349 in 2017–2020 to 0.469 in 2021–2022. This suggests that, in the short state, the imbalance price exhibits higher volatility during 2021–2022. The same pattern applies to the long state, in which the latter sub-period shows higher mean and volatility than the first sub-period. Second, the mean and volatility of the imbalance price began to decline in 2023 but remained higher than the first sub-period of 2017–2020 in both

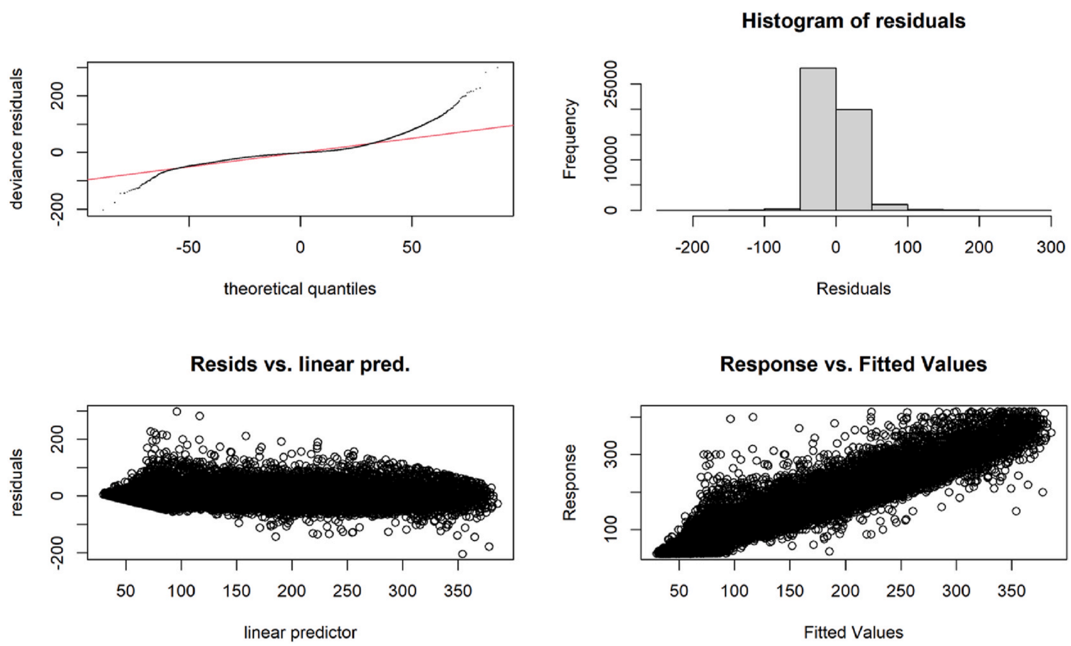

Fig. 7. Model fit for the short state.

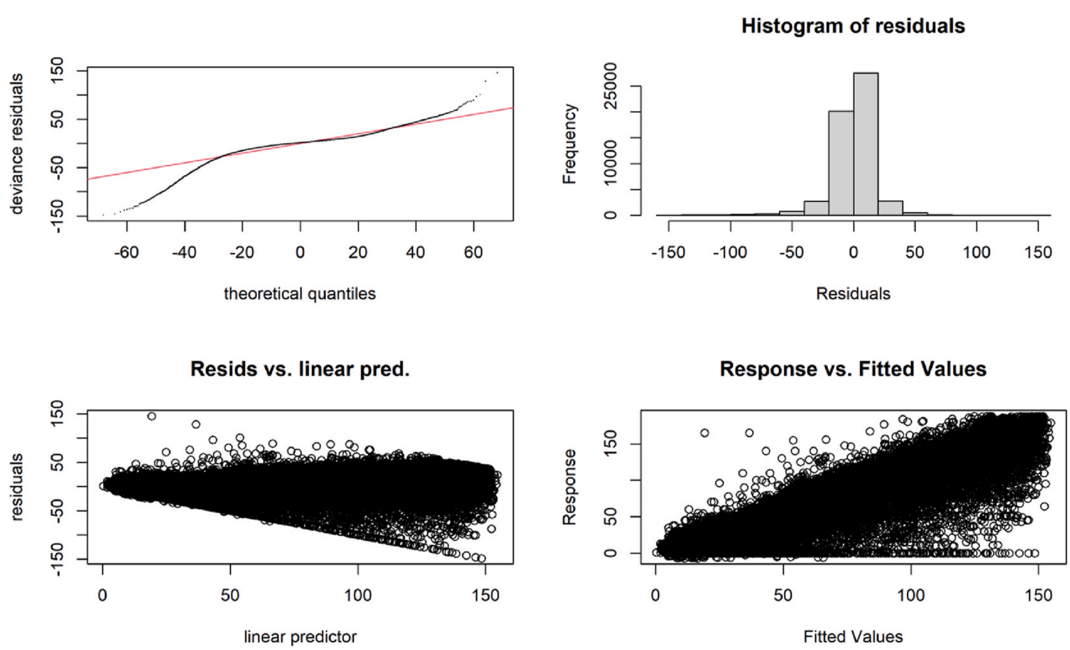

Fig. 8. Model fit for the long state.

short and long states. For example, in 2023, the mean of the imbalance price declined to £142.17/MWh in the short state. Third, among the independent variables, the wholesale price followed a similar pattern to the imbalance price, while the net imbalance volume and the de-rated margin changed slightly across the three sub-periods.

6.1.1. *Higher mean*

This subsection investigates the causes of higher means in 2021–2022 using the predicted (fitted) values from the GAM analysis. First, the values at five different percentiles are identified for the three independent variables across three sub-periods in both short and long states. Second, using the results from the GAM analysis, the predicted imbalance price is calculated for each percentile of an independent variable respectively while keeping the other independent variables at their mean values.

Fig. 9 illustrates the predicted imbalance price at different percentiles of the three independent variables in the three sub-periods based on the GAM results for the short state. Across the sub-periods, the predicted imbalance price increases marginally when the net imbalance volume increases from the 5th percentile to the 95th percentile, but falls moderately when the de-rated margin increases from the 5th percentile to the 95th percentile. In contrast, the predicted imbalance price changes markedly when the wholesale price increases from the 5th percentile to the 95th percentile across all three sub-periods, especially in the sub-period during 2021–2022. For example, in the sub-period of 2021–2022, the predicted imbalance price is £235.27/MWh when the wholesale price is at its 75th percentile in the short state. In contrast, the predicted imbalance price is £111.79/MWh when the net imbalance

Table 4
Descriptive statistics of variables for 2017–2020, 2021–2022, and 2023 in the short and long states.

	Short state											
	2017–2020 (n = 26,346)				2021–2022 (n = 15,659)				2023 (n = 7746)			
Variable	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max
Imbalance price (£/MWh)	64.97	22.67	35.75	412.46	179.98	84.48	40.26	415.00	142.17	38.97	39.57	370.00
Net imbalance volume (MWh)	232.98	178.92	8.05	814.66	232.55	176.19	8.05	814.44	207.68	167.08	7.67	806.45
De-rated margin (MW)	9720.62	5372.36	−181.24	22,349.67	9480.77	5383.54	−178.56	22,351.21	9956.79	5086.43	−19.37	22,228.15
Wholesale price (£/MWh)	48.93	15.06	23.53	284.80	145.65	71.67	23.61	345.20	109.72	33.39	24.27	264.65
	Long state											
	2017–2020 (n = 34,638)				2021–2022 (n = 12,544)				2023 (n = 7603)			
Variable	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max
Imbalance price (£/MWh)	30.53	12.86	0.00	88.73	78.69	47.41	0.00	188.00	59.01	27.20	−7.07	150.00
Net imbalance volume (MWh)	−266.59	194.32	−853.44	−9.18	−229.04	177.70	−851.98	−9.18	−219.16	174.75	−841.48	−8.70
De-rated margin (MW)	10,919.05	5879.44	109.04	23,563.61	10,667.22	5728.66	112.34	23,554.55	11,179.75	5577.55	178.57	23,576.17
Wholesale price (£/MWh)	42.73	14.63	9.79	272.79	117.15	58.83	9.82	274.62	87.26	31.65	5.24	234.28

volume is at its 75th percentile, and £120.30/MWh when the de-rated margin is at its 25th percentile (due to the negative relationship).

Therefore, across the sub-periods, while both net imbalance volume and de-rated margin were limited in explaining the increased imbalance price, the wholesale price plays a significant role, particularly during the sub-period 2021–2022. A similar conclusion can also be drawn for the long state, as shown in Fig. 10.

6.1.2. Higher volatility

Next, this subsection analyses the causes of the higher volatility in the imbalance price during 2021–2022 using incremental goodness of fit (incremental R^2) analysis. When an independent variable is the last one included in the regression model, the improvement in goodness of fit is attributable solely to this variable after accounting for the others. Therefore, the independent variables that result in the largest increases in R^2 are the main contributors to the higher volatility. The GAM analysis is conducted for both short and long states across the sub-periods 2017–2020, 2021–2022, and 2023. Then, the incremental R^2 of each independent variable is calculated when it is added to the specification after the other two variables.

Fig. 11 shows the incremental goodness of fit contributed by each independent variable. In the short state, the contribution from the net imbalance volume remained small in both periods, while the contribution of the de-rated margin was 10.6% in 2017–2020 and then declined to 1.4% in 2021–2022. In contrast, the wholesale price explained 44.7% of the variation in the imbalance price in 2017–2020, increasing to 87.5% in 2021–2022, and then dropping to 64.5% in 2023. Therefore, regarding the higher volatility that the imbalance price exhibited in 2021–2022, the wholesale price had the strongest explanatory power for this increased volatility. A similar conclusion can be drawn for the long state, where the wholesale price contributed 56.8%, 66.2%, and 46.6% to the variation in the imbalance price across the three periods, respectively.

6.2. Comparative studies

This study investigates the drivers of the imbalance price in the UK balancing mechanism, particularly during the sharp increases in 2021–2022. This section compares the findings of this study with previous UK-focused research on balancing costs and system dynamics, highlighting both similarities and unique contributions.

Early studies (Dale et al., 2004; Gross et al., 2006; Strbac et al., 2007)

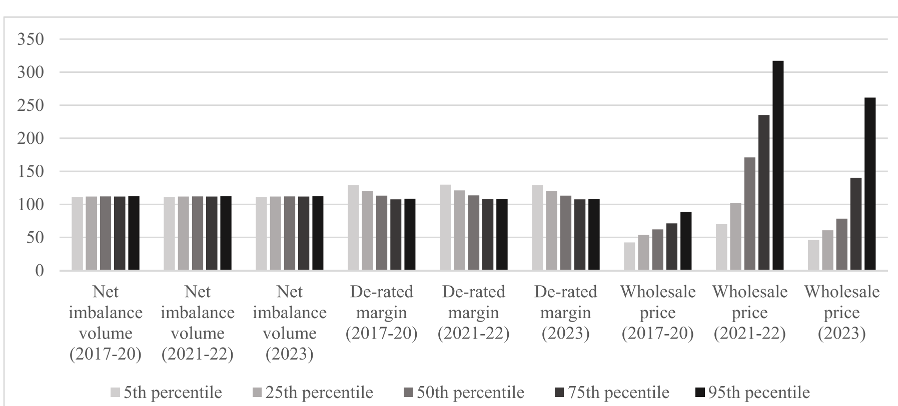

Fig. 9. Predicted imbalance price (£/MWh) based on percentiles of each independent variable in the short state, with other variables held constant at their mean values.

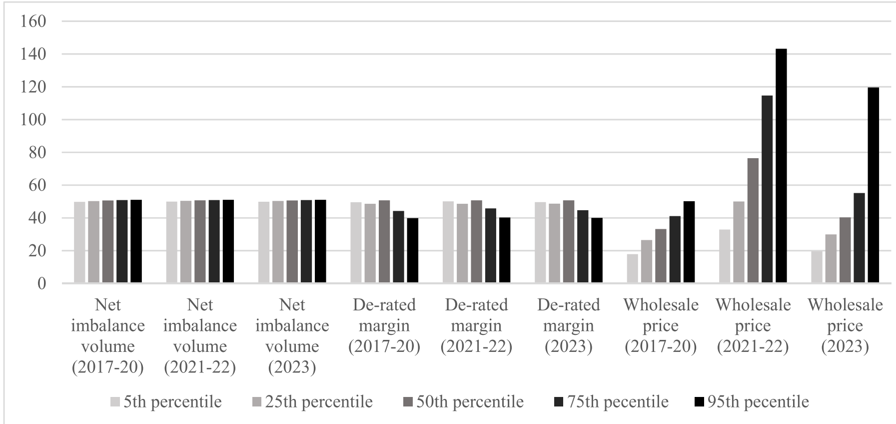

Fig. 10. Predicted imbalance price (£/MWh) based on percentiles of each independent variable in the long state, with other variables held constant at their mean values.

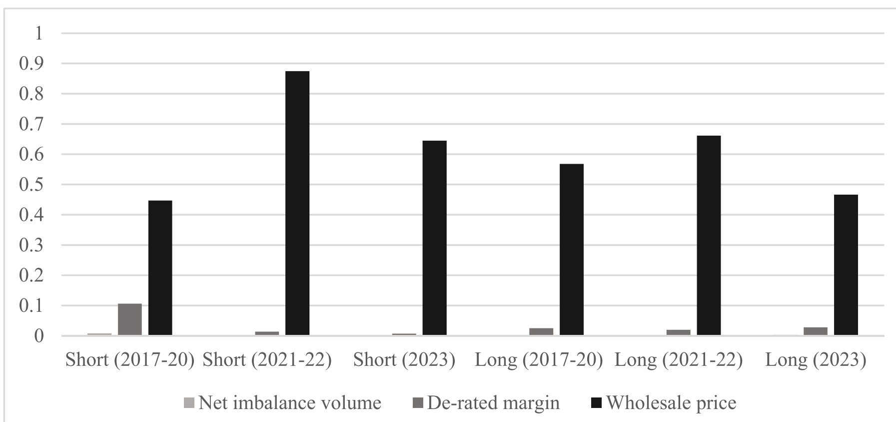

Fig. 11. Incremental goodness of fit by three independent variables.

predicted that increasing renewable energy integration would lead to higher balancing costs due to intermittency. Later empirical studies have explored the drivers of the imbalance price. Swinand and Godel (2012) found the positive impact of wind generation on the imbalance price, while a negative relationship between the wholesale price and the imbalance price was found but not explained, using data from 2008 to 2011. Lucas et al. (2020) identified wholesale electricity prices as one driver of the imbalance price in the period of 2019, but not as important as other variables such as net imbalance volume and de-rated margin. Bunn et al. (2021) confirmed the importance of system net imbalance volume and de-rated margin based on data from 2016 to 2019.

Compared with previous analyses, this study confirms the role of imbalance volume and de-rated margin; however, there are differences. First, early studies did not account for the extreme price volatility observed in 2021–2022. This study provides updated insights, showing that wholesale prices were the dominant factor behind the imbalance price surge during this period, contributing over 70% to the variation in the imbalance price, significantly more than the net imbalance volume and de-rated margin. These contributions are vital for informing future research and policy aimed at stabilising the imbalance price in the evolving energy market. Second, early studies did not explore the non-linear relationships between key variables in balancing markets. Bunn et al. (2021) used a non-linear Markov Switching model to capture different states, but it was linear in each state (i.e., the short and long states). By using a Generalised Additive Model (GAM), this analysis captures the non-linear impacts of net imbalance volume, de-rated margin, and wholesale prices on the imbalance price in each state, particularly during extreme market conditions. The estimated results confirm the existence of a non-linear relationship for each state. This provides a more detailed and accurate understanding of price formation in the balancing mechanism compared to previous linear models.

7. Conclusion

The increased electricity from renewable energy sources has posed challenges to the stability of the electricity system, and the costs of balancing services have increased sharply in recent years. Based on half-hourly data from January 2017 to December 2023, this study examined factors determining the imbalance price in the balancing mechanism, where the Electricity System Operator (ESO) balances the system through bid-offer acceptance. First, the demand-side factor is measured by the net imbalance volume, which is the remaining volume after netting accepted offers and bids in the balancing mechanism. Second, the supply-side factor is measured by the de-rated capacity margin, which is defined as the surplus of generation capacity over demand. Third, the wholesale price from the intraday trading market prior to the balancing mechanism is also considered as it is used in the computation of the imbalance price.

The system can be categorised into two states based on the sign of the net imbalance volume. First, the system is in a short state when it needs more energy, i.e., the net imbalance volume is positive. Second, the system is in a long state when it needs to remove energy, i.e., the net imbalance volume is negative. Due to different market conditions, the model specification was estimated for these two states, respectively.

This study employed the Generalised Additive Model (GAM) to capture non-linear relationships among variables in the model specification.

In the short state, the results indicated that (i) a higher net imbalance volume leads to a higher imbalance price because a higher volume of remaining accepted offers results in a marginal accepted offer with a higher price, and (ii) a higher de-rated margin leads to a lower imbalance price because stronger competition among standby parties incentivises them to submit lower prices in their offers (paid by the ESO) to increase generation. In contrast, in the long state, the results showed that (i) a higher net imbalance volume (a larger negative value) leads to a lower imbalance price because a higher volume of remaining accepted bids results in a marginal accepted bid with a lower price, (ii) a higher de-rated margin leads to a lower imbalance price because weaker competition among operating parties incentivises them to submit lower prices in their bids (pay to the ESO) to reduce generation. In addition, a positive relationship was identified between the wholesale price and the imbalance price in both short and long states, indicating a strong connection between these two prices from two adjacent markets.

Further, regarding the rising imbalance price in 2021–22, this study calculated the predicted imbalance prices based on different percentiles of independent variables and found that the predicted imbalance price responded dramatically when the wholesale price moved between percentiles. For example, in the sub-period of 2021–2022, the predicted imbalance price was £235.27/MWh when the wholesale price was at its 75th percentile. Moreover, the study also examined the higher volatility of the imbalance price using incremental goodness of fit and found that the wholesale price brought the largest increase in the goodness of fit when it was the last variable included in the specification. For example, for the sub-period of 2021–2022, in the short state, the wholesale price explained 87.5% of the variation in the imbalance price, much higher than the net imbalance volume and the de-rate margin. Therefore, the analysis suggest that the wholesale price was largely responsible for the higher mean and volatility of the imbalance price in 2021–22.

The results of this study highlight policy considerations for balancing services. First, the sharp increase in the imbalance price observed in 2021–2022 was primarily driven by rising wholesale electricity prices rather than dysfunctions in the balancing mechanism. Policymakers could reduce the volatility of wholesale prices by diversifying energy supply sources to reduce dependency on volatile fossil fuel markets and encouraging greater participation in electricity trading to improve liquidity and reduce the price effects of supply-demand mismatches. Policymakers might also consider alternatives to reduce the impact of wholesale price fluctuations on imbalance prices, such as decoupling imbalance prices from wholesale prices to reduce volatility pass-through, although this may create arbitrage opportunities. Alternatively, policymakers could introduce caps on imbalance prices to avoid extreme price spikes, but this might dampen market signals for flexibility and reduce incentives for participants to balance their portfolios efficiently.

Second, regarding the imbalance volume (demand-side), the challenges of intermittency will persist as the UK continues to increase its share of renewable energy. Policymakers must continue to support innovations in renewable forecasting and grid management. More accurate renewable generation forecasts can help reduce forecast errors and thus lower the need for balancing actions. As more renewable energy comes online, investments in grid infrastructure will be essential to manage larger flows of electricity and reduce constraint payments in the balancing services.

Third, the study identifies the de-rated margin (supply-side) as another factor influencing imbalance prices. One way is to increase flexibility in the energy system through expanding the role of battery storage and other flexible technologies. Also, demand-side response programs, which incentivise industrial and domestic consumers to adjust their electricity usage in response to grid needs, can further enhance system flexibility.

Finally, regulators need to closely monitor the drivers of these costs to ensure that consumers are not disproportionately burdened. The costs of balancing services should be passed through to consumers in a fair and transparent manner. This could involve increased regulatory scrutiny of cost allocation mechanisms to protect consumers from excessive price hikes. In particular, regulators need to ensure that parties causing the imbalance in the system (such as renewable generators) bear a proportionate share of the costs of balancing services, instead of shifting this burden to consumers.

The limitations of this study present opportunities for future research. First, this analysis focuses specifically on the balancing mechanism in the UK electricity sector. While this provides detailed insights into this market, the applicability of the results may differ across other countries due to variations in regulatory frameworks, market structures, and levels of renewable energy integration. Therefore, future cross-country comparative analyses could help validate the findings of this study and assess their relevance under different market conditions. Second, while this study captures non-linear relationships between imbalance prices and independent variables using aggregate data from the balancing mechanism, future research could explore disaggregated data and incorporate advanced machine learning techniques to better understand the behaviours and interactions of market participants.

CRediT authorship contribution statement

Huanhuan Chen: Writing – original draft, Formal analysis, Data curation, Conceptualization, Software. **Jinke Li:** Writing – review & editing, Investigation, Conceptualization, Writing – original draft. **Nigel O'Leary:** Supervision. **Jing Shao:** Writing – review & editing, Validation, Methodology.

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Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

Data will be made available on request.

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