Ofgem's response to balancing costs in winter 2024-25

Publication date: 27 November 2025

This document provides an update to market participants regarding our views about the high prices seen in the Balancing Mechanism earlier in the year and our analysis of the market impact of the Inflexible Offers Licence Condition since its adoption in 2023

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Executive summary

We introduced the Inflexible Offers Licence Condition (IOLC) in October 2023. This decision followed a sharp increase in balancing costs in winters 2021-22 and 2022-23, where certain thermal power plants were paid significant amounts in the Balancing Mechanism (BM) to continue generating after short-notice decisions to interrupt their supply ahead of the evening peak of demand. As thermal plants must stay idle for several hours after switching off, they were able to leverage system operator NESO's need to maintain capacity reserves later in the day, and extracted high prices in the BM even outside periods of true scarcity of supply.

We have evaluated the impact that the IOLC has had since its introduction in 2023 and whether the current rules are fit for purpose going forward. Our analysis of the effects of the IOLC on the market showed that it has been effective in moderating the BM prices offered by power plants that decide at short notice not to produce electricity during the evening peak on tight-margin days. In addition to this, we did not find a clear trend of units opting more often not to generate on tight-margin days at the day-ahead stage in response to the introduction of the IOLC. However, the analysis returned mixed results about the BM prices inflexible plants offer when entering a tight-margin day without a plan to generate, with instances of very high prices appearing in November 2023, December 2024 and January 2025 after the implementation of the IOLC.

One such occurrence was 8 January 2025, when some gas-fired power plants achieved some of the highest BM offer prices for inflexible assets seen in the sample of the analysis. Our review of the events showed that these prices did not violate the IOLC, as the units communicated their plans not to generate to NESO before the start of the operational day. Nevertheless, we consider some of the prices in question to have been extremely high, and note the limited options available to NESO despite the schedules for these units being submitted ahead of the operational day.

When we introduced the IOLC, we said we were aware that thermal units which decide not to generate before the start of the operational day could still use their inflexibility in a way that leads to high balancing costs. We therefore committed to monitor market behaviour post implementation.

We remain closely focused on whether these market rules are achieving the best possible results for the system and ultimately consumers. We will continue to monitor how day-ahead scheduling and pricing strategies develop to assess whether trends of concern for consumers are emerging. If we see continuing evidence of high prices exacerbating periods of scarcity and adding to consumer costs, we will consider further intervention.

We will continue to work closely with the Department for Energy Security and Net Zero to ensure market arrangements support government's net-zero goals, whilst also balancing cost to consumers and ensuring security of supply.

1. Introduction

1.1 The Balancing Mechanism (BM) is a core part of the electricity market in Great Britain. It is operated by electricity system operator NESO, which uses it to adjust generation or demand to maintain system frequency and ensure real-time balance between supply and demand. These adjustments take the form of NESO accepting offers to increase, or bids to decrease, output submitted by electricity generators, storage providers and other participants to the BM.

1.2 The costs NESO incurs to balance our power system depend on the price that BM participants attach to their BM bids and offers, and on the total volume of corrective actions that NESO takes. In terms of prices, the most notable driver over the past few years has been higher wholesale electricity prices.[1] With regard to the quantity of BM actions, the volume of bids and offers activated by NESO increased by 17% to 33TWh in 2024-25, up from 28TWh in 2023-24. The leading factor behind this increase was grid congestions caused by thermal constraints. These are driven by a mismatch between the amount of renewable generation available at some times and the rate of expansion of the grid infrastructure, as well as by renewables' intermittent nature.

1.3 As a result of the price and volume dynamics, BM costs have been increasing considerably in recent years (Figure 1). This is a major component of the £2.7 billion spent by NESO in 2024-25 to balance Great Britain's power system, which contributed 3.5% to electricity bills in 2024-25 for the average domestic consumer, or around £30 per year.[2] There are several actions being progressed to manage the rise in balancing costs, including accelerating transmission grid upgrades, government's Reformed National Pricing programme and locational planning reforms.[3]

1.4 During the winter of 2024-25, we noticed one particularly costly day on 8 January 2025. This was the fifth most expensive BM day in the 2024-25 financial year at a total cost of £20 million, £19 million of which was spent by NESO on three gas-fired power plants. Unlike other equally or more expensive BM days over the same period, 8 January 2025 was not mainly characterised by the presence of thermal constraints but rather by tight supply margins.

[1] The average day-ahead wholesale electricity price increased by 5% in 2024-25 compared with 2023-24. However, this was 24% below the five-year rolling average, which was lifted by the record prices seen during the 2021-22 energy crisis.
[2] Balancing costs | National Energy System Operator
[3] Review of electricity market arrangements (REMA): Summer update, 2025 (accessible webpage) - GOV.UK

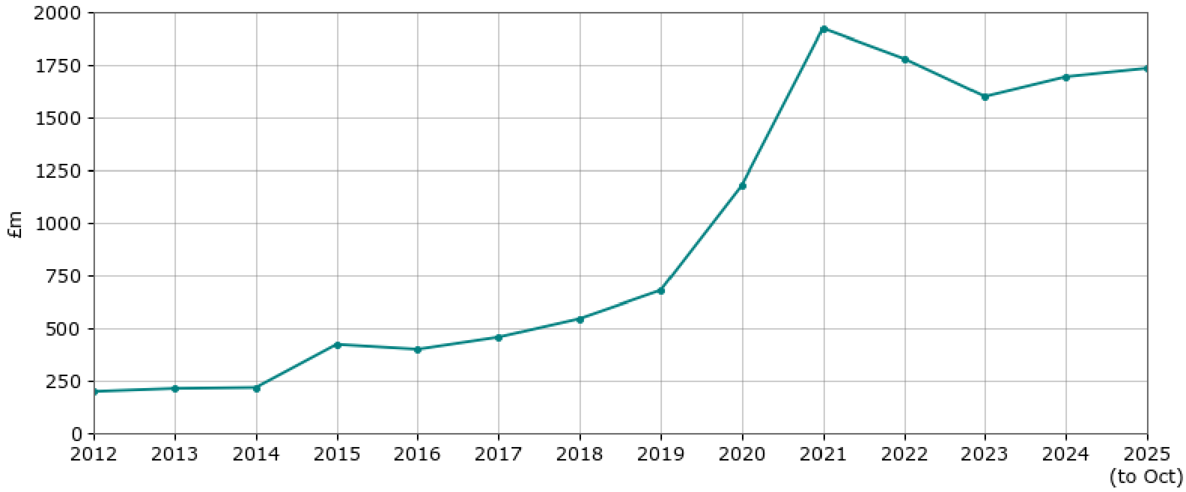

Figure 1 – Net cost of bids and offers accepted by NESO in the Balancing Mechanism, including Balancing Services Adjustment Data actions. (Source: Ofgem from BMRS data)

1.5 We have reviewed the events of 8 January as part of our regular market monitoring activity. The Secretary of State for Energy Security and Net Zero also wrote to us in August 2025 requesting we explore options to limit market power and excessive profits in the BM, and ensure that the existing market rules, particularly the Inflexible Offers Licence Condition, are fit for purpose.

1.6 This document provides an update to market participants regarding our views about the high prices seen in the BM on 8 January 2025 and our current thinking on next steps.

2. 8 January 2025: summary of events

2.1 The weather on 8 January 2025 was colder than average, clear and calm with low wind. Transmission demand on the day out-turned at 46.8GW against a forecast weather-corrected peak Transmission System Demand of 44.4GW. This was within system operator NESO's 90% confidence figure from its Winter Outlook.

2.2 A total of 2.9GW of interconnector capacity to continental Europe was unavailable on the day because of a number of unplanned technical issues. Wind generation output was also particularly low and approximately 2GW lower than had been forecast, with this value having deteriorated throughout the preceding week as weather conditions changed.

2.3 NESO issued an Electricity Market Notice (EMN) on the evening of 7 January 2025 for the period from 4pm to 7pm on 8 January because of insufficient operational surplus. NESO later withdrew the EMN as generation availability improved, before re-issuing it on the morning of 8 January following a trip at a gas-fired power station which reduced available capacity by a further 340MW.

2.4 A Capacity Market Notice (CMN) was also automatically triggered at 12:01pm on 8 January when the derated margin 4 hours ahead of delivery, a measure of likely infeed availability, was modelled at 215MW, which is less than the 500MW trigger threshold. This was cancelled at 12:32pm as margins improved, mostly owing to changes in interconnector flows.

2.5 Ultimately, NESO was able to resolve the energy supply-demand situation using the Balancing Mechanism (BM) and other services such as NESO's Demand Flexibility Service. The EMN and CMN system warnings worked as expected, as the market responded to them by making more capacity available to the system. NESO did not need to take any emergency actions.[4]

2.6 NESO paid a net figure of £20 million to generators for balancing services on 8 January, compared with a daily average of £4.6 million in 2024. Of this spend, a majority of slightly over £19 million was paid to three gas-fired power plants. This compares with a record daily BM expenditure of £62 million on 24 November 2021, which was caused by a combination of low supply margins and inflexible generation.

2.7 NESO has determined that the minimum margin of available infeeds that had not been instructed, plus partially loaded plants defined as headroom, was 3.7GW at 4:30pm on 8 January. We agree that NESO met the necessary reserve and margin requirements to comply with the Security and Quality of Supply Standard criteria for operating Great Britain's electricity transmission system.[5]

[4] What happened with margins on 8 January? | National Energy System Operator
[5] Section 5.1.2 and 5.1.3 of the SQSS

3. The Inflexible Offers Licence Condition

We have considered whether generators' actions on 8 January 2025 were compliant with the Inflexible Offers Licence Condition.

Background

3.1 The Inflexible Offers Licence Condition (IOLC) is the Standard Licence Condition 20B of the Generation Licence. It requires generators with a Minimum Zero Time (MZT)[6] above 60 minutes not to obtain, or seek to obtain, an excessive benefit on offers submitted to the Balancing Mechanism (BM) after revising a positive-value Physical Notification (PN)[7] to 0MW within the operational day, which starts at 5am.

3.2 The introduction of the IOLC in October 2023 followed a sharp rise in balancing costs in winters 2021-22 and 2022-23, where certain thermal power plants were sometimes paid significant amounts in the BM to continue operating into the evening peak period. The generators involved were typically inflexible in the sense that, where they indicated their intention to desynchronise to system operator NESO, this required them to stay inactive for a significant period of time before being able to generate again. Similarly, if activated by NESO, the units could only be synchronised for a minimum period of several hours even if their output was only required for a short period.

3.3 On the days in question, the generators involved would revise their PN from a positive megawatt value to 0MW close to PN gate closure. This sent NESO the signal that, contrary to what NESO had been expecting in its daily planning process, the generation unit now intended not to generate electricity in the evening peak of demand when generation is needed the most. NESO was often left with no choice but to pay the power plant very high BM offer prices to continue generating so as to protect supply reserves. The very high BM offers typically applied also to a number of hours before the peak demand periods of true supply scarcity, therefore reflecting the generator's inflexibility more than the conditions of the electricity system.

3.4 Price signals have an important role to play in orchestrating supply and demand to ensure energy flows to where it is needed at the right time. Occasional high prices in periods with tight margins can provide an important signal to help supply meet

[6] The Minimum Zero Time is the minimum time that a generation unit which has been generating power must operate at zero output before restarting its generation.
[7] Under the relevant industry codes, starting the day ahead of delivery, electricity generators must provide NESO with their best estimate of the expected output of their units. These are known as Physical Notifications. At the time of gate closure, which is an hour before delivery, Physical Notifications become final and cannot be changed.

demand, support companies to recover fixed costs and incentivise investors to bring forward additional generation.

3.5 However, on the days in question, the high prices observed resulted from the generators’ practice of withdrawing their supply at the last minute and leveraging their inflexibility to obtain high prices outside of periods of true market scarcity. As such, we considered this behaviour detrimental to consumers and introduced the IOLC in October 2023.

Compliance with the Inflexible Offers Licence Condition on 8 January 2025

3.6 The events of 8 January 2025 shared certain similarities with the conduct that the IOLC is designed to prevent. In particular, on that day some large gas-fired generation units with an MZT greater than 60 minutes informed NESO that they did not intend to generate during the evening peak period, unless they were paid to do so at very high prices in the BM.

3.7 However, the IOLC as currently designed does not apply if a generator informs NESO of its intentions not to generate before the operational day starts, for example at the day-ahead stage. We had consulted on a broader day-ahead implementation of the IOLC in 2023 but decided not to proceed on this basis at that time, as it would have increased the risk of unintended consequences. For example, if the IOLC applied to day-ahead 0MW PNs, generation assets returning from outage could have limited incentives to return quickly during times of system stress because of concerns about potentially breaching the IOLC.

3.8 Limiting the IOLC to within-day rescheduling focused our intervention on the behaviour that was most concerning at the time. This ensured that NESO was protected when facing a limited reaction time, while allowing prices to reflect supply scarcity when NESO had enough time to consider alternative balancing measures. We believed this to be a proportionate response to generators’ most aggressive behaviours and the associated balancing costs faced by consumers, without undue consequences on wider market operations.

3.9 On 8 January 2025, the two gas-fired generators that received the largest payments in the BM had informed NESO before the operational day began that they intended to generate in the morning but switch off at around 1pm. This meant that they would only be available in the evening peak if NESO instructed them in the BM to keep generating.

3.10 Since NESO was notified of the PNs before the start of the operational day, both power plants were not bound by the requirements of the IOLC when setting their BM offer prices, and the licence condition was not breached. Having considered the system requirements and the alternatives available, NESO ultimately took the decision to extend both units starting from 12:30-1:30pm until 5:13-6:55pm depending on the unit, with the generators receiving between £2,900/MWh and £5,750/MWh in the process.

3.11 A third gas-fired power plant had submitted a 0MW PN at day-ahead stage for delivery on 8 January because it was on a planned outage. This unit managed to interrupt the outage during the operational day and make its capacity available to NESO on the BM. Since no PN to generate had been withdrawn during the operational day, the asset’s BM offers were also not in breach of the IOLC. The asset was offered on by NESO from 1:30pm to 8:10pm at a price of £600/MWh.

3.12 Although none of the offer prices submitted by these generators were within scope of the IOLC, we consider some of the prices in question to have been extremely high. We also note the limited options available to NESO, despite the schedules for these units being submitted ahead of the operational day. In our IOLC decision document, we said we were aware that units that submit 0MW PNs prior to the operational day could use their inflexibility in a way that leads to high balancing costs, and committed to monitor market behaviour post implementation.

3.13 In light of all of this, we have evaluated the impact that the IOLC has had since its introduction in 2023 and whether the current rules are fit for purpose going forward. Our findings are set out in the next section of this document.

4. Our review of the Inflexible Offers Licence Condition and considerations on market rules going forward

We have reviewed the effectiveness of the Inflexible Offers Licence Condition. Our analysis shows that the licence condition has moderated the offer prices that generators submit to the Balancing Mechanism when switching off their plants at short notice. We found no clear trend of units opting more often not to generate on tight-margin days at the day-ahead stage, and mixed results about the prices they offer in the Balancing Mechanism in these circumstances.

Introduction

4.1 When adopting the Inflexible Offers Licence Condition (IOLC) in 2023 we committed to monitoring market behaviour following implementation.

4.2 The IOLC has now been in place for almost two complete energy winters, allowing for a meaningful comparison of market behaviours before and after its adoption during the period of the year in which supply margins are tightest. While we have entered a third winter with the IOLC in place, a review of the initial effects of this licence condition on the market can inform whether the scope of the IOLC as initially implemented is sufficient or needs to be corrected. It can also suggest whether some of the options which were eventually not adopted as part of the IOLC policymaking process should be given new consideration.[8]

4.3 Compounding our review commitments, the Secretary of State for Energy Security and Net Zero wrote to us in August 2025 encouraging us to continue exploring options that could limit excessive profits without compromising system balancing or security of supply. The Secretary of State also requested we set out proposed next steps in this area of the market, including the possibility of issuing public guidance where appropriate.

Assessment of the effects of the Inflexible Offers Licence Condition on market behaviours and balancing costs

4.4 We have reviewed the effectiveness of the IOLC by analysing market behaviour and balancing costs from the last winter before the licence condition was introduced (2021-22) to the latest fully delivered winter (2024-25).

[8] For a discussion of the options initially considered as part of the process that led to the adoption of the IOLC, and industry feedback on them, see: Call for Input on options to address high balancing costs | Ofgem. Further considerations on the options, as well as further industry feedback, can be found here: Consultation on the Inflexible Offers Licence Condition | Ofgem.

Methodology

4.5 For the purposes of this analysis, we decided to focus on the following parameters:

- Deliveries from October to March, particularly evening peak demand periods, because these experience the tightest supply margins and the highest offer prices in the Balancing Mechanism (BM). Concerns about exceptionally high BM prices in winter caused by market strategies leveraging inflexible dynamic parameters were among the main drivers of the adoption of the IOLC, adding interest to the chosen sample.
- Delivery days in which the derated supply margin of at least one settlement period of the evening peak was below 5GW, as forecast by system operator NESO at day-ahead stage.[9] Using derated margins to delimit the scope of our analysis was a way to ensure it focused on the periods of highest concern, based on the market behaviour that contributed to the introduction of the IOLC in 2023.

4.6 For the avoidance of doubt, the IOLC applies to all settlement periods no matter their forecast tightness, therefore we do not consider these parameters when monitoring generators' compliance with market rules.

4.7 Our analysis looked closely at how within-operational-day scheduling behaviours and pricing strategies have changed since the introduction of the IOLC. We also examined whether the BM offer prices of inflexible assets that decided not to generate at the day-ahead stage have changed. Widening our analysis beyond within-day changes to Physical Notifications (PNs) allowed us to check if aggressive strategies detrimental to consumers' welfare have moved from within-day to day-ahead stage, and the cost implications for consumers.

4.8 We have summarised the findings of our analysis below.

Effects on within-day strategies

4.9 Our analysis shows that the IOLC has been effective in moderating the BM prices of inflexible generators which, after the operational day has started, decide to stop generating on tight-margin days.

4.10 On days when supply margins fell below 5GW, NESO's expenditure on BM offers from inflexible units in these circumstances dropped from £23 million in winter 2022-23 to below £3 million in both winter 2023-24 and 2024-25 following the introduction of the IOLC.

4.11 The reduction in expenditure could partly be the result of fewer instances of inflexible generators withdrawing their PNs at short notice for the evening peak of

[9] NESO's derated margin calculations are available here: [Loss of Load Probability (LoLP) and De-rated Margin | Insights Solution](). We used the 12-hour forecast in our analysis.

tight-margin days, as well as of a lower number of tight-margin days themselves. The number of times units withdrew a PN within-day and kept generating in the BM on NESO's request dropped from 22 in 51 tight-margin days in winter 2022-23 to 9 in 23 days in winter 2023-24 and 13 in 30 days in winter 2024-25. However, the proportion of tight days that saw at least one inflexible unit withdraw its PN at short notice hovered around one-third for all three winters. This suggests that the reduction in the number of occurrences may have depended on more favourable system fundamentals resulting in fewer tight days, rather than on a widespread change in generators' behaviour.

4.12 Yet, consumers' savings on these tight days were also the result of lower BM offer prices being achieved by those units that still withdrew their PNs at short notice. To ensure we cleaned the data of the role played by variable gas and carbon emission prices in driving BM offer prices down, we analysed how the clean spark spread implied by the accepted BM offer prices changed after the introduction of the IOLC. The clean spark spread is a financial metric estimating the profitability of generating electricity from a gas-fired power plant, after accounting for fuel and carbon costs and adjusting for the plant's generation efficiency.

4.13 Data shows that generators captured considerably lower clean spark spreads when NESO accepted their BM offers in winters 2023-24 and 2024-25 compared with winter 2022-23, both in terms of average values and of maximum values achieved (Figure 2). The drop was especially noticeable for the delivery months of the fourth quarter.

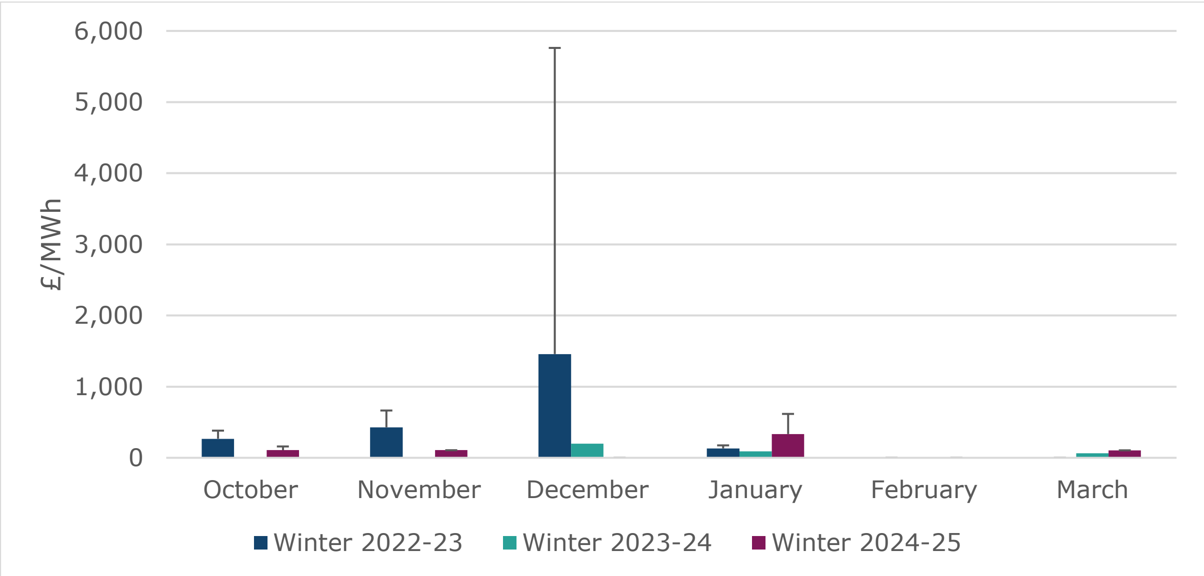

Figure 2 – Average clean spark spread of BM offers achieved by inflexible units that decided within-day to stop generating on tight-margin days. The line above each bar represents the highest clean spark spread achieved through a BM offer that month. (Source: Ofgem from NESO, LCP, ICIS and ICE data)

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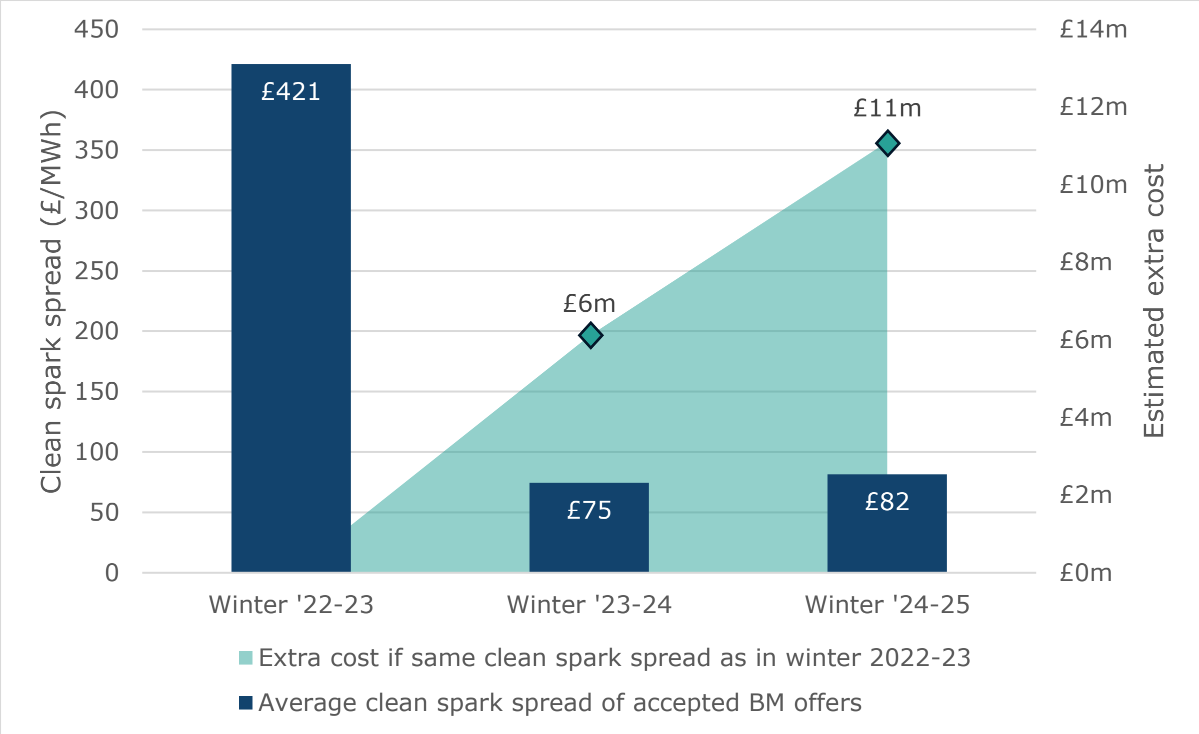

Figure 3 – Estimated extra costs avoided by NESO on BM offers from inflexible units that withdrew a positive PN within-day on winter days with supply margins below 5GW, using clean spark spread calculations. (Source: Ofgem from NESO, LCP, ICIS and ICE data)

4.14 When aggregating results by winter rather than month of delivery, the clean spark spread built into generators' BM offer prices dropped by around 80% from the £421/MWh seen on average on tight-margin days in winter 2022-23. Had the clean spark spread remained stable at the pre-IOLC levels of 2022-23, consumers would have spent an extra £17 million on aggregate in the latest two winters (Figure 3).

4.15 As this estimate is based on a recalculation of generators' margin on accepted BM offers, the calculated savings do not depend on the number of tight-margin days and can be attributed to a moderating effect of the IOLC on generators' pricing strategies.

4.16 The data provides supporting evidence that the IOLC has made an effective contribution towards limiting the specific behaviour that enabled inflexible generators to achieve very high revenues in the past.

Effects on day-ahead strategies

4.17 On days when supply margins fell below 5GW, NESO's BM expenditure on units opting to stay idle at day-ahead stage, thus avoiding IOLC's restrictions, also decreased from £87 million in winter 2022-23 to £14 million in winter 2023-24 and £36 million in winter 2024-25.

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4.18 Our analysis shows an initial drop in occurrences of gas-fired units staying spare from the day-ahead stage on tight-margin days after the introduction of the IOLC, from 147 over 51 days in winter 2022-23 to 69 over 23 days the following winter. However, this number rebounded to 126 over 30 days in winter 2024-25.

4.19 We also looked at the proportion of tight-margin winter days on which at least one gas-fired BM unit decided not to commit any generation at day-ahead stage. We found that this remained consistently above 90% across the three winters, but that the proportion was marginally higher in winter 2024-25 at 100%.

4.20 The numbers from the latest winter are not conclusive on whether, at day-ahead stage, market participants are keeping their inflexible units spare on tight-margin days more often to avoid the BM price restrictions introduced by the IOLC. The proportion of tight winter days where at least one power plant attempted this market strategy is only marginally higher than before the IOLC was adopted. However, such a behavioural shift cannot be ruled out, especially considering the increase in occurrences observed in winter 2024-25 compared with winter 2023-24.

4.21 As regards the BM offer prices achieved by spare units on tight-margin days before and after adopting the IOLC, our analysis returned a mixed picture. On average, the clean spark spread achieved by inflexible units in the BM was highest in winter 2022-23 for tight-margin days in October, February and March, but highest in winter 2023-24 for November and in winter 2024-25 for December and January (Figure 4).

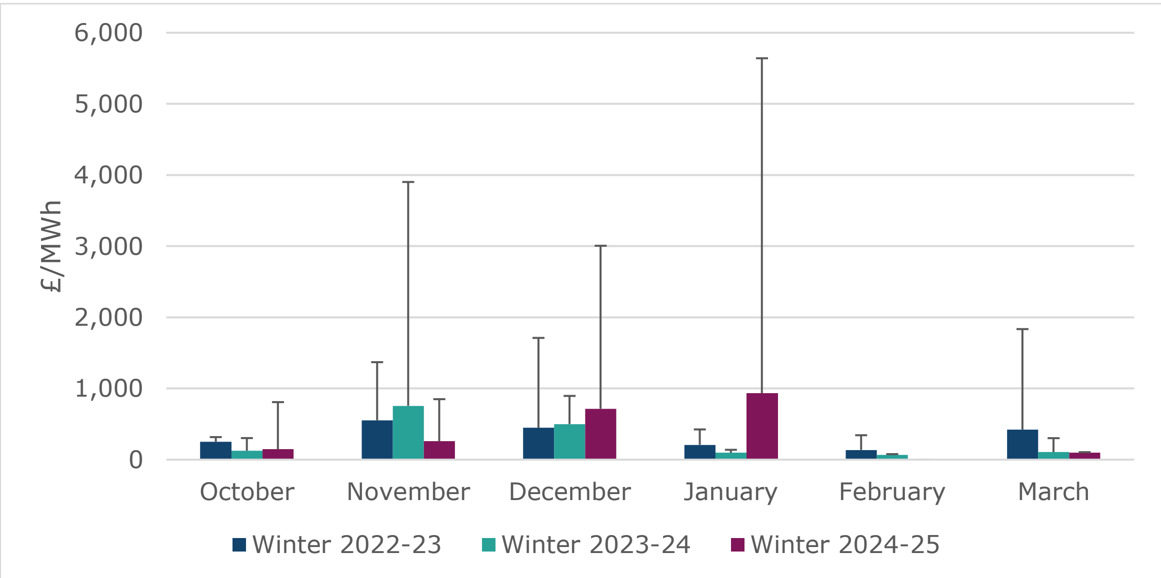

Figure 4 – Average clean spark spread of BM offers achieved by inflexible units that opted at day-ahead stage not to generate on tight-margin days. The line above each bar represents the highest clean spark spread achieved through a BM offer that month. (Source: Ofgem from NESO, LCP, ICIS and ICE data)

4.22 If focusing on the single-highest clean spark spread achieved for each month of delivery, winter 2022-23 topped the charts for February and March, winter 2023-24 for November and winter 2024-25 for October, December and January. January 2025 was the most expensive month when looking at both average and highest clean spark spreads achieved, although this was largely the result of a single delivery day – 8 January.

4.23 The absence of a clear trend suggests that the erratic nature of fundamentals is a major factor in the pricing strategy of inflexible generators, causing different winters to be more expensive than the others in each month depending on when tight-margin days materialised.

4.24 It is important to highlight that the earlier a market participant decides on whether to generate, the less certain is its forecast of fundamentals. Day-ahead forecasts are more uncertain than within-day calculations because of the inherent variability of renewables' output or domestic consumption, as well as real-time changes to available supply, grid congestions and interconnector flows from neighbouring markets.

4.25 In addition to this, the more advanced notice NESO is given about each generators' electricity production schedules, the better NESO can assess its options for securing supply reserves across various markets at the lowest cost for consumers.

4.26 As a consequence, generators face a higher risk when basing their decision not to generate on forecasts made at day-ahead stage, in contrast with within-day. For example, on 22 January 2025 many inflexible gas-fired units tried to replicate the scheduling and pricing strategy of 8 January. However, within-day improvements in supply margins and potentially an overestimation of system tightness at day-ahead stage meant that the revenue captured by spare inflexible units in the BM was considerably lower than that of units that had sold their output in the day-ahead auctions.

4.27 Before the IOLC was introduced, the risk of implementing a sub-optimal market strategy was markedly lower. Inflexible units could sell their generation in the day-ahead auctions to lock in a profit for a tight-margin day; then they could wait to observe within-day developments in fundamentals and calculate how many supply reserves NESO could count on. A lack of time for NESO to source alternative electricity often meant that short-notice, within-day PN withdrawals from inflexible assets were conducive to hours of exceptionally high BM offer prices being accepted even outside of periods of true scarcity of supply.

4.28 By constraining the financial benefit of withdrawing PNs at short notice, the IOLC has steered market participants towards a more binary day-ahead decision on whether to generate or not. As day-ahead forecasts are less reliable than within-day ones, we would expect that the risk of not committing the asset to generate at day-ahead stage and not being called by NESO on the back of improving within-day fundamentals is higher. This does seem to be reflected in the lack of clear trend in the data outlined above.

4.29 We remain focused on whether these market rules are achieving the best possible results for the system and ultimately consumers. We will continue to closely monitor how day-ahead scheduling and pricing strategies develop to assess whether trends of concern for consumers are emerging. If we see continuing evidence of high prices exacerbating periods of scarcity and adding to consumer costs, we will consider further intervention.

Wider context and other system considerations

4.30 NESO's resource adequacy analysis for the 2030s suggests that, with greater deployment of renewable generation and storage capacity, the nature of system needs will shift. Periods when capacity is tight will occur less frequently but for longer duration, for example when there are extended periods of low wind generation.[10]

4.31 A diverse portfolio of flexible technologies, each tailored to specific system needs, will be essential to balance supply and demand across varying timescales. Short-duration flexibility will play an increasingly important role in managing intraday imbalances and reducing system costs. Dispatchable capacity capable of providing enduring output is also required to maintain security of supply during prolonged periods of system stress.[11] Whilst low-carbon flexible capacity and its supporting infrastructure is scaled up, there is still a need to provide sufficient dispatchable capacity from existing sources.[12]

4.32 Under the government's Clean Power Action Plan, unabated gas generation is expected to fall significantly from 26% of total annual electricity in 2024 to around 5% in a typical weather year by 2030.[13] As Great Britain moves towards Clean Power 2030 targets, a typical gas-fired generator's revenue streams will change.

4.33 At present, gas-fired generators' profitability is underpinned by revenues from the Capacity Market, the wholesale market and the BM. Capacity market payments are linked to availability instead of actual energy output, and are designed to recover fixed costs. Wholesale market revenues primarily cover variable costs – such as fuel, carbon and operating costs – and occasionally contribute to fixed-cost recovery when prices are high. BM revenues provide additional income for flexibility and imbalance management.

[10] Resource adequacy | National Energy System Operator

[11] Dispatchable enduring capacity refers to generation assets that can deliver power on demand, are capable of sustained output over prolonged periods of system stress and do not rely on stored energy. Examples include gas-fired plants and future low-carbon dispatchable technologies such as hydrogen-to-power and Carbon Capture Utilisation and Storage-equipped plants.

[12] Capacity Market: proposed changes for Prequalification 2026 - GOV.UK

[13] Britain's Electricity Explained: 2024 Review | National Energy System Operator

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4.34 As gas-fired generators run less often and for shorter periods, their wholesale revenues are expected to fall considerably. To maintain profitability, they may seek to recover more of their costs either through the Capacity Market or the BM.

4.35 At the same time, during extended periods of low wind output, gas-fired generators may also experience periods of enhanced market power, particularly whilst alternative options such as low-carbon flexible capacity are scaled up. High prices charged during times of system stress can be expected, as they seek to recoup operating costs over fewer running hours.

4.36 We must consider these developments holistically and take a market-wide approach to managing changing market dynamics.

4.37 We are working closely with the Department for Energy Security and Net Zero to ensure that market arrangements align with and support government's net-zero goals, balance cost to consumers and ensure security of supply is maintained.

5. Next steps

5.1 **We will continue to monitor market participants’ conduct in the Balancing Mechanism**, and not hesitate to take action if we see behaviour that is in breach of market rules.

5.2 **We will continue to assess and review the effectiveness of the Inflexible Offers Licence Condition.** We will be closely monitoring market participants’ behaviour and pricing strategies to identify any trends of concern. This includes the monitoring of offer prices achieved in the Balancing Mechanism when inflexible units are kept spare at the day-ahead stage.

5.3 Our view remains that in certain situations, for example where the margin between available capacity and peak demand becomes tight, a scarcity premium may be built into offer prices. Occasional high prices in these periods of genuine scarcity can provide an important signal to support supply meeting demand and may also incentivise investment in additional generation capacity or demand response.

5.4 However, if we see evidence of generators persistently exploiting their inflexibility and market power via expensive prices in the Balancing Mechanism which are not reflective of the risks involved, we will consider further intervention to protect consumers’ interests.

5.5 We will continue to work closely with the Department for Energy Security and Net Zero to ensure market arrangements support government’s net-zero goals, whilst also balancing cost to consumers and ensuring security of supply.