Impact Assessment

Impact assessment of Inflexible Offers Licence Condition

Division:	Energy Systems Management & Security	**Type of measure:**	Licence Condition
Team:	Domestic Market Management Team	**Type of IA:**	Qualified under Section 5A UA 2000
Associated documents:	IOLC Proposed Licence Condition: - Statutory Consultation - IOLC Draft Guidance	**Contact for enquiries:**	Luke.McCartney@ofgem.gov.uk Holly.MacDonald@ofgem.gov.uk
Coverage:	Full		

This Impact Assessment is written in relation to the proposed Inflexible Offers Licence Condition (IOLC). It sets out the policy objectives, options assessed, and justification of the preferred option to progress the licence condition. The proposed licence condition prohibits electricity generators with a Minimum Zero Time (MZT) longer than 60 minutes from gaining excessive benefit when they revise their Physical Notification (PN) from a positive MW value to zero MW within the Operational Day.

Executive Summary

Following the open letter in response to high balancing costs in winter 2021/22 in July 2022, we published a Call for Input in November 2022[1] ("the Call for Input") seeking views on a number of options we were considering to reduce high balancing costs. In that Call for Input we set out our intention to move forward with a new licence condition to prohibit generators from obtaining excessive benefits following the submission of 0MW PNs. We used the feedback to publish a consultation in February 2023[2] ("the February Consultation") on our proposed Inflexible Offers Licence Condition ("IOLC"), as well as the draft Guidance which would sit alongside it.

We are now publishing our Statutory Consultation proposing to modify generation licences to include a new licence condition which would prohibit generators with an MZT of over 60 minutes obtaining an excessive benefit following the revision of a positive MW value PN to a 0MW PN within the operational day. This report describes our Impact Assessment of the proposed licence condition and supporting draft Guidance and draws on the feedback that stakeholders have provided as part of both the Call for Input and the February Consultation.

Problem under consideration and policy objectives

In winter 2021/22 we saw a large increase in balancing costs, this was primarily driven by increased offer prices in the BM rather than increased volumes having to be purchased by the ESO. During winter 2021/22 we witnessed some concerning generator behaviour. This behaviour saw generators revising their PN to zero, to send a signal to the ESO that the generation unit intended to cease generating electricity. Once a generation unit ceases to generate electricity, it must remain at zero output for a set period of time in order to comply with the unit's MZT, which is a pre-determined technical capability of the generation unit.[3] This behaviour has been observed predominately in the settlement periods during the run up to and over the evening peak of demand (i.e., when generation is needed the most). After the revision of the PN to 0MW, the generators then submitted higher offer prices in the BM. To avoid the generation unit from being unavailable for the evening peak the ESO therefore often had to accept these high-priced offers for several hours in advance of the evening peak of demand.

---

[1] Call for Input on options to address high balancing costs | Ofgem
[2] Consultation on the Inflexible Offers Licence Condition | Ofgem
[3] Generators' technical capabilities are known as dynamic parameters. The full list of dynamic parameters is set out in the Grid Code at BC1.A.1.5

The objective of introducing the licence condition is to prevent higher than necessary bills for consumers by prohibiting generation companies from obtaining excessive benefits as a result of their plant inflexibilities. Introducing this licence condition would prohibit the aforementioned behaviour and is needed to reduce unnecessary costs which would eventually be paid by consumers.

Options considered

The Call for Input sought views on the options we were considering to reduce high balancing costs. These options included:

- Option 1: Price cap on BM offer prices.
- Option 2: Changes to bid/offer structures.
- Option 3: A new ESO balancing service to procure firm reserve.
- Option 4: A new licence condition preventing excessive benefit after submitting a zero MW PN.
- Option 5: Restrictions on amending PNs after day ahead.
- Option 6: Clarifying 'good industry practice' in the Grid Code.

We stated in the Call for Input that Option 4 - introducing a new licence condition - was preferred against the other five options. We assessed all options and reviewed the responses to this call for input and found that Option 4 would be implementable within relatively short timescales and is best placed to directly reduce the market behaviour of concern without unduly impacting existing trading arrangements or impeding price signals during periods of scarcity. The other five options were discounted as they may have unduly impacted price signals, would be difficult to implement, were not compatible with existing market design or didn't have a material impact on reducing balancing costs. As such, only Option 4 was shortlisted as the preferred option of choice.

The February Consultation provided industry with our updated view on the detailed design of the proposed licence condition and our proposed draft IOLC Guidance. Following review of the responses to this consultation, we have made some amendments which are outlined in the Statutory Consultation published alongside this Impact Assessment.

The main amendment following the February Consultation has been to return to limiting the licence condition to apply to generators who have revised their PN from a positive MW value to 0MW within the operational day (and not day ahead or further out) and gained an excessive benefit. We are still aware that units with 0MW PNs prior to the operational day could cause high balancing costs and as a result we will continue to monitor the behaviour in the BM and will reintervene if necessary.

As a result, this Impact Assessment will assess the merits of the proposed policy and its intended objectives against the 'do nothing' scenario, with the implementation of the proposed licence condition being our preferred option.

Monetised impacts

We believe there is a positive net benefit of introducing the licence condition as it would reduce high balancing costs and ultimately consumers' bills. Data shows that there has been a reduction in BM costs during winter 22/23[4] by **£260m** compared to winter 21/22.[5,6] This is due to several reasons; however, we believe that our proposals and communications (and subsequent changes in market participant behaviours) have played an important role in this reduction. This conclusion is also supported by the ESO and LCP's recent balancing costs publications.[7]

We have provided a robust qualitative assessment of the expected costs, benefits and impacts of IOLC across key market aspects, such as price signals, competition, investment, and security of supply (as well as distributional and sustainability impacts).

Will the policy be reviewed?

A review of the policy (and the impact of the licence condition) will be appropriate as part of Ofgem's ongoing market monitoring obligations. We will continue to assess the impact and effectiveness of IOLC if introduced, to see if any further changes need to be made.

Following the feedback received in the February Consultation, we have reinstated the drafting of the licence condition such that it would only apply to PN revisions to 0MW within the operational day. We note that this scope would address the most concerning behaviour we witnessed in winter 21/22. However, we will continue to monitor generator behaviour based

[4] 1 September 2022 to 31 March 2023
[5] 1 September 2021 to 31 March 2022
[6] ESO Data Portal: Daily Balancing Services Use Of System (BSUoS) Historic & Forecast Costs - Dataset| National Grid Electricity System Operator (nationalgrideso.com)
[7] ESO's Winter Balancing Costs Review 2023 and LCP's Winter Balancing Costs Review 2023

on the concerns highlighted in our February Consultation that units may also obtain excessive benefit following 0MW PN submissions at day ahead. We will continue to monitor market outcomes and will look to intervene further if we were to believe that the submission of 0MW PNs at the day ahead stage was creating outcomes and costs that were not in consumers' interests.

1. Introduction

Background

1.1. National Grid Electricity System Operator's (NGESO or 'the ESO') role is to co-ordinate and direct the flow of electricity onto and over the National Electricity Transmission System (NETS) in an efficient, co-ordinated, and economic manner. It does this by procuring balancing services that are subject to transparent, non-discriminatory, and market-based procedures.

1.2. The BM is NGESO's primary tool to balance supply and demand in real time. In the BM, market participants signal to NGESO for each given settlement period the costs they are willing to pay or be paid to adjust their electricity output or consumption, as a deviation from the position they had notified to NGESO ahead of gate closure[8] for that settlement period. For electricity generators, a proposal to increase electricity output or decrease electricity consumption is known as an 'offer' and a proposal to decrease electricity output or increase electricity consumption is known as a 'bid'. NGESO typically takes actions using the most competitively priced bids and offers, however operational and locational factors can sometimes result in more expensive bids and offers being accepted in order to solve a specific network issue.

1.3. NGESO is informed in advance of the generators that are scheduled to run, and at what quantity of generation output, through the submission of PNs. These are notifications from generators of the amount of electricity that they intend to produce during a given settlement period (suppliers also submit PNs to notify expected consumption). PNs can be modified until gate closure, which is an hour before the start of a settlement period. At this point, the market closes for that settlement period and PNs become Final Physical Notifications (FPNs). The period between gate closure and the end of the settlement period is when NGESO accepts bids and offers submitted by BM participants.

1.4. All the costs incurred by NGESO to operate the NETS are recovered through Balancing Services Use of System (BSUoS) charges. From April 2023, generators are no longer liable

[8] Gate Closure is a point one hour prior to the start of a Settlement Period by which time generators submit to NGESO their planned generation for that Settlement Period

for these charges and instead suppliers are now solely liable. These charges are calculated daily depending on the cost of the ESO's balancing actions.[9]

1.5. Between 2017 and 2020 total NGESO balancing costs for the four months November to February averaged just under £500m. For 2021/22 this rose alarmingly to over £1.5bn, with record breaking daily costs being experienced during the period. Overall, in 2021/22 the ESO incurred balancing costs of £3.1bn.[10]

1.6. The large increase in balancing costs in 2021/22 was primarily driven by increased offer prices, rather than increased volumes having to be purchased by NGESO. Following record breaking daily balancing costs of over £60m on 24 November 2021, NGESO initiated an independent review of the BM.[11] The ESO's review provided analysis of the different drivers of the high balancing costs observed over the winter and described a number of potential market reforms.

1.7. One of the key cost drivers the ESO and Frontier's review found was that generators took part in the behaviour known as 'delayed desync'.[12] They highlight that this isn't a new strategy from generators, however the offer prices submitted when taking part in 'delayed desync' were much higher (approx. £200m)[13] in winter 21/22 compared to previous years – see Chapter 4 for more detail on this.

What has been done?

1.8. Following NGESO's review we published an open letter[14] on 15 July 2022, setting out our plan to explore a range of near-term interventions to improve existing market arrangements in response to the recent high prices and costs in the BM.

1.9. On 5 October 2022, we held an industry workshop to test several ideas we had to improve existing market arrangements and reduce balancing costs as a result.

---

[9] This change to BSUoS charging has been introduced following the approval of CUSC Modification Proposal 308. Further details can be found here CMP308: Removal of BSUoS charges from Generation
[10] ESO's Monthly Balancing Services Summary (MBSS)
[11] ESO Balancing Market Review
[12] Delayed desync is defined as BMUs dropping their PNs in advance of a period of system stress. Therefore the unit must be extended by the ESO to retain access to its operating margin.
[13] ESO Winter Balancing Cost Review 2023
[14] Open letter on responding to the high balancing costs | Ofgem

1.10. The Call for Input was published in November 2022 seeking views on the options we were considering, to reduce high balancing costs. We set out that we were planning on moving forward with a new licence condition to prohibit excessive benefits following the submission of 0MW PNs and also proposed initial drafting of the potential licence condition.

1.11. Following review of responses received and further consideration, we published the February Consultation on our proposed new licence condition to gain views on the detailed design of the proposed new licence condition and the draft Guidance that would sit alongside the new licence condition.

Scope of Impact Assessment

1.12. This Impact Assessment assesses the potential costs and benefits the new licence condition would have on generators, consumers, the ESO and Ofgem. It will also assess the impacts this licence condition could have on price signals, competition, security of supply, investments, distribution, and sustainability. We will also assess any unintended impacts the licence condition may create. We outline the risks and assumptions we have considered when carrying out this assessment.

1.13. The analysis is primarily qualitative. This is due to the complex nature of assessing the impact this licence condition could have prior to its introduction. Where possible we have attempted to give quantitative analysis to support our thinking, along with our qualitative assessment.

2. Policy objectives and rationale for intervention

Problem under consideration

2.1. As mentioned in Paragraph 1.5 and 1.6, balancing costs have increased considerably over the previous few years. This was largely due to the increase in offer prices in the BM, rather than an increase in volumes being purchased by NGESO.

2.2. It was found that a key driver for the increase in balancing costs was due to generator behaviours. This included instances of generators with inflexible technical capabilities revising their PN from a positive MW value to 0MW, to signal to the ESO that the generation unit intended to cease generating electricity in the run up to and over the evening peak of demand (i.e., when generation is needed the most). Once a generation unit ceases to generate electricity, it must remain at zero output for a set period of time in order to comply with the unit's MZT, which is a pre-determined technical capability of the generation unit.[15] Thermal generators typically have an MZT of six hours. In practice, this means once a thermal generator has ceased generating electricity, it won't be able to start generating electricity again for at least 6 hours. We observed instances of thermal generators informing the ESO, at times with little advance notice, that they would cease generating in the afternoon. Due to the generation unit's MZT, that meant the generator would then be unavailable to generate electricity later that day, for example, during the period of peak evening demand (i.e., when generation is most in need).

2.3. Although a generator may notify the ESO that it intends to cease generating electricity, it is possible for the ESO to take action to ensure the unit continues to generate electricity. This is achieved through the ESO accepting the generator's offers in the BM. We saw instances of generators notifying the ESO that they intended to cease generating electricity for a particular period before increasing the price of their offers to the ESO to continue generating during that period. In certain situations, where the margin between available capacity and peak demand becomes tight, a scarcity premium may be included in offer prices. This price rise can provide a signal that has an important role to play in orchestrating supply to meet demand and may also incentivise investment in additional generation or demand side response. However, when high offer prices were combined with a revision of PNs to 0MW

[15] Generators' technical capabilities are known as dynamic parameters. The full list of dynamic parameters is set out in the Grid Code at BC1.A.1.5

for units with lengthy MZTs, NGESO often had limited options available to maintain system security and incurred much higher costs.

Rationale for intervention

2.4. Ofgem's principal objective is to protect consumers' interests. We do this in part by stamping out sharp practices and enabling competition to drive down prices for consumers. Evidence from winter 21/22 showed that there is room within the existing wholesale market arrangements for changes that better ensure energy markets deliver in consumers' interests. The objective of our proposed intervention is to prohibit generators from participating in the behaviours that contributed to winter 21/22's high balancing costs. In reducing the costs incurred by the ESO to balance the system we would reduce prices for consumers as these costs are ultimately paid for through consumers' bills.

Policy objective

2.5. The objective of introducing a new licence condition is to prevent higher than necessary bills for consumers when generators, with an MZT above 60 minutes, obtain an excessive benefit after revising their PN from a positive MW value to 0MW within the operational day.

2.6. Ofgem is continuously monitoring the market as part of our ongoing obligations. We consider it important to continuously review whether there is a need for regulation, including in response to stakeholder feedback, and if so, whether it needs amending to ensure it meets its objectives. This new licence condition will be reviewed and updated when necessary, including to maintain consistency with other obligations. The ongoing need for the IOLC may also be considered as part of any wider market reforms introduced by Government's Review of Electricity Market Arrangements (REMA).[16]

[16] Review of electricity market arrangements - GOV.UK (www.gov.uk)

3. Description of options considered

Feedback received via the Call for Input

3.1. On 4 November 2022 we published the Call for Input. This set out our view on six possible intervention options which could help tackle the high balancing costs. We undertook an options assessment which used a qualitative approach to assessing each of the six options against the four pieces of criteria.

3.2. Table 1 shows our findings and provides a high-level summary of the options assessment using a red, amber and green (RAG) rating. In respect to each criterion, green suggests a positive impact, amber is neutral or negligible impact and red is a negative impact.

Table 1 - Options Assessment from Call for Input

	Balancing costs reduction	**Compatibility with existing market design**	**Impact on price signals**	**Ease of implementation**
Option 1 - Price cap on BM offers				
Option 2 - Changes to BM offer structures				
Option 3 - ESO balancing service				
Option 4 - New licence condition				
Option 5 - Restrict intraday changes to PN				
Option 6 - Clarifying the Grid Code				

3.3. As a result of this assessment we identified Option 4, introducing a new licence condition to prohibit excessive benefit after submitting a 0MW PN, as our preferred intervention. Reasons for this included that the option was implementable within relatively short timescales, whilst also being best placed to target the concerning market behaviours we saw in winter 21/22 (and therefore reduce balancing costs) without disrupting existing trading arrangements or impeding price signals during periods of scarcity. The other five options scored less favourably and were discounted as they may have unduly impacted price signals, be difficult to implement, were not compatible with existing market design or didn't have a material impact on reducing balancing costs. The majority of responses we received in the Call for Input also supported Option 4 as the preferred option. We published initial draft legal text of the licence condition alongside the Call for Input.

3.4. Following stakeholder feedback and analysis of BM behaviours since the publication of the Call for Input, our February Consultation considered potential adjustments to the proposed licence condition in two ways. Firstly, removing the 'within operational day' limitation for when 0MW PNs are submitted and, secondly introducing a new limitation on the scope of the condition to generating units with an MZT greater than 60 minutes. We published the February Consultation including these amendments alongside draft Guidance for the new licence condition.

3.5. After reviewing the responses to the February Consultation, the version of the licence condition included within the Statutory Consultation has a further revision, making it more specific to the concerning market behaviours we saw in winter 2021/22.

3.6. In this document we undertake a cost benefit analysis of the licence condition compared to a 'do nothing' scenario alongside a discussion on how we believe they would have an impact on competition, market and price signals, investment signals, security of supply, distribution effects, sustainability and any unintended consequences.

3.7. The recommended option would introduce the new licence condition. If implemented, this would prohibit generators (with an MZT of more than 60 minutes) from obtaining an excessive benefit when they have revised their PNs from a positive MW value to of 0MW within the operational day. We anticipate that the new licence condition would be permanent to prevent generators from returning to this behaviour in the future.

4. Review of the potential impact of the IOLC

History of balancing costs

4.1. Balancing costs were broadly flat for almost a decade; however they have risen sharply in recent years. Figure 1 below shows this increase. In FY2011/12 balancing costs were £886m. Just over a decade later, in FY2022/23 this had increased to £4,149m.

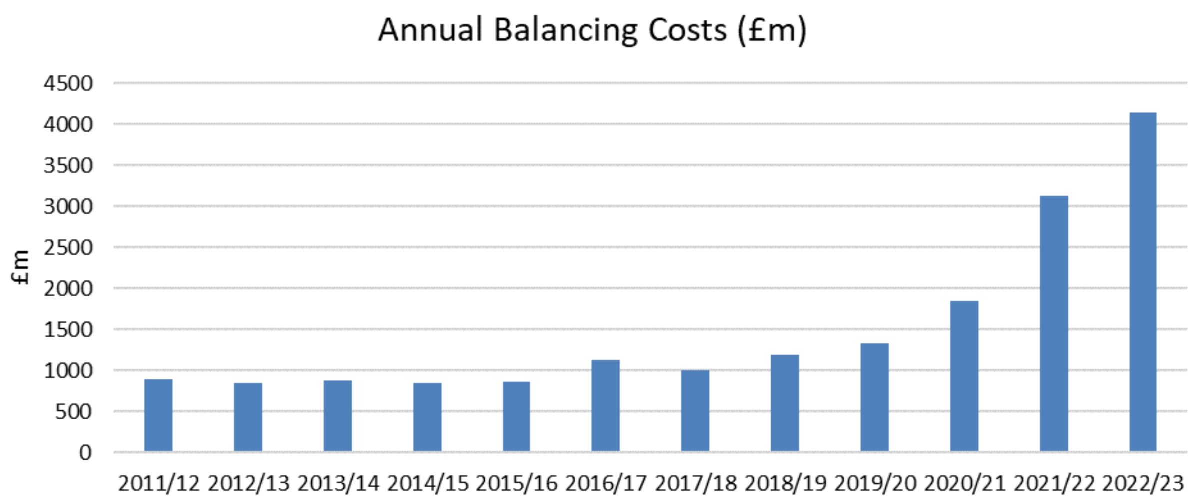

Figure 1 – Annual balancing costs from FY 2011/12 to FY 2022/23[17]

4.2. There are two predominant reasons for growth in balancing costs. Firstly, the ESO has experienced an ongoing and growing need to take actions to ensure system security and, secondly, the costs of those actions have increased rapidly in recent years. The rapid acceleration in total balancing costs throughout 2021/22 and 2022/23 was predominately driven by high prices throughout the wholesale market and in the BM. The rise in costs of gas and carbon drove significant increases in day ahead power prices, which in turn inflated the cost of the ESO's available actions to balance the system.

What we have witnessed in the BM in recent years

4.3. Throughout winter 21/22 and 22/23 there were periods of tight margins where pricing by generators in the BM meant that the ESO, at times, had little option other than to take high priced actions to meet operating reserve levels and maintain system security. Figure 2 below shows the 10 highest costing days that were witnessed in the BM during winter 21/22.

---

[17] ESO's Monthly Balancing Services Summary (MBSS)

During the months of September 2021 to March 2022 the ESO spent approximately £1.9bn, and the top 10 costing days during this seven-month period represented 19% of the total costs over that timeframe (approx. £357m). The highest costing day was on 24 November 2021, where the ESO had to spend over £62m in the BM to balance the system.[18]

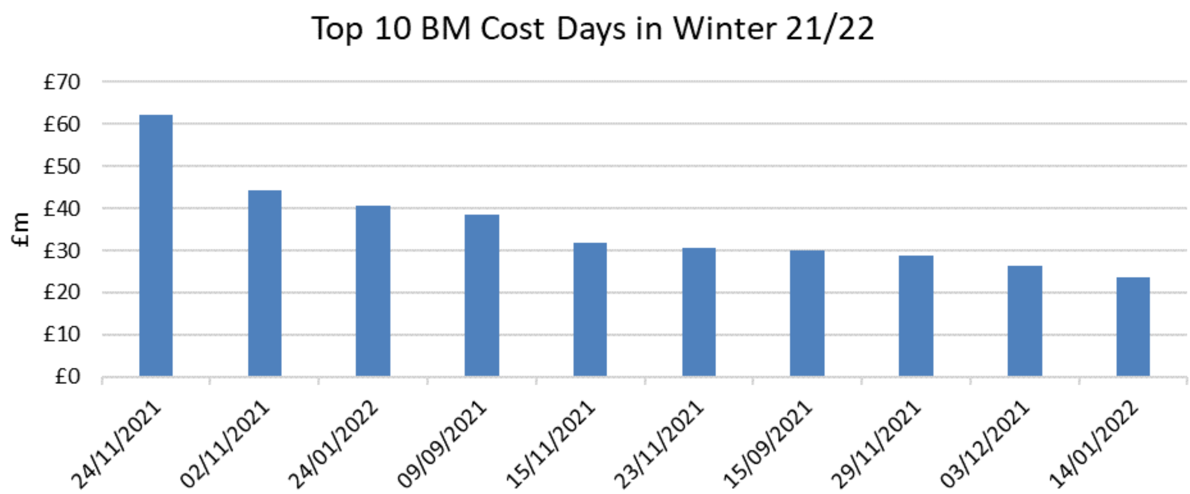

Figure 2 – Top 10 balancing market cost days in winter 2021/22

4.4. When looking at these high costs days it was notable that the price spikes in the BM were significantly more extended than those observed in the intraday and day ahead market. Figure 3 shows the Market Index Price (MIP)[19] (**blue**) and Day Ahead (DA) Price[20] (**green**) on 24 November 2021. It is clear the prices in these markets do not correlate with what was occurring in the BM. Figure 3 also shows the maximum accepted offer price (**red**) in the BM for each settlement period, along with the volume weighted average of accepted non-system flagged offer prices (**purple**). On 24 November 2021 the ESO accepted offer prices between £3250/MWh and £4000/MWh during Settlement Periods (SP) 23 to 40, which is much higher than the MIP and DA price spikes and for a much longer duration.

[18] ESO Data Portal: Daily Balancing Costs 2021 - 2023 - Dataset| National Grid Electricity System Operator (nationalgrideso.com)
[19] Market Index Price - This is the published Market Index Price which gives the volume weighted average price of trades in the continuous intraday market on EPEX. This is used to set the system price where there are no price setting units available to set the price
[20] Day Ahead HH EPEX Price - The half hourly price as set in the half hourly day-ahead GB wholesale market auction on EPEX

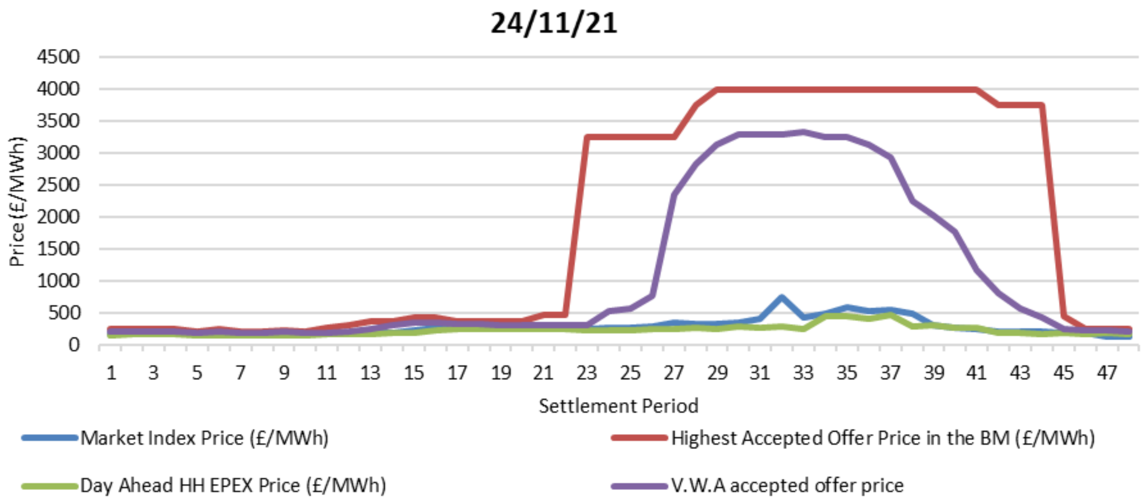

Figure 3 – Market Index price, Day Ahead price, highest accepted offer price in the BM and V.W.A accepted offer price on 24 November 2021[21]

4.5. This behaviour occurred on 9 of the 10 highest BM cost days during winter 21/22 as high offer prices were accepted in the BM in the region of £2000 to £4000/MWh, and these lasted over a number of hours compared to the sharper, shorter-duration spikes seen in the day ahead and intraday markets.

4.6. There appeared to be two key reasons why the high BM offer acceptance prices were extended over large periods: i) the MZT's of relevant generators; and ii) and revision of PNs to 0MW by those generators. This behaviour is set out in detail in Chapter 2, but to summarise, it is due to generators with long MZTs revising their PNs from a positive value to 0MW in the run up to and over the evening peak. As a result, the ESO was expecting this unit to be running, however after the revision of PN to 0MW it leaves the ESO with a decision on whether to let the unit desynchronise to 0MW and be unavailable for the peak or accept the high offer prices submitted by the generator in order to keep the system secure.

4.7. Figure 4 shows an example unit originally with a positive PN of 698MW for the full day (**navy**) at the DA stage. The example unit then revises their PN at 09:00 so that from SP28 onwards the PN would be 0MW (**blue**). This would likely mean that the example unit has bought back their traded position in the intraday market. Therefore, if the ESO allows this unit to ramp down to 0MW at SP28 (13:30), it would be unable to generate for 360 minutes due to its MZT. As a result, it would be unavailable until SP40 (19:30). The peak period during a winter's day is normally around SP35-37 (17:00-18:00), thus if the unit were to run

[21] Data obtained via LCP's Enact Platform

at its revised PN it would not be available to the ESO for the peak periods. As a result, when the system is tight, the ESO would have to accept this unit's offers in the BM to have this unit available in case it is needed.

4.8. When doing this, the generator may try to assess if the ESO is likely to need additional generation over the peak and in circumstances when they consider this to be the case, take a decision to submit high offer prices in the BM, resulting in situations where the ESO may have limited options but to accept high offer prices, and over a considerably longer time than needed. In the example above, resulting in higher offer prices being payable from SP28 onwards, as opposed to simply in SP35-37.

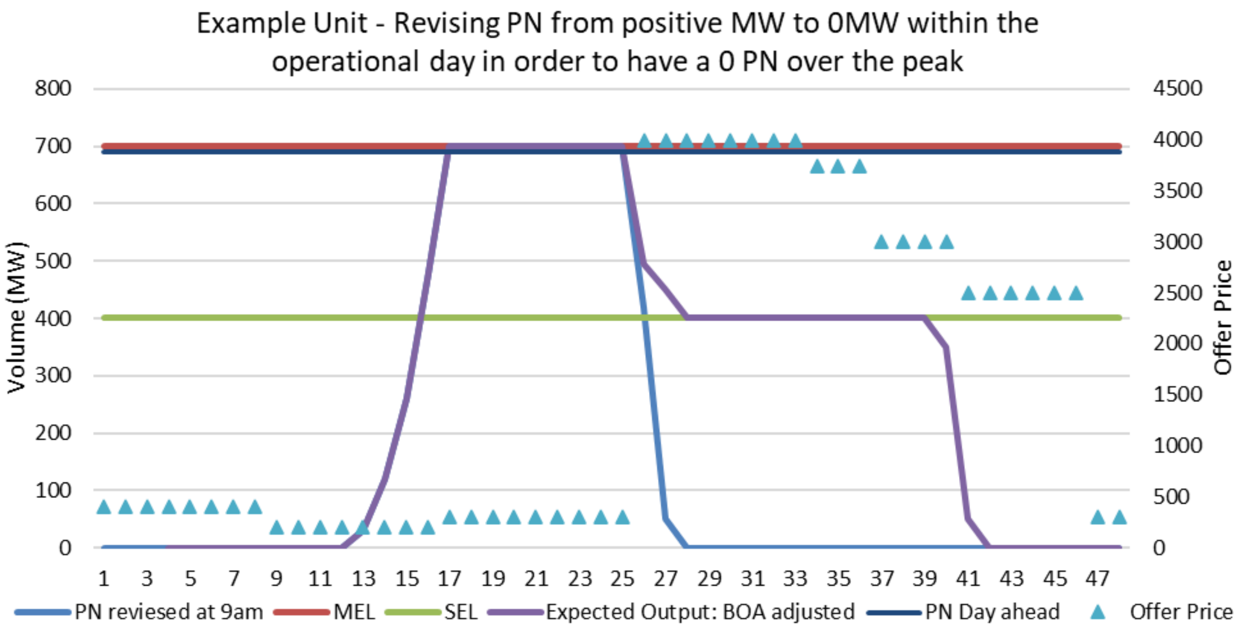

Figure 4 - Example Unit, Revising PN from positive MW to 0MW within the operational day in order to have a 0 PN over the peak

Change in Behaviour Between Winter 2021/22 and Winter 2022/23

4.9. Since our initial market communications and publications on this topic, we have witnessed some evident changes in the way generators behaved in the BM. We believe that some of the change in behaviour has been due to most generators acting in line with our proposals by either reducing the number times they revise their PNs to 0MW within the operational day or having a much lower offer price when doing this. This was evident in the

ESO's and LCP's 2023 BM Winter Review[22] as they highlighted that publications from Ofgem have likely had some impact in the reduction of costs in the BM. It should be noted however, that we have witnessed a few generators not acting in line with our proposals and thus we believe the intervention is still required.

4.10. It should also be noted that market communications and publications are not the sole reason for the reduction in BM costs. In winter 2021/22 we saw coal generators consistently price at £4,000/MWh in the BM. This effectively set a de facto cap on offer prices that would be accepted, and it was observed that thermal generators bid up to that price on tight margin days. In winter 22/23 these coal generators exited the BM as they were given winter contingency contracts to remain operation. This meant thermal generators had a less defined upper limit and therefore they typically did not submit offer prices as high as those in winter 21/22. We are also aware that other factors such as a milder winter and lower wholesale gas and power prices have also had an impact on the reduction of costs we have witnessed in the BM.

Comparison of Behaviours Between Winter 2021/22 and Winter 2022/23

4.11. The Frontier Economics BM review,[23] stated that the system was tight across each of the of the top 10 high costing days between September to December 2021. Figure 5 below shows the Volume Weighted Average (V.W.A) accepted offer price for each settlement period between September 2021 and February 2022 in the BM against the 1 hour derated margin[24] for that same settlement period. We can see that as the derated margin gets close to 0MW, the V.W.A of accepted offers in the BM are much higher. However, there are many periods where the system is significantly less scarce (6-8GW of derated margin) and the V.W.A accepted offer price is still very high.

[22] ESO's Winter Balancing Costs Review 2023 and LCP's Winter Balancing Costs Review 2023
[23] BM Review by Frontier Economics
[24] A measure of the amount of excess supply above peak demand, used as a proxy for system tightness.

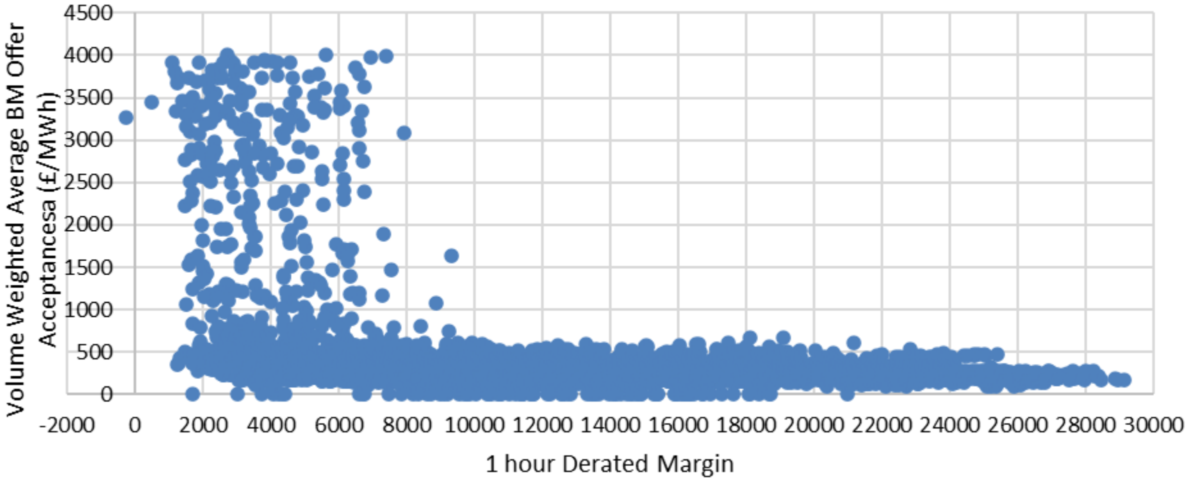

Figure 5 – The Volume Weighted Average (V.W.A) accepted offer price for each settlement period[25] between September 2021 and March 2022 in the BM against the 1 hour derated margin for that same settlement period[26].

Figure 6 shows the same graph but for winter 22/23. There is a clear difference in distribution between Figure 5 and 6. This shows that during tighter periods the pricing response itself is much more moderate in winter 22/23 than in winter 21/22.

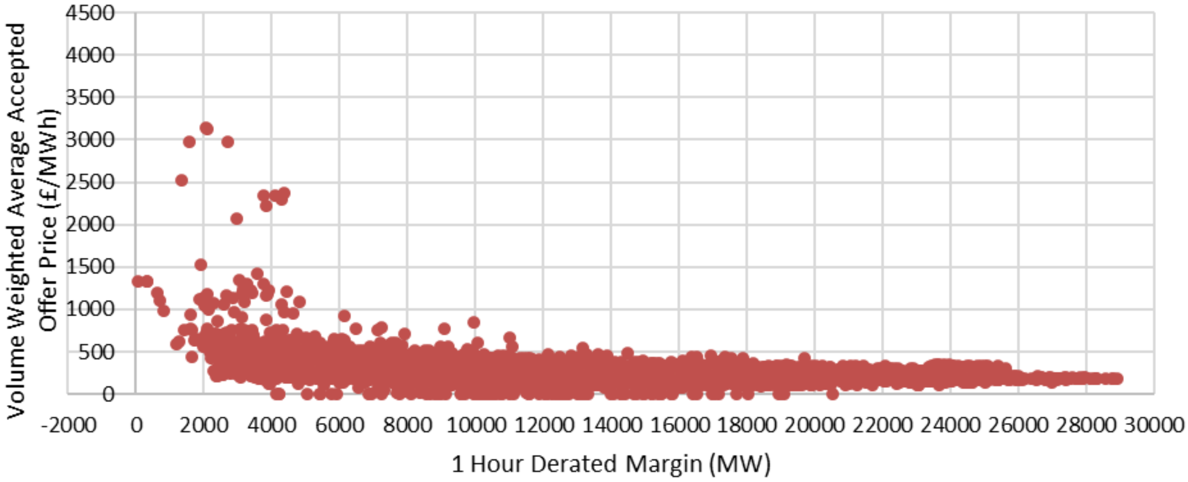

Figure 6 – The Volume Weighted Average (V.W.A) accepted offer price for each settlement period[27] between September 2022 and March 2023 in the BM against the 1 hour derated margin for that same settlement period[28].

---

[25] Data obtained via LCP's Enact Platform
[26] Data obtained via email from ESO on 19/06/23
[27] Data obtained via LCP's Enact Platform
[28] Data obtained via email from ESO on 14/06/23

Figure 7 shows the successful volume that participated in delayed desync in **red** (left-hand chart), the volume weighted average price of the accepted offer after delayed desync in **green** (middle chart) and the total BM costs from delayed desync in **purple** (right-hand chart) over the last 3 winters (November – March). We can see from Figure 7 that delayed desync is not a strategy that is new, and the volumes of successful delayed desync have decreased over the last three winters. However, in winter 21/22 we saw very high prices when generators participated in the delayed desync strategy, as the V.W.A offer price was over £1000/MWh compared to £132/MWh in winter 20/21. This winter we have seen the V.W.A offer price for this strategy decrease reduce to £295/MWh. As a result, the balancing costs from this behaviour have decreased from £250m in winter 21/22 to £51m in winter 22/23 due to a decrease in both volume and price.

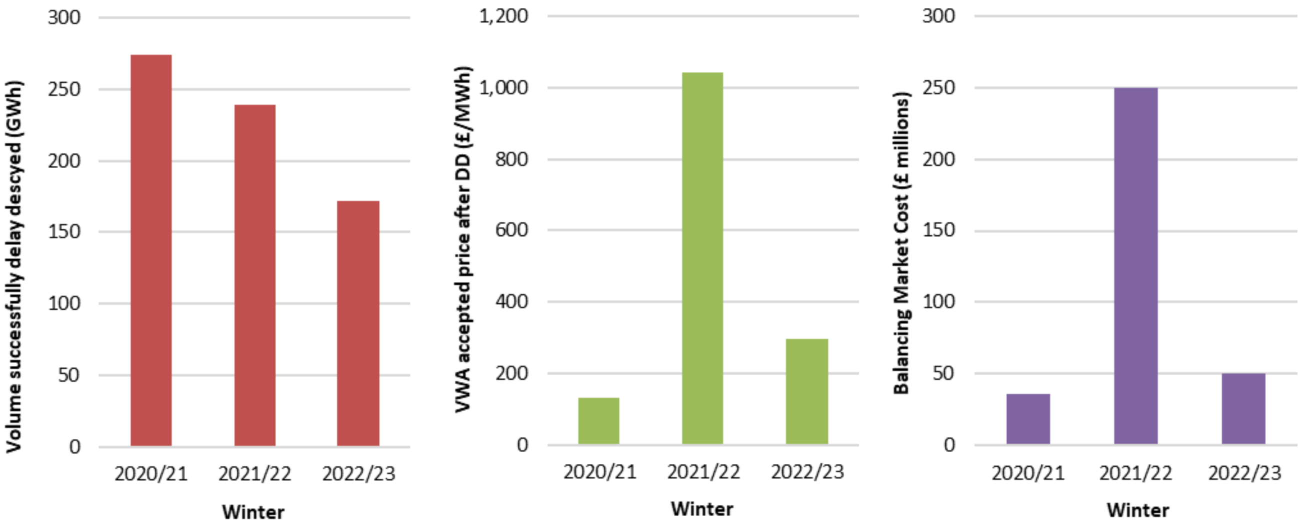

Figure 7 – Delayed desync volume, V.W.A accepted price after delayed desync, balancing market costs from delayed desync[29]

4.12. The net result of these behavioural changes noted above is that the most expensive days on the left-hand side of Figure 8 are substantially more muted in winter 22/23 when compared with winter 21/22. However, the 'average/lower cost days' across winter 22/23 are broadly consistent with winter 21/22 – see right-hand side of Figure 8.

[29] ESO's Winter Balancing Costs Review 2023 and LCP's Winter Balancing Costs Review 2023

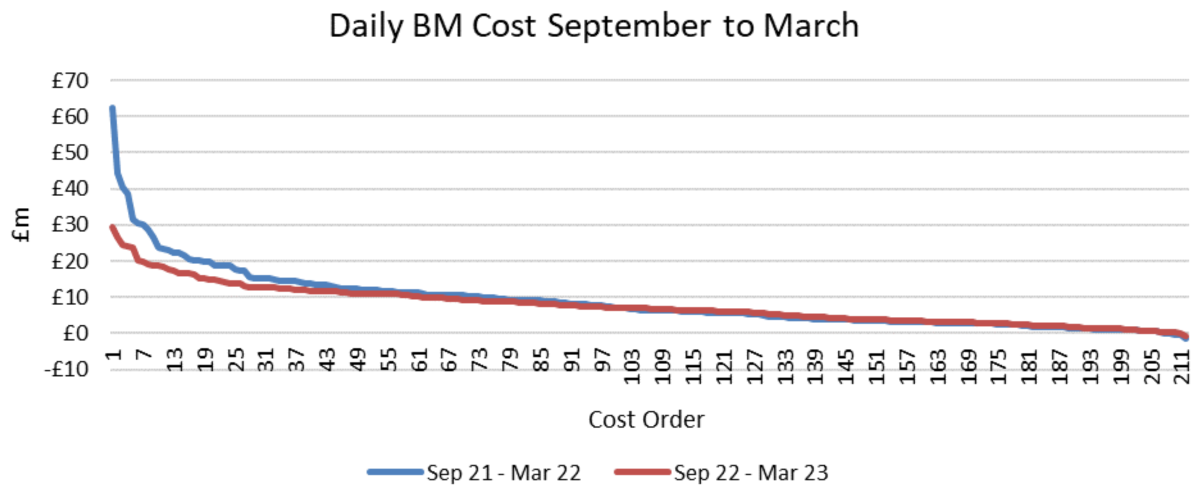

Figure 8 – Daily BM cost September to March[30]

[30] [ESO Data Portal: Daily Balancing Services Use Of System (BSUoS) Historic & Forecast Costs - Dataset| National Grid Electricity System Operator (nationalgrideso.com)]

5. Cost Benefit Analysis and Other impacts of IOLC

5.1. It is difficult to precisely isolate and quantify the expected costs, benefits and impact of the IOLC intervention. Besides the intervention, there are a multitude of additional factors that influence generators' behaviours in the BM and BM costs (notably weather, commodity prices, and plant or network availability). Therefore, we have sought to provide a robust qualitative assessment of the expected costs, benefits and impacts of IOLC across key market aspects, such as price signals, competition, investment, and security of supply (as well as distributional and sustainability impacts). This analysis is also supported by the quantitative evidence outlined in Chapter 4 illustrating the changes in generators' behaviours in the BM over winter 22/23 following our related communications and publications.

5.2. Following any potential implementation we will continue to monitor the effects the IOLC has on the BM, as well as other wholesale markets, in order to ensure the impacts are in line with our expectations.

Cost Benefit Assessment

Table 2 – Summary of qualitative costs and benefits

	Consumers	**Generators**	**ESO**	**Ofgem**
Option 1 (do nothing) - Cost	High BM costs continue to feed into consumer bill	No costs	High balancing cost feed into performance review scoring	Not acting in consumers' interests
Option 1 (do nothing) - Benefit	High BM costs continue to feed into consumer bill	Still earn excessive benefits	No change to control room or monitoring process	No Benefit
Option 2 (new licence condition) - Cost	No costs	Implement policies to comply with IOLC. Reduced revenue for some generators	Continued market monitoring	Small resourcing cost and cost of any enforcement cases opened if IOLC is breached
Option 2 (new licence condition) - Benefit	Reduced BM costs feed into consumer bill	Level playing field as unable to use technical parameters to gain benefit.	Better operational view of the system	Gives a clear mechanism to enforce against abuse in BM

Benefits to consumers

5.3. We expect that IOLC would provide benefits for consumers through reducing balancing costs, which are ultimately paid for through consumer bills. Chapter 4 shows that BM costs have reduced by over £200m when comparing winter 21/22 and winter 22/23. We note that some of this reduction may be attributable to other factors such as the exit from the market of price-setting coal plants, milder weather and a reduction in wholesale gas prices. However, the decline in offer prices when generators participated in the 'delay desync' strategy directly following the series of Ofgem communications suggests that the IOLC would have an enduring impact on reducing balancing costs.

5.4. This licence condition would also likely have a distributional impact as it would prevent the transfer of rent from consumers to generators if generators were disincentivised from seeking to charge "excessive" prices under the IOLC.

Benefits to generators

5.5. We believe that the IOLC would benefit the majority of generators as it would better promote a level playing field between different types of generators. The IOLC would prevent generators with inflexible technical parameters using their inflexibility to secure extended periods of high offer prices outside of periods of genuine scarcity. More flexible generators have not been able to secure similar levels of high offer prices outside of periods of genuine scarcity.

5.6. Although scarcity signals are part of a well-functioning market, long periods of scarcity pricing outside of genuine periods of scarcity do not represent a well-functioning market. We believe the majority of generators would benefit from IOLC as it would support more accurate market signals. IOLC could similarly also reduce imbalance price risk for all generators, as accepted offer prices outside of periods of genuine scarcity should be more reflective of system and market conditions.

Benefits to ESO

5.7. IOLC is likely to benefit the ESO through ensuring the control room has a better operational view of the system and improved foresight of the actions that would be needed to balance the system. During winter 21/22 the ESO had to take actions at short notice due to generators revising their schedules within the Operational Day in a manner which allowed them to obtain excessive benefit in advance of the evening peak. This meant that the running profiles of generation changed sometimes very close to gate closure and forced the ESO to take additional expensive actions over a prolonged period to secure the system. With IOLC in place there would be less of an incentive for generators to revise their PNs within the operational day as they would be prohibited from earning these excessive benefits.

Benefits to Ofgem

5.8. The IOLC would provide benefits to Ofgem as it would give us a clear mechanism to enforce against behaviour that is not in consumers' interests. Thus Ofgem would be acting in line with its principal duty of protecting the interest of electricity consumers. [31]

Cost to consumers

5.9. We believe there would be no cost for the consumer if the IOLC is implemented compared to the "do nothing" scenario, which would have resulted in the continued increase of balancing costs.

Costs to generators

5.10. Existing generators would likely have to put in place the appropriate policies and procedures to ensure compliance with the IOLC. However, we believe this to be a small cost. Licenced generators who participate in the BM should already have appropriate mechanisms in place to ensure compliance with existing wholesale market obligations.

5.11. New generators with MZTs above 60 minutes and obtain a generation licence would have to implement procedures to comply with the IOLC. However, we believe that this would be a low additional cost as these costs would be shared when setting up procedures to ensure they compliance with existing wholesale market obligations.

5.12. For a minority of generators that currently benefit excessively from the behaviours that IOLC is designed to prohibit, the introduction of IOLC would likely lead to reduced BM revenues.

[31] Section 3A of the Electricity Act 1989 (legislation.gov.uk)

Costs to ESO

5.13. Compared to the "do nothing" option, we expect that the IOLC would be negligible additional cost to the ESO. The ESO has an existing market monitoring team and systems in place to monitor the BM and flag any inconsistent behaviour with Ofgem. We believe that monitoring the IOLC can be achieved with the ESO's existing resources.

Costs to Ofgem

5.14. There would be a small resourcing costs incurred by Ofgem in order to conduct the implementation process for introducing the licence condition. Similarly, there may also be a small resourcing cost to Ofgem if there were any enforcement cases opened as a result of a breach of the IOLC.

Other Impacts of IOLC

Impact on price signals

5.15. We believe the IOLC would improve BM price signals by making them more reflective of market and system conditions. In recent years the delayed desync behaviour led to very high-priced BM offers being submitted and accepted outside of periods of genuine scarcity.

5.16. For example, on 16 December 2021 offer prices may not have been reflective of what was occurring on the system prior to the evening peak. At 14:30 derated margin forecasts (12:00 to 1 hour prior) were between 6.8GW and 8.3GW yet the V.W.A non-flagged offer price was £3,610/MWh for this settlement period. These prices did not accurately represent the system conditions as these offer prices were very high even though margins were not considered tight. On this day the peak demand occurred at 17:30 and derated margin forecasts for this period were between 3.1GW to 3.8GW, much tighter than 14:30. However the V.W.A non-flagged offer price at the peak was £3,125/MWh. Therefore, the system got tighter, yet the offer prices that were accepted reduced.

5.17. We are aware that some coal plants were active in the market at this point in time and their bidding behaviour acted like a de facto cap on offer prices at £4,000/MWh. CCGTs in the market then offered up to that price. However, since these coal plants exited the BM, some generators have continued the 'delayed desync' behaviour and have submitted very high BM offer prices outside of periods of genuine scarcity.

Impact on competition in the BM

5.18. Introducing the IOLC could have a small impact on competition in the BM that could be marginally negative or positive. For example, at present when generators revise their PNs to 0MW and then offer their full capacity to the ESO in the BM, they typically have to buy back the power they previously sold. This is often done through trading in the intraday market. Some generators have highlighted that when they trade in the intraday market with parties who cannot access the BM, the overall result is a net increase in capacity being offered into the BM.

5.19. We acknowledge this point, however, we note that intraday trades are anonymous and therefore the asset buying back its position cannot know who they are trading with, so we can't be certain this is a non-BM Unit and thus increasing competition in the BM. The asset may have traded with a BM Unit and therefore there would be no increase in competition in the BM. We also note that IOLC would not restrict intraday revision of PNs per se; IOLC's prohibition is on the excessive benefit gained by generators after revising their PNs from a positive MW value to 0MW within the operational day. Therefore generators would still be unrestricted when deciding to trade or not in the intraday market.

5.20. IOLC would also level the playing field between generators with inflexible technical parameters and those with more flexible technical parameters. At present only the generators with inflexible technical parameters are able to use these to gain excessive benefit from their BM offers. We anticipate that a more level playing field should lead to greater competition between generators in the BM.

5.21. The ESO has also been taking steps to improve competition in the BM and has sought to reduce barriers to entry through its work to widen access to the BM.[32] They are currently investing to improve their IT systems to enhance their balancing capability[33] in order to manage greater decentralisation of service providers and to accommodate closer to real time markets. Whilst also trying to increase the transparency on the operational decisions they make in the BM by releasing the dispatch transparency data sets.[34] There is still room for improvement in these areas but we believe that the ESO are looking at ways they can

[32] Balancing Mechanism Wider Access | ESO (nationalgrideso.com)
[33] Balancing programme | ESO (nationalgrideso.com)
[34] ESO Data Portal: Dispatch Transparency - Dataset| National Grid Electricity System Operator (nationalgrideso.com)

increase competition in the BM in order to have a more effective and efficient system. We also have in place an ESO Performance and Incentives Framework,[35] which holds the ESO to account for delivery in the areas mentioned above.

Impact on investments

5.22. As set out above, we believe IOLC would improve price signals by making them more reflective of market and system conditions. More reflective price signals would provide more certainty to investors in new electricity generation, particularly for investments in more flexible generation units.

5.23. A few consultation responses noted the importance of accessing BM scarcity revenues for investments in new generation. We are aware of this interaction and in certain situations, for example where the margin between available capacity and peak demand becomes tight, we still expect that a scarcity premium may be included in BM offer prices. However, we believe that scarcity pricing should be occasional and only ever occur during periods when there is genuine scarcity. However, during winter 21/22 we witnessed frequent occasions of scarcity pricing occurring over prolonged durations due to technical capabilities of generators, rather than being reflective of market and system conditions.

5.24. An LCP report[36] commissioned by the ESO to review its market design framework noted that the BM is primarily a short-term market for energy balancing that is in place to allow the ESO to balance the system. The BM was not designed to provide long term signals for investors. LCP highlighted that although the BM may provide some signals to bring forward investment in flexible assets, the BM isn't believed to be a critical factor in investment decisions. LCP stated that this is because the revenues achieved in the BM are highly variable and do not provide investors with the predictability, they need to underpin investment cases. Investors are likely to get most value from the BM through transparency, market coherence and a clear understanding of the when revenues are likely to be achieved. The IOLC should support this transparency through more reflective price signals.

5.25. A few respondents to our consultation noted that they believe that the IOLC could exacerbate the 'missing money' problem[37] within the GB electricity market. However, we

---

[35] How we're performing under RIIO-2 | ESO (nationalgrideso.com)
[36] Full Report - LCP Delta ESO Market Design Framework Assessment 2023-03 (nationalgrideso.com)
[37] The 'missing money' problem refers to the argument that revenues for generators are not sufficient to incentivise optimal levels of investment

don't believe this to be the case. The Capacity Market (CM) provides the primary route to solve the 'missing money' problem and facilitates investment in capacity to ensure security of supply.[38] As a result we believe that CM auctions are a stronger, more reliable investment signal to the market.

Impact on Security of Supply

5.26. The IOLC could have an impact on short term security of supply, as noted by a few respondents to the February Consultation. Some respondents highlighted that, when the system is tight, the IOLC could reduce the incentive for generators returning from outage to make themselves available as quickly as possible. We believe that in limiting the IOLC to only being applicable to generators who have revised their PN from a positive MW value to 0MW within the operational day this would materially reduce the negative impact on security of supply. This is because most generators capable of returning rapidly from outage would have submitted their 0MW PN before the operational day.

5.27. It should also be noted that the Capacity Market should further mitigate this impact for units that also hold a Capacity Market agreement. This is because the Capacity Market agreement creates an obligation for a unit to produce electricity during a Capacity Market System Stress Event. This should incentivise units to return if system conditions become tight as they would be subject to Capacity Market penalties should they not produce electricity during a Capacity Market System Stress Event.

Impact on Interconnector Flows

5.28. A response to the February Consultation asked if we had considered how IOLC would impact interconnector flows. Following further consideration and investigation, we don't think it will significantly change the interconnector flows as these are mostly dependent upon day ahead market prices and spreads. However, the impact on ESO interconnector trading which can change these flows will depend on the specific commercial strategies adopted by units included in the IOLC.

[38] capacity_market_policy_presentation.pdf (publishing.service.gov.uk)

Impact on Generator Running Profile Close to Real Time

5.29. The IOLC may impact the close-to-real-time running profile of generators who have MZT's above 60 minutes. Instead of revising PNs to 0MW, the IOLC may incentivise generators to revise their PNs to their Stable Export Limit (SEL), in order to maintain their ability to incorporate a scarcity premium in their BM offer prices. We believe this would be a positive impact of the IOLC. If a generator revises their output to SEL, they would maintain their flexibility to vary their output between SEL and their Maximum Export Limit (MEL) relatively quickly without triggering their MZT. This would provide the ESO with greater flexibility to balance the system.

Distributional Impacts

5.30. As mentioned in Paragraph 5.5, we believe that the distributional impact of IOLC would be to transfer revenue from generators to consumers. This is due to generators being prohibited from gaining 'excessive benefits' under the IOLC. Thus, generators loss of excessive profits is a gain for consumers by having lower balancing costs and therefore lower electricity bills.

5.31. The IOLC would have no impact on how consumers use electricity. However, since BSUoS is levied volumetrically those who consume more electricity may benefit more from the reduced balancing costs.

Sustainability impacts

5.32. We do not see this licence condition causing an impact on sustainability in the GB electricity system. We believe the IOLC would likely reduce revenues in the BM for some thermal generators but believe there is still a significant area for revenue to be gained by these thermal plants in the BM (and other markets, such as the CM) and thus should not materially affect their sustainability.

6. Risks and Assumptions

6.1. Our Impact Assessment is dependent on a number of assumptions. One of our main assumptions is that, in the absence of intervention, generators would continue to use their inflexible technical characteristics (eg, MZTs) and revised PNs to gain excessive benefits for the foreseeable future. Therefore, these high balancing costs would continue to persist. We expect the IOLC to have a positive impact on balancing costs in the future by prohibiting this from occurring.

6.2. Our other main assumption is that the licence condition has a distributional impact of transferring the revenue from generators to consumers. Some generators' loss of excessive benefits is a gain for consumers by having lower electricity bills.

6.3. Other assumptions we have made include:

- The IOLC would increase the level playing field across all BM participants as specific generators can no longer take advantage of gaining excessive revenue as a result of using their inflexible technical characteristics;

- The IOLC would facilitate more accurate price signals which are better reflective of system and market conditions;

- Recent Ofgem publications and communications on this behaviour have assisted in reducing BM costs;

- Compliance costs for generators are not significant and there is a relatively low cost for market participants to make changes to policies and procedures.

6.4. We acknowledge the risk that we may see a behavioural response to the new incentives created by the IOLC. For example, as the prohibition in the licence condition would only be triggered by PN revisions to 0MW during the operational day, generators may seek to gain excessive benefit by revising their PN to 0MW during the day ahead. As a result, we will continue to monitor the market behaviour in the BM and will reintervene if necessary.