Public

Frequency Risk and Control Report

Security and Quality of Supply Standards

The Report – For Consultation

Minimum Inertia Requirement and Additional Response Holding

March 2025

NESO
National Energy System Operator

Contents

1. Foreword

In 2024, the Great Britain electricity system celebrated a remarkable achievement by completely phasing out coal from its power system and reaching 95% zero-carbon operation for a brief period. This milestone underscores the power of world-leading engineering and innovation in the industry.

During the past few years, significant advancements have been realised through the Accelerated Loss of Mains Change Programme (ALoMCP) and the Stability Pathfinder Projects including the advancement of Grid Forming technology. The phase-out of the dynamic Firm Frequency Response (sFFR), the expansion of the market for Dynamic Containment (DC), Dynamic Regulation (DR), and Dynamic Moderation (DM), and the co-optimisation of Ancillary Services via the Enduring Auction Capability (EAC) also marked a significant shift in the energy landscape.

As we move towards operating a safe, secure, affordable and fully clean power system, we face substantial challenges. In accordance with the Security and Quality of Supply Standard (SQSS), the National Energy System Operator (NESO) produces an annual Frequency Risk and Control Report (FRCR) and consults with the industry on its assessments. Its previous recommendations along with the introduction of new dynamic response services have greatly enhanced system security, reduced costs, and will contribute to enablement of the Government's 2030 Clean Power Action Plan.

- FRCR 2021 established the baseline for cost vs. risk in frequency management;
- FRCR 2022 evaluated the consumer benefits of securing simultaneous events;
- FRCR 2023 assessed the benefits of reducing the minimum inertia requirement;
- FRCR 2024 assessed the benefit of using additional response to secure beyond BMU-only events whilst operating the system at the reduced minimum inertia level.

The FRCR 2025 aims to further reduce the minimum inertia requirement, mitigate all BMU-only loss risks, and apply additional frequency response controls to reduce residual risks, ultimately providing better value for consumers and maintaining system security. The consultation period for the FRCR 2025 will be held from 3 March 2025 to 31 March 2025.

2. Executive summary

The requirement for a Frequency Risk and Control Report (FRCR) was introduced following the approval of Security and Quality of Supply Standards (SQSS) modification GSR027.

This 2025 FRCR report assesses system risk and cost, at a minimum inertia of 102 GVA.s during 2025/26 and 2026/27. This report represents our continued effort to secure beyond BMU-only risks and to deliver NESO's 2025 ambition for zero carbon operation. The report also re-assesses whether the existing FRCR policy, of not taking additional actions to secure all simultaneous events, still delivers the best value for consumers.

FRCR 2025 Recommendations

- **Reduce the minimum inertia requirement from 120 GVA.s to 102 GVA.s**

The minimum inertia requirement under the FRCR policy refers to the minimum inertia required at national level to manage frequency risks. The report indicates there are significant cost benefits obtained by reducing the minimum inertia requirement from 120 GVA.s to the lower level of 102 GVA.s. There is no tangible increase in the overall system residual risk by operating at this reduced inertia level, and this reduction supports the delivery of 2025 zero carbon operation and 2030 clean power targets. The estimated cost saving from the inertia requirement reduction is **£96m per year**.

- **Secure all Balancing Mechanism Unit (BMU) only risks and do not apply additional actions to mitigate all BMU plus Vector Shift (BMU+VS) and simultaneous events**

The current policy of securing all BMU-only events still presents the best value. Securing against all BMU plus VS does not improve system security significantly but requires procuring a substantially uneven DC requirement across the year. Securing simultaneous events would require a significant increase in procured DC capacity. This volume is not currently available and would place the current market under significant pressure, while increasing operational risk and cost. Therefore, we do not see value in changing the current policy relating to securing all BMU plus VS and simultaneous events as it does not provide good value for consumers.

- **Consider additional Dynamic Containment -Low (DC-L) requirement to further reduce residual risks**

Dynamic Containment (DC) is currently the most cost-effective service for managing post-fault frequency risks. Market growth and the introduction of Enduring Auction

Capability (EAC) have improved the liquidity of the DC market and driven a cost reduction for procuring the service. Holding additional DC-Low response improves system security and signals the market to further grow its capacity in meeting future system needs. The report verifies that holding an additional 200 MW of DC-Low, presents the best value for consumers.

Impact of Recommendations

The implementation of this policy in 2025/26 with additional DC-Low holding, results in a residual risk of a **1-in-23** years occurrence of a 49.2 Hz event and **1-in-30** years occurrence of a 48.8 Hz event.

The residual risks have increased compared to last year's FRCR analysis, with the likelihood of 49.2 Hz events moving from 1-in-29 years in FRCR 2024 to 1-in-23 years in FRCR 2025. The likelihood of 48.8 Hz events happening remains the same as last year's analysis. The main cause of the risk change for the 49.2 Hz event is a review of simultaneous events, which shows a higher probability of these events occurring in our model. We believe this is more representative of our operational experiences. More information can be found in the **Handbook** section 5.4.

The estimated annual cost of managing frequency risks based on this year's FRCR is £173 million. This includes a £96 million cost saving from reducing the minimum inertia requirement and a £3.2 million cost for procuring additional DC.

When the FRCR 2025 policy is approved, the industry will be informed of the implementation plan through industry forums, such as the Operational Transparency Forum (OTF), before going live.

FRCR 2025 Integrated Technical Review

In December 2024, the SQSS Panel formalised a request for assurance of FRCR 2025. In January 2025, NESO proposed an integrated technical assurance approach whereby Accenture would perform an independent review, using NESO prepared test criteria, of the end-to-end FRCR report creation process, with oversight provided by NESO's functionally independent Engineering Assurance Team.

Phase 1 covered up to and including the development of the policy recommendations (included in this version for consultation). Testing was performed by Accenture using tests provided by NESO's Engineering Assurance Team. Having performed a challenge and review of the output from Accenture's testing, NESO's Engineering Assurance Team are satisfied that a rigorous process has been followed in: agreeing the methodology with industry; applying the methodology both in terms of sourcing and processing key supporting datasets; running the model, the outputs from which are reproducible and have been subject to expert challenge and review; and developing policy recommendations from the model outputs.

Phase 2 will cover the processing of feedback from industry consultation, including any re-running of the FRCR model.

Assurance reports from NESO's Engineering Assurance Team, covering Phases 1 and 2, will be published along with the FRCR 2025 suite of documents on the NESO website.

3. Background

3.1 Overview

The requirement for a Frequency Risk and Control Report (FRCR) was introduced following the approval of Security and Quality of Supply Standards (SQSS) modification GSR027: *'Review of the NETS SQSS Criteria for Frequency Control that drive reserve, frequency response and inertia holding on the GB electricity system in 2020'*. There are three main documents in the FRCR process which link together as follows:

Frequency Risk and Control Report (Report)

The report sets out the assessment results of the operational frequency risks on the system. It includes an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system. It confirms which risks we will or will not secure operationally in line with the expectation set out under the SQSS. The SQSS notes that the FRCR will set out those conditions under which unacceptable frequency conditions will not occur.

Frequency Risk and Control Report Methodology (Methodology)

The methodology sets out what will be assessed, how it will be assessed and the format of the outputs. The methodology inputs include: impacts, events and loss risks, controls, and metrics for reliability vs. cost.

Frequency Risk and Control Report Data Handbook (Handbook)

The handbook is designed to be used as a reference to provide a detailed explanation of how the data has been collected and used in the FRCR process. Furthermore, the handbook offers guidance on interpreting the results. It also includes case studies and examples to illustrate the application of the methodology, thus serving as a comprehensive guide for stakeholders involved in the process.

This report will be open for consultation from 3 March 2025 to 31 March 2025, accompanied by supplementary documents including the Methodology and Handbook. A webinar is also scheduled during the consultation period. The final report will then be submitted to the Authority for approval.

3.2 FRCR objectives

The FRCR sets out the results of an assessment of the operational frequency risks on the system which includes:

- the magnitude, duration and likelihood of transient frequency deviations,
- the forecast impact of these deviations,
- the cost associated with securing the system for these deviations, and
- confirms which risks we will or will not secure operationally under paragraphs 5.8, 5.11.2, 9.2 and 9.4.2 of the SQSS.

These objectives are formalised through the Security and Quality of Supply Standards (SQSS) and the FRCR **methodology**. This report provides an assessment and recommendation on achieving the right balance between the competing objectives of reliability and cost, focusing on the risks, impacts, and controls for managing system frequency.

The detailed methodology is outlined in the Methodology document, which offers an objective and transparent framework for assessing the risks associated with frequency deviations, identifying the events that could cause them, their magnitude, the impacts they have, and the cost and mix of controls needed to mitigate them.

Consultation and ongoing engagement with industry stakeholders are crucial for achieving this balance openly and transparently. Our role is to analyse the risks, impacts, and controls, and their effects on reliability and cost, and to present a recommendation on the appropriate balance. This enables the Authority to make an informed decision on balancing the reliability of electricity supplies with the cost to end consumers.

4. Scope of FRCR 2025

4.1 Assessment of FRCR policy on minimum inertia requirement

The minimum inertia requirement was reduced from 140 GVA.s to 120 GVA.s as recommended in FRCR 2023. We are re-evaluating the current minimum inertia requirement and assessing whether it is sufficient to manage the system frequency risks. System risks and costs will also be assessed when running the system with lower inertia levels of 110 GVA.s and 102 GVA.s.

The minimum inertia of 102 GVA.s is based on a future largest loss of 1800 MW and ensures the Rate of Change of Frequency (RoCoF) remains within 0.5 Hz/s. An 1800 MW loss would require 90 GVA.s of inertia to ensure RoCoF remains within 0.5 Hz/s. This assumes a loss of approximately 12 GVA.s of inertia from the 1800 MW unit. This results in the pre-fault minimum inertia requirement of 102 GVA.s. The 2024 Operability Strategy Report (OSR) discusses our zero carbon operation goals by end of 2025 and the delivery of clean power by 2030, detailing how the reduced minimum inertia levels interact with overall operability challenges. The 2024 OSR will be published in March 2025.

4.2 Assessment of FRCR policy on loss categories

We are assessing the cost-risk benefits of securing against different loss risk categories, namely BMU-only, BMU+VS (under outage or intact system conditions), and simultaneous events.

The analysis includes an assessment of the cost-risk benefits associated with applying additional controls, such as holding additional response, to further mitigate risks beyond the current policy of securing BMU-only events. This assessment aims to determine the effectiveness and efficiency of these additional measures in reducing risks and optimising the cost-risk balance.

4.3 Assessment of FRCR policy on additional Dynamic Containment

Under current system conditions, with increased system dynamic with less inertia, it is cost-effective to use the new suite of dynamic response services to manage the system. The new suite of dynamic response services has a fast-acting capability which ensures that the system remains stable and reliable at a reasonable cost.

As of February 2025, we currently see approximately 5000 MW of participation in the dynamic response auctions of which we secure around 3000 MW in each Electricity

Forward Agreement (EFA) block. Starting from last FRCR, the steady growth of the DC, DM and DR markets has enabled us to think beyond secure BMU-only events as we recommended additional 100 MW DC-low in FRCR 2024. We are continuing assessing potential benefits to hold additional DC-Low response this year to further mitigate residual risks on the system this year.

4.4 Outlook to 2026/2027

Since FRCR 2024, FRCR study covers an extended time horizon to assess system risks for multiple years. This forward-thinking approach ensures that potential future challenges and opportunities are thoroughly evaluated. Looking ahead to 2026/2027, the outlook will delves into how the proposed policy is expected to perform beyond just the next year.

5. Performance review of previous inertia requirement reduction

The FRCR 2023 recommendation was to reduce the minimum inertia requirement from 140 GVA.s to 120 GVA.s. The policy was approved by Ofgem on the 9 June 2023. The implementation of this policy was delayed due to system events such as the Sub-Synchronous Oscillations (SSO) during the summer of 2023.

Phase 1 of the implementation, which reduced the minimum inertia requirement from 140 GVA.s to 130 GVAs, was implemented on 28 February 2024. Phase 2, which reduced the requirement further from 130 GVA.s to 120 GVA.s, was implemented on 19 June 2024.

Following these changes, a performance review of the policy with reduced minimum inertia was conducted and presented at the NESO Operational Transparency Forum (OTF) on 29 January 2025[1]. The performance review of the inertia requirement reduction is included in this report. The main content of the review consists of three parts. The first part demonstrates how the system inertia has changed after the implementation. The second part reviewed system events happened after the change. The last part details the balancing cost savings resulting from the policy.

5.1 System inertia

The system inertia from January to December 2024 is plotted in Figure 1, showing the system daily maximum and minimum inertia over time and the 7-day average inertia.

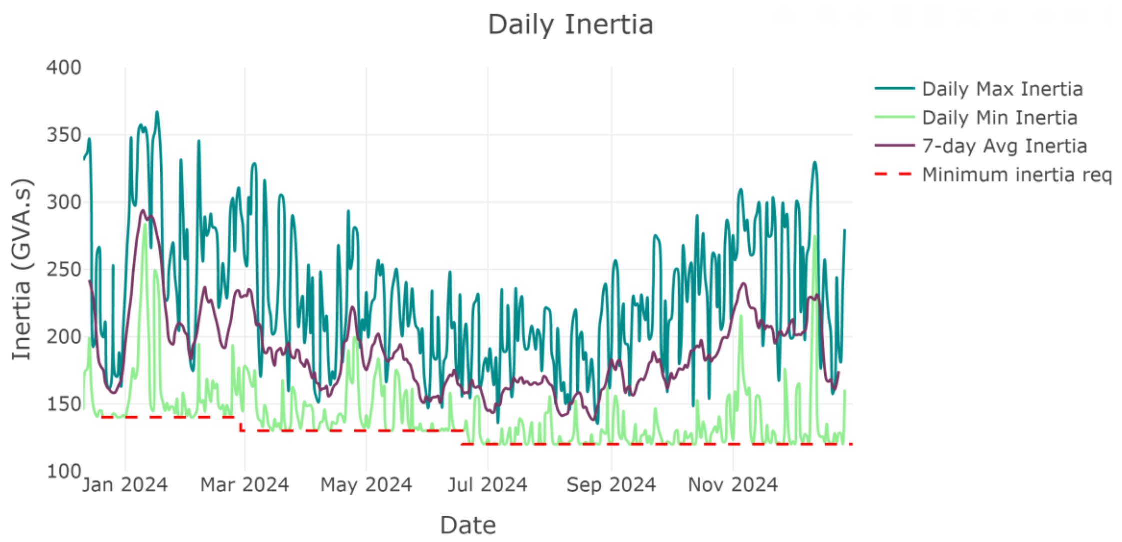

Figure 1 Daily inertia data in 2024

[1] Operational Transparency Forum 29.01.25

Following the policy implementation, we have seen more occasions when the system outturn inertia is at, or close to, the lower minimum requirement although distinct seasonal patterns remain. Figure 1 Daily inertia data in 2024has illustrates these trends.

As an example, Figure 2 provides a breakdown of inertia from 19 to 25 of August 2024. In this figure, the blue line represents the stability pathfinder phase 1 units, the orange line represents inertia from the market, the green line is the inertia from additional machines synchronised for voltage management, and the purple line indicates the actions taken by NESO to bring the inertia up to the minimum required level.

As demonstrated in both figures, the system inertia is always managed above the minimum inertia requirement. For detailed inertia calculation and assumptions please refer to the **Methodology** and **Handbook**.

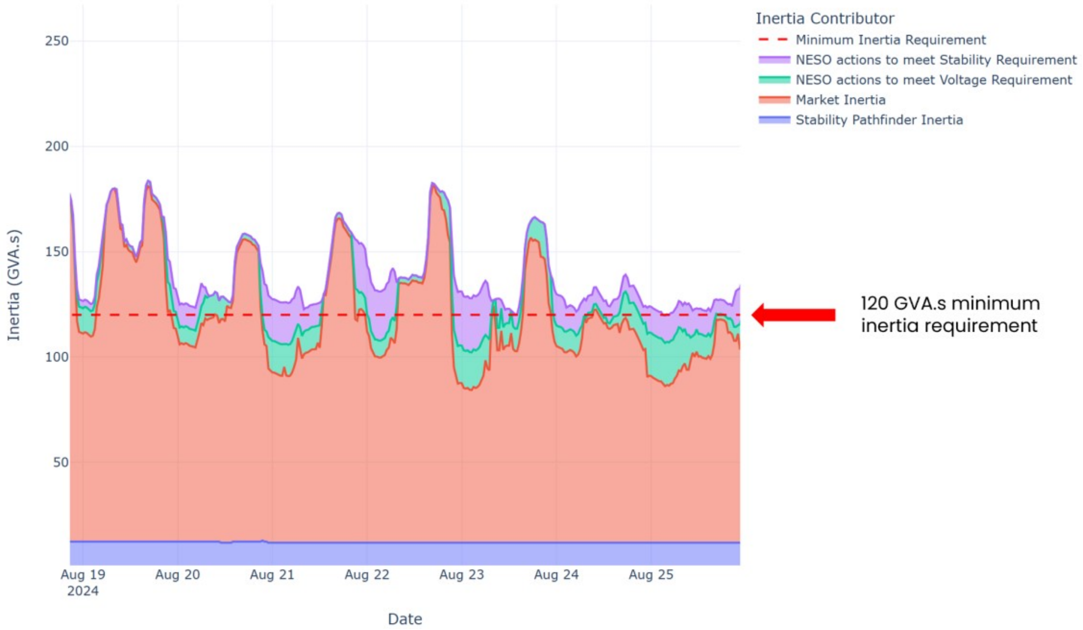

Figure 2 Inertia breakdown for a week in August 2024

5.2 System events

By the end of 2024 since implementing the lower minimum inertia policy, there was no reportable frequency events in the GB system, where the system frequency excursions outside statutory limits, i.e. a range of 49.5 Hz to 50.5 Hz, for 60 seconds or more, according to the Transmission Licence Standard Condition C17: Transmission System Security Standard and Quality of Service[2]. After implementing the lower minimum inertia

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[2] You can find past Transmission performance report (C17) from NESO website.

policy, there was no increasing trend observed in frequency events[3] based on Grid Code – OC3 reporting criteria. During those events the system and response services performed as expected, and the events were not initiated, caused or related to the lower system inertia policy.

We also observed a few Sub-Synchronous Oscillation (SSO) events on the Transmission System in Scotland in 2024. During one of the events, system inertia was recorded at 125.6 GVA.s which was close to the 120 GVA.s minimum requirement. For the remaining events, national inertia was much higher than the minimum level. Our investigation finds no correlation between lower system inertia and the SSO events. NESO has other workstreams actively addressing this issue to ensure that any potential impacts are thoroughly evaluated and managed.

Following the implementation of the lower minimum inertia policy, we have accordingly increased DC-Low and DC-High procurement volumes. We have observed increased capacity and adequate liquidity in the ancillary service market, which is helping us manage system frequency effectively.

5.2.1 Balancing cost saving

This section presents the balancing cost savings from reducing the inertia requirements. We used counterfactual calculations to estimate costs if the minimum inertia remained at 140 GVA.s. Savings result from needing fewer additional inertia machines. The figure below shows monthly and cumulative savings compared to FRCR 2024 projections.

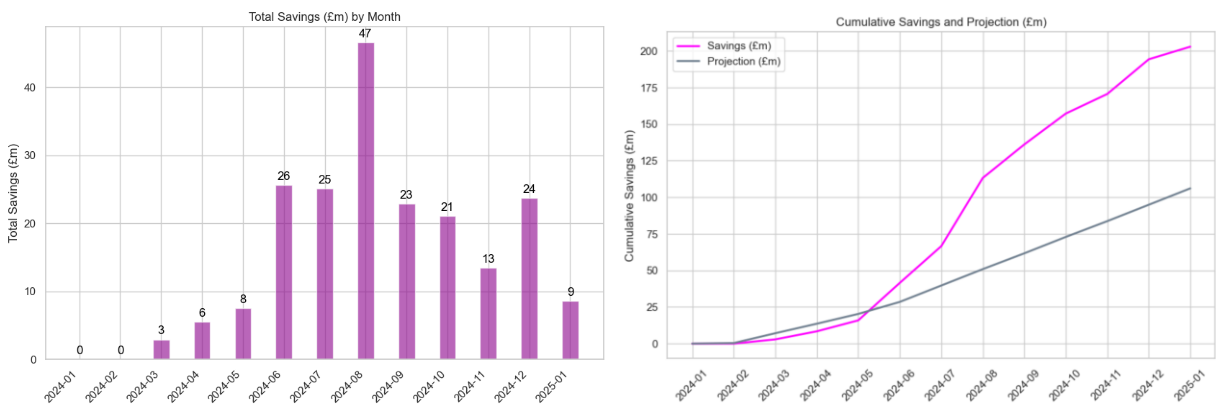

Figure 3 Savings from inertia requirement reduction

[3] events that meet GC105 and GC151 criteria are published on NESO website.

By January 2025, cost savings totalled over £200 million, that is well above the FRCR 2024 projection. Please note, in FRCR model we consider average offer and bid price from historical data and adjust by gas and electricity prices, whilst actual balancing costs are used in the counterfactual calculation. Therefore there may be a difference between the actual savings and the projection. For more details on the cost calculations, please refer to the OTF material.

6. Assessment and results

This chapter reviews the assessment carried out in FRCR 2025: minimum inertia requirements, securing different loss categories, and benefits of securing additional event categories while providing an outlook to 2026/27. Table 1 below presents the current policy alongside the potential policy evaluated in this report.

Table 1 Current policy vs. Tested policy in FRCR 2025

	Current policy	Tested policy
Minimum inertia requirement	120 GVA.s	140, 120, 110 and 102 GVA.s
Secured Loss group	BMU-only	BMU-only, BMU + VS (outage and intact), Simultaneous event
Additional DC-Low response	100 MW	0, 100, 200 and 300 MW

Each section within this chapter includes analysis, results and recommendations for each of the key areas. The analysis in each section focuses on the system residual risks, costs, and additional DC-Low response.

6.1 Assessment of minimum inertia requirements

This section assesses the impacts and benefits of operating at different minimum inertia requirement levels, including the legacy 140 GVA.s (before FRCR 2023), current 120 GVA.s (after FRCR 2023) and potential new levels at 110 and 102 GVA.s. The primary objective of this assessment is to understand the residual risks and overall costs associated with each of these inertia levels.

6.1.1 System residual risks

Table 2 System residual risks

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
49.5 Hz event	2.84 times per year	2.85 times per year	2.85 times per year	2.85 times per year
49.2 Hz event	1-in-7.40 years	1-in-7.28 years	1-in-7.25 years	1-in-7.24 years
48.8 Hz event	1-in-26.09 years	1-in-25.89 years	1-in-25.83 years	1-in-25.83 years
50.5 Hz event	1-in-78.96 years	1-in-78.99 years	1-in-79.04 years	1-in-79.06 years

The table above shows the system residual risks under different minimum inertia requirements when fully mitigating all BMU-only infeed and outfeed loss risks. A residual risk is calculated as the probability of all the unsecured events that could trigger 49.5 Hz, 49.2 Hz, 48.8 Hz or 50.5 Hz frequency deviations after controls are applied.

It is evident from the table that the residual risks for each frequency event scenario remain consistent across all levels, despite the differences in the minimum inertia required. This implies that DC is effectively balancing the variations in inertia requirements.

Comparing the residual risks to the FRCR 2024, there has been a notable change in the risk associated with the 49.2 Hz frequency event. Previously, the risk of encountering a 49.2 Hz event was estimated to be 1 in 27 years, and it has now increased to 1 in 7.3 years. Similarly, the residual risk of a 48.8 Hz event is increased from 1 in 30 years from 2024 assessment to 1 in 26 years in FRCR 2025.

This shift is primarily due to a comprehensive review of simultaneous events occurring between 2019 and 2024. The probability of these simultaneous events has been recalibrated from the previous estimate of 1 in 20 years to 1 in 1.3 year for upper quantile simultaneous events. This updated probability reflects a more frequent occurrence of simultaneous events, leading to a considerable change in the risk assessment. More information can be found in Section 5.4 in the **Handbook**.

Despite the updated event probabilities, it is important to note that the FRCR policy mandates securing all BMU-only events. Consequently, the response holding remains at a similar level and is not impacted by the updated probability of simultaneous events. This means that the system's security has not been diminished compared to previous years' assessment; instead, it has been updated to reflect the most recent event data.

6.1.2 System overall cost

Table 3 Cost breakdown under different minimum inertia requirements

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
Cost for system-wide controls (*NB: system-wide controls include inertia and all response costs*)	£524m	£266m	£198m	£170m
Cost to meet minimum inertia (this element is included in system wide cost)	£455m	£196m	£128m	£101m
Cost for Dynamic Containment (this element is included in system wide cost)	£24.3m	£24.5m	£24.6m	£24.6m
Incremental saving		**£258m**	**£68m**	**£28m**

The table above shows the costs and potential savings that could be achieved across the different minimum inertia requirements when fully mitigating all BMU-only infeed and outfeed loss risks.

When assessing the cost impact of a changing the minimum inertia requirement, only the costs of DC and inertia are impacted. All other system wide costs, such as DR, DM and static response, remain unchanged. Increasing the DC requirements results in higher DC-related costs, and increasing the inertia also leads to higher inertia-related costs. Since DC is a more effective tool for managing frequency risks, the cost savings achieved by reducing inertia are significantly greater than the cost increases associated with DC increases.

With the current 120 GVA.s minimum inertia policy, we estimate that a total saving of £258m has been achieved as we moved from 140 GVA.s to 120 GVA.s. Compared to 120 GVA.s, an estimated further cost saving of £96 million is expected when operating at 102 GVA.s. When reducing inertia requirement to 102 GVA.s, the additional DC volume to maintain the system security is not significant. The total additional cost is estimated around £22k per year which indicates DC is highly cost effective.

6.1.3 Recommendations

Analysis indicates that an additional £96m could be saved if we reduce the minimum inertia requirement to 102 GVA.s. There is no reduction in the overall system risks by operating at an inertia level lower than 120 GVA.s. It is likely that system events that cause frequency deviations outside of 48.8 Hz under 102 GVA.s would also result in frequency deviations outside of 48.8 Hz under a higher inertia level of 120 GVA.s. Hence the residual risk of 48.8Hz events remains largely the same under various inertia conditions.

The implementation of 120 GVA.s, as recommended by FRCR 2023, has been enabling us to gain experience associated with operating the system at a lower inertia level from 2024. Therefore, for the period covered by this report, 2025/26, we consider that it is beneficial to further reduce the minimum inertia to 102 GVA.s. This change represents our continued effort to operate the system at lower inertia levels, to help meet our zero carbon ambitions.

Based on the assessment conducted, we are recommending a reduction in the minimum inertia requirement from 120 GVA.s to 102 GVA.s.

6.2 Assessment of securing additional event categories

Current policy focuses on securing BMU-only events with their consequential RoCoF loss. In this section we review the impacts and benefits of securing additional event categories, including BMU+VS and simultaneous events under reduced inertia requirement. The primary objective of this assessment is to determine the appropriate approach regarding event categories to understand if there is any additional value to secure beyond BMU-only events under the recommended reduced minimum inertia level of 102 GVA.s. The analysis focuses on system residual risks and cost-benefit considerations.

6.2.1 System residual risks vs. cost

This section evaluates the risk vs. cost of using Response Control to secure the remaining event categories, i.e. BMU+VS (outage), BMU+VS (intact) and Simultaneous events. As mentioned in section 4.3, the cost reduction of DC presents an opportunity to use additional Response Control to mitigate the system risks beyond BMU-only events with little additional cost.

FRCR 2024 analysis compared BM Control and Response Control to mitigate beyond BMU-only events. It was concluded that Response Control offers significantly higher cost-effectiveness compared to BM Control. From this year's assessment, only Response Control is considered to assess beyond BMU-only events.

To mitigate all BMU+VS events, the estimated additional cost for Response Control is around £278k on top of the total cost under 102 GVA.s of £170m, whereas the additional cost for securing all simultaneous events would be around £20m. The system residual risks and additional costs associated are concluded in the below table.

Table 4 Risk and cost for different risk categories at 102 GVA.s

Event category	Response Control		
	Residual risk for 49.2 Hz event	Residual risk for 48.8 Hz event	Additional cost per year
BMU-only	1-in-7.24 years	1-in-25.83 years	£0
BMU+VS (outage)	1-in-7.25 years	1-in-25.84 years	£14k
BMU+VS (intact)	1-in-7.26 years	1-in-25.84 years	£278k
Simultaneous event	1-in-9999 years	1-in-9999 years	£20m

*minimum inertia requirement is 102 GVA.s

The current policy of securing all BMU-only events has achieved a balance between cost and risk, where system residual risk remains 1-in-7 years. By securing all BMU-only events, the majority of the BMU+VS and simultaneous events are naturally covered. The total system security, when assessing system residual risks at 49.2 and 48.8 Hz is not improved significantly following applying additional response controls to mitigate all BMU+VS events.

However to fully secure BMU+VS or sim events, due to the volatility in the event profile in some circumstances we would need up to 3 GW DC holding which is much beyond the current market available capacity and DC price may fluctuate significantly.

6.2.2 Historic trend of securing additional event categories

The table below shows the evolution of the cost of securing BMU-only as well as the additional cost of securing BMU+VS (outage), BMU+VS (intact) and simultaneous events in the latest four years' FRCR reports.

Table 5 Comparison of cost in mitigating all risks across different FRCR years

	Cost for system-wide controls (*include inertia and all response costs*)	**Additional Cost for BMU+VS (outage)**	**Additional Cost for BMU+VS (intact)**	**Additional Cost for simultaneous events**
FRCR 2022 (using BM Control)	£330m	£57m	£1.4b	£370m
FRCR 2023 (using BM Control)	£264m	£13m	£306m	£321m
FRCR 2024 (using Response Control)	£242m	£35k	£838k	£37m
FRCR 2025 (using Response Control)	**£170m**	**£14k**	**£280k**	**£20m**

*minimum inertia requirement is 120 GVA.s for FRCR 2023 and FRCR 2024, and 102 GVA.s for FRCR 2025

By applying Response Control as the additional measure to mitigate BMU+VS risks, the estimated additional costs are around £280k in FRCR 2025, which is significantly lower than previous years' estimates. This highlights the cost-effectiveness of using DC as a tool for managing frequency risks within the current system and market conditions. These results suggest further utilisation of DC to mitigate additional risks is highly favourable.

6.2.3 Recommendations

Securing to BMU-only events continues to present the best cost-risk balance. Considering the high cost-effectiveness of DC, there is a potential to utilise DC to address risks beyond BMU-only events and improve overall system security.

However, we would struggle to fully secure all BMU+VS risks by applying Response Control. This is primarily because significant and fluctuated DC volumes would be required to mitigate these risks due to the volatility in the event profile, and this capacity is not always available in the current market. The large fluctuations in DC volume also present uncertainty to the market, which could cause unexpected shortfalls in the service procurement and result in increased operational risks. In addition, further analysis is necessary to fully understand the complexity of transmission system conditions that could lead to the BMU+VS events as well as their impact on the increased response requirement.

Instead, an alternative approach of holding a fixed additional volume of DC is proposed and assessed in the section below. This approach is straightforward and can leverage the benefits of Response Control.

6.3 Assessment of additional Dynamic Containment - Low response

Analysis in 6.2 has indicated that Response Control is a cost-effective tool for mitigating beyond BMU-only risks. In this section, we will evaluate various options for holding additional DC-Low response. Our assessment will consider the potential benefits and drawbacks of options of holding additional 100, 200 and 300 MW additional DC-Low response under the recommended 102 GVA.s inertia requirements. By exploring these options, we aim to develop a comprehensive approach that balances cost and reliability.

6.3.1 System residual risks vs. cost

To find the optimal volume of additional DC-Low, a set of scenarios with different volumes of DC are studied with the risk vs. cost results presented. Additional DC-Low requirements of 100, 200 and 300 MW are considered. The associated system risk and cost are presented below.

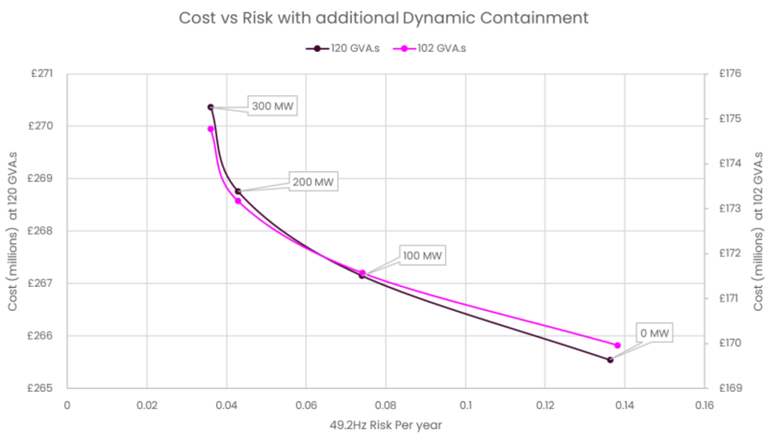

Figure 4 Cost vs risk with additional Dynamic Containment - Low

The cost and residual risk of the different scenarios are shown in Figure 4 under 120 and 102 GAV.s inertia requirement. An indicative curve is interpolated between the data points as well. It indicates that the system risk reduction is most significant when holding an additional 200 MW of DC-Low response both under 120 and 102 GVA.s inertia requirements.

Beyond this increment, the marginal benefits decrease significantly with 300 MW of DC-Low, while costs rise at a comparable rate. The Table 6 below presents more details by compares system residual risks and cost under three scenarios: BMU-only, BMU-only with 100 MW, 200 MW and 300 MW additional DC-Low at 102 GVA.s inertia requirement. All analysis is based on the latest market data and does not consider the price changes associated with the required increase.

Table 6 Cost vs risk with additional DC-Low response for 49.2 Hz event at 102 GVA.s

Option	Extra cost	Residual risk (49.5Hz)	Residual risk (49.2 Hz)	Residual risk (48.8Hz)
BMU-only (baseline policy)	£0	2.85 times per year	1-in-7 years	1-in-26 years
100 MW additional DC-Low (FRCR 2024 policy)	£1.61m	2.56 times per year	1-in-13 years	1-in-29 years
200 MW additional DC-Low	£3.23m	1.85 times per year	1-in-23 years	1-in-30 years
300 MW additional DC-Low	£4.84m	0.5 times per year	1-in-28 years	1-in-31 years

The additional cost and the updated residual risk have been calculated and are presented in the table. Holding an additional 200 MW of DC-Low provides enhanced risk mitigation, with an associated incremental expenditure of £3.23 million and a reduction in the residual risk of a 49.2 Hz event to a 1-in-23 years from 1-in-7 years, making it the most balanced option. However, 300 MW of DC-Low results in only a marginal further decrease in risk with higher cost. The impact of additional DC-Low holding on the risks of 49.5 Hz and 48.8 Hz events is also shown in the table showing good value for consumers in managing these risks.

6.3.2 Recommendations

Based on the findings, we recommend holding an additional DC-Low requirement of 200 MW. Holding additional volumes of DC provides a great system security improvement with a small amount of extra DC cost.

Increasing our DC-Low holding can also help further grow the response market. As our largest loss size increases, with sites such as Hinkley-C power station connecting to the network in the future, we will see a significant increase in DC requirements to cover a larger individual loss. By proactively expanding our DC holding capacity, we are not only making our system more secure but also stimulating the market to expand its capabilities prior to this increasing largest loss size. This is crucial for ensuring that we are capable of managing an 1800 MW loss size on the network in the near future.

6.4 Additional considerations

6.4.1 Effect of Limited Frequency Sensitive Mode – Over frequency

In FRCR 2025, the Limited Frequency Sensitive Mode – Over frequency (LFSM-O) is included in the model. The impact of LFSM-O is presented in this section. The Limited Frequency Sensitive Mode – Under frequency (LFSM-U) however is not considered as LFSM-U would only be expected to be delivered when the system frequency is below 49.5 Hz and the generator has available head room. Noting that this requirement generally applies only to plants connected to the system on or after April 2019, and concluded purchase contracts for major plant items on or after May 2018, and that, in the main, most plants are operating at maximum capacity, its impact on overall system performance is almost negligible. The detail of modelling the LFSM-O can be found in the FRCR **Handbook** section 3.1.3.

Table 7 Risk with and without LFSM-O for 50.5 Hz event

Scenario	140 GVA.s	120 GVA.s	110 GVA.s	102 GVA.s
50.5 Hz event	1-in-78.96 years	1-in-78.99 years	1-in-79.04 years	1-in-79.06 years
50.5 Hz event with LFSM-O	1-in-85.58 years	1-in-85.23 years	1-in-85.29 years	1-in-85.30 years

It can be observed from the table that LFSM-O can reduce the system's residual risk of 50.5 Hz events at various inertia levels. It is important to note that the baseline recommendation of FRCR 2025 is established without considering LFSM-O volumes. Analysis including LFSM-O represents NESO's initial attempt to quantify the impact of LFSM, and it is anticipated that the capacity of LFSM-O will enhance risk mitigation. We view LFSM-O as an additional layer of protection beyond the FRCR policy. The capacity of LFSM-O therefore is not considered in NESO's model in determining response service daily auctions but works as additional layer in real-time operation. LFSM capacity and modelling could be further reviewed following frequency events in the future.

6.4.2 Effectiveness of low frequency demand disconnection (LFDD)

The first stage of low frequency demand disconnection (LFDD) starts at 48.8 Hz and then subsequent stages apply in the range 48.8 Hz – 47.8 Hz. Under a 102 GVA.s system condition and to initiate a 48.8 Hz deviation, we would have an infeed loss at least 2000 MW. As illustrated in Table 2, the probability of a 48.8 Hz event or an LFDD event occurrence remains at approximately a same level regardless the minimum inertia level, i.e. 1-in-25.89 years under 120 GVA.s and 1-in-25.83 years under 102 GVA.s. .

The previous two occurrences of LFDD happened on 27 May 2008 and 9 August 2019 over a decade apart. These are the only two LFDD events since GB electricity industry privatisation in 1990. The limited operational experience however verifies the effectiveness of LFDD operation, including, replay triggering setting and time delay. Past experience indicates there is no unnecessary delay in causing the frequency to drop further or mal-operation leading to frequency overshooting post fault.

6.4.3 Wider system operability considerations

When running the system at the inertia of 102 GVA.s, a largest loss of 1800 MW would result in a RoCoF of 0.5 Hz/s. The ALoMCP has significantly reduced the risk of inadvertent tripping of embedded generation where the majority of RoCoF relay settings is now at 1

Hz/s. Following the trigger of 1 Hz/s RoCoF at a system inertia of 102 GVA.s, it is expected most of the embedded generation would start to trip based on their LoM protection settings. This would result in a national-wide power outage scenario. However, to initiate a 1 Hz/s RoCoF event under the proposed 102 GVA.s inertia level, the system would need an infeed loss at 3.3 GW. This level is far from the current largest loss we aim to secure and is much higher than any of the historical simultaneous events that we have observed. Proposing 102 GVA.s inertia requirement and limiting the post-fault RoCoF up to 0.5 Hz/s provides a security "buffer" under current and foreseen system conditions.

In terms of wider system operability, there are interactions between reducing the minimum inertia level and other system operability areas. Our Operability Strategy Report (OSR) looks at these interactions and considers the wider impact of lower inertia levels on all operability workstreams. We are developing new operational strategies, tools and processes to ensure we have visibility and can manage these challenges in a coordinated manner.

We will continue to solve any future challenges associated with zero carbon operation (for example, through the use of Grid Forming technologies and other tools), ensuring we understand the operability requirements and how these operability challenges interact.

6.5 Outlook to 2026/27

By the end of 2025, we aim to operate the electricity system at zero carbon for short periods of time, helping us move towards a clean power system by 2030 and go beyond. This FRCR also explores managing frequency risks with the system conditions anticipated in 2026/27. The results obtained from the analysis are preliminary. A more comprehensive assessment will be conducted in the future FRCR considering additional operational experiences and improved foresight of system conditions, to drive appropriate future frequency control policy.

6.5.1 Minimum inertia requirements

The impact of the current FRCR policy on the residual risk for 2026/27 is set out below. In the 2026/27 outlook, the assessment focuses on 120 GVA.s and 102 GVA.s minimum inertia policies. When securing BMU-only risks, the residual risks at different minimum inertia levels are shown in the table.

Table 8 System residual risk in 2026/27

Scenario	120 GVA.s	102 GVA.s
49.5 Hz event	3.48 times per year	3.49 times per year
49.2 Hz event	1-in-10.71 years	1-in-10.70 years
48.8 Hz event	1-in-27.94 years	1-in-27.87 years
50.5 Hz event	1-in-88.21 years	1-in-88.28 years

It should be noted that varying the minimum inertia in 2026/2027 would not pose additional risks to the system, similar to the analysis for 2025/26. Additionally, the residual risks for 49.2 Hz and 48.8 Hz events are reduced in 2026 compared to 2025. This improvement is due to differences in event profiles between the two years driven by new connections to the system in 2026. The actual risk in 2026 will be reassessed in next year's FRCR as more accurate and updated data becomes available.

Table 9 Cost breakdown in 2026/27

Scenario	120 GVA.s	102 GVA.s
Cost for system-wide controls (*NB: system wide controls include inertia and all response costs*)	£324m	£258m
Cost to meet minimum inertia this element is included in system wide cost	£255m	£188m
Overall saving		**£67m**

The table above shows the costs and potential savings that could be achieved with a minimum inertia of 102 GVA.s in 2026 when securing all BMU-only events. We estimate that a total saving of £67 million can be achieved by moving from 120 GVA.s to 102 GVA.s, with a total spending of £258 million at 102 GVA.s. This total spend figure has increased compared to the year 2025 (£170 million at 102 GVA.s). This is mainly due to higher cost to meet the minimum inertia requirement, while system inertia provided by synchronising units is expected to further reduce in 2026.

6.5.2 Securing additional event categories

The table below shows the system residual risk and costs of a 102 GVA.s minimum inertia policy in 2026, when securing beyond BMU-only events.

Table 10 Risk and cost for different risk categories in 2026/27 at 102 GVA.s minimum inertia

Event category	Response Control	
	Residual risks	Additional costs
BMU-only	1-in-10.70 years	£0
BMU+VS (outage)	1-in-10.72 years	£13k
BMU+VS (intact)	1-in-10.74 years	£261k
Simultaneous event	1-in-9999 years	£20m

With Response Control, an additional spending of £274k on top of the cost of securing BMU-only events allows us to manage all BMU+VS risks, resulting in a similar residual risk of 1-in-11 years compared to 2025 result. However, as discussed in section 6.2, fully mitigating BMU+VS risks is challenging due to the volatility in the event profile. Therefore, it is still preferable to use a fixed additional DC-Low response to further mitigate residual system risk.

6.5.3 Additional DC-Low holding

The table below provides a comparison of the risk vs. cost for holding different volumes of additional DC-Low in 2026. Similarly to 2025 analysis , 100, 200 and 300 MW of additional DC-Low volumes are considered under the 102 GVA.s minimum inertia policy.

Table 11 Cost vs risk with additional DC-Low response for 49.2 Hz event in 2026/27

Option	Extra cost on top of £258m	Residual risk (49.2 Hz)	Reduction in risk per year
BMU-only	£0	1-in-10.70 years	N/A
100 MW additional DC-Low	£1.61m	1-in-19.9 years	4.04%
200 MW additional DC-Low	£3.23m	1-in-27.25 years	1.27%
300 MW additional DC-Low	£4.84m	1-in-28.65 years	0.17%

This 2026 analysis shows similar trends to the 2025 analysis, verifying that the residual risk reduction is most effective when increasing DC-Low holding from 0 MW to 200 MW. System risk has improved from 1-in-11 years to 1-in-27 years, with an extra cost of £3.23m per annum. The reduction in risk per year is the difference in residual risk between each option. In this analysis the additional cost of DC remains the same with the price assumed to be unchanged from year 2025.

7. Conclusions

7.1 Recommendation

The recommendations within this report are:

- Reduce the minimum inertia requirement to 102 GVA.s.
- Secure all BMU-only events to keep resulting frequency deviations within 49.2 Hz and 50.5 Hz.
- Do not apply additional controls to secure all BMU+VS and simultaneous events.
- Apply additional 200 MW DC-Low control to increase system security and grow the market.

The analysis shows that the recommended policy represents good value for GB consumers. The recommendation to hold additional volumes of DC-Low enhances overall system security by enabling us to secure beyond BMU-only risks. Holding additional volumes of DC-Low helps us further grow the response market in preparation for securing the future largest loss of 1800 MW.

7.2 Implementation

The reduction of the minimum inertia requirement will be implemented following Ofgem's approval in a phased manner. The initial stage will lower the minimum inertia requirement to 110 GVA.s, followed by a second stage that will further reduce it to 102 GVA.s. We will gain operational experiences following the first stage of the reduction. There will be a minimum interval of four weeks between the two stages to allow adequate time for observation of the changes.

We also recommend an increase in the DC-Low requirement by 200 MW. Based on current market liquidity, we anticipate no issues with implementing this adjustment.

Upon receiving approval from Ofgem, we will announce the implementation through the OTF or separate webinars, providing at least five working days' notice via our standard response service forecasting and communication channels.

Variations to this policy

There are specific, limited variations to these policies based on technical, probabilistic and economic grounds, applied under paragraphs 5.11.2 and 9.4.2 of the SQSS. This includes additional actions taken by NESO, where appropriate, during times of increased system risk, such as during severe weather, and exceptions where risks does not feasibly occur under normal prevailing conditions[4].

[4] e.g., due to the configuration of the network making the loss of the whole BMU at once not credible.

8. Appendices

8.1 FRCR forward looking

In past FRCR editions we explained various events, loss risks, impacts and controls that could be considered in future FRCR modelling and assessments and these will still be valid future considerations following FRCR 2025. In addition to these considerations, there are other strategic directions that future FRCR could prospectively explore to tackle fast-changing system conditions. This section provides our initial thoughts on some potential areas for future FRCR work.

- **Simplified analysis**

Following the ALoMCP, the risk of inadvertent tripping of embedded generation has significantly reduced to a very low level by changes their protection settings and type. System security caused by transient frequency deviation becomes much less sensitive to unexpected LoM operations. This change enables the FRCR analysis to shift from a loss-risk-profile per settlement-period based calculations to a capacity-based analysis. This new approach would significantly simplify the calculation process and reduce computational capacity requirements when proposing new frequency control policies.

However, this approach is outside the currently agreed FRCR Methodology and hence requires industrial consultation and SQSS Panel approval, in accordance with the FRCR governance process.

- **Unified loss risk policy**

Based on the simplified analysis, a future FRCR policy would not differentiate the approach of securing loss risk categories, such as BMU only, BMU + VS, and simultaneous events. Instead, the FRCR policy would recommend securing a loss risk up to a certain level.

To effectively conduct the analysis and implement this policy, NESO will need to modify its existing operational tools, and develop new tools and models to enhance operational awareness. This will ensure that the loss risk from individual BMUs or from a NETS group can be effectively monitored and controlled. The frequency control analysis could necessarily expand to include transmission security discussions, for example, to clarify operational policy in securing switch faults. The FRCR may help to inform those developments that would be formalised in the SQSS and where necessary the other industry codes. This approach and its methodology will require careful feasibility assessment within NESO and with the industry.

- **Interaction between national inertia and regional inertia**

As we explained in Chapter 5, since implementing the 120 GVA.s minimum inertia policy, we have observed Sub-Synchronous Oscillation (SSO) events in the Scotland network. Our investigations found no correlation between lower overall system inertia and the initiation of these SSO events. Local inertia reduction, however, can have a negative impact on SSO events and other system operability issues such as the secondary effect of reducing the Short Circuit Level (SCL) and the inherent damping provided by synchronous generation at local levels. Several projects and programmes have been initiated by NESO and collaborated with the industry to address these challenges. More details can be found in OSR 2024 which will be published by end of March 2025. In the future, the frequency control workstream, collaborating with wider operability workstreams in NESO, would like to explore and investigate the following areas:

- Regional inertia monitoring and modelling,
- Interaction between regional inertia and system strength, and
- Regional frequency response requirements and procurement policy.
- Highlight the work completed in other areas such as Grid Forming.

We acknowledge the difficulties in exploring these areas. Some of the areas are neither within the scope of current FRCR Methodology nor the original purpose of the SQSS modification GSR027. We would like to initiate discussions with the industry, start with innovation feasibility studies, and allocate appropriate workstreams in leading the development before these can be incorporated into future FRCR policy development. We welcome your views on the future work of FRCR and the development of the GB frequency management policy.

8.2 FRCR future governance

Appendix H of the Security and Quality of Supply Standards (SQSS) sets out the process for production of a periodic FRCR report, detailed requirements and obligations on parties involved in this process. Under this arrangement, the SQSS Panel is required to review and approve the FRCR Methodology and the annual FRCR Report before NESO subsequently submits it to the Authority.

As part of FRCR 2024, a number of SQSS Panel members suggested that the obligation to produce the FRCR may better fit under a new NESO License Condition rather than an Annex to the SQSS. This is due to the fact that the SQSS sets the principles and the rules of planning and operation but does not detail how they are discharged. To address this, NESO are intending to engage with the Authority, the SQSS Panel, and the wider industry to consider this.

We are seeking your preliminary views about this proposal which are also specifically included as consultation questions.

- Do you foresee any issues that may arise from moving the obligation to produce the FRCR to a NESO Licence Condition rather than an Annex to the NETS SQSS?
- If the obligation to produce the FRCR and the governance rules surrounding that process are moved to NESO's Licence, do you believe that the NETS SQSS Panel should continue to provide oversight?
- If your answer to above question is yes, to what extent should this oversight be? For example, should it include technically assessing the recommendations and approving/rejecting it, or should it be limited to confirming that the governance process and methodology has been followed correctly?

We welcome your views to shape the future FRCR governance and its process. We note that any formal change will need to progress through the normal governance route and your responses to these consultation questions are intended to be informative only, with the aim being to improve the FRCR process in the future.