Frequency Risk and Control Report

Security and Quality of Supply Standards

Methodology and Assessment – For approval

Reducing minimum inertia requirement under FRCR policy

March 2023

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Contents

1. Foreword

In line with our Security and Quality of Supply Standard (SQSS) requirement, we are obliged to produce an annual Frequency Risk and Control Report (FRCR) and consult with industry on the methodology and assessment presented in the report.

We consulted on FRCR 2023 between 13th February 2023 and 24th February 2023. A webinar was held on 20th February to answer questions relating to the consultation. We received six responses to the consultation with all respondents agreeing in principle to the recommendation presented, to reduce minimum inertia policy to 120GVA.s. Whilst there was a broad agreement with the principal recommendation, there were a number of additional points raised relating to modelling data and other operability impacts. These have been summarised in section 7.2.

Large sudden changes in supply and demand can cause the frequency of the GB electricity system to change. This consultation sets out the parameters for how often, for how long and how large those frequency changes should be and sets out the criteria by which we shall manage such risks.

This 2023 edition of the FRCR assesses the costs and benefits of reducing our minimum inertia requirement under the policy. The focus of the report is to set out the right balance between risk and cost to the consumer to ensure the network is effectively and appropriately protected from frequency events for the following year. The report aims to improve transparency across industry and stakeholders, setting out clear and objective criteria by which we balance cost and risk to ensure the end consumer receives efficient security of supply.

As the energy system transitions to a low carbon system, the regular review of response, reserve and inertia holding will be important and this report allows us to review and manage emerging risks together with our stakeholders.

The combined impact of the recommendations in this report, the delivery of the Accelerated Loss of Mains Change Programme (ALoMCP) and the introduction of Dynamic Containment (DC) has meant the system risk is reduced, when compared with previous years. This is largely driven by a reduced overall aggregated loss size, a resulting factor from the ALoMCP.

This report confirms the value of these work programmes and presents our proposals for reducing the minimum inertia requirement under FRCR policy.

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. FRCR 2021 created a baseline for cost versus risk when managing frequency.

We currently operate the system at a 140GVA.s minimum inertia requirement under FRCR policy. Continual progress with our overarching frequency strategy, including the implementation of Dynamic Containment (DC) and the progress made on the Accelerated Loss of Mains Change Programme (ALoMCP), means that we are now in a position where it is appropriate to assess whether the minimum inertia requirement currently applied still represents the right balance of cost vs risk.

This report represents the first step in our process to move towards a future state of operating the system with lower inertia by considering whether there is consumer value in reducing our minimum inertia requirement. It also assesses whether the existing policy (approved in 2022, with a recommendation to not secure all simultaneous events), still delivers the best value for consumers. Within the report, we have considered different scenarios for reducing minimum inertia policy, ranging from 140GVA.s to 100GVA.s and assessed the system cost vs residual risk profile of managing the system at these different levels.

The recommendation within this report is to reduce the existing minimum inertia requirement under FRCR policy from 140GVA.s to 120GVA.s. This results in a saving of approximately £65m per year.

We do not consider the additional costs to mitigate the further risk of simultaneous events to represent good value for the end consumer under the FRCR framework and do not recommend changing the existing FRCR policy to secure for simultaneous events.

The growth in our DC pipeline, combined with improvements in overall system stability risks, facilitated through the ALoMCP, mean that there is **no increase in the overall risk profile of the system** by operating at 120GVA.s. Current policy (not securing for all simultaneous events) still represents good value for the consumer and so there is no change proposed to the policy approved in 2022 with regards to securing for simultaneous events.

The implementation of a 120GVA.s minimum inertia requirement would leave a residual risk of:

- **1-in-17-year** risk of a 49.2Hz event
- **1-in-30-year** risk of a 48.8Hz event

The total indicative cost of DC response services through implementing the proposed policy is £124million. To secure simultaneous events an additional £321million spend would be required on this service, meaning total DC response cost would be £445million (or an increase by a factor of ~3.5). Securing against all simultaneous events would also require a significant increase in DC capacity. At present, there are insufficient assets on the system to provide this response and is a considerable increase from current capacity volumes Therefore, we do not consider changes to current policy (regarding loss risks or simultaneous events) represents good value for consumers.

The risk profiles presented above, represent a reduction in risk when compared with the conclusions of FRCR 2022. In 2022, the risk profiles resulted in a residual risk of 1-in-14 years and 1-in-28 years of a 49.2 or 48.8Hz event respectively. This is primarily driven by the progress made through the ALoMCP, which now means that the capacity of Distributed Energy Resources (DER) at risk of disconnection from the operation of Loss of Mains (LoM) relays has decreased significantly (by an average of 58%). This has the impact of reducing RoCoF and Vector Shift (VS) loss risks and therefore, the aggregated system loss size has reduced.

Reducing minimum inertia from 140GVA.s to 120GVA.s from mid-2023 results in a **saving of up to £65m per year** in inertia costs. Reducing below 120GVA.s is currently not recommended as we do not consider it prudent to reduce minimum inertia below this level for the small number of periods where a lower inertia may provide a small consumer benefit. We will continue to reassess this conclusion in future versions of FRCR.

Based on an assessment of cost vs current accepted risk, we recommend that the optimal minimum inertia requirement is met at 120GVA.s.

If approved, the implementation from 140GVA.s to 120GVA.s would be via a phased approach. The initial reduction would be to 130GVA.s, for a one-to-two-month period, followed by a further reduction to the 120GVA.s proposal.

3. Background

3.1. Purpose

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 Policy

Current Policy resulting from the approved 2022 FRCR[1] is:

- Apply individual loss risk controls to Balancing Mechanism Unit (BMU)-only events to keep resulting frequency deviations within 49.2Hz and 50.5Hz
- To allow BMU-only infeed loss risks to cause a consequential Rate of Change of Frequency (RoCoF) loss, if the resulting loss can be contained to 49.2Hz and 50.5Hz
- Do not apply individual loss risk control to BMU + Vector Shift (VS) outage or BMU+VS intact events
- Do not apply additional system-wide controls to secure simultaneous events.

Frequency Risk and Control Report 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, metrics for reliability versus cost.

Frequency Risk and Control 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 paragraphs 5.8, 5.11.2, 9.2 and 9.4.2 of the SQSS. The SQSS notes that the FRCR will set out those conditions under which unacceptable frequency conditions will not occur.

In 2022, and following discussions with the SQSS panel and Ofgem, it was agreed that the 2022 edition of FRCR would combine both the report and methodology into a single consultation. We have applied this approach again for the 2023 FRCR.

This combined report and methodology considers the value proposition of reducing our minimum inertia requirement under the policy. This combined report and methodology will be consulted on between 13th February 2023 and 24th February 2023. The final report will be submitted to the Authority for approval on 31st March 2023.

3.2. What is the FRCR?

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,
- the cost of securing the system,
- 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.

[1] FRCR policy remained unchanged in the 2022 report.

3.3. What is the report trying to achieve?

In the context of system frequency, there are two key objectives:

- A reliable supply of electricity,
- At an affordable cost.

There is a balance between those objectives:

- Higher reliability requirements result in higher direct costs to meet that requirement,
- Lower reliability requirements result in lower direct costs to meet that requirement but have higher indirect costs and impacts arising from the lower reliability requirement.

These objectives are formalised through the SQSS and the FRCR. This report provides an assessment and recommendation on the right balance between the two competing objectives of reliability and cost, focusing on the risks, impacts and controls for managing the frequency.

3.4. Levels of impact

The report has used four levels of impact set out below when assessing the balance between the key objectives. These allow comparison with historic performance:

#	Deviation	Duration	Relevance
H1	50.5Hz < f	Any	• Above current frequency standards. • Plant performance prescribed in detail by Grid Code, but not tested often in real-life conditions.
L1	49.2Hz ≤ f < 49.5Hz	60 seconds	• Current SQSS and System Operation Guideline (SOGL) frequency standards. • Infrequent occurrence, but reasonable certainty over plant performance.
L2	48.8Hz < f < 49.2Hz	Any	• Beyond current frequency standards and SOGL, but without triggering Low Frequency Demand Disconnection (LFDD). • Plant performance prescribed in detail by Grid Code, but not tested often in real-life conditions.
L3	47.75Hz < f ≤ 48.8Hz	Any	• First stage of LFDD.

3.5. Metrics: What principles can be applied?

At its simplest for each level of impact, good value risks are likely to be those which are:

- Low cost to mitigate, and/or
- Likely to occur, and/or
- Have a large impact.

Poor value risks are likely to be those which are:

- High cost to mitigate, and/or
- Unlikely to occur, and/or
- Have a small impact.

There is a whole spectrum of costs and likelihoods across each of the events, meaning a clear-cut judgement of the balance between reliability and cost can be challenging to reach for one event in isolation. Instead, the FRCR assessment assesses the total risk and total cost across all events. Where risks are deemed to be of poor value and not actively mitigated, the backup measures prescribed through the Grid Code will act to minimise overall disruption to the system should they occur.

3.6. What is meant by reliability?

The SQSS refers to unacceptable frequency conditions as a measure of reliability. This encompasses whether transient frequency deviations outside the range 49.5Hz to 50.5Hz are considered infrequent and tolerable. Whether frequency deviations are acceptable depends on the exact combination of three factors:

1. How often they occur,
2. How long they last for,
3. How large they are.

Each of these affects the impacts of an event (see section 3.4). For example: larger or longer deviations that happen very rarely might be acceptable, but smaller or shorter deviations that happen very often might not. The report will define what is considered reasonable as infrequent and tolerable for each of these criteria for transient frequency deviations.

3.7. What drives direct costs?

We use Ancillary Services to manage frequency deviations. Some are automatic, like frequency response. Others are manually dispatched, like reserve, the Balancing Mechanism (BM), services to increase the inertia or services to pre-emptively decrease the size of potential loss risks. In this document, we refer to these Ancillary Services as "controls".

The size, duration and likelihood of transient frequency deviations depend on:

- The size of the event that caused the frequency deviation,
- How much of each of these controls are used, and the effectiveness of the controls:

Scenario	Direct costs	Frequency deviations
Small event/ more controls	Higher	Shorter, smaller, occur less often
Large event / fewer controls	Lower	Longer, larger, occur more often

The report has considered the relevant controls which we currently have access to, in order to meet our requirement.

3.8. How to balance between reliability and costs?

The methodology sets out an objective and transparent framework for us to assess risks associated with frequency deviations, the events which could cause them, their size, the impacts they have, and the cost and mix of controls to mitigate them. The assessment has been used to determine the appropriate balance between reliability and cost, as described in this report.

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

4. Scope of FRCR 2023

4.1. Performance of 2022 report

FRCR 2022 assessed the feasibility and value of securing simultaneous losses. The conclusions from this report were that it did not represent good value for money to secure all possible simultaneous losses on the system. As a result, there were no changes to policy and therefore no recommended actions from the 2022 report.

4.2. Scope of the 2023 edition

Review of current FRCR policy: Within this report, we review existing policy of securing against the different defined loss risk categories. In addition, we review whether our conclusion from the 2022 FRCR to not secure simultaneous events, still represents good value for the consumer.

Review of minimum inertia requirement under policy: The continued growth of new, faster acting frequency response products like Dynamic Containment (DC), combined with the impacts from the Accelerated Loss of Mains Change Programme (ALoMCP), means that we can start to consider a system with lower inertia. In this report, we consider the impact and benefits of reducing our minimum inertia requirement from the current policy of 140GVA.s, assessing different levels from 140GVA.s to 100GVA.s.

The methodology used sets out an objective and transparent framework to enable us to assess system risk when reducing minimum inertia to different thresholds.

4.3. Controls

There are four main controls for mitigating transient frequency deviations, set out below. The results within this report will demonstrate the value that can be gained through amending one of these controls 'increasing inertia' whilst still ensuring that transient frequency deviations are mitigated, even with a lower minimum level of inertia.

1. **Holding frequency response**: frequency response refers to the holding of frequency services that are automatically activated by a frequency measurement to determine an appropriate change in active power. This injection of active power helps offset the impact of lower inertia.
2. **Reducing BMU loss size**: this control aims to reduce the output of the BMU such that if the unit faults and disconnects, it will not result in the frequency dropping below the threshold we set out. Since the implementation of the first FRCR, the number of actions we are required to take to reduce loss sizes for managing RoCoF risks has reduced significantly. In 2021, total actions taken reached 3.2TWh (compared to 7.4TWh in 2020), however in 2022, only 0.36TWh actions were taken to reduce loss sizes.
3. **Reducing LoM loss size**: as a consequence of the ALoMCP, the capacity of Distributed Energy Resources (DERs) at risk of disconnection from the operation of Loss of Mains (LoM) relays has decreased significantly. This has an impact on the quantity of frequency response that needs to be procured.
4. **Increasing inertia**: we can take actions to increase inertia on the system in order to slow down frequency decline following a loss of generation. We currently synchronise additional units in the BM to increase inertia on the system, in order to meet the operational policy of 140GVA.s. Based on the tools we now have available, there is a significant cost saving to be realised by keeping system inertia at a lower base line than existing policy.

4.4. Why reduce minimum inertia?

Today, we operate the system at a minimum of 140GVA.s. This policy was established as, historically, RoCoF was the determining factor for manging system inertia. 140GVA.s ensured that RoCoF was no greater than 0.125Hz/s and ensured no subsequent disconnection of embedded generation. Prior to implementation of the 2021 FRCR, we did not allow any RoCoF events to occur, however under current FRCR policy, we are now able to allow consequential RoCoF events to occur[2].

A minimum inertia requirement of 140GVA.s was implemented before recent operational changes to the system including the ALoMCP and the implementation of DC. A combination of these means that we have been able to relax our policy on how we manage large losses and associated frequency risks. As a result of these changes to the system, it is now also appropriate for us to re-assess whether our minimum level of inertia is still appropriate and representative of the best value for consumers.

In line with our zero carbon ambition by 2025, our aim is to ensure that the system can operate at a minimum inertia of 102GVA.s. This is based on an assumed largest loss of 1.8GW and ensuring RoCoF remains within 0.5Hz/s. A 1.8GW loss would require 90GVA.s of inertia for RoCoF to remain within 0.5Hz/s, in addition to roughly 12GVA.s loss from a 1.8GW unit. This results in a requirement of 102GVA.s inertia to meet our 2025 ambition. We discuss this in further detail in our Operability Strategy Report.[3]

The recommendations in this year's FRCR aligns with this ambition and represents the first step in transitioning towards this future state.

4.5. What has changed: Main drivers that enable change

Accelerated Loss of Mains Change Programme (ALoMCP)

The ALoMCP was a programme which offered funding for distributed generators to upgrade their protection hardware settings to improve network resilience and improve system stability. As a consequence of this programme, the capacity of DERs at risk of disconnection from the operation of LoM relays has decreased significantly. This has the impact of reducing RoCoF and Vector Shift loss risks and therefore, the aggregated system loss size is reduced. This makes operating at lower inertia levels more achievable.

Growth of Dynamic Containment (DC)

Dynamic Containment (DC) is a fast-acting post-fault frequency service, which contains frequency within the statutory range of +/-0.5Hz. DC provides a method of rapidly injecting active power into the system, providing a very effective control for containing frequency deviations. The availability of DC has the benefit of helping us to manage a system with lower inertia.

The design and implementation of this service in 2021 has provided us with a very effective frequency control and the steady growth of the DC market is a key enabler of us being able to assess the feasibility of operating the system with a lower minimum inertia requirement. We are comfortable that we have access to sufficient DC to cover our largest loss risk, even when operating a lower inertia system. To date, we have successfully procured a maximum of 1148 MW of low frequency service and 983 MW of high frequency service from this market. As of January 2023, we have more than 2GW of quantified DC capability, and we have seen an increase in participation in the market over recent years.

Stability pathfinders

Through our stability pathfinders, phase 1, 2 and 3, we have procured stability services which will allow us to access to a total of 41GVA.s of inertia. We currently have access to the majority of phase 1 volumes (12.5GVA.s) and the additional inertia procured through phase 2 and 3 will be available to us from 2024 and 2025 respectively.

Whilst overall system inertia is declining, increasing our access to additional inertia via our stability pathfinders means that, in conjunction with the available DC and changing system conditions through ALoMCP, we are

[2] As long as the total loss is secured within 49.2Hz and 50.5Hz
[3] Operability Strategy Report, December 2022

able to investigate reducing the minimum inertia holding on the system. This will have the impact of less inertia being required in the BM and subsequent cost savings, discussed in section 6.1.

5. Methodology

The aim of the methodology is to set out an objective and transparent framework to enable us to assess risks associated with frequency deviations caused by lower minimum inertia. The assessment can then determine the optimal level of minimum inertia when balanced against reliability and cost. Based on consultation feedback, appendix 9.4 has been included to provide additional detail on inputs used in the methodology.

5.1. Methodology description

The methodology used in FRCR 2023 remains largely unchanged from that set out in the previous edition of the FRCR. There have been some adaptations and upgrades made to the methodology to assess the impact and benefits of reducing the minimum inertia requirement.

The overall process of the methodology can be summarised in the steps below:

1. Define scenario
2. Determine system-wide costs
3. Determine if targeted actions are required
4. Determine overall cost vs risk trade-off of the scenario

The remainder of this section explains the methodology steps in detail.

Step 1: Set-up scenario

Initially, all inputs are loaded into the model, including costs for response and targeted actions, LoM load factors and fault statistics. The relevant updates to the input dataset to represent the system changes expected for 2023 are included and more details can be found in section 5.2.

Baseline system conditions

The analysis uses historic scenarios adjusted for known or expected changes in the coming 12 months to isolate the reliability versus cost decisions from the impact of these wider changes. Example of adjustments include new connections to the National Electricity Transmission System (NETS) in 2023, which represent additional loss risks, and which impact the inertia of the system, as well as the up to date RoCoF and Vector Shift loss risks post ALoMCP.

Many of the key inputs such as demand, inertia, BMU loss size, LoM loss size, vary markedly with time; hourly, daily, weekly and seasonally. Analysis of a single point in time, for example winter peak or summer minimum, would not capture the intricacies and interactions or give a true picture of risk exposure. This approach is used by some system operators in other countries but is inappropriate for assessing frequency risks on the GB system. To overcome this, the analysis is performed as a time series at settlement period granularity.

These are the baseline system conditions against which the different control scenarios are assessed. We will unwind balancing actions from the historic data sets to get a representation of the “market position” for these baseline system conditions.

Define scenario parameters

The main aim of the 2023 FRCR analysis is to assess the impact and benefit of reducing the minimum inertia requirement, hence parameters applied within the scenarios are designed to fit that purpose. The assessment has considered the proposed minimum inertia requirement modifications and expected total DC market sizes. Different scenarios are assessed to determine the impact on the overall cost and baseline level of system risk. LoM capacity post ALoMCP is used for this FRCR analysis for both RoCoF and Vector Shift.

Step 2: Determine system wide costs

Frequency response (Primary, Secondary, High, Static, Enhanced Frequency Response and DC) and inertia costs are applied first as they affect all events and loss risks. Costs for inertia (including foot room) and BMU loss size are benchmarked against the typical prices achieved through the BM and trading.

The quantity of DC to be procured is calculated based on securing the maximum single BMU loss and any consequential RoCoF loss under the minimum inertia requirement set out in the scenarios to mirror the current day-ahead DC auction process. If the required DC quantity exceeds the DC market size set out in the scenarios, then additional response (Primary, Secondary, High) will be procured to fill the gap. The quantity and price of the different frequency response services are benchmarked against the results of previous tenders or auctions. Once the system-wide controls are in place, we calculate the expected loss size for the event, accounting for the BMU loss size and any consequential Vector Shift and / or RoCoF loss. Finally, we assess how often each event is at risk of causing each of the impacts before any individual loss risk controls are applied. It should be recognised that the costs produced are based on the current system and market conditions and therefore are purely indicative. They are not forecast costs for 2023 and outturn costs might well change due to pricing, behaviour and forecast uncertainty etc.

Step 3: Determine if targeted actions are required

Initially the required reduction in the BMU loss size is calculated to prevent the event loss size exceeding the level of frequency response being held under the system-wide controls for each event considered and for each settlement period. This reduction could be:

- Preventing a consequential RoCoF loss from occurring, by making sure the total BMU / VS loss stays within the rate of change of frequency threshold, or
- Allowing a consequential RoCoF loss, but making sure the total BMU / VS / RoCoF loss stays within the level secured by frequency response holdings.

The action selected is assumed to be the one with lowest MW reduction (and therefore cost). The main control for managing simultaneous events is to procure frequency response to cover the total loss and other options are not considered which aligns with the methodology used in FRCR 2022.

Step 4: Determine overall cost versus risk trade-offs of scenario

Determine costs of targeted actions

The cost for each targeted action is calculated for each event.

Calculate residual risk

Due to the physical constraints on BMUs, such as inflexible plant or other industrial processes, there may still be some periods which can't be mitigated by individual loss risk actions. A second assessment conducted, to evaluate how often each event is at risk of causing each of the impacts after both the system-wide and individual loss risk controls are applied. This is the residual risk.

Calculate risk reduction

The risk reduction achieved is calculated by applying the individual loss risk control and comparing the baseline risk (after system-wide controls) to the residual risk (after system-wide and individual loss risk controls).

Each event is ranked for risk reduction and the cost of applying the individual loss risk controls (in terms of the cost per avoided event), giving a “value for money” ranking. This allows the identification of a boundary between events which are good value to secure and those which are not good value to secure. The cost per avoided event is used at this boundary to determine the rate of occurrence of simultaneous events that would represent good value to secure. Additionally, the costs for system-wide controls and individual loss risk controls as well as the residual risk under different minimum inertia requirements can be compared and analysed.

5.2. Input dataset

The assessment requires data to assess the cost versus risk of different scenarios. We have updated the FRCR model used in previous versions of this report with:

1) up-to-date Loss of Mains risk profile post ALoMCP;
2) up-to-date costs for the controls such as DC and BM actions and;
3) known or expected changes in 2023 such as the planned delivery of Stability Pathfinder Phase 1 inertia. We have not assumed any contribution from Stability Pathfinder phase 2 as these units are not expected to go live until April 2024. FRCR 2023 will cover the period April 2023 – March 2024.

The 2022 calendar year dataset has been used as the baseline for the report. The impact of new transmission connections and growth of embedded generation on system inertia has also been factored into the dataset used for the assessment.

In the 2022 FRCR we also committed to providing a continuing assessment of the impact on securing simultaneous events. Therefore, we have included simultaneous events in the analysis of this year's methodology and overall system risk background. We have applied the following assumed risk profiles which we introduced in the 2022 FRCR which focused on simultaneous events[4]:

- 1-in-10-year risk of a median simultaneous event,
- 1-in-20-year risk of an upper quantile simultaneous event,
- 1-in-30-year risk of the peak simultaneous event.

5.3. Event categories

FRCR 2023 covers three categories of loss risks including:

- BMU-only
- BMU+VS
- Simultaneous events

BMU-only and BMU+VS risks were considered as part of FRCR 2021 and 2022 which recommended applying individual loss risk controls to BMU-only risks to keep frequency deviations within 49.2Hz and 50.5Hz. No additional loss risk controls are applied to BMU+VS events. Simultaneous events were introduced in FRCR 2022 and as per the recommendation, no additional system-wide controls are applied to simultaneous events. A detailed explanation of the different event categories can be found in Appendix 9.3.

[4] Frequency Risk and Control Report 2022

5.4. Application of controls within the methodology

Section 4.3 provides an overview of the main controls we have available for managing transient frequency variations. We set out below how each of the controls we have available have (or have not) been accounted for within the methodology of this report.

Control	How has this been applied in the methodology?
Meeting minimum inertia	Quantify the additional actions required to meet the minimum inertia set out in the scenarios.
Holding frequency response	The expected position for frequency response volumes has been applied for (1) current FRCR policy and (2) the additional actions required to secure simultaneous events.
Reducing BMU loss size	Only BMU+VS considered.
Reducing LoM size	Control not applied within the methodology.

The focus of the FRCR methodology and assessment is on determining the optimal balance of cost vs risk to ensure we avoid unacceptable frequency conditions. We have not optimised Primary, Secondary and High response in the current methodology, rather we have applied a set value of 550MW for pre-fault reasons.

6. Assessment and results

6.1. Assessment of reducing minimum inertia requirement

FRCR 2023 assesses the impact and benefit of reducing the minimum inertia requirement. The assessment was conducted at inertia levels of 140, 130, 120, 110 and 100 GVA.s respectively. To address the impacts and benefits of reduced inertia, we consider three main questions within this section:

1. What is the residual system risk profile with a reduction in minimum inertia for covering different loss risk events?
2. What are the potential cost savings associated with different levels of inertia?
3. What is the recommended minimum inertia requirement?

6.1.1 System risk profile (including a consideration of simultaneous events)

The impact of the current FRCR policy (see appendix 9.2) on the risk profile for 2023 is set out below. We have applied the current FRCR policy and included an assessment of the different minimum inertia requirement levels studied within the assessment. We have assessed different minimum inertia levels from 140GVA.s through to 100GVA.s.

The resulting risk profiles calculated below can be compared to last year's report and demonstrate an improvement in overall system risk, due to the combined changes to the system conditions detailed in 4.5. The following tables provide an overview of the system risk at the different levels of minimum inertia studied.

The costs applied are based on our recommendation of 120GVA.s minimum inertia requirement.

- A spend of £264million on frequency response controls to fully mitigate all BMU-only infeed and outfeed loss risks, results in a residual risk of;

Scenario	140 GVA.s	130 GVA.s	120 GVA.s	110 GVA.s	100 GVA.s
49.2Hz event	1-in-17 year	1-in-17 year	1-in-17 year	1-in-17 year	1-in-17 year
48.8Hz event	1-in-30 year	1-in-30 year	1-in-30 year	1-in-30 year	1-in-30 year

- An additional spend of £13million required to manage BMU+VS (outage) events results in a residual risk of;

Scenario	140 GVA.s	130 GVA.s	120 GVA.s	110 GVA.s	100 GVA.s
49.2Hz event	1-in-18 year	1-in-18 year	1-in-18 year	1-in-18 year	1-in-18 year
48.8Hz event	1-in-30 year	1-in-30 year	1-in-30 year	1-in-30 year	1-in-30 year

- A further spend of £306million to manage BMU+VS (intact) events results in a residual risk of;

Scenario	140 GVA.s	130 GVA.s	120 GVA.s	110 GVA.s	100 GVA.s
49.2Hz event	1-in-20 year	1-in-20 year	1-in-20 year	1-in-20 year	1-in-20 year
48.8Hz event	1-in-30 year	1-in-30 year	1-in-30 year	1-in-30 year	1-in-30 year

It is worth noting that, at 120GVA.s, the overall probability of BMU + VS (outage) triggering 49.2Hz events is 0.36% per year – this derives a risk profile of 1-in-275 years event. The annual spend of £13million would need to be continued for 275 years to fully mitigate the effect from a BMU+VS (outage) event. This would result in a cost per avoided event[5] of £3.58billion. We do not consider this to represent good value for consumers, and therefore do not consider any changes to current policy due to the small change in risk profile achieved vs the additional spend required.

The risk profiles remain the same at each of the studied minimum inertia requirements due to the other controls available to us for managing frequency risks. Primarily, the growth of DC means that at each of the minimum inertia levels studied, we can procure sufficient DC to secure the largest BMU-only loss risk. Differing the minimum inertia requirement does not impact our risk profile for securing against a 49.2Hz event.

Differing the minimum inertia requirement also does not impact the risk profile for 48.8Hz events as this is largely driven by the underlying assumption made within the FRCR modelling of a 1-in-30 year risk of a peak simultaneous event (referenced in 5.2 above).

6.1.2 Comparison of 2022 and 2023 risk profiles at the proposed 120GVA.s minimum inertia

The following table provides a comparison of 2022 risk profiles against the calculated risk profiles for 2023 with 120GVA.s as the applied minimum inertia requirement. Even whilst reducing minimum inertia, the overall system risk has improved since last year, primarily due to the impacts of the ALoMCP. In addition to no decrease in system risk profiles, there are significant cost savings that can be achieved from reducing minimum inertia (detailed in 6.1.3 below). We therefore consider that an assessment of reducing our minimum inertia represents good value for consumers.

Frequency deviation	2022 risk profile (at 140GVA.s)	2023 risk profile (at 120GVA.s)
49.2Hz event	1-in-14 year	1-in-17 year
48.8Hz event	1-in-28 year	1-in-30 year

The system risk profile for 2023, using FRCR 2022 as a comparison, results in an overall improvement in system risk. This is a result of the changes to system conditions implemented through the ALoMCP which means that the VS loss risks have reduced by, on average, 58%. This has the impact of reducing the number of BMU+VS events that are unsecured. In turn, this reduces the costs of those unsecured BMU+VS loss risks because less volumes are needed in terms of the controlled actions required to reduce loss size.

6.1.3 Expected cost saving against each minimum inertia requirement

The following table shows the costs and potential savings that could be achieved across the different inertia levels from 140GVA.s to 100GVA.s before any further individual loss risk controls are applied.

When assessing the cost impact of a changing minimum inertia requirement, only the costs of DC and inertia are impacted. All other system wide costs (such as primary, secondary and high response, or static response) remain unchanged. Whilst DC costs increase slightly to offset any reduction in inertia levels, this increase in cost is significantly offset by the inertia savings. We also consider the availability of DC a more effective tool than synchronising additional inertia when managing frequency risks.

We estimate that through our proposal of applying a 120GVA.s minimum inertia requirement, **there is a £65million per year saving to be realised** through reducing the number of inertia actions that will be required.

[5] Cost per avoided event is defined in section 5.1 of the methodology.

Scenario	140 GVA.s	130 GVA.s	120 GVA.s	110 GVA.s	100 GVA.s
Cost for system-wide controls (*NB: system wide controls include inertia and all response costs, including PSH, static response etc*)	£329m	£285m	£264m	£260m	£259m
Cost to meet minimum inertia this element is included in system wide cost	£70m	£26m	£5m	£0.4m	£0[6]
Overall saving		**£44m**	**£65m**	**£69m**	**£70m**

6.1.4 Reduction below 120GVA.s

System inertia is a key system attribute, and we continually review our studies for future system inertia requirements. For the period covered by this report, we consider that 120GVA.s is the optimal level of inertia to apply. This change to system operation represents the first stage in our ambition to move towards operating the system at lower inertia levels to meet our zero carbon ambition.

As a prudent system operator, we do not consider it sensible to reduce minimum inertia below the 120GVA.s level as the initial reduction. This will ensure that we can apply a level of caution to the changes we make to the system so not to have any unintended consequences for both system operation, as well as to any other assets connected to the system.

In addition, based on our view of 2022 outturn and an updated data set for 2023, we estimate that there are less than 1% of settlement periods where system inertia (market provided + voltage inertia + stability pathfinder inertia) will be below 120GVA.s. Since reducing inertia represents a notable change to both industry as well as for the ESO, combined with the small number of periods where system inertia would be below our proposed level, we do not propose a further reduction at this stage.

For future versions of FRCR, we will consider ongoing changes to the system dynamics which may impact this proposal (such as stability pathfinders phase 2 and 3 becoming available in 2024 and 2025 respectively). We anticipate that we will be able to consider a longer-term view of frequency risks, wider than the one-year window that we currently consider and will keep our minimum inertia requirement under review as part of this process.

6.1.5 Overall system operability

We have analysed our operability requirements across the system for every year from 2022 to 2035 which are detailed in our Operability Strategy Report (OSR). As part of these requirements, we assess different scenarios from our Future Energy Scenario (FES) which could affect our system stability requirements. From these studies we can determine that there is no system operability impacts for 2023 and 2024 when considering reduced inertia levels as far as 120GVA.s. This analysis is used to determine future system requirements and we will be setting out how we intend to work with industry to resolve our future requirements in the Markets Roadmap.

Additionally, we have ongoing work in the system operability space and will continue to monitor the impacts of declining short circuit levels on the system. At this time, we are comfortable there are no impacts based on the tools and processes we have available to us and changes to the system detailed in section 4.5.

6.1.6 Recommendation for a minimum inertia requirement of 120GVA.s for 2023

The recommendation based on the assessment conducted is to reduce our minimum inertia requirement to 120GVA.s. There are no other policy changes proposed meaning, under 120GVA.s operation, we would still secure BMU only infeed and outfeed losses and not secure for BMU+VS (outage) or BMU+VS (intact) events.

[6] Meeting 100GVA.s minimum inertia requirement has zero cost as 100GVA.s would already be satisfied by market inertia / system outturn, without the need for additional actions.

There is no reduction in the overall risk profile of the system from operating at a lower inertia level compared with 140GVA.s. Operating at 120GVA.s also presents a potential balancing cost saving of £65million per year.

6.2. Assessment of current policy (not securing simultaneous events)

The 2022 FRCR concluded that we did not consider the additional costs to mitigate the further risk of simultaneous events to represent good value for the consumers under the FRCR framework. No changes to policy were proposed within the report to secure for simultaneous events.

We have reassessed this conclusion within this report and consider that securing for simultaneous events still does not represent value for consumers. The additional cost of procuring response to secure all simultaneous events is estimated to be £321million per year. Securing against all simultaneous events would require a significant increase in DC capacity and up to ~3.5 times the volume would be needed. At present, there are insufficient assets on the system to provide this response and is a considerable increase from current capacity volumes.

As a large proportion of simultaneous events are already covered by existing policy; the low likelihood and additional cost to cover the rest is therefore not considered to be good value for consumers. **We therefore do not recommend, within this report, that any changes are made to existing policy regarding securing for simultaneous events.**

7. Conclusions

7.1. Recommendation

The recommendation within this report is to reduce our minimum inertia requirement under the policy from 140GVA.s to 120GVA.s.

We believe this represents good value for consumers and given the changes to overall system conditions discussed throughout the report, this change does not reduce the resulting system risk profile. Instead, for 2023, the resulting risk profile at a lower inertia level is improved when compared with the 2022 analysis, primarily due to the overall improvements made through the ALoMCP discussed earlier in this report.

Operating a lower inertia system would result in up to £65million per year saving on balancing costs.

We do not recommend changing current policy regarding the loss risks categories. Securing simultaneous events still does not represent good value for consumers. Current policy is set out below:

- Apply individual loss risk controls to BMU-only events to keep resulting frequency deviations within 49.2Hz and 50.5Hz.
- Do not apply individual loss risk controls to BMU+VS events (intact or outage).
- Do not apply additional system-wide controls to secure simultaneous events.

7.2. Consultation summary

The FRCR 2023 consultation was issued on 13th February 2023, closed on 24th February 2023 and received six responses. A summary of the responses can be found in the table below, and the full responses can be found in on our website[7]. The key points from the consultation are detailed below:

#	Question	Response summary
1	Overall, do you agree that the FRCR represents appropriate development in determining the way that the ESO will balance cost and risk in maintaining security of supply while operating the system?	Four respondents agreed in principle with the overall assessment process. There were clarifications required on the assumptions the ESO have used to derive the final recommendations as well as clarity on how inertia may impact other operational requirements.
2	Do you agree that the FRCR has been prepared appropriately?	Five out of six agreed that the report had been prepared appropriately, with one disagreeing. Broadly, there was an appetite to provide additional information on the supporting analysis and data inputs that go into the modelling.
3	*To help structure comments, do you agree with and what is your feedback on the specific recommendation in the FRCR?*	
4	**Recommendation**: **Minimum inertia policy** Reduce minimum inertia policy from 140GVA.s to 120GVA.s	Four out of the six respondents explicitly agreed with the proposal. The other two did not disagree, however highlighted concerns with potential risks outweighing a modest cost reduction. The other respondent flagged concerns over the impact that reduced inertia would have on load oscillations. It was also highlighted that lower inertia is sensible if the ESO intend to procure sufficient DC and avoid restrictions of operational interconnectors.
5	Do you have any suggestions for further areas that can be addressed in future editions of the FRCR	Two respondents had no further comments. The four respondents who provided suggestions included; • More detail on the methodology • A ‘significant’ emphasis on the impact of smart loads and their control systems

[7] https://www.nationalgrideso.com/industry-information/codes/security-and-quality-supply-standards/frequency-risk-control-report

		• A concern was flagged that the ESO is not procuring sufficient DC to avoid interconnector restrictions • The power quality issue of how smaller frequency deviations impact users and how often they occur.
6	Do you have any other comments?	Three from six respondents had no further comments. Comments from the other three respondents include; • No consideration of 'black swan events' and impact on LFDD • A review of historic performance against policy would be helpful • Consultation period for an important system parameter was too short.

7.3. Implementation

Pending approval from Ofgem, the implementation of reducing minimum inertia will be conducted in two phases.

- We initially propose reducing minimum inertia from 140GVA.s to 130GVA.s. This reduction would be implemented in one stage, so moving from 140GVA.s to 130GVA.s the following day. Exact dates and timings are still to be finalised, however we will provide at least five working days advanced notice to industry of timings once clarified. This will be through the Operational Transparency Forum (OTF) or similar industry fora.
- The first reduction is anticipated to be within Q2 2023, followed by an estimated one-to-two-month period of operation at this level. This is to ensure our tools and processes are fully capable of operating the system under lower inertia levels, with no unintended wider operability risks.
- After this initial reduction period, we propose a second staged reduction from 130GVA.s to 1200GVA.s. Again, this would be conducted via a single reduction from 130GVA.s to 120GVA.s, which we plan to communicate with industry ahead of making the change.
- This means that we anticipate we will be operating with this minimum inertia requirement within Q3 2023.

At the same time as reducing inertia, our ancillary markets are continuing to grow to meet further operational needs which will provide additional tools available to us for managing any frequency deviations.

8. Future considerations

There are various events, loss risks, impacts and controls which are not explicitly considered in this edition of the report. They will be prioritised for future inclusion in future reports, based on consultation with the industry and the Authority. Such examples are described in the following section.

8.1. Events and loss risks

Other events driven by planned transmission network outages: The change in the likelihood of existing events or new events created during outages on the NETS, other than those outages already considered by the methodology.

Weather conditions: The change in the likelihood of events during adverse conditions. The key complexity is how to quantify the increase in risk.

New causes of events: Such as Active Network Management schemes (AMNs), single control points for multiple-BMUs, IP risks. More work is required to understand and quantify these events.

Generation connections: Assets owned by generators that connect them to the NETS, but which are not covered by the SQSS e.g., short double circuit routes from a power station to a substation.

New causes of distributed resource losses: Any new causes that come to light as the power system evolves.

New infeed and outfeed losses: Future connections to the NETS, including new interconnectors, offshore wind, and nascent technologies. The key question to address is how to forecast the running-pattern and reliability of new connections.

Impact of system conditions in the run-up to an event: How this impacts on the ability of the system to cope with events e.g., more onerous starting frequency, sustained high or low frequency and the impact on energy-limited controls.

8.2. Impacts

Multiple stages of LFDD: Exploring whether events could cause more than one stage of LFDD, and how often this could happen. This would include the duration of LFDD events and the time taken to recover.

Further investigation of high frequency deviations: Historically the focus has been on low frequency, but as more large outfeed losses connect this may need to change.

Further investigations of frequency deviations closer to 50Hz: How smaller deviations impact users, and how often they should be allowed to occur.

8.3. Controls

Response and Reserve: Future services developed under the Response and Reserve roadmap.

Further reduction of minimum inertia requirement: We will continue to review our minimum inertia requirement in order to help achieve our zero carbon ambition to operate at 102GVA.s in 2025.

8.4. Metrics

Other approaches to valuing cost versus risk: Whether there are other projects, initiative or research which can help to inform the metrics and the tolerability of events to end consumers.

Ongoing updates: Regularly updating the metrics to incorporate the effect of changes in the value of security of supply as electricity demand changes e.g., due to the electrification of heat, electric vehicles or production of green hydrogen.

Implementation: The time and costs associated with implementing a change in policy.

8.5. Analysis and data

Improvements in statistical data inputs: Whether there is the opportunity for better quality or more accurate input data on the probability of the various types of faults, and how to reflect any uncertainties. Whether to model a range of possible weather scenarios to understand the variance this introduces.

Consideration of costs other than BSUoS charges: Whether to assess the wider costs of procuring controls over and above the direct Balancing Services Use of System (BSUoS) charges.

Longer time frame of analysis: With additional resource committed within our second Business Plan (BP2) for the RIIO-2 period[8], future versions of FRCR will analyse a longer time frame rather than the current 1 year ahead.

Collaboration with other system operability workstreams: We will look into FRCR future policy of frequency management in collaboration with other power system operability areas to understand wider system impacts, i.e., voltage control, fault level requirements, system restoration requirements.

[8] RIIO-2 BP2

9. Appendices

9.1 List of Abbreviations

ALoMCP	Accelerated Loss of Main Change Programme
AMNs	Active Network Management schemes
BMU	Balancing Mechanism Unit
BSUoS	Balancing Services Use of System
DC	Dynamic Containment
DER	Distributed Energy Resources
ESO	Electricity System Operator
FES	Future Energy Scenario
FRCR	Frequency Risk and Control Report
LFDD	Low Frequency Demand Disconnection
LoM	Loss of Main relay
NETS	National Electricity Transmission System
OSR	Operability Strategy Report
RoCoF	Rate of Change of Frequency
SOGL	System Operation Guideline
SQSS	Security and Quality of Supply Standards
VS	Vector Shift

9.2 FRCR April 2022 Policy

In 2022 FRCR, there was no recommended changes to policy and therefore, the policy below represents the policy applied in both 2021 and 2022 FRCR.

Frequency response

The ESO will:

a) **Infeed losses**

Prevent BMU-only and VS-only infeed losses causing a frequency deviation below 49.2Hz and restore frequency above 49.5Hz within 60s

b) **Demand losses**

Prevent all BMU-only outfeed losses causing a frequency deviation above 50.5Hz

Prevent the loss of Super Grid Transformer supplies to Distribution Networks causing a frequency deviation above 50.5Hz[9]

NB: VS-only losses can't cause outfeed losses, only infeed losses

Inertia

The ESO will:

a) **Minimum inertia**

Maintain system inertia at or above 140 GVA.s. This prevents all BMU-only, VS-only and BMU+VS loss risks up to approximately 700MW from causing a consequential RoCoF loss[10]

b) **Largest VS-only loss risk**

Ensure system inertia is maintained at or above the level that will prevent the largest VS-only loss from causing a consequential RoCoF loss.

Reduce Loss of Mains loss size:

The ESO will

a) **Accelerated Loss of Mains Change Programme (ALoMCP)**

Update operational tools with latest programme delivery, as a reduction against the initial baseline capacity estimate at the start of the programme.

Reduce BMU loss size

The ESO will

a) **Infeed loss risks**

Allow BMU-only infeed loss risks to cause a consequential RoCoF loss where the resulting loss can be contained to 49.2Hz. If the resulting loss cannot be contained to 49.2Hz, then take bids to reduce the BMU-only infeed loss to prevent a frequency deviation below 49.2Hz, either by preventing the consequential RoCoF loss or reducing the overall BMU+RoCoF loss.

b) **Outfeed loss risks**

Consider allowing BMU-only outfeed loss risks to cause a consequential RoCoF loss, as the two losses will partially offset each other[11]

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[9] these are a loss of power outfeed and are typically smaller than 560MW
[10] for some loss risks, the inertia lost with the event means the threshold is slightly below 700MW
[11] the BMU-only outfeed loss would make frequency rise, but the consequential RoCoF loss would make the frequency fall, so the net effect of the combined loss is smaller

- This is only permissible if the resulting high frequency and/or low frequency deviations are acceptable
- If they are not acceptable, then do not let BMU-only outfeed losses cause a consequential RoCoF loss, by taking offers to reduce the demand loss

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 where appropriate during times of increased system risk, such as during severe weather, and exceptions where risks cannot feasibly occur[12] .

The FRCR is an assessment of all events across 2022, made using assumptions as to the likelihood and impact to system security based on the controls the ESO expects to have available. If there are circumstances whereby a specific event would lead to overall system risk being significantly different to the expected case, the ESO reserves the right to take actions to ensure that system risk remains in line with the risk appetite outlined in the FRCR.

If and when this occurs, and as appropriate, the ESO will inform the Authority of such actions after they have been taken, and report relevant details in the following FRCR process

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

9.3 Events and loss risks

BMU-only	• an event that disconnects one or more BMUs, and may or may not also cause a consequential RoCoF loss (no Vector Shift loss) • caused by a **Loss of Power Infeed** or **Loss of Power Outfeed**
BMU + VS	• an event that disconnects one or more BMUs and causes a consequential VS loss, and may or may not also cause a consequential RoCoF loss • caused by **fault outages** of **primary transmission equipment** on the **National Electricity Transmission System** (i.e., a **single transmission circuit**, a **busbar** or **mesh corner**, or a **double circuit overhead line**)
Simultaneous Event	• an event that disconnects two BMUs at the same instant and may or may not also cause a consequential RoCoF loss

9.4 Inputs and data sources

Based on feedback from the consultation process, we have included the following additional detail regarding the model inputs and data sources. In addition, more detail on the methodology can be found in the 2021 methodology document[13]. This methodology remains unchanged for 2023, except for the known updates to the input data.

Period covered by 2023 FRCR	The model set up was completed in Q4 2022. The inputs used are based on historical data, amended to reflect known changes to the system. The data used covers the period from June 2021 – May 2022.
Cost assumptions	**BM cost assumption** The cost of BM actions takes the average prices during the FRCR investigation period, including Bid (to take a BMU from PN towards SEL), Offer (from PN towards MEL), and De-sync (from SEL to 0). Prices are categorised per fuel type and nuclear is assumed to be inflexible. **Response cost assumption** The cost for response services takes the average prices against different EFA blocks for each service during the FRCR investigation period. Response products are cleared in different market arrangements including FFR, MFR, and DC. Other legacy services use their contracted prices such as EFR and Interconnector static response. **Inertia cost assumption** The cost for accessing additional inertia is achieved by converting the required volume of inertia into the volume of energy that needs to be repositioned.
Event likelihood	The likelihood of each event occurring in each period. For BMU-only events this is based on the fuel-type breakdown statistics. For VS-only and BMU+VS Vector Shift events, this is based on the network equipment.
Network equipment fault probability	Gives the typical annual fault rate of different asset types on the network e.g., overhead lines, cables, busbars.
Risk profiles	The risk profiles within the report are the summation of the residual risks for all possible events in the system. For each individual event, the risk is calculated as the event likelihood multiplied by the percentage of time this event is at risk.

[13] Frequency Risk and Control Report 2021

For example, a particular event occurs two times a year and 5% of time this even is at risk, this ends up with a residual risk of 2 * 5% = 10% per year or 1-in-10-year risk. This is the same calculation used to derive the 0.36% likelihood (or 1 in 275 year) risk of a BMU+VS event triggering a 49.2Hz event.

DC holding

For each of the inertia levels assessed, the DC holding volume is determined at the day-ahead stage, for all EFA blocks the following day. Three factors determine the DC holding volume:

1. system conditions including demand and inertia
2. the expected largest loss considering consequential RoCoF loss
3. holding volume of other response products before DC auction.

Contribution of stability pathfinders

FRCR 2023 will be effective for the period April 2023 to March 2024. Only the contribution of stability phase 1 units that were live at the time of setting up model inputs were accounted for. Stability phase 2 contribution was not considered as these units will not be live until April 2024. This will be accounted for in future versions of FRCR.