Public

Frequency Risk and Control Report 2025

Supplementary Report

March 2026

NESO
National Energy System Operator

Executive Summary

This supplementary document to the Frequency Risk and Control Report (FRCR) 2025 provides additional substantive discourse around the assumptions and methodologies supporting the quantitative analysis underpinning the policy recommendations outlined by the FRCR as requested by Ofgem following the original submission of FRCR 2025 in May 2025.

The report provides various independent arguments and articles of evidence which underscore the validity of the frequency risk modelling framework used within the FRCR 2025. Firstly, the frequency model of the FRCR 2025 is grounded in established power system theory and simulates the trajectory of frequency over time in the GB electricity system following active power imbalances. The model takes account of prevailing system conditions defined by demand and inertia, as well as post-imbalance dynamics driven by credible contingencies, Loss of Mains (LoM) effects, and the delivery of frequency response services – thus, enabling the frequency assessment across a wide range of system operating conditions. Importantly, the same underlying model functions are used in NESO's realtime operational and planning tools within the Electricity National Control Centre (ENCC), ensuring alignment between policy assessment and operational practice.

Further, post-event analyses using the underlying model demonstrate close alignment between simulated and observed frequency traces across key performance metrics, including initial rate of change of frequency (RoCoF), frequency nadir and the impact of response services, even when there are uncertainties in the exact state of system parameters at the time of the event.

The report also highlights independent assessments of the FRCR 2025 methodology. With support from Accenture on testing, NESO's functionally independent Engineering Assurance team concluded that a rigorous process has been followed for FRCR 2025 in: 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 outputs. Complementing this, Industrial System and Control (ISC) have confirmed the theoretical foundations, numerical implementation, and practical applicability of the modelling framework. Together, this evidence provides assurance that the modelling accurately represents real system behaviour.

With respect to event risk assessment, the FRCR analysis considers three categories of events: BMU-only events, BMU + Vector Shift (BMU+VS) events, and simultaneous events. BMU-only and BMU+VS event probabilities are derived from recent historical asset outage and transmission fault data. Simultaneous events are developed statistically due to their complexity and rarity, with likelihoods calibrated conservatively to reflect limited data and uncertainty about the occurrence profile of extreme low-probability events. The report highlights the updates to likelihood assumptions adopted in FRCR 2025 are supported by recent frequency management operational experience and ensure that emerging frequency risks are not understated.

A key policy recommendation of the report is derived from a comparative assessment of alternative minimum inertia policies, demonstrating that reducing the minimum inertia requirement from 120 GVA·s to 102 GVA·s does not materially increase residual frequency risk faced by the GB power system in the coming year. On top of that, FRCR 2025 also recommends increasing the procurement of Dynamic Containment Low (DC-Low) by an additional 200 MW to mitigate further residual risks. NESO assesses there exists sufficient additional volume in the DC-Low market to meet the additional 200 MW procurement requirements. In general, Dynamic Response Services, which includes DC-Low, are mature, well-monitored services with clear performance standards, robust monitoring arrangements, and effective financial incentives. Taken together, the recommendations satisfy the three-way aims of NESO: it increases system security while improving economic efficiency and promoting lower carbon technologies.

This supplementary report also presents a revised extended implementation plan of the FRCR policy recommendations, with improved clarity on the success criteria and contingency plan. During the transition period, a number of metrics will be used to carefully assess the system performance before proceeding to subsequent stages. This approach ensures that changes can be paused, extended, or reversed if unexpected risks to frequency stability emerge, maintaining stakeholder confidence in frequency security throughout the transition.

Finally, the report outlines current FRCR governance arrangements and sets out a forward-looking vision for the evolution of the FRCR process, which will shape the form of the upcoming 2027 report, given the recent Ofgem decision to suspend the requirement to produce a 2026 report. This amended scope will ensure continued focus on actionable, evidence-based frequency security while transparently acknowledging areas of uncertainty and future development.

Contents

Introduction

Frequency Risk and Control Report (FRCR) 2025 is the fifth edition of the FRCR and provides technical assessments and policy recommendations to manage frequency security and stability in Great Britain's electricity network. The report continues NESO's approach of effectively managing the tripartite mandate of maintaining network operational frequency security per the standards established within the Security and Quality of Supply Standard (SQSS), supporting the development of a zero-carbon power system, while minimising energy costs where practical.

Given these requirements, FRCR 2025 provided the following recommendations:

1. Reduce the minimum inertia requirement from 120 GVA.s to 102 GVA.s,
2. Continue securing all BMU-only risks without applying additional actions to mitigate all BMU + Vector Shift or simultaneous events, and
3. Procure an additional 200 MW of Dynamic Containment Low (DC-Low) to further reduce residual risks.

Under the application of these policy recommendations, the report highlighted a residual risk corresponding to approximately a 1-in-23-year occurrence of a 49.2 Hz event and a 1-in-30-year occurrence of a 48.8 Hz event.

Following the initial submission of FRCR 2025 in May 2025, Ofgem conducted a public consultation on the results and policy proposals within the document: while a proportion of respondents supported the recommendations, citing the effectiveness and cost efficiency of dynamic response services, others raised concerns regarding modelling transparency, the proposed timescales for reducing minimum inertia, and the overall strategy for managing frequency risk. In response to these concerns, Ofgem took the additional step of commissioning an independent review[1] of FRCR 2025 by Professor Keith Bell from University of Strathclyde.

While Ofgem noted in its decision letter that FRCR 2025 met the criteria by which NESO balances cost and frequency risk, Ofgem was unable to approve FRCR 2025 based on the conclusions of the independent review and the responses received through the industry consultation, and subsequently issued a decision directing NESO to provide additional information.

Set out below are the areas of the FRCR 2025 report identified by Ofgem in its decision letter as requiring further clarification (in bold), together with references to the sections of this supplementary report where each request is addressed.

[1] Frequency Risk and Control Report 2025: independent review

- Clearer evidence of simulation validation and greater transparency in the estimation of probabilities.

This is addressed in **Sections 1.1** and **1.2**, including their accompanying subsections.

- More detailed information on modelling parameters and assumptions.

Further explanation and justification of modelling parameters and assumptions are provided in **Section 1.3**.

- A review of the Dynamic Containment Low (DC-Low) market.

This is addressed in **Section 2** of this report.

- A revised implementation plan for inertia reduction.

This is set out in **Section 4** of the report.

- A detailed outline of the scope of FRCR 2026.

Ofgem suspended the requirement to publish FRCR 2026 in March 2026. In light of this decision, **Section 6** outlines the proposed future direction of FRCR 2027 and subsequent reports.

In addition to addressing Ofgem's specific requests, this supplementary report also includes a review of the Low Frequency Demand Disconnection (LFDD) scheme (**Section 3**) and an overview of FRCR governance arrangements (**Section 5**). While these topics sit outside the formal scope of FRCR 2025, they are included to enhance transparency and respond to issues raised by stakeholders during consultation and engagement.

The purpose of this supplementary report is therefore to address the additional information request set out in Ofgem's decision letter. It should be read as supporting documentation to the original FRCR 2025 submission and is prepared on the assumption that the reader is familiar with the content of the FRCR 2025 report. Its intent is to provide additional clarity, context, and assurance in relation to the methodologies, assumptions, and policy conclusions presented in the original submission.

Section 1: Technical assurance

This section sets out the technical rationale underpinning the FRCR 2025 recommendations and explains the basis on which they represent an appropriate balance between cost and the residual likelihood of frequency deviations. It summarises the key modelling assumptions and evidence used to assess system risk.

1.1 Frequency simulation model in FRCR

The FRCR frequency modelling framework is grounded in established power system modelling, aligned with real-time operational practice at NESO. Further detail on the theoretical basis, operational use, validation, and external scrutiny is provided below.

1.1.1 Frequency simulation model foundations

The frequency modelling tool used within the FRCR analysis is grounded in well-established power system frequency modelling and reflects the fundamental physical behaviour of the electricity system active power balance. At its core, the modelling function is derived from the *swing equation* and represents the GB power system as a simplified single bus system, with frequency evaluated on the basis of total post-fault inertia, with generation and demand inertia aggregated into a single equivalent mass[2]. This is an accepted practice across the energy industry and academia. This approach captures the essential dynamics governing how system frequency responds to sudden active power imbalances, providing a representation of system behaviour following disturbances.

Key system characteristics are explicitly represented within the model, including prevailing system conditions such as demand and inertia, as well as frequency dynamic driven by credible system contingencies and the delivery of frequency response services. The total size of the contingency incorporates the consequential impact of Loss of Mains (LoM) Rate of Change of Frequency (RoCoF)-related losses, ensuring that the effective disturbance size is appropriately reflected. The characteristics of frequency response services follows the requirements specified in their Service Terms (more information on response services effectiveness can be found in **Section 2**), enabling an integrated assessment of both inherent system resilience and contracted operational mitigations. Together, these features allow the model to represent the system's frequency behaviour, including RoCoF, frequency nadir, and stabilised frequency.

[2] Kundur, Prabha. "Power system stability." Power system stability and control 10.1 (2007)

1.1.2 Consistency with control-room operational tools

The frequency modelling tool used in the FRCR analysis is not a stand-alone model, but directly aligned with the system operational tools. The same underlying modelling functions are employed within NESO for real-time operation and day ahead planning. This ensures consistency between the assessment of frequency risks presented in FRCR and the tools used by the ENCC to manage those risks in operational timescales. Such alignment supports FRCR's objective of reflecting actual system conditions and operations when evaluating the suitability and effectiveness of different policy and service options.

In the day-ahead timeframe, the tool is used to assess forecast system conditions and determine the response requirements needed to maintain- frequency security. In real time, the same frequency modelling framework is applied to quantify whether additional response services are required to securely operate the system under prevailing conditions. At present, only Mandatory Frequency Response (MFR) is instructed through this process; however, NESO is actively progressing work to expand this functionality to enable the instruction of Dynamic services[3].

1.1.3 Empirical validation based on events

The credibility of the FRCR frequency modelling tool is reinforced through systematic validation against historic frequency events. Following any significant system disturbance, NESO undertakes post-event analysis in which observed system frequency traces are compared with modelled outcomes. These comparisons consistently demonstrate close agreement across key performance metrics, including the initial RoCoF, the depth and timing of the frequency nadir, and the observed impact of contracted frequency response delivery. The ability of the model to reproduce these features provides reassurance in its ability to capture the frequency dynamics following an imbalance.

Figure 1 presents the frequency simulations for a major system frequency excursion that occurred on 14 March 2025.

[3] Dynamic Services (DC/DM/DR)

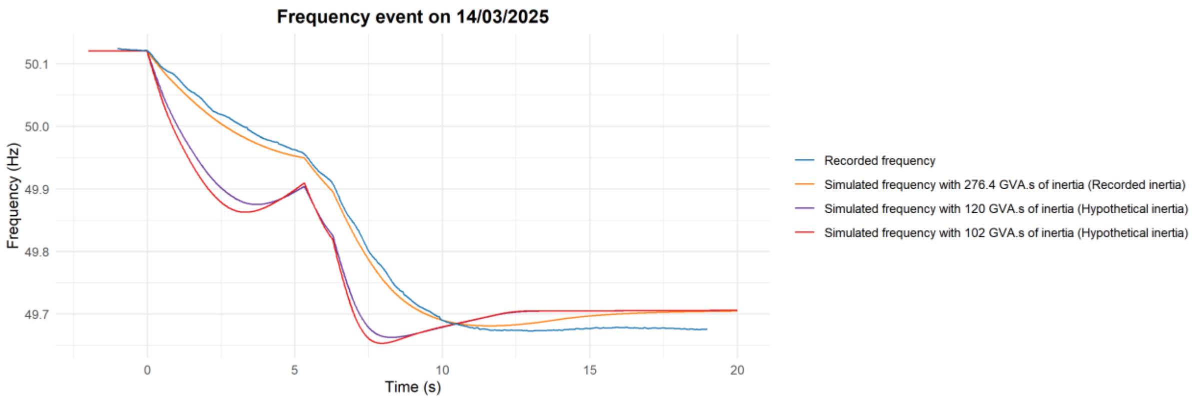

Figure 1 Frequency simulations under different inertia conditions versus recorded frequency for event on 14/03/2025

Of note, from an event review perspective, to reproduce the observed frequency trace for any event precisely requires complete and accurate system information, including system conditions, exact timing/sequence/size of the contingency, and characteristics of all mitigations in place. Having all such parameters available to the necessary degree of fidelity is impractical, leading to uncertainties in event reconstruction. However, despite these uncertainties, the simulation results shown in Figure 1 (Orange curve, with the recorded inertia at the time of the event) demonstrates that the model is able to re-generate the observed frequency trajectory (Blue curve in Figure 1) with a high degree of alignment. This close alignment provides confidence that the underlying dynamic representation is robust, even when some input parameters are uncertain or approximated.

More recent major event reviews are documented in the FRCR 2025 Main Report, Appendix 9.1, which provides further detail on the methodology and outcomes of these comparisons. Appendix 9.1 also provides a hypothetical scenario of frequency behaviours under a wide range of operating conditions, including those with reduced total system inertia (for examples, see the purple and red curves in Figure 1). Together, these provide additional confidence and assurance in the modelling approach to frequency security.

1.1.4 Additional assurance via third-party examination

In addition to event-based validation, the frequency modelling tool used in FRCR has been subject to independent third-party examination. Reviews were conducted by Accenture and Industrial System and Control (ISC) who have assessed the theoretical foundations, implementation, and practical applicability of the frequency modelling framework.

Accenture undertook an integrated audit with the NESO Assurance Team on FRCR 2025 process in March 2025. This work constituted a sensitivity analysis, recognising that the frequency calculations cannot be fully separated from the surrounding operational and governance processes. The audit tested that scenarios and input assumptions fed into the frequency model are reflected in the resulting outputs, with a focus on validating their appropriateness and consistency within the overall control and assurance framework[4]. The analysis concluded that the scenarios and input assumptions applied were appropriate and consistent for the purposes of the FRCR assessment.

Separately, ISC, a consultancy company, produced a review on the frequency simulation functions, documenting how the modelling functions operate. As part of this work, the ISC independently recreated the frequency simulations using a different development tool, specifically MATLAB Simulink, and demonstrated that the resulting frequency traces were the same as those produced by the NESO frequency simulation tool.

1.2 Probability used in FRCR analysis

This section summarises how probability is applied within the FRCR framework to quantify system frequency risk. It outlines the categories of risks considered, how event likelihoods and failure rates are derived, and how these are combined with system controls to calculate the final residual frequency risk.

1.2.1 Event categories

A key set of inputs into the FRCR analysis are the event categories and their associated probabilities. FRCR analysis considers the power system contingencies listed in SQSS 5.1 and 5.3, summarised as the following two types:

- **BMU-only**[5] event, caused by a loss of infeed or outfeed, and
- **BMU + VS**[6] event, caused by a fault outage on the transmission network.

Along with the above two categories of events, the FRCR analysis also incorporates an additional type of event that represents the risks beyond the N-1 criteria:

- **Simultaneous events**[7] that represent multiple BMUs lost in an event.

Simultaneous events were introduced into the FRCR analysis from FRCR 2022 onwards. This development was driven by several historical incidents where multiple generating units

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[4] Integrated technical review (Phase 1): FRCR 2025. Integrated technical review (Phase 2): FRCR 2025
[5] FRCR assessments account for the potential consequential RoCoF loss, i.e. embedded generation that may trip under RoCoF-based Loss-of-Mains protections, in accordance with SQSS 5.8. Therefore, BMU-only events consider the consequential RoCoF loss when the protection is triggered under the prevailing system conditions.
[6] BMU+VS events also considers the consequential RoCoF loss when the protection is triggered under the prevailing system conditions.
[7] Simultaneous events also consider the consequential RoCoF loss when the protection is triggered under the prevailing system conditions.

tripped coincidentally or within a very short time window, resulting in a combined loss significantly larger than any single registered contingency.

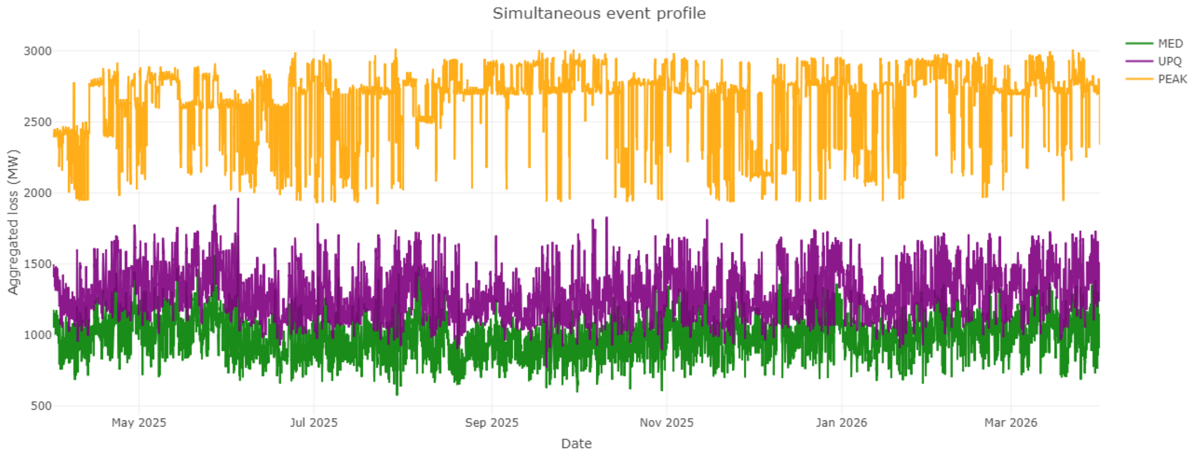

Figure 2: Modelled simultaneous event loss profile

Figure 5 plots a modelled profile of simultaneous event losses, showing the Peak possible loss (in yellow), the upper-quantile of possible loss (in purple), and the Median possible loss (in green). The figure demonstrates that even the Median possible loss in a typical settlement period is approximately 1 GW, while the Peak possible loss is often greater than 2 GW, highlighting that typical simultaneous event losses can be very large at all times. More information on the construction of the simultaneous event profile can be found in the FRCR Data Handbook[8] Section 5.2.4.

These events, although infrequent, demonstrate that real-world system risks extend beyond single loss of infeed and fault outages on the transmission network. The inclusion of simultaneous events therefore serves the purpose of capturing additional, potentially large, frequency risk that cannot be represented by a single contingency. By broadening the scope of credible events, FRCR provides a more comprehensive view of the system's exposure and strengthens the robustness of operational policy assessment. More information can be found in the FRCR Methodology Section 4.1.1[9] which provides a detailed definition of event categories, and Section 4.2, which discusses simultaneous events specifically.

1.2.2 Event probabilities

1.2.2.1 BMU-only

The BMU-only event probability represents the likelihood of an individual infeed or outfeed experiencing an unplanned outage. In the FRCR framework, this probability is derived

[8] FRCR Data Handbook
[9] FRCR Methodology

statistically using historical operational data and is intended to provide a robust, data-driven estimate of BMU reliability. The historical operational data are updated on a rolling basis to reflect the most recent evidence on event occurrence likelihood. The process of obtaining the event probability for BMU-only risks includes:

Outage Identification

The process begins by gathering the historical operational data for the past three years. It is assumed that most electrical equipment is under a three-year maintenance cycle, thus we analyse the past three years to determine the average failure rate per year. This is also to capture recent developments on asset reliability.

Unplanned outages are identified through a two-stage process:

1. Settlement Period (SP) output check: Check SP-level output and detect instances where BMU output changes from any positive value to zero.
2. Planned vs. unplanned confirmation: Check the 4-hour ahead Maximum Exporting Limit (MEL) to determine whether the zero-output transition reflects a planned outage or an unplanned event.

Multiple breakdowns occurring within a 24-hour window are treated as a single outage to avoid overstating failure frequency.

Failure Rate Derivation

Unplanned outages are aggregated by fuel type. For each type, the number of unplanned outages is normalised by the number of units of that fuel type and the number of years analysed, producing a fuel type failure rate. This failure rate is then assigned to individual BMUs on the assumption that units of the same technology share similar reliability characteristics. The only exceptions are Interconnectors, which are calculated individually.

1.2.2.2 BMU+VS

The BMU+VS event probability represents the likelihood of a transmission-initiated fault that leads to the loss of single or multiple BMUs, and embedded generation, due to VS-based LoM protection. This probability is derived by analysing historical transmission faults and their relevance to specific BMU+VS event configurations.

Fault Identification

The process starts with reviewing historical transmission faults across categories such as:

- single-circuit trips,
- double-circuit trips,
- busbar and mesh-corner faults, and
- Offshore Electricity Transmission (OFTO) network faults.

The methodology maps each fault listed above to BMU+VS events by analysing whether each fault type can lead to the subsequent loss of connection/transmission route for BMU(s) as well as the consequential embedded generation loss due to VS-based LoM protection associated with a particular BMU+VS configuration.

Fault frequencies are subsequently computed by dividing the number of observed faults by the total length of circuits **or** the number of bars associated with the fault category, then normalising by the number of years reviewed.

Failure Rate Derivation

For each BMU+VS event, the overall event probability is derived by combining the fault rates associated with all applicable transmission fault mechanisms. Where relevant network assets are subject to planned outages, the methodology distinguishes between intact-network conditions and outage conditions.

The final BMU+VS event probability reflects a weighted combination of the above potential operating contingencies, with intact-network condition fault rates applied for the proportion of the year when the network is fully available, and outage condition fault rates applied for the proportion of the year affected by planned outages. Where no outage specific risks are identified for a particular event, only intact condition fault exposure is considered.

1.2.2.3 Simultaneous events

As for simultaneous events, the probabilities are inherently difficult to model using purely physical or mechanistic representations. Two key issues contribute to this challenge:

- **Complexity of event mechanisms** – Multiple units tripping together involves interactions that may relate to plant configuration, protection schemes, local network conditions or common-mode failures. These mechanisms are difficult to characterise generically, with the large possibility-space of real-world scenarios rendering deterministic modelling impractical.
- **Rarity of occurrence** – Simultaneous events within power systems occur extraordinarily infrequently, meaning the historical dataset is sparse. The limited number of observations prevents the development of reliable, parameter-rich mechanistic models and makes it challenging to infer causality with confidence. In addition, it is a requirement of the Grid Code for Generators and Interconnectors to have Fault Ride Through capability to prevent tripping in the event of a credible fault.

Because of these constraints, FRCR adopts a statistical framework for the treatment for simultaneous events. Rather than attempting to replicate the physical chain of causation, the approach focuses on capturing the probabilistic characteristics of these events based on historical patterns. This allows FRCR to incorporate their impact in the overall risk framework while acknowledging the uncertainties and data limitations associated with them. The combination of expanded risk coverage and statistically grounded methods ensures that FRCR continues to reflect real system vulnerabilities, even in cases where full mechanistic modelling is not feasible.

As an example, on 14 March 2025, a cascading and near-simultaneous outage resulted in the loss of three generating units, with a combined loss of approximately 1.8 GW. Within the FRCR framework, this event is considered a simultaneous event, with its magnitude falling in the upper quantile of possible losses. In the FRCR 2025 analysis, the likelihood of Upper Quantile Simultaneous Events was calibrated at 0.73 events per year, representing a materially higher assessed likelihood than the historical 1-in-20-year assumption used in earlier FRCR studies. The occurrence of a large Simultaneous Event in 2025 provides reassurance that the updated assumptions adopted in FRCR 2025 are more robust and appropriately conservative. Further details of the event review can be found in the FRCR 2025 Report Appendix 9.1, while the underlying data and methodology for simultaneous event likelihood calibration are documented in the FRCR Data Handbook section 6.4.

For the Peak Simultaneous Event, based on the likelihood calibration, there is an occurrence rate of 0.0037 per year based on the observations from the past six years, corresponding to an implied annualised likelihood of approximately 1-in-272 years. Notwithstanding this empirical assessment, the FRCR analysis continues to apply a 1-in-30 year likelihood assumption for peak simultaneous events. This reflects a conservative perspective towards low-probability, high-impact risks, ensuring that the assessment does not understate system security requirements in the presence of limited historical data and residual uncertainty around the tail behaviour of extreme events. The conservative approach to modelling assumptions is discussed further in Section 1.3.6.

1.2.3 Residual risks

The FRCR framework determines the system's residual frequency risks through the following steps:

Step 1 — Translate the policy into required controls and derive the largest securable loss at each frequency threshold.

The policy defines the volume of controls to be held, i.e. the minimum inertia requirement and the quantity of frequency response services. Once these control volumes are fixed, the FRCR model computes the *largest securable loss* that can be contained without exceeding the nadir thresholds at 50.5 Hz, 49.5 Hz, 49.2 Hz, and 48.8 Hz. In other words, the policy selection is converted into a set of securable loss limits that describe the system's capability to ride through disturbances of different magnitudes.

Figure 3 shows the largest securable infeed losses for 49.2 Hz and 48.8 Hz events under the FRCR 2025 recommendations, i.e. hold at least 102 GVA·s of system inertia, mitigate all BMU-only risks, and hold an additional 200 MW of DC-Low services. Securing all BMU-only risks implies that the largest securable loss for 49.2 Hz events should be above the largest BMU-only loss, as is demonstrated in the figure. The holding of an additional 200 MW of DC-Low services further increases the securable loss threshold, extending coverage to additional residual risks.

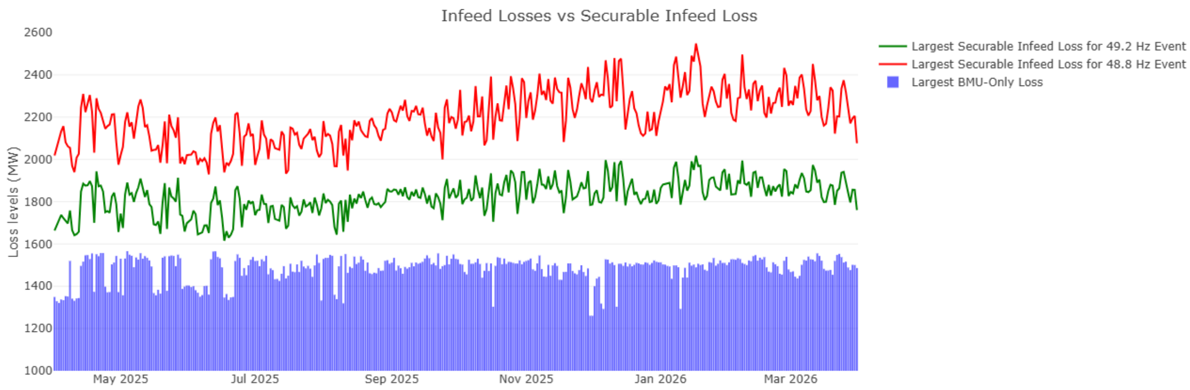

Figure 3 Largest securable losses for 49.2 Hz and 48.8 Hz events

Step 2 — Compare the securable loss threshold against the full distribution of risks in each event category.

For every BMU-only event, BMU + VS event, and simultaneous event, the model compares the event's total loss (including any consequential RoCoF losses) with the largest securable loss established under Step 1. Events with loss magnitudes below the threshold are considered *fully secured*, meaning the applied controls are sufficient to prevent unacceptable frequency conditions. Events that exceed those thresholds are *not fully secured*, and their contribution, accounted by their likelihood, becomes part of the residual risk. This step essentially identifies which risks are fully mitigated by the selected controls and which are not fully mitigated, hence has contributions to the residual risks.

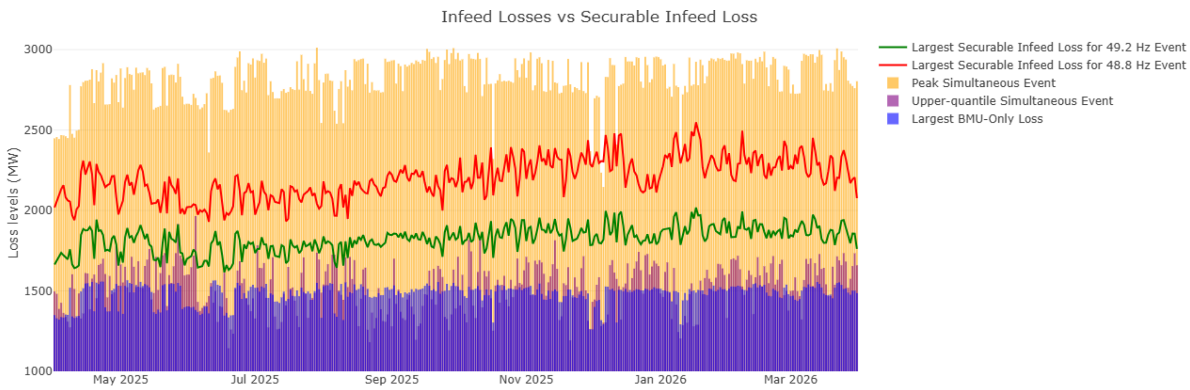

Figure 4 Comparing Largest Securable Losses with events

Figure 4 illustrates the process of assessing each risk against the largest securable loss, using the Largest BMU-only risk, the Upper-quantile Simultaneous event, and the Peak Simultaneous event as examples. The Largest BMU-only risk is fully covered under the policy. With an additional 200 MW of DC-Low services, the Upper-quantile Simultaneous event is covered in 98.8% of time – the purple bars are mostly below the green curve. In contrast, the Peak Simultaneous event exceeds the largest securable loss for the 48.8 Hz event; therefore, should such an event occur, it would be expected for the frequency to fall below 48.8 Hz.

Step 3 — Combine the unsecured portions of all events to form the final residual risks. All of the events derived in Step 2 that are not fully secured are aggregated across all settlement periods and frequency thresholds. The probability of each event, multiplied by its non-securable impact level, determines its contribution to the overall system risk. Summing these contributions yields the final residual risks, expressed as exceedance frequencies (e.g., expected number of 49.5 Hz events per year) or as return-period metrics (e.g., a 1-in-23-year risk level). This combined output represents the system's remaining exposure after all policy-driven controls have been applied.

1.3 Assumptions used and their justification

This section explains the rationale behind the assumptions made in the FRCR analysis. These assumptions were intentionally chosen to manage uncertainties and maintain the system's safety and reliability. Those assumptions serve as input data to the FRCR framework and are also used in our daily operations. Some assumptions, while potentially useful in real system events, are not specifically incorporated into the FRCR framework due to uncertainty surrounding their effectiveness. Detailing the reasoning behind each assumption shows how extra safety margins are associated with the FRCR results.

1.3.1 Initial frequency of ±0.15Hz.

Within the FRCR analysis and the daily DC response requirements calculations, the initial system frequency prior to a contingency event is modelled with a pre-existing deviation of ±0.15Hz, the same assumption used in NESO operation. Using this assumption is deliberately conservative. It represents a situation where Dynamic Regulation (DR) and Dynamic Moderation (DM) are already activated and partly consumed before an incident occurs, leaving less headroom than under ideal conditions. This helps ensure that the analysis does not rely on optimistic initial conditions.

As an illustration, for an infeed loss event, Figure 5 shows the likelihood of the system frequency staying above certain thresholds and details the extra response capability when the pre-fault frequency deviates less than the assumed 0.15 Hz. For example, the probability of frequency at and above 49.9 Hz is approximately 90% in average. If the frequency is actually at 49.9 Hz when an incident happens, there would be 357 MW of additional response available to mitigate the risk.

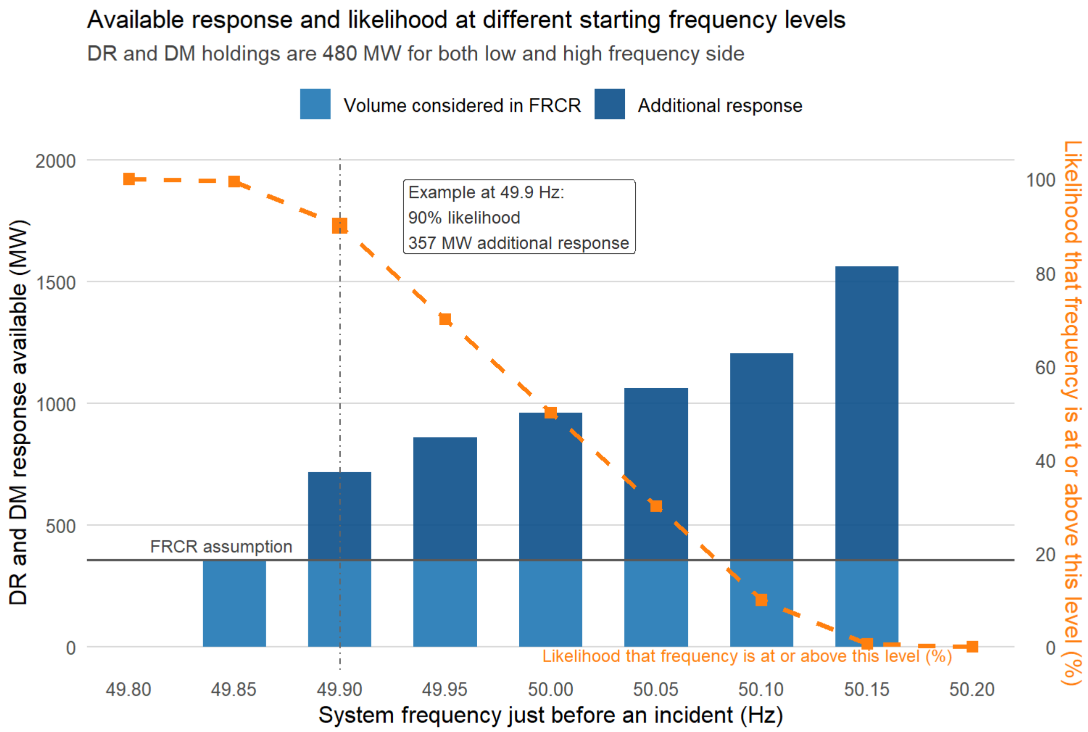

Figure 5: Available low frequency response for infeed loss at different frequency before an incident

1.3.2 Limited Frequency Sensitive Mode – Underfrequency (LFSM-U)

Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) is a Grid Code[10] capability designed to automatically increase active power output from generators when the system frequency drops below 49.5 Hz, provided there is sufficient generation headroom available. This mechanism offers a quick, decentralised response intended to support the grid during extreme frequency events. This is especially relevant for battery storage units, which are capable of rapidly switching between import and export modes or reducing output to zero megawatts. The overall system capacity of battery storage has grown substantially in recent years.

[10] This Grid Code requirement applies to generators falling under the European Connection Conditions, which generally include units connected after April 2019.

Nevertheless, due to the challenges associated with modelling headroom availability and limited real-world data, LFSM-U is not incorporated into the FRCR model, nor is it considered in the daily response service requirements. Instead, the necessary frequency response requirement is met through contracted services such as Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR). These services are specifically procured to meet the grid's operational needs and to ensure that the system can reliably respond to frequency disturbances and maintain resilience.

Consequently, LFSM-U is treated as an additional safety buffer rather than a primary resource for frequency response. While it may provide some supplementary support when facing extreme frequency events which are not secured under the FRCR policy due to the extremely low likelihood, it does not reduce or substitute the volumes of response required from contracted frequency services. Instead, it is regarded as offering some additional action in the event of unexpected system stress.

1.3.3 System inertia estimation

System inertia is a critical factor in frequency control. NESO has a comprehensive method to estimate the total system inertia in operation, where the total system inertia is calculated as the sum of inertia provided by both known generation in-service and demand inertia.

Demand inertia specifically refers to the inertial contribution from smaller generation and other frequency-sensitive equipment connected at the distribution level, which are not directly monitored and controlled by NESO. The modelling of demand inertia is informed by historical system frequency events and is reviewed periodically to maintain accuracy.

The system inertia of each historical event is estimated using the observed initial RoCoF and the size of the disturbance via the swing equation. After removing known synchronous inertia, the remaining contribution is attributed to demand inertia. Then, events are selected for a statistical analysis of the relationship between demand and demand inertia.

To ensure that the system's inertia is not overestimated, the modelling of demand inertia employs a fixed, conservative value corresponding to the 5th percentile of the demand inertia from the samples. This means that, statistically, for 95% of events, the model assumes a lower value of demand inertia, reducing the risk of overestimating the system's inertia. It is important to recognise that estimating inertia based on actual frequency events and a relatively limited number of observations inherently involves some degree of error. Adopting a lower percentile may result in overly conservative estimates, potentially increasing balancing costs for consumers. Based on our operational experience, the 5th percentile provides an effective balance.

Figure 6 below illustrates the historical frequency events used in this calibration process with its event estimated demand inertia versus model estimated demand inertia (5th percentile). The model estimated demand inertia (blue bar) is intentionally lower than the event estimated demand inertia (red bar) in most cases, reflecting the risk-conservative approach described above.

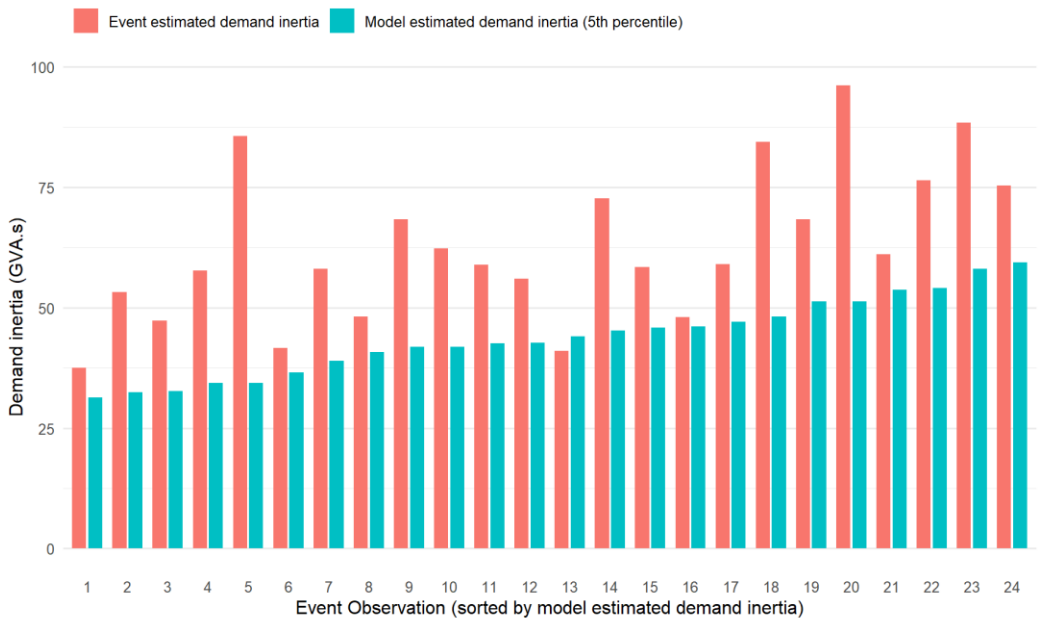

Figure 6: Demand inertia estimated from observed events vs model estimated demand inertia

The conservative approach applied to demand inertia modelling provides a robust safety margin, ensuring that frequency response services are procured at levels sufficient to maintain system resilience even in the most challenging scenarios.

1.3.4 Consequential Loss of Mains risk

Loss of Mains (LoM) protection is intended to automatically disconnect distribution-connected generation when it becomes electrically islanded from the main system. The risk arises from the operation of LoM protection systems on those generation, which may unintentionally disconnect during large system disturbances, especially under low inertia system condition. The Accelerated Loss of Mains Change Programme (ALoMCP)[11] has significantly reduced most of the risks associated with RoCoF- and VS-based LoM events.

[11]The Accelerated Loss of Mains Change Programme (ALoMCP) was a funding scheme that helped certain generators to upgrade or replace relays, to meet changes in protection requirements in the Distribution Code and associated documents.

The figures presented in the below table represent the total capacity affected by these LoM protections which are in line with the closure of the ALoMCP. Each column displays the protection relay operating at various RoCoF levels or VS. The numbers beneath each protection type are independent from other types of relays and reflect the remaining capacity in the system for that particular type. As shown in the table, much of the volume consists of either safety margins or capacity that is not reported, and future updates will incorporate emerging compliance information as it becomes available.

Table 1: LoM capacity post ALoMCP

	0.125 Hz/s	0.2 Hz/s	0.5 Hz/s	Other RoCoF	National Vector Shift (VS)*
Estimated total capacity remaining	54 MW	20 MW	100 MW	4 MW	371 MW
Safety margins to cater for uncertainty	29 MW	31 MW	59 MW	6 MW	1048 MW
Further capacity that has undergone enforcement but not formally reported	43 MW	16 MW	31 MW	2 MW	297 MW
Total	126 MW	67 MW	190 MW	12 MW	1717 MW

*The VS risk is regional-based, levels in this table are quantified as the national total

The volumes shown in Table 1 are the total capacity at risk. The actual risks, usually a proportion of the total capacity, are then assessed using an internal operational tool based on the system conditions, in the same way as the FRCR model.

It is important to note that the mechanism of VS LoM protection differs from RoCoF types. In this table, the national total level is reported; however, actual losses resulting from VS are considerably lower than the national total capacity (Table 1) due to the localised characteristics inherent to VS. The scale is comparable to RoCoF losses, with a typical regional maximum VS loss being approximately 131 MW.

This process employs conservative assumptions to ensure that the extent of non-compliance is not underestimated, thereby providing a robust evaluation of remaining vulnerabilities within the system.

1.3.5 The modelling of response services

The effectiveness of response services is influenced by their speed of delivery, with faster responses providing improved control of transient frequency deviations. The modelling of response services is based on the assumption that these services will only deliver at the slowest permitted delivery time and ramping rate. This conservative approach ensures that the modelled system architecture does not rely on optimistic expectations of performance, thus maintaining a robust level of resilience in the event of a sudden frequency disturbance.

In practice, however, the actual delivery of response services frequently exceeds these minimum requirements. **Section 2** discusses the differences between the theoretical and the observed delivery of dynamic services in more detail.

1.3.6 Modelling of simultaneous events

When modelling simultaneous events, we assume that two significant events occur simultaneously, thereby causing the maximum possible impact on consequential RoCoF and frequency deviations. This approach is designed to capture the worst-case scenario for our assessment. However, in actual system operations, such events typically unfold in sequence, with a gap of a few seconds between them and sometimes even longer. The sequential nature of real-world incidents means that the impact on system frequency is often less severe than what is observed in the simultaneous event model.

On the other hand, in the process of collecting suspect simultaneous events, a broader criterion has been applied: as long as multiple generators trip within a defined time window, the incident is classified as a simultaneous event.

For peak simultaneous events, the likelihood calibration reveals a frequency of 0.0037 per year, which equates to an annual risk of roughly 1-in-272 years. More details on the simultaneous events likelihood calibration can be found in Data Handbook Section 6.4. The FRCR analysis intentionally applies a more conservative 1-in-30 year likelihood to these extreme, low-probability, high-impact events. This ensures that even with limited historical data and uncertainty about the behaviour of rare incidents, system security requirements remain robust and are not understated.

This conservative methodology ensures that the frequency and severity of such occurrences are not underestimated. By adopting these assumptions, the modelling provides a robust safety margin, helping to ensure that operational risks are adequately accounted for.

1.4 Rationale for FRCR 2025 recommendations

A key objective of this supplementary report is to explain why the FRCR 2025 policy recommendations represent an appropriate balance between cost and the residual likelihood of frequency deviations.

The FRCR recommendations are drawn from a comparative assessment of a range of policy options, e.g. different minimum inertia requirements. This assessment therefore identifies trends in system residual risk and total system costs relative to a range of policy options, rather than isolated outcomes.

Table 2: Minimum inertia policy assessment

Residual Risks	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
Total annual costs	£524m	£266m	£198m	£170m

As shown in Table 2, reducing the minimum inertia requirement to 102 GVA·s presents no material reduction in system frequency security compared with 120 GVA·s. In particular, system events that would lead to frequency deviations below 49.5 Hz, 49.2 Hz, or 48.8 Hz under 102 GVA·s are likely to result in similar deviations under a higher inertia level of 120 GVA·s. Consequently, the residual risk of 49.5 Hz, 49.2 Hz, and 48.8 Hz events remains broadly unchanged across these inertia conditions. This is because sufficient DC services will be procured to maintain the same level of system security.

From a cost perspective, reducing the minimum inertia requirement to 102 GVA·s could deliver savings of up to £96 m from current level 120 GVA·s. While system security considerations remain the primary driver of the policy recommendation, these cost savings represent additional value where they can be achieved without increasing residual risk.

The comparison across policy options demonstrates that lowering the minimum inertia requirement does not materially compromise system security, while delivering meaningful cost efficiencies. Events that can be secured under a higher inertia requirement can also be secured at lower inertia levels, reflecting the increasing availability of fast, effective, and cost-efficient response services.

These conclusions are underpinned by the conservative assumptions described in Section 1.3, together with the model validation and likelihood assessments set out in Sections 1.1 and 1.2. Collectively, this evidence provides confidence that the analysis appropriately represents system behaviour and the probability of frequency deviations across different inertia scenarios.

Based on this assessment, FRCR 2025 recommends reducing the minimum inertia requirement from 120 GVA·s to 102 GVA·s. This approach further advances cost efficiency while maintaining an equivalent level of system security. This recommendation therefore aligns with NESO's continued mandate: to operate the system *securely* and *efficiently* to support the transition to a *zero-carbon* energy system.

Table 3: Cost vs risk with additional DC-Low response for 49.2 Hz event at 102 GVA.s

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

In addition, FRCR 2025 recommends procuring an additional 200 MW of DC-Low to further reduce residual risks. As shown in Table 3, the additional 200 MW of DC-Low reduces the likelihood of a 49.2 Hz event from approximately 1-in-7 years to around 1-in-23 years, at an additional cost of £3.23 m.

Section 2. Confidence in delivery of Dynamic Response services

2.1 Dynamic Response services overview

Dynamic Response Services fall under NESO Ancillary Services and thus any changes to them are included in response reform workstreams. The characteristics of Dynamic Response Services are defined in the Service Terms[12]. Any changes to these Service Terms are made as part of Article 18 consultations.

The performance of units providing Dynamic Response Services is heavily monitored. This monitoring is necessary for multiple reasons. One reason is system security; units must deliver the services according to the requirements set out to ensure that assumptions made when assessing system security, such as those made in FRCR, are satisfied. The next is financial; units must be paid accurately in a way that reflects the quality of the services that they provided. The market must be fair; all units participating in the market must be treated consistently and fairly. The market is open to any asset type. Participants can bid in for the individual services if they pass the relevant testing requirements[13]. Currently, all participating assets are battery assets.

2.2 Performance monitoring fundamentals

In the Service Terms, Schedule 2 and Schedule 3 define the performance monitoring requirements and the payment calculations for Dynamic Response Services. Dynamic Services provide response whenever the frequency deviates from 50Hz by more than $\pm$0.015Hz and are separated into High Frequency (HF) and Low Frequency (LF) response respectively. Dynamic Response Services are divided into two groups: slow (Dynamic Regulation [DR] only), and fast (Dynamic Moderation [DM], Dynamic Containment [DC], and stacked services). For services that are considered fast, such as DC, units are expected to submit 20Hz data, which is then used to assess their performance and determine the payments due. Slow services can submit 2Hz data, which is used for the same purposes. We encourage readers unfamiliar with Dynamic Response Services to read either the provider guidance[14] (Technical Guidance section) or the Service Terms. This will facilitate their understanding of the topics discussed in the next sections.

[12] Response Services Service Terms
[13] DC, DM, DR Testing Guidance
[14] Dynamic Response Services Provider Guidance

During performance monitoring the behaviour of the unit is assessed by comparing the response provided against an acceptable range defined by upper and lower performance bounds. These bounds use three main building blocks: the frequency window, the delivery curve, and the response time parameters. For DC LF response, the upper performance bound assumes an instantaneous reaction to a frequency delivery, whereas the lower bound assumes the slowest allowed response to a frequency deviation. For DC, the unit has 0.55 seconds from a frequency deviation being measured to start responding to the frequency deviation (see Figure 7). It has 1 second to achieve the full response output at maximum delivery if the frequency deviation requires full delivery from the moment the measurement is made. In FRCR it is assumed that the delivery of all units will follow this lower performance bound.

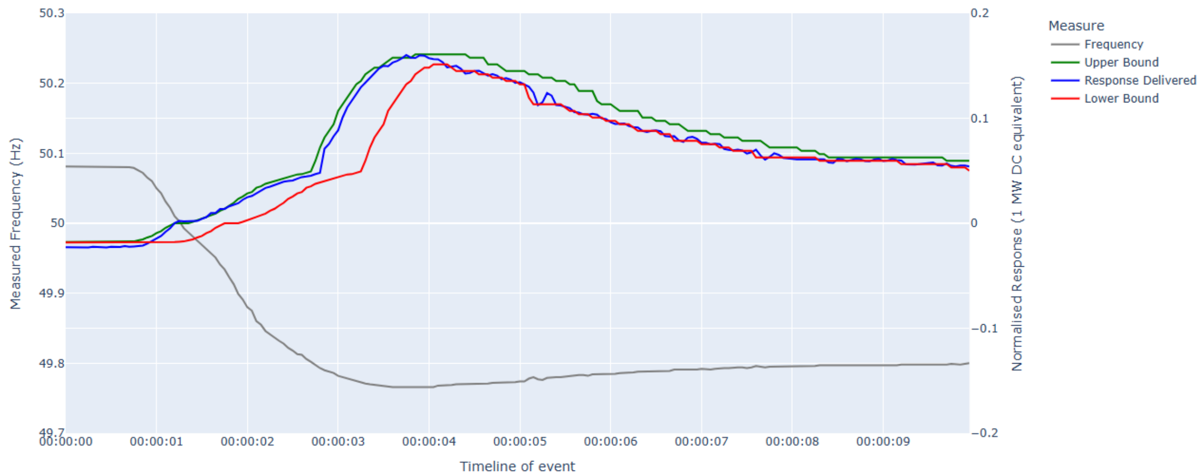

Figure 7: Example of DC unit behaviour during a low frequency event

Figure 7 shows data from a frequency event that occurred in June 2025. The date timestamps have been modified, and the response has been normalised to 1 MW contracted volume for provider anonymity, with no additional processing. We can observe that the response delivered by the unit (blue trace) follows the upper performance bound (green trace), rather than the lower performance bound (red trace). This means that the unit is responding faster than specified by the minimum requirements. This is a trend that is observed across the market. When frequency events occur, NESO performs investigations to ensure that Dynamic Response Services have been delivered as expected. If units are found to not have responded as per the minimum requirements set out in Schedule 2 of Service Terms, conversations are held with providers to understand why units did not respond as specified, and to improve response for future events.

With the introduction of stacking, where a unit may provide a combination of various Dynamic Response Services in the same contracted period, two variants of DR have been specified: slow DR and fast DR. When solely providing DR, a unit is assumed to provide slow DR, whereas if it stacks DR with any of the other services it must provide fast DR. On average around 23% of Low Frequency DR volume in an Electricity Forward Agreement (EFA) is stacked with other services and thus will be delivered as fast DR. Instances where no DR LF volume is stacked with other services do occur. Some providers may configure their assets to always provide fast DR, even when not stacking, but we do not have values for this. FRCR assumes that all DR response volume is provided as slow DR.

Additional aspects of Dynamic Response Service delivery are monitored by NESO, and they can also affect the payment for delivery of the service. One of these is the State of Energy (SOE) management of contracted energy limited units. They are required to start each EFA with at least a certain amount of energy, and recover energy after delivery, as set out in the SOE monitoring guidance document[15]. The non-submission of Physical Notifications (PNs) during a contracted period is another behaviour that can reduce the payments made to providers.

2.3 Dynamic Response market overview

The Enduring Auction Capability (EAC) is a highly liquid, co-optimised market through which all Dynamic Response (DC, DM, DR) are procured day ahead and historically has been able to absorb increases in requirement. This is demonstrated in 2025 through higher procurement of DR and DM. While the basket structure of EAC obscures the precise amount remaining capacity, short-term increases in requirement (typically driven by DC) have generally been met without disproportionate increases in cost. A recent example occurred on 19th and 20th September 2025, when the DC-LF requirement was substantially increased for three EFA blocks on each day. Also, across September, the average volume of DC-LF was around 1200 MW. For the higher-requirement EFA blocks, DC-LF target exceeded 1600 MW. These volumes were successfully procured in full and all other Dynamic Response services (DM, DR) were also fully filled.

While DC-LF costs on these were higher than the monthly average, the cost of the day in full were broadly in line with recent historical outcomes, suggesting some short-term cost uplift when additional DC-LF is procured. Thus, with respect to the FRCR 2025 policy recommendation of procuring an additional 200 MW of DC-LF, we would expect an enduring impact of an increase in the long-run average clearing price. This impact may be mitigated over time by increased competition, particularly as further large-scale battery capacity capable of providing DC-LF enters the market.

[15] SOE Monitoring Guidance for Energy Limited DC/DM/DR Providers

2.4 Further developments of Dynamic Response services

Dynamic Response Services markets are now well established, but this does not mean that they are standing still. Through the Article 18 consultation process, changes and improvements are frequently made to improve the reliability and performance of the services. Other changes and improvements, that do not fall under the Article 18 remit, are also implemented when such changes are identified.

As part of the current Article 18 consultation[16], a tiered performance regime has been proposed to monitor and penalise undesired behaviour from units participating in the Dynamic Response Service markets. Details for this can be found in Section 6[16] of the consultation document.

A workstream aiming to set out a frequency measurement standard for Dynamic Response Services is in progress. The current Service Terms define the minimum response times to frequency deviations, but there are no specifications for the way in which the frequency that the unit is responding to should be measured. This means that depending on the way the frequency measurements are taken and processed, additional lag or noise could be introduced into the response. The workstream aims to set a minimum standard to ensure consistent and effective frequency measurement techniques across all units in the market.

2.5 Conclusions on Dynamic Response services

The Dynamic Response Services market is a well-developed market. The performance of the services is heavily monitored, with effective penalties to discourage poor performance and behaviour. The monitoring results show that these services can be relied upon with high confidence in delivery, which either matches or exceeds the minimum expectations. The services are continuously evolving and improving to help operate the system in a safe and secure manner. In its modelling assumptions, FRCR assumes the delivery of Dynamic Response Services is as per the lower-bound set out in Schedule 2 of Dynamic Response Service Terms. However, in real-time operation based on current performance and behaviours, this lower-bound delivery is unlikely to occur.

[16] Dynamic Response Services November 2025 Consultation

Section 3. Review on Low Frequency Demand Disconnection scheme

Low Frequency Demand Disconnection (LFDD) is a defence measure designed to arrest frequency collapse during extreme system conditions outside the FRCR scope. The last full review of the LFDD scheme took place in 2001. NESO intends to initiate a comprehensive review beginning in 2026, working closely with industry stakeholders.

There have been a number of initiatives to look at the effectiveness of the LFDD scheme since it last operated during the 9th August 2019 event:

- NGESO (National Grid Electricity System Operator, now NESO) was part of a workgroup set up by the Energy Executive Committee (E3C) to specifically look at the performance of LFDD. The workgroup reported in 2020.
- NGESO undertook a System HILP (High Impact Low Probability) Event Demand Disconnection (SHEDD) project alongside WPD (Western Power Distribution, now National Grid Electricity Distribution or NGED) with the objective of "designing and testing a new LFDD scheme to maximise its future performance as the network continues to decarbonise, embedded generation integration increases, and system inertia continues to decrease." The final report was published in 2022.

Both of these initiatives emphasised the growing importance of embedded generation (i.e. generation connected to distribution networks) and the amount that is disconnected during an LFDD event, which counteracts the intention of the scheme. The volume of embedded generation on the system is one of the major changes since the last full review of the scheme in 2001, and this will be factored into the upcoming review.

NESO is working to produce a timeline for conducting a comprehensive review of the LFDD scheme, starting in 2026 and likely to continue into 2027. The review will consider the performance of the current LFDD scheme characteristics, including trigger settings, staging arrangements and regional impacts, as well as the wider impacts of LFDD operation on the power system. In particular, it will examine the interaction between LFDD operation and embedded generation during an LFDD event, alongside data availability and observability to support robust post-event assessment. As part of this work, NESO also intends to introduce a process for a regular review of the LFDD scheme to ensure it remains appropriate as system conditions continue to evolve.

While LFDD operates outside the core FRCR scope, it remains a critical last-resort defence against extreme frequency risks. The outcomes of the LFDD review will therefore be considered in the context of the wider system risk framework, including future FRCR assessments, to ensure a coherent and proportionate approach to frequency resilience.

Section 4: Expanded implementation plan for minimum inertia transition

After taking into consideration the feedback from Ofgem and industry stakeholders regarding the proposed transition of minimum inertia from 120 GVA.s to 102 GVA.s, this supplementary report presents a revised implementation plan to address concerns raised by these stakeholders. The new plan presents a slower, phased approach, combined with extended observation periods and clear success criteria so that adjustments are implemented in a structured manner while maintaining stakeholder confidence in frequency security.

4.1 Implementation plan for minimum inertia and DC-Low

Should Ofgem approve the FRCR 2025 recommendations, the reduction of the minimum inertia requirement will be implemented in two stages with defined trigger and success criteria:

- Stage 1: Lower the minimum inertia requirement to **110 GVA.s** and observe for a minimum of 10 weeks.
- Stage 2: Further reduce the requirement to **102 GVA.s** and observe for a minimum of 10 weeks.

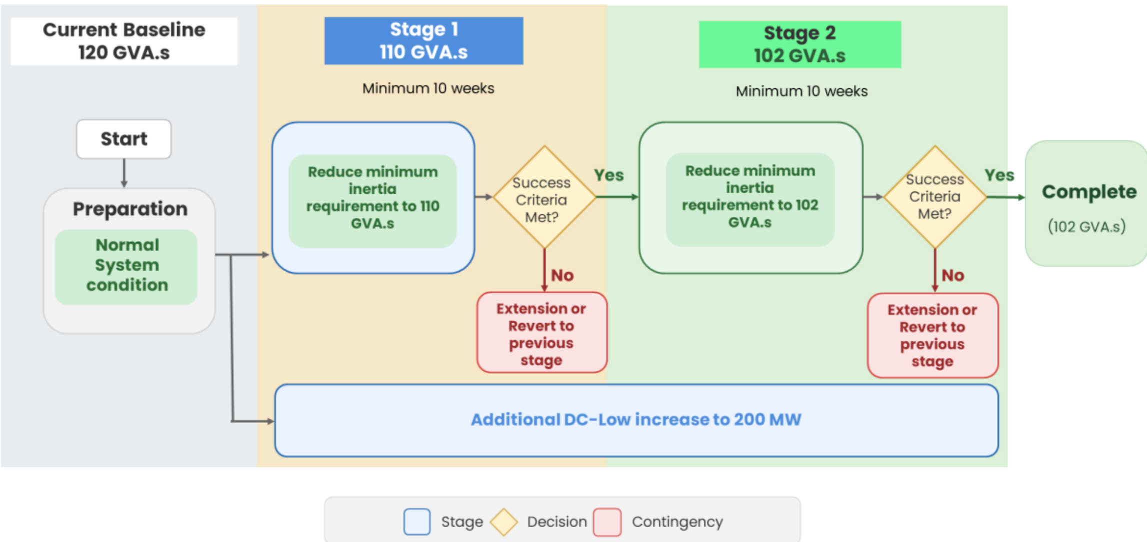

Figure 8 Simplified Flowchart of the FRCR implementation stages

Operational data and experience will be gathered throughout Stage 1 to inform Stage 2. To ensure robust assessment, a minimum observation period of **10 weeks** will be applied in both stages, allowing two separate weeks for each shift team for observation and analysis.

In addition, we recommend holding an additional 200 MW of DC-Low on top of the regular response holdings (a 100 MW increase compared with the current arrangement). This will be implemented along-side the Stage 1 minimum inertia requirement change, as shown in the flow chart. Based on current market liquidity, we do not anticipate any challenges in implementing this adjustment.

4.2 Success criteria

Before progressing from Stage 1 to Stage 2, and again following the initiation of Stage 2, an assessment period of 10 weeks will be applied to evaluate system behaviour and market response. Success criteria will have to be met to move from Stage 1 to Stage 2 and will also be evaluated at the close of Stage 2.

Success will be evaluated against the following defined criteria:

- **Frequency performance:** Assess frequency behaviour against standard seasonal metrics. Key indicators are the period of time frequency deviations of 0.15 Hz and 0.20 Hz, used to evaluate effects from inertia requirement changes. Performance should remain consistent with normal seasonal trends.
  - **Event-based assessment:** Evaluate at least one major frequency event (resulting in at least 0.125 Hz/s RoCoF) under low-inertia conditions to assess system stability and compliance. Key metrics include frequency nadir and post-event steady-state frequency versus FRCR modelling.
  - **Review of unexpected observations:** This involves identifying any new unexpected system behaviours and confirming that they are not related to changes in inertia. Any changes to the rate of occurrence, magnitude and risk of previously observed behaviours will be also considered and assessed. If significant concerns arise from these observations, the implementation may be reversed, as detailed in the section 4.3 below.
  - **Operational-hours requirement:** Stage 1 and 2 will aim to gain at least 20 Settlement Periods of operation within the 110–120 GVA.s and 102-110 GVA.s inertia range respectively. We may extend the stage to ensure we gain sufficient operational experience at lower inertia levels.
  - **DC Market Response:** Evaluation of market liquidity and performance at the updated DC-Low and inertia requirement thresholds. As DC procurement is prioritised in our daily auction process, we do not anticipate any significant challenges in accommodating the additional DC-Low volume based on current market capacity.

Once these factors have been reviewed and assessed, progression to the next stage or confirmation of the final change will take place.

4.3 Contingency plan

If the success criteria outlined above is not fully met during the 10-week assessment period, a contingency plan will be activated depending on the severity of the observation. This plan includes extending the assessment period by an additional five weeks or a period agreed with ENCC, providing more time to gather operational data and reassess system behaviour, market response, and overall compliance with the defined criteria. The extension aims to ensure that any uncertainties or unexpected observations can be thoroughly investigated before progressing to the next stage.

Should any significant risk be observed during this extended assessment, such as notable system instability or non-compliance with operational standards, the process will be immediately reverted to the previous stable stage. This precautionary measure is intended to safeguard against adverse impacts and maintain system reliability, ensuring that any changes implemented are sustainable, robust and agreed upon. The decision to revert will be based on the severity and nature of the risks identified, maintaining a cautious approach throughout the transition.

Once the event investigation has concluded and it has been confirmed that an event was not related to changes in inertia, and normal system conditions have resumed, the process will be restarted.

4.4 Communication

4.4.1 Within NESO

The performance data, measured against the established success criteria, will be summarised and presented internally every five weeks using various internal communication channels to connect the ENCC with analytical support teams. This approach ensures that progress and outcomes are regularly reviewed and communicated by all internal stakeholders, supporting ongoing improvement and transparency.

4.4.2 Wider industry

Should Ofgem approve the FRCR 2025 recommendations, each implementation stage and its findings will be communicated through the NESO Operational Transparency Forum (OTF) and SQSS Panel. Notice will be provided at least five working days in advance through our standard response service forecasting and communication channels.

Section 5: FRCR governance

The current FRCR governance arrangements are detailed in Appendix H of the SQSS. Under current arrangements, the FRCR is submitted to the SQSS Panel, who either recommend that the FRCR should be submitted to Ofgem, or direct NESO to further develop the FRCR. The SQSS Panel can seek guidance, where required. Similarly, Ofgem can either approve the FRCR or direct further development.

Following SQSS Panel discussions and feedback on FRCR24, in January 2025 NESO outlined some potential options to the SQSS Panel including Ofgem, for how the FRCR Governance arrangements could potentially be taken forward, either through NESO Licence changes, or changes to Appendix H of the SQSS, such that the SQSS Panel are informed of the FRCR output rather than having to approve it.

Since that time, NESO has undertaken some further thinking on this issue and intends to provide an update at a future SQSS Panel meeting in Q2 of 2026 on a range of Governance options over and above those initially presented in 2025.

Section 6: Future plans

Following the submission of FRCR 2025, Ofgem undertook further engagement to confirm whether stakeholder views had evolved and subsequently commissioned an independent review. In December 2025, Ofgem issued a decision requesting additional information.

NESO has requested that the requirement to produce FRCR 2026 be suspended, allowing focus to shift to a more substantive review of the scope and methodology for FRCR 2027. The request for suspension of FRCR 2026 was granted by Ofgem in March 2026. This decision permits NESO to redirect efforts on defining an FRCR scope focused on advancing targeted policies which secure the system against future adverse scenarios and so better aligns with the needs of decision-makers and its intended audience.

NESO's proposed direction for FRCR 2027 is to adopt a more structured, two-part framework. The first component would emphasise a focused assessment of credible, near-term frequency risks, supporting the establishment of a minimum safe operating baseline using established and well-evidenced methodologies. Enhancements to this component would be driven by improved risk identification and forecasting capability.

A second component would provide a transparent and proportionate mechanism for considering emerging frequency risks over a longer horizon. This would draw on both historic stakeholder insights and enhanced internal horizon-scanning activity, ensuring that future risks are identified early while maintaining appropriate evidential standards.

By distinguishing between near-term, quantifiable risks and longer-term emerging considerations, this approach strengthens the clarity and robustness of the FRCR. It preserves the report's focus on actionable, frequency-relevant recommendations, while ensuring that evolving risks are addressed in a disciplined and transparent manner. This provides a more resilient and forward-looking foundation for system operability decisions in 2027 and beyond.

Section 7: Conclusion

This supplementary report has been prepared to address the additional information requests set out in Ofgem's decision letter in relation to FRCR 2025. It provides further evidence, clarification, and assurance across the specific areas identified by Ofgem, while remaining consistent with the methodology, conclusions, and policy intent of the original FRCR 2025 submission.

In response to Ofgem's requests, the report presents expanded evidence of frequency simulation validation and improved transparency in the estimation of probabilities. It also provides more detailed explanation and justification of the modelling parameters and assumptions underpinning the FRCR framework, including the conservative approaches adopted to manage uncertainty and safeguard system security.

In addition, the supplementary report reiterates out the rationale for the FRCR 2025 recommendations. The analysis demonstrates that the recommended policy achieves an equivalent level of frequency security to higher inertia alternatives, while providing reductions in the balancing costs.

In light of Ofgem's decision to suspend the requirement to submit FRCR 2026, the report also outlines the proposed future direction of FRCR 2027 and beyond, including planned refinements to scope and structure intended to improve clarity, proportionality, and decision-making value. Supplementary discussion is also provided on the LFDD scheme and FRCR governance arrangements, reflecting stakeholder interest in wider system-level considerations.

Taken together, this supplementary report is intended to provide Ofgem and stakeholders with increased clarity, transparency, and assurance regarding the FRCR 2025 analysis, its underpinning rationale and assumptions, and its policy recommendations. It should be read alongside the original FRCR 2025 report and forms an integral part of the overall evidence base supporting NESO's approach to balancing cost, risk, and system security in the management of frequency stability.

Appendix: Abbreviation

Abbreviation	Full name
ALoMCP	Accelerated Loss of Mains Change Programme
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
DC	Dynamic Containment
DC-Low	Dynamic Containment – Low
DM	Dynamic Moderation
DNO	Distribution Network Operator
DR	Dynamic Regulation
DR-LF	Dynamic Regulation – Low
EFA	Electricity Forward Agreement
ENCC	Electricity National Control Centre
FRCR	Frequency Risk and Control Report
GB	Great Britain
GVA.s	Giga Volt Ampere Second
HF	High Frequency
HILP	High Impact Low Probability
HVDC	High Voltage Direct Current
ISC	Industrial Systems and Control
LoM	Loss of Mains
LF	Low Frequency
LFDD	Low Frequency Demand Disconnection
LFSM-U	Limited Frequency Sensitive Mode – Underfrequency
MATLAB	Matrix Laboratory

MEL	Maximum Export Limit
MFR	Mandatory Frequency Response
MW	Megawatt
NESO	National Energy System Operator
NGESO	National Grid Electricity System Operator
OFTO	Offshore Transmission Owner
OTF	Operational Transparency Forum
PV	Photovoltaic
SHEDD	System High Impact Low Probability Event Demand Disconnection
SOE	State of Energy
SP	Settlement Period
SQSS	Security and Quality of Supply Standards
STO	Short-Term Operability Obeya
VS	Vector Shift
WPD	Western Power Distribution