Public

Security & Quality of Supply Standards

Frequency Risk and Control Report

Data Handbook – May 2025

NESO
National Energy System Operator

Executive Summary

The requirement to produce a **Frequency Risk and Control Report (FRCR)** is an obligation on the National Energy System Operator (NESO) following the approval of Security and Quality of Supply Standard (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. This is an annual review with the aim to balance risk against the cost of securing different system events to maintain frequency within the SQSS frequency standards.

The analysis required for the FRCR, and subsequent recommendations, is both complex and requires numerous data sources. Starting from the 2025 cycle, this **Data Handbook** has been created to enhance transparency and encourage engagement with the FRCR, and to support its recommendations, the background to the **FRCR Methodology**. This document aims to provide an insight into the data used in producing the **FRCR Report** and how that is used, to enable stakeholders to better understand the underlying principles and considerations involved.

Contents

1. Overview of the document

1.1 Purpose of the document

This document is a guide to the data inputs involved to increase transparency and clarity of the process.

This data handbook and the methodology are supplementary documents to facilitate the FRCR 2025 policy understanding during its consultation. It should be noted that both documents however do not form part of the consultation. We appreciate any feedback and comments on the documents and will update them accordingly when we publish the final FRCR 2025 report.

1.2 FRCR 2025 documents suite

There are three main documents in the process, which link together as follows:

Frequency Risk and Control Report Methodology (Methodology)

The **Methodology** provides a comprehensive description of the FRCR framework. It details what will be assessed, how the assessment will be conducted, and the format of the outputs. The FRCR policy will be evaluated based on this **Methodology**.

Frequency Risk and Control Report Methodology Data Handbook (Handbook)

To improve the transparency and stakeholder access to the FRCR process, the **Handbook** serves as a complementary document to **Methodology** which provides explanations of the data used in the **Methodology**.

Frequency Risk and Control Report (Report)

This is the main policy recommendation in each FRCR cycle, which will be prepared in accordance with the **Methodology** and **Handbook**.

1.3 Structure of this document

This document begins with a diagram of the FRCR model and inputs, which is shown in the **Methodology**. The **Handbook** then focusses on each of these inputs. This structure aims to ensure a comprehensive understanding of the data, and together with the **Methodology** document, how this feeds into the model to ensure accurate results.

In each of the input data sections, we will address the following questions:

- **Purpose**

  Why do we need the data and which part the calculation does the data fit in?

- **Definition**

  What is the data?

- **Data**

  Where does the data come from, how do we process the data, and what are the main assumptions when processing the data. This includes **Source, Process and Assumptions**.

The FRCR model diagram in the **Methodology** v3 and in this **Handbook** has been revised and updated based on the diagram that was presented in FRCR 2025 Technical Webinar 2 Model and Data. This is to suit for presentation and information flow purpose in those documents instead of any model or data changes.

1.4 High-level assumptions

1.4.1 Historic vs. forecast

To understand the conclusions and recommendation of the **Report**, it is important to have a baseline against which to compare.

To isolate the reliability vs. cost decisions from the impact of these wider changes, the analysis will use historic scenarios adjusted for known or expected changes in the coming 12 months. Anticipated changes in the coming 24 months are also considered for indicative purposes.

Example of adjustments include new connections to the National Electricity Transmission System (NETS), which represent additional loss risks and which impact on the inertia of the system.

1.4.2 Granularity and time period

Many of the key inputs, like demand, inertia, Balancing Mechanism Unit (BMU) loss size, Loss of Main (LoM) loss size, vary markedly with time; hourly, daily, weekly and seasonally.

Analysis of single snapshot analysis of one 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 performed is a time series at Settlement Period (SP) granularity.

1.4.3 Baseline system conditions

As indicated above, many of the key inputs, like demand, inertia, BMU loss size, LoM loss size, and frequency response holding, vary markedly with time; hourly, daily, weekly and seasonally. These are the baseline system conditions against which the different policies will be assessed.

The analysis removes the balancing actions from the historic data sets to get a representation of the “market position” for these baseline system conditions.

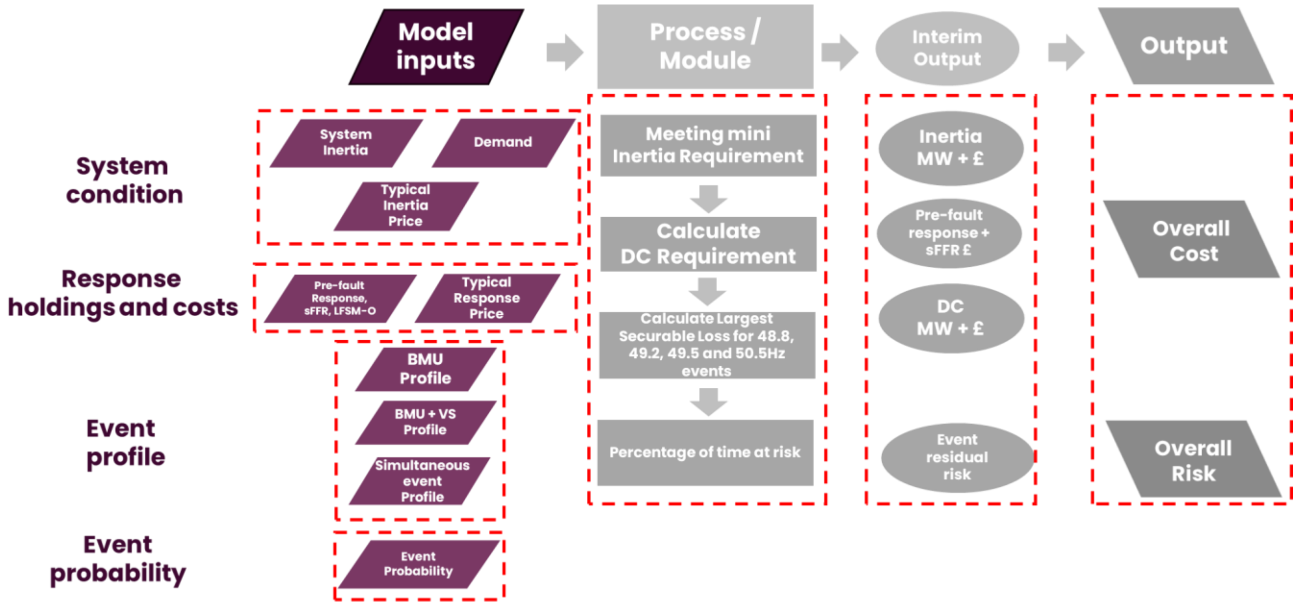
1.4.4 Cost of mitigations

Costs for increasing inertia and reducing BMU loss size will be benchmarked against the typical prices achieved through the Balancing Mechanism (BM) and trading.

The quantity and price of the different frequency response services will be benchmarked against the results of previous tenders or auctions.

2. Model overview

2.1 Flow chart



2.2 FRCR model inputs

The FRCR Model requires numerous inputs, the following sections will step through the definitions, calculation and /or processing of data, data source and assumptions involved with each input.

3. Input - System condition

The FRCR model requires a range of inputs which outline the nature of the transmission system conditions for each settlement period for the whole of the study period. This data is required to estimate the impact of various loss events.

3.1 Demand

Purpose:

Demand provides a certain level of damping capability when frequency deviates from the nominal value, hence is used in the response requirement calculation and largest securable loss calculations.

Definition:

National demand is the sum of the generation required on the transmission system to supply the customer. Any generation connected to the distribution system reduces the generation requirement on the transmission network and therefore acts to suppress the national demand.

Sources:

- In the calculation historic half hourly National demand from April 2023 to March 2024 is used. Data is available from https://www.neso.energy/data-portal/historic-demand-data.
- Increased capacity from embedded PV and wind is considered based on Future Energy Scenarios (FES) 5-year forecast for FRCR 2025 period of 2025-26, 2026-27.

Process:

- Historic half hourly national demand from April 2023 to March 2024 is used.
- The data is adjusted to account for the increase in embedded PV and wind generation which is planned during the FRCR study period. This adjustment is made using the following steps:
  - Determine the historic load factor for embedded PV and wind as a half hourly time series, for each Settlement Period (SP) from April 2023 to March 2024, for both embedded PV and wind,

$$Historic\ Load\ Factor\ =\frac{Generation}{(Capacity)}$$

  - Determine the power output for solar PV and wind for each SP accounting for growth in capacity.

$$\text{Additional Embedded Generation Output} = \text{Historic Load Factor} * \text{Additional Embedded Capacity}$$

- Forecast demand for 2025-2026 and 2026-2027, which the FRCR study covers, for both embedded PV and wind.

$$Forecasted\ Demand\ =\ Demand\ -\ Additional\ Embedded\ Generation\ Output$$

Assumptions:

- The growth in embedded wind and solar is in-line with estimates made in the FES modelling.

3.2 Inertia baseline

Purpose:

System inertia is estimated for 2025-2026 and 2026-2027 to provide a baseline when comparing with the minimum inertia requirement.

Definition:

System inertia is the sum of inertia provided by generators, the contribution from the demand side and the contribution from stability contracts (including Pathfinder units and Stability Market Y-1 Units if available). The inertia from generators includes NESO actions to meet minimum inertia requirement and voltage requirement.

Future system inertia is estimated based on historic system inertia and considering additional embedded generation and increased BMU wind generation.

Sources:

- Units and capacities from stability contracts including Pathfinder Projects and Stability Market (Y-1) published on the NESO website.
- Historic estimate of inertia is available from the NESO data portal – System Inertia. Note: We note the data published could be different to that we use for operation decisions. We are working on aligning two datasets and will update on the data portal accordingly.

Process:

- The historic system inertia is the sum of inertia provided by generators, the contribution from the synchronising elements in demand side and the contribution from Pathfinder units from April 2023 to March 2024.

$$Historic\ System\ Inertia = \ Inertia\ from\ generators + Inertia\ from\ demand + Pathfinder\ Inertia$$

- The Inertia provided by each generator is calculated based on its running mode and the inertia constant that is submitted to NESO via the data submissions required under the Grid Code.

- Inertia from the demand side is estimated by a demand inertia factor that is derived based on historic frequency events.
- NESO Bid and Offer Acceptance (BOA) actions to meet the minimum inertia requirement are removed from historic system inertia to reflect the "Market Position" before system operator's intervention.

$$Historic\ Market\ Inertia = Historic\ System\ Inertia - NESO\ actions\ to\ meet\ \min i\,mum\ inertia\ req.$$

- The projected system inertia baseline for the FRCR study period is the historic market inertia adjusted to account for additional embedded generation, increased BMU wind generation, and the changes in the inertia provision from stability contracts including Stability Pathfinder and Stability Y-1 units.

$$\begin{aligned} &Projected\ System\ Inertia \\ &= Historic\ Market\ Inertia + (New\ Connections\ Inertia - Offset\ Generation\ Inertia) \\ &\quad + (Embedded\ Generation\ Demand\ Change \cdot Demand\ Inertia\ Factor) + \\ &\quad Changes\ in\ inertia\ from\ stability\ contracts \end{aligned}$$

Assumptions:

- A historic profile of inertia is representative of the study period.
- New Connection timelines remain as expected.

3.3 Inertia cost

Purpose:

When System Inertia is not sufficient to meet the minimum inertia requirement. Additional inertia then needs to be procured to meet the minimum inertia requirement. The inertia cost is the cost involved in creating the required level of additional inertia.

Definition:

The cost to increase inertia is benchmarked against the cost to synchronise additional units, which is the offer price for typical Combined Cycle Gas Turbines (CCGTs), to provide inertia, and the reposition bid action.

Sources:

- **Bid and Offer Data:** Elexon – Insights Solution
- **Forward Energy Prices: Argus Natural Gas Report & ICE UKA futures & data.nationalgas**

Process:

- Most of the instructions to procure inertia on the system, when needed, are associated with CCGTs, the CCGTs instructed are not planned to generate by the market. In this sense, an average of available CCGT's to bring to SEL is calculated based on forward prices, to get the most up to date view of expected system costs.

- The repositioning bid price may vary depending on demand level, as the generation mix available for bids change significantly.

Assumptions:

- Typical parameters of an inertia unit are shown below.

Inertia Unit	Quantity	Units
GVA.s per machine	3	GVA.s
Typical machine Stable Export Limit (SEL)	250	MW

- Additional GVA.s are provided by CCGTs with a typical offer price.
- The repositioning cost is a typical bid price, which takes into consideration all possible technologies that could be used for energy replacement.

Typical CCGT offer price	**£112.50**
Typical bid (reposition) price	£42.50

4. Input - Response holding and costs

4.1 Response holding

4.1.1 Pre-fault response holding volumes

Purpose:

The purpose of this data is to provide scale and context to the simulation results. Pre-fault response services are assumed to be the same across all FRCR 2025 simulations. The current cost and volumes are included to provide a more complete picture of the response costs when comparing total cost for frequency control.

Definition:

Pre-fault response volumes are services armed to automatically manage frequency within the operational frequency range (49.8 Hz – 50.2 Hz). Pre-fault response services available to NESO are Dynamic Regulation (DR), Dynamic Moderation (DM) and Mandatory Frequency Response (MFR). Current operational policy is to procure sufficient pre-fault response from the day ahead dynamic response auctions for the DM and DR service, where cost effective to do so. Any shortfall in day ahead procurement is met in real time in the BM by arming units for MFR.

The pre-fault response holding volumes used in FRCR 2025 is the current operational policy requirement level for DR and DM.

Source:

- Internal NESO operational policy.

Process:

- The current Pre-fault response policy settings have been applied to the studies.

Service	DR-L & DR-H	DM-L & DM-H
Volume (MW)	500	200

Assumptions:

- The assumption used here is that sufficient DM and DR are procured at day ahead and additional MFR is not required.

4.1.2 Post -fault response holding – sFFR volumes

Purpose:

Post-fault response requirements are one of the outputs of the FRCR simulations, defined as a requirement for the Dynamic Containment (DC) service. Our current operational practice is to procure some post-fault response via the Static Firm Frequency Response (sFFR) where cost effective against the cost of extra DC. The existing cost and volumes of sFFR are included to provide a more complete picture of the costs when comparing simulations, these are assumed to be constant across all studies.

Definition:

Static Firm Frequency Response (sFFR) is a response service that delivers an agreed increased in MW output within 30 seconds and sustained for a 30-minute block, after the frequency decreases to 49.7 Hz. The service is procured daily on an Electricity Forward Agreement (EFA) block basis via day ahead auctions, the current operational policy is for a requirement of up to 250 MW of sFFR in the post-fault response mix.

The day ahead auction went live in April 2023, prior to this the service was procured via longer term tenders. The sFFR market currently has limited participation and the full 250 MW is not always available in the day ahead auction or may not be offered at a suitable price. The volume used in the simulations is the average cleared volume across the full history of the service from 1 April 2023 through to 24 October 2024.

Source:

- Internal NESO operational policy and historic daily auction results available on the data portal - Static Firm Frequency Response auction results.

Process:

- Cleared volumes per EFA per day were extracted from the published auction results.
- The average cleared volume was calculated per EFA across the date range.

EFA1	EFA2	EFA3	EFA4	EFA5	EFA6
244 MW	214 MW	232 MW	226 MW	225 MW	235 MW

Assumptions:

- The sFFR daily service is still relatively new, and there has been variation in volume and pricing as the market has become established. We have used the full available date range from 1 April 2023 through to 24 October 2024 to provide a more balanced picture of volumes and costs.

- The sFFR volume and costs are the same in all studies, using a different data range for this data set will not impact the outcome of the analysis.

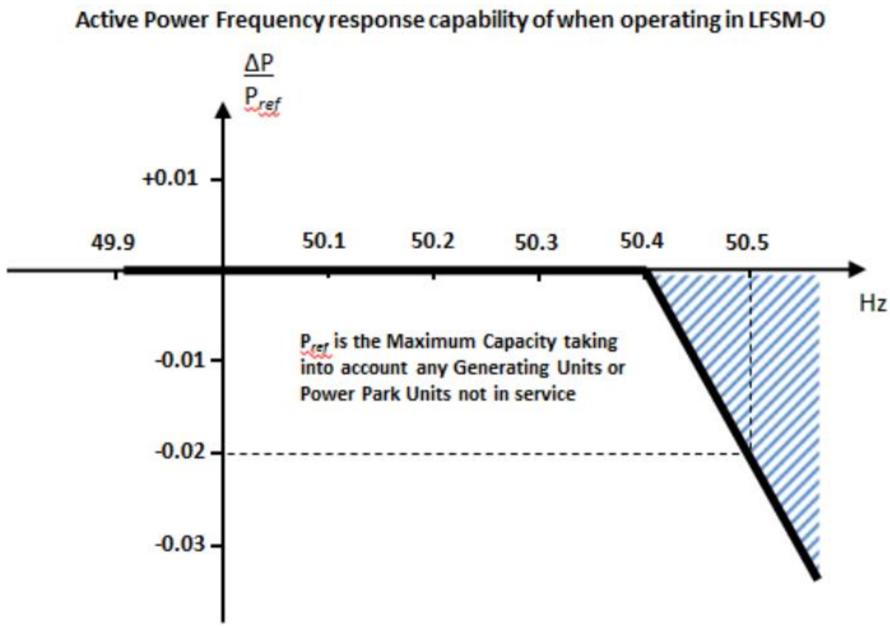
4.1.3 LFSM-O

Purpose:

In FRCR 2025, the Limited Frequency Sensitive Mode – Over frequency (LFSM-O) is considered in the analysis to present a complete picture of system residual risks following outfeed losses. The Limited Frequency Sensitive Mode – Underfrequency (LFSM-U) however is not considered as LFSM-U would only be expected to be delivered when the system frequency is below 49.5 Hz and the generator has available head room.

Definition:

Limited Frequency Sensitive Mode (LFSM) is defined in the Grid Code under European Connection Conditions Part 6 (ECC.6). Figure ECC.6.3.7.1 in Grid Code illustrates the LFSM-O delivery capability, where P_{ref} is the reference Active Power to which ΔP is related, and ΔP is the change in Active Power output from the Power Generating Module (including Direct Current Connected Power Park Modules) or High Voltage Direct Current (HVDC) System. The Power Generating Module (including Direct Current Connected Power Park Modules or HVDC Systems) has to provide a negative Active Power output change with a droop of 10% or less based on P_{ref}.



Process:

- The delivery characteristic is replicated from Figure ECC.6.3.7.1 from the Grid Code. LFSM-O volumes in FRCR model are modelled as a 2% reduction in the total generation output for each 0.1 Hz rise in system frequency above 50.4 Hz.

4.2 Pre-fault response holding prices and costs

Purpose:

The purpose of this data is to provide scale and context to the simulation results. Pre-fault response is assumed to be the same across all FRCR 2025 simulations. The current cost and volumes are included to provide a more complete picture of the response costs when comparing simulations.

Definition:

Pre-fault response prices are calculated using the volume weighted average clearing price for each of the 4 services: DR-Low, DR-High, DM-Low and DM-High.

The pre-fault response holding data is the current operational policy requirement level for DR and DM. The cleared volumes and prices are on a per hour basis per EFA block. The costs are therefore Price x Volume x 4 hours.

Source:

- Internal NESO operational policy and outturn EAC auction results for daily clearing prices for DM and DR. EAC auction results are available on the NESO data portal.

Process:

- For each service the volume weighted average price (VWAP) in £ per MWh, is calculated per EFA block.

$$VWAP\ (£/MWh) = \frac{\sum (Clearing\ Price \cdot\ Cleared\ Volume \cdot 4\ hours)}{\sum (Cleared\ Volume \cdot 4\ hours)}$$

- For the dynamic response services, we used all available data since the launch of the EAC. The data range used was 2 November 2023 to 24 October 2024. Data from the previous auction platform was not included due to significant changes in prices since the launch of EAC which enabled the possibility of negative pricing.

Assumptions:

- The assumptions used here are that sufficient DM and DR are procured at day ahead and additional MFR is not required.

EFA	DM-H	DM-L	DR-H	DR-L
1	£0.06	£3.29	-£4.60	£7.57
2	£1.39	£3.07	-£2.98	£7.23
3	£0.02	£4.17	-£5.27	£8.64
4	£0.45	£3.31	-£4.57	£7.45
5	£1.16	£4.84	-£4.16	£9.66
6	-£0.51	£4.79	-£6.20	£9.48

4.3 Post- fault response holding prices and costs

Purpose:

The purpose of this data is to provide scale and context to the simulation results. Static FFR (sFFR) volumes and costs are the same across all studies, the requirement for further post-fault response being met by the DC service. DC costs are calculated using the model output requirement and the prices calculated from historic outturn data.

Definition:

- sFFR response prices are calculated using the volume weighted average price (VWAP) for each EFA block, the volumes are calculated using the average cleared volume per EFA block.
- DC response prices are calculated using the volume weighted average price (VWAP) for each EFA. The DC volume requirement is the output of each study.

Source:

- For sFFR prices, outturn historic daily auction results are available on NESO data portal.
- For DC prices are available from EAC auction results.

Process:

- For sFFR the volume weighted average price (VWAP) was calculated per EFA block using the full data available from 1 April 2023 to 24 October 2024.

$$VWAP\ (£/MWh) = \frac{\sum(Clearing\ Price \cdot\ Cleared\ Volume \cdot 4\ hours)}{\sum(Cleared\ Volume \cdot 4\ hours)}$$

- For the DC prices, we used all available data since the launch of the Enduring Auction Capability (EAC). The data range used was 2 November 2023 to 24 October 2024. The volume weighted average price (VWAP) is also calculated per EFA block.

Assumptions:

EFA	DC-H	DC-L	sFFR
1	£1.68	£1.08	£1.31
2	£2.71	£1.08	£2.6
3	£1.39	£2.19	£4.99
4	£2.21	£1.25	£3.76
5	£2.10	£2.93	£5.78
6	£1.02	£2.47	£4.92

5. Input – Event profile

5.1 Categories of Loss Risk

FRCR 2025 considers three loss categories, these are known to as the event lists. The model requires a profile of events (MW losses) that could occur and the likelihood of them occurring. The three loss categories included in the FRCR 2025 studies are:

BMU-only	• an event that disconnects one BMU*, and may or may not also cause a consequential Rate of Change of Frequency (RoCoF) loss with no Vector Shift (VS) losses • caused by a Loss of Infeed or Loss of Outfeed
BMU + VS (outage or intact)	• 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 (NETS) (i.e. a single transmission circuit, a busbar or mesh corner, or a double circuit overhead line) • Trip rate for an event will normally be increased under outage conditions compared to that under intact conditions. It is also considered to involve the number of days of planned/unplanned outages to evaluate the severity.
Simultaneous Event	• an event that disconnects two BMUs at the same instant and may or may not also cause a consequential RoCoF loss. • The analysis focuses on a total loss made up of BMU-only events occurring at the same time instant as this represents the most onerous condition from a response perspective.

* Some exceptional cases where more than one BMU are disconnected, where the generating units are fed by a common energy source

The event list categorises MW losses into different studies. The event profiles are the forecasted MW profile of these events per SP for the two-year duration of the FRCR study. The process, source and assumptions in the BMU-only profile is the initial step that is applied to all three scenarios. RoCoF losses are also considered under each scenario.

5.2 Event profiles

The FRCR model requires a profile of events (MW losses) that could occur and the likelihood of them occurring. The event profiles are the profile or generated output of potential MW losses, per SP for the 2 years studied. For more information on how the data is used please refer to the **Methodology** document.

5.2.1 BMU profile

Purpose:

The BMU profile provides the FRCR model with a list of potential losses, considering single BMU's only, that is used in conjunction with the probability of losses.

Definition:

BMU-only event: This profile is the mean MW output for each BMU in each SP of study.

Sources:

- Historic BMU profile can be found from historic GB generation mix page on NESO data portal. & Wind Constraint data:
- New connections consider following information:
  - Transmission Entry Capacity (TEC) register, containing volumes, connection dates and locations of new generation. This is not publicly available or shareable.
  - Interconnector register, containing volumes, connection dates and locations of interconnectors. This is not publicly available or shareable.
  - Other connection information managed via NESO internal database which is not publicly available.
  - For new wind connection we refer to the information published on UK Wind Energy Database.

Process:

- For existing units, the profile is taken from historic data, this is the MW position of a generator prior to any actions taken by NESO in the balancing market, e.g. for a unit which was instructed via a BOA, the historic data is representative of their position prior to the instruction. The historic dataset used is from April 2023 to March 2024 and will take the format of a time series at a SP resolution.
- The raw data is then adjusted for known or expected changes, e.g. new connections, new plant commissioning or decommissioning in the next 12-24 months.
- For new connections, where possible we use the output of a similar existing unit (scaled to capacity). Particularly,
  - New wind farms are assigned the same load factor profile (based on the historic data) as the nearest existing neighbor.
  - Batteries use the mean profile across several existing batteries.
  - For interconnectors where possible, use the profile of existing interconnectors to the same country.

- For hybrid units we combine profiles of the two technologies:
    - PV/Battery: PV profile taken from Sheffield Solar as an estimate of regional outturn, combined with mean profile across several existing batteries.
    - Battery/Gas: Combine mean profile across several existing batteries with historic profile of similar sized gas generator.
- Wind is constrained by a maximum load factor curve per demand level based on historic profiles.
- The profile of generation from new connections are offset by reducing generation from gas units, repositioning units to balance the demand profile.
- In the FRCR calculations, consequential RoCoF loss volume is added to BMU profiles where appropriate.

Assumptions:

- A historic profile of generation as a baseline is representative of the future study period.
- New Connection timelines remain as expected.
- Any rebalancing actions to offset new renewable generation will be taken on gas units.
- The maximum wind power is highly related to the demand level and network capacity. There are no significant network reinforcements that can enlarge the network capacity dramatically, so that we can use last year's data to reflect the next two years' scenarios.

5.2.2 Loss of Mains profile (including RoCoF and Vector Shift)

Purpose:

Identify the MW at Risk associated with the inadvertent tripping of Loss of Mains (LoM) protection.

The specification of up-to-date requirements on the LoM protection via Distribution Code modification DC0079, the Accelerated Loss of Mains Change Programme (ALoMCP) that aimed to achieve compliance with the new requirements reduced the risk of inadvertent tripping of embedded generation to a very low level by changes to the settings and protection type. However, some several thousand sites, although of very low capacity, remain non-compliant and are undergoing an Enforcement Process managed by the Distribution Network Operators (DNOs).

Up until this risk is eliminated or reduced to a level that is immaterial, it will need to be included when producing the FRCR.

Definition:

The LoM non-compliance raw data is provided as a total MW of a certain generation technology (wind, solar, CHP, and other) connected to a certain DNO's area has one of five non-compliant settings, i.e. RoCoF 0.125Hz/s, RoCoF 0.2Hz/s, RoCoF 0.5Hz/s, RoCoF 1Hz/s with no time delay, and VS.

Process:

- The LoM non-compliance raw data are fed into a generation dispatch engine that produces a time series of the output of generation within a certain DNO's network that has a certain non-compliant LoM protection setting MW. This engine uses historic wind and solar generation outputs to estimate the outputs of these technologies and applies load factors on Combined Heat and Power (CHP) and other generation sites.
- Total RoCoF loss across GB: if RoCoF exceeds a certain value, is calculated as the sum of the output of all generation sites that have RoCoF protection below the value that has been exceeded.
- Total VS loss following a transmission fault: following a fault VS loss volume is estimated using an empirical formula that assumes that, for a fault at a certain node, a certain percentage of generation with VS protection that is connected to a certain DNO's network will trip. The total generation loss associated with VS operation for that fault, would be the sum of all the percentages across all affected DNO networks. This empirical formula has been calibrated for 42 distinct nodes against real system events.
- The FRCR model uses historical VS profiles, based on historical weather forecast and the location information for 42 nodes across GB.

The Accelerated Loss of Mains Change Programme (ALoMCP) finished on 31 March 2023, by when, estimated remaining LoM volumes are:

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

5.2.3 BMU + VS event profile

Purpose:

BMU+VS event profiles provide a more accurate assessment of generation at risk due to transmission faults, compared to relying solely on the theoretical maximum export levels.

Definition:

BMU+VS events are defined to represent transmission faults that could lead to loss of BMU(s), and distribution connected generators due to the operation of VS relays which is a type of LoM protection. Where credible transmission faults are considered in the FRCR model as: single circuit trips, double circuit trips, busbar/mesh corner risks and offshore transmission owner (OFTO) networks risks.

Source:

- BMU profile as per section 5.2.1.
- VS profile as per section 5.2.2.

Process:

The FRCR model uses historic profiles for 42 nodes across GB. The nearest or most appropriate node will be assigned to a BMU, and the historic VS profile will be added on top of the BMU output profile.

$$BMU + VS\ Loss\ Profile = BMU\ \ Profile\ +\ Vector\ Shift\ Profile$$

5.2.4 Simultaneous event profile

Purpose:

Simultaneous event profile is introduced to represent the loss level of simultaneous events in SP granularity.

Definition:

In FRCR analysis, simultaneous events consider each pair of BMU-only events, combining them into an aggregated loss along with any consequential RoCoF loss. For more information on the rationale of simultaneous events methodology, please refer to the **Report** for FRCR 2022 as well as the **Methodology** Section 4.2.

Sources:

- BMU Profile As per section 5.2.1.
- RoCoF Losses as per section 5.2.2.

Process:

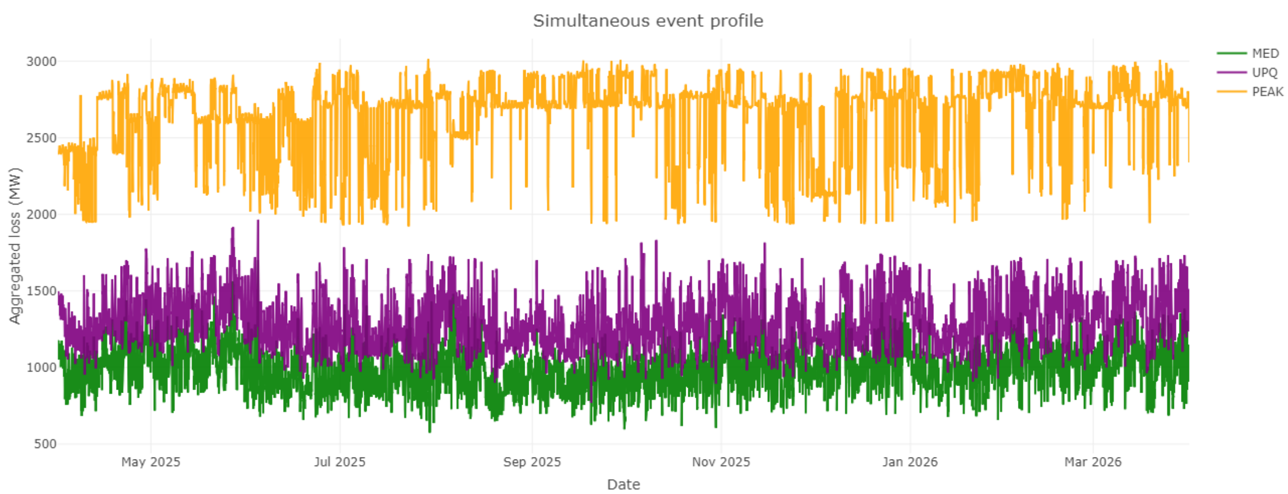
In every SP, the following calculations are performed.

- Pairing BMU-only risks:
    - Identify and pair each pair of BMU-only risks.
    - Calculate the aggregated loss for each pair.
- Adding consequential RoCoF loss:
    - For each aggregated loss, determine if consequential RoCoF loss will be triggered.
    - If triggered, include the RoCoF loss on top of the aggregated loss.
- Statistical Assignment:
    - Rank the aggregated loss from the largest to the smallest.
    - Use a statistical approach to assign the aggregated losses to different categories:
        - The largest aggregated loss is assigned to the **Peak** simultaneous event profile,
        - The top 75% of the largest aggregated losses are assigned to the **Upper quartile** simultaneous event, and
        - The top 50% of the largest aggregated losses are assigned to the **Median** simultaneous event.

Assumptions:

Simultaneous losses are assumed to be instantaneous to cover the most onerous case.

The median, upper-quartile and peak simultaneous event profiles used in FRCR assessment are shown below.



6. Input - Event probability

6.1 BMU failure probability

Purpose:

The BMU failure probability is used in the FRCR model to simulate an expected level of BMU loss for the study period. The probability of BMU failure probability is linked with the BMU-only event profile in section 5.2.1.

Definition:

BMU failure probability is the likelihood of a BMU failing based upon the failure rate of all units with the same energy source over the last 3 years. This data includes interconnector failure rates.

Process:

- A review of the past 3 years of operational data for each BMU is undertaken and the number of occurrences of change in Maximum Export Limit (MEL) between 4-hour ahead and real time is considered a breakdown or unplanned outage. The number of events are grouped by unit energy source. The number of unplanned outages per unit energy source observed is divided per the number of units results and years results in the BMU failure probability. The BMU failure probability is applied to all units of the same energy source.
- For each energy source:

$$BMU\ failure\ probability = \frac{(Number\ of\ Faults\ Observed)}{(Number\ of\ Units \cdot Number\ of\ Years\ Observed)}$$

- For Interconnectors, outage messages on REMIT are used from the Elexon Portal to calculate their failure probability.

Source:

- Data for the BMU outages are from an internal database and is not publicly accessible or shareable.
- REMIT on Elexon Portal and information on ENTSOE portal are used for interconnector outage calculation.

Assumptions:

- BMU failure rate per fuel type is representative of the individual BMUs.
- Multiple breakdowns within 24 hours is treated as one failure, as the unit is likely to be struggling to return.
- It is assumed that most electrical equipment are under a three-year maintenance cycle, thus we analyse past 3 years to find out the average failure rate per year.

6.2 Transmission fault probability

Purpose:

The transmission fault probability is used in the FRCR model to simulate an expected level of loss caused by a transmission fault for the study period.

Definition:

Transmission fault probability is the likelihood of a transmission fault. Within the FRCR scope, four types of transmission faults are considered.

- Single Circuit Fault
- Double Circuit Fault
- Busbar/Mesh Corner Fault
- OFTO (Offshore Transmission Owner) Fault

The OFTO network risk category is used due to the radial nature of the OFTO networks, representing any failure that would result in the loss of generation. This could be, but not limited to, a cable fault, a busbar fault, a transformer fault. The risk is calculated based on the total length of network combined with the failure rate per year.

Source:

- Recorded events are from 3rd party data, e.g. from Transmission Owners (TOs) and OFTOs, hence NESO is unable to publish the raw data. There is similar data available in GC0151 reports.
- Transmission circuit information can be found from the Electricity Ten Year Statement 2023 (ETYS 2023).
- Busbar/mesh corner information is obtained from the GB master model, which is submitted from TOs, hence NESO is unable to publish the raw data.

Process:

- Fault events reviewed are from August 2021 to end of August 2024 to cover 3 years. Calculate each of the different type of risks, the fault rates per year are derived as:

$$Circuit\ Fault\ Rate = \frac{Number\ of\ Circuit\ Faults}{Total\ Length\ of\ Circuits \cdot Number\ of\ Years}$$

$$Bar\ Fault\ Rate = \frac{Number\ of\ Bar\ Faults}{Total\ Number\ of\ Bars \cdot Number\ of\ Years}$$

- Fault Rates for each type of fault is in the subsequent table:

	Number/Length	Failure rate	Unit
No. of Busbar/mesh corner (132 kV, 275 kV, 400 kV)	1838	**0.29%**	fault rate per bar/corner per year
Total circuit length (132/275/400 kV, OFTO excluded)	24485	**0.43%**	fault rate per km per year
Double circuit length (assumed half of single circuit length)	12242.5	**0.06%**	fault rate per km per year
OFTO	2724	**0.07%**	fault rate per km per year

Assumptions:

- Fault rates from 2025 – 2027 for FRCR 2025 analysis behave similarly to that of the period studied.

6.3 BMU+VS event probability

Purpose:

The BM+VS event probability is used in the FRCR model to simulate an expected level of loss for the study period. The probability of BMU+VS event probability is linked with the transmission fault probability and the BMU+VS event profile in section 5.2.3.

Definition:

BMU+VS events are identified as BMUs or BMU groups that could potentially trip due to a single transmission fault. Within the FRCR scope, four types of transmission faults are considered that may lead to the loss of BMU or BMU groups, which is detailed in section 6.2.

For each BMU+VS event, its probability is determined by accumulating the likelihood of each applicable fault type under both intact and outage conditions.

- Intact conditions: These refer to scenarios where all relevant transmission circuits and equipment are fully operational for a specific BMU+VS event. In such cases, the risk of tripping is minimised.
- Outage conditions: These refer to scenarios where a planned outage could impact the trip rate of a BMU+VS event. To account for this, an analysis is conducted to estimate the average duration of outages per year for each BMU+VS event, considering the relevant circuits and equipment. The fault rate under outage conditions follows the same

derivation method but is adjusted based on the percentage of days affected by planned outages.

Process:

- Review the list of BMU+VS events and type of faults that can lead to trips of involved BMU(s). Update parameters including number of busbars/mesh corners, length of circuits, duration of planned outages, and fault rate for each type of fault.
- The overall probability of a specific BMU+VS event can be derived as:

$$Event\ probability = Rate_{intact} \cdot \left(1 - \frac{Days_{outage}}{365}\right) + Rate_{outage} \cdot \frac{Days_{outage}}{365}$$

where $Rate_{outage}$ are the accumulations of fault rate of any applicable fault types, $Days_{outage}$ is the average length of days where outages have been planned on relevant network equipment to a BMU+VS event. Hence the probability of an intact event is applied to the average number of days the network concerned is intact and the probability of an outage event is applied to the average number of days the piece of network concerned is under outage conditions, with that average being calculated from the observed 3-year period. The calculation here combines those two scenarios, intact and outage, into one fault rate per event. If a BMU+VS event is not identified with any risks under outage conditions, then $Days_{outage}$ is 0.

Example:

- BRITNED interconnector is identified to be a potential BMU+VS event with bar fault risk under intact conditions. The number of busbar that can lead to this BMU+VS event is one. Therefore, the probability of this BMU+VS event is:

$$Event\ probability = Rate_{Bar} \cdot Number_{Bar} \cdot \left(1 - \frac{Days_{outage}}{365}\right) = 0.29\% \cdot 1 \cdot \left(1 - \frac{0}{365}\right) = 0.29\%$$

- Torness Unit-2 is identified to be a potential BMU+VS event with a bar fault risk under both intact and outage conditions, along with a double circuit fault risk under outage conditions. The number of bars is one and the length of the double circuit is 34.2 km. The average days of planned outage on relevant circuits or equipment are 17 days per year. Therefore, the event probability is:

$$Event\ probability = Rate_{Bar} \cdot Number_{Bar} + Rate_{DoubleCircuit} \cdot Length_{DoubleCircuit} \cdot \left(\frac{Days_{outage}}{365}\right)$$

$$= 0.29\% \cdot 1 + 0.06\% \cdot 34.2 \cdot \left(\frac{17}{365}\right) = 0.38\%$$

Assumptions:

- It is assumed that most circuits and equipment are under a three-year maintenance cycle, thus we analyse past 3 years to find out the average length of planned outages per year.

6.4 Simultaneous event probability

Purpose:

The simultaneous event probability is used in the FRCR model to simulate an expected level of loss for the study period. The simultaneous event probability is linked with the simultaneous event profile in section 5.2.4.

Definition:

The simultaneous event probability is the likelihood of the simultaneous event occurring. In the FRCR analysis simultaneous event considers three events that represents the **median**, **upper quantile**, and **peak** loss levels. Hence, there is a corresponding probability for the **median**, **upper quantile**, and **peak** simultaneous event.

Process:

The simultaneous event probability is obtained by benchmarking the historical events, where there were multiple BMU trips reported in GC0105 and GC0151 according to Grid Code OC3 event reporting criteria, against the simultaneous event profiles. The historical events are divided into high-frequency events and low-frequency events.

The likelihood of high-frequency simultaneous event is consistent with the historic FRCR assumptions due to its rare occurrence and limited aggregated size.

The likelihood of low-frequency simultaneous event is calculated by accumulating the Cumulative Distribution Functions (CDFs) of these historical events.

- Review the historical events from January 2019 to December 2024. Please note, GC01015 and GC0151 were implemented in June 2021 and November 2021 respectively, following Ofgem's approval. Events occurred before the implemented reporting period were reviewed within FRCR 2025 cycle by applying the same reporting criteria.
- The simultaneous event profiles for median, upper quantile and peak in section 5.2.4.
- The simultaneous events probability is calculated by the sum of all Cumulative Distribution Functions (CDFs), the equations are shown below.

Likelihood of medial simultaneous events:

$$\sum_{All\ events} Prob(Loss\ of\ the\ event \geq Median\ sim\ event\ profile)$$

Likelihood of upper quantile simultaneous events:

$$\sum_{All\ events} Prob(Loss\ of\ the\ event \geq Upperquantile\ sim\ event\ profile)$$

Likelihood of peak quantile simultaneous events:

$$\sum_{All\ events} Prob(Loss\ of\ the\ event \geq Peak\ sim\ event\ profile)$$

Sources:

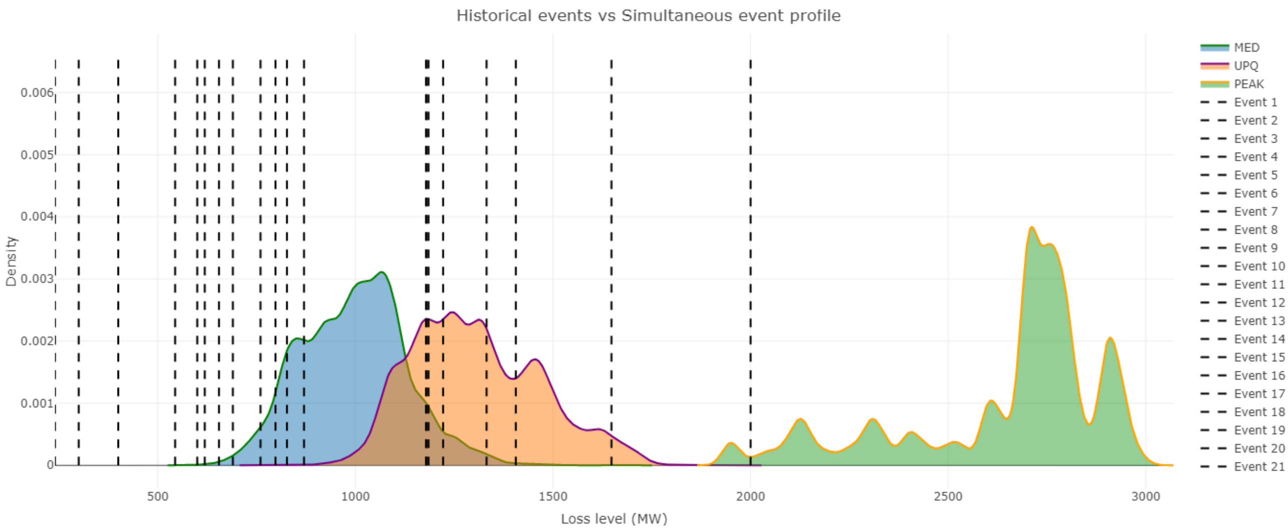
- GC0105 and GC0151 monthly report. Events occurred before the implementation of the Grid Code modification were recorded in NESO internal database.
- Simultaneous event profile detailed in section 5.2.4.

Data and examples:

- Historical low-frequency events and its CDF

Event number	*total loss (MW)*	*Event date*	*Median* CFD	*Upper quantile* CFD	*Peak* CFD
Event 1	240	23/08/2024	0	0	0
Event 2	240	24/08/2024	0	0	0
Event 3	300	28/03/2024	0	0	0
Event 4	400	26/12/2019	0	0	0
Event 5	544	06/07/2020	0	0	0
Event 6	600	24/05/2020	0	0	0
Event 7	619	09/12/2019	0	0	0
Event 8	655	05/04/2021	0.001	0	0
Event 9	690	06/04/2021	0.005	0	0
Event 10	760	20/02/2019	0.029	0	0
Event 11	798	10/06/2021	0.058	0	0
Event 12	827	07/10/2019	0.104	0	0
Event 13	870	12/05/2024	0.193	0	0
Event 14	1179	20/06/2019	0.921	0.245	0
Event 15	1180	02/05/2021	0.922	0.248	0
Event 16	1185	30/10/2020	0.927	0.26	0
Event 17	1222	11/03/2021	0.953	0.34	0
Event 18	1332	10/06/2023	0.991	0.608	0
Event 19	1406	10/02/2021	0.997	0.724	0
Event 20	1648	22/12/2023	1	0.971	0
Event 21	2000	09/08/2019	1	1	0.022
Total			8.101	4.396	0.022

- Historical low-frequency events vs. simultaneous event profile



7. Glossary and List of Abbreviations

Abbreviation	Definition
ALoMCP	Accelerated Loss of Main Change Programme
BM	Balancing Mechanism
BMU	Balancing Mechanism Unit
BOA	Bid Offer Acceptance
CCGT	Combined Cycle Gas Turbine
CDF	Cumulative Distribution Function
DC	Dynamic Containment
DM	Dynamic Moderation
DNO	Distribution Network Operator
DR	Dynamic Regulation
EAC	Enduring Auction Capability
EFA	Electricity Forward Agreement
FES	Future Energy Scenarios
FFR	Firm Frequency Response
FRCR	Frequency Risk and Control Report
HVDC	High Voltage Direct Current
LoM	Loss of Mains
MEL	Maximum Export Limit
MFR	Mandatory Frequency Response
NETS	National Electricity Transmission System
OFTO	Offshore Transmission Owner
RoCoF	Rate of Change of Frequency
SEL	Stable Export Limit
sFFR	Static Firm Frequency Response
SP	Settlement Period
SQSS	Security and Quality of Supply Standards
TEC	Transmission Entry Capacity
TO	Transmission Owner
VS	Vector Shift
VWAP	volume weighted average price