Public

Security & Quality of Supply Standards

Frequency Risk and Control Report

The Methodology – May 2025 (v3)

NESO
National Energy
System Operator

Version Control

Version	Date	Change Details
v2	April 2021	• First edition following consultation
v3	March 2025	• Streamline contents • Update to NESO report template

Executive Summary

The requirement for a Frequency Risk and Control Report (FRCR) has been introduced following the approval of Security and Quality of Supply Standards (SQSS) modification GSR027[1]: Review of the NETS SQSS Criteria for Frequency Control that drive reserve, frequency response and inertia holding on the GB electricity system.

This document is the Methodology which has been updated from the FRCR Methodology April 2021 (v2)[2], and aims to provide a comprehensive description on the FRCR framework. It outlines what will be assessed, how it will be assessed, and the format of the outputs.

[1] GSR027: Review of the NETS SQSS Criteria for Frequency Control that drive reserve, response and inertia holding on the GB electricity system

[2] Frequency Risk and Control Report Methodology 2021

Contents

1 Overview

1.1 Introduction

The Frequency Risk and Control Report (*FRCR*) process is an annual commitment of the National Energy System Operator (*NESO*) to update and refine the frequency policy that ensures the system has an appropriate level of security with a reasonable level of balancing services spending.

The main policy recommendation in each *FRCR* cycle will be presented in the **Report**, which will be prepared in accordance with the **Methodology** and **Handbook**. Once the **Report** is approved by the *Authority*, *NESO* will implement and embed it as part of its role in operating the system.

1.2 Suite of documents

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**.

This document is the **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 Defined terms

This document contains technical terms and phrases specific to *National Electricity Transmission Systems* (*NETS*) and the Electricity Supply Industry. The meaning of some terms or phrases in this document may also differ from those commonly used. For this reason, defined terms from the SQSS have been identified in the text using *purple italics*. A list of terms and definitions is included in Chapter 11 in this report.

2 Objectives

2.1 Objective of the FRCR process

The *FRCR*, as defined in the Security and Quality of Supply Standards (SQSS):

- sets out the results of an assessment of the operational frequency risks on the system, and
- includes an assessment of:
  - the magnitude, duration and likelihood of transient frequency deviations,
  - the forecast impact,
  - the cost of securing the system, and
  - confirms which risks will or will not be secured operationally by *NESO* in accordance with paragraphs 5.8, 5.11.2, 9.2 and 9.4.2 of the SQSS[3].

2.2 Objective of the FRCR Methodology

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

- a safe and reliable supply of electricity
- at an affordable cost.

There is a balance between those objectives:

- higher reliability requirements result in increased direct costs to meet the requirement;
- lower reliability requirements result in decreased direct costs to meet the requirement, but generally result in higher indirect costs and impacts.

These objectives are formalised through the SQSS and *FRCR*.

The aim of the **Methodology** is to lay out a transparent and objective framework to determine the right balance between reliability and cost, focusing on the risks, impacts and controls for managing frequency.

2.2.1 Reliability and impact

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

- how often they occur – the likelihood,
- how long they last for – the duration, and

[3] National Electricity Transmission System Security and Quality of Supply Standard

- how large they are – the size

as each of these affects the **Impacts** of an event.

For example: larger or longer deviations that happen very rarely may be acceptable, but smaller or shorter deviations that happen very often may not.

The **Report** will define what is considered reasonable as infrequent and tolerable for each of these criteria for transient frequency deviations.

2.2.2 Controls and direct costs

NESO use a set of *Ancillary Services* to control frequency deviations. Some are automatic, like frequency response, and others are manually dispatched, like reserve, instructions through the *Balancing Mechanism* (i.e. Bid Offer Acceptances), services to increase inertia, or services to pre-emptively decrease the size of potential loss risks.

In this document, we refer to the *Ancillary Services* as "**Controls**". The cost associated with controls forms the direct cost in *FRCR* assessment.

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

- the size of the event that caused the frequency deviation, and
- how much of each of these controls are used.

The **Methodology** will consider relevant controls which *NESO* currently has access to, or which *NESO* anticipates having access to during the period for which the *FRCR* is being written.

2.2.3 Balance between reliability and cost

The aim of the **Methodology** is to lay out an objective and transparent framework for *NESO* to assess risks associated with frequency deviations; the events which could cause them, the impacts they have, and the cost and mix of controls to mitigate them.

The assessment can then be used to determine the appropriate balance between reliability and cost, which will be the subject of the *FRCR*.

Consultation and ongoing engagement with industry stakeholders is key to achieving this in an open and transparent way: the role of *NESO* is to analyse the risks, impacts and controls, their impact on reliability and cost, and present a recommendation for where the appropriate balance may lie. This enables the *Authority* to make an informed decision on the right balance between reliability of electricity supplies and costs to end consumers.

NESO can then update their operational policy and procurement of controls to implement the outcome.

2.3 Wider considerations out of scope of the FRCR

The *FRCR* is not intended to develop the design of future controls, nor to consider other topics such as wider system operability interactions, market design, whole-system costs and interactions with other markets. There are projects ongoing to address these wider industry considerations[4]. However, the *FRCR* may help to inform these developments, and will use them as inputs to future editions.

The *FRCR* aims to update at least annually. As the projects develop, consideration will be given to how and when they will be included in future versions of the **Methodology**.

[4] More information on the development of new solutions can be found in the System Operability Framework page of NESO website.

3 Impacts

3.1 Context

The impact of a transient frequency deviations can be assessed by the combination of three metrics:

- size ⇒ how far they deviate
- duration ⇒ how long they persist for
- likelihood ⇒ how infrequent they occur

3.2 Level of impact

The *FRCR* will assess four levels of impact to cover these considerations, and allow comparison against historic performance:

Table 1 - Impacts to be assessed

#	Deviation	Duration	Relevance
H1	50.5 Hz < f	Any	• Above current SQSS implementation • Plant performance prescribed in detail by Grid Code
L1	49.2 Hz ≤ f < 49.5 Hz	60 seconds	• Current SQSS and System Operation Guideline (SOGL)[5] implementation • Infrequent occurrence
L2	48.8 Hz < f < 49.2 Hz	Any	• Beyond current SQSS implementation and SOGL, but without triggering Low Frequency Demand Disconnection (LFDD) operation • Plant performance prescribed in detail by Grid Code
L3	47.8 Hz < f ≤ 48.8 Hz	Any	• First stage of LFDD starts at 48.8 Hz and then subsequent stages apply in the range 48.8 Hz – 47.8 Hz. By the time all stages of the LFDD scheme has operated at 47.8 Hz over 50% of demand will have been lost.

[5] Annex III Article 127 Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation (Text with EEA relevance)

4 Events and loss risks

4.1 Events considered in FRCR

4.1.1 Categories of loss risks

The *FRCR* will cover the following categories of loss risks.

Table 2 – Events included in the FRCR assessment

BMU-only	• an event that disconnects one BMU[6], and may or may not also cause a consequential Rate of Change of Frequency (RoCoF) loss, with no Vector Shift (VS) loss • caused by a *Loss of Power Infeed* or *Loss of Power 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 *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 an outage condition compared to that under intact network conditions. It is also considered to involve 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.

NB: the loss of Super Grid Transformer supplies to Distribution Networks are also covered by the policy, and will continue to be covered. These are a *loss of power outfeed,* and are typically smaller than 560MW.

VS-only and VS+RoCoF risks[7] are fully mitigated post the Accelerated Loss of Main Change Program (ALoMCP).

4.1.2 Impact of transmission network outages on radial connection loss risks

In certain areas of the *NETS,* loss risks exist on radial connections. In the case of a double circuit radial connection, the likelihood of an event occurring increases during transmission network outage conditions.

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

[7] Frequency Risk and Control Report Methodology 2021

This is because transmission network outages leave these loss risks exposed to a single circuit fault, which is more likely than a double circuit fault.

The **Report** will review the occurrence of the change in likelihood of these events under outage conditions, and what specific consideration (if any) should be given during these periods.

4.2 Simultaneous event and other loss risks

Since FRCR 2022, simultaneous events have been added to the FRCR analysis. This addition was prompted by historical instances where multiple generating units tripped simultaneously or within a short period, leading to significant combined power losses. Incorporating simultaneous events into the analysis aims to develop a more robust and comprehensive risk assessment framework that accounts for these additional complexities and ensures system reliability.

4.2.1 Modelling Difficulties

However, modelling simultaneous event is inherently challenging due to the complex nature of these events as well as its limited occurrence.

- The complex nature of these events involves intricate interactions within the system, requiring sophisticated modelling techniques to accurately predict their occurrence.
- The limited occurrence of such events means there is often insufficient historical data to draw reliable conclusions. This scarcity of data makes it difficult to develop robust sophisticated models and accurately assess the risk for the occurrence.

4.2.2 FRCR Approach on simultaneous event

The FRCR approach to model simultaneous events focuses on the total volume of the combined loss as well as the likelihood of occurrence by using statistical method. The methodology considers two BMU-only events combining into a simultaneous event due to the computational complexity of investigating higher-order events. Key aspects of this approach include:

- The total loss size is the combined from each pair of BMU losses, including any consequential RoCoF losses. The median, upper 75% quantile, and maximum combined loss size per settlement period are selected due to the large number of possible simultaneous event combinations.
- The analysis focuses on the total loss made up of BMU-only events occurring at the same time instant, which represents the most onerous condition from a frequency modelling perspective.
- The Likelihood is calibrated against the historical occurrence of simultaneous and cascading events.

5 Controls

5.1 Assessment baseline

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

This can be achieved by looking at variations to current policy for applying each of the controls, whether more, the same, or less of each.

5.2 Controls options

There are four main controls for mitigating transient frequency deviations:

- holding frequency response
- reducing BMU loss size
- reducing Loss of Main (LoM) loss size
- increasing inertia

The **Report** will investigate variations to current policy for all four controls.

5.2.1 Frequency response

Dynamic Containment, Dynamic Moderation, Dynamic Regulation[8] are the main response services for the current system.

- Dynamic Containment (DC) is a post-fault service requiring participants to supply a response within 1 second of a frequency disturbance. The requirement is determined by the need to contain the infeed loss by 49.2 Hz and return to 49.5 Hz within 60s, and contain the outfeed loss by 50.5 Hz.
- Dynamic Regulation (DR) and Dynamic Moderation (DM) are pre-fault services. The requirement is determined by the frequency performance with the aim of contain the pre-fault frequency within operational limits.

In the FRCR assessment, DC is considered as the main control, while, DR and DM are treated as fixed inputs, which is determined based on the current operational experiences rather than from FRCR assessment.

FRCR analysis also have the functionality to incorporate *Limited Frequency Sensitive Mode* (*LFSM*).

5.2.2 Reducing BMU loss size

With the introduction of Dynamic Containment and The Accelerated Loss of Mains Change Programme (ALoMCP), reducing BMU loss size is no longer considered as good value, since increasing response holdings offers better value for money. The **Methodology** will still consider

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

reducing BMU loss size as an "individual loss-risk control" during analysis, but recommendations will only suggest the most cost-effective controls.

5.2.3 Reducing LoM loss size

The ALoMCP programme reduced the capacity of Distributed Energy Resources (DER) at risk of consequential loss due to Loss of Main protection. FRCR analysis adopted the outcome from ALoMCP.

5.2.4 Increase inertia

The **Report** proposes a minimum inertia level based on the assessment. The **Report** will look at the potential benefit of changing the minimum inertia limit above or below the current level in policy.

5.3 System-wide control vs individual loss-risk control

System-wide control refers to the measure or action that benefit the system rather than targeting specific individual risks. Hence, the main system-wide controls in *FRCR* framework include holding frequency response and increasing system inertia.

Individual loss-risk controls refer to specific measures or actions taken to mitigate or manage risks associated with potential losses from particular events. Hence, the main individual loss-risk control in *FRCR* framework is reducing the BMU loss size.

6 Metrics for reliability vs. cost

6.1 Applicable principles

At its simplest, for each level of impact:

- good value risks are likely to be those which are:
    - of low cost to mitigate,
    - likely to occur, or
    - which have a large impact.
- poor value risks are likely to be those which are:
    - of high cost to mitigate,
    - unlikely to occur, or
    - which have a small impact.

There is a whole spectrum of costs and likelihoods across each of the events, meaning a clear-cut judgement of the balance between reliability and cost can be difficult to reach for one event in isolation. Instead, the assessment must look at the total risk and total cost across all events.

Where risks are deemed to be poor value and not actively mitigated, the backup measures prescribed through the Grid Code will act to minimise overall disruption to the system should they occur.

6.2 Options of metrics

When deciding on the balance between reliability and cost, there are several metrics the industry and *Authority* may wish to consider.

Some example metrics are outlined below.

6.2.1 Likelihood of each impact

Frequency has rarely gone outside of statutory limits in recent years, due to the introduction of FRCR, new response services development, ALoMCP and other projects and programmes.

The previous two occurrences of LFDD happened on 27 May 2008 and 9 August 2019, just over a decade apart. These are the only two LFDD events since GB electricity industry privatisation in 1990.

One metric could be to define an upper limit or guide on how often each impact could be accepted to occur.

6.2.2 Total cost per year

The cost of controls for managing frequency includes expenses for reserve, frequency response, and inertia, although a portion of these costs is allocated to pre-fault rather than post-fault frequency management.

The second option for a metric could be to define an upper limit or guideline on the total cost of controls for managing frequency.

NB: *any costs produced in the* **Report** *will be a forecast, and so outturn costs are naturally subject to change due to pricing, behaviour and forecast uncertainty.*

6.2.3 Cost value per avoided occurrence

Another metric could be to assign a value to avoiding a particular occurrence, such as LFDD.

In theory, the Value of Lost Load (VoLL) "*represents the value that electricity users attribute to security of electricity supply and the estimates could be used to provide a price signal about the adequate level of security of supply in GB*"[9].

The current application of VoLL is more suited to capacity considerations, which are more predictable, and less suited to faults and any resulting transient frequency deviation, which are less predictable[10].

The relatively short-duration of LFDD events and the infrequent rate at which they occur means that the VoLL used for setting Reserve Scarcity Price is likely to be insufficient to provide the right balance between reliability and cost for the **Report**.

Therefore, a new "VoLL-like" parameter could be used to set a cost value per avoided occurrence for the **Report**.

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[9] The Value of Loss Load (VoLL) for Electricity in Great Britain

[10] Counting the cost: the economic and social costs of electricity shortfalls in the UK

7 Assessment – general approach and assumptions

7.1 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 *NETS*, which represent additional loss risks and which impact on the inertia of the system.

7.2 Granularity and time period

Many of the key inputs, like demand, inertia, BMU loss size, 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, however is inappropriate for assessing frequency risks on the GB system.

To overcome this, the analysis performed is a time series at Settlement Period granularity.

7.3 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.

NESO will remove the balancing actions from the historic data sets to get a representation of the "market position" for these baseline system conditions.

7.4 Cost of mitigations

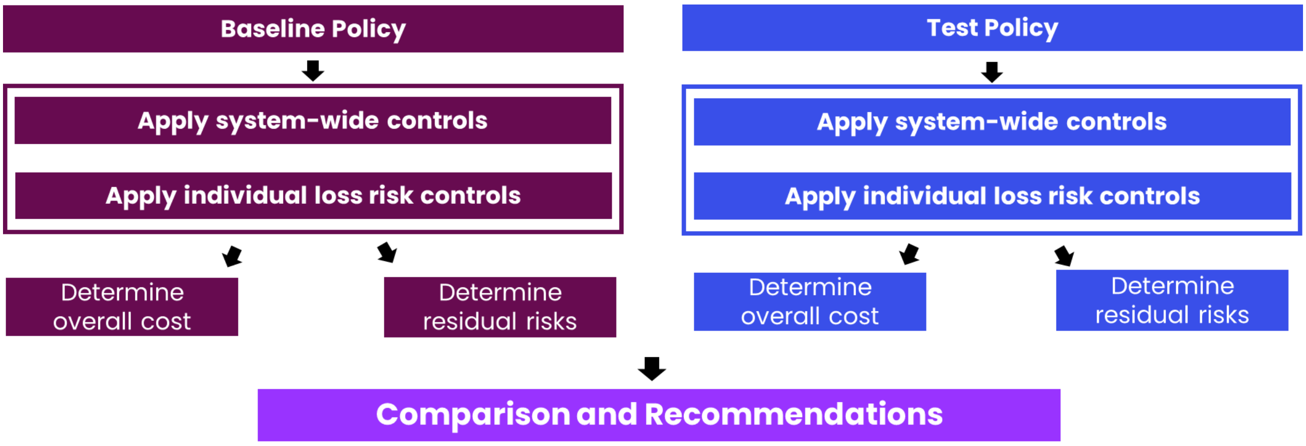
Costs for increasing inertia and reducing BMU loss size will be benchmarked against the typical prices achieved through the *Balancing Mechanism* and trading.

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

NB: *any costs produced in the **Report** will be an estimate, and so outturn costs are naturally subject to change due to pricing, behaviour and forecast uncertainty.*

8 Assessment – detailed process

8.1 Overview



The *FRCR* assessment framework involves assessing and comparing the effectiveness and cost-efficiency of various policy options to manage system frequency control risks by running parallel analyses of the Baseline Policy and the Test Policy.

The *FRCR* model includes gathering and updating system parameters, applying system-wide and individual loss risk controls, and assessing the costs and residual risks associated with each policy. The objective is to ensure a fair comparison and generate a clear cost vs. risk metrics to evaluate the effectiveness of the policies.

8.1.1 Policy

Policy refers to the specific parameters, rules, or actions proposed or implemented within a policy framework to achieve certain objectives. In the context of the *FRCR* framework these polices include various controls, i.e. how to apply system-wide controls and individual loss-risk controls. These policies can potentially be:

- Maintain system inertia above a certain level.
- Apply system-wide control to mitigate a certain category of loss risks.
- Apply further controls to mitigate all or a part of residual risks.

FRCR assesses the costs and residual risks by analysing these proposed polices, thereby facilitating a fair comparison between different policies.

8.1.2 Apply system-wide controls

System-wide control refers to the measure or action that benefit the system rather than targeting specific individual risks. Main system-wide controls are procuring response services and increasing system inertia.

8.1.3 Apply individual loss risk controls

Individual loss-risk controls refer to specific measures or actions taken to mitigate or manage risks associated with potential losses from particular events. Main individual loss-risk control is reducing the total loss size.

8.1.4 Determine overall cost and residual risks

Overall cost

Overall cost in the *FRCR* framework includes all expenses for procuring all controls.

Residual risks

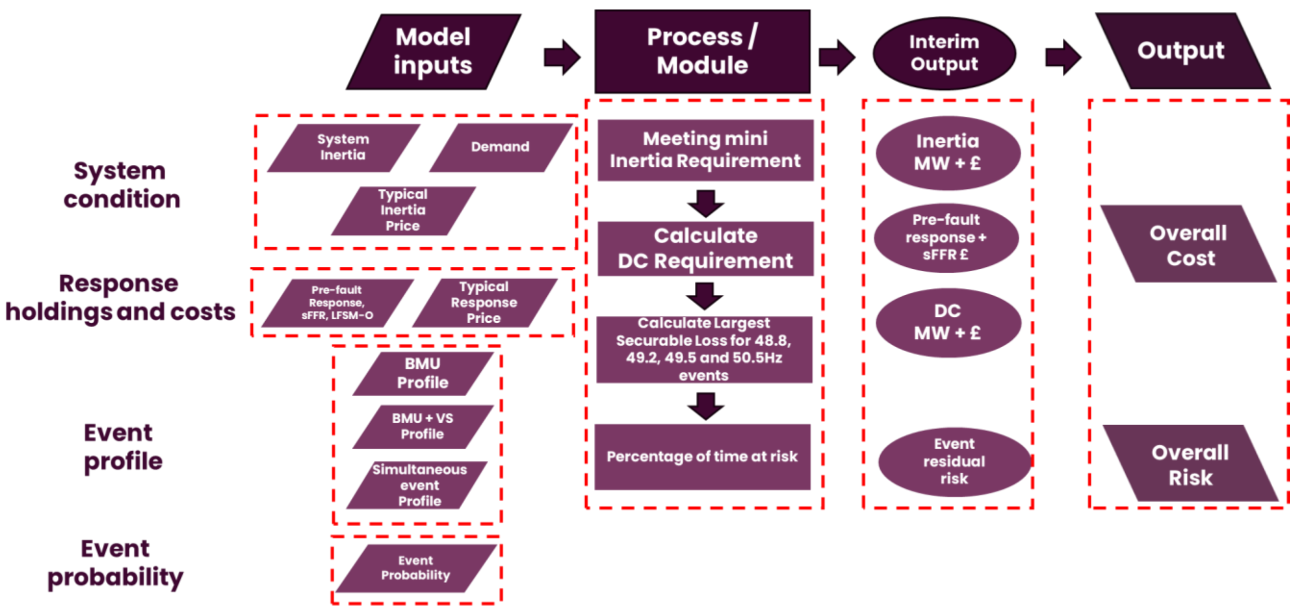
Residual risk in the *FRCR* framework is the remaining risk of frequency deviations after applying the controls specified in the Policy.

8.2 Detailed Process

This section provides a detailed explanation of the *FRCR* framework. It outlines the step-by-step process for:

1) how the controls are applied,
2) how overall costs are obtained, and
3) how residual risk is quantified.

The figure below shows the flowchart of *FRCR* framework



8.2.1 Model input

- **System conditions**
System parameters will be prepared and updated to reflect expected changes in the electricity system. The key inputs are **demand profile**, **inertia profile**. System conditions are prepared in line with data granularity requirements, with NESO extracting and reverting balancing actions from historical data sets to establish a representative "market position" for baseline conditions.

Costs for increasing inertia and reducing BMU loss size will be compared to the typical prices achieved through the *Balancing Mechanism* and trading.

More information can be found in Section 3 in the **Handbook**.

- **Response holdings and costs**
The quantity (except Dynamic Containment) and price of various frequency response services, namely, Dynamic Regulation (DR), Dynamic Moderation (DM) and static Firm Frequency Response (sFFR) will be benchmarked against the outcomes of previous results from Enduring Auction Capability (EAC). The holdings of Dynamic Containment is driven by the policy descriptions.

More information can be found in Section 4 in the **Handbook**.

- **Events profile**
This is to define the detail of each of the events that will be assessed in the *FRCR* framework, as outlined in Events and Loss Risks. The key inputs to generate all event profiles are **BMU profile** and **LoM profile**.

More information can be found in Section 5 in the **Handbook**.

- **Event probability**
Event probability is utilised for the calculation of residual risks. Details can be found in Section 6 in the **Handbook**.

BMU-only event probability: The BMU failure rate in the *FRCR* framework is obtained by analysing the past operational data for each BMU. The process involves identifying unplanned outages and multiple breakdowns within a 24-hour period which are counted as a single event. The number of these unplanned outages is then used to calculate the fault rate per year for each BMU type.

BMU+VS event probability: BMU+VS event is initiated by transmission fault. The transmission failure rate in the *FRCR* framework is determined by defining and analysing various transmission failure events, such as Single Circuit trips, Double Circuit trips, busbar/mesh corner risks, and OFTO network risks. The fault rates are calculated by dividing the number of faults by the total length of circuits or the total number of bars, and then dividing by the number of years reviewed.

Simultaneous event probability: The likelihood of simultaneous events in the *FRCR* model is determined by analysing historical cascading events, where multiple BMU trips, reported in GC105 and GC151[11]. These events are assumed to occur simultaneously in the worst-case scenario. The historical data is benchmarked against the distribution profiles of median, upper quantile, and

[11] GC105 & GC151 System Incidents Reports

peak simultaneous events. The likelihood is then calculated by accumulating the Cumulative Distribution Functions (CDFs)[12] of these historical events, providing a comprehensive assessment of the probability of simultaneous events.

8.2.2 Process / module

This part in the *FRCR* framework interprets the policy parameters into specific controls. The same logic is applied in every Settlement Period.

- **Calculate additional inertia needed to meet minimum inertia requirement**

The minimum inertia requirement refers to the minimum inertia required at national level for managing frequency risks which has no conflict with meeting locational stability requirements.

In the *FRCR* framework, the Minimum inertia requirement is part of the system-wide control, ensuring that post-fault frequency deviations are manageable with response services and the rate of change in post-fault frequency remains acceptable.

The logic used to calculate additional inertia is show below

```
# Calculate the market inertia
market inertia = outturn inertia - NESO actions to meet inertia
                 requirement

# Calculate the total inertia
system inertia = market inertia + stability workstream inertia

# Determine if additional inertia is required
if system inertia >= minimum inertia requirement:
   additional inertia required = 0
else:
   additional inertia required = minimum inertia requirement -
                                 system inertia
```

- **Calculate Response services Requirement**

Procuring frequency response services is also part of the system-wide Control. The response services in the *FRCR* framework aligns with the existing response services suite, including DR, DM, DC, and sFFR. Based on the Policy Input, the response requirement will be adjusted to reflect system needs.

Pre-fault response services

Dynamic Regulation (DR) and Dynamic Moderation (DM) are aligned with the current requirements.

Post-fault response services:

Static Firm Frequency Response (sFFR) is aligned with the current requirements.

Dynamic Containment (DC) is determined by the Policy description, i.e. what is the maximum loss level to be secured. The Logic of determining the DC requirement is shown below.

[12] Cumulative Distribution Functions

```
# Define largest loss
largest loss # is the maximum loss level to be secured

# Dynamic Containment requirement
Dynamic Containment nadir    # is the minimum volume of Dynamic
                               Containment required to ensure that the
                               frequency nadir does not fall below
                               49.2Hz.
Dynamic Containment recovery # is the minimum volume of Dynamic
                               Containment required to ensure that the
                               frequency recovers to 49.5Hz within 60
                               seconds.

Dynamic Containment for largest loss = max(Dynamic Containment nadir,
                                           Dynamic Containment recovery)
```

- **Calculate largest securable loss**

The largest securable loss is the maximum loss of infeed or outfeed that will not cause the system frequency to be beyond a certain threshold. These frequency thresholds in the *FRCR* framework are 48.8 HZ, 49.2 Hz, 49.5 Hz and 50.5 Hz respectively. By comparing the largest securable loss with each event profile, it can be determined if a specific event will cause the frequency to go beyond the frequency thresholds.

To calculate the largest securable loss in the FRCR analysis, the focus is primarily on the frequency nadir, which is the maximum frequency deviation following a disturbance, while disregarding the recovery to 49.5 Hz within 60 seconds. In real-time operation, the largest securable loss incorporates the recovery.

To calculate the largest securable loss, the required parameters include system conditions and response holdings, which are obtained in previous two steps.

```
# Largest securble loss
largest securble loss 48.8 # is the loss level that will bring
                             frequency down to 48.8 Hz.

largest securble loss 49.2 # is the loss level that will bring
                             frequency down to 49.2 Hz.

largest securble loss 49.5 # is the loss level that will bring
                             frequency down to 49.5 Hz.

largest securble loss 50.5 # is the loss level that will bring
                             frequency down to 50.5 Hz.
```

- **Apply individual loss-risk control**

Individual loss-risk control, such as reducing the loss level, is not as cost-effective as procuring more frequency response. *FRCR* framework has the functionality to evaluate the benefits of applying individual loss-risk control. However, the policy recommendations will focus on cost-effective controls of holding frequency response to manage system frequency security efficiently.

8.2.3 Outputs

- **Overall Cost**

Overall cost in the *FRCR* framework includes all expenses for procuring all controls. The logic of calculating all control related costs in one Settlement Period is shown below.

```
# Cost for inertia
typical unit inertia          # Typical inertia unit's inertia
                                contribution
typical unit SEL              # Typical inertia unit's Stable
                                Exporting Limit
typical unit reposition cost
per MWh                        # Typical inertia unit's reposition cost

number of typical unit = ceiling(additional inertia required/
                                 typical unit inertia)

cost for inertia = number of typical unit * typical unit SEL *
                   typical unit reposition cost

# Cost for frequency response services
# Note 1: DR, DM and sFFR volumes are fixed
          and aligned with the current system operation. DC
          volume is a variable calculated in the previous step.
# Note 2: the unit price for DR, DM, DC and sFFR is the volume weight
average price. More details can be found in the Handbook.
cost for DR   = DR volume   * unit price
cost for DM   = DM volume   * unit price
cost for DC   = DC volume   * unit price
cost for sFFR = sFFR volume * unit price

# Overall cost
overall cost = cost for inertia + cost for DR + cost for DM + cost for DC +
               cost for sFFR
```

- **Overall Residual Risk**

Residual risk in the *FRCR* framework is the remaining risk of frequency deviations after applying all controls. The logic of calculating the residual risks in is shown below.

```
# Residual risks for 48.8 Hz event
largest securble loss 48.8 # is the loss level that will bring
                             frequency down to 48.8 Hz.
for every event
   percentage at risk        # the precentage of event profile go beyong
                               largest securable loss 48.8
   event probability         # the probability of the event to occur
   residual risk for each event = percentage at risk * event probability

overall residual risk 48.8 = Σ (residual risk for each event)

# Residual risks for 49.2 Hz event
largest securble loss 49.2 # is the loss level that will bring
                             frequency down to 49.2 Hz.
for every event
   percentage at risk       # the precentage of event profile go beyong
                              largest securable loss 49.2
   event probability        # the probability of the event to occur
```

```
   residual risk for each event = percentage at risk * event probability

overall residual risk 49.2 = Σ (residual risk for each event)

# Residual risks for 49.5 Hz event
largest securble loss 49.5 # is the loss level that will bring
                             frequency down to 49.5 Hz.
for every event
   percentage at risk       # the precentage of event profile go beyong
                              largest securable loss 49.5
   event probability        # the probability of the event to occur
   residual risk for each event = percentage at risk * event probability

overall residual risk 49.5 = Σ (residual risk for each event)


# Residual risks for 50.5 Hz event
largest securble loss 50.5 # is the loss level that will bring
                             frequency down to 50.5 Hz.
for every event
   percentage at risk      # the precentage of event profile go beyong
                             largest securable loss 50.5
   event probability       # the probability of the event to occur
   residual risk for each event = percentage at risk * event probability

overall residual risk 50.5 = Σ (residual risk for each event)
```

9 Assessment – policy recommendations

9.1 Policy Options

Once the overall cost and overall residual risk are obtained for each proposed policy, conclusions can be drawn about the effectiveness of each proposed policy. This will enable the *Authority* to narrow down the options and identify the policy recommendations which brings appropriate balance between reliability and cost.

9.2 Main recommendations

An overall recommendation can then be made, on which set of controls represents the best balance between reliability and cost for the coming **Report** period, typically the coming year.

The **Report** will give:

- the policy for system-wide controls used,
- the expected total cost per year of all frequency controls, and
- the expected level of reliability achieved for each impact:

#	Deviation	Duration	Likelihood
H1	50.5 Hz < f	Any	*e.g. 1 in ___ years*
L1	49.2 Hz ≤ f < 49.5 Hz	60 seconds	*e.g. 1 in ___ years*
L2	48.8 Hz < f < 49.2 Hz	Any	*e.g. 1 in ___ years*
L3	47.8 Hz < f ≤ 48.8 Hz	Any	*e.g. 1 in ___ years*

The detailed version of the **Report** produced for the *Authority* will include further detailed information.

9.3 Other recommendations

There may be other, wider recommendations that can be made from the result of the **Report**, such as the delivery of new controls, network reinforcements and industry code changes, including any enduring modifications to the SQSS.

These wider recommendations will be highlighted by the **Report**.

10 Future considerations

There are a number of events, loss risks, impacts and controls which are not explicitly considered in this version of the **Methodology**. They could be prioritised for inclusion in future reports, based on consultation with the industry and the *Authority*.

The detailed list of future considerations can be found in the main **Report**.

11 Terms and Definitions

Ancillary Services	This means: (a) such services as any authorised electricity operator may be required to have available as Ancillary Services pursuant to the Grid Code; and (b) such services as any authorised electricity operator or person making transfers on external interconnections may have agreed to have available as being ancillary services pursuant to agreement made with NESO and which may be offered for purchase by NESO.
Authority	This means the Gas and Electricity Markets Authority established by section 1(1) of the Utilities Act 2000.
Balancing Mechanism	This is the mechanism for the making and acceptance of offers and bids pursuant to the arrangements contained in the Balancing and Settlement Code (BSC).
Busbar	The common connection point of two or more transmission circuits.
Double Circuit Overhead Line	In the case of the onshore transmission system, this is a transmission line which consists of two circuits sharing the same towers for at least one span in SHET's transmission system or NGET's transmission system or for at least 2 miles in SPT's transmission system. In the case of an offshore transmission system, this is a transmission line which consists of two circuits sharing the same towers for at least one span.
Fault outage	An outage of one or more items of primary transmission equipment and/or user equipment, which may or may not result in a loss of power infeed or loss of power outfeed, initiated by automatic action unplanned at that time, and which may or may not involve the passage of fault current.
Frequency Risk and Control Report (FRCR)	The periodic report setting out the results of an assessment of the operational frequency risks on the system produced by NGESO and approved by the Authority and as set out in the SQSS Appendix H, and prepared in accordance with the Frequency Risk and Control Report Methodology as also prepared and approved as set out in the SQSS Appendix H. The report shall include an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system and confirm which risks will or will not be secured operationally by NESO in accordance with paragraphs 5.8, 5.11.2, 9.2 and 9.4.2.

Loss of Power Infeed	The output of a generating unit or a group of generating units or the import from external systems disconnected from the national electricity transmission system by a secured event, less the demand disconnected from the national electricity transmission system by the same secured event. For the avoidance of doubt if, following such a secured event, demand associated with the normal operation of the affected generating unit or generating units is automatically transferred to a supply point which is not disconnected from the system, e.g. the station board, then this shall not be deducted from the total loss of power infeed to the system. For the purpose of the operational criteria: i) the loss of power infeed includes the output of a single generating unit, CCGT Module, boiler, nuclear reactor or import from an external system via a HVDC Link. ii) ii) In the case of an offshore generating unit or group of offshore generating units, the loss of power infeed is measured at the interface point, or user system interface point, as appropriate. iii) In the case of an offshore generating unit or group of offshore generating units for which infeed will be automatically re-distributed to one or more interface points or user system interface points through one or more interlinks, the re-distribution should be taken into account in determining the total generation capacity that is disconnected. However, in assessing this re-distribution, consequential losses of infeed that might occur in the re-distribution timescales due to wider generation instability or tripping, including losses at distribution voltage levels, should be taken into account.
Loss of Power Outfeed	The load taken by storage units, non-embedded customers, grid supply points, or the export to external systems disconnected from the national electricity transmission system by a secured event, less the generation disconnected from the national electricity transmission system by the same secured event. For the avoidance of doubt if, following such a secured event, demand associated with the normal operation of the affected outfeed is automatically transferred to a grid supply point which is not disconnected from the national electricity transmission system, then this shall not be added to the total loss of power outfeed to the system.

	For the purpose of the operational criteria: i) the loss of power outfeed includes demand from pump storage, battery storage and other storage, non-embedded customers, and export to external systems via a HVDC Link. ii) In the case of an offshore transmission system, the loss of power outfeed is measured at the interface point, or user system interface point, as appropriate.
National Energy System Operator (NESO)	The company with registered number 11014226 as the designated ISOP and holder of the ESO licence and the GSP licence.
National Electricity Transmission System (NETS)	The national electricity transmission system comprises the onshore transmission system and the offshore transmission systems.
Primary transmission equipment	Any equipment installed on the national electricity transmission system to enable bulk transfer of power. This will include transmission circuits, busbars, and switchgear.
Transmission circuit	This is either an onshore transmission circuit or an offshore transmission circuit.
Unacceptable frequency conditions	These are conditions where: i) the steady state frequency falls outside the statutory limits of 49.5Hz to 50.5Hz; or ii) a transient frequency deviation on the MITS does not meet the criteria below. Transient frequency deviations outside the limits of 49.5Hz and 50.5Hz shall: - only occur at intervals which ought to reasonably be considered as infrequent. - only persist for a duration which ought to reasonably be considered as tolerable; and - only deviate by a magnitude which ought to reasonably be considered as tolerable. The Frequency Risk and Control Report will define what is considered reasonable, infrequent and tolerable for each of these criteria for transient frequency deviations. It is not possible to be prescriptive with regard to the type of secured event which could lead to transient frequency deviations since this will depend on the extant frequency response characteristics of the system which NGESO adjust from time to time to meet the security and quality requirements of this Standard.