Security & Quality of Supply Standards

Frequency Risk and Control Report Methodology – 2020 v1

1. Executive Summary

The end consumer has two key objectives:

- a reliable supply of electricity
- at an affordable cost

There is a balance between those objectives:

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

These objectives are formalised through the Security and Quality of Supply Standards (SQSS), the *Frequency Risk and Control Report (FRCR)*, and *NGESO*'s transmission licence.

The aim of the *Frequency Risk and Control Report Methodology (methodology)* is to lay out a transparent and objective framework to determine the right balance between the two competing objectives of reliability and cost, focusing on the risks, impacts and controls for managing the frequency.

This *methodology* sets out the approach which will be used to complete the analysis required to produce the *FRCR*.

2. Contents

3. Aim

3.1. Role and Scope

3.1.1. What is the Frequency Risk and Control Report trying to achieve?

The end consumer has two key objectives:

- a reliable supply of electricity
- at an affordable cost

There is a balance between those objectives:

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

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The aim of the *Frequency Risk and Control Report methodology (methodology)* is to lay out a transparent and objective framework to determine the right balance between the two competing objectives of reliability and cost, focusing on the risks, impacts and controls for managing the frequency.

This *methodology* sets out the approach which will be used to complete the analysis required to produce the *FRCR*.

3.1.2. What is meant by "reliability"?

In the context of system frequency, the SQSS refers to *unacceptable frequency conditions* as a measure of reliability. The definition begins:

> ***Unacceptable frequency conditions***
>
> *These are conditions where:*
>
> - *the steady state frequency falls outside the statutory limits of 49.5Hz to 50.5Hz; or*
> - *a transient frequency deviation on the MITS which 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*
> - *only deviate by a magnitude which ought to reasonably be considered as tolerable.*
>
> *…*

"Reliability" encompasses whether transient frequency deviations are considered infrequent and tolerable. Whether frequency deviations are acceptable depends on the exact combination of these three factors: how often they occur, how long they last for, and how large they are, as each of these affects the impact of an event.

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

The SQSS definition of *unacceptable frequency conditions* therefore finishes with:

> *…*
>
> *The Frequency Risk and Control Report will define what is considered reasonable as infrequent and tolerable for each of these criteria for transient frequency deviations*

3.1.3. What drives direct costs?

NGESO use a set of *Ancillary Services* to control frequency deviations. Some are automatic, like response, and others are manually dispatched, like reserve, the Balancing Mechanism, services to increase the inertia, or services to pre-emptively decrease the size of potential losses. In this document, we refer to the *Ancillary Services* as "controls".

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

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

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

3.1.4. How to balance between reliability and cost?

The aim of the *methodology* is to lay out an objective and transparent framework for *NGESO* to assess risks associated with frequency deviations; the events which could cause them, their size, the impacts they have, and the cost and mix of controls to mitigate them. The assessment can then be used to determine the right balance between reliability and cost.

Consultation and ongoing engagement with industry stakeholders is key to achieving this in an open and transparent way: the role of *NGESO* is to analyse the risks, impacts and controls, their impact on reliability and cost, and present a recommendation for where the right balance might lie. This enables the *Authority* to make an informed decision on the right balance between reliability of electricity supplies and cost to end consumers. *NGESO* can then update their operational policies and procurement of controls to implement the outcome.

3.2. Key areas addressed in this edition

This first edition of the *FRCR* and *methodology* is focusing on the following key areas:

- establishing a clear, objective, transparent process for assessing reliability vs. cost
- making the assessment of the risk from the inadvertent operation of Loss of Mains protection transparent
- identifying quick, short-term improvements for reliability vs. cost, including the frequency standard that different size loss risks are held to

At the end of the report, the **8. Future considerations** section outlines opportunities to address other consideration in future editions of the *FRCR* and *methodology*.

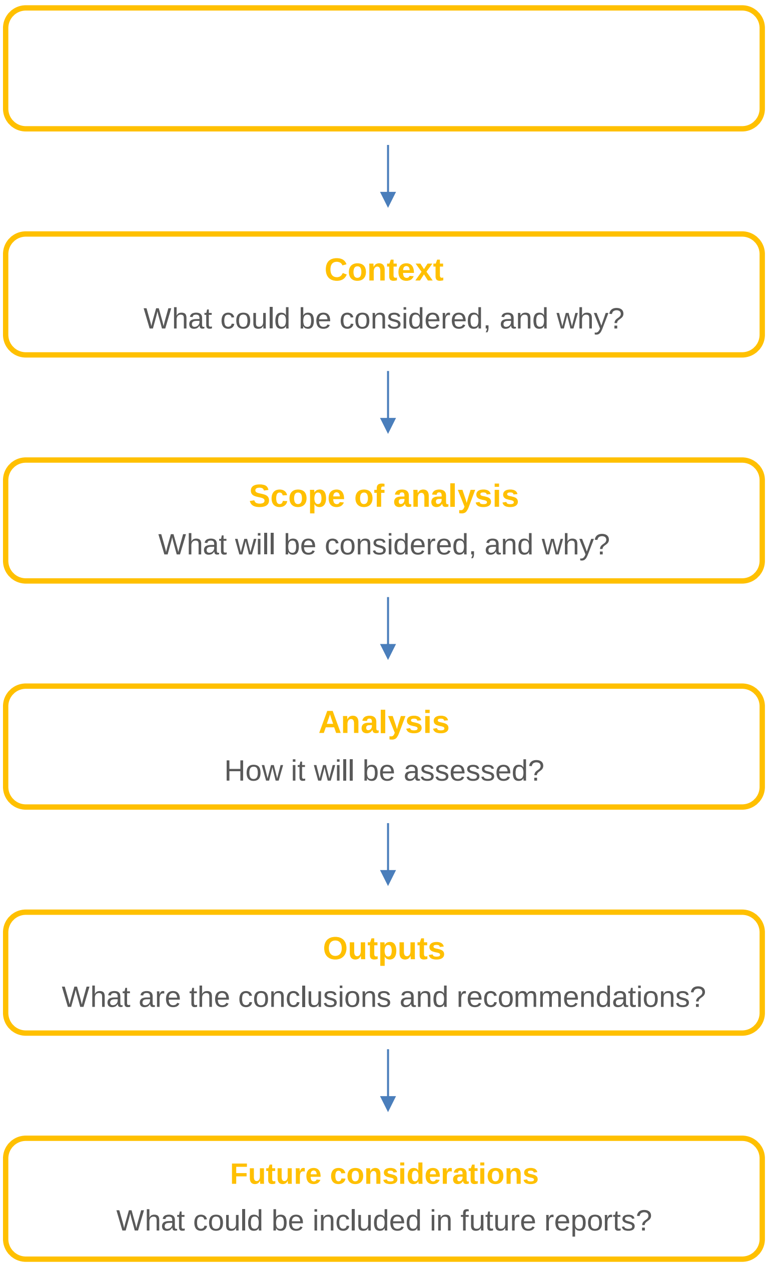
3.3. Structure of the report

3.3.1. Document structure

This document contains technical terms and phrases specific to *transmission systems* and the Electricity Supply Industry. The meaning of some terms or phrases in this document may also differ from this commonly used. For this reason, defined terms from the SQSS have been identified in the text using *blue italics*.

3.3.2. High-level overview

The *Frequency Risk and Control Report methodology* is structured as follows:



3.3.3. Section overview

Context

Events	how to select the events which will be assessed
Losses	how to select which losses will be assessed
Impact	how to decide relevant measures for *transient frequency deviations*: • how often they occur • how long they last for • how large they are
Controls	how to decide which control measures will be assessed
Reliability vs. cost	how to assess the risks, impacts and controls

Scope of analysis

Events and losses	which combination of events and losses will be assessed, and what information is needed to define them
Impact	which impacts will be assessed, and how
Controls	which combinations of controls will be assessed, and how
Other	any other assumptions that will feed in to the analysis

Analysis

Analysis	how the assessment of the risks, impact and controls will be done

Outputs

Conclusions	identifying key points and selecting which options give the best balance of reliability and cost
Main recommendation	which set of control measures should be adopted and which events should and should not be mitigated, to give the best balance of reliability and cost
Other recommendations	any other measures outside of the scope of the *Frequency Risk and Control Report* which could be adopted to improve reliably or lower cost e.g. code changes, new services, candidates for the Network Options Assessment

Future considerations

Future considerations	improvements that could be considered for future versions of the *methodology*

4. Context

This section sets out which events, impacts and controls could be assessed in the *Frequency Risk and Control Report*, and how reliability vs. cost and the treatment of DER is being formalised through the SQSS.

4.1. Events

This section sets out which events could be assessed in the *FRCR*.

4.1.1. What causes "transient frequency deviations"?

The frequency of the system will change:

- if generation exceeds demand, then the frequency will rise
- if demand exceeds generation, then the frequency will fall

The size of a frequency deviation is proportional to the size of the mismatch between generation and demand; bigger mismatches lead to bigger deviations.

Transient frequency deviations outside of *steady state frequency* limits only occur if a sufficiently large generation or large demand loss happens over very short timescales[1].

4.1.2. How to identify events that should be assessed?

The large generation and demand losses that lead to transient frequency deviations are generally caused by unplanned events such as *fault outages* on the *national electricity transmission system (NETS)*.

The most common examples of events that drive large changes in frequency are a large *loss of power infeed (infeed)*, such as an importing interconnector or a combined cycle gas turbine (CCGT), or a large *loss of power outfeed (outfeed)*, such as a pump storage unit[2], transmission-connected customer, or an exporting interconnector.

Consequential losses of other DER can also occur following *fault outages* on the *national electricity transmission system*. For example, some types of Loss of Mains (LoM) protection, either Rate of Change of Frequency (RoCoF) or Vector Shift (VS), have been observed to inadvertently operate and cause a loss of Distributed Energy Resources (DER) following events on the transmission system. These events can increase the total infeed or outfeed loss, and therefore affect the resulting frequency deviation.

Relevant events for which there is a known cause and effect will be assessed in the *FRCR*. In most cases these will be foreseen because of well understood features of plant and equipment performance, but, in some cases, they will need to be based on the observation of events that have already occurred.

[1] of the order of zero to sixty seconds

[2] while pumping

4.1.3. Transmission-connected events

The SQSS directly defines *secured events* on the *NETS*, both *onshore* and *offshore*, that should not cause *unacceptable frequency conditions*.

The causes of these transmission-connected events can be described as falling in to two categories: BMU faults, and transmission network faults.

4.1.3.1. BMU faults

These are *fault outages* of a particular *infeed* or *outfeed* that cause the associated generation (production) or demand (consumption) be disconnected from the *NETS*. Examples include CCGT modules, boilers, nuclear reactors, and interconnector imports and exports from *external systems*.

These are covered by the *single generating unit*, *single power park module*, *single DC converter*, *Loss of Power Infeed* and *Loss of Power Outfeed* criteria in the SQSS.

For the purpose of the *FRCR* these are collectively referred to as BMU[3] faults, in line with the Balancing and Settlement Code definitions.

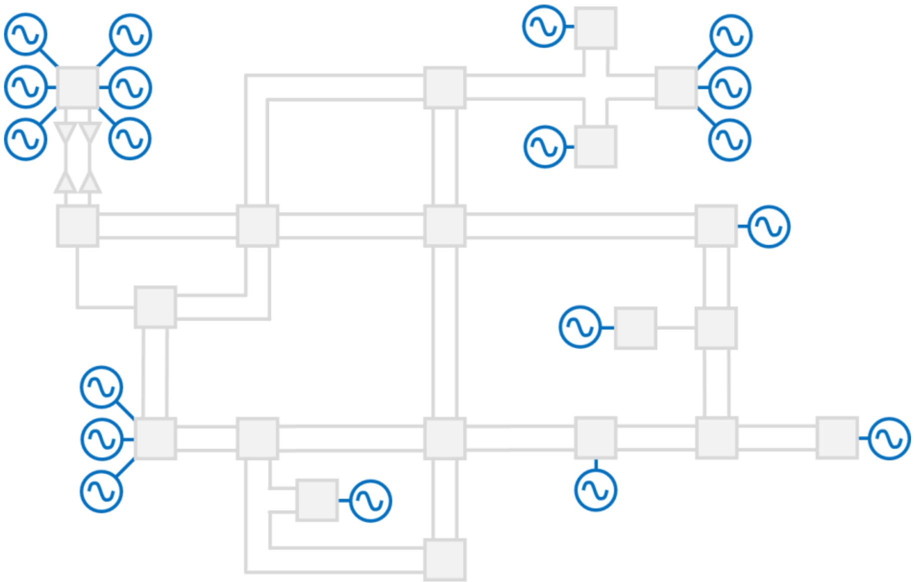


Figure 1 - potential BMU faults on an illustrative network

[3] https://www.elexon.co.uk/operations-settlement/balancing-mechanism-units/

4.1.3.2. Transmission network faults

These are *fault outages* on the *NETS* which can disconnect a particular BMU or group of BMU from the system due to the design of the network.

These are covered by the *single transmission circuit*, *single generation circuit*, *busbar / mesh corner* and *double circuit overhead line* criteria in the SQSS.

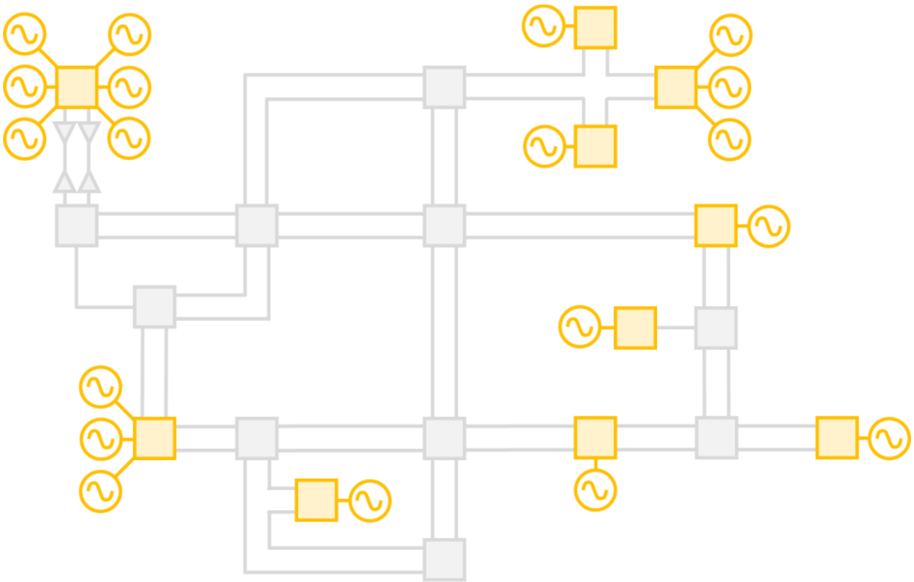


Figure 2 - potential busbar / mesh corner faults on an illustrative network

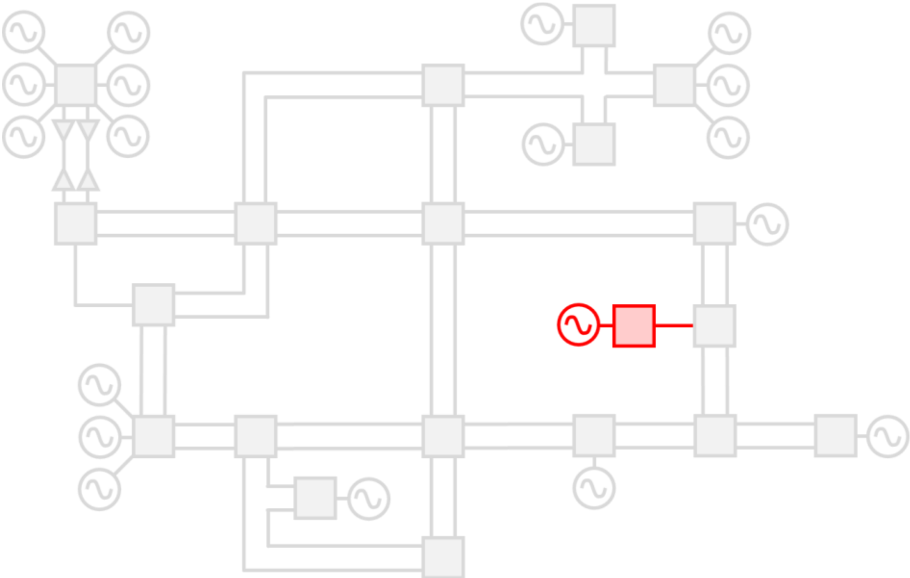


Figure 3 - potential single circuit faults on an illustrative network

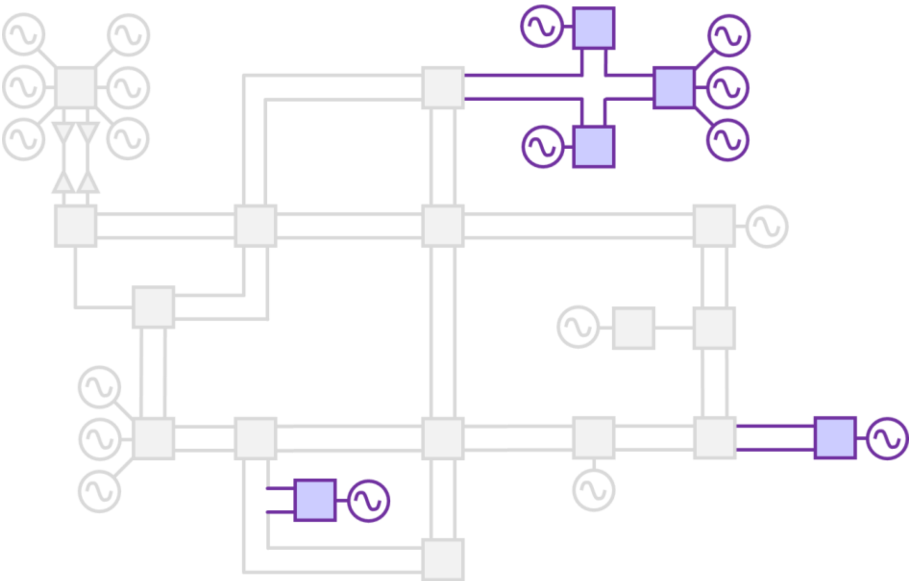


Figure 4 - potential double circuit faults on an illustrative network

4.2. Infeed and outfeed losses

This section sets out which *infeed* and *outfeed* losses could be assessed in the *FRCR*.

4.2.1. BMU losses

These are either:

- equipment failures within a BMU or group of BMUs, and affect only that BMU or group of BMUs.
- *fault outages* on the *NETS* which can disconnect a particular BMU or group of BMUs from the system due to the design of the network.

4.2.1.1. How big are the BMU loss sizes?

BMU loss sizes currently range from a few MW for the smallest *single generating unit* up to around 1400MW for the largest BMU group on a *double circuit overhead line*.

4.2.1.2. How likely are BMU losses?

There is a large range in the likelihood of these potential *infeed* and *outfeed* losses, from multiple times per year for a *single generating unit* or a *single DC converter* to one or twice per millennium for the shortest *double circuit overhead line* routes.

4.2.2. Distributed Energy Resources

Distributed Energy Resources (DERs) are a significant proportion of the generation feeding the electricity system, and so managing their loss and potential to cause or contribute to *unacceptable frequency conditions* has become important for the overall reliability of the electricity system.

The loss of one individual distribution-connected resource is unlikely to noticeably impact the frequency of the *NETS*. However, the inadvertent operation of some types of Loss of Mains (LoM) protection, either Rate of Change of Frequency or Vector Shift following events on the transmission system can cause the loss of multiple DERs, which can then cause a *transient frequency deviation*.

4.2.2.1. Why do we have Loss of Mains protection?

LoM protection is designed to prevent the formation of islanded networks following localised faults, and is a requirement of the Distribution Code and supporting recommendations for most small generators.

An islanded network is a section of network operating separately from the rest of the network, with its own demand, generation and frequency. This islanding could occur following a fault on the distribution network.

Islanded networks typically have an unstable frequency and alternating current (AC) waveforms, due to the potential for large mismatches between demand and generation and little to no inertia and response for damping. This gives rise to the possibility of equipment in the islanded network being damaged as it tries to stay connected to the rapidly changing frequency, or posing a danger to people who come across on unexpected live network.

It is possible that a stable island forms, if the demand and generation are matched closely enough. If this happens there is a risk of damage to equipment connected to the island, or that when a person comes to fix the initial fault that caused the island to separate, the network will still be live at one end and so pose an electrical danger to that person.

Loss of Mains protection seeks to detect a localised fault that may have led to islanding conditions, and quickly disconnects generation from the network. This prevents the island from forming, as there is no generation to sustain the demand, and removes the electrical risk to people and equipment.

4.2.2.2. How does Rate of Change of Frequency (RoCoF) protection work?

Islanded networks typically have large mismatches between demand and generation and little to no inertia and response for damping. This means that the frequency in an islanded network changes quickly.

RoCoF protection measures how quickly the frequency is changing; the Rate of Change of Frequency (RoCoF). If the RoCoF exceeds a pre-defined threshold for a certain duration then the protection will activate, disconnecting the generator from the network.

The most sensitive RoCoF protection on the GB system is set at 0.125Hz/s, with little to no minimum duration threshold.

There are further tranches of RoCoF relays at other thresholds, e.g. 0.2Hz/s, 0.5Hz/s and 1.0Hz/s, depending on manufacturer settings.

4.2.2.3. How does Vector Shift protection work?

When an electrical fault occurs, the phase angle between the voltage and current in the AC waveform can change significantly, by many degrees.

Vector Shift (VS) protection measures these phase angle changes. If the phase angle change exceeds a pre-defined threshold for a certain duration then the protection will activate, disconnecting the generator from the network.

The most sensitive Vector Shift protection on the GB system is set at six degrees, with no prescribed duration threshold.

4.2.2.4. Why has inadvertent tripping of DER become an issue?

Distributed Energy Resources now make up a significant proportion of the electricity generation feeding into the system. This significance, combined with risk inadvertent tripping of Loss of Mains protection, means there is a need to include DER in the list of events considered within *FRCR*.

RoCoF has become significant because of the decline in system inertia. Inertia is a measure of the stored energy in a system. This stored energy helps to resist and slow down changes in the frequency. The amount of inertia on the electricity transmission system depends on the level of demand and on the generation-mix that is meeting that demand[4].

The level of demand and inertia has decreased markedly over the last decade, as efficiency and environmental targets have led to wholesale change in the generation mix as Great Britain transitions to a low carbon economy.

When inertia is higher the Rate of Change of Frequency on the system following a large generation or demand losses would not exceed 0.125Hz/s, but as inertia has decreased, the same large generation or demand losses could now cause it to exceed 0.125Hz/s if not controlled.

RoCoF protection is now often unable to differentiate between localised events on the distribution networks, for which it should activate, and large events on the transmission network, for which it should not activate.

Vector Shift protection has similar issues with over-sensitivity, with faults on the transmission networks leading to large phase angle changes that propagate down into the distribution networks.

Vector Shift protection is now unable to differentiate between localised events on the distribution networks, for which it should activate, and large events on the transmission network, for which it should not activate.

[4] *see **4.4.4 Inertia** for more detail*

4.2.2.5. How big are consequential DER loss sizes?

A significant proportion of DER with RoCoF or Vector Shift protection is either wind or solar powered, and so its output changes with the prevailing weather conditions.

The RoCoF loss size does not vary with the location of the event as system frequency is the same across the transmission system[5].

The potential RoCoF loss sizes are forecast to be in the following range, depending on the weather conditions and resulting load factors of DER in that region:

Tranche	Threshold	Loss size
Tranche 1	0.125 Hz/s	250 – 750 MW
Tranche 2	0.200 Hz/s	200 – 625 MW

Table 1 – potential RoCoF loss sizes, as of August 2020

The Vector Shift loss size varies with the location of the event, as the topology of the transmission and distribution networks affects the propagation of the phase angle change.

Examples of the potential Vector Shift loss sizes are forecast to be in the following ranges, depending on the weather conditions and resulting load factors of DER in that region:

Location	Threshold	Loss size
Scotland	6 degrees	20 – 200 MW
South West England	6 degrees	100 – 600 MW
South and Central England	6 degrees	250 – 1000 MW

Table 2 - potential Vector Shift loss sizes, as of August 2020

[5] to a first approximation

4.2.2.6. How likely are consequential DER losses?

The likelihood of a consequential Loss of Mains loss depends on the likelihood of the preceding *fault outages* happening. This is because:

- For a RoCoF loss to happen there first needs to be a fast change in the frequency. This would be caused by a large, fast, *infeed* or *outfeed* loss during a low inertia period.

  The relationship between inertia, loss size and RoCoF is given by:

$$RoCoF\ [Hz/s] = \frac{50[Hz]}{2} \times \frac{loss\ size\ [MW]}{Inertia\ [MVA.s]}$$

  Table 3 shows how different loss sizes can reach the 0.125Hz/s threshold at different inertia levels. Table 4 shows how for the same loss size varying inertia at which the loss occurs will result in different RoCoFs.

Inertia	Loss size	Rate of Change of Frequency
140,000 MVA.s	700 MW	0.125 Hz/s
160,000 MVA.s	800 MW	0.125 Hz/s
180,000 MVA.s	900 MW	0.125 Hz/s
200,000 MVA.s	1000 MW	0.125 Hz/s

Table 3 - relationship between inertia, loss size and RoCoF

Inertia	Loss size	Rate of Change of Frequency
160,000 MVA.s	1000 MW	0.156 Hz/s
200,000 MVA.s	1000 MW	0.125 Hz/s
240,000 MVA.s	1000 MW	0.104 Hz/s

Table 4 - relationship between inertia, loss size and RoCoF

  Without control measures being used by *NGESO*, RoCoF losses could happen multiple times per year.

- For a Vector Shift loss to happen, there needs to be a sufficiently severe electrical fault, such as a phase-to-earth or phase-to-phase fault on an overhead line, cable circuit or busbar.
  These can occur multiple times per year, but the size of the loss varies as in Table 2. The size of the loss typically depends on the location of the fault, the DER output at the time and the impedance of the fault. The likelihood of the largest losses is of the order of once every few years to once every few decades.

4.2.3. Simultaneous events and losses

As identified above, events on the *NETS* may cause BMU losses, and/or consequential DER losses through inadvertent tripping of Loss of Mains protection.

It is important to clearly define which combinations of events and losses will be considered in this *methodology*.

This can be found in the **5.1 Events** section discusses which events, impacts and controls will be assessed in the *Frequency Risk and Control Report*.

Whether an event can cause some combination of BMU loss, VS loss or RoCoF loss depends on the exact nature of the event. For example:

- a single event of a network fault of a double circuit between two substations in a meshed area of the network should not cause a BMU loss, as it does not affect their connection, but could cause a VS loss, due to the electrical disturbance
- a single event of a network fault of a double-circuit on a radial area of the network which is also a BMU connection could cause both a BMU loss, and a VS loss
- each of the two scenarios above could lead to a consequential RoCoF loss, depending on the total size of the loss and the inertia on the system

4.3. Impact

This section sets out which impacts could be assessed in the *FRCR*.

4.3.1. SQSS definition

The SQSS definition of *unacceptable frequency conditions* states:

> *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*
> - *only deviate by a magnitude which ought to reasonably be considered as tolerable*

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

- interval ⇒ how infrequently they occur
- duration ⇒ how long they persist for
- magnitude ⇒ how far they deviate

4.3.2. Considerations

The impact of an event is a function of its duration, size and the conditions under which it occurs. Amongst other things, these affect automatic actions taken by equipment on the system, such as protection schemes, and the delivery of the **4.3.4 SQSS** implementation

To date *NGESO* has applied 49.2Hz as the lower bound for frequency following an *infeed* loss greater than 1000MW, 49.5Hz for an *infeed* loss less than or equal to 1000MW, and 50.5Hz for the upper bound of frequency following an *outfeed* loss.

These levels have been used to control how often *transient frequency deviations* occur in general, and to minimise the likelihood of LFDD.

4.3.3. System Operator Guideline

In 2017 the System Operator Guideline (commonly known as SOGL) enshrined the SQSS implementation of the frequency standards.

	CE	GB	IE/NI	Nordic
standard frequency range	± 50 mHz	± 200 mHz	± 200 mHz	± 100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1 000 mHz	1 000 mHz
maximum steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
frequency recovery range	not used	± 500 mHz	± 500 mHz	not used

time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	± 200 mHz	± 200 mHz	± 100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

Controls outlined below, as well as determining the consequences for the electricity system and its users as a whole.

One of the main considerations in this context are the requirements of the Grid Code, including Low Frequency Demand Disconnection (LFDD). Another is how often transient deviations happen at all, regardless of the size or duration.

Once relevant combinations of the duration and magnitude of deviations have been defined, we can establish what interval meets the third criteria of being “infrequent”.

4.3.4. Grid Code

4.3.4.1. What frequency ranges are prescribed in the Grid Code?

Section CC.6.1.3 of the Grid Code defines how long plant and apparatus is required to remain connected to the system as frequency moves between 47.0Hz and 52.0Hz:

- between 51.5Hz and 52.0Hz: for at least 15 minutes
- between 51.0Hz and 51.5Hz: for at least 90 minutes
- between 49.0Hz and 51.0Hz: continuous
- between 47.5Hz and 49.0Hz: for at least 90 minutes
- between 47.0Hz and 47.5Hz: for at least 20 seconds

However, there are other considerations which mean that using the full range of 47.0Hz to 52.0Hz is not likely to be acceptable.

4.3.4.2. Low Frequency Demand Disconnection

Low Frequency Demand Disconnection scheme is a set of automatic, frequency sensitive relays designed to disconnect bulk supply points in the DNO networks. The LFDD scheme to limit the fall in frequency of the electricity network during unusual events by disconnecting some electrical demand to ensure the protection of the whole system, but in doing so, some electricity consumers are exposed to the risk of temporary disconnection of their individual supply[6].

The LFDD scheme is managed by the distribution network operators (DNOs) in accordance with the requirements of the Grid Code. In designing their LFDD schemes DNO’s endeavour to ensure that disconnection is prioritised appropriately.

The first stage of LFDD is set at 48.8Hz, with eight further stages at intervals down to 47.8Hz.

[6] the precise levels of disconnection at different frequencies and in different geographic areas is defined in the Grid Code table CC.A.5.5.1a

4.3.5. SQSS implementation

To date *NGESO* has applied 49.2Hz as the lower bound for frequency following an *infeed* loss greater than 1000MW, 49.5Hz for an *infeed* loss less than or equal to 1000MW, and 50.5Hz for the upper bound of frequency following an *outfeed* loss.

These levels have been used to control how often *transient frequency deviations* occur in general, and to minimise the likelihood of LFDD.

4.3.6. System Operator Guideline

In 2017 the System Operator Guideline[7] (commonly known as SOGL) enshrined the SQSS implementation of the frequency standards[8].

	CE	GB	IE/NI	Nordic
standard frequency range	± 50 mHz	± 200 mHz	± 200 mHz	± 100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1 000 mHz	1 000 mHz
maximum steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
frequency recovery range	not used	± 500 mHz	± 500 mHz	not used
time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	± 200 mHz	± 200 mHz	± 100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

4.4. Controls

This section sets out which controls could be assessed in the *FRCR*. It includes controls which can prevent the occurrence of *transient frequency deviations* and controls which can reduce their size and duration (and hence impact).

4.4.1. Overview

There are four main ways of mitigating *transient frequency deviations*, split into two categories:

4.4.1.1. "Umbrella" controls

These controls affect all events, and so must be considered over the whole system:

Response
- arming additional response above typical levels

[7] Regulation EU 2017/1485 establishing a guideline on electricity transmission system operation

[8] Annex III Table 1 Frequency quality defining parameters of the synchronous areas

→ reduces the size of the frequency deviation

LoM loss size
- avoiding unintended tripping of DER

  → reduces the size of the frequency deviation

Inertia
- synchronising units with non-zero inertia

  → reduces the Rate of Change of Frequency following an event

  → allows response services more time to react

  → prevents the consequential loss of RoCoF generation

4.4.1.2. "Targeted" controls

These controls only affect one event, and so can be considered independently from each other:

BMU loss size
- reducing the size of individual *infeed* and *outfeed* losses:

  → reduces the size of the frequency deviation

  → reduces the Rate of Change of Frequency

  which:

  → allow response services more time to react

  → prevents the consequential loss of RoCoF generation

4.4.2. Response

4.4.2.1. Aim

The definition of *unacceptable frequency conditions* refers to *steady state frequency* (49.5Hz to 50.5Hz) and *transient frequency deviations* outside those limits.

To achieve this, *NGESO* aims to keep the frequency near to 50.0Hz most of the time; this is often called “pre-fault frequency” i.e. before an event has happened.

NGESO policy uses operational limits of 49.8Hz to 50.2Hz to manage the pre-fault frequency.

This means that when an event happens and causes a *transient frequency deviation*:

- frequency isn’t already close to the edge of the *steady state frequency* limits (49.5Hz to 50.5Hz)
- only a small amount of the response services will have been used to manage “pre-fault” frequency, so it is still available to manage the “post-fault” *transient frequency deviation*

NGESO currently procures two categories of response services;

- dynamic, which delivers proportionally to the frequency deviation
- Static, where full delivery is activated when a frequency threshold is passed

4.4.2.2. Strategy

NGESO meet the above aim through procurement of a variety of *Ancillary Services*, including dynamic and static response, reserve, bids and offers in the Balancing Mechanism, and trading.

All of these are part of controlling *steady state frequency* (keeping frequency near 50.0Hz), but the initial control of a *transient frequency deviation* is achieved with response.

Once the *transient frequency deviation* has been controlled and returned to the *steady state frequency* limits, the other services take over again.

4.4.2.3. Requirement

NGESO’s response requirements are split into two parts:

- pre-fault frequency – the minimum dynamic requirement
- post-fault frequency – the total requirement (including minimum dynamic)

The total response requirement changes with demand, inertia, the size of potential *infeed* and *outfeed* losses, and the combination of response services that are procured.

Larger losses	• bigger frequency deviations ⇒ more response required • higher Rate of Change of Frequency ⇒ faster acting response required
Lower demand	• demand changes by 2.5% per Hz with the frequency, assisting with the control of frequency deviations → lower demand means this effect is lessened ⇒ greater quantity of response required
Lower inertia	• higher Rate of change of Frequency ⇒ faster acting response required
Combination of response services	• high proportion of slow response services ⇒ more required → as each provider will only partly deliver in time for faster frequency deviations • too much static response can "overreact" to medium-sized events, as it does not deliver proportionally to the frequency deviation, and so can cause its own frequency deviation in the opposite direction

4.4.2.4. Services

The response requirements are currently met through a variety of services, including: Primary, Secondary and High dynamic, Enhanced Frequency Response, secondary-only static, Low Frequency Static, and Dynamic Low High.

These services have large overlaps in meeting the pre-fault and post-fault requirement, and are not well suited to meet the future operability challenges of lower inertia, lower demand and larger losses.

This is a key driver for *NGESO* transitioning to a new set of response services, such as Dynamic Containment which is designed for controlling *transient frequency deviations*.

4.4.2.5. Procurement

The baseline, firm requirement for response is procured through tenders and auctions ahead of real-time. Any additional, variable need is currently met through optional services and the mandatory market, as *NGESO* transition to closer to real-time procurement and the new response service suite.

4.4.2.6. Review

The requirements, controls and procurement are reviewed on a regular basis to determine the best approach, so any change in policy resulting from the *Frequency Risk and Control Report* will feed back in to this cycle.

4.4.3. Loss of Mains loss size

4.4.3.1. Background

A series of Grid Code and Distribution Code modifications have sought to address the inadvertent tripping of DER due to Loss of Mains protection.

Grid Code modification GC0035

The first of these modifications, Grid Code modification GC0035, was approved by Ofgem in 2014 and addressed the inadvertent tripping of RoCoF for generation capacity over 5MW.

The implementation of GC0035 was successfully completed in 2018, but left a remaining RoCoF risk for capacity under 5MW.

In this period, the inadvertent tripping of Vector Shift arose as a new issue on the system.

Distribution Code modification DC0079

The second series of these modifications, Distribution Code modification DC0079, addressed both Vector Shift (all capacities) and the remaining RoCoF capacity less than 5MW.

The deadline for compliance with the retrospective requirements of DC0079 is 01 September 2022.

Once DC0079 has been successfully implemented, the threshold for triggering the consequential loss of RoCoF protection will rise to 1.0 Hz/s (sustained over 500ms) and no generation will be allowed to use Vector Shift protection.

This will significantly reduce the risk associated with *transient frequency deviations* due to the consequential loss of DER.

4.4.3.2. Interim controls

Until the successful implementation of DC0079, there are two main options for reducing the Loss of Mains loss size:

Change LoM relay settings	• prevent the inadvertent trip of Loss of Mains protection by changing the relay settings • this is a one-off fix; when the relay settings are changed the risk of inadvertent tripping for the affected equipment is eliminated[9]
Curtail LoM output	• curtail the output of DER which could inadvertently trip through Loss of Mains protection, to reduce the loss size • this would have to be done on an enduring basis, until the relay settings are changed

[9] at 1.0 Hz/s the frequency would deviate outside of *statutory limits* within 0.5 seconds, meaning that response services would not have enough time to control *transient frequency deviations*. As such, there is no expectation to allow frequency changes to exceed this new Loss of Mains protection threshold.

4.4.3.3. Change LoM relay settings

The Accelerated Loss of Mains Change Programme (ALoMCP) aims to bring forward the date of full implementation of DC0079 by providing a financial incentive to DER at risk of inadvertent tripping due to LoM protection to change their relay or relay settings ahead of the 01 September 2022 deadline.

This aims to reduce the quantity of controls[10] and amount of time that *NGESO* uses them, reducing costs overall for the end consumer. It should be noted that this saving is only fully realised on completion of the project.

The main programme is run in quarterly windows, with applications from generators processed by DNOs and assessed by *NGESO*. Once accepted, successful applicants then deliver their relay changes in the agreed timescale. The maximum delivery lead time is 9 months, but most are within 3 months. The DNOs then perform validation checks that the work has been carried out successfully, and *NGESO* are notified to allow them to update their assumptions of the remaining capacity at risk of inadvertent tripping.

The Fast Track programme looks to further accelerate this for the highest value relay changes. It follows the same outline process as the main programme and condenses the timescale from months to weeks.

As a rolling programme, at any point in time there are many applicants at various stages of the process from application through to delivery and validation.

The *Frequency Risk and Control Report* analysis will need to make an assumption about future delivery under the ALoMCP, both of in-train applications and future applications, from those affected DER who have not yet stepped forwards.

4.4.3.4. Curtail LoM output

NGESO have not followed this option to date, for the following reasons:

Does not address the root cause	• curtailment actions would need to be taken on an enduring basis, costing consumers for a long period of time until the relay setting is changed
Ineffective	• doing only a small proportion of the capacity at risk doesn't solve the problem, as the remaining Loss of Mains loss size would still be large enough to cause a big frequency deviation • *NGESO* would still have to take the same actions for the other response, inertia and BMU loss size control, so it would not offset existing costs, and would incur more on top • *NGESO* would have to curtail most or all the affected capacity to have a material impact; this would represent a large cost to end consumers, and impose a large distortion to the energy market
Visibility	• *NGESO* don't have visibility of the affected parties to set up the arrangements with them

[10] inertia, response and BMU loss size

4.4.4. Inertia

4.4.4.1. What is inertia?

Inertia is a measure of the stored energy in a system. This stored energy helps to resist and slow down changes in the frequency.

4.4.4.2. What affects the amount of inertia on the system?

The amount of inertia on the electricity transmission system depends on the level of demand and on the generation mix that is meeting that demand.

All AC-connected synchronous generation has some level of inertia associated with it, from the rotating machinery that is producing the electricity. This includes biomass, CCGTs, coal, hydro, nuclear, and pump storage.

Other types of generation, connected through converters, traditionally do not have inertia associated with them. This includes renewables like wind and solar, and HVDC interconnectors to other countries. Renewable generation is often at the top of the merit order to run, due to environmental incentives, and interconnector imports are expected when the price in other markets is lower than in GB.

Some sources of demand and some DER also have some level of inertia associated with them. These are also considered in calculating the inertia of the system.

Finally, *NGESO* have access to additional inertia through firm and optional contracts with providers, through programmes like Stability Pathfinder Phase 1.

4.4.4.3. When do low and high inertia periods occur?

During low demand periods, like the summer minimum or the reduced demand levels during the initial COVID-19 restrictions of 2020, zero-inertia generation is theoretically able to meet a large proportion of demand, and there is little self-dispatch of non-nuclear synchronous generation with inertia.

Low inertia therefore correlates with low demand, high renewable output, and interconnector imports.

During high demand periods, like winter peak, more generation runs to meet the demand. As there is currently insufficient renewable and interconnector capacity to meet the high demand level, a higher proportion of the generation mix has inertia associated with it, as other fuel types have to run.

High inertia therefore currently correlates with high demand, low renewable output, and interconnector exports.

The following figure illustrates this correlation of demand and inertia, with the width of the scatter plot due to different levels of renewable outputs and interconnector flows.

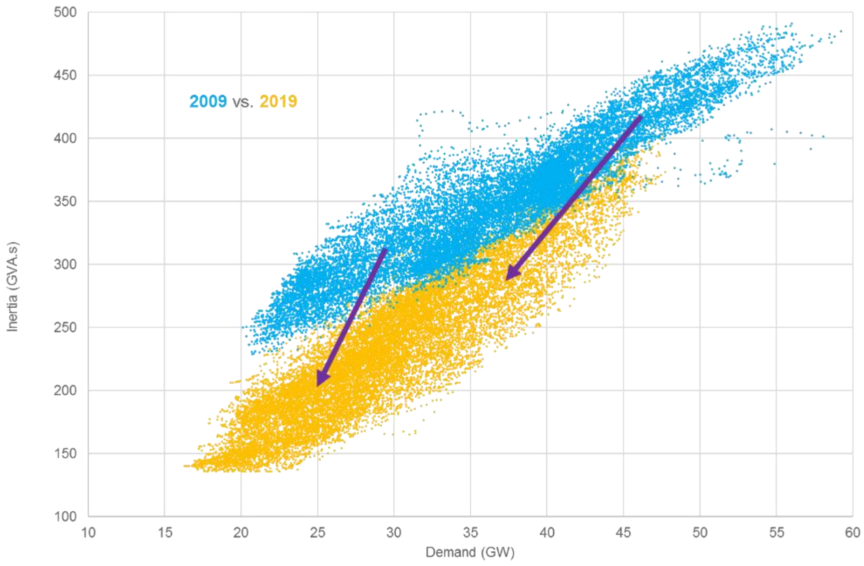


Figure 5 - Inertia vs. demand for 2009 vs. 2019

4.4.4.4. How to identify the need for additional inertia?

NGESO's forecast of the demand, the market position and Physical Notifications of the expected running of each BMU, and any inertia contracts it has, allows them to estimate the level of inertia that will be on the system.

If this is below required levels (see **5.3 Controls**), then they will take actions to increase the inertia of the system.

4.4.4.5. How to increase the inertia?

NGESO traditionally increases the inertia of the system by running synchronous units (BMUs) which provide inertia that would otherwise not be running.

This means that they have to buy energy in order to access inertia.

Each BMU comes with:

- a different amount of inertia, set by its electromechanical properties
- a different amount of energy, set by its Stable Export Limit[11]
- a different price for the energy, set by its offer price

Any additional energy that gets bought as a by-product of increasing the inertia must be balanced out with a corresponding quantity of bids (assuming that the market closes balanced, per the cash out incentive).

NGESO must also meet its negative reserve requirements, for real-time management of the frequency within *steady state limits*.

These bids are therefore mostly taken on BMUs which do not provide inertia, to avoid undermining the initial action to increase inertia and to maintain the negative reserve requirement.

[11] the Stable Export Limit, or SEL, is the minimum power level a BMU can operate at continuously

Typically, the bid prices of each fuel type put interconnector bids in merit first, mostly via trades, followed by renewables bids in the Balancing Mechanism.

Further actions are considered as a last resort, for example:

Optional Downward Flexibility Market	implemented as a time-limited measure[12] in 2020, because of the low demand levels bought about by the COVID-19 restrictions
System warnings	such as Negative Reserve Active Power Margin notices, designed to stimulate access to additional downwards flexibility

The optimisation of which BMU to synchronise for inertia must therefore maximise the inertia added whilst minimising the additional energy and associated cost.

Zero-megawatt and minimal-megawatt inertia services through Stability Pathfinder[13] and super-SEL contracts are aiming to reduce the cost and market impact of controlling inertia, by reducing or eliminating the energy component.

4.4.5. BMU loss size

Reducing the size of individual *infeed* and *outfeed* losses:

- reduces the size of the frequency deviation
- reduces the Rate of Change of Frequency

which in turn:

- allows response services more time to react
- prevents the consequential loss of RoCoF generation

This is achieved by taking bids or offers on individual large *infeed* and *outfeed* loss risks to decrease their size. This can be done through the Balancing Mechanism, trading or contracts.

[12] expires 25 October 2020

[13] such as synchronous compensators

4.5. Reliability vs. cost

This section sets out the principles for assessing reliability vs. cost in the *FRCR*.

4.5.1. What principles can be applied?

At its simplest, for each level of impact:

- good value risks are likely to be those which are low cost to mitigate, are likely to occur, or which have a large impact
- poor value risks are likely to be those which are 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 events in isolation. Instead, the assessment must look at the total risk and total cost across all events.

4.5.2. Treatment of risks from DER

New clauses have been added to the SQSS which give effect to a periodic assessment of the balance between reliability and cost in avoiding *unacceptable frequency conditions* and capture the need to deal with risks associated with DER.

In section “5. Operation of the Onshore Transmission System” these clauses are:

5.8 NGESO shall use the latest version of the Frequency Risk and Control Report to determine the additional events for which unacceptable frequency conditions shall not occur, including the consequential losses of distribution connected resources for events secured under sections 5.1 and 5.3 of this condition.

and

5.11 Exceptions to the criteria in paragraphs 5.1 to 5.8 may be required:

...

5.11.2 in relation to 5.1.7 and 5.3.4 only, based on the latest approved version of the Frequency Risk and Control Report

The equivalent clauses have been added to 9.2 and 9.4.2 of the Operation of an Offshore Transmission system.

These clauses capture the need to consider the explicit impacts of DER on the required level of security, and whether it is appropriate to provide flexibility in the requirements for securing against risk events with a very low likelihood, for example on a cost / risk basis.

This is achieved through the *Frequency Risk and Control Report*, which itself provides the appropriate channels for industry consultation and transparency, and a decision by the *Authority*.

4.5.3. What metrics can be applied?

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. Once the industry has decided on these metrics, they can be overlaid on the results of the analysis to help inform the recommendation.

4.5.3.1. Limit on total cost per year

Total balancing costs for 2019/20[14] across all categories were £1,322 million, of which £616 million was spent on controls for managing the frequency (reserve, response, inertia and Loss of Mains risks), although a portion of this is for pre-fault rather than post-fault frequency.

The industry may choose to defined an upper limit or guide on the total cost of controls for managing frequency.

4.5.3.2. Limit on how often each impact is expected occur

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 privatisation in the 1990s.

Frequency has rarely gone outside of statutory limits in recent years, due to the frequent curtailment of *infeed* and *outfeed* losses to control against the risk of a consequential RoCoF loss. In preceding years, the consultation for SQSS modification GSR015 made reference to a "historic rate of four times per year"[15].

The industry may choose to defined an upper limit or guide on how often each impact could be accepted to occur.

4.5.3.3. Cost value per avoided occurrence

The industry might choose 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."[16]

This works well for short-term decision making, and for setting the Reserve Scarcity Price.

However, the relatively short-duration of LFDD events and the relatively 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 *FRCR*:

- 1hr of demand disruption x 5% LFDD stage 1 x 20GW demand x £6,000 / MWh VoLL = £6m per event
- at a rate of one-in-ten years for LFDD, that would equate to a limit of £600k total cost per year (compared to £616m for 2019/20 as noted above).

A new, specific VoLL could be used to set a cost value per avoided occurrence for the *FRCR*, in addition to or instead of the other example metrics above.

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[14] https://data.nationalgrideso.com/balancing/mbss → March 2020

[15] https://www.nationalgrideso.com/document/15131/download

[16] https://www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gbpdf

5. Scope of analysis

This section sets out which events, impacts and controls will be assessed in the *Frequency Risk and Control Report*.

5.1. Events and losses

This section sets out which events will be assessed in the *Frequency Risk and Control Report*.

5.1.1. Which events will be considered?

As noted in **4.1 Events**, there are two categories of events to consider:

BMU faults
- these are faults inside a particular BMU, or particular group of BMUs, that cause the associated *infeed* or *outfeed* to be disconnected from the system.

Network faults
- these are faults on the *National Electricity Transmission System* which can disconnect a particular BMU or group of BMUs from the system due to the design of the network.

5.1.2. Simultaneous events and losses

The *FRCR* will only consider one event at a time, but will consider the combined loss of BMU and DER where there is an expected link between cause and effect.

As noted in **5.3.1 Which controls work for which event categories?** the size of the largest losses is too large to control with current response services, due to their technical specification. For this reason, securing simultaneous, independent events is often technically infeasible with current response services.

New response services will provide more capability to control larger losses. As the services come on line, future versions of the *FRCR* will be able to consider the value of securing against simultaneous, independent events.

5.1.3. Which combinations of losses will be considered?

The *Frequency Risk and Control Report* will consider the following combinations of losses:

BMU-only loss	an event which only disconnects one or more BMUs as described in the Transmission-connected events section (no Vector Shift loss)
VS-only loss	an event which only disconnects Vector Shift (no BMU loss)
BMU+VS loss	a combination of the two events above

and each of these causing the consequential loss of:

RoCoF tranche 1	Loss of Mains RoCoF capacity set at 0.125Hz/s
RoCoF tranche 2	Loss of Mains RoCoF capacity set at 0.200Hz/s

5.1.3.1. Combinations of events and losses

The following combinations[17] have a known link between cause and effect, and so will be considered.

Event	→	BMU loss				
Event	→			VS loss		
Event	→	BMU loss	+	VS loss		
Event	→	BMU loss			→	RoCoF loss
Event	→			VS loss	→	RoCoF loss
Event	→	BMU loss	+	VS loss	→	RoCoF loss

The following combination does not have a known link between cause and effect and so will not be considered, as you must have an initial BMU and/or VS loss to cause a high rate of change of frequency, which then causes the consequential RoCoF loss.

Event		→	RoCoF loss

[17] where the symbols mean:

a → **b**	means **a** causes **b**
c + **d**	means both **c** and **d** together

*NB: potential developments for future versions of the Frequency Risk and Control Report are listed in **8 Future considerations**.*

5.1.4. Required information

The following information is needed to define the events:

5.1.4.1. General

Network
- topology*
- fault probability for each type of network equipment
  → busbars / mesh corners
  → single circuit (per km route length)
  → double circuit (per km route length)

BMU
- BMU fault probability (per fuel type)

* *to determine faults on the National Electricity Transmission System which can disconnect a particular BMU or group of BMUs from the system due to the design of the network*

5.1.4.2. Per event

Event category
- BMU-only event
- VS-only event
- BMU + VS event

List of affected BMU(s)
- which BMU(s) are associated with the event

Per affected BMU
- umbrella control constraints
  → Sterilised inertia
- targeted control constraints
  → Stable Export Limit
  → bid / offer price
  → fuel-type
  → must run?
- probability of fault
  → fuel-type

Vector Shift node
- which forecast network node is associated with the event

Network
- associated equipment
  → busbars / mesh corners
  → single circuit route length
  → double circuit route length

Probability of event
- calculated from the “General” and “Per event” data

5.2. Impact

This section sets out which impacts will be assessed in the *Frequency Risk and Control Report*.

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
- interval ⇒ how infrequently they occur

Once combinations of the duration and size of deviations have been defined, it can be established what interval meets the third criteria of being “infrequent”.

One of the main considerations in this context is the Low Frequency Demand Disconnection scheme. Another is how often transient deviations happen at all, regardless of the size or duration.

The *Frequency Risk and Control Report* will assess three levels of impact, to cover these considerations and allow comparison to historic performance:

#	Deviation	Duration	Relevance
H1	50.5 < Hz	Any	• Above current SQSS implementation • Plant performance less certain
L1	49.2 ≤ Hz < 49.5	60 seconds	• Current SQSS implementation[18] • Infrequent occurrence, but reasonable certainty over plant performance
L2	48.8 < Hz < 49.2	Any	• Beyond current SQSS implementation and SOGL, but without triggering LFDD • Plant performance less certain
L3	47.75 < Hz ≤ 48.8	Any	• First stage of Low Frequency Demand Disconnection

Table 5 - Impacts to be assessed

The main focus of this edition of the *Frequency Risk and Control Report* is events causing low frequency; future editions may look in more detail at high frequency.

[18] The current implementation of a 0.8Hz max deviation was also written in to the System Operator Guidelines (SOGL)

5.3. Controls

This section sets out which controls will be assessed in the *Frequency Risk and Control Report*.

5.3.1. Which controls work for which event categories?

The effectiveness of each of the controls depends on the category of event they are being applied to. In the following tables, **green** indicates an **effective control**, **amber** indicated a **moderately effective control**, and **red** indicates a control with **limited to no effectiveness**.

NB: at the time of writing Dynamic Containment is under consultation, with first procurement expected in October 2020. As the supply of Dynamic Containment increases, the "response" control listed in each section below will become more and more effective.

5.3.1.1. BMU-only events

In order from most effective to least effective control:

G	**BMU loss size**	• effective for large, flexible BMUs → there are relatively few of these, so it is cheaper to reduce the loss size of a small number of units than it is to increase inertia or response
G	**Inertia**	• effective for medium-sized, inflexible BMUs
A	**LoM loss size**	• reduces the size of the RoCoF loss over the long-term, making response a feasible control option
R	**Response**	• the size of the largest BMU + RoCoF loss is too large to control with current response services, due to their technical specification

5.3.1.2. VS-only events

In order from most effective to least effective control:

G	**Inertia**	• so that the VS-only loss cannot cause a high enough rate of change of frequency to trigger a RoCoF loss → it can be expensive to sufficiently increase inertia and find the required footroom during the most challenging low demand, low inertia periods
A	**LoM loss size**	• reduces the VS-only loss to reduce the inertia requirement • reduces the size of the RoCoF loss over the long-term, making response a feasible control option
R	**Response**	• at the times where VS-only losses are a risk, the size of the largest VS loss + RoCoF loss is too large to control with current response services due to their technical specification
n/a	**BMU loss size**	• not applicable for a VS-only event

5.3.1.3. BMU+VS events

Due to the size of these events, they are the most difficult to manage. In order from most effective to least effective control:

A	**BMU loss size**	• often need to fully de-synchronise a BMU to achieve a sufficient reduction → this can interact with other requirements like voltage, inertia, and positive and negative reserve
A	**Inertia**	• so that the combined BMU+VS loss cannot cause a high enough rate of change of frequency to trigger a RoCoF loss → it can be expensive to sufficiently increase inertia and find the required footroom during the most challenging low demand, low inertia periods
A	**LoM loss size**	• reduces the size of the Vector Shift loss over the long-term, reducing the inertia requirement • reduces the size of the RoCoF loss over the long-term, making response a feasible control option
R	**Response**	• the size of the largest BMU + VS + RoCoF loss is too large to control with current response services due to their technical specification

5.3.2. How do you baseline the FRCR assessment?

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

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

5.3.3. What is current operational practice?

5.3.3.1. Inertia

NGESO's current policies for controlling inertia are:

Minimum inertia

- system inertia is maintained at or above 140 GVA.s
  → this is to control BMU-only events for medium-sized, inflexible BMUs

Inertia to control VS-only events

- system inertia is maintained at or above the level that will prevent the largest VS-only loss from causing a consequential RoCoF loss
  → this is to control the largest VS-only events

5.3.3.2. BMU loss size

NGESO's current policies for controlling BMU loss size are:

Infeed losses

- do not let BMU-only *infeed* losses cause a consequential RoCoF loss, by taking bids to reduce the *infeed* loss
  → this is to control BMU-only events, e.g. large, flexible BMUs

Outfeed losses

- consider letting BMU-only *outfeed* losses cause a consequential RoCoF loss, as the two will partially offset each other
  → this is only permissible if the resulting high and/or low frequency deviations are controllable
    → if not, then do not let BMU-only *outfeed* losses cause a consequential RoCoF loss, by taking offers to reduce the demand loss

5.3.3.3. Response

NGESO's current policies for controlling response are:

Infeed losses ≤ 1000MW	• prevent BMU-only and VS-only *infeed* losses ≤ 1000MW causing a frequency deviation below 49.5Hz
Infeed losses > 1000MW	• prevent BMU-only and VS-only *infeed* losses > 1000MW causing a frequency deviation below 49.2Hz • practically, 1260MW is typically the largest *infeed* loss that is secured.
Demand losses	• prevent all BMU-only *outfeed* losses causing a frequency deviation above 50.5Hz • VS-only losses can't cause an *outfeed* loss

5.3.3.4. Loss of Mains loss size

Accelerated Loss of Mains Change Programme	• regular updates from DNO on relay change progress • update operational tools with latest programme delivery, as a reduction against the initial baseline capacity estimate at the start of the programme

5.3.4. What variations will be considered?

The *Frequency Risk and Control Report* will look at variations to current operational policy for applying each of the controls, whether more, the same or less of each.

For the “umbrella” controls of inertia, response and LoM loss size, these variations will apply to the analysis of all events. Section **6 Analysis** refers to the different permutations of these controls as the “umbrella scenario”.

For the “targeted” control of BMU loss size, the **6 Analysis** will look at each event individually, to assess the additional cost of taking the control action, and the reduction in risk exposure it achieves.

The **7 Outputs** section will then address which combination of “umbrella” controls and which of the individual targeted controls should and should not be applied to achieve the right balance between reliability and cost.

5.3.4.1. Minimum inertia

Lower
- 112 GVA.s – equivalent to 560MW[19] instantaneous loss at 0.125 Hz/s

Same
- 140 GVA.s – equivalent to 700MW instantaneous loss at 0.125 Hz/s

More
- 160 GVA.s – equivalent to 800MW instantaneous loss at 0.125 Hz/s

5.3.4.2. Inertia to control VS-only events

Lower
- do not take actions to ensure system inertia is maintained at or above the level that will prevent the largest VS-only loss from causing a consequential RoCoF loss

Same
- do take actions to ensure system inertia is maintained at or above the level that will prevent the largest VS-only loss from causing a consequential RoCoF loss

5.3.4.3. Response

Lower
- *outfeed* losses of all sizes contained to 50.8Hz (bigger deviation)
- *infeed* losses ≤ 1260MW contained to 49.2Hz (bigger deviation)

Same
- *outfeed* losses of all sizes contained to 50.5Hz
- *infeed* losses ≤ 1000MW contained to 49.5Hz
- *infeed* losses ≤ 1260MW contained to 49.2Hz

More
- *outfeed* losses of all sizes contained to 50.5Hz
- *infeed* losses ≤ 1500MW contained to 49.2Hz (larger loss)

[19] many SGT demand connections have the potential to lose 560MW in certain circumstances

5.3.4.4. Loss of Mains loss size

Same

- as there is less opportunity to forecast and influence the ALoMCP delivery, and to limit the number of permutations to a reasonable number, a single Loss of Mains loss size scenario will be considered for this first version of the *Frequency Risk and Control Report*
  - → future versions of the report could include variations of the Loss of Mains loss size, to demonstrate the value of the Accelerated Loss of Mains Change Programme, see **8 Future considerations**
  - → alternatively, the ALoMCP could use the *FRCR* process for independent benchmarking of value delivery

5.3.4.5. BMU loss size

This targeted control will be applied and not applied to each individual event, to understand the individual cost-risk value of mitigating each.

This makes it difficult to define whether the result would be classed as “lower”, “same” or “more”, as it is likely to be a blend of these for different event categories.

However, two key examples of what would fit in to the “lower” and “more” categories are:

Lower

- consider not mitigating some BMU-only events

More

- consider mitigating some BMU+VS events

5.3.4.6. Permutations

The proposal gives twelve permutations of the “umbrella” controls, each of which will have its own analysis of applying targeted controls to each of the individual events.

This tries to balance having enough analysis to make an informed decision and not being overwhelmed with options, which risks overcomplicating the recommendation.

5.4. Other assumptions

This section sets out other relevant assumptions for the *Frequency Risk and Control Report*.

5.4.1. Data set

5.4.1.1. Historic vs. forecast

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

The electricity industry is in a period of rapid change, with significant changes year-to-year in many of the key inputs to the report. To isolate the reliability vs. cost decisions from the impact of these wider changes, the analysis should look at a historic scenario and a forecast.

The historic scenario will provide an understanding of the impact of a decision relative to a known, certain outturn that has already happened. The forecast will provide an understating of how a decision is likely to play out against known or expected changes in the near future.

5.4.1.2. 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.

A 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.

To overcome this, the analysis will assess a whole year at Settlement Period granularity.

5.4.2. Baseline system conditions

As indicated above many of the key inputs, like demand, inertia, BMU loss size, LoM loss size, and response holding, vary markedly with time; hourly, daily, weekly and seasonally.

These are the baseline system conditions against which the different control scenarios will be assessed.

5.4.3. Cost of mitigations

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

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

6. Analysis

This section sets out how the events, impacts and controls will be assessed in the *Frequency Risk and Control Report*.

6.1. Overview

Setup	• Setup • Define risks
For each "umbrella" scenario	• Apply “umbrella” controls → Determine required actions → Calculate cost of actions → Calculate loss sizes → Calculate baseline risk • Apply “targeted” controls → Determine required actions → Calculate cost of actions → Calculate residual risk → Calculate risk reduction • Determine overall cost vs. risk vs. impact curve for the “umbrella” scenario

6.2. Setup

6.2.1. Define events

The first step is to define the detail of each of the events that will be assessed, as outline in **5.1 Events**.

The dependency diagram below illustrates how the different inputs link together to calculate the probability of each event.

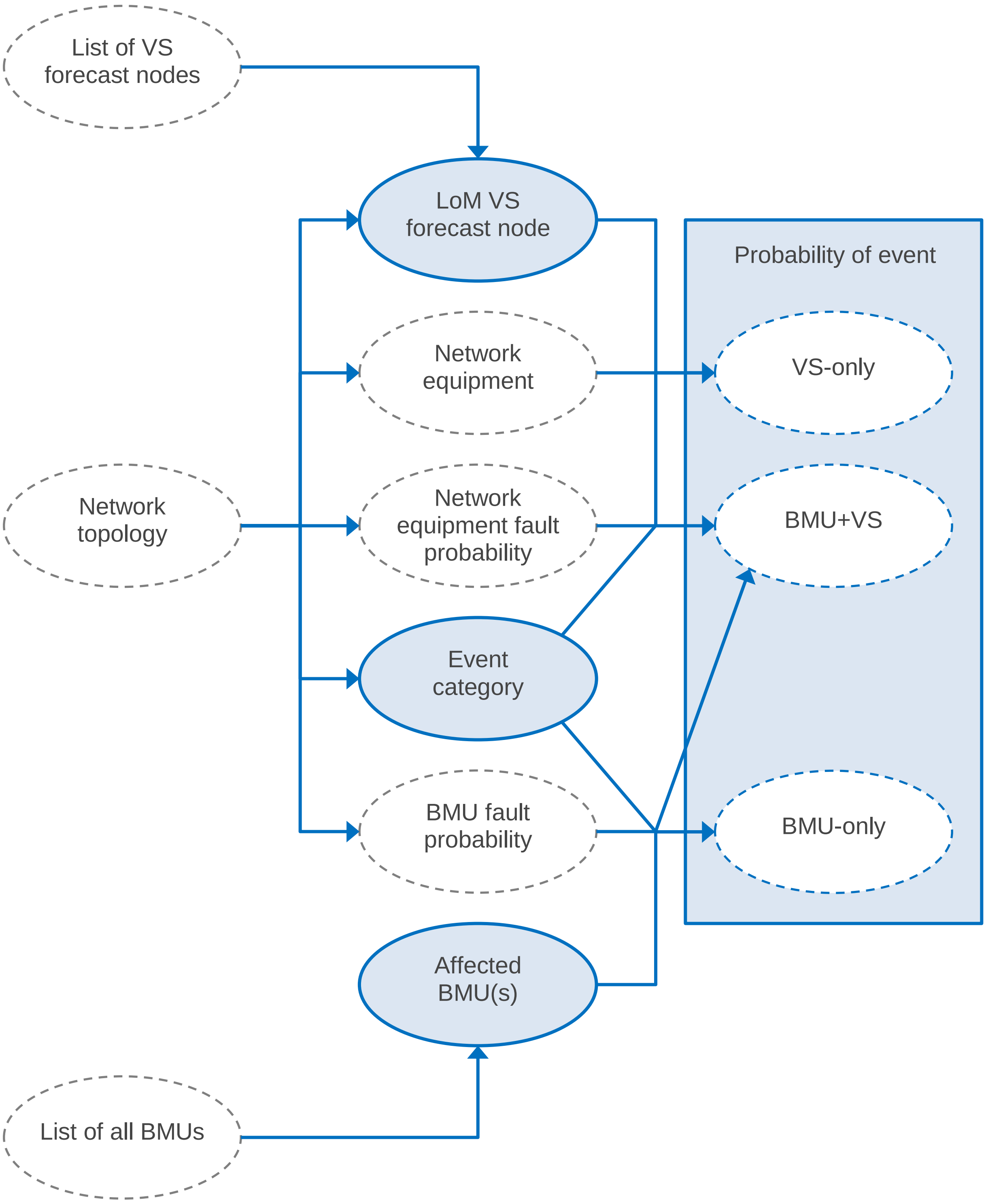
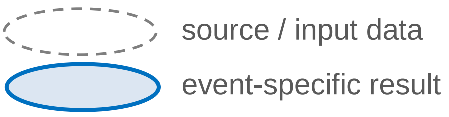


Figure 6 - Defining the events



6.3. For each "umbrella" scenario

Once the events have been defined in detail, the risks, impacts and controls can be assessed.

6.3.1. Choose combination

First, choose which combination of the “umbrella” control sensitivities are being assessed:

- Minimum inertia
- Inertia to control VS-only events
- Response

6.3.2. Apply "umbrella" controls

6.3.2.1. Determine required actions

Then compare the baseline system conditions with the required umbrella controls, and calculate how much additional inertia, footroom and response is required.

6.3.2.2. Calculate cost of actions

Then calculate the cost of these umbrella controls for the scenario.

6.3.2.3. Calculate loss sizes

Once the umbrella controls are in place, calculate the expected loss size for the event, accounting for the BMU loss size and any consequential Vector Shift and / or RoCoF loss.

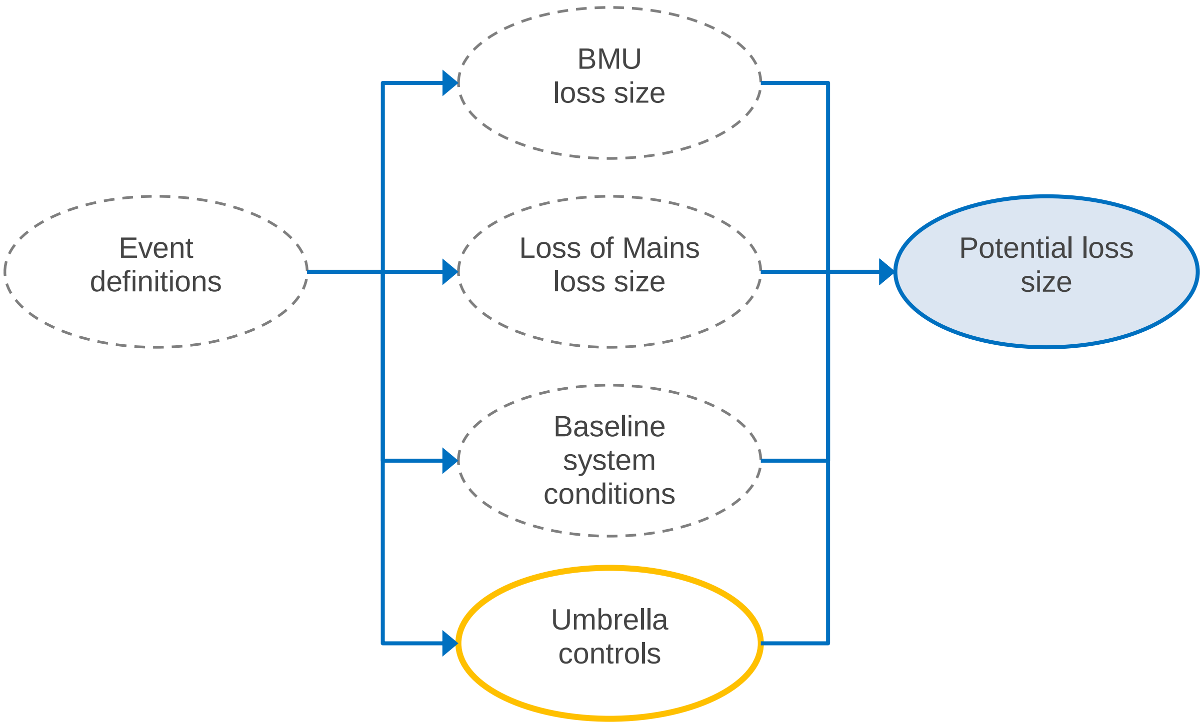


Figure 7 – Calculating the loss size after umbrella controls have been applied

6.3.2.4. Calculate baseline risk

Finally, assess how often each event is at risk of causing each of the impacts before any targeted controls are applied.

6.3.3. Apply “targeted” controls

Then apply the targeted control of reducing the BMU loss size to each event to assess the required actions, cost and risk reduction achieved.

6.3.3.1. Determine required actions

For each Settlement Period where the event loss size exceeds the level of response being held under the umbrella control, calculate the required reduction in the BMU loss size to prevent this.

This reduction could be:

- preventing a consequential RoCoF loss from occurring, by making sure the total BMU / Vector Shift loss stays within the rate of change of frequency threshold, or
- still allowing a consequential RoCoF loss, but making sure the total BMU / Vector Shift / RoCoF loss stays within the level of response

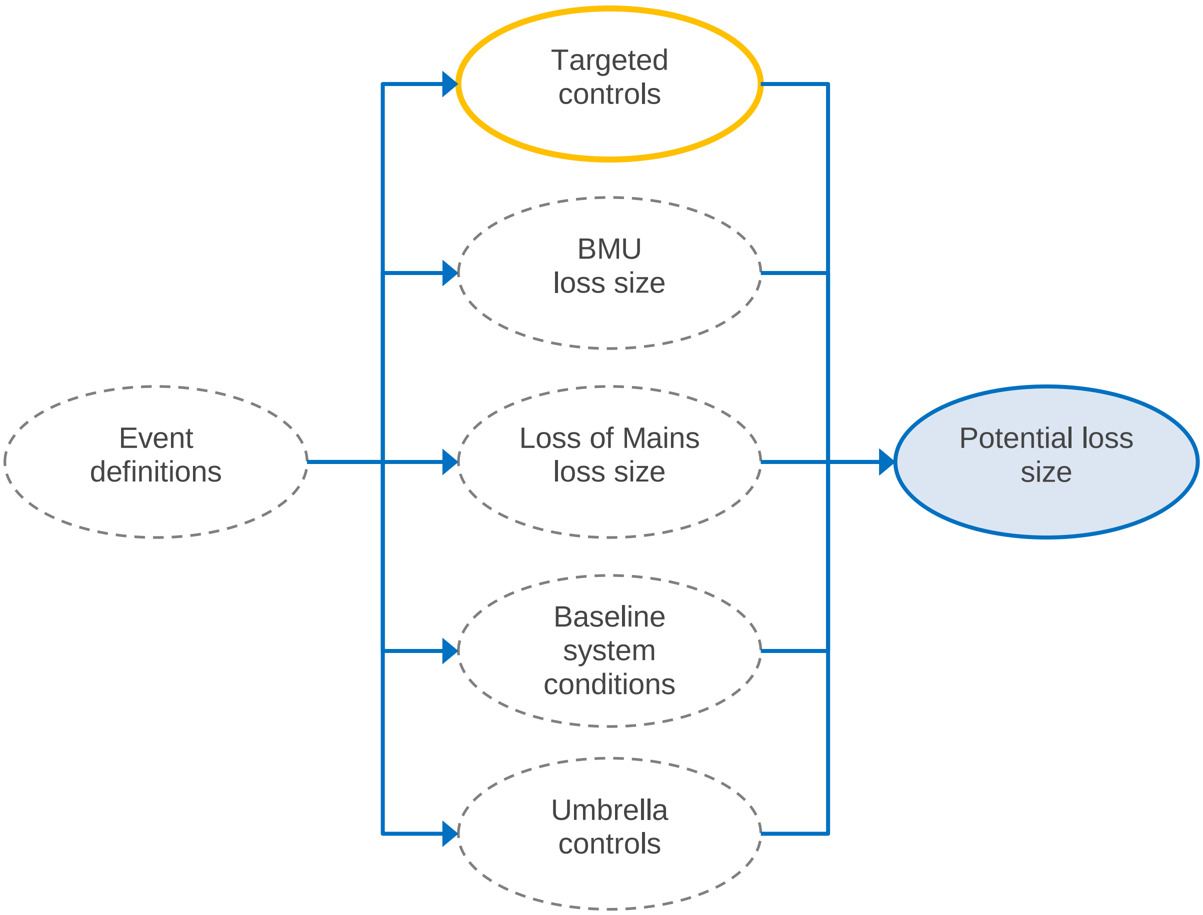


Figure 8 - Calculating the loss size after targeted controls have been applied

6.3.3.2. Calculate cost of actions

Then calculate the cost of these targeted controls for the scenario.

6.3.3.3. Calculate residual risk

Due to the physical constraints on BMUs, such as inflexible plant, there may still be some periods which can't be mitigated by targeted actions.

A second assessment can then be done, of how often each event is at risk of causing each of the impacts after both the umbrella and targeted controls are applied. This is the residual risk.

6.3.3.4. Calculate risk reduction

Finally, calculate the risk reduction achieved by applying the targeted control by comparing the baseline risk (after umbrella controls) to the residual risk (after umbrella and targeted controls).

6.3.4. Determine overall cost vs. risk vs. impact curve for the “umbrella” scenario

The last step is to determine overall cost vs. risk curve for the “umbrella” scenario. This can be done by ranking each event for risk reduction and cost of applying the targeted controls, giving a “value for money” ranking.

Adding on the baseline costs for the umbrella controls the allows us to plot the cumulative cost vs. cumulative risk reduction curves, with a curve representing each of the impacts.

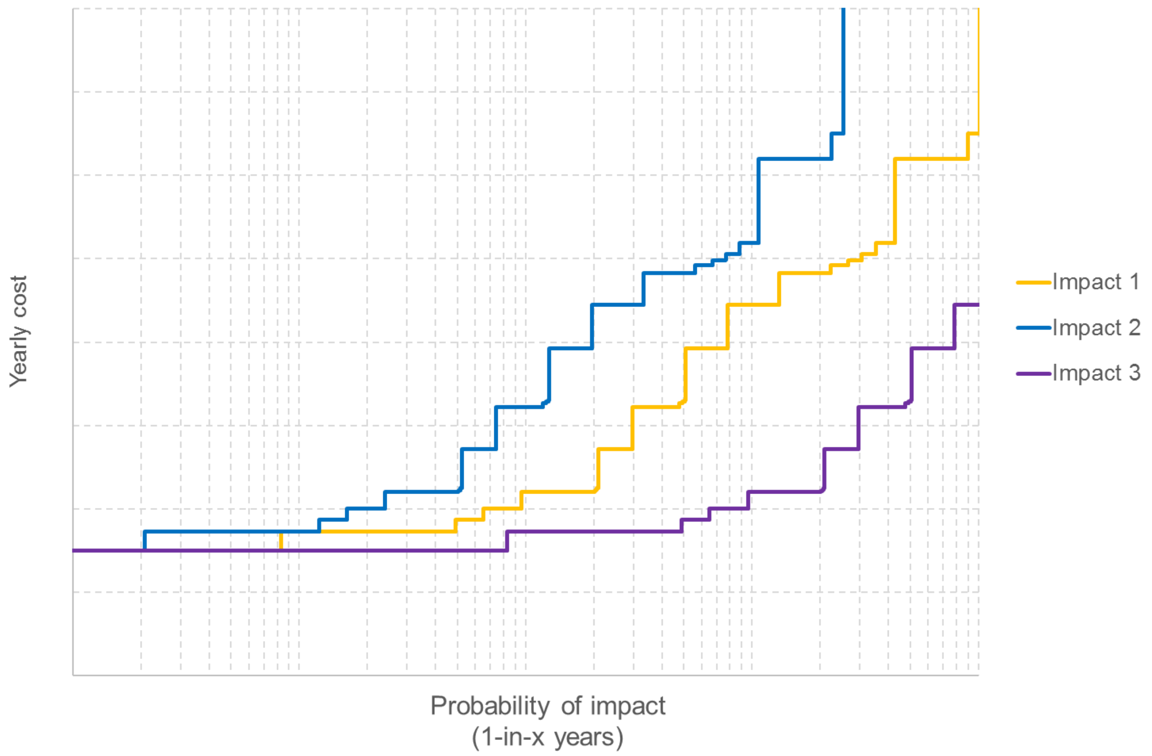


Figure 9 - Example cost vs. risk vs. impact chart

7. Outputs

7.1. Conclusions

Once the cost vs. risk vs. impact curves for each scenario have been created, conclusions can be drawn about the effectiveness of each umbrella strategy in providing a baseline level of reliability and cost.

Options can then be narrowed down to identify which additional targeted controls should or should not be pursued on a value for money basis.

This can be done by applying any **Reliability vs. cost** metrics defined by the industry in response to consultation on this *methodology*, such as those suggested in **0**.

For example:

- Limit on total cost per year
- Limit on how often each impact is expected occur
- Cost value per avoided occurrence

7.2. Main recommendation

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

The *FRCR* summary will give:

- the expected total cost per year of all frequency controls
- the expected level of reliability achieved for each impact:

#	Deviation	Duration	Likelihood
H1	50.5 < Hz	Any	1 in ___ years
L1	49.2 ≤ Hz < 49.5	60 seconds	1 in ___ years
L2	48.8 < Hz < 49.2	Any	1 in ___ years
L3	47.75 < Hz ≤ 48.8	Any	1 in ___ years

- the outline policy for umbrella controls used[20]

The detailed version of the *FRCR* produced for the *Authority* will include further, detailed information. Due to its sensitive nature, the specifics of which events or categories of events will and will not be secured with targeted controls will be in the detailed report, but not the summary report.

[20] i.e. the analysis scenario that supports in the best balance of reliability and cost

7.3. Other recommendations

There may be other, wider recommendations that can be made from the result of the *FRCR*, 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 *FRCR*.

8. Future considerations

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

Examples include:

8.1. Events

Simultaneous events

- as the new response services come on line, being able to assess the value of securing simultaneous events and also defining what would be classed a co-incident and simultaneous losses
  e.g. coincident faults in parts of the network
- assessing simultaneous losses will require a step-change in analysis, due to the scale of the data processing and complexity of how events can and can't interact
  e.g. 300 individual events become 44,850 pairs of simultaneous events
- once the *FRCR*, *methodology* and *NGESO* processes are established through the first edition, it will be possible to expand the analysis

Outage driven events

- the change in the likelihood of existing events or new events created during outages on the *NETS*
  e.g. going from a double circuit to a single circuit
- the key complexity is how to reflect and place a short-duration risk exposure on a dynamic time series of system conditions

Weather conditions

- the change in the likelihood of events during *adverse conditions*
- the key complexity is how to quantify the increase in risk

New causes of events

- such as single control points for multiple-BMUs, IP risks
- more work is required to understand and quantify these events

Generation connections

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

8.2. Losses

New causes of distributed resource losses	• any new causes that come to light as the power system evolves
New infeed and outfeed losses	• connections in coming years, including new interconnectors, offshore wind, and nascent technologies • the key question to address is how to forecast the running-pattern and reliability of new connections

8.3. Impacts

Multiple stages of LFDD	• if events could cause more than one stage of LFDD, and how often this could happen
Further investigation of high frequency deviations	• historically the focus has been on low frequency, but as more large *outfeed* losses connect this may need to change
Further investigations of frequency deviations closer to 50 Hz	• how smaller deviations[21] impact users, and how often they should be allowed to occur

8.4. Controls

Response and Reserve	• future services developed under the response and reserve roadmap
Inertia	• future stages of the Stability Pathfinder
ALoMCP delivery	• cost and risk reduction achievable through full delivery of the programme

8.5. Analysis and data

Improvements in statistical data inputs	• whether there is the opportunity for better quality or more accurate input data on the probability of the various types of faults, and how to reflect any uncertainties

[21] of the order of operational limits (49.8Hz to 50.2Hz)

9. Appendix – Glossary

9.1. General

System inertia	a measure of the stored rotational energy in the system (measured in MVA.s). directly affects the rate of change of frequency (df/dt) during a fault

9.2. Loss of Mains protection

Loss of Mains protection	protection on DER designed to detect a Loss of Mains condition to prevent the formation of islanded networks for local faults
df/dt	the Rate of Change of Frequency (RoCoF) observed on the electricity transmission system for a particular loss
RoCoF relay	a type of LoM protection which detects whether df/dt has exceed a particular threshold (e.g. 0.125Hz/s), indicating a possible islanding event
Vector Shift (VS) relay	a type of LoM protection which detects whether a sudden change in phase angle has exceed a particular threshold (e.g. 6 degrees), indicating a possible islanding event
RoCoF trigger threshold	the df/dt at which the first RoCoF protection is expected to trip (i.e. 0.125Hz/s)
RoCoF trigger level	the size of imbalance needed to cause df/dt to exceed the RoCoF trigger threshold, thereby tripping RoCoF protection and causing a RoCoF loss

9.3. Loss of Mains events

RoCoF loss	the loss of generation from DER due to the inadvertent tripping of LoM RoCoF relays, caused by an event on the electricity transmission system
Vector Shift loss	the loss of generation from DER due to the inadvertent tripping of LoM VS relays, caused by an event on the electricity transmission system
RoCoF loss forecast	the expected size of a RoCoF loss. this is the same nationally, regardless of event location
Vector Shift loss forecast	the expected size of a Vector Shift loss. this varies with the event location

10. Appendix – Inputs and data sources

Further information on inputs to the **6. Analysis** and specific data required for **6.2.1 Define events:**

List of VS forecast nodes	The size of Vector Shift losses has a location element, with different amounts expected to trip for events in different places on the system *NGESO* forecast the size of Vector Shift losses at 38 nodes spread across the system
LoM VS forecast node	From the set of 38 forecast nodes, the most appropriate will be chosen to reflect the size of Vector Shift loss that could occur with each event
Network topology	Describes the physical characteristics of the system, in terms of single circuits, double circuits, busbars etc.[22] From this we can determine which faults in the system could cause the loss of the BMUs associated with each *fault outage*, and whether it could also cause a Vector Shift event. This determines the "Event category" (see below)
Network equipment	Describes the number of assets or length of assets which could be associated with each event The likelihood of an event increases with the amount of equipment associated with the events, as there is more equipment which could fault
Network equipment fault probability	Gives the typical annual fault rate of different asset types on the network e.g. overhead lines, cables, busbars Initial taken from information produced to support SQSS modification proposal "GSR008: Regional Variations and Wider Issues"[23] Future editions of the *FRCR* may require updated statistics
Fuel-type breakdown statistics	Gives the typical annual fault rate of different generators by fuel type
List of all BMUs	Required to understand what would be disconnected from the system during the event

[22] Based on "Figure A4: GB Existing Transmission System" from the latest edition of the Electricity Ten Year Statement, with supporting information for internal national and regional planning diagrams

[23] https://www.nationalgrideso.com/document/14871/download

BMUs	Defines which BMU(s) would be disconnected from the system during the event
Sterilised inertia	When BMUs are disconnected from the system, their contribution to the total inertia of the system is also removed. This lowers the RoCoF trigger level, meaning this impact must be considered in assessing whether the Initial Loss from each event could cause a further RoCoF event
Event likelihood	The likelihood of each event occurring in each period For BMU-only events this is based on the fuel-type breakdown statistics For VS-only and BMU+VS Vector Shift events, this is based on the network equipment

Network equipment

For VS-only events, transmission overhead line and cable circuits between substations depicted in Figure A4: GB Existing Transmission System" from the latest edition of the Electricity Ten Year Statement will be considered.

This represents most overhead line and cable route km, and therefore the majority of faults that could cause an event, while avoiding having to exhaustively associate absolutely every asset to an event.

Fuel-type breakdown statistics

Some special cases are given an individual, per-event value, may be more appropriate than using average statistics

e.g. where the sample size is small, or where using an average is not reflective of an individual infeed or outfeed's reliability