Security & Quality of Supply Standards

Frequency Risk and Control Report

Methodology – April 2021

1. Executive Summary

Background

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

Scope

This first edition of the *Report* is focusing on the following key areas:

- establishing a clear, objective, transparent process for assessing reliability vs. cost to ensure the best outcome for consumers
- 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 delivery of the Dynamic Containment and Accelerated Loss of Mains Change programmes,
  - assessing the frequency standard that different size loss risks are held to, and
  - the impact of transmission network outages on radial connection loss risks

At the end of the report, the **12 Future considerations** section outlines opportunities to address other consideration in future editions of the *Methodology* and *Report*.

2. Contents

3. Overview

3.1. Suite of documents

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

Frequency Risk and Control Policy (Policy)

- states current *National Grid Electricity System Operator* (*NGESO*) policy for frequency risks and controls, and
- provides a baseline for the first edition of the *Frequency Risk and Control Report*

It is written with the intention of providing clarity and transparency to the way *NGESO* operates the system with respect to frequency control. As such, it is a necessary start-point for the process of developing the first edition of the *Frequency Risk and Control Report*.

Readers should familiarise themselves with the *Policy* document before proceeding to read this *Methodology*.

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Frequency Risk and Control Report Methodology (Methodology)

This document is the *Methodology*. It builds upon the *Policy* document, and lays out: what will be assessed in the April 2021 edition of the *Report*, how it will be assessed, and the format of the outputs. The *Methodology* comprises these steps:

Define inputs			
Impacts	Events & loss risks	Controls	Metrics for reliability vs. cost

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Conduct assessment

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Produce outputs		
Conclusions	Main recommendations	Other recommendations

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Frequency Risk and Control Report (Report)

The *Report* sets out the results of the assessment of the operational frequency risks on the system, and will be prepared in accordance with the *Methodology*.

It will 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 *NGESO* in accordance with paragraphs 5.8, 5.11.2, 9.2 and 9.4.2 of the SQSS.

The target date for the *Report* to be submitted to the *Authority* for approval is 01 April 2021.

3.2. Defined terms

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*.

4. Aim

4.1. Role of the Frequency Risk and Control Report

4.1.1. What is the Methodology trying to achieve?

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

- a reliable supply of electricity
- at an affordable cost

There is a balance between those objectives:

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

These objectives are formalised through the Security and Quality of Supply Standards (SQSS), the *Frequency Risk and Control Report*.

The aim of the *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.

4.1.2. What is meant by “reliability”?

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

- how often they occur
- how long they last for, and
- how large they are

as each of these affects the **Impacts** of an event (see Ch **5**).

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

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

4.1.3. What drives direct costs?

NGESO use a set of *Ancillary Services* to control frequency deviations. Some are automatic, like frequency 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 loss risks. 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

4.1.4. 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 appropriate balance between reliability and cost, which will be the subject of the *Report*.

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 appropriate 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 *Policy* and procurement of controls to implement the outcome.

4.2. Scope of this edition

This first edition of the *Frequency Risk and Control Report* is focusing on the following key areas:

- establishing a clear, objective, transparent process for assessing reliability vs. cost to ensure the best outcome for consumers
- 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 delivery of the Dynamic Containment and Accelerated Loss of Mains Change programmes,
    - asserssing the frequency standard that different size loss risks are held to, and
    - the impact of transmission network outages on radial connection loss risks

At the end of the report, the **12 Future considerations** section outlines opportunities to address other consideration in future editions of the *Frequency Risk and Control Report*.

5. Impacts

5.1. 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
- 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 (LFDD) scheme. Another is how often transient deviations happen at all, regardless of the size or duration.

5.2. Levels of impact

The *Report* will assess four 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 and SOGL implementation • 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 LFDD

Table 1 - Impacts to be assessed

These levels align to current frequency response holding policies, but provide more detail for the likelihood of triggering Low Frequency Demand Disconnection.

6. Events and loss risks

6.1. Which events will be considered?

6.1.1. Categories of loss risk

The aim of this first edition is to make the assessment of the risk from the inadvertent operation of Loss of Mains protection transparent.

The *Report* will cover the following six categories of loss risks, all of which are considered by current *Policy*:

- **BMU-only** — an event which only disconnects one or more BMUs (no Vector Shift loss or RoCoF loss)
- **VS-only** — an event which causes a consequential Vector Shift (VS) loss (no BMU loss or RoCoF loss)
- **BMU + VS** — an event which only disconnects one or more BMUs and causes a consequential VS loss (no RoCoF loss)
- **BMU + RoCoF** — a BMU loss which also causes a consequential RoCoF loss
- **VS + RoCoF** — a VS loss which also causes a consequential RoCoF loss
- **BMU + VS + RoCoF** — a BMU + VS loss which also causes a consequential RoCoF loss

6.1.2. Impact of transmission network outages on radial connection loss risks

In certain areas of the *National Electricity Transmission System* loss risks exist on radial connections. In the case of a *double circuit* radial connection, as depicted in **Figure 1**, the likelihood of an event occurring increases during transmission network outage conditions.

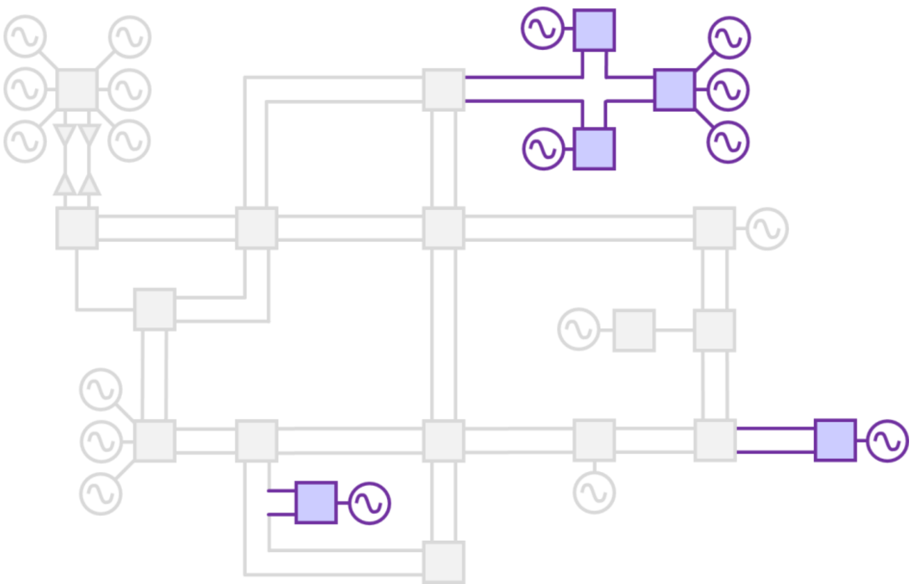

Figure 1 - potential double circuit faults on an illustrative network

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

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

6.2. Simultaneous events and other loss risks

This *Report* will only consider one event at a time, but will consider the combined loss of BMU and DER as specified in **6.1 Which events will be considered?**.

As noted in current *Policy*, the combined size of the largest losses is too large to control with current frequency response services, due to their technical specification. For this reason, securing simultaneous, independent events is often technically infeasible with current frequency response services.

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

There is also a significant increase in analytical complexity involved in assessing simultaneous events, due to the number of combinations that would have to be assessed. This means it is more appropriate in this first edition to focus on individual events, and to build on the capability in future.

7. Controls

7.1. How do you baseline the assessment?

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

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.

7.2. Which controls will be investigated?

There are four main controls for mitigating *transient frequency deviations*:

- holding frequency response
- reducing BMU loss size
- reducing LoM loss size
- increasing inertia

The *Report* will investigate variations to current *Policy* for the "holding response" and "reducing LoM loss size" controls.

The "reducing BMU loss size" and "increasing inertia" controls will be applied in the *Report* in the same way as current *Policy*.

7.3. Frequency response

The *Report* will investigate two variations to current *Policy*:

7.3.1. Dynamic Containment

The soft-launch of Dynamic Containment in October 2020 is the first of the new frequency response services under the "Response and Reserve Reform" programme. As the supply of Dynamic Containment increases, it will enable frequency response to cover BMU+VS loss risks and any loss risk that also causes a consequential RoCoF loss.

The cost-risk benefit of securing these larger, less frequent loss risks with larger quantities of Dynamic Containment will be assessed in the *Report*. This includes both low and high frequency variants of the services, for *infeed* and *outfeed* loss risks respectively.

7.3.3. Frequency limit for different size loss risks

Frequency Risk and Control Policy currently has two frequency limits for *infeed* losses, depending on their size:

- smaller losses (≤ 1000MW) are held to 49.5Hz
- larger losses (> 1000MW) are held to 49.2Hz

Historically, the amount of frequency response required to secure smaller losses to tighter limits had been approximately equal to the amount of frequency response required to secure larger losses to wider limits. This has resulted in savings in balancing costs by allowing a wider limit for the less frequent, larger losses.

Decreasing system inertia means that the equality in the requirement no longer holds, with the tighter limit for smaller losses often the driving factor.

The *Report* will investigate the impact of removing the tighter limit for smaller losses, and instead only applying the wider limit of 49.2Hz to all infeed losses.

7.4. LoM loss size

The Accelerated Loss of Mains Change Programme (ALoMCP) is reducing the capacity of DER at risk of consequential loss of RoCoF and Vector Shift. As the size of the consequential loss risks decreases, it will enable frequency response to cover BMU+VS loss risks and any loss risk that also causes a consequential RoCoF loss.

The cost-risk benefit of further delivery of the ALoMCP will be assessed in the *Report*.

8. Metrics for reliability vs. cost

8.1. 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,
  - 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 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.

8.2. 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 inform the recommendation.

8.2.1. How often each impact is expected to occur

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”[1].

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.

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

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

8.2.2. 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*."[2]

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 *Report*:

- 1hr of demand disruption
  x 20GW demand
  x 5% LFDD stage 1
  x £16,700 / MWh VoLL
  = £16.7m per event
- at a rate of one-in-ten years for LFDD, that would equate to a limit of £1.7m 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 *Report*, in addition to or instead of the other example metrics above.

8.2.3. Total cost per year

Total balancing costs for 2019/20[3] across all categories were £1,322 million, of which £616 million was spent on controls for managing the frequency (reserve, frequency 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 define an upper limit or guide 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.

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

3 https://data.nationalgrideso.com/balancing/mbss → March 2020

9. Assessment – general approach and assumptions

9.1. Historic vs. forecast

To understand the conclusions and recommendation of the *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. This is further complicated by the impact of COVID-19 restrictions on demand and consequential operation of the system in 2020.

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.

Example of adjustments include new connections to the *National Electricity Transmission System (NETS)* in 2021[4], which represent additional loss risks and which impact on the inertia of the system.

9.2. 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, but is inappropriate for assessing frequency risks on the GB system.

To overcome this, the analysis performed as a time series (at Settlement Period granularity) for the 2019 and 2020 calendar years, to allow a comparison for the impact of COVID-19 restrictions on demand and consequential operation of the system in 2020.

9.3. 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 control scenarios will be assessed.

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

9.4. 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 frequency response services will be benchmarked against the results of previous tenders or auctions.

[4] e.g. North Sea Link, IFA2, ElecLink and offshore windfarms

10. Assessment – step-by-step

10.1. Overview

The analysis will follow these steps:

Setup

Starting with current *Policy* as a baseline:

- Define Control scenarios
- Define Events and loss risks

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For each Control scenario

Apply "system-wide" controls

These are the frequency response, inertia and LoM loss size controls. These are applied first as they affect all events and loss risks.

- Determine required quantity of additional controls (with respect to the baseline)
- Calculate cost of controls
- Calculate loss sizes
- Calculate baseline scenario risk

↓

Apply "individual loss risk" controls

This is the BMU loss size control, and is applied after the "system-wide" controls to address any specific remaining risks

- Determine required quantity of additional controls
- Calculate cost of controls
- Calculate residual risk
- Calculate risk reduction

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Determine overall cost vs. risk vs. impact curve for the scenario

10.2. Setup

10.2.1. Define Control scenarios

The first step is to decide the specific levels and combination of each control which will be assessed. The combination of controls being assessed are:

- Dynamic Containment
- Frequency limit for generation loss risks
- Loss of Mains loss size

NGESO will ensure that this covers a sufficient range and meaningful granularity for the Dynamic Containment and Accelerated Loss of Mains Change Programme Controls.

The exact implementation is likely to require iterative analysis once the *Methodology* has been agreed and implemented and so is not possible to define up-front, but will be made clear in the final *Report*.

10.2.2. Define events and loss risks

The second step is to define the detail of each of the events that will be assessed, as outlined in **6.1 Which events will be considered?**. The dependency diagram below illustrates how the different inputs link together to calculate the probability of each event.

See **13 Appendix – Inputs and data sources** for more detail on each node in the diagram.

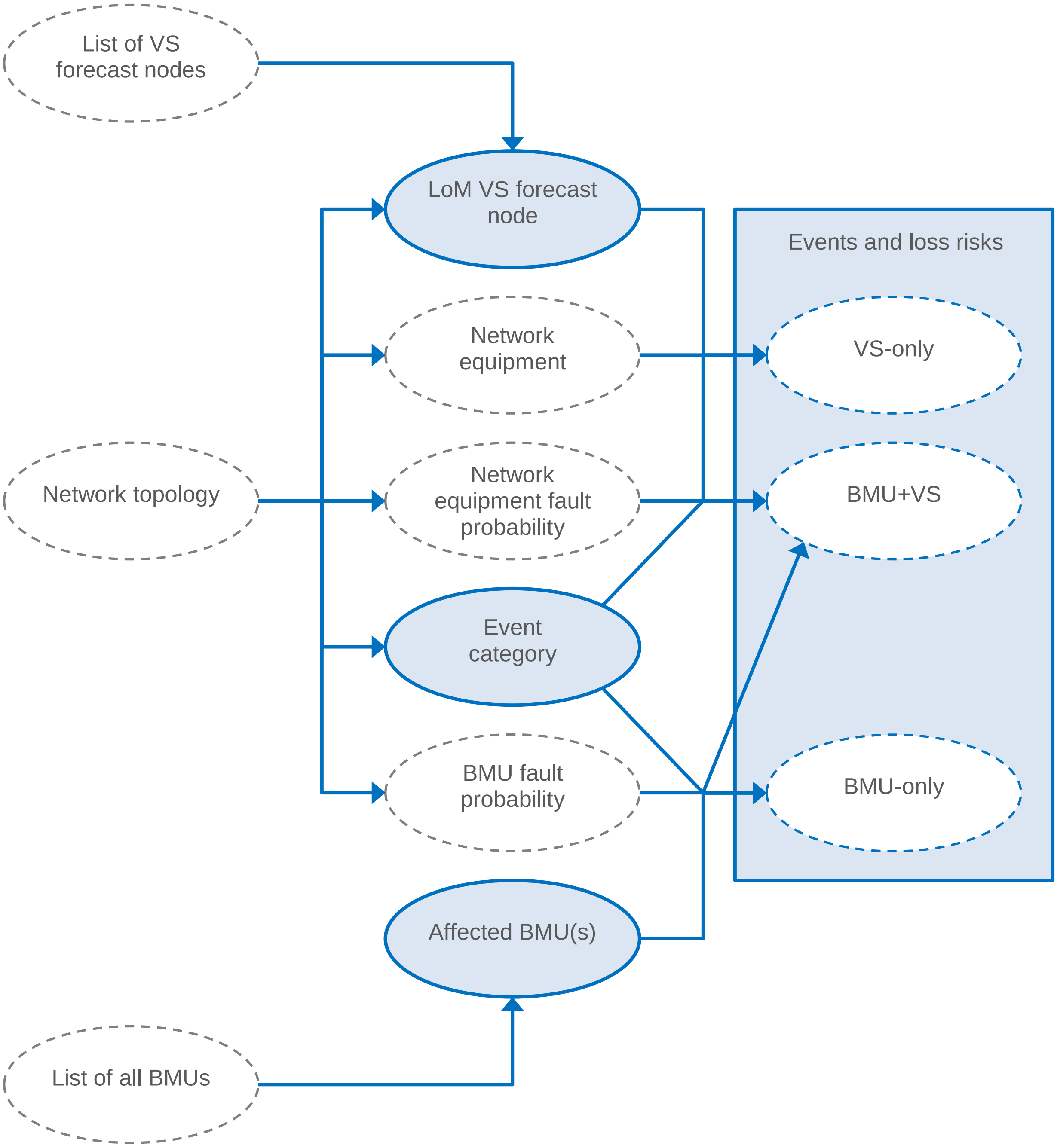
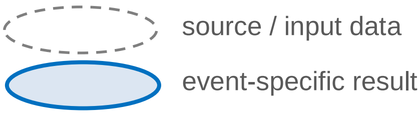


Figure 2 - Defining the events and loss risks



10.3. For each scenario

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

10.3.1. Choose combination

First, choose which combination of control is being assessed:

- Dynamic Containment
- Frequency limit for generation loss risks
- Loss of Mains loss size

10.3.2. Apply "system-wide" controls

10.3.2.1. Determine required quantity of additional controls

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

10.3.2.2. Calculate cost of controls

Then calculate the cost of these controls for the scenario.

10.3.2.3. Calculate loss sizes

Once the system-wide 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.

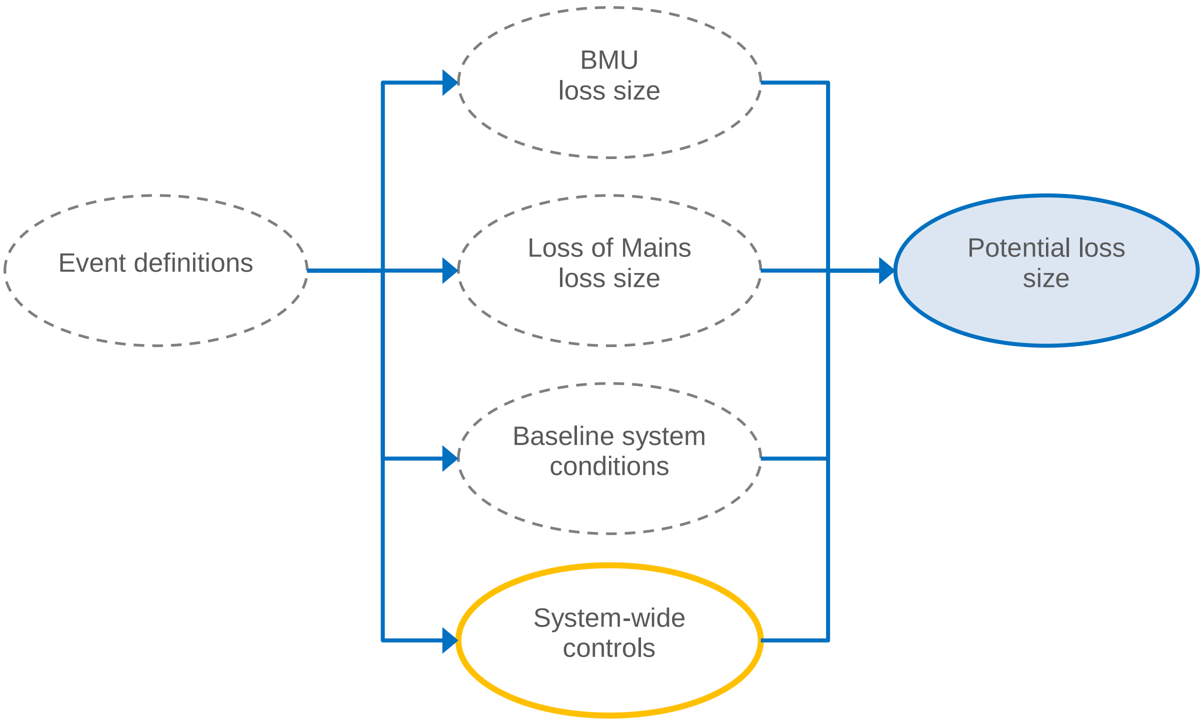


Figure 3 – Calculating the loss size after controls have been applied

10.3.2.4. Calculate baseline scenario risk

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

10.3.3. Apply "individual loss risk" controls

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

10.3.3.1. Determine required quantity of additional controls

For each Settlement Period where the event loss size exceeds the level of frequency response being held under the system-wide controls, 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 secured by frequency response holdings

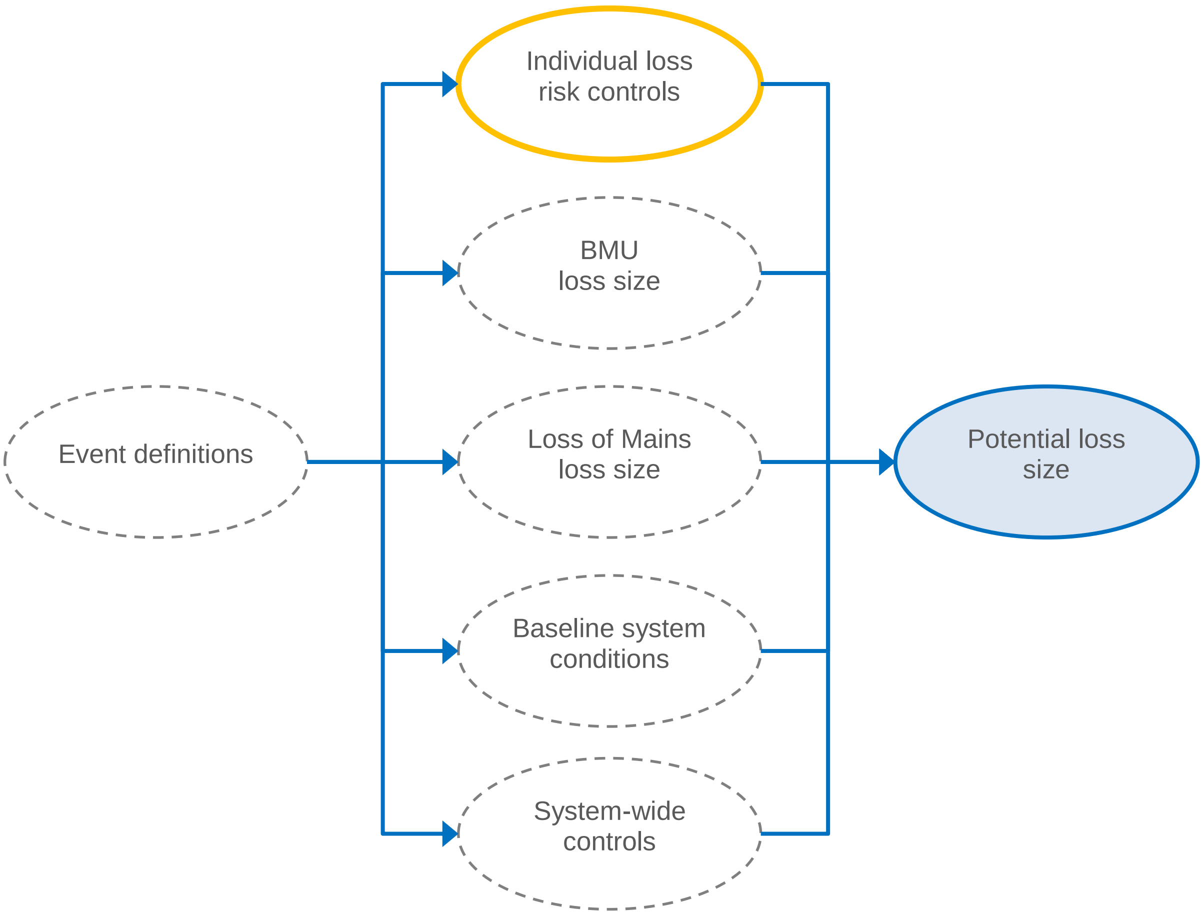


Figure 4 - Calculating the loss size after individual loss risk controls have been applied

10.3.3.2. Calculate cost of controls

Then calculate the cost of these individual loss risk controls for the scenario.

10.3.3.3. 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 individual loss risk 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 system-wide and individual loss risk controls are applied. This is the residual risk.

10.3.3.4. Calculate risk reduction

Finally, calculate the risk reduction achieved by applying the individual loss risk control by comparing the baseline risk (after system-wide controls) to the residual risk (after system-wide and individual loss risk controls).

10.3.4. Determine overall cost vs. risk vs. impact curve for the scenario

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

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

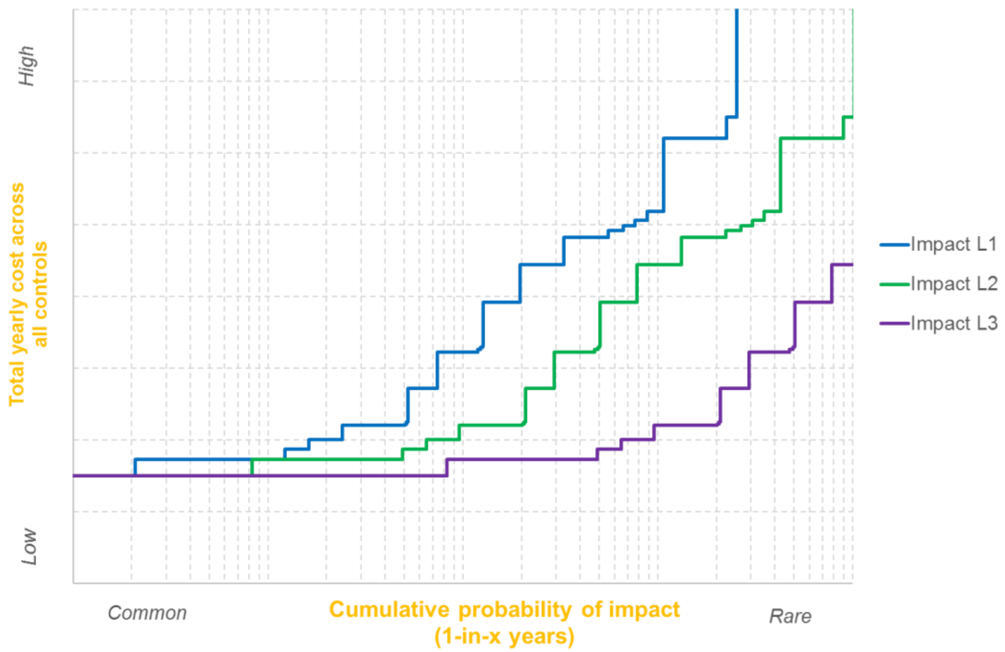


Figure 5 - Example cost vs. risk vs. impact chart

11. Outputs

11.1. Conclusions

11.1.1. Approach

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

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

This will be done by applying **Metrics for reliability vs. cost** defined by the industry in frequency response to consultation on this *Methodology*, such as those suggested in Ch **8.2**.

11.1.2. Example

An example of applying a limit on how often each impact is expected occur to a cost vs. risk vs. impact chart is shown in **Figure 6**.

In this example, avoiding impact L2 (green line) occurring more frequently than the specified limit is the driving factor behind the resulting expected level of spend on the system (red line). The controls applied to reach this level also reduce the likelihood the other two impacts to be less likely that the specified limit.

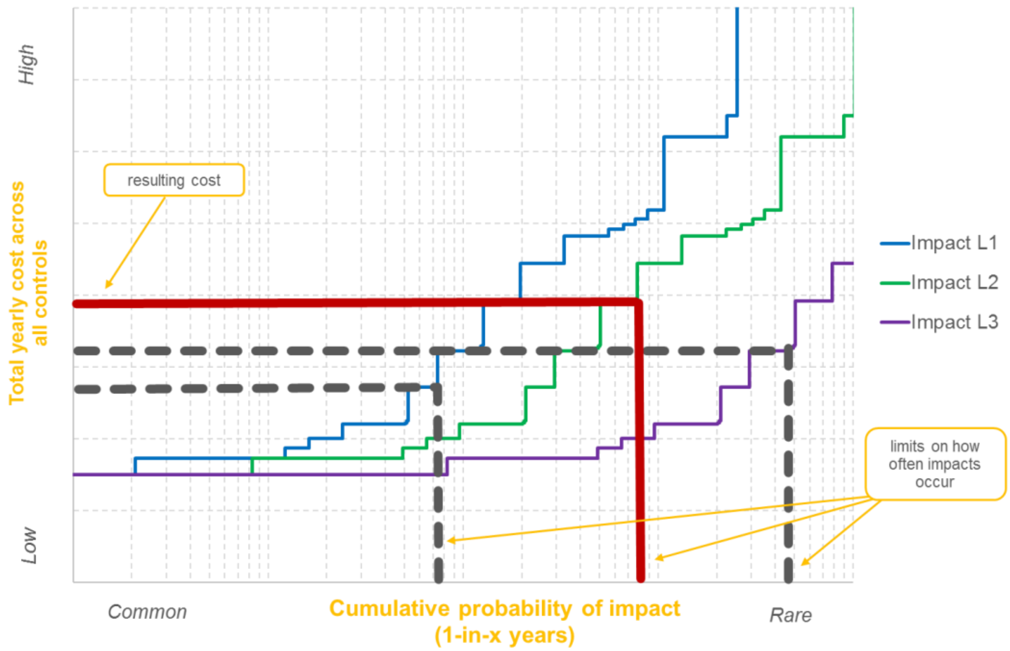


Figure 6 – example of applying a limit on how often each impact is expected occur

11.2. 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* 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	*e.g. 1 in ___ years*
L1	49.2 ≤ Hz < 49.5	60 seconds	*e.g. 1 in ___ years*
L2	48.8 < Hz < 49.2	Any	*e.g. 1 in ___ years*
L3	47.75 < Hz ≤ 48.8	Any	*e.g. 1 in ___ years*

- the outline policy for system-wide controls used[5]

The detailed version of the *Report* 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 individual loss risk controls will be in the detailed report, but not the summary report.

11.3. 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*.

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

12. 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 will be prioritised for future inclusion in future reports, based on consultation with the industry and the *Authority*.

Examples include:

12.1. Events and loss risks

Simultaneous events

- as the new frequency 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 *Report*, *Methodology* and *NGESO* processes are established through the first edition, it will be possible to expand the analysis

Other events driven by planned transmission network outages

- the change in the likelihood of existing events or new events created during outages on the *NETS*, other than those outages already considered by the *Methodology*

Weather conditions

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

New causes of events

- such as Active Network Management schemes (AMNs), single control points for multiple-BMUs, IP risks
- more work is required to understand and quantify these events

Generation connections

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

New causes of distributed resource losses

- any new causes that come to light as the power system evolves

New infeed and outfeed losses

- 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

12.2. 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[6] impact users, and how often they should be allowed to occur

12.3. 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

12.4. 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

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

13. Appendix – Inputs and data sources

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 42 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.[7] 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"[8] Future editions of the *Report* 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
BMUs	Defines which BMU(s) would be disconnected from the system during the event

[7] 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

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

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