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CHANGES TO SYSTEM INERTIA AND THE IMPACT ON FREQUENCY RESPONSE REQUIREMENTS

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Disclaimer

This thesis is the result of the author's original research. It has been composed by the author and has not been previously submitted for examination which has led to the award of a degree.

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ABSTRACT

The changing power landscape and associated reduction of inertia in the power system, introduces concerns about the assurance of frequency stability and the adequacy of dynamic frequency responses at low inertia. In islanded power systems, like those of Ireland and Great Britain (GB), understanding the issues posed and deploying effective solutions benefit from an investigation concerning the changing demand for frequency containment reserve and containment limits following a credible loss risk.

This thesis reviews frequency management in GB in the context of the changing energy landscape towards a lower inertia power system, identifying steps already taken by National Grid the GB Electricity System Operator (ESO) to address the issue, towards managing system frequency in a future lower inertia GB power system, without increasing the risk of system instability. A model and tools are developed to facilitate the studies presented in this thesis, and it is shown that methods can be employed to understand and define the factors influencing frequency behaviour, which can facilitate improved management of frequency and loss risk containment. In addition, an exchange rate method is proposed to convert the amount of reserve held between different frequency containment services, allowing one service to be compared and equated to another. In particular, a relationship is presented for converting response reserves from Primary to Enhanced response as they are defined in GB.

This work provides insight into the need and provision of future frequency response services in GB. It is shown that at low-demand and low-inertia existing dynamic frequency containment services alone are insufficient to manage a credible loss risk, highlighting the changing need for dynamic frequency containment reserve and the need for, and value of, faster dynamic frequency response services. In addition, it is estimated that in GB the demand for Primary response will exceed Secondary response for at least 41% of the year by 2025/26, compared to at least 21% in 2016/17, reinforcing the growing need for additional frequency containment to supplement existing services. In GB, at present, there exists no dynamic restoration only product,

as the services are bundled and the plants that deliver dynamic frequency containment also deliver dynamic frequency restoration as an extension of dynamic frequency containment, based on the operation of thermal plants. These services are procured as a bundle with demand for dynamic frequency restoration driving tenders in the commercial frequency response market. In order to meet the increasing demand for containment reserve, new frequency containment services are required, and these should be unbundled from frequency restoration services. A concept for a suitable framework of frequency containment services is presented that shows that deploying supplementary reserves as unbundled service manages frequency stability as effectively as the bundled services, while the inclusion of a rate of change of frequency management service improves performance at extremely low-inertia. In addition, to facilitate improved market participation and the competitive provision of containment services, it is argued that a shift in gate closure for the procurement of frequency containment services from month-ahead to day-ahead or even closer to real-time is required.

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ABBREVIATIONS

AC	Alternating Current
ANM	Active Network Management
CCS	Carbon Capture and Storage
CHP	Combined Heat Pump
CP	Consumer Power
DC	Direct Current
DSF	Demand Side Flexibility
DSO	Distribution System Operator
EFCC	Enhanced Frequency Control Capability
EFR	Enhanced Frequency Response
ESO	Electricity System Operator
EV	Electric Vehicle
FCDM	Frequency Control by Demand Management
FEROS	Frequency Energy Response Optimiser and Simulator
FES	Future Energy Scenarios
FFR	Firm Frequency Response
FNG	Flexible Non-Synchronous Generator
FSG	Flexible Synchronous Generator
GB	Great Britain
GG	Gone Green
HFR	High Frequency Response
HVDC	High Voltage Direct Current
IEEE	Institute of Electrical and Electronics Engineers
ING	Inflexible Non-Synchronous Generator
ISG	Inflexible Synchronous Generator
LCC	Line Commutated Converter
LFDD	Low Frequency Demand Disconnection
LoIF	Loss of In-Feed

LoL	Loss of Load
LoM	Loss of Mains
MFR	Mandatory Frequency Response
MITS	Main Interconnection Transmission System
NGET	National Grid Electricity Transmission
PFR	Primary Frequency Response
RFR	Rapid Frequency Response
RoCoF	Rate of change of frequency
SC	Synchronous Compensator / Synchronous Condenser
SFR	Secondary Frequency Response
SHET	Scottish Hydro Electric Transmission Plc
SNSP	System Non-Synchronous Penetration
SO	System Operator
SOF	System Operability Framework
SP	Slow Progression
SPP	Solar Power Plant
SPT	Scottish Power Transmission
SQSS	Security and Quality of Supply Standard
SS	Steady State
TD	Two Degrees
TSO	Transmission System Operator
UCPTE	Union for the Co-ordination of Transmission of Electricity
UK	United Kingdom
VSC	Voltage Source Converter
WPP	Wind Power Plant

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1

INTRODUCTION

There is concern over the future stability of the British power system as it incorporates reducing amounts of conventional synchronous generation and increasing amounts of nonsynchronous power devices (e.g. wind plants and interconnectors), further compounded by an increase in the largest credible loss risk. As a result, there are questions as to the assurance of frequency stability of a future system, particularly regarding the energy needed to manage a frequency excursion when there is a substantial imbalance between power supply and demand. In Great Britain (GB), the current prevalent frequency response services that contain frequency excursions are Primary response (for loss of infeed events) and High response (for loss of load events). At lower system inertia and demand with existing or future loss risks, such products may be inadequate. There is ongoing research, both academic and industry led, tailored to discerning solutions to the challenge posed to managing the frequency of a power system by the renewable energy generation drive. These challenges are of importance to islanded networks that are more susceptible to the issue of frequency management at reduced inertia.

To varying degrees, regions such as Ireland, GB and Texas have begun taking steps towards supporting the transitions towards a lower inertia power system. At present, the GB system operator can contain loss risks at reduced inertia[1] by taking certain balancing actions but at an increasingly high cost, which raises the question of how this can be done more effectively and efficiently, without increasing the risk of system instability. The provision of energy responses, both those inherent to the power system and those procured via the frequency response markets, are vital tools in containing credible loss risks. Frequency response, procured via the market and held as a dispatchable reserve, is one of the ancillary services in GB. As of the financial year of 2018/19 the ancillary services cost just over £480 million, with frequency response accounting for just over 20% of this cost [1]. This represents a significant cost to the consumer that without further action is expected to increase. It should be noted that the cost of these services doesn’t include the cost of constraint actions for managing the rate of change of frequency, i.e. limiting the largest loss risk, which for 2018/19 cost just over £120 million [1].

There is a need to understand how the demand for frequency response changes as the energy landscape changes and GB transitions towards a lower inertia power system. Understanding these requirements will help define suitable dynamic frequency response services for a future GB power system. In addition, understanding and identifying the relationship between energy responses[2] and the limit beyond which a loss event is no longer contained by the power system, will allow the efficient dispatch of available resources, and permit an understanding of the actions needed to facilitate higher penetration of non-synchronous devices without compromising system stability. In order to address these questions, a wide range of scenarios need to be simulated using a model (alongside specialised tools) that represents the components of the power system and their response behaviour to frequency disturbances.

[1] An example is presented in chapter 2.
[2] E.g. inertia, frequency response reserves, etc.

1.1 Research Brief

This research project has aimed to investigate and quantify the challenge posed by a future low inertia power system. It will also investigate the most suitable dispatchable energy response services in order to contain a credible loss risk in a future low inertia GB power system.

The main question being addressed is: 'How much response does the GB power system need in the future and what are the options for delivering it?'. The specific research questions considered over the course of this thesis are listed below.

- How is frequency currently managed in GB?
- What is the impact of the changing power landscape on frequency management in GB?
- Are existing GB frequency response services adequate for a future low inertia British power system?
- What strategies can be deployed to mitigate the challenge of frequency stability in a future low inertia British power system?
- Can rate of change of frequency and frequency limits be respected without the need for significant curtailment of non-synchronous power (or loss risk) and constraining on of fossil-fuelled synchronous plants?
- What are the key factors influencing frequency behaviour and how do they impact the likelihood of containing a credible loss event?
- How will the demand for frequency containment reserves change in the future?
- What does an adequate framework for frequency response entail?
- Will a frequency containment service that is faster than existing frequency containment services but slower than synchronous inertial response, be enough to manage credible loss events?

The project objectives include:

- a review of frequency management, the frequency response market and frequency response services in GB, and the impact of changing system inertia on frequency management in GB;

- the development of a model that represents the GB transmission network, including current and alternative frequency containment services, suitable for the studies that will be conducted as part of this research;
- the development of tools to support the use of said model;
- the modelling of credible loss risks for a range of scenarios, to identify and understand the factors influencing frequency behaviour;
- study of the impact that the speed of response has on frequency behaviour and limits to the system imposed by system inertia;
- investigation of the frequency stability limits of the future GB power system;
- identification of the changing demand for frequency response in a future GB power system for a range of scenarios; and
- use of a range of scenarios to study current and alternative frequency response strategies, to develop a proposal for a frequency containment response service that is suitable for a future low inertia GB power system.

1.2 Thesis Structure

The structure and summary of the thesis is outlined in this section.

Chapter 1	This chapter introduces the reader to the premise of the project outlining objectives, highlighting chapters in the thesis, and providing a summary of key contributions, and list of publications.
Chapter 2	Frequency management is introduced along with the definitions, statutory limits and requirements as they apply to the GB power system. Existing and proposed frequency response services are also discussed as well as the market structure for procuring frequency response services in Britain.
Chapter 3	The changing power landscape is discussed with specific reference to the potential outlook of the future GB power system, and the subsequent challenges that arise. In addition, a discussion is also presented concerning potential considerations for mitigating the challenges of a changing power landscape and reducing inertia as it relates to frequency management.
Chapter 4	Tools for modelling system frequency and conducting frequency stability studies are presented in this chapter, including a single bus model that aggregates elements of a power system based on how they respond to frequency, and an application developed in python that functions as either a set of algorithms that support the model or a standalone application, with the capability to retrospectively determine likely system conditions during a historic event.
Chapter 5	This chapter discusses the influence that certain factors have on maintaining frequency stability during a significant power imbalance, including demand sensitivity to frequency changes, inertia, and speed of frequency containment services.
Chapter 6	With the changing power landscape in GB, the challenge of containing loss risks within frequency stability constraints is discussed. In addition, metrics for determining frequency stability limits during a significant power imbalance are investigated and presented.
Chapter 7	The changing demand for frequency response in a future GB power system is investigated and discussed in this section, identifying the need for supplementary containment services. Furthermore, a concept for a framework of future dynamic containment services is proposed and tested.
Chapter 8	This chapter contains conclusions based on the findings presented in the thesis, and outlines avenues for future work.

1.3 Summary of Main Contributions

The main contributions of this thesis include:

- a validated single bus frequency stability model that includes a representation of the key attributes of the power system that influence frequency behaviour during a power imbalance and allows pragmatic assessment of system frequency variation and potential frequency management services;
- a program that can be used to optimise frequency response reserve, retrospectively replicate past frequency events, determine non-synchronous penetration limits, and consider frequency containment for a range of scenarios. This program can be used as either a companion tool to the single bus model or as a standalone application;
- proposal and demonstration of a procedure by which key factors of the model that influence frequency behaviour can be estimated for a range of conditions;
- a comparison and demonstration of metrics that can be used to understand and quantify the frequency stability limits of a power system when subjected to a significant power imbalance. The metrics proposed by this thesis are the critical inertia, and the frequency stability by components;
- proposal of an exchange rate method to convert the amount of reserve held between different frequency containment services, allowing one service to be compared and equated to a new or faster service.
- presentation of an expression representing the exchange rate between dynamic Primary response and Enhanced (or another equivalent) frequency response;
- evidence that at low-demand and low-inertia existing dynamic frequency containment services are insufficient to manage a credible loss risk, highlighting the changing need for dynamic frequency containment reserve and the need for, and value of, faster dynamic frequency response services;
- an assessment indicating that the demand for dynamic frequency containment response services may exceed that of dynamic frequency restoration services for at least 41% of the year by 2025/26, compared to at least 21% in 2016/17, reinforcing the growing need for additional frequency containment to supplement existing services; and

- the proposal of a dynamic containment service that addresses containment needs at extremely low inertia operational conditions.

1.4 Project Outputs

The following publications have been obtained as a direct result of work relating to this thesis:

1.4.1 Journal Publications

[1] Q. Hong, M. Nedd, S. Norris, I. Abdulhadi, M. Karimi, V. Terzija, B. Marshall, K. Bell and C. Booth, "Fast frequency response for effective frequency control in power systems with low inertia," in *Journal of Engineering*, vol. 2019, no. 16, pp. 1696 – 1702, 2019.

[2] M. Nedd, J. Browell, K. Bell and C. Booth, "Containing a credible loss to within frequency stability limits in a low inertia GB power system," in *IEEE Transactions on Industry Applications*, vol. 56, no. 2, pp. 1031 – 1039, 2020.

[3] M. Nedd, W. Bukhsh, C. MacIver and K. Bell, "Metrics for determining the frequency stability limits of a power system: A GB case study," in *Electric Power Systems Research*, accepted 11 Feb 2020.

1.4.2 Conference Proceedings

[1] M. Nedd, Q. Hong, K. Bell, C. Booth and P. Mohapatra, "Application of synchronous compensators in the GB transmission network to address protection challenges from increasing renewable generation," in *2017 CIGRE B5 Colloquium*, Auckland, 2017.

[2] M.Nedd, C. Booth, K. Bell, "Potential solutions to the challenges of low inertia power systems with a case study concerning synchronous condensers," in *2017 52nd International Universities Power Engineering Conference (UPEC)*, Heraklion, 2017.

[3] Q. Hong, M. Nedd, S. Norris, I. Abdulhadi, M. Karimi, V. Terzija, B. Marshall, K. Bell, C. Booth, "Fast frequency response for effective frequency control in power systems with low inertia," in *14th IET Conference on AC and DC Power Transmission*, Chengdu, 2018.

[4] M. Nedd, K. Bell, C. Booth, "Containing loss risk in a low inertia GB power system," in *18th International Conference on Environment and Electrical Engineering*, Palermo, 2018.

[5] M. Nedd, W. Bukhsh, C. MacIver and K. Bell, "Metrics for determining the frequency stability limits of a power system: A GB case study," in *21st Power Systems Computation Conference*, Porto, accepted 11 Feb 2020.

[6] W. A. Bukhsh, M. Nedd, C. MacIver and K. R. W. Bell, "The Impact of Reduced System Inertia on System Planning and HVDC Interconnection," *in 2020 CIGRE Session 48*, Paris, 2020.

2

FREQUENCY RESPONSE SERVICES AND MARKETS IN GB

Electric power systems, now and in the future, will be required to be more sustainable than in the past while maintaining security of supply and minimizing costs to the consumer. Such power systems will need to be robust enough to support the expected growth in demand amidst the ongoing changes to the energy landscape [2, 3, 4]. These changes include the increased proliferation of low carbon power generation, particularly renewables, both transmission and distribution connected.

In GB, as in many countries, the two major renewable sources that have grown in recent years are wind and solar power, which are (in their majority) converter connected. Including HVDC interconnectors and battery storage, these devices are also called non-synchronous devices because their converter connection means that their sources of energy are electromagnetically decoupled from the power system and therefore, unable to provide the inherent inertial response to a frequency disturbance that would be otherwise provided by a synchronous machine. That said, it is worth noting that doubly-fed induction generator wind turbines, deployed at many large wind farms, do provide a partial electrical coupling to the grid and due to controller delay in maintaining a particular rotor speed may provide a small inertia contribution to the system [5, 6]. In GB, the percentage share of renewable generation is expected to continue to grow [4], while coal plants are expected to close [7, 8], replaced by an increasing penetration of non-synchronous devices in the GB power system. The increasing penetration of non-synchronous power supplies, and associated reduction in synchronous generation, reduces the system inertia presenting challenges to the future GB power system [9]. One challenge relates to frequency stability, which is defined by [10] below.

> *"Frequency stability refers to the ability of a power system to maintain steady frequency following a severe system upset resulting in a significant imbalance between generation and load. It depends on the ability to maintain/restore equilibrium between system generation and load, with minimum unintentional loss of load."*

In an AC power system, a significant imbalance between generation and demand can be observed via an increase or decrease in frequency. An event that gives rise to a mismatch is referred to as a loss of in-feed (LoIF) or a loss of load (LoL), for a loss of power supply or a demand respectively. In order to contain the power imbalance, the system operator (SO) schedules energy reserves[3] to contain and restore frequency. Traditionally, transmission connected synchronous machines have been the main

[3] For example, for a loss of infeed event, a response in terms of increase in power output is typically enacted via a governor and sustained for some given minimum period of time thus delivering a certain amount of energy.

sources of reserve energy, delivered at different timescales via its inherent inertial response, and scheduled frequency containment and restoration reserves.

Inertial response is the instantaneous and automatic kinetic energy response from synchronously connected machines, via an electromagnetic coupling with the network that opposes changes in frequency [11, 12]. The relationship between system inertia, H_{sys}, and rate of change of frequency (RoCoF), df/dt, is shown in (2.1) where ΔP is the power imbalance and f_o is the nominal frequency.

$$\Delta P = \left(\frac{2 \times H_{sys}}{f_0}\right) \times \left(\frac{df}{dt}\right) \tag{2.1}$$

By considering (2.1), it can be seen that a power system with larger inertia that is subjected to a power imbalance will experience a lower RoCoF than a power system with a lower inertia under the same conditions. If the RoCoF following a power imbalance is too high, it increases the risk of cascading frequency events, as a result of the tripping of RoCoF relays which, under a loss of infeed event, cause more generation to be lost. An example of this is seen in the details surrounding the 9th of August 2019 event in GB [13]. RoCoF relays are widely used in some countries, including the UK and Ireland, in loss of mains (LoM) protection for distributed generation [14, 15]. These relays are designed to open the circuit when the system RoCoF reaches a given limit [16]. The resultant impact of the undesirable operation of RoCoF relays in low inertia power systems, is an increased risk of loss of supply.

The European Network of Transmission System Operators for Electricity (ENTSO-E) in [17] defines frequency containment reserve as: “The active power reserve available to contain system frequency after the occurrence of an imbalance” so that frequency can then be restored to within acceptable limits. In practice, the containment action can be thought to include inertial response. The rate of delivery and quantity of frequency containment reserves affect the frequency excursion, and how effectively frequency is contained and restored to acceptable limits. If the frequency excursion is not contained, it could lead to disconnection of demand or generation, and potentially a black out [18].

2.1 Frequency Management in a GB Power System

The SO has a licence obligation to control system frequency within defined limits, which they achieve by procuring a range of frequency response products from generators and demand side resources that can respond automatically to changes in frequency, changing their export or import to correct a frequency deviation, within defined compliance requirements. The Security and Quality of Supply Standard (SQSS) defines conditions such as normal and infrequent loss risks, as well as unacceptable frequency conditions [19]. Table 2.1 is extracted from [19] and it provides definitions for the aforementioned conditions.

Table 2.1: Definition of conditions extracted from [19].

Normal Loss Risk	That level of loss of power in-feed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5 Hz. Until 31st March 2014, this is 1000 MW. From April 1st 2014, this is 1320 MW, however as described in [20] the practical normal loss risk is still currently 1000 MW.
Infrequent Loss Risk	That level of loss of power in-feed risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5 Hz to 50.5 Hz for more than 60 seconds. Until 31st March 2014, this is 1320 MW. From April 1st 2014, this is 1800 MW, however as described in [20] the practical infrequent loss risk is still currently 1320 MW.
Unacceptable Frequency Conditions	These are conditions where: i) the steady state frequency falls outside the statutory limits of 49.5 Hz to 50.5 Hz; or ii) a transient frequency deviation on the MITS persists outside the above statutory limits and does not recover to within 49.5 Hz to 50.5 Hz within 60 seconds. Transient frequency deviations outside the limits of 49.5 Hz and 50.5 Hz shall only occur at intervals, which ought reasonably be considered as infrequent. It is not possible to be prescriptive with regard to the type of secured event which could lead to transient deviations since this will depend on the extant frequency response characteristics of the system which National Grid ESO shall adjust from time to time to meet the security and quality requirements of this Standard.

The loss limits were changed because in 2011 an SQSS review of infeed losses determined that the old limits were no longer consistent with the range of technologies available to developers, and presented itself as a barrier to the connection of planned large generating unit including new nuclear units with capacities up to 1800 MW. The decision was further justified by an Ofgem impact assessment associated with large nuclear plants, indicating carbon savings, wholesale price impact, etc. Details on the review of infeed losses in GB are available in [21]. While this review was motivated by planned new connections of large nuclear power plants, at the time of writing, none of those plants have been connected to the power system. However, in light of the infeed review, the SQSS already permits larger units or connection designs, such that a single event could cause a larger loss than seen in the system under the previous loss risk definitions. Examples include the North Sea Link 1400 MW HVDC interconnector [22] due to be completed in 2021, and, potentially, large offshore wind farm connections. National Grid is the Electricity System Operator (ESO) in GB, and it interprets its obligations pertinent to frequency response in [23], which is diagrammatically illustrated in Figure 2.1.

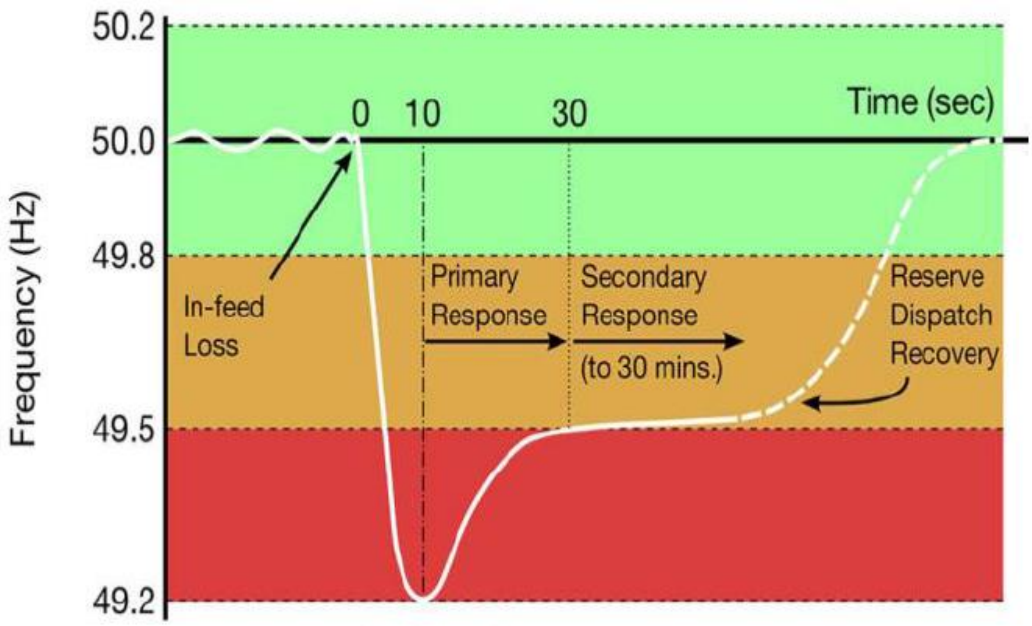


Figure 2.1: Diagrammatic representation of energy response for a maximum loss of in-feed event [24]. Green – normal operating conditions, Amber – normal loss conditions, Red – infrequenct loss conditions.

To summarise Figure 2.1 and Table 2.1, under normal operating conditions frequency can deviate from nominal 50 Hz by ±0.2 Hz. This limit is referred to as the operational limit (49.8 Hz – 50.2 Hz). However, during a loss event a larger frequency excursion can occur. If the loss event is within the definitions of a normal loss risk, then the event must be contained within ±0.5 Hz of nominal 50 Hz. If instead, the loss event is within the definitions of an infrequent loss risk, then an excursion outside ±0.5 Hz of nominal frequency must be returned to with ±0.5 Hz of nominal frequency within 60 seconds. The permitted range of 49.5 Hz – 50.5 Hz is referred to as the statutory limit. In order to comply with these specifications, National Grid applies a maximum deviation of ±0.8 Hz of nominal frequency for an infrequent loss risk and procures frequency response reserves via the GB ancillary markets to suit. These frequency response services and associated markets, will be discussed later in this chapter.

There are other thresholds that apply for larger excursions of frequency from 50 Hz, which require additional actions to be taken in order to manage frequency. The Low Frequency Demand Disconnection (LFDD) threshold starts at 48.8 Hz, and as the name implies, it is the disconnection of demand in order to prevent frequency collapse[4]. The full spread of the LFDD thresholds as they apply to the three GB Transmission Operators (TOs), National Grid Electricity Transmission (NGET), Scottish Power Transmission (SPT) and Scottish Hydro Electric Transmission Plc (SHET), is given in Appendix 1. In addition, the specifications regarding the operation of generators within different ranges of frequency are given in Appendix 2. There are also conditions relating to how quickly the system frequency changes, i.e. the RoCoF. These conditions, as set at the time of writing, are shown in Table 2.2 and Table 2.3.

Historically, the RoCoF setting in GB was 0.125 Hz/s until proposals for a change to settings for power stations greater than 5 MW were approved in 2014 [25]. Due to the changing power landscape and reducing inertia in the power (as will be discussed later in this chapter), a credible loss of infeed or demand event would lead to higher RoCoF in comparison to a power system with higher inertia. The consequence of the higher RoCoF for the same loss risk at reduced inertia, under the previous RoCoF settings, is

[4] Analogous to Under-Frequency Load Shedding (UFLS) as it is described in [14].

the risk of unintended operation of RoCoF LoM protection in distributed generation [16, 26]. This could lead to a cascading effect if enough distributed generation was disconnected, bringing the power system closer to the LFDD triggers in Appendix 1 [27]. Evidence of the impact of the risk associated with the unintended operation of LoM protection, is the 9th of August 2019 event in GB [28]. To reduce the risk of unintended operation during a loss event, the new settings in Table 2.2 and Table 2.3 were written into the Engineering Recommendation G59[5] in 2014 [29], now superseded by G99 for connections on or after 27 April 2019 [30].

Table 2.2: RoCoF settings for power stations <5 MW registered capacity [29].

<table>
<tr><th>Date of Commissioning</th><th>Asynchronous</th><th>Synchronous</th></tr>
<tr><td>Generating plant commissioned before 01/02/2018</td><td colspan="2">Not to be less than K2 × 0.125 Hz/s and not to be greater than 1.0 Hz/s, with 0.5 s time delay</td></tr>
<tr><td>Generating plant commissioned on or after 01/02/2018</td><td colspan="2">1.0 Hz/s with 0.5 s time delay</td></tr>
</table>

Table 2.3: RoCoF settings for power stations ≥5 MW registered capacity [29].

<table>
<tr><th colspan="2">Date of Commissioning</th><th>Asynchronous</th><th>Synchronous</th></tr>
<tr><td rowspan="2">Generating plant commissioned before 01/08/14</td><td>Settings Permitted until 01/08/16</td><td colspan="2">Not to be less than K2 × 0.125 Hz/s and not to be greater than 1.0 Hz/s, with 0.5 s time delay</td></tr>
<tr><td>Settings permitted on or after 01/08/16</td><td rowspan="2">1.0 Hz/s with 0.5 s time delay</td><td rowspan="2">0.5 Hz/s with 0.5 s time delay</td></tr>
<tr><td colspan="2">Generating plant commissioned between 01/08/14 and 31/07/16 inclusive</td></tr>
<tr><td colspan="2">Generating plant commissioned on or after 01/08/16</td><td colspan="2">1.0 Hz/s with 0.5 s time delay</td></tr>
</table>

[5] The Engineering Recommendation G59 (now superseded by G99 for connections on or after 27 April 2019 [116]) provides guidance to generators and DNOs on all aspects of the connection process.

It is stated in [29], and highlighted in Table 2.2 and Table 2.3, that on or after the 1st of August 2016, all generators greater than 5 MW in capacity must operate using a RoCoF relay setting of 1 Hz/s and 0.5 s delay[6], with synchronous generators commissioned before the 1st of August 2016 permitted to use a 0.5 Hz/s setting. Generators with registered capacity less than 5 MW that were commissioned on or after 1st of February 2018, must operate using a RoCoF relay setting of 1 Hz/s and 0.5 s delay, while generators commissioned before the 1st of February 2018 with a registered capacity less than 5 MW, are permitted to use a setting no lower than the original 0.125 Hz/s and not greater than 1 Hz/s with a 0.5 s delay. At the time of writing, there remains about 2 GW of distributed generation using relays that could activate if RoCoF exceeds ±0.125 Hz/s [28]. However, there are plans in place to update the LoM protection settings by 2022 [31].

[6] The definition of a "0.5 s delay" leaves room for interpretation. Although discussions with industry experts reveal a predominant interpretation to be that RoCoF must be above the threshold continuously for 0.5 s before delivering a response, the delay can also be interpreted to mean that once the RoCoF exceeds the threshold (i.e. in one measurement) the response to the measurement must include a 0.5 s delay. In this thesis, the former is adopted.

2.2 Frequency Response in GB

In a power system, frequency stability is managed with the use of frequency response services. Generally, the term 'frequency response' refers to frequency containment reserves[7], however, definitions and classifications can vary between regions and in some cases, there are also crossovers when definitions are made based on operating timescales. To unpack these terminologies and classifications, giving the reader a description of frequency response terminologies used in this thesis, Table 2.4 provides a broad frequency response classification based on response trigger, nature of response, impact on frequency behaviour[8], and mode of deployment.

Table 2.4: Classification of Frequency Responses.

Response Trigger	
Static: Discreet response to frequency deviations when a frequency threshold[9] is exceeded.	Dynamic: Continuously track frequency changes to provide a proportional response.
Nature of Response	
Inherent: These are responses to frequency that are a result of the characteristics and physics of the power system, e.g. inertia.	Dispatchable: These reserves specifically dispatched and held as reserve by providers of frequency response, e.g. Primary response[10].
Impact on Frequency Behaviour	
Containment: These are reserves designed to contain frequency deviations within predetermined frequency limits and are usually thought to include both inherent and dispatchable responses.	Restoration: These are reserves designed to restore frequency within predetermined frequency thresholds.
Deployment	
Pre-Fault Services: These are frequency response services that are usually deployed to manage small changes in frequency and are usually characterised by a narrow deadband. It is common for pre-fault services to also be operational in post-fault conditions.	Post-Fault Services: These are frequency response services that are usually deployed to manage significant changes in frequency and are usually characterised by wider deadbands (or frequency thresholds) in comparison to pre-fault services.

[7] See Table 2.4 for definition. Frequency reserves refer to frequency containment, frequency restoration and replacement reserves of energy held to manage frequency and ultimately return frequency to within normal operating conditions following a power imbalance.
[8] Or operating timescales.
[9] Based on the details presented in [15], the threshold for static primary response in 49.6 Hz and the threshold for static secondary response is 49.7 Hz.
[10] See Table 2.5 for service definition.

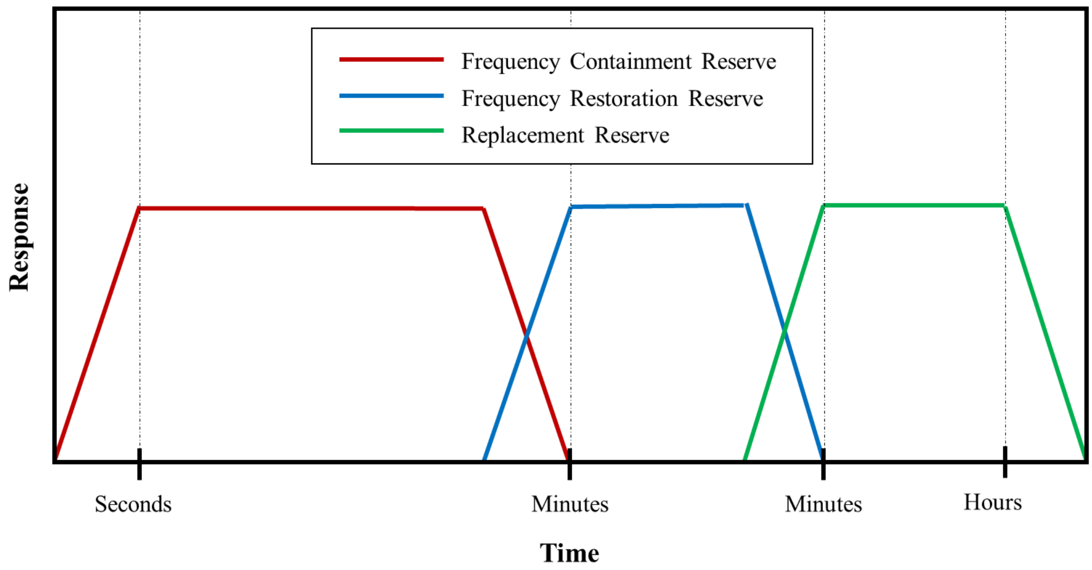


Figure 2.2: Illustrating the classification of frequency reserves based on operating timescales and role in frequency management.

Figure 2.2 further illustrates the distinction between frequency containment, frequency restoration and replacement reserve, where the latter is a reserve that corrects original power imbalance and 'resets' frequency containment and restoration reserves[11]. Figure 2.2 classifies frequency reserves by operational timescales based on the classification of reserves used by The European Network of Transmission System Operators for Electricity (ENTSO-E) [32]. The classification presented also leverages the work done in [33], alongside the definitions of frequency reserves across nine regions presented in [34]. It should be noted that frequency restoration reserves can be services that activate either within seconds or minutes depending on the region. That said, frequency restoration reserves are those that act after frequency containment reserves to restore frequency, operating into the minute's timescale, until replacement reserves can be deployed. This is why Secondary response in GB can be classified as both a frequency containment and frequency restoration service, however, for the purposes of this thesis, Secondary response (define in Table 2.7) will be classified as a frequency restoration service.

[11] Replacement reserves will not be discussed further in this thesis as it falls outside the scope of the work.

Static responses provide a discreet response when a frequency threshold has been exceeded, while dynamic responses provide a continuous proportional response to frequency changes when a frequency deadband has been exceeded. In some cases, as in GB, static responses can further include dynamic and non-dynamic services; i.e. services that would activate when a frequency threshold has been exceeded to provide either continuous or discreet response. The delivery of dynamic frequency response services is regulated via dedicated controllers such as a governor. As illustrated in Figure 2.3 below, the controller allows for a change in power output as a function of the gain and speed change, where the rate of the delivery of the response is limited by the ramp rate limiter, and the power output limited by the power limiter. The gain applied for a speed change as a result of a change in frequency is the inverse of the droop characteristic.

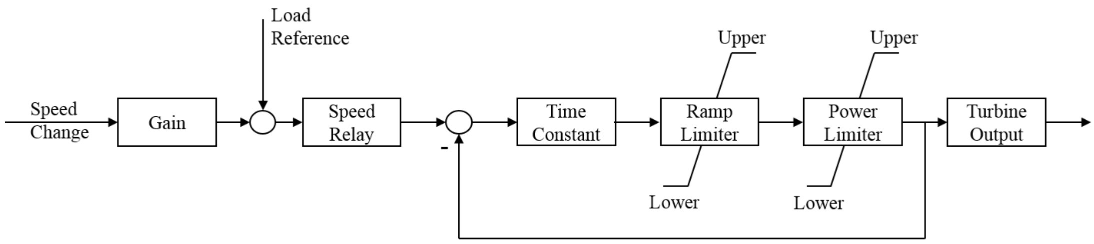


Figure 2.3: A simplified illustration of a basic turbine governor adapted from [35].

By their definition frequency restoration services will act after frequency containment services and are therefore solely post-fault services, and they include only dispatchable services. On the other hand, frequency containment services can be either pre-fault or post-fault, a distinction that is becoming increasingly prevalent in the new frequency response service designs that will be discussed in section 2.4.3. At the time of writing, the GB ESO utilises four frequency response services that are described in Table 2.5, highlighting their compliance definitions and relating their classification to Table 2.4.

Table 2.5: Overview of GB Frequency Response Services [9, 36, 37].

Service Name	Definition
Primary Frequency Response (PFR)	This is a dispatchable frequency containment service that is made up of both static and dynamic responses. It can be considered a pre-fault and post-fault service with a narrow operational deadband of 0.015 Hz for dynamic services and a 49.6 Hz threshold for static services. Dynamic: Full delivery of active power response no more than 10 seconds after the event with a maximum 2 second delay and sustained for a further 20 seconds. It is the dominant means of containing frequency excursions caused by LoIF events. Static: Full delivery of response within 1 second of frequency exceeding the frequency threshold.
Secondary Frequency Response (SFR)	This is a dispatchable, post-fault, frequency restoration service that is made up of both static and dynamic responses. There isn't a defined deadband for dynamic services but there is a 49.7 Hz threshold for static services. Dynamic: Full delivery of active power response no more than 30 seconds after the event and sustained for 30 minutes. It plays a vital role in restoring frequency excursions caused by LoIF events. Static: Full delivery of response within 30 seconds of frequency exceeding the frequency threshold with a maximum delay of 20 seconds.
High Frequency Response (HFR)	This is a dispatchable frequency containment service that persists into restoration timescales that is made up of both static and dynamic responses. It can be considered a pre-fault and post-fault service with a narrow operational deadband of 0.015 Hz for dynamic services. Dynamic: Full delivery of active power response no more than 10 seconds after the event with a maximum 2 second delay and sustained indefinitely. It is the dominant means of containing frequency excursions caused by LoL events. Static: The ESO indicates that this product/service exists and it is assumed to be symmetrical to that used in PFR, there is no indication of any additional definition specific to static High frequency response.
Enhanced Frequency Response (EFR)	This is a solely dynamic, pre-fault and post-fault dispatchable frequency containment service that persists into frequency restoration timescales. It is defined as the full delivery of response for a 0.5 Hz change from nominal 50 Hz frequency that is sustained for 15 minutes, with the capability to fully delivery response within 1 second. This supplementary service for both LoIF and LoL events is designed to improve response to frequency disturbances as the power system tends towards lower inertia.

The operational timescale of the dynamic versions of the services in Table 2.5 are illustrated in Figure 2.4. It should be noted however that in practice there is no distinction for a provider that is delivering dynamic Primary and Secondary, and indeed the combination of the two can be considered a symmetrical service to dynamic High frequency response. Contrary to definitions and market products, there exists no dynamic secondary-only frequency response product or service in GB.

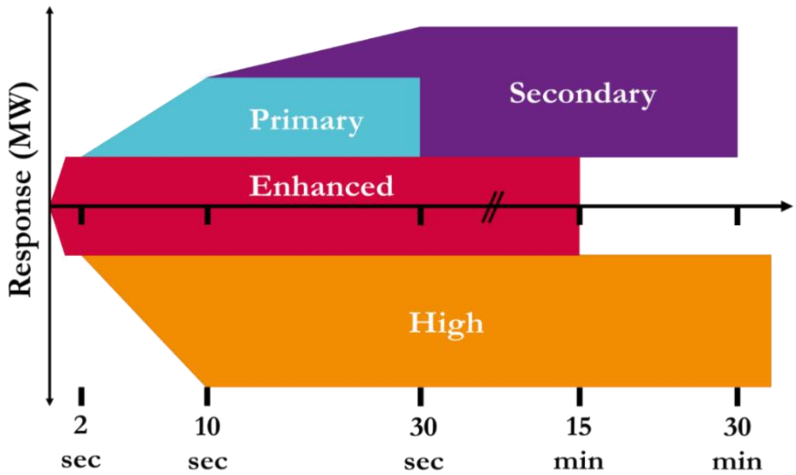


Figure 2.4: Current GB frequency response services [9].

Historically dynamic Primary, Secondary and High frequency responses have been delivered by synchronous generators, e.g. gas plants, however, non-synchronous providers such as wind turbines have recently started delivering these services [38]. Static versions of these frequency response products are typically delivered by demand side sources. Recently, advocates of future frequency response services propose fast frequency responses. These services are typically characterised as a classification of containment services that operate at a timescale that is faster than conventional frequency containment services, e.g. Primary response. Enhanced frequency response is a fast frequency response service deployed by the GB ESO. It is designed to supplement the existing Primary, Secondary and High frequency response services.

With the exception of EFR, the droop characteristic of dynamic services for in GB is between 3% and 5%, with 4% being typical [39]. A 4% droop means that the providers of this service must deliver 100% of its capacity for a 4% change in frequency or speed, as illustrated in Figure 2.5, where ΔP is the change in power, P_{ref} is the maximum capacity of the unit and Δf is the change in frequency. EFR utilises the droop characteristic illustrated in Figure 2.6, and the initial tender round of the service gave a choice of either a 'narrow-band' service that has a ±0.015 Hz deadband or a 'wide-band' service that has a ±0.05 Hz deadband. In either case, the service must take no longer than 500 ms to detect the event and instruct a response, so that the active power response is fully delivered within 1 second after the event [40]. All the existing EFR products procured via the tender round utilise the 'narrow-band', and the service is delivered by batteries [41].

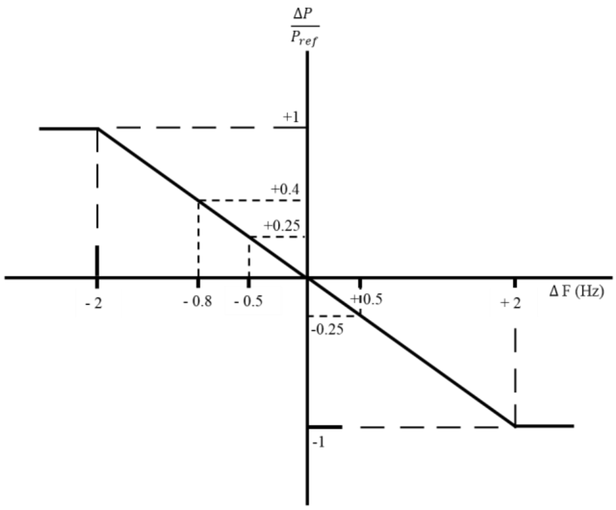


Figure 2.5: An illustration of the 4% droop characteristic adapted from [39].

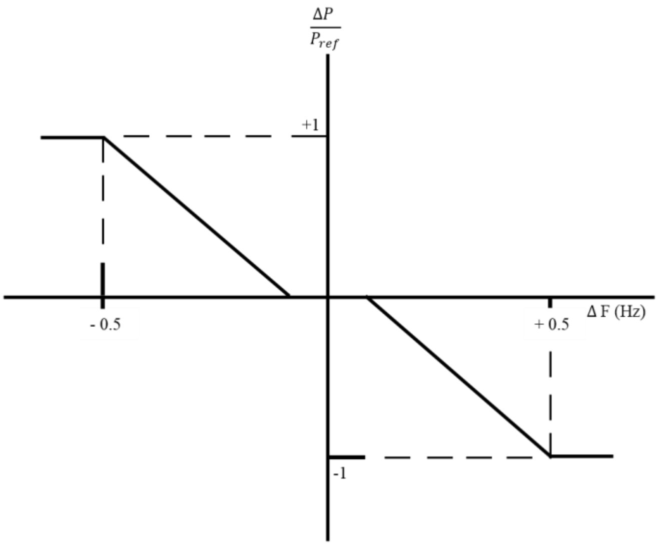


Figure 2.6: An illustration of the EFR droop characteristic adapted from [40].

2.3 GB Frequency Response Market and Procurement

The ESO has conducted a review and, at the time of writing, is updating frequency response services as well as other products that make up its ancillary services. Ancillary services facilitate and support the continuous flow of electricity so that supply will continually meet demand. Their purpose is to provide support across the electricity system and to ensure stability and security at all times [42, 43]. While the services and market structures are under review, existing contracts for the services listed below will be honoured. The proposed changes to the services will be presented later in this section.

At the time of writing, the ESO procures frequency response through service agreements, which include mandatory frequency response (MFR) and a commercial tender process called firm frequency response (FFR) [44], as shown in Appendix 3, with the payment structures outlined in Appendix 4. In 2016, a one-off tender for EFR was held and procured 201 MW of response through eight four-year contracts[12]. Plans are in place to commence a two-year trial of an auction mechanism for frequency response products from June 2019, during which time the precise arrangements for this market will be refined. In 2017/18, approximately 55% of the 12 TWh of response holding came from MFR, 44% from FFR and 1% from EFR, while in 2018/19 approximately 32% of the 19 TWh of response holding came from MFR, 58% from FFR and 10% from EFR [1][13].

All MFR is dynamic, meaning that active power changes automatically and proportionately in response to a frequency deviation outside the given deadband, and it is a Grid Code requirement for all large power stations[14] as defined in (Appendix 5) connected to the power network to have this capability [38]. The response products within the MFR market are dynamic Primary, Secondary and High frequency responses, and are procured from minutes to hours ahead by the ESO. Instructions to provide MFR are typically accompanied by repositioning instructions via the

[12] It should be noted that while there is also an additional 26 MW of EFR contracted through bilateral agreements ahead of the EFR procurement process. The ESO state 201 MW of EFR was procured during the 2016 tender process.
[13] EFR holdings are assumed based on the EFR tenders and deployment.
[14] This is true for all ‘large’ power stations regardless of technology.

Balancing Mechanism to create the necessary head-room or foot-room[15]. FFR has been designed to complement other frequency response services and, unlike MFR, the capability to provide FFR is not a Grid Code requirement but it is rather open to any potential provider not just those with a mandatory service agreement. Both dynamic and static Primary, Secondary and High frequency responses, are contracted via the FFR market.

Commercial Primary response is procured via monthly FFR tenders from one to 30 months ahead. In 2017-18, approximately half of accepted tenders for dynamic Primary response were for durations of one month, while the remainder were for periods of 2 to 24 months. However, these one-month contracts only represent 6% of the accepted tenders by volume, indicating that most FFR is procured through a small number of large contracts. In the FFR market, Primary, Secondary and High frequency response are often bundled together in a single tender meaning that National Grid must accept all or none of Primary, Secondary or High FFR from a single provider with a single payment structure, as outlined Appendix 4, regardless of whether all or only a subset of services are required. In practice, availability and nomination fees dominate the market, with small providers only requesting an availability fee, and larger providers requesting both an availability and nomination fee.

The volumes of each frequency response product procured are determined by analysis of the system's needs and current loss-risks, as well as commercial considerations, using simulation tools [13] very similar to those described in chapter 3. For procurement of FFR, a view of the system's requirements for the months ahead is required and tenders are accepted, or not, based on the GB ESO's assessment of their value relative to price. This can be challenging as potential providers can offer bundles of Primary, Secondary and High frequency response, and request various types of remuneration, e.g. availability fees, utilisation fees, nomination fees, and so on. Units with FFR contracts must then schedule and dispatch themselves in such a way that they are able to meet their contract obligations. MFR, on the other hand, has a simpler remuneration scheme (see Appendix 4) and is procured in close to real time from the

[15] Head-room and foot-room are the amount of spare capacity that a plant has from which response is delivered, e.g. if the plant is 75% loaded then the headroom is 25%.

pool of generators that are already operating as it is usually expensive (for consumers) for the ESO to instruct a generator to start-up if not already scheduled to do so.

Historically, National Grid's demand for Secondary response has been greater than Primary response, and as such, it is Secondary response that drives FFR tenders. Figure 2.7 and Figure 2.8 illustrate the effective supply curves for Primary and Secondary response for delivery in July 2017. The need for Secondary response is filled in a least-cost fashion. Furthermore, in practice, Secondary response, as defined in GB today, is the extended delivery of Primary response; no dynamic *Secondary-only* product or service exists. As a result, the procurement of Secondary response is always accompanied by some Primary response. This significantly impacts price discovery and competition for Primary response, effectively paying a premium for Primary response when it is bundled with Secondary. Figure 2.7 illustrates the supply curve for Primary response with accepted offers highlighted. Lower cost offers are not accepted, while more expensive offers are accepted because they are bundled together with offers for Secondary response. Many providers of Primary-only response are able to offer this service at much lower prices than the volume weighted FFR price [45].

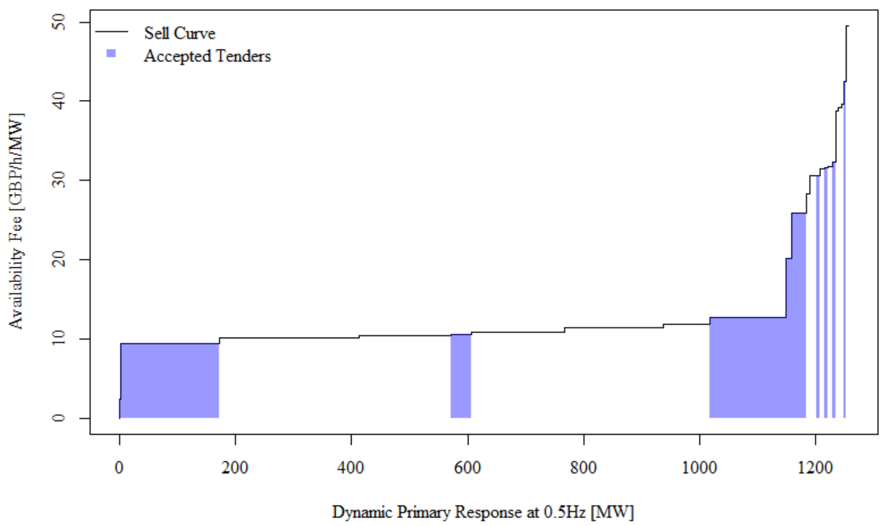


Figure 2.7: Effective Primary response supply curve for delivery in July 2017 [45].

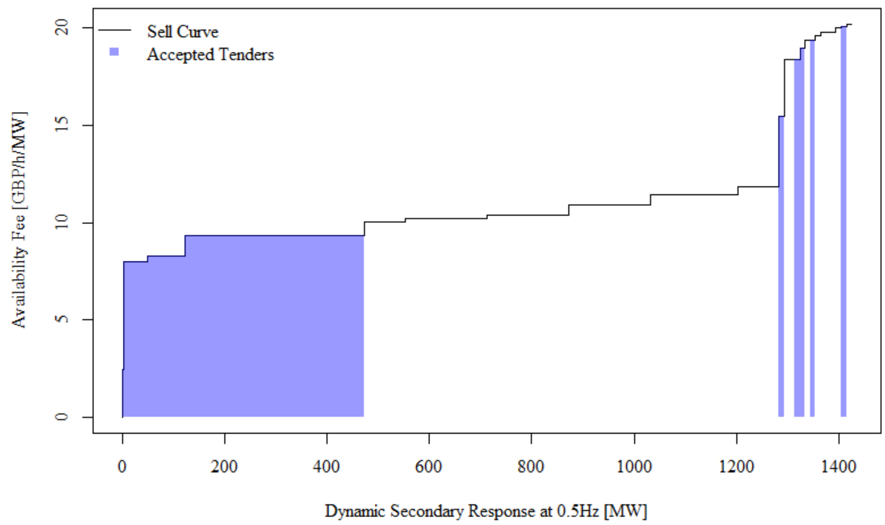


Figure 2.8: Effective Secondary response supply curve for delivery in July 2017 [45].

Although non-synchronous generators are increasingly displacing synchronous generators in the power landscape, they are typically not competitive in the provision of bundled response services under the current market arrangement and face other barriers to entry. Wind and solar power plants cannot participate in month-ahead FFR tenders because their availability to provide response services depends on the weather and cannot be accurately forecast on this timescale. The weather forecasts that drive power forecasts are accurate up to a few days ahead, but beyond this forecast uncertainty increases significantly [46]. Furthermore, because a wind or solar plant would need to leave headroom in order to be able to provide Primary or Secondary response, this would only be economic if the value of the response service was greater than the market value of the energy, plus any subsidy, if applicable[16]. In contrast, ancillary services are attractive for fuel-based generators if the value of the service is greater than the value of energy minus fuel costs. Periods where technologies with no fuel cost are more competitive may occur in the future but are not a feature of the present GB market.

Wind Power Plants (WPPs) can and do participate in the Mandatory market, where the GB ESO is able to procure services in close to real time when forecast uncertainty is

[16] i.e. the opportunity cost of providing the response service.

manageable. Participating WPPs are competitive providers of High frequency response; however, in order to procure Primary and Secondary response from wind, the GB ESO must take actions in the balancing mechanism to create the necessary headroom. These actions are paid-as-bid and remunerate any costs incurred by the unit being repositioned making it relatively expensive for WPPs to be used for Primary and Secondary response. Furthermore, WPPs must incorporate the uncertain cost of utilization into their availability fee, as they are not directly remunerated for energy delivered (or not) as a result of MFR provision, though they are impacted by lost/gained subsidy revenue from total energy produced (or not). These costs are likely to be much lower for future WPPs without energy-based subsidies, as at present the majority of this cost is to cover lost subsidy revenue.

In the case of technologies like WPPs that receive energy-based subsidy payments, the utilisation of High frequency response results in lost revenue, which would also need to be accounted for in the tendered price of the provision of this service [33]. This is particularly true in FFR. Since Primary, Secondary and High frequency responses are, at the time of writing, bought by the ESO as a bundle, generators such as WPPs would not be able to compete with other generators such as gas plants despite potentially being able to offer Primary response at a low cost. It should be noted that the provision of "synthetic inertia" [47, 48] makes it possible for WPPs to provide response without headroom; however, the response provision is followed by a recovery period (synthetic inertia is discussed in section 2.4.3) that may lead to further issues [47, 49]. Furthermore, there is no market for synthetic inertia in GB at present.

While the ESO honours existing contracts for the services under the arrangements in Appendix 3, the ancillary services and related markets are under review, and to date some definite changes have been made. Rapid frequency response has now been removed from the services market, the rationale being that, although the service was geared towards wind assets and other providers capable of providing this type of response, there had been no tenders, and so the delivery of this scale of response has been incorporated into the planned improved frequency response product [50]. Similar steps were taken for other products, detailed in [50].

Other changes in progress involve improvement to the procurement processes currently in place, including the length of contracts and the daily windows. National Grid ESO is moving towards a more standardised and comparable duration of contract. The new contract duration means that providers will only be able to submit tenders for fixed monthly, quarterly and seasonal durations [45]. Similarly, with regards to daily windows, National Grid is moving from ‘number of hours per day’ that the provider is available (further split by working days, Saturdays and Sundays/Bank Holidays), to a closer alignment with Electricity Forward Agreement (EFA) blocks, the timings of which are every four hours starting from 23:00 [51]. Lastly, the ESO is addressing one of the main barriers to entry into the commercial frequency response market faced by technologies that have limited forecast or control of their availability such as solar and WPPs, i.e. the procurement window. The GB ESO is working towards changing the process from a month-ahead market to a closer to real-time, with a trial using a pay as clear mechanism planned. This trial will initially procure frequency response at week-ahead and depending of the success of the trial potentially moving to day-ahead [51].

2.4 Frequency Response and Changing System Inertia in GB

Annual electricity demand in GB is expected to increase by 2050, especially when considering the electrification of heat and the uptake of electric vehicles (EVs), which would need to be met by increasing supply of electricity that, for the most part, is expected to come from renewable, non-synchronous, generation and HVDC interconnectors. According to the future energy scenarios (FES) reports that the GB ESO publishes annually, it is projected that up to 50% of installed generation will be distribution connected by 2050 [52]. Installed generation capacity will be increasingly met by non-synchronous generation (illustrated in Figure 2.9 and Figure 2.10), displacing synchronous generators that are the predominant providers of Primary, Secondary and High frequency responses. In addition to reducing the percentage of installed electricity capacity met by flexible synchronous generators, it is also projected that the inertia in the power system will reduce, as shown in Figure 2.11. These changes to the power landscape raise questions as to the assurance of frequency stability[17] in future low inertia power system.

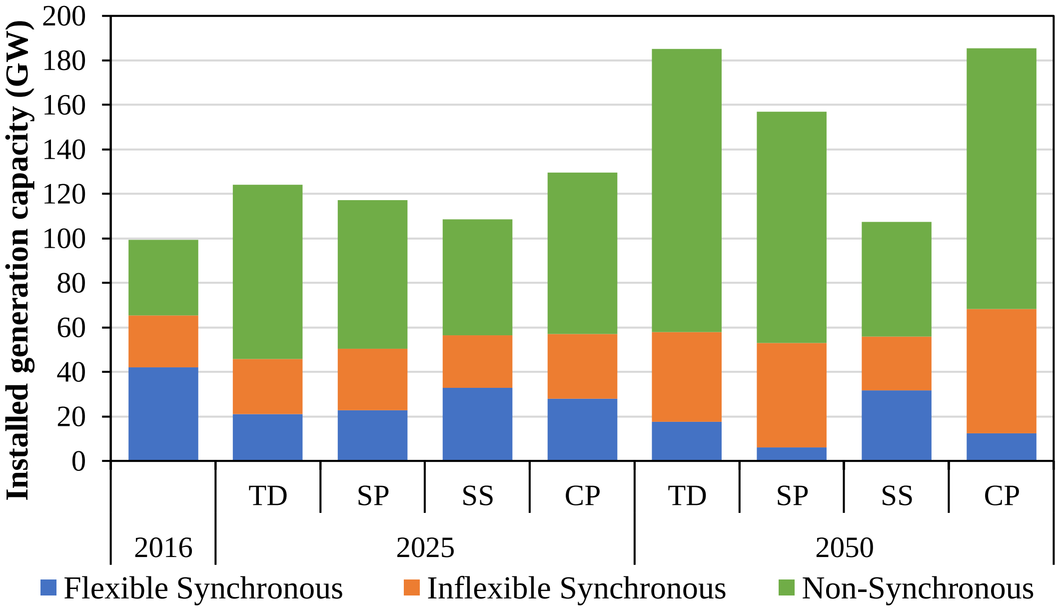


Figure 2.9: Synchronous and non-synchronous generation capacity, adapted from [52]. Two Degrees (TD), Slow Progression (SP), Steady State (SS), Consumer Power (CP).

[17] The assurance of dynamic frequency responses in particular.

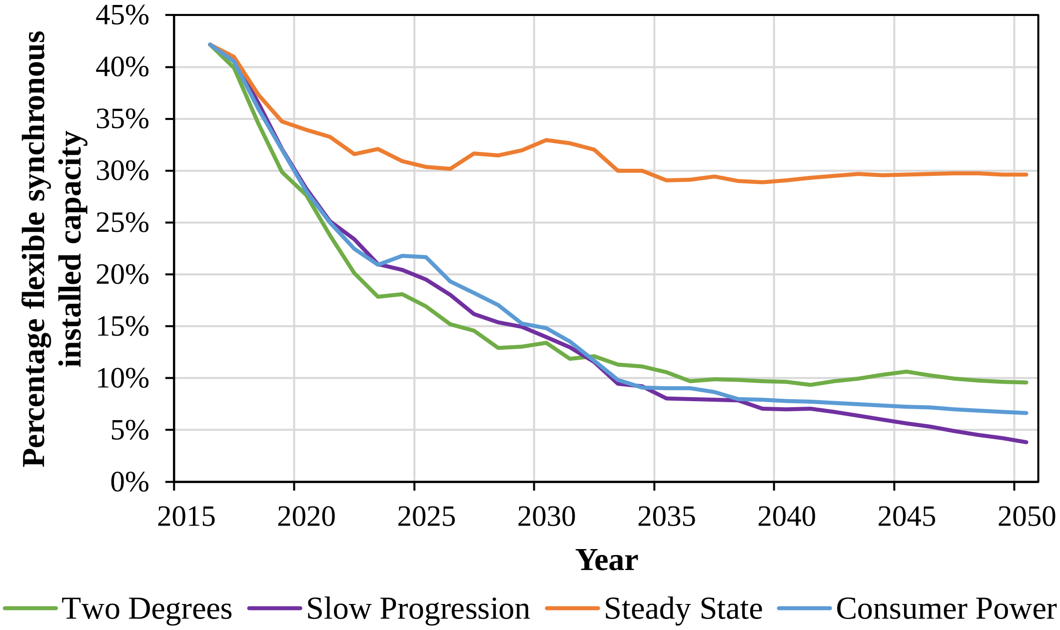


Figure 2.10: Reduction in percentage of flexible synchronous generation that makes up installed capacity, adapted from [52].

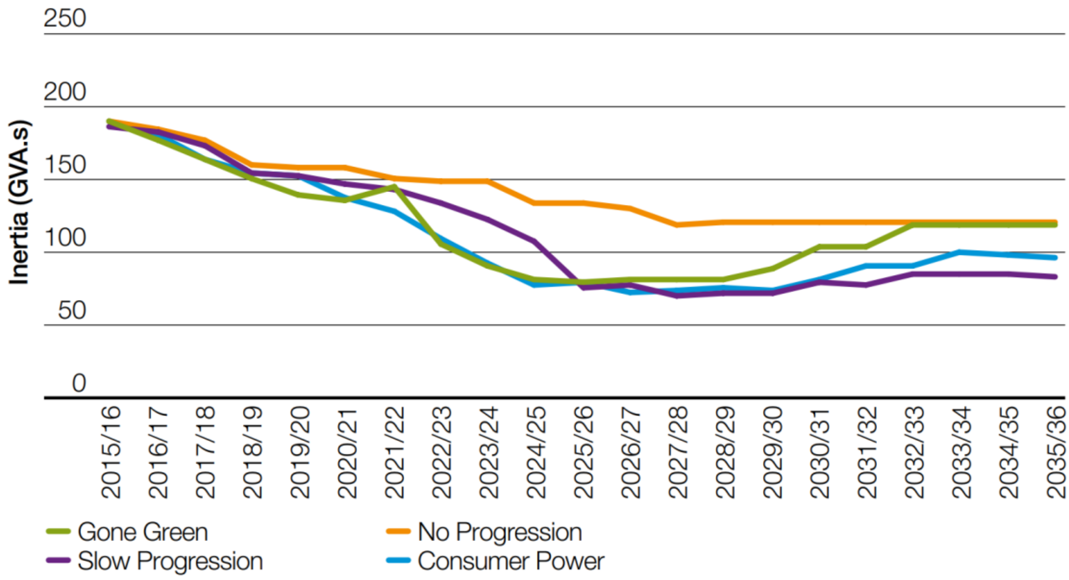


Figure 2.11: System inertia excluding contribution from embedded generation [53].

Another factor that exacerbates the challenge of managing frequency stability in a low inertia GB power system is the increase in maximum loss risk from 1320 MW to 1800 MW, as discussed previously in section 2.1, which translates to a higher RoCoF for the same system inertia via (2.1), with frequency able to fall or rise more rapidly that it has historically; further compounding the question around the assurance of frequency stability in a future low inertia GB power system. In addition, it is projected that in the Summer minimum demand on the transmission network will be as low as 5 GW (see Figure 2.12), with less than 30 GW of demand[18] expected for a little more than half the year by 2025 [9]; bearing in mind that the installed capacity of distributed generation is project to be up to 40% by 2025.

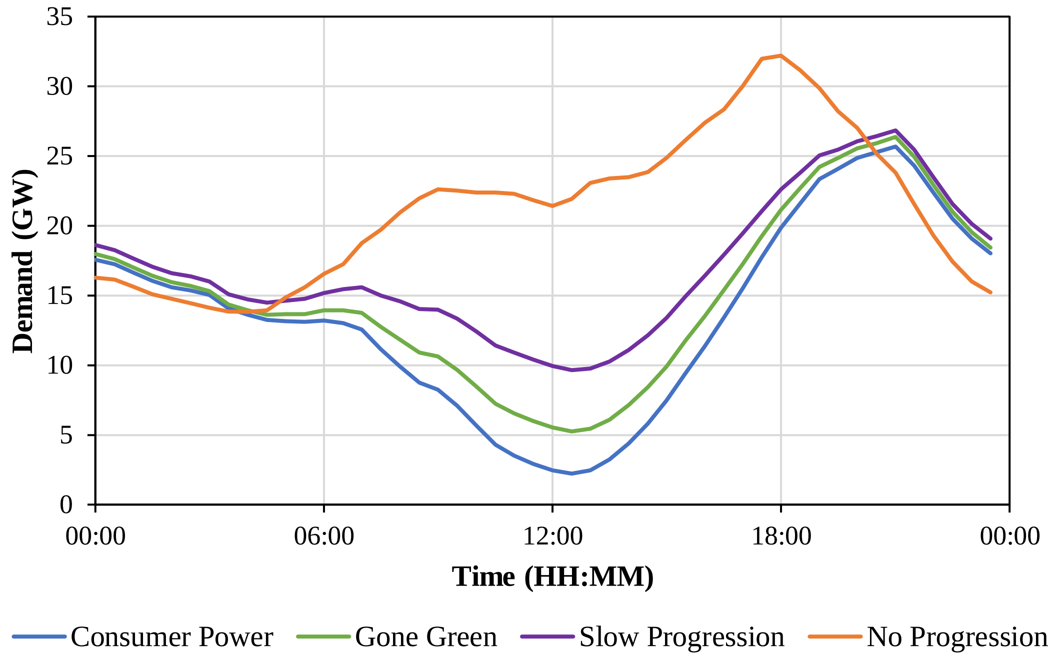


Figure 2.12: Variation in demand as seen from the transmission system, i.e, exported from the transmission network via grid supply points, for the 22nd June 2025 adapted from [9].

The system operator is obligated to manage credible loss risks within frequency and RoCoF limits, and as the inertia in the power system reduces, the challenge of assuring frequency stability increases which increases the risk of demand disconnection and blackouts. Power systems around the world are already experiencing the challenges associated with the changing power landscape. On the 7th of August 2016, the

[18] Although this might seem in conflict with higher annual demand projections, the reader is reminded that transmission demand refers to exports from the transmission network.

generation dispatched by the GB market participants delivered a system inertia of 135 GVAs, with a demand seen from the transmission system of 16.3 GW, due to the combination of a windy weekend with high output from WPPs, low demand and high solar output from the 7th to the 8th of August 2016 [9], as shown in Figure 2.13 and Figure 2.14.

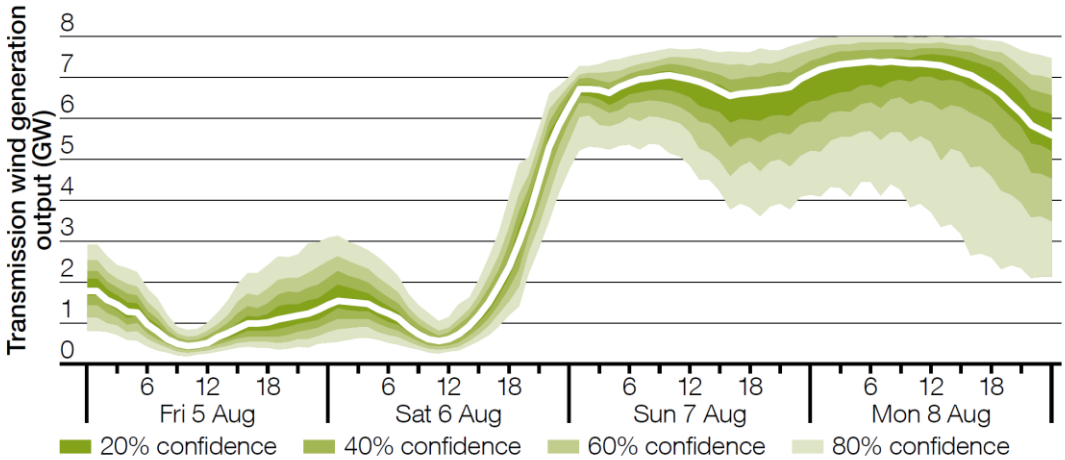


Figure 2.13: Transmission connected wind generation forecast [9].

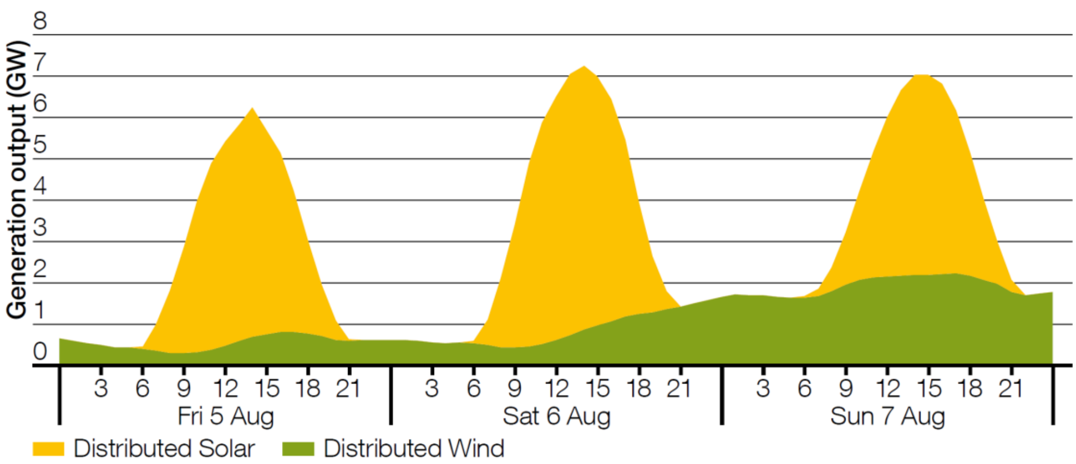


Figure 2.14: Distributed wind and solar generation forecast [9].

Alongside the forecasted production from WPPs and solar power plants (SPPs), it was also forecasted that there wouldn't be enough flexibility to manage any surplus generation (downward regulation). During this period, electricity was sold via the interconnectors, exporting power away from GB, which alleviated the downward regulation concern, since it increases power demand on power stations in GB and allowed more synchronous plant onto the system. Considering that there was already insufficient reserve to provide high frequency response for a loss greater than 580 MW, the amount of power sold over the Dutch interconnector was limited; if an interconnector bipole exported more than 560 MW, it would have become the largest demand loss risk. Further details on the chains of events can be found in [9].

The changing power landscape and the resultant question surrounding frequency stability in a low inertia power system isn't exclusive to the GB power system. Indeed, in recent years other countries have seen a significant increase in non-synchronous penetration. For instance, Nordic operators highlight frequency stability as one the concerns as a result of a lower inertia power system due to increasing renewables penetration and the shutting down of nuclear power plants [54]. In the United States of America (USA), the ERCOT (Electric Reliability Council of Texas) power system is composed of 20% wind generation capacity that meets around 15% of total power consumption on average with the occasional 54% instantaneous penetration, and there are plans to expand wind generation capacity [55].

The Irish power system is also facing similar challenges. The island of Ireland's power system historically consists of two networks in the Republic of Ireland and Northern Ireland, which, at present, are connected by one double circuit 275 kV and two 110 kV transmission lines [56]. There has also been a push towards more renewable generation that in the case of Ireland translates to about 4 GW of WPPs by 2020 [57, 56, 58]. Ireland has a target of 40% renewables by 2020 that is expected to come mostly from wind power plants [59], and as of 2018 wind power plants were 27.6% of the fuel mix in Ireland (total renewables were 32.5%) [60]. As already discussed, the uptake of such non-synchronous generation displaces synchronous generation and presents challenges to the power system, similar to those impacting the GB power system [57].

In a study reported in [57] concerning the maximum instantaneous non-synchronous penetration in the power system on the island of Ireland, a metric called the system non-synchronous penetration (SNSP) limit is proposed. The equation for calculating SNSP is defined in (2.2), where *NSG* refers to the system non-synchronous generation,

P_{load} is the system demand, and $P_{HVDC(import)}$ and $P_{HVDC(export)}$ are the power imported and exported through HVDC interconnections.

$$SNSP = \frac{NSG + P_{HVDC(import)}}{P_{load} + P_{HVDC(export)}} \tag{2.2}$$

Using a LoIF contingency of 500 MW, the study in [57], alongside other studies as part of the All Island Grid-Study [61], formed the basis of definitions in the operation of the Irish power system [56]. The base metric (the SNSP) was used and it showed that frequency stability of the power system could be compromised if the SNSP exceeded 50% without undertaking further actions. An upper limit was also defined at 75% SNSP that could be achieved if certain measures were taken, including: improvement to its frequency response services and market; enhanced performance monitoring; and improved resolution of RoCoF. It is shown in [56] that in January 2015 wind penetration exceeded 60% on several days, which is greater than the then prescribed 50% SNSP limit. The key question that arises, in relation to the scope of this research project, is: How does the Irish system cope with such penetration levels?

Operation and technical limits are often reached at high volumes of wind capacity, and, more often than not, any corrective actions taken by the Irish SO involve issuing commands to the WPP. These include active power dispatch, reactive power setpoints, and curtailment and constraint commands. A distinction is made here between curtailment and constraint in Ireland, where curtailment refers to dispatch down of generation for system-wide security reasons, while constraints refer to the same but for localised security reasons. According to [56], a WPP can be curtailed if any of the following limits are at risk: low synchronous inertia, approaching dynamic and transient stability boundaries; operating reserve requirements; steady-state and dynamic voltage control requirements; load rise requirements; and exceeding the SNSP limit. For the most part, these limits and resultant actions are concerned with maintaining a minimum number of synchronous generators online at strategic locations, particularly at night time and during low demand periods. In some cases, HVDC import into the island can be reduced to decrease the need for wind curtailment.

In order to cope with the challenges associated with managing a low inertia power system with increasing penetration of non-synchronous generation the DS3 (Delivering a Secure, Sustainable Electricity System) programme was deployed. The DS3 programme aims to facilitate secure operation of the power system at up 75% instantaneous penetration of non-synchronous renewable generation. Since it was established in 2011, the programme has focussed on technical and commercial mechanisms to incentivise and improve system performance and capability, including making grid code modifications and system policies [59]. The Irish have also introduced new products such as Synchronous Inertial Response (SIR) and Fast frequency response (frequency containment products) [62], which are deployed to support the transition towards a lower inertia power system. SIR is a stored kinetic energy response that is immediately available from synchronous machines. It has a significant impact on RoCoF and can therefore be deployed to facilitate increased penetration of non-synchronous generation. The Fast Frequency Response is a frequency containment service that is available to both synchronous and non-synchronous generators (also open to energy storage, HVDC interconnectors and demand side aggregators) that can provide a fast-acting response that supplements any inherent inertial response. This service is designed to activate faster than their Primary Operating Reserve product (the predominant frequency containment service used in Ireland prior to the service updates), increasing the time it takes for a significant power imbalance to cause frequency to reach a nadir (or zenith) [63]. The Fast Frequency Response product runs in conjunction with SIR, so providers that can maintain or increase their outputs are eligible for both services. In the Irish power system, the Fast Frequency Response product is defined as an active power response that is available within 2 seconds of the event and sustained for at least a further 8 seconds. Furthermore, any extra energy provided in the 2 – 10 second timeframe must be greater than any loss of energy in the 10 to 20 second timeframe [63]. The latter definition permits synthetic inertia as a service within Fast Frequency Response product [64]. In order to drive investment towards the necessary system services, Ireland also deployed scalars that account for the specific product, performance and scarcity, so that these factors are reflected in the payments made for the services. Further information on the system services scalar design can be found in [65].

Considering these cases and the changing power landscape in the context of the GB power system one might ask: What strategies can be deployed to mitigate the challenge of frequency stability in a future low inertia British power system? Operational practices such as the SNSP deployed in Ireland certainly have the potential to be a valuable tool for the system operator when dispatching and planning the system. However, any such practice designed to facilitate low inertia and increased uptake of renewables will also need to address these concepts: improving flexibility; increasing system inertia; and providing fast frequency response.

2.4.1 Flexibility

Flexibility is the extent to which a power system can respond to the imbalance between electricity production and consumption whether expected or not [66, 67]. The four main sources of flexibility are: grid infrastructure; dispatchable generation; storage; and flexible demand [68, 69]. The benefit provided by conventional plants in terms of flexibility is dependent, to varying degrees, on the fuel type, i.e. coal, gas, nuclear, etc. For instance, a gas plant can readily ramp up active power production via a dedicated controller in the event of a power imbalance, while nuclear plants, unless specifically designed to do so, do not provide this form of response to a power imbalance.

Dispatching more synchronous plants to improve flexibility, results in additional units to provide frequency response reserve with the added benefit of increasing the inertia in the power system. However, in their majority these synchronous plants utilise fossil fuels and, therefore, increasing flexibility in this manner can be in conflict with the current drive towards sustainability, not to mention the associated cost implications. On the note of cost, improving flexibility by deploying more synchronous plants was investigated by the Enhanced Frequency Control Capability (EFCC) project and was concluded to incur an additional cost of about £600m per annum by 2020 [70]. Although the basis behind these costs is unclear, it is evident that these factors will incur an increasing additional cost to system operation.

Although incapable of providing a synchronous inertia response, WPPs, HVDC interconnectors and other non-synchronous technologies offer flexibility by virtue of their high degree of controllability. Those non-synchronous technologies are particularly suitable for frequency management during periods of low inertia, which typically coincide with high productivity from sources such as WPPs and SPPs. However, these plants are considered variable since their production is heavily dependent on the environment, i.e. wind speed and solar irradiance. That said, innovative control strategies and market principles could be applied to optimise the capabilities of these technologies [53, 68].

Demand Side Flexibility (DSF) includes demand resources deployed to shift power demand from one period to another, and demand resources that provide a response during a power imbalance [71, 72]. The authors in [71] provide a review of flexible demand projects conducted in the UK. Participation in flexible demand services requires proactive consumers, typically under a prearranged agreement. Flexible demand services require accessibility and value that can be used to incentivise consumer participation [73]. According to the GB ESO in [72], there is an increasing participation in DSF. However, there is still the challenge of unpacking the complexities of services, supplier contracts and industry codes, and stacking revenue streams to justify investment. In addition, existing lack of knowledge and perception of risks and benefits leads some potential participants to consider the rewards insufficient [72]. Although aggregators offer a potential route to market for domestic households, their participation would be more technically feasible as an increasing number of smart meters are deployed. Furthermore, social barriers such as concerns over the control of appliances, behavioural change, and data security, remain existing barriers to domestic household participation in particular [73, 74].

Thermal storage, pumped hydro storage, compressed air, fly wheels, batteries, and even hydrogen, are optional methods for energy storage being investigated, which when applied to the grid will improve flexibility by facilitating the frequency response capability of the power system [75, 76, 77]. Storage technologies, such as batteries, allow excess energy produced to be stored for later use, they can be directly incorporated into frequency response services, and in the case of batteries can activate quickly; as with the battery assets that currently deliver EFR [41]. Although the speed of response activation of these and other non-synchronous technologies, is at present not fast enough to mimic inertia, they are capable of providing fast acting response. Energy storage can also be combined with WPPs and SPPs, so that energy can be stored during overproduction and utilized during underproduction [75, 76, 77, 78]. A study conducted in [79] suggests that storage technologies will become more competitive in the future, which will increase their viability in power system applications.

Interconnectors are bi-directional transmission lines that can be AC or DC, depending on the length of the cable. As an islanded transmission area surrounded by sea, the interconnectors between GB and other transmission areas are converter based HVDC transmission lines. HVDC interconnectors are classified, depending on the converter technology, into voltage source converters (VSC) and line commutated converters (LCC). HVDC interconnectors, like other non-synchronous technologies, are capable of employing control strategies that facilitate the increase or decrease of power flow for frequency management, increasing power system flexibility [80].

2.4.2 Increasing System Inertia

Improving flexibility by deploying more synchronous generators has the by-product of also increasing the inertia in the power system. However, if curtailment of renewables is too expensive, and short circuit, voltage control capability and synchronous inertia are important, then synchronous compensators (SCs) are an option. The typical configuration and components of a SC is shown in Figure 2.15.

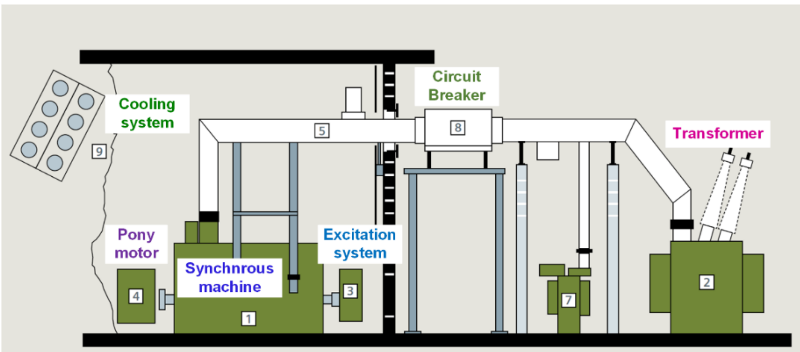


Figure 2.15: Typical configuration of a SC and its main components [81].

Also known as synchronous condensers, SCs are unloaded synchronous machines that are considered to have the potential to offer, among other benefits, a boost to system inertia and an increase to system fault level [82]. In [75], SCs are considered to have the potential to address RoCoF issues, regional stability, voltage management, and reduce the risk of loss of commutation in LCC HVDC links. It is an established technology, which could be purchased for purpose or retrofitted by taking advantage of synchronous plants scheduled for decommissioning. However, GB wide-deployment will require further investigation, a cost-benefit analysis and the determination of a suitable market arrangement. To that effect, a joint ScottishPower and National Grid project called Phoenix, is currently conducting studies on the deployment of SCs in GB [83].

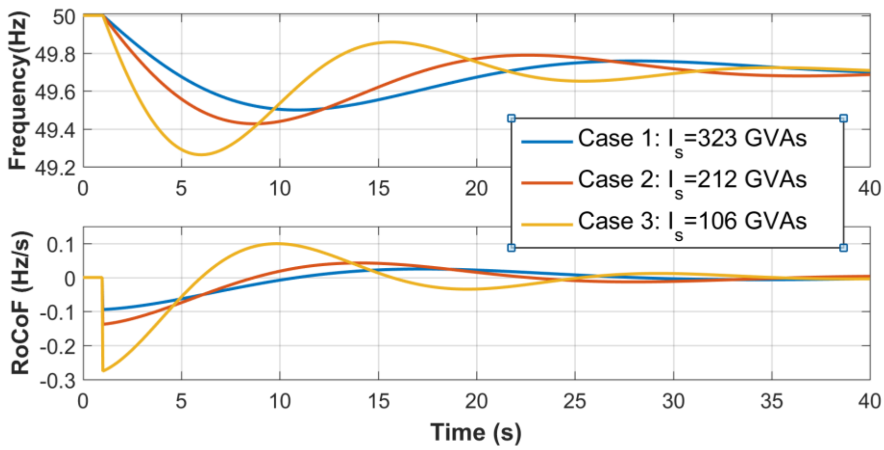


Figure 2.16: Impact of inertia on the frequency behaviour during power imbalance [84].

Figure 2.16 shows the frequency behaviour of a power system under the same amount of power imbalance but at different inertia levels, which is used to illustrate the benefit of using SCs to increase system inertia. It can be seen that, as the inertia value increases, the RoCoF decreases, which in turn leads to a higher minimum frequency (frequency nadir) for the same event. In Figure 2.16, from Case 2 to Case 1, the frequency nadir is raised from 49.42 Hz to 49.5 Hz, and the magnitude of initial RoCoF is decreased from 0.13 Hz/s to 0.10 Hz/s by deploying about 100 GVAs of additional inertia via SCs, equivalent to a 50 GVA SC that has an inertia constant of 2 s. In [85], the ESO considers using SCs to increase inertia to be less economic than managing the loss risk. However, a recent statement by the ESO indicates the possible emergence of an inertia market [86]. At present, managing the loss risk involves curtailing the largest loss, so that a loss during a period of low inertia prevents RoCoF from exceeding the ±0.125 Hz/s limit. The performance of ESO actions in containing current and future loss risks is discussed in section 5.1.

Consider for example the situation where the normal loss risk is still 1 GW as described in [20]. According to SOF by 2025/26 the loss limit will be 650 MW about 25% of the time [9]. This means that BritNed, a 1 GW interconnector, will have to be curtailed by 350 MW for more than 2000 hours a year to comply with system security limits. A constrained interconnector for 25% of the year means that a total of 705.6 GWh will be curtailed. National Grid in [70], puts the cost of curtailing loss risk as a solution to the issue of meeting the low RoCoF limit of ±0.125 Hz/s at £268m per annum by 2020, which is expected to increase year by year. Notwithstanding, this sort of curtailment already takes place [9], and while currently a viable solution, it is very likely that in the future the costs associated with curtailment will increase, fuelled in part by more HVDC interconnector capacity.

2.4.3 Fast Response

Relative to Primary response, a fast frequency response service is a frequency containment service that is capable of either or both:

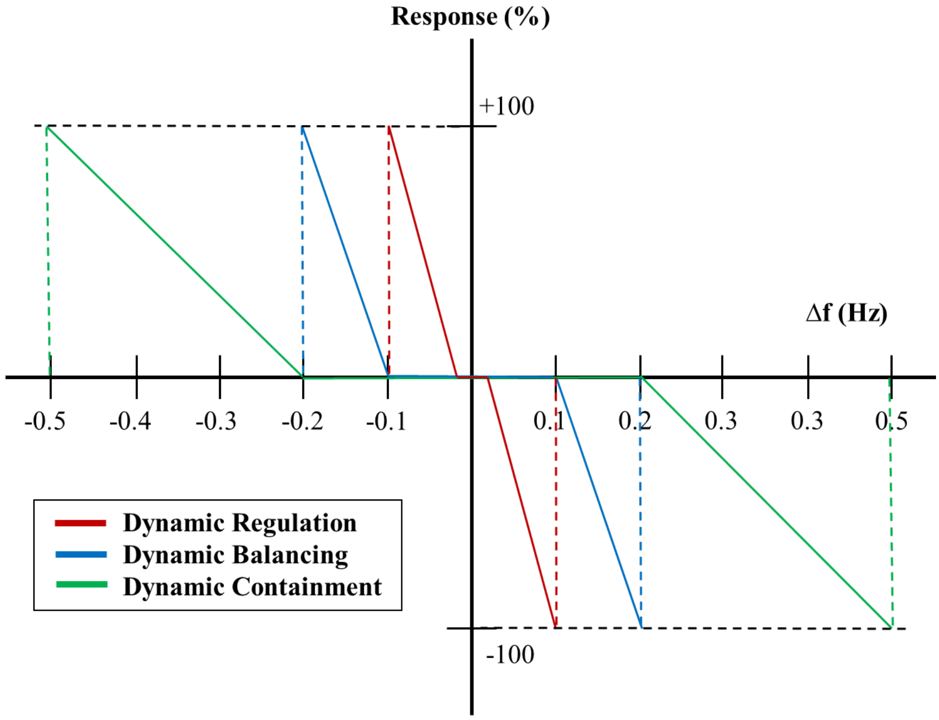
- <u>Fast acting</u> – a shorter time period between when the frequency event occurs and when the service responds, i.e. detection and instruction time period.
- <u>Fast ramping</u> – a shorter time period within which the service fully delivers response to a frequency change, i.e. the ramp rate.

Frequency response can be delivered by a range of sources including, HVDC links, DSF, flexible synchronous plants, WPPs, SPPs, storage, and any technology capable of utilising some form of controller action to access a store or source of energy in order to provide a frequency response service. One of the most prominent control strategies is Synthetic Inertia and it is classified as a subset of fast response [47]. Also known as Simulated or Emulated Inertia, it involves an approximation of the emulation of the inertial response of a synchronous machine [87, 88]. There is however a concern regarding Synthetic Inertia as it applies to WPPs. Synthetic Inertia in WPPs demands more torque from the turbine. However, this method comes with an energy deficit that causes a ‘recovery period’ [89]. The recovery period is described as the time after the delivery of response during which the WPP goes through a period of under production of power. It is a period where the rotor is re-energised following an injection of active power to the WPP. It should be noted that the occurrence of a recovery period is not exclusive to WPPs, a similar behaviour can be seen with synchronous machines, and overall existed frequency response will need to 'recover' so that they are available to provide a service again when they are called upon.

The study conducted by [90] shows that while Synthetic Inertia could indeed provide limited benefits in reducing the frequency nadir, the recovery period causes a delay in reaching steady state condition. Furthermore, [49] suggests that the recovery effects of wind plants could offset the benefits of providing Synthetic Inertia, potentially causing a reduction in overall benefit. According to [24, 91], a fast response service will allow frequency response volumes to be significantly reduced. These responses are viewed as a viable solution to the need for dynamic immediate changes to frequency excursions, but the question remains as to the source and speed of power delivery, and variability thereof, behind the controllers. Similarly, there are also questions as to the amount of response needed in the future, and how these fast response services will need to operate in order to coordinate with existing services and maintain frequency stability.

The ESO's SMART frequency project aims to develop and demonstrate monitoring and control systems that coordinate responses from multiple embedded sources, including faster response providers [53, 70]. This project emerged from a previous project called the Enhanced Frequency Control Capability project. The overall aim of both projects is to demonstrate the impact of coordinating frequency responses from different providers, optimising response to system events and thereby, improving power system flexibility, while providing the most economic and efficient frequency responses under different system conditions. The overall project also addresses concerns related to the availability of power for a given variable generation asset, by ascertaining availability data on regional assets [70].

Until recently, there was another frequency containment service in GB called Rapid Frequency Response (RFR) that was similar to PFR but required full delivery of response within 5 s with a maximum delay of 1 s. This fast response service has now been discontinued and the ESO is taking steps to introduce new services that would better accommodate a future low inertia power system [92]. During a seminar in 2018, National Grid proposed changes to how dynamic and static frequency responses are delivered [93]. The proposed design for static response involves multiple trigger points grouped by frequency thresholds, such that if frequency falls below a threshold a response group is activated, and when frequency rises above the threshold the response group is deactivated at varying, and as of yet undefined, activation and deactivation clearance times. These definitions have since been refined and as of 2019 the services proposed are highlighted in Figure 2.17[19].



	Operational Range (-ve dev)	Operational Range (+ve dev)	Max Lag (s)	Max Ramp (s)	Duration (mins)
Dynamic Regulation	0.015 – 0.1		2	8	∞
Dynamic Balancing	0.1 – 0.2		0.5	0.5	20
Dynamic Containment	0.2 – 0.5	0.2 – 0.5	0.5	0.5	20
Static Containment	0.3 – 0.5	0.3 – 0.5	1	N/A	30

Figure 2.17: National Grid's proposed future frequency response [94, 95].

[19] With the exception of Dynamic Containment, the services in this proposal may be subject to change once the GB ESO decides on actual deployment.

Increasing flexibility, inertia and the provision of fast response are potential solutions that can be deployed to mitigate the challenge of frequency stability in a future low inertia power system; however other questions remain:

- Can RoCoF limits and frequency limits be respected without the need for significant curtailment of non-synchronous power (or loss risk) and constraining on of fossil-fuelled synchronous plant?
- What are the key factors influencing frequency behaviour and how do they impact the likelihood of containing a credible loss event?
- How will the demand for frequency containment in GB change in the future?
- What does an adequate framework for frequency response entail?
- Will a frequency response service that is faster than existing frequency containment services but slower than synchronous inertial response, be enough to manage credible loss events?

The subsequent chapters of this thesis will address these questions using tools to experimentally investigate frequency behaviour. It should be noted that while the topics, concepts and indeed the challenges associated with low inertia can be related to other (similar) power systems, the work presented in this thesis focusses on the GB power system. That said, a model and tool for frequency studies will be presented in chapter 3, presenting the details, assumptions and rationale, behind the development and operation of these tools. Using the model and tool, chapter 4 investigates factors influencing frequency behaviour to understand the role that they play in frequency containment, and how their impact varies with different conditions. In section 5.1, the question regarding respecting frequency stability limits in GB without the need for curtailment, is addressed by considering frequency containment under current and future RoCoF and frequency limits, loss risk conditions, and response services. With an understanding of the factors influencing frequency behaviour and the challenge of containing loss risk, section 5.2 considers metrics for determining the frequency stability limit of a power system. Starting with the SNSP (used in Ireland), two other metrics (critical inertia and frequency stability by components) and an exchange rate methodology for frequency containment services are presented, based on assumptions of the GB power system. These metrics and methods can be used to understand the relationship between the factors influencing frequency containment, and they can be used as an operational tool when planning or dispatching the power system. Section 6.1, addresses the question of changing demand for frequency containment services, providing an understanding of the changes that a future GB power system would need to consider to improve the assurance of frequency stability. The work is further extended into the proposal of a framework for future frequency response services in section 6.2. This section considers supplementary services that can add to (or replace) existing services, incorporating fast frequency responses. The thesis concludes in chapter 7, which also includes a presentation of future work.

2.5 Summary

The ESO in GB is obligated to manage credible loss risks within frequency and RoCoF limits. As the inertia in the power system reduces, the challenge of assuring frequency stability increases which increases the risk of demand disconnection and blackouts.

There are existing services and markets for delivering and procuring frequency response services and, at the time of writing, the ESO is actively making improvements to both the services and markets that would address the changing demand for frequency response services and facilitate increased market participation. Some of these actions include the EFR auction, the new market trials in progress, and the design of the new dynamic frequency responses. However, there are still questions regarding how the demand for frequency response is changing with the change in the energy landscape, and how best to deliver adequate dynamic frequency responses. The bundling of frequency containment and restoration services (Primary, Secondary and High frequency response services) and the dominance of Secondary response in the FFR market present barriers to participation for potential alternative providers.

3

Modelling System Frequency

There are influences that determine the power system's ability to comply with acceptable frequency conditions and RoCoF limits, and these influences depend on the initial conditions. The market determines the mix of generation to meet a particular demand but the choice of generation in the market also depends on other factors such as weather and plant availability. The ESO modifies the market dispatch to ensure operability and in the specific case of frequency management, the ESO procures a mix of energy reserves, e.g. headroom for Primary response. Sometimes the ESO will need to take other actions to redispatch the power system. For instance, when the ESO needs more inertia to contain an event within RoCoF limits they may bring more synchronous plants online or curtail the loss risk, or if there is insufficient headroom to deliver response they would bring more providers online in order to hold sufficient reserve to contain an event within acceptable frequency conditions.

This chapter describes a model and tools used for conducting the frequency studies presented in this thesis. In order to assess the impact of reduction of inertia on a real power system and to evaluate potential new frequency management services, a model must be simple enough to allow the convenient study of many scenarios and sensitivity to different factors, while still being sufficiently accurate in reproducing actual system response. As will be shown later in this chapter, and indeed throughout the remainder of this thesis, there are a number of factors that influence frequency behaviour during a power imbalance. However, with present day monitoring of real systems, many of them cannot be known with certainty. It is therefore imperative that any published model is accompanied by documentation that details its inherent assumptions and operation. As well as being used to study the system for which the model was designed, such a model could be adapted to suit other regions. It should include the following key features:

- representation of a range of generation types including synchronous and non-synchronous generation, with the ability to specify present day or future frequency response services;
- representation of other non-synchronous sources of power such as interconnectors and storage, with the ability to represent the provision of frequency response from these devices;
- representation of embedded inertia, i.e. that associated with synchronously connected loads and generators within the distribution system, and the inherent dynamic frequency response of demand to power imbalances;
- representation of a range of frequency response services and providers, with the ability to model different control strategies for different frequency responsive elements in the model; and
- low computational complexity in order to facilitate the examination of a vast number of scenarios.

3.1 Existing Models

Existing models can be broadly categorised into full system, multi-node reduced system or simplified system models. Full system models would typically be used by network operators, containing the highest level of accuracy and details of the power system making them highly powerful tools that are capable of capturing most power system phenomena. However, such models are highly computationally intensive and, in general, are not publicly accessible.

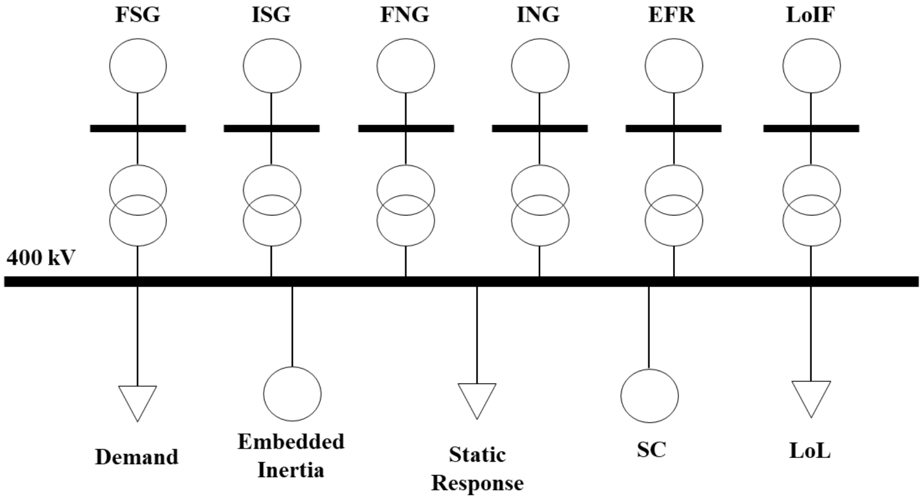
Multi-node reduced system models are greatly simplified network representations in comparison to full system models, but still contain a sufficiently high level of detail, such that they can model a range of power system phenomena, including voltage and regional behaviours [96]. Examples of these models include the National Grid ESO model in [97], the IEEE power system models such as the 39-bus model used in [98], and the real-time digital simulator reduced GB model used in [84]. Such models might typically be developed with a focus on the study of particular system stability phenomena and may not always be tailored to frequency studies. However, it would be possible to adapt or develop a multi-node representation to be capable of accurately modelling frequency stability issues, e.g. by addition of governor models and scheduling of margins in the dispatch of generation to be able to provide high or low frequency responses, i.e. 'footroom' and 'headroom'. A multi-node approach has certain advantages, including the ability to model locational influences on frequency behaviour, and the regional distribution of inertia and response. The main drawback of such an approach is that it needs many parameters to be defined and requires significant effort to properly define each new scenario, via not only a unit commitment and dispatch methodology but also an optimization of voltage profiles and reactive power. The relatively high level of detail also means the computational run time for each scenario is potentially significant when considering a power system like GB in relatively high detail. This makes the approach quite unwieldy for modelling a very large number of scenarios in a reasonable timeframe.

Simplified power system models offer a trade-off between the level of detail and low computational burden. Such models include the GB ESO's single bus model that has been used for frequency studies in the past [91], and equivalent system frequency models such as the model described in [99]. The latter differs from the former as it is more of a mathematical reduction of the power system rather than the aggregation of elements used in the former. Further examples of simplified models include the 'Mid-term-model of power system' in the Union for the Co-ordination of Transmission of Electricity (UCPTE) power system for frequency studies described in [100], the system frequency models in [101], and the single bus models in [102] and [103]. Although the inherent simplifications involved rule out the ability to examine issues like voltage stability or the regional effects of an event, the study of overall system frequency response and the need for new ancillary services can be considered conveniently and with good accuracy. Publicly available simplified models have certain limitations such as: the lack of a representation of demand sensitivity; the lack of flexibility to model a range of frequency services and providers; lack of detail of assumptions behind the model; and the lack of a representation of embedded inertia.

3.2 The Single Bus Model

A single bus model, depicted in Figure 3.1, has been developed in DigSILENT PowerFactory [104] that builds on work done in [91], existing literature [24, 105, 106], and discussions with industry experts, while meeting the requirements outlined at the start of this chapter. This model enables, for example, the manipulation of type and speed of primary frequency response provided and the investigation of the minimum system inertia that can be sustained within the operating limits defined, in the GB case, in the SQSS [19]. The model can be used to provide insights as to system conditions, and it also supports the inclusion of other technologies, such as synchronous compensation, to assess the potential benefits such solutions would have on a future power network [107]. The single bus model allows a systematic exploration of the main factors that influence RoCoF and frequency containment. Moreover, as will be presented later in section 3.2.3, although it is a simplified representation of a power system, it has been found to be capable of closely replicating real frequency behaviour.

The single bus model is made up of components of the power system that have been aggregated according to their response to frequency events. This involves splitting the generation and demand present within the background generation and demand scenario being considered into the different component elements, as shown in Figure 3.1 and expanded upon in section 3.2.1. The inertia contribution of a background scenario is one of the key inputs of the model. As stated in [11] and [12], the inertia constant, measured in seconds, of synchronous generators typically varies from plant to plant within the range of 2 – 10 seconds, depending on the size, speed and type of generator. Due to this uncertainty and lack of access to confidential data, the default inertia constants used in the model are simplified to representative values based on calculated averages, by generation type, using anonymised data provided for existing generation assets that have been verified as broadly representative via discussions with ScottishPower Transmission (the transmission owner in the south of Scotland in the Northern part of the GB system) and National Grid.



FSG: Flexible Synchronous Generation
ISG: Inflexible Synchronous Generation
FNG: Flexible Non-Synchronous Generation
ING: Inflexible Non-Synchronous Generation
EFR: Enhanced Frequency Response
LoIF: Loss of In-Feed
SC: Synchronous Compensator
LoL: Loss of Load

Figure 3.1: Single bus model.

These averages result in a default inertia constant in the model of 6 seconds for gas plants and future carbon capture and storage generation, while other synchronous generators, e.g. nuclear, coal, etc., have a default inertia constant of 4 seconds. HVDC interconnectors, SPPs, fully rated WPPs, and marine power, utilise a converter to interface with the grid, therefore it is assumed that they contribute no inertia to the power system. These inertia estimations are in broad agreement with [106]. As stated in chapter 2, doubly-fed induction generator wind turbines provide a small inertia contribution to the system, and it is assumed that any such contribution is incorporated into the model via the embedded inertia element. It should also be noted that the machine and transformer 'type' defaults in PowerFactory were augmented with data from [12], the values used are presented in Appendix 6 to Appendix 8.

3.2.1 Components of The Model

This section describes each of the model elements, shown in Figure 3.1, in more detail.

<u>Embedded Inertia</u>

This element represents inertia provided to the transmission system from synchronously connected loads and generators embedded within the distribution network. It is modelled with zero active power under normal operation (active power demand is represented by the Demand element). The value of this element is inherently unknown and is likely to vary over time, but based on discussions with (and previous estimates by) the GB ESO, the contribution to inertia from embedded or unknown elements in GB is assumed by default to be equivalent to a machine with an inertia constant of 1.83 seconds rated at the size of the total transmission system demand. The inertia constant in this element can be modified if required.

Demand

Demand, in the context of this model, refers to the net export from the transmission network, incorporating loads, network elements and any machines that are connected at the distribution level of the power network. This element is the total power demand on the transmission network. It also includes a sensitivity to frequency changes, such that a portion of demand in the system automatically responds to the power imbalance via changes in active power. By default, the demand sensitivity is modelled as a 2.5% change in active power per 1 Hz change in frequency [9], a figure that has been determined by the GB system operator based on the measured system response to a single event, that said, the value of this sensitivity can be modified if required.

Loss of In-Feed (LoIF)

This element is used to represent LoIF system events. By default, such events are simulated as instantaneous events, but it is also possible to model ramped events via this element of the model. The LoIF element can represent the loss of either synchronous or non-synchronous generation, or infeed from interconnectors. In synchronous generator mode this element has the inertia constant of the relevant synchronous generation (based on fuel type) and thus the pre-fault and post-fault system inertia are different. On the other hand, in non-synchronous generator mode or interconnector mode the pre-fault and post-fault system inertia are equal.

Loss of Load (LoL)

This element is used to represent LoL system events, where a portion of demand is allocated to this element to simulate an instantaneous or ramped loss of demand event. It also considers a proportional loss of demand sensitivity due to the LoL event, but since the related loss of embedded inertia is unknown, any potential loss of embedded inertia is not accounted for in this model.

Static Response

This element represents static frequency triggered response elements in the system that respond by discrete disconnection (or reduction) of demand elements (e.g. smelters). It is modelled with default frequency thresholds of 49.6 Hz and 49.7 Hz (for Primary and Secondary static response products respectively), representing the threshold typically used in the GB system [108], and can be implemented as an instantaneous trip or as a gradual ramp of steps.

Flexible Synchronous Generation (FSG)

This element is composed of the frequency responsive synchronous generation in a modelled operational scenario, i.e. components that respond to frequency events by providing both inertial and governor-controlled frequency response. A modified version of the IEEEG1 governor-turbine model available in DigSILENT PowerFactory is used in this element of the model. This controller is based on [35], as shown in Figure 3.2 below.

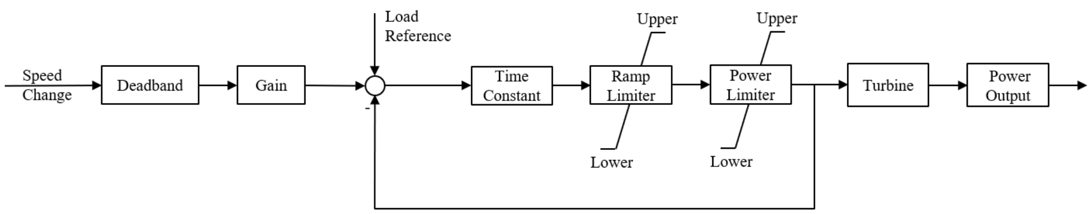


Figure 3.2: Modified IEEEG1 governor model adapted from [35].

This governor controller permits the modification of time constants, deadband, ramp rate, droop, and maximum/minimum power output. The default controller settings employ the minimum acceptable settings for Primary and High frequency response as defined in GB, such that a 4% droop is applied with a deadband of ±0.015 Hz and a ramp rate limiter that allows for full response delivery 10 seconds after the event, with a 2 second delay, sustained for a further 20 seconds (in the case of Primary response) or indefinitely (in the case of High frequency response) [9].

This element must be part loaded in order to provide 'headroom' for a response. The default setting for its dispatch is equivalent to 75% of the total power output capability. In accordance with [91], a response ratio is further applied at a default of 50%, which means that only 50% of the headroom is the frequency response reserve, i.e. 12.5% of the total active power capacity of this element. The specific composition of this element is scenario dependent but will often include gas and/or coal plants. For instance, a scenario that requires governor action from 50% gas and 50% coal would result in an inertia constant of 5 seconds in the FSG element.

Inflexible Synchronous Generation (ISG)

This element is composed of the frequency non-responsive synchronous generation in the power system. These components do not have an active governor-controlled response to frequency, but they do provide an inherent inertial response to frequency changes that limits RoCoF. The specific composition of this element is scenario dependent but will include any synchronous generation plant that is not part of the FSG element (or the LoIF element in cases where LoIF is in synchronous generation mode). The inertia constant in this component is the capacity-weighted average inertia constant of the non-responsive synchronous generation dispatched in the scenario. For instance, a scenario in which the ISG element consists only of coal and nuclear thermal units would mean an ISG inertia constant of 4 seconds.

Flexible Non-Synchronous Generation (FNG)

This element is technology neutral and can represent compliance with current and future definitions of frequency response. It includes any non-synchronous sources of power that can respond to frequency by controller action, providing active power response but no synchronous inertia response. It is modelled with a dynamic controller, based on [35], that continuously responds to frequency changes. This simplified controller model, illustrated in Figure 3.3, is equivalent to the controller model in the flexible synchronous generation element of the model without the turbine model. Consequently, this controller also allows for the modification of deadband, time constant, ramp rate, droop, and maximum/minimum power output.

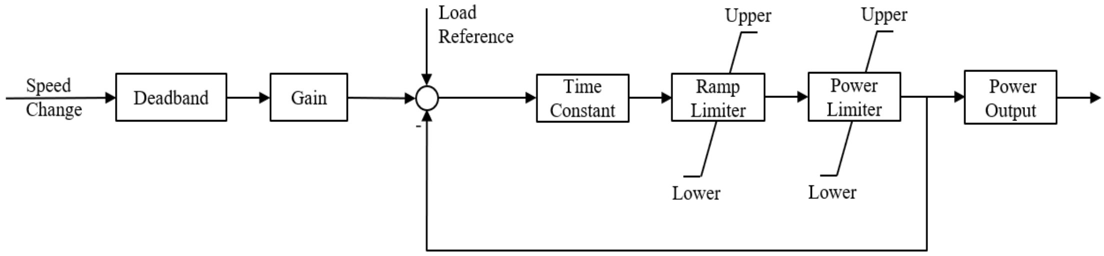


Figure 3.3: Controller model for the FNG element.

The FNG element is part loaded with frequency response reserve made available in a manner similar to the FSG element. However, via suitable modification of the controller parameters, this element and its controller can be used to test new services such as the fast-acting dynamic services under development in [109], and those discussed in section 6.2.

Inflexible Non-Synchronous Generators (ING)

This element is composed of the operational non-synchronous sources of power infeed that provide no frequency response. Consequently, ING is represented in the single bus model as a constant negative load. Depending on the scenario, this element can include WPPs, SPPs, HVDC interconnectors and any other non-responsive converter connected sources of power.

Enhanced Frequency Response (EFR)

This component of the model represents system elements that are controlled to give 100% active power response, as dictated by the definition of EFR in section 2.2. It is modelled using the ‘Battery Energy Storing System’ template in PowerFactory [104]. By default, the frequency controller is configured with a droop characteristic of 1% [40].

Synchronous Compensator (SC)

This element models the inclusion of additional synchronous compensation installed across the transmission network. It is a modified synchronous generator and AVR based on what is described in [107] and [110]. It is modelled with zero active power, and the required apparent power.

3.2.2 Dispatching the Model

Once the key parameters of the model have been defined, either via assumptions for a prospective scenario or estimated based on real events via the method discussed in section 3.3.2, a tool called FEROS[20] uses the method depicted in Figure 3.4 to generate an operational scenario and populate the elements of the model, allowing for different frequency stability studies to be conducted. The loss event and the generation background, response and reserve services, the required 'headrooms' and 'footrooms' for the frequency response services, and the parameters for the Demand and Embedded Inertia model elements are defined. This information is collated and, depending on the dispatch method applied, the scenario is created. Given a specific level of demand and the availability of power from weather-dependent renewables such as wind and solar, the dispatch can be made based on a merit order or set of short-run prices. Alternatively, in order to explore the effects of decarbonisation or reduced inertia more directly, the dispatch can be made based on a non-synchronous dispatch target or inertia target. After the model has been dispatched, FEROS executes the desired frequency study, e.g. containment limits, inertia spread, etc, via the processes described in section 3.3.

The headroom (or footroom) of a dispatched flexible generation determines the amount of frequency response available to contain the event, and the headroom is in turn dependent on the loading of the machine. Therefore, in the reverse, for a given amount of frequency response reserve, at a defined percentage loading, and response ratio of headroom[21], the required dispatch of the flexible generator can be determined.

$$F_d = \left(\frac{F_r \times L}{R_r \times (1 - L)}\right) \tag{3.1}$$

[20] The Frequency Energy Response Optimiser and Simulator (FEROS) as described section 3.3 is used as a companion tool to dispatch the single bus model and operate frequency studies using the SBM as the model of the power system. Unless otherwise stated, all studies presented in this thesis use the single bus model and FEROS as a companion tool, and not FEROS as a standalone application. FEROS will be discussed in section 3.3.

[21] This is the percentage of the headroom that is available for frequency response.

The amount of flexible generation dispatched is dependent on the amount of response scheduled via (3.1), where F_d is the active power dispatch of the flexible element, F_r is the frequency response active power reserve, R_r is the response ratio of the flexible element in the model, and L is percentage loading of the flexible element in the model. This method is applied to both the flexible synchronous and flexible non-synchronous generation elements depending on the type of frequency responses scheduled in the scenario, while the Static Response and EFR elements have their respective response reserves applied separately depending on the level of Static response and EFR defined as scenario inputs.

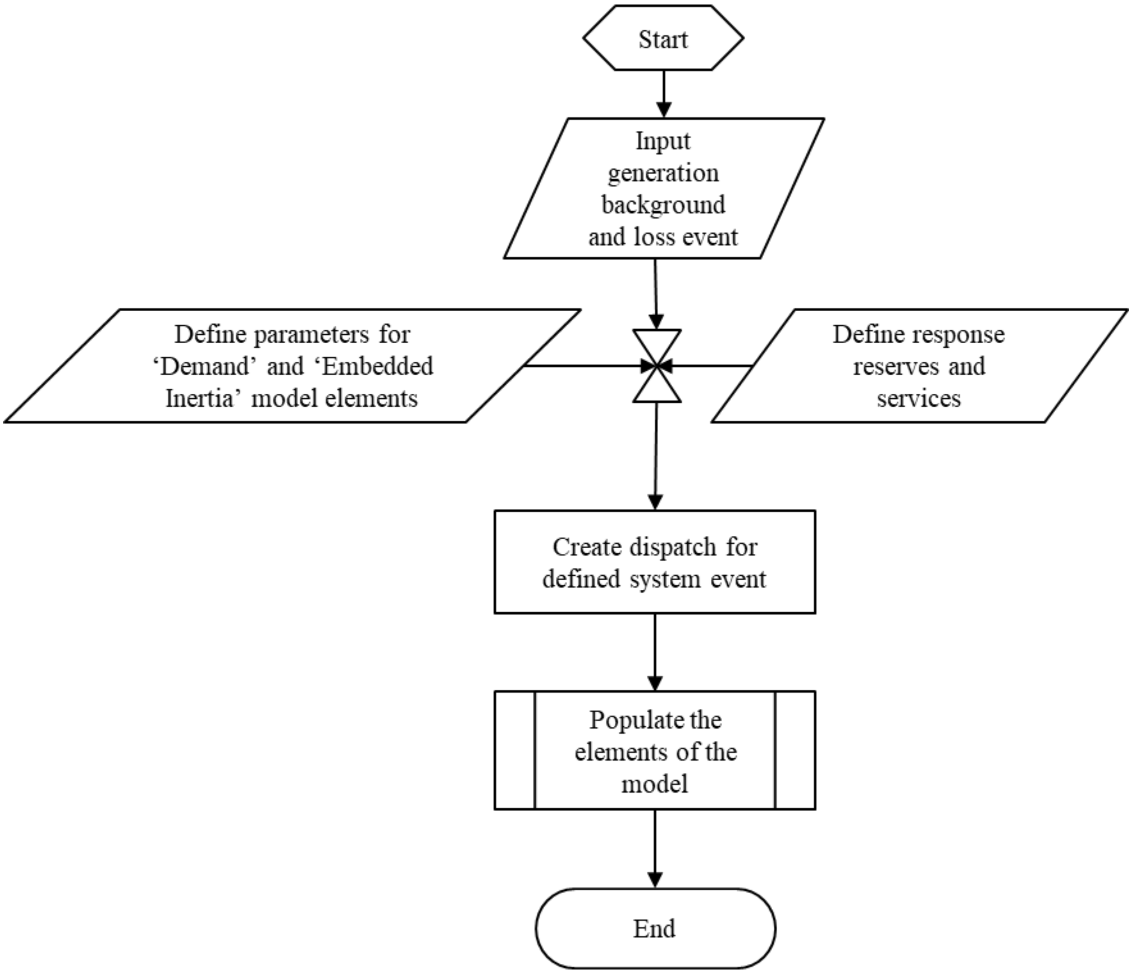


Figure 3.4: Flowchart depicting model dispatch.

3.2.3 Model Validation

On the 9th of August 2019, a lightning strike caused a circuit outage that triggered a series of events as illustrated in Figure 3.5. The single bus model has been used to replicate the initial phase of the frequency event, based on the data presented in [28, 111].

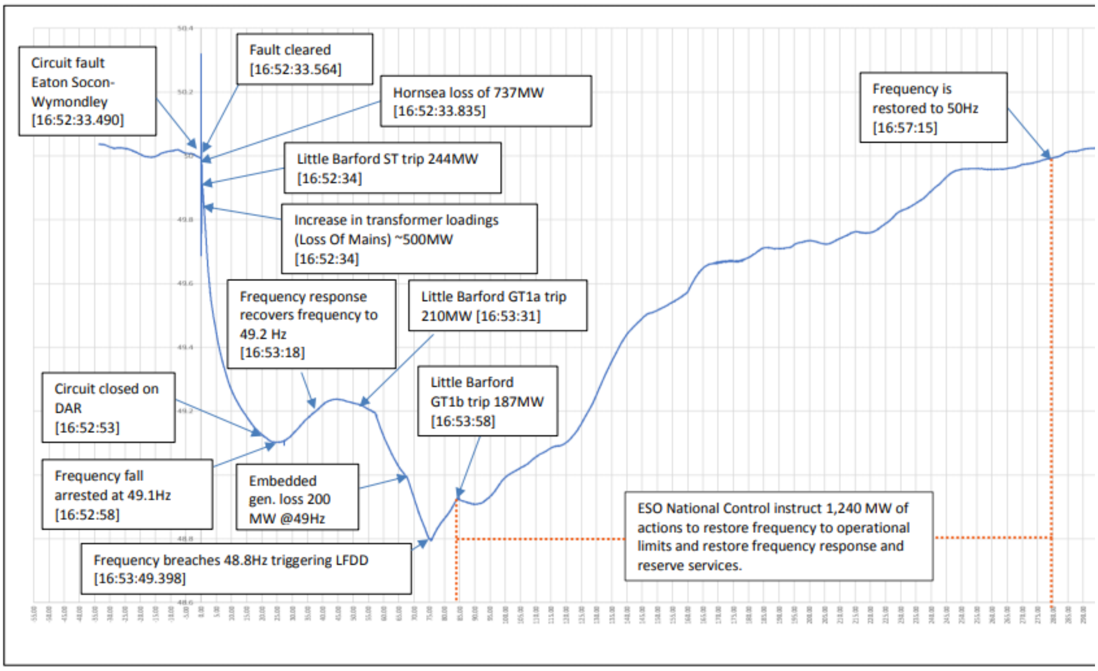


Figure 3.5: 9th of August 2019 sequence of events [111].

The public report of the event provides unusually complete details of the magnitude and timing of the loss events, the system conditions during the event, and the magnitude of the frequency response that was provided by the GB ESO. The initial phase of the 9th of August event is simulated by applying these known parameters to the model alongside the underlying assumptions outlined above. Although the default assumptions for dynamic Primary response are its statutory requirements as defined in chapter 2, in replicating the event, the speed of delivery of dynamic Primary response is tuned based on discussions with industry experts that the real-world delivery of the service often slightly outperforms the statutory requirements[22]. All other responses are

[22] A setting of full delivery within 6.3 s was used for dynamic primary response to replicate this event. The Flexible Synchronous Generator is 70% loaded with 30% headroom.

modelled in line with their statutory definitions, as outlined in the defaults presented in section 3.2.1. Actual and simulated frequency data for this event are available in Appendix 9.

Table 3.1: Scenario overview [28, 111].

Demand	29 GW
Inertia	210 GVAs
Demand Sensitivity	2.5 %/Hz
Enhanced Response	165 MW
Static Primary Response	230 MW
Static Secondary Response	198 MW
Dynamic Primary and Secondary Response	479 MW

The results of the simulation are compared with real 1 second frequency data from the time of the event in Figure 3.6. It is found that the comparative frequency and RoCoF traces of the simulated event are in close agreement with the real system measurements, which acts as a strong validation of the model's ability to accurately replicate real system frequency behaviour.

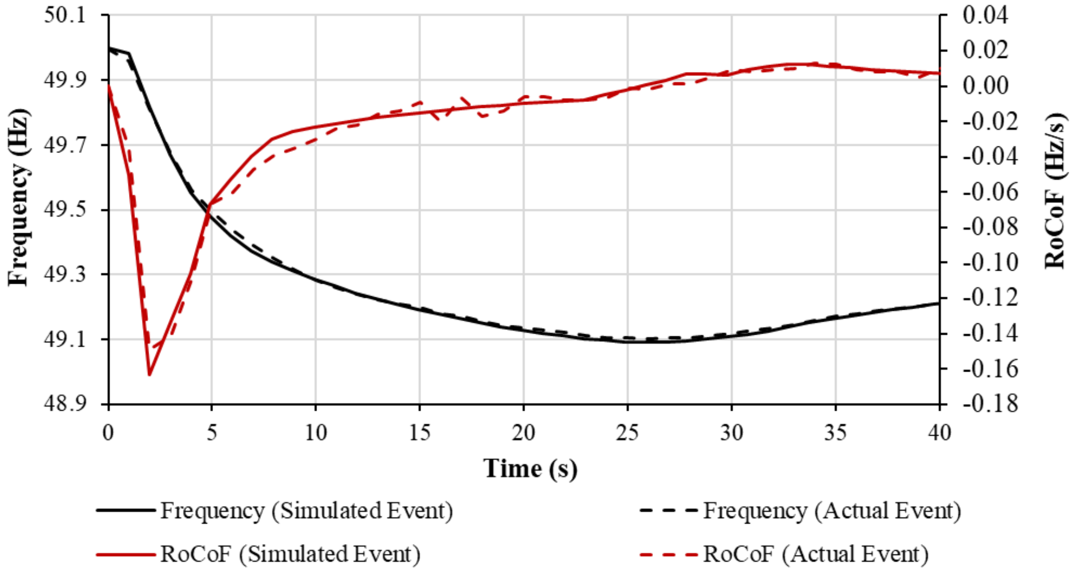


Figure 3.6: Replicating the 9th of August 2019 event.

3.3 Frequency Energy Response Optimiser and Simulator

The Frequency Energy Response Optimiser and Simulator (FEROS) developed using Python 3.6.1, was initially designed to dispatch scenarios, and to optimise and estimate frequency as a companion and interface tool for the single bus model previously discussed. FEROS was later expanded to include the functionality to operate as a standalone application, capable of optimising frequency response and simulating frequency behaviour without requiring any additional software to operate. At the time of writing, the current version of the standalone FEROS application is version 3.0 for Windows OS. FEROS is a set of modular algorithms that can be used to control the operation of the single bus model for a range of frequency studies, alongside the optimisation and estimation of frequency response reserves. Similarly, as FEROS is capable of simulating frequency within its own program using a built-in system frequency model, it can also facilitate frequency stability studies as a standalone application.

3.3.1 Operating Concept

A core function of FEROS is to dispatch a scenario, and to optimise and estimate frequency response reserves, which it does as either a companion tool to the single bus model or as a standalone application. The optimisation process is iterative and it employs (3.2) to determine the step sizes in the iterative process, where R_{step} is the step size of the response at a given system inertia, H, and nominal frequency, f_0. The value of R_{step} is also dependent on the difference between the simulated frequency minimum or maximum[23], f_{sim}, (for a loss of supply or demand respectively) and the target frequency, f_{target}, over the time (t) that it takes to frequency a simulated frequency minimum or maximum, as illustrated by Figure 3.7, where the initial frequency profile is the starting point before any optimisation begins and the final frequency profile is the end result[24]. The step size, R_{step}, is used to modify the frequency response reserve as indicated by (3.3). The frequency response reserve is

[23] In the case where multiple minimums or maximums are observed in the frequency profile only one is used, i.e. if there are two or more minimums due to oscillatory behaviour, then the lowest minimum is taken to be the minimum. That said, in most cases there will be only one turning point during optimisation of frequency response reserve.

[24] Note that f_{sim} and f_{target} can either be used in (3.2) or substituted with Δf_{sim} and $\Delta f_{target,}$ where Δf here is the total change of the frequency values when compared to nominal 50 Hz frequency.

initialised at zero and with each iteration step the change in active power reserve (R_{step}) is used to modify the initial frequency response reserve (iF_r), resulting in a new value for the frequency response reserve (F_r) that in turn becomes the initial frequency response reserve if another iterative step is required. At each step, the resultant frequency response reserve is used to determine F_d in (3.1), while ensuring that optimisation constraints are observed.

$$R_{step} = \left(\frac{2 \times H}{f_0}\right) \times \left(\frac{f_{sim} - f_{target}}{t}\right) \tag{3.2}$$

$$F_r = iF_r - R_{step} \tag{3.3}$$

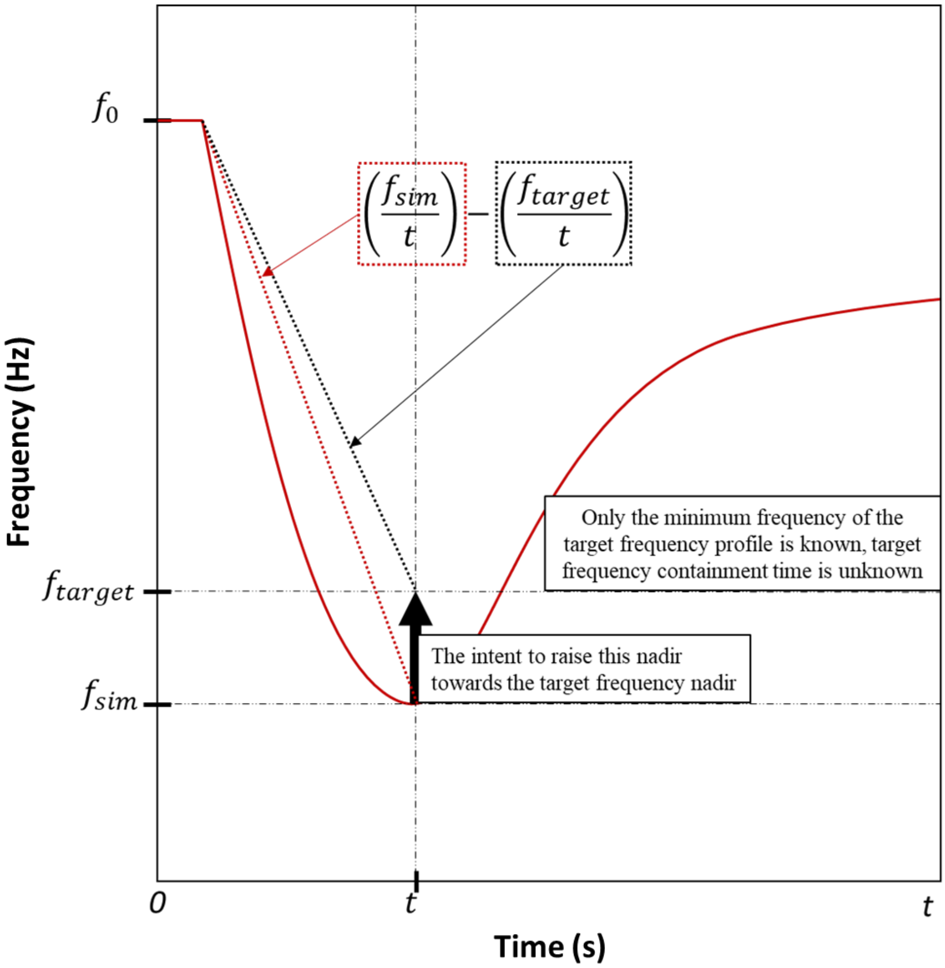


Figure 3.7: Diagram illustrating the optimisation process.

This optimisation continues until df/dt of the simulated frequency profile reaches zero at the frequency minimum/maximum, as defined by the frequency target. In some studies, this condition can be relaxed when the assumption is made that there is a secondary service available that is capable of achieving df/dt = 0 (in the simulated frequency), provided frequency doesn't exceed a target value within a predefined time. For instance, if it is assumed that there will be enough reserve from Secondary response fully delivered within 30 seconds to achieve df/dt = 0, then a service like Primary would only need to ensure that within 30 seconds of the simulation, frequency doesn't exceed frequency limits, df/dt = 0 is no longer a required condition. Although this doesn't necessarily meet the definition of containment it is useful for comparing different containment services at a common frequency nadir or zenith.

As an alternative[25] to 'optimisation method 1' described by (3.2), 'optimisation method 2' described below can also be used[26]. For dynamic frequency containment responses with fixed activation delay and ramp rate values, the containment error (E_c), between a target containment frequency and simulated containment frequency, is dependent on the amount of dynamic reserve ($\boldsymbol{d_a}$) as indicated by (3.4); where the vector term $\boldsymbol{d_a}$ is comprised of a set of variables such that $\boldsymbol{d_a} = \left(d_a^1, d_a^2, \dots, d_a^{\mathrm{k}}\right)$, for $k \in K$, and K is a set of all contributing dynamic frequency containment responses.

$$B := f(\boldsymbol{d_a}) \tag{3.4}$$

$$E_c = \left(f_{target} - f_{sim}\right)^2 \tag{3.5}$$

The squared error, E_c, as shown in (3.5), compares the simulated containment frequency to the target containment frequency, and the derivative of E_c with respect to $\boldsymbol{d_a}$ is used to modify and define response reserve values that result in the least error between simulated and target containment frequency. This process is repeated until the

[25] Note that in both optimisation methods consider constraints related to: the maximum error tolerance (a default of 0.005 Hz) for frequency values exceeding the frequency target; and the df/dt of simulated frequency.

[26] A general form of optimisation method 2 is presented in section 3.3.2.

containment component error is minimised to within a user defined error tolerance, preventing extremely long (or infinite) loops and a solution with an unacceptable error.

The initial change in reserve is represented by $\mathrm{w}d_a^c$,which is modified to produce the final change Δd_a^c and the final change is then added to the initial value. The final change of the independent variables in (3.4) is determined by (3.6).

$$\Delta d_a^c = \mathrm{w}d_a^c + \left(\frac{\delta E_c}{\delta d_a}\right) \tag{3.6}$$

The initial change parameters are initialised zero and increase (or decrease) in steps of partial derivatives, where (3.7) is the derivative of the squared error (3.5), and the expression in (3.8) is the partial derivative of (3.7) with respect to the independent variable in (3.4)[27].

$$E_c{}' = 2 \times \left(f_c - \widehat{f_c}\right) \tag{3.7}$$

$$\frac{\delta E_c}{\delta d_a} = E_c{}' \times d_a \tag{3.8}$$

The final change (Δd_a^c) is the frequency response reserve, and the system is re-dispatched using (3.1) as previously described in optimisation method 1. A user defined[28] target frequency is interpreted by FEROS as a constraint for a given scenario and the application can use either optimisation method to estimate the amount of response required to achieve the constraint. In addition to this constraint, there is also a user defined tolerance constraint, shown in (3.9), and a constraint on df/dt of the simulated frequency as previously discussed. These constraints make up the

[27] The amount of reserve to be held for containment, d_a, is initialised at a non-zero value.

[28] All user definitions are inputted via built-in graphic user interface when FEROS is used as a standalone application or via an excel spreadsheet when used as a companion tool to the single bus model.

containment conditions that need to be satisfied by the optimisation methods. Equation (3.9) defines the permitted absolute error tolerance between a simulated frequency minimum or maximum (f_{sim}) and the target frequency nadir or zenith (f_{target}), which must be greater than or equal to zero but less than a user defined simulation tolerance. It should be noted that the tolerance used in optimisation is relaxed when required, so that the simulated scenarios with frequency contained well within the defined limits, with a positive error ($f_{sim} - f_{target}$) greater than the tolerance, are accepted. Constraints for a damped settling frequency can also be defined and added to the optimisation conditions.

$$0 \leq |f_{sim} - f_{target}| \leq tolerance \tag{3.9}$$

Algorithm 3.1 describes how frequency response is optimised and estimated within the program. At the time of writing, this algorithm is only used for dynamic responses, but optimisation method 2 can also be applied to static responses. Algorithm 3.1 can be applied to multiple response services by applying weights and priorities to different frequency response services. For instance, if response is provided by EFR and Primary response, the priority of optimisation can be fastest service to slowest service, or cheapest to most expensive.

Algorithm 3.1: Method for optimising responses.

1. define target and system limits
2. run frequency simulation
3. check process conditions
4. while process conditions are false
   calculate frequency response reserve
   check constraint conditions
5. save results for optimised response and frequency behaviour

The two optimisation methods presented are compared using a hypothetical 20 GW demand scenario with 128 GVAs of inertia and an instantaneous loss of 1 GW. Using optimisation method 1, the optimisation is completed within 18 iterations and it is determined that at least 853 MW of Primary response, along with already dispatched 200 MW of EFR (EFR is not optimised), will be needed to contain frequency to 49.5 Hz. Since the target feature is the frequency nadir (or zenith in the case of a loss of load event) the optimisation minimises the frequency nadir error in reference to acceptable frequency limits[29]. In this case, the error is minimised by dispatching more headroom for Primary response until the frequency nadir is at least 49.5 Hz within a defined tolerance of 0.005 Hz.

In comparison to the optimisation method 1, optimisation method 2 takes 13 iterations to arrive at a containment frequency signal that requires 858 MW of Primary response reserve, for the same scenario[30]. The resultant frequency plots from both optimisation methods are compared in Figure 3.8. Optimisation method 2 is 28% faster than optimisation method 1 in terms of number of iterations, and while optimisation method 2 leads to improvements in accuracy, both results are well within the predefined tolerance of 0.005 Hz. Other comparisons were done for four additional scenarios where the amount of demand, inertia, and type of response service were varied to see the impact of the improvement of optimisation method 2 over optimisation method 1. Details of the scenarios considered are in Appendix 10 – Appendix 12.

It is found that optimisation method 2 is consistently faster (up to 90%) at executing the optimisation process than optimisation 1. The comparative accuracy varies between methods, at up to around 1% difference in reserve estimations, and up to around 0.004% in simulated frequency minimum (in relation to the target frequency). An overview of the accuracy results is presented in Figure 3.9, where a positive value implies that optimisation method 2 is more accurate and a negative value implies that optimisation method 1 is more accurate. However, it should be noted that the frequency accuracy error in both methods fall well within tolerance. The comparison shows that optimisation method 1 is mostly more accurate than optimisation method 2. However, it is also noted that two of those (scenarios 2 and 4) are instances where frequency containment occurs at values much higher than 49.5 Hz. This observation

[29] There is an error associated but this error is within the defined error tolerance of 0.005 Hz. The error in this case is -0.0042 Hz, i.e. containment frequency is 49.4958 Hz.

[30] There is an error associated but this error is within the defined error tolerance of 0.005 Hz. The error in this case is -0.0031 Hz, i.e. containment frequency is 49.4969 Hz.

implies that in such circumstances, when a minimum reserve and nadir is required, optimisation method 1 is marginally better than optimisation method 2. That said, the considerable speed improvements from optimisation method 2 can't be overlooked.

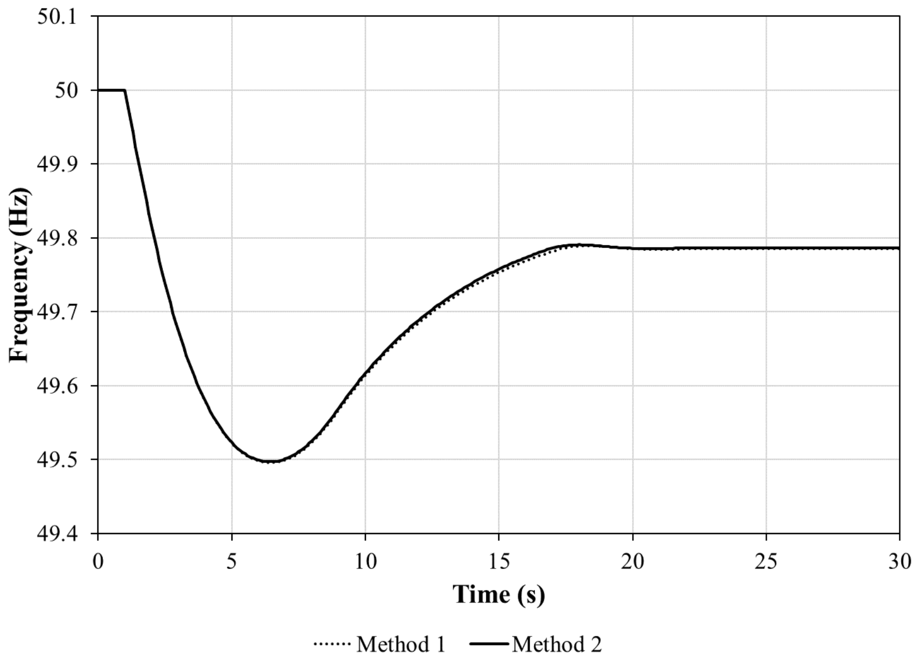


Figure 3.8: Comparison of optimisation methods. Method 1: Optimisation method 1 described by (3.2). Method 2: Optimisation method 2 described by (3.6).

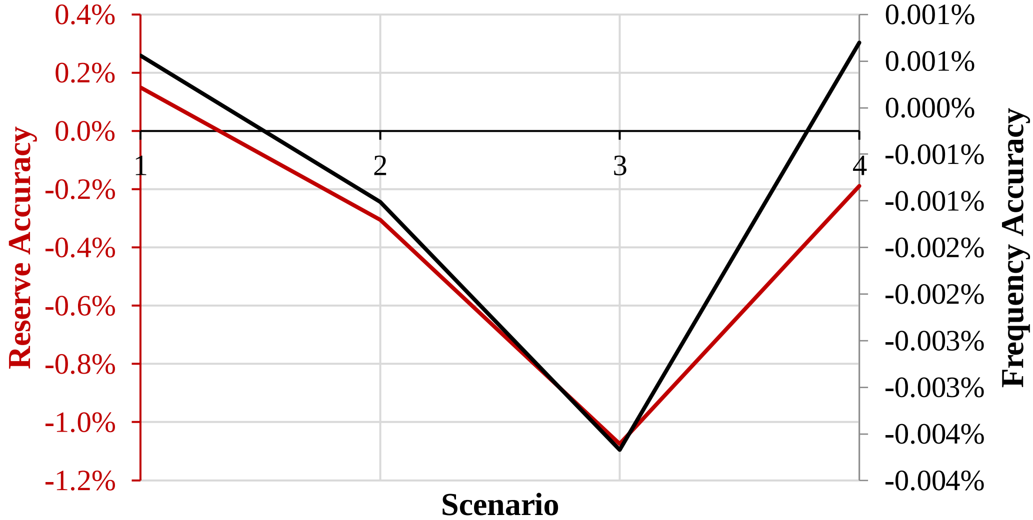


Figure 3.9: Accuracy compariosn of optimisation methods. Method 1: Optimisation method 1 described by (3.2). Method 2: Optimisation method 2 described by (3.6).

As previously stated, FEROS can operate as either a companion tool for the single bus model or as a standalone application, simulating frequency behaviour within its own program. Frequency is simulated in user defined discreet time steps, using a simplified system frequency model (SFM) based on [99], illustrated in Figure 3.10 below. In Figure 3.10, P_r is the total response provided, P_i is the initial power imbalance, and ΔP is the difference between the two that can act as accelerating or decelerating power, Δf is the change in frequency, H is the inertia in the power system, and D is the damping factor.

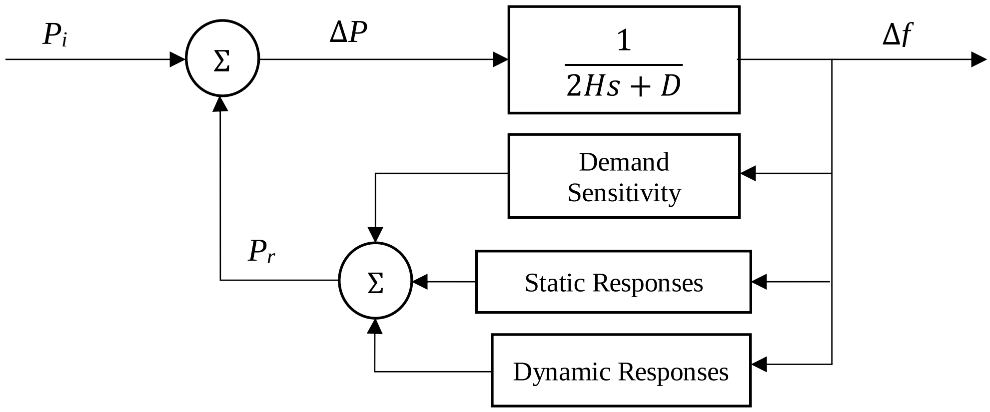


Figure 3.10: Line diagram for simulating frequency with responses.

Although Figure 3.10 illustrates singular fields for static and dynamic responses, as a standalone application FEROS can currently optimise and estimate up to seven different types of dynamic response services, and simulate up to six different static response triggers.

3.3.2 Retrospective Studies

This is an additional feature of FEROS that considers an event that occurred in the past and simulates a frequency trace that closely matches the real event, providing estimates of the likely system conditions. The operation of this module is based on the consideration that in respect of system operation there are three main things that need to be handled, namely, the initial RoCoF must be within acceptable limits, the frequency excursion must be contained, and then it can be restored, as depicted in Figure 3.11.

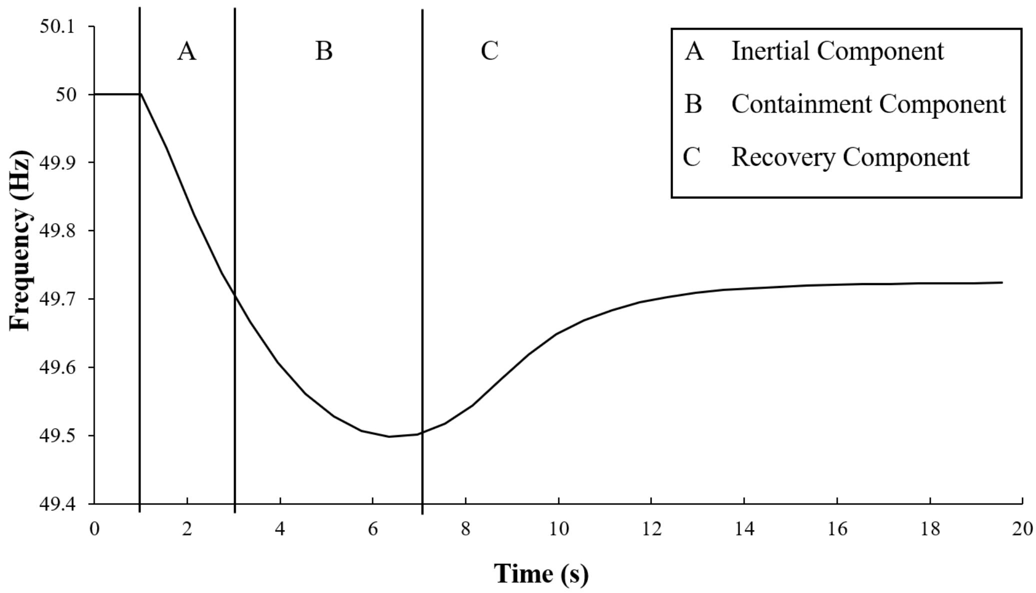


Figure 3.11: Illustrating three phases of frequency behaviour during an event.

Each of these phases is most sensitive to different parameters, such that the error of a model with a particular set of parameters relative to actual performance is defined in (3.10). The total simulation error (E_T) for the complete set of parameters is a function of the inertial component error (E_i), the containment component error (E_c), and the recovery component error (E_r).

$$E_T := f(E_i, E_c, E_r) \tag{3.10}$$

In addition to the specific build of system models, the capability of any model to reproduce a frequency event and thus validate its performance depends, at the very least, on the values of the key parameters that make up the component errors. These component errors (E_i, E_c, and E_r), are mostly dependent on key parameters such as inertia, demand sensitivity, and the speed, amount, and delay of the available response services. Therefore, a method can be employed to produce a simulated frequency profile with minimum total simulation error when compared to the real event via feature extraction, thereby defining the apparent values of the parameters that produce a frequency behaviour that closely matches the real event being simulated.

Neural networks, utilise weights, biases, nodes and activation functions to learn patterns and make predictions [112, 113], and they are suitable for assessing the features of each component towards estimating the values of the parameters that produce a frequency profile with the least total simulation error, when compared to the frequency profile of the real event. Consequently, a neural network with a combination of regression, binary functions and back-propagation is used in this module, with respect to the three phases in Figure 3.11. With a frequency profile provided as a target frequency, this algorithm goes through an iterative process of simulating a frequency profile, while reducing the error in each component of the total simulation error, until a solution is reached with a simulated frequency profile with the least total simulation error when compared to the target frequency profile. The expressions and process used in replicating the real event is detailed below.

Inertial Component Error

The expression in (3.11) shows that the inertial component (I) is dependent on: the total system inertia (H_{sys}) in GVAs (including embedded inertia); the sensitivity of transmission demand (D_s) to frequency in %/Hz; and the delay ($\boldsymbol{d_d}$) in seconds, the full-delivery/ramping time ($\boldsymbol{d_r}$) in seconds, and the amount ($\boldsymbol{d_a}$) in MW of any available dynamic containment service that activates within a 2 second threshold. A threshold of 2 seconds is chosen, since Primary response is defined as a service that is delivered with a 2 second delay. Therefore, it is assumed that prior to this time inherent system responses such as inertia and demand sensitivity, as well as other faster response services such as EFR, dominate frequency behaviour.

$$A := f\left(H_{sys}, D_s, \boldsymbol{d_d}, \boldsymbol{d_r}, \boldsymbol{d_a}\right) \tag{3.11}$$

The vector term $\boldsymbol{d_i}$ is comprised of a set of variables such that $\boldsymbol{d_i} = \left(d_i^1, d_i^2, \dots, d_i^{\mathrm{k}}\right)$, for $i = \{d, r, a\}$ and $k \in K$, where K is the set of all contributing dynamic response services. The inertial component of the real (I_c) and simulated ($\hat{I}_c$) frequency data are calculated for the 2 seconds following the frequency event using (3.12), where f_0 is the frequency at the start of the event and f_2 is the frequency 2 seconds after the event.

$$I = \frac{(f_0 - f_2)}{2} \tag{3.12}$$

$$E_i = \left(I_c - \hat{I}_c\right)^2 \tag{3.13}$$

The resultant real and simulated inertia component values are compared against each other as shown by the squared error in (3.13), to determine the inertial component error, E_i, whose derivatives with respect to the parameters in (3.11) are used to modify and define parameter values that result in the least error between the real and simulated inertial component. This process is repeated until the inertial component error is minimised to within a user defined error tolerance, preventing extremely long (or infinite) loops and a solution with an unacceptable error.

The inertial component error can be modified by considering the derivative of E_i with respect to each of the parameters in (3.11) as shown in (3.14) to (3.18), where L_j^i for $j = \{H_{sys}, D_s, d_d, d_r, d_a\}$ is a predefined learning rate, and $\mathrm{w}H_{sys}^i$, $\mathrm{w}D_s^i$, $\mathrm{w}d_d^i$, $\mathrm{w}d_r^i$ and $\mathrm{w}d_a^i$ are the initial change in these parameters that are modified to produce the final change ΔH_{sys}^i, ΔD_s^i, Δd_d^i, Δd_r^i and Δd_a^i respectively, which is then added to the initial value of the parameters[31].

$$\Delta H_{sys}^i = \mathrm{w}H_{sys}^i + \left(\frac{\delta E_i}{\delta H_{sys}} \times L_{Hsys}^i\right) \tag{3.14}$$

$$\Delta D_s^i = \mathrm{w}D_s^i + \left(\frac{\delta E_i}{\delta D_s} \times L_{Ds}^i\right) \tag{3.15}$$

$$\Delta d_d^i = \mathrm{w}d_d^i + \left(\frac{\delta E_i}{\delta d_d} \times L_{dd}^i\right) \tag{3.16}$$

[31] It should be noted that while the relationships for all three component errors are presented in singular form for simplicity, it is actually in the form presented in (3.11); i.e. a vector terms that are comprised of *k* number of response services that contribute to the component errors.

$$\Delta d_r^i = \mathrm{w}d_r^i + \left(\frac{\delta E_i}{\delta d_r} \times L_{dr}^i\right) \tag{3.17}$$

$$\Delta d_a^i = \mathrm{w}d_a^i + \left(\frac{\delta E_i}{\delta d_a} \times L_{da}^i\right) \tag{3.18}$$

The initial change parameters are initialised at zero and increases (or decreases) in steps of partial derivatives, where (3.19) is the derivative of the squared error (3.13), and the expressions in (3.20) to (3.24) are the partial derivatives of (3.19) with respect to each independent variable in (3.11).

$$E_i{}' = 2 \times \left(I_c - \widehat{I_c}\right) \tag{3.19}$$

$$\frac{\delta E_i}{\delta H_{sys}} = E_i{}' \times H_{sys} \tag{3.20}$$

$$\frac{\delta E_i}{\delta D_s} = E_i{}' \times D_s \tag{3.21}$$

$$\frac{\delta E_i}{\delta d_d} = E_i{}' \times d_d \tag{3.22}$$

$$\frac{\delta E_i}{\delta d_r} = E_i{}' \times d_r \tag{3.23}$$

$$\frac{\delta E_i}{\delta d_a} = E_i{}' \times d_a \tag{3.24}$$

Containment Component Error

The containment component in (3.25) is dependent on the $\boldsymbol{d_d}$, $\boldsymbol{d_r}$ and $\boldsymbol{d_a}$ terms outlined previously as well as the delay, delivery and amount of static containment response ($\boldsymbol{s_d}$, $\boldsymbol{s_r}$ and $\boldsymbol{s_a}$). The vector terms $\boldsymbol{s_i}$ is comprised of a set of variables such that $\boldsymbol{s_i} =$

$\left(s_i^1, s_i^2, \ldots, s_i^{\mathrm{k}}\right)$, for $i = \{d, r, a\}$ and $k \in K$, where K is the set of all contributing static response services.

$$B := f(\boldsymbol{d_d}, \boldsymbol{d_r}, \boldsymbol{d_a}, \boldsymbol{s_d}, \boldsymbol{s_r}, \boldsymbol{s_a}) \tag{3.25}$$

$$E_c = \left(f_c - \widehat{f_c}\right)^2 \tag{3.26}$$

The containment frequency is characterised as the value of the nadir (in the case of LoIF event) or zenith (in the case of a LoL event) following an event. The real (f_c) and simulated ($\widehat{f_c}$) containment frequency data are compared against each other to result in the squared error, E_c, as shown in (3.26), whose derivatives with respect to the parameters in (3.25) are used to modify and define parameter values that result in the least error between the real and simulated nadir. This process is repeated until the containment component error is minimised to within a user defined error tolerance, preventing extremely long (or infinite) loops and a solution with an unacceptable error.

The initial change in the parameters are represented by $\mathrm{w}d_d^c$, $\mathrm{w}d_r^c$, $\mathrm{w}d_a^c$, $\mathrm{w}s_d^c$, $\mathrm{w}s_r^c$ and $\mathrm{w}s_a^c$, which are modified to produce the final change Δd_d^c, Δd_r^c, Δd_a^c, Δs_d^c, Δs_r^c and Δs_a^c respectively, and the final change is then added to the initial value of each parameter. The final change of the independent variables in (3.25) is determined by (3.27) to (3.32), where L_j^c for $j = \{d_d, d_r, d_a, s_d, s_r, s_a\}$ is a predefined learning rate.

$$\Delta d_d^c = \mathrm{w}d_d^c + \left(\frac{\delta E_c}{\delta d_d} \times L_{dd}^c\right) \tag{3.27}$$

$$\Delta d_r^c = \mathrm{w}d_r^c + \left(\frac{\delta E_c}{\delta d_r} \times L_{dr}^c\right) \tag{3.28}$$

$$\Delta d_a^c = \mathrm{w}d_a^c + \left(\frac{\delta E_c}{\delta d_a} \times L_{da}^c\right) \tag{3.29}$$

$$\Delta s_d^c = \mathrm{w}s_d^c + \left(\frac{\delta E_c}{\delta s_d} \times L_{sd}^c\right) \tag{3.30}$$

$$\Delta s_r^c = \mathrm{w}s_r^c + \left(\frac{\delta E_c}{\delta s_r} \times L_{sr}^c\right) \tag{3.31}$$

$$\Delta s_a^c = \mathrm{w}s_a^c + \left(\frac{\delta E_c}{\delta s_a} \times L_{sa}^c\right) \tag{3.32}$$

The initial change parameters are initialised at zero and increase (or decrease) in steps of partial derivatives, where (3.33) is the derivative of the squared error (3.26), and the expressions in (3.34) to (3.39) are the partial derivatives of (3.33) with respect to each independent variable in (3.25).

$$E_c{}' = 2 \times \left(f_c - \widehat{f_c}\right) \tag{3.33}$$

$$\frac{\delta E_c}{\delta d_d} = E_c{}' \times d_d \tag{3.34}$$

$$\frac{\delta E_c}{\delta d_r} = E_c{}' \times d_r \tag{3.35}$$

$$\frac{\delta E_c}{\delta d_a} = E_c{}' \times d_a \tag{3.36}$$

$$\frac{\delta E_c}{\delta s_d} = E_c{}' \times s_d \tag{3.37}$$

$$\frac{\delta E_c}{\delta s_r} = E_c{}' \times s_r \tag{3.38}$$

$$\frac{\delta E_c}{\delta s_a} = E_c{}' \times s_a \tag{3.39}$$

Recovery Component Error

The expression in (3.40) shows that the recovery component is dependent on the same variables as the containment component, however, the frequency recovery gradient is based on an equivalent gradient from the nadir (or zenith) to the new settling frequency, or the maximum (or minimum in the case of LoL) frequency after containment, if no recovery to a settling frequency is observed within the length of the simulation.

$$C := f(\boldsymbol{d_d}, \boldsymbol{d_r}, \boldsymbol{d_a}, \boldsymbol{s_d}, \boldsymbol{s_r}, \boldsymbol{s_a}) \tag{3.40}$$

The frequency recovery gradient, for both real and simulated, is calculated using (3.41), i.e. the gradient of the nadir or zenith (f_n) to the new settling frequency (f_s), over time (Δt).

$$g = \frac{f_s - f_n}{\Delta t} \tag{3.41}$$

$$E_r = (g_r - \hat{g}_r)^2 \tag{3.42}$$

The recovery gradients in the real (g_r) and simulated frequency ($\hat{g}_r$) data are compared, resulting in the squared error, E_r, as shown in (3.42), whose derivatives with respect to the parameters in (3.40) are used to modify and define parameter values that result in the least error between the real and simulated recovery gradients. This process is repeated until the recovery component error is minimised to within a user defined error tolerance, preventing extremely long (or infinite) loops and a solution with an unacceptable error.

The initial change in the parameters are represented by $\mathrm{w}d_d^r$, $\mathrm{w}d_r^r$, $\mathrm{w}d_a^r$, $\mathrm{w}s_d^r$, $\mathrm{w}s_r^r$ and $\mathrm{w}s_a^r$, which are modified to produce the final change Δd_d^r, Δd_r^r, Δd_a^r, Δs_d^r, Δs_r^r and Δs_a^r respectively, and the final change is then added to the initial value of each parameter. The final change of the independent variables in (3.40) is determined by (3.43) to (3.48), where L_j^r for $j = \{d_d, d_r, d_a, s_d, s_r, s_a\}$ is a predefined learning rate.

$$\Delta d_d^r = \mathrm{w}d_d^r + \left(\frac{\delta E_r}{\delta d_d} \times L_{dd}^r\right) \tag{3.43}$$

$$\Delta d_r^r = \mathrm{w}d_r^r + \left(\frac{\delta E_r}{\delta d_r} \times L_{dr}^r\right) \tag{3.44}$$

$$\Delta d_a^r = \mathrm{w}d_a^r + \left(\frac{\delta E_r}{\delta d_a} \times L_{da}^r\right) \tag{3.45}$$

$$\Delta s_d^r = \mathrm{w}s_d^r + \left(\frac{\delta E_r}{\delta s_d} \times L_{sd}^r\right) \tag{3.46}$$

$$\Delta s_r^r = \mathrm{w}s_r^r + \left(\frac{\delta E_r}{\delta s_r} \times L_{sr}^r\right) \tag{3.47}$$

$$\Delta s_a^r = \mathrm{w}s_a^r + \left(\frac{\delta E_r}{\delta s_a} \times L_{sa}^r\right) \tag{3.48}$$

The initial change parameters are initialised at zero and increase (or decrease) in steps of partial derivatives, where (3.49) is the derivative of the squared error (3.42), and the expressions in (3.50) to (3.55) are the partial derivatives of (3.49) with respect to each independent variable in (3.40).

$$E_r{}' = 2 \times (g_r - \hat{g}_r) \tag{3.49}$$

$$\frac{\delta E_r}{\delta d_d} = E_r{}' \times d_d \tag{3.50}$$

$$\frac{\delta E_r}{\delta d_r} = E_r{}' \times d_r \tag{3.51}$$

$$\frac{\delta E_r}{\delta d_a} = E_r{}' \times d_a \tag{3.52}$$

$$\frac{\delta E_r}{\delta s_d} = E_r{}' \times s_d \tag{3.53}$$

$$\frac{\delta E_r}{\delta s_r} = E_r{}' \times s_r \tag{3.54}$$

$$\frac{\delta E_r}{\delta s_a} = E_r{}' \times s_a \tag{3.55}$$

3.3.3 Additional Features

In addition to the core functions previously described, FEROS also consists of other algorithms that facilitate frequency studies, either as a companion to the single bus model or as a standalone application.

Inertia Spread

This module facilitates the automated investigation of the minimum inertia that the system needs in order to contain a defined power imbalance, given available frequency response services, for a range of demand and inertia levels. The inertia spread module follows the process described in Algorithm 3.2.

Algorithm 3.2: Method for generating inertia spread.

1. define input parameters, and system and simulation limits
2. for decreasing demand level from user defined maximum to minimum demand
    - for decreasing inertia level from user defined maximum to minimum inertia
        - run Algorithm 3.1
    - save results
3. display graphs
4. end

Using the graphic user interface (GUI)[32] in the standalone version of FEROS, the user can see the results of the study, specifying demand and inertia values from a dropdown menu to display frequency, active power, RoCoF and energy plots for the selected scenario. When otherwise used as a companion to the single bus model, the final results of this study are saved to an excel file.

Penetration Limits

This module allows the user to investigate the penetration limits of non-synchronous dispatch in a power system. Like the inertia spread module, the algorithm also utilises Algorithm 3.1 to optimise and estimate frequency response reserves. It should be noted that this algorithm by default uses a relaxation of the tolerance constraint highlighted in section 3.3.1; i.e. a simulated event instance will be considered contained when the absolute value of the difference between the simulated frequency and the target frequency, $|\Delta\check{f}|$, is greater than the tolerance, provided the frequency nadir or zenith is within the range defined by the nominal frequency and the target frequency. The penetration limit study can be conducted in one of two formats: in terms of amount of non-synchronous power dispatched; or, in terms of minimum inertia required to contain the event. In the case of the latter, the algorithm applied is a variation Algorithm 3.2 that varies the inertia at each demand level until a point is reached that marks the point beyond which the event can no longer be contained. The penetration limits in terms of amount of non-synchronous power dispatched, uses an algorithm that varies non-synchronous power dispatched at each demand level to provide results either as a graded scale of severity, or as a pass/fail boundary limit.

3.3.4 Validating FEROS as a Standalone Application

As previously stated, as well as a companion program to the single bus model, FEROS is also capable of simulating frequency within its own program as a standalone application. In this case, FEROS has been used to replicate the power imbalances that occurred in GB on the 9th of June 2016 and the 10th of August 2016. Although there is limited data surrounding this event, by investigating the demand and generation around

[32] The GUI of the standalone version of FEROS gives the user the flexibility to: define a scenario and loss event; specify available responses, provider, and service definitions; define frequency stability limits and protection settings such as RoCoF LoM protection and LFDD; import real frequency event data; import generation background; export simulation results; select a specific study; display graphical results; and define simulation settings.

the time of the events [114], along with estimates of the frequency response reserve held by the ESO [115], the publicly available 1 second frequency data [115], and using the 'Retrospective Study' algorithm detailed in section 3.3.2, both events have been recreated. Table 3.2 below is an overview of the event and the predicted characteristics that result in frequency and RoCoF plots that closely match the real event, as shown in Figure 3.12.

Table 3.2: Retrospective study overview.

Retrospective Study Results		
	9th June 2016	**10th August 2016**
Loss Simulated	1 GW LoIF	
Demand	33.970 GW	32 GW
Predicted Demand Sensitivity	2.17 %/Hz	2.16 %/Hz
Predicted Inertia	325 GVAs	303 GVAs
Predicted Primary Response Reserve	496 MW	421 MW
Predicted Primary Response Delay	2 seconds	2 seconds
Predicted Primary Response Delivery	10 seconds	10 seconds
Predicted Static Response Reserve	226 MW	423 MW
Predicted Static Response Delay	1.8 seconds	0.9 seconds

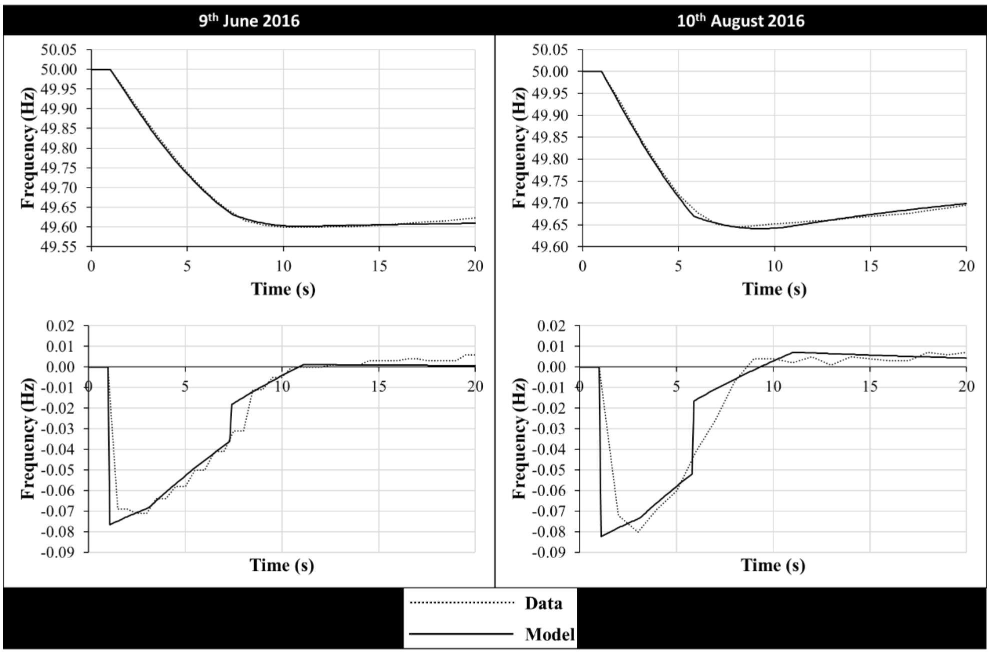


Figure 3.12: Replicated events. Left: 9th June 2016 loss event. Right: 10th August 2016 loss event.

In order to compare the performance of both the single bus model and the system frequency model, a scenario was simulated in both FEROS standalone and the single bus model. In this scenario, no responses to frequency were applied in order to compare the simplest form of the frequency simulation. The scenario is shown in Table 3.3 and the results are presented in Figure 3.13.

Table 3.3: Simulated scenario for testing free fall performance.

Demand	20 GW
Loss Simulated	1 GW LoIF
Inertia	250 GVAs

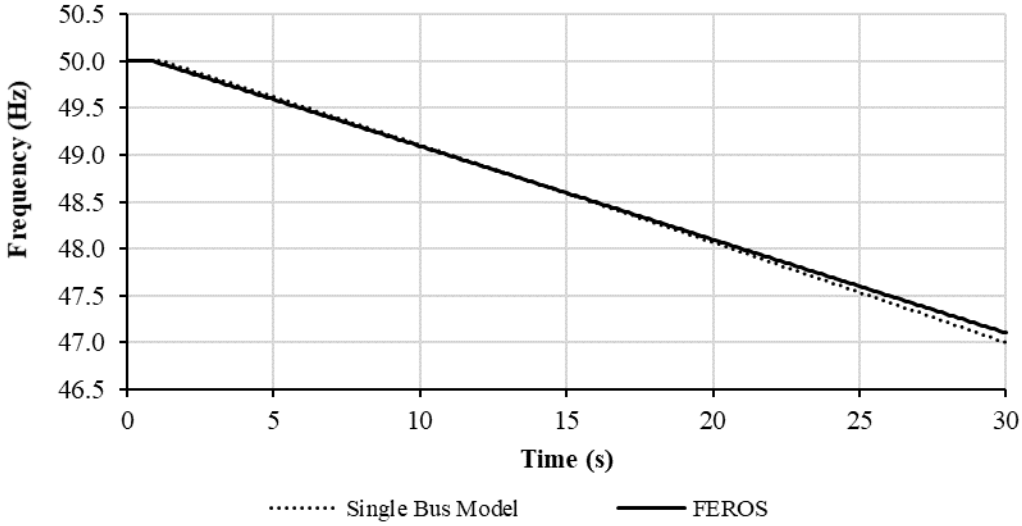


Figure 3.13: Comparing system frequency simulation.

The comparison shows that while the system frequency model[33] produces a frequency behaviour similar to that seen in the single bus model[34], the system frequency model over-estimates frequency behaviour in comparison to the single bus model (in PowerFactory) for the same scenario. The differences in the plots are attributed to differences in the methods for approximating frequency behaviour, and differences in the dynamics of the machine models. In particular, the system frequency model

[33] Power system model depicted in Figure 3.10.
[34] Power system model depicted in Figure 3.1.

simplifies the characteristics of all synchronous machines in the power system to a single expression[35]. The impact of this simplification is clearly seen in the results presented in Figure 3.14, where frequency containment solutions based on both models are compared.

The scenario described in Table 3.4 is optimised via (3.6) for frequency containment within 49.5 Hz using the single bus model as the model of the power system. It is determined that 870 MW of Primary response reserve[36] is required to contain the event when frequency is simulated by the single bus model. Using this value for Primary response, the frequency behaviour of the same scenario is simulated using the system frequency model, and a comparison is presented in Figure 3.14.

Table 3.4: Testing optimisation of frequency response reserve.

Demand	20 GW
Loss Simulated	1 GW LoIF
Inertia	250 GVAs
Frequency Target	49.5 Hz
Delay	2 s
Delivery	10 s

[35] $\frac{1}{2Hs+D}$

[36] No other frequency response service is deployed.

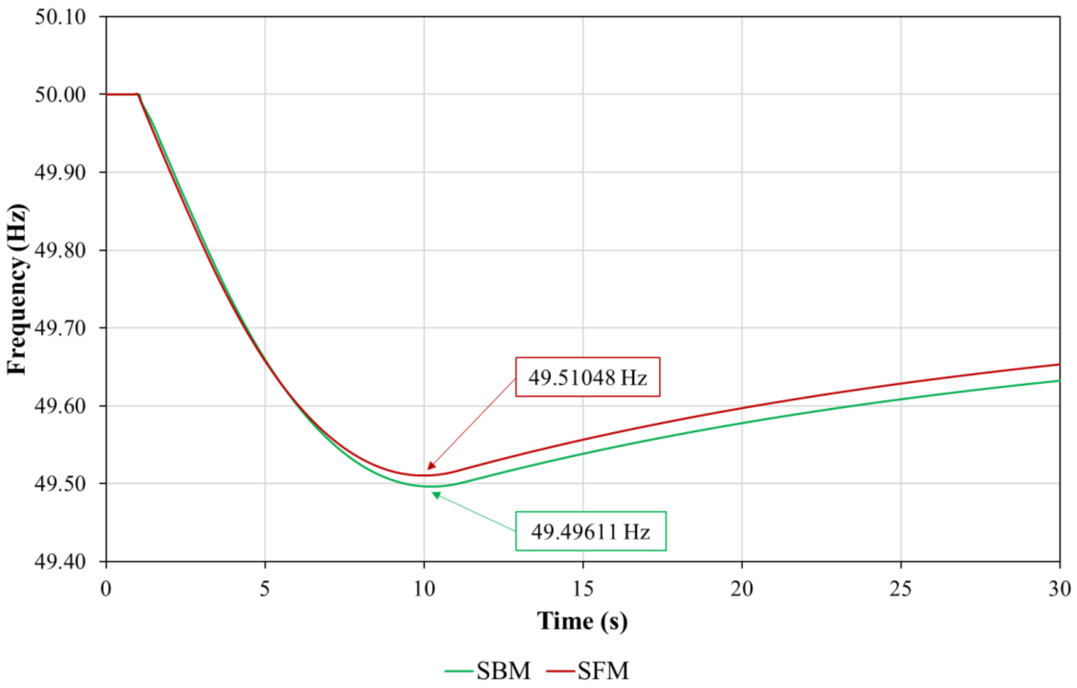


Figure 3.14: Comparing frequency containment profile in power system models with a Primary reserve of 870 MW. SBM: Single Bus Model. SFM: System Frequency Model.

Optimising the Primary frequency response reserve requirement using the system frequency model, produces a lower estimate of 820 MW. If this value of Primary response is dispatched in the single bus model, it would result in a frequency nadir that falls below 49.5 Hz and exceeds the 0.005 Hz error tolerance. Quantifying the difference between both models in terms of estimated Primary response reserve, gives a difference of about 6% with respect to the frequency response reserve estimated using the single bus model. Lastly, the plots presented in Figure 3.15, compare the response of both models to a generation step change of -200 MW that lasts for 3 seconds, with no frequency response service dispatched.

There are other limitations to the current version of system frequency model including the inability to simulate more than one event, and the restriction to using only one controller type for all services. Due to these limitations, the studies presented in this thesis use the single bus model instead of the system frequency model.

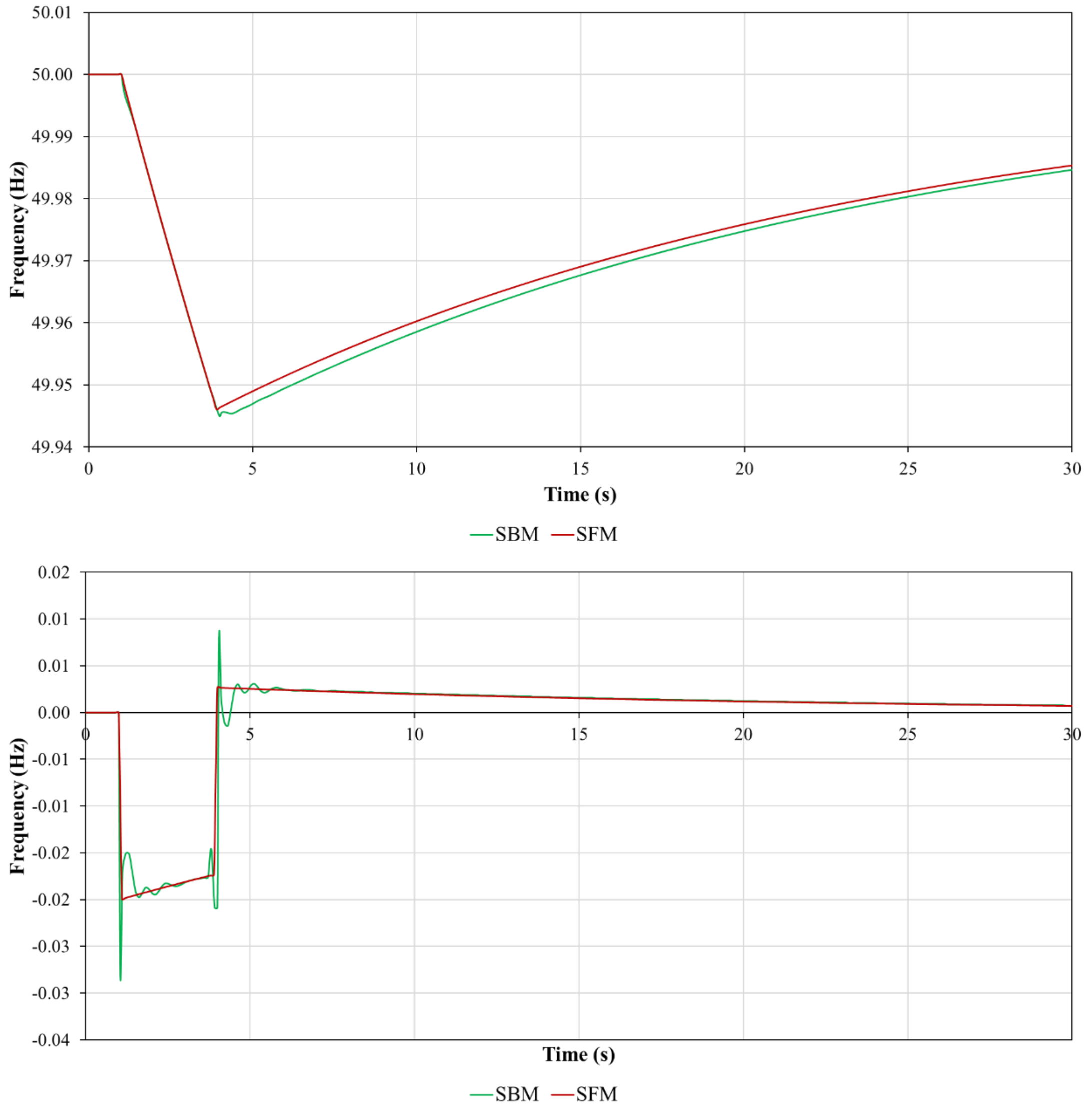


Figure 3.15: Comparing frequency behaviour during a step change of -200 MW. SBM: Single Bus Model. SFM: System Frequency Model.

FEROS as a standalone application is capable of producing fast solutions and can execute frequency studies quicker than the single bus model (operated by FEROS as a companion tool). If required, the results generated from the standalone application could then be further investigated on a more detailed model of the power system; however, the further work is planned to develop solutions that overcome the limitations of the system frequency model that is used to model frequency when FEROS is used as a standalone application.

3.4 Summary

Certain key features were identified for a model suitable for the studies required to deliver the objectives of this research project. Although there are existing power system models, none met all the requirements outlined at the start of this chapter. As a result, the single bus model and FEROS were developed for frequency stability studies. The single bus model incorporates representations of the behaviour of frequency responsive elements in a power system. It can be dispatched for a given operational scenario following the methodology described, and the frequency response reserve can be optimised and estimated using FEROS.

It is argued that the single bus model is a suitable tool for conducting frequency studies and assessing new ancillary service products, and its ability to reproduce frequency behaviours observed in real system events has been shown. Similarly, FEROS is a useful tool both as a companion collection of modular algorithms for operating the single bus model and as a standalone application. FEROS as a standalone application, uses a system frequency model that can be used to simulate frequency behaviour; however, it has been shown to over-estimate frequency behaviour and the system frequency model has limitations that require further development. That said, it can complete simulation studies in significantly less time, when compared to the single bus model in PowerFactory. This is attributed to the simplicity of the mathematical model in FEROS and the dedicated nature of the application for frequency studies in comparison to other more generalised power system analysis tools.

One of the additional features of FEROS, the module for conducting retrospective studies, highlights key factors that influence frequency behaviour during a power imbalance. A method is proposed, and demonstrated, that can be used to reproduce a historic frequency event, while providing an indication as to the likely system conditions around the time of the event. Further work on the modelling tools include improvements to the machine models in the system frequency model, and the flexibility of the system frequency model to permit the use of user define frequency response controllers.

4

FREQUENCY MANAGEMENT IN THE GB POWER SYSTEM

Frequency management in GB involves managing the power system within both RoCoF and frequency limits. In practice, this means that the inertia, loss risk and energy responses must be managed to keep the RoCoF and frequency following a power imbalance within defined limits.

4.1 The Role of Demand Sensitivity

The sensitivity of demand to frequency changes and embedded inertia influence system frequency during a loss event. This influence can be illustrated by considering minimum inertia simulations, where minimum inertia is the lowest inertia value of the system that can contain a loss event within frequency limits given the responses available to contain the power imbalance.

It is worth noting that RoCoF limits are not applied at this point of the study but are considered in the case of critical inertia in section 5.2.2. The minimum inertia is determined via the process described in Algorithm 4.1.

Algorithm 4.1: Minimum inertia.

1. Input generation background
2. Define response reserves and services
3. Define demand sensitivity
4. **for** i in a set of reducing inertia values

   Create dispatch for a defined system event

   Populate the elements of the model

   Run simulation

   Check to see if the event has been contained

   if the event is not contained **then**

       Break the loop

   else

       Record input parameters of the model in database
5. Export results to excel

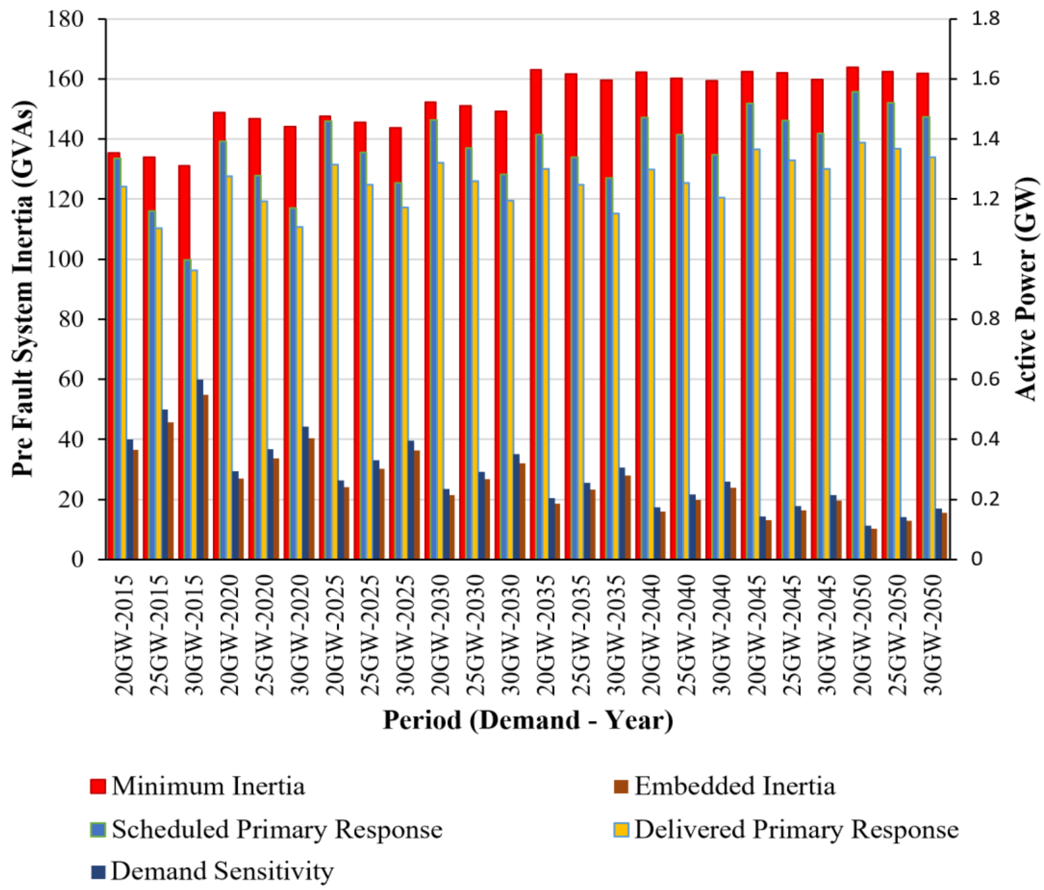


Figure 4.1: Trend of minimum inertia and response requirements for 2015 – 2050.

The results shown in Figure 4.1 are for a minimum inertia study for the loss of a 1320 MW synchronous generator, with dynamic Primary response provided by the flexible synchronous generation element of the single bus model. The study was repeated for 2015 to 2050 in 5-year intervals with 20 GW, 25 GW and 30 GW of demand. It can be seen from Figure 4.1 that as the amount of embedded inertia reduces with demand, a complimentary increase in Primary[37] response is required to contain the same event. Furthermore, it can also be seen that as demand sensitivity reduces with demand, the loss of energy response is compensated by more Primary response or a higher minimum inertia value for the same event.

The impact of demand sensitivity on the amount of Primary response reserve can be further illustrated by a linear decrease of demand sensitivity from 2.5%/Hz to 0.5%/Hz. It is shown in Figure 4.2 that for a fixed system inertia of 150 GVAs at 20 GW of demand, there is an increase in the Primary response required to contain a loss of 1 GW of interconnector infeed, as demand sensitivity reduces. In this case, the trend observed is about 200 MW per unit change in demand sensitivity, with frequency falling faster when demand sensitivity is lower.

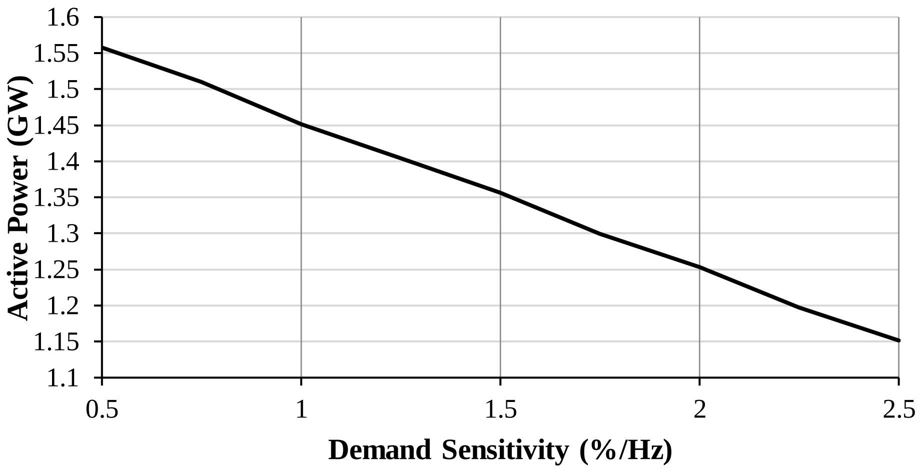


Figure 4.2: Primary response trend at 150 GVAs for a 20 GW demand scenario.

[37] It should be noted that in this instance Primary response was modelled with no delay for illustrative purposes. The impact of the delay will be illustrated in section 4.3.

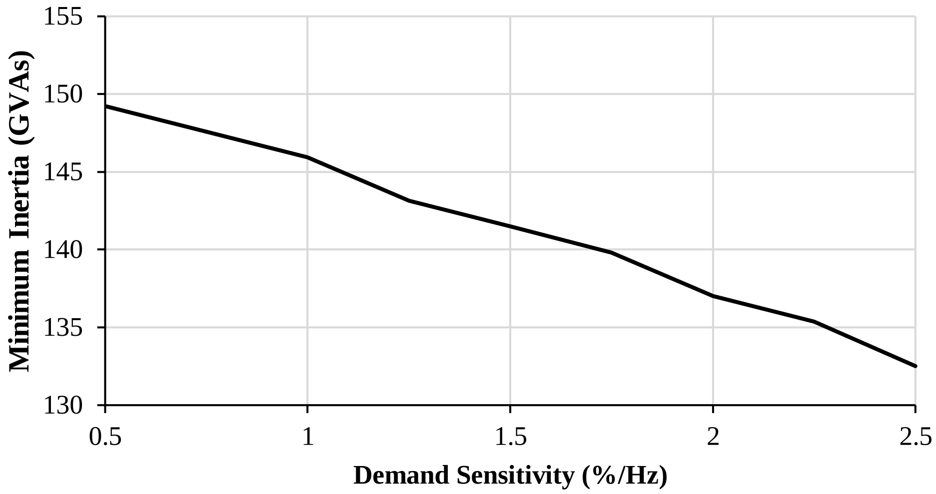


Figure 4.3: Minimum inertia trend at 20 GW demand.

Similarly, it can be seen from Figure 4.3 that, at 20 GW demand, as demand sensitivity reduces the minimum inertia increases. In this case, the trend observed is 8 GVAs per unit change in demand sensitivity. These trends indicate the influence that demand has on RoCoF and frequency containment, and frequency response reserve requirements. Demand sensitivity in particular, due to its fast acting and inherent nature, compliments inertia and can actively modify the RoCoF following the event and the RoCoF detected by LoM protection, particularly when wider detection windows are deployed.

4.2 The Role of Inertia

As discussed in section 2.4.2, SCs are inherently unloaded synchronous motors that are considered to have the potential to offer, among other benefits, a boost to system inertia and an increase of system fault level, which could facilitate the operation of the protection system in future energy scenarios [82]. The impact of additional inertia can be shown mathematically using (2.1) in an assessment that compares a scenario with and without the deployment of 5 GVA of SCs with an inertia constant of 2 s. A system inertia of 75 GVAs without SCs is assumed, representing a low inertia scenario, and a largest loss risk of 375 MW is calculated for a RoCoF limit of ±0.125 Hz/s. The results of the mathematical assessment, shown in Figure 4.4, suggest that 5 GVA of SCs can reduce RoCoF from ±0.125 Hz/s to ±0.11 Hz/s, or increase the loss risk tolerance from 375 MW to 425 MW at a RoCoF limit of ±0.125 Hz/s.

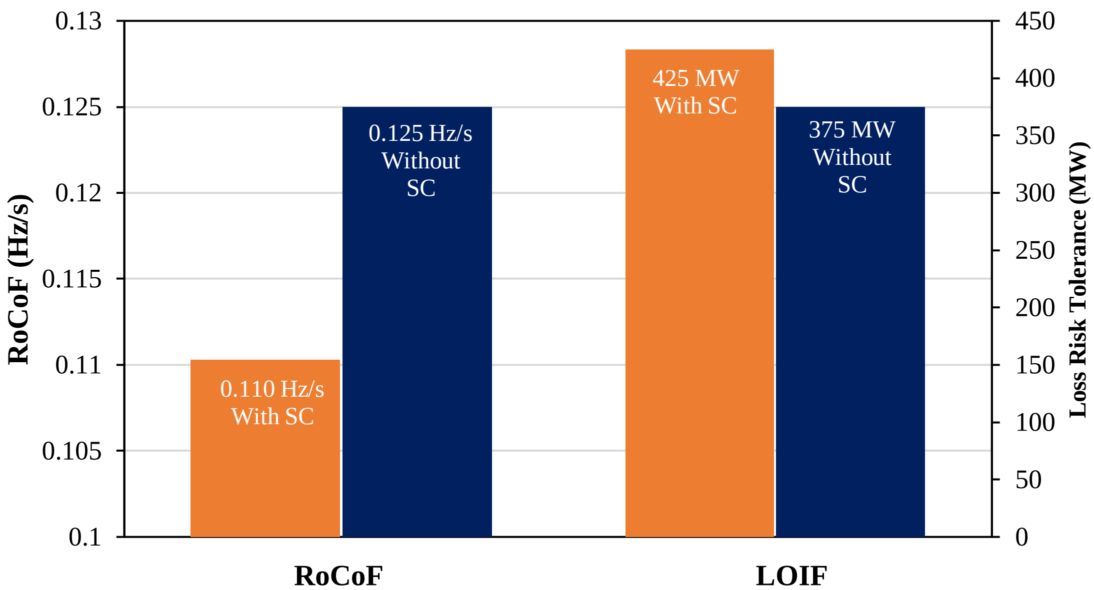


Figure 4.4: Loss risk tolerance and RoCoF comparison.

A similar comparison using the single bus model is conducted. The results of this study, shown in Figure 4.5, agree with the mathematical assessment and they indicate that 5 GVA of SCs can reduce the RoCoF from 0.116 Hz/s to 0.103 Hz/s for a 375 MW loss risk. Similarly, it was also observed that the deployment of 5 GVA of SCs for a RoCoF of 0.125 Hz/s raised the loss risk tolerance from 410 MW to 460 MW.

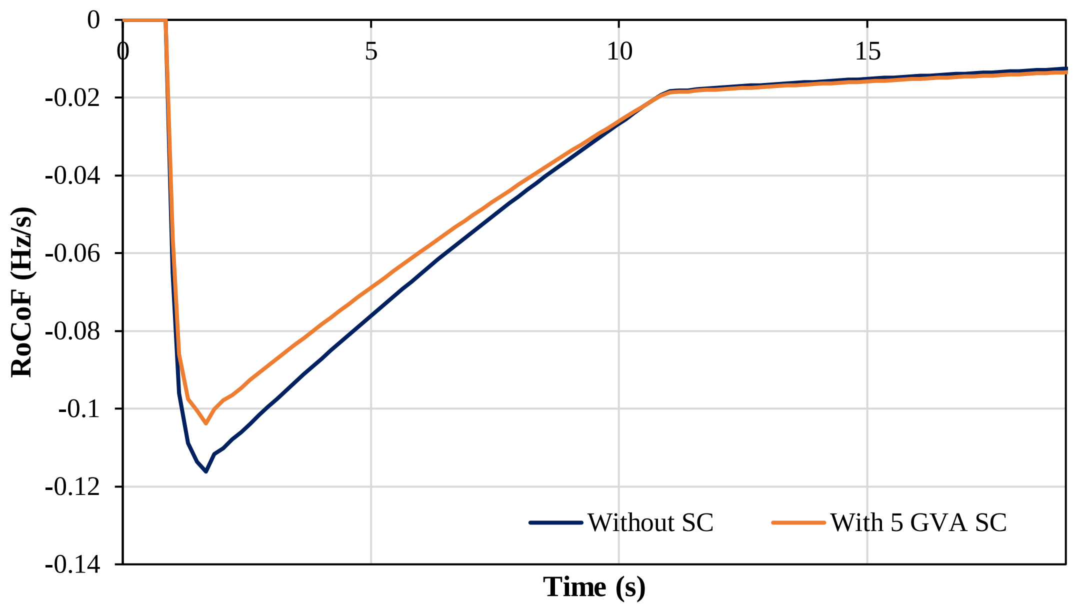


Figure 4.5: RoCoF Comparison with system dynamics.

These results show that the deployment of 5 GVA of SCs facilitates a larger loss risk for a given RoCoF limit, due to the deployment of an additional 10 GVAs of inertia, reducing the need to curtail the largest loss risk. In addition, the deployment of 10 GVAs of inertia via SCs means that a system event that would have originally been at risk of breaching the RoCoF limit is brought within the threshold. This benefit of increased inertia can mitigate the risk of a cascading event because of the tripping of RoCoF protection applied to distributed generation. It also gives frequency services more time to respond to a power imbalance and contributes to a reduction in the overall active power requirement for frequency containment, as indicated by Figure 4.1.

4.3 The Role of Dispatched Reserves

Dispatchable energy responses have a major role to play in frequency management, since they augment the inherent characteristics of the power system. In particular, frequency response services such as Primary and High, are vital for frequency containment. However, the value and impact of such services are dependent on the factors highlighted below.

- **The speed of activation of the service:** This refers to the length of time between the inception of the event and when the response service begins to respond, i.e. the amount of time for detection and instruction of response.
- **The rate of delivery of response:** This refers to the ramp rate, the amount of power delivered per second either in MW/s or pu/s. In the case of non-dispatchable dynamic energy responses such as demand sensitivity, this is the amount of power delivered per hertz change in frequency.
- **The amount of reserve scheduled:** This refers to the amount of power held in reserve for a frequency response service.
- **The duration of the service:** This refers to how long the service lasts after the response has been fully delivered.

The impact of the first three factors will be illustrated in this section, while the impact of the duration of the service will be highlighted when considering the framework of a future dynamic frequency containment service in section 6.2. To illustrate the impact of the first three factors, a study is conducted for a 1 GW interconnector LoIF with frequency falling from 50 Hz to 49.5 Hz. Unless otherwise stated, the assumptions applied in the modelling in this section were for 35 GW of demand, with a demand sensitivity and embedded inertia constant of 2.5%/Hz and 1.83 s respectively. Initially, no delay is modelled for the dynamic Primary response service, and the contribution from static Primary response is not included.

In Figure 4.6, it is observed that under the limited ramp rate condition of the Primary response delivered by flexible synchronous generators, as system inertia reduces, the amount of active power response required from Primary response to contain the LoIF event increases. This observation is an indication that lower inertia scenarios would benefit from a faster service; since the ramp rate of the controller is limited in per unit per second, this translates to scheduling more reserve in order to deliver more power per second at the same, fixed, per unit per second rate.

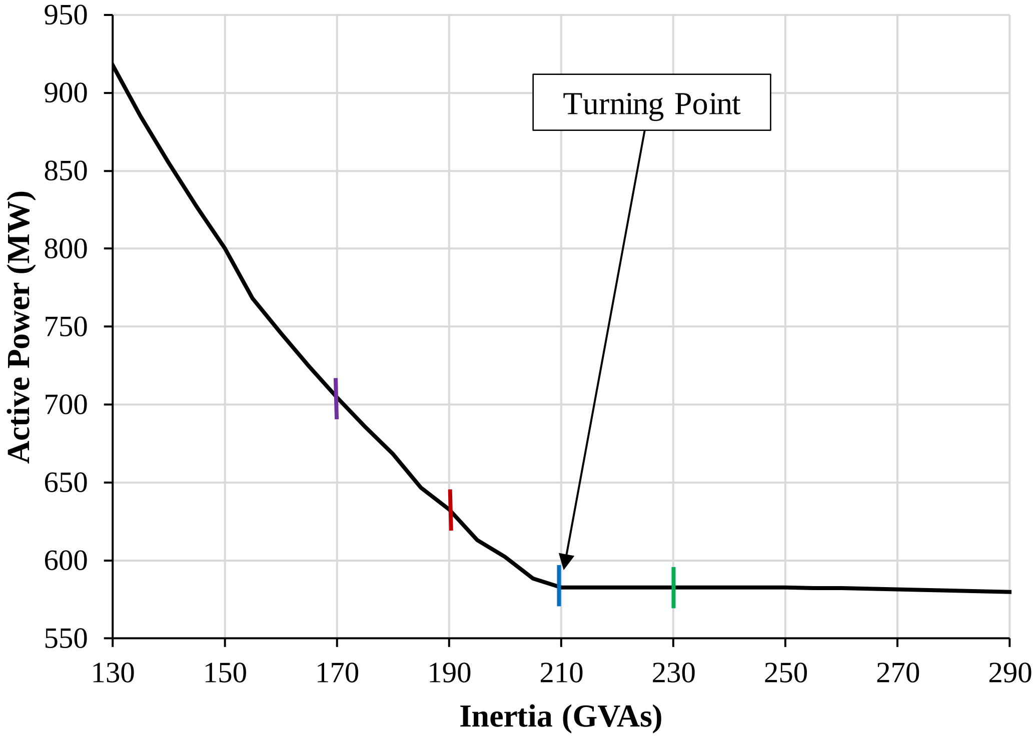


Figure 4.6: Response trend against system inertia at 35 GW demand.

Furthermore, Figure 4.6 indicates a turning point where the rate of change of response requirement increases. Figure 4.7 shows the frequency plots of selected inertia values around the turning point indicated by Figure 4.6. From these results, and the results in Figure 4.6, it can be surmised that as system inertia reduces and RoCoF increases, the speed of the response service or the amount of reserve needs to increase. It can also be seen that frequency containment (the frequency nadir) occurs sooner after the event at lower inertia than at higher inertia.

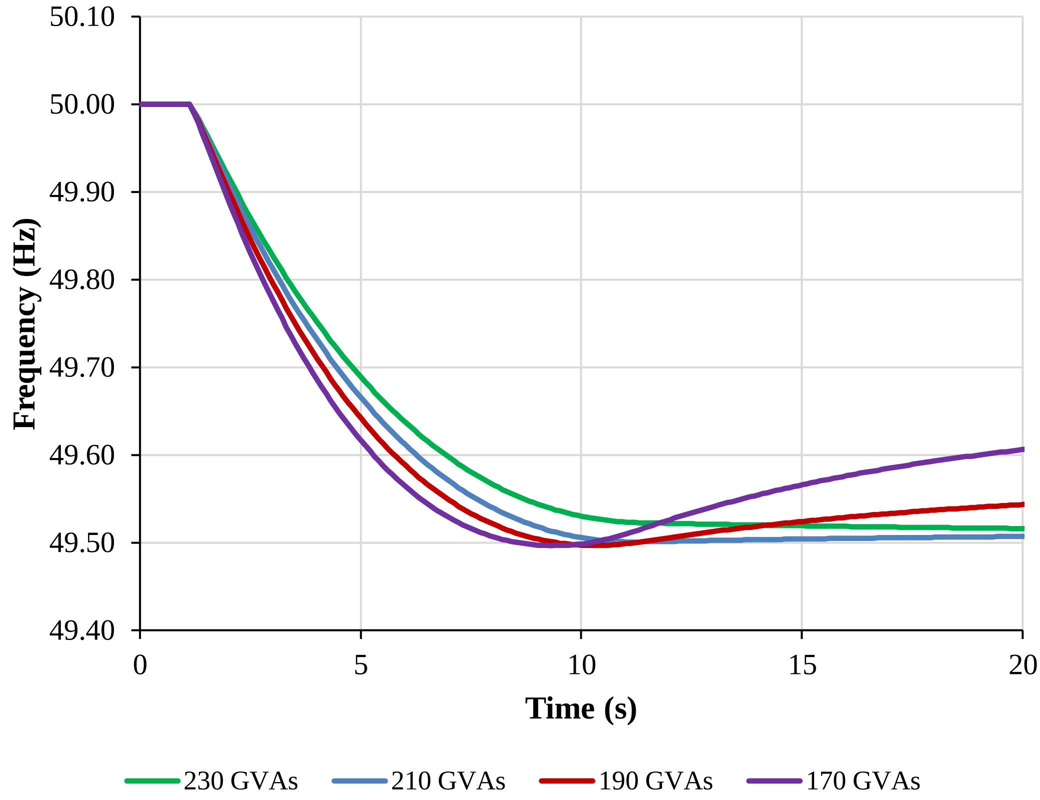


Figure 4.7: Response trend against system inertia at 35 GW demand.

The increasing inefficiency of Primary response as inertia reduces suggests that rather than increasing the reserve, a faster service may in fact be more suitable. Although the results presented specify Primary frequency response, the effect of the turning point is generic; i.e. the turning point manifests when frequency needs to be contained at a time that is faster than the full delivery time of the frequency response service. As a result, a slower service would manifest a turning point at a higher inertia, if and when frequency containment is required before the service can be fully delivered. Similarly, a faster service would manifest a turning point at a lower inertia, if and when frequency containment is required before the service can be fully delivered. In Figure 4.8, two hypothetical services are introduced: a service that fully delivers response in 12 seconds that is termed a ‘12s Service’; and a service that fully delivers response in 8 seconds that is termed an ‘8s Service’. These services show the impact on the occurrence of the turning point in the inertia spread as the speed of the service is changed, which in turn relates to a turning point occurring when frequency needs to be contained before the frequency response service can be fully delivered. A sufficiently fast service would therefore exhibit no turning point where a slower service did. In addition, a faster service also means less reserve is needed to contain the same event when compared to a slower frequency response service, especially at lower inertia.

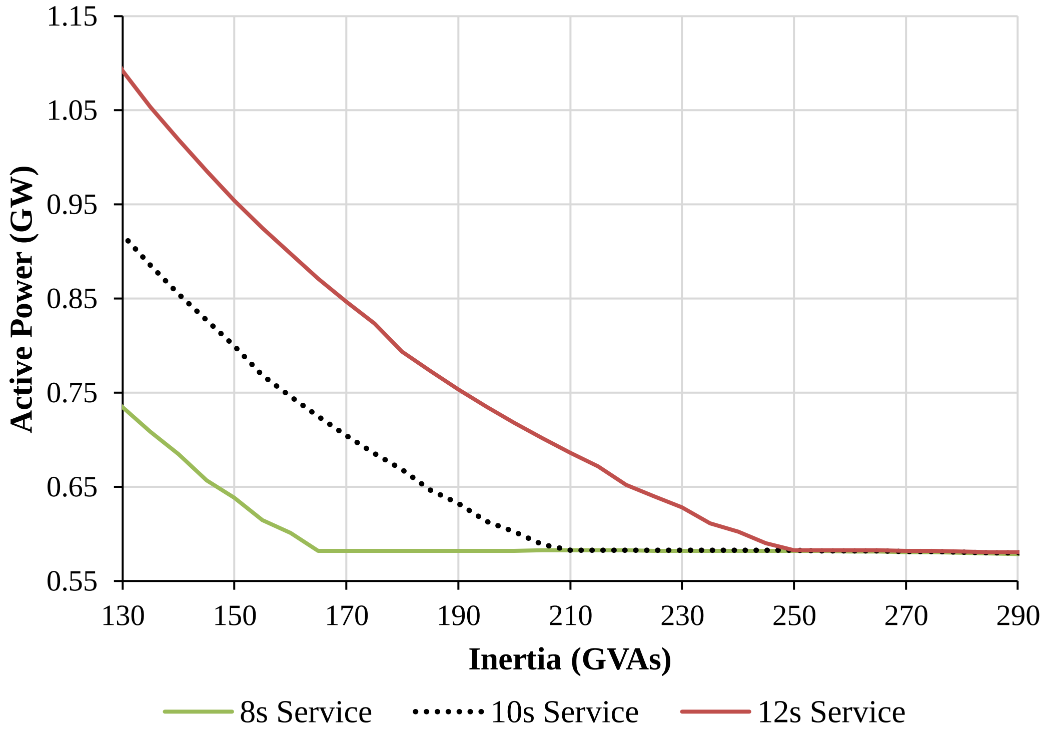


Figure 4.8: Effect of the speed of service on turning point.

The response of a system to a given loss event depends on the nature and characteristics of the frequency response services available at the time of the event, the size and type of loss event, the system inertia, and the inherent characteristics of demand. It also follows that the energy responses available determine the minimum inertia[38] that the system can have in order to contain a loss event under a given scenario. The impact of a faster ramp rate can be investigated by taking the inertia value of 210 GVAs as the

[38] It should be reiterated here that a distinction is made in this thesis between minimum inertia – termed to refer to frequency stability within acceptable frequency conditions alone – and critical inertia as presented in section 5.2.2 that is termed to refer to frequency stability within acceptable frequency conditions and RoCoF.

turning point of the Primary response trend lines in Figure 4.6, and varying the time until full delivery. The results of this study are shown in Figure 4.9, with Figure 4.10 presenting the same results with the ramp rate in pu/s on the x-axis. It should be noted that no governor delay is assumed in this investigation, and demand sensitivity and embedded inertia are ignored in this instance. The results in Figure 4.9 and Figure 4.10 support the previous assertion that the active power requirement decreases as the speed of response delivery increases.

Figure 4.9: Plot of the change in active power reserve held with change in full delivery time of response under the assumed system conditions.

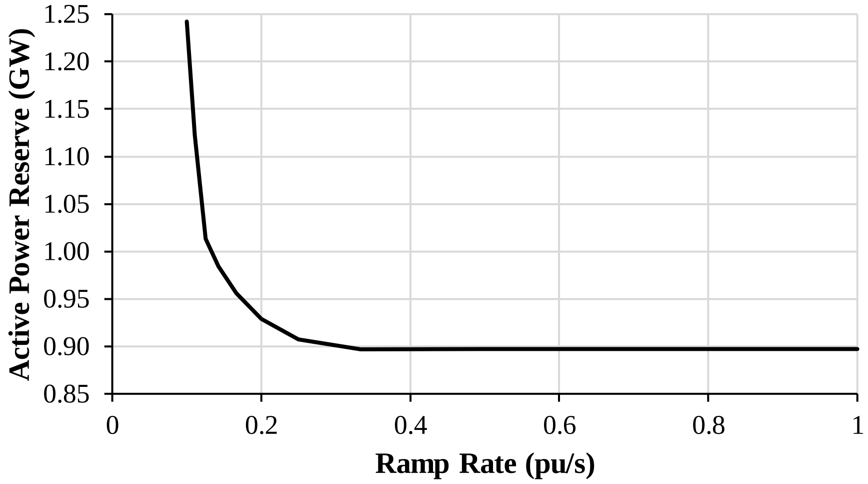


Figure 4.10: Plot of change in active power reserve held with change in ramp rate under the assumed system conditions.

The impact of the speed of activation on minimum system inertia and active power reserve is illustrated in Figure 4.11 to Figure 4.13, where a loss of 1 GW of interconnector capacity at 20 GW demand is simulated, with ramp rate limited at the definitions of Primary response, and the delay varied in the governor of the flexible synchronous generation element of the model (providing Primary response). Figure 4.11 shows the minimum inertia for different governor delays and demand sensitivities. It is observed that the speed of activation of response is related to minimum inertia, such that minimum inertia reduces with decreasing activation delay. In addition, a lower activation delay (or higher speed of activation) can contain the same event with less contribution from demand sensitivity than a similar scenario with a higher activation delay. A similar trend can be observed when considering the amount of Primary response required to contain an event at a given inertia value for different activation delays, as shown in Figure 4.12. By considering both Figure 4.11 and Figure 4.12, it can be said that the activation delay is proportional to the minimum inertia and active power response, where an increase in the activation delay would require an increase in either one or both of the other dependencies in order to contain the same event.

Figure 4.13 supports this inference and shows increasing active power response with increasing activation delay for a system inertia of 175 GVAs. It is observed that in Figure 4.13, while the difference between the scheduled and delivered active power increases as activation delay increases, the greater difference is seen at activation delays greater than 1 s. In addition to the turning point observed in Figure 4.6 and the discussion on ramp rate, the observations made on the speed of activation suggest the benefits of a faster dynamic containment service both in terms of speed of activation and ramp rate.

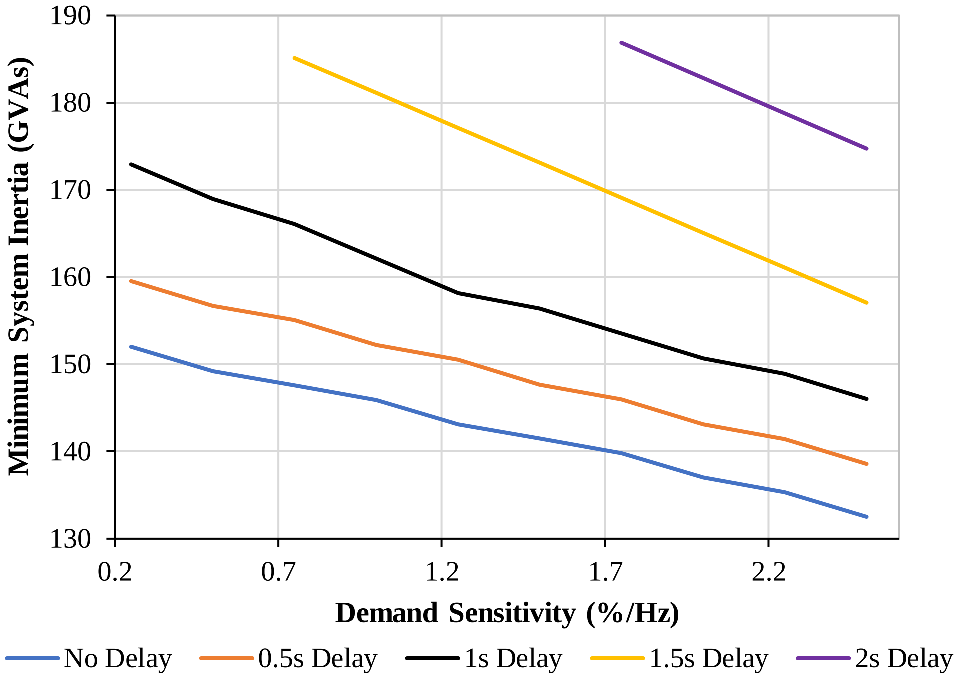


Figure 4.11: Comparing the impact of governor delays on the minimum system inertia at different demand sensitivity values.

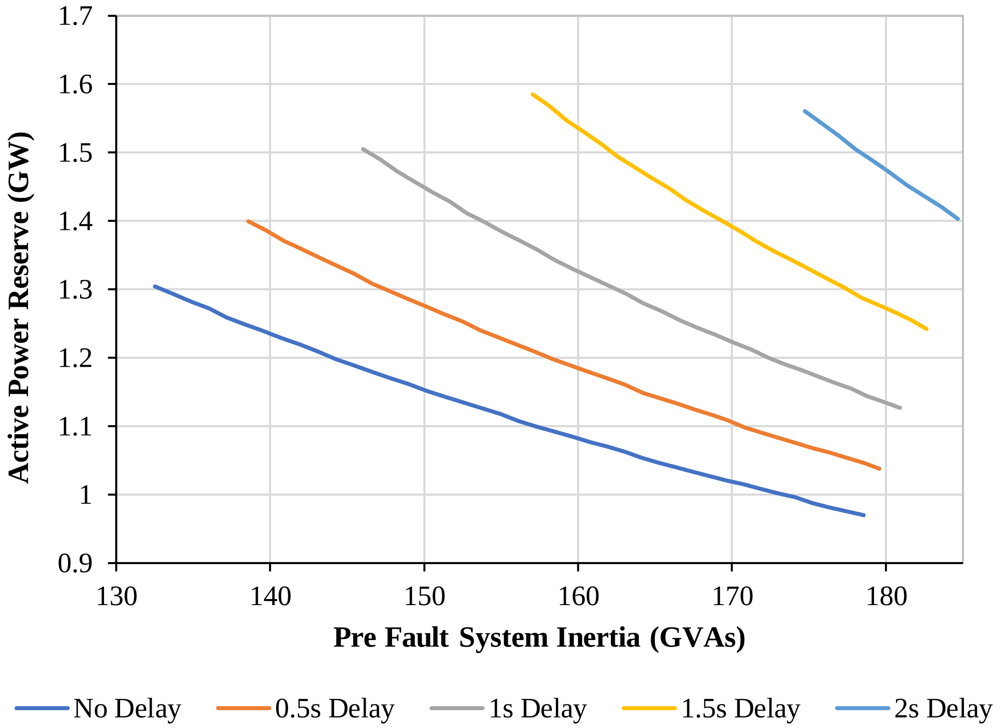


Figure 4.12: Comparing the impact of activation delays on active power reserve at different levels of system inertia.

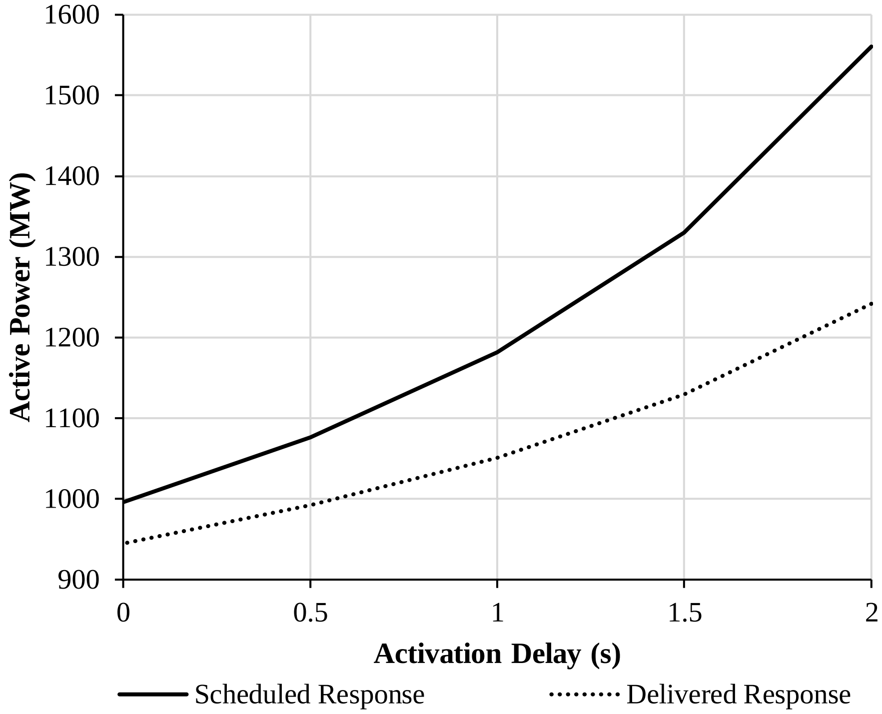


Figure 4.13: The trend of FSG response requirements and frequency nadir time at different activation delay settings.

4.4 Summary

It is shown that as demand sensitivity reduces, the reserve held for Primary response increases, similarly as demand sensitivity reduces the minimum inertia increases, where the minimum inertia is the lowest value of system inertia that can contain a loss event within frequency limits for a given set of energy responses, without the inclusion of a RoCoF limit. The trend of demand sensitivity is noteworthy, since this characteristic of transmission demand is dependent on the type and nature of devices connected to the transmission network. It is also shown that increasing the inertia in the power system reduces the RoCoF and permits a higher maximum loss risk.

Dispatchable energy responses such as those delivered by Primary response, augment the inherent characteristics of the power system and are vital tools for frequency containment and restoration. The value of such services to the grid is dependent on speed of activation, rate of delivery of response, amount of reserve held, and duration of the service. It is observed that as the inertia reduces the amount of reserve needed for Primary response to contain the same loss risk increases. In addition, a turning point is also observed, where the rate of change of reserve required for frequency containment increases. This indicates the increasing need for a faster response service as the power system tends towards lower inertia. It is determined that there is significant benefit to deploying a fast acting and high ramp rate dynamic containment service to contain loss risks more efficiently, particularly at low inertia.

5

CONTAINING LOSS RISK IN GB

The ESO's SOF 2016 highlights, among other factors, the limits to largest loss of demand or generation, which are constrained by the system inertia and RoCoF limit. The RoCoF limit in GB has been changed, as discussed in section 2.1, however, coordinating and implementing these changes, particularly in reference to distributed generation, has proven challenging. As a result, at the time of writing, there is still about 2 GW of distributed generation using relays that could activate if RoCoF exceeds ±0.125 Hz/s [28]. This is significant since RoCoF relays are widely used in the UK and Ireland, in LoM protection for distributed generation [14, 15]. These relays are designed to disconnect generation when the system RoCoF reaches a given limit [16]. If the RoCoF following a frequency disturbance is too high, it increases the risk of cascading frequency events as a result of the unintended tripping of RoCoF relays.

Without adequate safeguards, this risk is increased in low inertia power systems. Consequently, due to the 2 GW of distributed generation still using the ±0.125 Hz/s RoCoF setting, it is currently the practical limit in the GB power system, leading to a need to manage RoCoF within this limit. The RoCoF experienced by a power system is dependent on the inertia and the loss event. Considering (2.1) that shows the relationship between inertia, RoCoF, and the power imbalance, it is seen that as inertia reduces, the RoCoF increases for a given power imbalance that in turn, without remedial actions, reduces the system resilience to frequency disturbances [2, 116]. Such remedial actions include either or both holding sufficient and adequate energy response reserves (including inertia) and managing the loss risk.

5.1 The Challenge of Containing Loss Risk in GB

A larger loss leads to a higher RoCoF in the power system when compared to a smaller loss in an otherwise identical operational scenario. This presents a challenge in containing the loss risk in the British power system, given the changing power landscape, the higher maximum loss risk of 1.8 GW, and the legacy RoCoF relays on the old setting of 0.125 Hz/s. The challenge can be illustrated by considering two cases; containing a normal loss risk within ±0.125 Hz/s and containing a normal loss risk within ±0.5 Hz/s. The single bus model described in section 3.2 is used to investigate both cases, where unless otherwise stated, both cases apply the following assumptions:

- demand is set at 20 GW to illustrate the impact of low demand;
- in the context of this study, 'Demand' refers to demand on the transmission system and includes pumping hydro, interconnector exports and net unmetered embedded generation;
- embedded inertia is assumed to be applied as a function to total demand with an inertia constant of 1.83 seconds, i.e. the inertia in GVAs is 1.83 multiplied by transmission demand – based on discussions with industry experts;
- demand provides an inherent active power response of 2.5%/Hz [9];
- an inertia constant of 6 seconds is assumed for all gas units and 4 seconds for all other synchronous generators, these values are chosen following discussions with industry experts;
- generation is split into synchronous and non-synchronous generation;

- generation is further divided into flexible and non-flexible, where flexible generation can provide active power response, while non-flexible cannot;
- background generation is obtained from the ESO's future energy scenarios report under the gone green scenario for 2025 [117];
- in order to meet a given inertia target, generation is dispatched in the following order. Baseload power supply is first met by nuclear dispatched at 77% of the background capacity [118], gas plants are dispatched next to deliver the required Primary response until demand has been met or the inertia target has been achieved, or whichever of the two occurs first. If there is still a shortfall of demand it is met by dispatch from the remaining generation background, but if the inertia target has been achieved the remaining demand is met by non-synchronous dispatch;
- dynamic Primary response is delivered by flexible generation. Flexible generators are 75% loaded with response provided by 50% of the headroom [91];
- where applicable, EFR is dispatched at 201 MW, based on the tendered capacity in [41];
- containment is attempted for the least containment reserve holding using the FEROS method described in section 3.3.1, and all response is assumed to be dynamic; and
- the delivery of responses is at the limit of their definitions; however, it is recognised that delivery of responses may in practice have a shorter delay or in some cases faster ramp rates.

The cases presented in the subsequent studies, serve to illustrate the impact that curtailing the loss risk or procuring faster frequency response services have on the power system's ability to keep frequency within acceptable conditions during a normal loss of infeed event. The scenarios considered for study are those scenarios with an amount of inertia that puts the system at the precipice of the RoCoF constraint. To achieve this, the inertia-based scenarios were determined using (2.1). Consequently, the impact of increasing inertia isn't explicitly modelled in the subsequent studies but will be considered in later studies within this chapter.

5.1.1 Case 1: Containing Normal Loss Risk Within ±0.5 Hz of Nominal Frequency with a ±0.125 Hz/s RoCoF Limit

On the 7th of August 2016 the GB power system experienced a system inertia of 135 GVAs with a transmission system demand of 16.3 GW, as discussed in chapter 2. A similar case is considered for investigation in 2025, such that the power system has 20 GW of demand and 130 GVAs of inertia, while RoCoF and frequency limits are applied under current definitions. This case is used to illustrate the performance of frequency response services and loss risk curtailment actions in the GB power system to contain/manage the current normal loss risk of 1 GW.

There are two factors that determine acceptable frequency behaviour during a power imbalance, the frequency deviation and RoCoF. Consequently, the system must be secured against the normal loss risk in terms of both these factors. In the case of a 130 GVAs system, the loss risk defined by the ±0.125 Hz/s RoCoF limit is calculated to be 650 MW. When compared to a 1 GW normal loss risk for a frequency deviation of ±0.5 Hz, the system must be dispatched such that no single loss risk exceeds 650 MW, which requires curtailment of any single unit (or indeed point of failure) supplying power greater than the maximum loss risk.

Table 5.1: Scenarios for containing normal loss risk within the ±0.125 Hz/s RoCoF limit.

Title	Description
Scenario A	Included as a reference scenario, the simulated loss is 1 GW with only Primary response available to contain the event.
Scenario B	The simulated loss is 1 GW with Primary, Enhanced and the new Dynamic Containment frequency response services dispatched to contain frequency deviation.
Scenario C	The simulated loss is constrained from 1 GW to 650 MW, with only Primary response dispatched to contain the frequency deviation.
Scenario D	The simulated loss is 1 GW with Enhanced and the new Dynamic Containment frequency response services dispatched to contain frequency deviation.

To illustrate the impact of loss risk curtailment and faster frequency response services in managing a significant power imbalance within acceptable frequency limits, at low inertia and demand, four scenarios are investigated, which are presented in Table 5.1. Table 5.2 is an overview of the observations from the study, with Figure 5.1 and Figure 5.2 showing the frequency and RoCoF plots for scenarios A - D.

Table 5.2: Overview of study scenarios and observations for Case 1.

	A	B	C	D
Simulated Loss	1 GW	1 GW	650 MW	1 GW
RoCoF Contained	No	No	Yes	No
Frequency Contained	No	Yes	Yes	Yes
Dispatched Responses	Primary	Primary, Enhanced and Dynamic Containment	Primary	Enhanced and Dynamic Containment

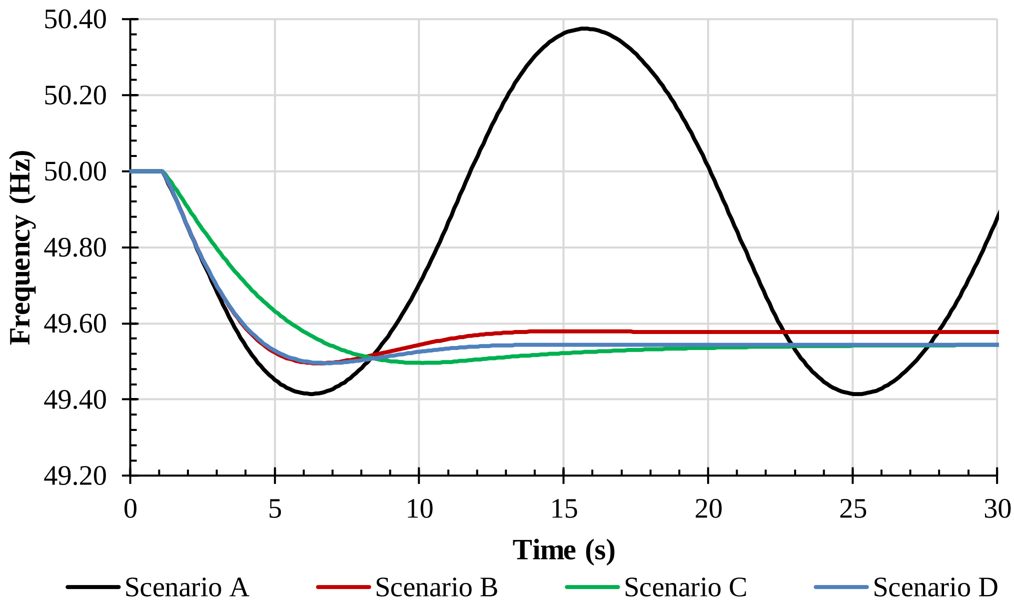


Figure 5.1: Frequency plots comparing the impact of different actions to meet operational limits for a system with 130 GVAs of inertia.

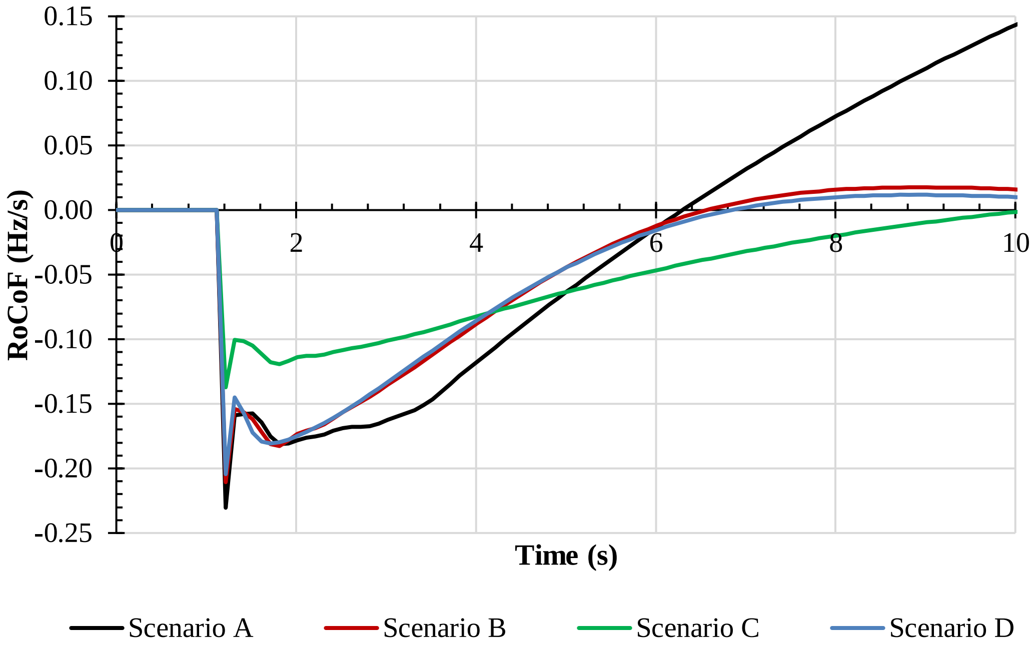


Figure 5.2: RoCoF plots comparing the impact of different actions to meet operational limits for a system with 130 GVAs of inertia.

It is demonstrated by Scenario C that curtailing the loss risk to manage frequency stability within RoCoF and frequency limits is indeed a viable option. Increasing the inertia of the power system will serve a similar purpose and the impact can indeed be seen when considering (2.1). It is seen in Figure 5.1 that while Scenario A produces a frequency behaviour that exceeds acceptable frequency conditions[39] for a normal loss risk, Scenario C successfully contains the event within frequency conditions due to the reduced loss risk, even though both scenarios deploy only Primary response. Similarly, it can be seen from Scenarios B and D in Figure 5.1 and Figure 5.2 that while the inclusion of faster frequency response services such as EFR and the Dynamic Containment concept produces results with frequency behaviour within acceptable frequency conditions, RoCoF limits are violated. This is because the service definitions of the faster services have no impact on RoCoF, particularly in reference to the current limit of ±0.125 Hz/s, which typically includes a detection window of 100 ms or less.

[39] As defined by the SQSS in [19] and highlighted in section 2.1.

5.1.2 Case 2: Containing Normal Loss Risk Within ±0.5 Hz of Nominal Frequency and a ±0.5 Hz/s RoCoF Limit

It is conceivable that unless the relevant plants are decommissioned by 2025, or otherwise not in merit, the RoCoF limit in the GB power system can be ±0.5 Hz/s, as recommended by [29]. Therefore, it is worth investigating the impact of faster response services on frequency limits during a credible loss event for an operational scenario approaching the ±0.5 Hz/s RoCoF limit, where the present (1 GW) and future (1.32 GW) normal loss risk conditions are considered. The inertia-based scenarios are determined by applying (2.1), and the system inertia for the cases being considered here are 50 GVAs (for the current normal loss risk) and 66 GVAs (for the future normal loss risk).

Table 5.3: Scenarios for containing a normal loss risk within the ±0.125 Hz/s RoCoF limit for both current and future normal loss risk values.

Title	Description
Scenario A	Included as a reference scenario with only Primary response available to contain the event.
Scenario B	Primary and Enhanced frequency response services dispatched to contain frequency deviation.
Scenario C	Primary, Enhanced and the Dynamic Containment frequency response services dispatched to contain frequency deviation.
Scenario D	Enhanced and the new Dynamic Containment frequency response services dispatched to contain frequency deviation.

Four scenarios are presented in Table 5.3 for investigation, which compare the capability of the different combinations to contain the power imbalance within acceptable frequency conditions. An overview of the results of this case study and the resultant frequency plots are presented in Table 5.4 and Figure 5.3 for a 1 GW normal loss risk, and Table 5.5 and Figure 5.4 for a 1.32 GW normal loss risk.

Table 5.4: Overview of study scenarios and observations for Case 2 at 1 GW normal loss risk.

	Frequency Contained	Frequency Stable	Dispatched Responses
A	No	No	Primary
B	No	No	Primary and Enhanced
C	Yes	Yes	Primary, Enhanced and Dynamic Containment
D	Yes	Yes	Enhanced and Dynamic Containment

Table 5.5: Overview of study scenarios and observations for Case 2 at 1.32 GW normal loss risk.

	Frequency Contained	Frequency Stable	Dispatched Responses
A	No	No	Primary
B	No	No	Primary and Enhanced
C	Yes	Yes	Primary, Enhanced and Dynamic Containment
D	Yes	Yes	Enhanced and Dynamic Containment

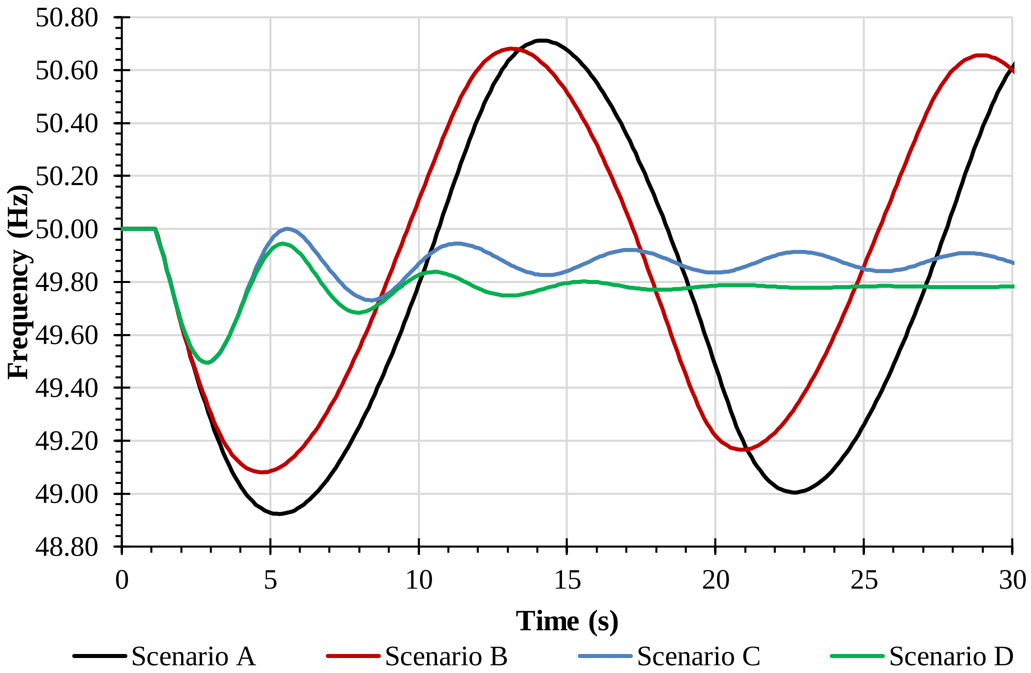


Figure 5.3: Frequency plots for 1 GW loss at 50 GVAs.

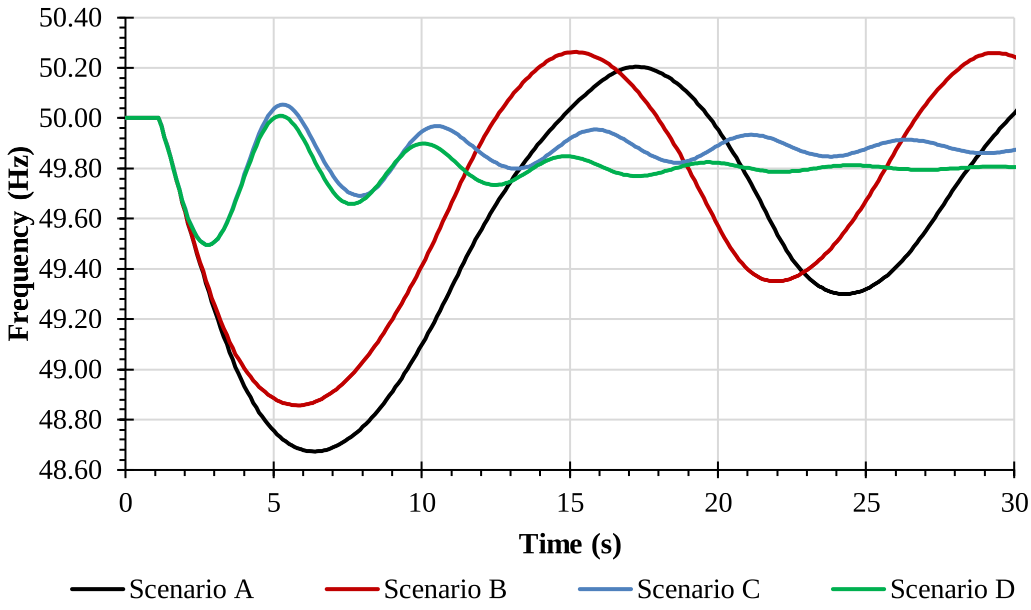


Figure 5.4: Frequency plots for 1.32 GW loss at 66 GVAs.

A similar trend is observed in both Figure 5.3 and Figure 5.4, indicating that while the addition of 201 MW of EFR to the already procured Primary response raises the frequency nadir in Scenario B when compared to Scenario A, both scenarios exceed acceptable frequency conditions for a normal loss risk. The inclusion of the Dynamic Containment service in Scenario C contains the event within acceptable frequency conditions and indicates a dampening of frequency oscillation after containment. That said, completely displacing Primary response with the Dynamic Containment service shows a more pronounced dampening effect in Scenario D.

It is expected that these effects will continue as the inertia in the power system reduces, towards the minimum inertia for a ±1 Hz/s RoCoF limit and corresponding loss risk. It can be said that even with a relaxed RoCoF limit, the activation delay, and indeed the speed of full delivery, of frequency containment services becomes more important for stable containment of frequency within acceptable frequency stability limits, since at lower inertia frequency limits would be reached sooner than at higher inertia and would need to be contained by a sufficiently fast response service.

5.1.3 Discussion

By considering the results of both Cases 1 and 2, the following points can be inferred.

1. Given the frequency response services currently available in the GB and the current practical RoCoF limit, a situation in the future like that described in Case 1 can only be managed by curtailing the loss risk or increasing the inertia in the power system.
2. Fast acting response, under the present assumptions, has no impact on the initial RoCoF experienced by the power system following a power imbalance due to the response delay. That said, the impact on RoCoF can be increased by reducing the time delay of the response service.
3. Once the GB power system is no longer constrained by the ±0.125 Hz/s, rather than managing loss risk and inertia for RoCoF containment, the actions needed will tend towards dispatching additional containment reserve above the 201 MW of EFR that supports the already existing Primary response. At the lower inertia, permitted by relaxed RoCoF settings, containing the loss risk becomes more of an issue of adequacy of dynamic frequency containment services.
4. As the GB power system tends towards lower inertia, limited by the ±0.5 Hz/s and ±1 Hz/s RoCoF limits, frequency containment reserves will increasingly need to be met by faster acting services, displacing/supplementing traditional Primary response that isn't quick enough. This factor raises questions due to how Primary and Secondary response are currently delivered by flexible synchronous plant in GB.

The results of this study reinforce the discussion presented in section 2.4.2 on curtailing the loss risk to manage frequency. Dispatching more deloaded synchronous plants or deploying synchronous compensation are also potential alternatives that would increase the inertia in the power system, while providing additional benefits, and reduce the need to curtail the loss risk. That said, the most direct solution would be to change the settings on the relevant RoCoF relays, as the current settings represent an increasing cost that would otherwise be avoided at the new prescribed settings. The GB ESO is aware of this and is currently taking steps to update the RoCoF settings on the relevant relays. It is expected that the RoCoF LoM relay settings would be updated by 2022 [31].

This leads to point three and four, i.e. the provision of adequate dynamic responses for frequency containment. The need for such services increases at low demand and inertia. Although the risk of the GB power system operating at low inertia levels sub 70 GVAs is low before 2025 [9], it is possible that this may become more likely as the power system tends towards a greater percentage penetration of non-synchronous generation and accompanying closure of synchronous plant in the future. Services such as the Dynamic Containment frequency response concept are a step in the right direction, however, the current service design and market structure exclude the participation of some providers such as WPPs. This is because the current market structure for commercial frequency response is a month ahead market [45], a timescale that for wind plants would mean participating with higher forecast errors [119]. Similarly, a Dynamic Containment persisting response for 20 minutes provides challenges for WPPs, but these are not insurmountable and can be overcome by strategies such as deploying complimentary storage, holding a headroom, or employing adapted wind farm level controllers. The last of which still carries a risk of non-delivery and the first two an additional nontrivial cost for the wind operator. Aside from this, there is also the practical challenge, namely, there is currently no real distinction between Primary and Secondary frequency response services. This is evident when considering the new proposed concept and indeed the reality of the delivery of Primary and Secondary response. There is no distinct dynamic Secondary response, rather dynamic Secondary response is an extension of Primary response.

Plants providing these services will typically perform an action during a power imbalance that meets both service requirements without further action on the part of the plant operator. Furthermore, the procurement of Primary, Secondary and High frequency responses as a bundle is a barrier to participation in the commercial frequency response market for some providers. That said, it’s worth noting that the GB ESO is currently running trials to investigate ways to improve the market practices towards furthering increased participation [51]. Nonetheless, it is likely that an unbundling, and clarified definition, of future containment and restoration response services would provide benefits to the power system, and allow the technologies that are displacing synchronous generators to participate in frequency response services that mitigate the impact of the changing power landscape in terms of frequency response. This will give providers the opportunity to participate in either or both frequency containment and restoration services depending on their capabilities and inclination.

5.2 Metrics for Determining the Frequency Stability Limits of a Power System

In a system with decreasing levels of system inertia, the challenge of complying with RoCoF and frequency limits increases. Consequently, there is a need to understand and quantify the limits that these constraints pose on the power system and develop metrics than can be easily integrated into current system planning and operational paradigms. As discussed in chapters 3 and 4, there are a number of influences that determine whether a given situation will be compliant in respect of acceptable frequency conditions and contain a power imbalance within RoCoF limits. In the subsequent studies the number of dimensions that these influences represent are reduced in order to be more manageable. Ultimately, in the last of the three metrics presented, three key parameters are defined that together can be used to represent a wide range of influences to frequency behaviour during a power imbalance.

At present, the GB ESO sometimes must constrain the largest loss risk to manage power imbalances within RoCoF and frequency limits [4]. It should be noted that other actions could be taken by the system operator including, either or both, curtailing non-synchronous power and constraining on synchronous generation to increase system inertia and make additional response services available.

In Ireland, the SO conducted a study that resulted in the creation of a metric referred to as the SNSP limit, defined in (2.2) as discussed in chapter 2. The SNSP limit is the system non-synchronous penetration ratio that if exceeded would lead to a breach of frequency and RoCoF limits, unless corrective actions are taken by the SO. Since the frequency stability limit during a significant power imbalance is dependent on RoCoF and frequency containment, the key factors influencing it are the frequency and RoCoF limits, the amount and speed of energy responses in the power system (including inertia), and the size and type of the loss that is to be secured.

The following subsections consider the frequency stability limits derived for GB using the SNSP approach, alongside two alternative approaches:

- a critical inertia metric that, for a given demand value, provides the limit of inertia in the power system required to meet acceptable frequency conditions and RoCoF limits; and

- proposal of a containment component metric that individually considers RoCoF limits and acceptable frequency conditions, while providing flexibility to understand and quantify the impact of three key factors influencing frequency and RoCoF containment. These factors are the frequency and RoCoF limits, the amount and speed of energy responses in the power system (including inertia), and the size and type of the loss event.

The model and tools described in chapter 3 are used to conduct the studies needed to define the metrics. It should be noted that although the studies and results focus on GB, the methodology used to produce these metrics can be applied to other similar power systems concerned with frequency management limits, provided they exhibit similar characteristics and include a set of equivalent system parameters. Unless otherwise stated, the subsequent studies are conducted for operational scenarios in 2025 defined in Table 5.6, using the tuned version of the single bus model described in section 3.2, with the following additional assumptions:

Table 5.6: Three scenarios based on three RoCoF settings.

Scenario	**A1**	**A2**	**A3**
Loss of Infeed (MW)	1320	1320	1320
RoCoF Limit (Hz/s)	1	0.5	0.125

- the loss of infeed is simulated as an instantaneous loss of power supply such that frequency is contained within ±0.5 Hz of nominal frequency based on the normal loss frequency conditions as detailed in [8]. A loss risk of 1320 MW is chosen for the normal loss event, as this is the frequency condition for a future GB power system [10, 23];
- demand is modelled as total demand in the power system including interconnector exports;
- average availability of nuclear plants is assumed to be 77% for older plants and 95% for the newer plants [25].

- dynamic response services are simulated as defined, with 227 MW of EFR[40] available;
- static Primary and Secondary responses are both assumed to have a fixed availability of 250 MW each[41];
- the flexible synchronous generator is assumed to have an inertia constant of 6 s and the inflexible synchronous generator is assumed to have an inertia constant of 4 s, while embedded inertia is assumed to have an inertia constant of 1.83 s, and demand sensitivity is assumed to be 2.5%/Hz;
- it is assumed that Primary response is delivered by gas plants in the FSG element of the model, and frequency is contained using the least response reserve holding, based on the method described in section 3.3.1;
- the flexible synchronous generator is modelled as 70% loaded with 30% headroom for delivery of response. It should be noted that percentage headroom and loading is dependent on the operation scenario and the assumption used here serves to illustrate the metric;
- no response from flexible non-synchronous generation is assumed;
- generation background is based on the GB ESO's Two Degrees future energy scenario in [24]; and
- in constructing the operational scenarios, non-synchronous generation is dispatched first in the merit order, followed by flexible synchronous generation to meet the demand for Primary response and securing the power system against the loss risk. Nuclear power is dispatched next, and any shortfall of power supply is met by dispatching the remaining synchronous generation.

Using the FEROS the amount of Primary response required is determined and using (5.1) the required flexible synchronous generation dispatch is calculated[42]. The

[40] Unlike other studies in this thesis that assumes 201 MW of EFR, this study includes the 26 MW of EFR procured pre EFR tender and not included the tendered sum of EFR available in GB.

[41] Static response reserve in GB can vary, historically it was typically around 225 MW, but it can be as high as 400 MW or more. A nominal value of 250 MW was chosen to represent the presence of static response while minimising the effect of reducing dynamic frequency response reserves – which are the focus of the work presented in this thesis.

[42] The total amount of generation dispatched is dependent on the available capacity per fuel type in the generation background.

operational scenario is redispatched[43] with non-synchronous generation, including interconnector imports, first in the merit order followed by Nuclear power, then flexible synchronous generation to meet the demand for Primary response and securing the power system against the loss risk. Any shortfall of power supply is met by dispatching the remaining synchronous generation.

5.2.1 System Non-Synchronous Penetration Metric

The SNSP method is applied to GB using the three scenarios presented in Table 5.6. For each demand level, the amount of non-synchronous dispatch is increased until the frequency stability limits for the loss event, in reference to frequency conditions and RoCoF limits, are breached. The value of non-synchronous dispatch achieved before the frequency stability limits are exceeded defines the maximum amount of non-synchronous dispatch that the scenario can accommodate.

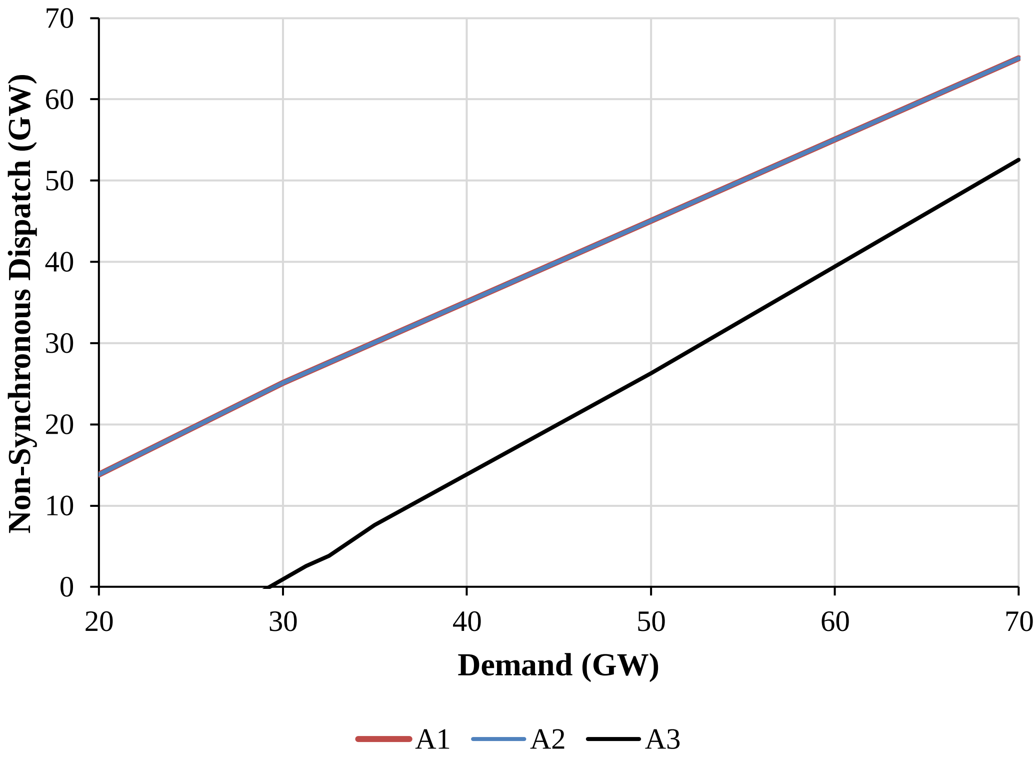


Figure 5.5: Frequency stability limits based on non-synchronous dispatch.

[43] It should be noted that for the purpose of the study flexible synchronous generation was prioritised over Nuclear power, such that, for a given non-synchronous dispatch and demand level, if flexible synchronous capacity is available in the generation background and more flexible dispatch is required to contain the event, then Nuclear power is displaced by flexible synchronous generation,

The results are presented in Figure 5.5, showing the trends of maximum non-synchronous power dispatch for a given demand level. The trend line produced for each scenario gives an expression for the SNSP limit in each scenario. It can be seen that at a higher RoCoF limit, for the same loss risk, the system can accommodate higher penetrations of non-synchronous dispatch at the same demand level when compared to the lower RoCoF limit. This is particularly true when comparing scenarios A1 (1 Hz/s) or A2 (0.5 Hz/s), for which there is no distinction between the calculated penetration limits, with A3 (0.125 Hz/s). This is because as the RoCoF limit increases from 0.125 Hz/s towards 0.5 Hz/s or 1 Hz/s, the dominance of the RoCoF limit as the key constraining factor reduces in favour of managing frequency within acceptable limits. The results for scenario A3, showing very low penetration limits, highlight the necessity for the removal of the existing RoCoF limit of 0.125 Hz/s under future operating conditions. Failure to do so would imply significant re-dispatch costs.

Although a useful metric that gives an indicative measure of curtailment requirements, a flaw has been identified in representing containment limits in terms of the amount of non-synchronous power dispatched that inhibits full accuracy. In particular, frequency stability limits in terms of amount of non-synchronous power dispatched, are limited to the specific assumptions associated with the operational dispatch of the case being considered, i.e. the amount and speed of dispatchable (e.g. Primary response) and inherent (e.g. inertia) energy responses assumed in the scenarios being considered. For instance, applying the limit of 4.75 GW of non-synchronous dispatch at a demand of 40 GW from scenario A3 (~12% SNSP), could result in an overestimation of containment capability if the operational dispatch for that SNSP limit resulted in an inertia value less than what was used when defining the SNSP limit.

That said, the results produced by this method offer some flexibility in the presentation of results: it can be binary with a trend line marking the point beyond which the loss event can or cannot be contained as shown in the previous plots; or graded with regions depicting varying severity of risk. The latter is illustrated in Figure 5.6, for a scenario equivalent to scenario A2 but with a 1 GW normal loss and 201 MW of EFR.

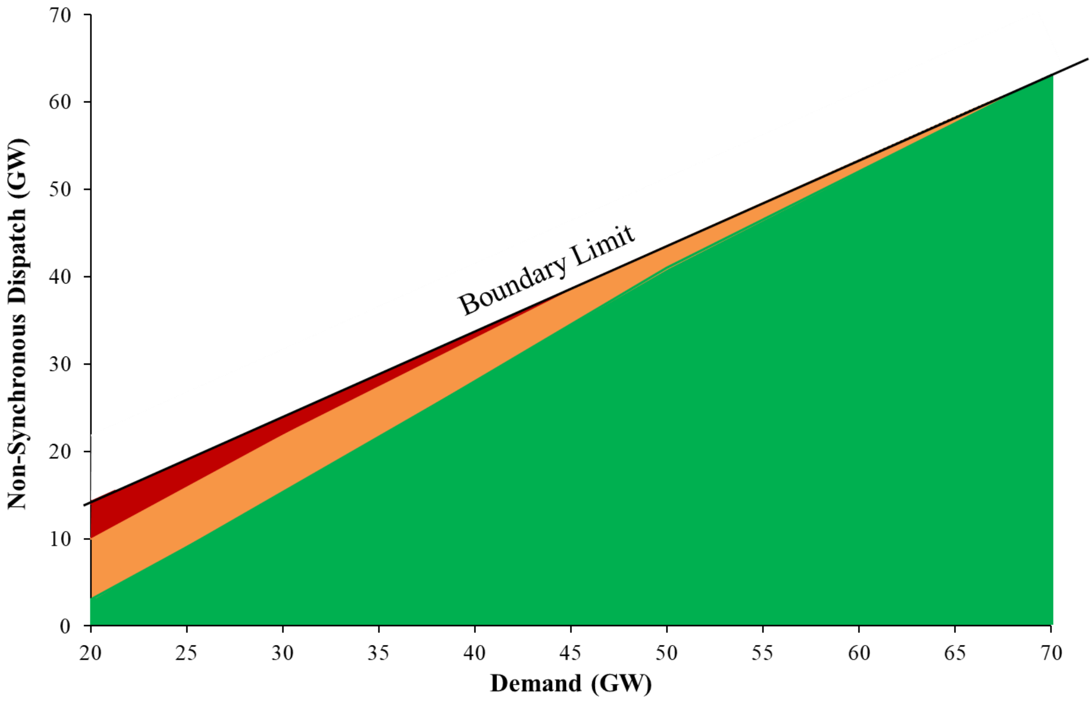


Figure 5.6: SNSP chart with varying degrees of severity.

Table 5.7: Description of the colour coded severities in Figure 5.6.

Colour	Description
Green	Event is contained.
Amber	Event isn't contained but frequency is greater than or equal to 49.0 Hz.
Red	Frequency excursion is less than 49.0 Hz.

The severity of the impact of the simulated event for a given dispatch is colour coded in Figure 5.6, where the colours relate to the degree of the severity in terms of RoCoF limits, and the frequency thresholds. A description of the colour coded severity of the simulated events is shown in Table 5.7, where the solid black 'Boundary Limit' line indicates the point beyond which simulation of a scenario is infeasible due to a dispatch constraint, as a result of the minimum dispatch of baseload power from nuclear power plants, which was applied as a constraint in the case of the studies that generated Figure 5.6.

5.2.2 Critical Inertia Metric

The limitation highlighted in section 5.2.1, can be partially remedied by representing frequency stability limits in terms of critical inertia, where critical inertia (unlike minimum inertia) considers frequency stability within both frequency and RoCoF limits. In this case the inertia in the power system is progressively reduced until the lowest inertia required to contain the event is identified for a given demand level. This process is then repeated across a range of demand values, with the modelling assumptions unchanged from those used for Figure 5.5.

The results presented in Figure 5.7 show inertia against demand instead of the amount of non-synchronous power dispatched against demand, where inertia in Figure 5.7 is the critical inertia required to contain the loss event, given the other energy responses that are available at the time of the event. The critical inertia is in GVAs/GW, as described by (5.2), and the plot in Figure 5.7 can be interpreted as expressions defining the critical inertia limits for each scenario. This method produces a metric that defines the penetration limits by identifying the critical inertia for a given demand beyond which frequency or RoCoF conditions are breached during a loss event, i.e. the frequency stability limit.

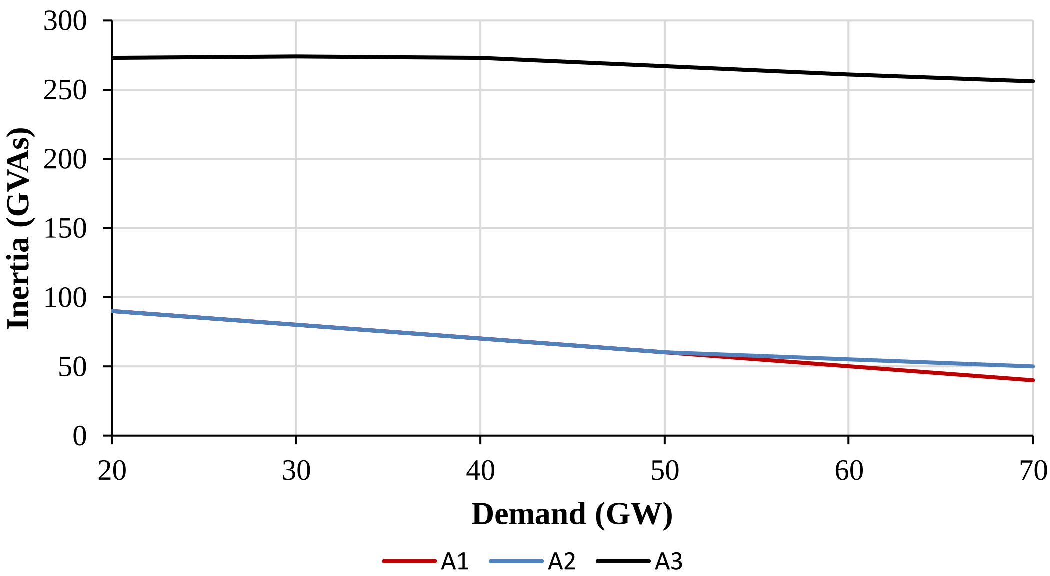


Figure 5.7: Frequency stability limits based on inertia.

$$Critical\ Inertia = \frac{Inertia}{Total\ Demand} \tag{5.2}$$

Upon considering scenarios A1, A2 and A3, a similar behaviour as observed in Figure 5.5, is seen in Figure 5.7, particularly in reference to the comparative trends of the scenarios. As with Figure 5.5, in Figure 5.7 there is a marked distinction between the critical inertia trend line observed in A3 (0.125 Hz/s) in comparison to A1 and A2. This highlights the previous assertion that the RoCoF limit is the dominant containment component in A3, with the dominance shifting towards frequency containment in A1 and A2. The slight difference at higher demand observed when comparing A1 and A2 is due to the higher RoCoF limit in A1 and the contribution to containment from demand sensitivity.

Although this representation of frequency stability limits improves on the previous, in respect to variations in inertia across similar containment limits, it also has its limitations. It only addresses variations in inertia, making no improvement on variations in demand sensitivity and dispatchable energy responses.

5.2.3 Frequency Stability by Components Metric

Defining the frequency stability limits of an operational dispatch by considering the containment components addresses some of the limitations previously described, i.e. by separately considering penetration limits in terms of the energy responses that dominate RoCoF and those that dominate acceptable frequency conditions. In this manner, RoCoF and frequency limits are treated as individual components, as discussed in the rest of this section

Identifying whether a scenario is likely to exceed RoCoF limits can be done using (5.3) below where the instantaneous RoCoF, g, at the inception of the event is a function of the power imbalance ΔP, at nominal frequency f_0, and H_t is the total inertia of the system for a given operational dispatch.

$$g = \left(\frac{\Delta P \times f_0}{2 \times H_t}\right) \tag{5.3}$$

The total inertia of a system depends on the specific generation dispatch and the embedded inertia. Equation (5.4) captures the total inertia of the system using inertial contributions from inflexible generation (e.g. nuclear plants), flexible generation (e.g. gas plants) and embedded inertia (see section 3.2.1).

$$H_t = FSG_{MVAs} + ISG_{MVAs} + Embedded_{MVAs} \tag{5.4}$$

The three components in the right-hand side of (5.4) are defined as follows:

$$SG_{supply} = T_g - T_n \tag{5.5}$$

$$FSG_{MVAs} = \left(\frac{SG_{supply} \times FG_{perc}}{L_1 \times pf_1}\right) \times H_{FSG} \tag{5.6}$$

$$ISG_{MVAs} = \left(\frac{SG_{supply} \times IG_{perc}}{L_2 \times pf_2}\right) \times H_{ISG} \tag{5.7}$$

$$Embedded_{MVAs} = Demand \times H_{embedded} \tag{5.8}$$

Equation (5.5) works out the amount of the dispatched synchronous generation (SG_{supply}) from the difference between total generation dispatch (T_g) and total non-synchronous dispatch (T_n). The inertia in MVAs of the flexible and inflexible synchronous generation elements is represented by FSG_{MVAS} and ISG_{MVAS} respectively, and defined in (5.6) and (5.7), where the percentage loading of the units (L_1 and L_2) defines the rating of the units based on the power factors (pf_1 and pf_2). The corresponding inertia constants H_{FSG} and H_{ISG} account for the mixture of the different inertia constants by fuel type, for a percentage of the dispatched synchronous generation that is flexible (FG_{perc}) or inflexible (IG_{perc}). Equation (5.8) defines the embedded inertia in MVAs as the product of the demand in MW and the embedded inertia constant ($H_{embedded}$) in seconds. It should however be noted that in power systems, the RoCoF observed by relays, such as LoM protection, differs from the instantaneous RoCoF value calculated using (5.3), which means that constraints using this method would be conservative in their assessment of the RoCoF component of the containment limit.

In order to provide an accompanying relationship for the frequency component, a range of scenarios are considered to produce a trend in terms of active power response and instantaneous RoCoF, denoted as *g*. To produce results in this format, a set of simulation studies are conducted. It is assumed here that all frequency response is delivered by EFR (as defined in chapter 2), and, apart from inertia, no other energy response is available to contain the event[44]. This assumption is made solely for the purpose of determining a trend and relationship between EFR reserve, inertia and loss risk values that is later used as the basis for determining an exchange rate between EFR and Primary response.

A constant demand level of 30 GW is chosen, while containment limits are assessed for a range of inertia values. It should be noted that a range of demand is not needed for this study, since demand sensitivity is not presently being considered and frequency response is only delivered by EFR. It should also be noted that, for the purposes of this study, in instances where additional inertia is required for a given instantaneous RoCoF operational scenario, additional inertia is provided by synchronous compensation. The simulations are repeated for a range of loss risk values to produce a series of trends based on the loss risk frequency conditions in [10]. These trends are combined to produce a surface function that determines the EFR reserve that needs to be held to keep frequency within limits for a given loss risk and instantaneous RoCoF. The equations of the surfaces were determined using a least regret fit, meaning that the curve of both surfaces sit above the data points in the reserve axis. Therefore, the reserve determined for combinations of instantaneous RoCoF and loss risk values will be greater than or equal to the amount of reserve determined in the individual simulation study. This conservative approach is chosen in favour of a best fit approach, which would give some combinations of RoCoF and loss risk that would result in a prediction of reserve less than what would be observed in the simulation. The resultant surfaces are shown in Figure 5.8, with associated expressions shown in (5.9) and (5.10), and the values of the constants are shown in Table 5.8. Equations (5.9) and (5.10) are expressions for the infrequent and normal loss risk conditions respectively.

[44] In particular, the contribution from demand sensitivity is not considered at present but will be accounted for in future work.

These two expressions represent the frequency stability limits for both loss risk frequency conditions, where g is the instantaneous RoCoF, ΔP is the loss risk, r_e is the EFR, and g_{th} is the threshold for the applicable constants; $g \leq g_{th}$ defines the lower bound and $g > g_{th}$ defines the upper bound. The upper and lower bounds split each loss risk condition, as depicted in Figure 5.8, into two expressions that describe both parts of the whole surface.

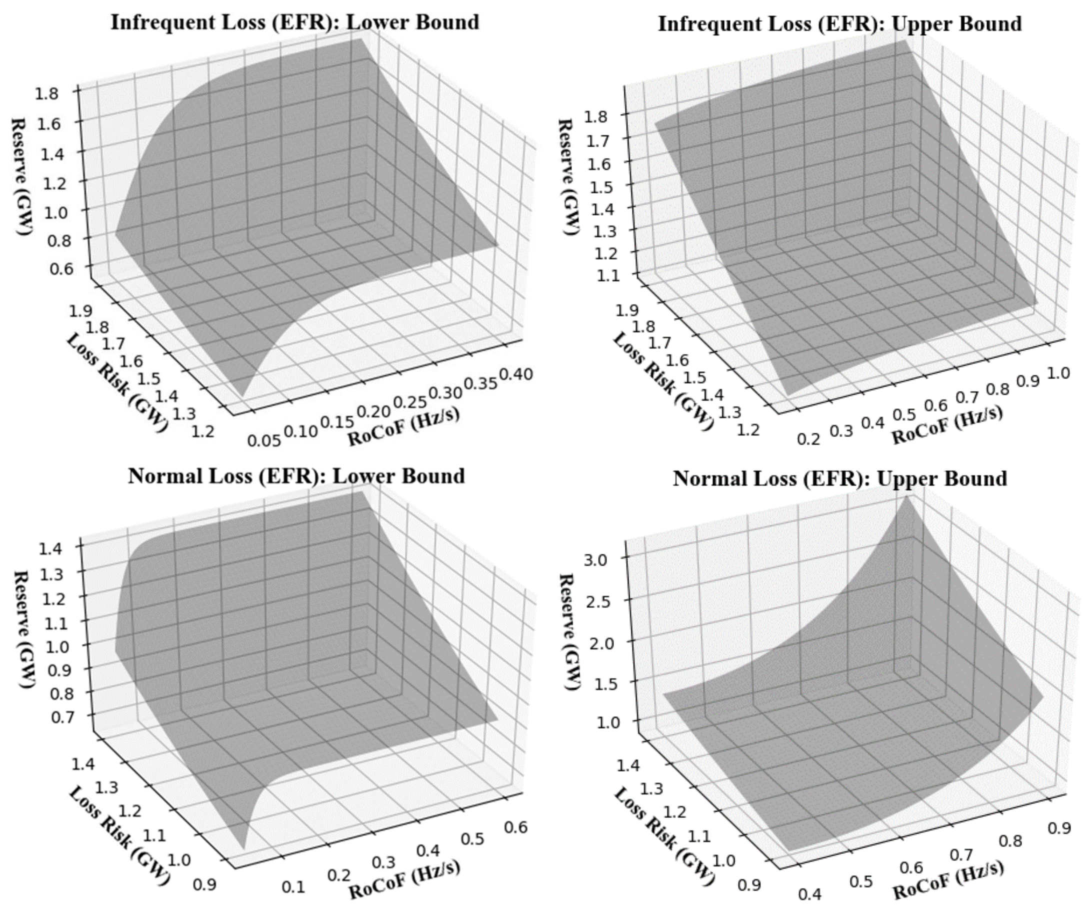


Figure 5.8: Surface plots for EFR showing infrequent loss risks and normal loss risks both below (Lower Bound) and above (Upper Bound) the RoCoF threshold.

$$a_5^e = \begin{cases} a_1^e e^{a_2^e g} + a_3^e \Delta P + a_4^e \ln r_e\,, & g \leq g_{th} \\ a_1^e \ln g + a_2^e \Delta P + a_3^e e^{a_4^e r_e}, & g > g_{th} \end{cases} \tag{5.9}$$

$$a_5^e = \begin{cases} a_1^e e^{a_2^e g} + a_3^e \Delta P + a_4^e \ln r_e\,, & g \le g_{th} \\ a_1^e g^2 - a_2^e g + a_3^e \Delta P + a_4^e \ln r_e\,, & g > g_{th} \end{cases} \tag{5.10}$$

Table 5.8: Constants for surface equations.

Infrequent loss risk		
Constant	**Lower Bound**	**Upper Bound**
g_{th}	0.3000	
a_1^e	1.4420×10^{0}	6.5414×10^{-3}
a_2^e	-2.1523×10^{1}	8.2146×10^{-2}
a_3^e	-4.2483×10^{-1}	-1.5089×10^{0}
a_4^e	6.4720×10^{-1}	5.1913×10^{-2}
a_5^e	-4.2336×10^{-1}	-1.5091×10^{0}
Normal loss risk		
Constant	**Lower Bound**	**Upper Bound**
g_{th}	0.5550	
a_1^e	4.1135×10^{0}	-1.0878×10^{1}
a_2^e	-4.6323×10^{1}	-8.8867×10^{0}
a_3^e	-1.5332×10^{0}	-2.8890×10^{0}
a_4^e	1.7888×10^{0}	3.2090×10^{0}
a_5^e	-1.5267×10^{0}	-1.1907×10^{0}

Equations (5.3), (5.9) and (5.10) can be used together to first constrain the power system within the RoCoF constraint via (5.3) and then, based on the resultant *g*, the frequency constraint can be determined using either (5.9) or (5.10), depending on the loss risk condition. This metric, expressed as a set of equations, can be used to determine the minimum amount of reserve that would need to be held, if EFR was the only energy response available to contain a given loss risk for an operational scenario at a given system inertia, represented here by instantaneous RoCoF. Similarly, the metric can also be used to determine how much inertia needs to be available for a given amount of EFR and loss risk value, or the maximum loss risk value for a given amount of inertia and EFR. Considering the frequency stability limits in this manner, shows that the amount of non-synchronous power dispatched is not an inherent limitation to containment and frequency management. Instead, the factors most dominant are the energy responses available, i.e. dispatchable services such as EFR and inherent responses such as inertia, and the size of the loss risk.

It should be noted that in generating (5.9) and (5.10), modifications such as the inclusion of demand sensitivity or different frequency conditions would change the value of the constants presented in Table 5.8, and a system operator applying this metric would need to first generate the expressions before they can be used for system management and planning. However, once the expressions have been generated, they can be applied to a wide range of operational scenarios without requiring further simulations, unlike the other methods previously described. It should also be noted that the results presented in this section consider EFR to be the only available dispatchable energy response service at the time of the event. This means that other energy responses would need to be equated to EFR, to determine whether the energy responses available, including those from other dispatchable services, e.g. Primary response, would adequately contain the event.

By repeating the approach used to determine (5.9) and (5.10) for Primary response instead of EFR, another set of expressions can be discerned. It should be noted that the required Primary response reserve (determined by the method described in section 3.3.1) is arbitrarily assumed to be always available, irrespectively of the amount of generation dispatched. Since the impact is only to do with the amount of Primary response being delivered (inertia is a separate sensitivity that is varied independent of the specific dispatch), this assumption is used to generate a trend and expressions for frequency stability limits when Primary response is deployed. The resultant surface plots for infrequent loss risk and normal loss risk frequency conditions are shown in Figure 5.9. Equation (5.11) is the expression describing the surfaces for both loss risk conditions, where g is the instantaneous RoCoF, ΔP is the loss risk, r_p is the Primary reserve, and g_{th} is the threshold for the applicable constants; $g \leq g_{th}$ defines the lower bound and $g > g_{th}$ defines the upper bound. The values of the constants a_n^p for the Primary reserve surface are given in Table 5.9 for infrequent and normal loss risk frequency conditions.

$$a_5^p = \begin{cases} a_1^p e^{a_2^p g} + a_3^p \Delta P + a_4^p \ln r_p\,, & g \leq g_{th} \\ a_1^p e^{a_2^p g} + a_3^p \Delta P + a_4^p \ln r_p\,, & g > g_{th} \end{cases} \tag{5.11}$$

Table 5.9: Constants for surface equation of Figure 5.9.

Infrequent loss risk		
Constant	**Lower Bound**	**Upper Bound**
g_{th}	0.1364	
a_1^p	5.0551×10^{0}	3.5933×10^{-1}
a_2^p	-2.8680×10^{1}	-1.7995×10^{0}
a_3^p	-6.8660×10^{-1}	-3.1240×10^{-2}
a_4^p	1.0757×10^{0}	4.9928×10^{-2}
a_5^p	-4.9912×10^{-1}	2.5688×10^{-1}
Normal loss risk		
Constant	**Lower Bound**	**Upper Bound**
g_{th}	0.0850	
a_1^p	1.7918×10^{0}	-1.2493×10^{0}
a_2^p	-4.1273×10^{1}	5.4841×10^{-3}
a_3^p	-4.0290×10^{-1}	-3.8629×10^{-4}
a_4^p	4.7028×10^{-1}	4.4218×10^{-4}
a_5^p	-3.4118×10^{-1}	-1.2502×10^{0}

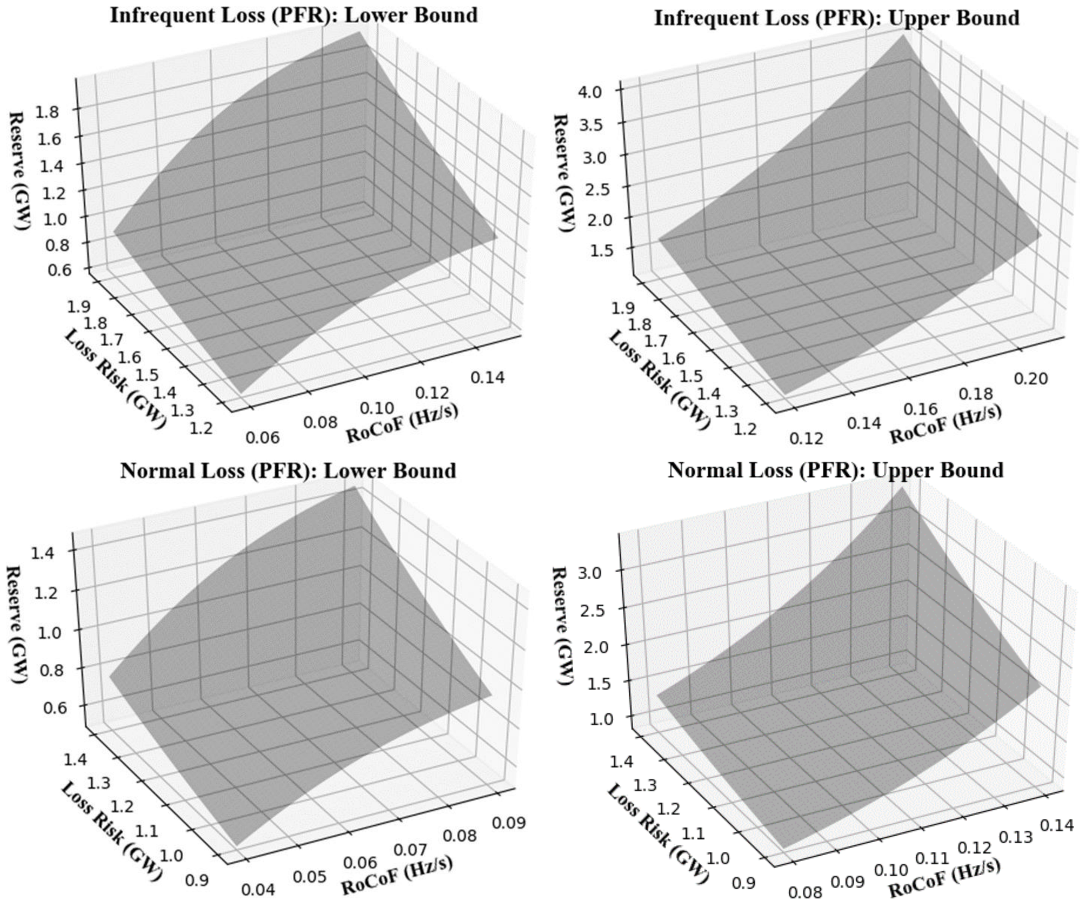


Figure 5.9: Surface plots for PFR showing infrequent loss risks and normal loss risks both below (Lower Bound) and above (Upper Bound) the RoCoF threshold.

5.2.4 Equivalence in Energy Responses

In light of the frequency stability by components metric discussed in section 5.2.3, it is useful to further derive a relationship that permits the conversion of one response type to another. In the context of currently existing dynamic services in the GB frequency response market that contribute to frequency containment, a relationship can be observed between Primary and Enhanced response, using the results from the studies conducted in section 5.2.3. This relationship is depicted in Figure 5.10, where the relationship between Primary (r_p) and Enhanced response (r_e), for a given instantaneous RoCoF (g), is expressed as a ratio, R_E^P, defined in (5.12).

$$R_E^P = \frac{r_e}{r_p} \tag{5.12}$$

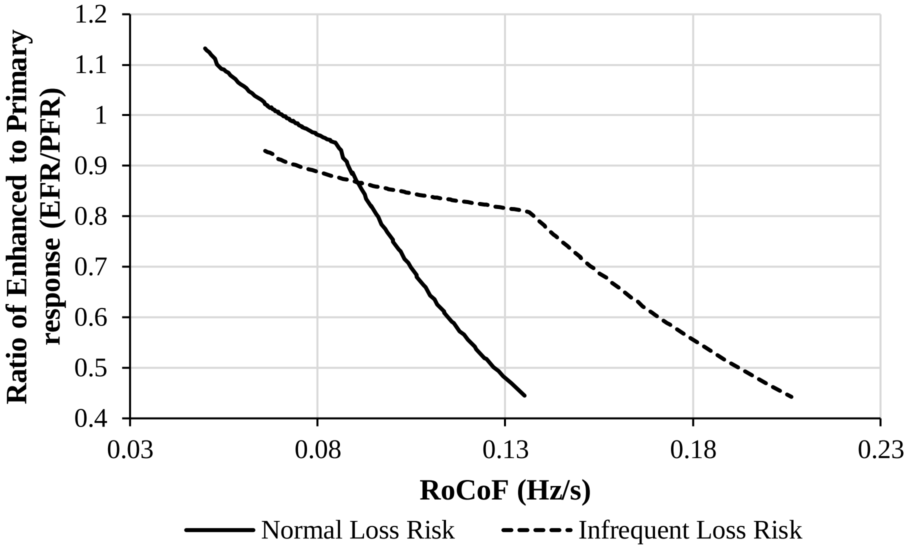


Figure 5.10: Changing frequency containment response ratio (EFR and PFR) for a range of instantenous RoCoF values for both normal and infrequent loss risks frequency conditions.

It is observed that the trend of the response ratio for normal loss risk frequency conditions, and indeed infrequent loss frequency conditions, is independent of the value of the loss being simulated because the value of the loss is captured in the instantaneous RoCoF. The trend also indicates that at higher inertia (lower instantaneous RoCoF), frequency containment reserves are dominated by demand for reserves to contain a normal loss risk, while at lower inertia, frequency containment reserves are dominated by demand for reserves to contain an infrequent loss risk; with the value of Enhanced response increasing with reducing inertia, as indicated by the reducing response ratio.

The result is two distinct trends that can be used to translate a reserve requirement in Primary response terms to a reserve requirement in Enhanced response terms, for either normal or infrequent loss risk frequency conditions. From these trends (5.13) is extracted: where g is instantaneous RoCoF given by (5.3), and g_{th} is instantaneous RoCoF threshold that determines the relationship. The values of the constants b_n and g_{th} are given in Table 5.10 for infrequent and normal loss risk frequency conditions.

$$R_E^P = \begin{cases} b_1 g^2 - b_2 g + b_3, & g \leq g_{th} \\ b_1 e^{-b_2 g}, & g > g_{th} \end{cases} \tag{5.13}$$

Table 5.10: Constants for equivalence expression.

Infrequent loss risk		
Constant	**Lower Bound**	**Upper Bound**
g_{th}	0.1347	
b_1	14.9520	2.6172
b_2	4.5813	8.6140
b_3	1.1609	
Normal loss risk		
Constant	**Lower Bound**	**Upper Bound**
g_{th}	0.0846	
b_1	73.4650	3.4012
b_2	15.1390	15.0900
b_3	1.7027	

By using the (5.13) in conjunction with (5.3), (5.9), (5.10) and (5.11), it is possible to estimate how much reserve is required to contain a loss event in terms of either or both Enhanced and Primary response services as they are defined in chapter 2.

5.2.5 Employing the Frequency Stability by Components Metric and Equivalence in Energy Responses Method

It should be noted that trends and expressions presented in sections 5.2.3 and 5.2.4 regarding response reserve are specific to the assumed definitions and operation of the frequency containment response services, i.e. if Primary response delivers a service faster than its definition (as is often the case in reality) then the amount of reserve that would need to be held to contain an event would reduce. In its current form the expressions presented would lead to an over estimation of reserve required since Primary response typical performs better than defined. That said, the methodology remains valid, as a relationship between the three dimensions of reserve, loss risk and RoCoF persists. Consequently, in a real-world application, this method will need to be replicated to suit the operational definitions of the frequency containment services being examined; however, once the trends and expressions are determined, they are valid for a range of operational scenarios. It is reiterated that the expressions in sections

5.2.3 and 5.2.4 in their current form exclude static response and demand sensitivity, further work developing the metric will include these factors in the metric. Notwithstanding, the expressions presented in section 5.2.3 and the exchange rate for Primary and Enhanced frequency responses presented in section 5.2.4 can be applied to the GB power system: to determine the likelihood of containing frequency and RoCoF; to provide an estimation of reserve requirements; and to convert reserve requirements from one service type to another. This capability is shown in this section for the scenarios presented in Table 5.11.

Table 5.11: Scenarios for testing frequency stability by components metric and reserve exchange.

Scenario No.	**1**	**2**	**3**
Total Generation/Demand (GW)	20	60	70
Total Non-Synchronous Power Dispatched (GW)	5	50	55
Total Synchronous Power Dispatched (GW)	15	10	15
Flexible Synchronous Generation (%)	50	55	65
FSG Loading	60	60	70
FSG Inertia Constant	6	6	5
Inflexible Synchronous Generation (%)	50	45	35
ISG Inertia Constant (s)	4	4	5
Embedded Inertia Constant (s)	1.83	1	2.5
Loss Risk (GW)	1	1.32	1.8
Loss Type (Normal = N, Infrequent = I)	N	N	I
Total Inertia (GVAs)	172	154	299
Instantaneous RoCoF (Hz/s)	0.1453	0.2146	0.1507
Reserve Requirement in terms of EFR (GW)	1.073	1.356	1.688
Reserve Requirement in terms of PFR (GW)	2.828	10.2	2.36
EFR Reserve (GW)	0.695	1.19	0.56
PFR Reserve (GW)	0.996	1	1.4

In these three scenarios it is assumed that the inflexible synchronous generator is 90% loaded and the percentage of the headroom in the flexible synchronous generators available for frequency response is 50%. In Table 5.11, the unshaded cells are input values and the shaded cells are calculated values: the grey cells contain values determined using (5.3) and its associated expressions; the blue cells contain values determined using (5.9), (5.10) and (5.11); and the green cells contain values determined using (5.12) and (5.13). The calculated instantaneous RoCoF can then be compared to a given RoCoF limit to give an indication of the likelihood that the RoCoF limits would be exceeded; i.e. all three scenarios exceed the 0.125 Hz/s RoCoF limit but fall within the 0.5 Hz/s, so if the operating RoCoF limit is the latter then it is very likely that the event would be contained within RoCoF limits. The values in the blue cells give an indication of how much reserve would need to be held to contain the event within acceptable frequency conditions, if frequency containment reserve was delivered by either EFR or dynamic PFR. The green cells utilise the exchange rate to split the reserve between two different frequency response services. These values can then be compared against reserve holdings (further redistributed using the exchange rate if necessary) to ascertain whether there is enough response reserve to contain the event.

The scenarios presented are simulated using the values in the green cells as the frequency response reserve dispatch to see if those scenarios do indeed contain the event within acceptable frequency conditions. The plots in Figure 5.11 to Figure 5.13 show the resultant frequency and RoCoF traces of the simulations. It can be seen that the reserve values determined using (5.9), (5.10) and (5.11), and distributed between both Primary and Enhanced response services using (5.12) and (5.13) are capable of containing frequency within limits. However, it is also observed that reserves are not the minimum values required to contain the event, due to the conservative nature of the trends that produced the expressions.

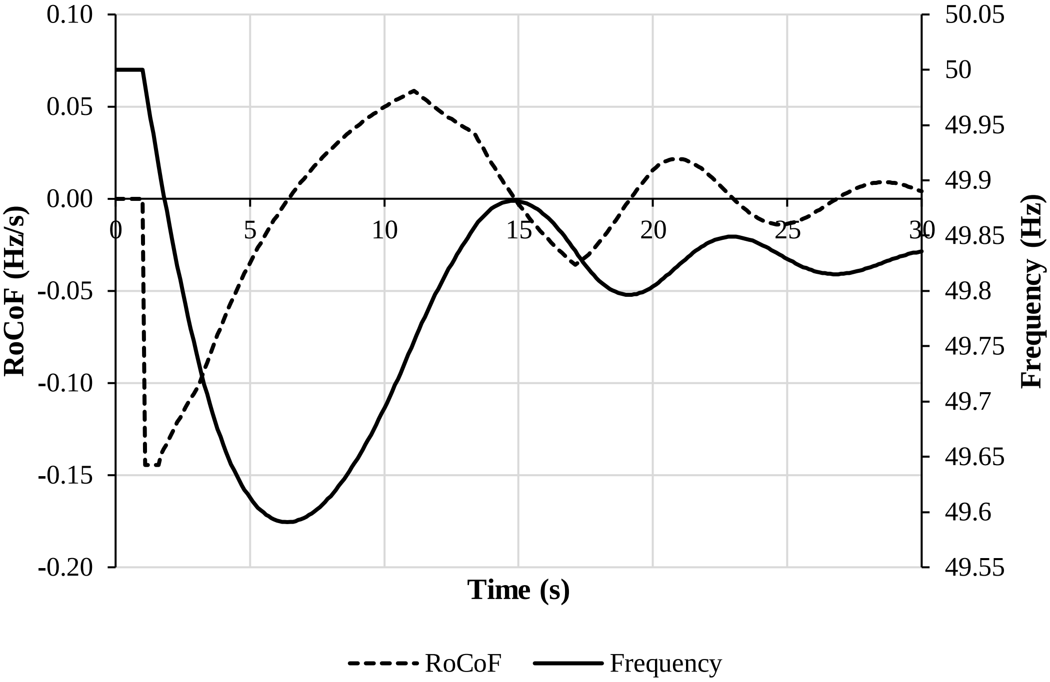


Figure 5.11: Frequency and RoCoF plots for Scenario 1.

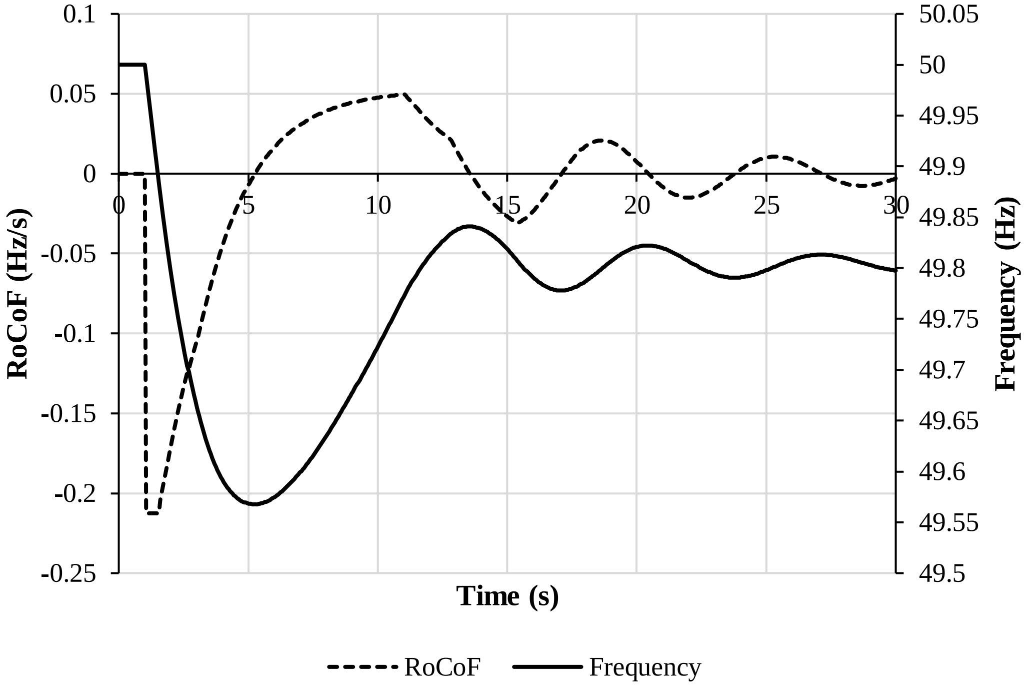


Figure 5.12: Frequency and RoCoF plots for Scenario 2.

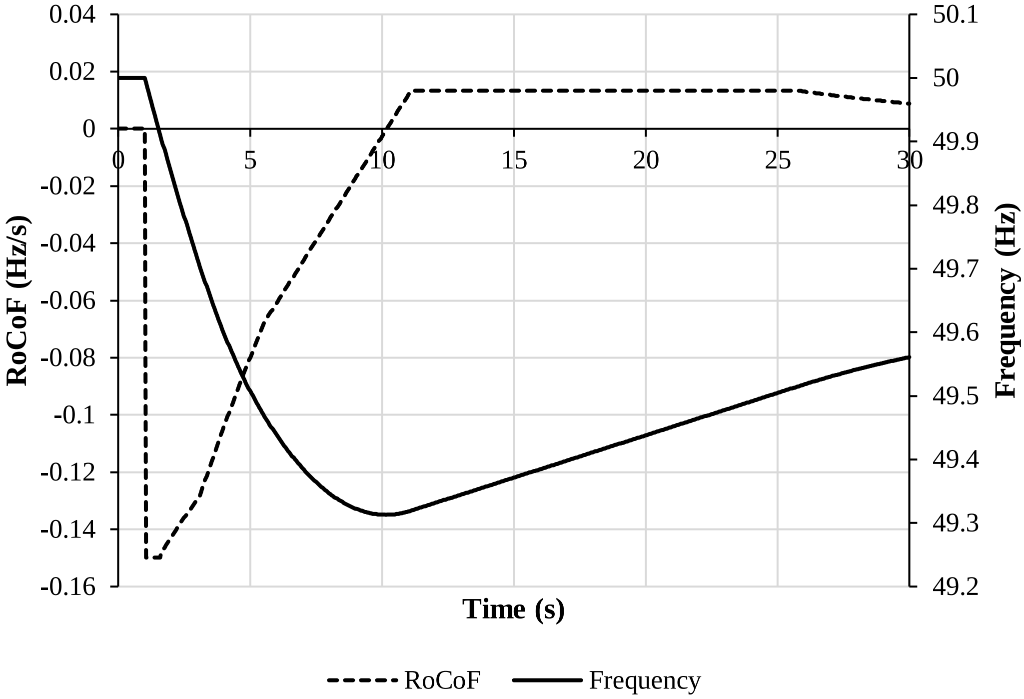


Figure 5.13: Frequency and RoCoF plots for Scenario 3.

5.3 Summary

The current effective practical RoCoF limit in GB poses the risk of the undesirable tripping of RoCoF relays that further increases the risk of cascading events. This risk is increased as the system inertia reduces, further reducing the power system's resilience to frequency disturbances. As a result, at present, the maximum loss risk in GB must be managed such that RoCoF is contained within 0.125 Hz/s. However, it is expected that by 2022, the settings will be updated to reflect the LoM settings described in the engineering recommendations.

By considering a low demand and inertia 2025 scenario, based on a historical event in GB, the performance of current and planned frequency response services and ESO actions is investigated. It is observed that assuming the current RoCoF limit and normal loss risk remain unchanged by 2025, RoCoF containment is dominant over frequency containment, and until the RoCoF relay settings are changed, curtailing the loss risk is currently the most viable option; since the provision of Enhanced or Dynamic Containment response services have no impact on RoCoF containment.

It is further observed that rather than managing containment in terms of the RoCoF limit, as the RoCoF tends towards 1 Hz/s in a lower inertia power system, the actions needed to contain a loss event will tend towards dispatching additional fast containment reserve to manage containment in terms of frequency limits. This indicates an increasing need for frequency containment services, in which case it would be beneficial to unbundle containment and restoration services, facilitating further market participation and the competitive provision of frequency containment services.

When managing frequency and loss risks, it is useful to understand the containment limits of the power system. The containment limits can be investigated in reference to the SNSP, the critical inertia, or by frequency stability by components. The last of which is a methodology that is suitable for any power system, that said, the expressions presented are applicable to the GB power system. It is also possible to convert one form of frequency response service to another, and an expression to convert frequency response reserves between Primary and Enhanced is shown. Using the methodology for the frequency stability component metric, and the exchange rate between energy responses, it is possible to determine whether or not a scenario is likely to be contained, and apportion the amount of reserve required for frequency containment between Primary and Enhanced (or Dynamic Containment) responses. The methodology can be applied, and the resultant expressions embedded in a tool or program so that frequency stability limits can be investigated without needing fresh simulations every time the scenario is modified.

6

Future Demand and Provision of Frequency Response

A future low inertia GB power system will need to be secured to contain the largest loss risk within RoCoF and frequency constraints, while also permitting the continued uptake of renewables. To determine the future provision of energy responses to contain a significant power imbalance within frequency stability limits, it is important to understand the changing demand for frequency response services.

6.1 Demand for Frequency Response in a Future GB Power System

In chapter 4, the impact that inertia, demand sensitivity and dispatched frequency response services have on the management of frequency following a loss event were investigated. The results of these studies imply the need for dynamic frequency containment services, which could either mean larger amounts of current services or altogether different frequency containment services.

However, in order to further investigate frequency response services, it is beneficial to gain an understanding of the demand for frequency response, particularly at low inertia, and the suitability of current market mechanisms in a future GB power system. To that effect, the following study is conducted for 2025 using the model and tools described in chapter 3, with the modelling assumptions listed below.

- In the context of the single bus model, ‘Demand’ refers to demand on the transmission system and includes pumping hydro, interconnector exports and net unmetered embedded generation.
- Embedded inertia is accounted for in the demand at an inertia constant of 1.83 seconds, a value derived from discussions with industry experts.
- Demand sensitivity, which is an inherent characteristic of demand that results in the provision of active power in response to frequency changes, is assumed to be 2.5%/Hz [9].
- The Dynamic Containment service described in section 2.4.3 is applied to supplement frequency response provision when required.
- An inertia constant of 6 seconds is assumed for all gas units and 4 seconds for all other synchronous generators, these values are chosen following discussions with industry experts.
- Generation is split into synchronous and non-synchronous generation, with non-synchronous generation providing no inertial response to changes in frequency.
- Primary frequency response is delivered by flexible synchronous generators.
- It is assumed that in 2025 Primary response is delivered by gas plants only.
- Containment is attempted for the least response reserve holding using the method described in section 3.3.1.
- The flexible synchronous generation element in the model is 75% loaded with response provided by 50% of the headroom (in the case of seasonal minimums), and 85% loaded with response provided by 55% of the headroom (in the case of seasonal peaks) [91].
- All response is assumed to be dynamic.
- RoCoF is constrained to 1 Hz/s or below [19, 120].

- A normal loss of in-feed event of 1 GW of interconnector supply is modelled with a maximum frequency deviation of -0.5 Hz from nominal 50 Hz [19, 23].
- The delivery of responses is at the limit of their definitions; however, it is recognised that delivery of responses may in practice have a shorter delay or in some cases faster ramp rates.

Unless otherwise stated, in constructing the operational scenarios, nuclear power is first dispatched in the merit order as the baseload power supply, with an assumed availability of 77% [121]. The flexible synchronous generation, made up solely of gas plants, is next in the merit order followed by the remaining synchronous generation plants until the target for the simulation has been reached. If there is a shortfall between supply and demand, then the difference is met by non-synchronous generation. The Dynamic Containment service is considered a technology neutral service and as such it is modelled as separate from generation but simulated using the flexible nom-synchronous generation element.

To define the reference scenarios, a year in Britain is split into Summer (June, July August), Winter (December, January, February), and Spring – Autumn (March, April, May, September, October, November). Indicative minimums and maximums for each season in 2016 were obtained from [122]. The highest and lowest demand periods in each season, along with the power dispatch for those periods, were taken to represent the minimums and peaks of each season. Non-synchronous power infeed includes WPPs and other transmission connected non-synchronous sources of power, including a minimum of 1 GW of HVDC interconnector import, which is the simulated loss risk. These levels of penetration are representative, and the impact of changing non-synchronous dispatch is captured by changing inertia in subsequent analysis, presented later in this section.

Table 6.1 shows an overview of the scenarios produced and the proportion of total demand met by generation of different types. In the baseline scenario, response is provided by only the flexible synchronous generation element of the model. However, for the purposes of this study it is assumed that by 2025, there will be response provided from other sources. Projecting the reference scenarios in Table 6.1 to 2025 gives the seasonal scenarios in Table 6.2, where the dispatches in each scenario have been checked against the generation background by fuel type in the Gone Green 2025 scenario obtained from the National Grid Future Energy Scenarios (FES) 2016 report [117]. In both the Winter Peak and Spring Autumn Peak scenarios, the extrapolated dispatch of flexible synchronous generation exceeds its available generation background. In these scenarios the flexible synchronous dispatch is capped, and the shortfall of power supply is made up by inflexible synchronous generation. Since the inflexible synchronous plants are assumed to have an inertia constant of 4 seconds, no specific merit order is applied when meeting the shortfall. It is however, noted that the inertia in the power system is reduced as a result of fewer gas plants being dispatched.

Table 6.1: 2016 reference seasonal scenarios.

	Flexible Synchronous Generation (%)	**Inflexible Synchronous Generation (%)**	**Non-Synchronous Dispatch (%)**	**Demand (MW)**
Summer Minimum	31%	47%	21%	18,201
Summer Peak	63%	29%	8%	37,394
Winter Minimum	20%	49%	31%	21,801
Winter Peak	71%	24%	6%	52,271
Spring - Autumn Minimum	30%	51%	20%	19,150
Spring Autumn Peak	70%	23%	7%	50,290

Table 6.2: 2025 seasonal scenarios.

	Flexible Synchronous Generation (MW)	Inflexible Synchronous Generation (MW)	Non-synchronous Dispatch (MW)	Demand (MW)
Summer Minimum	5,713	8,638	3,850	18,201
Summer Peak	23,658	10,662	3,074	37,394
Winter Minimum	4,438	10,622	6,741	21,801
Winter Peak	27,762	21,630	2,878	52,271
Spring - Autumn Minimum	5,650	9,752	3,748	19,150
Spring Autumn Peak	27,762	18,990	3,538	50,290

With the holding reserve for EFR fixed at 201 MW, a normal loss of in-feed across the 2025 seasonal scenarios is simulated, and a trend in the demand for frequency containment response can be identified as indicated by Table 6.3. It should be noted that the provision of supplementary response from the Dynamic Containment service, is only included if the event can't be contained with Primary response from the flexible synchronous generation and EFR. This is done to identify whether existing services would suffice to contain an event.

Table 6.3: Frequency response requirements for 2025 seasonal scenarios.

	Primary (MW)	Dynamic Containment (MW)	Enhanced (MW)
Summer Minimum	952	366	201
Summer Peak	336	0	201
Winter Minimum	740	332	201
Winter Peak	121	0	201
Spring - Autumn Minimum	942	306	201
Spring Autumn Peak	152	0	201

The results shown in Table 6.3 indicate that, given the underlying assumptions, by 2025 there will be a need for containment response in addition to Primary and Enhanced response particularly in periods of low demand. By taking an indicative 20 GW demand to represent low demand, the trend in the change of supplementary response requirement, in addition to existing Primary and Enhanced response capability, can be seen over a range of inertia values. The results are depicted in Figure 6.1 and Figure 6.2, showing how the need for a faster frequency containment service such as the Dynamic Containment service proposed by the ESO, changes with inertia.

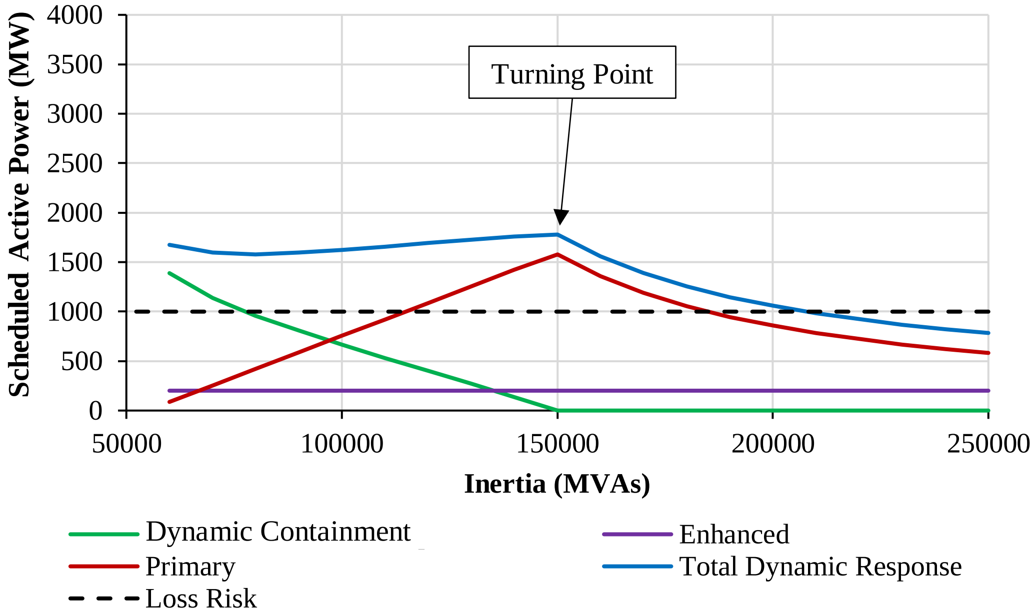


Figure 6.1: Active power trend for an inertia spread at 20 GW of demand in 2025 under the gone green FES scenario with demand sensitivity included.

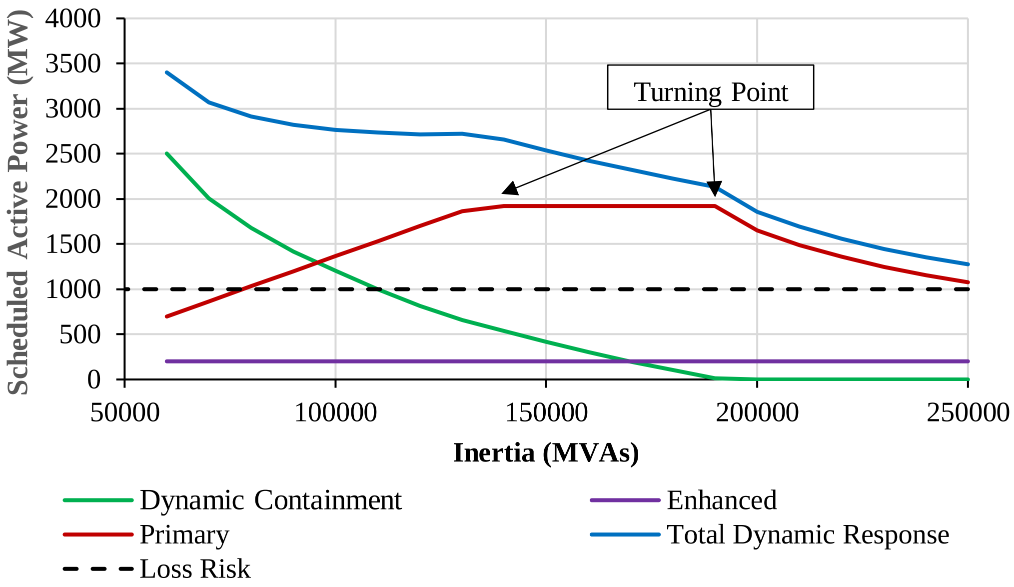


Figure 6.2: Active power trend for an inertia spread at 20 GW of demand in 2025 under the gone green FES scenario without demand sensitivity included.

The result depicted in Figure 6.1 is for an inertia spread with demand sensitivity included at 2.5%/Hz, while Figure 6.2 is without demand sensitivity included. Figure 6.1 and Figure 6.2 show two main characteristics, i.e. the turning points and that, for the most part, total dynamic containment response requirements exceed the magnitude of the loss of infeed. From the results depicted in Figure 6.1 and Figure 6.2, it can be seen that the total response is mostly greater than 1 GW at low inertia. This is significant because the loss simulated is 1 GW and so the minimum Secondary response requirement to restore this loss would also be 1 GW. This result indicates a high likelihood that the Primary (containment) response requirement will be greater than the Secondary response during seasonal minimums in 2025. This is relevant because as discussed earlier in chapter 2, historical demand for Secondary response is greater than Primary response, such that Secondary response drives FFR tenders, with both services along with High frequency response often times procured as a bundle. The implications of Primary response demand exceeding Secondary response represent a significant change in frequency response requirements.

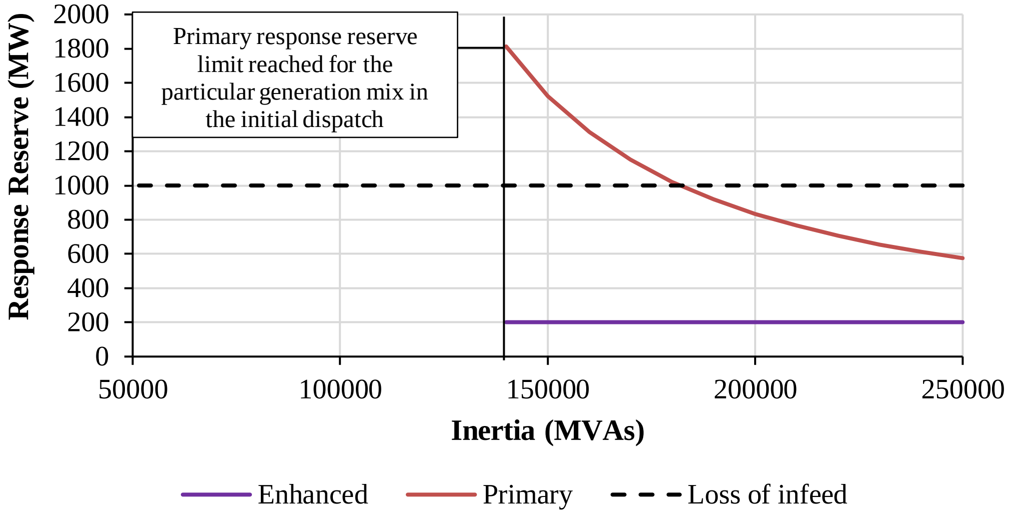


Figure 6.3: Need for response with changing inertia for 20 GW transmission demand: without the Dynamic Containment service.

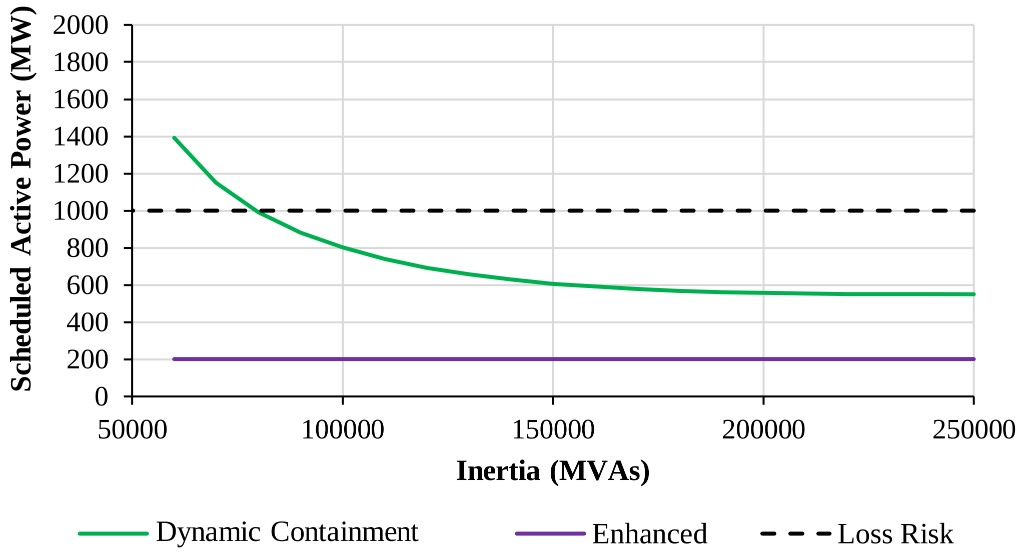


Figure 6.4: Need for response with changing inertia for 20 GW transmission demand: without Primary response.

As a comparison, the results in Figure 6.3 show an inertia spread for 20 GW with demand sensitivity but without the inclusion of the Dynamic Containment service, while Figure 6.4 shows the same scenario but with the Dynamic Containment service completely replacing Primary response. The impact of the faster frequency response service is evident. Figure 6.3 indicates that existing containment strategies alone are insufficient as the power system tends towards lower inertia, but when supplemented by a faster frequency containment response service, loss events at lower system inertia can be contained as indicated by Figure 6.1 and Figure 6.2. That said, as shown in Figure 6.4, replacing Primary response with a fast containment response service also contains the loss of infeed event at low inertia, and it does so more efficiently than Primary response.

6.1.1 Critical Inertia Levels for Frequency Containment Strategy

The studies presented in the previous section identify a characteristic of GB's frequency response requirements, specifically a need for response power to be delivered faster than existing Primary response product in certain conditions. The technical details are discussed in this section.

The turning point indicated in Figure 6.1 and Figure 6.2, is a symptom of the simulated loss of infeed event requiring a faster rate of Power delivery than Primary response is capable of accommodating, increasingly so as the RoCoF increases when the system tends towards lower inertia. Two turning points can be observed in Figure 6.2 in contrast with the single turning point observed in Figure 6.1, where the difference between both simulations is demand sensitivity. The absence of demand sensitivity in the simulation presented in Figure 6.2, results in the need for the Dynamic Containment service at a higher inertia value than observed in Figure 6.1[45]. The plateau observed in Primary response trend of Figure 6.2 arises because there is a need for a faster service but there is still flexible synchronous generation dispatch available to hold reserve for Primary response at the plateau. As the inertia reduces, this availability reduces while the need for the faster service increases, resulting in two turning points on the Primary response trend in Figure 6.2.

The definition of Primary response of full delivery within 10 seconds[46] is equivalent to a rate of response delivery in pu/s that is defined in the ramp rate limiter of the governor, but the loss event requires a faster rate of power delivery. Since the rate of delivery of response is limited in pu/s, the only way for Primary to attempt to overcome

[45] And altogether more response reserve as the system inertia reduces in Figure 6.2 when compared to Figure 6.1, in agreement with the results in section 4.1.

[46] Admittedly this limit only applies when the flexible synchronous plant is responding at the extremes of what is permitted by compliance.

its restriction is to hold more power in reserve so that for the same ramp rate limit in pu/s, more power per second (MW/s) is delivered. This is achieved by scheduling more reserve within the headroom of the flexible plant, which can be done by either increasing the size of the unit or increasing the headroom of the plant. However, either or both measures can only be taken up to a point, i.e. where there is insufficient flexible plant operating to provide the required amount of reserve, or when the plant reaches its minimum stable export limit. Under such a condition, Primary response must be supplemented in order to contain the loss event, as indicated by Figure 6.1 and Figure 6.2, which is where faster services such as the Dynamic Containment service, or other similar services, can provide a benefit. Similarly, a faster service displacing Primary response will require less total active power response as indicated when comparing Figure 6.3 and Figure 6.4.

The ESO, ahead of the event, could also decide to modify the original planned dispatch by reducing the magnitude of the loss of infeed[47], or by dispatching more flexible synchronous generators thereby increasing the available capacity of Primary response from the aggregated whole and the inertia in the power system. The retention of an overall balance with generation matching demand, means that bringing such generation onto the system would require a proportional reduction in the amount of non-synchronous power dispatched. Any reduction of renewables would entail an under-utilisation of the available resources. It is questionable whether such actions provide more benefit per cost than using the original dispatch while providing supplementary containment reserve.

6.1.2 Future Demand for Faster Frequency Response

Having identified a need for faster frequency response, the future demand for this service is estimated by calculating the proportion of the year that frequency containment response requirements exceed Secondary response requirements from 2016/17 to 2025/26. Using the model and tools introduced in chapter 3, the demand and corresponding inertia at which Primary response requirement exceeds the loss risk has been calculated. The study is conducted in terms of demand and inertia for a

[47] This measure will incorporate its own costs which are not insignificant [69].

normal loss risk of 1 GW of HVDC interconnector supply. The previous modelling assumptions are applied along with the following modifications:

- only Primary and Enhanced frequency responses are represented in the simulation, as they are the two currently existing applicable services in the GB frequency response market;
- Secondary frequency response reserve is assumed to be equal to the simulated loss, and EFR is assumed to provide 201 MW of response; and
- for the purposes of this study, the constraint imposed by dispatching a minimum amount of baseload supply in previous simulations (see section 6.1) is relaxed, allowing more flexible plants to be available to hold Primary response reserve, particularly at lower demand levels.

A point in each scenario characterizes the boundary condition termed frequency response demand threshold (F_{th}), where the amount of Primary response held for reserve (R_p) becomes greater than the Secondary response reserve (R_s), as shown in,

$$F_{th} = R_p, \qquad R_p > R_s. \tag{6.1}$$

This threshold is analysed in the context of the present and future joint distribution of future demand and inertia, based on the most recent estimates of these distributions available at the time of writing[48] [9]. This is done by simulating demand levels from 10 GW to 50 GW and noting the inertia for each demand level where Primary response exceeds Secondary. The results of the analysis reveal the boundary shown as the solid line in Figure 6.5 and Figure 6.6, where Figure 6.5 shows the operating conditions reported in [9] to be found in 2016/17 and Figure 6.6 shows the same for 2025/26.

[48] It should be noted that while the ESO continues to conduct operability studies, there have been no recent publications for future demand and inertia distributions.

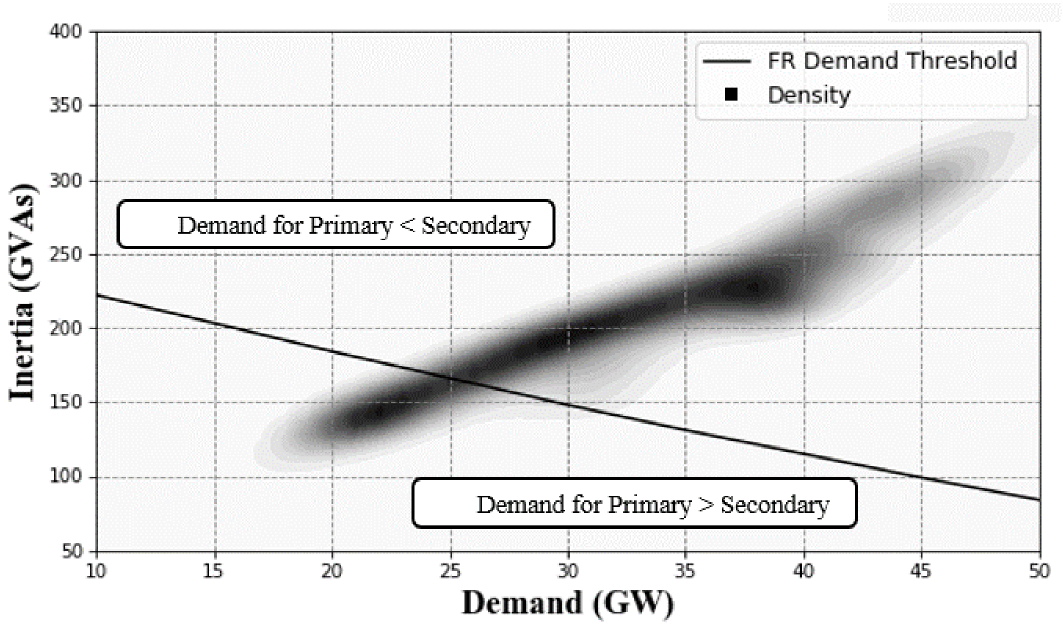


Figure 6.5: Joint distribution of demand and inertia in 2016/17 from SOF 2016 'Gone Green' Flexibility Case B.

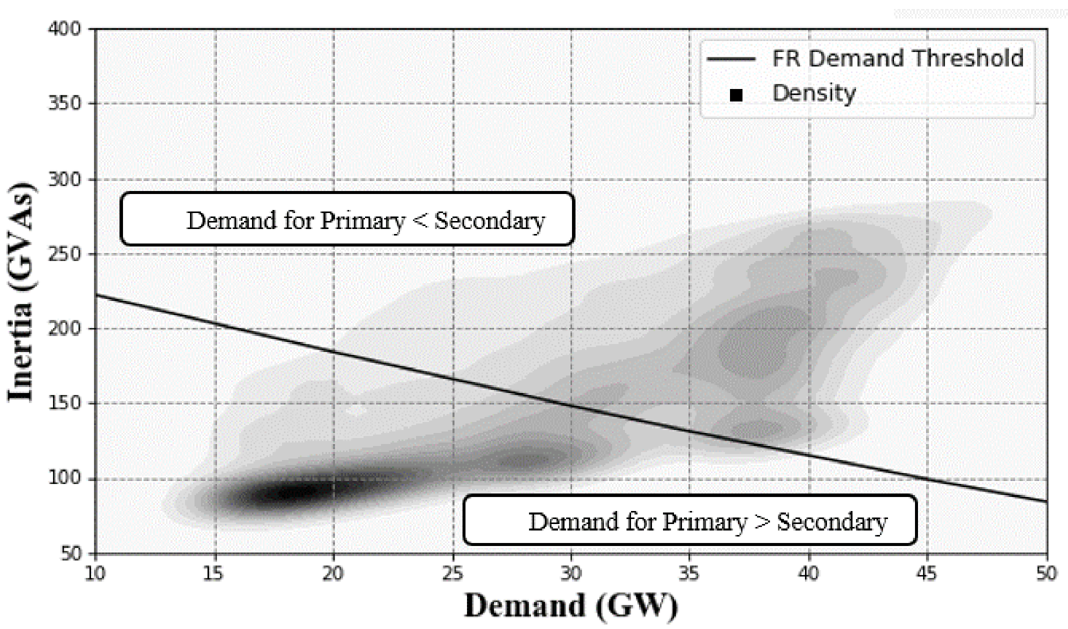


Figure 6.6: Joint distribution of demand and inertia in 2025/26 from SOF 2016 'Gone Green' Flexibility Case B.

As shown in Figure 6.7, in 2016/17 it is estimated that demand for Primary response would have exceeded demand for Secondary response for at least 21% of the year, corresponding to low-demand low-inertia periods such as windy summer nights and sunny weekends. Today, these periods are managed by procuring additional Primary response and/or restricting the largest infeed loss. The latter option requires plant to be re-dispatched which is expensive. In all scenarios described in the 2016 Future Energy Scenarios report [117], it is expected that there will be demand for additional Primary or faster response for at least 41% of the year by 2025/26, rising rapidly between 2017 and 2021 in both the Consumer Power and Gone Green scenarios. Increased demand for Primary and faster response is not accompanied by an increased demand for Secondary response, indicating that this is where new commercial opportunities lie in the future.

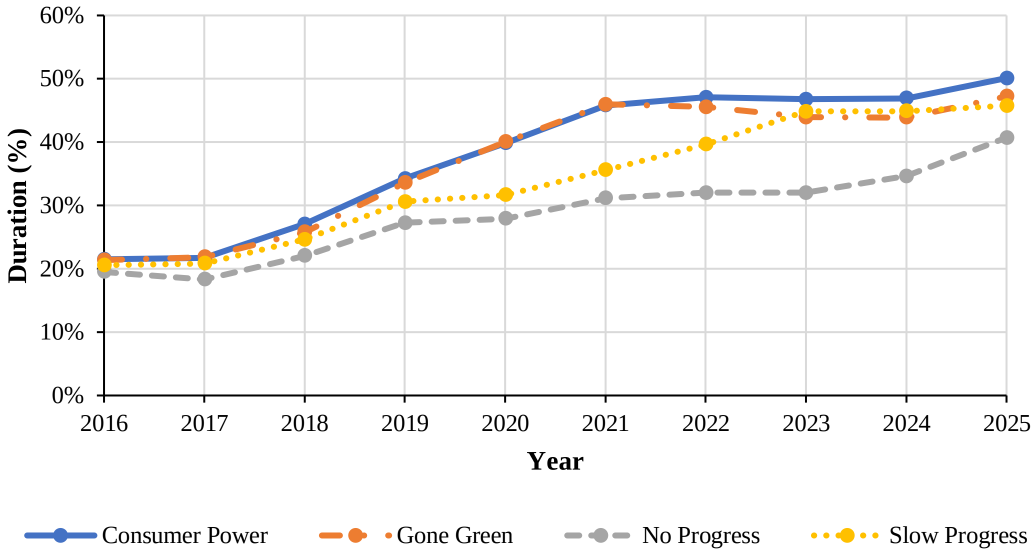


Figure 6.7: Percentage of the year that demand for Primary response is forecast to exceed demand for Secondary response.

It should be noted that the estimates above do not account for the contribution of static frequency responses that can be dispatched to supplement dynamic frequency response. In addition, the real-world variations in the amount of inertia in the power system differs based on the inertia constant of the plant in merit and its operating point relative to the size of the machine. Therefore, it is added that in addition to a supplementary dynamic containment service, deploying static response, increasing the inertia in the power system, or reducing the loss risk can also facilitate frequency containment when used individually or in some combination. Indeed, new static services have been proposed in [109] and could contribute to meeting the needs outlined above.

6.1.3 Implications for Market Design and Participants

Under current market arrangements in Britain, Primary frequency response is often procured as a by-product of Secondary response, around half of which is procured a month ahead or more, however, this chapter shows that the demand for Primary response will exceed the demand for Secondary response at least 41% of the time in 2025/26. Coupled with the inadequacy of existing frequency response services at low-demand and low-inertia periods, rather than expensive re-dispatch to procure more of the bundled services, a supplementary containment service is required. Furthermore, there is value in such a service being faster than Primary response, since it's shown that a faster service is a more efficient means of meeting the changing need for dynamic frequency containment response. New and existing technologies can provide these services, such as batteries and WPPs, but the latter would require the procurement window to be closer to real time when weather forecasts are more accurate in order to participate competitively.

The provision of a frequency containment service, faster than Primary response, will also reduce the need to curtail the loss risk at the relaxed RoCoF limits of ±0.5 Hz/s to ±1 Hz/s expected in the future, provided the speed of activation of the service is sufficiently fast. This is of importance due to the increase in interconnector capacity expected in the GB power system, which would otherwise need to be managed to preserve the system security and incur additional costs in the Balancing Market. Such a service could be provided by a range of technologies including energy storage, interconnectors, electric vehicles, wind plants and solar plants, and a future commercial frequency response market that includes an unbundled containment service and closer to real time procurement windows can facilitate the participation (and competition) of the range providers.

Creating a distinctive frequency containment service and incorporating its unbundled nature into the commercial frequency response market, will allow such services to supplement Primary response and High frequency response, particularly in low demand/inertia scenarios. Furthermore, the provision of a fast frequency containment response service as a supplementary reserve, in addition to existing services, means that the reserve for Secondary response can be provided by conventional means, while meeting the need for containment reserve as a distinct service without necessarily increasingly Secondary response holding. While these services do not have to be bundled together as is the current practice, there are questions regarding the performance of providers in this respect that fall beyond the scope of this paper and should be addressed in future work. However, the overriding thought is whether, or not, such providers (and which providers) will be able to efficiently and effectively perform as expected.

6.2 Future Frequency Response Services

As the system inertia reduces, the RoCoF experienced for the same loss event increases, and as a result the energy requirement for containing the power imbalance and resultant frequency deviation changes. In general, the response needs to be fully delivered sooner rather than later, where the critical factors are the speed of activation and ramp rate. This is because as the RoCoF increases, the frequency deviation must be contained sooner in order to prevent the excursion from exceeding acceptable limits, while giving time for slower acting response services to deliver their response. In this section, the frequency response services described in chapter 2 along with two other fast-acting are compared. These two fast-acting services are Synthetic Inertia and a new service proposed in this thesis called Improved Frequency Containment.

6.2.1 Frequency Response Performance at Different System Limits

Scenarios based on inertia values, shown in Table 6.4, were derived using (2.1) for a given RoCoF limit and loss risk, and modelled using the single bus model described in chapter 3. These scenarios were used to test the performance of different frequency responses, to determine their impact on frequency containment. In these studies, the distinction between embedded inertia and generation inertia is ignored, and instead inertia values represent total system inertia, with demand assumed to be 30 GW across all scenarios. In addition, static Primary and Secondary frequency responses are assumed to be available at 250 MW each, with all existing frequency response service delivered as modelled in the tuned single bus model from section 3.2.3.

Table 6.4: Scenarios devised to test the future frequency response concept.

Scenario	RoCoF Limit (Hz/s)	Loss Risk Value (GW)	Inertia (GVAs)	Frequency Condition
1	0.125	1	200	Normal loss
2		1.32	264	Normal loss
3		1.32	264	Infrequent Loss
4		1.8	360	Infrequent Loss
5	0.5	1	50	Normal loss
6		1.32	66	Normal loss
7		1.32	66	Infrequent Loss
8		1.8	90	Infrequent Loss
9	1	1	25	Normal loss
10		1.32	33	Normal loss
11		1.32	33	Infrequent Loss
12		1.8	45	Infrequent Loss

The scenarios were devised to meet three different RoCoF limits, ±0.125 Hz/s, ±0.5 Hz/s and ±1 Hz/s, such that the inertia in the power system was enough to contain both present and future normal and infrequent loss risk definitions within RoCoF limits. The studies presented are for 60 second simulations to represent the window for compliance with the SQSS requirements for acceptable frequency conditions in Table 2.1. As a result, frequency containment is only valid for a simulation that reaches a new steady state at a frequency greater than or equal to 49.5 Hz for the simulated loss of in-feed events. Considering how Primary and Secondary responses are delivered in practice, both services are modelled together such that the provider (a synchronous generator) delivers Primary response that persists into Secondary response timescales. It should be noted that since there are no specifications for frequency restoration to within the operational limits of ±0.2 Hz of nominal 50 Hz frequency, frequency containment is only optimised for maximum frequency deviations, i.e. no greater than ±0.5 Hz for a normal loss and ±0.8 Hz for an infrequent loss. Containment is optimised to achieve the minimum frequency constraints[49].

As expected, it can be seen in Figure 6.8 that existing frequency containment services are sufficient for frequency events when the power system is constrained within current RoCoF limits. However, in Figure 6.9, it is observed that existing services are inadequate for normal loss risk frequency conditions as the power system tends towards the 0.5 Hz/s RoCoF limit. Lastly, as the power system tends towards the 1 Hz/s (in Figure 6.10) existing services become inadequate. This supports one of the main points of this thesis, i.e. the increasing need for faster than existing dynamic frequency containment services for power systems tending towards lower inertia. Although it is unlikely that the GB power system would experience the low inertia defined by the 1 Hz/s limit in the near future, it is a RoCoF limit that would become the practical RoCoF limit in the future, as synchronous generators ≥ 5 MW commissioned before 31st June 2016 are decommissioned, and system inertia reduces due to increasing penetration of non-synchronous sources of power displacing

[49] That is to say, the minimum amount of response reserve required is a constraint in the optimisation of the frequency reserve.

synchronous generators, raising the need for the provision of a suitable dynamic response service.

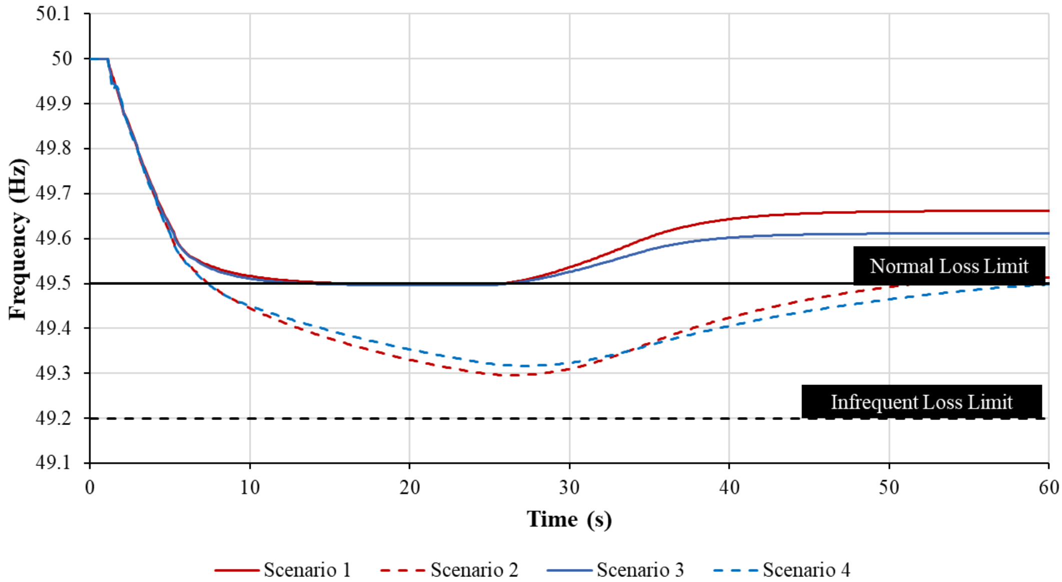


Figure 6.8: Frequency plots for both pairs of loss risks at 0.125 Hz/s RoCoF limit (Existing Services).

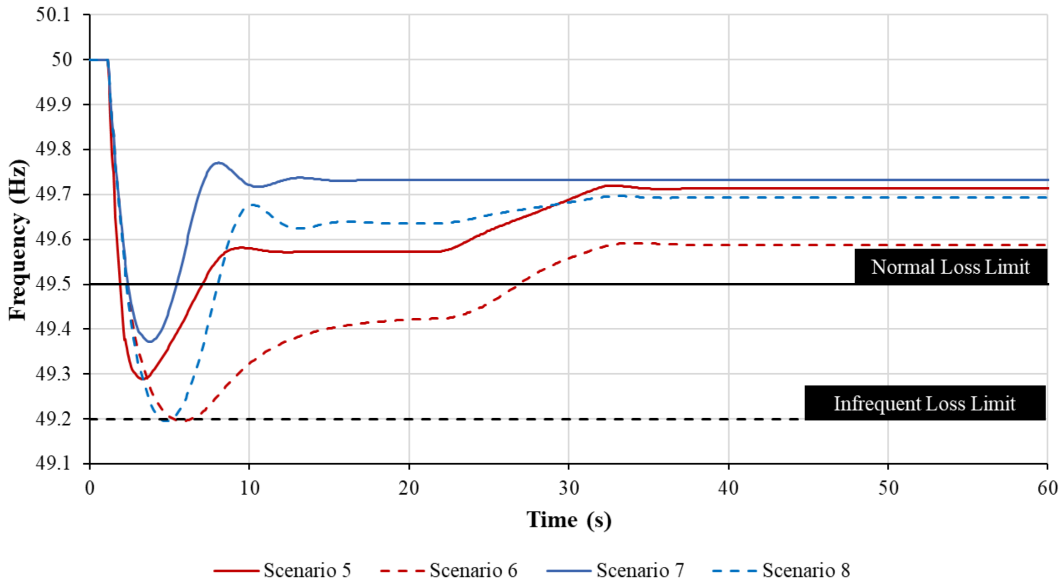


Figure 6.9: Frequency plots for both pairs of loss risks at 0.5 Hz/s RoCoF limit (Existing Services).

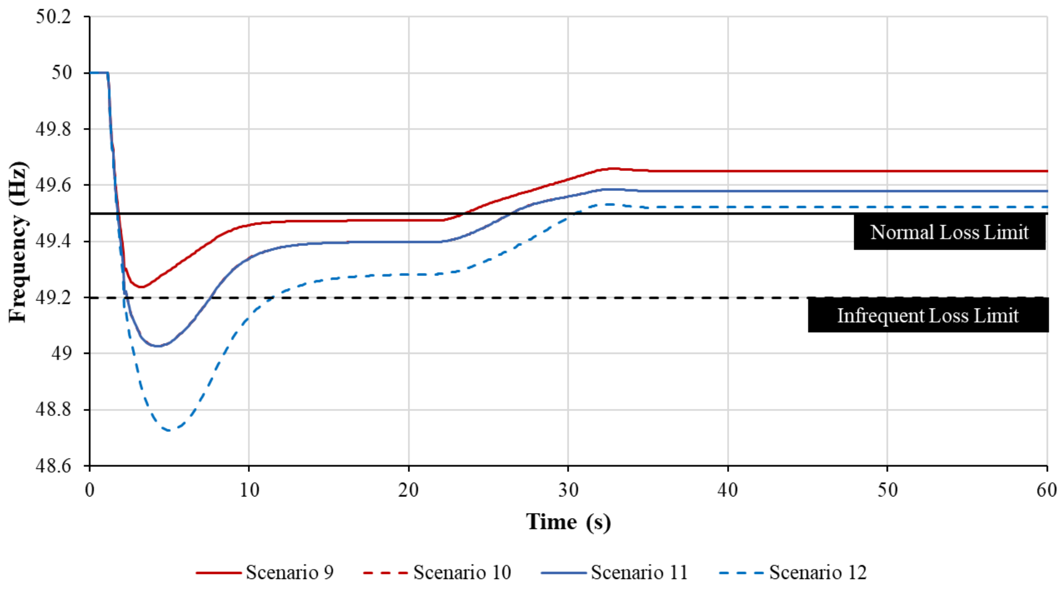


Figure 6.10: Frequency plots for both pairs of loss risks at 1 Hz/s RoCoF limit (Existing Services).

The GB ESO's proposed suite of dynamic frequency response services (see Figure 2.17) are designed to be an improvement on existing Primary, Secondary and High frequency response services, and are expected to replace those services in the future. The performance of the ESO's proposed future dynamic frequency response services (Dynamic Regulation, Dynamic Containment and Dynamic Balancing), can be considered via the scenarios in Table 6.4; however, the 0.125 Hz/s scenarios can be ignored since existing services are sufficient, and also because there is an accelerated programme in place to update the settings of legacy RoCoF relays by 2022.

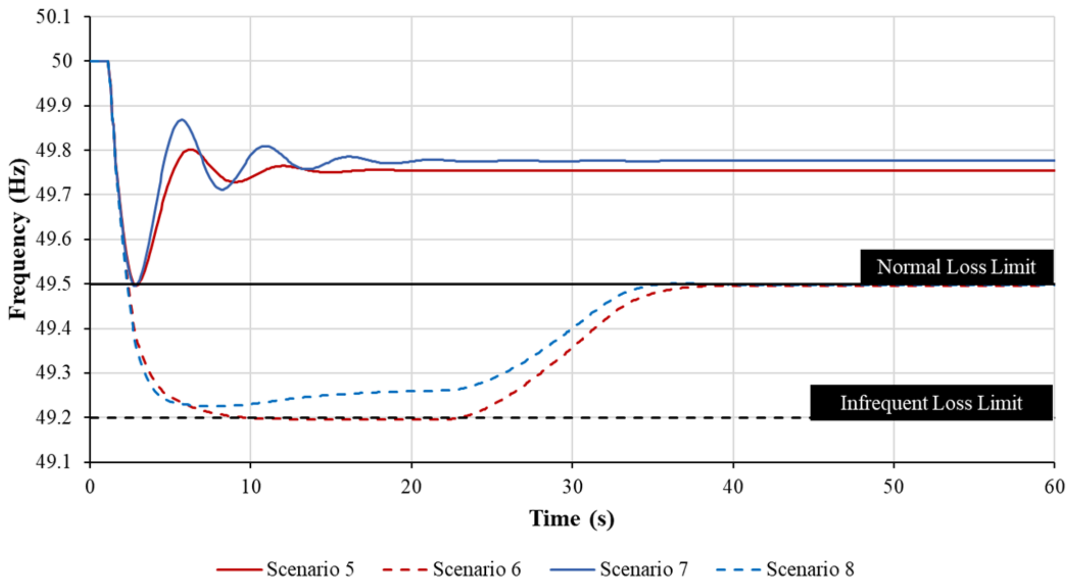


Figure 6.11: Frequency plots for both pairs of loss risks at 0.5 Hz/s RoCoF limit (ESO's Proposed Services).

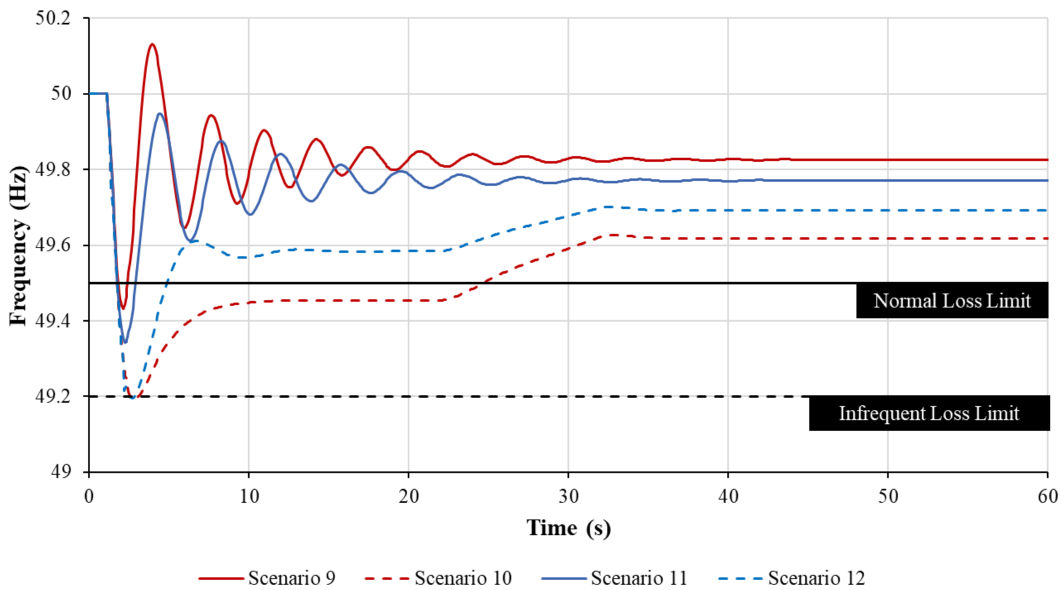


Figure 6.12: Frequency plots for both pairs of loss risks at 1 Hz/s RoCoF limit (ESO's Proposed Services).

Comparing the plots for existing and proposed services (Figure 6.9 and Figure 6.11, and Figure 6.10 and Figure 6.12), it is evident that the services proposed by the ESO are a significant improvement to the existing services[50], and while there is some oscillation when addressing normal loss risks, there is also strong damping[51]. A key factor influencing the appearance of the oscillations in these simulations is how quickly the event needs to be contained in relation to the detection and activation delay of the frequency response services. In Figure 6.12, increasing the response reserve in scenarios 9 and 11 would also dramatically increase the oscillations observed, since the service isn't acting quickly enough; i.e. the events must be contained within 0.5 s and the delay of the fastest service is 0.5 s. The dampened oscillations observed (e.g. Scenarios 5 and 7 in Figure 6.11 with a 1 s containment time and scenarios 9 and 11 in Figure 6.12 with a 0.5 s containment time) indicate a starting point beyond which the risk of containment failure and frequency instability increases. Further study shows that the boundary occurs when frequency needs to be contained to within 0.5 Hz of nominal 50 Hz frequency in less than 1.2 seconds, equivalent to 60 GVAs or 79.2 GVAs for a 1 GW or 1.32 GW normal loss risk, respectively.

The data presented in the system operability framework (SOF) 2016 report indicates that across all four future energy scenarios the minimum inertia is about 70 GVAs across all four scenarios in 2025/26. This indicates that while it is unlikely for the boundary to occur for 1 GW normal loss risk, it can occur up to 1.3% of the year in 2025/26[52] for a 1.32 GW normal loss risk. Looking ahead to 2030 using data from Antares based on a European market dispatch in hourly resolutions for a high wind[53] scenario (with wind displacing gas), it is observed that with the inclusion of embedded inertia (at the assumed inertia constant) it is unlikely that there would be an instance where the power system is dispatched at less than 60 GVAs of inertia. However, when embedded inertia is excluded, the likelihood of the boundary occurring increases to

[50] When simulating the ESO's proposed services, dynamic Primary response is replaced by Dynamic Regulation as it is defined, with the worst-case delivery of the service assumed, i.e. with a 2 second delay and 8 second delivery.

[51] It is acknowledged that improvements to the control strategy deployed could provide even stronger damping, but this does not represent a worst-case scenario and therefore simplified active power controllers that do the minimum required to comply with the definition of the frequency response services are deployed in these studies.

[52] 0.59% of the year in No Progression, 0.95% of the year in Slow Progression, 1.29% of the year in Gone Green and 1.32% of the year in Consumer Power.

[53] An average of 43.87% of non-synchronous generation across every hour of the year with an hourly minimum of 4.25% and maximum of 92.98%. In terms of system non-synchronous penetration this is an average of 40% with a minimum of 4.27% and a maximum of 89.76%.

about 16% of the year, as depicted in Figure 6.13. On the other hand, it is observed that with the inclusion of embedded inertia the power system is dispatched at less than 79.2 GVAs of inertia about 1% of the year, which increases to 22% of the year when embedded inertia is excluded.

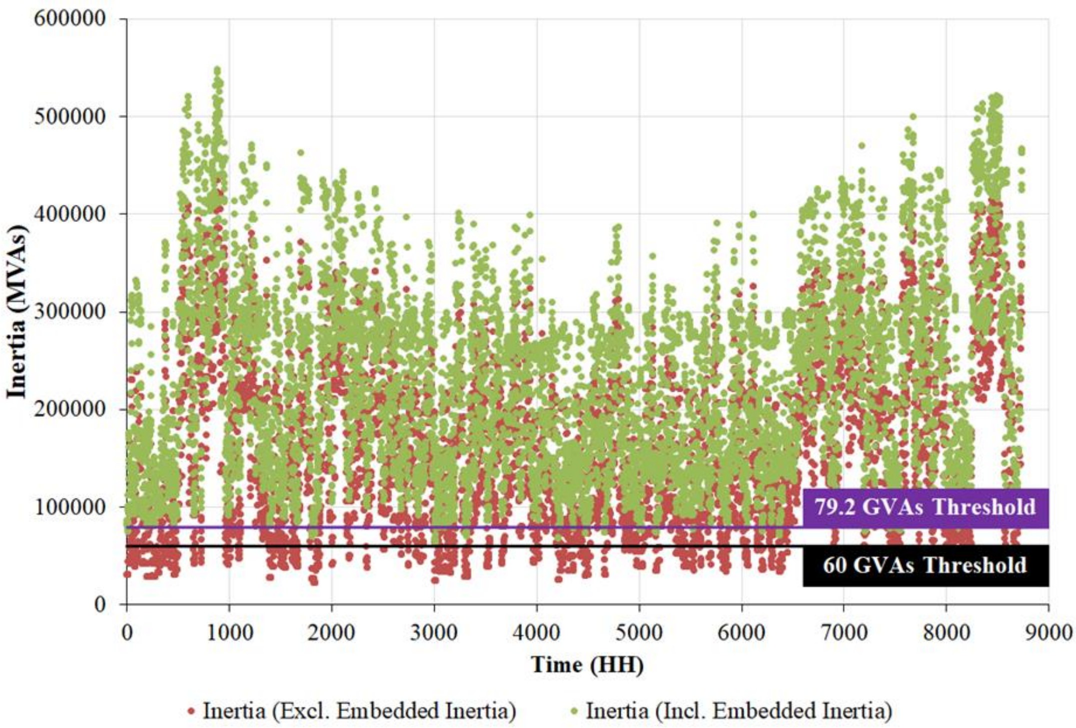


Figure 6.13: Inertia dispatched in 2030 for a high wind penetration scenario based on market dispatch.

It is reiterated that the defined threshold does not necessitate containment failure or instability, but rather it identifies a point beyond which the risk of one or both increases. The likelihood of this risk can be mitigated by improved control topologies[54] (details of which fall beyond the scope of the thesis), they can also be remedied if the proposed services activate quicker than defined, or if a fast-acting frequency response service is defined. The value in the provision of fast-acting frequency response is in RoCoF containment, or more precisely in slowing down RoCoF until slower frequency response services can activate. A fast-acting response could be an inherent

[54] E.g. improved damping could be used to reduce oscillations.

characteristic of the power system, e.g. synchronous inertia, or it could be dispatchable reserve such as synthetic inertia (SI), or some other fast-acting frequency response product.

A question raised in relation to the ESO's new dynamic services proposal, is whether the provision of a containment service needs to be sustained into restoration (Secondary response) timescales. The work covered so far in this thesis, suggests a need for containment services as power system inertia reduces, but there is no accompanying indication for a need for such services to persist into restoration timescales. Consequently, it is beneficial to unbundle these supplementary containment services from restoration services such as Secondary Response, facilitating the increased participation of alternative providers of frequency containment response[55].

6.2.2 Alternative Fast-Acting Dispatchable Frequency Response Services

With an unbundled service in mind and taking into consideration the points observed in the previous section, two alternative fast-acting frequency containment services are considered in this section. A simplified synthetic inertia service, depicted in Figure 6.14, is devised and modelled to investigate the impact of a controlled recovery period on frequency containment. Another service investigated, is a service that is being proposed by this thesis. The service is termed Improved Frequency Containment (IFC) and it is defined as a frequency response service with a deadband of 0.015 Hz, and a 250 ms detection and activation delay. IFC, illustrated in Figure 6.15, is designed to fully deliver response up to 500 ms of the event, such that 100% of the response is delivered for a 0.5 Hz frequency deviation. This service is sustained for the duration of the simulation but it is also capable of deactivation. In this study a controller deactivation, when simulated, occurs after response has been sustained for 30 seconds at a rate no faster than 0.05 pu/s[56].

[55] It is noted that the recently proposed Dynamic Regulation service that is designed to replace dynamic Primary, Secondary and High frequency responses, will be a frequency containment service that persists into the restoration timescales, especially is restoration is assumed to start with Fast Reserve, a service that currently operates in GB within a 5-minute timescale.

[56] This ramp down rate also applies when the service reduces response delivered even if the minimum sustain time hasn't elapsed.

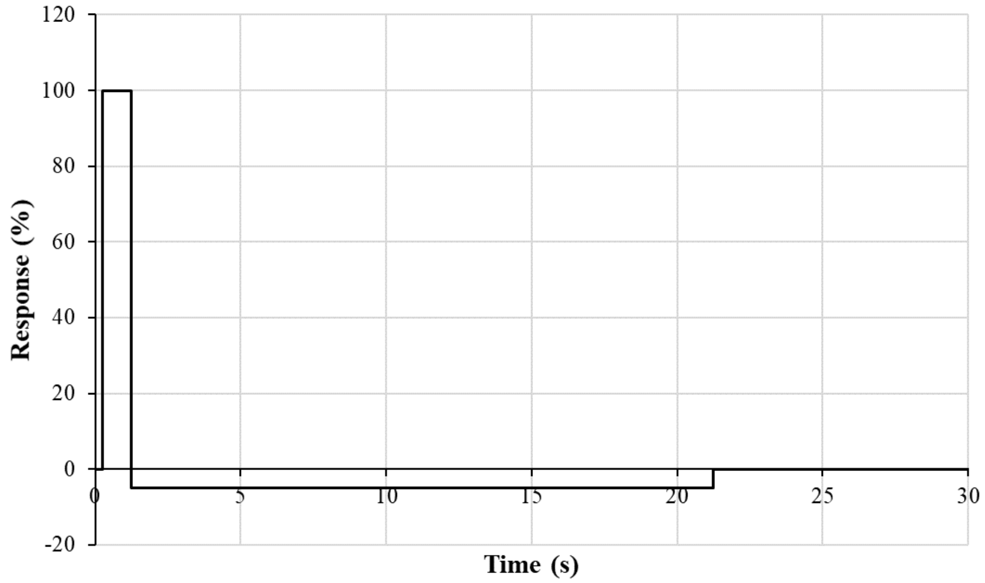


Figure 6.14: Simplified definition of a controlled synthetic inertia profile.

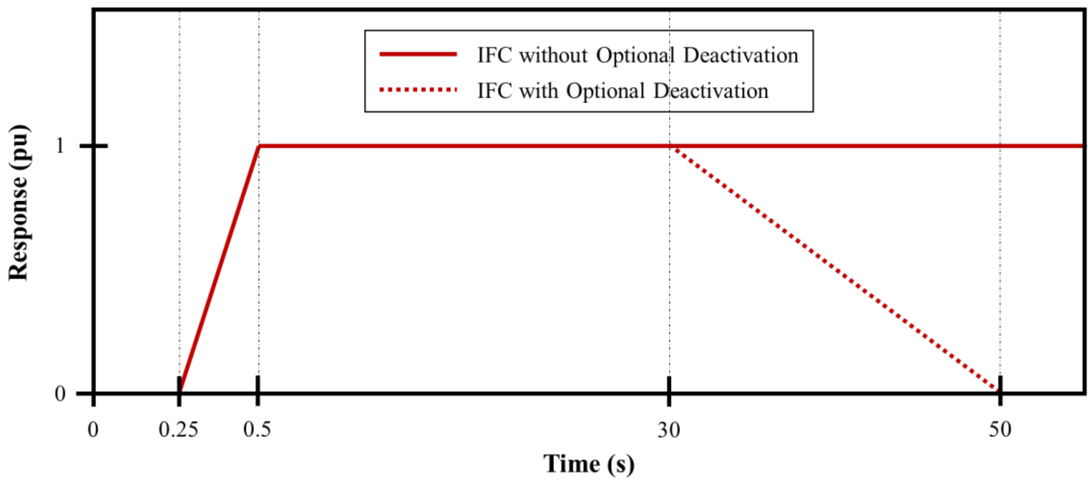


Figure 6.15: Active power profile of the Improved Frequency Containment service.

Although the deployment of 150 MW synthetic inertia, in addition to the proposed ESO services, was able to improve frequency containment in scenario 9 (see Figure 6.16), the service had only minimal impact on damping the oscillatory behaviour. Synthetic inertia is a fast-acting frequency response service and therefore capable of reducing the amplitude of the oscillation (as observed in the initial swing), however, since the service isn't sustained and is only available for 1 second the impact is restricted.

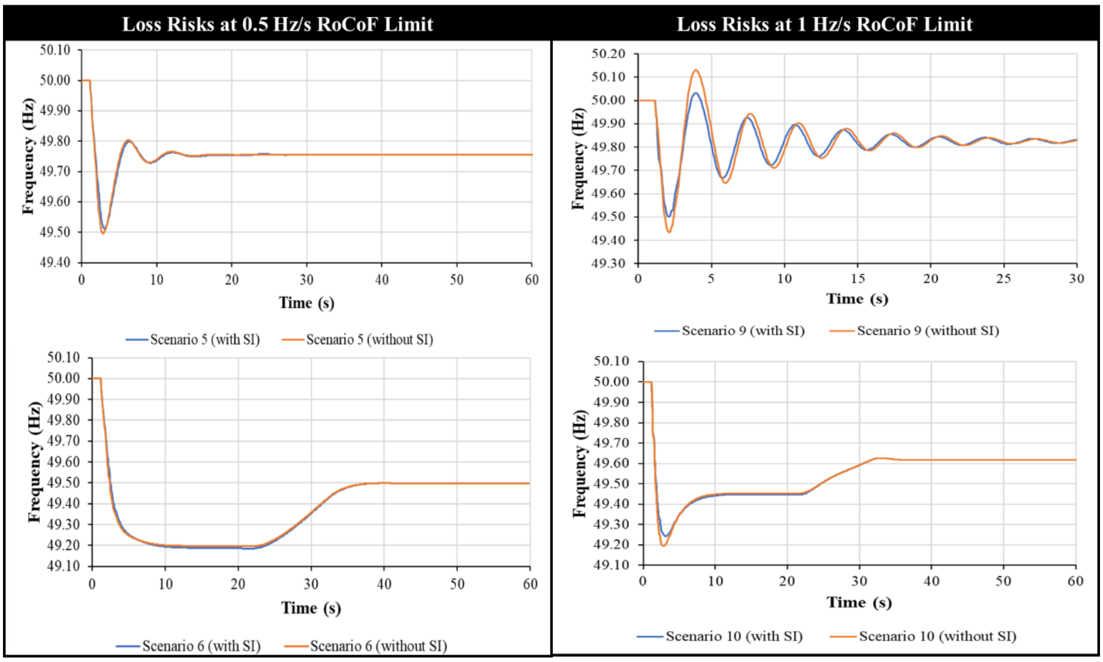


Figure 6.16: The impact of 150 MW of Synthetic Inertia with a controlled recovery period on normal (top plots) and infrequent (bottom plots) loss events.

From Figure 6.17, it is observed that in comparison to the ESO's proposed future frequency response services alone (red line), the inclusion of the fast-acting services (SI and IFC) to the ESO's services[57] improves frequency containment in scenario 9, however, unlike SI (blue line), IFC (green line) exhibits strong damping when used alongside the ESO's proposed services. When deployed alone, i.e. used as a frequency response service alongside only EFR and static responses, the IFC service (black line) is capable of containing the event and quickly damping out the initial overshoot[58].

[57] ESO services refer to Dynamic Regulation, Dynamic Balancing and Dynamic Containment services.
[58] It should be noted that in all cases, dynamic response services use simplified active power controllers that meet minimum service definition requirements.

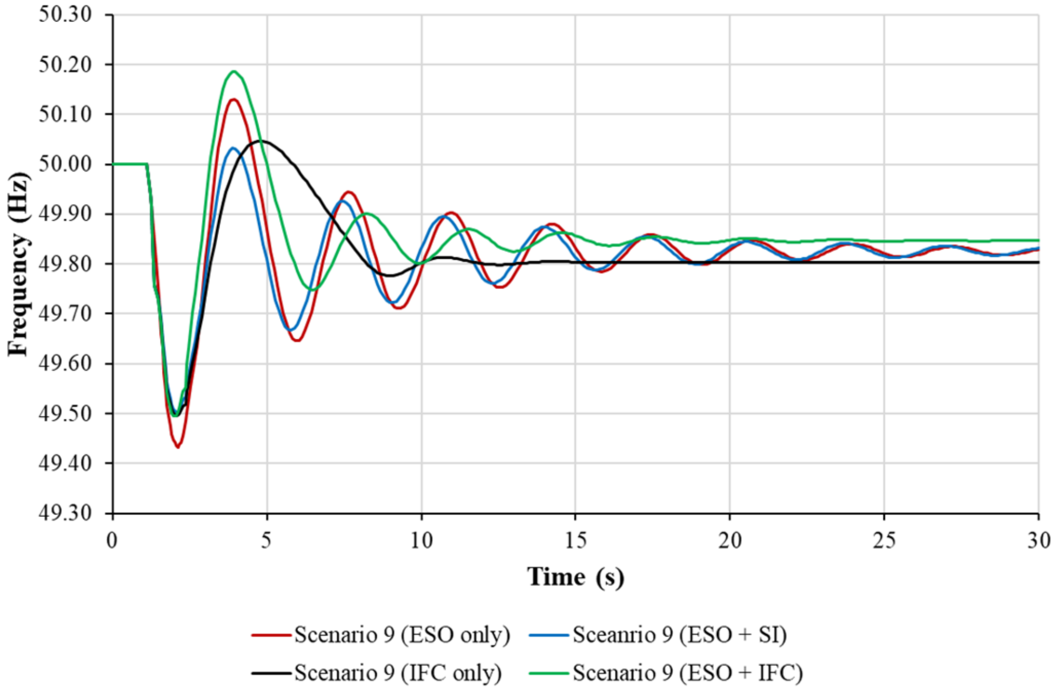


Figure 6.17: Modified versions of scenario 9 showing the performance of frequency response services for a normal loss event[59].

In the comparisons done using scenarios 9 and 10, the IFC-only simulations require less active power reserve to contain the event than the ESO's proposed services; about 17% for the normal loss risk and about 26% for the infrequent loss risk. It is also observed, from Figure 6.18, that when paired with the ESO's proposed services, frequency behaviour during a normal loss event is still acceptable when IFC deactivates after 30 seconds of response delivery, since the loss of IFC is balanced by other active services, but then from Figure 6.19 it is seen that the impact of the deactivation is more dramatic in the infrequent loss event (scenario 10) than in normal loss event (scenario 9). It should be noted that when IFC is deployed as the sole (or major) dynamic response service, any deactivation would need to be balanced by a supplementary secondary service. Further work on the IFC service should consider a deactivation definition linked to Fast Reserve, with a deactivation ramp down rate that is sufficiently defined to facilitate the handover of service requirements.

[59] The services depicted in these plots are used alongside EFR and static response as they were originally dispatched in scenario 9.

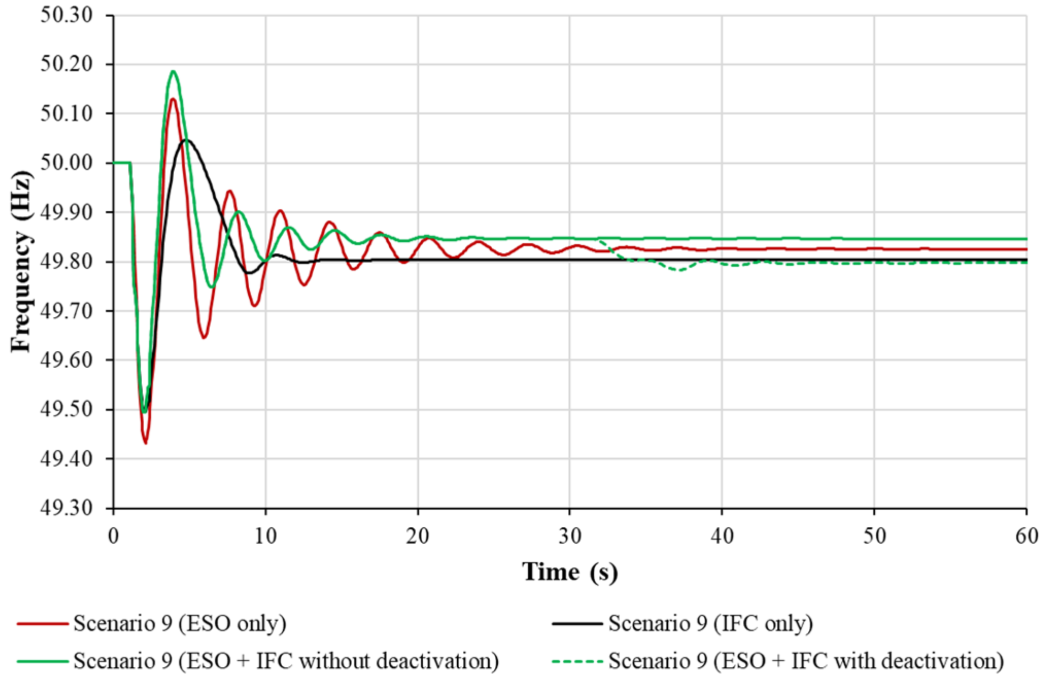


Figure 6.18: Frequency response comparison showing IFC deactivation for a normal loss risk event.

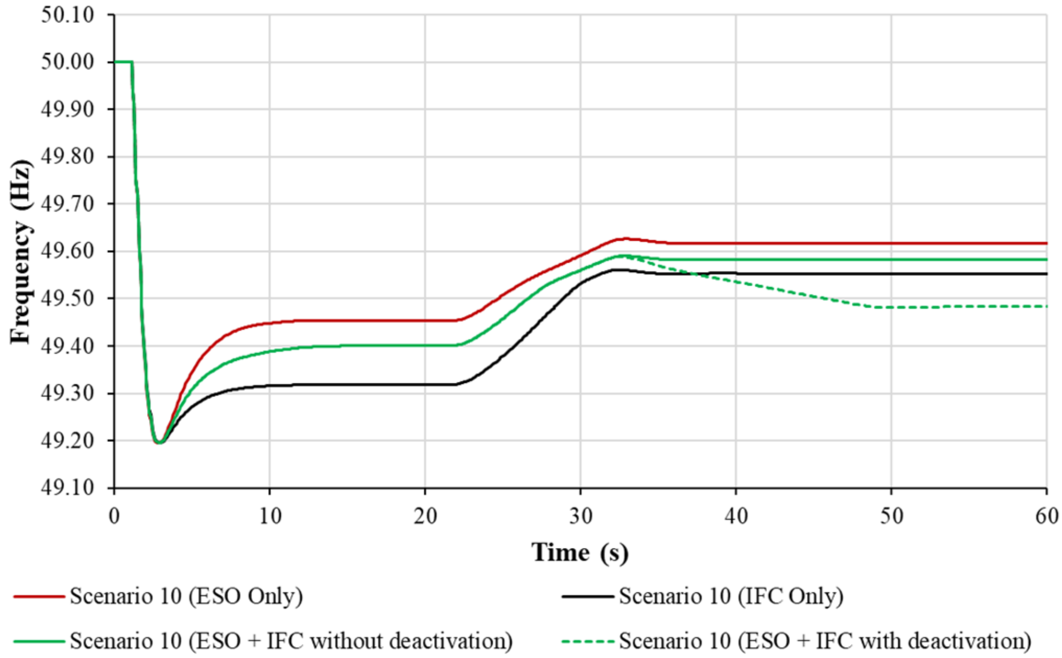


Figure 6.19: Frequency response comparison showing IFC deactivation for an infrequent loss risk event.

While the results show the benefit of fast-acting services such as Synthetic Inertia and IFC, there are still questions surrounding the unbundling of containment and restoration services in GB that while worth mentioning, fall outside the scope of the present research. There is no definition for an activation time for Secondary response, and any definition that unbundles dynamic Primary and Secondary response services may also need to include deactivation specifications for Primary response, as well as, activation specifications for Secondary response. However, in practice, unbundling Primary and Secondary response services raises further questions, as more of these plants are displaced there will be an increasing need for alternative providers to deliver these services. Under the status quo, there exist barriers to participation for potential alternative providers such as WPPs and SPPs, yet, there is also opportunity for interconnectors and storage. Although WPPs and SPPs would be capable of downward regulation for prolonged sustain times, as required by High frequency response, it would incur considerable risk of non-delivery of Secondary response from the WPP or SPP for upward regulation, and would require the WPP or SPP to either be part of a hybrid solution, or incorporate curtailment to address the risk of non-delivery, i.e. they would have to hold enough headroom to provide the response required while also accounting for forecast errors, especially with existing procurement windows.

An alternative means of delivering of Primary and Secondary responses would be to redefine Primary and Secondary as one containment service and treat them as such, since they are intrinsically linked when delivered by conventional providers. This approach is essentially what has been done by the GB ESO with the Dynamic Regulation service that is a symmetrical service for both high and low frequency events. This service can be supplemented by other unbundled and asymmetrical[60] frequency containment services that are tailored to deliver a faster service for a lower inertia power system. Restoration services could also be designed to act via later instructed services such as Fast reserve, and designed to complement frequency containment services so that these services are sustained for only as long as they are needed. Ultimately simplifying the definitions of existing frequency management

[60] i.e. a provider can participate in either delivering only a low frequency service or only a high frequency service.

services, unbundling frequency containment and restoration services in the GB, and providing and avenue for unbundled low and high frequency response products for competitive market participation.

6.3 Summary

It has been found that at modest demand levels Primary frequency response is insufficient at levels of inertia below 150 GVAs, and that faster frequency response products are required to supplement Primary response in order to contain credible loss risks, as defined by regulation. It is also shown that faster frequency response products need less reserve than conventional Primary response products to contain the same event. Using estimates of the joint demand and inertia distribution produced by National Grid ESO, it is estimated that faster frequency response products will be required at least 41% of the time in 2025/26 compared to 21% of the time in 2016/17. It is also shown that at lower inertia, tending towards ±1 Hz/s, the need for fast acting response services increases.

These findings have an impact and can indeed influence future frequency response market design and demand for frequency response services. Instead of purchasing a bundled service to meet a frequency containment reserve requirement, frequency response services could be unbundled such that containment reserve demand can be met without necessarily increasing the reserve for restoration services, potentially open the market to more technologies. The impact of the proposed fast-acting frequency containment services has been shown via the comparative results. Creating a distinctive fast-acting frequency containment service and incorporating its unbundled nature to the commercial frequency response market, will allow such services to supplement Primary response and High frequency response particularly in low demand/inertia scenarios.

A future commercial frequency response market with an unbundled containment service, can facilitate the participation of providers for the competitive provision of reserve by modifying the procurement window from month-ahead to day-ahead or even shorter horizons for adjustment close to real-time. In that context, there are a range of technologies that are capable, to varying degrees, of delivering Synthetic Inertia and Improved Frequency Containment, including energy storage, interconnectors, electric vehicles, wind plants, and solar plants. The provision of a containment response service, faster than Primary response, will also reduce the need to curtail the loss risk at relaxed RoCoF limits of ±0.5 Hz/s to ±1 Hz/s expected in the future. This is of particular importance due to the increase in interconnector capacity expected in the GB power system, and indeed the emergence of other credible loss risks such as the Hinckley Point C nuclear power station, which would otherwise need to be managed to preserve the system security, incurring additional costs.

7

CONCLUSIONS AND FUTURE WORK

The ESO is obligated to manage frequency within defined frequency and RoCoF limits. As the inertia in the power system reduces, the challenge of assuring frequency stability increases which, in turn, increases the risk of demand disconnection and blackouts. This challenge of managing frequency arises with the changing energy landscape driven by the increasing penetration of non-synchronous devices and changing nature of demand. The effects of these changes are already being experienced in GB and Ireland, with the latter already employing strategies that aim to support the transition towards a lower inertia power system. These challenges led to the need to conduct this research project towards the objective outlined in chapter 1, and the following paragraphs present the conclusions of this research.

In order to conduct the studies outlined in the objectives, tools were developed. Although there are existing models, none met all the requirements defined for a suitable model. They are not suited to accurately and efficiently execute the simulation of many different scenarios, while incorporating representations of the behaviour of a range of frequency responsive elements in the power system. Although simplified models have their limitations, they are suitable tools for conducting system frequency studies and assessing the performance of new products. In chapter 3, two models for conducting frequency studies on the GB system model are presented and validated. The single bus model includes a representation of the key attributes of the power system that influence frequency behaviour during a power imbalance and allows pragmatic assessment of system frequency variations and potential frequency management services. A second frequency stability model called the system frequency model is also presented, and while it isn't used in the studies presented in this thesis, it is a model that allows FEROS to operate as a standalone application. FEROS, a program for frequency studies, is presented in section 3.3. It can be used as a companion tool to the single bus model described in section 3.2 or as a standalone application. In either case, FEROS facilitates frequency studies and investigates the challenges of managing system frequency in a future power system. Section 3.3 also presents a procedure by which key factors of the power system model that influence frequency behaviour can be estimated for a range of conditions. In addition, chapter 4 shows the impact that inertia, the sensitivity of demand to frequency changes, and dispatchable energy reserves (such as Primary response) have on frequency management. It is shown that the speed of the activation, speed of delivery, and amount of dispatchable reserve are key factors determining the impact that dispatchable energy reserves have on frequency management during a disturbance. Similarly, it is shown, as expected, that reducing either or both inertia and demand sensitivity result in a shortfall of energy available to contain a frequency disturbance.

The requirement to contain loss risks presents limits to the operation of the power system that if breached could result in an uncontained event, demand disconnection and potentially blackouts. It is therefore useful to understand the containment limits of the power system. Section 5.2 presents a comparison of metrics, along with their benefits and limitations, that can be used to understand and quantify the frequency stability of a power system when subjected to a significant power imbalance. The three metrics considered include:

- the system non-synchronous penetration (SNSP) metric that, for a given demand value, provides the limit of non-synchronous sources of power required to meet acceptable frequency conditions and RoCoF limits;
- the critical inertia metric that, for a given demand value, provides the limit of inertia in the power system required to meet acceptable frequency conditions and RoCoF limits; and
- the frequency stability by components metric that considers a wider range of frequency stability factors within the three dimensions of dispatchable energy reserves (e.g. Primary response), loss risk and instantaneous RoCoF.

Although the specific presentation of these metrics considers the GB power system, the methods presented can be employed to produce metrics that can be applied to other power systems to determine whether or not the power system is likely to contain a given loss event under a defined operating scenario.

The trends and expressions presented in this thesis are particular, and can be applied as presented, to the GB power system. However, it is also possible to equate one form of dispatchable frequency response service to another. A method is proposed in section 5.2.4 that can be applied to a similar power system, along with an expression for the GB power system for converting from Primary response to Enhanced response, or any other service with equivalent service definitions.

The method involves simulating a range of system conditions to determine the relationship between instantaneous RoCoF, dispatchable reserve and loss risk, for frequency containment delivered by different services. Comparing any two frequency containment services produces a trend and expression similar to that presented in section 5.2.4, which can then be used as an exchange rate between those frequency containment services. This expression is a function of the ratio between the two services being compared and the instantaneous RoCoF. It is reiterated here that the instantaneous RoCoF is a measure of system inertia that accounts for the composition of the synchronous generation dispatched, the headroom held for the provision of frequency response reserve, the penetration of non-synchronous dispatch, and embedded inertia.

It is shown in section 6.1 that at 20 GW demand, frequency containment of a 1 GW normal loss of infeed results in a lower inertia limit of about 140 GVAs when using existing Primary and Enhanced frequency containment services. This limitation is surmounted when Primary response is replaced by the ESO's Dynamic Containment service. This result suggests that existing dynamic frequency containment services alone are insufficient to manage a credible loss risk at low demand and inertia levels below 140 GVAs. In addition, the amount of Primary response required to contain the loss risk at low demand and low inertia, exceeds the 1 GW loss risk at about 180 GVAs with a reserve requirement of about 1022 MW. The reserve requirement increases to just over 1800 MW at 140 GVAs. Extending this initial observation, it is further observed in section 6.1.2 that the demand for frequency containment response services (i.e. Primary response) may exceed that of dynamic frequency restoration services (i.e. Secondary response[61]) for at least 41% of the time in 2025/26 compared to 21% of the time in 2016/17, signalling the increasing need for supplementary fast containment response that, in theory, could be provided by a range of technologies.

Furthermore, it is shown in section 6.2 that the provision of fast-acting frequency containment services in addition to existing and planned response products, is beneficial to maintaining frequency stability and securing the power system against credible loss events, particularly at low inertia. A service such as the Improved Frequency Containment response concept, if deactivation is permitted, will need to be accompanied by a secondary response service that, in theory, can be delivered by static or dynamic services. Section 6.2 shows that at lower inertia, tending towards a RoCoF of 1 Hz/s, the ESO's current and planned services alone (as they are defined) are insufficient and there is a need for an even faster service that could be met by fast-acting frequency containment products such as Synthetic Inertia and Improved Frequency Containment. This is because the current and planned services are incapable of containing a normal loss risk within 0.5 Hz of nominal 50 Hz frequency (as defined

[61] Assumed to be equivalent to the loss risk.

in the SQSS), regardless of the amount of reserve dispatched; the services as they are defined are not activating quickly enough to slow the RoCoF effectively and thus contain the event within defined limits. On the other hand, the inclusion of a fast-acting service such as the Improved Frequency Containment service (or a similar product), would activate in a sufficiently fast and controlled manner to slow the RoCoF and contain frequency within defined limits.

The current practical RoCoF limit in GB is 0.125 Hz/s, which means that the ESO must manage the maximum loss risk in GB within this limit. Although curtailment action to reduce the size of the possible single largest loss is expensive, it is a suitable action until such time as the practical limit is raised to 0.5 Hz/s and then to 1 Hz/s depending on the operation scenario, as stated in section 5.1.2. In addition, the ESO is currently taking steps to initiate the changes to the settings of the old RoCoF relays, with the settings expected to be updated by 2022. When addressing the containment of loss risks at 0.125 Hz/s, RoCoF containment is dominant over frequency containment, and the provision of fast responses such as EFR have no impact on RoCoF due to their speed of activation and narrow window of the older relays (typically around 100 ms). On the other hand, when addressing containment of loss risks at 0.5 Hz/s and above, frequency containment becomes more dominant, except at periods of particularly low inertia and demand when RoCoF containment becomes more dominant. In this case, provided they are defined with a sufficient activation delay and ramp rate, the provision of fast responses would permit the increased uptake of non-synchronous generation and support the transition towards a lower inertia power system with more renewables.

Energy responses are instrumental in managing system frequency and they are delivered via both the inherent characteristics of the power system and dispatchable reserves. Traditionally synchronous machines have been the main source of these energy responses; however, as the energy landscape is tending towards a higher percentage of non-synchronous devices, synchronous machines are being displaced. This reduces the inertia in the power system as well as the amount of flexible synchronous plant available to deliver dispatched reserves, such as Primary response, to contain a frequency event. Moreover, the reducing inertia and the increase in maximum loss risk raise the need for faster dynamic containment responses that are quick to activate and fully deliver a response. Although there are currently response services and a market for delivering and procuring frequency response services, the ESO is currently in the process of making improvements to both, including a shift towards closer to real-time commercial frequency response procurement windows.

7.1 Future Work

There is the opportunity for further work on both simplified models. The inclusion of synthetic inertia and virtual synchronous machine controllers would improve the capabilities of the single bus model. Similarly, the inclusion of user defined control strategies to FEROS would further improve its capabilities.

The Improved Frequency Containment service should be compared to the ESO's current and planned services in terms of the cost of the provision of the service, alongside an investigation as to the viability of converter connected technologies delivering the proposed service, with attention paid to technical capabilities and any additional costs incurred. The inclusion of a definition for a 'recovery period' for a Synthetic Inertia service should also be considered in future work, and further development of a suitable distinct frequency containment response service will be conducted, while paying particular attention to the role and need for a frequency restoration service for acceptable frequency conditions as defined by the SQSS, and indeed the role and link to slower reserves such as Fast reserve, to create a wholistic framework for post and pre fault frequency management. Attention should also be paid to the ongoing work of the Phoenix project regarding the role that SCs and an Inertial response service would play in a future GB power system. Similarly, the cost-benefit analysis of the deployment of SCs by network operators to address other stability concerns should be investigated, with particular attention to the SPT network. Future work will also consider how the tenders for the different proposed new services might be run and how the purchase of a combination of service and their respective volumes might be optimised. In addition, the ESO in the control room might need a simple rule to be defined –using metrics such as the SNSP, critical inertia, or frequency stability by components– in order to be confident that loss of infeed and loss or load risks are contained. The latter of the three metrics in conjunction with an exchange rate and inertia monitoring would allow the system operator to determine a rule for the minimum inertia for a given loss risk based on the available frequency containment reserves. Conversely, the ESO would also be able to determine the frequency containment reserves required to contain a loss risk for a given operational scenario.

While the results of the present research produce conclusions pertaining to the power system, there are regional variations to consider that presently are of minimal concern in GB but could become of greater importance in the future as the power landscape undergoes further changes. Some of the issues worth considering are the effective coordination of reserves at the locations that they are most needed, without unintentionally delivering a service at an unsuitable location that could result in exacerbating the initial event. Consequently, future work will investigate frequency response services on a multi-node power system model, while considering the impact on angular stability and regional variations in observed frequency, and the role of strategies such as the ESO's Enhanced Frequency Control Capability. Future work will also expand upon the current work on frequency stability into security of electricity supply, with a focus on zero carbon operation of the GB power system in 2025 and Scotland in particular, considering: system operability issues and trends; a viable frequency response framework, the viability of the provision of response from virtual synchronous machines by 2025; short circuit current and voltage support from power electronic converters; the market and changes that would be required to facilitate zero carbon operation by 2025; an analysis of the limits to import and export of power into Scotland; fault levels in Scotland and the impact on protection; contributions to system operability of SCs in Scotland; and system restoration.

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APPENDICES

Appendix 1: Demand disconnection[62] for each Network Operator in Transmission Area [39].

Frequency (Hz)	NGET	SPT	SHET
48.80	5.0%	0%	0%
48.75	5.0%	0%	0%
48.70	10.0%	0%	0%
48.60	7.5%	0%	10%
48.50	7.5%	10%	0%
48.40	7.5%	10%	10%
48.20	7.5%	10%	10%
48.00	5.0%	10%	10%
47.80	5.0%	0%	0%
Total Demand	**60%**	**40%**	**40%**

Appendix 2: Plant operational requirements within 52 Hz and 47 Hz [39].

Frequency Range	Requirement
51.5 Hz – 52.0 Hz	Operation for a period of at least 15 minutes is required each time the frequency is above 51.5Hz.
51.0 Hz – 51.5 Hz	Operation for a period of at least 90 minutes is required each time the frequency is above 51Hz.
49.0 Hz – 51.0 Hz	Continuous operation is required.
47.5 Hz – 49.0 Hz	Operation for a period of at least 90 minutes is required each time the frequency is below 49.0Hz.
47.0 Hz – 47.5 Hz	Operation for a period of at least 20 seconds is required each time the frequency is below 47.5Hz.

[62] From the specifications in the grid code, it can be seen that the percentage of demand disconnected goes up and down as frequency falls. The rationale behind this behaviour is not investigated in this thesis as it falls outside the scope of the work.

Appendix 3: Frequency response services in the GB ancillary market in 2018 [42].

Service Type	Service	Response Time	Response Duration	Minimum Capacity	Procurement Process
Mandatory Frequency Response	Primary Frequency Response	<10 secs	20 secs	Transmission Network dependant: NGET ≥ 100 MW SPT ≥ 30 MW SHET ≥ 10 MW	Tendered
	Secondary Frequency Response	<30 secs	30 minutes		Tendered
	High Frequency Response	<10 secs	Indefinite		Tendered
Commercial Frequency Response	Primary Firm Frequency Response	<10 secs	20 secs	≥ 1 MW	Tendered
	Secondary Firm Frequency Response	< 30 secs	30 minutes	≥ 1 MW	Tendered
	High Firm Frequency Response	< 10 secs	indefinite	≥ 1 MW	Tendered
	FFR - Bridging	10 or 30 secs (depending on type of FFR offered)	30 secs – 30 minutes (depending on type of FFR offered)	1 – 10 MW	Bilateral Agreement
	Frequency Control by Demand Management	2 – 10 secs	30 minutes	> 3 MW	Bilateral Agreement
	Enhanced Frequency Response	< 1 sec	15 minutes	1 MW	Tendered

Appendix 4: GB frequency response payment structures adapted from [44].

Service Market	Payment Structures
MFR	A holding payment (£/h) is paid for the capability of the unit to provide response when the unit has been instructed into frequency response mode. Providers of the service submit prices on a monthly basis and there is price competition. A response energy payment (£/MWh) is paid for the amount of energy delivered to and from the system when providing frequency response. This price is determined by the Section 4.1.3.9A of the Connection and Use of System Code and is 1.25 times the market index price for positive volumes of utilisation energy, and 0.75 times the market index price for negative volumes. The prize is zero of “non-fuel” units, such as wind farms.

FFR	An availability fee (£/h) is paid per hour for the hours that a provider has tendered to make the service available. A window initiation fee (£/window) is paid for each FFR nominated window that the ESO instructs within the tendered frames. A nomination fee (£/h) is paid as a holding fee for each hour used within FFR nominated windows. A tendered window revision fee (£/h) is paid if tendered window nominations are revised by the ESO. A response energy fee (£/MWh) is paid for actual response energy provided in the nominated window.
EFR	An availability fee (£/MW/h) is paid for the hours a provider has tendered to make the service available. There has only been one EFR tender which was for four-year contracts providing continuous availability, with the optional exception of triad avoidance.

Appendix 5: Generation size classification in GB [38].

	NGET	**SPT**	**SHET**
Small	< 50 MW	< 30 MW	< 10 MW
Medium	50 MW – 100 MW	N/A	N/A
Large	≥ 100 MW	≥ 30 MW	≥ 10 MW

Appendix 6: Machine type RMS data in PowerFactory.

	Synchronous Generator	**Synchronous Compensator**	**Embedded Inertia**
Power Factor	0.8	1E-08	1
rstr	0.0025	0.008	0.0025
xl	0.1	0.06	0.1
xd	1.8	1.6	1.8
xq	1.7	1.1	1.7
Rotor Type	Round Rotor		
xrld	0	0	0
xrlq	0	0	0
Td'	6.5	1.474375	6.5
Tq'	1	0	1
xd'	0.337	0.337	0.337

xq'	0.557	0.557	0.557
Td''	0.035	0.011869	0.035
Tq''	0.03500002	0.022388	0.03500002
xd''	0.21	0.2	0.21
xq''	0.18	0.29	0.18

Appendix 7: RMS data in PowerFactory for Non-Synchronous Generation[63].

Inflexible Non-Synchronous Generation (Negative Load)		**Flexible Non-Synchronous Generation (Asynchronous Machine)**	
Static (Const Z)	0%	**Rs**	0
Dynamic	100%	**Xm**	4
Delay	0.1	**Xs**	0.01
P frequency dep.	0	**Xrm**	0
Q frequency dep.	0	**RrA0**	0
P voltage dep.	0	**RrA1**	0.1
Q voltage dep.	0	**RrA2**	0.1
All coefficients and exponents for frequency and voltage dependence = 0		**XrA0**	0
		XrA1	0.1
		XrA2	0.1
		RrB	0.1
		XrB	0.1

Appendix 8: RMS transformer type data in PowerFactory.

HV-side	YN
LV-Side	D
x1	0.03
r1	0
Phase Shift	0
uk0	3
uk0r	0

[63] Note that when a wind turbine is being simulated the asynchronous generator can be replaced with a WECC wind turbine model.

Appendix 9: One second resolution frequency and RoCoF data for 9th August 2019 event.

ACTUAL EVENT DATA			SIMULATED EVENT DATA		
Time	**Frequency (Hz)**	**RoCoF (Hz/s)**	**Time**	**Frequency (Hz)**	**RoCoF (Hz/s)**
0	49.994999	0	0	50	0
1	49.959999	-0.035	0.991667	49.982551	-0.017449
2	49.811001	-0.148998	1.981667	49.819301	-0.16325
3	49.669998	-0.141003	2.981667	49.67183	-0.147471
4	49.561001	-0.108997	3.943333	49.555297	-0.116533
5	49.494999	-0.066002	4.883333	49.478742	-0.076555
6	49.435001	-0.059998	5.883333	49.419016	-0.059726
7	49.388	-0.047001	6.883333	49.372801	-0.046215
8	49.348999	-0.039001	7.883333	49.338684	-0.034117
9	49.313999	-0.035	8.883333	49.31119	-0.027494
10	49.284	-0.029999	9.883333	49.286695	-0.024495
11	49.259998	-0.024002	10.883333	49.264331	-0.022364
12	49.237999	-0.021999	11.883333	49.243807	-0.020524
13	49.222	-0.015999	12.883333	49.224952	-0.018855
14	49.208	-0.014	13.883333	49.207625	-0.017327
15	49.199001	-0.008999	14.883333	49.191703	-0.015922
16	49.179001	-0.02	15.883333	49.177072	-0.014631
17	49.172001	-0.007	16.883333	49.163627	-0.013445
18	49.154999	-0.017002	17.883333	49.151273	-0.012354
19	49.140999	-0.014	18.883333	49.139922	-0.011351
20	49.134998	-0.006001	19.883333	49.129493	-0.010429
21	49.129002	-0.005996	20.883333	49.11991	-0.009583
22	49.120998	-0.008004	21.883333	49.111106	-0.008804
23	49.112999	-0.007999	22.883333	49.103018	-0.008088
24	49.105999	-0.007	23.865	49.096601	-0.006417
25	49.105	-0.000999	24.845	49.092837	-0.003764
26	49.103001	-0.001999	25.825	49.091573	-0.001264
27	49.104	0.000999	26.805	49.092614	0.001041
28	49.105	0.001	27.785	49.095769	0.003155
29	49.110001	0.005001	28.765	49.100846	0.005077

30	49.118999	0.008998	29.753333	49.107824	0.006978
31	49.126999	0.008	30.735	49.116448	0.008624
32	49.136002	0.009003	31.715	49.126579	0.010131
33	49.146	0.009998	32.695	49.138108	0.011529
34	49.159	0.013	33.685	49.150594	0.012486
35	49.171001	0.012001	34.685	49.162267	0.011673
36	49.18	0.008999	35.685	49.172987	0.01072
37	49.188	0.008	36.685	49.182836	0.009849
38	49.195999	0.007999	37.685	49.191884	0.009048
39	49.201	0.005001	38.685	49.200195	0.008311
40	49.210999	0.009999	39.685	49.20783	0.007635
41	49.223	0.012001	40.685	49.214843	0.007013
42	49.227001	0.004001	41.685	49.221284	0.006441
43	49.230999	0.003998	42.685	49.227201	0.005917
44	49.235001	0.004002	43.685	49.232637	0.005436
45	49.237999	0.002998	44.671667	49.237305	0.004668
46	49.237999	0	45.671667	49.240591	0.003286
47	49.236	-0.001999	46.671667	49.242455	0.001864
48	49.233002	-0.002998	47.671667	49.24301	0.000555
49	49.229	-0.004002	48.671667	49.242362	-0.000648
50	49.229	0	49.671667	49.240609	-0.001753
51	49.224998	-0.004002	50.671667	49.23784	-0.002769
52	49.221001	-0.003997	51.671667	49.234138	-0.003702
53	49.219002	-0.001999	52.671667	49.229577	-0.004561
54	49.217999	-0.001003	53.671667	49.224228	-0.005349
55	49.214001	-0.003998	54.661667	49.218471	-0.005757
56	49.203999	-0.010002	55.661667	49.213033	-0.005438
57	49.202	-0.001999	56.661667	49.208034	-0.004999
58	49.198002	-0.003998	57.661667	49.203439	-0.004595
59	49.181	-0.017002	58.651667	49.183709	-0.01973
60	49.150002	-0.030998	59.651667	49.157006	-0.026703
61	49.126999	-0.023003	60.651667	49.132234	-0.024772
62	49.104	-0.022999	61.651667	49.109444	-0.02279
63	49.084999	-0.019001	62.651667	49.088488	-0.020956
64	49.062	-0.022999	63.651667	49.069225	-0.019263

65	49.043999	-0.018001	64.651667	49.051522	-0.017703
66	49.028	-0.015999	65.651667	49.035255	-0.016267
67	49.014	-0.014	66.651667	49.020309	-0.014946
68	49.000999	-0.013001	67.651667	49.006578	-0.013731
69	48.984001	-0.016998	68.651667	48.993965	-0.012613
70	48.957001	-0.027	69.641667	48.967854	-0.026111
71	48.929001	-0.028	70.641667	48.935353	-0.032501
72	48.897999	-0.031002	71.641667	48.905275	-0.030078
73	48.872002	-0.025997	72.641667	48.877617	-0.027658
74	48.847	-0.025002	73.641667	48.852198	-0.025419
75	48.821999	-0.025001	74.641667	48.828841	-0.023357
76	48.800999	-0.021	75.641667	48.807383	-0.021458
77	48.801998	0.000999	76.633333	48.798242	-0.009141
78	48.821999	0.020001	77.623333	48.808572	0.01033
79	48.838001	0.016002	78.623333	48.823755	0.015183
80	48.853001	0.015	79.623333	48.837853	0.014098
81	48.865002	0.012001	80.611667	48.851107	0.013254
82	48.875999	0.010997	81.611667	48.865456	0.014349
83	48.889	0.013001	82.611667	48.880877	0.015421
84	48.909	0.02	83.611667	48.897283	0.016406
85	48.925999	0.016999	84.611667	48.914592	0.017309
86	48.922001	-0.003998	85.601667	48.926553	0.011961
87	48.919998	-0.002003	86.591667	48.923716	-0.002837
88	48.914001	-0.005997	87.581667	48.921449	-0.002267
89	48.91	-0.004001	88.581667	48.91934	-0.002109
90	48.91	0	89.581667	48.917427	-0.001913
91	48.91	0	90.581667	48.915699	-0.001728
92	48.91	0	91.581667	48.914141	-0.001558
93	48.911999	0.001999	92.571667	48.913486	-0.000655
94	48.914001	0.002002	93.571667	48.916818	0.003332
95	48.923	0.008999	94.571667	48.924336	0.007518
96	48.933998	0.010998	95.561667	48.934865	0.010529
97	48.945999	0.012001	96.561667	48.945169	0.010304
98	48.953999	0.008	97.561667	48.954653	0.009484

Appendix 10: Scenarios for comparing optimisation methods.

Scenario	1	2	3	4
Demand (GW)	30	40	30	20
Inertia (GVAs)	200	250	200	200
Response Service	Primary		Enhanced	
1 GW normal loss event for 0.5 Hz frequency deviation target.				

Appendix 11: Overview of differences observed in comparison.

Scenario	Reserve	Frequency	Speed
1	0.001497	5.63E-06	18%
2	-0.00305	-1E-05	43%
3	-0.01074	-3.7E-05	88%
4	-0.00188	6.99E-06	90%

Appendix 12: Plot showing speed and accuracy differences observed in comparison.