Containing Loss Risk in a Low Inertia GB Power System

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***Abstract*—There is a reduction in the percentage penetration of synchronous machines within the GB power system; leading to a decrease in inertia, and an increase in system rate of change of frequency (RoCoF) following a frequency event. This raises the challenge of containing frequency deviations within the relevant operational limits. As a result, steps need to be taken by the system operator to manage the risk to system security. In order to better understand this risk, this paper presents the challenge in light of the changing energy landscape and the current and future frequency response services available to contain frequency deviations. Although frequency response services may be capable of containing some events within frequency limits, in low inertia scenarios these responses alone are not capable of containing excursions within practical RoCoF limits. Consequently, further action must be taken to ensure system security. The system operator currently employs an interim solution of limiting the largest loss risk, depending on system inertia and the RoCoF limit. While this is suitable in the short-term, it is unlikely that this option will be viable in the future.**

Keywords—frequency response; frequency containment; loss risk; low inertia; RoCoF

I. INTRODUCTION

The inertia of a power system is an inherent capability that affects the rate of change of frequency (RoCoF) following a system event [1, 2]. Traditionally, inertia has been made available due to transmission connected synchronous machines; however, in Great Britain (GB) the percentage of synchronous machines in the power system is reducing [3, 4], while the penetration of technologies such as wind and solar power, which in their majority are converter connected, is increasing. These converter connected technologies, also referred to as non-synchronous technologies, are connected via a solid-state electronic converter and do not have the same inherent capability of providing inertia to the system [5, 1].

The relationship between system inertia, Hsys, and RoCoF, (df/dt), is shown in (1) where dP is the power imbalance and fo is the nominal frequency. It can be seen that as system inertia reduces, the RoCoF, increases for a given power imbalance.

$$dP = \left(\frac{2 \times H_{sys}}{f_o}\right) \times \left(\frac{df}{dt}\right) \tag{1}$$

This work has been supported through the EPSRC Centre for Doctoral Training in Future Power Networks and Smart Grids (EP/L015471/1).

If the RoCoF following a frequency deviation is too high, it increases the risk of cascading frequency events, as a result of the tripping of RoCoF relays; these relays, such as the loss of mains (LoM) protection relays, are designed to open relevant circuits when the system RoCoF reaches a given limit [6]. This raises concerns regarding the behaviour of the power system in the first few seconds following a mismatch of power supply and demand. There are operational limits, relating to both RoCoF and minimum or maximum frequency excursions that the GB system operator (SO) must ensure are respected in the event of a credible disturbance. In a system with decreasing penetration of synchronous generation the challenge of complying with these limits increases.

In Section II, this paper will discuss the provision of frequency response services in GB. Following this, Section III will present two studies that investigate the containment of loss risk in the GB power system. Lastly, Section IV contains a discussion of the findings and an outline of the next steps of the research.

II. FREQUENCY RESPONSE IN GB

Fig. 1 below is an illustration of the current GB frequency response services showing primary, secondary, and reserve. Fig. 2 illustrates the operating timescales of primary, secondary, high and enhanced frequency response services, while Table I provides the technical definitions of these services. With the exception of enhanced frequency response (EFR), these responses can be dynamic or non-dynamic. Dynamic frequency responses are response services that continuously track frequency deviations and provide the required response. Non-dynamic frequency responses are frequency-triggered services that include dynamic and static response; i.e., when a frequency trigger is reached these services can either continuously or discreetly respond to frequency deviations. Under European Network of Transmission System Operators for Electricity (ENTSO-E) definitions, primary response is roughly equivalent to frequency containment reserve, secondary response is equivalent to restoration reserve and reserve dispatch recovery is equivalent to replacement reserve [7].

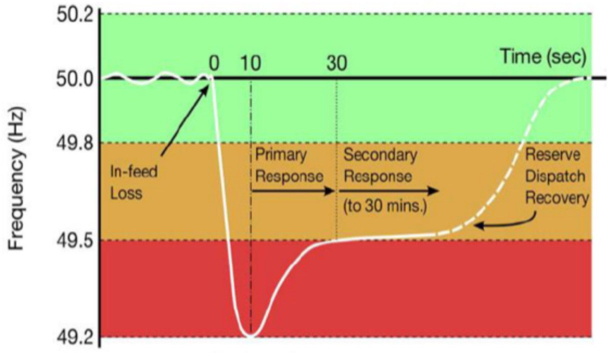

Fig. 1: Illustrating the operation of GB frequency response services [8].

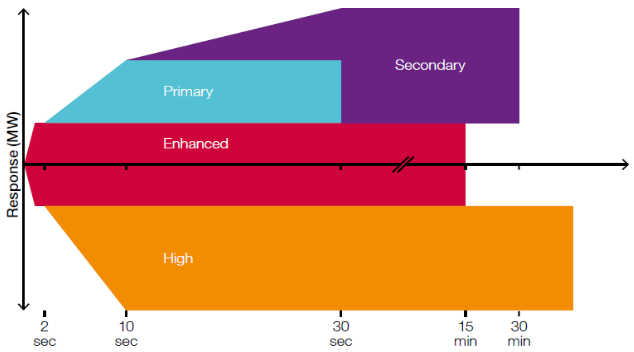

Fig. 2: Current GB frequency response services [9].

TABLE I. OVERVIEW OF FREQUENCY RESPONSE SERVICES [9, 10]

Service Name	Technical Definition
Primary Frequency Response	Full delivery of active power response 10 seconds after the event with a 2 second delay and sustained for a further 20 seconds.
Secondary Frequency Response	Full delivery of active power response 30 seconds after the event and sustained for 30 minutes.
High Frequency Response	Full delivery of active power response 10 seconds after the event with a 2 second delay and sustained indefinitely.
Enhanced Frequency Response	Full delivery of response for a 0.5 Hz change in frequency and sustained for 15 minutes.

Conventional providers of dynamic frequency response services are synchronous generators. On the other hand, non-synchronous generators are increasingly displacing synchronous generators. Under the status quo, the displacement of synchronous generation reduces system inertia and increases RoCoF during a power imbalance. Furthermore, the displacement results in simultaneously reducing the primary frequency response availability in terms of capacity and increasing primary frequency response requirement under traditional service arrangements, due to the higher RoCoF experienced for a given loss event. Consequently, the reduction in system inertia leads to concerns regarding containing a frequency event within the acceptable limits both in terms of RoCoF and frequency.

III. SYSTEM STUDIES

An in-house developed single bus model representing the GB transmission system [11] in DigSILENT PowerFactory is used for the present system study. The study applies the following assumptions:

- All the inertia in the system is represented in the inertia of the synchronous generators and no further inertia is provided by demand.
- Demand provides an inherent active power response of 2.5%/Hz [8].
- An inertia constant of 5 seconds is assumed for all synchronous generators.
- 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.
- The response provided by flexible units is modeled as dynamic response. Flexible units are 75% loaded with response provided by 50% of the headroom [12].
- A normal loss of in-feed event of 1 GW of interconnector supply in modeled with a maximum frequency deviation of -0.5 Hz from nominal 50 Hz [13, 14, 10].
- Unless otherwise stated system demand is 20 GW.

In GB, the SO published the system operability framework (SOF) 2016 [9]. This document 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 is ±1 Hz/s for all new and existing generators with a delay of 500 ms [21,22]. The original document gave existing generators until the 1st July 2016 to make the relevant changes, however there is about 6 GW of distributed generation that are still using relays that could activate if RoCoF exceeds ±0.125 Hz/s [9]. This is significant since RoCoF relays are widely used in the UK and Ireland, in loss of mains (LOM) protection for distributed generation [15, 16]. Consequently, due to the 6 GW of distributed generation still using the ±0.125 Hz/s RoCoF setting, ±0.125 Hz/s is the practical RoCoF limit in the GB power system, leading to a need to manage RoCoF within this limit during a frequency event.

A. Containing Normal Loss Risk Within ±0.5 Hz of Nominal Frequency with a ±0.125 Hz/s RoCoF Limit

The present study will investigate the performance of the frequency response services in the GB power system to contain a normal loss risk of 1 GW when system post-fault inertia is 130 GVAs. The performance will be measured in terms of containment to the defined limits of both RoCoF and frequency during a power imbalance.

There are two factors that determine acceptable frequency behaviour during a power imbalance, the size of frequency deviation and RoCoF. Consequently, the system must be secured against the normal loss risk in terms of the frequency deviation and against the loss risk in terms of the RoCoF limit. In the case of a 130 GVAs system the loss risk defined by the ±0.125 Hz/s RoCoF limit is calculated using (1) to be a loss risk of 650 MW. When compared to the 1 GW normal loss risk for a frequency deviation of ±0.5 Hz, the system must be secured against the smaller loss risk of 650 MW. However, in terms of generation a loss risk of 650 MW requires curtailment of any single unit (generator or interconnector) supplying power at the normal loss of in-feed limit of 1 GW.

TABLE II. STUDY SCENARIOS FOR CONTAINING NORMAL LOSS RISK WITHIN ±0.5 HZ OF NOMINAL FREQUENCY WITH A ±0.125 HZ/S ROCOF LIMIT

Title	Description
Scenario A	Loss risk is curtailed from 1 GW to 650 MW and implemented as the simulated loss of interconnector supply with primary response containing the frequency deviation.
Scenario B	Loss risk is 1 GW and implemented as the simulated loss of interconnector supply with no frequency response provision.
Scenario C	Loss risk is 1 GW and implemented as the simulated loss of interconnector supply with primary response and EFR containing the frequency deviation.
Scenario D	Loss risk is 1 GW and implemented as the simulated loss of interconnector supply with primary response containing the frequency deviation.

To illustrate the issues surrounding the containment of loss risk in a low inertia power system, four scenarios are investigated using the system model and assumptions previously defined, these scenarios are presented in Table II above. The scenarios illustrate what would happen if different actions were taken to address containment of frequency following a power imbalance. Table III is an overview of the observations from the study, investigating the individual scenarios, while Fig. 3 and 4 below show the frequency and RoCoF plots for scenarios A - D.

TABLE III. OVERVIEW OF STUDY SCENARIOS AND OBSERVATIONS

	A	B	C	D
Loss	650 MW	1000 MW		
RoCoF Contained	Yes	No		
Frequency Deviation Contained	Yes	No	Yes	
Inertia	130 GVAs			
Response Type	Primary Only	None	Primary and EFR	Primary Only

Only in scenario A is the system event contained within both frequency and RoCoF limits, even with EFR simulated in scenario C. Scenario B is modeled for reference to indicate the frequency behaviour if no action is taken to contain the event.

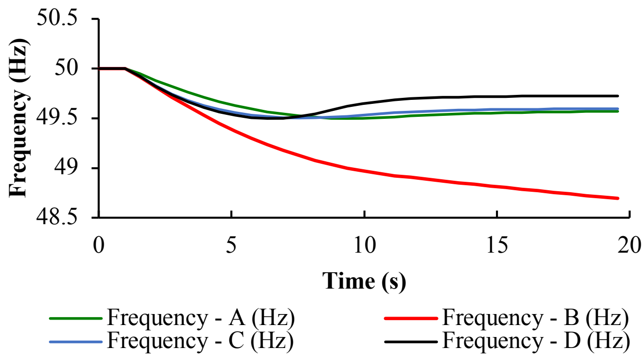

Fig. 3: Frequency plots comparing the impact of different actions to meet operational limits for a system with 130 GVAs of inertia.

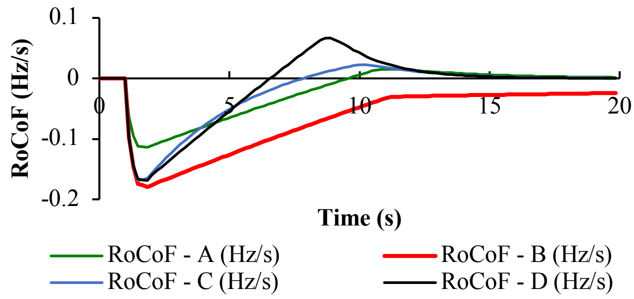

Fig. 4: RoCoF plots comparing the impact of different actions to meet operational limits for a system with 130 GVAs of inertia.

B. *Containing Normal Loss Risk Within ±0.5 Hz of Nominal Frequency and a ±1 Hz/s RoCoF Limit*

Considering the effort being made by the SO to change RoCoF relay settings to operate at ±1 Hz/s instead of ±0.125 Hz/s, the following study is conducted to investigate containment of loss risk using GB frequency response services at different system inertia, while remaining within the ±1 Hz/s RoCoF limit. The present study concerns the scenarios described in Table IV, and inherits the assumptions outlined in the previous study.

TABLE IV. STUDY SCENARIOS FOR CONTAINING NORMAL LOSS RISK WITHIN ±0.5 HZ OF NOMINAL FREQUENCY AND A ±1 HZ/S ROCOF LIMIT

Title	Description
Scenario 1	System inertia is 200 GVAs with EFR and TFR containing the frequency deviation.
Scenario 2	System inertia is 50 GVAs with EFR and TFR containing the frequency deviation.
Scenario 3	System inertia is 25 GVAs with EFR and TFR containing the frequency deviation.
Scenario 4	System inertia is 50 GVAs with EFR and a 1s service containing the frequency deviation.
Scenario 5	System inertia is 25 GVAs with EFR and a 1s service containing the frequency deviation.

While still under development, a new concept for a post-fault frequency response is proposed by the SO, alongside other improvements to the provision of frequency response. This concept post-fault service (1s service) is the full delivery of response within 1 second with a maximum delay of 0.5 seconds and sustained for 20 minutes [17]. The 1s service will work alongside existing services with the intent of replacing traditional primary response. As such, the 1s service will also be considered in this study.

Table V provides an overview of the scenarios and observations of this study, while Fig. 5 and Fig. 6 show how these services perform at different levels of system inertia in response to the same 1 GW loss of interconnector supply.

TABLE V. OVERVIEW OF STUDY SCENARIOS AND OBSERVATIONS

	Frequency Deviation Contained	Frequency Stable	Inertia	Response Type
Scenario 1	Yes	Yes	200 GVAs	EFR and Primary
Scenario 2	No (≈49 Hz)	No	50 GVAs	EFR and Primary
Scenario 3	No (≈48.6 Hz)	Yes	25 GVAs	EFR and Primary
Scenario 4	Yes	Yes	50 GVAs	EFR and 1s service
Scenario 5	Yes	No	25 GVAs	EFR and 1s service

Upon consideration of the results of the study shown in Fig. 5 and 6, and summarized in Table V, it is seen that while RoCoF is contained within the ±1 Hz/s limit in scenarios 1 - 5, frequency is contained in three of the five scenarios. Furthermore, two of those three scenarios indicate a stable frequency containment, with scenario 5 showing an instability that can lead to additional system events, exacerbating the impact of the loss of in-feed.

It should be noted that the benefit of a 1s service is apparent when comparing scenarios 2 and 4. In scenario 2, EFR and primary response are not sufficient to contain the frequency deviation, and also pose a risk of further instability; while in scenario 4, primary response is replaced with the 1s service that together with EFR is capable of containing the frequency deviation, while keeping frequency stable. In addition, the 1s service can contain the loss event with less than half the amount of response reserve that was dispatched in scenario 2 for primary response.

On the other hand, one of the risks that arises from the 1s service entirely replacing primary response is shown at the very low system inertia of 25 GVAs in scenario 5. This risk is increased as the loss risk tends towards the maximum loss risk of 1800 MW, defined in the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) [13]. Using (1), the mathematical calculation of RoCoF for a loss of 1 GW at 50 GVAs of inertia is 0.5 Hz/s. This RoCoF of 0.5 Hz/s increases to 0.9 Hz/s for a loss of 1.8 GW at 50 GVAs. This suggests that an increase of loss of in-feed from 1 GW to 1.8 GW for a system inertia of 50 GVAs in scenario 4 tends towards the results in scenario 5. Limiting the maximum output of the 1s service can reduce the risk of instability but this would also require the response reserve deficit to be met by other alternative frequency response services. Similarly, the loss risk can be curtailed but this incurs an additional cost that may not be sustainable in perpetuity.

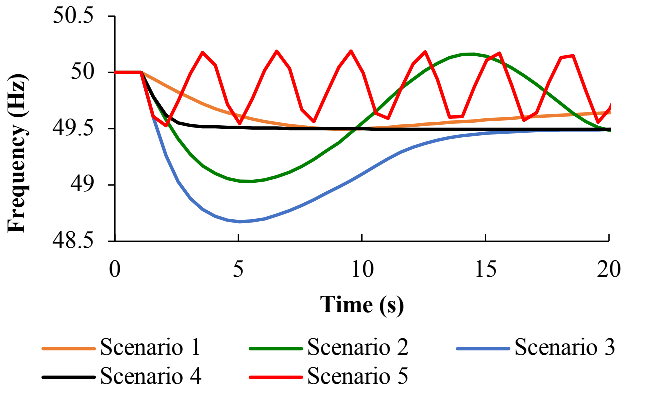

Fig. 5: Frequency plots comparing containment capabilities at different inertia levels with different response services.

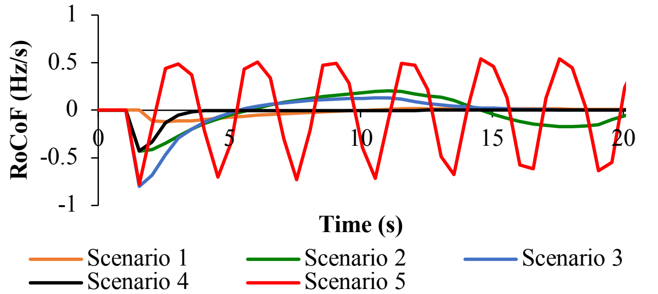

Fig. 6: RoCoF plots comparing containment capabilities at different inertia levels with different response services.

IV. DISCUSSION

According to SOF by 2025/26 the loss limit will be 650 MW about 25% of the time, in order to comply with the practical RoCoF limit of ±0.125 Hz/s; leading to curtailment of loss risk to comply. National Grid in [5] puts the cost of curtailing loss risk at £268m per annum by 2020, expected to increase year by year. Synchronous compensators are a potential solution that provides a range of system benefits [18]. It is plausible that implementation as the single solution to the issues of a very low (sub 75 GVAs) inertia GB power system would not be commercially viable, and indeed, the optimal solution may require a range of complimenting options.

While it is likely that the practical RoCoF limit will be relaxed in the future, there is no indication as to when or how this will happen, and at what cost. Meanwhile, the costs to system security are increased because the GB power system already experiences operational scenarios where loss risk has to be curtailed for system security. In the meantime existing synchronous generators that are considering decommissioning could convert their stations to synchronous compensators, providing inertia alongside other benefits. Similarly, there may be an incentive for new installations at key locations across the power system. However, locational placement raises additional questions regarding regional variations in service requirements.

The paper shows that conventional frequency response services are unsuitable for adequately containing a normal loss risk as RoCoF approaches ±1 Hz/s. Similarly, while the study indicates the benefits of 1s service in comparison to primary response, it carries a risk at high RoCoF if the service completely replaces primary response. Although, the risk of the GB power system operating at low inertia levels sub 75 GVAs is extremely low before 2025 [9], it is possible that this may become more likely as the power system tends towards a greater percentage penetration of converter connected generation and accompanying closure of synchronous plant in the future. This raises the need for further study into how future frequency response services can be designed to accommodate such scenarios. In addition, while the 1s service as described in [17] is still under development, there are concerns raised by industry regarding the requirement to sustain a post-fault response for 20 minutes. This requirement is perceived to exclude wind only response services, while providing market signals for storage technologies – requiring more capital investments.

The next steps of this work will be to further investigate the challenges and costs of implementing solutions to the concerns raised in this paper that best fit the energy trilemma, especially regarding low inertia scenarios experiencing the maximum loss risk described by SQSS.

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