Operating a Zero Carbon GB Power System in 2025: Frequency and Fault Current

Market Needs

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1 MARKET NEEDS: FREQUENCY RESPONSE AND FAST RESERVE

1.1 Executive summary

This report reviews the GB electrical power system's frequency response and Fast Reserve services, and their suitability to meet the system needs, now, an in 2025. It also discusses the evolution of ancillary service markets, analysing planned changes and those recommended by the authors.

The GB power system is currently experiencing operational challenges, and the challenges associated with the changing power landscape have arrived sooner than expected. These operational challenges aren't unique to GB, indeed, Australia and Ireland are adopting their own approaches to meet their systems' changing needs, as the penetration of non-synchronous generation increases in their power systems.

As indicated in earlier Work Packages of this project, NGESO is reviewing response and reserve services. Their proposed frequency response "end-state" services Dynamic Restoration (DR), Moderation (DM) and Containment (DC) are designed to replace existing response services, and their introduction is expected soon. Fast Reserve is also under review, though its direction is unclear.

1.1.1 Key findings

Frequency Response services

- Needs for frequency response will increase substantially over the coming decade, both in terms of volume, and required speed of activation
- New entrants will provide most of the "end-state" services, as many incumbents lack the technical capability to do so. Ideally, new entrants will comprise a diverse range of technologies
- Proposed market arrangements for the "end-state" services DC, DM & DR, have positive features:
    - The closer-to real time trading will enable a broader range of technologies to participate, compared to the current commercial frequency products
    - Potential un-bundling of upward and downward DC
    - Pay-as-clear auctions
- However, the proposed arrangements are not altogether technology agnostic and favour battery storage over wind, solar and demand response:
    - The requirement for symmetrical, rather than separate upward and downward provision, is a barrier to some providers, and appears to be contrary to the EU Electricity Markets (recast) regulation of 2019
    - The restriction in geographical area of a portfolio is detrimental to some providers
    - Controller/software updates required to provide the required response characteristic may be more onerous for wind farms than some other providers

Fast Reserve (FR)

- The needs for Fast Reserve, to perform all its current roles, is expected to increase
- Today FR is an "upward only" service; however, there is increasing need for downward reserve on similar time scales
- The industry has no vision for a new "end-state" service for Fast Reserve
- EU regulation may require Firm FR to move towards day-ahead procurement, but NGESO has requested a derogation for procurement to remain month-ahead, which would continue to prevent non-schedulable providers from participating in this market

1.1.2 Key recommendations

Market actions – frequency response, relating to the "end-state services": DC, DM and DR.

- **Unbundle upward and downward response** products
- Move to **day-ahead procurement**
- Enable **additional market platforms:** futures, and secondary/intraday trading/procurement
- Prepare to procure products with **faster activation times,** which will be required by 2020s
- Enable portfolio provision beyond a single GSP

Market actions – fast reserve

- Engage with industry to create a "**route-map**" to new "**end-state**" reserve services
- Expand Fast Reserve to include **downward as well as upward service** (separately).
- Introduce **closer-to real-time procurement**, ideally in line with frequency response products
- Publish more complete market data

Non-market actions

- **Accelerate the upgrade of old loss-of-mains settings on small generators** (0.125Hz/s and vector shift), and **extend programme** to generators on **0.5Hz/s settings** by the mid-2020s
- **Review loss risks** and system frequency limits more broadly
- Create an additional **fast (sub-second) mandatory frequency response product** to complement new "end-state" commercial services
- I**mproving forecasting and use of probabilistic forecasts** to reduce and better manage pre-fault actions
- Introduce and publish **carbon accounting for all SO actions**
- Publish system inertia estimates, operational limits and forecasts

1.2 Introduction

Frequency response is an automatic change in generation or demand to counteract changes in system frequency [1].Under normal circumstances, frequency in GB remains within the operational range of 50Hz +/- 0.2Hz. The Security and Quality of Supply Standard (SQSS) defines unacceptable frequency conditions as either:

- steady state frequency deviations outside the *statutory range, i.e.* of more than +/- 0.5Hz (illustrated in Figure 1.1); or
- transient frequency deviations outside the statutory range, lasting for longer than 60 seconds

Transient deviations, lasting no longer than 60 seconds, outside of the +/- 0.5Hz are permitted, but must occur only "reasonably… infrequent[ly]"

Figure 1.1 Pre and post-fault system frequency [2], [3]

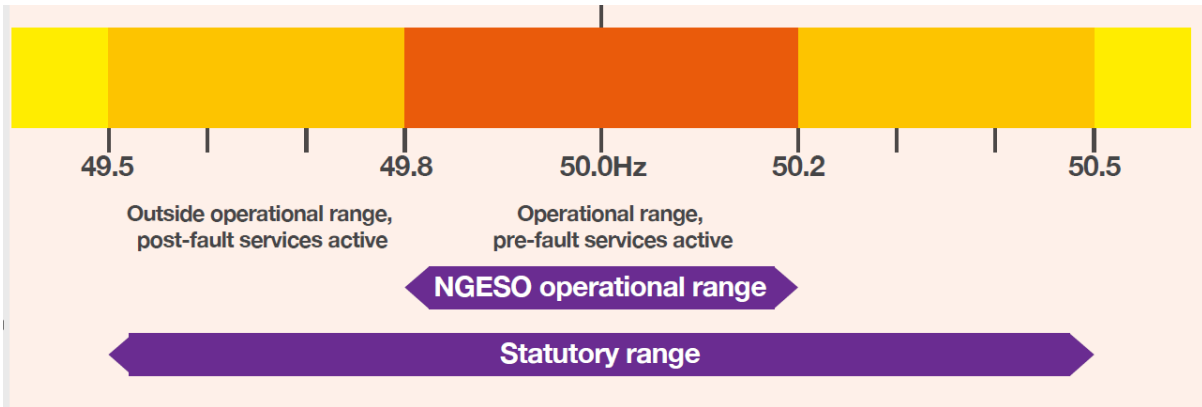


Figure 1.2 illustrates frequency behaviour in response to a disturbance to the power system. In the steady state, frequency is regulated within ±0.2 Hz of nominal 50 Hz frequency. However, when there is a significant power imbalance (a loss of power infeed in the case of Figure 1.2), frequency must be contained within acceptable frequency conditions definitions outlined by the Security and Quality of Supply Standard (SQSS) [4]. Reserve services are manually instructed to correct the power imbalance after automatic frequency response services have been used to contain the disturbance[1]. National Grid Electricity System Operator (NGESO) has a plethora of reserve services, of which Fast Reserve is the fastest-acting. Figure 1.3 illustrates frequency response and reserve services' roles, post-fault.

Figure 1.2 Illustrative frequency trace during a system imbalance [1]

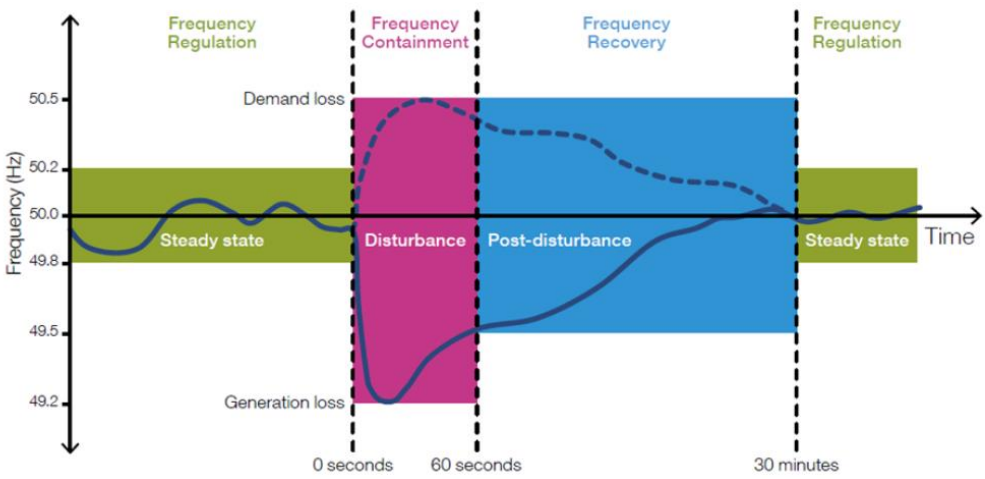
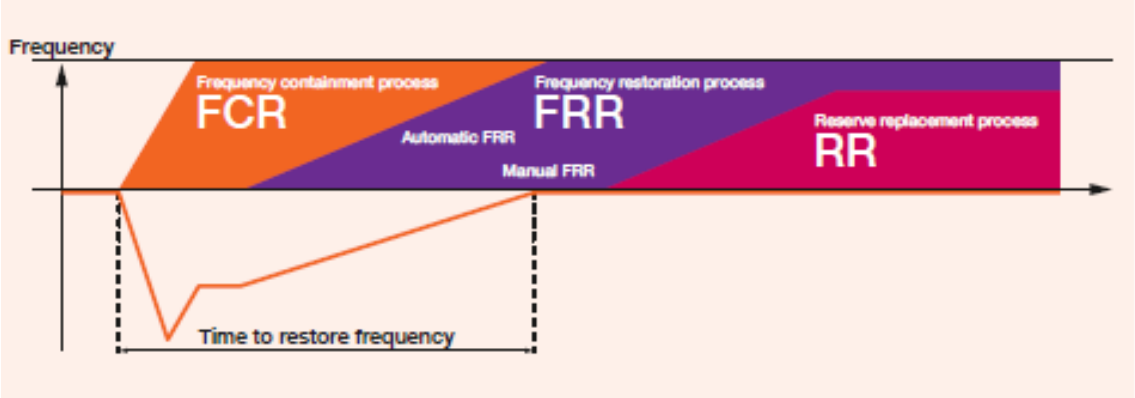


Figure 1.3 Frequency restoration process. From NGESO's Operability Strategy Report, 2019 [3]



National Grid's Operability Strategy Report, 2019 states:

"The end-to-end process [of using response and reserve services to arrest and recover from changes in frequency] … is shown above. For NGESO, the frequency containment process consists of our frequency response products (both dynamic and static). The balancing mechanism, fast reserve and STOR are key tools in the frequency restoration and reserve replacement process." [3]

Section 2 describes the current portfolio of frequency response and the Fast Reserve products, and Section 3 describes forthcoming services that National Grid has already announced. Section 4 gives a short description of some other electricity systems actions, and includes the Irish and Australian power systems as case studies. Section 5 describes *technical needs* of the GB power system in 2025 and shortly afterwards, and section 6 has comments on "*market needs*". The report ends with conclusions and recommendations.

1.3 Overview of current Frequency Response and Fast Reserve Services

National Grid ESO currently has a broad portfolio of response services. Mandatory and Commercial frequency response markets are used to procure frequency response services, and both markets are some common products; however, there are other frequency response products procured in commercial tenders or auctions. Fast Reserve is solely procured via commercial tenders. The different markets and products for both frequency response and Fast Reserve will be described in this section.

1.3.1 Mandatory Frequency Response (MFR)

All large[1] transmission-connected generators and power park modules, including HVDC systems, must have the ability to provide Mandatory Frequency Response (MFR) when required, as detailed in the Grid Code [5] in CC 8.1 and ECC 8.1 . When instructed, plants operate in Frequency Sensitive Mode (FSM), in order to provide the response service.

1.3.1.1 Operation in Frequency Sensitive Mode (FSM)

National Grid wrote in 2017 that the MFR "the Mandatory Market [MFR] is accessed within day by the SO to manage short-term variability in requirement driven by changes in the generation mix" [1]. Only dynamic frequency response services are procured via the MFR market. The MFR products include upward and downward frequency response services, over timescales and frequency deviations detailed in [6]. It should be noted that there exists no dynamic Secondary-only product or service, dynamic Secondary is the sustained delivery of Primary response beyond 30s.

Table 1.1 Mandatory Frequency Response services

Main requirements	**Types of MFR services**		
	Upward		**Downward**
	Primary	**Secondary**	**High**
Start delivering in full	Within 10s	Within 30s	Within 10s
Must sustain delivery for	A further 20s	30 minutes	Indefinitely (unless otherwise agreed with NG)
Frequency deviation – dynamic range	-0.2 to -0.8 Hz	-0.2 to -0.5 Hz	+0.2 to +0.5 Hz

The magnitude of a plant's response, and the payment it requires for being available to operate in FSM (£/MW/h) (known as the "holding payment" or "availability payment"), is submitted in advance to NGESO. Prices can be updated monthly. Plants can request amendments to their capability to provide response, though such requests should not be frequent: not generally more than once every two months, unless otherwise agreed (CUSC 4.3.1.14).

Some plants which are not obliged to provide this service, such as small or medium windfarms, opt to do so, to access the payment for this service. Participants must be Balancing Mechanism Units (BMUs) which meet the relevant technical requirements. The call-up within the day allows windfarm operators and NGESO to have confidence in availability based on short-term forecasts.

1.3.1.2 Calendar

Early in the month preceding the delivery month, NGESO publishes its requirements for MFR for the following month. Towards the end of the month (Working Day, WD 16), NGESO publishes holding rates and available response volumes from each plant, for the following month [7].Around mid-month (WD 9) following the delivery month, NGESO publishes the volumes of Primary, Secondary and High MFR held from each unit for each day [8].All units called up to deliver MFR are paid-as-bid, the month after delivery.

[1] NGET ≥ 100 MW, SPT ≥ 30 MW, SHET ≥ 10 MW

1.3.1.3 Other payments

In addition to holding payments, there are two further types of payments that MFR providers can receive: -

- Plants which need to adjust their operating positions to create headroom or footroom to deliver the response, would be called to do so via the Balancing Mechanism (BM). The units are then paid according to their bids or offers.
- Providers which use fuel would be entitled to a Response Energy Payment: a little above market rate (1.25 times) during the settlement period, for upward response, and a little below market rate (0.75 times) for downward response. However wind and other renewable generators do not receive any response energy payment (CUSC [9] 4.1.3.9A) .

1.3.1.4 Operating in Limited Frequency Sensitive Mode

Plants which are required to provide MFR, when not is FSM, must operate in Limited Frequency Sensitive Mode (LFSM). Such plants are required to provide response to high frequency events (LFSM over-frequency response, LFSM-O), at frequencies exceeding 50.4 Hz, by reducing their active power export by at least 2% per 0.1 Hz deviation over 50.4 Hz, up to 52 Hz. Response is to be delivered "as fast as possible", ideally within 10s, depending upon plant controller type and operating conditions. Details are set out in the Grid Code [5], BC 3.5.2 and BC 3.7.2. (Plants are not expected to operate below their minimum Stable Export Limit.)

Newer (post ~ 2019) plants and HVDC system owners[2], which are EU Code Users[3] are required to provide LFSM-O, as above, faster: "*with an initial delay as short as possible*". Plants are expected to start delivery within 2s, and to deliver in full within 10s. Requirements are set out in the Grid Code ECC 6.3.7.1.

EU Code Users are also required to provide under-frequency response (LFSM-U), when grid frequency falls below 49.5 Hz, where headroom and an energy source exist (Grid Code ECC 6.3.7.2). Units which can do so, are required to increase active power output, by at least 2% of output per 0.1 Hz deviation below 49.5 Hz. Response is expected to start within "minimal delay", and should be within 2 seconds.

1.3.2 Firm Frequency Response, FFR

Plants can opt to offer to provide Firm Frequency Response (FFR). This is open to BM and non-BM Units, distribution- as well as transmission-connected plant, and single and aggregated units, which can provide at least 1MW of response, and meet the relevant technical requirements. These requirements include submission of evidence of capability.

National Grid wrote in 2017: *"this [FFR] market is accessed monthly by the SO to lock in a committed level of frequency response."* [1]

The main requirements are very similar to those of MFR, shown in Table 1.1. There is an additional service: static secondary, an upward response service with the same response time and duration requirements as the dynamic secondary (though faster response may be offered), to be triggered at the frequency level offered in the tender [10]–[12].Plants submit capability information in advance, to prepare a Framework Agreement, which is necessary prior to any tender submission.

1.3.2.1 Tender Calendar

Plant wishing to submit a tender must do so on the first working day of the month preceding the delivery month. The tender period can be for a single month, or several months, up to two years [13]. NGESO informs successful applicants by mid-month (WD 12) and also publishes post-tender reports, detailing the tenders submitted, and their acceptance or rejection [14]. Market information, which summarises the contracted volumes and information from the most-recently

[2] This obligation is for "Type C" and Type D" generators, power park modules and HVDC system owners

[3] EU Code Users are bound by the European Connections Conditions (ECC) portion of the Grid Code. Older plant are GB Code Users, and are bound by the Connections Conditions (CC) portion of the Grid Code.

accepted tender round, and lists requirements for the following month (i.e. about six weeks ahead), is published later in the month (WD 15 / 18) [15], [16]. All successful participants are paid-as-bid, the month after delivery.

1.3.2.2 Windows

National Grid wrote in 2017 [1] that is was moving from allowing any windows of the providers' choice, to requiring tenders to be for standard Electricity Forward Allocation (EFA) windows. Currently, all tenders must be for whole EFA blocks. (There are 6 EFA blocks every day, each of 4 hours, starting at: 23:00, 03:00, 07:00, 11:00, 15:00 and 19:00; they are numbered 1-6, starting at 23:00).

1.3.2.3 Other payments

Response energy payments can be paid for plants that use fuel, but not generators such as wind, which do not. Calculation is set out in the standard contract terms [12]; these are calculated in the same way as for MFR.

1.3.2.4 Current purchases and volumes

The latest annual FFR Market Report [17] states that roughly 10,000 MWh per day, each of Primary, Secondary and High response, have been held in recent months. These daily totals represent average holdings of around 400 MW at any time. Looking back to totals during summer 2019, similar quantities of secondary response were held, but lower quantities of primary and high response, down to ~ 6,000 MWh/day (250 MW) and ~ 4,000 MWh/day (~ 170 MW) respectively.

Looking forward, outstanding requirements for May 2020 [15] (i.e. above those currently agreed with longer terms tenders) were around 350 MW for dynamic Primary, Secondary and High response (all at frequency deviations of ±0.5 Hz), across all EFA blocks. Static response (Secondary only) is currently only required in EFA blocks 3-6, and in smaller quantities: 110-160 MW. Requirements for the next few months are expected to be similar [16]; an increase in requirement for all three dynamic services (each up to 450 MW) is expected in October, accompanied by a drop in static response requirement.

NGESO states it might meet its requirement for static response by purchasing in the dynamic market, if economic to do so; it also states that 100 MW of dynamic Primary, Secondary and High, have been moved into the phase two auction trial weekly auctions [15], described in Section 1.3.4 below.

1.3.2.5 Prices paid

A range of prices are paid for all the response services [16]. The majority of Primary and Secondary response is paid within the £0 – 2/MW/h range; most high response falls within the £2–4/MW/h range. Payment at the "greater than £8/MW/h" range was made for ~ 1% of the primary, none of the secondary, and 0.2% of the high response procured. Average prices are shown in Table 1.2.

Table 1.2 Volumes and prices of FFR in February 2020 [16]

	Primary	**Secondary**	**High**
Total volume	236.0 GWh	152.5 GWh	302.4 GWh
Total cost	£0.44 M	£0.24 M	£1.02 M
Average cost	£1.9 / MWh	£1.6 /MWh	£3.4 /MWh
Average response held	339 MW	219 MW	434 MW

1.3.3 Enhanced Frequency Response

National Grid ran a single auction for Enhanced Frequency Response (EFR) in 2016, for contracts of four years [18]. Delivery started between April 2017 and March 2018 [19]. Any type of provider meeting the technical requirements could participate, including distribution-connected units, and aggregated units. Plants could offer between 1MW and 50MW of response [20].

EFR is a service that delivers a response that is proportional to frequency deviation. This service is fully delivered for a ±0.5 Hz frequency deviation at speeds of up to 1 second including a maximum activation delay of 500 ms. This response is sustained for 15 minutes, and the service delivers both high and low frequency response. Units are expected to be available continuously (95% availability), outside of any planned periods of unavailability. There is no built in recovery period. National Grid stated it was agnostic to technology, location and connection voltage of applicants, and allowed bidding from plants not yet operational.

Participants tendered for availability prices for the four years. There are no additional payments to cover the providers' energy costs (recharging within the deadband) though providers are reimbursed for their energy use outside of the deadband, when they are providing high frequency response service. The auction was decided on a pay-as-bid basis.

The auction received 1600MW worth of applicants for the wider deadband service (0.05Hz) option, and 4000MW of applicants for the narrower deadband service (0.015Hz). The narrower deadband service was the one which was selected. 201 MW of response were procured, at an average price of £9.44/MW/h, and a total cost of £65.95m over the four years. Almost all participants, and all successful ones, were storage sites [19], [21]. A further 26 MW of EFR have been procured separately [22, p. 81], bringing the total to 227 MW.

1.3.4 Phase two auction trial: Low Frequency Static and Dynamic Low High

A trial of two new frequency response products was launched in 2019: Phase 1 in June [23] (and since discontinued), and Phase 2 in November. Phase 2 consists of weekly auctions, which are ongoing [24]. This trial is expected to run until Q3 2021/22 [25]. These two services are open to providers of any type, which can provide at least 1MW, and meet the relevant technical requirements.

There are two products: Low Frequency Static (LFS) and Dynamic Low High (DLH). DLH is similar to the dynamic FFR products: it consists of equal volumes of Primary, Secondary and High response. The main requirements of both LFS and DLH products are listed in Table 1.3.

Table 1.3 Main requirements of Frequency Response products: Low Frequency Static and Dynamic Low High

	Low Frequency Static	**Dynamic Low High**
Trigger frequency	49.6 Hz	Frequency deviation |0.1 Hz|
Response time	Full response within 1 second	Full response within 10 seconds.
Response duration	30 minutes	As for FFR: - Low frequency – 30 minutes - High frequency – indefinitely[4]
Response magnitude	Full response at frequency < 49.6 Hz.	Linear response for deviations 0.1 Hz to 0.5Hz. Full output at |0.5Hz| deviation.

1.3.4.1 Windows

All tender offerings must be in whole EFA blocks; there are 42 blocks per tender.

1.3.4.2 Tender Process and calendar

Participants must submit pre-qualification information in advance (2 weeks prior to auction date) [26]. The tenders take place weekly, on the EPEX platform, starting on Friday nights at 23:00. The auction gate opens on Thursday mornings at 08:00, and remains open until 09:30 the next day (Friday). Auction results are published that afternoon (Friday), and delivery starts late the same evening (Friday at 23:00).

[4] Unless otherwise agreed with NGESO

The auction is "pay-as-clear". Participants have the option of allowing, or not allowing, curtailment of orders. Units' availability can be conditional on linked units being successful in the tender. For DLH and/or LFS, participants offer a single price, and availability for as many of the week's EFA blocks as they wish. Volumes of up to 20 MW are allowed from any unit. Offered volumes can differ between EFA blocks, but not prices.

National Grid ESO is the only buyer. It submits its "demand order price" ahead of the auction, which sets its desired volume to be procured, and its maximum price. If there is insufficient volume offered, or if the market clearing price is higher than the demand order price, then the order will not be met (or not met in full), and National Grid will procure the unmet response services elsewhere.

1.3.4.3 Volumes

Initially, up to 100 MW of each service is procured. National Grid intends the 20 MW cap per provider *"to promote competition and maximise learning during the first months of the Phase 2 Auction trial"* [27]. NGESO had planned to review volumes by the end of 2019/20 [25].

Tender results show that volumes bought vary from EFA block to block, with maximum purchase of both products being 100MW. Lower amounts of both products are purchased at times, especially during the daytime [28].

1.3.4.4 Prices

Prices of DLH are often higher, but more volatile, than LFS. Prices of £5-15/MWh for DLH are typical, occasionally higher or lower. LFS prices are more stable, often around £3-5/MWh, but sometimes reaching £15/MWh. Results are available from [28].

1.3.4.5 Forthcoming changes

The Response and Reserve Roadmap [25] states that:

- Unbundling high and low frequency response – this will be trialled "on or before Q3 2020/21"
- Day-ahead procurement – planning and consultation will continue during 2020/21, and a small-volume trial will happen in Q1 2021/22.

1.3.4.6 Dynamic Containment – about to be launched

National Grid ESO has announced the launch of a new frequency response service: Dynamic Containment (DC). Preliminary information has been provided, and the launch has been planned for Q1 2020/21. This product is described in Section 1.4.

1.3.5 Fast Reserve

Fast Reserve is among the portfolio of reserve services: services which are activated by instruction from National Grid ESO. Other key reserve services include Short Term Operating Reserve (STOR), Negative Reserve, and the newly-launched Optional Downward Flexibility Management (ODSM).

Fast Reserve, as the name suggests, is the fastest-acting of the reserve services. Fast Reserve is delivered following receipt of an electronic instruction from National Grid ESO. During agreed availability periods, units must be ready to receive an instruction from National Grid, and to despatch automatically.

The portfolio of reserve services includes downwards, as well as upward reserves, but Fast Reserve is an upward only service, i.e. only providing extra power (no equivalent of "high" response).

There are two Fast Reserve (FR) services: Optional Fast Reserve (Optional FR), and Firm Fast Reserve (Firm FR). They have very similar technical and delivery requirements [29]–[31], summarised in Table 1.4, but different procurement arrangements, which are summarised in Table 1.5.

Table 1.4 Main requirements of Fast Reserve provision

	Optional Fast Reserve	Firm Fast Reserve
Eligible participants	Any unit meeting technical requirements. Includes • BMUs and non-BMUs, • transmission and distribution-connected plant, • aggregated units (with single point of contact) • demand-side participants	
Start delivery	Automatically, within 2 minutes of instruction	
Minimum ramp rate	At least 25 MW/minute	
Delivery duration	Must be capable of at least 15 minutes delivery (though usually required for shorter durations)	
Delivery cessation	As for start: • start to ramp down within 2 minutes of instruction • at rate of at least 25MW/min	
Minimum size	25 MW	
Upward / downward delivery of energy	Upward only	
Recovery period	Only possible for non-BMUs providing Optional FR [32]	

Interested participants complete a pre-qualification questionnaire [33], in which they self-declare capability. If NGESO finds the plant particulars satisfactory, the provider is invited to submit "base service parameters" and fees for provision of optional service [34].

Applicants state in their Framework Agreement [32] their base service parameters, which detail plant capability (limits to delivery, response time, delivery duration, and ramp rates). They can specify a flat-rate or a profiled offering; periods of non-availability are permitted.

Table 1.5 Fast Reserve: fees, availability and procurement and delivery arrangement (up to end of 2019)

		Optional Fast Reserve	Firm Fast Reserve
fees		Stated in Framework Agreement. May be revised by informing NGESO	Stated for each tender
Fees - availability		Availability (£/hr)	Firm availability fee (£/hr) Positional payment (£/hr) Window initiation fee (£/Firm FR Window)
Fees – energy use	**BMUs**	as per Offer in BM	
	Non-BMUs	Optional Energy Fee (£/MWh) in Framework Agreement / as updated	Firm Energy Fee (£/MWh) in tender
Tenders		n/a	Monthly (with rules about longer tender-submission).
Duration of offer term		ongoing	From 1 month to 10 years
Windows / availability		As stated in Framework Agreement	As offered in tender
Flat or profiled offering		Can be flat, or profiled by SP (same for each day). Can vary by month, and "operational day type" (Mon-Fri, Sat; Sun & English Bank Holiday)	

		Stated in Framework Agreement (or any update)	Stated in each tender
Pre-tender information		n/a	NG publishes before end of month (WD 18) preceding tender month i.e. ~ 6 weeks before delivery
Tender submission		n/a	Beginning of month prior to delivery month (WD 1)
Tender results		n/a	By ~ WD 13 month ahead
Call-up to be available		In day. Providers confirms availability / not	Expected as per tender results. Confirmed at least 36 hrs in advance of first SP required
Call-up for delivery	**BMUs**	By issue of a Bid-Offer Acceptance during agreed SPs.	
	Non-BMUs	By issue of a Firm Instruction, during agreed SPs.	
Payment		Pay as bid	Pay as bid
Stacking possible?		Yes, outside of SPs agreed to be available to deliver FR	Yes, outside of tendered availability windows

1.3.5.1 Volumes and cost

National Grid ESO's reported requirement for Fast Reserve holding does not vary greatly during 2020, from April onwards: Zero during EFA blocks 1 & 2; and 300 MW during EFA blocks 3-6. Between January and March 2020 NGESO ran a procurement trial, in which much larger volumes of Firm FR were procured (150 MW during EFA blocks 1 and 2; 60 0MW during EFA blocks 3-6) [35], [36].

Monthly utilisation of all Fast Reserve (both types together) over the past year have been 11,000 to 30,000 MWh per month, with particularly high volumes (around 25,000 MWh per month) during the last 3 months, Jan-March 2020 [37]. June – December 2019 saw procurement of 10-15,000 MWh per month of Optional FR, and 4,000 – 8,000 MWh per month of Firm FR. The last 3 months have been anomalous with the bulk of Fast Reserve alternately from Firm, then Optional Fast Reserve.

Most of the utilisation is procured for between £70 and £110 /MWh [37]. However, occasionally a price as low as <£60/MWh, or above £200/MWh, are taken up. The most common prices for both Firm and Optional FR are broadly similar. Most Optional FR providers fall in a slightly cheaper price range (£70-90/ MWh), but in some months, include some very expensive outliers.

1.3.5.2 Existing Market mechanisms – who can participate?

Optional Fast Reserve can be offered by plant with variable resources, because timescales can be compatible with weather forecast windows. Firm Fast Reserve is only open to schedulable plant, because of the requirement to tender for availability well in advance. Current providers are pumped hydro and thermal plants, with some DNO participation.

In all but non-BM providers of Optional FR, there is no option to request recovery time [32]. Any battery storage operators would have to consider how they might manage State of Energy of their equipment. However, recent market data [37] show that about half of call-ups were for up to around 9 minutes.

1.3.6 Summary of Existing Response and Fast Reserve services

The main features of the various services are summarised in Table 1.6.

Table 1.6 Summary of Frequency Response and Fast Reserve Services, April 2020. Ordered by speed of response. Any unit(s) – means any unit meeting technical and testing requirements stipulated by National Grid. These include aggregated units, which meet the conditions for that service: single point of contact and metering.

Service	Speed of response: time to full response	Duration of response	Upward or downward	Who can participate/ response size	When decided	Window	Contract Duration	mechanism
EFR	1 s	15 mins	symmetrical	Any unit(s), 1-50MW	2016, "one-off"	Near continuous	4 yrs	Single auction pay-as-bid
LFS (Phase 2 trial)	1 s	30 mins	upward	Any unit(s), 1-20MW	Day to week ahead	EFA blocks	1 week *(small daily trial 2021)*	weekly auctions *(some daily in 2021)* pay-as-clear
MFR LFSM-O	"as fast as poss." ideally 10s	As long as possible / needed	downward	Obligatory for "large" plant, when not in FSM	Freq. >50.4Hz	n/a	Always. Grid Code.	Obligatory (is it done?)
MFR LFSM-U	"as fast as poss." ideally start in 2s	As long as possible / needed	upward	Obligatory for "large" EU Code Users, when not in FSM	Freq. <49.5Hz	n/a	Always. Grid Code.	Obligatory
MFR high	Within 10 s	Indefinite	Downward	BMUs. Obligatory for "large" plant	"in day"	As called	Ongoing. (Monthly updates)	Price offered in advance. NG "calls up" in day
FFR high	Within 10 s	Indefinite	downward	Any unit(s)	At least month ahead	EFA blocks	1 month – 2 yrs	Monthly auctions, pay-as-bid
MFR primary	Within 10 s	Further 20s	upward	BMUs. Obligatory for "large" plant	In day	As called	Ongoing (Monthly updates)	Price offered in advance. NG "calls up" in day
FFR primary	Within 10 s	Further 20s	upward	Any unit(s)	At least month ahead	EFA blocks	1 month – 2 yrs	Monthly auctions, pay-as-bid
DLH (Phase 2 trial)	Within 10 s	30 mins	Symmetrical *(some unbundled later 2020)*	Any unit(s), 1-20MW	Day to week ahead	EFA blocks	1 week *(small daily trial 2021)*	weekly auctions *(some daily in 2021)* pay-as-clear
MFR second-ary	Within 30 s	30 mins	upward	BMUs only. Obligatory for "large" plant	In day	As called	Ongoing. (Monthly updates)	Price offered in advance. NG "calls up" in day
FFR second-ary	Within 30 s	30 mins	upward	Any unit(s)	At least month ahead	EFA blocks	1 month – 2 yrs	Monthly auctions, pay-as-bid
Fast Reserve - Optional	Start within 2 mins, ramp at least 25MW/min	15 mins or as called	upward	Any unit 25MW+	In day	By SPs	ongoing	Price offered in advance. NG "calls up" in day
Fast Reserve - Firm					At least month ahead	By SPs	1 month *(till end 2019, up to 10 yrs)*	Monthly auctions, pay-as-bid

1.3.7 Volumes procured and cost

Taking February 2020 as a "snapshot", a summary of volumes and prices paid for all the services discussed in this section is provided in Table 1.7 and Table 1.8.

Table 1.7 Frequency Response services in February 2020. Holding volumes and pricing information

Service	Holding Volumes procured Feb 2020, MW	Holding Volumes procured Feb 2020, GWh	Total tendered / offered volume incl. rejected	Average holding price paid	Total holding payments	Holding Price Range	Types of provider	How much is low-carbon	referenc e
EFR	227 MW not including downtime	~158 GWh	4,000 MW	£9.44/ MW/h;	£1.31M	£7–£45 / MW/h	Storage	all	[19], [22, p. 81]
LFS (Phase 2 trial)	30-75 MW at any time, av 50MW	34.6	Not clear from mkt info	£4 /MW/h	£0.14M	£3 - £5 / MW/h	Incl. aggregator s	Much?	[28]
MFR LFSM-O	Vol. available – most of transmission generation?	n/a	n/a	n/a	n/a	n/a	Large plant: all types	Little?	
MFR LFSM-U	Vol available – new plant since summer 2019?	n/a	n/a	n/a	n/a	n/a	New large plant	?	
MFR high	n/a	302.4	8,100 MW[3]		£1.01M		CCGT, coal, biomass wind.	~ 20%	[38], [39]
FFR high	Retrospective: av. 434MW To fill month-ahead: 238-326 MW	302.4	1,400 MW (not all at same time)	£1.02M / vol = £3.40/ MWh	£1.02M	£0 - >8 /MW/h	aggre-gators, storage, flex dmnd	Much?	[16], [40], [41]
MFR primary	n/a	234.8	8200 MW[5]		£0.44M		Mainly CCGT.	<10%	[38], [39]
FFR primary	Retrospective: av 339 MW. To fill month ahead: 216 – 326 MW	236.0	1,600 MW[6]	*£0.44M / vol =* **£1.90/ MWh**	£0.44M	£0 - >8 /MW/h	aggre-gators, storage, flex demand	Much?	[16], [40], [41]
DLH (Phase 2 trial)	7-100 MW at any time Av 53MW	37.0	Not clear from mkt info		£0.32M	£5 - £16 / MW/h	Incl. aggregator s	Much?	[28]
MFR second-ary	n/a	153.9	10,700 MW[3]		£0.24M		Mainly CCGT	<10%	[38], [39]
FFR second-ary	Retrospective: av. 219 MW. To fill month ahead: 210-320 MW	152.5	1,600 MW (not all at same time)	*£0.24M / vol =* **£1.60 / MWh**	£0.24M	£0 - 6 /MW/h	Schedul-able plant, storage, flex demand	Much?	[16], [40], [41]

Table 1.8 Fast Reserve services in February 2020. Holding volumes and pricing information

Service	Holding Volumes procured Feb 2020 MW	Holding Volumes procured Feb 2020 GWh	Total tendered / offered volume incl. rejected	Average utilisation price paid	Total utilisation payments	Utilisation Price Range	Types of provider	How much is low-carbon	referenc e
FR Opt.	n/a	19.8	Not published	£105 /MWh	~ £1.9M	£100 - >£110 /MWh	Not published	Not known	[35], [37]
FR Firm	~ 500 MW (EFA blocks 3-6. Usually 300MW)	5.3	Not published	~£100 /MWh	~ £0.56M	£60- >£200 /MWh	Pumped hydro & thermal plant; DNO	Variable, can be high	[35], [37]

[5] Assuming all plants are on, and operating at full "genset de-load" capability. Some plants prohibitively expensive. These figures will be overestimates.

[6] Total of all capabilities of all successful plants, at 0.5Hz deviation. Plants do not run all the time, so this total is an overestimate.

Quoted prices for Firm Frequency Response differ greatly from Fast Reserve because they are measuring different quantities. The frequency response prices are for being ready to deliver; for Fast Reserve, 'utilisation' refers to actual delivery. The monthly market data reports do not give details of availability payments. Holding volumes for all services vary between months and between EFA blocks. Commercial services holdings are published in detail.

Frequency response holdings are primarily 200 MW symmetrical EFR, with an additional ~ 50 MW of upward from LFS. Primary (upward) around 340 MW, and secondary ~ 220 MW. High (downward) response volumes were ~ 430 MW. Fast Reserve volumes held were around 500 MW in February; around 300 MW has been typical in the recent past.

There are insufficient published market data for either Mandatory response, or optional Fast Reserve, to deduce holdings on a MW basis. However, published utilisation data show similar utilisation of Mandatory and Commercial frequency response services (with the exception of "fast" services), but much greater utilisation of optional Fast Reserve compared with commercial Fast Reserve (by a factor of 4).

1.3.7.1 Payment totals: Frequency Response

Total holding payments for the month of February 2020, for MFR, FFR, EFR, and Phase 2 trial products, are estimated to be £5.2 million, from the monthly market information reports for FFR, Phase 2 trial products, and EFR market information published in 2016. This total is roughly similar to totals in March 2020's MBSS report, in Table 1.9.

Table 1.9 Frequency Response expenditure, during February 2020, according to March 2020 MBSS report [42]

Frequency Response Service, category	Payments, £M	Comment
NBM FFR (Tendered)	1.59	Included in holding payments
BM FFR Response Energy (Tendered)	0.25	
BM FFR (Tendered)	1.44	
NBM Other Response (Commercial)	0.46	
BM Other response (Commercial)	0.00	
BM Demand side response (Commercial)	0.00	
NBM EFR (Commercial)	0.68	
Interconnector response (Commercial)	0.00	
BM EFR (Commercial)	0.98	
Hydro pump de-load	0.34	
Hydro spin gen with LF	2.72	
BM generator response energy (Commercial)	0.03	
BM generator response energy (Mandatory)	0.13	
BM generator response (Commercial)	0.06	
BM generator response (Mandatory)	1.70	
BM - response	2.25	

The MBSS report shows that other categories of expenditure on frequency response services are very significant, in particular: hydro spin gen, BM Response, and Mandatory BM Generator response, which totalled approaching £7 M for Feb 2020.

1.3.7.2 Payment totals: Fast Reserve

Fast reserve payments (for utilisation only) are estimated from Fast Reserve monthly market information reports, to be £2.5 million. MBSS data list additional categories of Fast reserve payments, listed in Table 1.10.

Table 1.10 Fast reserve expenditure, during February 2020, according to March 2020 MBSS report [42]

Fast reserve service, category	Payments, £M	Comments
NBM Firm FR utilisation (tendered)	n/a	

NBM Firm FR avail + Nom (tendered)	n/a	Quoted as "£0". It is expected these figures might be updated in later reports.
BM Firm Fast Reserve (Tendered)	0.21	Taken in aggregate, these figures are consistent with utilisation totals in monthly market data reports
NBM Optional FR Utilisation (Commercial)	1.35	
NBM Optional FR Utilisation (Commercial)	1.08	
BM Optional FR (Commercial)	0.00	
Hydro Spin Gen no LF (Commercial)	4.89	No information about these on "Fast Reserve" part of NG's website; excluded from market information reports
BM – Fast reserves	0.96	

1.3.7.3 Comment on payment totals

There is information available from monthly market information reports, and in MBSS reports. The monthly market information reports only include some categories of information. This is particularly true for Fast Reserve, which lists utilisation payments but not holding payments. Further categories of payment for both services are listed in MBSS reports.

It would be very helpful to the industry and observers if categories of payment types were standardised over all types of reports, and if the monthly market data reports gave full information, including availability, nomination and delivery payments, for all categories of response and Fast Reserve.

1.4 National Grid's vision for balancing products in 2025

National Grid ESO has outlined a number of changes to balancing services in a series of publications that begun with the System Needs and Products Strategy in 2016. In this section, we summarise NGESO's most present vision of frequency response and Fast Reserve services in 2025.

1.4.1 Frequency Response

National Grid ESO has announced major changes to its procurement of response and other ancillary services, in an overhaul already underway in 2017 [1], [43]. More recent publications [25], [44] describe three new "end-state services" that are expected to be launched, starting this year. They are:

- Dynamic containment (DC)
- Dynamic regulation (DR)
- Dynamic moderation (DM)

Their features are summarised in Table 1.11 and Table 1.12.

Table 1.11 Summary of NGESO's proposed "end-state" frequency response services

Service	Nature of response	Frequency deviation range	Speed of response: time to full response	Duration of response	Purpose	Upward or downward	Expected launch
DR	Dynamic within frequency deviation range	+/- 0.015 - 0.1 Hz	10 s	Indefinite	To correct continuous but small deviations in freq.	Symmetrical	Design ongoing thro' 2021
DM		+/- 0.1 - 0.2 Hz	0.5 s to 1 s	15-20 mins	To manage sudden imbalances	Symmetrical	
DC		+/- 0.2 - 0.5 Hz		15-20 mins	Post-fault – after a significant freq. dev'n.	Symmetrical *(Maybe later: high and low, unbundled)*	Q1, 2020/21

Table 1.12 NGESO's proposed "end-state" frequency response services: procurement and volumes

Service	Who can participate / response size	When decided	Duration of agreement	Windows	Procurement mechanism	Expected volume
DR	Any unit(s), 1MW+, at same GSP	Day- to week-ahead	1 week. *(Maybe later: 1 day.)*	EFA blocks	Weekly auctions, as per Phase 2 trial. *(Maybe later: daily.)* Pay-as-clear	At first: ~250MW each. Later: scale up to 1GW each.
DM						
DC						

Further guidance on Dynamic Containment, the first to be launched, is available [2], [45], [46]. Precise details are still under development. NGESO states in [25],

"We are designing this suite of services [DC, DR, DM] to offer opportunities for market participation to a diverse range of technologies and asset capabilities, while recognising the value of faster-acting response services in supporting the operability of the electricity system. In Q1 2020/21 we will engage with external stakeholders on our vision for these end-state frequency services and take industry feedback into our detailed implementation plan.

As part of the development of the new suite of frequency response services, we aim to ensure that their design enables procurement from diverse providers including variable generation, storage and demand-side participants…. We will therefore publish our strategy on mitigating barriers to entry for frequency response services in Q4 2019/20."

Alongside the introduction of the new services, some existing ones will be phased out:

- FFR is already being replaced in part by the Phase 2 trial products: it is expected to be phased out by Q4 2021/22 [25]
- EFR contracts were for 4 years, starting between April 2017 and March 2018 [19]. Thus, all contracts are expected to lapse during 2021 and early 2022
- The phase 2 trial, launched in November 2019, is expected to run for two years, up to Q3 2021/22 [25]

MFR services will remain in place, though proposals for their reform are notably absent from recent roadmap documents. The ESOs apparent lack of within-day access additional fast-acting frequency response (faster than mandatory Primary response) is something we address in our recommendations.

1.4.1.1 Uncertainty over day-ahead procurement and unbundling

NGESO's Response and Reserve Roadmap [25] states *"we will likely procure high frequency and low-frequency versions of [DC] separately."* However, more detailed information on DC [2], [46] is far more cautious, suggesting this change is a possibility to be decided later.

Similarly, on the possibility of moving from week-ahead to day-ahead procurement, the Response and Reserve Roadmap states this is likely for the end-state services, and that day-ahead procurement will be trialled for a small volume of Phase 2 product(s) in Q1 2021/22. However, the guidance for DC suggests day-ahead procurement is an option to be considered later.

1.4.1.2 Monitoring requirements

Providers of new services are being required to have 20 Hz metering, which is far more granular than current requirements of 1 Hz or less. This enhanced visibility is an opportunity for National Grid to know details of availability, delivery and non-delivery. The events of August 9 2019 highlighted possible compliance issues, which the ESO will be able to identify more easily with higher resolution metering. It is not yet clear whether this level of monitoring (and associated communication requirements) will present difficulty to some providers.

1.4.1.3 Locational requirements

Aggregation of units is allowed, but only for distributed resources connected to the same GSP. This is a new requirement – for other services, aggregated units within the same GSP zone were allowed. National Grid argues this requirement is needed to enhance visibility of offering. For some providers, notably wind and solar, this may present a significant barrier. Furthermore, aggregating BMUs with a GSP group would enhance the reliability of response and reserve services from wind farms.

1.4.1.4 Battery sizing

Technical guidance on battery sizing and possible de-rating factors is expected from NGESO. Generic guidance suggests an expectation of provision of new "end-state" services entirely or predominantly by batteries.

1.4.2 Fast Reserve

Provision of Fast Reserve is currently undergoing major changes. Some of these are part of NGESO's own developments, which have been ongoing for several years, others are being driven by recent European legislation. Information available from National Grid is summarised below.

1.4.2.1 National Grid's longer term plans for Fast Reserve

In 2017, National Grid stated a desire to rationalise reserve services, including Fast Reserve [1]. NGESO:

- Stated a desire to move to one-month tenders, because the mix of short and long term tender durations "is problematic, adding complexity"
- Wished to move to EFA block tender windows (as for frequency response products)
- Wished to rationalise products, with potentially new products operating in sub-15 minute timescales, and the pan-European reserve products MARI and TERRE meeting needs for slower-acting reserve
- Recognised that advance tendering was a barrier to wind and other potential new entrants.
- Was cautiously considering, as a possible future improvement, moving to week-ahead or day-ahead procurement, to lower a barrier to market entry to non-traditional providers (such as wind and solar). Caveats were:
    - Auction trials on close-to-real-time frequency response services [the Phase 2 trial, which started November 2019], were to go well; and
    - Such measures would have to fit with wider changes to reserve products envisaged

The 2019 Roadmap [25] stated a desire to overhaul the current Fast Reserve services, to produce a single transparent service.

There remains a plethora of reserve services. The process of rationalisation and simplification of these services is at a very early stage. Early work on the reserve portfolio is prioritising the integration of the pan-European services MARI (Manually Activated Reserves Initiative) and TERRE (Trans-European Replacement Reserve Exchange) into the GB service portfolio. We assume, changes to the other reserve services, including Fast Reserve, will be tabled in the future.

1.4.2.2 Electricity Markets Regulation (recast) – suspension of tenders

Tenders longer than one month have not been accepted since the end of 2019 [35]; the current tender rounds have been suspended altogether until further notice, with the last tender due to expire in March [47].

The driver for these changes is reported [35] as being a piece of European legislation*: The Regulation on the internal market for electricity (recast)*, of June 2019, which is part of the Clean Energy Package [48]. Article 6 states an intention to make balancing services accessible to new entrants, including weather-dependent renewables. Article 6(9) has a requirement for balancing services to be procured no more than day-ahead, and for no longer than one day, unless a derogation is granted by the Member State's regulator. Derogations may be granted if needed to ensure security of supply, or to improve market economy. However, even with such a derogation, procurement can only be up to month-ahead and for up to one month; the regulation sets limits to the proportion of balancing services which can be acquired with such a derogation. More information about this piece of legislation is given in Section 1.7.2.

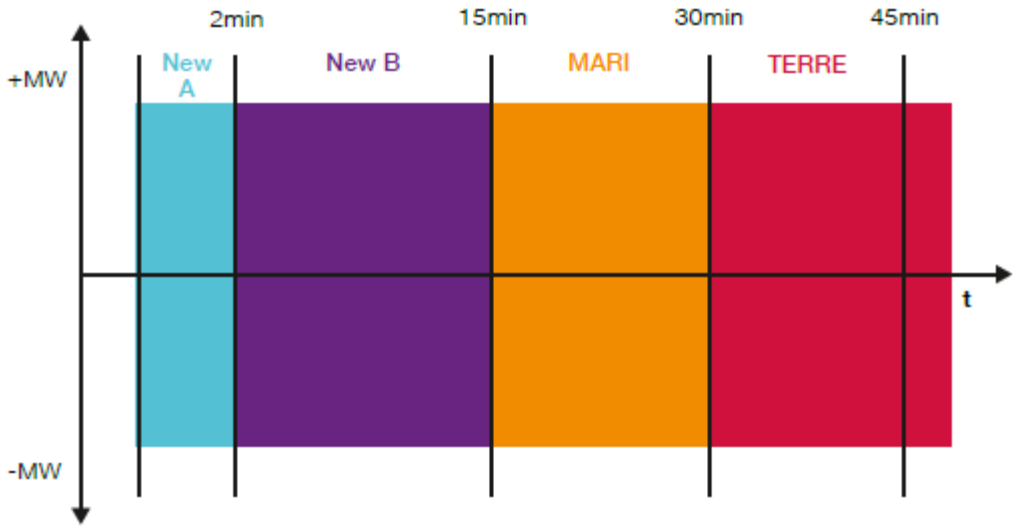
National Grid ESO states it has applied to Ofgem for such a derogation, for the procurement of Fast Reserve on a month-head rather than day-ahead basis, and discussions are ongoing [35]. Re-instatement of monthly Firm Fast Reserve tenders appears to be conditional on award of this derogation from Ofgem.

1.4.2.3 Possible end-state for Fast Reserve

Unlike for Frequency Response, there is currently no clear "end-state" for Fast Reserve. Hints as to how this may emerge are available from National Grid's Product Roadmap for Frequency Response and Reserve, 2017 [1], the Response and Reserve Roadmap, 2019 [25], and December 2019's Operability Strategy Report [3].

Figure 1.4, from NGESO's 2017 *Product Roadmap for Frequency Response and Reserve*, suggests a future service *may* include downward as well as upward reserve. However, in the last couple of months, National Grid has created a new downward only reserve service (circumstances described in more detail in Section 1.6.4): we might continue with separate upward and downward products. There is no further information about projected volumes or market mechanisms.

Figure 1.4 National Grid's 2017 view of possible "end-state" reserve services [1]



1.5 Overview of arrangements in comparable power systems

There is a considerable variety in requirements for frequency response, and the manner in which response services are obtained, as illustrated in Figure 1.5, a 2018 summary from Lawrence Berkley National Laboratory in the US [49]. Many systems rely entirely on market provision; others have some or all response obtained as a mandatory requirement.

There are also differences between countries' operational limits. For example, GB currently needs to constrain largest credible loss, to ensure the resulting RoCoF would not exceed 0.125Hz/s, pending upgrading old loss-of-mains protection settings on small generators (to ride-through for RoCoF of at least 0.5Hz/s, for newer equipment, 1Hz/s). Once this update programme is complete, a power imbalance resulting in up to 0.5Hz/s would be tolerable to GB power system's operation. A selection of ride-through requirements for generators in other countries is summarised in Table 1.13. This table shows that several countries mandate small generators must remain connected during disturbances that result in a much higher RoCoF than is allowed in GB, up to 2.5 Hz/s in Denmark.

This section gives more detail on two individual power systems: those of Ireland and Australia. Ireland is chosen because its power system has, arguably, greater challenges than GB's, owing to its small size, limited interconnection and high penetration of wind. Australia was chosen because of its National Electricity Market's comparable size and renewables penetration to the GB grid.

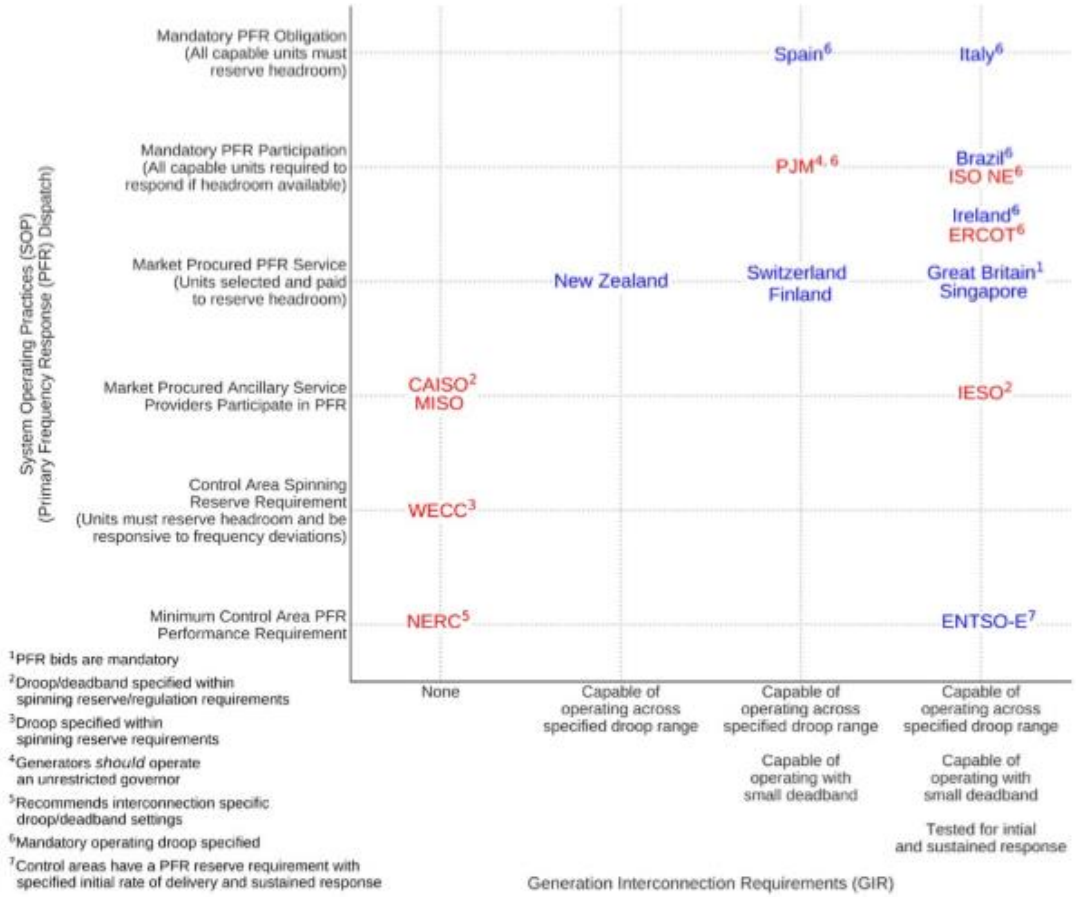
Table 1.13 RoCoF ride-through requirements in several countries, 2018 [49]

Table 9. ROCOF Ride-Through requirements

Region	ROCOF Ride-Through Requirement	Status/Applicability
Denmark[42]	2.5 Hz/s	Active
Finland[43]	2 Hz/s	Active
Ireland[44,45]	0.5 Hz/s 1 Hz/s	Active Approved for implementation
Spain[46]	2 Hz/s	Proposal

[41] Eirgrid and Soni (2014): *Consultation on DS3 System Services Interim Tariffs.*
[42] ENERGINET (2017): *Technical Regulation 3.2.3 for Thermal Plants Above 11 KW. Revision 1.*
[43] Fingrid (2013): *Specifications for the Operational Performance of Power Generating Facilities VJV2013.*
[44] EirGrid (2015) EirGrid Grid Code
[45] Commission for Energy Regulation (2014): *Rate of Change of Frequency (ROCOF) Modification to the Grid Code.*
[46] Red Eléctrica de España S.A. (2017): *Desarrollo de los requisitos técnicos del Reglamento (UE) 2016/631.*

Figure 1.5 Summary of Primary Frequency Response provision and basic requirements, in several US and other power systems [49]



1.5.1 Ireland

Ireland has a single electricity system (Eirgrid Group) with system operators Eirgrid in the Republic, and SONI in Northern Ireland. Its runs at roughly 10% of GB grid demand [50], has high wind penetration, and so, for some years, has considered the challenges of maintaining stability on a small grid within decreasing inertia, for example in [51].

1.5.1.1 System Services

Ireland's electricity system operator, Eirgrid, has a programme, "DS3" ("Delivering a Secure Sustainable Electricity System"), which aims to facilitate higher levels of renewable generation on its system [52]. System Services sit within the DS3 programme.

Eirgrid and SONI write that "events up to 1Hz/s may occur and thus it is imperative that the quality of the FFR [Fast Frequency Response] provision provided is... as good as it can be..." [53]

There are 14 services, which cover frequency response, reserve, "ramping", reactive power, post-fault active power, and inertia provision [53], [54]. The services most relevant to GB frequency response and fast reserve are listed in Table 1.14.

The Fast Frequency Response service can be either dynamic or static. Prospective providers offer one or the other. The following types of plants are eligible to offer fast response and reserve services [54]:

- Synchronous plant
- Wind generators

- Solar PV units
- Storage units
- Demand-side units, including those aggregated

The System Operators state aims to make provision technology-neutral [53]. Providers of the slower-acting services (TOR-2 and slower, defined in Table 1.14) are required to be registered in Ireland's Single Electricity Market (equivalent of the BM in GB) [54]. Providers are invited to submit forecasts of their expected availability to provide the system services, within the day. There is an expectation that wind and solar units' availability will vary and adjustments to settlement payments are made according to units' estimated availability [54]. Storage units can also provide services: their recharge limits must be agreed by the TSOs. A consultation is currently running, on minor amendments to the current protocol [53].

1.5.1.2 Tender Process

An overview of the tender process for system services is given in a webinar, delivered late 2019 [55]. Contracts run for six months. There is no mention of availability windows, so presumably all providers are available continuously.

Participants, having obtained prequalification, including meeting requirements for testing, may submit tenders. Tenders must contain technical information about their unit and its capability. Successful participants enter into a DS3 System Services Agreement with either Eirgrid or SONI, according to their location. The most recent tender had a deadline in early January, 2020, with notification to successful participants promised by the end of February 2020, for contracts to begin 1st April.

Table 1.14 Summary of System Services in Ireland: Frequency Response and the faster reserves. (Other services are omitted)

	Delivery time after trigger or signal [53], [54]		Winter 2019/20 tender [55]		Payment rates, 2019-20, "£/MWh" [56]
	to deliver in full within	to continue up until	Max volume - Normal Operation	Max volume requested by TSO	
Fast Frequency Response (FFR)	2 s	10 s	75 MW	100 MW	£1.98
Primary Operating Reserve (POR)	5 s	15 s	75 MW	100 MW	£2.97
Secondary Operating Reserve (SOR)	15 s	90 s	75 MW	100 MW	£1.80
Tertiary Operating Reserve 1 (TOR1)	90 s	5 mins	75 MW	100 MW	£1.42
Tertiary Operating Reserve 2 (TOR2)	5 mins	20 mins	75 MW	100 MW	£1.14
Replacement Reserve (De-synchronised) RRD	20 mins	1 hour	300 MW	n/a	£0.51
Replacement Reserve (Synchronised) RRS	20 mins	1 hour	300 MW	n/a	£0.23

The pre-tender information states: "*as the payment rate for each System Service will be fixed [as set out in* [56]], *responses will be assessed… upon quality (technical compliance) only."* (These payments are slightly higher than most GB FFR payments; but lower than the current payments for DLH and LFS.)

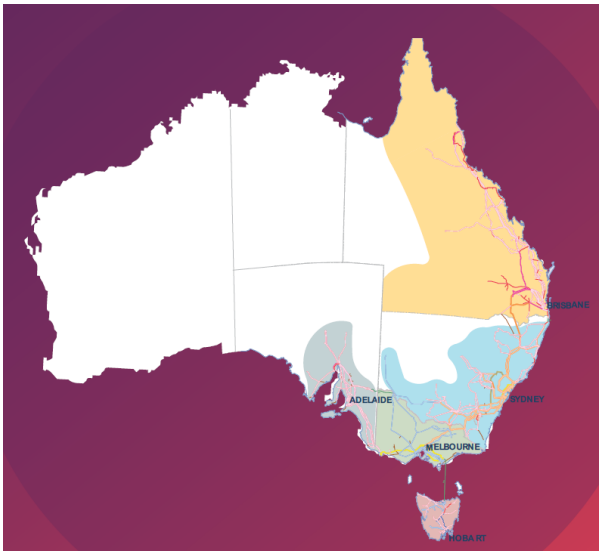
1.5.1.3 Balancing Market

In addition to the system services, changes over timescales of minutes to hours can be effected within Ireland's equivalent of the Balancing Mechanism, called the "Balancing Market", operated by Ireland's Single Electricity Market Operator (SEMO). Ireland's balancing market operates in a similar fashion to GB's [57], [58].

1.5.2 Australia

Australia's National Electricity Market (NEM) connects the electricity systems in five states in the east and south of the continent, as shown in Figure 1.6. The systems of the western and northern states are not part of NEM because the distances are too great [59]. The system operator is Australian Energy Market Operator, AEMO.

Figure 1.6 Map of Australia's National Electricity Market [59]



NEM's five individual state electricity systems run at an aggregated demand of roughly 30 GW [60], and had a reported total generation capacity (including rooftop solar PV) of 54 GW in 2018 [59]. Electricity is despatched in 5-minute periods. Wholesale electricity market spot prices are currently for 30 minute intervals, but are in transition to 5 minute periods by July 2021 [61].

1.5.2.1 System Services

Primary Frequency Response (PFR), analogous to primary MFR in Britain, has historically been a requirement for all major power stations, and has been required continuously whenever frequency falls outside of a deadband no larger than +/- 0.050Hz [62]. Contractual arrangements supported this provision.

In 2001, ancillary services markets were established, which included eight different frequency control services (described below). It was decided that these markets would provide all the necessary response services. Major power units' obligation to provide PFR was removed, though PFR remained an optional service, which many existing power stations continued to provide.

1.5.2.2 Commercial Frequency Control Products.

There are eight distinct markets for Frequency Control Ancillary Services (FCAS), described in 2015 in [63] . The two "Regulation" services operate, upwards and downwards, within +/- 0.015Hz, to correct minor disturbances in frequency. The six "contingency" services also operate upwards and downwards: "fast" (within 6s); "slow" (within 60s) and "delayed" (within 5 minutes), following a major drop or rise in frequency.

Prospective participants must pre-register, then submit a FCAS offer or bid in the relevant market. The requirement for all eight services is set in advance. Bidding is done day-ahead [64], for 5-minute settlement periods. Pay-as-clear rules apply.

1.5.2.3 Recent developments

In 2018-19, AEMO reported a significant decline in the frequency performance of the power system. AEMO states "On their own, market ancillary services have proven inadequate to address the challenges AEMO faces to control power system frequency" [62]. [65], [66] describe the increasing challenges posed by high penetration of non-synchronous generation onto the power system, including difficulties in managing frequency within an increasingly low-inertia system.

Remedial actions include: -

- Re-introduction of mandatory Primary Frequency Response (PFR), soon to be a "near-universal" requirement across the generation fleet. In process, 2020-21 [62], [65] *(Note: "generators are not required to reserve headroom to provide PFR but where they are safely and stably capable of providing PFR .... they would be expected to do so"* [62]*)*
- Major revision of the commercial services, "to ensure the required speed and volume match…requirements for the range of expected future operating conditions"
- Measures to support and manage system inertia. Minimum desired inertia levels in each individual state electricity system are published

1.5.3 Concluding remarks

Power systems around the world are grappling with challenges of managing increasing penetration of non-synchronous generation, much of this from weather-dependent renewable sources. System operators and regulators are pioneering various actions to attempt to make their power systems continue to run safely, reliably and economically.

There is no single approach or solution: power systems adopt their individual approaches. Even very liquid markets for frequency response and reserve services, as in Australia, give no guarantee of good service: the portfolio has to be suitable. It is interesting that Australia sees the need to reintroduce mandatory provision, to complement commercial services, after two decades of "market-only" frequency response. Ireland, on the other hand, has fairly long auctions for ancillary services, offering six month tenders, with rules which allow participation of renewables, and prices, which are fairly modest, fixed at the outset. These arrangements appear to meet Ireland's system needs for the time being.

We can learn from the experience of other power systems, and a broader study would be beneficial. However, the GB system will have to find its own approach.

1.6 Technical requirements for response and reserve in 2025

This section describes the technical needs we believe the GB system will have as we approach 2025 and beyond. We consider both current frequency response and fast reserve services, and those which National Grid propose to bring in by then. It is likely that it will remain more cost effective to secure the system with frequency response services rather than through re-dispatch to increase inertia and/or reducing largest losses [72].

Section 1.7 will discuss features we believe are needed for a viable market to deliver these services, and our thoughts on National Grid's proposed approaches.

1.6.1 System conditions in 2025 and 2030

1.6.1.1 Predicted levels of system inertia

A study of system inertia is beyond the scope of this report, but some reference is necessary to understand potential future needs for response and reserve services. Work Package 2 (WP2) of this project described how system inertia levels are falling: by 2025, minimum inertia levels around 70 GVA.s may be expected, according to National Grid's 2016 SoF, using 2016 FES data. Inertia levels are widely expected to continue to decline in the mid and late 2020s, as further interconnection and wind generation comes online (Table 1.15).

Table 1.15 National Grid ESO's predictions of some GB system parameters to 2030, from Future Energy Scenarios 2019 [67]

Year	**2018**	**2020**	**2023**	**2030**	**2030**
Scenario	**5-yr forecast**			**Community renewables**	**Two degrees**
Total interconnector import capacity	4 GW	7GW	8 GW	17 GW	20 GW
Total electricity storage capacity	4 GW	5 GW	6 GW	13 GW	12 GW
Total wind capacity (onshore & offshore)	21 GW	23 GW	28 GW	53 GW	54 GW

National Grid publishes predictions of inertia (in system operability framework documents, here "Operating a Low Inertia System, Feb 2020" [68]), with average inertia levels expected to fall to around 120-130GVA.s by 2030 (according to 2018 FES data). The same document suggests "typical" diurnal inertia patterns in which inertia varies +/- 50 GVA.s or so around daily average values.

WP2 found estimates including "embedded inertia" may rarely fall much below high 70 GVAs. However, future embedded inertia estimates are difficult to predict. A "safer" approach is to exclude embedded inertia, to form a "worst case" estimate. It was found in WP2 that inertia levels, excluding embedded inertia, could occasionally fall to around 30 GVA.s by 2030, in some scenarios. Predicted inertia levels are shown in Table 1.16.

Table 1.16 Predictions of GB system inertia by 2025 and 2030

Year	**Minimum inertia level**	**Average inertia level**	**Other inertia level**	**source**	**comment**
2025	~ 70 – 75 GVA.s	125 - 170 GVA.s		National Grid, 2016 [69]; National Grid SoF 2020 [68] (using current data with FES 2018)	Across all FES scenarios

		120 - 135 GVA.s		National Grid SoF 2020 [68] (using FES 2018)	
2030	~ 25 - 30 GVA.s		60 GVA.s "16% of the time"	Work Package 2 of this project	Excludes embedded inertia ("worst case") Based on modelling using a "high wind" scenario.

It would help power systems researchers if National Grid would publish more details of its own estimates for current and future system inertia levels. Of course, National Grid ESO might choose to manage system inertia levels, by constraining actions and / or use of new "inertia products" (as seen in Stability Pathfinder Phase 1 tender, launched winter 2019/20 [70]). Synchronous Inertia is significant because it is an inherent response of synchronous machines to power imbalances. As shown in Equation 1, inertia has an indirect relationship with RoCoF, i.e. at low inertia the RoCoF for a given power imbalance is higher than that for the same imbalance at higher inertia. Furthermore, securing the power system, in terms of a frequency stability, requires consideration to both the RoCoF (and therefore inertia and loss risk) and the frequency deviations as a result of a power imbalance.

$$Power\ Imbalance = \left(\frac{2\ \times Inertia}{Nominal\ Frequency}\right) \times RoCoF \qquad \text{Equation 1}$$

1.6.2 What "credible losses" are expected in 2025 and 2030?

1.6.2.1 Current and suggested future SQSS-defined losses

As Work Package 2 explains, the SQSS standards state a "normal loss" is 1.32 GW, and an "infrequent loss" is 1.8 GW. Prior to 2014, the normal and infrequent losses were 1 GW and 1.32 GW respectively. NGESO is not expected to secure against events greater than those stipulated by SQSS.

There are strong grounds for revising the size of secured losses. Revisions to "Normal loss" could consider the following factors:

1. Several interconnectors are expected to become operational in the mid-to-late 2020s, with capacities of 1.4GW. A sudden failure of a fully importing interconnector would cause an instantaneous loss of infeed of 1.4GW.
2. A sudden failure of a fully exporting interconnector would cause a "loss of outfeed" of 1.4 GW. (There is further discussion on export loss in 1.6.3.2.)

Revisions to "infrequent loss" could consider

1. Multiple failures. While such events have not been considered credible in the past, near-simultaneous large losses did occur on August 9th 2019: a repeat of such an event should be considered. Extreme weather events could also – potentially - cause multiple equipment failures.
2. Quantities of other equipment, including Distributed Generation (DG) (and / or potentially, some demand) which could reasonably be expected to trip off under unusual grid conditions. August 9th 2019 saw ~ 2GW of DG trip off. National Grid ESO has an accelerated programme to upgrade old settings (loss-of-mains detection, using vector shift, and RoCoF settings of 0.125Hz/s) on small generators, which were largely responsible for the large loss of DG on August 9th [68]. This programme will clearly reduce such behaviour in the future, but may not eliminate it.

1.6.2.2 Generators with 0.5Hz/s RoCoF settings

Even with the current programme to upgrade equipment with over-sensitive loss-of-mains protection, designed to trip at RoCoF of 0.125Hz/s, described above, other equipment could continue to cause a similar problem. There remain significant quantities of DG with "slightly less old" 0.5 Hz/s loss-of-mains settings, settings that are also allowed for some thermal plant. There is no current plan to change these settings. While not considered a major system risk at present, a credible loss on a low-inertia day, would be expected to cause RoCoF over 0.5 Hz/s by 2025, and potentially over 1 Hz/s by 2030 in "worst case" scenario, without constraining actions by the System Operator. Not changing these 0.5 Hz/s RoCoF settings on equipment is forcing the System Operator to continue to take costly actions to maintain high inertia and / or constrain largest losses. It is interesting to note that some other countries have requirements for ride through of 2 Hz/s, detailed in Table 1.13 in Section 1.5.

1.6.2.3 Interconnectors and volatile trading conditions

Interconnectors are a valuable asset to the GB system. They provide options for System Operators on both sides to undertake balancing actions, in addition to the options they can use within their own domestic power systems.

Interconnectors, like other BM participants, are required to notify System Operators of forecasted power flows at Gate Closure. The System Operator has time to deploy resources or engage in BM trades, to manage any impacts interconnector changes might have on the GB system, if needed. The following situations could arise, which might require further actions by the SO:

- "Herd behaviour": market conditions which encourage similar changes in imports or exports across multiple interconnectors; and
- Power flow reversals in interconnectors. Currently very unusual (twelve significant power reversal events during May 2019-May 2020 [71])[7], but such events may occur more often with further interconnection

Such events may require increased use of BM trades and faster-acting reserve services, both upwards and downwards, to manage changes.

1.6.2.4 What levels of RoCoF might credible events cause, by 2025 and 2030?

Section 1.6.1.1 and Table 1.16 discuss some future system inertia scenarios. Table 1.17 shows the degree of system disturbance (RoCoF) which could follow a large loss, under these low inertia scenarios, by 2025 and 2030, in the absence of NGESO actions to increase inertia or reduce the largest credible loss. RoCoF values were obtained using the swing equation, Equation 1.

Table 1.17 Potential RoCoFs which could occur following large losses in 2025 and 2030: low and minimum inertia scenarios

Year	Inertia scenario	Low and Minimum inertia scenarios	Loss, GW	RoCoF
2025	Low	90 GVA.s	1.4 GW	0.4 Hz/s
			1.8 GW	0.5 Hz/s
2025	Near-minimum	70 GVA.s	1.4 GW	0.5 Hz/s
			1.8 GW	0.6 Hz/s
2030	Low	60 GVA.s	1.4 GW	0.6 Hz/s
			1.8 GW	0.75 Hz/s
2030	Possible minimum ("worst case" estimate)	30 GVA.s	1.4 GW	1.2 Hz/s
			1.8 GW	1.5 Hz/s

[7] Gridwatch Data May 2019-2020. 5-minute resolution. Power flows in all 5 GB-connected interconnectors were inspected. A "significant power reversal" was taken as over around 75% of the maximum possible power flow reversal, over a single 5-minute time step.

These losses are credible, and do not take into account multiple losses or additional generation tripping out which could further increase their magnitude. One can discuss the likelihood of various inertia scenarios. However, scenarios with RoCoF approaching and exceeding 0.5Hz/s following a large loss appear credible by 2025, as do scenarios with RoCoF exceeding 1Hz/s by 2030.

These RoCoF values have major implications for the response services the GB system will need over the coming years, which are discussed in the next subsection. Furthermore, high values of RoCoF imply that the system frequency can quickly move from nominal 50 Hz frequency to breaching operational and statutory limits.

There are alternatives to NGESO continuing to take expensive actions to increase inertia or decrease largest loss. Widening the system frequency limits between which generators must remain connected would allow response services more time to act, and could act as a further "safety net", in addition to ensuring a suitable portfolio of ancillary services. Such work is beyond the scope of this report, but is a suggestion for further work.

1.6.3 Frequency response requirements in 2025 and beyond

1.6.3.1 Simple study of end-state services: system frequency at start of delivery

National Grid's proposed new end-state frequency response services, DC, DM and DR, if eventually having 3 GW of provision across services, both upward and downward, are expected to rapidly arrest system frequency changes post-fault.

The fastest of the end-state services can fully deliver a response, ramping up over a time interval of up to 500 ms, after a maximum detection delay of 500 ms. A major disturbance will cause system frequency to change significantly even before these services start to act. Table 1.18 shows the state the system frequency would have reached, at the time the response services would start to act, taking extreme "fastest" and "slowest" delivery, and different initial system states. The final columns display performance of a possible future response product, which acts more quickly.

Table 1.18 National Grid's proposed "End-state" frequency response services (DC, DM and DR), and disturbances causing RoCoFs of 0.125Hz/s; 0.5Hz/s and 1Hz/s. System frequency at start of delivery. Comparison with a possible future fast response service.

Disturbance causing a RoCoF	**DC & DM: Fastest response start, 0.5 s**			**DC & DM: Slowest response start, 1s**			**Possible future service, starting at 0.25 seconds**		
RoCoF *(and when it might occur)*	Frequency change in 0.5 seconds	System frequency at time response starts to act		Frequency change in 1 second	System frequency at time response starts to act		Frequency change in 0.25 seconds	System frequency at time response starts to act	
		Initial system state			Initial system state			Initial system state	
		At target frequency 50.00 Hz	At edge of operational range, 49.8 Hz / 50.2 Hz		At target frequency, 50.00 Hz	At edge of operational range, 49.8 Hz / 50.2 Hz		At target frequency 50.00 Hz	At edge of operational range, 49.8 Hz / 50.2 Hz
0.125 Hz/s *(2019)*	0.06 Hz	49.94 Hz / 50.06 Hz	49.74 Hz / 50.26 Hz	0.125 Hz	49.875 Hz / 50.125 Hz	49.675 Hz / 50.325 Hz	0.03 Hz	49.97 Hz / 50.03 Hz	49.77 Hz / 50.23 Hz
0.5 Hz/s *(2025?)*	0.25 Hz	49.75 Hz / 50.25 Hz	49.55 Hz / 50.45 Hz	0.5 Hz	49.5 Hz / 50.5 Hz	49.3Hz / 50.7 Hz	0.125 Hz	49.875 Hz / 50.125 Hz	49.675 Hz / 50.325 Hz
1 Hz/s *(Late 2020s?)*	0.5 Hz	49.5 Hz / 50.5 Hz	49.3 Hz / 50.7 Hz	1 Hz	49.0 Hz / 51.0 Hz	48.8 Hz / 51.2 Hz	0.25 Hz	49.25 Hz / 50.25 Hz	49.55 Hz / 50.45 Hz

Current SQSS rules state for a normal loss, frequency must remain within +/- 0.5 Hz of 50 Hz. By 2025, system inertia could have minimum levels in which a credible loss could cause a RoCoF approaching 0.5 Hz /s (as discussed above, and shown in Table 1.17). If the response services deliver "slow in range", towards 1 s after disturbance, or, if the system frequency has deviated prior to the event, there is a risk of statutory limits being breached even before the services have started to act.

Towards 2030, worst case scenarios suggest credible losses *could* cause the RoCoF exceeding 1 Hz/s. In such an event, statutory frequency limit would have been reached before the services start to act, even at "fast-in-range" (0.5s) response, and even if system frequency has no prior deviation. "Slow-in-range" (1 s) response, combined with prior system frequency deviation in operational range, could potentially see frequency reaching LFDD levels before any action is taken at all.

Two of the end-state services (DR and DM) act within the operational range. These services are intended to reduce pre-fault frequency deviations within this range. Further work would be needed to assess the possibility of a fault occurring while the system is on the edge of the operational range.

To allow the system to operate with an expected post-fault RoCoF of 0.5 Hz/s, the end-state services should be supplemented with some faster-acting provision, or, required to deliver a little faster, e.g. within 0.5 s or faster. This would be particularly important if frequency might commonly deviate within the operational range of +/- 0.2 Hz.

If the system were operated with an expected post-fault RoCoF closer to 1 Hz/s, loss of the largest infeed would cause the system frequency to breach statutory limits before any of the "end state" frequency response services even start to act. As highlighted by the findings from WP2, faster-acting provision would be essential in such system conditions. Existing services are adequate for containing events that result in a 0.125 Hz/s RoCoF but they are inadequate for normal loss events with a RoCoF of 0.5 Hz/s and any loss event with a RoCoF of 1 Hz/s. The ESO's proposed frequency response products, as they are defined, are adequate for any loss event with a RoCoF of 0.125 Hz/s to 0.5 Hz/s, but inadequate for normal loss events with a RoCoF of 1 Hz/s. Fast-acting **(faster than DC, DM, and DR)** frequency response services can be deployed as solutions, e.g. Improved Frequency Response, or some version of Synthetic Inertia. Alternatively, the ESO can also constrain the system inertia and/or the largest loss risk.

Work Package 2 undertook more detailed analysis of current and "end-state" frequency response services, under several credible loss scenarios. This work found that the "end-state" services are likely to be adequate much of the time up to around 2025, though faster-acting services, or SO actions, may be needed under minimum inertia conditions. Faster services, or actions to increase system inertia or reduce loss risks, will be needed towards 2030.

1.6.3.2 A high frequency event – a possible future system need?

Traditionally, major "loss" event have considered only loss of infeed, from generators. Interconnectors currently are the largest instantaneous loss risks, and, as they both import and export, a loss could be either loss of infeed or a loss of outfeed.

Increasing interconnection raises the probability of such an event. While electricity price differences between GB and continental Europe make it likely that interconnectors will import more of the time than they will export [72]; a loss in either direction is credible. Whether multiple simultaneous or near-simultaneous losses are credible, and should be secured against, is a matter for discussion.

In the event of a major loss-of-infeed (generation) which the frequency response services fail to contain within required limits, there is the "fall-back" of Low Frequency Demand Disconnection (LFDD). LFDD involves some automatic demand disconnections activated in stages by relays set at trigger frequencies from 48.8 Hz downwards. Only the first stage of LFDD actions were needed on August 9th 2019, when multiple near-coincident losses of transmission and distribution-connected infeed, overwhelmed frequency response services.

There is no equivalent of LFDD as a back-up for high frequency events. All generators disconnect at the same over-frequency limit of 52 Hz, although they are mandated to reduce output dynamically before this. In the worst-case

scenario where this mandatory dynamic response is insufficient to contain the frequency below 52 Hz, many generators would disconnect and partial or complete blackout would ensue.

Detailed examination of this scenario is beyond the scope of this project; however, we make the following observations:

- National Grid is currently taking actions to reduce largest loss risks, or to increase system inertia, when necessary to reduce the disturbance a credible loss would cause, and apparently will continue to do so
- The new "end-state" services provide equal upward and downward response. We believe these "end-state" services will be adequate, under normal conditions up to the mid-2020s, though there is a risk of instability and lack of containment for some loss conditions during minimum inertia conditions by 2025

<u>Mandatory Frequency response: Limited Frequency response LFSM-O.</u>

The Grid Code mandates that all "large plant" covered by mandatory requirements, when not delivering frequency response (when plant would be in Frequency Sensitive Mode, FSM), must operate in Limited Frequency Sensitive Mode (LFSM).

All large plants, while operating in LFSM, are required to provide LFSM Over-frequency response (LFSM-O) in the event of a significant over-frequency event. Plants must reduce active power outputs, in the event frequency exceeding 50.4 Hz, and deliver response (i.e. reduce their output) in proportion to the deviation. Delivery should be "as fast as possible", ideally within 10s, depending on plant governor type. Stricter delivery times apply to newer plant connected under the European Connections Code.

In theory, LFSM could support response services, in the event of a major high frequency excursion. As this requirement applies to all large plant not already delivering response, the resource is, apparently, huge: most of the generation on the system. However, there are major uncertainties:

- Whether response would act quickly enough. This is an increasing concern as system inertia falls and faster-acting response is needed;
- Whether plant would actually deliver, as mandated; and
- Whether sufficient monitoring is in place to know whether or not the required LFSM-O response was delivered at all.

In addition to the "planned responses", it is highly possible that a major high frequency event could result in some small generators disconnecting, despite National Grid's efforts to upgrade old loss-of-mains settings and reduce this kind of behaviour. Some unplanned loss of generation would actually be helpful in a loss-of export situation (while of course, any tripping of other exporting interconnectors, or major demands, would exacerbate the problem). This is an area that merits further study.

1.6.4 Case study: Spring 2020 during Covid-19 lockdown

1.6.4.1 Description of the situation

National Grid has reported how the current COVID-19 lockdown circumstances are having a major effect on system operation. This situation is ongoing at time of writing, May 2020. Demands for electricity, during this lockdown period, are significantly lower than are usual for the time of year, as illustrated in Figure 1.7 and Figure 1.8.

Figure 1.7 Actual demand, compared with estimated pre-Covid demand, Monday 30th March 2020 [73]

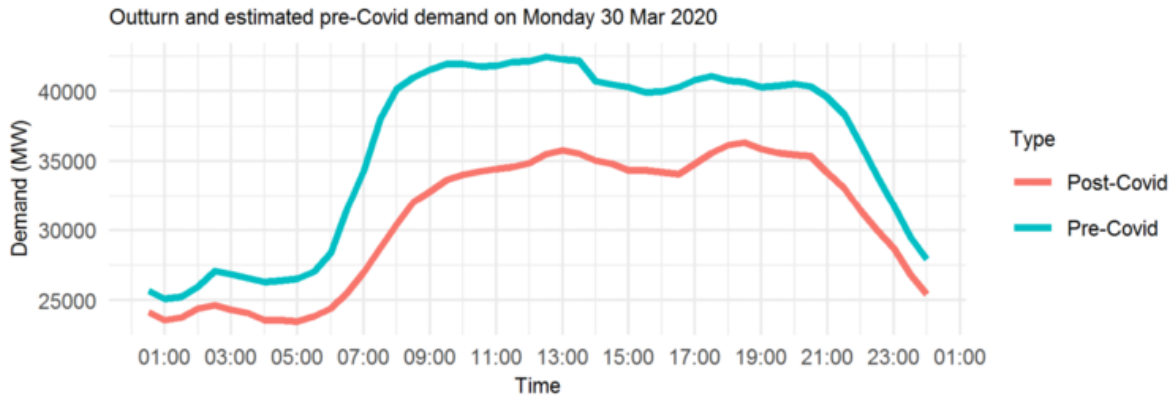


Figure 1.8 Spring 2020 demand and Covid: estimated change in demand, compared with pre-COVID expectations [74].

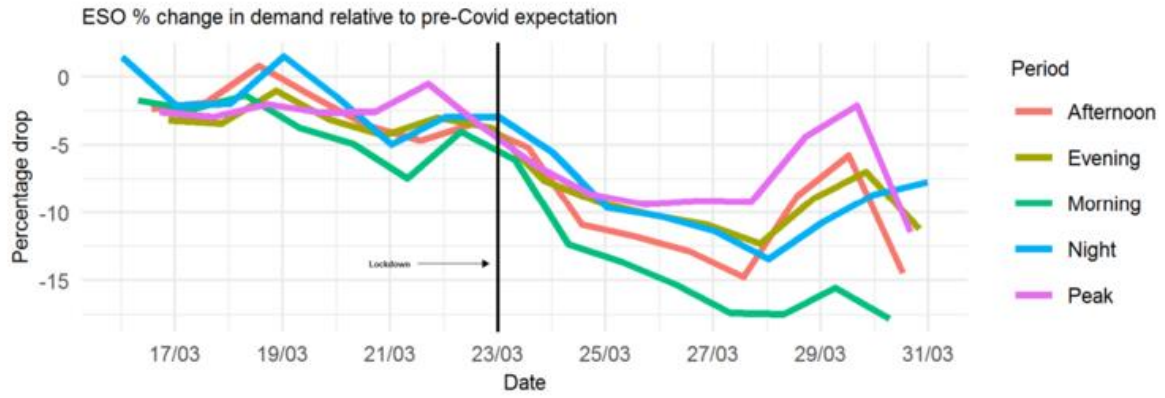
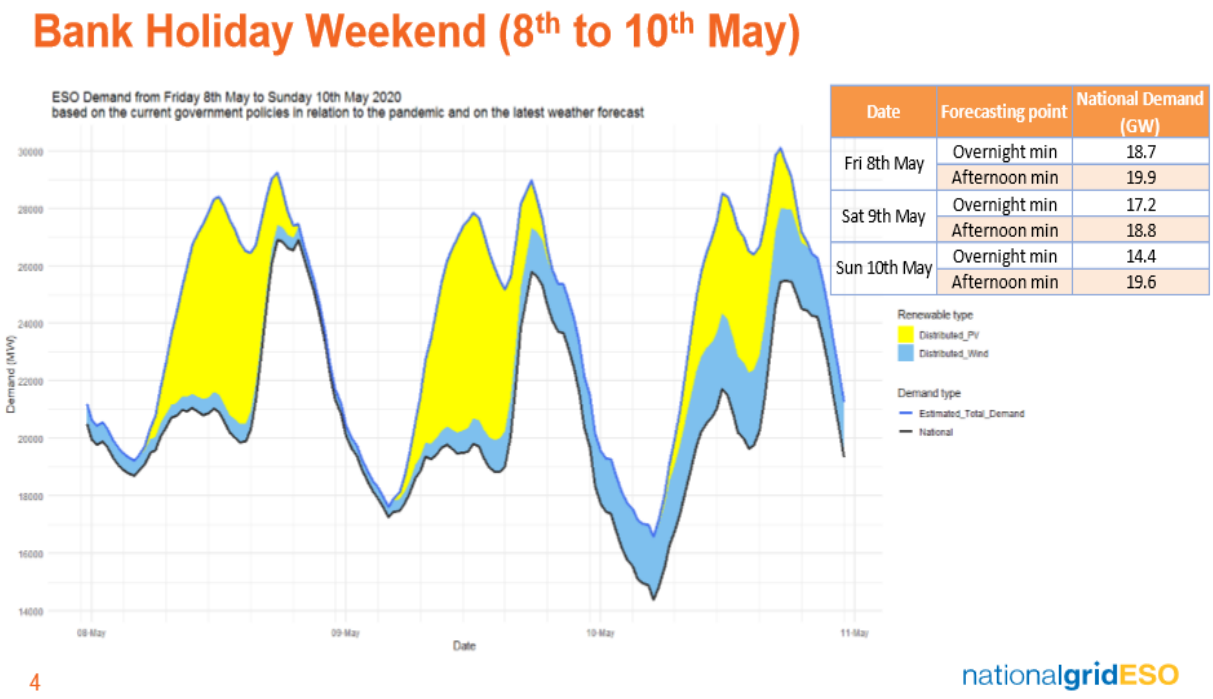


Figure 1.9 Predicted May Bank Holiday 2020 System demand, as of 6th May [74]



Date	Forecasting point	National Demand (GW)
Fri 8th May	Overnight min	18.7
	Afternoon min	19.9
Sat 9th May	Overnight min	17.2
	Afternoon min	18.8
Sun 10th May	Overnight min	14.4
	Afternoon min	19.6

Not only is total demand low, but sunny and windy weather is enabling high outputs from wind and solar generation, plant which do not add (or add significantly) to the inertia of the system. National Grid predicted record minimum demands during May bank holiday weekend, of around 15 GW, as shown in Figure 1.9.

In its Summer Outlook 2020 [75], National Grid describes the use of "tools" to manage the rate of change of frequency (RoCoF) and vector shift.

The COVID-slide briefing 6th May [74], and Summer Outlook, describe:

- the need for downward as well as upward response and reserve services
- the need to create footroom services for periods of low demand
- the need to bring on CCGT and biomass plant, which provide inertia and a host of other system services
- a list of actions being taken, to create room for the necessary high-inertia and flexible plant, including:
    - instructing pumped hydro plants to pump/import
    - reducing output from certain plant, including wind generators
    - reducing imports from interconnectors
    - issuing negative reserve instructions
    - increasing use of "Super SEL", an arrangement which incentivises plants to operate at lower output than their normal "Stable Export Limit"
    - de-loading Sizewell B nuclear power station (announced 13th May briefing)

To support such needs, National Grid has also launched a new downward flexibility product, Optional Downward Flexibility Management (ODFM), and is actively seeking providers (including solar, wind, and aggregators) to sign up and start delivering as soon as possible.

1.6.4.2 Discussion of the spring 2020 situation

At present, it is imperative that any sudden loss (of generation or export) would not cause a rate of change of frequency greater than 0.125 Hz/s. This is because there are significant quantities of small generators, with old loss-of-mains protection settings, which are set to trip following a RoCoF of 0.125 Hz/s. Other small generators have "vector shift" detection of loss-of-mains, which is over-sensitive to system disturbances. Any event that causes these generators to trip will immediately escalate into a much more severe disturbance, as happened on August 9th 2019.

Without the current set of actions by NGESO, a "credible loss" would cause a rate of change of frequency (RoCoF) well in excess of 0.125Hz/s. The market is delivering a low-inertia generation mix, which, at times of low demand, the system cannot safely operate. NGESO is therefore forced to amend the generation mix to reduce the largest loss risks and/or increase inertia.

A programme of updating these small generators' protection settings, after which they would trip at RoCoFs of 1Hz/s is underway. Once complete, a RoCoF of up to 0.5 Hz/s (a level at which other DG will trip) will become the new operational RoCoF limit. Until this is complete, NGESO must either increase system inertia, or decrease the largest loss risks, or both.

1.6.5 Fast Reserve

In the 2017, in SNAPS and the Product Roadmap for Frequency Response and Reserve reports [1], [43], National Grid wrote:

"Reserve is needed to ensure imbalances that arise from forecasting errors or unexpected losses on the system can be managed."

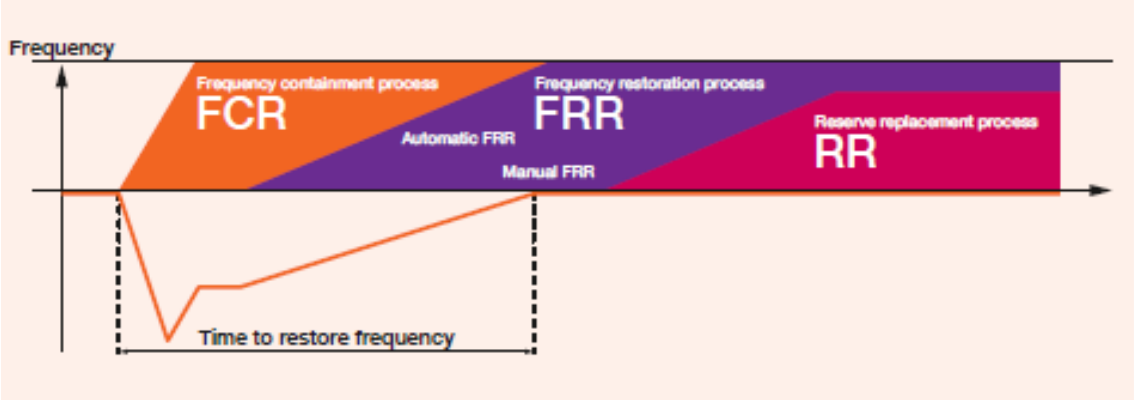
Reserves, being manually activated, are slower-acting than frequency response services, which respond automatically to local frequency measurements. Fast Reserve, delivering automatically within 2 minutes of instruction, is the fastest acting reserve service available to NGESO. There are two distinct needs that Fast Reserve, together with other reserve products, is meeting:

- ***Post-fault:*** To aid the return of system frequency to normal operational levels and enable frequency response services recover
- ***Pre-fault***: To compensate for demand and generation forecast errors

1.6.5.1 Post-fault

Regarding the post-fault needs, National Grid illustrates the function of response and reserve services in in its Operability Strategy Report [3], shown in Figure 1.10.

Figure 1.10 Frequency restoration process. From NGESO's Operability Strategy Report, 2019 [3]



The continental European electricity system uses the following definitions [76]: -

- **Frequency containment reserves (FCR)** means the active power reserves available to contain system frequency after the occurrence of an imbalance
- **Frequency restoration reserves (FRR)** means the active power reserves available to restore system frequency to the nominal frequency
- **Replacement reserves (RR)** means the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves

National Grid considers [3]:

- the Frequency Containment (FCR) is the job of the suite of frequency response services
- Frequency restoration (FRR) and Reserve Replacement (RR) are achieved using a combination of Fast Reserve, STOR and the Balancing Mechanism.

The specific system needs being met by Fast Reserve today are evolving, and the future needs that may be met by Fast Reserve are uncertain. However, as the fastest acting flexibility service in GB that is activated by instruction from the NGESO control room, it, or something very similar, is here to stay and we make the following observations.

1.6.5.2 Pre-fault

Fast Reserve, together with other "fairly fast" reserve services and BM trades, are invaluable in correcting small imbalances in generation and demand, in timescales of a few minutes. These actions are needed to manage uncertainties and errors in demand and generation forecasts. Forecasting is complicated by variable output from renewables, and NGESO's lack of visibility of generation on distribution networks, especially at times of high renewables output. This challenge was mentioned in the 2016 System Operability Framework [69] and will only increase with further deployment of renewable DG. Furthermore, changing patterns of demand may further complicate demand forecasting.

In the absence of any action to further improve forecasting, we expect the need for Fast and "fairly fast" Reserve services, under pre-fault conditions, to increase. A programme to further improve forecasts, and the use of forecast information, may reduce the need for additional Fast Reserve.

National Grid has demonstrated the urgent need for much greater provision of downward-acting reserve [74], at time of writing, by hurriedly launching a new downward reserve service, and seeking immediate offerings. **It would make sense to extend the scope of Fast Reserve to include downward provision, in addition to the existing upward.** This would give the System Operator further flexibility to undertake both upward and downward actions, within Fast Reserve timescales.

1.6.5.3 Future needs for Fast Reserve

With a lower inertia system, and potentially larger credible losses, greater disturbances to system frequency are expected. While containment is the role of Frequency Response services, additional Fast Reserve and similar services will be needed to assist with restoration and reserve replacement. With increasing interconnection planned, the risk of high frequency events is likely to be increasing, and so downward as well as upward-acting reserve services are needed to return system frequency to target.

Similarly, as the penetration of embedded and BMU renewables increases, and the nature of demand become more complex (e.g. as a results of price-sensitive demand flexibility and DSO actions), forecast errors are likely to increase in magnitude. It therefore stands to reason that the requirement for both upwards and downward reserve services will also increase.

Both current practice at NGESO and our experience of evaluating energy forecasts suggest that the need for reserve to manage wind power forecast errors will increase roughly in proportion to the installed wind capacity. Similar trend is likely to hold for installed solar capacity. The impact of demand flexibility is uncertain, and may result in a significant increase in demand forecast errors; particularly early in the DNO-DSO transition while lessons are being learnt, similar to the increase in error during 2010-2015 as solar capacity grew quickly.

1.6.6 Locational Factors

Traditional power system theory states that frequency response could be provided, in principle, anywhere within an interconnected synchronous power system, so long as the network connections have sufficient capacity to deliver the response from the providers to the wider system [77]. However, recent studies, such as [78], [79], recognise that there can be locational variations within a system, and locational approaches may be needed. This is increasingly relevant for the GB power system, where increasing wind penetration and reducing inertia in Scotland leads to more prominent locational variations.

The "Enhanced Frequency Control Capability (EFCC)" project (and proposed frequency response service of the same name) was a NIC project that proved the principle of a Wide Area Monitoring and Control (WAMC) for fast frequency response [79]. This approach monitors phasor measurement units (PMUs) in real time across the network, detects disturbances, and aims to provide a coordinated frequency response, taking into account the resources available to provide frequency response. The response controller aims to deploy response local to the fault, to reduce the risk of transient instability or a split in the power system. The work was primarily done by simulation: validation included case studies and tests on a real piece of 11kV network. The WAMC requires a communication infrastructure to operate; initial work suggests the WAMC may still operate even with fairly poor communication system performance.

In short, as overall system inertia levels are reducing, there is increasing evidence to support deployment of, not only additional and faster frequency response resources, but also that response should be deployed in different locations. Locational response could be most needed in geographical areas of the system which have particularly low inertia. In GB, Scotland would be such an area.

The product has not been commercialised. The system's need for locational response is apparently not severe enough to warrant the necessary investment. The need for a parallel communications network and significant novel market arrangements make operationalising EFCC a significant challenge.

1.7 Commercial requirements for response and reserve in 2025

The previous section discussed the GB system's *technical needs* for frequency response services, by 2025 and beyond. *This* section discusses how easy, or otherwise, we believe National Grid could find *procurement* of the response services it proposes to use, within the projected market framework. Discussion includes which types of providers can access existing markets and those proposed.

1.7.1 Views from industry

1.7.1.1 Energy UK: Future of Energy

Energy UK, a trade body representing a range of organisations in the energy industry, published a report in 2019, "The Future of Energy," in which chapter 2 discusses the funding of electricity system services (as well as generation) [80].

There is a general desire to see flexibility markets that are "open and liquid". Energy UK sees increasing need for flexibility services, while at the same time, greater opportunity, particularly as digitisation allows consumers to participate via aggregators. Energy UK's desired features of ancillary services markets are listed below. Ancillary services markets should:

- Be simple, stable and transparent
- Avoid design assumptions relating to specific technologies
- Allow the broadest range of participants, including distribution-connected providers, and new as well as existing technologies
- Contains a balanced mix of
    - short contracts – for liquidity and competition; and
    - longer contracts, to encourage investment and innovation
- Take account of system needs in different areas
- Publish data on past auctions
- Provide clear information on how providers may participate in different ancillary services markets, providing the services do not conflict.

"Potential of Flexibility. A smart flexible energy system in the transition to a net-zero economy" in February 2020

Trade bodies Energy UK, the ADE and BEAMA, which together represent a variety of players in the industry, including distribution-connected assets and aggregators, wrote a joint report "*Potential of Flexibility. A smart flexible energy system in the transition to a net-zero economy*" in February 2020 [81]. The report authors welcome work already done to widen access to balancing services, and trials such as those in the Open Networks project. However, the authors insist that further work is needed to address existing barriers, especially those affecting storage and demand-side providers.

The report states numerous times that there is need for significant additional flexibility provision, as GB system needs increase, and many incumbents are due to retire. "A*lthough there is high interest in flexibility in the GB market, market drivers are weak at this time […]*". The authors discuss the needs of providers, particularly new entrants. These needs include:

- Access to granular market data (a need stated in the strongest of terms)
- Further IT measures to enable new entrants. The authors welcome the Platform for Ancillary Services, and National Grid's Distributed Desk
- Policy clarity and clear market mechanisms, that define routes to revenue and potential returns on investment; *"a level of certainty"* – a particular need for "*nascent markets*"
- Better communication from NGESO, particularly regarding any changes to requirements, or timelines, to give industry the maximum time possible to prepare
- Government support for trials of new services
- Access to revenue streams from accessing multiple markets

The authors expect that effective competition and economies of scale will enable lower-cost provision of flexibility services, in time.

The authors are particularly scathing about UK rules, which allow DNOs to participate in flexibility markets. The report quotes from the Council of European Energy Regulators, CEER's 2019 publication "New services and DSO involvement" [82] to support its claim. CEER writes that participation of DNOs or DSO in ancillary services markets would cause a distortion to markets, as DNOs / DSOs have access both to a wealth of operational data, and also, as a regulated monopolies, lower cost access to capital. The report authors (Energy UK *et al*) write that DNOs undercut alternative providers in some flexibility markets[8] (the report cites FFR markets in 2018 as an example), and in so doing, discourage new entrants' participation, and thus, future flexibility provision. DNOs are not offering significant commercial frequency response services at present, but one DNO has provided Firm Fast Reserve this year (50-70MW in January 2020 [35]). The report authors are also concerned that these actions may reduce distribution-connected units' ability to provide services, and also hamper DNOs' ability to take emergency action, if needed.

Finally, the authors emphasise the importance of the broader charging and policy environment. Wider network charging arrangements have significant impacts on the viability, or otherwise, of some potential providers, especially of storage providers. One Significant Charging Review (Access & Forward Looking Charges Review) is in process; another ("The TCR") has recently concluded and details on actual charges are still being worked out [83]. Other instruments, such as subsidies and tax bases, are also pertinent. In short, the functioning of ancillary services markets, and their participants, is affected by factors far beyond the narrow remit of the design of these markets themselves. The authors state "*the range of market mechanisms and wider regulatory frameworks will require comprehensive coordination in order to ensure consistent price signals.*"

1.7.1.2 Renewables UK – Energy Storage Conference, London, December 2019

A RenewablesUK representative described a 13GW of storage "pipeline" – projects which are planned, and in many cases, have achieved consent, but are not yet built. Many such projects are waiting for improvements in market conditions. "Storage" covers a broad range of technologies and operational timescales, so by no means all of this "pipeline" would deliver the ancillary services which this report discusses. However, such a large "pipeline" demonstrates that significant volumes of storage provision could be built, in appropriate market conditions.

1.7.1.3 Wind Europe

Back in 2014, the European Wind Energy Association EWEA (Wind Europe's former name), commissioned a report "*Economic grid support services by wind and solar PV*" [84]. Recommendations to facilitate wind and solar provision of frequency response services included the following:

- Set small bid sizes, to allow relatively small entrants to participate
- Separate upward and downward products
- Allow a portfolio from a wide geographical area, or alternatively, allow the uncertainty in provision to be aggregated over multiple units
- Keep frequency response provision as an *option* for wind and solar plants, which requires financial compensation or reward, rather than a *requirement* on all generators
- Ensure Grid code and product specifications are "function-oriented", and do not prescribe technical solutions
- Take into account the requirements, abilities and limitations of different types of providers when writing service specifications
- Harmonise standards across Europe, and use or build on existing standards where possible

Research and development needs were also discussed, in areas including of forecasting, communications infrastructure, control algorithms, and tools to assess system needs.

Wind Europe's report *"Breaking New Ground. Wind energy and the electrification of Europe's energy system"*, written in 2018 [85], discusses wind energy's role in achieving Paris-compatible energy systems. Regarding balancing services

[8] The report cites 2019 research (which is not referenced) on FFR data from April 2018: it states that bids from DNO accounted for almost half of successful tenders.

for electricity systems, the report states that *"flexibility may also come from improved market design, e.g. intraday trading… significantly reducing balancing and reserves costs. Other examples include ... aggregating generation over a larger geographical areas and / or different technologies when bidding in the market."*

A position paper written in 2019 *"Future system needs and the role of grid-forming converters"* [86] – largely about the potential for wind generators to provide virtual synchronous machine and other support for grids – lists requests which include:

- clarity from TSOs regarding future requirements and specifications [of new grid services]
- the assumptions and criteria on which TSOs base their "future requirements" scenarios
- understanding that new hardware solutions will require R&D, and so take several years to implement and add to costs
- the necessity of a business case for providers (whether it be market-based service, or on a "cost-recovery" basis)

In short, the European wind industry in general is interested in providing further ancillary services to electricity grids, both alone, and in combination with other technologies such as storage. Some of its requests are the same as those from other trade bodies: enabling systems, technology-agnostic product specifications accessible to its members, clarity and advance notice of electricity industry requirements, and a benign broader business environment. Measures which benefit specifically wind (and also solar) include: close to real-time trading; unbundling upward and downward products; and rules which allow offerings aggregated from providers spread over a wide geographical area.

1.7.1.4 The Solar Commission

The Solar Commission, a consortium of academic and industrial partners, from solar, electricity and energy systems sectors, wrote a report *"A bright future: opportunities for UK innovation in solar energy"* in July 2019. [87]

While the report mainly describes broader challenges and opportunities for the solar industry, there is a brief mention of opportunities to provide ancillary services or to enable domestic demand-side response, by co-locating solar generation with storage. The report cites an example of an industrial site with rooftop PV panels and large battery, providing Firm Frequency Response. The report also describes, with enthusiasm, solar providers' participation in the ongoing Power Potential innovation trial within UKPN's area, aiming to establish a new reactive power market.

In short, the idea of providing ancillary services seems to be fairly new to the Solar Commission. However, this organisation has very similar "asks" to those of other trade bodies:

- Access to standardised, open, accessible market data
- That ESO and DSO markets for ancillary services are fully open to small decentralised energy resources
- That Ofgem's reform of how we pay for the electricity system provides clear signals to support the value of flexibility to the network and decarbonisation

1.7.1.5 Summary of Industry Positions

Many potential providers of response and reserve services, including non-traditional assets and businesses, are watching opportunities in flexibility markets with interest. Industry bodies are calling for the creation of open, transparent markets, which are truly competitive and technology-agnostic; however, some also wish for Government support of emerging technologies.

In many cases, the business case to participate in flexibility markets, does not, at present, stack up. Industry groups point at a range of features, both of the rules of the markets themselves, and wider policy and regulatory structures, which undermine the business case. Barriers include:

- technical or market requirements, or IT difficulties, which are difficult for some non-conventional providers to overcome;
- relatively low market prices for services (artificially low, in the opinion of some), and the need for new-build to access additional revenue streams
- the need for greater visibility of future income, to encourage investment

The EU Regulation on Electricity Markets (recast, see next subsection) has numerous provisions that are favourable to many new entrants, including renewables, though some would prefer the certainty of longer contracts. National Grid's Firm Fast Reserve market is being reviewed and influenced by some of this law's provisions. However, National Grid is resisting its full implementation, by: -

- wishing to retain month-ahead tendering for Firm Fast Reserve, and week-ahead tendering for end-stat frequency response services (though day-ahead tendering may follow later)
- wishing to retain combined upward and downward service provision for most or all of the end-state frequency response services

1.7.2 European legislation

The Electricity Markets Regulation (recast) of June 2019 [48], introduced as part of the Clean Energy Package, aims to enable competitive markets within electricity industries. Regarding balancing services, Article 6 includes the following provisions:

- Markets should be technology agnostic, and open to new entrants across technologies, including variable renewable generation.
- Upward and downward services should be procured separately
- Procurement should be close to real time, ideally no more than day-ahead, for contracts ideally not longer than one day
- Markets should operate on "pay-as-clear" principles

Exceptions are allowed, where necessary for market efficiency or system security, but should be approved by a country's regulator. Regarding the periods between bidding and delivery, and contract durations, even with a derogation, purchases can be only up to one month ahead, and for contracts not longer than one month.

1.7.3 Current and future requirements for response and reserve: volumes

1.7.3.1 Total volumes required

Table 1.19 and Table 1.20 compare average holding volumes for frequency response services in February 2020, with the proposed volumes of the "end-state" frequency response services, taking information in Table 1.7 and section 1.4.

Table 1.19 Current average holding volumes of commercial frequency response and fast reserve services, February 2020

Service	Total upward holdings, MW	Total downward holdings, MW	Of which symmetrical, MW
Fast: EFR, LFS total	277	227	227
Primary & High (FFR, DLH) *excluding MFR*	383	487	53
Secondary (FFR only) excl. MFR	219	-	0
Fast Reserve (Firm FR only, *not Optional FR*)	500	*0*	*0*
Total Holdings	**1160[9]**	**714**	**280**

[9] Secondary not added to total, as it is assumed that they are the same units which would deliver Primary response

Volumes held can fluctuate, +/- 50% between EFA blocks, and vary between seasons. Table 1.20 lists the volumes and key delivery times for National Grid ESO's proposed "end-state serves" which are expected to be operational well-before 2025, as described in Section 1.4.1, Table *1.12*.

Table 1.20 Proposed holding volumes of new end-state frequency response services

	Total upward, MW	**Total downward, MW**	**Of which symmetrical, MW**
Fast – within 1 second: DM & DC	2000	2000	Initially 2000. Maybe 1000 later
Primary – within 10s: DR	1000	1000	1000
Total Holdings	**3000**	**3000**	2000-3000

As seen, the expected future provision will be at far greater volumes than those currently procured. As discussed in Section 1.6, it is possible that some faster-acting service will be needed to replace, or possibly complement, the proposed "end-state" services, particularly in the years following 2025, unless NGESO takes actions to stop inertia decline during this time. Predictions of quantities are beyond the scope of this report: this report will simply consider provision of the proposed end-state services.

1.7.3.2 Can current providers meet the new needs?

Unsuccessful tender applicants

Tender information for FFR tenders, and the 2016 EFR tender, found that volumes well over National Grid's needs are available from the market: 4000 MW was offered in the 2016 EFR tenders, and well over 1000 MW offered in FFR tenders for each Primary, Secondary and High service, though participating plants do not offer these services at all times. Some of these plant could be available (or in the right business environment, could be built) to offer the additional volumes of end-state services.

Obviously, not all applicants would be able to meet the new service requirements; the unsuccessful applicants were also more expensive than those chosen. Meeting the new service needs, economically, and indeed, in full at any price, will require new market entrants.

Mandatory Frequency Response and Optional Fast Reserve providers

Mandatory Frequency Response is expected to remain an option for the SO, to complement commercial service provision. MFR data are not included above, because utilisations are published as MWh per day basis, so it is not possible to know actual the MW called up. However, the total utilisations, in GWh, procured in February were very similar to those of FFR.

From February's MFR capability table, theoretically over 8000 MW of services are available for each of the Primary, Secondary and High services. However, service capability is an obligation, not a choice, for larger plants. Some reluctant providers, such as nuclear reactors, price their offerings prohibitively highly. More importantly, many of the traditional providers will not be able to respond within the faster timescales.

Similarly, Optional Fast Reserve deliveries are reported (MWh used per month), but the quantities available to be called up are not listed in monthly market reports.

Mandatory Frequency Response – Limited Frequency Sensitive Mode

In severe frequency deviation situations, large plant, which is not already providing frequency response, may be required by the Grid Code to deliver "limited frequency sensitive mode" (LFSM) response, as described in section 1.3.1.4 LFSM over-frequency response (LFSM-O) is required by all large plant, starting at deviations over 50.4 Hz. New plant, connected under the "EU Connections Code" rules, is additionally required to deliver under-frequency response (LFSM-U), as far as existing headroom and energy resources allow, when frequency falls under 49.6Hz. These provisions could support the portfolio of other mandatory and commercial services. For over-frequency events, in theory,

this LFSM-O requirement commands a large resource: most connected large plant. Whether plant would deliver fast enough, or even at all, is another question.

Summary

To obtain the new 3 GW of upward and downward frequency response services which National Grid intends to procure, significant volumes of new market entrants will be needed, even expecting some current providers and tender participants to continue to deliver services. New entrants could include non-schedulable generators (wind and solar), battery storage, and flexible demands. The next section describes how markets might - or might not - attract new entrants.

1.7.4 Existing market and products

1.7.4.1 General features of current and future response and fast reserve products

The requirements for participation in existing frequency response and fast reserve services are shown in Table 1.21.

Table 1.21 Current frequency response and fast reserve services: who can participate? By 2025, all of the listed frequency response services, with the exception of MFR, are expected to have been discontinued. The future of Fast Reserve (FR) is unclear

	Open to non-schedulable plant, requiring weather forecasts?	Medium-long term "bankable" contacts available	Open to smaller plant / DG?	Option to offer high frequency response only?	Providers
MFR	✔	✗	✗ BMUs only	✔	Largely gas, with a little biomass, coal and wind
FFR	✗	✔	✔	(✗) No current demand	Largely aggregators, flexible demand, and storage. A little small diesel / unspecified plant
EFR	✗	✔ (in 2016)	✔	✗	Batteries
DLH	(✔)	✗	✔	✗	Includes aggregators. Full breakdown not available.
LFS	(✔)	✗	✔	✗	
FR – Opt	✔	✗	(✔)	✗	Not published
FR - Firm	✗	✗ [was ✔]	(✔)	✗	Pumped Hydro, thermal plant & DNOs

National Grid ESO has stated a desire to create market structures which enable participation of different types of providers, including storage and variable generation. Table 1.22 summarises main features of plant eligible to provide the new frequency response services.

Table 1.22 National Grid ESO's proposed end-state frequency response services, and current Fast Reserve. Who can participate?

Service	Open to non-schedulable plant, requiring weather forecasts?	Medium or long term "bankable" contacts available?	Open to smaller plant / DG?	Open to aggregated units?	Option to offer high frequency response only?	Possible providers
DR		✗	✔	(✔)	✗	

Service	Open to non-schedulable plant, requiring weather forecasts?	Medium or long term "bankable" contacts available?	Open to smaller plant / DG?	Open to aggregated units?	Option to offer high frequency response only?	Possible providers
DM	(✔) – week ahead Maybe ✔ later (day ahead)	✗	✔	Must be connected to same GSP	✗	Theoretically, any kind of plant meeting the technical requirements. (See Table 23)
DC		✗	✔		✗ maybe ✔ later	
Fast reserve - opt	✔	✗	(✔) 25MW minimum delivery	✔	✗ Upward only	Not published
Fast reserve - Firm	✗	✗ [was ✔]				Pumped Hydro, thermal plant & DNOs

1.7.4.2 Potential providers of "end-state" services

Table 1.23 summarises the new end-state frequency response services (DC, DM and DR) which different technology types may be able to offer, based on available information.

Table 1.23 Requirements and potential providers of new end-state frequency response services

	Main service requirements					
Potential provider	**Start upward response**		**Start downward response**		**Sustain for minimum period**	
	DC, DM (within 1 s)	**DR** (within 10 s)	**DC, DM** (within 1 s)	**DR** (within 10 s)	**DC, DM** (20 mins)	**DR** (indefinite)
Thermal plant	✗	✓	✗	✓	✓	✓
Wind	(✗)	(✓)	✓	✓	✓ when windy	✓ when windy
Solar	(✓)	(✓)	✓	✓	✓ when sunny	✓ when sunny
Batteries	✓	✓	✓	✓	(✓) if enough State of Energy & size	✗ State of Energy
Pumped hydro	✗	✓	✗	✓	✓ if enough State of Energy	✗ State of Energy
Other hydro	✗	(✓)	✗	✓	✓ when wet	✓ when wet
Interconnectors	✓	✓	✓	✓	✓	✓ provided other power system can export
Demand-response	Some ✓	Some ✓	Some ✓	Some ✓	Probably ✓	Probably ✗
Aggregator	Some ✓	Some ✓	Some ✓	Some ✓	Probably ✓	Depends on resource base

1.7.5 Features of new markets: enablers and barriers

1.7.5.1 Upward, downward and symmetrical response

The introductory slide pack for the new response services [2] and especially the webinar on Dynamic Containment [46] discuss State of Energy requirements at length. It appears that NGESO expects most participants to be batteries or other storage units (based on repeated reference to state of charge and no discussion of weather-related issues), which would easily provide a symmetrical service.

Wind and solar plants can offer fast downward response, if set up to provide such a service. These units *could* also offer fast upward response, though output from the units would need to be curtailed (by the units themselves, or the System Operator) to create headroom. It is harder to create a business case for such behaviour in commercial services as discussed further below.

Thus, setting the new end-state services as symmetrical, rather than separate upward and downward, represents a significant economic barrier to wind and solar participation. This feature might also be detrimental to some aggregators or demand-side providers. Rules requiring symmetrical rather than separated upward and downward services appear to be contrary to the requirements of the 2019 Electricity Markets (recast) EU Regulation (Article 6 (9) [48]).

1.7.5.2 Contract length

The National Grid's proposed new end-state frequency response services: Dynamic Containment (DC); Dynamic Moderation (DM); and Dynamic Regulation (DR), are described in Section 1.4.

The move to week-ahead auctions (already being trialled in the Phase 2 DLH and LFS products) which may evolve into day-ahead later, opens up frequency response provision to weather-dependent resources. This feature potentially enables many GW of existing wind and solar plant to take part, at times when they have resources to do so. A move by National Grid ESO from week-ahead to day-ahead tendering for these response services would further benefit wind and solar providers, as greater certainty with forecasts would reduce risks of under-delivery.

On the downside, the enthusiastic response to the 2016 EFR auction showed that long-term contracts encourage investment in new plant, and significant volumes at low prices, which is in consumers' interest. The new end-state services, having rolling week-long contracts (which may become rolling day-long contracts later), may not offer a strong enough market signal to support the construction of new plant. In this report, in Section 1.7.6.2., we briefly discuss possible alternative approaches - establishing additional market platforms - to increase certainty regarding volumes and prices, which may encourage market development and allow providers to manage risks.

National Grid considered this conundrum back in 2017 in SNAPS [43]:

"A key design question in developing the future product strategy relates to industry's preference for short-term markets or longer term contracts to drive investor confidence in developing new flexible assets.
Stakeholders have told us that short-term markets (e.g. day ahead) can provide confidence to investors as every day provides a new opportunity for revenues. This could also unlock more demand side capacity because office, consumption and manufacturing processes are more certain nearer to real time. It may also allow us to be more certain about our requirement, and therefore increase the volume that we buy through the market. On the other hand, some parties have outlined the need for longer-term contracts to provide the revenue streams to support investment. We believe that there may be merit in providing a long term route to market in the current climate to instil confidence in balancing services' revenue streams, particularly if and while short-term markets are developing."

The 2017 Product Roadmap for Frequency Response and Reserve [1] suggests National Grid wished to move closer to real-time procurement for frequency response, and later, for reserve services, while learning from week-ahead or day-ahead experiences in response provision.

"Rollout of closer to real-time procurement in reserve services represents an opportunity for participation by new technologies [in reserve markets], and lowers another barrier to market entry for non-traditional providers."

And regarding both response and reserve markets:

"Alignment of procurement activities closer to real time would also allow all parties to assess which revenue streams offer them greatest value thereby being able to determine where and when to offer their Megawatts."

However, at present, the intention of National Grid ESO of having week-ahead markets for frequency response, while retaining month-ahead markets for Fast Reserve, **does not** allow free movement between these markets for potential providers: providers cannot "*determine when and where to offer their Megawatts"*.

In short, the interests of existing and new providers are not aligned on product specifications or procurement mechanism. Many favour very short contracts, arranged very close to real-time; others favour longer-term contracts to provide certainty and a "bankable" business case. As new markets mature, they could provide the "bankable" price signals that many new entrants need to find a route to market. However, some industry participants are not convinced and are lobbying to retain a mix of longer and shorter-term contracts.

1.7.5.3 Geographical factors and portfolio provision

Wind and solar industry voices state clearly that they wish to be able to offer services from a *portfolio* of wind or solar farms, which could be dispersed over a geographical area, though they may well be in the same region (GSP Group) of the transmission network. This is how distributed resources access the Balancing Mechanism, for example. A similar arrangement for frequency response would increase competition, opening up the market to distributed resources, including DSR and wind farms. The latter would benefit by increasing service reliability through geographic diversity, which positively affects both wind resource and predictability, enabling a greater volume of frequency response to be offered from a portfolio of wind farms rather than individual units.

The new "end-state" frequency response services allow aggregation of smaller resources, but stipulate that they must be connected to the same GSP. This requirement will reduce the ability of weather-dependent renewable generators to reduce risks of forecast errors. It is also likely to be detrimental to aggregators sourcing from outside of a local area.

1.7.5.4 Service availability

Service availability of contracted units must be maintained at an acceptable level and non-compliant units may be excluded from providing services. For the new Dynamic Containment service, non-delivery is only permissible if a unit is unavailable due to a *Technical* reason. Non-delivery for *Commercial* reasons is not permitted under any circumstance. Information on failure modes should be supplied to NGESO. It is not clear whether non-delivery due to a wind power forecast error would be considered *Commercial* or *Technical*, though as there is not commercial gain being made, a strong case for the latter can be made.

We recommend that non-delivery due to forecast errors be considered *Technical* and that the NGESO work with the wind industry to agree suitable definition of a "best industry practice" for offering response services based on forecasts and uncertainty quantification. This would follow on from the president set by Physical Notification submissions from wind farms.

1.7.5.5 Pay as clear

Most of the current commercial response and reserve products are procured on a "pay-as-bid" basis. The new "end-state" services are to remunerate providers on a "pay-as-clear" basis. Pay-as-clear market rules are expected to benefit participants, especially those with low short-run marginal costs. The 2019 EU Regulation on Electricity Markets (recast [48]) calls for pay-as-clear markets.

1.7.5.6 Summary

In short, the new services have features that will enable some new entrants to participate: namely, the week-ahead trading, which enables non-schedulable plant to take part. This is significant as it enables potentially several GW of provision from wind and solar units, and potentially also some other resources, such as demand-side units, which may know resource availability closer to real time. A possible move to day-ahead trading will further improve these providers' ability to participate. The pay-as-clear feature is also considered beneficial.

NGESO's intention of keeping month-ahead procurement for Firm Fast Reserve prevents non-schedulable plant from participating, though some larger units may be able to offer Optional Fast Reserve. However, the absence of long

"bankable contracts" will be barrier to other providers: we suggest creation of additional market platforms to facilitate the development of price and volume signals.

Other rules of the new response services present significant barriers for some providers.

- The requirement for symmetrical service provision – disadvantages wind and solar, and potentially some demand-side units, whereas most storage easily meets this requirement
- The geographical limitation, to a single GSP, severely limits the options for a portfolio offering, especially for weather-dependent renewables
- Clarification on service unavailability is needed, to be clear on whether a unit's non-delivery because of a forecast error would be classed as a permissible "*technical reason*", or a "*commercial reason"*, which is not allowed

Regarding Firm Fast Reserve, the biggest barrier to participation is the current suspension of tender rounds, and the lack of visibility of this service's future requirements. Extending this service to allow separate downward provision, in addition to the current upward provision, would be attractive to new entrants, especially some wind generators, provided other rules did not present barriers.

1.7.6 Other features of reserve and response markets

1.7.6.1 Windfarms: when is it worth holding headroom to provide upward response?

What kinds of wholesale and ancillary prices are needed for ancillary service provision to be attractive to wind generators? Business models for variable renewable generators, such as wind or solar, to offer ancillary services differ from those of other types of provider. For example, if thermal plants reduce their active power output, in order to create headroom to provide upward services, revenue is lost from active power sales but reduced fuel costs offset this.

This does not apply to *non-fuel* wind and solar plants. Offering downward reserve is inexpensive, provided revenue from service provision exceeds any subsidy revenue that may be lost due to reduced energy production. However, to provide upward response or reserve, the unit must reduce its output in order to create the necessary headroom to respond to an under-frequency event, and thus lose revenue from energy sales with no savings on fuel costs. Thus, the revenue from the ancillary services must at least compensate for revenue forgone by reduced energy sales.

The presence of energy subsidies for many windfarms further complicates the matter. Some windfarms are supported by Renewable Obligation Certificates (ROCs), in which windfarm exports enjoy an additional sum per MWh supplied to the Grid. This scheme closed to new entrants in 2017 [88], but most windfarms will continue to be eligible for 15 years. The current value of a ROC is around £50 [89] with most onshore wind farms receiving 1 or 0.9 ROCs per MWh.

Other windfarms (and other low-carbon generators) are supported by Contracts for Difference (CfDs), which set a "strike price", in £/MWh, which is, in effect, the price the generator will receive for their electricity exports, regardless of market price. The difference between a market index price and the strike price is paid to the generator (price may be negative) based on metered energy in each settlement period to achieve this. Therefore, utilisation energy from the provision of frequency response services impacts revenue in proportion to the metered volume and top-up price in any given settlement period. Both support schemes make it relatively expensive for windfarms to reduce outputs in order to provide ancillary services compared to other technologies in commercial markets.

However, in the Mandatory market, the situation is different. If instructed by National Grid, providers are repositioned in order to create the necessary headroom for upward response via a Bid-Offer Acceptance, which is paid-as-bid. Wind farms are able to set their Bid price to cover lost subsidy revenue (ROC or CfD) and their MFR holding price relative to the cost of utilisation energy. While using wind for Mandatory Primary and Secondary response is expensive for the ESO compared to other technologies, if a wind farm Bid is being accepted for other reasons (e.g. energy balance or constraints), frequency response can be procured in addition to the BOA at competitive rates.

Using historic price data it is possible to estimate the break-even price at which wind farms recover their cost from provision of frequency response services. The requirement for *upward only* frequency response has been estimated by

examining GB frequency data for 2018 and 2019, at 1-second resolution, assuming realistic parameters[10]. These data have been analysed to estimate what proportion of upward response holding would be utilised, on average. This research found that a provider offering a given number of MW/h for upward response services during 2018 and 2019 would have delivered 4.12% of the available energy, on average.

The conditions in which it is attractive, or unattractive, for windfarms to reduce power output, in order to create headroom to offer upward reserve, are summarised in Table 1.24. These scenarios use the same utilisation levels (4.12%), considered a reasonable first approximation. The final column in the table states how an increase in utilisation would affect the business case.

Table 1.24 Viability for windfarms of offering **upward** response. Effect of wholesale energy market price and subsidies. Assumes 4.12% utilisation, (i.e. response services are "called up" to deliver 4.12% of total possible response over a year).

Type of subsidy	**Type of response service**	**Cost which the income from response services must meet or exceed, to "break even"**	**Viability of providing upward response services – windfarm's perspective**		**Effect of higher utilisation ("call-up") of services** (to 20%)
			Highest Wholesale Energy Market Price, at which a frequency response service price of £0 would "break even"	**Viability for windfarm (& SO)**	
None	**Mandatory**	Zero. W/fms set BOAs & holding payments to compensate for loss of energy sales	All prices	Viable for windfarm **in all circumstances** ***Moderate costs for SO***	No change
	Commercial	Market price of energy sales	Zero £/MWh	Viable for windfarm **only when market price of energy is low or negative**, and ancillary service payments exceed lost sales revenue **Good option for SO**	No change
ROC, £50/ MWh	**Mandatory**	No costs, and small benefit, ~£2/MWh. W/fms set BOAs & holding payments to compensate for loss of energy sales, and also, during utilisation, ROC	All prices	Beneficial to windfarm **in all circumstances.** ***Very expensive for SO***	Even better for windfarm – benefit increased
	Commercial	Market price of energy sales, plus ROC payment during majority of time when not utilised.	Around **negative of the ROC price** (-£50/MWh) or more negative	Only viable for w/fm when **market price is negative**, around minus the ROC value Good option for SO – if any provision	Small improvement, but still needs negative market price
CfD, £40/ MWh; and **CfD, £140 /MWh**	**Mandatory**	Difference between market price and strike price, during periods of utilisation only. W/fms set BOAs & holding payments to recover sales losses	**~ strike price** *(e.g. +£40/MWh or +£140/MWh)* **or lower**	**Viable for w/fm in most circumstances**, as low costs to be offset. ***Expensive for SO***	Little change in "break even" price. Less profitable to w/fm at high market prices, and increasingly profitable at low market prices.

[10] Assumed GB system deadband as +/- 0.015Hz, as per Grid Code, and a linear frequency response requirement outside of the deadband.

Type of subsidy	Type of response service	Cost which the income from response services must meet or exceed, to "break even"	Viability of providing upward response services – windfarm's perspective		Effect of higher utilisation ("call-up") of services (to 20%)
			Highest Wholesale Energy Market Price, at which a frequency response service price of £0 would "break even"	Viability for windfarm (& SO)	
CfD, £40/ MWh	**Commercial**	Strike price, plus, during periods of utilisation only, the difference between market price and strike price	~ negative £800/MWh **Needs low strike price combined with strongly negative market price**	Completely **unviable** for w/fm in all but extreme circumstances Unlikely to be any provision	Improves viability, but still needs strong negative market price and also low strike price.

1.7.6.2 Additional market platforms

Section 1.7.5.2 discusses the pros and cons of moving from long-term contracts to close-to real time procurement. While close-to-real time procurement is an enabler for weather-dependant renewables, some "new-build" providers may need the certainty of long contracts, in order to access investment.

In theory, a mature market, even a day-ahead one, could provide sufficient price signals to provide a business case for a new entrant. However, such markets may take time to develop. We suggest that additional market platforms are set up, by National Grid, to facilitate trading and encourage wider participation.

First, a Futures Market would allow participants to trade (potentially long-term) response service contracts in advance of the day-ahead market. Participants could bid in advance, and make later adjustments though other futures trades or in the auction itself. Trades might be: between a provider and NGESO (e.g. to offer some minimum volume at specified price points into the auction); between providers; or between several providers and an aggregator or other third party. Such a market could provide long-term confidence on volumes and prices, but would probably only develop once the auction mechanism is well established.

Secondly, a platform to facilitate intra-day or "Secondary Trading" would allow participants to adjustment their position if, for example, a more attractive commercial opportunity arose or delivery was compromised by an outage or forecast error. An intra-day market would be particularly useful for participants whose needs or resources become clearer in the hours or minutes approaching delivery time. Such a market could provide a further mechanism for National Grid to tailor its procurements "within-day" (currently done using the BM, MFR and certain reserve services); it would also offer a mechanism for variable generators and demand-side resources to trim their offerings in the light of fuller information. It is noteworthy that to date NGESO has had the ability to adjust holdings of all dynamic frequency response services (Primary, Secondary and High) within day via MFR, but no such mechanism has been proposed for the new end-state services. In short, there is no single approach regarding contract length that will satisfy all potential providers and meet the needs of NGESO.

1.7.6.3 Wind farm control: set point lock vs delta control

This section deals with a technical detail of windfarms' downward frequency response characteristic, which is potentially detrimental to some aspects of system operation.

Set Point Lock is a control strategy in place at GB wind farms that effects high-only frequency response provision. Response is provided relative to the power output at the moment the system frequency first exceeds 50.015 Hz. This "locked set point" remains in effect until the system frequency returns to below 50.015 Hz. If the wind speed has increased, this can result in a large step-increase in power when the locked set point is "unlocked". It can also result in no dynamic response being provided if the wind speed drops while the set point is locked. Both consequences are undesirable from a system operation perspective and may result in wind farms being viewed unfavourably by operators.

An alternative control strategy would be delta control, where response is provided relative to the power available in the wind. Delta control would eliminate both issues as response would be provided dynamically regardless of wind conditions with no abrupt changes in power output when the frequency returns to nominal.

It is conceivable that set point lock would preclude wind farms from offering new frequency response products if they are deemed to not meet the services specification. If NGESO prefers calling on wind farms with delta control rather than set point lock for MFR, operators will have to make a business decision as to whether controller upgrades are economical. In any case, wind farms are highly likely to require new controller/software to be updated or retrofit in order to provide any of the new "end state" services, which may be expensive.

1.7.7 Local Markets

Section 1.6.6 discussed a growing view that there is need to deploy response services at different locations within a power system, and that geographical regions of low inertia are in particular need of having such services.

In its guidance for new response service Dynamic Containment, National Grid ESO states that providers' locations will be taken into account, when deciding which tenders to accept. If national markets do not receive suitable offers of response services provision from all required geographical areas, or if provision is inadequate in some areas, it may be necessary for local markets to be created to stimulate such provision.

1.7.8 Observations from overseas

Electricity systems around the world use a variety of approaches to procure balancing services, as discussed briefly in Section 1.5. Some systems use entirely market-based provision, while others rely at least in part on mandatory provision, as shown in Figure 1.5 in Section 1.5. The case studies of Ireland and Australia found very different market approaches.

Main lessons for the GB system:

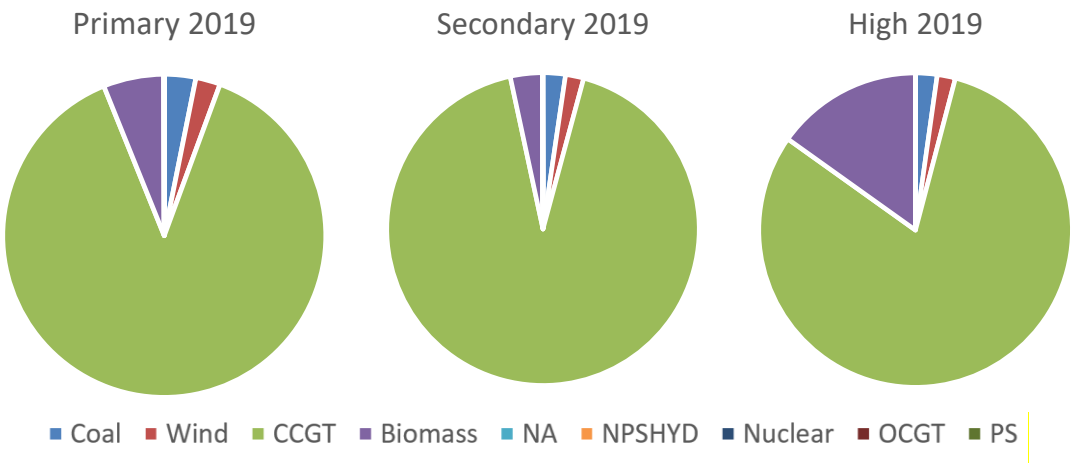
- Given increasing penetration of renewables, construct markets which enable these resources to provide flexibility and contribute to system services. (Ireland)
- Frequency response services are likely to be needed at different locations. (Ireland)
- Even very liquid markets do not guarantee good service provision: the portfolio must be the right one. (Australia)
- Some systems meet needs with entirely commercial services (e.g. USA); however, a combination of mandatory and commercial services provision may be the best way to meet system needs. (Australia)
- Decide which pathway the GB system is taking. In particular, decide whether challenges will be addressed by procuring inertia, and if, or to what extent, we need to design our GB system to operate under ever-falling inertia conditions
- Look at RoCoFs which generators are required to ride-through in other power systems: 1Hz/s, is fairly common, and there are several examples of 2 Hz/s requirements

1.7.9 Low carbon frequency response and Fast Reserve

National Grid ESO has promised a "zero carbon electricity system" by 2025. This term is defined as follows: *"National Grid ESO's ambition is to be able to operate a zero-carbon electricity system by 2025. This means if the market provides us purely with electricity generated from zero carbon sources, we can run the system without needing to use any extra services that emit carbon. So Britain's electricity will be carbon free."* [90]

It is therefore of interest to examine the penetration of low-carbon technologies in existing balancing services. Volumes of MFR by fuel source are shown in Figure 1.11. Wind and biomass contributed to the totals, but procurement was overwhelmingly from CCGT plant.

Figure 1.11 MFR provision by fuel type, 2019. Data from National Grid ESO's MFR market reports.



Recent FFR tenders (February and March 2020 post-tender reports, available [14]), are dominated by distribution-connected flexible demand and storage providers, with diesel and other thermal plant providing very small quantities of static response. EFR is provided entirely by batteries.

It is worth noting that distribution-connected assets, such as aggregators and "flexible demands", may often have, within portfolio, small despatchable units such as diesel generators or gas CHP plant [91]. Heavy use of such units may result in balancing services that are considerably more carbon-intensive than offerings from CCGT plant. Firm Fast Reserve has largely been provided by pumped hydro plants, though thermal plant and at least one DNO also take part. We recommend that NGESO starts to account carbon costs (and benefits) of its balancing actions and services.

1.8 Conclusions

Frequency response

The current suite of frequency response services broadly meets system requirements under normal conditions, though under unusual system conditions (such as spring 2020/national lockdown) additional actions by the System Operator are needed. The current product suite will be unfit for purpose before 2025; much faster-acting response services, and increased volumes, will be required.

Analysis in this work package and work package 2 of this project indicates that the proposed "end-state" services of Dynamic Containment (DC), Dynamic Regulation (DR) and Dynamic Moderation (DM), will be broadly suitable for system needs to in 2025. However, at times of low system inertia (and without the option of bringing on fossil fuel-based plant to increase inertia) these services may need to be supplemented by an additional, very fast acting service, such as synthetic inertia or Improved Frequency Containment (IFC), described in WP2. Alternatively, National Grid could amend the "end-state services" to require slightly faster delivery.

During the late 2020s, with expected further inertia decline, we expect the GB system will need a different, yet-faster acting suite of response services, or mechanisms to increase inertia.

The proposed suite of new frequency response services (DC, DM and DR) will require many new entrants, to offer the proposed volumes of 3 GW. Ideally, providers will be from a range of technology types. Despite interest from a variety of providers, there is a risk that the necessary volumes may not be offered, especially if prices remain low or uncertain, or if the wider business conditions are difficult. A shortage of providers could necessitate expensive actions, such as BM trades, actions to reduce largest loss risks, or to increase system inertia.

We believe that the market mechanisms proposed for the end-state services are a considerable improvement on those which exist today. The much-closer-to-real-time trading will enable many new providers – those with non-schedulable plant – to enter these new markets, and facilitate competition. These benefits will be further aided if the services move from week-ahead to day-ahead procurement, a change NGESO states is under consideration. However, competitive markets, which deliver price signals that are clear enough to attract investment, will take time to develop. Some industry voices wish to see longer term markets run alongside close-to-time ones. Creation of additional market platforms to facilitate long-term contracting or futures, and secondary trading within-day, may support development and reduce risks for both providers and the ESO.

We find that the proposed rules governing the "end-state service" are not altogether technology agnostic. National Grid materials heralding the launch of DC address the specific needs of storage units in some detail; however, some of the rules are detrimental to other provider types. In particular, the requirement for symmetrical service provision, rather than separated upward and downward services, presents difficulties for some providers, such as wind, solar, and potentially some demand-side units. This requirement also appears to be contrary to the requirements of the 2019 EU Regulation on Electricity Markets (recast). Other DC market rules, allowing participation of aggregated small units, are welcome, but the current limitation to units connected to a single grid supply point (GSP) reduces opportunities for wind and solar units, in particular, to offer competitive entries based on a geographically spaced portfolio. Some relaxation of this locational restriction would be welcome. We do, however, recognise that the location of service provision is important, and that services should ideally be at different places around the power system, with low-inertia areas, such as Scotland, potentially being most in need. Additional measures might be needed to encourage service provision in such areas, perhaps by creating locational markets, if the system-wide market does not deliver.

Fast reserve

Fast Reserve, together with other "fairly fast reserve" services, provides very valuable system services, both pre-fault, in compensating for forecasting errors and, post-fault, in returning the system to normal conditions, and allowing response services to recover.

GB system needs for *post-fault* Fast Reserve are expected to increase as system inertia declines and greater disturbances occur and need corrective action. The need for *pre-fault* Fast Reserve is also expected to increase, as short-term variability and forecast errors introduced by wind, solar and demand response increase. At the time of writing, the system has a great need for additional downward reserve. It would make sense to extend the scope of Fast Reserve to include downward as well as upward provision.

At the time of writing, there is considerable uncertainty in the reserve services portfolio in general, and with Fast Reserve in particular, with no view of any "end-state". Changes are being driven both by National Grid's long-term plan to improve response and reserves portfolios, and more pressingly, the stipulations of the 2019 EU Regulation on Electricity Markets, part of the Clean Energy Package. The tender rounds of Firm Fast Reserve are at present suspended, pending discussions with Ofgem.

Procurement of commercial Firm Fast Reserve has recently changed from a mix of month-to-years long tenders, to month-long only. National Grid is resisting regulatory pressure to move to day-ahead procurement. Retention of month-ahead procurement will continue exclude non-schedulable plant, such as wind and solar, and is a barrier to market liquidity, because it will be difficult for providers to switch between response and Fast Reserve markets. However, some providers may be able to offer Optional Fast Reserve, which can be called up within day.

Regarding system operation in general

Work Package 2 found that system inertia is expected to continue to decrease throughout the 2020s. In the absence of actions from the System Operator to raise inertia, minimum inertia levels of 70 GVA.s could be seen by 2025, and potentially around 30 GVA.s by 2030. Credible losses during such system conditions would cause severe system disturbances: rates of change of frequency (RoCoF) of around 0.5 Hz/s by 2025, and potentially of around 1 Hz/s towards 2030, without NGESO taking action to increase inertia of reduce credible infeed/demand losses. Frequency response and reserve services have crucial roles to play, though actions beyond ancillary services markets will be necessary to ensure secure system operation. Development of a longer-term vision for the system would be invaluable.

Upgrading old loss-of-mains settings on small generators (the 0.125Hz/s RoCoF and vector shift loss-of-mains settings) is a clear priority. Work is underway to address this matter, and expected to resolve this (for the most part, at least) over the coming months or so. However, there is no programme to replace generators with settings on 0.5 Hz/s, which could become the limiting factor for system operation regarding RoCoF by the mid-2020s. The GB system appears to be an outlier in having these settings, with some other countries requiring 1 or even 2 Hz/s. The experience of spring 2020 shows that difficult operating conditions can arrive much sooner than expected: we urge timely work to address these challenges.

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1.9 Recommendations and Further Work

We make recommendations for actions, primarily for National Grid ESO, with the support of Ofgem.

1.9.1 Market measures

Frequency response: end state services Dynamic Containment, Dynamic Moderation and Dynamic Response (DC, DR and DM):

- Move procurement arrangements from week-ahead to day-ahead
- Introduce additional trading platforms:
    - A ***futures*** platform, to allow trading ahead of time, and
    - A ***secondary trading platform***, to allow ***intra-day*** trading in hours (maybe minutes) approaching delivery time
    - A mechanism by which NGESO can procure additional DC, DR and DM within day, which could be the above platform or a separate mechanism similar to MFR
- Consider whether having some provision via long contracts would stimulate new entrants. Could be facilitated to some extent by the above futures market
- Unbundle requirements to provide upward and downward response
- Maintain proposed "pay-as-clear" market rules
- Allow provision from a portfolio of units, over a greater physical distance than a single GSP, e.g. GSP Group
- Class any unavailability to provide frequency response services DC, DM or DR, due to wind or solar power forecast errors, as a *Technical* failure, rather than *Commercial*, and develop best practice guidance for participation from weather-dependent resources
- Be ready to create **locational markets**, to ensure provision in different parts of the system, if the market does not provide these. The need may be greatest in low-inertia areas, such as Scotland, which may benefit from EFCC-style operation
- Consider, as soon as possible, whether to increase delivery speed requirements for these services, or to supplement the services with a further faster service, such as synthetic inertia or Improved Frequency Containment, as one of these approaches is likely to be needed during low-inertia periods by the mid-2020s. Give potential providers the maximum possible notice of any change to requirements
- Plan for additional services with faster activation times from the mid- to late-2020s

Fast reserve:

- Create a route-map, arriving at an "end-state" service for Fast Reserve and other reserve products. Ideally, this process will bring rationalisation, simplification and improvement already seen in the review of frequency response services
- Modify the Fast Reserve product to include downward as well as upward provision, which would be offered separately
- Change procurement arrangements for at least some of the Fast Reserve requirements to much closer to real-time provision, ideally compatible with the trading schedule in the new frequency response services, to allow providers free movement between these markets
- Consider creating additional market platforms (e.g. Futures and Secondary Trading) for trading in these services, and potentially coupling with frequency response markets

Both services:

- Review rules allowing DNO participation, which is considered a market distortion by CEER
- Publish much fuller market data, including holding and energy payments, technology types, and carbon intensity

1.9.2 Non-Market Measures

Loss-of-mains settings on generators

- Accelerate the current programme to replace generators' loss-of mains settings based on vector shift, and 0.125 Hz/s RoCoF
- Extend the programme to replace generators' loss-of-mains settings of 0.5Hz/s RoCoF, to at least 1Hz/s, by the mid-2020s at the latest

System parameters

- Review the SQSS-defined "normal" and "infrequent" losses, taking into account new interconnection, and the possibility of multiple failures, potentially triggered by the initial disturbance
- Consider a wider review of system frequency limits, and whether these are fit for purpose in a low-inertia system which could see RoCoF exceeding 0.5Hz/s and potentially 1 Hz/s

Future vision

- Decide whether the GB system is to follow a "keep inertia high" pathway, or a "manage a low-inertia system" one. This decision will inform the other system requirements

Mandatory frequency response

- Introduce an additional "fast" mandatory frequency response service based on new "end state" products for types of units that are technically able to provide it to give NGESO access to this service within day and in the event of market failure
- Review whether large plant, operating in Limited Frequency Sensitive Mode, would actually support the system in the event of a major disturbance, as per Grid Code requirements. Study expected effectiveness of this requirement, in particular, for a high frequency event. Investigate options to make this requirement more effective

Data and information

- Introduce carbon accounting for all System Operator actions (including those involving distribution-connected resources). Make the carbon costs / benefits of System Operator actions public, as close to real-time as is practical
- Investigate possible improvements to forecasts and forecast end-use, in an effort to limit expected increases in the need for Fast Reserve (and similar services) in pre-fault conditions
- Publish estimated system inertia levels and limits, of the current and projected future GB power system, as far as possible, while respecting commercial sensitivities

For the wind industry

- Wind farms should provide high-only response via delta control, rather than Set Point Lock. A transition plan should be agreed between the wind industry and NGESO

1.10 Glossary

Acronym	Full term	Further information
AEMO	Australian Energy Market Operator	System operator covering southern and eastern Australia
BM	Balancing Mechanism	Trading platform in the GB system, in which larger providers can offer to increase or decrease output, for prices they set
CEER	Council of European Energy Regulators	Ofgem is the UK's representative in this organisation.
CEP	The Clean Energy Package	A package of EU legislation, some provisions applying to electrical power systems
CUSC	Connection and Use of System Conditions	Rules applicable to the GB electrical power system
DC	Dynamic Containment	One of National Grid's proposed new "end-state" frequency response services
DG	Distributed generation	Generators connected to distribution networks, as opposed to transmission networks
DLH	Dynamic low high	One of GB's frequency response services, introduced in Nov 2019, as part of the "phase 2 trial"
DM	Dynamic moderation	One of National Grid's proposed new "end-state" frequency response services
DN	Distribution network	Local electricity network
DR	Dynamic regulation	One of National Grid's proposed new "end-state" frequency response services
DS3	Delivering a Secure Sustainable Electricity System	A programme within the Irish electricity system, which aims to facilitate further renewables penetration. System Services sit within this programme
EFR	Enhanced frequency response	One of GB's existing frequency response services
EIRGRID		Eirgrid Group plc includes several Eirgrid organisations, including: Ireland's electricity system owner; and the system operator (TSO) in the Republic of Ireland (which works with SONI, TSO in Northern Ireland)
FCR	Frequency Containment Reserve	A function in the frequency restoration process: European terminology
FES	Future Energy Scenarios	A set of scenarios NGESO prepares annually, to identify possible GB generation and consumption patterns and future challenges.
FFR	Firm Frequency Response	One of GB's existing frequency response services
FR	Fast Reserve	A reserve product on the GB system which delivers automatically within 2 minutes of receiving an electronic instruction from National Grid. The main types are Firm FR and Optional FR.

FRR	Frequency Restoration Reserve	A function in the frequency restoration process: European terminology
GB	Great Britain	
HVDC	High Voltage Direct Current	A type of electrical connection, generally used for international connections between non-synchronous power systems, and also long-distance connections under sea.
LFS	Low frequency static	One of GB's frequency response services, introduced in Nov 2019, as part of the "phase 2 trial"
LFSM	Limited Frequency Sensitive Mode	An operational mode which large power providers are required to operate within, when not providing frequency response services
MFR	Mandatory frequency response	One of the existing GB frequency response services
NG	National Grid	GB power system operator, and also owner of transmission infrastructure in England and Wales
NGESO	National Grid Electricity System Operator	GB's electricity system operator
RoCoF	Rate of Change of Frequency	Refers to changes in frequency in the GB system, which in nominally 50Hz
RR	Replacement Reserve	A function in the frequency restoration process: European terminology
SEMO	Single Energy Market Operator	Energy market authority in the island of Ireland
SO	System Operator	Taken to mean the GB electricity system operator
SoF	System Operability Framework	A set of documents NGESO prepares, which discuss GB system operability challenges and actions
SONI	System Operator of Northern Ireland	TSO in Northern Ireland. Works with Eirgrid, TSO in the Republic of Ireland
SQSS	Security and Quality of Supply Standard	Rules applicable to the GB electrical power system
STOR	Short Term Operating Reserve	One of the reserve services in the GB portfolio, which acts more slowly than Fast Reserve.
TN	Transmission network	National, high voltage electricity network
TSO	Transmission System Operator	Same as SO, but term normally used for overseas power systems

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2 MARKET NEEDS: FAULT CURRENT

2.1 Executive summary

Fault current performs key roles in contributing to *system strength*: contribution to a voltage waveform, which is essential for other connected equipment to function, especially converters' "Phase Lock Loop" control systems under fault conditions. A high fault current is also necessary for protection to detect and discriminate a fault.

There has not been, to date, any market for fault current, because it is provided "for free" from synchronous generators. With changing generation patterns, system strength, measured by short circuit levels, is falling in some parts of the country. This report has surveyed industry publications; novel quantification of the GB system needs by modelling was beyond the scope of this project and identified as important future work to inform decisions making by NGESO and the wider industry.

While there is presently no market for fault current in GB, there are indications of what a future fault current market could look like. In the recent Stability Pathfinder Phase 1 tender, which procured inertia, minimum fault current delivery requirements were also stipulated. Data from this tender provide an insight into pricing, although the tender was only open to synchronous technologies.

The Phase 1 auction results give an indication of the prices at which synchronous plants could offer fault current provision, based on participants' MVA ratings and tendered prices. This report has used these market data to estimate the capital costs of some of the tender participants, and compared these capital costs to costs of oversizing wind turbine converters to enable the same fault current provision. We found that fault current from synchronous plant appears to cost less than oversizing wind turbine converters, probably by a factor of 2 to 3, measured in capital cost per unit of fault current, although the cost ranges of both technologies overlap, and these estimates are sensitive to assumptions about the tender participants' business models. However, other power systems are also considering their own approaches to declining fault levels, which need to be considered for the cost benefit analysis. For instance:

- The power system of Ireland is in the process of introducing two products: *Fast Post Fault Active Power Recovery,* to be delivered within 250ms of a voltage perturbation; and *Dynamic Reactive Response,* to be delivered during voltage dips
- The Australian system operator AEMO is reviewing how best to support system strength; however, a "fault current market" is not mentioned. AEMO refers separately to the challenges of protection in some locations, and suggests modifying protection components

Recommendations made by this report include:

- The publication of minimum required fault level requirements across the GB system
- Greater clarity about system service(s) fault level is performing in different locations
- Investigation of protection measures able to function with lower fault currents
- Future stability tenders should be open to all technology types, and separate fault current from other services, to allow new entrants to propose alternative approaches. Regional linked tenders/markets across these services may be required in order to achieve the least-cost result for consumers

2.2 Introduction

National Grid ESO has expressed concern about declining fault levels in some parts of the country, particularly in geographical areas with large proportion of input from non-synchronous generators or HVDC interconnectors [1]–[3]. This work package explores the potential for generators, connected to the grid via PE converters, to access revenue by delivering fault current as a product.

Fault current, in transmission networks, performs two distinct functions: it contributes to system strength, and it is often necessary for the proper operation of protection.

2.2.1 System strength

The Australian system operator AEMO defines system strength as follows [4]:

> *"System strength is a complex concept, and an area of emerging understanding internationally. Definitions vary across jurisdictions, and continue to evolve as the international power system community's collective understanding of power system phenomena continues to grow.*
>
> *AEMO sees system strength as the ability of the power system to maintain and control the voltage waveform at any given location in the power system, both during steady state operation and following a disturbance. System strength can be related to the available fault current at a specified location in the power system, with higher fault current indicating higher system strength with greater ability to maintain the voltage waveform."*

National Grid gave a slightly different definition in its 2016 System Operability Framework [1]:

> *"System strength is a regional characteristic which can be expressed as short circuit level (SCL), measured in kA. It provides an indication of the local dynamic performance of the system and behaviours in response to a disturbance…. SCL is often also referred to as fault current…. For transmission network owners and distribution network operators SCL is an important marker for regional network performance across a range of voltage management criteria. … If SCL is too low, it can result in a dynamic performance deficit during a fault and consequential challenges in network protection operation."*

In National Grid's definition, "system strength" or "SCL" is a combination of

- maintaining the voltage waveform, and
- there being enough fault current available to promptly operate protection, which his discussed next

Other documents, e.g. *System Operability Framework: impact of declining short circuit levels*, 2018 [2] give attention to both system needs.

2.2.2 Operation of protection

Protection systems, necessary to isolate sections of network in the event of a fault, are built to give very good reliability and selectivity, at reasonable cost, on "traditional" (synchronous generation-powered) electrical power systems. Increasing levels of non-synchronous penetration, which would not normally deliver much, if any, additional fault current, introduce the risk that existing protection systems may not operate correctly under fault conditions.

The System Operator and Network Operators require protection to be present across the networks, to isolate faulted sections of network promptly, in order to minimise the damage caused by a fault. Fault are detected by measurements of magnitude, and in some cases phase angle or direction, of current, and / or of voltage. Measurement could be at a single location, or use measurements at two different locations.

In a power system with powered largely by synchronous generators, a fault will normally cause a collapse of voltage, and great increase in current (several per unit or higher), very near to the fault. Further away from the fault, the changes to current and voltage are smaller. These features can be used to detect and to discriminate the location of a fault, and to design equipment to isolate the affected part of the network, but as little as possible un-faulted network. Some but not all types of protection require an increased fault current, to be sustained for the duration which the protection takes to operate, typically around 100-140 ms [1], [3].

Synchronous generators generally provide a short circuit current of several pu for this period [3], which allows existing protection systems to detect the fault and isolate the network. In a future power system dominated by PE converter-connected generators, fault current of around 1 pu might be the maximum that is provided under fault conditions. Table 2.1 briefly describes some of the main protection types and states which protection types would work, would not work, and may work, with fault current limited to around 1 pu. National Grid ESO lists overcurrent, distance and differential protection as the main types in use on networks [3].

Table 2.1 Summary of the main protection types, and whether they could function on fault current of 1 pu. [5], [6]

Protection type	**Principle**	**Where used**	**Could I_{fault} = 1 pu work?**
Overcurrent	Increase in current near to a fault Can set speed of operation to increase with magnitude of fault current, or a combination of magnitude and direction of fault current.	Common in DNs especially at lower voltages, and as backup protection in transmission networks [2] *Cheap and simple. No comms needed.*	No. Several pu of current usually needed. Selectivity on basis of magnitude of fault current.
Directional	Fault causes current to flow in the "wrong" direction	Needs to be on simple network, where no reverse power flows would occur under un-faulted conditions	Yes. But needs careful siting to ensure new generation won't cause mal operation
Distance	Measures both **V** and **I**, and is triggered in certain ratios of these parameters. Often 3 sets of relays, of different sensitivity (for "zones 1, 2 and 3"), with different response times.	Common in higher voltages in distribution networks (EHV, 132Kv), and as backup in transmission networks	Yes. But protection could well need different settings, as it would be less sensitive to a fault causing only voltage collapse, than one causing voltage drop combined with current rise.
Differential	Compares magnitude of currents from two points along a conductor. Under normal circumstances they should be identical. In fault conditions within the defined area, these currents will differ.	In transmission lines, and individual equipment such as generators and transformers. *Needs comms to work.*	Yes. Could work very well. As long as set with appropriate sensitivity, could potentially work for relatively small differences in current.

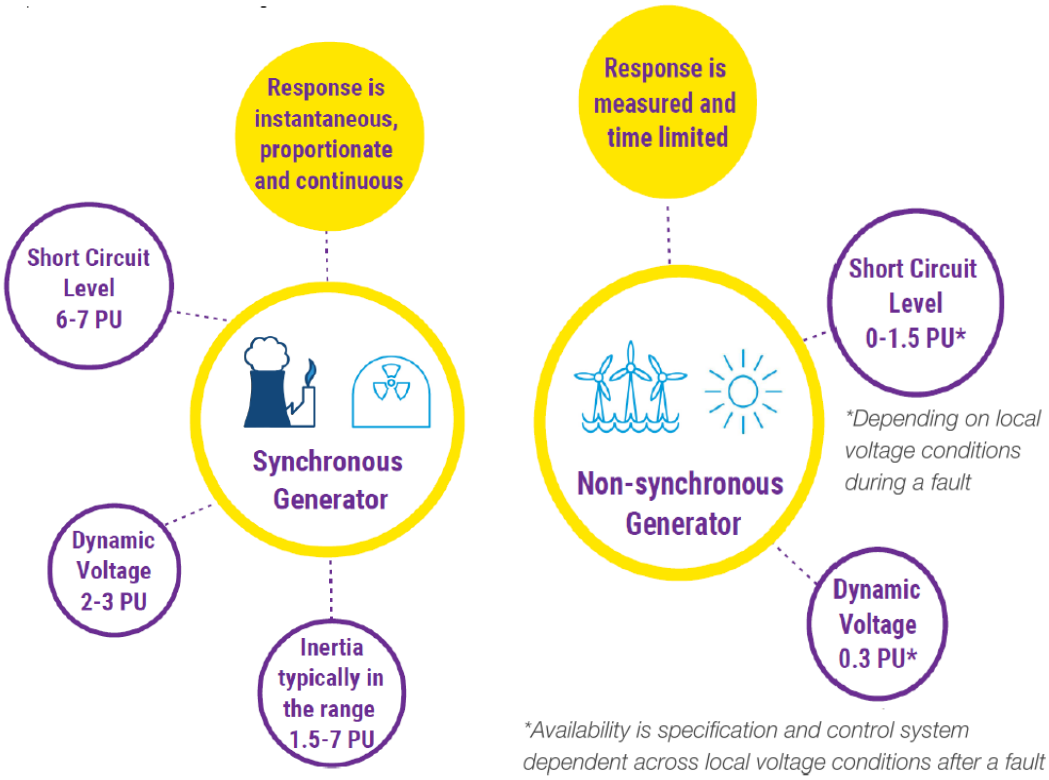
National Grid stated in 2016 "Reduction in minimum fault levels drives a need to find alternative protection approaches or increase fast fault current injection which also alleviates voltage dips. We have outlines regional assessments of protection and fault current required to maintain existing approaches." [1, p. 107]

2.3 Fault current: existing arrangements

Under fault conditions, synchronous machines automatically deliver a high fault current, several per unit. Power systems around the world have been constructed to operate with such generators being the main or only power sources.

However, many renewables, and HVDC connections, deliver to grids via power electronics converters, and they behave differently. National Grid ESO describes why short circuit levels are declining in areas of networks with increasing non-synchronous penetration, in the diagram reproduced in Figure 2.1.

Figure 2.1 Properties of synchronous and non-synchronous generators. National Grid ESO, 2018 [3]



While power electronic (PE) converters may be capable of operating better than Figure 2 indicates, short circuit currents from PE-connected devices are typically around 1 pu, unless the converter is deliberately oversized in order to be able to deliver higher currents. This option was discussed in Work Package 3.

National Grid ESO stated in 2018 [2] that declining short circuit levels pose two main risks to the system:

- In the event of a fault, protection might not operate correctly.
- In the event of a fault, there is some disturbance to the voltage waveform, in locations near to the fault. In a strong system, the disturbance is relatively small and localised. In a weak system, the disturbance is greater and extends over greater distances. A significant voltage disturbance carries the risk that that converter-connected generators, using Phase Lock Loop technology, may not behave correctly, and could even lose contact with the system.

Fault current has not been a tradeable commodity, because it is delivered "for free" from synchronous generators, which previously dominated power systems. However, as non-synchronous penetration increases, GB and some other power systems are considering measures to preserve fault current and system strength. National Grid estimates that needs are greatest in northern Scotland and parts of Eastern England [2]. The possibility of launching fault current, as a commercial product, is considered, but not yet realised.

2.4 Phase one stability tender: winter 2019/2020

2.4.1 Background and tender requirements

Stability pathfinder information, in summer 2019 [7], suggested provision of fault current would be an important component, along with inertia and voltage support. However, the actual Phase 1 tender, launched at the end of 2019 [8]–[12], was a little different:

- It prioritised the provision of inertia, though also stipulated voltage support and fault current requirements

- It limited participants to synchronous compensators and synchronous generators operating in synchronous compensation mode (i.e. not exporting any active power). National Grid ESO stated an intention to open up future tenders to other technology types

Tender requirements included:

- Provide inertia, H >= 1.5s
- Provide short circuit current of at least 1.5 pu MVA rating under fault conditions
- Provide reactive injection and absorption currents, to start delivery within 5 ms of voltage dip or rise outside of normal operational limits
- Maintain fault ride through capability, including toleration of a transient over-voltage of 1.4 pu on fault clearance
- Be connected at 132kV or higher voltage
- Operate throughout the tendered period

Full conditions are set out in Appendix E of the contract conditions [13].

2.4.2 Tender results

National Grid awarded 12 tenders to 5 providers, procuring 12.5 GVA.s of inertia, out of a possible 22.5 GVA.s offered [14]. The tender results are listed in [15]. Market information from this tender included: participants' MVA ratings, inertia provision (in s, and MVA.s), reactive current provision (MVAr), Firm Costs per settlement period, and delivery dates.

The Supplementary Information issued with this report gives more detailed information about the tender and its participants. Some aspects of the results are detailed below.

2.4.2.1 Tender durations

National Grid invited tenders for periods:

- starting between 1 April 2020 and 1 April 2021
- continuing until March 2023 and/or March 2026

Entrants were invited to enter bids for both end-dates if they wishes. All participants that entered different bids offered lower prices for the longer tenders than the shorter ones. National Grid selected offers to March 2026 only.

2.4.2.2 Selection basis – inertia

Analysis of the results found that selection was made on the basis of lowest cost inertia provision. Ten of the twelve selected plants were the cheapest eligible inertia providers, for the contract window selected. Low power consumption appears to have been another characteristic which National Grid viewed favourably. Other factors may have included location. An estimation of fault current price was made (discussed below). This parameter did not appear to influence the tender decisions.

2.4.2.3 Fault current prices

This tender, while not seeking best or cheapest fault current providers, did give information on prices the tender participants had offered for the package of services: fault current together with inertia and voltage support. It is therefore possible to estimate the prices at which participants were willing to offer fault current provision, together with other services. This tender is the nearest thing there is, to a market for fault current provision.

There are different metrics that could be used for fault current provision. Here, the plant MVA rating is used, as this is a key requirement of National Grid [11, p. 18], [13, p. 40]. The tender terms required plants to deliver at least 1.5 pu of their normal MVA rating under fault conditions (references as above). There was no incentive to deliver more.

To calculate a price of fault current, it is necessary to estimate how much fault current the plants would actually deliver, in fault conditions, compared to their normal rating. Here, three different scenarios are explored. Initially:

- Plants would deliver exactly 1.5 pu, compared to their normal rating, as per tender requirement

However, synchronous plant can typically deliver around 3-5 pu of their MVA rating under fault conditions. So two other scenarios are also examined:

- Plants deliver exactly 3 pu of their normal rating
- Plants deliver exactly 5 pu of their normal rating

The accepted entrants, and some of the rejected offers, are listed in Table 2.2, ranked by price per fault current provision per MVA per settlement period. Most are offers below are for bids from April 2021 to March 2026. (Note: contract durations of Sellindge plant are different to the others).

Table 2.2 Phase 1 tender: Cost of fault current delivery (£ per MVA rating per SP) from a selection of entrants [15]

Plant	**Plant type** [16]–[20]	**Owner**	**Location**	**Volts level kV**	**Cost per MVA rating, in £ per Settlement Period per MVA, assuming**			**Tender outcome**
					1.5pu	**3pu**	**5pu**	
Indian Queens	Diesel	Indian Queens	SW England	400	30 pence	15 pence	9 pence	Rejected, price
Ratcliffe-on-Soar	Coal	Uniper	Midlands	400	55 pence	27 pence	16 pence	Rejected, price
Sellindge	New build	ESBAD	Kent	400	62 pence	31 pence	19 pence	Rejected, dates[11] & terms[12]
Sellindge	New build	ESBAD	Kent	400	68 pence	34 pence	20 pence	Rejected, dates[1] & terms[2]
Deeside Power	CCGT	Deeside Power	NE Wales	400	69 pence	35 pence	21 pence	Accepted
Drax	Biomass	Drax Power	NE England	400	71 pence	36 pence	21 pence	Rejected, price
Killing-holme	Repurposed generator	Uniper	Humber	400	£1.08	54 pence	32 pence	Accepted
Sellindge	New build	ESBAD	Kent	400	£1.10	55 pence	33 pence	Rejected, dates[1]
Sellindge	New build	ESBAD	Kent	400	£1.21	60 pence	36 pence	Rejected, dates[1]
Keith	New build	Statkraft	N Scotland	132	£1.32	66 pence	40 pence	Accepted
Lister Drive	New build	Statkraft	Mersey	275	£1.32	66 pence	40 pence	Accepted
Cruachan	Hydro PHS	Drax Power	W Scotland	275	£1.55	78 pence	47 pence	Accepted
Killing-holme	Repurposed generator	Uniper	Humber	400	£1.64	82 pence	49 pence	Accepted
Ffestiniog	Hydro PHS	First Hydro	N Wales	275	£2.11	£1.05	63 pence	Rejected, price
Grain	New build at CCGT site	Uniper	Kent	400	£2.20	£1.10	66 pence	Accepted
Sloy	Hydro	Drax Power	W Scotland	132	£2.35	£1.18	71 pence	Rejected, price
Rassau	New build	Welsh	S Wales	132	£2.51	£1.25	75 pence	Accepted

[11] Start date in 2022, after latest acceptable start date
[12] For an almost 8-year contract, to 31 March 2030. Contracts were permitted to March 2026.

Plant	Plant type [16]–[20]	Owner	Location	Volts level kV	Cost per MVA rating, in £ per Settlement Period per MVA, assuming			Tender outcome
					1.5pu	3pu	5pu	
		Power						
Dinorwig	Hydro PHS	First Hydro	N Wales	400	£2.62	£1.31	79 pence	Rejected, price
Grain	New build at CCGT site	Uniper	Kent	400	£3.00	£1.50	90 pence	Accepted

Key:

	Successful in tender
	Eligible, but unsuccessful in tender. Rejected on price (inertia)
	Ineligible in tender. Non-compliant on dates and / or contract terms.

Here, the cheapest offerings were from existing thermal plant, some but not all of which were accepted. ESB Asset Development UK's Sellindge bids were the most competitive new-build (though the cheapest prices were for a longer contract term than was permitted) – these bids were rejected as the plant would not be operational by the latest permitted start date. Moderately-priced entrants included some repurposed plant (Killingholme), other new-build (Statkraft's offerings), and other hydro plant. The most expensive offerings which were accepted were from Grain (new-build synchronous compensators at Grain CCGT site) and Rassau (apparently new-build at new site). Some other entrants would have been more expensive. Further details are given in the Supplementary Material which accompanies this report.

2.5 Costs of fault current providers: converters vs synchronous plant

Fault current has traditionally been provided, free, from synchronous generators. It could, in the future, be provide by PE converter-connected generators. This section attempts to give a rough comparisons of likely costs.

Work Package 3 explored options for obtaining fault current from converters, and found that it is necessary to oversize them, as operating them above their rated current, for any duration, risks damaging them. This work found cost range for such plant.

Market data from Stability Phase 1 tender[15], described above, have been interrogated, to attempt to estimated possible capital costs of plants. The business models are not known, so some broad assumptions have been made, including:

- Plants will operate 24/7 throughout the contract duration, with no down-time
- The revenue accrued will cover capital repayment, interest, and operational expenses
- There are no other income streams

If, alternatively, capital is not to be paid off during the loan period, then capital costs of the synchronous plant would be higher than those presented, perhaps by a factor of 2 or 3. The presence of additional income streams, or different patterns of operation, would also significantly change results. Therefore, these figures must be viewed as *a rough estimate*. Further details are given in the Supplementary Material. The main results are presented in Table 2.3.

Table 2.3 Estimated CAPEX costs for fault current provision, from PE converters and synchronous plant

Plant	**Estimated capital costs, £ k / MVA rated output**			**Source**
PE converters, oversized	£40 k - £100 k			Work Package 3
Synchronous plant: -	**Assumed performance of synchronous plant**			
	1.5pu	3pu	5pu	
Cheapest new-builds (ESBAD, Statkraft)	£50 - £60 k	£25 - £30 k	£15 - £17 k	Stability Phase 1 tender market info. Many assumptions, including tender revenue repays capital and all costs.
Other new build (Grain)	£90 k	£45 k	£26 k	
Most expensive new-build (Rassau)	~£110 k	~ £55 k	~ £33 k	

These results suggest that, if the synchronous plant only offered 1.5 per unit MVA performance in fault conditions, the cost range for both technologies is very similar. If, as is believed more likely, synchronous plant would deliver greater fault current, of 3-5 pu, then the synchronous plant are cheaper, by a factor of 2-3, though the cost ranges overlap.

Given the uncertainties in these estimates, the cost differences may be smaller than these figures suggest. Alternative metrics, such as reactive injection provision (MVAr), or even current (Amps or Amps reactive) would give different results. These have not been explored in detail.

2.6 Announced future developments by National Grid ESO

National Grid announced in its Operability Strategy report, 2019, its intention of further stability auctions [21].

> *"The next step will be stability pathfinder phase two which will allow a longer tender process to support new technology types participating. Phase two is seeking to fulfil a locational requirement in Scotland..."*

The document hints that this next phase might include reducing short circuit level. At the time of writing, National Grid has announced that further details of Phase 2, which will apply in Scotland, will follow shortly.

2.7 Brief overview of arrangements in other countries

2.7.1 Australia

The Australian system operator AEMO, describes the need for action to ensure minimum levels of *system strength* throughout the network [4]. AEMO acknowledges that the term "system strength" has different and evolving definitions, and adds the one it uses. Its definition of system strength, reproduced in Section 2.2.1, separates the need to create a voltage waveform, from the need to safely operate protection.

In its 2020 Renewable Integration Study Stage 1 report, AEMO describes maintaining system strength as a major and growing challenge in parts of its jurisdiction, and one which requires coordinated work, frameworks, planning and review, across the individual transmission owners[13]. AEMO notes that system strength can be supported in a number of ways, including ensuring minimum levels of synchronous generation, the use of synchronous compensators; as well as "control system tuning" and "new network". The report does not elaborate on these options.

The main report only refers to fault current in the context of system strength. However, an appendix describes ways that new patterns of generation (distributed solar PV) can interfere with networks' protection systems [22]. The appendix notes the presence of distributed solar PV can lead to reduced fault currents, or reverse power flows under fault conditions, which can reduce the ability of a network's protection systems to detect or discriminate a fault. The Appendix suggests "*reconfigure and upgrade network components to accommodate changing fault level requirements*" and "*upgrade protection and / or modify protection settings"* as suitable mitigation.

In a separate report surveying power systems around the world [23], AEMO states it believes *"minimum inertia requirements in Texas and Great Britain… and the minimum synchronous generation requirements of Ireland, would likely be supporting minimum fault level in those systems as a by-product of keeping synchronous generators online for other purposes."* There is no sign of any new "fault current" product.

2.7.2 Ireland

The TSOs in Ireland are in the process of introducing two new ancillary services related to fault current. These are displayed in Table 2.4 [24]. These services are not yet being procured and further details are not readily available.

Table 2.4 Ireland's "fault current" ancillary services

New product	**acronym**	**requirement**	**2019-20 price** [25]
Fast Post Fault Active Power Recovery	FPFAPR	Active power (MW) > 90% within 250ms of voltage < 90%	£0.14/MWh
Dynamic reactive response	DRR	MVAr capability during large (>30%) voltage dips	£0.04/MWh

[13] More information on the Australian power system is available from AEMO https://aemo.com.au/about/who-we-are. Further information is included in the WP4: Frequency Response and Fault Current report, which accompanies this document.

2.8 Conclusions

Fault protection performs key roles in supporting system strength: maintenance of a voltage waveform, necessary for operation of equipment, especially converter PLLs, in the event of a disturbance. It is also necessary for timely operation of protection. Fault levels are declining in parts of the country.

There is no existing market for fault current. However, there are hints that such a market may emerge. The Stability Phase 1 tender required a modest level of fault current provision along with the main objective of procuring inertia, but was only open to synchronous plant. Long contract durations allowed participation of schedulable plant only. National Grid ESO is developing the Stability Phase 2 tender, which will focus on network issues in Scotland. Non-synchronous plant may be allowed to participate in future tenders. If in future, fault current procurement is separated from inertia, the other conditions of the Phase 1 tender appear achievable for PE converter-connected generators.

Market data from the Phase 1 tender found that National Grid's selection:

- was based overwhelmingly on low-cost inertia provision, and
- did not correlate with fault current price

It is possible to estimate fault current prices from the Phase 1 tender, from entrant prices (£ per settlement period). It is necessary to define a suitable metric: here, plant MVA rating was used. A further definition of performance were necessary, to assume the actual fault current (in MVA) that the plant would deliver during a fault. Three performance levels were used:

- 1.5 pu of normal delivery. This was the minimum requirement in this tender
- 3 pu, and also 5 pu, of normal delivery. These values are more typical of synchronous plant behaviour

Successful tender applicants quoted prices from £0.70 to £3.00 per settlement period per MVA rating, assuming 1.5 pu performance, over the course of the 5-year tender. Prices are 2 times, and 3.3 times lower, if one assumes 3pu or 5pu performance, respectively.

Tentative estimates of possible capital costs of some of the Phase 1 tender entrants have been made from published market data. These results have been compared with Work Package 3 work, which estimated CAPEX for fault current provision by oversizing converters. This comparison found:

- If the synchronous plant delivers 1.5 pu, the price ranges for both technologies are similar
- If the synchronous plant deliver 3-5 pu, the synchronous plants are cheaper, by a factor of roughly 2-3, though there is some overlap in price ranges

Alternative metrics could be selected, such as reactive injection current (MVAr) or even current (Amps or Amps reactive), which might be more appropriate if the fault current is required to trip local protection. Different metrics would change rankings based on cost per "service". The most appropriate metric may depend upon which role or roles the fault current is to provide.

National Grid refers to "system strength" as a mixture of tripping protection, and maintaining a voltage waveform. Clearer definition of the term "system strength", and, of which need the fault current is to meet in a particular location, would be very helpful. Such clarity could help PE converter-connected generators, in particular, to provide the most appropriate offering.

2.9 Recommendations and future work

Fault current requirements are highly locational and also depend on protection mechanisms and their settings. Given the rapidly changing characteristics of the GB power system, a detailed analysis of future options for fault current and protection settings is required to inform decisions in the medium-term. The current trajectory, charted by NGESO Stability Pathfinders and network owners' RIIO-T2 investment plans, using fault level as the only relevant measure, appears to favour the use of synchronous compensators and conventional plant acting as synchronous compensators (operating in so-called *spin-gen* mode), rather than changes to protection schemes and use of power electronic devices.

We make the following recommendations for the near-term:

Market needs

- Open future stability tenders to providers of all technology types
- Unbundle stability services of fault current provision, voltage support, and inertia provision, in order to allow new entrants to offer innovative solutions. Regional linked tenders/markets across these services may be required in order to achieve the least-cost result for consumers
- Incorporate both firm (continuous) and non-firm products to increase optionality to the ESO and diversity of potential providers. Weather dependent and some demand-side providers could likely only offer on a non-firm basis
- Publish full market data, including technology type of all participants
- Review the rules allowing participation of network owners and operators in tenders, as a possible market distortion

Non-market

- Assess and publish minimum required fault currents across the system
- Provide clarity on what role or roles fault current is required to perform, where it is needed
- Consider using alternative measures of fault current provision, depending upon the role it would be performing
- Investigate alternative protection approaches that are able to work with lower fault currents
- Publish carbon-intensity data for all services procured

2.10 Grid Code requirements for fault current

This section is based on The Grid Code, Issue 5, Revision 40, dated 5th March 2020 [26]. Different provisions apply, according to type of generator (or other party connected to the transmission system) and the date of connection, or purchase of plant.

Customers connected before around 2018/ 2019 are likely to be classified as "GB Code Users", and must comply with the Grid Code section "Connections Conditions (CC)". Customers connected after around 2019, or for plant purchased after around 2018, are likely to be classified as "EU Code Users", and must comply with the Grid Code section "European Connection Conditions (ECC)".

In all circumstances, the bilateral agreement between the network and an individual generator may include further requirements or conditions.

2.10.1 Connections Conditions (CC)

These conditions apply to *GB Code Users*, i.e. plant purchased / connected before around 2018 / 2019.

All generators and other power providers are required to comply with *fault ride through conditions,* set out in *CC.6.3.15*. That is, in the event of major voltage disturbances outside of normal operational limits, at the point where a generator / power plant connects to the onshore transmission system, generators are required to

- remain transiently stable, without tripping
- to stay connected for at least 140ms, unless the voltage dips below 0.33pu (for synchronous generators) or 0.15pu (for converter-connected power plant)

During the period of voltage disturbance outside of normal operating range, generators / power plants are required to deliver the maximum reactive current they can (and also reactive compensation, for plant installed after around 2017), within the transient limits of their own equipment. The Grid Code sets no further stipulations about the magnitude of current to be delivered.

Upon clearance of the fault, generators are expected to assist the Transmission System voltage recovery, by delivering at least 90% of their pre-fault active power delivery, within 0.5 seconds of system voltage recovering to normal operational limits. (Exceptions are allowed for wind generators, in the event of a fall in wind resource.)

Very similar requirements apply to offshore generating units which opt to meet their fault ride through requirements at the LV side of the Offshore Platform. (CC.6.3.15.2).

2.10.2 European connection conditions (ECC)

These conditions apply to *EU Code Users*, i.e. plant purchased / connected after around 2018 / 2019.

2.10.2.1 Fault Ride Through

All generators and other power providers are required to comply with *fault ride through conditions,* set out in section ECC.6.3.15.

For faults up to 140ms in duration, both synchronous plant, and converter-connector generators and power sources, are required to stay connected for 140ms, in the event of voltage drops, down to as low as 0.30pu, 0.10pu, or 0pu, depending on the class of equipment, and voltage of the connection point. For faults lasting longer than 140ms, requirements are set out, which are very similar to those set out in the Connections Conditions.

2.10.2.2 Fast Fault delivery requirement

Unlike the Connections Conditions chapter in the Grid Code, the European Connection Conditions chapter does include a defined requirement for fast fault current injection, set out in section ECC.6.3.16. These requirements are set

out for “Power Park Modules and HVDC Equipment” (all types). No equivalent requirements are set out for synchronous generators.

The Grid Code’s definition of “fast fault current” is:

> *A current delivered by a **Power Park Module** or **HVDC System** during and after a voltage deviation caused by an electrical fault within the **System** with the aim of identifying a fault by network **Protection** systems at the initial stage of the fault, supporting **System** voltage retention at a later stage of the fault and **System** voltage restoration after fault clearance.*

Non-synchronous generators are required to deliver a reactive current injection, in the event of the system voltage falling below normal operational limits. The maximum reactive (or active) current delivery requirement is up to its transient or steady state rated output, i.e. up to 1.0 pu (ECC.6.3.16.1.6). There is no requirement to exceed this level.

When the voltage falls below 0.9 pu, converter-connected generators and equipment are required to deliver reactive current. The amount of reactive current:

- must be, as a minimum, no less than the reactive current being delivered immediately pre-fault
- increases with decreasing level of transmission system voltage, up to 1.0 pu reactive current for a voltage of 0.5 pu
- must be within the rated capacity of the generator or equipment

There is no requirement to deliver reactive current when the voltage is below 0.5 pu.

The timescale in which the reactive current must be delivered depends upon the level of reactive current being delivered pre-fault. Additional reactive current delivery (i.e. above the level delivered immediately pre-fault) must start within 20ms of the voltage falling outside of normal operational limits, and full reactive current delivery is expected within 120 ms.

2.11 References

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