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

Review of System and Network Issues

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1 Executive Summary

National Grid ESO has an ambition to be able to operate the GB transmission system carbon-free by 2025. Today, NGESO depends on gas and coal plants for a range of essential ancillary services and takes actions to ensure they are online and able to provide them. To enable zero-carbon operation, zero-carbon technologies require routes to market for all of these services. In many cases, either the current technical specifications or procurement mechanisms prevent zero-carbon generators from participating.

This report is the first of four to be produced as part of the Netorks-06 project. It surveys the current suite of ancillary services, as well as emerging system needs that may lead to the need for new ancillary services in the future. Furthermore, a number of recommendations have been made for the next work packages of Networks-06 and future work.

Main Findings:

- Frequency Response: Increased share from FFR along with price drop from over £30/MW/h to under £10/MW/h. Wind providers are providing increasing shares of the MFR volumes, with a combined revenue of £150k in August 2019. Most advanced of the ancillary services considered in terms of market re-design, with phase out of FFR and the introduction of new auction mechanism over the next three years.
- Reserve: Apparent change in strategy as NGESO doubles Fast Reserve procurement to 600 MW from January 2020. NGESO control room has an apparent growing need to access flexible energy for balancing on minute-by-minute basis.
- Reactive Power: Demand for reactive power services has increased in recent years, particularly in spring and summer months. The increase in reactive power demand is largely for reactive power absorption due to high voltages under lightly loaded system conditions. These trends are true for the whole of the GB system, but the North of England in particular.

Recommendations for next Work Packages:

- WP2: Properties and implications of proposed product design for future frequency response services should be scrutinised.
- WP3: The viability of the provision of fault current support from power electronic devices.
- WP4: Suitability of existing and proposed market structures and mechanisms for the provision of ancillary services in a net zero 2025 GB power system.

Recommendations for future work:

- Assessment of impact of plant closure on fault current. This is highly locational and findings from locational analysis of reactive power requirements in this report can inform future work on this topic.
- Particular attention should be given to Fast Reserve, which to date has a very low technology diversity that could be widened if market arrangements were modified.

2 GB Power System Operability Concerns and Themes

The electricity generation mix in GB has changed significantly over the past decade (Figure 2.1), with coal generation drastically reduced to near zero. By 2025, National Grid aim to have the systems, products and services in place to allow zero carbon operation of the power system of Great Britain. To achieve this, significant changes in the way the system is managed will be required to ensure new low carbon technologies are able to be integrated.

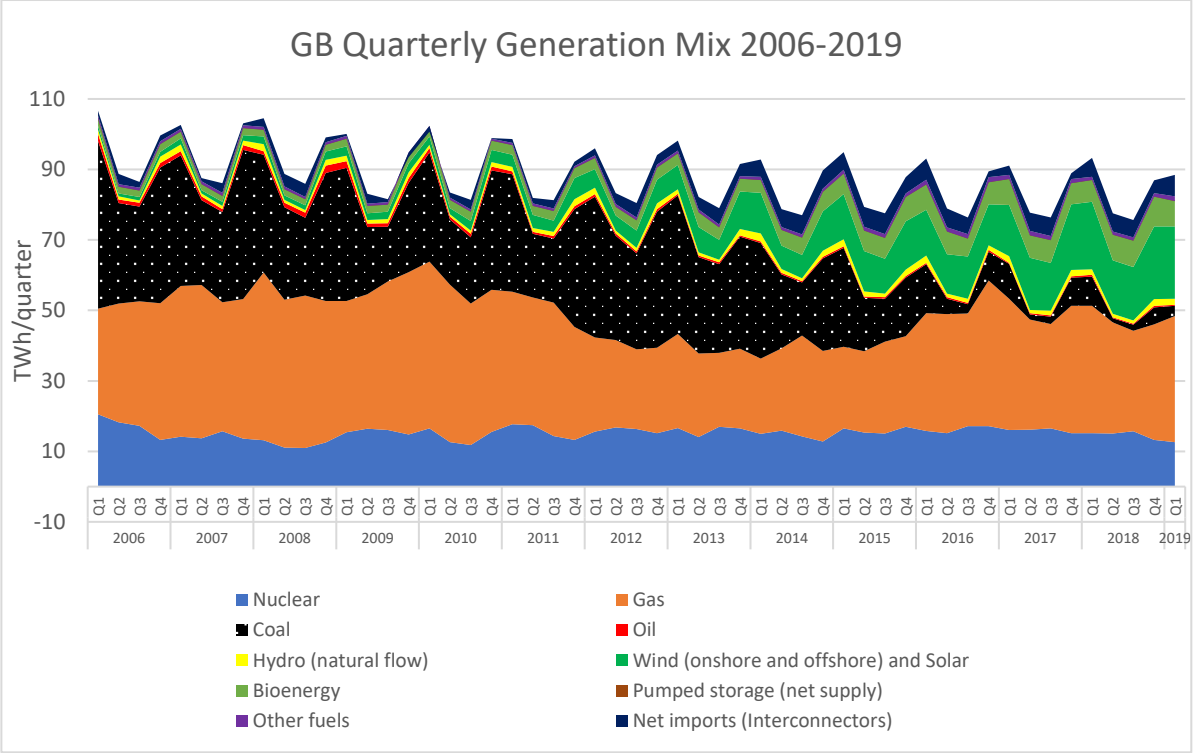

Figure 2.1: GB quarterly generation mix from 2010 to 2019. Source: BEIS.

There is increasing uncertainty over the future of existing synchronous plant such as coal and nuclear assets reaching end of life, and timescales for new nuclear builds (Figure 2.2) and HVDC interconnection with Europe (GB HVDC interconnector capacity is expected to quadruple from 5GW within 10 years). Additionally, Scottish wind output is projected to grow from the current 8 GW levels, likely leading to increasing constraint costs to curtail wind generation north of B6. In turn, this results in increased uncertainty over inertia level (national and regional), system frequency, voltage regulation capabilities, regional system strength, rate of change of power flow over boundaries (e.g. B6 boundary, amongst others), system balancing, thermal constraints and system restoration following black out. Many of these are already a concern for GB system operation and are expected to be exacerbated as more synchronous generation goes offline to make way for low-carbon – often non-synchronous – generation. Whilst these new technologies must be capable of offering services to support system operation, system services must also be designed to be technology agnostic.

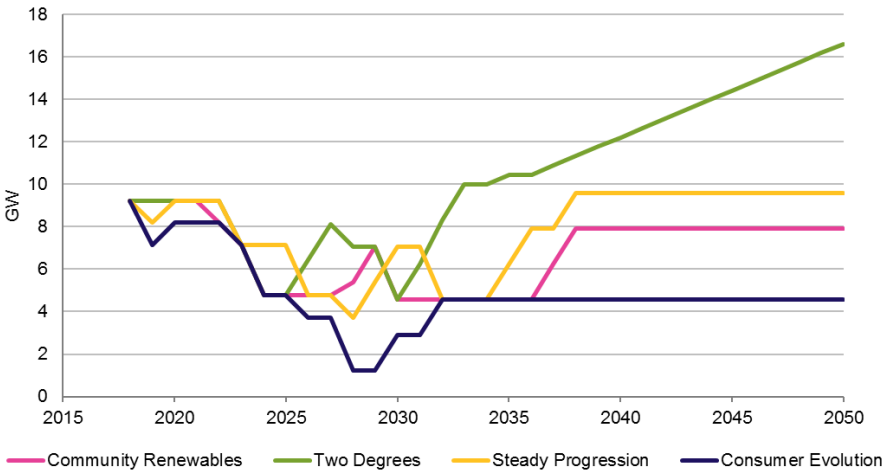

Figure 2.2: Installed nuclear capacity. Source: FES 2019 data workbook.

3 Key GB Operability Themes

A brief summary of the current and emerging system operability concerns in GB is provided below. Themes have been extracted from various System Operability Framework (SOF) documents by National Grid [1].

3.1 Inertia and RoCoF

System inertia is expected to continue to decline over the coming years, as a result of planning and operational decisions. Reducing system inertia results in higher RoCoF. As a result, there will be an increased need for system operator interventions to limit the largest loss and manage increasingly volatile system frequency. In the short term, the RoCoF relay settings for embedded generation on loss of mains (LoM) protection continues to be a concern until relay desensitisation programme is complete. There is a growing requirement to manage system frequency and RoCoF on a regional basis, as regions of the system – such as Scotland – experiences significant displacement of synchronous generation. This links to growing concerns over the angular stability of electrically remote synchronous plant such as Peterhead.

3.2 System Frequency

Frequency response requirements are higher when system inertia is lower, which will become increasingly common in the future. As a result, it is expected that fast acting frequency response services will be required to contain system frequency following an event. These faster acting services are likely to be valued highly, since fast acting response reduces the overall response required. The need for faster acting containment services has already been identified by the ESO and the enhanced frequency response tender in 2016 meets some of the this need; however, the ESO is currently taking steps to revise the frequency response market and suite of services which would include other fast acting frequency response products.

3.3 System Strength

System strength is conventionally measured as short circuit level (SCL). Synchronous plants have traditionally contributed to system strength, so as synchronous plants are displaced by non-synchronous sources, the fault level will reduce. This has impact on the operation of protection, power quality, stability, PLL stability and voltage volatility. System strength decline is a regional issue that will impact locations of the system where synchronous plant is going offline.

Traditionally, fault level and grid stiffness have been considered to be the same thing in networks dominated by synchronous generation. This is because synchronous generation gives the same fault level contribution and grid stiffness. Converter connected devices controlled, as virtual synchronous machines, would struggle to provide more than 1.2 p.u. fault current during a fault without oversizing the converter, however converters would be able to provide grid stiffness in steady state. In converter dominated networks, defining exactly what the system requires is crucial.

3.4 Voltage

Voltage is a localised property of the system and is affected by changes in the network itself, which means that requirements vary from one region to another. At present, a voltage issue is managed by synchronising traditional plant (often needing to buy active power to access the generators reactive power capabilities) and desynchronising some other generation (often renewable generation). As synchronous plant is displaced, there is less synchronised generation available to provide reactive power support. This is particularly an issue at low demand periods (which are expected to become more frequent with increasing penetrations of weather-dependent distributed generation) where there is a growing need for reactive power absorption to prevent high network voltages. Moving towards zero carbon operation, converter connected sources must offer voltage management capabilities; of this, a greater proportion must be dynamic in order to follow the daily reactive load profile and ensure voltage containment and recovery after a disturbance.

3.5 Balancing and Flexibility

Flexibility is required to manage the variable output of weather-dependent renewables, particularly wind and solar. Operating margins, volumes of energy available for dispatch by NGESO to manage this variation, are typically

maintained by operating plant part-loaded. There is an increase in embedded generation (namely wind and solar) unable to take instruction from the SO. In addition to this, access to flexible plant is limited at times of low transmission demand (and high renewable output). Additional balancing actions are required to ensure sufficient flexibility when large generators are displaced by small generators, which is likely to increase operability costs. In coming years, more flexibility will be required from small generators, demand and HVDC interconnectors to help create more head/footroom to manage renewable variability.

3.6 System Restoration

As the transition to low carbon operation continues, there will be a reduction in large transmission connected plant – which have traditionally provided black start capabilities. This has already happened in Scottish Power Transmission network area, where they are left with limited black start options in the region. The system operator must consider alternative approaches from new technologies moving forward.

3.7 Thermal Constraints

Historically, BM units were used to manage thermal constraints (either through instruction in the BM, or via Constraint Management Contracts). As GB transitions to zero carbon, the changing generation mix will result in different network power flows and voltage levels, leading to constraints in new areas. Many of these providers are not accessible via the BM, reducing SO constraint management options. New providers must participate in constraint management services.

4 System Operation on Difficult Day – 21st April 2019

Understanding recent days that posed operability challenges for the GB system operator may provide insights into how an average day of operation may look in the future. On Easter Sunday 2019 the daytime demand of 18.2GW was reported to be lower than the morning demand of 19.2GW, largely down to a high solar output on the day. In addition to this, there was congestion on the B6 boundary due to high wind output in Scotland and GB was trading on interconnectors. During the afternoon period generators in National Grid Transmission are constrained on (e.g. Langage and Rocksavage), whilst generation in Scotland is constrained off (e.g. Dersalloch and Hadyard Hill windfarms). Over the afternoon period there is a great deal of activity on the interconnectors, none of which is actioned via the BM. Presumably these actions are therefore either due to a price change, or a result of trading activity (managing largest loss risk).

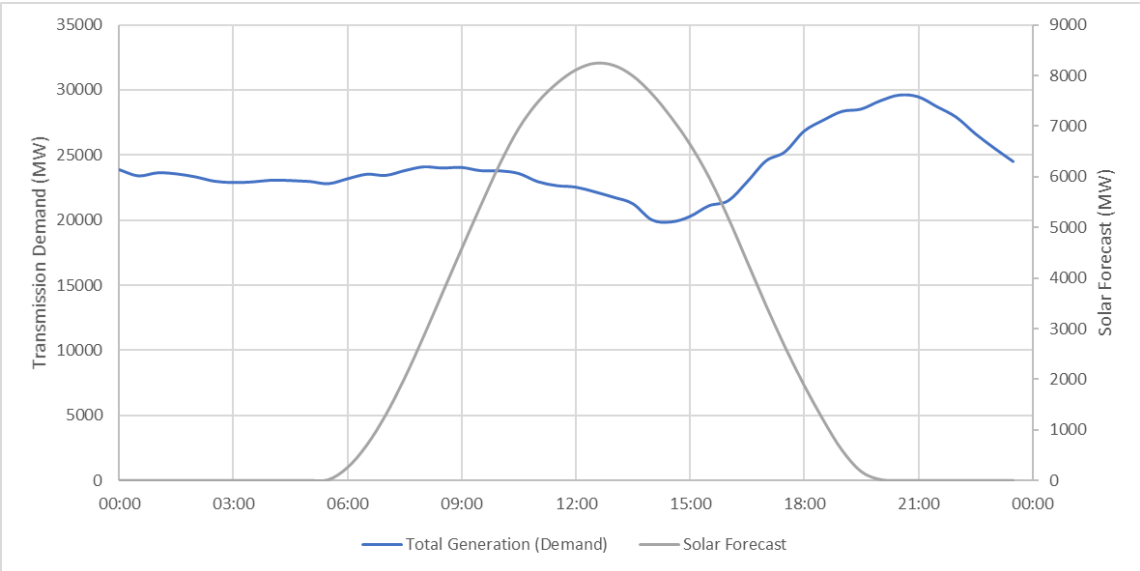

Figure 4.1: Total GB generation and solar forecast for 21st April 2019.

Figure 4.2: Key sources of active power on 21st April 2019 with afternoon period highlighted.

Actions in the BM are flagged with an 'SO flag' if the action is taken to resolve a system issue rather than total energy balance, making it difficult to assess the actual reason actions are taken (or indeed if an action is taken to resolve multiple issues). For example, it is likely to be more cost effective and/or practical for the National Electricity Control Centre to take one single action to resolve a voltage and thermal constraint, rather than multiple. The current reporting format does not provide such information.

Improved reporting as to why actions are taken in the BM would be of great use for understanding how GB is operated. Actions that are not taken for energy balancing purposes could be reported with thermal, voltage and/or RoCoF constraint flags in BM reports. Alternatively (if the system operator is unable to provide this level of detail for whatever reason), this level of detail could be provided on a case by case basis through the Transmission Operational Forum (either for entire days or sections of days, deemed to be operationally difficult). As it stands, the level of detail provided for 'difficult days' is not currently detailed enough to draw any meaningful conclusions around how GB is operated under different scenarios. That said, these 'difficult days' are likely to become more common in the future, with large volumes of wind in Scotland and high penetration of embedded solar in the south, leaving the system operator with limited options other than to constrain off wind and constrain on synchronous plant in England to deal with thermal, margin, voltage, RoCoF and response/reserve requirements whilst limiting the largest loss of infeed (usually interconnector or nuclear).

5 Total Cost of Balancing

Balancing services are procured from suppliers to manage system issues and ensure the power system remains operational in an efficient, economical and coordinated manner. Figure 5.1 shows the annual spend on balancing services remained relatively constant from 2011/12 to 2017/18 at an average of approximately £870m per year. This increased in 2018/19 to over £1200m, significantly higher than the previous year. These costs do not include any bi-lateral contracts between National Grid SO and suppliers. Figure 5.2 shows the same data, in a monthly resolution. Much of the volatility in balancing services spend comes from constraints (which includes voltage, RoCoF and transmission constraints, but the Monthly Balancing Services Summaries (MBSS) [2] reporting format does not differentiate between them before 2018/19). Constraints are discussed in more detail in section 7.1.

If constraint costs are excluded, when combined; operating reserve, STOR and Fast Reserve account for the majority of the money spent in these key markets. This is followed by spend in response markets, which has been decreasing over the reporting period. There has been an increase in reactive and black start spending. Further analysis of volumes and costs are provided in the relevant sections of this report (see section 0 for reserve, section 10 for response and section 11 for reactive).

Key Points:

- Balancing service spend in 2018/19 was £1.2 billion (higher than any other year since 2011/12).
- Much of the balancing service costs come from constraints (reported in detail in section 7.1).
    - Detailed breakdown of constraint reasons (voltage, ROCOF and transmission) is only available in MBSS from April 2018 onwards.
- When constraint costs are removed from balancing service spend, spend on other services has remained relatively constant since 2011/12, with a slight increase in spend in 2016/17 due to an increased spend on operating reserve.
- Black start spend has increased significantly since 2015/16.
- Volumes and costs of reserve services, frequency response services and reactive power services is provided in more detail in section 0, section 10 and section 11 respectively.

Further Investigation:

- Balancing service volume and spend would have been expected to have risen over the past few years, reasons why this has not been the case should be investigated.

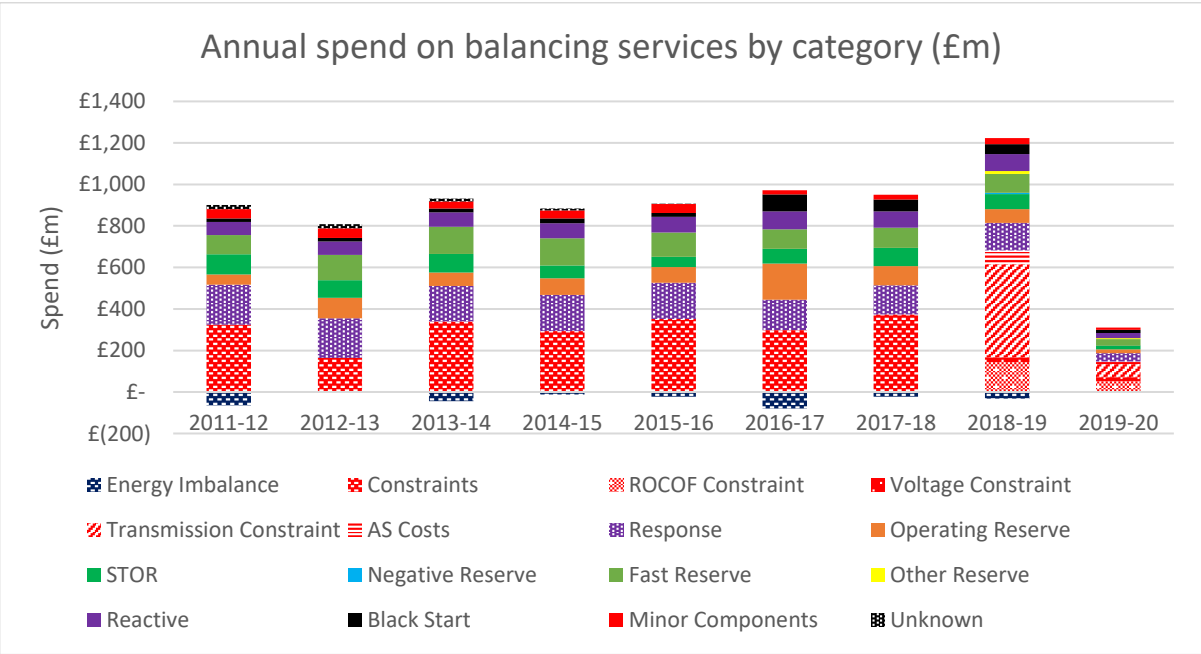

Figure 5.1: Annual spend on balancing services by category (£m). 2019-20 data only includes April – July 2019. Detailed breakdown of constraints only available from April 2018 [2].

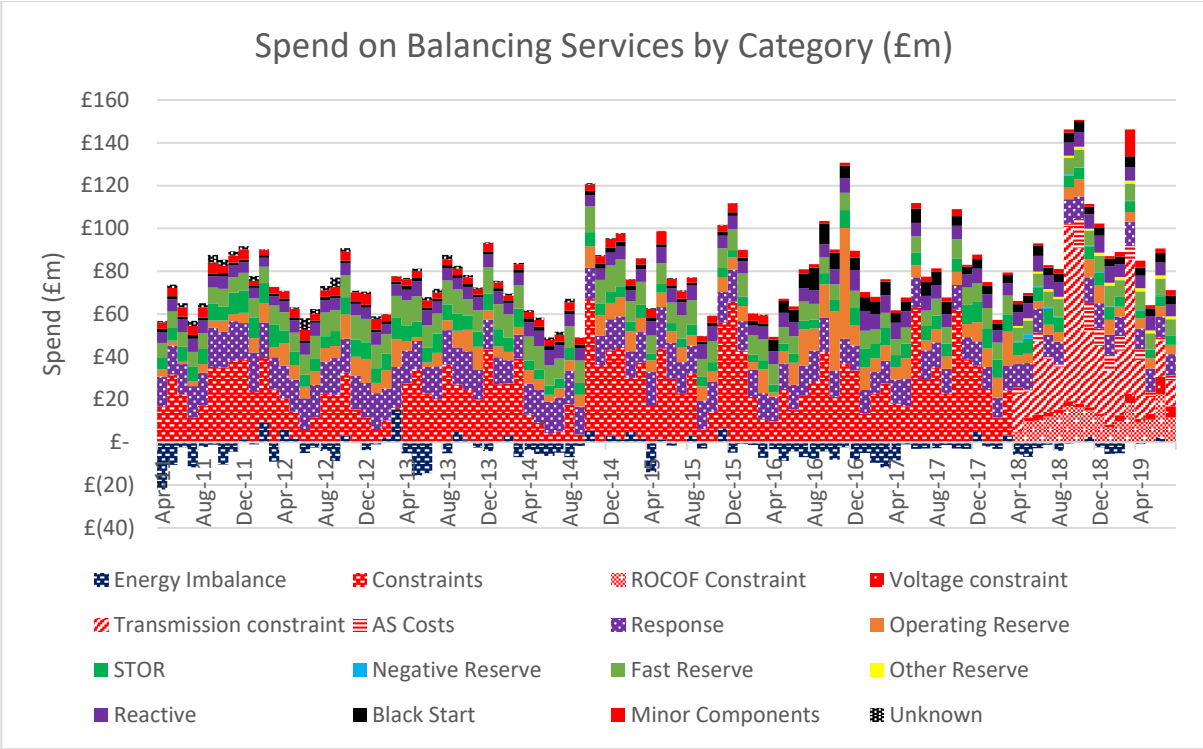

Figure 5.2: Monthly spend on balancing services by category (£m). Detailed breakdown of constraints only available from April 2018 [2].

6 Balancing Services Definitions

6.1 Energy Imbalance

Energy imbalance is the difference between the amount of energy generated in real time, the amount of energy consumed during that same time, and the amount of energy sold ahead of the generation time for that specific time period. The monthly energy imbalance cost can be negative or positive depending whether the market was predominantly long or short.

6.2 Reserve

In coming months, National Grid aim to standardise the reserve service portfolio. This will be done based on the outcomes of the Wider Access to Balancing Mechanism project and Project TERRE.

6.2.1 Operating (Positive) Reserve

Operating (or Positive) Reserve is required to operate the transmission system securely, and provides the reserve energy required to meet the demand when there are shortfalls, due to demand changes or generation breakdowns.

6.2.2 Short Term Operating Reserve (STOR)

Short-term Operating Reserve (STOR) allows National Grid to have extra power in reserve for when we need it. It helps National Grid meet extra demand at certain times of the day or if there's an unexpected drop in generation.

6.2.3 Fast Reserve

Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic dispatch instruction from National Grid.

6.2.4 Negative Reserve

Negative Reserve services provide the flexibility to reduce generation or increase demand to ensure supply and demand are balanced. The service is held in reserve to cover unforeseen fluctuations in demand, or generation from demand side PV and wind.

6.2.5 Other Reserve

Other reserves consist of other contracted reserve services that help to offset the cost of managing reserve in the BM (these include Hydro Optional Spin Pump (Commercial), Hydro Rapid Start and GT Fast Start Utilisation (Commercial), BM GT Fast Start Availability (Commercial), NBM Demand Turn Up (Commercial), BM Power Potential (Commercial), BM Demand Turn Up (Commercial) and BM Warming (Commercial)).

6.3 Response

Response is a service we use to keep the system frequency close to 50Hz. Providers respond automatically to a local measurement of system frequency. Generation and demand units are held in readiness to respond to any deviation in the system frequency from 50Hz, which could be caused by normal variations in the energy balance or sudden loss of generation or demand. Frequency response in GB can be categorised into "enhanced", "primary", "secondary" and "high" which may be dynamic (continuously responding to frequency deviations) or static (also known as non-dynamic, triggered at a defined frequency deviation) in nature. The difference between enhanced, primary and secondary is the speed at which they act recover the system frequency. Both enhanced, primary and secondary react to low frequency conditions, and high response reacts to high system frequency conditions, restoring the frequency to normal operational limits.

6.4 Black Start

Black start is the procedure we use to restore power in the event of a total or partial shutdown of the national electricity transmission system. It means we can start up each power station in turn and reconnect them to the grid one by one.

6.5 Constraints

Constraints relate to, requests from National Grid to a generator to reduce, or constrain, the amount of electricity it's producing. This assists National Grid in keeping within the SQSS and prevent the loss of large parts of the network. This is broken down into transmission, voltage and RoCoF constraints.

6.6 Reactive

National Grid manage voltage levels across the grid to make sure we stay within operational standards and avoid damage to transmission equipment. Voltage levels are controlled by reactive power, providers help manage voltage levels on the system by controlling the volume of reactive power that they absorb or generate.

7 Constraints

The MBSS reporting structure only breaks down constraints into voltage, RoCoF and transmission from 2018/19. Reporting categories may not be strictly accurate in the MBSS since the system operator will often take one action to deal with multiple issues where possible. This makes it difficult to know for certain how volumes and costs of constraints evolve over time. For the dates available, breakdown of volume (Figure 7.1) and spend (Figure 7.2) is provided.

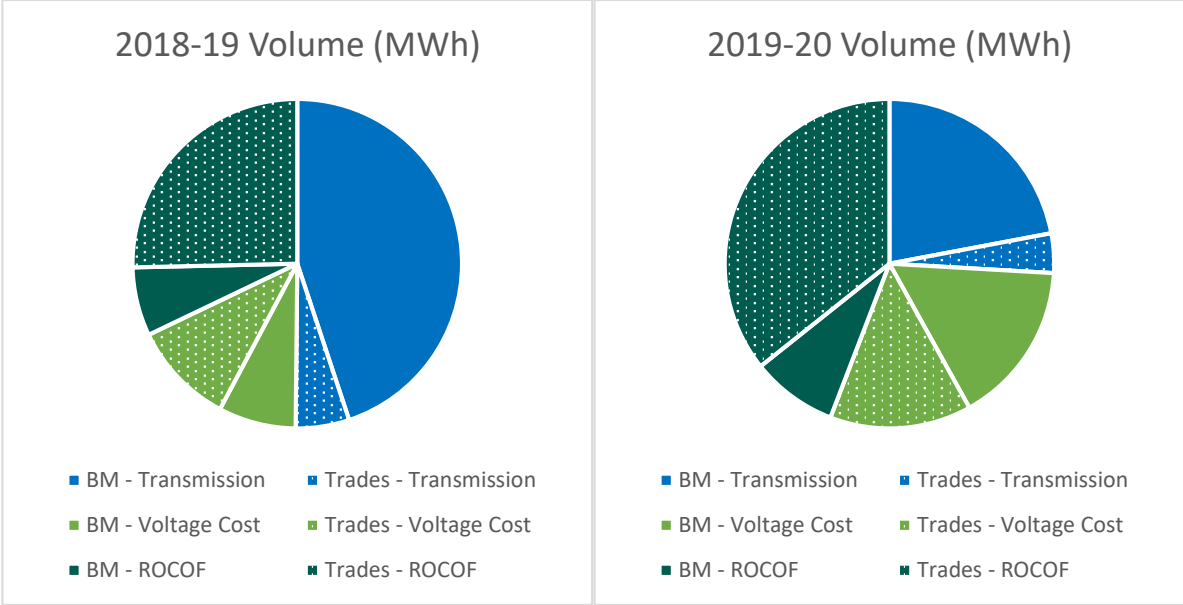

Figure 7.1: Annual constraint volume by type (MWh) available from April 2018 – July 2019. 2019-20 data only includes April – July 2019 [2].

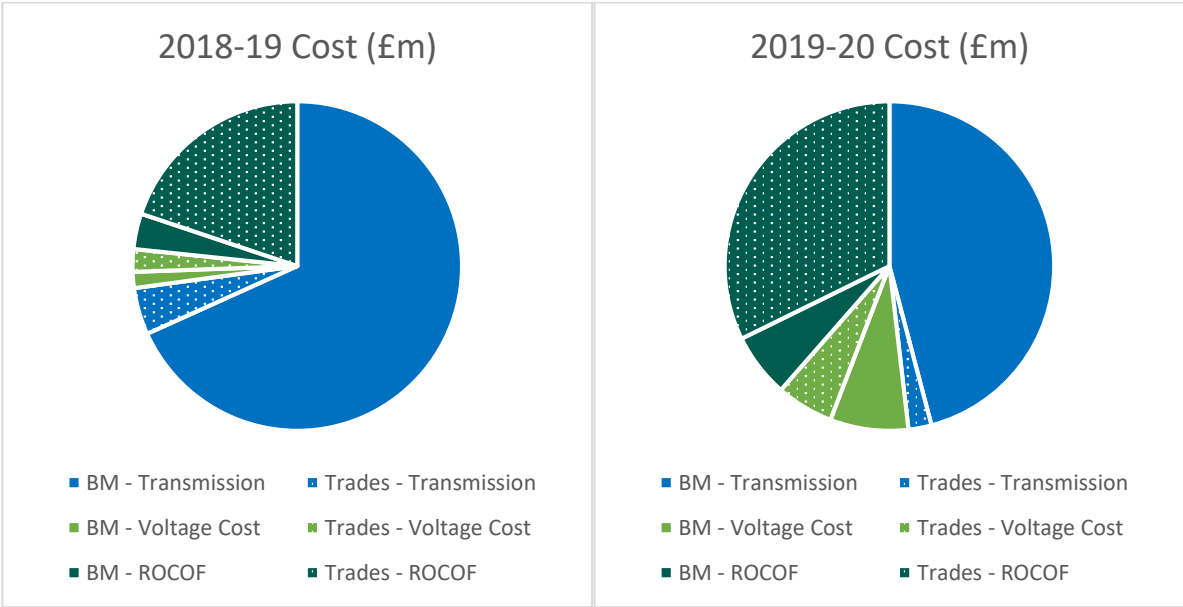

Figure 7.2: Annual constraint spend by type (£m) available from April 2018 – July 2019. 2019-20 data only includes April – July 2019 [2].

Key Points:

- The majority of constraint volume and cost relates to transmission constraints, specifically BM transmission constraints.
- Reason for variations in the volume and spend on constraints overall is usually down to variations in the cost of transmission constraints.

Further Investigation:

- Constraint cost reporting detail improved in MBSS from April 2018 to specify transmission, voltage and RoCoF constraints.
    - This level of detail from National Grid going back in time would be useful for analysis purposes, since changes over time could be analysed.
- Unclear how accurate constraint reporting in the MBSS is since one action could be taken to deal with multiple issues. In such a case, what category is the constraint reported under?

The monthly breakdown of constraint volume and constraint cost by category is given in Figure 7.3 and Figure 7.4 respectively. It is difficult to identify clear trends since the data set does not go far enough back in time to draw clear conclusions.

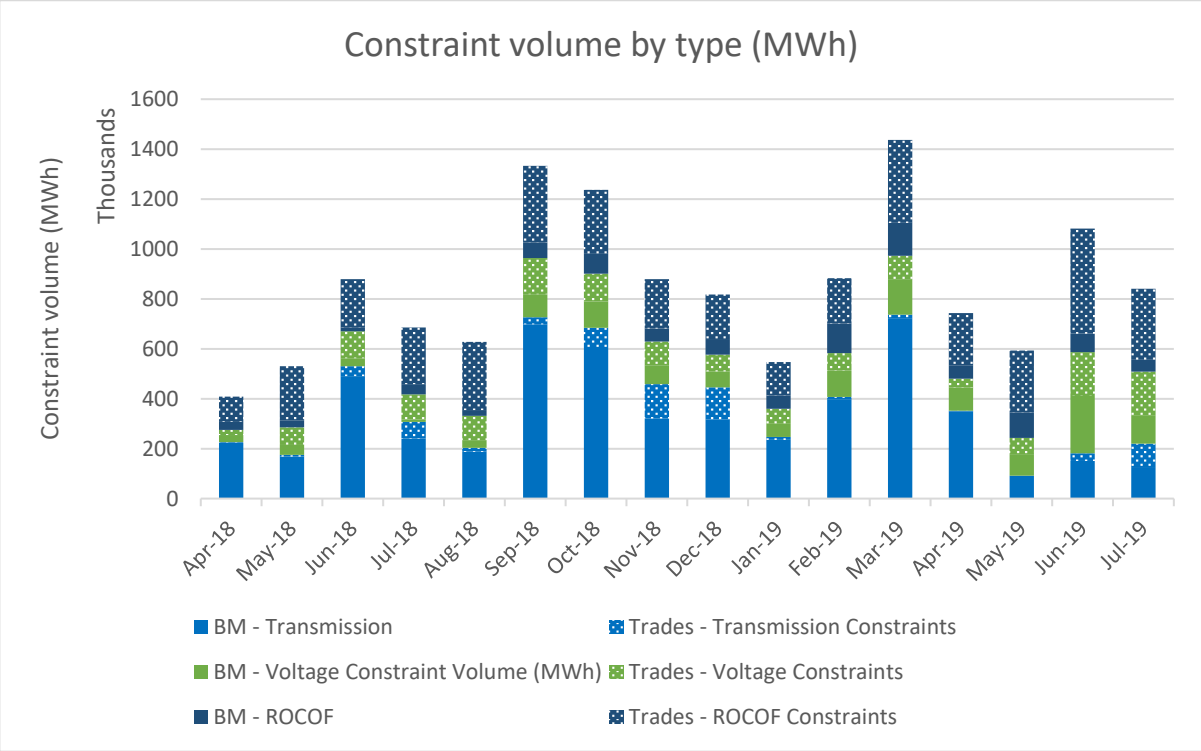

Figure 7.3: Monthly constraint volume by type (MWh) available from April 2018 – July 2019 [2].

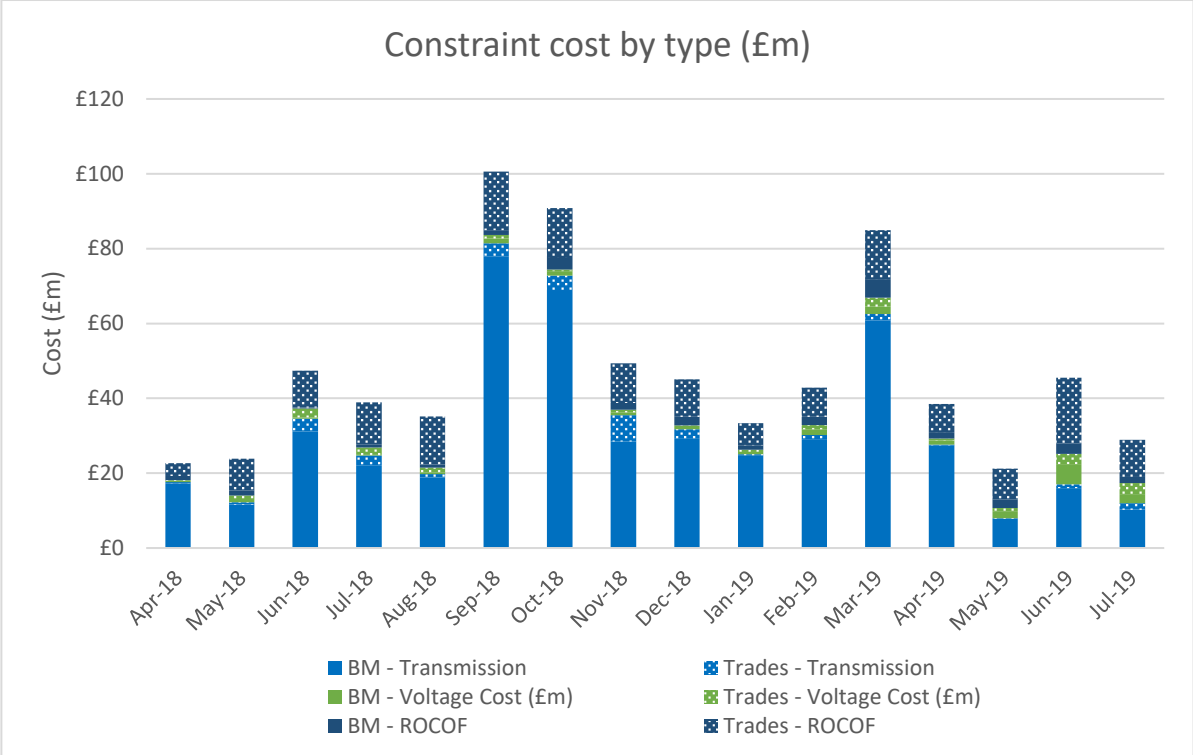

Figure 7.4: Monthly constraint spend by type (£m) available from April 2018 – July 2019 [2].

7.1 Constraint Breakdown by Type

Constraint volumes and costs are separated into transmission (Figure 7.5), voltage (Figure 7.6) and RoCoF (Figure 7.7) below. It can be seen that the majority of transmission constraints are dealt with through the balancing mechanism, voltage constraints are dealt with by a mix of balancing mechanism and forward trades, whilst RoCoF constraints are predominantly dealt with through forward trades.

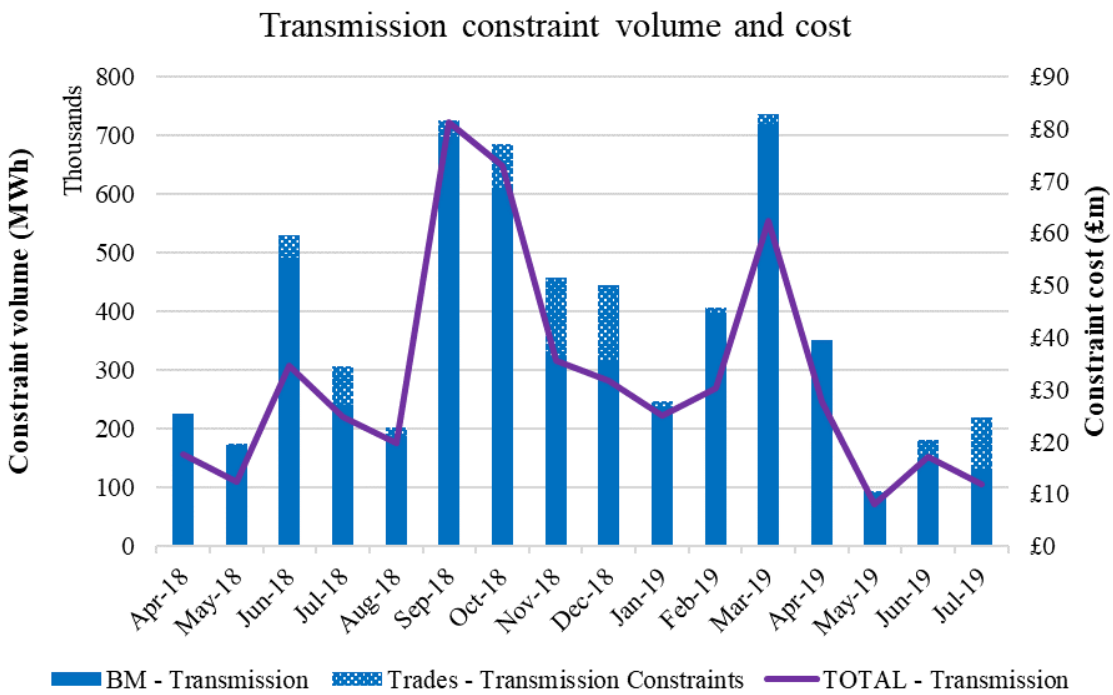

Figure 7.5: Monthly transmission constraint volumes [2].

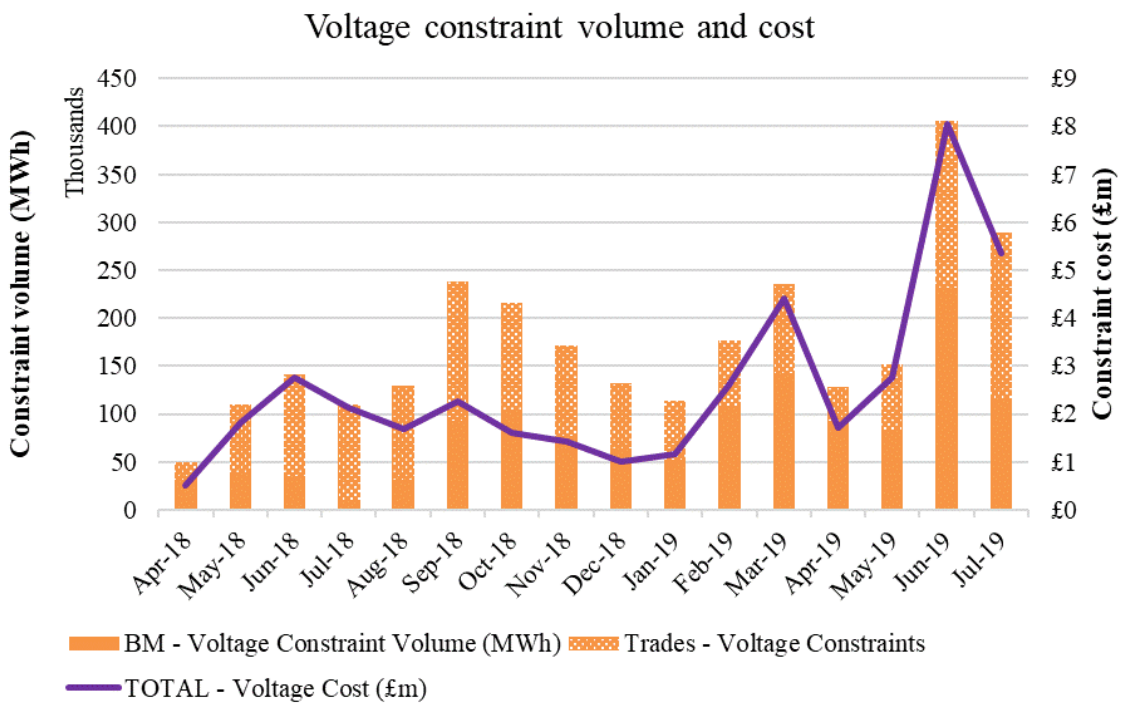

Figure 7.6: Monthly voltage constraint volumes [2].

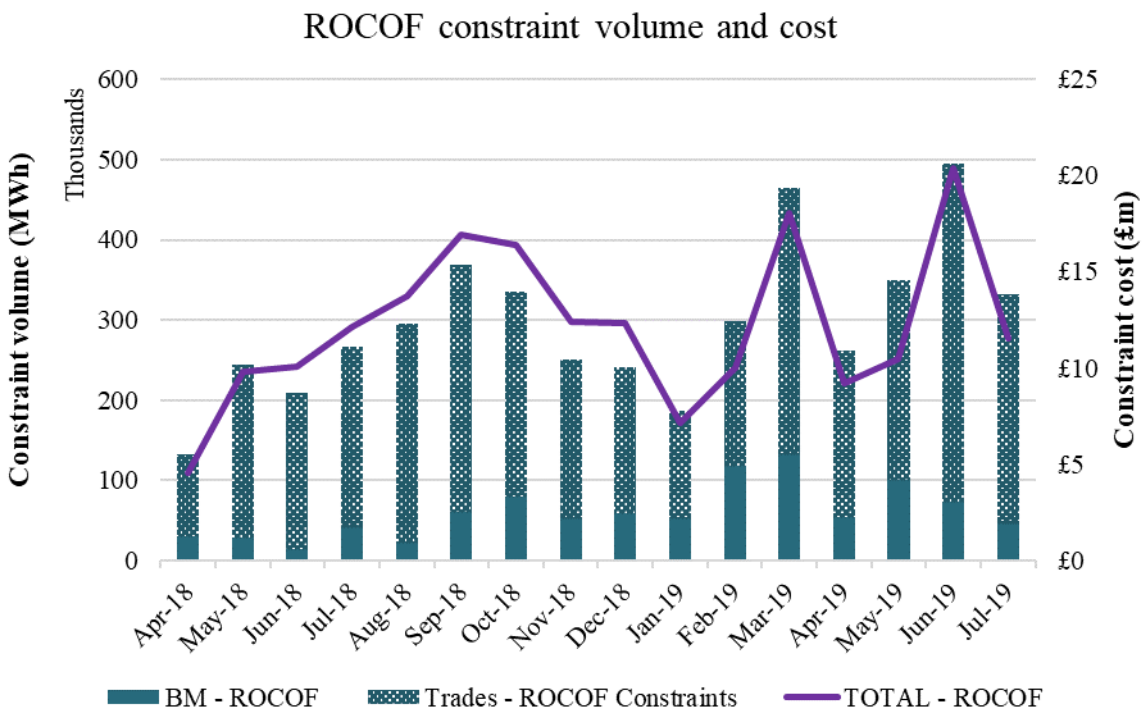

Figure 7.7: Monthly RoCoF constraint volumes [2].

8 Forward Trades

National Grid takes trading actions to fulfil a system need pre-gate closure, where it is likely to be more economic to do so. The volume of pre-gate trades National Grid has been taking has consistently increased since 2014 (Figure 8.1).

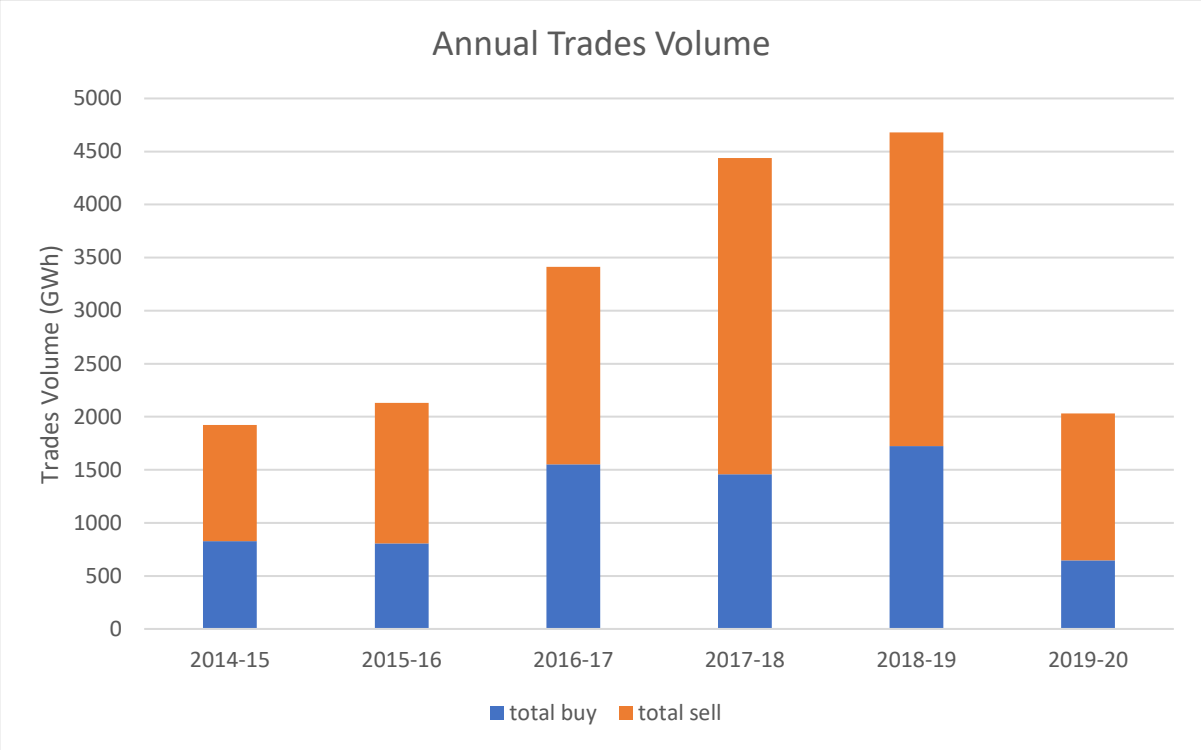

Figure 8.1: Annual trades volume (GWh) broken down into buy volume and sell volume from 2014 to 2019. 2019-20 data only includes April – July 2019. Source: National Grid MBSS.

Key Points:

- ROCOF constraints make up the majority of forward trade actions
    - Detail regarding reasons for trades has only become available in the MBSS since April 2019.
- National Grid Electricity System Operator has been taking increasingly more actions using pre-gate trades, where it is likely to be more economic do so
    - Data from the past 16 months shows that this is not the case for RoCoF constraints since the average spend on RoCoF constraints via trades is £44/MWh and only £32/MWh in the BM.

Further Investigation:

- Access details on the reason for forward trades before April 2018.
- Identify reason why system operator favours forward trades for RoCoF despite the higher price per MWh.

Figure 8.2 shows that the primary reason for trades is to manage network constraints (either voltage, transmission or RoCoF). The makeup of 'other' is unclear from the MBSS, but is likely to include downward regulation, margin, response and energy balancing. This detailed breakdown of reasons trades are made is only available from April 2018 when MBSS reporting changed, making it difficult to identify long-term trends.

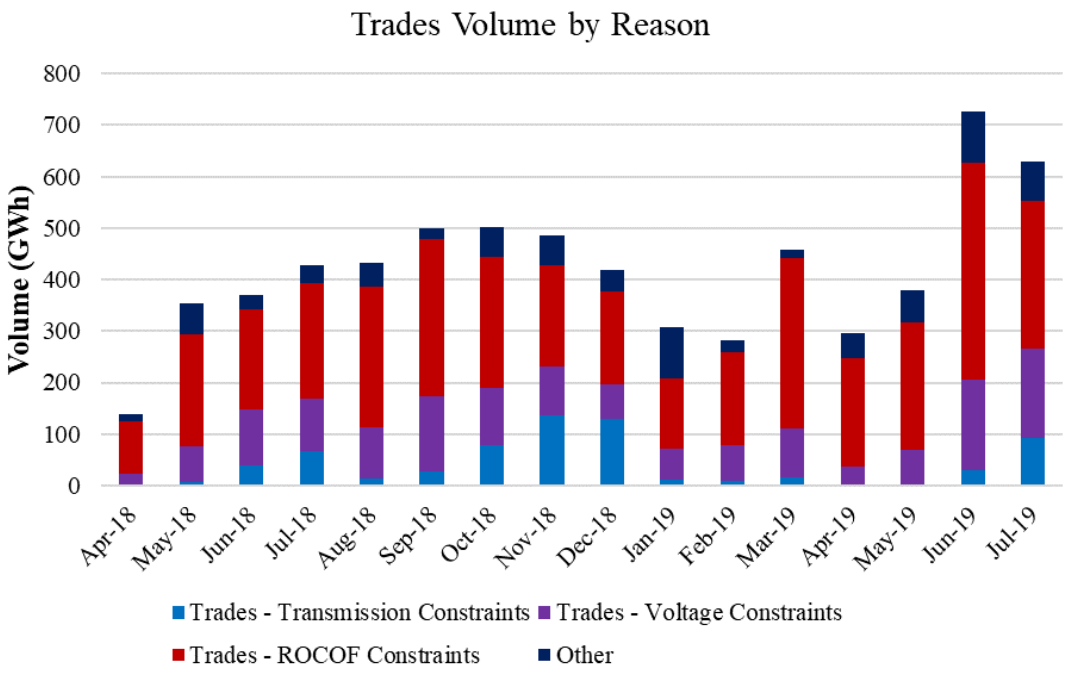

Figure 8.2: Monthly trades volume (GWh) by reason (transmission, voltage or RoCoF constraint and other) from April 2018 to July 2019 [2].

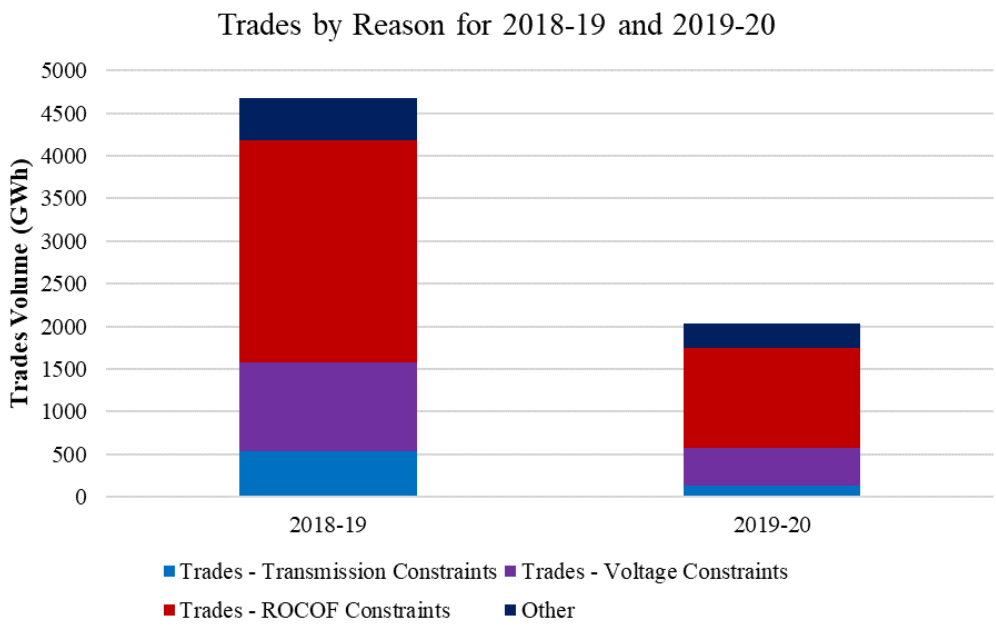

Figure 8.3: Annual trades volume (GWh) by reason (transmission, voltage or RoCoF constraint and other). 2019-20 data only includes April – July 2019 [2].

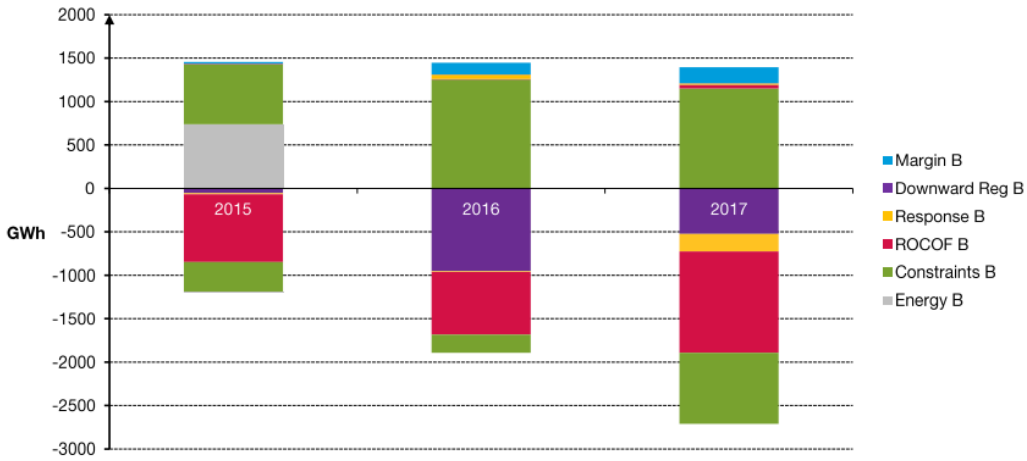

Figure 8.4: Annual trades volume (GWh) by category [3].

Although it is reported that forward trades are taken since it is more economic than post gate alternatives, data from the past 16 months shows that this is not the case for RoCoF constraints since the average spend on RoCoF constraints via trades is £44/MWh and only £32/MWh in the BM.

Table 8.1: Average constraint spend per MWh for transmission, voltage and RoCoF constraints in the BM vs trades from April 2018 to July 2019 (£/MWh) [2].

	Transmission	Voltage	ROCOF
BM	88.84	14.30	31.51
Trades	71.48	13.92	43.99

9 Reserve Services

National Grid holds reserves from both generation and demand providers to deal with large ramp rates (e.g. solar decline and demand increase), demand and generation forecast errors and unexpected generator unavailability. At present, the range of reserve services mainly consists of Short Term Operating Reserve (STOR), Fast Reserve and Operating Reserve. Since 2011/12, National Grid has spent on average £275m per year on reserve services (Figure 9.1).

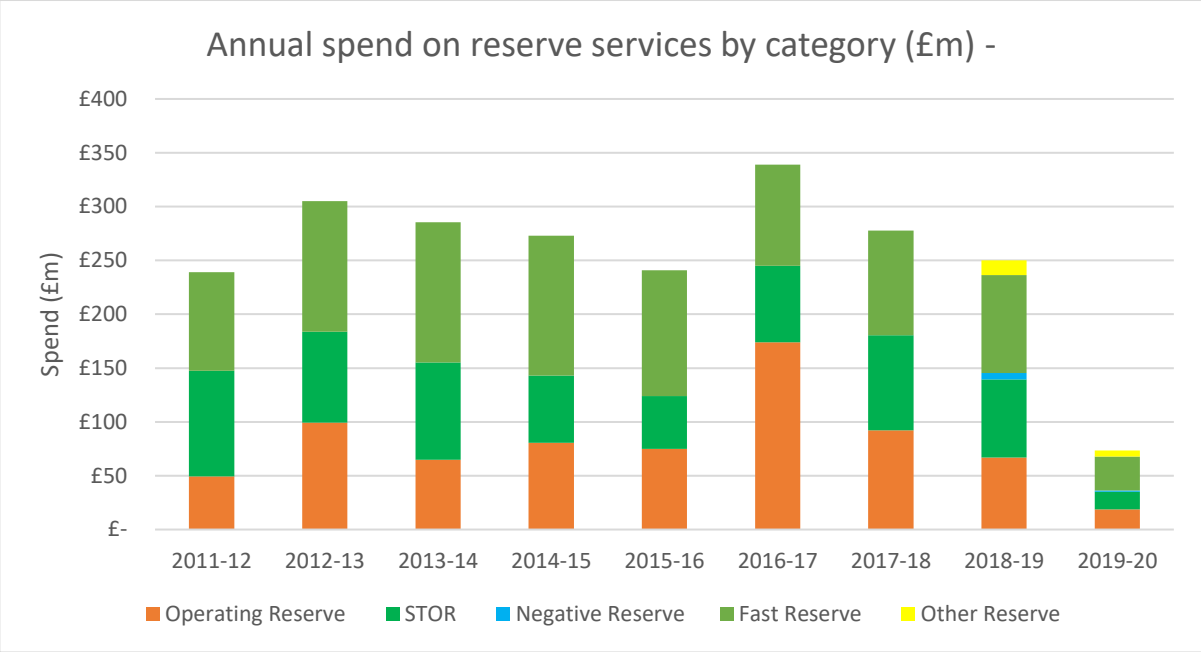

Figure 9.1: Annual spend reserve on services. 2019-20 data only includes April – July 2019 [2].

National Grid's fast-acting reserve services are currently fragmented including Fast Reserve, optional reserve services, and some static response services. In order to open the Fast Reserve market to more transparency of procurement and activation, National Grid plan to review these services to see how they can be harmonised, standardised and integrated into a single, dispatchable service.

National Grid have launched a trial for the procurement of 600 MW of Fast Reserve, 300 MW more usual, via the monthly tender beginning in December 2019, for delivery in January 2020 (source: National Grid Response and Reserve Product Roadmap (03 Dec 2019)). In this document National Grid suggest that this additional 300 MW trial is to "*improve market transparency and competitiveness*", which does not provide any real insight into why they are interested in this. It could be speculated that NGESO is confident that increasing volumes of energy for balancing will be required so is procuring it ahead of the balancing mechanism.

Key Points:

- STOR is an upward reserve product and would require wind to be curtailed/re-positioned to provide headroom if it was to enter this market. Wind is currently unable to tender for STOR as it is contracted 3 months in advance. Procurement would need to move to day-ahead or closer for wind power to participate.
- STOR volumes have increased over the past 2 years (mostly coming from non-BM providers), whilst price per GWh has reduced. In STOR year 10, most STOR volume is located in the South.
    - It is recommended that National Grid increase the transparency of the location of procured STOR
- Fast Reserve is procured monthly and requires providers to deliver at least a 25MW active power response within 2 minutes of instruction at a delivery rate of 25MW/minute and be capable of sustaining for at least 15 minutes on receipt of an electronic instruction.
    - Fast Reserve was used on average 35 times per day, with 61% of all instructions being less than 10 minutes and 35% less than 5 minutes (Figure 9.11).
    - Fast Reserve requirement sits around 200-300MW depending on the time of day.
    - The average annual spend on Fast Reserve since 2011 has been £109m (Figure 9.10), with the cost per MWh averaging £400/MWh since November 2017.

- Wind is capable of ramping requirements for Fast Reserve (wind ramp capability is reported at +/-100% of available power in 5 seconds), but the monthly tender procurement window would need to move closer to real-time for wind to participate with reasonable forecast certainty.
- National Grid have launched a trial for the procurement of an additional 300 MW of Fast Reserve via the monthly tender beginning in December 2019, for delivery in January 2020.

Further Investigation:

- Understanding what changes would be required to STOR market to make it possible for wind to wind participate.
- Understanding how demand for Fast Reserve is likely to change in the future and if new procurement mechanisms could widen access. This should be done in the context of the system operator gaining access to windfarms power available signal etc.
- Investigation into Fast Reserve service definition and assessment of its fitness for purpose moving forward[1]. Identify if Fast Reserve should be included in system services overhaul. In doing so, the capability of wind providing the service should be assessed.
    - Fast Reserve trial in December 2019 should be monitored closely.
- Identification of the location of reserve providers, in particular STOR and Fast Reserve. Service provider locational information should be made standard by National Grid in reporting format across all markets.

9.1 Short-Term Operating Reserve (STOR)

STOR is an upward reserve product, required to provide replacement reserve up to the size of the most credible outage (1320MW at present, and expected to rise to 1800MW on completion of Hinkley Point C nuclear) and can be provided by either generation or demand assets. STOR also provides National Grid with additional active power sources when actual transmission demand is greater than forecast. As such, the STOR requirement for a given day is dependent on the demand profile of that day. The STOR year starts in April and is divided into 6 seasons, which specify availability windows where STOR is required each day. The service is typically used over two pre-defined availability windows; morning and evening peak windows. Tenders can be for one or more STOR seasons, up to a total contracted period of two years. National Grid aims to procure 1800MW of STOR per year. Demand forecasting is becoming increasingly difficult due to intermittent wind and solar, leading to increased utilisation of STOR.

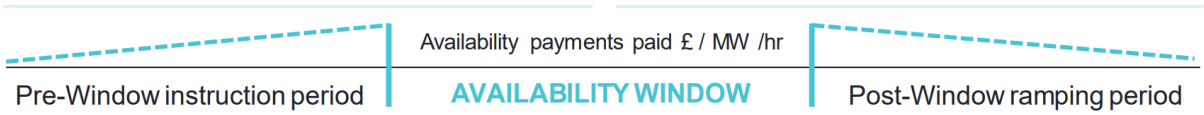

Figure 9.2: STOR service description. Source: National Grid STOR Interactive Guidance.

Payments for STOR include three components. An availability payment for the hours which the service has been made available (£/MW/hr). A utilisation fee for the energy delivered when instructed to deliver STOR, including the ramping volumes (£/MWh). There is also an optional fee, for where STOR is utilised outside of contracted windows (£/MWh). STOR is contracted 3 months in advance, making it very difficult for wind generators to have confidence to participate. Technical requirements for STOR require the provider to offer 3MW of generation or demand reduction, which can be aggregated across multiple sites within a maximum of 240 minutes (but 20 minutes is preferable). The response must be sustained for 2 hours, with a recovery period of less than 1200 minutes. There are two routes to market: the committed and the flexible service. The committed service is open to BM and non-BM providers and requires the provider to be accessible for all availability windows over the contract term. The flexible service (split into premium flexible and flexible) is only open to non-BM providers and involves providers submitting week ahead availability declarations, which are finalised by 10:00 on the previous Friday.

The total STOR utilisation volume for both BM and non-BM providers remained relatively steady at an average of 225GWh between 2011/12 and 2016/17 (with the majority of STOR volume coming from non-BM assets). In 2017/18

[1] That said, any future product replaces that Fast Reserve should be compliant with the Clean Energy Package [9].

and 2018/19, this increased to an average of 462GWh (Figure 9.3). Monthly utilisation volumes are reported in Figure 9.4. The total STOR expenditure on availability and utilisation payments to both BM and non-BM providers per GWh has consistently reduced over the reporting period (Figure 9.5). Figure 9.6 shows how STOR volumes have changed between seasons over the reporting period, showing a significant increase in STOR utilisation in spring and summer in 2018 (before then, seasons were fairly balanced).

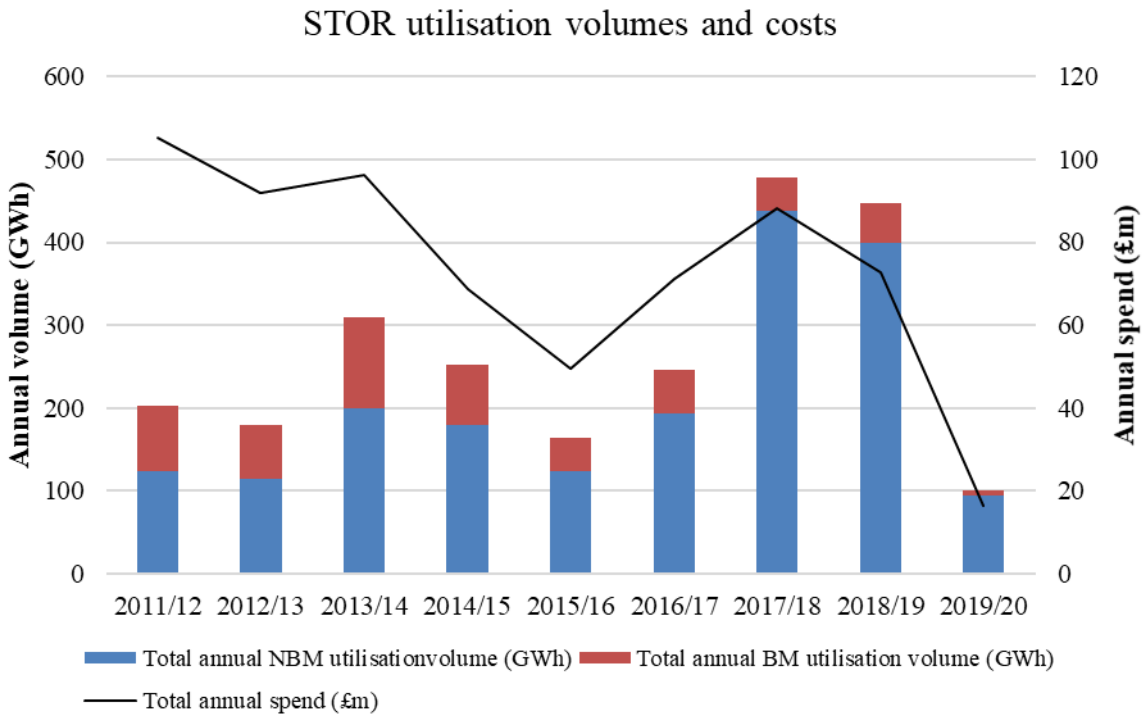

Figure 9.3: Annual STOR volume and spend [2].

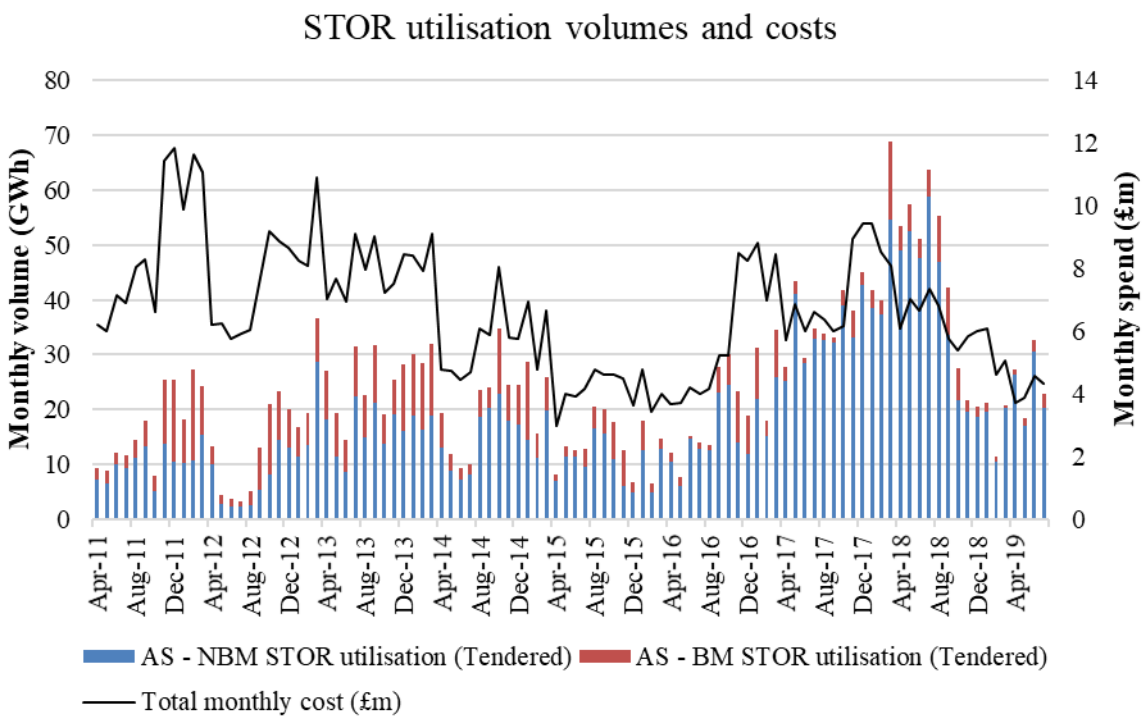

Figure 9.4: Monthly STOR volume and spend [2].

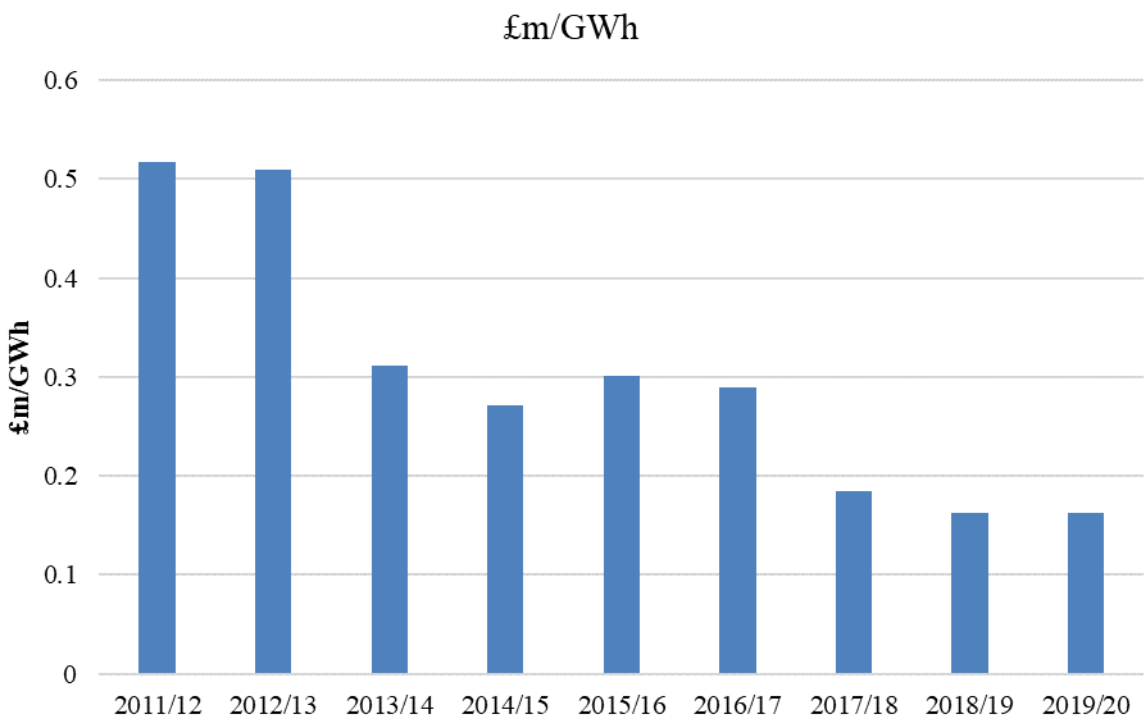

Figure 9.5: Annual STOR spend per GWh [2].

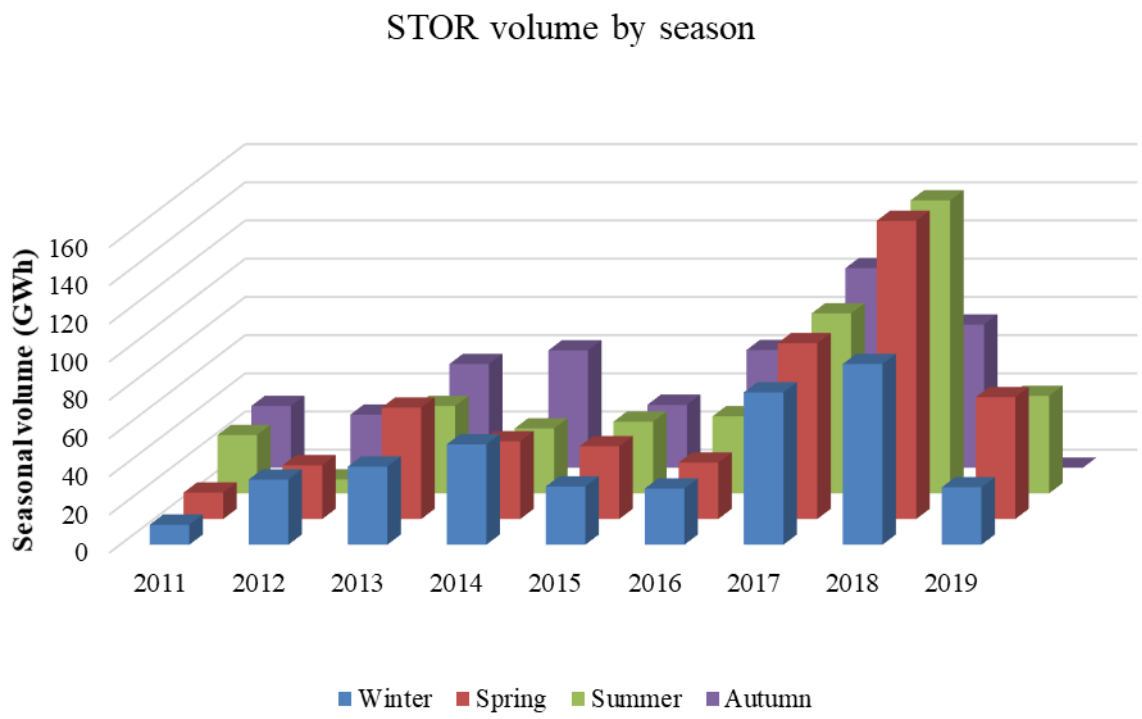

Figure 9.6: Seasonal STOR volumes [2].

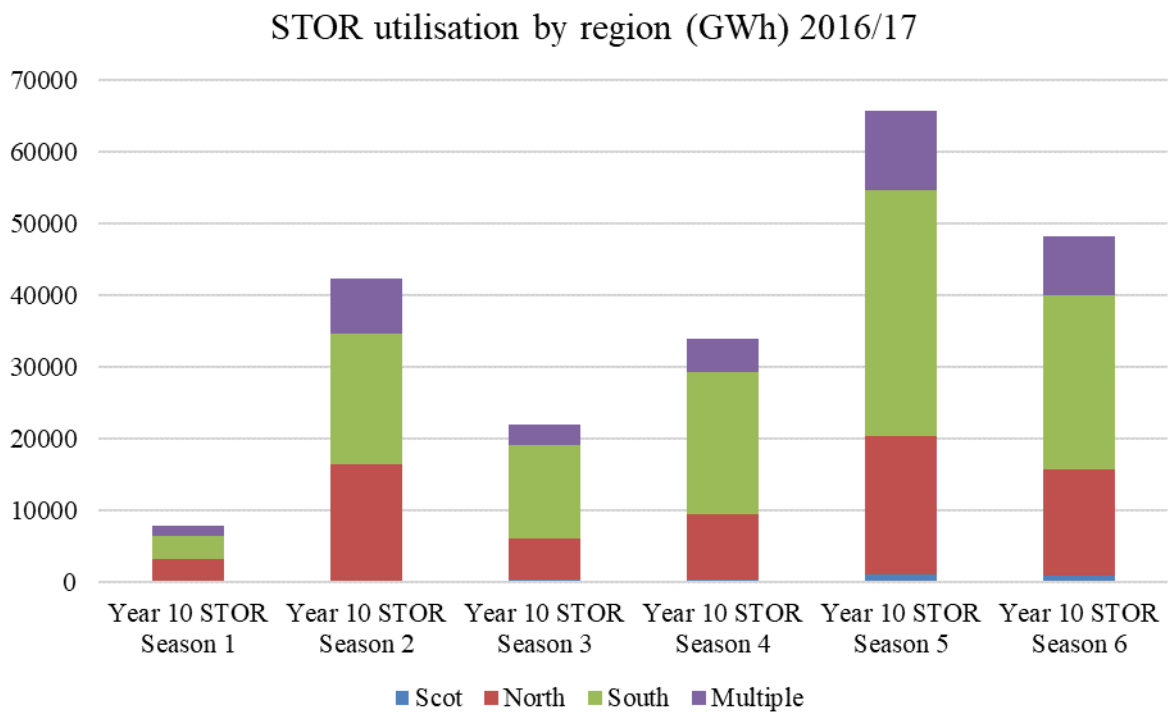

Figure 9.7: STOR utilisation by region (GWh) 2016/17 [4].

9.2 Fast Reserve

Fast Reserve is the fastest acting upward reserve service used to manage frequency deviations that arise from unforeseen changes in generation and demand. The service is procured in monthly tenders, and it is open to both BM and non-BM providers (as well as aggregated BMUs) able to deliver at least a 25 MW active power response, starting active power delivery within 2 minutes of electronic instruction and at a delivery rate in excess of 25 MW/minute (was until recently a 50 MW requirement at a 25 MW/minute delivery rate). Reserve energy must be sustained for at least 15 minutes. Units providing Fast Reserve must be ready to receive instructions at the start of each Fast Reserve window to allow them to be automatically dispatched. The requirement for Fast Reserve can change dependent on both the time of year and time of the day, being related to the system demand profile at the time.

Fast Reserve is split into three services; Firm Fast Reserve, Optional Fast Reserve (for BM and non-BM suppliers) and Optional Spin Gen. The Fast Reserve service is required 24 hours a day, 7 days a week. National Grid state that there is a greater requirement for the service during the daytime, typically between 06:00-23:00. Figure 9.9 represents the total utilisation per settlement period, highlighting that this could be further divided into the morning and evening peak demand periods. The Fast Reserve requirement is between 200-300 MW depending on the time of day (lower requirement overnight than during day) and EFA block. For October 2019, most of the Fast Reserve requirement was met by Ffestiniog Power Station (most of the requirement typically comes from pumped storage stations); however, gas, demand response, batteries and other peaking plant have also participated [5]. Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from National Grid. Fast Reserve is also described in some National Grid resources as a ‘frequency restoration reserve’ service, suggesting that it is required to restore system frequency following a disturbance that brings frequency out with normal operational limits.

Figure 9.8 depicts how the fast frequency service definition and most frequent utilisation fits around the frequency response service definitions; however, the utilisation of the service suggests that Fast Reserve is used more as a ‘peaking’ service. Figure 9.9 indicates that the service is used as reserve generation to meet any mismatch between demand and generation as a result of forecast errors. This could be viewed as a faster alternative to taking a BM action to bring on a generator. If Fast Reserve is to be used as the service definition specifies – as a frequency restoration service – then depleting the service volume to meet mismatches in generation and demand throughout the day (due to demand and wind generation forecasting errors, as depicted in Figure 9.9) could result in frequency restoration issues following a severe frequency event (e.g. as a result of a large infeed trip). It is recommended that further investigation into the Fast Reserve service definition versus its utilisation – and how it fits around other response and reserve services in the context of National Grid’s Response and Reserve Roadmap – is conducted.

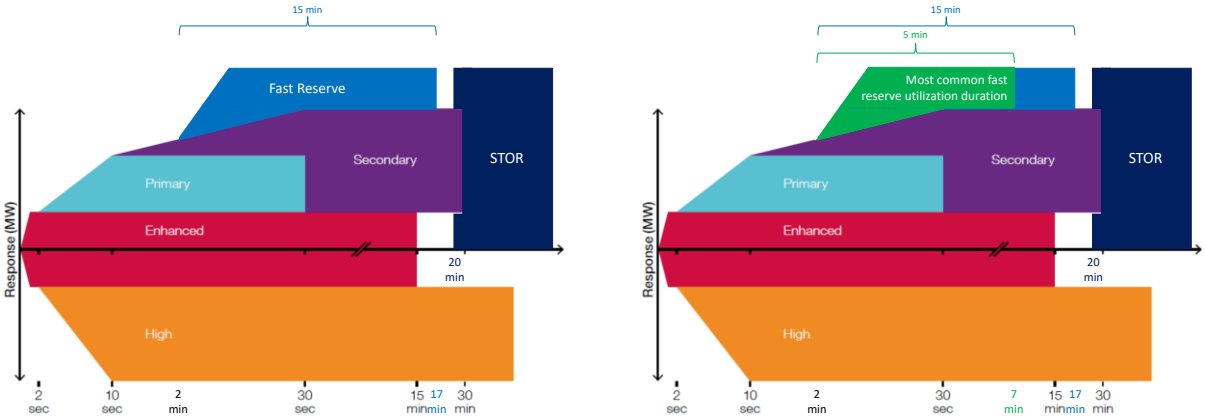

Figure 9.8: National Grid frequency response service definitions with Fast Reserve and STOR services overlaid. Note that this timeline for Fast Reserve relies on electronic dispatch being sent at the time of the event to the providers.

Wind is able to provide the ramping requirements (Fast Reserve required 25 MW/minute, wind ramp capability is reported at +/-100% of available power in 5 seconds) for Fast Reserve but the tendering process would need to change to being closer to delivery (i.e. day ahead or intraday) to be within accurate forecasting windows to allow wind to reliably offer Fast Reserve.

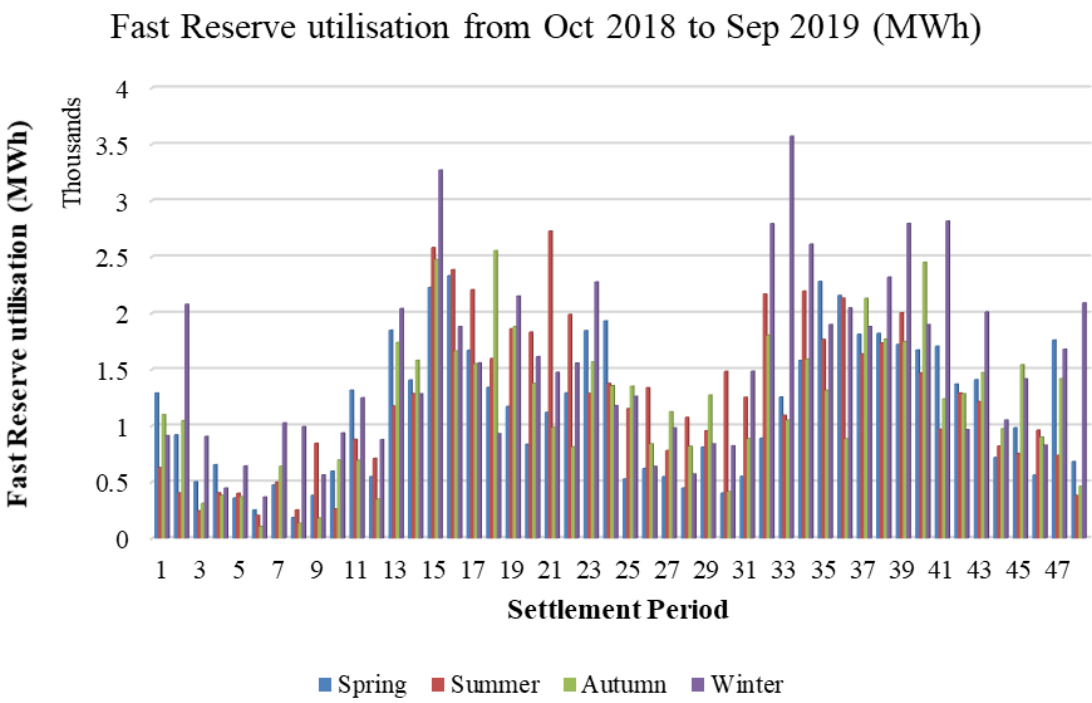

Figure 9.9: Fast Reserve utilisation for Firm and Optional services by settlement period [6].

Fast Reserve is tendered at a month ahead timescale, with payments for availability (£/hr, paid for the hours a provider is available), nomination fee (£/hr, paid for being called upon to provide the service) and utilisation fee (£/MWh, for the response energy delivered). However, it should be noted that most contracts are non-tendered (bilateral). In the 2017 financial year £60m was spent on non-tendered Fast Reserve, compared to £13m on tendered [5]. The average annual spend on Fast Reserve since 2011 has been £109m (Figure 9.10).

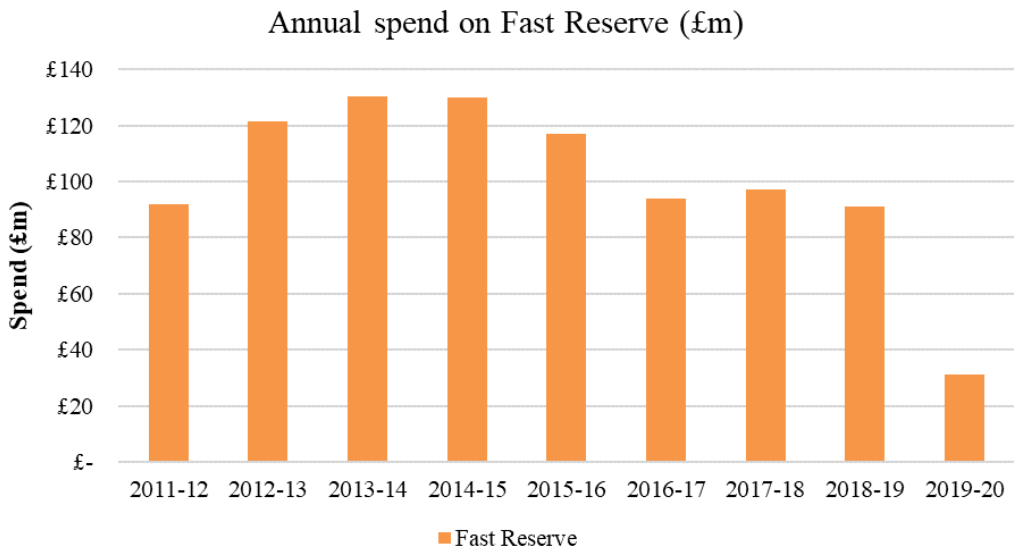

Figure 9.10: Annual spend on Fast Reserve (£m) [2].

Between April 1st 2016 and August 1st 2019 Fast Reserve was used on average 35 times per day, with 61% of all instructions being less than 10 minutes and 35% less than 5 minutes (Figure 9.11). The most common instruction duration over the same period was 5 minutes, significantly shorter than the service requirements defined by National Grid.

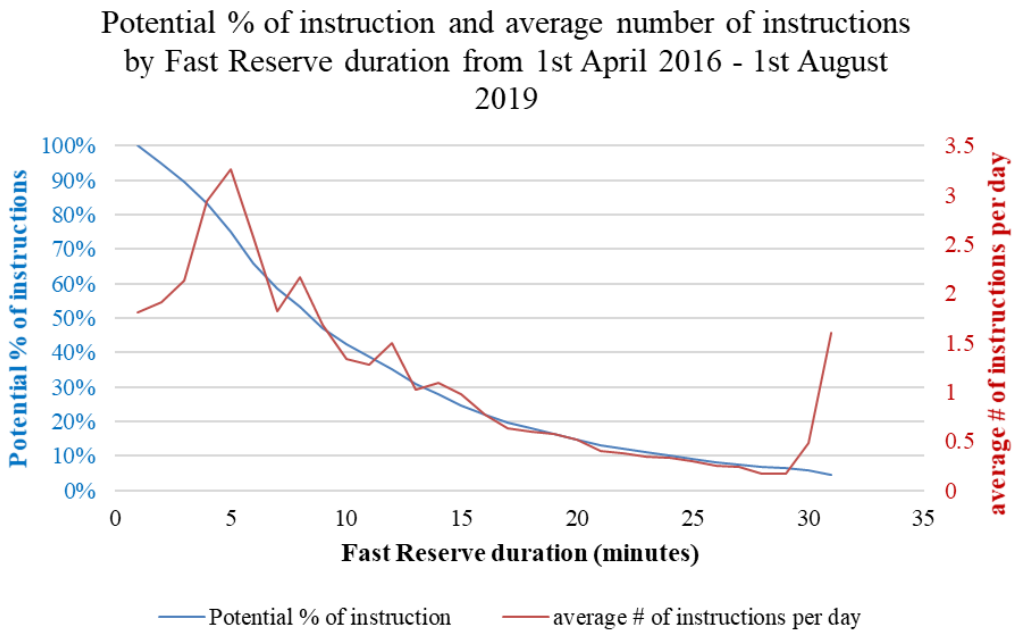

Figure 9.11: Potential % of instruction and number of instructions by Fast Reserve (Firm and Optional services) duration from 1st April 2016 to 1st August 2019 [6].

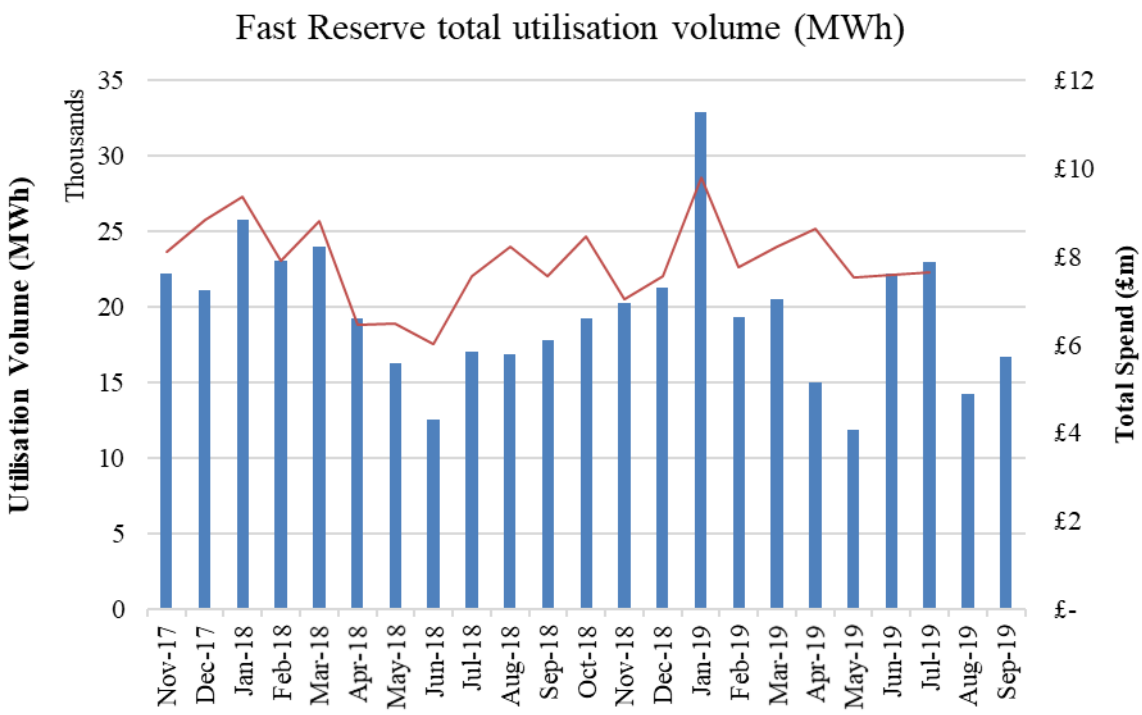

Figure 9.12: Fast Reserve monthly utilisation volume (Firm and Optional services) and spend from November 2017 to Sept 2019 (costs only reported to July 2019) [2] [6].

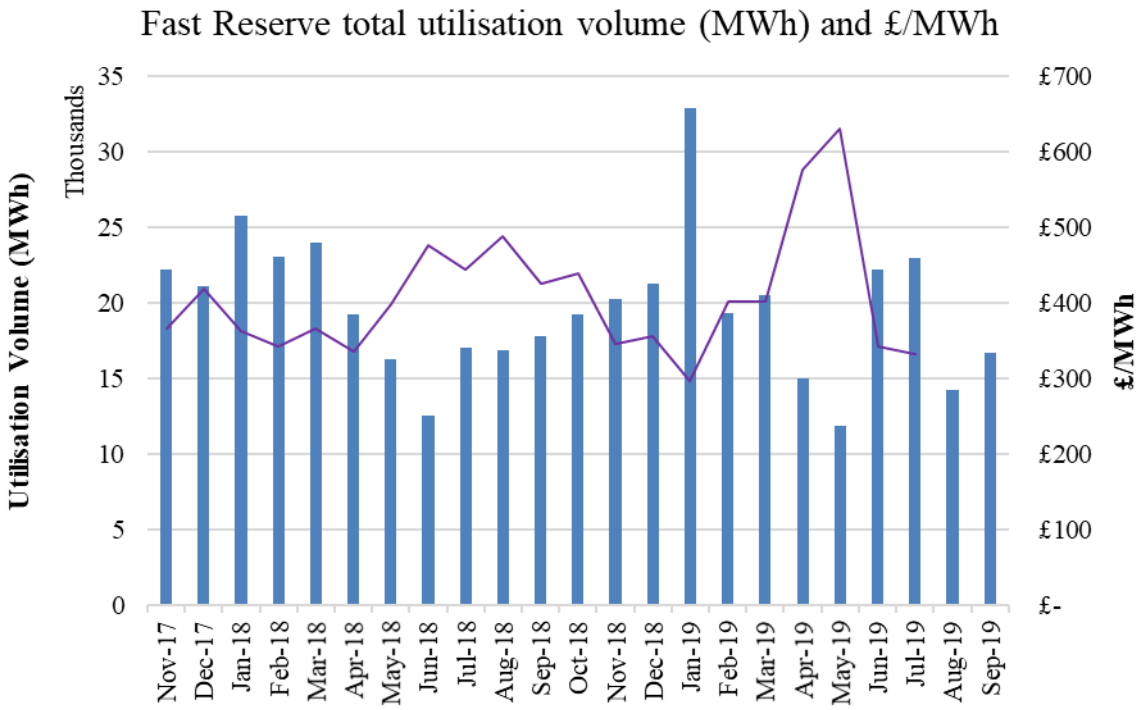

Figure 9.13: Fast Reserve monthly utilisation volume (Firm and Optional services) and £/MWh from November 2017 to Sept 2019 (costs only reported to July 2019) [2] [6].

When the total monthly spend on Fast Reserve is divided by the total monthly volume (Figure 9.12), the average £/MWh since November 2017 has averaged around £400/MWh (Figure 9.13). Figure 9.14 shows the breakdown of Fast Reserve utilisation by offer price. It can be seen that almost all offers are less than £150/MWh, with offers under £100/MWh making up more of the total volume in recent months. Holding fees up until September 2019 have varied from £33/hr to £504/hr depending on provider. Upon normalising by the volume being held, the average for September 2019 was £3.36/MW/hr (maximum was £5.6/MW/hr, minimum £1.1/MW/hr).

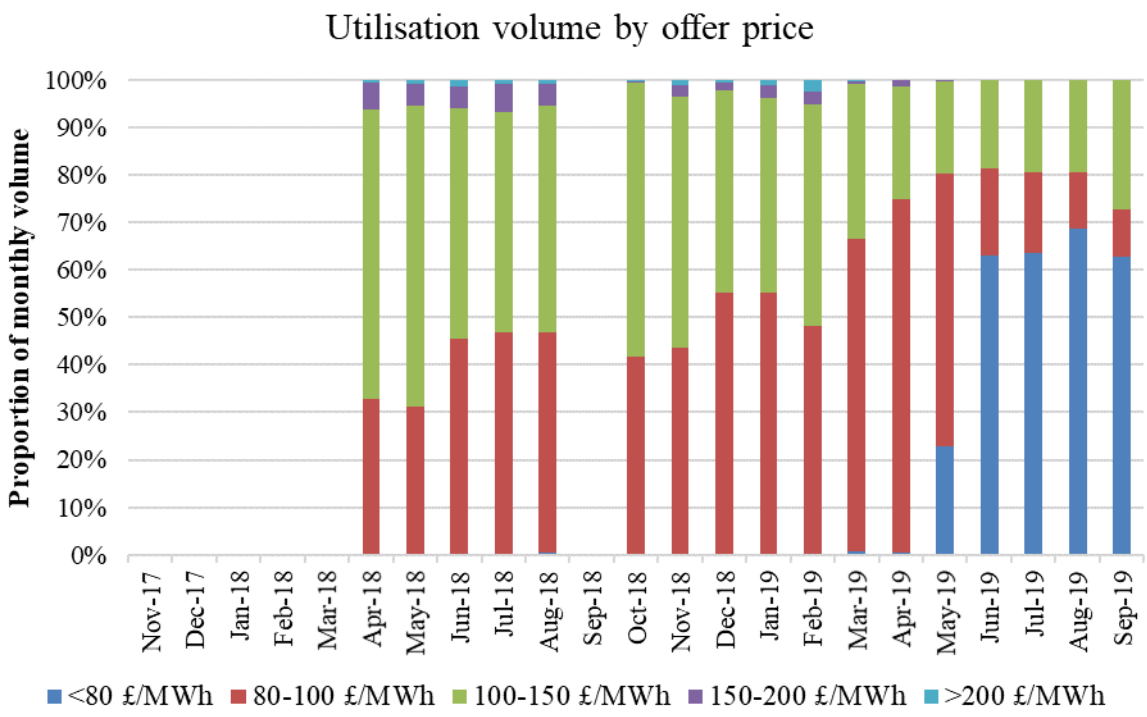

Figure 9.14: Fast Reserve utilisation volume for Firm and Optional services by offer price [6].

9.3 Operating Reserve (Positive Reserve)

Operating reserve is managed through the BM, trades of SO-SO services, providing reserve energy to meet system demand when there are unforeseen changes to demand or generation outages. A trial was held in 2015/16 where National Grid was seeking to procure 300 MW of additional reserve capacity.

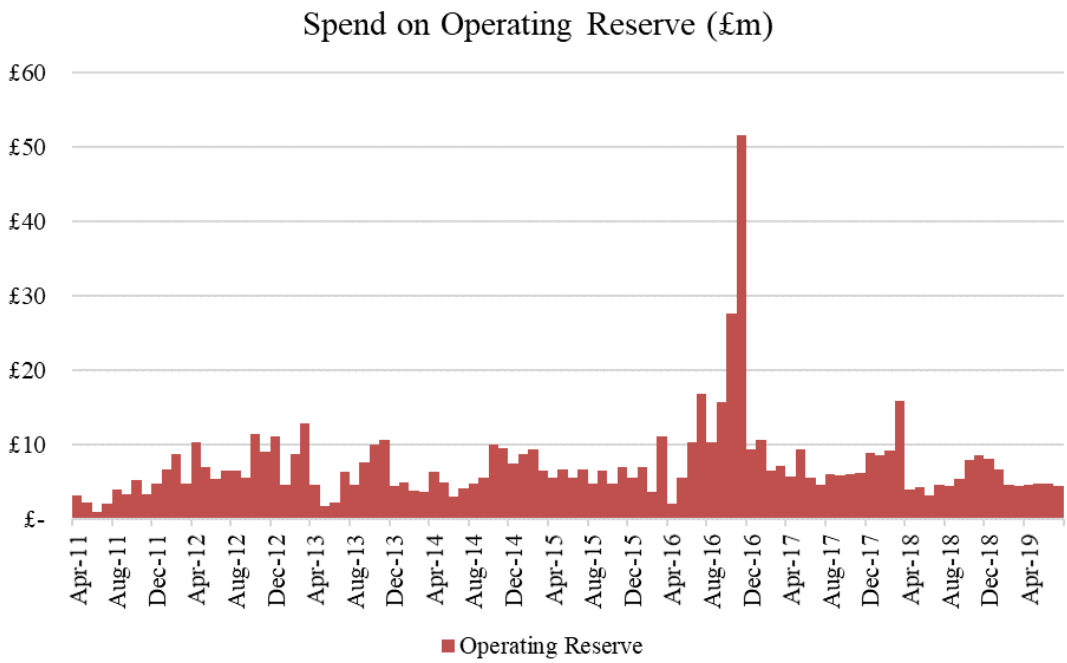

Figure 9.15: Monthly spend on operating reserve (£m) [2].

9.4 Negative and Other Reserve

A Negative Reserve service can provide the flexibility to reduce generation or increase demand to ensure supply and demand are balanced. The service is held in reserve to cover unforeseen fluctuations in demand and generation. 'Other

reserve' accounts for services that help to offset the cost of managing reserve in the BM (e.g. hydro optional spin pump, demand turn up and BM warming etc.).

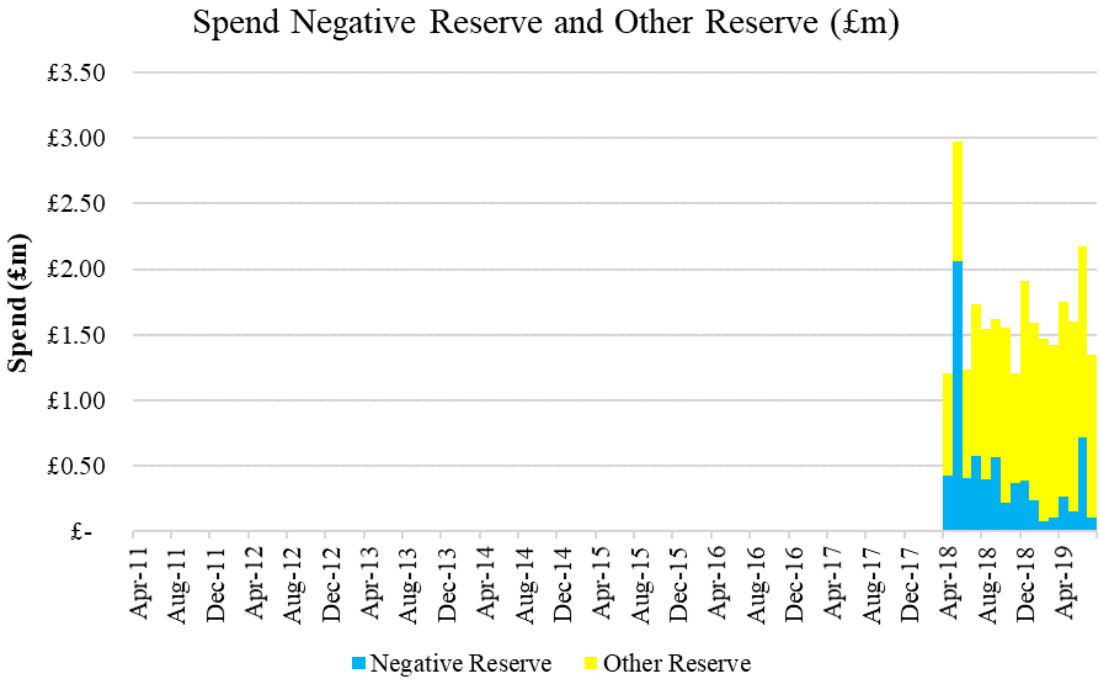

Figure 9.16: Monthly spend on negative and other reserve (£m) [2].

10 Frequency Response Services

National Grid procures frequency response services to maintain the system frequency between the statutory limits of 49.5 and 50.5 Hz. Frequency response services are procured from one of three markets: firm frequency response (FFR), mandatory frequency response (MFR) and enhanced frequency response (EFR). Primary, Secondary and High frequency response services are procured in both the FFR and MFR markets, with the latter only procuring dynamic services and the former procuring both dynamic and static services. Enhanced frequency response was procured via a one-off tender in 2016 through eight four-year contracts. Primary and Secondary frequency response services are used to manage a fall in frequency, while the High frequency response is a service that is roughly equivalent to a combined Primary and Secondary frequency response service, and it is used to manage a rise in frequency. The difference between Primary and Secondary response products is in their service definitions, with Secondary response being the slower acting of the two. The definitions of the current frequency response services is shown in Table 2.

Table 2: Frequency response definitions in GB.

Service Name	Technical Definition
Primary Frequency Response	Full delivery of active power response 10 seconds after the event with a 2 second delay and sustained for a further 20 seconds.
Secondary Frequency Response	Full delivery of active power response 30 seconds after the event and sustained for 30 minutes.
High Frequency Response	Full delivery of active power response 10 seconds after the event with a 2 second delay and sustained indefinitely.
Enhanced Frequency Response	Full delivery of response for a 0.5 Hz change in frequency and sustained for 15 minutes. This service further defines a product with a maximum of 500 ms detection and instruction delay, such that the response is fully delivered within 1 second.

National Grid is currently developing new frequency response services, with a focus around fast acting services in the context of a low inertia GB power system as the system move towards the zero-carbon 2025 ambition. As part of this, National Grid plans to replace existing frequency response services with a new, integrated suite of services: Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR). Engagement with industry is expected in January 2020, with first procurement of dynamic containment expected in Q1 2020/21.

Key Points:

- There was a reduction in annual frequency response holding between 2014/15 and 2017/18. Holding volume restored back to pre-2014/15 level in 2018/19.
- Total spend on these frequency response services has not changed a great deal over the reporting period, although there is a slight reduction from 2016/17 from £150m/year to £126m/year.
- There has been a shift from predominantly procuring services via the MFR market to commercial over the reporting period (e.g. commercial services provided 20% of the total frequency response volume in 2011/12 compared to 65% in 2018/19).
    - National Grid are aiming to phase out the monthly tenders for FFR by Q4 2021/22.
- There has been a significant reduction in the cost per MWh of commercial services (peaked at an average price of £34.9/MWh in 2013/14 and reduced to £8.6/MWh in 2018/19) in the market, bringing their cost down close to MFR services at around £4.2/MWh.
- Wind now provides 2.46% of mandatory primary, 1.89% of mandatory secondary and 1.88% of mandatory high frequency response, with a combined revenue of £150k from MFR in August 2019.
    - Wind is taking an increasing share in provision of MFR, however, the size of the MFR market is tending to reduce.

Further Investigation

- Identification of firm frequency response provider by type over the past 10 years, along with analysis of the prices bid by providers and economics of participation for different technologies, including wind.
- Investigation into the drivers for price changes within the MFR and FFR markets that have resulted in significant changes to the total share of frequency response these services make up.
- Understanding how wind could participate in tenders. Identification of what prices would be appropriate for wind to bid at and what locations of the network would be best (e.g. what side of a network constraint).
- Identify where future demand for frequency services is likely to be by location. Work on this has begun, however data availability around BMU ID and corresponding location has halted progress.
    - A rapid injection of active power following a network fault in an accelerating region of the power system could further separate rotor angles and cause an angular stability issue. Such studies may be conducted via Robert Hamilton's PhD research project ending March 2021.
- Investigation into system benefits of fast response services from wind that operate in timescales faster than EFR but slower than synchronous machine inertial response. An increase in generators providing such a service may reduce the frequency response holding. If this can be done at a relatively low cost to wind providers, this could be made mandatory as part of a connection agreement. Wind providers must consider this moving forward.
    - Energy payments are likely to be very low. Uncertain costs include changes to turbine software systems and implications for asset health.

10.1 Existing Frequency Response Services

Frequency response (FR) services in GB can be procured via mandatory frequency response (MFR), firm frequency response (FFR) and enhanced frequency response (EFR). MFR and FFR services are further categorised into primary, secondary and high based on the speed and duration of response. Low frequency response is categorised into primary and secondary FR, defined as full delivery of active power response within 10s and 30s, respectively. High frequency response is only procured based on a 10s response time. Provision of MFR is a requirement for all large generators as part of their connection agreement, whilst FFR is open to small generators (>1 MW), which accommodates new market participants. EFR requires an active power response within 1s and has only been procured once in 2016, resulting in 201 MW of EFR from 8 battery projects for 4 years (along with an additional 26 MW procured via bilateral arrangements).

10.1.1 Total Response Volume and Cost (Mandatory and Commercial)

Figure 10.1 shows that between 2011/12 and 2017/18, the annual frequency response holding decreased between 2014/15 and 2017/18, before increasing back in 2018/19. Over the same period (2011/12 to 2017/19), the holding volume of MFR tended to decrease whilst the holding volume of commercial frequency response tended to increase.

Over the same period, the total spend on these services has remained relatively constant, although there does appear to be a slight reduction from 2016/17 onwards. Figure 10.2 shows that before 2016/17, the average annual spend on these services was £150m/year and after has been £126m/year (excluding 2019/20 since the data is incomplete). In line with this, Figure 10.3 shows that the total spend on FR services has tended to decrease since 2016 from an average of £12.5m/month to £10.5m/month.

Figure 10.4 shows the share of total response made up from MFR and commercial FR, clearly showing commercial FR making up an increasing share of total response. In 2011/12, commercial services made up 20% of total frequency response volume. By 2018/19 this increased to 65%, highlighting a clear (and significant) shift in choice of frequency response markets. The price per unit for each response type is also shown, illustrating how the cost of commercial FR has reduced from around £30/MWh to around £8/MWh. The spend per unit for MFR has remained fairly constant over the reporting period at around £4.2/MWh, increasing slightly since April 2018 to just over £6/MWh (note this is the price paid by NGESO, not he asking price from the generator). Figure 10.5 shows seasonal volumes for total frequency response, along with mandatory and commercial volumes.

National Grid aim to transition from existing services to the new suite of services: Dynamic Containment (DC), Dynamic Moderation (DM), and Dynamic Regulation (DR) progressively. As this is done, they will gradually procure

less of the monthly-tendered FFR service, with the intention of phasing out the monthly tenders for FFR by Q4 2021/22. Clearly this will significantly impact Figure 10.4 going forward.

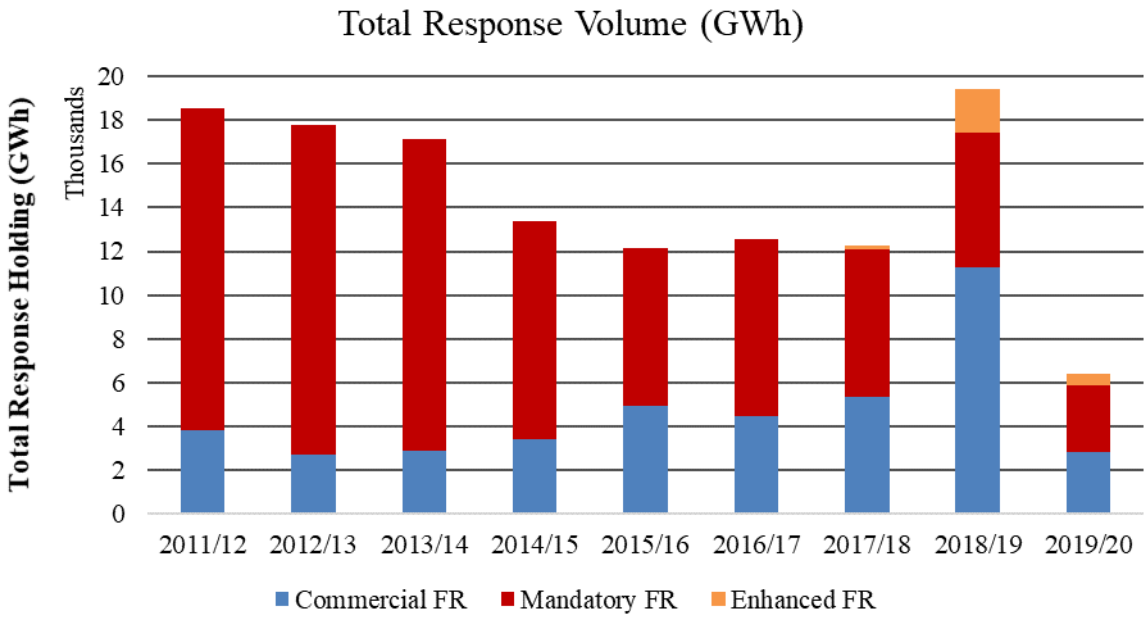

Figure 10.1:Total annual response volume by category from 2011/12 to 2019/20 (up until July 2019). Enhanced FR assumes constant 227MW available volume & that nothing was online before March 1st 2018 [2].

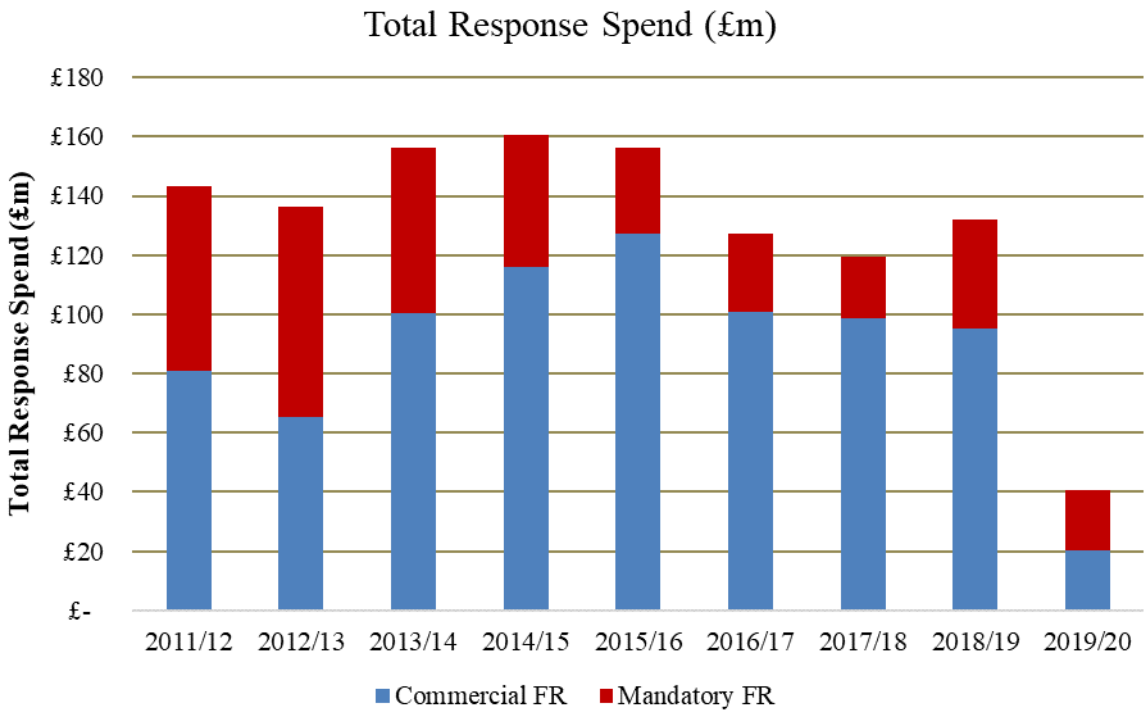

Figure 10.2: Annual spend on response by category from 2011/12 to 2019/20 (up until July 2019). Enhanced FR spend included in Commercial FR spend [2].

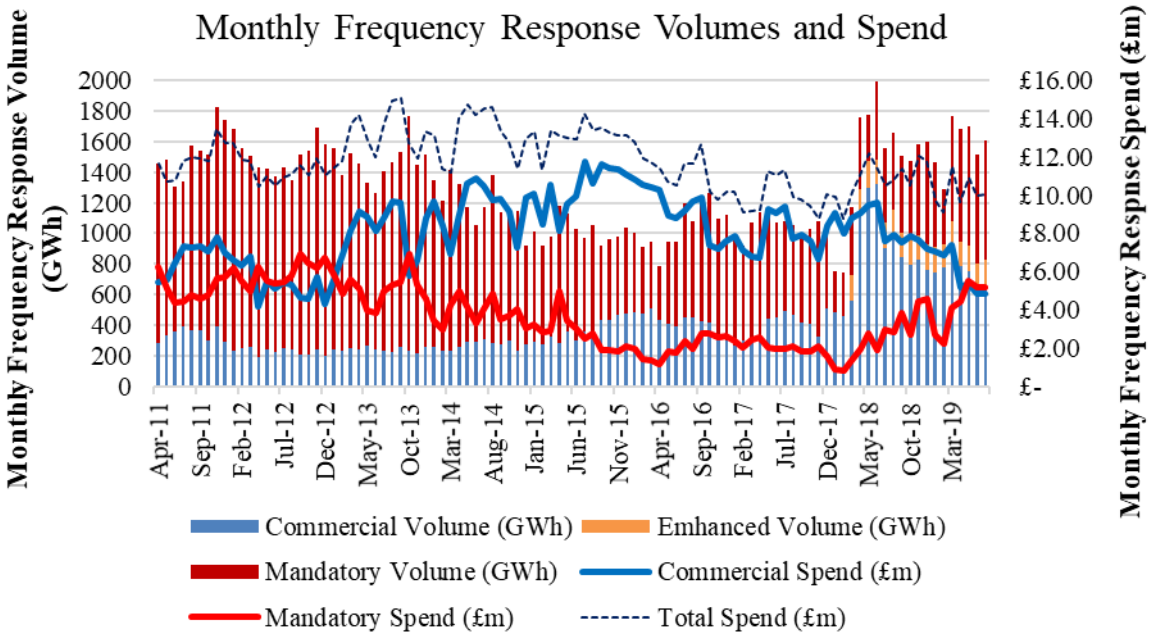

Figure 10.3: Monthly frequency response volume and spend by category from April 2011 to July 2019. Enhanced FR assumes constant 227MW available volume & that nothing was online before March 1st 2018 [2].

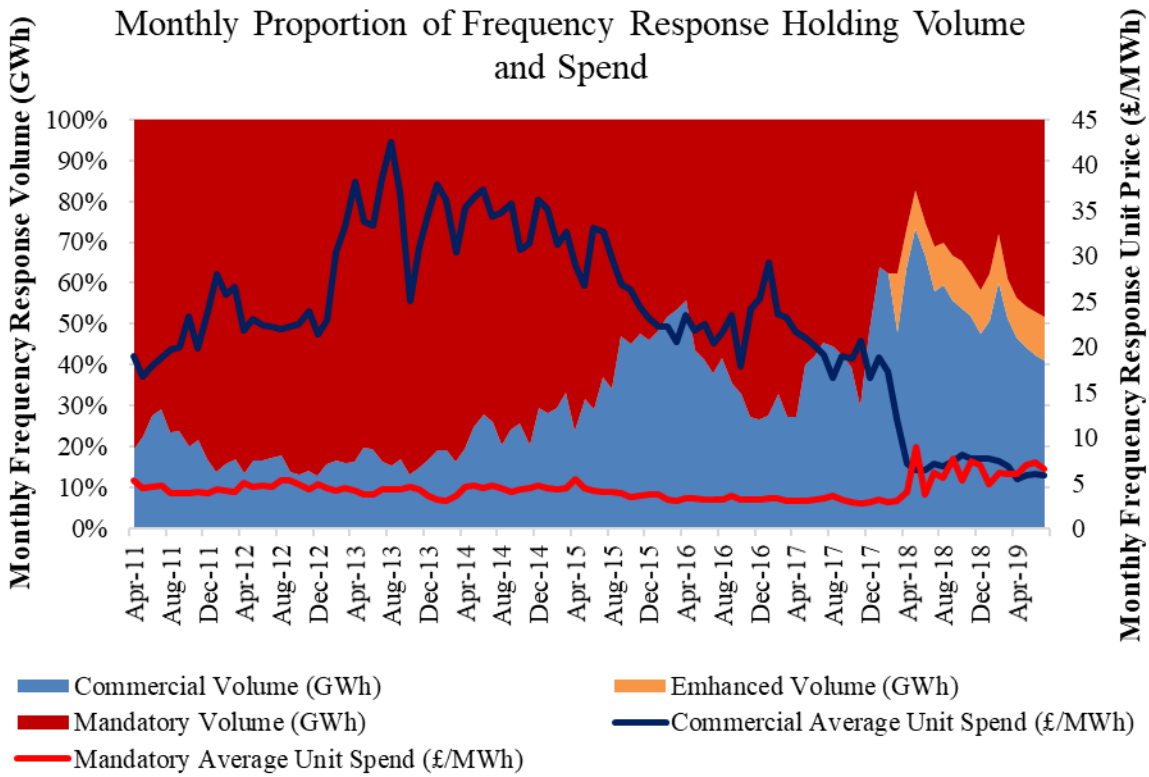

Figure 10.4: Monthly proportions of frequency response volume and average monthly spend by category from April 2011 to July 2019. Enhanced FR assumes constant 227MW available volume & that nothing was online before March 1st 2018 [2].

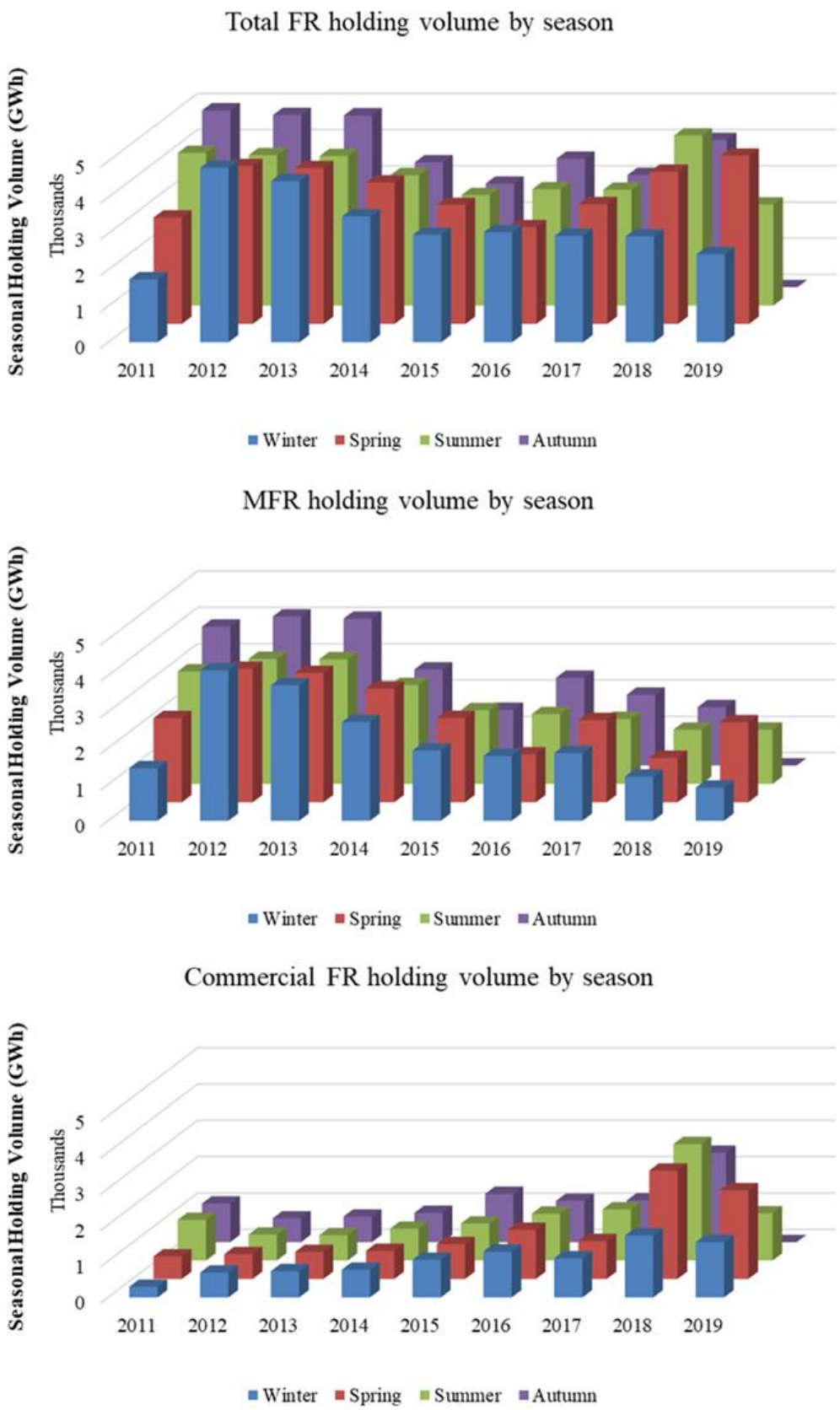

Figure 10.5: Seasonal volumes of total FR, MFR and commercial FR services from 2011 to 2019 [2].

10.1.2 Mandatory Frequency Response

Mandatory FR services are negotiated as part of connection agreements depending on their size and location. MFR is remunerated via a holding payment (£/hr) and a response energy payment (£/MWh). The former payment is for the capability of the unit to provide frequency response when the unit is instructed to be in frequency response mode, whilst

the latter remunerates the energy delivered when providing frequency response service and is set out in the Connection and Use of System Code (CUSC).

Holding volume and average holding price of mandatory frequency services since April 2011 are illustrated in Figure 10.6 (some price data is unavailable). The price of secondary FR has remained relatively stable over the reporting period, whilst holding prices for primary and high FR have steadily decreased since around 2014-15. Despite this reduction in price, the total holding volume of MFR has reduced by 58% from 2011 to 2018 (Figure 10.7). This reduction in MFR volume is likely to be linked to the reduction in coal fired power generating capacity over the same period.

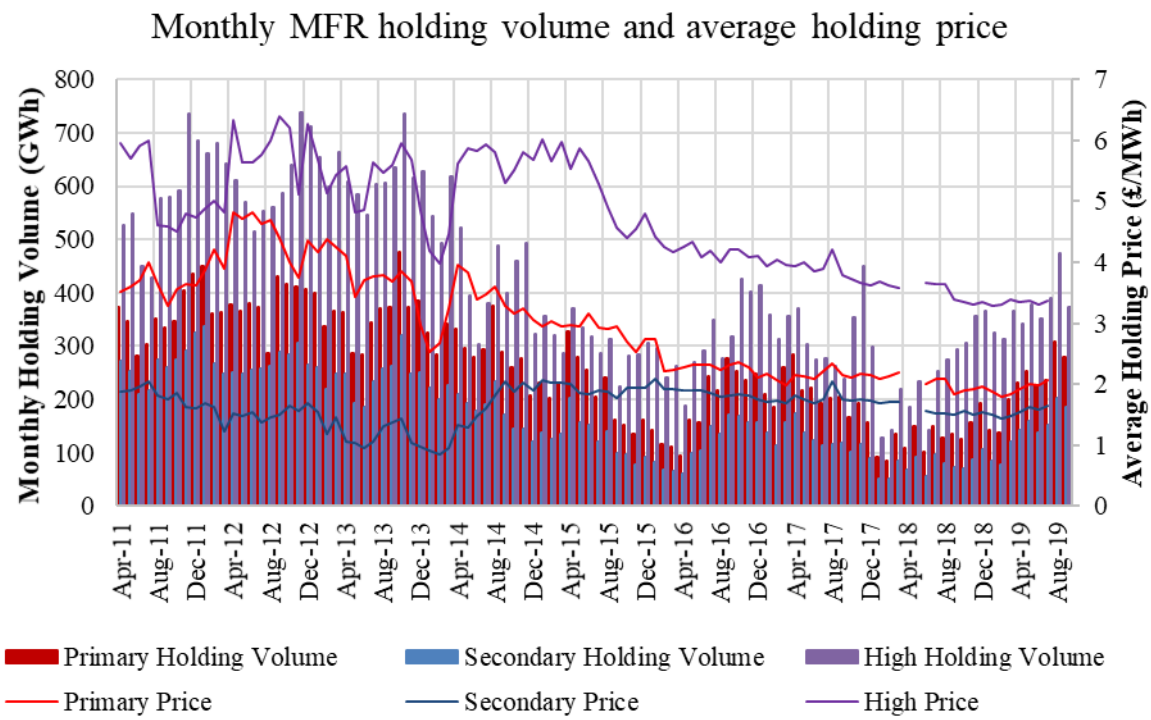

Figure 10.6: Monthly mandatory frequency response holding volume and average holding price for services (gaps due to missing data from MBSS or MFR reports) [2] [7].

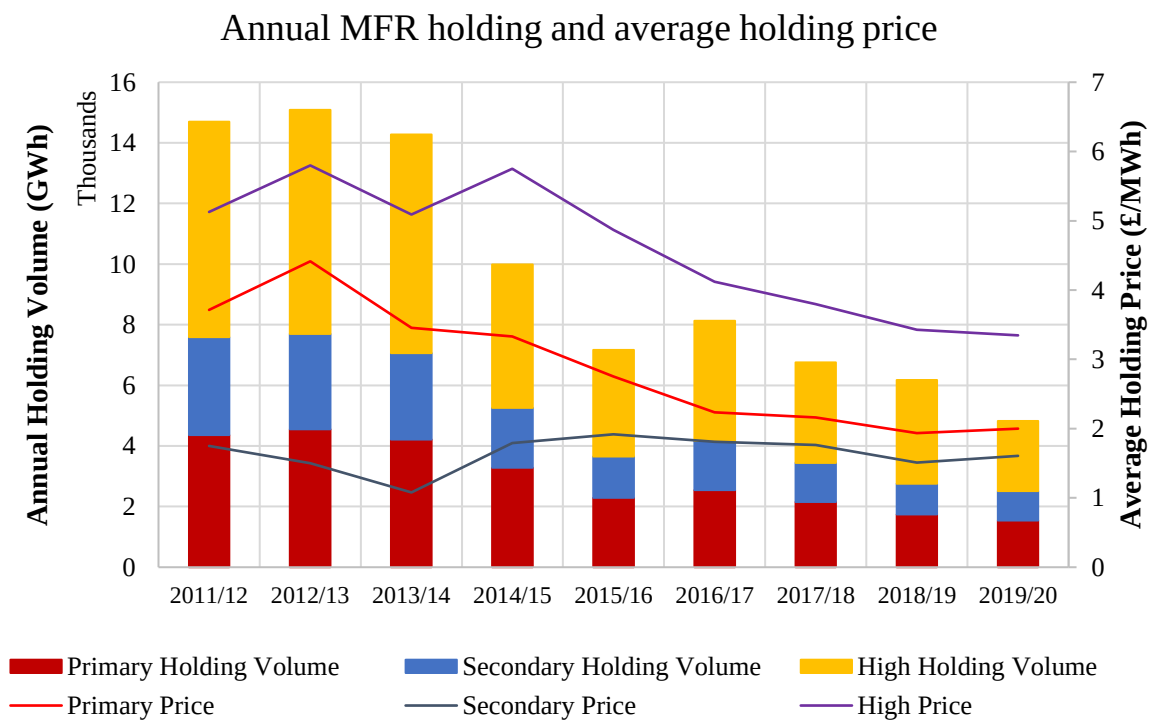

Figure 10.7: Annual mandatory frequency response holding volume and average holding price for services [2] [7].

Providers of mandatory frequency response have changed over recent years with the generation mix. In 2015, gas and coal providers contributed towards the majority of holding volume across primary, secondary and high frequency response (Figure 10.8, Figure 10.9 and Figure 10.10). As coal is phased out of the generation mix (either through plant closure, or plant conversion (e.g. Drax converted from coal to biofuel), new providers of MFR have emerged – including wind from 2016. Wind now provides 2.46% of primary, 1.89% of secondary and 1.88% of high mandatory frequency response. Clearly, there is still significant opportunities for wind to increase its share in the MFR market. In August 2019, wind providers earned a combined total of £150k revenue from MFR.

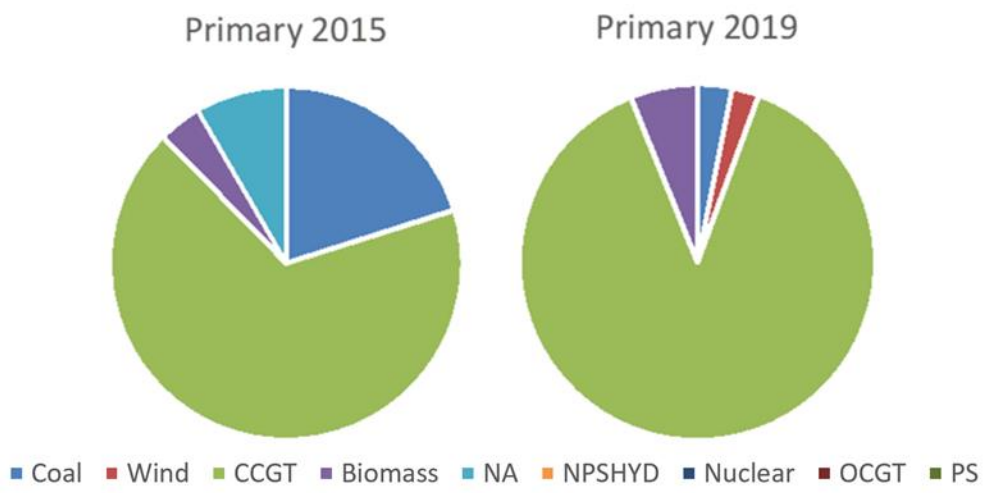

Figure 10.8: Mandatory primary frequency response by provider in 2015 versus 2019 [7].

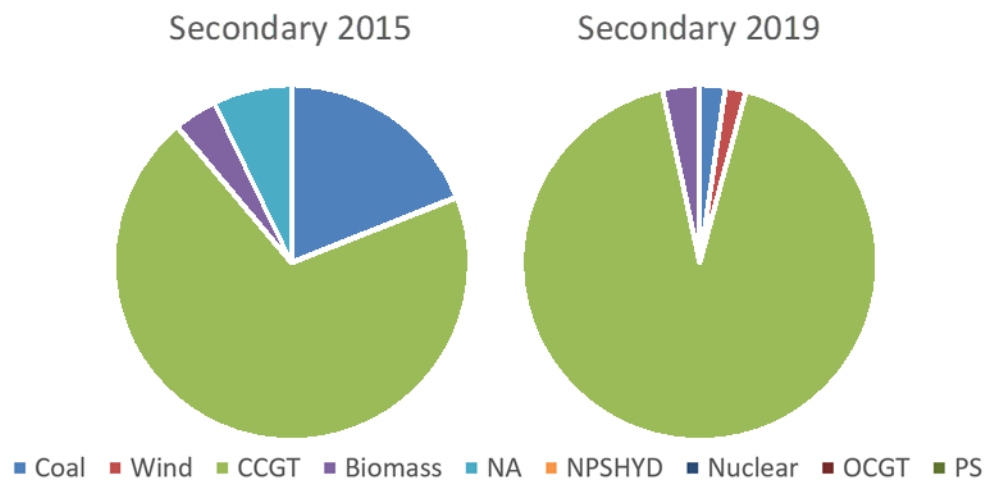

Figure 10.9: Mandatory secondary frequency response by provider in 2015 versus 2019 [7].

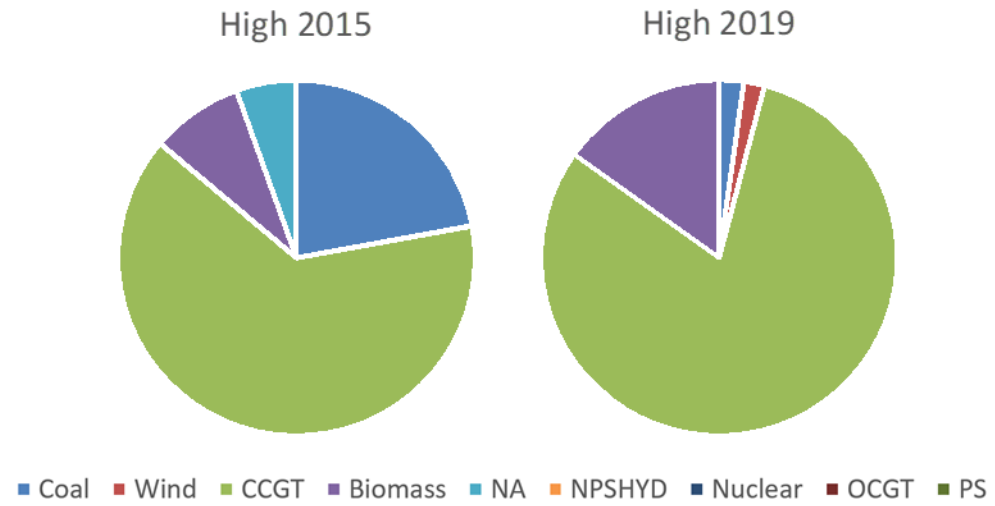

Figure 10.10: Mandatory high frequency response by provider in 2015 versus 2019 [7].

10.1.3 Commercial Frequency Response

The current commercial frequency response suite from National Grid includes firm frequency response (FFR), FFR Bridging and Frequency Control by Demand Management (FCDM). At the time of writing, Enhanced Frequency Response (EFR) is considered to stand alone as a service. Generally, in the commercial frequency response market, larger actors tender for availability fee (£/hr for the hours that the provider is available) and nomination fee (£/hr for the hours used). Other components that may be included in such tenders include window initiation fee (£/window), tendered window reservation fee (£/hr) and response energy fee (£/MWh, paid as per CUSC Section 4.1.3.9A for BMU and is a tendered parameter for non-BMU providers).

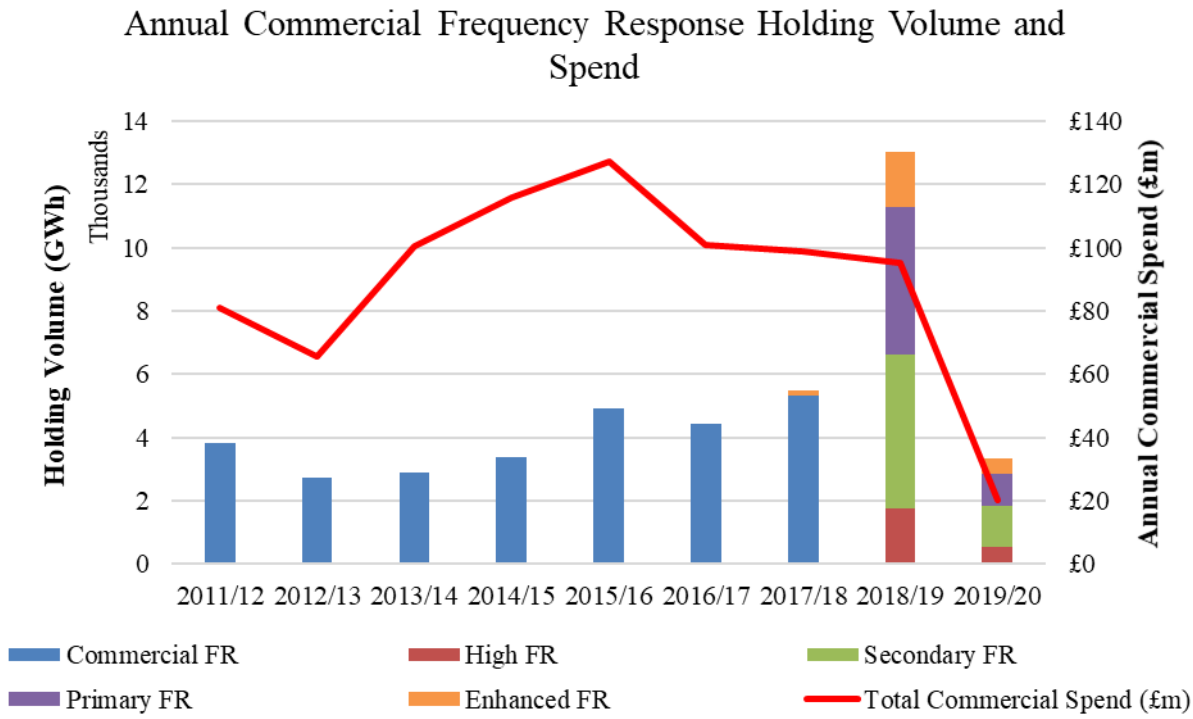

Figure 10.11: Annual commercial frequency response holding volume and annual spend. Enhanced FR assumes constant 227MW available volume & that nothing was online before March 1st 2018 [2].

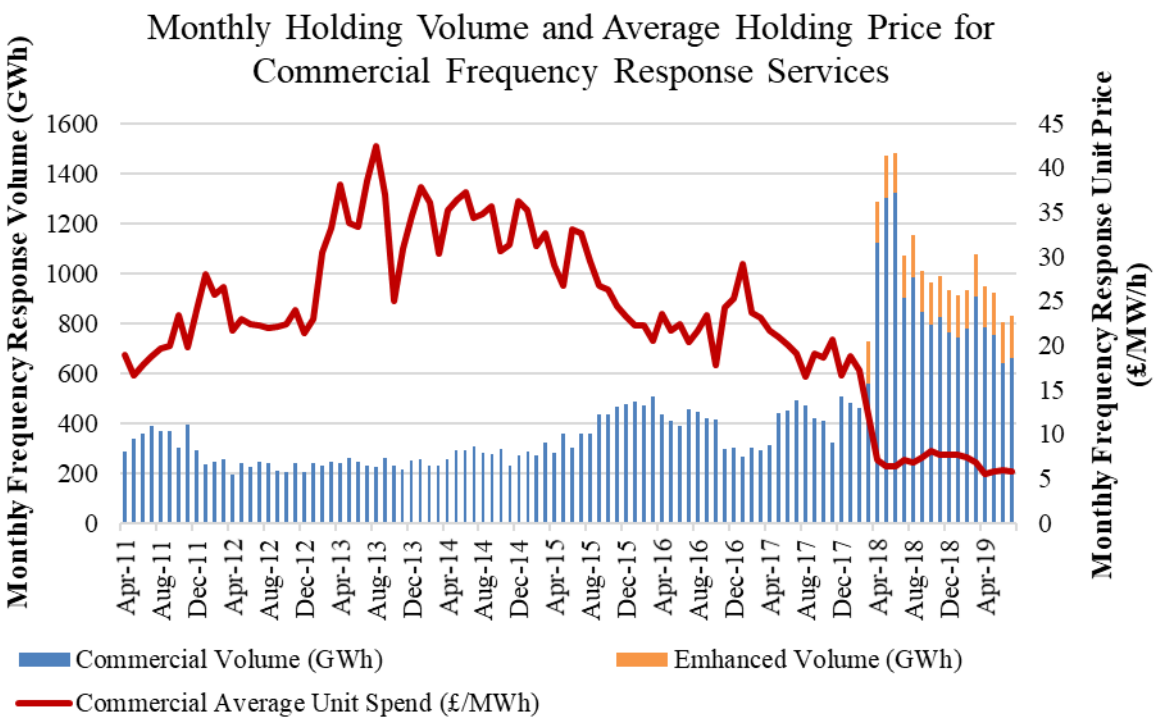

Figure 10.12: Monthly holding volume and monthly average holding price for commercial frequency services. Enhanced FR assumes constant 227MW available volume & that nothing was online before March 1st 2018 [2].

11 Reactive Power Services

National Electricity Transmission System (NETS) voltages are managed under statutory obligation in GB by National Grid to ensure the secure and stable power operation of the power system, defined in the Security and Quality of Supply Standard (SQSS). Voltage is a localised property of the power system, mainly determined by reactive power flows. National Grid ensures that reactive power is generated or absorbed at a regional level to meet the constantly varying needs of the system and hold sufficient reactive power reserves to ensure the system can withstand credible contingencies. In tandem to this, National Grid may contract additional reactive power capability through market arrangements in order to ensure the availability of reactive power reserves.

National Grid manages system voltages by utilising a mixture of network assets (e.g. shunt reactors) and balancing services (Obligatory and Enhanced Reactive Power Services (ORPS and ERPS) which are outlined below). Balancing services can only be used if the provider is online, which is increasingly difficult during periods of low active power demand on the transmission system. A voltage constraint arises when there is insufficient reactive power generation or absorption in a region, meaning that network voltages would go outside secure limits unless actions are taken to address the reactive power requirement. At this stage, National Grid must pay a generator in that region to turn on and be in a position to generate or absorb reactive power (i.e. buy active power in order to access the reactive capability of the machine). This concept is illustrated in Figure 11.1. This is achieved through either regional voltage constraint contracts, forward energy trades of accepting offers from Balancing Mechanism (BM) participants.

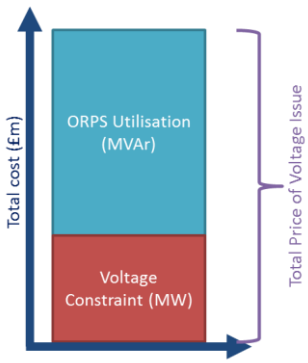

Figure 11.1: Total cost of procuring reactive power during a voltage constraint (costs illustrative only).

Key Points:

- The volume and cost of reactive power services procured through balancing services has grown in recent years, peaking in the 2016-17 financial year at 31 million MVArh, with a total cost of £85.73m (2.76 £/MVArh).
- The greatest increase in the volume of reactive power services procured has been in spring and summer months.
    - Lightly loaded transmission system results in higher network voltages, increasing the demand for reactive power absorption.
- The price per unit of reactive power peaked in the 2018-19 financial year at £3.30/MVArh.
- The majority of the reactive power services procured for balancing is via the Obligatory Reactive Power Service (ORPS).
- In the financial year 2018-19 the average ORPS utilisation price was £3.48/MVArh.
- No Enhanced Reactive Power Service (ERPS) tenders have submitted by providers since 2011.
- Increasing periods of low transmission demand results in fewer ORPS providers running, leading to voltage constraints.
    - Increasing cost to manage voltage constraints, managed through forward trades and BM actions.
- Increased demand for reactive support mostly observed in North England, however the whole of GB has an increasing reactive absorption requirement.
- Wind is capable of providing reactive power, even when there is no wind.
- The BM mandatory reactive market does not transparently signal the requirement as it relies on dispatching MW to access reactive support.

Further Investigation:

- Continue to look into regional use of reactive power under the ORPS to see regional trends (monthly reporting data available showing BMU ID and lead/lag provision)
    - Locational requirements likely to be of great value since this provides insights for developers into where to build windfarms and to what specifications (e.g. electrical topology of site and component properties)
    - Mapping BMUs to GSP zone work recommended to continue
    - This will also input into Mandatory and Firm frequency response regional volume analysis (section 10.1)
- Identify future reactive power demand trends by region to inform the technology choices of windfarm owners and developers in different areas of the network.
- Establish impact of providing large amounts of reactive power on converter lifetime and reliability
- Improvements to MBSS reporting format should be implemented to increase the level of detail available and transparency of actions taken by National Grid
    - This should be backdated to allow market participants (or future participants) to analyse potential markets

11.1 Total Reactive Power Volumes and Costs

Reactive power services procured through balancing services has increased since 2010 (see Figure 11.5 and Figure 11.6). Over the same period the total spend on reactive power has increased, with the total spend on reactive power balancing services peaking in 2016-17 at £85.73m (Figure 11.5). The majority of the reactive power volume is made up from 'BM Default Utilisation' (i.e. ORPS payments), although this data is only available after April 2018 due to a change in reporting transparency in the MBSS from National Grid. In line with this, the majority of the cost relates to the ORPS payment, however costs such as BM Synchronous Compensation (Commercial) are included in the total cost reported in Figure 11.5.

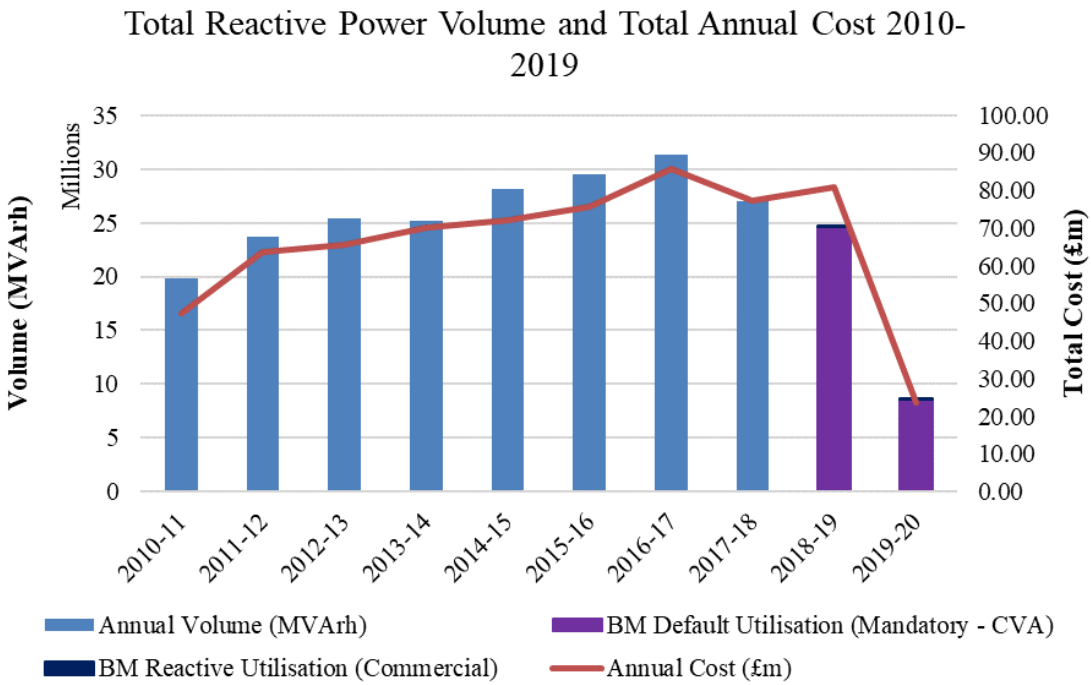

Figure 11.2: Total reactive power volume procured via balancing services and total annual cost from 2010-2019 (2019-20 data only includes April – July 2019) [2].

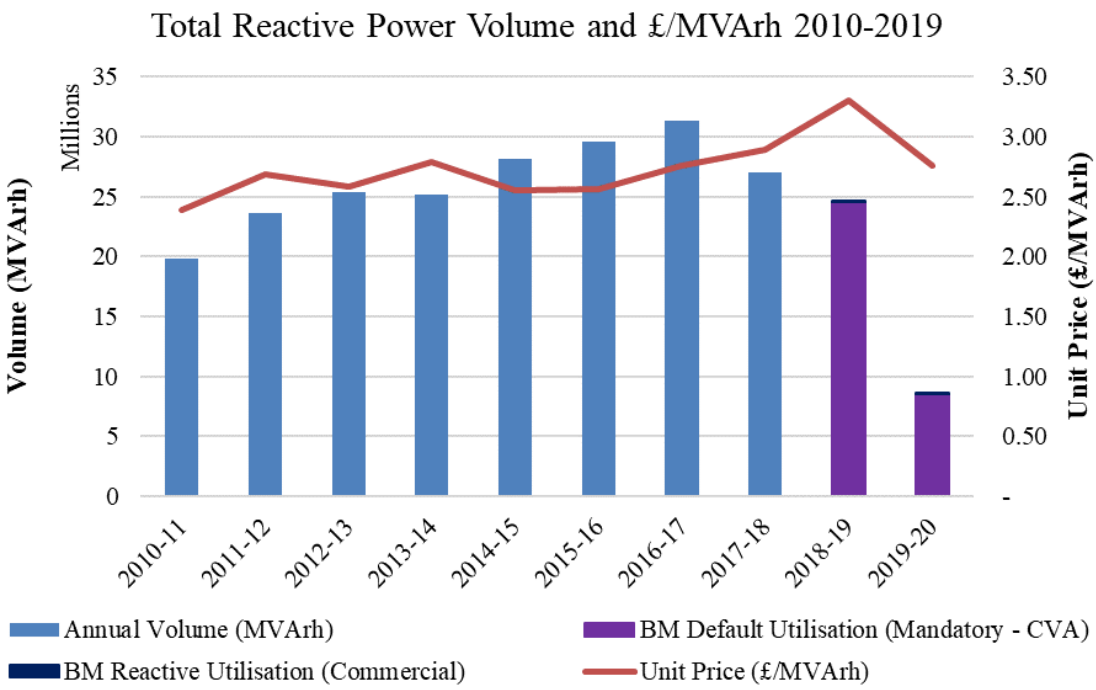

Figure 11.3: Total reactive power volume procured via balancing services and average annual unit price from 2010-2019 (2019-20 data only includes April – July 2019) [2].

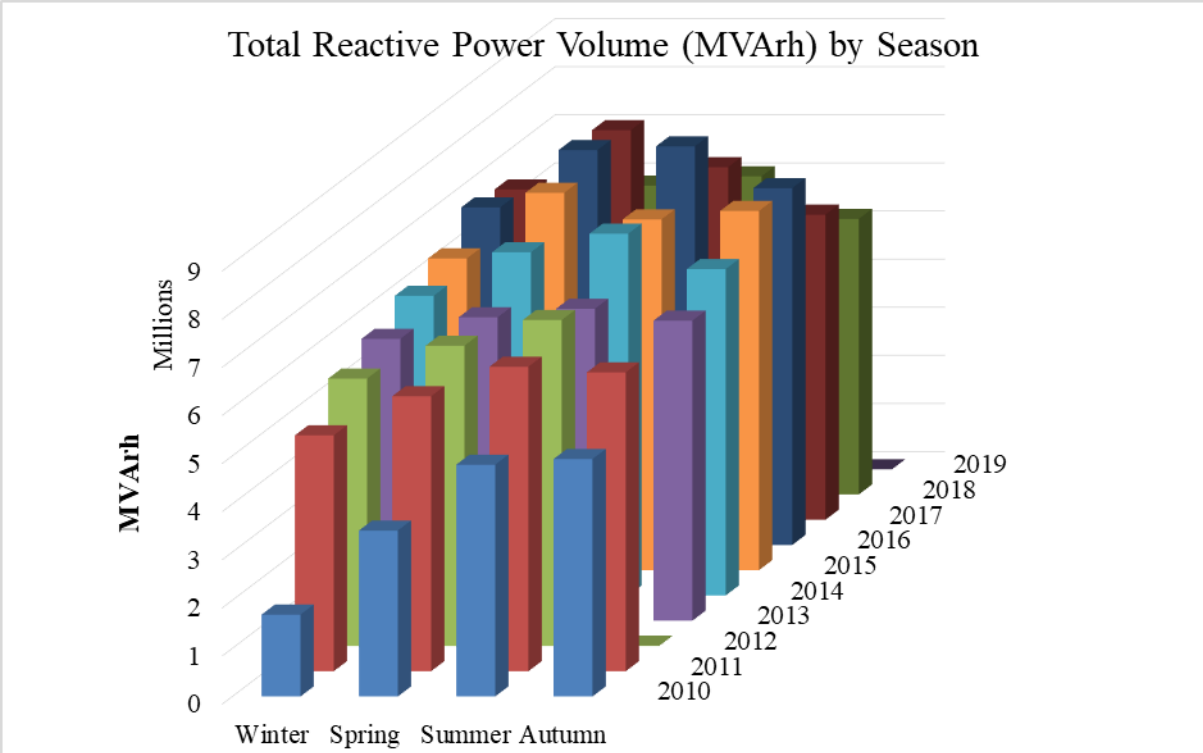

Figure 11.4: Total monthly reactive power volume procured via balancing services from 2010-2019 (2019-20 data only includes April – July 2019) [2].

11.2 Obligatory Reactive Power Service (ORPS)

The Obligatory Reactive Power Service (ORPS) is the minimum capability of generators (over 50 MW) to vary their reactive power output on instruction from National Grid. The ORPS can be provided by synchronous and non-synchronous generation and may be required to produce or absorb reactive power to help maintain system voltages close to the point of connection. Generators are generally instructed to a target reactive power level (0.85 pf lag to 0.95 pf lead at rated active power output) that must be reached within 2 minutes. Minimum technical requirements for the

obligatory reactive power service are given in the Grid Code (CC.6.3.2(c)) and summarised below. The reactive power provider must:

- Be capable of supplying their rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the BMU terminals when operating above 20% of rated output.

- Have the short circuit ratio of the BMU less than 0.5.
- Keep the reactive power output under steady state conditions fully available with the voltage range of ±5%.
- Have a continuously acting automatic excitation control system to provide constant terminal voltage control of the BMU without instability over the entire operating range of the BMU.
- Must be capable of maintaining zero transfer of Reactive Power at the Onshore Grid Entry Point (or User System Entry Point if Embedded) at all Active Power output levels under steady state voltage conditions.

Generators under ORPS receive a default payment for utilisation (£/MVArh), which is updated monthly based on market indicators (Schedule 3 of the CUSC). In the financial year 2018-19 the average utilisation price was £3.48/MVArh (Figure 11.6).

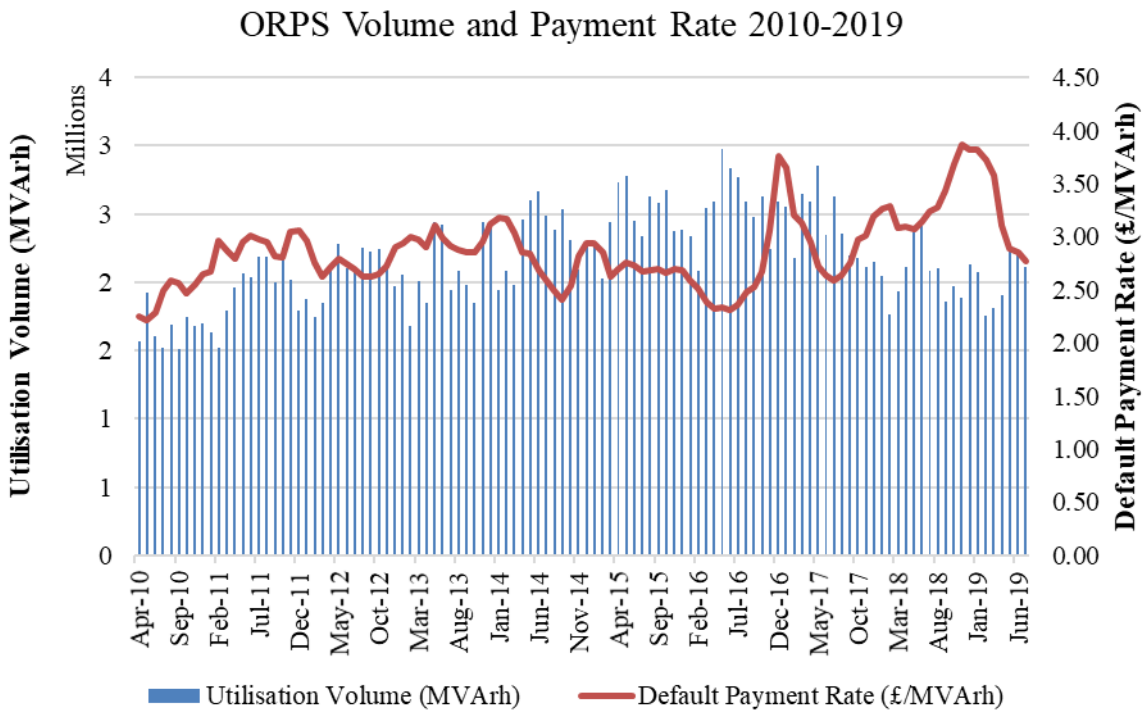

Figure 11.5: Utilisation and remuneration for obligatory reactive power service by month from April 2010 to July 2019 [8].

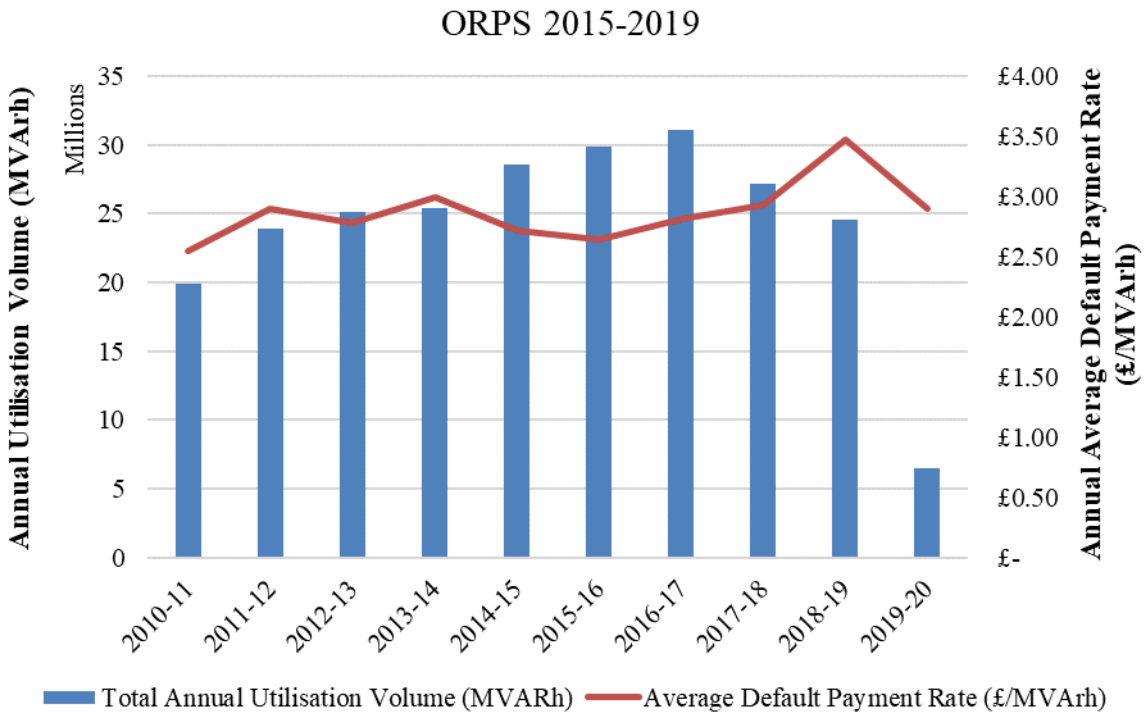

Figure 11.6: Utilisation and remuneration for obligatory reactive power service by financial year from 2010 to 2019 (2019-20 data only includes April – July 2019) [8].

11.3 Enhanced Reactive Power Service (ERPS)

The Enhanced Reactive Power Service (ERPS) requires the provision of voltage support over and above the minimum technical requirement of the obligatory service. Although the service is still open to tenders, the service has not been procured since 2009 and there have been no offers received by National Grid since 2011. This provides a route to market for generators that are not required to provide the ORPS. This service is procured through tenders which are held every 6 months, and contracts have a minimum term of 12 months. There is a capability price (£/MVAr/hr) and/or synchronised capability price (£/MVAr/hr) and/or utilisation price (£/MVArh).

11.4 Locational Reactive Power Trends

As stated previously, demand for reactive power is highly locational. National Grid do provide locational data for provision of reactive power services. Demand for reactive power by region is provided in Figure 11.7. There has been significant growth in the demand for reactive power in the north of England between 2009/10 and 2018/19. Reactive demand in other regions has also grown, but not to the same extent. Further locational granularity is recommended to identify network areas where reactive power is likely to be highly valued by the system operator.

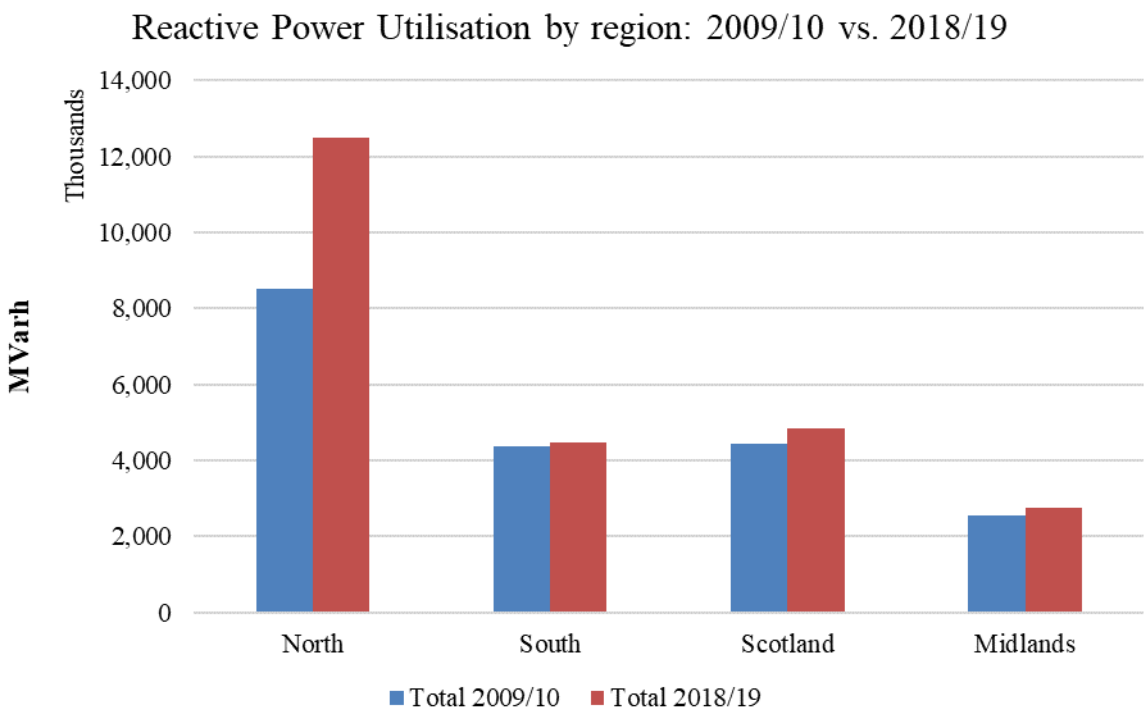

Figure 11.7: Reactive power utilisation (MVArh) by region in 2009/10 vs. 2018/19 [8].

Reactive power reports from National Grid also specify the lead/lag requirement by region (Figure 11.8). Across all areas, the need for leading reactive power has grown – most significantly in the North and Midlands. This is linked to high voltage issues, meaning reactive power must be absorbed to reduce network voltages.

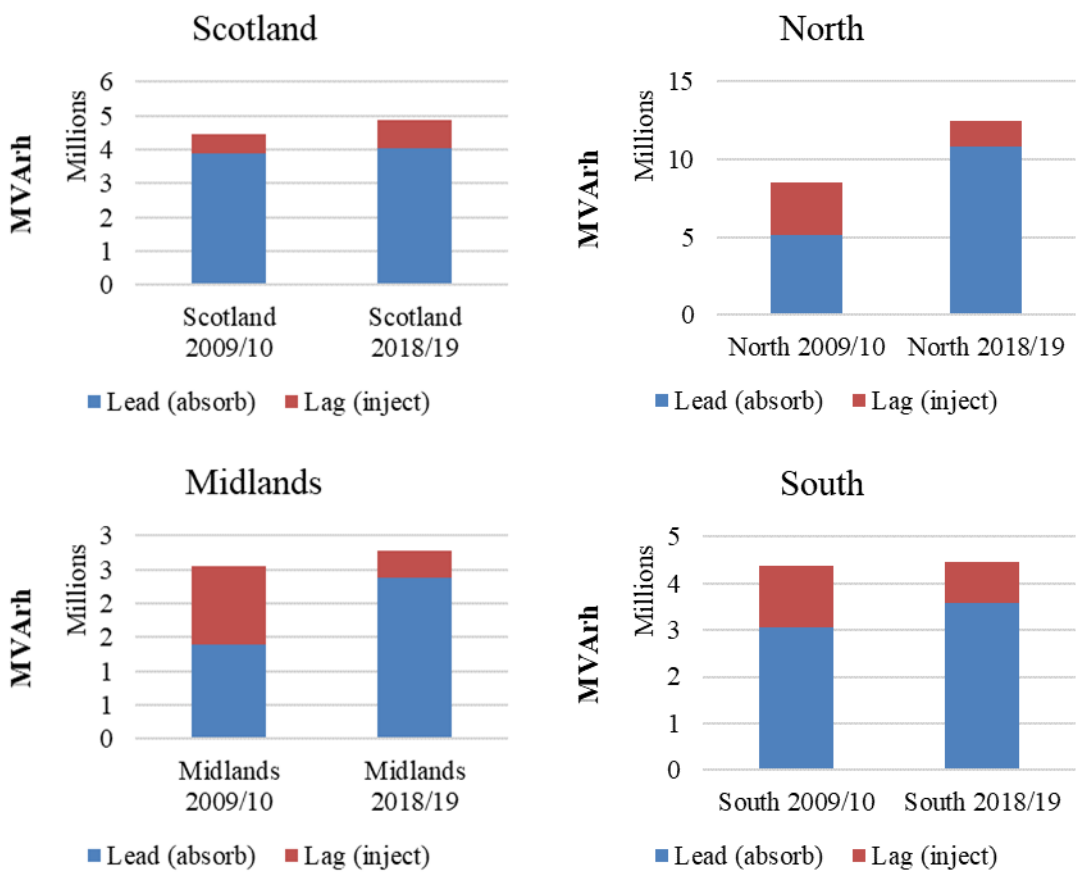

Figure 11.8: Lead/lag reactive power utilisation (MVArh) by region in 2009/10 vs. 2018/19 [8].

12 Overall Voltage Management

As outlined previously, a voltage constraint arises when there is insufficient reactive power provision in a region to maintain voltages within secure limits. At this stage, the SO must procure active power to access the reactive power. National Grid only breakdown constraints in the MBSS into voltage, transmission and RoCoF from April 2018, making the identification of trends difficult since only 16 months of detailed data is available.

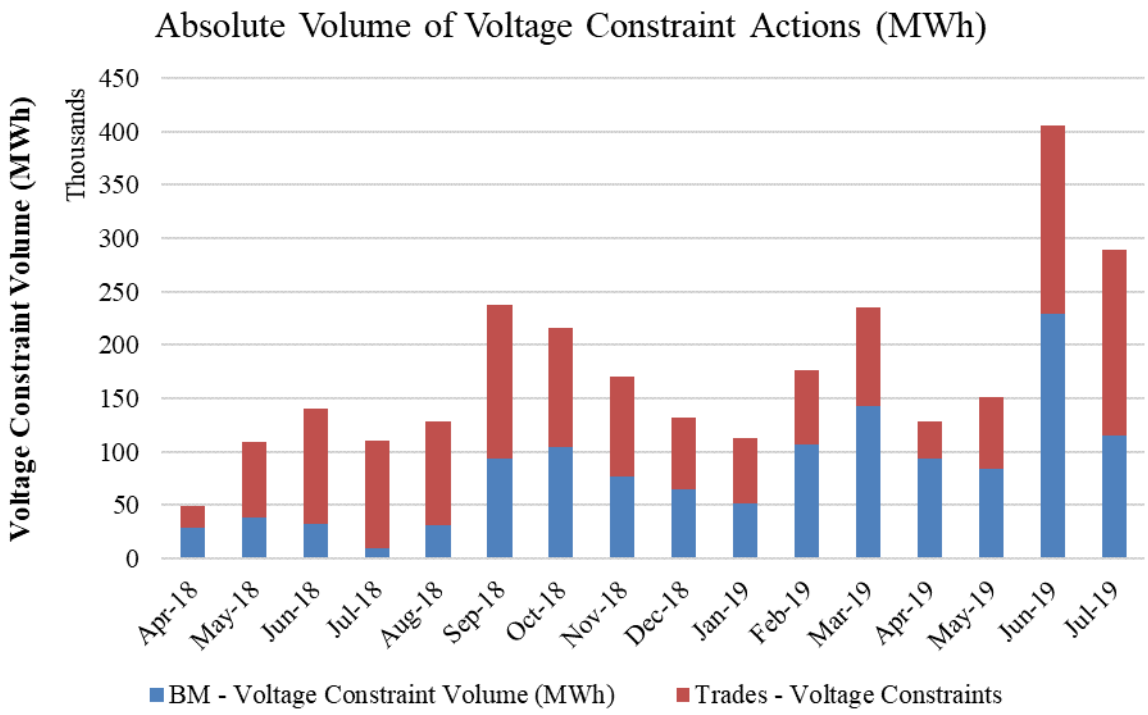

Figure 12.1: Voltage constraint volume (broken down into trades and BM actions) from April 2018 to July 2019 [2].

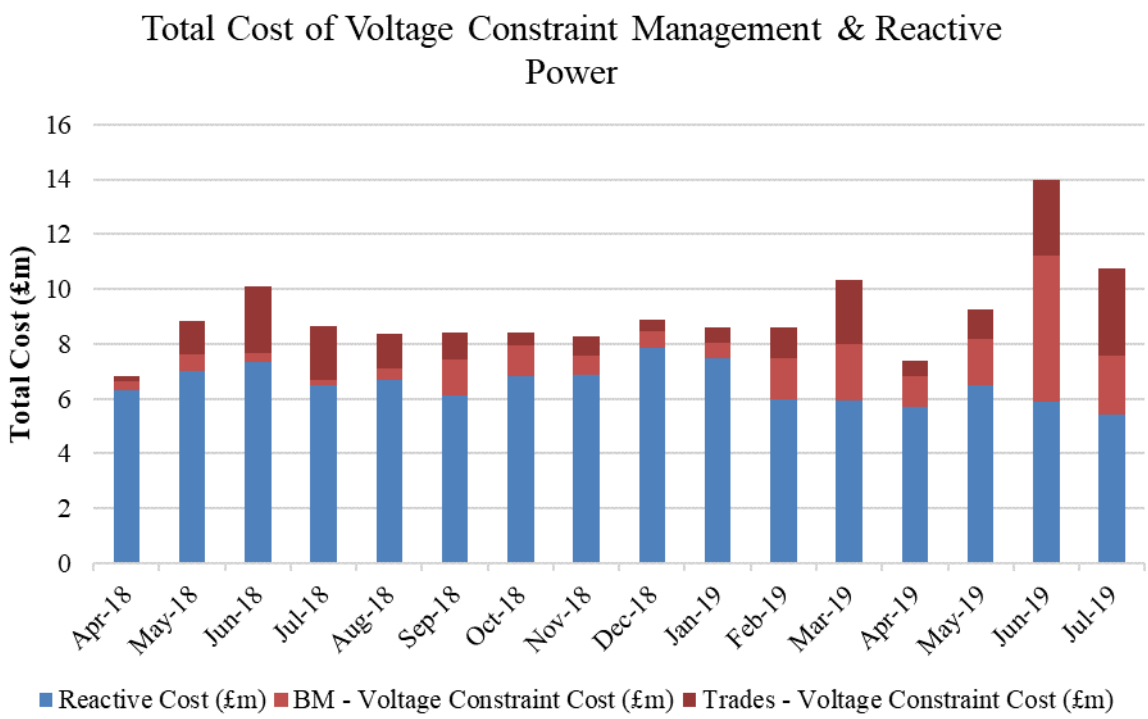

Figure 12.2: Total cost of voltage constraints and reactive power procurement from April 2018 to July 2019 [2].

13 Current Projects

13.1 Scotland Enhanced Reactive

National Grid indicate in the tender guidance that there is a 300 MVAr lead and 400 MVAr lag requirement in Scotland, depending on the location of the reactive capability required and the effectiveness of the provider (requirement can be 24/7 at some periods of the year). The tender aims to procure reactive power when the active power output of the provider is less than 20% of the rated active power of the unit, increasing the range of options available to the SO during periods of low generation. There are payments for availability (£/hr) and reactive power utilisation payment, paid at the ORPS rate (£/MVArh). Tenders are given an effectiveness score based on a combination of the providers location and connection voltage level.

Table 13.1: list of accepted tenders for Scottish Enhanced Reactive

Accepted Tenders		
T_ACHRW-1	AChruach Wind Farm	Mobius Renewables Gen. (GB2
T_ACHRW-1	AChruach Wind Farm	Mobius Renewables Gen. (GB2
T_ACHRW-1	AChruach Wind Farm	Mobius Renewables Gen. (GB2
T_ACHRW-1	AChruach Wind Farm	Mobius Renewables Gen. (GB2
E_BTUIW-2	Beinn An Tuirc 2	SP Renewables (UK) Limited
T_DRSLW-1	Dersalloch Windfarm	SP Renewables (UK) Limited
T_KLGLW-1	Kilgallioch Windfarm	SP Renewables (UK) Limited
T_MKHLW-1	Mark Hill	SP Renewables (UK) Limited
STLGW	Stronelairg Windfarm	Stronelairg Windfarm Limited
T_WHILW-1	T_WHILW-1	SP Renewables (UK) Limited
T_WHILW-2	T_WHILW-1	SP Renewables (UK) Limited

13.2 Mersey Reactive Power

A tender was launched by National Grid for a static reactive power service in the Mersey region. This tender enables embedded generators to participate to assist transmission system voltage requirements. National Grid are releasing both short and long-term tenders, the former closing in November 2019 and the latter in February 2020. There are four service types available, all of which have a service period from 2300 to 0700 hours:

- Voltage only (BM Firm): This is a firm service to run at the stable export limit (SEL) for the overnight period every night. This is remunerated on a payment per settlement period (£/SP), where there are 16 settlement periods per day.
- Voltage only (BM Call-Off): Option price without availability payment. This is to be paid based on the difference between the day ahead dark/spark spread and the pre-agreed strike price for the contracted period.
- Voltage only (Embedded Non-Flexible): This is a firm availability service, where generators receive the availability rate for all settlement periods in a service period when the provider is available. Where reactive power is required, the generator will receive a utilisation payment equal to the ORPS rate.
- Voltage only (Embedded Flexible): Operational availability, where National Grid will pay will pay the activation rate for all settlement periods whilst under instruction, based on the available MVAr volume, and a utilisation rate equal to the ORPS rate.

14 Conclusions

A detailed review of the evolution of volumes and costs of balancing services in GB since 2011/12 has been provided. The total spend on balancing services in 2018/19 was £1.2 billion (higher than any other year since 2011/12). This was largely due to increased transmission constraint costs. Moreover, National Grid has been taking more and more actions using pre-gate trades, where it is likely to be more economic do so. The majority of forward trades are taken to deal with ROCOF constraints but National Grid reporting hasn't – until recently – provided data in a format that permits analysis of constraint by category.

In recent years, there has been a shift from predominantly using MFR services to commercial services, with commercial services providing 20% of the total 18.5 TWh of frequency response volume in 2011/12, compared to 65% of 17.4 TWh in 2018/19 (excluding EFR volumes). This is likely due to the significant reduction in the cost per MWh in the commercial frequency response market (peaking at an average price of £34.9/MWh in 2013/14 and reducing to £8.6/MWh in 2018/19), bringing their cost down close to MFR services at around £4.2/MWh (excluding any repositioning costs). How this will develop as FFR is phased out over the next three years is of great importance and should be monitored.

Out of the reserve product suite, Fast Reserve is likely to be of most significance in future work packages relating to this project. As it stands, Fast Reserve procured monthly and requires providers to deliver at least a 25 MW active power response within 2 minutes of instruction at a delivery rate of 25 MW/minute and be capable of sustaining for at least 15 minutes on receipt of an electronic instruction. It is used on average 35 times per day, with 61% of all instructions being less than 10 minutes and 35% less than 5 minutes (Figure 9.11). Fast Reserve requirement sits around 200-300 MW depending on the time of day; however, in an apparent change of strategy NGESO indicated that it intends to procure 600 MW across January to March 2020. The average annual spend on Fast Reserve since 2011 has been £109m (Figure 9.10), with the cost per MWh averaging £400/MWh since November 2017. Questions remain around (a) why National Grid are trialling an additional 300 MW of Fast Reserve in January 2020, (b) what the future demand for Fast Reserve is likely to be, and (c) the fitness for purpose of the Fast Reserve service definition as it stands. It should also be pointed out that any service designed to replace Fast Reserve, provides an opportunity to create a service that is complaint with the Clean Energy for all Europeans Package [9].

The volume and cost of reactive power services procured through balancing services has grown in recent years, peaking in the 2016-17 financial year at 31 million MVArh, with a total cost of £85.73m (2.76 £/MVArh). The majority of the reactive power services procured for balancing is via the Obligatory Reactive Power Service (ORPS), which had an average utilisation price of £3.48/MVArh in 2018/19. The greatest increase in the volume of reactive power services procured has been in spring and summer months, due to increasing periods of low transmission demand resulting in fewer ORPS providers online, leading to voltage constraints.

15 References

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[8] National Grid ESO, "Obligatory reactive power service (ORPS)," National Grid, 2020. [Online]. Available: https://tinyurl.com/y7a7uco6. [Accessed 14 05 2020].