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A closed-loop analysis of grid scale battery systems providing frequency response and reserve services in a variable inertia grid

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Abstract

With increasing penetration of wind and solar generation the deployment of fast response plant, principally batteries, is currently considered necessary to mitigate reduced system inertia and the possibility of demand-supply imbalances. In this work the impact of these factors on battery cycling rates, taking into account the input from the batteries themselves, are analysed by applying the swing equation to a future inertia based on forecast generation mix. The operational capacity of batteries is a determining factor in their cycling rate, though the depth of discharge appears to be less well correlated. It is found that reducing system inertia does not, of itself, significantly impact on frequency volatility where the volatility of the generation to load imbalance is unchanged. However, the potential for a reduction in the damping of frequency deviations as a result of an increase in inverter connected motor drives may have a large impact on battery cycling characteristics. Provision of reserve services from battery systems requires a more complex operational strategy to ensure services are always deliverable and results in a significantly different cycling profile that may lead to greater battery degradation and consequently higher operational costs.

Keywords

Frequency response; system inertia; energy storage; power systems; batteries; grid services

1. Introduction

Traditional fossil fuel dominated electricity systems typically comprise a small number of large generators, such as coal, gas and hydro plant, which can provide load following and frequency response capability and provide the grid with inertia. The level of inertia on the grid determines the rate at which frequency changes following a step change in generation or demand. Many renewable generators, particularly solar and wind, either have no inherent inertia, being inverter connected, or reduced inertia as a result of being small, light-weight and often non-synchronous, machines. The UK electricity grid has seen the contribution from renewables grow from under 5% in 2004 to around 25% in 2016 [1], that proportion is expected to continue to grow [2] as the UK aims to meet its climate change targets. Several papers have been published that examine various forms of frequency response in consideration of the increase in low inertia renewable generation. Tielens et al. [3] describe the impact of increasing low inertia plant on frequency control and stability in grid systems and, together with Dreidy et al. [4], consider approaches to the use of renewable plant, such as wind generators, to provide real inertia together with the potential for inverter connected systems to mimic the speed control functions of synchronous generators. Thiesen et al. [5], however, propose that inertia should become a traded commodity with flywheels providing the lowest cost solution.

In an electricity grid system, all synchronous generators connected to the grid rotate at the same grid system frequency. If there is an imbalance between generation and demand on the system, the rotational kinetic energy (RKE) of the synchronous generators changes such that energy is conserved; it goes up when generation is greater than demand, absorbing energy through an increase in speed and therefore system frequency, and vice versa when demand exceeds generation. Thus, imbalances between generation and demand in power systems cause deviations in frequency from the target (50 Hz in the UK). Consequently, frequency is the primary control parameter used to ensure that generation matches demand at all times. The RKE of the synchronous machines is proportional to their inertia, the term 'system inertia' is then used for the aggregated inertia of all the rotating machines (generators, turbines, other mechanical components) coupled to the power system. Having a large amount of inertia on the system, predominantly provided by the large rotating masses of fossil fuel generation, helps to reduce the rate of change of frequency (RoCoF) in the few seconds required for primary frequency response (PFR) plant to begin adjusting its output [3]. Thus, in a traditional grid system, the initial frequency disturbance caused by a power imbalance is 'damped' by system inertia and then responded to within a few seconds by generation plant and subsequently, if required, by dispatching fast response plant, such as hydro operating as spinning reserve, to balance the system.

The TSO (Transmission System Operator) for Great Britain (National Grid) has recognised the need to address its existing balancing services. National Grid published a report [8] in June 2017, which outlines plans to overhaul current balancing services with new, future-proof, services due to changing system needs. The report highlights that system inertia is expected to decrease as the energy mix changes in the future, increasing the RoCoF during a generation or demand loss. Some distributed generators have RoCoF protection relays in place, which disconnect them from the grid at between 0.125 Hzs^{-1} and 0.2 Hzs^{-1} depending on the application [9]; less system inertia increases the likelihood of a worst-case situation where numerous generators are disconnected in quick succession, possibly resulting in a partial system shut down. In [8], it is proposed that desensitising RoCoF relays would mitigate the risk of a cascade trigger event and allow the system to operate at lower levels of system inertia. Work is currently being done on this by NGC and the Electricity Networks Association, with generators over 5 MW having a 0.5 s time delay implemented at a RoCoF of 1 Hzs^{-1}. The report also discusses a potential fast response product that will include sub-second response and inertia and will provide a route to market for fast-acting response (e.g. batteries).

Ulbig, Borsche and Andersson [6] described the mechanisms for modelling the effects of system inertia, deriving the swing equation, and studied the impacts of low, and variable, rotational inertia on power system stability and operation. In the System Operability Framework 2016 [7], the UK's National Grid Company (NGC) set out their own empirical observations relating to components of the swing equation for the UK grid, enabling the construction of models to evaluate the impact of reduced inertia and the more unpredictable system imbalances expected with increasing renewable generation. These techniques are most frequently employed to examine the effects of large disturbances in generation or demand caused by, for example, the sudden loss of a large generator or load.

There have been a number of previous studies on the efficacy of Energy Storage Systems (ESS), mainly batteries, providing frequency or inertial response to the grid. Johnston et al [10] presents a methodology for the economic optimisation of the sizing of an ESS integrated in a wind power plant providing frequency response in the UK market. The study uses the system frequency as an input in the model rather than a variable and so dynamic interactions with the system frequency is not accounted for. Knap et al. [11] evaluate the viability of ESS (based on lithium-ion batteries) for providing inertial response (IR) using simulations on a 12-bus grid model. The authors suggest that the impact of wind penetration on RoCoF can be reduced or neutralised with an appropriate size ESS. It is also suggested that providing IR in combination with another grid service would be more economic, improving utilisation of the ESS capacity. Knap et al. [12] build on this study by exploring the sizing of an ESS for both IR and PFR by using simulations on a similar grid model as before. The PFR response of the ESS within the model is a function of the frequency deviation, and the IR is based on RoCoF, using droop controllers. The results indicate that ESS can provide a response that is fast enough to counteract high RoCoF; however, there may still need to be a slight time delay on RoCoF relays to avoid triggering. For a system with 50% renewable penetration, the required storage capacity is a little under 5% of the total generation capacity with a power to energy ratio of approximately 2:1. The optimum power energy ratio was also calculated in [13] for the UK firm frequency response (FFR) market and was found to be approximately 2:1 as well. Cheng et al [14] investigate whether a coordination of an ESS and demand response as a virtual energy storage system can participate successfully in the FFR market. Over a timescale of 20 years, they conclude that a virtual energy storage system can provide greater profits than just an ESS alone. Goebel et al. [15] investigate the application of lithium-ion battery ESS for secondary reserve applications in the German power market. They conclude that dispatch strategies incorporating detailed battery models can reduce operating costs, but also note the need to increase profitability by providing multiple services.

Whilst there has been discussion of the impact of reducing system inertia, much of the modelling carried out to-date makes use of historic system frequency data, which is unlikely to reflect the increased volatility expected in a lower inertia system. To address this, Lian, Sims and Yu et al. [13] use a Fast Fourier Transform analysis on historic frequency to extract balancing and frequency response components and consider how increases in forecast error, due to higher wind penetration, might impact on future frequency response requirements. They conclude that the increased reserve requirement balances out the impact of increased frequency response demand; however, importantly, their analysis does not take into account lower system inertia. Greenwood et al. [16] highlight the need for improved frequency response in future power systems and investigate how energy storage can fulfil this need. Two experiments are conducted in their study: one that evaluates the performance of an ESS emulator responding to historic frequency data and performing Enhanced Frequency Response (EFR) [17], and another that uses a real-time simulated 24-bus grid model to examine the ESS emulator response to frequency events (e.g. generator loss). The authors claim that their methods can be extended to investigate frequency response services in low inertia systems.

In a normally operating network, the system inertia will affect the RoCoF and frequency minima and maxima during typical load variations. Thus a battery system responding automatically to frequency, such as under the EFR service, is likely to experience more volatile operation as system inertia reduces. Intuitively, the total installed battery capacity will also affect the depth of cycling and cycle count, and hence battery life, of individual installations. This is an area largely unexplored by existing studies.

In this paper we seek to address the above by moving beyond analysis of battery response to historic frequency data. We do this by:

- first, developing a novel methodology with which to predict how battery response will alter system frequency;
- secondly, applying this to study how such response will change that frequency data for various scenarios, which are intended to be reflective of likely future changes in power system dynamics.

A key outcome of this approach is that the impact that differing volumes of frequency response on the cycling rates of batteries can be studied directly. This analysis is essential for network operators to accurately determine appropriate volumes of response and for plant operators in understanding the impact on battery cycling rates, potential future operational impacts and thus required control system functionality and battery chemistries. Though, we do not attempt here to determine specific battery degradation as this will depend on the selected chemistries.

This work is organised as follows: in Section 2, a method to generate a future 1s interval load profile to provide a basis against which to analyse high speed ESS response is developed. Section 3 presents the case study load profiles used to evaluate the operation of the battery ESS, including a high renewables, low inertia generation mix based on NGCs 2025 Consumer Power summer profile [7]. In Section 4, the results of analysing various ESS operational regimes on frequency volatility and battery cycling are presented and discussed. Section 5 summarises the findings and Section 6 sets out the limitations of the study and areas for future work.

2. Methodology

To understand how future generation mix may impact on frequency volatility and battery operation, it is necessary to develop a sufficiently high resolution load profile against which forecast generation mixes and frequency response volumes can be tested.

In this section we firstly develop a method to estimate the system inertia based on the mix of generation connected at each modelled time interval. Secondly, by applying this method to a period of system operation for which 0.5h interval generation mix data and 1s interval frequency data are available, we develop a 1s interval demand profile. In principle this demand profile could be expressed as a supply demand imbalance to assess the impact of differing generation mixes in combination with different load profiles, however, in this analysis we keep the load profile the same and vary only the generation mix. Thirdly, we present the method by which this load profile is combined with a future, lower inertia, generation mix to develop the system frequency response. Finally, we present the method for including battery systems in the future generation mix and incorporating the output of those systems at sufficiently fine time intervals to provide a novel closed loop analysis of the network.

Load profile Development

True demand data is not readily available; the data often quoted as demand in the UK is, in fact, generation data from plant that is a party to the Balancing and Settlement Code. This means that it excludes both the increasingly large volume of smaller distributed and 'behind-the-meter' generation and any small discrepancies caused by system imbalance (i.e. when the system frequency is not exactly 50Hz).

Load following generation is assumed to move smoothly between each 0.5 hour data point. The system inertia is calculated based on an estimate of the total rated capacity of each type of generation (1 to n respectively) connected to the network and estimates of generator inertia constants provided by NGC (Table 1). The quantity of inertia will depend on the total capacity of each type of generator connected rather than the output of the generator. Average load factors for different types of generator are given in the Digest of United Kingdom Energy Statistics (DUKES) Table 5.10 [1], however, these reflect the annual output against theoretical maximum output and do not take into account what capacity is on line at any given time. Table 1 presents the values used here, these estimates based on DUKES data [1], assumptions about minimum load and the need for spinning reserve. The system inertia E_s can be calculated from:

$$E_s = \sum_{i=1}^{n} \left\lceil \frac{P_i}{U_i R_i} \right\rceil R_i H_i \tag{1}$$

Where, P_i is the generator power output for each generator type (i) at each model timestep, U_i is the assumed average load factor for the type of generator and. R_i is the typical unit capacity (estimated from DUKES station data [1] and number of units at each site) and H_i the associated inertia constant. By rounding up the number of generators to the nearest integer, E_s gives an estimate of the total system inertia based on the expected number of units of each type on line at each timestep; this figure is most frequently quoted in 'GVA.s' in industrial publications. The resulting system inertia values (refer Figure 6) lie at the lower end of the bounds estimated in NGCs System Operability Framework [7], which would be expected given the summer week modelled.

A system moment of inertia is determined from:

$$I_m = \frac{2E_s}{{\omega_0}^2} \quad (where\ \omega_o = 2\pi \times 50Hz) \tag{2}$$

Table 1 - Generator inertia constants [19]

Plant Type	Inertia Constant Range (s)	Modelled Value, H (s)	Assumed Load Factor, U (%)	Assumed Unit Size, R (MVA)
Nuclear	4-6	5	90%	500
Hydro	3-4	3.5	60%	200
Biomass	4	4	80%	500
Coal	4	4	75%	500
Open Cycle Gas Turbine	4	4	75%	50
Combined Cycle Gas Turbine	8	8	75%	400
Other distributed generation	N/A	4	80%	5
Renewable generation	0	0s	-	-
Interconnectors	0	0s	-	-

Demand at each time-step and at the target system frequency, D_{t,f_0}, is calculated using the NGC empirical formula for frequency sensitive load [7] and the power delivered by, or drawn from, generator inertia over the previous time-step:

$$D_{t,f_0} = \frac{D_{t,f_t}}{(1-0.025(f_0-f_t))} + \frac{I_m(\omega_t{}^2-\omega_{t-1}{}^2)}{2\Delta t} \qquad (3)$$

Where D_{t,f_t} is the demand at time t, and at actual frequency, f_0 is the nominal system frequency (50Hz), f_t the frequency at time t, while ω_t and Δt are the system frequency at time t in radians/s and the model time-step respectively.

Equation (3) can be solved for demand at time t and 50Hz using 1s interval frequency data and the interpolated 0.5 hour generation data (from which the estimated system inertia, I_m is also developed – Equation (2)). This provides a notional 1s interval system demand; it is not possible to state that this profile represents the actual demand at a given time since the generation is assumed to move linearly between 0.5 hour data points and this is unlikely to be the case in practice. However, given that the future modelled generation profile is also 0.5 hour interval data, the load deviations caused as a result of comparing this scenario data with the generated 1s demand data will be identical and thus the impact of inertia changes and ESS output (modelled at 1s intervals) can be analysed.

Contributions from energy storage are applied to the demand imbalance, subject to a 0.5s delay representing the speed of response of the storage system. The EFR contract requires the ESS to be capable of swinging from 100% import to 100% export in under 1s [17]. A report by National Grid on battery systems [20] indicates times of 100ms are achievable, so a response time of 0.5s would seem a reasonable average expectation. The overall scheme is illustrated in Figure 1, where 'Inertial Power' corresponds to the first half of equation (3) and 'Freq. Sens. Load Adjustment' corresponds to the second half. The top box illustrates how the 1s load profile is developed, whilst the lower box depicts how this load profile is then analysed for a future generation mix and ESS response. 'Stored Energy', S_t, is the total system stored energy, expressed in GVA.s (GJ), adjusted according step changes to the estimated online capacity from Equation (1) and the load imbalance at each time-step as expressed in Equation (4):

$$S_t = S_{t-1} + (E_{s,t} - E_{s,t-1}) + \left(\sum_{i=1}^{n} P_i + P_{ESS} - D_{t,f_t}\right) \qquad (4)$$

Where $E_{s,t}$ is the system inertia at time t and P_{ESS} is the output of the battery, calculated using the EFR2 algorithm (Figure 2) based on f_{t-1}, the system frequency at time t-1s, but applied to the model at time t-0.5s.

D_{t,f_t} is the system demand adjusted for frequency sensitive load using NGC's empirical function:

$$D_{t,f_t} = D_{t,f_0} + (0.025 \times (f_0 - f_{t-1})) \quad (5)$$

Re-arranging Equation (2) and converting from rotational frequency, we derive the system frequency at time t:

$$f_t = \frac{1}{2\pi}\sqrt{\frac{2S_t}{I_m}} \quad (6)$$

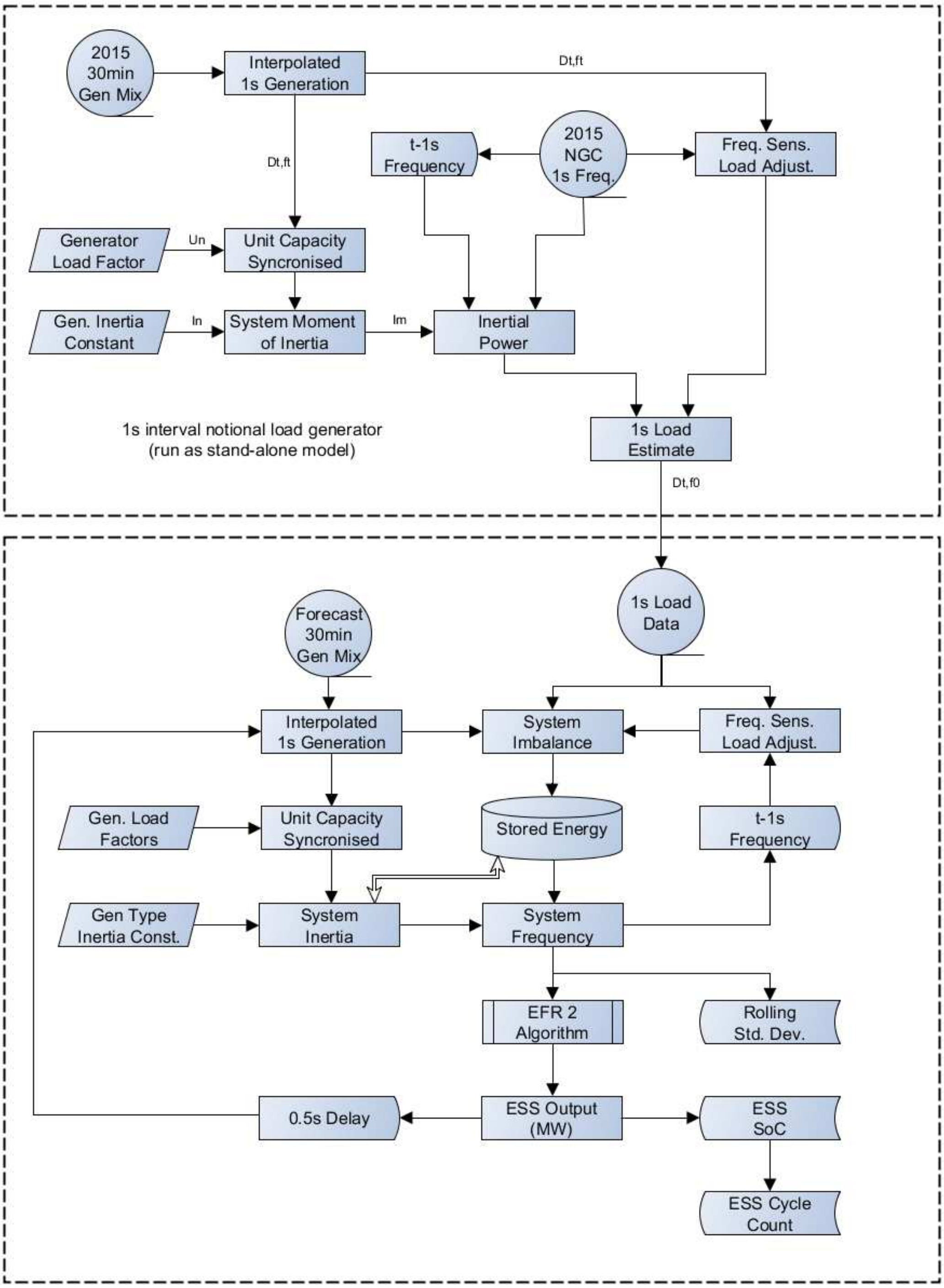

Figure 1 - Overview of simulation structure showing development of 1s load profile and subsequent use in a demand imbalance model, in this case with contributions from energy storage operating to the Enhanced Frequency Response algorithm

Description of method for Energy Storage System operation

Frequency Regulation Service

Where frequency regulation is modelled, the battery is operated under the NGC Enhanced Frequency Response Service 2 envelope [17], as illustrated in Figure 2. When the system frequency falls below 49.985Hz, the battery must begin to ramp to its full output, achieving 100% rated output at a frequency of 49.5Hz, and it must be able to deliver the full response capability in 1s. Similarly, on rising frequency, the battery must begin importing from 50.015Hz and be importing at its rated capacity at 50.5Hz. Between 49.985Hz and 50.015Hz, the battery is free to operate at any power within ±9% of its rated power. In this work, the battery is set to charge at 9% provided the current battery State of Charge (SoC – expressed as energy stored as a percentage of maximum storage) is below 47.5% or discharge at 9% if the SoC is greater than 52.5%. This allowable swing of 5% ensures that the battery is able to provide the required service provision whilst preventing hunting of the SoC.

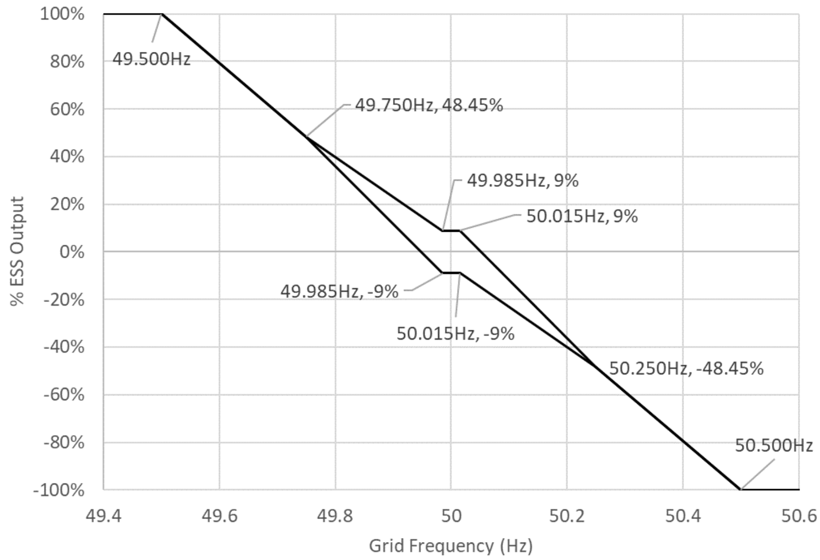

Figure 2 – NGC Enhanced Frequency Response envelope, service 2 [17]

Reserve Service

In addition to considering operation of the battery solely under the EFR regime, this study also considers how the battery might perform when combining this service with the provision of Short Term Operating Reserve (STOR) [21]. STOR is a service contracted by NGC whereby generators or loads can help to balance the system over a longer time frame than under frequency response services. Generators are contracted with a minimum of 4 hours notice to provide up to 2 hours of generation at their contracted output. Loads can also be contracted to reduce demand on a similar basis.

To model STOR operation, the sample week is run 25 times with different historic summer STOR dispatch profiles, obtained from the Elexon market data portal [22], being applied on each run to develop an average battery performance. The quantity of STOR provided from the ESS is deducted from the gas generation and interconnector import volumes in equal proportions to avoid creating an additional system imbalance.

3. Case study development

In this section, we present the development of a 1s interval load profile from 1s interval UK grid frequency data [17] and 0.5 hour interval generation mix data (downloaded using the Elexon API [18]) for one week in June 2015. This week was picked because system inertia is, historically, likely to be lowest in the summer when demand is low and the proportion of renewables is higher. This particular week also has periods of both high and low renewable generation and is therefore a good exemplar of the behaviour this study addresses. Figure 3 shows a sample of system demand using the method described earlier in the previous section, where the red line is the interpolated total generation, the green line is actual 1s interval frequency data and the blue line is the calculated system demand at 50Hz.

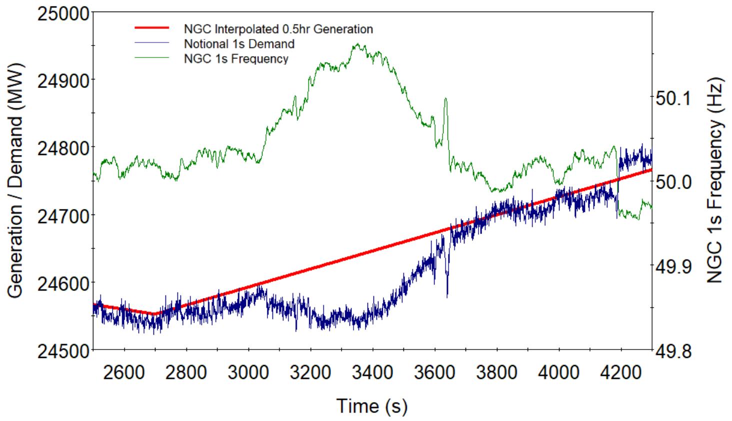

Figure 3 - NGC interpolated 0.5hr total generation, NGC 1s interval system frequency and calculated 1s interval demand over a 0.5hr period

This 1s demand profile can then be analysed against different generation mixes, at half-hourly interval resolution, to simulate a frequency profile under differing inertia conditions.

NGC's SOF 2016 [7] projects a 'Consumer Power' load profile very similar to that in 2015 and so this scenario has been used as the basis for modelling. Rather than apply the generation mix suggested for a 'typical summer day' in SOF 2016, the 2015 generation mix is used to develop a revised mix by assuming that generation sources are pro-rated according to the change in installed capacity projected in NGC's Future Energy Scenarios [2]. The 2015 generation mix is adjusted for 'invisible' embedded plant by adding distributed solar generation estimated by Sheffield University's PV Live project [23]. Embedded wind capacity is estimated by analysis of renewable energy installations [24] compared to registered Transmission Entry Capacity (TEC) [25] (where TEC capacity is assumed to be included in the Transmission connected wind data from Elexon); half hourly generation is then pro-rated from the transmission connected output with utilisation adjustment for the proportion of onshore and off-shore generation [26]. Given that the 2025 market price differentials between the UK and interconnected states are unknown, it seems reasonable to assume that gas plant and interconnectors share the load balancing evenly subject to gas plant operating at a minimum load of 4GW (approximately equal to the minimum gas plant generation in June 2015).

Figure 4 and 5 show the 2015 and 2025 generation profiles respectively where a prefix of 'T' indicates transmission connected and 'D' distribution connected solar and wind generation. Other distributed connected generation is assumed to be negligible. Figure 6 illustrates the impact of these generation mixes on system inertia over the same first week of June. The inertia during the first three days is low, with contributions primarily from nuclear and gas plant (running at the minimum load of 4GW) and a small contribution from hydro. During day 4, whilst wind output is low, gas plant ramps up during the evening and morning peaks when solar contribution is small, increasing system inertia.

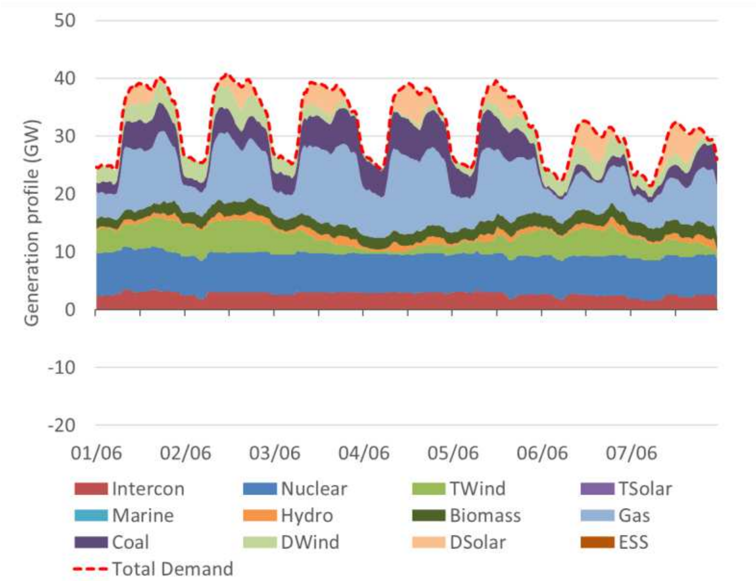

Figure 4 - Elexon generation profile week commencing 1st June 2015 plus estimated embedded solar and wind (D prefix implies distribution connected, T prefix transmission connected)

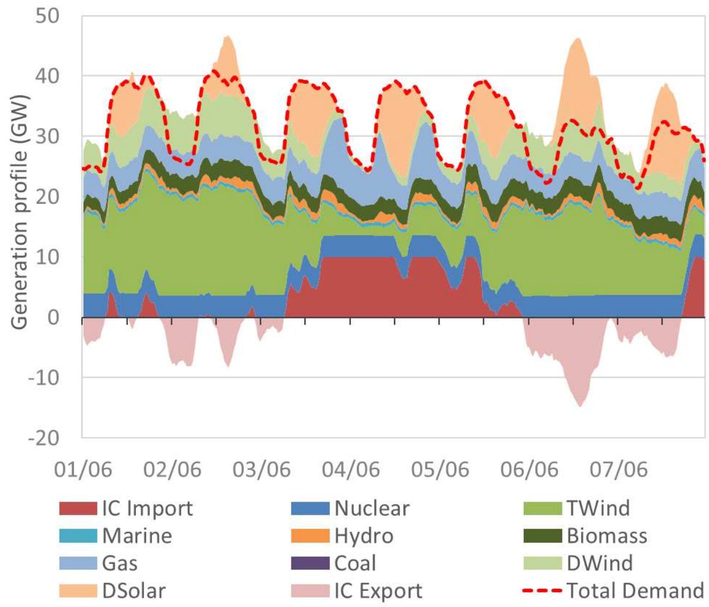

Figure 5 - Notional generation mix in modified 2025 'Consumer Power' scenario (D prefix implies distribution connected, T prefix transmission connected)

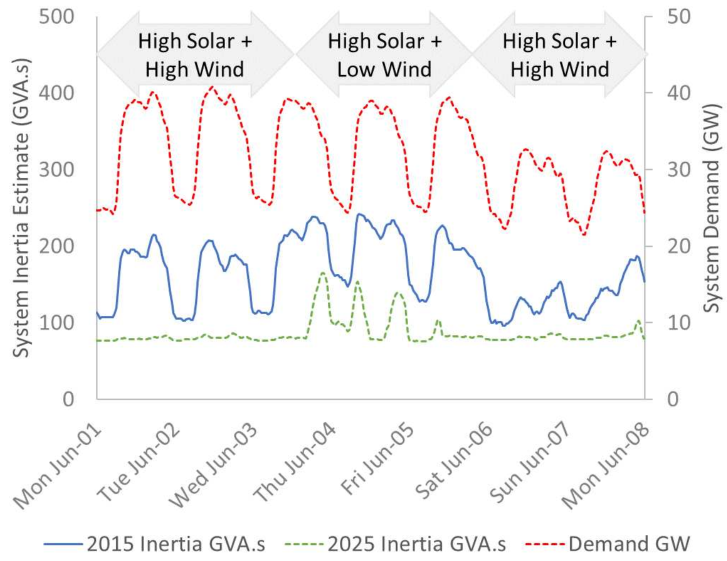

Figure 6 – Estimated system inertia constant based on actual generation mix in 2015 and projected 2025 generation mix over one week in June

4. Results

In this section we make use of the closed-functionality developed to first analyse the impact of varying volumes of ESS operating the EFR service on frequency volatility and ESS SoC range. Second, we consider how a future system with introduced supply/demand imbalance will respond given the presence of ESS and traditional generator controls. Third, we investigate how a reduction in frequency sensitive load may impact on ESS response requirements and finally we consider how ESS may provide additional services in parallel with EFR.

Impact of reduced inertia on frequency volatility

Figure 7 plots the standard deviation of system frequency over the 7 day period for the actual 2015 1s interval data together with the expected response in 2025, calculated using the methodology described in section 2, against the volume of ESS operating the EFR service. The reduction in inertia between 2015 and 2025 appears to have little impact on frequency volatility, however, there is an implicit assumption in the model that the volatility of both generation and demand do not change and, as a result, differences that do exist are a result of the inertial response to the ESS output. Increasing the operational capacity of EFR does have a significant dampening effect on standard deviation (Figure 7). The effect of the current proposed EFR capacity of 200MW on the frequency probability density function is illustrated in Figure 8 In practice, the capacity will be spread over 8 units ranging from 10 to 49MW [17], however, provided the batteries operate with similar response speeds, then the modelling as a single 200MW system will give an equivalent overall output and SoC.

Returning to Figure 8 we can see here that the presence of EFR capacity reduces the spread in frequency, but also has the effect of generating higher probability peaks either side of the nominal 50Hz value. This is a function of the dead band within the EFR envelope and may be exascerbated in this analysis by the absence of droop-frequency control provision by other generation sources. Droop frequency control is the method implemented to ensure that changes in system load are balanced evenly between all generators providing frequency control services. Since any one indivdual generator is unlikely to be able to influence the system frequency, all generators in droop control mode increase their output in proportion to their rated capacity for a specified change in system frequency. In the UK generators must be capable of operating between 3% and 5% speed droop, nominally 4%. This implies that for each 1% change in system frequency the turbine power output will change by 25% of its rated capacity.

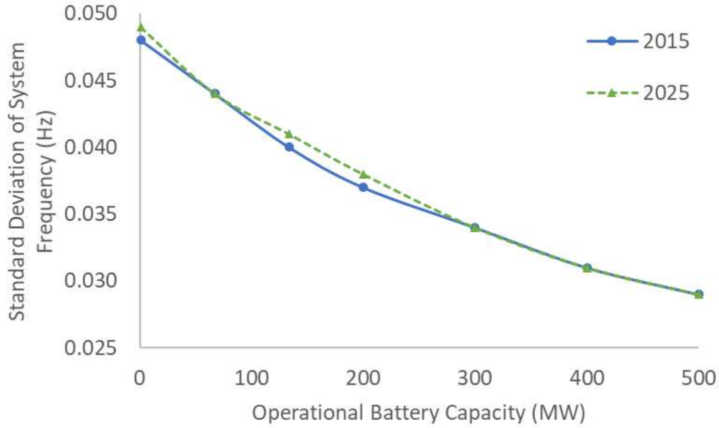

Figure 7 - Frequency volatility (measured as standard deviation in frequency over the week modelled) vs operational EFR capacity, showing how increasing capacity of EFR reduces volatility

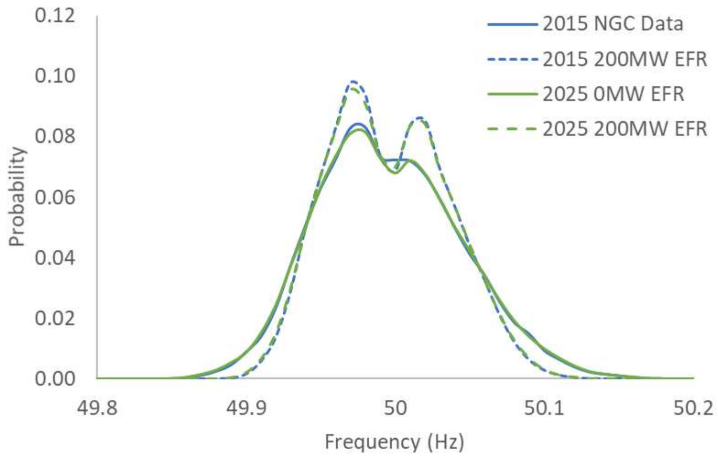

Figure 8 - Probability density functions for system frequency with varying EFR volumes for 2015 and 2025 inertia scenarios

Figure 9 plots the number of equivalent full cycles per day (assuming 24 hour operation) against the operational EFR capacity. As can be observed, the cycling rate is slightly higher in 2025 due to the small increase in frequency volatility. Cycling rates reduce substantially with increasing operational EFR capacity. In theory, this would have operational cost implications; i.e. greater installed capacity implies lower cycling and therefore lower degradation costs. However, Figure 10, showing the probability that the battery is in any given SoC (either active, implying it is generating or absorbing power, or inactive), shows that the battery is largely micro-cycling with a depth of discharge less than 10%; there is little change in shape or spread of this probability density function with changing installed capacity.

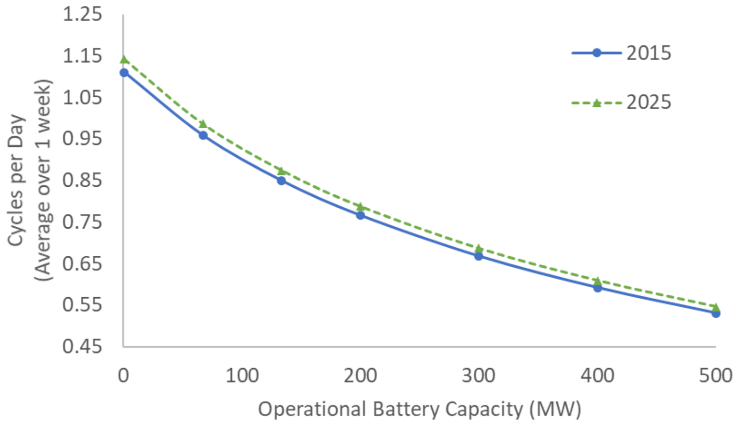

Figure 9 - Sensitivity of battery cycling, measures as full cycle-equivalents, to operational capacity under EFR regime

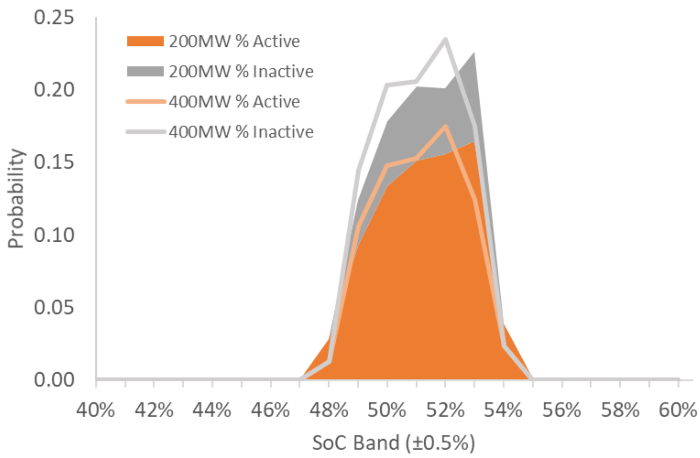

Figure 10 - State of charge probability density function for 200 & 400MW EFR, summer 2025

Effects of increasing power imbalance: 2025 scenario

We have seen in Figure 9, that the system inertia does not, of itself, significantly impact on frequency volatility or the response of the energy storage units where the system imbalances, and the rate of change of imbalance, are unchanged from the 2015 data. However, a future grid system may have a very different pattern of system imbalances as a result of more unpredictable generation. To provide some insight into how increasing load imbalance volatility might affect ESS operation, a scenario in which a hypothetical high wind front moves across the UK causing rapid reductions in wind generation due to high wind speed shutdowns, which generally occur at over 25m/s wind speeds, is modelled. Figure 11 shows an example of the wind-loss profile modelled; a wind loss event is triggered with a Poisson distributed time interval of 5 minutes for 6 hours from 12.00 noon on the second modelled day. At each event, a normally distributed quantity of wind capacity with a mean equal to 0.75% of the current wind output and standard deviation of 0.25% of the wind output, is instantly deducted from the generation mix. This corresponds to losses in the range 0-360MW at each event; the top end of this representing the size of a large on-shore wind farm [27]. The size of wind farms is not normally distributed, but wind farms tend to be concentrated into specific areas [26] and thus a single high wind event might affect multiple smaller farms simultaneously. An outage duration period is also sampled with a mean of 20 minutes and standard deviation of 5 minutes. After this duration, the percentage loss associated with that event is ramped back to zero over a normally distributed time period with a mean of 15 minutes and standard deviation of 3 minutes. Figure 11 also shows the impact on system frequency where the only response to the events is from 200MW/100MWh of EFR battery capacity.

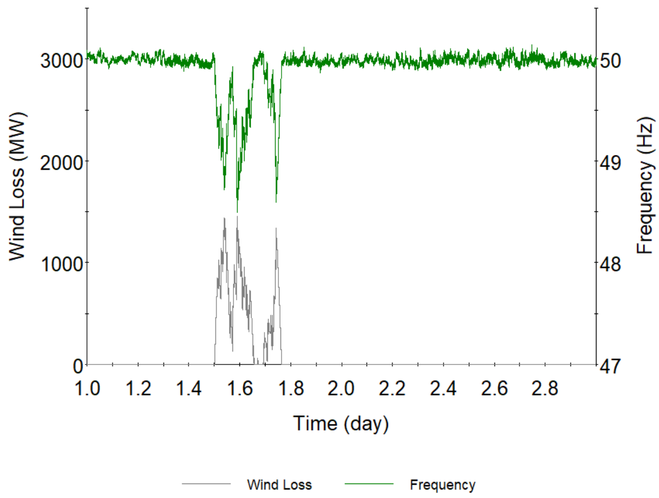

Figure 11 - Wind generation loss profile and resulting system frequency where 200MW of EFR ESS capacity is the only response

The magnitude of the power imbalance inevitably results in the EFR ESS capacity reaching its minimum SoC (see Figure 12) and thus it is necessary to consider how other generation plant would respond to this sequence of events. This is simulated by requiring the gas turbine plant to respond under NGCs primary frequency mandatory response commencing at +/-0.1Hz and with a maximum ramp rate of 25MW/min per 400MW unit. The actual response is also dispersed, such that a step change in required gas plant output is delivered with a mean delay of 5s and standard deviation of 1.5s, which meets NGC requirement to deliver primary response within 10s. The total response is capped at the initial synchronised gas generation for 2 hours; i.e., as gas plant output increases, the available spare capacity for a fixed 75% load factor increases, but this additional capacity does not become available for 2 hours, reflecting plant start-up time.

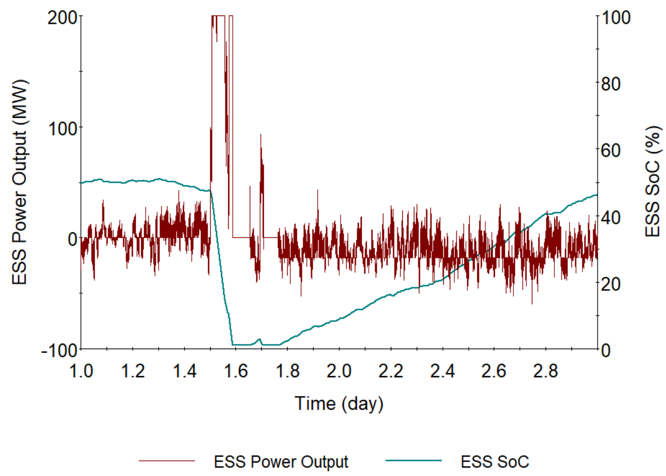

Figure 12 - ESS response to wind outage event sequence with no other frequency response

The effect of this additional frequency response is dramatic and shown in Figure 13; the EFR capacity is no longer required to deliver its fully rated output even immediately after a loss event. The resulting impact on the ESS SoC is shown in Figure 14. Understanding the interaction between gas (and other balancing plant) control systems, typically operating in speed-droop control and with varying response rates, and the algorithms used to manage many distributed ESS units will be critical in ensuring the most economically efficient and secure use of grid resources.

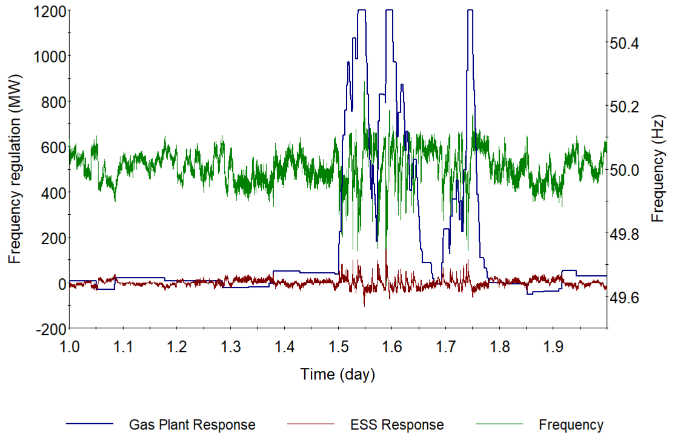

Figure 13 - ESS and gas plant response to wind outage event sequence with resulting system frequency

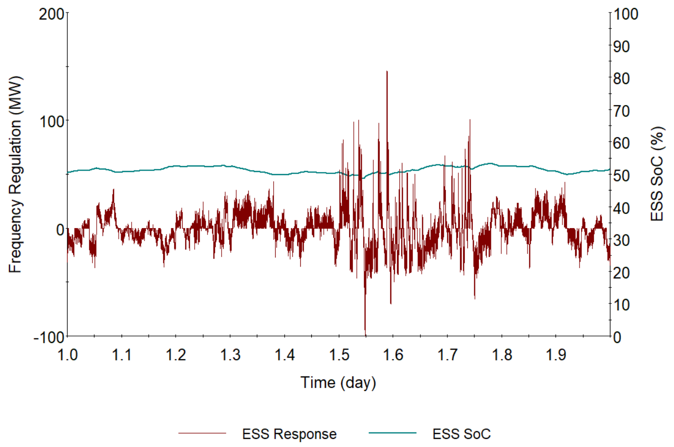

Figure 14 – Detailed ESS response to event with gas plant also responding

Effects of a reduction in frequency sensitive load

The extent to which the ESS must respond is also a function of the grid inertia and the volume of frequency sensitive load. Figure 15 shows how the ESS responds with the frequency sensitive load, the swing equation damping component, reduced from 2.5% of demand per Hz (NGC's current empirical observation) to 2.0% per Hz; clearly showing higher magnitude responses and greater impact on SoC. Note also that ESS operation is substantially more variable in normal system operation, outside of the modelled event sequence. The extent to which that sensitive load might reduce, due for example, to the increased use of inverter drives in industrial and commercial settings, could usefully be explored further.

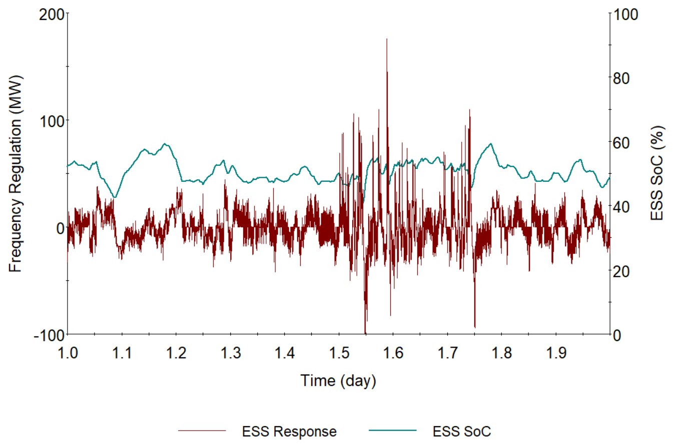

Figure 15 – Detailed ESS response to event with gas plant also responding - reduced frequency sensitive load

Provision of multiple services

Proponents of battery systems promote their flexibility to deliver multiple services, either concurrently or sequentially; this is often referred to as stacking [28–30]. Many of the services procured by grid operators require several hours of operation. In the UK, for example, Short Term Operating Reserve (STOR) requires 2 hours service provision [31] and more recently, for non-derated access to the Capacity Market, a 4 hour operating window has been proposed [32]. Here, we extend our analysis to evaluate the impact on battery SoC for 200MW/250MWh of energy storage provision.

To provide EFR, such a battery could operate with a target nominal SoC anywhere in the range 20% to 80%, and deliver 15 minutes of peak generation or load as required by the service. For the provision of STOR services, the battery is ideally fully charged at the start of each availability window, thus it makes sense to operate EFR only windows with a nominal SoC of 80%, being as high as possible. It is clearly not possible to provide both STOR and EFR at the maximum power rating of the installed capacity, since a call on STOR at 200MW would leave no EFR capability. Reducing EFR to 50% of capacity with STOR at 50% capacity requires 200MWh for STOR and ±25MWh for EFR, thus the battery can be operated at a nominal 90% SoC (225MWh) to give allowance for EFR operation. The model achieves this by adjusting the target SoC from 80% to 90% under the EFR algorithm in the half hour trading period prior to the start of a STOR availability window and then providing one half-hour trading period after the availability window where 100MW of capacity is available to provide an initial fast recharge if STOR has been dispatched. The simulation has been run 25 times, reflecting a number of different STOR dispatch events. For each run, the EFR service provision is based on the same 1st week of June, with 2025 inertia data

Figure 16 shows one realisation from the 25 run simulation where STOR is dispatched on four occasions, indicated by S1 through S4. The ESS continues to provide the EFR service during these periods, superimposed on the STOR dispatch volume, but charge/discharge for SoC restoration within the frequency dead-band region is not permitted. One potential concern with the use of ESS to provide reserve services is the need to re-charge the ESS after dispatch. The S4 dispatch in Figure 16 results in the storage being depleted, in this case 7 minutes prior to the end of the required window. Clearly if a system stress event extended beyond the end of the availability window, then re-charging of ESS could exacerbate the situation; something that would not occur where STOR is provided by fuelled generators.

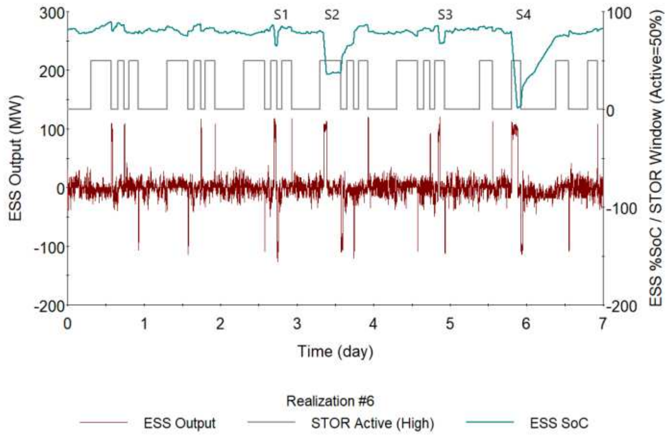

Figure 16 - Example ESS Response to EFR and STOR Services

Figure 17 summarises the 25 realisations, showing where STOR has been dispatched most frequently with a probabilistic view of the SoC of the ESS. We can see that the ESS does reach a low SoC on a number of occasions. Also determined is the number of hours for which the delivery of EFR and STOR might be compromised due to the SoC; despite these low states of charge, there are in fact no occasions when the ESS did not provide the service, although there were, on average across all 25 realisations, 3.25 hours when EFR might have been undeliverable had it been required and just 0.02 hours where the STOR service would have failed had it been dispatched. Due to the random nature of these requirements, these potential failures were not revealed.

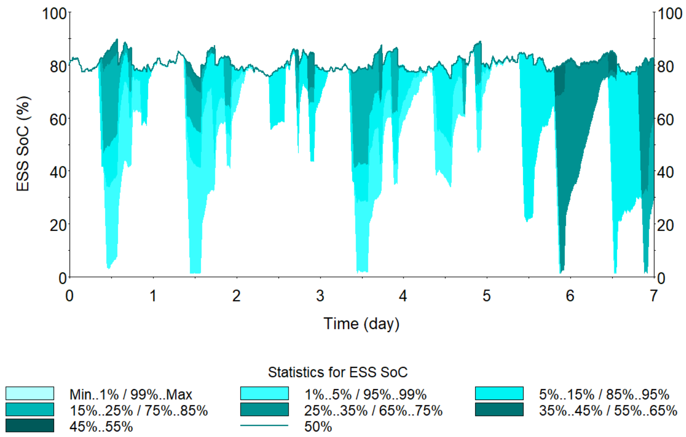

Figure 17 - Probability plot of ESS response to EFR and STOR Services

Discussion

The demand profile that the approach developed in Section 2 produces allows the analysis of the performance of ESS and the systems reaction to this. The results indicate that ESS of relatively small magnitude compared to total installed generation, are able to play a significant role in stabilising system frequency. The capacity of ESS operating in various modes (whether frequency response or reserve services) will impact the cycling rate of each individual ESS, although the effects of this on battery degradation are not always clear. Furthermore, the way in which traditionally controlled generators interact with the algorithms used for distributed ESS have not been accounted for in the method in this work, but will also impact on ESS cycling.

Whilst using the method developed in this work the system inertia appears to have a relatively small impact on frequency volatility when analysed in this way, the quantity of frequency sensitive load, which is out-with the control of the system operator, could have significant implications for system stability and the operational cycling of ESS.

Application of Results

The results presented above are useful to system operators in understanding future influences on frequency volatility and the volumes of response required. Of importance is the volume of response contracted will impact on the cycling rates of individual ESS installations and thus on degradation and cost of service provision. The results identify that reductions in frequency sensitive load, which is a likely outcome of the increasing use of inverter-connected motors, can have a significant impact on frequency volatility and battery cycling. This is an area not well studied in the literature; our model allows this aspect of system stability to be explored in more detail in real-world situations.

For ESS owners and operators, understanding how changes to the future generation and load mix will impact on battery cycling is important in assessing longer-term project risk. The data available in the form of SoC time-series and power flows would also enable degradation analysis to be conducted for specific battery chemistries.

Whilst this study considers an aggregated 200MW battery, it is also clear from the results that in the real world scenario of multiple battery installations operating with differing time lags, there will be differences in the power delivery and cycling rates of each installation.

5. Conclusion

This study provides insight into the closed-loop response of the UK grid to the provision of fast frequency services from Energy Storage Systems (ESS) and an understanding of how that grid response affects battery cycling. Given the current relatively high costs of battery technology, it is also useful to understand how multiple services might be provided, with greater potential revenues per unit; the analysis here presents just one case for this, providing both Short Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR).

A method for developing a demand profile and matching this to an estimate of the inertia present in the grid system on a second-by-second basis has been developed and demonstrated. This has enabled the impact of battery system frequency response services on frequency volatility and battery cycling to be analysed. It has been shown that the frequency volatility and cycling rate of batteries providing frequency regulation under the EFR algorithm reduces as operational capacity increases. Whilst the change in total number of cycles with installed capacity is significant, the SoC range over which the batteries cycle is not substantially different for the two cases analysed. Our modelling approach did not identify a significant change in cycling due to reduced system inertia.

The extent to which second-by-second load mismatches impact on frequency volatility in a future power system with lower rotational inertia has also been considered through the application of a hypothetical sequence of generation outages. The response of remaining gas turbine plant (and other dispatchable plant) to such outages has a substantial impact on the operational outcomes for battery plant operating under EFR. The power capacity required under EFR is also a function of the frequency sensitive load, which may reduce in future. The capacity of EFR required within the network will be governed by these grid features; there is therefore a limited, though potentially increasing, market for such high-speed frequency response services.

Introducing today's reserve services, such as STOR, to battery plant requires a greater energy capacity than those being developed to deliver EFR. It is practical to optimise the sizing of a battery system to deliver both EFR and STOR and to do so, at reduced capacity, concurrently. This may be useful in that the need for EFR may not always align with the requirement for STOR availability. The provision for re-charging within the EFR envelope provides some opportunity to re-charge the battery system following a STOR despatch event whilst continuing to earn revenues from EFR, but the State of Charge (SoC) of the battery needs to be carefully managed to ensure that the ability to deliver either service is not compromised. Providing STOR services dramatically changes the cycling profile of the ESS; EFR, on the whole, requires micro-cycling in the range of ±5%, whereas STOR, for the modelled battery capacity, sees 20-80% depth of discharge cycles superimposed on this. The impact of micro-cycling is not clearly understood, but the provision of STOR services is likely to substantially increase battery degradation.

6. Limitations & further work

The analysis of multiple services in this study was limited to just EFR and STOR. This was in part because of the ongoing NGC consultation over the shape of such services in the future and thus the limited value in analysing all existing services. The value of the STOR and EFR analysis could be improved by running more sample weeks from typical periods within the year (i.e. summer, winter, shoulder) and making use of more STOR dispatch data to run a greater number of realisations.

The model currently takes an existing load profile and modifies it in line with a specific NGC profile for 2025. A useful additional analysis would be to compare alternative NGC profiles, and consider how the uptake of electric vehicles and domestic heat pump systems may impact on future operability.

This study does not attempt to analyse the impact of different cycling regimes on battery degradation since the chemistries adopted are not known. However, the model does produce very detailed cycling and load data which are ideally suited to degradation analysis. A detailed analysis of the cycle profiles and rates of charge and discharge, perhaps applying a multi-factor methodology such as that proposed by Muenzel, de Hoog and Brazil et al. [33] , would provide insight into the relative costs of degradation and therefore a more cost-reflective price for delivering services.

The study has highlighted the critical damping effect of frequency sensitive load on the cycling of ESS providing EFR and the complexities of the interaction of traditional plant frequency control with distributed ESS algorithms. It seems likely that frequency responsive load may reduce further in future as more power electronics are incorporated into electrical equipment. Further work to evaluate the scale of this and to understand how control algorithms interact with both these slowly changing grid properties and the response of remaining large plant would be valuable in both assessing risks to future grid stability and impacts on ESS. It would also be useful to analyse the volatility of 1s interval frequency data as the proportion of wind and solar has increased, for example, 2015 data compared to 2017 data, to investigate whether the variability of distributed renewables is apparent at the system level.

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