Providing Stacked Balancing Services using Wind-Storage systems

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Abstract

In order to decarbonize the electricity grid, renewable energy sources must be utilised in conjunction with energy storage to provide ancillary services, which maintain electricity supply quality, reliability and restorability, whilst remaining affordable. Due to a lack of knowledge about the potential of stacking UK ancillary services and electricity markets to improve service affordability, this study of a wind farm with a co-located battery system compares the UK Black Start service, Firm Frequency Response static low frequency secondary and dynamic high frequency services, alongside the day-ahead market as sources of revenue, both provided individually and stacked, with all mismatches handled in the balancing market, to identify the most profitable method of operation. A model of the wind farm - battery system power and energy flows is used to assess availability of Black Start and two Firm Frequency Response services, as well as operation in the day-ahead and balancing market, for a one-year period. Internal rate of return and levelized cost of electricity are used to measure financial performance, with a weighted average cost of capital (WACC) of 7.75%. Is is found that no service or market provision is profitable compared to the WACC, and the most profitable method of operating the system is to sell all wind energy forecast on the day-ahead market, not using storage and not stacking services. The most profitable method of providing the BS service is when stacked with the FFR static low frequency secondary service. The most profitable method of providing either the FFR static low frequency secondary service or FFR dynamic high frequency service is alone, not stacked. The profitability of stacks are most sensitive to the changing of BS requirements, although the profitability rank order of stacks doesn't change. A single bad wind year has a very small effect on BS availability, and the effect of increased frequency deviations doesn't affect the stacks of FFR services due to limited income from FFR service energy provision compared to the balancing market or from FFR service availability.

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Nomenclature

Abbreviations

BS Black Start

ENTSO-E European Network of Transmission System Operators for Electricity

ESO National Grid Electricity System Operator

FFR Firm Frequency Response

IRR Internal rate of return

LCOE Levelized cost of electricity

LiFePO4 Lithium iron phosphate

NPV Net Present Value

O&M Operation and maintenance

SoC State of charge

SP Settlement Period

VRES Variable renewable energy sources

WACC Weighted average cost of capital

Symbols

α	Alpha, the power law coefficient	[-]
$\dot{\theta}_{pitch}$	Rate of pitch rotation	[degrees/second]
$\dot{\theta}_{yaw}$	Rate of yaw rotation	[degrees/second
η_{B2B}	Back-to-back converter efficiency	[%]
η_{DC-AC}	Three phase conversion efficiency	[%]
$\eta_{drivetrain}$	wind turbine drivetrain efficiency	[%]
$\eta_{transformer}$	Transformer efficiency	[%]
$\eta_{transport}$	Efficiency of electrical transport along the grid	[%]
ρ	Air mass density	$[kg/m^3]$
θ_{pitch}	Pitch rotation required per BS restart	[degrees]
θ_{yaw}	Yaw rotation required per BS restart	[degrees]

A_{rot} Wind turbine rotor area [m^2]

$Avail_{BS}$ Black start availability at a single settlement period [-]

$Avail_{FFR\,dynamic}$ FFR dynamic high frequency service availability at a single settlement period [-]

$Avail_{FFR\,static}$ FFR static secondary service availability at a single settlement period [-]

$c\,rate$ Charge/discharge rate of battery [/hour]

$c\,rate_{max}$ Maximum charge/discharge rate of battery [/hour]

C_p Power coefficient of a wind turbine [-]

$C_{batt\,ann\,O\&M\,MW}$ Battery operation and maintenance costs per year per MW rating [£/MW.yr]

$C_{batt\,ann\,O\&M}$ Annual cost of battery operation and maintenance [£/yr]

$C_{batt\,capital\,MWh}$ Cost of purchasing battery per MWh installed [£/MWh]

$C_{batt\,capital\,MW}$ Cost of purchasing battery per MW rating [£/MW]

$C_{batt\,capital}$ Total capital investment cost of battery [£]

$C_{WF\,ann\,O\&M}$ Annual cost of wind farm due to O&M costs [£.yr]

$C_{WF\,capital\,MW}$ Capital investment cost of wind farm per MW [£/MW]

$C_{WF\,capital}$ Total capital investment cost of wind farm [£]

$C_{WF\,O\&M\,tot\,MW}$ Lifetime cost of wind turbine operation and maintenance per MW [£/MW]

$C_{WT\,BOP\,MW}$ Cost of offshore wind farm balance of plant per MW [£/MW]

$C_{WT\,decomm\,MW}$ Cost of offshore wind farm decommissioning per MW [£/MW]

$C_{WT\,install\,commiss\,MW}$ Cost of offshore wind farm installation and commissioning per MW [£/MW]

$C_{WT\,land\,MW}$ Cost of land leased for an offshore wind farm per MW [£/MW]

$C_{WT\,other\,MW}$ Other costs of an offshore wind farm per MW [£/MW]

$C_{WT\,proj\,dev\,manag\,MW}$ Cost of offshore wind farm project development and management per MW [£/MW]

$C_{WT\,purch\,MW}$ Cost of purchasing wind turbines per MW [£/MW]

$C_{WT\,transm\,assets\,MW}$ Cost of offshore wind farm transmission assets per MW [£/MW]

$Cycles_{total}$ Number of completed discharge cycles in the simulation, i.e. per year [Cycles]

$E_{bought\,BA}$ Energy purchased in the balancing market as part of managing mismatch [MWh]

E_{BS} Black Start energy requirement [MWh]

E_{buy} Energy that must be bought in the balancing market after battery discharge available is used up [MWh]

E_{capac} Battery capacity [MWh]

$E_{charge\,avail}$ Battery charge available at start of a SP [MWh]

E_{charge} Actual battery charge in a SP [MWh]

E_{crank} Energy required for cranking of a wind turbine during a BS [MWh]

$E_{disch\,avail\,SP\,end}$ Battery discharge available at the end of a SP [MWh]

$E_{disch\,avail}$ Battery discharge available at the start of a SP [MWh]

E_{disch} Actual battery discharge in a SP [MWh]

E_{extra} Energy required for battery functions other than cranking energy [MWh]

E_{pitch} Maximum energy required in storage for pitching mechanism in BS [MWh]

$E_{sell\,curtail}$ Energy that must be sold in the balancing market or curtailed, after battery charge available used up [MWh]

$E_{sold\,BA}$ Energy sold in the balancing market as part of managing mismatch [MWh]

$E_{util\,yr}$ Energy utilised by the wind farm - battery system per year [MWh/year]

E_{yaw} Maximum energy required in storage for pitching mechanism in BS [MWh]

$f_{avail\,BS}$ Fraction of black start availability for the whole simulation [-]

$f_{current\,to\,DA}$ Ratio of total UK day-ahead forecast offshore wind power, to total actual UK offshore wind power [-]

f_{cycles} Scaling factor for battery cycles [-]

$f_{DA\,bid}$ Day-ahead bid factor, ratio of Walney day-ahead forecast wind farm power, to day-ahead market bid [-]

$f_{FFR\,dynamic}$ Fraction of volume response required for FFR dynamic high frequency service [-]

$f_{FFR\,static}$ Fraction of volume response required for FFR static secondary service [-]

$f_{passive\,disch}$ Battery passive discharge factor [-]

f_{wake} Wake effect factor [-]

h_{hub} Hub height of wind turbine [m]

h_{ref} Reference height that wind speed data is measured at [m]

$n_{batts\,requ}$ Number of battery replacements required due to reaching maximum number of discharge cycles [-]

N_{WT} Number of wind turbines installed [Wind turbines]

$p\,rate$ Maximum power of battery [MW]

$P_{bid\,dynamic}$ Bid for FFR dynamic high frequency service all 6 blocks [MW]

$P_{bid\,static}$ Bid for FFR static secondary service all 6 blocks [MW]

P_{BS} Power commitment for the Black Start generation block [MW]

$P_{DA\,bid}$ Day-ahead market bid [MW]

P_{dissip} Power dissipated due to c-rate limit [MW]

$P_{FFR\,dynamic}$ Load for FFR dynamic high frequency service [MW]

$P_{FFR\,static}$ Load for FFR static secondary service [MW]

P_{load} Power required by service bids [MW]

$P_{MM\,p\,rate}$ Mismatch after battery power rate is applied as a limit [MW]

P_{MM} Mismatch between P_{WF} and P_{load} [MW]

P_{pitch} Power of pitch mechanism unit [MW]

P_{unmet} Load unmet by the wind farm - battery system and balancing market [MW]

$P_{WF\,rated}$ Rated power of wind farm [MW]

P_{WF} Actual power of wind farm [MW]

$P_{WT\,rated}$ Rated power of wind turbine [MW]

P_{WT} Actual power of wind turbine [MW]

P_{yaw} Power of yaw mechanism unit [MW]

$Price_{BA}$ Buy/sell price of energy in the balancing market [£/MWh]

$Price_{BS}$ Average price paid by the ESO for BS provision [£/MW.yr]

$Price_{DA}$ Buy/sell price of energy in the day-ahead market [£/MWh]

$Price_{dynamic}$ Average price paid by the ESO for FFR dynamic high frequency service availability, which varies each month [£/MW.hr]

$Price_{static}$ Average price paid by the ESO for FFR static secondary service availability, which varies each month [£/MW.hr]

R_{BA} Revenue from selling energy in the balancing market [£]

R_{BS} Revenue from providing the Black start service [£]

R_{DA} Revenue from energy sold in the day-ahead market [£]

$R_{dynamic\,avail}$ Revenue for providing a 100% available FFR dynamic high frequency service [£]

$R_{dynamic\,energy}$ Revenue for energy sold or bought in the balancing market as part of the FFR dynamic high frequency service [£]

r_{rot} Rotor radius [m]

$R_{static\,avail}$ Revenue for providing a 100% available FFR static secondary service [£]

$R_{static\,energy}$ Revenue for energy sold in the balancing market as part of the FFR static secondary service [£]

SoC_{max} Maximum battery SoC at present point in simulation [-]

SoC_{min} Minimum battery SoC [-]

t_{oper} Total operational time of a wind farm-battery project [years]

t_{pitch} Time required for operation of pitching mechanism for three BS restarts [hours]

t_{proj} Lifetime of wind farm-battery project, including installation and operation [years]

t_{yaw} Time required for operation of pitching mechanism in three BS restarts [hours]

u_x East to West wind speed component [m/s]

u_y South to North wind speed component [m/s]

u_{avail} Wind speeds available for the wind turbine, after cut-in and cut-out wind speeds are excluded [m/s]

$u_{cut\,in}$ Cut-in wind speed of wind turbine [m/s]

$u_{cut\,out}$ Cut-out wind speed of wind turbine [m/s]

u_{hub} Wind speed at hub height [m/s]

u_{rated} Rated wind speed of wind turbine [m/s]

u_{ref} Resultant wind speed vector, at wind speed measurement height [m/s]

1 Introduction

In this chapter, the background of the project will be introduced, which will inform the reader briefly about the thesis topic in general, before moving into the problem analysis, which will justify the research objectives. After the research questions are stated, the project scope will be defined, and then the methodologies used to answer the research question will be made clear.

1.1 Background

In order to prevent the worst impacts of climate change, widespread implementation of renewable energy is vital, whilst limiting its effect on electricity quality, security and cost, to prevent knock-on-effects. In Figure 1.1 below, the UK National Grid Electricity System Operator's (ESO) fastest UK electricity decarbonisation scenario is shown (ESO, 2020j). The offshore wind energy sector will grow the most in this scenario, despite wind energy already making up 20% of UK electricity supply in 2019 (10% from offshore) (GOV.UK, 2020).

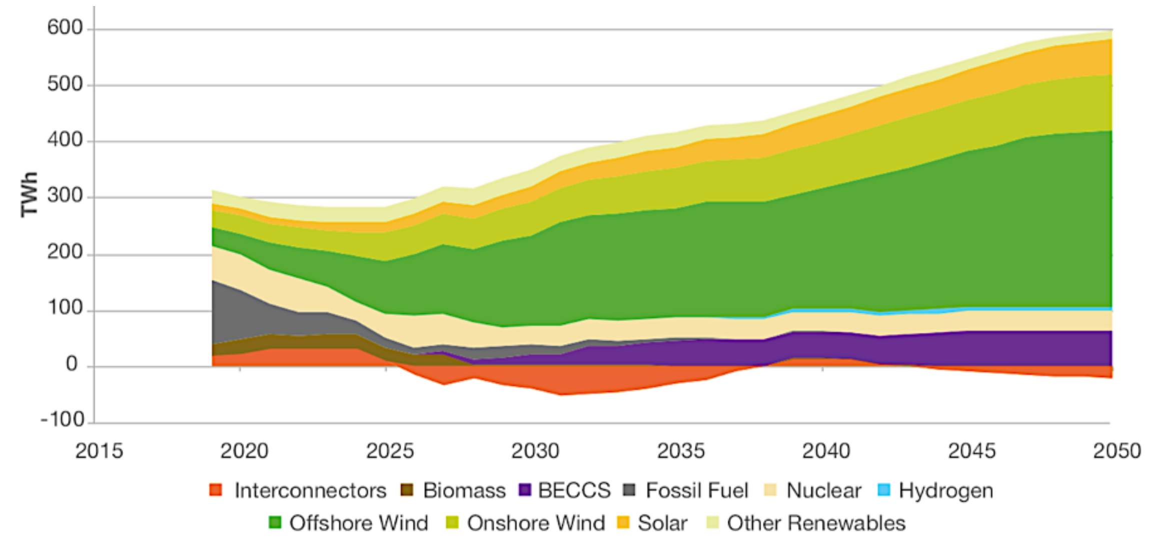

Figure 1.1: The ESO's leading the way decarbonisation scenario (ESO, 2020j).

The current study focuses on the UK energy system and grid balancing mechanisms. Presently, a mix of mostly controllable non-renewable sources, uncontrollable variable renewable energy sources (VRES) and a low volume of storage is used. While wind generation has an energy potential over 40 times that required to provide all electricity required on Earth, the generation is intermittent due to short and long term weather events, diurnal cycles and seasonal differences, which can lead to grid imbalances, instability and ultimately outages if left unchecked (Lu, McElroy, & Kiviluoma, 2009). To prevent these imbalances, controllable sources and storage can be used to provide flexible power when utilised through balancing services, which the ESO contract out (ESO, 2020a; WindEurope, 2017):

- **Energy time shift**: Arbitrage (store energy to dispatch later at higher prices), self-consumption (store energy to consume later)
- **Grid adequacy**: Reducing congestion and curtailment, deferring network upgrades, ramping control, capacity firming
- **System adequacy (longer term storage)**: Capacity reserve, seasonal storage

– **Ancillary services**: Reactive power services, Black Start (BS) and Firm Frequency Response (FFR)

Of the ancillary services, reactive power services keep voltage stable within 5% of its local value; voltage is reduced by reactive power consumption due to inductive loads, and increased by reactive power provision (ESO, 2020k). A BS service is used in the rare event of a partial or total grid blackout, enabling quick grid restoration; this requires facilities capable of starting independently of grid supply (ESO, 2020a). FFR services are used to reduce domestic imbalances, and are broken up into static and dynamic response services (ESO, 2020e). Dynamic response operates continuously outside a small frequency deadband, whilst static response is triggered at a pre-defined frequency deviation from 50 Hz. Frequency control can require flexibility in both energy supply and storage. Dynamic and static services both include three response types:

– **Low frequency primary response:** Occurs within 10 seconds of event, sustained up to 20 seconds

– **Low frequency secondary response:** Occurs within 30 seconds of event, sustained up to 30 minutes

– **High frequency response:** Occurs within 10 seconds of event, sustained for up to an indefinite period of time

To implement these essential services, controllable generation is needed; unfortunately, replacing fossil fuels with VRES will eliminate the majority of existing controllable sources. A solution to this capability gap is to utilise wind turbines in cooperation with utility scale battery storage systems, combining the advantages of cheap wind energy and responsive storage in one system, which can then act as a controllable power plant. An example of such a system is the Husahagi wind farm shown below in Figure 1.2.

Figure 1.2: Husahagi wind farm - battery system, used for ramping control and ancillary services (EASE, 2017).

While the wind itself is uncontrollable, wind turbines have some inherent flexibility built in; firstly, they require no fuel, so they can economically operate in the short term at prices of 0 £/MWh. Further, they have no thermal inertia, unlike traditional fossil fuel or nuclear power plants, making wind turbines quick to curtail (to prevent excess supply and grid congestion) and quick to ramp back up after curtailment has ceased.

The addition of cooperating battery storage alongside wind turbines to form a co-located system provides short-term responsiveness that allows the wind farm-battery system to be used for FFR and reactive power services and gives better control of power delivery, whether that be for the purpose of price arbitrage, to abide by ramping limits or to manage congestion. This leads to a reduction of wind farm curtailment and fewer balancing market costs according to WindEurope (WindEurope, 2017). Due to the efficiency of UK generation capacity sizing, there is a larger base-peak load price difference in the UK than in mainland Europe, so price arbitrage can be quite profitable (WindEurope, 2017). Utility scale batteries also provide the possibility of long-term storage, enabling capacity reserve and BS services. In other words, only when wind turbine and batteries cooperate can they provide ancillary services (WindEurope, 2017).

While stand-alone wind energy is both cost competitive and commercially successful, with successful tenders as low as 39.65 GBP/MWh for 2023-2024 offshore wind, utility-scale batteries are constrained by cost and an insufficient understanding of their role, and as a result are currently installed in a capacity far too small to meet the challenge of energy decarbonisation (Carbon Brief, 2019). High battery costs have meant that co-located wind farm-battery systems are rare with limited commercial viability. Li-ion battery costs are expected to fall 64% from 2019 to 2030, but alternative cost reduction methods should still be explored to make co-located wind farm-battery systems commercially viable; Staffell & Rustomji suggests that storage utilisation be improved (BloombergNEF, 2019; Staffel & Rustomji, 2016).

1.2 Problem analysis

To make cooperating co-located wind turbine-battery systems more cost effective, balancing services should be stacked in an effort to maximise utilisation; the ESO allow this, as long as applications don't interfere (ESO, 2020a, 2020e). Stacking balancing services is not a new concept; Staffell & Rustomji found that stand-alone UK battery storage operators could triple their rate of return by adding FFR services on top of energy arbitrage, from 1.98% annually with arbitrage alone, to 7.50% (Staffel & Rustomji, 2016). However, Staffell & Rustomji also learned that the addition of battery storage to wind energy as a method to shift time of delivery (on top of regular sales of wind energy) was not sufficiently cost effective, suggesting other options be explored, such as capacity reserve (Staffel & Rustomji, 2016).
As a result, it is believed that wind farm – battery systems are capable of fulfilling stacked services and markets, but research into ESO service and market combinations so far is insufficient to know if this method is commercially viable, with current technology and costs. Therefore, the ability and cost effectiveness of modern cooperating co-located wind farm-battery systems in providing individual and stacked ESO services and markets should be assessed. In the process, issues with modelling, technology, or service requirements will be found. Many services and markets exist, and attempts should be made to identify clashing or complementary services and markets for stacking. Additionally, it is yet unknown how the chosen services and markets are affected by external variables, such as lower than average wind speeds, changes to service requirements, or an increase in the quantity of VRES implemented on the electricity grid; this area should also be explored.

1.3 Research objectives and questions

In this study of a wind farm with a co-located battery system, the main objective is to identify the pros and cons of different service and market stacks, and understand how these stacks are affected by changing operational and environmental variables. Sub-questions used to achieve this objective are listed below:

- For a location in the UK, what is required to implement a wind farm, with on-site battery storage capable of providing the BS service?
- For a wind farm-battery system, what is required to implement the FFR static low frequency secondary service?
- For a wind farm-battery system, what is required to implement the FFR dynamic high frequency service?
- For a wind farm-battery system, what is required to implement grid dispatch in day-ahead and balancing markets?
- How can service and market stacking produce the optimal economic output?
- To what external variables are service and market stack selections most sensitive?

1.4 Scope

In this section, the project scope is defined:

- Wind turbines provide generation; other VRES aren't considered
- The wind farm is located offshore in the UK, for flexibility of system sizing
- Lithium Iron Phosphate batteries (LiFePO4), which is a type of Lithium-ion battery, provide storage. Other storage technologies aren't considered
- Battery location is not considered, though it is assumed to co-operate with the wind farm
- The wind farm-battery system will provide/operate in no more than the BS and FFR services, day-ahead market and balancing (mechanism) market
- 2020 BS and FFR service specifications are used
- The case study will use historical data inputs from the same year, except the wind farm and battery cost assessments, which use historical inputs from 2019 and/or 2020, and weighted average cost of capital (WACC) used, which is from 2017
- Reactive power control isn't included in BS requirement, as it is primarily an electrical control element
- Of the FFR static services, only the low frequency secondary service is modelled, as the low frequency primary and high frequency services are no longer tendered. The FFR static low frequency secondary service is referred to as the FFR static secondary service in the remainder of this report.
- Of the FFR dynamic services, only the high frequency service is modelled, excluding the dynamic primary and secondary to save time.

- No other balancing services are considered, hence the (usually) obligatory reactive power service isn't considered obligatory for the wind turbine-battery system, to save time
- The model only simulates power flows, rather than voltage, current, because the study is about assessing the financial capabilities of service and market stacks
- Grid frequency only determines the load for FFR services; the relationship between generation from the wind farm and grid frequency is not explore
- Grid congestion is not considered in power dispatch from the wind farm-battery system
- A real world validation of the model isn't conducted, and the model is not validated against other models

1.5 Methodology

In this section the methods used to answer the research questions are briefly described:

1. Make an inventory of ESO balancing service requirements, using online sources
2. Build the wind turbine-battery model, implementing physical equations for wind turbine and battery behaviour
3. Based on inventory of balancing service, model services using arbitrary data
4. Determine a UK case study and obtain appropriate data
5. Obtain costs and revenues for wind turbine, battery, and services, relevant for a chosen method of financial assessment
6. Stack BS, FFR static secondary, FFR dynamic high frequency, day-ahead market and balancing market, to function simultaneously in the model
7. Collect baseline results and discussion for both individual services and markets, as well as stacked
8. Build sensitivity analysis for external conditions in the model
9. Complete sensitivity analysis results and discussion, indicating how stack results change when external variables are changed

1.6 Report layout

The layout of the report roughly follows the order in the methodology section above: First is the introduction, which lays out the reasoning for the project and project plan. Then, real world elements of the study are explained in Chapter 2, so that the subsequent model chapter makes sense. In Chapter 3, the model flowchart is shown, giving a simplified view on the model functions, followed by an explanation of the model, its implementation and assumptions used. After the model has been conveyed to the user, it is validated. Then in Chapter 4, the baseline case study is given, where model inputs specific to the case study are stated. Then in Chapter 5, baseline case study results are shown and discussed, for both individual and stacked services/markets. Then in Chapter 6, the sensitivity case study and results are given and discussed, assessing the sensitivity of stack combinations to external variables. Finally is the conclusion, with an evaluation of the results, project, and suggestions for future work.

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2 Real world elements

This chapter is comprised of real world elements that will be modelled in this study, providing a point of reference for the model assumptions. The current chapter is broken up into sections, each describing a different element: wind generation, batteries, financial assessment of wind turbine-battery systems, ancillary services provided, service stacking and electricity markets.

2.1 Wind generation

In this section, some less obvious elements of real world wind generation will be explained, specific to an offshore wind farm (due to its relevance to UK future energy scenarios). Wind energy is usually sold on the market regardless of prices, unless prices are negative; in which case curtailment occurs. Oversupply of energy at a grid node, due to unusually high wind speeds, can cause grid instability, another reason for wind energy curtailment. This is especially relevant for countries with high levels of wind penetration; Østergaard found that curtailment is key to prevent grid instability in Denmark (Østergaard, 2006). Supplying the electricity produced by a wind turbine or battery to the grid involves conversion of DC electricity to AC, and voltage to be stepped up by a transformer, depending on the plants position in the transmission or distribution network. DC to AC conversion uncouples wind turbine generator frequency from grid frequency, reducing overall grid frequency stability, as a wind turbine generator's inertia cannot be used in the spinning reserve (modern wind turbines use asynchronous generators). Spinning reserve is when the rotational speed of a synchronous generator is reduced in order to transmit inertia as power to the grid, and is the reason why frequency deviation is used to measure grid power imbalance.

2.2 LiFePO4 battery Storage

In this section, real world elements of batteries are explained. Several parameters can be used to describe battery behaviour; energy to power ratio, of course, determines the amount of power a battery can supply or store for a given energy size; according to a study of utility scale Li-ion battery systems, energy to power ratios average around 1, meaning a 1 MWh battery can deliver 1 MW (Hesse, Schimpe, Kucevic, & Jossen, 2017). This would be a charge/discharge rate limit, $c\,rate_{max}$ of one, where one divided by $c\,rate_{max}$ is the time in hours that a battery discharges its capacity in, i.e. half an hour for 2C. Another important parameter is charge and discharge efficiency, which depends on battery discharge and charge rates actually used (not the limit), $c\,rate$, and ambient temperature, amongst other factors. As the number of completed discharge cycles increases, battery capacity degrades, depending on depth of discharge reached, with deeper discharge cycles causing faster degradation; this means that service provision strategies may change over time. LiFePO4 battery response time is sufficiently fast to provide FFR services (EASE, 2018). Finally, it is useful to note that batteries self-discharge over time, although Li-ion type batteries experience very little of this, with the amount of self-discharge depending on ambient temperature, depth of discharge and $c\,rate$.

2.3 Financial assessment of wind farm-battery systems

In this section, the use of Levelized Cost of Electricity (LCOE) and Internal Rate of Return (IRR) to assess the commercial viability of wind farm-battery systems is discussed.

LCOE is commonly used to compare the cost of electricity utilised over the lifetime of a power plant, measured in £/MWh, to market prices. For reference, UK offshore wind energy contracts have been won at 39.65 GBP/MWh for the 2023-2024 period (Carbon Brief, 2019). System cost is generally broken down into initial costs and annual cost. All costs in LCOE are then modified with the inclusion of WACC, which reflects the time-value of money. In the UK, average unlevered and levered WACCs of 7.75% and 9% are used respectively for financing offshore wind farms (GrantThornton, 2018). An unlevered discount rate doesn't assume a certain capital structure of the company (in relation to debt or to equity), as unlevered cash flow is calculated before debts have been paid, while a levered rate is relevant for those purchasing equity, as a levered cash flow accounts for cash after financial obligations (debts) have been met. A cost breakdown for a generic offshore wind farm and battery in the UK are given in Table 2.1 below.

Table 2.1: Generic UK offshore wind farm and Li-ion battery cost breakdown used as inputs to IRR and LCOE (BVG Associates, 2019; NREL, 2019).

Element (-)	**Cost component (-)**	**Cost (m GBP/MW unless stated)**
Wind farm	$C_{purch\ MW}$	0.661
Wind farm	$C_{install\ commiss\ MW}$	0.651
Wind farm	$C_{BOP\ MW}$	0.603
Wind farm	$C_{other\ MW}$	0.340
Wind farm	$C_{decomm\ MW}$	0.325
Wind farm	$C_{proj\ dev\ manag\ MW}$	0.120
Wind farm	$C_{WF\ O\&M\ tot\ MW}$	1.899
Battery	$C_{batt\ capital\ MW}$	0.492
Battery	$C_{batt\ capital\ MWh}$	0.151 (m GBP/MWh)
Battery	$C_{batt\ ann\ O\&M\ MW}$	0.019 (m GBP/MW-yr)

Where:
$C_{purch\ MW}$ = Wind farm purchase cost per MW installed
$C_{install\ commiss\ MW}$ = Installation and commissioning cost per MW installed in the wind farm
$C_{BOP\ MW}$ = Balance of plant cost per MW installed in the wind farm
$C_{other\ MW}$ = Other costs of the wind farm per MW installed
$C_{decomm\ MW}$ = Cost of wind farm decommissioning per MW installed
$C_{proj\ dev\ manag\ MW}$ = Cost of project development and management per MW installed
$C_{WF\ O\&M\ tot\ MW}$ = Lifetime total operation and maintenance (O&M) cost of the wind farm per MW installed
$C_{batt\ capital\ MW}$ = Lifetime capital cost of the battery per MW
$C_{batt\ capital\ MWh}$ = Lifetime capital cost of the battery per MWh
$C_{batt\ ann\ O\&M\ MW}$ = Annual cost of the battery O&M per year

Note that in Table 2.1 the cost of leasing land for the wind farm site is not included, that the costs in Table 2.1 are calculated before WACC is included (in the case of LCOE), and that battery costs shown are selected from a range of studies collected by NREL, originally for a 4-hour battery (NREL, 2019). When calculating IRR, WACC is not used; instead, the yearly return is calculated based on initial investment and yearly cash flows, and compared to WACC to determine if an investment decision is profitable.

2.4 Black Start Service

In this section, the requirements needed to provide the real-world BS service are explained, which are derived from online ESO sources.

2.4.1 BS market

In the UK, BS tenders are established by the ESO for different regions of the UK, as shown below in Figure 2.1, where each region has multiple providers (ESO, 2019). BS tenders start two years ahead of service provision, with provision lasting almost three years (ESO, 2020b).

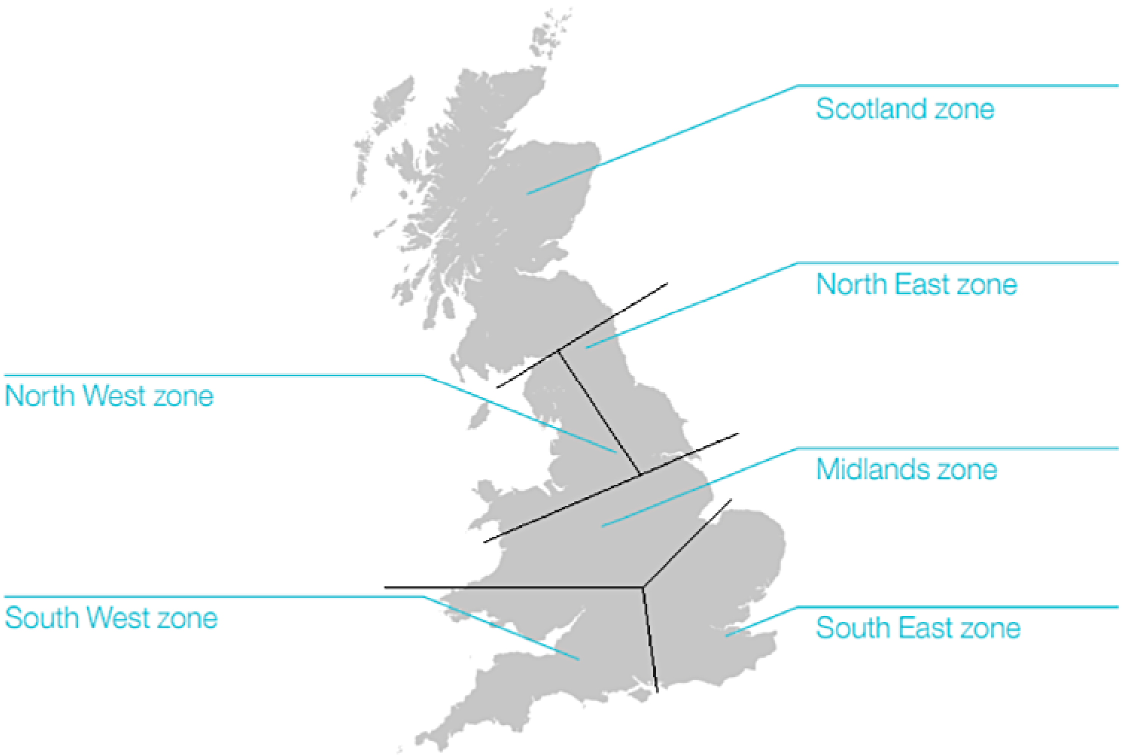

Figure 2.1: UK BS zones (ESO, 2019).

The total UK BS service volume requirement is around 30 GW (11 GW for Scotland, NE and NW zones, and around 22 GW for the Midlands, SW and SE zones). Any bid that meets the minimum BS requirements can be submitted, though BS requirements can also be partially met on a case-by-case-basis, according to the ESO (ESO, 2019, 2020a). The National Grid expect the BS provision to restore 60% of load within 24 hours of a blackout (National Grid, 2017). Wind turbine-battery systems are technically able to provide the BS service, but due to a low amount of storage utilisation, it may be preferable to rely on battery devices as little as possible (WindEurope, 2017). Fossil fuel BS systems are becoming uneconomical for this reason, according to the ESO's new BS strategy; to retain controllability, they have previously used peaking gas plants for BS, which are not cost effective to run at usual electricity prices, and expensive to keep on standby. In contrast, wind energy can provide energy regardless of prices and therefore even when assigned as a BS site, can retain profitability by selling in day-ahead and balancing markets (ESO, 2020b). In Table 2.2 below are the ESO's payments to BS providers for period April 1st 2019 - March 31st 2020.

Table 2.2: Costs of BS provision paid by ESO for period April 1st 2019 – March 31st 2020 (ESO, 2020o).

Breakdown of Costs (£)	
Availability Payments	£40,330,496.12
Capital Investment	£8,879,754.29
Feasibility Studies	£69,815
Testing	£462,437.75
Warming	£5,170,241.09
Total	**£54,912,744.25**

Below in Table 2.3, average annual revenues for providing the BS service per MW are shown.

Table 2.3: Average annual revenue for BS service per MW (National Statistics, 2019; GOV.UK, 2019; ESO, 2020o).

Revenue	**Detail**	**Income** (£/yr MW)
Availability	Fraction of this paid when BS service is available for a half-hour settlement period (SP), with the annual revenue based on 100% availability and average tender price	1222
Investment compensation	ESO supports companies with necessary capital investments	269

2.4.2 ESO BS requirements

In order to provide the BS service, many requirements must be met, which are listed below (ESO, 2020a):

1. **Generation block(s) $\geq$ 20 MW:** Though blocks of 35-50 MW are preferred.
2. **Generation block duration $\geq$ 10 hours:** Therefore, a minimum of 200 MWh must be delivered in a BS.
3. **Ability to provide three BS in sequence:** Catering for two failed BS, energy must be stored for three restarts of the main generation units (the power plant)
4. **BS units must pass several tests:** A BS event is "High Impact, Low Probability", so the service must be stringently tested (National Grid, 2017). Test types include commissioning assessments, capability assessments, remote synchronisation tests, dead line charge tests (re-energising) and reproving assessments, the latter in the event that a BS unit has been unavailable for a period of time (ESO, 2021). Components to BS testing include testing the resiliency and capability of the auxiliary unit, a grid code BS test and a remote synchronisation test. In the grid code BS test, it must be shown that the provider can synchronise generation to the transmission network within two hours of removing grid electricity supply, testing performance of the auxiliary unit, response time, and ability to stay within frequency limits. In the remote synchronisation test, which can occur once every two years, a section of the transmission system is isolated and de-energised, and then the BS provider must re-energise it and connect the isolated area back to the transmission network, which tests the full capability of the BS system (ESO, 2012).

5. **Dispatch generation block(s) within two hours**
6. **BS provision availability ≥ 90%:** A blackout has a 0.5 - 5% chance of occurring from 2017 – 2022, but high availability is needed (UK Power Networks, 2017)
7. **BS providers must report BS availability in real time**
8. **BS facility must function without grid support for ≥ three days:** A BS auxiliary unit, used to keep the main generation unit running, must run for a minimum of three days, with longer preferred.
9. **Generation units must be capable of safe shutdown without grid supply**
10. **Reactive power capability:** Sufficient reactive power must be available for consumption where BS energy is distributed, for example, "a generating plant connected at 400kV or 275kV with a reactive power capability of 100MVAr leading" will meet the requirement
11. **52 Hz ≥ BS output frequency ≥ 47.5 Hz**

2.5 Firm Frequency Response

In this section, requirements to provide a real-world FFR service are given, based on online ESO sources. Grid frequency must be managed on a second-second basis in order to control supply-demand mismatch. In the UK, the ESO is obligated to maintain frequency within the 49.5 - 50.5 Hz range, using FFR and spinning reserve to accomplish this.

2.5.1 FFR market

The ESO carry out monthly tenders of FFR services, split up into six, four hour time blocks starting and ending at 2300, 0300, 0700, 1100, 1500 and 1900 hrs, with blocks repeated every day of the month. These tenders are finalised one month before delivery begins (ESO, 2020f). The price paid to providers is the same per MWh regardless of volume provided. Below in Tables 2.4 and 2.5, revenues and penalties for the FFR services are shown respectively, with exact values determined in the suppliers tender.

Table 2.4: Potential revenues for FFR services (ESO, 2020f).

Revenue source	Detail	Price
Availability	When service available	Variable – see Case study Table 4.8 (£/hr)
Energy provision	When energy is provided	Paid balancing market price x 1.25
Energy storage (FFR dynamic only)	When energy is stored	Storage provider PAYS balancing market price x 0.75
Nomination	When asked to provide; usually for all hours in tendered window.	See above (£/hr)
Optional: Window initiation	Per nominated window in tendered periods	See above (£/window)
Optional: Window revision	IF ESO makes changes to nominated window	See above (£/hr)

Table 2.5: Potential penalties for FFR services (ESO, 2020f).

<table>
<tr><th>Penalty source</th><th colspan="2">Price / deduction</th></tr>
<tr><td>Zero SP availability fee if unavailable</td><td colspan="2">0 for the SP(s)</td></tr>
<tr><td>Zero SP nomination fee if fails to respond</td><td colspan="2">0 for the SP(s)</td></tr>
<tr><td>Deduction of window initiation fee if unavailable or fails to respond</td><td colspan="2">0 for window</td></tr>
<tr><td>Agreement termination possible if unavailable or fails to respond > 3 times in calendar month</td><td colspan="2">-</td></tr>
<tr><td rowspan="5">Variable deduction of availability & nomination fee for under-response of FFR unit: where P = $\frac{MW_{peak\ provided}}{MW_{contracted}}$</td><td>P (-)</td><td>Deduction (%)</td></tr>
<tr><td>$0.10 > P$</td><td>100</td></tr>
<tr><td>$0.60 > P >= 0.10$</td><td>50</td></tr>
<tr><td>$0.95 > P >= 0.60$</td><td>25</td></tr>
<tr><td>$P >= 0.95$</td><td>0</td></tr>
</table>

As shown in Table 2.4, if the balancing market price is negative and energy is provided, then FFR service revenue can be negative. Equally if energy is stored as part of the dynamic service with a positive balancing market price, then FFR revenue can also be negative.

2.5.2 FFR general requirements

FFR service information comes from the ESO's website and FAQ document (ESO, 2020e, 2020f). For both static and dynamic services, no recovery period is allowed, as frequency events can occur continuously. Other requirements are specific to each service, and are shown for the FFR static and FFR dynamic services in Sections 2.5.3 and 2.5.4 below.

2.5.3 FFR static low frequency secondary response requirements

In the static services, an agreed amount of energy is delivered if the trigger frequency is met. The only static service now procured is the secondary service, as the static low frequency primary and static high frequency services were replaced with dynamic services (ESO, 2020f, 2020g). Requirements are given below:

1. **A range of frequency triggers from 49.5 - 49.7 Hz (2300 – 0700 hrs) and 49.5 – 49.8 Hz (0700 – 2300 hrs) for different generation units**
2. **Zero-point frequency is 49.95 Hz for 50% of tendered response volume, 50.00 Hz for the other 50%, although it is acceptable for a provider to use a single zero-point frequency**
3. **Response within 30 seconds of frequency trigger**
4. **Response volume depends on the size of frequency deviation:** Volume is linearly interpolated from 1 MW at 49.50 Hz to 0 MW at zero-point frequency
5. **Proportional response occurs for the terms' duration, even if frequency zero-point is reached**
6. **Response duration $\leq$ 30 minutes**
7. **Response $\geq$ 1 MW:** The secondary static service is based on expected generation loss of 1260MW, so requires a positive response

2.5.4 FFR dynamic response requirements

In dynamic response, volume rises and falls in line with frequency, accommodating both generation loss and demand loss. Detailed requirements are listed below in a list and in Table 2.6.

1. **Deadband frequency of 50 Hz +/- 0.015 Hz:** Energy delivered below 49.985 Hz, and stored above 50.015 Hz (ESO, 2020g)

2. **Linear volume response:** For 1 MW commitment, 1 MW is generated at 49.50 Hz, to 0 MW at 49.985 Hz, and 1 MW is stored at 50.50 Hz, to 0 MW at 50.015 Hz

3. **Response $\geq$ 1 MW:** For either load or generation loss.

4. **Response speed and duration:** Requirements for primary, secondary and high response are shown in Table 2.6 below.

Table 2.6: FFR dynamic service response speed and duration requirements (ESO, 2020g).

FFR product type		Response speed	Length of response
Dynamic – A Dynamic service can provide Primary, Secondary and High response, or Primary and Secondary only or High only.	Primary	Response required within 2 secs, with full response by 10 secs.	20 secs
	Secondary	Within 30 secs	30 mins
	High	Within 10 secs	Indefinitely unless otherwise agreed.

2.6 Service stacking

The ESO has a flexible view on the stacking of ancillary services, stating "It is possible to provide other balancing services, as long as doing so does not interfere with your ability to deliver black start" (ESO, 2020a). In the event of a BS event, the provision of additional balancing services will be stopped, and resumed when feasible. Also, when actively providing a FFR block, the generating unit providing the service cannot provide other balancing services, ie both FFR and capacity reserve, or both FFR and a reactive power service (ESO, 2020e). Outside of the block duration, the generating unit can provide other services. As a result, the wind farm - battery system may be broken up into units to provide the FFR service.

2.7 Electricity markets

Electricity is bought and sold in several different markets: Private bilateral agreements, ancillary service markets, which have already been detailed in this study, spot/day-ahead markets, intra-day markets, and finally balancing markets (Pérez-Arriaga, 2013). Spot/day-ahead markets are the largest market, where electricity is traded 24 hours before dispatch in one hour trading periods (ENTSO-E, 2020). The balancing market/mechanism is where electricity is exchanged in half-hour SPs to resolve imbalances in real time. In the balancing market bids can be made for both increases in energy production and reductions in energy production (Elexon, 2021).

3 Model

In this chapter, the model explanation and implementation are given, followed by the model validation.

3.1 Model explanation, assumptions and implementation

In this section, the model flowchart is given for a brief overview. Then the model blocks are broken down with relevant equations given and explained, with details of the implementation, and assumptions stated as necessary.

The model flowchart for the stacked service/market scenario is shown below in Figure 3.1. This scenario flowchart is chosen as it represents the most complex model operation, with all services and markets shown. For individual service and market provisions, the respective flowcharts (which can be seen in Appendix Section A) are similar but slightly simpler.

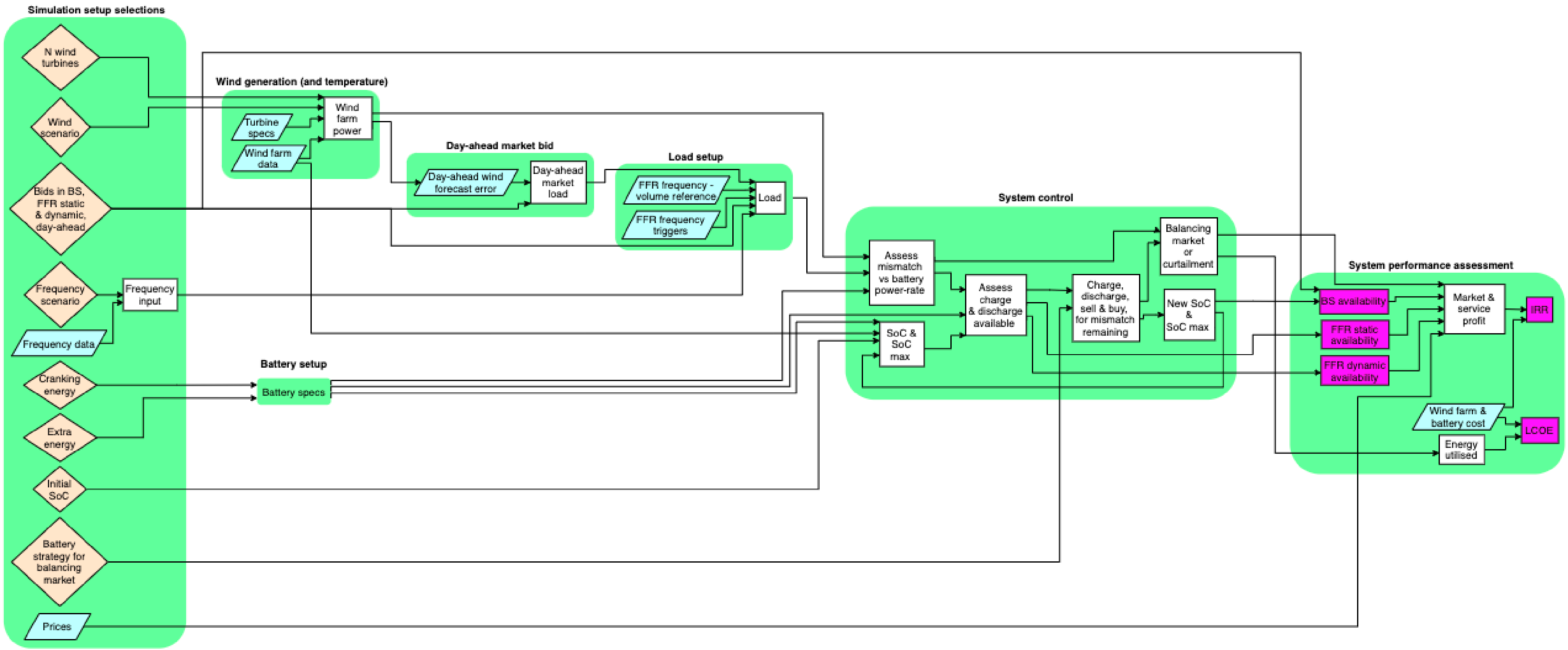

Figure 3.1: Model flowchart for scenario six, the stacked service/market scenario.

3.1.1 Simulation setup block

First in the simulation setup block, several parameters are determined for each simulation, which overall make up the compositions run in the model to obtain results.

Scenario used is given, which determines which markets and services are run in the simulation, and therefore changes the flow of the model. As mentioned before, the flow in Figure 3.1 occurs when services and/or markets are stacked.

Wind year is stated, which determines the wind data input (either an average wind year, baseline, or a bad wind year with hypothetically reduced wind speeds) that is passed on to the wind generation and temperature block. Frequency scenario is given, which determines either direct use of the frequency data (baseline), or hypothetical increases of the frequency deviations in the frequency data.

After this, generation and storage parameters are given, starting with the number of wind turbines in the wind farm, N_{WT}. Cranking energy per wind turbine, E_{crank} (MWh) is given if the BS service is required, for the BS restart of wind turbines. The value of E_{crank} is determined by the user for the wind turbine model, depending on wind turbine rated power. Extra energy required by the battery, E_{extra} (MWh), refers to energy required other than for the BS auxiliary unit (cranking energy), such as for the BS primary load, for FFR provision etc. Initial battery SoC is chosen, which contributes to availability of a service at the simulation start (first time step). Then bids are given for the BS service, power, P_{BS} (MW) and duration, t_{BS} (hours), the FFR static secondary service, $P_{bid\,static}$ (MW) and FFR dynamic high frequency service, $P_{bid\,dynamic}$ (MW), for the day-ahead market, $f_{day\,ahead}$ (-) which are transferred to the load block. The last parameter selected as part of the composition is the battery strategy to be used in the balancing market, of one or two. Battery strategy one means that the battery is always charged in the event of positive generation-load mismatch, until full, with any excess energy sold in the balancing market, whereas strategy two means that if the balancing market price is higher than the average balancing market price, energy is sold in the balancing market first, instead of charging the battery. These selections determine several other components, some in the simulation setup block, and others in the rest of the model.

In a spreadsheet, parameter setups for each simulation are each given a unique composition identifier. This spreadsheet is referenced by the model, with the user determining which single composition, or range of compositions, they would like to run in simulations in the model and achieve results from. When running the model, it will go down the list of compositions, simulating them one at a time. A template of this spreadsheet can be seen below in Table 3.1.

Table 3.1: Spreadsheet used for model parameter selections.

Identifier	Scen	Wind year	Frequ scen	Sizing				Bid composition					
				N_WT	E_crank	E_extra	Initial SoC	P_BS	t_BS	FFR stat	FFR dyn	f day-ahead	Batt strat
(-)	(-)	(-)	(-)	(Wind turbines)	(MWh)	(MWh)	(-)	(MW)	(h)	(MW)	(MW)	(-)	(-)

The user manually sets up the parameters in this reference spreadsheet. The user can select an option of scenario, "Scen" in the simulation setup block, by allocating an integer number from one to six, representing one of the following selections.

- 1 = BS test alone
- 2 = BS assessment alongside balancing market
- 3 = FFR static service secondary response alongside balancing market
- 4 = FFR dynamic service high frequency response alongside balancing market
- 5 = Grid dispatch in day-ahead and balancing markets
- 6 = All services stacked

The user can select a "Wind year" option of one or two, referring to the baseline and bad wind year respectively (whose meanings are clarified in Section 3.1.2). The user can also select a frequency scenario, "Frequ scen", with options of one to four, referring to the following selections.

- 1 = Frequency data used unmodified
- 2 = 20% increased frequency deviations
- 3 = 50% increased frequency deviations
- 4 = 100% increased frequency deviations

The user can select an option for number of wind turbines, "N_{WT}" in the simulation setup block. The user can select "E_{crank}" and "E_{extra}". The user can select a value for "Initial SoC" of the battery at the first time step. Then the user can select a single bid value for each of the following: "P_{BS}", "t_{BS}", "FFR stat", "FFR dyn", "f day-ahead". The number for "f day-ahead" should be between zero and one. Finally the user can select "Batt strat", the balancing market battery strategy by assigning an integer number of one or two.

Battery capacity, E_{capac} is based on the selections of N_{WT}, E_{crank} and E_{extra}, calculated in Equation 3.1, below.

$$E_{capac} = (E_{crank} \cdot 2 \cdot N_{WT}) + E_{extra} \tag{3.1}$$

Here, a safety factor of two is applied to wind turbine cranking energy stored in the battery, to ensure sufficient battery capacity is available to provide cranking energy during a BS event, regardless of the number of battery cycles completed (at maximum cycles, SoC_{max} equals 0.5, thus accounting for degradation over time.

BS bids contribute alongside E_{crank} and N_{WT} to create the BS energy requirement, E_{BS} for each half-hour SP, using Equation 3.2. This is required in the system performance assessment block to assess BS availability.

$$E_{BS} = (E_{crank} \cdot N_{WT}) + P_{BS} \tag{3.2}$$

Bids for each FFR service are modelled as power, with only one bid size per service, because the ability to vary FFR bids based on the time of day (in the six respective FFR blocks) is not needed for these results. FFR bids are passed on to the load setup block as an input to create the FFR load.

Day-ahead bid is the proportion of the day-ahead wind power forecast that should be bid on the day-ahead market; this is transferred to the day-ahead market bid block.

Service and market prices are imported here and forwarded to the battery operation block, to determine curtailment, balancing market sales or charging, as well as later in the financial assessment block to determine costs and revenues. It is assumed that service and market prices are not influenced by bidding decisions made by the wind farm - storage plant operator.

Then, if a frequency scenario other than one is selected, increased frequency deviations which simulates introduction of more VRES onto the electricity grid, are implemented using the same frequency data but with increased deviations in both the positive and negative directions from 50 Hz.

As in the real world, two different FFR static secondary service frequency triggers are used, for between 2300 to 0700 hours, and for between 0700 and 2300 hours. These two triggers are implemented as setting one and two in the simulation setup block here, and then fully implemented in the load setup block.

Different frequency deviations demand different volume responses in the services; as in reality, with maximum bid provision at 0.5 Hz deviation from 50 Hz, and zero provision above the trigger. This is modelled for the static secondary service as follows in Table 3.2.

Table 3.2: FFR static secondary service volume response factor as it relates to frequency (ESO, 2020g).

Frequency	**Delivery Factor**
49.50	1
49.55	0.9
49.60	0.8
49.65	0.7
49.70	0.6
49.75	0.5
49.80	0.4
49.85	0.3
49.90	0.2
49.95	0.1
50.00	0.0

And volume response used to model the dynamic high frequency service is as follows in Table 3.3.

Table 3.3: FFR dynamic high frequency service volume response factor as it relates to frequency (ESO, 2020g).

Frequency	Delivery Factor
49.500	1
49.985	0
50.000	0
50.015	0
50.500	-1

Tables 3.2 and 3.3 are implemented in this model section, then passed on to the load setup block for use in creating load due to frequency deviations.

3.1.2 Wind generation and temperature block

In the wind generation block, several wind turbine constants are defined: cut-in wind speed, $u_{cut\,in}$, rated wind speed, u_{rated}, cut-out wind speed, $u_{cut\,out}$, wind turbine rotor radius, r_{rot} (and as a result wind turbine rotor area, A_{rot}), rated power of wind turbine, $P_{WF\,rated}$, air mass density, ρ and wind turbine drivetrain efficiency, $\eta_{drivetrain}$.

Then, hourly average wind speed data is imported with x and y components. The difference between hourly average wind speed and ten-minute average wind speed data is assumed to be negligible here. Hourly average wind speed data is used as an input in this study; preferably, 10-minute average wind speed data would be used, which gives a more accurate value of wind turbine power. The effect of using hourly average wind speed changes depending on wind speed distribution, because of Equation 3.5 shown later in this section; the lower the average wind speed is compared to rated wind speed, the greater the under-prediction of wind turbine power. Resultant hourly average wind speed, u_{ref}, is calculated using Equation 3.3 below.

$$u_{ref} = \sqrt{u_x^2 + u_y^2} \tag{3.3}$$

This resultant wind speed is based on the assumption that wind direction always perfectly in line with rotor direction. For an 8 MW wind turbine, yaw power, P_{yaw} and pitch power, P_{pitch} equal 0.0255 MW and 0.0192 MW respectively, and the time for yawing and pitching is negligible compared to the hourly resolution. Therefore the energy required to accommodate wind direction changes during normal operation is negligible, and the energy not produced due to not operating in the optimal rotor direction is negligible.

Ambient temperature data is then imported for the same location as the wind data; this is passed on to the system control block.

Because u_{ref} is not measured at wind turbine hub height, h_{hub}, wind speed is calculated at wind turbine hub height using the Power Law below in Equation 3.4 (Zaayer & Viré, 2020).

$$u_{hub} = u_{ref} \cdot (\frac{h_{hub}}{h_{ref}})^{\alpha} \tag{3.4}$$

Where α is power law coefficient, u_{hub} equals wind speed at hub height, and h_{ref} equals wind speed data measurement height. Here u_{hub} is then used in the rest of the model based on the assumption that wind speed is instantaneously identical for all wind turbines in the wind farm.

If wind year option two is selected in the simulation setup block, a factor of 0.95 is applied to hub height wind speed. Hub height wind speed is modified so that it equals zero where it less than, or greater than, cut-in wind speed, and cut-out wind speed respectively, to create u_{avail}.

Then the wind turbine power curve is imported, where the relationship between power and wind speed is given to a wind speed precision of 1 m/s. From this the wind turbine power coefficient, C_p, is found. A lookup table is used to implement the wind turbine power curve in the model, where for a given hourly average hub height wind speed, an interpolated value of C_p is returned (interpolated as the hourly average hub height wind speed is measured to four decimal places). Interpolating the power curve to obtain an exact value of C_p for hourly average wind speed can result in a value C_p that is slightly too high, and wind turbine power can exceed rated wind turbine power as a result. To counteract this, the value of wind turbine power is limited to $P_{WF\,rated}$ afterwards. Then wind turbine power, P_{WT} is calculated using Equation 3.5 below. Note, it is assumed that the wind turbines are fully operational in the first time step; they do not have to start up and as such are immediately each producing P_{WT}.

$$P_{WT} = 1e^{-6} \cdot 0.5 \cdot \rho \cdot A_{rot} \cdot C_p \cdot u_{avail}^3 \cdot \eta_{drivetrain} \tag{3.5}$$

Here $\eta_{drivetrain}$ is assumed to be a constant value, independent of wind speed or operating condition. Next a single wind turbine is scaled up to the wind farm. To do this, wake effect factor, f_{wake}, is created, which is used to account for wake effects when there is more than one wind turbine; so the model only accounts for wake losses at a basic level. Three phase connection between the wind farm and grid is then modelled, but only by efficiency values for the back-to-back converter, η_{B2B}, transformer efficiency, $\eta_{transformer}$ and transport efficiency, $\eta_{transport}$, respectively, as the study only models power flows. Three phase connection efficiency, η_{DC-AC}, is then calculated below using Equation 3.6.

$$\eta_{DC-AC} = \eta_{B2B} \cdot \eta_{transformer} \cdot \eta_{transport} \tag{3.6}$$

Wind farm power, P_{WF}, is then calculated using Equation 3.7.

$$P_{WF} = P_{WT} \cdot N_{WT} \cdot f_{wake} \cdot \eta_{DC-AC} \tag{3.7}$$

Wind farm power, calculated at an hourly temporal resolution, is then resampled into a half-hour resolution, using the same wind farm power for each of the two half-hourly value. This uses the fundamental model assumption that all model data and physics can be aligned with a single half-hourly temporal resolution; for this example, it is assumed that the resultant hourly average wind speed may be split into two equal half-hourly wind speed values, used for the half-hourly temporal resolution required later in the model system control block.
Note that it is assumed that no spinning reserve is provided to the grid by the wind turbine-battery device.

3.1.3 Day-ahead market bid block

To simulate the effect of weather forecasting in the model, the difference between day-ahead wind generation forecast and current forecast is used (current forecast is the wind energy forecast at time of delivery, according to Elexon), for the same year as the wind and frequency data, for all of the UK's offshore wind energy fleet (bmreports.com, 2020). Here, day-ahead wind energy forecast at each SP is divided by current wind energy forecast at each SP, to form factor $f_{current\,to\,DA}$ at each SP, as shown in Equation 3.8.

$$f_{current\,to\,DA} = \frac{P_{forecast\,day-ahead}}{P_{forecast\,current}} \tag{3.8}$$

This factor is then used to convert actual wind farm generation into a day-ahead forecast of wind farm generation. Note that the difference in UK offshore wind generation day-ahead and current forecast not only accounts for change in weather, but also accounts for any wind turbine failures and unplanned maintenance that occur or is required in the last 24 hours between forecast and delivery. The proportion of forecast wind energy that should be bid in the day-ahead market, $f_{DA\,bid}$, is used, in conjunction with actual wind farm power and $f_{current\,to\,DA}$, to generate the day-ahead market bid, $P_{DA\,bid}$, as below in Equation 3.9.

$$P_{DA\,bid} = P_{WF} \cdot f_{DA\,bid} \cdot f_{current\,to\,DA} \tag{3.9}$$

This means that while day-ahead bid has a value for every half-hour SP, it is identical for both SPs in the hour, because day-ahead bids are made in one hour blocks in reality.

If day-ahead bid exceeds, $P_{WF\,rated}$, it is limited to $P_{WF\,rated}$, to prevent over bidding. This can occur if $f_{current\,to\,DA}$ is greater than one. A minimum day-ahead market price of zero is also defined, so that day-ahead market bidding is zero at negative day-ahead market prices. This day-ahead market bid is then passed on to the load setup block as the load from the day-ahead market, and any mismatches created due to forecasting errors must be managed by the battery storage or in the balancing market.

3.1.4 Battery setup block

In this study, battery cell voltage and current behaviour isn't modelled; instead the battery is modelled in terms of power and energy flows, as defined by the project scope (using charge and discharge limits, cycle deterioration, state of charge (SoC), capacity). In the battery setup block of the model, several battery variables are defined, aiming to facilitate the modelling of battery power flows. Battery $c\,rate_{max}$ is given, which equals the energy to power ratio, and then maximum battery power rate (power for charging or discharging), $p\,rate$, is calculated with Equation 3.10 below, which requires battery capacity from the simulation setup block.

$$p\,rate = c\,rate_{max} \cdot E_{capac} \tag{3.10}$$

$p\,rate$ is then transferred to the system control block to limit the power charged or discharged from the battery in each SP.

It is assumed that average battery $c\,rate$ to be used used in the battery operation simulation (not $c\,rate_{max}$) equals 0.5, representing the fact that the minimum possible battery size is used for each application, hence $c\,rate$ is often high. This average value of $c\,rate$ determines charge and discharge efficiency, η_{charge} and η_{disch}, which are then given, along with minimum SoC, SoC_{min}. These battery parameters are all passed forward to the system control block of the model.

3.1.5 Load setup block

The function of the load setup block is to make the load input for each scenario modelled. Therefore this section of the model takes parameters determined in the simulation setup block (scenario, grid frequency, FFR static secondary and dynamic high frequency service bids) and day-ahead market bid block (day-ahead market bid), to calculate the load in each time step of the simulation, equivalent to one SP. Each run of the model simulates a one year period.

Scenario selected determines how the load is calculated. For scenario equals one, two or five, where FFR services are not provided, implementation of the load setup in the model is fairly straightforward, creating load inputs with a half-hour time step, equivalent to one SP. For scenario equals three, four or six in the load setup block, load due to FFR static secondary and dynamic high frequency services respectively, $P_{FFR\,static}$ and $P_{FFR\,dynamic}$, are initially calculated at a temporal resolution of one second, allowing the exact FFR static secondary and/or FFR dynamic high frequency load to be calculated for the grid frequency at each second. Then these loads are averaged to a half-hour resolution, and in the case of scenario three and four, used to calculate total load, P_{load}, or in the case of scenario six, combined with load due to the day-ahead bid, $P_{DA\,bid}$, to again calculate total load, P_{load}. P_{load} is then passed on to use in the system control block. Using a half-hour temporal resolution in the system control block reduces its computational expense. This again uses the fundamental model assumption that all model data and physics can be aligned with a single half-hourly temporal resolution.

To carry out a BS test in the model, only power and duration of power provision are assessed; it is assumed that the system passes other elements of real world BS testing. The wind farm is assumed to have sufficient leading reactive power provision to meet the BS requirement, and frequency limits of BS power output are not modelled, as wind turbine generator frequency is uncoupled from grid frequency. For the BS service in scenario one, load is calculated for the first time step when the BS is initiated, using Equation 3.11 below.

$$P_{load\,1} = E_{BS} \tag{3.11}$$

For the following 19 SPs, load in scenario one is calculated as follows in Equation 3.12 below.

$$P_{load\,2-20} = P_{BS} \tag{3.12}$$

Here, the BS is modelled to occur randomly once in the one year simulation for a ten hour period. Note that this scenario is not used to produce results in this study, but was kept as an original component from the model design. For the BS service in scenario two, load equals zero, as no test or simulation of a BS event occurs, although BS availability is still assessed after the simulation for the composition used.

For the FFR static secondary service, in scenario three, load is calculated using Equation 3.13 below.

$$P_{load} = P_{FFR\,static} = P_{bid\,static} \cdot f_{FFR\,static} \tag{3.13}$$

When frequency setting one is active (2300-0700 hours), trigger one is used, and when setting two is active (0700 – 2300 hours), trigger two is used. When the frequency is below these triggers, P_{load} has a non-zero value, as it is assumed that response to a static secondary frequency trigger is instant (the option to respond up-to 30 seconds after a trigger is removed). Once the frequency trigger is passed, the fraction of volume response required, $f_{FFR\,static}$, is calculated

by interpolating the lookup tables found in the simulation setup block explanation, for grid frequency.
For the FFR dynamic high frequency service, in scenario four, load is calculated as follows in Equation 3.14.

$$P_{load} = P_{FFR\,dynamic} = P_{bid\,dynamic} \cdot f_{FFR\,dynamic} \tag{3.14}$$

The fraction of volume response required, $f_{FFR\,dynamic}$ is calculated by interpolating the lookup tables found in the simulation setup block explanation, for grid frequency. Load has a non-zero value when frequency is outside the deadband (49.985 to 50.015 Hz), given the assumption that response to a dynamic frequency trigger is instant (the option to respond up to 10 seconds after the frequency trigger is removed). Once the frequency deadband is passed once, $P_{FFR\,dynamic}$ is implemented for the FFR dynamic high frequency service response duration.

For the day-ahead bid, in scenario five, load is calculated as follows in Equation 3.15 below.

$$P_{load} = P_{DA\,bid} \tag{3.15}$$

For scenario six, with stacked services, load is calculated from a combination of the previous load components mentioned, except scenario one, as follows in Equation 3.16 below.

$$P_{load} = P_{FFR\,static} + P_{FFR\,dynamic} + P_{DA\,bid} \tag{3.16}$$

3.1.6 System control block

In the system control block, the model first calculates self-discharge rate of battery for the various SoC ranges possible, interpolating self-discharge for the ambient temperature retrieved in the wind generation and temperature block. Therefore, ambient temperature at the battery site is assumed to be the same as at the offshore wind farm site; in reality, the battery will be installed at or near the onshore substation meaning ambient temperature differences will exist, due to height differences, but be minor. Hourly self-discharge inputs for the model, for the LiFePO4 in this study are shown in Table 3.4 below.

Table 3.4: Hourly self-discharge of LiFePO4 battery, depending on temperature and SoC (Omar et al., 2015).

Temperature (K)	SOC Range (-)			
	1.00 - 0.75	0.75 - 0.50	0.50 - 0.25	0.25 - 0
313.15	0.00005	0.00005	0.00004	0.00002
298.15	0.00002	0.00001	0.00001	0.00000
283.15	0.00001	0.00001	0.00000	0.00000
273.15	0.00001	0.00001	0.00000	0.00000
263.15	0.00001	0.00001	0.00000	0.00000

Note self-discharge graphs provided by Omar et al. are legible to an uncertainty of ± 0.5%, so hourly self-discharge is correct to five decimal places (Omar et al., 2015). These interpolated

hourly self-discharge values are divided by two to obtain half-hourly self-discharge, $f_{passive\,disch}$, used later in this section, in Equation 3.19.
Also note that in the model, all wind turbines in the wind farm and batteries in the battery system are controlled as one unit, delivering multiple services, though according to the ESO, a production unit providing a FFR service can only provide other balancing services outside of its tendered FFR windows. This assumption is acceptable for the sake of managing power and energy volumes; in reality the wind farm - battery system would be split up into units to comply with the requirement.

Then, generation-load mismatch, P_{MM}, is calculated using Equation 3.17 below.

$$P_{MM} = P_{WF} - P_{load} \tag{3.17}$$

If the wind farm has an accompanying battery, i.e. E_{capac} is greater than zero, then the energy that must immediately be curtailed, sold or bought on the balancing market due to battery p rate limit is calculated, P_{dissip}, using Equation 3.18.

$$P_{dissip} = P_{MM} - P_{MM\,p\,rate} \tag{3.18}$$

It is assumed that wind turbine curtailment in the model occurs immediately if required, as time to curtail is negligible compared to the half-hour temporal resolution, and curtailment is assumed to be unpaid. Positive mismatch greater than battery p rate is sold on the balancing market or curtailed (if there are negative balancing market prices). Negative mismatch less than negative power rate is purchased on the balancing market (except in the BS restart). Then, for the remaining $P_{MM\,p\,rate}$, the model calculates how the battery charges and discharges over time during the simulation, depending on battery strategy used, with additional calculations for curtailment, balancing market sales and purchases. To do this, battery SoC is calculated at every time-step in the simulation. For the first time step, SoC equals initial SoC determined by the user in the simulation setup block, and maximum SoC equals 0.95 as stated in the assumptions. For subsequent time steps, SoC is calculated using Equation 3.19 below.

$$SoC(i) = SoC(i-1) + \frac{(E_{charge}(i-1))}{E_{capac}} + \frac{(E_{discharge}(i-1))}{(E_{capac})} - f_{passive\,disch}(i-1) \tag{3.19}$$

and maximum SoC, SoC_{max}, is calculated with Equation 3.20.

$$SoC_{max}(i) = 0.95 - Cycles(i-1) \cdot 0.00003 \tag{3.20}$$

This means that battery p rate itself doesn't deteriorate with cycles completed; SoC_{max} reduces over cycles completed, but this doesn't affect capacity used to calculate battery p rate.

Then self-discharge, calculated before the battery operation, is allocated based on the SoC calculated, for the following SoC ranges: $SoC > 0.75, 0.75 \geq SoC > 0.5, 0.50 \geq SoC > 0.25$, and $0.25 \geq SoC$. Therefore this is a very simplified model of passive discharge rate.

After this the availability of charge and discharge in the battery can be calculated, which determines FFR availability and decisions on how to deal with $P_{MM\,p\,rate}$. If charge available, $E_{charge\,avail}$, is less than zero, the FFR dynamic high frequency service availability ($FFR_{dynamic\,avail}$) is zero for that SP, and if discharge available, $E_{disch\,avail}$, is less than zero, FFR static secondary ($FFR_{static\,avail}$) and dynamic high frequency service availability are both zero for that

SP. However, it is assumed that FFR services are always delivered, with imbalances settled in the balancing market; to make this assumption plausible, a limit is set to the battery so that sufficient discharge is always available for the FFR static secondary service and/or FFR dynamic high frequency service bid, and so that sufficient charge is available for the FFR dynamic high frequency service bid. This assumes that the battery is sufficiently sized; the limit can be exceeded due to insufficient storage, so that the respective service is unavailable for that SP. Therefore, to prevent failure to provide the FFR services, the battery can only be charged or discharged if it does not prevent the bid FFR services from being provided. To do this, charge available is calculated below (when both FFR services are provided in this example) in Equation 3.21.

$$E_{charge\,avail} = (E_{capac} \cdot (SoC_{max} - SoC)) - 0.5 \cdot P_{bid\,dynamic} \tag{3.21}$$

And discharge available is calculated as below (when both FFR services are provided in this example) in Equation 3.22 below.

$$E_{disch\,avail} = (E_{capac} \cdot (SoC - SoC_{min})) - 0.5 \cdot P_{bid\,static} - 0.5 \cdot P_{bid\,dynamic} \tag{3.22}$$

Note that battery charge, discharge efficiencies, and DC-AC conversion efficiencies are included in all relevant model calculations, but they are removed from the equations in this section for the sake of readability. As bids and mismatch are both calculated in MW, conversion from MW to MWh is required in the simulation, so power is divided by two as a result (because of the half-hour time step).

Then battery charge and discharge are calculated, noting that the battery is assumed to responds instantly to charging or discharging requests. For a positive value of $P_{MM\,p\,rate}$, and using battery strategy one, the battery is charged till charge available equals zero, and any remaining mismatch, $E_{sell\,curtail}$, is sold in the balancing market, unless balancing market price is negative, in which case it is curtailed. Using battery strategy two, balancing market sales are prioritised. If $P_{MM\,p\,rate}$ exceeds charge available, then charge is calculated as follows as in Equation 3.23.

$$E_{charge} = E_{charge\,avail} \tag{3.23}$$

And here remaining mismatch is calculated as follows, in Equation 3.24.

$$E_{sell\,curtail} = (0.5 \cdot P_{MM\,p\,rate}) - E_{charge\,avail} \tag{3.24}$$

Otherwise, charge equals mismatch after power rate limits, as in Equation 3.25.

$$E_{charge} = 0.5 \cdot P_{MM\,p\,rate} \tag{3.25}$$

For a negative value of $P_{MM\,p\,rate}$ the battery is discharged until discharge available equals zero, then any remaining mismatch is purchased in the balancing market. If $P_{MM\,p\,rate}$ is lower than discharge available, then discharge is calculated as follows in Equation 3.26.

$$E_{disch} = E_{disch\,avail} \tag{3.26}$$

And here remaining mismatch is calculated as follows, in Equation 3.27.

$$E_{buy} = (0.5 \cdot P_{MM\,p\,rate}) + E_{disch\,avail} \tag{3.27}$$

Otherwise, discharge equals mismatch after power rate limits, as in Equation 3.28.

$$E_{disch} = 0.5 \cdot P_{MM\,p\,rate} \tag{3.28}$$

During a BS event, the wind turbine-battery site is disconnected from the grid; it is assumed that wind turbine braking (and curtailment) occurs immediately, where wind turbines brake using built-in batteries, with negligible braking energy. The wind turbine is then assumed to restart instantly, because time for the battery to start-up a wind turbine is negligible compared to the study's half-hour temporal resolution. In addition, power cannot be pulled from the grid, so any power pulled is load not met. At the end of each time step, the model calculates the number of battery cycles that have occurred, with battery cycle degradation calculated depending on depth of discharge. Note that the number of battery cycles completed in each time step can be, and often is, less than one. Table 3.5 below is used as a basis for the model of the LiFePO4 battery.

Table 3.5: Effect of depth of discharge on number of discharge cycles for a LiFePO4 battery (Battery University, 2020a).

Depth of discharge (%)	**LiFePO4 discharge cycles (-)**
100	600
80	900
60	1500
40	3000
20	9000
10	15000

Table 3.5 is interpreted in the model via a scaling factor for number of battery discharge cycles, f_{cycles}, as indicated in Table 3.6 below.

Table 3.6: Relationship between battery SoC and cycle scaling factor used in the model.

SoC (-)	f_{cycles} (-)
0.95	1
0.85	1
0.75	1.67
0.60	5
0.40	10
0.20	16.67
0.02	25

This means that deeper discharge cycles are counted correctly, based on the battery SoC. Note that in this study $SoC_{max} - SoC_{min}$ is considered to be 100% depth of discharge. To calculate battery cycles completed in the first time step (where there is no previous value of battery cycles completed), Equation 3.29 is used.

$$Cycles = \frac{f_{cycles} \cdot -1 \cdot E_{disch}}{(E_{capac} \cdot (SoC_{max} - SoC_{min})} \tag{3.29}$$

Subsequent calculations of completed battery cycles are done using Equation 3.30, which cumulatively adds the previous number of cycles completed.

$$Cycles = \frac{f_{cycles} \cdot -1 \cdot E_{disch}}{E_{capac} \cdot (SoC_{max} - SoC_{min})} + Cycles(i-1) \tag{3.30}$$

If instead battery sizing, E_{capac} equals zero, as can be set in the parameters E_{crank} and E_{extra}, then no battery calculations are needed; the balancing market handles generation-load mismatch, except for negative prices, when curtailment occurs.

3.1.7 System performance assessment block

This model block calculates BS availability, FFR static secondary and dynamic high frequency service availability, IRR and LCOE.

To carry out the BS availability assessment, BS availability is calculated in each half-hour SP, $Avail_{BS}$, and then total BS availability fraction is calculated for the simulation.

First, Equation 3.31 is used to calculate if sufficient is energy available in each SP, where $E_{disch\,avail\,SP\,end}$ is battery discharge available at the end of each SP.

$$P_{WF} + \frac{1}{t_{BS}} \cdot E_{disch\,avail\,SP\,end} \geq E_{BS} \tag{3.31}$$

For a BS to be considered available in a SP, energy must be available for that SP and the following 19 SPs. Total BS availability fraction is calculated using Equation 3.32.

$$f_{avail\,BS} = \frac{\sum_{t=1}^{17520} Avail_{BS\,t}}{17520} \tag{3.32}$$

Where 17520 refers to the maximum number of half-hour SPs in the simulation. If $f_{avail\,BS}$ is greater than 0.90, the BS service can be provided. FFR static secondary and dynamic high frequency service availability for each SP, $Avail_{FFR\,static\,t}$ and $Avail_{FFR\,dynamic\,t}$ respectively, is assessed by checks of charge and discharge available, as in Section 3.1.6. Equations 3.33 and 3.34 are used to assess the fraction of FFR static secondary and dynamic high frequency service availability for the whole simulation, respectively.

$$f_{avail\,FFR\,static} = \frac{\sum_{t=1}^{17520} Avail_{FFR\,static\,t}}{17520} \tag{3.33}$$

$$f_{avail\,FFR\,dynamic} = \frac{\sum_{t=1}^{17520} Avail_{FFR\,dynamic\,t}}{17520} \tag{3.34}$$

To calculate IRR and LCOE, several parameters are required, including project lifetime, t_{proj}, operational time, t_{oper}, WACC, wind turbine costs and battery costs. Then to calculate IRR results for each composition, the value of IRR is iteratively changed using Equation 3.35 below until net present value, NPV, equals zero.

$$NPV = \sum_{t=1}^{t_{proj}} \frac{Cashflow_t}{(1+IRR)^{t-1}} \tag{3.35}$$

To calculate $Cashflow_t$ in IRR, two different Equations are used. In year one (project start till one year later), annual cashflow is calculated using Equation 3.36.

$$Cashflow_1 = -(C_{WF\,capital} + C_{batt\,capital}) \tag{3.36}$$

Where:
$C_{WF\,capital}$ = Total wind farm capital cost
$C_{batt\,capital}$ = Total battery capital cost

Here no revenue is generated, as the project is being installed. In year two, cashflow equals zero. From the year three, annual cashflow is calculated using Equation 3.37 below.

$$Cashflow_{(1+t_{proj}-t_{oper})-t_{proj}} = Revenue - (C_{WF\,ann\,O\&M} + C_{batt\,ann\,O\&M}) \tag{3.37}$$

Where:
$C_{WF\,ann\,O\&M}$ = Annual wind farm O&M cost
$C_{batt\,ann\,O\&M}$ = Annual battery O&M cost

Here, the wind farm-battery system has finished being installed and is generating both O&M costs, $C_{WF\,ann\,O\&M}$ and $C_{batt\,ann\,O\&M}$, given later, as well as revenue. First, $Revenue$ in Equation 3.37, which refers to total annual revenue, is calculated using Equation 3.38 below.

$$Revenue = R_{BS} + R_{static\,avail} + R_{static\,energy} + R_{dynamic\,avail} + R_{dynamic\,energy} + R_{DA} + R_{BA} \tag{3.38}$$

Inputs to Equation 3.38 are then given. In Equation 3.39 below the revenue from BS service provision is calculated.

$$R_{BS} = f_{avail\,BS} \cdot Price_{BS} \cdot P_{BS} \tag{3.39}$$

Where $Price_{BS}$ = Price paid for BS provision
Service availability isn't included for calculating revenue of the FFR static secondary and dynamic high frequency services, because if availability of a FFR service is less than 100%, it cannot be provided. In Equation 3.40 the revenue from providing an FFR static secondary service is calculated. Note that a factor of 0.5 is used to convert MW to MWh in Equations 3.40, 3.41, 3.42, 3.43 and 3.44.

$$R_{static\,avail} = \sum_{t=1}^{17520} 0.5 \cdot Price_{static\,t} \cdot P_{bid\,static} \tag{3.40}$$

Where $Price_{static\,t}$ = Price for availability of the FFR static secondary service in each SP
Then in Equation 3.41, revenue from selling energy in the balancing market due to the provision of the FFR static secondary service is calculated.

$$R_{static\,energy} = \sum_{t=1}^{17520} 0.5 \cdot 1.25 \cdot Price_{BA\,t} \cdot P_{FFR\,static\,t} \tag{3.41}$$

Where $Price_{BA\,t}$ = Balancing market price during each SP
Below in Equation 3.42, the revenue from providing a FFR dynamic high frequency service is calculated.

$$R_{dynamic\,avail} = \sum_{t=1}^{17520} 0.5 \cdot Price_{dynamic\,t} \cdot P_{bid\,dynamic} \tag{3.42}$$

Where $Price_{dynamic\,t}$ = FFR dynamic high frequency service price during each SP
Again, for the FFR dynamic high frequency service, energy can be both supplied and stored, with a respective balancing market price modifier of 1.25 and 0.75 applied. This means revenue for providing the FFR dynamic high frequency service can be negative. Revenue from the FFR dynamic high frequency service is calculated using Equation 3.43.

$$R_{dynamic\,energy} = \sum_{t=1}^{17520} 0.5 \cdot Price_{BA\,t} \cdot (1.25 \cdot P_{dynamic\,pos\,t} + 0.75 \cdot P_{dynamic\,neg\,t}) \tag{3.43}$$

Revenue for selling energy in the day-ahead market is calculated below in Equation 3.44.

$$R_{DA} = \sum_{t=1}^{17520} 0.5 \cdot Price_{DA\,t} \cdot P_{DA\,bid\,t} \tag{3.44}$$

Where $Price_{DA\,t}$ = Price of electricity in the day-ahead market during each SP.
Equation 3.45 below calculates balancing market revenue (accounting for balancing market costs).

$$R_{BA} = \sum_{t=1}^{17520} Price_{BA\,t} \cdot (E_{sold\,BA\,t} + E_{bought\,BA\,t}) \tag{3.45}$$

In Equations 3.36 and 3.37, inputs of $C_{WF\,capital}$, $C_{batt\,capital}$, $C_{WF\,ann\,O\&M}$ and $C_{batt\,ann\,O\&M}$ were used. The cost calculations of the wind-farm battery system are now shown. Annual operational cost of the wind farm, due to O&M costs, is calculated using Equation 3.46.

$$C_{WF\,ann\,O\&M} = N_{WT} \cdot P_{WT\,rated} \cdot \frac{C_{WF\,O\&M\,tot\,MW}}{t_{oper}} \tag{3.46}$$

Where $P_{WT\,rated}$ = Rated power of the wind turbine model
Note that the annual operation cost of the wind farm is assumed to be the same each year. The output of 3.46 is used as an input to prior IRR related Equation 3.37. Capital expenditure for the wind farm is calculated as follows in Equation 3.47.

$$C_{WF\,capital} = N_{WT} \cdot P_{WT\,rated} \cdot (C_{purch\,MW} + C_{install\,commiss\,MW} + C_{land\,MW} + C_{proj\,dev\,manag\,MW} + C_{decomm\,MW} + C_{BOP\,MW} + C_{other\,MW} + C_{transm\,assets\,MW}) \tag{3.47}$$

The output of Equation 3.47 is used as input to prior IRR related Equation 3.36. Then, cost inputs for the battery are calculated. The number of battery sets (where a single set refers to batteries of total capacity E_{capac}) required due to cycle life replacement is calculated in Equation 3.48 below, based on the number of battery cycles that are completed each year.

$$n_{batts\,requ} = \frac{Cycles_{total}}{15000} \cdot t_{oper} \tag{3.48}$$

In this way, for every 15000 cycles completed in the project life, an additional battery set of capacity E_{capac} is required. However, the minimum value for number of batteries required equals project operational life divided by the battery shelf life, which is assumed to be unaffected by number of completed discharge cycles; therefore the higher value of number of batteries required is used. Annual operational cost of the battery storage is calculated using Equation 3.49.

$$C_{batt\,ann\,O\&M} = E_{capac} \cdot 1 \cdot C_{batt\,ann\,O\&M\,MW} \tag{3.49}$$

The value of annual operation cost of battery storage is assumed to the same each year. The output of Equation 3.49 is used in prior IRR related Equation 3.37. Total capital investment in the battery storage (given an energy to power ratio of one) is calculated in Equation 3.50 and then used as input to LCOE and IRR.

$$C_{batt\,capital} = E_{capac} \cdot n_{batts\,requ} \cdot ((1 \cdot C_{batt\,capital\,MW}) + C_{batt\,capital\,MWh}) \tag{3.50}$$

The output of Equation 3.50 is used in prior IRR related Equation 3.36. At this point, all IRR and LCOE inputs have been given. To calculate LCOE, Equation 3.51 is used.

$$LCOE = \frac{C_{WF\,capital} + C_{batt\,capital} + \sum_{t=1+t_{proj}-t_{oper}}^{t_{proj}} \frac{C_{WF\,ann\,O\&M} + C_{batt\,ann\,O\&M}}{(1+WACC)^{t-1}}}{\sum_{1+t_{proj}-t_{oper}}^{t_{proj}} \frac{0.5\cdot(P_{load}+P_{unmet})+E_{sold\,BA}+E_{bought\,BA}}{(1+WACC)^{t-1}}} \tag{3.51}$$

The numerators used in the LCOE equation consist of capital investment costs for the wind farm and battery in year one (and hence they are not discounted) and then O&M costs for the wind farm and battery, which are calculated in prior Equations 3.47, 3.50, 3.46 and 3.49 respectively, and then discounted by the WACC. The denominator in the LCOE calculation equals total energy produced during the lifetime of the wind farm-battery system, consisting of the load before mismatch, (negative) load unsupplied (where a factor of 0.5 converts MW to MWh), energy sold on the balancing market and (negative) energy bought on the balancing market, and this is then discounted. Note that this assumes the energy utilised is constant each year.

3.2 Model validation

In this section, validation of the model is carried out by comparing expected model output against actual model output, for regular and irregular operational inputs. As stated in the scope, the model is not validated against the real world, or other models. Model blocks explained in this chapter are very integrated, making it is easier to assess multiple blocks at the same time. The model validation is given in the bullet points below:

- **Checking relationship between N_{WT}, P_{WT} and P_{WF}:** For N_{WT} equals 1, P_{WT} and P_{WF} stay within the range 0 - 8 MW as expected. For N_{WT} equals 100, P_{WF} stays within the range 0 - 800 MW, again as expected.

- **Checking response of system to battery capacity:** If E_{crank} equals zero, then provided E_{capac} has no extra capacity, E_{capac} equals zero. The model works regardless of battery selection, although a battery is always used to make BS and FFR service provision possible.

- **Checking response of FFR loads and availability fractions to zero FFR bids:** If bids in FFR for static secondary, dynamic high frequency are zero respectively, the model correctly gives load for FFR static secondary and FFR dynamic high frequency services as both zero respectively, and FFR availability fractions as both zero respectively.

- **Checking that BS availability value is correct:** For BS availability to be assessed as one for a SP, P_{WF} for that SP and the next 9.5 hours (19 SPs), plus 10% of the Discharge available at the end of each SP, must be at least equal to black start energy required, given by Equation 3.2. Total BS availability is the sum of the SP values divided by time. The BS availability assessment is working, as seen in Figure 3.2.

```
Load scenario:     2

Wind year:     1

Number of WT:     1

Battery capacity (MWh):  300.0332

Black start bid (MW):    20

Scenario 2 = BS Assess only
BS availability fraction:     1
```

Figure 3.2: Correct operation of BS availability assessment.

If storage is reduced to 100 MWh, which with one wind turbine is insufficient to provide a BS capability (must reliably have 200 MWh available in total for a BS), BS availability fraction equals 0, as expected.

- **Checking mismatch and battery operation:** Evidence that the mismatch and battery operation work correctly is shown. First, the stacked provision is shown, with regular inputs, to demonstrate battery charging and discharging due to mismatch, in Figures 3.3, 3.4 and 3.5.

```
Load scenario:     6

Wind year:     1

Number of WT:     1

Battery capacity (MWh):   10.0332

Black start bid (MW):    20

FFR static bid (MW):     1     1     1     1     1     1

FFR dynamic HF bid (MW):     1     1     1     1     1     1

Fraction of wind generation bid on DA market, f_DA_bid:    0.5000

Battery strategy used in DA market:     1

Scenario 6 = BS + FFR static + FFR dynamic + Grid bidding
BS availability fraction:     0

FFR static availability fraction:     1

FFR dynamic availability fraction:     1

Lifetime WF cost (£):   7.6646e+06

Lifetime battery cost (£):   2.3418e+07

Lifetime energy utilised by system (MWh):   8.1268e+05

LCOE (£/MWh) equals:   38.2471

Elapsed time is 41.177604 seconds.
```

Figure 3.3: Options and outputs, shown to validate standard operation.

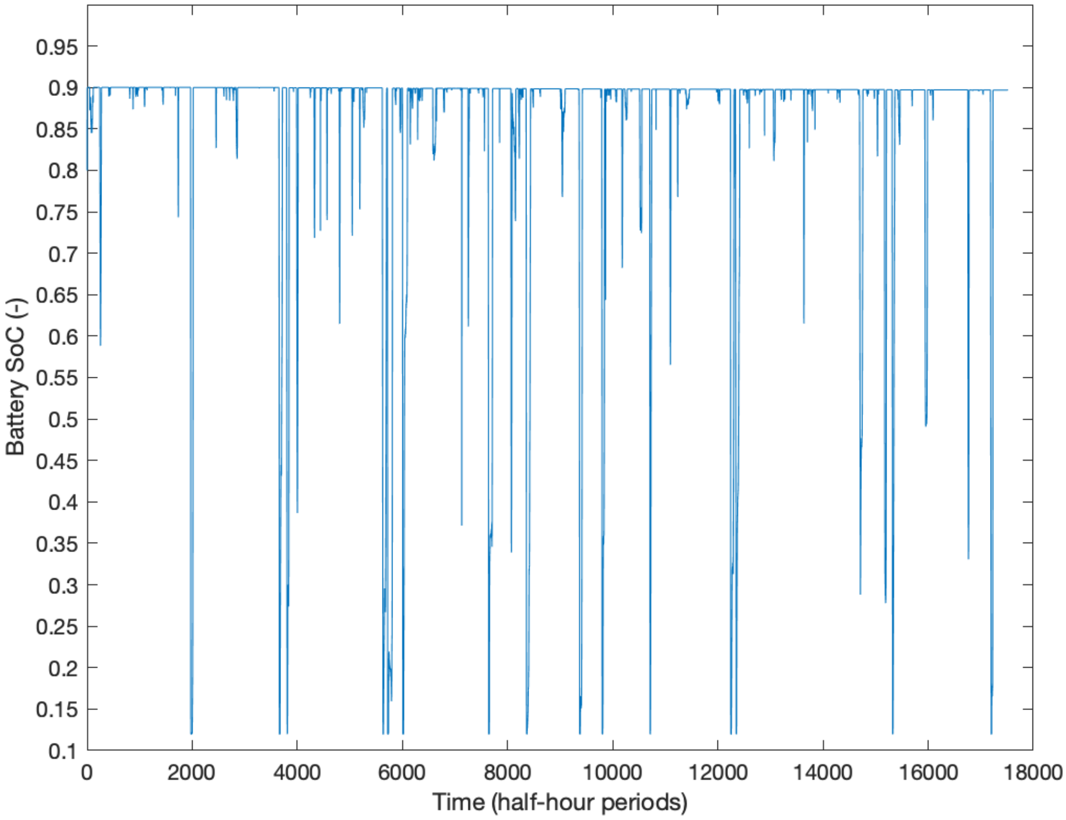

Figure 3.4: Battery SoC shown to validate standard operation.

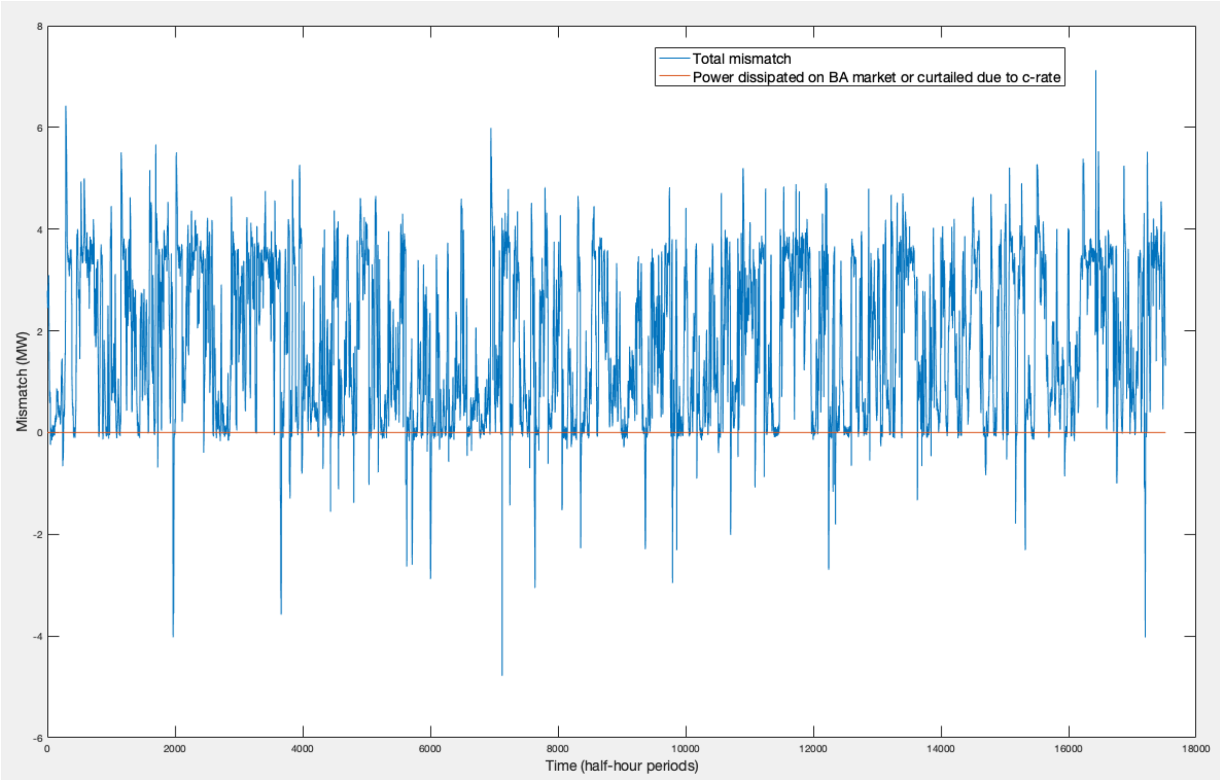

Figure 3.5: Mismatch is small here, so doesn't exceed c-rate limit.

If instead the wind farm is massively oversized, with 100 wind turbines but otherwise the same setup, it can be seen that excess power is removed in Figures 3.6 and 3.7 below.

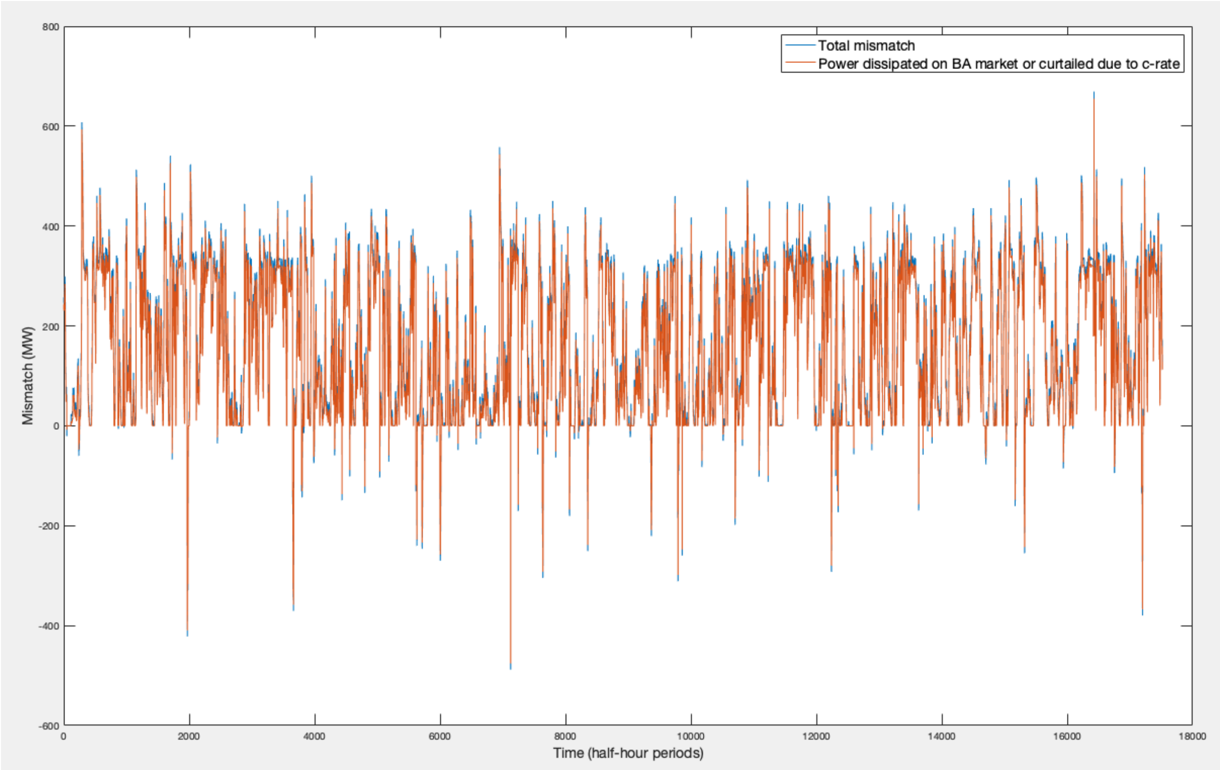

Figure 3.6: Mismatch and power dissipated in balancing market or curtailed for 100 wind turbines, due to battery c-rate limit.

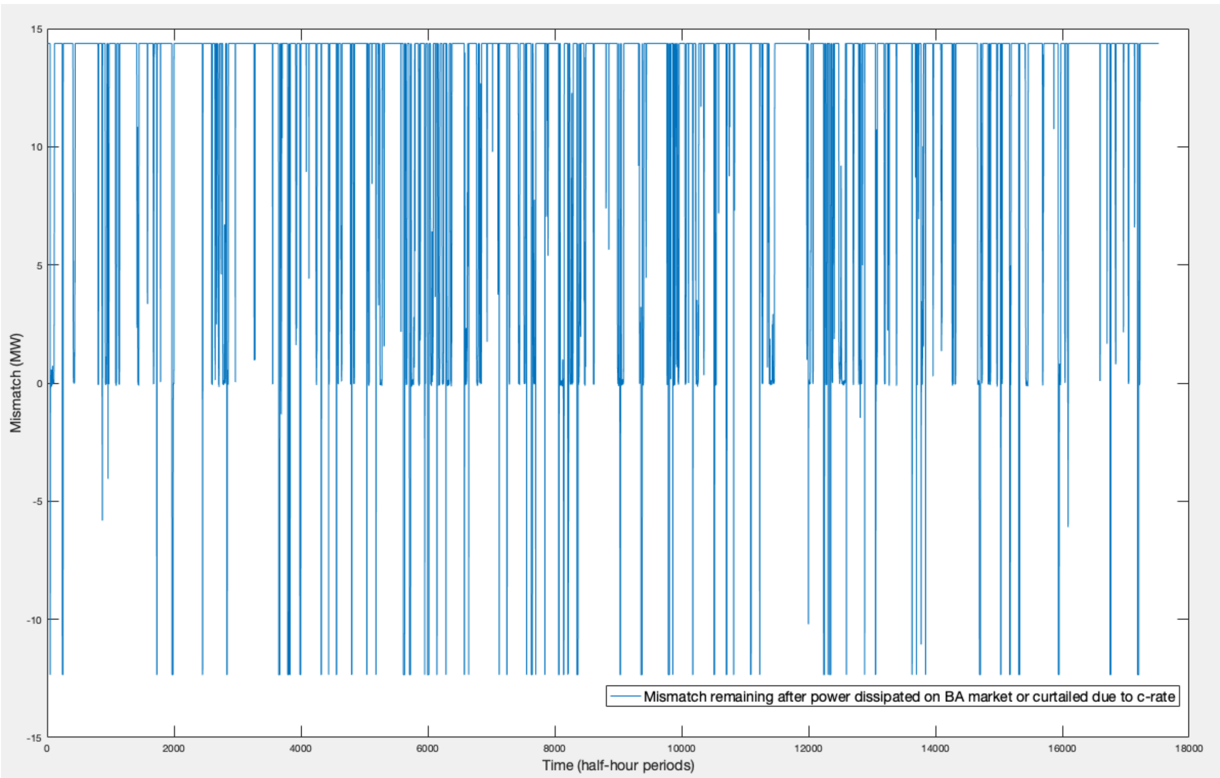

Figure 3.7: Mismatch remaining for 100 wind turbines, which will be assessed against available battery charge, discharge.

Now it is shown in Figure 3.8 that if load equals zero, i.e. for scenario two, then battery SoC becomes maximum and stays there, aside from passive discharging with time.

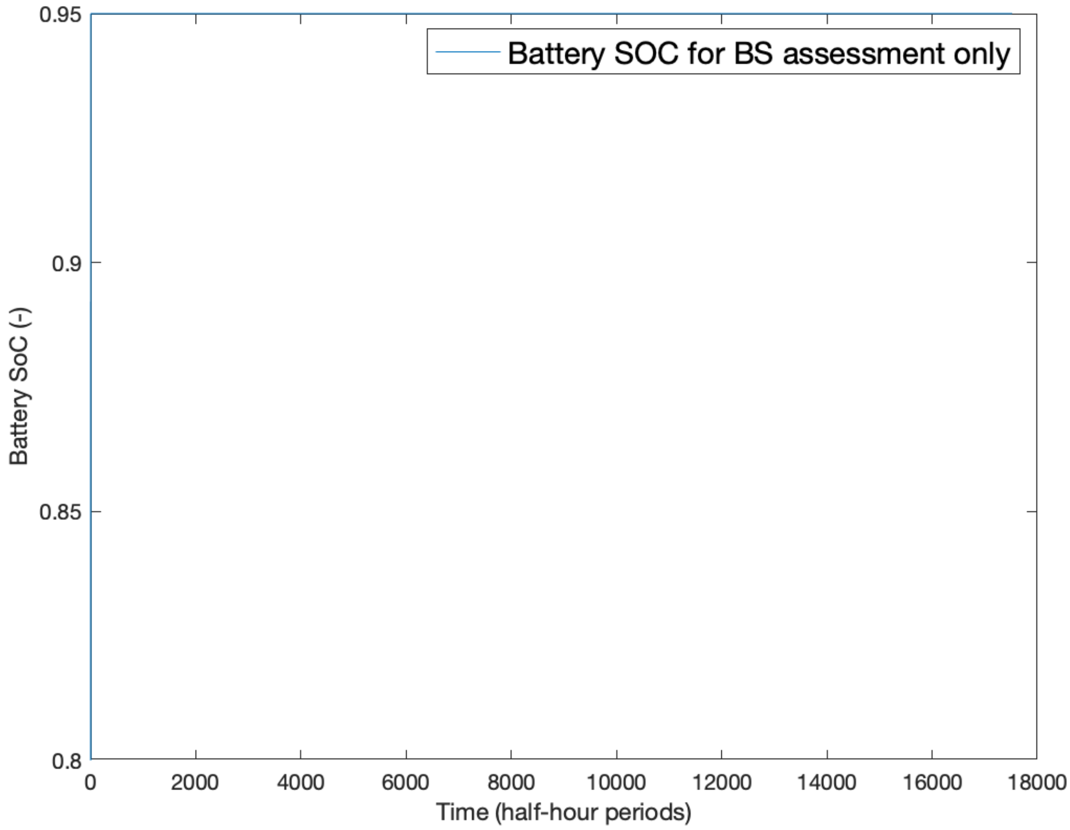

Figure 3.8: SoC for load scenario two; doesn't decrease over time because load equals zero.

- **Showing that maximum SoC degradation and cycle counting work:** In Figure 3.9 below, the battery maximum SoC can be seen against number of cumulative battery cycles completed, showing that as the number of equivalent cycles increases, maximum SoC reduces. It can be seen after approximately 110 equivalent cycles, maximum SoC equals 0.9467, in accordance with a degradation rate of 0.00003 per cycle (degradation of the maximum SoC value).

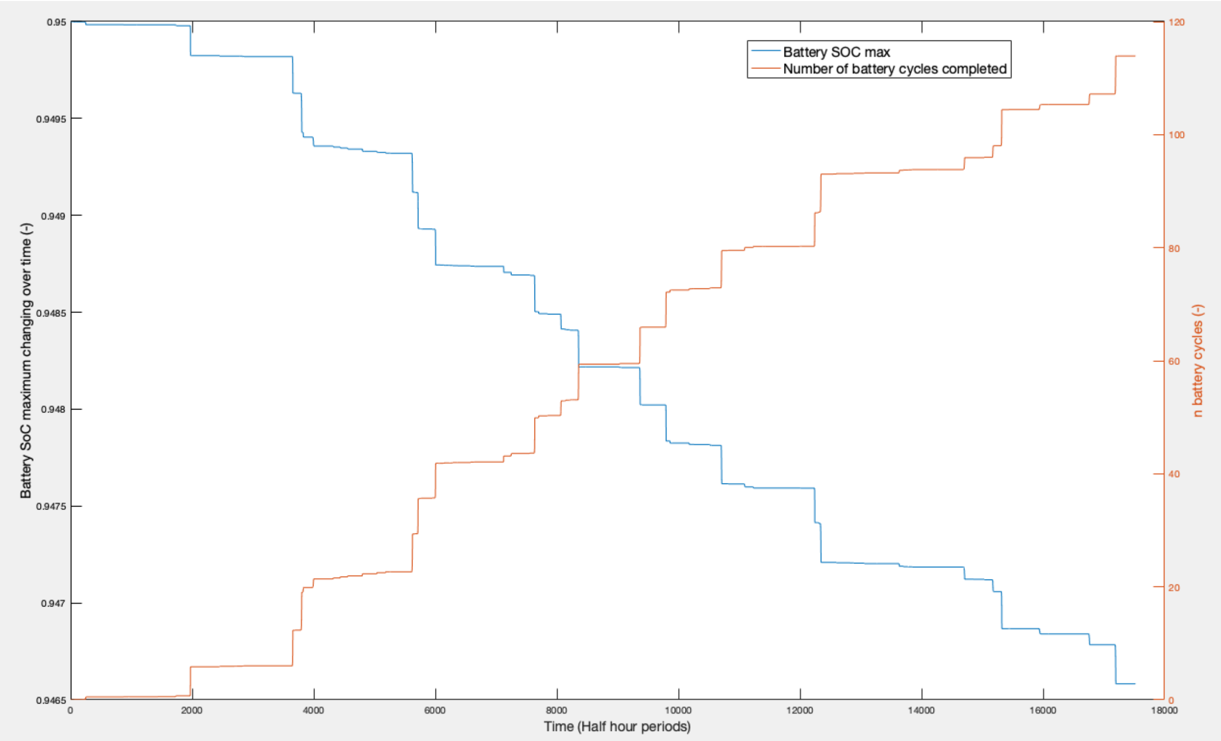

Figure 3.9: Showing degradation of maximum SoC, as number of completed battery cycles increases.

4 Baseline Case Study

This chapter describes the baseline case study implemented in the model in order to obtain results relevant to the study.

4.1 Wind farm case study elements

The wind turbine selected in this study is the Vestas V164 8 MW turbine, with specifications from wind-turbine-models.com (2015). This wind turbine was arbitrarily selected as an example of a utility scale turbine, located offshore due to ESO decarbonisation expectations discussed earlier in Figure 1.1. The wind turbine is shown operating below in Figure 4.1.

Figure 4.1: Vestas V164 8MW wind turbine (wind-turbine models.com, 2015).

Wind turbine specifications are given in Table 4.1 below.

Table 4.1: Wind turbine specifications (wind-turbine models.com, 2015).

$u_{cut\,in}$ **(m/s)**	u_{rated} **(m/s)**	$u_{cut\,out}$ **(m/s)**	h_{hub} **(m)**	r_{rot} **(m)**	$P_{WT\,rated}$ **(MW)**
3	13	25	110	82	8

The wind turbine power curve is shown in Figure 4.2.

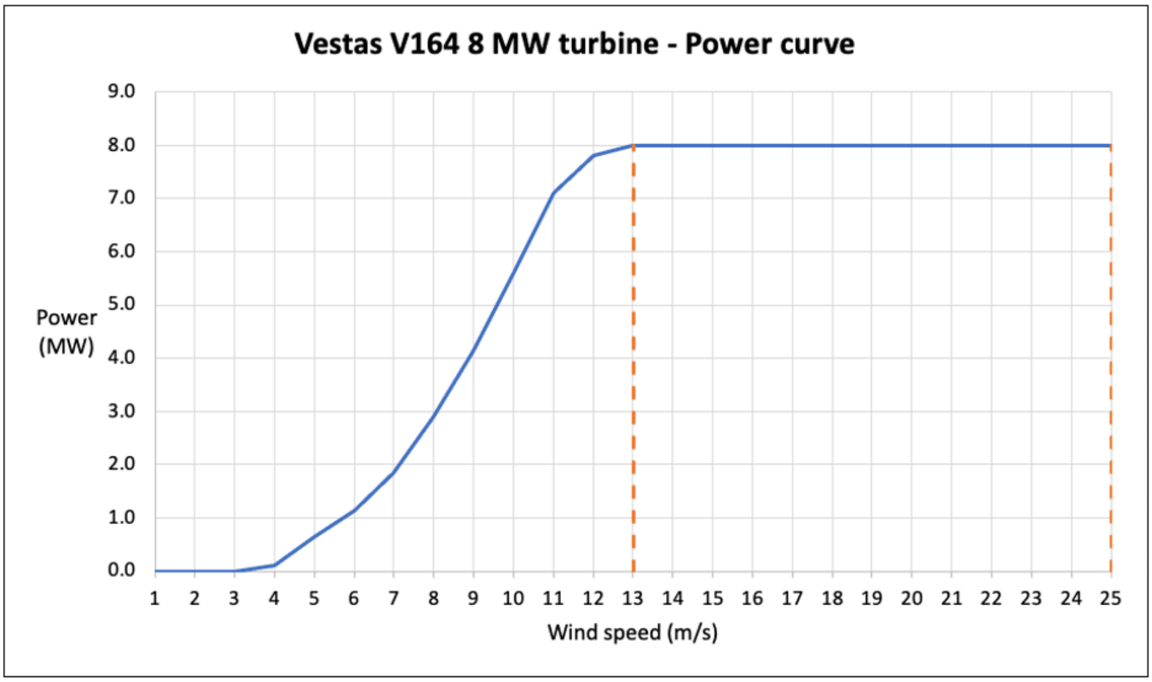

Figure 4.2: Power curve for Vestas V164 wind turbine (wind-turbine models.com, 2015).

For this wind turbine, cranking energy, E_{crank} was calculated as 0.0166 MWh, which is the amount of energy that must be stored in the battery, per wind turbine, in order for a BS to be possible in terms of auxiliary unit availability with three restarts. Cranking energy is calculated using Equation 4.1 below.

$$E_{crank} = E_{pitch} + E_{yaw} \tag{4.1}$$

Here, E_{pitch} is energy to be stored for the pitch mechanism in the event of a BS, and E_{yaw} is energy to be stored for the yaw mechanism in the event of a BS. Values used to calculate E_{pitch} and E_{yaw} are shown in Tables 4.2 and 4.3 respectively.

Table 4.2: Pitch energy per wind turbine.

$\dot{\theta}_{pitch}$ **(deg/s)**	θ_{pitch} **(deg)**	t_{pitch}**(h)**	P_{pitch} **(MW)**	E_{pitch} **(MWh)**
0.5	40	0.067	0.0192	0.0013

The value of rate of pitch rotation, $\dot{\theta}_{pitch}$, used in Table 4.2 was chosen based on the yaw rate sourced from Kim and Dalhoff (Kim and Dalhoff, 2014). The degrees of pitch rotation required, θ_{pitch}, is selected based on a realistic maximum amount of pitch change per for the three restarts. t_{pitch} is the time required to operate the pitching mechanism per restart. The value of P_{pitch} is calculated based on scaling up a general electric brand pitch motor used for a 2.5 MW wind turbine (Spares in motion, 2021).

Table 4.3: Yaw energy per wind turbine (Kim and Dalhoff, 2014).

$\dot{\theta}_{yaw}$ **(deg/s)**	θ_{yaw} **(deg)**	t_{yaw} **(h)**	P_{yaw} **(MW)**	E_{yaw} **(MWh)**
0.5	360	0.60	0.0255	0.0153

The value of rate of yaw rotation, $\dot{\theta}_{yaw}$, used in Table 4.3 is from literature by Dalhoff (Kim and Dalhoff, 2014). The degrees of yaw rotation required, θ_{yaw} is selected based on a maximum possible amount of yaw change per restart. t_{yaw} is the time required to operate the yaw mechanism for the three restarts. The value of P_{yaw} is found by extrapolating values from the Siemens D3 3MW and D7 7MW wind turbines, which use yaw systems requiring 0.018 MW and 0.024 MW respectively (Smalley, 2015). Pitch energy and yaw energy are calculated using Equations 4.2 and 4.3 below.

$$E_{pitch} = t_{pitch} \cdot P_{pitch} \tag{4.2}$$

$$E_{yaw} = t_{yaw} \cdot P_{yaw} \tag{4.3}$$

t_{pitch} and t_{yaw} are calculated below in Equations 4.4 and 4.5.

$$t_{pitch} = \theta_{pitch} \cdot \dot{\theta}_{pitch} \cdot 3 \cdot \frac{1}{3600} \tag{4.4}$$

$$t_{pitch} = \theta_{yaw} \cdot \dot{\theta}_{yaw} \cdot 3 \cdot \frac{1}{3600} \tag{4.5}$$

To choose a wind farm site, existing GW scale offshore wind farms in the UK were explored. The Walney wind farm, in the Irish Sea, was chosen as the site for this case study, and can be seen in Figure 4.3.

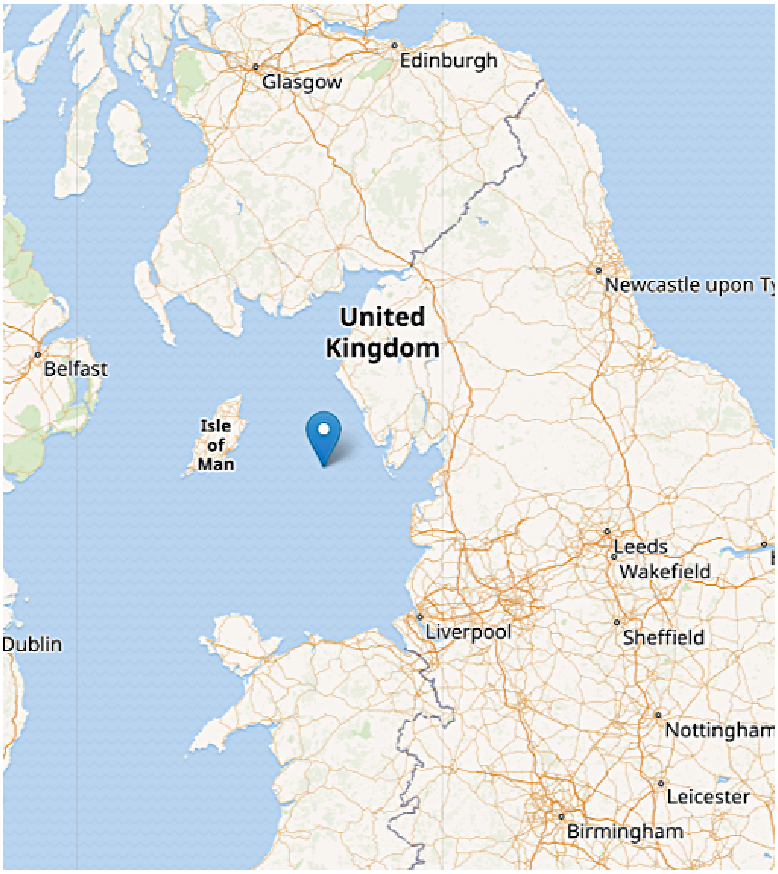

Figure 4.3: Walney wind farm location.

The real world Walney wind farm plus Walney extension has an installed capacity of 1.026 GW, large enough to use for this case study. This location was deemed appropriate for UK service provision as the onshore substation is only 23 km from the offshore wind farm site, in Lancaster, leading to minimal electrical transport losses. The Walney site is also reasonably suitable for BS provision, given that it is situated in a densely populated area near to the cities of Liverpool, Manchester, Sheffield and Leeds, and additionally, the onshore substation is located nearby 400 kV lines, ideal for transmission from the high capacity offshore wind farm during a BS event (National Grid, 2021). An alternative GW scale offshore wind farm location considered was Hornsea One, which has an installed capacity of 1.218 GW. As seen in Figure 4.4, this site is far further from shore than Walney, 120 km, leading to greater electrical transport losses (Ørsted, 2020).

Figure 4.4: Location of Hornsea One, an alternative GW scale wind farm site (Ørsted, 2020).

For the Walney site case study, wind and temperature data was obtained from Climate Data Store 'ERA5 hourly data on pressure levels from 1979 to present' re-analysis dataset from, with an hourly temporal resolution (Hersbach et al., 2018). Data from reanalysis combines model and actual weather data, and here, the original resolution is reduced to enable a larger dataset. Data is given for an air pressure that corresponds with a height above sea-level of 110.77m. The data for the case study has been inspected, with no anomolies identified, giving confidence to the user. According to C3S, a known issue with the dataset is a mismatch between the near surface wind speeds at the end of a 12 hour assimilation cycle, and at the start of the next, which occur at 0900 and 2100 hours; affecting lower latitudes and some parts of Europe. However, manually checking a sample of the data for the case study in the UK has shown this to not be a problem (C3S, 2021b). Wind speed for the year 2019 at Walney at the Vestas turbine hub height, is shown in Figure 4.5 below.

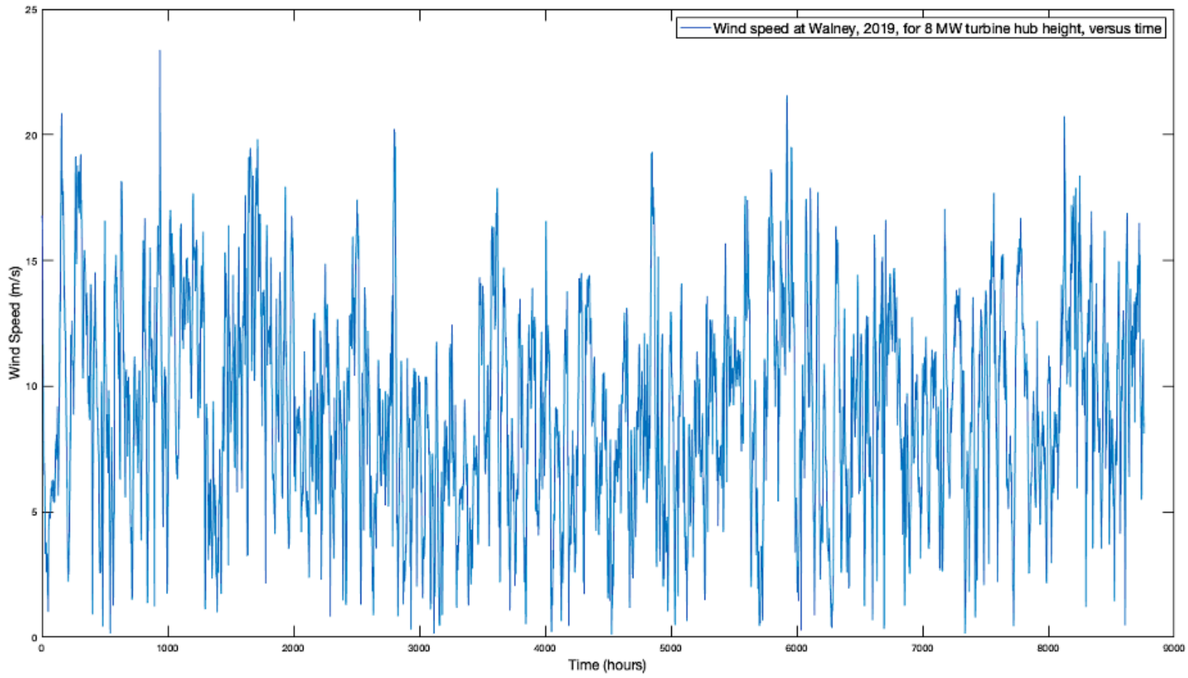

Figure 4.5: Wind speed at hub height using 2019 wind data from Walney (C3S, 2021b).

Other case study specifications used in the wind generation and temperature model block are given in Table 4.4 below.

Table 4.4: Wind generation and temperature block parameters for the case study (Hsu et al., 1994).

Parameter	**Value**
α	0.11
ρ	$1.225kg/m^3$
$\eta_{drivetrain}$	95%
f_{wake}	0.95
η_{B2B}	98%
$\eta_{transformer}$	97%
$\eta_{transport}$	97.5%

Here, the value of $\eta_{drivetrain}$ represents assumed efficiencies of the gearbox and generator, of 98% and 97% respectively (mpoweruk, 2005; Ukonsaari & Bennstedt, 2016). The value of f_{wake} assumes spacing of ten wind turbine rotor diameters, and a turbulence intensity of 8% (Manwell, McGowan, & Rogers, 2009; Bierbooms, n.d.). The value of $\eta_{transport}$ assumes an average transport distance of 100km from the offshore wind farm to a large population centre (Ackerman, Negra, Todorovic, & Lazaridis, 2005).

4.2 Battery case study elements

LiFePO4 battery behaviour specifications are given below in Table 4.5

Table 4.5: Battery setup block parameters for the case study (Battery University, 2020b, 2020d; BatteryStuff.com, 2012).

Parameter	Value
Energy to power ratio	1
$c\,rate_{max}$	1
$SoC_{max\,init}$	0.95
SoC_{min}	0.02
η_{charge}	97%
η_{disch}	97%
Shelf life	7 years

4.3 Financial assessment case study elements

In this section, IRR and LCOE inputs for the case study are given. First in Table 4.6, project related inputs for the baseline case study are given.

Table 4.6: Wind farm-battery project inputs for the baseline case study (GrantThornton, 2018; NS Energy, 2018).

Parameter	Value
Unlevered discount rate (WACC)	7.75%
Installation time	2 years
Operation time	25 years

The chosen unlevered discount rate is taken from Grant Thornton for the UK offshore wind market in 2017 (GrantThornton, 2018). The unlevered rate is used, because as stated in Section 2.3, it doesn't assume a certain capital structure of the wind farm - battery operator. An installation time of two years is used regardless of wind farm and/or battery sizing. According to NS Energy, the Walney extension offshore wind farm project has a life expectancy of 25 years; so a project operational life of 25 years is used in this study, meaning a total project life of 27 years (NS Energy, 2018). This means that battery replacements are required during the project, based on the previously stated assumption of a seven year shelf-life.

In Chapter 2.3 a generic list of wind turbine and battery costs was given; costs that remain unchanged are given again, supplemented with the costs that are case study specific (acknowledged with an asterisk), below in Table 4.7, and followed by their justification.

Table 4.7: Wind farm and battery cost inputs for the baseline case study (BVG Associates, 2019; NREL, 2019).

Cost section	**Cost component**	**Cost (m GBP/MW, unless stated)**
Wind farm init	$C_{purch\,MW}$	*0.700
Wind farm init	$C_{transm\,assets\,MW}$	*0.678
Wind farm init	$C_{land\,MW}$	*0.088
Wind farm init	$C_{install\,commiss\,MW}$	*0.564
Wind farm init	$C_{BOP\,MW}$	*0.324
Wind farm init	$C_{other\,MW}$	0.340
Wind farm init	$C_{decomm\,MW}$	0.325
Wind farm init	$C_{proj\,dev\,manag\,MW}$	0.120
Wind farm ann	$C_{WF\,O\&M\,tot\,MW}$	1.899
Battery init	$C_{batt\,capital\,MW}$	0.492
Battery init	$C_{batt\,capital\,MWh}$	0.151 (m GBP/MWh)
Battery ann	$C_{batt\,ann\,O\&M\,MW}$	0.019 (m GBP/MW.yr)

Wind turbine cost per MW is calculated using Vestas financial reports, which give 2020 Quarter 1, 2, 3, and average 2019 cost, with an overall average of 0.700 GBP million per MW (Vestas, 2020a, 2020b, 2020c).

For Walney specifically, transmission owner, Ofgem, paid 466.6 GBP million to the transmission asset developer, Ørsted (Ofgem, 2020a, 2020b). This includes engineering (planning, land development and project management), purchases and installation of the offshore assets with the assets counted as onshore and offshore substations and cables (Ofgem, 2020a). Transmission asset costs are calculated as $0.678\frac{mGBP}{MW}$ based on a 659 MW wind farm. The generic costs for installation and commissioning, and balance of plant, stated in Section 2.3, included elements of the transmission asset costs, and so the values in Table 4.7 above were modified accordingly so that the case study specific transmission asset costs could be included (BVG Associates, 2019).

The Walney Extension (659 MW, sized for up to 750 MW) and Walney 1 and 2 (totalling 367 MW) sites are leased from The Crown Estate, of areas 145 km^2 and 73 km^2 respectively (NS Energy, 2018). Lease cost in this study is calculated according to The Crown Estate's round 4 rules, for the new offshore wind farm tender, using Equation 4.6 (The Crown Estate, 2019).

$$C_{total\,lease} = AEP \cdot 0.80 \cdot 0.90 \cdot T_{project} \tag{4.6}$$

Where AEP equals Annual Energy Production (AEP) in MWh (The Crown Estate, 2019). The AEP is not calculated using the traditional method in this study, as 10-minute average wind speed data is not collected. Instead, for the Vestas V164 at Walney using 2019 wind data (which again has the average mean wind speed of the 20 years of data obtained for the case study), the sum of energy produced in one year by the wind turbine alone and by a wind turbine in the wind farm is calculated using the wind generation and temperature block of the model. This gives an energy production of 37344 MWh or 4668 MWh per MW for a wind turbine installed alone, and 35477 MWh or 4435 MWh per MW for a wind turbine installed in a wind farm. Therefore, where $T_{project}$ equals 27 years, total lease cost equals 86000 GBP/MW.

4.4 BS service case study elements

In the baseline case study used, P_{BS} equals 20 MW, and t_{BS} equals 10 hours. Therefore a generation block of 20 MW is provided during the BS test and assessed in regular operational mode, both with a 10 hour duration. For the 2019 year, $Price_{BS}$ equals 1222 £/MW.yr.

4.5 FFR service case study elements

In Table 4.8 below, the average successful FFR tender submissions in 2019 are given, for battery systems (ESO, 2020n). Where no battery units bid, an exception is made, and the average of all bids is used. The month stated in Table 4.8 refers to the month in which the service is provided, not when the tender was submitted. These FFR static secondary and dynamic high frequency availability prices are used for parameters $Price_{static\,t}$ and $Price_{dynamic\,t}$ in the model.

Table 4.8: Average prices in ESOs monthly FFR tenders for 2019 supply months (ESO, 2020n).

Provision month	Total tender	Average tendered prices for 1 MW		
		Availability	Nomination	Window initiation
	(MW)	(£/h)	(£/h)	(£/window)
Static secondary service				
Jan	361	1.59	0	0
Feb	129	1.1		
Mar	256	1.39		
Apr	171	3.125		
May	170	3.63		
Jun	170	3.9		
Jul	185	3.55		
Aug	193	3.61		
Sep	108	3.57		
Oct	385	3.85		
Nov	0	0		
Dec	0	0		
Dynamic high frequency service				
Jan	588	6.16	0	0
Feb	168	6.6		
Mar	225	7.51		
Apr	295	5.09		
May	290	6.06		
Jun	358	5.04		
Jul	351	4.15		
Aug	262	5.27		
Sep	394	6.28		
Oct	295	5.78		
Nov	654	14.3		
Dec	687	14.3		

Therefore, for months November and December 2019, $Price_{static\,t}$ equals zero, because no FFR static secondary service is required by the ESO. Based on Table 4.8, bids are set for the compositions; where the maximum bid is 108 MW and 168 MW for the FFR static secondary and dynamic high frequency services respectively.

In Tables 4.9 and 4.10 below, other case study parameters for the FFR static secondary and dynamic high frequency services, based on the service requirements, are given.

Table 4.9: FFR static secondary service parameters for the case study.

Parameter	Value
Zero-point frequency	50Hz
Trigger one	49.7 Hz
Trigger two	49.8 Hz
Response duration	1800 s

Again, for the FFR static secondary service, the trigger for setting one applies for 2300-0700 hours, and for setting two applies for 0700 - 2300 hours. These trigger values are acceptable as the ESO purchases services with a range of other frequency triggers.

Table 4.10: FFR dynamic high frequency parameters for the case study.

Parameter	Value
Response duration	indefinite

Historic UK grid frequency data with a temporal resolution of one second is available for the years 2014-2019 from the ESO (ESO, 2020i). In Figure 4.6 below, frequency data for 2019 is shown against the frequency triggers for the FFR static secondary and dynamic high frequency services.

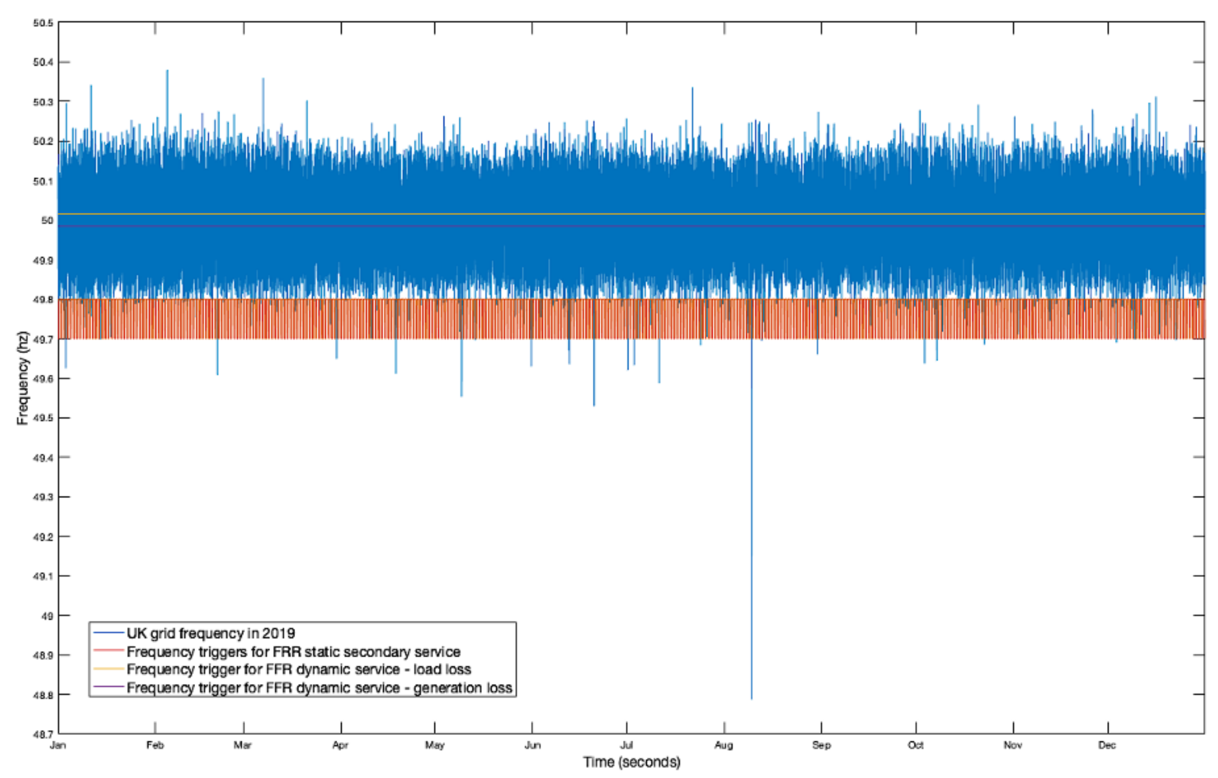

Figure 4.6: UK Grid frequency in 2019 alongside FFR static secondary and dynamic high frequency triggers (ESO, 2020i).

4.6 Day-ahead and balancing market case study elements

For the grid dispatch case study, market pricing was obtained in order to calculate cash flows in IRR. Hour resolution day-ahead market prices were available for the years 2014-2019, obtained from ENTSO-E, who are The European Network of Transmission System Operators for Electricity (ENTSO-E, 2020). Half-hour resolution balancing market prices were available for the years 2018-2019, obtained from Elexon, who deliver the UK balancing and settlement code provisions (bmreports.com, 2020). UK offshore wind generation day-ahead and current energy forecast information was available to a half-hour resolution for years 2019-2020 from Elexon's balancing mechanism data site, BMReports (bmreports.com, 2020). Below in Figure 4.7, day-ahead (UK offshore wind energy) forecast is shown alongside current (UK offshore wind energy) forecast for 2019.

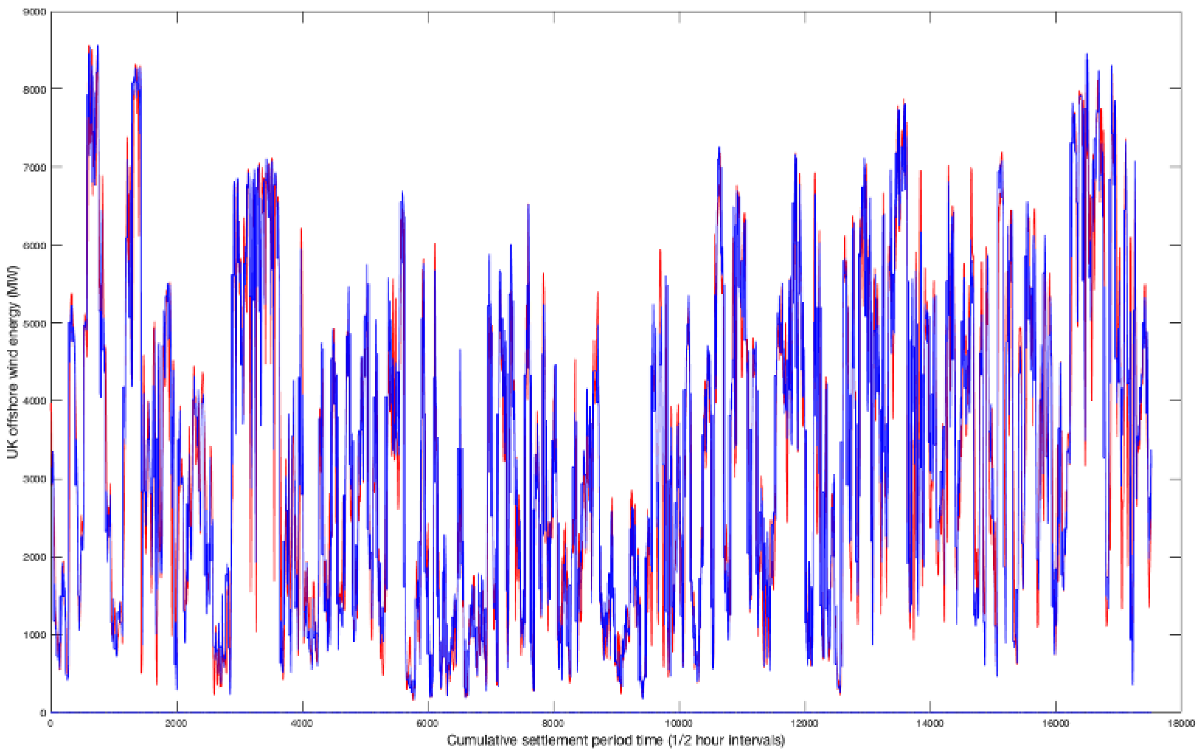

Figure 4.7: UK offshore wind energy day-ahead forecast in red, against current forecast in blue, for 2019 (bmreports.com, 2020).

Day-ahead market prices for 2019 are shown below in Figure 4.8.

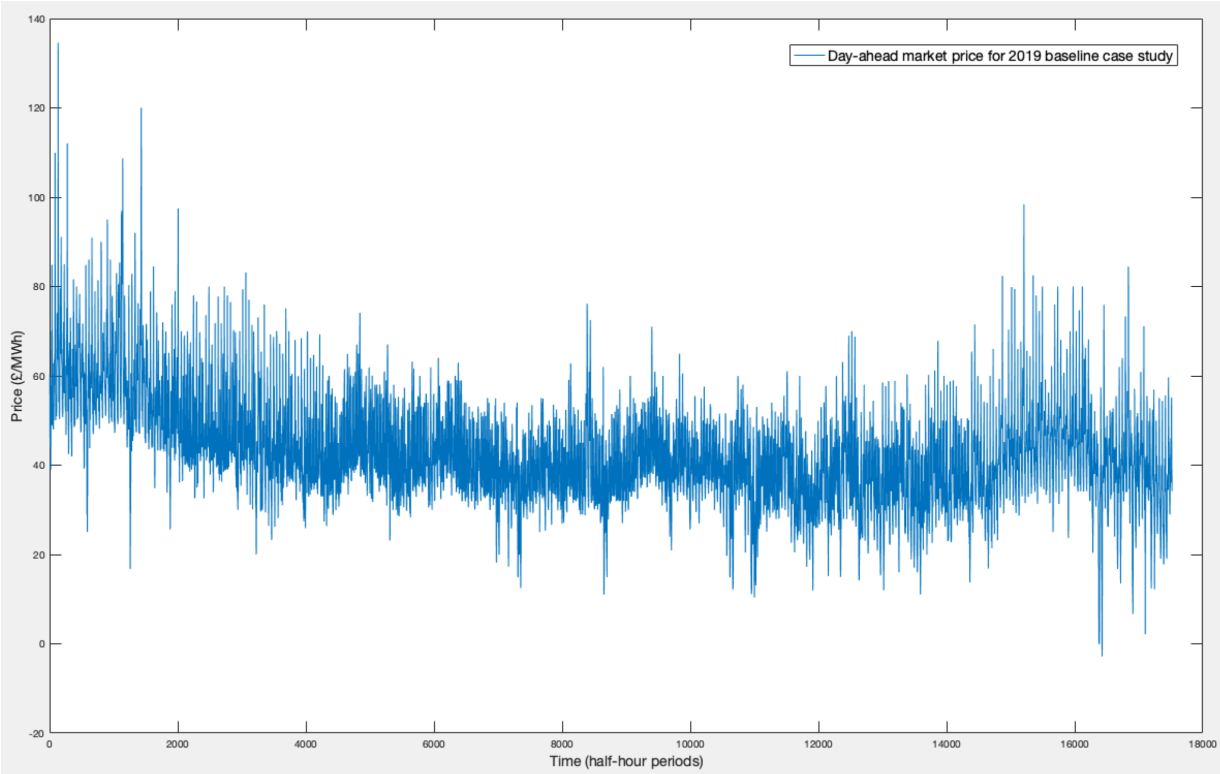

Figure 4.8: UK day-ahead electricity market buy/sell prices for each SP in 2019 (ENTSO-E, 2020).

Balancing market prices for 2019 are shown below in Figure 4.9.

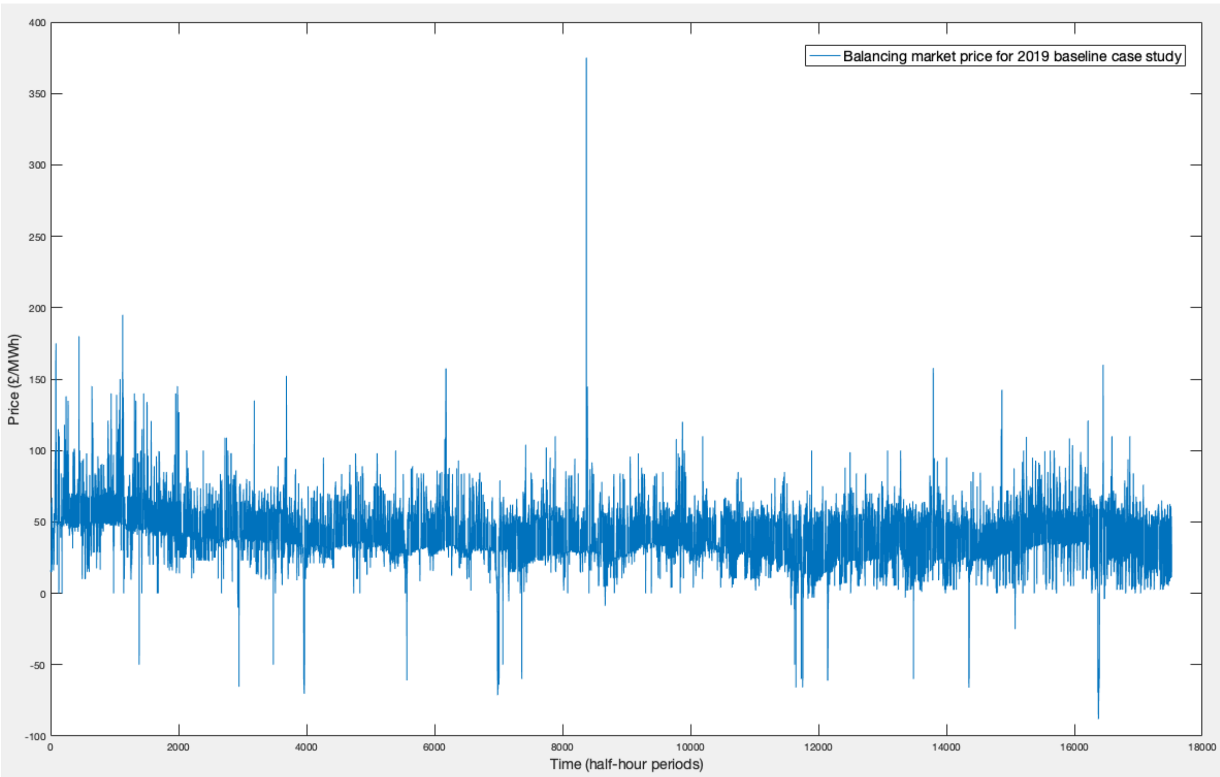

Figure 4.9: UK balancing market electricity buy/sell prices for each SP in 2019 (bmreports.com, 2020).

4.7 Input data synchronisation

In this study, the year 2019 was selected as the case study year; due to availability of data for all inputs, although 10 minute average resolution wind data for Walney would have been preferable.

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5 Baseline Case Study Results and Discussion

In this chapter, the results table for the baseline case study is shown and explained, with details given on how the results are achieved by the simulations. Then results from the baseline case study are discussed. Individual service and market provision results are discussed first, in the order of: day-ahead market only, BS service only, FFR static secondary service only and the FFR dynamic high frequency service only. These results are followed by stacked service and market results, in the order of: BS service plus day-ahead market bidding, BS service plus FFR static secondary service, BS service plus FFR dynamic high frequency service, BS plus both FFR static secondary and FFR dynamic high frequency services, the FFR static secondary and FFR dynamic high frequency services stacked without the BS service, and finally, both FFR services stacked alongside day-ahead market bidding. All results use the balancing market to handle mismatch, and that this is not considered stacking. This is done because providing a service without selling excess energy when convenient gives an unrealistic view of the financial potential of a service, using a business strategy that wouldn't be pursued in reality. This means that the balancing market is effectively the default mode of operation, requiring no foresight of wind energy production, service requirements etc.

5.1 Results table for baseline case study

Below in Table 5.1, the results in the baseline case study are shown.

Table 5.1: Key inputs and results for both individual and stacked services and markets.

					Sizing				Bid composition						Service avail						Capital investment		Ann cost			Balancing market				FFR static		FFR dynamic	
Case study	Identifier	Scen	Wind year	Frequ scen	N_WT	E_crank	E_extra	Initial SoC	P_BS	t_BS	FFR stat	FFR dyn	f day-ahead	Batt strat	BS	FFR stat	FFR dyn	E_capac	LCOE	Ann IRR	Wind farm	Battery	Wind farm	Battery	Total ann revenue	Ann revenue	Ann cost	Day-ahead market ann revenue	BS ann revenue	Ann avail revenue	Ann energy revenue/cost	Ann avail revenue	Ann energy revenue/cost
(-)	(-)	(-)	(-)	(-)	(Wind turbines)	(MWh)	(MWh)	(-)	(MW)	(h)	(MW)	(MW)	(-)	(-)	(-)	(-)	(-)	(MWh)	(£/MWh)	(%)	(M£)	(M£)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)
Baseline case study	BaDA1	5	1	1	1	0	0	0	0	0	0	0	1	0	-	-	-	0	93.8	-1.8	25.1	0	0.6	0	1.4	0.1	-0.1	1.4	0	0	0	0	0
	BaDA2	5	1	1	100	0	0	0	0	0	0	0	1	0	-	-	-	0	98.8	-2.4	2509.6	0	60.8	0	129.9	9.7	-10.7	130.8	0	0	0	0	0
	BaDA3	5	1	1	100	0	0	0	0	0	0	0	0.5	0	-	-	-	0	99.4	-2.5	2509.6	0	60.8	0	128.1	61.1	-1.2	68.2	0	0	0	0	0
	BaDA4	5	1	1	100	0	0	0	0	0	0	0	0	0	-	-	-	0	100.1	-2.6	2509.6	0	60.8	0	126.8	126.8	0	0	0	0	0	0	0
	BaDA5	5	1	1	100	0	6	0.95	0	0	0	0	1	1	-	-	-	6	99.2	-2.4	2509.6	15.4	60.8	0.1	129.8	9.6	-10.6	130.8	0	0	0	0	0
	BaDA6	5	1	1	100	0	6	0.95	0	0	0	0	1	2	-	-	-	6	99.2	-2.4	2509.6	15.4	60.8	0.1	129.8	9.6	-10.6	130.8	0	0	0	0	0
	BaDA7	5	1	1	100	0	10	0.95	0	0	0	0	1	1	-	-	-	10	99.6	-2.4	2509.6	25.7	60.8	0.2	129.8	9.5	-10.6	130.8	0	0	0	0	0
	BaDA8	5	1	1	100	0	20	0.95	0	0	0	0	1	1	-	-	-	20	100.5	-2.5	2509.6	51.4	60.8	0.4	129.7	9.4	-10.5	130.8	0	0	0	0	0
	BaDA9	5	1	1	100	0	20	0.95	0	0	0	0	1	2	-	-	-	20	100.5	-2.5	2509.6	51.4	60.8	0.4	129.8	9.5	-10.5	130.8	0	0	0	0	0
	BaDA10	5	1	1	100	0	40	0.95	0	0	0	0	1	1	-	-	-	40	102.3	-2.7	2509.6	102.9	60.8	0.8	129.7	9.2	-10.3	130.8	0	0	0	0	0
	BaDA11	5	1	1	100	0	6	0.95	0	0	0	0	0.5	1	-	-	-	6	99.2	-2.6	2509.6	15.4	60.8	0.1	127.2	60.2	-1.2	68.2	0	0	0	0	0
	BaBS1	2	1	1	100	0.0166	0	0.95	20	10	0	0	0	1	0.732	-	-	3	99.0	-2.8	2509.6	8.5	60.8	0.1	125.0	125.0	0	0	0.02	0	0	0	0
	BaBS2	2	1	1	1	0.0166	240	0.95	20	10	0	0	0	1	1	-	-	240	2113.8	-180.9	25.1	617.4	0.6	4.6	1.4	1.3	0	0	0.02	0	0	0	0
	BaBS3	2	1	1	100	0.0166	256	0.95	20	10	0	0	0	1	1	-	-	259	122.0	-4.5	2509.6	667.0	60.8	4.9	125.8	125.8	0	0	0.02	0	0	0	0
	BaBS4	2	1	1	100	0.0166	256	0.95	20	10	0	0	0	2	1	-	-	259	122.0	-4.5	2509.6	667.0	60.8	4.9	125.8	125.8	0	0	0.02	0	0	0	0
	BaFFRS1	3	1	1	1	0	5	0.95	0	0	8	0	0	1	-	1	-	5	136.7	-3.9	25.1	12.9	0.6	0.1	1.5	1.3	0	0	0	0.2	0.001	0	0
	BaFFRS2	3	1	1	100	0	30	0.95	0	0	54	0	0	1	-	1	-	30	101.4	-2.9	2509.6	77.2	60.8	0.6	126.3	125.1	0.0	0	0	1.2	0.004	0	0
	BaFFRS3	3	1	1	100	0	59	0.95	0	0	108	0	0	1	-	1	-	59	104.0	-3.0	2509.6	151.7	60.8	1.1	127.5	125.2	0.0	0	0	2.3	0.008	0	0
	BaFFRD1	4	1	1	1	0	9	0.49	0	0	0	8	0	1	-	-	1	9	171.2	-3.5	25.1	23.2	0.6	0.2	1.9	1.3	0.0	0	0	0	0	0.51	0.04
	BaFFRD2	4	1	1	100	0	92	0.49	0	0	0	84	0	1	-	-	1	92	106.9	-3.0	2509.6	236.6	60.8	1.7	131.0	125.3	0.0	0	0	0	0	5.31	0.39
	BaFFRD3	4	1	1	100	0	183	0.49	0	0	0	168	0	1	-	-	1	183	115.1	-3.1	2509.6	470.7	60.8	3.5	136.9	125.7	-0.1	0	0	0	0	10.61	0.78
	BaS1	6	1	1	100	0.0166	256	0.95	20	10	0	0	0.3	1	0.923	-	-	259	122.1	-4.4	2509.6	667.0	60.8	4.9	127.0	85.8	-0.2	41.4	0.02	0	0	0	0
	BaS2	6	1	1	100	0.0166	257	0.95	20	10	30	0	0	1	1	1	-	260	122.1	-4.5	2509.6	669.5	60.8	4.9	126.4	125.8	0	0	0.02	0.6	0.002	0	0
	BaS3	6	1	1	100	0.0166	256	0.95	20	10	30	0	0	1	0.997	1	-	259	122.0	-4.5	2509.6	667.0	60.8	4.9	126.4	125.8	0	0	0.02	0.6	0.002	0	0
	BaS4	6	1	1	100	0.0166	257	0.95	20	10	108	0	0	1	1	1	-	260	122.1	-4.3	2509.6	669.5	60.8	4.9	128.1	125.8	0	0	0.02	2.3	0.008	0	0
	BaS5	6	1	1	100	0.0166	292	0.85	20	10	0	30	0	1	1	-	1	295	125.3	-4.5	2509.6	759.6	60.8	5.6	127.9	125.9	0	0	0.02	0	0	1.90	0.14
	BaS6	6	1	1	100	0.0166	272	0.85	20	10	0	30	0	1	0.950	-	1	275	123.5	-4.4	2509.6	708.1	60.8	5.2	127.9	125.8	0	0	0.02	0	0	1.90	0.14
	BaS7	6	1	1	100	0.0166	293	0.85	20	10	30	30	0	1	1	1	1	296	125.4	-4.5	2509.6	762.1	60.8	5.6	128.6	125.9	0	0	0.02	0.6	0.002	1.90	0.14
	BaS8	6	1	1	100	0.0166	272	0.85	20	10	108	30	0	1	0.949	1	1	275	123.5	-4.2	2509.6	708.1	60.8	5.2	130.2	125.8	0	0	0.02	2.3	0.008	1.90	0.14
	BaS9	6	1	1	100	0	151	0.85	0	0	30	30	0	1	-	1	1	151	112.3	-3.6	2509.6	388.4	60.8	2.9	128.1	125.4	0	0	0	0.6	0.002	1.90	0.14
	BaS10	6	1	1	100	0	151	0.85	0	0	108	30	0	1	-	1	1	151	112.3	-3.5	2509.6	388.4	60.8	2.9	129.8	125.4	0	0	0	2.3	0.008	1.90	0.14
	BaS11	6	1	1	100	0	151	0.85	0	0	108	30	1	1	-	1	1	151	112.1	-3.1	2509.6	388.4	60.8	2.9	134.0	8.9	-10.1	130.8	0	2.3	0.008	1.90	0.14
	BaS12	6	1	1	100	0	151	0.85	0	0	108	30	0.5	1	-	1	1	151	112.3	-3.3	2509.6	388.4	60.8	2.9	131.9	60.4	-1.1	68.2	0	2.3	0.008	1.90	0.14

Table 5.1 includes both important input parameters that are changed depending on the result desired, service availability results, and results related to IRR and LCOE.
Each case study and related result in the table is given a different designation based on the input parameters, where 'BaDAx' refers to a composition for the baseline case-study ('Ba'), where energy is sold in the day-ahead market ('DA'). A composition including the 'BSx' identifier refers to providing the BS service, with 'FFRSx' refers to provision of the FFR static secondary service. An identifier including 'FFRDx' refers to providing the FFR dynamic high frequency service. Identifier component 'Sx' refers to a composition where services and markets are stacked. Other identifiers are used for the sensitivity case study, for the bad wind year ('SBWY'), modified BS requirements ('SMBS') and increased frequency deviations ('SIFD').

In the table, "Scen" refers to the model scenario run. The options for N_{WT} of 1 and 100 wind turbines are used in this study for simplicity's sake, where 100 wind turbines represents an arbitrary maximum for the wind farm site (in reality, the Walney extension wind farm is sized for up to 750 MW), and 1 wind turbine is used as a comparison point, to help demonstrate the importance of generation compared to battery storage in providing a service. This also can be used to demonstrate the importance of managing excess generation-load mismatch in the balancing market to profitability. Battery sizing is compartmentalised into cranking energy, "E_{crank}" and extra energy, "E_{extra}". Wind turbine cranking energy is given a value when the BS service is to be provided, as for 100 wind turbines the BS event cranking energy is a non-negligible amount compared to total storage. Extra energy is given a value if other battery storage is required. If a BS service is provided, total energy stored must sufficient for a BS availability of > 0.90. If a FFR static secondary or dynamic high frequency service is provided alone, then extra energy stored must facilitate 100% availability of the respective FFR service. Most of these extra energy quantities were calculated by iterating the value (by 1 MWh as a time) until the required service could be provided at a selected availability, with the intention that results between service and market choices/stacks, along with the sensitivity studies, could be comparable. Initial battery SoC is changed depending on the requirements of the service bids; for a FFR dynamic high frequency service, both storage and supply are needed from the battery, so to maximise service availability, initial SoC is reduced. BS bid composition is given in terms of power bid and duration bid, which are constant for the baseline case, but changed for the sensitivity study. Next are the FFR static secondary and dynamic high frequency service bids, which are given once, as the same bid volume is used for each of the six respective four-hour blocks in each service. Then "f day-ahead" represents the fraction of the day-ahead wind generation forecast that is bid in the day-ahead electricity market. Next, "Batt strat" represents the two battery strategy options. After the battery strategy column, the results are shown, which are fairly straightforward. When availability is shown as "1", or a fraction "0.732" the service is 100% available, or 73.2% available respectively. When service availability is shown as "-", this means the service is not included in the service/market provision set for that composition.

The phrase 'composition' used in this text designates the variable input parameters, such as wind farm sizing, battery storage sizing, initial battery SoC, battery strategy used in the balancing market, and bids for markets and services. These compositions, when run in the model, lead to the simulation results.

5.2 Behind the results of the baseline case study

So the results can be understood, the simulation from composition BaS7 is broken down. Composition BaS7 is chosen as results show all services and markets except day-ahead market bidding. Day-ahead market bidding is shown at the end of this section for composition BaDA1.

In Figure 5.1 below, the relationship between FFR service bids, second resolution UK grid frequency and actual FFR service load can be seen for the time period 154000 seconds to 158000 seconds. This time-period is selected as the provision of both FFR services due to frequency deviations can be clearly seen.

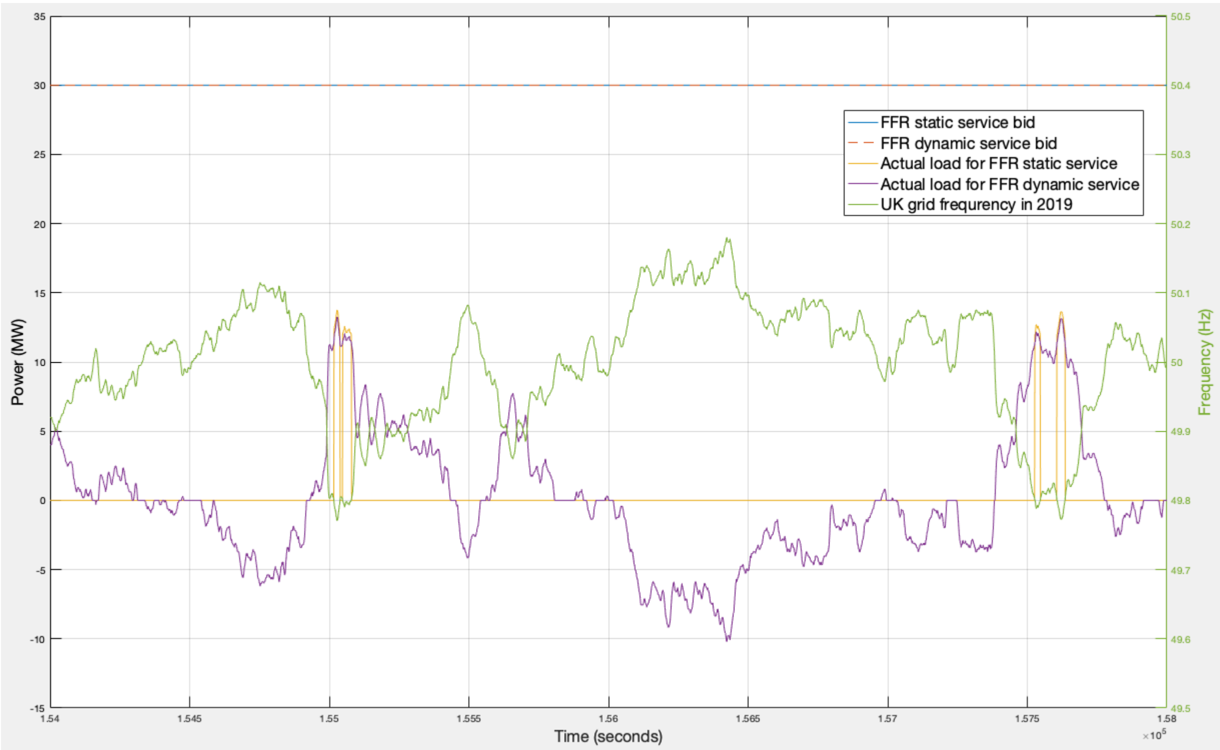

Figure 5.1: Segment of simulation of composition BaS7, showing FFR bids, and some of the grid frequency and corresponding load for FFR static secondary and dynamic high frequency services.

In the related Figure 5.2 the average FFR service load is seen, which is used for the half-hour temporal resolution in the model battery operation, to reduce computational effort. The time range in seconds, from 154000 to 158000, used in Figure 5.1 above corresponds with the SPs' 85 to 88 in Figure 5.2 below.

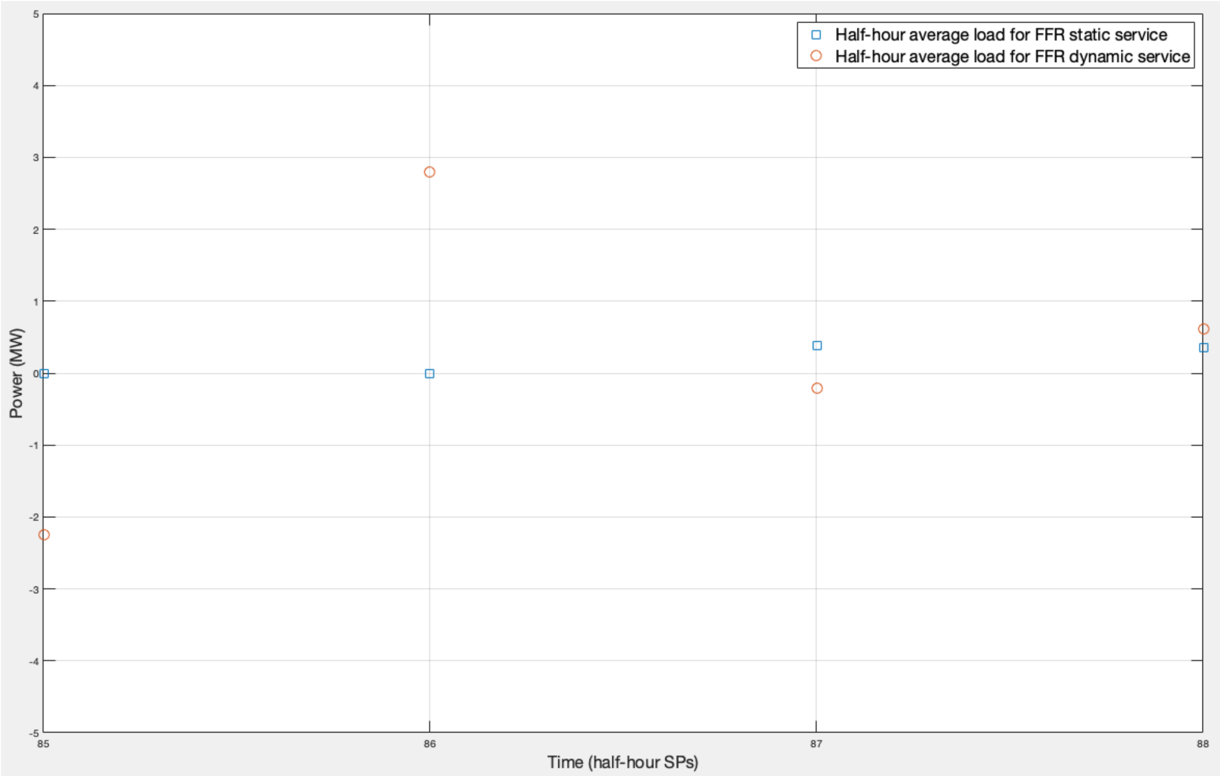

Figure 5.2: Segment of simulation of composition BaS7, showing half-hourly average load for FFR static secondary and dynamic high frequency services.

In the next figure, the wind farm generation, load (which here is due to FFR service provision as in Figure 5.2 above) and resulting mismatch can be seen for SPs' 0 to 60 in the simulation of composition BaS7. The application of the battery power limit is not shown as the time-series would be misleading without being immediately accompanied by the model implementation.

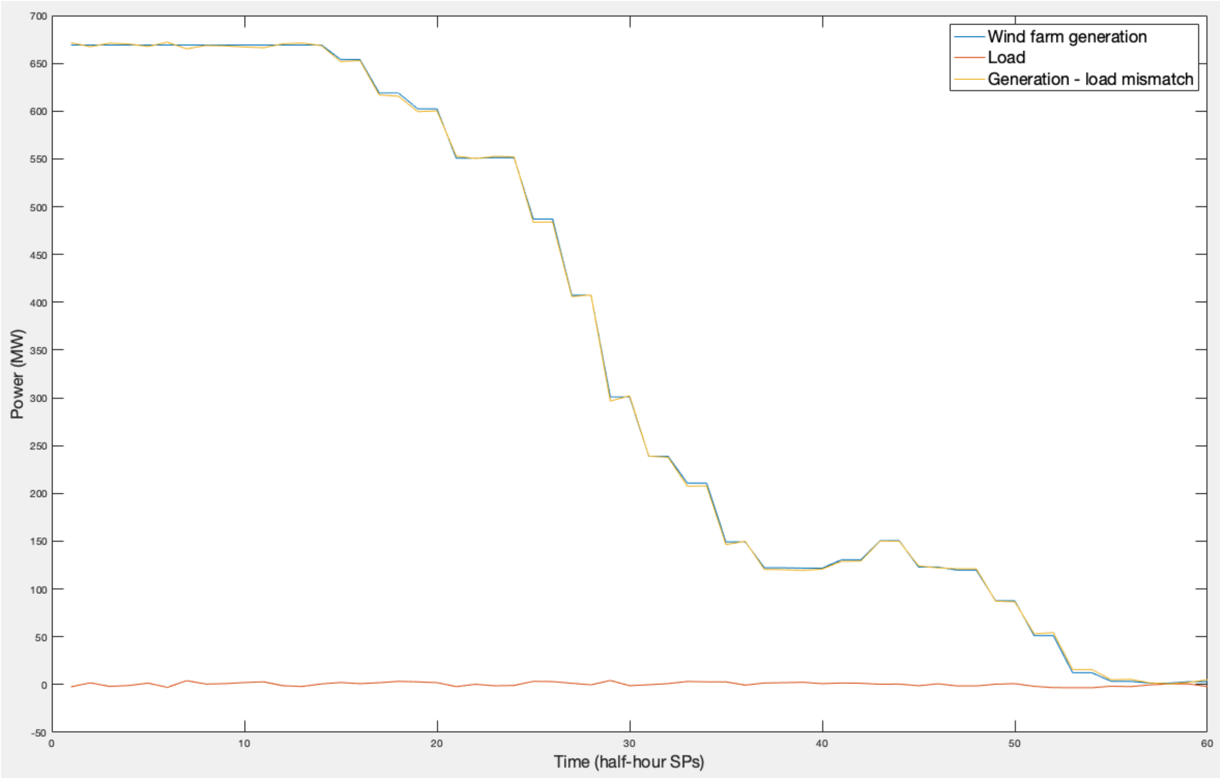

Figure 5.3: Segment of simulation of composition BaS7, showing wind farm generation, load and mismatch.

In Figure 5.4 below, it can be seen for the SPs' 0 to 60 how the generation-load mismatch leads to selling most of the energy in the balancing market, after charging the battery till it is full.

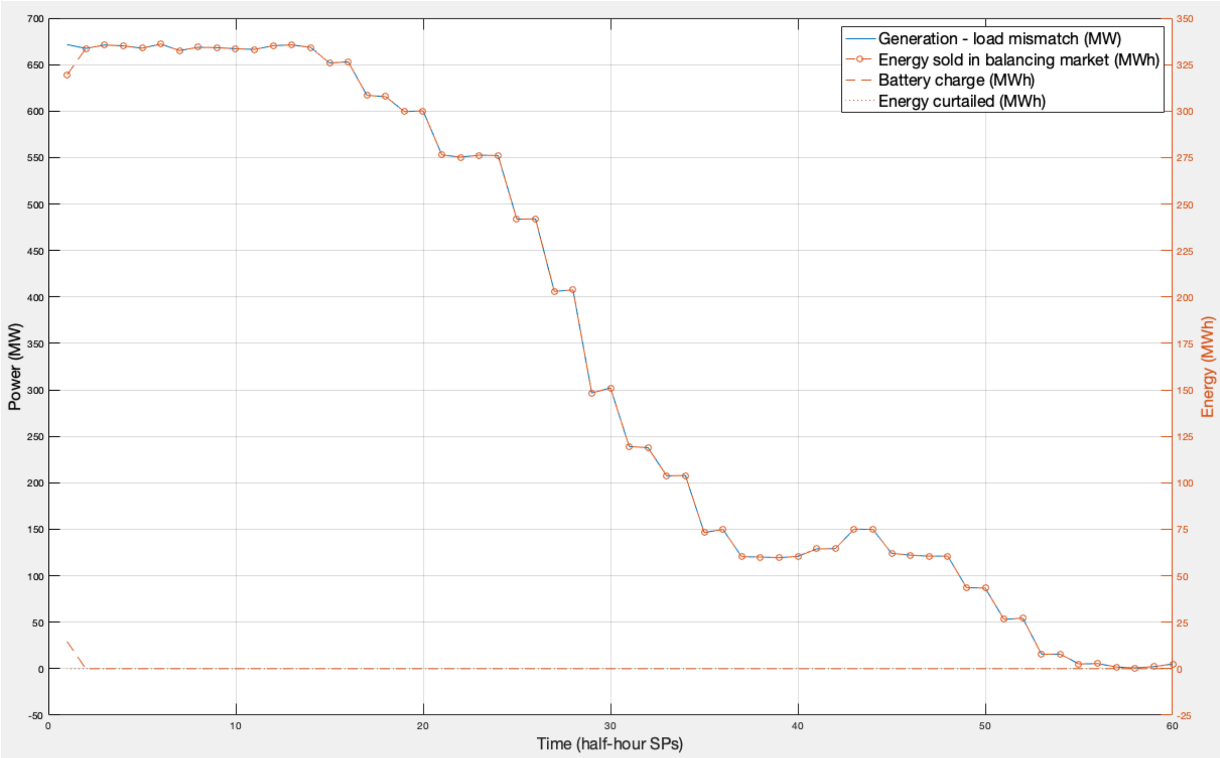

Figure 5.4: Segment of simulation from composition BaS7 showing a positive generation-load mismatch, and the resulting balancing market energy sales, energy charged in the battery and curtailed generation.

In Figure 5.5 below, for comparison, in between the 50th and 100th SP, a negative mismatch can be seen, with a small amount of battery discharge used from SP 70 onwards, preventing purchases on the balancing market from being required; if the battery was discharged to the point that service provision is challenged, balancing market purchases would take place to provide for the load, preventing further discharging. Note that battery discharge is more negative than the negative mismatch due to battery discharging efficiency, and due to the conversion of DC power to AC.

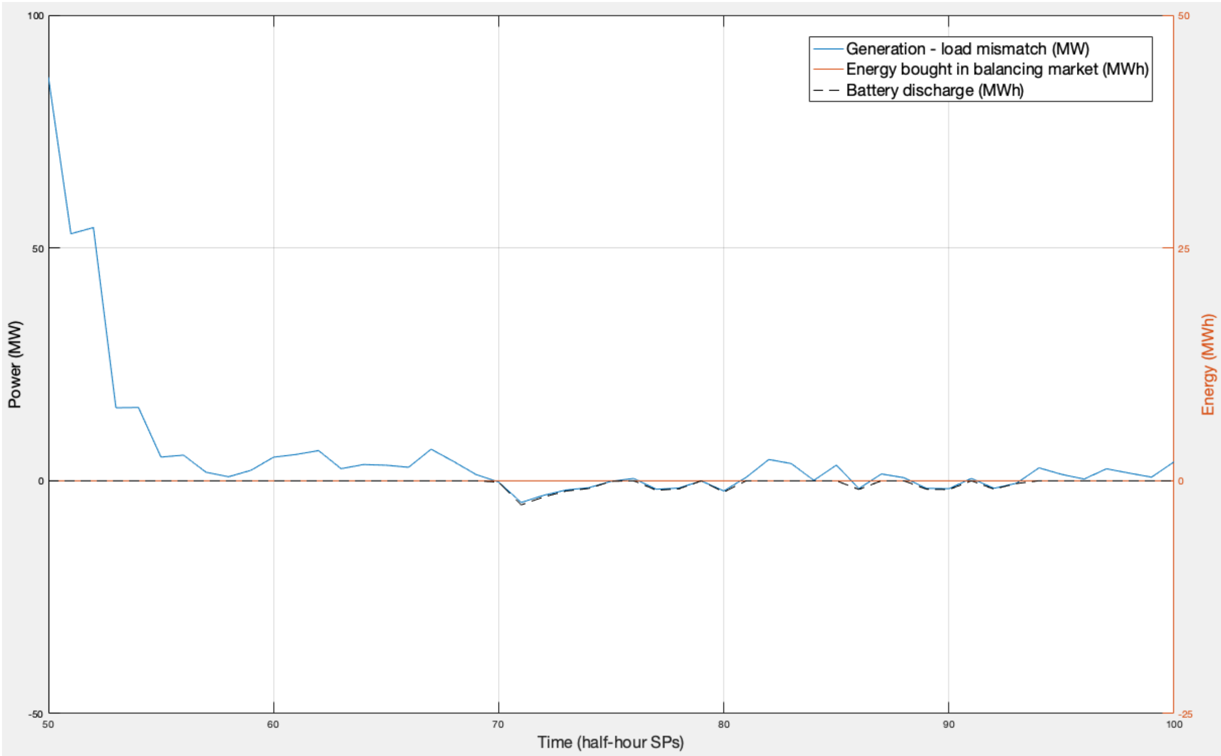

Figure 5.5: Segment of simulation from composition BaS7 showing a negative generation-load mismatch, and the resulting battery discharge, while no balancing market energy purchases occur.

In Figure 5.6 below, it can be clearly seen how composition BaS7 achieves a 100% BS availability; battery energy available is just slightly higher than the energy required for the BS service and FFR services; hence the inconsistency of energy available from the wind farm doesn't impact BS availability. If the FFR service load was higher for the same bid, due to a larger frequency deviation, to the point of challenging the ability of the battery to provide the service in the following SP, energy would be purchased in the balancing market to compensate. If the bid was higher, storage sizing would have to increase in order to facilitate the maximum FFR load possible in a half-hour period (one SP).

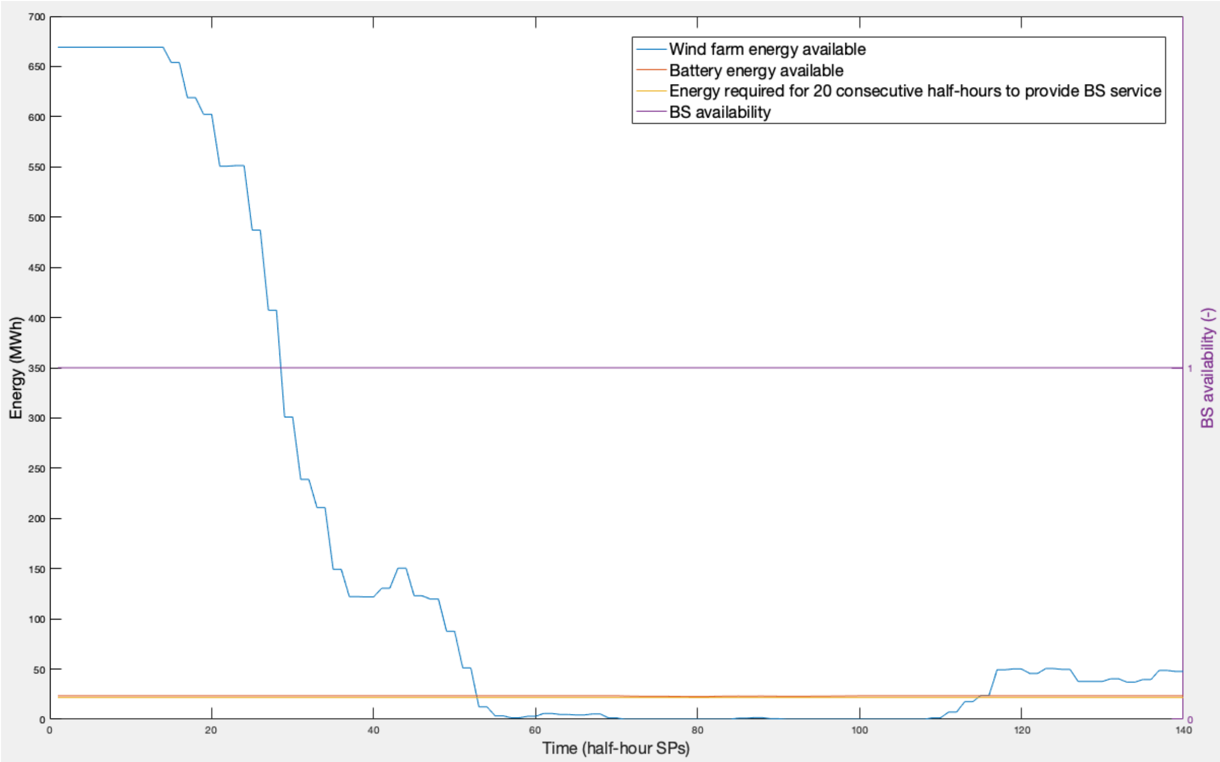

Figure 5.6: Segment of simulation from composition BaS7, showing wind farm energy, battery energy available, the energy required to provide a BS service and the resulting BS availability.

In Figure 5.7 below, it can be seen for SPs' 0 to 100 that FFR static secondary service and FFR dynamic high frequency service availability equals one. This is because, for the former, battery discharge available after the inclusion of the FFR static secondary and dynamic high frequency loads, is never less than zero. For the latter, both battery discharge available, and charge available, is never less than zero after the inclusion of FFR static secondary and dynamic high frequency loads (both positive and negative).

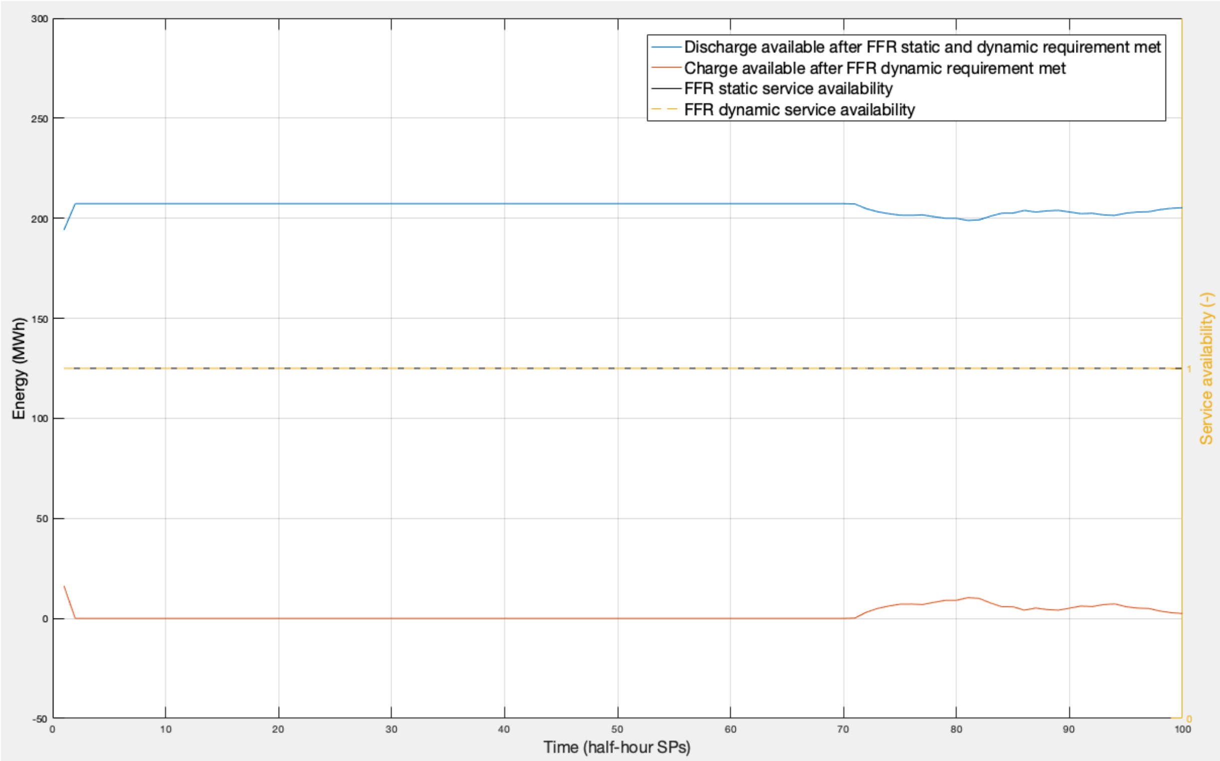

Figure 5.7: Segment of simulation from composition BaS7, showing that FFR static secondary and dynamic high frequency service availability is achieved through control of battery charge and discharge availability.

In this chapter, it is later shown how revenue (service and market revenue minus service and market cost) is broken down into different services, and markets, in Section 5.7, Figure 5.16. As such this is not repeated here.

Below in Figure 5.8, day-ahead market bidding is shown from a segment of the simulation of composition BaDA1 (not BaS7 like the other figures).

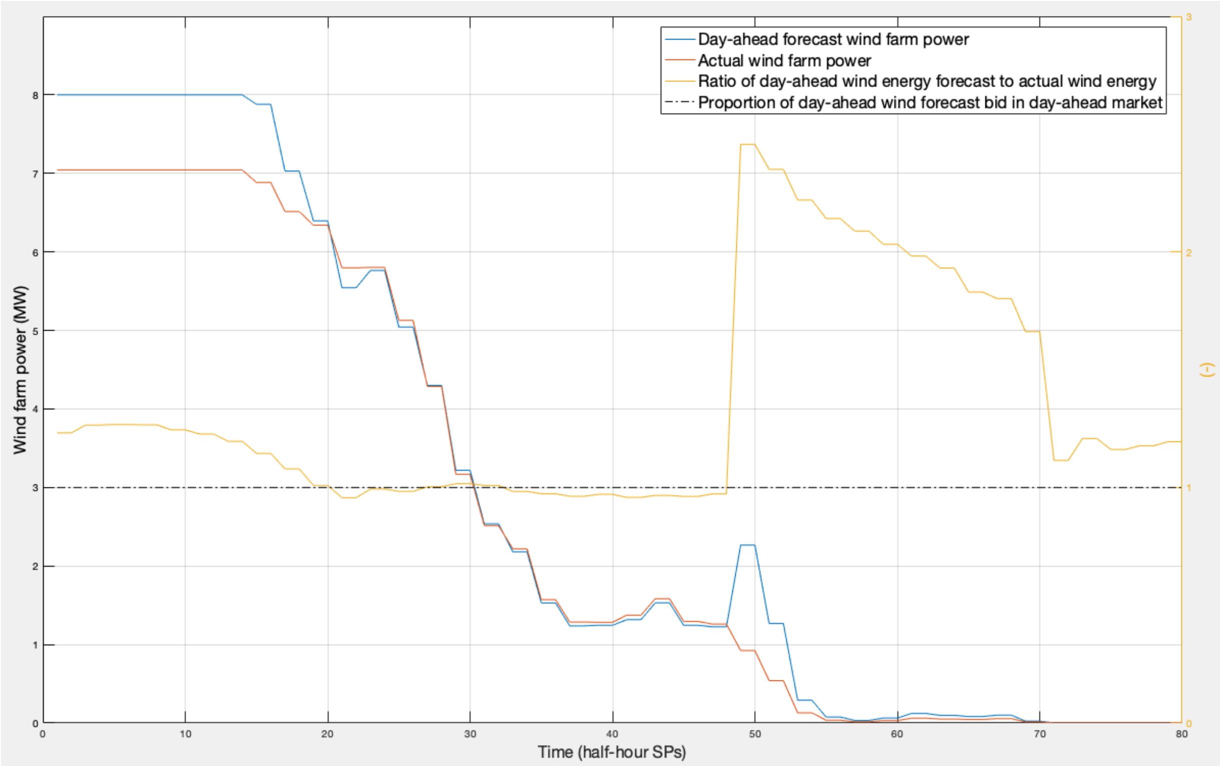

Figure 5.8: Segment of simulation for composition BaDA1, showing the workings of the day-ahead market bidding.

As can be seen, the day-ahead bid never exceeds the rated power of the wind turbine. The proportion of wind power forecast that is bid in the day-ahead market is constant for the whole simulation. When the day-ahead forecast is overzealous, the day-ahead bid follows suit, which must be later dealt with in the balancing market.

In the following sections, the results discussions take place.

5.3 Results of day-ahead market grid dispatch with balancing market for mismatch

Results from compositions BaDA1 to BaDA11 show this operational mode. These bid compositions were chosen to obtain results from a variety of wind farm - storage compositions, and so that the effect of changing bid proportions between the day-ahead market and balancing market could be seen.

By comparing the resulting IRR from compositions BaDA1 and BaDA2 to all other IRR results in the table, it is seen that bidding all forecast wind generation in the day-ahead market and handling all mismatch in the balancing market is the most profitable method of operating a wind turbine or wind farm, with the highest IRR values. The difference in IRR results between compositions BaDA1 and BaDA2 occurs due to the higher number of wind turbines in the latter, meaning that wake losses of 5% in the model are included. This also causes a minor LCOE difference, as a lower proportion of energy is utilised.

It is seen when comparing the results of compositions BaDA2, BaDA3 and BaDA4 that selling all forecast energy in the day-ahead market has a slightly higher IRR than selling all energy in the balancing market, and as such is more profitable. Differences in IRR and LCOE occur due to differences between day-ahead and balancing market prices, which contribute to higher curtailment in BaDA4 than BaDA2, and greater revenue in BaDA2 than in BaDA4. This can be seen in Figures 4.8 and 4.9, where the balancing market price is zero more often than the day-ahead market price, and the average day-ahead market price is higher than balancing market prices; indeed, the average day-ahead market price is 42.9 £/MWh for the case study year (both including and excluding the few SPs' with negative pricing, during which the wind farm generator won't sell) while the average balancing market price is 41.9 £/MWh (including negative prices, or 42.2 £/MWh without, which is the average sold for in the balancing market, showing that balancing market prices are zero far more often than day-ahead market prices). The difference in prices also suggests an under-supply in the day-ahead market and over-supply in the balancing market for the case study year. For BaDA2, curtailment equals 2300 MWh per year, while for BaDA4 curtailment equals 43400 MWh per year, hence more energy is utilised for BaDA2 and so LCOE for BaDA2 is lower.

As shown from comparing the results from compositions BaDA2, to the set of BaDA5 to BaDA11, adding amounts of storage above 10 MWh to this operational mode noticeably decreases profitability, and increases the cost of energy provided, and the greater this quantity of storage, the more profitability decreases. This is in part because the storage quantities attempted are insufficient to prevent purchases in the balancing market due to day-ahead bid mistakes, but mainly because the cost of storage required far outweighs that of the mistakes that must be accommodated in the balancing market. For example, in BaDA2, 9.7 million GBP is made in the balancing market over the one-year period, and 10.7 million GBP is lost in the balancing market (again this is when 100% of forecast wind energy is sold in the day-ahead market). In comparison, in BaDA10, 9.1 million GBP is made in sales on the balancing market due to a wind energy forecast lower than actual wind energy, while 10.3 million GBP is lost due to too high wind energy forecasts, with an additional initial investment of 103 million GBP and annual cost of 0.8 million GBP required for the battery system. So balancing market revenue is actually lower for BaDA10, despite fewer losses in the balancing market, as balancing market revenue is reducing due to charging of the battery, which means some energy is unsold, and more importantly causes battery charging and discharging losses. A similar outcome occurs for the other results in this set with storage, hence, storage is infeasible for balancing market operation. Although differences of revenue are negligible, the cost of battery storage is not, hence the changes in IRR.

It is also seen when comparing the results from compositions BaDA5 and BaDA6, and BaDA8 and BaDA9, that changing the battery strategy (discussed in Section 5.1) to prioritise selling energy when the balancing market price is above average instead of charging (the default), has a negligible effect on IRR. Mean battery SoC values for BaDA5 and BaDA6 are 0.48 and 0.41, which can be seen somewhat in Figures 5.9 and 5.10 below, and mean SoC for BaDA8 and BaDA9 are 0.47 and 0.40, and so it is clear that less charging does occur in strategy two, with a change in IRR of plus 0.01% (not shown in the table as differences occur at two decimal places) from BaDA8 to BaDA9 due to extra balancing market sales (an increase from 9.4 million GBP to 9.5 million GBP respectively). This effect is slightly smaller for BaDA5 and BaDA6 as these compositions use less storage (not shown in the table as differences occur at 3 decimal places).

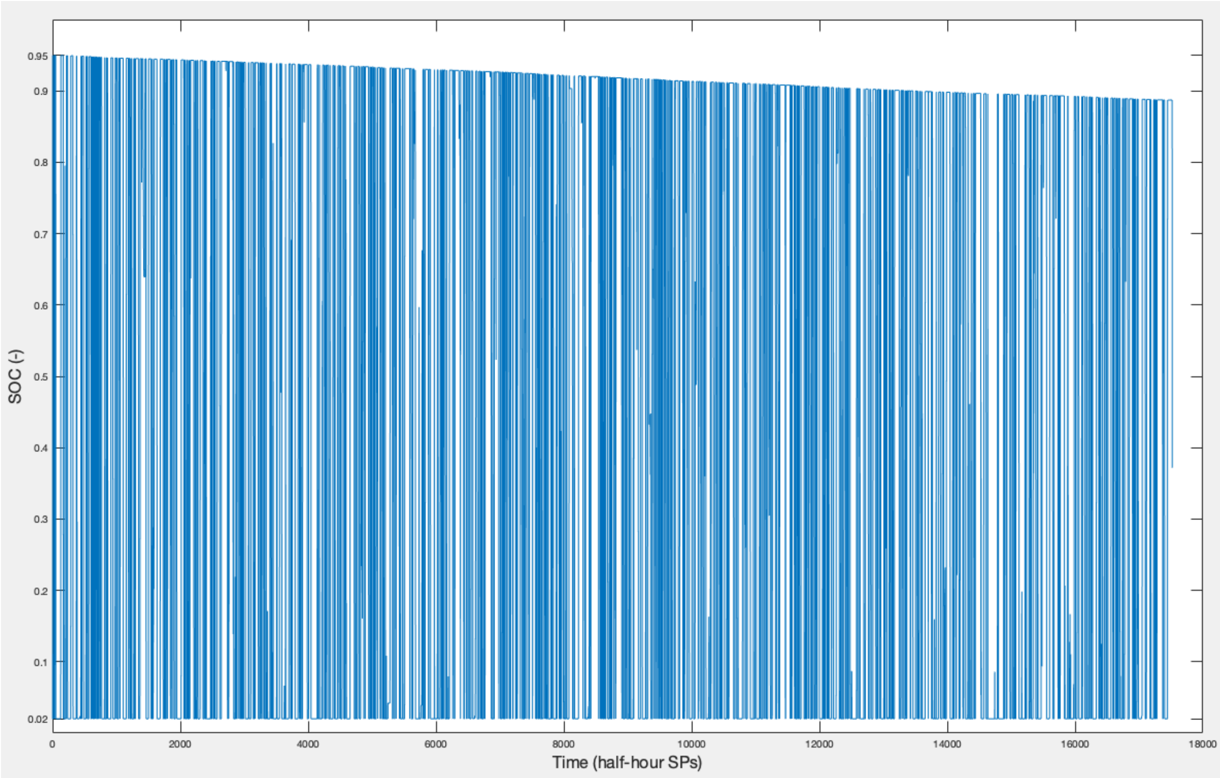

Figure 5.9: SoC over time for the simulation of composition BaDA5.

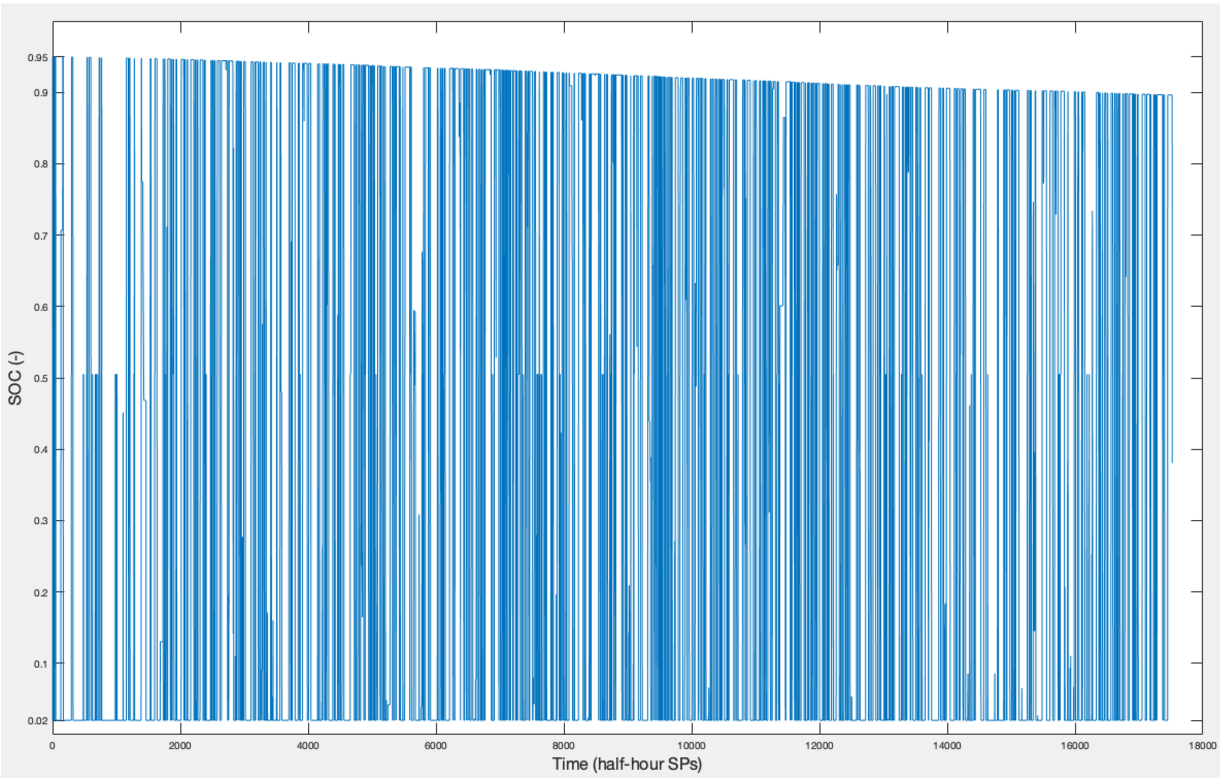

Figure 5.10: SoC over time for the simulation of composition BaDA6.

This means that utilisation of storage is very high in this case; with 2100 battery cycles completed in a year, resulting in a final maximum SoC value of 88.7% for BaDA5. Due to battery strategy two in BaDA6, fewer cycles are completed; 1800, and maximum SoC is reduced to 89.6% instead. Despite the increased amount of storage, as in cases BaDA8 and BaDA9, mean SoC values are about the same, and as a result, battery utilisation is very similar. This adds weight to the evidence that storage is unprofitable in the day-ahead and balancing markets only, as even with a high battery utilisation, reduced profitability is still seen. In summary, it is most profitable to operate with just wind turbines in the day-ahead market, dealing with any wind energy forecast errors in the balancing market, without battery storage, for the 2019 case study.

5.4 Results of BS service with balancing market for mismatch

The BS test function is not included in the results here, but it would demonstrate that if sized correctly, the system can meet the BS power and duration requirements during a BS test, during which, all excess generation not stored in the battery is curtailed, as no transactions can occur in the balancing market. Otherwise, the operation would be the same as in the results below. The effect of a BS test on IRR and LCOE is negligible, as the test is only delivered every two years, meaning minimal difference in energy utilised.

In Table 5.1, results from compositions BaBS1 to BaBS4 show BS service availability for different wind farm-battery sizing setups, with excess energy sold in the balancing market (the battery is always full so cannot be charged). The results from composition BaBS1 show that BS provision is impossible with 100 wind turbines and just a cranking sized battery (3.32 MWh), given a BS availability of only 73%. By comparing wind speed, wind farm power and BS availability, it is found that wind speeds must exceed 4.404 m/s in order for the BS to be considered available for BaBS1, assuming the cranking size battery is fully charged; 23.32 MWh must be available from the wind farm and the allocated 10% of the battery storage, for each of the 10 hours, so 23.01 MW must be produced by the wind farm here. The calculation of the BS availability from composition BaBS1 can be understood by observing Figure 5.11 below.

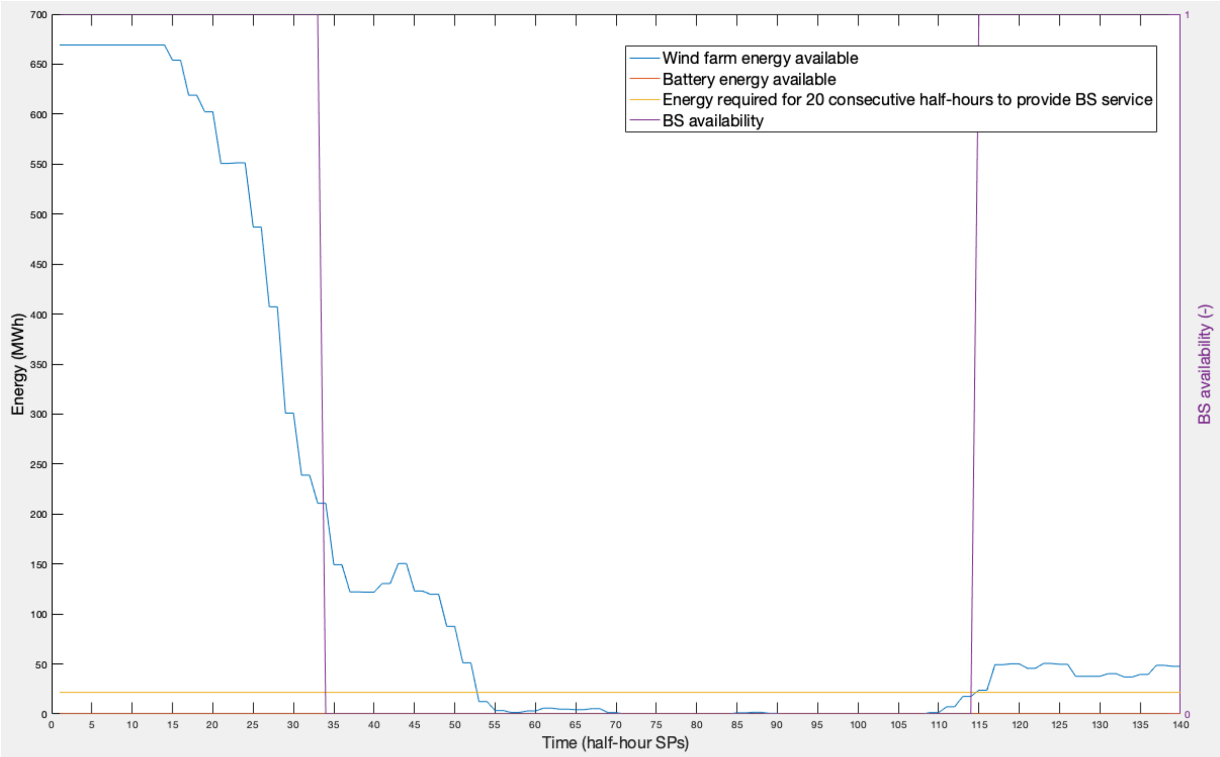

Figure 5.11: Demonstration of BS availability from a segment of the simulation of composition BaBS1.

It can be clearly seen that the cranking sized battery provides a negligible amount of energy towards the BS energy requirement, as the energy stored must be split over 10 hours; therefore BS availability is almost entirely dependant on energy from the wind farm. It can be seen that from the 34th SP, BS availability is zero, which is a result of wind farm energy being too low from the 53rd SP onwards.

It is possible to provide a 100% available BS service with a single wind turbine and 240.0332 MWh of battery storage, as in the results of composition BaBS2, but this produces a very negative IRR and and infeasibly high LCOE; this is because the ratio of wind turbines to storage is very low, and as such, not enough energy can be sold in the balancing market to offset the investment cost. A better solution is to use 100 wind turbines and increase the battery storage capacity to 259.32 MWh (3.32 MWh of cranking storage and 256 MWh of extra storage), providing a 100% available BS service with a -4.5% IRR, as seen in BaBS3. To determine the minimum quantity of storage required to provide a 100% available BS service for 1 and 100 wind turbines, as in results BaBS2 and BaBS3, extra energy in the battery was set high, where BS availability equalled one, and then iteratively reduced until the point where any less storage would result in a reduction of BS availability from one.

Comparing results from compositions BaBS3 and BaBS4 shows that changing the battery strategy used in the balancing market has a negligible effect on the amount of energy sold in the balancing market, or the price for which this energy is sold for, because in this bid setup, the battery is always full, so cannot be used for further storage.

From these results, the volume of storage required shows that a BS system with the ESO's requirements in this location cannot rely on the wind farm for BS provision; the wind turbines are used to increase profitability (although for these case study inputs the project isn't profitable), but the storage is used to actually achieve BS availability. Reducing u_{cut-in} has zero effect on BS availability; instead, to increase BS availability for this wind farm-battery sizing, a wind farm site with a higher average wind speed, higher hub height wind turbines, or a more flexible BS requirement are necessary.

5.5 Results of FFR static low frequency secondary service with balancing market for mismatch

In Table 5.1, results for compositions BaFFRS1 to BaFFRS3 are taken for the individual FFR static secondary service, with mismatch handled by the battery and in the balancing market.

As in the baseline case study, it is assumed that the FFR static secondary service bid cannot exceed the minimum monthly bid required by the ESO, apart from the November and December 2019 months where 0 MW is tendered; therefore the maximum bid is set at 108 MW. This bid limit is the maximum bid used in BaFFRS3. Also, it is assumed that the FFR static service bid cannot exceed the rated power of the wind farm, which is arbitrary, because only the condition of the storage is measured to assess FFR availability; excluding wind farm power. This bid limit was used to determine the FFR static service bid in BaFFRS1, for one wind turbine. To size the battery, "E_{extra}" is sized high and then reduced iteratively until a further reduction would lead to a FFR static service availability of less than 100% (establishing the minimum battery sizing). In reality a wind turbine could take part in the provision, particularly when operate below optimum C_p, increasing power output when a negative frequency deviation occurs. However, involving the wind turbine is not a conservative decision, which is important as 100% availability is required to provide a FFR service; therefore, the battery is sized to always be able to provide the FFR service in the next time step of the simulation; this means that for every MW bid, 0.5 MWh of storage is required for the FFR static service, where any extra energy required is purchased in the balancing market. This conservative requirement based sizing negates the fact that only one year of frequency data is used; if instead sizing for maximum power actually required in a one year period for the FFR service, it is likely that power required for the FFR service in the remaining 24 years would exceed that installed. Using a frequency dataset with a larger temporal range, and a higher temporal resolution in the rest of the model, would allow a better assessment of system availability and a more realistic wind turbine-battery sizing. However, frequency data was not available for the project lifetime, and this method would require much greater computational effort, to the point of making the results infeasible.

Again, it is assumed that the behaviour of this wind turbine - battery system, including service and market bids, has a negligible effect on those markets. In reality, if energy is required for the FFR static service, and it has to be purchased in the balancing market by the system to ensure availability in the following half-hour period, balancing market price will increase, depending on the FFR volume. This effect depends on the proportions of FFR static volume supplied that are purchased on the balancing market, which are shown in Figures 5.12 and 5.13 for compositions BaFFRS1 and BaFFRS3 respectively below.

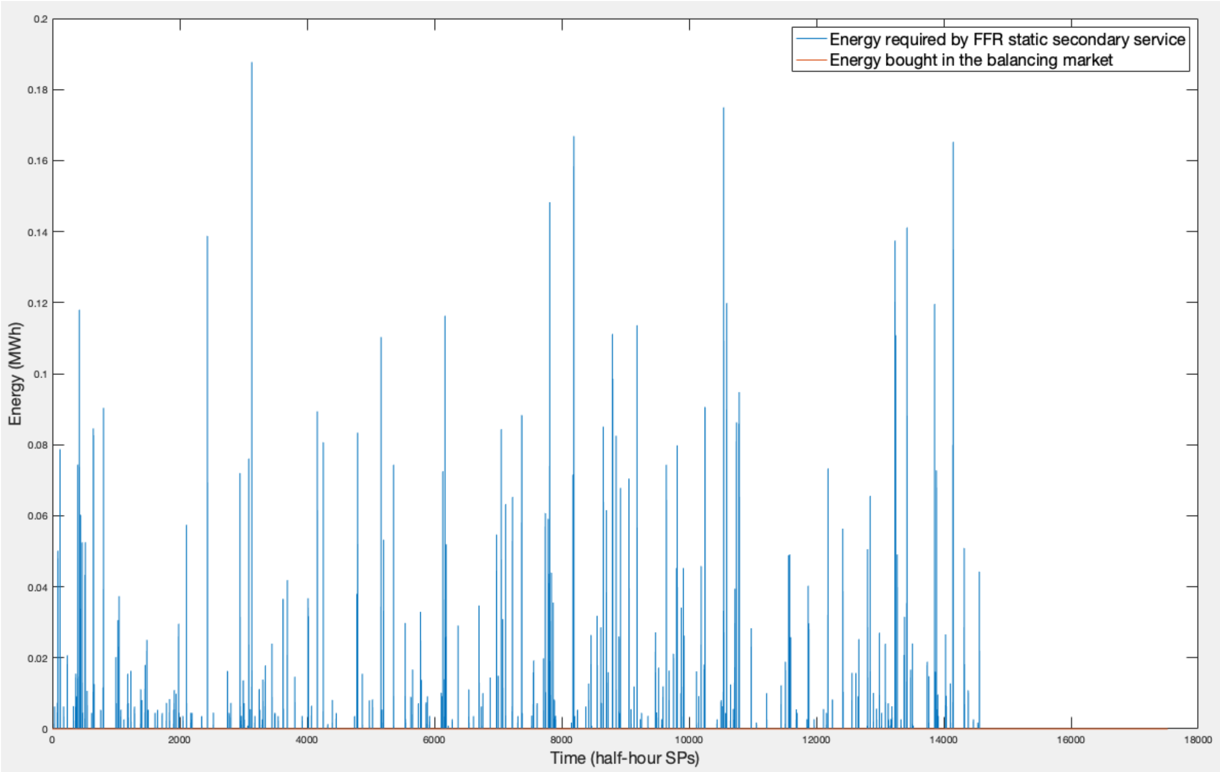

Figure 5.12: FFR static secondary service energy required versus energy bought in the balancing market, for corresponding SPs' in the simulation of composition BaFFRS1.

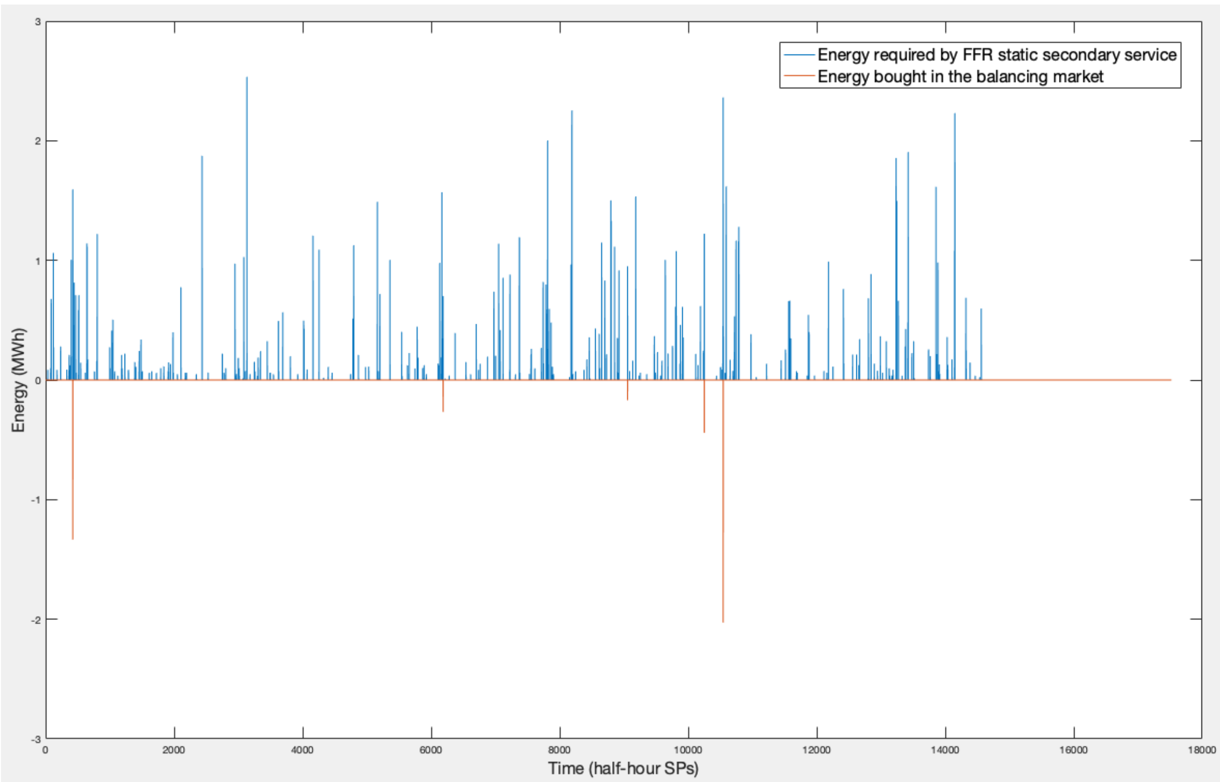

Figure 5.13: FFR static secondary service energy required versus energy bought in the balancing market, for corresponding SPs' in the simulation of composition BaFFRS3.

In the results of composition BaFFRS1, the 8 MW bid, total FFR load is 9.3 MWh, and energy bought on the balancing market equals 0 MWh; this is because the 5 MWh battery is slightly oversized, as the 8MW bid cannot be supplied using a 4 MWh battery. In BaFFRS3, the 108 MW bid, total FFR load is 126.7 MWh, and energy bought on the balancing market equals 4.2 MWh. This shows that comparatively little energy from the balancing market is used to provide the FFR static service (3.3%), so the wind farm - battery systems are quite self-sufficient. Therefore, the influence of real world balancing market price elasticity is unlikely to significantly affect the profitability of the FFR static service provision results.

Comparing the results of FFR static provision only to BaBS3 shows that providing an FFR static service is more profitable than a BS service (both using the balancing market for imbalances). From comparing BaFFRS2 and BaFFRS3, it can be seen that when more of the FFR static service is offered, the service is less profitable; this is because extra revenue from providing the static service is outweighed by extra cost of storage to reliably provide that service.

5.6 Results of FFR dynamic high frequency service with balancing market for mismatch

Before discussing the results for this service, it must be stated that in real life, the option of operating a wind turbine below optimum C_p or to curtail the wind turbine allow some of the flexibility required by the dynamic high frequency service. However, like for the FFR static service, in this study, only battery SoC is used to assess dynamic high frequency service availability. Involving the wind turbine in FFR dynamic high frequency service availability would certainly reduce storage utilisation, but it would not affect storage volume required for the worst case scenario, when wind turbines are not operating, and therefore this doesn't affect IRR and LCOE results here. However it is possible that again, like in the FFR static service, the half-hour temporal resolution of the system limits the accuracy of the storage sizing, hence a conservative sizing must be used. For the FFR dynamic high frequency service a bid limit equals to the minimum monthly tender submitted in the 2019 period is used; the month with the least FFR dynamic high frequency bid had a total bid of 168 MW, and so this set the limit in BaFFRD3. Another bid limit is set equal to the rated power of the wind farm, which determined the maximum FFR dynamic high frequency service bid used in BaFFRD1 for one wind turbine. To size the battery storage, capcity was set high and then reduced iteratively until a further reduction would lead to FFR dynamic high frequency service availability of less than 100% (establishing the minimum battery sizing).
Compositions BaFFRD1 to BaFFRD3 provide the FFR dynamic high frequency service, with mismatch handled by the battery and in the balancing market. Results from simulating these compositions show that providing the maximum possible FFR dynamic high frequency service from a wind turbine with onsite battery storage is marginally less profitable than the same for the FFR static service, but still more profitable than the BS service. This is because providing a FFR dynamic high frequency service deals with both positive and negative frequency deviations, and as a result requires twice as much battery storage in this model compared to the FFR static service. This is despite the fact that the FFR dynamic high frequency service has a far greater hourly availability fee, averaging 7.21 £/MW.h in 2019, versus £2.44 £/MW.h for the FFR static service. The dynamic high frequency service has *much* larger profits from selling energy and services than the BS service, largely because the availability fee payment is much higher over the year than the £1222/MW.year paid for a BS service, i.e. an availability revenue of

10.6 million GBP from a 100% available 168 MW FFR dynamic high frequency service (in BaFFRD3) vs only 0.024 million GBP of availability revenue from a 100% available 20 MW BS service (in BaBS3). Additionally, energy provided for the FFR dynamic high frequency service is sold at a 25% higher price than the balancing market price, and if the battery is full, energy purchased on the balancing market to provide the dynamic high frequency service of storage is bought at 25% less than the balancing market price. This means a total balancing market revenue (including FFR dynamic energy sales) of 126.2 million GBP for BaFFRD3 vs 125.6 million GBP for BaBS3.

5.7 Results of stacked service and market provisions

In this section, results are shown from compositions where there will always be more than one service or market implemented (not counting the balancing market), with all mismatch still handled by the battery and balancing market.

Composition BaS1 explored the provision of a BS service whilst bidding 30% of the wind generation forecast in the day-ahead market and managing energy mismatch in the balancing market. For the same storage sizing as composition BaBS3, this slightly increased IRR in spite of a reduced BS availability, which reduces BS service revenue. Bidding in the day-ahead market increases IRR because day-ahead market prices are higher than balancing market prices, as discussed earlier in the day-ahead and balancing market only results. Prioritising a minor increase in IRR at the cost of BS availability, in real life, will reduce the likelihood of maintaining a BS tender, as higher reliability is favoured by the ESO. BS availability is reduced because with a day-ahead bid, less energy is charged to the battery, and the battery must be discharged to account for day-ahead bidding mistakes, which are shown when generation-load mismatch falls below zero, in Figure 5.14.

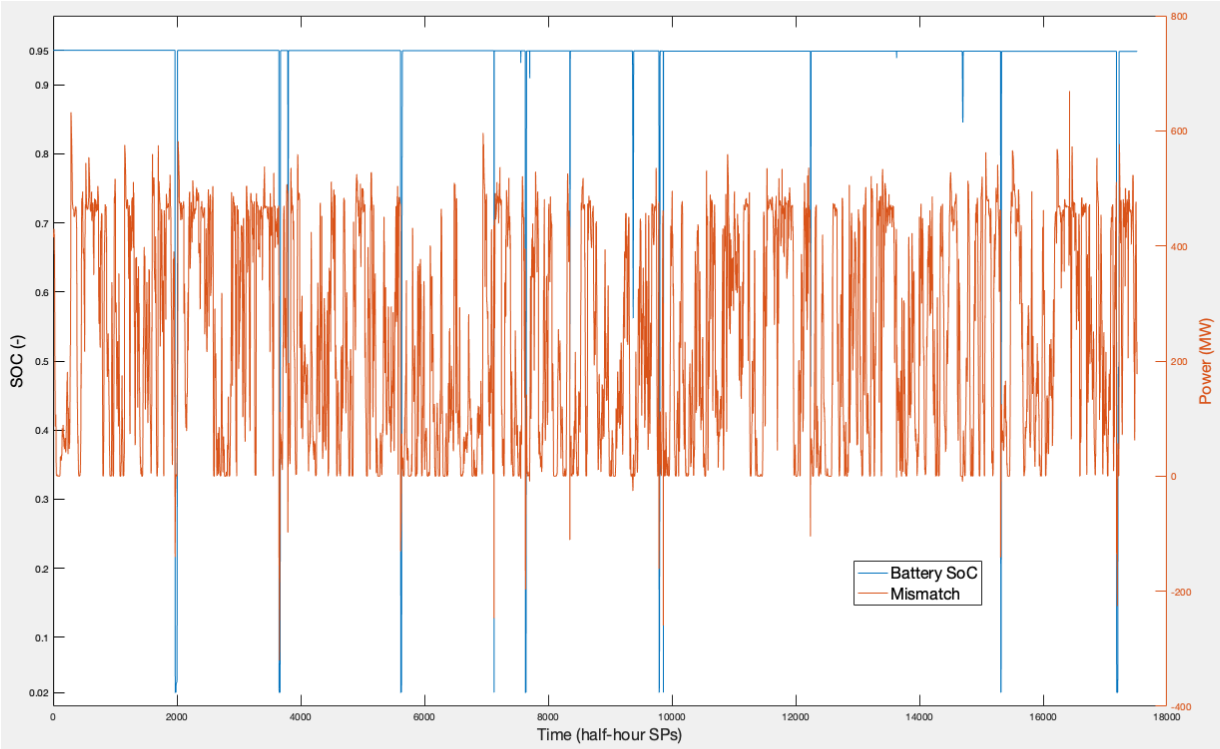

Figure 5.14: Battery SoC alongside generation-load mismatch, over time for the simulation of composition BaS1.

As composition BaS1 already uses a conservative battery strategy (strategy one), this is not an area that improvement in BS availability can be found. Instead, further increases of BS availability require extra storage, negating the extra revenue from bidding in the day-ahead market, or a better day-ahead forecasting mechanism to reduce mistakes, which can be seen as negative mismatch in Figure 5.14.

Compositions BaS2 to BaS4 explore the idea of providing a BS service alongside a FFR static service, managing energy mismatch in the balancing market. Results from simulating these compositions show a slight increase in IRR for BaS4 compared to the BS and balancing market only (in BaBS3), but not BaS2 or BaS3. This is not because extra energy is delivered (as indicated by negligible differences in LCOE) but because of the FFR availability payments, leading to greater annual revenue. Note that because FFR static service frequency triggers occur are 49.7 or 49.8 Hz, and only requires maximum power at 49.5 Hz, FFR static load is much lower than the bid volume suggests.

BaS5 and BaS6 explore the idea of providing a BS service alongside a FFR dynamic high frequency service, managing energy mismatch in the balancing market. The results from simulating compositions BaS5 and BaS6 are shown to be only equally or slightly more profitable than just the BS and balancing market in BaBS3, because the dynamic high frequency service requires a lower SoC to be maintained to increase charge available, and as a result battery capacity must be higher to maintain BS availability. To be more profitable than BaBS3, as in BaS6, requires a reduced BS availability. Despite this, compared to BaS5 and BaS6, BaS4 using the FFR static service instead of the FFR dynamic high frequency service, is more profitable.

Compositions BaS7 and BaS8 explore the idea of stacking all three services, again while managing mismatch in the balancing market. This can be more profitable, as in BaS8, than stacking the provision of the BS service, FFR static service and balancing market, in BaS4, but this causes a reduction in BS availability.

Compositions BaS9 and BaS10 stack the FFR static and dynamic high frequency service, managing mismatch in the balancing market. This stack design achieves the second highest IRR value of the stacked results set. It can therefore be seen that dropping the BS service from the service stack improves profitability, but this still falls short when compared to profitability in the results from composition BaDA2. Removing the BS service allows much more utilisation of the battery SoC range, and as a result lower battery capacity, reducing cost.

Finally, compositions BaS11 and BaS12 stack the FFR static and dynamic high frequency service alongside DA market bidding, managing mismatch in the balancing market. This stack achieves the highest IRR value of the stacked results set, however it is an unethical method of service provision; when bidding a large proportion of wind energy in the day-ahead market, the ability of the system to provide the maximum load that could occur due to FFR service bids is hindered, which makes provision of FFR services strongly reliant on operation in the balancing market, which decreases grid stability, rather than increasing it; therefore this approach is not considered further in the results discussion.

5.8 Overall discussion of service and market provisions

On a basis of pure profitability, stacking services is not more profitable than selling energy in the day-ahead and balancing markets; this can be seen clearly in Table 5.15 below. Results from compositions BaFFRS3 and BaFFRD3 are used instead of BaFFRS2 and BaFFRD2, because for the latter, the IRR is increased only by reducing the provision of FFR service, whereas in the study we are trying to compare the maximum service provision from the wind farm - battery storage system.

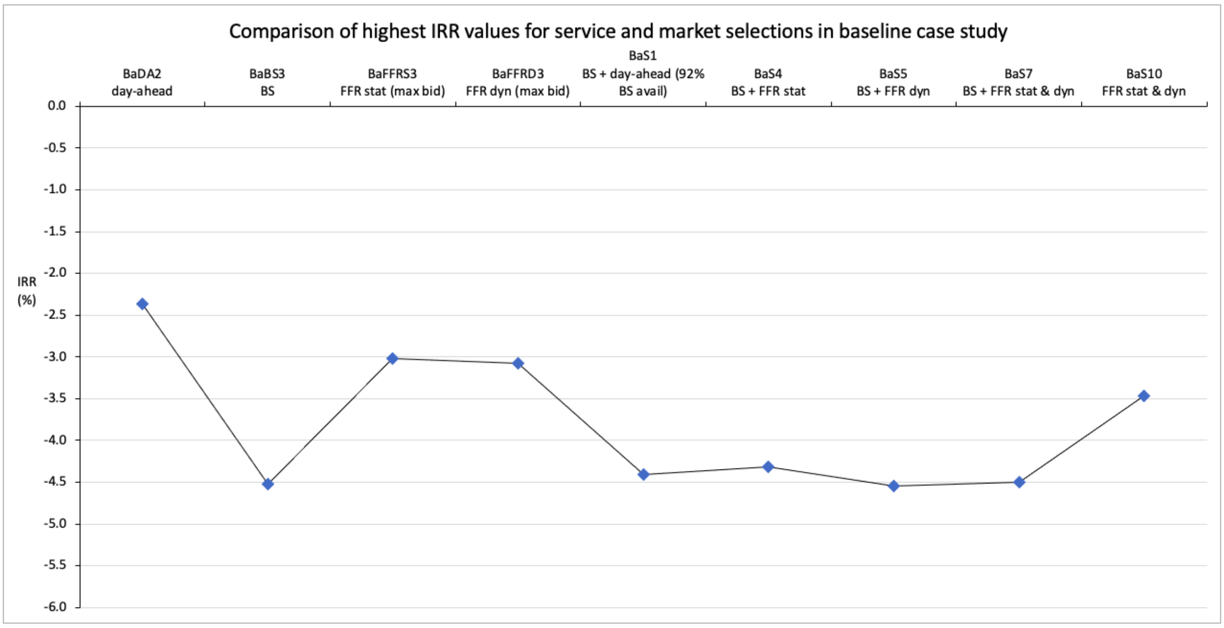

Figure 5.15: The highest IRR results for each permutation of services and markets attempted.

These results suggests that in a free market, incentives for providing the BS and FFR service need to be increased for services to be supplied, but that also, for this case study, selling energy in just the day-ahead and balancing markets is not actually profitable compared to a 7.75% WACC. Be aware that in the model, optional investment compensation from the ESO was not included, which can total 269 £/MW.yr; a 22% increase in revenue from the BS service (National Statistics, 2019; GOV.UK, 2019; ESO, 2020o). However, this is negligible as the majority of revenue comes from selling electricity directly. Below in Figure 5.16 is shown a brief breakdown of the IRR calculation for each of the highest IRR results in the baseline case study.

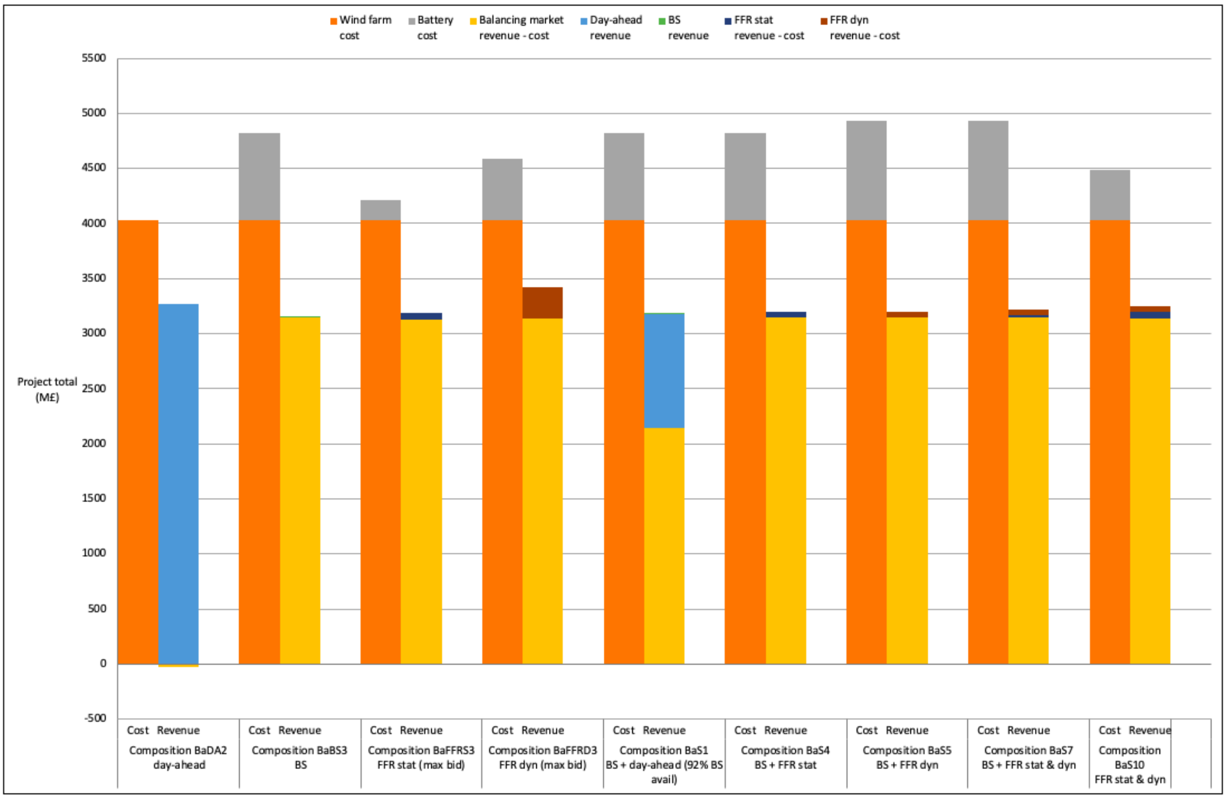

Figure 5.16: Breakdown of the highest IRR results for each permutation of services and markets attempted.

The lack of profitability for all results can be clearly seen by comparing project costs and total revenue in Figure 5.16. It is also very obvious that aside from in the results of composition BaDA2, the vast majority of income comes from the balancing market.

Profitability of BS stacked with FFR static services (with or without the addition of the FFR dynamic high frequency service) is slightly higher than for BS alone. If the BS service is to be provided at roughly 100% availability, it is most profitable to provide the BS service stacked with the maximum possible bid for the FFR static service, (accommodating mismatch in the balancing market), as in BaS4. If a non-negligible reduction in BS availability can be accepted, then it is most profitable to stack both the FFR static service and FFR dynamic high frequency service alongside the BS service, as in BaS8.

If operating in either of the FFR markets and the balancing market only, then stacking a BS service alongside this reduces profitability in all cases, as does stacking another FFR service (for example, compare results BaFFRS3 and BaFFRD3 against BaS10).

Unlike the balancing market, tenders for BS and FFR services guarantee a certain revenue on top of the balancing market prices for any energy provided. However it is also obvious that the cost of LiFePO4 battery storage far outweighs this additional revenue. In order for the incentive for generators to provide BS and FFR services to be equal to that of just day-ahead and balancing market operation, for the baseline case study, the BS and FFR availability fees discussed in Sections 2.4.1 and 4.5 should be modified. Of the different stacks involving the BS in Table 5.1 (the most profitable way to provide a BS service), composition BaS4 achieves the highest IRR value, and of the individual services involving the FFR static and FFR dynamic high frequency services (the most profitable way to provide those respective services), compositions BaFFRS3 and BaFFRD4 achieve the highest IRR values. Below the modifications to fees required for the profitability of BaS4, BaFFRS3 and BaFFRD3 to match the IRR resulting from composition BaDA2 are given.
For the IRR result of composition BaS4 to match that of BaDA2 with BS service price modification only, an increase in BS availability payment from 1222 £/MW.year by a factor of 1000 is required. For BaS4 to match the IRR resulting from composition BaDA2 with FFR static service price modification only, the FFR availability payment should be increased by a factor of 11.5. For the IRR result of composition BaFFRS3 to match that of BaDA2 with FFR static service price modification only, the FFR static service availability payment should be increased by a factor of 4. For the IRR result of composition BaFFRD3 to match that of BaDA2 with FFR dynamic high frequency service price modification only, the FFR dynamic high frequency service availability payment should be increased by a factor of 1.8.

Lastly, for the IRR result of composition BaDA2 to be profitable compared to the WACC (i.e. greater than 7.75% annually), average day-ahead and balancing market prices should be increased by 160%.

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6 Sensitivity Case Study and Results

In order to test how the introduction of different external circumstances affects the individual and stacked service and market results, a sensitivity study is conducted, with sensitivity elements consisting of a bad wind year, modified BS service requirements, and increased frequency deviations, discussed in this order.

6.1 Bad wind year

A wind speed dataset with a lower average annual wind speed (compared to the baseline case) is used to assess the sensitivity of service availability to the occurrence of a bad wind year. To create this dataset, mean wind speed was calculated for the years 2000-2019 at the Walney site, using data from Climate Data Service (Hersbach et al., 2018). The year with the lowest mean annual wind speed, of 8.14 m/s, was 2010, 89.3% of the case study year mean wind speed, 9.11 m/s. It was chosen to use a modified 2019 wind dataset for this scenario, with an intermediate factor of 0.95 applied to all hourly wind speed values. The resulting wind data is shown in Figure 6.1. This intermediate factor prevents the result becoming too detached from grid frequency and electricity market prices, because only wind speed is modified.

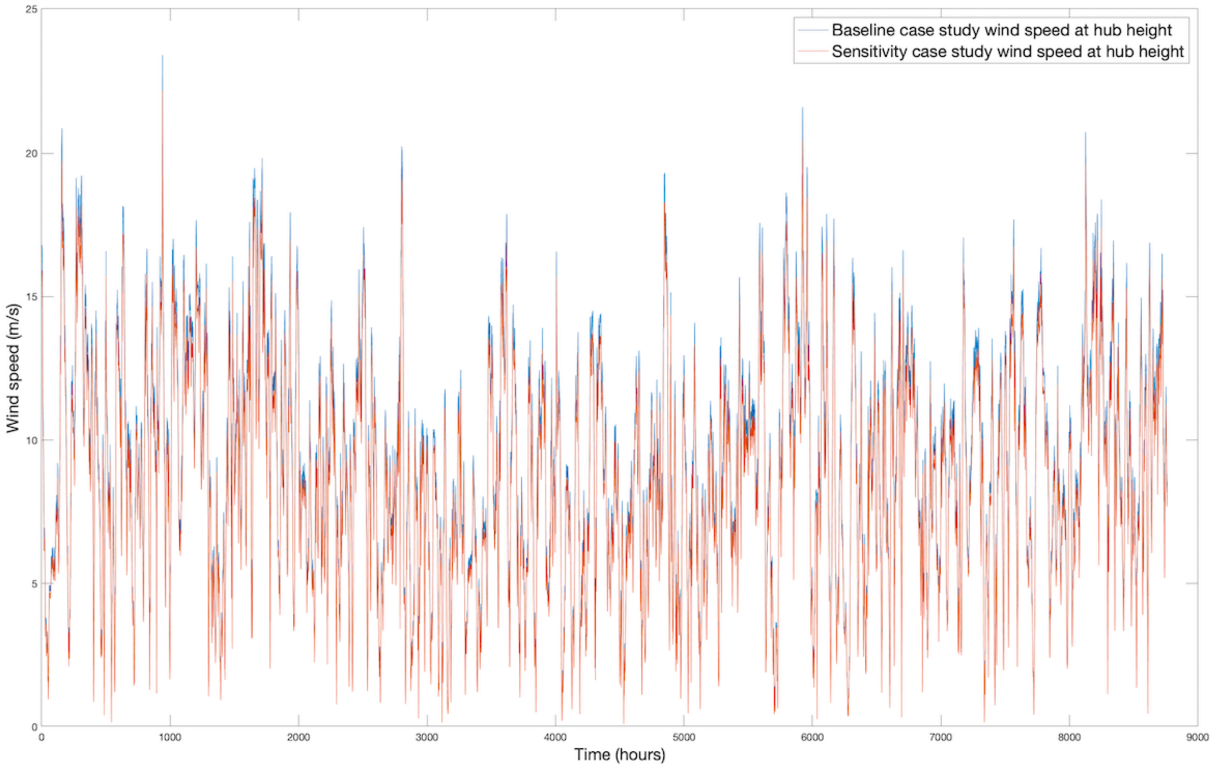

Figure 6.1: Bad wind year alongside regular 2019 wind year at the Walney wind farm site.

In Table 6.1 below, compositions and results for the bad wind year are shown, presented in the following order: First the individual services/markets, with the BS service, FFR static secondary service and then FFR dynamic high frequency service, and then the stacked services and markets in the order of: BS plus day-ahead market bidding, BS plus FFR static secondary service, BS plus FFR dynamic high frequency service, BS plus both the FFR static secondary service and FFR dynamic high frequency services, and then finally the FFR static secondary service stacked with the FFR dynamic high frequency service (without the BS service). For the bad wind year results, IRR and LCOE values are not given, as bad wind years are cancelled out, on average, by good wind years (the baseline case study is an average wind year); IRR and LCOE values can be taken to be the same as for the other half of the composition pairs in the baseline case study.

Table 6.1: Simulation results for when a 'bad wind year' dataset is introduced to the baseline case study.

Case study	Identifier	Scen	Wind year	Frequ scen	Sizing				Bid composition						Service avail			E_capac
					N_WT	E_crank	E_extra	Initial SoC	P_BS	t_BS	FFR stat	FFR dyn	f day-ahead	Batt strat	BS	FFR stat	FFR dyn	
(-)	(-)	(-)	(-)	(-)	(Wind turbines)	(MWh)	(MWh)	(-)	(MW)	(h)	(MW)	(MW)	(-)	(-)	(-)	(-)	(-)	(MWh)
Sensitivity case study: Bad wind year	SBWY1	2	2	1	100	0.0166	256	0.95	20	10	0	0	0	1	1	-	-	259
	SBWY2	3	2	1	100	0	59	0.95	0	0	108	0	0	1	-	1	-	59
	SBWY3	4	2	1	100	0	183	0.49	0	0	0	168	0	1	-	-	1	183
	SBWY4	6	2	1	100	0.0166	256	0.95	20	10	0	0	0.3	1	0.919	-	-	259
	SBWY5	6	2	1	100	0.0166	257	0.95	20	10	30	0	0	1	1	1	-	260
	SBWY6	6	2	1	100	0.0166	257	0.95	20	10	108	0	0	1	1	1	-	260
	SBWY7	6	2	1	100	0.0166	292	0.85	20	10	0	30	0	1	1	-	1	295
	SBWY8	6	2	1	100	0.0166	272	0.85	20	10	0	30	0	1	0.944	-	1	275
	SBWY9	6	2	1	100	0.0166	293	0.85	20	10	30	30	0	1	1	1	1	296
	SBWY10	6	2	1	100	0	151	0.85	0	0	30	30	0	1	-	1	1	151

These results are discussed in the same order that they are given, and are paired with the identical results from the baseline case study. For the results of composition pairs BaBS3 and SBWY1,BaFFRS3 and SBWY2, BaFFRD3 and SBWY3, BaS2 and SBWY5, BaS4 and SBWY6, BaS5 and SBWY7, BaS7 and SBWY9, BaS9 and SBWY10, no effect on either BS, FFR static secondary or FFR dynamic high frequency service availability is seen, for the compositions that those respective services are relevant. For the results of composition pairs BaS1 and SBWY4, and BaS6 and SBWY8, BS availability is reduced from 0.923 to 0.919, and from 0.950 to 0.944 respectively. No effect on FFR static secondary or FFR dynamic high frequency service availability is seen for pair BaS6 and SBWY8.

Therefore in general, the effects of the bad wind year must occur in balancing market operations, by reducing generation - load mismatch, rather than affecting BS or FFR availability, because the storage provision has sufficient margin of safety, except for cases SBWY4 and SBWY8. Even so, the effect of the bad wind year on the latter two results, reducing availability of the BS service by less than 1%, is negligible as the BS service can still be provided with an availability of more than 90%. Because cases SBWY4 and SBWY8 do not have sufficient margin of safety in energy storage, they rely somewhat on the wind turbines to produce energy for the BS requirement. Comparisons between compositions BaS6 and SBWY8 can be seen in Figures 6.2 and 6.3 below.

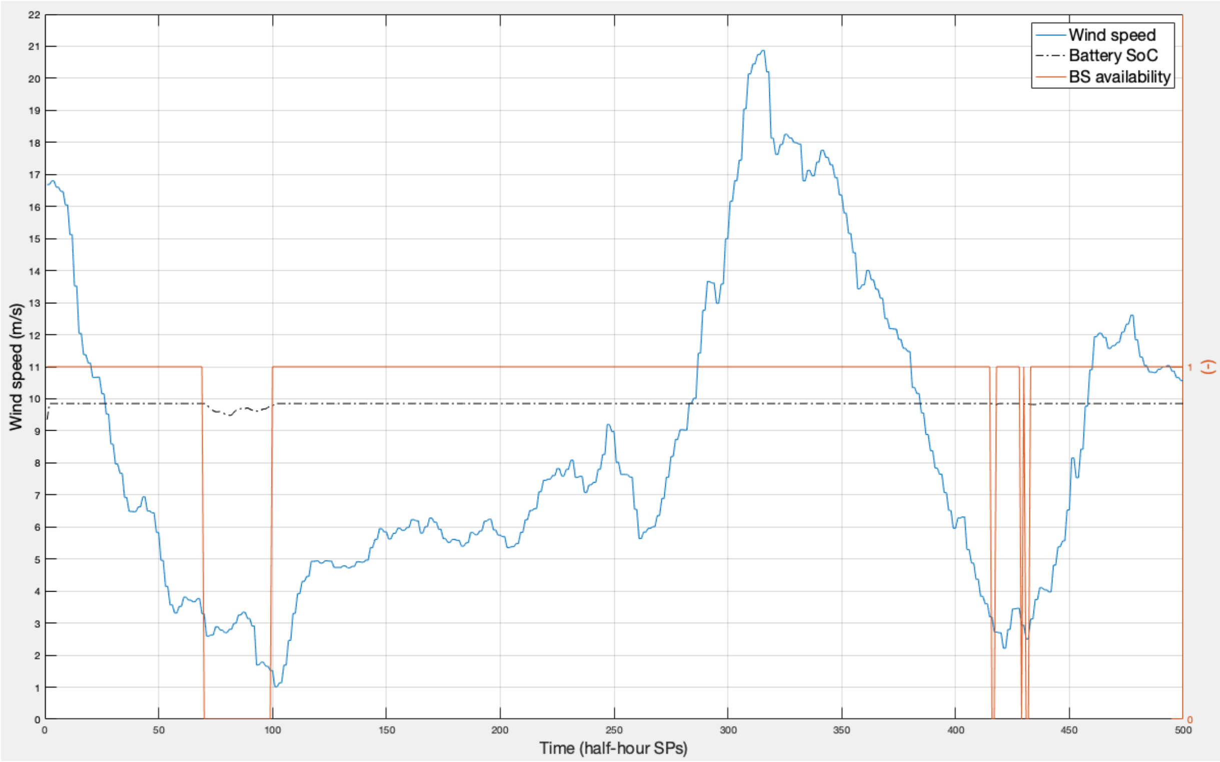

Figure 6.2: Segment of the simulation of composition BaS6, showing wind speed, battery SoC and the resulting BS availability.

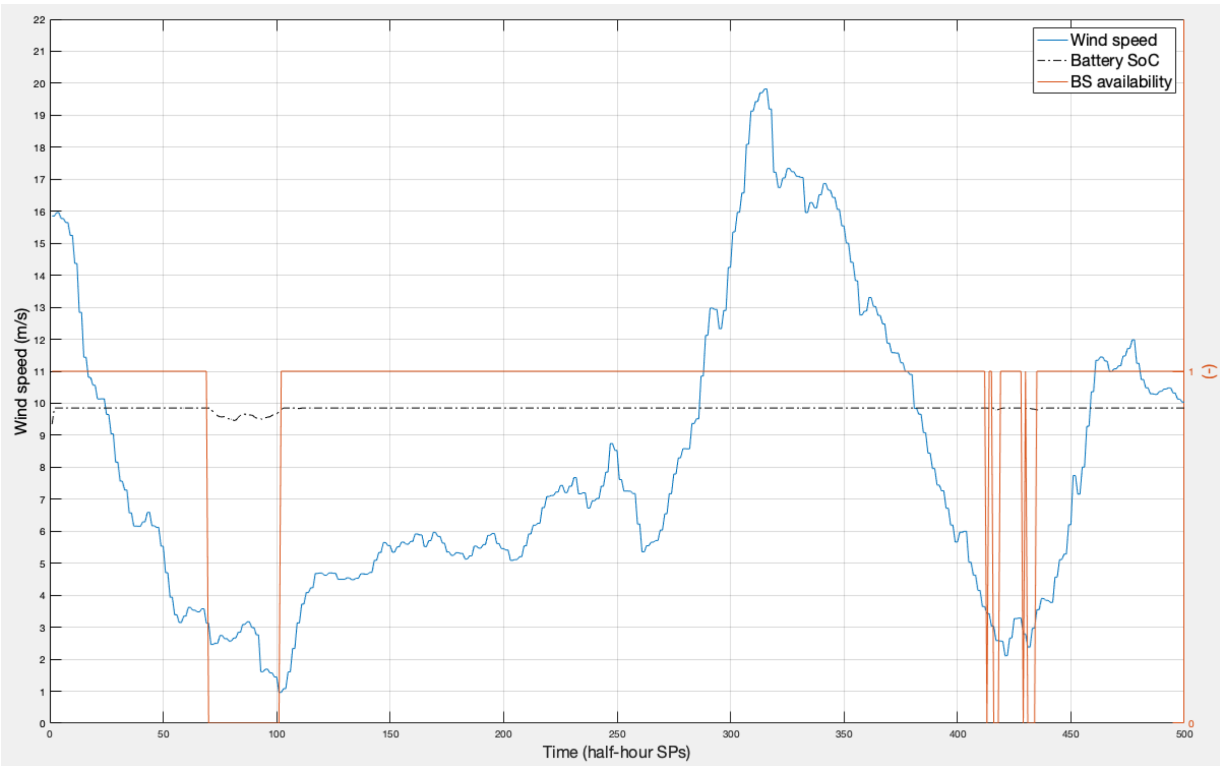

Figure 6.3: Segment of the simulation of composition SBWY8, showing wind speed, battery SoC and the resulting BS availability.

As seen for the results of composition pairs BaS6, and SBWY8, BS availability for the latter is reduced due to more occurrences of wind speed falling below cut-in wind speed, in addition to the fact that lower wind speeds slightly reduce battery charging after a discharge due to providing energy for the FFR dynamic high frequency service (compare SPs' of range 60 to 110, for example). The reduction of BS availability can be clearly seen between SPs' 400 and 450.

To improve BS availability for composition SBWY8 without affecting dynamic high frequency service availability, storage capacity should be increased, so the FFR dynamic high frequency service can still be supplied, with sufficient energy for a BS (instead of reducing the dynamic high frequency service bid, which would allow a higher SoC). A wind turbine with a lower cut-in wind speed would have a negligible effect on increasing BS availability, compared to increased storage capacity, due to the cubic relationship between wind speed and wind farm power. The same reason for a reduction in BS availability is true for composition pair BaS1 and SBWY4 (it is not due to the day-ahead market bid, which is proportionally reduced in line with the lower expected wind speeds). For a BS system more reliant on wind generation (and less reliant on energy storage), which would require a higher annual average wind speed, the effect of a bad wind year could have a greater effect on BS service availability, but this is not explored in this study.

6.2 Change in BS service requirements

To assess the sensitivity of stack selections to a change in BS service requirements, both less and more demanding requirements are assigned. This includes shortening and extending the BS duration, and reducing and increasing the BS power requirement. Compositions and results for the modified BS requirements are shown in Table 6.2, presented in the following order: First the individual BS service, followed by the stacks, of BS plus day-ahead market bidding, BS plus FFR static secondary service, BS plus FFR dynamic high frequency service and finally BS plus both the FFR static secondary service and FFR dynamic high frequency services. These results are given in sets for each BS service modification; first the 20 MW - 24 hour duration, then 35 MW - 10 hour duration, 50 MW - 10 hour duration, 20 MW - 5 hour duration and finally the 10 MW - 10 hour duration.

Table 6.2: Compositions and resulting IRR and LCOE values when BS requirements are modified from the baseline case study.

					Sizing				Bid composition						Service avail						Capital investment		Ann cost			Balancing market				FFR static		FFR dynamic	
Case study	Identifier	Scen	Wind year	Frequ scen	N_WT	E_crank	E_extra	Initial SoC	P_BS	t_BS	FFR stat	FFR dyn	f day-ahead	Batt strat	BS	FFR stat	FFR dyn	E_capac	LCOE	Ann IRR	Wind farm	Battery	Wind farm	Battery	Total ann revenue	Ann revenue	Ann cost	Day-ahead market ann revenue	BS ann revenue	Ann avail revenue	Ann energy revenue/cost	Ann avail revenue	Ann energy revenue/cost
(-)	(-)	(-)	(-)	(-)	(Wind turbines)	(MWh)	(MWh)	(-)	(MW)	(h)	(MW)	(MW)	(-)	(-)	(-)	(-)	(-)	(MWh)	(£/MWh)	(%)	(M£)	(M£)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)
Sensitivity case study: Modified BS requirements	SMBS1	2	1	1	100	0.0166	256	0.95	20	24	0	0	0	1	0.600	-	-	259	122.0	-4.5	2509.6	667.0	60.8	4.9	125.8	125.8	0	0	0.01	0	0	0	0
	SMBS2	2	1	1	100	0.0166	619	0.95	20	24	0	0	0	1	1	-	-	622	155.2	-6.4	2509.6	1600.6	60.8	11.8	126.8	126.8	0	0	0.02	0	0	0	0
	SMBS3	6	1	1	100	0.0166	619	0.95	20	24	0	0	0.3	1	0.826	-	-	622	154.6	-6.4	2509.6	1600.6	60.8	11.8	127.4	86.1	-0.1	41.4	0.02	0	0	0	0
	SMBS4	6	1	1	100	0.0166	619	0.95	20	24	0	0	0.15	1	1	-	-	622	154.8	-6.4	2509.6	1600.6	60.8	11.8	127.1	106.3	0	20.8	0.02	0	0	0	0
	SMBS5	6	1	1	100	0.0166	620	0.95	20	24	30	0	0	1	1	1	-	623	155.3	-6.4	2509.6	1603.2	60.8	11.8	127.4	126.8	0	0	0.02	0.6	0.002	0	0
	SMBS6	6	1	1	100	0.0166	620	0.95	20	24	108	0	0	1	1	1	-	623	155.3	-6.2	2509.6	1603.2	60.8	11.8	129.1	126.8	0	0	0.02	2.3	0.008	0	0
	SMBS7	6	1	1	100	0.0166	655	0.85	20	24	0	30	0	1	1	-	1	658	158.4	-6.4	2509.6	1693.2	60.8	12.5	128.8	126.8	0	0	0.02	0	0	1.90	0.14
	SMBS8	6	1	1	100	0.0166	656	0.85	20	24	30	30	0	1	1	1	1	659	158.4	-6.4	2509.6	1695.8	60.8	12.5	129.5	126.8	0	0	0.02	0.6	0.002	1.90	0.14
	SMBS9	2	1	1	100	0.0166	436	0.95	35	10	0	0	0	1	1	-	-	439	138.4	-5.5	2509.6	1129.9	60.8	8.3	126.3	126.3	0	0	0.04	0	0	0	0
	SMBS10	6	1	1	100	0.0166	436	0.95	35	10	0	0	0.15	1	1	-	-	439	138.4	-5.5	2509.6	1129.9	60.8	8.3	126.9	106.1	0	20.8	0.04	0	0	0	0
	SMBS11	6	1	1	100	0.0166	437	0.95	35	10	30	0	0	1	1	1	-	440	138.5	-5.5	2509.6	1132.5	60.8	8.4	127.0	126.3	0	0	0.04	0.6	0.002	0	0
	SMBS12	6	1	1	100	0.0166	437	0.95	35	10	108	0	0	1	1	1	-	440	138.5	-5.3	2509.6	1132.5	60.8	8.4	128.6	126.3	0	0	0.04	2.3	0.008	0	0
	SMBS13	6	1	1	100	0.0166	472	0.85	35	10	0	30	0	1	1	-	1	475	141.7	-5.5	2509.6	1222.5	60.8	9.0	128.4	126.4	0	0	0.04	0	0	1.90	0.14
	SMBS14	6	1	1	100	0.0166	473	0.85	35	10	30	30	0	1	1	1	1	476	141.8	-5.5	2509.6	1225.1	60.8	9.1	129.1	126.4	0	0	0.04	0.6	0.002	1.90	0.14
	SMBS15	2	1	1	100	0.0166	615	0.95	50	10	0	0	0	1	1	-	-	618	154.8	-6.4	2509.6	1590.3	60.8	11.7	126.8	126.8	0	0	0.06	0	0	0	0
	SMBS16	6	1	1	100	0.0166	615	0.95	50	10	0	0	0.15	1	1	-	-	618	154.5	-6.4	2509.6	1590.3	60.8	11.7	127.2	106.3	0	20.8	0.06	0	0	0	0
	SMBS17	6	1	1	100	0.0166	616	0.95	50	10	30	0	0	1	1	1	-	619	154.9	-6.4	2509.6	1592.9	60.8	11.8	127.5	126.8	0	0	0.06	0.6	0.002	0	0
	SMBS18	6	1	1	100	0.0166	616	0.95	50	10	108	0	0	1	1	1	-	619	154.9	-6.2	2509.6	1592.9	60.8	11.8	129.1	126.7	0	0	0.06	2.3	0.008	0	0
	SMBS19	6	1	1	100	0.0166	651	0.85	50	10	0	30	0	1	1	-	1	654	158.0	-6.4	2509.6	1682.9	60.8	12.4	128.9	126.8	0	0	0.06	0	0	1.90	0.14
	SMBS20	6	1	1	100	0.0166	652	0.85	50	10	30	30	0	1	1	1	1	655	158.1	-6.3	2509.6	1685.5	60.8	12.5	129.5	126.8	0	0	0.06	0.6	0.002	1.90	0.14
	SMBS21	2	1	1	100	0.0166	127	0.95	20	5	0	0	0	1	1	-	-	130	110.4	-3.7	2509.6	335.2	60.8	2.5	125.4	125.4	0	0	0.02	0	0	0	0
	SMBS22	6	1	1	100	0.0166	127	0.95	20	5	0	0	0.15	1	1	-	-	130	110.4	-3.7	2509.6	335.2	60.8	2.5	126.0	105.2	0.0	20.8	0.02	0	0	0	0
	SMBS23	6	1	1	100	0.0166	128	0.95	20	5	30	0	0	1	1	1	-	131	110.5	-3.7	2509.6	337.8	60.8	2.5	126.1	125.4	0	0	0.02	0.6	0.002	0	0
	SMBS24	6	1	1	100	0.0166	128	0.95	20	5	108	0	0	1	1	1	-	131	110.5	-3.5	2509.6	337.8	60.8	2.5	127.7	125.4	0	0	0.02	2.3	0.008	0	0
	SMBS25	6	1	1	100	0.0166	163	0.85	20	5	0	30	0	1	1	-	1	166	113.6	-3.8	2509.6	427.8	60.8	3.2	127.5	125.5	0	0	0.02	0	0	1.90	0.14
	SMBS26	6	1	1	100	0.0166	164	0.85	20	5	30	30	0	1	1	1	1	167	113.7	-3.7	2509.6	430.3	60.8	3.2	128.2	125.5	0	0	0.02	0.6	0.002	1.90	0.14
	SMBS27	2	1	1	100	0.0166	137	0.95	10	10	0	0	0	1	1	-	-	140	111.3	-3.8	2509.6	360.9	60.8	2.7	125.4	125.4	0	0	0.01	0	0	0	0
	SMBS28	6	1	1	100	0.0166	137	0.95	10	10	0	0	0.15	1	1	-	-	140	111.3	-3.7	2509.6	360.9	60.8	2.7	126.0	105.3	0.0	20.8	0.01	0	0	0	0
	SMBS29	6	1	1	100	0.0166	138	0.95	10	10	30	0	0	1	1	1	-	141	111.4	-3.7	2509.6	363.5	60.8	2.7	126.1	125.4	0	0	0.01	0.6	0.002	0	0
	SMBS30	6	1	1	100	0.0166	138	0.95	10	10	108	0	0	1	1	1	-	141	111.4	-3.6	2509.6	363.5	60.8	2.7	127.8	125.4	0	0	0.01	2.3	0.008	0	0
	SMBS31	6	1	1	100	0.0166	173	0.85	10	10	0	30	0	1	1	-	1	176	114.5	-3.8	2509.6	453.5	60.8	3.4	127.6	125.5	0	0	0.01	0	0	1.90	0.14
	SMBS32	6	1	1	100	0.0166	174	0.85	10	10	30	30	0	1	1	1	1	177	114.6	-3.8	2509.6	456.1	60.8	3.4	128.2	125.5	0	0	0.01	0.6	0.002	1.90	0.14

These results are further visualised, in a comparison to the baseline case study results, in Figure 6.4 below.

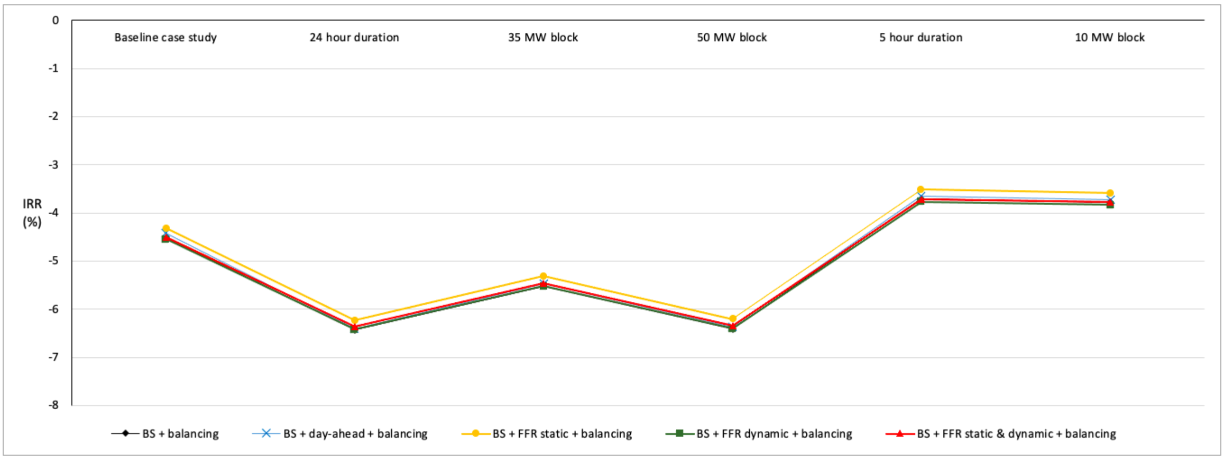

Figure 6.4: BS baseline case study results (20 MW power and 10 hour duration) compared with sensitivity case study results, for different stack combinations.

Now the results in Table 6.2 above are discussed. The 24 hour BS duration results demonstrate that when operating the BS system alone, a system with 259.32 MWh of storage that could previously produce a 100% available 10 hour duration BS system (as in the results for composition BaBS3), can now only produce a BS availability of 60%, as in the result for composition SMBS1. In order to achieve 100% BS availability for a 24 hour duration, a 622.32 MWh battery system is required; this is obvious, as the increased energy storage matches the increased duration requirement. This results in a reduction of IRR from -4.5% to -6.4%, making BS provision even more less unprofitable.
When increasing the BS power bid requirement, to 35 and 50 MW, it is found that again, as expected, more storage is required, and a reduction in IRR is seen, because there are now more instances where power from the wind farm is not sufficient, and as such the cost of storage goes up. As a result, it is clear that the BS availability payment increase per MW is insufficient to account for extra provided battery capacity.

If reducing the 20 MW BS duration requirement to five hours, 100 % BS availability can be achieved with a reduced storage capacity of 130.32 MWh, leading to IRR and LCOE improvements when comparing results for composition SMBS21 when compared to BaBS3. If reducing the BS power requirement from 20 MW to 10 MW, keeping the 10 hour duration, 100 % BS availability can be achieved with a reduced storage size of 140.32 MWh; this leads to IRR and LCOE improvements shown for composition SMBS27.
Compared to the baseline case, the modified BS requirement sets eliminate many of the small differences between IRR values for different stacks, although it is still clear that when operating the BS service, stacked it with the FFR static secondary service is the most profitable stack in all instances of BS requirement modification. Comparing the BS sensitivity study results to the baseline results for FFR static secondary and dynamic high frequency services, it can be seen that even when reducing BS requirements, it is still more profitable to operate the FFR static secondary and/or FFR dynamic high frequency services alone without the BS.

6.3 Increased grid frequency deviations

Finally, it is worth exploring the effect of increasing frequency deviations on stack selections. This is due to a higher level of VRES, as the UK government are planning to generate 50% of renewable electricity by 2030 (Fawthrop, 2020). Not intended to replicate a specific percentage of electricity being renewable, the modified 2019 dataset was created by increasing any deviation of frequency from 50 Hz by 20%. The increased deviation frequency data is shown below in Figure 6.5, alongside 2019 frequency data and 2014 frequency data to provide a point of comparison (from 2014 to 2019, UK renewable electricity production increased from 19% to 37%) (Department of Energy and Climate Change, 2015; Department for Business, 2020).

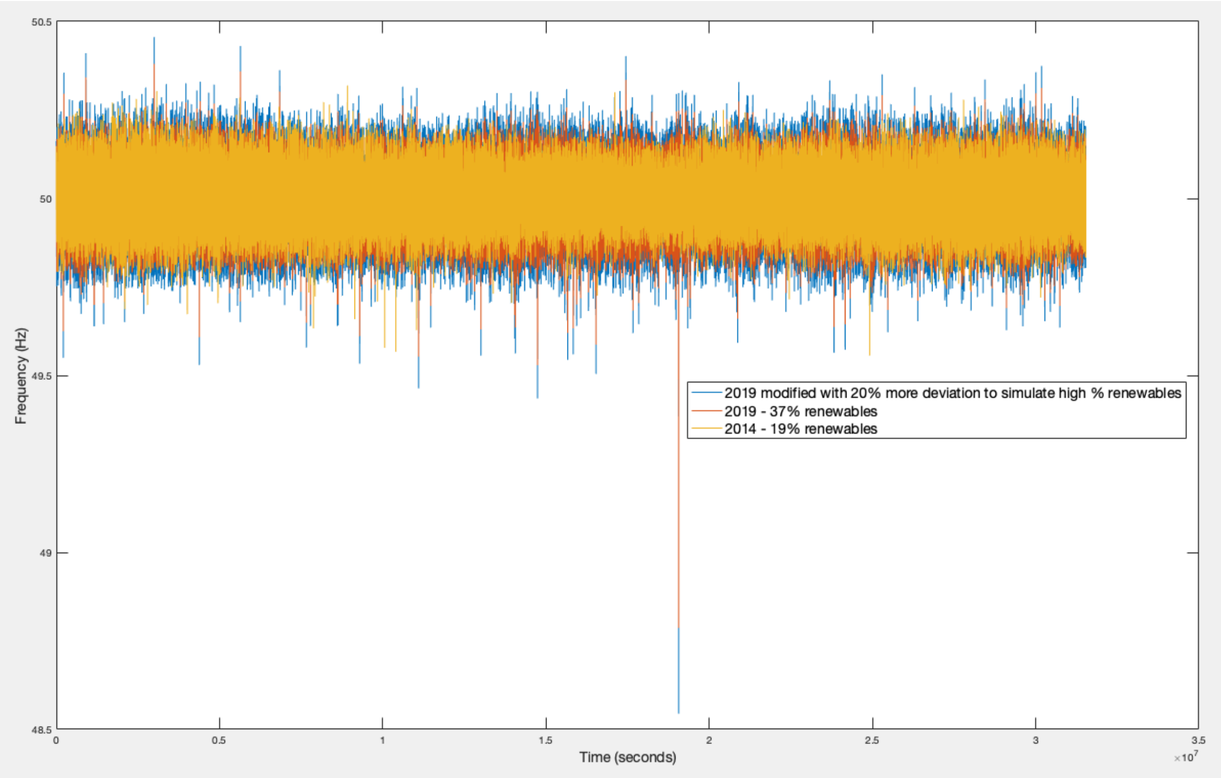

Figure 6.5: Modified 2019 frequency data, alongside original 2019 frequency data and 2014 frequency data.

Sensitivity of the stacking results to increased frequency deviations is shown in Table 6.3 below, with results presented in the following order: First the individual services/markets, with the FFR static secondary service and then FFR dynamic high frequency service, and then the stacked services and markets in the order of: BS plus FFR static secondary service, BS plus FFR dynamic high frequency service, BS plus both the FFR static secondary service and FFR dynamic high frequency services, and then finally the FFR static secondary service stacked with the FFR dynamic high frequency service (without the BS service). The first nine rows are for the 20% increased frequency deviations, then the following four rows are for 50% increased frequency deviations. and the last four rows are for 100% increased frequency deviations.

Table 6.3: IRR and LCOE results for when frequency deviations are increased 20%, 50% and 100% from the baseline case study.

Case study	Identifier	Scen	Wind year	Frequ scen	Sizing				Bid composition						Service avail			E_capac
					N_WT	E_crank	E_extra	Initial SoC	P_BS	t_BS	FFR stat	FFR dyn	f day-ahead	Batt strat	BS	FFR stat	FFR dyn	
(-)	(-)	(-)	(-)	(-)	(Wind turbines)	(MWh)	(MWh)	(-)	(MW)	(h)	(MW)	(MW)	(-)	(-)	(-)	(-)	(-)	(MWh)
Sensitivity case study: Increased frequency deviations	SIFD1	3	1	2	100	0	59	0.95	0	0	108	0	0	1	-	1	-	59
	SIFD2	4	1	2	100	0	183	0.49	0	0	0	168	0	1	-	-	1	183
	SIFD3	6	1	2	100	0.0166	257	0.95	20	10	30	0	0	1	1	1	-	260
	SIFD4	6	1	2	100	0.0166	257	0.95	20	10	108	0	0	1	0.989	1	-	260
	SIFD5	6	1	2	100	0.0166	298	0.85	20	10	0	30	0	1	1	-	1	301
	SIFD6	6	1	2	100	0.0166	272	0.85	20	10	108	30	0	1	0.946	1	1	275
	SIFD7	6	1	2	100	0.0166	301	0.85	20	10	30	30	0	1	1	1	1	304
	SIFD8	6	1	2	100	0	151	0.85	0	0	30	30	0	1	-	1	1	151
	SIFD9	6	1	2	100	0	151	0.85	0	0	108	30	0	1	-	1	1	151
	SIFD10	3	1	3	100	0	59	0.95	0	0	108	0	0	1	-	1	-	59
	SIFD11	4	1	3	100	0	183	0.49	0	0	0	168	0	1	-	-	1	183
	SIFD12	6	1	3	100	0.0166	257	0.95	20	10	108	0	0	1	0.966	1	-	260
	SIFD13	6	1	3	100	0.0166	298	0.85	20	10	0	30	0	1	0.999	-	1	301
	SIFD14	6	1	3	100	0.0166	301	0.85	20	10	30	30	0	1	0.999	1	1	304
	SIFD15	6	1	3	100	0	151	0.85	0	0	108	30	0	1	-	1	1	151
	SIFD16	3	1	4	100	0	59	0.95	0	0	108	0	0	1	-	1	-	59
	SIFD17	4	1	4	100	0	183	0.49	0	0	0	168	0	1	-	-	1	183
	SIFD18	6	1	4	100	0.0166	257	0.95	20	10	108	0	0	1	0.940	1	-	260
	SIFD19	6	1	4	100	0.0166	298	0.85	20	10	0	30	0	1	0.997	-	1	301
	SIFD20	6	1	4	100	0.0166	301	0.85	20	10	30	30	0	1	0.994	1	1	304
	SIFD21	6	1	4	100	0	151	0.85	0	0	108	30	0	1	-	1	1	151

Identifier	LCOE	Ann IRR	Capital investment		Ann cost		Total ann revenue	Balancing market		Day-ahead market ann revenue	BS ann revenue	FFR static		FFR dynamic	
			Wind farm	Battery	Wind farm	Battery		Ann revenue	Ann cost			Ann avail revenue	Ann energy revenue/cost	Ann avail revenue	Ann energy revenue/cost
(-)	(£/MWh)	(%)	(M£)	(M£)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)	(M£/yr)
SIFD1	104.0	-3.0	2509.6	151.7	60.8	1.1	127.5	125.2	0.0	0	0	2.3	0.039	0	0
SIFD2	115.1	-3.1	2509.6	470.7	60.8	3.5	137.1	125.7	-0.2	0	0	0	0	10.61	0.98
SIFD3	122.1	-4.5	2509.6	669.5	60.8	4.9	126.4	125.8	0	0	0.02	0.6	0.011	0	0
SIFD4	122.1	-4.3	2509.6	669.5	60.8	4.9	128.1	125.7	0	0	0.02	2.3	0.039	0	0
SIFD5	125.9	-4.6	2509.6	775.0	60.8	5.7	128.0	125.9	0	0	0.02	0	0	1.90	0.17
SIFD6	123.5	-4.2	2509.6	708.1	60.8	5.2	130.2	125.8	0	0	0.02	2.3	0.039	1.90	0.17
SIFD7	126.1	-4.5	2509.6	782.7	60.8	5.8	128.6	125.9	0	0	0.02	0.6	0.011	1.90	0.17
SIFD8	112.3	-3.6	2509.6	388.4	60.8	2.9	128.2	125.4	0	0	0	0.6	0.011	1.90	0.17
SIFD9	112.3	-3.5	2509.6	388.4	60.8	2.9	129.8	125.4	0	0	0	2.3	0.039	1.90	0.17
SIFD10	104.0	-3.0	2509.6	151.7	60.8	1.1	127.5	125.0	0.0	0.0	0.00	2.3	0.205	0.00	0.00
SIFD11	115.1	-3.0	2509.6	470.7	60.8	3.5	137.4	125.8	-0.2	0	0	0	0	10.61	1.27
SIFD12	122.1	-4.3	2509.6	669.5	60.8	4.9	128.1	125.6	0	0	0.02	2.3	0.205	0	0
SIFD13	125.9	-4.6	2509.6	775.0	60.8	5.7	128.0	125.9	0	0	0.02	0	0	1.90	0.23
SIFD14	126.1	-4.5	2509.6	782.7	60.8	5.8	128.7	125.8	0	0	0.02	0.6	0.057	1.90	0.23
SIFD15	112.3	-3.5	2509.6	388.4	60.8	2.9	129.9	125.3	0	0	0	2.3	0.205	1.90	0.23
SIFD16	104.0	-3.0	2509.6	151.7	60.8	1.1	127.7	124.5	-0.1	0	0	2.3	0.924	0	0
SIFD17	115.1	-3.0	2509.6	470.7	60.8	3.5	138.0	125.9	-0.4	0	0	0	0	10.61	1.77
SIFD18	122.1	-4.3	2509.6	669.5	60.8	4.9	128.3	125.0	0	0.0	0.02	2.3	0.924	0.00	0.00
SIFD19	125.9	-4.6	2509.6	775.0	60.8	5.7	128.1	125.9	0.0	0.0	0.02	0.0	0.000	1.90	0.32
SIFD20	126.1	-4.5	2509.6	782.7	60.8	5.8	128.8	125.7	0.0	0.0	0.02	0.6	0.257	1.90	0.32
SIFD21	112.3	-3.4	2509.6	388.4	60.8	2.9	130.1	124.7	0.0	0.0	0.00	2.3	0.924	1.90	0.32

Now the results in Table 6.3 above are discussed. Comparing results from compositions BaFFRS3 and SIFD1, for the static secondary service alone, the 20% increased frequency deviations have a negligible effect on either IRR or LCOE. This is because the energy provided in the 2019 case study year by the static secondary service is low, due to low frequency deviations already; the 20% increase doesn't have much effect on load.

Comparing BaFFRD3 and SIFD2, for the dynamic high frequency service alone, is the same story; a negligible change in IRR and LCOE is seen, due to a slightly higher energy demand. This indicates that the majority of revenue for FFR static secondary and dynamic high frequency services comes from the FFR availability fee and the balancing market. Other results mirror the points made for the two results above, and as a result, the increased frequency deviations have a negligible effect on the profitability or preference of stacks.

However, when comparing compositions BaS5 and SIFD5, BaS7 and SIFD7, it is seen that higher quantities of storage (6 MWh more and 8 MWh more respectively) are required to retain the same BS service availability. Likewise, when comparing pair BaS8 and SIFD6, a very small reduction in BS service availability is seen, with the same storage sizing used. Though as previously stated, the effect on profitability is small or negligible in these cases.

To quantify the size of these increased frequency deviations, the mean FFR static secondary load between results BaS4 and SIFD4 are compared; mean FFR static secondary load increased from 0.015 MW in the results of composition BaS4 to 0.073 MW in SIFD4. Based on the limited effect of 20% increased frequency deviations, it was decided to trial 50% increased frequency deviations, shown below in Figure 6.6.

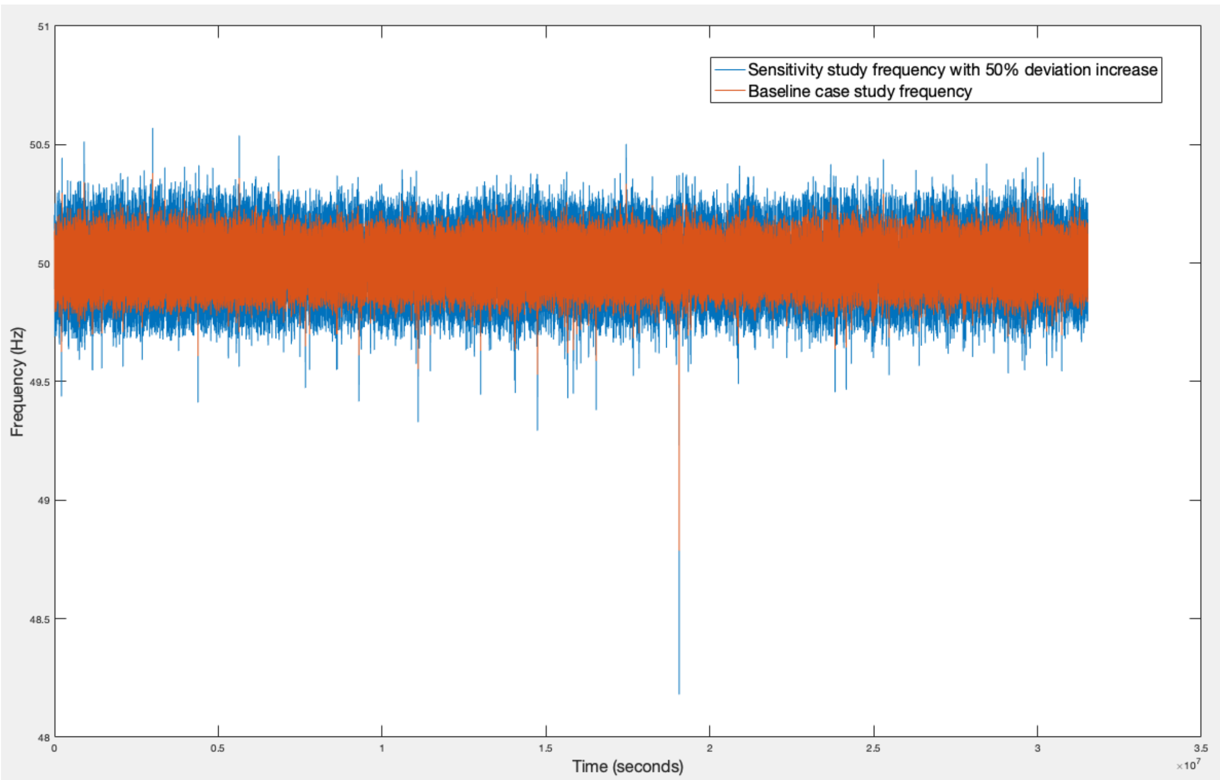

Figure 6.6: 50% enhanced frequency variation compared to baseline case study frequency.

For the results of compositions SIFD1 to SIFD10, SIFD4 to SIFD12, SIFD5 to SIFD13, SIFD7 to SIFD14, SIFD9 to SIFD15, no increase in IRR can be seen, although for the example of SIFD4 to SIFD12, the mean FFR static secondary load increases from 0.073 MW to 0.402 MW. A 0.1% increase in IRR can be seen from SIFD2 to SIFD11. Therefore increasing the frequency deviation from 20% to 50% has virtually zero effect on the profitability of FFR static or dynamic services. A small reduction in BS availability can be seen from the results of compositions SIFD4, SIFD6, SIFD7 to SIFD12, SIFD13 and SIFD14 respectively, given the same respective storage sizing. Lastly, it was decided to trial a 100% increase in frequency deviations, seen in Figure 6.7.

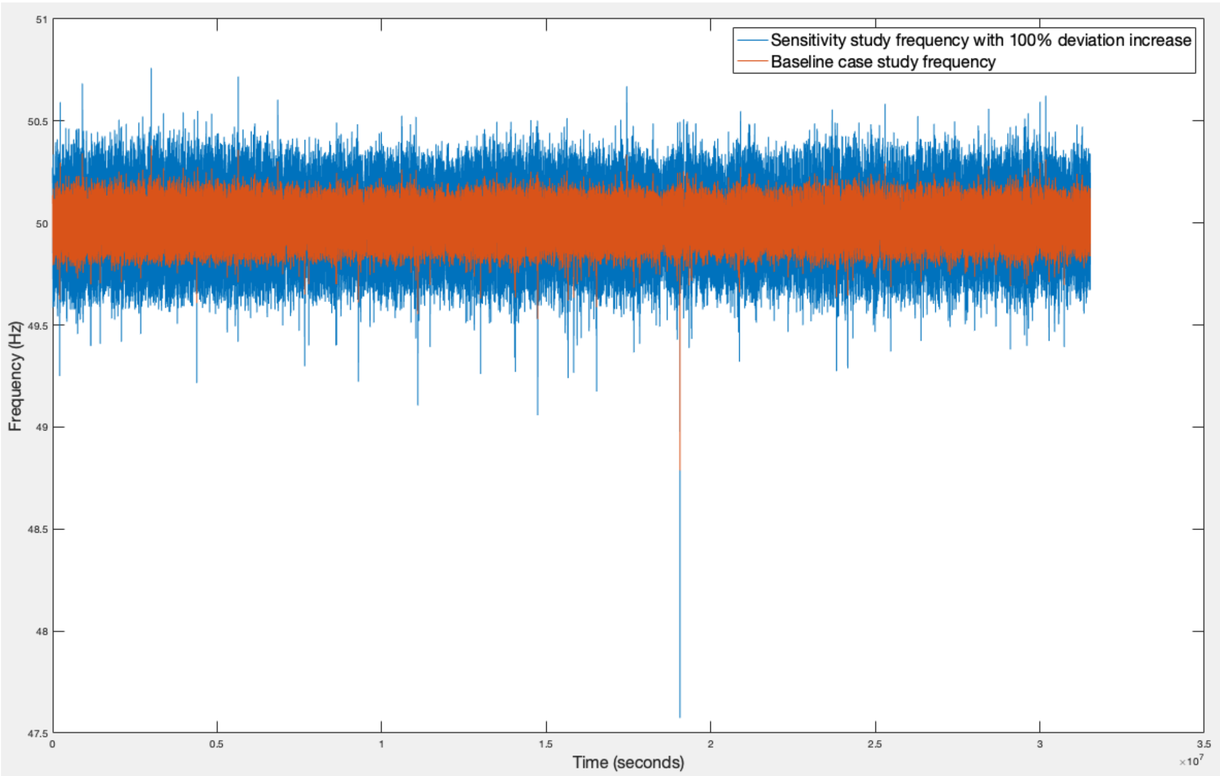

Figure 6.7: 100% enhanced frequency variation compared to baseline case study frequency.

No change in IRR can be seen from the results of compositions SIFD10 to SIFD16, SIFD11 to SIFD17, SIFD12 to SIFD18, SIFD13 to SIFD19 or from SIFD14 to SIFD20. Although for the example of SIFD12 to SIFD18, mean FFR static secondary load increases from 0.402 MW to 1.877 MW. From SIFD15 to SIFD21, a 0.1% increase in IRR can be seen; therefore increasing the frequency deviation from 50% to 100% has almost no effect on the profitability of FFR static or dynamic services. Again, a small reduction in BS availability can be seen from the results of compositions SIFD12, SIFD13 and SIFD14 to SIFD18, SIFD19 and SIFD20 respectively, again given the same respective storage sizing.

7 Conclusion

In this chapter, the satisfaction of the research objectives is assessed, as is the implementation of the project. Recommendations for further work are then made.

7.1 Results evaluation

In this section, the baseline case study and sensitivity case study results will be evaluated against the research objectives, for which the main objective was, for a wind farm with a co-located battery system, to identify the pros and cons of different service stacks, and understand how these stacks are affected by changing operational and environmental variables. The questions asked to answer this main question are given below, with conclusions stated.

7.1.1 For a location in the UK, what is required to implement a wind farm, with on-site battery storage capable of providing the BS service?

It was found that for a WF with on-site battery, providing a BS service while managing mismatch in the balancing market requires a significant amount of battery energy storage, sized equal to the quantity of energy that must be delivered during the BS, because for the case study wind farm, wind energy cannot be sufficiently relied upon. It was also found that providing a BS service for this case study isn't profitable. When providing a BS service, income is heavily reliant upon the sale of excess generation in the balancing market, because of the low price paid for providing a BS service.

7.1.2 For a wind farm-battery system, what is required to implement the FFR static low frequency secondary service?

It was found that for a WF with on-site battery, providing an FFR static secondary service alone while managing mismatch in the balancing market requires a relatively small amount of storage, but isn't profitable. It was learnt that energy supplied is far lower than bid volume would suggest, as frequency deviations seldom reach the point of maximum delivery. Like the BS service, income for a wind farm-battery system providing an FFR static secondary service heavily relies upon the sale of excess wind energy in the balancing markets, because the hourly availability rates paid for providing a FFR static secondary service are quite low, and due to the low amounts of revenue from supplying energy for the service. Providing the FFR static secondary service alone is shown to be much more profitable than providing the BS service alone.

7.1.3 For a wind farm-battery system, what is required to implement the FFR dynamic high frequency service?

It was found that for a WF with on-site battery, providing an FFR dynamic high frequency service requires a larger amount of storage than for the FFR static secondary service, as a battery SoC around 0.5 is required in order to provide equal amounts of storage and supply. Providing this service while managing energy mismatch in the balancing market, for the case study, is not profitable. Despite the larger storage requirement compared to the FFR static secondary service, the higher availability fee paid for the dynamic high frequency service means that the IRR values are very similar for the static secondary and dynamic high frequency services, with the highest dynamic high frequency service bid having a slightly lower rate of return. Providing the FFR dynamic high frequency service alone is much more profitable than providing the BS service alone.

7.1.4 For a wind farm-battery system, what is required to implement grid dispatch in day-ahead and balancing markets?

It was found that operating a wind farm with an on-site battery for this case study in the day-ahead and balancing markets is slightly less profitable when compared with a storage-less system. This is because the cost of storage outweighs the benefit of reducing purchases in the balancing market due to day-ahead wind forecast errors which can lead to over-bidding, noting that in the case study year, the balancing market price is on average lower than the day-ahead price, so mistakes in the day-ahead bid aren't penalised (on average). Further, the addition of storage reduces profit in the balancing market due to charging and discharging losses. Overall, it is found that without (or with only a small quantity of) storage, bidding all forecast energy in the day-ahead market and managing mismatch in the balancing market is the most profitable method of operating a wind farm compared to other services and markets explored here.

7.1.5 How can service stacking produce the optimal economic output?

When comparing both individual and stacked services and markets, it was found that the most profitable action for a wind turbine generator overall, again, is to just sell electricity on the day-ahead and balancing markets without exploring the ancillary services, and without installing battery storage, and therefore, to not stack services. If the ESO wishes to increase BS and FFR market participation without changing service requirements, incentives for the BS and FFR services should be drastically increased. If it is agreed to provide the BS service, then the most profitable stack is with either the FFR static high frequency service or both FFR static secondary and dynamic high frequency services, provided a reduction in BS availability is acceptable for the latter, while managing mismatch in the balancing market. But this is less profitable than the stacked provision of FFR static secondary and FFR dynamic high frequency services without BS provision. Therefore, if currently providing a BS or FFR service alone, it is more profitable to stack additional services or markets, though it is not recommended to stack BS provision alongside operation in the day-ahead market, unless a storage algorithm that prioritises purchasing energy on the balancing market (instead of discharging) in the case of a day-ahead bidding mistake, is used. In this study, an algorithm that prioritised discharging the battery before purchasing energy in the balancing market was used, with controls for provision of FFR static secondary and dynamic high frequency services.

7.1.6 To what external variables are service stack selections most sensitive?

When assessing the sensitivity of service stack selections to external variables, it is found that realistic changes to the annual average wind speed for one year, BS requirements and grid frequency deviations do not change the choice of stack preferred.

Reducing the mean wind speed for one year has no effect on the profitability of stacks, as bad wind years are cancelled out by good wind years on average. Storage is the primary mechanism used to provide BS and FFR services, seldom requiring discharge, while wind speed is mainly used to sell energy on the balancing market. For compositions with insufficient storage for the BS, relying somewhat on wind energy, BS availability is affected. FFR service availability isn't affected, due to conservative storage sizing.

Changing the BS requirements in a realistic manner, which are directly related to storage requirements, has a large effect on the profitability of all results. Reducing BS requirements reduces the storage required and therefore improves the services profitability.

Changing frequency deviation has very little effect on the profitability of FFR services, because response required is negligible compared to other sources of revenue. An even larger frequency deviation increase could change the stack selection, but this would simulate an unstable grid that wouldn't exist for a long period of time in reality. A higher temporal resolution in the model could reduce the amount of storage required, and then increasing frequency deviations may affect stack selections.

7.2 Project assessment

In this section, the execution of the project will be self-assessed. The results of the project are limited due to the compromise of using a half-hour temporal resolution in results, to reduce computational time. This meant that the storage systems used to provide FFR services are conservatively sized, whereas a higher temporal resolution would have allowed for more experimentation with storage for FFR services, which would possibly result in more profitable FFR service provision.

The availability of wind data, which meant using an average hourly wind speed input, instead of 10-minute average wind speeds, means slightly reduce BS availability when the storage is undersized, due to reliance on wind speed, and reduces day-ahead and balancing market sales. However FFR availability is unaffected, which solely depends on storage sizing with the battery algorithm used. Not using 10-minute average wind speed is unlikely to have a noticeable effect on the profitability rank order of the compositions.

7.3 Further work

A similar study for other countries could be conducted, as these grid balancing service types vary from country to country, although in the EU, the services tend to be similar due to ENTSO-E requirements, and many countries in the EU are following a similar path of decarbonisation.

It would be very useful to assess other services and markets, as mentioned in the introduction, especially with the inclusion of the obligatory reactive power service, which is omitted in this study. It is possible that other services not explored here are more profitable, changing the conclusion that operating in the day-ahead market without storage is the most profitable option.

It may be worthwhile to compare this case study location to one with a higher annual mean wind speed location (and appropriate wind turbine), to see how storage requirements for the BS change, though it is likely that significant quantities of storage are still required.

It is worthwhile to explore how realistic the suggestions in Section 5.7 of increasing BS and FFR service availability fees are.

An investigation into how other VRES and storage systems compare for the same service provision would be worthwhile, specifically for a source with less intermittent energy production, such as a geothermal power plant.

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Appendices

A Flowcharts for Scenarios One to Five

In this section, flowcharts for the non-stacked services and markets are shown, to supplement Figure 3.1. Because fewer blocks are required, these flowcharts go into greater detail, for use alongside the model section.

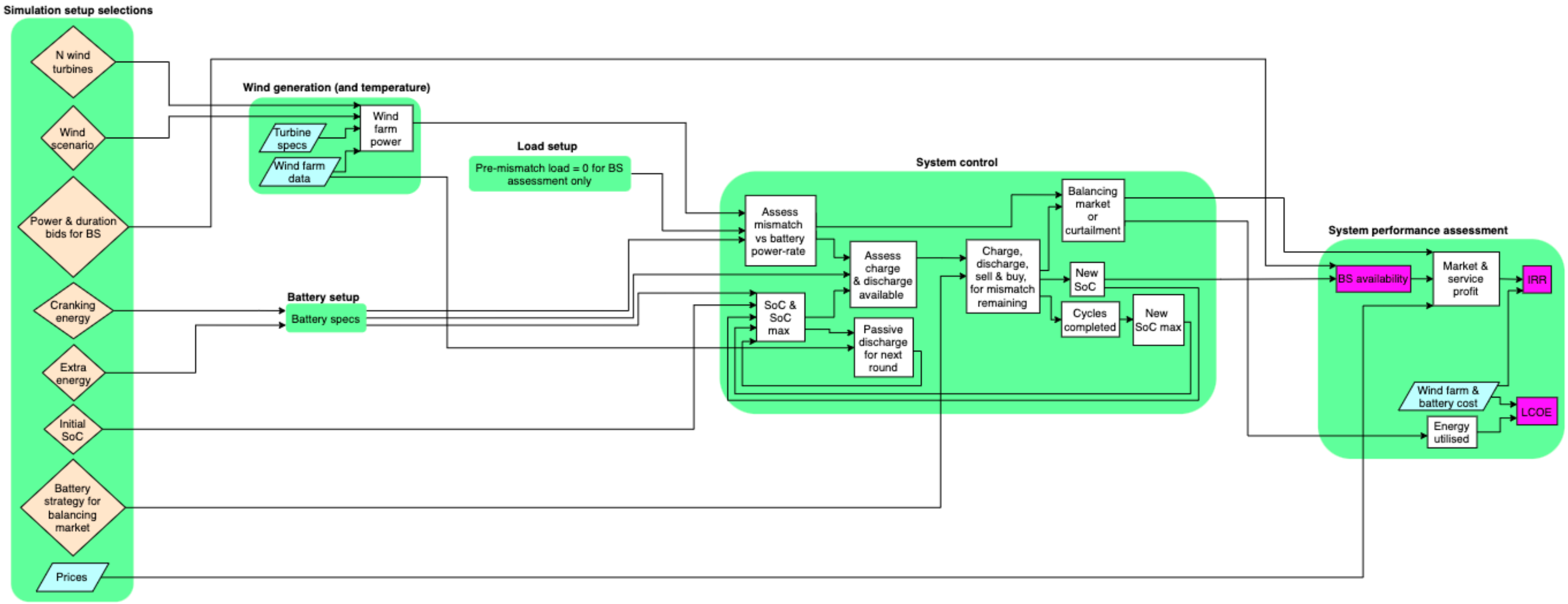

Figure A.1: Flowchart for scenario two, bidding for the BS service only, with mismatch managed in the balancing market.

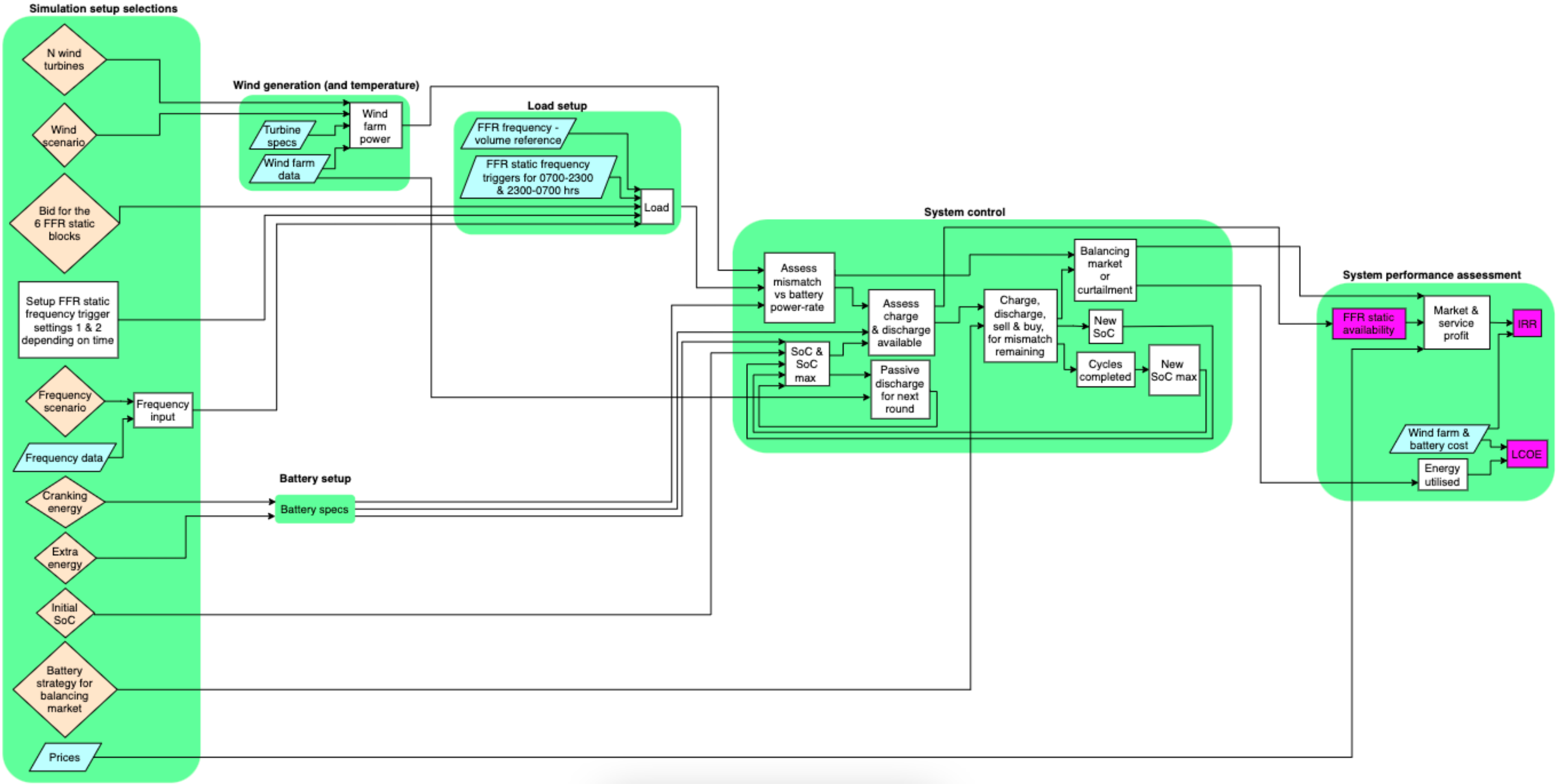

Figure A.2: Flowchart for scenario three, bidding for the FFR static secondary service only, with mismatch managed in the balancing market.

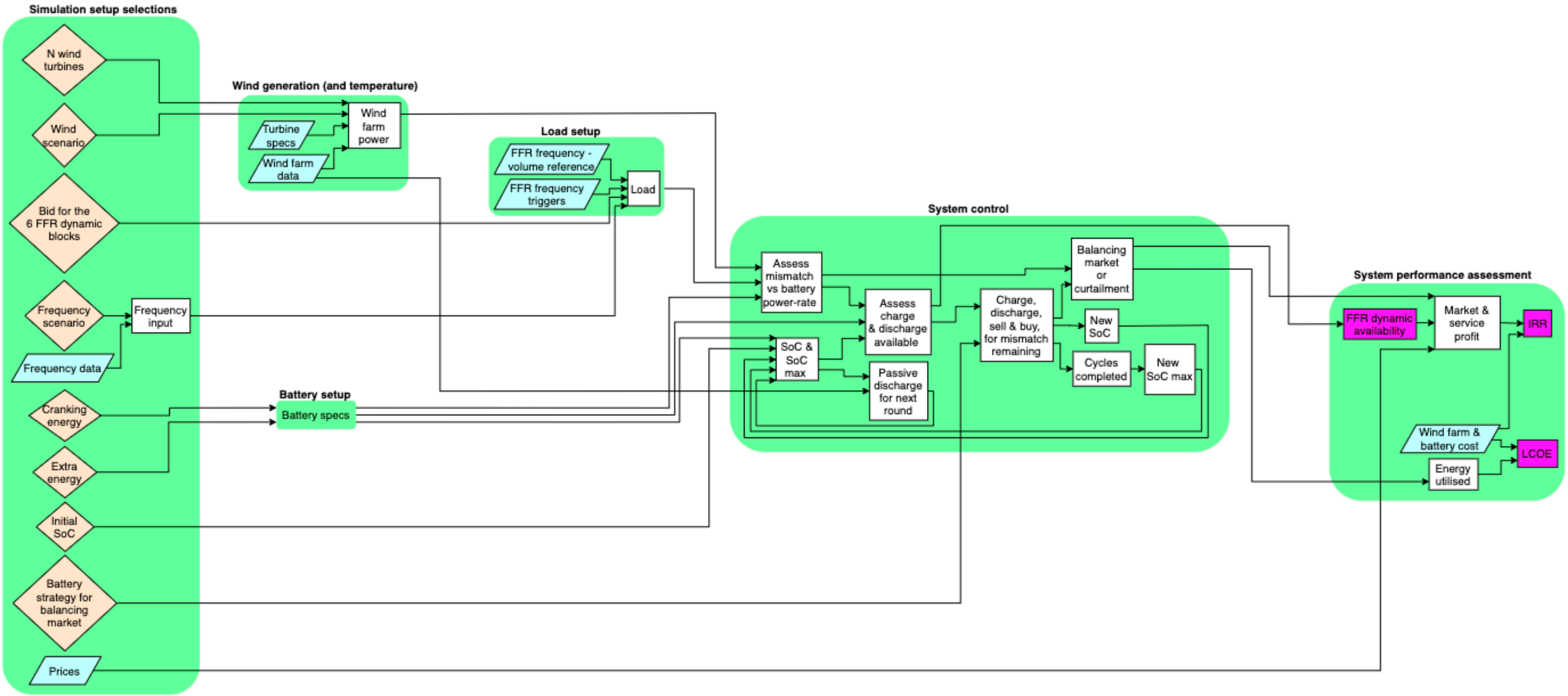

Figure A.3: Flowchart for scenario four, bidding for the FFR dynamic high frequency service only, with mismatch managed in the balancing market.

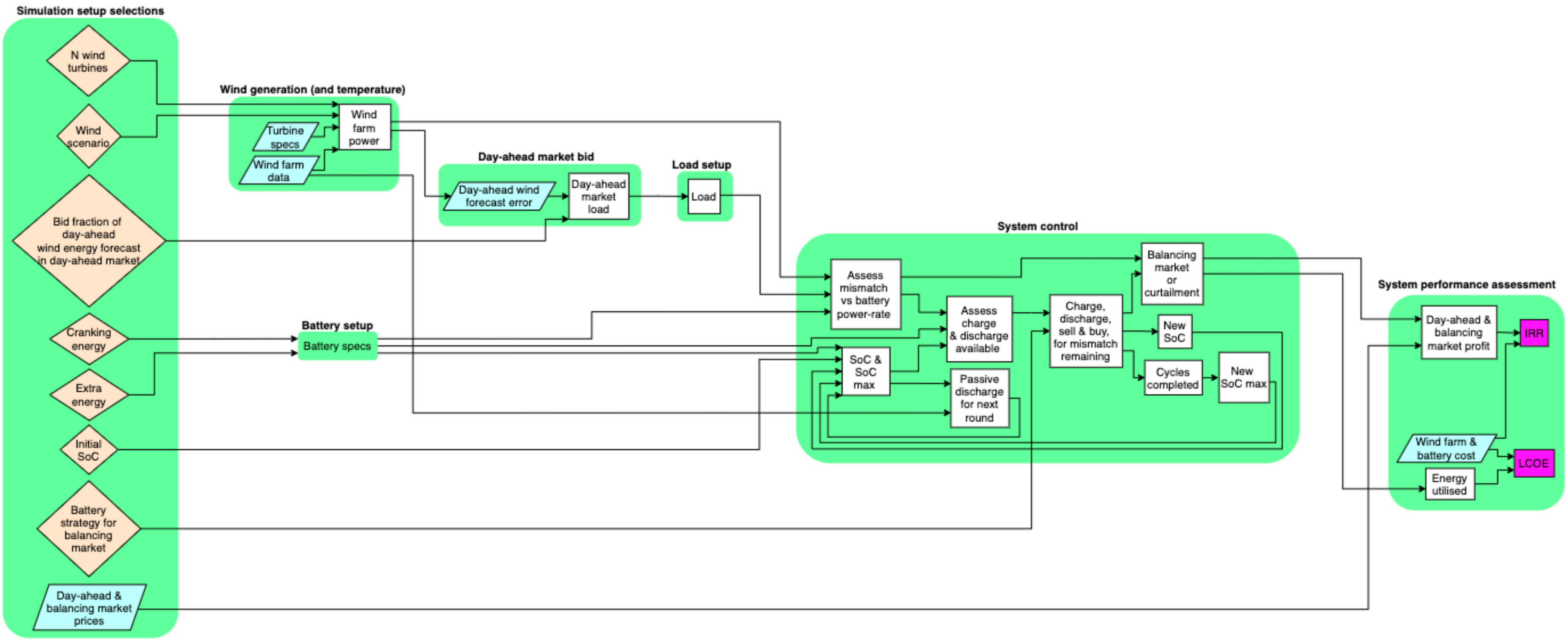

Figure A.4: Flowchart for scenario five, bidding in the day-ahead market only, with mismatch managed in the balancing market.