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Techno-economic optimisation of battery storage for grid-level energy services using curtailed energy from wind

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Abstract

The increasing integration of renewable energy sources makes balancing a grid challenging due to their intermittency. Renewable energy can be curtailed especially when production exceeds demand or when there is transmission and/or distribution network congestions within a grid. However, curtailment would become unnecessary with battery storage, provided the battery storage has enough available storage capacity, which can store energy during the time of excess generation and discharge it to the grid once the demand is high during peak times. Hence, stored energy from batteries can potentially offset supply from expensive and environmentally harmful peak plants e.g. open/combined cycle gas turbine. We investigated the techno-economic prospects of the utilisation of curtailed energy from wind with bulk battery storage to replace open and combined cycle gas turbine power plants, by taking the UK as a case study. A techno-economic model to size and optimise a Li-ion type battery was developed. The optimisation aimed to determine at what cost and size the storage can be commercially viable for grid-level energy applications. Results show that under base case assumptions of a 15% day to day curtailment from wind and £200/kWh battery cost, an optimised battery size of 1.25 GWh could supply 285 GWh peak demand per annum and its corresponding net present value of £22.4m, internal rate of return of 1.7% and a payback period of 14 years could be achieved. However, to achieve the internal rate of return of 8%, a minimum hurdle rate for investment, the cost of battery would need to be below £150/kWh. Sensitivity analyses with parameters such as curtailed wind, depth of discharge, battery efficiency, and cost and income of battery show that all techno-economic parameters considered in this research have significant impacts on the commercial viability of battery storage for grid applications.

Keywords: Battery energy storage system (BESS), wind curtailment, techno-economic optimisation, open/combined cycle gas turbine, grid-level storage

1. Introduction

The Paris agreement of 2015 [1] was a key milestone, with its central aim to limit global warming to less than 2°C above pre-industrial levels and to pursue efforts to limit to 1.5°C. To this effort, the UK Government has passed a law, the first major economy to do so, to bring all the greenhouse gas (GHG) emissions to net-zero by 2050 from 1990 levels [2]. To achieve this target, it is expected that wind energy can play a crucial role. According to UK's National Grid Future Energy Scenario (FES), renewable energy could potentially supply 80% of total electricity by 2030 where wind was estimated to be the dominating source (70% of total renewables) [3].

The UK's renewable energy generation has been growing over the last decade, particularly wind energy due to the availability of wind as a natural resource. Wind energy generation in the UK has increased from 13.8% in 2017 to 21.2% in 2019 of the overall UK electricity demand, that is an increase of 7.4% in the last 2 years [4]. However, the investments by the UK's transmission network operator, National Grid Electricity System Operator (NGESO), and Distribution Network Operators (DNO), have not kept in line with this growth [5,6]. This has led to a curtailment of the use of renewable energy due to its intermittent nature and the mismatch between supply and demand. The curtailment of wind energy was estimated to be between 5-6% for the UK and 15% for Scotland in 2016 [5]. As renewable energy grew from 4% in 2008 to 22% in 2017 and was projected to grow to 30% by 2020 [7], the percentage of curtailment is likely to increase (up to 30GW in 2030 at a high renewable scenario [8]) in the future if transmission and distribution network upgrades do not follow in line with this growth.

To help manage the curtailment and intermittency issues of renewable energy, excess energy needs to be stored during curtailment or when the supply is higher than the demand. The stored energy can then be used when demand is high, in particular, during peak times [9]. Use of storage to manage peak demand can help to reduce or replace completely the use of expensive and environmentally harmful peaking power plants such as open cycle gas turbines (OCGT). Depending on the capacity of storage, it can also supply some of the variable demand that is otherwise supplied by the combined cycle gas turbine (CCGT)[1]. Replacing OCGT and reducing CCGT supply can have a positive impact on the reduction of GHG emissions that will eventually help the transition to net-zero target [10,11]. In addition, storage can also provide contingency if a power plant fails and can be used as a backup supply when required, which provides energy security.

Storage can be provided using several technologies e.g. pumped hydro, Compressed Air Energy Storage (CAES), molten salts and batteries. Batteries are the most common technology for storage and have been successfully demonstrated in microgrid applications [12] and also at grid-level [13] in particular to manage the frequency of electricity supply. Lithium-ion (Li-ion) batteries have been developed over the last 10-15 years and are ideal candidates for grid use due to their technical performance [14], in particular, due to better charge and discharge efficiencies and high energy density [15]. Recent battery chemistries for example Sodium Sulphur (NaS) may provide better performances in the future. Other battery technologies like Vanadium Redox Batteries (VRB), developed over the last 5 years, show promising performance [14]. It has been estimated that VRB can provide longer lifetime e.g. 20-25 years and a larger number of charge and discharge cycles than Li-ion batteries [14]. However, VRB are

[1] Due to flexibility of operation, CCGT plants supply both the baseload and some part of the variable peak load.

nearly 2-3 times more expensive than Li-ion batteries [15]. Besides the batteries, costs of other components of Battery Energy Storage Systems (BESS) need to be considered [16]. BESS comprises batteries, inverters (both AC-DC & DC-AC), and management systems to manage temperature and how stored energy is used.

BESS applications are of two types: energy and power applications [17]. “Energy applications” is a term used to define a storage that supplies electricity for a period of hours such as peak load management and load shifting, energy arbitrage, support for renewable energy curtailment [18,19], while a storage for “power applications” supplies electricity for a short term (seconds to minutes) for various ancillary services such as frequency and voltage regulations [20,21]. Grid-scale BESS for various ancillary services have already been attractive in the UK and many other countries around the world. However their energy applications are very limited, even though we can scale up and use the same BESS for multi-hour energy supply and load shifting [22–26]. Many countries in the world including the US, the UK, the EU, China, Japan, etc. have implemented BESS projects for grid applications, mainly for power applications and some for energy applications [27–31]. Those BESS projects have power ratings as low as 0.5 MW up to 50 MW and energy ratings from 0.5 MWh to 50 MWh. Tesla, however, has built the largest BESS in the world as a single unit (100MW/129MWh) in Australia to prevent the grid blackouts from renewable intermittency [32]. Although these implementation cases suggest that BESS has been successfully implemented in small-scale applications, no large-scale energy applications, such as GW/GWh capacity, have been implemented so far at grid level anywhere in the world that enables many hours of electricity supply for peak load management, e.g. offsetting supply from OCGT/CCGT. The reasons for this are the high investment cost and poor and/or uncertain return of investment compared with alternatives such as demand side response and thermal generations [17,28], the lack of large-scale trials for validity and safety, the lack of equitable regulatory environment [33], and the absence of market and policy frameworks [34].

In the face of the above limitations, a smaller number of studies on BESS for energy applications, e.g. peak load management, peak shaving and energy arbitrage, can be found in the literature. Those studies are further limited to investigation on (a) batteries other than Li-ion, (b) small-scale (kW to MW range) applications and (c) technical suitability rather than economic viability. For examples, operation scheduling of 1 MWh BESS (NaS) with a wind turbine for an industrial application [35], 2kW/30kWh BESS (VRB) as an energy storage for small grids and stand-alone PV systems [36], optimal operation strategy of 3MW/10MWh BESS (VRB and polysulfide-bromine (PSB)) for energy arbitrage in a wind dominated power system [37], and an optimal operation strategy for a wind-solar-hydro-battery power system for a regional power grid, with a 6MWh BESS particularly managing the peak demand [38]. On the other hand, only a few investigations for the economic suitability of wind-battery systems for grid applications can be found in the literature. For example, the authors in [39] discussed how to maximise profit of a wind-battery power station based on wind and energy price forecasting. An optimisation algorithm coupled with a model predictive control strategy was used to enhance the economic benefits of BESS for energy arbitrage through a coordinated action of Wind-BESS system. Khalid M, et al [39], however, did not use some key economic factors such as operation and maintenance costs, battery degradation, costs for converters in the study that have a significant influence on the economic outcomes. Another investigation on the economic feasibility of replacing two thirds of coal generation with
119 renewable energy (wind and solar) integrated with a large scale BESS (Li-ion) in Alberta electricity

system was studied in [40]. The economic results were compared with other options such as a 100% renewable and baseline scenario (coal 48%, gas 47% and wind 5%). The authors concluded that a battery of 350MW/350MWh size could facilitate replacing two thirds of coal generation from the Alberta grid with renewable. However, this option was estimated to be very costly due to large size of batteries needed. Furthermore, the study only focused on economic aspects that are related to investment cost such as capital cost of wind, solar and storage, operation and maintenance and ignored other techno-economic parameters such as efficiency, storage degradation, capacity factor, internal rate of return (IRR), inflation, etc. for the entire lifetime of storage. Lai and Locatelli [41] has recently investigated the economic and financial appraisal of a 100MWh Li-ion battery coupled with a 100MW wind turbine in the UK. It was reported that the levelized cost of electricity for the storage are in the range of 0.07 £/kWh to 0.11 £/kWh. An example of a techno-economic analysis of a wind-batteries system (3MW battery) to manage peak demand in Spain is discussed in [18], where it was found that a fixed cost of 0.22-0.66€/kWh (depending on battery types) of electricity from BESS was needed for the system to be economically viable while the actual electricity price was 0.04-0.05 €/kWh at the time. Authors concluded that the investigated BESS was commercially unsustainable, and the project could not survive without significant incentives for BESS. However, we argue that the techno-economic performance of the same BESS could be different if the authors would (a) consider Li-ion battery that has a higher efficiency than other types they considered e.g. NaS, VRB, etc., (b) investigate countries with higher electricity prices such as the UK, (c) optimise the size of batteries to ensure an optimal net present value (NPV) for BESS, and (d) consider a large-scale (GW-range) BESS with all the supply and demand at grid level.

Although there have been some studies of BESS coupled with wind for grid level peak load management, they are focused mostly on small scale BESS (MW-range) and covered either a fraction of total wind generation of a grid or applied the wind-BESS systems for maximising the financial indicators only. Particularly, it is evident from the literature that there have been no studies that dedicated the use of BESS coupled with wind solely for the replacement of OCGT/CCGT generation at grid level that covers entire generation and demand of a national grid. Such a study is much needed to understand the techno-economic-environmental potentials of BESS for replacing OCGT/CCGT plants from a national grid for countries such as the UK who has already set out the plan to become net-zero emission country by 2050. The authors previously studied a techno-environmental aspect of BESS for replacing CCGT, that shows that the BESS could reduce up to 2MtCO_2 from the UK grid if it replaces around 30% of its CCGT generation [11]. To realise overall benefits of BESS (Li-ion) for a grid, this study investigated the techno-economic aspects of BESS coupled with curtailed wind, which are solely used for replacing OCGT/CCGT plants, by taking the UK as a case study. Since the cost of BESS for grid applications can be high due to large batteries required, their lifetime, and operational and maintenance costs [6,42], a careful balancing of technical and economic performance is required. Therefore, the main contributions of this work are the following:

- Development and optimisation of techno-economic model to determine at what size, capacity factor, and cost and income of BESS will it be commercially viable and beneficial for grid-level peak demand management applications.
- Analysis of key parameters and how they influence the technical and economic performances of BESS for offsetting OCGT/CCGT generations. These key parameters include curtailed wind

energy, depth of discharge, battery efficiencies and degradation, battery costs and income from electricity stored in BESS.

The rest of the paper is organised as follows: methodology on key design criteria and development of the models is presented in Section 2, followed by results and discussion including sensitivity analysis in Section 3. Finally, section 4 covers the conclusions of this work and recommendations for future research.

2. Methodology

2.1 Key design criteria of the model

Electricity cannot be stored directly. It must be converted to another form of energy if it is to be stored. As a result, national electricity supply and demand is balanced on an instantaneous basis by the UK Electricity System Operator (National Grid ESO; www.nationalgrid.com). This balancing act becomes more challenging and costly with the increase of renewables such as wind generation due to their intermittent, variable and non-programmable nature. Traditionally, the baseload power plants (e.g. nuclear, CCGT base, and coal) are used to supply electricity for the baseload demand, while the peak variable demand is met by the combination of renewables, OCGT, and CCGT variable plants (see Fig. 1). Due to network congestions or supply-demand imbalance, a significant portion of wind generation has always been curtailed [5], as discussed in Section 1. Instead of curtailment, we aimed to use this curtailed wind energy to charge bulk size batteries at off-peak times when demand for electricity is low (e.g. during the night). During peak time the stored energy in the batteries can be discharged to the grid to supply some or all the peak demand, which otherwise would have come from OCGT peak and CCGT variable power plants. The aim of discharging the BESS is to replace the OCGT peak generation first and then, if there remains enough stored energy, to replace some or all CCGT variable generation from the grid. Supply of the peak demand by BESS will reduce the need for the running of costly and more environmentally harmful OCGT and CCGT peak plants. The batteries are charged to their maximum capacity based on how much curtailed wind energy is available and then discharged to the grid over peak periods within each day. Fig.1 summaries this basic principle of charging and discharging the batteries for 24-hours a day.

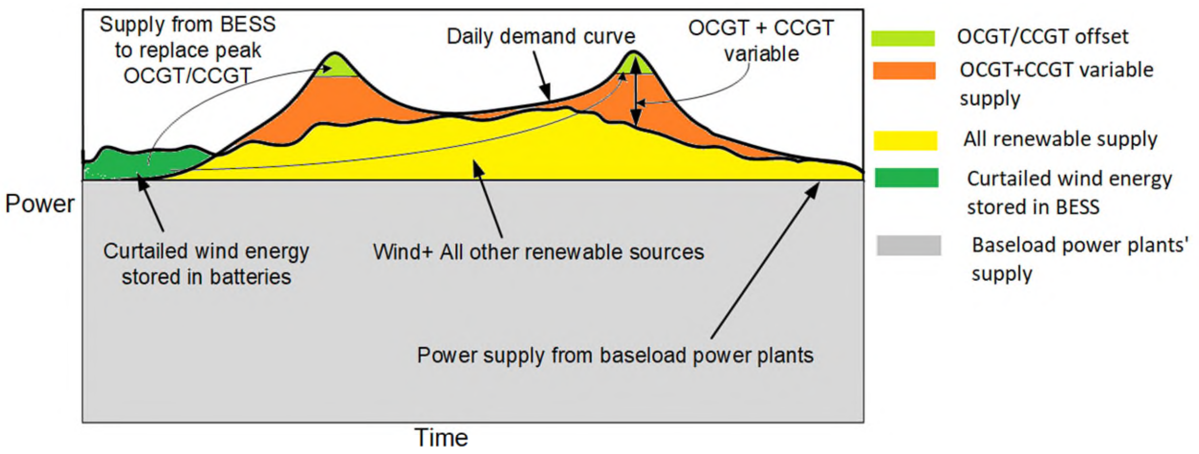

Fig.1. Supply and demand management utilising excess energy from wind curtailment.

2.2 Technical model of BESS

The batteries used in the BESS model are a Li-ion type due to its high-power density, efficiency and lifetime over other battery types, as discussed in Section 1. The aggregate size requirement of grid-level BESS is modelled taking the UK as a case study, utilising national supply and demand and wind curtailment data. The objective of the technical model is to utilise the curtailed wind available during the night, when demand is low, and discharge the stored energy during the two peak times of the day, morning and evening. Although the study focuses on the UK grid, the same study can be applied to any electricity grids in the world where there exists a wind curtailment from the supply side. The details of the technical model are shown in Fig. 2.

The technical model comprises data inputs, mathematical functions and evaluation parts. Details of the data, inputs and assumptions for the model are provided in Table 1. The model starts by processing electricity supply and demand data for the UK grid. Since the data from National Grid [43] does not include information regarding the curtailed wind, we have added the wind curtailment portion (ref. [5]) to the electricity supply data to get the actual generation data across the UK. The percentage of curtailed wind power S_{CW} available at time t_1 to t_2, which was from 9:00 pm to 6:00 am, is added to determine total new supply TS (or total grid generation) in addition to the grid supply GS, as shown in Eq. (1).

$$TS(t) = GS(t) + S_W(t) \times S_{CW} \quad if\ t \in (t_1\ to\ t_2) \tag{1}$$

Where grid supply $GS(t)$ is the sum of all supply from baseload, wind, solar, pumped hydro, biomass, nuclear, OCGT peak, and CCGT variable plants and $S_W(t)$ is the supply of electricity from wind.

Instead of allowing a curtailment to occur, we want to store any excess energy from wind in batteries and to supply some part of the peak demand during the day. Hence, we take out OCGT peak $S_{OCGT,peak}(t)$ and CCGT variable supply $S_{CCGT,var}(t)$ from total supply $TS(t)$ to create an alternative new supply $NS(t)$ where some or all peak demand will be supplied by BESS as described in Fig. 1.

$$NS(t) = TS(t) - S_{OCGT,peak}(t) - S_{CCGT,var}(t) \tag{2}$$

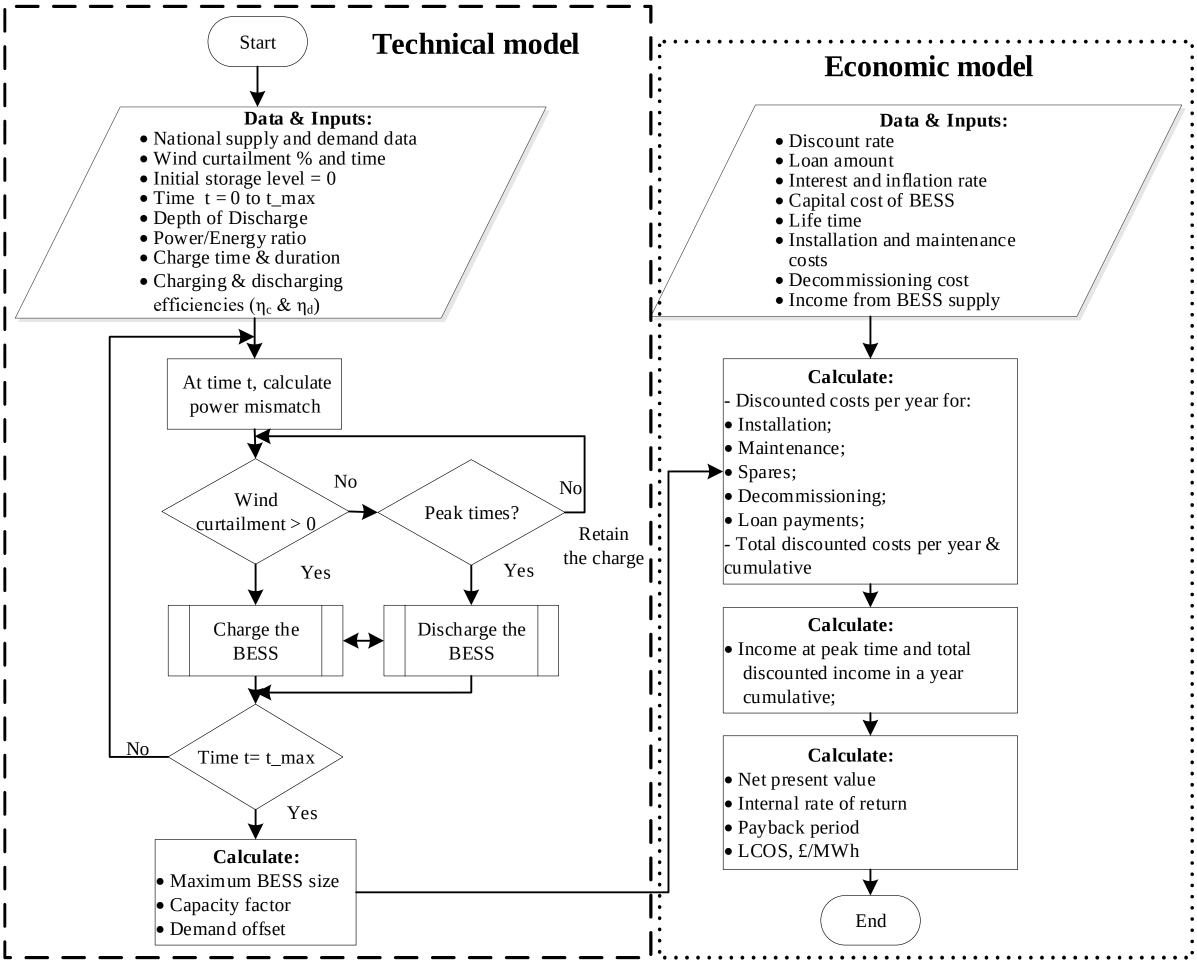

Fig. 2. Flow chart of techno-economic model (input data for technical model are provided in Table 1 while data for economic model are provided in Tables 2-3)

In this new supply and demand scenario, a power mismatch $\Delta W(t)$ between the supply $NS(t)$ and demand $D(t)$ can be calculated as follows:

$$\Delta W(t) = NS(t) - D(t) \tag{3}$$

Based on the level of curtailed wind and the power mismatch, a BESS model to charge/discharge was developed as follows [44]:

$$H(t) = H(t-1) + \begin{cases} \Delta W(t) \times \eta_c & if\ \Delta W(t) \geq 0\ \&\ t \in (t_1\ to\ t_2) \\ \Delta W(t) \times {\eta_d}^{-1} & if\ \Delta W(t) < 0\ \&\ t \in (t_3\ to\ t_4\ \&\ t_5\ to\ t_6) \end{cases} \tag{4}$$

The $H(t)$ time series describes the charging and discharging of a storage system with charging efficiency of η_c and discharging efficiency of η_d. Once there is a power mismatch and the time constraints are met, the model starts to charge and discharge the energy. Since historically, the UK has two peak periods of its electricity demand, the aim was to supply some or all the peak demands from BESS and reduce or offset supply from peak plants. We considered the following peak periods: the time between 7.00 am to 8.00 am (t_3 to t_4) and 5.00 pm to 9:00 pm (t_5 to t_6). These time slots were used in the model to enforce discharging at different times of the day.

The maximum storage energy capacity (E_H), measured in MWh, for a given wind curtailment can be calculated in Eq. (5).

$$E_H = max_t H(t) - min_t H(t) \tag{5}$$

Where $max_t H(t)$ is the maximum energy at time t and $min_t H(t)$ is the minimum energy at time t. From the technical model, we evaluated the maximum capacity of storage that is needed to store all the curtailed wind power and its corresponding technical performance without any optimisations. A separate algorithm to optimise the size of BESS was used which is discussed in Section 2.4.

The capacity factor B_{cf} is an important measure of utilization efficiency, and is the ratio of actual energy supplied by the system compared to the maximum possible energy that could have been supplied, over one year, and was calculated in Eq. (6).

$$B_{cf} = \frac{DO_{total}}{E_H * 365} \tag{6}$$

where DO_{total} is the actual energy supplied in MWh by BESS over one year and E_H is the maximum size of batteries in MWh. DO_{total} for one year was obtained from the simulation of technical model.

Table 1. Input parameters for technical model in base case simulation

Parameter	Values	References
Electricity supply and demand data for UK	5 mins interval	[5,43]
Curtailed wind supply (S_{CW})	15%	[5]
Solar energy split between demand and supply	50-50%	assumption
Battery charging efficiency η_c	90%	[14]
Charge time period (t_1 to t_2)	21.00 – 06.00hrs	
Battery discharging efficiency η_d	90%	[14]
Discharge time periods (t_3 to t_4)	07.00 – 08.00hrs	
& (t_5 to t_6)	17.00 – 21.00hrs	
Depth of Discharge (DOD)	90%	[15]
Battery end of life	70%	[45]
Battery lifetime (years)	15 years	[14]

In the simulation, we used various data sets and input parameters for the technical model which are shown in Table 1. Historical data of total demand for electricity in the UK as well as supply data for each type of electricity generation was used in the technical and economic models developed in this paper. This includes nuclear, coal, CCGT, OCGT oil, hydro, interconnectors that import and export from/to Europe, and renewable energy sources such as wind, solar, and biomass. Demand and supply data of UK electricity were downloaded from the Gridwatch [43] for one year from 15th June 2018 to 14th June 2019. Gridwatch, aggregates all renewable energy from each of renewable energy farms in the UK, grouped into wind, solar and biomass. Renewable energy farms need to be registered and only than it appears on Gridwatch as an aggregated amount. One year's data was selected so to represent all seasonal variations for both demand and supply. The data was first cleansed to ensure there were no anomalies including blank cells. This data, except for solar energy, was scraped every 5 minutes intervals from Elexon Portal. Solar energy, which is generated by solar farms as well as commercial and residential generators, was estimated at every 5 minutes intervals by Sheffield University [43]. It should be noted that some of the solar energy which was generated as unmetered was used to meet demand by the solar facility owners and some are fed back into the domestic grid at low voltage as supply. In this paper, an assumption was made with a 50%:50% split in solar energy for demand and supply so that this had a minimum impact on the results. For the base case scenario, we used 15% wind curtailment [5]. Battery charge and discharge efficiencies and depth of discharge were considered to be 90% each [14,15]. Battery degradation loss was also considered, which is 30% over its lifetime of 15 years [45].

The information related to storage sizing, demand offset, and capacity factor was fed into the economic model, to calculate economic parameters to determine the commercial viability of BESS, as shown in Fig. 2.

2.3 Economic model of BESS

The economic model calculates all costs over the entire life of the project and all income over the operational life and then calculates if the project is going to a make profit or loss by discounting future costs and incomes to present value. The structure of the model consists of the first year as installation and commissioning year, followed by 15 years of operation and finally last year for de-commissioning. Both the total costs (battery, inverter, etc., installation, maintenance and loan costs) and the income (income by reselling electricity back to the grid) are discounted across all 15 years of operation including the last year of decommissioning costs. These are required to calculate financial indicators: NPV, IRR and payback period. These financial indicators would need to meet certain thresholds required by investors. For example, IRR may be required to meet a hurdle rate between 8-9% as summarised by Judge et al. [46] for renewable energy projects to be financially viable. NPV would need to be positive to give profit at a required level. Payback would certainly need to be within the end of life and preferably much earlier, in this case <15 years. The main parts of the economic model are shown in Fig. 2. From the economic model we also calculated Levelised Cost of Storage (LCOS) to determine the cost of storage per kWh of electricity over the entire lifetime.

Table 2. BESS cost breakdown (source: [42] – Adapted).

BESS component	£ Cost/kWh (% of battery cost)
CAPEX	
Li-ion battery purchase costs	200
Inverters purchase cost	20 (10%)
Electrical & management systems	8 (4%)
Structural costs	6 (3%)
Subtotal	234 (117%)
OPEX	
Installation costs C_I (1st year only)	6 (3%)
Operational and maintenance costs C_{OM} per year	4 (2%)
Spares costs (included in O & M) per year	2 (1%)
Decommissioning costs C_D (year 16)	4 (2%)

Fu et al. [42] presented a benchmark of breakdown of the individual component costs for a 60MW/240MWh storage system at the National Renewable Energy Laboratory. These costs were extrapolated per MWh of battery size for use in this paper, which is shown in Table 2. The costs of the BESS were broken into CAPEX (Capital expenditure) which includes batteries, inverters, electrical and management systems, and structural costs. Operational expenditure (OPEX) costs include installation (including labour costs), operational and maintenance (including spares) and de-commissioning.

Using the battery size determined in the technical model, the discounted cumulative costs C_{cum} per year were calculated as per Eq. (7).

$$C_{cum} = C_I + \sum_{n=0}^{n=N} \frac{C_{OM}}{(1+r)^n} + \sum_{n=0}^{n=N} (L_R + L_i) + \frac{C_D}{(1+r)^{N+1}} \qquad 7$$

where C_I is the installation costs, C_{OM} are operational and maintenance costs per year, L_R is the loan repayment, L_i is loan interest, C_D is the decommissioning costs, r is the discount rate and N is the lifetime in years.

The $LCOS$ defined by Schmidt et al. [47] was calculated in Eq. (8).

$$LCOS = \frac{C_{cum}}{\sum_{n=1}^{n=N}(E_H)} \qquad 8$$

In addition, the performance and capacity of batteries will decline over the lifetime. Marques et al. [45] suggest a 70% capacity at the end of life of a Li-ion battery can be considered a realistic choice for modelling the battery degradations. With operating duration of 15 years, this would give a decline of 2% every year for 15 years assuming new batteries are used at the start with a linear degradation. This 2% decline was included in the economic model.

The cumulative income I_{cum} from the BESS over the lifetime is calculated as follows:

$$I_{cum} = \sum_{n=1}^{n=N} \frac{I}{(1+r)^n} \qquad 9$$

where I is the income from BESS in each year.

The NPV over the life of the project is calculated using Eq. (10).

$$NPV = I_{cum} - C_{cum} \qquad 10$$

The IRR, which is a measure of return on investment, can be calculated by setting NPV to zero as shown in Eq. (11).

$$NPV = \sum_{n=1}^{n=N} \frac{I}{(1+IRR)^n} - C_{cum} = 0 \quad (11)$$

IRR is effectively the new discount rate [48] that gives NPV of zero over the entire life of the project.

Payback period N_{PB}, which can be defined as period when difference between I_{cum} and C_{cum} equals zero as shown in Eq. (12).

$$\sum_{n=0}^{N_{PB}} I_{cum} = \sum_{n=0}^{N_{PB}} C_{cum} \quad (12)$$

Economic parameters and assumptions used in the model are shown in Table 3, which shows a split between loan and available capital as well as repayments. Interest rate and discounts used were similar to that used recently by Judge et al. [46] for an offshore wind farm project. For this paper, it was assumed that residual or scrap value of BESS (batteries, inverters, etc.) would be zero. Although, in reality, there would be some residual value, especially for the batteries and which can be as much as 15% of initial costs [49].

Table 3. Inputs for economic model

Parameters	Values (base case)	References
System operating life (N years)	15 years	[14]
Loan/available capital split (%)	50/50 %	assumption
Loan payback period (years)	10 years	assumption
Repayments of loan per year $\boldsymbol{L_R}$	1/10 of loan each year	assumption
Discount rate r (%)	5%	[46]
Interest rate for loan $\boldsymbol{L_i}$ (%)	4%	[46]
Residual value at end of operation	0	assumption
Inflation Rate	5%	assumption
BESS income	£74.75/MWh	[50]

For any curtailment, the wind farm generators are compensated by National Grid where curtailment occurs due to congestion in network transmission and distribution. The compensation is at similar rates that are used to pay for generations. In the UK, this is based on Contracts for Difference (CfD) [4], where wind generators get their income guaranteed by the government at a specific level called CfD strike price. So that if electricity price goes below CfD strike price, the wind farm generators still get paid the strike price. However, if the price goes above the strike price the wind generators have to pay back the difference between the strike price and the price of electricity. CfD strike prices have been reducing from £120/MWh between 2017-18 to £114/MWh in 2018-20, to £74.75 for 2021-22 [50]. In absence of policy or industrial standards on income structure using electricity from BESS, for this research it was assumed that the income was same as the income wind energy generators receive based on CfD. This can be justified as wind energy is being generated and in turn being used to charge BESS before energy is finally used. Hence, a figure of £74.75/MWh for income as a base case scenario was used in the model during the lifetime of the battery.

2.4 Optimisation of BESS

Fig. 3 shows the flow chart for sizing and optimisation of BESS using the technical and economic models. The size of the BESS battery is determined by the technical model for a given curtailed wind energy. This information is fed into the economic model which calculates NPV. The battery size is then optimised to achieve a maximum NPV from the investment. A linear programming optimisation was used to size the battery to achieve maximum NPV from the investment. This optimisation is represented by an objective function in Eq. (13). Assessment is then carried out to determine if this financial indicator meet the required IRR threshold. If the IRR threshold is not met with the base case assumptions, the model predicts at what cost and income the BESS can hit the IRR target. This iterative process is allowed to continue until required NPV, and IRR are achieved.

$$objective\ funciton = \underset{E_{H,min}, E_{H,max}}{max}(NPV) \qquad 13$$

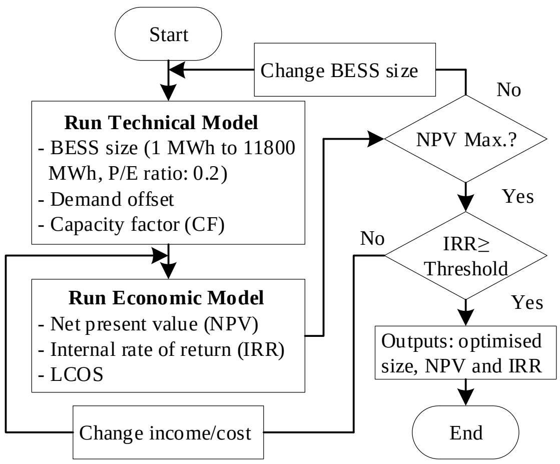

Fig. 3. Flow chart for multi-objective techno-economic optimisation of BESS.

3. Results and discussions

This section covers results and discussion based on demand and supply of electricity data for the UK over 1 year between 15th June 2018 to 14th June 2019. This was used in both technical and economic models as discussed in the methodology section. In this paper, we have considered charging during off peak time and discharging charged batteries to reduce two demand peaks in a day, though battery energy can be used to supply the demand during any time of the day and even in grid power failure scenarios.

3.1 Base case results

With the new supply demand management strategy as discussed in Fig. 1, the model estimated a power mismatch ΔW for the simulated time (see Fig. 4). The positive power mismatch implies that there is a curtailed energy from wind that can be stored in batteries, while a negative mismatch is the representation of excess demand at the grid which is either supplied by OCGT peak/ CCGT variable plants or a combined supply from BESS and OCGT/CCGT plants. It is worth mentioning that the charge and discharge (up to a depth of discharge of 90%) of BESS took place every day in the modelled year.

The model with the base case (non-optimised) simulation indicated that a maximum battery size of 11.8 GWh was required based on the available curtailment and maximum demand mismatch (see Table 4). Since the power to energy ratio for the battery was assumed 0.2, a battery size of a 2.38GW/11.8GWh was obtained. With this size of battery, the BESS could supply a total of 1368 GWh electricity during the two peak times of a day over 1 year, which would offset 6.98 GWh (34.05% of total OCGT in one year) of OCGT and 1361.02 GWh (2.56% of total variable CCGT) of variable CCGT. At this size (non-optimised), the battery capacity factor was found to be 35%, which seems to be poor, and the battery was inefficient as was not being used throughout the year to its maximum capability due to limitation in the amount of curtailed wind that was available to charge the battery to its maximum.

From the simulation of non-optimised economic model (see Table 4), it was found that the investment would make a loss of £1,075m over the entire life of the project, with payback not until 200+ years. In addition, IRR is -11.4% and therefore this project would not be financially viable. However, at this stage, the battery size was purely determined by maximum power mismatch and charge and discharge energies and not optimised for maximum NPV and IRR.

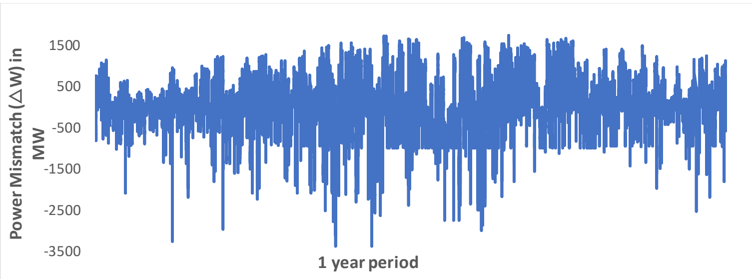

Fig. 4. Power mismatch over 1 year (Non-Optimised)

3.2 Optimisation results

To optimise the BESS, the battery size was adjusted and both technical and economic models were executed. The criteria used for optimisation was to achieve optimal NPV and IRR while capacity factor lies at a reasonably high end. The results from BESS optimisation that ensure an optimal NPV is shown in Fig. 5, where NPV is plotted against the capacity factor and size of the batteries. An optimal BESS size of 1.25 GWh and its corresponding NPV of £22.6m and a capacity factor of 69% was achieved. Graphical results of charge and discharge of BESS over 1 year within charging time (9:00pm to 6:00am) and discharge times (7:00am to 8:00am and 5:00pm to 9:00pm) and corresponding energy supplied by BESS for the optimised BESS size are shown in Fig. 6 and Fig. 7, respectively. On day one, the battery was charged from zero and discharge was then limited to DOD which is 90% every day of the year as shown in Fig. 6. Daily wind energy and hence curtailed energy can also vary in different seasons as seen in these graphs. For instance, there was less wind energy in the first few weeks of Jan 2019 and hence the BESS were not able to charge fully. On the other hand, there were many occasions throughout the year that the optimised BESS were fully charged as can be seen in Fig. 6. Indeed, it is worth noting that with the optimised battery, only 20% of excess wind were utilised while rest of the excess generation were wasted due to BESS size limitation (see Table 4).

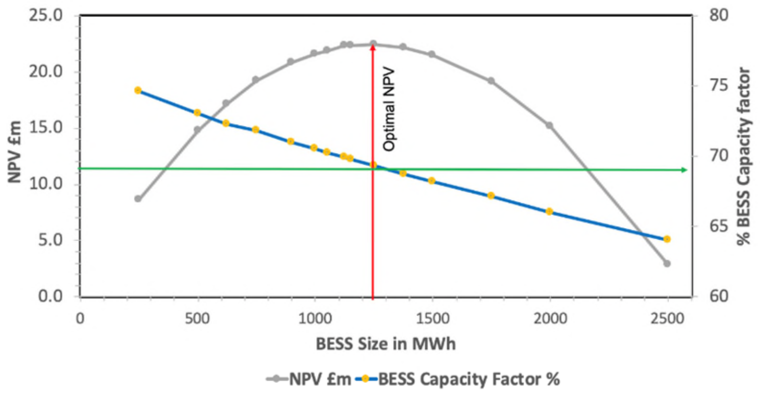

Fig. 5. BESS size vs NPV and corresponding BESS capacity factor.

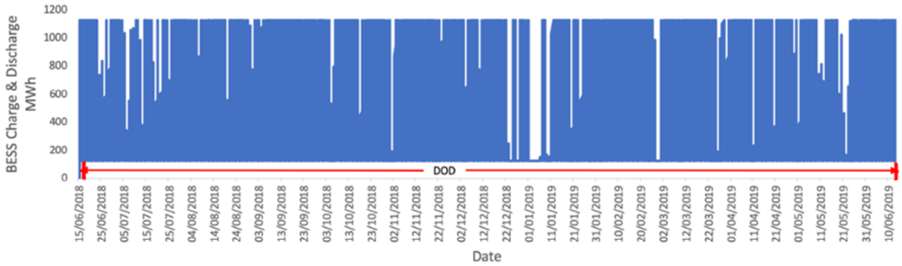

Fig. 6. Charge and discharge of BESS over 1-year period (Optimised).

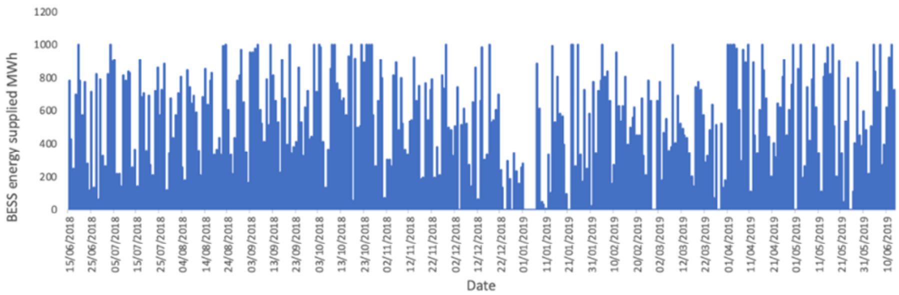

Fig. 7. Energy supplied by BESS during two peak times daily over 1-year period (Optimised).

Table 4. Techno-economic performance of non-optimised and optimised BESS

Parameters	Non-optimised	Optimised
Technical		
BESS size	11.8 GWh	1.25 GWh
Total energy supplied by BESS	1368 GWh	285 GWh
Total OCGT offset by BESS (GWh and %)	6.98 GWh (34.05%)	6.98 GWh (34.05%)
Total variable CCGT offset by BESS (GWh and %)	1361.02 GWh (2.56%)	278.02 GWh (0.52%)
BESS capacity factor	35%	69%
Number of days with Full charge over 1 year	36	311
Utilisation of curtailed wind	100%	20%
Financial		
NPV & IRR	-£1075m & -11.4%	£22.4m & 1.7%
Payback period	200+ years	14 years
LCOS	£0.037/kWh	£0.037/kWh
Income from BESS	£0.020/kWh	£0.040/kWh
Net profit	-0.017/kWh	£0.03/kWh

Other key results from the optimisation of BESS size for optimal NPV and its corresponding economic indicators including LCOS, IRR, payback period, etc. are shown in Table 4. For the optimised BESS the key points are:

- Optimised BESS size is almost 10% of the bases (1.25 GWh compared to 11.8 GWh).
- Total energy supplied by BESS was 285 GWh, approximately 21% of the base case (non-optimised) of 1368 GWh. This equates to 278.02 GWh (0.52%) yearly variable CCGT offset with optimised BESS compared to the base case of 2.53%, which is almost a fifth of the base case. The rest of the BESS energy (6.98 GWh) was supplied to offset OCGT peak generation.
- Both the non-optimised and optimised BESS were able to supply all the OCGT (6.98 GWh) during the two selected peak times. However, similar to CCGT variable generation, OCGT is also connected to the grid different time of a day to balance the supply and demand. Hence, if we were to remove the restriction of discharging batteries only for two peaks, the BESS could offset all the OCGT (which was 20.5 GWh) and 0.50% of variable CCGT from the grid.
- BESS capacity factor in optimised case was 69%, almost double compared to only 35% for the base case. The main reason being that a smaller battery will be able to charge and discharge fully more often than a large battery under the same curtailed wind energy.
- Utilisation of curtailed wind in base case, non-optimised, scenario is 100% compared to 20% in the optimal case. The reason for this is the compromise choice of battery size for improving technical performance such as the capacity factor and number of full cycles and the economic viability indicators such as NPV and IRR.
- NPV, IRR and payback of £22.4m, 1.7% and 14 years compared to -£1075m, -11.4% and 200+ years for the non-optimised case.

Due to high capacity factor of optimised BESS, income and net profit of £0.040/kWh and £0.03/kWh compared to £0.020/kWh and £-0.017/kWh of non-optimised case.

From an economic point, where investors are funding this type of project, maximum NPV and IRR are important for the viability of the project. Although the NPV and payback period from the optimised battery is positive, the IRR is much lower than a hurdle rate of 8-9% [46] that investors on renewable energy projects would expect. To take this hurdle rate into account, we investigated how we might achieve this target. The main factors determining IRR are the costs and income. The main costs are due to battery capital cost, loan interest payments and O & M costs. Out of these, battery cost is the most important as it represents almost 70% of the total costs. Nguyen et al. [51] use lifetime costs as a key factor to optimise the size of battery with optimised BESS capacity factor. Others like Johnston et al. [52] used income as the main factor for optimisation.

Reducing battery size also reduces costs which increases the IRR. Nevertheless, this has an opposite effect on the NPV since the income reduces and therefore NPV reduces. Hence, we kept the optimal size of batteries the same but considered both the cost and income adjustments to get the IRR hurdle rate. Results from the simulation show that to achieve the hurdle rate IRR, cost of battery would need to be below £150/kWh and ideally around £125/kWh, while keeping the income is constant at £74.75/MWh. However, if we keep the cost of batteries constant at £200/kWh, the income from BESS to achieve the same IRR needs to be above £100/MWh. We discussed these points in detail in the sensitivity analysis of cost and income, in the next section.

3.3 Sensitivity analysis

To understand the impact of small changes in technical and economic parameters, sensitivity analyses were carried out for the optimised BESS size on (a) curtailed wind energy, (b) DOD, (c) battery efficiencies, (d) battery costs and (e) battery income.

3.3.1 Curtailed wind energy

With all the variables kept constant for the optimised BESS, the amount of day to day curtailed energy was altered between 5% to 25% in steps of 5% and both models were executed. For each curtailed energy, the battery size was then optimised for maximum NPV. Corresponding results against the optimised battery are shown in Figs. 8-9. Fig. 8 shows that as day to day % curtailment increases the optimised battery size requirement increases. At 10% curtailment, BESS optimised size was 625 MWh, at 15% BESS size was 1250 MWh – an increase of 625 MWh and at 20% BESS size was 2000 MWh - an increase of 750 MWh. Therefore, the larger the curtailment the larger the optimised battery and this is a non-linear relationship. This is important since larger batteries result in larger NPV and therefore right size of the battery needs to be determined using the model rather than linear extrapolation when calculating the size of the battery. On the other hand, Fig. 8 also shows the BESS capacity factor increases at a much slower rate from 69% to 70% with an increase in curtailment from 10% to 25%. The main reason is that each battery has been optimised for NPV by reducing the battery size and therefore capacity factor has been improved. This result shows improvement to within 1% for different curtailment.

Fig. 9 shows that the optimised NPV increases at a higher rate with the increase of wind curtailment, which is very similar to the change of battery size in Fig. 8. This is as expected as we optimised the battery size and NPV which are related to each other. The result indicates that a 1% increase in curtailment from 15% increases the NPV by £4m and IRR by 0.1%. This NPV increase from base value is significant. This graph also illustrates that the larger the curtailment the larger the optimised battery size which in turn means the larger NPV. The one-off costs of installation and decommissioning become insignificant at large curtailment with all the optimised conditions being constant. The corresponding change in IRR is much slower from 1% to 2% between curtailments of 5% to 25 %, respectively, which is due to the higher investment cost in the bigger size of BESS. It should be noted that whilst IRR as percentages are small, they correspond to larger values of total investment.

Since the percentage of overall wind energy generation in the UK has increased from 13.8% (8.3% on-shore and 5.5% off-shore) in Qtr1 2017 to 21.2% (11.3% on-shore and 9.9% off-shore) in Qtr1 2019, revealing an increase of 7.4%, according to BEIS energy trends [4]. Therefore, it can be deduced that a similar increase in wind energy curtailment would have followed assuming similar percentage of congestion in the network [6] in 2019 compared to 2016. This is a worst-case scenario and would result in wind curtailment of 13.1% in 2019. For this amount of curtailment, the model forecasts an optimised battery size of 1.0 GWh (Fig. 8) with 329 GWh BESS energy supplied which is equivalent to offset 34.04% of OCGT peak (or 100% peak-non peak) and 0.60% of annual CCGT variable supply (or 0.58% if OCGT offset is 100%). In addition, NPV of £17.1m, IRR of 1.7% and a payback period of 14 years would be achieved.

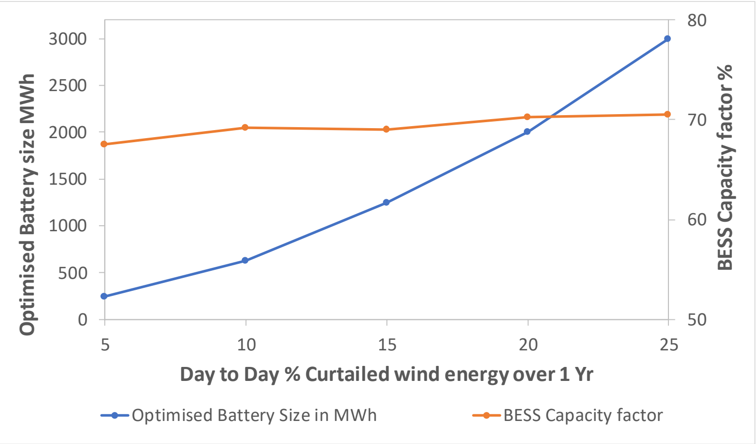

Fig. 8. Impact of curtail wind on capacity factor and size of optimised battery[2] (Optimised)

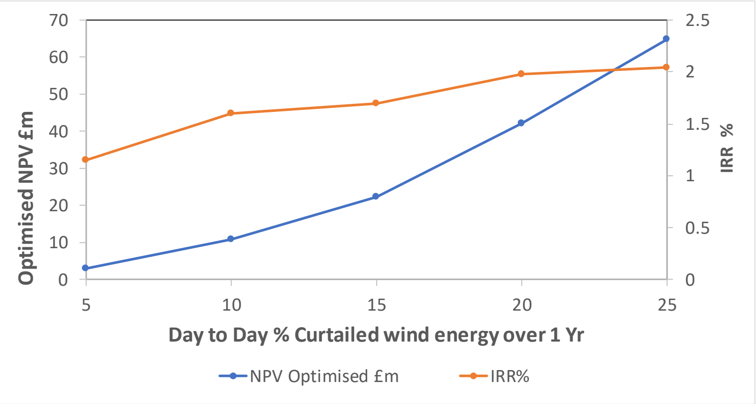

Fig. 9. Impact of curtail wind on IRR and optimal NPV (Optimised)

[2] Optimised conditions – P/E: 0.2, DOD: 90%, η_c & η_d: 90%, End of life 70% over 15 years, discount rate 5%, interest rate 4%, BESS income £74.75/MWh, battery cost £200/kWh & BESS (Inc., inverters) cost £234k /MWh.

3.3.2 Depth of discharge

To conduct a sensitivity analysis for depth of discharge of the battery, all the variables for the optimised battery size were kept constant and only DOD was changed from 80% to 100%. Fig. 10 shows sensitivity to the change in DOD on NPV and BESS capacity factor.

Change in DOD has a large impact on NPV as shown in the figure, at a rate of £6m per 1% change in DOD, but only 0.7% change in BESS capacity factor. The reason is that by increasing DOD more of the energy in the battery is available for charge and discharge cycles which is similar to increasing battery size. However, Kempener et al. [15] show that an increase in % DOD reduces the number of charge and discharge cycles available during the lifetime of a battery. On the other hand, if the batteries were discharged below to a certain level of DOD, which in our case is 86.5% (see Fig. 10), the BESS would make a negative NPV. Therefore, it is evident that a 90% DOD was a balanced choice for ensuring a positive NPV and prolonging the lifetime of the batteries.

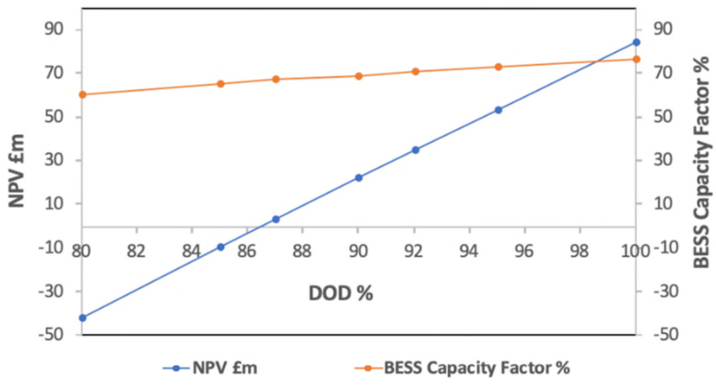

Fig. 10. Impact of DOD on NPV and capacity factor (Optimised)

3.3.3 Battery efficiency

For this sensitivity analysis, all the variables for the optimised battery size were kept constant and only battery charge and discharge efficiencies were changed from 75% to 100% in steps of 5%. Results of sensitivity analysis on η_c and η_d are shown in Fig. 11. It shows a linear relationship between battery efficiencies and NPV and BESS capacity factor.

An increase in η_c and η_d by 1% gives a corresponding increase of £3.3m and an increase in BESS capacity factor by 0.84%. Therefore, an increase in battery efficiency increases available energy within the battery for use. In contrast, if the efficiencies are reduced to below 83%, the model predicts a negative NPV. Li-ion batteries efficiencies of 85-98% have been reported [53] and further developments in battery chemistries and internal structures will improve efficiencies. However, in many research work, battery efficiencies up to 95% have been used [16,54]. In such a case, NPV and capacity factor of the BESS is much better as can be seen in Fig. 11.

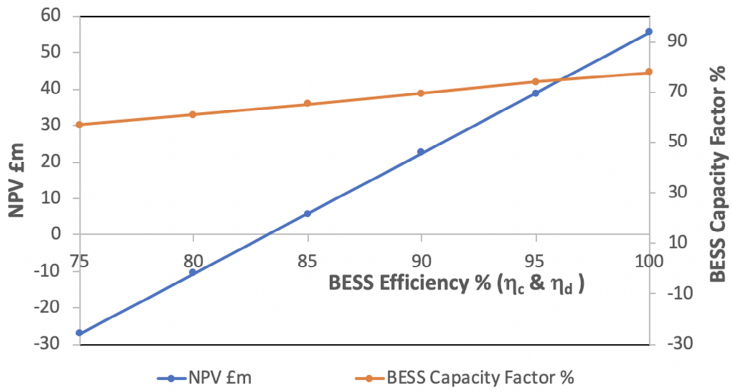

Fig. 11. Impact of charge and discharge efficiencies on NPV and capacity factor (Optimised)

3.3.4 Battery cost

In addition to the optimisation of IRR to ensure that the investment gets the hurdle rate as discussed in Section 3.2, we also conducted a sensitivity analysis for the battery cost. All the variables for the optimised battery size were kept constant and only battery costs £ per kWh were altered in steps of £25/kWh from £100/kWh to £250/kWh with the base case cost of £200/kWh. The results of the analysis are shown in Fig. 12. A positive NPV is achieved with battery cost below £220/kWh for the optimised battery size, which is in contrast to the base case (non-optimised) condition that estimated a negative NPV of £1075m due to a low capacity factor of BESS, as mentioned before.

If the battery cost were reduced by 12.5% from £200/kWh i.e. £175/kWh, NPV of £54m and IRR of 4.5% would be achieved. However, if the battery costs were reduced by 25%, e.g. £150/kWh, NPV of £85.5m and IRR of 8.0% would be achieved which represents an improvement of £63.1m in NPV and 6.3% in IRR. Therefore, this corresponds to an improvement in NPV of £1.3m for every £1/kWh reduction in the cost of the battery. This, however, assumes there is no change in costs of all the other parts of the BESS e.g. inverters, cooling, and management systems. In order to achieve the hurdle rate IRR for investment, the cost of batteries should have to be below £150/kWh, as can be seen in Fig. 12.

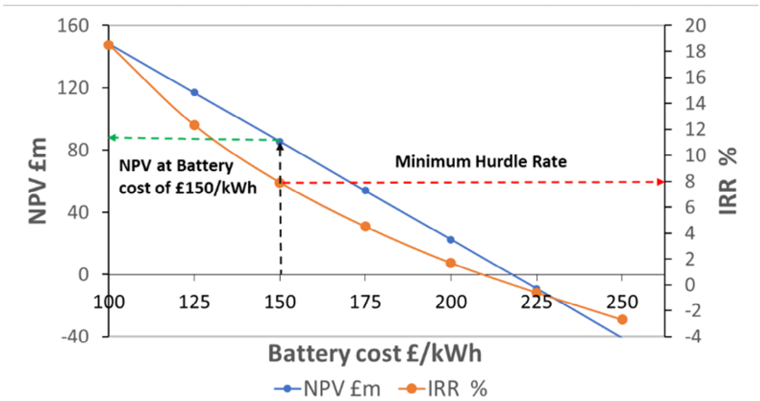

Fig. 12. Impact of battery cost on NPV and IRR (keeping the optimised battery size constant)

3.3.5 BESS income

Income from BESS was changed in the model from £120/MWh to £30/MWh to assess its impacts on financial indicators, while other parameters such as cost of the battery remained the same (£200/kWh).

Fig. 13 shows a linear relationship between income and NPV. Our model predicts that if the income is below £70/MWh, we will have a negative NPV and IRR. This will mean the project becomes not viable from a commercial point of view unless there is a significant decrease in the cost of batteries. To achieve a hurdle rate of 8% for IRR the income would need to be above £100/MWh.

To understand the impact of change in income in the future, and expected reduction in battery costs, a sensitivity analysis was also carried out by changing the income from £120/MWh to £30/MWh with battery cost of £125/kWh that ensures a minimum hurdle rate IRR. It can be seen from Fig. 14 that for income below £44/MWh the model predicts a negative NPV and IRR. However, government incentives and policy for battery storage can shift this financial scenario from commercially unviable to an attractive one for BESS investors. Whilst reduction in battery cost will improve financial indicators, to achieve a hurdle rate of 8% for IRR the income would need to be above £63/MWh.

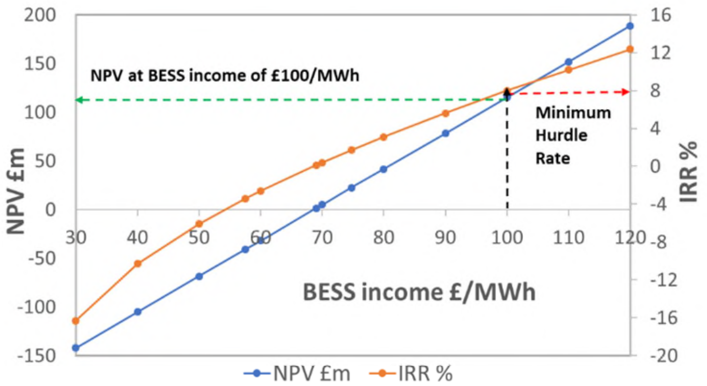

Fig. 13. Impact of BESS income on NPV and IRR (with a fixed battery cost of £200/kWh)

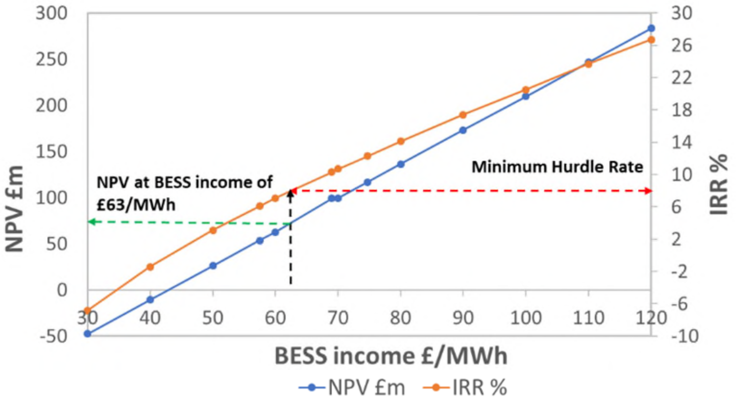

Fig. 14. Impact of BESS income on NPV and IRR (with a fixed battery cost of £125/kWh)

Fig. 15 shows a comparison of payback in years based on the two different battery costs (base case and hurdle rate costs). For a constant BESS income of £74.75/MWh over its lifetime, for a battery cost of £200/kWh a payback of 14 years can be expected and for a battery cost of £125/kWh a payback of 7 years can be expected. Similarly, for a reduced constant BESS income of £57.5/MWh over its lifetime, for a battery cost of £200/kWh a payback of 20 years can be expected and for a battery cost of £125/kWh a payback of 10 years can be expected. Therefore, from 'investors' point of view, the most favourable scenario would be a constant income of £74.75/MWh over the lifetime of battery and battery cost of £125/kWh as this would achieve a payback of 7 years with IRR of 12% and NPV of £117m.

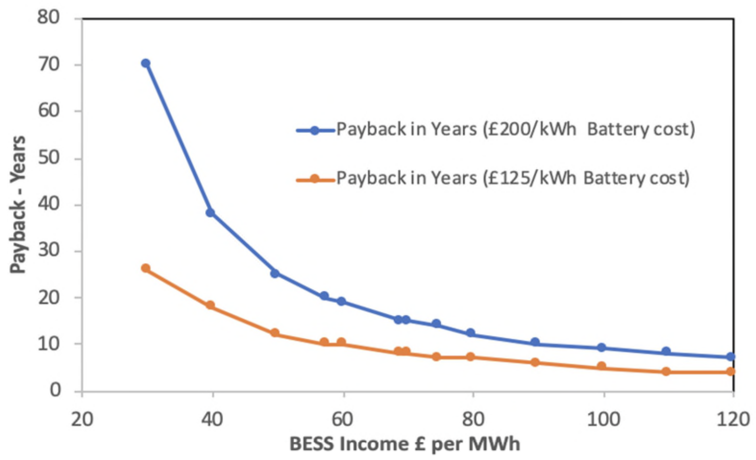

Fig. 15. Payback comparison based on two different battery costs (Optimised)

3.4 Discussion

Whilst batteries have been used at micro-grids level [49] and for Islands [12] their use as BESS at grid-level for energy applications such as peak demand management has been limited. The main reasons why these have not been implemented at grid level in the industry are (a) high cost of batteries, (b) lack of clarity on income from storage, (c) lack of clarity in regulation and incentives to underpin rollout of BESS and (d) lack of supply of batteries to meet demand at large scale required for grid use [55].

Sensitivity analyses show that cost and income from storage are the key factors for the financial viability of energy storage for replacing OCGT and CGT at grid level. In this study it was observed that the IRR for storage were uncertain and range from 1.7% to 12.5%, depending on the income which was range from £74.75/MWh to £120/MWh for fixed cost of battery of £200/kWh. These figures are in close agreement with the values (5% - 14%) obtained by Lai and Locatelli [41] for their study of 100 MWh storage coupled with 100 MW wind farm. The discrepancy between two studies is because the income and cost estimation are slightly different to each other. Also, in current case the storage was solely used for replacing peak times OCGT and CCGT supply and that it generates income from one revenue, which is via energy service. While Lai and Locatelli [41] considered income from storage via multiple revenue streams such as selling to wholesale market, Fast Reserve, and Sort-Term Operating reserve (SORT). Especially, income from Fast Reserve and STOR are much higher (up to £150/MWh) compared to our case of a fixed income of £74.75/MWh (base case price) for selling the electricity during the peak and off-peak times.

It is evident, unsurprisingly, that cost and income are important to the financial outcome of grid scale battery utilisation. However, policy and regulation can also play a key role with respect to the growth and adoption of new technology solutions. Renewable energy generators have already raised their concerns about regulation on prices of stored energy especially when renewable energy, priced at CfD, has been used to charge batteries. Ofgem [56], the energy market regulator in the UK, in consultation with government, are working to provide clarity and favourable conditions to overcome these concerns.

In addition, by offsetting OCGT and some part of variable CCGT there is a reduction in GHG and therefore it can be argued that the cost of avoidance in GHG ought to be considered in the income from storage.

It is important to recognise that the results of this paper are based on costs from 2018 and with income based on CfD valid for 2021-2022. It is anticipated that costs would have not changed significantly and If either or both change then the results of this paper will be different. Therefore, both costs and income used in this paper are limitations in this research. Moreover, it is expected that batteries would be able to generate cash flows in many ways including by providing various energy and ancillary services such as energy arbitrage, peak shaving, fast reserve, short term-operating reserve, etc. However, in this paper we only considered income from batteries via long-term (hour range) energy service such as the supplying electricity mainly during the peak times to replace OCGT and CCGT. Therefore, it is worth noting that the economic results presented in this paper was expected be changed if we were to consider all types of revenue streams for the battery storage at the grid application.

Besides energy applications, the use of BESS at grid-level can also provide energy security should a failure occur in the main baseload or within renewable energy generation. Recently, on 9th Aug 2019, there was a major power cut in the UK as a result of lightening as reported by National Grid [57]. This tripped out a CCGT in Bedfordshire and the Hornsea offshore wind farm simultaneously, reducing overall supply by 5%. As the UK National grid only carries 1% of the demand as a reserve, 100,000 households suffered a power outage. Recent experiences of using storage to reduce the impact of power failures demonstrate success in using storage for power security. For example, in 2017, soon after completion of Tesla's largest battery (129 MWh) installation integrated with solar PV in the north of Adelaide, Australia, two power cuts were restored by these batteries within seconds [32]. Therefore, it can be argued that if BESS of suitable size was available in the UK during the recent incident, stored energy from batteries could have been used for a short period of time until the two generators were restored.

4. Conclusions

This paper presented a techno-economic model of a battery energy storage system for the utilisation of curtail wind to supply grid-level peak demand. The model with key technical and economic parameters of batteries was simulated with one year of supply and demand data from the UK grid. Optimisation of the battery storage system model demonstrated at what size BESS would be commercially and technically viable and beneficial to both the owner of the storage and grid network operator.

We investigated key techno-economic parameters that influences performance and viability of energy storage for the utilisation of curtailed wind. Key technical parameters which determines size of batteries is the excess energy, e.g. amount of curtailment from wind, although the larger the optimised batteries the larger net present value with small corresponding change in storage capacity factors. Depth of discharge of batteries was the next important parameter, giving largest improvement in NPV with the increase of depth of discharge. However, increasing the depth of discharge will reduce number of charge and discharge cycles available during the life of the battery, which was not considered in this study. A further investigation on the impact of depth of discharge on number of cycles available needs to be considered, which will be a task for future work. The battery efficiency is another important parameter that influences the net present value. However, this only exhibits half the improvement in NPV compared to that of depth of discharge with similar percentage increase. Battery efficiency also has a small influence in capacity factor of battery storage system.

Key factors determining economic performance are the cost of batteries and followed by income per MWh. For battery storage system at grid level to be commercially viable, battery costs need to be between £125-150/kWh which would mean a reduction of 25% on today's costs of Li-ion batteries. However, income from BESS is also very important and at present the model predicts a threshold income of £70/MWh, below which net present value and internal rate of return are negative for optimised battery size. However, with lower cost of batteries (<£125/kWh) it was demonstrated that a lower income threshold of £45/MWh could be sustained. The income for BESS to be commercially viable requires careful consideration by policy and regulation makers to ensure (i) incentives, similar to renewable energy generation, are in place for investment due to high initial costs and (ii) a framework to ensure predictability of income for the duration of batteries and (iii) clarity on regulation when storage is used by renewable energy generators, where storage investment ought perhaps to be seen as separate investment from the energy generation plant. Although, on-going work is in progress by Ofgem to provide further clarity on the treatment of electricity storage within regulatory framework, further delays are likely to increase amount of curtailment due to the continued build out of wind power systems.

This research has identified limitations and a number of areas of work has been recommended to further enhance the modelling. These include use of different BESS parameters e.g. temperature and combination of charge cycles with DOD, use of different charging and discharging strategies such as non-linear, and improvement in financial optimisation by using other services e.g. Fast Reserve, Short-term Operating Reserve. To validate and enhance accuracy of the model, practical simulations of BESS with the conditions used in the modelling is recommended.

In summary, this paper has demonstrated that battery storage for grid-level energy applications (to supply electricity for offsetting OCGT and some of the variable CCGT) is a viable option and has commercial potential in the future. However, it needs to be underpinned by favourable economic drivers and policies and regulations.

Acknowledgements

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Nomenclature

BEIS	Department of Business, Energy & Industrial Strategy
BESS	Battery Energy Storage System
CAES	Compressed Air Energy Storage
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CfD	Contracts for Difference
DNO	Distribution Network Operators
DOD	Depth of Discharge
EV	Electric Vehicle

ESO	Electricity System Operator
GHG	Green House Gases
GWh	Gigawatt hour
IRR	Internal Rate of Return
kWh	Kilowatt hour
LCOS	Levelised Cost Of Storage
Li-ion	Lithium Ion
MWh	Megawatt hour
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
Ofgem	Office of Gas and Electricity Markets
O&M	Operational and Maintenance
OPEX	Operating Expenditure
PV	Photovoltaic
VRB	Vanadium Redox Battery
Notations	
$TS(t)$	Total New Supply in MWh
$GS(t)$	Sum of all supply from baseload ie wind, solar, pumped hydro, etc
$S_W(t)$	Supply of electricity from wind in MWh
S_{CW}	Percentage of wind energy available %
$S_{OCGT,peak}(t)$	OCGT peak energy in MWh at time t
$S_{CCGT,var}(t)$	CCGT variable energy in MWh at time t
$NS(t)$	Alternative new supply in MWh at time t
$\Delta W(t)$	Power mismatch in MW at time t
$D(t)$	Demand in supply at time t
$H(t)$	Time series of charging and discharging of a storage system
η_c	Charging efficiency
η_d	Discharging efficiency
E_H	Maximum storage energy in MWh
B_{cf}	Capacity factor
DO_{total}	Actual energy supplied in MWh by BESS over one year
P/E	Power/Energy ratio
C_{cum}	Discounted cumulative costs per year in £
C_I	Installation costs in £
C_{OM}	Operational and maintenance costs per year in £
L_R	Loan repayment in £
L_i	Loan interest rate %
C_D	Decommissioning costs in £
r	Discount rate %
N	Total Lifetime in years
I_{cum}	Cumulative income over lifetime
I	Income each year

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