Techno-Economic Sizing of a Community Battery to Provide Community Energy Billing and Additional Ancillary Services

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A B S T R A C T

This paper presents a novel sizing methodology (energy and power rating) for a Community Battery Energy Storage System (CBESS). The CBESS provides management of the local community energy, and also delivers ancillary services. The investigation considers the economic performance of the CBESS over a 20 year lifetime, including potential revenue when the CBESS provides services for the National Grid such as participation in the Capacity Market and Dynamic Firm Frequency Response services. Furthermore, an economic study is performed to investigate if an addition revenue could be obtained if the CBESS is used to provide more than one service. The methodologies presented for sizing the battery for communities are based on real historic data of several households. The results demonstrate that for a 20 year period, using a 1000 kWh/500 kW CBESS to provide more than one service in any single day achieves the highest value of internal rate of return (10.15%), compared to using the same CBESS to provide only one service for the whole day.

1. Introduction

The future of electricity transmission and distribution faces significant challenges with the increasing use of non-dispatchable supplies (renewable energy sources), the reduction of dispatchable supplies (oil and gas), and the increasing use of electricity, especially at peak times, for transport, heating and air conditioning [1]. New technologies such as energy storage and load shifting are required to move electricity consumption to match supply availability, particularly at consumer level, where the penetration of domestic PV panels, and electric vehicles will place strains on the end-user distribution system.

Community Energy Systems (CES) are seen as an area which can unlock the potential of distributed energy resources and at the same time offer collective benefits to the end-users involved. The term 'Community Energy' can be defined as any energy project that is wholly or partly owned or controlled by a community group [2], [3]. A community group can be a group of neighboring domestic dwellings, where some have their own generation such as PV systems, which are able to trade any excess generation in a hierarchical way: first, with other users in the community; second, with a centralized community battery energy storage system (CBESS) and finally (as a last resort) exporting to the main power grid [4].

CESs have grown gradually in the UK over the past two decades. The UK government has encouraged individuals to work as an energy group over the last 5 years, and more than 5000 community led projects have been created across the UK as a significant proportion of consumers have expressed a desire to become involved in an CES to reduce electricity costs [2]. In addition to achieving benefits for their own customers, these communities offer the potential to adjust the national network generation/demand profile through the use of distributed energy resources such as PV panels, Wind Turbines, Demand-Side Management, as well as battery energy storage systems (BESS).

There is growing trend towards encouraging consumption of locally generated renewable energy at the lowest layer of the grid, rather than exporting excess energy to the national grid [5]. This trend is receiving increasing attention with the development of large scale energy storage systems (>1MWh) [6] as well as domestic battery technologies (<20kWh) and technologies for integrating these into energy communities architectures [7].

The sizing of an energy storage system in terms of both energy and power rating is among the most challenging, complex and important calculations when designing a CES [8]. An efficient and economic component sizing strategy must meet all the system requirements with the minimum operating cost [9], [10]. A deep understanding of the specifications and operational requirements of the overall energy system will lead to more effective installations with less waste in terms of investment costs and energy use during the life of the energy system [11]. Therefore, the sizing methodology must include a proper design analysis rather than simply oversizing the system components [12].

There has been much research into sizing approaches for BESS over recent years [13]. For instance, [14] studied a stand-alone system which contains a wind turbine, PV and battery system. A grid-connected system with PV and battery was presented in [15], analyzing the relationship between electricity and the capacity of battery. [16] compared possible combinations of systems with PV, wind turbine and battery capacity, under either grid-connected or stand-alone mode. Many algorithms were applied for optimal sizing of BESSs. [17] provided a Genetic Algorithm (GA) with a fuzzy expert system to minimize the operating costs of a microgrid by correct sizing of a BESS. [18] presented a method for maximizing the net present value of a BESS, with a matrix real-coded GA. The authors in [19] explored a large-scale battery application which provides ancillary services in an electricity market, while in [20], energy storage is used to provide load-levelling through DSM and PV-shifting under a TOU tariff scheme.

Focusing on the economic benefit of correct sizing of a battery, [21] presented the technical feasibility and the economic profitability of a system with PV and battery energy storage. Working with a time of use (TOU) tariff, [22] investigated the impact of the demand response on BESS optimal sizing. Optimal sizing is also determined in [23], while wind power dispatch and investment costs lead to some constraints. In [24], a BESS is examined for a behind-the-meter application to achieve demand charge reduction. Also, [25] examined various technologies for BESS and assessed their economic viability and impacts on power systems.

Efficient BESSs are essential for providing ancillary services, and lithium is the currently chosen material, considering safety, lifespan and reliability [26]. The use of a BESS connected to the main electricity grid, to participate in Energy and Ancillary Services was discussed in [27]. [28] demonstrated that a BESS can discharge at peak hours to obtain benefits, based on price arbitrage. They also predicted high revenues from spot market price arbitrage. Furthermore, the potential and significance of participation of BESS in electricity market is emphasized in [29].

The authors in [30] described the participation of BESSs in a frequency response service, as a part of energy market services. Furthermore, based on the studies of both the Germany and Netherlands Markets, [31] showed the role of profitability and the feasibility of BESSs in frequency response services, and suggested that the power and capacity of energy storage systems is significant for ensuring contract services. [32] investigated the sizing of battery storage based on power and energy for frequency response. In [25], a virtual energy storage system is modelled by combining demand response of domestic refrigerators and flywheels, which have a significant cost reduction.

It is observed that the economics of sizing a community battery energy storage system to enable the CES to participate in different electricity markets is rarely addressed in the literature. Furthermore, the previously described papers have not examined the participation of the community battery storage in different electricity markets in great detail considering the payback period. Given that little of the previous research has considered these concerns, a comprehensive research on these issues is necessary to understand the potential for increased benefits for CESs.

To close this research gap, this paper focuses on developing a sizing scheme to select the best size (in terms of energy and power rating) for a Community Battery Storage System (CBESS), considering its economic performance over a 20-year lifetime. The CBESS could be either used to directly reduce consumer bills by enabling local energy trading, or to participate in the UK capacity/energy markets. The paper therefore includes an investigation of the potential revenue when using the CBESS in the National Grid's Capacity Market (CM) and Dynamic Firm Frequency Response (DFFR) market, as these services potentially offer the best revenues from the UK energy market. Also, to maximize the profits from the investment in the CBESS, the size of the CBESS has been selected accurately following novel sizing criteria to enable the CBESS to provide more than one service.

The main contributions of this paper can be summarized as follows:

- It provides a proper sizing for a CBESS to provide a community energy bill management (CEBM) service considering the economic performance over a 20 year lifetime.
- It presents a novel selection procedure for the optimal CBESS size to provide multiple services over a 20 year period.
- It compares the economic revenue from the participation of the CBESS in UK energy/capacity markets instead of being used for bill management services.
- It studies the effect of CBESS sizing on the revenue from using the CBESS for CEBM, capacity, and energy market services.

The paper is organized as follows: Section II introduces the architecture of the CES used in this study. Section III presents the Techno-Economic Sizing methodology followed in this paper. Section IV focuses on sizing the CBESS to provide CEBM services including the formulation of the sizing optimization problem and the system's constraints. Section V and section VI show the economic revenue from using the CBESS to provide a DFFR and CM service in the UK respectively. Section VII describes the economic analysis for the system under study. Section VIII presents the results obtained from participation of the CBESS in in CEBM, CM, and DFFR service. Section IX proposes a sensitivity analysis for changing the size of the CBESS on the Internal Rate of Return (IRR) while participating in only one service. Section X shows the selection process for the best size of the CBESS to be able to provide more than one service and details the extra revenue that could be achieved. Finally, the conclusions of this paper are presented.

2. Architecture of the community studied

The case study used in this paper is a UK-based community which includes distributed rooftop PV generation systems and a central CBESS. Fig. 1. shows the architecture of the community system. The community comprises 114 houses with a daily average demand of 2.1 MWh. The distributed PV panels with a peak of 500 kW generate an average energy of 1.25 MWh per day. Also, the community is connected to the main distribution grid via a single connection point. The community load power profile has been created using measured data of multiple houses located in Milton Keynes, UK [33] to consider the aggregation effect of community loads, i.e. the demand behaviour of a 114 homes collective. The PV generation profiles have been created using measured data of a 3.8 kW PV system located in Nottingham [34]]. The PV generation profile has been scaled up to give an equivalent average of 1.25 MWh per day, with the assumption that the PV panels are positioned on the 114 co-located houses at the same orientation. The data for the load demand and the PV generation is for one year.

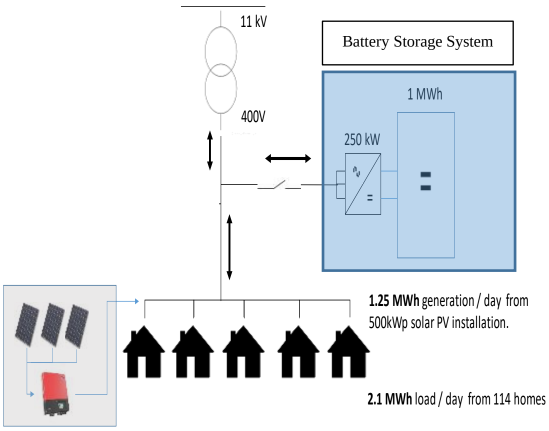


Fig. 1. Community architecture.

3. Techno-Economic sizing methodology

This paper introduces a proper sizing scheme to select the best size (in terms of energy and power rating) for a CBESS, taking into account its economic performance over a 20 year lifetime. The CBESS could either be used to directly reduce consumer bills, or to participate in the UK capacity/energy markets. The sizing process includes an investigation of the potential revenue when using the CBESS in National Grid services such as the CM and DFFR market - the services which currently offer the best revenues from the UK energy market.

Initially it is assumed that the CBESS is used to provide the CEBM service. The best size of CBESS to provide CEBM for one year is determined using the optimization model presented in section 4. The results obtained are then used in the economic study presented in section 7 to obtain the IRR for this investment over a period of 20 years. The effect on the IRR of changing both the size of the power converter and the capacity of the CBESS is also studied.

The IRR value resulting from using the CBESS for CEBM service, is then compared with calculations where the same CBESS is used instead to provide CM or DFFR services in the UK energy market. The size of the CBESS is then varied to determine the maximum revenue that can be obtained from the energy and capacity markets in the UK. A further study is then performed to investigate if addition revenue could be obtained if the CBESS is used to concurrently provide more than one service.

4. Sizing the CBESS to provide the CEBM service

The CBESS shown in Fig. 1. is used to provide the CEBM service to the community and is evaluated off-line using historical data. The CBESS is charged at night (low tariff period) to a certain level, then topped up with the surplus PV generation available during the following day. The stored energy in the CBESS is then used to feed the loads in the morning and during the peak tariff periods to avoid purchasing energy from the main electricity grid when prices are high. The CBESS is used to reduce the annual community energy bill and maximize the PV self-consumption within the community system. The optimal size of the CBESS is the size that minimizes both the CBESS investment cost and the operating costs when used to provide CEBM service, see Fig. 2.

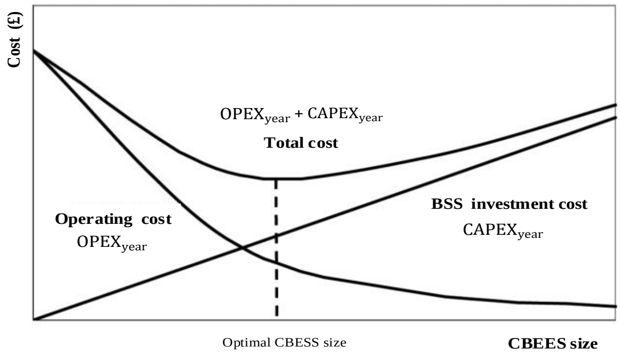


Fig. 2. Effect of changing the CBESS size on the initial investment cost, operating cost, and the total project cost.

4.1 Formulation of the optimization problem and its constraints

The objective function described here aims to determine the best size for the battery storage system as well as the best size for the power converter to minimize both the capital investment cost of the CBESS ‘ $\mathrm{CAPEX_{year}}$ ’ and the annual operating costs of the community system ‘ $\mathrm{OPEX_{year}}$ ’. The objective function, which needs to be minimized, is formulated as a Mixed Integer Linear Programming (MILP) optimization problem as in (1).

$$min\ \left(CAPEX_{year} + OPEX_{year} \right) \tag{1}$$

$$CAPEX_{year} = \frac{IC_{energy}}{LF} \times C_B + \frac{IC_{power}}{LF} \times P_{CBESS\,rating} \tag{2}$$

$$OPEX_{year} = C_{buy} + C_{sell} + SC + Y_{main\_cost} + C_{CBESS_d} \tag{3}$$

$$C_{buy} = \sum_{day\,1}^{day\,365} \sum_{to}^{T=24h} \Delta T \times f_{buy}(t) \times P_{Grid}(t) \quad , at\ P_{Grid}(t) > 0 \tag{4}$$

$$C_{sell} = \sum_{day\,1}^{day\,365} \sum_{to}^{T=24h} \Delta T \times f_{sell}(t) \times P_{Grid}(t) \quad , at\ P_{Grid}(t) < 0 \tag{5}$$

$$Y_{main\_cost} = 0.45\% \times CAPEX_{year} \times LF \tag{6}$$

$$C_{CBESS_d} = \frac{CAPEX_{year}}{N_{cycle}} \sum_{day\,1}^{day\,365} \sum_{to}^{T} \{ \frac{\eta_{Conv} \times \eta_c \times \Delta T \times P_{CBESS}{}^{charg}(t)}{C_B \times 2} + \frac{\Delta T \times P_{CBESS}{}^{disch}(t)}{C_B \times \eta_{Conv} \times \eta_d \times 2} \} \qquad \forall\ v > N_{cycle} \tag{7}$$

where IC_{energy} is the CBESS investment cost based on energy rating (£/kWh), IC_{power} is the CBESS investment cost based on power rating (£/kW), C_B is the CBESS rated capacity (kWh), $P_{CBESS\,rating}$ is the converter rated discharge/charge power (kW), LF is the CBESS lifetime (assumed 20 years), SC is the yearly standing charge price (£/year), C_{CBESS_d} (7) is the annualized battery replacement cost (£/year) due to the battery degradation from charging and discharging cycles [35]; A full degradation cycle is defined as the sum of a full charging and a full discharging cycle. Hence, this cost is formulated into two parts: the battery degradation during charging cycles, and the battery degradation during discharging cycles. N_{cycle} is the typical number of life cycles of the battery, v is the total number of charging/discharging cycles, which depend on the operational strategy chosen for the CBESS, $P_{CBESS}{}^{disch}(t)$ and $P_{CBESS}{}^{charg}(t)$ are respectively the CBESS discharge and charge powers at a time interval t (kW), $P_{CBESS}{}^{disch}(t)$ is always a positive value whilst $P_{CBESS}{}^{charg}(t)$ is always a negative value, η_d , η_c are the battery discharging and charging efficiencies respectively (%); the battery efficiencies are assumed to be constant averaged values, neglecting the variation of the efficiency for different values of charging or discharging power, η_{Conv} is the efficiency of the power converter (%); the efficiency of the power converter is assumed constant in this research, ΔT is the sample time (h), $P_{grid}(t)$ is the electrical power imported/exported from the main electricity grid (kW) at a time interval (t) (a positive value means that the community is importing power from the main electricity grid while a negative value means exporting power to the main electricity grid), $f_{buy}(t)$ is the electricity purchase tariff from the main electricity grid a time interval t (£/kWh), $f_{sell}(t)$ is the electricity sale tariff to the main electricity grid at a time interval t (£/kWh), Y_{main_cost} is the yearly maintenance (£) cost of the CBESS.

The CBESS investment cost ' $CAPEX_{year}$ ' (2) includes the initial cost of the battery and the initial cost of the battery's power converter. It includes also pro-rata installation costs for energy rating (IC_{energy}) and power rating (IC_{power}). The CBESS investment cost is normalized on an annual basis (i.e. distributed over the lifespan of the CBESS).

The expected operating costs of the community after using the CBESS '$OPEX_{year}$ ' (3) are: (a) 'C_{buy}' the cost of imported electricity from the main distribution grid to feed the community's load demands and charge the CBESS over a year, (b) 'C_{sell}' the revenue of the surplus energy sold to the main grid, i.e. the excess electricity produced by the PV generation after satisfying the community demands and charging the CBESS [36], (c) 'SC 'the annual standing charge, (d) '$Y_{main_{cost}}$' the annual maintenance cost of the CBESS (6); this cost is divided into fixed and variable maintenance costs. The fixed maintenance cost is used for regular services of the BESS, whilst the variable cost accounts for on demand maintenance. The annual maintenance cost is assumed to be 0.45 % of the total investment cost of the CBESS [37], and (e) 'C_{CBESS_d}' the annualized battery replacement cost due to the battery degradation from charging and discharging cycles. The number of charging/discharging cycles per day depends on the way in which the battery is operated [38]. Therefore, the annualized battery replacement cost is incurred to consider battery replacement, if the total number of life cycles undergone by the battery is higher than the typical life cycles specified by the manufacturer [8].

4.2 CBESS Model

The model of the CBESS is represented as follows. The stored energy in the battery, every sample time, can be formulated as (8).

$$E(t) = E(t-1) - \frac{\Delta T \times P_{CBESS}{}^{disch}(t)}{\eta_d} - \Delta T \times \eta_c \times P_{CBESS}{}^{charg}(t) \quad (8)$$

where $E(t)$ and $E(t-1)$ are the stored energy (kWh) in the CBESS at time intervals t and t-1 respectively.

The status of the stored energy of a battery every sample time is defined as state of charge (SOC) (9):

$$SOC(t) = \frac{E(t)}{C_B} \times 100 \quad (9)$$

Minimum and maximum SOC level constraints (10), are used to avoid deep discharging or overcharging the CBESS, as that can significantly reduce the battery lifetime [39]. This constraint is critical to the CBESS operation and is recommended by the IEEE [40]. The SOC limits of the lithium-ion battery, considered in this research, are restricted to a range between 20 and 90% of the nominal battery capacity.

$$SOC_{min} \le SOC(t) \le SOC_{max} \quad (10)$$

where SOC_{max} and SOC_{min} are the maximum and minimum allowable SOC limit (%).

The model of the battery power converter is represented by (11). The battery power converter acts as an interface between the battery and the CEMS and is used to control the battery.

$$P_{CBESS}(t) = P_{CBESS}{}^{disch}(t) \times \eta_{Conv} + \frac{P_{CBESS}{}^{charg}(t)}{\eta_{Conv}} \quad (11)$$

where $P_{CBESS}(t)$ is the electrical power discharged/charged from the CBESS at time interval t (kW), where a negative value means the CBESS is charging, while a positive value means the CBESS is discharging.

Constraint (12) reflects the operating limits of the CBESS and defines the maximum power that can be discharged/charged by the CBESS.

$$-P_{CBESS\,rating} \le P_{CBESS}(t) \le P_{CBESS\,rating} \quad (12)$$

where $P_{CBESS\,rating}$ is the rated (maximum allowable) CBESS charge/discharge power (kW) (i.e. rated converter power).

Two binary variables $б_{B\,disch}(t)$ and $б_{B\,charg}(t)$ are introduced to ensure battery's power flows only in one direction at any given time, see (13-15):

$$б_{B\,disch}(t) + б_{B\,charg}(t) \leq 1 \tag{13}$$

$$б_{B\,disch}(t) = \begin{cases} 1 & , P_{CBESS}(t) \geq 0 \\ 0 & , P_{CBESS}(t) < 0 \end{cases} \tag{14}$$

$$б_{B\,charg}(t) = \begin{cases} 1 & , P_{CBESS}(t) < 0 \\ 0 & , P_{CBESS}(t) > 0 \end{cases} \tag{15}$$

where $б_{B\,disch}(t)$ equals 1 if the battery is discharging and equals 0 otherwise. $б_{B\,charg}(t)$ equals 1 if the battery is charging and 0 otherwise.

Constraints (16, 17) are used to create a link between the battery power and the binary variables $б_{B\,disch}(t)$ and $б_{B\,charg}(t)$.

$$P_{CBESS}{}^{disch}(t) \leq б_{B\,disch}(t) \times (P_{CBESS\,rating}) \tag{16}$$

$$P_{CBESS}{}^{charg}(t) \leq б_{B\,charg}(t) \times (-P_{CBESS\,rating}) \tag{17}$$

4.3 Imported/exported power model

The community imports energy from the main electricity grid to feed the household consumption and charges the CBESS. Also, the community exports any excess PV energy to the main grid, after satisfying the household demands and charging the CBESS. Two binary variables $\Phi_{import}(t)$ and $\Phi_{export}(t)$ are introduced to create a link restriction to ensure the community is either only importing or only exporting power at a certain time t, i.e. grid power flows in one direction at any given time, see (18-20):

$$\Phi_{import}(t) + \Phi_{export}(t) \leq 1 \tag{18}$$

$$\Phi_{import}(t) = \begin{cases} 1 & , P_{Grid}(t) \geq 0 \\ 0 & , P_{Grid}(t) < 0 \end{cases} \tag{19}$$

$$\Phi_{export}(t) = \begin{cases} 1 & , P_{Grid}(t) < 0 \\ 0 & , P_{Grid}(t) > 0 \end{cases} \tag{20}$$

where $\Phi_{import}(t)$ equals 1 if the community is importing power from the main electricity grid at time interval t, and equals 0 otherwise, $\Phi_{export}(t)$ equals 1 if the community is exporting power to the main electricity grid at time interval t, and 0 otherwise, $P_{Grid}(t)$ is the power imported/exported by the community from the main electricity grid at time interval t (kW); i.e. a positive value means the community is importing power from the main electricity grid, and a negative value means it is exporting.

In some countries, penalties are added to the electricity bill if the power to or from the main electricity grid increases over a certain limit. To control the maximum imported or exported power by the community at time interval t, constraints (21, 22) are used, which link the grid power, and the binary variables $\Phi_{import}(t)$ and $\Phi_{export}(t)$.

$$P_{Grid}{}^{import}(t) \leq \Phi_{import}(t) \times P_{Grid}{}^{max\ import} \tag{21}$$

$$P_{Grid}{}^{export}(t) \leq \Phi_{export}(t) \times P_{Grid}{}^{max\ export} \tag{22}$$

where $P_{Grid}{}^{import}(t)$ is the power imported from the main electricity grid at time interval t, $P_{Grid}{}^{export}(t)$ is the power exported to the main electricity grid at time interval t, $P_{Grid}{}^{max\ import}$ is the limit for the imported power from the main electricity grid, i.e. this value is assumed infinite, unless specified by the electricity provider, $P_{Grid}{}^{max\ export}$ is the limit for the exported power from the community to the main electricity grid, i.e. this value is assumed infinite, unless specified by the electricity provider.

The term $P_{GCP}(t)$ will be used to refer to the power imported/exported at time interval t, see (23), where $P_{GCP}(t)$ is the power at the grid connection point between the community and the main electricity grid; a positive value means that the CES is importing power from the main electricity grid, whilst a negative value means exporting power to the main electricity grid.

$$P_{GCP}(t) = P_{Grid}{}^{import}(t) - P_{Grid}{}^{export}(t) \tag{23}$$

4.4 Constraints of the energy community

The power balance equation of the total active power in the community is formulated as (24):

$$P_{GCP}(t) + P_{CBESS}(t) = P_{load}(t) - P_{PV}(t) \tag{24}$$

where $P_{load}(t)$ is the daily power profile of the community's load demand (kW); i.e. a power profile of one hour samples over a 24 hour period, $P_{PV}(t)$ is the power profile of the power generated by the aggregated PV systems located in the community (kW), $P_{CBESS}(t)$ is the net daily electrical power profile of the power discharged/charged by the CBESS (kW).

To prevent the CBESS from exporting energy to the main electricity grid, the following constraint (25) is used to introduce link restrictions between the discharging of the CBESS and exporting power to the grid.

$$б_{B\,disch}(t) + \Phi_{export}(t) \leq 1 \tag{25}$$

Also, all the constraints associated with the CBESS model (8-17) and the constraints of the imported/exported power from the main electricity grid (18-23) are applied to the MILP optimization process. The CBESS model feeds into the power calculations of the MILP optimization problem, i.e. $P_{CBESS}(t)$ in (24), and the constraints of the CBESS model are considered as MILP optimization constraints.

5. Capacity Market service in the UK

The UK Government introduced the CM mechanism to ensure that the supply of electricity continues to meet demand as the proportion of more variable renewable energy generation is increasing [41]. The CM service aims to achieve security of supply for a long-term period. It also provides fixed annual payments to generators within the CM and buys capacity (£/kW/year) ahead of delivery. The CBESS operation within the CM is focused on being directed to discharge over a fixed time period during the day, usually at rated capacity, based on the requirements of the Transmission Network Operators. The CBESS is charged from the surplus PV energy during the day or at night (i.e. using the low purchasing electricity tariff). This operation procedure is repeated daily. The CM service is offered in the form of two auctions: (a) T-1 auction: this auction is performed each year to be delivered one year ahead, and (b) T-4 auction: this auction is performed each year to be delivered four years ahead. This program encourages the building of new power stations.

The National Grid operators notify the providers (i.e. CBESS in this case) that they will be required to deliver the agreed capacity. The Notification includes the start time, the duration period for which the delivery is applicable, and the percentage of their total obligation that providers will deliver [42]. All these requirements should be agreed in advance during the auction process, based on provider requests and availability times, i.e. the Energy Community determines its available times for charging and discharging, and also the capacity it can deliver. If the Energy Community is instructed to deliver its CM service, it must guarantee the delivery of the agreed capacity. Failure to deliver the agreed capacity during system stress events will result in penalties [43].

The yearly revenue from using the CBESS to provide CM services can be presented in terms of incomes and payments as follows:

The incomes include:

- The CM contract fee (£/KW/year): the service providers (CBESS owners) provide energy to the National Grid based on a certain contract fee. This fee determines the amount of money payable by the National Grid to the service providers for the contracted power (kW/year); it is assumed that the contract fee is £16.8/kW/year [43]. This value is not fixed for all service providers, but depends on the size of the generation unit(s) and the auction values.
- The cost of the discharged energy to the National Grid by the CBESS during a CM event, at a sale price of 11.99 pence/kWh [42], [44].

The payments include:

- The yearly standing charge for Transmission Network Use of System (TNUOS) and Distribution Use of System (DUOS).
- Energy Service Company Fee (for project management): it is assumed that 20% of the net yearly profits goes to the Energy Service Company for the management of the project and applying for the auctions.
- Charging the CBESS: the CBESS is charged at night using off-peak energy purchased at a tariff of 4.99 pence/kWh; the CBESS is not fully charged at night to be able to store surplus PV energy available during the following day.
- The yearly maintenance cost of the CBESS.

6. Dynamic Firm Frequency Response service in the UK

The UK National Grid needs energy users to provide frequency response services, where they are expected to act quickly and increase/decrease or shift demand, or switch back-up generation to help stabilize the grid. DFFR services enable energy providers to provide a service that can reduce demand or increase generation when instructed by the UK National Grid [45]. DFFR is one of the UK National Grid's most valuable balancing services on a £/MW hour basis, see [46].

The UK National Grid buys DFFR services through a monthly electronic tendering process. Service providers can participate in the tendering process once they have passed the pre-qualification assessment and can tender either for a single month or for several months.

There are three sub-services embedded in the DFFR service as shown in Fig. 3 [47].

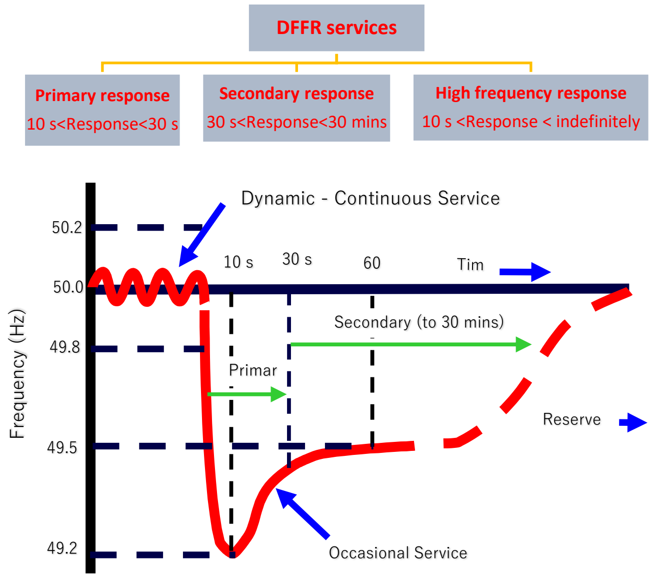


Fig. 3. DFFR sub-services and speeds [48].

(a) Primary response: the provider should ensure the response is provided within 10 seconds of an event, which can then continue for another 20 seconds; (b) Secondary response: response provided within 30 seconds of an event, which may be sustained for another 30 minutes; (c) High frequency response: - response provided within 10 seconds of an event, which can be sustained indefinitely. Providers may only offer one of these or a combination of different response times. Note that the electronic tenders are evaluated based on the ability to provide all three services together (i.e. the providers get a higher revenue for the tender if they can participate in all three services).

The operation of the CBESS to provide the DFFR service is based on being ordered to discharge or charge, usually at rated power, for a certain event (i.e. typically the event lasts for 3-4 minutes up to a maximum of 30 minutes [48]). The CBESS should be capable of maintaining discharging/charging at rated power for up to 30 minutes as one of the requirements of the National Grid. Also, the state of charge of the CBESS, while participating in the DFFR service, should normally be 50 % in order to be able to respond to any discharging or charging events.

The yearly revenue from using the CBESS to provide the DFFR service can be presented in terms of incomes and payments as follows:

the incomes include:

- Availability Fee (£/MW/hr) [48] – related to the number of hours of availability from the provider. In this research, the Availability Fee is assumed (£8/MW/hour) [49]. Also, it is assumed that the CBESS is available 24 hours per day all the year with a guaranteed response of 95%.
- Response Energy Fee (£/MWh) [48]– based upon the actual response energy provided. Actually, the National Grid usually offers a zero value for the Response Energy Fee since the purchasing and the selling electricity tariff from/to the main grid, while participating in DFFR, have the same value [50].

The payments include:

- The yearly standing charge for TNUOS and DUOS.
- Energy Service Company Fee for project management, (it is assumed that the Energy Service Company takes 20% of the net annual profits for the project management).
- The annual maintenance cost of the CBESS.

7. Computational procedure and economic analysis

The optimization problem, mentioned in section 4.1, is solved using the MILP optimization technique. The solution to the optimization problem determines the best size of CBESS (rated capacity of the battery and the rated value of the power converter) which minimizes both the annual operating costs of the community system and the capital investment cost. The optimization process is performed using minute by minute historical data for the load and the PV generation and with the aid of a battery management algorithm implemented in MATLAB, to create power profiles for grid and battery usage which can be allocated to specific charges using a TOU tariff. The system parameters and tariff values used in the simulation process are shown in **Table 1**. The results obtained are then used in an economic study to obtain the IRR of this investment over a 20-year period.

Table 1. Values used in the simulation process for the participation of the CBESS in the CEBM, CM and DFFR services.

Parameter	Service type		
	CEBM	CM	DFFR
CBESS energy rating investment cost (IC_{energy}) [51]	£350 /kWh -£500 /kWh (used £350 /kWh)		
CBESS power rating investment cost (IC_{power})	£95 /kW -£400 /kW (used £115.5 /kW)		
Battery efficiency η_d , η_c	90%		
Battery minimum - maximum state of charge limit (SOC_{min}) , (SOC_{max})	20%- 90%		
Converter efficiency (η_{Conv})	98%		
Average annual inflation rate [52]	2 %		
CBESS Capacity fade [53]	2 % p.a.		
Energy prices increase rate [54]	5 % p.a.		
N_{cycle}	8000		
Standing charge (SC)	80.2 £/year		
Purchasing electricity tariff [44]	TOU tariff	4.99 pence/kWh	-
Sell electricity price	4.85 pence/kWh	11.99 pence/kWh	-
CM revenue (contract fees) [43]	-	£16.8 /kW /year	-
Energy services company management fee	-	20% of net yearly profit	20% of net yearly profit
Availability fees [49]	-	-	£8 /MW /hour
Response Energy Fee (£/MWh)	-	-	£0/MWh
CBESS guaranteed response [40]	-	-	95%

The IRR is a metric used in capital budgeting to estimate the revenue of potential investment over a fixed time period. The IRR is a discount rate that makes the net present value of all cash flows from a particular project equal to zero [55]. The IRR value is calculated using (26) [55]. IRR is used to determine whether a project or investment is attractive. If the IRR of a new project exceeds a company's required rate of return, that project is desirable. If IRR falls below the required rate of return, the project should be rejected; i.e. the higher a project's IRR, the more desirable it is to undertake. Generally speaking, if the IRR value is more than zero, this means that investment in this project will make a profit, whereas if the IRR value is negative, the project will make a loss.

$$0 = \mathrm{NPV} = \sum_{\mathrm{Yr}=1}^{\mathrm{Yr}} \frac{\mathrm{Cash_t}}{(1+\mathrm{IRR})^{\mathrm{Yr}}} - \mathrm{Cash_0} \qquad (26)$$

where NPV is the net present value. $\mathrm{Cash_t}$ is the net cash inflow during the period Yr. Yr is the number of years. IRR is the internal rate of return. $\mathrm{Cash_0}$ is the total initial investment costs.

The economic analysis is performed using a spreadsheet in which the yearly revenue from using the CBESS in CEBM service can be presented in terms of incomes and payments. The incomes include the difference between the annual energy costs before using the CBESS (the cost of the electricity purchased by the community from the supply utility before using the CBESS, assuming a flat rate for the whole day, i.e. 13.15 pence/kWh), compared to the annual energy costs after using the CBESS to provide CEBM service, assuming the use of the TOU tariff. The payments include (a) the yearly standing charge 'SC' for TNUOS and DUOS, and (b) the annual maintenance cost of the CBESS. The economic analysis considered the operation of the CBESS for 20 years. Important factors such as the capacity fade of the battery, the battery's efficiency, inflation rate and energy price increase are assumed for the economic analysis. These factors have a great effect on the investment in the CBESS to provide CEBM service for a long period of time.

8. Results

8.1 Participation in the CEBM service

The optimization problem is solved using the MILP optimization technique. The optimal CBESS size to provide the CEBM service is found to be 1000 kWh capacity and 250 kW power rating. The annual operating cost of the community system with PV generation is reduced from £64,562 (before using the CBESS) -i.e. the cost of the electricity purchased by the community from the supply utility before using the CBESS, assuming a flat rate of 13.15 pence/kWh for the whole day - to £33,872 when using the optimal size of the CBESS (i.e. the reduction percentage is 47.5 %). This percentage reduction is considered the annual income from investment in using CBESS for CEBM. Also, the local self-consumption of the PV generation within the community increased to 93.5 % after using the CBESS, compared to 53% before using the CBESS.

The results obtained are then used to obtain the IRR for this investment over a 20 year period. The study used the IRR equation (26) and the assumptions shown in Table 1.

For the CEBM service case, Fig. 4 shows the cumulative cash flow over 20 years for the investment in the 1000kWh/250kW CBESS to provide the CEBM service. The cumulative cash flow for each year is calculated by adding the yearly income from using the CBESS to the initial investment cost of the CBESS. Appendix A-CEBM shows the calculations used to obtain these results. The initial investment cost in the CBESS is £378,960 (i.e. this value is calculated using the 1000kWh/250kW CBESS and the energy rating /power rating investment costs in shown in Table 1).

It is observed from Fig. 4 that the return on investment in the CBESS to provide CEBM service over 20 years is £397,882, and the payback period is 12 years. The IRR is calculated to be 7.26%. From the results obtained, the investment in this kind of service needs a long time (more than 10 years) to achieve reasonable profits and therefore the CBESS should have a long lifetime and guarantees a minimum of 8000 cycles. The return on investment is expected to increase as the initial cost of batteries decreases (the initial cost of batteries is expected to decrease over the next few years [51]). These results encourage the investment in the CBESS to provide a CEBM service as it provides a high IRR (7.2%) and achieves an average local PV self-consumption of 88.4% over the 20 years.

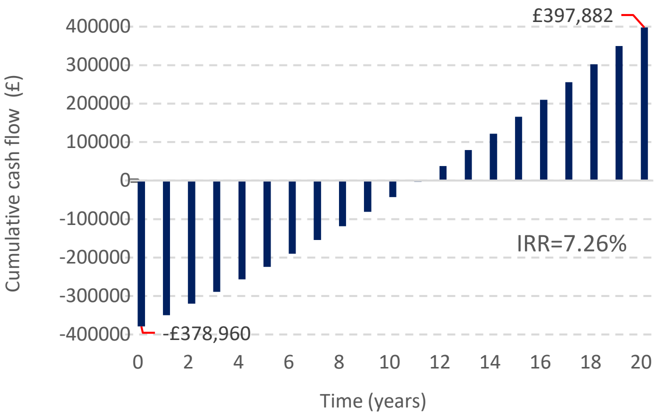


Fig. 4. Cumulative cash flow over 20 years for using a 1000kWh/250kW CBESS to provide Community Energy Bill Management services.

8.2 Participation in the CM service

The operation of the CBESS has been simulated for participating in CM services over a 20-year period. The size of the CBESS used in the simulation is 1000 kWh/250 kW. The same assumptions (Table 1) have been used in this simulation. Appendix B-CM shows the calculations used in the simulation process.

Fig. 5. Cumulative cash flow over 20 years for using a 1000kWh/250kW CBESS to provide Capacity Market services. shows the cumulative cash flow over 20 years. The return on investment is £236,521 over that period, the payback period is 14 years and the IRR is calculated as 4.49%. The return on investment when using the CBESS to provide the CM service could be increased by obtaining a higher contract fee from the auctions, or by increasing the tariff for selling energy to the National Grid. Higher contract fees could be secured by aggregating a number of suppliers (CBESS) and applying for auctions using a higher total value of power and capacity.

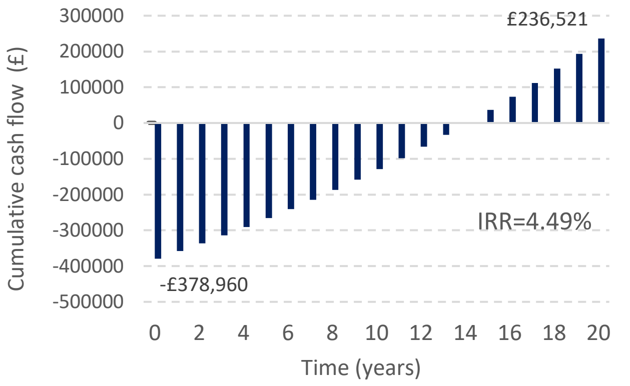


Fig. 5. Cumulative cash flow over 20 years for using a 1000kWh/250kW CBESS to provide Capacity Market services.

8.3 Participation in the DFFR service

The operation of the CBESS has been simulated for 20 years while participating in DFFR services. The same size CBESS was used, as were the assumptions of Table 1. Appendix C-DFFR shows the calculations used in the simulation process.

Fig. 6. shows the cumulative cash flow over 20 years for DFFR services. The return on investment is £26,051, the payback period is 20 years and the IRR is 0.53%. This payback period is too long and the IRR is too low.

By comparing the results obtained from Fig. 4, Fig. 5 and Fig. 6, it is observed that using the CBESS to provide CEBM service achieves the largest value for IRR (7.26%) and also the fastest payback period (12 years), compared to using the same CBESS to provide the CM service which achieves 4.49% IRR and 14 year payback period, or to provide the DFFR service which achieves 0.53% IRR and 20 year payback period. The results obtained encourage the investment in the 1000kWh/250kW CBESS to provide CEBM services.

It is worth noting that the CBESS should guarantee a certain relation between the rated power and the rated capacity to agree with the requirements of the National Grid in the UK. For example, to be eligible to participate in the DFFR, it is required to deliver a minimum of 1 MW. This value can be from a single unit or aggregated from several smaller units (needing an Aggregator). Also, the unit should guarantee the full contracted kW rating for 30 minutes (secondary response): this means that, for a rated power of 250 kW, a CBESS of 250 kWh net capacity should be used, and this should be guaranteed after considering the maximum and minimum SOC limits of the CBESS, roundtrip efficiency, and annual capacity degradation. Also, it is worth noting that the CBESS has to keep its SOC near 50%, while participating in the DFFR service, to be able to respond to charging or discharging events.

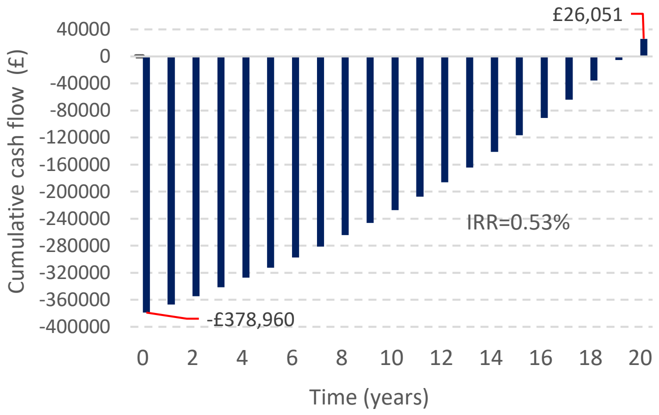


Fig. 6. Cumulative cash flow over 20 years for using a 1000kWh/250kW CBESS to provide DFFR services.

9. Sensitivity analysis

This section studies the effect of changing the size of the CBESS (the rated capacity and the rated power) on the IRR while participating in only one of the CEBM, CM, DFFR services. The operation of the CBESS has been simulated for 20 years.

9.1 Participation in the CEBM service

Fig. 7 shows the effect of using different capacities of CBESS and different sizes of the power converter on the IRR while participating in the CEBM service.

It is observed from the results that, for each CBESS capacity, the IRR decreases as the rated power increases. Also, for each value of the rated converter power, the IRR decreases as the rated capacity of the CBESS increases Fig. 7. shows that using a 1000kWh/250kW CBESS to provide the CEBM service achieves an IRR of 7.26% over a 20 year period, whilst using a 2000kWh/1000kW CBESS achieves an IRR of 1.81% over a 20 year period. Note that the capacity of the used CBESS should not be less than 1000kWh to be able to participate in the energy/capacity market as discussed in section 8.3.

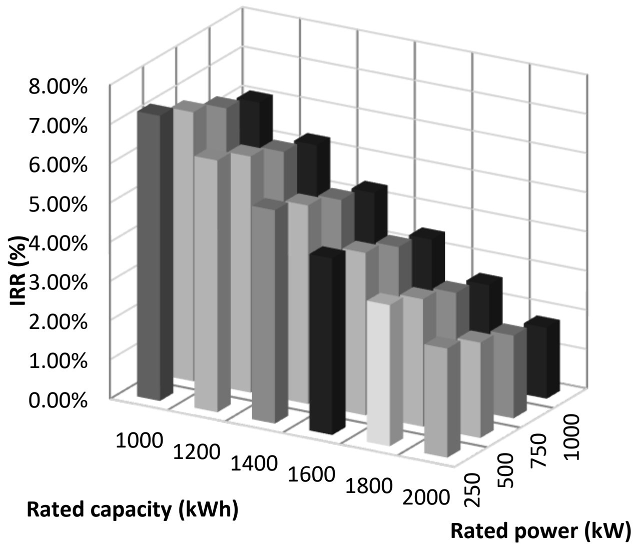


Fig. 7. Effect of changing the size of the CBESS (the rated capacity and the rated power) on the IRR while participating in the CEBM service.

9.2 Participation in the CM service

The effect of using different capacities of CBESS and different sizes of the power converter on the IRR when participating in the CM service is shown in Fig. 8. It is clear from the figure that, for each value of CBESS capacity, the IRR increases as the power inverter rating increases. Also, for each value of the power rating, the IRR decreases as the rated capacity of the CBESS increases.

Fig. 8 shows that the maximum IRR (8%) is achieved using a CBESS with the maximum power rating (in this case 1000kW) and the minimum capacity rating (in this case 1000kWh). Using a CBESS of rating 2000kWh/250kW for CM services achieves an IRR of 1.3% over a 20 year period. It is clear that power delivery is extremely important for CM services since the incomes are directly proportional to the rated power of the CBESS. Note that a CBESS with a capacity lower than 1000kWh is not appropriate in the UK capacity market at the moment since low capacity units face challenges in achieving successful bids.

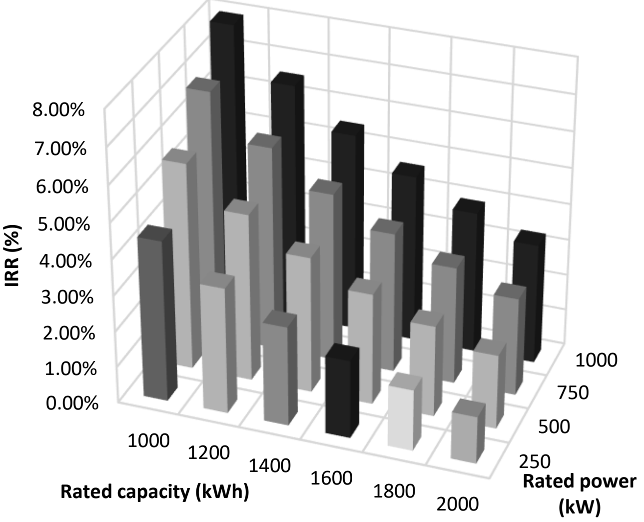


Fig. 8. Effect of changing the size of the CBESS (the rated capacity and the rated power) on the IRR over 20 years while participating in the CM service.

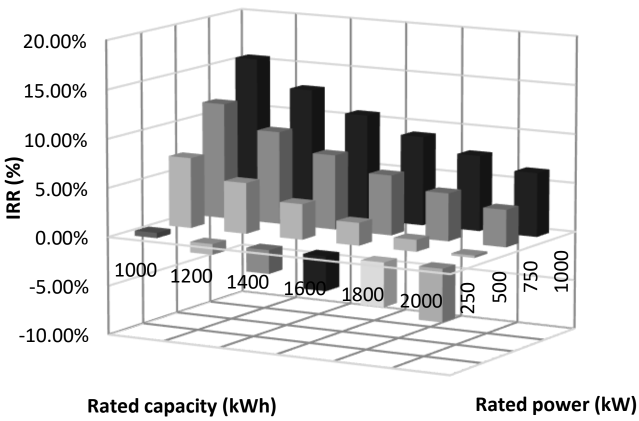


Fig. 9. Effect of changing the size of the CBESS (the rated capacity and the rated power) on the IRR over 20 years while participating in the DFFR services.

9.3 Participation in the DFFR service

Fig. 9 shows the effect of changing the size of the CBESS on the IRR over 20 years when providing DFFR services.

It is clear from Fig. 9 that, for each value of the CBESS capacity, the IRR value increases as the power inverter rating increases. Also, for each value of the power rating, the IRR decreases as the rated capacity of the CBESS increases. It is observed from the figure that using a 1000kWh/1000kW CBESS to provide DFFR service achieves a 15.61 % IRR over a 20 year period. This value is high compared to using the same size of the CBESS to provide other services such as CEBM or CM.

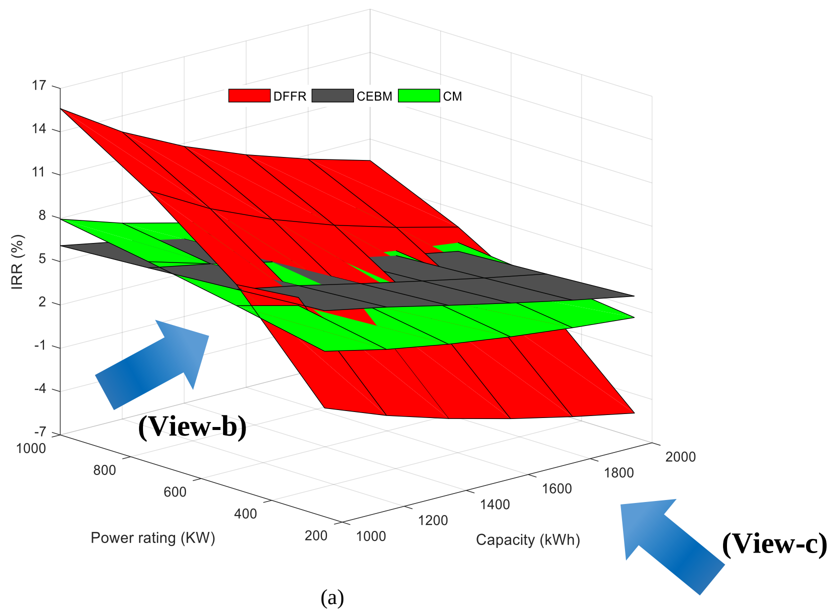
It is interesting to note from Fig. 9 that using a CBESS of a large energy and low power rating achieves investment losses. Power delivery is extremely important for the participation of the CBESS in DFFR services, since the main income from participation in the DFFR service is the Availability Fee (£/MW/hr), and this value is directly proportional to the rated power of the CBESS. Also, it is worth noting that the return on investment in using the CBESS to provide DFFR service could also be increased by participating in the DFFR for a longer number of hours per day, i.e. the main income (i.e. Availability Fee (£/MW/hr)) is directly proportional to the number of hours per day that the CBESS is used.

10. Selection of the CBESS size to provide multiple services

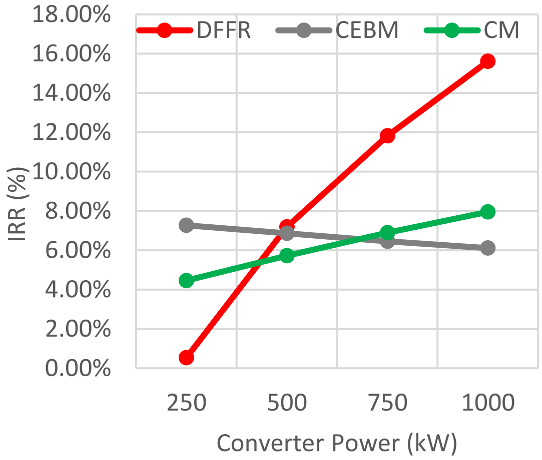
To maximize the income from the investment in the CBESS, the size of the CBESS should be selected accurately to enable the CBESS to provide more than one service instead of providing only one service. This section studies the selection process for the best size of CBESS and the extra income that could be achieved.

The importance of selecting the best CBESS size to provide more than one service is: (a) the CBESS could achieves higher IRR values if it is able to provide more than one service, compared to using the same CBESS to provide only one service for the whole year. (b) The CBESS will have alternatives (services) to participate in if the contract fees and/or revenue fees for any of the services decrease below the estimated values used at the design period. The IRR of the investment in the CBESS to participate in the CM and DFFR services is directly proportion to the changes in the contract fees and revenue fees. The values of these fees are not fixed as they depend on auctions, i.e. can vary every month for the DFFR service or every year for the CM service. (c) The CBESS could participate in alternative services if there is no requirement for additional capacities in the energy capacity market, or no more assistance is required for DFFR service in a particular year. (d) The investment in the CBESS becomes more robust and less affected by changes in the electricity market. This encourages investors to participate in this investment, especially when a guaranteed fixed value of IRR (as opposed to a range of IRR values) is expected.

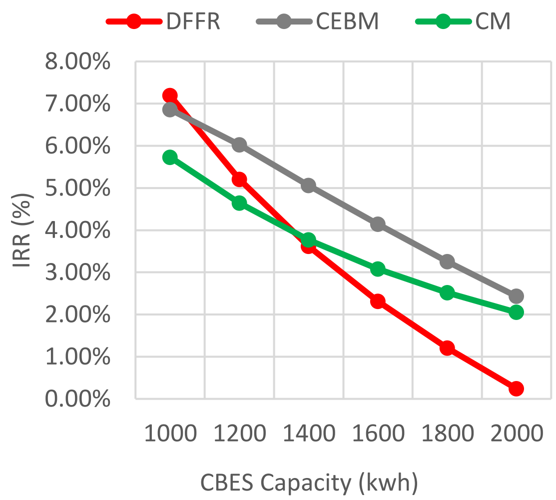
Fig. 10.a shows the effect of changing the size of the CBESS on the IRR while participating in the CEBM, CM and DFFR services over a 20 year period. It is observed from Fig. 10.a that the values of the IRR of the investment in the CBESS to provide the CEBM, CM, and DFFR services are convergent when using a particular value for the rated power and the rated capacity of the CBESS. This means that the CBESS could be used to provide any of the three services (DFFR, CM, and CEBM) with almost the same IRR value while using the same CBESS size. It is clear from Fig. 10.(view-b) that using a CBESS with a rated power of 500kW provides a similar IRR if used for any of the services (DFFR, CM, and CEBM). From the results, the 500kW is selected as the best size of the power converter which enables the CBESS to provide more than one service with similar IRR values.



(a)



(view-b)



(view-c)

Fig. 10. (a) Effect of changing the size of the CBESS (the rated capacity and the rated power) on the IRR while participating in the CEBM, CM and DFFR services over a 20 year period, (view-b) 2D view to show only the variation of the IRR as the size of the power converter changes when using a 1000 kWh CBESS. (view-c) 2D view to show only the variation of the IRR as the capacity of the CBESS changes when using a 500kW power converter

It is observed from Fig. 10.(view-c) that using a CBESS capacity of 1000kWh achieves the highest IRR value for all services while using a 500kW power converter. Also, it is observed that, for each CBESS capacity, the change in the IRR value is in the range of (0.2-2%) if the CBESS is used for any service of the three services. From the results, the best size for the central CBESS which enables it to provide more than one service with almost the same IRR value is 1000kWh/500kW

It can be observed from Fig. 10.(view-b) that the IRR of the investment in the CBESS to provide DFFR service is greatly affected by increasing the rated power of the CBESS, compared to the other two services (CEBM and CM) in which a slight changed in the IRR is observed as the rated power of the CBESS increases. Also, it is clear from Fig. 10.(View-c) that, for the same power converter size (500kW), increasing the capacity of the CBESS decreases the IRR for all services.

Table 2 shows the economic revenue of the investment in a 1000 kWh/500 kW CBESS if used to provide one of the three services (CEBM, CM, and DFFR) over a 20 year period. Using the 1000 kWh/500 kW CBESS achieves convergent IRR values if used to provide any of the three services. The payback period for all services is in the range of 10-13 years. It is important to select the CBESS size, which enables the CBESS to provide more than one service with similar IRR values, so that the average IRR value if the CBESS is used to provide more than one service over the 20 year period is the close to the IRR value obtained from providing only one service over the 20 year period. The results obtained encourage the investment in the 1000 kWh/500 kW CBESS as it achieves a high IRR value and capable of participating in more than one service.

Table 2. Economic revenue of investment in a 1000 kWh/500 kW CBESS if used to provide any of the CEBM, CM, or DFFR services over a 20 year period.

	CEBM	CM	DFFR
Initial investment	£393,000	£393,000	£393,000
IRR (20 years)	6.82 %	5.79 %	7.19 %
Return on investment after 20 years	£393,976	£332,354	£451,062
Payback period	12 year	13 year	10 year

10.1 Providing multiple services over the 20 year period with only one service per year

If the CBESS is used to provide multiple services over the 20 year period, and it is assumed that it will provide only one service each year, then it is important to select the best service (most profitable) in which the CBESS should participate in each year. Fig. 11. shows the annual selection criteria for the most profitable service in which the 1000 kWh/500 kW CBESS should participate in each year.

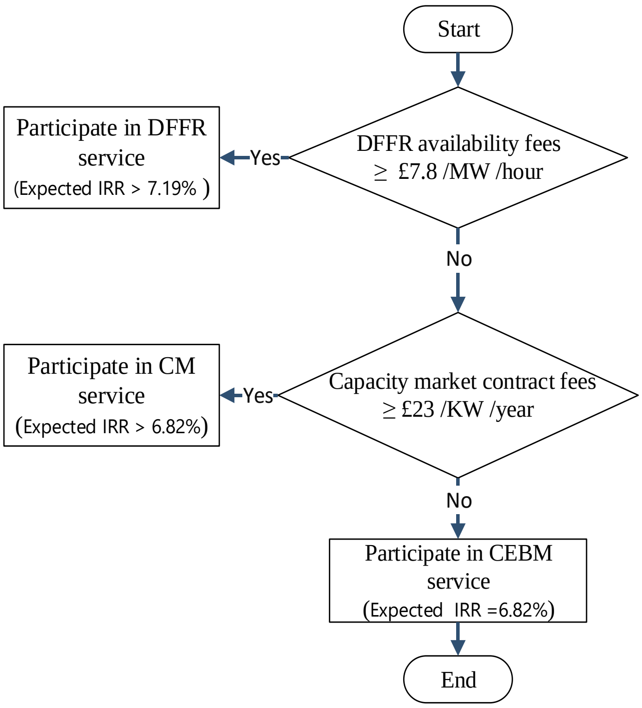


Fig. 11 Selection criteria of the most profitable service in which the 1000 kWh/500 kW CBESS should participate in each year.

It is observed from Fig. 11. that the best service for the 1000 kWh/500 kW CBESS to participate in for a certain year is the DFFR service, if the Energy Service Company were successful in obtaining an annual or monthly electronic tender of a minimum of £7.8/MW/hour for the DFFR availability fees. In this case the IRR will be 7.19%. Higher IRR values could be achieved if the company obtained higher DFFR availability fees. If the Energy Service Company fails to secure a suitable tender then the CBESS should participate in other services. The next-best service for the CBESS is the CM service, if a minimum capacity market contract fee of £23/kW/year is obtained at the annual auction. In this case the IRR will be 6.82%. Higher IRR values could be achieved if higher contract fees are obtained. If neither of these contracts is obtained, then the CBESS should participate in the CEBM service where it can achieve 6.82% IRR.

10.2 Providing multiple services with more than one service per day

The CBESS could be used to provide more than one service per day, instead of providing only one service for the whole day. For example, the CBESS could provide both the CEBM and DFFR services on the same day instead of providing only one of these. This is achieved by providing the DFFR service for a certain number of hours (usually night times) whilst providing the CEBM service during the rest of the day. Table 3 shows the IRR if the CBESS is used to provide both DFFR and CEBM services during the same day (as in cases 2, 3, and 4), compared to being used to provide only DFFR or CEBM for the whole day (as in case 1 and case 2).

It can be seen from Table 3 that using the 1000 kWh/500 kW CBESS to provide both CEBM and DFFR services on the same day achieves higher IRR values compared to using the same CBESS to provide only one service for the whole day. Using the CBESS to provide a DFFR service from 1:00 to 7:00 and a CEBM service for the rest of day achieves the highest IRR value (10.15%), compared to all other cases. When using the CBESS to provide both services in the same day (cases 3-5), the value of the IRR changes as the number of hours of providing the DFFR service is changed. The highest IRR is achieved when the DFFR service is provided for 5 hours (case 4), compared to case 3 in which the DFFR service is provided for only 4 hours, and case 5 in which the DFFR service is provided for 7 hours. The duration of the participation of the CBESS in the DFFR service per day should not be long as in case 5, to enable the CBESS to store sufficient energy during the night (at low tariff period) to provide the CEBM service for the rest of the day. Also, the duration of the participation in the DFFR service should not be short as in case 3, to maximize the benefits of participating in the DFFR service (income from participation in the DFFR service increases with the number of hours).

To maximize the benefits from participating in both the DFFR and CEBM services, the CBESS should participate in the DFFR service only during the overnight period (23:00 to 6:00) and avoid participating in this is service during the daytime. During the daytime, it is important to participate in the CEBM service to achieve sufficient income (and goodwill) for the community members. Note that selecting the time period in which the CBESS could provide DFFR service to the National Grid is an available option for the DFFR service in the UK [56].

Comparing the results obtained in Table 2 and Table 3, it is observed that using the 1000 kWh/500 kW CBESS to provide more than one service in the same day achieves higher IRR values (from 8.71% to 10.15%), compared to using the same CBESS to provide only one service for the whole day (IRR in the range of 6.82%-7.19%) for the 20-year period. The results obtained encourage the investment in the CBESS to provide more than one service in the same day.

Table 3. IRR of the investment in the 1000 kWh/500 kW CBESS if used to provide both DFFR and CEBM services in the same day, compared to being used to provide only DFFR or CEBM service for the whole day.

Case	Daily service	IRR (%)
1	DFFR only (all the day)	7.19
2	CEBM only (all the day)	6.82
3	DFFR (from 1:00 to 5:00) plus CEBM in the rest of day	9.27
4	DFFR (from 00:00 to 5:00) plus CEBM in the rest of day	10.15
5	DFFR (from 00:00 to 7:00) plus CEBM in the rest of day	8.71

11. Conclusion.

The Optimal sizing methodology for a community battery storage system (CBESS) presented in this paper, reduces the annual community energy bill by 45% and maximizes the PV self-consumption within the community to 93.5%, compared to the case where no CBESS is used. Using the 1000 kWh/250 kW CBESS to provide community energy bill management (CEBM) achieves a higher internal rate of return (IRR) value, compared to using the same CBESS to provide other services such as capacity market (CM) or dynamic firm frequency response (DFFR) services. Also, the payback period when using the 1000 kWh/250 kW CBESS to provide a CEBM service is shorter than using the same CBESS to provide CM or DFFR services. The results show that using a CBESS with high rated power and low capacity size achieves more income when participating in the CM and DFFR services. Power delivery is extremely important for the participation of the CBESS in DFFR or CM services. The lifetime of the CBESS should be as long as possible to obtain a high IRR for the investment. Furthermore, the capacity of the CBESS should not be less than 1000kWh to be qualified to participate in the capacity/energy market.

The participation of the community CBESS in DFFR, CM, and CEBM services achieves an IRR of up to 16 %, 7.95 % and 7.26% for the three services respectively, depending on system size. However, the high IRR values are obtained for the DFFR service, it should be noted that this gives no operational advantages for the local community (for example, self-consumption of locally generated PV is not increased significantly), and the higher IRR values are not always guaranteed since it depends on the availability fee value (£/MW/hr) and this value may decreases sharply in a certain months if a plenty generation options are offered in the monthly electronic tendering process.

Using the 1000 kWh/500 kW CBESS to provide more than one service in the same day achieves the highest IRR value (10.15%), compared to using the same CBESS to provide only one service for the whole day for 20 years, and compared to using the same CBESS to provide multiple services over the 20 year period (assuming it is providing only one service each year). The return on investment for the CBESS to provide any of these services is expected to increase as the initial cost of the CBESS decreases.

The results obtained encourage the investment in the 1000 kWh/500 kW CBESS as it achieves a high IRR value, capable of participating in more than one service each day, and guarantees the estimated IRR. The size of the CBESS should be selected accurately to enable the CBESS to provide more than one service instead of providing only one service.

Acknowledgment

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Appendix A-CEBM

Year	Standing charge	OP. cost [1] with BSS	Maintenance [2] cost (Y_{main_cost})	OP. cost [3] without BSS	Percentage [4] reduction in OP. cost	Total [5] income	Cashflow [6]	PV self-consumption
0						-£378,960	-£378,960	
1	£80	£33,872	£1,705	£64,562	47.5%	£28,985	-£349,975	93.5%
2	£84	£36,074	£1,739	£67,790	46.8%	£29,977	-£319,998	92.9%
3	£88	£38,418	£1,774	£71,180	46.0%	£30,987	-£289,011	92.4%
4	£93	£40,916	£1,810	£74,739	45.3%	£32,013	-£256,998	91.8%
5	£97	£43,575	£1,846	£78,476	44.5%	£33,054	-£223,944	91.3%
6	£102	£46,408	£1,883	£82,399	43.7%	£34,109	-£189,835	90.7%
7	£107	£49,424	£1,920	£86,519	42.9%	£35,175	-£154,660	90.2%
8	£113	£52,637	£1,959	£90,845	42.1%	£36,250	-£118,410	89.6%
9	£118	£56,058	£1,998	£95,387	41.2%	£37,331	-£81,079	89.1%
10	£124	£59,660	£2,038	£100,157	40.4%	£38,459	-£42,620	88.6%
11	£131	£63,562	£2,079	£105,165	39.6%	£39,524	-£3,096	88.0%
12	£137	£67,719	£2,120	£110,423	38.7%	£40,584	£37,488	87.5%
13	£144	£72,148	£2,163	£115,944	37.8%	£41,634	£79,122	87.0%
14	£151	£76,866	£2,206	£121,741	36.9%	£42,669	£121,791	86.5%
15	£159	£81,893	£2,250	£127,828	35.9%	£43,685	£165,476	85.9%
16	£167	£87,249	£2,295	£134,220	35.0%	£44,676	£210,152	85.4%
17	£175	£92,955	£2,341	£140,931	34.0%	£45,635	£255,787	84.9%
18	£184	£99,034	£2,388	£147,977	33.1%	£46,555	£302,342	84.4%
19	£193	£105,511	£2,436	£155,376	32.1%	£47,430	£349,772	83.9%
20	£203	£112,550	£2,484	£163,145	31.0%	£48,111	£397,882	83.5%

[1] '*OP. cost with BSS*' is calculated using the annual community load profile, the annual PV generation profile, the TOU tariff and the other operating terms as shown in equation (3).

[2] Annual '*Maintenance cost*' is calculated using equation (6).

[3] '*OP. cost without BSS*' is calculated using the annual community load profile and the annual PV generation profile, using a flat purchasing tariff of 13.15 pence/kWh and an export tariff of 4.85 pence/kWh for selling the surplus PV generation to the main electricity grid.

[4] '*Percentage reduction in OP. cost*' is the annual reduction in the total operating cost of the community after using the BSS and participating in CBEM services, compared to the case without using the BSS.

[5] '*Total income*' is the difference between the annual operating costs of the community before and after using the BSS.

[6] '*Cashflow*' is the cumulative cash and asset values resulting from the investment in the BSS; this value is calculated by adding the total income each year to the initial capital cost of the BSS.

Appendix B-CM

Year	Maint. cost	Standing charge	Night [1] charging cost	Income [2] from the discharged energy to ESCO	Income [3] from CM contract fee	Annual [4] total income	Aggreg -ator cost [5]	Annual [6] total revenue	Cash [7] flow
0									-£378,960
1	£1,705	£80	£3,643	£27,265	£4,200	£26,036	£5,207	£20,829	-£358,131
2	£1,739	£84	£3,557	£28,055	£4,410	£27,085	£5,417	£21,668	-£336,463
3	£1,774	£88	£3,454	£28,857	£4,631	£28,171	£5,634	£22,537	-£313,926
4	£1,810	£93	£3,331	£29,669	£4,862	£29,297	£5,859	£23,437	-£290,489
5	£1,846	£97	£3,188	£30,489	£5,105	£30,463	£6,093	£24,370	-£266,119
6	£1,883	£102	£3,022	£31,318	£5,360	£31,671	£6,334	£25,337	-£240,782
7	£1,920	£107	£2,831	£32,153	£5,628	£32,922	£6,584	£26,338	-£214,444
8	£1,959	£113	£2,614	£32,993	£5,910	£34,217	£6,843	£27,374	-£187,071
9	£1,998	£118	£2,368	£33,837	£6,205	£35,558	£7,112	£28,446	-£158,624
10	£2,038	£124	£2,091	£34,683	£6,516	£36,945	£7,389	£29,556	-£129,068
11	£2,079	£131	£1,780	£35,529	£6,841	£38,381	£7,676	£30,705	-£98,363
12	£2,120	£137	£1,433	£36,373	£7,183	£39,866	£7,973	£31,893	-£66,471
13	£2,163	£144	£1,047	£37,212	£7,543	£41,401	£8,280	£33,121	-£33,350
14	£2,206	£151	£618	£38,045	£7,920	£42,989	£8,598	£34,391	£1,041
15	£2,250	£159	£144	£38,867	£8,316	£44,630	£8,926	£35,704	£36,745
16	£2,295	£167	£0	£40,056	£8,731	£46,325	£9,265	£37,060	£73,805
17	£2,341	£175	£0	£41,424	£9,168	£48,077	£9,615	£38,461	£112,267
18	£2,388	£184	£0	£42,830	£9,626	£49,885	£9,977	£39,908	£152,175
19	£2,436	£193	£0	£44,273	£10,108	£51,753	£10,351	£41,402	£193,577
20	£2,484	£203	£0	£45,754	£10,613	£53,680	£10,736	£42,944	£236,521

[1] '*Night charging cost*': the cost of the energy used to charge the battery during the night. The battery is charged during the night up to a certain percentage to keep spare capacity for the battery to be charged with free PV energy during the day. The electricity used during night time charging is purchased at 4.99 pence /kWh.

[2] '*Income from the discharged energy to ESCO*': the income from selling electricity to the ESCO at 11.99 pence/kWh. It is assumed that the battery discharges the rated energy when instructed to deliver energy to the ESCO.

[3] '*Income from CM contract fee*': this value is calculated using the CM contract fees available in Table 1 and the rated BSS power of 250 kW.

[4] '*Total income'* is the net income from the participation of the BSS in CM services. This value is calculated using the income from the discharged energy to the ESCO, the income from CM contract fees and the payments for the night time energy supply, the standing charge and the maintenance costs.

[5] 'Aggregator cost*'*: it is assumed that 20% of annual total income goes to the ESCO for their project management services.

[6] '*Total revenue':* is the net revenue from the participation of the BSS in CM services. This value is calculated using the 'annual total income' minus the annual 'aggregator cost'.

[7] '*Cashflow*': is the cumulative cash and asset values resulting from the investment in the BSS; this value is calculated by adding the total income each year to the initial capital cost of the BSS.

Appendix C-DFFR

Year	Maintenance cost	Standing charge	DFFR [1] availability income	Annual [2] total income	Aggregator [3] cost	Annual [4] total revenue	Cash [5] flow
0						-£378,960	-£378,960
1	£1,705	£80	£16,644	£14,858	£2,972	£11,887	-£367,073
2	£1,739	£84	£17,476	£15,653	£3,131	£12,522	-£354,551
3	£1,774	£88	£18,350	£16,487	£3,297	£13,190	-£341,361
4	£1,810	£93	£19,268	£17,365	£3,473	£13,892	-£327,469
5	£1,846	£97	£20,231	£18,288	£3,658	£14,630	-£312,839
6	£1,883	£102	£21,242	£19,257	£3,851	£15,406	-£297,433
7	£1,920	£107	£22,305	£20,277	£4,055	£16,221	-£281,212
8	£1,959	£113	£23,420	£21,348	£4,270	£17,078	-£264,134
9	£1,998	£118	£24,591	£22,474	£4,495	£17,979	-£246,154
10	£2,038	£124	£25,820	£23,658	£4,732	£18,926	-£227,228
11	£2,079	£131	£27,111	£24,902	£4,980	£19,922	-£207,306
12	£2,120	£137	£28,467	£26,209	£5,242	£20,968	-£186,339
13	£2,163	£144	£29,890	£27,583	£5,517	£22,067	-£164,272
14	£2,206	£151	£31,385	£29,028	£5,806	£23,222	-£141,050
15	£2,250	£159	£32,954	£30,545	£6,109	£24,436	-£116,614
16	£2,295	£167	£34,602	£32,140	£6,428	£25,712	-£90,902
17	£2,341	£175	£36,332	£33,816	£6,763	£27,053	-£63,850
18	£2,388	£184	£38,148	£35,577	£7,115	£28,461	-£35,388
19	£2,436	£193	£40,056	£37,427	£7,485	£29,942	-£5,447
20	£2,484	£203	£42,059	£39,372	£7,874	£31,497	£26,051

[1] 'DFFR availability income': this value is calculated by multiplying the DFFR availability fees available in Table 1 by the availability period (i.e. 365 day * 24 hour) and by the CBESS guaranteed response (0.95).

[2] '*Annual total income'* is the net income from the participation of the BSS in DFFR services. This value is calculated using the availability income minus the payment for the standing charge and maintenance costs.

[3] 'Aggregator cost*'*: it is assumed that 20% of annual total income is paid to the ESCO for their project management services.

[4] '*Annual total revenue':* is the net revenue from the BSS' participation in DFFR services. This value is calculated using the '*annual total income'* minus the annual 'aggregator cost'.

[5] '*Cashflow*': is the cumulative cash and asset values results from the investment in the BSS; this value is calculated by adding the total income each year to the initial capital cost of the BSS.