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Assessing the economics of large Energy Storage Plants with an optimisation methodology

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A B S T R A C T

Power plants, such as wind farms, that harvest renewable energy are increasing their share of the energy portfolio in several countries, including the United Kingdom. Their inability to match demand power profiles is stimulating an increasing need for large ESP (Energy Storage Plants), capable of balancing their instability and shifting power produced during low demand to peak periods. This paper presents and applies an innovative methodology to assess the economics of ESP utilising UK electricity price data, resulting in three key findings. Firstly the paper provides a methodology to assess the trade-off "reserve capacity vs. profitability" and the possibility of establishing the "optimum size capacity". The optimal reserve size capacity maximizing the NPV (Net Present Value) is smaller than the optimum size capacity minimizing the subsidies. This is not an optimal result since it complicates the incentive scheme to align investors and policy makers' interests. Secondly, without subsidies, none of the existing ESP technologies are economically sustainable. However, subsidies are a relatively small percentage of the average price of electricity in UK. Thirdly, the possibility of operating ESP as both as a reserve and do price arbitrage was identified as a mean of decreasing subsidies for the ESP technologies.

1. Introduction

During the last decade the electricity production from renewable sources has increased all over the world. In Europe, where further development of large hydroelectric plants is limited by the shortage of new locations, solar, biomass and particularly wind farms will play a key role in increasing the share of renewable energy in the next decades [1]. The increasing penetration of variable RET (Renewable Energy Technologies) in power provision is becoming a key issue for the management of the electrical grid. A high percentage of RET (particularly RET generating non-dispatchable electricity) requires flexible power systems that can quickly react to variability in supply and demand. Having a levelised cost of electricity greater than fossil fuel power plants, RET requires further expense in ancillary service as the electricity produced is not dispatchable. Generally the electricity is defined as dispatchable if it is possible to plan and regulate it in order to fulfil demand requirements [2]. Examples of sources producing dispatchable electricity are thermal power plants powered by natural gas and coal, nuclear power plants and hydro-electricity using dams; non-dispatchable electricity comes from sources such as wind farms and solar photovoltaic plants. A high penetration of RETs (producing non-dispatchable and highly variable electricity) negatively affects power system reliability and efficiency requiring mitigations such as [1]:

1. availability of large ESP (Energy Storage Plants), mainly CAES (Compressed Air Energy Storage) and PHS (Pumped Hydroelectric Storage);
2. availability of power plants (*e.g.* natural gas fired plants) producing readily dispatchable electricity;
3. more grid interconnections: isolated systems have more difficulty managing the instability of wind generation than interconnected areas. For isolated locations thermal plants (mostly Diesel engines and gas turbines) are commonly used to support the production of electricity. For instance for the Fair Isle (a small Scottish island) two thirds of the community's power is supplied by wind turbines, and a third by diesel generators [3].

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ESP (Energy Storage Plants) can play a key role in power systems, bridging the gap between variable sources of energy and electricity demand [4]. Renewable energy sources producing non-dispatchable electricity are expected to increase in the UK (United Kingdom) because the government issued a "National Renewable Plan" [5] targeting approximately one third, of all electricity consumption by 2020 to come from renewable sources.

In this paper we introduce and apply a methodology to investigate the technical and economic feasibility of building an ESP according to two scenarios:

1. ESP operating only on price arbitrage
2. ESP operating on price arbitrage and operating reserve.

The method is applied from both the investors' and policy makers' point of view. The research focuses on the UK because of the availability of appropriate public information. Nevertheless, the method and the results are widely applicable.

2. Literature review

2.1. Effect of wind on the power system and its cost

According to a study by the Royal Academy of Engineering [6] in the UK, the levelised cost of generating electricity from wind farms is higher that of fossil fuel, moreover there are standby generation costs that can increase the wind farms generation cost by another 30%–50%. Standby costs exist since electricity output varies as the cube of the wind speed [7]. This causes variability in electricity production. In addition, there is uncertainty as to when wind energy is available. Variability and uncertainty affect different areas of the power system and the relevance of their impact varies with the time scales considered [8]. The cost of coping with this variability and uncertainty is ultimately paid by the consumers.

With regard to variability, very short-term variations (minute time scale) are partially smoothed by the inertia of wind turbines rotor and are levelled out when a large area of production is considered [9]. In suitable regions (usually not in the UK) short-term variations arise mostly from the change of weather patterns and can be moderately smoothed by interconnecting various wind farms installed in locations with different weather patterns [10,11]. Long-term variations are considered as variations of output with time intervals greater than four hours.

With regard to uncertainty, it is not possible to exactly define the wind intensity in a specific location at a given time. The residual error between real data and model results depends on the lead-time considered and on geographical aspects [7,12]. According to [13,14] the impact of wind integration become relevant when wind capacity reaches a penetration of 10-15%. Above this threshold, wind variability and uncertainty significantly affect the power system influencing 1) demand-supply balancing 2) power availability 3) grid stability [15].

2.1.1. Demand-supply balancing

The key responsibility of a power system operator is to synchronize the production and consumption of electricity [16]. The wind variability and uncertainty significantly complicates the demand-supply balancing system and requires additional flexibility in power systems. At high penetration, wind uncertainty requires additional secondary and tertiary operating reserves (see Appendix A) while wind variability can be managed with additional load following power plants and with ESP able to time-shifting electricity from off-peak periods to on-peak periods (i.e. adopting the price arbitrage).

2.1.2. Power availability

The impact on the adequacy of power is determined by long-term wind variability and by the low capacity factor (20–40%) of wind farms [17]. Because of this variability, wind turbines do not increase system-generating capacity by themselves. This is done by increasing the capacity of the dispatchable power generator or storing electricity. Where there is a strong penetration by wind farms, the electricity system will need a higher installed capacity to supply the power required and to ensure the reliability of the system even in case of long periods of still weather.

2.1.3. Grid

A high penetration of wind farms may affect the grid for the following reasons:

1) The fluctuations of wind farm output can affect transmission efficiency.
2) Improvements to the grid may be necessary to smooth short-term variability and uncertainty.
3) An improvement of the grid is necessary to switch from a centralized generation to a distributed generation.

An ESP can operate as a transmission congestion relief, reducing considerably the impact of wind power integration on the grid.

2.2. Energy Storage Plants

2.2.1. ESP technologies

There are many types of ESP, some of them are already commercially available, others are still in the Research & Development phase. ESP can be clustered according to:

- *Storage Properties*: storage scale, ESP efficiency, charge/discharge time.
- *Operation Properties:* facility response time, partial load feature lifetime and reliability.
- *Storage Costs:* consisting of energy costs, power costs, and O&M (Operation & Maintenance) costs.

As seen in Section 2.1 the deployment of wind farms requires additional operating reserves and additional long-term power system flexibility. This section focuses on large ESP suitable for operating both as an operational reserve and as a load following/shifting facility and considers ESP technologies both commercially available and in the pre-commercial phase [18]. Table 1 highlights

Table 1
Overview of Storage technology. Based on [29,34,35].

Storage technology	Typical power output [MW]	Charge/Discharge efficiency	Time of response	Duration of discharge
PHS	250–1000	80–87%	Seconds to Minutes	Several hours
CAES	100–300	54–80%	Minutes	Hours
NaS battery	35	80–85% (DC)	Seconds	Minutes to hours
Lead acid battery	3–20	75–80% (DC)	Seconds	Minutes to hours
Li- Ions battery	0.1–10	90%	Seconds	Minutes to hours
Super capacitors	0.1–10	90%	Seconds	Seconds
SMES	0.1–10	>90%	Immediate	1–100 sec
VRB flow cell	0.01–10	75–80% (DC)	Seconds	2–8 hours
ZnBr flow cell	0.01–10	75–80% (DC)	Seconds	2–8 hours
High power fly wheels	0.01–10	>85%	Seconds	Seconds to minutes

that batteries are suitable as primary operating reserves since have a time of response within seconds and a limited power output. PHS (Pumped Hydroelectric Storage) and CAES (Compressed Air Energy Storage) have a time of response of minutes and can provide more power, therefore are suitable as large ESP for the secondary reserve and time shifting/price arbitrage applications. Beside the technologies in Table 1, hydrogen is a promising solution [19]–[23], however the technology is still at the prototype stage, not enough mature yet for large-scale industrial applications.

CAES plants have the lowest capital cost and efficiency but, at the same time, they also have the lowest charge/discharge efficiency. Given that the charge/discharge efficiency is strictly related with O&M cost, CAES plants require a relatively small initial investment but at the same time they have the highest cost of operation. PHS plants have a charge/discharge efficiency comparable to batteries, with an equal or higher capital cost. However due to its capital cost/service life ratio, PHS are more economically viable, as secondary-tertiary reserve, than batteries.

There are two key reasons to explain why batteries are still not fully economically viable for bulk energy services:

1. They have a limited service life. Even if there are batteries with the same charge/discharge efficiency of PHS, high cycling rates will give an operating life of some 8–15 years.
2. Their energy density is poor. Batteries cannot economically store large amount of energy in small volumes.

However, CAES and PHS plants need minutes to be activated and become fully operative while batteries have a time of response in the order of few seconds. Therefore batteries are ideal for being used as primary reserve, while CAES and PHS are more suitable for secondary and tertiary reserve [24]. Since CAES and PHS are the most suitable for bulk services this paper focuses on these technologies.

2.2.1.1. CAES and AACAES. A CAES system consists of a motor unit, gas turbine, and underground compressed air storage usually in natural or artificial underground chambers. Charged when the price of electricity is low, the motor unit uses electricity to compress and store air in the chamber. The compressed air is usually cooled via a cooler unit. When discharging, when the price of electricity is high or the service of operating reserves are required, the compressed air is supplied to a combustor in the gas turbine to burn fuel. The combusted gas is expanded through the turbine, which drives the generator and produces electricity [25]. The cost of CAES plants is strongly influenced by the geology of the reserve (see Table 2). As at January 2015 there are only five operational CAES plants in the world, with a few others are pilot plants or in the planning stage. Updated information for several types of ESP plants can be freely retrieved from Ref. [26].

The AACAES (Advanced Adiabatic CAES) has an additional storage reserve that captures the thermal energy released during the compression stage. The thermal energy storage during off-peak periods works as intercooler absorbing the heat released by the compressor and allowing a more efficient compression. This cools the air during compression, increasing compressor efficiency. While, during on peak periods (when the AACAES operates as generator and the compressed air is expanded into the turbine) the thermal energy storage preheats the compressed air upstream the expander [27].

Table 2
CAES capacity and reserve cost.

Geology	Reserve capacity cost (Reference values for this paper) [£/KWh]	Reserve capacity cost (Reference values from the literature) [$/KWh]	Reference
Salt Cavern solution mining	0.6 – 3	1	[36]
		2	[38]
		5	[34]
Salt Cavern dry mining	6	10	[36]
Porous rock aquifer	0.06	0.10	[36]
Hard rock existing mines	6 – 18	10	[38]
Hard rock excavated mines	18	30	[36]
		30	[38]
Abandoned limestone or coalmines	6	10	[36]

2.2.1.2. PHS and upgraded PHS. In a PHS plant, water is pumped from a low-level reserve to a high-level reserve via an above-ground pipe or underground tunnel using pumps and turbines or reversible turbines. Pumped hydro construction costs are very site specific. According to [26] the size of PHS installed in UK ranges between 5 and 22 h and their time of response is in the order of seconds-minutes. (e.g. Dinorwig Power Station has a time of response of 16 s).

The IEA in Ref. [25] discusses also the idea of “upgraded PHS”. In a typical PHS, pumps are operated at a constant rotational speed to pump water from a low reserve to a higher one, which makes pumped hydro generally unsuitable for absorbing net wind power variations. That would require the “upgrade” of using adjustable-speed pumped hydro. One successful example of upgrading a pumped hydro plant is the Blenheim Gilboa pumped storage project in New York State where efficiency was increased significantly with the new operating range. Based on equivalent pulsations, vibrations and other parameters, it increased from 140 [MW] to 290 [MW] (more information in Ref. [25]). The goal of the paper is not to compare CAES with PHS, rather to present and apply a methodology for their economic assessment as large ESP. A number of site and market dependent variables (beginning from the availability of suitable locations) influences the overall specific evaluation.

2.2.2. Applications

ESP are multi-service facilities capable to carry out simultaneously two or more applications. Ref. [28] describes the main services that ESP can carry out, highlighting the benefits provided to the power system and the time scale of operation of each application. The applications that require the storage of large amounts of energy, such as time shifting[1] and load following, are called “bulk energy services”, while the term “ancillary service” is used to refer to the applications that necessitate short response time and limited storage reserve capacity, like operating reserves [29]. This study focuses on operating reserve, load following and time shifting applications since are the most relevant for the integration of large amount of wind power [28].

ESP are not conventional power plants and, in order to carry out any of the application described, they have to draw electricity from the grid, store it and reintroduce it into the grid when required. Therefore “price arbitrage” applies to both time shifting and load following services, which are both bulk energy services [30]. Price arbitrage refers to the leveraging of the price spread of electricity

[1] Electric energy time-shifting involves purchasing inexpensive electric energy, available during periods when prices or system marginal costs are low, to charge the storage system so that the stored energy can be used or sold at a later time when the price or costs are high [49]. Therefore the application of time shifting can be carried out only by ESP. In a liberalized electricity market, when an ESP is operating “time shifting” it is leveraging the price spread between peak and off-peak periods (Price Arbitrage).

between peak and off-peak periods [31]. At low electricity prices, during off-peak periods, storage power stations draw electricity from the grid and store. During on-peak periods, the energy accumulated is discharged to provide electricity at higher prices. In the case of time shifting, the electricity is purchased and sold in the day-ahead market while in load following/ramping application the electricity is sold in intraday or balancing markets

The storage technologies that best facilitate the integration of wind power are those that can operate price arbitrage and at the same time can work as secondary/tertiary reserves. Therefore this study focuses on the storage technologies with short time of response and large energy storage capacity, adequate for both operating reserve and price arbitrage applications.

2.2.3. Literature benchmark

A growing body of literature has investigated the role of ESP in current and future power systems. Table 3 summarizes and compares the latest studies and benchmarks them against this paper. The key differences of this analysis with the literature are:

- The assumption of multiservice ESP operating as: 1) time shifting facility 2) operating reserve.
- Optimization of ESP capacity/size with maximum NPV – private investor perspective.
- Optimization of ESP capacity/size with minimum subsidies – policy maker and investor perspective.
- Calculation of the subsidies required to make the technology economically viable.
- Transparent ESP profitability analysis based on public UK electricity market price data.

Other studies that are worth mentioning are: [32], offering a detailed review of ESP for wind power integration support and [8], providing a comprehensive guiding strategy to help to identify overlaps between service needs and ESP capabilities.

3. Methodology

3.1. Price arbitrage only

3.1.1. Hypothesis

In order to develop a mathematical model for the price arbitrage it is necessary to introduce the following hypotheses:

HP1: For every ESP, the maximum rates of energy charged and discharged in a given time are equals.

HP2: The ESP absorbs and provides the same amount of energy, balancing the process inefficiencies using external source of power (e.g. natural gas for CAES).

HP3: The ESP cannot charge and discharge the reserve at the same time. Hence, the charge system and the discharge systems cannot work simultaneously.

HP4: The ESP reserve capacity is limited and sized according to an economic optimum (see later). The storage capacities are calculated in hours i.e. the ratio between storage capacity [MWh] and storage nominal power [MW]. Therefore reserve capacity is expressed as the number of hours (h) for which the ESP can generate the maximum power continuously.

HP5: The ESP operator knows the prices of electricity in advance (common knowledge with the day-ahead market and/or elaboration of historical series).

3.1.2. Method

The Price Arbitrage profitability analysis has four main steps, applied by the way of example to the UK electricity market.

Step 1 – Correlation between electricity power market data and storage station short-term choices

An ESP operates price arbitrage if the difference between electricity purchase and selling price (Δp) is equal or greater than the marginal cost of storing and introducing additional MWh into the electricity grid.

Assuming that production cost (C) is:

$$C = VOC \cdot Heq + FOC$$

where VOC (Variable Operating Cost) are the Variable Operating Costs, Heq the equivalent operating hours (i.e. the number of hours, over one year, in which the ESP is providing power at nominal capacity) and FOC (Fixed Operating Costs) of the ESP, the smallest Δp for which a Storage Station will charge and discharge the reserve is defined as:

$$\Delta p_{min} = Marginal\ Cost = \frac{\partial C}{\partial Heq} = VOC$$

Step 2 – Correlation between Heq and the VOC

Heq depends on the price volatility of the market considered and on the VOC of the ESP. For instance battery storage with high efficiency (and consequently low VOC) can operate even when the difference between off-peak and on-peak price is small. Inversely, a CAES storage, with higher VOC, can run only with large price spreads and therefore it will operate for less equivalent hours then a battery storage. Fig. 1 shows the correlation between Heq and VOC ($=\Delta p_{min}$) obtained with the data of the day-ahead UK electricity market. Fig. 1 is generic and applicable to any kind of storage. The equivalent operating hours of every ESP depends on its VOC and the volatility of the electricity price. In fact, an ESP with high VOC can operate only when the difference between peak and off-peak prices is high, while an ESP with lower VOC has a higher capacity factor.

Step 3 – Calculation of annual revenue and the contribution margin for any storage technologies

The annual Revenues are calculated by multiplying the difference between Selling and Purchase Electricity Price by the Equivalent Operation Hours.

$$Annual\ Revenue = Heq \cdot \overline{\Delta p} = Heq \cdot \sum_{i=min}^{max} \frac{\Delta p_i \cdot H_i}{Heq} = \sum_{i=min}^{max} \Delta p_i \cdot H_i$$

The Contribution Margin is obtained by subtracting VOC from annual Revenue.

$$CM = Annual\ Revenue - VOC \cdot Heq$$

Fig. 2 provides an example of an ESP operating with a VOC of 15.8 [£/MWh]. The maximum operating hours results from the intersection of Heq curve with the VOC (i.e. about 1278 h) while the annual Revenue is the red area lying below the Heq curve, indicated with the cross-hatch. The Contribution Margin is obtained by subtracting the VOC • Heq from the Revenue Area and is represented with the solid orange area.

Table 3
Benchmark with similar studies in the literature.

Author	This work	[43]	[44]	[45]	[46]	[47]
SCENARIO	• Economic feasibility of ESP technologies in UK Electricity Market, two different scenarios are considered: 1) ESP operating time shifting 2) ESP operating time shifting + Operating Reserves • Investor Perspective	• ESP profitability in German-Austria Power Markets. • Investor perspective	• ESP in Isolated Power Systems (Canary Islands) • Centralized Power Production (Electricity Market not liberalized)	The paper analyses the economic feasibility of ESP in three different scenarios: 1) Wind Farm without feed-in tariff 2) Wind Farm + Centralized ESP 3) Wind Farm + Decentralized ESP (1 Compressor for each Turbine)	• ESP in French Power System by 2030. Minimization of Power System Costs • Power System perspective	• ESP in Dutch Power System with different wind power penetration levels • Power System Perspective
Applications	• Time shifting • Operating Reserve	• Time shifting	• Time shifting • Operating Reserve	• Time shifting • Operating Reserve	• Time shifting • Operating Reserve • Transmission Congestion Relief	• Time shifting • Load Following
ESP Technologies	• CAES • AACAES • PHS • Applicable to any ESP Technology	• PHS • AACAES • Hydrogen Storage • Methane Storage	The study doesn't consider a specific ESP technology. The charge/discharge efficiency is considered to be 70%.	• CAES • AACAES	• CAES	• CAES • PHS • Power to Gas
Input	• UK Electricity Market Price Data (2012) • ESP TCC • ESP Operating Costs	• German and Austrian Electricity Market Price Data (2007/2011) • ESP TCC • ESP Maintenance Cost	• Weekly Electricity Demand Canary Islands • Wind Power Production	• German Electricity Market Price Data (2007) • Wind Power Production • CAES/AACAES TCC • CAES/AACAES Operating Costs	• Installed power generators in France in 2030 (based on Europe Commission and French Transmission System Operator development Scenarios) • Power generators operating costs. • Wind Power Production (Germany 2007)	• Installed generators in Netherlands 2012 • Hourly Wind Speed Patterns • Dutch electricity demand Pattern
Model	Maximize the profit of ESP technologies in both the Scenarios considered. The optimization is carried out defining the optimum Storage Reserve Capacity for each ESP technology.	Maximize the ESP yearly profit. Defines the ESP optimal operations through a linear optimization implemented in GAMS	Minimize the total thermal generation costs. Linear-Integer Optimization implemented in GAMS.	• Scenario 1: Optimization of Revenues according to Wind Power Production • Scenario 2: Optimization of profit according to spot market prices. • Scenario 3: Optimization of Revenues according to Wind Power (Compressor) and according to spot market prices (Turbine)	Minimize the annual power system cost of operating power generators under technical and economic constrains.	Minimize the total economic power system costs. The model determines when and if applying storage results in most economic benefits.
Results	In UK electricity market, current ESP technologies are not economically viable without subsidies. However, operating ESP as multiservice facilities increases their profitability. The study provides the optimum reserve capacity for every technology and the subsidies required.	In Austrian-German power markets ESP time shifting revenues have been declining between 2007 and 2011. PHS is still the best option for time shifting	Power Systems Savings in Gomera and Gran Canaria Island, obtained operating ESP technologies as Operating Reserves, Time Shifting and Operating Reserves + Time shifting	The ESP is economically beneficial in all the cases. CAES is more advantageous than AACAES and decentralized ESP are less attractive than centralized.	The CAES NPV obtained scheduling energy storage operations in order to minimize power system cost is negative. However CAES reduces the wind power curtailment by 50% and increase the use of grid assets by 14%.	Adding large scale ESP to the electricity systems, the overall cost of energy production decreases. The highest cost reduction resulted from the application of PHS followed by the cost reduction obtained with CAES and P2G. Optimizing power system costs does not by definition result in fuel use and emissions reduction.

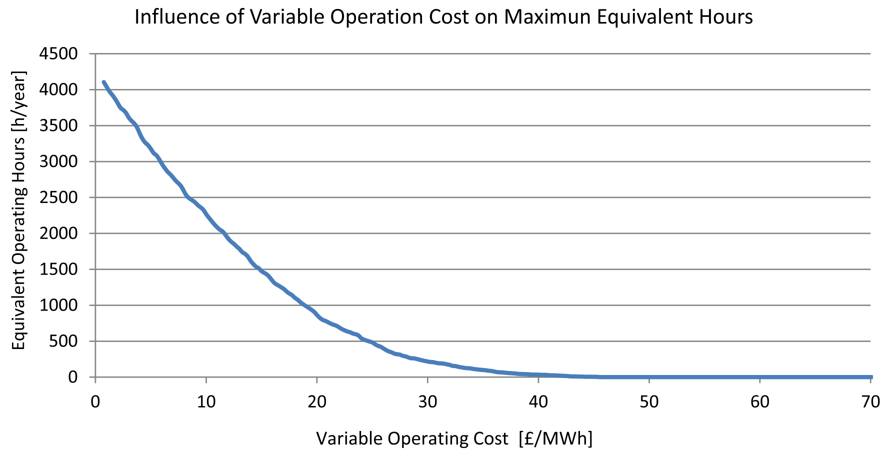

Fig. 1. Correlation between Variable Operating Cost (VOC) and number of Equivalent Hours (Heq), in day ahead electricity market with a maximum reserve capacity of 12 h.

Step 4 – Life cycle economics

The EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization – e.g. the economics of the "pure engineering solution") of each ESP is calculated as follows:

Annual Revenues [£/(MW·Year)] – VOC [£/MWh] · Heq[h/year] = Contribution Margin [£/(MW·Year)]

Contribution Margin [£/(MW·Year)] – FOC [£/(MW·Year)]= EBITDA [£/(MW·Year)]

Finally the profitability condition is expressed as NPV (Net Present Value) ≥ 0. An ESP can profitably operate price arbitrage if the discounted sum ($r =$ discount rate) of the EBITDA throughout its entire SL (Service Life) is greater than the TCC (Technology construction Capital Cost). i.e. the cost to build the ESP.

$$-TCC + \sum_{i=1}^{SL} \frac{EBITDA_i}{(1+r)^i} \geq 0$$

3.1.3. Optimum ESP reserve capacity

The capacity of the ESP reserve is a key driver of the ESP profitability analysis. Firstly, the capacity of the reserve limits the price arbitrage operations reducing the Heq and affecting the EBITDA value. Secondly, the cost of the reserve is a substantial part of the TCC and directly affects its profitability. In order to identify the optimum reserve capacity the ESP TCC is divided into:

1. *Energy Cost [£/MWh]* that is the capital cost proportional to the size of the storage reserve.
2. *Power Cost [£/MW]*, that is the capital cost of all the power plant components (e.g. the turbine and its systems) proportional to the nominal power plant size.

The energy cost of ESP technologies, such as the AACAES or the PHS plants, is a relevant part of the overall cost of technology. For instance, in a PHS plants, the energy cost is about the 60% of the overall TCC [18]. Therefore reducing the reserve capacity may increase the profitability of the plant, even if it will operate for less equivalent hours.

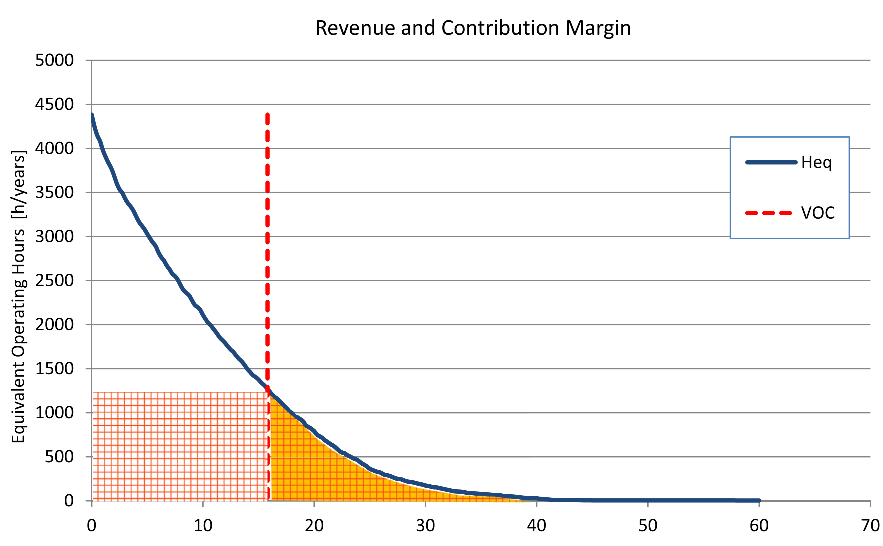

Fig. 2. Revenue (all shaded area) and Contribution Margin (yellow area) in the day ahead market. Example with VOC equal to 15.8 [£/MWh]. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

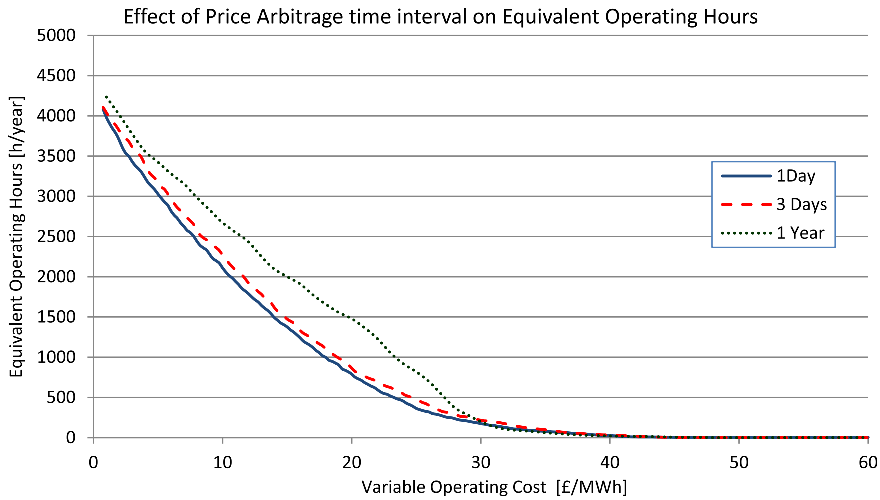

Fig. 3. Impact of time frame considered for the storage on the Equivalent Operating hours.

The average weekly and monthly electricity price remains (beside isolate peaks) quite constant over the year. Fig. 3 shows that the Heq for one day or three days are roughly the same and, even considering the extreme theoretical case of one year, the number of Heq depends mostly just from the VOC. Consequently, a reasonable way to operate the ESP is according to the daily market.

The "Maximum Storage Capacity" is defined as the reserve capacity that an ESP requires to operate Price Arbitrage during all of the Heq allowed by the market. This capacity is defined as "Maximum" because every additional MWh of capacity installed exceeding this value is useless for the price arbitrage process.

In the case of an ideal ESP with $\eta_{ST} \rightarrow 1$ and consequentially $\Delta p_{min} \rightarrow 0$ the ESP will charge and discharge continuously all day. Since ESP are not ideal and have VOC that require a Δp_{min} (calculated as in Section 3.1.2), there are 3 possible states: charging, discharging and idle. Due to their high VOC, ESP technologies, such as CAES and AACAES, require a Storage Capacity of 8–9 h to operate all the Heq allowed by the day-ahead market prices.

Given the high capital costs of the reserve, the construction of an oversized reserve for few additional hours every year is not economically justified. Therefore the optimal capacity of the storage reserve must be smaller than the Maximum Storage Capacity.

Fig. 4[2] shows how the storage capacity affects the price arbitrage operations reducing the equivalent operating hours. The upper line shown in Fig. 4 is the correlation between the Heq and VOC for ESP with a storage capacity equal to the maximum. In the case of ESP with a high VOC, storage reserve restrictions slightly affect price arbitrage operations. Fig. 5 shows how the yearly EBITDA of CAES, AACAES and PHS technologies vary with ESP capacity. The maximum value of the EBITDA is obtained for a reserve capacity of 8 h or higher, however if this capacity is reduced to 5–6 h, the EBIDA of the AACAES (and technologies with VOC greater then 10 [£/MWh]) will not vary considerably. These results are consistent with [33].

The optimal capacity of ESP can be numerically calculated according to two different criteria:

1. Optimizing the difference between the EBITDA and the Energy Cost, hence maximizing the NPV value of the ESP.
2. Minimizing the (eventual) subsidies [£/MWh] that the ESP requires to break even on its life cycle (i.e. obtaining NPV = 0)

Criterion 1 is particularly relevant for investors, such as utilities, who aim to maximize the profit from the investment over the life cycle (i.e. the NPV). Criterion 2 is more meaningful for the policy makers aiming to minimize the subsidies to make the technology viable to investors. The calculations in this paper are done assuming a return of investment equal to 5% (reasonable for this kind of subsidized project). If the return is higher, either the NPV will be reduced or subsidies need to be increased.

As Fig. 6 shows, results obtained according to these two criteria differ substantially and depend on the Energy Cost, the VOC and the subsidies scheme employed. The reserve capacity that maximizes the NPV of an AACAES is 3 h: this is where the NPV curve has its peak. However at this level, the NPV is still negative and subsidies are required. The optimum capacity obtained minimizing subsidies is 6 h; this is where the histogram (representing the subsidies level) is at a minimum. This discrepancy is a significant result both for investors and for policy makers.

3.1.4. Inputs modelling

As seen in Section 3.1.2 the profitability model receives as input TCC, O&M costs and the service life of the storage power plant. The TCC are divided into Energy Cost [£/KWh] and Power Cost [£/KW]. Operation and Maintenance costs consist of VOC and FOC. The VOC are mainly the fuel/electricity costs and are calculated starting from the charge/discharge efficiency of the power plant. FOC are all the expenses that the ESP incurs regardless the power generated (e.g. wages of permanent staff).

Table 4 shows all the ESP technologies data used as input to this profitability analysis. The PHS/PHS-upgrade power and energy costs reported in Table 4 are based on cost estimates of [18,29,34], while VOC are calculated assuming a charge/discharge efficiency of 85% [35] and an average off-peak electricity Price of 34 [£/MWh] (based on UK day-ahead electricity price, N2EX). PHS Fixed Costs are provided in Ref. [29].

CAES and AACAES Power Costs are similar since their plant design differs only in the thermal storage reserve. Power Costs estimates are based on [29,34,36,37]. Energy cost of CAES and

[2] The full set of data used to obtain this and the following figures are presented in the next section along with a sensitivity analysis. The figures in this section support the reader in understanding the methodology.

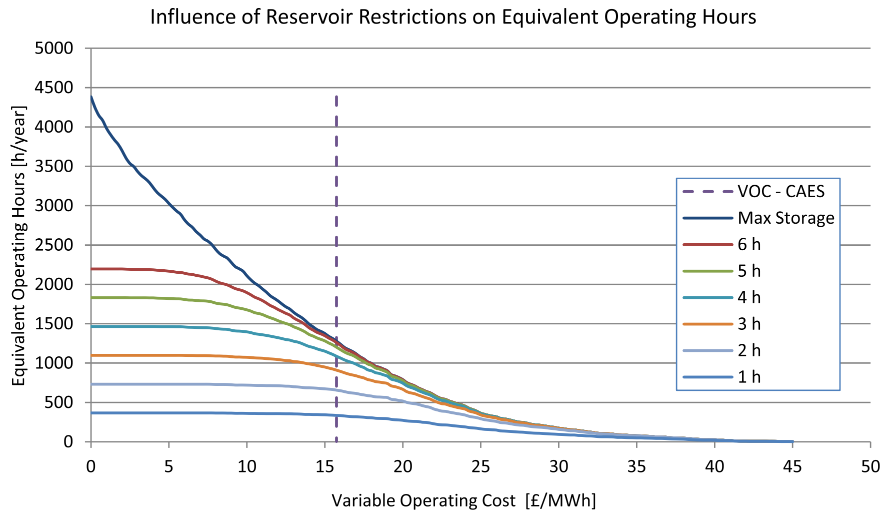

Fig. 4. Influence of energy storage size [h] on the Equivalent Operating hours [h/years]. The dashed line for VOC = 15.8 [£/MWh] shows the increasing the size above 5 h has little effect.

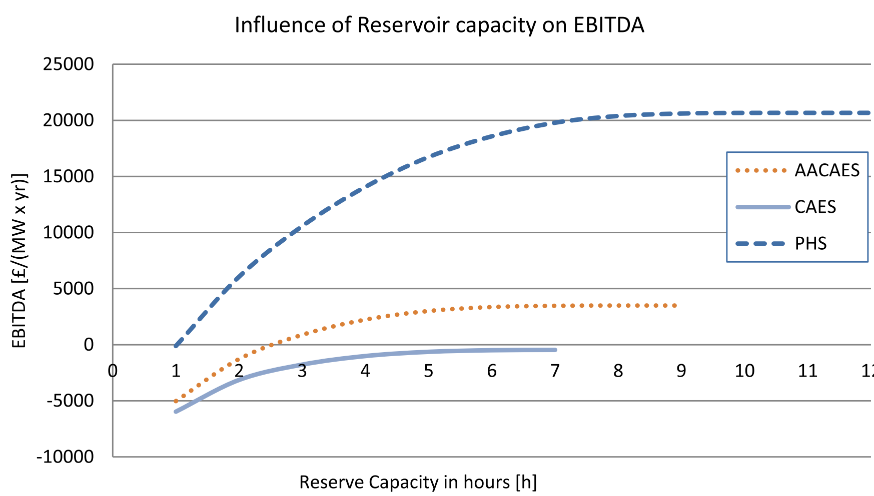

Fig. 5. Correlation between EBITDA and Reserve Capacity for a PHS, CAES and AACAES plant.

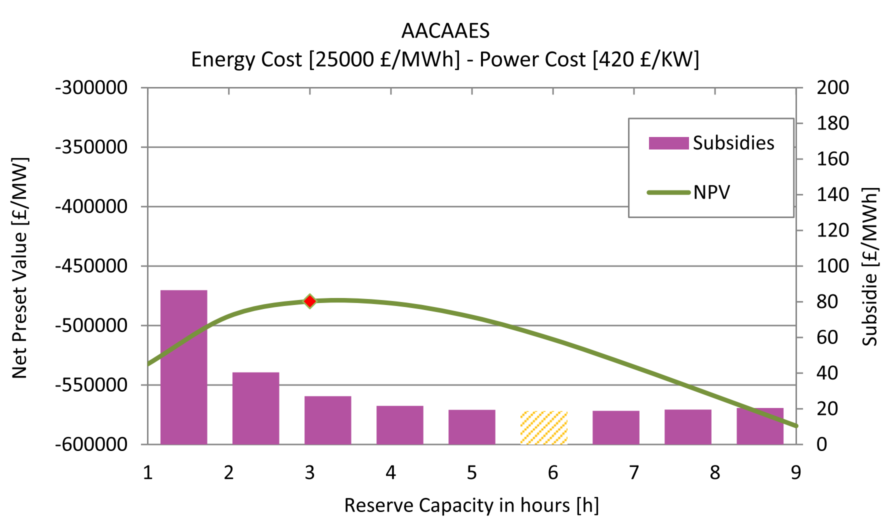

Fig. 6. Optimum Storage Reserve Capacity for a AACAES plant – Plant with 25000 [£/MWh] as Energy Cost and 420 [£/KW] as Power Cost. On the left the axis related to the NPV (continuous line maximized for a reserve capacity of 3 h), on the right the axis with the subsidies required to break-even (histogram with a minimum value for a reserve capacity of 6 h).

Table 4
Storage Technologies Capital Costs, O&M costs and Service life data.

	PHS	Upgraded PHS	CAES	AACAES
Power cost [£/KW]	1200	180	300–500	300–500
Energy cost [£/KWh]	25–145	–	0.6–18	3–40
VOC [£/MWh]	6.3	6.3	15.8	13
Fixed operating cost [£/(KW·year)]	7.04	7.04	9.51	9.51
Service life [years]	60	60	35	35

AACAES are different. For the CAES the cost of the underground storage varies substantially with the geological formation and the mining technology. Reasonable estimations are provided by Refs. [34,36,38]. The AACAES in addition to an underground reserve, has also a thermal energy storage reserve.

The VOC of AACAES are obtained considering a charge/discharge efficiency of 75% [39] and the average Off-Peak electricity price. CAES's VOC are more difficult to calculate since they depend on two factors: the price of the electricity drawn from the grid and the price of the natural gas burned to generate power. The average Natural Gas price in UK is 20.8 [£/MWh] as reported in Ref. [40].

3.2. Expansion to Short Term Operating Reserves

As seen in Section 2.1 the requirement for additional operational reserve is of interest mainly for the secondary and tertiary reserves and depends on the accuracy of wind forecasting and the grid interconnections that smooth short term and very short-term wind farm output variability.

In the UK the system operator (i.e. UK National Grid) has to maintain the operating reserve requirement from 4 h ahead to real time in order to consider demand and load uncertainty, power plant losses and market imbalances. The UK National Grid can meet the operating reserve requirement by accepting offers and bids in the Balancing Mechanism and with contracted reserve products. STOR (Short Term Operating Reserves) are one of these contracted reserve products.

Fig. 7 shows the Operating reserves of the UK power system sorted according to the time of response required. Every power system in Europe has a different reserves categorization. In the case of the UK power system, the STOR are secondary/tertiary reserves and might be the most affected by wind power integration. The STOR reserves are dispatchable power plants contracted by the UK National Grid to protect the grid against sudden losses in

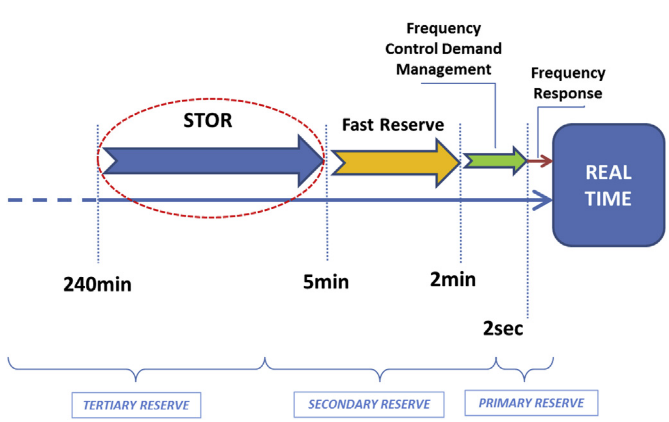

Fig. 7. Operating Reserves of the UK Power System sorted according to the Time of Response required.

generation or unforeseen increases in demand [16]. To operate as STOR, a power plant must be able to:

1. Deliver the full power contracted within few minutes.
2. Provide the power contracted for at least 2 h when instructed.
3. Be able to provide STOR at least 3 times a week
4. Have a Recovery Period after provision of Reserve of not more than 20 h.

Both PHS plants and CAES systems fulfill all the requirements mentioned above. The total amount of STOR capacity required varies between 2.5 [GW] and 4 [GW]. Ref. [16] shows the power plant that provided the STOR capacity in 2012. Open Cycle Gas Turbine and Combined Cycle Gas Turbine plants provide together the 61% of the total STOR capacity. PHS plants are already employed as operating reserves and provide the 10% of the total capacity.

The need of STOR varies depending on the time of the year, the time of the week and the time of the day. The National Grid splits the year into seasons and divides the days of the week into working days and not-working days. For every seasons and days the National Grid specifies the hours in which the operating reserves are required. The periods in which STOR are required are defined “Availability Windows”.

The STOR Service is paid by the UK National Grid according to:

1. The Availability Windows contracted. (Time intervals in which the power plant must be able to provide power within few minutes)
2. The energy delivered.

Generally a STOR facility is contracted for 4860 [h/year] and provides energy for 50–80 [h]. The average payment in the year 2012 for the availability window was 7.66 [£/(MW × h)] and 209 [£/MWh] for the energy generated. The average capacity of the power plants contracted by the UK national grid to operate as STOR is 50 [MW] [16]. The ESP technologies introduced in Section 2.2.1 are able to work as STOR. Since the STOR is potentially a profitable market the key idea is to assess the economics of ESP to purse both price arbitrage and work as STOR.

Further hypothesis (see section 3.1.1) need to be introduced about the STOR plant:

HP 6: The availability windows required for the STOR service is compatible with the hours in which the ESP usually operates price arbitrage, discharging the reserve. In order to simplify the analysis it is possible to consider separately the nominal power of the plant dedicated to price arbitrage and the nominal power dedicated to the STOR service.

HP 7: the STOR service, providing energy to the grid only 50–80 hours every year, doesn't affect the reserve energy capacity and doesn't limit the operation of price arbitrage service even when discharges energy from the reserve.

4. Results

4.1. Price arbitrage only

This section applies the methodology previously presented to determine the economics of CAES and PHS operating price arbitrage on the UK electricity market.

For the CAES there are two different power plant designs:

1. traditional CAES.
2. AACAES (Advanced Adiabatic CAES), still in the research and development phase.

Similarly, for the PHS two different options are taken into consideration:

1. PHS plant located in greenfield sites.
2. PHS plant obtained from the upgrading of an existing hydroelectric plant.

As terms of reference is useful to remember that in UK the average wholesale electricity price is 45–50 [£/MWh], while the average domestic electricity price is 100 [£/MWh] [16].

4.1.1. CAES

The CAES optimal capacity is obtained maximizing the NPV (i.e. the difference between the EBITDA produced along all the CAES service life and the capital cost). Fig. 8 shows the results obtained for seven different reserve costs. Each curve on the chart of Fig. 8 represents the NPV. The maximum is indicated with a red marker (in web version) and corresponds to the optimum reserve capacity maximizing the NPV.

The profitability analysis is carried out for three different power costs and seven different energy costs. Considering only revenues from the market the NPV are negative: the CAES is not economically viable "as is" (Table 5).

There are three main factors affecting the profitability of CAES power plants and increasing the EBITDA and the NPV:

1. A reduction of VOC, resulting mainly from an increment of charge/discharge efficiency.
2. An increment of the equivalent operating hours due to an increment of price volatility in the day-ahead electricity markets or due to operate price arbitrage in intraday or balancing markets (which have higher volatility).
3. Actions from the government (i.e. some form of subsidies or market scheme)

The last option is the more practical (and common in UK) for the short term and can provide the momentum for further technology development focused on cost reduction. Table 5 shows the minimum subsidies that a CAES plant requires to satisfy the profitability condition and break-even. For a CAES plant with a power cost of 300 [£/KW] the subsidies required are about 14–19 [£/MWh], some 31–43% of the average electricity price in UK. This value of subsidies is in the order of magnitude (or less) of subsidies provided to renewable plants.

4.1.2. AACAES

AACAES are based on the same concept of the first and second generation CAES with the difference that AACAES has an additional storage reserve to accumulate the thermal energy released in the compression stage [41]. The AACAES has lower VOC than the CAES, therefore it can operate price arbitrage for more equivalent hours. Since the AACAES requires both a thermal reserve and an underground reserve, its overall capital cost is significantly affected by the "energy costs". Despite the lower VOC and the higher annual revenue, also the AACAES cannot operate price arbitrage generating profits without subsidies (Table 6). Similarly to the CAES, there are three factors that might modify the profitability of AACAES technology: electricity price volatility, subsidies and a reduction of VOC. Table 6 shows for which subsidies AACAES might become a profitable solution for price arbitrage and what is the reserve capacity that minimizes the subsidies required. Table 6 stresses the difference between the optimal reserve capacity that maximizes the NPV and the optimal capacity that minimizes the subsidies.

4.1.3. PHS and PHS from upgraded hydroelectric power plant

Fig. 9 shows, for each energy cost level, the optimum reserve capacity. With respect to CAES, there are scenarios where a PHS plant has a positive EBITDA (but because of the TCC the NPV is still negative). As seen in Section 2.2.1 the PHS plants are characterized by lower VOC (and consequently more Heq), lower FOC and longer service life. Since the cost of a dam and associated civil works accounts for the 60% of the overall PHS capital cost [22], there is a substantial difference between the capital cost of a PHS constructed in a greenfield site and that achieved by upgrading an existing hydroelectric plant. For new PHS it is necessary to consider both the energy and the power costs while for PHS from existing hydroelectric facilities the capital cost consists only of the power cost since the reserve has already been built.

Table 7 presents the results of the PHS profitability analysis. Even if PHS technologies seem the most appropriate storage technology for price arbitrage, none of the cases has a positive NPV. Table 7 stresses the correlation between profitability, energy cost and reserve capacity.

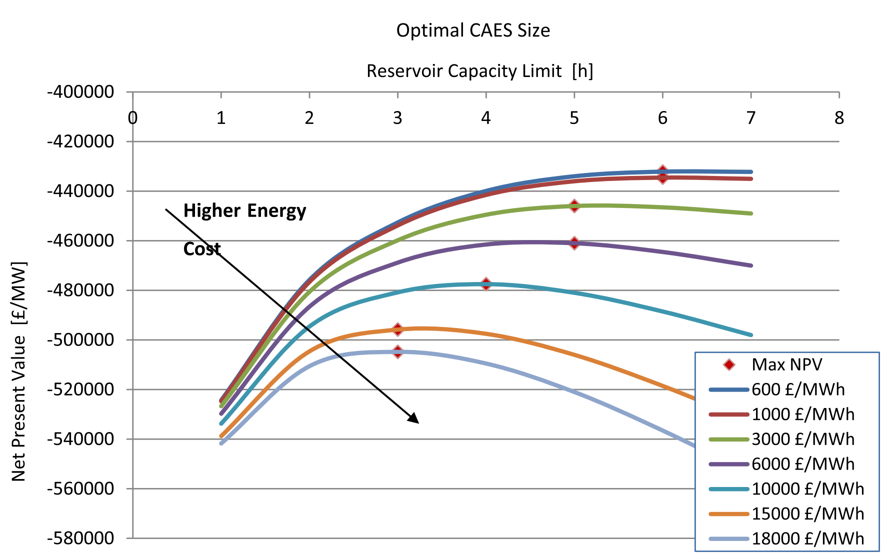

Fig. 8. Optimum CAES Reserve Capacity for Seven different Storage Costs – Power Cost 420 [£/KW].

Table 5
CAES, Results of Profitability Analysis: NPV [K£/MW] and Subsidies required [£/MWh]. Optimum storage calculated with the two criteria.

Energy cost [£/MWh]	CAES power cost [£/KW]						Reserve [h]	
	300		420		500		Max NPV	Min subsidies
	NPV	Subsidies	NPV	Subsidies	NPV	Subsidies		
600	−312	14.06	−432	19.47	−512	23.07	6	7
1000	−315	14.19	−435	19.59	−515	23.2	6	7
3000	−326	14.82	−446	20.22	−526	23.83	5	7
6000	−341	15.74	−461	21.17	−541	24.77	5	6
10,000	−358	16.83	−478	22.32	−558	25.97	4	6
15,000	−376	18.21	−496	23.69	−576	27.34	3	6
18,000	−385	19.03	−505	24.51	−585	28.16	3	6

Table 6
AACAES, Results of Profitability Analysis: NPV [K£/MW] and Subsidies required [£/MWh]. Optimum storage calculated with the two criteria.

Energy cost [£/MWh]	AACAES power cost [£/KW]						Reserve [h]	
	300		420		500		Max NPV	Min subsidies
	NPV	Subsidies	NPV	Subsidies	NPV	Subsidies		
3000	−260	9.21	−380	13.42	−460	16.22	6	8
7000	−283	10.2	−403	14.43	−483	17.26	5	7
15,000	−321	12.13	−441	16.41	−521	19.23	4	7
25,000	−360	14.32	−480	18.71	−560	21.63	3	6
30,000	−375	15.42	−495	19.81	−575	22.73	3	6
35,000	−390	16.52	−510	20.90	−590	23.83	3	6
40,000	−402	17.61	−522	22.00	−602	24.93	2	6

4.1.4. Upgraded PHS

Calculating the optimum reserve capacity for upgraded PHS stations is irrelevant as this technology employs the reserve of existing hydroelectric plants. Nevertheless it is reasonable to perform a profitability analysis for different reserve capacities as the existing reserve might not be fully dedicated to price arbitrage operations. The results obtained are presented in Table 8. Only when upgrading costs are 180 [£/KW] or lower, operating price arbitrage in the UK electricity market will be profitable. For higher upgrading costs, operating price arbitrage is not profitable, regardless the reserve capacity dedicated.

4.2. Combined operating reserve and price arbitrage

As mentioned in Section 2.1, the increasing integration of wind farms might require a more flexible power system. Part of the additional flexibility required can be obtained by deploying ESP.

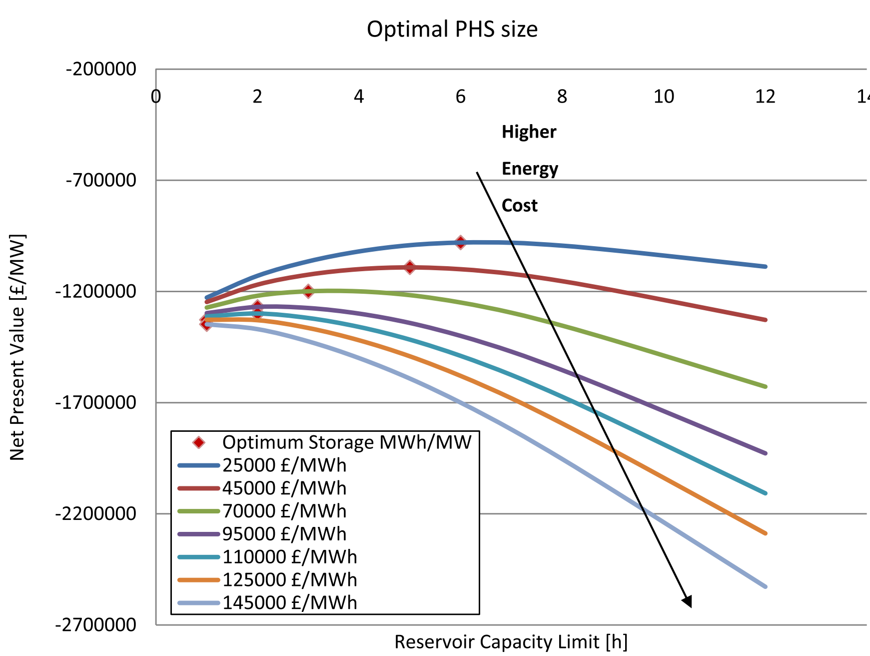

Fig. 9. Optimum PHS Reserve Capacity for Seven different Storage Costs.

Table 7
Results of profitability analysis —PHS @1200 [£/KW].

ENERGY cost [£/MWh]	NPV analysis		Subsidies analysis	
	NPV [K£/MW]	Reserve [h]	Subsidies [£/MWh]	Reserve [h]
25,000	−980	6	18.73	9
45,000	−1091	5	22.06	9
70,000	−1199	3	26.09	8
95,000	−1269	2	29.95	8
110,000	−1299	2	32.26	8
125,000	−1327	1	34.58	8
145,000	−1347	1	37.66	8

Table 9
Results of Profitability Analysis— Price Arbitrage + STOR - Subsidies Reduction % respect to price arbitrage only.

Technology	Energy Cost [K£/MWh]	Subsidies [£/MWh]	Subsidies Reduction [%]
350 MW PHS — Power Cost 1200 [£/KW]	25	16.07	−14.20
	45	19.40	−12.06
	70	23.32	−10.64
	95	27.17	−9.27
	110	29.49	−8.61
	125	31.80	−8.03
	145	34.88	−7.37
350 MW AACAES - Power Cost 420 [£/KW]	3	9.31	−52.19
	7	10.30	−47.45
	15	12.23	−39.52
	25	14.43	−31.85
	30	15.52	−30.44
	35	16.62	−29.84
	40	17.72	−27.71
350 MW CAES - Power Cost 420 [£/KW]	0.600	14.21	−26.98
	1	14.34	−26.81
	3	14.97	−25.97
	6	15.89	−24.92
	10	16.99	−23.87
	15	18.36	−22.49
	18	19.18	−21.74

There are two main storage applications useful for wind farms integration:

1. Time shifting and Load Following (Price Arbitrage)
2. Operating Reserve (STOR)

As see in Section 4.1 operating only price arbitrage with the existing storage technologies and current electricity prices is not profitable. The aim of this section is to evaluate the profitability of an ESP operating both as operating reserve and as a load following/shifting power plant. Consistently with [42] the ESP has a power of 350 [MW], with 50 [MW] dedicated to the STOR service and 300 [MW] to price arbitrage.

Table 9 shows the results obtained, reporting the subsidies required for every ESP technology. None of the cases considered is capable to generate profits but, operating both applications, significantly reduces the subsidies required. The ESP with lower technology capital costs and higher VOC, such as CAES and AACAES, are the ESP that mostly benefit from the multiservice use of the plant. The revenues obtained from STOR service are mainly derived from the availability windows contracted that do not imply VOC. The subsides required to make CAES and AACAES viable are reduced by 50-20% compared to the price arbitrage alone (Section 4.1).

5. Summary and conclusions

In most European countries, the generating capacity of wind farms is substantially increasing. Electricity costs from wind farms are higher than from traditional fossil fuel plants and further increase when standby costs are included. Moreover, the addition of wind farms requires an overall power system capable of matching demand and supply, even where there is a large share of non-dispatchable electricity. Under these conditions, an ESP can operate concurrently both as operating reserve and as a load following plant, with the additional capability of shifting electricity from off-peak periods to on-peak periods.

Starting from the analysis of the historical prices of the UK electricity market, this paper presents and applies a methodology to assess under which technical-economic conditions an ESP can operate price arbitrage and operating reserve. PHS and CAES facilities are selected for the analysis firstly because they have a short time of response and can operate as secondary/tertiary reserves and secondly because they can store large amounts of energy allowing price arbitrage operations. This paper provides three key results.

The ESP capital cost and its capacity influence the size of ESP subsidies required. The first result of the study is a method to investigate the trade-off of "reserve capacity vs. subsidy" and the possibility of establishing an "optimum size capacity". The results show that the optimal reserve size capacity for maximizing the NPV is smaller than the optimum for minimizing the subsidies: maximizing NPV requires more than the minimum subsidies.

A second result is that without subsidies, none of the existing storage technologies is economically viable. With the present price structure the difference between the purchase and selling price of electricity is not enough to cover both capital and operating costs. However, given that variable operating costs and the efficiency of storage and dispatch are strictly related, it is possible to estimate the improvements required in efficiency for the ESP break-even.

The third finding is the quantification of the potential for ESP as an operating reserve and for price arbitrage. For example, a 350 [MW] ESP operating with 50 [MW] for operating reserve and 300

Table 8
Upgraded PHS, Results of Profitability Analysis: NPV [K£/MW] and Subsidies required [£/MWh].

Reserve dedicated [h]	Upgraded PHS - power cost [£/KW]							
	180		500		900		1200	
	NPV	Subsidies	NPV	Subsidies	NPV	Subsidies	NPV	Subsidies
2	−59	4.06	−379	26.00	−779	53.42	−1079	73.98
3	31	0	−289	13.25	−689	31.56	−989	45.29
4	100	0	−220	7.57	−620	21.37	−920	31.71
5	153	0	−167	4.64	−567	15.79	−867	24.14
6	190	0	−130	3.06	−530	12.47	−830	19.54
7	214	0	−105	2.21	−506	10.57	−806	16.84
8	226	0	−93	1.81	−494	9.52	−794	15.30

[MW] for price arbitrage requires less subsidy than a 350 [MW] power plant operating only for price arbitrage. The subsidies required for a multiservice facility are 10%–50% lower than the subsidies needed to operate only for price arbitrage.

Appendix A. Reserves

The procurement of reserves and additional types of required reserves are set by the individual countries and are presented on a country-by-country basis [24]. This section presents the key terms for the operating reserves, as presented in Ref. [48].

Primary reserves are activated when system frequency deviates by 20 [mHz] from the set point value and must be fully operational within 30 s. Their purpose is to limit the deviation of system frequency following a system event. **Secondary reserves** consist of units controlled by automatic generation control and fast starting units. These are engaged 30 s after a contingency event and must be fully operational within 15 min. This category of control attempts to restore the frequency to its nominal value and reduces the area control error. **Tertiary reserves** have a slower response and are engaged to restore primary and secondary reserves back to the reserve state. The ESP assessed in this paper are suitable for secondary and tertiary reserves. **Fast Reserves** provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from National Grid. Fast Reserves are used, in addition to other energy balancing services, to control frequency changes that might arise from sudden, and sometimes unpredictable, changes in generation or demand. Active power delivery must start within 2 min of the despatch instruction at a delivery rate in excess of 25 MW/min, and the reserve energy should be sustainable for a minimum of 15 min. It must be able to deliver minimum of 50 MW.

FCDM (Frequency Control Demand Management) provides frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site. An FCDM provider must: provide the service within 2 s of instruction, deliver for minimum 30 min, deliver minimum 3 MW, which may be achieved by aggregating a number of small loads at same site, at the discretion of National Grid, have suitable operational metering, provide output signal into National Grid's monitoring equipment.

Frequency Response copes with system frequency, a continuously changing variable that is determined and controlled by the second-by-second (real time) balance between system demand and total generation. If demand is greater than generation, the frequency falls while if generation is greater than demand, the frequency rises. National Grid has a licence obligation to control frequency within the limits specified in the 'Electricity Supply Regulations', i.e. ±1% of nominal system frequency (50.00 Hz) save in abnormal or exceptional circumstances. National Grid must therefore ensure that sufficient generation and/or demand is held in automatic readiness to manage all credible circumstances that might result in frequency variations.

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