An economic feasibility assessment of decoupled energy storage in the UK

Xie, Chunping; Hong, Yan; Ding, Yulong; Li, Yongliang; Radcliffe, Jonathan

DOI:
10.1016/j.apenergy.2018.04.074

An economic feasibility assessment of decoupled energy storage in the UK: with liquid air energy storage as a case study

Chunping Xie, Yan Hong, Yulong Ding, Yongliang Li and Jonathan Radcliffe*

Birmingham Centre for Energy Storage & School of Chemical Engineering, University of Birmingham, Edgbaston, Birmingham B15 2TT
*Corresponding author. Email: c.xie@bham.ac.uk

Abstract
This work assesses the economic feasibility of adopting decoupled energy storage technologies in the UK, using a methodology to optimise the size of individual components for charging, storing and discharging energy. Such technologies, including pumped hydro and compressed air energy storage, are likely to become more important in the future energy system. In this paper we consider liquid air energy storage as a case study - a technology that has the potential to provide multiple balancing and ancillary services to the electricity grid, and also to obtain revenues through energy price arbitrage. A key feature of liquid air energy storage is that the charge/discharge and storage components are fully decoupled so that the specific capacities of liquefaction unit (charge component), storage tank and power recovery unit (discharge component) can be designed independently according to the individual requirements and costs. Based on UK's half-hourly electricity spot price in 2015, the developed numeric model calculates the revenue streams of a liquid air energy storage system from providing reserve service and arbitrage every half hour. Results from the genetic algorithm give the optimal sizes for the liquefaction, storage and recovery units, to maximize the net present value and allow us to calculate other economic objectives. Other key factors that affect the economic performance including the use of waste heat and discount rates are also investigated in this paper.

Keywords: Liquid Air Energy Storage (LAES); techno economic analysis; decoupled energy storage; ancillary services, energy arbitrage

Nomenclature

CAES	Compressed Air Energy Storage
EES	Electrical Energy Storage
EFR	Enhanced Frequency Response
FFR	Firm Frequency Response
GA	Genetic Algorithm
GHG	Greenhouse Gas
IRR	Internal Rate of Return
LAES	Liquid Air Energy Storage
NCI	Net Cash Inflow
NPV	Net Present Value
PHES	Pumped Hydroelectric Energy Storage
STOR	Short Term Operating Reserve
C_{NCI}	Net Cash Inflow (£)
C_{inv}	Initial Investment (£)
r	Discount Rate (%)
C_L	Cost for the Liquefaction Unit (£)
C_T	Cost for Cryogenic Tanks (£)
C_D	Cost for the Discharging Unit (£)
$\dot{m}$	Liquefaction Capacity (tonnes/day or MWh/day)
V	Storage Capacity (tonnes or MWh)
PR	Discharge Power Rating (MW)
$R_{reserve}$	Revenue Obtained by Providing Reserve Services (£)
$R_{arbitrage}$	Revenue Achieve by Electricity Price Arbitrage (£)
$C_{purchase}$	Electricity Purchasing Cost (£)
$C_{O\&M}$	Operating and Maintenance Costs (£)
L_{SA}	Level of Stored Air (tonnes)
L_{min}	Minimum Level of Stored Air (tonnes)
P_{mt}	Mean Price for the Last 5 Days before Time t (£/kWh)
P_t	Spot Price at Time t (£/kWh)
η	Round-trip Efficiency (%)

1 Introduction

1.1 The role of energy storage

Electricity generation from renewable sources has grown rapidly due to the promotion of clean energy policies in many countries. This presents challenges to the grid when the supply is from variable sources, such as wind and solar (Ren et al., 2017). In order to integrate large amounts of intermittent generation into the grid, (Barton and Infield, 2004), (Arani et al., 2017) and many others suggested that Electrical Energy Storage (EES) system is a potential solution for increasing the penetration of renewable on the power network.

Large-capacity energy storage is now widely recognised as one of the technologies with most potential for the successful integration of renewable electricity generation [(Bird et al., 2013), (Luo et al., 2015), (Weitemeyer et al., 2015), etc.]. Many studies focus on a variety of EES technologies and their uses with intermittent renewable sources, such as (Rehman et al., 2015) and (Larcher and Tarascon, 2015). An ideal EES technology to cope with the increasing deployment of renewable electricity generation on electricity grids should have a high power rating, a large storage capacity, high efficiency, low costs and no geographic constraints (Antonelli et al., 2016). Currently, only two technologies are considered mature for grid-scale energy storage [(Evans et al., 2012), (Rodrigues et al., 2014), (Guizzi et al., 2015), etc.]: PHES and CAES. Traditionally, PHES is used for large capacity storage due to its low cost per stored MWh (Rastler, 2010) and many other factors such as the lack of other proven technologies. However, the capacity for using large-scale water reservoirs has reached its limit in many developed countries due to geographic constraints (Ameel et al., 2013). Similarly, specific geographical conditions are also required for the application of large-scale underground CAES, and to date, there are only two such grid-scale CAES plants that have been demonstrated in operation: a 110 MW plant in McIntosh, Alabama and a 290 MW plant in Huntorf, Germany [(McGrail et al., 2013), (IRENA, 2017)]. Due to the drawback that their application is constrained by geological features, considerable effort has been made in order to find different EES approaches that can provide large scale, cost-efficient solutions without such constraints.

Besides energy arbitrage, EES systems can achieve economic benefits by participating in ancillary service markets. Currently ancillary services are significant for the balance of supply-demand differences over a range of timescales, from seconds to hours, and they are expected to play an increasingly important role to balance the power network in the future because of the increase in intermittent renewable generation (National Grid, 2011).

Frequency response is a mechanism aimed at maintaining the real time balance of generation and system demand within a certain boundary. Firm Frequency Response (FFR) and Enhanced Frequency Response (EFR), both procured by National Grid via a tender process, are two types of commercial frequency response services that are open to any generation plant or energy storage system which is able to meet the service requirements. EFR as a new service with response timescales of no more than 1 second, its first tender held in July 2016 captured extensive attention. Eight tenders succeeded in the auction process with a price range from £7/MW/h to £11.97/MW/h.[1]

Reserve services are needed to cope with unexpected increase on electricity demand or decrease on generation. Short Term Operating Reserve (STOR)[2] is a service which is very suitable for distributed energy storage to provide due to its smaller capacity requirements. The payment structure of STOR is comprised of availability fee (£/MW/h) and utilization fee (£/MWh): the former is paid when the STOR supplier make its service available during the reserve windows defined by National Grid; while the latter is paid when called upon for each unit of electricity it provides. In STOR Year 8 (1st April 2014 to 31st March 2015), the average contracted price for availability was £3.87/MW/h and the average contracted price for utilisation was £169.78/MWh.[3]

1.2 Liquid air energy storage (LAES)

Compared to CAES, which stores air as a gaseous phase, a much higher energy density can be achieved by liquid air energy storage (LAES) that stores air in its liquid phase (for more details, please refer to (Ameel et

---

[1] Enhanced Frequency Response Market Information Report, http://www2.nationalgrid.com/Enhanced-Frequency-Response.aspx [accessed 20/03/2017].

[2] Highview's 5MW Liquid Air Energy Storage Demonstrator Starting Operations This Winter, http://www.highview-power.com/wp-content/uploads/HPS-Press-Release-Pilsworth-Update-19.08.15.pdf [accessed 20/03/2017].

[3] Market Information & Tender Round Results, http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Short-Term-Operating-Reserve/Short-Term-Operating-Reserve-Information/ [accessed 20/03/2017].

al., 2013), (Ding et al., 2016), etc.). LAES uses liquid air as a storage medium and includes three distinct processes: charging, storing and discharging (see Figure 1).

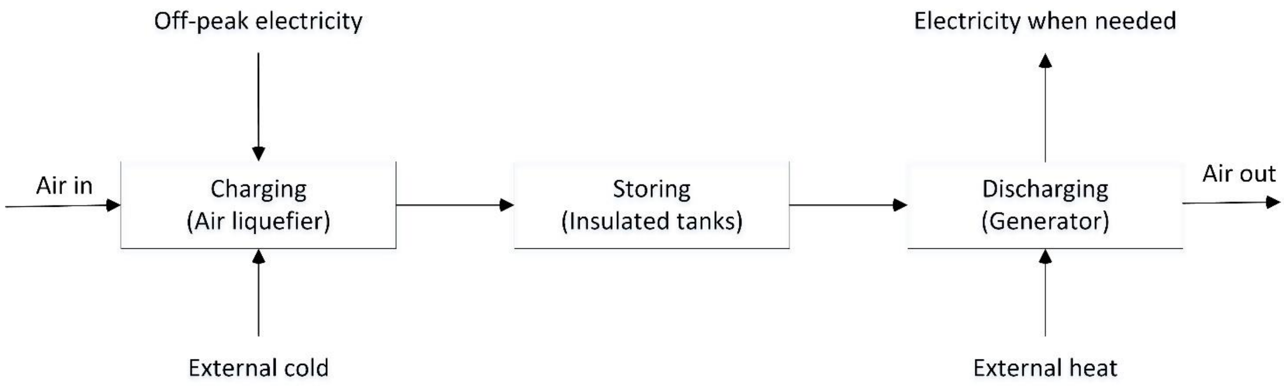

Figure 1: Schematic diagram of a LAES system.

To charge the store, air is liquefied through standard industrial gas processes by compression and cooling to an extremely low temperature. According to (Ding et al., 2016), the volumetric exergy density of liquid air is at least 10 times that of compressed air when the storage pressure is lower than 10 MPa, which enables liquid air to be highly competitive in terms of volumetric energy density even compared with battery technologies (Chen et al., 2009). In the storing process, the liquefied air is stored in insulated tanks at around -196 °C at near atmospheric pressure, and thus the off-peak electricity consumed during the liquefaction process is converted into cryogenic energy (Chen et al., 2016). In the discharging process, the stored liquid air is pumped and evaporated, and its expansion turns turbines to generate electricity when needed. The LAES system is able to enhance its round trip efficiency by capturing and recycling the heat of compression, and coolth of expansion.

The features of LAES include: 1) it is a grid-scale energy storage system using established technology with no geographic constraints; 2) the effective round trip efficiency of the LAES system can be improved significantly by the utilization of external heat/cold through integration with other systems such as thermal power plants or a LNG regasification facilities; 3) there are three physically different components which can be independently sized, making it possible and also essential to optimize the LAES system for different applications (Morgan et al., 2015).

LAES has drawn increasing attention in the UK since the 300 kW/2.5 MWh pilot scale demonstration plant, built by Highview Power Storage, started operations in 2010 (Brett, 2011), now in use at the University of Birmingham (Sciacovelli et al., 2017). Commercial trials have been undertaken for the evaluation of the LAES pilot plant against a range of reserve and response services (Morgan et al., 2015). Highview's 5MW/15 MWh pre-commercial demonstration plant is expected to start operating very shortly, with the capacity of providing balancing services including reserve and secondary frequency response.[4] In 2016, Highview Power Storage announced an approach for providing sub-second EFR, and got prequalification to bid for the contract of being an EFR provider to the national grid.[5] On 1st August 2017, Highview Power Storage was awarded a £1.5 million grant from Innovate UK to add supercapacitors and flywheel technology to the existing 5MW/15 MWh demonstration plant. The new hybrid system will cut down the time needed to respond to the grid frequency events to no more than one second, and have the ability of providing both EFR and FFR services to National Grid.[6]

---

[4] Liquid Air Energy Storage (LAES) 2016, http://www.highview-power.com/wp-content/uploads/2016-Highview-LAES-Two-Pager2.pdf [accessed 20/03/2017]
See also: Highview's 5MW Liquid Air Energy Storage Demonstrator Starting Operations This Winter, http://www.highview-power.com/wp-content/uploads/HPS-Press-Release-Pilsworth-Update-19.08.15.pdf [accessed 20/03/2017]
[5] Enhanced Frequency Response from a Liquid Air Energy Storage (LAES) plant, http://gtr.rcuk.ac.uk/projects?ref=971495 [accessed 20/03/2017]
See also: National Grid to tender for two lots of enhanced frequency response, http://theenergyst.com/national-grid-to-tender-for-two-lots-of-enhanced-frequency-response/ [accessed 20/03/2017]
[6] Highview Power Storage: Highview awarded £1.5 million for new Hybrid LAES system to respond to frequency response market, http://www.highview-power.com/wp-content/uploads/FINAL-Highview-Innovate-UK-funding-PR-01.08.17.pdf [accessed 17/08/2017]

LAES being a decoupled energy storage system, its liquefaction unit (charging), cryogenic tank (storage) and recovery unit (discharging) can be fully and physically decoupled, and the capability of each service maybe different being determined by different components (Ding et al., 2015). For example, LAES is able to provide both up response service through the recovery unit and/or down response services through the liquefaction unit. As the frequency response is a power-related function instead of energy-oriented function, it consumes/generates very small amount of liquid air and as a result the size of the cryogenic tank will not affect the capability of this service of the LAES system. On the other hand, both energy price arbitrage and STOR service are energy-oriented function, so the size of the storage tank is an important factor. To maximise the economic competitiveness for LAES system requires the optimal design of the size/capacity of different components based on the desired services. In practice, the energy storage systems will seek to maximize profit by delivering multiple services. In addition, both technical factors (i.e. waste heat, scale) and economic factors (i.e. capital cost, energy spot price, prices associated with different services, discount rate) will also affect its optimal design and operation. Therefore this paper aims to develop an effective model to assess the economic feasibility of such a technology in the UK.

Though LAES has the potential of providing EFR to the grid, it does require additional configuration which will increase the cost of the plant significantly. As a result, this paper will only focus on the STOR service provided by a stand-alone LAES system. Our future work will take into consideration the EFR service when analysing a hybrid LAES system.

It is worth mentioning that, the research framework presented in this paper can also be employed in other decoupled energy storage systems. According to (Ding et al., 2015), a decoupled energy storage system means the storage medium is stored independently and can be physically separated from the charging and discharging units. In a decoupled energy storage system, each unit (charging, storing and discharging) can be sized independently, with examples include Pumped Hydroelectric Energy Storage (PHES), Compressed Air Energy Storage (CAES), etc.

This article is organized as follows: Section 2 describes the key assumptions and the optimisation methodology; Section 3 presents the simulation results and carries out the sensitivity studies for different key factors. Section 4 is conclusions and implications.

2 Methodology and Data

2.1 Objective function

The objective function in our model is to maximise the net present value (NPV), as NPV is a generally used criterion in capital budgeting for measuring the profitability of an investment project. By taking into account the time value of money, NPV measures the difference between the present value of revenue and the present value of cost. According to the definition, a positive NPV suggests that the investment project is financially feasible, while a negative NPV implies a financial loss.

$$max\ NPV = \sum_{i=1}^{lifetime} \frac{C_{NCI}}{(1+r)^i} - C_{inv} \tag{1}$$

where, C_{NCI} denotes the net cash inflow during time period i, C_{inv} denotes the total initial investment cost, superscript ^{lifetime} denotes the service life of the energy storage system and r represents the discount rate. (Hoppmann et al., 2014) analysed the economic feasibility of battery storage for residential PV in Germany, and based on a review of previous literature they chose 4% as the discount rate. Similarly, 4% is selected as the base value of discount rate in our analysis, but we include an assessment of how sensitive profitability is to changes in discount rate.

As a LAES system includes three major processes: the charging process, storing process and discharging process, the initial investment consists of three parts accordingly: C_L (cost for the liquefaction unit); C_T (cost for cryogenic tanks); C_D (cost for the discharging unit), thus:

$$C_{inv} = C_L + C_T + C_D = f_1(\dot{m}) + f_2(V) + f_3(P) \tag{2}$$
$$(\dot{m} > 0;\ V > 0;\ 10MW < P < 300MW)$$

$\dot{m}$ denotes liquefaction capacity (unit: MWh per day or tonnes per day); while V represents storage capacity (unit: MWh or tonnes), and P represents discharge power rating (unit: MW, power rating of the discharge device is assumed to be between 10MW to 300MW). For the unit of liquefaction capacity, both tonnes per day and MWh per day can be used. According to Highview, 1 tonne per day equals 0.12 MWh per day in the measurement of liquefaction capacity, which means, 0.12 MWh of electricity is consumed to generate 1 tonne of liquid air, or in other words, the exergy in 1 tonne of liquid air is approximately 0.12 MWh.
The net cash inflow C_{NCI} can be written as the difference of cash outflows and cash inflows:

$$C_{NCI} = R_{reserve} + R_{arbitrage} - C_{purchase} - C_{O\&M} \quad (3)$$

Two revenue streams are considered in this paper: $R_{reserve}$ denotes revenue obtained by providing reserve service and $R_{arbitrage}$ represents revenue achieved by electricity price arbitrage. While $C_{purchase}$ denotes the annual cost of purchasing electricity from the grid and $C_{O\&M}$ denotes the operating and maintenance costs per annum. According to (Strahan et al., 2013), the operating and maintenance costs typically amount to between 1.5% and 3% of the capital cost of the plant per annum. In this paper, O&M costs are assumed to take up 1.5% of the plant purchase price per annum.

Besides NPV, the internal rate of return (IRR) is another criterion for investment project assessment, which is also derived from the time value of money formula. By assuming a neutral NPV (the value of NPV is set equals to zero), the IRR of an investment project can be obtained, which is a cut-off discount rate that reaches the break-even point of the initial investment. A higher IRR suggests a higher predicted rate of growth for the initial investment. In most cases both NPV and IRR come up with the same rankings on profitability for selecting investment projects, but sometimes have inconformity on rankings, which has resulted in a debate lasting for over a century on which one is more favourable (Osborne, 2010). The IRR equation can be written as,

$$0 = \sum_{i=1}^{lifetime} \frac{C_{NCI}}{(1+IRR)^i} - C_{inv} \quad (4)$$

Payback period is also a widely used decision procedure in capital budgeting for estimating how much time is needed to recoup the initial capital cost of a project. The formula of static payback period is given as follows (the net cash inflow is assumed to be the same in each year),

$$payback\ period = \frac{C_{inv}}{C_{NCI}} \quad (5)$$

In order to obtain a more reliable evaluation for the economic feasibility of a LAES system, our model provides different capital budgeting decision procedures for estimating the profitability, including NPV, IRR and payback period.

2.2 The main assumptions

For our analysis, to optimise the components of a decoupled energy storage unit and assess its financial viability, we make a number of assumptions:

(1) The energy storage plant is owned and operated by an independent third party either buying or selling electricity at spot market prices.
(2) The storage device does not influence the overall market price, i.e. it is a price-taker.
(3) The auxiliary services it provides can be bought by the electricity industry. In this paper, we assume it has 10MW of capacity tendered by the grid for providing STOR service.[7]
(4) The service life of the LAES system is 30 years. According to Highview Power Storage [8], the lifetime of their LAES plant is at least 30 years. The value of NPV can then be calculated based on this assumption.
(5) The LAES system has a stand-alone round trip efficiency of 60%.[9] This means the system efficiency without the use of waste heat and this value is not subject to its scale.
(6) Effective round trip efficiency of the LAES system increases with the use of external heat according to (Li, 2011) pages 93-94. Also Highview Power Storage have stated that the round trip efficiency of the LAES system can reach 70% with the use of waste heat at 115C, consistent with (Bañares-Alcántara et al., 2015).
(7) External heat is a by-product from another process and supplied at zero cost.

2.3 Cost data

The operating data is obtained from Highview[10], from which the cost model for each component unit can be built, shown as Figure 2.[11]

[7] According to ' *STOR Annual Market Report 2014_2015*', around 60% of STOR Providers are between 3-10MW in size, the rest 40% are above 10MW. As a result, 10 MW of contracted capacity is assumed in this paper.
[8] Liquid Air Energy Storage 2017, http://www.highview-power.com/wp-content/uploads/Highview-Brochure-August-2017-Online-A4.pdf [accessed 17/08/2017]
[9] Liquid Air Energy Storage 2017, http://www.highview-power.com/wp-content/uploads/Highview-Brochure-August-2017-Online-A4.pdf [accessed 17/08/2017]
[10] Available at: http://www.highview-power.com/market/#calc-jumper [accessed 20/03/2017].

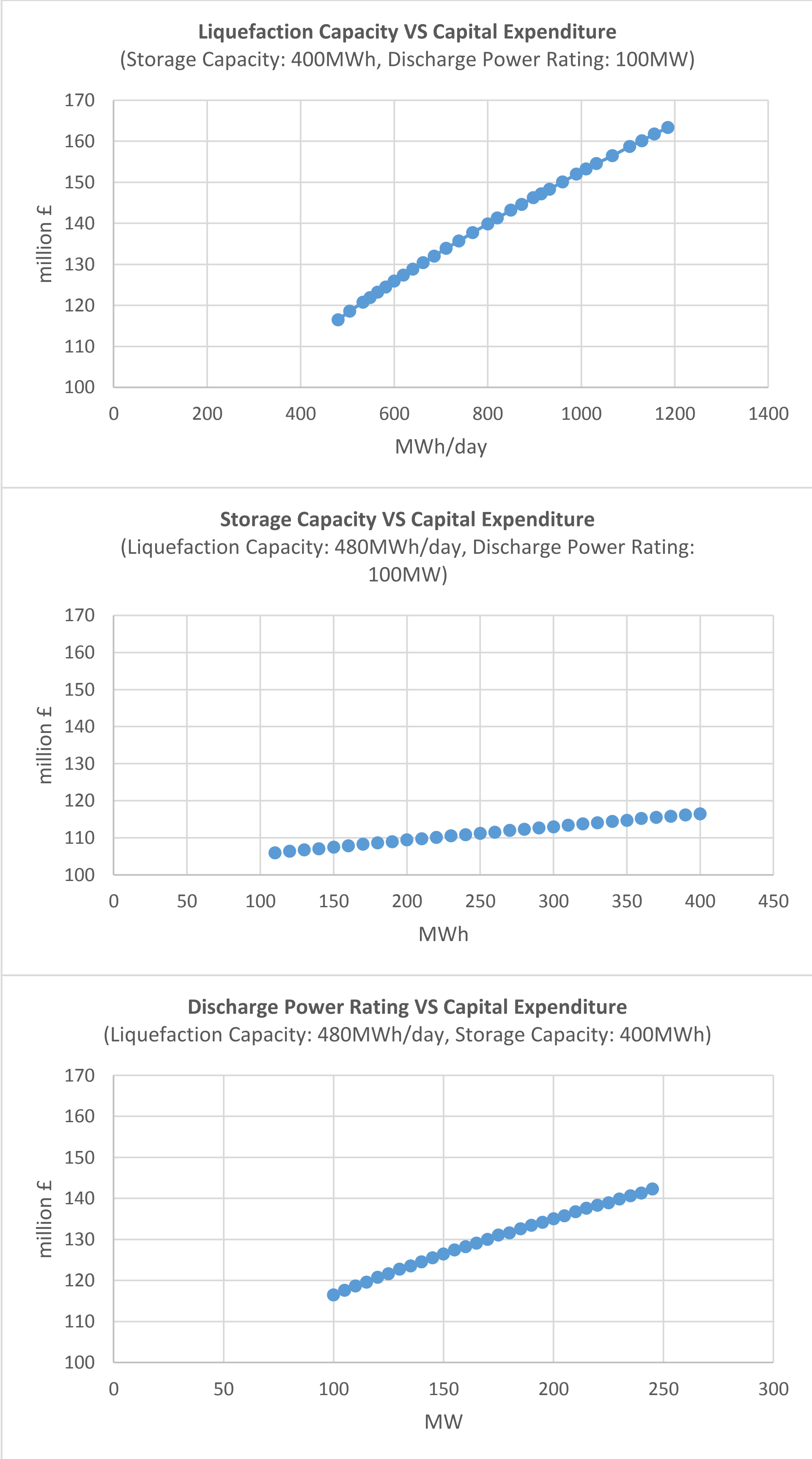

Figure 2: Capacity of each component and the corresponding capital expenditure.

[11] In this paper we assume an exchange rate of '1GBP=1.6USD' [21th June 2015].

Based on Highview's cost estimator, the above data samples are obtained by changing the value of one parameter and keeping the other two unchanged. For the liquefaction unit, as the liquefaction capacity $\dot{m}$ increases from 480 to 1185 MWh/day, the total capital expenditure will rise from 116.5 to 163.4 million GBP, given that the storage capacity and discharge power rating maintain unchanged at 400 MWh and 100 MW, respectively. For the cryogenic tank, with a constant liquefaction capacity of 480 MWh/day and a constant discharge power rating of 100 MW, the capital expenditure will rise from 105.9 to 116.5 million GBP, as the storage capacity V increases from 110 to 400 MWh. Similarly, for the discharging unit, when the liquefaction capacity and storage capacity stays at the level of 480 MWh/day and 400 MWh respectively, the increase of discharge power rating P from 100 to 245 MW will lead to an increased cost from 116.5 to 142.3 million GBP.

2.4 Optimisation algorithm

As the liquefaction unit, cryogenic tank and recovery unit can be fully decoupled, it is possible to find the optimal design of the size/capacity of different components to maximise the economic competitiveness for the LAES system.

In this paper we also assess how two different operating strategies of the LAES system affect its profitability, defined in Table 1.

Table 1: Different operating strategies for the LAES system.

Service mode	Operating Strategy
1	Reserve services + arbitrage
2	Arbitrage only

Based on the UK's half-hourly electricity spot price in 2015 and the payments available for providing reserve services, each revenue stream can be calculated every half hour under different operating strategies. The optimisation algorithm (see Figure 3) in our model is to find the optimal design of the size/capacity of different components using the method of Genetic Algorithm (GA). As a computational model, GA searches the solution space of an objective function by simulated evolution (Whitley, 1994), and is widely used for solving optimization problems, such as (Arabali et al., 2013), (Qiu et al., 2015), (Asadi et al., 2014), etc.

Figure 3 describes the processes of the optimisation algorithm, which are designed as follows (taking service mode 1 as an example):

a.) When within a reserve service window, generate a random number (a) ranging from 0 to 1, and compare it with the probability (p) of receiving a call-off instruction from National Grid for providing reserve service.[12]

$$a = rand(0,1)$$
$$j = \begin{cases} 0 \ when \ a > p; \\ 1 \ when \ a \le p; \end{cases} \tag{6}$$

If j equals 1, suggesting the reserve service is being requested, 10 MW of capacity will be provided to National Grid and the LAES plant would be paid an availability fee within the contracted window and an utilisation fee for the energy delivered. The rest part of the capacity (if there is any) can still seek for arbitrage opportunity.[13]
If j equals 0, which means the reserve service is not being requested, only an availability fee would be paid to the LAES plant, and it is able to arbitrage with its full capacity.

b.) When not within a reserve service window, check whether a reserve service window will be within the next 2 hours. The average call-off duration is around 100 minutes in STOR Year 8.[14] As a result, in this paper the level of stored air (L_{SA}) is examined during the 120 minutes before entering a reserve window, to make sure the LAES plant has the ability to accept a call-off instruction when being in a reserve window, in other words, L_{SA} should be greater than a minimum level of L_{min} during the reserve window.[15] In order to meet this requirement, for a reserve window starting from the ith half-hour:

the level of stored air in the (i-4)th half-hour should meet: $L_{SA} > \frac{1}{4} L_{min}$

[12] The value of p is estimated based on the ratio of the average daily utilized capacity to the average daily contracted capacity (daily availability) in STOR Year 8.
[13] As mentioned above, power rating of the discharge device is assumed to be between 10MW to 300MW.
[14] See '*STOR Annual Market Report 2014_2015*'.
[15] L_{min} is the amount of liquid air that needed to produce 10 MW*2h of electricity.

the level of stored air in the (i-3)th half-hour should meet: $L_{SA} > \frac{2}{4} L_{min}$ (7)

……

the level of stored air in the (i-1)th half-hour should meet: $L_{SA} > \frac{4}{4} L_{min}$

Charging is needed for the LAES system if any of these requirements has not been met, no matter at what price. After meeting equation (7), the LAES system can take part in arbitraging with its full capacity.

c.) Whenever arbitrage is available, compare the current electricity price with a reference price decided by arbitrage strategy so that a decision can be made to charge or discharge the liquid tank, or just stand by. Following (Barbour et al., 2012), a possible arbitrage window should be based on the price differentials which are large enough to cover the round trip energy losses. In this paper, the mean price (P_{mt}) for the last 5 days before time t is calculated, and the system will discharge when $P_t > \frac{P_{mt}}{\eta}$; while charge when $P_t < \eta * P_{mt}$.

d.) For the given discharge power rating P (for example, 20 MW), find the optimal set of storage capacity V and liquefaction capacity $\dot{m}$ to maximize the NPV, based on GA algorithm.

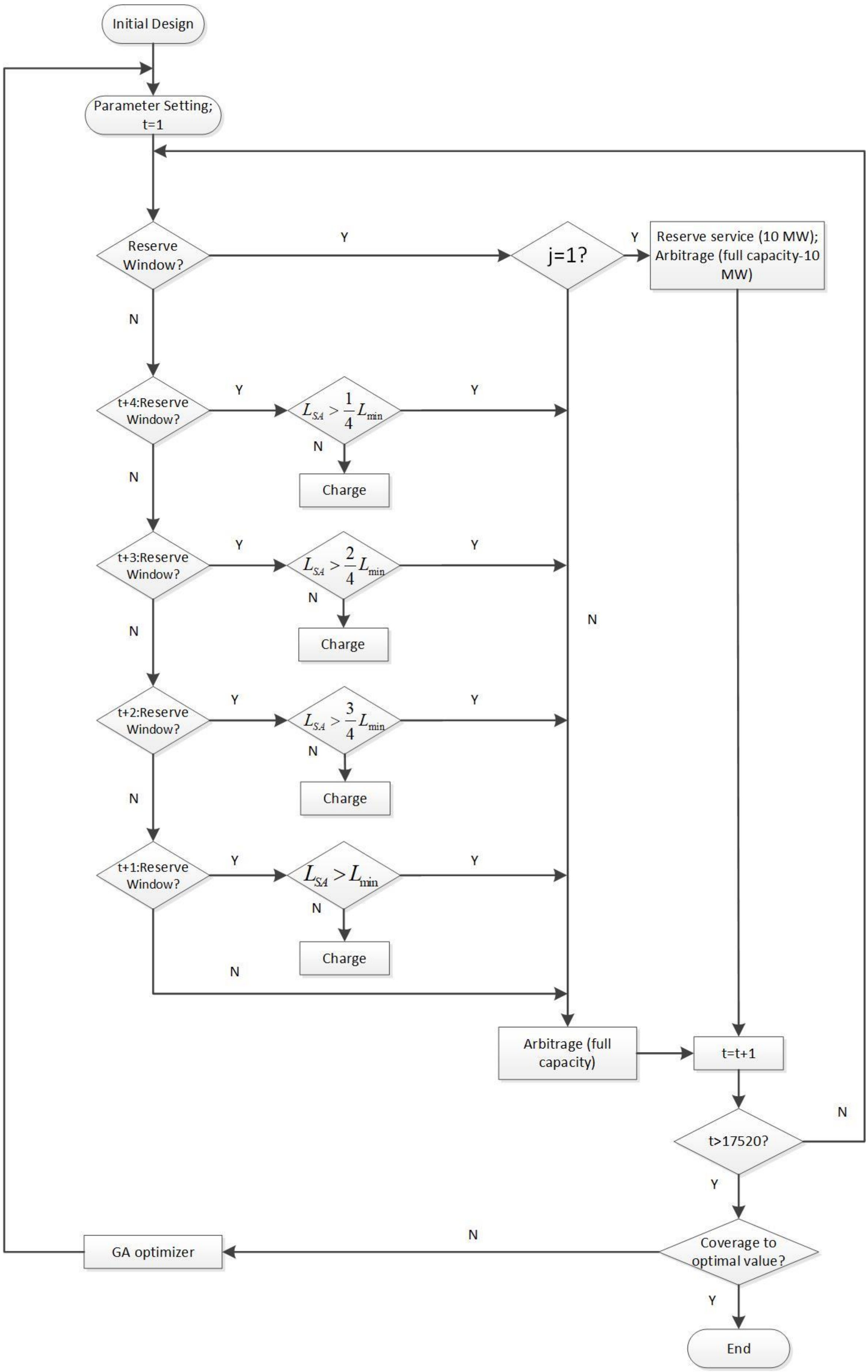

Figure 3: A flowchart depicting the action of the optimisation algorithm.

2.5 Market data

(Moreno et al., 2015) analysed multi-service portfolios of distributed energy storage with the attempt to maximise the net revenue of distributed storage through coordinating supply of a range of ancillary services that are rewarded at different market prices. Following their analysis, we consider reserve service and arbitrage as two revenue streams for the LAES system in this paper.

Reserve windows were defined by '*STOR Annual Market Report 2014_2015'*, which followed actual GB requirements for balancing services in STOR Year 8, as shown in Table 2.

Table 2: Start and end times for reserve service windows.

Month	Week days		Non week days	
	Start time	End time	Start time	End time
27/10/2014 - 01/02/2015	07:00	13:30	10:30	13:30
	16:00	21:00	16:00	20:30
02/02/2015 - 31/03/2015	07:00	13:30	10:30	13:30
	16:30	21:00	16:30	21:00
01/04/2015 - 26/04/2015	07:00	13:30	10:00	14:00
	19:00	22:00	19:30	22:00
27/04/2015 - 23/08/2015	07:30	14:00	09:30	13:30
	16:00	18:00	19:30	22:30
	19:30	22:30		
24/08/2015 - 20/09/2015	07:30	14:00	10:30	13:30
	16:00	21:30	19:00	22:00
21/09/2015 - 25/10/2015	07:00	13:30	10:30	13:30
	16:30	21:00	17:30	21:00
26/10/2015 - 1/02/2016	07:00	13:30	10:30	13:30
	16:00	21:00	16:00	20:30

Source: STOR Annual Market Report 2014_2015

In STOR Year 8, the average contracted capacity was 3040MW, weighted by Season hours, with an average contracted price of £3.87/MW/h for being available during the reserve windows. In the meanwhile, the average daily utilized capacity was 382.8MW, suggesting that approximately 12.6% of the contracted volume was requested, at a price of £169.78/MWh for utilisation.[16]

Figure 4 shows the average electricity prices during summer weeks and winter weeks in 2015. Observing the real-time spot prices of electricity in the UK (2015 half-hourly data), we notice that there was larger difference in electricity prices during winter months (from October to March), which means it would be more profitable for arbitraging in winter.

[16] Market Information & Tender Round Results, http://www2.nationalgrid.com/UK/Services/Balancing-services/Reserve-services/Short-Term-Operating-Reserve/Short-Term-Operating-Reserve-Information/ [accessed 20/03/2017].

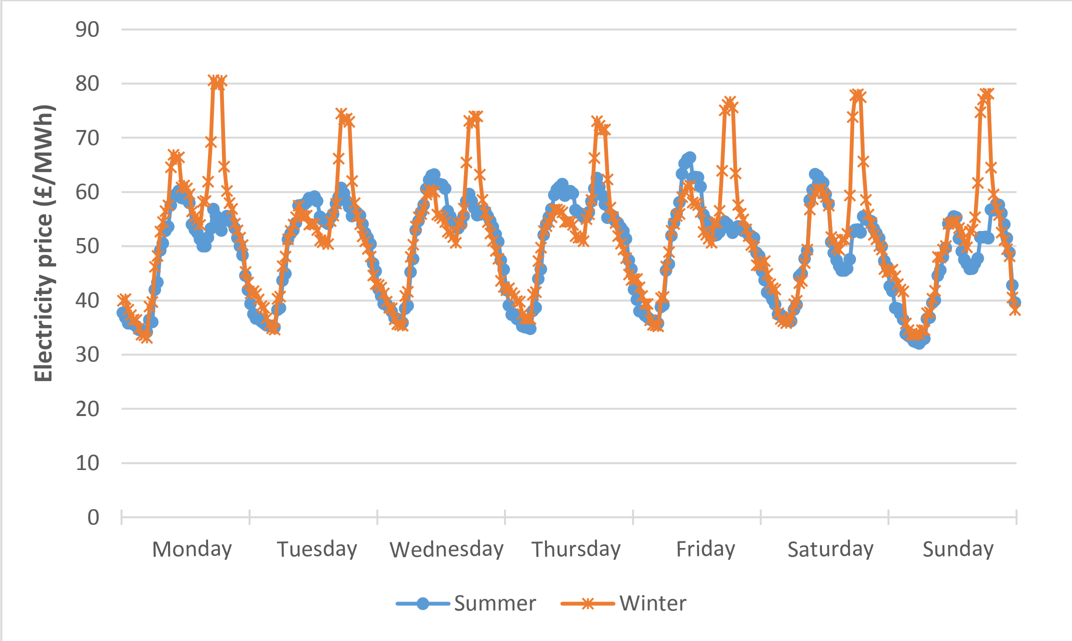

Figure 4: Average electricity prices during summer weeks and winter weeks.

3 Results and discussion

3.1 Simulation results

To illustrate the functioning of the algorithm, Figure 5 shows the simulation results for the first week (336 half-hours) in 2015, from which the change of level of stored liquid air is observed. It is noticed that the level of stored air keeps fluctuating due to the activities of arbitrage and reserve services. When it is within an arbitrage window, a charging decision will result in an increase in the level of stored air, while a discharging decision do the opposite. When it is within a reserve window, the level of stored air will decrease if the reserve service is requested, otherwise it will maintain unchanged.

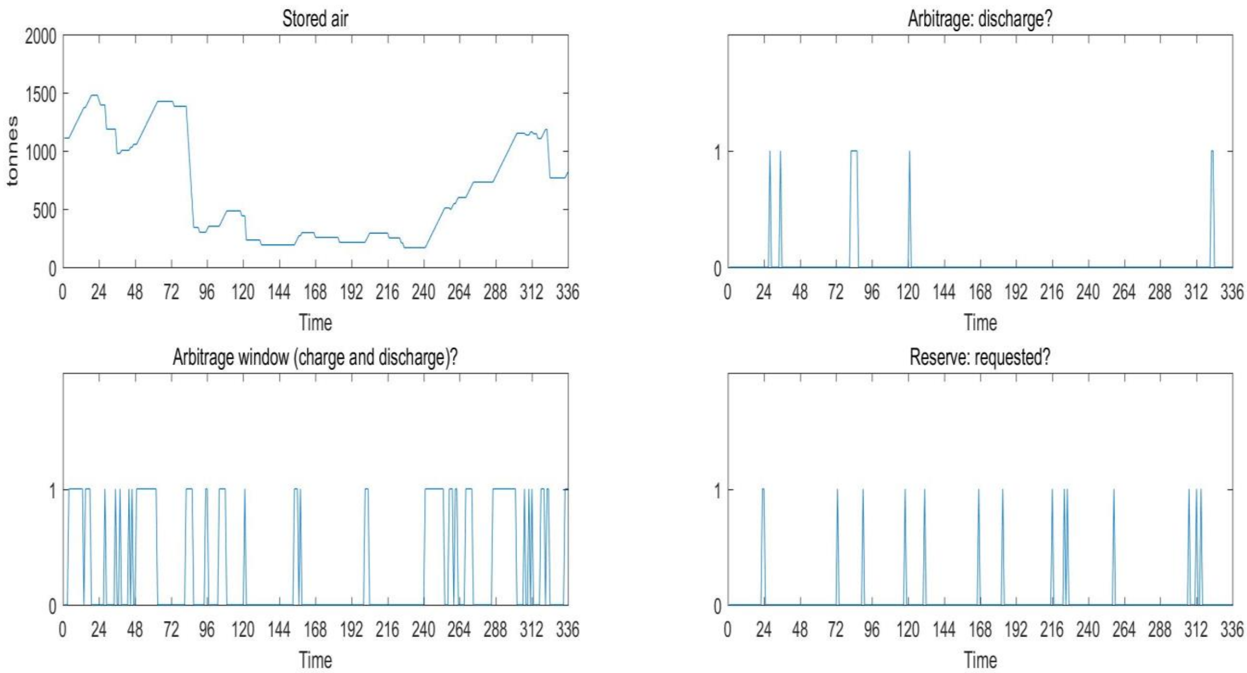

Figure 5: The change of level of stored air in the first week in 2015.

Figure 6 describes arbitrage possibilities according to the UK's real-time spot price in 2015. Apparently, most of the low-price periods have been captured in the arbitrage windows, which means the LAES system charges during off-peak hours. However, it is notable that some high-price periods, such as the peak price period between time 120 and 144, are not included in arbitrage windows. Historical data show that electricity price increased sharply from 38.66 £/MWh in time 129 (the half hour of 16:00-16:30 in 3rd January 2015) to 61.14 £/MWh in time 130 (the half hour of 16:30-17:00 in 3rd January 2015). In the meanwhile, 16:30-21:00 in 3rd January 2015 (Saturday) was a reserve window according to Table 2. Therefore, the LAES system was unavailable for arbitraging (discharging) because of the low level of stored liquid air (see Figure 5) and the commitment of providing reserve service. A better performance on arbitrage revenue can be achieved in service mode 2 (arbitrage only). For a 200MW system without waste heat, the arbitrage revenue would be £11,059 under service mode 1, and £27,293 under service mode 2, for the first week in 2015.

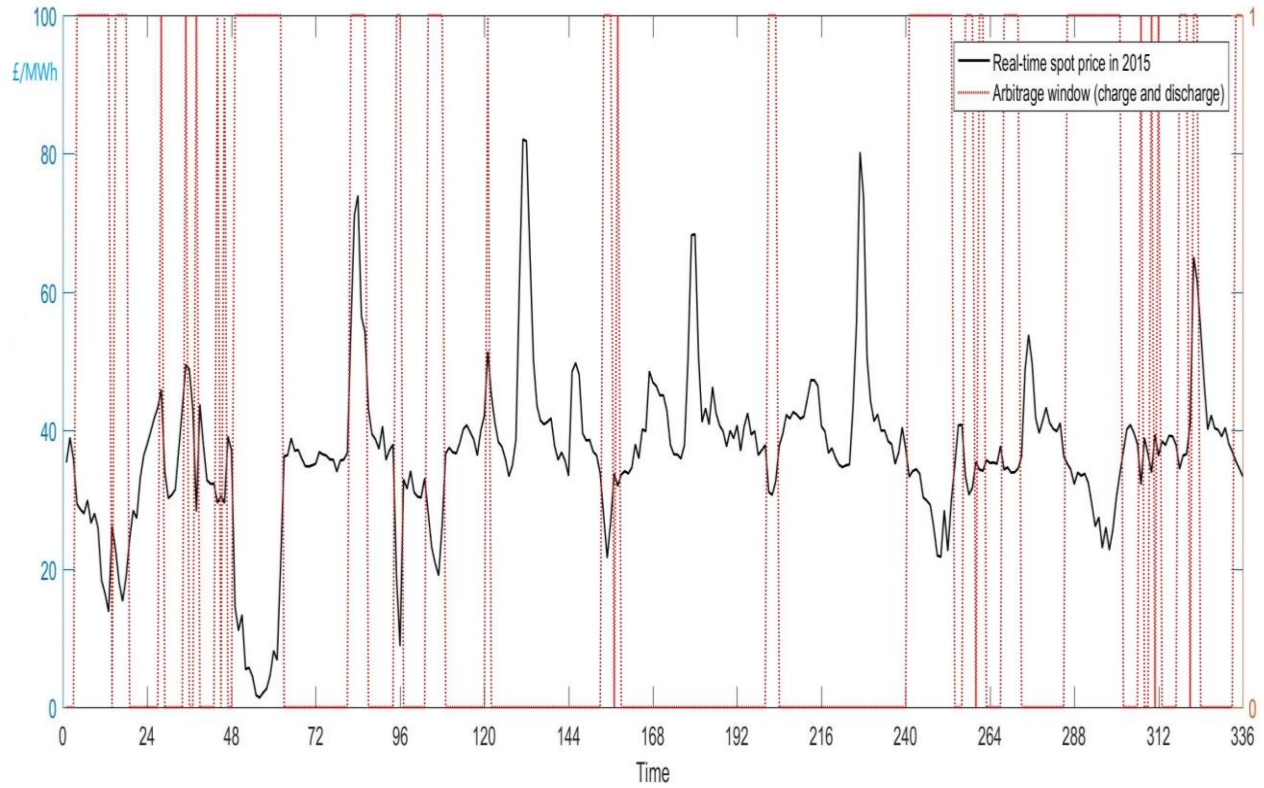

Figure 6: Arbitrage windows within the first week in 2015.

3.2 Influence of system scale

Table 3: Economic feasibility under different system scales (with 150°C waste heat).

Discharge power rating (MW)	Service mode	Liquefaction capacity (thousand tonnes/day)	Tank size (thousand tonnes)	Initial investment (£M)	Reserve net revenue p.a.(£M)	Arbitrage net revenue p.a. (£M)
50	1	4.6	5.8	43.3	0.9	2.0
	2	5.1	6.8	46.1	0.0	2.5
100	1	10.4	9.8	69.2	1.0	4.4
	2	10.2	12.8	71.4	0.0	5.0
150	1	14.9	14.3	87.3	1.0	6.6
	2	15.4	19.5	92.9	0.0	7.5
200	1	22.0	25.3	113.0	1.0	9.7
	2	21.8	24.9	112.4	0.0	10.1

Table 3 shows economic feasibility of the LAES system under different system scales. It is observed that the system scale has a significant influence on the profitability of the project. With the use of 150°C waste heat, a 50 MW LAES has a negative NPV of £-2.7 M under service mode 1. However, it turns to be profitable as the scale increases to 100 MW or more.

Under service mode 1, the optimal matching sizes for a 50 MW system are liquefaction capacity of 4,600 tonnes per day (approximately 38 MW input power) and tank size of 5,800 tonnes (approximately 580 MWh), which would add up to a total investment cost as high as £43.3 M.

From Figure 7 the cost difference on the optimal size of a LAES system under these two service modes can be seen. With the same discharge power rating (which means a same cost for discharging unit), the optimal matching sizes for liquefaction unit under the two service modes are close to each other; however, larger capacity of cryogenic tanks is demanded under service mode 2. As the cost of cryogenic tanks contributes only a small proportion to the total investment cost, the difference on initial investment is not much for the two service modes. It is also worth noting that the current cost of LAES components, especially for the liquefaction unit, is the most important reason that constrains its profitability.

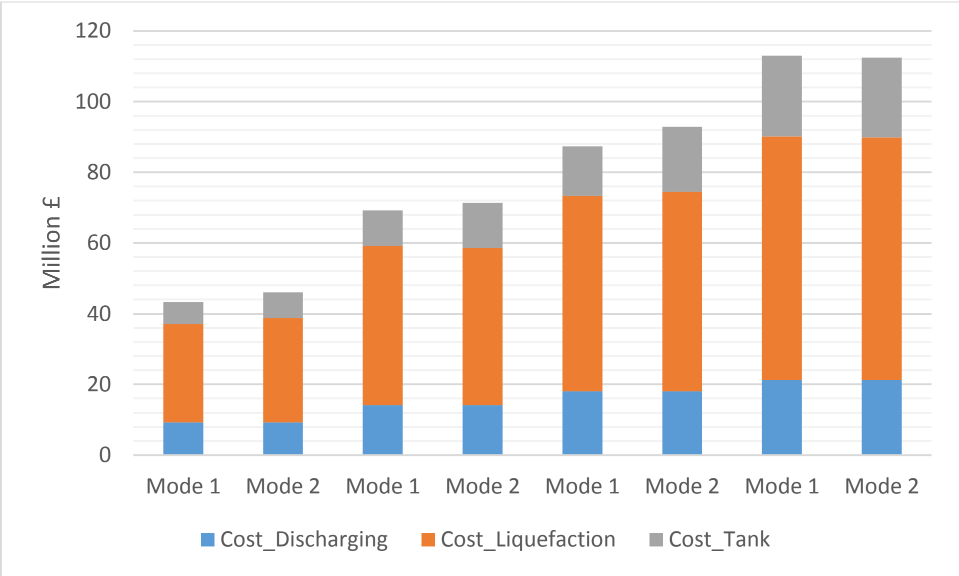

Figure 7: Cost for the optimal size of each component under different scales (with waste heat of 150^{o}C)

Figure 8 indicates as system scale (in terms of generation output) increases, the NPV of the project increases as well, and the payback period is shortened. With waste heat of 150^{o}C, the payback period under optimal design for a 50MW LAES system is 14.9 years, dropping to 10.5 years for a 200MW LAES system. In addition, service mode 1 is always found to be more profitable than service mode 2, suggesting the importance for EES systems to participate in the ancillary service markets.

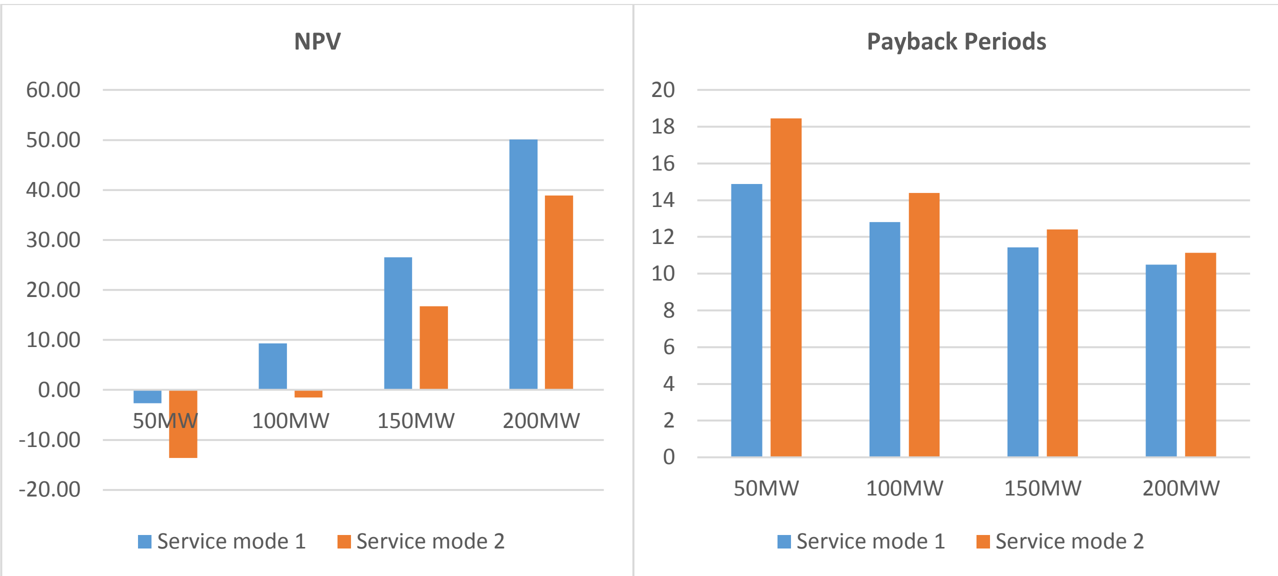

Figure 8: Comparison on NPV and payback periods under different scales (with waste heat of 150^{o}C)

3.3 Influence of waste heat

Table 4: 200MW (generator) system using different degree of waste heat.

Waste heat temperature (^oC)	Service Mode	Liquefaction capacity (thousand tonnes/day)	Tank size (thousand tonnes)	Initial investment (£M)	O&M cost p.a. (£M)	Reserve net revenue p.a.(£M)	Arbitrage net revenue p.a. (£M)	NPV (£M)	IRR (%)	Payback period (year)
No waste heat*	1	3.9	8.6	55.7	0.8	1.0	1.1	-31.8	-2.2	25.7
	2	4.0	9.5	56.9	0.9	0.0	1.5	-45.0	-6.1	37.5
50	1	5.1	8.0	59.5	0.9	1.0	1.9	-22.4	0.3	20.1
	2	5.4	11.5	63.5	1.0	0.0	2.5	-35.9	-2.1	25.6
100	1	10.4	15.5	81.5	1.2	1.0	4.6	-2.7	3.7	14.5
	2	11.1	17.8	85.2	1.3	0.0	5.2	-13.7	2.5	16.2
150	1	22.0	25.3	113.0	1.7	1.0	9.7	50.1	7.7	10.5
	2	21.8	24.9	112.4	1.7	0.0	10.1	38.9	6.9	11.1
200	1	29.4	25.2	125.0	1.9	1.1	16.0	148.1	13.5	7.3
	2	28.4	24.1	122.7	1.8	0.0	16.2	135.6	12.9	7.6
250	1	40.5	30.2	144.2	2.2	1.1	24.5	276.4	19.2	5.6
	2	40.3	27.9	142.3	2.1	0.0	24.7	264.1	18.8	5.8

*Notes: * ambient temperature is assumed to be 20 ^oC.*

Table 4 shows the optimal design of the liquefaction capacity and tank size for a 200MW LAES system under two operating strategies, with the use of different degree of waste heat. Results show that in order to achieve a positive NPV, waste heat of more than 100 ^oC is required.

There is considerable waste heat or surplus heat generated from industrial process. Connective Energy estimated that 40 TWh/y of waste heat associated with industrial process can be captured in the UK (McKenna and Norman, 2010), and it is sensible to assume this number to be within 10-40 TWh each year according to (Strahan et al., 2013). However, due to the inconsistency of the heat sources and heat demands, technologies converting waste heat into more easily usable forms of energy are needed. LAES is a possible solution for heat recovery, by converting low grade heat into power. By integrating waste heat into the discharging process, it can help the vaporization of liquid air and make more work available to the generator, which then creates more discharging power from a given amount of liquid air and improves the round trip efficiency of the LAES system significantly. A higher degree of waste heat adopted means a better performance of the system.[17]

Low grade heat has been defined by (Crook, 1994) as those no exceeding 250^{o}C. By utilizing waste heat of 250 ^{o}C, the 200 MW LAES system can achieve a NPV of £276.4 M under services mode 1, with a payback period of 5.6 years, demonstrating high profitability of the investment project. This implies great potential for the LAES system to improve its economic feasibility through integrating with other systems with considerable waste heat.

Some interesting conclusion can be drawn between the two service modes. Table 4 suggests there is no much difference on the system initial investment between service mode 1 and service mode 2. Unlike the frequency response which is a power-related function so its capability can hardly be affected by the size of the cryogenic tank, both arbitrage and STOR service are energy-oriented function, which means their capability is closely related to the size of each device (liquefaction and storage), and thus the scale of initial investment.

However, major differences are observed on the value of NPV and revenue streams. Without the use of waste heat, revenue from reserve service and arbitrage is £1.0 M and £1.1 M, respectively, under service mode 1. As the use of waste heat can improve the round trip efficiency, a higher arbitrage revenue can be achieved. However, this does not affect the value of providing frequency response or reserve service. As a

[17] Liquid Air Energy Storage (LAES) 2015, http://www.highview-power.com/wp-content/uploads/Highview-Brochure-2015.pdf [accessed 20/03/2017].

result, when the degree of waste heat employed by the LAES system increases to 250 °C, revenue from providing reserve service rises slightly to £1.1 M, and revenue from arbitraging grow rapidly to £24.5 M. As shown in Figure 9, the contribution of arbitraging to the system revenue keeps increasing as the degree of waste heat rises.

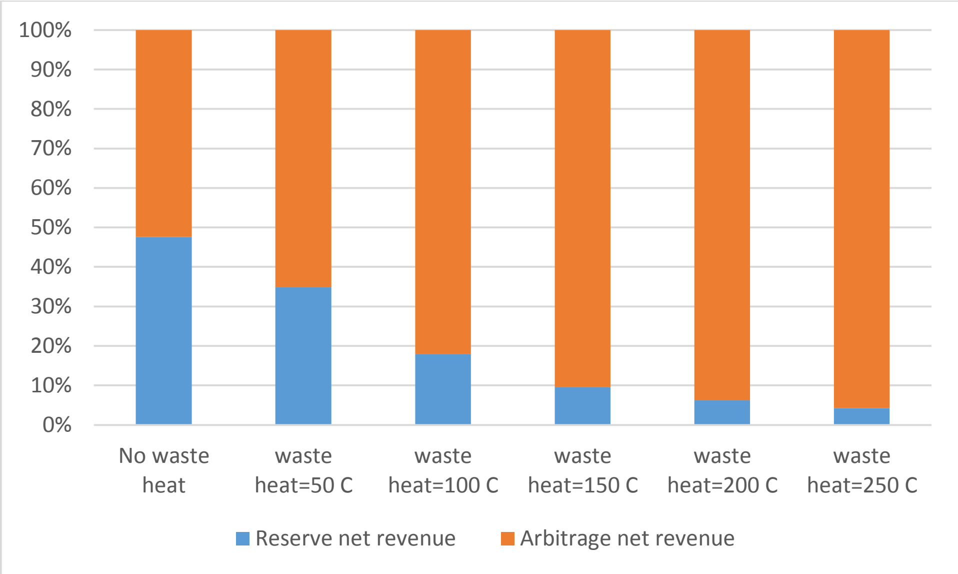

Figure 9: Revenue streams with different degree of waste heat under service mode 1.

With no waste heat employed, the value of NPV is £-31.8 M under service mode 1, and £-45.0 M under arbitrage only strategy, suggesting service mode 1 is more preferable. When the use of waste heat increases to 150 °C, the value of NPV increases to £50.1 M under service mode 1, and £38.9 M under arbitrage only strategy, which means the investment project is now financially feasible, and the difference on profitability between the two service modes is reduced. For the case using waste heat of 250 °C, the values of NPV under the two service modes are close to each other.

3.4 Sensitivity study on discount rate

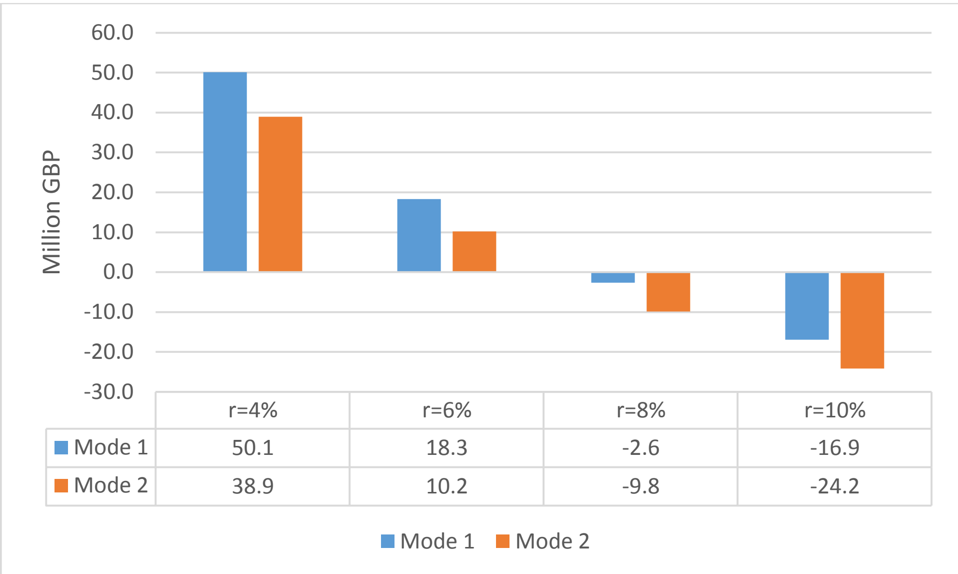

Figure 10: 200MW (generator) system with 150°C waste heat: under different discount rates.

Figure 10 suggests a 200MW LAES with waste heat of 150°C can make good profit under discount rate of 4%-6%, however, as the discount rate rises, the profitability of the LAES system shows a significant decline: when the discount rate rises to 6% from 4%, the value of NPV under the optimal design drops sharply to £18.3 M from £50.1 M. If the discount rate increases further to 8%-10%, even a 200 MW system with 150°C waste heat can not be profitable, indicating that the value of NPV is highly sensitive to the discount rates.

However, Table 6 indicates that discount rate has little impact on criteria of IRR and payback period. Due to the definition of payback period, which is the time needed to recoup the initial investment of a project, it does not take into account the time value of money. As a result, the changes of discount rate can hardly affect the payback period.

Table 6: Economic feasibility under different discount rates (200MW system with 150 ^{o}C waste heat).

Discount rate (%)	NPV (£M)	IRR (%)	Payback period (year)
4	50.1	7.7	10.5
6	18.3	7.7	10.5
8	-2.6	7.7	10.5
10	-16.9	7.7	10.5

4 Conclusions

This paper proposes a methodology to assess the economic feasibility of using decoupled energy storage technologies such as LAES in the UK. Results suggest that the profitability of a LAES system can be improved by either introducing waste heat into the system or increasing system scale. A LAES system is unlikely to be economically feasible without using waste heat, even for a 200MW system. In order to achieve a positive NPV, a 50 MW LAES needs to employ waste heat of at least 200^{o}C, and a 100 MW LAES needs to employ waste heat of 150^{o}C. This implies great potential for the LAES system to improve its economic feasibility through integrating with energy intensive industries to get access to waste heat. Besides waste heat, waste cold is also an option for increasing its profitability, which would be analysed in our further study.

For the scaling of a LAES system, larger capacity of cryogenic tanks is needed under service mode 2, in order to maximum potential revenue from arbitraging. As the cost of cryogenic tanks contributes only a small proportion to the total investment cost, the difference on initial investment is not much for the two service modes.

Under the optimal design, the payback period for a 200MW LAES system with liquefaction capacity of 22,000 tonnes per day (approximately 183 MW input power) and tank size of 25,300 tonnes (approximately 2,530 MWh) is 10.5 years. The IRR for this project would be 7.7%, implying the project is profitable with a discount rate of no more than 7.7%. With a discount rate of 4%, it can achieve a NPV of £50.1 M.

With regard to the evaluation of the economic feasibility of a LAES system, NPV, IRR and payback period are calculated in this paper. The changes of discount rate can hardly affect IRR and the payback period. However, the value of NPV is highly sensitive to different discount rates, which means that a favourable discount rate is crucial for LAES's attractiveness as an investment project.

Acknowledgements
The authors gratefully acknowledge the financial support of the Engineering and Physical Sciences Research Council (EPSRC) of the United Kingdom under grants EP/N032888/1 and EP/N000714/1.

References

Ameel, B., T'Joen, C., De Kerpel, K., De Jaeger, P., Huisseune, H., Van Belleghem, M., De Paepe, M., 2013. Thermodynamic analysis of energy storage with a liquid air Rankine cycle. Applied Thermal Engineering 52, 130-140.
Antonelli, M., Barsali, S., Desideri, U., Giglioli, R., Paganucci, F., Pasini, G., 2016. Liquid air energy storage: Potential and challenges of hybrid power plants. Applied Energy.
Arabali, A., Ghofrani, M., Etezadi-Amoli, M., Fadali, M.S., Baghzouz, Y., 2013. Genetic-Algorithm-Based Optimization Approach for Energy Management. IEEE Transactions on Power Delivery 28, 162-170.
Arani, A.A.K., Karami, H., Gharehpetian, G.B., Hejazi, M.S.A., 2017. Review of Flywheel Energy Storage Systems structures and applications in power systems and microgrids. Renewable and Sustainable Energy Reviews 69, 9-18.

Asadi, E., Silva, M.G.d., Antunes, C.H., Dias, L., Glicksman, L., 2014. Multi-objective optimization for building retrofit: A model using genetic algorithm and artificial neural network and an application. Energy and Buildings 81, 444-456.
Bañares-Alcántara, R., Dericks III, G., Fiaschetti, M., Grünewald, P., Lopez, J.M., Tsang, E., Yang, A., Ye, L., Zhao, S., 2015. Analysis of Islanded Ammonia-based Energy Storage Systems. University of Oxford, Oxford, p. 158.
Barbour, E., Wilson, I.A.G., Bryden, I., McGregor, P., Mulheran, P., Hall, P., 2012. Towards an objective method to compare energy storage technologies: Development and validation of a model to determine the upper boundary of revenue available from electrical price arbitrage.
Barton, J.P., Infield, D.G., 2004. Energy storage and its use with intermittent renewable energy. IEEE transactions on energy conversion 19, 441-448.
Bird, L., Milligan, M., Lew, D., 2013. Integrating variable renewable energy: Challenges and solutions. National Renewable Energy Laboratory.
Brett, G., 2011. Cryogenic Energy Storage: Introduction. Highview Power Storage.
Chen, H., Cong, T.N., Yang, W., Tan, C., Li, Y., Ding, Y., 2009. Progress in electrical energy storage system: A critical review. Progress in Natural Science 19, 291-312.
Chen, H., Ding, Y., Peters, T., Berger, F., 2016. Method of Storing Energy and a Cryogenic Energy Storage System. Google Patents.
Crook, A., 1994. Profiting from low-grade heat: thermodynamic cycles for low-temperature heat sources. IET.
Ding, Y., Li, Y., Li, D., Radcliffe, J., Huang, Y., 2015. Cryogenic Energy Storage, Handbook of Clean Energy Systems. John Wiley & Sons, Ltd.
Ding, Y., Tong, L., Zhang, P., Li, Y., Radcliffe, J., Wang, L., 2016. Chapter 9 - Liquid Air Energy Storage A2 - Letcher, Trevor M, Storing Energy. Elsevier, Oxford, pp. 167-181.
Evans, A., Strezov, V., Evans, T.J., 2012. Assessment of utility energy storage options for increased renewable energy penetration. Renewable and Sustainable Energy Reviews 16, 4141-4147.
Guizzi, G.L., Manno, M., Tolomei, L.M., Vitali, R.M., 2015. Thermodynamic analysis of a liquid air energy storage system. Energy 93, 1639-1647.
Hoppmann, J., Volland, J., Schmidt, T.S., Hoffmann, V.H., 2014. The economic viability of battery storage for residential solar photovoltaic systems–A review and a simulation model. Renewable and Sustainable Energy Reviews 39, 1101-1118.
IRENA, 2017. Electricity Storage and Renewables: Costs and Markets to 2030. International Renewable Energy Agency, Abu Dhabi, p. 132.
Larcher, D., Tarascon, J.M., 2015. Towards greener and more sustainable batteries for electrical energy storage. Nat Chem 7, 19-29.
Li, Y., 2011. Cryogen based energy storage: process modelling and optimisation. University of Leeds.
Luo, X., Wang, J., Dooner, M., Clarke, J., 2015. Overview of current development in electrical energy storage technologies and the application potential in power system operation. Applied Energy 137, 511-536.
McGrail, B., Cabe, J., Davidson, C., Knudsen, F., Bacon, D., Bearden, M., Charmness, M., 2013. Technoeconomic performance evaluation of compressed air energy storage in the Pacific Northwest. PNNL-22235, Pacific Northwest National Laboratory, http://caes. pnnl. gov/pdf/PNNL-22235. pdf (accessed 24 July 2017).
McKenna, R.C., Norman, J.B., 2010. Spatial modelling of industrial heat loads and recovery potentials in the UK. Energy Policy 38, 5878-5891.
Moreno, R., Moreira, R., Strbac, G., 2015. A MILP model for optimising multi-service portfolios of distributed energy storage. Applied Energy 137, 554-566.
Morgan, R., Nelmes, S., Gibson, E., Brett, G., 2015. Liquid air energy storage – Analysis and first results from a pilot scale demonstration plant. Applied Energy 137, 845-853.
National Grid, 2011. Operating the Electricity Transmission Networks in 2020 – Update June 2011.
Osborne, M.J., 2010. A resolution to the NPV–IRR debate? The Quarterly Review of Economics and Finance 50, 234-239.
Qiu, M., Ming, Z., Li, J., Gai, K., Zong, Z., 2015. Phase-Change Memory Optimization for Green Cloud with Genetic Algorithm. IEEE Transactions on Computers 64, 3528-3540.
Rastler, D., 2010. Electricity energy storage technology options: a white paper primer on applications, costs and benefits. Electric Power Research Institute.
Rehman, S., Al-Hadhrami, L.M., Alam, M.M., 2015. Pumped hydro energy storage system: A technological review. Renewable and Sustainable Energy Reviews 44, 586-598.

Ren, G., Liu, J., Wan, J., Guo, Y., Yu, D., 2017. Overview of wind power intermittency: Impacts, measurements, and mitigation solutions. Applied Energy 204, 47-65.
Rodrigues, E., Godina, R., Santos, S., Bizuayehu, A., Contreras, J., Catalão, J., 2014. Energy storage systems supporting increased penetration of renewables in islanded systems. Energy 75, 265-280.
Sciacovelli, A., Vecchi, A., Ding, Y., 2017. Liquid air energy storage (LAES) with packed bed cold thermal storage – From component to system level performance through dynamic modelling. Applied Energy 190, 84-98.
Strahan, D., Akhurst, M., Atkins, A., 2013. Liquid Air in the energy and transport systems: Opportunities for industry and innovation in the UK. Centre for Low Carbon Futures report 20.
Weitemeyer, S., Kleinhans, D., Vogt, T., Agert, C., 2015. Integration of Renewable Energy Sources in future power systems: The role of storage. Renewable Energy 75, 14-20.
Whitley, D., 1994. A genetic algorithm tutorial. Statistics and Computing 4, 65-85.