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Levelised Cost of Storage for Pumped Heat Energy Storage in comparison with other energy storage technologies

Andrew Smallbone[a,*], Verena Jülch[b], Robin Wardle[a], Anthony Paul Roskilly[a]

[a] Sir Joseph Swan Centre for Energy Research, Newcastle University, Newcastle upon Tyne NE1 7RU, UK
[b] Fraunhofer Insitute for Solar Energy Systems ISE, Freiburg, Germany

A R T I C L E I N F O

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A B S T R A C T

Future electricity systems which plan to use large proportions of intermittent (*e.g.* wind, solar or tidal generation) or inflexible (*e.g.* nuclear, coal, *etc.*) electricity generation sources require an increasing scale-up of energy storage to match the supply with hourly, daily and seasonal electricity demand profiles. Evaluation of how to meet this scale of energy storage has predominantly been based on the deployment of a handful of technologies including batteries, Pumped Hydroelectricity Storage, Compressed Air Energy Storage and Power-to-Gas. However, for technical, confidentiality and data availability reasons the majority of such analyses have been unable to properly consider and have therefore neglected the potential of Pumped Heat Energy Storage, which has thus not been benchmarked or considered in a much detail relative to competitive solutions. This paper presents an economic analysis of a Pumped Heat Energy Storage system using data obtained during the development of the world's first grid-scale demonstrator project. A Pumped Heat Energy Storage system stores electricity in the form of thermal energy using a proprietary reversible heat pump (engine) by compressing and expanding gas. Two thermal storage tanks are used to store heat at the temperature of the hot and cold gas. Using the Levelised Cost of Storage method, the cost of stored electricity of a demonstration plant proved to be between 2.7 and 5.0 €ct/kW h, depending on the assumptions considered. The Levelised Cost of Storage of Pumped Heat Energy Storage was then compared to other energy storage technologies at 100 MW and 400 MW h scales. The results show that Pumped Heat Energy Storage is cost-competitive with Compressed Air Energy Storage systems and may be even cost-competitive with Pumped Hydroelectricity Storage with the additional advantage of full flexibility for location. As with all other technologies, the Levelised Cost of Storage proved strongly dependent on the number of storage cycles per year. The low specific cost per storage capacity of Pumped Heat Energy Storage indicated that the technology could also be a valid option for long-term storage, even though it was designed for short-term operation. Based on the resulting Levelised Cost of Storage, Pumped Heat Energy Storage should be considered a cost-effective solution for electricity storage. However, the analysis did highlight that the Levelised Cost of Storage of a Pumped Heat Energy Storage system is sensitive to assumptions on capital expenditure and round trip efficiencies, emphasising a need for further empirical evidence at grid-scale and detailed cost analysis.

1. Introduction

A total of 7200 gigawatts (GW) of electricity capacity needs to be built worldwide to keep pace with increasing electricity demand while also replacing existing power plants expected to be retired by 2040 (around 40% of the current fleet) [1]. If future electricity systems are planned to use large proportions of intermittent (such as from wind, solar or tidal generation) or inflexible (*e.g.* nuclear, coal, *etc.*) electricity generation sources then an increasing scale-up of energy storage is necessary to match the supply with hourly, daily and seasonal electricity demand profiles. Reflecting this, the International Energy Agency [2] projects that 310 GW of additional grid-connected electricity storage capacity will be necessary in the United States, Europe, China and India.

To date, the economic and technical evaluation of how to meet this scale of energy storage has predominantly been based on the deployment of well-known technologies including batteries, Pumped Hydroelectricity Storage (PHS), Compressed Air Energy Storage (CAES) and Power-to-Gas (PtG) solutions. IEA [2] find that PHS and CAES can already reach the cost targets for widespread application in providing

* Corresponding author.
E-mail address: andrew.smallbone@ncl.ac.uk (A. Smallbone).

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Nomenclature

A_t	annual cost of storage
c_{el}	cost of electricity
i	discount factor
n	system lifetime
Q	net heat flow
R	recovery value
T	temperature
t	year
W_{in}	amount of energy charged by the storage system per year
W_{out}	amount of energy discharged by the storage system per year
T_{amb}	ambient temperature
T_{hot}	temperature on the hot side of the PHES system
T_{cold}	temperature on the cold side of the PHES system
aCAES	adiabatic Compressed Air Energy Storage
CAPEX	capital expenditure
CHEST	Compressed Heat Energy Storage
CH_4	methane storage
dCAES	diabatic Compressed Air Energy Storage
GW	gigawatts
H_2	hydrogen storage
LCOE	Levelised Cost of Electricity
LCOS	Levelised Cost of Storage
Li-ion	Lithium-ion
ORC	Organic Rankine Cycle
OPEX	operational expenditure
Pb	Lead
PCES	Pumped Cryogenic Energy Storage
PHES	Pumped Heat Energy Storage
PSH	Pumped Hydroelectricity Storage
PTES	Pumped Thermal Energy Storage
PtG	Power to Gas
TRL	Technology Readiness Level
VRF	vanadium redox flow

arbitrage services, while battery technologies need considerable cost reductions to compete. Jülch [3] shows that the operation of the storage system has a vast impact on the LCOS. Zakeri et al. [4] calculate the lowest LCOS for PHS and CAES in providing energy arbitrage (5.4–7.1 €ct/kW h). Lazard [5] compare LCOS of several technologies in defined applications. They find that PHS can be competitive to fossil fuels at the transmission system level while batteries are starting to become competitive in frequency regulation. However, largely due to issues around commercial confidentiality, novelty of the solution and therefore a lack of technical data available in the public domain, the majority of such analyses have been unable to properly consider and have therefore neglected the potential of Pumped Heat Energy Storage (PHES). As such, despite its huge potential for delivering low-cost energy storage with a low footprint and high flexibility on the location of deployment, it has not been benchmarked or considered in a much detail as one might expect relative to competitive solutions.

The practical and theoretical aspects of a PHES system that come under the general term *Pumped Heat Energy Storage* (PHES) or *Pumped Thermal Energy Storage* (PTES) have been examined in a number of recent papers. The term *electricity* is sometimes used instead of energy. Pumped Cryogenic Energy Storage (PCES) is used to describe a system that stores energy at a temperature below ambient. In a review of recent literature, Steinmann [6] categorises PHES systems according to their thermodynamic cycle and working fluid: reversible Brayton cycle machines using a super-critical single-phase gas (air or an inert gas) and low- and high-temperature storage reservoirs; reversible trans-critical Organic Rankine Cycle (ORC) devices (often using CO_2) with ice and pressurised water storage reservoirs; and Compressed Heat Energy Storage (CHEST) systems [7] which use a conventional (but reversible) critical-region steam Rankine cycle with a latent-heat high-temperature reservoir and with the ambient environment as the low-temperature source. Recent literature describing PHES systems are generally variations on these three designs. A series of working prototypes of a Brayton-type device using thermally stratified (constant-temperature) storage were presented by Howes [8] who provides a simple theoretical and practical analysis, this analysis was considered in more detail by White et al. [9] and optimised by McTigue et al. [10]. These articles detail the development of, The work of Desrues et al. [11] also describes a very similar system. This type of constant-temperature storage design is the method studied in the present paper. Benato [12] describes the modelling of a PHES system which also operates in a similar manner, but which adds an electric heater to stabilise the charging temperature. The effects of varying bed characteristics and maximum cycle temperature are explored. The modelling predicts very low round-trip efficiencies for this configuration, and consequently specific energy costs which are higher than those used in the present analysis.

In [13] Thess formulates a finite-time thermodynamic model predicting the efficiency of PHES as a function of the temperature storage at maximum output power. Guo et al. [14] explore the performance of PHES and PCES machines using a finite-time thermodynamics approach, and develop the limiting efficiencies and the effect of varying parameters. Guo et al. [15] further derive expressions for the round trip efficiency and power output of a PTES system using a Brayton cycle. These three studies assume that the environment is used for one of the reservoirs. In contrast Frate et al. [16] examine the efficiencies for various working temperatures and fluids of a PTES system which uses a third reservoir at above ambient temperature as the cold source for a vapour compression heat pump (charging) component, with an ORC discharging section. This arrangement naturally leads to efficiencies of over 100% but the system is essentially the same as that analysed by other authors. Wang and Zhang [17] also describe a conceptually similar system producing efficiencies of over 100%, only in their case discharge occurs between the hot (charged) reservoir and a liquid natural gas store. Charging takes place via a CO_2 heat pump cycle, and discharge through cascaded CO_2/NH_4 Rankine cycles. Ni and Caram [18] conduct an analysis of a Brayton cycle PHES using discretised (stratified) storage using an exponential matrix method, and characterise the system round-trip efficiency and utilisation ratio as a function of a number of system design characteristics. Vinnemeier et al. [19] describe a system for integrating heat pumps into conventional thermal plants, giving bounds for efficiencies; the systems described here falling into the CHEST model category. Abarr et al. [20] develop a model for an ammonia-based PHES system with tube-in-concrete hot-store and ambient cool-store. This system's operation is slightly different to others studied in that it is primarily designed as a flexible bottoming-plant for a gas turbine generator, operating an asymmetric charge/discharge cycle.

To date, most of the work analysing PHES has been concerned with the engineering aspects of PHES storage devices. The theoretical studies (using conventional engine cycle analysis and/or finite-time thermodynamics) have the aim of determining limiting efficiencies, parameterised by working temperature range and other design variables. The small number of papers describing working prototypes examine practical designs for reducing irreversibilities, particularly in the compression, heat transfer and storage parts of the system. Only two papers move further into fully examining the economic aspects of PHES. Dietrich et al. [21] conduct a classical exergeoeconomic analysis of a hybrid CHEST-type system using an off-the shelf vapour-compression heat pump and a low-temperature ORC using butane, with ambient low-temperature source and a single daily charge-discharge schedule.

The analysis quantifies the per-sub-component and overall plant energy and exergy efficiencies, computes the levelised cost of exergy for each sub-system, and thus the overall cost of each subsystem for the operational period (24 h). The authors conclude that this system is uncompetitive at current prices; although, the efficiencies of this particular design are rather low. Abarr et al. [22] compute the levelised cost of energy (LCOE) for the system described in [20]. The study uses an LCOE model modified by one created by the National Energy Technology Laboratory to include the system charging cost; LCOE values for the PHES system as well as a Compressed Air Energy Storage (CAES) system and Li-ion battery storage installation are calculated. The authors present an LCOE range for the studied PHES which compares favourably with the CAES and Li-ion battery options, and competitively with existing primary generation sources.

In this paper an LCOS analysis for PHES is presented. A previous paper presents a broader review of energy storage in general and derives LCOS values for technologies that are compared herein to PHES [3]. The innovative contribution of this paper is that it will use the first data (and current best estimates) for the CAPEX, OPEX and efficiency obtained from a £15 m project to establish the world's first grid-scale demonstration PHES system as inputs to a standard LCOS analysis benchmarked against similar and competitive energy storage technologies to provide a new perspective on the cost potential of PHES to meet global grid-scale energy storage demands.

2. Pumped Heat Energy Storage

This section describes the PHES configuration and operation, and the demonstrator and a proposed commercial system.

2.1. Pumped Heat Energy Storage configuration and operation

A PHES system is used to store electricity using a proprietary reciprocating heat pump and two novel thermal storage vessels. Presented in Fig. 1 is a schematic of the operation and configuration of a general PHES system.

The operating cycle can be summarised as:

(1) First Charging: Powered by low-cost electricity from the grid, the heat pump with two pistons acting as a compressor (hot) and an expander (cold) is used to "charge" the two thermal storage vessels containing a stratified thermal storage medium. During charging, an electrical motor/generator acting as a motor (W_{hot}/W_{cold} or W_{net}) powers the heat pump moving pistons which causes compression of gas (hot side) and expansion of gas (cold side). On the hot side, gas leaves the compressor with the temperature, T_{hot}, entering the top of the hot store and giving up its heat to the storage media. Since the storage media in the hot store is initially at ambient temperature, T_{amb}, the gas leaving the hot-store during the first charging cycle will be at T_{amb}. On the cold side, the gas is expanded, cooled, and passed into the bottom of the cold store where it takes up heat from the storage media. The temperature of the gas lowers to T_{cold} during expansion. As with the hot store, the gas will leave the cold store at T_{amb}. As more work is done by the pistons, W_{net}, the system continues to charge and thermal fronts move down and up through the two hot and cold stores respectively.

(2) System Charged: Charging continues until the user stops the process or the leading edges of the two thermal fronts reach the ends of their respective stores. At this point, the system is fully charged and the heat pump is stopped. The majority of the hot store is at T_{hot} and the cold store at T_{cold}. Each store will have an axial temperature gradient at one end between the core temperature and T_{amb}.

(3) Discharging: When the system is discharging, gas at T_{hot} will exit the top of the hot store and pass into the expander. Similarly, the gas leaving the bottom of the cold store ends at T_{cold} is compressed. This causes for the pistons to be moved, producing work W_{net}, thus turning the heat engine and an electrical generator.

(4) Discharged: When the system is fully discharged, the two stores will be at T_{amb}.

In Fig. 1, the thermal stores are represented by the hatched lines, one end of each store is held at ambient temperature, T_{amb}, whilst the other will be either hot, T_{hot} or cold, T_{cold} depending on the store's primary function. The stores consist of multiple layers separated by thermal insulation, this means that each can layer be considered as isolated and is independent. As such as each layer is supplied (or discharged) with thermal energy, it reaches that thermal state quickly and maximises the thermal gradient across the whole store.

2.2. The Pumped Heat Energy Storage grid-scale demonstration

The world's first grid-scale demonstration is currently being commissioned by Newcastle University. The facility includes a first-of-a-kind demonstration of grid-scale PHES energy storage together with supporting research and development apparatus and test equipment all

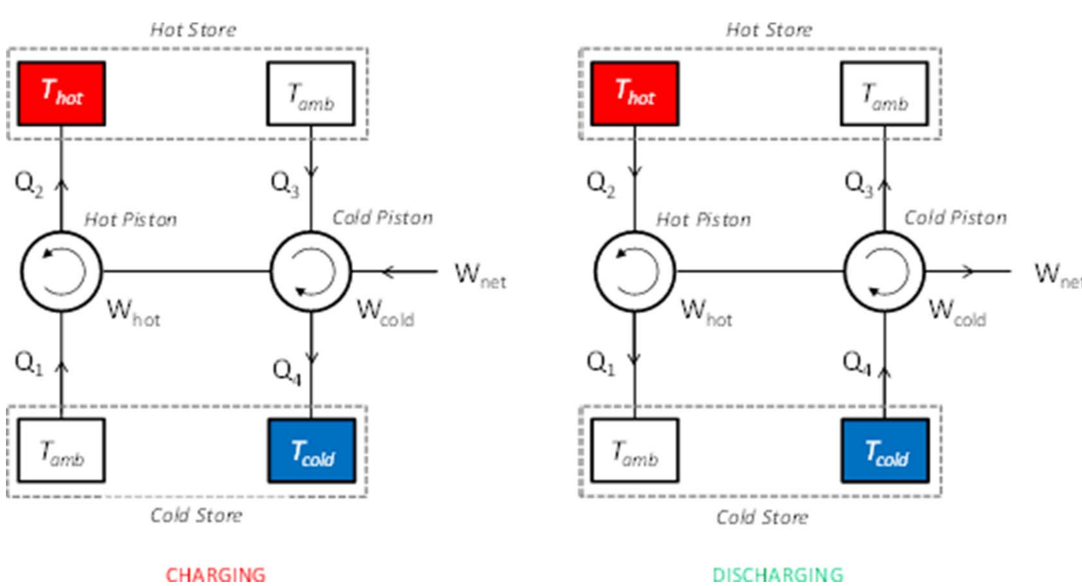

Fig. 1. Schematic of a Pumped Heat Energy Storage system.

developed from a £15 m investment into the technology. The PHES research facility uses 150 kW of excess electricity from the grid to drive a novel compression and expansion engine to heat (500 °C) and cool (−160 °C) argon working fluid streams. The working fluid is used to heat/cool two novel thermal storage tanks cumulatively storing 600 kW h of energy. The process is reversed to generate 120 kW of electricity for the grid when required.

The work that follows utilises the experience and data obtained during the design, manufacture, commissioning, operation and maintenance of the system detailed above.

2.3. A commercial Pumped Heat Energy Storage system

The target size of a commercial system is shown in Table 1. An image of the proposed layout of a commercial PHES system is presented in Fig. 2, and the relative locations of each of the main components is shown and their corresponding technical details are summarised in Table 2.

3. Method

The Levelised Cost of Electricity method was developed to compare the cost of electricity from renewable energy sources with the cost for conventionally-generated electricity [23,24]. The Levelised Cost of Storage method is derived from the LCOE method and described in detail in [3]. The LCOS equation is shown in Eq. (1). All expenses (capital expenditures CAPEX and annual cost A_t at each point of time t over the system lifetime n) are divided by the amount of energy discharged by the storage system, W_{out}, over the same time period. The annual cost as well as the energy output is discounted to account for the time factor of the investment using the discount factor i (for explanations see [23,24]). The annual cost is composed of the operation cost OPEX, reinvestments in storage components where necessary and the cost of buying electricity (see Eq. (2)). At the end of the system lifetime, a recovery value R can be included for components with a longer lifetime.

$$LCOS = \frac{CAPEX + \sum_{t=1}^{t=n} \frac{A_t}{(1+i)^t}}{\sum_{t=1}^{t=n} \frac{W_{out}}{(1+i)^t}} \tag{1}$$

$$A_t = OPEX_t + CAPEX_{re,t} + c_{el} \cdot W_{in} - R_t \tag{2}$$

The key inputs for the analysis are summarised and defined for the PHES commercial system as follows. All financial data is given in €$_{2016}$ values.

System lifetime [years]: The system design specification has been set as 20 years of life based on two charge and discharge events per day *i.e.* 14,600 cycles. Critical components subject to the most wear (piston rings, valves, *etc.*) have been designed and tested to meet this requirement.

Specific CAPEX charging unit [€/kW]: The CAPEX was determined by considering the: (a) fixed building costs (modification), planning application (based on a UK installation), legal costs, control system and meeting safety protocols; (b) the manufacture and installation of the heat pump; (c) electrical generator and associated systems; (d) gas ducting between the stores, engines and other systems. These were then considered in terms of expanding out to an *n*-th-of-a-kind system (*i.e.* when there have been enough systems manufactured to benefit from the economies of scale). The CAPEX values per charging unit can be grouped into those related to:

1. A reversible heat pump at 166 €/kW: This total was determined based on the results of a comprehensive cost analysis of each component, final assembly, installation and commissioning. The majority of the costs comes from the manufacture of the heat pump itself and for context, a diesel engine could be considered a component of similar manufacturing complexity. A typical diesel engine vendors price list [25] shows that a similarly-sized diesel engine technology (F.G. Wilson branded and Caterpillar Ltd manufactured engines) would cost between 106 €/kW (low end) to 133 €/kW (high end).
2. An electric motor generator at 64 €/kW: This price reflects the relative cost of the electric motor generator purchased and installed on the site. An off-the-shelf motor/generator (without controller) is currently available at 50 €/kW [26].
3. Other system components at 170 €/kW: The costs associated with the site, pipe ducting, insulation, electrical control system, *etc.* has also been included. These costs are of a similar magnitude to the cost of the reversible heat pump.

A total of 350 €/kW for the whole system would represent a "lowest cost scenario" or Scenario 1. This is consistent with the estimate carried out by Howes [8] who used a similar method to estimate the total C-APEX to be 367 €/kW for a similar system. A more cost-conservative approach was also considered which estimated higher costs for the reversible heat pump (294 €/kW), the electric motor generator (64 €/kW – the same as in Scenario 1 as it is an off-the-shelf component), and the other system components (439 €/kW). A total of 797 €/kW for the whole system was applied to represent a "conservative cost scenario" or Scenario 3. The final system costs are more likely to be within these two extreme scenarios and as such an average or expected system cost was also determined and named Scenario 2. These costs were based on an engineer's best estimate of the system costs based on most probable (*i.e.* neither conservative nor aggressive) costing estimates. The data used for the three PHES scenarios are summarised in Table 3.

Specific CAPEX storage unit [€/kW h]: The costs of the storage were estimated by considering the gas buffer, manufacture of the stores (including insulation materials, control systems, layers, tanks, *etc.*). For an *n*-th-of-a-kind system at the proposed scale, the hot store is expected to cost between 11 and 17 €/kW h and the cold store 2 and 4 €/kW h. Overall, this was estimated between 13 and 21 €/kW h. This estimate was consistent with the one reported by Howes [8] as 13.2 €/kW h. The above can be rationalised against equivalent off-the-shelf costings by considering the:

1. Thermal storage medium: The costs of the thermal storage medium is extremely low at 0.015 €/kW h [27], the total contribution of the cost of this aspect of the technology is negligible.
2. Storage tank: The main contribution to the storage unit CAPEX is the requirement for a low (1 bar) and a high pressure (12 bar) thermal store. Nevertheless the required pressures for both stores are considerably lower than typically would be required in CAES (50–200 bar) [28], as such alternative materials other than steel (an off-the-shelf solution currently costs 1.2–1.54 €/l [29]) can be utilised in its construction. For example, a steel/concrete design for high pressure (160–860 bar) hydrogen storage has been shown to reduce the cost of storage unit by 60% [30]. At only 1 and 12 bar respectively the opportunity for a concrete tank (0.12 €/l [31]) (or composite) is technically viable; for context, an off-the-shelf concrete tank (including storage medium) currently costs approximately 17 €/kW h.

Table 1
Technical summary of the proposed commercial system.

Rated power during charging	2 MW
Rate power during discharge	1.6 MW
Storage capacity	16 MW h
Footprint	17 m × 7 m
Lifetime	20 years
Location	Anywhere

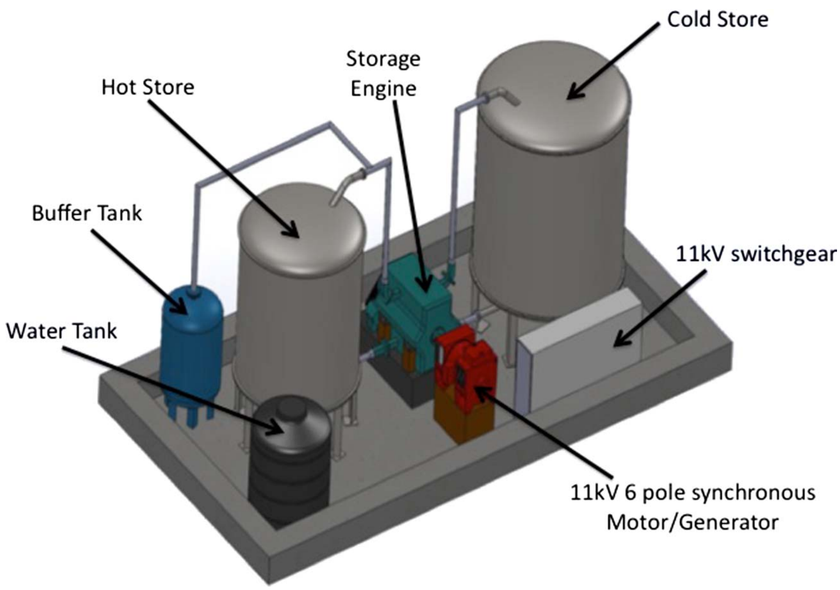

Fig. 2. Image showing the key elements of a Pumped Heat Energy Storage system.

Table 2
Summary of the main system components.

Motor/Generator	Synchronous machine which converts electrical power to shaft work or vice versa
Hot Store	Pressure vessel held at 12.0 bar containing thermal storage material and gas between 25 °C and 500 °C
Cold Store	Pressure vessel held at 1.0 bar containing storage material and gas between −160 °C and 25 °C
Storage Engine	Proprietary reciprocating reversible heat engine
Buffer Tank	Pressure vessel to cope with any mass-balancing of the working gas
Switchgear	Fail-safe connection to the 11 kV network

Specific OPEX energy based [€ct/kW h] and power based [€/kW]: Due to being of a similar complexity and type of system, the energy-based operating costs (OPEX) are considered to be similar to those of adiabatic Compressed Air Energy Storage (aCAES) systems and as such a value of 0.26 €ct/kW has been used from Jülch [3] based itself on data from Madlener et al. [32].

Insurance [% CAPEX/year]: Insurance costs are estimated as 0.5% of CAPEX cost per year. This assumption is applied in the analysis across all other technologies considered.

Self-discharge rate [% loss per day]: In line with the design specification, the thermal stores are expected to lose their charge (thermal losses) at a rate of 1% of energy stored per day (based on the expected performance of the proprietary design).

Typical input/output power ratio: The grid-scale demonstrator has an input of 150 kW and an output of 120 kW, thus has an input/output power ratio of 1.25. This number is expected to scale proportionally with the system size. However in principle, a PHES system can charge and discharge at part-load if required.

Round trip energy storage efficiency: The round trip efficiency represents the energy required to charge and what is available to discharge the system, and was originally estimated by Howes [8]. In his estimate, the round trip efficiency was computed as the product of the electrical efficiency of a motor generator (98%), the storage efficiency of the thermal stores (98%), mechanical efficiency (losses due to bearing friction, *etc.*) (90%) and thermal efficiency of the compression/expansion cycle (97%). This yields a round trip efficiency of 72%. A more detailed thermodynamic analysis by White et al. [9] and a parametric and optimisation study by McTigue et al. [10] quantify both the thermal and pressure losses of a PHES system and estimate round trip efficiencies between 66% and 71% depending on the mode of operation. In context with CAES efficiencies (42–54%) [28], which offers a similar cycle at higher Technology Readiness Level (TRL) this is notably higher, however there are three fundamental reasons for this: (1) The working fluid is monatomic gas (rather than air) which has a 22% higher ratio of specific heat (at standard conditions) thus increasing the thermodynamic efficiency directly; (2) the reversible heat pump is based on a positive displacement system thus reducing pumping losses; and, (3) a novel valve design which minimises losses through the gas-exchange process.

In the current analysis, a round trip efficiency of 72% was

Table 3
Summary of the three scenarios.

	unit	Scenario 1 – technical potential	Scenario 2 – target system	Scenario 3 – conservative estimate
Roundtrip efficiency	%	72	67	52
Self-discharge rate (loss of energy in storage)	% per day	1	1	1
Component lifetimes				
Engine	years	20	20	20
Storage tanks	years	20	20	20
System lifetime	years	20	20	20
Specific CAPEX power based (per charging unit power)	€/kW	350	573.5	797
Specific CAPEX energy based	€/kW h	13	17	21
Specific OPEX power based	€/kW	0.0026	0.0026	0.0026
Specific OPEX energy based	€/kW h	11	11	11
Insurance rate	%	0.5	0.5	0.5
Discount rate	%	8	8	8
Input/output power ratio	kW/kW	1.25	1.25	1.25

considered to represent the most favourable and the "technical potential" of the system and was adopted in Scenario 1. However, without empirical evidence of this level of efficiency, alternative efficiencies were also considered for three scenarios. Based on the existing design and corresponding extensive thermodynamic and system modelling, system round trip efficiency of 67% is anticipated for a commercial system, as such this was employed within Scenario 2. Finally, using the current design specification and component testing results, the development team considered a most conservative estimate considers that a round trip efficiency of 52% might be appropriate and on-par with those of a CAES system – representing the expected efficiencies expected for the grid-scale demonstration system.

To put the LCOS of PHES in perspective, it is compared to the LCOS of other storage technologies. Jülch [3] analysed the LCOS of five technology groups using the same method as applied in this paper. These technologies are: Pumped Hydroelectricity Storage (PHS); Compressed Air Energy Storage (diabatic (dCAES) and adiabatic (aCAES)); battery technologies (Lithium-ion (Li-ion), Lead (Pb) and vanadium redox flow (VRF) batteries) and Power to Gas (PtG) (both hydrogen (H_2) storage within a cavern and methane (CH_4) storage using the national gas grid). For the benchmark with PHES, the same input data is used.

Fig. 3 shows the power-based and energy-based specific CAPEX for the analysed technologies. Compared with other technologies PHES has a low power-based CAPEX, while the energy-based CAPEX is comparable to that of PHS. The PHES system is designed for operating at two cycles per day, however the cost structure indicates that this technology could in principle offer a cost-effective solution for longer-term storage of energy.

4. Discussion of results

Fig. 4 shows the LCOS for a PHES system at demonstrator size of 2 MW charging power/1.6 MW discharging power and a capacity of 16 MW h. This corresponds to 8 h charging time and 10 h discharging time. The three scenarios are based on different efficiencies and different cost, as described before. Scenario 1 has the lowest CAPEX and highest efficiencies, while Scenario 3 has the highest CAPEX and lowest efficiencies.

The LCOS ranges between 0.070 and 0.110 €/kW h. This includes the electricity cost to charge the system, which is fixed at 0.03 €/kW h to highlight the impact of the system's efficiency on the LCOS. In Scenario 1 the efficiency is 72%, resulting in an electricity cost of roughly 0.042 €/kW h, while the lower efficiency of 52% produces an electricity cost of 0.058 € per kW h provided by the PHES system. Excluding the electricity cost to charge the system would result in an LCOS of 0.028 to 0.0502 €/kW h.

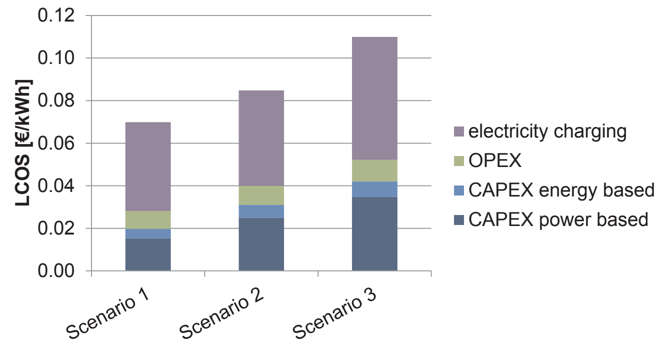

Fig. 4. Composition of the LCOS for the 2 MW/16 MW h PHES demonstrator.

In comparing the LCOS of PHES with that of other technologies, the system sizes and configurations need to be similar. In Jülch [3], the LCOS of storage technologies for short-term storage (power-to-capacity-ratio of 1:4) and long-term storage (power-to-capacity-ratio of 1:700) are compared. In order to meet the 100 MW scale, the prospect of fifty 2 MW commercial PHES systems were considered. It should be noted that larger scale 10 MW systems have also been evaluated during the project development, however their round trip efficiencies and other parameters typically scaled linearly (*i.e.* that a single 10 MW system operates like 10 × 1 MW systems). During this analysis, as are often observed in thermal-power engineering systems (reciprocating engines, gas turbines, compressors, heat pumps, *etc.*) percentage point efficiency gains as the systems are scaled-up were identified, particularly around the reciprocating heat pump, but it was felt that these fitted within the levels of uncertainty considered across the scenarios and as such were not explored here in detail.

Fig. 5 shows the LCOS for a large-scale storage system (100 MW; 400 MW h) for short-term energy storage. The LCOS decreases as the number of cycles per year and the amount of energy discharged per year increases, according to an approximately inverse relationship. PHES systems, shown in red, are among the technology options with the lowest cost of storage. The range of the LCOS refers to the input parameters for Scenario 1 (low cost, high efficiency) and Scenario 3 (high cost, low efficiency). Compared to the other large-scale storage systems PHS and CAES, PHES have a relatively low LCOS. This graph however reflects the cost per kW h if the electricity for charging the storage is free. Including a cost of electricity may change the picture due to the different efficiencies of the technologies.

Fig. 6 shows the range of LCOS of PHES systems (based on Scenarios 1–3) compared with the LCOS of other storage systems for one specific charge/discharge event costed over a year. The results are sorted by their mean values (using Scenario 2 for PHES). For a large scale system

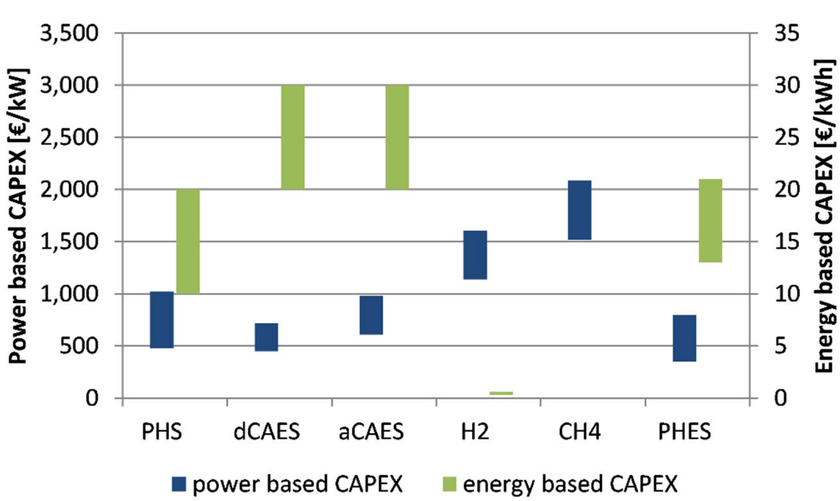

Fig. 3. Power based and energy based CAPEX of PHES in comparison with other storage technologies.

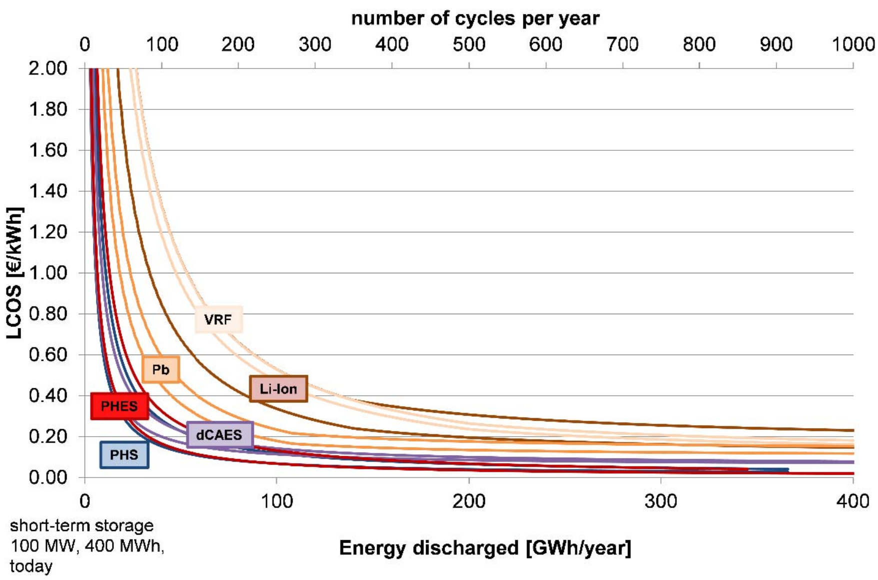

Fig. 5. LCOS as a function of the amount of energy discharged/number of cycles annually for a short-term storage system with 100 MW output power and 400 MW h storage capacity, excluding cost of electricity for charging the storage (data for other storage technologies from [3]).

and with a charging electricity price of 3 €ct/kW h, the LCOS of PHES ranges between 8.9 and 11.4 €ct/kW h. The lower end is about equal with the lower end of the LCOS of PHS, while the range, due to data uncertainties, is quite wide relative to the LCOS ranges of comparable technologies. The estimated LCOS of CAES systems is within the range of expected cost for PHES, assuming that the same specific cost applies as for the small scale demonstrator.

5. Sensitivity analysis

Fig. 7 shows the sensitivity analysis for the LCOS of PHES. Sensitivity analyses for the other technologies are presented in [3]. The amount of energy discharged per year has the highest effect on the resulting LCOS; if the energy output is varied by 20%, the LCOS changes by 10–15%. Other main influencing factors are the efficiency and the specific CAPEX, of which variation by 20% results in a change in LCOS of about 10%. The impact of the price of charging electricity, the discount rate and the specific OPEX is lower than that of the other parameters. This means that the cost is highly sensitive to the operational regime and to assumptions made about the efficiency and specific C-APEX of the system.

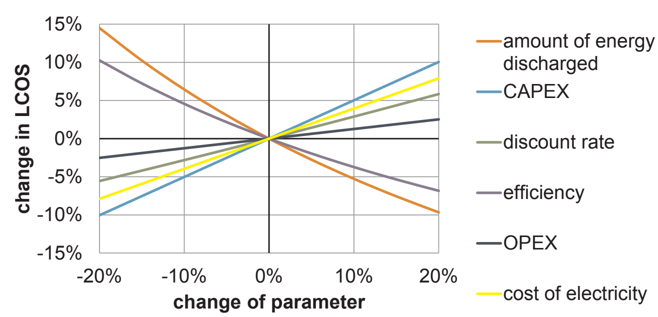

Fig. 7. Sensitivity analysis for the LCOS of PHES (100 MW, 400 MW h system, medium cost values, 3 €ct/kW h, 365 cycles per year).

6. Conclusion

This paper presents an economic analysis of a Pumped Heat Energy Storage (PHES) system. Using the Levelised Cost of Storage (LCOS) method, the cost per unit of electricity was determined for a 2 MW/16 MW h demonstrator plant. The LCOS was then estimated for a large-scale system and compared with that of other energy storage technologies. The results show that PHES could be cost-competitive with CAES systems or even with PHS systems, depending on the capital cost and

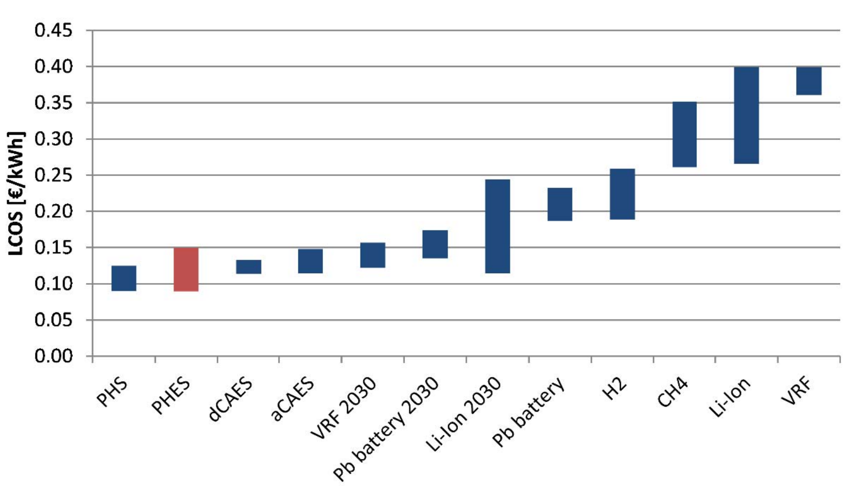

Fig. 6. Comparison of the LCOS of PHES with all other technologies, for a 100 MW/400 MW h system with 365 cycles per year, and including an assumed electricity price of 3 €ct/kW h (data for other storage technologies from [3]).

system efficiencies that are realised. The sensitivity analysis presented makes it clear that the resulting LCOS is very sensitive to the operation of the plant, demonstrating that with an increasing number of cycles per year the cost per kW h decreases strongly; although this effect is similar for all technologies. Therefore, in order to be able to carry out a fair comparison of the LCOS of a range of technologies, the number of storage cycles per year must be the same for each technology under study.

The LCOS of PHES is also very sensitive to those parameters for which only estimations are currently available, *i.e.* the capital expenditure and the efficiency. The first objective for further research should be to determine these parameters more precisely. Following this, research should focus on improving the efficiency of the system and the application of low-cost components and assembly.

A comparison of the power-based and energy-based CAPEX of several technologies showed that PHES has a comparatively low energy-based CAPEX. Even though the system was designed as a short-term storage with a power to energy ratio of 1:8 and 730 cycles per year, the possibility of using the system as a long-term energy storage should be considered in detail.

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