

Research papers

Benchmarking of liquid air energy storage with and without added firing against batteries and gas-fired power plants

Carlos Arnaiz del Pozo^{a,*}, Ángel Jiménez Álvaro^a, Schalk Cloete^b

^a Universidad Politécnica de Madrid, Spain

^b SINTEF, Norway



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ABSTRACT

Rapid deployment of variable renewables is broadly viewed as the primary mechanism for reducing the carbon intensity of electricity systems, motivating the development and implementation of technologies such as liquid air energy storage (LAES). This study investigates the thermodynamic performance of LAES and evaluates the improvements attained through natural gas added firing (AF), determining the coefficients of structural bonds to identify design optimization priorities. Subsequently, LAES configurations are benchmarked against mid-scale natural gas combined cycles (NGCC) and batteries through an economic optimization based on electricity price profiles from different European markets for the year 2023. At a CO₂ emissions tax of 100 €/ton, results reveal that the LAES-AF concept located in Germany could compete with an NGCC plant if natural gas prices exceed 8.3 €/GJ, while for prices above 9.1 €/GJ batteries (with cost reduction projected to 2030) were the preferred option. In this range, the LAES-AF plant reduced fuel consumption by 24.0–27.2 % relative to the NGCC benchmark, which would reduce emissions when using natural gas or costs when using costlier carbon-neutral fuels. The standalone LAES plant did not prove economically viable in any location, being outperformed by batteries and requiring a CO₂ price above 300 €/ton to compete with LAES-AF. As electricity price volatility keeps rising with growing wind and solar market shares, the economic attractiveness of LAES should improve as longer periods of near-zero electricity prices negate its lower round-trip efficiency and capitalize on its lower cost for energy storage. Therefore, further work on the development of innovative LAES cycles is recommended.

Acronyms

AF	Added Firing
API	Annualized Profitability Index
BEC	Bare erected cost
BESS	Battery energy storage systems
CAES	Compressed air energy storage
CEPCI	Chemical engineering plant cost index
CCS	Carbon capture and storage
Ch.	Charge
CSB	Coefficient of structural bonds
Dch.	Discharge
EES	Engineering equation solver
EPC	Engineering procurement and construction
GAMS	General algebraic modelling system
GHG	Greenhouse gas emissions

HP	High pressure
IP	Intermediate pressure
LAES	Liquid air energy storage
LP	Low pressure
LNG	Liquefied natural gas
PT	Project contingency
PtA	Power to ammonia
MITA	Minimum temperature approach
NG	Natural gas
NGCC	Natural gas combined cycle
OC	Owner's costs
ORC	Organic Rankine cycle
PHS	Pumped hydropower storage
PtA	Power to Ammonia
PV	Photovoltaic
RTE	Round-trip efficiency

* Corresponding author.

E-mail address: cr.arnaiz@upm.es (C. Arnaiz del Pozo).

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SEA	Standardized economic assessment
TES	Thermal energy storage
TTT	Turbine inlet temperature
TOC	Total overnight cost
TPE	Two-phase expander
VRE	Variable renewable energy

List of symbols

B	Exergy (kJ)
$\dot{E}$	Total exergy flow (kW)
E_{CO_2}	Specific CO ₂ intensity of fuel (kg/GJ)
$\dot{I}$	Exergy destruction (kW)
V	Volume (m ³)
T	Temperature (K)
P	Pressure (bar)
$\dot{Q}$	Heat (kW)
$\dot{W}$	Work (kW)
e	Exergy flow (kJ/kg)
$\dot{m}$	Flow rate (kg/s)
η_t	Thermal efficiency (%)
x_k	Design parameter (—)
$\delta_{j,k}$	Coefficient of structural bonds
i	Discount rate (%)
i_j	Specific exergy destruction in subsystem j (kJ/kg)
c	Unit capital cost (€/kW, €/kWh, €/kg)
$\hat{v}$	Installed storage capacity (kg, MWh)
$\emptyset$	Storage losses (% per unit of time)
g	Hourly power generation (MWh)
$\hat{g}$	Installed generating capacity (MW)
p	Price (€/MWh, €/ton, €/GJ)
n	Plant lifetime (years)
ξ	Exergy efficiency (%)
$\varepsilon_{k,s}$	Conversion factor generating-storage node (MJ/MJ, MJ/kg)
θ	mass ratio of natural gas to air (—)

Subscripts/Superscripts

j	Time interval (h) / subsystem (—)
i	Stream
k	Generating technology index
s	Storage technology index
Ph	Physical
Ch	Chemical
cap	Capital
fix	Fixed
var	Variable
0	Ambient conditions

1. Introduction

Efforts to decarbonize the global economy with the objective of limiting global mean temperature rise below 1.5 °C above pre-industrial levels are presently insufficient, with record high CO₂ emissions of 37.4 Gt being reached in 2023 [1]. Under continued current policies, the estimated greenhouse gas (GHG) emissions median gap to the year 2050 for achieving that target is of 46 Gt equivalent CO₂ [2]. Within the electricity generation sector, which accounted for approximately 29 % of the global GHG emissions in 2021 [3], it is vital to shift to renewable energy sources and energy vectors with a lower carbon intensity displacing fossil fuels like coal. However, wind and solar energy present the challenge of variable availability throughout the year, increasing the electricity price volatility [4]. Furthermore, the value of renewable electricity in the market drops as the degree of penetration increases [5], thereby decelerating the renewable power generation roll-out required

to effectively displace CO₂ emitters in energy systems. Incipient energy storage technologies [6] can help to mitigate the adverse effects of increasing renewable shares by providing flexibility to balance the grid, capitalizing on price fluctuations as supply of electricity is transferred from peak to valley periods.

Liquid air energy storage (LAES) [7] emerges as an interesting thermomechanical storage option for this purpose because it consists of a scalable solution which does not present the geographical limitations of pumped hydropower storage (PHS) or compressed air energy storage (CAES) [8], nor does it face the critical material constraints and availability limitations of batteries [9]. Krawczyk et al. [10] carried out a technical comparison between CAES and LAES highlighting that LAES presents better prospects because of its higher efficiency (15.43 %-points) and storage energy density, which is approximately twice the energy density of CAES and 100 times that of PHS [11]. PHS comprises approximately 96 % of the actual energy storage capacity [12]; a study by Klumpp [13] revealed that it can outcompete CAES in terms of cost for short to medium storage periods. As drawbacks, PHS presents a large environmental impact, with high water and land requirements, while CAES necessitates geological caverns to be cost-competitive. On the contrary, LAES can be deployed generically featuring de-risked and commercially available technological components, constituting a technology package with high operational flexibility currently offered by several companies [14–16], which can be constructed with a fast schedule without public opposition. Highview Power [17] built the first grid-scale 5 MW/15MWh LAES plant in 2018 [18] and has recently announced the construction of a 50 MW/300MWh LAES plant in Manchester, UK [19]. Because of its reduced space requirements and high flexibility, LAES presents the opportunity of integration with other industrial processes to simultaneously produce electricity, cold, heat and air components operating as a polygeneration system [20]. For instance, Babaei et al. [21] designed a hybrid multi-generating LAES system for the production of power, heat and potable achieving an overall efficiency of 71 %. Meng et al. [22] evaluated the potential of integrating LAES in a power to ammonia (PtA) production scheme from renewable sources, reaching a cost-optimal design comparable to fossil-based ammonia processes. Lu et al. [23] presented a LAES polygeneration system integrating liquefied natural gas (LNG) cold exergy for water desalination with attractive economic prospects. Alternatively, Damak et al. [24] discussed the possibilities of employing cryogenic energy from LAES as a carbon capture and storage (CCS) technology in power generation plants.

LAES technology is a Carnot battery variant [25] that employs electrical power to generate cold and hot reservoirs in which energy is stored. Then, at a later time, the temperature gradient between the two reservoirs is used as driving force to produce power. The working principle of LAES is depicted in Fig. 1, consisting of charge, storage and discharge sections. The round-trip efficiency (RTE) is defined as the ratio of the energy delivered by the discharge section relative to that invested in the charge section along a whole cycle. Air is liquefied in a charge cycle by means of cheap electricity and sensible heat from liquid refrigerants [26], two levels of temperature are typically employed using methanol and propane to cover a liquefaction range of 200 K, and it is subsequently stored at close to atmospheric pressure. The simplest configuration involves a Linde liquefier operating at high pressure (hundreds of bars), which is reached with at least two adiabatic, inter-cooled compression stages. Despite the low exergy efficiency (2.47 %) reported by Borri et al. [27] for this process, high pressure operation and cold integration with refrigerant enables a high thermal performance. The heat of compression is transferred to a thermal oil, which is also stored. At times of electricity scarcity and high market prices, the liquefied air is pressurized in a cryogenic pump and re-gasified, producing cold refrigerants (methanol and propane) earlier employed in the charge section to facilitate air liquefaction. Some designs employ packed beds with rocks/pebbles or phase change materials for cold energy storage [28], but achieve a comparatively lower RTE as a result of energy losses

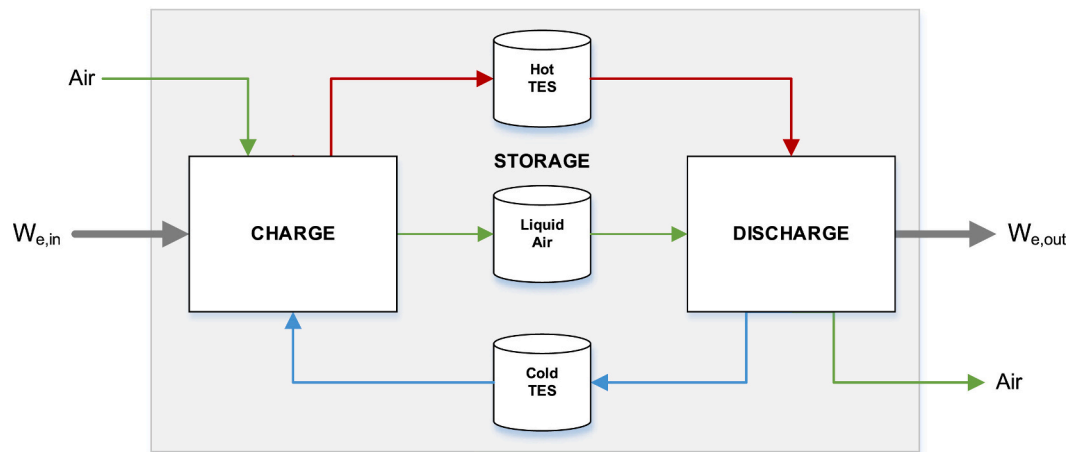


Fig. 1. LAES working principle.

from axial dispersion and the fact that cold cannot be completely retrieved from the bed. Sensible heat materials pose operational challenges due to the propagation of a thermal front across the bed [29], while phase change materials potentially allow reduced volumes for equivalent storage capacities while mitigating the thermal fluctuations, albeit at a higher capital cost [30]. The high pressure air is then heated with the thermal oil and expanded in a turbine in a sequence of three to four reheating and expansion stages, producing electricity in the process. Storage times for commercial LAES applications range between 2 h to 1 day [16]. For a standard LAES system with heat and cold storage, Guizzi et al. [31] determined that an RTE in the range of 54–55 % can be achieved, underlining the importance of the two-phase expander (TPE) in the charge section to accomplish this. Zhang et al. [32] considered the integration of Organic Rankine Cycles (ORC) with dry working fluids to reach an RTE of 56.85 %. Antonelli et al. [33] revealed that hybrid LAES-thermal plants as large-scale energy storage systems attain an equivalent RTE above 80 %, due to the high temperatures reached prior to the expansion turbines (1400 °C in that study). The RTE definition in that study considers a fuel thermal conversion to electricity factor of 0.6, corresponding to a combined cycle plant efficiency. As an alternative means to combustion of a fuel in order to increase the temperature of air in the discharge section, Nabat et al. [34] assessed the potential of employing high temperature thermal energy storage (HTES) attained with extra power from off-peak times, achieving an RTE of 61.1 % while avoiding carbonaceous emissions. Legrand et al. [35] performed a price arbitrage optimization of adiabatic and diabatic LAES schemes with packed beds for high grade cold storage in a 100 MW solar PV plant, indicating that natural gas firing was necessary to reach a profitable case. Despite the attractiveness of LAES to accelerate the penetration of renewable energy, O'Callaghan et al. [36] highlighted that there is still a gap to bridge in terms of optimal design and dynamic operation of LAES, as well as economic benchmarking of alternatives for deployment at scale.

As an alternative to LAES for balancing supply and demand electricity generation, battery energy storage systems (BESS) are conceived as a dispatchable fast response power source which can release the stored power in a short period of time for a storage duration of up to 4 h [37]. Longer storage periods currently prove uneconomical due to the high cost of battery storage capacity requiring frequent cycling for economic viability. Furthermore, power ratings for batteries above tens of MW generation are still challenging to achieve [38]. On the other hand, a relevant technological competitor to energy storage systems are flexible thermal power plants operating at low capacity factors to complement variable renewable energy (VRE), using natural gas or decarbonized fuels as primary energy input [39]. Mid-scale natural gas combined cycles (NGCC) offer and off-the-shelf technology with power

ratings in the order of hundreds of MW, and with hot start-up times within one hour [40]. These power plants are not very capital intensive compared to the energy storage options because they exploit the inherently stored energy in the fuel, but they present a significant operating cost (fuel) and emit CO₂, in case a carbonaceous fuel is employed. The profitability of the thermal plant will be tightly correlated to the number of operating hours in a given electricity system, which will depend on market electricity prices as well as fuel costs and CO₂ taxes imposed.

The thermodynamic performance of LAES technology has been widely studied in the scientific literature [31,41–43]. However, there is an important knowledge gap which this study aims to address in terms of consistent comparisons between alternatives to balance variable renewable energy. The present work provides a thorough techno-economic benchmarking of electricity storage systems and thermal power plants for grid balancing. The storage technologies evaluated were batteries, standalone LAES technology and a hybrid thermal-LAES plant with natural gas added firing, while a mid-scale natural gas combined cycle was selected as baseline thermal plant in the assessment. For that purpose, an economic optimization of the hourly power generation of each plant for a whole year, given location-dependant electricity price profiles, is conducted. Additionally, an in-depth thermodynamic analysis of the LAES concepts is also presented, determining the coefficients of structural bonds (CSB) in order to identify the design parameter optimization priorities which can enable to accelerate the deployment of these technologies.

The following section provides a description of the methodology employed to carry out the evaluation, describing the technological features of the plants, the exergy analysis approach employed to evaluate the LAES concepts as well as defining economic value functions defined for the optimization. Then, results are presented according to the metrics introduced in the preceding section. Finally, the main conclusions of the work are summarized and recommendations for future work are suggested.

2. Methodology

The models were developed in UniSim Design R492 [44] using Peng-Robinson equation of state for property estimation of main flow streams, while using ASME steam tables for steam cycle elements. Correlations for enthalpy, specific heat capacity and entropy of thermal oil Therminol VP-1 were derived from Engineering Equation Solver (EES) database [45]. The capital cost estimation of each plant was performed in the Standardized Economic Assessment (SEA) tool developed by the authors [46]. Finally, the optimization model was developed in GAMS [47] (General Algebraic Modelling System). Wholesale day-ahead spot

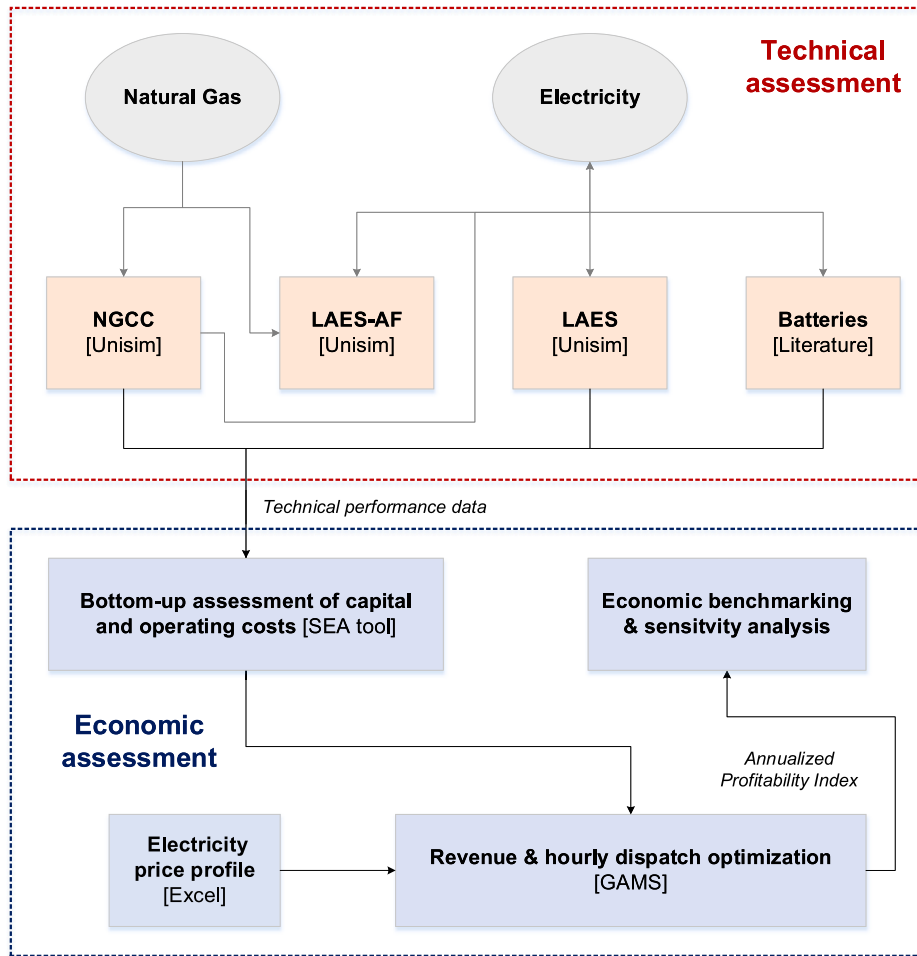


Fig. 2. Methodology and modelling tools employed in this study.

electricity prices for every hour of the year 2023 in different European markets (Norway, Germany and Spain) were taken from Ember Climate [48] as input to the model, covering a range of data of one year at every hour in the optimization to reach representative results. Fig. 2 depicts the methodology and tools employed in this work.

2.1. Plant description

The following section provides a technical overview of the plants evaluated. Two reference, currently available technologies: batteries (BAT) and a mid-scale power generation plant fuelled by natural gas (NGCC) are first presented and then the liquid air energy storage without (LAES) and with added firing (LAES-AF) are described.

2.1.1. Benchmarks

A mid-scale natural gas combined cycle (NGCC) power plant is modelled based on General Electric (GE) 9E.04 gas turbine, featuring a

bottoming cycle with two pressure levels to attain a net efficiency of 55.0 % and a power output of 215 MW [49]. The cycle is intended for power back-up applications when market conditions are favourable, as a competing alternative comparable in scale to the LAES cycles investigated in this study. The NGCC plant is modelled based on the parameters and operating conditions provided by the manufacturer [49], while the model topology is schematically depicted in Fig. 3. Further details regarding the modelling mid-scale power cycle can be found in prior work [50].

Alternatively, electricity purchased at a low price can be stored in batteries and sold at a price premium. This benchmark technology requires no thermal input, and a net storage efficiency output/input electricity of 90 % was assumed, consistently to prior assessments [51]. Battery volume storage costs and power systems as well as the fixed operating maintenance costs assumed in the evaluation correspond to the cost projections to the year 2030 for this technology [52].

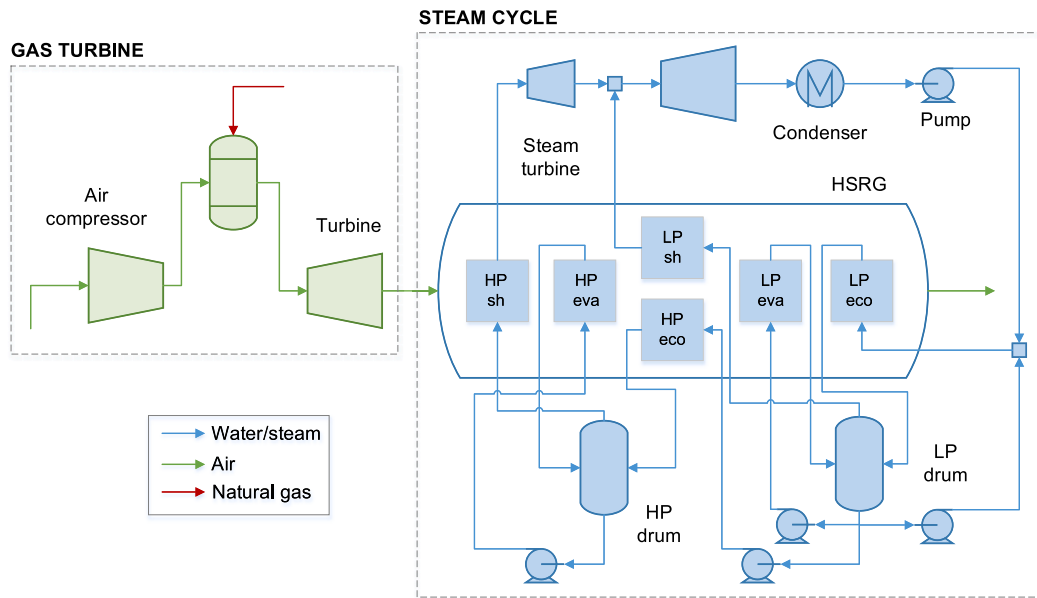


Fig. 3. NGCC plant technology benchmark.

2.1.2. LAES systems

The liquid air energy storage (LAES) plant evaluated in this work has been previously studied [31], although an improved thermodynamic performance has been attained in the present assessment by optimizing the operating conditions of several subsystems as well as assuming somewhat higher equipment performance for turbomachinery and heat exchangers, and is briefly depicted in Fig. 4. The charge section consists of a Linde liquefier where air is pressurized in a two adiabatic stage intercooled compressors to a maximum pressure of 250 bar [20]. Adding more compression stages would decrease too much the air temperature at the compressor discharge, leading to lower TITs in the discharge section. Heat from the compressor stage discharge is removed by means of a thermal fluid, which is then stored in the hot oil tanks. Therminol

VP1 has been selected for this purpose, as this synthetic oil can reach temperatures up to 400 °C and it is widely employed for thermal energy storage (TES) applications, such as a thermo-solar plants [53]. After transferring heat to the TES fluid, the air stream is finally cooled down to close to ambient temperature by cooling water. Subsequently, the high-pressure air is routed to the cold box, where the temperature is reduced to approximately −180 °C by means of sensible heat exchange with two liquid refrigerants available at low temperatures from the cold TES tanks: methanol (MeOH) at −65 °C and propane at −180 °C, which heat up in the process. It is noteworthy to mention that high pressure, significantly above the critical pressure of the air components, is desirable because the specific heat capacity is relatively constant across the operating temperature range, thereby achieving a close temperature

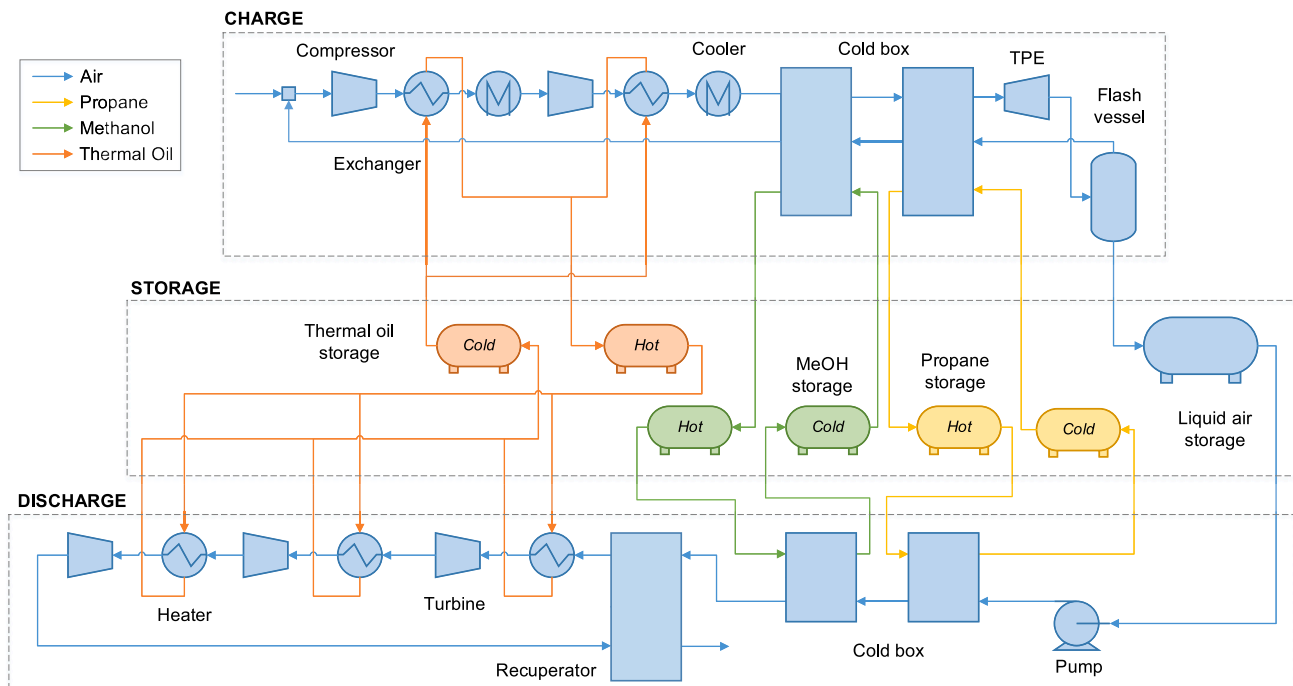


Fig. 4. LAES plant.

Table 1

Design parameters of LAES plant.

Design parameter	Units	Min.	Base	Max.
<i>Common parameters</i>				
Charge cold box MITA	°C	3	2	1
Discharge cold box MITA	°C	3	2	1
Polytropic efficiency of compressor stages	%	87	89	91
Polytropic efficiency of TPE	%	75	80	85
Intercoolers MITA	°C	15	10	5
Isentropic efficiency of cryogenic pump	%	75	80	85
Polytropic efficiency of turbines stages	%	87	89	91
Air recuperator MITA	°C	30	20	10
<i>LAES standalone parameters</i>				
Charge hot exchangers MITA	°C	15	10	5
Discharge hot exchangers MITA	°C	15	10	5
<i>LAES-AF parameters</i>				
Firing temperature	°C	925	950	975

approach in the heat exchanger. The pressurized air at low temperature is then expanded to ambient pressure by means of a two phase expander (TPE), and flashed in a separation vessel. The use of a TPE allows to minimize the vaporized fraction of air, due to a close to isentropic expansion relative to a Joule-Thompson expansion in a valve (isenthalpic). Maximizing the liquid yield is beneficial because the vapour fraction is recycled to the air feed stream and must be recompressed, consequently reducing the specific work of air liquefaction. The liquid fraction in the flash vessel is stored in the liquid air storage tank. The discharge section of the LAES plant employs a cryogenic pump to increase the pressure of the liquid air. The final pressure is selected to achieve a minimum temperature approach in the cold box, where it cools down the methanol and propane refrigerants from the hot TES tanks (MeOH at ambient temperature of 15 °C and propane at −65 °C). Then, the air is preheated in a recuperator prior to a heat exchanger where it absorbs heat from the thermal oil, which is cooled down and stored in the cold oil tank. The high temperature and high pressure air stream is expanded in a turbine producing power. It is reheated and expanded again for a total of three stages and then routed to the recuperator to preheat the inlet stream, after which it is released to the atmosphere at ambient pressure and close to ambient temperature. A relative pressure drop of 1 % has been supposed in all heat exchangers (ref [31]) in both sides. The base case design parameter assumptions for the equipment of the LAES plant are in the range of those given by previous works [11,28,31,54], and are provided in Table 1, in the next section.

The hybrid thermal-LAES plant (LAES-AF) depicted in Fig. 5 also employs cold TES from the discharge section, which is integrated in the charge cycle. However, thermal oil and hot TES are avoided by implementing natural gas extra firing, thereby avoiding their contribution to the capital investment which the subsequent economic assessment revealed to be around of 66 % of the total storage costs of the standalone LAES plant. It is noted that, even though natural gas was considered in the present study, carbon-neutral fuels like biogas or hydrogen could also be used. When added firing is incorporated, hot TES is not critical to obtain a high thermodynamic efficiency as elevated turbine inlet temperatures can be achieved through combustion of fuel with stored air. Since the heat from compression is not recovered, the charge cycle of the LAES-AF plant is designed with a more efficient air compression train employing four intercooled stages. A scheme based on four compression stages has been chosen as an optimal between RTE and capital cost. On the other hand, the heating of air in the discharge section therefore carried out by means of natural gas to a temperature of 950 °C, introducing a variable operating cost in the form of fuel and CO₂ emissions. This value for the firing temperature was selected as a compromise between high thermal efficiency and power output (elevated temperatures are desirable) and the technological constraint of achievable uncooled turbine blade temperature [55]. Blade cooling was avoided to keep the

thermodynamic cycle as simple as possible, and since it poses an additional challenge in a scheme where air pressurization (compressor stages from which cooling flow is usually taken) and expansion are decoupled in time. The use of added firing of natural gas presents a higher environmental impact in the form of CO₂ emissions, but allows to produce significantly more power per kilogram of air stored relative to the standalone LAES plant; this implies a downsizing of the charge (and therefore a reduction of charge cycle capital costs) for a fixed power output of the discharge section.

If the electricity selling price is sufficiently high and the natural gas and CO₂ emissions taxes are low, it may be profitable to operate charge and discharge sections simultaneously. In this case, the corresponding fraction of air employed in the discharge section can be by-passed from the compressor at the appropriate pressure in the charge section of the plant without the need to liquefy it and performing the refrigerant cycles. This by-pass operating mode will result in a somewhat higher thermal efficiency than simultaneous charge and discharge as the losses associated to the cryogenic components of the charge and discharge systems are avoided. The design parameter assumptions for the equipment of the LAES-AF plant are provided in Table 1, in the next section, and are consistent to those of the standalone LAES plant.

2.2. Analysis metrics

Given that the systems investigated are not designed to operate full time, the conventional assessment criteria for stationary plants are not suitable for the current evaluation. Thus, two different analysis tools are employed: an exergy analysis of the LAES configurations, to identify effective technological improvement avenues for the design of these novel technologies, and an economic optimization study benchmarking them against batteries and a combined cycle thermal plant to identify the business potential of these technologies in different electricity markets, considering the optimal hourly dispatch profile of each technology throughout one full year.

2.2.1. Exergy evaluation

The exergy balance to an open system in Eq. 1 enables to determine the thermodynamic losses taking place in each of the plant components under the assumption that the processes are stationary. The determination of the exergy flow e_i in Eq. 2 is performed considering chemical e_{ch} and physical e_{ph} exergy of the streams. Variations of kinetic and potential energy in the systems analysed are considered negligible. The exergy study of the LAES configurations is attractive because it will enable to direct optimization efforts to improve the performance of the components which present the highest degree of irreversibility. The rational exergy efficiency in Eq. 3 is the ratio between the exergy output and exergy input to the plant, considering both charge (Ch.) and discharge (Dch.) sections consumption and generation. For the LAES standalone configuration, the exergy efficiency defined in Eq. 3 coincides with the RTE, while for the LAES-AF plant, exergy is introduced in the form of electrical power in the charge section and natural gas in the discharge section. The exergy balances were performed with an automated tool in Excel, SysBaC: System Balance Calculator, and the files corresponding to the plants models can be downloaded from [56].

$$dB = \int dQ \left(1 - \frac{T_0}{T} \right) - (dW - P_0 dV) - dI + \sum e_i dm_i \quad (1)$$

$$e_i = e_{ph,i} + e_{ch,i} \quad (2)$$

$$\xi = \frac{w_{Dch}}{w_{Ch} + \vartheta \cdot e_{NG}} = \frac{w_{Dch}}{e_{in}} = 1 - \frac{i_{tot}}{e_{in}} \quad (3)$$

Where w_{Dch} and w_{Ch} represent the net specific work per kg of liquefied air of the charge and discharge sections respectively, ϑ is the ratio of natural gas fuel to liquefied air for the LAES-AF plant, e_{in} is the total exergy consumption per kg of liquefied air and i_{tot} is the total specific

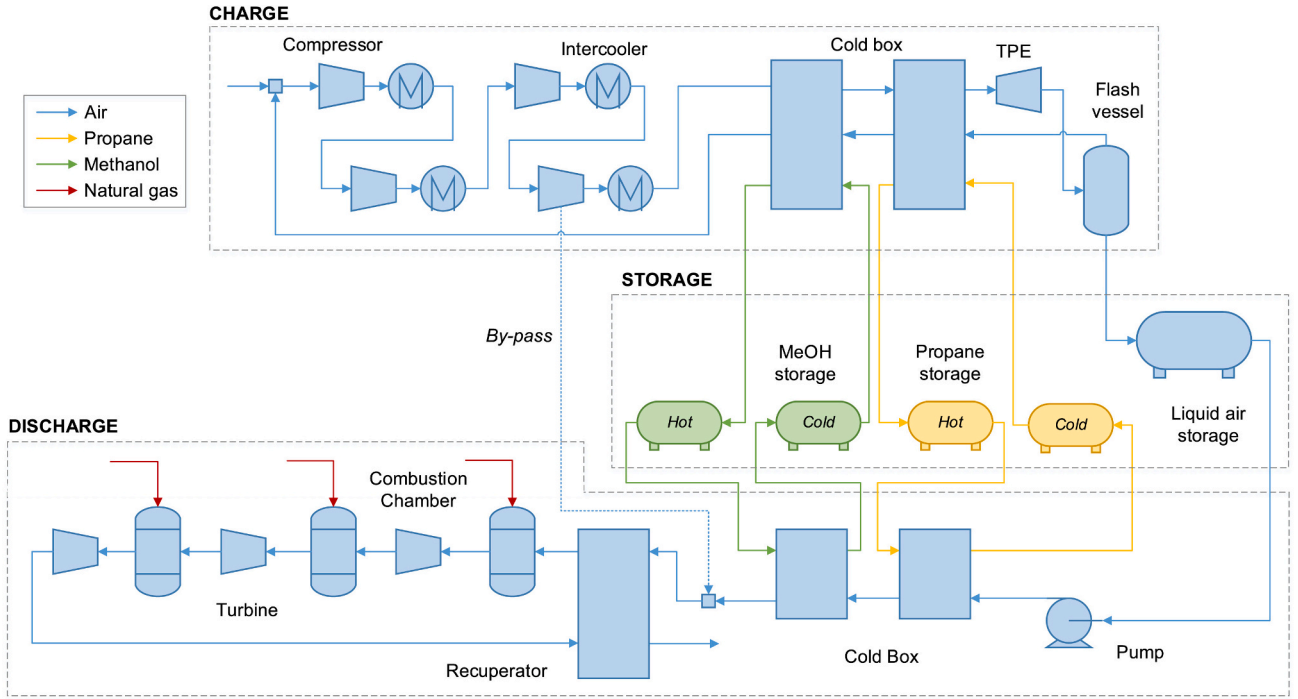


Fig. 5. LAES-AF plant.

exergy destruction. To support this exergy analysis, the coefficients of structural bonds (CSB) $\delta_{j,k}$ are also determined according to Eq. 4 for the LAES and LAES-AF plants. The CSBs reflect the specific exergy destruction change in the system $\frac{i_{tot}}{e_{in}}$ with respect to the change of specific exergy destruction in a certain subsystem j : $\frac{i_j}{e_{in}}$, when a design parameter of the subsystem x_k is modified. The design parameters for each subsystem are the technological performance assumptions made for the different equipment units of the plant. Table 1 summarizes the ranges taken for the design parameters of the different components of the plant to determine the CSBs for the LAES and LAES-AF cases, with a Minimum, Base and Maximum values. Thus, CSBs quantify the synergistic effect of improving a certain equipment parameter on the overall system performance: a value greater than one means that a favourable variation of that parameter has a positive impact on that particular unit and also on the rest of the subsystems generating additional benefits; if it is lower than one, that means that the benefits of the design parameter improvements in a particular subsystem are cancelled to some extent by a negative effect on some other ones. Finally, if the CSB is negative, the detrimental effects on the remaining subsystems outweigh the improvements achieved on a specific unit. This analysis allows to detect for which design parameters the greatest payoff is obtained, thus prioritizing which design parameters should be optimized.

$$\delta_{j,k} = \frac{\partial \left(\frac{i_{tot}}{e_{in}} \right) / \partial x_k}{\partial \left(\frac{i_j}{e_{in}} \right) / \partial x_k} = - \frac{d\xi}{d \left(\frac{i_j}{e_{in}} \right)} \quad (4)$$

The CSBs are calculated considering a constant exergy input to the plant when modifying a design parameter of a subsystem. This is highlighted because, for a given flow rate of air withdrawn from the storage tanks to the discharge section, a variation of a design parameter (e.g., the turbine efficiency or the combustor outlet temperature for the LAES-AF) will imply a change in total exergy input to the plant (i.e., fuel flow rate), and thus the exergy destruction terms of the whole system and subsystems will vary in that proportion.

Table 2

Capital cost estimate methodology, cost correlations for storage and operating cost & economic assessment assumptions.

Capital estimation methodology		
Bare Erected Cost (BEC)		SEA Tool Estimate
Engineering Procurement and Construction (EPC)		10 % BEC
Project Contingency (PT)		20 % (BEC + EPC)
Owners Costs (OC)		15 % (BEC + EPC + PT)
Total Overnight Costs (TOC)		BEC + EPC + PT + OC

Item	Value	Units
Bare erected cost of storage		
Cryogenic propane & LA tanks	320 [59]	\$-2018/m ³
Methanol cold tank	572 [58]	\$-2018/m ³
Methanol ambient temperature tank	0.1 [39]	\$-2018/kWh _{LHV}
Thermal oil tanks	423 [58]	\$-2018/m ³
Cost of TES fluids		
Methanol	519 [58]	\$-2018/ t
Propane	264 [58]	\$-2018/m ³
Therminol VP-1 (thermal oil)	2830 [53]	€-2011/t
Operating & maintenance costs		
Maintenance	2.5	%TOC
Insurance	1	%TOC
Natural gas price	7.5	€/GJ
CO ₂ tax	100	€/ton
Economic optimization assumptions		
Discount Rate	8	%
Construction period	2	years
Plant Lifetime	30	years

2.2.2. Economic optimization

The capital cost estimation of the plants was carried out by means of the Standardized Economic Assessment (SEA) tool developed by the authors [46]. Turton correlations [57] are used to estimate the bare erected cost of individual equipment and several capacity cost correlations from prior LAES assessments were employed to estimate the cost of several items such as thermal oil, storage tanks etc. [39,53,58,59]. The capital cost estimation methodology to calculate the total overnight

costs (TOC) is reflected in Table 2, as well as other relevant economic assumptions for subsequent optimization. The target cost basis assumed was 2021 Euros for a plant located in Western Europe; the SEA tool incorporates location, exchange rate, and yearly CEPCI factors to convert cost references from the source basis in Table 2 to the target basis, thus enabling a consistent assessment. A 10 % process contingency was assumed for the discharge section of the LAES-AF plant with extra firing chambers. Fixed operating and maintenance costs assumptions for batteries were taken from [60].

The unit cost, energy and emissions performance of each node of the LAES and LAES-AF configurations are then transferred to an input file of an optimization model developed in GAMS, which minimizes the annualized capital and operating costs of the plants via optimized capital deployment and hourly dispatch, considering an annual profile of electricity prices to determine the annual revenues from electricity sales and, in the case of energy storage technologies, the annual costs of electricity purchases. The model is developed under the simplifying assumptions of 1) perfect forecast of prices throughout the year: the price in all hours of the year is known to the model in order to most optimally allocate sales and purchases for a limited investment in storage capacity) and 2) the deployed technologies do not influence the electricity price profile since the capacity of the plants is small relative to the overall electricity system size. The first simplification implies an optimistic evaluation because the actual inaccuracy in the prediction of prices will require an oversizing of the storage elements. NGCC will not be affected, as the plant operates when it is profitable to do so based on operational costs. On the other hand, batteries will be most benefited from this assumption since they present the largest storage costs per unit of energy, which are approximately four times those of the standalone LAES (see Table 4). On the other hand, the large reduction in storage costs achieved with natural gas added firing for the LAES-AF plant through avoidance of thermal oil and enhanced power generation per kg of stored air in the discharge cycle (around 1/6 of the cost per MWh of delivered power relative to standalone LAES), will allow a reasonable benchmarking against NGCC without critically overestimating the prospects of the storage option.

Simulating optimized deployment following real-world electricity price profiles is seen as a more reliable benchmarking methodology than commonly calculated leveled cost of storage (LCOS) for two reasons: 1) it allows the inclusion of thermal power plants and added firing in the benchmarking and 2) it eliminates the large technology- and market-specific uncertainty of assuming capacity factors for the power and storage sections of the different energy storage technologies.

Optimization is done by minimizing the total system cost (C) depicted in Eq. 5. The four terms on the right-hand side represent the annualized fixed costs of the power generation (or consumption) capital of each technology (k) deployed, the annualized fixed costs of the energy storage capital of each technology (s) deployed, the variable costs of power generation (fuel and CO₂ costs), and the revenues received from electricity sales. Annualized fixed costs scale only with the installed capacity ($\hat{g}$ or $\hat{s}$) of each technology, whereas variable costs and electricity sales revenues scale with the generation (g) in each hour (j) of the year (electricity purchases are modelled as negative generation). Electricity sales revenues are calculated using a fixed hourly electricity price profile, p_j^{el} .

$$C = \sum_k c_k^{fix} \hat{g}_k + \sum_s c_s^{fix} \hat{s}_s + \sum_{j,k} c_k^{var} g_{j,k} - \sum_{j,k} p_j^{el} g_{j,k} \quad (5)$$

Variable operating costs c_k^{var} in Eq. 6 take into consideration specific fuel costs p_{NG} and CO₂ taxes p_{CO_2} , and depend on the hourly generation and the thermal efficacy η_t of each natural gas-consuming power generating technology, defined as the ratio between the power output and the heat input on a lower heating value basis. Annualized fixed costs c_k^{fix} are the summation of unit capital (cap) and fixed (fix) operating and maintenance costs (FOM). Annual FOM costs are estimated as a

percentage of the capital unit cost c_k , and represent the periodic maintenance costs and insurance of the plant, while the annualized capital costs c_k^{cap} are determined based on the unit capital cost according to Eq. 7:

$$c_k^{var} = \frac{p_{NG} + p_{CO_2} E_{CO_2}}{\eta_t} \quad (6)$$

$$c_k^{cap} = \frac{c_k \cdot i \cdot (1+i)^n}{(1+i)^n - 1} \quad (7)$$

Here, i is the weighted average cost of capital or discount rate, and n is the plant lifetime. The unit capital cost c_k is obtained from the SEA tool specific total overnight costs (TOC) estimation, assuming a certain construction period for each technology. In order to comprehensively compare all technologies, the annualized profitability index API is calculated according to Eq. 8, considering only capital unit costs for generating and storage technology nodes:

$$API = \frac{\sum_k c_k^{cap} \hat{g}_k + \sum_s c_s^{cap} \hat{s}_s - C}{\sum_k c_k^{cap} \hat{g}_k + \sum_s c_s^{cap} \hat{s}_s} \quad (8)$$

Thus, it can be clearly seen that if the API is greater than unity, the technology is profitable, for which the total system cost C has a negative value.

The model is constrained by specifying that no technology can generate or consume more electricity than its installed capacity (Eq. 9) or store more energy than its installed storage capacity (Eq. 10).

$$|g_{j,k}| \leq \hat{g}_k \quad (9)$$

$$v_{j,s} \leq \hat{s}_s \quad (10)$$

The level of stored energy (i.e., compressed air for LAES and chemical energy in batteries) is tracked on an hourly basis considering the storage level in the previous hour and the amount of charge/discharge in the current hour. Eq. 11 shows this relation for batteries, where the battery RTE is expressed by setting ε_{bat} to 1 for charging and 0.9 for discharging, thereby ensuring that only 90 % of the electricity used to charge the battery can be recovered during discharge. Eq. 12 shows a similar relation for LAES with two primary differences: 1) the factor $\varnothing$ indicates the loss of storage per time interval, which is calculated assuming 0.5 % per day of boil off gas for air storage and 2) there are two LAES technologies: LAES and LAES-AF with charging and discharging sections of a liquid air reservoir, represented by the index k_{LAES} . In addition, the LAES storage volume is quantified in terms of kg of stored air, so $\varepsilon_{k_{LAES}}$ represents an energy conversion factor in MJ of generated or consumed electricity per kg of stored air discharged from or charged to storage. These conversion factors are determined from the Unisim simulations of the LAES systems.

$$v_{j,bat} = v_{j-1,bat} + \frac{g_{j,bat}}{\varepsilon_{bat}} \quad (11)$$

$$v_{j,LAES} = v_{j-1,LAES} \cdot (1 - \varnothing) + \sum_{k_{LAES}} \frac{g_{j,k_{LAES}}}{\varepsilon_{k_{LAES}}} \quad (12)$$

The by-pass operating mode for the LAES-AF plant is modelled as a technology node assuming a thermal plant with negligible capital cost and a higher thermal efficiency given that it will only use already

Table 3
Electricity price mean and standard deviation values and location [48].

Location	Mean (€/MWh)	Standard deviation (€/MWh)
Spain	88.5	42.0
Germany	96.7	56.7
Norway	58.6	33.9

installed capital and avoid the losses associated to air liquefaction. However, the use of existing infrastructure imposes an additional constraint: The by-pass power generation from the expansion must be lower or equal to the discharge size of the LAES and the compression power of the bypass mode must be smaller or equal to that of the LAES charge. In the next section, the performance parameters for each of the technologies and corresponding nodes used as input for the optimization model are provided.

Finally, three location-specific electricity price profiles for the year 2023 are considered in the evaluation as shown in Table 3, with their respective mean and standard deviation values. For a given natural gas price, high mean values favour thermal power plants relative to power storage technologies because conventional power plants will earn greater revenues. On the other hand, large variability around the mean will make storage technologies more appealing, providing a sufficiently large price range for a profitable arbitrage of selling and purchasing electricity. The frequency of the variations will also be an influential aspect, influencing the duration over which energy needs to be stored and the achievable cycle frequency of the storage technology. In general, faster and more regular fluctuations in electricity prices, as may be expected from a system dominated by solar power, will be more favourable for energy storage than slower and more irregular fluctuations typically observed in a system dominated by wind power.

The SEA tool files with the capital cost estimations and the optimization models in GAMS with the input and output Excel files containing the electricity price profiles for each region can be downloaded from [56].

3. Results

Results are provided in three sections. First the outcomes of the exergy analysis for the LAES and LAES-AF configurations are shown. Then, the performance in terms of energy conversion and specific overnight costs from the stationary model and SEA tool files for each of the nodes of the technologies evaluated is presented, as a subsequent input to the economic optimization model. The results of the optimization are later presented and discussed, with appropriate sensitivity studies.

3.1. Exergy results

The exergy analysis was performed for the LAES and LAES-AF configurations because these novel plants will be potentially designed and deployed in the future, whereas the NGCC case is already a known commercial technology, with a small improvement margin. Fig. 6 shows the overall exergy balance for LAES and LAES-AF technologies normalized for a unit output of electricity for the LAES standalone configuration, employing the Base design parameter assumptions detailed in Table 1. For a consistent comparison, the LAES-AF plant is sized with equivalent liquefied air flow rate. It can be seen that the total exergy input to the LAES-AF case is more than twice that of the standalone LAES system. Approximately 2/3 of the exergy is delivered in the former case as natural gas fuel, whereas for the latter only electricity in the charge section is consumed. For the LAES standalone case, the exergy efficiency shown in Fig. 6 corresponds to the RTE of the plant, which is in line with the results obtained by Liu et al. [11] of 66.7 %, for the same topology and similar modelling assumptions.

The net exergy efficiency is lower for the case with added firing primarily due to the large exergy destruction occurring in the combustion of fuel, although the power output per kg of stored air increases significantly (approximately by a factor of 2.1) compared to the standalone LAES scheme. This implies that surplus power is delivered during electricity valley periods at peak prices. On the other hand, intercooled compression in several additional stages for the LAES-AF and heat rejection to ambient, as opposed to the thermal oil interface between charge and discharge for the LAES standalone plant, increases the losses associated to these components in the charge section of the natural gas-fired configuration.

Secondly, the exergy destruction distribution in % of the total is shown for the two configurations in Fig. 7 and Fig. 8 for the LAES and LAES-AF, respectively, attending to the equipment type and the different sections of the plants. The power - charge section for the standalone LAES plant comprises the compressor stages, intercoolers and oil exchangers, while the cryogenic - charge section corresponds to the cold box and TPE. On the other hand, the cryogenic - discharge section consists of the pump and cold box, whereas the power - discharge section includes the turbine stages, oil exchangers and recuperator. Analogously for the LAES-AF plant, the power - charge section contains the air compressor and intercoolers, while the power - discharge section

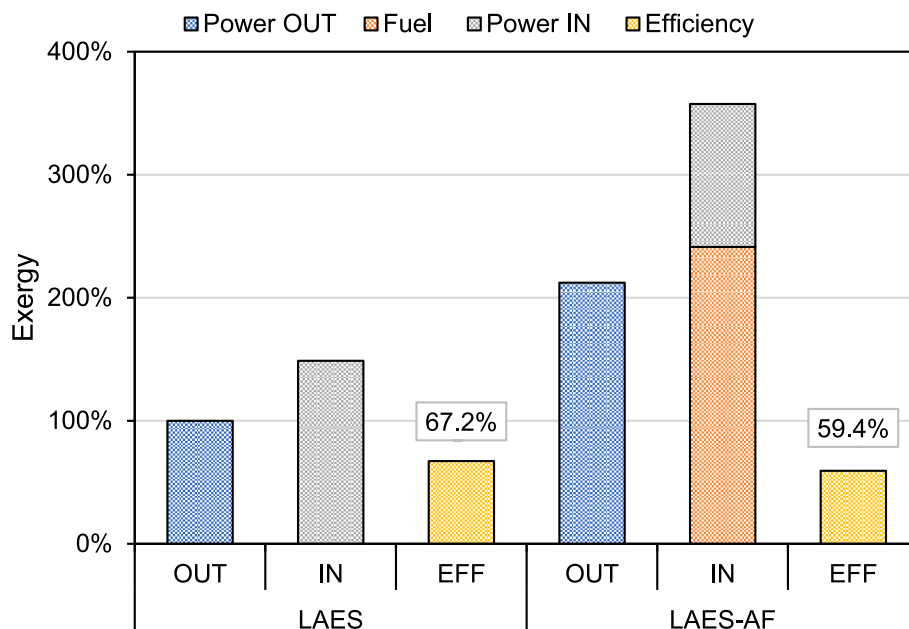


Fig. 6. Overall exergy balance for LAES and LAES-AF configurations.

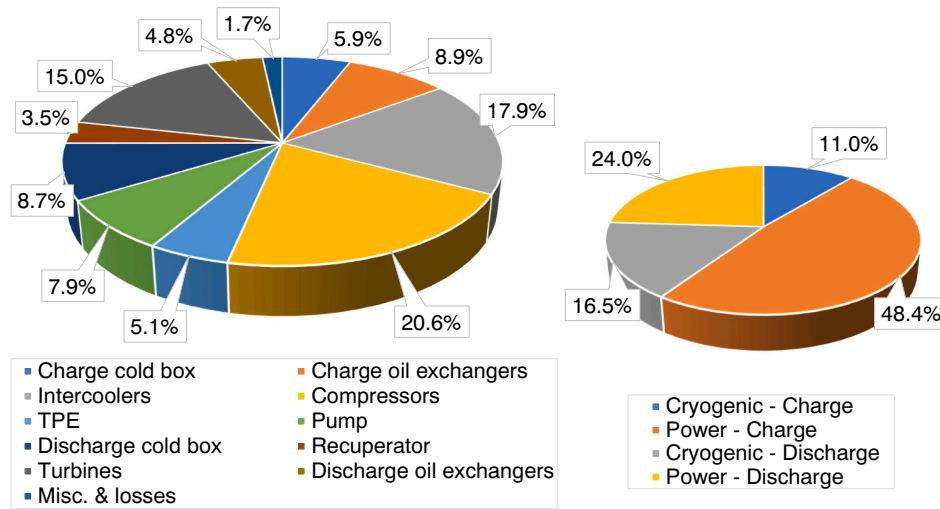


Fig. 7. Exergy destruction breakdown for the LAES case based on equipment type (left) and plant section (right).

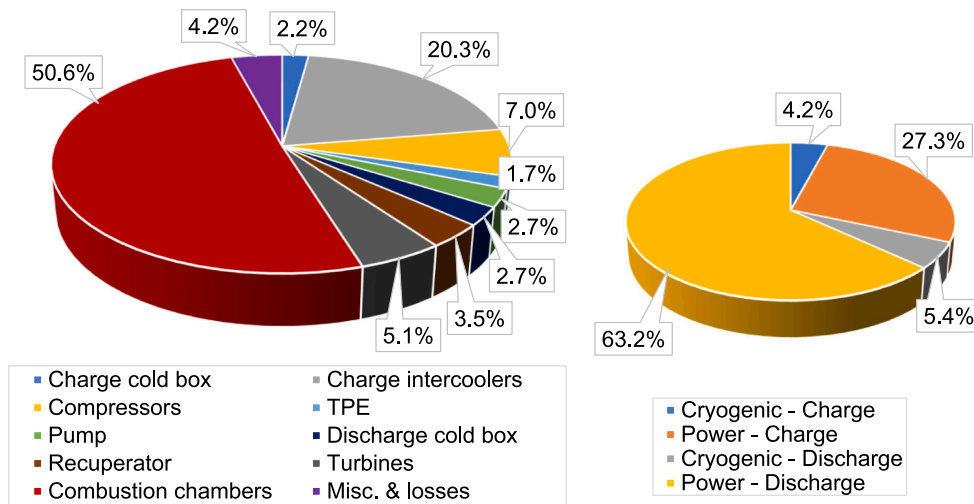


Fig. 8. Exergy destruction breakdown for the LAES-AF case based on equipment type (left) and plant section (right).

consists of the turbines, combustion chambers and recuperator. The cryogenic sections of charge and discharge remain with identical components. It should be noted that the total exergy destruction is approximately 3 times larger for the LAES-AF case. More than half of the exergy destroyed in the LAES-AF case corresponds to the chemical degradation of fuel in the combustion chamber, while for this case the contribution of intercooler losses is substantial because, as mentioned earlier, a larger amount of heat is rejected in the charge compressor intercoolers, since storage of heat is not employed. In the LAES plant, almost half of the overall losses take place in the power section of the charge (compressors and intercoolers), whereas for the LAES-AF configuration, due to the fuel exergy input, the discharge power generation section accounts for >60 % of the losses. Note that 100 % of the exergy in Fig. 7 and Fig. 8 represent different absolute values (difference between input and output bars in Fig. 6), for the LAES and LAES-AF plants.

The exergy flow diagrams illustrate the amount of exergy exchanged between the subsystems of each plant configuration and the associated exergy losses. This is shown in Fig. 9 and Fig. 10 for the LAES and LAES-

AF, respectively, where the numerical values in black indicate exergy flow in kJ per kg of liquefied air. Negative red values indicate the irreversibility losses of the process taking place in each component. Given the large chemical exergy of the species used for cold and heat storage (oil, propane and methanol), which remains invariant in the processes as there is no chemical transformation of these components, the exergy diagrams show only the physical exergy flow terms, which are proportional to the exergy flows of air in the main process. Several equipment units are lumped into a single block in the exergy flow figure for simplicity, but the reader is referred to Fig. 4 and Fig. 5 to identify all units. The cryogenic section of the LAES and LAES-AF plants remain very similar to each other, while the power sections are modified. Further iterations could explore avoiding the storage of cold in refrigerant sensible heat by designing a more efficient charge cycle operating at lower pressures (e.g. Collins or Kaptiza cycles [7]), if an effective means to utilize the cold energy of liquefied air were available. For example, extra duty could be obtained by means of an Organic Rankine Cycle (ORC) where the ambient is used as heat source [61]. Nevertheless, the

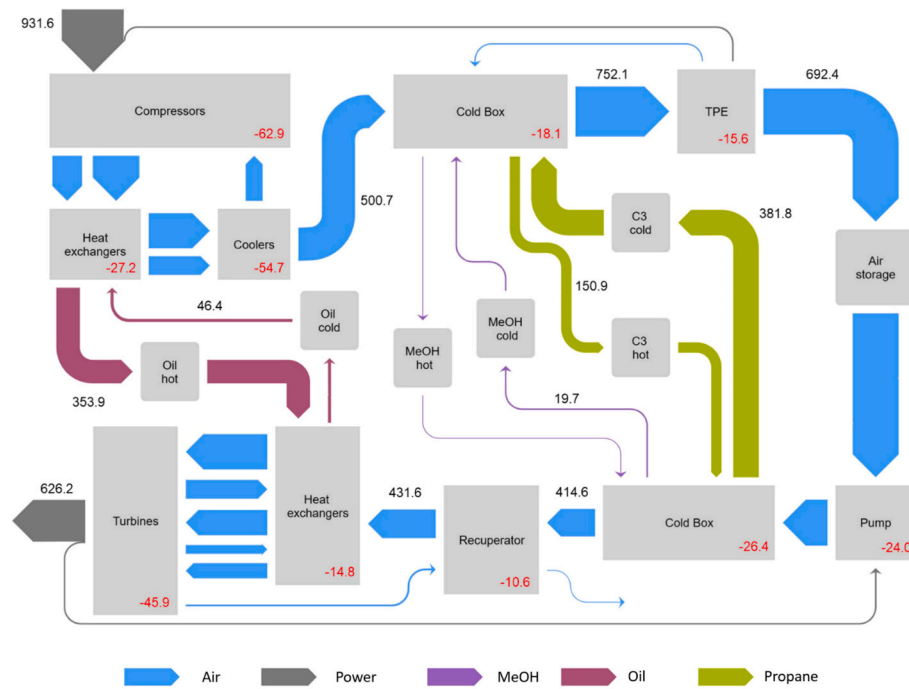


Fig. 9. Exergy flow diagram for the LAES plant. Values are in kJ per kg of liquefied air.

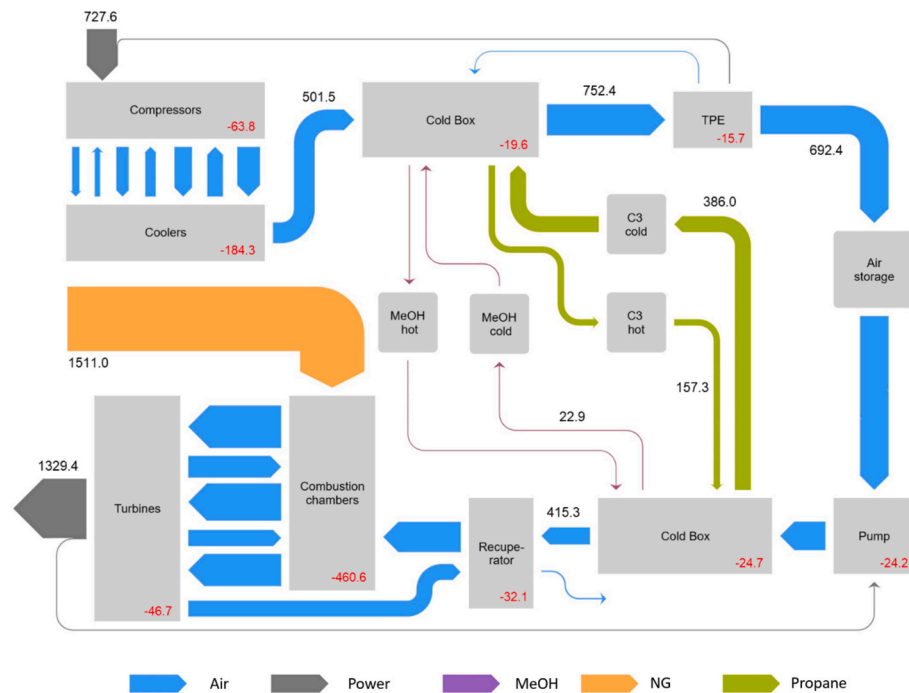


Fig. 10. Exergy flow diagram of the LAES-AF plant. Values are in kJ per kg of air.

efficiencies attained and capital costs potential savings from avoiding storage completely (except for air) should be traded off with the extra costs of more complex cryogenic cycles.

Finally, the CSB analysis results are shown in Fig. 11 and Fig. 12 for the LAES and LAES-AF plants respectively, showing the charge and discharge sections separately for greater clarity. The CSB values in the figures correspond to the slope of the trend lines in the figures corresponding to the points for design parameter values previously detailed in Table 1. The CSB value for each equipment item is provided in the figures in the colour indicated in the legend. The meaning of the CSB values

is the percentage of overall exergy destruction reduction when the exergy destruction contribution of the evaluated equipment is reduced by 1 %. Thus, greater values than one indicate the synergistic effect of improving the performance of one item on the whole system's performance.

For the LAES plant charge section, it can be seen that the most influential design parameter is the intercooler temperature approach, as the slope (CSB) value is the highest amongst the analysed variables: reduced intercooler approaches result in a decrease of compressor duty (where all exergy is introduced) because the suction temperature is

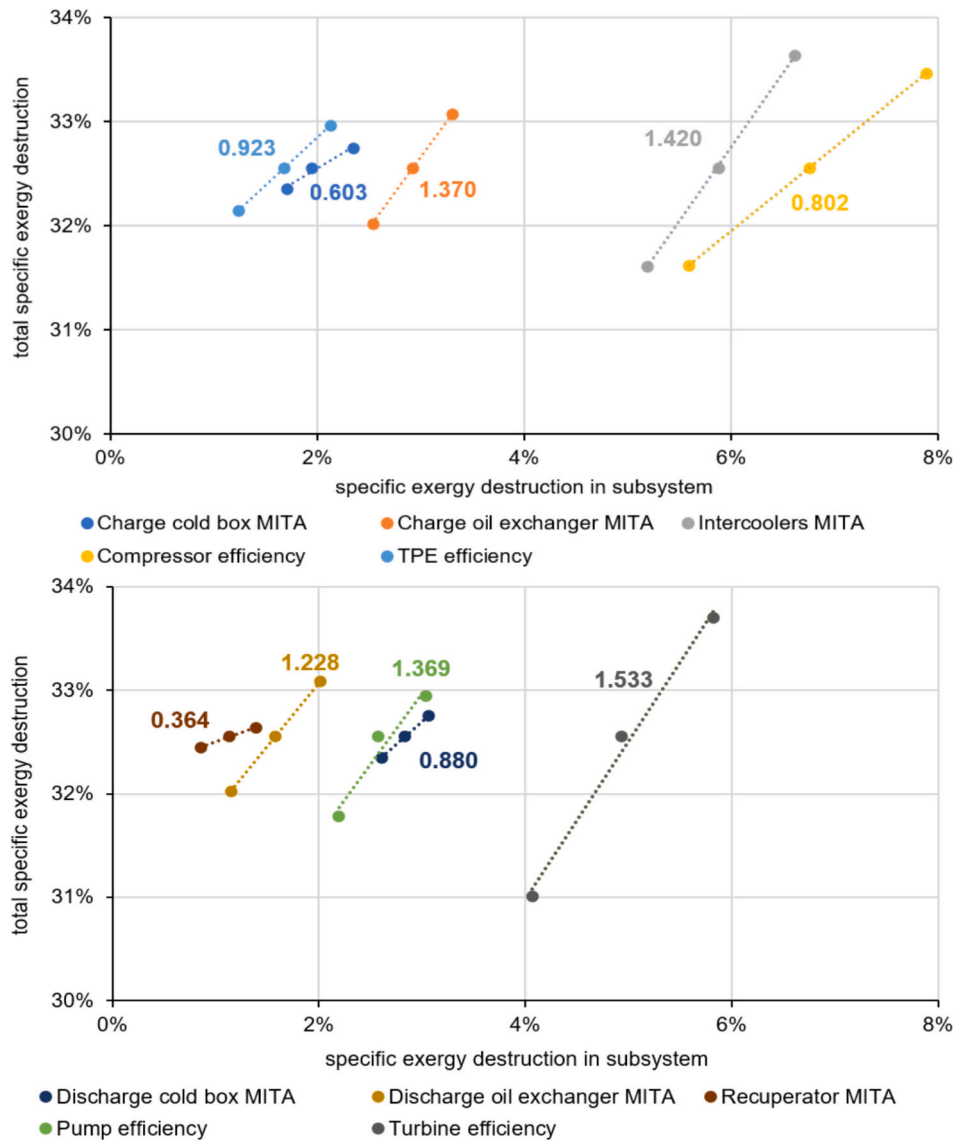


Fig. 11. CSB results of the LAES plant for the charge (above) and discharge (below) sections

lower. Furthermore, this does not affect the thermal oil hot outlet temperature (compressor discharge temperature is lower) as the temperature pinch in the hot oil exchangers does not occur in the hot end, and therefore the turbine inlet temperature (TIT) of the discharge remains unaffected. The charge hot exchangers (between hot air and thermal oil) temperature approach shows the second greatest influence. A closer temperature approach in the heat exchangers implies are larger heat recovery in the charge section, reducing the losses in the compressor intercoolers and consequently, increasing the heat injected in the discharge cycle and therefore the turbine power output. Interestingly, the approach temperature of the cryogenic cold box and compressor efficiencies are less influential on overall performance, while the CSB for TPE efficiency is greater, as it affects the liquified fraction and therefore the recycled air flow across the charge section. Regarding the discharge, turbine efficiency presents the largest improvement potential followed by the cryogenic pump efficiency and hot exchanger approaches. If the isentropic efficiency of the turbine is higher, the turbine outlet temperature is reduced while the power output is increased. The former implies that a larger amount of heat is then reinjected in the re-heating of air with hot oil, lowering the cold temperature storage of oil and further increasing the power output of the discharge while simultaneously, in the charge section, increasing the amount of heat that is

stored from the compressors. Pump efficiency shows a CSB higher than unity as a more efficient pump results in smaller temperature rise upon pressurization of liquid air, increasing the pressure ratio achievable to meet cold temperature approach. Analogously to the charge hot exchangers, discharge hot exchangers MITA is influential as it directly affects the TIT (and thus power generation).

The CSB calculation for the LAES-AF plant reveals that the changes in the design parameters for the charge section of the plant present a relatively smaller influence compared to the LAES case, given that the exergy input to the plant is in this case greater and this difference is introduced in the discharge section where fuel is added: the net changes in total exergy destruction (y-axis) when varying the design parameters from minimum to maximum values are smaller. Reducing the inter-cooler temperature approach has a more moderate effect, despite showing a substantially higher exergy loss, as there are no longer hot oil exchangers in this configuration (the primary energy for power generation is the fuel) and all the heat of compression is rejected to ambient. The CSB results for the discharge section show that the firing temperature is by far the most influential variable, which is unsurprising given that fuel conversion accounts for >50 % of the total exergy losses. Thus, efforts to increase the achievable TIT should be prioritized in this kind of scheme because it minimizes the exergy destruction taking place in the

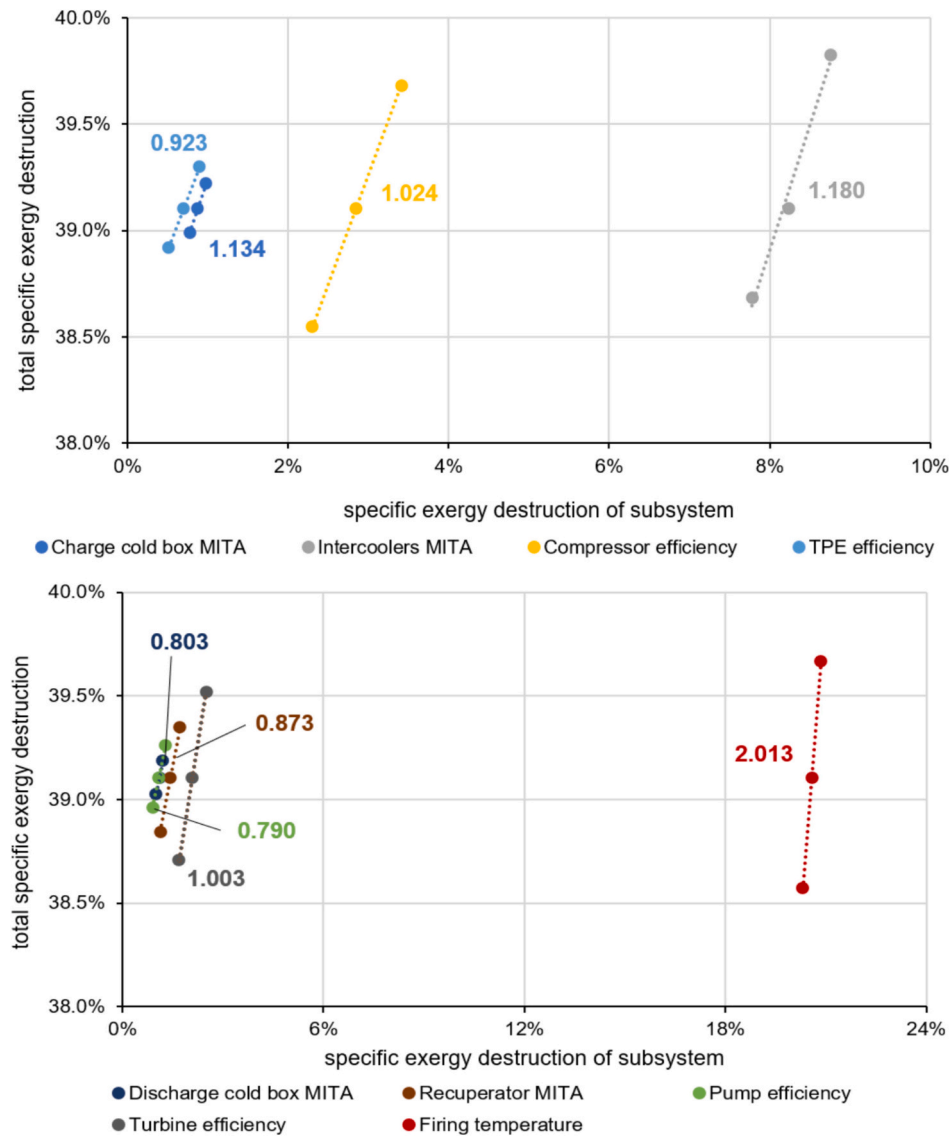


Fig. 12. CSB results of the LAES-AF plant for the charge (above) and discharge (below) sections.

Table 4

Energy results and specific capital cost estimates for the technologies, as input to optimization model.

Technology	Node	Specific TOC		Efficiency		
		Value	Units	$\epsilon_{k,s}$	Units	η_t
LAES	Charge	573.0	€/kW	931.6	kJ/kg	–
	Discharge	454.2	€/kW	626.2	kJ/kg	–
	Storage	9.6	€/kg	–	–	–
LAES-AF	Charge	835	€/kW	727.6	kJ/kg	–
	Discharge	417	€/kW	1329.4	kJ/kg	92.6 %
	Storage	3.2	€/kg	–	–	–
	By-pass	–	€/kW	–	–	51.8 %
Batteries	Power	86	€/kW	–	–	–
	Volume	200	€/kWh	0.90	kJ/kJ	–
NGCC	–	1063	€/kW	–	–	55.0 %

combustion chambers. It should be noted that a higher TIT not only reduces the exergy destruction of the combustion chamber but also increases the net power output per kg of stored air of the plant. Using an ideal Carnot thermal machine analogy, increasing the firing temperature is equivalent to increasing the average temperature of heat absorption, thereby achieving a higher utilization of the fuel's exergy. Additionally

for this case, a comparatively higher recuperator CSB is observed because the exergy content of the turbine exhaust is higher in the natural gas fired plant, resulting from an increased turbine outlet temperature, and a larger preheating of air to the combustor chamber is required, relative to the oil heated case. Conversely, the turbine efficiency CSB is smaller because a higher turbine efficiency leads to a lower outlet temperature, requiring extra natural gas firing in the combustor chamber to achieve the same firing temperature, therefore the improvement of the turbomachinery performance leads to increasing the exergy destruction of the extra firing chambers due to the additional exergy input required, for all remaining design variables at a constant performance.

3.2. Technology performance results

The analysis of the stationary plant model and capital cost economic estimate results in the values provided in Table 4 for the technologies considered. These results are then employed as inputs to the optimization model to determine the profitability and hourly generation of each technology, given an electricity market price profile.

To calculate CO₂ emissions, the CO₂ intensity of the natural gas fuel of 57.0 kg of CO₂ per GJ of NG was assumed. The NGCC plant is sized

based on the GE brochure data (215 MW net power output) while the discharge capacity of the LAES and LAES-AF cases was set to 300 MW, from which the capital costs of the different sections was estimated. This capacity approximately corresponds to the scale of the mid-scale combined cycle plant employed for benchmarking. Values of specific capital in Table 4 reflect the total overnight cost per kW of charge or discharge power, respectively. The LAES-AF plant charge section shows an increase in cost relative to the corresponding LAES standalone case because of the increased number of intercooled compression stages. Also, for a fixed discharge capacity, the charge section of the LAES plant is larger (in terms of power rating) compared to that the LAES-AF case, for a given charge and discharge time, leading to a small benefit of economies of scale from the correlations employed to estimate capital cost. On the other hand, the specific costs of storage, which are expressed per kg of stored air, are significantly reduced for the LAES-AF plant as a result of avoiding heat storage with thermal oil in this scheme.

It is informative to compare the LAES storage costs to that of batteries. For the standalone LAES concept, dividing the storage cost in €/kg of liquid air capacity with the discharge efficiency in kJ/kg yields a cost of 55.2 €/kWh of discharged electricity storage capacity – almost 4× lower than that of batteries. However, the major economic hurdle for the LAES plant is that its charge and discharge sections are an order of magnitude more expensive than the power component of battery

storage. For the LAES-AF plant, storage becomes 3× cheaper, yielding energy storage costs about an order of magnitude cheaper than batteries. Thus, the LAES-AF plant can be economically equipped with much larger storage volumes than batteries, allowing for balancing of longer-term wind/solar variability.

Conversion factors $\varepsilon_{k,s}$ in Table 4 for the LAES cases reflect the electrical duty required or produced in the charge and discharge sections respectively per kg of air that flows through the technology node. The charge factor for the LAES-AF plant is smaller than that of the LAES standalone plant because of the larger number of intercooled compression stages, which translate into a lower specific duty for liquefaction. For the discharge, the conversion factor for the LAES-AF plant is approximately 2.1 times greater than that of the LAES plant, which mirrors the exergy output relationship described in Fig. 6. This large increase in power output per kg of air is due to the higher TIT facilitated by NG firing.

The thermal efficiency η_t is the ratio between the power produced by the generating node or technology relative to the fuel heat input in an LHV basis, which is translated into an operational cost when the plant node is functional. For the LAES-AF plant, η_t is substantially high (92.6 %) because pressurization of air is carried out in liquid state with a pump, instead of a compressor. The ratio of the discharge and charge electricity-air conversion factor $\varepsilon_{k,s}$ for the standalone LAES plant results

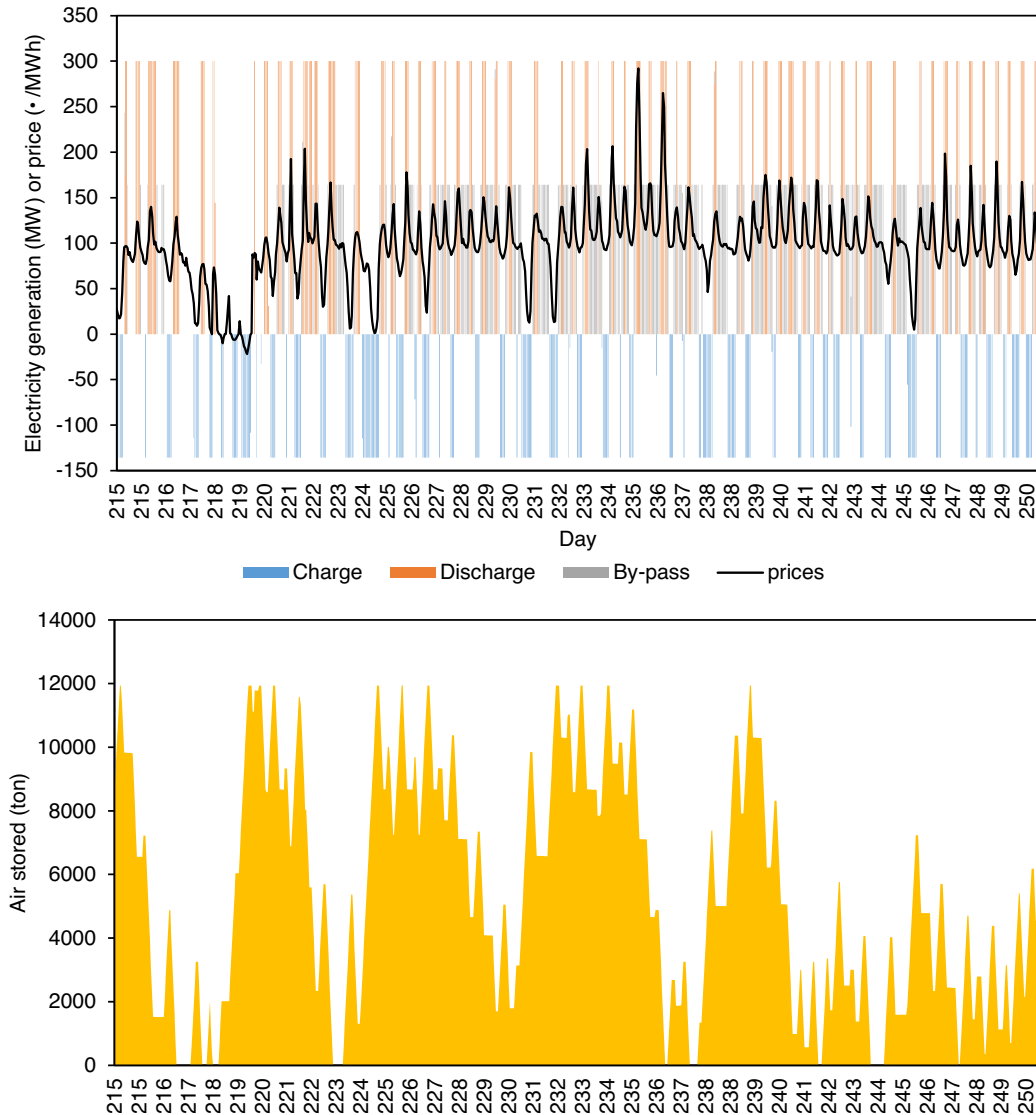


Fig. 13. Electricity price profile in Germany and generation of technology nodes (above), and liquid air storage level (below) for the LAES-AF from days 215 to 250.

in the RTE of 67.2 %, while for the LAES-AF configuration that factor is larger for the discharge relative to the charge because of the added firing of natural gas. When the LAES-AF plant operates in by-pass mode (no air storage), the thermal efficiency is 3.2 %-points lower than that of the NGCC benchmark.

Several model simplifications are further considered: the plants are assumed to ramp-up within a time interval at nominal efficiencies (1 h), which would in principle benefit the combined cycle design since the steam cycle presents a longer thermal inertia for cold start-ups [49]. LAES technology presents a faster response and smaller start-up times to reach nominal load [54,62]. Furthermore the economic model consists of a linear optimization and the effect of economies of scale for the deployed capacities of the technology nodes is not captured because capital costs are unit costs, i.e., for LAES with a specified discharge capacity, the trade-off between the deployed capacity of the charge and the storage time does not reflect the nonlinear effect of relative cost reduction as the deployed size of a technology node increases. Furthermore, correlations available in literature for storage costs (reflected in Table 2) are unit costs (proportional to capacity). Despite these simplifying underlying assumptions, the model is adequate to showcase the relative potential of the technologies evaluated for the capacity ranges imposed. Finally, although the optimization assumes a constant natural gas price for API calculation, it should be mentioned that there is a tight correlation between this operating cost of the thermal plants and

market electricity prices [63]. Nevertheless, this methodology allows to parametrically compare each of the technologies at different locations, in the understanding that the actual natural gas price will also vary throughout the year and will depend on the specific contract between the plant operator and fuel supplier.

3.3. Economic optimization

The economic model was run obtaining an optimized capital investment and hourly dispatch profile of each technology for a whole year. Fig. 13 illustrates the profile obtained for the LAES-AF technology deployed in Germany, for a natural gas price of 7.5 €/GJ and a CO₂ tax of 100 €/ton. The expected behaviour is observed where the discharge section runs during times of higher prices and the charge section during times of lower prices. However, since the air storage capacity is limited, relatively frequent alteration between charge and discharge is required. This constraint means that there are some charge hours (e.g. days 227–229) when the price is higher than some discharge hours (e.g., days 217–218). When the price is high and not highly volatile, the plant operates in by-pass mode where it essentially behaves as a conventional natural gas-fired power plant because the direct conversion of natural gas to electricity is profitable and the electricity price arbitrage opportunity is relatively small. The net generation in by-pass mode is only about half the specified discharge capacity of 300 MW because the charge section works concurrently to compress the air. For the periods in which the plant operates in by-pass mode, it can be observed from Fig. 13 (below) that the level of stored liquid air remains invariant.

The annualized profitability index (API) for all technologies is presented in Fig. 14 for electricity price profiles from Norway, Germany and Spain from the year 2023 at varying natural gas prices and constant CO₂ tax of 100 €/ton. For LAES and batteries, the API is unaffected by the fuel and CO₂ costs. These results were compiled by activating only one technology at a time in the optimization model. This methodology was validated by also running the model with the freedom to deploy any technology, which resulted in sharp transitions from one technology to another as the natural gas price was altered, confirming perfect competition between the four technologies investigated.

It can be seen that for a location such as Norway characterized by low mean electricity price and small fluctuations with respect to the average, LAES and battery storage technologies are not even deployed by the model, because these fluctuations are so small that investment in storage options are not justified leading to an API of 0. For the natural gas price ranges considered, the remaining technologies (NGCC and LAES-AF) are not profitable either ($API < 1$) in this location because the average electricity price is too low.

On the other hand, for Germany, the break-even natural gas price between LAES-AF and NGCC is approximately 8.3 €/GJ at an API which is 1.34. At lower natural gas prices, the by-pass operation for the LAES-AF becomes more prevalent (it is employed at higher capacity factors) and therefore the more thermally efficient and less capital intensive NGCC option becomes more appealing. The storage of liquid air by means of cheap electricity sustains the competitiveness of the LAES-AF at increasing natural gas prices relative to the NGCC. Nevertheless, in this location batteries are cost competitive achieving API of 1.25, and break-even with the LAES-AF case for a natural gas price of 9.1 €/GJ. However, the model considers the same plant lifetime for all technologies, which is an optimistic assumption for batteries, given that their lifespan is actually limited [21]. The LAES standalone plant is not profitable, indicating that capital cost reductions and RTE improvements are still necessary for this technology to become an economically viable option for the historical market prices considered. For perspective, a CO₂ tax of 333.4 €/ton is needed for the standalone LAES plant to break even with the LAES-AF plant in this location, whereas displacing the natural gas used in the LAES-AF plant with blue hydrogen from natural gas using conventional processes [64] would become viable at a CO₂ price below 200 €/ton [65]. Despite this, LAES can be expected to

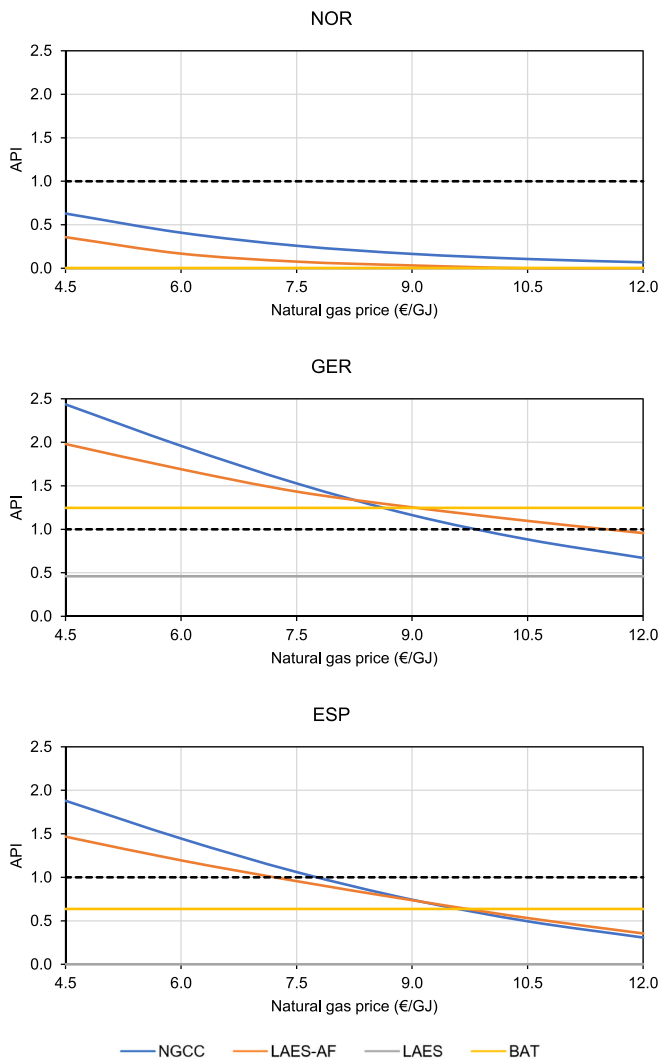


Fig. 14. API of the different technologies in different locations for varying natural gas price.

become more competitive compared to batteries in future electricity systems where price variability increases and electricity can frequently be bought at a cost close to zero (which mitigates the adverse effect of the lower RTE of LAES) and when price fluctuations occur over longer timescales (which better capitalizes on the lower electricity storage costs of LAES relative to batteries). Such conditions can be expected in future electricity markets with rising shares of variable renewables, especially those relying primarily on wind power.

When an analogous comparison is performed for the Spanish electricity market, it can be seen that the break-even price for the LAES-AF and the NGCC results in approximately 9.1 €/GJ. At this point, both technologies are no longer profitable $API < 1$, showcasing that the established and de-risked NGCC plant would be the preferred option to back up renewables at lower fuel costs. In this location, there price fluctuations are not sufficiently large for batteries to be competitive and LAES standalone is even less attractive from an economic perspective, as the model does not deploy any air storage. CO₂ prices will influence the profitability of the different options similarly to the price of natural gas: considering that each GJ of natural gas releases 57 kg of CO₂, a CO₂ price increase of 50 €/ton is equivalent to 2.85€/GJ higher natural gas costs. Batteries and standalone LAES options will remain unaffected whereas a higher CO₂ taxes will be most detrimental for the NGCC plant, as the possibility of storing liquid air can curtail CO₂ emissions (and natural gas consumption) and thereby effectively reduce operational costs for the LAES-AF configuration. Combined cycle and LAES-AF plants environmental footprint may be mitigated when carbon-neutral using biogas for added firing, obtaining equivalent results as shown previously in an open market where both fuels are interchangeable, as the price of biogas is set by the summation of the natural gas energy cost and the CO₂ tax adopted.

From an operation point of view, it interesting to analyse the average electricity purchase and selling prices (Fig. 15) and the optimal capacity factors (Fig. 16) for the technology nodes at different locations. These results are shown for Germany and Spain, at varying natural gas price, where it can be seen that the average purchase price (charge) for both markets is approximately the same, but Germany offers higher selling prices, making the LAES-AF and NGCC more attractive for equivalent natural gas costs. As fuel costs increase, the number of hours where a natural gas-fired power plant can operate profitably reduces, concentrating production in a smaller number of hours with the highest electricity prices. As a result, higher natural gas prices increase the average selling price of the NGCC and LAES-AF by-pass and discharge modes while reducing their capacity factors. The trend is weaker for the LAES-AF discharge than for the by-pass mode because the discharge mode uses only about half the fuel of the by-pass mode per unit power output. At low natural gas prices, the capacity factor of the discharge mode also

reduces slightly as the by-pass operating mode becomes increasingly profitable.

Finally, Fig. 17 shows the specific emissions reduction potential of the LAES-AF scheme relative to an NGCC for Germany as a result of storing liquid air, at a varying natural gas price. For low natural gas prices, the LAES-AF by-pass operating mode presents a higher capacity factor, leading to a smaller reduction in specific CO₂ emissions, whereas at high thermal energy costs a greater utilization of the cryogenic charge section occurs, reducing the emitted CO₂ per unit of electricity sold. For the range of natural gas prices evaluated (4.5 to 12.0 €/GJ), specific CO₂ emissions are reduced between 12.7 and 34.3 % in that location. The NGCC plant produces electricity at a constant efficiency using only thermal input, therefore the specific emissions are independent of primary energy costs.

Even though the direct emissions reduction offered by the LAES-AF technology is modest, it clearly presents a significantly improved avenue for using natural gas (or carbon-neutral alternatives like biogas or hydrogen) to integrate higher shares of variable renewables. Dispatchable power plants will retain an important role in most power systems because longer periods of limited wind and solar cannot be economically covered by batteries. As discussed below Table 4, storing electrical energy as liquid air in the LAES-AF plant is about an order of magnitude cheaper than battery storage. This enables the LAES-AF plant to shift considerably longer periods of excess wind/solar electricity to periods of shortage than would be economically feasible with batteries. Compared to conventional dispatchable power plants that can only address periods of wind/solar shortage, this is a considerable advantage that will facilitate substantially higher renewable shares per unit of fuel consumed. Specifically, the LAES-AF plant consumes up to 40 % less fuel than conventional NGCC plants that would otherwise be deployed during longer periods of limited wind/solar availability (calculated from the thermal efficiencies of NGCC and LAES-AF plants in Table 4). Integration of LAES-AF technology into full energy system models will be required to better quantify this benefit.

4. Conclusions

Liquid air energy storage (LAES) offers a potential solution for energy systems with rising shares of variable renewables, avoiding fundamental limitations related to geography for pumped hydro storage or high material intensity for batteries. However, LAES systems face challenges related to round-trip efficiency and capital cost, which were investigated in the present study. In addition, a LAES plant enhanced with added firing (AF) of natural gas in the discharge section is proposed to reduce capital costs by doubling the amount of power that can be generated from each unit of stored air while avoiding the need for heat

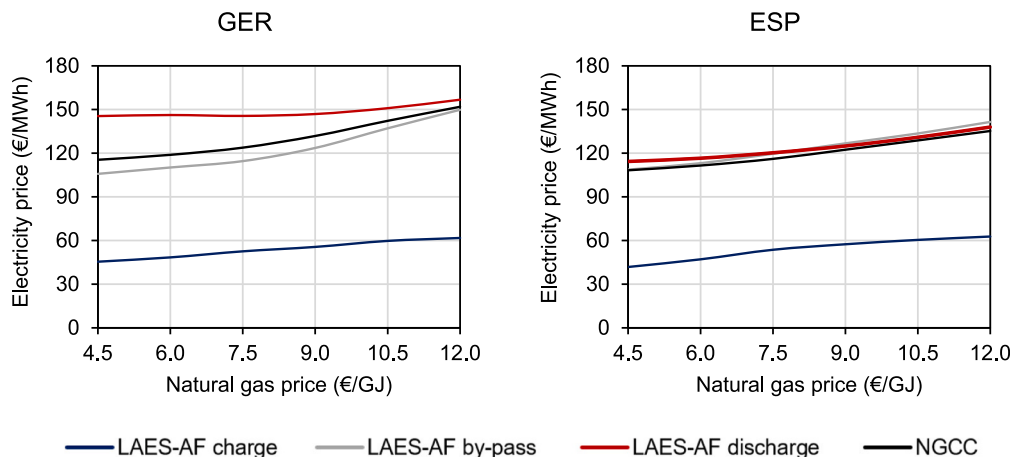


Fig. 15. Average electricity purchase and selling prices for the thermal plant nodes at varying natural gas price for different locations.

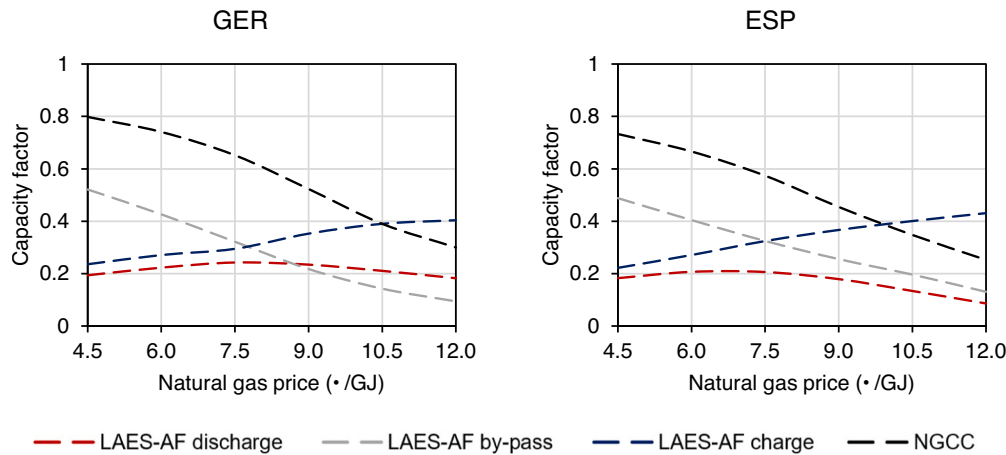


Fig. 16. Capacity factor for the thermal plant nodes at varying natural gas price for different locations.

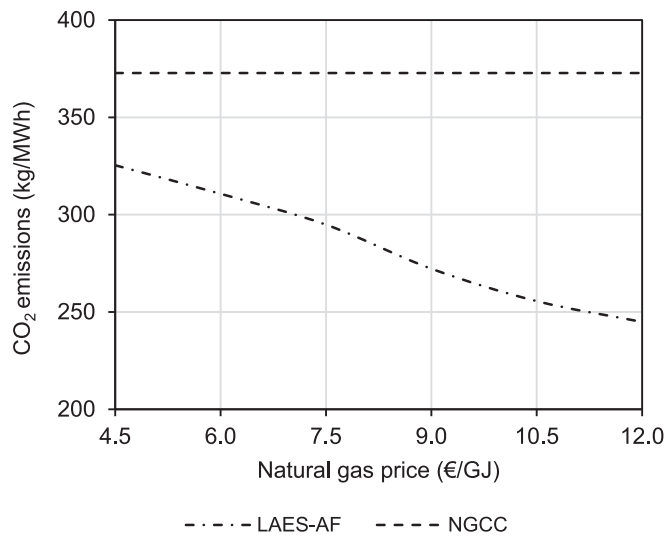


Fig. 17. Specific CO₂ emissions for the NGCC and LAES-AF plants at varying natural gas prices in Germany

storage in thermal oil, which represents around 66 % of the total storage costs of the standalone LAES plant, constituting the largest environmental drawback of that technology. In exchange, LAES-AF plant presents higher operational costs and a carbon footprint due to the combustion of a fossil fuel and derived CO₂ emissions taxes.

An exergy analysis revealed the most influential parameters for reducing exergy destruction in LAES plants. For a standalone LAES configuration, increasing turbine isentropic efficiency and achieving a closer temperature approach in the heat exchangers facilitating heat transfer from the compression section to the expansion section via thermal oil will bring the greatest benefits. In the LAES-AF configuration, the firing temperature in the expansion section dominates the exergy performance. Achieving higher firing temperatures will require improved blade materials because blade cooling will be challenging to implement effectively in a power plant where the compression and expansion sections are decoupled in time.

Economic optimization using electricity price profiles from 2023 for Germany and Spain revealed that standalone LAES is unlikely to be competitive with batteries and mid-scale natural gas combined cycle (NGCC) power plants. The LAES-AF plant showed better prospects, demonstrating a potential to outcompete NGCC and batteries within a window of natural gas prices. In Germany, the LAES-AF plant proved economically attractive and outperformed the alternatives for a natural

gas price range of 8.3–9.1 €/GJ. Below this range, NGCC becomes more competitive than LAES-AF, whereas batteries are the preferred option above this range.

Although LAES-AF is more environmentally friendly than NGCC, the requirement for natural gas combustion in the discharge section means that significant CO₂ emissions remain; specific CO₂ emissions reduced by only 24.0–27.2 % relative to the NGCC plant for the natural gas price window in which the LAES-AF plant proved the most economically attractive option. However, added firing has a large economic benefit, quantified by the high CO₂ price of 333.4 €/ton that would be required for the standalone LAES plant to break even with the LAES-AF plant. Despite the limited direct emissions reductions offered by the LAES-AF plant, it will allow substantially higher shares of wind and solar to be integrated per unit of fuel consumed. Thermal power plants will remain part of most power systems to secure supply during longer periods of wind/solar scarcity, and LAES-AF can reduce the associated fuel demand of these plants by up to 40 % relative to NGCC benchmarks, reducing emissions if natural gas is used or costs when more expensive carbon-neutral fuels like biogas or hydrogen are used.

In conclusion, LAES shows potential for deployment in future energy systems in a hybrid configuration with added natural gas firing in the discharge section. As more renewables are deployed, the business case for energy storage technologies such as LAES will improve relative to the 2023 electricity price profiles employed in the present study. Furthermore, increased electricity price volatility may advance the business case for LAES (without added firing) relative to batteries because lower or even negative buying prices will mitigate the negative effect of the relatively low RTE of LAES. Thus, further development of LAES cycles, particularly regarding the most effective improvement handles identified in the exergy analysis, can be recommended. In addition, full system modelling of future energy systems with high wind and solar shares will offer a more complete illustration of the techno-economic potential of LAES with and without added firing.

CRediT authorship contribution statement

Carlos Arnaiz del Pozo: Writing – original draft, Visualization, Methodology, Investigation, Formal analysis, Conceptualization. **Ángel Jiménez Álvaro:** Supervision, Project administration, Methodology, Investigation, Formal analysis, Conceptualization. **Schalk Cloete:** Writing – original draft, Validation, Methodology, Formal analysis, Conceptualization.

Declaration of competing interest

The authors declare that they have no known competing financial

interests or personal relationships that could have appeared to influence the work reported in this paper.

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Data availability

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