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Levelised Cost of Storage (LCOS) analysis of Liquid Air Energy Storage system integrated with Organic Rankine Cycle

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Abstract

Liquid Air Energy Storage (LAES) is a unique decoupled grid-scale energy storage system that stores energy through air liquefaction process. In order to further increase the utilization ratio of the available waste heat discharged by the air compression and not effectively recovered during the discharge phase, the authors have previously investigated the thermodynamic feasibility of different integrated LAES systems and promising results have been shown for the LAES coupled with Organic Rankine Cycle (integrated system LAORC). In order to assess the economic feasibility of the integrated system, this paper presents a techno-economic comparative analysis of the stand-alone LAES and the integrated system LAORC. The LAES systems have been designed by means of the quasi non-dimensional maps developed by the authors and the Levelised Cost of Storage (LCOS) has been employed to evaluate the economic viability of the investment by also comparing the LAES with Li-ion batteries. The results show that the stand-alone LAES system is generally cost-competitive with Li-ion batteries and even more in LAORC integrated system with the advantage of additional power output from the ORC. When LAES is operated in cogenerative configuration, the LAORC integrated system produces the most significant results decreasing the LCOS by 10 %.

Keywords:

Liquid Air Energy Storage; Levelized Cost of Storage; Economic Analysis; Waste Heat Recovery; Organic Rankine Cycle; Cogeneration.

1. Introduction

In order to face the environmental challenge posed by the global warming threat due to greenhouse gas emission, the development and deployment of Renewable Energy Sources (RESs) has increased significantly: due to the combined action of supporting policies and the rapid falling costs, in 2017 wind power and solar photovoltaic accounted for 1100 TWh_e and 435 TWh_e of electricity generation; this represents a dramatic increase compared to the 1 TWh and 31 TWh recorded in 2000 for photovoltaic and wind power, respectively [1]. The increase in installed capacity of renewables is expected to be constant in the future with a 2040 scenario presenting a share of renewables equivalent to the two-thirds of the power mix [1].

Nomenclature			
$\dot{m}$	Mass flow rate [kg/s]	SC	Specific Consumption [kWh _e /kg]
N	Storage total lifetime	SH	SuperHeater
n_c	Compression stages [-]	SP	Specific Power output [kWh _e /kg]
n_{cycles}	Number of cycles per year [cycle/year]	TIT	Turbine Inlet Temperature [°C]
n_e	Expansion stages [-]	WH	Waste Heat
$\dot{Q}$	Thermal power [MW _{th}]	<i>Subscripts</i>	
P	Electrical power [MW _e]	amb	ambient
p	Pressure [bar]	ave	average
T	Temperature [°C]	c	compression
ΔT	Pinch point temperature difference [°C]	CB	Cold Box
<i>Acronyms</i>		ch	charge
CAPEX	Capital Cost [€]	COGE	Cogenerative configuration
CE	Specific CAPEX energy based [€/kWh _e]	CP	Cryogenic Pump
CP	Specific CAPEX power based [€/kW _e]	CT	CryoTurbine
EC	Annual electricity charging cost [€/year]	d	discharge
ET	Electricity tariff [€/kWh _e]	E	Energy based
HGCS	High Grade Cold Recycle	e	electric
HGWS	High Grade Warm Recycle	ELE	Full electric Configuration
IC	Insurance cost	ex	expansion
LAES	Liquid Air Energy Storage	iso	isentropic
LAORC	Liquid Air - Organic Rankine Cycle	LA	Liquid Air
LCOS	Levelised Cost Of Energy [€/kWh _e]	P	Power Based
MAC	Main Air compressor	PT	Power Turbine
OPEX	Operation & Maintenance costs	RF	Recirculation Fraction
ORC	Organic Rankine Cycle	s	storage
RAC	Recycle Air compressor	tot	total
RT	Round Trip	u	utilization

As a consequence, the radical transformation of the electricity generation mix might trigger several challenges in electricity grid, among which for instance the unbalance between power supply and demand, due to the intermittent and unpredictable nature of the RESs. In such a context, Energy Storage Systems (ESSs), either electrical or thermal [2], are playing a key role allowing at the same time to boost renewables power generation and to decarbonize key sectors of energy market. In the potential scenario where future electricity systems are planning to use larger and larger shares of renewables, a significant scale-up of energy storage capacity will be necessary to match the supply with the electricity demand profiles. Indeed, the International Renewable Energy Agency [3] projects that the total stock of electricity storage capacity will need to grow from 4.67 TWh_e in 2017 to 11.89-15.72 TWh_e in 2030 if the share of renewable energy in the world's energy system is to be doubled by 2030. Available for different applications at different scales [4] with the predominance of batteries and Pumped Hydroelectricity Storage (PHS), electrical energy storage systems will play an important role in the future energy transition scenario. Among grid scale energy storage solutions, Liquid Air Energy Storage (LAES) has attracted significant interest in recent years due to several advantages: high volumetric energy density, no geographical constraints [5], long total lifetime of the system (30–

40 years) [5], integration with waste heat/cold recovery processes, low capital cost per installed capacity [6].

Recalling the battery analogy, three different phases can be identified in LAES operation: charge, storage and discharge. During the first phase intermittent renewable energy sources or off-peak electricity are used to compress and liquefy the air, stored at low pressure in insulated tanks. During the peak hours period, the LAES is discharged: after cryogenic pump compression, the liquid air at high pressure is evaporated to ambient temperature and expanded in power producing devices to generate electricity. The pre-commercial development and application of LAES has been demonstrated by Highview Power through a 350 kW_e/2.5 MWh_e pilot plant [7], currently installed at the University of Birmingham (UK), and through the world's first grid-scale demonstrator plant 5 MW_e/15 MWh_e [8] located at Pilsworth landfill site in Bury (UK), near Manchester. The grid-scale plant efficiently converts waste heat into power by using the waste heat discharged by the on-site landfill gas engine thus enabling to achieve a round trip efficiency between 50 - 60%.

So far, the research interest toward LAES has been growing year by year with a significant research production mainly focused on techno-economic analysis and system optimization [9–13] and LAES hybridization with a possible waste heat/cold recovery integration from external/internal sources [14–18].

Belonging to the first macro research area, a thermodynamic study of a LAES was proposed by Guizzi et. al [9]. The system composed by a Linde cycle and a direct expansion process for the liquefaction and discharge phases, respectively, obtained a round trip efficiency as high as 55 % mainly due to the implementation of both cold and heat thermal storage. A first analysis and result of the experimental test on the LAES pilot plant has been carried out by Morgan et al. [7]. Due to the small size of the plant and the low amount of the cold thermal energy recycled by liquid air regasification, a low round trip efficiency (8%) was achieved by the plant operation. A thermodynamic analysis of a LAES system comprising a detailed numerical model of the warm thermal energy storage has been proposed by Peng et al. [11]. Achieving a round-trip efficiency in the range 50–62%, the system presented a lower storage volume and higher volumetric energy density compared to a A-CAES system. Bernagozzi et al. [12] carried out an in-depth study on the effect of different molten salts material for medium-grade heat recovery in LAES. Sixteen new molten salts mixtures were selected and experimentally investigated, showing that two new salt mixtures (CaLiNaK 4 and 11) lead to a 37% and 34 % increase in the performance indicator value, respectively. Tafone et al. [13] have developed quasi non-dimensional LAES performance maps as a user-friendly tool for LAES design highlighting the significant impact of the sub-thermal energy storage performance over the LAES round trip efficiency.

In order to significantly improve the LAES performance, different technical options have been proposed. Antonelli et al. [14] has carried out a technical comparative analysis of different hybrid LAES systems coupled with Organic Rankine Cycle (ORC) and cold Brayton cycle: attaining a round trip efficiency of 90 %, LAES integrated with cold Bryton cycle has been proposed as the most performing hybrid solution. Pimm et al. [15] techno-economically analyzed a hybrid LAES-CAES energy storage system. The proposed system is found to economically perform better than the respective stand-alone systems, CAES and LAES, under certain conditions (storage duration longer than 36 hours). Farres-Antunez et al.[16] have proposed a hybrid energy storage system combining LAES and Pumped Thermal Energy Storage system (PTES). The hybrid system is found to increase the round trip efficiency by 10 % compared to the respective stand-alone systems. She et al. [17] carried out a thermodynamic analysis of a hybrid LAES combined with LNG regasification in order to increase the power generation of the discharge process by means of a closed Brayton cycle. The cold energy discharged by the LNG regasification process is recovered by the intermediate loop of pressurized propane. The LAES-Brayton-LNG system allows to significantly improve up to 56.5 % the round trip efficiency of the stand-alone LAES. A possibility to further enhance the performance of the hybrid system was found in the possibility to implement a double-stage Brayton cycle increasing the round trip efficiency up to 72 %. Zhang et al. [18] have proposed a hybrid LAES system making use of the cold energy discharged by LNG regasification combined with an organic

Rankine cycle (ORC). Compared to the stand-alone configuration, the proposed system is found to increase the round trip efficiency and the energy density guaranteeing at the same time a simplification of the cold energy storage system.

Until now, the most effective option to significantly increase the efficiency of a stand-alone LAES, not relying on any external waste heat/ cold energy source, is represented by the waste heat recovery from the air compression during the charge phase. Indeed, as confirmed by the works carried out by Guizzi et al. [9] and Tafone et al. [19], the warm thermal energy storage coupled with the LAES is still not able to fully efficiently utilized the whole amount of waste heat discharged by the air compression process. Zhang et al. [20] proposed to couple the LAES with a Kalina cycle operating with a mixture of ammonia-water, as working fluid. Compared to the stand-alone system, the proposed system is able to increase the round trip efficiency from 52.1% to 57.18%. She et al. [21] and Tafone et al. [22] proposed an ORC as an efficient technical solution to integrate with the LAES system achieving improvements of the round trip efficiency up to 18% and 20%, respectively.

Despite these promising technical results, due to the additional capital and operational costs introduced by the new system, a comprehensive economic analysis requires to be carried out. Indeed, the economic characteristics of LAES is vital for its wider adoption, and these have been subject of earlier studies. Georgiou et al. [23] techno-economically compared PTES with LAES system. Although PTES is found to be more economical at higher electricity buying prices, the two technologies were found to be similar to each other with a slight predominance of LAES in term of power and energy capital cost. Xie et al. [24] has assessed the economic feasibility of a LAES system by means of a numerical method based on a genetic algorithm used to identify the optimal LAES size (50,100,150 and 200 MWe) and the optimal operational strategy through price arbitrage and/or short term operating service (STOR). The economic profitability of the system is highly dependent on the temperature level of the waste heat recovery and size plant. It has been found that, without using waste heat, LAES is not economically advantageous: a positive net present value (NPV) is achieved only for a waste heat of at least 150 °C for a LAES plant of 200 MWe. Indeed, the payback period achieves interesting values (5.6 years) with a waste heat temperature of 250 °C. Confirming these results, Lin et al. [25] have evaluated the economic feasibility of LAES based on price arbitrage operations in the UK real-time electricity market. Recently a new metric, Levelised Cost of Storage (LCOS), directly comparable to Levelised Cost of Energy (LCOE) [26] for generation technologies, has been introduced as a valid tool for cost comparison of electricity storage technologies [27]. The LCOS quantifies the discounted cost per unit of discharged electricity for a specific storage technology and application and it mathematically represents the internal average price at which the electricity can be sold for the investment's net present value to be zero [28]. The metric therefore accounts for all technical and economic parameters affecting the lifetime cost of discharging stored electricity. Julch [29] and Smallbone et al. [30] based on that metric their economic comparative analysis of different electricity storage technologies: PHS, CAES, PTES, various battery technologies and Power-to-Gas storage. Likewise, Schmidt [28] shows LCOS of energy storage technologies including PHS, CAES and battery energy storage systems. It can be seen that the economic evaluation has been predominantly based on the deployment of well-known technologies including batteries, CAES and Power-to-Gas Solution. In addition, a detailed costing exercise comparing LAES and batteries systems in these configurations, in particular based on LCOS methodology, is currently lacking.

Based on these considerations, the present paper aims to propose an economic analysis of the different LAES systems, proposed in [22], in full electric mode (in which the only output is the electricity released by the LAES) and in cogenerative mode (in which electricity and cold thermal energy are produced simultaneously). Aiming at evaluating the economic viability of the investment, this work has employed the novel LCOS analysis. The methodology will employ as inputs both technical data obtained by means of the quasi non-dimensional LAES performance maps and economic data obtained during the development and the installation of the LAES pilot plant. Finally, in order to compare LAES with a mature and well established energy storage technology without any

geological and geophysical constrain, a comparative analysis has been carried out between LAORC integrated system and Li-ion battery.

The methodology and the relative results are reported as follows: in Section 2, the different LAES systems are designed and their process flow diagrams described. Section 2.2 will present the LCOS methodology along with the formulation of the main LCOS components. In Section 3, the results obtained from the economic analysis of the different systems under investigation are presented and comparatively assessed; the conclusions are reported; in Section 4 the main conclusion will be drawn.

2. Material and methods

2.1. Stand-alone and integrated LAES system design

A 100 MW_e/400 MWh_e commercial size LAES plant, with air as working fluid and a power to energy-storage ratio close to that proposed in [31] for commercial-scale systems, has been taken as a reference for this study. The process flow diagrams and the technical assumptions of the full electric and cogenerative LAES plant configurations have been already proposed by the authors previously in [22] and will be therefore described here briefly. The process flow diagrams of the plants under investigation, including the three LAES phases, are shown in Fig. 1, Fig. 2 and Fig. 3.

Fig. 1. Stand-alone LAES charge phase.

The charge phase (Fig. 1) allows to turn the gaseous air at ambient pressure and temperature into liquid air by means of the Kapitza thermodynamic process which includes two stages intercooled compression; the liquid air is then stored in a low pressure cryogenic tank (LAir Storage). During the discharge phase (Fig. 2), the liquid air is pumped to high pressure and evaporated: the excess cold released during the evaporation process is stored in a cold thermal energy storage (HGCS- High Grade Cold Storage). The high pressure gaseous air is then re-heated in 4 stages at the end of which it is expanded in turbine producing electricity. The heat of compression stored in the High Grade Warm Storage (HGWS) is used to further increase the air temperature at the inlet of each superheater (SH). The heat transfer fluids employed in the HGWS and the HGCS are Therminol 66 and air, respectively. The cogenerative (cooling) subsection, where the cooling load is provided, is enclosed in the smaller dashed box.

Fig. 2. Stand-alone LAES discharge phase – Full electric and cogenerative configurations (dashed lines).

In full electric configuration, the Turbine Inlet Temperature (TIT) of the air is derived by the thermodynamic condition imposed at each superheater SH ($\Delta T_{SH} = T_{7H} - T_{3D} = 10^{\circ}\text{C}$). Conversely, in cogenerative configuration, since the cooling load is provided by the flow at the outlet of the Power Turbines (PT), the TIT is constrained by a defined Turbine Outlet Temperature (TOT = 5°C) required by the cogenerative section (dashed box in Fig. 2).

As already highlighted the heat discharged by the compression of air during the charge phase is not fully utilized during the air superheating process. In order to further enhance the efficiency of the discharge phase, the LAES has been coupled with an ORC (LAORC integrated system) that allows to produce an additional power partially recovering the exergy of the waste heat lost after the superheaters.

Fig. 3. LAORC integrated system.

A mass flow derivation of the thermal oil stored in the HGWS is used as the heat source in the ORC for the evaporation process of the organic fluid. The organic working fluid is then expanded in the ORC-turbine, condensed (K) and pumped to high pressure. Due to the available heat source temperature for the ORC (T_{WH} in Fig. 3), R245fa has been considered as the ORC working fluid [32].

2.1.1. Technical input data

The round trip efficiency of the LAES systems has been computed by means of quasi non-dimensional LAES performance maps developed by the authors. The method and the main technical inputs implemented to derive the LAES performance maps are described in detail in [13]. The numerical values of the main operative parameters of the LAES system, adopted for this work, are shown in Table 1. Once these latter ones are defined, the following key performance parameters can be computed by means of the performance maps:

- Specific electric power output, SP [kW_e/kg]:

$$SP = \frac{P_{net,d}}{\dot{m}_{LA}} = \frac{\sum_i^{n_e} P_{i,d} - P_{CP}}{\dot{m}_{LA}} \quad (1)$$

- Liquefaction specific consumption, SC [kWh_e/kg]:

$$SC = \frac{P_{net,ch}}{\dot{m}_{LA}} = \frac{\sum_i^{n_c} P_{i,ch} - P_{CT}}{\dot{m}_{LA}} \quad (2)$$

- Round trip efficiency, η_{RT} [%]:

$$\eta_{RT} = \frac{P_{net,d}}{P_{net,ch}} = \frac{\sum_i^{n_e} P_{i,d} - P_{CP}}{\sum_i^{n_c} P_{i,ch} - P_{CT}} \quad (3)$$

where $P_{net,ch}$ [kW_e] is the net electric power required during the LAES charge phase; n_c is the number of compression stages; P_{CT} [kW_e] is the electric power produced by the Cryo-Turbine; x_{RF} is the recirculation fraction, namely the ratio of the mass flow elaborated by the J-T valve (point 6C) and the mass flow entering the Cold Box (point 6C); η_{HGCS} and η_{HGWS} are the utilization factors of HGCS and HGWS, namely the share of waste cold and waste heat effectively utilized; $\dot{m}_{LA}$ [kg/h] is the liquid air mass flow after the phase separator, $P_{net,d}$ [kW_e] is the net electric power produced by the power turbines, n_e is the number of the expansion stages and P_{CP} [kW_e] is the electric power required by the cryogenic pump. It is worth stressing that pressure losses in the components other than the turbines are neglected.

Table 1. Technical input data for the LAES system under study.

Parameters	Value	Unit
$T_{air,in}$	25	°C
p_s	8	bar
p_{ch}	80	bar
p_d	160	bar
x_{RF}	0.46	-
ΔT_{CB}	3	°C
ΔT_{IC}	5	°C
ΔT_{AFC}	5	°C
ΔT_{SH}	10	°C
η_{HGCS}	91	%
$\eta_{HGWS,ELE}$	98	%
$\eta_{HGWS,COGE}$	50	%
$\eta_{iso,c}$	85	%
$\eta_{iso,CT}$	75	%
$\eta_{iso,CP}$	80	%

Once the TIT and the mass flow of liquid air required to achieve the nominal power of 100 MW_e are defined, based on the waste heat temperature T_{WH} and the available waste heat thermal power $\dot{Q}_{WH,ORC}$, an EES numerical model will consequently compute the ORC power output and the overall round trip efficiency for the LAORC integrated system.

2.2. Levelised Cost of Storage (LCOS) Methodology

In order to reflect in a simple metric all of the cost factors for energy storage technologies, a constant or levelized cost per kWh_e over the storage system lifetime is introduced. LCOS (€/kWh_e) can be mathematically described as the total lifetime cost of the investment in an electricity storage technology divided by its cumulative delivered electricity estimated at each n step (years) over the total storage lifetime N (years) discounted with the interest rate i (%):

$$LCOS = \frac{CAPEX + \sum_{n=1}^N \frac{OPEX}{(1+i)^n} + \sum_{n=1}^N \frac{EC}{(1+i)^n} + \sum_{n=1}^N \frac{IC}{(1+i)^n}}{\sum_{n=1}^N \frac{E_d}{(1+i)^n}} \quad (4)$$

In the current LCOS formula it has been assumed that the residual value for the system components at the end of LAES lifetime is neglected and the financial lifetime N of the plants is equal to the lifetime of the storage capacity. The key parameters for the economic analysis are defined for a LAES commercial plant as follows.

$CAPEX$ [€] is the capital cost of the investment computed as:

$$CAPEX = CP_{ch} * P_{net,ch} + CP_{PT} * P_{net,d} + CE_{LA\&HGCS} * C_{rate} + CE_{HGWS} * C_{WH} + CP_{ORC} * P_{ORC} \quad (5)$$

where CP_{ch} [€/kW_e] is the specific CAPEX power based per charging of power unit, CP_{PT} [€/kW_e] is the specific CAPEX power based per discharging of power unit, CE_{tanks} [€/kWh] is the specific CAPEX energy based for the liquid air storage tank and the HCGS, C_{rate} [kWh] is the rated capacity of the plant, CE_{HGWS} [€/kWh] is the specific CAPEX energy based for the HGWS, C_{WH} [kWh] is the thermal capacity of the HGWS and CP_{ORC} [€/kW_e] is the specific CAPEX per power unit of ORC (P_{ORC} [kW]).

$OPEX$ [€/year] accounts for the power ($OPEX_P$ [€/kW_e/year]) and energy specific ($OPEX_E$ [€/kWh_e/year]) operation and maintenance costs related to the nominal power capacity and annual charged electricity:

$$OPEX = OPEX_P * P_{net,d} + OPEX_E * E_d * n_{cycles} + OPEX_{ORC} \quad (6)$$

where E_d [kWh_e] is the electricity discharged in one operation cycle, n_{cycles} [cycle/year] is the number of cycle per year and $OPEX_{ORC}$ [€/year] is the operational cost for ORC estimated as a fraction of the total ORC capital cost.

EC [€/year] are the annual electricity charging costs, namely the cost of purchasing charging electricity at a certain electricity tariff ET [€/kWh_e]. Mathematically manipulating LCOS definition, EC can be alternatively expressed as a function of the LAES round trip efficiency and the electricity tariff:

$$\frac{\sum_{n=1}^N \frac{EC}{(1+i)^n}}{\sum_{n=1}^N \frac{E_d}{(1+i)^n}} = \frac{ET}{\eta_{RT}} \quad (7)$$

IC [€/year] is the insurance cost estimated as a fraction of the capital cost $CAPEX$.

The key input numerical data for LAES and ORC for LCOS calculation are summarised in Table 2 along with the assumed references.

Table 2. Summary of the input data for the LCOS calculation

Parameter	Value	Unit	Reference
Storage lifetime	30	year	[24]
Self discharge rate	1	%	[30]
CP_{ch}	480.2	€/kW _e	[33]
CP_{PT}	162.6	€/kW _e	[33]
$CE_{LA\&HGCS}$	27.8	€/kWh	[33]
CE_{HGWS}	15	€/kWh	[30]
CP_{ORC}	2200	€/kW _e	[34]
OPEX _P	11.2	€/kW _e /year	[30]
OPEX _E	0.00264	€/kW _e /year	[30]
OPEX _{ORC}	2.5	% of CP _{ORC}	[35]
i	8	%	[30]
IC	0.5	% of CAPEX	[29]

3. Results and discussion

Table 3 and Fig. 6-Fig. 10 present the energetic and economic comparative analysis results of the stand-alone LAES and LAORC integrated system modelled in this paper. A global sensitivity analysis has been carried out in order to evaluate the influence of the main parameters affecting LCOS analysis. Finally, the LCOS of both stand-alone and integrated LAES has been compared to Li-ion battery previously analyzed by Julch [29].

3.1. Energy analysis

Assuming the technical input data shown in Section 2, two different scenarios corresponding to two different LAES configurations have been provided and assessed. As a general observation, the LAES technical performances computed by means of the quasi non-dimensional maps implementation confirmed the outcomes presented by the authors in their previous work [22]. The main results of the technical analysis are summarised in Table 3.

The first scenario considers a LAES operating in full electric configuration (LAES_{ELE}), namely the main LAES output is represented by the electric power production to discharge to the electric grid. A liquefaction specific consumption of 0.243 kWh_e/kg_{LA}, a specific electric power output of 0.115 kWh_e/kg_{LA}, a TIT of 174 °C and a round trip efficiency of 47.4 % have been computed by means of the performance maps shown in Fig. 4.

Table 3. Performance parameters for LAES_{ELE} and LAES_{COGE} configurations.

Performance parameters	LAES _{ELE}		LAES _{COGE}		Unit
	LAES	LAORC	LAES	LAORC	
η_{RT}	47.4	52.6	38.4	47.5	%
SC	0.243	0.243	0.243	0.243	kWh _e /kg
TIT	174	174	97	97	°C
T_{WH}	-	183.6	-	183.6	°C
$\dot{Q}_{WH,ORC}$	-	83.4	-	146.8	MW _{th}
η_{ORC}	-	13.2	-	13.2	%

$P_{e,tot}$	100	110.1	100	119.4	MW _e
T_{CS}	10	10	10	10	°C
$\dot{Q}_{c,LAES}$	-	-	9.8	8	MW _c

In fact, once the charge pressure and the HGCS utilization factor are defined, the SC is computed. Assuming a thermal efficiency of 98 % for the HGWS, both the SP and the round trip efficiency are derived from Fig. 4.c and Fig. 4.d with a TIT of 174 °C. The second scenario refers to the potential of LAES operating in cogenerative configuration LAES_{COGE}, where both an electric power output and a cooling power are available for the electric grid and district cooling system, respectively. The cooling output is provided by the direct expansion of gaseous air; as a consequence, the turbine inlet temperature of gaseous air is constrained (97 °C) by a defined turbine outlet temperature (5°C) which is required as a cold source by the district cooling system. As shown in Fig. 5, the same procedure applied to full electric configuration could be followed for the cogenerative configuration in order to derive the main operative parameters.

Fig. 4. Full electric configuration: graphical method to derive the main KPIs using the performance maps.

Fig. 5. Cogenerative configuration: graphical method to derive the main KPIs using the performance maps.

3.2. Economic analysis

3.2.1. LCOS of different LAES systems

Fig. 6 shows the LCOS of the LAES and LAORC systems considered in this paper. The commercial size LAES (100 MW_e/ 400 MWh_e) is supposed to operate for 365 cycles per year. As already stated, two different LAES configurations (full electric and cogenerative) have been considered. The average electricity tariff of Singapore (0.15 €/kWh_e) [36] has been taken as reference for the whole economic analysis. Nevertheless, this value can be representative of any other case scenario and country.

The economic analysis confirms the technical outcomes discussed in the previous paragraph, namely the LAORC integrated system shows better economic performance compared to the stand-alone LAES: lower LCOS is achieved at 0.385 and 0.437 €/kWh_e for the electric and the cogenerative configurations, respectively. The inhomogeneous distribution of the share of the main cost components within the LCOS of each system provides an explanation for the economic performance of the LAORC integrated system. With an average share around 77 % the electricity charging cost is predominant compared to the other components: as a consequence, the round trip efficiency and the electricity tariff have a significant impact on the LCOS value. Due to this reason, the additional capital and operational cost introduced with the ORC is balanced by the increase in round trip efficiency that allows to decrease the share of the electricity charging cost. Although the LCOS of the LAES_{COGE} is higher than the LAES_{ELE} due to the lower round trip efficiency, the most significant results are achieved in cogenerative configuration where the LAORC integrated system is found to decrease the LCOS by 10%. The share of charging, discharging and storage units within the CAPEX is almost uniform among the different systems analyzed with the highest impact of the liquefaction plant capital cost over the discharge phase due to the relatively low round trip efficiency especially in cogenerative configurations. Another significant impact on the CAPEX share is represented by the storage units due to the presence of two thermal energy storages (HGCS and HGWS) that are thermally coupling the charge and discharge phase. It is worth noting that the share of CAPEX_{storages} is higher for full electric configuration compared to cogenerative configuration due to the higher η_{HGWS} (98 % vs 50 %). As a consequence, the HGWS of the LAES operating in cogenerative mode can be downscaled with a resulting lower CAPEX.

Fig. 6. Cost components of the LCOS for electric and cogenerative configurations at 365 cycles per year and an electricity price of 0.15 €/kWh_e

3.2.2. LCOS sensitivity analysis

Fig. 7 reports the results of the sensitivity analysis carried out in order to assess the influence of the electricity tariff and the number of cycles per year over the LCOS. The cogenerative system has been taken as a reference for the sensitivity analysis. Four different electricity tariffs have been considered, from the scenario when electricity for charging is free or entirely provided by a renewable energy source ($ET = 0 \text{ €/kWh}_e$) up to the reference scenario ($ET = 0.15 \text{ €/kWh}_e$). According to an approximately inverse relation, the LCOS decreases as the number of cycles per year, and therefore the total amount of energy discharged, increase. In fact, by increasing the amount of energy discharged per year, the LCOS decreases significantly due to the fact that the same CAPEX and OPEX costs are distributed over a larger amount of energy discharged. In addition, Fig. 7 provides a further explanation on how the round trip efficiency strongly affects the LCOS. Excluding the cost of electricity for charging the LAES, the LCOS curves of both systems show better performance of the stand-alone LAES especially at low number of cycles per year. As long as the number of cycles is below a certain threshold value for every electricity tariff scenario this trend is almost identical. Nevertheless, the higher is the electricity tariff, the lower will be the threshold value of the number of cycles per year beyond which the LCOS of the LAORC integrated system becomes lower than the one of the stand-alone LAES. In fact, the gap between the two curves becomes significant as the electricity tariff increases up to the reference value of 0.15 €/kWh_e with a LCOS decrease as high as 14 % at n higher than 700 cycles per year. Further manipulating the data obtained, the so called “turning points” curve shown in Fig. 8 has been created in order to immediately correlate the number of cycles that guarantee, at a fixed electricity tariff, the same LCOS between LAORC integrated system and stand-alone LAES.

Fig. 7. LCOS depending on the cycles per year at different electricity tariffs for LAES cogenerative configuration.

Fig. 8. Turning points curve between LAORC and LAES systems for cogenerative configuration.

Fig. 9 shows the global sensitivity analysis for the LCOS of the LAORC integrated system for full electric configuration. The analysis has been carried out by fixing a reference case scenario and varying the considered parameters (round trip efficiency, electricity tariff, number of cycles, specific CAPEX power based per charging of power unit, per discharging of power unit and per power unit of ORC, interest rate and total lifetime) by $\pm 30\%$. A linear proportional dependency can be seen between LCOS and the specific CAPEX figures, the electricity tariff and the interest rate while, as already shown in the previous sections, the round trip efficiency, the number of cycles and the total lifetime have an inverse and non-linear relation to the LCOS. Both the round trip efficiency and the electricity tariff have the most significant impact on LCOS due to the relatively high electricity tariff taken into account for the reference case. In fact, confirming the results of Fig. 9, the higher is the electricity tariff, the more significant will be the impact of the round trip efficiency over the LCOS. Other main impacting parameters are represented by the number of cycles and the discount rate of which variation by $\pm 30\%$ leads to a LCOS change up to 10% and 4%, respectively. Among the specific CAPEX figures, the cost of liquefaction plant has the strongest influence on LCOS with a change up to 3%.

Fig. 9. LCOS sensitivity analysis for LAORC full electric configuration. Reference case at 365 cycles per year and 0.15 €/kWh_e electricity tariff.

3.2.3. LAES vs Li-ion battery

The LCOS of the LAORC integrated system in full electric configuration has been compared with Li-ion battery technology. In particular, Fig. 10 and Fig. 11 report the results of the analysis carried out by Julch [29] that has computed the LCOS of five energy storage technologies applying the same methodology employed in this paper. In order to fairly compare the results of the two analysis, a LAORC in full electric configuration has been taken as a reference and the cost of electricity for charging has been considered equal to 0 €/kWh_e and 0.03 €/kWh_e for Fig. 10 and Fig. 11, respectively. Fig. 10 shows that LAORC integrated system generally achieves the lowest LCOS with 0.16 vs 0.34 €/kWh_e for Li-ion battery at 365 cycles per year. The share of the main cost components within the LCOS of each system for 365 cycles per year and an ET equal to 0.03 €/kWh_e is reported in Fig. 11. It clearly shows that LAORC has a high share of electricity cost component while Li-ion battery is dominated by the CAPEX, in which the storage unit has the highest cost share.

Fig. 10. LCOS depending on the cycles per year not including electricity costs for LAORC integrated system in full electric configuration and Li-ion battery technology.

Fig. 11. Cost components of the LCOS for LAORC integrated system in full electric configuration and Li-ion battery technology at 365 cycles per year and an electricity price of 0.03 €/kWh_e.

4. Conclusions

In this paper, the techno-economic feasibility analysis of the implementation of Organic Rankine Cycle technology for waste heat recovery purpose in Liquid Air Energy Storage has been carried out under full electric and cogenerative configurations. The study showed that the implementation of an Organic Rankine Cycle to recover the low-grade waste heat discharged by the Liquid Air Energy Storage charge phase seems to be economically viable and capable to significantly decrease the levelized cost of storage of the plant under opportune conditions. In fact, the economic benefit due to Organic Rankine Cycle integration depends significantly on both the configuration (full electric or cogenerative) and the related round trip efficiency, the electricity tariff and the number of cycles per year strictly related to the amount of energy discharged per year. More in particular, the most remarkable results are achieved by cogenerative configuration where the LAORC integrated system, compensating the large amount of waste heat discharged to the environment in stand-alone LAES, was found to decrease LCOS by 10 % considering the same electricity tariff applied in Singapore. The sensitivity analysis has shown that, similar to the other energy storage technologies, the LCOS of LAES is very sensitive to the operation of the plant, namely an increasing of the number of cycles per year produces a significant LCOS decrease. In particular, for every electricity tariff a threshold value of the number of cycles per year beyond which the LCOS of the LAORC integrated system is lower than the one for stand-alone LAES has been identified. Analyzing the LCOS cost structure for LAES, the annual electricity charging costs are the predominant component: the higher is the electricity tariff, the more economically profitable will be the LAORC integrated system compared to stand-alone LAES due to the higher economical valorization of the additional electricity output produced by the ORC. Finally, neglecting the annual electricity charging costs, an economic comparison carried out with Li-ion battery showed that LAORC integrated system has a comparatively lower LCOS. Indeed, since LAES is currently in development stage, a larger potential for cost reduction is expected in the future. As a final remark, since only an estimation of the capital cost and operative costs are available due to the novel nature of LAES system, a more precise determination of these parameters should be required.

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I confirm that the authors listed in the paper have actively contributed to the paper and are agreeable to be included as co-authors.

Journal Pre-proof

Declaration of interests

☒ 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.

☐ The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

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Highlights

- Levelised Cost of Storage is used to evaluate LAES with ORC.
- The number of cycles and electricity price significantly affect economic feasibility.
- ORC integration decreases LCOS by 10 %.
- LCOS for LAES with ORC is more competitive than Li-ion batteries.