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Techno-economic comparison of diabatic CAES with artificial air reservoir and battery energy storage systems

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Abstract

In the present paper, D-CAES storage systems are compared with Sodium–Sulfur (Na–S) and Lithium-ion (Li-ion) based ones on the basis of the Levelized Cost of Storage (LCOS). Utility-scale systems characterized by a rated power in the range of 5–20 MW and storage capacity of tens/hundreds megawatt-hours have been addressed. Analyses have been carried out by varying key parameters such as the installed power, the charge/discharge time periods, the price of electricity and the fuel cost. Results show that the adoption of D-CAES systems can lead to a better economic performance in respect to BES technologies. Na–S battery based systems show a better economic performance in comparison with Li-ion based ones. It has been noticed how D-CAES economic performance improves by increasing the size of the system both in terms of installed power and storage capacity. D-CAES solutions can achieve a LCOS lower than that shown by Na–S batteries, provided that the size of the system and the price of electricity are large enough.

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Keywords: Battery Energy Storage (BES); Compressed Air Energy Storage (CAES); Electric Energy Storage (EES); Levelized Cost of Storage (LCOS)

1. Introduction

In recent years, the generation of electricity from non-programmable Renewable Energy Sources (RES) – primarily from wind and sun – has dramatically increased worldwide. Such a growth has lead to a significant decrease of CO2 emissions and to a noticeable improvement of the sustainability of the whole energy system On the other hand, the intermittency of RES and the uncertainty in forecasting their availability represent major issues affecting the safety and the reliability of electric grids. Electric Energy Storage (EES) systems can give a relevant contribution in alleviating such issues and, consequently, facilitate a further spread of RES in the electricity markets.

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The present paper focuses on EES applications suitable to foster the use of RES and their integration in the electric system, i.e. energy management and transmission upgrade postponement [1]. Such applications typically require the installation of EES systems capable of managing electric power in the range of 1–100 MW for quite long charging/discharging periods (in the order of hours or days). Technologies that best suit the above target are Pumped Hydro Storage (PHS), Battery Energy Storage (BES) and Compressed Air Energy Storage (CAES).

At the present, PHS represents the most consolidate and affordable technology for large energy storage needs. The construction of new plants – especially in developed world – is hampered by the scarcity of new suitable sites and by the impact on the environment of the artificial water reservoir.

BES is widely used for small scale applications. However, significant utility-scale applications based on consolidated technologies are reported by Xing et al. [1]: Lead–Acid batteries storage systems, ranging from 1 MW–1.4 MWh to 36 MW–24 MWh, Sodium–Sulfur batteries based systems (from 1 MW–7 MWh to 34 MW–245 MWh), and finally Lithium-ion batteries based facilities ranging from 6 MW–10 MWh to 32 MW–8 MWh. A 100 MW–139 MWh Lithium-ion based storage facility has been commissioned in South Australia in December 2017. Another remarkable example is the installation in southern Italy of three storage systems based on Na–S technology. Such storage plants have been commissioned by TERNA (the Italian Transmission System Operator) in 2016 to reduce wind energy curtailments caused by the inadequate capacity of transmission lines. The overall installed rated power and storage capacity are of 35 MW and 350 MWh respectively [2].

In Compressed Air Energy Storage (CAES) plants, surplus electricity is taken from the grid to drive a compressor train operating on air. The compressed air is stored in a natural or artificial reservoir and then used to generate electricity during peak demand periods. Starting from this core concept, different solutions have been proposed over time. Such solutions can be classified into three main CAES typologies: Diabatic CAES (D-CAES), Adiabatic CAES (A-CAES) and Isothermal CAES (I-CAES). Only D-CAES can be at the moment regarded as a mature technology [3,4]. In D-CAES (Fig. 1a), an external energy source (normally a fossil fuel, but alternative options are available, as reported in [5,6]) is employed for air heating before expansion to improve both system output and efficiency. It has to be highlighted that CAES, despite its undeniable potential has not yet become a popular storage technology. The reasons why CAES based systems had a limited diffusion are widely analyzed and discussed in [4]. However, they consider CAES a very promising storage technology for off-grid and self-consumption applications and for ancillary services provision on the lower grid levels.

Such applications, together with those previously mentioned to promote and to expand the use of RES in electric systems (i.e. energy management and transmission upgrade postponement), typically require small/medium scale EES facilities (rated power in the range 5–20 MW and storage capacity of tens/hundreds megawatt-hours) conveniently located on the electric grid.

Bearing this in mind, a techno-economic analysis has been carried out and discussed in a previous work [7]. In such a work, to avoid constraints stemming from the location of the plant, both PHS and CAES plants with natural underground reservoir have been excluded. The actual feasibility of storage systems under comparison has been considered a key issue. Therefore, the analysis has been carried out taking into account only consolidated or emerging storage technologies: Sodium–Sulfur (Na–S) batteries, Lead–Acid (Pb–Acid) batteries, Lithium-ion (Li-ion) batteries, Vanadium Redox Flow batteries (VRF) and diabatic CAES (D-CAES) plants with artificial storage reservoir. Techno-economic performance of the different storage concepts under comparison was assessed in terms of Levelized Cost of Storage (LCOS). In order to perform a reliable comparison, an actual energy storage application has been taken into consideration. Design data of a Na–S based storage facility installed in southern Italy by the Italian Transmission System Operator [2] have been assumed as a reference for the sizing of the D-CAES plant and the BES based systems under comparison. Two different design approaches have been applied to arrange the D-CAES power production sections: the Steam Turbine (ST) and the Gas Turbine (GT) technology [7]. The two technologies are characterized by quite different turbine inlet pressure (p_{IN}) and temperature (T_{IN}) values. In fact ST technology allows really high p_{IN} values (up to 250 bar) but relatively low T_{IN} values (up to 600 °C). On the contrary, GT technology is characterized by moderate inlet pressure (up to 30 bar) and high T_{IN} values (up to 1500 °C). Concerning the actual case taken into consideration, the adoption of D-CAES (especially plant arrangements based on GT technology) can achieve better economic performance with respect to mature and emerging BES technologies.

In order to draw more general conclusions, in the present paper the techno-economic performance mature BES technologies and D-CAES with artificial storage will be investigated in a suitable range of design rated power and storage capacity. The influence of other key quantities such as the electricity and fuel prices will be also explored.

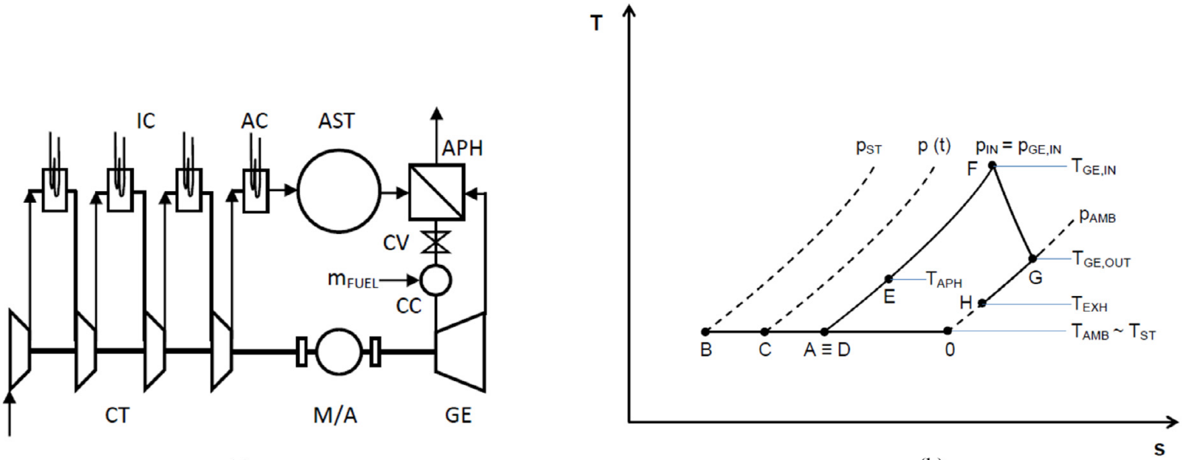

Fig. 1. (a) Proposed D-CAES plant scheme. (b) Representation on a T–s diagram of processes occurring in the D-CAES plant under consideration.

2. D-CAES plant description and modeling

The proposed D-CAES system is shown in Fig. 1a. Main plant components are the compressor train (CT), the artificial air storage tank (AST), the combustion chamber (CC), the gas expander (GE) and, finally, the air pre-heater (APH).

In Fig. 1b, processes occurring in plant components are represented on a T–s (temperature–entropy) diagram. The compression train is constituted by four intercooled compression stages followed by an after-cooler (AC). The actual intercooled/after-cooled compression is depicted as an isothermal compression process only for ease of representation. The complete charging of the reservoir, therefore, is represented by the line which connects point A at pressure p_{IN} to point B at pressure p_{ST}.

The GE is operated in a constant pressure mode. The GE inlet pressure $p_{GE,IN}$ is therefore held constant during discharge by the plant control system. This operating mode implies throttling losses across the control valve (CV, see Fig. 1a), but it has the significant advantage of facilitating plant operations. During the discharge phase, the pressure inside the storage tank p(t) – point C on the diagram – ranges from p_{ST} to p_{IN}. Therefore, the air withdrawn from the reservoir is throttled to reduce its pressure to the rated GE inlet value $p_{GE,IN} = p_{IN}$ (line CD). Subsequently, the air mass flow enters the APH to be preheated to the temperature T_{APH} (line DE). The air temperature is then raised up to the value $T_{GE,IN}$ in the CC (line EF). The combustion gas are subsequently expanded in the GE (line FG), cooled in the APH (line GH) and, finally, discharged into the environment.

A computational model (widely described in [5,7,8]) has been developed by the Authors to evaluate the thermodynamic performance. The thermodynamic model output quantities (mass flows, pressures, temperatures, powers, etc.) constitute the input data for the sizing of main plant items. Results of sizing calculations (i.e. lengths, areas, volumes, weights and so on) are then used to estimate the plant investment and operational costs. To evaluate the plant investment cost, an individual cost factor approach has been applied [9].

The artificial reservoir is constituted by sections of large diameter steel pipe welded together. The required storage volume V is given by the following equation:

$$V = m_{CH} R\, T_{ST}/(p_{ST} - p_{IN}) \tag{1}$$

where m_{CH} and T_{ST} represent the mass and the temperature of the stored air respectively and R the air gas constant. p_{ST} represents the pressure inside the reservoir when the charging phase is completed and, finally, p_{IN} is the pressure at beginning of the charging phase. Carbon steel tubes (ANSI b.125.1.) are used. The reservoir is assembled by joining 30″ OD, 12 m length tube sections. The tube thickness is established according to ANSI specifications. The investment cost is evaluated following the procedure described in detail in [6].

The intercooled compressor and the gas expander costs are estimated according to the methodology proposed by Douglas [9]. The methodology includes information to estimate costs incurred to install the above plant items.

The air pre-heater is manufactured as the Heat Recovery Steam Generators (HRSG) used in gas–steam combined cycle, the only difference being the tube side fluid. In fact, in the air pre-heater, water (or steam) is substituted by pressurized air. The air pre-heater is therefore sized by applying a procedure developed for HRSG and described in [10]. The investment cost (including the installation cost) is evaluated using the methodology proposed by Foster-Pegg [11] for HRSGs, successively updated by Salvini et al. [12].

Results presented in [7] highlighted how the use of GT based technology can lead to the achievement of lower LCOS values. In the present analysis, consequently, the GE inlet pressure $p_{GE,\ IN}$ has been set equal to 20 bar. Moreover, the assumption of high storage pressure values, despite the detrimental impact on efficiency, leads to a decrease in investment cost, which in turn results in significant LCOS reductions. In fact, it is found that the largest investment cost item is represented by the artificial air storage tank, and that such a cost mainly depends on the storage volume V. Recalling Eq. (1), the higher p_{ST} is, the lower the storage volume (and the investment cost) is. According to the above, p_{ST} has been set equal to 100 bar.

Data assumed to carry out the thermodynamic analysis are reported in Table 1. It has to be pointed out that in a D-CAES system, the electricity produced during discharge can differ considerably from that absorbed during the charging phase, being the generated electricity strongly dependent on the quantity of fuel energy provided to the system. In BES based storage facilities, the ratio between produced and absorbed electricity is close to one, representing such a ratio the round trip efficiency of the system. In order to compare storage systems characterized by similar design specifications (i.e. absorbed and delivered electric power), D-CAES systems are sized to achieve a ratio between generated/absorbed electricity close to one. On the basis of Table 1 assumptions, such a target is achieved by assuming a GE inlet temperature of 700 °C.

Table 1. Main assumption for CAES thermodynamic analysis.

Ambient temperature T_{AMB} [°C]	20
Ambient pressure p_{AMB} [kPa]	100
Intercoolers/Aftercooler outlet temp. [°C]	35
Compression polytropic efficiency [%]	85
Mechanical–Electrical efficiency [%]	97
Stored air temperature [°C]	30
Storage pressure [bar]	100
Natural gas lower heating value [MJ/kg]	50
Combustion chamber efficiency [%]	99
Air pre-heater effectiveness [%]	80
Gas expander inlet pressure [bar]	20
Gas expander inlet temperature [°C]	700
Air expander polytropic efficiency [%]	85

3. Battery energy storage techno-economic model

As stated in Chapter 1, to ensure the feasibility of the storage systems under comparison, only mature and consolidated technologies are taken into consideration. Among them, Lithium-ion (Li-ion) and Sodium–Sulfur (Na–S) batteries have been selected because they are generally considered the most suited for utility scale applications.

BES based storage systems, unlike CAES plants here considered, because of their modular design can be scaled-up to fulfill any required storage capacity by disposing in a parallel arrangement an appropriate number of elementary units. Consequently, a simpler techno-economic modeling approach based on few global design quantities and performance indexes can be successfully applied.

Therefore, BES investment cost C_{INV} can be evaluated by using the following formula [13,14]:

$$C_{INV} = P_{EL,DS} \times C_{POWER} + W_{EL,DS} \times C_{STORAGE} \times (100/DOD) \tag{2}$$

being $p_{EL,DS}$ the rated discharge electric power, $W_{EL,DS}$ the amount of discharged electricity and DOD the specified deep of discharge. C_{POWER} is a coefficient to estimate the cost of the power conversion equipment and $C_{STORAGE}$ a coefficient to estimate the storage equipment and the installation costs. BES techno-economic performance is evaluated on the basis of averaged data shown in Table 2. To complete the BES techno-economic model, a coefficient C_M that allows the estimation of the annual maintenance cost is introduced. Na–S and Li-ion data reported in Table 2 have been taken from [15] and from [16], respectively.

Table 2. Data assumed for techno-economic BES model.

BES type	Na–S	Li-ion
Technical data		
Efficiency [%]	75	80
Deep of discharge DOD [%]	80	80
Life duration [years]	15	10
Investment cost data		
C_{POWER} [€/kW]	350	250
$C_{STORAGE}$ [€/kWh]	240	250
Maintenance cost data		
C_M [€/kW/year]	26	25

4. Techno-economic performance assessment

LCOS expresses the cost of the unit of electricity (e.g. one kilowatt-hour) discharged by a storage system taking the total cost incurred and the overall amount of electricity discharged during the entire system lifetime into account. LCOS can be calculated according to the following formula:

$$LCOS = \frac{C_{INV} + \sum_{j=1}^{j=T_L} \frac{c_{A,j}}{(1+i)^j}}{\sum_{j=1}^{j=T_L} \frac{W_{EL,DS,j}}{(1+i)^j}} \tag{3}$$

The total cost is the sum of investment cost C_{INV} and the overall operating cost C_A. The latter is evaluated by cumulating annual operating costs $c_{A,j}$ (each incurred in the jth year of operation and discounted according to the assumed interest rate i) throughout the entire life of the plant T_L. The overall amount of discharged electricity is evaluated in a similar way, being $W_{EL,DS,j}$ the annual amount of discharged electricity.

The techno-economic analysis has been carried out according to the following assumptions:

- for all the storage systems under comparison, LCOS has been evaluated by assuming a 90% plant availability and one operating cycle per day at rated design condition;
- cost of Natural Gas varying from 0.20 to 0.30 €/Sm^3;
- D-CAES life duration equal to 30 years. It has been foreseen to replace the GE after 15 years of operation;
- Na–S and Li-ion based systems life duration assumed according to data reported in Table 2.

Results are summarized in Fig. 2a and b, where the LCOS achieved by the different EES systems under comparison is plotted against the rated design power absorbed during the charging phase $p_{EL,CH}$. Figures refer to systems sized for charging time periods t_{CH} of 6 and 10 h, respectively. The discharge time duration t_{DS} is assumed equal to the charging one t_{CH}. Curves plotted in the upper part of both figures refer to an electricity price of 0.1 €/kWh, while curves in the lower region of the graph concern with a free provision of electricity.

In any case, it can be seen that the LCOS of BES systems does not change with $p_{EL,CH}$. This is because, for a given value of t_{CH}, both numerator (i.e. the BES total cost, evaluated according to Eq. (2)) and denominator (the generated electricity) of Eq. (3) are proportional to $p_{EL,CH}$. The D-CAES levelized cost shows instead a decreasing trend by increasing $p_{EL,CH}$. In fact, by increasing the design power, the specific investment cost of those components whose cost depend markedly on power, i.e. the compressor train, the expander and the heat transfer devices tends to decrease because of the scale effect. Otherwise, the investment cost of the artificial storage tank is roughly proportional to the amount of stored energy. Consequently, by increasing the installed power, the numerator of Eq. (3) grows more slowly than the denominator, which, as previously stated, is proportional to $p_{EL,CH}$.

Fig. 2a shows results achieved by assuming $t_{CH} = t_{DS} = 6$ h. In case of electricity price of 0.1 €/kWh, the LCOS of D-CAES is always lower than that achievable by Li-Ion based systems. D-CAES shows the ability to achieve an LCOS even lower than that of Na–S based systems (i.e. 0.257 €/kWh). As an example, for a fuel cost of 0.2 €/Sm^3, the levelized cost of D-CAES becomes smaller than that of Na–S if the design charging power becomes higher than 7.5 MW. If instead the fuel cost is raised to 0.3 €/Sm^3, the break-even point is achieved for a at $p_{EL,CH}$ value of some 13 MW.

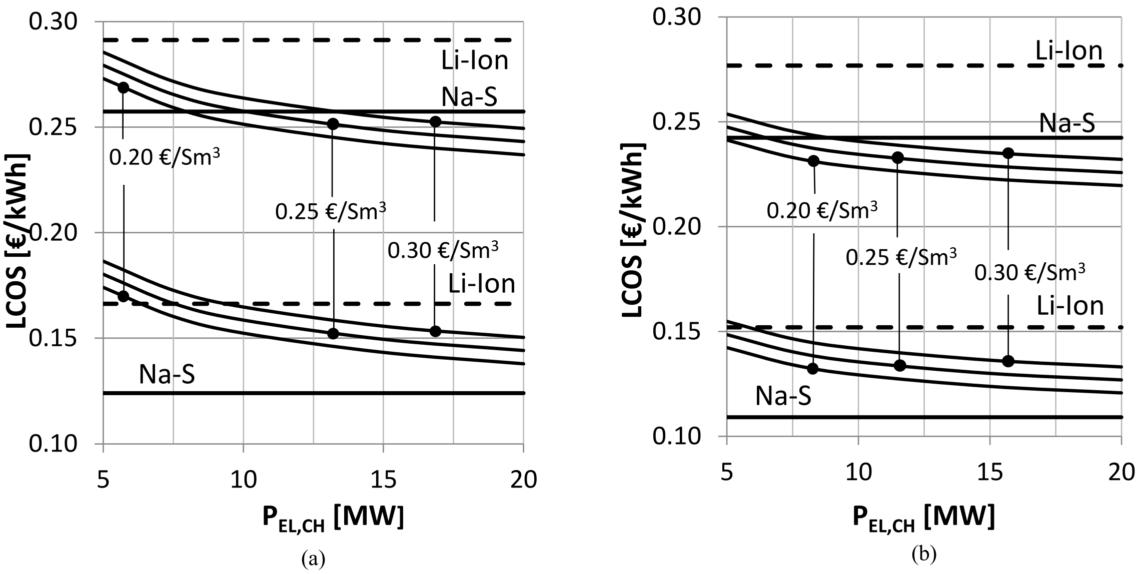

Fig. 2. (a) LCOS by varying the rated charging power of storage systems under comparison. Case $t_{CH} = t_{DS} = 6$ h. (b) LCOS by varying the rated charging power of storage systems under comparison. Case $t_{CH} = t_{DS} = 10$ h.

The same trends can be observed in case of cost free electricity (lower part of Fig. 2a). Na–S based systems show anyway the best LCOS. D-CAES achieves a better performance in respect to Li-ion batteries for values of $p_{EL,CH}$ higher than 6 MW if the fuel cost is set at 0.2 €/Sm^3, and higher than 10 MW if the fuel cost is increased to 0.3 €/Sm^3.

Fig. 2b refers to storage systems sized for a charge/discharge periods of 10 h. It follows that, in respect to the above analyzed cases, plant sized for the same charging power are characterized by a higher storage capacity. It can be noticed how LCOS values found for all EES systems under consideration are, all things being equal, lower than those shown in the previously discussed Fig. 2a. In case of electricity price equal to 0.1 €/kWh, D-CAES prevails over Na–S if the installed power is greater than 8 MW, whatever the fuel cost. Interesting values around 0.22–0.23 €/kWh are achieved for D-CAES systems sized for a rated design power in the order of 15–20 MW. In case of cost free electricity supply, the LCOS of D-CAES is always between the Li-ion (0.15 €/kWh) and the Na–S (0.11 €/kWh) ones.

5. Conclusion

D-CAES design solutions are compared with Na–S and Li-Ion Battery Energy Storage (BES) systems on the basis of the Levelized Cost of Storage (LCOS) method. Utility-scale storage systems characterized by a rated power in the range of 5–20 MW and storage capacity of tens/hundreds megawatt-hours have been addressed. Analyses have been carried out by varying key parameters such as the installed power, the charge/discharge time periods, the price of electricity and the fuel cost.

Results show that the adoption of D-CAES systems can lead to a better economic performance in respect to mature and emerging BES technologies. Na–S battery based systems show a better performance in comparison with Li-ion based ones. It has been noticed as D-CAES economic performance improves by increasing the size of the system both in terms of installed power and storage capacity. D-CAES solutions can achieve a LCOS lower than that shown by Na–S batteries, provided that the size of the system and the price of electricity are large enough.

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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