Journal of Energy Storage 75 (2024) 109238

Contents lists available at ScienceDirect

Journal of Energy Storage

journal homepage: www.elsevier.com/locate/est

Research papers

Retrofit of a coal-fired power plant with a rock bed thermal energy storage

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ARTICLE INFO

Keywords:
Thermal energy storage
Techno-economic analysis
Packed bed
Power plant
Carnot battery

ABSTRACT

Power production accounts for about one-fifth of the global final energy consumption and over one-third of all energy-related CO_2 emissions. Low-cost, large-scale thermal energy storages are considered as solutions for the decarbonization of fossil-fired power plants by their conversion into power-to-heat-to-power systems, so-called thermal storage power plants. This paper investigates the retrofit of a Chilean coal-fired power plant with an innovative solid media storage from a techno-economic perspective. Selecting a storage capacity of 5.27 GWh_{th}, corresponding to 8 h of discharge, and increasing the inlet steam generator temperature from 590 to 650 °C lead to the highest annual round-trip efficiency of 34.9% and to up to 3.4% lower levelized cost of electricity. Minimum levelized cost of electricity as low as 88.1 €/MWh is attained and considered as close to competitiveness with well-established molten salt storage systems. A sensitivity analysis shows that assuming even five times lower storage costs, initially the strongest driver of capital expenditure, only meant 4% lower levelized costs of electricity on average. On the other hand, the design of electricity purchase for charging, for example with green power purchase agreements, turns out to be the key lever to a successful implementation.

1. Introduction

Electricity is central to our daily life and is more than ever necessary considering expanding end-users such as electric vehicles and heat pumps. Already today, electricity accounts for about one-fifth of the world's total final consumption of energy and over one-third of all energy-related CO_2 emissions [1]. Also being responsible for around 60% of the global coal usage [1], emissions from electricity production must decline by 55% by 2030 to meet the *Net Zero Emissions by 2050* scenario [2]. But in the absence of major policy action from governments, a plateauing of emissions from electricity generation is expected since renewables are set to meet the increase in global electricity demand in the coming years.

According to a global management consulting firm, electricity consumption is projected to triple by 2050 as living standards and electrification, considered as first decarbonization levers due to lowest-cost and easy implementation, grow [5]. Although renewables-based electricity is now the cheapest option in many regions [6] and the decarbonization of other sectors follows hand-in-hand, there is a massive pressure to bring the electricity sector to carbon neutrality. Today, in particular, emerging and developing countries show shortfalls in clean energy investment, despite their rapid projected growth in demand for energy services [1].

In that context, retrofitting fossil-fired power plants with an electric heater and thermal storage appears as an economically, ecologically and socially friendly solution for the decarbonization of power production. Such a *thermal storage power plant*, which could also be classified as a so-called Carnot Battery [7], would enable the shift from fossil- to renewables-based power production, most likely with operation schedules as daily storages compensating fluctuating generation.

1.1. Retrofitting power plants

Several examples demonstrate that retrofitting existing fossil-fired plants is of topical interest nowadays: whereas carbon capture and storage is already an important component of many national and worldwide strategies for realizing carbon neutrality [8,9], the replacement of firing chambers with renewables-powered thermal storage (see one example in Fig. 1) lacks implementation in both policy as well as reality. The reuse of existing equipment such as steam turbine, heat recovery boiler or heat exchangers, however, promises cost-effectiveness compared to new stand-alone solutions and comes with a decreased risk of stranded assets [3,10].

Chile is the only country from South America which is a member of the Organization of Economic Cooperation and Development (OECD).

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https://doi.org/10.1016/j.est.2023.109238
Received 10 May 2023; Received in revised form 10 September 2023; Accepted 6 October 2023
Available online 16 November 2023

Abbreviations

4e	Program for Renewable Energies and Energy Effiency
BOP	Balance of Plant
CAD	Computer Aided Design
CFD	Computational Fluid Dynamics
EPC	Engineering, Procurement and Construction
EUDP	Energy Development and Demonstration Program
GIZ	Gesellschaft für Internationale Zusammenarbeit GmbH
HTF	Heat Transfer Fluid
IEA	International Energy Agency
OECD	Organization for Economic Cooperation and Development
PPA	Power Purchase Agreement
PV	Photovoltaics
TES	Thermal Energy Storage

Latin symbols

c_p	Specific heat capacity (J/(kg K))
$CAPEX$	Capital expenditure (€)
p	Pressure (mbar)
E	Energy (J)
FCR	Annuity factor (–)
i	Interest rate (%)
$LCOE$	Levelized Cost of Electricity (€/MWh$_{el}$)
$\dot{m}$	Mass flow rate (kg/s)
n	Loan duration (years)
$OPEX$	Operational expenditure (€)
P	Power (kW)
Q	Heat (kJ)
t	Time (s)
T	Temperature (°C)
V	Volume (m^3)
W	Work (kJ)

Greek symbols

ϵ	Porosity (–)
η	Efficiency (–)
ρ	Density (kg/m^3)

Subscripts

0	Discharge cut-off value
amb	Ambient
b	(Packed) bed
ch	Charge operation
dis	Discharge operation
el	Electric
gross	Value before subtractions
heater	Electrical heater
net	Value after subtractions
PB	Power block
plant	Power plant
P2H2P	Power-to-Heat-to-Power (round-trip)
r	Rock
rest	Rest operation (standby)
SG	Steam Generator
th	Thermal
theo	Theoretical

Despite being the fifth-largest consumer of energy on the continent, it is only a minor producer of fossil fuels, unlike most other large economies in the region [11]. In addition to that dependency on energy imports, half of the Chilean electricity in their two main electrical systems stems from non-renewable production [6], with coal being the dominating fuel [11]. While Chile has hardly any feed-in tariffs and a marginal price market, meaning that the variable costs of the most expensive producer that is required to serve the demand sets the electricity price, a strong surge of so-called power purchase agreements (PPA) is observable. Here, electricity is directly purchased from independent generators, typically for fixed prices and depending on the time of supply.

In addition, new tax regulations as well as environmental standards now aim at the coal-fired power production [12]. More precisely, an agreement between the Ministry of Energy and Environment, the Chilean Association of Power Generators and four power plant companies (Enel, AES Gener, Engie, and Colbún), was signed in 2018 and a bill on the prohibition of coal-fired thermoelectric plants has been approved in 2021 [13]. The bill entered into law immediately, but its biggest impact is still in the future since power plants that are less than 30 years old are exempted from this ban until the end of 2025. However, legacy companies already signed agreements about the retirement of eight units with a total of 1047 MW by the end of 2024 [14].

In this context, the Program for Renewable Energies and Energy Efficiency (4E) has grown as an initiative of the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH of Germany. Since 2014, the 4E Program has been working in Chile to increase the sustainability of the energy sector by providing technical assistance and promoting initiatives [15].

The technical potential of power plant retrofits and the fast-paced decarbonization agenda from countries like Chile, also home of the Atacama region with one of the highest solar irradiations of the world, align well. From an economic perspective, recent studies [16] estimate the costs for electricity from retrofitted power plants to be between 80 and 100 €/MWh$_{el}$ and hence close to competitiveness with today's coal-fired and gas-fired plants (63–76 and 65–91 €/MWh$_{el}$, respectively). In contrast to large-scale retrofits [10], retrofits for small-scale coal-fired combined heat and power plants up to 50 MW$_e$ can lead to costs up to 291 €/MWh$_{el}$, but in this case estimated for a plant in Czech Republic [17]. Such values would be clearly above the 63–76 €/MWh$_{el}$ estimated for cost neutrality in a 100% renewable scenario for Denmark in 2045 [18]. In all of these cases, potential fuel market price escalations and CO_2 cost additions are successfully obviated, as highlighted by Liu and Trieb [19], as well as curtailment from wind and solar, as elaborated by Gong and Ottermo [20]. Furthermore, conventional generators, rather than inverter-based resources, are able to retain a significant amount of inertia for grid frequency stabilization, are conserved. In that regard, the authors would like to highlight that such services can be provided during discharge operation, while the renewable penetration (and stabilization needs) within the grid is typically higher during charge operation. Consequently, the advantage of preserving inertia might be limited and thorough operation planning becomes key.

Generally, a wide range of different thermal energy storage concepts is conceivable, with those featuring molten salt as heat transfer fluid as the most prominent ones. However, packed bed storages with air as the heat transfer fluid are characterized by significant advantages such as hardly any operating temperature limitations [21], limited

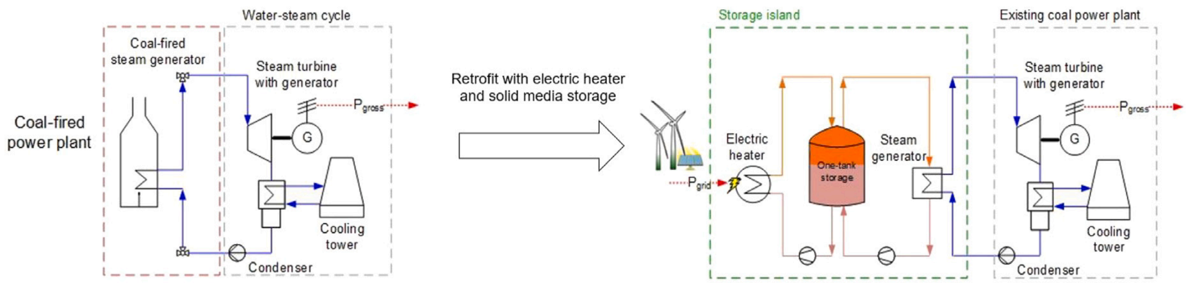


Fig. 1. Integration of a solid storage in retrofit concepts with electrical heater (adapted from [3,4]). Please note that a by-pass in the storage discharge circuit for the control of the steam generator inlet temperature is not depicted here for the sake of simplicity.

degradation [22] and the elimination of chemicals and corrosive materials. In order to limit the temperature destratification due to natural convection, packed beds with can be equipped with convection barriers inside the storage [23], particularly important for those with a horizontal flow orientation. Overall, cylindrical shapes dominate compared to truncated conical tanks [24] or rectangular shapes [25] due to the small lateral surface, but maximum packed heights and the accessibility of equipment should be considered [7]. While the charge duration is often directly related to the supply from renewables, discharge durations can be varied in principle. Operation modes with longer discharge durations (e.g. up to 16 h [24]) require large storage capacities and auxiliary demand but decrease the effect of start-up losses. The current literature lacks concrete studies investigating different discharge durations for one specific integration scenario. Moreover, packed beds allow inlet temperatures at the steam generator above the typical 590 °C. In that context, the trade-off between higher heat losses but smaller heat exchange surface is currently insufficiently studied from both technical as well as economic perspective.

1.2. Novelty and goal of this work

Overall, there are two main observations: (i) power plant retrofits using packed bed thermal energy storages are rarely investigated from a techno-economic perspective, in particular for specific power plants, even though they have the potential to act as a key lever to fast, cost-effective implementation, and (ii) the impacts of process design and operation on technical as well as economic key performance indicators have never been quantified together for retrofits with the selected packed bed storage. Therefore, this work aims at comparing different technical variants of an innovative packed bed storage design [26] integrated into a specific power plant as well as its economic consequences in multiple operation cases, exemplarily applied for a scenario in Chile, but transferable to other regions with similar boundary conditions. Within that, particular focus is put on different storage discharge durations and hence capacities as well as the choice of inlet temperatures for the attached steam generator. In addition, a sensitivity analysis is applied for the derived levelized costs of electricity in order to quantify the relevance of selected economic assumptions, in this case storage costs and electricity price for charging.

Following this introduction in Section 1, Section 2 presents the description of the reference power plant and the selected thermal storage system, investigated with the methods introduced in Section 3. The technical as well as economic results of this work are presented and discussed in Section 4. Section 5 provides a conclusion with an outlook regarding further work.

2. System description

2.1. Power plant

The power-plant concept analyzed for the integration of a thermal-storage technology with solid material is based on the implementation of an electric heater and a steam generator that uses air as the heat transfer fluid (see Fig. 1). The system with the new components (electric heater, storage and steam generator) is the so-called storage island. As shown in Fig. 1, the boiler of the existing coal fired power is eliminated and replaced by the storage island.

Table 1
Main parameters of the reference coal-fired power plant, also part of other related studies [3] [27].

Parameters	Unit	Value
Efficiency coal-fired boiler	%	87.5
Nominal gross power	MW_{el}	277
Auxiliary demand in operation[a]	MW_{el}	24
Electric gross efficiency	%	43.6
Live-steam temp. (160 bar)	°C	565
Reheat-steam tem. (39.5 bar)	°C	565
Cooling water temp.	°C	28
Specific CO_2 emissions	kg/MWh_{el}	1170

[a] Mostly power for fans, balance of plant and pumps.

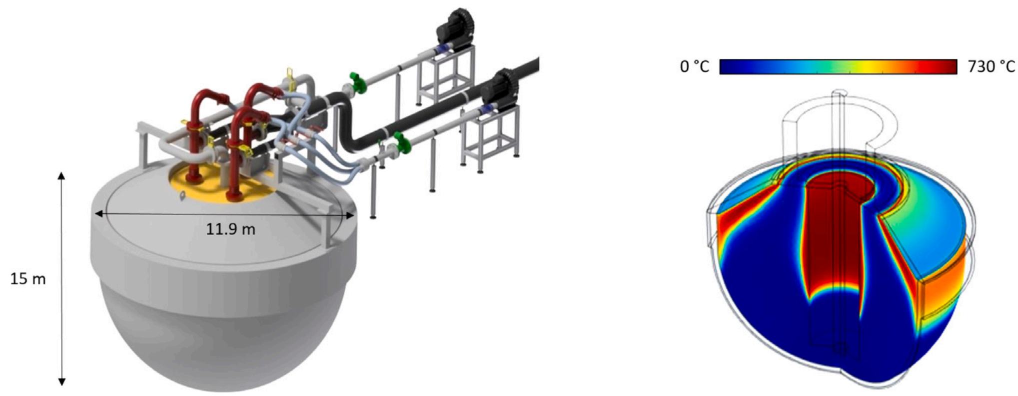
In this work, a techno-economic analysis of the retrofitting of an existing Chilean coal power plant (see Fig. 1) is performed. The selected plant has a power class of 300 MW_{el} (gross) with a production of live-steam at 565 °C and 160 bar. The main design-point parameters of the plant are collected in Table 1. The steam cycle includes a re-heater with several preheaters to increase the cycle efficiency. The feedwater temperature of this specific steam cycle is 261 °C. For the integration of a thermal storage system, the lower temperature needs to be greater than 262 °C and the higher temperature over 565 °C. In this study, the lower temperature is set to 312 °C due to a 50 °C safety margin and 590/650 °C since the typical inlet steam generator temperature should be compared to a higher one which can still be implemented without changing the material of the equipment. The air temperature at the steam generator inlet is controlled by a bypass integrated in the storage discharge circuit (not depicted in Fig. 1 due to simplicity), while the storage temperature itself stays constant.

In general, the efficiency can be defined based on i) energy flows at the nominal operating point or ii) integrated energy flows over a defined time period. For the power plant retrofit in this work, the energy-based approach is chosen with a time period of one year since the operation strategy (see Section 4.1) as well as standby losses and self-discharge are inherently taken into account. Consequently, the (annual) round-trip efficiency of the system η_{P2H2P} is defined by the ratio between the net electrical energy produced $W_{net,plant}$ and the electrical energy used from the grid $W_{total,input}$ for charging and auxiliaries (in stand-by, start-up, shut-down):

$$\eta_{P2H2P} = \frac{W_{net,el}}{W_{total,input}} \tag{1}$$

Similarly, the gross efficiency of the power block $\eta_{PB,gross}$ can be calculated with the gross electrical energy output $W_{gross,el}$ and the total thermal energy provided to the power block $Q_{PB,in}$:

$$\eta_{PB,gross} = \frac{W_{gross,el}}{Q_{PB,in}} \tag{2}$$



(a) 3-D drawing including dimensions (CAD model). (b) Temperature distribution after discharge (CFD model).

Fig. 2. Thermal energy storage module used in this work. Main parameters are provided in Table 2.

Table 2
Main parameters of the used thermal storage module, scaled up based on the work in [26][22].

Parameters	Unit	Value
Storage material	–	Diabase
Storage temperature	°C	730
Storage capacity	GWh_{th}	1.37
Self-discharge rate	%/day	1.94
Particle diameter	mm	12
Avg. specific heat capacity[a]	kJ/(kg K)	0.86
Packed bed volume	m^3	4659
Total packed bed mass	ton	7856
Max. pressure drop (packed bed)	mbar	49

[a] Measured after cycling and for 0 to 600 °C [22].

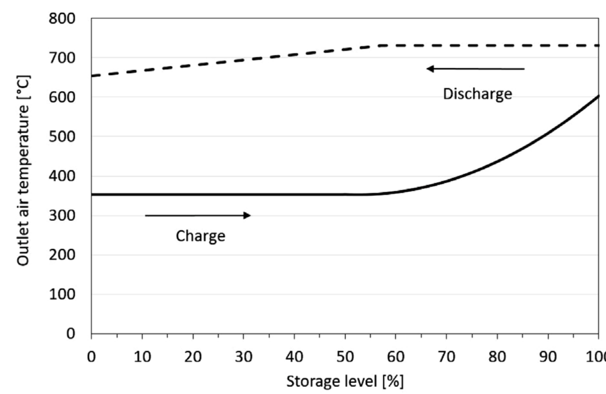


Fig. 3. Characteristic storage outlet air temperature during charge and discharge. No cyclic effects considered, valid for all boundary conditions used in this study. The storage level is defined as the ratio between the actual stored energy and the maximum thermal capacity from Eq. (3).

The following definitions are used for the rest of this work: the total electric energy input $W_{\text{total,input}}$ considers the required electric energy to charge the electrical heater $W_{\text{heater,input}}$ together with the auxiliary demand from the grid when this energy cannot be covered with the electricity production. The thermal energy to the storage Q_{heater} is obtained from the conversion in the electric heater and, according to the demand, this energy is converted back into electricity $W_{\text{gross,el (P2H2P)}}$. The net electricity production $W_{\text{net,el}}$ is obtained after covering the auxiliary demand of the plant.

2.2. Rock bed thermal storage

Fig. 2 shows the thermal energy storage module used in this work. It is scaled up from a previously built pilot plant with 1 MWh_{th} storage capacity for a storage temperature of 600 °C [26] to 1.37 GWh_{th} for the storage temperature of 730 °C for this study. The combination of a conical frustum and hemispherical shaped housing gives a droplet-like shape. Being classified as an unpressurized gas/solid packed-bed storage, The system uses atmospheric air as the HTF and solid material as the storage medium. One novel element is that the heaters, valves, and inlet and outlet pipes are located on top of the storage to avoid additional excavation, simplify maintenance, and allow the rock bed to be installed partially below ground level. Air enters and exits the rock bed in the vertical direction during charge and discharge by means of separate fans for the charge and discharge processes. The flow scheme, being a mix of radial but predominantly vertical air flow direction, uses natural thermal stratification to its advantage. A pipe leading to the bottom of the rock bed makes it possible to reverse the flow direction for charge and discharge to obtain a nearly flat thermocline. This inner pipe acts as an outlet during charge and an inlet during discharge phases, respectively, in both cases for ambient air.

The selection of storage material is based on studies performed for a previous storage system built [23]. Irregular shaped diabase from southern Sweden is selected as the storage material for this storage system since it performed well in laboratory tests and is readily available in a range of sizes. Potential degradation after 249 cycles up to 675 °C (3458 h total) is reported by Knobloch et al. [22].

The thermal capacity E_{store} of the system can be calculated by using Eq. (3) and assuming a homogeneous temperature in the rock bed. A calculation based on the rock mass m_r is favored over its estimation with bed porosity ϵ, bed volume V_b and rock density ρ_r.

$$E_{\text{store}} = (1-\epsilon)V_b\rho_r \int_{T_0}^{T_{\text{heater}}} c_{p,r}(T)\,dT \approx m_r \bar{c}_{p,r} \Delta T \tag{3}$$

Where T_{heater} is the heater temperature, $\bar{c}_{p,r}$ is the average specific heat capacity of the rock as received (0.86 kJ kg^{-1} K^{-1} between 0 and 600 °C after thermal cycling), $c_{p,r}$ is the temperature-dependent specific heat capacity of the rock, T_0 is the discharge cut-off temperature assumed to be the ambient temperature. Here, T_0 is 0 °C and ΔT is the difference between heater temperature T_{heater} and the discharge cut-off temperature T_0.

For its integration as thermal storage in the power plant retrofit, multiple scaled-up modules are required since the module dimensions are limited, mostly due to mechanical issues resulting from packed bed heights larger than 15 m (see Fig. 2(a)). Longer discharge durations, see Section 4.1, are hence realized by means of multiple modules. The main parameters of the used thermal storage module are given in Table 2. Please note that the storage temperature of 730 °C is constant throughout the whole study while the steam generator inlet temperature is varied by using a by-pass between storage outlet and steam generator inlet, as explained in Section 2.1.

Table 3
Cases evaluated in this work with the main differences marked in bold.

Case	Charge duration t_{ch} (h)	**Discharge duration** t_{dis} **(h)**	Rest duration t_{rest} (h)	Total storage capacity E_{store} (GWh_{th})	**Air temperature at steam generator inlet** $T_{SG,in}$ (°C) *	Steam generator load $\dot{Q}_{th}$ (MW_{th})
1	10	**4**	10	2.73	**590** **	626.5
2	10	**8**	6	5.27	**590** **	626.5
3	10	**12**	2	7.82	**590** **	626.5
4	10	**4**	10	2.73	**650**	626.5
5	10	**8**	6	5.27	**650**	626.5
6	10	**12**	2	7.82	**650**	626.5

* Realized by a by-pass. Please note that the storage temperature of 730 °C is the same in all cases.

Based on CFD simulations [28] for the 2-D, axi-symmetric temperature distribution inside the packed bed during operation (see 2(b)), temperatures curves, as shown in Fig. 3, are created in order to describe the storage behavior. Here, the storage outlet temperature during charge and discharge are depicted for different storage levels, defined as the ratio between the actual stored energy in comparison to the maximum thermal capacity from Eq. (3). The outlet air temperature during discharge decreases from 730 °C to 650 °C when the storage level ranges between 55% and 0% (typically compensated with an increased mass flow), while it increases from 350 °C to 600 °C during charge for storage levels between 55% and 100%. The differences in charge and discharge behavior mainly stem from the fact that the mass flow during discharge is not constant and multiple modules allow additional mixing of streams, in particular when oversized as a total. The fixed TES module size corresponds to a storage capacity of 1.37 GWh_{th} for the storage temperature of 730 °C. The estimated thermal losses for this configuration are 1.94% per day, while the maximum pressure loss over the packed bed, in this work observable during discharge, is calculated to be 49 mbar.

3. Methodology

In order to study the power plant retrofit, an analysis of the interactions between components of the thermal storage power plant is performed based on system modeling of a selected concept and its variations, which leads to a techno-economic assessment in a further step. The study of the economic feasibility requires the determination of the investment, operating and integration costs. For that purpose, a cost model for the evaluation of the conversion investment and operating costs is developed. For the techno-economic analysis, both the evaluation of thermodynamic variables and the power-unit yield calculation are performed by a system simulation model.

3.1. Cases studied and boundary conditions

For the concept considered here, several discharging times are analyzed (4, 8 and 12 h) for a 10 h charging time in order to obtain the optimal configuration of the storage capacity, see Table 3. The charging time was selected to use the maximum hours of sunlight to represent the use of renewable power from photovoltaic (PV) plants, and in this way, the discharge will take place during the night or when the sunlight is not available. Different discharging timeframes are considered in order to analyze different electricity supply characteristics. Thus, the discharging duration is directly related to the storage capacity, whereas the charging duration is directly linked to the installed capacity of the electric heater. For instance, since the discharge takes place with a constant nominal power at a full-load operation, the required electric heater power for 8 h discharge is twice as high as for the 4 h discharge. In this case, double the amount of energy must be stored during the same 10 h. Additionally, two inlet temperatures of the heat transfer fluid (air) for the steam generator (590 °C and 650 °C) are considered to determine the favorable temperature difference of the steam generator, because a smaller heat exchange surface might lead to lower costs. In order to perform the energy yield analysis, a typical daily profile with one charging and one discharging period is calculated. As the financial evaluation requires an annual energy yields, this typical day is used for every day during the year. Fig. 4 presents typical daily operation profiles according to the charging and discharging duration for a power class of 300 MW_{el}. This operation mode shows an electric generation without fossil boiler that depends on the defined discharging time (red area). The analysis of the varied parameters shows their sensitivity to techno-economic variables (e.g. $LCOE$ and annual yield). Additionally, $LCOE$ sensitivity analysis based on both specific storage cost and grid electricity price are performed. The reference cases consider a specific storage cost of 13.8 €/kWh_{th} and a constant electricity price of 18.6 €/MWh_{el} [3], representing a PPA for time block 1-B (8AM-6PM) with e.g. large-scale PV plant developer and estimated to be at the lower but representative end of current PPA price ranges [29]. Independent of the actual PV availability throughout the year, such PPA guarantees the daily charging of 10 h.

In the techno-economic analysis, a defined reference day at design-point conditions (ambient pressure of 1 bar, ambient temperature of 22 °C and cooling water temperature of 28 °C) is used for the annual calculations. This means that, during charging and discharging, the plant is under design-point conditions at every hour of the year. It should be noted that the consideration of real meteorological data (such as ambient temperature, cooling water temperature, etc.) will have a certain influence on the results. For example, a temperature change of the cooling water could influence the auxiliary demand required for the condenser and steam preheater. Since these values do not vary significantly in the selected location, this simplification is acceptable for this study.

3.2. Definition of the operation strategy

The selected operating mode with associated operating states (e.g. charging and discharging) and their transitions is defined to achieve a safe and efficient operation. Based on this operation strategy, the possible operating states for the considered technical concept are included in the yield modeling by means of a script programming, taking into account the available power in grid and thermal storage level as well as the required electricity demand for each time-step. A yearly yield analysis provides the comparison of the presented retrofit configuration with those proposed in previous studies [3,10]. In general, the operation strategy depends on many factors, such as the system configuration of the plant, the available electricity on the grid and the price for charging, the load demand for discharging and the price for the delivered electricity, the current status of the plant (warm/cold), and the start-up/shut-down boundary conditions. For this analysis, a simplified operating strategy is defined, regarding the following assumptions:

1. The power plant operates at its design performance based on the selected charging and discharging duration.
2. A typical daily profile with one charging and one discharging period is calculated. As the financial evaluation requires an annual performance, this typical day is used for every day during the year.

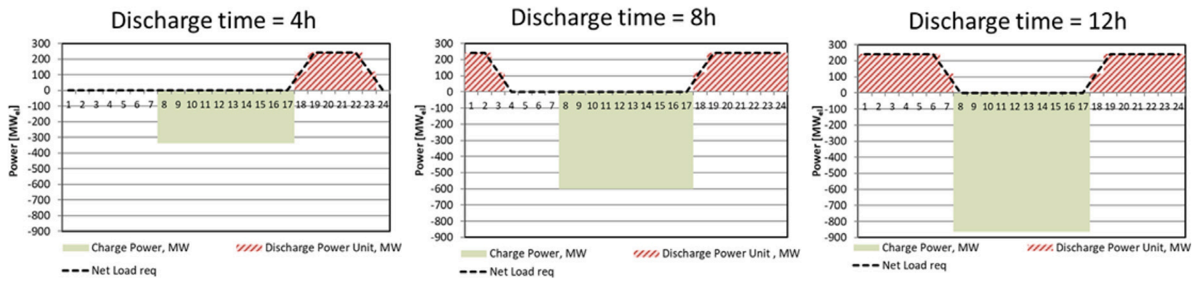


Fig. 4. Daily operation profiles for the cases studied (Table 3): 300-MWel plant, 10-h charging duration and discharging duration of 4 h, 8 h and 12 h.

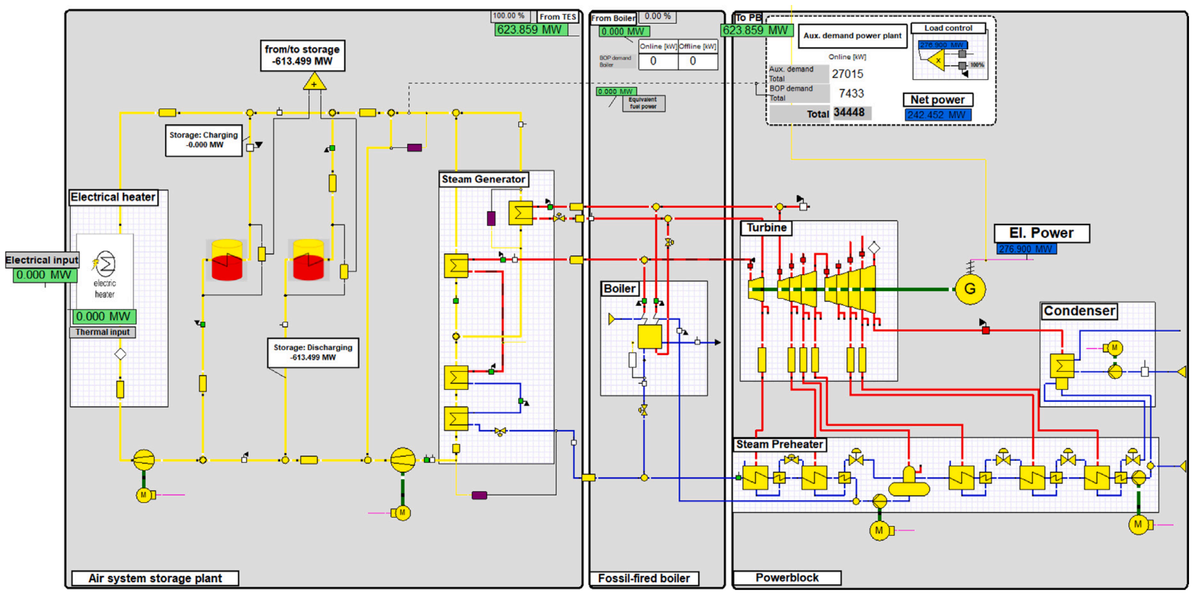


Fig. 5. Overview of the process simulation model for the discharging profile.

3. The charging power is constant during the charging duration. In real operation, when a PV power plant supplies the charging energy, a variation of the charging power is possible due to cloud passages and the non-constant intensity of the solar power during the day.
4. A simplified approach is used for the start-up energy of the power plant (8% of the thermal power in steam generator).
5. The process model can only simulate some of the auxiliary consumers such as feed-water pumps and blowers. Other consumers from the balance of plant (BOP) are not modeled in detail but considered as a lump sum depending on the load. As shown in Fig. 5, one blower for charging and another for discharging are implemented in the simulation model with a nominal isentropic efficiency of 82%. Additionally, the auxiliaries of both the steam pre-heater and condenser pumps are also calculated by the process model. The plant auxiliary demand comes from the lump sum of the calculated auxiliaries and those resulting from the balance of plant.
6. Thermal losses in the pipes are calculated according to estimated specific thermal losses for cold and hot pipes (150 W/m^2 and 200 W/m^2 [4], respectively).
7. Storage pressure losses are calculated according to the operation and rock bed geometry, achieving values up to 49 mbar.

3.3. Annual-yield modeling

The overall methodology for the techno-economic analysis of the selected variations is based on an annual yield calculation with individual operating states performed by combining two different simulation tools. The system process and yield models for the selected technical concept (including electric heater, heat transfer fluid circuit, storage system and power block) are developed in Ebsilon Professional [31]. These models are able to simulate the different operation modes (e.g. charge and discharge). According to the used electricity from the grid and the load, the power-plant yield is calculated over a given period of time (e.g. one year) based on hourly time steps. In this evaluation, since a daily operation is repeated during the whole year, the simulation is performed for 24 h and the results are multiplied by 365 days. The annual yield calculation is developed by an Excel program, which calls the thermal storage power plant model in Ebsilon at each calculation interval, using the defined operation profile with the required load and charging power. The operation strategy is partly implemented in the Ebsilon model by script programming (selection of operation state such as charging and discharging) and partly in the Excel sheet (integration of the dynamic effects and start-up process). The data exchange and the evaluation of the results are done in Excel.

3.4. Cost model

The following simplified cost model, according to a proposal of the International Energy Agency [32], is used for this study. The objective of this economic calculation is to evaluate the relative differences between several technical concepts or configurations. The main benchmark used for this purpose is the electricity generation costs or the levelized cost of electricity ($LCOE$). Therefore, project-specific parameters are neglected, such as taxes or financing concepts. The IEA method is very simple but provides suitable results for comparing

Table 4
Main specific costs for the 300 MW_{el} power plant.

Parameters	Unit[a]	Value	Ref.
Owner cost	% $CAPEX$	5	[4]
Electrical equipment	€/kW_{el}	48	[4]
Integration cost to existing power block	€/kW_{th}	36	[4]
Heat transfer fluid circuit charging/discharging	€/MW_{th}	39.2	[4]
Blower	€/kW_{th}	16.8	[4]
Indirect EPC cost (project management, contingencies...)	€/kW_{el}	84	[4]
Civil works and structural steel construction	€/kW_{el}	43	[4]
Instrumentation and control	€/kW_{el}	12	[4]
Heat recovery steam generator	€/kW_{th}	73.4	[4]
Electrical heater (able to withstand high inlet temp.)	€/kW_{el}	128.5	[4]
Thermal storage system	€/kW_{th}	13.8[b]	[30]
Heat recovery steam generator	€/kW_{th}	73.4	[4]
Balance of plant (BOP)	€/kW_{el}	18	[4]
Modification cost of grid connection	€/kW_{el}	0	[3]
Electricity price (constant and based on PV production costs)	€/MWh_{el}	18.6[b]	[3]

[a] kW_{el} refers to the electrical power from the power block, except for the electrical heater and electrical equipment.
[b] A variation in costs for the storage system and buying electricity is later investigated, see Fig. 11.

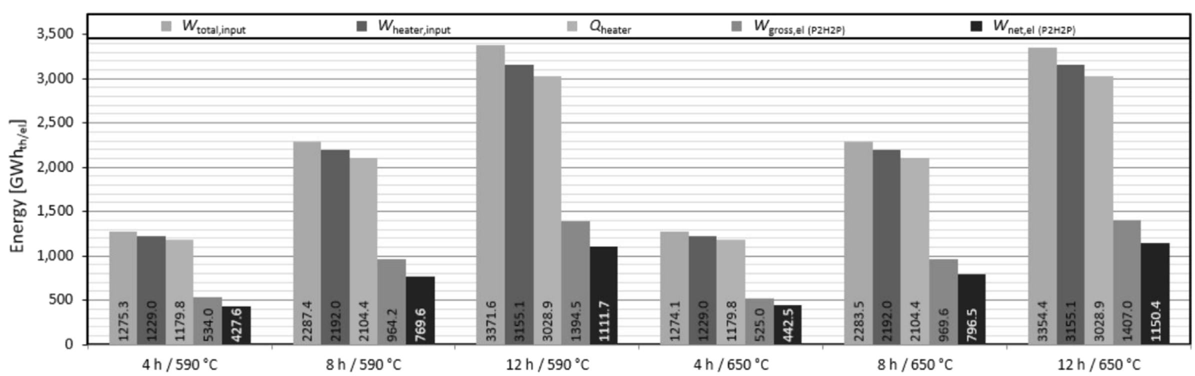


Fig. 6. Comparison of energies for all considered cases (all 10 h charge).

different systems. The following simplifying assumptions are based on the IEA method:

- 100% loan financing at fixed interest rate,
- annuity method,
- operating method of the power plants (term of the loan)
- neglect of taxes
- neglect price increases and inflation during construction
- neglect price increases and inflation regarding operation and management, insurance costs or similar.

Based on these assumptions, the levelized cost of electricity $LCOE$, going beyond a simple difference between electricity purchase and selling, can be evaluated using the following equation:

$$LCOE = \frac{CAPEX \cdot FCR + OPEX}{E_{el}} \tag{4}$$

with

$$FCR = \frac{i \cdot (1+i)^n}{(1+i)^n - 1} \tag{5}$$

where $CAPEX$ corresponds to the investment costs for the reference year, FCR is the annuity factor (fixed interest rate), $OPEX$ refers to the annual operation and maintenance costs together with the insurance costs, E_{el} is the annual electricity yield, i corresponds to the interest rate and n is the loan duration in years. While the main cost assumptions considered in this study are summarized in Table 4, Table 5 lists the financing parameters used.

The authors highlight the assumption that no change in grid connection is required. Consequently, no additional costs are considered. It should also be noted that the electricity price is assumed to be constant and identical for conventional and PV grids (18.6 €/MWh_{el} [3]). If these prices differ, the electricity cost for self-consumption should be considered separately.

Table 5
Financing parameters [3].

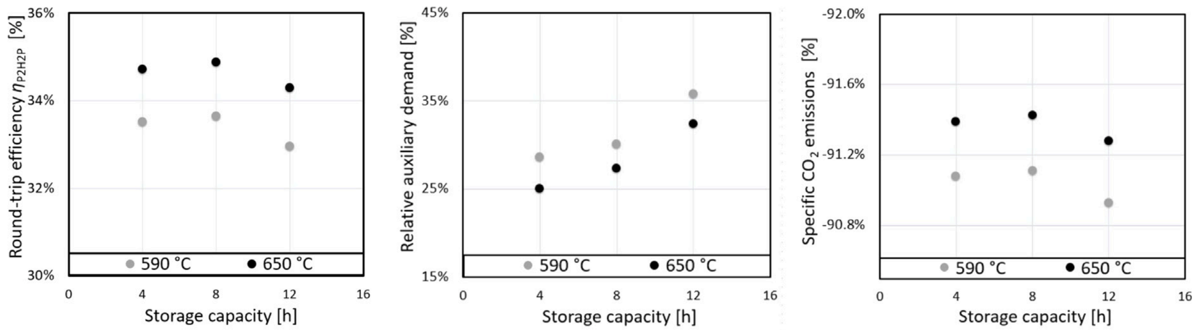
Parameters	Unit	Value
Debt interest rate	%	5
Annuity factor	%	6.11
Debt period	years	35

4. Results and discussion

4.1. Technical results

The results of the annual yield analysis considering a typical daily profile and charging durations of 4, 8 and 12 h for the selected configurations are shown in Fig. 6. For the configuration with a steam-generator inlet temperature of 650 °C, Fig. 6 shows a total annual net power production of around 443 GWh_{el} for 4 h storage capacity, 797 GWh_{el} for 8 h storage capacity and 1150 GWh_{el} for the 12 h storage. These values are around 3.4% lower when the air temperature at the steam generator inlet is set to 590 °C.

The annual efficiencies (see Eq. (1) and (2)) are illustrated in Fig. 8. The gross annual efficiencies of the power block with an air temperature of 590 °C at the steam-generator inlet are slightly higher than for the 650 °C inlet temperature, presumably because the live steam is generated with a lower temperature difference to the heat transfer fluid. Contrary, the annual round-trip efficiencies are higher when using 650 °C air at the steam generator inlet. For both steam generator inlet temperatures, the maximum annual round-trip efficiency η_{P2H2P} is



(a) Round-trip efficiency. (b) Auxiliary demand. (c) CO_2 emission reduction.

Fig. 7. Evaluation of three main technical parameters for all cases considered in this work.

Table 6
Capacity and power specific investment costs of all considered cases.

Case	4 h (590 and 650 °C)	8 h (590 and 650 °C)	12 h (590 and 650 °C)
Capacity specific costs (€/kWh$_{th}$)	101.2	70.7	59.9
Charge power specific costs (€/MW$_{el,in}$)	972.5	677.9	575.1
Discharge power specific costs (€/MW$_{el,out}$)	998.2	1344.6	1691.0

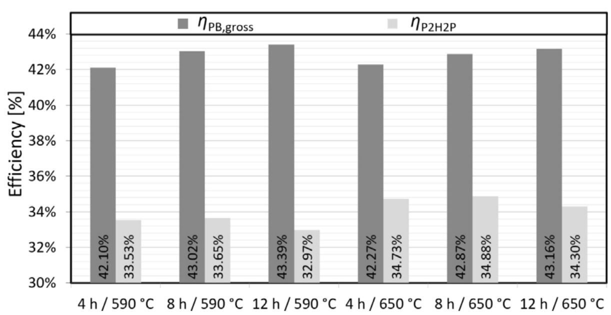


Fig. 8. Comparison of annual efficiencies.

achieved for a storage capacity of 8 h (34.9% for an air temperature of 650 °C and 33.7% for 590 °C). The authors explain that with a trade-off between start-up losses and auxiliary demand (see Fig. 7(b)): While the start-up losses have significant influence on the 4 h configurations, the long discharge duration of 12 h also comes with a higher (absolute and relative) auxiliary demand since the total operation time is longer and in particular the blower power for discharging increases the auxiliary demand significantly. These effects are considered to be generalizable and so is the observation of a higher auxiliary demand for lower steam inlet temperature since the requirement of higher mass flow inevitably leads to an increase in blower power. In this study, the self-discharge affects all cases and operation modes equally, while in reality rest periods might be characterized by lower self-discharge due to completely closed storage valves.

In order to analyze the reduction in CO_2 emissions, the specific CO_2 emissions relative to the reference coal plant are presented in Fig. 7(c). The conversion of the coal power plant into a thermal storage power plant shows a maximum reduction level of around 91.4% for the configuration with an inlet air temperature of 650 °C and a storage capacity of 8 h (see Table 1 for reference CO_2 emissions). Configurations with inlet air temperature of 590 °C present slightly lower reduction levels around 91% due to the lower annual round-trip efficiency previously mentioned. It should be noted that the results are based on charging with nearly CO_2-free electricity which is, at the time being, only conceivable with renewables located directly on site, e.g. an independent, local PV grid (here considered with 35 kg$_{CO_2,eq.}$ /MWh$_{el}$). Nevertheless, taking into account that around 31% of all CO_2 emissions from energy production and industry is caused by the burning of coal [33], significant emission reduction potential within the Chilean energy system can be concluded.

4.2. Economic results

For the economic evaluation, investment and operation costs ($CAPEX$ and $OPEX$) are calculated together with the levelized cost of electricity $LCOE$, see Eq. (4), in order to compare the different cases (techno-) economically. The analysis of the investment costs (Fig. 9) shows a higher absolute $CAPEX$ with the increment of the storage capacity due to the cost increase in storage, electrical heater, charging circuit and electrical equipment (mentioned in decreasing value increase). Owner's costs, which include all costs in addition to the EPC costs and project contingency, are defined according to $CAPEX$ (see Table 6). Thus, they increase accordingly.

Configurations with different air temperatures at the boiler inlet and same storage capacity do not present any change in $CAPEX$, because, in this study, the costs associated with the heat recovery steam generator were evaluated considering the thermal power needed by the power block at the design point. This is considered suitable since both configurations operate with the same live-steam temperature. Nevertheless, for future works, a more detailed approach with a specific component analysis should be performed to analyze the influence of steam generator inlet temperatures on the equipment cost. For example, a higher steam generator inlet could allow a reduced heat transfer surface and hence costs but be associated with higher specific material costs.

Even though the $CAPEX$ increases from 276.39 to 372.31 and 468.23 Mio. €, respectively, are striking, the specific costs given in Table 6 have higher informative value. Here, discharge power specific costs increase for longer discharge durations since the electric output is fixed, while both capacity-specific as well as charge-power-specific costs significantly decrease and indicate economic advantages, checked for validity in the following.

For the final techno-economic evaluation, $LCOE$ is used, based on the results of the annual energy yields and annual costs. Fig. 10 presents the $LCOE$ of all cases. Similar to the capacity and charge power specific costs in Table 6, the $LCOE$ decrease with increasing storage capacity. The maximum derived $LCOE$ is 107.73 €/MWh for the configuration 4 h/590 °C and the minimum one is 88.09 €/MWh$_{el}$ for the configuration 12 h/650 °C. Fig. 10(a) additionally demonstrates the large influence from the electricity price on $LCOE$ with a share of up to 62% in this study. The reason for that is the inverse proportionality

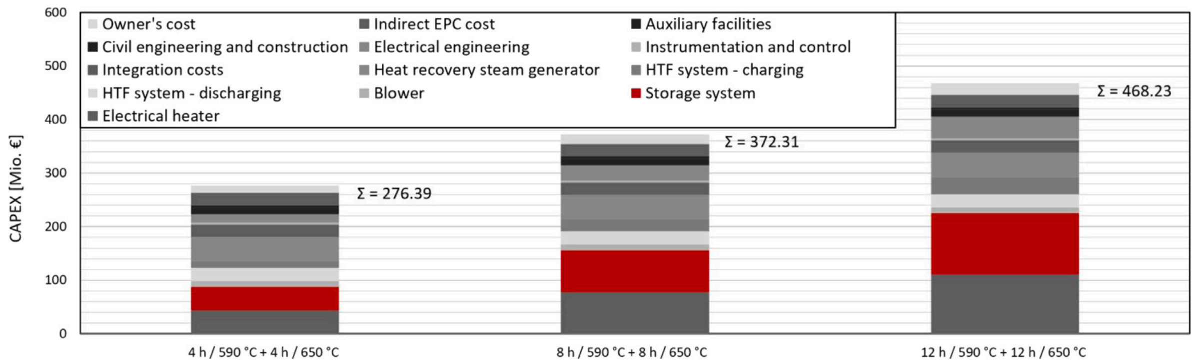
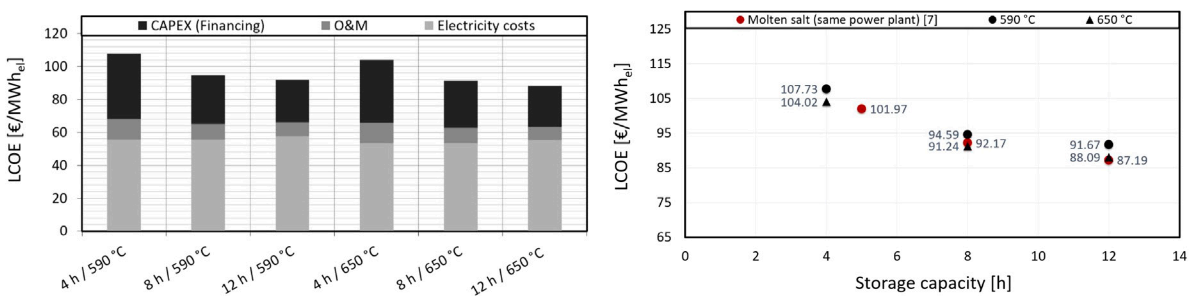


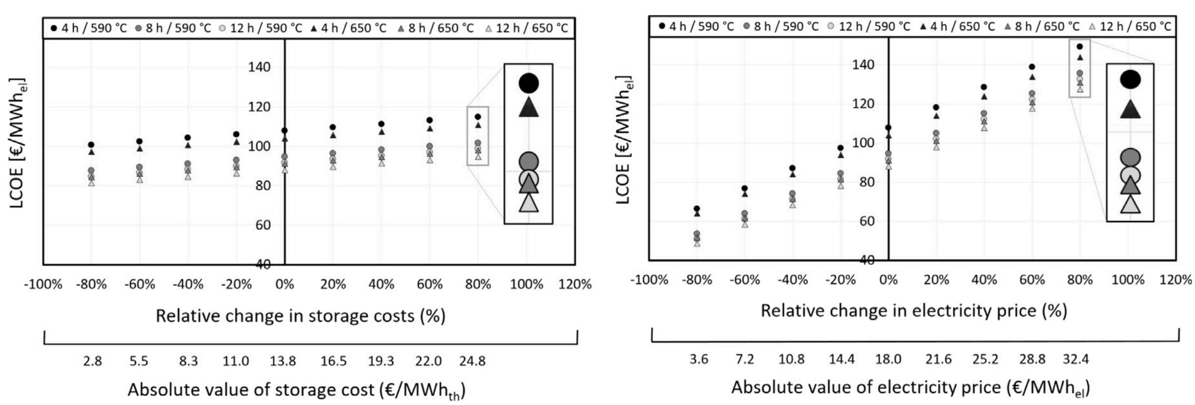
Fig. 9. $CAPEX$ of all considered cases. The different categories are consistent with Table 4.



(a) Composition of LCOE for all cases.

(b) LCOE over capacity for all cases incl. molten salt reference.

Fig. 10. $LCOE$ evaluation.



(a) Variation of storage costs.

(b) Variation of electricity costs for charging.

Fig. 11. Sensitivity analysis of $LCOE$. Please note that absolute $LCOE$ values are plotted on the ordinate.

between heat engine efficiency and electricity used rather than the actual assumption of 18.3 €/MWh$_{el}$. The observation that the $LCOE$ differences between 4 and 8 h storage capacity are notably larger than the ones between 8 h and 12 h can be explained with the annual round-trip efficiency being lowest for the highest storage capacity, and hence leading to higher $LCOE$ than the 12 h cases would have with the same annual round-trip efficiencies as in the 4 and 8 h cases.

Moreover, Fig. 10(b) includes the results obtained from a previous study for a retrofit with molten-salt storage considering the same reference coal plant [3]. In the referred study, results show $LCOE$ of 87.2 €/MWh$_{el}$ for a storage capacity of 12 h with 10 h charging, and 102 €/MWh$_{el}$ for the minimum storage capacity (5 h) and same charging time. The cost assumptions for both studies are not identical but comparable, allowing a comparison of $LCOE$. Based on this, the $LCOE$ from the retrofit with the rock storage are considered to be competitive, according to this study in particular for low storage capacities which could be due to the assumed self-discharge rate. In any case, a full comparability is questionable and further work needs to assess what is not only feasible but also favored over alternatives. The advantage that solid media storages can operate at higher temperatures than 565 °C, which is the operating limit of commercial molten salts, should be quantified and a comparison of different solid media storage concepts would be of interest, both under equal boundary conditions.

Finally, since storage costs account for the largest $CAPEX$ share of up to one quarter according to Fig. 9 but electricity costs stand out in Fig. 10(a), a sensitivity analysis of the $LCOE$ is done for both of these economic assumptions, presented in Fig. 11. As the larger share of electricity for charging over financing in Fig. 10(a) already indicates, the $LCOE$ is significantly more sensitive to changes in electricity price than in storage costs: Lowering storage costs by a factor of five, corresponding to 2.8 €/MWh$_{th}$ which is even lower than the supposedly most promising values reported by Allen et al. [30], leads to a maximum $LCOE$ reduction of less than 8%, while the $LCOE$ would decrease by 42% on average for the same relative change but in electricity price for charging. This finding showcases that storage systems with higher costs should not be excluded right off but instead be evaluated holistically. Furthermore, it also highlights the importance of electricity purchase for charging. In this regard, either fixed price options such as self-owned renewables on site or green power purchase agreements [34] or variable price options such as arbitrage business, typically on the day-ahead market, are possible. A follow-up study could drop the assumption of a fixed operation strategy and sizing in order to implement the methods presented in this work in a techno-economic optimization algorithm which identifies the ideal operation for different electricity purchase options for charging. In that context, charging hours with least cost and discharging hours with highest revenue are key.

5. Conclusions

This paper demonstrates that thermal storage based on solid media such as rocks is a promising alternative to molten salt storage when existing (traditional) fossil-fired power plants are retrofitted within decarbonization efforts. The technical integration of an innovative packed bed storage design into a specific Chilean power plant as well as its economic consequences in multiple operation cases by the variation of storage discharge time and air temperature at the steam-generator inlet is presented. The main conclusions of this work are described as follows:

- The maximum annual round-trip efficiency is achieved for a storage capacity of 8 h, since there is a trade-off between the effect of start-up losses and auxiliary demands.
- Increasing the inlet steam generator temperature from 590 to 650 °C leads to a higher annual round-trip efficiency (33.7 vs. 34.9% for the 8 h discharge case) and hence up to 3.4% lower $LCOE$.
- Minimum $LCOE$ as low as 88.09 €/MWh is attainable for the largest storage capacity. This value appears competitive with both state-of-the-art conventional power plants and alternatives such as the ones powered with thermal storages based on molten salt..
- Assuming five times lower storage costs, the largest $CAPEX$ driver, results in only 4% lower $LCOE$ on average. Hence, also more expensive storage systems should be considered holistically. On the contrary, the electricity costs for charging represent up to 62% of the $LCOE$ and are thus identified as the crucial parameter, also confirmed by the sensitivity analysis performed in this work.

Future studies should take into account that a higher steam generator inlet temperature not only affects the round-trip efficiency but might decrease the $CAPEX$ if the reduced required heat transfer area overcompensates the material costs for withstanding higher temperatures. However, this work brings into sharp relief the significant importance of the electricity purchase. Power purchase agreements, if properly designed, can become a key lever to capture the value of thermal storage power plants. A follow-up study implementing the tools developed in this work in a techno-economic optimization could pave the way towards implementation, identifying the ideal operation and sizing for lowest cost and maximum revenue.

CRediT authorship contribution statement

María Isabel Roldán Serrano: Conceptualization, Data curation, Software, Writing, Visualization. **Kai Knobloch:** Conceptualization, Data curation, Software, Writing, Visualization. **Stefano Giuliano:** Software, Writing – review, Funding acquisition. **Kurt Engelbrecht:** Writing – review, Funding acquisition. **Tobias Hirsch:** Writing – review, Funding acquisition.

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.

Data availability

Data will be made available on request.

Acknowledgments

KK an KE would like to express their gratitude to the Energy Technology Development and Demonstration Programme, Denmark (EUDP No. 64019-0520 - IEA Task 36 Carnot Batteries) for funding this work. This work is also related to the 4e Program for the decarbonization of the electricity matrix in Chile. The authors would like to thank AES Chile for the valuable technical input and support.

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