Techno-economic Evaluation of Solar-based Thermal Energy Storage Systems

Spandan Thaker, Abayomi Olufemi Oni, Amit Kumar*

Department of Mechanical Engineering, 10-203 Donadeo Innovation Centre for Engineering, University of Alberta, Edmonton, Alberta T6G 1H9, Canada

Abstract

In this paper, a data-intensive cost model was developed for sensible heat, latent heat and thermochemical storage systems. In order to evaluate the economic feasibility of storage systems, five scenarios were developed depending on the method of storage. The five scenarios considered were indirect sensible heat, direct sensible heat using two tanks, direct sensible heat using one tank, latent heat and thermochemical storage. A Monte Carlo simulation was performed for all the scenarios to examine the uncertainty in the levelized cost of electricity when parameters such as solar multiple, plant capacity, storage duration, capacity factor, and discount rate are changed. The levelized cost of electricity ranges for individual scenarios are; 0.08 – 0.59 \$/kWh for indirect sensible heat, 0.03 – 0.22 \$/kWh for direct sensible heat using two tank, 0.02 – 0.16 \$/kWh for direct sensible heat using one tank, 0.06 – 0.43 \$/kWh for latent heat, and 0.22 – 1.19 \$/kWh for thermochemical storage. The results indicate that when uncertainty is taken into account, the investment cost for thermochemical storage is clearly higher than other scenarios. This study will provide key information for industry and policy makers in decision making and in determining the economic viability of thermal energy storage systems.

Acronyms

A ❼ Total heat exchanger area

C ❼ Total investment cost ($)

CSP ❼ Concentrated solar power

c_p ❼ Specific heat capacity

D ❼ Discount rate (%)

Energy ❼ Total energy produced (kWh)

G ❼ Variable O&M escalation due to inflation (%)

GHG ❼ Greenhouse gas

h ❼ Enthalpy

LCOE ❼ Levelized cost of electricity ($/kWh)

$\dot{m}$ ❼ Mass flow rate

N ❼ Total life (years)

O&M ❼ Operation and Maintenance

PCM ❼ Phase change material

$\dot{Q}$ ❼ Rate of heat transfer

$\dot{Q}_{loss}$ ❼ Rate of heat loss

SM Solar multiple

S1 ❼ Scenario 1: Indirect sensible heat storage using two tanks

S2 ❼ Scenario 2: Direct sensible heat storage using two tanks

S3 ❼ Scenario 3: Direct sensible heat storage using one tank

S4 ❼ Scenario 4: Latent heat storage using one tank

S5 ❼ Scenario 5: Thermochemical heat storage

T ❼ Temperature of heat transfer fluid

TES ❼ Thermal energy storage

Δ▯▯ ❼ Log mean temperature difference

U.S. DOE ❼ Department of energy

U ❼ Overall heat transfer coefficient

▯̇ ❼ Rate of work

Δ▯▯ ❼ Change in kinetic energy

Δ▯▯ ❼ Change in potential energy

Keywords

Cost comparison; thermal storage systems; sensible heat storage system; latent heat storage system; thermochemical storage system.

1.0 Introduction

Thermal energy storage (TES) has the potential to store energy in the form of heat over a period of time for later use. It is a promising technology that can reduce reliance on fossil fuels and help avoid penalties related to environmental regulations. The use of TES to meet environmental standards and energy requirement is now receiving the attention it has always deserved. TES is expected to grow by 11% between 2017 and 2022 [1]. The growth rate of TES can be affected by the intermittency issues in solar radiation (i.e., cloudy days and night-time). For this reason, there is a need to integrate the storage of thermal energy (i.e., sensible heat, latent heat, and thermochemical) with electrical power generating systems. However, despite challenges around the integration of TES, it is not yet known if it is economically feasible. For this reason, the cost-effectiveness of integrating TES into existing technologies is a subject of discussion.

A recent development is to improve the cost-effectiveness of TES by reducing the levelized cost of electricity. For example, in March 2015, the U.S. Department of Energy (DOE) announced a plan to reduce the levelized cost of electricity from solar-based electrical power generation to below \$0.06/kWh by 2020 [2]. This plan prompted the search for cost-effective ways to store energy in the form of heat. In view of this, sensible heat, latent heat, and thermochemical storage are considered for storing thermal energy. Sensible heat storage is a commercially available technology that can store thermal energy for up to 15 hours using a heat transfer medium such as molten salt [3]. Molten salts have high storage efficiencies that allow sensible heat storage to produce electricity during peak energy demand, thereby making electricity more economical [4]. Latent heat storage can store energy at relatively low investment costs [5]. Because of the high energy densities of the phase change materials (PCMs) used in latent heat storage, there is a potential to reduce storage tank costs compared to sensible heat storage [6]. However, latent heat storage is still in the research and development (R&D) phase to optimize the trade-off between reducing the cost of the PCMs and improving its thermal conductivity. Thermochemical storage is also still in the R&D phase. Because there are insufficient data on it, its economic feasibility has been examined through hypothetical models [7]. A widely used economic indicator to assess the economic feasibility of TES is the levelized cost of electricity (LCOE).

The LCOE is often evaluated while performing techno-economic assessments. To accurately perform a techno-economic assessment, a system boundary needs to be defined. The system boundary determines which components are included. A solar-based TES system boundary has three parts: solar field, storage block, and power block [8]. A study by Sioshansi et al. [4] showed that the size of the equipment in all three affect the economic viability of solar-based power generation systems (i.e., concentrated solar power). The solar field equipment includes mirrors, piping, pumps, valves, and parabolic troughs. The storage block consists of heat exchangers, pumps, piping, valves and storage tanks to store the heat transfer fluid. The power block includes a turbine, condenser, pumps, piping, and valves. The sizing of this equipment affects the investment cost of concentrated solar power (CSP) plants. Several researchers estimated the LCOE and investment costs for TES technologies using different system boundaries. Flueckiger et al. [9] evaluated the LCOE of a thermocline storage system by considering solar field, storage block, and power block as a system boundary. In addition to the aforementioned system boundary, Montes et al. [10] included an auxiliary natural gas-fired boiler for steam generation. However, a study by Heller et al. [11] evaluated the LCOE without considering the power block in the system boundary.

Other than through a system boundary, the LCOE can be evaluated as a function of capacity factor, solar multiple, storage duration, and plant capacity. Storage duration is defined as the length of time heat can be stored in a system. The ability of TES to store energy for long periods suggests greater economic viability as stored heat can be used to generate power during peak load when solar energy is absent or insufficient. As storage time increases, it gives the freedom to dispatch electricity when electricity prices are at their peak and thereby increase profit [4].

Another important factor in evaluating the LCOE is the solar multiple. The solar multiple is the ratio of thermal energy collected in the solar field to the thermal energy input for the turbine [12]. A solar multiple of one, for instance, indicates that the energy produced in the solar field is equal to the energy consumed by the turbine, leaving no excess energy to be stored [4]. A solar multiple of two, on the other hand, indicates that the energy produced in the solar field is twice that consumed by the turbine, leaving excess energy to be stored as heat for later use, thus making the technology more economical. However, the solar multiple is not the sole indicator of economic feasibility. The capacity factor is also used to evaluate economic viability. It is the ratio of actual energy produced to the theoretical energy produced per annum [12]. The capacity factor of TES would affect the LCOE because the energy produced from thermal storage can be sold in the form of electricity. Plant capacity can also be used to evaluate the LCOE. Plant capacity is measured in megawatts (MW) and is defined as the electrical power output that can be provided by the thermal storage system. The LCOE associated with varying plant capacity would demonstrate economies of scale. Thus, storage duration, capacity factor, solar multiple, plant capacity, and system boundary are few of the key factors to be considered when evaluating the LCOE to determine the economic feasibility of TES.

A few studies developed techno-economic models to examine the economics of TES technologies. These models can be classified into three types. Type 1 models examined the economics of sensible heat storage [13]. The costs of thermal storage for parabolic troughs and central tower solar field systems were evaluated by Turchi et al. [14] using the Solar Advisor Model (SAM) software and found to be less than 11 cents/kWh. In a similar study by Hinkley et al. [15], the LCOE was evaluated for both technologies using SAM software. Hinkley et al. [15] showed that at a higher operating temperature, there is a significant potential to reduce LCOE. SAM software performed a techno-economic assessment of TES using input parameters such as unit capital cost ($/kW) and storage duration [15]. Boudaoud et al. [13] evaluated the investment costs of individual equipment using first principles. The estimated LCOE values were approximately 0.66 – 0.78 $/kWh and 0.6 – 1.3 $/kWh, respectively, when storage duration and solar multiples were varied [13]. Lund et al. [16] examined the economics of a hybrid system integrating thermal storage with battery storage and liquid fuel storage within the system boundary. The hypothetical storage system proposed in Lund et al. [16] aims to take a holistic approach by integrating cross-sector energy conversion technologies to address the needs of district heating and power generation. The Type 1 techno-economic assessments had different system boundaries and assumptions, making it difficult to compare them. Type 2 models examined the economics of latent heat storage [17]. Hubner et al. [18] evaluated the unit capital cost of various phase change materials to examine its effect on the LCOE. Xu et al. [5] used first principles to evaluate investment costs of individual equipment. The investment costs were used to estimate the LCOE for latent heat storage. Xu et al. [5] estimated the LCOE for various phase change materials to be approximately 0.098 – 0.10 $/kWh. Seitz et al. [17] estimated the LCOE by evaluating unit costs of equipment in the solar field, power block, and storage block. It is difficult to assess the models developed in the previous studies because the system boundaries, process conditions, and economic parameters are different. Type 3 models examined the economics of thermochemical storage [19]. Wenger et al. [20] evaluated the economics of a hypothetical electrochemical plant that considered a hybrid of both thermochemical and battery systems. The proposed plant aimed to reduce investment costs by replacing turbine systems with a battery system to generate electricity. Luzzi et al. [7] assessed the economic viability of thermochemical storage by evaluating the LCOE for a hypothetical power plant. Luzzi et al. [7] estimated the LCOE to be approximately 0.25 AUD/kWh (Australian dollar per kilowatt-hour) for a 10 MW hypothetical plant capacity.

Few studies assess the economic feasibility of TES. The purpose of this paper is to develop a techno-economic model that concurrently compares the economic feasibility of sensible heat, latent heat, and thermochemical storage. To make an “apples-to-apples” comparison between TES technologies, moreover, the LCOE must be evaluated using a well-defined system boundary. For these reasons, comprehensive cost models for sensible heat, latent heat and thermochemical storage were developed in this study. This study focuses solely on the storage block, which is the study’s system boundary. In other words, the LCOE calculated in this study does not include costs from the solar field or the power block. In addition, a sensitivity analysis of the LCOE was done by varying parameters, i.e., plant capacity, solar multiple, storage duration, discount rate, and capacity factor. The impact of these parameters on the LCOE was determined through an uncertainty analysis. There is limited work done on uncertainty analyses in literature. Hanel and Escobar [21] have considered the uncertainty of the levelized cost of electricity by varying parameters such as solar radiation, plant configuration, and solar field area. However, other key parameters such as storage duration, solar multiple, capacity factor, discount rate, and plant capacity are not considered in the uncertainty analysis. Filling the aforementioned gaps would provide key information to industry and policy makers in decision making and in determining the economic viability of TES systems.

The main objective of this study is to conduct a comprehensive techno-economic assessment of sensible heat, latent heat, and thermochemical storage using a data-intensive bottom-up methodology. The specific objectives of this study are to:

1. Develop a techno-economic model to estimate the LCOE for sensible heat, latent heat, and thermochemical storage.

2. Conduct a comprehensive sensitivity analysis to assess the impact on the LCOE for sensible heat, latent heat, and thermochemical storage.
3. Conduct an uncertainty analysis using a Monte Carlo simulation to determine the uncertainty in the LCOE.

2.0 Methods

A detailed description of the solar-based thermal energy storage systems is presented in this section. The assumptions and the techno-economical models developed to evaluate the economic feasibility of the storage systems are also discussed.

2.1 Indirect sensible heat storage using two tanks (S1)

In two-tank indirect sensible heat storage, heat transfer fluids (HTF) such as Dowtherm A©, synthetic oils, and Therminol VP© are heated through parabolic troughs. The HTF used in parabolic trough technology can be heated to approximately 608 – 752 °F (320 - 400 °C) [22]. The system boundary illustrated in Figure 1 shows heated HTF as input in a temperature range of 608 – 752°F (320 - 400 °C). During peak demand, the HTF flows through the 3-way valve allowing the fluid to flow through heat exchanger #2. Subsequently, heat is extracted from the HTF to convert water into superheated steam. The HTF is then re-circulated back to the system to be reheated. During low energy demand, the HTF flows through heat exchanger #1, where excess heat from the HTF (synthetic oil) is transferred to heat up molten salt. The chemical mixture of molten salt is taken to be 60% sodium nitrate ($NaNO_3$) and 40% potassium nitrate (KNO_3) [23]. The heated molten salt is stored in a hot tank and the cold molten salt in a cold tank. The cold molten salt would have to be stored at approximately 554°F (290°C) to prevent the salt from solidifying [22]. During night-time, heat is then extracted from the hot molten salt by circulating through heat exchanger #1 where HTF is reheated to approximately 725 °F (385 °C). Subsequently, the HTF is circulated in heat exchanger #2 to convert water into superheated steam. The superheated steam has two applications, power generation and process heating. A report published by Siemens© provides inlet steam operating temperature and pressure for steam turbines used in concentrated solar power (CSP) plants [24]. Siemens© developed steam turbines for CSP technology with turbine capacities from 1 to 250 MW [24]. The maximum attainable inlet steam temperature and pressure are 1085 °F (585 °C) and 165 bar, respectively [24].

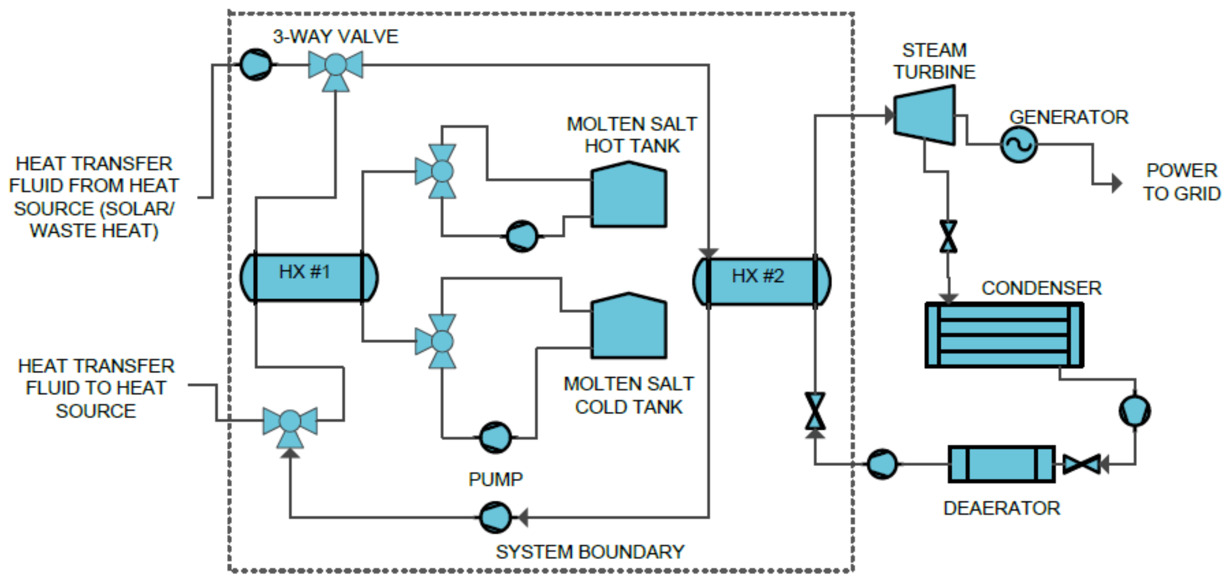

Figure 1: Schematic of two-tank indirect thermal storage

2.2 Direct sensible heat storage using two tanks (S2)

Two-tank direct sensible heat storage operates on the same principle as S1. However, one heat exchanger is used instead of two (see Figure 2). The elimination of a heat exchanger and pumps could reduce capital cost. Heat from the sun is directly concentrated onto a central tower, allowing direct heat transfer to heat molten salt. This direct heat transfer allows for a higher operating temperature of approximately 554 – 1050 °F (290°C – 565°C) [22]. In contrast, S1 requires an intermediate heat transfer medium such as synthetic oil that is heated to an operating temperature of approximately 608 – 752 °F (320 - 400 °C) [22].

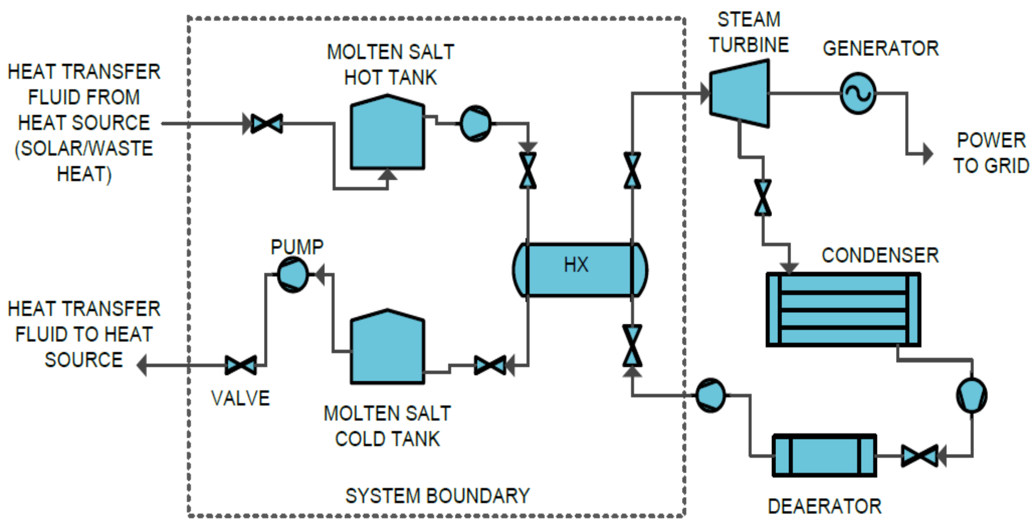

Figure 2: Schematic of two-tank direct sensible heat storage

2.3 Direct sensible heat storage using one tank (S3)

One-tank direct sensible heat storage, also known as thermocline storage, uses one tank to store both hot and cold molten salt. However, thermocline storage does not operate under steady state. In other words, as hot molten salt is pumped into the tank, cold molten salt is pump out and vice-versa. Figure 3 illustrates the single storage tank in which hot molten salt flows from the top while cold molten salt flows from the bottom. One of the advantages to thermocline storage is a reduced tank volume of approximately 66% from two tank storage; this reduces the total amount of molten salt by 66% [25, 26].

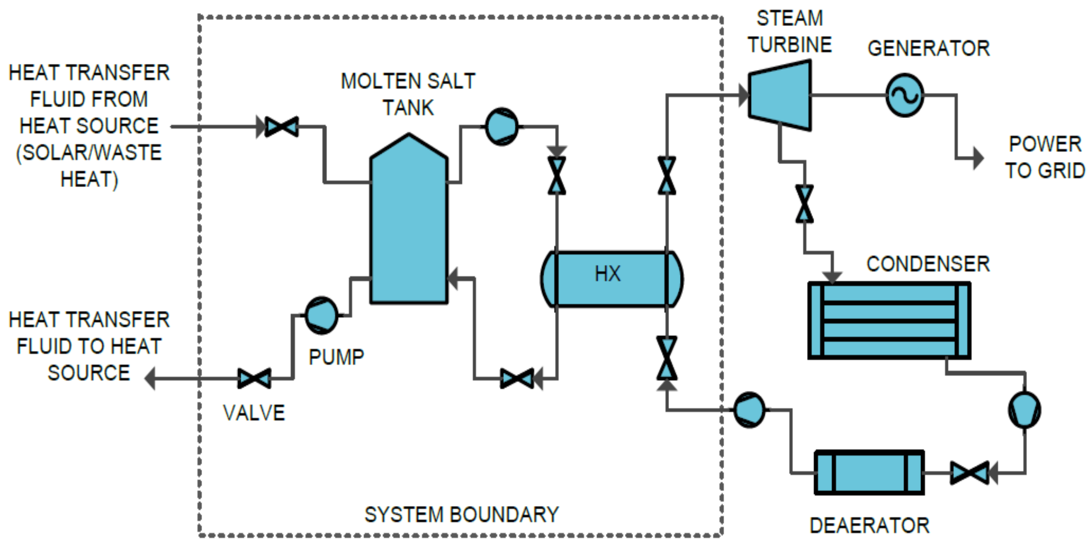

Figure 3: Schematic of one-tank direct sensible heat storage

2.4 Latent heat storage using one tank (S4)

In one-tank latent heat storage, phase change materials in the form of pellets are used as the heat transfer medium. The pellets change from solid to liquid when heat is absorbed from the sun. Subsequently, heat is released by reversing the phase change process from liquid to solid. This heat is used to convert water into superheated steam using a heat exchanger, as shown in Figure 4. Figure 4 outlines a schematic of one-tank latent heat storage where phase change materials in the form of pellets occupy the tank while the spaces between pellets are filled with molten salt. Kuravi et al. [26] reported that the phase change pellets occupy approximately 75% of the tank's volume, allowing the remaining volume to be filled with molten salt. Studies show that PCMs have higher energy densities than molten salt, resulting in an approximately 65% decrease in overall storage tank volume and a 30% decrease in storage material volume [27]. Smith et al. [27] reported a 40% reduction in cost for one-tank latent heat storage using PCMs as the storage medium compared to the widely used molten salt storage medium. The cost of thermal storage using PCM as the storage medium was calculated based on a 50% reduction in tank cost, a 30% reduction in storage material cost, a 50% reduction in cost for piping, and 40% cost reduction in construction materials [27].

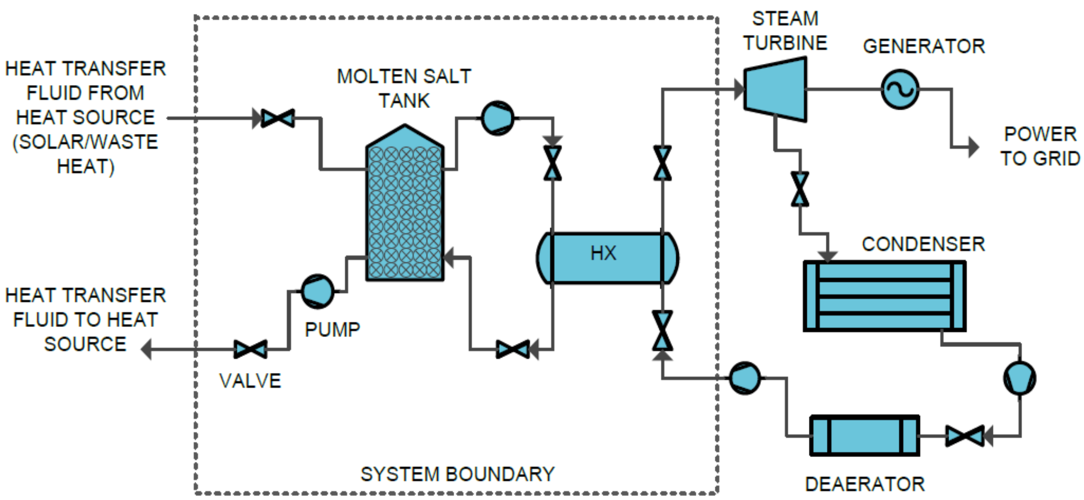

Figure 4: Schematic of one-tank latent heat storage

2.5 Thermochemical heat storage (S5)

Thermochemical energy storage was modelled in Aspen HYSYS [28], which simulated a reversible reaction through dissociation and synthesis of ammonia, as shown in the chemical formula below where ∆H represents reaction enthalpy:

Endothermic dissociation reaction: $2NH_3 + \Delta H \leftrightarrow N_2 + 3H_2$

Exothermic synthesis reaction: $N_2 + 3H_2 \leftrightarrow 2NH_3 + \Delta H$

Figure 5 is a process flow schematic of thermochemical energy storage. In this scenario, a stream of pure ammonia in gaseous form is the input (labelled "1"). The input ammonia is assumed to be heated to approximately 1742 °F (950°C) and 2900 psi (20 MPa) using concentrated solar radiation. The mass flow of the input ammonia stream was calculated using mass and energy balance to be approximately 6.99×10^6 lb/hr (3.17×10^6 kg/h). The heated ammonia gas is diverted into a dissociation reactor labelled "GBR-100." Studies show that the percentage of ammonia dissociation is directly proportional to high temperatures and high pressures [19]. The dissociated gas mixture of hydrogen and nitrogen is cooled to 77 °F (25 °C) by liquid ammonia in a heat exchanger below (labelled "E-100") before being stored in a two-phase high-pressure tank (labelled "V-100") [19]. The two-phase tank can store this gas mixture for long periods with minimal heat loss; this is a major advantage of thermochemical energy storage. In order to generate heat, the gas mixture is preheated in a heat exchanger (labelled "E-102") to around 527 °F

(275 °C). The resulting hot gas mixture is diverted into a synthesis reactor ("CRV-100") where ammonia is produced in the presence of a catalyst. This synthesis reaction is highly exothermic and releases large amounts of heat that are used to convert water into high-pressure superheated steam at approximately 806 °F (430 °C) and 1500 psi (10MPa) [7]. The high-pressure steam can be used for power generation or process heating.

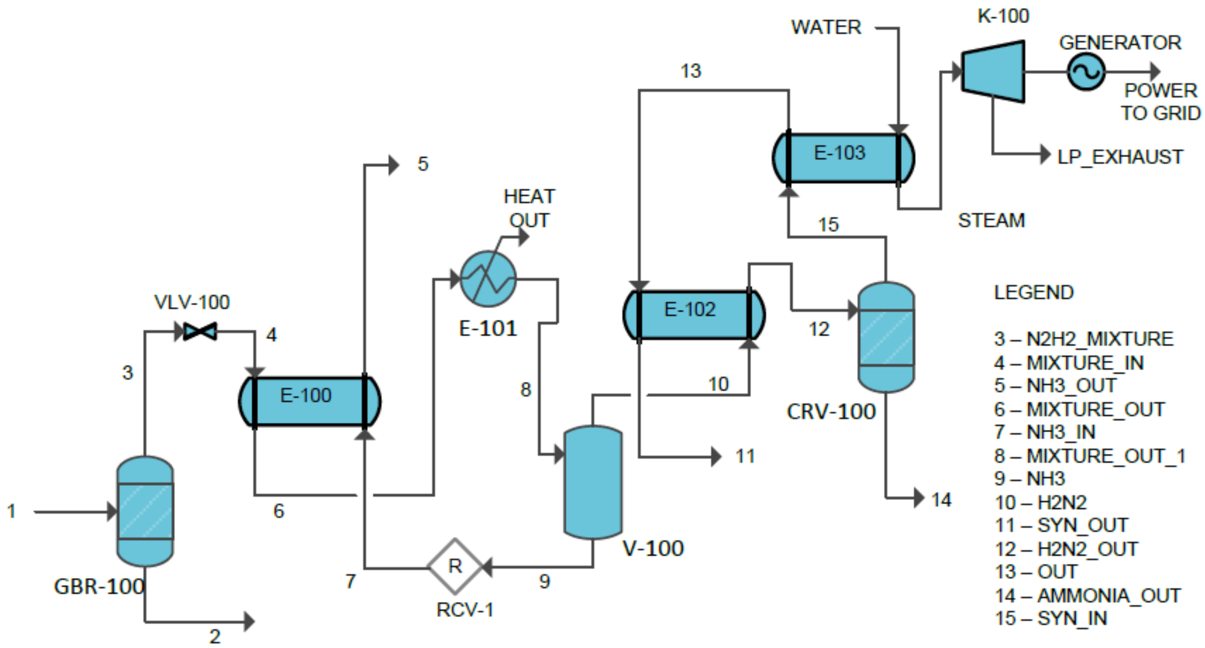

Figure 5: Thermochemical energy storage software model using Aspen HYSYS

2.6 Cost estimation

The methodology used in this paper has three parts. First, technical parameters such as mass flow rate, heat transfer rate, and pressure drop across equipment were computed. Second, individual equipment costs were computed along with a sensitivity analysis and an uncertainty analysis (using a Monte Carlo simulation). Third, a comprehensive cost model was developed using the assumptions listed in Table 1. The total investment cost was estimated in a cost model by calculating individual equipment purchased and installed (P&I) cost as outlined in Table 2. All costs are evaluated in 2016 US dollars. The equipment P&I costs were calculated using equations reported by Gabbrielli et al. [29]. Their equations require parameters such as pump power, pump efficiency, heat exchanger area, and heat exchanger pressure drop. These parameters were calculated using the first principles of mass and energy balance to compute mass flow rates and pressure drop across equipment (heat exchangers, pumps, steam turbines). Furthermore, Excel-based spreadsheets were integrated with Aspen HYSYS to determine parameters such as heat transfer rate, mass flow rate, heat exchanger area, and pressure drop pertaining to unit operations.

Table 1: Assumptions for cost estimation and LCOE calculation

Assumptions	Parameter values	Refs.
N (yrs)	30	[30]
Inflation (2010 to 2016)	2.0%	[31, 32]
N (yrs) due to inflation from 2010	6	
Variable O&M escalation per annum	2.5%	
Variable O&M cost (% of investment cost)	2%	[30]
Fixed O&M cost (% of investment cost)	2%	[30]

Table 2: Parameters considered for bottom-up cost estimation [29]

Components for bottom-up	Cost estimation parameter values

cost estimation	
Equipment purchase and installed (P&I) cost	Sum of individual equipment cost
Other miscellaneous equipment (i.e., piping, valves, deaerator)	10% of equipment of P&I cost
Process building cost ($)	Material cost (10% of P&I cost) Labour cost @$25.18/hr (5% of material cost)
Service building cost ($)	Material cost (7.5% of P&I cost) Labour cost @$25.18/hr (5% of material cost)
Service system cost ($)	Material cost (10% of P&I cost) Labour cost @$25.18/hr (2% of material cost)
Site development cost ($)	Material cost (1% of subtotal P&I cost) + land (2% of subtotal P&I cost) + freight cost (2% of subtotal P&I cost) + labour cost (2% of material cost)
Total indirect cost ($)	Contractor's cost (12% of direct cost) + owner's cost (5.6% of direct cost) + fees and insurance (8% of direct cost)
Contingency cost (3% of direct cost)	3% of direct cost
Total investment cost ($)	Summation of above costs

2.6.1 Mass flow rate requirement in condensing steam turbine

Mass flow rate ($\dot{m}$) is calculated based on the capacity ($\dot{W}$) measured in MW, and the rate of heat loss ($\dot{Q}_{loss}$) in the steam turbine is assumed to be negligible [33]:

$$\dot{Q}_{loss} \quad (1)$$

where h, ΔE$_k$, and ΔE$_p$ represent the enthalpy, change in kinetic energy, and change in potential energy, respectively for the steam turbine. The change in kinetic energy is assumed to be zero as the steam turbine operates at steady state conditions. The change in potential energy for the steam turbine is zero as the change in elevation is negligible.

2.6.2 Heat exchanger energy balance

The heat transfer rate ($\dot{Q}$) in the heat exchangers was calculated using the following energy balance equation, where c_p represents specific heat capacity and $(T_2 - T_1)$ is change in temperature of the heat transfer fluid [33]:

$$\dot{Q} == \dot{m}_2 c_p (T_2 - T_1) \quad (2)$$

2.6.3 Heat exchanger area

Heat transfer area is calculated using the following equation:

$$\dot{Q} = UA(\Delta T_m) \quad (3)$$

where $\dot{Q}$, U, A, and ΔT_m represent the heat transfer rate, overall heat transfer coefficient, total heat transfer area, and log mean temperature difference, respectively [33].

Upon computing heat exchanger area, mass flow rate, heat transfer rate and pressure drop pertaining to unit operations, the total purchase and installed (P&I) cost of individual equipment were calculated. The LCOE was then evaluated for sensible heat, latent heat, and thermochemical storage. A comprehensive evaluation of the LCOE can be carried out using discounted cash flow analysis, which considers input parameters such as capacity factor, discount rate, plant capacity (MW), operation and maintenance (O&M) costs, total life (years), total investment cost ($ in USD), and total energy produced (kWh). Equation 4 outlines a derived expression for the levelized cost of electricity using a discounted cash flow, which mathematically correlates the above parameters as follows:

$$LCOE = \frac{(C*(1+D))+((C*0.02)*(\frac{1-(\frac{1+G}{1+D})^{N}}{1-(\frac{1+G}{1+D})}))+((C*0.02)*(\frac{1-(\frac{1}{1+D})^{N}}{1-(\frac{1}{1+D})}))}{(\frac{1-(\frac{1}{1+D})^{N}}{1-(\frac{1}{1+D})})*(energy)} \quad (4)$$

$$energy = (MW)*(\text{[illegible]})*(SM)*(\text{[illegible]})*365*1000 \quad (5)$$

Where LCOE, energy, MW, and SM correspond to the levelized cost of electricity, total energy produced, plant capacity, and solar multiple, respectively. C, D, G, and N correspond to total purchase and installed (P&I) investment cost, discount rate, variable O&M escalation, and total asset life (years), respectively. The process of calculating the LCOE using a discounted cash flow analysis was performed with the following assumptions:

2.6.4 Assumptions to compute LCOE

1) The total energy produced is assumed to be constant over the life cycle

2) The total energy is assumed to be generated 365 days per annum

2.7 Uncertainty analysis

The overall uncertainty in each of the systems was evaluated by considering the thermodynamic and economic parameters. A rigorous data-intensive model was developed in this study to evaluate the process conditions of each system by varying parameters such as plant capacity, storage duration, solar multiple, and capacity factor. Economic uncertainty, however, was evaluated by varying parameters such as discount rate and total plant life (N).

3.0 Results and discussion

Thermal energy storage (TES) systems can be sized using a few key parameters, namely, storage duration, capacity factor, solar multiple, and plant capacity. These parameters were given a base value, as shown in Table 3. The base case was selected from values commonly used in the industry. A base case of 50 MW was chosen for S1 based on an existing plant [34]. Subsequently, a base case of 100 MW was selected for S2 – S5 because the largest turbine capacity commercially operating is approximately 133 MW [35]. Furthermore, eight hours of storage time is commonly achieved commercially, along with a capacity factor of approximately 40%. Capacity factors of plants with thermal energy storage implemented commercially are typically 20% to 60% [36]. Solar multiple figures were also selected from values found in existing commercial plants, and they range from 1.5 to 2 [36].

Table 3: Base case parameter values

Base case parameters	S1	S2 – S5	Refs.
Plant capacity (MW)	50	100	
Storage duration (hrs)	8	8	[36]
Solar multiple	1.75	1.75	[36]
Capacity factor (%)	40%	40%	[36]
Discount rate (%)	10	10%	[30]
Labour cost ($/hr)	$25.18	$25.18	

The mass and energy balance was used to calculate the technical parameters of individual equipment (listed in Tables 4 through 6). As shown in Table 4, the inlet pressure and temperature in S1 are different from those in the other scenarios. Limitations to inlet steam pressure and temperature occur because of the maximum temperature to which molten salt can be heated in S1 is approximately 390 ^{o}C (734 ^{o}F). For this reason, the HTF (i.e., synthetic oil) in S1 can be heated to a temperature of approximately 385 ^{o}C (725 ^{o}F) using molten salt [22].

Table 4: Base case values for condensing steam turbine

Condensing steam turbine parameters	S1	S2	S3	S4	S5
Inlet pressure (psia)	1450	2393.13	2393.13	2393.13	1500
Inlet temperature (F)	710.6	1025	1025	1025	806
Outlet pressure (psia)	15	15	15	15	0.02

Outlet temperature (F)	213	213	213	213	-3.68
Steam turbine mass flow rate (klb/hr)	734	1094	1094	1094	665
Turbine losses	30%	30%	30%	30%	30%
Generator efficiency	95%	95%	95%	95%	95%

Another key aspect to S1 is noted in Table 5 as no values are calculated for S2 - S4. The parabolic trough technology used in S1 requires an intermediate HTF (such as Dowtherm A©), which requires an additional heat exchanger where heat from the molten salt is transferred to the HTF. This heat can be used to convert water into superheated steam for expansion in the steam turbine. The absence of an additional heat exchanger means that no values need to be calculated for S2 – S4.

Table 5: Base case values for Dowtherm A© heat exchanger

Dowtherm A© heat exchanger parameters	**S1**
Heat transfer coefficient (U in btu/(hr ft^2 °F))	425
t1 (for salt in shell) (°F)	734
t2 (for salt in shell) (°F)	559.4
T1 (for HTF in tube) (°F)	554
T2 (for HTF in tube) (°F)	725
Cp of Dowtherm A© HTF (btu/lb °F)	0.58
Pressure (psi)	580
Salt mass flow rate (klb/hr)	8478

As noted in Table 6, the temperature of salt for S2 - S4 is 1050 ^{o}F (565 ^{o}C), well above the 734^{o}F (390 ^{o}C) in S1. This is because S2 - S4 use solar power tower technology in which a centralized tower absorbs concentrated heat from surrounding mirrors. One of the key advantages of this technology is the ability to heat molten salt to a temperature of approximately 1050^{o}F (565 ^{o}C) [22].

Table 6: Base case values for evaporation heat exchanger

Evaporation heat exchanger parameters	**S1**	**Evaporation heat exchanger parameters**	**S2**	**S3**	**S4**
Heat transfer coefficient (U in btu/(hr ft^2 °F))	325	Heat transfer coefficient (U in btu/(hr ft^2 °F))	325	325	325
t1 (for HTF in shell) (°F)	725	**t**1 (for salt in shell) (°F)	1050	1050	1050
t2 (for HTF in shell) (°F)	554	**t**2 (for salt in shell) (°F)	554	554	554
T1 (for water in tube) (°F)	86	T1 (for water in tube) (°F)	86	86	86
T2 (for water in tube) (°F)	710.6	T2 (for water in tube) (°F)	1025	1025	1025
Cp of salt (btu/lb °F)	0.644	Cp of salt (btu/lb °F)	0.358	0.358	0.358
Pressure (psia)	1450	Pressure (psia)	2393	2393	2393
Water mass flow rate (klb/hr)	734	Water mass flow rate (klb/hr)	1094	1094	1094
Salt mass flow rate (klb/hr)	8478	Salt mass flow rate (klb/hr)	9103	9103	9103

The LCOE is an important factor that is often used for comparing the economic viability of technologies. In order to compare the LCOE for the scenarios in Table 7, it is important to understand the definition of LCOE. The LCOE is the price at which electricity would have to be sold in order to offset the total investment over the total plant life cycle. Often mature fossil fuel technologies have a low LCOE in the range of approximately 6 to 8 cents/kWh [37]. To compete with fossil fuels, the US Department of Energy devised a goal to reduce the LCOE for thermal storage to around 2 cents/kWh by 2020 [2]. A disadvantage to using solar as a renewable energy source is its intermittency, which results in a higher LCOE to produce electricity. The inability to supply energy during peak demand using solar energy increases the LCOE. Thus, thermal energy storage technologies such as sensible heat, latent heat, and thermochemical storage can bridge the gap between energy demand and energy supplied during peak loads and lower the LCOE.

Furthermore, the LCOE is affected by the total investment cost of individual thermal storage scenarios, as shown in Table 7. S1 uses parabolic troughs, which is the most mature technology and thus the most widespread commercially. However, the LCOE of 56 cents/kWh (as shown in Table 7) demonstrates the need to implement other forms of thermal storage technologies. It is imperative to note that the LCOE for S1 includes the cost of an extra heat exchanger, which includes extra pumps, piping, and valves. Synthetic oils are another cost incurred in S1 that contribute to a higher total investment cost. The component costs of an extra heat exchanger, heat transfer fluid pumps, along with the cost of synthetic oils, amount to approximately $93 million, as calculated through an Excel-based model. The cost of synthetic oils makes up nearly

83% of this $78 million. This is because of the high cost of synthetic oil, which is approximately $2.2/kg [38].

The LCOE for S2 was calculated to be approximately 10 cents/kWh. S2 uses centralized tower technology with concentrated solar power (CSP). The overall component cost in S2 was calculated to be approximately $46 million. This cost is significantly lower than the component cost of S1 since no additional heat exchanger or pumps are required. The major portion of the component cost incurred in S2 is the cost of molten salt, which is approximately $36 million. The raw material per unit cost of molten salt used in the calculation is $1.08/kg [23].

The lower LCOE of approximately 8 cents/kWh for S3 is because of the lower total investment cost. As shown in Figure 3, the configuration requires only one tank for storing both hot and cold molten salts. Advantages of this configuration are lower storage tank and molten salt costs. Studies show that a configuration with one storage tank results in a savings of approximately 33% in required molten salt [9]. Additionally, the cost of the storage tank falls by approximately 66% [26].

Figure 4 illustrates a configuration for S4 where phase change materials (PCM) in the form of pellets fill a single storage tank and gaps are filled with molten salt. One of the key advantages to using PCMs is their high energy density compared to molten salt. This high energy density means less molten salt is required, as pellets would occupy approximately 75% of the tank volume [26], leaving only 25% molten salt. The cost of the PCM used to calculate material cost is approximately $3.21/kg [5]. The cost of the storage tank is reduced by approximately 66% along with an increase in PCM cost per unit cost [26]. This results in a relatively high LCOE, which was calculated to be approximately 20 cents/kWh.

The LCOE for S5 was calculated to be approximately 51 cents/kWh, as shown in Table 7. This high cost is likely due to the high investment cost of approximately $684 million. The cost of ammonia used as the working fluid is approximately $100 to $920 per tonne [39]. The high cost of ammonia used increased both the investment cost and the LCOE for thermochemical storage. Another component that contributes to high investment cost is the ammonia pump. A mass flow of input ammonia stream was taken to be approximately 6.99 x 10^6 lb/hr (3.17×10^6 kg/h), which requires a high capacity pump.

As noted at the start of the paper, that the LCOE was calculated for thermal energy storage; it does not include the cost of the solar field or power generation components. A report published by the International Renewable Energy Agency (IRENA) suggests that capital costs for solar field and power generation components add nearly 53% to the total investment cost [40]. Thus, the LCOE shown in Table 7 would increase proportionately if the capital cost of solar field components and power generation components are included.

Table 7: LCOE and capital cost summary for the base case

Costs	**S1**	**S2**	**S3**	**S4**	**S5**
Total investment cost ($ millions)	378	138	102	277	684
LCOE (cents/kWh)	56	10	8	20	51

3.1 Sensitivity analysis

In order to analyze the effect of individual parameters on a given output parameter, a sensitivity analysis was performed. The sensitivity plot for S1 (Figure 6) shows that the most sensitive parameters are solar multiple and capacity factor while the second most sensitive parameter is material cost variation, thus implying solar multiple, capacity factor, and material cost would have a significant impact on the LCOE given in equations 4 and 5. In contrast, the sensitivity plots for S2 - S4 (shown in Figures 7 through 9) correspond to a solar tower configuration where solar multiple, storage duration, capacity factor, and material cost variation are highly sensitive to LCOE. One of the primary reasons is that the solar tower configuration entails direct heat transfer from solar heat to the molten salt. Subsequently, it can be noted from the plots that parameters such as discount rate, plant capacity, and labour cost have relatively little impact on the LCOE. The most sensitive factors in thermochemical storage (S5), as illustrated in Figure 10, are solar multiple and capacity factor. Storage duration, however, was found to be the second most sensitive parameter.

Figure 6: Sensitivity analysis for the LCOE (S1)

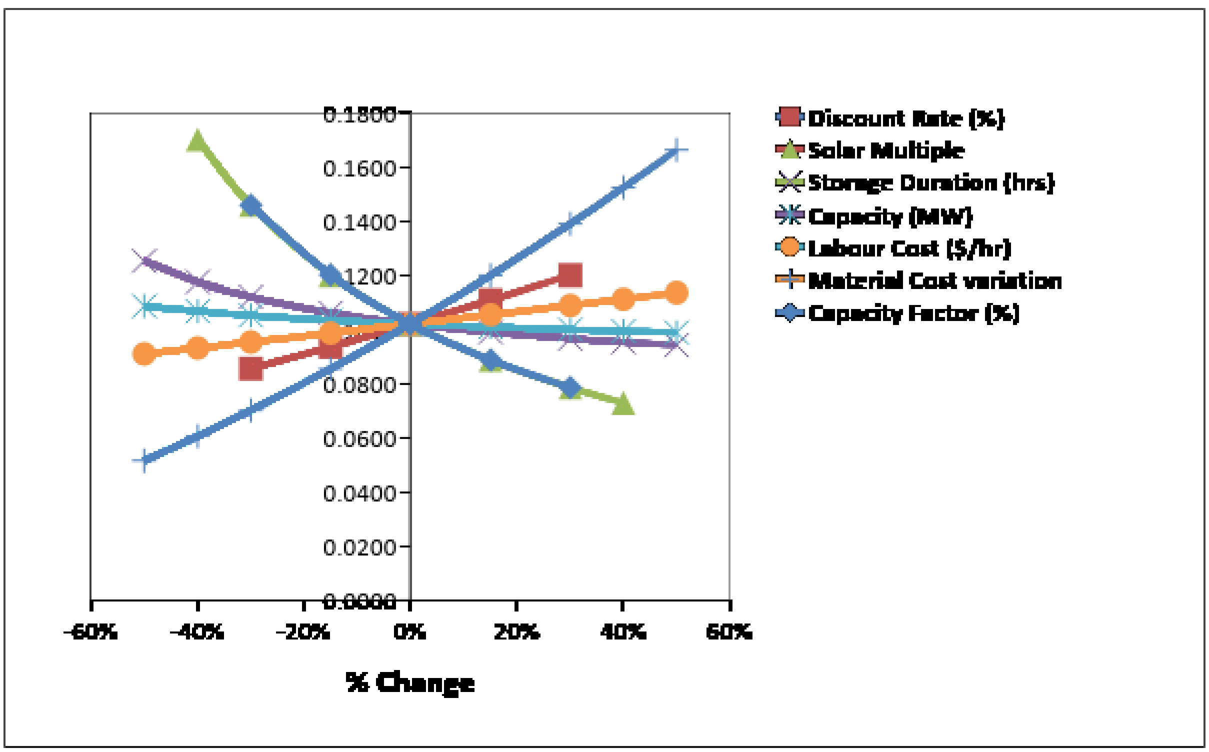

Figure 7: Sensitivity analysis for the LCOE (S2)

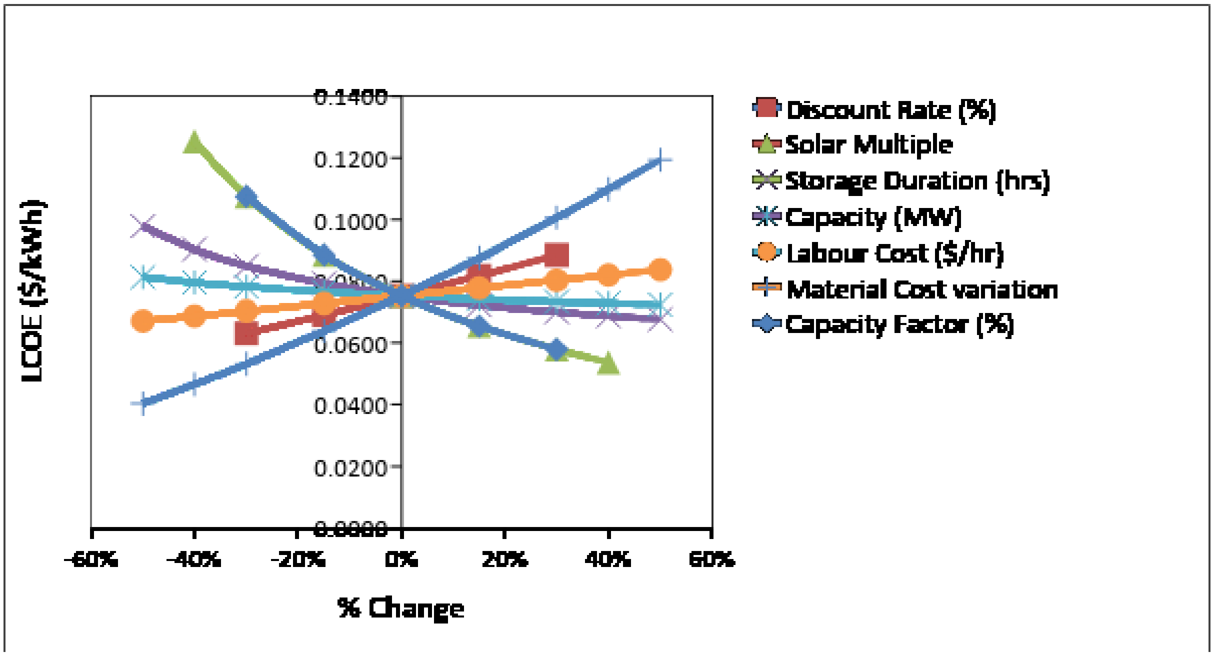

Figure 8: Sensitivity analysis for the LCOE (S3)

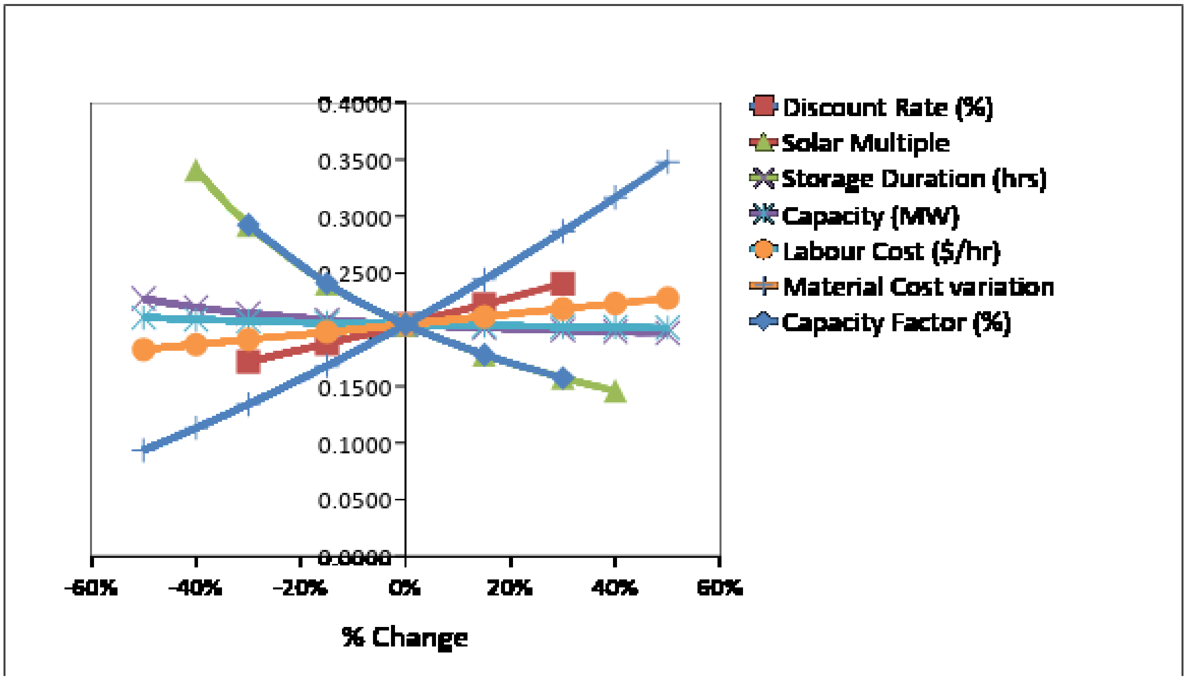

Figure 9: Sensitivity analysis for the LCOE (S4)

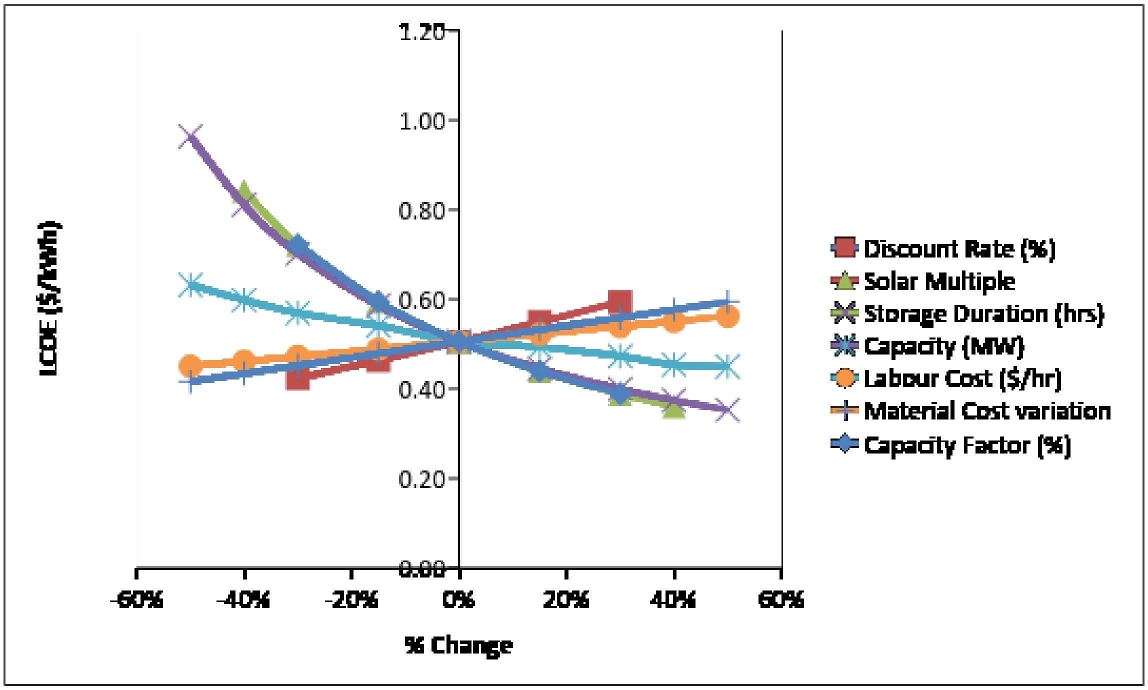

Figure 10: Sensitivity analysis for the LCOE (S5)

3.2 Scenario optimization

The optimization of thermal energy storage is a key aspect to competing with mature fossil fuel technologies with low LCOEs. The optimization process adopted in this paper uses correlations reported by the International Renewable Energy Agency (IRENA) [36]. The sensitive parameters identified in the prior discussion (plant capacity, storage duration, solar multiple, and capacity factor) are considered in the optimization process. For S1, the parabolic trough configuration, the lowest cost is reached at nine hours of storage (see Figure 11). Figure 12 shows that nine hours of storage reach its lowest value when the solar multiple is 2.5. A capacity factor of approximately 45% corresponds to nine hours of storage and 2.5 solar multiple (shown in Figure 13). Lastly, the change in LCOE for plant capacity higher than 180 MW is not significant. Thus, 180 MW is considered to be the optimized capacity for S1.

In contrast, S2 - S5 corresponds to a solar tower configuration. Figure 11 suggests 13.4 hours of storage duration to minimize cost. The optimal solar multiple and capacity factor were determined to be 3 and 55%, respectively and the optimal capacities for S2 - S5 were deduced to be 130 MW, 135 MW, 120 MW and 190 MW, respectively. Table 8 gives the optimized parameters for all scenarios.

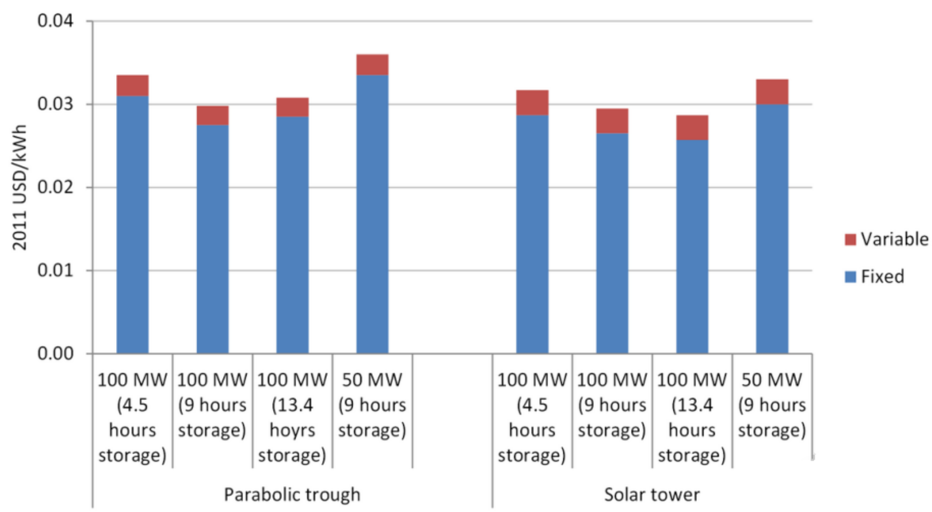

Figure 11: Parabolic trough and solar tower cost comparison [41]

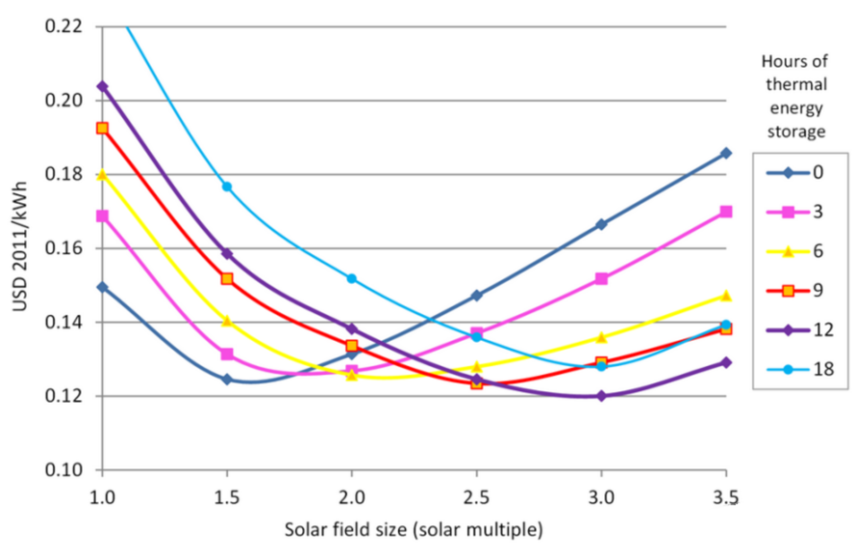

Figure 12: Correlation between solar multiple and hours of storage [42]

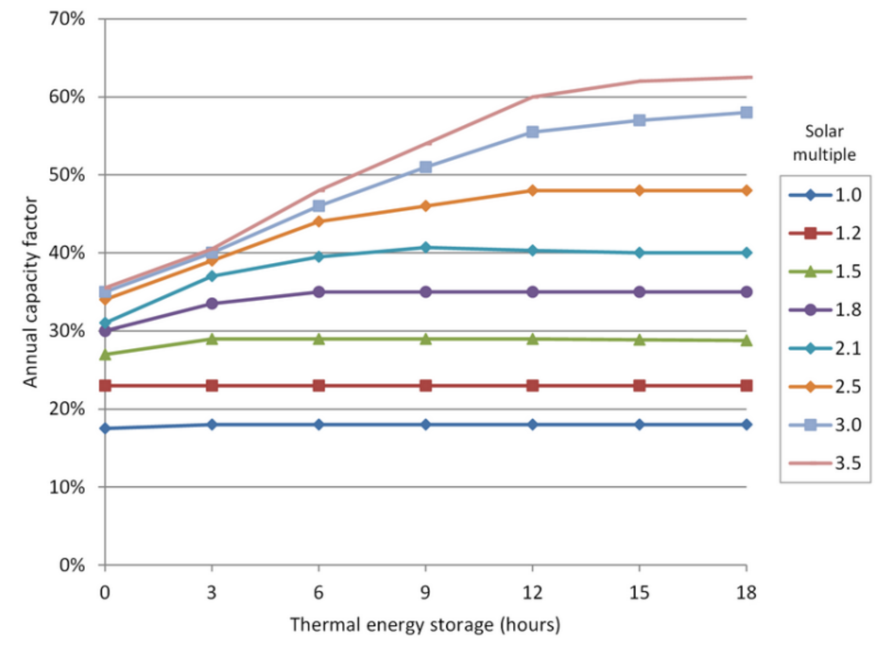

Figure 13: Correlation between solar multiple and capacity factor [43]

Table 8: Optimized parameter values

Optimized parameters	**S1**	**S2**	**S3**	**S4**	**S5**
Capacity (MW)	180	130	135	120	190
Storage duration (hrs)	9	13.4	13.4	13.4	13.4
Solar multiple	2.5	3	3	3	3
Capacity factor (%)	45%	55%	55%	55%	55%
Discount rate (%)	10%	10%	10%	10%	10%
Labour cost ($/hr)	$25.18	$25.18	$25.18	$25.18	$25.18

Table 9 lists the calculated LCOE for each scenario taking into consideration the optimized parameters listed in Table 8. It can be noted in Table 9 that the optimized

LCOEs for individual scenarios are significantly lower than the base case LCOE in Table 7. It is imperative to note that the LCOEs in Table 9 include the cost of storing thermal energy but not the cost of the solar field or power generation components. As suggested in a report published by IRENA, the cost of solar field and power generation components adds up to approximately 53% of the total investment cost [40]. Therefore, the LCOEs listed in Table 9 would increase accordingly if the costs of solar field and power generation components were to be taken into account.

Table 9: LCOE and cost summary for the optimized cases

Costs	S1	S2	S3	S4	S5
Total investment cost ($ millions)	1416	269	198	529	1116
LCOE (cents/kwh)	32	4	3	8	11

3.3 Uncertainty analysis

An uncertainty analysis can give a pictorial representation of the LCOEs falling within a given quartile. The sampling error, standard deviation, and number of samples considered in calculating uncertainties were approximately 0.001, 0.18, and 200000, respectively. Figure 14 depicts a box plot representation of uncertainty in each scenario. Note that the LCOE for storage in S1 ranges from approximately 13 – 30 cents/kWh while uncertainty ranges from 8 – 59 cents/kWh. Output values for the LCOE in S1 have a relatively wider range of possible values, which is due to the uncertainty in the cost of the heat transfer fluid. As discussed earlier, S1 is the configuration in which total investment costs vary greatly with the cost of the synthetic oils used as the heat transfer fluid. S2 and

S3 have less uncertainty as investment costs are lower than in S1. The LCOE uncertainty values for S2 are from 3 – 22 cents/kWh and 2 – 16 cents/kWh for S3. However, S4 has a wider range of uncertainty, around 6 – 43 cents/kWh, which can be attributed to the commodity pricing of industry grade PCM materials ($0.05/kg to $5.71/kg) [5]. Figure 14 shows quartile ranges of 25% and 75% for S5 do not overlap with the other scenarios, indicating that S5 has highest LCOE (as it does, at 32 – 64 cents/kWh).

Table 10 gives the Monte Carlo input distributions used for each parameter. The input values for a triangle distribution are the minimum value, most likely value, and maximum value. The most likely value is the base case value while minimum and maximum values are taken from the literature.

Table 10: Monte Carlo input distributions

Costs	Monte Carlo input distributions	Refs.
Capacity (MW)	Vosetriangle (50,100,250)	
Storage duration (hrs)	Vosetriangle (1.05,8,15)	[36]
Solar multiple	Vosetriangle (1,1.75,3.5)	[36]
Capacity factor (%)	Vosetriangle (0.3,0.4,0.55)	[36]
Discount rate (%)	Vosetriangle (0.07,0.1,0.14)	[30]
N (yrs) =	Vosetriangle (25,30, 40)	

The uncertainty of LCOE illustrated in Figure 14 has two components, system uncertainty and economic uncertainty. The system uncertainty can be observed when equipment such as pumps and heat exchangers are sized according to the required plant capacity. Thus the data-intensive model developed in this study calculates the mass flow rate requirement in individual equipment by varying parameters such as plant capacity, storage duration, solar multiple, and capacity factor. Economic uncertainty, however, is evaluated by varying parameters such as discount rate and total plant life (N). Therefore, the overall uncertainty illustrated in Figure 14 encompasses both system uncertainty and economic uncertainty.

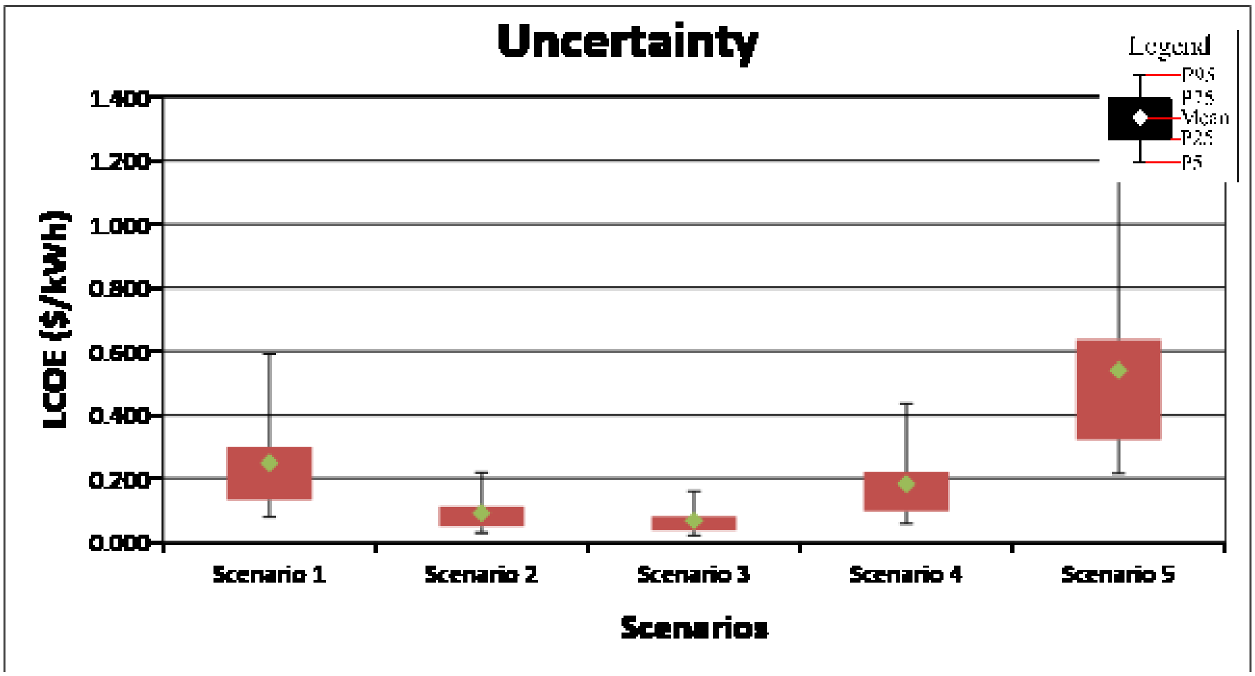

Figure 14: Uncertainty box plots for individual scenarios

4.0 Conclusion

In conclusion, the focus of this study was to develop a data-intensive techno-economic model to evaluate the economic feasibility of various thermal energy storage scenarios. Economic feasibility was determined by evaluating the LCOE for five scenarios (S1 – S5). S1 is the most mature technology in concentrated solar power and showed relatively higher LCOE for storage due to the increased raw material cost for heat transfer fluids. S1 has higher capital investment than S2 because of the additional component costs of the added heat exchanger, extra pumps, and greater amount of heat transfer fluids. S2, on the other hand, has a lower investment cost because it does not need an additional heat exchanger or extra pumps. Because of the higher operating temperatures of 554 – 1050 ^{o}F (290 – 565 ^{o}C) in S2, the heat transfer rate from molten salt to water is greater and generating higher quality superheated steam. S1 and S2 are widely implemented for commercial applications. In contrast, S3 – S5 is still in the research and development phase and thus there is greater scope for improving their economic viability. Although the cost of a thermocline system (i.e., S3) is relatively lower than a parabolic trough (S1) or solar tower (S2, S4, and S5), there is significant opportunity to reduce investment cost and the LCOE. S4 is another system in which PCMs greatly affect the cost of latent heat storage. PCMs have higher energy density than materials used in sensible heat storage (S1 – S3). Thus, optimizing the system would be the first step to achieve a lower LCOE. The optimized LCOEs of storage for S1 - S5 were estimated to be approximately 33 cents/kWh, 4 cents/kWh, 3 cents/kWh, 8 cents/kWh and 11 cents/kWh, respectively. The US Department of Energy recommended the goal of LCOE of 2 cents/kWh for thermal storage by 2020. The optimized scenarios in this paper demonstrate a potential to achieve that goal.

Acknowledgements

The authors thank the NSERC Energy Storage Technology (NEST) Network (RYERU NSERC 468468 Kumar) and the University of Alberta (UOFAB VPRGRF NEST KUMAR) for the financial support provided to carry out this research. The authors are thankful to Astrid Blodgett for editing this paper.

References

[1] Thermal Energy Storage Market by Technology, Storage Material, Application, End-User, and Region - Global Forecast to 2022. 2016.

[2] SOLAR ENERGY TECHNOLOGIES OFFICE FY2016 BUDGET AT-A-GLANCE. Department of Energy2015.

[3] M. Liu, N.S. Tay, S. Bell, M. Belusko, R. Jacob, G. Will, et al. Review on concentrating solar power plants and new developments in high temperature thermal energy storage technologies. Renewable and Sustainable Energy Reviews. 53 (2016) 1411-32.

[4] R. Sioshansi, P. Denholm. The value of concentrating solar power and thermal energy storage. IEEE Transactions on Sustainable Energy. 1 (2010) 173-83.

[5] B. Xu, P. Li, C. Chan. Application of phase change materials for thermal energy storage in concentrated solar thermal power plants: A review to recent developments. Applied Energy. 160 (2015) 286-307.

[6] B. Xu, P. Li, C. Chan, E. Tumilowicz. General volume sizing strategy for thermal storage system using phase change material for concentrated solar thermal power plant. Applied Energy. 140 (2015) 256-68.

[7] A. Luzzi, K. Lovegrove, E. Filippi, H. Fricker, M. Schmitz-goeb, M. Chandapillai, et al. Techno-Economic analysis of a 10 MW e solar thermal power plant using ammonia-based thermochemical energy storage. Solar energy. 66 (1999) 91-101.

[8] M. Mehos, J. Jorgenson, P. Denholm, C. Turchi. An assessment of the net value of CSP systems integrated with thermal energy storage. Energy Procedia. 69 (2015) 2060-71.

[9] S.M. Flueckiger, B.D. Iverson, S.V. Garimella. Simulation of a Concentrating Solar Power Plant With Molten-Salt Thermocline Storage for Optimized Annual Performance. ASME 2013 7th International Conference on Energy Sustainability collocated with the ASME 2013 Heat Transfer Summer Conference and the ASME 2013 11th International Conference on Fuel Cell Science, Engineering and Technology. American Society of Mechanical Engineers2013. pp. V001T03A11-VT03A11.

[10] M. Montes, A. Abánades, J. Martínez-Val. Performance of a direct steam generation solar thermal power plant for electricity production as a function of the solar multiple. Solar Energy. 83 (2009) 679-89.

[11] L. Heller, P. Gauché. Modeling of the rock bed thermal energy storage system of a combined cycle solar thermal power plant in South Africa. Solar Energy. 93 (2013) 345-56.

[12] S. Izquierdo, C. Montañés, C. Dopazo, N. Fueyo. Analysis of CSP plants for the definition of energy policies: the influence on electricity cost of solar multiples, capacity factors and energy storage. Energy Policy. 38 (2010) 6215-21.

[13] S. Boudaoud, A. Khellaf, K. Mohammedi, O. Behar. Thermal performance prediction and sensitivity analysis for future deployment of molten salt cavity receiver solar power plants in Algeria. Energy Conversion and Management. 89 (2015) 655-64.

[14] C. Turchi, M. Mehos, C.K. Ho, G.J. Kolb. Current and future costs for parabolic trough and power tower systems in the US market. Proceedings of the 16th SolarPACES Conference, Perpignan, France2010.

[15] J.T. Hinkley, J.A. Hayward, B. Curtin, A. Wonhas, R. Boyd, C. Grima, et al. An analysis of the costs and opportunities for concentrating solar power in Australia. Renewable Energy. 57 (2013) 653-61.

[16] H. Lund, P.A. Østergaard, D. Connolly, I. Ridjan, B.V. Mathiesen, F. Hvelplund, et al. Energy storage and smart energy systems. International Journal of Sustainable Energy Planning and Management. 11 (2016) 3-14.

[17] M. Seitz, M. Johnson, S. Hübner. Economic impact of latent heat thermal energy storage systems within direct steam generating solar thermal power plants with parabolic troughs. Energy Conversion and Management. 143 (2017) 286-94.

[18] S. Hübner, M. Eck, C. Stiller, M. Seitz. Techno-economic heat transfer optimization of large scale latent heat energy storage systems in solar thermal power plants. Applied Thermal Engineering. 98 (2016) 483-91.

[19] R. Dunn, K. Lovegrove, G. Burgess. A review of ammonia-based thermochemical energy storage for concentrating solar power. Proceedings of the IEEE. 100 (2012) 391-400.
[20] E. Wenger, M. Epstein, A. Kribus. Thermo-electro-chemical storage (TECS) of solar energy. Applied Energy. 190 (2017) 788-99.
[21] M. Hanel, R. Escobar. Influence of solar energy resource assessment uncertainty in the levelized electricity cost of concentrated solar power plants in Chile. Renewable energy. 49 (2013) 96-100.
[22] R.I. Dunn, P.J. Hearps, M.N. Wright. Molten-salt power towers: newly commercial concentrating solar storage. Proceedings of the IEEE. 100 (2012) 504-15.
[23] H. Zhang, J. Baeyens, G. Cáceres, J. Degrève, Y. Lv. Thermal energy storage: Recent developments and practical aspects. Progress in Energy and Combustion Science. 53 (2016) 1-40.
[24] Steam Turbines for CSP Plants. 2010.
[25] A. Modi, C.D. Pérez-Segarra. Thermocline thermal storage systems for concentrated solar power plants: One-dimensional numerical model and comparative analysis. Solar Energy. 100 (2014) 84-93.
[26] S. Kuravi, Y. Goswami, E.K. Stefanakos, M. Ram, C. Jotshi, S. Pendyala, et al. Thermal energy storage for concentrating solar power plants. Technology & Innovation. 14 (2012) 81-91.
[27] C. Smith, Y. SUNb, B. WEBBY, A. Beath, F. Bruno. Cost analysis of high temperature thermal energy storage for solar power plant. Proceedings of the 52nd Annual Conference, Australian Solar Energy Society (Australian Solar Council) Melbourne May2014.
[28] Aspen HYSYS. 2017.
[29] R. Gabbrielli, R. Singh. Economic and scenario analyses of new gas turbine combined cycles with no emissions of carbon dioxide. ASME Turbo Expo 2004: Power for Land, Sea, and Air. American Society of Mechanical Engineers2004. pp. 665-73.
[30] C. Parrado, A. Marzo, E. Fuentealba, A. Fernández. 2050 LCOE improvement using new molten salts for thermal energy storage in CSP plants. Renewable and Sustainable Energy Reviews. 57 (2016) 505-14.
[31] M.I. Hussain, A. Ali, G.H. Lee. Performance and economic analyses of linear and spot Fresnel lens solar collectors used for greenhouse heating in South Korea. Energy. 90 (2015) 1522-31.
[32] Current US Inflation Rates: 2006-2017.
[33] Chapter 7 – Energy and Energy Balances
[34] Andasol-1. National Renewable Energy Laboratory (NREL).
[35] Ivanpah Solar Electric Generating System. National Renewable Energy Laboratory (NREL).
[36] Concentrating Solar Power. 2012.
[37] World Energy Perspective Cost of Energy Technologies. World Energy Council2013.
[38] R. Chacartegui, L. Vigna, J. Becerra, V. Verda. Analysis of two heat storage integrations for an Organic Rankine Cycle Parabolic trough solar power plant. Energy Conversion and Management. 125 (2016) 353-67.
[39] Ammonia Prices Fell Slightly from the Previous Week. 2016.
[40] Concentrating Solar Power Technology Brief. International Renewable Energy Agency (IRENA)2013.
[41] Operations and maintenance costs for parabolic trough and solar tower CSP plants. International Renewable Energy Agency (IRENA)2014.
[42] The LCOE of CSP plants as a function of the solar multiple and hours of thermal energy storage. International Renewable Energy Agency (IRENA)2014.
[43] Annual capacity factor for a 100MW parabolic trough plant as a function of solar field size and size of thermal energy storage. International Renewable Energy Agency (IRENA)2014.