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TECHNO-ECONOMIC ASSESSMENT OF RETROFITTING CONCEPTS FOR PARABOLIC TROUGH POWER PLANTS WITH SOLAR TOWERS

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Techno-Economic Assessment of Retrofitting Concepts for Parabolic Trough Power Plants with Solar Towers

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Abstract

This thesis investigates the cost-efficiency of retrofitting concepts based on the addition of a solar tower to an existing parabolic trough power plant. It is assumed that existing infrastructure can be used to avoid costs for additional generation capacity. A reference power plant and retrofitting concepts for different scenarios have been selected a priori. A benchmark methodology is developed, which considers the generation capacity of a power plant and thus allows the techno-economic comparison of retrofitted power plants to reference cases. Furthermore estimations about the ageing behaviour of the reference power plant are defined. A simulation tool is selected, which simulates the retrofitted power plants. Finally the developed benchmark methodology is applied and a decision about the cost-efficiency of retrofitted parabolic trough power plants with solar towers, compared to overhauled PTC power plants combined with new solar towers, is worked out.

Vorwort

Die vorliegende Arbeit entstand während meiner Tätigkeit am Institut für Solarforschung des Deutsche Zentrums für Luft- und Raumfahrt (DLR), von Februar bis August 2016, in Köln.

Für das angenehme Arbeitsklima und das stets kollegiale Umfeld bedanke ich mich herzlich bei allen meinen Vorgesetzten und Kollegen des Instituts. Besonders bedanken möchte ich mich bei meinem Betreuer Simon Dieckmann, für die vielen Fachdiskussionen und Anregungen, die zu einem Gelingen der Arbeit beigetragen haben.

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1. Introduction

Climate Change and the need for renewable energy

Global CO_2 emissions have increased enormously over the last decade, with an average annual growth rate of 4%. In 2014, 35.7 Gt of CO_2 were emitted, exacerbating global climate change; this was the warmest year on record (Olivier et al., 2015). Some of the long-term effects of climate change include rising sea level, changes in precipitation, modification of the Gulf Stream, droughts, heat waves, an increasing number of diseases, and massive loss of biodiversity (UNFCCC, 2007).

At the conclusion of the Paris climate conference in December 2015, 195 states adopted the legally binding global climate deal. Their governments made a number of agreements, including maintaining the increase in global average temperature above pre-industrial levels to well below 2 °C, with the aim of limiting the increase to 1.5 °C. Also included were the acknowledgement of the need for global emissions to peak as soon as possible, and subsequently the facilitation of rapid reduction by making use of the best available science (CoP21, 2015).

The primary driver of greenhouse gas (GHG) emissions is population growth in combination with increasing per-capita energy consumption. The global population has nearly doubled since 1970, and reached more than 7 billion people in 2015. Global primary energy consumption per capita has also more than doubled in the same period of time, to over 140,000 TWh (Economy, 2014).

Approximately 25% of global GHG emissions can be attributed to the electricity and heat generation sector. Here, the burning of coal, natural gas, and oil is the largest single source of GHG emissions (IPCC, 2014).

A fundamental and structural change in energy supply for electricity and heat generation is evidently essential, in order to reduce GHG emissions and save limited resources. Fossil fuels must be replaced by renewable energy resources, which enable clean, secure, reliable, and affordable energy for regional as well as national and transnational communities.

Concentrated solar power

Solar irradiation is available in abundance on the earth’s surface. In addition to the photovoltaic generation of electricity, direct irradiation of the sun can be used by concentrated solar power

(CSP) for electricity generation. In order to reach high temperatures, CSP power plants use mirrors to concentrate the sun's rays, which in turn heat a fluid and ultimately produce steam. The steam drives a turbine and generates kinetic power, which can be converted into electrical power by a generator. CSP can furthermore be divided into two groups: line focus systems, where solar collectors concentrate the sun's rays onto a focal line, and point focus systems, where the rays are concentrated onto a single focal point. Line focus systems include parabolic trough collectors (PTC) and Fresnel collectors, while point focus systems include solar dish systems and solar tower plants. When combined with thermal energy storage, CSP power plants offer schedulable electricity production even when the sky is cloudy or after sunset.

Many of the CSP power plants found worldwide were installed in the USA, between 1984 and 2000, and are still operational today. Since 2006, a number of CSP projects have also been developed and installed both in Europe, and the Middle East and North Africa (MENA) region, where the Sunbelt of the world offers good solar irradiation conditions for CSP. Many of these projects have been developed and produced with major participation by German companies and research centres. Further CSP projects have also been implemented in the USA.

In total, almost 5 GW of electrical capacity is installed worldwide, of which over 2 GW can be found in Europe (mainly Spain). Greenpeace et al. (2016) expects a double-digit GW capacity within the next five years.

PTCs account for more than 90% of the installed CSP capacity and can be seen as state-of-the-art-technology in CSP. Nevertheless, two particular characteristics of PTCs show considerable room for improvement.

The first is their significant fluctuation in annual power generation, due to the low elevation of the sun during winter months and the corresponding lower solar irradiation. This effect is strengthened with increasing distance from the equator. The second is that PTCs can only reach temperatures of about 380 °C, which is significantly lower than the 600 °C reached by fossil-generated steam. The limiting factor for thermal power plants is the Carnot efficiency, which is determined by the inlet and outlet temperatures. The wider the range of these temperatures, the more efficient the power plant cycle becomes. Consequently, PTCs are disadvantaged in comparison to fossil-powered energy generation. Additionally, CSP plants combined with thermal energy storage (e.g. six hours' capacity) show higher capacity factors, lower specific operation and maintenance (O&M) costs, and a similar or lower levelised cost of electricity (LCOE) than those without storage (IRENA, 2012).

Solar tower plants can help to reduce these disadvantages. They can achieve temperatures of up to 600 °C by using molten salt as the heat transfer fluid (HTF), which allows higher operating temperatures and higher steam cycle efficiencies. Furthermore, the cost of thermal energy storage can be reduced by allowing a higher temperature differential across the storage tanks. Because solar tower plants have two-axis tracking systems, the generation profile is usually more consistent over the year.

Considering that component costs of solar towers have dropped significantly in recent years due to economies of scale, it is safe to assume that new solar thermal power plants will increasingly adopt this technology. According to IRENA (2016a), by 2025 solar towers are expected to be a more cost-efficient technology than parabolic troughs.

Retrofitting of PTC power plants

With the help of technical measures, PTC power plants can be used beyond their estimated lifespan of 25 years. Furthermore, retrofitting thus power plants with a solar tower or thermal storage system could increase their energy yield, while maintaining low investment costs for additional capacity. Turbines can also be retrofitted to increase the power output capacity; this would result in a lower LCOE for additional capacity. Existing access to resources (e.g. land, infrastructure, human resources) can be optimised using and extending the available infrastructure of PTC power plants (for instance the solar field, thermal storage, turbines, pipes, or generators) with energy storage systems and solar towers. A resource-efficient alternative could thus be achieved, avoiding a completely new construction.

This thesis investigates three possible concepts to retrofit an existing parabolic trough power plant: with a solar tower, thermal storage, and a turbine power extension. These three concepts can be classified into two groups with different bases.

- The **first base** consists of a 50 MW power plant located in the south of Spain, with seven hours of thermal storage.
- The **second base** consists of the same 50 MW power plant located in the south of Spain, but without thermal storage.

Two concepts based on different scenarios are investigated.

- In the **first scenario,** space for additional power capacity is available.
- In the **second scenario,** available space is limited so that the retrofit concept must fit into the initial area.

- The **retrofit concepts in the first base** are based on the integration of a solar tower plant and the possibility of extending the turbine capacity.
- The **retrofit concept in the second base** consists of the addition of a seven-hour thermal storage system, thus making it technically equal to the first base case before the retrofit. In this base additional space is indispensable, and so the scenario without additional space is not investigated further within this thesis.

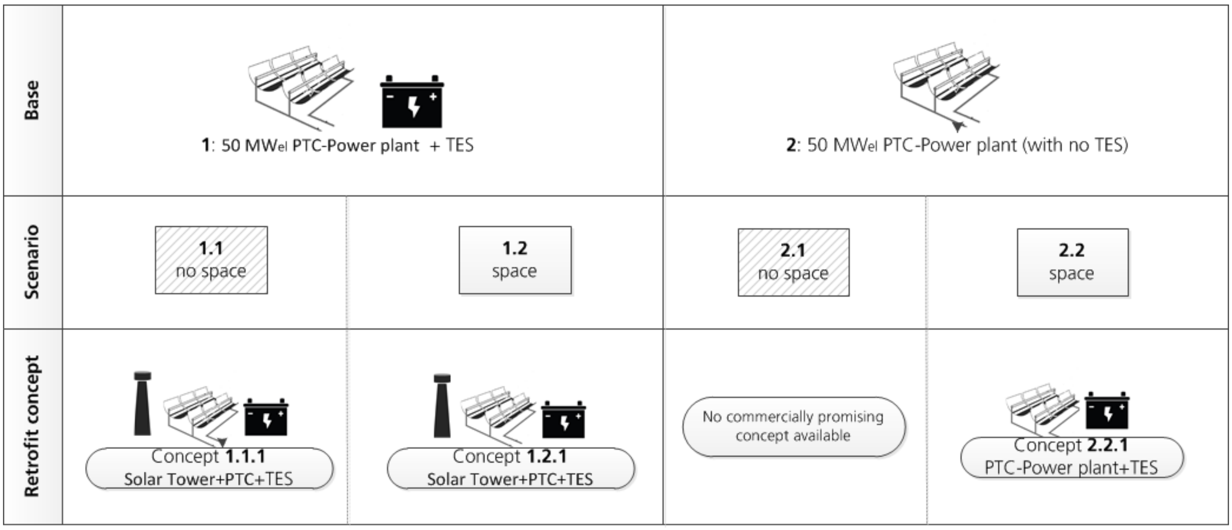


Figure 1: Schematic overview of bases, scenarios and concepts

Objectives and methodology

The aim of this thesis is to assess the three different concepts in a consistent manner. This includes both a technical and an economic evaluation. Keeping the initial goals in mind, the objective is to calculate the LCOE of each concept for comparison with the LCOE of a technically equivalent system that needs to be defined. The additional steps as described below are mandatory to evaluate the suitability of each concept, and to achieve the overall objective of the thesis.

A benchmark methodology first needs to be developed, which serves to design a comparable benchmark for each retrofitting concept. Economic performance can be described with the help of the LCOE, but the LCOE itself is not an adequate criterion for evaluating the cost-effectiveness of the retrofit concepts, since the additional electricity output after the retrofit is not considered.

Secondly, it is necessary to assess the technical condition of the reference power plant after its lifespan of 20 years. Required investments and labour inputs must be estimated, and a general statement about the technical condition of the power plant is required. Furthermore, technical and economic framework conditions need to be derived, in order to model the retrofitting concepts.

A proper simulation tool then needs to be selected for use in techno-economic modelling of the concepts. A number of tools are available on the market, but they need to be assessed regarding their usability for techno-economic simulations of PTC and solar tower hybrid power plants.

The benchmark designs, the characteristic parameters of the existing power plant, and a usable software tool are established. The technical parameters of the retrofit concepts, meteorological data, and economic parameters can therefore be used to calculate LCOEs, typical operation years (known as TOYs), and cash flows of the chosen concepts as well as of the benchmarks. The results of the retrofit concepts are then assessed regarding their technical and economic performance, and compared against the benchmarks.

The technical design and details of the concepts have been developed upfront within the corresponding research project.

The LCOE shall be calculated after Konstantin (2009). The LCOE in general means the costs per unit of electricity – typically $/MWh or $/kWh. To calculate the LCOE of a certain plant, all accumulated building and operating costs are summarized and then divided by the net electricity output. The result is an average calculated price of the specific costs for one unit of electricity. Since the LCOE calculation method is a dynamic method, the net present value (NPV) must be used for all monetary values and for the amount of electricity. The NPV considers the current value of money; this means a dollar in your hand today is considered to be worth more than a dollar earned in the next year. Moreover, the NPV is also used for discounting the generated electricity. This is necessary because the generated electricity implicitly corresponds to the earnings from the sale of this energy. The further these earnings are displaced in the future, the lower their cash value.

2. Theory

2.1. Fundamental principles of solar thermal power plants

2.1.1. History and context

The concept of concentrating solar energy has been a technology of interest throughout history. The first description of mirrored panels that could be used to concentrate solar radiation was written around 200 BC by Archimedes. The Greek mathematician Diocles described the optical properties of a parabolic trough in the same century. Comte de Buffon gave a more applied approach in 1746, in the form of his development of heliostat designs. However, it was over 100 years until 1878, when Augustin Mouchot demonstrated a dish-driven steam engine which could convert the collected heat into mechanical energy. The first applications of CSP were then introduced in the 20th century. In 1913, Frank Schuman built a parabolic trough driven pumping system in Egypt. This successfully operating plant can be considered as the first of a number of experiments and prototypes of CSP plants which followed during the 20th century. The first contemporary CSP power plants became realized in California in the 1980s; led by governmental incentives, nine separate parabolic trough-based Solar Electric Generating Systems (SEGS) with a total nominal electricity output of 354 MW_{el} were built and put into service, all of which are still in operation today.

Compared to photovoltaics and wind power, at about 5 GW installed CSP capacity is still low (Greenpeace et al., 2016). The relatively new technology leads to large levels of risk capital per project, which have recently been scaring investors.

However, the aim of reducing GHG emissions and the need for dispatchable energy supports investments in CSP. CSP is able to quickly cut large amounts of GHG gas emissions, and can shift electricity generation to peak load hours in the evening using an integrated thermal energy storage (TES) system.

These advantages led to a resurgence of CSP around 2005. This occurred predominantly in Spain, as well as other countries including the USA, Algeria, Morocco, Egypt, Israel, China, India, Australia, and many others who announced new CSP projects; almost half of these power plants included a TES (Lovegrove and Stein, 2012).

In order of deployment level, the technologies that are currently being used commercially are as follows(Lovegrove and Stein, 2012):

- Parabolic trough
- Central receiver tower
- Linear Fresnel
- Fresnel lenses (for CPV)
- Paraboloidal dishes

This thesis is focused on the technological approach of parabolic trough and central receiver tower systems.

2.1.2. Technological approaches

Parabolic trough technology

PTCs consist of parabolic mirrors that concentrate the sun's radiation on a linear focus. A receiver tube is installed exactly in the centre of the linear focus, and the solar radiation is converted into thermal energy. A HTF, which circulates inside the receiver tube, transports the heat. The thermal energy can be used either directly as process heat, stored with the help of a TES system, or to generate steam and run a steam turbine, thereby generating electricity. Depending on the HTF, common PTCs can reach temperatures of about 380 °C (Lovegrove and Stein, 2012).

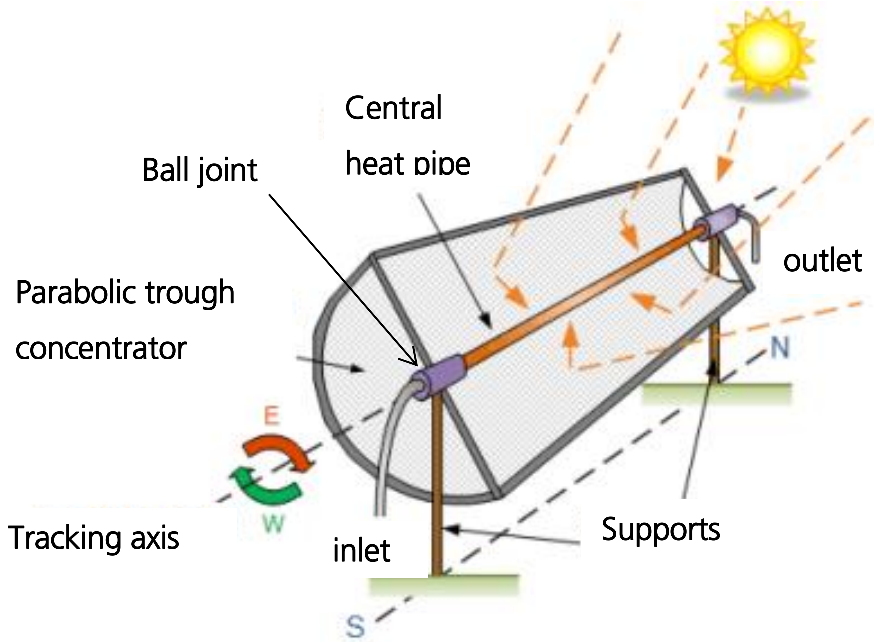


Figure 2: Scheme of a PTC (Sabry et al., 2015)

Commercial PTC designs have a length of about 100 to 150 meters and a parabola width of about 6 meters. PTCs are tracked in one axis, according to the sun's position. Therefore a sun tracking system is installed, as well as gears and swivel joints to move the PTC. Usually four PTCs are connected to each other in series, and referred to as a loop. Loops are connected in parallel. The connected PTCs in a power plant are also known as a solar field. To allow thermal expansion of the receiver pipes, ball joints are installed between adjacent collectors (Lovegrove and Stein, 2012).

In order to guarantee the best possible efficiency of the overall system, it is crucial to minimize the energy losses of a PTC. The following measures are therefore relevant for the effective O&M of a parabolic trough system (Lovegrove and Stein, 2012):

- Frequent washing of the mirrors, in order to ensure a high mirror reflectivity.
  In particular, dust can decrease the reflectivity and thus needs to be removed.
- Replacement of broken mirrors.
- Checking of collector alignment and solar tracking system.
- Maintenance of the installed ball joints.
  Here the periodic refill of the graphite packing is important.
- Monitoring of the thermal oil parameter

PTC power plants have been commercially available since the 1980s. A great amount of field experience is available, and the systems in general are bankable. Nevertheless, from a technical point of view some disadvantages do exist; two particular characteristics of PTC show considerable room for improvement. First is the significant fluctuation in annual power generation, due to the low elevation of the sun during the winter months and the corresponding lower solar irradiation.[1] Since the PTC's tracking system is usually designed for one-axis-tracking, it is not possible to vary the position of the PTC with the variation of the sun's position over the period of a year. This effect is strengthened with increasing distance from the equator.

Secondly, PTC can reach temperatures of about 380 °C, which is significantly lower than temperatures reached by fossil-generated steam. The limiting factor for the efficiency of thermal power plants is the Carnot efficiency (Eq. 2-1), which is determined by the inlet and outlet temperatures. The wider the range of these temperatures, the more efficient the cycle becomes.

[1] During the winter months, the sun's radiation must travel a longer distance through the atmosphere. Therefore, it is reflected more often by particles in the atmosphere. Additionally, the solar irradiance decreases with increasing distance from the sun to the earth. This distance varies over the period of a year, and thus the amount of solar irradiation varies correspondingly.

Further background on this theory is given in several textbooks, such as Cengel and Boles (2014) or Moran et al. (2010).

$$\boldsymbol{\eta = \frac{W}{Q_H} = \frac{Q_H - Q_L}{Q_H}} \qquad \text{Eq. 2-1}$$

W Work done [J]

Q_H Heat input into the system [J]

Q_L Heat out of the system [J]

As long as the temperature is significantly lower, PTCs are disadvantaged in comparison to fossil-powered energy generation, or any other energy generation technology using higher temperatures.

Solar tower technology

A central receiver system, also known as a solar tower, consists of an array of tracking mirrors (heliostats) and a receiver, which is mounted on a tower and absorbs the irradiation energy. Solar radiation is focused on a punctual area, which is why the system is categorised within the group of point focus systems. It can therefore reach higher temperatures than PTC systems, reaching about 1000 °C. Accordingly, the Carnot efficiency is higher, which allows the application of smaller and cheaper steam turbines while generating equal energy output. A higher temperature difference between storage tanks also reduces investment costs for the TES. Solar tower power plants differ mainly in the type of HTF used and the technology of the receiver. The integration of a TES is possible, and can drop O&M costs as well as LCOE (IRENA, 2012).

Mirrors of a heliostat are usually slightly curved, and mounted on a rack which is movable in two axes. The mirror can therefore be adjusted at any time, according to the direction of the sun. The mirrors can reflect incident direct-beam sunlight onto the receiver and concentrate it by a factor of 500 to 1000, which is enough to reach receiver temperatures of up to 1200 °C. The receiver converts the concentrated incoming sunlight into high-temperature heat, and transmits it to the heat transfer medium. The heat can then be used as process heat, and can either be stored as thermal energy or be used directly to generate steam and thus drive a generator. A detailed explanation of the issues which must be addressed when designing, building, and operating a complete solar thermal power station can be found in a Sandia report (Kolb, 2011).

Solar towers possess a number of advantages in comparison to, for example, PTC systems, and supports the hypothesis that they may soon become a preferred CSP technology. According to a IRENA working paper (IRENA, 2012) the main advantage is higher temperatures, which:

- Potentially allow greater efficiency of the steam cycle, and reduce water consumption for cooling the condenser;
- Make the use of TES to achieve schedulable power generation more attractive;
- Allow greater temperature differentials in the storage system, either reducing costs or allowing greater storage for the same cost;
- Allow a solar tower to achieve an annual energy yield that is more constant than that produced by PTC. This is due to the fact that the heliostats are trackable in two axes, and thereby able to adapt to the variation of the sun's altitude during the year.

Despite these advantages, investment in solar towers is lacking since it includes significant technical and financial risks, which are due to relatively low experience with this technology (IRENA, 2012).
Table 1 presents an overview of the differences between PTC and solar towers.

Table 1 Comparison of PTC and solar tower technology (IRENA, 2012)

	Parabolic trough	Solar tower
Maturity of technology	Commercially proven	First commercial projects
Technology development risk	Low	Medium
Operating temperatures (°C)	350–400	250–565
Plant peak efficiency (%)	14–20	23–35
Annual capacity factor (%)	25–28 (no TES) 29–43 (7h TES)	55 (10h TES)
Collector concentration	70–80	>1000
Storage system	Indirect two-tank molten salt at 380 °C (Δ T=100 °K)	Direct two-tank molten salt at 550 °C (Δ T=300 °K)
Storage with molten salt	Commercially available	Commercially available

Power block

A power block converts thermal energy into mechanic and finally into electrical energy. This technology can generally be used to convert thermal energy that results from any process, and not only from solar thermal processes; in principle, energy can be generated from nuclear, fossil or renewable resources.

For CSP systems a number of different solar-to-electric energy conversion systems can be applied. The most common systems are steam turbines, and this technology shall thus be introduced at this point. The steam turbine cycle is based on a fundamental understanding of the principles of physics, thermodynamics and engineering. A detailed explanation of the relevant basics can be found in the lectures on physics given by Feynman (1963-1965), while a more applied approach can be found in textbooks, e.g. by Nag (2013).

A model to predict the performance steam turbine systems can be derived by using the Rankine cycle, which is named after the German physician Rudolf Julius Emanuel Clausius and the Scottish engineer William John Macquorn Rankine. A detailed theory-driven description of the cycle is given for instance by Planck (1964). Lovegrove and Stein (2012) defines the general processing steps of a solar power plant with a Rankine cycle with the following steps:

- Compressing pure feed water to high pressure (over 10 MPa, for example);
- Boiling and superheating steam in a boiler which may be located in the focal point, or which may be heated using a heat exchanger with another HTF;
- Expanding the steam to low pressure via a series of turbines that drive a generator; and
- At the end of the expansion process, condensing the low-pressure steam with the aid of a cooling tower and re-using it in the cycle.

This means that first feed water is conducted through a steam generator. Inside the steam generator, heat from the solar field is used to heat and consequently vaporise the incoming feed water. According to the Carnot efficiency ratio (mentioned above), the efficiency of such a cycle is limited by the temperature difference between inlet and outlet temperature. Consequently, it is essential to raise the medium inlet temperature as high as possible. This can be done in two ways: firstly, by pressuring the feed water, before conducting it into the steam generator. With higher pressure, the vaporising temperature also rises. Secondly, the steam can be superheated after vaporising, heating up the saturated steam even further. By relaxing the superheated steam through a turbine, the thermal energy can be converted into mechanical energy, which then can be used to run a generator. During the process of expansion in the turbine, the steam begins to condense and drops of water form. These drops are not desirable inside a turbine, due to two main reasons: firstly, the danger of corrosion of the turbines, and secondly, possible damage to the turbines due to the high collision-speed of the drops. In order to avoid these problems, the steam, which is partially expanded and leaves the high-pressure turbine, is again heated to 810 °K and is then forwarded to the low-pressure part of the turbine. This process is called reheating. The steam expands through the multi-stage turbines and drives the generator. After condensation of the steam, a low amount of thermal energy with a low temperature difference remains. This part is removed by the cooling water, which is close to ambient temperature. Finally, the liquid feed water is returned to the steam generator and can be used again. Depending on the system and the heat transfer medium, which limits the live steam temperature, common thermal efficiencies (heat to AC electricity) can reach about 40% gross at full load.

Molten salt storage systems

Thermal energy storage can generate a number of advantages for plant operators as well as for customers. The first advantage is that electricity generation can be shifted to times where it is needed, thus increasing the value of the electricity. Moreover, TES can not only shift the energy output, but also extend the annual electricity production, which can raise the economic yield. Beside these economic advantages, some advantages also exist from a technical point of view. TES can help to reduce the number of shut-downs of the power block by buffering periods of no-sun. It also reduces times with part-load operation and lower efficiency ratios, and it can help to shorten start-up periods by preheating the absorber systems. All of these technical advantages extend the lifetime and energy output of the overall system, thus contributing to increased economic efficiency. An detailed example of the economic advantages of storage integration into CSP plants in the southwestern US is given by Denholm (2010). He concludes that storage generally improves the cost-efficiency of CSP plants.

Numerous storage concepts are currently available or under development. They can differ in the kind of working fluid used, storage capacity, temperature range, power level, reaction time, and many more factors. It is evident that no single storage technology will be able to meet the different requirements of all power plants. The following technologies are currently used commercially in CSP plants:

- Steam accumulators
- Two-tank sensible molten salt storage systems (based on nitrate salts)
- Improved molten salt storage concepts (lower melting points, higher thermal stabilities, improved thermo-physical properties)
- Solid medium sensible heat storage (e.g. concrete storage)
- Phase-change memory (PCM) storage for latent heat storage
- Combined storage systems (concrete/PCM)
- Solid media storage for solar towers with air receiver (e.g. natural rocks, checker bricks, sand)
- Thermo-chemical storage

According to Ruegamer et al. (2013), two-tank molten salt storage systems are a state-of-the-art thermal storage technology, and "have become a proven standard" (Lovergrove, 2012).

As the name indicates, a two-tank molten salt storage system mainly consists of two tanks: one hot tank, and one cold tank at a lower temperature. A liquid medium, in this case molten salt, is shifted between these two tanks. Depending on how the heat is transferred into the storage system, the systems can be further categorised into direct and indirect systems. While direct systems use the same medium in both the solar field and in the tanks, indirect systems use different mediums in the solar field and the tanks. Both parts are then connected via a heat exchanger. Indirect systems can be mostly found in PTC plants, where the HTF in the solar field is thermal oil and the storage fluid is molten salt. Solar towers commonly use salt as an HTF and therewith can integrate direct salt storage systems. Direct storage systems are usually cheaper and need fewer O&M measures, than indirect systems. The working principle and the main system components of direct and indirect TES is shown in Figure 3.

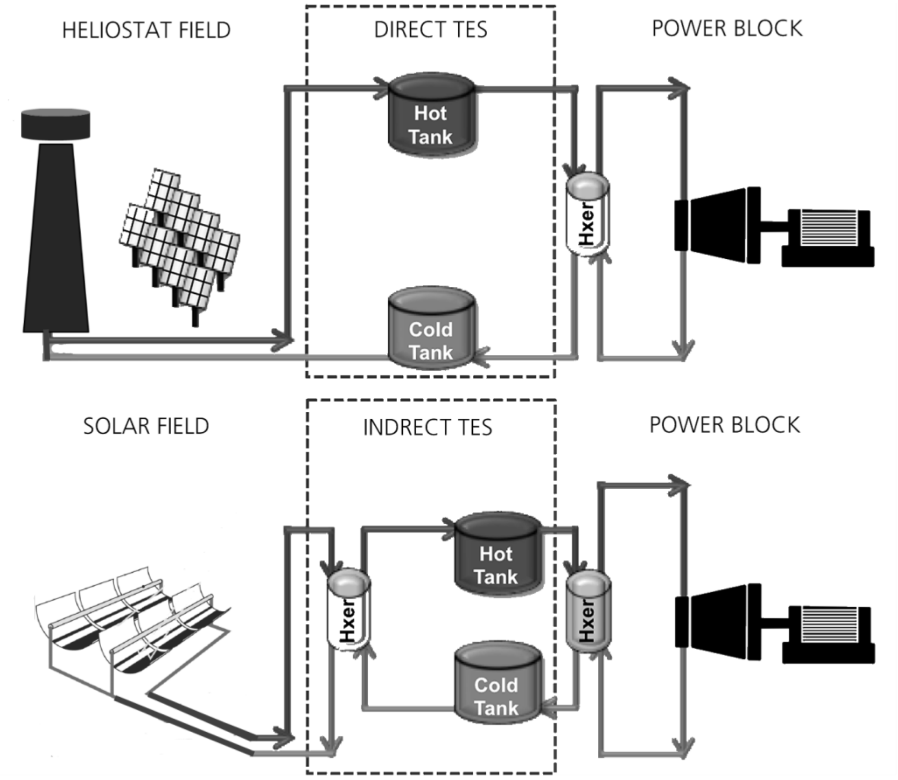


Figure 3: Direct and indirect TES (Stekli et al., 2013)

One major weakness of molten salt storage systems is the vulnerability of the commonly used mixtures of nitrates to freezing. This must absolutely be avoided, since re-melting is extremely complex and cost intensive. The freezing points of common nitrate salt mixes range around 140–220 °C. Conversely, thermochemical properties of salt change permanently if they are exposed to hot temperatures over a long period of time, and storage tanks exposed to higher temperatures are more expensive in general (Lovegrove and Stein, 2012, Ruegamer et al., 2013, Laing, 2011).

2.2. Technical description of the reference power plant

2.2.1. Overview

The Andasol 3 power plant serves as a reference power plant for this thesis. It is situated in southern Spain and was erected between 2009 and 2011. It operates using the technology of PTCs, using thermal oil as an HTF. Andasol 3 also has a two-tank molten salt storage system. The power plant has an installed capacity of about 50 MW_{el}, and represents the most common size and configuration of a PTC power plant with TES in Spain.

A brief description of the key data of the Andasol 3 power plant now follows. The data are also summarized in Table 2.

2.2.2. Site and meteorology

Location

The Andasol 3 power plant is located on the high plateau of Guadix, which is situated 1,100 m above sea level in the Granada Province. The plant is located in an unpopulated area 10 km from the city of Guadix, where the ground is solid and sandy. The next connection to the grid is found 7 km away in the City of Huénja.

Natural resources and meteorology

Measurements taken from the nearby Plataforma Solar de Almería by the DLR are used as a reference for a typical meteorological year (TMY) at Andasol 3. They display a direct normal irradiation (DNI) of about 2,162 kWh per square metre per year for a TMY, and a maximum wind speed of 18.1 m/s for a small number of days.

Since the plateau of Guadix is surrounded by the Sierra Nevada, the water supply is good. Nearby springs ensure an adequate water supply for the power plant in addition to the other essential demands of the region.

2.2.3. Technical equipment

Collector field

The collector field is equipped with Skal-ET2 mirrors and Schott PTR70 receivers. In total, 608 PTCs are installed in 152 loops, with 4 collectors per loop. The collector field therefore requires an area of approximately 1,910,000 m². The rows are oriented in a north-south direction, and the mirrors and receivers are fixed on a steel construction, which can resist a wind speed of 13.6 m/s. At a DNI of 800 W/m² the collector field can deliver 267 MW of thermal power.

Storage system

The Andasol 3 power plant comes with a thermal storage system, which consists of two-tank molten salt storage filled with a salt-mix of sodium nitrate ($NaNO_3$) and potassium nitrate (KNO_3). The two tanks have a diameter of 36 m and a height of 14 m. The cold tank stores the salt-mix at

290 °C, whereas the hot tank stores it at 390 °C. It has a net capacity of 970,000 kWh, which can deliver 7.5 full load hours for electrical energy generation.

Power block

The turbine, generator and peripheral equipment in the power block are similar to the equipment found in conventional power blocks (e.g. coal power plants or gas power plants). The turbine, which is made by MAN Turbo, is designed to generate a maximal gross electrical output of 52 MW_{el}. Part load operation down to about 20% is possible.

Table 2: Key data of the Andasol 3 power plant (SolarMillennium, 2008)

Key data of the Andasol 3 power plant	
Location	
Location	10 km east of Guadix, Granada Province
Land use	Approx. 1,910,000 m²
High-voltage line access	Connection to the 400 kV line near Huéneja (approx. 7 km away)
Meteorology	
Annual direct standard radiation (DNI)	2,162 kWh/m²a
Maximum wind speed	18.1 m/s
Water supply	Good conditions, supplied by Sierra Nevada
Solar field	
Concentrator	Skal-ET2
Receiver	Schott PTR70
Size of solar field	Approx. 500,000 m²
Number of collectors	608
Thermal power output (at a DNI of 800 W/m²)	267 MW_{th}
Mean solar field efficiency	Approx. 45%
Estimated lifespan	25 years
Thermal storage	
Heat storage net capacity	970,000 kWh
Full load hour capacity	7.5 hours
Heat storage medium	Molten salt-mix ($NaNO_3$ and KNO_3)
Freeze protection temperature	60 °C
Hot tank temperature	390 °C
Cold tank temperature	290 °C
Estimated lifespan	25 years
Power block	
Turbine capacity	52 MW_{el}
Mean system efficiency	Approx. 15%
Estimated lifespan	40 years

2.3. Ageing behaviour of parabolic trough power plant components

2.3.1. Approach

The technical condition of a power plant degrades with usage and time; this process is also called ageing. Although O&M costs include the periodic replacement of wearing parts, not all components of the power plant are considered for this factor. Those parts which are not replaced regularly will either reach their lifetime at a certain point and break completely, or will degrade in performance over time. If a power plant is operated after the planned lifespan, e.g. 25 years, these components must also be checked regarding replacement, in order to guarantee a secure and safe operational mode with low downtimes. The technical condition and further life expectancy of the components must be assessed and if necessary, components must be revised or replaced.

A literature review about ageing of PTCs and the associated components of a power plant now follows, and will serve as the basis for an estimation of the ageing of the Andasol 3 power plant by the year 2030.

The main components of a parabolic trough power plant are its steel construction, receivers, mirrors, pumps, HTFs, the HTF system, swivel joints and ball joints.
Where parts of the pumps, HTF, HTF system, swivel joints and ball joints are concerned as wearing parts, and therewith replaced as technically necessary; steel construction, receiver and mirrors need to be assessed regarding their technical condition, after the assumed lifespan of the power plant. Therewith these three components can be seen as crucial, for an operation of the power plant after the expected life time.
A molten salt storage system needs also to be assessed. Therefore a literature review about the ageing behaviour of molten salt storage systems is also part of this work.

Power blocks installed in combination with parabolic trough systems are known to operate for over 40 years, and so they will not be considered in this section (Yang, 2007).

2.3.2. Literature review

PTC components

Steel construction

Steel constructions are one of the most common constructional elements in modern architecture (Collins, 1965). Their technical and constructional properties are well known. The main potential problems with steel constructions of parabolic trough power plants are corrosion and deformations, although both issues can be avoided by proper planning at an early stage. This includes an appropriate payload, a sufficient safety factor against wind forces, and good protection against external impacts that could cause corrosion. If all of these issues are considered from the beginning, it can be assumed that a steel construction of a parabolic trough power plant can be used for over 25 years. Otherwise a revision, or even a complete replacement, of the steel construction is necessary at a much earlier stage (Grote and Feldhusen, 2007).

Receiver

The performance of a parabolic trough receiver, also called a heat-collecting element (HCE), is crucial for the overall performance of the power plant. Among others, two factors have the most influence on the efficiency of a HCE: firstly, a high absorption factor is important, in order to gather as much solar energy as possible. Secondly, a low emission factor is also important, to keep the solar energy within the HCE and to keep heat losses as low as possible.
To reduce heat losses and protect the solar-selective absorber surface from oxidation, the HCE is designed with a vacuum-tight enclosure (Figure 4). The vacuum in an HCE is typically at approximately 0.013 Pa. Damage to the vacuum-tight enclosure causes a radical drop in the efficiency. The main reason for a dilution of this vacuum is diffused hydrogen; due to high operation temperatures, the thermal oil decomposes and hydrogen is released, which permeates into the vacuum. This effect is also called the “hot tube phenomenon” (Price et al., 2006).

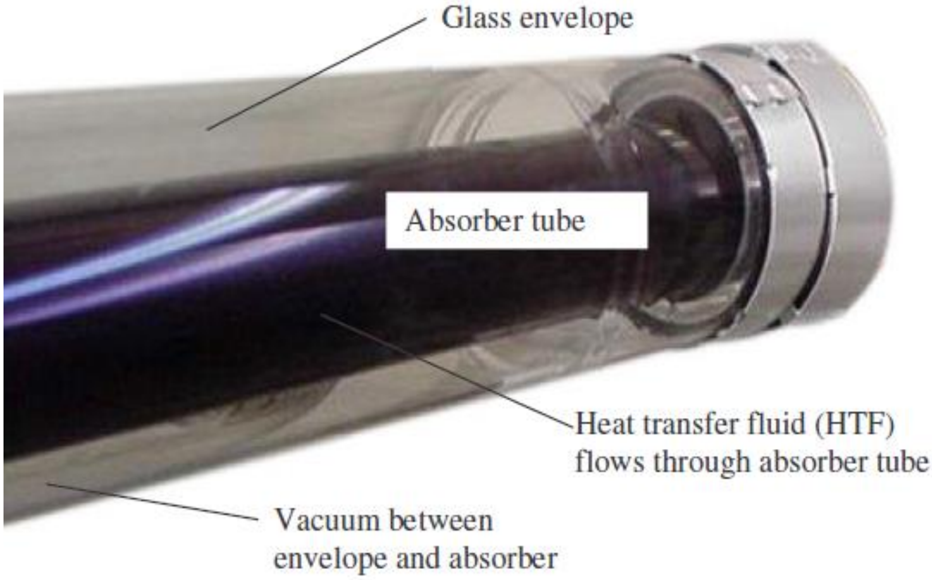


Figure 4: Heat collecting element (Patnode, 2006)

“Field experience has [also] demonstrated that, over time, the vacuum in the annulus can be compromised, allowing air to infiltrate the annulus.” (Patnode, 2006) The effects experienced in this case are the same as those resulting from the permeation of hydrogen into the vacuum. The introduction of air into the annular space will increase thermal losses, and will consequently decrease the efficiency of the HCEs.

The issues of how to determine these problems and which possible solutions are available seem to be the most important, in terms of the ideal technical operation mode of the power plant.

Three common technologies are available to detect and eliminate vacuum dilutes that are caused by gas molecules.

Firstly is the equipment of the HCEs with getters, which are metallic compounds that absorb gas molecules. They can be installed inside the vacuum space, and absorb hydrogen and other gases that permeate into the vacuum annulus over time. They also serve to detect a loss of vacuum (Price et al., 2006).

Secondly, so-called hydrogen removers (HR) are available. A hydrogen removal membrane made from a palladium alloy removes excess hydrogen from the vacuum annulus. Mounted with one side exposed to an oxidising atmosphere and the other side to the evacuated space, the membrane enables the flow of hydrogen from the evacuated space through the membrane and into the oxidising atmosphere (Price et al., 2006, Isaac J. Labaton, 1989).

Thirdly, the company SCHOTT introduced a HCE with a capsule containing noble gas placed into the evacuated annulus. If a "hot tube phenomenon" is detected, the encapsulated noble gas will be released by laser drilling of the capsule. By moderating the movements of hydrogen with a heavy mass noble gas (e.g. Xenon), the heat loss can be reduced (Sohr et al., 2013).

Unfortunately, none of the above-mentioned technologies serve as a repair solution, which re-establish the initial efficiency of an HCE; a total replacement of the HCEs will be necessary if a "hot tube phenomenon" is detected.

For this reason, an assumption about the proportion of HCEs concerned by the "hot tube phenomenon" is needed.
In 2006, researchers from the National Renewable Energy Laboratory (NREL) believed that out of the solar energy generating system (SEGS) power plants in California, as many as 50% of the collectors in the solar field have been compromised, in part, by hydrogen permeation. These SEGS power plants were erected between 1985 and 1991 (Price et al., 2006).
Patnode (2006) used a computer model to quantify performance degradation of the solar field, due to loss of vacuum in the annulus space. By estimating that 50% of the collectors in the solar field have been compromised by either air or hydrogen, the model predictions for power output agree with the measured data from the field. Although agreement between model predictions and measured data alone cannot be used to conclude that the behaviour observed in the field is driven by losses of vacuum, it has been demonstrated that a share of 50% of affected HCEs would decrease the gross power output of the plant by 10–15% (Patnode, 2006).

Mirrors

The mirrors in a solar field of a parabolic trough power plant are a major driver of cost, and have a great influence on the cost-efficiency of the entire power plant. Known problems of mirrors in solar thermal power plants include glass breakage, and degradation of the optical reflectivity (FVEE, 2002).

Most glass breakage is caused by external stresses. Notably, storms in desert regions contribute to a high mechanical stress and therefore to a high share of glass breakage. One other possible reason is damage during maintenance or cleaning processes. At the SEGS power plants, which are located in a stormy desert region, less than 1% of the reflectors need to be replaced each year. This amount is seen as component of the standard maintenance costs (FVEE, 2016, FVEE, 2002) .

After ten years of operation, the reflectors of the SEGS power plants exhibited no degradation of reflectivity (FVEE, 2002). Nevertheless, optical degradation in particular is heavily dependent on climatic conditions, as well as the technology and materials used for the mirrors. Brogren et al. (2004) et al. investigated mirrors with six different reflector materials, which were aged both outdoors and in a climatic test chamber. They concluded that in general, laminated and lacquered reflectors withstood outdoor ageing better than unprotected thin film-coated and anodised aluminium mirrors. Furthermore, this study demonstrated that if mirrors do degrade, this occurs within a short period; the solar reflectance of anodised sheet aluminium decreased from 88% to 83% within nine months of outdoor ageing.

Molten salt storage components

Common molten salt storage systems include salt as a storage medium, tank(s), pumps, heat exchangers and the balance of plant (BoP), which refers to infrastructural components. The function of pumps, the heat exchanger, the boiler and the BoP can be maintained by periodically replacing wearing parts, but the storage medium and the tanks must be assessed by examination of their technical condition after the assumed lifespan of the power plant.

The main problem regarding a reliable estimation of the storage condition is insufficient long-term experience with this technology. One of the first molten salt storage systems was launched in 1984, in France. The project, called THEMIS, was followed by the Solar Two power plant in the USA, launched in 1996, which used a nitrate salt as a storage medium. Both projects were later shut down, in 1986 and 1999 respectively. The THEMIS power plant, with 2.5 MW electrical capacity, and the Solar Two power plant, with 10 MW electrical capacity, were rather small projects compared to the sizes of modern parabolic trough power plants. The first commercial molten salt storage system, with a large thermal capacity of 970,000 kWh, has been installed as part of the Andasol 1 power plant, and has been operating since 2009 (Dunn et al., 2012).

Properties of salts are well known from a number of industrial applications related to heat treatment, electrochemical reactions, and heat transfer. From general experience it can be said that at high temperatures, salt stabilities and corrosion aspects play a major role; the thermochemical properties of salt change permanently if exposed to hot temperatures over a long period of time, and salt affects metallic components by corrosion (Lovegrove, 2012). Thus, an assessment of salt stability as well as any corrosion of the tank is required.

Salt

Salt is heated up to almost 400 °C inside the storage system, and at high temperatures aspects of salt stability play a major role. General experience with nitrate salts, in a number of industrial applications, reveals no common problems regarding life expectancy and durability (Bauer et al., 2012). The thermal stability of solar salt, which is a salt mixture, is higher compared to standard $NaNO_3$ (Bauer et al., 2012).

Tanks

Using molten salt as a storage medium generally increases the rate of steel corrosion. The rate of corrosion particularly depends on the type of steel which is used and the wall thickness. Based on this fact, the tanks of the storage system should be designed taking into consideration this special requirement, to allow them to accommodate the increased rate of corrosion without damage (Bergmann, 2013).

In addition, two-tank molten salt systems were optimized to allow infrastructural parts such as valves and the heat exchanger to be easily replaced, due to the fact that they are affected by corrosion (SIJ, 2016).

2.4. Technical description of retrofit concepts for the reference power plant

The existing PTC power plants in Spain are quite similar to one other, the single difference between most being whether or not thermal storage is included. It is thus important when reviewing the results of the thesis to always refer to the base, scenario and concept being considered (Figure 5).

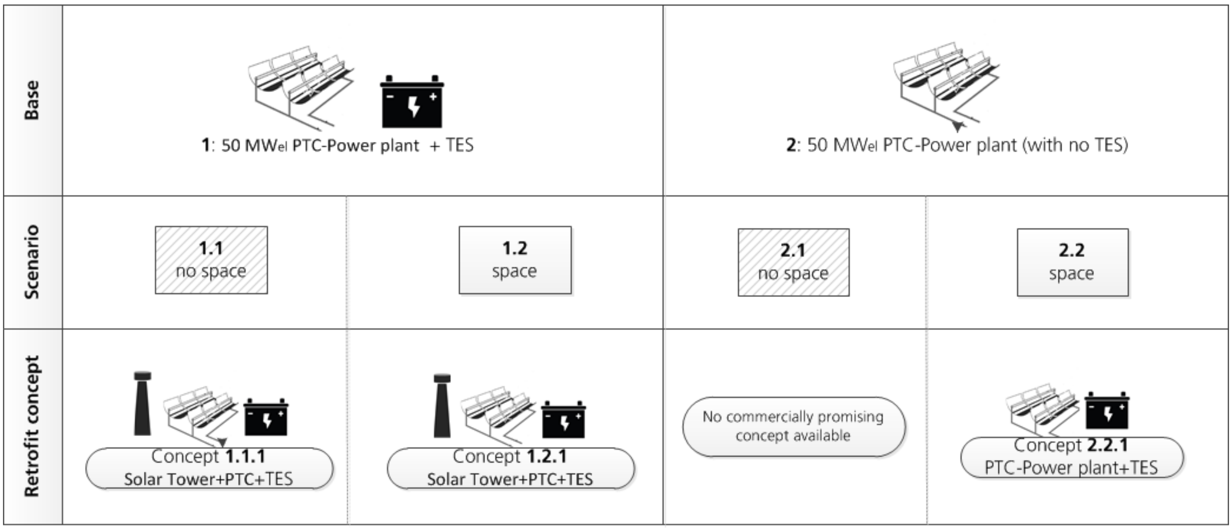


Figure 5: Base cases, scenarios and concepts

Base cases

This thesis will review retrofitting concepts for PTC power plants. Therefore, the base technological approach will always be an existing 50 MW_{el} PTC power plant (section 2.2), which is a common size for PTC power plants. In Spain two kinds of PTC power plant compositions can be found, and so the following two base cases are defined here:

- Base 1: PTC power plants with TES
- Base 2: PTC power plants with no TES

Scenarios

If a retrofit with additional components and parts of the power plant is to be implemented, additional area could be required. In this case two scenarios become relevant, regarding the retrofitting of PTC power plants with solar towers:

- Scenario 1: Assumes that no space for an extension of the area of the power plant is available. For example, the area could be limited by surrounding housing, an area development plan or simply unsuitable ground conditions.
- Scenario 2: Assumes that sufficient area is available to implement retrofit measures.

Retrofit concepts

For each base case and scenario, a number of possible retrofitting concepts have been developed upfront within the corresponding research project. They have then been assessed regarding their technical feasibility, output, and resource requirement. All of the components and combinations shown in Table 3 have been taken into account for the model-building process. For each base case and scenario, one possible retrofitting concept will be investigated from a techno-economic perspective.

Table 3: Components and combinations for retrofitting concepts

Objective: Parabolic trough with thermo-oil + solar tower + storage	
Solar tower with	Open volumetric receiver
	Molten salt
	Direct steam
Steam boiler	Shared steam boiler
	Two parallel used steam boiler
Coupling/connection to the tower	Feed water preheating
	Volatilisation
	Superheating
	Intermediate superheating
Additional storage	Ceramics
	Molten salt
	Sensitive and latent heat storage

A combination of a solar tower with molten salt as HTF, a shared steam boiler and a molten salt storage system is viewed as the preferable basic concept. Even though other concepts could reach a slightly higher efficiency, the assumed investment would be higher in these cases.

Besides the idea of retrofitting a solar tower, it seems meaningful to also consider the retrofitting of a PTC power plant with a TES (combined with an adaption of the number of PTCs). For this concept, the requirement for additional space is inevitable.
The cost-effectiveness of retrofitting a solar power plant without TES and with no available additional space is not expected, and thus is not investigated further within this thesis.

The following retrofitting concepts have been selected and described in a higher level of detail.

Concept 1.1.1

The base case is a PTC power plant with TES (section 2.2). The objective is to remain within the land area already being used, and the concept therefore consists of dismantling approximately 190,000 m² of the existing solar field. A solar tower can then be constructed in this space, with a heliostat field of 149,388 m². The installed receiver can deliver 89,390 MW_{th} at the design point, and the salt returned from the solar tower can be led to a cold storage tank at 290 °C. The power plant will be further extended by an additional storage tank with a capacity of 200,000 kWh.

Concept 1.2.1

The base case is a PTC power plant with TES (section 2.2). The objective is to extend the installed capacity of the solar field as well as of the power block. A solar tower with a receiver capacity of 107,95 MW_{th} at the design point will therefore be installed, and a heliostat field with an area of 184,957 m² is also needed. The power block capacity will be extended to 68,102 MW_{el}, by retrofitting measures. The return temperature of the salt is 390 °C, which is high enough to be stored in the hot tank. Additionally, an extra tank is needed for the heat at a temperature above 500 °C, with a capacity of 330,000 kWh.

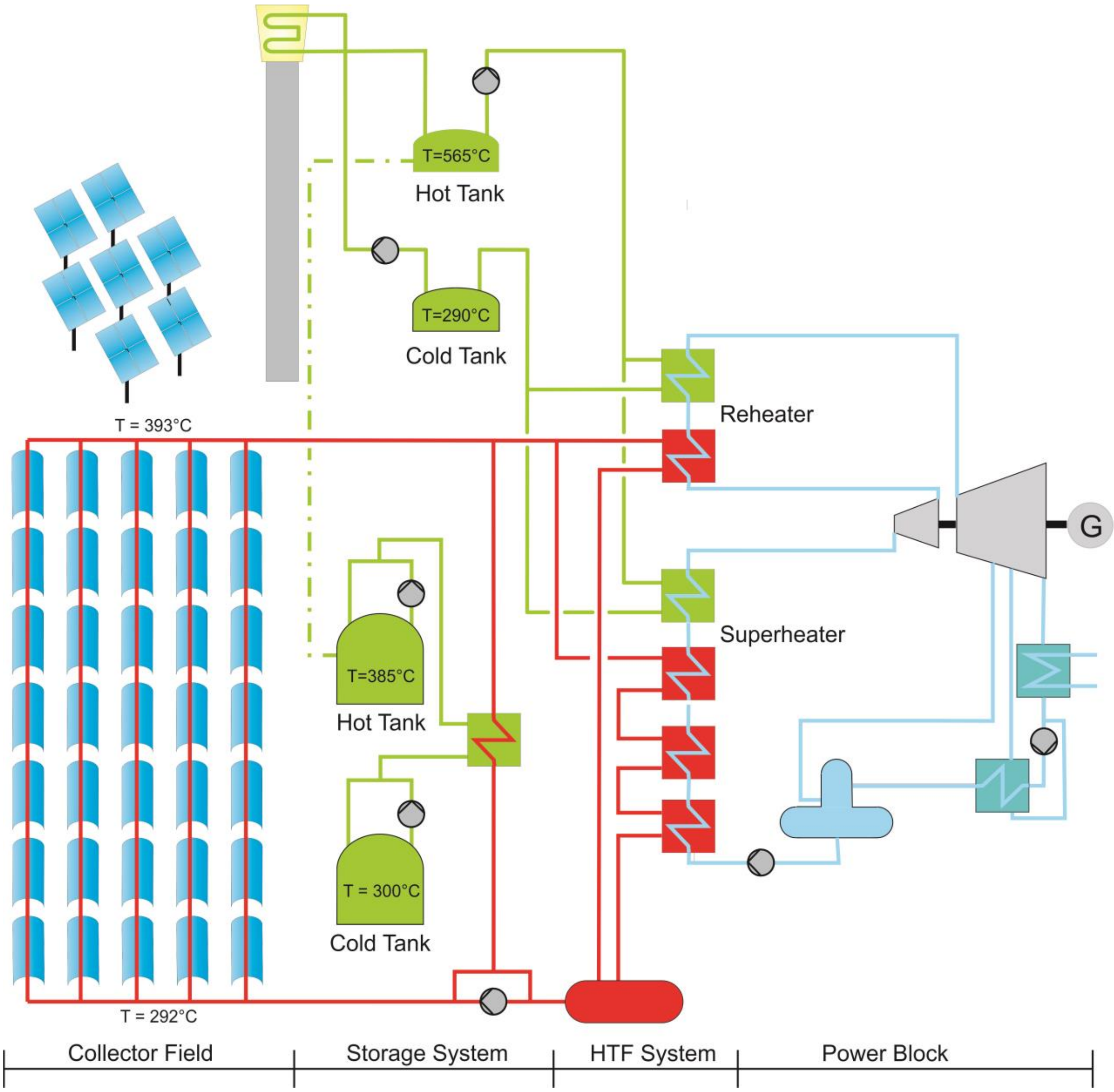


Figure 6: Scheme of concept 1.1.1 and 1.2.1 (DLR, 2016)

Concept 2.2.1

The base case is the PTC power plant described in section 2.2, but without TES. The reflective area of the solar field is 294,300 m², and the power block capacity is 52,000 MW_{el}. A TES with 7 hours of capacity will be added. Power block capacity will remain constant, but reflective area will need to be adapted to the TES with a capacity of 970,000 kWh. The final system then contains a reflective area of 497,000 m² and a TES of 970,000 kWh capacity. The system is therefore technically equal to the base case 2.

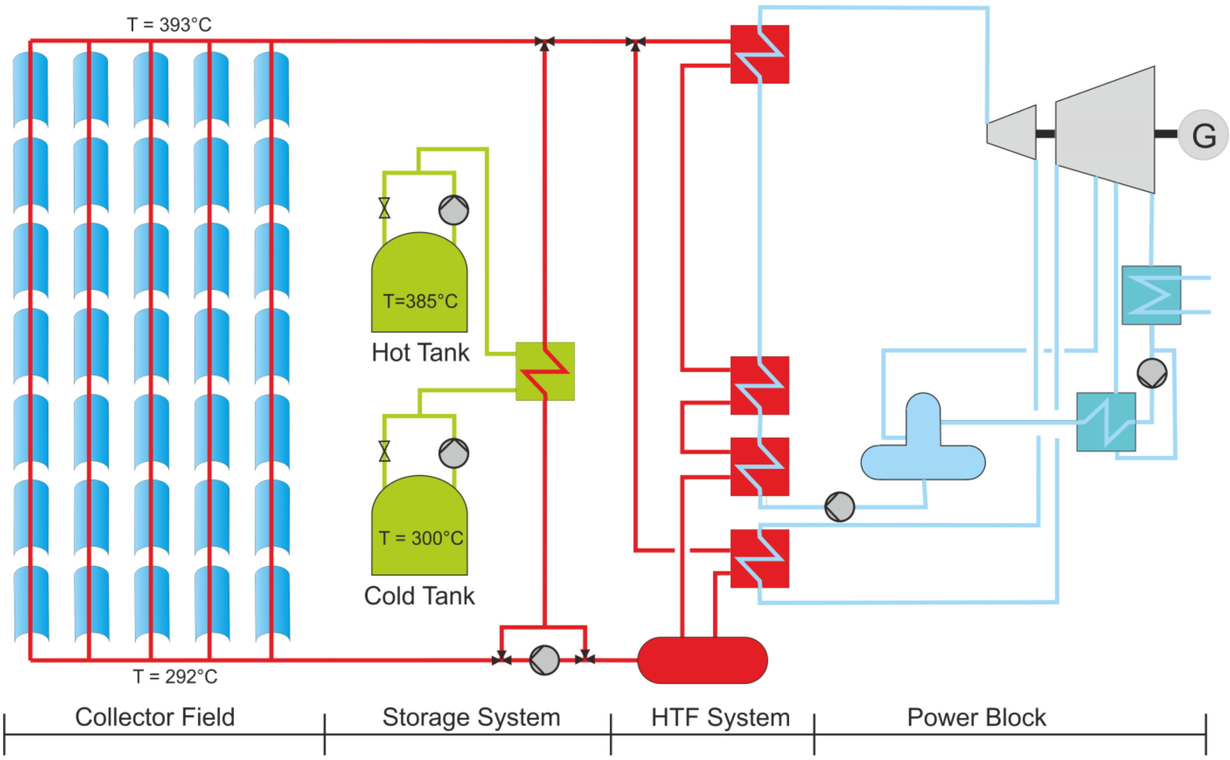


Figure 7: Scheme of concept 2.2.1 (DLR, 2016)

For the purpose of simplification, the concept names are referred to as Concept A (concept 1.1.1), Concept B (concept 1.2.1), and Concept C (concept 2.2.1) in the following.

Table 4: Renaming of the concepts

Renaming of the concepts

Concept	Reference case I	Reference case II	1.1.1	1.2.1	2.2.1
Concept – renamed	RC1	RC2	A	B	C

2.5. Techno-economic simulation models for CSP power plants

2.5.1. Technical performance modelling

During the planning phase of a CSP power plant it is essential to have data about the predicted output of an intended power plant. An adequate number of calculations are required to assess the feasibility and economic efficiency of a power plant. This is a complex process, which can be achieved by different approaches. The power plant system consists of a number of subsystems, whose output parameters vary depending on the condition of the whole system at any one moment. Power cycle efficiencies change with load and operation mode, and also depend heavily on the thermodynamic behaviour of technical components. System parameters and meteorology change continuously.

A number of models for CSP performance predictions are available. Every model attempts to include and consider the above-mentioned factors as far as possible. However, every approach has special characteristics, advantages and disadvantages, which need to be considered when being used to model a certain system. A general difference between the system models is the time-step used for calculations. The literature differentiates between two approaches (Lovegrove and Stein, 2012). The first is known as the 'pseudo-steady-state', which models half to one-hour steps. The second approach attempts to track short-duration cloud and thermo-fluid transients. It is crucial to assess the results of such calculations according to the chosen approach, and taking into account all possible deviations and uncertainties.

An overview of different models is given by García et al. (2011). Complete models for trough plants with TES are documented by the System Advisor Model (*SAM*) (Price, 2003, Blair, 2008a, Blair, 2008b, Wagner et al., 2010, SAM, 2016) from the NREL in the USA, *greenius* (Dersch et al., 2008, Hennecke et al., 2010) from the German Aerospace Centre (DLR), and *SOLERGY* (Stoddard et al., 1987) from Sandia National Laboratories in the USA. A standardisation of modelling is in progress by the SolarPACES organisation (Eck et al., 2011), and several tools for modelling energy systems in general, and thermal energy processes and systems in particular, are commercially available. The software *Ebsilon, IPSEpro, Mathematica, TRNSYS, Dymola and Aspen* can be used to model the subsystems of a CSP power plant, or even an entire CSP power plant, in one or more design points (Lovegrove and Stein, 2012).

An overall calculation of system performance usually results in the calculation of a TOY, which includes annual values of solar irradiation, energy yield, energy dumping, and system efficiency. In addition to this technical analysis of a power plant, an economic analysis is crucial to establish the optimal sizing and operational strategy (Lovegrove and Stein, 2012).

2.5.2. Economic performance modelling

A wide range of methodologies is available for the financial analysis of energy systems, which is explained by Short et al. (1995). The dynamic method of using the LCOE (also known as LEC) for economic calculation is considered state-of-the-art and is widespread (DIN, 2008, ISE, 2013, Konstantin, 2009, Lovegrove and Stein, 2012). It is defined as the constant per unit cost of energy, which over the system's lifetime will result in a total NPV of zero.

The LCOE method makes it possible to compare power plants of different generations and cost structures with one another. It is important to note that this method is an abstraction from reality, with the goal of making plants from different generations comparable, and is not suitable for determining the cost-efficiency of a specific power plant. In this case a financing calculation must be completed, taking into account all revenues and expenditures on the basis of a cash-flow model.

The calculation of the LCOE is performed on the basis of the NPV method, in which the cash flow from earnings and generated electricity during the plant's lifetime are discounted to the point of investment. Discounting the generation of electricity seems, at first glance, incomprehensible from a physical point of view but is a consequence of accounting transformations. The underlying idea is that the energy generated implicitly corresponds to the earnings from the sale of this energy. The further these earnings are displaced in the future, the lower their cash value (Konstantin 2009).

To calculate the LCOE, the following applies (Konstantin, 2009):

$$\boldsymbol{LCOE} = \frac{\boldsymbol{I_0} + \sum_{t=1}^{n} \frac{\boldsymbol{A_t}}{(\boldsymbol{1}+\boldsymbol{i})^{\boldsymbol{t}}}}{\sum_{t=1}^{n} \frac{\boldsymbol{M_{t,el}}}{(\boldsymbol{1}+\boldsymbol{i})^{\boldsymbol{t}}}} \qquad \text{Eq. 2-2}$$

LCOE	Levelised costs of electricity, in \$/kWh
I_0	Investment expenditures, in US Dollars
A_t	Annual total costs, in US Dollars per year (t)
$M_{t,el}$	Quantity of electricity produced in the considered year, in kWh
i	Real interest rate, in %
n	Economic operational lifetime, in years
t	Year of lifetime (1,2,… n)

A detailed explanation for calculation of the LCOE is presented in the textbooks by Konstantin (2009) and by the Fraunhofer Institute for Solar Energy Systems (ISE, 2013).

By applying the approach of a dynamic model, money could theoretically become an infinite value (dependent on timescale) and also obtain a negative value (depending on rate of return and inflation ratio). Continuous growth of capital over a long period is not possible in reality, and following this approach is not applicable for long periods. At this stage it is not possible to predict when a “long period” starts, and classical economy approaches cannot solve this conflict (Quaschning, 2011).

2.5.3. *Greenius* for techno-economic modelling

In order to support the planning and building of renewable energy power plants, the software termed *greenius* was developed at the the German Aerospace Center (DLR). This software aims to provide fast and detailed data for supporting decisions in an early assessment of feasability. For this purpose, it derives both technical and economic parameters. *greenius* was initially developed to model PTC and other solar thermal applications; today, it is also possible to model photovoltaic, wind power, fuel cell and process heat applications. The possible applications of the software were recently extended to modelling the hybrid operation of PTC and solar towers. The model uses a pseudo-steady-state approach to simulate a system.

A number of different parameters are required for the simulation. Regardless of the technology, the following parameters must be specified:

- Economic parameters (feed-in-tariff, specific land costs, etc.)
- Meteorological data (temperature, solar radiation, wind speed, etc.)
- Project location (geographical location, soil conditions, etc.)
- Load profile and operating strategy

For modelling PTC and solar tower power plants, technical information about the following system components is required:

- Collectors/heliostats (geometric data, collector efficiency, etc.)
- Tower system (intercept power, receiver design, etc.)
- Solar field (number of collectors, length of pipelines, etc.)
- Thermal storage (capacity, losses, etc.)
- Power block

Based on this data, the techno-economic performance of the plant can be modelled. The temporal resolution of the TOY is variable; in addition to the default value of 60 minutes, it is possible to decrease the resolution to 30, 20, 15, or 10 minutes. Since *greenius* is based on pseudo-steady-state models, which neglect transient effects, the use of shorter time steps are not possible. The workflow principle of *greenius* is presented in Figure 8, and the model used by *greenius* is completely described by Dersch et al. (2008).

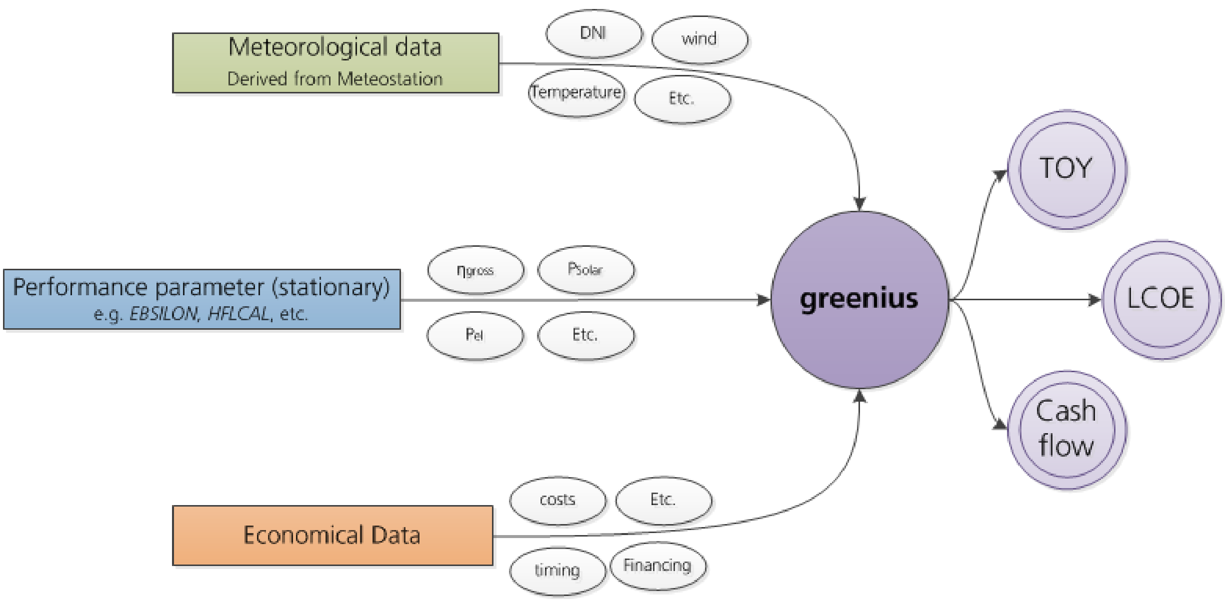


Figure 8: Workflow of the software *greenius*

2.6. Fundamentals of benchmarking

Benchmarking is a tool for the continuous comparison of products, services, concepts, processes or methods. A benchmark is either a value that is best-in-class, or a common standard. The term was introduced in the 1980s by Robert C. Camp, who worked for the company Xerox, and developed the concept in order to improve the company's products. Camp described the principles of the concept in Camp (1989).

The objective of benchmarking is to understand the advantages and disadvantages of a certain object, in order to improve its comparison against comparable objects. This can help to increase efficiency, enable innovations, lower costs and open new perspectives.
While the compared objectives in early benchmarking studies were products, modern benchmarking also focuses on processes and strategies. Benchmarking can be separated into two approaches. The first is internal benchmarking, where different products, processes, or departments of a single company are compared. The second approach is external benchmarking, where the object is compared to others. According to the chosen criteria, a distinction can be made between competitive, functional, and anonymous benchmarking.

Nevertheless, the principles of a benchmarking process are always more or less the same and follow these steps (Camp, 1989):

1. Planning
    a. Identify what is to be benchmarked
    b. Identify comparative companies
    c. Determine data collection method, and collect data
2. Analysis
    a. Determine current performance "gap"
    b. Project future performance levels
3. Integration
    a. Communicate benchmark findings and gain acceptance
    b. Establish functional goals
4. Action
    a. Develop action plans
    b. Implement specific actions and monitor progress
    c. Recalibrate benchmarks

In the planning and definition phase it is important to precisely define the object, process or concept which is to be benchmarked. A target unit must be set, which quantifies the rate, and supporting indicators can also be determined. These are known as key performance indicators (KPI), and show important performance factors. They can be qualitative or quantitative. Following this, a comparative object needs to be identified; this can be a best-in-class object, which is either internal or external. Access to and availability of data should also be considered when choosing a comparative object. The type, source, and quality of data are also crucial for benchmarking.

When data are collected, the gap between the objects being researched can be determined. It is possible that every object has its own advantages and disadvantages, which must be assessed with consideration of the initially defined target unit. This can be done by normalising the collected data. In this case, normalising means the adjustment of values which are measured on different scales to one pre-defined scale. This can help to compare objects of different scales (e.g. CSP power plants).

Objectives will then be developed, in order to improve the identified gap. Functional goals may help to achieve these objectives. In the final step, specific action plans will be developed and implemented. The integration of benchmarking into the management process could help to establish the success of the action plans.

3. Development of a benchmark methodology for CSP retrofits

The main principles and terminology of benchmarking are described in section 2.6. The approach provided by Camp (1989) will be used to derive a specific benchmark methodology for CSP power plants, which is then applied to the power plant concepts investigated in this thesis.

Applying the principles of benchmarking provided by Camp (1989), firstly the object, in this case the retrofit concepts, must be defined. A benchmark must then be defined, and a target unit needs to be set. This allows a comparison of the retrofitting concepts to the benchmark. The resulting data can then be collected and analysed.

3.1. Object and benchmark definition

The objects of research in this thesis are the retrofitting concepts and the reference cases. The three concepts investigated are explained in section 2.4, and the reference cases are explained in section 2.2. The concepts shall be compared on a concept level, i.e. from a systemic rather than a technical perspective.

As global energy demand is increasing, energy supply capacity must be extended in the future. The existing PTC power plants will not be removed at the end of their lifespan; instead, with the help of technical measures, their lifetime will be extended. Furthermore, the future installation of solar tower systems is very likely, due to comparatively low LCOEs (IRENA, 2012) and other technical advantages (Greenpeace et al., 2016, IRENA, 2012). As the benchmark will deliver extended energy capacity, the combination of overhauled PTC power plants and the addition of new solar towers can be seen as the reference case, representing the benchmark for a future CSP power system.

3.2. Target unit definition

Among others, the KPIs of power plants include (WEC, 2016):

- Electricity output
- Costs
- Storage
- Energy dumping
- Availability
- O&M costs
- Emissions
- Dispatch response
- Peak capacity
- Heat rate
- Reliability
- Maintainability

The LCOE (section 2.5.2) captures many of these KPIs. Electricity output, costs, availability, O&M costs, emissions (if priced) and reliability are integrated in the LCOE calculation. Thus LCOE is an eligible target unit for the benchmarking of CSP power plants. In fact, LCOE is already used as a benchmark and ranking tool to assess different energy generation technologies (Branker et al., 2011, Hegedus, 2011, Short et al., 1995, ISE, 2013).

3.3. Data collection

The data required for calculation of the LCOE are well defined by ISE (2013) and Konstantin (2009). The derivation and collection of technical as well as economic data for CSP power plants is described in Section 4. Where no reliable data are available, assumptions must be made. Assumptions and their uncertainties must always be indicated, and their use is inevitable if calculations are performed for a future point in time.

3.4. Data analysis

"The method of levelised cost of electricity (LCOE) makes it possible to compare power plants of different generation and cost structures with each other." (ISE, 2013) However, the method of LCOE is not sufficient to achieve a consistent ranking of retrofitted power plants with pre-existing capacity and gained electricity. In order to do so, the LCOE must be re-normalised (see section 2.6) from costs per kWh to costs per kWh of a certain plant capacity. Consequently, a benchmark LCOE for each concept needs to be calculated, which consists of an overhauled PTC power plant and additional electricity from a solar tower (see above), generating the same electricity yield as the retrofit concept. Using this approach, the benchmark LCOE and retrofitting concepts are calculated for the same amount of generated energy. This is necessary, since the volume and specific LCOE of additional gained energy is relevant for a consistent comparison. If, for instance, a power plant were able to generate a low amount of energy at a low LCOE, the remaining energy would need to be provided from an alternative source, which might induce higher costs. Concluding specific LCOE of a retrofitting concept are low, but overall LCOE for the total amount of required energy are high. The calculation of LCOE for the same amount of energy allows the assessment of whether it is cheaper to integrate a solar tower into an existing PTC power plant, or to build a whole new power plant, since the final systems are equal regarding energy output and installed technology. In order to make use of sufficient data for new solar tower power plants, LCOE calculations from IRENA (2016b) are consulted. For the benchmark, electricity from a solar tower can be seen as external supply, which is available in any amount needed. In this way, any power plant can be compared to its specific benchmark.

The LCOE for the reviewed power plant is calculated according to Eq. 2-2.

The benchmark LCOE is calculated according to:

$$\boldsymbol{LCOE_{BM}} = \frac{\sum_{t=1}^{t=n} \boldsymbol{LCOE_t} \times \boldsymbol{W_{E,t}}}{\sum_{t=1}^{t=n} \boldsymbol{W_{E,t}}} \qquad \text{Eq. 3-1}$$

t	Specific technology
$LCOE_t$	LCOE, in $/kWh
$W_{E,t}$	Annual generated electricity, in kWh/a

3.5. Example

The methodology will now be explained using a fictitious example (Table 5 and Figure 9).
The exemplary power plant has a total electricity output of 200 GWh per year, at $LCOE_{ex}$ of 0.08 $/kWh. The benchmark is represented by a power plant consisting of Technology 1 (e.g. PTC) and Technology 2 (e.g. solar tower). The benchmark generates the same amount of electricity (200 GWh/a). Assuming a $LCOE_1$ of 0.06 $/kWh and a $LCOE_2$ of 0.09 $/kWh yields a benchmark LCOE ($LCOE_{BM}$) of 0.07 $/kWh. $LCOE_{ex}$ and $LCOE_{BM}$ are comparable, due to an equal energy yield. Thus,

the LCOE of two different power plants with equal energy output can be compared and the power plant concepts can be ranked. In this case the benchmark would be preferable.

$$LCOE_{BM} = \frac{180\ \frac{GWh}{a} \times 0.06\ \frac{\$}{kWh} + 20\ \frac{GWh}{a} \times 0.09\ \frac{\$}{kWh}}{200\,\frac{GWh}{a}} = 0.0630\ \$/kWh$$

Table 5: Key economic data of the exemplary power plants

Power plant X	
Electricity output	200 GWh/a
$LCOE_{ex}$	**0.0800 \$/kWh**
Benchmark X	
Electricity output – Technology 1	180 GWh/a
Electricity output – Technology 2	20 GWh/a
Total electricity output	200 GWh/a
LCOE – Technology 1	0.0600 \$/kWh
LCOE – Technology 2	0.0900 \$/kWh
$LCOE_{BM}$	**0.0630 \$/kWh**

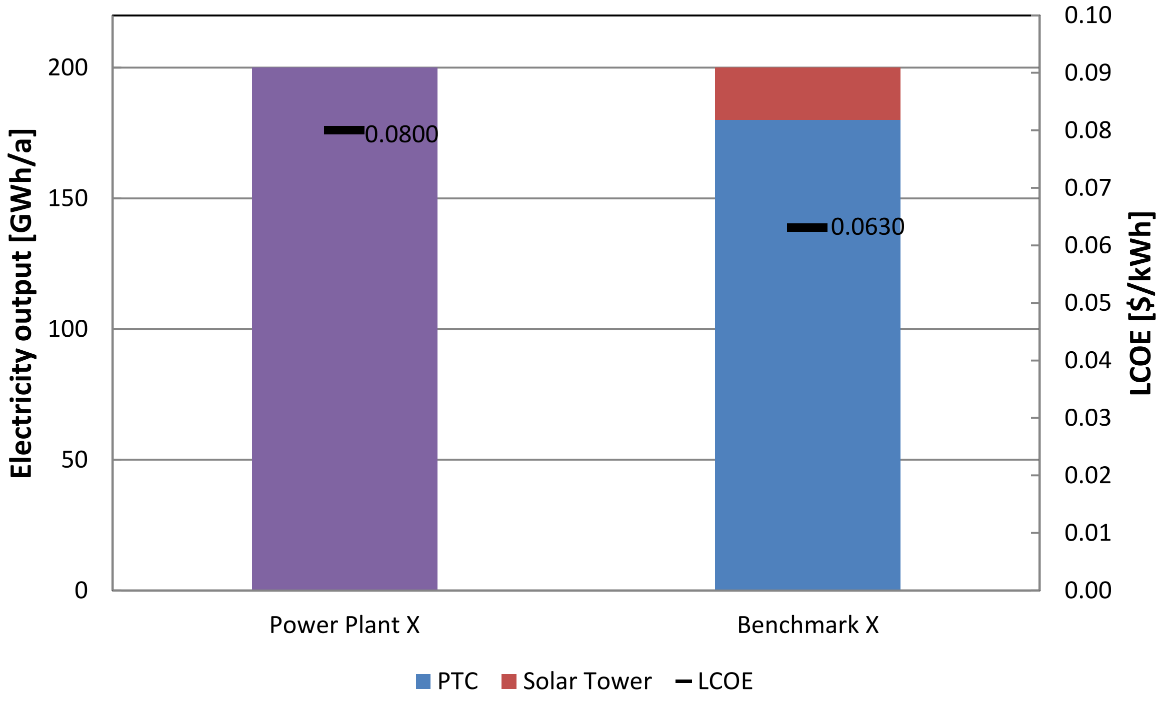


Figure 9: Description of the benchmark LCOE

4. Methodological derivation of techno-economic framework conditions

4.1. Technical framework conditions

4.1.1. Approach

In order to extend the lifetime of a PTC power plant beyond 25 years, the technical condition and further lifetime expectancy of critical power plant components must be assessed, and if necessary, these components must be replaced. The ageing process of a PTC power plant and the findings from a literature review on the subject are described in section 2.3.

An assumption of the technical ageing will now be derived for the critical components of the reference power plant. For this purpose, the findings about the ageing of these components shall be analysed and discussed, before the definition of specific assumptions for the reference power plant. The critical components of the trough field are namely the steel construction, receiver, and mirrors, which need to be assessed regarding their technical condition after the assumed lifespan of the power plant (see 2.3). Furthermore, an assumption about the technical condition of a molten salt storage system (if installed) is required, and shall be derived in the same manner. The year used for the assumptions is 2030. At that time the power plant will have passed an operation time of approximately 25 years, with the forecast of another 20 years remaining. Since experience with the long-term operation of parabolic trough power plants is limited to the SEGS power plants, the assumptions in this work include those experiences as well as in-house expertise, but cannot currently be validated.

4.1.2. Analysis and discussion

PTC components

Steel construction

No major problems regarding the durability of the steel construction are known. It is assumed that under the meteorological circumstances of southern Spain, a steel construction of a PTC power plant is not exposed to unusual loads or troubles. Common experiences and handling specifications are therefore applicable. This also includes an appropriate payload design, the use of a sufficient safety factor against wind forces, and good protection against external impacts that could cause corrosion (see 2.3.2).

Receiver

Common problems affecting receivers include the so-called hot tube phenomenon, and air infiltration in the annulus (see 2.3.2). Three main technologies are available to detect these kinds of problems, although replacement of the affected receiver is necessary for the initial efficiency of the HCE to be re-established. The receiver can be replaced part by part, and without removing other components of the PTC. Studies (Patnode, 2006, Price et al., 2006, IRENA, 2012) indicate that as many as 50% of the collectors in the solar field of the SEGS power plants in California have been compromised, in part, by hydrogen permeation. This would have an essential influence on the gross power output of a power plant. The power plants investigated in the above studies were erected between 1985 and 1991. They are equipped with parabolic trough linear receiver, designed and produced by the company Luz, which went out of business in 1991. The power plant investigated in this thesis was erected in 2005. It is equipped with the receiver model PTR®70, designed and produced by the German company Schott. Even though the installed receivers differ, they can be considered to be from the same receiver generation, with similar properties. Major improvements in receiver design can be seen from the year 2005, when new designs of receivers being commercially sold were introduced by companies such as Schott and Solel Solar (Price et al., 2006).

As mentioned in section 2.3.2, the complete replacement of the affected receivers would be a viable solution, despite the significant cost, which could be paid back within three years. The case analysed by (Röger et al., 2015) would also be valid for the Andasol 3 power plant.

Mirrors

The main problems encountered with mirrors in solar thermal power plants are glass breakage and degradation of the optical reflectivity. Compared to the SEGS power plant, the Andasol 3 power plant is located in a moderate surrounding. It is built on a fertile plateau close to the only European desert – the Tabernas Desert. Wind speeds are moderate and environmental hazards are rare at this location. Therefore it seems unlikely that the rate of mirror breakage due to external stresses, will exceed that of the SEGS power plants. Nor further reasons for mirror breakage can be demonstrated.

The mirrors installed in the reference power plant are silver-coated glass mirrors. If the mirrors degrade, as explained in section 2.3.2, it is supposed that a high rate of optical degradation would occur far before the end of the expected lifetime. They would be subject to warranty or simply a design error, but not considered an intrinsic part of maintenance.

Molten salt storage components

The storage medium and the tank in a molten salt storage system must be assessed regarding their technical condition, after the assumed lifespan of the power plant. Here, salt stabilities and corrosion aspects of the tank play major roles and shall both be analysed.

Salt

Freezing of salt in the thermal storage, or especially the heat exchangers, must be avoided at any cost in order to guarantee safety and operational reliability of all parts. No common problems regarding life expectancy and durability are known from a number of industrial applications, so it can be assumed that expected lifespan should be reached without problems. Moreover, there is no evidence that the salt's thermochemical properties could change after the lifespan of 25 years. The tanks of the Andasol 3 storage systems are filled with solar salt, which is aligned to the special requirements of a solar thermal storage system. The Andasol 3 power plant has no exceptional characteristics which could cause additional problems. Besides this kind of ageing, the salt could be contaminated with external pollutants; this needs to be avoided by taking appropriate measures.

Tanks

If the tanks of the storage system are designed taking into account the high corrosion rate of salt, they should reach the end of the plant lifetime without damage. There is no evident reason for unexpected or impending corrosion after the expected lifespan; nevertheless, corrosion should be monitored by operational staff. Furthermore, the TES system installed in the reference power plant is designed in the standard way, which enables the straightforward replacement of infrastructural parts such as valves or the heat exchanger.

Power block

Most of the world's electricity is generated by steam turbines, such as those in the power plants being investigated; it is considered the dominant power-generating technology. Standard turbines from the 1960s have now been operating for over forty years (Leĭzerovich, 2008).

Advanced turbines are installed at modern PTC power plants. Neither extraordinary loads nor an extreme rate of shut-off/on periods are expected.

4.1.3. Determination of technical framework conditions

Parabolic trough components

The following assumptions are determined for a PTC power plant, after a time of operation of 25 years:

Steel construction: It is assumed that a steel construction of a parabolic trough power plant can be used for another 20 years, without having to be replaced, or revised.

Receiver: A moderate assumption can be made in that 50% of the receivers in the solar field are affected by hydrogen accumulation in the receiver annulus, and they all need to be replaced completely after 25 years of operation.

Mirrors: It is assumed that the amount of mirror breakage does not exceed the predicted proportion. There is no evident reason for increased mirror breakage after 25 years of operation.

Molten salt storage components

If the molten salt storage of a power plant (e.g. Andasol 3) continues to be operated after the estimated lifespan of e.g. 25 years, the critical TES components (see above) must be handled in the following manner:

Salt: It is assumed that the salt can be used without limitation, and that no exchange is required. Salt stability is still under investigation, but comparable industrial processes show a high durability.

Tanks: It is assumed that tanks can be used beyond the expected lifespan of 25 years, without having to be replaced and or revised.

Power block

It is assumed that a power block will last for 40 years without any interruption. No replacement is needed.

Finally, an overview of all the parameters defined above is given in Table 6.

Table 6: Defined parameters for the ageing of a parabolic trough collector and molten salt storage

	Replacement required after 25 years?
Steel construction	No
Receiver	Yes, 50% of those initially installed
Mirrors	No
Salt	No
Tanks	No
Power block	No

4.2. Economic framework conditions

4.2.1. Approach

The following section presents the derivation of the investment costs for each concept. Furthermore, a framework for financing and timing shall be defined.

The following approach is used to define economic parameters:

As component costs are given for the year 2025 (IRENA, 2012, CSP, 2013), and retrofit measures will take place in 2030, costs must be adapted to the year 2030. The inflation ratio and learning curves must be taken into account, and additional surcharges for a low order volume must be added.

The specific costs for new system components (required for the retrofitting measures) and their installation are provided by IRENA (2012), but as mentioned in 2.3.2, a certain share of the absorber tubes need to be replaced. The amount of work, and the costs of labour for replacement and dismantling of a PTC must be estimated.

A detailed breakdown of the power block costs is provided by CSP (2013). The study defines costs per power block unit. This unit is applicable for an estimate of the costs for a new power plant, but not for the calculation of the investment costs of retrofitting concepts. Information is required about costs related to the unit of a certain system component, which is to be replaced or added. Therefore the ‘costs per system component unit’ need to be derived from the ‘costs per power block unit’ for the power block components.

Financial parameters for the calculation of LCOE also need to be defined. Parameters based on experience shall be derived from literature.

Where necessary, prices in Euros have been converted into US Dollars, with a currency exchange rate of 1.10 US Dollar/Euro.

4.2.2. Analysis and discussion

Cost adaption

Predictions by IRENA (2012) use a 160 MW_{el} power plant as reference. Values from CSP (2013) are valid for a 150 MW_{el} power plant. It is clear that component costs for single subsystem components are higher, when an entire power plant is not built. Surcharges for low purchased amounts are likely, and can vary between 15% and 30% of the component costs, depending on production, specialization, and availability of a certain product.

Cost values from IRENA (2012) are calculated to be valid for the year 2025. The retrofitting concepts will be implemented in 2030; combined with technological improvement, a price deduction of 2% for the period of 2025 to 2030 represents a conservative case.

presents component prices adapted to the year 2030.

Table 7: CSP component costs adapted to the year 2030

	Unit	Costs (2025)	Sur-charges	Costs (2025) + surcharges	Price deduction	Costs (2030)
PTC	$/m²	193	+30%	251	-2%	246
Dismantling – receiver	$/Rec.	5,000	0%	5,000	0%	5,000
Replacement of damaged HCE	$/HCE	960	0%	960	0%	960
Heliostat	$/m²	103	+30%	134	-2%	131
Receiver	$/kW	100	+15%	115	-2%	113
Tower	$/m	72,000	0%	72,000	-2%	70,560
Storage (tower)	$/kW$_{th}$	22	+15%	25	-2%	25
Storage (PTC)	$/kW$_{th}$	26	0%	26	-2%	25
Exchange of steam turbine (high pressure, 540 °C)	$/MW$_{el}$	347,390	+15%	399,499	-2%	391,509
Exchange of steam turbine (low pressure, 540 °C)	$/MW$_{el}$	247,654	+15%	284,802	-2%	279,106
Economiser/heat exchanger	$/MW$_{th}$	87,812	+15%	100,983	-2%	98,964
Superheater (salt/steam)	$/MW$_{th}$	92,196	+15%	106,026	-2%	103,905
Reheater (salt/steam)	$/MW$_{th}$	92,196	+15%	106,026	-2%	103,905
Steam generator (salt)	$/MW$_{th}$	51,802	+15%	59,573	-2%	58,381
Cooling system (extension)	$/MW$_{th}$	21,865	+30%	28,425	-2%	27,856
Exchange generator	$/MW$_{el}$	47,474	+15%	54,595	-2%	53,503
Feed water preheater (high pressure)	$/MW$_{th}$	146,577	+15%	168,564	-2%	165,193
Pumps	$/MW	607,084	0%	607,084	-2%	594,942
Feed water preheater (low pressure)	$/MW$_{th}$	66,586	+15%	76,574	-2%	75,042
Balance of the system	$/MW$_{th}$	24,950	0%	24,950	-2%	24,451
Engineering and project management	%	20				20
Risk and margin	%	10				10

Dismantling of collectors and replacement of absorber tubes

Dismantling of PTCs requires a trained workforce. It is assumed that five employees can dismantle one PTC within eight hours, at an hourly expenditure of $50. A crane is also needed, the cost of which can be estimated at $2,400 for eight hours. Including a surplus of $600, the dismantling of a single PTC results in a financial expenditure of $5,000 (Table 8).

Table 8: Assumed costs for dismantling a single PTC

Asset	Cost
Labour (5 people, 8 hours)	50 $/hour/person
Crane (8 hours)	300 $/h
Miscellaneous	600 $/PTC
Total	5,000 $/PTC (800 m²)

The replacement of damaged absorber tubes can be conducted by two trained employees within two hours, absorber by absorber. With an hourly expenditure of $50 for labour, and material costs of $190 per meter (IRENA, 2012) (absorber length = 4 m), the cost to exchange a single HCE are $960.

Table 9: Costs for replacement of a single absorber tube

Asset	Cost
Labour (2 people, 2 hours)	50 $/hour
Material (absorber length = 4 m)	190 $/m
Total	960 $/HCE

The residual value of a dismantled PTC and exchanged absorber tubes is neglected. In order to execute the retrofit measures, general downtime of the power plant is also taken into account, and thus no additional downtime is generated.

According to the retrofitting concepts described in section 2.4, the number of components of the solar field and molten salt storage needing to be replaced or added is presented in Table 10.

Table 10: Number of replaced and added components

Subsystems	Unit	RC1	RC2	Concept A	Concept B	Concept C
PTC solar field - added	m²	---	---	---	---	202,740
PTC solar field - dismantled	m²	---	---	186,390	---	---
Solar tower field - added	m²	---	---	149,388	184,957	---
Solar tower storage - added	kWh_{th}	---	---	200,000	33,000	---
PTC storage - added	kWh_{th}	---	---	---	---	970,000
HCE replaced	Units	10,944	6,480	6,840	10,944	6,480

Power block

The average costs for each system component per power block unit are available from IRENA (2012) and CSP (2013). An estimation of the individual costs of the system components, per system component unit, can be derived by dividing the investment costs of a certain system component by its installed volume. An example is provided in Table 11, by calculating the average costs per heat exchanger unit (MW_{th}).

Table 11: Example calculation of the costs per heat exchanger unit

Asset	Calculation
Costs heat exchanger (per power block unit)	34.6 $/kW_{el}$
Power block capacity at Andasol 3	52,000 kW_{el}
Costs for heat exchanger at Andasol 3	34.6 $/kW_{el}$ · 52000 kW_{el} = $1,779,200
Installed heat exchanger capacity at Andasol 3	20,500 kW_{th}
Specific heat exchanger costs	$1,779,200 ÷ 20,500 kW_{th} = 87.8 $/kW_{th}$

The calculation needs to be performed for each component of the power block (Table 12).

Table 12: Derivation of specific power block component costs

	Specific costs per power block unit ($/kW$_{el}$) (CSP, 2013)	Installed component volume at Andasol 3 (50 MW$_{el}$)	Derived specific component costs
Exchange of steam turbine (high pressure, 540 °C)	114.4	15.0 MW	396.7 $/MW
Exchange of steam turbine (low pressure, 540 °C)	193.6	37.9 MW	265.6 $/MW
Economiser/heat exchanger (water-steam cycle/salt)	34.6	20.5 MW$_{th}$	87.8 $/MW$_{th}$
Superheater (salt/steam)	32.4	18.3 MW$_{th}$	92.2 $/MW$_{th}$
Reheater (salt/steam)	36.9	20.8 MW$_{th}$	92.2 $/MW$_{th}$
Steam generator (salt)	69.2	69.5 MW$_{th}$	51.8 $/MW$_{th}$
Cooling system (extension)	80.8	76.8 MW$_{el}$	54.7 $/MW$_{th}$
Exchange generator	47.5	52.0 MW$_{el}$	47.5 $/MW$_{el}$
Feed water preheater (high pressure)	39.2	13.9 MW$_{th}$	146.6 $/MW$_{th}$
Pumps	10.9	0.93 MW$_{el}$	607.9 $/MW
Feed water preheater (low pressure)	31.6	24.7 MW$_{th}$	66.6 $/MW$_{th}$
Balance of the system	61.9	129.0 MW$_{th}$	24.950 $/MW$_{th}$

Calculation of the investment for each retrofitting concept requires the volume of added or replaced power block-components for each concept, which are shown in Table 13.

Table 13: Volume of replaced or added capacity of power block components

Component	Unit	RC1/RC2	Concept A	Concept B	Concept C
Steam turbine (high pressure, 540 °C)	MW	---	15.477	21.252	---
Steam turbine (low pressure, 540 °C)	MW	---	36.459	48.138	---
Economiser/heat exchanger (water-steam cycle/salt)	MW_{th}	---	---	---	---
Superheater (salt/steam)	MW_{th}	---	17.497	23.929	---
Reheater (salt/steam)	MW_{th}	---	11.610	15.878	---
Steam generator (salt)	MW_{th}	---	---	---	---
Cooling system (extension)	MW_{el}	---	---	16.102	---
Exchange generator	MW_{el}	---	---	68.102	---
Feed water preheater (high pressure)	MW_{th}	---	---	15.000	---
Pumps (extension)	MW_{el}	---	---	0.710	---
Feed water preheater (low pressure)	MW_{th}	---	15.500	15.500	---
Power block – balance of the plant	MW_{th}	---	129,000	170,254	129,000

Miscellaneous

In engineering, additional charges for project management and risks should be considered. ISE (2013) takes into account 14% of engineering, procurement and construction (EPC). This value is valid for common CSP power plants that are built completely from new.

Running costs

In addition to investment costs, running costs significantly influence the LCOE of a CSP power plant. Running costs comprise O&M costs, replacement costs, and insurance costs. These costs are usually related to the initial investment costs, power plant size, or energy output. Retrofitting measures may change the power plant size as well as its output; however, since running cost factors are relative to the system size, they do not need to be re-calculated.

Usually, O&M costs are on average 2-3% of EPC costs per year, consisting of approximately 1% for specific O&M measures, 0.2% for replacement parts, and 1% for insurance costs.

Financing parameters

Several financing parameters influence the LCOE. Figures used in the calculations within this thesis are accurate for the scenarios and circumstances defined above.
For the economic calculation performed in *greenius*, discount rate, interest rate, debt ratio, and maturity need to be defined. These parameters can be found in most publications dealing with the LCOE and economic efficiency of CSP power plants.

Current discount rates range between 7% (Hinkley et al., 2011) and 10% (IEA, 2010). (Fichtner, 2010) uses a discount rate of 8%. Discount rates depend on the specific risk and investor structure of an individual project (ISE, 2013). It is most likely that the risk for CSP projects will decrease in forthcoming years; experience with this kind of project will increase, and the technology itself will become more commonplace. Therefore, a decreasing discount rate is also likely.

Among other factors, interest rates depend on risk, technology, subsidies, and the economic situation in general. Previous studies have used an interest rate of 8% p.a. (ISE, 2013) or 7.5 % p.a. (IRENA, 2012) for calculations. Currently, the key interest rate from the European Central Bank is 0% p.a. (ECB, 2016). With acknowledgment of the difficulty of predictions in this field, a probable value for 2030 will be between 0% p.a. and 8% p.a.

Assumptions for debt ratios of CSP projects vary between 60% and 80% (Greenpeace et al., 2016). ISE (2013) assumes a debt ratio of 70% for CSP projects in Europe. Over the last decade, the debt ratio has been more or less constant, and no reason for any fundamental change can be seen. The same is true for maturity, where values between 15 years (Greenpeace et al., 2016) and 20 years (ISE, 2013) are common.

4.2.3. Determination of economic framework conditions

Investment costs

By combining Table 10, Table 12 and Table 13, the total investment costs for each retrofitting concept can be derived (Table 14). Specific investment costs for each component are also listed, and multiplying these factors yields the total EPC costs. Totalling the surcharges for project management, engineering, and risks yields the total investment costs for each retrofitting concept. As retrofitting concepts cannot be compared to standard CSP projects, 20% of the EPC shall be added for engineering and construction, and 10% of the EPC shall be added for risks.

Table 14: Derived total investment costs for the retrofitting concepts

	RC1	RC2	A	B	C
PTC	$0	$0	$0	$0	$49,850,117
Dismantling	$0	$0	$1,140,000	$0	$0
Replacement of damaged HCEs	$10,506,240	$6,220,800	$6,566,400	$10,506,240	$6,220,800
Heliostat	$0	$0	$19,602,992	$24,270,427	$0
Receiver	$0	$0	$10,074,	$12,165,965	$0
Tower	$0	$0	$9,525,600	$9,878,400	$0
Storage (tower)	$0	$0	$4,958,800	$8,182,020	$0
Storage (PTC)	$0	$0	$0	$0	$24,715,60$0
Exchange of steam turbine (high pressure, 540 °C)	$0	$0	$6,059,340	$8,320,381	$0
Exchange of steam turbine (low pressure, 540 °C)	$0	$0	$10,176,023	$13,435,475	$0
Economiser	$0	$0	$0	$0	$0
Superheater (salt/steam)	$0	$0	$1,818,033	$2,486,353	$0
Reheater (salt/steam)	$0	$0	$1,206,342	$1,649,810	$0
Steam generator (salt)	$0	$0	$0	$0	$0
Cooling system (extension)	$0	$0	$0	$448,532	$0
Exchange generator	$0	$0	$0	$3,643,673	$0
Feed water preheater (HP)	$0	$0	$0	$2,477,892	$0
Pumps	$0	$0	$0	$422,478	$0
Feed water preheater (LP)	$0	$0	$0	$1,163,154	$0
Balance of the system	$0	$0	$3,154,143	$4,162,834	$3,154,143
Engineering and project management	$2,101,248	$1,244,160	$14,856,386	$20,642,727	$16,788,132
Risk and margin	$1,050,624	$622,080	$7,428,193	$10,321,363	$8,394,066
Land costs	$0	$0	$0	$1,754,648	$1,419,180
Total	**$13,658,112**	**$8,087,040**	**$96,566,506**	**$134,328,631**	**$109,122,858**

Running costs

Since EPC costs change with retrofit measures, a new reference value for the running costs needs to be set. The total investment cost, which is the sum of the initial investment costs and costs of the retrofit measures, will serve as the new reference value.

Table 15 presents an overview of the estimated running cost factors and their reference values, for retrofitted power plants.

Table 15: Estimated running cost factors for retrofitted PTC power plants

	Factor	Reference value
Specific O&M costs	1.0%	Total investment costs
Replacement costs	0.2%	Total investment costs
Insurance costs	1.0%	Total investment costs

Financing parameters

According to the above-mentioned assumptions, financing parameters have been chosen from the literature (Table 16). Where different values are available in the literature, the selection has been based on conservative assumptions. Values are estimated for the year 2030.

Table 16: Defined financing parameters for retrofitting projects of PTC power plants

Asset	Value
Discount rate	7.50%
Interest rate	5%
Debt ratio	70%
Maturity	15 years
Income tax rate	30%
Fuel price escalation	1.8%
Commitment fee	0.4%
Energy costs	0.10 $/kWh
Land costs	2 $/m²
Water	0.05 $/m³

5. Selection of a techno-economic simulation tool for CSP power plants

5.1. Definition of model requirements

A software tool is required for modelling retrofitting concepts of CSP power plants. As explained in section 2.5, a number of software tools are commercially available, and their use has been proven in the field for several cases. An appropriate software tool for modelling the chosen retrofitting concepts must fulfil the following requirements:

- The application of a pseudo-steady state approach in order to generate reliable predictions.
- The assessment of retrofitting concepts in a techno-economic manner. This requires technical data, known as TOY (see section 2.5.1), as well as economic data in the form of the LCOE (2.5.2).
- The modelling of concepts where PTC power plants operate in combination with a two-tank molten salt storage system, of and systems with no storage.
- The inclusion of a hybrid operation mode, for the configuration where a PTC power plant operates in combination with a solar tower and a molten salt storage system.

If no single software tool able to fulfil all of the above-mentioned features is available, a combination of software tools may also serve for modelling.

5.2. Comparison of available models and discussion

The most common available software tools are *SAM* and *greenius*. It will now be proven which tool fulfils the above-mentioned requirements. For this purpose, a methodological review will be detailed, and the software tools will be reviewed regarding the defined requirements (Table 17), which are, in short:

- Time-step approach
- Technical performance model (in the form of TOY)
- Economic performance model (in the form of LCOE)
- PTC power plants with TES
- PTC with no TES
- Hybrid PTC/solar tower power plant

Table 17: Comparison of the available software tools for CSP modelling

	System Advisor Model (SAM)	*greenius*
Time-steps applied (shortest)	Hourly	10 minutes
Technical performance (TOY)	Yes	Yes
Economic performance (LCOE)	Yes	Yes
PTC + TES	Yes	Yes
PTC w/o TES	Yes	Yes
Hybrid PTC/solar tower + TES	No	Yes
Source	(SAM, 2016)	(Hennecke et al., 2010)

SAM cannot model the hybrid operation mode of a PTC/solar tower power plant combined with a TES. The only software tool able to achieve all the requirements is *greenius*, which is a common tool for CSP system modelling (García et al., 2011), with a proved performance. Furthermore, access to the source-code is given at the *DLR*, and modifications are possible.

5.3. Selection

Greenius is the only software tool able to achieve all the requirements of this thesis. It can be used for technical and economic performance predictions, and it is suitable for modelling all of the power plant configurations under investigation. In conclusion, *greenius* is an appropriate software tool for the requirements in this thesis, and shall be used to elaborate the techno-economic performance predictions of the chosen retrofitting concepts.

6. Simulation results of the techno-economic simulation tool

The modelling results of the retrofitting concepts are now presented and discussed. The investigated retrofitting concepts differ from one another in terms of their scenario and base case, and are not directly comparable. Nevertheless, there are a number of tendencies, influencing parameters, and other characteristics regarding the LCOE, which will be analysed afterwards.

6.1. Concept A

Table 18: Key results of the techno-economic simulation of concept A

Key results of concept A	
Thermal output of the collector field	343,369 MWh/a
Thermal output of the tower field	192,506 MWh/a
Total net electricity generation	199,981 MWh/a
Gain in electricity	14,580 MWh/a
Average net system efficiency	17.3%
Total investment costs	$96,566,506
NPV	$117,448,104
Annual running costs	$6,893,361
LCOE	**0.0819 $/kWh**

Concept A shows a low gain in energy output. With 14,580 MWh per year of additional generated electricity, the energy yield raises by approx. 8%. Besides the addition of a solar tower and the accompanying additional capacity, the concept also includes dismantling and the subsequent reduction of the trough field capacity. Following the trough field capacity is partly substituted, what needs to be taken into account when assessing the overall energy output, and what is why the gain in overall energy output is relatively low. The LCOE for concept A is 0.0819 $/kWh.

The trough and tower systems of the concept A differ significantly regarding their seasonal heat output profiles. On a typical day in summer (e.g. 21st June) the trough field delivers more than double the amount of heat in comparison to the tower. However, on a day in winter (e.g. 21st December.), peak heat output is similar, while total heat output from the solar tower is higher. Peak energy generation at the tower is more constant on a winter day. Due to the solar tower and particularly during days in winter, the power block more often runs at high efficiency. An increase in efficiency can be seen during a day in summer, where the power block efficiency drops at around midnight; this is mainly caused by the depleted storage of the solar tower. Thus during the period of time from midnight until sunrise, the plant no longer uses a hybrid operation mode, and the power block runs at a lower efficiency. In conclusion, the addition of a solar tower increases the overall efficiency of the system, and the energy yield is more constant over the year.

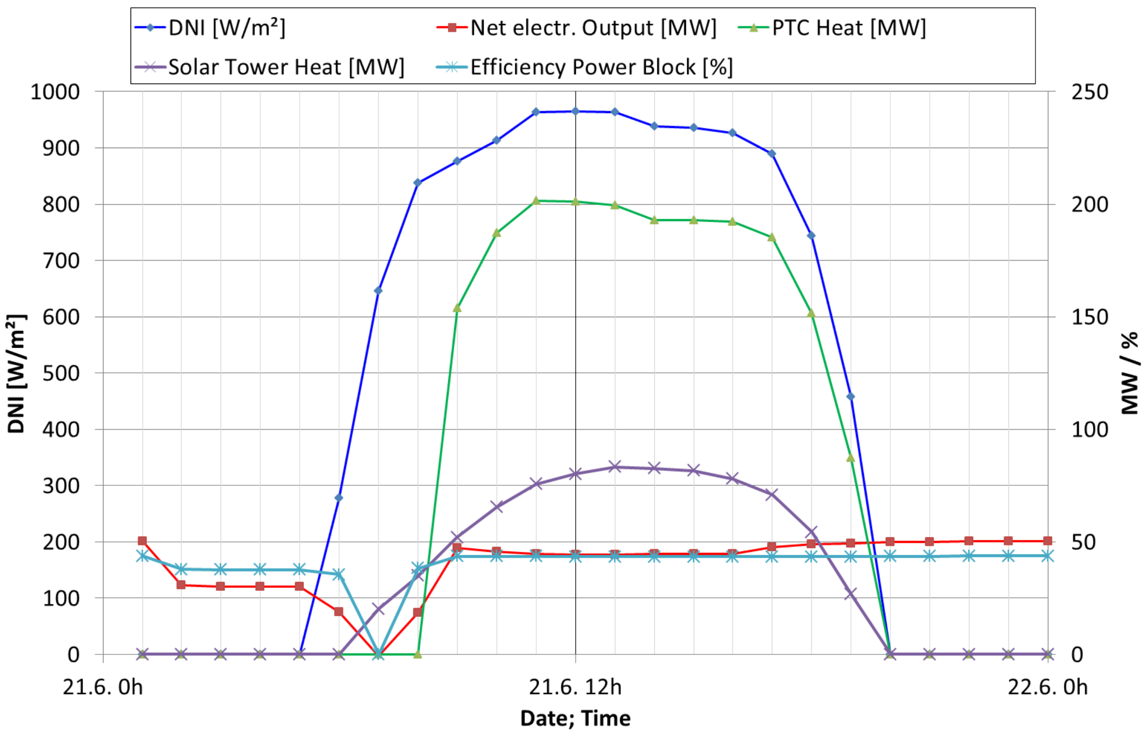


Figure 10: Generation profile for concept A on the 21st June.

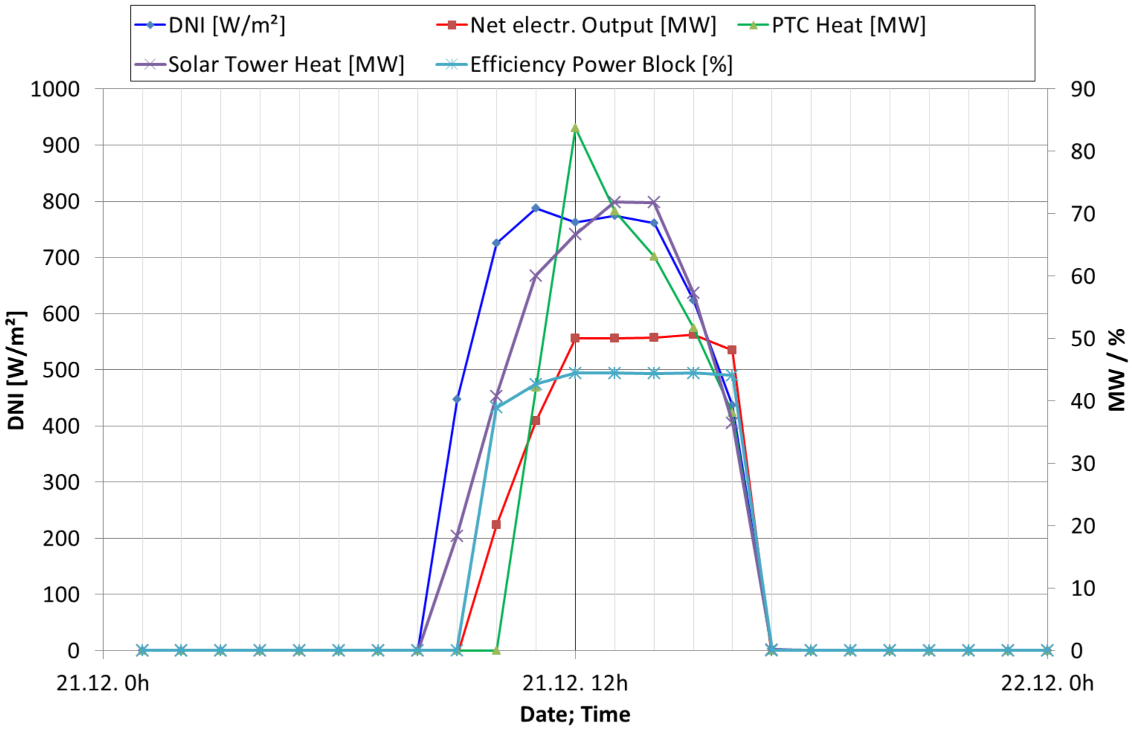


Figure 11: Generation profile for concept A on the 21st December.

6.2. Concept B

Table 19: Key results of the techno-economic simulation of concept B

Key results of concept B	
Thermal output of the collector field	551,946 MWh/a
Thermal output of the tower field	232,040 MWh/a
Total net electricity generation	272,922 MWh/a
Gain in electricity	87,521 MWh/a
Average net system efficiency	15.9%
Total investment costs	$134,177,725
NPV	$155,004,618
Annual running costs	$8,266,256
LCOE	**0.0790 $/kWh**

Concept B shows a high gain in energy generation, with an additional 87,521 MWh per year. This is an increase of almost 50%. The PTC field accounts for double the amount of energy in comparison to the tower field. Total power output is also high at 272,922 MWh/a, mainly due to the fact that the complete PTC solar field is preserved. With investment costs of $135,984,155, an increase of almost 50% of the total energy output can be achieved, at an LCOE of 0.0792 $/kWh.

Trough and tower systems differ significantly regarding their seasonal heat output profiles. On a typical day in summer (e.g. 21st June), the trough field delivers more than three times as much heat as the tower. In contrast, on a day in winter (e.g. 21st December), peak heat output from the trough field is still approximately 50 MW higher, but the total daily heat output is below the output from the solar tower. Energy generation at the tower is more constant on a day in winter. Due to the solar tower, the power block also runs more often at a higher efficiency during days in winter. The overall efficiency of the system increases, and energy yield is more constant over the year.

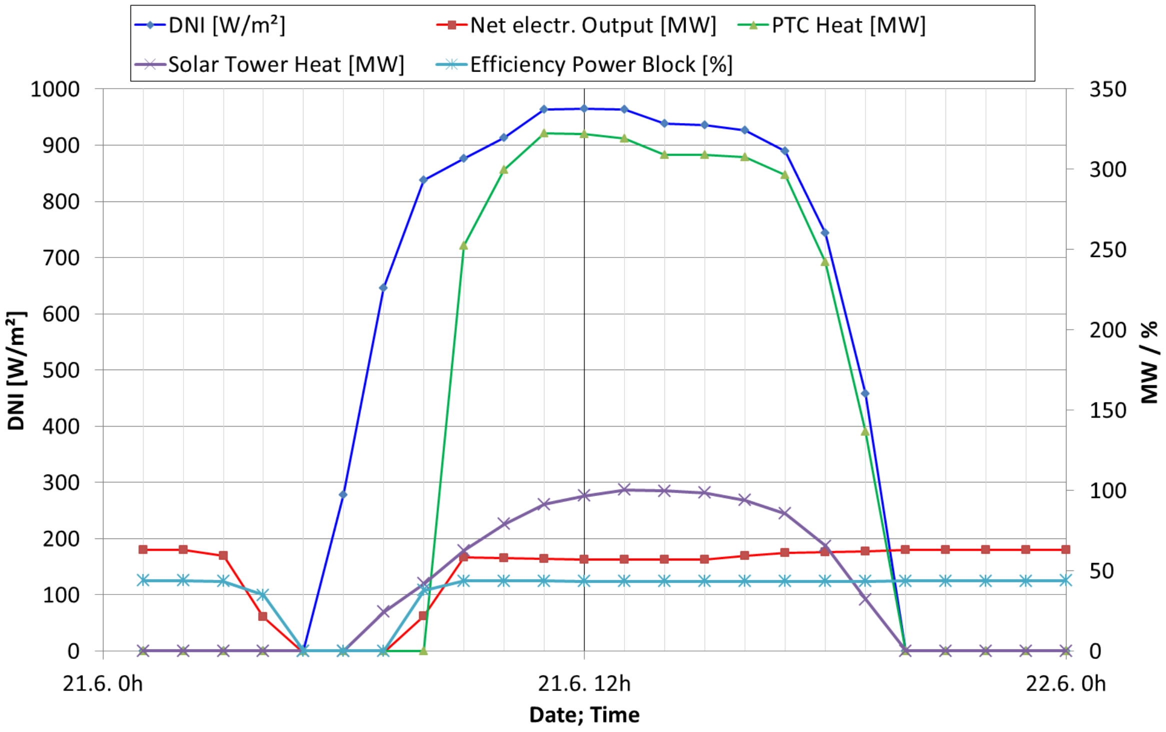


Figure 12: Generation profile for concept B on the 21st June.

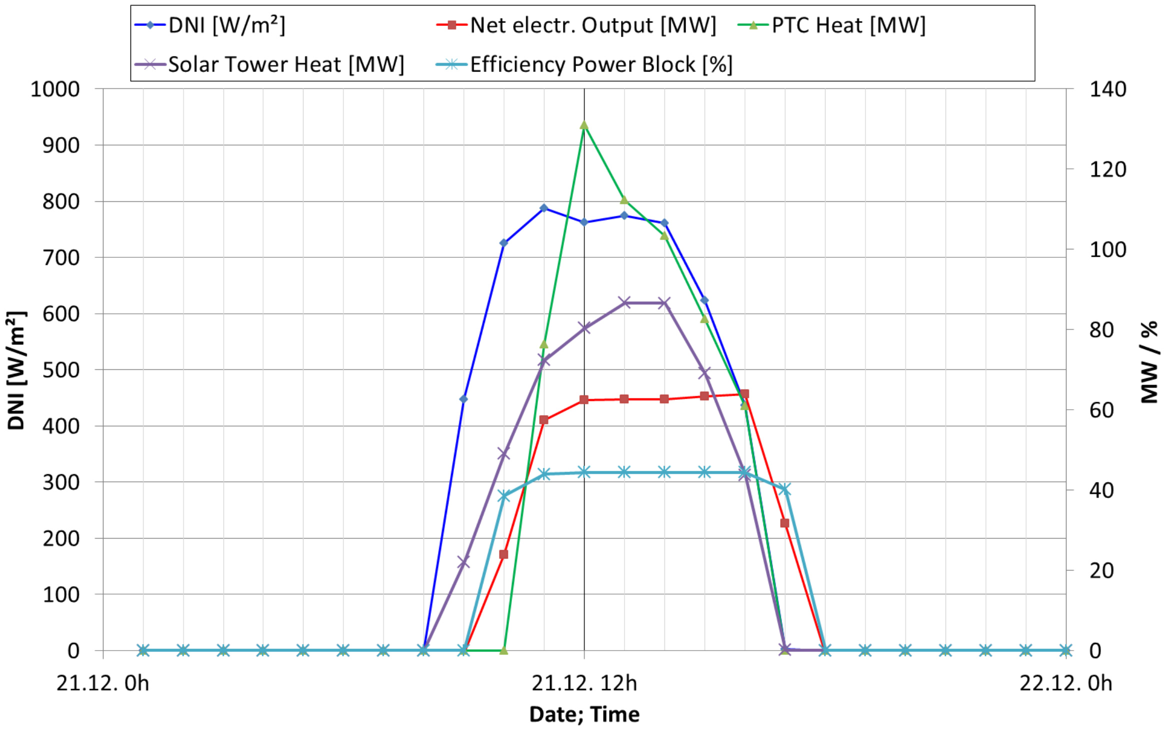


Figure 13: Generation profile for concept B on the 21st December.

6.3. Concept C

Table 20: Key results of the techno-economic simulation of concept C

Key results of concept C

Thermal output of the collector field	551,946 MWh/a
Thermal output of the tower field	0 MWh/a
Total net electricity generation	185,401 MWh/a
Gain in electricity	80,399 MWh/a
Average system efficiency	14.8%
Total investment costs	$109,122,858
NPV	$129,300,992
Annual running costs	$6,565,214
LCOE	**0.0939 $/kWh**

Concept C shows a gain in energy generation of 80,399 MWh/a, and an overall energy output of 185,401 MWh/a. Thus, the yield is increased by almost 76%. Concept C is designed for PTC power plants without TES; the objective is to add a TES and increase the amount of installed PTCs from 360 to 608. This would incur costs of $110,563,716, and annual running costs of $6,565,214. Based on these values, an LCOE of 0.0939 $/kWh is calculated.
The heat output of the trough field in concept C significantly depends on the season. On a typical day in summer (e.g. 21st June), peak heat output is relatively constant at around 300 MW, with a power block efficiency of around 40%. In contrast, on a typical day in winter (e.g. 21st December), peak heat output briefly peaks at 130 MW, while power block efficiency peaks at around 40% at the same point in time.

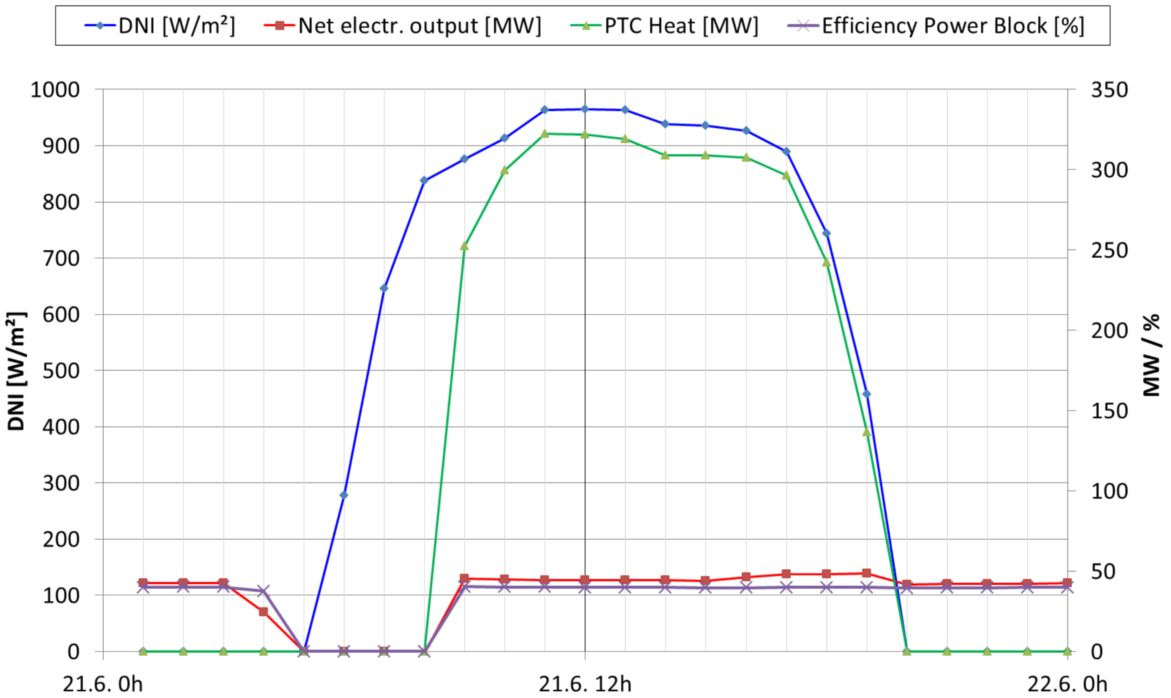


Figure 14: Generation profile for concept C on 21st June.

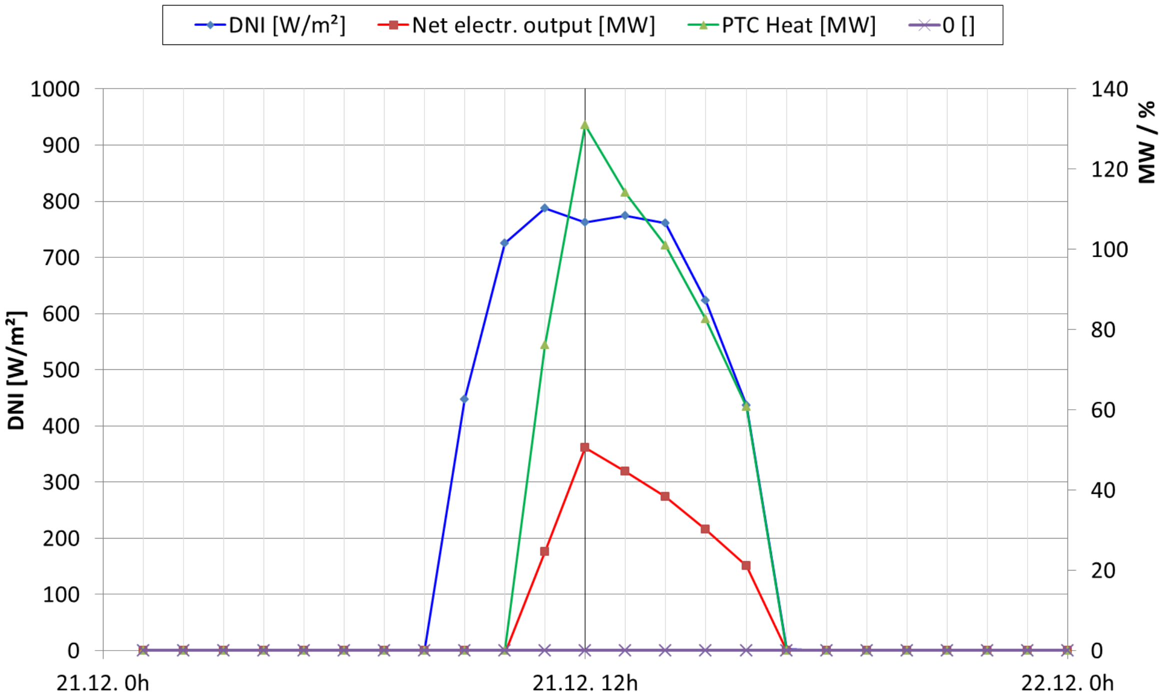


Figure 15: Generation profile for concept C on 21st December.

6.4. Summary and analysis

Table 21: LCOE of the retrofitting concepts

	A	B	C
Total net electricity generation	199,981 MWh/a	272,922 MWh/a	185,401 MWh/a
Gain in electricity	14,580 MWh/a	87,521 MWh/a	80,399 MWh/a
Total investment costs	$96,566,506	$134,177,725	$109,122,858
LCOE	**0.0819 $/kWh**	**0.0790 $/kWh**	**0.0939 $/kWh**

Key results from the simulation of the retrofitting concepts are summarised in Table 21. Figure 16 shows the gain in energy for each retrofitting concept. It can be seen that investment costs and the gain in energy are not proportional to one other, nor do they indicate a tendency of the LCOE. Concept A shows the lowest investment costs, with $96,767,47, but its retrofit measures raise the total energy output by only 8%. Concept B shows the highest gain in energy generation, but also requires the highest investment. Additionally, total energy output is the highest and its LCOE is the lowest. Concept C shows a similar gain in energy output to concept B, but requires lower investment costs. The LCOE is higher because the total energy output is lower. The relative share of running costs at the LCOE is almost equal (Figure 17) and has no significant influence on the LCOE.

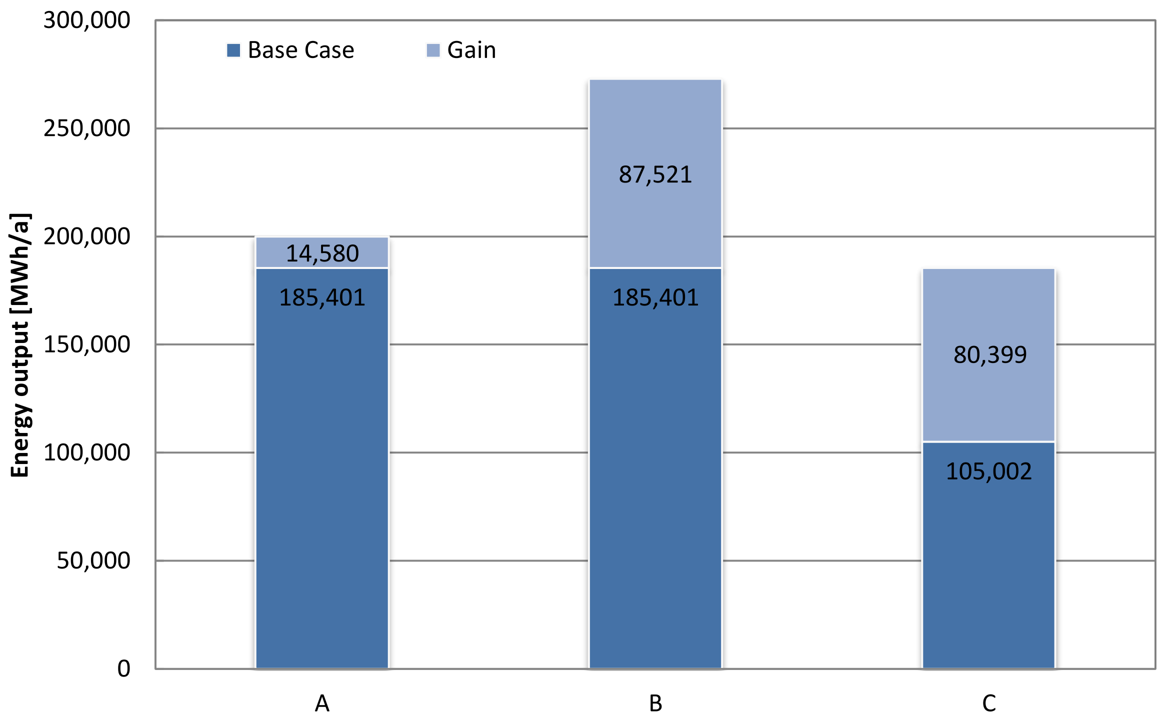


Figure 16: Gain in energy of the retrofitting concepts

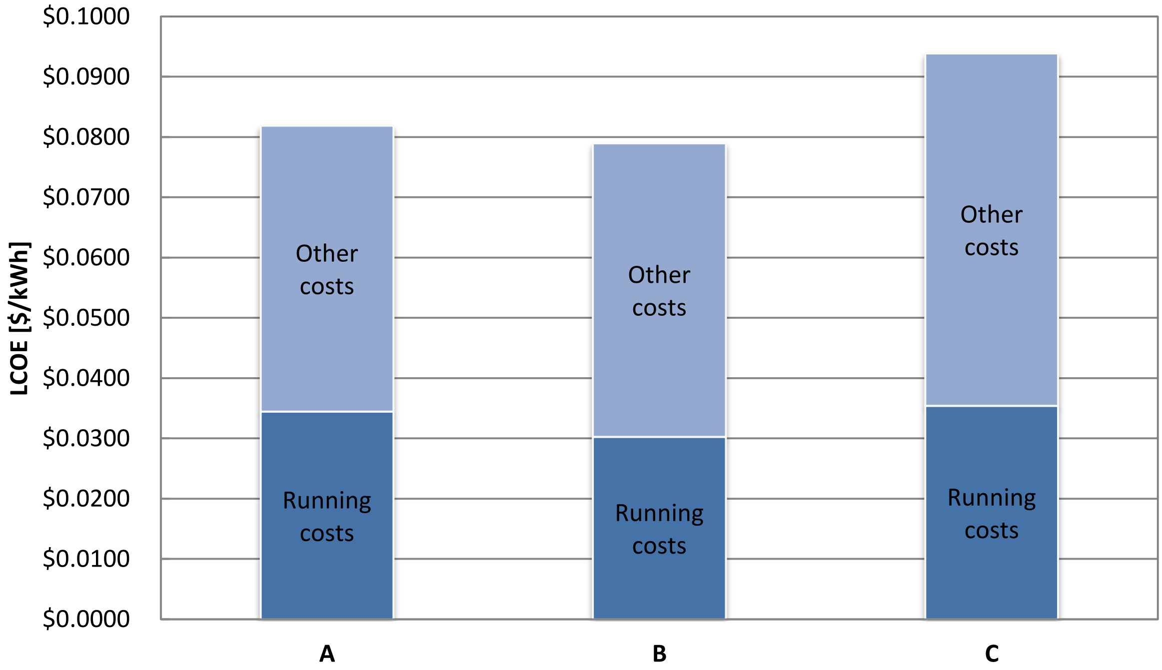


Figure 17: Share of running costs at the LCOE of the retrofitting concepts

The composition of costs is similar for concept A and concept B. The solar tower requires the largest proportion of the investment. The power block, and engineering and management, each require a quarter of the investment costs. The remaining costs are shared between storage and overhaul measures for the PTC solar field. The breakdown of costs agrees with the predictions by IRENA (2016b), which also mentions indirect costs and owner's costs. In this thesis, these costs are distributed between all assets in equal measure.

Concept C does not require any major measures at the power block, due to constant capacity and live steam parameters of the power block. Therefore expenditures for the power block are minimal, costs for the solar tower account for more than half of the entire expenditures, and costs for storage as well as engineering and management account for nearly a quarter of the total investment costs.

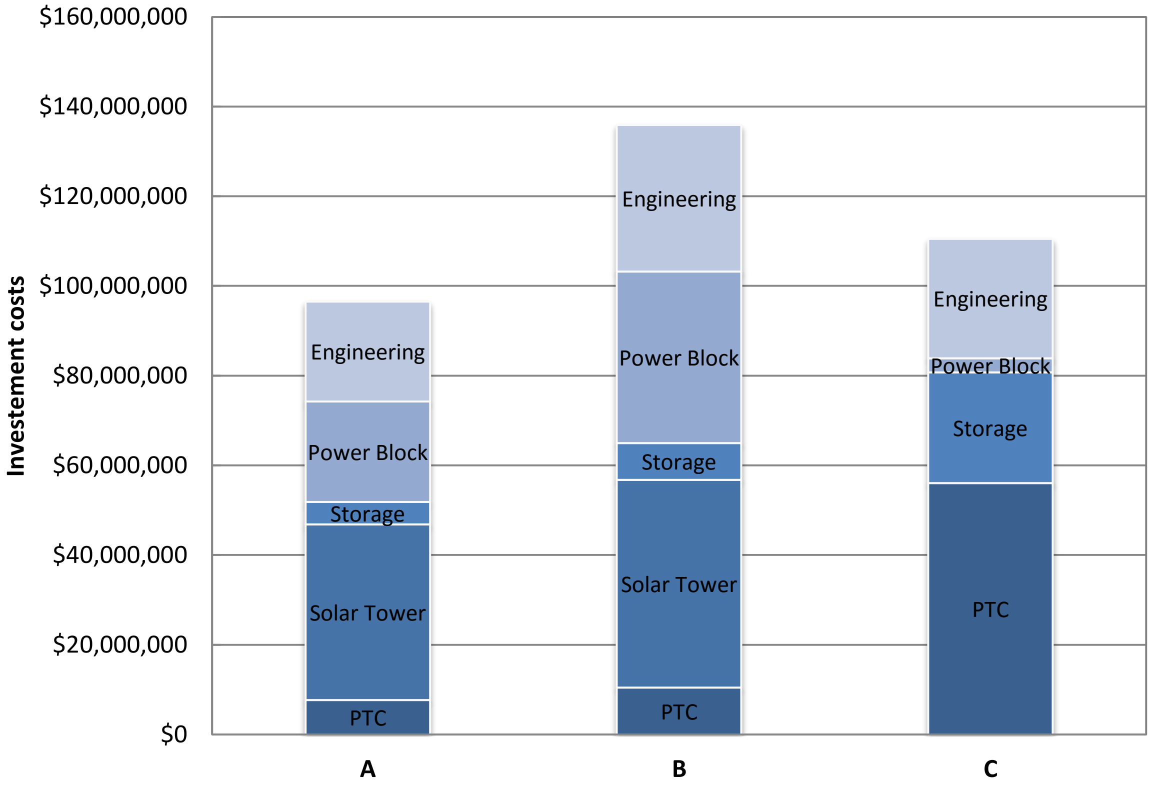


Figure 18: Composition of costs for the retrofitting concepts

6.5. Sensitivity analysis

As predictions regarding O&M costs for a power plant in operation for more than 25 years are rather uncertain, the sensitivity of the LCOE due to changes in running costs are investigated in the following. The following cases shall serve as the base for the sensitivity analysis:

- The base case is given by the above-mentioned calculation of the LCOE, where relative running costs do not change with time of operation.
- A best case shall also be investigated, where O&M costs and the replacement factor are halved after 25 years of operation. This case could be a result of improved O&M measures or falling costs for replacement components.
- A worst case shall also be investigated, where O&M costs and the replacement factor for pre-retrofit components are doubled. This case could be a result of unexpected ageing or changes in mode of operation.

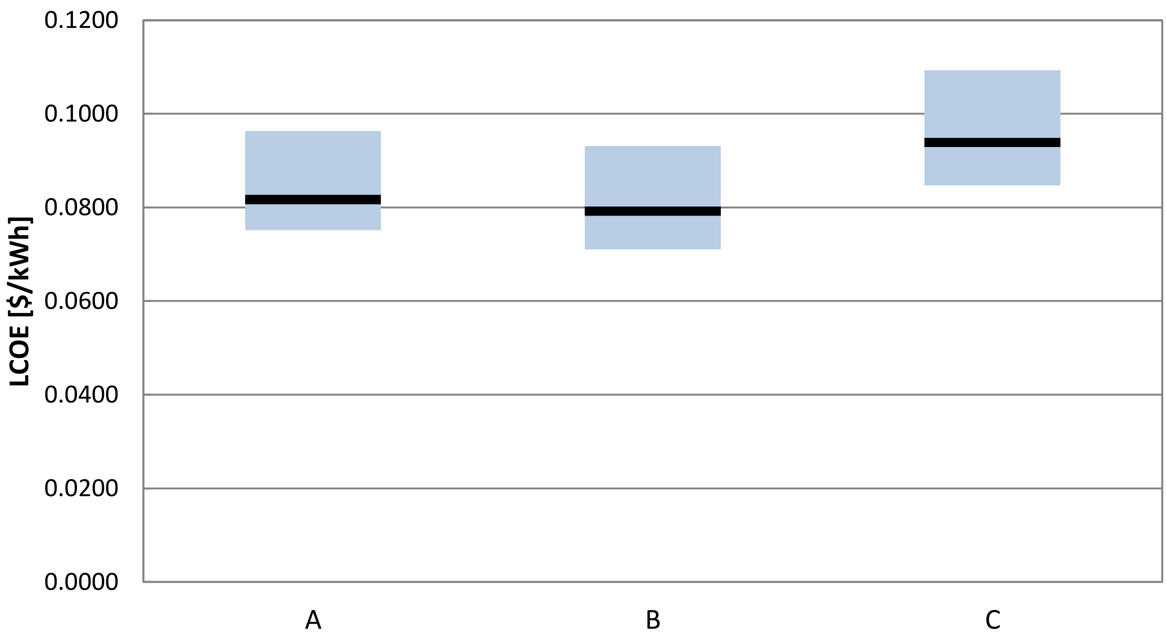
The cases and values are summarised in Table 22.

Table 22: Overview of running cost factors used in the sensitivity analysis

	Old components			New components		
	O&M	**Replacement**	**Insurance**	**O&M**	**Replacement**	**Insurance**
Worst case	2.0%	0.4%	1.0%	1.0%	0.2%	1.0%
Base case	1.0%	0.2%	1.0%	1.0%	0.2%	1.0%
Best case	0.5%	0.1%	1.0%	1.0%	0.2%	1.0%

Table 23 shows the sensitivity of all LCOEs to a change in running costs. For all three concepts the best-case assumptions lead to a lower LCOE by approximately 0.005 $/kWh compared to the base case, while the worst case entails an increase by more than the doubled magnitude.

Table 23: Sensitivity of the LCOE regarding changes in running costs



In summary, the LCOE could vary by around 0.005 $/kWh less and 0.015 $/kWh more if a change as mentioned above was to occur. Even though predictions of running costs are potentially uncertain, the sensitivity is rather low.

7. Application of the simulation results to the benchmark methodology

7.1. Results and benchmarking

The results in section 6 do not supply evidence to establish whether it is more cost-efficient to build an entirely new solar power plant, or to integrate a solar tower into an existing PTC power plant

The results from section 6 will now be applied to the benchmarking method developed in section 3. For this purpose, a benchmark for each retrofitting concept needs to be provided. The benchmark will deliver the same amount of energy as the respective retrofitting concept. Therefore, the overhauled PTC power plant is complemented with energy from a new solar power plant. This new solar plant is assumed to be a solar tower, since according to IRENA (2016a), in 2025 the LCOEs are expected to be a more cost-efficient technology in comparison to parabolic troughs. The costs of electricity from the solar tower have been calculated by (IRENA, 2016a). Accordingly, the LCOE for a kWh from a solar tower ranges between \$0.08 and \$0.11. The mean value of \$0.095 is used for this study.

The costs for energy from an overhauled PTC power plant are also required. The costs for overhauling measures are derived in section 4.2. The model selected in section 5 is used to predict a TOY, and following the LCOE for the overhauled reference power plant, yields an LCOE of 0.0408 \$/kWh for RC1 and 0.0475 \$/kWh for RC2.

Figure 19 presents the composition of the benchmark for each retrofitting concept. The benchmark consists of energy from the reference case (PTC/blue) and energy delivered from a solar tower (red). The energy output of the benchmark is equal to the corresponding retrofitting concept. The energy output of both reference cases is equal to the share of PTCs in the benchmarks. The LCOE is indicated for each concept and benchmark, as well as for the reference cases and the solar tower. It can be seen that for each case, the LCOEs of the retrofitting concept are higher than the LCOEs of the corresponding benchmark.

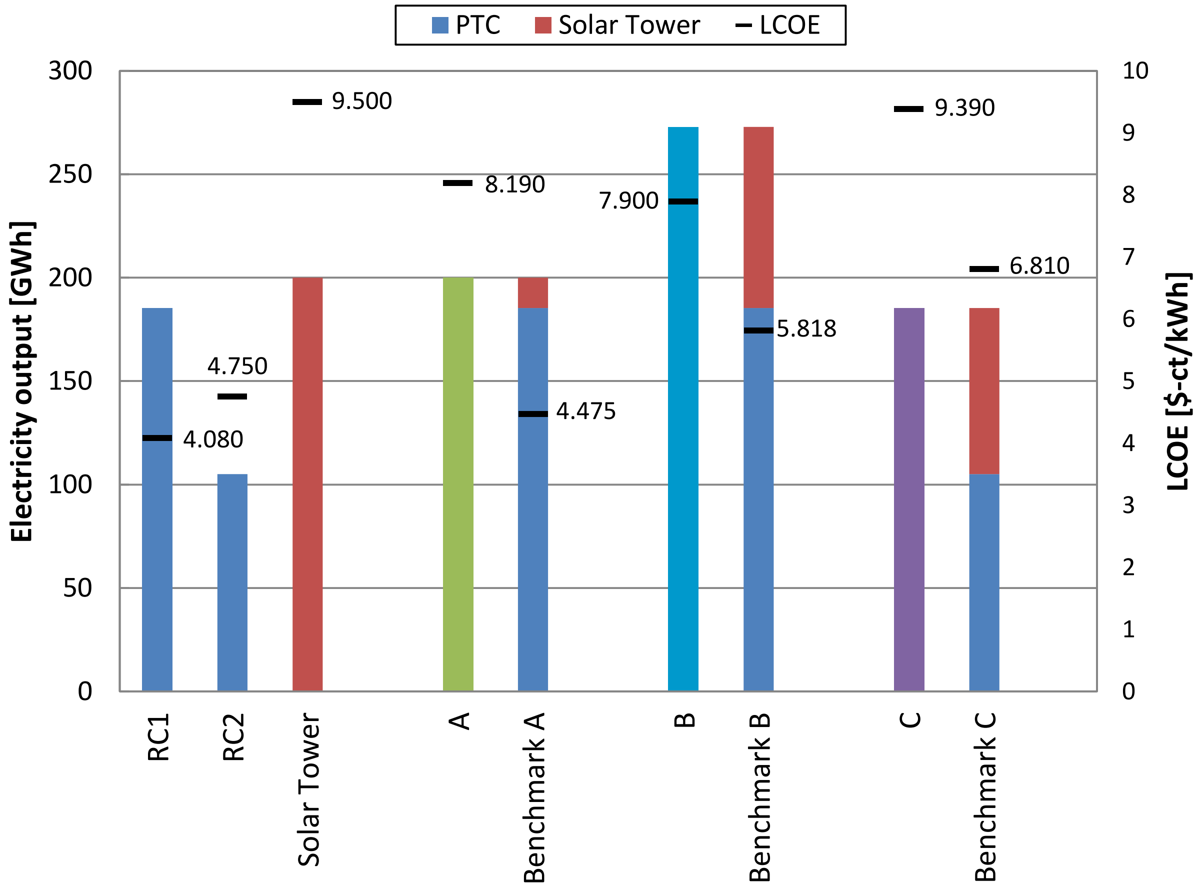


Figure 19: LCOE and energy output of benchmarks and retrofitting concepts

It can be seen that the LCOE of the benchmarks is always lower than those of the respective retrofitting concept. For concept A, the benchmark LCOE is 0.0374 $/kWh lower. Benchmark B is $0.022 per kWh cheaper than the respective retrofitting concept. For the case of concept C, it is $0.0274 per kWh cheaper to build a new solar tower and overhaul an existing PTC power plant than to retrofit a TES (Table 24). However, using values of the sensitivity analysis, where in the best case the LCOE could fall by 0.01 $/kWh, this would not improve the position of the retrofitting concept against the benchmarks.

Table 24: Overview of the LCOE for retrofitting concepts and benchmarks

	RC1	RC2	Solar tower	A	B	C
LCOE [$/kWh]	0.0408	0.0475	0.0950	0.0819	0.0790	0.0939
Benchmark LCOE [$/kWh]	-	-	-	0.0448	0.0582	0.0681
Difference [$/kWh]	-	-	-	+0.0371	+0.018	+0.0258

For the benchmarks, the composition of the LCOE is clear. Energy from RC1 and RC2 can be delivered for 0.0408 $/kWh and 0.0475 $/kWh, respectively, and the remaining energy must be purchased from a solar tower at 0.095 $/kWh.

7.2. Analysis

The virtual $LCOE_{Gain}$ for the energy gained by the retrofit can be calculated using Eq. 2-2. In this case, I_0 includes only investment costs for the retrofit, and not for the overhaul of the trough field. A_t represents the additional annual costs caused by the retrofit compared to the reference case, and $M_{t,el}$ is the energy gain produced by the retrofit. The real interest rate is 7.6% p.a. and the economic lifetime is 20 years. Results are shown in Table 25.

Table 25: Overview of $LCOE_{Gain}$ values

	A	B	C
Worst $LCOE_{Gain}$ [$-ct/kWh]	**62.51**	**16.39**	**16.62**
Base $LCOE_{Gain}$ [$-ct/kWh]	**60.82**	**15.95**	**15.37**
Best $LCOE_{Gain}$ [$-ct/kWh]	**57.11**	**15.25**	**14.36**

In summary, retrofitting concepts are a cheaper alternative to a new solar tower combined with an overhauled PTC power plant, as long as the $LCOE_{Gain}$ is lower than the LCOE of a solar tower (in this case 0.095 $/kWh). This is not the case for the retrofitting concepts investigated in this study (Table 25).

To conclude the results presented in Table 25, energy from retrofitting concepts becomes economically attractive, as soon as the LCOE for energy delivered by a solar tower is higher than 0.6082 $/kWh for concept A, 0.1595 $/kWh for concept B, and 0.1375 $/kWh for concept C (always the base case).

8. Conclusion and outlook

This thesis investigates the cost-efficiency of retrofitting concepts based on the addition of a solar tower to an existing parabolic trough power plant. The main advantages of these retrofit concepts are higher steam cycle efficiencies, due to higher live steam temperatures, and a more constant energy generation profile over the year. Furthermore, the existing infrastructure can be used to avoid costs for additional generation capacity. The retrofitting measures may increase the energy yield of a power plant, lower investment costs for additional capacity, and thus lower the LCOE for additional generation capacity.

The reference power plant and the three retrofitting concepts used for this study have been defined and developed a priori within the corresponding research project.

The benchmark methodology developed in this thesis compares the techno-economic performance of the retrofitting concepts in a consistent manner. The benchmark is represented by a system with an energy output equal to that of the corresponding retrofitting concept, but comprised of an overhauled PTC power plant and a new solar tower power plant, which is separate.

Estimations about the ageing behaviour of the reference power plant are done in order to derive the investment costs for each retrofitting concept. It is assumed that a PTC power plant similar to the reference power plant does not require extensive overhaul measures after a lifetime of 25 years. Just 50% of the receivers need to be replaced, due to hydrogen accumulation in the receiver annulus.
The component costs are adapted to relevant price changes in the future, i.e. price escalation and learning rate. Moreover, it is assumed that surcharges are applied due to the fact that retrofit measures have a higher level of complexity, and thus require more complex engineering than a green-field project. A low order volume for the components increase costs further and therefore induces surcharges.

The simulation tool *greenius* is selected to simulate the retrofitting concepts and the benchmarks. It is proven to fulfil all the requirements of this thesis, and no alternative is present.

The primary benchmark methodology developed in this thesis is applied to the retrofitting concepts. In each case, the estimated LCOEs of the retrofitting concepts are higher than the LCOEs of the benchmarks. In summary, retrofitting concepts are not cost-efficient as long as the gained energy is more expensive than the energy from a new solar tower plant built in 2030, which has an LCOE of 0.095 $/kWh. The gained energy has a LCOE of 0.6082 $/kWh for concept A, 0.1595 $/kWh for concept B, and 0.1357 $/kWh for concept C. Moreover, an investigation into variations in running cost shows no significant changes. As expected, the generation profile of power plants retrofitted with a solar tower is more constant over the period of a year. Furthermore, retrofitting a solar tower can increase the system efficiency.

The calculations in this thesis are based on assumptions with significant uncertainties, due to the lack of experience with the long-term operation of parabolic trough solar fields. Additionally, a detailed engineering of the required retrofit measures at the power block would be necessary to constrain the corresponding cost estimations. Nevertheless, the benchmark methodology, the workflow of techno-economic framework derivation, and the techno-economic model of *greenius* can be applied to similar studies in the future.

The case of feed-in tariffs for existing power plants changing or being withdrawn, if retrofit measures are applied, has been neglected. In this case, the retrofit would have to challenge the existing feed-in tariff in addition to the defined benchmark. The technical feasibility of an extension of the grid connection has also not been considered, but may be essential for projects where power capacity will be extended.

Regarding further investigations, predicted cost data and the methodological derivation of cost data should be validated and, if necessary, adapted. Reduced costs for a retrofit could improve its position against the benchmark and the potential for savings should be checked. Furthermore, a validation of the applied methodology and data should be undertaken in order to check its usability and accuracy. Here, the consultation of real operation and cost data should be adequate. In doing so, the methodology may help to choose reliable strategies for depreciated CSP power plants in the future, and serve as a general decision making-support tool.

Summary

Parabolic trough power plants are a state-of-the-art technology in CSP. After an estimated lifespan of 25 years, power plants can be overhauled and subsequently retrofitted with solar towers. It is assumed that retrofitting existing PTC power plants with solar towers avoids costs and increases energy output, and that the LCOE for additional generation capacity could be decreased. This thesis aims to investigate the cost-efficiency of this kind of retrofitting concept for the year 2030. For this purpose, a reference power plant located in Spain and retrofitting concepts for different scenarios have been defined a priori within a corresponding research project.

No prior methodology is available to assess the techno-economic performance of retrofitted power plants, and thus needs to be developed. The LCOE is not sufficient for this purpose, since a certain volume of generation capacity already exists. The benchmark methodology developed in this thesis considers the generation capacity of a power plant by using the LCOE for a certain plant capacity as a target unit. Furthermore, a benchmark is designed, against which each retrofitting concept can be compared.

The technical condition of the reference power plant after a lifetime of 25 years is also assessed. Due to a lack of experience with the long-term operation of parabolic trough solar fields, the ageing behaviour of all system components is estimated based on both a literature review and on assumptions. It is assumed that the required overhaul measures are only necessary for half of the receivers. Investment costs for system components are then estimated based on the literature. Furthermore, component costs are adapted to the year 2030, and to special requirements such as complex engineering. The resulting total investment costs for the overhaul measures and the retrofitting concepts are derived, and a financial framework is defined for the economic modelling.

To model the retrofitting concepts in a techno-economic manner, two simulation tools are critically reviewed. The simulation tool *greenius* fulfils all the requirements and is used for the simulations which follow.

In each case, the estimated LCOEs of the retrofitting concepts are higher than the LCOEs of the benchmarks. Investigations in running cost variation show no significant changes. The generation

profile of retrofitted power plants is more constant over the year and system efficiency can be increased.

The main driver for higher LCOEs of the retrofitting concepts is the investment cost. The virtual LCOE of energy gained by retrofit measures shows that it is much more expensive than energy from a new solar tower. In conclusion, retrofitting concepts would be cheaper if investment costs could be reduced.

List of abbreviations

BoP	Balance of plant
CSP	Concentrated solar power
CST	Concentrated solar thermal
DLR	Deutsches Zentrum für Luft- und Raumfahrt (German Aerospace Centre)
DNI	Direct normal irradiation
EPC	Engineering, procurement and construction
FIT	Feed-in tariff
HR	Hydrogen removers
HTF	Heat transfer fluid
LCOE	Levelised costs of electricity
MENA	Middle East and North Africa
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operation and maintenance
PCM	Phase-change memory
PSA	Plataforma Solar de Almería
PTC	Parabolic trough collector
SEGS	Solar Electric Generating Systems
TOY	Typical operation year
TMY	Typical meteorological year
WACC	Weighted average costs of capital

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