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Retrofitting of Existing Parabolic Trough Collector Power Plants with Molten Salt Tower Systems

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Abstract. Existing thermal oil based parabolic trough collector (PTC) power plants have been commercially deployed since 2008. Parabolic trough technology dominates by ca. 90 % the global market of all operational commercial concentrated solar power (CSP) plants. Worldwide over 32 % of these PTC power plants have an indirect salt thermal storage system that enables night operation [1, 2]. Since existing parabolic trough power plants with thermal oil are limited regarding their maximum operating temperature, the addition and integration with a molten salt tower systems (MSTS) could be an attractive option to increase the temperature level of the thermal storage and steam cycle and thus the overall efficiency of the plant. This paper describes the conception, investigation and techno-economic evaluation for retrofitting an existing Andasol type parabolic trough power plant. The most promising out of five coupling configurations has been analyzed and evaluated for three different retrofitting concepts using *greenius* and EBSILON®*Professional* simulation tools. The analysis shows that retrofitting concepts based on the addition of a MSTS are only economically attractive, if the capital expenditure for the power block modification does not exceed 440 $/kW. The retrofitting of existing PTCs with a MSTS is economically unviable.

INTRODUCTION

The basic motivation for retrofitting existing PTC plants with a solar tower system is to increase the live steam temperature of the steam cycle. Molten salt deployed as heat transfer fluid for the solar receiver reaches higher operating temperature up to 565 °C and thus, higher cycle efficiencies than systems based on conventional thermal oil. A combination of a PTC and a MSTS may allow an additional boost of the thermal power input of the plant, depending on the retrofit design. This paper will be focused on the development and assessment of retrofit concepts for existing parabolic trough collector solar thermal power plants that are technically feasible and economically viable by being combined with a molten salt tower system. Three retrofit concepts have been analyzed. Each concept has individual boundary conditions and pursues a strategic goal (see Fig. 1).

In Concept A additional ground area next to the existing solar field is unavailable. Thus, the goal is to increase the annual energy outcome of the facility by replacing a part of the PTC solar field with the tower system. In contrast, Concept B aims to increase the annual energy outcome of the plant, while the nominal turbine power capacity is increased and additional area for the construction of the solar tower system is available. The analysis for Concept A and B is carried out with the reference facility Andasol 3. This facility represents the current state of the art for a PTC plant with 7.5 h thermal storage capacity. Since about one third of the worldwide commercial PTC plants do not comprise a thermal storage system, the aim of Concept C is to enlarge the solar thermal power capacity and enable night operation with the implementation of a salt storage system. In order to preserve the existing power block this concept does not involve an increase of the live steam temperature. Consequently, the aperture area is increased using

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additional PTCs. The analysis for Concept C is performed with a second reference plant, which represents most of the commercial 50MW PTCs plants without thermal storage system (TES). The main features of the considered reference plants are presented in Table1.

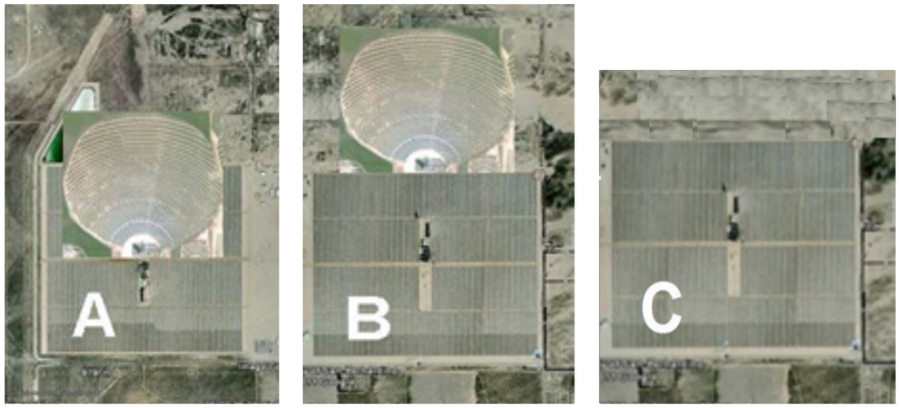

FIGURE 1: Photo montage of the Concept A, B and C

TABLE 1: Main features of the selected reference plants with and without thermal storage system

Features of the Plant	Unit	Andasol 3 (with TES)	Reference Plant II (without TES)
Number of loops	-	152	90
Total effective mirror area	m²	497,040	294,300
Thermal storage capacity	kWh_{th}	970,000	0
Gross electrical power	kW_{el}	52,000	52,000
Net electrical power	kW_{el}	50,000	50,000
Power block thermal input	kW_{th}	129,000	129,000

SOLAR POWER PLANT CONFIGURATION

Several integration concepts for the solar tower into the PTC plant have been conceived and evaluated regarding the extent of required power block modifications and associated costs. The result of the investigation is the favored configuration shown in Fig. 2, which is used for Concept A and B. The water steam cycle of the plant has been extended with two additional components, a molten salt/steam superheater and reheater. The thermal storage system of the PTC and MSTS consist of two storage tanks, one hot tank and one cold tank. On the PTC side, the thermal storage is coupled to a reversible salt/oil heat exchanger, while on the MSTS side, the thermal storage system is directly coupled to the power block. The molten salt is heated up to 565°C at the central tower receiver during day operation and deployed in the power block to increase the steam operation temperature from 384 °C to 540 °C. Due to this, technical modification in the turbine, generator and the steam piping system must be undertaken. A salt mixing station must be foreseen to be able to shift the excess of heat in the tower's hot storage tank to the trough's storage system, in order to compensate the different seasonal heat output of trough and tower [7].

The overall efficiency of the system reaches over 40 % at design-point operation, showing an increase of about 2 percentage points compared to the reference plant. Detailed information regarding the design of the individual component: parabolic trough collector solar field, heliostat field and salt receiver, thermal storage system and power block are summarized in the following sections.

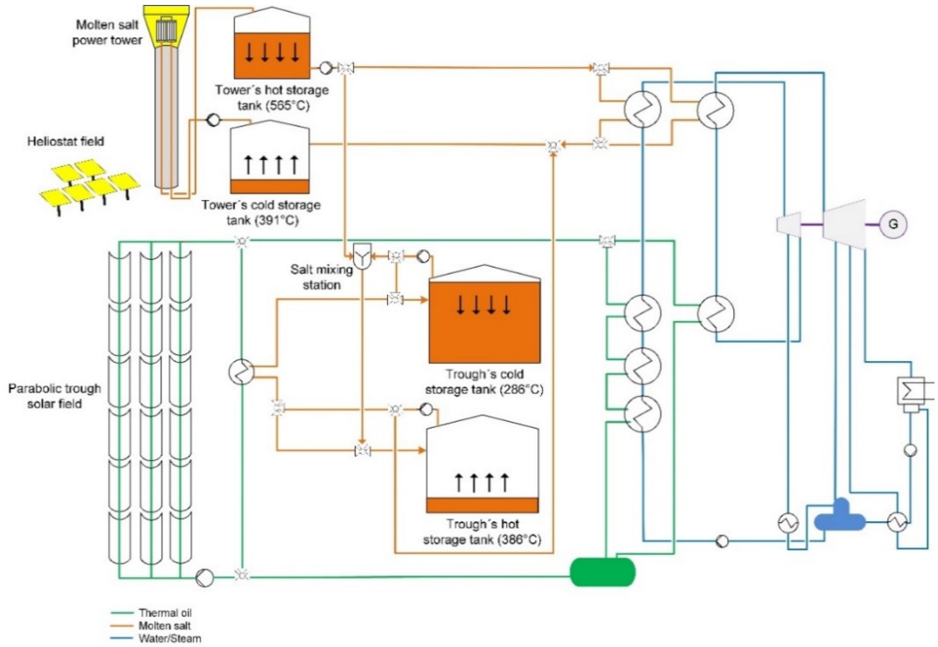

FIGURE 2: Schematic of the retrofitting solar power plant

Parabolic Trough Collector Solar Field

Each loop in the reference solar fields consists of four solar collector assemblies (SCA) coupled in series having each of these an aperture area of 817.5 m². For Concept A the solar field has been reduced by a fraction of 3/8. This means that 3/8 of the total solar field area of the reference plant (Andasol 3) are dismantled. This factor shows in comparison to other studied dismantling factors (3/16 and 1/4) a facility with a better performance in winter time and a similar annual energy generation than the reference plant. Due to the deconstruction of the solar field, the thermal power available for charging the PTC's thermal storage decreases approximately by 75 %, however, this missing thermal power is partially compensated by the heat surplus stored at the tower's hot storage tank that is redistributed to the PTC's storage system. For Concept B the size of the solar field has been kept the same as in the reference plant (Andasol 3) and for Concept C likewise as in the Reference Plant II as shown in Table 2.

TABLE 2: Arrangement of the PTC solar field for concept A, B and C

Features	**Unit**	**Concept A**	**Concept B** (Andasol 3)	**Concept C** (Reference Plant II)
Solar field fraction to be dismantled (deconstructed)	-	3/8	0	0
Number of dismantled solar collector assemblies	-	228	0	0
Number of remaining solar collector assemblies in the solar field	-	380	608	360
Number of remaining loops in the solar field	-	95	152	90
Total effective aperture area	m²	310,650	497,040	294,300

Heliostat Field and Salt Receiver

The heliostat field for Concept A and B were designed using the software "Heliostats Field Layout CALculations'' (HFLCAL) and were optimized for minimum LCOE. A summary of the dimensions of the heliostat field, the receiver and the solar tower is given in Table 3. A solar power tower system in Concept C has not been required.

TABLE 3: Heliostat field design for Concept A and B

Feature	Unit	Concept A	Concept B
Tower nominal thermal output	MW	89.4	95.6
Single heliostat reflective surface	m²	70	70
Total number of heliostats	-	2,078	2,214
Total heliostat field reflective area	m²	149,388	155,003
Height of the receiver center	m	135	131
Receiver aperture	m²	162	169
Heliostat field efficiency (annual)	%	63.5	63.9
Receiver efficiency (annual)	%	85.8	86.7

The heliostat field for both concepts is configured in the northern part of the solar field. The available area for the heliostat field in Concept A is about 650,000 m². Within a preliminary stage of this assessment, this area was filled with a heliostat field delivering 68 MW intercept power at a nominal field efficiency of 63.5%. The economic analysis revealed the LCOE minimum for significantly bigger heliostat fields, but at the same time no economic viability. Therefore, no effort was put into updating the heliostat field efficiency. Instead, it is optimistically assumed that this much denser heliostat field operates with the same field efficiency. Concept B requires an additional ground area of ca. 1.13 km². In Concept A the semicircular heliostat field is arranged within the thermal storage system and power block as presented in Fig. 3 (left) and in the Concept B in the north edge of the solar field and the closest point to the power block Fig. 3 (right).

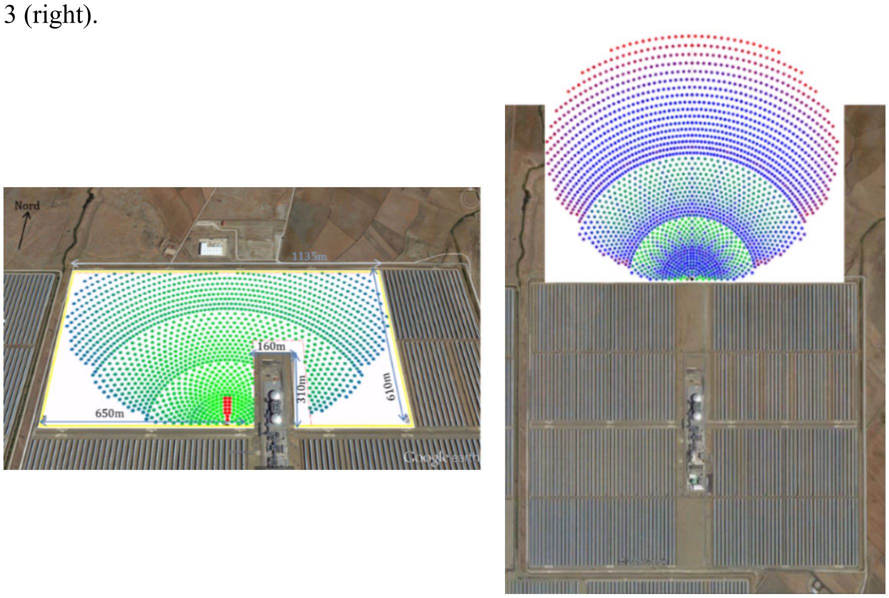

FIGURE 3: Heliostat field design for Concept A (left) and B (right)

Power Block

The power block of both reference PTC thermal oil based power plants is arranged as shown in Fig. 2. In contrast to Concept A and B, a molten salt/steam superheating and reheating unit is not required in Concept C. The design of the steam turbines for the retrofitted Concepts A and B are presented in Table 4. For Concept A the live steam temperature in the high pressure turbine is increased from 384 °C to 540 °C only, while in the low-pressure turbine it is hold with 384 °C. A reduction of the thermal power results favorable for Concept A as less nominal thermal output of the receiver and therefore less ground area for the construction of the MSTS system is needed. The retrofitted power block in Concept A requires ca. 40 % (~16 MW_{th}) less heat input from the tower than the power block in Concept B, which demands a nominal thermal power of ca. 40 MW_{th} to achieve the superheating and reheating of the live steam temperature from 384 °C to 540 °C. The turbine design of Concept C is considered the same as in the reference plant (Andasol 3).s

TABLE 4: Design of the Turbine

	Parameter	Unit	Andasol	Concept A	Concept B
High pressure turbine	Live steam (LS) pressure	bar	103	103	103
	LS temperature	°C	384	540	540
	LS mass flow rate	kg/s	53.2	55	55
Low pressure turbine	LS pressure	bar	19.4	19.4	19.4
	LS temperature	°C	384	384	540
	LS mass flow rate	kg/s	44.2	47.1	48.2
String	Net electrical power	MW	50.0	59.5	68,8
	Cycle efficiency (normalized)	%	100	104.92	107.97

Thermal Storage System

The existing two-tank indirect thermal storage systems for oil based PTC plants are temperature limited and can only be heated up to around 386 °C. Using the power tower technology the molten salt can reach higher operating temperature up to 565 °C. Two thermal storage configurations for the retrofit plant have been analysed in this paper. Each storage system consists of one hot and one cold storage tank respectively. The configuration 1 in Fig. 4 (left) presents two separated (not interconnected) storage systems, while the configuration 2 in Fig. 4 (right) deploys a new developed idea that couples both PTC and MSTS storage systems via a switchable salt mixing station.

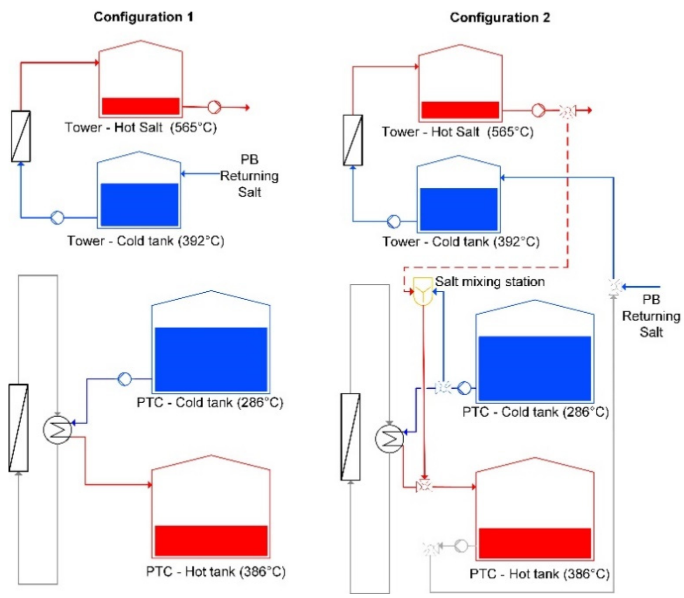

FIGURE 4: Thermal storage configurations for the retrofitted PTC plant. Configuration 1: Separated PTC and MSTS storage system (left) and Configuration 2: Interconnected storage system via a salt mixing station (right)

For comparison purposes both storage configurations were implemented in the retrofitted power plant. As most of the thermal energy input into the water steam cycle is performed with thermal oil, the power generation with the implementation of the storage Configuration 1 is limited by the stored thermal energy at the PTC side available. In contrast, the storage Configuration 2 enables a redistribution of the surplus stored thermal energy in the tower's hot tank to the PTC storage system. This configuration offers a significant potential to prolong power production during night operation and especially allows the compensation for seasonally different thermal production of PTC and MSTS. The excess of salt at 565 °C available at the end of the PTC discharge mode can be mixed together with the PTC's cold salt at 286 °C and transferred with 386 °C to the PTC's hot storage tank. The salt stream is adjusted by a PID controller for a set temperature of 386 °C. Thus is the PTC's hot tank charged, which enables the extension of a continuous discharging process. The application of such a storage interconnection, as carried out in Configuration 2 is more appropriate for retrofitted PTC plants like in Concept B. The larger the installed thermal storage capacity of the tower, the longer and more stable the steam turbine can be driven. Concept B using the storage Configuration 2 can produce at minimum of ca. 8.3 % more of the annual electrical energy, than implementing the storage Configuration 1. For similar locations to Guadix, Spain, a theoretical improvement in the annual capacity factor of the plant was observed. With the implementation of the storage Configuration 2 the power generation of the plant over one year operation can be extended from 40.29 % to 43.64 %. The implementation of the storage Configuration 2 in Concept A shows likewise an increase between 8.8 % and 26.1 % in the power generation than with the implementation of Configuration 1 for typical seasonal days (with a good solar radiation profile). Nevertheless, in retrofitted plants like Concept A, a boost of the annual energy yield in the regards to the reference plant (Andasol 3) for a typical meteorological year has not been achieved. [6]

SYSTEM SIMULATION AND ECONOMICAL EVALUATION

Dynamic and steady-state simulations of the configured retrofitted solar power plant have been carried out in *greenius* and EBSILON®*Professional* using hourly weather data with an annual DNI-value of 2,207 kWh/m² from a typical meteorological year (TMY) measured at Plataforma Solar Almería (PSA), Spain [5]. The cost estimation below is based on the assumption that at the point of the retrofit in 2030 (after about 20-25 years of operation) all major components of the PTC plant except for the receiver tubes can be used beyond the scheduled life time. About 50 % of the receiver tubes are expected to be replaced during the retrofit, e.g. due to vacuum dilution and thus loss of thermal performance. This assumption matches to the experiences with the SEGS plants in California which are in operation for more than 25 years. The investment costs are derived from [3, 4]. Due to the fact that the MSTS in the retrofit concepts is significantly smaller than the MSTS described in [3, 4] individual surcharges of 0 %, 15 % or 30 % are added. The more detailed cost data for individual power block components is based on [8] and internal expertise. Table 5 gives an overview of the required CAPEX for the three different retrofit concepts. For the cost analysis, a complete substitution of the high and low pressure turbine has been considered for Concept A and B.

TABLE 5: Overview of retrofit base case cost scenario for three different concepts (all costs given in 2015 US-$)

			Concept A		**Concept B**		**Concept C**	
Component	Specific Cost [$ /Size Unit]	Size Unit	Size	Cost [Mio. $]	Size	Cost [Mio. $]	Size	Cost [Mio. $]
New PTCs	246	m²	0	0	0	0	202,740	49.9
Dismantling of old PTCs	5,000	SCA[1]	228	1.1	0	0	0	0
HCE replacement	960	HCE	6,840	6.6	10,944	10.5	6,480	6.2
Heliostat	131	m²	149,388	19.6	155,003	20.3	0	0
Receiver	113	kW_th	89,390	10.1	95,580	10.8	0	0
Tower	70,560	m	135	9.5	131	9.2	0	0
Storage (Tower)	25	kWh_th	200,000	5.0	240,000	6.0	0	0
Storage (PTC)	34	kWh_th	0	0	0	0	970,000	33.3
Exchange HP turbine	391,509	MW_el	15.5	6.1	21.3	8.3	0	0
Exchange LP turbine	279,106	MW_el	36.5	10.2	48.1	13.4	0	0
Addition salt superheater	103,905	MW_th	17.5	1.8	23.9	2.5	0	0
Addition salt reheater	103,905	MW_th	11.6	1.2	15.9	1.6	0	0
Cooling system (extension)	27,856	MW_th	0	0	16.1	0.4	0	0
Exchange generator	53,503	MW_el	0	0	68.1	3.6	0	0
Feed water pre-heater (HP)	165,193	MW_th	0	0	15.0	2.5	0	0
Pumps	594,942	MW_el	0	0	0.7	0.4	0	0
Feed water pre-heater (LP)	75,042	MW_th	0	0	15.5	1.2	0	0
Balance of the system	24,451	MW_th	129.0	3.2	157.6	3.9	0	0
Engin. & prj. management	14 (20[2])	%		14.9		13.3		12.5
Risk and margin	10	%		7.4		9.5		8.9
Land costs	2.0 Mio.	km²	0	0	1.13	2.3	0.71	1.4
Total Retrofit CAPEX				**96.6**		**119.7**		**112.2**
Annual OPEX				**6.9**		**7.9**		**5.4**
Annual Electricity Output		**GWh**	**179**		**244**		**165**	

[1] SCA = Solar Collector Assembly (150m); one loop consists of four SCAs
[2] Value of 20% is used for Concept A

The net dismantling cost for Concept A are estimated at 5,000 $/SCA which includes e.g. revenues from recycling of the steel structures. This leads to negligible dismantling cost compared to e.g. the cost for the addition of the MSTS or the power block modifications. Since the total thermal input into the power block remains rather constant, it is assumed that several power block components like the cooling system or the generator can be preserved. In contrast, Concept B requires major modifications of the power block for about 557 $/kW$_{el}$, which is about half the cost for a complete new power block. Concept C does not require any power block modifications, however, the cost for the addition of PTCs and a thermal storage system sum up to almost the same CAPEX as for Concept B (112.2 vs. 119.7 Mio. $). The general approach for annual performance simulation of trough/tower hybrid plants using *greenius* has already been discussed in [7]. Figure 5 summarizes electricity output and LCOE for the continued operation of the reference plants (after replacement of 50 % of the HCEs), a MSTS built in 2030 and all three retrofitting concepts (base case: A, B and C) with their corresponding benchmarks.

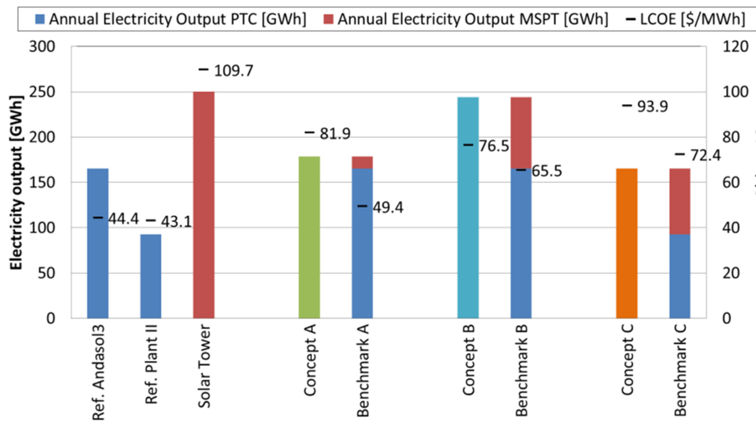

FIGURE 5: Annual electricity output and levelized cost of electricity for reference cases, retrofit concepts and corresponding benchmarks

All three retrofitting concepts have to compete against an alternative benchmark scenario, which mainly consists of the continued operation of the depreciated reference PTC plants after a major overhaul, e.g. HCE replacement (Ref. Andasol 3 and Ref. Plant II, blue bars). The depreciated reference PTC plants reach LCOEs as low as 44 $/MWh while the MSTS a LCOE of 109.7 $/MWh. The comparison between the benchmark and the retrofitting concept is based on the same annual electricity output. The gap between reference plant output and retrofit concept output is filled with electricity provided by a (virtual) newly built MSTS (red bar in each benchmark). The benchmark LCOE is the weighted average of the overhauled PTC plant and the new MSTS. With the given base case cost estimations all three retrofit concepts are not cost-effective compared to the benchmark values. The electricity surplus delivered by Concept A is marginal while the CAPEX sum up to 97 Mio. $. Both concepts B and C lead to about 75 GWh higher electricity output and require CAPEX of about 115 Mio. $. For Concept B the LCOE gap between benchmark and retrofit is the smallest (10.7 $/MWh). Therefore, alternative cost retrofit cost scenarios have been investigated for this concept. The results are shown in Fig. 6.

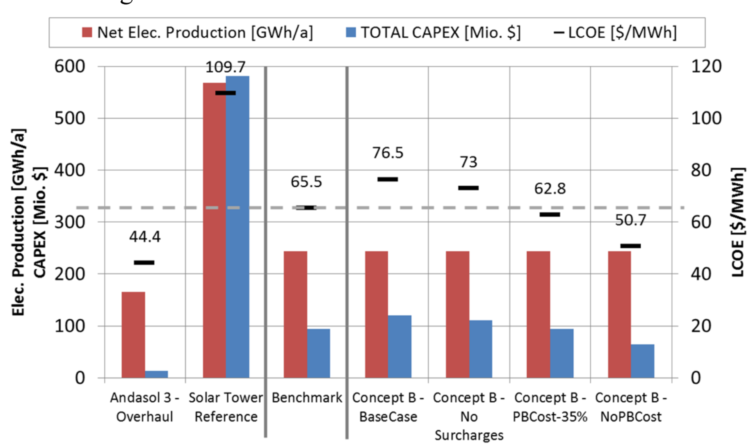

FIGURE 6: Annual net electricity production, CAPEX and LCOE for several cost scenarios in Concept B.

Compared to the base case scenario, the three alternative cost scenarios account lower CAPEX. Omitting the surcharges accounting for smaller volume leads to a CAPEX reduction of 8.5 Mio. $ (-7 %). Additionally decreasing the cost for the power block modification by 35 % entails a total CAPEX reduction of 25.3 Mio. $ (-21 %) compared to the base case and offers LCOEs marginally below the benchmark. Within the (unrealistic) best case scenario *NoPBCost* the power block modification cost are neglected, which would allow significantly lower LCOE than the benchmark.

CONCLUSION

Three different retrofitting concepts applied to two types of PTC power plant with and without thermal storage system have been studied. With the implementation of a new molten salt/steam superheater and reheater, the live steam operation temperature can be increased from 384 °C to 540 °C raising the power block's efficiency from 40.01 % to 44.28 %. The developed interconnection between the PTC's and MSTS's thermal storage system permits a shift of energy that compensate the different seasonal variations of both technologies and enable the prolongation of the PTC's discharge operating process. The annual electrical energy output of power plants similar to Andasol 3 can be potentially increased by 30 %.

The economic boundary conditions for the three investigated retrofit concepts are challenging. The application of Concept A is economically not viable; even Concept B is only cost-efficient, if the costs for the power block modification are below 440 $/kW and surcharges are neglected. In contrast to [4] where PTC technology is competitive compared to MSTS technology in 2025, the LCOE gap between Concept C and the benchmark is surprisingly big (even without surcharges). The major reason for this apparent discrepancy is the fact that the PTC in Concept C is based on thermal oil as HTF while newly built PTC plants in 2025 would use molten salt and thus higher operation temperatures resulting in significantly lower LCOEs.

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