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Hybridization of Concentrated Solar Power and Biomass Combustion for Combined Heat and Power Generation in Northern Europe

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Abstract. Decreasing installation costs and maturing of the technologies associated with concentrated solar power pave the way for new areas of application. One possible application could be district heating systems, which are especially common in Nordic countries. The objective of this paper is to evaluate the prospects of retrofitting an existing district heating plant located in Northern Europe with parabolic trough collectors. The study investigates the techno-economic feasibility of hybridization with parabolic trough collectors. For this purpose, a computer model of an existing district heating plant, located on the Danish island of Ærø, was developed. The model allows annual simulations of energy flows within the system. Validation of the model against measured data from the operational year of 2016 indicates agreement between simulated results and measured data within an accuracy of ±3.5 %. After validation, changes in the control strategy and the plant layout are implemented in the model. The sizing of the collector field is described and the results of annual simulations are presented in terms of electricity- and heat production. Due to a payback period of 31 years, it is concluded that such a hybridisation is economically infeasible under present conditions, but could become attractive when investment costs are lowered or a higher tariff for the electricity produced is granted. Furthermore, it is indicated that in a case, where the location of the plant is changed to Torino, Italy, the economic results increase significantly with the simple payback period lowered to 14 years.

INTRODUCTION

More than 50 % of the total energy consumption in the EU is due to the need for heating and cooling in buildings and industry. At the same time, only 18 % of the primary energy supply for heating and cooling is covered by renewable energy sources [1]. This number could be increased significantly by implementing renewables into existing district heating (DH) systems and by building new DH infrastructure relying on renewable technologies.

Denmark is a leading country within DH, as 64 % of all households are connected to a DH network, supplying both domestic hot water and space heating [2]. More than half of this energy comes from renewable sources, especially biomass. However, it is discussed whether the increment in biomass consumption is sustainable. Therefore, the application of solar technologies in DH systems is of increasing interest. At the same time, decreasing installation costs and continuously maturing of the concentrated solar power (CSP) technology could increase the feasibility of applying such technology in the context of DH [3]. Previous work has indicated promising results for adapting CSP technology in DH systems in central- and southern Europe [4]. However, no previous work has been conducted on retrofitting a DH system located in Northern Europe with CSP collectors. Two newly constructed DH facilities in Denmark feature parabolic trough collectors (PTC's) in order to increase flexibility of DH production and to supply heat for combined heat and power production [5, 6]. This shows that it is possible to utilize CSP technology in DH systems, even in Denmark. However, the two mentioned plants are designed from scratch,

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enabling favorable integration of parabolic troughs in the system layout without having to deal with the challenges that arise when retrofitting a plant. The objective of this paper is to evaluate the prospects of retrofitting an existing DH plant located in Northern Europe with parabolic trough collectors. The study investigates the techno-economic feasibility of hybridization with PTC's. This has been done by building a numerical simulation of an existing DH facility. TRNSYS was employed as the main simulation platform, while preliminary modelling was carried out in Engineering Equation Solver (EES) and Matlab. The model has been validated against measured data from the plant. Furthermore, the study presents how the economic results change as the location of the plant is changed to a location with higher solar radiation.

The District Heating Plant at Marstal, Denmark

The DH plant studied in this paper is located in Marstal on the Danish island of Ærø in southern Denmark. The total number of households connected to the DH network is 1600, requiring 33 000 MW_{th} of heat to be produced annually. The main components of the plant are solar flat plate collectors (FPC's) with a total area of 33 000 m^2, a seasonal pit storage with a capacity of 75 000 m^3, a 1.5 MW_{th} heat pump and a 4.4 MW_{th} biomass burner connected to a 750 kW_e organic Rankine cycle (ORC). [4]

Figure 1 shows a simplified layout of the plant. The annual production pattern of the plant can be summarized as follows. In the summer months (June-September), the DH demand is covered by the FPCs alone. Depending on the amount of heat available, it is fed directly into the district heating network or heats up the thermal storages. In autumn, when heat demand cannot be met by solar collectors and thermal storage alone, the wood chip boiler connected to the organic Rankine cycle starts operating. Heat is continuously drawn from the seasonal storage, both directly by means of a heat exchanger and by cooling the storage with the evaporator side of the heat pump. When heat demand exceeds available supply from all the mentioned means of production, the oil burners start operating. This only happens in the coldest month of the winter.

Due to the above, the ORC unit is not operational during summer months, resulting in a low annual capacity factor (31 % for the operational year of 2016). Therefore, hybridization with PTC's is a promising option.

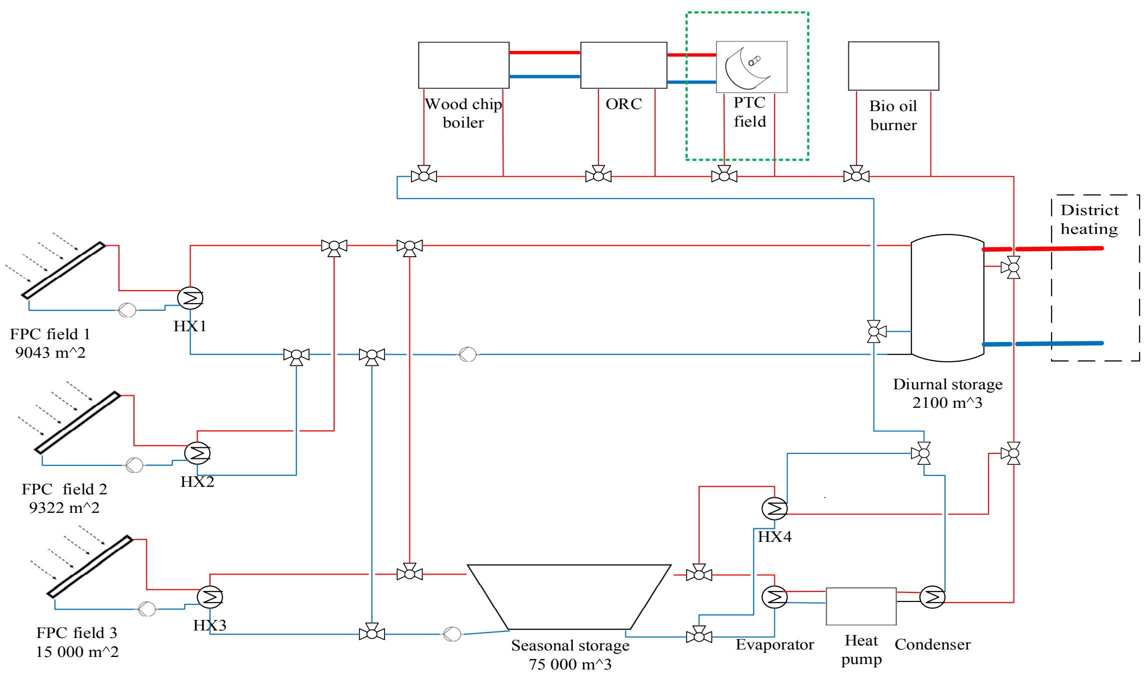

FIGURE 1. Simplified layout of the DH plant in this paper. Components represented as black boxes. Possible hybridization with PTC is indicated by dotted, green line.

METHODS

As a first step in the process of evaluating improvements and additions to the described district heating plant, a numerical model of the current plant was developed in TRNSYS and validated. The following assumptions were employed in order to obtain a model with reasonable accuracy:

- The parasitic consumption of pumps in the system was neglected.
- The forward temperature of the district heating system was assumed constant at 72 ^{o}C throughout the year.
- All heat producing components fed into either diurnal- or seasonal storage from where DH demand was drawn. In the real plant configuration heat can be fed directly into the DH stream using sophisticated controllers.
- The temperature level at the top of the diurnal storage was decisive for which components of the plant to be operational. The order of activation with increasing DH demand was FPC's (always active) – wood chip boiler in combined heat and power production with ORC unit – wood chip boiler without power production – heat pump – bio oil burner. This activation order ensures the lowest possible variable cost of heat production at all times.

Modelling of components

Most of the components in the model were modeled by components from commercially available TRNSYS libraries. Table 1 presents the components of choice for the modelling of each element.

TABLE 1. TRNSYS components applied in modelling

Component of plant	Applied TRNSYS component	Description of component
Weather data	Type 15	Weather data processor (Copenhagen)
Diurnal storage	Type 4	Stratified storage tank
FPC's	Type 539	Flat plate solar collectors with capacitance and flow modulation
Heat exchangers	Type 5	Counter flow heat exchanger
PTC's	Type 396	Parabolic trough field model
Seasonal storage	Type 60 and type 77	Storage tank and simple ground temperature model

Furthermore, the wood chip boiler, the bio oil burner and the heat pump were modelled as auxiliary heating elements in the diurnal storage. The DH demand was modelled by means of measured data from 2016 applied as a cooling load to the DH network.

Since TRNSYS does not feature an applicable model of an ORC unit, this component has been modelled in Engineering Equation Solver (EES). In a first step, a model at rated design conditions as provided by the manufacturer was developed [7]. Afterwards, part load characteristics of all major components of the ORC unit (expander, heat exchangers, pump, generator and pressure drops) were added to the tool [8]. The model was used to generate a characteristic of the thermal efficiency of the ORC unit as a function of available heat input. This curve was imported to TRNSYS in order to simulate the behavior of the component in the DH plant.

Sizing and implementation of parabolic trough collectors

The reasoning behind implementation of a field of parabolic troughs to the DH plant is to increase the utilization of the ORC unit, resulting in an increase in annual electricity production. At the same time, the excess heat from this process can be fed into the DH system.

The collector manufacturer was chosen to be Aalborg CSP, since this company offers a collector specially designed for operation in Nordic regions [9]. Table 2 presents the specifications of this collector. However, no efficiency parameters of this collector are publically available, which is why these have been adapted from the EuroTrough 150, having a similar geometry [10].

In order to obtain a suitable size of the PTC field, the following method was adapted [11]. First, the overall efficiency of the parabolic troughs at the design conditions presented in table 2 was determined using an in-house

Matlab script, taking thermal and optical losses of the collector into account. The design date was chosen to be noon at the 21st of June, representing the summer solstice in the northern hemisphere, This resulted in a total efficiency of $\eta_{PTC,tot}$=0.55. The area, A_{PTC}, needed in order to meet the thermal output at nominal conditions, $Q_{ORC,in}$, was found using an energy balance of the PTC field:

$$A_{PTC} = \frac{Q_{ORC,in} \cdot SM}{DNI_d \cdot \eta_{PTC,tot}} \tag{1}$$

In equation (1), SM is the solar multiple and DNI_d is the direct normal irradiance at design time. The solar multiple was varied in the range of 0.9 to 1.3 during simulations. Positive effects on the economic results were observed with increasing SM. However, at a SM of 1.1 the DH system starts overheating during summer. Therefore, a SM of 1 has been chosen, representing a reasonable tradeoff between electricity production and overheating of the thermal storages. The presented sizing methodology resulted in a field consisting of 12 rows of PTC's and a total aperture area of 8088 m^2.

The total investment costs, I_{tot}, of a hybridization with the mentioned size were evaluated to be 2.48 M USD. The PTC's, site improvements and the heat transfer fluid system contribute with 1.92 M USD to this number [12]. The rest is made up by cost of land (0.1 M UDS), balance of plant (0.31 M USD) and engineering costs (0.15 M USD) [4].

TABLE 2. Design conditions and parameters of the PTC field

Parameter	Symbol	Value
Nominal thermal output	$Q_{ORCin,d}$	3910 kW
Inlet temperature to PTC	T_{PTCin}	252 ^{o}C
Outlet temperature	T_{PTCout}	320 ^{o}C
DNI at design date	DNI_d	750 W/m^2
Ambient temperature	T_{amb}	20.4 ^{o}C
Aperture width of collector	W_{aper}	5.7 m
Length of solar collector assembly (SCA)	L_{SCA}	125 m
Aperture area of SCA	A_{SCA}	674 m^2
Spacing between collector rows	L_{spsc}	15 m

Economic assessments

Four different economic assessments were performed in order to investigate the economic impact of the addition of a PTC field to the plant layout and of changes made to the operational strategy of the plant. First, a simple payback period, $N_{y,pb,simple}$, is defined as the total investment, I_{tot}, required divided by the sum of annual revenues from production of electricity, $r_{el,an}$, and annual savings in fuel due to the additional heat gain to the DH system, $s_{heat,an}$:

$$N_{y,pb,simple} = \frac{I_{tot}}{r_{el,an} + s_{heat,an}} \tag{2}$$

In order to take the time value of money into account, a more sophisticated calculation of payback period, $N_{y,pb}$, was also used [13]:

$$N_{y,pb} = \frac{\log\left(\dfrac{r_{el,an} + s_{heat,an}}{r_{el,an} + s_{heat,an} - I_{tot} \cdot i}\right)}{\log(1+i)} \tag{3}$$

with i being the interest rate of the investment, assumed to be 5 %. Lastly, the net present value, NPV, of the investment after a given number of years, N_y, was found [13]:

$$NPV = \frac{(1+i)^{N_y} - 1}{i \cdot (1+i)^{N_y}} (r_{el,an} + s_{heat,an}) - I_{tot} \tag{4}$$

Validation of model

The model of the DH system has been validated against data from 2016 with 5 minutes time steps. Two different approaches were used to validate the model. First, at daily validation was performed in order to check the production of the heat producing components at a selected day in summer and winter respectively. This indicates a general agreement between modelling results and measured data. The biggest deviations (up to 4.6 %) were observed for the heat production of the FPC's which is mainly caused by the difference between the weather data applied in the model (typical meteorological year) and the actual weather of 2016 [14].

Secondly, the year-round performance of the model was validated by comparing monthly heat production of the various modelled components against data. Figure 2 shows the result of this validation. As it may be noted, the model follows the general production pattern of the plant. However, monthly deviations do occur. These are mainly caused by differences in weather data and the fact that the operation of components is controlled by logics in the model as appose to it being mostly human decisions in the real operation of the plant.

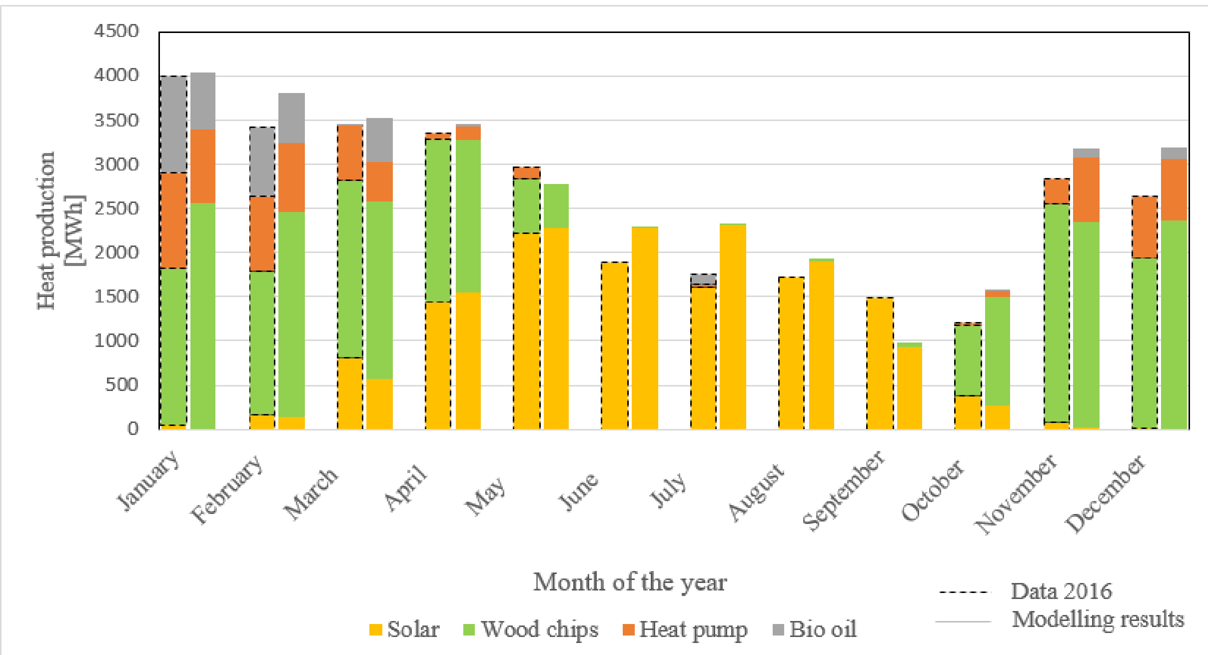

FIGURE 2. Validation of the monthly heat production of the model against measured data from 2016

The annual production values are summed up in table 3. As it may be noticed, the annual heat production of all components lies within a deviation of 3.5 %. Considering the fact that the modelled system was heavily weather dependent, the shown deviations are considered to be acceptable.

Validation of the temperature development in the seasonal storage revealed a good match between measured data and modelling results, especially when considering degree of stratification and the min/max temperatures during the year. Short term deviations in temperatures did occur, resulting in root mean square deviations of 3.8 ^{o}C and 5.3 ^{o}C for temperatures measured at the top and the middle of the tank, respectively.

TABLE 3. Total sum of heat production by component for a whole year of operation

	FPC 1	FPC 2	FPC 3	Wood chips	Heat pump	Bio oil	DH demand
Data 2016 [MWh]	3333	3681	5265	15398	3767	2002	33446
Model [MWh]	3337	3551	5379	15103	3710	1995	33074
Deviation [%]	0.12	-3.5	2.2	-1.9	-1.5	-0.35	-1.1

RESULTS AND DISCUSSION

The results of the hybridisation in terms of electricity production and additional heat gain to the DH system are shown in figure 3.

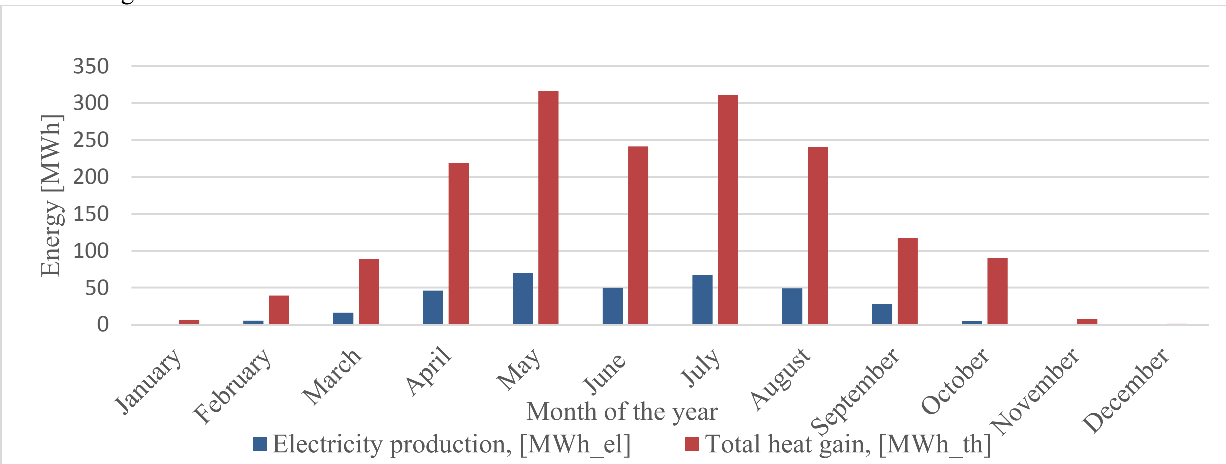

FIGURE 3. Results of hybridization. Electricity production of the ORC unit due to heat input from the PTC's and additional heat gain to the DH system.

On an annual basis, the hybridization with PTC's results in electricity production of 320 MWh and an additional heat gain of 1625 MWh. Under current conditions, a feed in tariff (FIT) of 121.7 USD/MWh is paid for the electricity produced by the ORC unit and the average variable production cost for heat is 27.8 USD/MWh. Using these numbers, the sum of annual revenues and savings due to the hybridization with parabolic troughs is 0.081 M USD. This results in a simple payback period of 31 years and a NPV after 25 years of -1.35 M USD. The negative NPV indicates that money is lost on the investment under current conditions.

However, as both CSP and ORC are novel technologies in the Nordic energy sector, special subsidies are likely to be granted for such innovative power plants. Furthermore, the applied investment costs rely on conservative figures, making it likely for these to decrease in the near future. Therefore, a sensitivity analysis of the economic results has been carried out, varying both the investment costs of the installation and the FIT of electricity. The results of these scenarios are shown in figure 4.

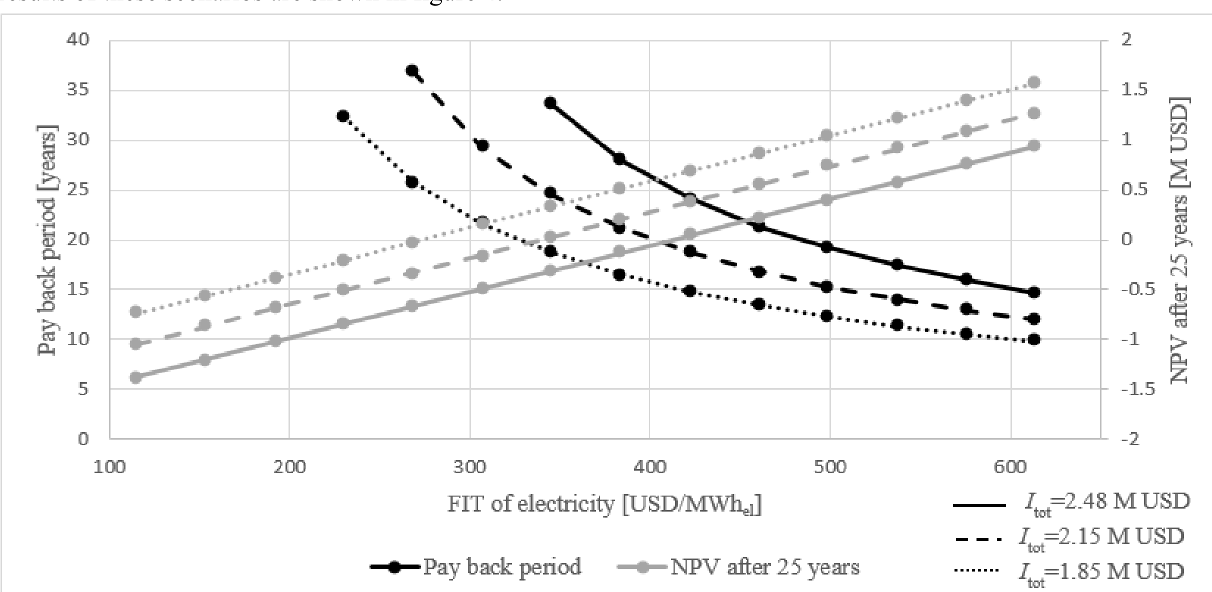

FIGURE 4. Economic sensitivity analysis of hybridization with PTC's. Investment costs and FIT are varied.

If the presented current investment cost of I_{tot} =2.48 M USD is considered, the NPV after 25 years turns positive at a FIT of 420 USD/MWh. This number can be compared to former subsidies granted to novel energy technologies. As an example, the FIT for electricity for solar PV in Germany was 491 USD/MWh in 2008 and has been decreased steadily as the technology matured. If investment costs are brought down to 1.85 M USD, the NPV would turn positive at a FIT of 280 USD/MWh.

Generally, it must be concluded that the presented hybridization of a Danish DH system with PTC's is economically infeasible at present conditions. However, the results are likely to be more promising for new-build DH plants featuring PTC', due to several reasons. Firstly, the size of the components, including the ratio between the area of FPC's and PTC's, could be optimized in a new-build plant. Secondly, a new plant would allow a configuration with FPC's and PTC's in series, taking advantage of the low specific costs of FPC's and the high thermal efficiency at elevated fluid temperatures of PTC's. Lastly, the ability of PTC's to defocus would allow for designs with higher solar fractions without running the risk of system overheating during summer.

Another aspect of interest is to determine how the economic results change as the location of the plant is moved to a place with higher annual values of solar radiation. For this investigation the city of Turin, Italy is considered, as it represents a southern European city with an existing DH network. The results suggest that if the described plant configuration is located in Turin, the economic results improve considerably, assuming the same pricing for electricity and heat as in the calculations for Denmark. The simple payback period is more than halved, from 31 year for the Denmark case to 14 year for the Turin case. When considering the time value of money, the payback period is $N_{y,pb}$= 25.2 years, which is slightly higher than the expected lifetime of 25 years. This is further confirmed by a NPV that turns positive after 26 years for the Turin case, indicating that the hybridization would be close to feasible if located in northern Italy. This indicates that the Turin case requires a FIT of slightly higher than 121.7 USD/MWh to be economically feasible.

CONCLUSIONS

The methodology of developing a simplified computer model of a Danish district heating plant was presented in this paper. Validation of the model against measured operational data was carried out in order to prove the usefulness of the model. Deviations of the annual thermal production of the various components lies within ±3.5 %.

The possibility of adding PTC's to the plant layout was examined. The applied sizing methodology resulted in a field of 12 collector rows from the Danish manufacturer Aalborg CSP, having a total aperture area of 8088 m^2. This corresponds to a solar multiple of 1 at design conditions, representing a trade of between electricity production and overheating of the DH system during summer.

Due to a simple payback period of 31 years and a negative NPV at the end of the expected lifetime of 25 years, the hybridization was concluded to be economically infeasible under present conditions. However, a sensitivity analysis, in which the FIT and the upfront investment costs where varied, revealed that the hybridization would become feasible at a FIT of 420 UDS/MWh at present installation costs and even earlier if costs of installation are lowered. Further, it was concluded that parabolic troughs are more likely to be installed in newly constructed plants in which the ratio between non-concentrating- and concentrating collectors can be matched. Lastly it was shown how the economic results improve as the locations of the plant is moved from Denmark to Turin in northern Italy, resulting in the simple payback period to be more than halved due to increased solar radiation. Hence, the Turin case showed a simple payback period of 14 years and the NPV after 25 years would turn positive at a FIT of slightly above 121.7 USD/MWh.

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