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Techno-economic comparison of solar thermal and PV for heat generation in industrial processes

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Abstract

The interest for renewable based water heating via electricity has increased in recent years due to the reducing costs of photovoltaics (PV) coupled with their inherent ease of installation, especially for domestic hot water applications. In larger scale solar thermal (ST) systems, namely for industrial process heat demand, solar heating has only been done by thermal collectors to date. Given the regular cost reductions for PV, this technology may one day supplant certain segments of the industrial heating market, if renewable based heating is desired. To determine if and when this may happen, a comparative analysis between PV and ST heating systems for three industrial processes operating at different temperatures was undertaken.

Results demonstrated that for applications operating below 100 °C, ST systems will still provide cheaper thermal energy as compared to PV installed between1… 2 €/W_p. To generate saturated steam at 150 °C, PV systems can provide a better economic solution when a parabolic trough ST system specific investment is more than 700 €/m^2 turnkey while being located in a region with less than 1,700 kWh/m^2a beam surface irradiation. In lower irradiation regions, the ST system cost must be even lower to compete. When PV system costs reduce to1 €/W_p, concentrating systems must reduce their costs below 400 €/m^2 to have cost superiority.

Keywords: *industrial process heat, PV, solar thermal, economic comparison*

1. Introduction

Thermal energy is the largest segment of global energy demand, accounting for nearly half of the final energy consumption (Beerepoot and Marmion, 2012). Industrial process heat comprises one third of this end use and it is estimated that solar derived thermal energy can help meet up to 5 % of global industrial demand (Lauterbach, 2014), especially when focusing on temperatures between 50 °C and 150 °C. While an interesting route to reduce fuel consumption, very few projects have been realized due to a host of factors, with high upfront project costs being a main deterrent.

With the recent and rapid improvement of PV technology, ease of installation, and its associated cost reduction, this technology is now being considered for thermal energy projects, simply by using a resistance heating element directly into a fluid stream or connected to an industrial steam boiler. Prior studies have focused mainly on small systems which provide domestic hot water (DHW). An early report (Fanney and Dougherty, 1997) shows that assuming a solar thermal DHW system costs between 4,500…6,000 USD (inflation adjusted), energy cost parity could be reached when a PV system costs between 1.65…2.85 USD/W_p (1.48…2.55 €/W_p). Current DHW systems in developed countries are estimated to cost approximately 4,500 USD turnkey, depending on local labor markets and supplies (DGS, 2012). Current PV systems for electricity generation now cost approximately 1.48 €/W_p for small commercial projects in Germany and 2.06 €/W_p in the United States, with costs reducing for larger projects (Shah and Booream-Phelps, 2015). Prices for both systems are within the range to generate thermal energy competitively. This has also been confirmed by Le Berre et al., (2014).

To date, the use of PV generated electricity to directly provide heat for industrial applications has not been rigorously studied. This is due to the more complicated nature of process integration, as industrial energy demand varies both temporally (hourly, daily and weekly) and energetically, with process temperatures ranging from 50…200 °C, and has no external grid which can be fed (which is the case with electricity). Therefore, it is imperative that an analysis be undertaken to compare both the technical and economic performance of both types of systems to determine their suitability, both now and in the future.

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2. Methodology

To determine the feasibility of different solar heating technologies in different industrial applications, three different process and temperatures were selected: from 15...60 °C or stream pre-heating (PH), from 60…90 °C or bath heating (BH), and process steam generation at 150 °C (SG). The heating demand of all three systems was constant throughout the year, which exemplifies the ideal situation for solar thermal (ST), as storage and heat exchange losses are minimized. To dimension and subsequently calculate the energy yield in such systems, a methodology described in VDI - 6002, (2014) and expanded by Lauterbach, (2014) was implemented. This approach analyzes a solar project in terms of specific collector performance, which allows for easy scalability when designing multiple systems. This method begins to size a solar field based on a "good summer day", where the highest daily yield from one square meter of collector (q_{design}), tilted to the latitude of the site, is scaled up to match the daily demand of the process. In this manner, no energy will be wasted during the annual operation of the system, as it will be undersized for the remainder of the year. For example, one process consumes 1.5 MWh/d at a temperature of 60 °C ($Q_{process,day}$). A selected solar collector, on the highest solar irradiation day, can produce 3.6 kWh/m^{2}d (determined via TRNSYS simulation in Lauterbach, 2014). By using (eq. 1), the required field size can be calculated.

$$A_{coll}^{ST} = \frac{Q_{process,day}}{q_{design}} = \frac{1.5\,\frac{MWh}{d}}{3.6\,\frac{kWh}{m^2 d}} = 416\ m^2 \qquad \text{(eq. 1)}$$

Once the collector field size is determined, it can be multiplied by the annual utilization factor (η_{sys}), generated by annual dynamic simulation (Lauterbach, 2014) and the annual irradiation incident on the collector ($H_{t,b}$ for either total or beam radiation on the collector surface) to estimate the yield of the system (eq. 2).

$$Yield_a^{ST,PV} = A_{coll}^{ST,PV} * \eta_{sys} * H_{t,b} \qquad \text{(eq. 2)}$$

Lauterbach (2014) conducted these simulations for various regions in Europe, process temperature levels, demand schedules, and storage sizes. For the PH and BH cases, results were utilized from this work to calculate the energy yields. Flat Plate and Evacuated Tube Collectors were chosen for these cases, respectively. The SG case required additional programming in MATLAB, which simulated the performance of a parabolic trough collector using the same methodology, only forgoing storage, which is rarely used while creating process steam (outside of a small buffer tank). The design yield and utilization factor for four selected regions (Würzburg, Toulouse, Madrid, and Windhoek) was calculated using a simple model with the following input parameters (Tab. 1). It was assumed that the mass flow rate of the collector could be modulated to always produce a thermal oil outlet temperature of 190 °C, required generating steam at 150 °C. Field efficiency incorporated the losses due to solar field shading, piping and heat exchanges with the boiler to generate steam. The effects of the Incident Angle Modifier (IAM) were included; however optical effects for concentrating collectors, such as end losses, were not.

Tab. 1 - Simulation parameters of the steam generation case.

	η_o	0.689	
Parabolic Trough Collector (NEP 1800)	a_1	0.36	(W/m^{2}K)
	a_2	0.0011	(W/m^{2}K^2)
Field Inlet Temperature		140	°C
Field Outlet Temperature		190	°C
Field Efficiency		90	%

Through an annual simulation, sizing parameters for steam generation case were generated. A summary of the sizing parameters used can be found in Tab. 2, Tab. 3, and Tab. 4 in Section 3.

For the PV system, it was assumed that all electrical energy will directly be consumed by the process (via resistance heating) with no storage needed. As this is a highly flexible energy source, if it could not be used directly in the process, additional resistance heaters were assumed to be installed in other processes in the factory. It is important to note that the PV generated electricity can certainly be used to decrease net demand from the electrical grid, but this is not the focus of the work. The sizing of the PV field was done to match the annual energy output of the comparative solar thermal system, as seen in (eq. 3), where the solar thermal yield is divided by the average PV system efficiency (assumed 15 %) and the incident annual irradiation (H_t).

$$A_{coll}^{PV} = \frac{Yield_a^{ST}}{\eta_{pv} * H_t} \qquad \text{(eq. 3)}$$

The financial comparison was conducted by calculating the 20 year Levelized Cost of Energy (LCOE) of both solar heating systems (eq. 4). As the energy yields were calculated in the different cases, systems costs were assumed to be directly related to their size. PV system costs are well known (Shah and Booream-Phelps, 2015) and have been assumed to be 2 €/W_p installed (or 300 €/m^2 assuming again a 15 % system efficiency), inclusive of wiring and heating equipment. ST system costs vary considerably, depending on size, balance of systems, and technology. As such, an array of LCOE calculations were conducted by varying the specific system cost from 200 €/m^2 to 1,200 €/m^2, to capture the lowest flat plate cost to the most expensive parabolic trough cost (including the effect of potential subsidies). The costs of the solar systems ($Cost_{ST,PV}$) were calculated by multiplying the calculated area of collectors or modules ($A_{coll}^{ST,PV}$) in each case by the specific cost. Other important parameters of the LCOE calculation were Discount Rate (*DR*, 5%), Operations and Maintenance (*OM*, 1.5% and 1% of system cost for ST and PV, respectively), and system degradation (*SD*, 0.5% and 1%, for ST and PV, respectively). There was assumed to be no recovery value of the systems.

$$LCOE = \frac{Cost_{ST,PV} + \sum_{n=1}^{20} \frac{OM}{(1+DR)^n}}{\sum_{n=1}^{20} \frac{Yield_a^{ST,PV} * (1-SD)^n}{(1+DR)^n}} \quad \text{(eq. 4)}$$

3. Simulation Yields

The two applications below 100 °C (PH, BH) utilized the same four regions of varying solar resource (Copenhagen, Würzburg, Toulouse, and Madrid). The SG case used the latter three and also included Windhoek, Namibia, a city with rather high direct normal insolation (DNI). Different for this case was the use of direct irradiation (H_b) on a single axis N-S tracking surface due to the parabolic trough concentrators, while the PV system yield was calculated with the global surface irradiation (H_t). The simulations assumed a daily demand of 5 MWh/day during the whole year. Storage was used for the low and medium cases, pegged at 5 kWh/m^2 of collector field size.

Tab. 2 shows the required input data, as referenced in Section 2, necessary to estimate the performance in these four locations for the PH flat plate collector case, along with the resulting annual energy yields for both the ST and PV systems, collector area, and the range of project costs. Tab. 3 depicts the same for the BH evacuated tube collector case, and Tab. 4 for the SG parabolic trough. Fig. 1 summarizes the specific yield (kWh/m^2a) for all collector types in the three cases. The PV yields are the same for the three cases, as it was assumed that the conversion efficiency for resistance heating is temperature insensitive. The results clearly show an increasing yield as a function of higher solar irradiation, and a decreasing trend as the working fluid temperature increases, even if more efficient collectors are used.

Tab. 2 - Energetic yield results from the PH case using flat plate collectors

Pre-heating (15…60 °C)		Copenhagen	Würzburg	Toulouse	Madrid
Solar Thermal	Sizing Yield (kWh/m²d)	4.4	4.4	4.8	5
	Field Size (m²)	1,136	1,136	1,042	1,000
	Storage Size (m³)	110	110	101	97
	Utilization Factor (%)	54	56	59	60
	H_t (kWh/m²a)	1191	1264	1552	1887
	Specific Yield (kWh/m²a)	643	708	916	1,132
	Annual Yield (MWh)	731	804	954	1,132
	Project Costs (k€)	227-1,136	227-1,136	208-1,042	200-1,000
PV	Field Size (m²)	4091	4242	4097	4000
	System Efficiency (%)	15	15	15	15
	Specific Yield (kWh/m²a)	179	190	233	283
	Annual Yield (MWh)	731	804	954	1,132
	Project Costs (k€)	1,227	1,273	1,229	1,200

Tab. 3 - Energetic yield results from the BH case using evacuated tube collectors

Bath Heating (60…90 °C)		Copenhagen	Würzburg	Toulouse	Madrid
Solar Thermal	Sizing Yield (kWh/m²d)	3.8	4	4.2	4.4
	Field Size (m²)	1,316	1,250	1,190	1,136
	Storage Size (m³)	191	181	173	165
	Utilization Factor (%)	37	39	44	46
	H_t (kWh/m²a)	1,191	1,264	1,552	1,887
	Specific Yield (kWh/m²a)	441	493	683	868
	Annual Yield (MWh)	579	616	812	986
	Project Costs (k€)	263-1,316	250-1,250	238-1,190	227-1,136
PV	Field Size (m²)	3246	3250	3492	3485
	System Efficiency (%)	15	15	15	15
	Specific Yield (kWh/m²a)	179	190	233	283
	Annual Yield (MWh)	579	616	812	986
	Project Costs (k€)	973	975	1047	1045

Tab. 4 - Energetic yield results from the SG case using parabolic trough collectors

Steam (150 °C)		Würzburg	Toulouse	Madrid	Windhoek
Solar Thermal	Sizing Yield (kWh/m²d)	4.9	4.3	5.3	6.18
	Field Size (m²)	1,020	1,163	943	809
	Utilization Factor (%)	37	37	45	50
	H_b (kWh/m²a)	743	912	1,490	2,441
	Specific Yield (kWh/m²a)	275	337	663	1221
	Annual Yield (MWh)	320	344	626	987
	Project Costs (k€)	204-1,531	233-1,744	189-1,415	162-1,214
PV	Field Size (m²)	1,686	1,479	2,210	2,611
	System Efficiency (%)	15	15	15	15
	H_b (kWh/m²a)	1,264	1,552	1,887	2,521
	Specific Yield (kWh/m²a)	190	233	283	378
	Annual Yield (MWh)	320	344	626	987
	Project Costs (k€)	506	444	663	783

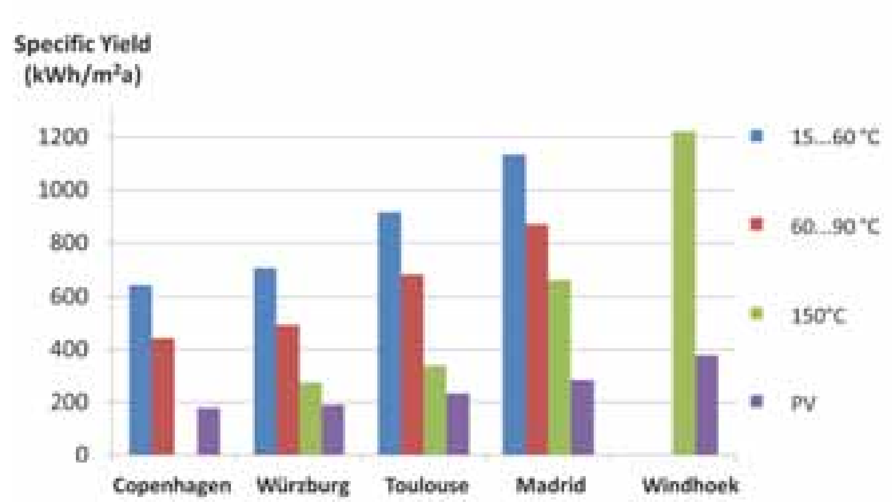

Fig. 1 - Summary of the specific collector yields in all cases

4. Comparative Analysis Results

From the previously calculated energy yields and their respective project costs, a relationship was established between them and the available solar irradiation. A metric was created to determine the better financial choice to generate thermal energy. For each financial case (solar costs, case, location), the LCOE for the ST and PV systems were calculated. The ST LCOE was then divided by the PV LCOE, yielding a ratio that if greater than one; the PV system would produce cheaper thermal energy. If less than one, the ST system would be cheaper. The results of the calculated ratio are show in Tab. 5 for the three cases. The assumed specific PV collector cost was 2 €/W_p.

Tab. 5 – Simulated LCOE Ratios for solar process heat projects. The highlighted and bold cells indicate situations where PV heating is more economically viable than ST heating. White cells with regular font show the situations where ST heating is more economically viable.

		Solar Thermal System Investment (€/m²)										
Case	**Location**	**200**	**300**	**400**	**500**	**600**	**700**	**800**	**900**	**1000**	**1100**	**1200**
15…60 °C	**Copenhagen**	0.19	0.28	0.37	0.47	0.56	0.65	0.75	0.84	0.94	***1.03***	***1.12***
	Würzburg	0.18	0.27	0.36	0.45	0.54	0.63	0.72	0.81	0.90	0.99	***1.08***
	Toulouse	0.17	0.26	0.34	0.43	0.51	0.60	0.68	0.77	0.86	0.94	***1.03***
	Madrid	0.17	0.25	0.34	0.42	0.51	0.59	0.67	0.76	0.84	0.93	***1.01***
60…90 °C	**Copenhagen**	0.24	0.35	0.47	0.59	0.71	0.83	0.94	***1.06***	***1.18***	***1.30***	***1.41***
	Würzburg	0.24	0.35	0.47	0.59	0.71	0.82	0.94	***1.06***	***1.18***	***1.30***	***1.41***
	Toulouse	0.20	0.30	0.40	0.50	0.60	0.70	0.80	0.90	***1.00***	***1.11***	***1.21***
	Madrid	0.19	0.29	0.39	0.48	0.58	0.68	0.77	0.87	0.97	***1.06***	***1.16***
150 °C	**Würzburg**	0.49	0.73	0.97	***1.22***	***1.46***	***1.71***	***1.95***	***2.19***	***2.44***	***2.68***	***2.92***
	Toulouse	0.37	0.55	0.74	0.92	***1.11***	***1.29***	***1.48***	***1.66***	***1.85***	***2.03***	***2.22***
	Madrid	0.26	0.39	0.52	0.65	0.77	0.90	***1.03***	***1.16***	***1.29***	***1.42***	***1.55***
	Windhoek	0.19	0.29	0.39	0.48	0.58	0.68	0.77	0.87	0.97	***1.07***	***1.16***

These results were further analyzed, generating a relationship between the LCOE ratio, ST system costs, and available solar irradiation, via multiple linear regression, with the following relationship (eq. 5). For the PH and BH cases, H_t was used and H_b for the SG case. Statistics for the curve fit are seen in Tab. 6.

$$Ratio_{LCOE} = b_0 + b_1 * ST_{Specific\ Cost} + b_2 * ST_{Specific\ Cost} * H_{t.b} \qquad \text{(eq. 5)}$$

Tab. 6 - Multiple Linear Regression results

	R^2_{adj}	RMSE	F statistic	p-value	b_o	b_1	b_2
Pre-Heating	0.999	0.011	16690	0	0	0.001069	-1.26E-07
Bath Heating	0.995	0.025	5066	0	0	0.00157	-3.36E-07
Steam Generation	0.931	0.188	316	0	0	0.0027	-7.70E-07

The result of (eq. 5) coupled with an array of feasible ST system costs (200…1,200 €/m²) and incident solar irradiation values (1,000…2,600 kWh/m²a) showed the changing feasibility of ST systems to provide thermal energy as compared to PV. The results for the PH case are shown in Fig. 2, the BH case in Fig. 3, and the SG case in Fig. 4. The thick white line indicates the point where PV and ST LCOE's are the same, so parameters right of this line favor ST projects and to the left favor PV projects.

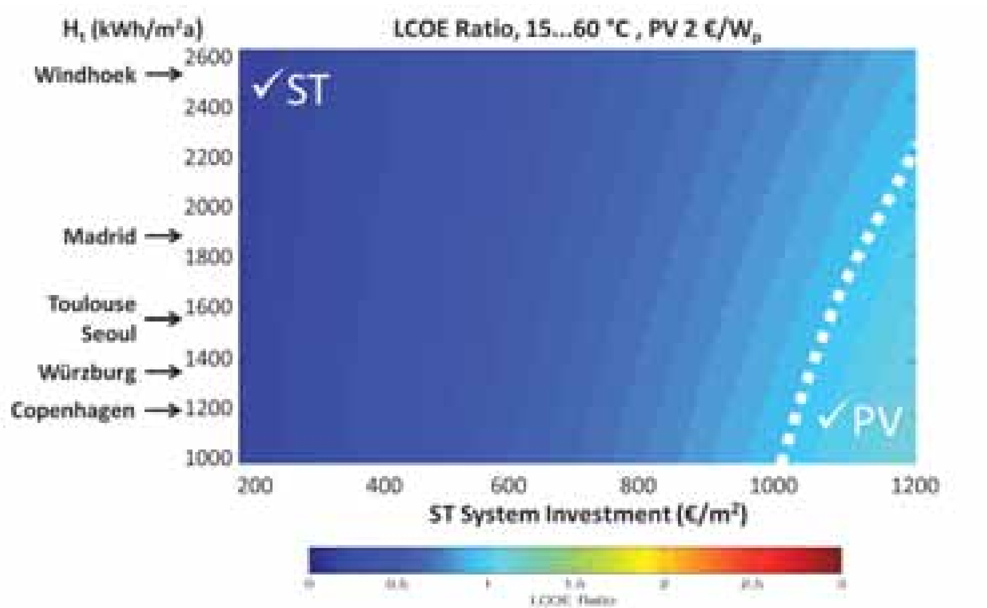

Fig. 2 – Pre-Heating LCOE comparison, where ST is the preferred choice under one, and PV over one.

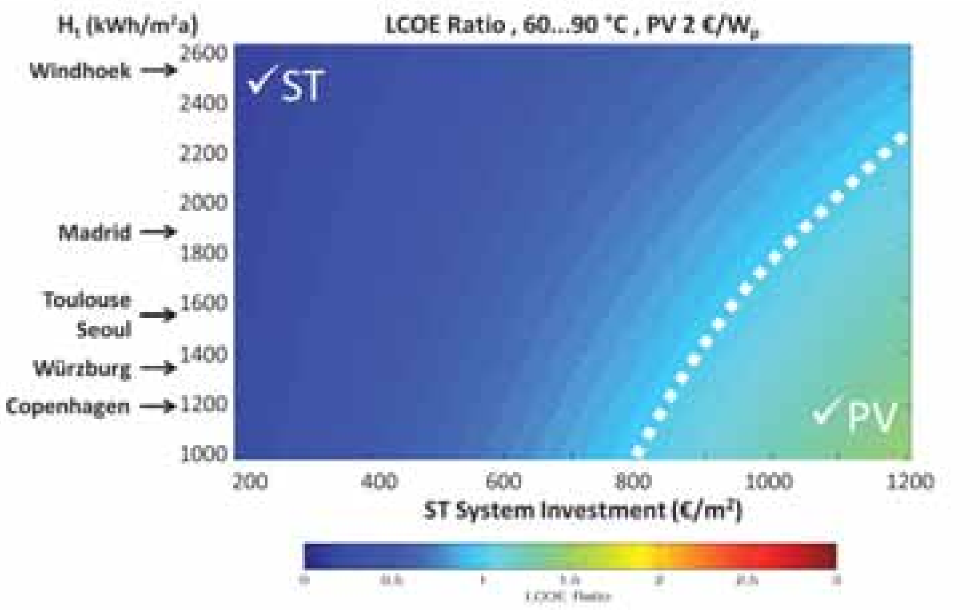

Fig. 3 – Bath Heating LCOE comparison, where ST is the preferred choice under one, and PV over one.

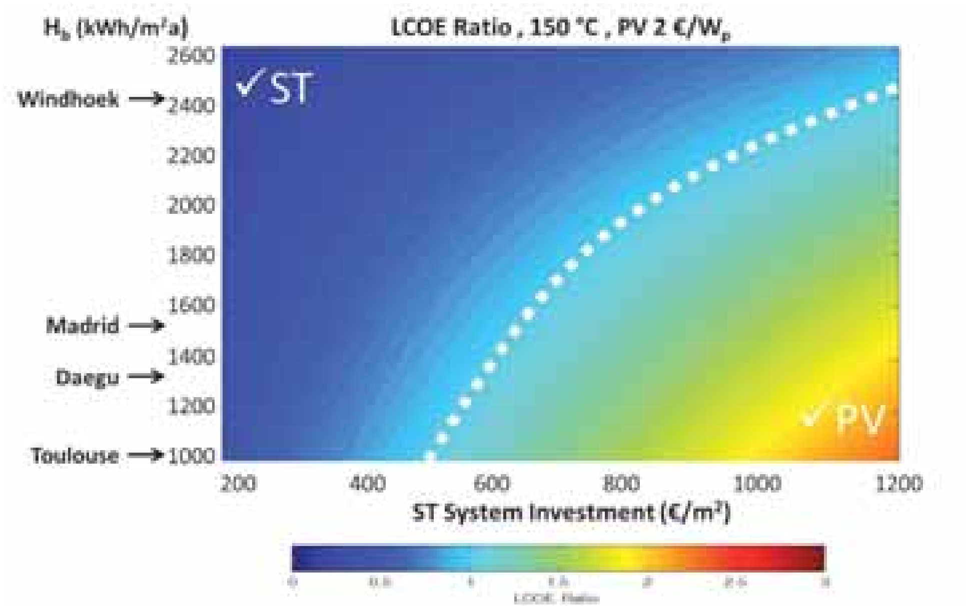

Fig. 4 – Steam Generation LCOE comparison, where ST is the preferred choice under one, and PV over one.

5. Discussion and Example Case

The tabular results in Tab. 5 clearly show that within applications and temperature levels, there are situations where PV heating is more cost effective than ST. This is most notably observed when ST system costs are significantly higher, operating at higher temperatures, and when installed in lower solar resource regions. This trend is progressively seen in Fig. 2, Fig. 3, and Fig. 4. These results are logical, as PV or electrical based heating is temperature insensitive (i.e. near constant thermal conversion efficiency), while the efficiency of a solar thermal collector decreases when operating at higher temperatures. Furthermore, PV can still produce useable energy in lower radiation, while ST struggles since there are inherent thermal losses to overcome. This helps to explain how, for example, PV may be better adapted to generate steam in most regions in Europe, as the beam irradiation is marginal at best while global irradiation is more consistent and beneficial to non-concentrating technologies. It should go without saying that steam generation with flat plate collectors would be rather challenging. Also interpreted from this table is a reason why DHW is at times being heated through PV resistance heating. In very small projects, the specific ST cost can be 900…1200 €/m^2 (DGS, 2012), making the costs very comparable with PV. Given the ease and minimal risk to install PV, this solution is gaining in popularity.

Fig. 2, Fig. 3, and Fig. 4 show a clear trend, that ST performs better compared to PV in higher irradiation regions than lower. The figures also indicate that as ST collector operating temperatures increases, so does the cost feasibility of a PV heating solution. A simple observation in all three figures again points to the fact that the area of acceptable ST projects shrinks as the collector temperature increases, while the PV area increases. This leads to the conclusion that PV heating may soon play a more important role in steam generation applications in relatively lower solar irradiation regions. This is made evident by the greater than one LCOE ratios in Fig. 4 above 700 €/m^2 ST project specific investment cost while H_b remains less than 1,700 kWh/m^{2}a. Both of these keystone values are often observed in projects within Europe.

As steam generation applications have demonstrated the nearest term situation where PV heating may be feasible, a reference case was used to assess its current state. In 2012, NEP Solar built a 627 m^2 parabolic trough collector field for a diary company in Switzerland, which generates 120 °C pressurized hot water for a cheese manufacturing facility. The specific subsidized project investment for the total system was approximately 595 €/m^2 (Frank et al., 2013), of which half was dedicated to the collector field. At this site, the annual DNI was 1,119 kWh/m^{2}a with a reported net specific steam yield of 406 kWh/m^{2}a. This value is comparable when interpreting the parabolic trough simulation results from Tab. 4 (445 kWh/m^{2}a), however operating at a higher mean plate temperature. Interpreting Fig. 4, the LCOE ratio at this point (595 €/m^2 and 1,119 kWh/m^{2}a) is 1.15, clearly indicating that a PV heating system would provide heating at a lower cost. If the solar thermal system investment could be reduced to below 550 €/m^2, it would be competitive against PV. If the incentives were removed, the project cost would increase to 990 €/m^2. To be competitive at this specific collector cost, the beam irradiation H_b must be rather high (2,200 kWh/m^{2}a). If the PV costs increased to 3 €/W$_p$, the competitive H_b changes to 1550 kWh/m^{2}a or ST system costs must be reduced to 825 €/m^2. When the PV cost is greater than 3.65 €/W$_p$, the currently designed and unsubsidized ST system becomes the preferred solution.

While PV may outperform ST in some situations, like above, it is important to point out the practicality of using PV for heating, with respect to the required land area needed to build such a project. Tab. 2, Tab. 3, and Tab. 4 display a significantly higher area required by PV to generate the same amount of thermal energy compared to ST. The multiple of land area required for the PV system relative to the ST system is shown in Tab. 7. The results indicate that PV requires relatively more space in higher solar irradiation regions, but less when operating at higher temperatures.

Tab. 7 - System size comparison between PV and ST, showing the significantly higher space needed for PV to generate thermal energy.

	Copenhagen	Würzburg	Toulouse	Madrid	Windhoek
Pre-Heating	3.6	3.7	3.9	4.0	----------------
Bath Heating	2.5	2.6	2.9	3.0	----------------
Steam Generation	-----------------	1.7	1.3	2.3	3.2

In reality, there is often limited available rooftop or land space at an industrial facility to build a solar system. This means that if a larger amount of thermal energy is desired to be displaced by solar on the same rooftop, ST may still be chosen even if it costs more. This is one major drawback of employing PV heating for industrial heat demand. To combat the greater required PV size, a heat pump could be employed to generate the targeted energy. If the COP of the heat pump can equal the relative size difference in Tab. 7, the PV field can be sized the same as ST, generating the same thermal energy (but not necessarily at the same cost). This also assumes that there is suitable available heat from waste streams. This analysis is not pursued in this paper, but is an interest for future work.

6. Future Scenario

The results from the reference case study show that current costs for ST projects operating at higher temperatures are similar to those of PV, if not higher. While future ST costs are challenging to predict, it is well accepted that PV cost will regularly decrease in the coming years. By setting the price of PV to 1 €/W_p, an understanding can be gained as to which technology may be chosen for future projects. This will also serve as a price target for ST systems to achieve so that PV electrical heating will not supplant them as the chosen technology for thermal energy generation.

In PH applications (Fig. 5), it appears that as long as ST project costs remain under 500 €/m^2, they should be the preferred choice, no matter the available solar irradiation. Similarly in BH applications (Fig. 6), ST should be chosen if costs are below 400 €/m^2 in all irradiation conditions. However, some evacuated tube projects are currently above this cost target, emphasizing the need to still reduce costs. The motivation to reduce costs is clearly evident when using concentrating collectors (Fig. 7), as the breakeven point for concentrating ST collectors generating steam is below 300 €/m^2 for lower irradiation climates and up to 500 €/m^2 in ideal solar locations (2250 kWh/m^2a). The current project costs for SG concentrating collectors are well above this price point and significant efforts must be made to reduce costs, both with the collector and balance-of-systems, in order for ST to generate steam in the future.

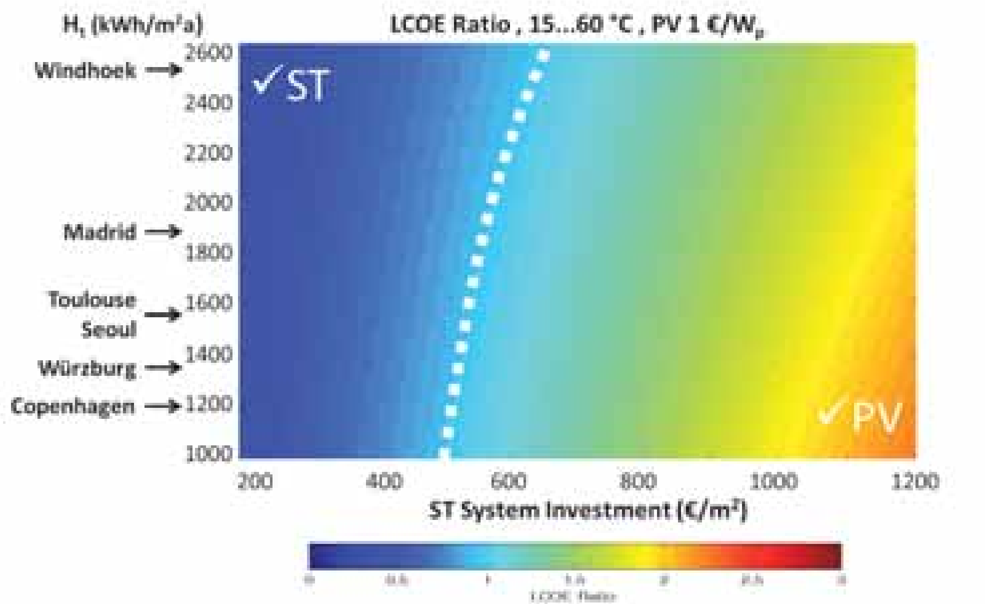

Fig. 5 – Pre Heating LCOE comparison when PV costs 1 €/W_p

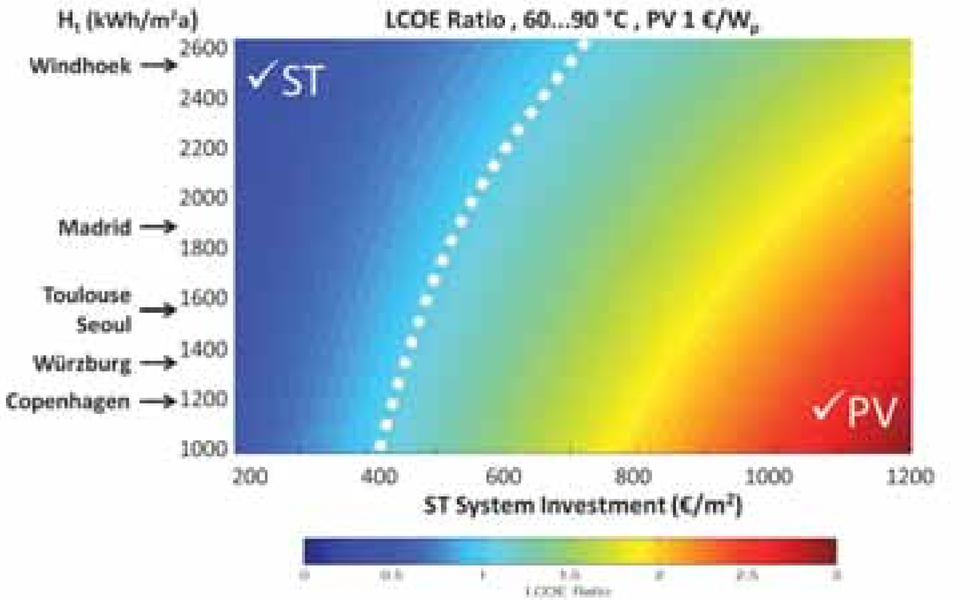

Fig. 6 – Bath Heating LCOE comparison when PV costs 1 €/W_p

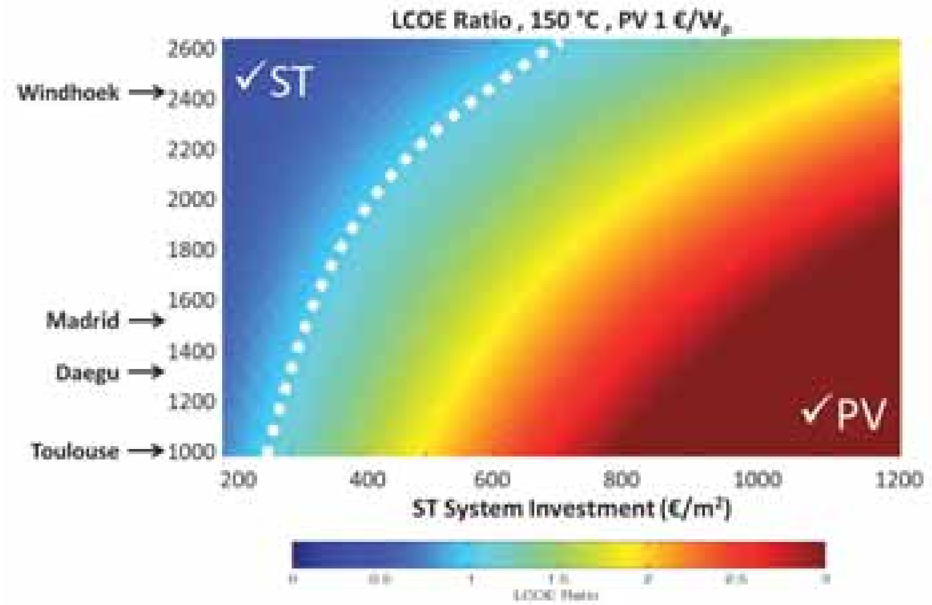

Fig. 7 – Steam Generation LCOE comparison when PV costs 1 €/W_p

7. Conclusions

The previous analysis showcased the comparison between Solar Thermal and Photovoltaics to generate thermal energy for industrial processes. At current costs, ST is still a more economic choice for applications below 100 °C, but when generating steam, PV can provide relatively lower costs when the direct solar resource is less than 1,700 kWh/m^{2}a. From the provided reference case in Switzerland, PV is already a more economical solution, mainly due to the low solar resource and high specific project cost for ST.

The 2020 specific cost goal for non-concentrating systems is 250 €/m^2, and 300 €/m^2 for concentrating, according to (Ivancic et al., 2014). These figures, especially for concentrating collectors, remain good targets to stem the competition from PV based heating. Significant efforts are still needed to realize such goals.

It is important to note that the price of fossil fuel, or its comparison with thermal energy generation, was not mentioned during this analysis. This omission was intentional, as the focus was a technical comparison between the two solar technologies.

8. Acknowledgements

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