THE IMPACT OF RENEWABLE POWER GENERATION ON THE PROFITABILITY OF SOLAR DISTRICT HEATING – AN ECONOMIC POINT OF VIEW

Evelyn Sperber
Systems Analysis & Technology Assessment, Institute of Engineering Thermodynamics, German Aerospace Center, Wankelstraße 5, Stuttgart, 70563, Germany,
Telephone: +49 711 6862-8145, Telefax: +49 711 6862-8100, E-mail: evelyn.sperber@dlr.de

Abstract – The intermittency of power generation by wind and photovoltaic results in volatile spot prices at the power exchanges. As a consequence amendments in the operational strategies of power plants are required. For combined heat and power (CHP) units in district heating (DH) networks this means that production is particularly profitable in periods with high spot prices. In situations with low spot prices, in turn, it can be more cost-efficient to operate available peak load boilers instead of the CHP to supply the required heat. These circumstances can make solar district heating economically attractive. Additional flexibility in DH systems based on CHP is achieved by integrating electric boilers and heat pumps into the operational strategy. In this paper concepts for technically and economically optimized "smart" DH systems including solar are presented. The interaction of heat producers in different configurations of DH systems is simulated with a dynamic simulation tool (TRNSYS 17). To investigate the profitability of solar district heating, heat costs of different configurations of DH systems with and without solar are computed. The simulations reveal that in smart DH systems solar heat can displace expensive heat from peak load boilers. It is further shown that solar collectors do not only reduce operating costs of DH systems but are even profitable from a full cost perspective. Sensitivity tests point out that increasing prices of fossil fuels as well as higher shares of PV in power generation prove advantageous to solar district heating.

1. INTRODUCTION

The power generation by renewable energy sources (RES) in Germany and other European countries has been growing significantly throughout the past years. This development has been showing considerable effects on spot market pricing: on the one hand power generation by RES reduces the residual load that has to be met by conventional power plants, resulting in a decrease of spot market prices at the power exchange (merit-order effect). On the other hand the fluctuating nature of intermittent RES such as wind and photovoltaic (PV) enlarges spot price variability. Historic analysis has proven that spot market prices are a good indicator for current power generation by RES. In future energy systems with high penetration levels of RES, power plant operators should consider the dynamics of the electricity spot exchanges with regard to the feasible operation of the plants: Spot prices should be the decisive factor for operation decisions in order to gain maximum revenues for individual power plants.

CHP as flexible power production units will play an important role for the integration of RES into the power sector. While CHP plants have originally been designed for high utilization that was based on fixed tariffs for power generation (i.e. "heat controlled" CHP) this model will be replaced by economically optimized power generation based on spot market prices (i.e. flexible or "power controlled" CHP). Correspondingly production will be shifted from high utilization to limited utilization restricted to times with high spot prices. Heat storages allow such flexible CHP operation since heat production can be decoupled from heat demand. Due to the lower relative losses and lower specific costs of larger thermal storages this coupling of heat and power market is particularly reasonable in district heating (DH) networks.

However, this power controlled operation of CHP plants results in decreasing operation hours and lower heat production for DH feed-in. As long as no alternative heat source is available peak load boilers must supply the required heat in situations with low spot prices. Since those boilers are generally based on fossil fuels market opportunities arise for heat producers that can supply heat more cost-efficiently (and more economically friendly) in the absence of CHP heat. Especially solar DH in connection to heat storages thus becomes economically attractive.

Additional flexibility in DH systems based on CHP is achieved by integrating electric boilers and heat pumps into the operational strategy. These cannot only maintain heat supply at situations with low spot prices but can also contribute to stability in the grid by offering negative balancing energy.

The operational strategy of such DH systems consisting of CHP, conventional peak load boilers, solar collectors and electric boilers or heat pumps is adopted to the electricity spot market: in situations with high power generation by fluctuating RES and consequently low spot prices electric boilers are switched on and CHP off respectively vice versa in situations with high spot prices. Solar heat can assist heat generation whenever alternative heat production is not profitable – and whenever meteorology allows to. Peak load boilers are operated when neither CHP nor electric devices can be operated profitably or when the heat demand cannot be met entirely by the other generators (see Figure 1). Such economically optimized, “smart” DH systems can already be observed in Denmark toady where high wind power generation called for an alignment of CHP power production with the power market.

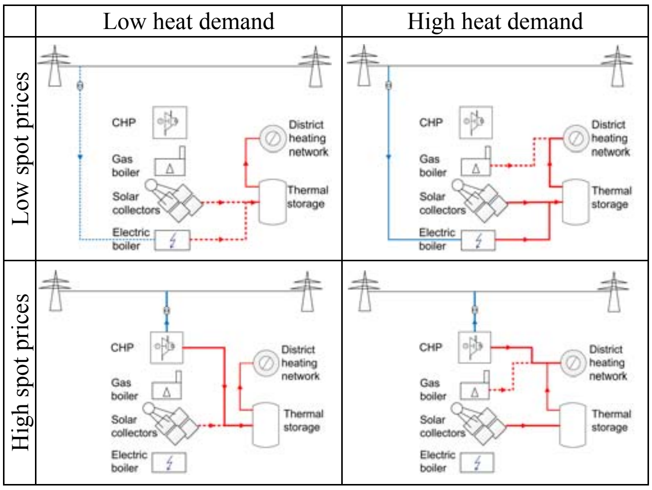

Figure 1: Operation of heat producers at different states of spot prices and heat demand

Several qualitative analyses of the influence of RES in the power market on solar DH exist, i.a. [Dalenbäck 2010, Nast and Sperber 2012, Schulz and Brandstätt 2013, Nielsen 2014]. Quantitative economic investigations are not known by the author. This work therefore aims at quantitatively analyzing the impact of increasing power generation by RES on the profitability of solar DH. Thereby, the technical and economic performance of flexible CHP systems combined with solar is assessed. The examination is based on a comparison of heat costs in DH systems consisting of different configurations of heat producers (CHP and peak load boiler with/ without solar feed-in and with/ without electric boiler).

2. SIMULATION METHODOLOGY

2.1 Configurations considered

The interaction of different heat producers in power controlled, CHP-based DH systems is simulated with a dynamic simulation tool (TRNSYS 17) and evaluated from an economic point of view (compare [Sperber and Viebahn 2013]). The focus is on investigating the impact of volatile spot prices on the profitability of solar DH.

Four alternative (fictional) DH configurations are modelled:

1. **Reference**
   Consisting of a heat controlled CHP and a peak load gas boiler
2. **Flexible CHP**
   Consisting of a power controlled CHP, heat storage and a peak load gas boiler
3. **Flexible CHP + Solar**
   Consisting of a power controlled CHP, heat storage, a solar collector and a peak load gas boiler
4. **Flexible CHP + Solar + Power to heat (P2H)**
   Consisting of a power controlled CHP, heat storage, a solar collector, an electric boiler integrated into the heat storage and a peak load gas boiler

2.2 Technical figures

The technical characteristics of the components used in configurations 1-4 are given in Table 1.

Table 1: Characteristics of the considered DH system

DH network	Heat demand: 12,700 MWh/a Peak load: 5 MW_{th}, Nominal DH temperatures: 95/60°C
CHP	El. capacity: 1.4 MW_{el}, th. capacity: 1.5 MW_{th} Total efficiency: 85 %
Gas boiler	Th. capacity: 5 MW_{th} Efficiency: 88 %
Electric boiler	Th. capacity: 1 MW Efficiency: 100 %
Solar collector field (flat plate)	Collector area: 4,000 m² η_0=0.82, α_1=2.43W/(m²K), α_2=0.012W/(m²K²) Tilt: 40°, azimuth: 0° Flow rate: 15 l/(m²h)
Thermal storage tank	Storage volume: 1,500 m³ (i.e. 12 h peak load)

This layout reflects a typical CHP-system in a small district heating network with the addition of a moderate extra heat storage providing the necessary flexibility for the power controlled operation and a moderate sized collector field that is capable to provide about 15% of the total heat demand.

The principal setup of the solar assisted DH system including an electric boiler (configuration No. 4) is shown in Figure 2.

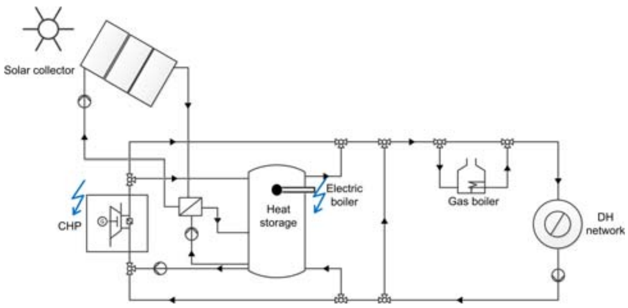

Figure 2: Principal setup of configuration No. 4

2.3 Spot price modelling

Two different scenarios related to the RES share in power generation are assumed in the dynamic simulation. In the base scenario a RES share of 40% in power generation is underlying. In Germany this is expected to be the case by 2020. Therefore spot price time series for the year 2020 are modeled in order to quantify the economic situation of CHP and solar DH at share of 40%

RES in the power market. A higher share of RES in power generation will be considered in a sensitivity analysis (see Chapter 4).

The simulation of the spot price time series for 2020 is performed as follows: A positive correlation between the residual load[1] in Germany and the spot market prices at the European power exchange EPEX was established from German electricity data for the year 2012 (data source for power generation by RES and spot prices in 2012: [Bach 2013], for power consumption: [ENTSO-E 2013]). This correlation is apparent from Figure 3. The correlation coefficients have been used to generate synthetic spot prices from an estimate of residual load time series in 2020.

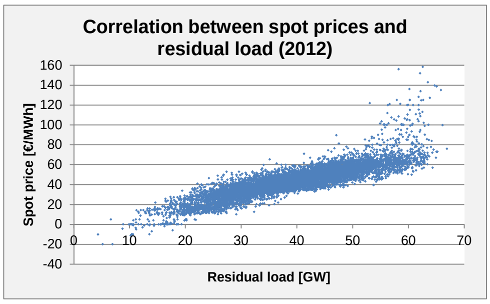

Figure 3: Correlation between spot prices and residual load

This residual load time series for 2020, in turn, is based on 2012 normalized feed-in time series of RES. For the base scenario those normalized time series are scaled by the estimated capacity of RES plants in the German power system in 2020 according to the "long term scenarios" of the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety ("BMU Leitstudie 2011", [Nitsch et al. 2012]). 2012 values are given by way of comparison (data source: [BMWI 2013]) in Table 2.

Table 2: Installed capacities of RES in 2012 and 2020 (base scenario)

P_{el} [MW]	Technology	2012	2020
Intermittent	Photovoltaic	32,640	53,500
	Wind	31,315	49,000
(Partially) adjustable	Biomass	7,410	8,960
	Hydro	5,600	4,700
	Geothermal	12	300

Taking into account 2012 meteorological conditions, the given installed capacities result in a share of RES power generation of 40%. Under these circumstances, there will be phases in which power generation by RES exceeds total power demand. 83 hours with negative residual load are simulated by the model. In contrast to today's market design, negative spot market prices are not allowed in this scenario. The model assumes that negative residual loads result in a spot price of 0. The time series of the synthetic spot market prices is given in Figure 4. The synthetic spot prices range between 0 and 100 €/MWh$_{el}$. The annual mean spot price is 36.4 €/MWh$_{el}$ (compared to 42.6 €/MWh$_{el}$ in 2012).

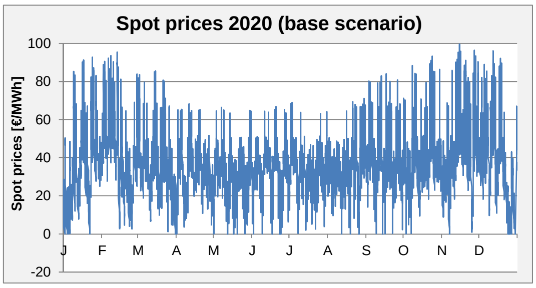

Figure 4: Synthetic spot prices in 2020

2.4 Meteorological data

The dynamic simulations are based on meteorological data of Würzburg (southern Germany) for the year 2012. Temperature affects both heat demand (load profile for DH network) and the output of the solar collectors. The annual global horizontal radiation in Würzburg is 1,215 kWh/m² in 2012 (maximum radiation: 971 W/m²). The time series of temperature and global horizontal radiation for Würzburg in 2012 are given in Figure 5.

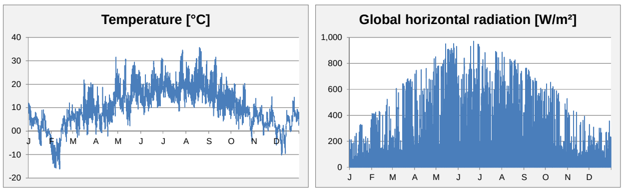

Figure 5: Temperature (left) and global horizontal radiation (right) in Würzburg, 2012

2.5 Economic framework conditions

To investigate the economics of the simulated configurations, legal and economic framework conditions for Germany are taken into account: According to German CHP-law, operators of CHP plants receive a premium for the power produced in CHP. Moreover, heat controlled CHP obtain a price for each kWh of power produced. This price typically corresponds to the average price of base load power at the power exchange and is called "CHP Index". By contrast, power controlled CHP sell the electricity at the power exchange and receive the actual spot market price at the time of production. In addition, since CHP power is generated decentralized, avoided network usage charges are refunded (regardless of whether the CHP is heat or power controlled). Another condition is related to taxes on natural gas which can generally be refunded to operators of highly efficient CHP (if $P_{el} < 2$ MW).

When purchasing power from the power exchange – as required for P2H[2] – several fees and taxes are levied in Germany. Currently those fees and taxes amount to more than 100 €/MWh$_{el}$. Since P2H is expected to be

[1] The residual load is defined as the total power demand less the power generated by RES.

[2] In this analysis P2H means operating the electric boiler oriented at spot prices. The simulations do not encounter revenues that could be obtained at the Electricity Balancing Market with P2H.

understood as purpose for stabilizing the grid, it is assumed here that this "P2H power charge" will be reduced to 45 €/MWh_{el} by 2020.

The main financial conditions for the calculation are summarized in Table 3. Regarding natural gas taxes, avoided network usage charges and CHP-premiums it is assumed that they remain unchanged until 2020.

Table 3: Main financial conditions underlying the analysis

Financial constraints			
Interest rate	4%		
Lifetime	20 a		
Natural gas price	40 €/MWh_{Hi} (base) 55 €/MWh_{Hi} (sensitivity)		
Natural gas tax	5.5 €/MWh_{Hs} (CHP is exempted)		
Avoided network usage charge	5 €/MWh_{el}		
CHP premium	27.5 €/MWh_{el}		
CHP Index	29 €/MWh_{el} [3]		
P2H power charge	45 €/MWh_{el}		
	Spec. CAPEX	**Fixed O&M**	**Variable O&M**
CHP	850 €/kW_{el}	2%/a	12 €/MWh_{el}
Gas boiler	75 €/kW_{th}	2%/a	0.13 €/MWh_{th}
Solar collector	200 €/m²	-	1 €/MWh_{th}
Electric boiler	100 €/kW_{el}	-	-
Thermal storage	500 €/m³	0.7%/a	-

In order to reflect the effect of natural gas prices, a sensitivity analysis based on a higher gas price of 55 €/MWh_{Hi} is carried out ceteris paribus[4].

2.6 Criteria of profitability

As evaluation criterion for the economic efficiency, both levelized cost of heat (LCOH) as well as levelized marginal costs (LMC) of different DH configurations are calculated and compared. LCOH of a DH configuration take into account the sum of full costs of each component in a DH configuration, including capital expenditures (CAPEX) as well as operational expenditures (OPEX), divided by the sum of the annual heat production from each component, see Eq. (1).

$$LCOH_{conf.m} = \frac{\sum_{component\ i}^{n} annual\ full\ cost_i}{\sum_{component\ i}^{n} annual\ heat\ generation_i} \quad \textbf{Equation 1}$$

LCOH are a key criterion for investment decisions since they are necessary for cost coverage in a long-term perspective. In contrast, LMC do not consider investment but only operating costs (variable O&M and fuel cost). Hence, LMC are an appropriate indicator of profitability when investments have already been transacted.

For the gas boiler, the solar collector and the electric boiler, levelized CAPEX as well as O&M and – if applicable – fuel costs according to Table 3 apply. The costs of the power purchase from the spot market must additionally be taken into account in the case of the electric boiler.

In order to determine net heat costs of CHP all revenues resulting from the sale of electricity – including revenues from the power exchange or the CHP Index respectively, CHP premiums and avoided network usage charge – must be considered additionally. Since the heat storage is necessary for the flexible operation of the CHP the costs of the heat storage are integrated into the costs of the CHP. Table 4 summarizes the composition of net LCOH for CHP.

Table 4: Composition of LCOH for CHP

Components of (net) LCOH for CHP
+ CAPEX (levelized) for CHP and storage
+ Fuel cost
+ Fixed O&M cost for CHP and storage
+ Variable O&M cost
– Revenues for electricity (Index or spot price)
– CHP premium
– Avoided network usage charge

Correspondingly LMC for CHP are net meaning that revenues from electricity are subtracted. LMC for CHP consist of the components as depicted in Table 5.

Table 5: Composition of LMC for CHP

Components of (net) LCOH for CHP
+ Fuel cost
+ Variable O&M cost
– Revenues for electricity (Index or spot price)
– CHP premium
– Avoided network usage charge

The calculations make use of the annuity approach and do not comprise project-specific cash flow considerations. The financial figures represent real, i.e. inflation adjusted, values. The cost of the DH network is not relevant for the economic comparison of the four alternative DH configurations and is therefore not taken into account.

2.7 Operational strategy

The operation of heat producers in the reference case (configuration No. 1) is irrespective of the signals of the power market. Here, CHP is used for base load heat production, while the gas boiler is used for reheating especially in the heating period. For the configurations that are based on the price signals provided by the power exchange (configurations No. 2-4) the operation of individual heat producers is as follows: Regardless of the solar output, CHP is operated only if the spot market prices result in LMC for CHP heat which are lower than the corresponding LMC for heat from the gas boiler. Otherwise, the heat demand will be supplied by the gas boiler. With respect to the financial constraints given in Table 3, this threshold equals 20.5 €/MWh_{el}, given a gas

[3] Derived from 2020 spot price time series

[4] Such a high gas price does not necessarily have to be due to higher commodity prices. Instead, either taxation can raise fuel costs to those levels (as it is already the case in Denmark) or it can be assumed that CO_2 costs will be internalized in fuel costs.

price of 40 €/MWh (respectively at 38.8 €/MWh$_{el}$, given a gas price of 55 €/MWh).

Irrespective of the signals of the power market, the CHP can produce only as long as either heat is demanded in the DH network or – provided that heat demand in the DH network is low – the heat storage has free capacity. In the latter case, an intelligent storage management ensures that the CHP plant is in operation only in the hours with the highest spot prices in order to avoid, for example, that the storage is already fully charged when spot prices are only beginning to rise. It is therefore presumed in the simulations that the plant operator can forecast spot prices, the course of heat demand and solar radiation for the subsequent 24 hours.

The CHP system competes for storage capacity with the solar collectors. Given the economic parameters from Table 3, the solar thermal system has priority because of its lower marginal costs up to a spot price of 77.8 €/MWh$_{el}$ (115.0 €/MWh$_{el}$)[5]. Only above this threshold CHP operation is more profitable due to high achievable spot prices. The gas boiler is the cheapest heat producer in the absence of solar output and spot prices below 20.5 €/MWh$_{el}$ (38.8 €/MWh$_{el}$). Furthermore it is generally used for reheating provided that neither CHP nor solar system can deliver the required flow temperature.

Heating configuration no. 4 makes use of an electric heater (P2H). P2H can only compete against the gas boiler below spot prices of 7.5 €/MWh$_{el}$ (24.6 €/MWh$_{el}$). Due to the power charge (Table 3) and resulting higher LMC compared to the solar LMC it is subordinated to the solar system with regard to the operation sequence.

3. SIMULATION RESULTS

3.1 *Cost-optimized operation of heat producers*

TRNSYS simulations were carried out for the four alternative DH configurations. For each DH configuration the operational regime is cost-optimized according to the operational strategy explained in section 2.7. This effects that total LMC are minimized. Figure 6 shows the results of the simulations for all four alternative DH configurations as annual shares of each heat generation component (CHP, gas boiler, solar thermal, P2H) in total heat production. The shaded bars show results for the sensitivity test (higher gas price of 55 €/MWh). In the calculated shares, storage losses are subtracted from solar and CHP production.

In the reference case that is irrespective of spot prices CHP amounts to about three quarters of the heat production. It is reduced to about 65% in the case of flexible CHP given a **gas price of 40 €/MWh**. This reduction is explained by the fact that CHP is only operated at times with profitable spot prices, leaving heat production to the gas boiler at times with low spot prices. The integration of a solar collector (configuration No. 3), which contributes to approximately 15% to the total heat demand, results in a reduction of heat production from the gas boiler by 17% compared to configuration No. 2 (the share of the gas boiler then amounts to 30%). The economically optimized operation of the heat producers also has the result that CHP heat is replaced by solar heat. However, the solar collectors replace relatively less CHP heat than heat generated from gas boilers. P2H is the cheapest heat producer in only few hours per year resulting in an annual share of 2% (configuration No. 4).

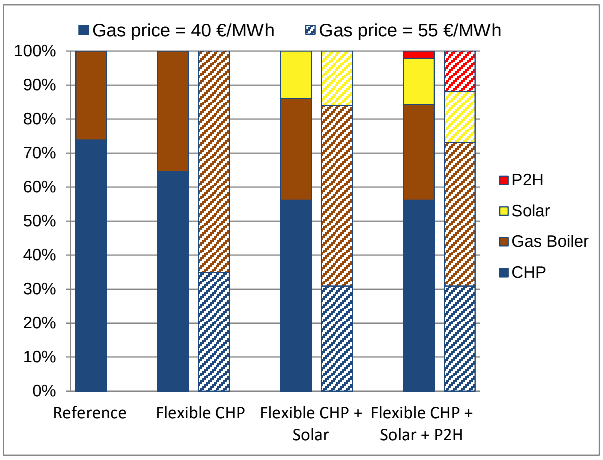

Figure 6: Annual shares of heat producers for the four DH configurations

Assuming a **gas price of 55 €/MWh**, higher spot prices must be realized by the CHP in order to compete against the gas boiler. Since the number of hours with sufficient spot prices for the CHP is quite limited in the 2020 scenario – and assuming that no further compensations for the CHP are given by legislature – the share of CHP drastically reduces for the sensitivity test with a higher gas price. Here, solar thermal as well as P2H (configurations 3 and 4) can displace even more heat from the gas boiler: The share of the gas boiler is reduced by up to 36% compared to configuration No. 2.

Table 6 shows the annual net solar output (collector output less storage and solar pipe losses).

Table 6: Annual net solar output

	Conf. No. 3	Conf. No. 4
Gas price = 40 €/MWh	435 kWh/(m²a)	424 kWh/(m²a)
Gas price = 55 €/MWh	458 kWh/(m²a)	442 kWh/(m²a)

Figure 7 schematically highlights the economically optimized operation of the different heat production components depending on spot prices as well as the corresponding course of the heat storage content in an autumn week in 2020 (configuration No. 4, gas price = 40 €/MWh).

[5] Thresholds in brackets refer to the higher gas price of 55 €/MWh.

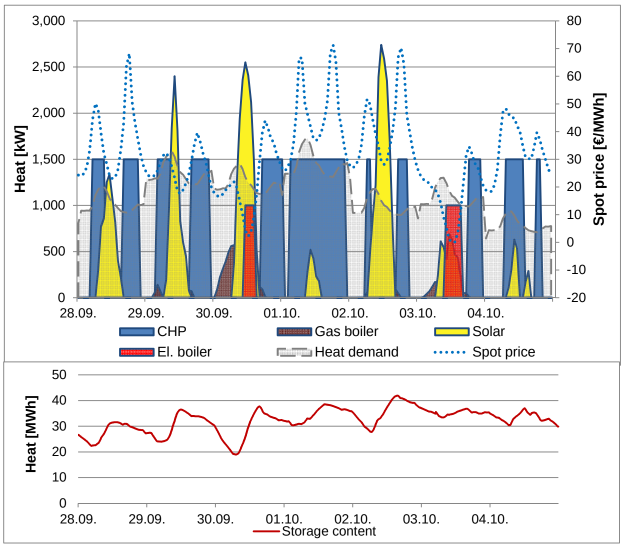

Figure 7: Operation of heat producers in an autumn week 2020 (configuration No. 4)

Figure 8 shows the monthly heat production of the different heat production components at a gas price of 40 €/MWh as well as the monthly solar fraction (configuration No. 4).

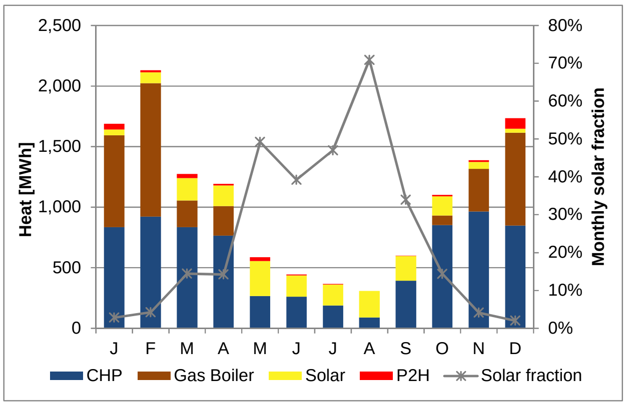

Figure 8: Monthly heat production and solar fraction (configuration No. 4)

3.2 Economic comparison

LMC and LCOH were calculated based on TRNSYS simulation results. They are illustrated for both gas price scenarios in Figure 9 and Figure 10.

As can be seen from Figure 9, LMC are notably lower for the flexible CHP configurations. This can be explained by the fact that the power controlled CHP on average realizes higher revenues (on average 45 €/MWh$_{el}$ (56 €/MWh$_{el}$)[6] compared to the reference case where the CHP Index is comparably low. LMC are especially lower for the solar assisted DH configurations – about -15% (-17%) compared to configuration No. 2 – since expensive heat generated by gas boilers can be replaced by inexpensive solar heat.

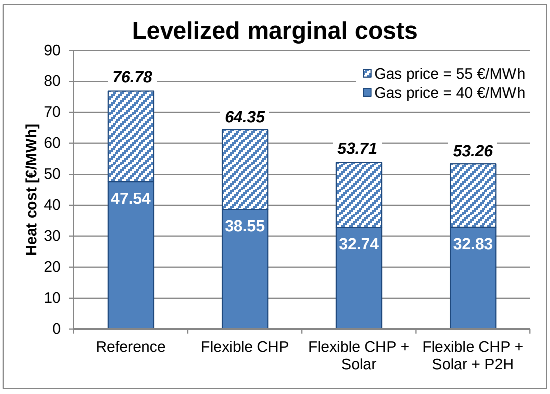

Figure 9: LMC for the different DH configurations

Figure 9 also reveals that higher gas prices have a determining effect on LMC. This adversely affects the configurations without solar (No. 1 and No. 2) more than those with solar (No. 3 and No. 4).

Additional revenues could be achieved by providing balancing power with CHP and P2H. However, the Electricity Balancing Market is not taken into consideration in this analysis.

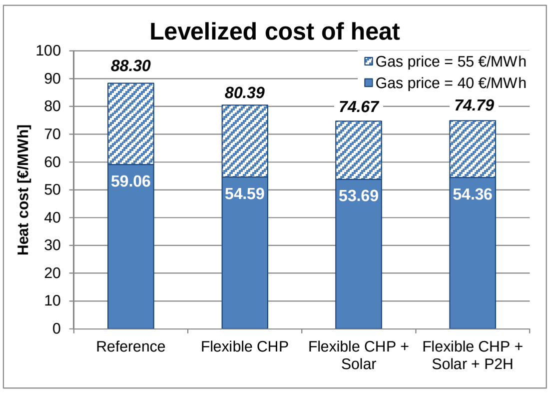

Figure 10: LCOH for the different DH configurations

Figure 10 reveals that – when LCOH are chosen as criterion for economic efficiency – flexible CHP is profitable despite lower shares in total heat production (compare with Figure 6) and especially despite the necessary investment in large heat storages compared to the reference case. The main finding is that even when incorporating investment for solar collectors, LCOH of configurations without solar assistance can be undercut. The reductions of LCOH for configurations with solar support compared to configurations without notably increase with higher gas prices. Generally it can be said that even in a full cost perspective there is no economic disadvantage resulting from investments in a solar heating system and additionally in an electric boiler. Therefore DH systems should be equipped with additional heat producers in order to provide more flexibility with regard to the power market.

[6] Figures in brackets are related to the higher gas price of 55 €/MWh.

4. SENSITIVY ANALYSIS FOR HIGHER SHARES OF PV IN THE POWER MARKET

The immense cost reductions of PV modules throughout the last years could lead to higher penetration levels of PV in our power system. Some researchers even expect PV to amount to more than 100 GW in Germany in the near future [Quaschning 2012, Henning and Palzer 2012]. A sensitivity analysis therefore investigates the profitability of solar thermal DH in a power system with 100 GW of PV systems installed. The installed capacities of the other RES power technologies thereby remain unchanged (compare Table 7 to Table 2).

Table 7: Installed capacities of RES for the PV scenario

P_{el} [MW]	Technology	2020[7]
Intermittent	Photovoltaic	100,000
	Wind	49,000
(Partially) adjustable	Biomass	8,960
	Hydro	4,700
	Geothermal	300

The higher share of intermittent PV will trigger lower and more volatile spot prices. As a consequence of the installed capacities as stated in Table 7 and the meteorological conditions in 2012, RES will amount to approximately half of the total power demand in this scenario. According to the method described in section 2.3 the resulting spot prices can be expected as depicted in Figure 11.

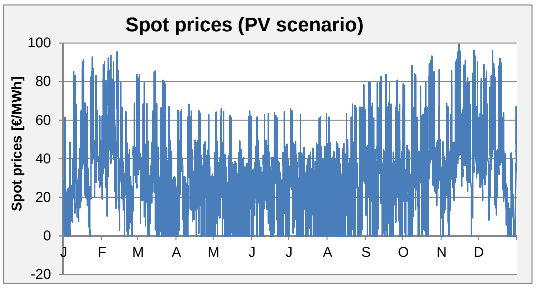

Figure 11: Synthetic spot prices for the PV scenario

The average spot price amounts to 31.6 €/MWh. Particularly summer spot prices are noticeably lower compared to a scenario with 54 GW PV.

Due to higher fluctuations, a larger heat storage is required in order to cover heat demand in the periods when CHP power is not feasible. Also larger solar collectors are reasonable in order to keep up heat production especially in summer with low residual load in the power market and low CHP power (and heat) production. Consequently this sensitivity analysis investigates the costs of the different alternative DH configurations, incorporating a 10,000 m² solar collector field as well as a 3,000 m³ heat storage (compared to 4.000 m²/1.500 m³ in the base case). The specific CAPEX of the larger heat storage in the PV scenario is assumed to be 400 €/m³. Apart from that, the simulations are carried out considering the same financial constraints and the same technical scheme as for the base simulations.

The results of the sensitivity analysis are illustrated in the figures below.

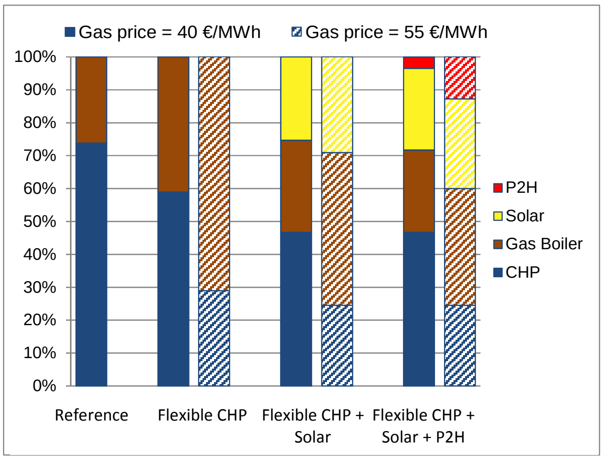

Figure 12: Annual shares of individual heat producers for the PV scenario

Compared to the base scenario, the share of CHP in the flexible configurations is reduced (compare Figure 12 to Figure 6). This is due to the fact that the number of hours with spot prices that are profitable for CHP decreases in the PV scenario. Due to larger solar collectors the solar fraction rises to about 25% (29%) in configuration No. 3. Here, the share of the gas boiler decreases from 41% (71%) to 28% (46%) compared to configuration No. 2. P2H can supply 3% (13%) of the heat demand (configuration No. 4). Given a gas price of 55 €/MWh, more than half of the heat produced by the gas boiler can be displaced by solar and P2H .

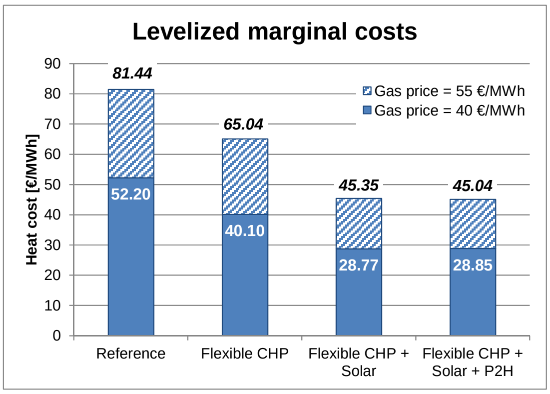

Figure 13: LMC for the PV scenario

The advantage of low cost solar heat increases in the PV scenario (compare Figure 9 to Figure 13): in DH configurations without solar assistance LMC rise because of decreasing spot prices and higher fractions of (expensive) heat from gas boilers. Solar heat can reverse this unfavorable economic situation and decrease LMC by about 28% (30%) compared to the configuration without solar (No. 2).

[7] Whether 100 GW PV will be realized in 2020 or later is not relevant for the simulations.

When taking CAPEX and fixed costs into account, solar DH is slightly disadvantageous compared to configuration No. 2 when assuming a gas price of 40 €/MWh (see Figure 14). However, the sensitivity test reveals that higher gas prices make configurations No. 3 and 4 more economically attractive: LCOH of DH systems including solar are less sensitive to increasing gas prices than DH systems without.

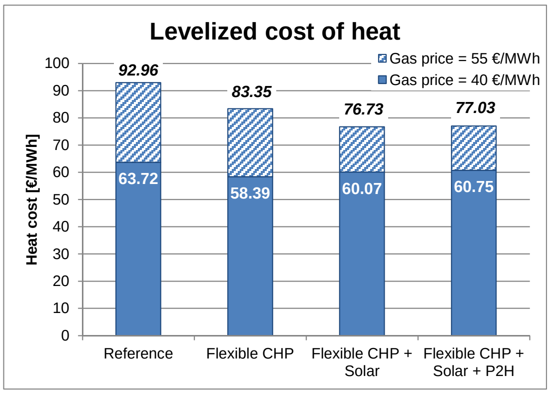

Figure 14: LCOH for the PV scenario

5. CONCLUSION

In a power system dominated by wind and PV, CHP systems should be flexibilized in order to balance the fluctuations of power generation and thus the volatile spot prices caused by intermittent RES. By means of TRNSYS simulations it has been shown that in smart DH systems solar collectors (and electric heaters) can displace environmentally harmful and expensive heat from peak boilers based on fossil fuels. Higher gas prices increase this effect. Electric heaters that are operated at very low spot prices have both low investment and operating costs and therefore prove as feasible equipment in smart DH systems. Solar collectors (and additionally P2H) do not only reduce operating costs of DH systems, but are even economically attractive on a full cost base. A higher penetration of PV in the power system as well as increasing gas prices can facilitate this development. Thus RES in the power sector make room for renewable energies in the heat sector.

As long as RES have been insignificant in the power market, CHP and solar competed to supply the heat demand during summer. This study has shown that in future CHP and solar do not exclude each other. Especially the fact that summer PV power generation – which triggers low spot prices and thus makes CHP operation unprofitable – and solar thermal heat production are synchronal makes solar DH complementary to CHP.

In the course of depleting fossil resources and climate change, solar DH, combined with seasonal heat storages, can be a key factor for the decarbonization of the heat sector. Thus it is even more important to pave the way for solar DH by integrating solar into existing DH systems.

REFERENCES

Bach, P.F. (2013) [Online] http://pfbach.dk/ Last access on 20 September 2013

BMWI (2013) [Online] http://bmwi.de/DE/Themen/Energie/Energiedaten-und-analysen/energiedaten.html Last access on 20 September 2013

Dalenbäck, J.-O. (2010) Success Factors in Solar District Heating. WP2 - Micro Analyses Report. Deliverable D2.1. Gothenburg.

ENTSO-E (2013) [Online] https://www.entsoe.eu/data/data-portal/consumption/ Last access on 20 September 2013

Henning, H.M. and Palzer, A. (2012) 100 % Erneuerbare Energien für Strom und Wärme in Deutschland. Freiburg.

Nast, M. and Sperber, E. (2012) Entwicklungen beim Wärmenetzausbau und -betrieb. *Proceedings of VDI Fachkonferenz: Thermische Energiespeicher in der Energieversorgung*, 23-22 October 2012, Ludwigsburg, Germany

Nielsen (2014) Solar District Heating. Experiences from Denmark. *Energy Platform Workshop 3*, 13 February 2014, Zurich, Switzerland

Nitsch, J. et al. (2012) Langfristszenarien und Strategien für den Ausbau der erneuerbaren Energien in Deutschland bei Berücksichtigung der Entwicklung in Europa und global. Schlussbericht von DLR, IWES und IFNE für das BMU. Stuttgart.

Quaschning, V. (2012) Einsatzmöglichkeiten und Potentiale der Photovoltaik in Deutschland ohne erhöhte EEG-Vergütung. *Proceedings of 27. Symposium Photovoltaische Solarenergie*, 29 February - 02 March 2012, Bad Staffelstein, Germany.

Schulz, W. and Brandstätt, C. (2013) Flexibilitätsreserven auf dem Wärmemarkt. Bremen.

Sperber, E. and Viebahn, P. (2013) Techno-ökonomische Perspektive – Systeminnovationen am Beispiel des Strom-Wärme-Systems. *Proceedings of FVEE Jahrestagung*, 24-25 October 2013, Freiburg, Germany, pp 23-28