Energy 189 (2019) 116367

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

The marginal-cost pricing for a competitive wholesale district heating market: A case study in the Netherlands

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ARTICLE INFO

Article history:
Received 25 March 2019
Received in revised form
16 September 2019
Accepted 15 October 2019
Available online 18 October 2019

Keywords:
District heating
Marginal-cost pricing
Wholesale market
The Netherlands

ABSTRACT

District heating represents a viable way to reduce carbon dioxide emissions in the built environment. This paper aims to assess the extent to which the market revenues of multiple heat production technologies can cover their fixed costs in a competitive wholesale district heating market. Marginal-cost pricing is applied in a case study of the Netherlands. A linear programming model incorporating heat supply and demand is developed to obtain hourly dispatch and heat market prices. It is concluded that low carbon heat generation technologies tend to have low short-run marginal costs. All examined heat producers have an under-recovery of fixed costs in a range between 60% and 90% except the waste incineration combined heat and power plant. It has an overall return on investment of 44% and 12% within the reference and heat pump scenario respectively. Although marginal-cost pricing may ensure cost-efficient dispatch, the market revenues are far from enough to recoup the investment costs for the majority of the heat producer, let alone the network costs. Significant additional remuneration is required to sustain a competitive heat market and ensure sufficient investment in new generation capacity in the long run.

1. Introduction

The production of heat accounts for more than 50% of total final energy consumption worldwide [1]. In countries with cold climates, the built environment represents a large share of heat demand. For example in the Netherlands, about 70% of the energy consumed in the built environment is used for heating purposes, with the built environment accounting for one-third of final energy consumption [2]. Given the substantial share of energy used for heating purposes, the built environment has a relatively large potential for reducing carbon dioxide (CO_2) emissions. Consequently, the Dutch government aims to reduce carbon-dioxide emissions by 95% in 2050, compared to 1990 levels [1,3].

As one of the strategies to achieve a sustainable heat transition, district heating (DH) systems have several economic and environmental advantages compared to on-site heat production at the household level, e.g. with a natural gas-fired condensing boiler or small-scale heat pump (HP), as DH allows for (1) the inclusion of large-scale Combined Heat and Power (CHP) production, (2) the utilization of residual industrial heat and, (3) the introduction of Renewable Energy Sources (RES) such as large-scale geothermal, solar thermal and biomass for heat supply [4–7]. Moreover, by replacing small-scale residential boilers with large-scale centralized heat generation plants equipped with emission control technologies, emissions of airborne pollutants such as oxides of nitrogen (NO_x) can be reduced [8], as large installations generally must adhere to stricter environmental regulation and emissions standards [9].

DH systems have a limited geographic scope, as in general the systems are only economical in typically densely populated areas with a high density of heat demand. This density is crucial as the costs of the infrastructure and the energy losses during transport must be offset by the efficiency gains from producing the heat at large scale [10,11]. Furthermore, the production and distribution of heat are closely interlinked by the inlet and return temperature of the DH system [12]. As a result, the need for coordination between heat production and distribution is relatively high, and it is, therefore, a logical choice that many DH systems have traditionally

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https://doi.org/10.1016/j.energy.2019.116367
0360-5442/

Abbreviation

CAPEX	Capital expenditure
CCGT	Combined cycle gas turbine
CHP	Combined heat and power
CF	Capacity factor
CO_2	Carbon dioxide
COP	Coefficient of performance
DH	District heating
ED	Economic dispatch
FOR	Feasible operating region
HP	Heat pump
HOB	Heat-only boiler
LP	Linear programming
MCP	Marginal cost pricing
MIP	Mixed integer programing
NO_2	Nitrogen dioxide
NH_3	Ammonia
OCGT	Open cycle gas turbine
OPEX	Operational cost
P2H	Power to heat
PDC	Price duration curve
RES	Renewable energy sources
SRMC	Short-run marginal cost
UC	Unit commitment
VO&M	Variable operation and Maintenance
WACC	Weighted average cost of capital

been owned and operated by a single utility. To overcome these natural monopoly positions of the heat distribution systems, the price of heat is often subject to regulation [13]. For example, the end-user price for DH in the Netherlands is regulated so that it cannot be more expensive than the cost of the most prominent alternative residential heat source which is a condensing gas boiler.

As opposed to price regulation, open markets, and specifically competition, often lead to an economically efficient allocation of resources. Therefore, increasing market competition in the production of heat in DH systems has received attention from policymakers, companies, and academia [12,14–17]. In liberalized DH markets, such as those operating in Sweden and Finland, the consumer prices for heat production commonly consist of an energy component, which includes the variable cost of heat production; and a capacity component, which includes other fixed costs associated with the production of heat [9,18,19]. The price of the energy component is an outcome of a competitive bidding process in which producers made bids to supply their heat, typically based on their marginal cost. Some previous works applied marginal-cost pricing (MCP) in a single utility to optimize its generation costs. For example, the effect of having thermal storage on the marginal cost of a DH system was assessed in Ref. [20]. It was found that even though the total system costs are reduced, the inclusion of thermal storage in the DH system can lead to a period of higher marginal costs. The marginal cost of a single DH utility in the city Linköping in Sweden was analyzed. The utility running on multiple fuels was modeled to achieve portfolio optimization [18]. In a case study of Espoo in Finland, CHP plants were dispatched based on a linear optimization incorporating with MCP [19]. However, it is not assessed whether the generated income is sufficient to recover investment costs. A recent study investigated the potential effect of applying MCP on two DH systems in Denmark and Finland [21]. The total CO_2 emissions, total turnover of the DH systems and weighted average marginal heat prices were calculated. The results indicated that the use of waste heat decreased both total heat production costs and CO_2 emissions. The addition of low marginal cost heat production decreased marginal prices close to zero during the summertime. However, the recovery of fixed costs was also not examined.

Based on the discussion above, there is a limit understanding of the efficacy of MCP for the DH system and the degree to which the market revenues contribute to the generator income. To partly fill these knowledge gaps, this study aims to assess the extent to which market revenues from a competitive wholesale DH market, based on MCP, are sufficient to cover the fixed costs of multiple producers in an open DH system market. It specifically focuses on the energy components of the DH price and provides insight into the performance of different heat production technologies and competitiveness relative to each other. The Dutch “Warmterotonde” project (or “Heat Roundabout” in English), which aims to develop a large-scale DH system in the province of Zuid-Holland in the Netherlands, is used as a case study.

This paper is structured into six parts: the introduction (1); a description of the DH system in the case area (2); research methods including heat demand and heat supply scenarios, techno-economic inputs, model application and sensitivity analysis (3); results and their interpretation (4); discussion on the results, contributions and research limitations (5) and conclusion (6).

1.1. Case study description: district heating in Zuid-Holland

The objective of the Warmterotonde project is to construct a large-scale DH system in the province of Zuid-Holland. In this DH system, the industrial cluster in the harbor of Rotterdam will supply residual heat to the horticulture sector, and the residential DH systems in the cities of Rotterdam, Den Haag, Leiden and the smaller municipalities of Delft, Rijswijk, Schiedam, and Vlaardingen (see Fig. 1).

The utilization of residual heat from the industrial processes in the Rotterdam harbor, including an oil refinery and chemical plants, has been investigated in several studies [22–24]. In addition, a large amount of electricity generation capacity has been installed in the Rotterdam harbor, including two ultra-supercritical coal-fired power plants which could be converted to CHP plants and deliver heat to the grids. In Den Haag, Leiden and Rotterdam, existing DH systems are in place in the residential areas. Heat is supplied by natural-gas-fired CHP plants, heat-only boilers (HOBs) and a waste incineration CHP plant. According to the Warmterotonde plan, the existing DH systems are expected to be geographically expanded, and the number of households connected will increase. In addition to the residential areas, the province of Zuid-Holland also has a large horticultural sector. Greenhouses, which enable the cultivation of crops outside their normal growing seasons, are very energy-intensive, as they require heating and often additional illumination to enhance plant growth. To provide this heat, many companies operate a small-scale natural-gas-fired CHP plant with capacities ranging from 1 to 5 MWe, or a natural-gas-fired HOB. Thus, there is both heat and electricity production capacity present in these areas. The case of the Warmterotonde DH system in Zuid-Holland is special as it connects a number of large consumers with multiple heat generators, operated by different parties. With such a large number of potential buyers and sellers, it presents an excellent opportunity to introduce a competitive heat market.

Fig. 1. An overview of predominantly residential (orange) and horticultural (green) areas within the geographical scope of this study. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

2. Method

The research method consists of five steps. First, hourly heat demand profiles are collected for residential and agricultural consumers. Second, three different heat production portfolio scenarios are developed with different generation technologies having varying ratios of capital expenditure (CAPEX) to operational expenditure (OPEX) requirements, as well as operational flexibilities. Thirdly, techno-economic parameters for the different technologies considered are collected. Fourthly, a market model is used to determine the dispatch of thermal generators for each scenario to obtain the hourly heat market price formation, accounting for hourly varying electricity and fuel prices. Finally, based on these results, an analysis of the thermal generator revenues and costs is made. As the Warmterotonde DH system in Zuid-Holland is planned for commissioning sometime in 2020, this study model the DH system for the year 2020.

2.1. Heat demand

The annual residential and horticultural heat demand projections for 2020 are based on data from the publication of Cluster West project [25] and CE Delft respectively [26]. The total annual heat demand is estimated as 30 PJ consisting of 9.3 PJ of residential and 20.7 of horticultural heat demand. The individual and total combined heat load duration curves are shown in Fig. 2. The maximum system load amounts to 2608 MWth. A more detailed description of how thermal demand is estimated is provided in Appendix A.

The mix of heat generation technologies may influence the extent to which parties can recover their fixed costs under MCP. In particular, the ratio of CAPEX to OPEX is expected to be important in determining the heat market price. To explore these differences, a scenario approach is used to investigate the impact of different

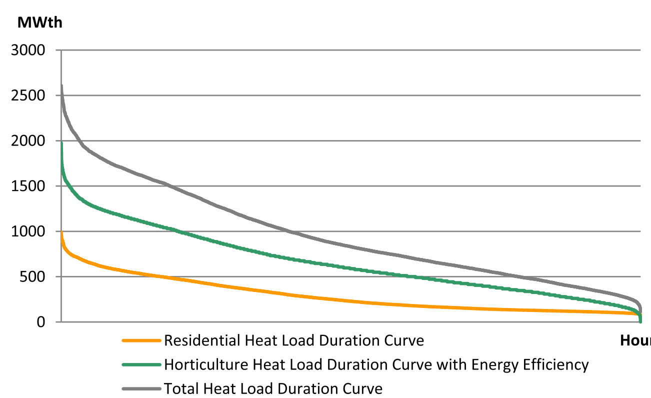

Fig. 2. Heat load duration curves for the DH system in 2020 [25,26].

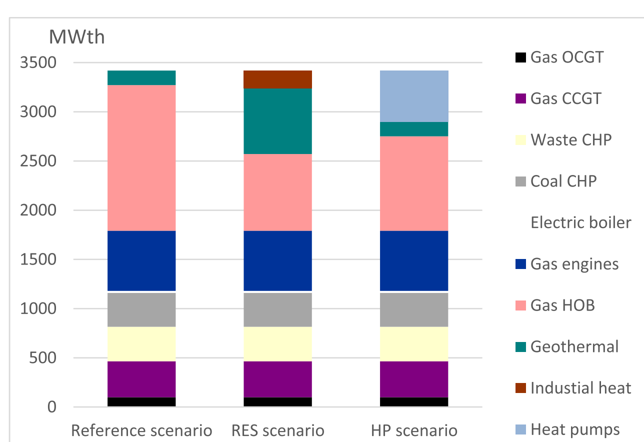

Fig. 3. Overview of the generation portfolio mix for the three scenarios in 2020.

Table 1
Key techno-economic parameters of generator types.

Type	Power-to-heat (P2H) ratio (CHP only)	Fuel	CAPEX (€/kW)	FO&M (%CAPEX/a)	Efficiency/COP(H/E)	Reference
HOB	–	Gas	110–160	2.5–3.3	85%–90% (thermal)	[25]
OCGT	Fixed	Gas	1200	3.3	[a]	[25]
CCGT	Fixed	Gas	1200–1700	2.5–3.3	[a]	[25]
Waste (incineration) CHP	Variable (FOR)	Waste	300	5	40% (electric)/30% (thermal)	[26]
Coal CHP	Variable (FOR)	Coal	300–400	5	[a]	[26]
Gas engine	Fixed	Gas	1500–2200	3.5	42%–46% (electric)/43%–45% (thermal)	[30,31]
Geothermal	–	Electricity	1500	3	COP: 20	[32,33]
Deep Geothermal	–	Electricity	2300	2	COP: 26.7	[32,33]
Industrial waste heat	–	–	500–600	2	–	[25,34]
Electric boiler	–	Electricity	600		100% (thermal)	[26]
Heat pump (CO_2)	–	Electricity	800	3.5	COP: 3.8–4.0	[28]
Heat pump (NH_3)	–	Electricity	500	2.5	COP: 3.5–4.5	[28]

[a] these data are confidential.

technology portfolios. Three scenarios of different heat generation mixes are developed: a *Reference scenario*, a high renewable energy source (*RES*) *scenario* and, an electricity-dominated heat pump *(HP) scenario*. The three portfolios are shown in Fig. 3.

The *Reference scenario* primarily consists of the existing conventional thermal generation capacity located in the study region [25]. In addition, two coal-fired CHP plants in the harbor of Rotterdam and a direct resistive electric boiler and a HOB in Den Haag are included. These plants are expected to be connected to the DH grid by 2020. In the *RES scenario,* more capacity from RES, mainly geothermal [27], and waste heat from the industry sector are included compared to the Reference scenario [22]. The *HP scenario* includes a similar generator of the residential DH as in the Reference scenario. A substantial share of heat pumps is adopted in the horticulture sector [28].

These scenarios encompass the installed DH generators in 2015, as well as some of the foreseen additions up to 2020 depending on the scenario. As a result, only 25% of the portfolio capacity varies between scenarios. The total installed capacity is 3400 MWth and set in such a way that each scenario has a conservative 30% overcapacity based on the existing DH system to guarantee sufficient heat production.

2.2. Techno-economic inputs

2.2.1. Annualized CAPEX of the heat generator types

The fixed costs of heat production include the CAPEX and Fixed Operation and Maintenance (FO&M) costs. The cost of physical DH infrastructure is not included in this study. In order to compare the annual revenues with the initial investment, the CAPEX is annualized according to Equation (1) [29]. The economic lifetime for most of the heat generators has been set at 20 years. Only for gas engines and OCGTs, the lifetime is assumed to be 15 years. For the Weighted Average Cost of Capital (WACC), a value of 8% was assumed [26]. Table 1 provides an overview of the techno-economic parameters of the generator types. Appendix B provides a comprehensive overview of the generation mix for three scenarios and the techno-economic parameters.

$$Annualized\ CAPEX = \frac{I*r}{\left(1-\left(\frac{1}{1+r}\right)^{L}\right)} \quad (1)$$

Where:

I= The initial investment (€)
r = The Weighted Average Cost of Capital (%)
L = The economic life of the generator (y)

For the CHP plants, it is important to differentiate between the CAPEX of the incremental investment costs for the heat extraction equipment or the CAPEX of the entire plant. If the main product of the CHP plant is heat, as the case for some dedicated DH plants, the CAPEX of the entire plant is considered. This is the case for natural gas OCGTs, CCGTs and gas engines. In assessing if they can recover their fixed costs the revenues from heat as well as electricity are taken into account. If the main product of the CHP plant is electricity, then only the incremental costs of heat extraction are relevant. The majority of its income is from electricity sales and heat production is considered a secondary activity. This is considered to be the case for the coal-fired CHP plants and the waste incineration plant. In assessing if they can recover their fixed costs only the revenues from heat are taken into account.

Techno-economic parameters are provided by existing studies [25,26,28] or based on vendor data. These parameters include the (electric) efficiency or Coefficient Of Performance (COP), minimum stable level, start cost, minimum up/downtimes, Variable Operation and Maintenance (VO&M) charge, the power-to-heat (P2H) ratio and/or the Feasible Operating Region (FOR).

2.2.2. Fuel, electricity and carbon prices

The relative competitiveness of heat generators is influenced by the prices of the input fuels, the electricity price, and the carbon price. These are all taken as exogenous in the model, based on historical data for the year 2015 (Table 2). Hourly electricity spot prices are taken from the Amsterdam Power Exchange (APX), daily natural gas spot prices are taken from the Dutch Title Transfer Facility (TTF), daily CO_2 prices are taken from the European Emission Allowances (EU EUA), while the coal price is based on the API 2 Rotterdam coal Futures index. Further details of these price assumptions are presented in Appendix C. To examine the impact of these price assumptions on our results, they are also varied as part of a sensitivity analysis (see section 4.3).

2.3. Model development

The Warmterotonde DH system is modeled and simulated using Plexos, a commercial mixed-integer linear programming (LP) based model, developed by Energy Exemplar for simulating power, water and gas markets [41].[1] The model solves both the Unit Commitment (UC) and Economic Dispatch (ED) problems by optimizing an

[1] Plexos version 6.4 https://energyexemplar.com/.

Table 2
Overview of the input and output prices.

	Base assumptions (2015)					Sensitivity analysis	
	Average	Minimum	Maximum	Data resolution	Reference	Average	Reference
Electricity	52.0 €/MWh (0.1–96.7 €/MWh)	0.1 €/MWh	96.7 €/MWh	Hourly	[35]	78 €/MWh (0–253 €/MWh)	[36]
Natural gas	5.8 €/GJ	4.2 €/GJ	7.5 €/GJ	Daily	[37]	8.7 €/GJ	[38]
CO_2[a]	23.1 €/tonne	15.6 €/tonne	29.8 €/tonne	Daily	[39]	43.5 €/tonne	[38]
Coal[b]	2.5 €/GJ			Annual	[40]	3.1 €/GJ	[38]

[a] CO_2 price from August 2018 to August 2019 is used as the average in 2015 was 6.0 which is much less than the current value. Other energy and fuel prices in the last year have no significant difference compared to the prices in 2015.
[b] Based on a raw price of 63 €/tonne assuming an energy content of 25.12 GJ/tonne.

Table 3
Electric and thermal capacity factor (CF) and heat RMC per generator type in the three scenarios.

Generator types	Reference scenario			RES scenario			HP scenario		
	Electric CF (%)	Heat CF (%)	Heat SRMC (€/GJ)	Electric CF (%)	Heat CF (%)	Heat SRMC (€/GJ)	Electric CF (%)	Heat CF (%)	Heat SRMC (€/GJ)
Geothermal		78%	0.7		64%	0.6		78%	0.7
Waste CHP	86%	58%	0.3	94%	24%	0.3	86%	58%	0.3
Gas engines	56%	50%	9.7	41%	33%	9.7	51%	44%	9.7
Gas CCGT	76%	56%	10.2	65%	34%	10.3	69%	50%	10.3
Coal CHP	95%	34%	8.0	96%	10%	7.9	95%	34%	8.0
Gas HOB		3%	8.4			8.4			8.4
Gas OCGT	5%	16%	11.1			11.1	1%	3%	11.1
Industrial heat					55%	0.6			
Heat pumps								16%	2.5

(note: CF represents the actual electricity and heat output as a share of the electricity and heat output if the plants would have produced at maximum electric and thermal output respectively).

objective function subject to various constraints. The UC determines which generators should be on or off, depending on the cost of the unit and the demand that should be fulfilled. The generators are allowed to be shut off entirely if this is economic to do so. The UC incorporates cost factors and constraints associated with shutting down and starting up, such as start costs and minimum up/downtimes. The UC is a Mixed Integer Programming (MIP) problem as it involves the optimization of a binary variable (on/off) [42]. The ED determines how much the various units should produce once they have been committed. The Plexos model co-optimizes the UC and ED such that the total system costs are minimized to find the dispatch of the generators.[2]

By applying the model, revenues from selling heat can be calculated. The operating profit is calculated to assess if the generators can earn back their fixed costs. Subsequently, the total operating profit for 2020 is compared with the annualized fixed costs to assess whether there is an overall net profit or under-recovery of fixed costs.

2.4. Sensitivity analysis

In addition to the main scenario runs, an additional sensitivity analysis is carried out to observe the effect of different market environment conditions representing more aggressive decarbonization efforts, implemented by using an alternative set of fuel, electricity and carbon prices. The fuel and CO_2 prices are set according to the "450 scenario" from the IEA report for the year 2022 [38]. The electricity prices in the sensitivity analysis are obtained from a previous study [36], which projected electricity prices with the input prices, e.g. coal, natural gas, and CO_2, from the 450 scenario. The policy framework assumed in the 450 Scenario reflects developments in the power system with more renewables. Therefore, volatility of electricity prices is higher in this scenario (Table 2).

3. Results

3.1. Thermal dispatch and heat market prices

This section presents results for the thermal dispatch and heat market prices. Table 3 provides the electric and heat capacity factors (CF) as well as the average short-run marginal cost (SRMC) of each generator type. The total annual heat production in the three scenarios is shown in Fig. 4. It can be seen that the heat CF and annual heat generation of each generator type in the reference and HP scenario are, to a large extent, similar. The major difference is that the natural gas HOB is replaced by the HPs. However, the heat production portfolio in the RES scenario is much different compared with another two scenarios. Geothermal has the highest heat CF in all scenarios. Even though its heat CF drops from 76% in the reference and HP scenarios to 62% in the RES scenario, the share of its production is the highest (78.5%). It mainly because of the increased capacity of geothermal in the RES scenario (see Fig. 3). It is observed that the average SRMC of each generator type slightly differs in three scenarios. It is because of the existence of multiple generators with different efficiency within one generator type. For example, there are five gas CCGT generators and two coal CHP plants (See Table A3).

The heat production per generator type of each month in three scenarios is presented in Fig. 5. In the Reference Scenario, the gas engines, waste CHP and gas CCGT plants produce the most heat, amounting to about 31%, 21% and 19% of total annual production respectively. Notable seasonal differences are apparent between

[2] As a power market model, Plexos is typically used to solve the UC and ED problem to give the dispatch solution which results in minimal total costs, and calculate the resulting electricity market prices. However, as we only model a small number of CHP plants connected to the Warmterotonde and not the whole electricity market, we instead supply the hourly electricity price as an input and assume that the modeled CHP plants are price-takers. Under this configuration, the Plexos objective function changes to maximize the generator net profits, based on the exogenously-defined electricity prices.

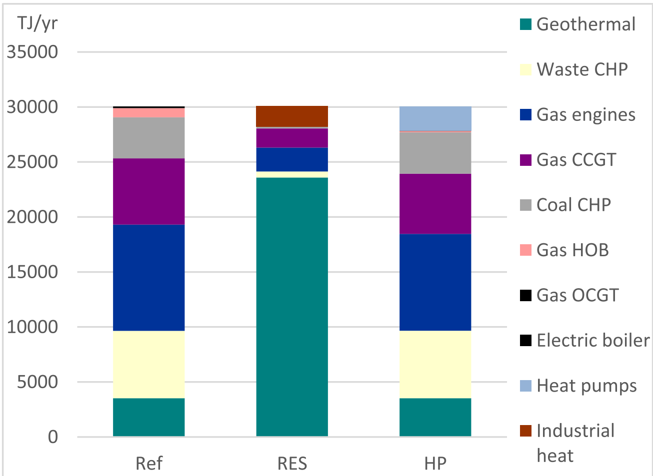

Fig. 4. Annual heat production per generator type in three scenarios.

different heat suppliers. Production from coal CHP, gas HOBs, gas CCGT, and waste CHP falls off considerably during summer. For example, the waste CHP plant has a relatively stable share in the winter, amounting to about 26%, which drops to around 19% in the summer. The coal-fired CHP units and natural gas HOBs primarily contribute to heat production during the winter and are almost fully displaced by other heat sources in the summer.

In the RES scenario, geothermal units clearly dominate the production accounting to 79% of total annual heat production. Gas engines, industrial heat, and CCGTs provide both 6% of the total heat demand. The heat production by waste- and coal CHP is marginalized with only 2% and 0.5% of total heat production. Their electric and heat capacity factors indicate that the waste- and coal-fired CHP plants are almost fully dedicated to electricity production.

In the HP scenario, the baseload provision of heat is very similar to that of the Reference scenario. Again the gas engines and CCGT units produce most on an annual basis, amounting to roughly 32%, followed by coal and waste CHP with 20% and 19% respectively. Heat pumps fulfill only 9% of the total heat production, but in winter their share of monthly production is between 8% and 19%.

Taking a closer look at the hourly dispatch for a typical winter and summer week in the reference scenario, Fig. 6 shows that the electricity price is a key driver determining the thermal dispatch. For instance in winter when heat demand is high (Fig. 6a) and the electricity price is low (e.g. below ~30 €/MWh), it is not profitable for CHP generators to generate electricity. In these cases, HOBs are typically the marginal producer. When electricity prices are moderately high (e.g. 30–50 €/MWh), the CHP plants with fixed P2H ratios (i.e. gas engines and CCGTs) are activated as they can offer their heat at low prices.[3] Finally, when electricity prices are very high (e.g. above ~50 €/MWh), the plants with variable P2H ratio (e.g. coal and waste CHP plants) reduce their heat output in order to produce more electricity, as this is more profitable. Geothermal, with its low marginal cost, generates very consistently with a high capacity factor. By contrast, in summer (Fig. 6b) when heat demand is low, geothermal production is sometimes pushed out of the merit order during periods of high electricity prices by gas engines and CCGT units as, given their fixed power-to-heat ratio, these plants can offer their heat at a price even below geothermal plants. This is exacerbated during periods of high electricity price since geothermal heating requires electricity to drive water circulation pumps, and their thermal SRMC increases with electricity price. On the other hand, plants with a variable P2H ratio that can operate in full condensing mode and produce electricity only (i.e. coal and waste CHP plants) do not displace geothermal heating.

Turning to the *RES scenario*, the electricity prices are low in the first hours of the week (Fig. 7). Almost all the heat is being supplied by industrial heat, geothermal, waste CHP. It indicates the large amounts of low-marginal-cost industrial waste heat and more geothermal heat pushes higher-cost providers like gas HOBs and gas engines out of the merit order during periods of low electricity price. However, even in this scenario, heat from fixed P2H ratio CHP units (e.g. gas engines and CCGT units) displaces geothermal and industrial waste heat during periods of high electricity price, especially during summer when both heat demand and gas prices are lower.

In the *HP scenario* (Fig. 8), the winter baseload heat provision is similar to the reference scenario with geothermal, waste CHP and coal CHP providing the majority of the heat. Instead of providing baseload capacity, HPs compete with HOBs to be the marginal producer and set the heat market price, but only when electricity prices are sufficiently low and heat demand is high.

Fig. 9 shows the heat market price duration curves (PDC) for all three scenarios.[4] Due to a large amount of low cost geothermal and industrial heat, the *RES scenario* has the lowest annual average heat price of 1.2 €/GJ. The average heat price in the *HP scenario* of 2.2 €/GJ is slightly lower than in the *Reference scenario* (2.7 €/GJ). The difference between the Reference PDC and heat pump PDC originates from the fact that heat pumps displace HOBs as the marginal generator. The curves of the Reference and HP scenario merge at the moment that the heat pumps are not competitive and the remaining generation mix has the same composition. The three lines merge at a certain moment reflecting the hours with high electricity prices where gas engines and CCGT units are price setting, resulting in a heat price of zero. As a result, about 1800 h in which electricity prices are sufficiently high (62 €/MWhe and higher) that gas engines and CCGT units are price setting, all three scenarios have about 1800 h with a heat price of zero.

3.2. Recovery of fixed costs

With respect to cost recovery, Fig. 10 depicts the gross income from energy sales,[5] operational costs and fixed costs for each generator type for all three scenarios.

It the case of the gas engines and CCGT plants, it can be seen that the income from energy sales exceed the operational costs in all scenarios but cannot cover the fixed costs resulting in an under-recovery of fixed costs in the range of 60%–80%. None of the gas engine and CCGT generators has a positive business case. The reference scenario shows the least under-recovery of costs, followed by the HP and RES scenario. The coal-fired CHP plants have fixed costs under-recovery in all the scenarios. They perform best in the reference scenario with about 75% of under-recovery of fixed costs. Note that only the fixed costs for the heat extraction equipment (about 19% of the total investment) are considered as the main product of these plants is electricity production. It means the

[3] For generators with fixed P2H ratios there is always heat production associated with the production of electricity. This means that if these plants are making a positive margin on the electricity market, the associated heat production will be offered at zero or even negative prices.

[4] Price duration curves take the hourly prices for the whole year and rank them from highest to lowest.

[5] For CHP plants, the revenues from electricity are not taken into account in the coal and waste inceration plants.

Fig. 5. Monthly heat production per generator type in three scenarios.

revenues from electricity are not taken into account and only the operational profits from heat production are considered in assessing the recovery of fixed costs. Regarding the waste incineration CHP, it is observed that the plant has a higher gross income than the sum of annual operational and fixed costs in the Reference and HP scenario. This means the plant can recover its fixed costs and makes an overall return on investment of 51% and 15% within the reference and HP scenario respectively. The results of the geothermal heat production show that even though the geothermal heat production has low operating cost and a high heat load factor, the investment costs are still too high to be earned back with the observed heat market prices. In the reference and HP scenarios, the existing geothermal assets in the horticulture sector have an under-recovery rate of 54% and 62% respectively. The geothermal assets in the RES scenario have an under-recovery rate about 80%. The difference can be explained by the high investment costs in the deep geothermal wells. The heat pump units also show an overall under-recovery of fixed costs. This can be explained by the fact that they only have a load factor of 16%, meaning other generators are more competitive. As such, the heat pumps are often price setting, leaving only the times when HOBs are price setting to make an operational profit. Given the low electric efficiency of the OCGT units, they are only dispatched when electricity prices are very high and heat demand is high. This means that they only make a marginal operating profit and as such they face a very high under-recovery of fixed costs in all scenarios. To summarize, only the waste CHP plant in the reference and HP scenarios has a positive business case. Note that these results are sensitive to the underlying assumptions of the CAPEX and FO&M charge.

3.3. *Sensitivity analysis*

Fig. 11 compares the yearly heat production in all three scenarios between the base set of inputs, and the sensitivity values (Table 2). In the reference scenario, it is observed that the gas engines have increased their share of annual heat production from 32% to 47%,

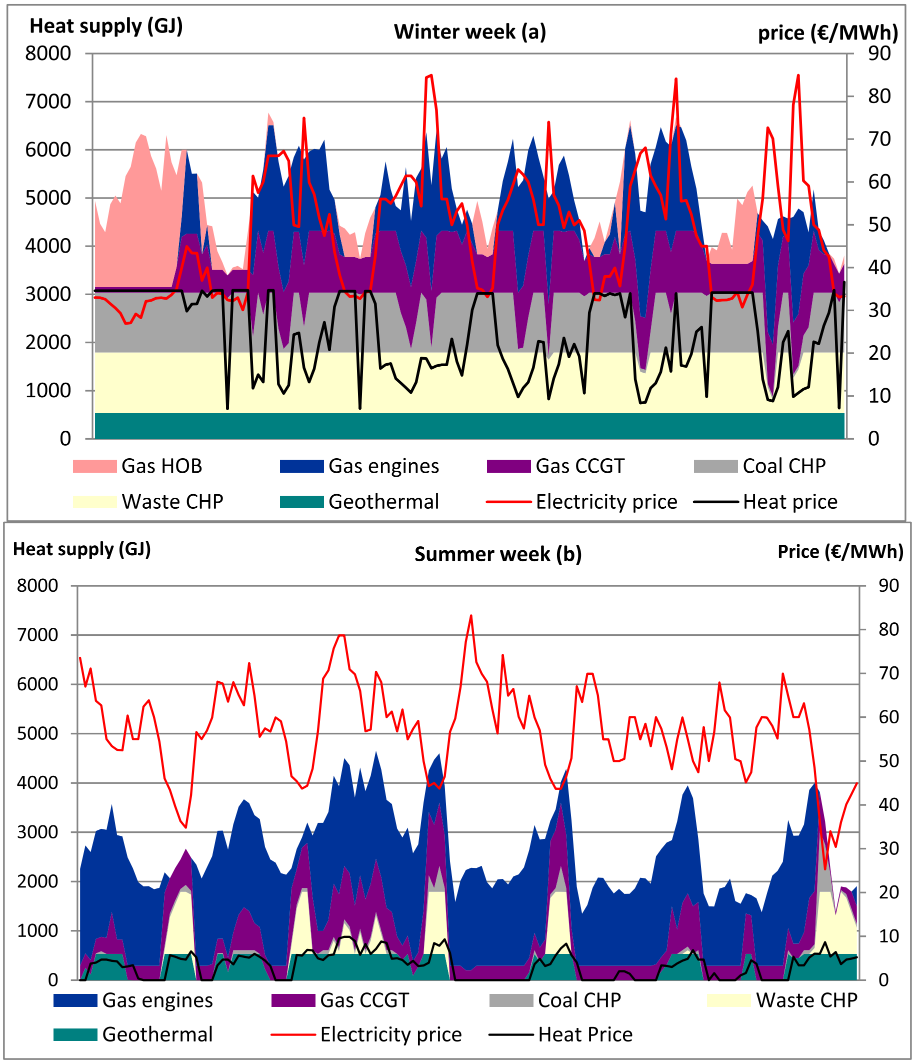

Fig. 6. Hourly heat production per generator type in the Reference scenario for (a) a winter week and (b) a summer week.

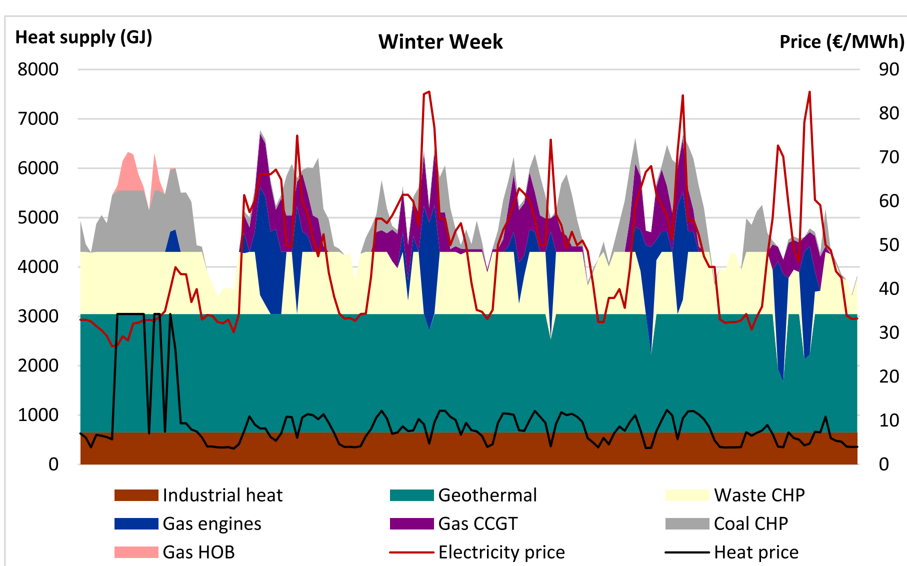

Fig. 7. Hourly heat production per generator type in the RES scenario in a typical winter week.

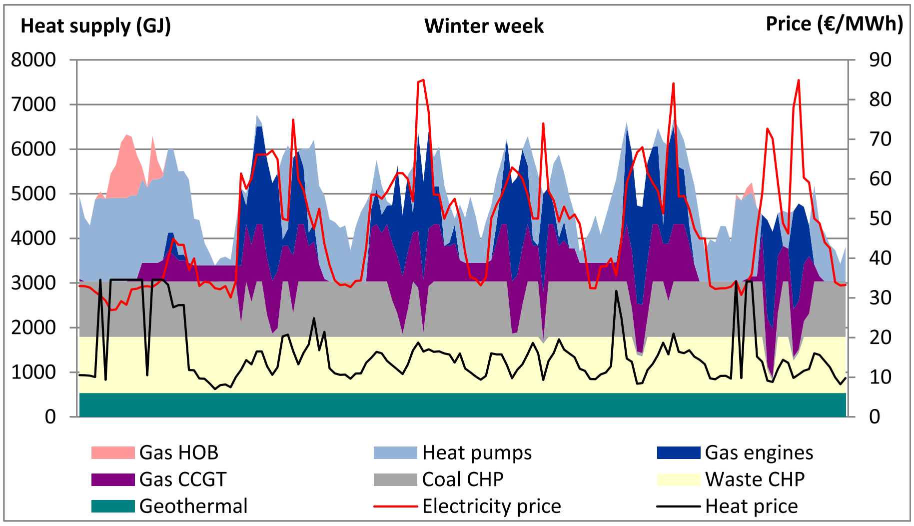

Fig. 8. Hourly heat production per generator type for the HP scenario in a typical winter week.

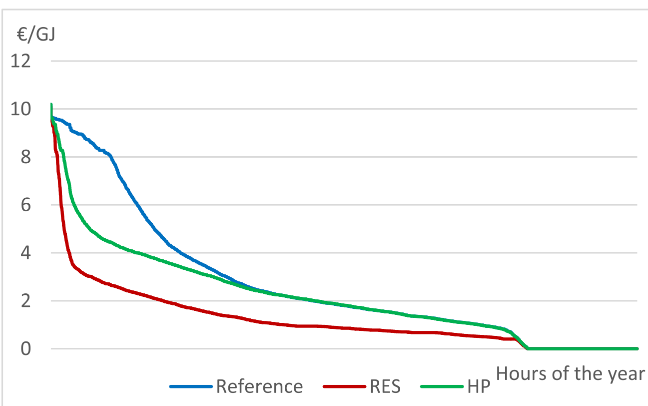

Fig. 9. Heat market PDC for the Reference, RES and HP scenarios.

while the share of the CCGT units reduces from 20% to 12%. The waste CHP plants are the second supplier of heat with 18% of annual production. The share of geothermal heat production is slightly decreased from 12% to 11% compared to the main analysis. The displacement of geothermal heat production by CHP units, especially during summer, is the result of the higher electricity prices. In the RES scenario, it is obvious that the dominant role of geothermal heat as observed with the prices in 2015 is significantly decreased. The share of geothermal is reduced from 78% to 37%. It is largely due to the increase in heat production from gas engines and industrial heat sources, which amount to 32% and 14% of the total respectively. The higher electricity prices result in the higher cost of geothermal heat and increased competitiveness of gas engine CHP production. The cost for the industrial heat is fixed and have not increased which make making them more attractive. The results of sensitivity analysis in the HP scenario are similar to the changes in the reference scenario.

To summarize, the main impacts of the sensitivity changes (i.e. higher gas, coal, and CO_2 prices, higher and more volatile electricity prices) are:

- With higher and more volatile electricity prices, fixed P2H ratio CHP generators are more frequently dispatched. During the summertime with low heat demand, they further displace geothermal heat which becomes more expensive as a result of the higher electricity price. As the fuel price increase is the same for all generators, the dispatch changes slightly depending on their efficiency and resulting competitiveness of their SRMC, and gas engines tend to be dispatched more than CCGTs as they perform better in terms of handling the volatility of the electricity price.
- The average heat market prices increase by around 25% to 3.0 €/GJ, 1.4 €/GJ, and 2.5 €/GJ in the *Reference*, *RES* and *HP* scenarios respectively due to the higher fuel and electricity price. The maximum price increases to 12.3 €/GJ.
- Overall, fixed cost recovery was not significantly affected by the increase in electricity, fuel and CO_2 prices. The waste CHP plant performs slightly better as it receives higher heat market incomes while their fuel cost remains the same. HPs perform somewhat worse due to the higher electricity prices.

4. Discussion

4.1. Research results

From the modeling results, it is clear that most of the generators derive insufficient income from a competitive wholesale DH market assuming marginal-cost-based pricing to cover their fixed costs. Several factors contribute to this outcome:

- Large amounts of low carbon and low-marginal-cost heat from geothermal and industry push more expensive gas- and coal-fired heat generators out of the merit order, reducing their operation hours and opportunities for revenue.
- The CHP plants with fixed P2H ratios can have a similar effect by dumping 'free' heat onto the heat market when electricity prices are favorable. Consequently, even low-cost heat-only suppliers like geothermal and industrial waste heat are pushed out of the merit order.
- Due to the capacity margin of 30% in the scenario design, no hours of scarcity are observed, and costly peak generators (e.g. HOBs) have no opportunity to exercise market power. This

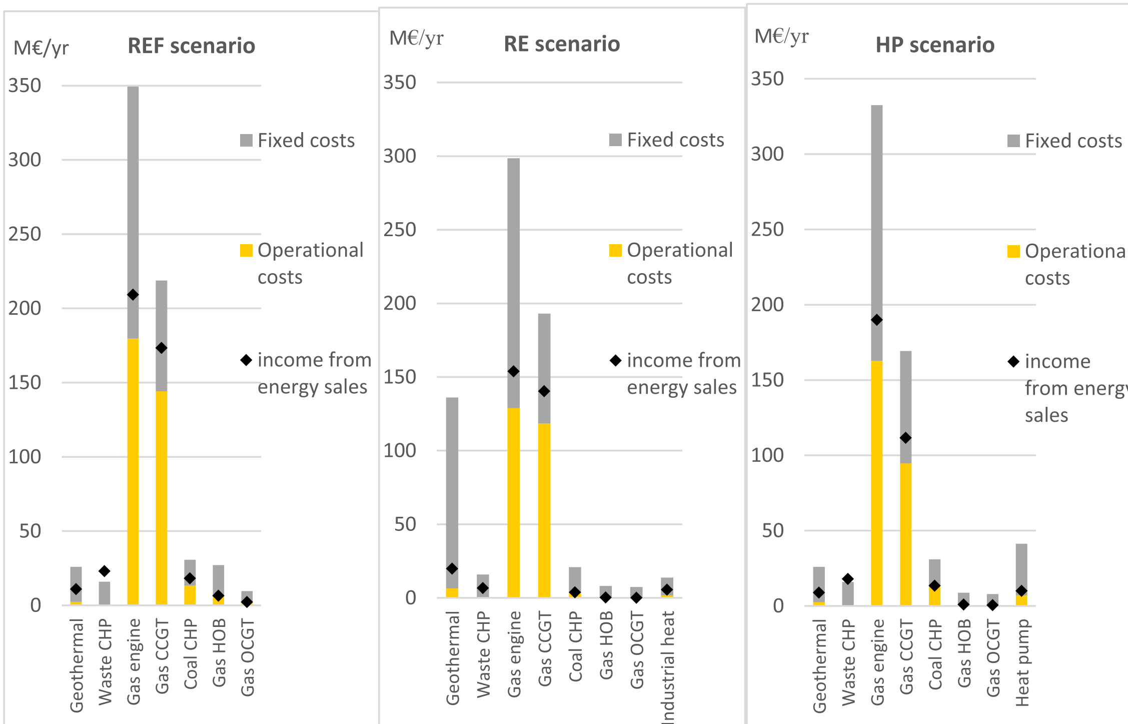

Fig. 10. Recovery of the fixed costs for different types of generators in the three scenarios.

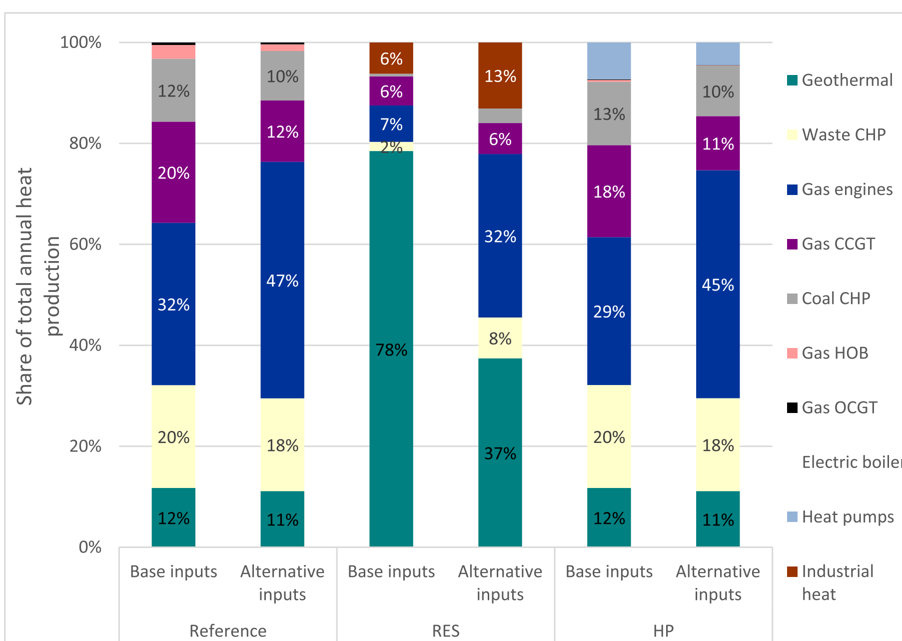

Fig. 11. The share annual heat production in the sensitivity analysis.

absence of scarcity prices or a ‘value of lost heat’ (VoLL) poses further challenges for generators to recover their fixed costs.[6] Moreover, the significant over-capacity means that the total operating hours available must be shared across more generation capacity, reducing the potential revenues for individual generators. In a perfectly competitive district heating market at long-term equilibrium, the optimal capacity of the system would be such that the price of heat would be equal to the long-run marginal cost.

[6] In electricity markets, the VoLL is a concept used to express the cost to consumers of having one unit of their electricity demand unmet, which commonly arises when generation resources in the market are not sufficient to meet demand, and the market is unable to clear and set a price.

4.2. Research implication

The feasibility of competitive wholesale district heating systems would be contingent on the market design and associated pricing structure, and regulation. From the results of this study, it follows that a market design based on MCP ensures the most cost-efficient dispatch of generators, but may yield insufficient revenues for heat producers to earn back their fixed costs. Therefore, more criteria should be used to design a feasible district heating market system than the cost-effectiveness of the dispatch of heat generators. Other criteria may encompass factors such as the viability for generators to recoup their investments, the easiness of entry for new environmentally benign heat generators, the reliability of the system ensured by sufficient thermal reserve capacity, transparency about the pricing structure for consumers, and sufficient consumer control over their heat use. One important element in a market design could be the establishment of independent heat distribution system operators (HDSOs) who own and operate the actual heat distribution infrastructure. Charged with ensuring reliable supply and stable operation of the district heating network (e.g. temperatures and pressures within required operating limits), these HDSOs would play a role analogous to transmission system operators and distribution system operators in electricity networks.

The so-called “merit-order effect” has been observed in the study. Such an effect has also been found in electricity markets as a result of the integration of wind and solar photovoltaics. However, the results of this study show that the heat market can be regarded as the inverse of the electricity market, where gas fired CHP plant performs the role of the intermittent generators that depress the heat market prices when electricity prices are favorable. This causes a merit order effect within the heat market, where heat only technologies, such as geothermal, industrial heat and HOBs, are pushed out of the merit order.

4.3. Research limitations

A number of caveats in the study influenced the results. For example, the OPEX of industrial waste heat is assumed to be fixed, which might be unrealistic as it depends on the specific process industry. Furthermore, the flexibility of waste and coal-fired CHP plants and their ability to independently vary heat and electricity production can have a significant impact on results. For the HPs and geothermal wells a fixed COP was assumed, while in reality the COP depends on the temperature of the cold reservoir in the case of HPs, and on the aquifer geological conditions (e.g. depth, permeability, and porosity) in case of geothermal wells.

This study has assumed that all generators would bid into an open heat market based on their SRMC, in reality, suppliers may also offer their heat at a higher price by (i) bidding strategically (e.g. bidding just below the SRMC of the next-highest generator in the thermal merit order), or (ii) exercising market power during times of scarcity. Due to the objective of this study, these aspects were, however, not considered.

Another limitation is the exclusion of the physical DH infrastructure. This excludes the possibility of a mismatch between supply and demand geographically. Moreover, some of the market outcomes from the model might be infeasible in terms of the capacity of the DH network or the operational constraints of the network. The physical infrastructure is usually dimensioned according to the peak load of the system, to ensure the peak heat demand can be met. As a result, the capacity of the network forms a constraint, which necessitates the activation of local peak boilers. Another aspect that comes into play is the competitiveness of the heat sources over distance. This is affected by losses associated with transport, such as pumping energy and heat losses. In addition, heat travels slower than e.g. gas or electricity. Therefore, there is also a time component to take into account. It is also unknown if the sometimes highly fluctuating output of the heat production, in response to the electricity prices, could be accommodated by the network. These factors and their effects are left out of the analysis. However, the inclusion of extra constraints in the form of heat transmission capacity or limited operational flexibility will limit the ability of the most cost-efficient generators to be dispatched and would result in the occasional dispatch of more expensive generators, which will inevitably increase the overall system costs.

Besides minimization of operational costs, there are more factors that could influence the dispatch but which have not been included in this study. These range from electricity market developments, specifically the volatility of electricity markets, to secondary monetary incentives for producers, ranging from subsidies for renewable energy sources to must run situations for industrial processes and CO_2 demand for horticulture. For example, feed-in-tariff subsidies for renewable CHP or heating technologies could lead suppliers to offer their heat at negative prices into open DH markets. Policymakers should realize this when contemplating the design for a competitive DH market.

5. Conclusion

District heating systems serve as one of the strategies to achieve a low-carbon built environment. In anticipation of the development of a sustainable heat transition, the concept of market design, in particular, wholesale competition, for DH systems has gained attention. A linear programming model was developed to simulate the dispatch for a competitive wholesale DH market, and to assess the extent to which revenues from such a market, based on marginal-cost pricing, are sufficient to cover the fixed costs of multiple heat supply technologies. A DH system in Zuid-Holland in the Netherlands was analyzed as the case study. Three scenarios were developed to determine the effect that different heat supply technology mixes have on the operation of the market. They are reference, renewable energy source (RES) and heat pump (HP) scenarios. The portfolios of heat supply included natural gas open and combined cycle gas turbines, combined heat and power plants with both fixed and variable power-to-heat ratios, a waste incinerator, a coal-fired CHP plant, geothermal heat, industrial waste heat, heat only boilers and heat pumps.

It is concluded that low carbon heat generation technologies tend to have low short-run marginal costs. the RES scenario has the lowest annual average heat price of 1.1 €/GJ due to a large amount of low cost geothermal and industrial heat. The average heat price in the HP scenario of 1.9 €/GJ is lower than in the Reference scenario (2.4 €/GJ) as heat pumps displace HOBs as the marginal generator. A merit-order effect is observed in the district heating market with significant amounts of zero- or negative-marginal cost heat. It pushes higher cost generators out of the merit order. Periods of high electricity prices contribute to this merit order effect as CHP plants with fixed power-to-heat ratios can offer their heat onto the market at very low prices. The electricity price is found to have a significant impact on the heat market dispatch, with high electricity prices favoring CHP plants with fixed power-to-heat ratios. The sensitivity analysis indicates that the capability of CHP plants to handle the volatility of the electricity price is crucial for achieving higher dispatch rates.

Although the marginal-cost pricing could ensure a cost-efficient dispatch, it does not provide enough revenues for almost all heat producers to recover their fixed costs for a competitive wholesale DH market except for the waste incinerator, let alone the costs of physical infrastructure. All examined heat producers have an under-recovery of fixed costs in a range between 60% and 90%, while the waste incineration CHP plant has an overall return on investment of 44% and 12% within the reference and HP scenario respectively. Additional income is required to sustain a competitive heat market and ensure sufficient investment in new heat production capacity. Two aspects are found crucial in selecting appropriate methods to determine the fixed charge and payments of the heat producers: 1) rewarding more cost-efficient generators in order to obtain the lowest total system cost for the end-user and 2) allowing for the entry of new, more efficient and environmentally benign heat production capacities.

Acknowledgments

The authors would like to thank Uniper Benelux for providing heat demand data, and the parameters for the CHP plant. The authors would also like to thank Energy Exemplar for their support and access to an academic license for the Plexos software. This research did not receive any funding from commercial or government sources.

Appendix A. Residential and horticultural heat demand

Table A1
Estimated annual residential heat demand supplied by DH in 2020 [25,26].

Municipality	Actual heat demand in 2015 (PJ/a)	Heat demand supplied by DH in 2015 (PJ/a)	Potential heat delivery by DH in 2020 (PJ/a)
Den Haag	16.3	1.4	1.4
Ypenburg	0.5	0.5	0.3
Delft	2.9	0	0.2
Rijswijk	Unknown	0	0.1
Vlaardingen/Schiedam	Unknown	0	0.1
Rotterdam	29	6.3	6.3
Leiden	Unknown	0.9	0.9
Total	48.7	9.1	9.3

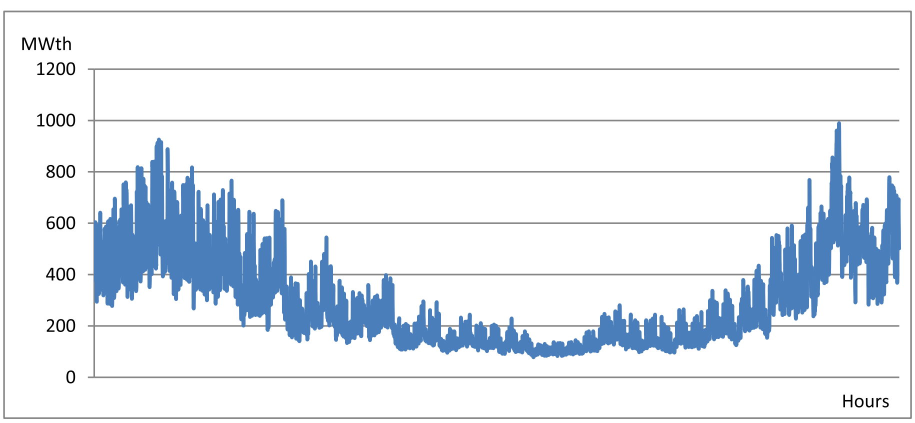

Fig. A1. The hourly residential heat demand pattern in 2015 [25]. .

Table A2
Potential agriculture heat demand expected to connect to the DH network in 2020 [26].

Agricultural area	Agricultural heat demand connected to the foreseen DH infrastructure (PJ/year)	Agricultural heat demand corrected for energy efficiency measures (PJ/year)
Westland	14.4	12.8
Pijnacker-Nootdorp	2.1	1.9
Langsingerland	4.3	3.8
Zuidplas	1.6	1.4
Midden-Delfland	1.1	1.0
Total:	23.5	20.7

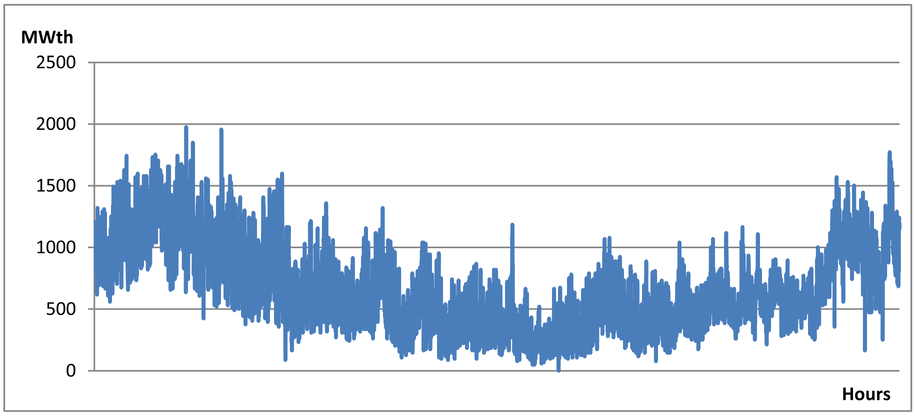

Fig. A2. The horticultural heat demand pattern [26]. .

Appendix B. Detailed techno-economic parameters of heat generators

Table A3
Overview of heat generators and techno-economic characteristics for all scenarios

Generator	Abbreviation	Type	Fuel	Reference scenario		RES scenario		Heat pump scenario					
				Electric Capacity	Thermal Capacity	Electric Capacity	Thermal Capacity	Electric Capacity	Thermal Capacity	Electric efficiency	Thermal efficiency	COP	VO&M
				(MWe)	(MWth)	(MWe)	(MWth)	(MWe)	(MWth)	ηe	ηth	(H/E)	€/MWhe
Gas turbine RoCa 1	RC1	OCGT	Gas	20	50	20	50	20	50	×	×		4
Gas Turbine RoCa 2	RC2	OCGT	Gas	20	50	20	50	20	50	×	×		4
Gas Turbine RoCa 3	RC3	CCGT	Gas	200	200	200	200	200	200	×	×		4
Gas Turbine Leiden 1	GTL1	CCGT	Gas	40	35	40	35	40	35	×	×		4
Gas Turbine Leiden 2	GTL2	CCGT	Gas	45	40	45	40	45	40	×	×		4
Gas Turbine Den Haag 1	GTD1	CCGT	Gas	55	45	55	45	55	45	×	×		4
Gas Turbine Den Haag 2	GTD2	CCGT	Gas	70	45	70	45	70	45	×	×		4
Boiler Leiden 1	HOBL1	HOB	Gas		50		50		50		90		
Boiler Leiden 2	HOBL2	HOB	Gas		20		20		20		85		
Boiler Den Haag	HOBD	HOB	Gas		110		110		110		85		
Boiler Rotterdam	HOBRD	HOB	Gas		200		200		200		90		
Boiler RoCa	RCHOB	HOB	Gas		135		135		135		85		
Waste incinerator	AVR	Waste CHP	Waste	160	350	160	350	160	350	40	30		2
Coal fired CHP 1 (Uniper Benelux)	MPP3	Coal CHP	Coal	1050	200	1050	200	1050	200	×	×		2
Coal fired CHP 2 (Engi)	ENGI	Coal CHP	Coal	760	145	760	145	760	145	×	×		2
Electric boiler Den Haag	DH EB	Electric boiler	Electricity		20		20		20			1	
Gas engine (J624)	HOR CHPa	Gas engines	Gas	123	114	123	114	123	114	46.3	43.0		7
Gas engine (JMS 620 GS-N.LC)	HOR CHPb	Gas engines	Gas	123	122	123	122	123	122	43.0	42.7		7
Gas engine (JMS 616 GS-N.LC)	HOR CHPc	Gas engines	Gas	123	121	123	121	123	121	43.4	42.8		7
Gas engine (JMS 612 GS-N.LC)	HOR CHPd	Gas engines	Gas	123	125	123	125	123	125	42.6	43.2		7
Gas engine (JMS 420 GS-N.LC)	HOR CHPe	Gas engines	Gas	123	130	123	130	123	130	41.9	44.2		7
Boiler residential sector	HOB Base	HOB	Gas		70						90		
Boilers horticulture	HOR HOB	HOB	Gas		894		264		444		90		
Existing geothermal	HOR GEO	Geothermal	Electricity		148		148		148			20	
Geothermal horticulture	HOR GEO RES1	Geothermal	Electricity				150					20	
Deep Geothermal horticulture	HOR GEO RES2	Geothermal	Electricity				300					26.7	
Geothermal Den Haag	GEO DH	Geothermal	Electricity				35					20	

(continued on next page)

Table A3 (*continued*)

Generator	Abbreviation	Type	Fuel	Reference scenario		RES scenario		Heat pump scenario					
				Electric Capacity	Thermal Capacity	Electric Capacity	Thermal Capacity	Electric Capacity	Thermal Capacity	Electric efficiency	Thermal efficiency	COP	VO&M
				(MWe)	(MWth)	(MWe)	(MWth)	(MWe)	(MWth)	ηe	ηth	(H/E)	€/MWhe
Geothermal Leiden	GEO L	Geothermal	Electricity				35					20	
Industrial source 1	ID1	Industrial					60						
Industrial source 2	ID2	Industrial					60						
Industrial source 3	ID3	Industrial					60						
Heat pump horticulture 1	HOR HP1	CO_2 heat pump	Electricity						112.5			4	0.4
Heat pump horticulture 2	HOR HP2	CO_2 heat pump	Electricity						112.5			3.8	0.4
Heat pump horticulture 3	HOR HP3	NH3 heat pump	Electricity						112.5			3.5	0.4
Heat pump horticulture 4	HOR HP4	NH3 heat pump	Electricity						112.5			4.5	0.4
Heat pump Den Haag	HP DH	NH3 heat pump	Electricity						35			4	0.4
Heat pump Leiden	HP L	NH3 heat pump	Electricity						35			4	0.4
Total				3035	3419	3035	3419	3035	3419				

(Note: 1. capacities have been rounded for reasons of confidentiality; 2. Some parameters are considered confidential and therefore not displayed.)

Appendix C. Electricity, fuel and carbon price assumptions

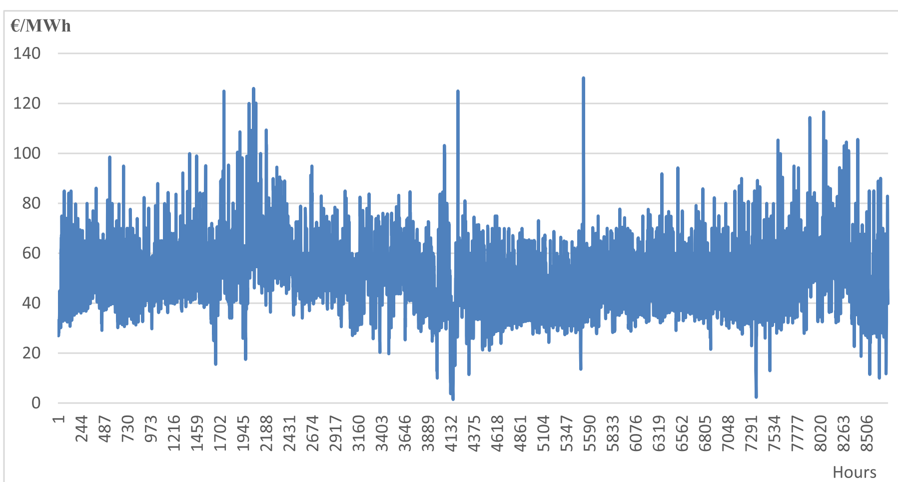

Fig. A3. APX electricity spot prices in 2015 [35]. .

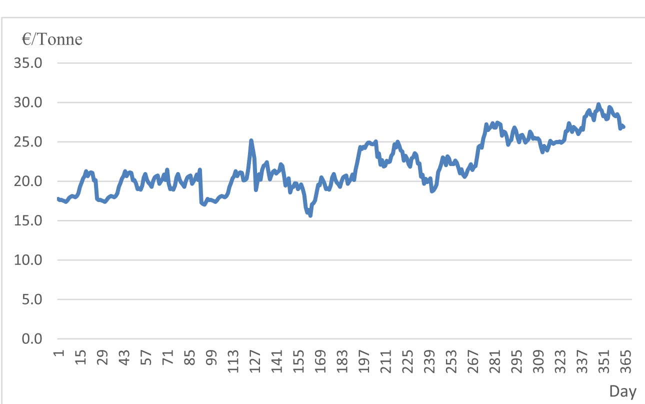

Fig. A4. EU ETS CO_2 prices from August 2018 to August 2019 [39]. .

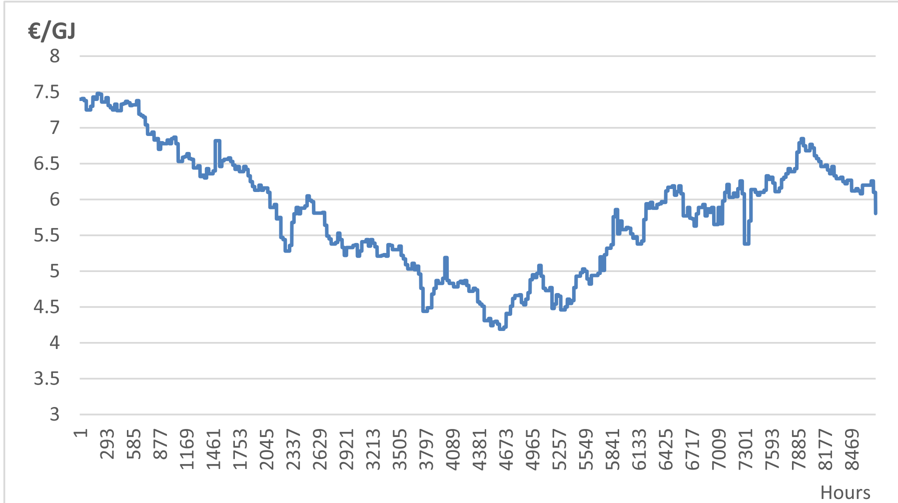

Fig. A5. TTF spot natural gas prices in 2015 [37].

Appendix D. Additional results

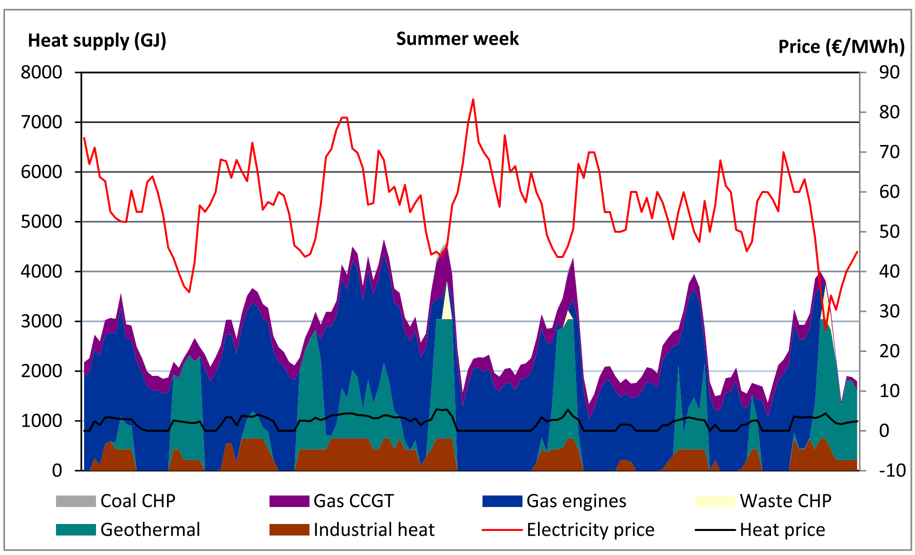

Fig. A6. Hourly heat production per generator type in the RES scenario in a summer week.

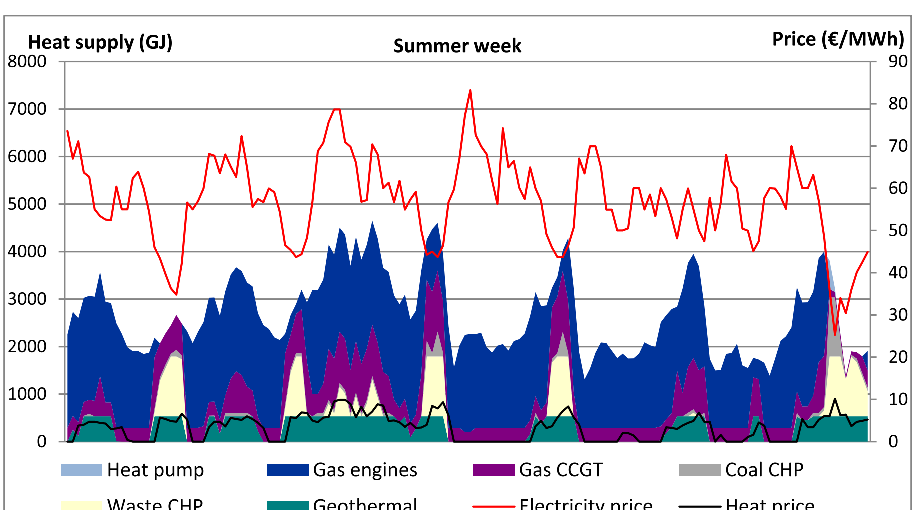

Fig. A7. Hourly heat production per generator type in the HP scenario in a summer week.

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