INTEGRATION OF HEAT PUMPS AND RENEWABLE HEAT SUPPLIERS IN OPTIMIZED SHORT-TERM PLANNING FOR DISTRICT HEATING SYSTEMS

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ABSTRACT

District Heating Systems (DHS) need to improve operational efficiency and sustainability by integrating multiple renewable heat suppliers into the short-term planning paradigm. DHS are undergoing a significant transformation, moving from combined heat and power (CHP) plants to a diverse technology mix to meet the evolving zero emission energy landscape. The dynamics of heat demand and diverse renewable supply require novel flexible planning mechanisms to balance the residual heat load and to ensure optimal use of resources. To address these challenges, this paper includes a thorough modeling and simulation of the heat suppliers in a DHS with a focus on improved operational efficiency and sustainability, as well as model application to two large-scale DHS operated by German utilities. The methodology used is Mixed Integer Linear Programming to develop a comprehensive model. This model includes CHP (internal combustion engines and gas turbines), large river water and waste water heat pumps, as well as large heat pumps using industrial waste heat, deep geothermal doublets, large solar thermal plants, and thermal energy storage, taking into account the discrete and continuous variables inherent in the short-term scheduling of DHS. Real world data is incorporated during the simulation phase to check the plausibility of the model in terms of accuracy and effectiveness. By minimizing the target variable, heating costs, under various constraints such as carbon emissions, or operating costs (e.g., emission costs, or energy source prices), the simulation results of significant framework scenarios show that multiple renewable heat sources in coordination with thermal storage can cover up to 100% of the heat load replacing conventional supply systems based on fossil fuels. In particular, the paper examines the challenges associated with integrating diverse renewable heat supplies during periods of low heat demand and the continuing challenge of meeting high heat demand during cold periods. Depending on the constraints, the results differ between CHP and heat pumps, especially when considering variations in carbon dioxide emissions from electricity consumption. The paper provides analysis and strategies for optimizing DHS operations, promoting sustainability, and addressing the challenges of integrating multiple renewable heat suppliers in a cost-effective manner. By applying the model to two German DHS, the practical suitability of the model is evaluated, providing insights into its adaptability and potential benefits to current energy management systems. However, the model is not yet able to represent all real-world conditions, such as failure scenarios for different heat suppliers or seasonal thermal storage. To overcome this, further research can extend the developed model for short-term planning optimization, e.g., for planning and evaluation of individual technological improvements or for integration of complex storage solutions.

1 INTRODUCTION

Faced with the challenges of climate change, district heating systems (DHS), which are dominated by conventional heat generation from fossil fuels, need to be transformed through the integration of renewable heat suppliers. DHS have long been recognized as an efficient and sustainable solution for

https://doi.org/10.52202/077185-0065

providing heat to residential, commercial and industrial buildings. By centralizing heat generation and distribution, DHS offer benefits such as reduced energy consumption, lower emissions, and increased reliability compared to decentralized heating systems. Historically, DHS have relied heavily on combined heat and power (CHP) plants that produce electricity and heat simultaneously. However, with the growing emphasis on decarbonization and the integration of renewable energy sources, DHS are undergoing a significant transformation. This transition aims to diversify the heat supply mix by incorporating various renewable energy sources, such as solar thermal, geothermal, and waste heat recovery systems.

The integration of multiple renewable heat suppliers into the DHS introduces new challenges and complexities. One of the main challenges is the intermittency of renewable energy sources, which can lead to fluctuations in heat supply and demand. E.g., solar thermal systems are dependent on weather conditions, while geothermal systems may have limited capacity or require significant initial investment. In addition, the intermittent nature of renewable energy sources can present challenges in maintaining system reliability and meeting peak demand periods.

Furthermore, traditional design paradigms for DHS may not be well suited to the dynamic nature of renewable heat supply. Traditional optimization models often assume steady state conditions and may not adequately account for the variability and uncertainty associated with renewable energy sources. As a result, there is a need for novel design mechanisms and optimization techniques that can effectively balance the fluctuating heat supply and demand within DHS.

In light of these challenges, this paper aims to address the need for improved operational efficiency and sustainability in DHS through the development of advanced modeling and simulation techniques. Mixed Integer Linear Programming (MILP) is used to develop a comprehensive model that can optimize short-term planning for DHS while incorporating multiple renewable heat suppliers. Real-world data will be used to validate the accuracy and effectiveness of the model, with a focus on minimizing heating costs and reducing carbon emissions.

This work differs from other research, as demonstrated in Table 1. The unique selling point is the consideration of various heat generators (including different renewable ones) and their optimized operation in existing DHS, even if other studies include more complex modeling approaches or more detailed individual components.

Table 1: Comparing optimization problems from a literature review

study	method	fossil boilers	electric boilers	fossil CHP	biomass CHP	heat pumps	solar thermal	thermal storage	focus
Christidis, 2019	MILP	✓	✗	✓	✗	✗	✗	✓	operation
Delubac et al., 2024	NLP	✓	✗	✓	✓	✗	✓	✓	design
Fang et al., 2016	MILP	✓	✗	✓	✗	✗	✗	✓	operation
Groß, 2012	MILP	✓	✗	✓	✗	✓	✓	✓	operation
Mollenhauer, 2019	MILP	✓	✓	✓	✗	✓	✗	✗	operation
Résimont, 2021	MILP	✓	✗	✗	✗	✓	✓	✓	design
Thommessen et al., 2020	MILP	✓	✗	✓	✗	✗	✗	✓	operation
van der Heijde et al., 2019	MIQP	✗	✗	✗	✗	✗	✓	✓	design
Wirtz et al., 2021	MILP	✓	✗	✓	✗	✗	✗	✓	model
this research	MILP	✓	✓	✓	✓	✓	✓	✓	operation

This paper is structured as follows. Section 2 ‘Methods’ describes the mathematical structure of the developed optimization model, along with all defined assumptions for the two use cases, DHS in Berlin and Duisburg. The simulation results are presented and analyzed in section 3 ‘Results’, followed by a detailed discussion, a comparison with related literature and an outlook on future extensions of this research in section 4 ‘Discussion’. Finally, the most significant findings of the study and identified potentials for future research are summarized in the section 5 ‘Conclusions’.

https://doi.org/10.52202/077185-0065

2 METHODS

In order to analyze the challenges of integrating renewable heat generators into existing DHS, a mathematical optimization model based on MILP is developed first. Then the two use cases, Berlin and Duisburg, are described, along with their associated scenarios and assumptions.

2.1 Linear optimization approach

MILP is a branch of mathematical optimization. Like (continuous) linear optimization, it deals with the optimization of linear objective functions over a set constrained by linear equations and inequalities. The difference is that some of the decision variables are integer and others are continuous, and it can be used to model optimization problems that are NP-hard from a complexity point of view. MILP has many applications, e.g., in manufacturing, network planning or route planning. In this work, it is used to describe a cost optimization problem for the short-term scheduling of plants in DHS to achieve beneficial operation for both heat generation and the electricity grid. The objective function shown in Equation (1) minimizes the total operating cost (C_{total}) for the time horizon ($t = 1, \dots, T$). Capital costs generally are not considered in optimized short-term planning.

$$\min C_{total} = \sum_{t=1}^{T} \left(\sum_{b=1}^{B} C_{b,t} + \sum_{l=1}^{L} C_{l,t} + \sum_{j=1}^{J} C_{j,t} + \sum_{k=1}^{K} C_{k,t} \right) \tag{1}$$

This total cost equation includes the different costs for boilers $C_{b,t}$, large heat pumps $C_{l,t}$, solar thermal system $C_{j,t}$ and CHP $C_{k,t}$. Based on the energy source of the boiler (electricity or a fuel gas), the cost of the boiler heat production $C_{b,t}$, depending on the time step t and the respective boiler b, can be calculated from the duration of a time step d, the associated heat supply $\dot{Q}_{b,t}$, the thermal efficiency $\eta_{th,b}$, the specific fuel costs $c_{f,b,t}$ and the specific emission costs (calculated using the mass-related emission costs $e_{b,t}$ and the specific emissions $\varepsilon_{b,t}$) or the electricity purchase costs ($c_{el,t} + c_a$), and the specific heat-related and hourly maintenance costs ($c_{mh,b}$ and m_b) in Equation (2), while the Boolean operating variable $X_{b,t}$ is equal to 1 for $Q_{b,t} > 0$.

$$C_{b,t} = \begin{cases} d \cdot \left(\dot{Q}_{b,t} \cdot \left(\dfrac{c_{el,t} + c_a}{\eta_{th,b}} + c_{mh,b} \right) + X_{b,t} \cdot m_b \right) & \textit{electricity} \\ d \cdot \left(\dot{Q}_{b,t} \cdot \left(\dfrac{c_{f,b,t} + e_{b,t} \cdot \varepsilon_b}{\eta_{th,b}} + c_{mh,b} \right) + X_{b,t} \cdot m_b \right) & \textit{else} \end{cases} \quad \forall b, t \tag{2}$$

Similar to the electric boiler, the cost of large heat pumps can be calculated using Equation (3). The main difference is that the coefficient of performance $COP_{l,t}$ is used instead of the efficiency.

$$C_{l,t} = d \cdot \left(\dot{Q}_{l,t} \cdot \left(\frac{c_{el,t} + c_a + c_{me,l}}{COP_{l,t}} + c_{mh,l} \right) + X_{l,t} \cdot m_l \right) \quad \forall l, t \tag{3}$$

For solar thermal systems, the cost $C_{j,t}$ is calculated from the hourly heat yield $\dot{Q}_{j,t}$ and the specific maintenance cost $c_{mh,j}$, Equation (4). The solar thermal energy $\dot{Q}_{j,t}$ is determined by given parameters and therefore, it is not a decision variable. Additionally, no Boolean variable is needed due to negligible hourly maintenance costs.

$$C_{j,t} = d \cdot \left(\dot{Q}_{j,t} \cdot c_{mh,j} \right) \quad \forall j, t \tag{4}$$

Equation (5) represents the cost calculation for CHP plants. It includes operating maintenance cost $m_{k,t}$, fuel-related costs $c_{th,k,t}$, electricity-related costs $c_{el,k,t}$, heat-related maintenance cost $c_{mh,k,t}$ and hourly maintenance costs $m_{k,t}$. The electrical and thermal efficiencies ($\eta_{el,k}$ and $\eta_{th,k}$) must be used.

$$C_{k,t} = d \cdot \left(\dot{Q}_{k,t} \left(\frac{c_{th,k,t} + \eta_{el,k} \cdot c_{el,k,t}}{\eta_{th,k}} + c_{mh,k,t} \right) + X_{k,t} \cdot m_{k,t} \right) \quad \forall k, t \tag{5}$$

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The fuel-related costs consist of the fuel price $c_{f,k,t}$ and the emission price, which is calculated on the basis of the specific emission cost $e_{k,t}$ and the specific emissions of the fuel ε_k, see formula (6).

$$c_{th,k,t} = c_{f,k,t} + e_{k,t} \cdot \varepsilon_k \quad \forall k, t \tag{6}$$

Within function (7), the electricity-related costs can be calculated from the electricity-related maintenance cost $c_{me,k,t}$ and the price of electricity $c_{el,t}$. When the price of electricity is high, this factor becomes negative, corresponding to a revenue from feeding electricity into the grid.

$$c_{el,k,t} = c_{me,k,t} - c_{el,t} \quad \forall k, t \tag{7}$$

In the following section, in addition to the description of the objective function, the relevant constraints and decision variables are defined. First, the energy balance (8) must be maintained on an hourly basis, ensuring that the sum of all consumption flows is equal to the amount of heat produced. The consumption flows consist of the demand from the district heating network $\dot{Q}_{DHS,t}$ and the supply to the thermal storages $\dot{Q}_{s,t}$ (which can also be negative and therefore an injection). The heat is generated by boilers $\dot{Q}_{b,t}$, large heat pumps $\dot{Q}_{l,t}$, solar thermal systems $\dot{Q}_{j,t}$ and cogeneration plants $\dot{Q}_{k,t}$.

$$\dot{Q}_{DHS,t} + \sum_{s=1}^{S} \dot{Q}_{s,t} = \sum_{b=1}^{B} \dot{Q}_{b,t} + \sum_{l=1}^{L} \dot{Q}_{l,t} + \sum_{j=1}^{J} \dot{Q}_{j,t} + \sum_{k=1}^{K} \dot{Q}_{k,t} \quad \forall t \tag{8}$$

The thermal storage levels $QS_{s,t}$ must not exceed the storage capacities QSC_s, equation (9).

$$QS_{s,t} \leq QSC_s \quad \forall s, t \tag{9}$$

Assuming that no heat is generated or released from nothing, the thermal storage level at the end of the time horizon $QS_{s,T}$ in formula (10) must be equal to the parameter for the start level $QS_{s,0}$.

$$QS_{s,T} = QS_{s,0} \quad \forall s \tag{10}$$

Function (11) describes the relationship between the storage charge or discharge $\dot{Q}_{s,t}$ and the thermal storage level $QS_{s,t}$, while the initial level $QS_{s,0}$ is a defined parameter. The heat storage losses $\dot{Q}_{loss,s,t-1}$ depend on the storage level of the previous time step $QS_{s,t-1}$ and defined parameters of the storage, such as geometry, location, ambient temperature, insulation material, or insulation layer thickness.

$$QS_{s,t} = QS_{s,t-1} + d \cdot \left(\dot{Q}_{s,t} - \dot{Q}_{loss,s,t-1}\right) \quad \forall s, t \tag{11}$$

For a better overview, all controllable plants ($i = 1, \dots, I$) are summarized in the next sections. Boilers, heat pumps and cogeneration plants are controllable, but solar thermal systems are not. Most controllable systems have a minimum operating time $TO_{min,i}$ and a minimum stop time $TS_{min,i}$ (during which they must remain switched off after shutdown). If the system is switched off ($TS_{i,t} > 0$), it may not produce heat $Q_{i,t}$ again until the minimum stop time has been observed ($TS_{i,t} > TS_{min,i}$). If the generation system is allowed to supply heat, the maximum nominal load $Q_{max,i}$ must be taken into account (12). The similar relationship regarding the minimum operating time to be observed is described in formula (15). When the system is in operation ($TO_{i,t} > 0$) but below the minimum operating time ($TO_{i,t} \leq TO_{min,i}$), the heat load can be regulated but the minimum partial load $Q_{min,i}$ must not be undershot.

$$\dot{Q}_{i,t} \leq \begin{cases} 0 & 0 < TS_{i,t} \leq TS_{min,i} \\ \dot{Q}_{max,i} & else \end{cases} \quad \forall i, t \tag{12}$$

$$\dot{Q}_{i,t} \geq \begin{cases} \dot{Q}_{min,i} & 0 < TO_{i,t} \leq TO_{min,i} \\ 0 & else \end{cases} \quad \forall i, t \tag{13}$$

Equations (14) and (15) can be used to calculate the current operating time $TO_{i,t}$ and stop time $TS_{i,t}$ depending on their previous values ($TO_{i,t-1}$ and $TS_{i,t-1}$) and the operating binary variable $X_{i,t}$.

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$$TO_{i,t} = X_{i,t} \cdot \left(1 + TO_{i,t-1}\right) \quad \forall i,t \tag{14}$$

$$TS_{i,t} = \left(1 - X_{i,t}\right) \cdot \left(1 + TS_{i,t-1}\right) \quad \forall i,t \tag{15}$$

The binary operating variable $X_{i,t}$ in formula (16) is equal to zero if no heat is generated and equal to one if heat is generated ($Q_{i,t} > 0$). The equation can be solved using the Big M method.

$$X_{i,t} = \begin{cases} 1 & \dot{Q}_{i,t} > 0 \\ 0 & \dot{Q}_{i,t} = 0 \end{cases} \quad \forall i,t \tag{16}$$

To finalize the definition of the mathematical model, the decision variables are defined in (17).

$$\dot{Q}_{i,t} \in \mathbb{R}^{+};\ \ \dot{Q}_{s,t} \in \mathbb{R}^{+,-};\ \ QS_{s,t} \in \mathbb{R}^{+};\ \ TO_{i,t} \in \mathbb{N}_0;\ \ TS_{i,t} \in \mathbb{N}_0;\ \ X_{i,t} \in (0,1) \quad \forall i,s,t \tag{17}$$

The mathematical model described in this text is implemented in Python using the Gurobi Optimizer, which is a solver for prescriptive analytics.

2.2 Use cases, data and assumptions

Having established the mathematical framework, the model is now applied on two large-scale DHS operated by German utilities, located in Berlin and Duisburg. This section outlines the considered use cases, focusing on the portfolio of plants used for heat generation in the respective DHS (the primary energy sources used, the electrical and thermal nominal loads, and the maintenance costs), information on thermal energy storages and further assumptions (wholesale fuel prices, emissions, electricity prices and additional costs associated with electricity consumption). This contextualization is important for the subsequent analysis, where the model is used to explain the operational dynamics and assess the economic and environmental impacts of the DHS scenarios. Table 2 summarizes the current heat generation plants in Berlin and Duisburg, as well as some planned and assumed plants for a better analysis of the renewable energy integration. The number of units, the energy source and nominal loads (electricity P_{max}, DHS supply $\dot{Q}_{max}$, and fuel $\dot{Q}_{f,max}$) are considered.

Table 2: Total nominal load, energy source, and units of the use case's DHS plants (*peak)

	Berlin					**Duisburg**				
plant	**units**	**source**	P_{max}	$\dot{Q}_{max}$	$\dot{Q}_{f,max}$	**units**	**source**	P_{max}	$\dot{Q}_{max}$	$\dot{Q}_{f,max}$
CHP 1	1	biomass	21.6	66	106	1	CH_4	32	66	139
CHP 2	9	CH_4	26.4	27.7	59.3	1	CH_4	203.4	170	434.9
CHP 3	1	CH_4	0.4	0.5	1.1	3	CH_4	3	3,3	6,9
CHP 4	1	CH_4	0.8	0.9	1.9	9	CH_4 / H_2	40.5	46.8	95.4
oil boiler 1	2	fuel oil		37	41.4	1	fuel oil		163	178
oil boiler 2	1	fuel oil		10	10.6	1	fuel oil		25	30
gas boiler 1	2	CH_4		37	41.4	1	CH_4		100	110
gas boiler 2	3	CH_4		99	109.2	1	CH_4		25	30
gas boiler 3	2	CH_4 / H_2		40	41.2					
gas boiler 4	1	CH_4		10	10.4					
gas boiler 5	2	CH_4		4	4.4		*not part of the portfolio*			
gas boiler 6	10	CH_4		27.6	30.6					
gas boiler 7	1	CH_4		1	1.4					
e-boiler 1	2	electricity	6.6	6.6		1	electricity	30	30	
e-boiler 2	1	electricity	0.4	0.4		1	electricity	30	30	
LHP geothermal		*not part of the portfolio*				1	geothermal	2.2	10	
LHP river	2	Spree > 8 °C	3.4	8.6		3	Rhine > 6 °C	10	30	
LHP waste water		*not part of the portfolio*				2	waste water	1.6	4	
LHP waste heat	1	waste water	0.2	1		2	industry heat	0.4	2.2	
solar thermal	1	solar		6.2*			*not part of the portfolio*			

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Only for two plants (Berlin's gas boiler 3 and Duisburg's CHP 4) a conversion from natural gas (CH_4) to hydrogen (H_2) is possible. The biomass used by Berlin's CHP 1 is in particular waste wood. Another energy source can be electricity for electric boilers (e-boilers) and large heat pumps (LHP), while LHP additionally use a heat source such as river water (Spree, Rhine) or geothermal energy. There is an operating restriction for river water heat pumps: Berlin's LHP requires a Spree temperature above 8 °C and Duisburg's LHP requires a Rhine temperature above 6 °C. The solar thermal plant in Berlin is assumed to have a size of 15,000 m² vacuum tube collector field with an annual solar yield in 2023 of about 6 GWh at a peak load of 9 MW. For the reference weeks, the peak load is 6.2 MW and the weekly solar yield is 248.8 MWh in summer and 5.1 MWh in winter.

The CHP's operating parameters and maintenance costs are presented in Table 3. Operating and shutdown times are not relevant for the other technologies, because these technologies are more flexible (except for the geothermal LHP with 100 h minimal operating and shutdown time).

Table 3: Minimal operating and shutdown times, and maintenance costs of the CHP plants

plant	Berlin				Duisburg		
	TO_{min}	TS_{min}	c_{me}	m	TO_{min}	TS_{min}	m
CHP 1	4	4	13	25	2	8	400
CHP 2	2	1		30	24	15	238
CHP 3	2	1		12	1	2	12
CHP 4	2	1		15	1	2	30

Hourly maintenance costs are assumed to be 60 €/h for the geothermal heat pump in Duisburg and 15 €/h for the other heat pumps. Thermal related maintenance costs are assumed to be about 0-10 €/MWh for boilers, 3 €/MWh for solar thermal systems and 1 €/MWh for large heat pumps. Both DHS include thermal storage systems with a total capacity of 1,450 MWh for Duisburg and 121 MWh for Berlin. All assumptions are based on data and experience of the associated partners.

To simulate the portfolios within the generated model, four observation periods were selected based on available real operating data. Two reference weeks show a low summer heat demand of 3,630 MWh for Berlin (August 2023) and 3,920 MWh for Duisburg (August 2021) and the other weeks are characterized by a particularly high heat demand for the DHS, in Berlin 22,150 MWh (November 2023) and in Duisburg 38,480 MWh (February 2021). In addition to the corresponding electricity prices in Figure 1, extremely low and high electricity prices were selected based on historical data (May 2016 *summer low*, December 2017 *winter low*, August 2022 *summer high*, December 2022 *winter high*).

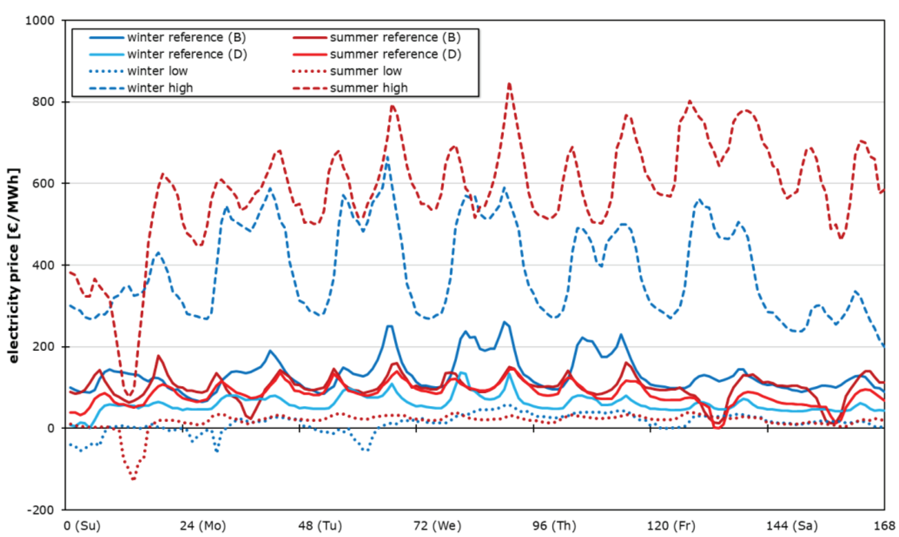

Figure 1: Electricity prices for simulations (low, high and reference-weeks for Berlin and Duisburg)

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These scenarios should represent extreme but not unrealistic situations of the German electricity market. Electricity fed into the grid is purchased by this varying wholesale electricity price. If the plants receive electricity from the grid (electric boilers and heat pumps), they have to pay taxes, surcharges, concession fees and location-dependent grid usage fees. In Berlin these specific costs amount to 65.8 €/MWh and in Duisburg to 54.1 €/MWh. The emission price, paid for the amount of carbon dioxide (CO_2) emitted, can vary between national and European emissions trading, depending on the legal situation. In the long term, it can be assumed that the various emissions trading schemes will align, which means that only one CO_2 price is defined for the assumptions. It varies between 50 € per ton CO_2 and 150 € per ton CO_2 (only for extreme scenarios with hydrogen an even higher value of 450 or 475 € per ton is assumed). The specific fuel prices and specific emissions based on literature and real-world are shown in Table 4.

Table 4: Assumptions for fuel costs and their specific carbon emissions (BAFA, 2023), (Kruse et al., 2022), (Merten et al., 2023)

Position	Wholesale Price, €/MWh	Emissions, kg CO_2/MWh
Electricity	Variable (Figure 1)	Variable
Natural gas CH_4	37.5	201
Fuel oil	117.4	266
Biomass	20	27
Hydrogen H_2 (green)	130 (extreme: 65)	25

3 RESULTS

This section of the paper presents 48 of the numerous simulations performed with the optimization program written in Python. Four of them (reference electricity prices and two CO_2 prices for a winter week in Duisburg and a summer week in Berlin) are presented in detail.
The optimization model produces several results for each simulation. It generates graphs displaying the hourly cumulative heat production of all plants during the observation period, as well as the storage operation and the storage level. In addition, pie charts are used to show the total weekly heat supply and incurred CO_2 emissions based on the producer. By categorizing heat-producing plants as either renewable or conventional, it is possible to improve the evaluation of heat quantities, carbon emissions, and total costs by incorporating the respective share of renewable energy producers. To make the results more comparable, the specific costs and specific CO_2 emissions per megawatt-hour of heat are also calculated. Figure 2 shows two representative optimization results for a winter week in Duisburg at two different CO_2 prices: 50 €/MWh and 150 €/MWh. The input data are otherwise identical.

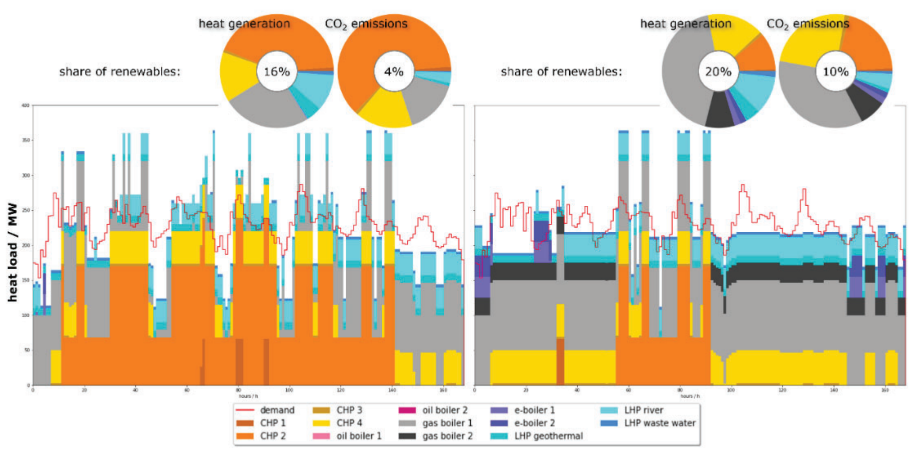

Figure 2: DHS plant operation in Duisburg, winter, reference electricity price, various emission price: 50 €/t CO_2 (left) and 150 €/t CO_2 (right)

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The figure illustrates a shift in the plant operation from CHP systems to boilers (including electric boilers, which are considered renewable) and heat pumps. This shift leads to an increase in the share of renewable energies in heat supply from 16 % to 20 %. At the same time, the share of renewables in CO_2 emissions increases. The evaluations take into account the fluctuating emission factor of the electricity mix, but it is not considered in the optimization process as there are no emission costs for electricity consumption. Additionally, it is evident that the utilization of CHP is primarily dependent on periods of high electricity prices, while the relatively costly electric boilers are only used during periods of low electricity prices. Storage operation depends on optimizing plant operations to minimize costs or maximize revenues.

A clear system change between lower and higher emission prices can also be seen in Figure 3, which shows the optimized plant operation for the selected summer week in the Berlin portfolio. During summer, CHP systems operate in close correlation with the peak electricity prices that occur in the morning and evening. Although cogeneration is not required to provide heat because of availability of alternative renewable heat generators, such as heat pumps, it is often a significant part of the heat supply to take advantage of the revenue generated by feeding electricity to the grid. As a result of the higher emission price, the biomass CHP 1 system displaces the CHP 2 system with a higher electricity index, so that the share of renewable heat reaches almost 100 %.

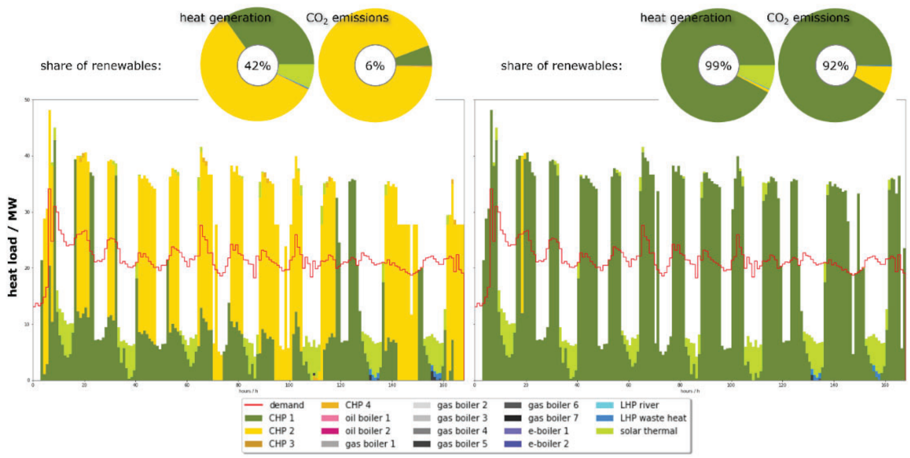

Figure 3: DHS plant operation in Berlin, summer, reference electricity price, various emission price: 50 €/t CO_2 (left) and 150 €/t CO_2 (right)

An overview of all simulations can be found in the following diagrams. Figure 4 shows the specific CO_2 emissions per heat supply, divided into the total generation (sum), and the generation from renewable or conventional plants. Figure 5 shows the specific costs (or revenues if the costs are negative) in the same division. The secondary axis in both figures shows the share of renewable heat generators in the total heat supply in the respective scenario.

In general, higher shares of renewable energy sources are present in all summer scenarios. In winter, when electricity prices are high, negative heat production costs (i.e., profits) can be achieved due to the economic CHP systems, regardless of the location and the slightly different individual portfolios. Costs tend to increase as electricity prices decrease, except in the Duisburg summer scenario with a CO_2 price of 150 €/MWh. The share of renewable heat is generally below 50 % in most scenarios, especially during periods of high electricity prices. The energy systems exhibit greater flexibility in response to extremely low and high electricity prices during the summer, resulting in more variable renewable shares, emissions, and costs. Duisburg has greater flexibility in terms of fluctuating electricity prices compared to Berlin. The winter scenarios show almost constant values for renewable share, emissions and costs.

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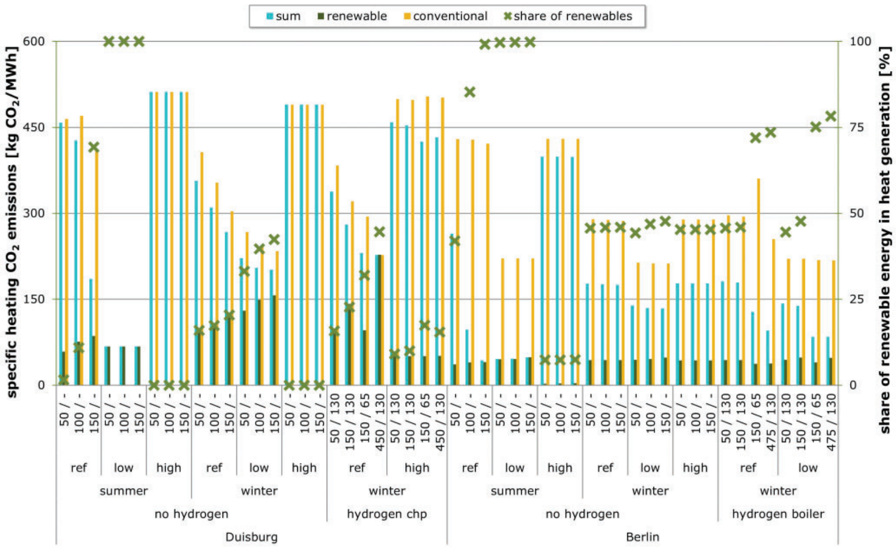

Figure 4: Specific heating CO_2 emissions for simulations with varied prices: electricity (reference, low, high), CO_2 emissions (50-475 €/t CO_2), green H_2 price (65-130 €/MWh)

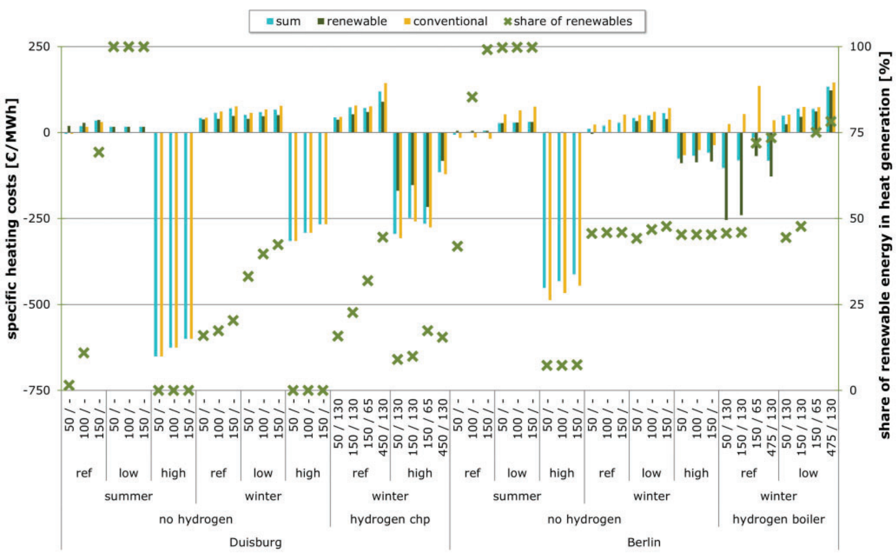

Figure 5: Specific heating costs for simulations with varied prices: electricity (reference, low, high), CO_2 emissions (50-475 €/MWh), green H_2 price (65-130 €/MWh)

In addition, there are clear differences in the evaluations considered for the hydrogen scenarios. The choice of electricity prices considered depends on the type of technologies used. In Berlin a boiler is used while in Duisburg a CHP system is used. It was found that if the price of green hydrogen is 65 €/MWh or if the emission cost is 450 €/MWh or 475 €/MWh, the hydrogen system will mostly displace the respective natural gas competing systems. The limit for the CHP plant in Duisburg is less strict than that for the boiler in Berlin. This is because the point at which natural gas or hydrogen technology becomes more cost-effective depends on the fluctuating price of electricity. Comparing scenarios with and without hydrogen technology shows that the CHP system has a greater impact. At high electricity prices, the share of renewable energy sources increases from 0 % to about 12 %. At reference electricity prices, the share increases from approximately 20 % to 23 % when the emission price is set at 150 €/MWh.

https://doi.org/10.52202/077185-0065

4 DISCUSSION

The successful cost-optimal integration of renewable heat generators into existing DHS was achieved through Python programming, in which MILP was integrated using Gurobi. Numerous analysis options can highlight the challenges based on the selected scenarios and thus derive recommendations for DHS utilities.

As expected, the share of renewable energy in heat generation can be increased by rising emission prices because of to the fact that renewable energy producers (electric boilers, heat pumps and solar thermal) do not have direct CO_2 emissions. Even if emissions can be attributed to them due to the consumption of electricity from the grid. However, since the controllable renewable generators tend to operate when electricity prices are particularly low, the emissions attributable to them will continue to decrease in the future, as the emission factor for the electricity mix is strongly correlated with the electricity price. The lower the price of electricity, the more renewable energy is in the grid and the lower are the emissions in the electricity mix. Certainly, 100 % renewable heat can only be provided during the summer weeks. Due to the chosen framework conditions, the share of renewables can be significantly increased in the winter weeks as well, e.g., through lower electricity prices, higher CO_2 prices or through the conversion of some plants to the use hydrogen instead of natural gas. Nevertheless, the winter weeks reach a maximum share of about 45 % for Duisburg and around 75 % for Berlin. At the same time, the significantly better values for Berlin must also be viewed critically, since the major share results from the biomass cogeneration plant. Biomass (here waste wood) is currently exempt from the CO_2 price according to the European Emissions Trading Act. In terms of cross-sectoral sustainability, the goal for waste wood should be material use rather than thermal conversion. Therefore, the legal classification of waste wood may change in the future.

The decrease in heat production costs with higher electricity prices and the increase with lower electricity prices can be explained by the dominance of the installed CHP capacity over heat pumps or electric boilers. This effect would be reversed if the predominant installations were to become more electricity consumers rather than electricity producers, as the summer scenario in Duisburg already shows. The higher share of heat pumps leads to a shift away from CHP, at least if the emission price is sufficiently high.

The lower flexibility to fluctuating electricity prices winter in Berlin compared to Duisburg is due to the significant imbalance between the installed heat load of electricity consumers and producers, as well as the higher proportion of producers that are independent of the electricity market. Duisburg has about 290 MW of CHP (electricity producers), 110 MW of power to heat systems (consumers), and 310 MW of fuel boilers (unaffected) installed (roughly a 3:1:3 ratio). In contrast, Berlin has about 100 MW of CHP, 20 MW of power to heat, and 270 MW of oil and gas boilers (about a 5:1:15 ratio).

To increase the share of renewables, hydrogen cogeneration can be used without significantly increasing operating costs, assuming relatively low hydrogen prices or high emission costs. However, the use of a hydrogen boiler must be critically evaluated based on the scenarios considered. The simulations show that the success of both hydrogen technologies is heavily reliant on future developments in requirements, emission costs, and fuel prices. Certainly, hydrogen cogeneration may already be a viable option in the right winter hours (depending on electricity prices).

It should be noted that, despite the potential feasibility, large-scale existing energy production still faces a major challenge in increasing the share of renewable energy, especially in times of high heat demand. At the same time, as the example of the summer week in Berlin has just shown, the available sustainable technologies (even with high emission prices) cannot always be used in a cost-optimal manner and the potential for higher yields from renewable heat generation cannot be exploited. The installed storage systems tend to be used for the economically optimal operation of CHP plants and are not nearly large enough to store renewable heat quantities over longer periods of time. Accordingly, the importance of seasonal thermal energy storage from the perspective of DHS operators becomes more acute. Longer observation periods are a limitation for the model as well as detailed technical description for temperature or load-dependent efficiencies. The program structure is not yet purely mathematical, which could lead to longer computation times.

https://doi.org/10.52202/077185-0065

5 CONCLUSIONS

The achieved aim of this study was to investigate the cost-optimal operation of renewable heat generators in existing DHS using MILP. The results showed that in summer scenarios with low electricity prices, a 100 % share of renewable energies was achieved for both application cases, Berlin and Duisburg, despite the low expansion of renewable energies. However, the share of renewables in heat supply tended to be lower due to high electricity prices and lower costs for CO_2 emissions. In the scenarios considered, the shares are mostly below 50 %. When electricity prices are high, the dominant CHP systems generate negative heat production costs, resulting in income. Otherwise, the costs of the scenarios increase slightly with higher shares of renewables. The energy system responded more flexibly to fluctuating costs of energy sources (electricity, gas, etc.) depending on the relationship between heat producers that generate electricity, consume electricity or are independent of the electricity market. In certain cases, hydrogen cogeneration can be a viable option to reduce emissions, especially in the face of rising emissions costs and high electricity prices, assuming that the hydrogen used is produced from green electricity in the long term.

Interesting possibilities for extending the model are the comparison of minimized emissions as a new objective function with minimized costs, the addition of seasonal thermal storage for longer time periods, and the incorporating of heating network restrictions such as hydraulic limitations of decentralized or centralized energy supply, the reduction of heat and pressure losses, the consideration of thermal inertia, or the optimization of supply temperatures. Furthermore, future studies could take into account other framework conditions, such as varying emission factors in the electricity mix between Berlin and Duisburg. This could lead to different spatial advantages for the renewable technologies.

NOMENCLATURE

B	quantity of boilers	(-)
C	costs	(€)
c	specific costs	(€/MWh)
COP	coefficient of performance	(-)
d	duration of a time step	(h)
e	specific emission costs	(€/t CO_2)
ε	specific emissions	(t CO_2/MWh)
η	efficiency	(-)
I	quantity of all plants, but solar	(-)
J	quantity of solar thermal plants	(-)
K	quantity of cogeneration plants	(-)
L	quantity of large heat pumps	(-)
m	specific maintenance costs	(€/h)
P	electric power	(MW)
$\dot{Q}$	thermal load	(MW)
QS	storage level	(MWh)
QSC	storage capacity	(MWh)
S	quantity of thermal storages	(-)
T	time horizon	(h)
TO / TS	operation / shutdown time	(h)
X	operating binary variable	(-)

Subscripts

a	allocations on electricity price	k	cogeneration plant
b	boiler	max / min	maximal / minimal
el	electric, electricity	me	el.-related maintenance
f	fuel	mh	heat-related maintenance
i	all controllable plants (not solar)	s	thermal storage
j	solar thermal plant	t	time step
l	large heat pump	th	thermal, heat

https://doi.org/10.52202/077185-0065

Abbreviations

CH_4	natural gas
CHP	combined heat and power, cogeneration
DHS	district heating system(s)
H_2	hydrogen
LHP	large heat pump(s)
MILP	mixed-integer linear programming
Ref	reference

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ACKNOWLEDGEMENT

Dissemination of this work is funded by Germany's Federal Ministry for Economic Affairs and Climate Action within the scope of the project "Technology-Open Energy System Analysis for the Derivation of Measures for the Decarbonization of Urban Heating Networks" ("*Technologieoffene Energiesystemanalyse zur Ableitung von Handlungsmaßnahmen für die Dekarbonisierung urbaner Wärmenetze*", TeoS, research grant no. 03EI1060A). Special gratitude to M. Lehmann, N. Löser, J. Scheipers, and C. Franck from *Stadtwerke Duisburg*, as well as J. Hinrichsen, S. Matthies, and J. Richter from *BTB Berlin* for providing relevant real-world data and for the extensive discussions regarding their district heating systems.

https://doi.org/10.52202/077185-0065