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Carbon capture from combined heat and power plants – Impact on the supply and cost of electricity and district heating in cities

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ABSTRACT

The capture and storage of biogenic CO_2 emissions from large point sources, such as biomass-combusting combined heat and power (CHP) plants, can contribute to climate change mitigation and provide carbon-negative electricity while supplying district heating in urban areas. This work investigates the impact of retrofitting CO_2 capture processes to CHP plants in a city energy system context. An energy system optimization model is applied to a case study of the city Västerås, Sweden, with scenarios involving two existing CHP plants in the city, retrofitted with either a heat-driven (MEA) or an electricity-driven (HPC) carbon capture process. The results show that the CHP plants might be retrofitted with either option without significantly impacting the district heating system operation or the marginal costs of electricity and district heating in the city. The MEA process mainly causes a reduction in district heating output (up to 30% decrease on an annual basis), which can be offset by heat recovery from the capture unit. The electrified HPC process does not impact the CHP plant steam cycle but implies increased import of electricity to the city (up to 44% increase annually) compared to a reference scenario.

1. Introduction

Cities and urban areas are major contributors to climate change, accounting for around 75% of CO_2 emissions from global final energy use (UN Habitat, 2022), and therefore play a key role in the mitigation of CO_2 emissions. The energy use for heating, electricity and cooling in cities is substantial and needs to be supplied with a low climate impact. Additionally, there is a need to not only reduce CO_2 emissions, but also to remove CO_2 from the atmosphere through carbon dioxide removal (CDR). The IPCC (2018) includes CDR in several of their scenarios to limit global warming to 1.5 °C. In this context, the capture and storage of biogenic CO_2 emissions (BECCS) applied to combined heat and power (CHP) plants in cities is an opportunity to contribute to carbon-negative energy supply in urban areas.

In Sweden, which is used as a case study in this work, biogenic CO_2 emissions are generated in large scale in the district heating sector, in which municipal waste and forest residues are combusted in CHP plants to produce electricity and district heating for space heating in cities. If applied to all existing CHP plants in Sweden, the potential for BECCS amounts to at least 10 $MtCO_2$ removed per year (Beiron et al., 2022a), which can be compared to the total amount of fossil CO_2 emitted in Sweden in 2019, amounting to 41 $MtCO_2$. This would be sufficient to meet the proposed BECCS target in Sweden (SOU, 2020), stating that BECCS should contribute with 3–10 $MtCO_2$ of CDR annually by year 2045 to achieve net-zero and thereafter net-negative emissions. Rapid deployment of BECCS is needed to be able to scale up CDR to the levels required to meet climate targets (Fuss and Johnsson, 2021), and business models and/or policy support are needed to incentivize CDR installations (Zetterberg et al., 2021). In response to this, The Swedish Energy Agency (Energimyndigheten, 2021) has announced that a reversed auctioning system will be put in place by year 2023 to help financing CDR projects in Sweden. This makes Sweden an interesting case as a potential forerunner in real implementation of CDR at scale.

Several Swedish municipal district heating companies have expressed their interest in retrofitting CHP plants with carbon capture systems (Avfall Sverige et al., 2022) and feasibility studies have been conducted to investigate site-specific conditions for BECCS and to estimate costs (Energimyndigheten, 2022). The utility company Stockholm Exergi has received funding from the EU innovation fund to support the construction of a full-scale BECCS unit at a biomass-fired CHP plant in central Stockholm to remove 800 $ktCO_2$ annually (2022).

Absorption-based carbon capture applied to flue gases has an energy penalty that impacts the energy performance of CHP plants, although

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Nomenclature

Latin

C	cost
D	demand
E	annual CO_2 emissions
i	technology in the set of technologies, I
k	carbon capture process in the set of processes, K
m	mass flow of CO_2 captured
p	electricity
q	thermal energy (heat, fuel, cooling)
s	capacity of investment
t	timestep in the set of timesteps, T
TT	length of timestep
w	imported electricity
W	limit on electricity import
z	stored energy

Greek

α	power-to-heat ratio
λ	carbon capture energy demand
γ	heat recovery factor
η	efficiency
ϕ	steam turbine electricity reduction factor
σ	CO_2 emission factor
ω	electricity demand, CO_2 conditioning

Subscripts and superscripts

bat	battery
CC	carbon capture
ch	charge
comp	compression
cool	cooling
cycl	cycling
dch	discharge
el	electricity
inv	investment
HP	heat pump
recov	recovered heat
run	running
SC	steam cycle
store	storage

Abbreviations

BECCS	bio-energy carbon capture and storage
CDR	carbon dioxide removal
CHP	combined heat and power
COP	coefficient of performance
HPC	hot potassium carbonate
MEA	monoethanolamine

the magnitude of this impact will depend on (i) the type of capture process, and (ii) the heat integration of the capture unit. Previous works have assessed the energy penalty incurred when CHP plants are retrofitted with the monoethanolamine (MEA) (Beiron et al., 2022a; Roshan Kumar et al., 2023) and hot potassium carbonate (HPC) (Gustafsson et al., 2021; Roshan Kumar et al., 2023) CO_2 capture processes. The results from the cited studies indicate a reduction in electricity generation and that the district heating generation can be either increased or decreased compared to the reference depending on the type of capture process and the level of heat recovery from the capture process. If CHP generated steam is used to drive the capture process, the point of steam extraction can also impact the energy penalty (Magnanelli et al., 2021).

Thus, the capture process is highly integrated with the CHP plant and might thereby impact the city electricity and district heating supply, making it relevant to consider variability in energy prices and demands for cost-effective integration of capture processes in the city energy system. Here, a city-level energy system refers to the local district heating and electricity systems in an urban area, distinguished by a limited import of electricity to the city from the regional transmission grid, and no import/export of district heating to/from the city. Levihn et al. (2019) discuss the cost of operating the Stockholm district heating system with BECCS, and Beiron et al. (2022a) show that the level of heat recovered from the CO_2 capture process can impact the operation of other units in the local district heating system. Apart from these references, there is a lack of studies that examine the city-level integration of BECCS from CHP plants. With the high interest in BECCS in the Swedish district heating sector, there is a need for more research on the topic.

This work analyses the integration of BECCS in a city for generation of carbon-negative electricity and district heating. The work compares the retrofit of two absorption-based carbon capture processes (one heat-driven, MEA, and one electricity-driven, HPC) to a waste-fired and a biomass-fired CHP plant, considering the impact of the carbon capture processes on the city energy balance and the marginal costs of heat and electricity. An energy system optimization model is applied to study the cost-optimal dispatch of technologies in the city energy system. To the best of our knowledge, this is the first model presented that considers in detail a city-level energy system with BECCS applied to CHP plants, and the integration of these in the city energy system. Thus, the main novelty of the work lies in the modeling of carbon capture processes and heat recovery related constraints in a city energy system context, as well as the estimation of carbon capture-induced impacts on the city energy supply and cost.

2. Method

The work models CHP plants with BECCS in a city context, including the district heating and electricity sectors. Two absorption-based carbon capture processes are compared – the MEA process that is commonly used for benchmarking, and the HPC process that will be installed at a CHP plant in Stockholm. The capture processes are described in Section 2.1. The modeling method is described in Sections 2.2 and Section 2.3 presents the case study and the scenarios examined.

2.1. Carbon capture processes

Both the MEA and HPC processes are based on absorption of CO_2 from flue gases. The CO_2 is absorbed by a solvent (MEA or HPC) in the absorber column, from which CO_2-lean flue gas exits. The solvent is regenerated (i.e., CO_2 is desorbed) in the stripper column. The desorbed CO_2 leaves the stripper column with high purity and is sent to compression and liquefaction processes prior to being transported to a permanent storage site. In the MEA process, the absorption/desorption is driven by temperature differences (temperature-swing), where the absorption is carried out at low temperature, and heat is added for the desorption step. Condensing steam at around 120–130°C is typically used to supply the heat for solvent regeneration. In contrast, the HPC process uses a pressure-swing to drive the absorption/desorption. The absorption is carried out at elevated pressure, and the desorption at a lower pressure level. Thus, the flue gas needs to be compressed for the absorption, implying an electricity demand. Heat is also needed for solvent regeneration in the HPC process, but in slightly lower quantities than the MEA process. An internal heat recuperation system with flash boxes can be applied to supply the HPC heat demand without using external steam (Capsol, 2023).

Both capture processes have cooling demands at temperature levels that could be recovered for district heating generation, i.e., above 60°C, as well as cooling demands at temperatures lower than 60°C, that could be recovered by heat pumps. If not used for district heating, the low-grade heat must be cooled from the process using cooling utilities. The two capture processes are based on similar equipment (absorption and desorption columns, CO_2 conditioning plant) and can be assumed to have approximately the same investment cost. The main equipment differences are the HPC flue gas compressor and the slightly bigger reboiler heat exchanger in the MEA process. The transport and storage costs are also independent of the choice of process, but the energy requirement (electricity or heat consumption) and the corresponding operating cost of carbon capture differ.

2.2. City energy system optimization model

The city energy system model applied in this work was first presented by Heinisch et al. (2019) and has been extended to enable flexible operation of CHP plants by Beiron et al. (2022b). In the present work, the model is further developed to consider carbon capture from CHP plants. The model adopts a social planner perspective, with the objective to minimize the total system cost of supplying demands for electricity and district heating, including investment and operating costs [Eqs. (1)–(3)], while complying with targets on CO_2 capture from specific CHP plants, Eq. (4). CHP plant capture targets are chosen rather than a system-wide capture target for the city (without specifying which plant should capture CO_2), based on the format for reversed auctioning of negative emissions planned in Sweden, in which plant owners make bids to capture a given amount of CO_2 to a certain cost. The modeling does not allow for fossil CO_2 emissions in the city, other than from waste incineration (around 48% fossil origin (Statistics Sweden, 2019)). Transmission between the regional electricity grid and the city is included, but with a limit on grid connection capacity, Eq. (5). Descriptions of terms are given in the nomenclature list. The available technologies and cost data can be found in Appendix A. The model is run for one year with a time resolution of three hours.

$$MIN : C^{tot}$$

$$= \sum_{i \in I \setminus I_{store}} \left(C_i^{inv} s_i + TT \sum_{t \in T} \left(C_i^{run} p_{i,t} + C_i^{run} q_{i,t} + C_{i,t}^{cycl} \right) \right) + \sum_{i \in I_{store}} C_i^{inv} s_i + \sum_{t \in T} \left(C_t^{el} w_t + C^{cool} q_{cool,t} \right) + C_{CC}^{inv} s_{CC} \tag{1}$$

$$D_t^P + z_{bat,t}^{ch} + \sum_{i \in I_{PtH}} p_{i,t} + \omega \sum_{k \in K} \sum_{i \in I_{CHP}} m_{CO2,i,k,t} + p_{HPC,t} \le \sum_{i \in I_{El}} p_{i,t} + w_t + z_{bat,t}^{dch}, \quad \forall t \in T \tag{2}$$

$$D_t^{DH} + \sum_{i \in I_{TES}} z_{i,t}^{ch} \le \sum_{i \in I_{Heat}} q_{i,t} + \sum_{i \in I_{TES}} z_{i,t}^{dch} + q_{recov,t}, \quad \forall t \in T \tag{3}$$

$$\sum_{k \in K} \sum_{t \in T} m_{CO2,i,k,t} \le 0.9 E_i, \quad \forall i \in I_{CHP} \tag{4}$$

$$w_t \le W, \quad \forall t \in T \tag{5}$$

The carbon capture processes are considered as possible retrofits to CHP plants. The HPC process is assumed to be fully driven by electricity ($p_{HPC,t}$) with an electricity consumption proportional to the amount of CO_2 captured ($m_{CO2,i,k,t}$), Eq. (6). The MEA process is assumed to be driven by heat, through the condensation of steam extracted from the CHP steam cycle, and is modeled as described in Eqs. (7) – (11). The steam extraction causes a reduction in CHP steam turbine electricity generation, Eq. (7), that also incurs a penalty on district heating delivery, Eq. (8). The electricity reduction is calculated assuming that 10% of the nominal electricity generation capacity is lost Beiron et al., 2022a). A share of the energy used to drive the MEA and HPC capture and CO_2 conditioning processes can be recovered as low-grade heat of sufficient temperature to be used for district heating, as stated in Eq. (9). The share of low-grade heat that cannot be recovered for district heating directly through heat exchanging must either be cooled from the process, Eq. (10), or recovered for district heating generation with a heat pump, Eq. (11) (coefficient of performance (COP) = 3). A cooling cost of 5 €/MWh (Zhai and Rubin, 2011) is included in Eq. (1). The mass flow of CO_2 captured is limited by the fuel load, the design capture rate of the capture unit (assumed to be 90% of CO_2 emissions at full load) and the carbon content of the fuel, σ_C, Eq. (12). The actual capture rate during operation is optimized by the model and can vary between 0 – 90% of flue gas emissions. Higher capture rates have been demonstrated via modeling and pilot scale operation, for example with advanced solvents (Gao et al., 2019; Hirata et al., 2020) and with process design modifications for 35% wt MEA (Michailos and Gibbins, 2022). The capture-related parameters in Eqs. (6)–((12) are given in Table 1.

$$p_{HPC,t} = \lambda_{HPC} \sum_{i \in I_{CHP}} m_{CO2,i,HPC,t}, \quad \forall t \in T \tag{6}$$

$$p_{i,t} = p_{SC,i,t} - \phi_i m_{CO2,i,MEA,t}, \quad \forall t \in T, \ i \in I_{CHP} \tag{7}$$

$$q_{i,t} = q_{SC,i,t} - m_{CO2,i,MEA,t} (\lambda_{MEA} - \phi_i), \quad \forall t \in T, i \in I_{CHP} \tag{8}$$

$$q_{recov,t} \le \sum_{i \in I_{CHP}} \sum_{k \in K} \lambda_k \gamma_k \theta_k m_{CO2,i,k,t}, \quad \forall t \in T \tag{9}$$

$$q_{cool,t} = \sum_{i \in I_{CHP}} \sum_{k \in K} \lambda_k \gamma_k m_{CO2,i,k,t} - q_{recov,t} - q_{HP,CC,t} \frac{COP_{HP} - 1}{COP_{HP}}, \quad \forall t \in T \tag{10}$$

$$q_{HP,CC,t} \le \sum_{i \in I_{CHP}} \sum_{k \in K} m_{CO2,i,k,t} \lambda_k (1 - \gamma_k \theta_k) \frac{COP_{HP}}{COP_{HP} - 1}, \quad \forall t \in T \tag{11}$$

$$\sum_{k \in K} m_{CO2,i,k,t} \le 0.9 q_{fuel,i,t} \sigma_{C,i}, \quad \forall t \in T, i \in I_{CHP} \tag{12}$$

In addition to the energy demand for carbon capture, the electricity

Table 1
Parameters describing the carbon capture processes.

Parameter	MEA	HPC	Unit	Reference
Steam turbine electricity reduction, ϕ	0.31–0.37	–	MJ_{el}/$kgCO_2$	
Electricity for compression and liquefaction, ω	0.1	0.1	MWh_{el}/t_{CO2}	Ignell and Johansson (2021)
Carbon capture energy demand, λ	3.6 (heat)	0.85 (power)	MJ/$kgCO_2$	Beiron et al. (2022c), Gardarsdóttir et al. (2018)
Cooling demand factor[a], γ	1.1	1.4	MW_{cool}/MW_{λ}	Roshan Kumar et al. (2023)
Share of cooling demand recoverable for DH through heat exchangers, θ	0.64[b]	0.67	[-]	Ignell and Johansson (2021), Roshan Kumar et al. (2023)
	Biomass	**Waste**		
CO_2 emissions, σ_C	0.405	0.33	tCO_2/MWh_{fuel}	

[a] Cooling demand of CO_2 capture, compression and liquefaction processes, relative to capture process energy demand.
[b] The share 0.64 is based on the MEA capture process design simulated by (Ignell and Johansson, 2021) which does not include a rich-stream split (a measure to slightly reduce the capture process heat demand). With the rich-stream split, a heat recovery for DH share of 0.25 has been reported (Eliasson and Fahrman, 2020).
DH, district heating.

consumption associated with CO_2 compression and liquefaction (ω) is included in the modeling, Eq. (2). Costs for CO_2 transport and storage are not included since these are assumed to be the same for both capture options, and the analysis of these costs is outside the scope of this work and will strongly depend on how the transport logistics are established, e.g., if several sites share transportation system. Yet, CO_2 capture and conditioning plant investment costs are included in Eq. (1).

2.3. Case study and scenarios

The model is applied to a case study of the city Västerås in Southern Sweden (NordPool electricity price area SE3) and, as mentioned above, the model minimizes the total system cost of supplying demands for electricity and district heating while complying with targets on CO_2 capture from CHP plants. A brownfield approach is chosen, in which current capacities of district heating production units are included in the system, but new investments in non-fossil generation and storage technologies are possible, e.g., solar PV and thermal energy storage. Table 2 gives the current plant portfolio of the district heating system in Västerås, which is CHP-dominated. Hourly demand profiles for district heating and electricity are based on data from the city of Gothenburg, Sweden, and scaled to fit the annual demand data in Table 2. Data for Västerås was not available, but the district heating demand generally correlates with the air temperature, which follows similar patterns in Gothenburg and Västerås. The shape of the demand profiles are found in (Beiron et al., 2022b). The waste-fired plant is constrained to operate with a constant waste supply rate on a monthly basis, due to the inappropriateness of storing waste for extended time periods.

The model is run for the scenarios summarized in Table 3. We study ambitious scenarios in which either the MEA or the HPC process is installed at both the waste-fired and the recycled wood CHP plants. Annual CO_2 capture targets for each plant are derived from reference runs without carbon capture, and set to 90% of plant CO_2 emissions in the reference run, i.e., corresponding to regular operation with a 90% carbon capture rate. However, the model is free to choose when to capture CO_2 and can increase the fuel use to generate more CO_2 than in the reference run to enhance this flexibility (i.e., any extra CO_2 generated does not have to be captured, as long as the annual capture targets are met). The reference dispatch of the plants is found in Appendix B. The scenarios also cover the impact on the dispatch of increased electricity and biomass prices, with low and high levels for price input data. The low-level biomass costs are based on current price levels (The Swedish Energy Agency, 2021), and the higher level assumes a doubling of prices. The fuel costs are found in Table 4. The prices of wood fuels are based on price data in Sweden (The Swedish Energy Agency, 2021). The cost of wood pellets includes pre-processing costs. The biogas price is coupled to the price of wood chips, under the assumption that biogas is produced through gasification of wood chips with 70% conversion efficiency, with the cost of the gasifier equipment included in the form of 20 €/MWh being added to the fuel cost. The total cost of the gasifier equipment is taken from a previous paper (Thunman et al., 2015), under the assumption of 8000 full-load hours. The electricity import price profiles, plotted in Fig. 1, are based on historical price data in the SE3 area for year 2019 (low level) and the period July 2021 – June 2022 (high level), with average prices of 38 €/MWh (2019) and 95 €/MWh (2021/22), respectively.

Table 2
District heating system plant portfolios of Västerås and annual electricity and district heating demand (year 2018). Based on (Daraei et al., 2021). CHP heat generation capacity is exclusive of flue gas condenser heat.

Plant type	Capacity	Unit
Municipal solid waste CHP	48 / 98	MW_{el} / MW_{heat}
Recycled wood[a] CHP	53 / 92	MW_{el} / MW_{heat}
Wood chip[b] CHP	56 / 118	MW_{el} / MW_{heat}
Heat pump	27[c]	MW_{heat}
Tank thermal energy storage	2100	MWh_{heat}
Annual electricity demand	1248	GWh_{el}
Annual district heating demand	1695	GWh_{heat}

[a] Recycled wood refers to demolition wood from building construction material, pallets etc.
[b] Wood chips refers to forest residues (slash), e.g., tops and branches from harvested trees.
[c] COP = 3.5.

Table 3
Scenarios studied. CO_2 capture targets are based on the reference scenario without capture.

Scenario	Capture process	CHP plants with BECCS	CO_2 capture target [$ktCO_2$/year] (Waste CHP + recycled wood CHP)
Ref	None	None	0
MEA	MEA	Waste CHP + Recycled wood CHP	518 + 282
HPC	HPC	Waste CHP + Recycled wood CHP	518 + 282
Electricity price	*Low level*: profile for year 2019		
	High level: profile for the period July 2021 – June 2022		
Biomass price	*Low level*: recycled wood: 10 €/MWh, wood chips: 20 €/MWh		
	High level: recycled wood: 20 €/MWh, wood chips: 40 €/MWh		

Table 4
Fuel costs.

Fuel	Cost [€/MWh] Low level	High level
Municipal solid waste	1	1
Recycled wood	10	20
Wood chips	20	40
Wood pellets	30	50
Biogas	49	77

3. Results and discussion

The results provide the impact of BECCS on the CHP plant and city energy balances, the marginal costs of electricity and district heating, and the cost-optimal heat integration of the capture processes.

3.1. Impact of CO_2 capture on the CHP and city energy balances

3.1.1. CHP plants

The studied carbon capture processes are energy intensive and impact the annual CHP energy supply to the city. Fig. 2 shows the cost-optimal CHP production levels of electricity and district heating for three scenarios modeled with low electricity and biomass price levels, with the carbon capture energy use marked. The MEA process causes a 30% reduction in annual district heating generation from the waste-fired plant, while the decrease in electricity generation is 10% (as assumed in Section 2.2). The electrified HPC process is not directly integrated with the CHP steam cycle, but if the HPC electricity demand is provided by the steam turbine generator, there is a 25% reduction in the net annual electricity supply from the waste CHP plant, compared to the reference scenario.

The waste-fired plant operates as baseload in the district heating system with a high number of full-load hours, both in the reference and carbon capture scenarios. Thereby, the reduced energy output from the waste CHP plant cannot be compensated with increased plant utilization, and the plant energy output is not impacted by increased electricity or biomass price levels. In contrast, the recycled wood CHP plant operates as intermediate load in the district heating system (around

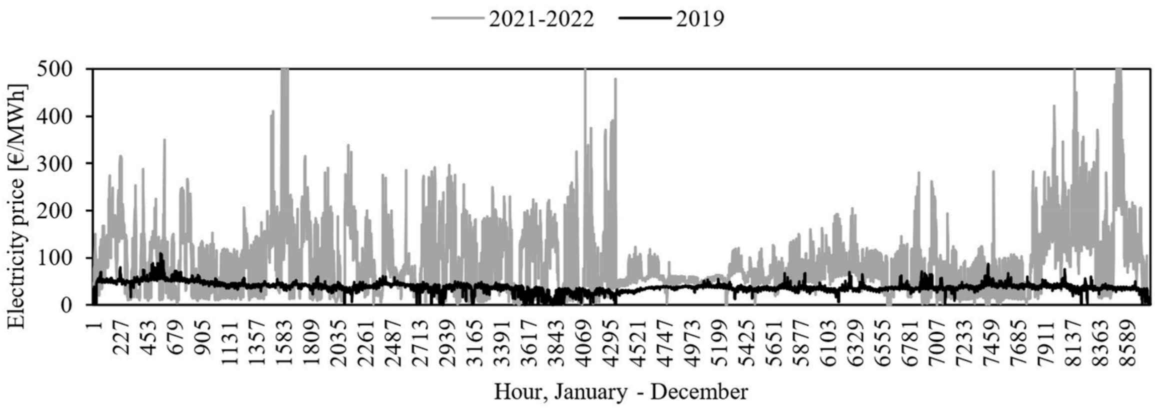

Fig. 1. Electricity price profiles for year 2019 and the period July 2021-June 2022 in the NordPool price area SE3.

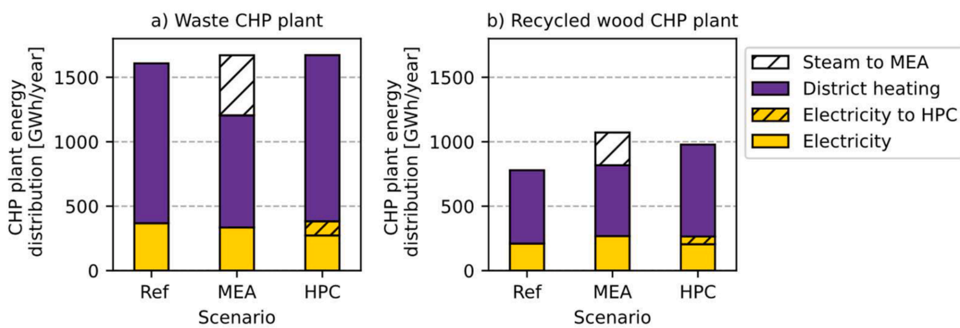

Fig. 2. Modeled annual CHP plant energy distributions for a) the waste-fired CHP plant, and b) the recycled wood CHP plant, with respect to electricity and district heating generation, and carbon capture process energy consumption. The numbers represent the 2019 electricity price level and lower biomass prices. The sum of the energy outputs corresponds to the total thermal energy input to the steam cycle.

4400 full-load hours in the reference scenario) with the possibility to increase utilization. This is seen in the increased energy output levels in the MEA and HPC scenarios in Fig. 2b. That is, the recycled wood fuel use increases to compensate for the carbon capture-induced loss of heat and electricity production.

Based on the plant annual utilization rates and full-load hours, it is deduced that the waste-fired plant has limited possibilities for flexible capture of CO_2, i.e., the plant capture target is set at a high level which requires continuous carbon capture with a high utilization level of the capture process. The recycled wood plant, with its lower degree of utilization and possibility for increased fuel use, has a greater freedom in choosing when to capture CO_2. Flexible carbon capture (i.e., varying the CO_2 capture rate over time) is incentivized by electricity price variability. At times when electricity prices are high, the CO_2 capture rate decreases, which enables increased electricity supply from the CHP plants, as well as reduced electricity consumption by the CO_2 conditioning plant. Similar patterns are also observed when the district heating demand peaks, and the capture plant load is reduced to avoid the loss of CHP heat generation. District heating demand peaks might also coincide with electricity price peaks, resulting in double benefits of reduced capture plant load (increased supply of electricity and district heating). In this way, the operation of the capture process is adapted (although still meeting the annual capture targets) to support the city energy balance and minimize the system cost of electricity and heat supply.

3.1.2. *City energy system*

Retrofitting CHP plants with CO_2 capture affects the electricity balance in the city. In particular, the HPC process causes an increased electricity demand (+170 GWh), together with the electricity consumption of the CO_2 compression and liquefaction unit (+72 GWh), increasing the annual city electricity demand with 19.4%. If the new electricity demand is provided by the CHP plant with capture, there would be a corresponding decrease in the net electricity generation supplied to the city from that plant. The intermediate and peak CHP plants can potentially increase their operation slightly to supply more electricity, but the resulting electricity import to the city also increases significantly in the model results. New investments in solar PV are cost-competitive in all scenarios, in particular in the scenarios with high electricity price levels. New intermediate load biogas combined cycle condensing plants are also cost-competitive investments with the high electricity price levels, but only for low biomass price levels.

With the HPC process, in the 2019 scenarios with low price levels, the annual electricity import increases with 30–44% compared to the reference without capture. The corresponding increase in import is 6–11% for the HPC scenarios with high electricity prices. That is, the higher electricity prices incentivize increased electricity generation from units in the city (CHP plants, and the new investments in solar PV and biogas combined cycle), and results in a five-fold increase in the export of electricity from the city to the regional grid compared to the scenarios with low electricity price levels (for both HPC and MEA). Hence, with high electricity price levels, the modeled reduction in net CHP electricity generation in the capture cases is, to some extent, offset by the increased electricity generation from solar PV and biogas combined cycles.

In the studied district heating system, the use of the two peak-load heat production units (i.e., the wood chip CHP plant (not retrofitted with carbon capture due to few operating hours) and the heat pump, Table 2) is affected by the carbon capture targets. However, the wood chip CHP plant and heat pump are used sparingly in the reference scenario (140 and 10 GWh of annual heat production, respectively, compared to the total demand of 1695 GWh). Therefore, changes in the operation of these units have a small impact on the system as a whole. With the MEA process, the heat supply from CHP plants with carbon capture decreases, and leads to larger heat production from the wood chip CHP plant and heat pump. With the HPC process, the wood chip CHP plant and heat pump operation decreases, as extra heat is available to recover from the capture unit (as shown in Section 3.2 below), reducing the need for additional heat production. Thermal energy storage capacity is, to some extent, a cost-effective investment in all scenarios, and acts as an additional buffer in the district heating system that reduces the need for peak heat generation.

3.2. Heat integration of carbon capture processes

Fig. 3 visualizes the cost-optimal share of heat recovered from the MEA and HPC processes in the modeled scenarios on an annual basis. Independent of electricity and biomass price levels, the share of heat recovered from the MEA and HPC processes, 64% and 67% respectively (Table 1), equals the maximum recoverable share without applying heat pumps. The recovered MEA process heat offsets a large share of the lost CHP district heating output (Fig. 2), which is also compensated by the increased utilization of the recycled wood CHP plant. Since the HPC process does not impact the district heating production from the steam cycle, the recovered heat from the HPC process does not compensate for any heat loss, as is the case for the MEA process, and instead represents a "new" heat production source in the district heating system. Depending on heat demand variations (mainly seasonal), the value of heat recovery changes over time. For instance, during summer when the heat demand is low, there is limited use for additional district heating supply from heat recovery, as the waste CHP plant can meet the heat demand on its own. Thereby, large-scale heat storage systems are needed to efficiently take advantage of larger shares of heat recovery, to be used at times with high heat demand.

New heat pump installations to increase the share of recoverable heat from the capture processes are not cost-optimal investments in any scenarios. Again, increased heat output is not necessarily valuable in the studied district heating system, making a new heat pump installation for process heat recovery redundant. However, in district heating systems with a need for increased heat production (due to increased demand or replacement of production units) or limited access to cooling utilities, heat pumps might be incentivized.

3.3. The cost of carbon capture

3.3.1. Marginal energy cost of operating CO_2 capture plants

The marginal cost of energy utilities (electricity, heat and/or cooling) for carbon capture from the two CHP plants in the studied system are plotted in Fig. 4, as obtained from the resulting marginal values on Eq. (12). This marginal value is interpreted as the cost to capture one unit more of CO_2 from each CHP plant, in terms of the cost for electricity, cooling utility and/or fuel consumption in the city, similar to what is commonly denoted as the operating expenditure of carbon capture but derived using a different method.[1] Consistently, the city marginal energy cost of carbon capture is higher for the HPC process than for the MEA process, considering that the HPC process consumes electricity which is, for most hours, a more expensive energy carrier than the CHP-generated steam used in the MEA process. The HPC process also impacts the net CHP electricity supply to a greater extent than the MEA process (Fig. 2).

In most cases, the cost is higher for carbon capture from the waste-fired plant than from the recycled wood plant, although this is an effect of the differing utilization levels. That is, the cost of capturing one additional ton of CO_2 from the waste-fired plant is high, because it already captures a high share of the annual emissions possible to capture, and additional CO_2 would have to be captured during unfavorable market conditions (high electricity price and/or heat demand). Lowering the annual CO_2 capture target thereby reduces the marginal cost of energy for carbon capture. In contrast, the recycled wood CHP plant can increase the fuel use to generate more CO_2 when market conditions are favorable and capture it to a lower cost. The exception is seen when biomass prices are high and electricity prices are low, which makes capture from the biomass-fired plant more expensive.

3.3.2. Impact on marginal costs of electricity and district heating

The resulting marginal values on Eqs. (2) and (3) give the marginal costs of producing electricity and district heating in the city. The marginal cost of electricity does not differ significantly between the reference, MEA and HPC scenarios. That is, carbon capture can be expected to have a low impact on the marginal cost of electricity in the city, as long as sufficient transmission capacity from the regional grid is available, and/or new investments can be made in local electricity generation, e.g., solar PV. The average marginal cost of electricity differs with less than 0.1 €/MWh with the 2019 electricity price profile and up to 2 €/MWh with the 2021/22 prices.

Fig. 5 plots the duration curves of the marginal cost of district heating in the city for one year. The marginal cost of heat is zero for many hours of the year in all scenarios, due to the must-run constraint on the waste-fired plant, that results in excess heat generation during the summer. In the HPC scenarios, the abundance of capture process heat available to recover for district heating increases the number of hours with excess heat and zero marginal cost, and reduces the cost of heat compared to the reference without capture. The MEA process displays a similar but weaker trend, and follows the marginal cost of heat in the reference scenario to a large extent due to the possibility for heat recovery. However, without the possibility to recover heat from the MEA capture process, or if a lower share than assumed in this work can be recovered (see Table 1), the marginal cost of district heating increases compared to the reference scenario (not shown), because the reduction in CHP heat production cannot be sufficiently compensated by (the low degree of) heat recovery, i.e., the city heat production cost increases. However, the carbon capture-induced impact on the marginal cost is small relative to the difference caused by increased electricity and/or biomass prices (compare Fig. 5a–c). The annual average marginal cost of heat in the city is 0.5 –10.8 €/MWh in all scenarios, and the maximum increase in the average marginal cost of heat with carbon capture is +1.6 €/MWh with the MEA process. The HPC process gives a reduced average marginal cost of heat in all scenarios (up to 7 €/MWh decrease).

3.3.3. Financing BECCS

At the city level, the results indicate that the capture process energy demand does not significantly impact the marginal electricity or heat costs in the studied city. However, at the plant level, the CO_2 capture energy demand is more noticeable and costly, and the energy cost is impacted by electricity and biomass price levels. The social planner perspective adopted in the modeling does not offer insights into financial models to cover the cost of BECCS that the plant must pay and is an area for further research. In addition to government support, supply chain driven commercialization of BECCS has been suggested (Klement et al., 2021), as a way to project the cost of BECCS to consumer products while only marginally increasing the product cost. For instance, this work shows that the energy cost of BECCS has a small impact on the cost of electricity and heat in the city (i.e., low impact on the product cost) and could promote a customer-based financing strategy. However, it should also be kept in mind that the energy cost of carbon capture is only a part of the total cost of BECCS, which also includes investment, transport and storage costs, as studied in previous publications (Beiron et al., 2022a; Karlsson et al., 2023). For CHP plants, the capture plant

[1] The operating expenditure of carbon capture is typically calculated based on fixed-value assumptions on utility costs, without considering variability in energy prices or system interaction, as is enabled by the energy system optimization modeling method.

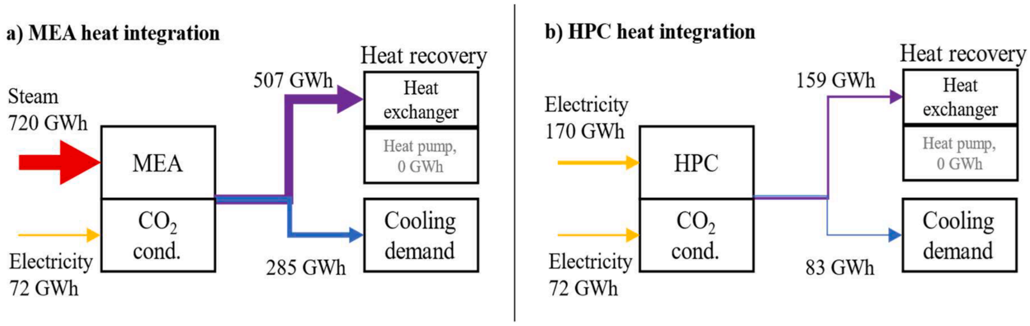

Fig. 3. Cost-optimal carbon capture process heat integration, with heat recovery to district heating and cooling demand. **(a)** MEA process. **(b)** HPC process. The same amount of CO_2 is captured from both processes (800 ktCO_2/year). The box "CO_2 cond." represents the CO_2 compression and liquefaction process.

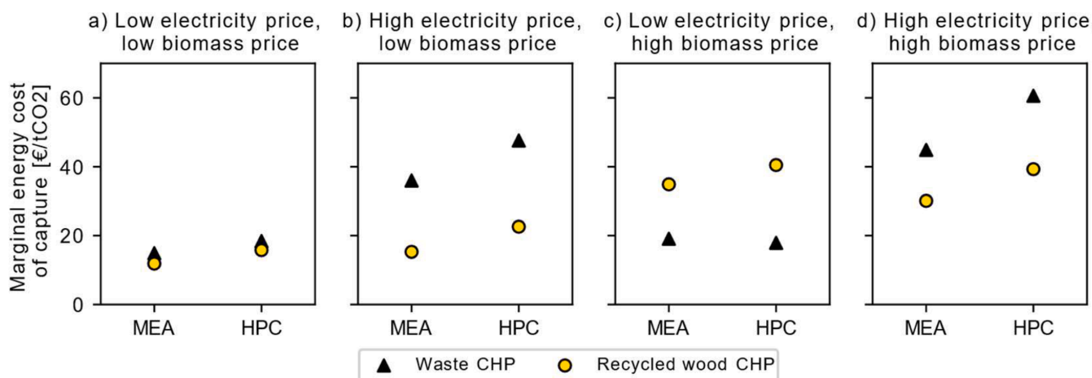

Fig. 4. Marginal cost of energy to capture CO_2 from the waste-fired and recycled wood CHP plants using the MEA and HPC capture processes for different energy price levels (Table 3). (a) Low electricity and biomass prices, (b) High electricity prices and low biomass prices, (c) Low electricity prices and high biomass prices, (d) High electricity and biomass prices.

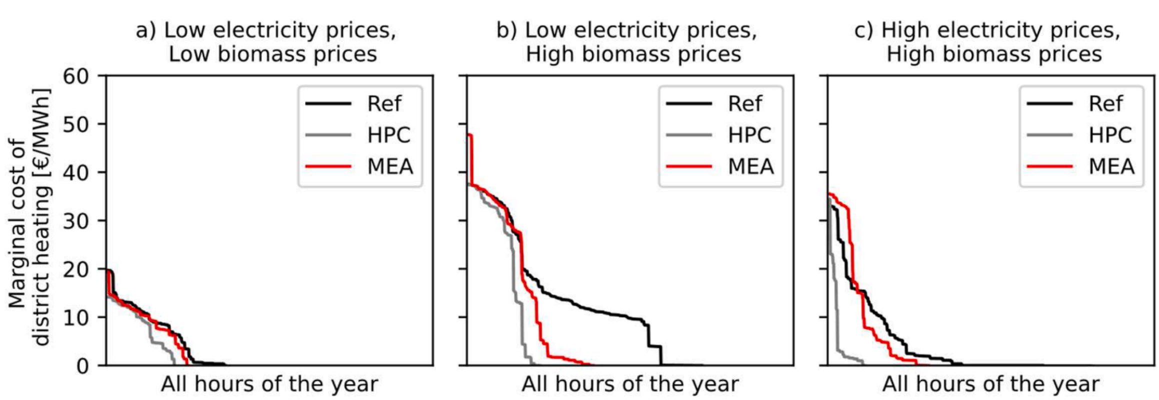

Fig. 5. Duration curves for the marginal cost of district heating in the city, comparing the reference scenario and scenarios with carbon capture using the MEA or HPC process. (a) Low electricity and biomass price levels, (b) Low electricity prices and high biomass prices, (c) High electricity and biomass price levels. The data are not plotted in chronological order.

operating cost was found to be around 25–30% of the total cost of BECCS (Beiron et al., 2022a). Thus, if the investment, transport and storage costs are also projected to electricity and district heating in the city, the impact on the consumer prices might be larger than seen in the modeling presented in this work.

3.4. Setting CO_2 capture targets

The modeling of CO_2 capture targets is subject to discussion. In this work, CHP plants are required to capture a given amount of CO_2 annually, but the model is free to choose *when* to capture CO_2 and can generate more CO_2 than in the reference scenario to enhance this flexibility (with the implication that the actual annual capture rate becomes lower than 90%, i.e., the additional CO_2 generated is not captured). This strategy reflects the reversed auctioning system being planned in Sweden, in which bids will be placed by plant owners to capture a certain amount of CO_2 to a certain cost. An alternative would be to continuously capture CO_2 with a fixed capture rate, whenever the CHP plant runs. This would make the amount of CO_2 captured annually more difficult to predict and dependent on plant operation, but might reduce the amount of CO_2 emitted to the atmosphere. A constant capture rate might also increase the energy cost of capture, since the capture process would operate during all hours, including those with high utility prices (otherwise avoided by the model as far as possible). However, some level of flexibility might be available in the capture process to shift the energy penalty in time, if sufficient solvent storage capacity is installed (Mechleri et al., 2017).

As stated in Section 2.2, CO_2 capture rates above 90% might be techno-economically feasible. A higher capture rate would enable the annual plant CO_2 capture targets to also be set at a higher level without increasing the fuel use. However, approaching a 100% annual capture target (compared to the reference scenario) implies that less flexibility is available for the plant to optimize when in time the CO_2 capture is performed and will cause increased energy costs for the system, as discussed in Section 3.3.1. This is true especially for the waste-fired CHP plant with carbon capture that operates year-round, since with a near 100% capture target, carbon capture cannot be avoided during high-cost hours (high electricity price and/or high district heating demand), i.e., the operation resembles that of having a fixed capture rate. On the other hand, if the annual plant capture target is kept at a 90% level, CO_2 capture rates above 90% would increase the flexibility inherent to the capture process, and the CHP plant would be able to fulfill its annual capture target while minimizing "extra" fuel use for increased flexibility (i.e., generating CO_2 that is not captured), or lowering the marginal energy cost of capture.

Instead of plant-specific capture targets, a CO_2 price or cap could be implemented in the model to compare different policy measures (other than reversed auctioning) to incentivize CDR. A potential concern with a modeled CO_2 price or cap could, however, be that it might be challenging to set the CO_2 price or cap at a level that is high enough to motivate capture, but also not too high. For instance, a high market price for negative emissions might imply that biomass is combusted only to generate CO_2 for capture, without there being a demand for the fuel energy released (electricity or district heating). Such a scenario would be inefficient in terms of energy and resource scarcity. If a cap on CO_2 is introduced, for instance, a city-wide target on CDR, other options to achieve negative emissions in the city could also be considered, e.g., storing carbon in the urban residential environment (Kinnunen et al., 2022), and as biochar in parks (Tammeorg et al., 2021).

4. Conclusion

This work investigates the cost-optimal operation of combined heat and power (CHP) plants retrofitted with a carbon capture process (heat-driven, MEA, or electricity-driven, HPC) in a city energy system. A novel optimization model formulation, with a detailed representation of the carbon capture processes and their heat integration possibilities, is presented and applied to a case study of the city Västerås, Sweden. Based on the results, it is concluded that both the MEA and HPC processes can be integrated in the city energy system to capture 800 $ktCO_2$/year without significant impact on the dispatch of district heating production units or on the marginal costs of electricity and heat in the studied city. Factors such as the import electricity and biomass price levels have a stronger impact on the city energy system and cost than the carbon capture processes. For the MEA process, there is a loss of CHP heat production when retrofitting the capture process, which can be offset by heat recovery from the capture plant. The electrified HPC process is not directly integrated with the CHP steam cycle, as grid electricity can power the process, but causes up to 44% increased electricity import to the city. While substantial heat recovery opportunities are considered a benefit of the HPC process, this possibility is only partially utilized in the studied system. The optimal choice of capture process might, thereby, be a result of other factors than the energy performance itself. For instance, local conditions, such as grid connection capacity or the existing portfolio of production units, might be important to consider.

CRediT authorship contribution statement

Johanna Beiron: Conceptualization, Methodology, Writing – original draft. **Fredrik Normann:** Writing – review & editing, Funding acquisition. **Filip Johnsson:** Writing – review & editing, Funding acquisition.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A. Technology and cost data

Tables A1 and A2 present the cost and technology data provided as inputs to the regional and city models. The investment costs are annualized with a discount rate of 5%. Cycling costs are calculated based on a previous publication (Jordan and Venkataraman, 2012).

Table A1
Cost and technology data for electricity and heat production technologies.

	Investment cost	Fixed O&M cost	Variable O&M cost	Lifetime [yr]	Start-up time [h]	Start-up cost [€/MW]	Electric efficiency [%]
Electricity generation	[k€/MW_{el}]	[k€/MW_{el}/yr]	[€/MWh_{el}]				
Biogas, turbine	466	7.9	0.7	30	0	20.2	42
Biogas, combined cycle	932	13.0	0.8	30	6	42.9	62
Solar PV	450	7.8	1.1	40	0	0	- [a]
CHP plants	[k€/MW_{fuel}]	[k€/MW_{fuel}/yr]	[€/MWh_{fuel}]				
Municipal solid waste, CHP	1610	37	5.9	40	24	56.9	24
Recycled wood, CHP	880	25	1.4	40	12	56.9	30
Wood chip, CHP	880	25	1.4	40	12	56.9	30
Wood pellet, CHP	650	20	0.6	40	12	56.9	34
Biogas, combined cycle CHP	495	11	1.7	30	6	50.6	34 (steam turbine) / 42 (gas turbine)

(continued on next page)

Table A1 (*continued*)

	Investment cost	Fixed O&M cost	Variable O&M cost	Lifetime [yr]	Start-up time [h]	Start-up cost [€/MW]	Electric efficiency [%]
Heat generation	[k€/MW$_{heat}$]	[k€/MW$_{heat}$/yr]	[€/MWh$_{heat}$]				Heat efficiency [%]
Electric boiler	50	0.9	1.0	20	0	0	98
Heat pump	530	1.0	1.6	25	0	0	3.5 (COP)
Biogas, HOB	50	1.7	1.0	25	0	0	104[b]
Waste, HOB	1240	50.6	4.1	25	12	56.9	106[b]
Biomass, HOB	490	29.3	0.7	20	0	0	115[b]
Solar heat	244	0	0.6	30	0	0	- [a]
Electricity storage	[k€/MWh]	[k€/MWh]					
Li-ion battery (energy)	79	–	–	15	–	–	98
Li-ion battery (capacity)	68	0.54	–	30	–	–	–

COP, coefficient of performance. HOB, heat-only boiler. O&M, Operation and maintenance.

[a] Limited by generation profile based on geographic area.

[b] Based on the lower heating value of fuel. The lower heating value of biomass and waste fuels is around 19 MJ/kg dry substance (The Swedish Envirnomental Protection Agency, 2004), and typically yields flue gas CO_2 concentrations of around 13–15% in biomass boilers (Gardarsdóttir et al., 2018).

Table A2 **p**resents the input data related to thermal energy storages, as implemented in the model presented by Holmér et al. (2020), where further details can be found. The storages are assumed to be mixed and not stratified (see (Holmér et al., 2020) for an analysis of the impact of stratification). Storages with heat pumps increase the temperature of the stored water from 40 to 45°C to 80°C with a system efficiency of 60%. Storages without heat pumps operate at a temperature interval of 80–95°C.

Table A2

Thermal storage technology properties and cost data. Tank and pit thermal energy storages are available with/without heat pumps (HP) for discharging heat (the cost for the heat pump is not included in the storage investment cost).

Storage type	Investment cost [k€/MWh]	Lifetime [yr]	Efficiency (charge) [%]	C-factor [-]	Loss [%/h]	Constant loss [%/h]
TTES (HP)	5.69	25	98	1/6	1/240	–
TTES (no HP)	8.85	25	98	1/6	1/240	4.3/240
PTES (HP)	0.27	25	98	1/168	1/240	–
PTES (no HP)	1.25	25	98	1/168	1/240	4.3/240
BTES	0.46	25	98	1/3000	1/240	–

TTES, tank storage; PTES, pit storage; BTES, borehole storage; HP, heat pump.

Appendix B. Reference dispatch of district heating system units

Fig. B1

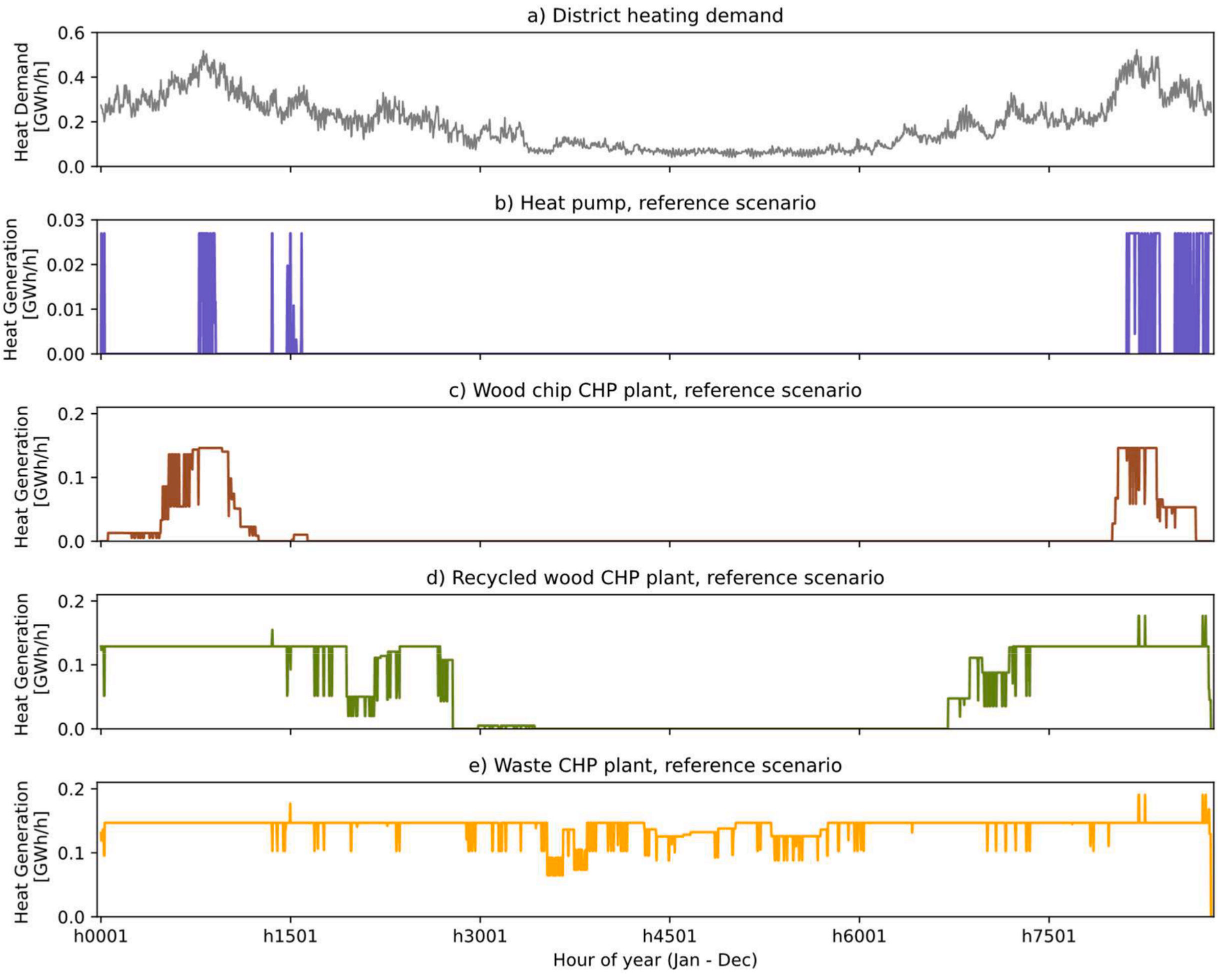

Fig. B1. Dispatch of district heating system units in the reference scenario without CO_2 capture targets. (a) District heating demand profile; (b) heat pump operation; (c) operation of wood chip CHP plant; (d) operation of recycled wood CHP plant; (e) operation of waste-fired CHP plant.

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