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Flexibility provision by combined heat and power plants – An evaluation of benefits from a plant and system perspective

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ABSTRACT

Variable renewable electricity generation is likely to constitute a large share of future electricity systems. In such electricity systems, the cost and resource efficiency can be improved by employing strategies to manage variations. This work investigates combined heat and power (CHP) plant flexibility as a variation management strategy in an energy system context, considering the operation and cost-competitiveness of CHP plants. An energy system optimization model with detailed representation of CHP plant flexibility is applied, covering the electricity and district heating sectors in one Swedish electricity price area. The results show that investments in CHP plants are dimensioned based on the demand for district heating rather than electricity. In the system studied, this implies that CHP plant capacity is small relative to electricity system variations, and variation management using CHP plants has a weak impact on the total system cost of supplying electricity and district heating. However, flexibility measures increase CHP plant competitiveness in scenarios with low system flexibility (assuming low availability of hydropower or no thermal energy storage) although investments in CHP capacity are sensitive to fuel cost. It is found that while district heating is the dominant CHP product (constituting 50%–90% of the annual CHP energy output), the dispatchable electricity supply has a high value and comprises around 60% of the annual CHP plant revenue. In all scenarios, operational flexibility of the boiler is more valuable than a flexible steam cycle power-to-heat ratio.

1. Introduction

Variable renewable electricity (VRE) generation is expected to constitute a large share of future electricity systems. In electricity systems that have high shares of VRE generation, the cost and resource efficiency can be improved by strategies to manage variations. Various types of variation management strategies (VMS) have been researched, including those for dispatchable thermal power generation [1,2], energy storage [3], transmission [4], sector coupling to, for example, the heat [5] or transportation sectors [6], and demand-side response [7]. The optimal combination of these measures depends on the specific system context and the cost structure of the VMS [8].

Dispatchable combined heat and power (CHP) plants can act as a VMS, i.e., operating CHP plants flexibly to contribute to net-load management. CHP plants are in widespread use in Sweden for the co-production of electricity and district heating. Co-generation and district heating systems are promoted in the EU energy efficiency directive [9,10] and could be a strategy to decarbonize the heating sector [11]. Usually, CHP plants are operated so as to follow the seasonally varying district heating demand, although the possibility to dispatch CHP plants to balance the electricity system is being discussed, and has been investigated previously in the Danish [12–14], Chinese [15] and Finnish [16] contexts. In fact, not operating CHP plants in a variable manner, i.e., strictly following the heat load and not adapting the dispatch to the electricity net load (if possible), has been found to limit wind power integration [17].

However, on a global level, many CHP plants combust fossil fuels (e.g., in Germany [18], Denmark [19], the US [20] and China [21]), and to comply with decarbonization targets, CHP plans need to either switch to non-fossil fuels, install carbon capture systems [22] or be shut down. The main non-fossil fuel alternative for CHP plants is biomass, and biomass CHP plants may become more widespread in future energy systems. Sweden, with a heat generation widely based on biomass, is, therefore, an interesting case study for flexibility provision from fossil-free CHP plants.

In the Swedish context, the interaction between CHP plants and storage systems for balancing of renewable power generation has been studied on county level [23] and community level [24]. Mikovits et al. [25] studied how flexibility measures in Swedish hydropower and

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Nomenclature

Latin

C	Cost [k€ or k€/GW or k€/GWh]
Cap	Capacity [GW/$GW_{installed}$]
D	Demand [GWh/h]
L	Load level [–]
p	Electricity generation [GWh/h]
q	Heat generation [GWh/h]
s	Installed capacity [GW]
TT	Length of time-step [h]
z	Storage charge/discharge [GWh/h]

Greek

α	Power-to-heat ratio [–]
β	Coefficient [–]
η	Efficiency [–]
ϕ	FGC heat generation factor [–]

Subscripts and superscripts

active	Available capacity
b	Boiler
bat	Battery
bp	Backpressure mode
ch	Charge
cool	Cooling
cycl	Cycling
dch	Discharge
El	Set of electricity-generating technologies
ext	Extraction mode
Heat	Set of district heating-generating technologies
i	Technology
inv	Investment
j	Time-step in startup interval J
k	District heating subsystem in region
max	Maximum load
min	Minimum load
on	Capacity started
P	Electricity
part	Part load
SC	Steam cycle
ST	Steam turbine
t	Time-step
tot	Total
ramp	Ramping
run	Running

Abbreviations

CHP	Combined heat and power
DH	District heating
EB	Electric boiler
FGC	Flue gas condenser
GT	Gas turbine
GTCC	Gas turbine combined cycle
HOB	Heat-only boiler
HP	Heat pump
PtH	Power-to-Heat
PV	Photovoltaics
TES	Thermal energy storage
VMS	Variation management strategy
VRE	Variable renewable energy

thermal power generation can be used to stabilize electrolyzer hydrogen production, although with must-run conditions for CHP plants. Romanchenko et al. [26] found that electricity price volatility can impact the unit commitment of CHP plants, and the district heating system operator in Stockholm use CHP plants and heat pumps as a strategy to balance renewable electricity generation [27].

Previous works have investigated strategies to increase the flexibility of CHP plants (mainly coal and natural gas-fired plants) and evaluated the profitability of flexibility measures on a plant level. Table 1 provides an overview of main outcomes from studies that investigate plant-level flexibility measures, including turbine bypasses [28–30], a variable power-to-heat ratio [28,30,31], thermal energy storage (TES) [28,29,32–35], coordination with electric boilers [29,32,33,36], steam extraction regulation [37,38], steam storage systems [39,40], thermal buffers [41], disconnection of the low-pressure turbine section [29,32,42], and control systems for improved operational flexibility (e.g., cycling and ramp rates) [43–45]. The cited studies demonstrate that there are several ways to enhance the technical potential for CHP plant flexibility, that might increase the plant revenue. However, it has not been studied to what extent flexibility provision from CHP plants impacts their competitiveness in the energy system and the energy system cost, or which types of CHP plant flexibility measures that are beneficial from a system perspective.

Techno-economic optimization modeling can be applied to study the competitiveness and dispatch of technologies in the energy system. Several studies have examined the cost-optimal operation of CHP plants in existing district heating systems [26,46,47] or in pre-defined case studies [14,18,48]. Operating district heating systems and CHP plants to improve wind power integration has been investigated [49], as well as CHP investment trends in energy systems but without detailed analysis of operational patterns [50]. Concurrent optimization of investments and operation of CHP units have been analyzed on the microgrid level [51] and for a solar-aided CHP system [52]. However, to our knowledge, there is no publication that assesses both the optimal investments and dispatch of conventional CHP plants in relation to flexibility provision in a regional system context, in which both the electricity and district heating sectors are included. Optimizing investments and operation in the same model can give insights regarding the extent to which the ability to operate flexibly is important for the cost-competitiveness of the investigated technology, as well as for the cost-competitiveness of other generation and storage technologies available for investment.

The aim of this work is to investigate the role and competitiveness of CHP plant flexibility as a variation management provider in the energy system on hourly to seasonal timescales. The work quantifies the system value of CHP plant flexibility and the importance of flexibility for CHP plant competitiveness. The operational strategies of CHP plants and the utilization of plant-level flexibility measures are analyzed and quantified. The CHP plant flexibility measures considered are the: (i) operational flexibility (boiler load control); (ii) flexible steam cycle power-to-heat ratio; and (iii) load control of the flue gas condenser (FGC) heat production. The main novelty of the work lies in the combined assessment of the impact of flexibility on CHP plant investments and dispatch, which is enabled by the application of an energy system model. In addition, while several of the above-referenced studies on CHP plant flexibility consider fossil-fueled plants (coal or natural gas), this work focuses on biomass- and waste-fired CHP plants.

2. Method

Fig. 1 gives an overview of the method applied in the work. To investigate the system value of CHP plant flexibility and the importance of flexibility for CHP plant competitiveness, an energy system

Table 1
Overview of studies that investigate plant-level CHP flexibility measures.

Reference	CHP plant type	Flexibility measure(s)	Method	Conclusions
Beiron et al., 2020a. [28]	Waste CHP	Product flexibility, TES	Process simulation and optimization modeling	Flexibility measures might increase the plant revenue and utilization. TES is important.
Beiron et al., 2020b. [30]	Combined cycle CHP	Product flexibility, TES	Process simulation and optimization modeling	Flexibility measures might increase the plant revenue by decreased fuel cost, if price volatility is high.
Zhang et al., 2022. [29]	Coal CHP	Turbine bypass, low-pressure cylinder removal, TES, EB	Process analysis	All flexibility measures studied benefit the integration of wind power in China.
Koller and Hofmann, 2018. [31]	Combined cycle CHP	Variable power-to-heat ratio	Optimization modeling, process level	The model presented analyzes operation of decoupled CHP components with a high level of detail.
Liu et al., 2021. [32]	Coal CHP	TES, EB, HP, steam turbine renovation	Techno-economic analysis	The economic performance of flexibility measures is determined by the extent of decreased power sale and fuel consumption.
Mollenhauer et al., 2018. [33]	Coal CHP, Combined cycle CHP	HP, TES, backpressure vs extraction steam turbine	Optimization modeling, local DH system	HP and TES expand the operating capabilities of the DH system, to take advantage of electricity price volatility.
McDaniel and Kosanovic, 2016. [34]	Combined cycle CHP	TES	Dynamic simulation	Seasonal TES enables greater flexibility in CHP operation and reduced operating costs and emissions.
Benalcazar, 2021. [35]	Coal CHP	TES	Optimization modeling	TES increases CHP plant electricity generation.
Zhao et al., 2019. [36]	Coal CHP	EB, HP, HOB, TES	Techno-economic analysis	TES and EB increase CHP plant revenue more than HOB.
Zhao et al., 2018. [37]	Coal CHP	Steam extraction regulation	Dynamic process simulation	Extraction control might provide flexibility on short timescales.
Liu et al., 2022. [38]	Coal CHP	Steam extraction regulation	Control system simulation	A novel control strategy that improves primary frequency control provision is presented.
Richter et al., 2019. [39]	Coal CHP	Steam accumulator	Dynamic simulation	The steam storage improves load flexibility, e.g., with a temporary reduction of minimum load.
Guo et al., 2022. [40]	Coal CHP	TES (internal vs external)	Optimization modeling	Double TES (internal and external) increases CHP robustness to variability and wind power accommodation.
Angerer et al., 2017. [41]	Combined cycle CHP	TES (thermochemical)	Process simulation and optimization modeling	The TES can be integrated into the CHP plant with a high roundtrip system efficiency.
Darozhka et al., 2015. [42]	Waste CHP, Combined cycle CHP	SSS-clutch	Review, case descriptions	The SSS-clutch is applicable in a broad versatility of CHP plants to enhance operational flexibility.
Wang et al., 2022. [43]	Coal CHP	Control strategy	Dynamic simulation	The control strategy proposed is reliable and suitable for various CHP operating scenarios.
Ivanova et al., 2016. [44]	Combined cycle CHP	Cycling (start-up)	Process analysis	For the case analyzed, the cold start-up should be improved (measures suggested) to reduce fuel consumption.
Kunickis et al., 2015. [45]	Combined cycle CHP	Cycling	Process analysis	Measures for improved cycling efficiency are recommended.

TES, thermal energy storage; EB, electric boiler; HP, heat pump; DH, district heating; HOB, heat-only boiler; SSS, synchronous-self-shifting.

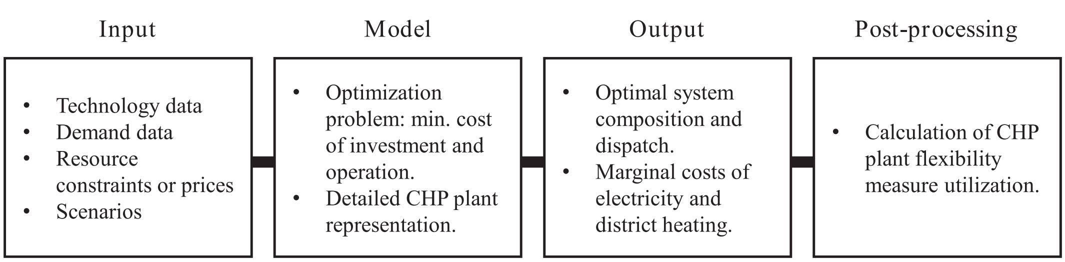

Fig. 1. Overview of the method applied.

investment model that incorporates a detailed representation of CHP plants is applied to a region (electricity price area) with favorable conditions for wind power. The representation of CHP plants includes costs and constraints on the operation of the boiler, steam cycle, and flue gas condenser. The impact of CHP plant flexibility is investigated for four scenarios, which differ with respect to the availability of low-cost flexibility in the system and the cost of biomass. Section 2.3 defines six indicators to measure the utilization of CHP plant flexibility. These indicators are applied to the model output in a post-processing step.

2.1. Energy system optimization model

An energy system model is applied to identify the optimal investments in and operation of production and storage units in the electricity and district heating sectors. A region (electricity price area) without transmission to/from neighboring regions is considered. The objective of the model, as given in Eq. (1), is to minimize the total cost of electricity and district heating generation, considering the investment in and running costs of the production and storage technologies. For every time-step, the heat and electricity demand must be met [Eqs. (2) and (3)]. The model is linear and is run for 1 year, with a temporal resolution of 3 h. The model is implemented in the software GAMS. Please see the nomenclature list for a description of the variables and parameters used in Eqs. (1)-(3).

$$
MIN : C^{tot} = \sum_{i\in I_{El}}\sum_{k\in K}\left(C_i^{inv}s_{i,k} + TT\sum_{t\in T}\left(C_i^{run}p_{i,k,t} + C_{i,k,t}^{cycl}\right)\right) + \sum_{i\in I_{Heat}}\sum_{k\in K}\left(C_i^{inv}s_{i,k} + TT\sum_{t\in T}\left(C_i^{run}q_{i,k,t} + C_{i,k,t}^{cycl}\right)\right) + \sum_{i\in I_{TES}}\sum_{k\in K}C_i^{inv}s_{i,k} + C_{bat}^{inv}s_{bat} \tag{1}
$$

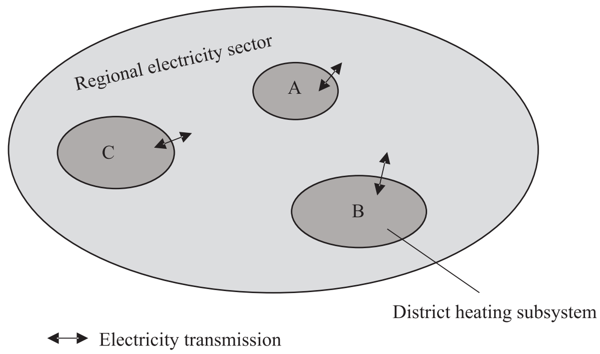

Fig. 2. Illustration of the energy system modeled. A-C represent district heating subsystems in which the district heating demand of small (A), medium (B) and large (C) cities are aggregated. The arrows indicate unlimited transmission of electricity between the regional grid and the district heating subsystems.

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

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

The model has been well-documented in previous studies, where specific parts of the model formulation have been described in detail: for instance, district heating and thermal energy storage [5], thermal power plant operation [53], and battery storage [8]. The district heating sector is represented by three types of district heating subsystems (A, B, and C), as proposed in [54] and illustrated in Fig. 2. These correspond to aggregates of the demand for district heating in small (A), medium (B) and large (C) cities in the region. Each subsystem has its own set of heat generation technologies in which investments can be made, accounting for economy-of-scale effects.

Electricity can be provided by a selection of CO_2-neutral power generation technologies, including wind and solar power, thermal generation (biogas turbines or combined cycles, biomass power plants or CHP plants), biomass co-fired thermal plants with carbon capture and storage, and batteries. District heating can be supplied by CHP plants, heat-only boilers (HOB), heat pumps or electric boilers, and TES. Waste is allowed as a fuel, under the assumption that the fossil share of the waste is phased out. Due to the inappropriateness of storing waste for extended periods of time, waste-fired plants are forced to operate with constant fuel consumption on a monthly basis. Hydropower is available according to region-specific data. The cost data and technical properties for all the technologies are given in Appendix B.

2.2. Flexible combined heat and power plants

The following three options for flexible operation of CHP plants [55] are implemented in the model:

(i) *Operational flexibility*, with load control of the entire plant through variable fuel usage.
(ii) Flexible *power-to-heat ratio* of the CHP steam cycle through variable utilization of steam turbine bypass or electricity-only production.
(iii) Heat load control of the *flue gas condenser* (FGC).

The operational flexibility is associated with costs for startup and part-load, while the flexible steam cycle power-to-heat ratio and FGC load flexibility are modeled without costs. The model implementation of each flexibility type is described in the following subsections.

2.2.1. Operational flexibility and cycling

The operational flexibility of thermal power plants is defined by the following three parameters: (i) cycling properties; (ii) ramp rate; and (iii) minimum load level. The model explicitly considers the cycling limitations of thermal power plants, while the ramp rate and minimum load properties are included as approximations due to the timescale and the linear model formulation with aggregated plant capacity. However, for the modeled plant types, the ramp rates are sufficiently high so as not to be limiting on a 3-hour time-step basis [30,56]. The cycling constraint formulation is described by Eqs. (4)–(8), based on the original implementation described previously [53].

$$p_{i,k,t} \le p_{i,k,t}^{active}, \quad \forall k \in K, t \in T, i \in I \tag{4}$$

$$L_{i,k}^{min} p_{i,k,t}^{active} \le p_{i,k,t}, \quad \forall k \in K, t \in T, i \in I \tag{5}$$

$$p_{i,k,t}^{on} \ge p_{i,k,t}^{active} - p_{i,k,t-1}^{active}, \quad \forall k \in K, t \in T, i \in I \tag{6}$$

$$C_{i,k,t}^{cycl} \ge p_{i,k,t}^{on} C_{i,k,t}^{on} + \left(p_{i,k,t}^{active} - p_{i,k,t}\right) C_{i,k,t}^{part}, \quad \forall k \in K, t \in T, i \in I \tag{7}$$

$$p_{i,k,t}^{on} \le s_{i,k} - p_{i,k,t-j}^{active}, \quad \forall k \in K, j \in J \tag{8}$$

2.2.2. Flexible steam cycle power-to-heat ratio

In addition to the operational flexibility of the boiler, CHP plants can vary the steam cycle power-to-heat ratio, α_{SC}, i.e., the relationship between heat generation and electricity generation, so as to increase flexibility in terms of product output levels, Eq. (9).

$$\alpha_{SC} = \frac{p_{CHP}^{SC}}{q_{CHP}^{SC}} \tag{9}$$

Co-generation steam turbines can be of the backpressure or extraction type. The extraction turbine has a higher investment cost and higher electric efficiency than the backpressure option, and it can operate in condensing mode (i.e., producing only electricity). Both turbine types can operate with a flexible product ratio, i.e., a power-to-heat ratio that deviates from α_{SC}^{design}, through bypassing the steam turbine for increased district heating generation, according to Eq. (10). Condensing operation is represented by a cooling water variable (q_{cool}) and coefficients (β) that describe the increases and reductions in electricity and heat generation, respectively [Eqs. (11) and (12)]. Thus, q_{cool} represents the fraction of thermal energy for district heating that is lost when increased electricity generation is prioritized. Equation (13) ensures that the steam cycle energy balance is preserved.

$$p_{CHP,k,t}^{SC,bp} \le \alpha_{CHP}^{SC,design} q_{CHP,k,t}^{SC,bp}, \quad \forall k \in K, t \in T \tag{10}$$

$$q_{CHP,k,t}^{SC,ext} = q_{CHP,k,t}^{SC,bp} - \beta_{DH} q_{CHP,k,t}^{cool}, \quad \forall k \in K, t \in T \tag{11}$$

$$p_{CHP,k,t}^{SC,ext} = p_{CHP,k,t}^{SC,bp} + \beta_{el} q_{CHP,k,t}^{cool}, \quad \forall k \in K, t \in T \tag{12}$$

$$p_{CHP,k,t}^{SC,ext} + q_{CHP,k,t}^{SC,bp} + q_{CHP,k,t}^{cool} = q_{CHP,k,t}^{fuel} \eta_b, \quad \forall k \in K, t \in T \tag{13}$$

Combined cycle CHP plants have a gas turbine and a steam cycle part. The steam cycle part is represented in the same way as a steam boiler CHP plant, while the gas turbine operation is implicitly determined by a factor, f_{GT}, which relates the gas turbine electricity production to the steam cycle load (expressed as the sum of the steam cycle heat and electricity generation) and steam turbine design electric efficiency [Eq. (14)]. Combined cycles are modeled without supplementary firing.

$$p_{CHP,k,t}^{GT} = \frac{p_{CHP,k,t}^{SC,bp} + q_{CHP,k,t}^{SC,bp}}{\eta_b} \eta_{el,ST,CHP} f_{GT}, \quad \forall k \in K, t \in T \tag{14}$$

2.2.3. Flexible flue gas condenser load

The CHP plant flue gas condenser (FGC), which is located at the end of the flue gas train, condenses water vapor, thereby releasing low-grade

Table 2
Flue gas condenser-related properties of waste and biomass fuels and the corresponding CHP steam cycles modeled. The total efficiency depends on the district heating subsystem (A/B/C) and turbine type (backpressure/extraction); see Table B2 for electric and boiler efficiencies.

Fuel	Moisture content, as-received basis [%]	FGC heat generation, ϕ_{FGC} [MW_{heat}/MW_{fuel}]	Total efficiency[1], η_{tot} [%]
Waste	36	0.17	102
Wood chips	36	0.17	107–112
Wood pellets	9	0.10	94–99

[1] Calculated on a lower heating value basis.

heat. The heat generation in an FGC correlates with the moisture content of the fuel. Table 2 lists the moisture contents of the fuels considered in the model, and the corresponding FGC heat generation factors, ϕ_{FGC}, as described by Eq. (15). Wood chips and waste materials typically have high moisture contents and can through the FGC increase the district heating output, leading to high total efficiencies [η_{tot}, Eq. (16)], which can reach >100 % based on the lower heating value of the fuel, and considering electricity and low-grade heat products as equally valuable, regardless of exergy.

$$\phi_{FGC} = \frac{q_{CHP}^{FGC,design}}{q_{CHP}^{fuel,design}} \tag{15}$$

$$\eta_{tot} = \frac{p_{CHP}^{tot} + q_{CHP}^{SC} + q_{CHP}^{FGC}}{q_{CHP}^{fuel}} \tag{16}$$

The level of heat generation in the FGC is independent of the operation of the steam cycle, and only depends on the fuel load. It is, however, possible to reduce the load on the FGC, so as to enable increased flexibility with respect to product output and CHP plant power-to-heat ratio, as described in Eq. (17).

$$q_{CHP,k,t}^{FGC} \le q_{CHP,k,t}^{fuel} \phi_{FGC} \ , \quad \forall k \in K, t \in T \tag{17}$$

With the FGC load control option, the overall level of CHP plant heat generation is given by Eq. (18).

$$q_{CHP,k,t}^{tot} = q_{CHP,k,t}^{SC} + q_{CHP,k,t}^{FGC} \ , \quad \forall k \in K, t \in T \tag{18}$$

2.3. Measures of flexibility utilization

To compare the utilization of CHP plant flexibility measures between scenarios and system contexts, six indicators are applied to characterize the CHP plant operation. The indicators are:

- Total annual capacity cycled, Cap^{cycl}
- Total annual capacity in part load, Cap^{part}
- Total annual capacity ramped, Cap^{ramp}
- Boiler load level duration
- Steam cycle electricity production duration
- Flue gas condenser load duration

The first four indicators (capacity cycled, in part load and ramped, and boiler load level duration) describe the boiler operation for one year, i.e., the utilization of operational flexibility. The steam cycle electricity production duration is indicative of the utilization of power-to-heat ratio flexibility, while the last indicator characterizes the utilization of flue gas condenser load control flexibility. Together, the indicators present a view of which flexibility measures that are most frequently used on an annual basis. This information can serve as a basis for future development of CHP plant design and operational strategies.

The capacity-related indicators are calculated according to Eqs. (19)–(21), while the load durations are derived directly from the

Table 3
Scenarios and CHP plant flexibility cases.

Parameter	Main scenario	NoHydro scenario	NoTES scenario	HighBio scenario
Hydropower available [GW]	9.6	0	9.6	9.6
Thermal energy storage systems available [yes/no]	Yes	Yes	No	Yes
Biomass price [€/MWh]				
Wood chips	20	20	20	40
Wood pellets	30	30	30	50
Biogas	48.6	48.6	48.6	77.1
CHP plant flexibility cases	(i) full flexibility (boiler, steam cycle and FGC)			
	(ii) limited flexibility			

dispatch results. Cap^{ramp} is calculated as the sum of the boiler load changes over the year, minus the startup and stop of the boiler (2 times capacity cycled), so as to avoid double-counting the load changes pertaining to cycling.

$$Cap^{cycl} = \frac{\sum_{t=1}^{T} p_{i,k,t}^{on}}{s_{i,k}} \ , \quad \forall i \in I_{CHP}, k \in K \tag{19}$$

$$Cap^{part} = \frac{\sum_{t=1}^{T} \left(p_{i,k,t}^{active} - p_{i,k,t} \right)}{s_{i,k}} \ , \quad \forall i \in I_{CHP}, k \in K \tag{20}$$

$$Cap^{ramp} = \frac{\sum_{t=1}^{T} \left(p_{i,k,t} - p_{i,k,t-1} - 2p_{i,k,t}^{on} \right)}{s_{i,k}} \ , \quad \forall i \in I_{CHP}, k \in K \tag{21}$$

Due to the linear model formulation, the aggregated capacity of all units of the same plant type are considered, rather than the operation of individual units. Therefore, the capacity-related indicators are expressed as the total GW of cycled capacity in the system, and so on, rather than ascribing a number of starts to a particular unit (not measurable in the model).

2.4. Case study and scenarios

The contribution of CHP plant flexibility to cost-effective variation management is investigated for a region with a heat demand corresponding to 24% of the electricity demand, in terms of energy on an annual basis, and good conditions for wind power. The timeframe of the study is Year 2045, under the assumption that the energy system generates no CO_2 emissions, in order to comply with national climate targets. Thus, a Greenfield approach is chosen. The input data, such as the electricity and heat demand profiles, are based on data for the Swedish electricity price area SE3 in Year 2012. Electricity demand is scaled by a factor of 1.5 compared to Year 2012 to account for increased electrification.[1] Although Sweden is currently a net-exporter of electricity, electricity export is not included in the modeling. The total district heating demand of SE3 is distributed among the subsystems (A-C) according to a previous publication [5]. The district heating demand is assumed to remain at current levels, considering that energy efficiency measures are expected to offset increased heat demand from an expanding building stock. The availability of waste as a fuel is limited for the region based on the current usage of waste by CHP plants in the SE3 region, and is not expected to increase in the future. Due to the ongoing transition of the industrial sector to comply with climate targets, current

[1] The scaling factor 1.5 is an average value of the estimated increase in electricity demand in Sweden by Year 2045–2050, based on Refs [66–68].

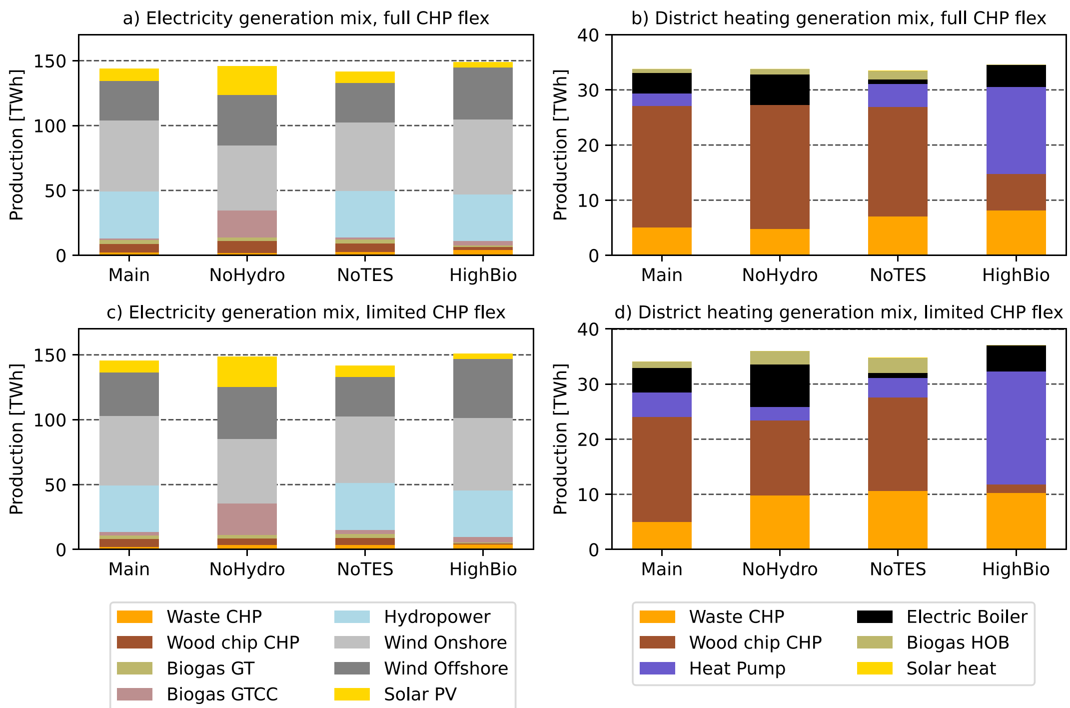

Fig. 3. Total annual electricity production (**a** and **c**) and total annual district heating production (**b** and **d**), by technology types for each scenario. Panels **a** and **b** show the results obtained with full CHP flexibility, while panels **c** and **d** show the results obtained with limited CHP flexibility. The district heating production level is an aggregate of the three subsystems.

deliveries of industrial excess heat to the district heating sector are not included, as their future availability is uncertain.[2]

Table 3 presents an overview of the scenarios studied. Since SE3 includes hydropower, which may reduce the need for flexibility in the region, a scenario without hydropower is also investigated to increase the generalizability of the results. In addition, the sensitivity of the results to the availability of TES and increased biomass price is studied. The prices of wood chips and pellets are based on data for wood fuel prices in Sweden [57]. 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 [58], under the assumption of 8,000 full-load hours.

To capture the impact of CHP plant flexibility on system composition and cost, each scenario is modeled with full and limited CHP plant flexibility. The full flexibility case implies that all the CHP flexibility measures described in Section 2.2 can be used in the plant dispatch. In the case with limited CHP plant flexibility, the plant cannot use the flexible power-to-heat ratio or FGC load flexibility, and is penalized with a sufficiently high startup cost and part-load cost to avoid flexible boiler operation (i.e., cycling and ramping). Thus, when operating, a CHP plant with limited flexibility is forced to operate at full load with a fixed power-to-heat ratio.

3. Results

Section 3.1 presents the results relating to the impact of CHP plant flexibility measures on the optimal system composition and system cost. The operational strategies of flexible CHP plants are described in Section 3.2, while the utilization of flexibility measures is quantified in Section 3.3.

3.1. *Impact of CHP plant flexibility on system design and plant competitiveness*

3.1.1. *System composition and annual production*

Fig. 3 presents the modeled zero-CO_2-emitting production mix of electricity and district heating for the four scenarios, with full and limited CHP plant flexibility measures. The corresponding capacity investments are given in Appendix A together with annual biomass usage and curtailed energy. Comparing panels b and d in Fig. 3, it is clear that the absence of CHP plant flexibility has a negative impact on the cost-competitiveness of wood chip-fired CHP plants, especially in scenarios with low levels of system flexibility (NoHydro and NoTES), in which operational flexibility is valuable. Restricting only the power-to-heat ratio or flue gas condenser flexibility does not influence the investments significantly, as compared to the full flexibility cases (Fig. 3, a and b). That is, for CHP plants, operational flexibility is of greater importance than the power-to-heat ratio flexibility or FGC flexibility.

In all the scenarios, wind power produces the largest share of electricity, followed by hydropower (when applicable), solar PV, open-cycle biogas turbines, and combined cycle biogas turbines. CHP plants supply 4%–8% of the total annual electricity production. Given this relatively small contribution to the total electricity demand, the impact of limited CHP plant flexibility on the electricity system is minor. Regardless of the scenario, the investments in CHP capacity never exceed the instantaneous peak demand for district heating. Thus, the heat demand imposes an upper limit on the economically feasible CHP capacity and, thereby,

[2] In Year 2019, industrial excess heat provided around 10% of the total district heating produced in Sweden [69], for instance, from pulp mills, refineries and steel mills. More industrial excess heat could be available for district heating [70] but factors such as the distance between the industrial site and the district heating network, and the incongruence between the even supply of industrial excess heat over the year and uneven district heating demand, limit the potential. Decarbonization and energy efficiency measures in the industrial sector might reduce the future availability of excess heat in suitable temperature intervals, although new sources of excess heat might emerge, for example, data centers [71].

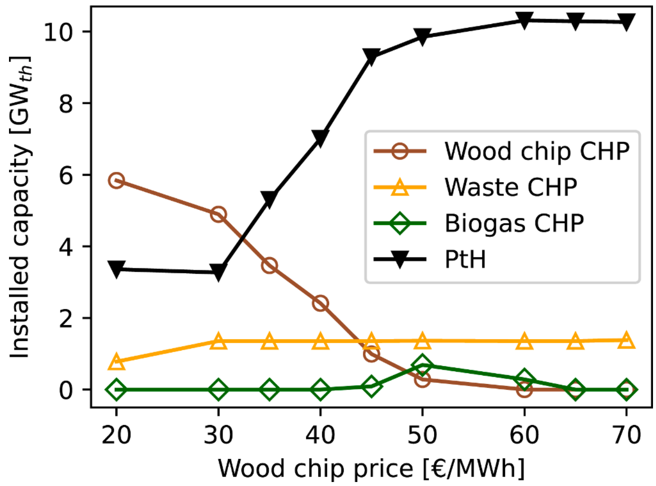

Fig. 4. Impact of the price of wood chips on the optimal installed capacity [GW$_{th}$] of selected heat production technologies in the Main scenario with full flexibility.

also restricts the potential of CHP plants to contribute to variation management.

For district heating generation, CHP plants are prominent, producing 32%–81% of the annual heat production, depending on the scenario and level of CHP plant flexibility. In the Main scenario, wood chip-fired CHP plants are competitive with both full and limited flexibility, indicating that other heat production options (PtH or HOB) are not nearly as cost-effective for heat production. However, if the operational cost of wood chip-fired CHP plants increases (HighBio), PtH becomes cost-competitive relative to wood chip-fired CHPs, and for further increases in biomass price (wood chips 60 €/MWh, biogas 106 €/MWh; not shown in Fig. 3), wood chip-fired CHP plants receive no investment (see Section 3.1.2). If there is less flexibility in the system (NoHydro) electric boilers replace heat pumps (Fig. 3b). As seen in the NoTES scenario, investments in electric boilers are strongly dependent upon the presence of TES.

3.1.2. Competitive CHP plant types

The optimization model results indicate which types of CHP plants are cost-competitive in the system investigated. As shown in Fig. 3, the CHP plants with the lowest costs for fuel (waste and wood chips) are the optimal choice. The low cost of waste (1 €/MWh in the modeling; Appendix B, Table B4) drives investments in base-load waste-fired CHP plants, despite the large investment cost and low level of flexibility in boiler operation. Wood chip-fired CHP plants have a higher fuel cost but a lower investment cost, and are better-suited to flexible operation with a lower number of full-load hours (around 2,500–5,000 h/year in the modeling results, depending on the scenario). Thus, if wood chip-fueled CHP plant flexibility is removed, these plants lose competitiveness in the heat sector relative to waste-fired CHP and PtH (Fig. 3d and Appendix A).

On the other hand, wood chip CHP investments are more sensitive to fuel price than limited flexibility (compare the HighBio scenario with flexibility, and the Main scenario without flexibility; Fig. 3, b and d). Fig. 4 plots the investments in heat production technologies for a range of wood chip prices in the Main scenario with full flexibility. The capacity of wood chip-fired CHP decreases steadily as the fuel price increases, while the capacity of waste-fired CHP is maximized so as to use all the available waste resources. The cost-competitiveness of PtH units increases with the price of wood chips. Although biogas combined cycle CHP plants have the best technical properties for flexible operation (cycling and ramping) of all the CHP plant options, they are only cost-competitive in terms of attracting investment when wood chip prices are in the range of 45–65 €/MWh (corresponding to biogas prices in the range of 84–113 €/MWh). Within this fuel price range, both wood chip-fired and biogas-fired CHP plants get few full-load hours, and the low investment cost and good cycling properties make the biogas combined cycle CHP plant a competitive option, even though biogas is more expensive than wood chips. Thus, a low-cost fuel, which incentivizes many full-load hours, is generally more important for CHP plant cost-competitiveness than flexibility.

Steam turbines that have the possibility to increase electricity generation at the expense of decreased heat production, i.e., extraction turbines, are cost-efficient for wood chip-fired plants in the NoHydro scenario, but not in the HighBio scenario. The value of dispatchable electricity is particularly high in the NoHydro scenario with low system flexibility. This motivates investments in extraction turbines, although the ability to produce only electricity in the HighBio scenario is not cost-competitive for wood chip-driven plants when the fuel price is high. The Main and NoTES scenarios invest mainly in backpressure turbines for wood chip-fired CHP plants. The investments in waste-fired CHP plants include the extraction turbine option when possible (in the large district heating subsystem, C). The extraction turbine has a higher electric efficiency in co-generation mode, as compared to the backpressure option (Appendix B, Table B2). Moreover, the gain in electric efficiency, as well as the possibility to increase the electricity output (condensing operation) when the net load is high, compensates for the increase in investment cost associated with the extraction turbine.

3.1.3. Economic impact of CHP plant flexibility

The increase in total system cost linked to restricting CHP plant flexibility is small, at <1%. Removing operational flexibility has a stronger impact than removing power-to-heat ratio flexibility and FGC flexibility, increasing the system cost by <0.93% or <0.07%, respectively. The cost increase is mainly seen in the heat sector, in which the average heat production cost in CHP-dominated district heating subsystems (most notably the large subsystem, C) increases as CHP plant flexibility is removed. This is true in particular for the NoTES scenario, in which the use of flexible electric boilers is challenging due to the lack of heat storage systems. The average cost of electricity production is not significantly impacted by the level of CHP plant flexibility. These findings indicate that other variation management strategies in the electricity sector can replace the (small) contribution of CHP plant flexibility to a low cost, while CHP heat production is more costly to replace in the district heating sector, since CHP heat production constitutes a large part of the total heat demand (Fig. 3).

From a stakeholder perspective, if the system cost reduction accrued from CHP flexibility measures is given as a benefit to the CHP plant owners, a 1% system cost reduction would for the studied case correspond to an annual “bonus” of around 54 k€/MW installed capacity. In a situation with 4,000–8,760 full-load hours per year, depending on the plant type and merit order, the hourly operating benefit would be in the range of 6–14 €/MWh, whereby operational flexibility confers the major part of the benefit. Power-to-heat ratio and FGC flexibility would correspond to an hourly operating benefit of <1.5 €/MWh. In comparison, the wood chip fuel price is 20–40 €/MWh in the scenarios, which again indicates that fuel price variability has a stronger impact on CHP plant economy than flexibility.

3.2. Operational strategies for flexible CHP plants

3.2.1. Seasonal dependency of operational strategies

Fig. 5 plots the electricity net load (Fig. 5a), district heating demand (Fig. 5b), and optimal dispatch of wood chip-fired and waste-fired CHP plants with full flexibility in the Main scenario (Fig. 5, c–g), for the three differently sized district heating subsystems (A–C). The optimal dispatch distinguishes between electricity generation, district heating from steam cycle condensers, district heating from flue gas condensers, and the cooling of heat when operating in condensing mode. The operational strategies of the wood chip-fueled CHP plant show seasonal dependency

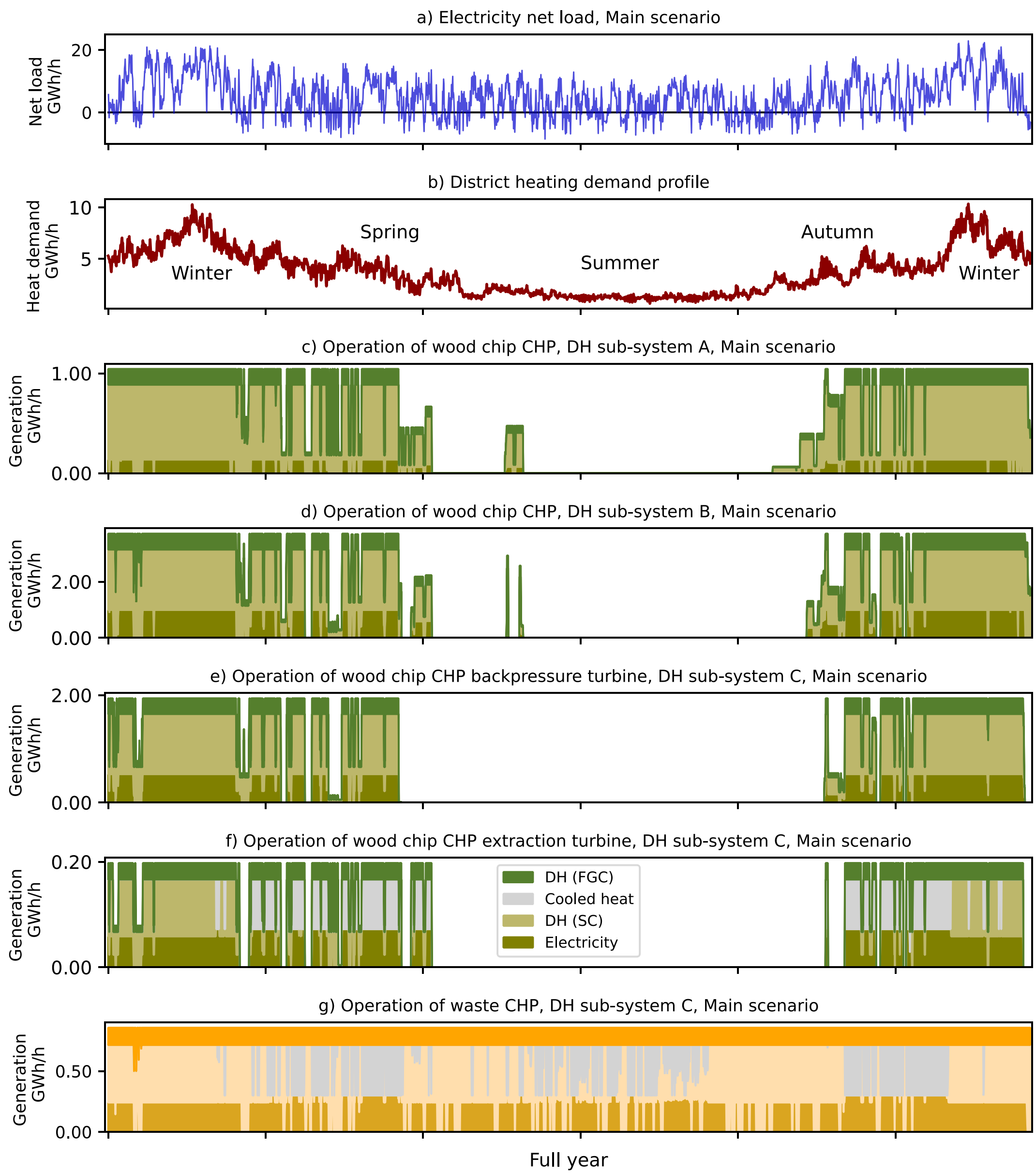

Fig. 5. Optimal CHP plant dispatch in the Main scenario with full CHP plant flexibility. **a**) Electricity net load. **b**) District heating demand profile. **c–g**) Dispatch profiles for wood chip-fired and waste-fired CHP plants, divided into electricity generation, district heating from steam cycle (SC) condensers and flue gas condensers (FGC), and cooled heat during condensing operation (gray area). The sum of the colored areas indicates the boiler load level.

related to the varying heat demand. During winter, when the heat demand peaks and the electricity net load is high, the CHP boiler operates at full load without any need for operational flexibility or load changing, while peak heat production units or TES manage the variability in heat demand. During summer, the heat demand is low, and the wood chip-fired CHP plants are generally not operated. However, in the NoHydro scenario (not shown), electricity system flexibility is lowered, and under these conditions, wood chip-fueled CHP plants are dispatched as a peak-technology during summer, even though the heat demand is low. In spring and autumn, a third type of operation is seen with increased flexibility, in which load changes and cycling of the boiler occur in response to volatility in the electricity net load, which oscillates between negative and positive numbers (see Section 3.2.3). The net-load variability also leads to changes in the steam cycle mode of operation (power-to-heat ratio flexibility), with a mix of steam cycle cogeneration, heat-only operation, and electricity-only operation (applicable to extraction turbines, flue gas condensers still produce heat). Waste-fired plants are operated year-round as district heating base-load units, albeit with a mix of operating modes.

If CHP plant flexibility is limited (not shown in Fig. 5), the operational season and number of full-load hours are generally similar to those seen in the full-flexibility case, although without the heat-only or condensing operation, or the cycling observed in response to electricity net-load variability. In the HighBio scenario, the competitiveness of wood chip-fueled CHP plants is reduced, and the operation is concentrated to the wintertime, when both the heat demand and electricity net load are high.

3.2.2. *Contribution to variation management*

In terms of variation management in the electricity sector, Fig. 5 shows that flexible operation of wood chip-fueled CHP plants contributes to variation management mainly on a seasonal timescale, with higher production during wintertime when the net load is, overall, at a higher level. To an extent, CHP plants manage variability on hourly to weekly timescales, with the main contributions being made at medium heat demand levels in the spring and autumn. Waste-fired CHP plants do

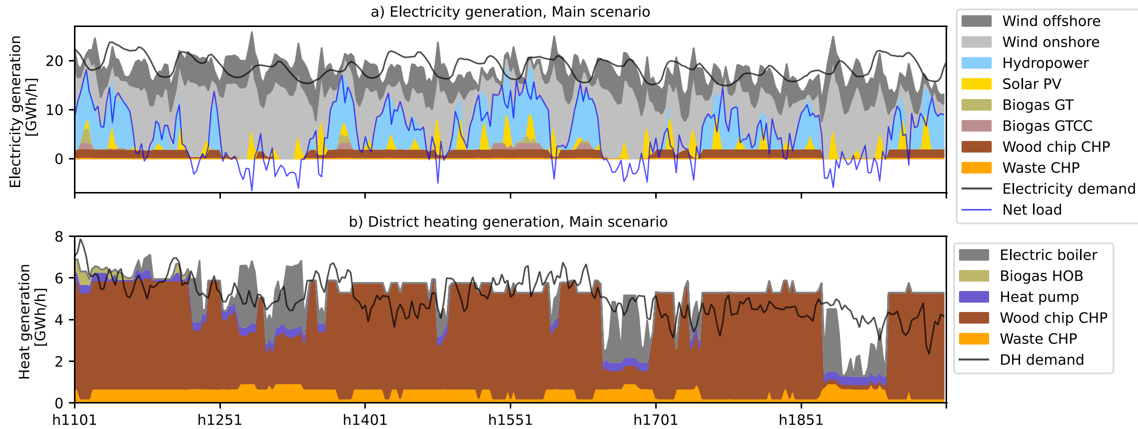

Fig. 6. Optimal dispatch of the: **a**) electricity sector, and **b**) aggregated district heating sector, during 5 weeks in springtime in the Main scenario with full CHP plant flexibility.

not significantly contribute to variation management through operational flexibility, owing to the forced boiler operation needed to manage waste. However, the power-to-heat ratio flexibility of waste-fired plants makes a contribution on hourly to weekly timescales, most notably when the net load fluctuates in the summer, spring and autumn.

The seasonally dependent operating patterns mean that CHP plants can exert three variation management functions. First, during the winter, CHP plants can reduce the level of electricity generation by operating in heat-only mode (power-to-heat ratio flexibility) when the net load is low. That is, electricity that would otherwise have been generated is absorbed by the heat sector. Second, in spring and autumn, CHP plants maximize the boiler load for high-level electricity generation when the net load is high (Fig. 5) and reduce the boiler load when the net load is low, i.e., load-following operation based on operational flexibility. With an extraction turbine, CHP plant electricity-only (condensing) operation, which maximizes the electricity output at the expense of heat production, enhances the flexibility of electricity and heat generation. Third, during the summer, CHP plants can act as peak electricity generation units when the net load is high, as occurs particularly in the NoHydro scenario.

3.2.3. Interaction between CHP plants and PtH units

Electricity net load volatility in the spring and autumn results in operational interactions between the CHP plants and PtH units. Fig. 6 plots the optimal dispatch of the electricity and district heating sectors during 5 weeks in springtime. There is a strong dependency of the district heating dispatch on the electricity net load. When the net load is high, CHP plants operate at full load, while the boiler load is reduced as the net load decreases to negative numbers and PtH units are dispatched instead. That is, for negative net loads, PtH heat generation is less-costly than wood chip-fueled CHP plant heat generation, resulting in recurrent changes to the merit order for the district heating sector. The dispatch of waste-fired CHP plants is not dependent upon the merit order in the same way, since these plants are required to operate with constant fuel consumption. From the variation management perspective, the PtH and CHP plants do not compete as heat production units, and while they do manage the same variations within the electricity system, the size of the heat demand relative to the electricity demand ensures that flexibility is needed from both plant types.

In Fig. 6, it is also evident that the CHP plant flexible power-to-heat ratio is used when the net load fluctuates. Thus: (i) when the net load is low, CHP electricity generation is superfluous and heat-only operation is applied (i.e., no electricity production from CHP plants in Fig. 6a); (ii) when the net load is high, electricity-only operation is preferred to support the electricity sector (see the reduced heat production of the waste-fired CHP plant in Fig. 6b, indicative of condensing operation). On the other hand, even without a flexible power-to-heat ratio, the wood chip-fueled CHP plant electricity generation is adapted by changing the boiler load, with similar electricity and district heating production patterns.

TES systems are an important feature of the district heating system in terms of variation management, for two reasons. First, TES allows wood chip-fueled CHP plants to operate at full load for maximal power generation when the net load is high, even if the heat demand does not motivate such a high load level (see Fig. 6b). Second, the ability to store heat is crucial for the application of electric boilers, as their heat production is opportunistic based on the varying net load.

3.2.4. CHP plant economy and cost allocation

Although CHP plant flexibility has weak impacts on the electricity sector composition and production cost, electricity generation has a high value for CHP plants. Assuming that the modeled marginal costs of

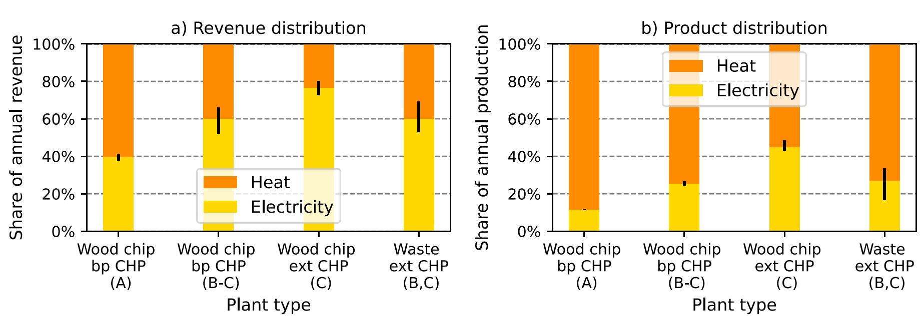

Fig. 7. Distributions of CHP plant annual **a**) revenues, and **b**) energy outputs between electricity and district heating. The bars show the average values considering all scenarios with full CHP plant flexibility, and the error bars show the spread of distributions. The letters in parentheses represent district heating subsystems. Turbine types: ext, extraction; bp, backpressure.

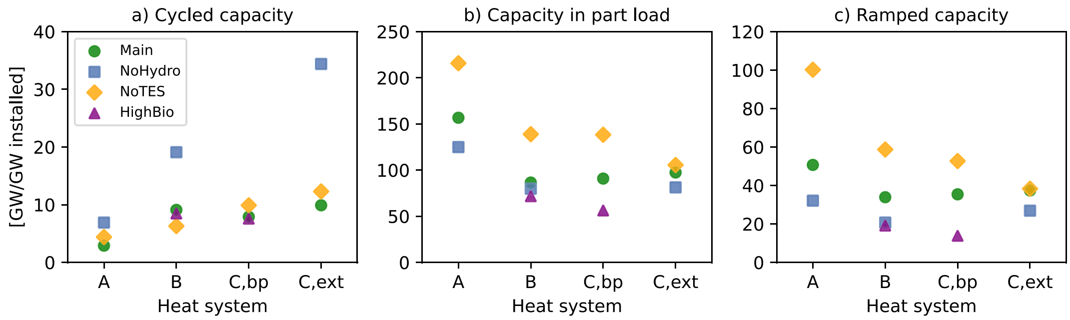

Fig. 8. Flexibility utilization indicators for wood chip-fueled CHP plants in the three district heating subsystems (A – small, B – medium, C - large), with full CHP plant flexibility. **a)** Cycled capacity. **b)** Capacity in part load. **c)** Ramped capacity. The annual accumulated capacities are normalized to the installed capacity of the respective plant type. Waste-fired CHP plants are omitted due to the operational constraint related to constant waste consumption. Turbine types: bp, backpressure; ext, extraction.

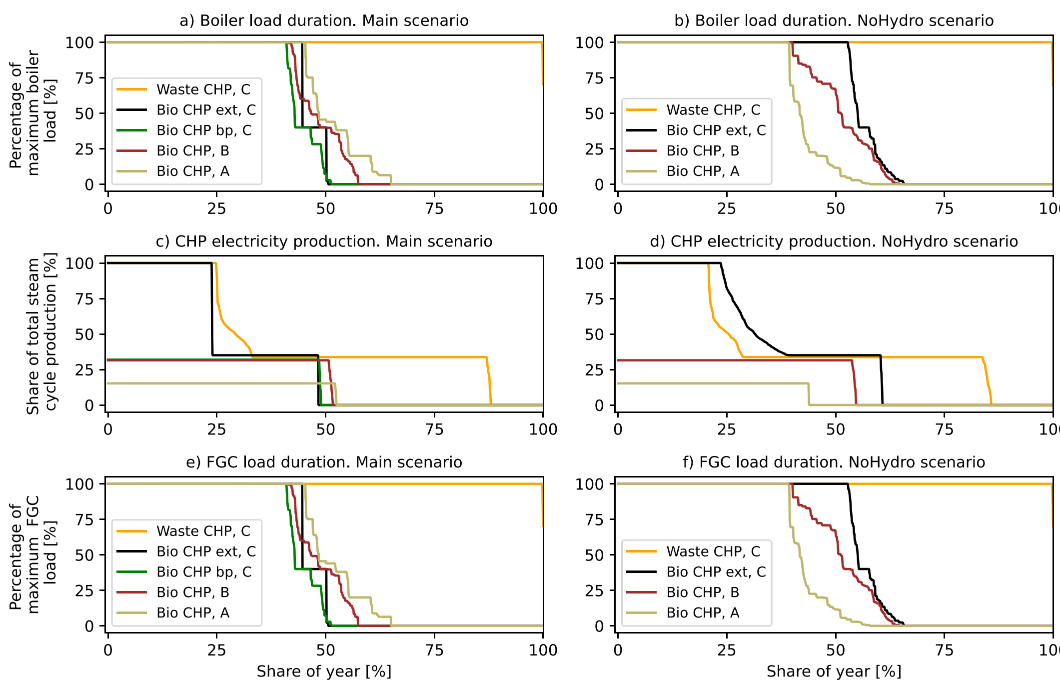

Fig. 9. Duration curves for: **a** and **b**) boiler load; **c** and **d**) electricity production; and **e** and **f**) flue gas condenser load, for the Main and NoHydro scenarios. The letters A, B and C correspond to the small, medium and large district heating subsystems, respectively, while “Bio” denotes wood chips. Note that the durations cover the whole year and not only the operational hours of the plant, i.e., the electricity production level and FGC load should be compared to the boiler load duration. Turbine types: bp, backpressure; ext, extraction.

electricity and heat correspond to the market prices, Fig. 7 gives the resulting distributions of CHP plant annual revenues (Fig. 7a) and production levels (Fig. 7b) in the three district heating subsystems (A-C). Backpressure turbine, wood chip-fueled CHP plants and waste-fueled CHP plants accrue a larger share of their revenues (around 60% on average) from supplying electricity than from heat production, even though the quantity of heat produced exceeds the quantity of electricity generated (with around 25% of the total production being electricity). Wood chip-fueled CHP plants in the small district heating subsystem (A) earn a smaller share of the revenue from electricity supply, 40%, since they have a significantly lower electric efficiency and power-to-heat ratio than the CHP plants in the larger heat systems (B and C). The extraction turbine, wood chip-fueled CHP plants in the largest system (C) produce less heat than the backpressure turbine plants when operating in condensing mode, and thereby earn a larger share of the revenue (around 75%) from supplying electricity.

In this regard, operational flexibility is valuable for CHP plants, to adapt the load in response to the fluctuating net load and marginal cost of electricity, both to take advantage of high electricity prices and reduce fuel consumption when electricity prices are low. Flexible application of the power-to-heat ratio through electricity-only operation is motivated for similar reasons. The potential value of heat-only operation is lower because it reduces the output of the most valuable product (electricity) and increases the CHP heat production cost, since all of the operational expenses must now be covered by heat sales.

3.3. Utilization of CHP plant flexibility measures

3.3.1. Operational flexibility

The operational flexibility relates to the operation of the boiler (fuel conversion system) and the overall load level of the plant. Fig. 8 presents the operational flexibility indicators defined in Eqs. (19)–(21), for wood chip-fueled CHP plants (with full flexibility) in the four scenarios studied. Fig. 8a plots the number of load cycles of the installed CHP boilers (cycled capacity). Fig. 8b shows the level of boiler capacity that has been available but not utilized, i.e., the extent of boiler part-load operation.

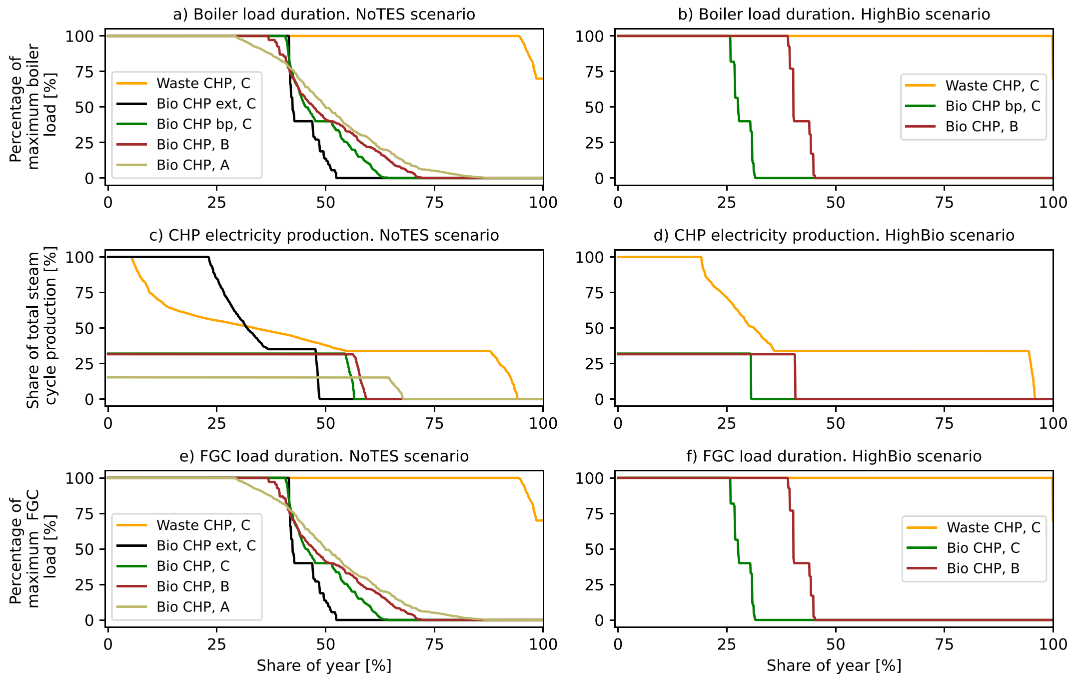

Fig. 10. Duration curves for: **a** and **b**) boiler load; **c** and **d**) electricity production; and **e** and **f**) flue gas condenser load, for the NoTES and HighBio scenarios. The letters A, B and C correspond to the small, medium and large district heating subsystems, respectively, while "Bio" denotes wood chips. Note that the durations cover the whole year and not only the operational hours of the plant, i.e., the electricity production level and FGC load should be compared to the boiler load duration. Turbine types: bp, backpressure; ext, extraction.

Fig. 8c gives the level of boiler capacity that has been ramped during the year (load changes). The indicator values are normalized for the installed CHP boiler capacity. The indicators provide a measure of the system contexts in which certain types of flexibility measures are valuable: high indicator values represent high-level use of operational flexibility. As a complement to Fig. 8, Fig. 9, a and b and Fig. 10, a and b show the CHP plant boiler load durations, giving an indication of the extent of annual boiler utilization.

The tendency to cycle CHP plants is strongest in the NoHydro scenario, reflecting the increased need for variation management when hydropower is removed: some 20–35 load cycles in total for the CHP plants in the large/medium district heating systems, compared to <15 load cycles in the remaining scenarios. The CHP plants in the small district heating system have a lower minimum load level than those in the larger heating systems, so they are cycled less and instead operate in part load to a greater extent. Part-load operation and ramping are most-prevalent in the NoTES scenario, as the lack of TES systems forces CHP plants to operate following the variability in the heat demand profile. This is also seen in Fig. 10a, in which the slope between full load and shut down is comparatively flat for wood chip-fueled CHP plants in the NoTES scenario, indicating more time in part load compared to the other scenarios.

The cycling and part-load trends relate to a need for system flexibility in different sectors. Both the NoHydro and NoTES scenarios confer reduced system flexibility, although the lack of hydropower mainly affects the electricity sector, and the lack of TES is most notable in the district heating sector. The CHP plants are small relative to the electricity system (4%–8% of annual electricity generation) and need to implement large load changes (on/off) in order to make a significant contribution to electricity system variation management; thus, the increased cycling seen in the NoHydro scenario. In the heat sector, the CHP plant capacity is large relative to the demand (Fig. 3), and smaller load changes within the part load operating range are sufficient to balance the heat demand without TES.

The share of full-load operation for wood chip-fueled CHP plants differs among the scenarios, in the range of 25%–60% of the year, with 20%–70% down-time. The wood chip-fired CHP plants in the HighBio scenario have the highest share of down-time (Fig. 10b) and the lowest part-load and ramping indicator values; these plants typically operate at full load or not at all, due to their increased fuel cost and reduced competitiveness.

3.3.2. *Flexible steam cycle power-to-heat ratio*

Fig. 9, c and d and Fig. 10, c and d show the steam cycle electricity production duration plots for the CHP plants in the four scenarios. Note that the duration curves cover the whole year and not only the operational hours of the plant. The plots indicate that condensing operation (electricity production accounting for 100% of total production) is viable up to 25% of the year for extraction turbine CHP plants, while co-generation (electricity production accounting for around 30% of total production) is, in most cases, the predominant mode of operation for backpressure plants. Waste-fired plants have a slightly stronger tendency than wood chip-fueled plants to operate in heat-only mode (electricity production accounting for 0% of total production) in response to net-load variability, as their operational flexibility is limited by the waste-use constraint.

For backpressure turbines, turbine operation follows an on/off pattern, as evidenced by the steep decline of the electricity production duration curves from the 30% level (co-generation) to 0%; either co-generation with the rated electricity generation or heat-only mode with no electricity production is preferred. The extraction turbine plants utilize a wider range of condensing operation loads, as seen in the decline of the curve slopes from 100% to 30%. This is especially notable in the NoTES scenario (Fig. 10c), in which the heat load-following operation incentivizes a wide range of cooling utility load levels to regulate the heat output for demand balancing, while maintaining a high level of electricity generation through condensing operation.

As a flexibility measure, the utilization and potential of power-to-heat ratio flexibility is dependent upon and limited by the boiler operation, as most clearly seen in Fig. 10d where the electricity production duration curve of Bio CHP in heat system C (green line) ends at the same point as the corresponding boiler load duration curve in Fig. 10b reaches zero. Variation management through reduced electricity generation is not available unless the plant is already in operation and has an alternative valuable product (in this case, heat) to deliver.

3.3.3. Flue gas condenser load flexibility

Fig. 9, e and f and Fig. 10, e and f present the load duration curves for the CHP plants' flue gas condensers. Since the maximum output of the FGC is proportional to the boiler load [Eq. (17)], the FGC load duration is limited by the boiler load duration curve, and the FGC and boiler load duration curves share the same profile if the FGC is always used to the maximum. The observed similarity between the FGC duration curves and boiler load duration curves in Figs. 9 and 10 (*cf.* Fig. 9a and e) indicate that the FGC output is maximized most of the time and that flexible FGC load is seldom used. Since the district heating generation from the FGC comes at no extra cost (other than for the boiler operation and fuel expenses), it is, of course, favorable to utilize the heat. To reduce the heat output, it is more-advantageous either to operate the steam cycle in condensing mode, which gives an increased electricity output, or to reduce the boiler load level, which reduces the fuel cost.

4. Discussion

The modeling results (Fig. 3) show that the use of flexibility in CHP plant operation is important for the competitiveness of wood chip-fired CHP plants in scenarios with low levels of system flexibility, while waste-fired plants with a low fuel cost can be competitive even though they are less-flexible and operationally limited. However, the price of fuel and the demand for heat production (rather than the level of CHP plant flexibility) are the predominant considerations for CHP plant competitiveness (Fig. 4). The level of integrated VRE is also important to consider, as low-cost electricity production favors PtH units in the heating sector, in competition with CHP plants. Monie et al. [24] have made a similar observation, stating that a large electricity surplus, if converted to heat and stored, limits the ability to utilize CHP units for power balancing. However, based on the modeling results, it seems more likely that existing biomass heat-only boilers (currently frequently used in Swedish district heating systems) are phased out by the expansion of PtH and TES, rather than CHP plants. Heat-only boilers generally have larger heat production costs than CHP plants and are, therefore, suitable peak heat production units. The results show that TES discharge is to a large extent used instead of heat-only boilers to meet peak heat demand. Furthermore, heat-only boilers cannot provide the flexible electricity generation that CHP plants can supply.

Other factors that support the use of CHP plants in future energy systems have been identified in previous studies. CHP plants have been recognized as having positive impacts on securing power and heat supplies and on network congestion management [55,59], although they might need support schemes to create sufficiently secure investment conditions [60]. On the other hand, if the biomass price increases significantly relative to heat and electricity prices, CHP plant competitiveness will decrease, unless other incentives for using biomass in CHP units are introduced. An example is bio-energy carbon capture and storage [61], which has been proposed as a measure to reach net-zero emissions in Sweden by Year 2045 [62].

The operational patterns observed in this work, entailing flexible operation of CHP plants and the interaction with PtH, differ from the present operational setup of Swedish district heating systems, which is more in line with the operating patterns seen when modeling CHP plants with limited flexibility. The summertime peak operation of wood chip-fueled CHP plants observed in the NoHydro scenario stands out, as frequent cycling of solid-fuel thermal power plants is usually avoided (as far as possible), so as to minimize lifetime degradation of thermally exposed components and the associated maintenance costs. The electricity-only operation observed in this work is discrepant with the present operating patterns, as condensing operation is, in general, currently not allowed for Swedish CHP plants, whose main purpose is to supply heat.

The results obtained based on Swedish conditions can to some extent be applied also to other conditions. The high availability of biomass in Sweden gives the Main scenario a low generalizability, while the NoHydro and HighBio scenarios could be representative of systems with a lower availability of hydropower and biomass resources, such as continental Europe. However, the heat supply systems presently in place should be considered before extrapolating results to other countries. In energy systems where district heating is currently not used in large scale to supply space heating, the incentives for CHP installments will naturally be low unless district heating expands. As mentioned in the Introduction, district heating system decarbonization strategies might also lead to reduced competitiveness of CHP plants, as previously shown for Finland [46,47], and in countries where biomass is scarce.

Given the observed interactions between CHP plants and electric boilers in the modeling results, the district heating systems themselves might hold greater potential for variation management than the individual heat production technologies. Compared to direct electric heating or heat pumps in residential buildings, in which the heat load can only be shifted in the near term (up to 12 h [7]) to comply with thermal comfort regulations, the load of a district heating system can potentially be shifted for long periods (up to months), given the presence of seasonal heat storage. This motivates the continued use of district heating systems for variation management as electricity generation becomes more variable.

There are also options for flexibility provision in the electricity system that are not included in this work, and might reduce the benefit of CHP plant flexibility services. Examples include transmission to/from other regional electricity price areas [4] and demand side management, for instance, in the industrial sector though hydrogen storage [63], in the transport sector using battery storage and vehicle-to-grid [6] and heat storage through electric heating in residential buildings [7]. However, batteries and heat storage in residential buildings would typically manage variability on short timescales and do not stand in direct competition to the variation management properties displayed by CHP plants and hydrogen storage, that are suited for longer timescales. Thus, a combination of several flexibility measures might be beneficial to manage a wide range of variability.

5. Conclusion

This study provides an analysis of the value, utilization, and operational strategies of CHP plant flexibility measures in four energy system scenarios. The flexibility measures considered are: operational flexibility, flexible steam cycle power-to-heat ratio, and flexible flue gas condenser load. Energy system modeling is applied to identify the cost-optimal investments and dispatch of technologies to meet the demands for electricity and district heating. The main conclusions of the work are summarized in five points:

- **CHP plant flexibility measures increase the competitiveness of wood chip-fired CHP plants,** in particular in scenarios with low-flexibility electricity systems (i.e., with low availability of hydropower or no thermal energy storage). However, the investments are sensitive to fuel cost. Waste-fired CHP plants are competitive due to a low-cost fuel, even though they are modeled as being less-flexible than wood chip-fired plants.
- **The demand for district heating dimensions the capacity of CHP plants**, thus, a low district heating demand relative to the demand for electricity results in a low electricity production capacity of CHP plants relative to the total electricity demand, and a small impact of CHP flexibility on the total cost of electricity and district heating. Thereby, **the value of flexible CHP capacity is low for the electricity and district heating system in total** (<1% decrease in total system cost).
- **Variability of the electricity net load influences the operation of CHP plants** and causes recurring changes in the district heating system merit order between wood chip-fired CHP plants and PtH technologies. As a result, district heating systems with large-scale thermal energy storage systems hold a large potential for variation management.
- **Load-following electricity generation is a valuable product for CHP plants.** Although the sum of the heat and power production levels in a CHP plant is dominated by district heating (50%–90% of annual production), electricity generation is more valuable as a product, accounting for 40%–75% of the annual revenue.
- **Boiler operational flexibility has a higher value than a flexible power-to-heat ratio or flue gas condenser flexibility.** Operational flexibility combined with power-to-heat ratio flexibility (heat-only operation) are used to decrease the level of CHP plant electricity generation during low-net-load events, and steam cycle electricity-only operation is used to maximize the level of CHP plant electricity generation when the net load is high and the heat demand is moderate.

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. System composition results

Table A1 shows the results for the cost-optimal investments in electricity and heat generation technologies, storage capacity, the curtailment of electricity and heat, and biomass usage, for the four scenarios studied. The results are presented for cases with and without modeling of CHP plant flexibility measures.

Table A1
Optimal system compositions for the different scenarios.

	Full CHP plant flexibility				No CHP plant flexibility			
Capacity installed	Main	NoHydro	NoTES	HighBio	Main	NoHydro	NoTES	HighBio
Electricity generation [GW]								
Wood chip-fired CHP	1.7	2.0	1.6	0.8	1.5	1.2	1.2	0.2
Waste-fired CHP	0.2	0.2	0.3	0.4	0.2	0.4	0.4	0.4
Wind power, onshore	16.3	16.0	16.1	18.6	16.1	16.0	15.8	19.1
Wind power, offshore	5.9	8.0	6.0	8.1	6.4	8.3	6.0	8.9
Solar PV	9.5	21.7	9.5	4.0	9.3	22.9	9.4	5.1
Biogas GT	8.4	7.7	8.2	5.6	8.2	7.4	8.0	5.4
Biogas CCGT	1.3	8.5	1.3	3.7	1.6	9.3	1.8	4.2
Hydropower	9.6	0	9.6	9.6	9.6	0	9.6	9.6
Heat generation [GW]								
Electric boilers	2.9	2.7	0.7	3.2	2.7	3.7	1.0	4.2
Heat pumps	0.4	0	0.7	3.8	0.9	0.5	0.7	5.4
Biogas HOB	0.6	0.9	4.1	0.9	1.2	1.7	4.9	0.8
Solar heat	0	0	0.1	0	0	0	0.1	0
Storage systems [GWh][a]								
Battery	10.8	39.7	12.5	18.3	11.5	38.7	13.6	18.9
Pit-TES (long-term)	512.1	448.0	0	888.7	577.0	579.2	0	1,112.1
Tank-TES (short-term)	3.5	1.8	0	3.4	6.9	2.5	0	4.0
Curtailment and biomass usage [TWh/year]								
Curtailed electricity	4.88	6.48	2.43	9.58	6.27	9.53	2.32	11.95
Curtailed heat	1.04	1.04	0.78	1.79	1.30	3.17	2.02	4.27
Biomass usage	11.72	20.55	10.77	5.50	11.55	21.52	11.61	3.61

[a] The storage capacities represent the *aggregated* capacity of storage in the entire region. For example, thermal energy storages might be located in several cities in the region, in smaller sizes than reported in the table, as the district heating demand represents an aggregate of the total demand from all cities in the region.

Appendix B. Technology and cost data

Tables B1–B4 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 [64].

Table B3 presents the input data related to thermal energy storages, as implemented in the model presented by Holmér et al. [5], where further details can be found. The storages are assumed to be mixed and not stratified (see [5] for an analysis of the impact of stratification).

Table B1
Cost and technology data for electricity and heat production technologies. CHP plants are presented separately in Table B2.

	Investment cost [k€/MW]	Fixed O&M cost [k€/MW/yr]	Variable O&M cost [€/MWh]	Lifetime [yr]	Start time [h]	Start cost [€/MW]	Electric or heat efficiency [%]
Electricity generation							
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
Coal/biomass CCS	3,463	107.6	2.1	40	12	56.9	34
Gas/biogas CCS	1,800	35.1	2.1	30	12	56.9	46
Wood chip-fired, condensing	2,049	54.2	2.1	40	12	56.9	36
Wind, onshore	1,389	12.6	1.1	30	0	0	- [a]
Wind, offshore	2,594	36.0	1.1	30	0	0	- [a]
Solar PV	450	7.8	1.1	40	0	0	- [a]
Nuclear power	4,770	0.1	0.1	60	24	400	33
Heat generation							
Electric boiler	50	0.9	1.0	20	0	0	98
Heat pump	530	1.0	1.6	25	0	0	3 (COP)
Biogas HOB	50	1.7	1.0	25	0	0	104[b]
Waste-fired HOB	1,240	50.6	4.1	25	12	56.9	106[b]
Wood chip-fired 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	–	–	–

[a] Limited by generation profiles based on geographic area and wind classes.
[b] Based on the lower heating value of fuel.

Table B2
Combined heat and power plant technology properties and cost data. Source: [65].

Plant type		Investment cost [k€/MW_{fuel}]	Fixed O&M [k€/MW/yr]	Variable O&M [€/MWh]	Lifetime [yr]	Start time [h]	Start cost [€/MW]	Power-to-heat ratio of steam cycle [–]	Steam turbine electric efficiency [%]	Boiler efficiency [%]	Extraction mode cooling coefficient, DH, β_{DH} [–]	Extraction mode cooling coefficient, electricity, β_{el} [–]	Gas turbine electricity generation factor, f_{GT} [–]
CHP, wood chips	S[a]	840	39	1.40	40	12	56.9	0.18	15	94	–	–	–
	M	940	38	1.40	40	12	56.9	0.46	30	93	–	–	–
	L, bp[b]	880	25	1.40	40	12	56.9	0.47	30	95	–	–	–
	L, ext	940	26	1.10	40	12	56.9	0.54	32	90	−1.135	0.153	–
CHP, wood pellets	S	840	40	0.60	40	12	56.9	0.21	15	89	–	–	–
	M	830	33	0.57	40	12	56.9	0.53	31	89	–	–	–
	L, bp	650	20	0.58	40	12	56.9	0.61	34	89	–	–	–
	L, ext	850	22	0.51	40	12	56.9	0.71	35	84	−1.135	0.153	–
CHP, waste	S	2,090	78	5.90	40	12	56.9	0.36	23	85	–	–	–
	M	1,860	51	5.90	40	24	56.9	0.38	23	85	–	–	–
	L, bp	1,610	37	5.90	40	24	56.9	0.38	24	86	–	–	–
	L, ext	1,860	38	5.90	40	24	56.9	0.51	26	85	−1.126	0.145	–
CHP, biogas combined cycle	M	605	14	2.20	30	6	50.6	0.41	31	86	–	–	2.6
	L, bp	495	11	1.70	30	6	50.6	0.41	34	89	–	–	2.0
	L, ext	540	12	1.80	30	6	50.6	0.41	35	90	−1.128	0.139	2.3

[a] S, M, and L denote plant size categories that are available in heat systems A, B and C, respectively.
[b] The designations *bp* and *ext* refer to the backpressure and extraction types of steam turbine, respectively.

Table B3
Thermal storage technology characteristics and cost data. TTES and PTES are available with or without heat pumps for discharging heat (the cost of the heat pump is not included in the storage investment cost).

Storage type	Investment cost [k€/MWh]	Lifetime [yr]	Size [m^3]	Efficiency (charge) [%]	C-factor [–]	Loss [%/h]	Constant loss [%/h]
TTES (HP)	5.69	25	600	98	1/6	1/240	–
TTES (no HP)	8.85	25	600	98	1/6	1/240	4.3/240
PTES (HP)	0.27	25	75,000	98	1/168	1/240	–
PTES (no HP)	1.25	25	75,000	98	1/168	1/240	4.3/240
BTES	0.46	25	10,000	98	1/3000	1/240	–

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

Table B4
Fuel costs. Biomass and biogas costs are subject to scenario variations (see Table 3).

Fuel	Cost [€/MWh]
Waste[a]	1
Wood chips	20
Wood pellets	30
Biogas	48.6
Uranium	8.1
Hard coal/biomass co-firing	10.9
Natural gas/biogas co-firing	32.6

[a] Waste is assumed to be municipal solid waste. Industrial waste is not considered.

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.

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