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A multiple system level modeling approach to coupled energy markets: Incentives for combined heat and power generation at the plant, city and regional energy system levels

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The energy system can be subdivided into interconnected structural levels with differing boundary conditions and objectives. For heat and power generation, these levels may be the: electricity price area (regional); heat price area (city); and production site (power plant). This work presents a multi-system modeling approach for the analysis of investments and operation of combined heat and power (CHP) plants, as optimized on a regional, city, or production site energy system level. The modeling framework, comprising three energy system optimization models at the respective levels, is applied to a case study of Sweden, electricity price area SE3. The modeling levels are optimized separately but linked through electricity and heat prices. The results show that optimized CHP plant investments and operation on the three levels can both align and differ, depending on conditions. With a low biomass price and moderate congestion in transmission capacity into the city, the results from the three levels generally align. Differences arise if the biomass price is increased, which impacts the competitiveness of CHP plants in the region, while city-level CHP investments are mainly determined by the local heat demand and less-sensitive to external changes. The differences indicate a risk for diverging expectations between system levels.

1. Introduction

Energy-efficient processes are crucial for the transition towards a sustainable energy system. Polygeneration, which is the simultaneous production of two or more utilities in an integrated process, represents a category of technologies that use primary energy sources with high efficiency [1] and that might be suitable for integration into distributed energy systems [2]. A common form of polygeneration is combined heat and power (CHP), in which electricity and district heating (DH) are co-generated. CHP based on biomass has been proposed as a potential low-carbon complement to variable renewable energy (VRE) from, for example, wind or solar electricity generation [3]. In addition, the use of DH systems has been identified as a cost-efficient way to decarbonize the European energy systems [4], which could further support the growing shares of renewable energy [5].

District heating systems typically prioritize the use of different forms of waste heat, such as from biomass or municipal solid waste. Since the value of biomass will likely increase in the future, with an increased competition over biomass residues, it is important to ensure that CHP plants are efficient and can be adapted to future heat and electricity markets, which will most likely require increased flexibility in electricity generation from CHP plants.

In Sweden, which has a significant demand for heat during the winter, CHP plants are in widespread use for DH production, with electricity generated as a by-product that brings in revenue. However, with the strong expansion of VRE from, especially, wind power in the electricity system, the competitiveness of CHP plant electricity generation may change. Furthermore, as polygeneration units, CHP plants act both in the regional electricity market and in the local DH market, i.e., at the city level. In this work we focus on electricity and DH, which is typically the main CHP plant product combination. Ancillary services [6–8], industrial process heat delivery [8,9], biofuel production [10,11], or negative emissions through bio-energy carbon capture and storage [12,13] are potential additional products of polygeneration units. Studies have also considered the plant's fuel supply system [14,15]. Since the electricity and DH sectors differ in terms of their geographic scope and

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Nomenclature

Latin	
C	Cost
D	Demand
M	Import capacity, city
p	Electricity generation
q	Heat generation
s	Installed capacity
TT	Length of time-step
w	Electricity import/export
y	Fuel consumption
z	Storage charge/discharge
Greek	
α	Power-to-heat ratio
β	Coefficient
η	Efficiency
Subscripts and superscripts	
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
k	District heating subsystem in region
max	Maximum load
OMvar	Variable operation and maintenance
P	Electricity
PtH	Set of power-to-heat technologies
ST	Steam turbine
store	Set of storage technologies
t	Time-step
TES	Set of thermal energy storages
tot	Total
run	Running
Abbreviations	
CHP	Combined heat and power
DH	District heating
FGC	Flue gas condenser
HOB	Heat-only boiler
PtH	Power-to-Heat
PV	Photovoltaics
SC	Steam cycle
VRE	Variable renewable energy

net load variability, it is not obvious how to optimally invest in and operate the plants. In this work we identify three system-level perspectives:

1. *Regional electricity system level.* CHP plants generate electricity that is traded on the energy-only market in a regional price area. Previous works [16,17] have shown that CHP plants, in the form of dispatchable generation, could contribute to electricity system balancing in a scenario in which complementing generation is important. This would imply that the CHP plant capacity and operation might optimally be dimensioned based on, and scheduled to follow, net load variations in the electricity sector. Such a strategy implies that the CHP plant heat supply follows the electricity net load rather than the DH demand, and will require additional measures (for example, thermal energy storage) in the DH sector to manage the heat load balance.
2. *City-level electricity system and district heating network.* From the perspective of the DH system operator, the objective is to supply the heat demand at the lowest cost, and CHP plants operate based on the expected heat demand, typically as part of a portfolio of heat supply units. However, electricity prices influence the CHP plant dispatch [18], as well as other heat generation technologies, such as Power-to-Heat (PtH) in the form of heat pumps and/or electric boilers. Furthermore, the electricity demand of the city is expected to grow due to extended urbanization and increased electrification of, for example, transportation and space heating [19]. To supply the higher electricity demand, either an increased share of the local electricity-generating capacity or increased transmission line capacity for the import of electricity to the city from the distribution grid is required. CHP plants located within cities (where the DH networks are found) can be valuable contributors to local electricity balancing. Decisions regarding CHP plant operation and investments will, therefore, be influenced by the local demand for electricity.
3. *Individual CHP plant level.* The plant level concerns individual CHP plants whose objective is to maximize the plant revenue from sales of heat and electricity, without obligations to meet demand levels in the surrounding system. The investment in a CHP plant is associated with risk, due to uncertainties in relation to electricity prices, while the possible consequences of VRE expansion include fewer operational hours and increased complexity of daily operation. These factors might lead to lower plant profitability and a long-term risk of CHPs being phased out of the energy system [20,21]. With respect to the competitiveness of an individual CHP plant, which will typically have DH as the main product, it might be unfavorable to invest in expensive steam cycles with electricity generation, and more-beneficial to consider the alternatives of heat-only boilers [22] or PtH technologies [23].

These system levels are linked to different objectives and the boundary conditions of the region, the city, and the plant differ significantly, for example regarding the scope of the markets, demand levels in the city vs the region, and priorities regarding how to operate the system or plant. Several studies have presented models that optimize CHP plant operation in various system contexts, geographically relating to a region [17,24], a city or a district heating system [16,18,25–27], a district or community [28,29], a neighborhood [30], or to the power plant itself [9,31,32].

Methods have also been developed that take into account multiple objectives or actor perspectives in optimization models, for example using bi-level programs that jointly optimize a cost minimizing problem (e.g. representing a system operator) and a revenue maximizing problem (e.g. representing a power plant owner) with a single-solution market clearing [33,34]. Bi-level optimization programs have also been applied to connect the regional electricity and local district heating markets [35], to study the interaction of the transmission system and distribution system grid levels [36], or for integration of the power, heat and natural gas systems [37]. Another method that has been applied is the decomposition of a non-linear energy system optimization problem into subproblems for an electric system and district heating systems, that exchange boundary energy flows and local marginal prices [38]. Heinisch et al. [39] studied the interaction between centralized (electricity system price area) and decentralized (city with limited grid connection capacity) parts of the energy system. Lindroos et al. [15] combined multiple energy system layers in a single model, albeit without considering investment optimization, and their findings indicate differences between the value assigned to CHP units based on local and regional viewpoints.

However, the integration of multiple objectives or system levels in the same model yields solutions that represent a compromise between the objectives, and do not allow the comparison of what would be optimal from different perspectives. In practice, energy system development and CHP plant investment decisions might be taken by actors that only consider their own objectives and not the entire integrated system. In this regard, it is of interest to study the differences and similarities between models that optimize the same feature but on different system levels.

To this end, this work presents a method to represent and compare multiple system levels in a modeling framework, by modeling CHP plant operation according to the above three system levels separately while keeping them connected through the exchange of market price signals. The novelty and main contribution of the work, thus, lies in the methodological approach that enables the comparison of optimization model results at different system levels. The method is applied to investigate the incentives for and role of CHP plants in future energy systems from perspectives 1–3. The sensitivity of CHP plant investments and dispatch to the boundary conditions of each system level is analyzed, focusing on biomass price, transmission capacity limitations, and the availability of nuclear power in the regional electricity system.

2. Method

2.1. Modeling framework

The work is conceptually based on the idea of “energy systems in energy systems”: A CHP plant can be perceived not only as an individual energy system in itself, but also as a part of a local or regional energy system, together with many other electricity and heat generation technologies. Fig. 1 visualizes the framework based on the energy system levels: a region, a city, and a CHP plant. Here, a region is defined as an electricity price area, and a city corresponds to a local DH price area. These three system levels are linked through the heating and electricity markets and their price signals.

The plant, city and regional levels are chosen because they are all connected to the markets that are most relevant for CHP plants; for example, the district heating market is typically a local heat delivery monopoly limited by the city boundaries, since heat is costly to transport over long distances. Similarly, the individual plant manager is mainly concerned with the energy system bounded by the production site area. Although the electricity system spans multiple regions that are interconnected with transmission lines, the electricity price is specific for each region, and motivates a regional system level. Multiregional electricity system models are found in the literature (see, for example, [40]), but commonly have a limited representation of the district heating sector to keep the computational complexity at a manageable level. Since district heating is an important product for CHP plants, a multiregional modeling level is excluded from the work. Additional markets or sectors are potential additions to the modeling, for example, the fuel market or ancillary service markets, but are neglected in this work to keep the focus on heat and electricity, which are typically the main revenue streams of CHP plants. However, the sensitivity of the results to fuel cost is investigated (Section 2.3).

Compared to other optimization modeling approaches that jointly optimize the three system levels with a single solution (see Section 1 for references), the soft-linking of three separate models is preferred in this study to highlight resulting discrepancies and similarities between the system levels. Thus, the methodological framework developed in this work enables a comparison of how the modeled system-level perspectives would optimally place investments in, and operate, CHP plants.

The region and city have different portfolios of options for investment in electricity-generating technology, summarized in Table 1. The region has a full set of technologies to choose from, while the city is limited to locally available technologies. The plant-level model only considers the unit commitment of CHP plants, and no investments. The cost data and technical properties of the technologies are given in the *Supplementary Material*. The objective of the regional and city levels is to supply a given demand for electricity and DH to the lowest cost, while the CHP plant's objective is to maximize the revenue from sales of electricity and DH based on given price signals.

2.2. The three energy system optimization models

Three energy system models are applied to represent the different system levels, including the electricity and DH sectors. The models are formulated as linear optimization models with the objective to identify the cost-optimal investment and dispatch of each system level. Table 2 gives the boundary conditions for each model. The regional model considers an isolated region without transmission of electricity to neighboring regions. The city model

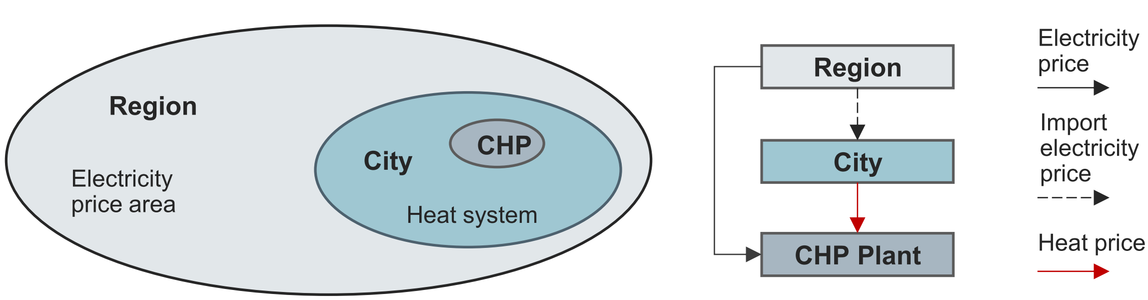

Fig. 1. Overview of the conceptual framework and the system levels considered (region, city, CHP plant), and a schematic of the soft-linking of system levels through electricity and/or district heating price signals.

Table 1
Technology options included in the optimization models at the three system levels.

Technology		Region	City	Plant
Electricity sector	Wind, onshore/offshore	X		
	Solar PV	X	X	
	Hydropower	X		
	Nuclear power	X		
	Biomass, condensing	X		
	CCS (Coal/NG/co-firing)	X		
	Biogas, combined cycle	X	X	
	Biogas, turbine	X	X	
Heat sector	CHP (Waste/Biomass/Biogas)	X	X	X
	HOB (Waste/Biomass/Biogas)	X	X	
	Heat pump	X	X	
	Electric boiler	X	X	
	Solar heat	X	X	
Storages	Long-term heat storage (PTES)	X	X	
	Short-term heat storage (TTES)	X	X	
	Battery	X	X	

PV, photovoltaics; CCS, carbon capture and storage; NG, natural gas; CHP, combined heat and power; HOB, heat-only boiler; PTES, pit thermal energy storage; TTES, tank thermal energy storage.

Table 2
Model boundary conditions for the region, city and plant-level models. The exogenously provided inputs are further described in Section 2.3.

Boundary condition	Regional model	City model	Plant model
Electricity demand	Exogenous profile for region	Exogenous profile for city	None
District heating demand	Exogenous profile for region, divided over three DH subsystems (A/B/C)	Exogenous heat demand profile for city	None
Electricity cost	Model output	Model output. Possibility to trade using electricity price profile from regional model, with limited import/export	Input: Electricity price profile from regional model
District heating cost	Model output	Model output	Input: Heat price profile from city model
Fuel cost	Exogenously provided to all models		

can import and export electricity to/from the regional grid at a price that is set by the modeled regional marginal cost of electricity, although it is subject to a limited transmission line capacity. Heat cannot be imported or exported, as DH systems are local markets, due to the expense of transporting heat over long distances. In contrast to the region and city, the CHP plant model is not subject to the constraint of meeting an electricity or heat demand; it can operate freely to maximize the revenue based on prices set by the marginal costs of the regional electricity market and city DH system. Fuel costs are provided exogenously, with the same cost levels applied in all the models. Note that there is no feedback between the models, i.e., the price signals are unidirectional from the region to the city and CHP plant levels. All models are run for 1 year with a time resolution of 3 h.

A shared feature of the regional and city models is that a Greenfield approach is chosen based on the timeframe of the study: around Year 2045, under the assumption that the energy system is CO_2 neutral (no fossil CO_2 emissions). Waste is allowed as a fuel in CHP plants under the assumption that the fossil share of waste is phased out by Year 2045, for plastic recycling. Waste-fired plants are forced to operate year-round in the regional and city models due to the inappropriateness of storing waste for extended periods.

The modeling focus is on CHP plants that are available as two types in all the models: a backpressure turbine and an extraction turbine. While backpressure turbines have a lower investment cost than extraction turbines, they also have a lower electric efficiency. Biomass- and waste-fired CHP plants are equipped with flue gas condensers (FGCs) that generate DH. CHP plants are able to operate flexibly by varying: 1) the fuel load level; 2) the power-to-heat ratio of the steam cycle; and 3) the FGC generation of DH. Variations in fuel load levels are subject to cycling restrictions and start/part-load costs. Backpressure turbines can only reduce the power-to-heat ratio by using a steam turbine bypass, whereas extraction turbines can both increase and decrease the power-to-heat ratio.

2.2.1. Regional model

The regional model optimizes the investment in and dispatch of production units in the electricity and heat sectors for one electricity price area, where transmission to/from neighboring price areas is excluded. The DH demand in the region is divided across three subsystems (A, B, C) as proposed by Goop [41], which represent the aggregated demand for DH in small (A), medium (B) and large (C) cities in the region. The CHP and heat generation technology types available for each DH subsystem differ in terms of investment cost and performance data: A-system technologies are more expensive and have a lower electric efficiency than C-system technologies due to efficiency of scale.

The regional model has been used in previous studies and is well-described in the referenced literature. The model was first presented by Göransson and colleagues [42], focusing on the electricity sector and cycling of thermal plants. The model was then further developed to include a representation of the DH sector and thermal energy storage systems [43], battery storage [44], and CCS technology options [45]. The objective of the model, given in Eq. (1), is to minimize the total cost of electricity and DH generation, considering investments and the running costs of production and storage technologies. For every time-step, the heat and electricity demand in the region must be met [Eqs. (2) and (3)], as given by the input demand profiles (Section 2.3).

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

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

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

The model is well suited for the present work, as it includes features that are important for the study of CHP plants. These features include a representation of thermal power plant operational dynamics, a detailed representation of both the electricity and district heating sectors, and works with chronological time rather than representative days or time slices that limit the modeling of storage systems, in particular long-term storages such as seasonal heat storage systems.

For the present study, the model is expanded with flexibility measures for the operation of CHP plants. The steam turbine can be bypassed to increase DH generation (heat-only operation in the extreme case), where Eq. (4) allows the ratio of electricity generation to heat generation to deviate from the design power-to-heat ratio (α, model parameter). Plants that have extraction turbines also have the option to increase electricity generation at the expense of reduced heat production (condensing operation) by cooling away DH via the variable q^{cool} and coefficients that describe the increase and reduction of electricity and heat production, respectively [Eqs. (5) and (6)]. Equation (7) ensures that the steam cycle energy balance holds. Finally, the FGC load can be reduced from the maximum (design) value, Eq. (8).

$$p_{CHP,k,t}^{SC,bp} \le \alpha_{CHP}^{SC,design}q_{CHP,k,t}^{SC,bp}\ ,\ \forall k\in K, t\in T \quad (4)$$

$$q_{CHP,k,t}^{SC,ext} = q_{CHP,k,t}^{SC,bp} - \beta_{DH}\cdot q_{CHP,k,t}^{cool}\ ,\ \forall k\in K, t\in T \quad (5)$$

$$p_{CHP,k,t}^{SC,ext} = p_{CHP,k,t}^{SC,bp} + \beta_{el}\cdot q_{CHP,k,t}^{cool}\ ,\ \forall k\in K, t\in T \quad (6)$$

$$p_{CHP,k,t}^{SC,ext} + q_{CHP,k,t}^{SC,bp} + q_{CHP,k,t}^{cool} = q_{CHP,k,t}^{fuel}\cdot\eta_b\ ,\ \forall k\in K, t\in T \quad (7)$$

$$q_{CHP,k,t}^{FGC} \le q_{max}^{FGC}\ ,\ \forall k\in K, t\in T \quad (8)$$

2.2.2. City model

The city-level energy system model is derived from the regional model and is formulated on a similar form, as presented previously [25]. Just like the regional model, the objective is to minimize the total cost of electricity and DH generation, Eq. (9), while satisfying the corresponding demands [Eqs. (10) and (11)]. A feature that distinguishes the city model from the regional model is that transmission between the regional grid and the city is included, albeit with a limit imposed on the transmission capacity to represent power system congestion, as expressed by Eq. (12). In addition, the available technology options for the city model are more limited than those for the regional model, as given in Table 1.

$$MIN : C^{tot} = \sum_{i\in I_{El}}\left(C_i^{inv}s_i + TT\cdot\sum_{t\in T}\left(C_i^{run}p_{i,t} + C_{i,t}^{cycl}\right)\right) + \sum_{i\in I_{Heat}}\left(C_i^{inv}s_i + TT\cdot\sum_{t\in T}\left(C_i^{run}q_{i,t} + C_{i,t}^{cycl}\right)\right) + \sum_{i\in I_{TES}}C_i^{inv}s_i + C_{bat}^{inv}s_{bat} + TT\cdot\sum_{t\in T}C_t^{el}w_t \quad (9)$$

$$D_t^P + z_{bat,t}^{ch} + \sum_{i\in I_{PtH}}p_{i,t} \le \sum_{i\in I_{El}}p_{i,t} + w_t + z_{bat,t}^{dch}\ ,\ \forall t\in T \quad (10)$$

$$D_t^{DH} + \sum_{i\in I_{TES}}z_{i,t}^{ch} \le \sum_{i\in I_{Heat}}q_{i,t} + \sum_{i\in I_{TES}}z_{i,t}^{dch}\ ,\ \forall t\in T \quad (11)$$

$$w_t \le M\ ,\ \forall t\in T \quad (12)$$

2.2.3. Plant model

The plant-level model considers the unit commitment of individual CHP plants with a given installed capacity, i.e., investments are not considered. The objective of the model, expressed by Eq. (13), is to maximize the annual plant revenue from sales of electricity and DH, taking into account the expenses for associated fuel use, operational and maintenance costs, start costs, and part-load costs. Electricity and DH prices are given as input profiles, according to Table 2. A mixed integer formulation is applied to account for minimum load levels, where binary variables indicate whether the plant is in operation or turned off or on in a given time-step. The implementation of cycling and minimum load constraints are given in a previous publication [31]. In the plant-level model, waste-fired plants are not subject to constant waste-use, as in the regional and city models.

$$MAX : C^{revenue} = TT\cdot\sum_{t\in T}\left(p_tC_t^{el} + q_tC_t^{heat} - y_t\left(C^{fuel} + C^{OMvar}\right) - C_t^{cycl}\right) \quad (13)$$

2.3. Case study and sensitivity analysis

The modeling framework is demonstrated for a case study of the power market (region) in Nordpool's price area SE3, where many of the existing Swedish CHP plants are located. The City of Gothenburg, categorized as a large-city (C-type) DH subsystem, is chosen as a case study for the city model.

Electricity and DH demand profiles for Year 2012 are provided as model inputs. The regional electricity demand profile is based on data from ENTSOE, while the regional DH demand profile is obtained from data for the Gothenburg DH system. The regional DH demand is distributed between the DH subsystems according to a previous paper [43]. For the city model, data for the electricity and DH demands in Gothenburg are used as inputs. Both the regional and the city electricity demands are scaled by a factor of 1.5 compared to the Year 2012 levels, to account for an expected increase in future electricity demand through increased electrification. The heat demand is assumed to remain at Year 2012 levels. The demand profiles are plotted in Fig. 2 for the region and city, respectively. The regional electricity demand is significantly higher than the regional DH demand, while in the city they are of

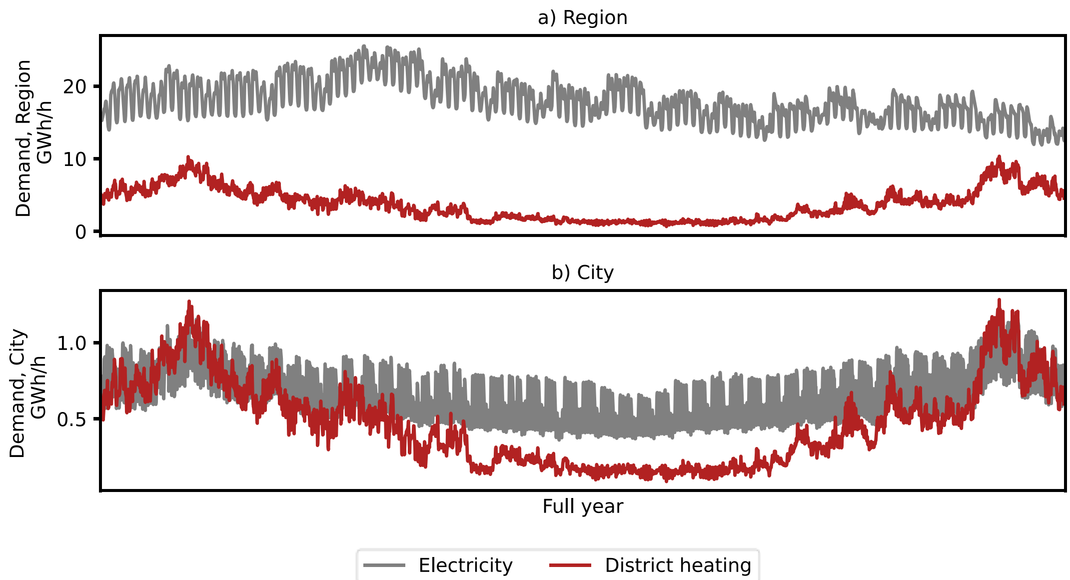

Fig. 2. Electricity and district heating demand profiles for the case studies of: a) the SE3 region; and b) the City of Gothenburg. Electricity demand profiles are scaled by a factor 1.5 compared to Year 2012 levels.

comparable magnitude during wintertime.

The availability of waste fuels is limited for the region and city based on the current usage of waste by CHP plants in the SE3 region and Gothenburg, respectively. Due to the ongoing transition of the industrial sector to comply with climate targets, current industrial excess heat deliveries to the district heating sector are not included.

Table 3 summarizes the scenarios studied in the present work. The main parameters in the region that differentiate the scenarios are the biomass price level and the presence or non-presence of nuclear power. The Main and Nuclear scenarios assume that biomass prices remain at current levels, while the HighBio scenario analyzes the sensitivity of the results to increased biomass prices. The Nuclear scenario assumes that the capacity of nuclear power remains at a level similar to the currently installed capacity of nuclear power in Sweden (some 6.9 GW) and forces the model to invest in nuclear power. In contrast, the Main and HighBio scenarios can freely optimize new investments in nuclear power.

The prices of wood chips and wood pellets are based on data for wood fuel prices in Sweden [46]. The wood chip price is doubled for the higher price level, and the price difference between wood chips and pellets is assumed to be maintained (i.e., the cost of pellet production is constant). The biogas price is calculated based on the price of wood chips, assuming that biogas is produced from the gasification of solid biomass 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 [47], under the assumption of 8000 full-load hours.

For the city model, the connection capacity to the regional grid is in the Main scenario assumed to remain at its current level, resulting in a 56% connection capacity relative to the (up-scaled) peak electricity demand. The import capacity is varied within the range of 28%–83% (the current import capacity is 83% of peak demand) in a sensitivity analysis, to study the impact of congestion on the model results. There is no transmission capacity limitation within the region, i.e., the regional model has only one node. As an additional sensitivity analysis, the city model is also optimized for the A and B DH subsystem categories.

3. Results

The results from the regional-, city-, and plant-level perspectives are compared, primarily with respect to the investment levels and operational patterns of CHP plants, describing the roles and competitiveness of CHP plants in each system-level context. In addition, we look at the marginal price formation, which influences the plant-level operational profitability.

3.1. Cost-effective investments on the regional and city levels

Fig. 3 plots the cost-optimal investments in DH and electricity generating capacity on the regional and city levels, respectively, for scenarios with and without nuclear power in the region, high biomass prices, and different capacities for city electricity import. The investment capacities are normalized by the peak electricity or heat demand. Thus, the investments are not for separate systems, but reflect two views of the same system, i.e., what would be cost-effective on different system modeling levels.[1]

In Fig. 3, two main discrepancies are evident between the regional and city levels, relating to the cost-optimal investments in biomass CHP plants and solar PV. On the city level, since the selection of technologies is limited, local solar PV generation becomes more prevalent than on the regional level, and even more so when the electricity import capacity is reduced (compare the Main 83% and 56% scenarios in Fig. 3b). With access to hydropower and wind power, the regional level includes relatively low shares of solar PV (Fig. 3a).

The amount of CHP investments is, on the city level, primarily determined by the heat demand and corresponds to 59%–78% of the peak heat demand in all the scenarios. On the regional level, the optimal DH sector investments instead include a larger share of PtH

[1] It should be noted that the methodological approach applied in the Nuclear scenario (forced investment) does not fully account for the cost of nuclear power. As nuclear power is not present in the optimal system portfolio in the Main scenario, the regional system cost is increased when forcing investments in nuclear power: from 7.44 G€ to 8.60 G€. This cost increase is not fully represented in the system model, i.e., it is not clear who will pay for the investments in nuclear power so as to cover the costs.

Table 3
Scenarios studied and associated parameter values.

Regional parameters	Main scenario	HighBio scenario	Nuclear scenario
Nuclear power capacity in region [GW]	Optimized	Optimized	6 (forced investments)
Biomass price [€/MWh]			
Wood chips	20	40	20
Wood pellets	30	50	30
Biogas	48.6	77.1	48.6
City parameters	Main scenario	Sensitivity analyses	
City import capacity [% of peak demand]	56	28, 36, 45, 83	
City model heat system type	C	A, B	

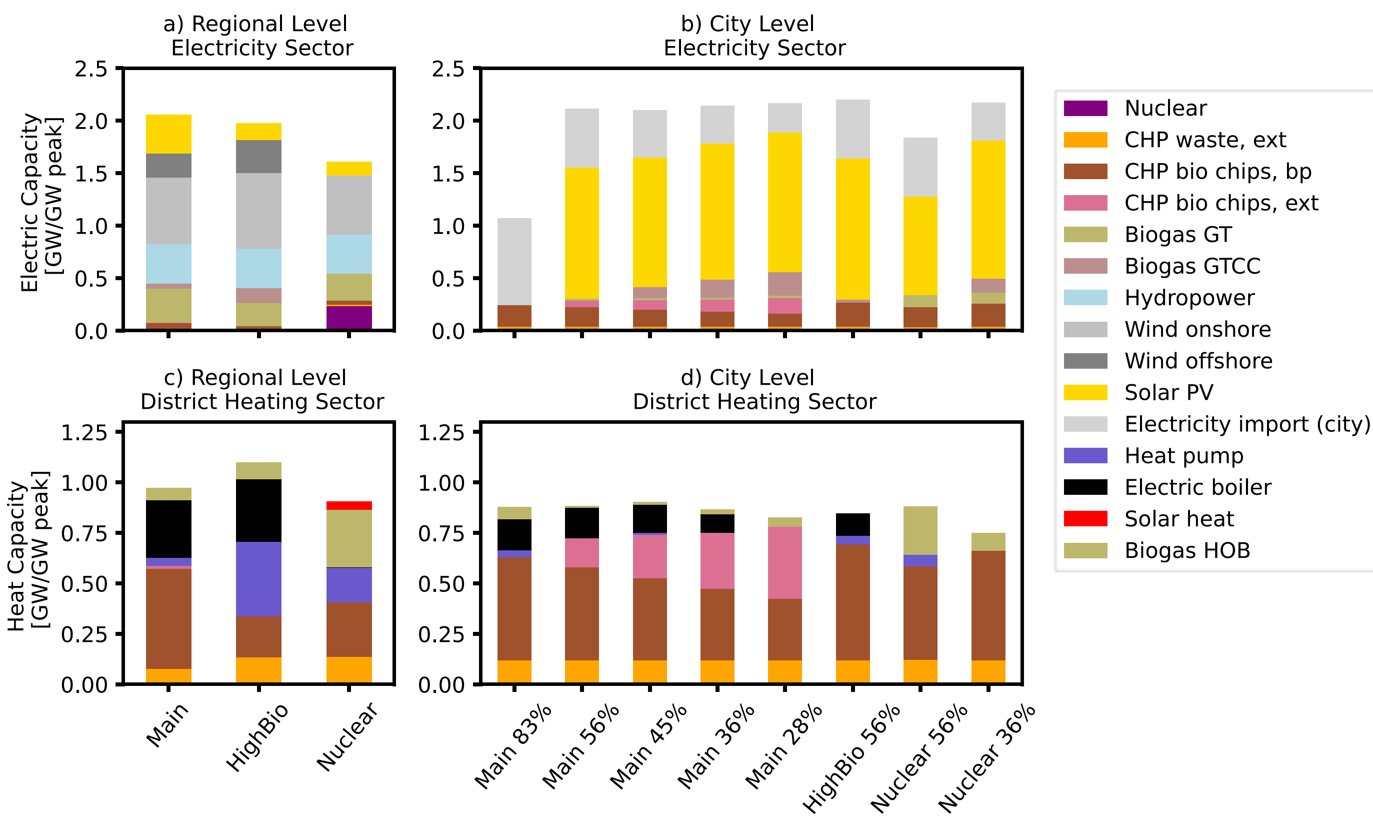

Fig. 3. Normalized optimal investments in electricity and DH generating technologies, on the regional and city levels, for the Main, HighBio and Nuclear scenarios, with different levels of city electricity import capacity (denoted by percentages of the peak city demand). Panels a) and c) consider the regional level, while panels b) and d) show the city level. Ext, extraction turbine; bp, backpressure turbine.

and/or biogas HOB technologies, and the share of CHP capacity is dependent upon the scenario (Fig. 3c). In the Main scenario, the CHP investments in the regional model aligns with that from the city model. If the net electricity demand is decreased (Nuclear scenario) or the relative biomass price is increased (HighBio scenario), CHP plants are to some extent outcompeted by investments in PtH and/or biogas HOB on a regional level. PtH is a cost-effective strategy for the region to manage VRE variability in the HighBio scenario when biomass and biogas peak technologies are expensive to run. In the city, PtH investments are limited due to the electricity import capacity constraint, and the results indicate that, for the costs of PV and biofuels assumed in this work, it is not cost-effective to invest in local electricity generation capacity (e.g., biogas combined cycles) in the city to drive PtH technologies for heat generation when CHP plants can supply both heat and electricity.

Wood pellet or biogas combined cycle CHP plants are not competitive in any scenario or at any system level, due to the higher fuel cost compared to waste and wood chips (Table 3) and the presence of thermal energy storage systems which reduce the need for peak heat generation technologies (with high operational cost) in the district heating dispatch. Extraction turbine CHP plants are competitive in the city as the electricity import capacity decreases (Fig. 3d) and CHP plants are dispatched for electricity-only generation at times when the city electricity system is strained and/or the import price is high.

The discharging of thermal energy storage systems complements the heat production technologies to meet the peak heat demand in both the city and the region (not shown in Fig. 3). This is especially true in the city, where the total heat production capacity is less than 100% of the peak demand in all scenarios (Fig. 3d).

3.2. Operational patterns of CHP plants

Fig. 4 shows the optimal dispatch of backpressure biomass

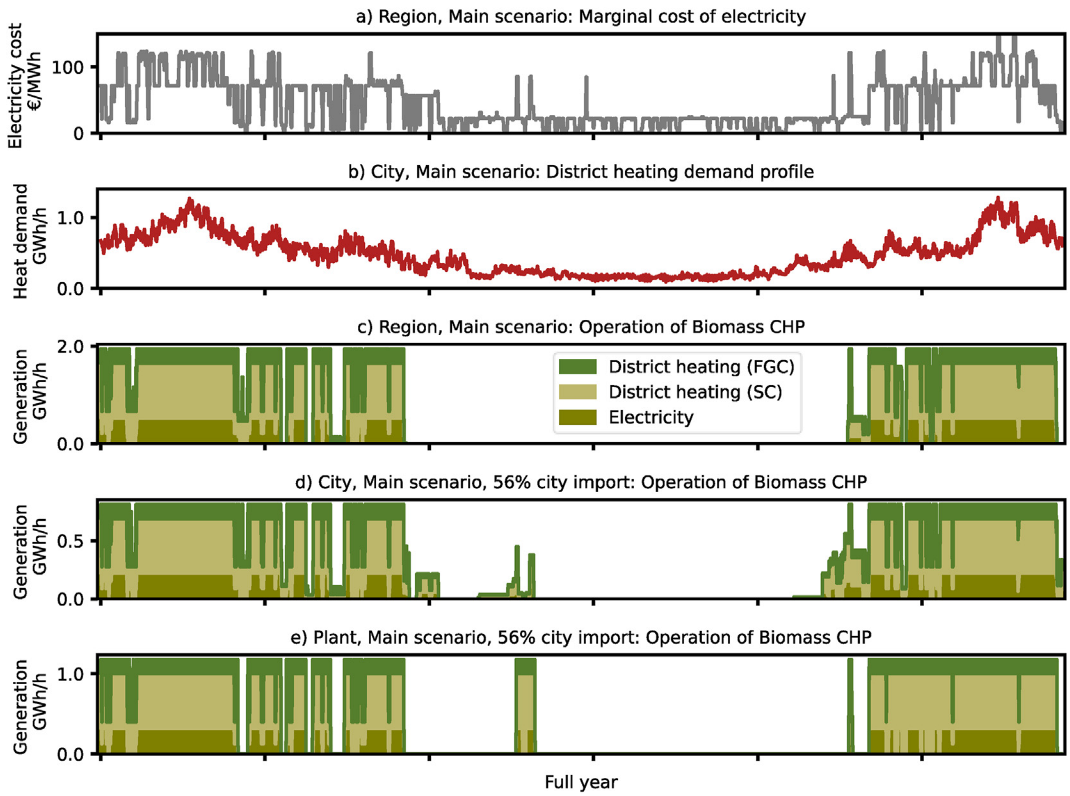

Fig. 4. a) Marginal cost of electricity in the region in the Main scenario. b) District heating demand in the city. c)–e) Optimal dispatch of backpressure biomass (wood chip) CHP plants in the Main scenario, as obtained from the: c) regional model, d) city model, and e) plant model, divided into electricity generation and district heating production from the CHP steam cycle (SC) and the flue gas condenser (FGC). Note that the plant-level thermal capacity is not optimized but set to 1 GW to exemplify the operational pattern.

(wood chip) CHP plants as obtained from the regional, city, and plant-level models, in the Main scenario. The dispatches are divided into electricity generation and DH production from the steam cycle and FGC. The regional marginal electricity cost and city heat demand are included for reference.

Irrespective of modeling level, the biomass CHP plant dispatch generally follows the DH demand profile, with operational stops during the summer and full-load operation during the winter. Hours with low electricity prices result in a reduced load level, with cycling or heat-only operation, while high-price hours incentivize condensing (electricity-only) operation in extraction turbine CHP plants (not shown). Thus, on all system levels, there are incentives to operate the CHP plant according to the regional net electricity load (or price), even though CHP plants constitute only a small share of the total regional electricity production and have limited potential to contribute to the regional system balancing.

The CHP plant load level and operational mode are often in alignment between the regional and city perspectives, and cogeneration is the dominant mode. Differences between these two levels occur mainly during periods with intermediate-level heat demands (spring and autumn). The plant level dispatch occasionally differs from the regional and city level results because it is not constrained by the condition to meet a heat demand; instead, it can optimize the dispatch freely based on price signals. Therefore, operational stops occur in the plant-level dispatch that are not seen in the regional or city perspectives, and vice versa. Conflicting situations might, therefore, arise, forcing the CHP plant to operate even though it is not profitable from a plant perspective.

In the case of a high biomass price (HighBio scenario), biomass CHP plants are on all three levels operated mainly during hours that have both a high heat demand (high heat price) and high electricity costs, and heat-only operation is reduced significantly. For waste-fired CHP plants, a difference is observed between the regional and city levels in the HighBio scenario: on the regional level, waste-fired CHP plants produce electricity throughout the summer with frequent operation in condensing mode, while on the city level heat-only operation predominates. This is due to the different system designs: in the city, other heat production units are scarce (PtH) or expensive to run (biomass), leading to maximized heat production from the waste-fired plant, while in the region, PtH is used during the summer as a variation management strategy, reducing the need for heat generation from waste-fired CHP plants.

3.3. Cost setting mechanisms and plant profitability

Since the three system-level models are soft-linked via electricity and DH price signals, the dynamics of marginal cost formation is a key factor to examine, as well as the consequent impact on plant profitability. Although local day-ahead electricity markets are currently not in use in the studied region, the city model output includes the local marginal costs of electricity and DH, representative of the city perspective.

Since the region has a wider range of technology options than the city, the region's marginal cost of electricity will be lower or equal to the city's marginal cost of electricity. Therefore, it is advantageous for the city to import electricity from the region. In the case of unlimited import capacity, the marginal cost of electricity in the city and region would be the same. However, congestion influences the marginal cost for the city. Fig. 5a plots the marginal electricity cost duration curves for the city, with different electricity import capacities, and Fig. 5b gives the corresponding marginal cost duration curves for DH. As the import capacity decreases, the

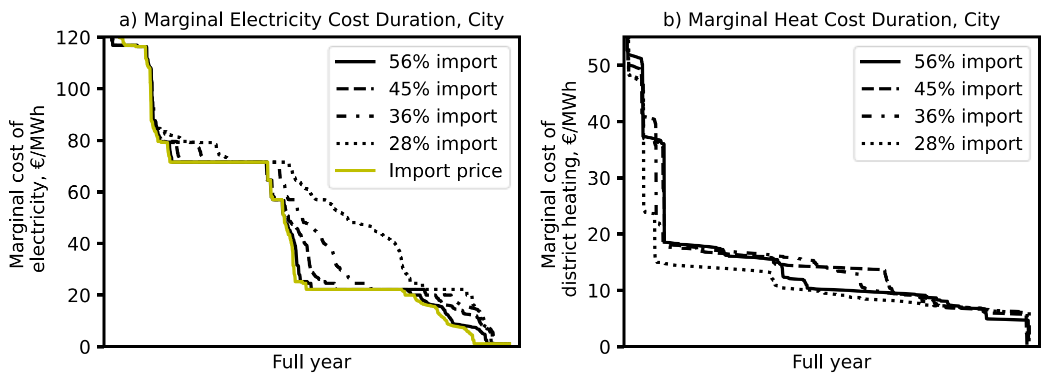

Fig. 5. Marginal cost duration curves for the city, with different levels of electricity import capacity, for the Main scenario. a) Marginal cost of electricity. b) Marginal cost of district heating. The Import price refers to the marginal cost of electricity in the region. The import capacities are expressed as percentages of the peak electricity demand in the city.

city-level marginal electricity cost tends to increase. However, even with an import capacity corresponding to 56% of peak electricity demand, the city electricity cost is for most of the year equal or similar to the import price (marginal cost of electricity in the region). That is, at moderate levels of congestion, the city manages the electricity supply without a significant increase in the electricity cost. The current import capacity to Gothenburg is around 83% of peak demand. Thus, the results indicate that the city can become significantly more congested before a large difference is noticed between the modeled city and regional system level marginal costs of electricity.

Given the strong presence of CHP plants and/or PtH technologies in the cost-optimal system designs, the electricity and DH markets are coupled. This coupling is mainly unidirectional. The modeling gives that electricity generation is generally more valuable and expensive to store for long time periods than heat generation, implying that it is less costly for the heat sector to adapt to the electricity market price than the other way around. Thus, electricity is the governing market, and the results indicate that the marginal cost of electricity acts as a price setter in the DH sector, through CHP or PtH units, except for hours of high heat demand when biogas HOB is the marginal heat production technology without any dependency on the electricity cost.

CHP plants are often the marginal heat production units during winter in scenarios with significant city congestion and a shortage (and higher cost) of electricity to power PtH units. The CHP plant covers its running expenses by selling electricity and DH. Thus, the additional cost of one unit of heat production from the CHP plant, i.e., the marginal cost of heat on the city level, is the running cost of the CHP plant minus the value of the electricity produced. It follows that, in systems that are dominated by CHP plants (such as the 28% import capacity system, Fig. 3), with CHP as the marginal heat production unit, the marginal cost of heat is reduced as the marginal cost of electricity is increased, which is clear when comparing the 56% and 28% import capacity cases in Fig. 5b.

PtH units have an opposite effect on the marginal cost of heat compared to CHP plants, i.e., the marginal cost of heat increases with the marginal cost of electricity. This occurs, for instance, in the summer when biomass CHP plants are not in operation and heat generated by PtH units is on the margin. Although PtH units are typically dispatched when the cost of electricity is low, the load shifting enabled by the heat storage increases the marginal cost of the heat produced by PtH, since the stored heat can be dispatched instead of activating PtH units when the cost of electricity is high. As the marginal cost of electricity in the city increases with reduced import capacity, the heat production cost of PtH units increases. Therefore, the marginal cost of heat is higher during the summer in the 45% and 36% import capacity cases compared to the 56% import capacity case, as is shown in Fig. 5b. Again, the 28% import capacity case does not follow this trend due to the lack of PtH investments (Fig. 3).

From the modeling at plant level, there is an impact of congestion on plant profitability since the plant trades with the regional electricity cost and the city-level DH cost. That is, even though there is an increase in the marginal cost of electricity in the city with increased congestion, the plant will not benefit from this because the electricity market is regional. However, it will be subject to the city-level DH cost. Fig. 6 shows the modeled annual

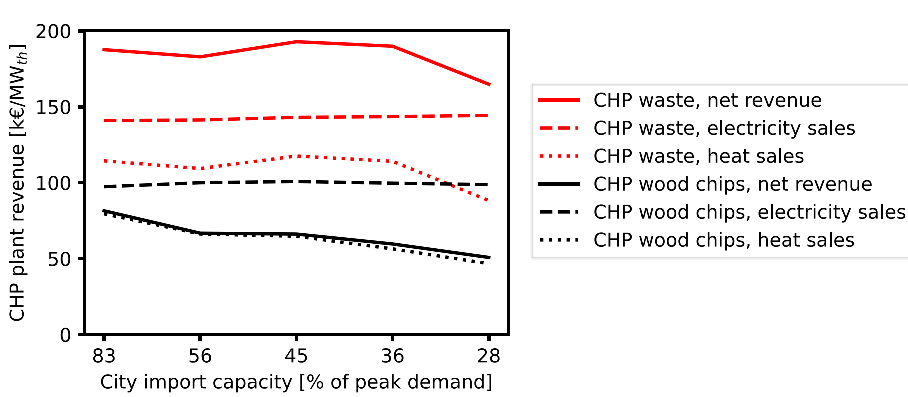

Fig. 6. Modeled annual revenues of wood chip and waste-fired CHP plants, as obtained from the plant model, for different levels of congestion, represented by the city electricity import capacity, for the Main scenario. The net revenue is calculated with Eq. (13), normalized by the installed thermal capacity and accounts for fuel expenses. The revenues obtained from sales of electricity and district heating are also plotted.

revenues of wood chip and waste-fired CHP plants for five levels of congestion, represented by the city import capacity, for the Main scenario. For the seasonally operating wood chip CHP plant (Fig. 4), the net revenue decreases as the city becomes more congested, due to the winter-time reduction in the marginal cost of heat explained above, which gives a lowered revenue from CHP heat sales. For instance, a reduction in import capacity from 56% to 36% gives a 10.6% reduction in net revenue for the wood chip CHP plant. The revenue obtained from electricity sales is stable regardless of import capacity level, meaning that the decrease in net revenue is mainly explained by the reduced revenues from heat sales. Due to the wood chip fuel cost (20 €/MWh in the Main scenario), the net revenue of the wood chip plant is lower than the sum of the heat and electricity sales.

For the waste-fired CHP plant, which operates year-round, the increase in the marginal cost of heat in the city during the summer causes the revenue from heat sales to increase by 7.5% as the import capacity is reduced from 56% to 45%. A decrease in revenue is noticed as the import capacity is reduced to 28% and the marginal cost of heat is lower than the cases with higher import capacity (Fig. 5b). Since the cost of waste is low (1 €/MWh in this work) and waste-fired plants have a high number of full load hours (approaching 8760 h in the modeling), the net revenue per installed thermal capacity is higher than for the wood chip CHP plant.

3.4. Centralized vs local investment planning

The division of the regional DH demand into three subsystems enables comparison of energy planning from a centralized (regional) perspective and a distributed (city) perspective. Fig. 7 plots the distribution of optimal investments in heat generating capacity between the regional DH subsystems and the corresponding investments in the city model, which is optimized as an A/B/C-heat system, for the Main and HighBio scenarios. Note that in Fig. 7a, the sum of the capacities indicated by bars A–C for one scenario corresponds to the total investments in the region presented in Fig. 3c.

As shown in Fig. 3, the region has a stronger tendency than the city to invest in PtH technologies, which are primarily allocated to the smaller subsystems (A and B), especially in the HighBio scenario where increased biomass prices reduce the competitiveness of biomass-fired CHP plants. The regional tendency to locate CHP plants in larger DH subsystems is motivated by the economy of scale associated with constructing large thermal plants in the large subsystems, which entail a lower investment cost per MW and a higher electric efficiency compared to small units. The optimal city investment trends are independent of heat system type and performance data of available technologies, with a significant share of CHP capacity in all the scenarios.

Furthermore, the limited waste fuel resource is in the regional perspective prioritized for usage in large DH systems (C). This implies that waste is transported from smaller cities to larger ones. In the city perspective, the opposite trend is seen, where the use of waste is maximized in the local system independent of city size, since in the city model there is no benefit associated with exporting waste. Thus, the centralized planning in the regional perspective allocates resources in the most cost-effective way for the whole region, while the local planning in cities can create sub-optimal system designs for the region. On the other hand, the local planning perspective might be necessary for the city to manage congestion.

4. Discussion

Comparing the region-, city-, and plant-level modeling results shows that there are conditions in which the results on investments in, and operation of, CHP plants align and differ (Fig. 3). Thus, the methodological framework applied in this work demonstrates the importance of considering system-level differences. In particular, the application of the method is found to be relevant when boundary conditions relating to electricity generation and transmission (the availability of low-cost electricity) differ between the modeling levels. The availability of regional low-cost electricity is limited to the city by: the geographic scope of the city limits, the portfolio of electricity generating technologies that can be invested in compared to the region (no wind/hydro/nuclear power), and region-internal transmission grid bottlenecks. These boundary conditions influence the competitiveness levels of CHP plants and cause differences in the optimal investments between the regional and city levels.

The modeling framework applied enables the identification of issues that might occur but are not obvious when only studying one system level. Grid congestion within the region has an impact on optimal CHP investments, which might be overlooked if not both the regional and city (subset of the region) models are considered. If CHP plant investment decisions are taken based on the city's demand for local generation capacity but the regional electricity market fails to impose an electricity cost that is sufficiently high to cover the plant's expenses, the economic viability of CHP plants, as perceived by the plant owner, might be affected. The same reasoning applies if the city heat cost is low, given that CHP plants typically have rather low power-to-heat ratios and prioritize heat

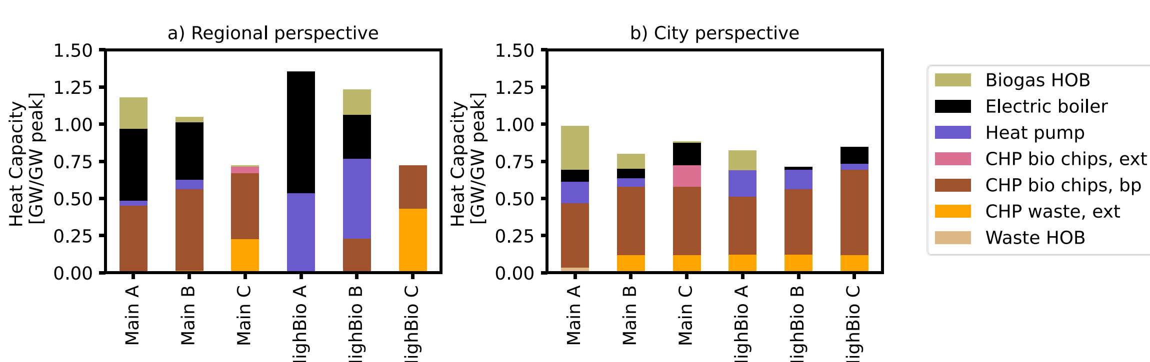

Fig. 7. Normalized optimal investments in district heating production in heat systems as obtained from: a) the regional model, and b) the city model, with the current (Main scenario) and relatively increased (HighBio) biomass price levels. The letters A, B and C denote investments for the three district heating subsystem types: A, small; B, medium; and C, large systems. The city import capacity corresponds to 56% of the peak electricity demand. Ext, extraction turbine; bp, backpressure turbine.

production, which is the main revenue stream to the plant. Such issues are not reflected in the standalone regional and city energy system models, in which the investments are dimensioned so that all the costs are covered, and an economic break-even point is achieved (social planner perspectives).

The introduction of local electricity markets could be beneficial from the CHP plant perspective, as it would increase the likelihood that investment costs could be covered, although significant levels of congestion might be required for this to be an effective measure (i.e., for regional and city marginal electricity prices to differ significantly). As an example, it was proposed to make Stockholm a separate price area [48]. In the absence of local electricity markets, it is not realistic for the local DH price to be determined based on a local electricity price signal, as is the case in the city model in this work. This inherent local electricity pricing deviates from the real conditions of the case study and represents a limitation in the modeling approach. Therefore, given current market designs, the plant model results are of greater relevance for scenarios with moderate congestion, while scenarios with extensive grid congestion reflect market designs with a local social planner perspective on the city level, with a single actor that governs both the local electricity and heat markets. Currently, local DH markets are often natural monopolies, and price models other than the perfect market applied in the modeling could be more suitable for representing the DH market.

In addition to considering different system levels, the importance of including both the heat and electricity sectors is apparent in this work. Although the electricity and DH markets are separate (in terms of price models, geographic scope), they are not independent given the coupling between the electricity and heat sectors through CHP and PtH units. CHP plants would not attract investment if only the electricity sector was modeled, and the electricity price is a factor that can significantly affect the operation of and investments in DH production units. Although it is commonly found that different actors control different sectors and at different system levels, e.g., municipal DH monopolies vs regional electricity price areas, multi-product facilities such as CHP plants will be undervalued and lose competitiveness compared to single-product plants unless they are given a fair market context (i.e., representing both the heat and electricity markets) in which to be evaluated.

The modeling framework developed in this work can be applied to other types of polygeneration facilities that operate in more than one market, and where there might be a coupling between markets. The modeling levels can be adapted accordingly to adequately represent the scope of each market. Since all energy conversion processes have an input and output of energy, the modeling approach can also be applied to single-product facilities, if the fuel (input energy) market is included in addition to the product market. Due to the linear formulation with aggregated capacity, the models can easily be applied to systems of larger scales and complexities than the system studied in this work.

5. Conclusion

This work proposes a method for comparing multiple system levels in energy system analyses, relating to regional, city and plant levels. The method soft-links these three levels by applying one energy system optimization model for each level, and is demonstrated for the case of CHP plants that act on electricity and DH markets. The results obtained from the three models are compared in terms of CHP plant investment and operational patterns, and highlight the importance of considering the different system levels to understand the role of CHP plants in the regional and city-level energy systems.

A comparison of the results on the regional, city, and plant modeling levels show that the optimal CHP plant investments and dispatch on these levels can both align or differ, depending on conditions. At current biomass price levels, the CHP plant investments and dispatch results on the regional, city, and plant levels generally align, where bulk DH supply is the main role of the CHP plants. From the city point-of-view, a limited electricity import capacity makes CHP plants a robust investment, regardless of the electricity or biomass price development. CHP plants are generally operated to follow the heat demand profile, although the electricity price has impacts on the load level and mode of operation.

High availability of low-cost electricity and a high biomass price negatively affect the cost-competitiveness of CHP plants on the regional level, creating substantial differences in the desired investments and operation of the CHP capacity between the city and the region. Extensive congestion amplifies this difference. The difference indicates a risk for diverging expectations between system levels on CHP plant investments and operation.

Author statement

Johanna Beiron: Conceptualization, Design of Method, Modeling, Investigation, Writing – original draft.; **Lisa Göransson:** Conceptualization, Design of Method, Writing – review & editing, Supervision.; **Fredrik Normann:** Conceptualization, Design of Method, Writing – review & editing, Supervision, Funding acquisition.; **Filip Johnsson:** Writing – review & editing, Supervision, 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.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.energy.2022.124337.

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