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Cost-efficiency of urban heating strategies – Modelling scale effects of low-energy building heat supply

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A B S T R A C T

There is now a strong demand in Sweden for construction of new low energy buildings (LEB) areas. There are essentially three options for heat supply to these LEB areas: “individual”, “on-site” and “large heat network” supply. The chosen option is of strategic societal interest. Thus, this study aims at comparing the long-term system cost of the three heat supply options. A dynamic modelling approach is applied in a systematic analysis designed to investigate the threshold for the various options' cost-efficiency. The study addresses scale impacts of hypothetical LEB areas and district heating systems. The results show that, generally, the large heat network option has the lowest system cost whereas in most cases the individual option has the highest system cost.

1. Introduction

The building sector accounts for 40% of the total energy consumption and 36% of carbon dioxide (CO_2) emissions in the European Union [1]. The European Commission has passed two Directives - the 2010 Energy Performance of Buildings Directive and the 2012 Energy Efficiency Directive - aiming at reducing buildings energy consumption.

In Sweden, the residential and service sector accounted for 38% of the total final energy use, 144 TWh, in 2011. About 60% of this was used for space heating and to provide hot tap water [2]. The national goal is to reduce the total energy use per unit of area in residential and commercial buildings by 20%–2020 and by 50%–2050 compared to the 1995 level [3]. The development of buildings with very low energy use (i.e., at least 50% lower than the present requirements; see Ref. [4]) is supported by the Swedish Energy Agency, which aims at promoting energy efficient new construction and renovation [3]. Consequently, in some new residential areas there are buildings built based on low energy building (LEB) standards. These buildings require little space heating even during the cold seasons.

Due to ongoing urbanisation, new building areas are often built within or in the vicinity of a city or town, and thus there is the possibility of district heating (DH) supply to the LEB areas. There are generally three options to supply heat to new LEB areas within or in the vicinity of urban areas: an “individual”, an “on-site” and a “large heat network” option, assuming that there is a DH system in the urban area (which is the case in almost all urban areas in Sweden). These heat supply options are able to independently meet 100% of end-user's heat demand. The “individual” option means that each building has its own heat production device, installed within the building, to meet its heat demand. The “on-site” option implies heat supply by a small local DH system within the LEB area, including a centralized heat production unit within the area and a distribution network for heat distribution from the heat production unit to each building. Similar to the “on-site” option, the “large heat network” option also includes a distribution network within the LEB area while the heat is produced in the DH system of the close-by urban area and transmitted to the LEB area by a transmission pipeline.

In Sweden, DH has developed substantially since the 1960's and today accounts for over 60% of the heat market in the residential and service sectors [5]. The rate of construction of new buildings and residential areas is likely to be high in the foreseeable future because of increasing population in Sweden but DH is not always

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the preferred heat supply option to new LEB areas, implying that opportunities associated with large DH systems might be missed: the greater efficiency of energy conversion in large-scale heat production plants, co-generation of heat and electricity, and the use of excess heat from industrial processes, waste incineration or thermal power plants. Four parameters that could discourage investments in the large heat network are: low heat demand of LEB areas leading to large heat losses [5], high investment cost of construction of DH transmission and distribution pipelines [6,7], business strategy disagreements between building and energy companies [8] and fossil fuel use in the DH production.

Impacts of different heat supply options to LEBs have been assessed by studying a single building [9,10]. Since such assessments do not include the full systems effects of simultaneously implementing heat supply options at a greater scale, sub-optimization could occur if the conclusions from such studies are implemented in areas with many LEBs.

Studies at the national level (e.g. [11–13]) represented the existing building stock in Sweden and applied various energy efficiency measures to the buildings to assess energy system impacts of different heat supply options with a long-term perspective. They also investigated trade-offs between heat supply options and energy efficiency measures by minimizing the total system cost. In these studies the local conditions, of great importance for optimal heat supply, were partially ignored since the buildings were represented in an aggregate way.

The environmental and energy system impacts of heat supply options in LEB areas have also been assessed at the local level. The connection of 20,000 new energy efficient apartments to an existing DH system led only to a small increase of DH demand while it contributed to leveling of the annual DH demand profile [14]. The study excluded changes in the DH system (e.g. forward temperature reduction in the DH network) that could occur due to low heat demand of the apartments. A recent study compared energy system impacts of on-site and individual heat supply options in a new building area in which half of the buildings are built as LEB. The area, located in mid-Sweden, would be occupied by 10,000 inhabitants by 2025 [8]. The study excluded an assessment of a heat connection between the new building area and its close-by town.

Decisions on heat supply to new LEB areas are of strategic importance for the countries' ability to mitigate greenhouse gases in a cost-efficient way and to combat local air pollution, and have long-term impacts due to infrastructural lifetimes and system inertia. Further, economic optimality of the heat supply investment is stakeholder dependent and the best option from the developer's point of view might not be the best from the societal point of view. Thus, due to the importance of the investment decision, comprehensive knowledge is essential and, due to the dynamics of the systems and fuel costs, a long-term system approach taking into account the dynamics and the interactions between the heat, electricity and buildings energy systems is needed to acquire the necessary knowledge.

This study thus aims at assessing the system scale economy of the three presented heat supply options to LEB areas in a systematic way, and to determine the approximate thresholds for the cost-efficiency of the various options. In this way, the following two question will be answered:

- Which is the most cost-efficient heat supply option to LEB areas from a societal point of view?
- How do the various cost components of the long-term system cost compare between the three heating options?

The study will apply an approach with system boundaries widened to include both the LEB area and its assumed nearby urban DH system in the assessment. This allows for a comparison of the three heat supply options. Unlike previous studies, a dynamic approach is applied, implying that the heat and electricity systems are allowed to develop with time during the studied time period. Finally, strategic implications of the results are discussed.

2. Method

The study is carried out based on 1) a literature review, 2) creation of hypothetical cases, 3) dynamic energy system modelling, and 4) policy scenarios and assumptions. The literature review presents recent literature findings on the three heat options to be analyzed and serves as a basis for the study (see Section 2.1). The data used in the study are inspired by three real LEB areas and three real DH system (see Section 2.2). In order to be able to draw general conclusions and to investigate the threshold for the most cost-efficient of the various heat supply options under varying conditions, a systematic analysis combining parameters is implemented. A dynamic energy system model, including the heat sector and part of the electricity and building sector (see Section 2.3), is built and used for the calculations. Two scenarios (see Section 2.4) corresponding to different climate ambitions are designed and applied in order to test the robustness of the results.

2.1. Literature review

2.1.1. Individual heat supply

Environmental and economic impacts of individual versus DH supply to buildings were assessed for Danish conditions in Möller and Lund [15], who assessed the economic potential of DH expansion into areas supplied with individual natural gas boilers in a future energy system with higher shares of renewables. In the cost-effective solution, the boilers were replaced with individual heat pumps in rural and remote areas. Petrovic and Karlsson [16] showed by using the marginal cost of DH expansion into different areas where buildings were supplied with heat by individual options that DH supply has low socio-economic potential for buildings located in areas requiring not only investments in DH distribution but also in transmission infrastructure.

In Sweden, because of high fuel and CO_2 taxes on oil and natural gas, individual heat pumps are the main competitors of DH in low linear heat density (i.e. the ratio between annul heat quantity sold to customers and the trench length) areas [2,7]. In 2011, while DH use was 6 TWh, electricity and biofuels (e.g., wood chips and pellets) use in single-family and two-family detached buildings accounted for 14 TWh and 12 TWh, respectively [2]. In the same year, individual heat pumps supplied heat in 923,000 (46% of total) single-family and two-family detached buildings [2].

2.1.2. On-site heat supply

The concept of 4th generation DH or low-temperature DH (LTDH) (i.e. forward/return temperatures of 50/25 °C rather than the current 80/40 °C), was recently introduced to describe a development including several different measures that each contribute to a more sustainable system [17]. Brand [18] showed the LTDH system to be competitive to individual heat supply options in LEB areas. Dalla Rosa and Christensen [19] identified the LTDH systems to be a cost-effective option leading to reduced primary energy use for heating purposes in areas with linear heat densities down to 0.20 MWh/m/year (0.72 GJ/m/year). Moreover, the system resulted in 50% lower distribution heat losses and slightly lower investment cost of pipelines compared to the current DH networks. Li and Svendsen [20] designed different hypothetical LTDH systems to meet the heat demand of 30 LEBs in an area with a heat density of 187 kWh/m/year (0.67 GJ/m/year). When the LTDH was designed based on an instantaneous heat exchanger substation in each building, a network energy efficiency of 91.5% and 63.4%, corresponding to the coldest and the hottest season of the year, was reached. In reality, this LTDH system was built to supply heat to a LEB area including 40 terraced houses in Lystrup, Denmark (linear heat density of 1 GJ/m/year and plot ratio (i.e. the ratio between the heated area and the associated land area [21]) of 0.24 [21]), and successfully tested in 2010. The annual heat loss was as low as 17% of delivered heat, i.e. one quarter of the value of current DH networks in areas with similar heat density (i.e. the ratio between the heat demand and the associated land area [21]) and plot ratio [18].

2.1.3. Large heat network

Werner and Reidhav [7] identified the minimum annual heat demand (50 GJ/house) and heat density (2 GJ/m) required for the profitability of DH expansion into low heat density areas. They also identified that the investment cost of DH network constitutes a considerable fraction of the total heat supply cost. Karlsson et al. [6] showed DH expansion from a close-by city into a group of single-family buildings with an existing local DH network to be cost-effective from the entire energy system perspective in Denmark. Lund et al. [22] included the whole Danish energy system to compare the impacts of different individual heat supply options as well as DH option on fuel use and CO_2 emissions in the long-term. The study concluded that given a continuous improvement of DH distribution, a gradual DH expansion into areas within a distance up to 1 km from existing DH systems together with individual heat pumps in the rest of the areas was the most cost-effective solution in a future 100% renewable energy system.

2.2. Hypothetical cases

The heat demand profile, the linear heat density and the plot ratio differ between residential areas. The characteristics of DH systems, in terms of fuel use and heat production technology, vary depending not only on local conditions but also on the size (heat demand) of the system. The assessment is carried out in the form of a study applying hypothetical cases constructed based on data from three real LEB areas and three real DH systems. In the model we systematically combine the three LEB areas with the three DH systems and also vary the distance between the two in order to represent a wide range of conditions. This approach allows us, while using information from real systems, to investigate different heat supply options in a more general context.

2.2.1. Low-energy building areas

The three LEB areas are selected starting with a low plot ratio area (PR-1A), with a plot ratio of 0.15, representing a mainly residential area with primarily one-family houses. Then, two more dense areas, with plot ratios about five times (PR-5A) and nine times (PR-9A) larger than PR-1A were selected. Areas with these plot ratios have been chosen to well represent the common range of plot ratios (i.e. 0.05–2) [23] for residential areas in Sweden.

2.2.1.1. PR-1A: mainly detached one-family houses. The first real LEB area is located in the suburb of a small town in the Halland County in west Sweden. The area, which was mainly constructed during 2011–2014, consists of 26 one-family houses, four small apartment buildings, six terraced houses, a nursing home for elderly people with 64 apartments and commercial buildings [24]. The total heated area is 15,300 m^2, the heat density is 27.2 MJ/m^2 and the plot ratio 0.15 [25]. All the buildings in the area were designed and built based on LEB requirements (<45 kWh/m^2/year [24]). The total annual heat demand in the area, including space heating and hot tap-water demand, accounts for approx. 756 MWh (2720 GJ) [26,27]. The demand load profile of the one-family houses is presented in Fig. 1 and the area characteristics provides the basis for the first hypothetical case, hereafter referred to as PR-1A. For the purpose of this study we designed a DH network that serves as a basis for the DH network cost calculations in PR-1A (see Appendices A, B and C).

2.2.1.2. PR-5A: mainly multi-family buildings. The second selected LEB area is located within the Falkenberg town in the Halland County in Sweden, constructed during 2008–2010. The area consists of four eight-store multi-family buildings with a total heated area and specific heat demand of 10,208 m^2 and 36.7 kWh/m^2/year, respectively [21]. This area characteristic provides the basis for the hypothetical case PR-5A (plot ratio of 0.73). Since the area is rather small in terms of total heated area and in order to make PR-5A comparable to the other LEB areas in the calculations, the number of buildings in the model of PR-5A is multiplied by three relative to the heat demand of the real LEB area without changing the plot ratio. Thus, in this study the total annual heat demand in PR-5A is equal to 4041 GJ.

2.2.1.3. PR-9A: mainly large multi-family buildings. The third hypothetical case, PR-9A, with a plot ratio of 1.3, is inspired by a real LEB area located within the Munich City in Germany. The area consists of 13 multi-family buildings with the total heated area of 28,550 m^2 and specific heat demand of 62 kWh/m^2/year. The measured annual heat demand in PR-9A is equal to 6267 GJ [21].

2.2.2. District heating systems

Due to, for example, economies of scale and differences in resource availability, DH systems vary considerably not only due to their size (annual heat demand) but also due to location. In order to capture the scale effects and the resource availability, we selected three DH systems: a small-town DH system, a medium and a large DH system. Each of these has its own specific characteristics in terms of DH technologies and fuel use.

The LEB area providing input data for our PR-1A area is located close to a small town along the west coast of Sweden (Kungsbacka) with an existing DH system. This DH system was thus selected to inspire our small town hypothetical DH system. It had a total annual heat demand of 105 GWh in the year 2014. This heat demand increases annually by approximately 4 GWh due to DH network expansion [28]. The DH system is today based on a biomass combined heat and power (CHP) plant, biomass heat-only boilers (HOB), oil HOBs and a heat pump.

The medium hypothetical DH system is inspired by the DH

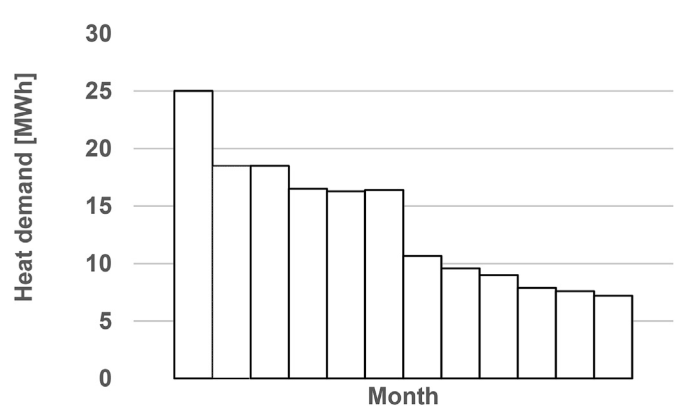

Fig. 1. Distribution of annual heat demand, including hot tap water and space heating, in 26 one-family houses in PR-1A (adapted from Ref. [27]).

system in the larger town Linköping and is based on a biomass HOB, oil HOBs, an electric boiler, a coal CHP, oil CHPs, municipal solid waste (MSW) CHPs and a biomass CHP with a constant total annual heat demand of 1312 GWh [29].

The large hypothetical DH system, inspired by the DH system in the city of Gothenburg, has a constant annual heat demand of 3177 GWh, is based on biomass HOBs, oil HOBs, natural gas (NG) HOBs, industrial excess heat, heat pumps, an electric boiler, NG CHPs, a biomass CHP and a MSW CHP [30]. See Table 1 for the production capacity of different technologies in the three DH systems.

2.3. Dynamic energy system modelling

For the purpose of this study we developed and applied a local TIMES (The Integrated MARKAL [31] -EFOM [32] System) model, TIMES_UH (Urban Heating). This model only represents the heat sector, implying that other sectors, i.e. the power, residential and transport sector, are exogenous. A TIMES model [6,31,32] is a partial equilibrium optimization model which can be used to optimize energy systems over a short to long-term horizon. The TIMES model framework was developed by the International Energy Agency (IEA) implementing agreement International Energy Technology System Analysis Program (ETSAP). The TIMES model is driven by an exogenously given demand for energy services and based on a perfect-foresight, linear programming bottom-up approach, where the objective function is minimization of the total system cost. The studied energy system is represented by different technologies that are connected by flows of commodities. Each technology is described by its input and output commodities, efficiency, availability, lifetime, costs and environmental impacts, whereas each commodity is described by which technologies it can be produced or consumed, and its availability, extraction or import cost and demand.

2.3.1. Model calculations

Assuming heat demand to be completely inelastic, the objective function of the model is the net cost (including revenues for electricity sale at exogenously assumed prices) minimization of one of the following four modes over the entire model time horizon, 2014–2052:

1. Individual heat supply in the LEB area (i.e. individual)
2. DH supplied to the LEB area (i.e. on-site)
3. DH supplied to the nearby town
4. DH supplied to both the nearby town and LEB area

Mode one and mode two only include one of the three LEB areas, mode three only includes one of the three existing DH systems, mode four includes one of the LEB areas and one of the existing DH systems. In the model, there is the possibility to select any LEB area or any existing DH system or any combination of these and to exclude other LEB and exiting DH systems. For the combination of a LEB and an existing DH system, an alternative heat-transmission distance should also be selected.

For each of these modes and each scenario (see Section 2), the model generates future energy system developments and calculates the associated system costs, discounted to the year 2014 with an annual discount rate of 5%. While the system cost of the individual and on-site options is directly calculated by the model (i.e. mode 1 and mode 2, respectively), the system cost of the large heat network option is obtained by inserting the model results in equation (1):

$$\text{system cost}_{\text{(Large heat network)}} = \text{system cost}_{\text{(DH supplied to town and LEB area (i.e. mode 4))}} - \text{system cost}_{\text{(DH supplied to town (i.e. mode 3))}} \quad (1)$$

2.3.2. Model assumptions

The TIMES_UH model covers the time between 2014 and 2052 divided into 10 time periods with shorter lengths in the beginning (two one year; 2014 and 2015 and one two years; 2016–2017) and longer lengths from 2018 (5 years). Each year has been divided into eight time slices, representing day and night in four different seasons. The seasons are: summer (6 months), spring/fall (3 months), winter (2 months) and cold winter (1 month). Daytime lasts 8 h, 8 h, 12 h and 16 h per day during winter, cold winter, intermediate and summer, respectively.

When the large heat network option is investigated, the model includes two regions; a LEB area (i.e. one of the PR-1A, PR-5A or PR-9A areas) and one of the three assumed DH systems. From 2015 in the LEB area, the duration curve of the DH demand and the individual heat demand for each building type are defined for each time slice.

The model representation of the nearby DH system is built on the existing DH production units in the respective DH systems, as described in Table 1. The DH systems are represented in detail, including annual heat demand, heat duration curve, technologies, fuels input, capacities, efficiencies, lifetimes, availabilities, heat to electricity ratios (only for CHP plants), and operation and maintenance (O&M) costs. The running cost of the existing DH system, i.e. fuel and electricity cost and O&M are included in the model.

Table 1
Existing DH production technologies and their production capacity in the three DH systems.

Technology	Small DH [28]		Medium DH [29]		Large DH [30]	
Heat-only plants	*Heat capacity [MW]*		*Heat capacity [MW]*		*Heat capacity [MW]*	
Biomass HOB	17.6		42		107	
NG HOB	–		–		325	
Oil HOB	34		298		628.5	
Electric HOB	–		25		8	
Heat pump	2.8		–		160	
Industrial excess heat[a]	–		–		150	
CHP plants	*Heat to power ratio*	*Electricity capacity [MW]*	*Heat to power ratio*	*Electricity capacity [MW]*	*Heat to power ratio*	*Electricity capacity [MW]*
MSW CHP[b]	–	–	1.9/3.86	47.4/15.4	7	20.4
Biomass CHP	9	0.8	5.06	10.8	9.23	13
NG CHP[b]	–	–	–	–	1.2/2.8/1.12	12.9/36/261
Oil CHP[b]	–	–	3.55/1.05	30/12	–	–
Coal CHP	–	–	3.84	12	–	–

Abbreviations: Heat only Boiler (HOB), NG (Natural Gas), MSW (municipal solid waste), and CHP (Combined Heat and Power).
[a] Industrial excess heat capacity remains unchanged until 2052 and it is continuously available over an entire year.
[b] When there are more than one plan with a different heat to power ratio, the electric capacity of each plant and its corresponding heat to power ratio are given (separated with/).

However, the investment cost of the existing DH production plants and DH network are treated as sunk cost. The DH distribution networks are in the model represented with their seasonal efficiency.

From 2015 investment options for DH supply technologies in the LEB area and the DH system (Table 2), DH transmission pipeline between the LEB area and DH system (Table 3) and DH distribution network (Table 4) and individual heat production technologies (i.e. bio pellet boilers, brine to water heat pumps and electric boilers, Table 5) in the LEB area are included in the model. All investment options for DH technologies and individual heat production technologies in the LEB area and DH system can only be made at discrete capacity levels. Thus, these investment options change the linear model into an integer programming (IP) model.

In our study, as a starting point, the distance between the LEB area and the DH network is assumed to be zero; that is, the LEB area is assumed to be located within or next to an existing DH system. The distance between the LEB area and the DH system is then systematically increased in steps of one km to a maximum of three km.

2.4. Policy scenarios and related assumptions

2.4.1. Policy scenarios

Two policy scenarios representing possible climate policy developments are applied; 450PPM and BAU, corresponding to the 450 ppm and New Policies scenarios of the IEA World Energy Outlook [33]. The 450PPM scenario represents ambitious climate policies in line with the Paris agreement aiming at limiting global warming to below 2 °C [34]. In the 450PPM scenario a national political ambition, which asks for phasing out of the fossil fuel use after 2030 is also included. The less ambitious BAU scenario represents broad policy commitments and plans that had been announced by countries before the Paris agreement, including national pledges to reduce greenhouse gas emissions and plans to phase out fossil fuel subsidies.

Table 2
Main model input assumptions regarding DH technologies in the LEB areas, small, medium and large DH systems based on [35,39,40].

Technology	Parameter	Unit	Value
Heat plants			
(Heat capacity)			
Biomass HOB	Total efficiency[a]	–	1.08
(0.5 MW-50 MW)	Specific investment cost[b]	[k€/kW$_{heat}$]	0.35–1.3
	Total O&M cost (25 MW - 50 MW)	[% of inv. cost/year]	6.7
	Total O&M cost (0.5 MW - 20 MW)	[€/MWh$_{heat}$]	5.4
	Lifetime	Year	20
Oil and natural gas HOB	Total efficiency	–	0.97
(0.5 MW-20 MW)	Specific investment cost[b]	[k€/kW$_{heat}$]	0.061–0.13
	Total O&M cost[b]	[% of inv. cost/year]	0.05–2.0
	Lifetime	Year	35
Heat pump	Coefficient of performance (COP)	–	3.7
(0.5 MW-10 MW)	Specific investment cost[b]	[k€/kW$_{heat}$]	0.49–1.1
	Total O&M cost	[% of inv. cost/year]	0.7
	Lifetime	Year	20
Solar collector[c]	Specific investment cost	[k€/m^2]	0.23/0.17
	Total O&M cost	[€/MWh$_{heat}$]	0.57
	Lifetime	Year	30
Combined heat and power plants			
(Electricity capacity)			
Biomass CHP	Efficiency Electricity (Total)[a,b]	–	0.25–0.46 (1.03–1.05)
(0.6 MW-100 MW)	Specific investment cost[b]	[k€/kW$_{Electricity}$]	1.37–7.0
	Total O&M cost[b] (capacities up to 70 MW)	[% of inv. cost/year]	0.7–3
	Total O&M cost (capacities above 70 MW)	[€/MWh$_{electricity}$]	3.2
	Lifetime	Year	20 (below 10 MW) 30 (above 10 MW)
MSW CHP[d]	Efficiency Electricity (Total)	–	0.26 (0.97)
(20.5 MW-28.5 MW)	Total O&M cost	[k€/kW$_{Electricity}$]	0.08
	Lifetime	Year	20
NGCC CHP	Efficiency Electricity (Total)[b]	–	0.48–0.58 (0.9–1.0)
(10 MW- 400 MW)	Specific investment cost[b]	[k€/kW$_{Electricity}$]	0.82–1.5
	Total O&M cost	[€/MWh$_{electricity}$]	2.5
	Lifetime	Year	25
NGGTCHP	Efficiency Electricity (Total)[b]	–	0.42–0.5 (0.82–0.92)
(5 MW- 125 MW)	Specific investment cost[b]	[k€/kW$_{Electricity}$]	0.46–1.2
	Total O&M cost	[€/MWh$_{electricity}$]	3.4–7
	Lifetime	Year	25

Abbreviations: CHP: combined heat and power; HOB: heat only boiler; NG: natural gas; MSW: municipal solid waste; CC: combined cycle; GT: gas turbine; O&M: operation and maintenance.
Data for model year 2015 and 2050 are separated with/.
[a] Efficiencies are based on lower heating value.
[b] Due to the scale of economy, the larger plants have lower specific investment cost and total O&M costs, for the CHP plant, higher electricity output.
[c] Collector output is 0.5 MWh/m2/year. Availability factor of the technology is 0.34, 0.2, 0.09 and 0.06 in summer, intermediate, winter and cold winter, respectively.
[d] Since waste management is the main idea with this technology, MSW CHP is always available as base load technology in the medium and large DH system (i.e. its investment cost is not included in the model). However, the MSW availability is limited to 1000 GWh/year [41] and 1700 GWh/year [30] in the medium and large DH system, respectively.

Table 3
Assumptions for the LTDH transmission pipelines (55/25 °C) to PR-1A, PR-5A and PR-9A.

	Transmission efficiency	Specific investment cost	Total O&M cost
	Summer/Spring& fall/Winter/Cold winter	[€/kW/km]	[% of inv. cost/year]
PR-1A	0.65–0.68/0.87–0.92/0.93–0.97/0.97–0.99[a]	1073	0.7
PR-5A		600	0.5
PR-9A		180	0.6

Abbreviation: O&M: operation and maintenance.
[a] Efficiencies during cold winter are calculated based on [42] and are adapted for the other seasons base on [20]. The higher efficiencies are related to the LEB areas with larger plot ratio. A lifetime of 50 years is assumed for the investments in the DH transmission networks.

Table 4
Characteristics and costs of LTDH network (55/25 °C) in the LEB areas (PR-1A, PR-5A and PT-9A).

	Heat demand	Plot ratio	Linear heat density	Distribution efficiency [20,21]	Specific investment cost[a]	Fixed O&M cost	Variable O&M cost
	[GJ/year]	–	[GJ/m/year]	Summer/Spring& fall/Winter/Cold winter	[€/kW]	[% of inv. cost/year]	[€/MWh_{heat}]
PR-1A[b]	2720	0.15	1.29	0.63/0.85/0.9/0.915	2830	1.2	3.57
PR-5A	4041	0.73	3.9	0.68/0.92/0.97/0.99	870	2.6	–
PR_9A	6267	1.3	5	0.68/0.92/0.97/0.99	431	3	–

Abbreviation: O&M: operation and maintenance.
[a] The investment cost includes both the cost of DH network and substations. A lifetime of 50 years is assumed for the investments in the DH distribution networks.
[b] For the design of this network, see Appendices.

Table 5
Main model input assumptions regarding individual heat supply options in PR-1A, PR-5A and PR-9A from one-family houses to large multi-family buildings, based on [38].

Technology (Heat capacity)	Parameter	Unit	Value[a]
Bio pellet boiler	Efficiency	-	0.8–0.85
(6 kW - 1000 kW)	Specific investment cost	[k€/kW_{heat}]	0.2–0.63
	Fixed O&M cost	[% of inv. cost/year]	0.2–3
	Variable O&M cost[b]	[€/MWh_{heat}]	36
	Lifetime	Year	20
Heat Pump - brine to water	Coefficient of performance (COP)	-	3.3
(5 kW–300 kW)	Specific investment cost	[k€/kW_{heat}]	1.77–4
	Total O&M[c] cost	[% of inv. cost/year]	2–22.6
	Lifetime	Year	20
Electric boiler	Efficiency	-	1
(5 kW- 400 kW)	Specific investment cost	[k€/kW_{heat}]	0.7–0.8
	Total O&M[c] cost	[% of inv. cost/year]	1.6–15
	Lifetime	Year	30

Abbreviation: O&M: operation and maintenance.
[a] Due to the scale of economy, the larger plants have lower specific investment cost and fixed/total O&M costs.
[b] The higher price of bio pellet for households is included, based on current market prices.
[c] The higher price of electricity for households is included, based on [43].

2.4.2. *Energy market assumptions*

The fossil fuel price assumptions are a consequence of the climate policies (including resulting CO_2 charges) in the respective scenario (Table 6).

In addition to the CO_2 charge, both scenarios include a subsidy supporting renewable electricity generation. The subsidy level is constant at 20 €/$MWh_{electricity}$ until 2020, in line with historical values of tradable green certificates in Sweden, and thereafter linearly declines and reaches zero in 2030 (Table 6).

In the 450PPM scenario, wood chip prices correspond to the regional/local marginal cost of forest residues until 2030. After that, it is assumed that with increasing CO_2 charges competition for biomass between different energy sectors creates an international market for unrefined biomass, leading to increasing wood chip price. In the BAU scenario, with lower climate ambitions, the wood chip price is assumed to equal production costs and thus remain constant (Table 6).

Electricity prices are calculated based on the assumption that the variable cost of the marginal technology (i.e., the sum of fuel cost, CO_2 charge and variable operation and maintenance cost) determines the electricity price. Since the price setting technology depends on the CO_2 charge, these are scenario dependent. The calculations are based on a selection of various coal and natural gas thermal power plants (Table 7). The variable cost of the marginal technology is assumed to set the electricity price for each time period and time slice. The carbon capture and storage (CCS) technology is assumed to be available after 2040. The variable O&M cost of coal and natural gas based technologies with CCS is increased by 50% and 40%, respectively, compared with the similar technologies without CCS [35]. Table 6 presents the results of the electricity price calculations.

3. Results

In this chapter, the modelling results are presented. First, for each scenario the cost-efficiency ranking for the various combinations of the hypothetical cases are presented in a comprehensive graph, and from this the thresholds of the three heat supply options can be determined. This is followed by a breakdown of the various cost components presented for each LEB area. All results present

Table 6
Summary of input data for the 450PPM and BAU scenarios.

	Unit	450PPM	BAU
		2014/2020/2030/2040/2050	2014/2020/2030/2040/2050
Policy tools			
CO2 charge	€/tonne	16.9/25.2/68.4/110/153	16.9/14.4/23.8/33.5/43
Renewable electricity subsidy	€/MWh	20/20/0/0/0	20/20/0/0/0
Energy prices/costs [a]			
Natural gas	€/MWh	28.7/28.3/25.1/22/18.5	28.7/29.2/30.2/32/33
Fuel oil, light	€/MWh	64.2/64.7/61.8/58/54.9	64.2/66.2/70/75/80
Fuel oil, heavy	€/MWh	41.6/42/39.8/37.2/34.6	41.6/43.1/46/50/53.5
Coal	€/MWh	8.8/8.9/7.6/6/4	8.8/9.4/9.7/9.7/9.7
Bio-oil[b]	€/MWh	42/44.5/53.9/62.5/71.5	42/42.6/47.7/53.9/59.5
Wood chip[c]	€/MWh	20/20/20/40.5/55	20
Bio pellet	€/MWh	35/44/50/59/78	35/41/45/50/53
Excess heat[d]	€/MWh	0.56	0.56
MSW[e]	€/MWh	−14.5	−14.5
Electricity[c]			
Winter cold (1 month)	€/MWh	55.2/62.9/98/122.2/74.4	55.2/54.6/63.8/72.5/80.9
Winter (2 months)		54.3/61.4/93.2/122.2/74.4	54.3/53.7/62.1/70/77.6
Spring and fall (3 months)		51.3/57.9/73.1/80/74.4	51.3/50.8/57/60.8/67.5
Summer (6 months)		51.3/64.2/73.1/80/74.4	51.3/50.8/63.2/61.4/67.8

Abbreviation: municipal solid waste (MSW).
For the parameter values, which are not constant over the whole model time period, values for different time periods between 2014 and 2052 are given (separated with/).
[a] Energy prices represent payments by DH plants, based on [33]. CO_2 charges are not included in the fossil fuel prices.
[b] CO_2 charges are included in the bio-oil prices.
[c] Wood chip and electricity prices represent payments by DH plants.
[d] For excess heat, the value represents an assumed minimum compensation for excess heat providers over and above the technical costs of bringing the heat to the DH system - it does not represent a market price.
[e] For MSW, revenues from the gate fee (i.e., the fee charged for treating the waste) is included, based on [35].

Table 7
Available technologies and their characteristics for the short-term marginal electricity prices. Conversion efficiencies are based on [44]. Variable costs are adapted from Refs. [35,44].

Fuel input	Technology	Season	Efficiency	Variable O&M cost [EUR/MWh_{fuel}]
			2014–2020/2021–2030/2031–2040/2041–2052	2014–2020/2021–2030/2031–2040/2041–2052
Coal	Steam Coal_subcritical	Cold winter	0.39	6.9
	Steam Coal_supercritical	Winter	0.43	8.7
	Steam Coal_Ultra	Spring/fall	0.46/0.47/0.49/0.49	9/8.8/8.4/8.4
	supercritical	Summer	0.46/–/–/–	9/–/–/–
	IGCC	Summer	–/0.47/0.51/0.51	-/11.7/9.9/9.9
	Coal + CCS	Cold winter	–/–/–/0.35	–/–/–/15.2
	Oxyfuel + CCS	Spring/fall/winter	–/–/–/0.41	–/–/–/14.5
	IGCC + CCS	Summer	–/–/–/0.44	–/–/–/18.7
Natural gas	CCGT	Spring/fall/summer	0.6/0.61/0.63/0.63	4.8/4.7/4.5/4.5
		Winter	–/0.61/0.63/0.63	–/4.7/4.5/4.5
	Gas turbine	Winter/cold winter	0.39/0.4/0.42/0.42	5.9/5.7/5.4/5.4
	CCGT + CCS	Spring/fall/summer/winter/cold winter	–/–/–/0.56	–/–/–/8

Abbreviations: IGCC (Integrated gasification combined cycle); CCS (carbon capture and storage); CCGT (combined cycle gas turbine); O&M (operation and maintenance cost). For parameter values, which are not constant over the whole model time period, values for different time periods between 2014 and 2052 are given (separated with/). Efficiency and variable cost are not given (–) if the associated technology is not available in a time period.

the cost for the entire modelled time horizon.

3.1. Threshold analysis

The systematic analysis (see Section 2.2) of LEB area and DH system combinations specifies the most cost-efficient heat supply option. Fig. 2 shows that the large heat network is the most cost-efficient heat supply for all combinations of plot ratio and DH system as long as the LEB-DH system distance is very short; and that for large DH systems the large heat network option is the most cost-efficient also at heat transmission distances of a few kilometres. The general patterns in the result trends seem robust with regards to climate policy developments and associated carbon costs and fuel prices. Thus, based on the cost-efficiency rankings the thresholds between the three heat supply options can be determined mainly as a function of LEB area plot ratio and DH system scale.

3.2. Breakdown of cost components

Fig. 3 shows the breakdown of the various cost components of the model results. A PR-1A location within the small DH (implying zero transmission distance) results in the large heat network option having the lowest system cost, i.e. 30 (29) % and 13 (8) %, less than the on-site and individual options, respectively, under the 450PPM (BAU) scenario.

For the individual option, the model invests in pellet boilers for all types of buildings, except for the small apartment buildings, under both scenarios. For the small apartment buildings, the model invests in pellet boilers in 2015 and in electric boilers in 2050 under

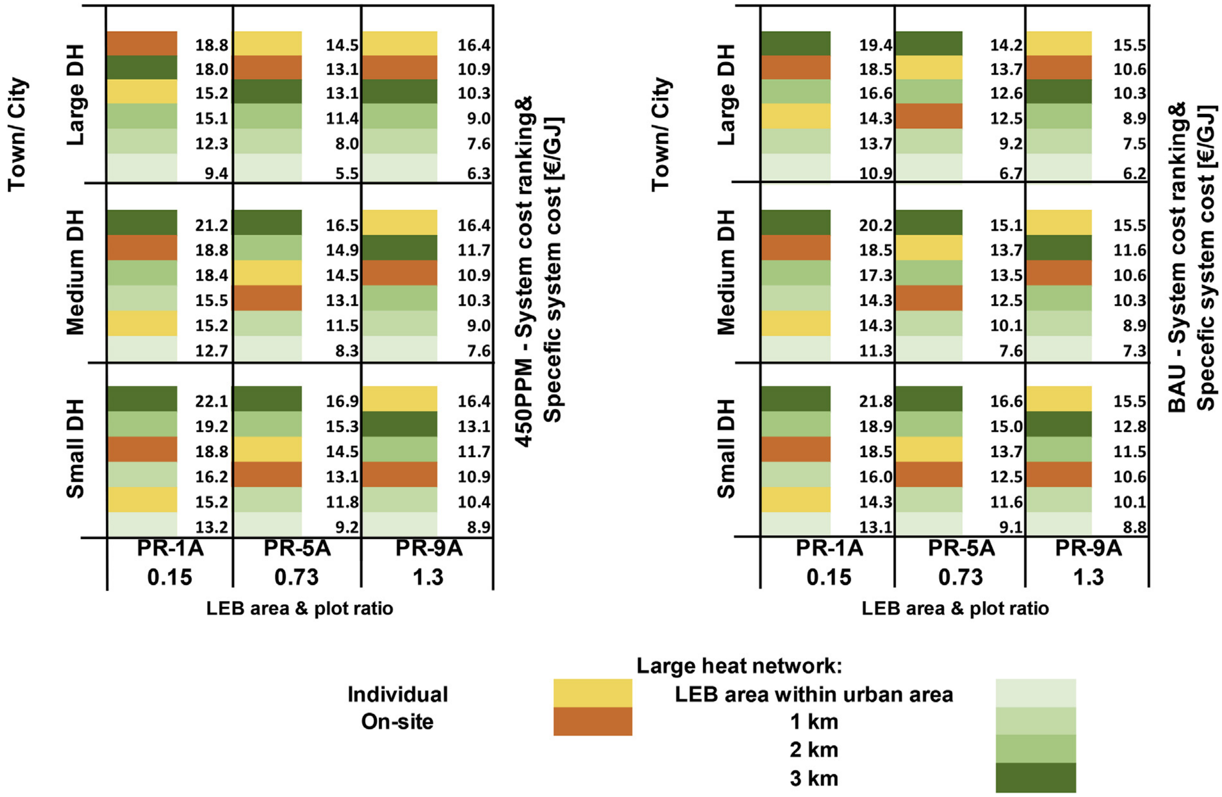

Fig. 2. System cost ranking of the various combinations of the hypothetical cases showing the cost-efficiency thresholds.

the 450PPM scenario whereas under the BAU it only invests in electric boilers. The specific heat supply cost for the individual option in the 450PPM(BAU) scenario is equal to 15.2(14.2) €/GJ of which 49(53)% belongs to the costs of heat supply technologies (investment and operation costs) and the rest corresponds to the pellets and electricity costs.

The on-site option represents a higher system cost compared to the individual heating option, if PR-1A is located within the small town DH system. The cost of the DH distribution network is the same in the on-site and large heat network options, if the heat-transmission distance in the large heat network is zero; however, the cost of DH supply in the large heat network option is less than the on-site option. The reason is that in the large heat network option involves a slight increase in already existing and newly-invested DH supply in the small town to supply heat to PR-1A, whereas the on-site option requires totally new investments in DH production (Fig. 3(a)).

Fig. 3(a) also illustrates that the DH distribution and transmission costs dominate the total system cost in the large heat network option, implying that fuels and electricity prices as well as CO_2 charges in the 450PPM and BAU scenarios cannot significantly influence the results of the large heat network option.

3.2.1. DH system and its distance to LEB area

As Fig. 3(a) illustrates, the cost of DH transmission in the large heat network option gradually increases with distance, resulting in a higher total system cost of the large heat network option compared to the on-site option if a DH transmission pipeline of more than 2 km is needed.

Compared to a PR-1A location within a small town, the system cost of the large heat network option decreases by 4 (13) % and 29 (17) % for PR-1A locations within medium DH and large DH systems, respectively (Fig. 3(a)). One reason for the lower costs is the availability of low-cost heat sources in these DH systems, i.e. MSW CHP in the medium DH system, and MSW CHP and industrial excess heat in the large DH system. The other reason for the lower cost is the possibility of investments in larger heat production plants with lower specific investment cost in these DH systems. Consequently, the low-cost heat supply in these DH systems allows for increased distances between the LEB and urban areas, i.e. extension of the DH transmission pipeline length up to 1 km and 2 km in the BAU and 450PPM scenarios, respectively, while still supplying heat to PR-1A at lower system costs than the individual option.

The model results also show that the cost-efficient DH transmission pipeline length is scenario dependent. In the 450PPM scenario with higher CO_2 charges, the cost-efficient transmission pipeline from the large DH system to PR-1A is extended compared to the BAU scenario.

3.2.2. Plot ratio of LEB area

The model results show that, in the on-site option the DH distribution cost contributes to 38% and 46% of the total system cost in PR-5A and PR-1A, respectively (Fig. 3 (a), (b)). The share of the DH distribution cost is less in PR-5A because a higher plot ratio in PR-5A results in shorter DH distribution pipelines, and in fewer and larger end-user substations. Consequently, and unlike PR-1A, the on-site option has a lower total system cost compared to the individual option in PR-5A.

The share of the DH transmission cost in the large heat network option is dependent on the plot ratio and the linear heat density in the LEB area. Compared to PR-1A, in PR-5A and PR-9A the cost of the DH transmission in the large heat network option decreases by 7%–12% and 7%–52%, respectively, depending on the length of the transmission pipeline, resulting in significantly reduction in the system cost of the large heat network (Fig. 3 (a), (b) and (c)).

In PR-5A and PR-9A the specific heat supply cost for the

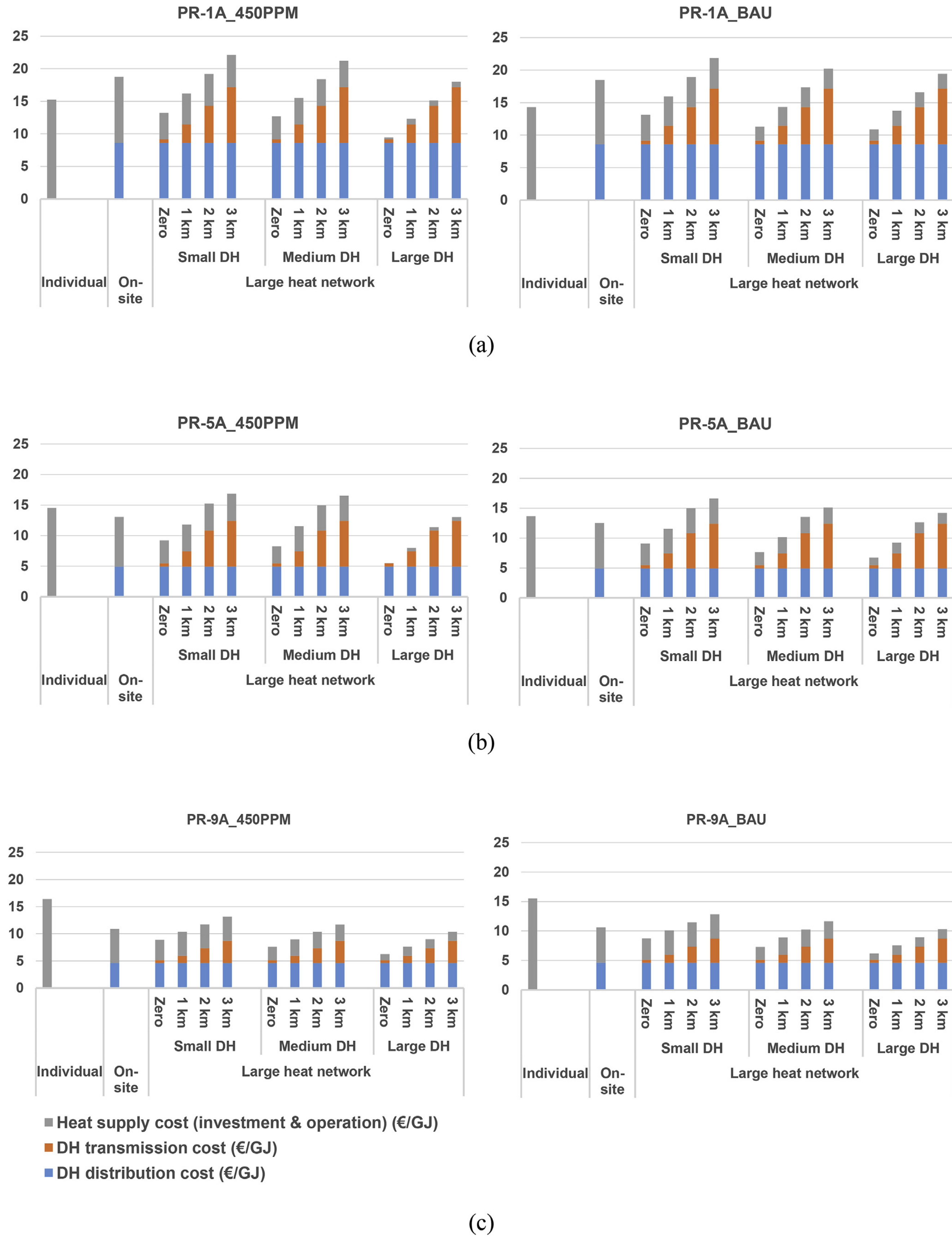

Fig. 3. Breakdown of the system cost components in PR-1A (a), PR-5A (b), PR-9A (c) (if applicable, including heat supply cost, DH distribution and transmission costs) in the individual, on-site and large heat network options; 450PPM (left) and BAU (right).

individual option in the 450PPM (BAU) scenario are equal to 14.5 (13.7) €/GJ and 16.4 (15.5) €/GJ, of which 50 (53) % and 56 (59) % are investment and maintenance costs of pellet boilers and the rest is the cost of pellets, respectively. The comparison between the individual options in PR-1A, PR-5A and PR-9A shows that the share of the heat supply devices of the system cost almost remains unchanged for the plot ratio between 0.15 and 0.73, whereas it slightly increases if the plot ratio increases from 0.73 to 1.3.

In order to further test the robustness of results, we carried out a sensitivity analysis on the investment cost of individual heat pumps (see Table 5 for investment cost assumptions). It was assumed that the investment costs decreased linearly from 2015 to 2050 and reached to 50% of its cost level in 2015. These assumptions did not change the main results of the study, the ranking, and only resulted in heat pumps (instead of pellet boilers) becoming the most cost-effective heat supply between 2040 and 2050 for apartment and commercial buildings in PR-1A.

4. Discussion

In this study, the DH in LEB areas was assumed to be LTDH. This will not necessarily be the case in reality, but the advantages of LTDH in LEB areas make the assumption reasonable. LTDH enables lower temperature waste heat to be utilised and therefore contributes to system energy efficiency and potential carbon emission mitigation. The LTDH concept is recently developed and has been successfully tested and shown to be able to overcome shortcomings of current DH systems such as high heat losses in areas with low plot ratio and low linear heat density. If conventional DH is used instead of LTDH, the on-site and large network options would be more costly, especially in LEB areas with plot ratios equal to or less than 0.15.

In this study, the results and conclusions are based on the selected hypothetical cases. These have a size (total heat demand) of 3–6 TJ annually. The large heat network option costs include a considerable transmission share. These transmission costs are highly non-linear and are thus strongly size dependent. This implies that our results will be underestimating the large heat network costs for LEB areas smaller than our assumed hypothetical cases and overestimating the costs for LEB areas larger than our assumed hypothetical cases. This also has an important strategical implication since our hypothetical cases are built on a developer perspective in terms of assumed reasonable LEB area sizes but from a strategic urban planning horizon the planned areas are in most instances much larger. Departing rather from this urban planner perspective, this strengthens strongly our conclusion that the large heat network is the most cost-efficient option for all investigated scale combinations.

In this study real life data on total heat demand, heat demand of each building and relative location of buildings were used to represent the LEB areas. This was done both due to lack of reported values and since the use of real life data allowed for achieving higher precision in the design of the LEB area heat supply options and, thus, in better estimation of the DH distribution network cost. This also included DH distribution costs based on LTDH specifications. The results illustrate, due to the importance of the DH distribution network costs, that good cost estimates of these are critical for the cost-efficiency assessment.

A DH distribution and transmission network technical lifetime of 50 years was assumed in the study, considerably longer than the assumed lifetimes of the other heating technologies. This long lifetime assumption originates from current Swedish DH network experience. It is also in line with the other use of real life data in the study but certainly has a significant impact on the resulting cost-effectiveness of the DH system investments.

The results are obtained based on Swedish conditions in terms of the heat load curve, plot ratios, the DH system configurations and the selected technology option for the individual and on-site options. For other countries with DH systems in place many of the conditions are similar and the results will thus be directly applicable. In these countries there is apparently a large demand for heat and while the actual load curve shape might differ, the total heat demand are rather similar. Plot ratios also differ and are in many countries higher than in Sweden, and this will thus not have any large impact of the resulting ranking of the options. However, the Swedish DH systems are generally based on a larger share of low-cost heat supply (excess heat in particular) than in most other countries and therefore operation cost of DH in Sweden is lower than in most other countries with DH. This would have an impact on the applicability of the results to the conditions of other countries but since the major part of the large network option cost is the investment, this operation cost difference is likely of minor importance.

The model results confirms the importance of a wide system boundary, including not only the buildings or building areas but also the possibility of existing DH systems, when addressing optimal heating strategies of urban or semi-urban areas. Further, it confirms the importance of a representation of various DH system scales. Thereby, by applying a wide system boundaries, and addressing scale impacts, it is possible to draw more general conclusions from the study.

Finally, it should be stressed that the presented modelling results are representing the least cost option from a systems point of view applying a long-term perspective; that is the combination of the heat supply of the LEB area and the district heating system when applicable. These two entities are likely invested in and operated by different enterprises with differing investment strategies and investment time horizon. However, even if the economically optimal solution in the social planner's view might not be the preferred option by the investor, this indicates the existence of possibly profitable heat collaborations.

5. Conclusions

The choice of heating supply to new residential areas is of strategic importance both for mitigation of greenhouse gases, for local air pollution mitigation and for a cost-optimal energy system. Due to urbanisation an increasing share of carbon emissions, energy use and energy system costs are due to urban dwellers and activities, and due to the long lifetime of energy infrastructure, short-term optimisation and too narrow system boundaries may lead to long-term sub-optimality and lock-in situations. Thus, it is of strategic importance from an energy planning perspective to address heating options from a system-wide and long-term perspective.

In this study, we investigated the long-term cost-efficiency of the three main heating options to LEB areas with a particular emphasis on scale impacts. The obtained results seem to be rather robust and points at the importance of the applied system-wide long-term approach.

From the model results, the economically optimal heat supply to LEB areas within or near urban areas in Sweden over the modelled time horizon seems to be the large heat network option, i.e. heat production in the DH system of the urban area and transmission to the LEB area by a pipeline. However, the large heat network is only the economically optimal option for heat transmission distances of a few kilometres for the LEB area sizes examined. Under strict climate policies, corresponding to high CO_2 charges, and under the size (total heat demand) assumptions applied for each of the LEB cases, for LEB areas with a plot ratio less than about one and a distribution linear heat density less than 4 GJ/m/year the large heat network is the economically optimal option if the area is within a couple of km from a large DH system or within a small or medium DH system. However, for LEB areas with a plot ratio above one and a distribution linear heat density above 4 GJ/m/year the large heat network is the cost-optimal option even if the area is built up to 3 km away from the current DH distribution network.

Since a large share of the system cost of the large heat network option is due to the DH distribution and transmission costs, these results are rather robust with respect to climate polices, which mainly affects the cost of carbon emissions and energy carriers. However, under less ambitious climate policies, i.e. lower CO_2 charges, in some cases the large heat network option becomes relatively less favourable than the other options and thus the DH transmission distance where the threshold occurs becomes shorter.

The results of the study show that with increasing DH system scale the large heat network becomes relatively more cost-efficient compared to the other two heat supply options. The reason is both economies of scale and that a major characteristic of large DH systems in Sweden is the existence of low cost DH production technologies, such as MSW CHP and industrial excess heat.

In this study, for areas with a plot ratio above 0.73, the individual option is the least economically viable independent of the future climate policy scenarios. This shows that in sufficiently dense LEB areas a small local DH system is more cost-efficient than individual heating.

Finally, the study shows the long-term system cost-efficiency of the urban district heating option relative the individual and local DH options. It also shows that the scale of the urban DH systems is important and should be considered in heating planning. The study also demonstrates the importance of a long-term time horizon and wide system boundaries for strategic energy planning decisions since with shorter time scales and more narrow system boundaries the cost-optimal solutions would not have been the same.

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Appendices

Appendix A

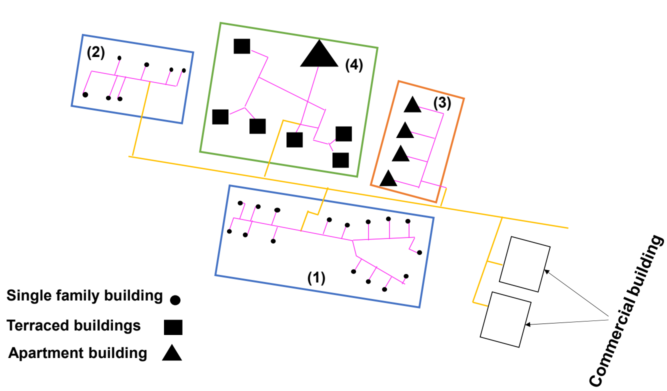

Fig. A1. Designed DH network in PR-1A, main pipelines in yellow and branch pipelines in purple (adapted from Ref. [36]).

Appendix B

Table B1
Characteristics and costs of pipelines in PR-1A (supply and return temperature of 55 °C and 25 °C, respectively).

Area number/name	Max. Power demand [25,36]	Pipe type [19]	Inner diameter [19]	Water[a] velocity	Length [36]	Investment cost [37],[d]
	[kW]	–	[mm]	[m/s]	[m]	[EUR/m]
1	39.9	Alx26	20	1.02	469	229
2	14.7	Alx16	12	1.04	215	179
3	19.4	Alx20	15	0.88	180	183
4	135.6	Tws40	48.3	0.6	244	272
Commercial buildings	20.25[b]	Alx20	15	0.92	183	183
Main pipelines	275.8[c]	Tws50	60.3	0.8	817	296

Abbreviation: Alx, AluxFlex multilayer flexible twin pipes; Tws, steel twin pipeline.
[a] Calculated by Q = π (d/2)2*ν*ρ*Cp* ΔT, where Q: power [kW], d: pipe inner diameter[m], ν: water velocity [m/s], ρ: density of water [kg/m3], Cp: specific heat capacity of water [kJ/kg K], ΔT: difference in supply and return temperature [K].
[b] Estimated based on [8].
[c] Sum of maximum power demand in PR-1A, taking into account 20% heat losses in branch pipelines.
[d] A currency exchange rate of 1EUR = 1.3 Dollar (2013) is used.

Appendix C

Table C1
Assumptions for investment costs of substations in PR-1A, based on [38].

Building	Investment cost [k€]	Fixed O&M cost [k€/year]
One-family, terraced, apartments and commercial buildings	4.5	0.15
Nursing home building	17.5	0.25

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