Available online at www.sciencedirect.com

ScienceDirect

Energy Procedia 149 (2018) 286–296

Energy Procedia

www.elsevier.com/locate/procedia

16th International Symposium on District Heating and Cooling, DHC2018, 9–12 September 2018, Hamburg, Germany

Techno-economic Analysis Of Integrated Energy Systems At Urban District Level – A Swedish Case Study

Monica Arnaudo[a]*, Osama Ali Zaalouk[b], Monika Topel[a], Björn Laumert[a]

[a]Royal Institute of Technology, Brinellvägen 68, Stockholm 11428, Sweden
[b]Europe Power Solutions, Brinellvägen 68, Stockholm 11428, Sweden

Abstract

Within the Nordic countries, distributed heat and power supply technologies, like domestic scale heat pumps and photovoltaics, are challenging the current centralized district energy infrastructure. An increasing number of customers decide to disconnect from the traditional heating network by comparing the bill to the potential economic savings which can be generated by a residential heat pump system. However, this approach can be considered valid only on a short-term perspective. This paper presents a new approach to compare the techno-economic performance of alternative technologies, based on their lifetime average cost of generation. The proposed analysis is able to determine the optimal energy infrastructure at urban district level. Within this solution, operators, city planners and users will have a solid reference for their decision making process on resources investment. From a first step analysis of a few Swedish case studies, it was found that a district heating based system is more techno-economically efficient compared to the distributed alternative. By comparing the district heating production cost to its final price, a significant profit margin for the utility was qualitatively highlighted. Thus, from a customer perspective, on the medium run, the district heating tariff can be adapted and the estimated savings from switching to a residential heat pump system can be nullified.

Keywords: district heating, heat pumps, levelized cost of energy, distributed generation

* Monica Arnaudo. Tel.: +46-762964027
E-mail address: monica.arnaudo@energy.kth.se

1876-6102 © 2018 The Authors. Published by Elsevier Ltd.
This is an open access article under the CC BY-NC-ND license (https://creativecommons.org/licenses/by-nc-nd/4.0/)
Selection and peer-review under responsibility of the scientific committee of the 16th International Symposium on District Heating and Cooling, DHC2018.
10.1016/j.egypro.2018.08.229

1. Introduction

Two major trends are shaping the current energy transition, namely the increasing share of renewables and the increasing penetration of distributed supply technologies. Within the Nordic Countries, hydro- and wind-power based solutions are predicted to dominate the power supply mix by 2050 [1]. While being beneficial to the environment, this phenomenon is affecting the stability of the energy system by raising the levels of unpredictability and variability of the power supply. Distributed technologies, like domestic scale heat pumps (dsHPs) and photovoltaics (PV), come both as part of the renewables complexity but also as one of the potential solutions to the power fluctuation issue.

At the same time, centralized technologies are also re-evaluated as cost-efficient solutions for providing flexibility to the supply-demand balancing process. By linking the heat and the electricity sectors, cogeneration plants for district heating (DH) networks are analyzed as competitors with respect to the distributed dsHPs option [2]. Briefly, DH is considered as a centralized system where one or multiple generation units provide heat to a water network reaching each customer through a substation [3]. A heat pump (HP) is a system able to bring heat from a relatively low-temperature resource (the ground for instance) to a higher temperature one (the heating circuit of a building) [4]. Given this framework, the main question relates to which system configuration would be the most beneficial in terms of technical, environmental and economic impact. A second related question would be which indicators should be used in order to quantify and compare the benefit itself.

When planning the energy infrastructure of a new urban area, previous literature exists comparing DH and dsHPs. The Danish community is intensively working for assessing the future potential of DH. In [5] and [6] the latter is compared to different alternatives, among which dsHPs, in terms of fuel demand, CO_2 emissions and absolute costs. Differently from the present work, a national level perspective is adopted and the cost estimation is referenced to a specific year. The study performed by [7] also discounts the cost analysis to one year. The focus is on low-heat demand buildings and the distributed options are considered as a single category with no technology differentiation. The techno-economic comparison study in [8] is performed with respect to the DH price tariff proposed by the operator, which, according to the authors of this work, prevents a fair determination of the optimal system infrastructure. Within the Swedish context, techno-economic estimations are reported in [12] and [13]. The objective is to develop a new DH tariff model based on the heat generation cost. The DH tariff is considered also in the report provided by [14].

Within the present work, four main types of approaches are collected and briefly analyzed. From the comparison among a techno-economic analysis, a thermo-economic analysis, an equivalent coefficient of performance estimation and a primary energy factor calculation, the first option is selected as the most relevant approach for the objective of the study. Furthermore, in order to investigate the environmental impact, a carbon emission factor is included as well. The overall approach is applied to the techno-economic performance comparison between an energy infrastructure based on a DH technology and an alternative solution based on distributed dsHPs. Two neighborhoods within the Stockholm area are used as reference real cases in terms of design and data: Hammarby Sjöstad (HS) and the aggregation of Högdalen, Farsta and Alvsjö (HFA). The average cost of heat generation is estimated for different scenarios based on centralized and distributed technologies over their economic lifetime. The real cost of generation is highlighted and proposed as an indicator for planning new energy infrastructures. By excluding the DH utility profit from the comparison and by considering the discounted average cost over the lifetime, the present study aims at proposing a new approach for assessing the optimal configuration of an energy system at urban district level. City planners, operators and policy makers can thus direct their resources towards an optimal techno-economic infrastructure. Users can embrace a better understanding of the energy cost structure and thus plan their choices on a longer-term scenario.

2. Methodology

This section first discusses the performance indicators, which are selected in order to answer the questions proposed within this study. The main scenarios for the performance comparison are presented in paragraph 2.2. The different case studies are detailed through both technical and economic parameters. Finally, in paragraph 2.5, the simulation models for the techno-economic analysis are introduced.

2.1. Performance indicators

Four main types of approaches to estimate performance indicators for energy systems are here highlighted:

- Techno- economic analysis (TcEA)
- Thermo-economic analysis (TrEA)
- Coefficient of performance estimation (CP)
- Primary energy factor estimation (PEF)

In order to specifically compare the performance of DH to dsHPs, a thermodynamic CP approach is proposed in [3]. Concerning the DH system, the analysis focuses on a cogeneration plant as supply unit. The latter can be interpreted as a virtual HP, as described in [15]. The coefficient of performance (COP) of the virtual power plant is defined as the inverse of the specific electrical power loss and it can be compared to the conventional COP of HPs. Reference [3] proposes an additional option where dsHPs and cogeneration-DH can be implemented as a hybrid system. Besides a growing interest at industrial level, the CP analysis is still scarcely used and documented. In addition, the complexity to adapt the virtual COP calculation to different technologies is not negligible.

At European level, the PEF approach is discussed as a method to assess the competitiveness of energy systems [16]. For instance, reference [17] draws conclusions on the comparison between dsHPs and alternative technologies, including DH, in terms of their long term sustainability. However, the PEF method is influenced by strong country based assumptions. The Swedish context, in particular, is not currently making use of this method ([18][19]).

The CP and PEF approaches do not include cost estimations. This is the main reason for assigning to them a lower level of priority within a context where the decision making process is strongly linked to economic assessments.

The TrEA is an alternative approach for assessing the competitiveness of an energy supply system. Different types of energy can be considered more valuable than others depending on the capacity to reverse the process, which has led to their transformation. A cost can be associated to the latter, so that different heat and power supply technologies can be compared in terms of energy quality (exergy) [20]. Within a TrEA rules and assumptions are introduced in order to estimate both the irreversibility and the economic cost which are generated during an energy input-output process [21]. References [22]–[24] use exergy and TrEA to optimize DH systems when compared to alternative technologies at user level. The main drawback of the TrEA is related to its complexity, which compromises its acceptance at industry and sometimes even academic level.

The TcEA approach is usually based on the estimation of the Levelized Cost of Energy (LCOE) [25]. The latter is a widely used figure for estimating the average cost of electric power generation over the lifetime of power plants [25]. This indicator is quite well documented and brings to transparent results, which can be explained by a clear statement of the assumptions. Furthermore, the LCOE can be applied to several types of technologies and it can be handled in complexity by including different levels of details. Thus, the TcEA appears to be an effective choice for the approach adopted within this study. When the heat generation is considered, the Levelized Cost of Heat (LCOH) is calculated [12]. The formula (1) is applied to each selected technology:

$$LCOH = \frac{\sum_{t=1}^{n}\left[(CAPEX_t+OPEX_t+Fuel_t)*(1+r)^{-t}\right]}{\sum_{t=1}^{n} Q_{th}*(1+r)^{-t}} \quad (1)$$

The investment (CAPEX), operation and maintenance (OPEX) and fuel costs are estimated on an annual basis through the economic lifetime n of the technologies. These costs are averaged on the corresponding heat generation Q_{th}. The discount rate r is assumed as a constant parameter. When different technologies are combined within the same system, the overall LCOH should be calculated as the weighted sum based on the contribution of each option.

As environmental indicator, the CO_2 emissions associated with the fuels are estimated by using pre-calculated emission factors [26]–[28]. When it comes to the electricity supply mix, the Swedish context is used as a reference. In Table 1, the emission factors included in this study are shown. The described performance indicators are estimated considering new urban areas to be built from green field. The link to already existing neighborhoods is exclusively used in terms of scale and reference data.

Table 1. Emission factors for different types of fuels

Fuel	Unit	CO_2 factor
Waste	gr/kWh	100
Biomass	gr/kWh	17
Oil	gr/kWh	274
Electricity	gr/kWh	46

2.2. Scenarios definition

A scenario is here introduced as a set of parameters defining a specific case study. Different scenarios are based on three design categories: technology for heat generation and distribution, heating load scale (community size) and fuels.

Figure 1 shows two case studies, which are characterized by different technologies for the heat generation and distribution. The electricity grid is represented as well because of the interaction with the heat carrier due to the chosen technologies. Notice that in case A only the heat supply pipes are illustrated. The buildings are residential multi-apartments. The number of units is conceptually reduced to four for the sake of clarity.

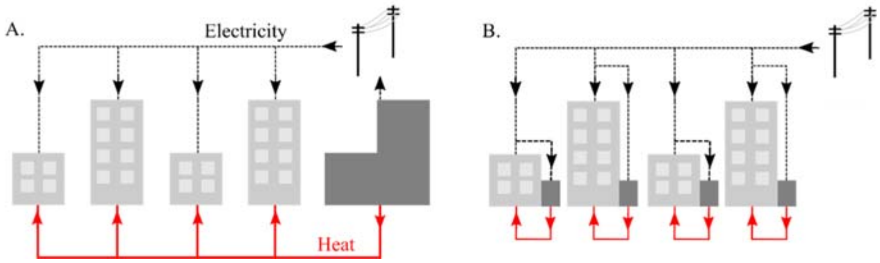

Figure 1. District heating (A) and domestic scale HP (B)

The infrastructure of case A is a DH network with a single supply unit. In this specific representation, a cogeneration plant is considered. As a first sub-case, the latter can be fueled by waste or by biomass. These two resources bring to contrasting result in terms of costs and environmental impact (see section 3). In both sub-cases, oil boilers, flue gas condensation and a hot water tank storage are integrated respectively to cover peak demand, pre-heating and off-design conditions. The technology of large scale HPs (lsHPs) is used as an alternative option within case A. Thus, electricity becomes the relevant fuel in terms of annual costs and environmental emissions. Within this study, the main source for the lsHP is sewage water recovered by a waste water treatment plant. Two real plants are used as reference in terms of design: Högdalenverket for the cogeneration plants and Hammarbyverket for the lsHPs ([29], [30]). Case B of Figure 1 represents the scenario where the same neighborhood of case A is heated through dsHPs distributed at building level. A further sub-set of cases is developed by considering two different community sizes. HS is ranked within the small-scale level with a design peak heat load of about 50 MW. In order to highlight the economy of scale of the selected technologies, the aggregation of the three Swedish neighborhoods of HFA is analyzed across the previously described scenarios. The design peak heat load for HFA is around 400 MW.

A sum up of the case studies, with reference to the size of HS, is reported in Table 2. The set of cases for HFA is indicated by the number 2 (Case 2a, b, c, d). In all cases, the heat load includes both the space heating and the domestic hot water (DHW) needs at building level. In some cases, two or three buildings are grouped together.

Table 2. Case studies with Hammarby Sjöstad as reference size.

Case	Baseload Technologies	Fuels
1a	DH + cogeneration	Waste
1b	DH + cogeneration	Biomass
1c	DH + lsHPs	Electricity
1d	dsHPs	Electricity

2.3. Technical parameters

The cogeneration plant within the cases 1a, 1b, 2a and 2b is a backpressure technology and it is sized to cover 40% of the peak heat load. The flue gases condensation is integrated in order to preheat the DH water temperature from its actual return value to around 40°C. A pressurized water tank is used to compensate for the off-design conditions. An oil-fueled boiler is sized on the remaining 60% part of the load in order to cover the peaks and the potential unavailability of the thermal storage. The cogeneration plant layout and the main technical design parameters for the HS and HFA cases are shown in Figure 2 and Table 3 respectively. The thermodynamic conditions of the steam cycle are based on data provided by the industrial partners. Within this analysis, the cogeneration plant is considered in continuous operation by covering the heat demand when required and charging the water tank with the excess generation. The DH network is characterized by underground pipes, which reach each building (or group of buildings) through a substation. The latter is of the indirect type with no domestic hot water storage. The emission system inside the apartments is a radiator technology with mean temperature around 45°C. The electrical energy required by the plant itself is subtracted from the production.

The lsHP technology of case 1c and 2c is sized as the cogeneration plant previously described. Within the HFA case, multiple units are combined to cover the design heat capacity. The HP source is the sewage water recovered from a waste water treatment plant located nearby. An average COP of 3.5 is assumed.

A dsHP is designed based on an average reference building extracted from the HS neighborhood. The related peak load is around 140 kW. Because of this assumption, the final results are to be regarded as an average over the selected community. The HP is of the ground source type with a design heat capacity of 80 kW [31] (around 55% of the peak load). An average COP of 3.2 is assumed [5]. A thermal energy storage (TES) unit is integrated to cover the load within a demand response (DR) program. The TES is a stratified water tank and is equipped with an auxiliary internal electrical coil. An independent electrical heater (EH) is sized to cover the peak load (around 60 kW). The system layout and the main technical design parameters are shown in

Figure 3 and Table 4 respectively.

The emission system is again a radiator technology with mean temperature around 45°C. The DR program is based on a time-of-use tariff. Price-signals are sent to the system, which is set to "off" during peak hours (6-8am, 6-9pm) and to "on" during the rest of the day. The TES unit is designed to balance the operation. An independent electrical heater and a TES integrated electrical coil are included in order to guarantee that the heat demand is covered during the peaks and off-design conditions.

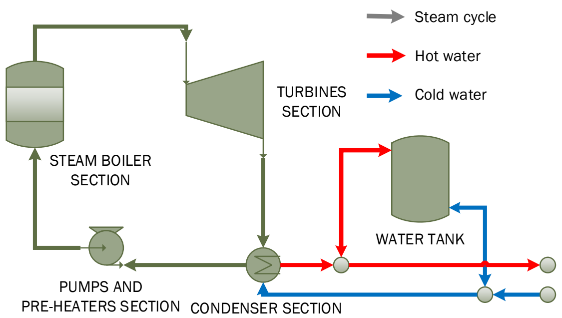

Figure 2. Conceptual layout of a cogeneration plant

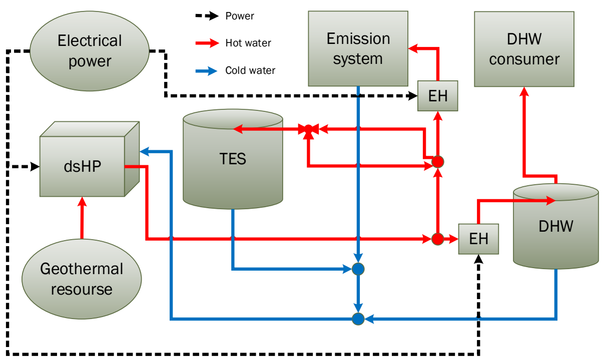

Figure 3. Conceptual layout for a ground source dsHP

Table 3. Main technical design parameters for the cogeneration plant and the DH network for HS and HFA

Design parameters	Units	HS	HFA
Peak heat load	MW	50	400
Cogeneration plant heat capacity	MW	20	175
Steam cycle inlet temperature	°C	520	520
Steam cycle inlet pressure	bar	90	90
Oil boilers overall capacity	MW	30	225
DH supply temperature	°C	70	70
DH return temperature	°C	40	40
DH network pipe length	km	15	120

Table 4. Main technical design parameters for the system of dsHP, TES and backup heaters

Design parameters	Units	HS
Peak heat load	kW	140
dsHP heat capacity	kW	79
dsHP max outlet temperature	°C	70
EH heat capacity	kW	61

2.4. Economic parameters

In order to estimate the LCOH according to equation (1), a literature review and discussions with industrial project partners were carried on. Table 5 and Table 6 report the assumed figures for the main technologies adopted in Case 1a and Case 1-2d. Concerning Table 5, the operation and maintenance costs for the network are extracted from the discussion presented in [3]. These costs are reported as percentage of the capital investment.

Table 5. Economic input parameters for a 50MW waste fuelled cogeneration plant and the corresponding DH network

Design parameters	Units	Waste cog.-DH	Refs.
r	%	8	[12]
lifetime	years	30	[12]
CAPEX plant	sek/kW	108600	[32]
CAPEX network	sek/m	10319	[33]
OPEX fixed	sek/kW	3140	[32]
OPEX variable	sek/MWh	40	[32]
Fuel (waste)	sek/MWh	-130	[32]

Within this analysis, the cogeneration plant costs are entirely allocated on the heat generation. The net electricity sold to the grid is considered as a revenue at a fixed spot market price of 0.375 sek/kwh [34]. The reference figures for the peak boilers, the water tank and the case studies 1b (biomass-based technology), 1c (lsHP) and 2a-c can be found in the same or similar literature, as reported in Table 5 ([5], [32], [35], [36]). It is important to notice that the specific costs scale down by increasing the capacity range and that the biomass-based technology is overall more expensive than the waste incineration option.

Table 6 shows the figures assumed for the case of a ground source dsHP. The drilling costs are included in the capital investment. From discussions with industrial project partners, the operation and maintenance costs are overall considered negligible and thus dominated by the electricity consumption cost. Since the dsHP is involved in a DR program based on a time-of-use electricity tariff, during off-peak hours the electricity bill cost is assumed to be reduced to half of its actual value.

Table 6. Economic input parameters for a dsHP

Design parameters	Units	dsHP	Refs.
r	%	4	[12]
lifetime	years	15	[14]
CAPEX	sek/kW	14560	[37]
OPEX fixed	-	-	-
OPEX variable	öre/kWh	48	[38]

2.5. Models

The models for the thermal performance simulation of the cogeneration plant, the lsHP and the geothermal dsHP are implemented in the TRNSYS [32] environment. The latter is a software for pseudo-dynamic performance simulation of energy systems. A quite developed library of black-box components is available. In addition, the user is able to integrate missing features when necessary.

A yearly simulation with one-hour time step is considered in all scenarios. The objective is to determine how the pre-heating, base- and peak-load options cover the given load, within each sub-case.

The heat load is extracted from real data as a time series curve. Case 1 refers to a representative multi-apartments residential building within HS. The information is extracted from the user account. The neighborhood performance is the result of a scale up process. Case 2 refers to the aggregated performance of HFA. The information is extracted from data provided by the operator. Because of the Swedish context, the weather related parameters refer to Stockholm in terms of location. All the performance data are historical and are related to year 2016.

As an illustration of the results from the TRNSYS simulations, Case 1a and 1d are here discussed for a reference winter day. No degradation factor is considered over the lifetime.

As it can be seen in Figure 4, the load curve is mainly covered by preheating from the flue gas condensers and by the operation of the steam condenser section of the cogeneration plant. Notice that the curves add on each other. The daily load trend is characterized by two peaks, one in the morning and one in the evening, which are considered to be fully covered by the oil boiler. The performance of the latter is estimated in order to exactly compensate the peaks. The water tank is used to respond to the load changes in terms of mass flow rate imposed by the users' substations. In the specific case of Figure 4, no TES charging is happening. On a yearly basis, the steam condenser section covers around 74% of the total load. Around 17% comes from the boiler, while the remaining part is covered by the flue gas condensation and the water tank.

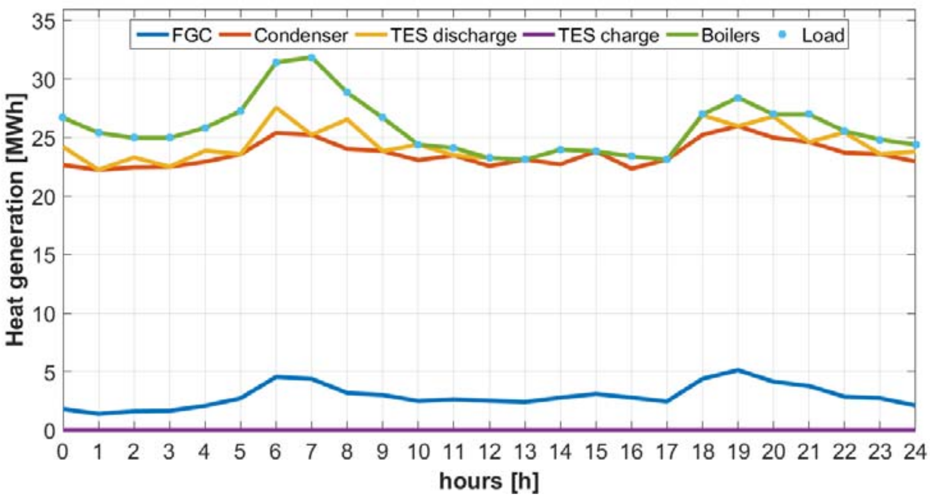

Figure 4. A reference winter day performance for the cogeneration plant of Case 1a

Concerning Case 1d, the daily operation based on the DR program is clearly shown in Figure 5.

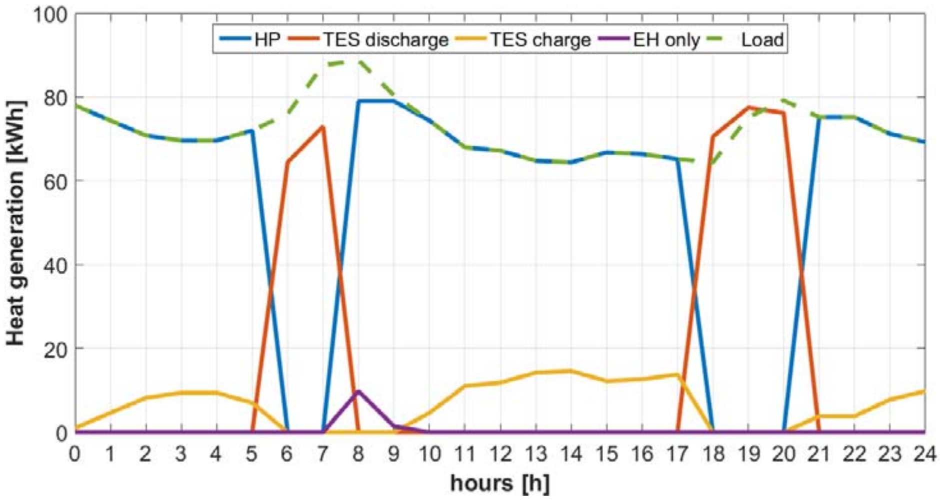

Figure 5. A reference winter day performance for the dsHP of Case 1d

The time-of-use tariff for electricity is imposed by a step function, which sets the dsHP "off" between h6-8 am and h6-9 pm. This is a simplified assumption based on the real possibility to stipulate a contract with variable tariff [39].

The dsHP covers most of the load and can also provide heat to the TES unit for charging. If a peak demand phenomenon occurs outside the set time range, an independent electrical heater is activated. When the HP is forced to the "off" mode, the TES is responsible for covering the load. As it can be noticed, this is not an easy task. Based on the TES state of charge, the unit can sometimes under-perform and sometimes over-perform. This situation might affect the comfort condition for the user. The investigation of the latter is out of the scope of this study. On a yearly basis, the dsHP covers around 74% of the total load. The TES unit contributes as much as around 21%, while the remaining part comes from the electrical heaters.

3. Results and discussions

A sum up of the results for the different scenarios of this study is presented in Table 7 and Table 8 for Case 1 and Case 2 respectively. The estimated figures are to be considered as preliminary values, which indicate a direction of study, namely the comparison of different technologies performance based on their generation cost. The validity of the results is cross checked with the studies presented in [2] and [8] and through discussions with project partners.

Concerning Case 1 (Table 7), it can be observed that a strong contrasting outcome is related to the use of a different fuel for the cogeneration plant feeding the DH network. Waste incineration for heat recovery is considered a convenient process as an alternative solution to its disposal. Therefore, its implementation is economically incentivized. Thus, the operational costs associated with Case 1a are low enough to reduce the final LCOH of about 40% with respect to the biomass-based Case 1b. However, the environmental impact leads to an opposite conclusion concerning the advantages of the two technologies. Overall, the waste incineration option is characterized by a significantly higher carbon emission performance with respect to all the other cases.

Table 7. LCOH and CO_2 results for the HS referenced scenario (Case 1)

Indicators	Units	Case 1a DH + waste cog.	Case 1b DH + bio cog.	Case 1c DH + lsHPs	Case 1d dsHPs
LCOH	sek/kWh	0.45	0.62	0.32	0.52
CO_2	kt	42	15	11	9

Case 1c represents the most interesting solution at a community scale like HS. The main reason is linked to the much lower operating costs compared to the cogeneration plant cases. When DH systems with multiple supply units are considered, these two options are combined in order to profit or save from the variability of electricity prices. Concerning the CO_2 emissions, the Swedish electricity supply mix is characterized by a high share of low or no-carbon emission technologies. This is the reason for the environmental friendly performance of Case 1c and 1d.

When it comes to the LCOH value for Case 1d, it is important to remember that this estimation is made for an average building type, which is assumed as representative for the whole neighborhood. Within this frame and given the assumptions described in Section 2, it can be concluded that the option of distributed dsHP should be in general considered as less techno-economically convenient compared to the DH alternatives. The main reason for this outcome is related to the higher investment cost spread on a shorter economical life of the technology. Furthermore, the cogeneration process brings the opportunity of performing full heat recovery while still profiting from power generation. The option of lsHP is more cost-efficient, given the economy of scale. The introduced type of DR program is not sufficient to justify the choice of a dsHP instead of a DH substation. The only exception, within Case 1, is given by Case 1b which is affected by relatively higher investment and operating costs.

This is a relevant conclusion in the light of comparing the heat production cost of both technologies rather than considering the tariff imposed by the DH operator. The DH final heat price is based on a benchmarking study of the alternative technologies. From the perspective of one or few users, it can be convenient to install a dsHP, thus reducing the heat bill with respect to the current DH tariff. However, on a longer term perspective which includes more users choosing or switching to the alternative technology (dsHP), the DH tariff can change, nullifying the estimated savings. This conclusion assumes that the DH utility has no decisional constraints on the profit margin range, which can be thus reduced to maintain the competitiveness. In the opposite scenario, the alternative technology could take over.

The results of this study are compared to the statistics reported in [14]. Figure 6 shows the generation costs of a DH option compared to the alternative option of geothermal HPs with different levels of interest rates and economic lifetime ranges. The values in Figure 6 include the DH utility profit and the HP connection share, which are not considered in the present study.

Figure 7 shows the results of the LCOH for Case 1 with the costs break-down between capital investment and operation and maintenance. In Case 1a, the incentive on the fuel leads to a reduction of the result (striped texture).

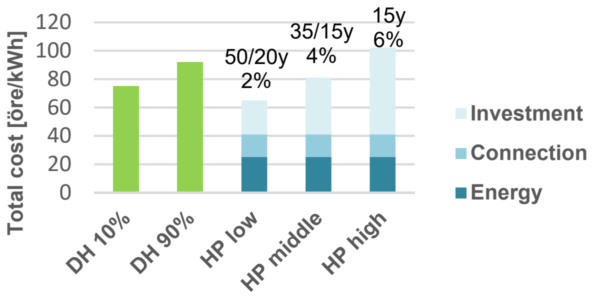

Figure 6. Comparison of generation costs extracted from [14]

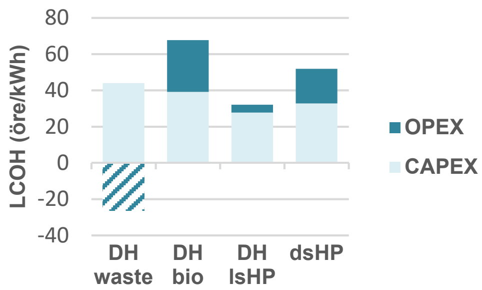

Figure 7. Generation costs from this study for Cases 1a, b, c, d

By comparing Figure 6 and Figure 7, the first outcome is the impact of the profit margin on the DH final heat cost. This observation confirms the previous discussion on the DH tariff composition. The result should be considered as an estimation of order of magnitudes. The precise profit calculation belongs to the business model of the operator. Concerning the HP, it can be noticed that the LCOH value is lower, which is due to two main reasons related to this study. First, the connection costs are not included and, second, the revenues from the DR program are taken into account. Besides these assumptions, the result is considered within the range of validity.

Case 2 refers to the larger scale neighborhood of HFA. The relevance of this scenario is related to the possibility to show the impact of the economy of scale, especially for the DH-based cases. Table 8 shows the results for the second set of case studies within this work.

Table 8. LCOH and CO_2 results for the HFA referenced scenario (Case 2)

Indicators	Units	Case 2a DH + waste cog.	Case 2b DH + bio cog.	Case 2c DH + lsHPs	Case 2d dsHPs
LCOH	sek/kWh	0.09	0.35	0.20	0.52
CO_2	kt	435	158	160	74

When comparing to Case 1, the LCOH value of the waste incineration scenario highlights the strong impact of the economic incentive for this type of fuel. Case 2b benefits more from the scale phenomenon than Case 2c. Thanks to a more efficient allocation of the costs, the DH biomass option gets in line with the other DH cases when compared to the dsHP scenario. Besides the impact of the economy of scale, similar comments as for Case 1 can be applied when dealing with the comparison between a centralized and a distributed energy infrastructure.

4. Conclusion

A techno-economic performance analysis is applied to compare different options of centralized and distributed heat supply technologies. The average cost of heat generation over the lifetime is estimated for three district heating solutions and a distributed domestic scale heat pump option. The same case studies are also scaled-up to highlight the impact of the economy of scale.

The fist district heating case is based on a waste incineration technology, which is characterized by significantly lower fuel costs. The second option is a biomass-fueled solution, which is more expensive but brings an advantage in terms of CO_2 emissions. Large-scale heat pumps are used in the third case study, which represents the most interesting scenario at relatively small community scale. The last option is based on distributed domestic scale heat pumps. The results from the techno-economic analysis show that this solution cannot overcome the benefits of a district heating technology. The advantages derived from heat recovery, economy of scale and fuel diversification are even more evident at a larger community size.

Given the discussed boundary conditions and assumptions, the results of this study are considered as a preliminary overview. A direction of research is indicated by proposing future work improvements of the current analysis. For instance, the different proposed cases can be combined with each other to increase the flexibility of the system. A closer look on the user comfort conditions should be included. The heat pump technologies, both at large and domestic scale, should be considered at their full potential by combining the heating and cooling options. Finally, a further optimization of the size of the main technologies would influence the investment costs.

Acknowledgements

The authors would like to thank the industrial and academic partners for the fruitful discussions about district heating networks (Stockholm Exergi), heat pumps (KTH-ETT) and perspective of the customers (ElectriCITY).

References

[1] IEA, “Nordic Energy Technology Perspectives 2016,” *Energy Technol. Policy Div.*, no. April, p. 269, 2016.

[2] S. Werner, “District Heating and Cooling in Sweden,” *Energy*, vol. 126, pp. 419–129, 2017.

[3] S. Frederiksen and S. Werner, *District Heating and Cooling*, First Edit. Lund: Dimograf, 2013.

[4] Energy Saving Trust, “Domestic Ground Source Heat Pumps: Design and installation of closed-loop systems – A guide for specifiers, their advisors and potential users,” p. 22, 2007.

[5] H. Lund, B. Möller, B. V. Mathiesen, and A. Dyrelund, “The role of district heating in future renewable energy systems,” *Energy*, vol. 35, no. 3, pp. 1381–1390, 2010.

[6] O. Gudmundsson, J. E. Thorsen, and L. Zhang, “Cost analysis of district heating compared to its competing technologies,” *WIT Trans. Ecol. Environ.*, vol. 176, pp. 107–118, 2013.

[7] A. F. Sandvall, E. O. Ahlgren, and T. Ekvall, “Cost-efficiency of urban heating strategies – Modelling scale effects of low-energy building heat supply,” *Energy Strateg. Rev.*, vol. 18, pp. 212–223, 2017.

[8] A. Dalla Rosa and J. E. Christensen, “Low-energy district heating in energy-efficient building areas,” *Energy*, vol. 36, no. 12, pp. 6890–6899, 2011.
[9] R. Lazzarin and M. Noro, “Local or district heating by natural gas: Which is better from energetic, environmental and economic point of views?,” *Appl. Therm. Eng.*, vol. 26, no. 2–3, pp. 244–250, 2006.
[10] F. Busato, R. M. Lazzarin, and M. Noro, “Ten years history of a real gas driven heat pump plant: Energetic, economic and maintenance issues based on a case study,” *Appl. Therm. Eng.*, vol. 31, no. 10, pp. 1648–1654, 2011.
[11] F. Mauthner and S. Herkel, “Technical Report Subtask C – Part C1,” no. January, pp. 1–31, 2016.
[12] H. Li, F. Wallin, and J. Song, “A dynamic pricing mechanism for district heating,” 2017.
[13] J. Song, H. Li, and F. Wallin, “Cost Comparison between District Heating and Alternatives during the Price Model Restructuring Process,” *Energy Procedia*, vol. 105, pp. 3922–3927, 2017.
[14] Värmemarknad Sverige, “Slutrapport - Vår gemensamma värmemarknad,” 2017.
[15] R. Lowe, “Combined heat and power considered as a virtual steam cycle heat pump,” *Energy Policy*, vol. 39, no. 9, pp. 5528–5534, 2011.
[16] A. Esser and F. Sensfuss, “Final report Evaluation of primary energy factor calcula- tion options for electricity,” Karlsruhe (Germany), 2016.
[17] B. Vidrih, A. Kitanovski, and A. Poredo, “Eligibility of a Heat Pump Based on the Primary Energy Factor,” pp. 1–13, 2017.
[18] T. Persson, “Energimyndighetens syn på viktnings- och primärenergifaktorer,” vol. 1, no. 202100, pp. 1–5, 2015.
[19] E. Latõšov, A. Volkova, A. Siirde, J. Kurnitski, and M. Thalfeldt, “Primary energy factor for district heating networks in European Union member states,” *Energy Procedia*, vol. 116, pp. 69–77, 2017.
[20] Y. M. El Sayed, *The thermoeconomics of energy conversion*. 2003.
[21] C. Torres Cuadra and A. Valero Capilla, “Thermoeconomics,” Centro de Investigaciòn de Recursos y Consumos Energéticos, 2005.
[22] V. Verda, R. Borchiellini, and M. Cali, “A thermoeconomic approach for the analysis of district heating systems,” *Int. J. Appl. Thermodyn.*, vol. 4, no. 4, pp. 183–190, 2001.
[23] V. Verda and A. Krona, “Thermoecnpomic approach for the analysis of low temperature district heating systems,” in *THE 25TH INTERNATIONAL CONFERENCE ON EFFICIENCY, COST, OPTIMIZATION, SIMULATION AND ENVIRONMENTAL IMPACT OF ENERGY SYSTEMS*, 2012.
[24] A. Krona, “Exergetic and thermoeconomic approach for optimal planning of district energy systems,” Politecnico di Torino, 2013.
[25] IEA, “Projected Costs of Generating Electricity,” Paris, 2015.
[26] O. Eriksson and G. Finnveden, “Energy Recovery from Waste Incineration—The Importance of Technology Data and System Boundaries on CO2 Emissions,” *Energies*, vol. 10, no. 4, p. 539, 2017.
[27] T. Duveau and N. Tewes, “Climate Scorecard Sweden,” Germany, 2009.
[28] A. Moro and L. Lonza, “Electricity carbon intensity in European Member States: Impacts on GHG emissions of electric vehicles,” *Transp. Res. Part D Transp. Environ.*, no. November 2016, pp. 0–1, 2017.
[29] Fortum Värme, “Högdalenverket Miljörapport 2016.” 2017.
[30] Fortum, “Hammarbyverket,” Stockholm, 2016.
[31] Thermia, “Thermia Mega Tekniska data.”
[32] I. Nohlgren, M. Jansson, and J. Rodin, “Electricity from new and future plants 2014,” no. October, 2014.
[33] International Energy Agency, “District Heating,” *ETSAP - Energy Technol. Syst. Anal. Program.*, no. January, p. 7, 2013.
[34] NordPool, “Price Chart,” 2018. [Online]. Available: https://www.nordpoolgroup.com/Market-data1/#/nordic/chart. [Accessed: 07-May-2018].
[35] Danish Energy Authority and Energinet.dk, *Technology Data for Energy Plants*, vol. 978-87–784. 2012.
[36] D. F. Dominković, R. Lund, and B. V Mathiesen, “Large Scale Heat Pumps as a Link Between Intermittent Electrical Energy Sources and District Heating Sector,” no. April, p. 2014, 2016.
[37] C. Boissavy, “Cost and Return on Investment for Geothermal Heat Pump Systems in France,” *World Geotherm. Congr. 2015*, no. April, pp. 1–9, 2015.
[38] Energimarknadsinspektionen, “Elpriskollen,” 2018. [Online]. Available: https://www.ei.se/en/Elpriskollen/Avtalssok/?avtalstypid=13&forbrukning=40000&postnr=12068. [Accessed: 07-May-2018].
[39] Vattenfall, “Så här fungerar rörligt elpris,” 2018. [Online]. Available: https://www.vattenfall.se/elavtal/elpriser/rorligt-elpris/. [Accessed: 26-May-2018].