



HAL
open science

Assessing the techno-economic impact of low-temperature subnets in conventional district heating networks

Jose Fiacro Castro Flores, Bruno Lacarrière, J.N.W. Chiu, V. Martin

► To cite this version:

Jose Fiacro Castro Flores, Bruno Lacarrière, J.N.W. Chiu, V. Martin. Assessing the techno-economic impact of low-temperature subnets in conventional district heating networks. *Energy Procedia*, 2017, 116, pp.260 - 272. 10.1016/j.egypro.2017.05.073 . hal-01735279

HAL Id: hal-01735279

<https://hal.science/hal-01735279>

Submitted on 13 Sep 2023

HAL is a multi-disciplinary open access archive for the deposit and dissemination of scientific research documents, whether they are published or not. The documents may come from teaching and research institutions in France or abroad, or from public or private research centers.

L'archive ouverte pluridisciplinaire **HAL**, est destinée au dépôt et à la diffusion de documents scientifiques de niveau recherche, publiés ou non, émanant des établissements d'enseignement et de recherche français ou étrangers, des laboratoires publics ou privés.



The 15th International Symposium on District Heating and Cooling

Assessing the techno-economic impact of low-temperature subnets in conventional district heating networks

J.F. Castro Flores^{a,b,*}, B. Lacarrière^b, J. NW. Chiu^a, and V. Martin^a

^a Royal Institute of Technology, Department of Energy Technology, Stockholm, Sweden

^b IMT Atlantique, Department of Energy Systems and Environment, UMR CNRS GEPEA, Nantes, France

Abstract

The 4th generation Low-Temperature District Heating (LTDH) is envisioned as a more efficient and environmentally friendly solution to provide heating services to the building stock. Specifically, in countries already with a large share of well-established DH systems, conventional DH and LTDH technologies will be operating simultaneously in the near future. Newly built or refurbished buildings have lower heat demands, which in combination with LTDH brings potential savings compared to conventional DH. This work explores the advantages in DH operation by connecting these loads via LTDH subnets to a conventional DH system, supplied by a Combined Heat and Power (CHP) plant. A techno-economic analysis was performed, through modelling and simulation, by estimating the annual DH operating costs and revenues achieved by the reduction in return temperatures that LTDH would bring. The savings are related to: (1) the reduction in distribution heat losses in the return pipe; and (2) lower pumping power demand. Likewise, additional revenues are assessed from: (3) improved Power-to-Heat ratio for electricity production; and (4) enhanced heat recovery through Flue Gas Condensation (FGC). The annual savings per kWh of delivered heat are estimated as a function of the penetration percentage of 'energy efficient' loads over the conventional DH network. Key outcomes show the trade-offs between the potential savings in operating costs and the reduction in heat demand: relative losses in this scenario are maintained at 13.1% compared to 15.3% expected with conventional DH; and relative pumping power demand decreased as well. In other words, the costs of supplying heat decrease, even though the total heat supplied is less.

© 2017 The Authors. Published by Elsevier Ltd.

Peer-review under responsibility of the Scientific Committee of The 15th International Symposium on District Heating and Cooling.

Keywords: district heating; low-temperature; subnet; energy savings; techno-economic assessment;

* Corresponding author. Tel.: +46-8-790-7481.

E-mail address: jfcf@kth.se

1. Introduction

The current district heating technology is facing changing circumstances that challenge the profitability of the DH industry in the future. Existing DH production and distribution networks have been appropriately designed technically and economically for typical levels of heat demand. However, due to factors such as new energy efficiency policies in place, the heat demand in urban areas is expected to gradually decrease in the future [1],[2]. New directives on the construction and refurbishment of buildings define higher requirements of building energy performance, so the existing DH system may not be as technically and economically effective to cope with a decrease on heat demand and heat density. Thus, the system requires an enhancement to effectively adapt to the changing conditions so as to maximize their benefits [3].

Heat demand and linear heat density are two related parameters that determine the profitability of a DH system. However, heat density in the future will decrease due to multiple factors, including building renovation and global warming [4],[5]. Consequently relative distribution heat losses are higher, and so, from the supply and distribution perspectives, investment and operating costs increase relative to total heat sales. Since the return of investment in DH systems is based on heat sales, which depend on the heat demand over periods of several years, the profitability of new DH networks, expansions and/or refurbishment of the existing ones should be carefully planned and analysed.

The DH industry is facing challenges of lower linear heat density in existing DH networks, on top of servicing newly built energy efficient buildings, whose connection might not be either effective or profitable if the conventional DH technology is used. In light of these issues, the 4th generation Low Temperature District Heating (LTDH) set of technologies described in [6] is projected as a solution able to cope with the coming challenges to be able to cost-effectively provide heating services to the building stock.

Nomenclature

Acronyms

CHP	combined heat and power
DH	district heating
DHW	domestic hot water
FGC	flue (exhaust) gases condenser
HEX	heat exchanger
LEB	low energy buildings
LHV	low heating value
LT	low-temperature
LDC	load duration curve
SH	space heating
TMY	typical meteorological year

Latin Characters

C	cost	[EUR]
h	specific enthalpy	[kJ/kg]
l	pipe length	[m]
\dot{m}	mass flow rate	[kg/s]
P	power	[kW]
\dot{q}	heat load	[kW]
Q	heat	[kWh]
t	temperature	[°C]

Greek symbols

α	power-to-heat ratio	[MW _{el} /MW _{th}]
Δ	delta, difference	[-]
λ	thermal loss coefficient	[W/m_K]

Subscripts and superscripts

amb	ambient/outdoor
el	electrical
eq	equivalent
g	ground
$loss$	heat losses related
mch	marginal cost of heat
r	return line
s	supply/forward line
sav	savings related
sr	substation return
th	thermal
tot	total

Due to the lower operating temperatures, LTDH has the potential to reduce the network distribution heat loss, among others. LTDH is characterised by network operating temperatures below 65°C for the forward flow and aiming for 25°C in the return. Less heat losses lead to lower temperature drop along the network, thus for a given heat demand a lower flow rate is required, and so the pressure drop also decreases. Consequently, this results in a lower pumping energy demand [5] as well. LTDH represents a potential advantage for DH operation by keeping relative losses at margin, and potentially making the connection of low heat density areas more cost-efficient. Moreover, the DH network coverage could be expanded to service more customers incurring in lower investments.

It is expected that the DH sector will experience a transition period of several decades during which both the conventional DH networks and the LTDH will be operating simultaneously, complementing each other to meet the thermal energy demand of the building stock. Particularly, in countries with a large share of well-established DH systems, LTDH can be integrated to the existing systems through secondary (cascade) networks operating at lower temperatures and pressures. In the longer term, a nearly full penetration of the 4th generation DH technology is the target [1],[6].

1.1. Operating temperatures and distribution costs

Nominal and operating network temperatures (supply/return) influence investment and operating costs of the DH system components. Since production and distribution costs are closely related to these temperatures, they are key factors in the overall techno-economic design and operation of the system, as well as its optimisation [7]. While heat producers set the network supply temperatures to optimise their operation and profits, the return temperature is the result of the combination of the customer base substations which should comply with minimum design and operating conditions, although malfunctioning is common. Heat production units (HPU) have little influence over this, except for establishing higher tariffs on high return temperatures. Improved operation and settings of the substations can lead to lower network return temperatures, and therefore a more efficient network operation.

Regarding heat generation costs, the impact of the supply temperature is dependent on the heat generation technology in place. On the other hand, the impact of the return temperature on these costs is usually larger, and it benefits the efficiency of heat pump systems, renewable energy systems such as solar and geothermal, as well as heat recovery from industrial processes and exhaust gases. Likewise, lower return temperatures enable a higher electricity production capacity at CHP plants. Concerning heat distribution costs, lower operating temperatures in both, supply and return flows, lead to reduced heat losses. Moreover, a decrease on the return temperature (or increase of supply temperature) increases the delivery capacity of the network, i.e. the heat transport per unit mass of heat transfer fluid. As a result, the flow rate required is lower and thus the pressure drop. Assuming the same amount of heat shall be supplied, increasing the temperature difference between the supply and return flows lead to lower pumping costs.

In terms of distribution heat losses and pumping energy on conventional DH systems, there are limited studies on the impact of end-use energy savings until now. In a previous study [8], proposing a methodological approach to assess the minimization of losses and pumping energy, the authors optimize both a conventional DH scenario and a LTDH one; however, only in a supplementary scenario they considered a heat demand reduction of 20% due to end-use energy savings. In other relevant contributions, a methodology to estimate cost savings and additional production resulting from lower return temperatures was described in [9] and summarized in [7]. However, this methodology is applied on existing DH systems with conventional operation without referencing LTDH technology.

The purpose of this paper is to present a techno-economic assessment of the impact of LTDH subnets and energy efficient loads on operational costs and revenues of a conventional DH system. This study considers both the impact of the reduction of the return temperature, as well as the heat demand reduction as a result of the end-use energy savings due to renovation and LTDH. Furthermore, besides the thermodynamic analysis of temperatures, distribution heat losses, and pumping power, an economic evaluation of the savings and potential earnings is performed for the scenario of a DH network mainly fed by a CHP plant.

2. Methodology

2.1. Scenario Description

In this study, we assess the impact of introducing energy efficient loads through LT subnets into a conventional DH network from a techno-economic perspective. The studied scenario was developed based on a Swedish DH network studied in [10] supplied mainly by a CHP plant (two-stage extraction) introducing simplifications and assumptions for ease to be described throughout this section. The total annual heat supplied is estimated at 82 GWh, from which 10.6 GWh are distribution losses (13%). The load duration curve (LDC) in **Fig. 1** depicts the heat production units, their power and operating hours. The heat input to the DH network is driven by a bio-fueled CHP station such that the heat demand drives the electricity production. The LDC shows that the year could be divided in four periods as far as heat production is concerned:

- During the period of low heat load (3100 hrs/yr), all heat is produced by a heat-only boiler in order to satisfy the domestic hot water (DHW) demand.
- Throughout most of the year (4980 hrs/yr) the supply comes from a CHP unit delivering heat to the network at part load, and that is also producing electricity. The FGC unit does not run during this period, in order to generate the maximum electricity possible in the CHP unit.
- When CHP reaches full load, the flue gas condensation unit (FGC) starts operation (330 hrs/yr), adding a maximum of 14% over the total heat produced.
- During the periods of highest load (350 hrs/yr), when both the CHP and the FGC unit are at maximum capacity, an auxiliary (peak-only) oil boiler enters operation.

Assuming a moderate building renovation for higher energy efficiency, allowing the use of LTDH, it is assumed that the space heating (SH) load is 20% lower, that would lead to a 15% reduction in total annual heat demand when all buildings in the network have been refurbished.

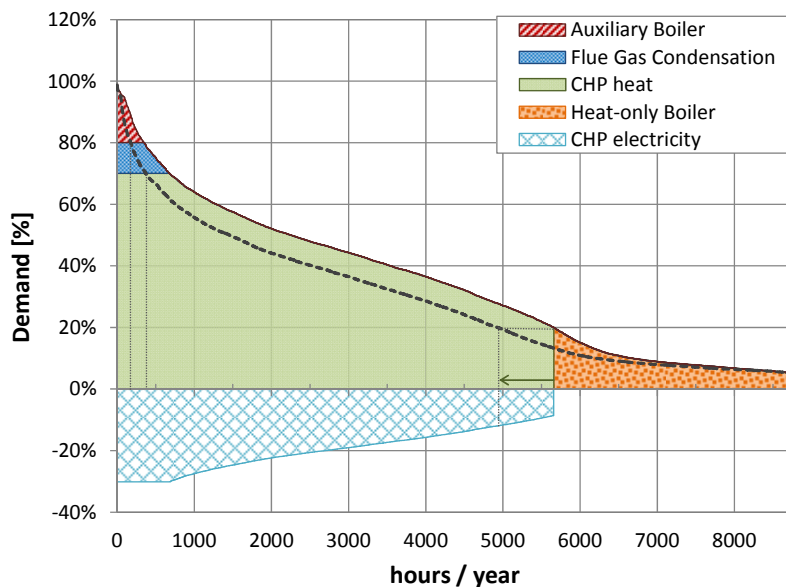


Figure 1. Load duration curve (LDC) and heat production units supplying the DH network: The LDC shows the DH network supplied mainly by the CHP plant, with additional heat recovery through flue gas condensation (FGC) and supported by heat only boilers. The dotted line represents the shifted heat load profile occurring when all the network customers would have sustained a moderate renovation to become more energy efficient.

Moreover, to estimate savings and revenues, two parameters are required: the electricity tariff paid for the pumping work, and the electricity market spot price at which the CHP electricity is sold. All prices vary throughout the year, so average values were used for these periods. **Table 1** shows the corresponding costs and prices of the heat production units and electricity. When several heat production units are operating simultaneously, the marginal cost of heat generation is established by the unit with the highest cost, corresponding to the last produced MWh (the most expensive).

Table 1. Heat Production Units Capacity and Costs

	Maximum Capacity	Marginal Cost of Heat (average) Ref. [14]	Electricity Market Spot Price (CHP) Ref. [15]	Electricity Tariff (avg.) Pumping Ref. [16]	Annual Heat Production (baseline scenario)
	MW_{th}	EUR/MWh_{th}	EUR/MWh_{el}	EUR/MWh_{el}	GWh_{th}/yr
Heat-only boiler	5	<u>69</u>	-	59	9.1
CHP (partial load)	17.5	<u>62</u>	22	55	56.8
CHP (full load) + FGC	17.5 + 2.5	<u>62</u> , 10	30	51	7.2 + 0.3
CHP + FGC + Aux. Boiler	17.5 + 2.5 + 5	62, 10, <u>84</u>	30	51	7.1 + 0.9 + 0.8
Network Total	25				82.1

Table 1. The characteristics of the heat generation units in place for the baseline scenario are shown. The marginal cost of heat generation depends on each production unit, being the highest for the auxiliary (peak-only) boiler. Electricity prices and tariffs vary slightly from summer to winter, so average values are used for each period.

2.2. Modelling: substations, subnets, & representative network

In order to study the temperature profile of the piping in an accurate and simplified manner, a single linear network branch was modelled. The loads on this representative branch are assumed to be of the same magnitude and regularly distributed along the length so as to define a constant baseline. Each load (customer) represents a subnet coupled by an individual DH substation, all with similar load and temperature patterns.

The substations allow hydraulic separation from the main network as well as the operation at different temperature levels. In this analysis, the substations are firstly assumed to operate with a conventional DH temperature programme (100-40/43-60), and they are gradually replaced by LTDH substations. This replacement occurs at the subnet level assuming large buildings are renovated or secondary networks with a group of customers are refurbished. The various load and temperature dynamics inside the subnets are aggregated in the substation patterns as hourly steady-state conditions. It is assumed that all substations present similar patterns.

In order to compare the impact of the LTDH subnets on the primary network, one LTDH substation arrangement is simulated and compared to a conventional substation selected as a reference. The reference substation is based on commercially available equipment [12], suitable for this type of application (a multi-dwelling building with c.a. 50 multi-family households). Each substation is designed for a nominal load of 250 kW_{th} that is assumed to occur when the outdoor ambient temperature reaches -20°C. For this study, the outdoor ambient temperature distribution data used correspond to a Typical Meteorological Year (TMY) which is a statistically representative year at the selected location, in this case Stockholm, Sweden. The data are obtained from the uniform meteorological data base Meteonorm [13].

To study and compare the performance of the network, substations and subnets, a thermodynamic simulation model of each system was developed. A particular toolbox, detailed in [11] and based on Matlab/Simulink, was employed containing the thermodynamic models of most of the components, and the numerical models were then solved by the software internal optimization algorithm.

2.2.1. Operating temperatures and flows

Two of the main parameters that determine the operating costs of a DH network are the supply/return temperatures and the mass flow rate. The temperatures are related to the distribution losses and the mass flow rate to the pumping power. The supply flow temperature is defined by the heat production unit. The supply mass flow rate is calculated with **Equation (1)** as the addition of the flow rates demanded by the individual substations according to the corresponding loads, plus the make-up water flow required to compensate for heat losses.

$$\dot{m}_{tot} = \sum_1^n \dot{m}_n + \dot{m}_{q_loss} = \sum_1^n \frac{\dot{q}_n}{(h_s - h_{sr})} + \frac{\dot{q}_{loss}}{(h_s - h_r)} \quad (1)$$

Where \dot{m} is the mass flow rate, n the number of substations, \dot{q} the load per substation, and h the specific enthalpy of the flowing water. The subscripts are s for supply, r for return, and sr for the substation return (outlet).

The return mass flow rate is equal to the supply, but the temperature profile varies depending on the individual substations return temperature and flow. In order to calculate the local temperatures of the return flow a mixing flow equation is used. The temperature is then calculated from the local enthalpy values as in **Equation (2)**:

$$\dot{m}_{tot} h_{tot} = \sum_1^n \dot{m}_n h_n \quad (2)$$

2.2.2. Distribution heat losses

In DH networks, the magnitude of distribution heat losses generally have a rather uniform distribution throughout the year, particularly for the return pipe whose temperature has comparatively less variation than the supply pipe [17]. For the latter, losses are slightly lower in summer compared to winter due to the lower supply temperature set by the utility during the non-heating season. Therefore, while absolute losses are rather uniform throughout the year, relative losses are the highest during summertime when loads are the lowest.

The overall heat transfer resistance between the DH water and the environment is mainly composed of the thermal resistance of the insulation and the thermal resistance of the ground; the thermal resistance of the pipe wall and the convective resistance at the surface water-pipe are in practice negligible compared to the other two. This heat transfer resistance is in reality dependent both on temperature and time: the time dependency due to ageing of the pipes. In this analysis, the steady-state loss is estimated using a constant average value for thermal loss coefficient; this approach commonly employed yields acceptable results from the engineering point of view. In this case, two values are used: one for the supply pipe and another for the return, in order to account for the dependence on the average supply/return temperatures: $\lambda_{eq_s} = 0.520 \text{ W/m_K}$ and $\lambda_{eq_r} = 0.505 \text{ W/m_K}$, which are within the typical value range of newly built DH piping in northern Europe [18].

In this study, the distribution losses are calculated for steady-state conditions, and the total heat loss in the network is calculated as the sum of the individual heat losses in each pipe section assuming regularly distributed loads. The temperature drop along the pipes due to distribution heat losses is at this point neglected. The heat losses per pipe section can be calculated as:

$$\dot{q}_s = (t_s - t_g) \cdot \lambda_{eq,s} \cdot l \quad (3)$$

$$\dot{q}_r = (t_r - t_g) \cdot \lambda_{eq,r} \cdot l \quad (4)$$

Where \dot{q} represents the heat flow from each pipe in kW, t_s and t_r are the supply and return temperature of the pipes respectively, t_g the undisturbed ground temperature, λ_{eq} the equivalent thermal coefficient in W/m_K (for a buried one pipe/conduit in a two-pipe system) and l the length of the pipe section. The undisturbed ground temperature is approximated [19] as the average air temperature for the defined period.

Heat losses are also proportional to the pipe diameters, which are larger near the supply unit or backbone distribution loops, and smaller at the end of branches. In this case, the lambda coefficients used assume an equal average pipe diameter [20]. The total distribution heat losses are calculated using a representative network branch of 20.5 km length. Typically, for piping types of two buried pipes (or conduits), the ratio of losses from the supply pipe to the return pipe hold a relation of at least 2:1, i.e. for every kW of heat lost in the return pipe, 2 kW or more are lost in the supply pipe. Hence, the heat loss occurring in the return pipe would count up, in average, to a maximum of one third of the total heat loss.

2.2.3. Pumping Effort

Pumping work is necessary to circulate the flow from the heat production unit to the customers. Thus, the pumps have to be able to overcome the pressure drop due to friction and keep the differential pressure between the supply and return pipes of the critical customer above the minimum. For a given load, a reduction in the return temperature increases the temperature difference between the supply and return, and so the delivery capacity of the network. Thus, the total energy input required for pumping and its related costs are lower.

In this analysis, the pumping power is calculated using the characteristic curve of an existing pump and determining the power for the different operating points depending on the volumetric flow and head [21]. As variations in pressure drop are neglected, and with a constant pressure difference required at the critical customer, the pressure head is assumed constant.

2.2.4. Additional heat and power generation

Lower return temperatures have a positive effect on CHP plants and increase the available heat recovery from exhaust gases. It also benefits renewable energy systems such as solar and geothermal, as well as heat pumps allowing higher operating efficiencies.

The flue gas condenser (FGC) recovers latent heat of the water vapour content of the exhaust gases resulting from the combustion process. The recovered heat is then used to preheat the DH water before entering the main plant HEx, resulting in an improvement on the plant efficiency. A lower return temperature increases the cooling capacity of the FGC, so more moisture is condensed, and thus more latent heat is recovered. The economic advantage of the FGC lays on the fact that fuels are priced according to their dry energy content –Low Heating Value (LHV). Therefore, the heat recovered with this technology is not priced. For this reason, the marginal cost of heat production of a FGC is very low, around 5-10 EUR/MWh, compared to the fuel driven heat plant.

FGC increases the total heat recovery in a range from 10% to 35% depending on the technology and the fuel characteristics. In this analysis, a maximum value of 14% is used, typical for gaseous fuels. Also, in terms of the return temperature, the heat recovery at the FGC unit is assumed to increase 1% over the total heat production per every 5 °C reduction of the return temperature [7].

Regarding electricity generation, the return temperature has also an important effect on 2-stage CHP plants where electricity generation is driven by the heat production. The Power-to-Heat ratio, also referred as *alpha value*, expresses how many MW of electricity are produced per every MW of heat, shown in **Equation (5)**. Only heat recovered in the condensers is considered (heat recovery from FGC is excluded), and is influenced by various operating parameters, the return temperature being one of them. As the return temperature decreases, the alpha value increases making it possible to generate more electricity for every MW of total heat produced.

$$\alpha = \frac{P_{el}}{P_{th}} \quad (5)$$

Although the *alpha value* varies slightly throughout the year, in this study a constant average value of 0.43 is selected as baseline and the increase of electricity production is assumed to be 5 kW_{el}/MW_{th} for every 10°C reduction of the return temperature [7]. Although this amount may not seem significant enough from the energy perspective, from the economic point of view it is valuable due to the electricity sales in a yearly basis.

2.3. Estimation of savings and additional revenues

The thermodynamic assessment yields as main outputs: the total mass flow, the temperature profile of the return pipe of the branch, and the return temperature at the heat plant. The savings and additional revenue are calculated based on the baseline scenario without LTDH. The savings are defined and estimated in terms of heat losses and pumping energy, while the earnings are the additional electricity generation from the CHP and additional heat recovery from the FGC. The total is calculated using the prices from **Table 1**, and **Equation (6)**:

$$S = Q_{loss_sav} \cdot C_{mch} + E_{pump_sav} \cdot C_{el_tariff} - 0.75 \cdot E_{pump_sav} \cdot C_{mch} + E_{CHP} \cdot C_{el_spot} + Q_{FGC} \cdot C_{mch} \quad (6)$$

Where Q represents heat saved or produced, E_{pump} the energy saved in the pumps, E_{CHP} the additional electrical energy produced by the CHP; C_{mch} is the marginal cost of heat production; C_{el_tariff} , the electricity tariff and C_{el_spot} the electricity market spot price. Note that it is assumed that on average 75% of the pumping work is converted into heat, thus the equivalent saved pumping energy has to be produced as heat at the corresponding marginal cost.

3. Results & Discussion

The influence of the LTDH subnets on the network operation is assessed in an annual scenario. The LTDH substation type is considered to gradually replace the conventional DH substations, so as to benefit the DH return operation by yielding a lower aggregated return temperature at the heat plant. For this evaluation, the input operating parameters in terms of the average values of each corresponding period are described in **Table 2**. The reduction on the heat demand due to energy efficient building renovation modifies the operating hours of each heat production unit (see **Table 2**, and in **Fig. 1** the dotted line).

3.1. Distribution heat losses and pumping effort

The first section of these results comprises the impact of the LTDH penetration on the two operating parameters related to distribution costs: heat losses and pumping energy. It is estimated that if the demand reduction due to end use energy efficiency savings would occur at the conventional DH temperature levels, the relative losses would increase from 13% to 15.3%. **Figure 2** compares the relative heat losses as a function of the percentage of LTDH load. It is found that, despite the reduced heat demand, the lower return temperature keeps the relative heat losses at a similar level instead of increasing, and so the cost per MWh of heat delivered is also maintained.

Table 2. Heat production units and operating conditions

	Operating hours (baseline)	Operating hours (20% reduction in SH demand)	t_{amb} (avg)	t_s (avg)	t_r (avg)	LT_s (avg)	LTr (avg)	Relative Losses
	hr/yr	hr/yr	°C	°C	°C	°C	°C	%
Heat-only boiler	3100	3830	14.9	74.2	49.7	54.8	32.8	34.22
CHP (partial load)	4980	4560	2.2	83.9	44.7	55.7	29.0	11.39
CHP (full load) + FGC	330	195	-7.5	92.6	44.5	56.5	27.4	7.62
CHP + FGC + Aux. Boiler	350	175	-11.3	96.5	46.9	56.3	27.0	6.56
Network (annual)	8760	8760	5.3	81.7	46.3	55.2	30.1	13.05

Table 2: The operating conditions of the heat production units and the primary and secondary networks are detailed. Relative losses are considerably higher during the periods of low heat demand. The difference in operating hours of the units with higher capacity is due to the building renovation and so the shift in the load duration curve.

This result is similar to that of a previous study [8] where the authors compare the relative heat losses, assuming a 20% annual heat demand reduction, in a conventional DH network compared to a LTDH network. In that study, the authors estimated that the relative losses in conventional DH would increase from 10.9% to 13.1%. Conversely, with the LTDH operation they found that it is possible to maintain the annual relative heat losses at 11.2% maximum.

With respect to the pumping effort, we analyse the ratio of energy required for pumping throughout the year to the total heat delivered: relative pumping energy demand. The results show that the ratio decreases in spite of the reduction in annual heat demand (see **Fig. 3**); and this is due to the increase in the network operating ΔT caused by the lower return temperature, as well as the decrease in distribution losses. If this demand reduction would occur holding the conventional DH temperature levels, the relative pumping power would increase to 1.31%.

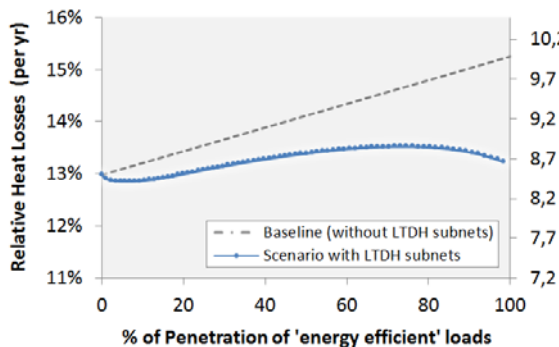


Figure 2. Relative losses as a function of 'energy efficient' load percentage: the two curves refer to both axes, the relative losses shown on the left, and the equivalent annual cost on the right. Due to operation with LTDH, relative heat losses are kept in a similar level in spite of the total 15% demand reduction due to energy efficiency savings. The dotted line represents the increase in relative heat losses assuming the demand reduction occurs with conventional DH temperature levels.

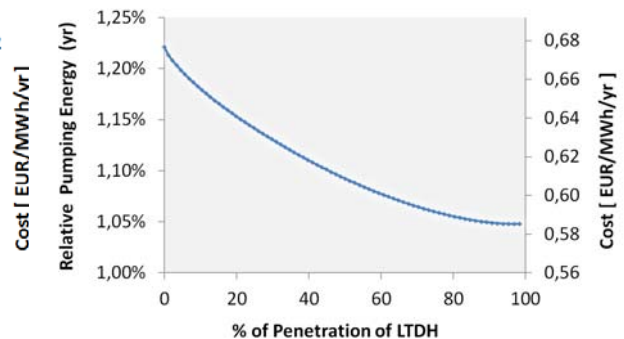


Figure 3. Pumping energy relative to the annual heat demand as a function of LTDH load percentage: the relative pumping energy demand (left axis) and the corresponding related costs (right axis) decrease due to the LTDH return temperature levels; if the demand reduction due to renovation would occur with the conventional DH temperature levels the value would increase; instead with LTDH, it decreases from 1.22% to 1.05%.

In absolute terms of savings in distribution heat losses and pumping energy, it is estimated that for a 10°C drop in the return temperature, there is a reduction of 6.7% in total distribution heat losses and 23% in total pumping energy. This occurs when LTDH penetration would reach 75%. According to previous studies [7], for a 10°C drop in the return temperature the heat loss reduction expected would be around 6%, and the pumping energy would be reduced by 40% approximately. The difference in the latter figure is partly because the present study considered a constant differential pressure at the heating plant, and so constant pressure drop along the network. Still, this difference is also partly attributed to the fact that in the current study the variations in pumping efficiency are considered using curves of existing equipment: the operating efficiency decreases when the pumped flow reduces.

3.2. Annual savings and additional revenues

The total savings and additional revenues are calculated using the results from the previous analysis, and taking into consideration the total annual heat delivered. As seen from **Fig. 4a**, the combined potential revenues and savings increase as the percentage of LTDH also increases. It is possible to conclude that although the annual heat demand decreases due to the renovation, the costs for supplying each MWh of heat also decrease. Then, as seen from **Fig. 4b**, most of the savings are driven by the heat losses which have a larger share at low percentage of LTDH, which slowly decreases and then increases again.

Consider different points of the curve shown in **Fig. 4a**, for instance, *a*) at 10% penetration of LTDH the total cost reduction would be 19.5 k€/yr distributed as: 68% heat losses, 14% pumping costs, 8% CHP electricity, and 10% FGC heat. This represents 2.8% of the total costs of heat losses of the baseline scenario, achieving a reduction of ~1.5°C in the return temperature at the heating plant. Moreover in Sweden, with the green certificate system in place, additional earnings are generated, due to the extra 54.7 MWh_{el}/yr which can be produced by the CHP plant (not shown in the figures). In a second example: *b*) a return temperature drop by 10°C (occurring at 75% penetration of LTDH) leads to a total cost reduction of 65.6 k€/yr distributed as: 57% heat losses, 18% pumping costs, 12% CHP electricity, and 13% FGC heat. This represents 9.7% of the total costs of heat losses of the baseline scenario. In this case, 297 MWh_{el}/yr extra are produced by the CHP plant that would become additional earnings from the green certificate system.

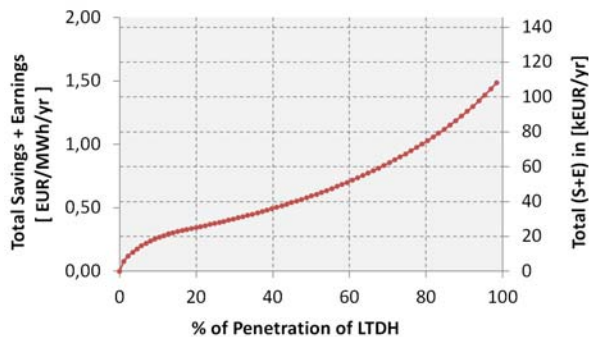


Figure 4 a) Total Savings & Earnings

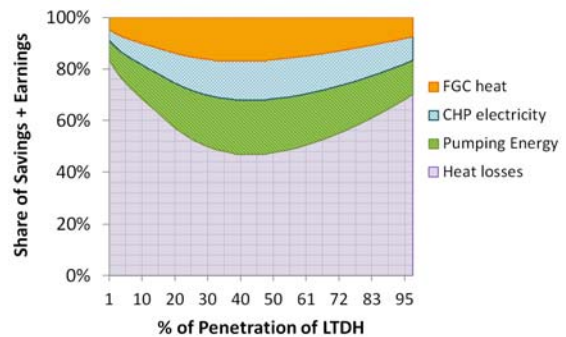


Figure 4 b) Share of Savings & Earnings

Figure 4. Total savings plus revenues as a function of LTDH load percentage: The curve (a) shows a positive relation between savings and the increase of LTDH load. Moreover, the proportion of the contribution of savings and earnings varies depending on the LTDH load percentage (b). It is also noted that more than half of the total amount is given by the savings in heat losses.

Figure 4a, shows the savings per MWh as a function of the percentage of penetration of LTDH subnets. In order to supplement this information, **Fig. 5** shows the cost reduction gradient also as a function of LTDH penetration. This value represents the amount, in EUR, that the utility saves, per MW produced, and per each deg. C reduced in the return flow which is a meaningful parameter to evaluate DH systems refurbishment projects [18]. In this case, the reduction in the return temperature is given as a result of substitution of conventional DH subnets LTDH feeding

energy efficient loads. As seen from the figure, the savings don't present a linear behaviour such as the reduction in return temperature; the gradient becomes smaller as LTDH penetration increases. This means that, although all LTDH loads contribute to a similar reduction of the return temperature, the first loads that are replaced or refurbished contribute to more savings per °C reduced. As the penetration percentage increases, the additional LTDH loads don't contribute as much in savings per °C, as the initial ones.

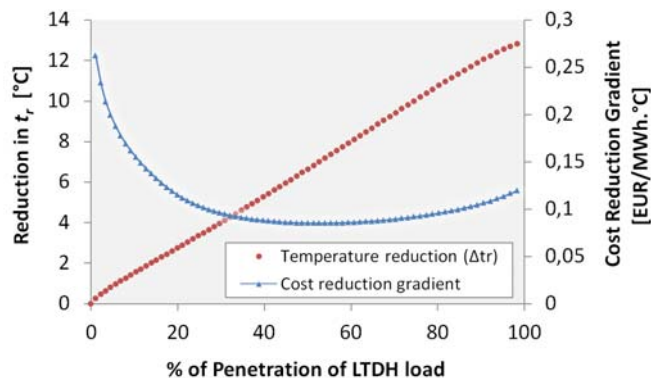


Figure 5. Cost reduction gradient and temperature reduction in the return flow: Although the return temperature at the heating plant decreases continuously with higher penetration of LTDH, the cost reduction gradient behaves in a different manner. The cost reduction is higher at low penetration of LTDH and as the penetration increases, the gradient shows a decline.

3.3. Overall discussion & outlook

With respect to the decrease in operating hours of the heat production units caused by the future reduction in heat demand due to renovation for energy efficiency, there are both advantages and drawbacks: on the one hand, it reduces the operating hours of the auxiliary (peak only) oil boiler and thus the amount of heat produced which is beneficial, considering its higher marginal cost and GHG emissions, but the operating hours of the heat-only boiler increase; on the other hand, it also reduces the operating hours of both the FGC, which produces heat at a very low marginal cost, and the CHP, such that less electricity is generated during the year (ref. Table 1). Nevertheless, in a long term perspective it also means that additional customers can be connected to the network without causing bottlenecks or increasing peak demands, and thus additional investments can be postponed or avoided.

The impact of changing the network operating temperatures can be conflictive for costs reduction. Therefore, a careful evaluation is needed with respect to each DH system. The potential savings of the combined measures should be then compared with the respective investment costs and/or depreciation, such that the most economical alternative is chosen. Still, in most cases, lowering the network operating temperatures leads to reduced operating costs, and if the investment necessary for achieving these lower temperatures based on LTDH are balanced, an improvement in economic performance is achieved.

The substitution of conventional DH loads by LTDH is a process that will occur gradually spanning several decades. Therefore, the utilities will have to adapt to the different conditions and plan their investments carefully. A possible alternative to use the low-temperature flow from the LTDH substations directly would be to add a third pipe to separate the primary return from the low-temperature return. Nevertheless, due to the higher investment costs the returns might not balance the investment.

In the future, as the penetration rate of LTDH increases, it might be possible to lower the supply temperature a few degrees. Consequently, distribution thermal energy losses would substantially decrease, and since the losses on the supply pipe represent more than two thirds of the total losses, larger savings would be then achieved. Nonetheless, this reduction may come at the expense of increased mass flow rate and thus, increased pumping energy and its related costs.

4. Concluding Remarks

This study presented a techno-economic assessment of the impact of LTDH loads & subnets in a conventional DH network considering both reductions in the return temperature and heat demand due to end use energy efficiency savings. The outcome comprises, besides the technical assessment, an economic estimation of the savings and potential revenues in the defined scenario. The key takeaways of these results are:

- With the reduction in return temperature, due to the LTDH loads & subnets, relative distribution heat losses are maintained at a similar level despite the decline in heat demand.
- Relative pumping power decreases due to the combination of lower return temperatures and lower heat demand.
- For a 10 °C drop in the return temperature, there is a reduction of 6.7% in total distribution heat losses and 23% in total pumping energy.
- With the combination of savings and additional revenue, despite the demand reduction, the costs for heat supply relative to the total demand still decrease.

These results represent a step forward in understanding the advantages and drawbacks of the next generation DH technologies that will shape the future smart energy system.

Acknowledgements

The research presented is performed within the framework of the Erasmus Mundus Joint Doctorate SELECT+ ‘Environomical Pathways for Sustainable Energy Services’ and funded with support from the Education, Audio-visual, and Culture Executive Agency (EACEA) of the European Commission under Erasmus Mundus Action 1 programmes. This publication reflects the views only of the author(s), and the Commission cannot be held responsible for any use which may be made of the information contained therein. The lead author would also like to express his gratitude to the National Council on Science and Technology (CONACYT) of Mexico for providing supplementary funding.

References

- [1] DHC+ Technology Platform (2012) ‘DHC Strategic Research Agenda’, Euroheat and Power, Brussels, Belgium, March 2012
- [2] A. Hepbasli, (2012) ‘Low exergy (LowEx) heating and cooling systems for sustainable buildings and societies’, in *Renewable and Sustainable Energy Reviews*, Volume 16, Issue 1, January 2012, Pages 73-104
- [3] B. Rezaie, M.A. Rosen, (2012) ‘District heating and cooling: Review of technology and potential enhancements’, in *Applied Energy*, Volume 93, May 2012, Pages 2-10
- [4] I. Andrić, N. Gomes, et. al. (2016) ‘Modeling the long-term effect of climate change on building heat demand: case study on a district level’, in *Energy and Buildings*, doi:10.1016/j.enbuild.2016.04.082
- [5] A. Dalla Rosa, J.E. Christensen (2011) ‘Low-energy district heating in energy-efficient building areas’, in *Energy*, Volume 36, Issue 12, December 2011, Pages 6890-6899
- [6] H. Lund, S. Werner, et. al. (2014), ‘4th Generation District Heating (4GDH): Integrating smart thermal grids into future sustainable energy systems’, in *Energy* 2014;68:1-11
- [7] H. Zinko, (2005) ‘IEA ANNEX VII: Improvement of operational temperature differences in district heating systems’, Senternovem, Netherlands, March 2005 | 2005:8DHC-05.03
- [8] Y. Xing, A. Bagdanavicius, et. Al. (2012), ‘Low-temperature district heating network planning with focus on distribution energy losses’, in: *ICAE 2012: Proceedings of the International Conference on Applied Energy; 2012 July 5-8; Suzhou, China. ICAE2012-A10103*
- [9] H. Wallatun, (2002) ‘Description of Lava calculus for calculation of district heating network temperature economy’, ZW working document, Nyköping, Sweden 2002
- [10] P.-O. Johansson, K. Jonshagen, and M. Genrup. (2009), ‘Influence of district heating temperature level on a CHP station’, in: *ECOS 2009: Proceedings of the 22nd International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems; 2009 Aug 31- Sep 3; Foz do Iguaçu, Brazil.*
- [11] Thermolib [software toolbox], Modeling of thermodynamic systems in Matlab/Simulink – Available at: <<http://www.thermolib.de/>> [accessed 15.04.2016]

- [12] Alfa Laval, Midi Compact (Swedish market) [datasheet] – Available at: <<http://www.alfalaval.com/solution-finder/products/district-heating-systems/pages/documentation.aspx>> [accessed 08.09.2014].
- [13] Meteonorm [computer software], Global Meteorological Database – Available at: <<http://meteonorm.com/products/meteonorm-dataset/>> [accessed 12.04.2015]
- [14] Swedish Energy Market Inspectorate, ‘The accounts of district heating companies’, [datasheet] – Available at: <<http://ei.se/sv/Fjarrvarme/inrapporterad-data/>> [accessed 04.04.2016].
- [15] NordPool ‘Elspot prices SE’, [datasheet] – Available at: <<http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/SE/Monthly/?view=table>> [accessed 04.04.2016].
- [16] Statistics Sweden ‘Priser på el för industrikunder 2007’, [datasheet] – Available at: <http://www.scb.se/sv/_Hitta-statistik/Statistik-efter-amne/Energi/Prisutvecklingen-inom-energiomradet/Energipriser-pa-naturgas-och-el/24719/24726/Genomsnittspriser-per-halvar-2007/212961/> [accessed 04.04.2016].
- [17] B. Bøhm (2001) ‘Experimental Determination of Heat Losses from Buried District Heating Pipes in Normal Operation’, in Heat Transfer Engineering, 22:3, 41-51
- [18] S. Frederiksen and S. Werner (2013) District Heating and Cooling, Studentlitteratur AB, Lund, 2013, pp. 586
- [19] American Society of Heating, ‘Refrigerating and Air-Conditioning Engineers’, (2009) ASHRAE Handbook—HVAC Systems and Equipment :: District Heating and Cooling. Atlanta, GA: American Society of Heating, Refrigeration and Air-Conditioning Engineers.
- [20] Vesterlund, J. Sandberg, et. Al. (2013), ‘Evaluation of losses in district heating system, a case study’, in: ECOS 2013: Proceedings of International Conference on Efficiency, Cost, Optimization, Simulation and Environmental Impact of Energy Systems; 2013 July 16-19; Guilin, China.
- [21] Grundfoss, 5TUF13B -2-UL-1/9-P-M-MA-R - 98907334 [datasheet] – Available at: <<http://product-selection.grundfos.com/product-detail.product-detail.html?custid=GMA&productnumber=98907334&qcid=110578220>> [accessed 10.04.2016]
- [22] J.E. Thorsen, O. Gudmundsson and M. Brand (2014), ‘Performance Specifications for heat exchangers of district heating substations of the future’, in: DHC14: Proceedings of The 14th International Symposium on District Heating and Cooling; 2014 Sep 7-9; Stockholm, Sweden. Swedish District Heating Association: ISBN 978-91-85775-24-8