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Research paper

Transition towards university campus carbon neutrality by connecting to city district heating network

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ABSTRACT

The campus of Tallinn University of Technology consists of 26 buildings with a total annual heat demand of approximately 20 GWh. A local natural gas-fired boiler provides annually approximately 13 GWh of heating to 12 buildings in the campus and 14 buildings are connected to district heating system. This paper analyses the possibilities of replacing the natural gas boiler with district heating. Two systems were modelled using EnergyPRO software and compared to the reference system of the local boiler and heating network: connection to an existing high-temperature district heating network and a low-temperature energy cascade. All the three systems were modelled with two different energy price scenarios. The results were analysed from the perspective of the university campus and the entire city's system. The low-temperature energy cascade connection to the city's network will reduce carbon dioxide emissions by 955 tonnes CO_2. The conventional high-temperature connection would reduce the emission by 765 tons CO_2. District heating connection will also lead to primary energy savings supporting the university's efforts towards achieving its sustainable development goals. The low-temperature energy cascade utilising the return water of the city's district heating network reduces the heat losses and increases the efficiency of heat and electricity production when compared to the systems with separate campus heating or the conventional high-temperature district heating.

1. Introduction

Many universities around the world have set their own goals for decarbonising campuses. They also support the transition to more sustainable energy systems by providing expertise and developing new technologies (International district energy association, 2021). District heating (DH) is not as widespread in North America as it is in Europe, which is why universities have pioneered the development of district energy systems on their campuses. According to Han et al. (2021), university campuses are suitable places for the development and testing of district energy systems, thereby helping the urban transition to more sustainable energy systems; however, lack of regulation and investment support are the most significant obstacles to expanding the campus district energy systems to nearby cities. Eriksson et al. (2015) studied the retrofitting of three university campuses in the Nordic countries, with a focus on economic, environmental, and social sustainability. According to the study, university learning hubs bring together people with different backgrounds and expertise. Universities can provide a conducive environment for innovation and entrepreneurship and facilitate collaboration between academia and industry.

Murray et al. (2020) used multi-objective optimisation to investigate the optimal methods for reaching the Swiss CO_2 reduction targets. The results show that energy efficiency measures on a district level in urban areas are favourable over measures on individual buildings, whereas district energy systems face barriers in rural areas. If a district energy system is highly developed in a certain area, further CO_2 emission reductions by retrofitting buildings become more expensive. In a building level, reaching the climate targets would require abandoning fossil fuel-based heating systems. Romanchenko et al. (2020) created a model to study the balance between energy efficiency refurbishments in buildings and investments in the DH system. The least-cost solution is a combination of investments on the building stock and heat supply. Kılkış (2021) compared the Turkish city of Çankaya with cities in Southeastern Europe in terms of various sustainability indicators in a case study. Among other sustainability improvements, the paper proposes that the development of a district heating network (DHN) in the area could reduce dependence on natural gas in the heating sector.

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The goal of the Tallinn 2035 development strategy is to make the city a better place to live for its residents and more appealing to tourists while also promoting a green economy and lifestyle (The city of Tallinn, 2020). In terms of climate, the goal is to reduce carbon emissions by 40% compared to 2007 levels and to achieve climate neutrality by 2050. Among other measures to accomplish this, the climate plan also includes expanding the existing DHN and developing a district cooling network (The city of Tallinn, 2021). Sarv and Soe (2021) interviewed a number of city officials responsible for smart city innovations in Tallinn. Many interviewees emphasised the importance of collaborating with universities in the smart city transition. Universities were perceived as knowledge providers rather than decision-making leaders. This paper investigates the university's possibilities to reduce campus CO_2 emissions caused by university energy supply, as well as contribute to the city's sustainable development goals by shifting from fossil-based heating to highly renewable DH.

District heating is already widely used in Estonia, with Tallinn having the country's largest DHN. Tallinn DHN is operated by the energy company Utilitas OÜ, and it provides heat to over 4000 buildings. The total length of the network is 479 km (Utilitas Energy Group, 2021a). The DHN is powered by three biomass-based combined-heat-and-power (CHP) plants, natural gas-fired heat-only boilers (HOB) and a waste incineration plant. In Estonia, renewable electricity generation in CHP plants is supported by a feed-in premium (FIP) of 53.7 €/MWh. Volkova et al. (2020a) used EnergyPRO to investigate the feasibility of introducing heat storage into the Tallinn DHN, where a FIP scheme is applied to electricity generated at biomass-based CHP plants, even if it is generated in condensing mode. This support scheme reduces the benefits of heat storage, as opposed to a support scheme that only subsidises electricity generated in CHP mode.

In district heating systems thermal energy is delivered to the customers via a network of water pipes. Usually, the supply water is heated up to a temperature of more than 100 °C. The supply water cools down in the customers' substations giving energy for space heating (SH) and heating up domestic hot water (DHW). DH water returns to the heat plants to be heated up again. However, the high supply and return temperatures increase the distribution losses and hinder the introduction of some low-temperature heat sources to the network. In the 4th generation district heating concept, the aim is to improve the efficiency of district heating systems by developing low-temperature district heating networks (LTDHN) with supply temperatures between 30 °C and 70 °C (Rämä and Sipilä, 2017).

One of the goals of sustainable development, according to Tallinn University of Technology, is the creation of a smart and environmentally friendly university (TalTech, 2021b). The Climate-smart TalTech by 2035 concept (KliimaNutikas TalTech) envisions an increase in the share of renewable energy in energy supply, an increase in energy efficiency and a reduction of the TalTech campus' carbon footprint (TalTech, 2021a). Developing a sustainable heating system for the campus will help to achieve this goal. Oltmanns et al. (2018) studied various ways to reduce carbon dioxide (CO_2) emissions and primary energy consumption on the campus of the Technical University of Darmstadt in Germany. The implementation of an absorption chiller, the implementation of heat storage, and a reduction in the DH supply and return temperatures to improve network energy efficiency and facilitate the integration of low-temperature heat sources into the system were all considered as ways to improve network performance. Lowering the DH operating temperatures will reduce primary energy consumption due to less heat loss. The introduction of an absorption chiller will increase the use of gas-based CHP plants, so primary energy consumption will be higher than in the lower operating temperature scenario; however, because CHP electricity production emits less CO_2 than grid electricity, increasing CHP production will reduce overall CO_2 emissions. The implementation of heat storage will result in a slight reduction in primary energy consumption and emissions only in the spring and autumn.

Aalto University and Fortum, the local DH operator, have launched a pilot project in Espoo, Finland, to implement a campus-wide low-temperature heating and cooling network. During the first stage of the project, at the beginning of 2021, five buildings were connected to a new LTDHN, which operates alongside the existing DH network (Aalto University, 2020). The supply temperature of the new LTDHN ranges from 35 °C to 45 °C, and it supplies most of the space heating demand in the connected buildings. Heat from the Espoo DHN will still be needed for DHW. The required heat for the LTDHN is generated by two dual-source heat pumps (HP) that use ambient air and waste heat from the cooling network. In addition, a helium production unit, as well as other processes that require a constant source of cooling generate a significant amount of waste heat that can be used in the heating network (Nyrhilä, 2021).

Lowering the operating temperature of DH systems can benefit all three components: heat supply, distribution, and consumer. Lower temperatures reduce distribution losses, and if DH prices can also be reduced by improving system efficiency, consumers will benefit from the transition (Rämä and Sipilä, 2017). According to Li and Wang (2014), DH systems have traditionally been designed with a large safety margin. As a result, large equipment and high supply temperatures are often used. The heating costs of the system can be lowered by reducing system design safety margins and operating temperatures, but this also means that there will be more requirements for more accurate design and operation. In many countries, the minimum DH supply temperature is regulated due to the increased risk of Legionella bacteria at water temperatures ranging from 25 °C to 45 °C (Yang et al., 2016).

Supply temperatures as low as 45 °C may be sufficient to meet space heating (SH) demand in new energy-efficient buildings and buildings with renovated heating systems (Lund et al., 2018). Because distribution pipes and consumer heating systems are often designed for higher temperatures, old infrastructure acts as a barrier to lower operating temperatures in existing DH systems. If the temperature difference between supply and return flows decreases due to lower supply temperature, a higher water flow is required to deliver the same amount of heat, which increases the pumping costs of a DHN. While modern underfloor heating systems can operate at low supply temperatures, radiator-based heating systems may require substation refurbishment and system resizing (Rämä and Sipilä, 2017). Due to these renovation requirements, the transition to lower operating temperatures in existing large-scale DH systems may take a long time (Volkova et al., 2020b). According to Flores et al. (2017), the transition to lower operating temperatures could take decades. During this time, high-temperature district heating networks (HTDHN) and LTDHNs are likely to operate concurrently.

During the transition period, sub-LTDHN could be one of the solutions for implementing LTDH. An LTDHN can be established when a new house is being built or renovated. The network can be isolated from the existing HTDHN by producing its own heat, or it can be supplied by the nearest HTDHN (Köfinger et al., 2016). Volkova et al. (2020b) investigated the feasibility of establishing a sub-LTDHN in a new district of Tallinn. The district is located next to a back-pressure steam turbine (BPST) plant, and the LTDHN will be supplied via the return line of the city's HTDHN. Since the return temperature will not be high enough to meet the district's needs throughout the year, a backup connection to the supply line and a three-way mixing shunt must be installed. The use of return water to supply the LTDHN reduces the return temperature while increasing the efficiency of both the CHP plant's electricity production and the flue gas condenser (FGC). This type of connection will reduce annual heat loss in the HTDHN by 0.18% while increasing annual electricity production by 400 MWh. The LTDHN will have a two-year payback period.

In another study (Volkova et al., 2019), Volkova et al. investigated a small district in Tallinn with a separate LTDHN supplied by a seawater HP and a gas boiler instead of the usual HTDHN connection. According to the study findings, the relative heat loss and primary energy consumption in the LTDHN scenario were significantly lower than in the HTDHN scenario. The use of HPs in the LTDHN scenario resulted in an increase in overall CO_2 emissions. This is due to the high emission factor for electricity generation in Estonia. Although the LTDHN connection required a higher investment than the HTDHN connection, the LTDH production cost was lower than the price of DH in Tallinn.

None of the Estonian case studies mentioned above have been implemented. One of the identified barriers to the implementation of LTDHNs in Estonia is that, while they can provide cost savings for DH operators, consumers and real estate developers do not benefit from energy efficiency improvements due to the regulated DH price structure. This lessens the incentive for developers to invest in heating systems designed for lower distribution temperatures (Volkova et al., 2020b).

Tunzi et al. (2018) conducted a study to optimise supply and return temperatures in a small DHN, where DHW is prepared separately with electric heaters. By optimising the operation of the customers' substations, the average DH return temperature can be lowered from 55 °C to 35.6 °C. Lower return temperature led to 9% decrease of distribution losses, and the efficiency of the biomass boilers improved from 86% to 94%. Tunzi et al. also noted that to successfully lower the return temperature, the DH producer should offer incentives for the end-users. For example, in Denmark, 1% discount in the energy bill can be offered for every 1 °C drop in return temperature.

Puschnigg et al. (2021) conducted a survey of DH companies in Germany and in the Baltic and Nordic countries that have implemented or have considered implementing a sub-LTDHN powered by the return flow of a larger high temperature network. A total of four implemented cases were identified in the survey. Two of those sub-LTDHNs are located in Germany and two in Denmark. In addition to those four companies, five companies had analysed the feasibility of a sub-LTDHN, but had decided not to implement one. Next study on sub-LTDHN has shown, that the most significant technical barriers to cascading are related to possible low return temperatures and mass flow limitations in the HTDHN. This problem can be solved, applying local backup supply units and demand response options in the sub-LTDHN itself (Volkova et al., 2022).

The campus of Tallinn Technical University (TalTech) is located in the Mustamäe district of Tallinn close to the 2019 commissioned biomass CHP plant, making it a suitable place to implement a sub-LTDHN. Currently, only the smallest part of the campus is supplied by heat from the city's DHN. The rest of the campus is heated by a local natural gas HOB, with heat distributed to the buildings via a separate heating network. The aim of this research is to investigate the feasibility of connecting the buildings heated by the local boiler to the city's DHN by comparing two possible connections, a sub-LTDHN connection and a conventional HTDHN connection. The sub-LTDHN will be connected to the city's DHN via a three-way mixing shunt and will primarily use the heat from the DHN return water. If the return temperature is not high enough, an additional connection to the supply line can be used to reach the required temperature level. Using heat from the DHN return line in the sub-LTDHN will reduce its temperature. Lowering the return temperature improves the efficiency of both electricity generation and the CHP plants' FGCs. The impact on production costs, CO_2 emissions, fossil fuel and primary energy consumption is analysed.

The novelty of this paper includes analysis of this option from the perspective of both, the small campus district and the large DHN, and how the CO_2 emission factor would change for the large system when new customers are added to the system. Section 2 describes data and methods, Section 3 shows the numerical results, in Section 4, the results are discussed, and the most important conclusions are drawn in Section 5.

2. Methods

To consider the uncertainty of the future energy prices, two different energy price scenarios were used to model all the three studied systems, thus the total number of scenarios is six (Ref. 1, A1, B1, Ref. 2, A2, B2). Ref. 2, A2 and B2 have higher electricity, natural gas and CO_2 emission allowance prices. Parameters for assessing the feasibility of various types of connections include operating costs, fuel and primary energy consumption, CO_2 emissions, and campus heat loss.

The following Tallinn DHN scenarios were studied:

- Ref. 1 and Ref. 2. The city's DHN and the campus heating network are separate networks. The EnergyPRO software was used to model the city network, and heat consumption data were used for the campus network.
- A1 and A2. The campus is connected as a sub-LTDHN via a mixing shunt. Most of the heat on the campus comes from the Tallinn DHN return line.
- B1 and B2. The campus is connected to the Tallinn DHN via a conventional high-temperature connection.

2.1. Tallinn district heating network

The Tallinn DHN is modelled using the EnergyPRO software version 4.7.66 from EMD International A/S (Aalborg, Denmark). EnergyPRO is widely used in academic research to simulate complex energy systems linking heat and electricity markets (EMD International A/S, 2020). The time resolution used in this study is one hour and the modelling period is one year.

A waste incinerating CHP plant and three biomass-based CHP plants provide the base load of the DHN. Several large-scale natural gas HOBs handle the peak load. During the heating season 2019/2020 56% of DH was produced from biomass, 19% in the waste incineration plant, and 25% from natural gas (Utilitas Tallinn). In the model, all HOBs are treated as a single unit with a thermal efficiency of 95%. In the Tallinn district heating region, the Competition Authority regulates the running order of the DH production units, with the waste incineration plant having the highest priority, followed by the biomass-based CHP plants. The HOBs are last in the running order.

The DHN return temperature affects the efficiency of both FGCs and electricity generation in BPSTs. Lower return temperatures allow a greater proportion of the flues gas's latent heat to be captured in the FGCs. Lower return temperatures also reduce back pressure in the turbines, so more high-pressure steam energy can be converted into electricity.

Lee et al. (2020) studied the performance of a BPST in a combined cycle power plant at different DH return temperatures. The BPST generates a DH load of 203 MW, and, according to the simulation, a 10 °C decrease in return temperature increases the electricity output of the turbine by 983 kW. Flores et al. (2017) used a value of 5 kW_{el} per 10 °C decrease in return temperature per thermal capacity of a turbine condensing unit. This study used actual return temperature data from the Tallinn

Table 1
Production units used in the EnergyPRO model.

	Fuel capacity (MW)	Thermal capacity (MW)	Electric capacity (MW)	Priority number
Iru (waste)	–	50	–	1
Tallinn 2 CHP (wood chips) (Volkova et al., 2020b)	97.9	73.3	21.4	2
Mustamäe CHP (wood chips) (Lepiksaar et al., 2020)	57	45.2	10	3
Tallinn 1 CHP (wood chips) (Volkova et al., 2020b)	92	63.5	25	4
HOBs (natural gas)	775.8	737	–	5

2 CHP plant. After removing obviously incorrect data values, it was discovered that the return temperature ranges from 41.6 °C to 59.9 °C, with an average of 50.0 °C. In this study, it was assumed that the turbines of the CHP plants can produce the design electrical load at the average return temperature, and a 1 °C change in return temperature alters the electric capacity by 0.5 kW $_{el}$/MW$_{th}$. Electricity production capacity per hour can be calculated using Eq. (1), where the thermal capacity of the condensing units of the BPSTs, $\phi^{turbine}$, is 60.1 MW for the Tallinn 2 CHP, 38 MW for the Mustamäe CHP, and 49 MW for the Tallinn 1 CHP. P^{design} is the design electricity production capacity of the turbine, and T_i^r is the hourly return temperature.

$$P_i = P^{design} + \left(50 - T_i^r\right) * 0.5\,\mathrm{k}W_{el}/\mathrm{M}W_{th} * \phi^{turbine} \tag{1}$$

Lepiksaar et al. (2020) created a mathematical model for calculating the effect of the return temperature on the efficiency of FGCs, using measured data from the Mustamäe CHP plant. Reducing the temperature of the DH water entering the FGC will increase the efficiency of heat recovery. The effect of temperature reduction is stronger at higher temperatures. The heat exchange surface area of the FGC sets the limit for heat recovery. When the amount of heat recovered reaches the design capacity of the FGC, a further decrease in the return temperature will no longer lead to an increase in heat recovery.

Since the DH return temperature affects FGC efficiency at the CHP plants, the thermal output of the CHP plant changes depending on the return temperature. Thermal capacity per hour can be calculated using Eq. (2), where $\phi^{turbine}$ and ϕ^{FGC} are the design heat recovery capacities for the turbine and the FGC. This function is used for all CHP plants. The design capacity of the FGC is 16.4 MW for the Tallinn 2 CHP, 9 MW for the Mustamäe plant, and 18 MW for the Tallinn 1 CHP (Volkova et al., 2020b; Lepiksaar et al., 2020).

$$\phi_i^{CHP} = \phi^{turbine} + \eta_i^{\mathrm{FGC}} \phi^{\mathrm{FGC}} \tag{2}$$

The efficiency of the FGC, η_i^{FGC}, was estimated over a return temperature, T_i^r, range of 41 °C to 60 °C using Eq. (3), which is based on the results obtained by Lepiksaar et al. (2020).

$$\eta_i^{FGC} = -0.001381 * {T_i^r}^2 + 0.11478 * T_i^r - 1.4827 \tag{3}$$

Functions (1) and (2) were used in the EnergyPRO model to calculate the thermal and electrical capacity of the CHP plant for each hour. The hourly return temperature was input into the model as a time series. In the sub-LTDHN scenario, a time series of lower return temperatures was used for all CHP plants.

According to the data from Utilitas Energy Group, average return temperature is 50.0 °C. Table 1 shows the calculated capacities of the production units in Tallinn DHN at the average return temperature according to the Eqs. (1)–(3) and the priority numbers of each unit.

In the model, heat is produced in order of priority according to Table 1. CHP units can reject heat if electricity generation in condensing mode is profitable. Because CHP units sell the generated electricity at the hourly price of the Estonian spot market, 2018 spot market data were used (Nord pool AS, 2020). In addition to the market price, a FIP of 53.70 €/MWh is paid for biomass-generated electricity at CHP plants 12 years after construction (Ministry of Economic Affairs and Communication, 2016). The first CHP unit, Tallinn 1 CHP, was commissioned in 2009, whereas Tallinn 2 CHP was commissioned in 2016 (Utilitas Energy Group, 2017), and Mustamäe CHP in 2019 (Utilitas Energy Group, 2019). Therefore, only electricity generated at the Tallinn 2 CHP and the Mustamäe CHP is subsidised. The average price for natural gas in Estonia in 2019, 0.328 €/m^3, was used in this study (Statistics Estonia, 2021). The energy density of natural gas is assumed to be 36.58 MJ/m^3 (0.010 MWh/m^3) (Statistics Finland, 2021). The price of wood chips is 12 €/MWh (Volkova et al., 2020a). Variable operations and maintenance costs (O&M) were assumed to be 1.4 €/MWh$_{\mathrm{fuel}}$ for the CHP plants and 1.1 €/MWh$_{\mathrm{fuel}}$ for the HOBs (Danish Energy Agency, 2020). For the combustion of natural gas in the HOBs, CO_2 emission allowances must be purchased. The price of the allowances is assumed to be 40 €/tonCO2. In 2021, electricity, natural gas and CO_2 prices saw a rapid increase, and therefore additional price scenarios were modelled as well. In 2021, the average electricity price in Estonia was 86.73 €/MWh (Nord pool AS, 2020). The hourly spot market prices of 2018 were scaled up to correspond the higher average price. Also, the emission allowance price was assumed to be 80 €/tonCO2 and natural gas price 50% higher. All production unit costs are listed in Table 2. Combustion of natural gas emits 0.199 t_{CO2}/MWh$_{\mathrm{fuel}}$ (Statistics Finland, 2021). The DH operator in Tallinn, Utilitas, buys heat from the Iru waste incineration plant at a price of 7.89 €/MWh (Enefit Green, 2021).

Table 2
Costs of the fuels and production units.

	Price 1 (€/MWh)	Price 2 (€/MWh)	O&M (€/MWh$_{\mathrm{fuel}}$)
Wood chips (CHP)	12	12	1.4
Natural gas (HOB)	32.28	48.42	1.1
Heat from Iru	7.89	7.89	
Electricity	47.07 (average)	86.60 (average)	–
Electricity FIP	53.70	53.70	–

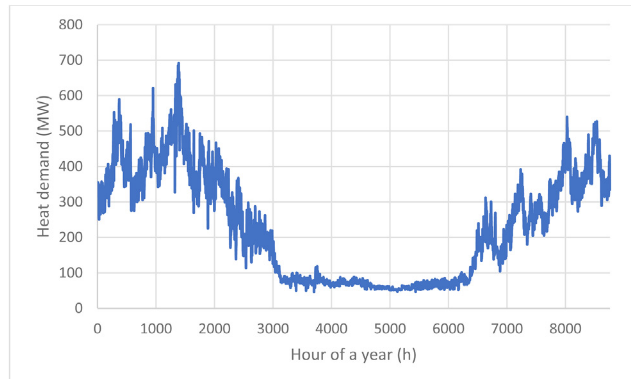

Fig. 1. Tallinn's heat demand.

Tallinn DHN's heat demand was defined using production data from district heating plants. Tallinn's annual demand is 2014 GWh including the distribution losses. In scenarios where the campus is connected to the city's DHN, the heat demand of the campus is added to the city's demand. Fig. 1 shows the heat demand of the city, including heat loss. The annual heat loss is estimated at 13% of the total heat demand, so the amount of heat supplied is 1752 GWh.

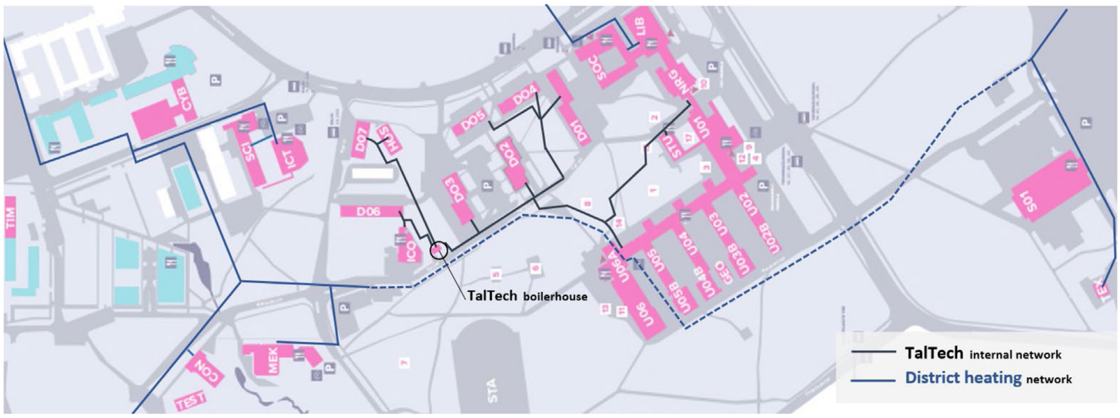

Fig. 2. Local heating network of the TalTech campus.

2.2. Low-temperature energy cascade

The primary energy source of the sub-LTDHN is the return line of the Tallinn DHN. A secondary connection to the HTDHN's supply line ensures that the sub-LTDHN maintains a sufficient temperature level. The local heating network is shown in Fig. 2. It is assumed that the existing heat piping can be used for the sub-LTDHN.

2.2.1. Heat demand

The TalTech campus consists of 26 buildings, 12 of which are currently heated by the local heating network via a TalTech-owned natural gas boiler. This paper investigates the feasibility of connecting these buildings to the Tallinn DHN using two different scenarios: a conventional connection to the HTDHN and a sub-LTDHN connection. The heat demand of the local heating network on campus is based on the 2018 measured monthly heat consumption. 2018 was chosen as a reference year since the data for Tallinn DHN was available only for that year. Heat consumption data for 2018 for the ICO building (Fig. 2) is not available, so the data for 2019 was used instead.

The total annual heat demand of buildings connected to the local heating network is 13,068 MWh. It is assumed that space heating is turned off from mid-May to mid-September, so the heat demand consists solely of the heat required for DHW. The heat demand was 298 MWh in June, 162 MWh in July, and 179 MWh in August, with an hourly heat demand of 41.1 kW, 21.8 kW and 24.1 kW, respectively. Because most on-campus courses are on a break in July and August, DHW demand is lower. At other times of the year, the constant hourly DHW demand is assumed to be 298 MWh per month. Based on these assumptions, the annual DHW demand is 3324 MWh.

Monthly SH demand can be obtained by subtracting the DHW demand from the total demand. Hourly SH demand is calculated separately for each month using heating degree hours (HDh) with a reference temperature of 17 °C. The hourly heat demand Φ_i^{SH} can be calculated using Eq. (4), where Q_{SH} is the monthly space heating demand, Φ_i^{DHW} is the hourly domestic hot water demand. Heating degree hours for hour i, HDh_i, can be calculated using Eq. (5), where T_i^0 is the hourly outdoor temperature. From mid-May to mid-September $HDh_i = 0$. The hourly heat demand of the TalTech campus is available in Fig. 3.

$$\phi_i = \frac{Q_{SH}}{\sum_i HDh_i} HDh_i + \phi_i^{DHW} \tag{4}$$

$$HDh_i = max\{0, 17\ ^\circ\mathrm{C} - T_i^0\} * 1\ \mathrm{h} \tag{5}$$

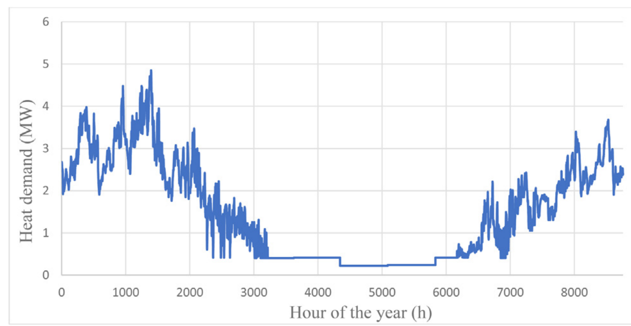

Fig. 3. Hourly heat demand of the local network.

2.2.2. Supply and return temperatures

DHNs are generally designed to increase the temperature difference between supply and return water flows as heat demand rises. The supply temperature is typically set at the heating plant based on the outdoor temperature. On the DH supply temperature control curve presented in Energiateollisuus ry (2006), the supply temperature varies between 75 and 120 °C, so that the minimum value is set when the outdoor temperature is +5 °C or higher, and the maximum temperature is set when the outdoor temperature drops below −30 °C. The supply temperature must be high enough to ensure a sufficient temperature difference in the consumer substations. It is also necessary to account for temperature drops caused by heat loss during distribution (Energiateollisuus ry, 2006).

According to Ref. (Olsen et al., 2014) supply temperature between 50 °C and 60 °C can be sufficient to meet the customer's demand in a properly designed and operated LTDH system during summer. During winter, the supply temperature can vary between 60 °C and 70 °C. Here, it is assumed that the maximum temperature of the sub-LTDHN during winter is relatively conservative 70 °C, and it is used if the outdoor temperature lowers below −20 °C. To avoid the legionella bacteria risk (Toffanin et al., 2021), minimum supply temperature is set to 60 °C. The minimum supply temperature is used when the outdoor temperature is more than +5 °C and during summer when the space heating is turned off. When the outdoor temperature is between −20 °C and +5 °C, the supply temperature decreases linearly as the outdoor temperature rises. In 2018, the minimum temperature in Tallinn was −17.3 °C and average temperature +7.2 °C. Based on these assumptions and the 2018 weather data, the maximum supply temperature is 68.9 °C and the average supply temperature is 61.2 °C.

The return temperature is determined by the heat load and the characteristics of the consumer substations. There is usually little correlation between the return temperature and the outdoor temperature; the return temperature is higher when the heat demand is higher, but the correlation is not as significant as in the case of the supply temperature (Frederiksen and Werner, 2017). According to Ref. (Olsen et al., 2014), the return temperature in a LTDHN can vary between 25 °C and 40 °C. In this paper, it is assumed that the return temperature in the sub-LTDHN is constant at 30 °C.

The mass flow of DH water is calculated for each hour of the year using Eq. (6), where t_i^s is the supply temperature, t_i^r is the return temperature, ϕ_i is the hourly heat demand, and ϕ_i^{loss} is the hourly heat loss. The specific heat capacity of water is assumed to be constant $c_p = 4.18$ kJ/kg K.

$$F_i^{LT} = \frac{\phi_i + \phi_i^{loss}}{c_p\left(t_i^s - t_i^r\right)} \tag{6}$$

2.2.3. Heat loss

Annual heat loss in the local heating network on campus is $Q_{loss} = 1245$ MWh. Based on this, it is possible to estimate the heat transfer coefficient of the entire network U using Eq. (7), where $t_{s,a}$ and $t_{t,a}$ are the average supply and return temperatures of the local network, which are assumed to be equal to the supply and return temperatures of the Tallinn DHN at the Tallinn 2 CHP. Average DHN supply and return temperatures are 84.1 °C and 50.0 °C. $T_{g,a}$ is the average ground temperature, which is assumed to be equal to the average outdoor temperature of 7.2 °C.

$$U = \frac{Q_{loss}}{\left[\frac{1}{2}\left(t_{s,a} + t_{r,a}\right) - T_{g,a}\right] * 8760 \text{ h}} \tag{7}$$

The equation yields the network's average heat transfer coefficient (including the supply and return lines) $U = 2.37$ kW/K. The hourly heat loss ϕ_i^{loss} is calculated using Eq. (8), where t_i^s and t_i^r are the hourly supply and return temperatures described in Section 2.2.2. T_i^g is the hourly ground temperature. At the typical depth of DH pipes, ground temperature follows the changes in outdoor air temperature, but with a couple of weeks lag and a decrease in amplitude (Frederiksen and Werner, 2017). In this study, the hourly ground temperature is estimated by calculating a moving average of the outdoor temperature for the previous two weeks.

$$\phi_i^{loss} = U\left(\frac{t_i^s + t_i^r}{2} - T_i^g\right) \tag{8}$$

2.2.4. Mixing shunt

The sub-LTDHN is connected to the city's HTDHN via a mixing shunt. In the mixing shunt, the flows from the HTDHN return and supply lines are mixed to obtain the required temperature and mass flow in the sub-LTDHN. The energy carrier water of the LTDHN is fed back into the HTDHN return line after it has provided heat to the campus. The connection of the sub-LTDHN to the HTDHN is shown in Fig. 4 (Volkova et al., 2020b).

In the mixing shunt, the required LTDHN mass flow and temperature must be achieved as described in Section 2.2.2. When the cooler return water of the sub-LTDHN is fed back into the return line of the HTDHN, it lowers the return temperature. The reduced return temperature of the HTDHN can be calculated using Eq. (9), where F_i^{HT} is the total mass flow of the HTDHN return water, F_i^{LT} is the mass flow of the sub-LTDHN, T_i^r is the return temperature of the HTDHN and t_i^r is the return temperature of the sub-LTDHN.

$$T_i^{r,mix} = \frac{F_i^{LT} t_i^r + F_i^{HT} T_i^r}{F_i^{HT} + F_i^{LT}} \tag{9}$$

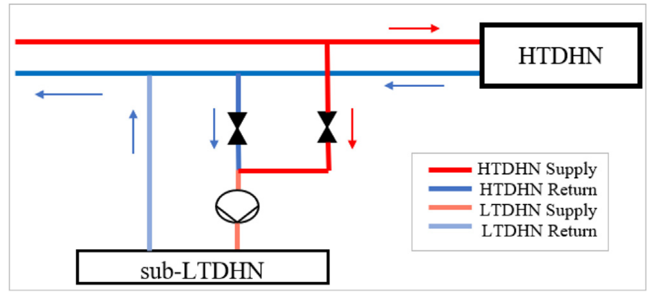

Fig. 4. Illustration of a three-way mixing shunt.

2.3. High-temperature connection to the district heating network

In the scenario of connecting the campus to the HTDHN via a direct connection, the same campus heat demand described in Section 2.2.1 applies. Hourly campus heat loss is calculated using Eq. (8), assuming the same heat transfer coefficient U and ground temperature T_i^g. For the supply and return temperatures T_i^s and T_i^r, the outlet and inlet temperatures of Tallinn 2 were used.

2.4. Primary energy consumption

Primary energy consumption (PEC) can be calculated using Eq. (10), where the primary energy factor (PEF) of natural gas, f_{NG}, is 1, wood chips, f_{Chips}, is 0.75, and electricity, f_{el}, is 2 (Latõšov et al., 2016). According to the methodology for defining PEC of different DHNs, a DHN can be awarded with efficient DH label, if it uses at least 50% of renewable energy, 75% of cogenerated heat, 50% waste heat, or 50% of combination of renewable energy, waste heat and cogenerated heat. The primary energy factor for efficient DH is 0.65 (Latõšov et al., 2022). Since the DH in Iru waste incineration plant is produced in cogeneration mode, the heat purchased from there can be considered as efficient DH, and therefore the PEF of the purchased heat, f_{Buy}, is assumed to be 0.65 (Latõšov et al., 2022). Q_{Buy} is the purchased thermal energy, Q_{NG} is the consumed natural gas, Q_{Chips} is the consumed wood chips, and E_{el} is the electricity generated at the CHP plants. Q_{DH} is the sum of the heat supplied in the Tallinn DHN and in the campus. In the reference scenario, the PEC of the campus local network was calculated separately. Energy efficiency of the system can be evaluated by calculating average PEC of the DHN and marginal PEC. Average PEC is the PEC of the DHN divided by delivered heat, and the marginal PEC is the change of PEC after connecting the campus to the DHN divided by the heat consumption of the campus buildings.

$$PEC = f_{Buy}Q_{Buy} + f_{NG}Q_{NG} + f_{Chips}Q_{Chips} - f_{el}E_{el} \tag{10}$$

3. Results

The CHP plants combusting biomass produce 49% of the annual DH demand. Because of the small heat demand of the campus compared to Tallinn's heat demand, these shares of production do not vary significantly in different scenarios. Natural gas is used for producing 29%–30% of the annual heat demand.

Fig. 5 presents the production graph acquired from the EnergyPRO model. In the production order, the waste incineration plant has the highest priority, which means that the plant operates 8760 h a year. The minimum heat demand in the reference scenario is 46 MW, and for most of the year, the 50 MW waste incineration plant is not enough to meet the demand. Thus, the Tallinn 2 CHP, which is second in priority, operates at full load almost all year round. The FIP payment to the Tallinn 2 CHP

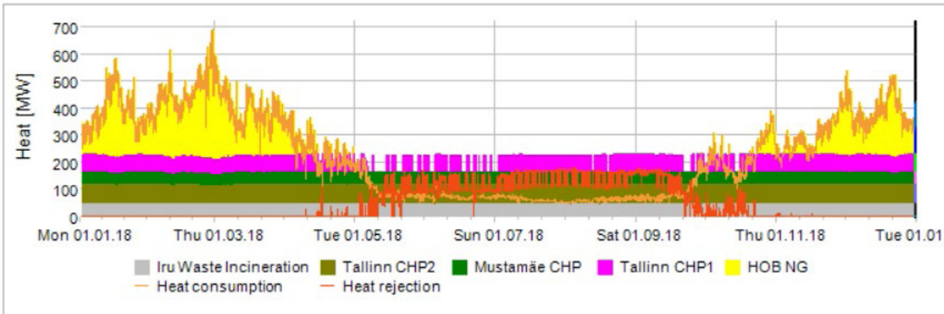

Fig. 5. Heat production in the reference scenario.

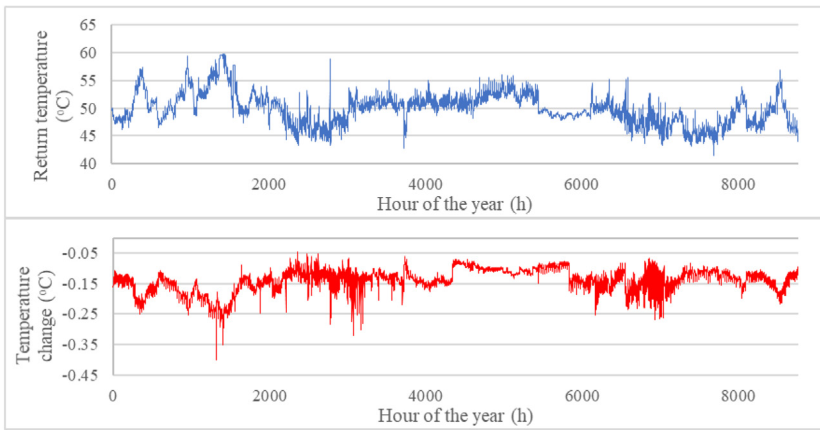

Fig. 6. (a) The reduced HTDHN return temperature due to the sub-LTDHN. (b) Decrease in HTDHN return water temperature due to sub-LTDHN connection.

makes electricity production highly profitable even in condensing mode, and therefore a part of the heat produced by the Tallinn 2 CHP is rejected in the summer. These two plants are sufficient to meet the demand during the summer. The FIP is also paid to the Mustamäe CHP. It operates almost all year round, but in the summer most of the heat produced is rejected. The FIP is not paid to the Tallinn 1 CHP due to its older age, which means that when the heat demand is lower during the summer, there may be more breaks in operation if the spot electricity price is not enough for the production to be profitable. In the scenarios with higher electricity price, the profitability of Tallinn 1 CHP increases significantly even without the FIP. The annual full load hours exceed 8400 h in the scenarios 2 (high prices), while in the scenarios 1 (low prices), full load hours of Tallinn 1 CHP are approximately 6500 h. When the above-mentioned units are unable to meet the demand, natural gas HOBs are used.

In scenarios A1 and A2, after delivering heat to consumers, water from the sub-LTDH is fed back into the return line of the HTDHN, reducing its temperature. On average, the return temperature is reduced by 0.14 °C. The maximum temperature reduction is 0.40 °C. The lower the outdoor temperature, the greater the decrease. Fig. 6 depicts the temperature decrease and the reduced return temperature. These temperature reductions are presented as an average in the entire HTDHN. Locally in the pipeline connecting the sub-LTDHN to the HTDHN, larger temperature reductions can be seen.

Table 3 presents DH production costs per MWh of delivered heat, cost of heating in the local campus network, and the total costs including the DHN and the campus network. Revenues of electricity sales are considered in the production costs by subtracting them from the expenditures. Fuel consumption and CO_2 emissions for different scenarios are given in Table 4. The

Table 3
Production costs of DH and the campus' local network, and the total costs of both of the systems.

	DH production costs (€/MWh)	Campus heating cost (€/MWh)	Total costs (k€)
Ref. 1	11.18	39.74	20 107
A1	11.35	–	20 028
B1	11.38	–	20 075
Ref. 2	8.87	58.95	16 319
A2	9.21	–	16 242
B2	9.25	–	16 316

emission factors (EF) in Table 4 are calculated for MWh of delivered heat with an assumption that the relative heat losses of the existing HTDHN are 13%. In the reference scenario, heat loss at the campus is the same as in Scenario B, and marginal costs were calculated assuming a boiler efficiency of 92% and the same O&M costs and fuel price as for the HTDHN. Since the campus boiler has a capacity of less than 20 MW, it is not subject to the European Union Emission Trading System.

Connecting the campus to the HTDHN increases the consumption of natural gas in the city's DHN faster than the consumption of wood chips, and as a result, the EF of the DHN is rising. However, since the EF of the local heating network is higher than the DHN's, connection to the city's DHN results in total emission savings. Due to the higher heat demand, less heat has to be rejected at the CHP plants when the campus is connected to the city's heating system. Since the running order of the production units is predetermined, the change of natural gas price or CO_2 allowance prices does not have an impact on natural gas consumption. However, the higher electricity price in the scenarios Ref. 2, A2, and B2 makes electricity production in condensing mode more profitable, and thus wood chip consumption in the

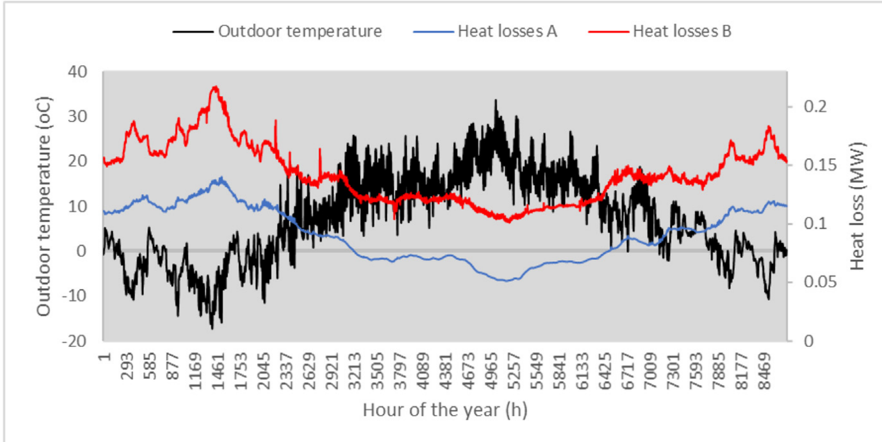

Fig. 7. Heat loss and outdoor temperature.

Table 4
Natural gas consumed for each scenario and emission factors (EF) for Tallinn DHN and the campus' local network. EF = Emission factor, DHN = District heating network.

	Natural gas DHN (MWh)	Natural gas Campus (MWh)	EF DHN (kg_{CO2}/MWh)	EF Campus (kg_{CO2}/MWh)	EF Total (kg_{CO2}/MWh)	CO_2 Total (t_{CO2})
Ref. 1/Ref. 2	623 664	15 558	70.83	236.9	72.06	127 205
A1/A2	634 424	–	71.56	–	71.56	126 250
B1/B2	635 376	–	71.65	–	71.65	126 440

Table 5
CHP fuel consumption, heat and electricity production, and heat rejection in Tallinn DHN.

	CHP fuel (MWh)	CHP heat (MWh)	CHP electricity (MWh)	Rejected heat (MWh)
Ref. 1	1 946 517	1 439 250	436 286	455 686
A1	1 947 871	1 441 441	436 730	454 163
B1	1 948 004	1 440 372	436 682	453 552
Ref. 2	2 133 021	1 568 388	486 462	584 752
A2	2 133 148	1 569 757	486 581	582 478
B2	2 133 163	1 568 493	486 495	581 673

CHP plants increases. Increased use of condensing mode results in higher amount of annually rejected heat. Annually consumed wood chips and rejected heat are presented in Table 5.

When comparing scenarios A and B, it is evident that the sub-LTDHN system is superior due to lower heat loss and increased heat and electricity generation. However, the benefits are not spread equally throughout the year. In the summer, CHP plants operate in condensing mode, resulting in a large amount of unused heat. Consequently, an increase in thermal efficiency and a decrease in heat loss do not affect fuel consumption. Table 6 compares operating costs, electricity sales revenue and net production costs for the months of highest and lowest heat demand. Net operating costs are calculated by subtracting the revenue of electricity sales from the costs.

Including the campus heat demand in the model increased total annual operating costs of the DH operator by about 463 k€ in scenario A1 and by 504 k€ in scenario B1. In the scenarios A2 and B2, the increase is 706 k€ and 768 k€ These cost increases can be viewed as the cost of covering the campus heat demand. Connecting the campus to the DHN increases revenues from electricity production as well, because higher heat demand allows the power plants to run in CHP mode longer. This can be seen especially in the operation of Tallinn 1 CHP, which operates less in condensing mode, so the increase of heat demand affects more in its operation time. In the scenarios of higher electricity price, the CHP plants run in condensing mode more, and for that reason, the increase of heat demand has lesser impact on electricity production. Table 7 presents the campus network's heat losses, efficiency, DH operator's production expenditures, sales of electricity, and marginal costs of heating for of the campus.

The results show that covering the campus heat demand is significantly cheaper for the DH operator in the case of a sub-LTDHN than with a conventional high-temperature connection. The highest production costs were observed in the local heating network reference scenario. The price of district heating in Estonia is set by regulations, and till November 2021 the price in Tallinn was 50.14 €/MWh. Due to natural gas price increase, Competition Authority has approved maximum DH price for Tallinn as 97.15 €/MWh in February 2022 (Utilitas Energy Group, 2021b).

The heat loss on campus can be reduced by 36% by implementing the sub-LTDHN compared to Scenario B or the reference scenario value of 1245 MWh. The absolute heat loss is higher during the colder months. The maximum heat loss in B is 0.218 MW, and in A it is 36% lower at 0.140 MW; however, the decrease in heat loss reduces the peak demand of the campus network by only 1.5%. The hourly heat losses and outdoor temperature are compared in Fig. 7.

Table 8 shows the PEC for the city's DHN and the local campus network, marginal PEC and primary energy savings. In the scenarios A1, A2, B1 and B2, all PEC is allocated to the city's DHN. In the reference scenario, campus PEC is calculated separately for the local HOB.

4. Discussion

4.1. Impact on the city's district heating system

According to the model's results, the base load to the city's DHN is provided by the waste incineration plant and the three biomass-fired CHP plants, which accounts for 22% and 49% shares of annual DH production. The peak demand is produced by natural gas-fired HOBs. The total share of the HOBs in annual production is 29%.

The total costs of the city's DHN and the local heating network decrease, if the local boiler is replaced by heat from the city's

Table 6
Operating costs, electricity sales revenue and net production costs in February and August in Tallinn DHN.

	February (€)			August (€)		
	Operating costs	Revenue	Net production costs	Operating costs	Revenue	Net production costs
A1	9 380 615	2 761 181	6 619 434	2 510 781	3 346 763	−835 982
B1	9 391 406	2 760 377	6 631 029	2 510 785	3 346 286	−835 501
A2	13 398 579	4 134 237	9 264 342	2 754 876	5 526 281	−2 771 405
B2	13 415 661	4 133 060	9 282 601	2 754 879	5 525 525	−2 770 646

Table 7
Costs of covering campus heat demand under different scenarios. The reference scenario is based on TalTech data. In the reference scenarios, total costs are the annual costs of the separate heating network. In the scenarios A1, B1, A2, and B2 total expenditures mean the annual cost increase of the city's DHN resulted by connecting the campus to the DHN. In scenarios A1/2 and B1/2, marginal heating costs are calculated by dividing the difference between cost increase and revenue increase by the total campus heat demand of 13,068 MWh.

	Campus heat loss (MWh)	Campus heat demand (MWh)	Campus network efficiency	Total expenditures (€)	Electricity revenue increase (€)	Marginal cost of heating (€/MWh)
Ref. 1	1245	13 068	91.30%	519 313	0	39.74
A1	799	13 068	94.24%	462 972	21 715	33.77
B1	1245	13 068	91.30%	504 102	16 020	37.35
Ref. 2	1245	13 068	91.30%	770 413	0	58.95
A2	799	13 068	94.24%	705 821	12 350	53.07
B2	1245	13 068	91.30%	768 324	1590	58.67

Table 8
Primary energy consumption (PEC) of the city's network and the local campus network and primary energy factors for heat supplied to the city's network and the local campus network. The marginal PEC is calculated by dividing the change in the PEC in the Tallinn DHN after connecting the campus to the HTDHN in Scenarios A and B, with the campus' heat demand.

	PEC Tallinn (GWh)	PEC Campus (GWh)	Delivered DH (GWh)	Tallinn average PEC (MWh/MWh)	Marginal PEC (MWh/MWh)	PEC Saving (GWh)
Ref. 1	1496	15.56	1752	0.8536	1.1905	0
A1	1507	0.0	1765	0.8534	0.8333	4.67
B2	1508	0.0	1765	0.8541	0.9211	3.52
Ref. 2	1535	15.56	1752	0.8761	1.1905	0
A2	1546	0	1765	0.8757	0.8159	4.90
B2	1547	0	1765	0.8763	0.9028	3.76

DHN. In the summer, CHP heat production is rather cost-efficient, and an increase in heat demand in the DHN does not have a significant impact on production costs from May to September due to the large amount of heat rejected during electricity production in condensing mode. However, higher heat demand increases the use of HOBs in the DHN during winter, which results in higher DH operator's production costs.

Lower campus operating temperatures result in less heat loss, while the sub-LTDHN connection increases the thermal efficiency of the CHP plants. This may reduce the need for HOBs in the winter, but in the summer, when CHP plants have a lot of unused heat, improved heat production and network efficiency have no significant impact on fuel consumption or production costs.

The sub-LTDHN system reduces the HTDHN return temperature by 0.14 °C on average. The annual heat production by the CHP plants is 1070 MWh greater in Scenario A1 than in B1, the amount of rejected heat is 611 MWh greater in A1 than in B1, so only 43% of the increased heat production is actually utilised. Increased electricity generation benefits the DH operator throughout the year, but the impact of lower return temperature on electrical efficiency is not as significant. In A1, the annual electricity production is 47.8 MWh greater than in B1. In the scenarios with higher electricity price, A2 and B2, the CHP plants operate more in condensing mode. This is seen especially in the operation of Tallinn 1 CHP, which does not receive FIP anymore. If A2 is compared to B2, the improved efficiency of the FGCs increases the heat production by 1264 MWh, of which only 36% is utilised in the DHN. In A2, electricity was produced 86 MWh more than in B2.

The benefits of the sub-LTDHN seem small on a scale of the city's DHN, but the campus heat demand is less than 1% of the city's demand, and the higher demand added via the sub-LTDHN connection will lead to a greater decrease in the return temperature, while increasing benefits. This study only examined the possibility of implementing the sub-LTDHN into the buildings that are currently heated by the local network. Using the already existing network on campus will reduce investment costs. Some of the buildings on campus are already directly connected to the HTDHN. Expanding the sub-LTDHN to these buildings would increase the benefits of the sub-LTDHN. Higher heat demand in the sub-LTDHN will require a higher mass flow of DH water, resulting in a greater decrease in the HTDHN return temperature.

In addition to the economic and environmental benefits, an innovative heating system at the university campus can provide valuable experience of connecting a low-temperature energy cascade to existing DHNs, and help the various stakeholders to overcome the barriers of implementing such a system in a wider scale. Projects of developing sustainable energy networks may face challenges related to, for example, legislation, creating a suitable business model benefitting all the stakeholders or introducing new technologies (Mlecnik et al., 2018).

4.2. Campus heating

Campus heating costs can be estimated by comparing the marginal costs of DH with the costs of the current campus heating system (see Table 8). Connecting the campus with sub-LTDHN to the city's HTDHN in the scenario A1 increases the DH company's annual operation costs by 463 k€, but due to the increased production in the CHP plants and lower return temperature of the network, revenues from the electricity sales increase by 22 k€. The marginal cost of heating in the scenario A1 is 33.77 €/MWh. This is significantly lower than the cost of heating with the local boiler in the reference scenario1, 39.74 €/MWh. With the conventional HTDHN connection heat can be delivered to the campus with lowers costs as well. In the scenario B1, the DH company's operation expenditures increase by 504 k€ and the revenues from electricity sales increase by 16 k€ resulting in marginal cost of heating of 37.35 €/MWh. However, since the DH price in Tallinn was regulated and fixed at a relatively high level of 50.14 €/MWh in 2021, there has been no economic incentive for the university to stop using the local boiler for heating on campus and switch to DH. Naturally, the price of gas significantly affects the profitability of the local boiler as well.

In the scenarios with higher energy prices, the production costs of the local boiler in the reference scenario 2 are 58.95 €/MWh. In the scenario A2, DH company's expenditures increased by 706 k€ and revenues from electricity sales by 12 k€. Marginal cost in A2 is 53.07 €/MWh. In the scenario B2 with the conventional HTDHN connection DH operator's expenditures increased by 768 k€, electricity sales by 1.6 k€, and the marginal cost is 58.67 €/MWh. In February 2022, the DH price was raised to 97.15 €/MWh, so DH would not be economic alternative to the local boiler in the higher price scenario either. Regardless the price scenario, the economic benefits of sub-LTDHN connection over the conventional connection are similar. In both of the price scenarios, marginal cost of campus heating was approximately 9.6% lower with the sub-LTDHN connection.

Kontu et al. (2020) concluded that a hybrid system in which the base load is purchased from the DHN and the peak load is generated locally, will benefit property owners, particularly office building owners, and will make DH more competitive against local HPs if prices are updated so that the base load and the peak load are priced differently. This kind of system would also make it easier for the DH operator to cover the expensive peak demand. Pieper et al. (2019) studied the feasibility of replacing peak natural gas boilers in the Tallinn DH system with large-scale HPs based on various heat sources. Heat pumps could reduce natural gas consumption and save money, but due to the high emission factor for Estonia's electricity markets, they would not be able to reduce emissions from DH production. However, the share of renewable energy is expected to increase in the near future, making HPs more sustainable. The possibility of covering peak demand locally with heat pumps on the campus could be a topic for future research. Lower supply and return temperatures in the sub-LTDHN will improve the efficiency of heat pumps, while locally produced heat will reduce the heat demand in the city's DHN.

Implementing a low-temperature district heating system is possible only with additional investments and refurbishments to the energy efficiency and heating systems of the buildings. In this case the sub-LTDHN would improve the energy efficiency of the network in the campus. Reducing the supply temperature of heating may also require more detailed control and monitoring of the system (Mlecnik et al., 2018). This kind of costs were not considered in this study. These renovations could potentially improve the sustainability of the campus while also generating savings due to lower heat demand regardless of the type of heating network is used. Boyano et al. (2013) conducted an office building case study in three different European cities. In the study, Tallinn was chosen to represent a cold climate zone. The results show that improved thermal insulation of walls and windows leads to significant energy and cost savings in colder climates, but in warmer areas, it could increase building cooling costs. According to Airaksinen and Vuolle (2013), energy-efficient buildings can also reduce the peak power demand for heating, but the reduction is not as significant as for heating energy consumption.

Sub-LTDHN reduces annual heat loss by 36% compared to direct connection. The efficiency of the network can be improved from 91.30% for B1 and B2 to 94.24% for A1 and A2. The maximum heat loss in Scenarios A1 and A2 is 36% lower than in B1 and B2, but this represents only a 1.5% decrease in the maximum peak demand of the campus network. The reason for such insignificant decrease is that the greatest absolute heat loss occurs in cold weather when demand is highest, while relative heat loss is greater in the summer.

This study was done as a case study of the university campus, but the results can be generalised to evaluate similar systems in other locations that meet the requirements. To implement a sub-LTDHN to an area, it should be newly built or renovated so that delivering heat in lower temperatures would be possible, the area should be close to a HTDHN, and the flow rate and return temperature of the HTDHN should be high enough. Preferably, the sub-LTDHN should be near to a heat production plant of the HTDHN to ensure high enough flow rate at all times.

4.3. CO_2 emissions

Connecting the campus to the city's HTDHN increases the use of the natural gas-fired DH boilers, and thus increases the CO_2 emissions of the DHN, but since most of the base load is produced from carbon neutral fuels, replacing the local campus boiler with DH decreases the total emissions. Connecting the campus to the HTDHN with the sub-LTDHN connection reduces the total emissions by 955 tonnes CO_2. Conventional high-temperature connection reduces the emission by 765 tonnes CO_2. In addition to reducing emissions from the heating system, increasing electricity production from renewable fuels can reduce emissions in electricity markets if fossil fuels in the production mix are replaced. For example, the average emission factor for electricity generation in Estonia was 746 g_{CO2}/kWh in 2019 (European Environment Agency, 2021). Based on the average emission factor, it can be roughly estimated that an increase in electricity production would result in an additional emission reduction of 330 tonnes of CO_2 for the scenario A1 with the sub-LTDHN and 295 tonnes of CO_2 for the scenario B1 with conventional HTDHN connection. Similarly, in the scenarios with higher energy prices, the increased renewable electricity could decrease national emissions in A2 and B2 by 89 and 25 tonnes CO_2.

4.4. Primary energy consumption

Table 8 provides PEC values for all the scenarios. Connecting the campus to the HTDHN increases PEC of Tallinn DHN by 0.7%–0.8% depending on the scenario. When the natural gas used in the campus' local boiler is considered as well, total PEC decreases approximately 0.2%–0.3% depending on the scenario. With the sub-LTDHN, total primary energy savings of 4.7 GWh can be achieved in the scenario A1. In B1, the conventional DH connection results in primary energy savings of 3.5 GWh. In the scenarios of higher energy prices, primary energy savings are 4.9 GWh in A2 and 3.8 GWh B2 when compared to the reference scenario 2. Although, higher natural gas and emission prices do not affect the consumption of natural gas, the higher electricity price increased PEC in the higher price scenario. This happens, because higher electricity price increases electricity production in condensing mode implying that producing electricity in the CHP plants without utilising the heat may not be ecological solution. The average PEC of Tallinn DHN is 0.85 MWh/MWh in the lower price scenarios and 0.88 MWh/MWh in the higher price scenario. To assess the increase in PEC caused by connecting the campus to the HTDHN, the marginal PEC was calculated. In a situation, when CHP plants produce large amounts of electricity in condensing mode, increasing the heat demand by connecting new districts to the DHN can decrease the average PEC, and thus improve the energy efficiency of the entire system. However, this happened only in the scenarios of the more efficient sub-LTDHN connection. In A1, the marginal PEC is 0.83 MWh/MWh, 2.0% lower than the average PEC. In A2, marginal PEC is 0.82 MWh/MWh, 6.0% lower than the average PEC. In B1 and B2, marginal PECs were 6.7% and 2.7% higher than the average PECs.

Primary energy factors are used to assess the energy performance of buildings in the European Union. The definition of PEF of DH varies from country to country. In some countries, a single fixed PEF is set for all DHNs, while in other countries it may vary (Latõšov et al., 2017). In Estonia, fixed PEFs are used for heat supplied from DHNs. The default value is 0.9, and for efficient DHNs the PEF is set at 0.65.

Latõšov et al. (2022) presented a methodology to label efficient DHNs. A DHN can be labelled as efficient system, if 50% of heat in the DHN is from renewable fuels, 50% is recovered waste heat, 75% is produced in CHP plants, or 50% is from the combination of these three sources. Since 49% of the DHN's heat is produced in the CHP plants combusting biomass and 22% is purchased waste heat from the waste incineration plant, the Tallinn DHN can be considered as an efficient system according to the model and the proposed methodology.

4.5. Limitations of the study

The supply and return temperatures of the city's DHN were based on the measured inlet and outlet temperatures at Tallinn 2 CHP. This study did not take into account the temperature difference caused by network heat loss between the campus connection point and the heating plants. However, the campus is located close to Mustamäe CHP plant, and therefore the temperature drops in the supply and return lines can be assumed to be small between the connection point and the CHP plant. The used inlet and outlet temperature data was from the year 2018, and the Mustamäe CHP plant was not yet commissioned then. For this reason, inlet and outlet temperatures of Tallinn 2 CHP was chosen as a reference.

In DH systems, pumps are used to maintain sufficient pressure in the network. Connecting the campus to the HTDHN via a direct connection will not increase the need for pumping, but the separate local network in the reference scenario requires its own pump. In the sub-LTDHN scenario, the pressure difference over the mixing shunt in the HTDHN return line is zero, so additional pumping is required. The pressure difference between the supply and return lines of the HTDHN can be used, so pumping is only necessary for the flow from the return line. Volkova et al. (2020b) Pump electricity consumption was not taken into account in the reference scenario and Scenario A. However, the power needed for pumping is usually relatively low compared to the network's thermal capacity.

Thermal and electrical capacity of the CHP plants was calculated as a function of the return temperature regardless of the operating mode. When the CHP plant is running in condensing mode, the electrical capacity is independent of the DHN return temperature, so the capacity can be maximised by lowering the condensing temperature. FGCs can be switched off to increase electricity production when operating at partial load or when some of the generated heat is rejected. Flores et al. (2017) These differences in operating modes were not included in the model but taking them into account would increase electricity production in all scenarios.

The running order of the various production units in the EnergyPRO model was based on the order of priority established by the Competition Authority. However, there are some technical limitations that may result in exceptions to the order. For example, maintenance breaks, start-up or ramp-up times of various units were not considered in this study.

In Scenario A, lowering the return temperature of the city's DHN will also reduce heat loss in the return line. The decrease was not calculated or accounted for as a benefit of the sub-LTDHN in this paper. The average return temperature drop was 0.14 °C, and a subsequent decrease in heat loss would not have significantly altered the results or conclusions.

5. Conclusions

In this study, the effects of introducing a sub-LTDHN for campus heating in Tallinn were investigated from the perspective of the campus and the city's DH system. The results show that reductions in CO_2 emissions and primary energy consumption can be achieved by connecting campus buildings to the city's DHN. The investigated sub-LTDHN will lower the return temperature of the HTDHN, resulting in improved electricity generation and FGC efficiency. Such efficiency improvements will lead to additional decrease in emissions and PEC. The city's DH operator will also benefit financially from the sub-LTDHN. However, part of the heat produced at the CHP plants is rejected, so FGCs can be switched off in the summer due to low heat demand. Because of this, the lower return temperature of the HTDHN is more beneficial in winter when increased thermal efficiency is able to replace some of the heat that would have been produced using natural gas.

From the university's point of view, DH will provide a more sustainable heating solution for the campus compared to the current system of the university's own boiler and network. Due to the regulated DH prices in Tallinn, the university may not benefit financially from switching from the local boiler to DH. Both the city of Tallinn and Tallinn University of Technology have announced their sustainable development targets, including clean energy goals. Key outcomes and recommendations can be formulated as follows:

- Since DH in Tallinn is mainly produced using renewable fuels, connecting the campus to the DHN can be environmentally beneficial in terms of CO_2 emissions and primary energy consumption in compared to the local natural gas boiler.
- With the sub-LTDHN emissions can be reduced by 955 tonnes CO_2 annually. Conventional HTDHN connection reduces emissions by 765 tonnes CO_2.
- Sub-LTDHN can result in primary energy saving of 4.7 GWh–4.9 GWh, and HTDHN connection to 3.5 GWh–3.8 GWh depending on the different energy price scenarios.
- With sub-LTDHN, the annual network losses in the campus are 36% lower than with the high-temperature network. Annual network efficiency can be improved from 91.3% to 94.2% with the sub-LTDHN.
- The sub-LTDHN is superior to the direct HTDHN connection in these aspects. This example shows how expanding the LTDHN further in other districts can increase both environmental and economic benefits on the city's network.
- The sub-LTDHN in the university campus can help implementing similar systems in a larger scale by providing knowledge of overcoming the various challenges related to such a system and introducing new innovations.
- Similarly, the LTDHN facilitates utilisation of waste heat streams as well. As Estonia so far has a high CO_2 emission factor of electricity generation, heat pumps would not bring environmental benefits yet.
- The implementation of a sub-LTDHN in the campus is possible, when the buildings in the campus will be renovated. There are plans for campus buildings refurbishment in the nearest future.
- Tallinn DH uses still a significant amount of natural gas during peak hours in heating season, whereas heat from CHP plants is rejected in summertime. The reason for this is the Estonian renewable electricity support programme, which allows rejecting heat in biomass-fuelled CHP plants.
- In 2021, electricity market price in Estonia saw a rapid increase as well as the price of emission allowances. Since the running order of the production units is regulated, these

price changes have only limited impact on the operation of the production units. For better understanding of economic feasibility of the proposed system, more detailed financial analysis should be done.

Abbreviations:

DH	District heating	SH	Space heating
DHN	District heating network	HTDHN	High-temperature district heating network
CHP	Combined heat and power	BPST	Back-pressure steam turbine
HOB	Heat-only boiler	FIP	Feed-in premium
FGC	Flue gas condenser	O&M	Operations and maintenance
LTDHN	Low-temperature district heating network	PEC	Primary energy consumption
DHW	Domestic hot water	PEF	Primary energy factor
HP	Heat pump	EF	Emission factor

CRediT authorship contribution statement

Pauli Hiltunen: Conceptualization, Methodology, Formal analysis, Writing – original draft, Visualization. **Anna Volkova:** Conceptualization, Methodology, Writing – review & editing, Supervision. **Eduard Latõšov:** Conceptualization, Data curation, Writing – review & editing, Supervision. **Kertu Lepiksaar:** Methodology, Writing – review & editing. **Sanna Syri:** Conceptualization, Writing – review & editing, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The data that has been used is confidential.

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