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Energy planning of district heating for future building stock based on renewable energies and increasing supply flexibility

Nomenclature:

$C(EUR)$	– total annual cost
$c(EUR/kW)$	– specific total cost per capacity unit
$\tau(hours)$	– operation time
$P(MW)$	– installed heat power capacity for each plant
$Q(MWh)$	– annual thermal production
$\tau_{n,m}(hours/year)$	– break-even operation time for two energy units
$F(EUR)$	– fuel cost;

$I(EUR)$ – investment cost;

$LCOE\ (EUR/kW)$ – levelised cost of energy;

$M(EUR)$ – operations and maintenance cost;

$P_{CHP}\ (MW)$ – power production in a CHP plant;

$P_{HP}\ (MW)$ – power needed for HP operation;

$E(MW)$ – electrical production;

$R^2(-)$ – goodness of fit;

$a_i\ (-)$ – model coefficients for the CHP power production;

$b_i\ (-)$ – model coefficients for CHP fuel input;

$c_i\ (-)$ – model coefficients for HOB fuel input;

$d_i\ (-)$ – model coefficients for HP power use;

n *(years)* – system's lifetime;

r (%) – discount rate;

η (%) – efficiency;

Subscript/Superscript

CHP – combined heat and power plant;

el – electricity cost;

Elb – electric boiler;

HOB	– heat only boiler;
HP	– heat pump;
fix	– fixed O&M cost;
$fuel$	– fuel cost;
$t\ (-)$	– year;
var	– variable O&M cost.

Abstract

This paper discussed factors associated with the decisions on energy supply plants in new or existing district heating (DH) systems. Three highly efficient energy conversion technologies were considered. The study focused on assessment of the heat supply units considering economic aspects and technical limitation of the technologies. Further, risks associated with the changes in heat load profiles and fuel price volatility were investigated. The existing method for heat supply optimization was compared with a new method, suggested in this paper. The new method was based on detailed performance simulation models developed in Aspen HYSYS software and data post-processing in MATLAB. The results showed that the existing method for the heat supply optimization cannot show all the advantages of highly efficient conversion technologies. The study on the new method examined 36 plant combinations and identified eight with levelized cost of energy (LCOE) under 0.15 EUR/kWh. The results showed that increase in flexibility of DH provided better reliability of heat supply, while increasing the heat cost. The total deviation in LCOE due to fuel and electricity price volatility was in the rage of 1.6% – 3.6%. Further, a change of 20 % in the plant investment costs induced almost the same variation in LCOE.

1. Introduction

Economy of district heating (DH) companies is highly dependent on heat sales. The rule is quite simple: the more heating energy is consumed by the customers, the higher the profitability of district heating DH companies. This tendency was good explain by authors in [1]. Today, with the new building codes and standards, a lot of attention is devoted to efficient energy use in buildings and reduction of heat losses [2, 3].

DH service is quite flexible and allows to employ different energy conversion technologies for heat energy generation. When the question is which technology to use, many issues should be considered. One scenario is when the energy production plants are already installed and in operation. Then, it is fundamental to find a solution how the existing plants can be operated with the lowest possible annual costs. On country, when planning a new DH system, the heat demands of the different target areas and the possible future development of these should be analyzed, as well as available heat sources should be investigated. Finally, an important task in decision on optimal generation units' combination, optimum configuration of DH network, and the optimum water temperature levels arises [4]. In addition, economics, energy saving, and environmental impact have become more important criteria for system design and operation, which designers have been burdened more heavily [5].

DH production units are chosen based on the scale and variation of heat demand, the local availability, costs of energy sources, and the investment cost of each technology [6]. Hence, for optimal utilization of the renewable energy and for economic reasons, the thermodynamic performance of energy production units is of major interest [7]. If the simulation approach has significant influence on operation results, then the cost of utility for society and the revenue for the investor will be also influenced by quality of simulation model [8]. This means that the decision on different technologies has to be based on proper evaluation by the help of relevant simulation models. In turn, this have to include the variability of the system parameters, aiming to find the best performance obtainable from the matching between production plants and users [9].

In liberalized energy markets, the installed utility technologies are optimized in an effort to reduce total production cost for each individual hour of production [7], to find the cheapest unit commitment and load dispatch satisfying given heat, power and reserve demands using given units [10]. These makes economy of production together with technical aspects of technology to be the main parameters that should be investigated before the final verdict is handed down.

When the combination of energy supply plants is under consideration, capital investment and operation and maintenance (O&M) costs should be carefully examined for each production unit. The main idea here is that different fuels can be utilized depending on their availability and cost. In addition, electricity rates should be considered. According to [11], electricity rates affects the operation of combined heat and power (CHP) plants as well as heat pumps (HP), and electric boilers. At the same time, the plant running costs put extra pressure on economic decision when annual operation is considered. Appropriate sizing of production plants is vital to achieve good levels of utilization, to ensure suitable performance for chosen systems, and to enable effective integration with existing or new DH systems [12]. Further, it should be noticed, that in most cases the plant operation becomes inefficient if the energy production unit operates under a low plant load [11, 13]. Given the high costs of installation and the tight energy saving constraints at which these plants are subjected, an incorrect predictive analysis can result in investment unsustainability either in economic or environmental terms [14, 15].

Ultimately, possible change in heat load profiles should be taken into account. According to [16], it is expected that in the medium term the heat load patterns can demonstrate fluctuations.

The main reasons for that are: improved insulation of buildings, installation of ventilation systems with heat recovery, creation of heat islands due to growth of cities and global warming [17, 18] and legislation amendments. The mentioned facts facilitates change in customers' heat load profiles. However, the rise in population [19] and housing comfort levels [20], will contribute to the increase of the load to be heated. Thus, the levelling and size of the future DH demand will influence future DH operation and local DH system development [11].

The existing method of heat supply optimization that DH companies use currently is based on methodology on construction of optimal generation mix [21]. This method implies an energy unit with the highest investment cost be employed as a base load plant. In turn, this gives lover specific heat cost and higher plant efficiency [1]. This means that economy-of-size takes place that denotes energy plants with lower cost at higher production volumes be the main driving force. However, these arguments are no longer as strong, since more efficient heat generation technologies are available. Unfortunately, this method does not provide clear explanation which plant should be used by DH companies in various situations. Further, the energy efficiency of energy production units is treated as constant regardless of the load change. As mentioned before, the energy production unit operates inefficiently under a low plant load [11, 13].

Low DH price and ability to withstand energy efficient stand-alone heat generation solutions are the key factors that would make DH companies profitable in a long term. Therefore, this work aimed to propose a methodology that allows to identify the best combination of energy supply plants employing renewable energies and decreasing DH generation cost. The new method considers different input variables and operation constraints that makes it robust tool for heat energy planning.

The economic and technical aspects of heat generation were considered as well as yearly operation. In addition, the study provided information on consequences due to change in heat load patterns and fuel price volatility. In comparison to existing literature, this paper shed light on how to combine a few energy supply technologies including significant economic data. In addition, the models used in the analysis were based on detail thermodynamic models that made the results reliable.

2. Relevant energy supply technologies

Different energy supply plants are available for employment in the DH system. However, it is not an easy task to make a decision, which of them should be installed in particular situation. Due to technological complexity and limitations in operation, their applicability decreases. Therefore, the following section focusses on pros and cons of analyzed energy supply plants.

2.1 Biomass combined heat and power plant

CHP technology is well known and proved to be reliable nowadays. This technology was put forward more than a century ago [22]. According to [23, 24] CHP systems can be classified into topping and bottoming cycle with different exploitation regimes such as heat-much mode, electricity-much mode, mixed-much mode, and stand-alone mode [25]. CHP is efficient because it avoids the large amounts of waste heat produced in typical power generation plants [26]. In comparison to other energy conversion technologies used today, CHP has one of the highest indicators and its energy efficiency can reach up to 90% leading to better utilization of primary energy [27]. The attractive property of a CHP plant connected to a DH network is the possibility to massively include renewable sources of energy into energy systems at a reasonable cost [28]. Biomass CHP plants are often seen as an efficient way to reduce greenhouse gases emissions due to their very low CO_2 emissions level [29, 30].

However, there are several drawbacks associated with biomass CHP. Some biomass resources, in particular straw, contain aggressive components such as chlorine. These can lead to slagging and corrosion that reduces security of supply of DH customers. Further, biomass fuel has great variety of composition and therefore, different lower heating values (LHV) can effect efficiency of CHP plants and it outputs [31]. These put limitations on plant operation, for example when the peak load should be covered. Slow start up of this technology requires startup load and extra operation hours. Further, most CHP plants designed for DH purposes are characterized by very low power to heat ratio [32]. In addition, biomass-based CHP plants are widely used in regions that have ample fuel wood resources, forestry or agricultural residues. A business plan including the cost of the biomass resource collection and logistics is needed to ensure that CHP or power generation from solid biomass is economically viable [33].

2.2 Biomass heat only boiler

Nowadays, the modern heat only boilers (HOBs) are biomass based. Type of fuel propagates which equipment should be installed for the best fuel utilization. The main advantage of such systems is their high efficiency, especially when energy recovery technology is applied. If a moisture content of the fuel is above 30 – 35%, as with forest wood-chips, flue gas condensation should be employed. Flue-gas condensation can improve the overall maximum efficiency of plant up to 30% depending on fuel type and the temperature of the DH water [34]. For plants firing wood-chips with 45 – 55% moisture content, the thermal efficiency of more than 100% could be reached based on LHV [35]. Biomass HOB provides possibility to maximize CO_2 savings and potentially eliminate all emissions from fossil fuel systems. The costs of biomass fuels are typically lower than the fossil fuels and such systems can therefore provide significant operational savings, which reduces the payback period [12].

The drawback of such systems is high complexity that required highly trained operation staff. Higher combustion temperatures can lead to high temperature corrosion, soot, and wear out of equipment [36]. Biomass heating systems generally have higher initial capital cost than fossil fuel systems of equivalent rated capacity. Although biomass systems have higher upfront costs than fossil fuel boilers. If there is a need to run at low load conditions for extended periods, potentially higher maintenance cost appears [12].

2.3 Heat pump

Heat pump (HP) systems offer economical alternatives of recovering heat from different sources for use in various industrial, commercial, and residential applications [37]. A DH system is a promising energy-saving measure for high-density cities and HP systems play an essential role in such large-scale system [38, 39]. Further, DH systems with HP technology has demonstrated significant reduction in annual energy bill [40]. Today, the most advanced technical developments in the HP field provides opportunity to deliver heat at a temperature of 110°C [41-43]. According to [40, 44], the large-scale HP applications based on mechanical vapor compression and absorption closed cycle principles can be successfully applied in the DH systems.

A general advantage of HP technology is ability to utilize energy at a low temperature level. In addition, the HP is flexible concerning use of renewable energy, waste, and surplus heat. Compared with traditional heating technologies, the HPs are more complex and have high investments costs. However, this is counterbalanced by considerable savings in operation costs [31].

The main drawback associated with HP technology is electricity use. This is particularly relevant when the electricity prices in local conditions are rather high. At the same time, the use of large HPs can be called into question due to high carbon content in the marginal or incremental electricity generation in most industrialized regions and countries [1]. Investment cost of high temperature HP is typically the same for the different technologies, when only the HP itself is considered [31]. Economically, simple payback period for industrial HP applications is between 2 and 5 years [44].

2.4 Electric boiler

Even though nondesirable in new requirements, electric boilers are sometimes necessary for energy supply to cover the extreme operation situations and as a back-up plant. Electric boilers for DH are used to some extent in countries where electricity is occasionally available at a low price, for example in Sweden and Norway [1]. Due to its very simple design, the electric boiler is extremely undependable and easy to maintain. The operating costs are very dependent on the size of the boiler. Thus, heat production from electric boilers can only compete with other heat production units at low electricity prices [31]. If necessary, an electric boiler can also be operated as a peak load plant, even though this may be problematic from the perspective that in many countries there is a tendency that peak heat demand coincides with the peak in electric power demand [1].

3. Economic data on energy supply technologies

This section focuses on various economic issues associated with the installation of energy production unit. The presented information is based on literature review. The aim was to identify available economic data associated with capital investment and O&M values for each technology. In addition, fuel prices and electricity rates were considered.

Several issues should be considered when one does a decision about installation of energy production unit. First, the technology should meet customer requirements in providing heat to the DH system. At this point, it can be noted that different customers can use wide range of temperatures due to their various purposes. Further, heat load patterns should be taken into account. Due to changeable climate characteristics and continuous improvements in building codes and standards, the heat load patterns can show variation from year to year. On the other hand, employed energy conversion technology should be environmentally friendly and certainly display positive economy under its long term operation. Therefore, a detailed feasibility study should be carried out considering installation of certain system.

Normally, three economic key-points should be analyzed before doing investment in certain technology. These are following: capital investment cost, fixed O&M costs, variable O&M cost, and fuel costs.

Due to significant amount of found cost data for each technology, the corresponding tables are presented in Appendix. The data in Appendix are organized in tables, for each technology separately. However, the most important information selected for the analysis is listed further in Section 4.7.

The comprehensive economic feasibility of heat production units is impossible without fuel prices. In this study both CHP and HOB systems utilized biomass as a fuel. At the same time, electricity was required for HP operation. Hence, Table 1 summarizes the fuel prices for these technologies found in the literature for EU countries.

Table 1. Prices for biomass fuel and electricity

Fuel type	Price	Comment	Reference
Electricity	0.120 EUR/kWh	Annual consumption level: 500 MWh – 2000 MWh; EU-28 in 2013	[45]
	0.127 EUR/kWh	Annual consumption level: 500 MWh – 2000 MWh; Euro Area (EA-17) in 2013	[45]
Wood chips	40 EUR/tonne		[46]
	70 EUR/tonne		[47, 48]
	56 EUR/tonne	Croatia, 2014	[49]
	58 EUR/tonne	Romania, 2014	
	136 EUR/tonne	Ireland, 2014	
	132 EUR/tonne	Austria, 2014	
	113 EUR/tonne	Germany, 2014	

4. Methodology

In this section, the methodology for analysis of energy supply technologies and economic evaluations are described. In this study, three state of the art technologies have been chosen for the analysis. In addition, electric boiler was considered for heat supply during extreme operation situations. For the feasibility purpose, the detailed plant models are necessary. Therefore, the simulation of energy supply sources was done in Aspen HYSYS [50] simulation software. The Aspen HYSYS simulation software is well known in process simulation and gives possibility to include different components. Some examples of application are mentioned in [51-53]. For the purpose of this study, simplified plant models were developed based on detailed HYSYS models. The simplified, polynomial models were necessary to enable easier link between different plant performance data and heat load data. Detail explanation on the new method is given in Section 4.6. In addition, the analysis considered three scenarios of heat load patterns. The heat duration curves are introduced in Section 5. Based on the polynomial plant models and heat load data, the methodology for plant analysis was developed in MATLAB software [54].

4.1 Biomass based CHP models, detailed and simplified

The biomass CHP plant is shown in Fig. 1.

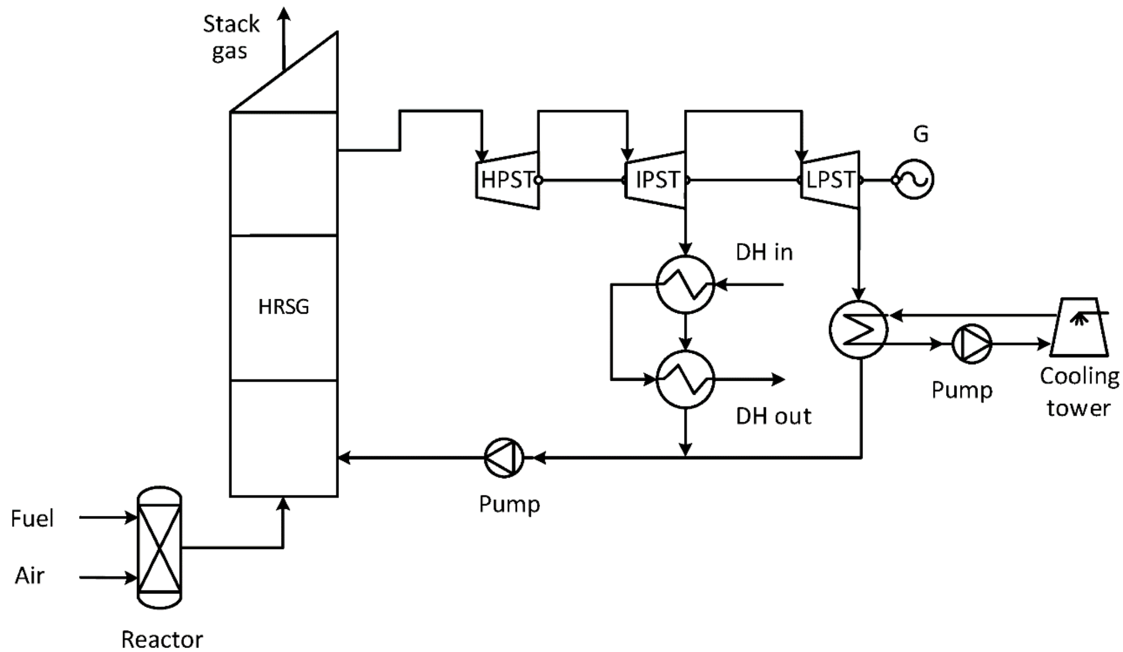

Fig. 1. Schematic of the biomass based CHP

The LHV of biomass fuel was assumed 19 MJ/kg with a moisture content of 40%. The ambient conditions were 15°C and 1.015 bar. After fuel combustion in the reactor, the flue gases with the temperature of 880°C flew in a high recovery steam generator (HRST) where the pressurized water carrier was heated up to 540°C. The HRSG was modeled as three stages heat exchangers. These are an economizer, an evaporator, and a superheater. The steam turbine cycle (STC) contained high pressure steam turbine (HPST), intermediate pressure steam turbine (IPST), and low pressure steam turbine (LPST). The live steam flowing from HRSG expanded in

HPST from 540°C and 100 bar to 259°C and 12 bar. The expansion continued in the IPST to 239°C and 10 bar. IPST was with one extraction for DH purposes. The DH was satisfied based on required values of heat energy from consumers. Finally, in the LPST the steam expanded to 33°C and 0.05 bar after the condenser, the water was pumped back to HRSG. The total efficiency of CHP plant operation was 88%.

The dynamic behavior of modern CHP plants is characterized by the short startup time and quick load change capability [55]. In order to ensure that operation of CHP plant is realistic, the startup and standstill intervals were considered in the analysis. It was assumed that the CHP plant did not operate (was in standstill mode) if DH load was low for longer than 72 hours. Therefore, the three startup modes [55] were applied when the condition of plant operation was satisfied:

- Hot start after 8 hours standstill: 40 – 60 minutes;
- Warm start after 48 hours standstill: 80 – 120 minutes;
- Cold start after 120 hours standstill: 120 – 170 minutes.

According to [12], from both technical and economic points of view, a biomass CHP plant is best operated relatively continuously at between 30% and 100% of its rated output. Biomass plants do not generally respond well to rapidly varying loads, or long periods at low load conditions below a minimum modulating range. Therefore, the lower bound of CHP's heat capacity applied in this study was equal to 30% of full plant capacity.

After the model simulation was conducted in Aspen HYSYS, enough data points for defining the simplified model were obtained. Fig. 2. shows relationship between power production and DH load, and fuel consumption and DH load in CHP plant. The plant performance for three different sizes of the heat load are given in Fig. 2. These three sizes were chosen based on the maximum heat demand, see Section 5.

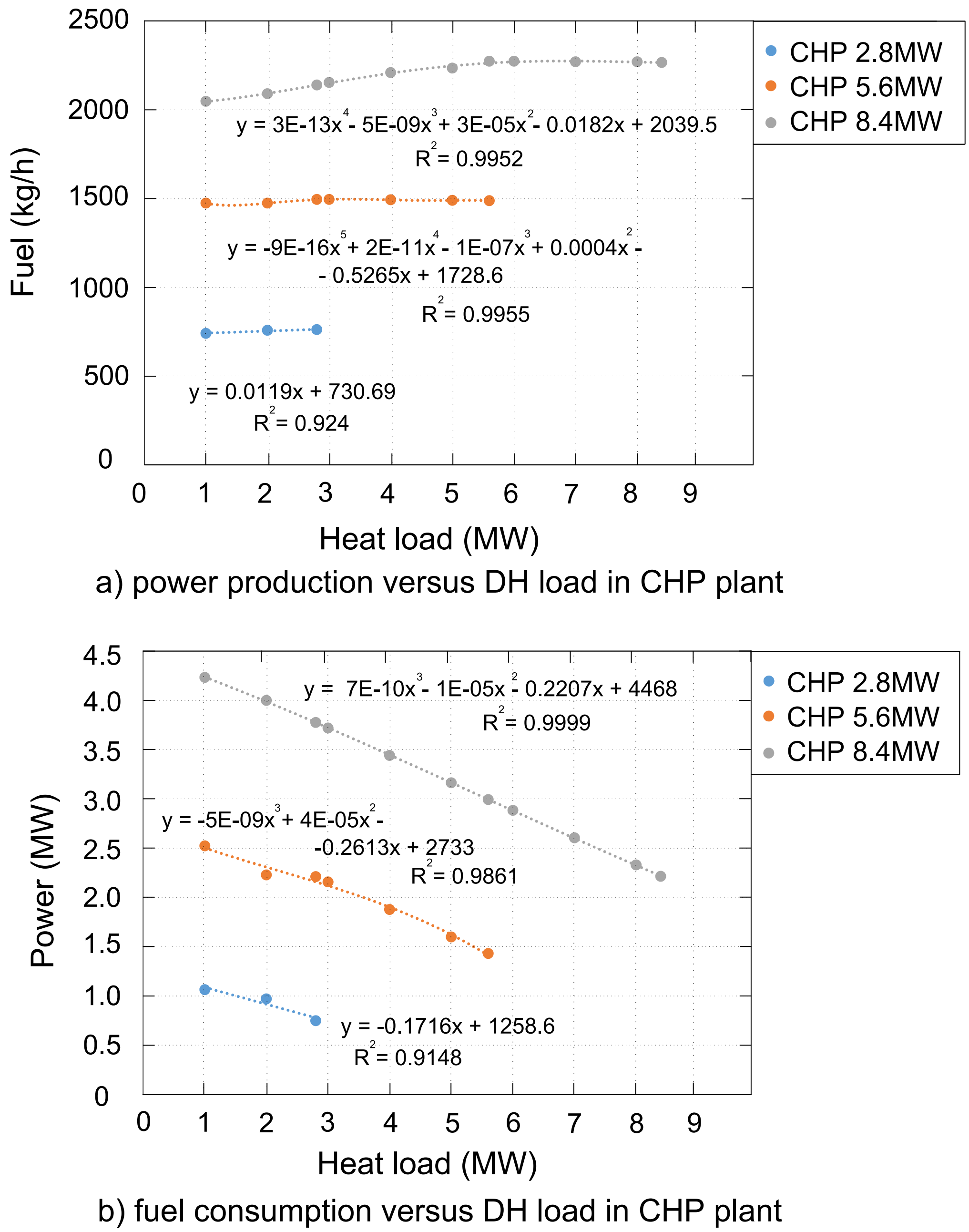

Fig. 2. Operational characteristics of three CHP plants with various heat capacities

From Fig. 2a the power production of a CHP plant can be described by using heat output as:

$$P_{CHP}(Q_{CHP}) = a_3 \cdot Q_{CHP}^3 + a_2 \cdot Q_{CHP}^2 + a_1 \cdot Q_{CHP} + a_0 \quad (1)$$

where Q_{CHP} is required heat output to the DH system and a_3, a_2, a_1, a_0 are model coefficients. Further, the dependencies between fuel consumption and DH load in CHP plant can be described as fifth-polynomial model for fuel input, as a function of heat output:

$$F_{CHP}(Q_{CHP}) = b_5 \cdot Q_{CHP}^5 + b_4 \cdot Q_{CHP}^4 + b_3 \cdot Q_{CHP}^3 + b_2 \cdot Q_{CHP}^2 + b_1 \cdot Q_{CHP} + b_0 \quad (2)$$

where Q_{CHP} is required heat output to the DH system and $b_5, b_4, b_3, b_2, b_1, b_0$ are model coefficients. The accuracy of the curve fitting and future model ability can be measured by R^2 value. The closer R^2 value to 1, the better the model.

Finally, based on the model data, it was possible to calculate the CHP energy efficiency as a function of the heat load. The maximum energy efficiency of CHP model was close to 0.9, for all three CHP sizes. The maximum efficiency was reached for the maximum heat load. Hence, the found CHPs' energy efficiencies fits well with data presented in Appendix, which proved the high degree of quality of the applied CHP models.

4.2 Biomass HOB models, detailed and simplified

Nowadays, the most advanced HOB are designed with the heat recovery of the flue gases that leads to improved efficiency.

Fig. 3 shows a layout of biomass HOB with energy recovery.

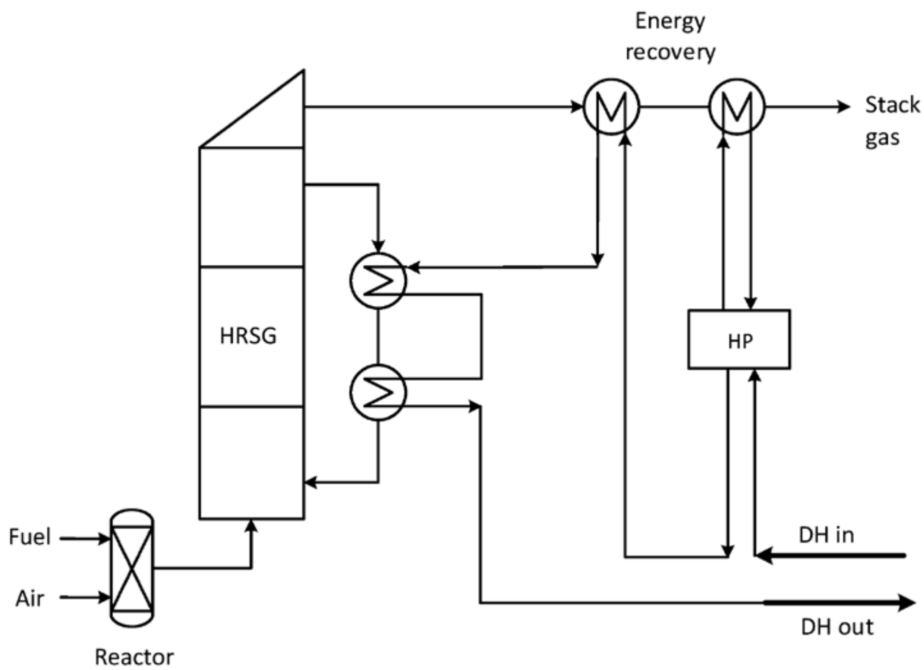

Fig. 3. Schematic of HOB

The fuel with the air were supplied to the reactor where the combustion process took place. Further, the heat was released to heat up the DH water in the HRSG. In this study, the model of biomass HOB was constructed in two stage flue gas condensing system for maximum energy conversion. In the first stage the incoming DH water was preheated by absorption HP, while in the second was after heated and then supplied to HRSG of HOB. The absorption HP was driven by high-pressure steam with ammonia as a working liquid and a water as an absorbent. In the condensing system the temperature of flue gases decreased to 35°C and the most of water vapor was condensed to water. The supplied water temperature to HRSG after condensing system constituted 80°C. In this study, both HOB and absorption HP were evaluated as a single unit. The return DH water from consumers had temperature of 50°C and after warming up in the HOB the temperature of 105°C was reached. Normally, the typical wood fired HOB plants are regulated in the interval of 25 – 100% of full capacity, without violating emission standards. The best technologies can be controlled 10 – 100% with fuel not exceeding 35% moisture content [31]. Therefore, the lower bound of HOB's heat capacity applied in this study was equal to 25% of full plant capacity.

In the HOB model the main interest was relationship between fuel use and DH load. Therefore, Eq. (3) presents a simplified model of the HOB based on detailed HYSYS model.

$$F_{HOB}(Q_{HOB}) = c_5 \cdot Q_{HOB}^5 + c_4 \cdot Q_{HOB}^4 + c_3 \cdot Q_{HOB}^3 + c_2 \cdot Q_{HOB}^2 + c_1 \cdot Q_{HOB} + c_0 \qquad (3)$$

where Q_{HOB} is required heat output to the DH system; $c_5, c_4, c_3, c_2, c_1, c_0$ – model coefficients.

Fig. 4. shows polynomial models for the HOB in Fig. 3.

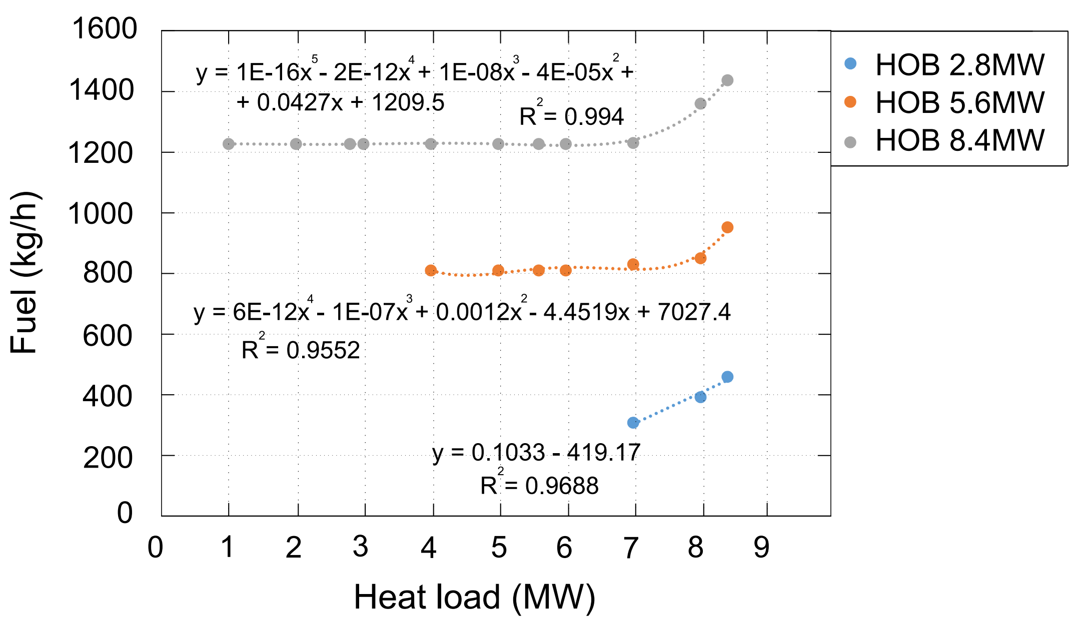

Fig. 4. Fuel consumption versus DH load in HOB

The developed HOB models showed maximum heat efficiencies of 1.12 - 1.16. This is mainly because flue gas condensation technology was used. The heat efficiencies showed match with existing literature, see Appendix, which proved that the introduced HOB models were good and reliable for further analysis.

4.3 Vapor compression HP, detailed and simplified models

The main issue associated with the use of HP technology in DH systems is to ensure that desired supply temperature is satisfied. This HP modification uses NH_3 (ammonia/ R717) as a working fluid and Vilter's single-screw compressor [43]. This technology is referred as high temperature heat pump (HTHP) used for industrial installations.

In this study, a large mechanical heat pump (MHP) was considered for the analysis. The MHP was based on vapor compression principle and utilized ammonia as a working fluid. The scheme of two stage MHP presented in Fig. 5..

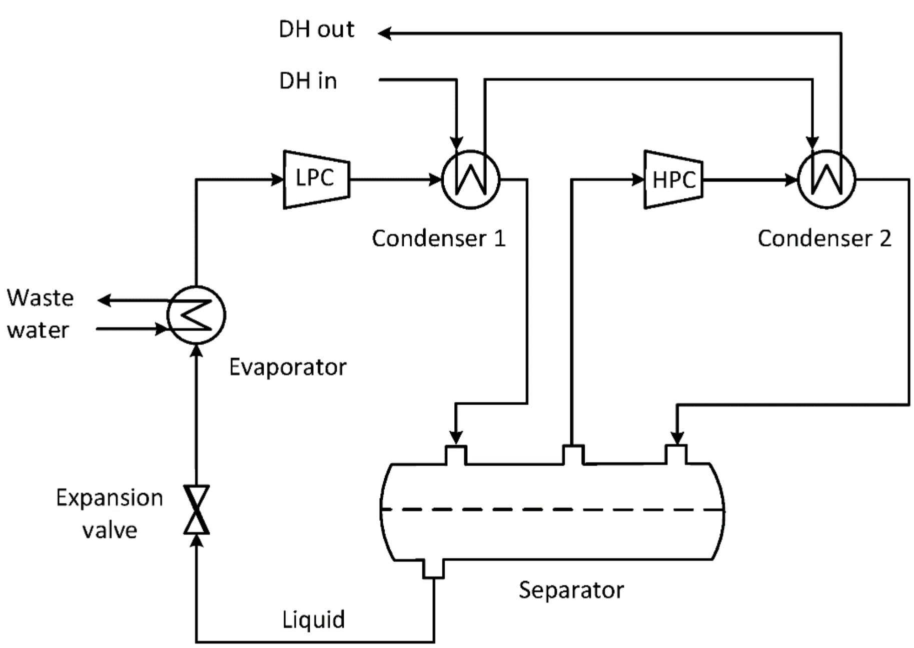

Fig. 5. MHP with two stage compression and separation vessel

In the MHP system, four main components of HP such as evaporator, compressor, condenser, and expansion valve were connected to a closed circuit. The MHP contained a separator vessel. The function of vessel is to separate the refrigerant in liquid and vapor. In the analyzed model, the MHP was assumed to upgrade heat from residual waste water. The incoming temperature of residual water to the evaporator was 27°C. After releasing heat in the evaporator, the temperature dropped to 24°C. Further, the ammonia vapor was compressed in the low-pressure compressor (LPC) from 7 bar and 15°C to 30 bar and 167°C. The refrigerant in the gaseous state flowed to Condenser 1 where the water from the DH greed preheated up to 70°C. After Condenser 1, the mixture of fluid and gaseous refrigerant flowed to the separator vessel. In the separation vessel the refrigerant was separated into two fractions. The liquid fraction was forward to the evaporator via expansion valve and gaseous refrigerant continued be compressed in the high-pressure compressor (HPC). The HPC compressed working fluid from 30 bar and 66°C to 76 bar and 172°C. Further, the hot vapor flowed the condenser 2 and DH water was after-heated up to the temperature of 105°C. Finally, the high-pressure refrigerant flowed back to the separator and cycle continued.

The simplified model of HP's power use can be expressed as:

$$P_{HP}(Q_{HP}) = d_3 \cdot Q_{HP}^3 + d_2 \cdot Q_{HP}^2 + d_1 \cdot Q_{HP} + d_0 \qquad (4)$$

where Q_{HP} is required heat output to the DH system, d_3, d_2, d_1, d_0 are the model coefficients.

The polynomial model of the HP is depicted on the Fig. 6..

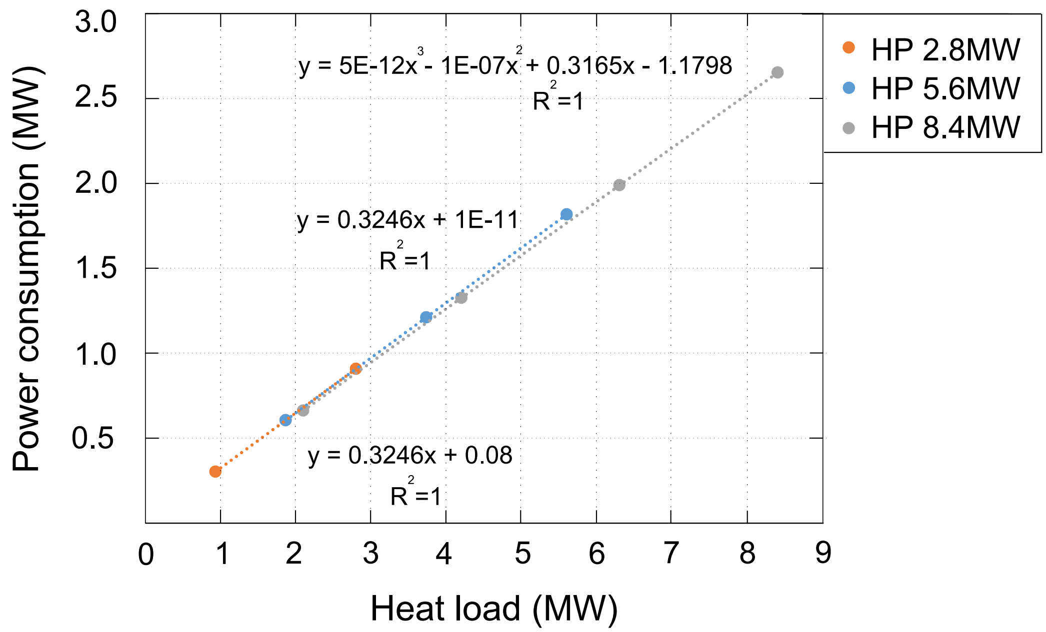

Fig. 6. Power consumption versus DH load in HP

Due to low variation of heat source temperature, the COP of the analyzed HP was almost equal to 3.3. Similar valued were found in the literature for the HP performance.

4.4 Electric boiler

The employed electric boiler model was described by linear dependency. The boiler control ability was adjusted between 10 – 100% [31] and had efficiency of $\eta = 99\%$.

4.5 Existing method for heat supply optimization

In this paper the new, suggested, method is compared to the existing method of heat supply optimization. The existing method implies the following assumptions: constant energy price; 0 – 100% control range of the plant capacities; no influence of plant size on investment cost; constant plant efficiency regardless of the plant load. This method was developed primarily for electrical energy planning and explained in details in [21]. Further, the method was adjusted to DH needs [1].

The total cost for the heat generation can be expressed as:

$$C = C_{fix} + C_{var} \tag{5}$$

where C is a total annual cost which consists of an annual fixed cost, C_{fix}, and a variable operating cost C_{var}.

The specific cost for each heat unit will be:

$$c = c_{fix} + c_{var} \cdot \tau \tag{6}$$

where c is a specific total cost per capacity unit, c_{fix} is a specific investment cost per installed heat unit, c_{var} is a variable cost per heat unit, τ is operation time.

The specific total cost per installed heat unit can be found as:

$$c = C/P \tag{7}$$

where P is installed heat rate for each plant.

The specific investment cost can be found as:

$$c_{fix} = C_{fix}/P \tag{8}$$

Thus, the variable cost per heat unit can be expressed as:

$$c_{var} = C_{var}/Q \tag{9}$$

where Q is annual heat supply.

The break-even times of plants operation can be found for a various number of energy production units that are taken in optimization process. Eq. (10) and Eq. (11) shows situation where three energy production plants are optimized in order to find the lowest annual total cost. The break-even times $\tau_{1,2}$ and $\tau_{2,3}$ are obtained using the basic optimization condition that stipulates that the total cost should be equal for two competing plants at each intersection:

$$\tau_{1,2} = (c_{fix,2} - c_{fix,1})/(c_{var,1} - c_{var,2}) \tag{10}$$

$$\tau_{2,3} = (c_{fix,3} - c_{fix,2})/(c_{var,2} - c_{var,3}) \tag{11}$$

4.6 The suggested methodology for analysis of the energy supply plants

In order to combine the plants properly, there is a need to identify the total number of combinations. Therefore, the basic formula for the number of possible combinations of k objects from a set of n objects can be written as:

$$\binom{n}{k} = \frac{n \cdot (n-1) \ldots (n-k+1)}{k \cdot (k-1) \ldots 1} = \frac{n!}{k! \cdot (n-k)!} \tag{12}$$

The Eq. (12) applied in this study allows finding the total number of possible plants' sets with three elements in each of them.

The method implied to use plant capacities in proportion of 20%, 40%, and 60% of the maximum DH load (see Section 5), which makes it easier to develop combinations sets. In this study heat generation units were combined in three dimension sizes: 2.8 MW that corresponds to 20% of the full DH load, 5.6 MW equal to 40% of the full DH load, and 8.4 MW equal to 60% of the DH load. One of the conditions is that a combination set should employ different technologies in it without repetitions. Another is that three plants should not have total heat capacity more than 100% of the DH load e.g. 14 MW. Therefore, under these conditions a number of generated plant combinations (PCs) by Eq. (12) was limited to 36.

Fig. 7. shows how the plants were combined. The PCs are based on plant ability to satisfy base load. When one technology is chosen for the base load, other technologies cover the rest of the load as an intermediate and peak load plants.

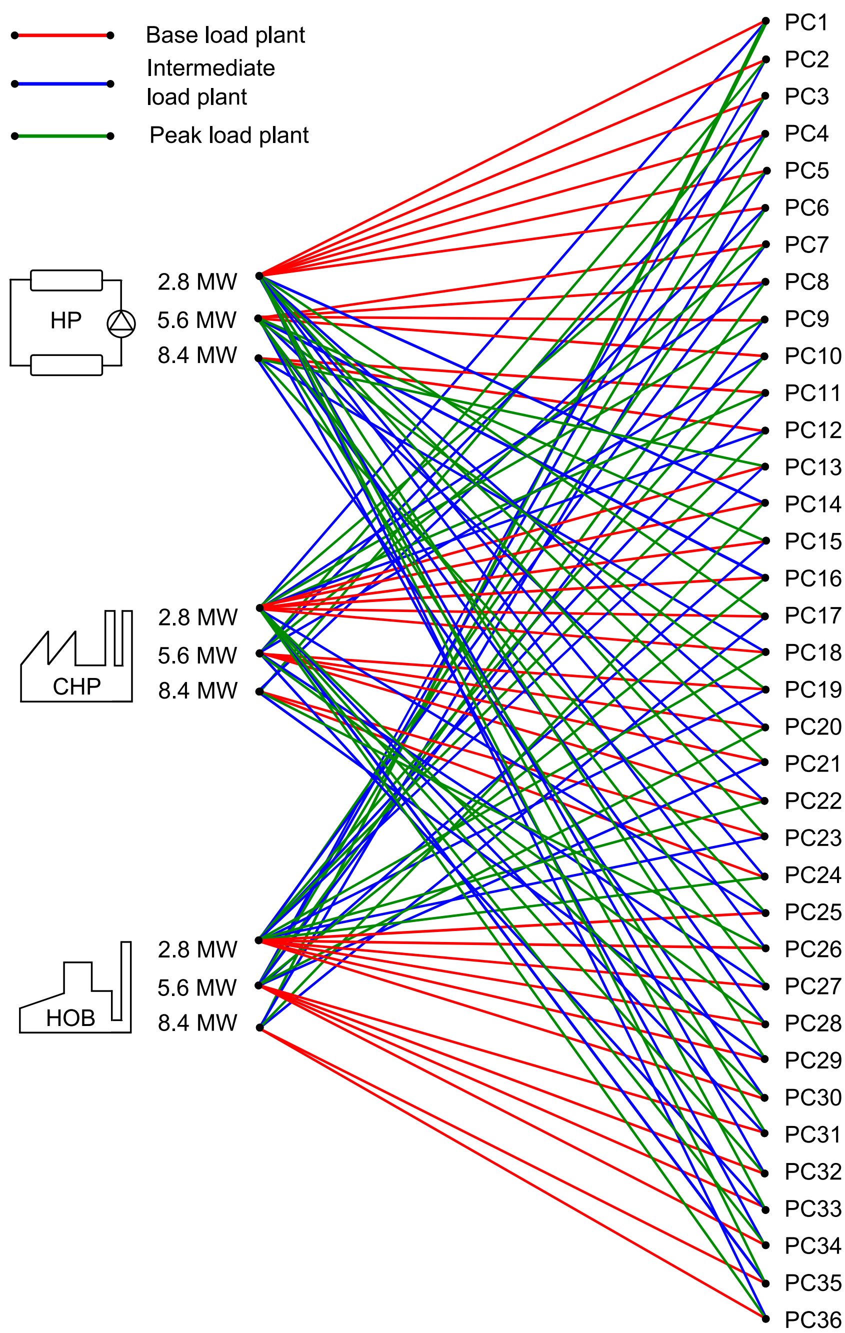

Fig. 7. Analyzed combinations of energy supply sources

Fig. 7. shows three energy generation technologies with different heat outputs developed in combination sets. The color lines indicates plant's attachment to base load, intermediate load or peak load. The electric boiler was not included in Fig. 7, however, each combination has an

electric boiler of 3 MW of heat output to cover extreme operation situations and as a back-up plant. Fig. 8. introduces the information flowchart for the new method used in this analysis.

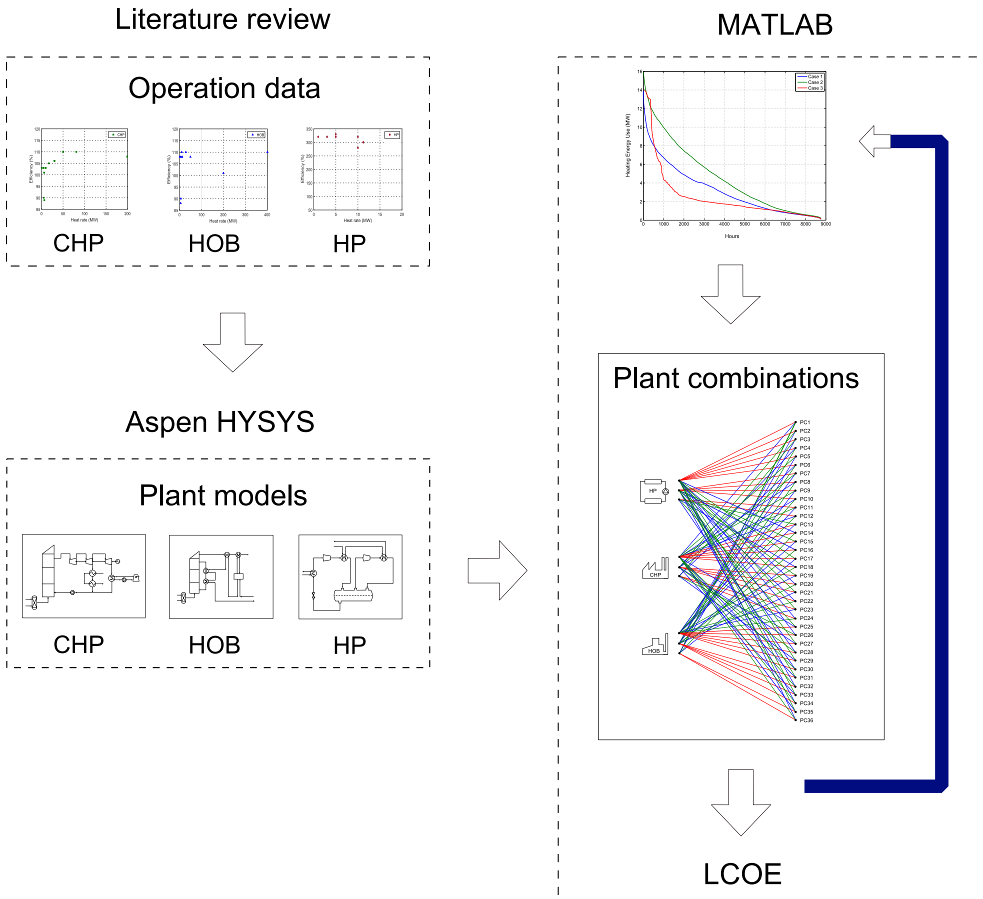

Fig. 8. Information flowchart for the new method for energy planning

4.7 Economical evaluation

In Section 3 the overview of the cost data for technologies and fuel prices was presented. This section introduces technique for performing the cost analysis. In this study, the levelized cost of energy (LCOE) [56] approach was used to compare PCs. The LCOE of a given technology is the ratio of lifetime costs to lifetime energy generation, both of which are discounted back to a common year using a discount rate that reflects the average cost of capital

[57]. The LCOE allows alternative technologies to be compared when different scales of operation, different investment and operating time periods, or both exist [56].

The LCOE can simply be presented as:

$$LCOE = \frac{Total\ Life\ Cycle\ Cost}{Total\ Lifetime\ Energy\ Production} \tag{13}$$

The total life cycle cost in the Eq. (13) includes capital investment cost, O&M cost, and fuel cost. The capital investment cost can be estimated as:

$$I_t = I_{CHP} + I_{HOB} + I_{HP} + I_{Elb} \tag{14}$$

where, I_{CHP}, I_{HOB}, I_{HP}, I_{Elb} are investment costs for installation of CHP, HOB, HP and electric boiler.

The fixed share of O&M includes all costs, which are independent of how the plant is operated, e.g. administration, operational staff, planned and unplanned maintenance, payments for O&M service agreements, network use of system charges, property tax, and insurance. Re-investments within the scheduled lifetime are also included, whereas re-investments to extend the life are excluded. While variable O&M costs included consumption of auxiliary materials (water, lubricants, fuel additives), treatment and disposal of residuals, output related repair and maintenance, and spare parts (however not costs covered by guarantees and insurance) [31]. Therefore, the O&M costs can be found as:

$$M_t = C_{var}^{CHP} + C_{var}^{HOB} + C_{var}^{HP} + C_{var}^{Elb} + C_{fix}^{CHP} + C_{fix}^{HOB} + C_{fix}^{HP} + C_{fix}^{Elb} \tag{15}$$

where, C_{var}^{CHP}, C_{var}^{HOB}, C_{var}^{HP}, C_{var}^{Elb} are variable O&M costs, and C_{fix}^{CHP}, C_{fix}^{HOB}, C_{fix}^{HP}, C_{fix}^{Elb} are fixed O&M for CHP, HOB, HP, and electric boiler.

The fuel consumption cost was evaluated as a sum of biomass fuel consumed by CHP, and HOB, and electricity needed for operation of electric boiler and HP:

$$F_t = C_{fuel}^{CHP} + C_{fuel}^{HOB} + C_{el}^{HP} + C_{el}^{Elb} \tag{16}$$

where, C_{fuel}^{CHP}, C_{fuel}^{HOB} present the fuel cost for operation of CHP, HOB, HP and electric boiler. The allocation of CHP's fuel cost between thermal production and electrical production was based on an energy method [58]:

$$f_Q = Q/(Q+E) \tag{17}$$

where, Q and E represent thermal and electrical production.

Finally, including all the costs, Eq. (13) can be rewritten as:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{Q_t}{(1+r)^t}} \tag{18}$$

where, I_t is investment expenditures in the year t; M_t is O&M expenditures in the year t; F_t is fuel expenditures in the year t; Q_t is heat generation in the year t; r is a discount rate; and n is life of the system.

The discount rate is meant to reflect the loss of utility from deferred consumption and the degree of systematic risk of the project [59]. The discount rate used in various analyses in the energy sector in Norway is determined by the Norwegian Water Resources and Energy Directorate (NVE) [60], based on instructions from the Ministry of Finance. Since DH is normally considered as investment with low economic risks [1], the NVE has stated to apply discount rate of 4.0 – 6.5% for bio-based DH systems [61, 62].

The technical life of technologies can be adopted from [31, 33, 63], for biomass CHP is typically 20 – 25 years, for biomass HOB and large scale vapor compression HP and electric boiler this value is 20 years [31].

Based on literature review presented in Section 3, the investment and O&M costs given in Table 2 were selected for this analysis. However, some uncertainty in these values could take place. Therefore, in order to evaluate consequences due to inaccurate cost data, the uncertainty analysis is presented in Section 6.

Table 2. Investment and O&M costs used in the analysis

Plant type	Plant capacity (MW)	Investment costs (MEUR/MW)	Fixed O&M cost (EUR/MWhfuel)	Variable O&M cost (EUR/MWhfuel)
CHP	2.8	3.0	2.0	2.6
	5.6	2.6	2.0	2.6
	8.4	2.3	2.0	2.6
Biomass HOB	2.8	0.8	2.1	2.0
	5.6	0.6	2.1	2.0
	8.4	0.5	2.1	2.0
HP	2.8	0.25	6.0	0.2
	5.6	0.42	6.0	0.2
	8.4	0.6	6.0	0.2
Electric boiler	3.0	0.15	1100 EUR/MW/year	0.5 EUR/MWh

After evaluation of different prices of biomass fuel and electricity rates presented in Table 1, the biomass fuel price was chosen as 75 EUR/tonne and electricity price 0.12 EUR/kWh.

5. Case study

The analysis of different combinations of energy supply technologies was based on heat energy demand measured in the university campus. The required supply and return temperature levels in the DH system were assumed 105 – 50°C. In this study, three heat demand profiles were considered to illustrate influence of different load distribution. The analyzed duration curves are depicted in Fig. 9..

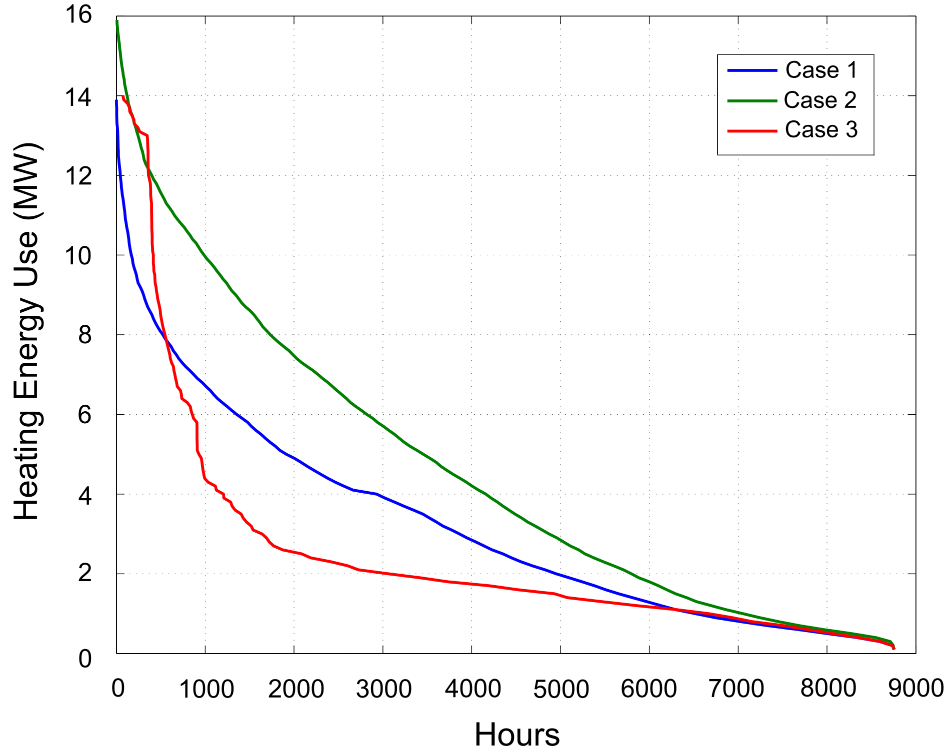

Fig. 9. Heat duration curves

Case 1 in Fig. 9. presented the heat duration curve during a regular year in the analyzed location and was used as a reference year. Case 2 presented the heat duration curve under a higher occupancy level and lower outdoor temperature. The heat duration curves in Case 1 and Case 2 were measured at the university campus. Case 3 presents the situation for future energy use, taking into account newly-built passive houses and nearly zero energy buildings (nZEB) with low heat energy use throughout the year and high peaks occasionally. Case 3 is the result of an assumption and is characterized by a decrease in heating energy use of 22.17% in comparison with the reference year. The heat load characteristics of the analyzed cases are summarized in Table 3.

Table 3. Heat load characteristics

	Case 1	Case 2	Case 3
Heating energy use (GWh)	27.48	40.06	21.39
Average DH load (MW)	3.14	4.57	2.44
Heat rate under maximum hours' frequency (MW)	1	1	2
Duration of maximum heat rate (hours)	2465	1887	3547
Heat rate under minimum hours' frequency (MW)	14	16	11
Duration of minimum heat rate (hours)	14	38	12
Utilization time (hours)	1962	2861	1528

6. Results

Energy planning results by using the existing method of heat supply optimization are shown first. Afterwards, the findings from the new method of energy planning are shown.

6.1 Results on the existing method

The main idea of different optimization techniques is finding the best solution that satisfies DH operation from both technical and economical points. Therefore, the existing method for heat supply optimization balances operation cost and investment cost for achieving the lowest total annual cost. This method is explained in Section 4.5. Fig. 10. introduces the existing plant optimization method.

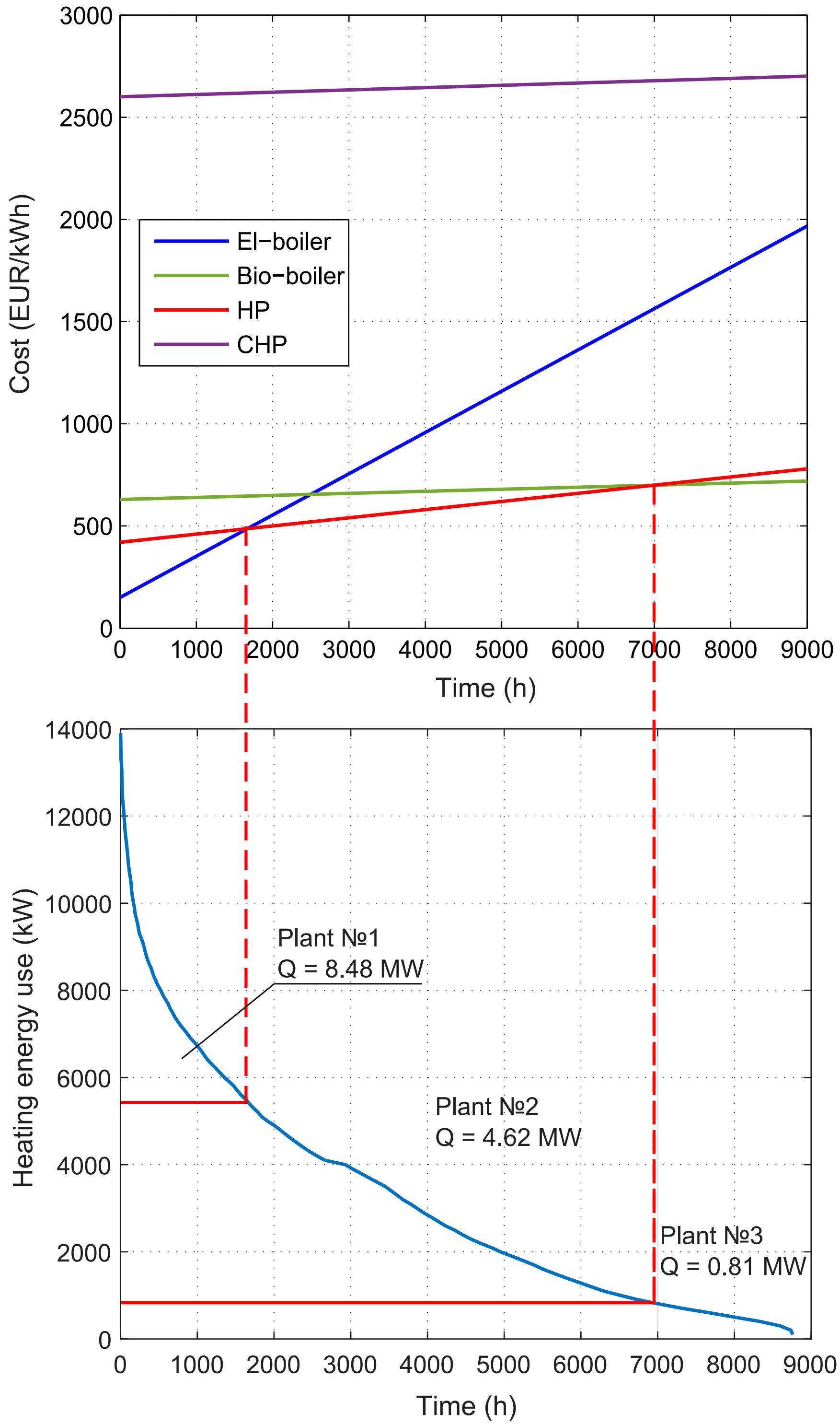

Fig. 10. The linear cost characteristics for three plant model is shown in the upper diagram and the corresponding optimal division of plant capacities are shown in the lower duration diagram

Fig. 10. shows that the electric boiler has lowest investment cost and therefore, it is beneficial be utilized as a peak load plant from 0 – 1760 hours. The intermediate load should be covered by the HP and the base load by HOB. Further, it can be noted that CHP is not a relevant plant according to the existing method, because the investment is too high. In reality, it is well known that CHP is reliable provider of heat supply and it is beneficial to run it as a base load plant. In Fig. 10., the plant capacities could be distributed as follows: for the peak load plant an electric boiler of 8.48 MW maximum rate, for the intermediate load plant HP of 4.62 MW, and for the base load plant HOB of 0.81 MW.

The sensitivity analysis of the current optimization method (Fig. 10) was performed in order to estimate robustness of the method due to change in heat load. Table 4 shows sensitivity results.

Table 4. Sensitivity of the current optimization method due to different load profiles

		Electric boiler	HP	HOB
Case 1 DH cost – 0.109 EUR/kWh	Heat capacity (MW)	8.48	4.62	0.81
	Heat energy use (MWh)	1352	12899	13216
Case 2 DH cost – 0.104 EUR/kWh	Heat capacity (MW)	8.22	7.13	1.03
	Heat energy use (MWh)	304	18510	21232
Case 3 DH cost – 0.083 EUR/kWh	Heat capacity (MW)	11.05	2.08	0.87
	Heat energy use (MWh)	1458	7902	12005
Operation hours		1166	5334	1 760

From Table 4 it can be seen that change in heat load induced significant variation in the plant heat capacities . For the electric boiler the induced change was between 1% and 23%, for HP was 55% and 70%, and for HOB was between 7% and 22% due to load change. This showed that this method is very sensitive to changes in heat load profile. In turn, this can lead to low load factor for operated plants and further effect the DH price.

The uncertainty due to change in investment cost in the range of ±10% showed that electric boiler was not sensitive, which lead to negligible change in DH price of less than 1%. However, HP and HOB were more effected. The change in HP's investment cost induced +9.6% – -12% change in DH cost. For HOB these values were even higher and constituted -22% – +18%. The effect due to multiple uncertainty induced change of -11% – +11.4% on DH cost or ±0.01 EUR/kWh for both reduction and increase in investment cost. In addition, these lead to change in heat capacities of selected plants. Hence, the method is also sensitive to variation in investment cost.

The uncertainty due to change in energy cost for chosen plants was carried out in the range of ±10%. The largest change in DH cost induced the HP (+7.61% – -6.79%). For the HOB these values were in the range of -2.2% – +2.7%, while for the electric boiler -3.4% – +3.5%. However, the impact due to multiple uncertainty showed 1% change in DH cost. As it can be seen, the change in the investment cost induced larger change in DH cost than change in energy cost. This means that existing method of heat supply optimization is sensitive to change in investment cost of analyzed technologies.

The conclusion from the above analysis was that the existing method was sensitive to variations in heat load profiles. This meant that any future change in heat demand would influence the heat cost. Further, some expensive technologies such as CHP might be excluded due to high investment cost. Finally, it does not show how DH should be equipped and operated over a long term in order to minimize the annual cost of heat supply [1].

6.2 Results on the new method

The entire approach for the new method was introduced in Section 4.6. and 4.7. The most relevant results are presented here. Fig. 11. present LCOE for different combinations of energy supply technologies, based on heating load profile marked with Case 1. Under the reference year, the LCOE varied from 0.085 – 2.554 EUR/kWh. Therefore, for the purpose of better representation and further analysis, the found values were sorted in two categories: lower than 0.2 EUR/kWh and higher than 0.2 EUR/kWh. According to [57], the cost for electricity generation in Europe varies from low 0.06 EUR/kWh to high 0.19 EUR/kWh depending on technology and local conditions. Therefore, Fig. 11. shows the LCOE results for the analyzed PCs that are competitive with power generation cost and consequently, with the direct electric heating.

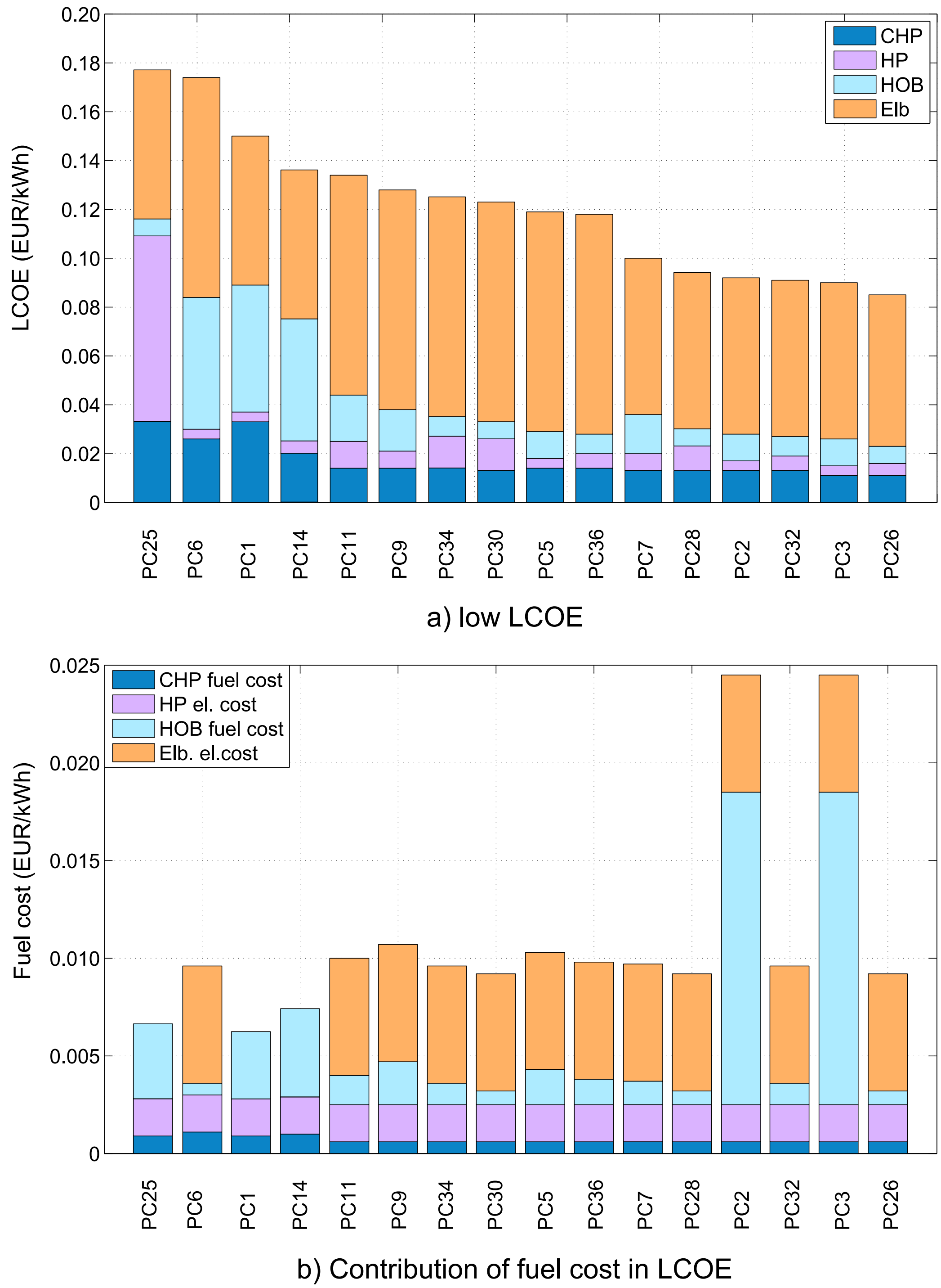

Fig. 11. Low LCOE and fuel cost in these plant combinations

In this study, it was assumed that electric boiler would be used to cover heat load in the DH system due to limitations in combined operation of the HP, the CHP, the HOB, and during extreme operation situations. From Fig. 11.a it can be seen, that heat energy produced by electric boiler constitutes a high portion of the LCOE. Due to high value of O&M cost, the operation of electric boiler makes DH not competitive in comparison to direct electric heating. Next, it can be noticed that the HP's contribution to the LCOE was relatively low for presented plant combinations. From this point, it can be concluded that presented heat capacities of the HP fits well to the analyzed PCs. The exception was combination PC25, where the 8.4MW HP was operated as a peak load plant. This means that the HP should not be used as a peak load plant with a high installed heat rate.

Fig. 11b shows again that the highest fuel cost of each combination was due to operation of electric boiler. The exceptions were PC2 and PC3, where the HOB was operated as an intermediate load plant. In addition, PC1, PC14, and PC25 operated without electric boiler. Due to high COP of the HP, the electricity use was low in comparison to total LCOE value presented in Fig. 11.a. In the countries with low electricity prices, like in Scandinavia, the employment of the HP for heat supply purpose is a good option of efficient heat energy supply. The fuel use for the CHP was low, even for configuration where its heat load share was 60 %. The similar trend was found for the HOB operation.

As it was highlighted earlier, the electric boiler was used during extreme operation situations. Fig. 12 shows combined operation of energy supply plants based on PC28, where the HOB was used as base load plant covering 20% of the maximum heat demand, the HP was used to cover the intermediate load covering 40 % of the maximum load, and the CHP was utilized to cover the peak load with 20 % of the maximum load.

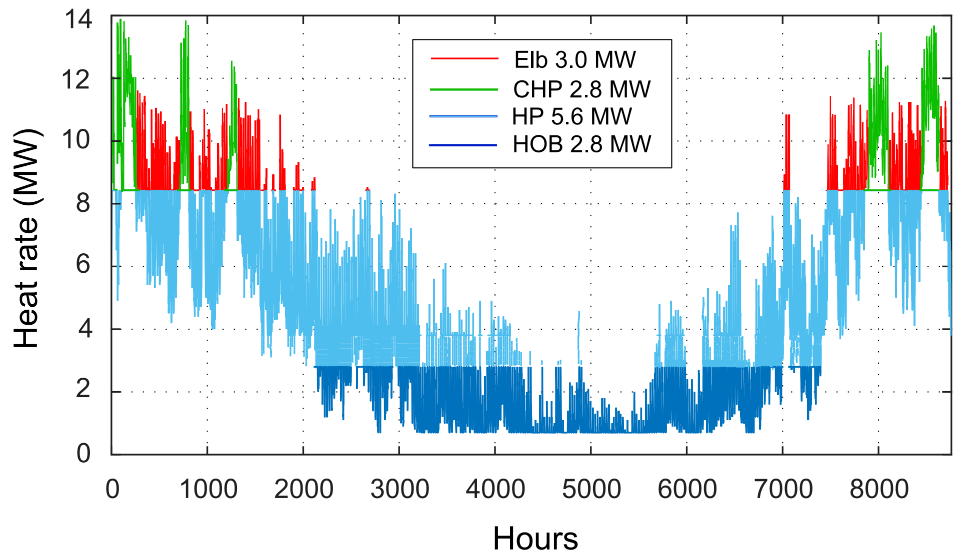

Fig. 12. Hourly heat rate distribution for the PC28

From Fig. 12 it can be seen that due to limitations in CHP operation, see Section 4.1, the electric boiler was used to cover DH load when CHP was in standstill mode. In general, to run electric boiler is convenient due to simplicity and no limitations in operation regimes. However, in a long-term operation this can lead to an increase in DH price, which existing and new customers consider impermissible.

The second part of PCs consist of combinations where the LCOE values were higher than 0.2 EUR/kWh, see Fig. 13.

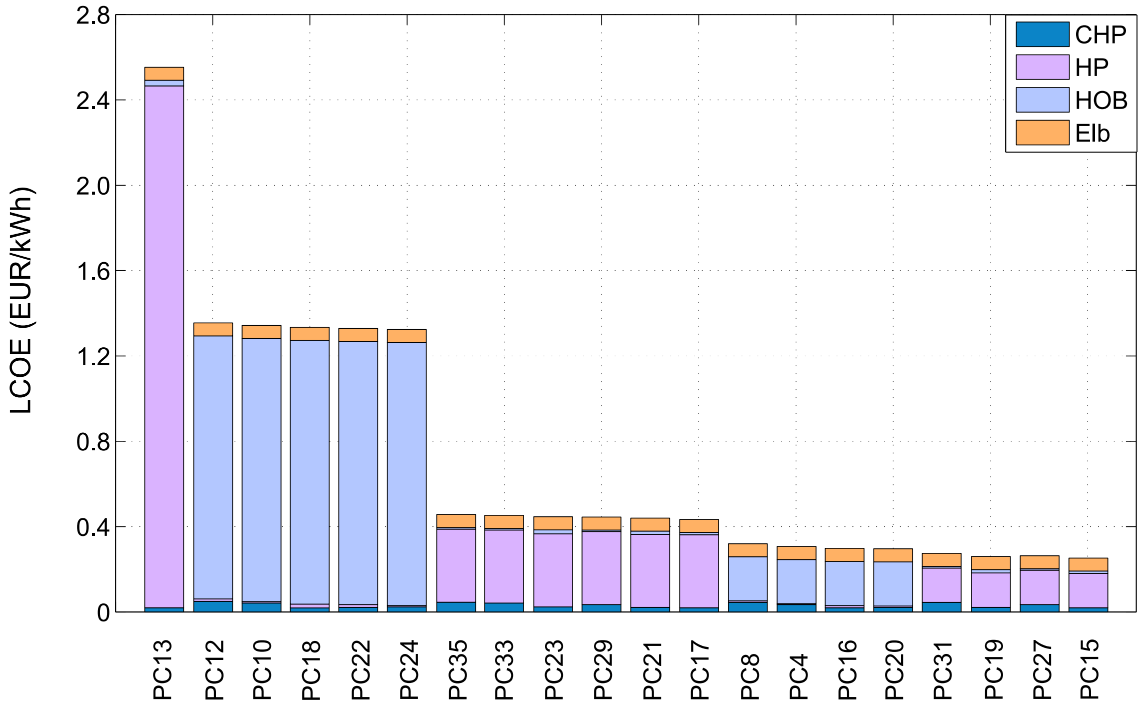

Fig. 13 High LCOE

It was found that the contribution of the electric boiler to LCOE was equal in all combinations. This meant that it was not operated. These values present the investment cost for this technology. Next, the high values of the LCOE for the HOB and the HP were due to low heat load factor. However, in the case of the CHP, the low heat load factor was substituted by electricity production and corresponding heat allocation factor of utilized fuel. Therefore, there was no high discrepancy between the presented CHPs’ cost in the LCOE and it was very low. PC13 showed the highest value of LCOE. The reason for this is the same as for the PC25, where the HP with the high heat capacity was operated as the peak load plant.

Changes in the LCOE due to different heat load patterns were also investigated. The analysis was performed for combinations that have low LCOE and introduced in Fig. 11.

Fig. 14 present the LCOE for different heat load patterns and different combinations of energy supply technology. To recall, Case 2 introduces the scenario where the heat duration curve was under high occupancy and lower outdoor temperatures, Case 3 shows scenario where heat duration curve is constructed for future building stock.

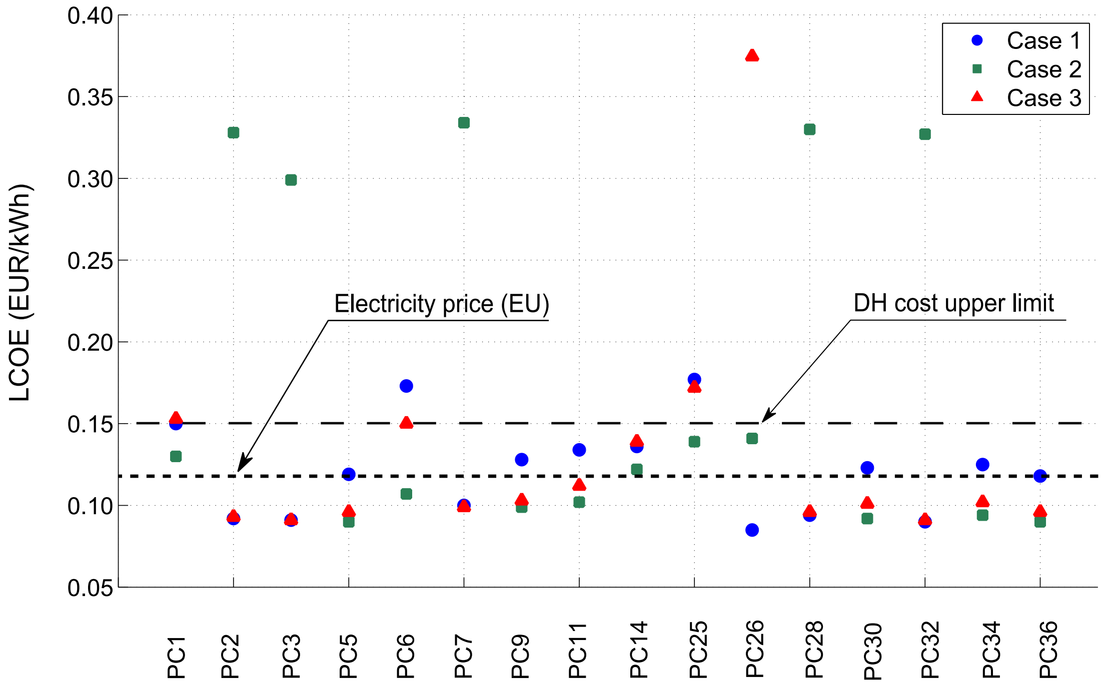

Fig. 14 LCOE values for analyzed scenarios

In order to stay competitive on the energy market, the heat generation cost should be lower than alternatives. At this point, this means that heat generation cost should be lower than the electricity production, to avoid switching to the direct electric heating. As it can be seen from Fig. 14, several combinations could be highlighted to be competitive in a long-term perspective, because the gave the low heat cost regardless of the heat load change These combinations were: PC5, PC30, PC34, and PC36. Four additional combinations PC1, PC9, PC11, and PC14 could be underlined as an alternatives with the LCOE values lower than 0.15 EUR/kWh. It can be noticed, that all these combinations have a small CHP as a peak load plant. The exception is combination

PC14, where a large HOB was utilized for this purpose. Further, in comparison to all the PCs presented in Fig. 7., the above-mentioned combinations found the lowest LCOE values under the duration curve of Case 2. This means that the heat load factor increased, which provided better energy utilization in mentioned combinations. The found plant sizes fitted perfectly to required DH loads.

Among eight PCs (PC1, PC5, PC9, PC11, PC14, PC30, PC34, PC36) only one employed the CHP as a base load plant. In addition, its heat capacity was only 2.8 MW. At the same time different sizes of the HOB and the HP were utilized for the base load plant. For the intermediate load plants the trend was similar, while for peak load plants the most of combinations employed the small CHP. The found trend for peak load plants was found due to application of CHP's allocation method.

The summary of the LCOE values under different heat load profiles can be seen in Table 5.

Table 5. Heat generation cost under different load profiles

Combination	Case1 (EUR/kWh)	Case 2 (EUR/kWh)	Case 3 (EUR/kWh)
PC1	0.150	0.130	0.153
PC5	0.119	0.090	0.096
PC9	0.128	0.099	0.103
PC11	0.134	0.102	0.112
PC14	0.136	0.122	0.139
PC30	0.123	0.092	0.101
PC34	0.125	0.094	0.102
PC36	0.118	0.090	0.096

Table 5 shows that the variation in the heat generation cost due to change in heat load patterns was in the range of 12.2 – 25.2% or 0.017 – 0.031 EUR/kWh of heat. The lowest differences were found for the combinations PC14 and PC30. At this point it could be concluded that these two combinations were the best solution for customers due to smallest change in DH cost under different heat loads. However, combinations PC5 and PC36 should be highlighted, because they showed generation cost reduction for both increase and decrease of the DH load. In PC36, a 8.4 MW HOB was employed for the base load plant, a 2.8 MW CHP covered intermediate load, and a 2.8 MW HP was used for peak load. PC5 included the following plants: a HP of 2.8 MW for the base load plant, a HOB of 8.4 MW for the intermediate load, and a CHP of 2.8 MW for the peak load. The combinations presented in Table 5 showed the lowest LCOE for different heat load profiles among all the 36 combinations. This is very important, since employing these combinations DH customers would pay upon consumed heat based on best matched operation of heat production units.

Fig. 15 shows dependence between the LCOE and system efficiency for different PCs under different heat load profiles.

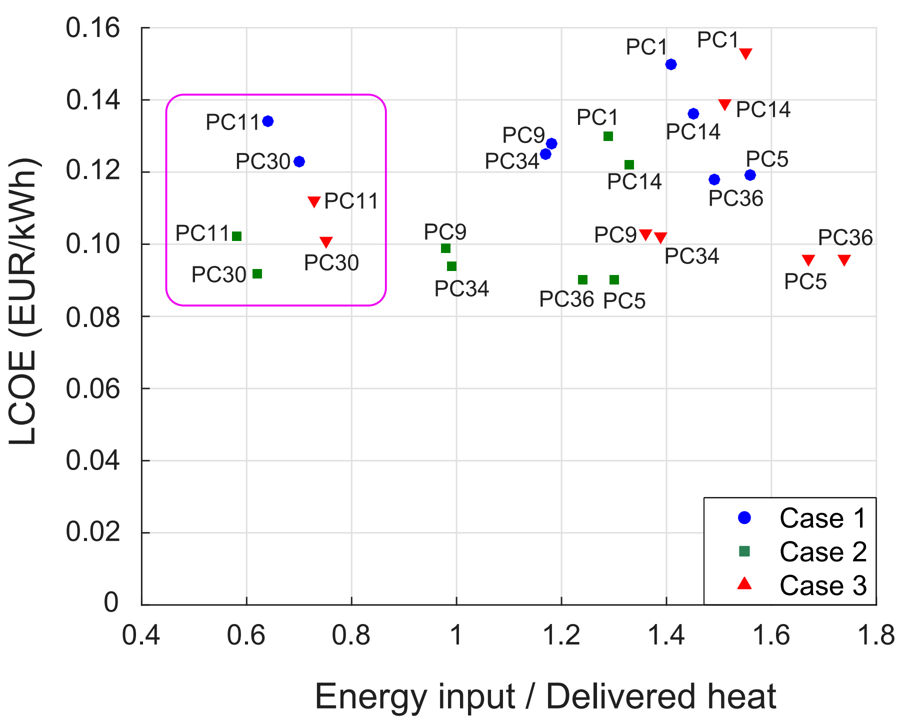

Fig. 15 LCOE and system efficiency for different heat supply options under three heat loads

Fig. 15 shows that plant combinations PC11 and PC30 are more energy efficient under different heat loads than other combinations. As it found before, the PC30 and PC14 had the lowest difference in values of LCOE under different heat loads, see Table 5. However, Fig. 15 shows that in terms of energy input per delivered heat, the PC30 is more efficient than PC14. Apart from PC30, the low value was found in combination PC11. The reason for this is that both PC11 and PC30 employed large HP for base load and intermediate load.

6.3 Uncertainties due to fuel price volatility, variation in investment cost, and model quality

The uncertainty analysis performed in this section was executed for eight PCs with low LCOE and showed in Table 5. The analysis was based on values from the literature review and presented in Table 1. The following fuel prices were considered: the minimum for electricity was 0.113 EUR/kWh, for wood chips was 40 EUR/kWh, while the maximum for electricity was 0.127 EUR/kWh and for wood chips 136 EUR/kWh.

The analysis found that the highest variation in total LCOE had combinations where the HOB was operated as an intermediate load plant. This mean that increase in the fuel price would have negative effect on LCOE for this technology. The total deviation in LCOE values for the presented PCs due to price volatility was in the rage of 1.6% – 3.6% or 0.002 – 0.005 EUR/kWh. The largest deviation for the CHP fuel cost was found in combinations where the CHP was operated as an intermediate load plant (PC1, PC6 PC14, and PC25), while the smallest deviation was found where the CHP was operated for the peak load. The largest deviations for the HOB fuel cost were found for the HOB operated as the intermediate load plant for small and intermediate heat capacities. Further, operation of the HOB as a base load plant showed the smallest variance in cost. In comparison to the results found for the CHP and the HOB, the consequences of the HP's price variation were minor in the analyzed range. One of the reasons for this is that the cost foundation for electricity production and wood chips collection is different.

The uncertainty due to variation in investment cost showed that the increase in the CHP's investment cost by 20% induced changes in the LCOE by 15 – 16% for the analyzed combinations. When the CHP's investment cost were decreased by 20%, the change in LCOE constituted around 19%. In comparison to the CHP, the change in investment cost for the HP and the HOB had similar trend. The increase and decrease in the HP's investment cost by 20% led to change in total annual cost by around 14 – 17 %. For the HOB these values were in the range of 14 – 20%. Hence, underestimation of investment cost can lead to significant changes in LCOE values for these technologies.

The introduced energy plant models presented Section 4 were simplified by using polynomial models as shown in Fig. 2., Fig. 4. and Fig. 6.. Even though the obtained goodness of fit (R^2) was high, some uncertainty could take place.

The uncertainty due to model quality showed that The HP's model had larger effect on LCOE in comparison to the CHP and the HOB model. The deviation in the HP model in the range of ±10% induced a change in LCOE by 1.42 – 4.7%. In the case of the HOB and the CHP models, the consequences were smaller, around 1%. The impact of multiple uncertainties simultaneously induced changes in the range of 1%. The conclusion is that the introduced models proved to be accurate enough for this analysis.

7 Discussion

The existing method of heat supply optimization was found to be simple to treat all the costs and operation issues. A number of additional important factors affecting plants operation are missing. It was found that the method is sensitive to change in heat load profiles. In turn, this could lead to low load factor for operated plants and further increase the DH cost. Further, the calculated DH cost showed that with the decrease of heat load, the DH cost decreases. However, it is not always the case due to possible mismatch in plants' operation. This means that more operation hours required fulfilling the same DH load and increase in DH cost is inevitable. In addition, the existing method is also sensitive to variation in investment cost, while the variation in energy cost induced minor changes to DH cost. All these causes misleading results, affecting the DH cost foundation. Further, it is very simplified with respect to real sizes, operation times, and actual plant performance. In comparison to the existing methodology, the new method suggested by the authors is sophisticated and involves deeper analysis.

The analysis of found results for the new method showed that the operation of the electric boiler could be avoided and DH companies should eliminate this technology from the DH system. In all the analyzed combinations the electric boiler operation constituted from 38 to 790 hours of intermittent operation at full heat capacity. As an alternative to this, the thermal energy storage (TES) could be considered. In addition, employing TES could lead to increase in heat load factor for intermediate and peak load plants.

All the PCs showed high LCOE values due to operation of electric boiler. The LCOE remained high even when electric boiler was not put in operation. The reason for this might be the high value of the fixed O&M cost used in the analysis. This value was adopted from technical report [31] with reference in 2012 year. It can be doubted about meaningfulness of this value. However, the report dated two years earlier showed this value in the same range that makes adopted value be reasonable. Therefore, some changes in this value might change the results of the study. However, any decrease of this high value of the fixed O&M cost would give a decrease in the DH cost.

Further, it was not appropriate to conclude that all the combinations presented in Fig. 13 were not competitive to direct electric heating. As it was discussed previously, the found values were mainly due to actual operation and low heat load factor facing those combinations. Hence, at this point, it is possible to look at those combinations at an angle of future development and extension of DH systems.

The fuel between heat and power production was allocated by the energy method. In turn, this made the CHP operation highly efficient due to substitution of low heat load by electricity load and further fuel allocation to power production. This showed that the CHP operation as a peak load plant was efficient. However, a number of technical allocation methods were developed and used in different countries. Therefore, the possible deviations in LCOE might be present due to application of different allocation methods.

The example with the existing method of heat supply optimization found that it was inappropriate to utilize the CHP due to its high investment cost. However, the new method showed opposite. The small CHP plants could be employed for peak load operation. This was a god observation, since this goes along with the Directive 2004/8/EC [64] on promotion of highly-efficient cogeneration. The more CHP used, the more primary energy is saved and the higher the security of the energy supply.

If one considers four technologies discussed in this study, it was shown that modern HOBs were very efficient. In comparison to other technologies, its linear cost characteristic could show decrease with the increase of operation hours. This provides possibility to employ a single HOB for annual operation. However, the employment of a single plant decreases security of supply in the DH systems. To avoid this, the need in several heat production units arises. Hence, the cost difference utilizing four plants would always be higher than with three or two. Therefore, it can be concluded, that with the increase of DH's flexibility and reliability of supply, the heat generation cost increases.

8 Conclusion

In this paper, the economic issues associated with the decision on heat production plant combinations were analyzed. The study focused on the situation when there is a need in construction of a set of plants for new DH system. Three heat duration curves together with three highly efficient energy conversion technologies were considered. The existing method of heat supply optimization was compared to the new method.

The results on the new method found that the operation of electric boiler led to high value of the LCOE, in spite of the fact, that it was operated sporadically and maximum heat output was 3 MW of heat. Next, one should consider electricity rates, since not many countries have cheap electricity like in case of Norway and Sweden. This revealed that operation of electric boiler was rather expensive and should be limited to minimum. In addition, policy makers should provide legislative framework to ban this technology from DH.

The study identified sixteen PCs with the LCOE under 0.2 EUR/kWh. However, not all of them were found non sensitive to change in heat load profiles. Further, eight PCs were selected as those with low sensitivity to heat load variation and the LCOE under 0.15 EUR/kWh (PC, PC5, PC9, PC11, PC14, PC30, PC34 and PC36). It was noticed that six of those had a small CHP as a peak load plant. However, it was opposite compared what the existing method suggested. Among the eight combinations only one employed the CHP as a base load plant with heat capacity of 2.8 MW. At the same time, the HOB and the HP technologies utilized all there sizes for the base load plant. For intermediate load plants the trend was similar, while for the peak load plants, most of the combinations employed a small CHP. It was concluded that the operation of a large HP for the peak should be avoided due to low heat load factor and high investment cost.

The change in heat load profiles showed that with the increase of heat use (Case 2), the mentioned eight combinations showed the lowest LCOE. This meant that the heat load factor increased that provided better energy utilization. The found plant sizes fitted perfectly to satisfy required DH loads. The lowest difference in the LCOE under different heat loads were found for the combination PC14 and PC30. These two combinations were the best solution due to smallest change in DH cost under different heat loads. The normal trend of DH cost was increase over the years due to change in heat load, however, PC5 and PC36 showed that DH generation cost could be lowered. This was a good finding for future development of DH and for customers due to protection against increase in price.

The analysis on system efficiency found the most rational utilization of energy input under different heat loads had combinations PC11 and PC30. The main reason for this is that large HP was used in these combinations to satisfy the base load and intermediate load.

The uncertainty in fuel price found that the highest variation in the LCOE had combinations where the HOB was operated as an intermediate load plant. This means that increase in fuel cost would have negative effect on the LCOE for this technology employed for intermediate load. The total deviation in the LCOE values for presented combinations due to price variation was in the rage of 1.6% – 3.6% or 0.002 – 0.005 EUR/kWh. The consequences of price variation for the HP were smaller than for the CHP and the HOB in the analyzed range. One of the reasons for this was that the cost foundation for electricity production and wood chips collection was different. However, in some countries electricity rates are rather high and a normal trend is its increase within the time. In turn, this can lead to additional portion of O&M cost when HP technology is chosen for operation.

The uncertainty in the PCs due to changes in investment cost in the range of ±20% had an effect of 14 – 20% on the LCOE. Hence, underestimation of investment cost can lead to significant changes in LCOE values for these technologies.

The uncertainty due to model quality found that the HP's model had larger effect on the LCOE in comparison to the CHP and the HOB. The deviation in the range of ±10% induced change in LCOE by 1.42 – 4.7%. In the case of the HOB and the CHP models, the consequences were smaller, around 1%. The impact of multiple uncertainties simultaneously found changes in the range of 4 – 6%. The conclusion is that presented models and the analysis approach proved to be accurate enough for the purpose of this study. Thereby the results and conclusions might be treated as reliable.

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Appendix

Table 6- Table 9 provides a summary of different costs for the following technologies: biomass HOB, CHP, HP and electric boiler. The presented data is given based on LHV of fuels.

Table 6. Investment and O&M costs for biomass HOB

Heat output	Efficiency (%)	Investment costs (MEUR/MW)	Fixed O&M cost (EUR/kW)	Variable O&M cost	Reference
1 MW	108	0.5	Total O&M 5.4 EUR/MWh		[31]
5 MW	108	0.75	Total O&M 5.4 EUR/MWh		[31]
5 MW	88	0.29	Total O&M 278180 EUR		[65]
5.8 MW	90	0.82	Operational costs 1110 kEUR/year		[66]
10.3 MW	110	0.4	2 EUR/MWhfuel	2 EUR/MWhfuel	[67]
12 MW	108	0.5	10	2 EUR/MWhfuel	[6]
12 MW	108	1.1	Total O&M 5.4 EUR/MWh		[31]
28.5 MW	110	0.36	2 EUR/MWhfuel	2 EUR/MWhfuel	[67]
50 MW	108	0.42	8.3	2 EUR/MWhfuel	[68]
200 MW	101	0.09	3.3	-	[69]
400 MW	110	0.33	2 EUR/MWhfuel	2 EUR/MWhfuel	[67]

Table 7. Investment and O&M costs for biomass CHP

Heat/power output	Efficiency (%)	Investment costs (MEUR/MW)	Fixed O&M cost (EUR/kW)	Variable O&M cost	Reference
1 MW	heat - 78 electric - 25	3.6 of heat	3-4 % of investment per year		[31]
5 MW	heat - 78 electric - 25	4.64 of heat	3-4% of investment per year		[31]
5 MW	total - 90	6.0 of heat	Total O&M 0.055 EUR/kWh		[70]
0.5 MWel 5.5 MWheat	electric - 18 total - 83	0.56 of heat 4.71of electric	0.128 EUR/kWel 0.0367 EUR/kWheat		[71, 72]
1.0 MWel 5.8 Mwheat	heat - 65 electric - 24	4.2 of electric 0.4 of heat	Total O&M 0.032 EUR/kW		[66]
10.3 MW	electric - 25 total - 105	3.9 of electric	2 EUR/MWhfuel	2.6 EUR/MWhfuel	[67]
10 MW	heat - 78 electric - 25	4.9 of heat	3-4% of investment per year		[31]

17 MW	heat - 81 electric - 24	1.85 of heat	41	2.4 EUR/MWhfuel	[6]
5 MWel 18 MWheat	electric - 22 total - 104	6.49 of electric	157	2.3 EUR/MWhfuel	[63]
28.5 MW	electric - 27 total - 110	2.3 of electric	2 EUR/MWhfuel	2.6 EUR/MWhfuel	[67]
30 MW	heat - 77 electric - 29	2.6 of heat	29	3.9 EUR/MWh	[31]
30 MW	heat - 79.5 electric - 26.5	1.72 of heat	35.2	2.9 EUR/MWhfuel	[68]
10 MWel 28 MWheat	electric – 27 total - 105	5.15 of electric	116	2.3 EUR/MWhfuel	[63]
50 MW	heat - 81 electric - 29	1.68 of heat	34	kEUR/MW year 24.1	[69]
80 MW	electric - 30 total - 110	1.7 of electric	2 EUR/MWhfuel	2.6 EUR/MWhfuel	[67]
81 MW	heat - 81 electric - 29	1.47 of heat	24.8	3 EUR/MWhfuel	[68]
30 MWel 75 MWheat	heat - 60 electric - 30	3.0 of electric	2.1 EUR/MWhfuel	2.5 EUR/MWhfuel	[73]
30 MWel 76 MWheat	electric - 28 total - 105	4.06 of electric	77	2.3 EUR/MWhfuel	[63]
36 MWel 72 MWheat	electric - 30 heat - 60	1.5 of electric	37 EUR/kWel	4.5 EUR/MWh el	[74]
199 MW	heat - 77 electric - 31	1.18 of heat	17.6	3.1 EUR/MWhfuel	[68]
80 MWel 195 MWheat	electric - 31 total - 106	3.23 of electric	55	2.3 EUR/MWhfuel	[63]
479 MW	electric - 34 total - 110	1.3 of electric	2 EUR/MWhfuel	2.6 EUR/MWhfuel	[67]

Table 8. Investment and O&M costs for HP

Heat output	COP	Investment costs (MEUR/MW)	Fixed O&M cost (EUR/kW)	Variable O&M cost	Reference
1 MW	3.2	0.51	4.2 EUR/kW		[31]
3 MW	3.2	0.67	5.9 EUR/kW		[31]

5 MW	3.2	0.79	7.3 EUR/kW		[31]
5 MW	3.3	0.7	7.0 EUR/kW		[69]
10 MW	3.2	0.6	0.5	0.7 EUR/MWhfuel	[67]
10 MW	2.8	0.52	3.7	0.2 EUR/MWhfuel	[6]
11.2 MW	3.0	0.21	8.9 EUR/kW		[75]

Table 9. Investment and O&M costs for electric boiler

Technology	Efficiency (%)	Investment costs (MEUR/MW)	Fixed O&M cost (EUR/kW)	Variable O&M cost	Reference
1 - 3 MW	electric - 99	0.14	1.1	0.5 EUR/MWh	[31]
10 MW	electric - 99	0.08	1.1	0.5 EUR/MWh	[31]
20 MW	electric - 99	0.06	1.1	0.5 EUR/MWh	[31]

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